RIIO T1 nationalgrid

Annex A – Buybacks/ Constraint Management

National Grid
Gas Transmission

May 2012

Target audience

All Stakeholders

About this annex

This annex sets out the updated analysis which has been undertaken to inform our proposals concerning the constraint management scheme to apply during the RIIO-T1 period.

Annex A - Buybacks / Constraint Management

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How to use this annex

1 In the Buybacks/Constraint Management section of our 'Managing Risk and Uncertainty' Annex submitted as part of our March 2012 RIIO-T1 business plan submission we detailed the results from the preliminary analysis that we had undertaken to quantify constraint management risk over the RIIO-T1 period. We also suggested that we should revisit this analysis and provide further details in our May 2012 SO external incentives submission.

2 This Annex has been written to provide that further detail and therefore builds on the information contained within the March submission. For ease and completeness, a copy of the relevant details from our March submission has been included as Addendum 1 to this Annex so that readers can refer back to it if necessary.

3 We begin by including an overview, then a section outlining the changes and further details proposed in this May submission and conclude by outlining our proposals for the constraint management scheme over the RIIO-T1 period. Our updated constraint forecasting assumptions are included as Addendum 2.

Overview

4 The workings of the existing capacity regime leave us with an inherent level of constraint risk on the system to manage. The current regulatory and commercial frameworks oblige us on every day of the year to release obligated levels of capacity significantly in excess of peak demand at both entry and exit. Flows of gas commensurate with these levels of capacity cannot occur concurrently, so we take a view of the likely combinations of supply and demand patterns we could experience and an assessment of the most efficient solution to meet customer capacity requirements (consider the rules, tools and asset options available to us).

5 In the instances where we believe we cannot accommodate a user's flow requirements associated with booked capacity, we undertake constraint management actions in accordance with the Uniform Network Code (UNC) and System Management Principles Statement[1].

6 There will be challenges going forward over the RIIO-T1 period driven by increased requirements for system access, driven by maintenance, Asset Health investment, statutory work (such as to comply with requirements under the Dangerous Substances and Explosive Atmospheres Regulations (DSEAR) and Industrial Emissions Directive (IED)), and construction activities relating to the provision of incremental capacity or Network Flexibility being envisaged. We propose to address each of these areas separately.

7 Our main focus has been on articulating the level of inherent risk which exists on the system and to that end we provide our current view of the quantification of this inherent level of constraint management risk.

8 In this document, we consider the impact that the levels of required system access identified within the RIIO-T1 business plan (in terms of both the more traditional Asset Health type work and the increased level of work due to environmental legislation, such as under IED) will mean for forecast constraint management costs and present our findings in this area.

9 We also note the effects of the potential levels of incremental spend which could be seen on the system due to either changes in the use of existing capacity (Network Flexibility) or requests for additional capacity (Incremental Entry and Exit). Furthermore, we note the potential for material consequences on the constraint risk profile driven by European-led change (such as the Nomination rules under the EU Balancing code). Given the uncertainty surrounding all these requirements into the future, we propose that it is not reasonable to try to set ex-ante allowances to deal with these elements and that the effects on constraint costs should be explicitly considered as part of the relevant uncertainty mechanisms.

10 We have engaged with our stakeholders about our proposed incentives in relation to capacity management. The results of our stakeholder engagement have informed our thinking and helped us to develop our proposals for inclusion in this document. We will continue further engagement with

[1] For details, see http://www.nationalgrid.com/uk/Gas/OperationalInfo/operationaldocuments/ProcurementSystemManagementServicesStatementsReports/doc_req_by_SCC8D/Stmt_Ent_Cap_Const_MGMT

stakeholders over the coming months in relation to the capacity regime and in line with our proposals for how uncertainty mechanisms will apply over the RIIO-T1 period. Whenever an uncertainty mechanism (such as in relation to the provision of incremental capacity) is triggered, a consultation will take place providing details of our preferred solution[2]. Therefore consultation relating to the appropriate constraint management target will be an ongoing process.

11 The main changes between our March 2012 RIIO-T1 business plan and this document are:

(a) We have decided not to pursue the introduction of 'maintenance days' for entry as we do not feel there is enough evidence to support these being introduced and stakeholders were generally not supportive of this proposal, but do consider that this should be kept under review during the RIIO-T1 period.

(b) We have updated the analysis in order to provide parameters for the relevant incentive schemes by carrying out analysis of additional years within the RIIO-T1 period and by considering the effects of unplanned maintenance on the forecast level of constraint risk over the RIIO-T1 period.

Proposed scheme for constraint management

Structure

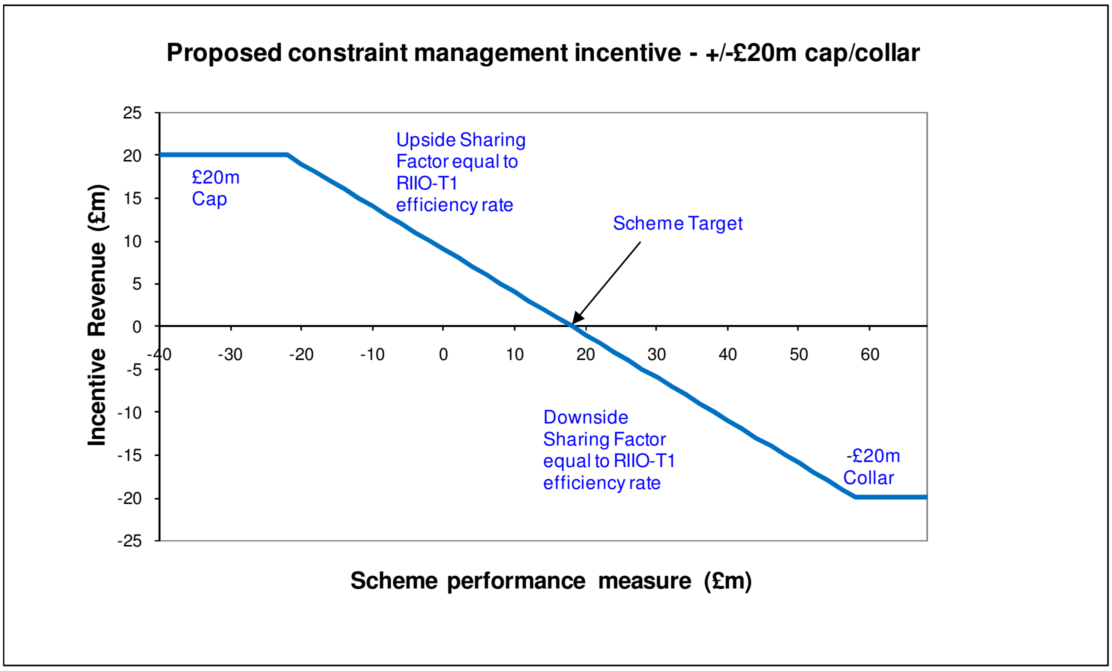
12 In line with our March 2012 RIIO-T1 business plan, we propose that the constraint management scheme should retain the same structure as the existing operational entry capacity buyback scheme, i.e. it should be a simple sliding scale incentive with an annual target, upside and downside sharing factors and a cap/collar. The scheme will include both costs and revenues associated with entry capacity and exit capacity (both operational and investment).

13 The performance measure for the scheme is the net position of the relevant costs to be included in the scheme less the relevant revenue terms, as indicated below:

Constraint Management Performance Measure = Relevant Costs - Relevant Revenues

14 The following illustrates how the scheme would operate in each year (based on the parameters suggested for the first year of the RIIO-T1 period):

[2] In this case, our preferred solution will be based on the economic assessment of investment, commercial solutions or risk management as per the "Generic Revenue Driver Methodology" which itself will be subject to consultation.



15 Within our March 2012 RIIO-T1 business plan submission, we suggested that the target for the scheme should take account of four distinct categories of constraint management costs[3], and therefore be calculated as follows:

Constraint management target = Ex-ante operational constraints + Ex-ante investment constraints + Incremental operational constraints + Incremental investment constraints

16 The 'Ex-ante' terms in the equation above are linked to the investments within the RIIO-T1 business plan for which we have asked funding to be provided as part of the settlement, whereas the 'Incremental' terms relate to the relevant uncertainty mechanisms. Within our analysis, we have assumed that the two incremental categories above are zero (as the uncertainty mechanisms are not yet in place) and therefore we would expect that the target will change over time as and when the uncertainty mechanisms are triggered. Hence our analysis has only considered the ex-ante terms above.

Proposed parameters

17 Our proposed scheme parameters (ex-ante target level, sharing factors and caps/collars) for the elements of the constraint management scheme in each year are as outlined in the table below:

[3] For further details see paragraphs 70 to 77 of the 'Buybacks/Constraint Management' section of our 'Managing Risk and Uncertainty' annex of the March 2012 submission, which for completeness, is attached as 'Addendum 1' to this annex.

	Annual constraint management scheme parameters (09/10 prices)							
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Collar (£m)	-20	-20	-20	-20	-20	-20	-20	-20
Cap (£m)	20	20	20	20	20	20	20	20
Target (£m)	**17.9**	**24.5**	**21.1**	**27.1**	**21.6**	**18.5**	**56.7**	**24.3**
Sharing factors	RIIO-T1 efficiency rate 40%-50%							

18 As noted above, as we expect that the impacts of potential incremental capacity release would be considered by the application of the relevant uncertainty mechanism, we have not factored this into this analysis. We recognise, however, that before start of the RIIO-T1 period, the July 2012 exit application window and the March 2013 QSEC auction could result in incremental capacity release which could lead to incremental constraint risk.

19 Within our 'Delivering connections and capacity' annex, we suggest that the existing arrangements could be amended[4] to cover the interim period until such time as the proposed change to the commercial regime in relation to connection and capacity processes may be implemented via the UNC governance process. If accepted, this change would also apply for the rollover year and therefore mitigates some of the risks which relate to capacity release obligations within the March 2013 QSEC auction.

Scheme length

20 If our proposed approach to mitigating the risks associated with the March 2013 QSEC auction were to be agreed, we could set all the parameters of this scheme (including the target) for the first four years of the RIIO-T1 control period with the expectation that it would be subject to the mid-period review.

21 If this were not to be the case, due to the risks posed by the current arrangements concerning the March 2013 QSEC auction, we would propose that the target level for the scheme is only set for the first three years of the RIIO-T1 period as we would need to factor in potential risks from October 2016 onwards.

Proposed scheme for transmission support services

22 We propose that there should be a separate incentive scheme to cover Transmission Support Services (TSS)[5] (which are defined in our Safety Case as a substitute for pipeline capacity at high demands to support a 1 in 20 peak day). We currently have two different forms of TSS available to us; contracts under the Long Run Contracting Incentive and Constrained LNG (CLNG).

23 We therefore propose that the existing exit schemes entitled 'Long Run Contracting incentive' and 'Constrained LNG incentive' are merged to create a combined scheme in the RIIO-T1 period. This incentive should continue until

[4] Via either the revision of the existing permits scheme or by modification of the relevant methodology statements relating to the release of capacity
[5] For details, see the 'Provision of Operating Margins and Constrained LNG for the South West' section of the 'Detailed plan' annex

the pipeline solution has been delivered to replace the Avonmouth LNG storage facility (proposed to be delivered in October 2018).

24 This is consistent with our proposal that an ex-ante allowance within the TO control should be provided to fund these investments. If this were not the case, then we would need this incentive to carry on into the RIIO-T1 period.

25 As outlined within our 'Detailed Plan' annex of the March 2012 submission, we propose the following Transmission Support Services (TSS) annual target:

Incentive scheme	£m (09/10 prices)	Sharing factor
CLNG	3.33 (2012/13 annual target)	100%
Long Run Contracting Incentive	3.90 (annual target starting Oct 2012)	50%
Proposed TSS annual target	**7.23** **(RIIO-T1 period annual target)**	**RIIO-T1 efficiency rate 40%-50%**

May 2012 Update

Introduction

26 Since our March 2012 RIIO-T1 business plan submission ('our March submission'), we have updated our assumptions and modelling in order to evolve our strategy in relation to constraint management and buybacks, taking into account the views expressed by our stakeholders. The results of our updated modelling, along with our proposals for a constraint management incentive scheme, are outlined below. We have looked at the inherent level of risk on the system along with incremental risk introduced by maintenance, system access and unplanned outages.

27 We continue to believe that the change to the level of risk on the system which relate to the future investment decisions made by our TO business should be dealt with through the appropriate uncertainty mechanisms as the level of uncertainty surrounding them makes it unreasonable for this to be factored into ex ante funding. As outlined in our March 2012 submission, we therefore consider that an appropriate adjustment must be made to the constraint management target whenever the relevant uncertainty mechanism has been triggered for calculation.

Overview of stakeholder feedback

28 Stakeholders have commented on our initial thoughts in relation to constraint management both through their responses to our March 2012 RIIO-T1 business plan and through our May 2012 stakeholder engagement consultation.

29 Stakeholders who responded to the May stakeholder engagement consultation were supportive of the principle of the SO incentive targets changing to reflect the application of the TO uncertainty mechanisms:

"The TO uncertainty mechanism should have an impact on the capacity constraint management incentive and so it appears appropriate to update the targets to reflect any developments as a result of the TO uncertainty mechanism."

EdF Energy, May 2012 stakeholder engagement consultation response

30 We have therefore continued with this approach of reflecting the impact of triggered TO uncertainty mechanisms in our SO constraint management incentive target.

31 In relation to the constraint management incentive itself, most stakeholders were not supportive of our approach of combining the entry and exit schemes:

"We do not support the bundling of exit and entry buy-back costs and do not understand the rational for change."

E.On, May 2012 stakeholder engagement consultation response

32 In particular stakeholders were concerned about the effect this would have on our behaviour in relation to constraints:

"The act of combining will lead to the loss of targeted incentives on exit and entry which affect different customer groups and interests."

SSE, May 2012 stakeholder engagement consultation response

33 Although it appears that some stakeholders may have understood the rationale for our proposals:

"There could be merits in combining the entry and exit incentives into one scheme as this may lead to a wider consideration of options to address a constraint."

Energy UK, April 2012 Comments on National Grid Gas' Business Plan

34 We note the views which stakeholders have expressed regarding National Grid Gas (NGG) reducing its risk if exit is included within a single constraint management scheme. We do not, however, agree with this as:

- There are several schemes within the licence which cover the arrangements regarding exit capacity constraint costs as outlined in paragraphs 109 to 112 of the 'Managing Risk and Uncertainty' annex of our March submission.

- These arrangements provide for different sharing of costs between NGG and its Users. For example certain types of exit constraint costs are allowed to be fully passed through to Users[6], whereas other costs are fully borne by NGG.

35 Clearly the risks which we face under the existing arrangements will depend on the mix of the different types of exit constraint management cost faced. As the enduring exit regime is not yet operational, it is difficult to state definitively whether the risk balance has changed from our existing incentive arrangements to those being proposed as part of the RIIO-T1 submission. We do however consider that it is not clear that our proposals do result in a lower risk position.

36 We consider that equalisation of the treatment of all constraint costs irrespective of whether they relate to entry or exit will ensure that the incentive treatment does not lead to any perversions or distortions of the appropriate trade-offs between actions which could be taken by the control room. Treating all constraint management costs in an equitable manner is consistent with the underlying RIIO-T1 principles regarding ensuring that efficient trade offs occur (such as the Totex approach, equalisation of efficiency rates where appropriate). Additionally, including a single scheme which covers entry and exit capacity constraint management will allow the licence to be simplified such that there is more clarity and transparency over the resultant incentive arrangements.

37 For these reasons, we continue to believe that the scheme should be designed to cover both entry and exit.

[6] These are contained within the licence term $ExBBCNLR_t$

38 Finally, specifically in relation to the price we have used in our modelling assumptions, stakeholder views centred on the difficulty of setting a price for an 8 year control period:

"Defining a single price over a long period is clearly a major challenge."

E.On, May 2012 stakeholder engagement consultation response

39 However some stakeholders did note that, taking into account the above point, our assumptions seem appropriate:

"We acknowledge that some assumptions on price need to be made [and] to that extent these prices may be reasonable but the circumstances of each constraint action are likely to be different and lead to different outcomes. The values seem broadly reasonable, but may change significantly over an eight year time period."

Energy UK, May 2012 stakeholder engagement consultation response

40 We have therefore continued to apply the same pricing assumption principles as used in the March submission, updating them to provide more detail on the assumptions we have made in relation to exit. However, we recognise that setting a price for the whole of the RIIO-T1 period is challenging and therefore we are not proposing to set the parameters of the scheme for the whole eight year period.

Changes to the March proposals

41 We have given further thought to the introduction of 'maintenance days' on entry. When asked about the concept of maintenance days applying at entry points, stakeholders expressed a variety of opinions.

"We are a little confused by this proposal since maintenance days already apply at Burton Point, which is an entry point."

E.On, May 2012 stakeholder engagement consultation response

42 The above point was raised by two stakeholders, however we would like to clarify that the maintenance days at Burton Point only apply to the Burton Point exit point and consequently can not be used in relation to entry capacity.

43 One stakeholder was supportive of the concept of maintenance days on entry:

"SSE agree that maintenance days for entry points should be developed further."

SSE, May 2012 stakeholder engagement consultation response

44 Other stakeholders, however, were concerned about the complexity that this change would introduce:

"It seems an entry maintenance day would not require cessation of flows as required at exit, rather management of flows. This could be complex to apply at multi-shipper entry points, further consideration of this is required. We would

have concerns if this led to a wide ranging review of maintenance days already agreed in NExAs."

Energy UK, May 2012 stakeholder engagement consultation response

45 At the current time we do not consider there is enough evidence to support these being introduced, but propose that this should be kept under review during the RIIO-T1 period. Additionally, following stakeholder feedback (which was not supportive of this proposal if the introduction of entry maintenance days would lead to additional complexity) we are no longer suggesting that these should be introduced at this time.

46 We do, however, continue to feel that an incentive on maintenance activities should be developed and the proposals surrounding this are contained in the main May SO external incentives plan.

Further analysis

Consideration of additional years

47 We have carried out further analysis to investigate both the likely occurrences of constraints on the system and the associated volumes. In our March submission we provided details based on analysis of two formula years; 2012/13 and 2020/21. We have now considered three further formula years; 2014/15, 2016/17 and 2018/19[7] and have used the results from this analysis to inform the level of potential constraints over the RIIO-T1 period, such that each forecast is then used for 2 years, i.e. the 2014/15 network has been used when modelling 2013/14 as well as 2014/15, 2016/17 has been used when modelling 2015/16 as well as 2016/17 and so on (as described further in Addendum 2).

Consideration of unplanned maintenance

48 In the March submission, we provided initial analysis of the impact of the IED (LCP and IPPC)[8] replacement programme within the TO plan on potential constraints over the RIIO-T1 period. In March we had suggested that 'maintenance days' should be introduced at entry to help manage any constraints, however, following stakeholder feedback we have now decided not to pursue that at this point in time.

49 We have therefore refined our analysis in light of the updated supply and demand patterns for the intervening years and have also undertaken further analysis of the effects of unplanned compressor outages on the system. Additionally, we have investigated the effects of planned maintenance on the system (such as feature inspections resulting from pipeline inspection).

50 This has enabled us to build up a picture of the risks on the system[9] by considering each of these three elements in term as described below:

[7] Note due to time constraints, we were not able to consider supply/demand patterns for all the years of the RIIO-T1 period, but believe that analysis over each second year (with that analysis applying for two years) is reasonable.
[8] Industrial Emissions Directive (IED – directive 2010/75/EU), Integrated Pollution Prevention and Control (IPPC) and Large Combustion Plant (LCP)
[9] Note that the modelling is still limited to end of day flow patterns so does not consider the within day transient flows on the system.

- Intact network – this part of the model assumes an intact system (i.e. no planned/unplanned outages) and uses the methodology described within the March submission

- Compressor outages – this part of the model builds on the IED/IPPC compressor replacement (which is funded on an ex-ante basis) impact described in the March submission, but now also includes the impact of unplanned compressor outages[10]

- Pipeline impact – this part of the model forecasts the impact of feature inspections resulting from inline inspections (ILIs)[11] on the entry/exit capabilities of the system.

51 Additionally, the capability modelling within the model has been updated to include the effects of the *[text deleted]* pipelines *[text deleted]* that have been proposed to replace the Avonmouth LNG facility from October 2018. This leads to a reduction in our forecast level of risk from that point onwards and is consistent with our proposal that an ex-ante allowance within the TO control should be provided to fund these investments. If this were not to be the case, then we would need to revisit the analysis to reflect this from 2017/18 onwards.

Refined costing assumptions

52 As noted within our March submission, constraints identified by the model can be resolved via a combination of actions, either at entry or exit. Where possible we have chosen to resolve constraints in our modelling at entry as this allows us to use established methods to calculate volumes and costs. We have, however, also updated the costing assumptions within the model relating to exit capacity constraints.

53 At entry points the current choices are between buybacks (prompts, forwards or options) or locational actions and clearly this affects the costs that the model produces. In March we considered three potential methods of costing the constraints identified:

(a) Case 1: an assumption that 100% of the constraints identified are resolved by buyback actions and that the price of these is 1p/kWh[12;]

(b) Case 2: an assumption that 25% of the constraints identified are resolved by locational sell actions[13] and 75% buyback actions (again using the price of 1p/kWh).

(c) Case 3: an assumption that 50% of the constraints identified are resolved by locational sell actions (but again that only 50% of these

[10] Note that if the scheduling of the IED replacement programme is materially changed, we would need to review our analysis.

[11] An inline inspection (ILI) is a method of testing the integrity of given sections of pipe. This is undertaken using a series of tests performed by PIGs (Pipeline Inspection Gauges) which are passed through the pipe. The pipe data is recorded as the PIG passes through the pipe and this data is analysed after the event to determine the state of the pipe.

[12] This price assumption is based on previous experience of buyback actions. It also allows the resultant costs to be easily scaled if other price assumptions are used.

[13] Note that Locational Sell actions may result in a revenue into both Entry Capacity Neutrality and the current operational Buyback scheme, however this may be negated by costs relating to any corresponding locational buys to keep the system in balance. In this modelling, we have assumed that only 50% of the locational sell actions need a corresponding locational buy action. The Locational actions have been priced relative to an assumption for SAP of 50p/th (1.71 p/kWh).

actions also require a corresponding locational buy) and 50% buyback actions (again using the price of 1p/kWh).

54 In March we proposed using the Case 3 costing assumption and we continue to feel that this is an appropriate working assumption for determining the constraint management cost target absent further evidence from the market. However, we have updated the price assumption for System Average Price (SAP)[14] to 58p/therm (from 50p/therm used in the March submission) to be consistent with more recent market information and that used in the modelling of SO costs for NGET.

55 In view of the additional analysis regarding constraint volumes due to the impact of feature inspections (as described in paragraph 50 above), we have built in pricing assumptions relating to exit constraints. These assumptions are presented in our updated entry and exit constraint forecasting methodology (Addendum 2). We have used different pricing assumptions for CCGTs and for industrial connections. Note that within our modelling, we have not included any specific analysis relating to constraints being resolved at DN offtakes as we would expect the costs to resolve such constraints to be broadly equivalent based on the DN needing to enter into contracts with its Users in order to offer such services to NGG. As the enduring exit regime becomes operational, we may gain further information regarding this assumption and therefore would expect to revisit our analysis if this is the case.

Revenue modelling

56 As noted in paragraphs 190 to 195 of the 'Managing Risk and Uncertainty' annex of our March submission, it is important to also consider the level of revenue which could be expected to be included within the capacity constraint management scheme over the RIIO-T1 period as the performance measure for the scheme is the net position of cost less revenue.

57 The following table provides a summary of the revenues which have been included within the entry capacity operational buyback scheme over the last five years:

	Formula year				
	2007/8	2008/9	2009/10	2010/11	2011/12
Within day Firm	0.84	0.08	0.11	0.14	0.06
Interruptible[15]	1.04	0.37	0.44	0.32	0.23
Non-obligated	0.08	4.41	0.12	0.71	0.86
Overruns[16]	1.66	0.82	0.82	5.29	0.21
Locational Sells	0.00	0.00	0.00	2.35	1.19
Total	**3.61**	**5.69**	**1.49**	**8.80**	**2.55**

[14] As defined within Section F1.2.1(c) of the UNC TPD
[15] Note that within our modelling, we have assumed that the revenues associated with interruptible entry capacity (and in the future NTS off-peak exit capacity) are included within the constraint management scheme. However, we note that if an incentive were to be introduced relating to the scaling back of capacity, this assumption may need to be revisited.
[16] Note that the revenues from overruns relate to Shippers flowing gas without having associated capacity rights. These revenues are therefore completely outside our control.

58 The figure above clearly shows that the various revenues have been variable over the last few years and therefore it is difficult to forecast the likely level of revenues which may be experienced going forwards.

59 Given that the new arrangements surrounding exit capacity do not begin until October 2012, we have limited information regarding the potential level of exit revenues to expect. To date we have sold some NTS non-obligated incremental exit flat capacity for the 2012/13 formula year with a value of £0.216m.

60 Given the uncertainty in this area and the impact this has on our ability to forecast revenues going forwards, in order to model the potential level of revenues, we have assumed a distribution around the mean level of revenues experienced to date (based on the mean, minimum and maximum values of the data in the table above). This results in our expected levels of revenue having a distribution as per the following table:

	Forecast level of revenues (£m)
Minimum	0.6
Maximum	12.7
Mean	**3.3**
10%	1.6
50%	3.0
90%	4.9
Std Dev	**1.7**
2.5%	0.8
97.5%	8.0

61 This distribution has been used for each year of the RIIO-T1 period.

Updated modelling results

62 This additional analysis has enabled us to provide a more refined view of the inherent level of risk over the RIIO-T1 period. We begin by providing an updated view of the potential range of the underlying constraint management risk for the 2014/15 to 2020/21 formula years. It should be noted that this modelling is based on the particular range of supply/demand scenarios considered (see paragraph 47 for more details), end of day flow patterns and takes no account of any plant failure or maintenance activities.

Results for the 2014/15 to 2020/21 formula years (intact network)

63 Our updated view of the potential level of the underlying constraint management risk volume[17] and forecast number of constraint days for the 2014/15, 2016/17, 2018/19 and 2020/21 formula years (as per the updated supply/demand assumptions for these years) is as per the following two tables:

[17] Note that the volume is based on needing to buy-back up to the obligated levels of capacity.

	2014/15			2016/17		
	Forecast number of constraint days	Volume (mcm)	Volume (GWh)	Forecast number of constraint days	Volume (mcm)	Volume (GWh)
Minimum	0	0	0	0	0	0
Maximum	83	1422	15400	76	1337	14480
Mean	**9**	**131**	**1421**	**10**	**143**	**1546**
10%	2	22	234	2	26	282
50%	6	87	946	7	97	1046
90%	21	305	3299	21	311	3371
Std Dev	**9**	**137**	**1487**	**10**	**148**	**1605**
2.5%	0	0	0	1	6	60
97.5%	34	512	5545	38	579	6275

	2018/19			2020/21		
	Forecast number of constraint days	Volume (mcm)	Volume (GWh)	Forecast number of constraint days	Volume (mcm)	Volume (GWh)
Minimum	0	0	0	0	0	0
Maximum	91	896	9700	109	1441	15608
Mean	**10**	**105**	**1136**	**12**	**132**	**1435**
10%	3	26	279	3	34	372
50%	7	77	833	9	98	1067
90%	20	215	2329	25	261	2829
Std Dev	**9**	**96**	**1043**	**11**	**123**	**1335**
2.5%	1	10	110	1	13	140
97.5%	34	380	4117	43	443	4793

64 The figures above show that, for the:

(a) 2014/15 formula year there is an expectation of 9 days within the year when constraints would occur (in the range 2 to 21 with 80% confidence) and that the expected constraint volume within the year would be 131 mcm or 1421 GWh (i.e. 158 GWh/d on average)

(b) 2016/17 formula year there is an expectation of 10 days within the year when constraints would occur (in the range 2 to 21 days with 80% confidence) and that the expected constraint volume within the year would be 143 mcm or 1546 GWh (i.e. 159 GWh/d on average)

(c) 2018/19 formula year there is an expectation of 10 days within the year when constraints would occur (in the range 3 to 20 days with 80% confidence) and that the expected constraint volume within the year would be 105 mcm or 1136 GWh (i.e. 116 GWh/d on average). Note that the reduction in volume is primarily due to the assumption that there is extra capability in the south west due to the additional pipelines to replace Avonmouth being included

(d) 2020/21 formula year there is an expectation of 12 days within the year when constraints would occur (in the range 3 to 25 days with 80%

confidence) and that the expected constraint volume within the year would be 132 mcm or 1435 GWh (i.e. 117 GWh/d on average). Note that the increase in volume from 2018/19 is due to 2 more constraint days being forecast.

65 Comparing these results back to the analysis included within the 'Managing Risk and Uncertainty' annex of our March submission (the tables included within paragraphs 157 for the 2012/13 formula year and 162 for the 2020/21 formula year), there is a step up in the forecast level of constraint days from 2012/13 to 2014/15, primarily driven by the change in supply/demand patterns. Note that the number of forecast constraint days is largely unchanged from the 2020/21 case. However, the expected daily constraint volume is lower for the 2018/19 and 2020/21 formula years due to the addition of the extra pipelines to replace Avonmouth. As noted within paragraph 51 if the funding for these pipelines is not provided, this assumption of a reduction in risk would no longer be valid.

Results for the 2014/15 to 2020/21 formula years (intact network and compressor outages)

66 Building on the analysis previously undertaken to investigate the effect of the aggressive schedule of work to respond to the IED legislation and based on stakeholder challenge and our subsequent decision not to pursue the inclusion of 'maintenance days' at entry, we have updated the analysis to consider further years in the RIIO-T1 period and to also take account of unplanned compressor outages.

67 Our updated view of the potential level of the constraint management risk volume and forecast number of constraint days covering the inherent risk on the system plus the planned and unplanned compressor maintenance for the 2014/15, 2016/17, 2018/19 and 2020/21 formula years is as per the following two tables:

	2014/15			2016/17		
	Forecast number of constraint days	Volume (mcm)	Volume (GWh)	Forecast number of constraint days	Volume (mcm)	Volume (GWh)
Minimum	0	0	0	0	0	0
Maximum	85	1514	16396	80	1504	16284
Mean	**12**	**285**	**3089**	**14**	**339**	**3671**
10%	4	115	1244	6	153	1655
50%	10	252	2733	11	307	3320
90%	25	500	5412	26	568	6149
Std Dev	**9**	**165**	**1789**	**10**	**181**	**1955**
2.5%	3	70	763	4	94	1022
97.5%	37	704	7629	43	809	8759

	2018/19			2020/21		
	Forecast number of constraint days	Volume (mcm)	Volume (GWh)	Forecast number of constraint days	Volume (mcm)	Volume (GWh)
Minimum	1	9	95	2	31	331
Maximum	98	1082	11713	115	1675	18138
Mean	**14**	**284**	**3074**	**19**	**410**	**4439**
10%	7	143	1553	9	230	2492
50%	12	263	2851	16	389	4209
90%	25	447	4845	32	600	6500
Std Dev	**9**	**129**	**1396**	**11**	**164**	**1772**
2.5%	4	88	953	6	163	1760
97.5%	40	604	6546	50	802	8687

68 The figures above show that, for the:

(a) 2014/15 formula year there is an expectation of 12 days within the year when constraints would occur (in the range 4 to 25 with 80% confidence) and that the expected constraint volume within the year would be 285 mcm or 3089 GWh (i.e. 249 GWh/d on average)

(b) 2016/17 formula year there is an expectation of 14 days within the year when constraints would occur (in the range 6 to 26 days with 80% confidence) and that the expected constraint volume within the year would be 339 mcm or 3671 GWh (i.e. 260 GWh/d on average)

(c) 2018/19 formula year there is an expectation of 14 days within the year when constraints would occur (in the range 7 to 25 days with 80% confidence) and that the expected constraint volume within the year would be 284 mcm or 3074 GWh (i.e. 213 GWh/d on average)

(d) 2020/21 formula year there is an expectation of 19 days within the year when constraints would occur (in the range 9 to 32 days with 80% confidence) and that the expected constraint volume within the year would be 410 mcm or 4439 GWh (i.e. 236 GWh/d on average). The increase in the volume and number of days forecast this year is primarily due to the assumptions *[text deleted]*.

69 Unsurprisingly, comparing these results to those for the intact network (paragraphs 63 to 65), the addition of the compressor outages increases both the likelihood of constraints happening (i.e. there are more constraint days being forecast) and the volume of constraint that would be forecast to occur.

Results for the 2014/15 to 2020/21 formula years (intact network, compressor outages and pipeline impact)

70 Building on the previous analysis we have included the effects of feature inspections following inline inspections on the forecast level of constraints[18].

[18] Note we assume that the existing 'maintenance days' on exit would be used to cover the ILI runs themselves. The modelling covers the additional system access which would be needed to cover the feature inspections and any resultant work on the system which could follow.

71 Our updated view of the potential level of the constraint management risk volume and forecast number of constraint days covering the inherent risk on the system plus the planned and unplanned compressor maintenance and effects of feature inspections for the 2014/15, 2016/17, 2018/19 and 2020/21 formula years is as per the following two tables:

	2014/15			2016/17		
	Forecast number of constraint days	Volume (mcm)	Volume (GWh)	Forecast number of constraint days	Volume (mcm)	Volume (GWh)
Minimum	0	0	0	0	0	0
Maximum	85	1514	16396	80	1504	16284
Mean	**13**	**287**	**3111**	**14**	**341**	**3692**
10%	4	115	1247	6	154	1667
50%	10	253	2739	11	309	3348
90%	25	505	5467	26	570	6171
Std Dev	**9**	**166**	**1802**	**10**	**181**	**1964**
2.5%	3	71	769	4	94	1022
97.5%	37	709	7673	43	810	8775

	2018/19			2020/21		
	Forecast number of constraint days	Volume (mcm)	Volume (GWh)	Forecast number of constraint days	Volume (mcm)	Volume (GWh)
Minimum	1	9	95	2	31	331
Maximum	98	1082	11713	115	1675	18138
Mean	**14**	**286**	**3092**	**19**	**410**	**4439**
10%	7	144	1554	9	230	2492
50%	12	264	2863	16	389	4209
90%	25	448	4849	32	600	6500
Std Dev	**9**	**130**	**1408**	**11**	**164**	**1772**
2.5%	4	90	971	6	163	1760
97.5%	40	607	6574	50	802	8687

72 The figures above show that, for the:

(a) 2014/15 formula year there is an expectation of 13 days within the year when constraints would occur (in the range 4 to 25 with 80% confidence) and that the expected constraint volume within the year would be 287 mcm or 3111 GWh

(b) 2016/17 formula year there is an expectation of 14 days within the year when constraints would occur (in the range 6 to 26 days with 80% confidence) and that the expected constraint volume within the year would be 341 mcm or 3692 GWh

(c) 2018/19 formula year there is an expectation of 14 days within the year when constraints would occur (in the range 6 to 25 days with 80%

confidence) and that the expected constraint volume within the year would be 286 mcm or 3092 GWh

(d) 2020/21 formula year there is an expectation of 19 days within the year when constraints would occur (in the range 9 to 32 days with 80% confidence) and that the expected constraint volume within the year would be 410 mcm or 4439 GWh.

73 Comparing these results to those for the intact network plus compressor outages (paragraphs 66 to 69), the addition of the pipeline inspection and expected subsequent feature resolution activity outages marginally increases both the likelihood of constraints happening (i.e. there are more constraint days being forecast) and the volume of constraint that would be forecast to occur.

74 The analysis presented in the sections above looks at the distribution of risk in terms of volume and number of days. In order to determine the appropriate parameters for the scheme, we need to convert this to a monetary value. We propose to continue to apply the Case 3 costing assumption discussed in paragraphs 52 to 55.

Proposed scheme performance measure

75 In line with our March 2012 RIIO-T1 business plan, we propose that the constraint management scheme should retain the same structure as the existing operational entry capacity buyback scheme, i.e. it should be a simple sliding scale incentive with an annual target, upside and downside sharing factors and a cap/collar. The scheme will include both costs and revenues associated with entry capacity and exit capacity (both operational and investment).

76 We propose that the performance measure for the scheme should be based on the existing operational entry capacity buyback scheme, i.e it should be the net position of the relevant costs less the relevant revenue term, as indicated below:

$$\text{Constraint Management Performance Measure} = \text{Relevant Costs} - \text{Relevant Revenues}$$

77 We believe that the following costs should be included within the Relevant Costs term above[19] (changes from the current arrangements are shown in blue italics):

- Costs relating to the buying back of entry *or exit capacity* (including the costs of forwards or options)
- *Costs relating to accepted offtake reduction offers*
- Costs relating to locational buy actions
- Costs relating to any turn-up or turn-down contracts

[19] Note that if further products are introduced within the UNC, these may also need to be reflected within the licence.

78 We believe that the revenues[20] from the following should be included within the Relevant Revenues term above:

- Sale of on-the-day firm entry capacity
- Sale of interruptible entry capacity
- *Sale of NTS off peak exit capacity*
- Sale of non-obligated incremental firm entry capacity
- *Sale of NTS non-obligated exit capacity*
- Overrun charges (both entry *and exit*)
- Locational sells
- Physical Renomination Incentive (PRI) charges
- *From specific Users overrunning and causing a cost at another exit point (as per the $ExBBNLR_t$ term currently within the licence)*

79 Therefore the performance measure should be the net of these two sets of terms, i.e. the Relevant Costs – Relevant Revenues. We will use the modelling outlined above to set the appropriate target for the scheme in each year.

Risks from the release of incremental capacity

80 No further analysis (beyond that carried out for the March submission and included in Addendum 1) has been done to consider the constraint management risks from new incremental capacity as no incremental capacity has been released as yet for the RIIO-T1 period which has necessitated investment on the system. Note that as outlined in our March submission (for details see paragraphs 68 to 77 in Addendum 1), we expect the constraint management target would be adjusted accordingly following the release of any incremental capacity. This principle is also contained within the Generic revenue driver methodology and details can be found in Addendum 3 of Annex B (Delivering connections and capacity).

81 Dependent on the outcome of the July 2012 exit application window and the March 2013 QSEC auction we may need to revisit this assumption. We suggest that the same principles should apply to the release of this incremental capacity as we are proposing for the RIIO-T1 period, i.e. that the constraint management target should be reviewed accordingly.

Results for proposed scheme performance measure for the 2014/15 to 2020/21 formula years (intact network, compressor outages and pipeline impact)

82 Using the volume analysis outlined above and the costing and revenue assumptions discussed in paragraphs 52 to 55, we have calculated our updated view of the performance measure for the constraint management scheme over the RIIO-T1 period. Note that for the 2013/14 formula year we have used the 2014/15 supply/demand assumptions and as discussed earlier

[20] Note that within our modelling, we have assumed that the revenues associated with interruptible entry capacity (and in the future NTS off-peak exit capacity) are included within the constraint management scheme. However, we note that if an incentive were to be introduced relating to the scaling back of capacity, this assumption may need to be revisited.

in paragraph 47 we have used the 2016/17 supply/demand assumptions as the basis for the analysis for 2016/17 and 2015/16, 2018/19 supply/demand assumptions as the basis for the analysis for 2017/18 and 2018/19 and so on.

83 As discussed above, we suggest that the performance measure for the scheme should be set equal to the costs less the revenues. We therefore present the results for the net position of cost less revenue from the modelling analysis in the following table:

	Total net buy-back performance measure (costs less revenues) (£m) - Case 3 costing[21]								
	2013/14	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**Total over RIIO-T1 period[22]**
Minimum	-46	-71	-64	-36	-17	-90	-6	-25	**-19**
Maximum	226	201	162	211	232	150	225	270	**536**
Mean	**14**	**20**	**17**	**23**	**17**	**14**	**53**	**20**	**178**
10%	0	2	2	6	6	2	29	5	**105**
50%	11	17	14	20	15	12	51	18	**170**
90%	29	40	34	42	29	28	77	35	**260**
Std Dev	**17**	**18**	**17**	**18**	**12**	**12**	**21**	**15**	**62**
2.5%	-5	-4	-4	-1	1	-3	20	0	**73**
97.5%	57	64	62	69	44	42	99	54	**317**

84 This table indicates that under the costing assumptions used within this analysis the year with the lowest expected cost less revenue is 2013/14, where the expected value would be £13.8m (with the 80% range between £0.8m to £28.6m). By contrast, the year with the highest expected cost less revenue is 2019/20, where the expected value would be £53.4m (with the 80% range between £29.3m to £77.1m). The reason that the costs are higher in the 2019/20 year is due to the impact of the outages of the Industrial Emissions Directive (IED) programme, *[text deleted].*

85 Comparing these results back to the analysis included within the 'Managing Risk and Uncertainty' annex of the March submission (the table in paragraph 184) and taking account of the revenue forecasting we have presented in paragraphs 52 to 55, our updated modelling has resulted in a reduced forecast for the level of costs to be expected over the RIIO-T1 period. This is due to the updated supply/demand assumptions, further consideration of the impact of the IED programme and the addition of the extra pipelines to replace Avonmouth. As noted within paragraph 51 if the funding for these pipelines is not provided, this assumption of a reduction in risk would no longer be valid.

Consideration of appropriate risk premium for the SO

86 As noted within paragraphs 399 to 403 of the 'Finance' annex of our March submission, consideration of the risks that we face within our SO business need to be appropriately accounted for. We noted that return on equity for the SO business on a standalone basis is inadequate (due to the small size of the

[21] See paragraph 146 for further details behind this costing assumption
[22] Note that the total over the period will not equal the sum of the individual years' statistics as it has been separately calculated for each simulation run

SO RAV) and we stated that there were two alternatives which could be considered:

(a) Provide for a net positive expected incentive outcome in the SO control

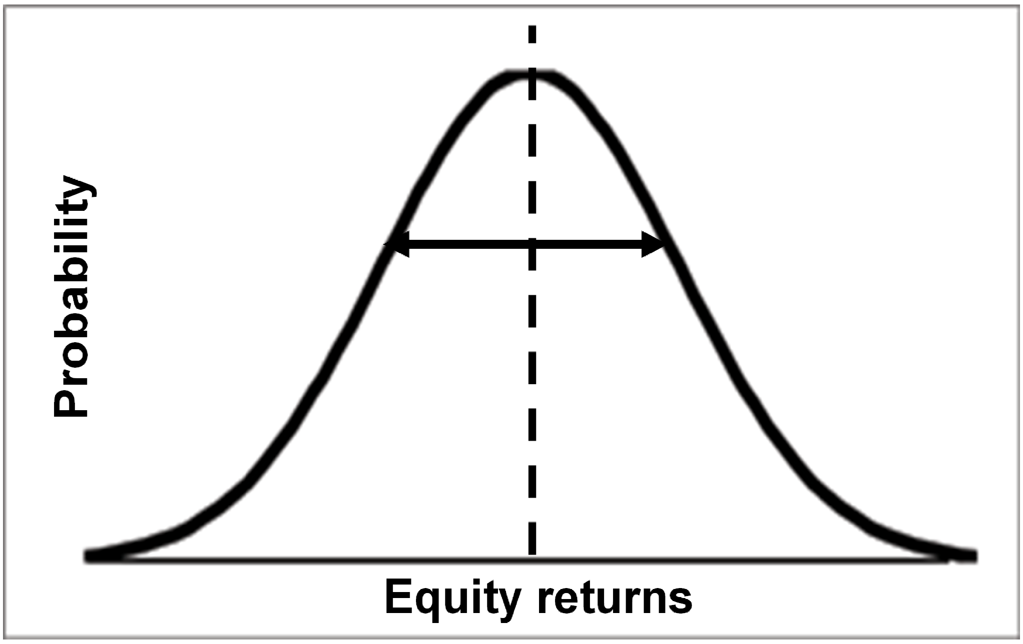
(b) Allow a premium to the TO cost of equity.

87 We do not believe that providing additional return via the TO control itself is an appropriate solution as this could result in a cross-subsidy between different classes of user. This is, however, an appropriate way of determining a value for the risk premium which the SO should receive commensurate with the level of risks from application of the various SO incentive schemes.

88 Risk can be defined as the variation in asset returns around expected asset returns, i.e. it is a measure of volatility. The Sharpe ratio can be used to compare two portfolios with different degrees of volatility to assess whether the risk-return trade off is appropriate. Within the March submission, we investigated the relationship between the required return on equity and variation in equity returns. We propose to use the same approach to determine the appropriate premium for the risks posed by the various SO incentive schemes.

Sharpe ratio

89 The cost of equity should be set to ensure an appropriate reward to compensate for the risks to equity holders. The narrower the dispersion in equity returns, the lower the justified premium over risk free rates. Dispersion is illustrated in the diagram below.



90 On the assumption that the RIIO-T1 TO control provides an appropriate risk / return package, it is possible to derive the return that would be appropriate for the SO control using the Sharpe ratio. Assuming the risk free rate to be constant, the risk / return balance is maintained if:

$$\frac{Return_{TO} - Return_{Risk\ free}}{\sigma_{TO}} = \frac{Return_{TO+SO} - Return_{Risk\ free}}{\sigma_{TO+SO}}$$

where σ represents the standard deviation of returns.

Translating the change in risk to a return

91 Once a particular initial SO incentive scheme design has been set, we apply the Sharpe ratio (as discussed above) to determine the impact of the incremental risk from that SO incentive scheme on the required return on equity. We calculate the incremental return relative to the TO control (which has been assumed to be commensurate with a 7.50% return on equity) and use the equity portion of the TO RAV to determine the annual monetary value for the appropriate risk premium that the increased level of risk from the SO scheme would imply. This should then be reflected in the setting of the parameters for the relevant SO incentive scheme such that the scheme provides for a net positive expected incentive outcome. In line with our 7.50% return on equity assumption for our TO control, we have assumed a risk free rate of 2.50% in this analysis[23].

92 We need to firstly determine the appropriate design for each incentive scheme so that we can calibrate the corresponding incremental return on equity required.

Proposed scheme design for constraint management

93 As noted in paragraph 75 to 79 we propose that the performance measure for the incentive scheme should be the net position of costs less revenues. We also propose that the incentive scheme should be set such that the sharing factors are aligned with the Totex incentive mechanism (TIM) efficiency rate which will be applied to opex and capex in the TO control. We have assumed 50% for the modelling results we present in this Annex, but have also looked at a sensitivity of a 40% sharing factor (as per the suggested range for the RIIO-T1 efficiency rate of 40% to 50%).

94 We have investigated the impact of different caps/collars on the expected incentive outcome and have used these results to calculate the appropriate risk premium which would be needed to reward the risks under the different incentive scheme parameters. The risk premium has then been factored into the resultant target levels to be suggested for the scheme.

Results from initial scheme design

95 Using the performance measure described above to set the target level (i.e. net cost less revenue from simulation run) and sharing factors described above, we initially investigated the incentive performance under a simple sliding scale incentive with no cap or collar. Unsurprisingly, this provides an annual expected performance under the scheme of zero (as the performance equals the target in each year).

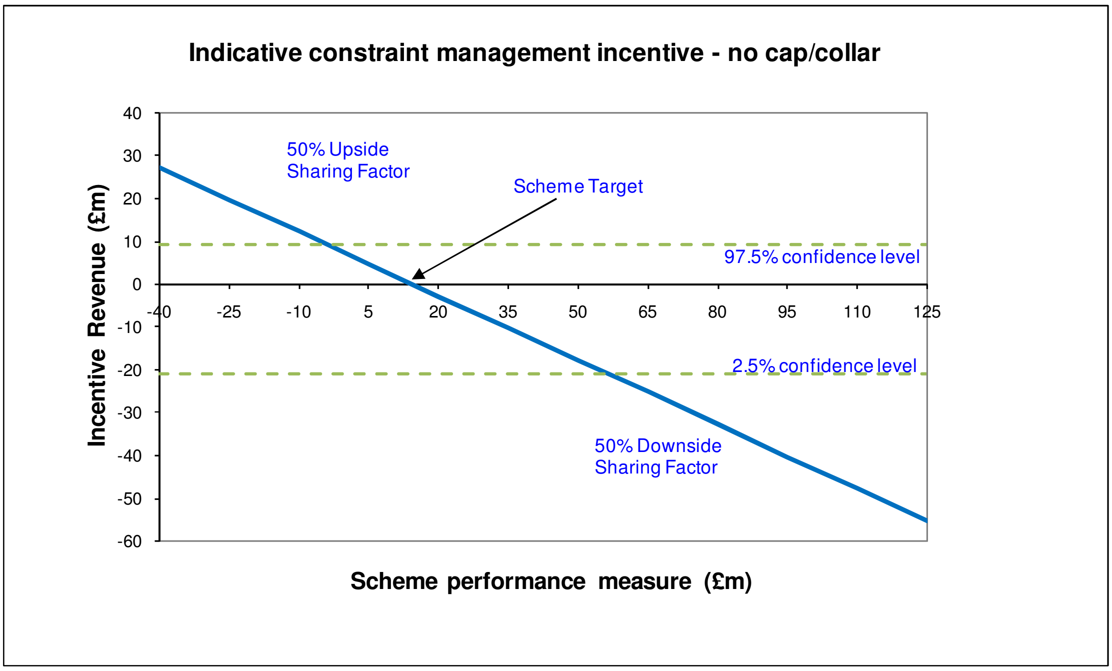
[23] Note that the results would be unchanged under an assumption of 7.00% rate of return commensurate with a 2.00% risk free rate

96 Statistics concerning the incentive performance under this scheme are shown in the following table:

	Incentive Revenue (£m) - Assuming 50% sharing factors, no cap/collar								
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total over RIIO-T1 period
Minimum	-97	-97	-120	-107	-88	-97	-84	-118	**-184**
Maximum	50	37	38	40	19	21	31	22	**88**
Mean	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
10%	-8	-10	-9	-9	-6	-7	-13	-8	**-41**
50%	2	1	2	2	1	1	1	1	**3**
90%	7	9	8	9	6	6	12	7	**38**
Std Dev	**8**	**9**	**9**	**9**	**6**	**6**	**10**	**8**	**32**
2.5%	-21	-23	-24	-22	-13	-15	-23	-18	**-72**
97.5%	9	12	10	12	8	8	17	10	**53**

97 The table shows that without a cap or collar the risk is asymmetric, meaning that there is more downside within the scheme than upside, as shown by the potential to lose more than £100m in several years of the RIIO-T1 control period, but only the opportunity to receive a maximum incentive profit of £50m in the first year. The 95% confidence interval for annual scheme performance shows a lower limit of around £20m loss in most years with a potential upper limit of around £10m profit. Over the RIIO-T1 period, the 95% confidence interval is loss of £72m, profit of £53m.

98 This is illustrated below (based on the results above for the first year of the RIIO-T1 period):



99 As noted in paragraph 111 of the 'Managing Risk and Uncertainty' of our March submission, our current incentive arrangements contain an annual cap (of

£55m, 2009/10 prices[24]) on the total exposure to entry operational buybacks, entry investment buybacks and exit investment buybacks, but note that certain exit revenues and exit constraint costs are not subject to this limit.

100 Were adverse incentive performance experienced under the scheme, our first management response would be to ensure that we have taken all actions we can to manage the risk. If our actions are not effective, however, or we simply cannot reduce costs because the risk is out of our control or we are not best placed to manage that risk, appropriate risk sharing arrangements need to be put in place to deal with this.

101 One of the main principles under the RIIO-T1 framework concerns the equalisation of the treatment of spend; i.e treat as totex rather than capex and opex, and ensure there are no distortions between different incentive arrangements. There is a natural cap and collar on the level of investment spend to provide capacity (i.e. from zero up to the efficient price to deliver), but constraint management risk at a LNG terminal, for example, could manifest itself every day if the required infrastructure is not built. It is therefore appropriate for a cap and collar to also apply to constraint management costs. We have therefore investigated different combinations of cap and collar to apply.

102 Using the lower 2.5% confidence interval in the table above as a reference, we have considered a scheme with an annual collar of -£20m. In order to provide a balance, we have set the scheme to have a cap of £20m. The statistics concerning the incentive performance under this scheme are shown in the following table:

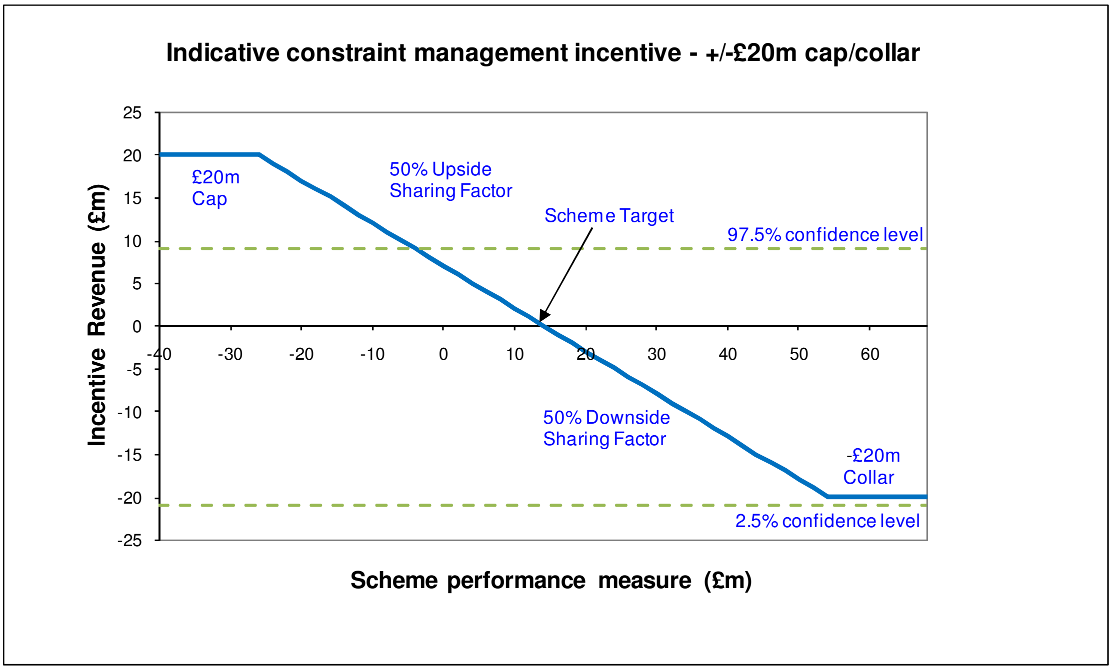
	Incentive Revenue (£m) - Assuming 50% sharing factors, £20m cap/-£20m collar								
	2013/14	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**Total over RIIO-T1 period**
Minimum	-20	-20	-20	-20	-20	-20	-20	-20	**-111**
Maximum	20	20	20	20	19	20	20	20	**88**
Mean	**0**	**0**	**0**	**1**	**0**	**0**	**0**	**0**	**2**
10%	-8	-10	-9	-9	-6	-7	-13	-8	**-36**
50%	2	1	2	2	1	1	1	1	**4**
90%	7	9	8	9	6	6	12	7	**38**
Std Dev	**7**	**8**	**7**	**7**	**5**	**6**	**9**	**6**	**29**
2.5%	-20	-20	-20	-20	-13	-15	-20	-18	**-57**
97.5%	9	12	10	12	8	8	17	10	**53**

103 This table shows that the inclusion of a collar limits the downside risk, but given that the cap has been set above the 97.5% interval for the uncollared/uncapped scheme above, it has no impact on the upside potential. The resultant 95% confidence interval for annual scheme performance shows a lower limit which is equal to the collar in four years of the control period with the same potential upper limit of around £10m profit per year. The downside exposure over the RIIO-T1 period is reduced with the 95% confidence interval

[24] This is equivalent to £48m in 2004/5 prices

now showing the lower limit equal to a loss of £57m with the upper limit still equal to a profit of £53m.

104 This is illustrated below (based on the results above for the first year of the RIIO-T1 period):



105 We consider that this provides a more balanced incentive package.

106 We have also considered other combinations of cap/collar and the following table provides a summary of the statistics relating to these over the RIIO-T1 period:

	Comparison of Incentive Revenue sensitivities over the RIIO-T1 period (£m)					
	Proposal 50% sharing factors £20m/-£20m cap/collar	50% sharing factors no cap/collar	50% sharing factors £15m/-£15m cap/collar	50% sharing factors £48m/-£48m cap/collar	40% sharing factors £20m/-£20m cap/collar	50% sharing factors £15.5m/-£11.5m cap/collar
Minimum	-111	-184	-101	-155	-91	-89
Maximum	88	88	88	98	68	85
Mean	**2**	**0**	**3**	**1**	**1**	**5**
10%	-36	-41	-32	-40	-29	-30
50%	4	3	5	3	3	6
90%	38	38	37	37	31	37
Std Dev	**29**	**32**	**27**	**30**	**23**	**26**
2.5%	-57	-72	-54	-65	-49	-49
97.5%	53	53	51	53	42	52

107 In order to consider which combination of target, cap and collar is appropriate, we need to calculate the resultant risk premium for each of these using the methodology described in paragraphs 86 to 92 and then build this into the scheme design.

Results of analysis

108 Applying the Sharpe ratio to the resultant standard deviations of pre-tax return on equity, results in the following implied post tax cost of equity figures:

Differences between TO control and TO plus Constraint Management				
Constraint management scheme considered	**Standard deviation of pre-tax return on equity**	**Implied post tax cost of equity**	**Implied additional post tax cost of equity to RIIO-T1 control alone**	**Resultant annual risk premium (£m)[25]**
Risk associated with RIIO-T1 control	0.6475%	7.50%	-	-
Add in Constraint Management scheme with 50% sharing factors and no cap/collar, target equal to expected performance measure	0.6595%	7.59%	0.092%	2.60
As above, but a +/-£20m cap/collar	0.6570%	7.57%	0.073%	2.06
As above, but a +/-£15m cap/collar	0.6560%	7.57%	0.065%	1.83
As above, but a +/-£48m cap/collar	0.6591%	7.59%	0.089%	2.52
As above, but a cap of +£15.5m and a collar of -£11.5m collar	0.6550%	7.56%	0.058%	1.63

109 In order to compare the total expected performance under each of the different designs of scheme over the RIIO-T1 period, we need to also consider the expected (mean) performance under the incentive scheme itself, as shown within the table in paragraph 106. This is then added to the RIIO-T1 risk premium, which is calculated as 8 times the figures in the table above.

110 This results in the following total expected performance under each of the different scheme designs:

[25] This has been calculated using the average over the RIIO-T1 period of the opening RAV for the TO control of £6,263m (2009/10 prices). Assuming a gearing level of 55%, this implies that the equity portion of this is £2,818m (45% x £6,263m), therefore the resultant annual risk premium is calculated as the implied additional post tax cost of equity multiplied by £2,818m.

Constraint management scheme considered	Incentive scheme performance over the RIIO-T1 period (£m)	Risk premium over the RIIO-T1 period (£m)	Resultant total expected performance over the RIIO-T1 period (£m)
Constraint Management scheme with 50% sharing factors and no cap/collar, target equal to expected performance measure	0.0	20.67	20.67
As above, but a +/-£20m cap/collar	2.33	16.46	18.79
As above, but a +/-£15m cap/collar	3.41	14.67	18.08
As above, but a +/-£48m cap/collar	0.56	20.16	20.72
As above, but a cap of +£15.5m and a collar of -£11.5m collar	4.66	13.01	17.67

111 Our proposal of a cap/collar of +/-£20m results in a total expected performance over the RIIO-T1 period of £18.79m, which is the middle case of those considered in this analysis. This provides a risk profile commensurate with the RIIO-T1 NGG risk appetite with reasonable protection for consumers and also provides a sufficiently strong incentive to align NGG's interests with those of the consumer.

112 In order to calibrate the scheme to receive this expected outcome, given the 50% sharing factor assumption, we need to add on twice the risk premium as shown in the table in paragraph 108 (2 x £2.06m per year). Given that the collar affects the resultant outcome, we have further applied a scaling factor to deliver the desired performance under the scheme. This means that we apply a premium of £4.30m to the original target as given in the table in paragraph 83.

Sense check

113 In our modelling we have used the risks associated with the TO control as the base case upon which we have modelled the SO risks. This has the effect of dampening the volatility of the SO risks, in effect the SO risks have been diversified. The precise level of diversification is difficult to determine, however an alternative method of evaluating the premium would provide a sense check on the appropriateness of the risk premiums determined above.

114 A standalone SO business carrying the risk proposed would need a balance sheet to absorb the risk, a balance sheet size of 3 years of losses appears reasonable.

115 The 95% confidence interval for annual scheme performance shows an average lower limit of around -£19.9m with a 50% sharing factor only scheme and -£18.3m for a scheme with +/-£20m cap/collar[26]. The results are shown in the table below.

[26] These are from the tables in paragraph 96 and 102 resp.

	Annual scheme performance - 95% confidence interval (lower limit)								
	2013/ 14 £m	2014/ 15 £m	2015/ 16 £m	2016/ 17 £m	2017/ 18 £m	2018/ 19 £m	2019/ 20 £m	2020/ 21 £m	Average over RIIO-T1 period £m
50% sharing factor, no cap collar	-21	-23	-24	-22	-13	-15	-23	-18	**-19.9**
50% sharing factor & +/-£20m cap/collar	-20	-20	-20	-20	-13	-15	-20	-18	**-18.3**

116 Under a scheme without caps/collars the expected loss over three years amounts to -£59.7m (-£19.9m x 3) and -£54.9m for a scheme with +/-£20m annual cap/collar.

117 Given the scale of risks such a business would need to be wholly equity funded. Equally, such a business would be expected to have a cost of equity higher than that of the TO business predicated by the fact that the SO business balance sheet does not have the capability to absorb these risks.

118 We have used a range of equity return to illustrate the potential risk premium requirements to attract equity investors. For NGG (in its role as combined TO and SO) to undertake the risk, a return of 7.5% would be appropriate, however a standalone SO business is more risky and thus would require a return of 10% or higher. The results are shown in the table below.

Rate of equity return	50% sharing factor (£m)	50% sharing factor and +/-£20m cap/collar (£m)
7.5%	4.5	4.1
10%	**6.0**	**5.5**
12%	7.2	6.6

119 We have proposed 7.5% equity return for our NGG TO business, the SO as a standalone business is substantially more risky and thus would command a greater rate of return. The expected range of annual premium will range from £4.1m and £7.2m dependant on the scheme parameters.

120 We have proposed a risk premium of £2.15m per annum (in 09/10 prices) (half of the risk premium of £4.30m outlined in paragraph 112) which is below the low end of the premium requirement for a standalone SO business. This illustrates our proposed risk premium is lower than what would be required for a standalone SO business as we are taking advantage of our TO balance sheet for the benefit of our customers.

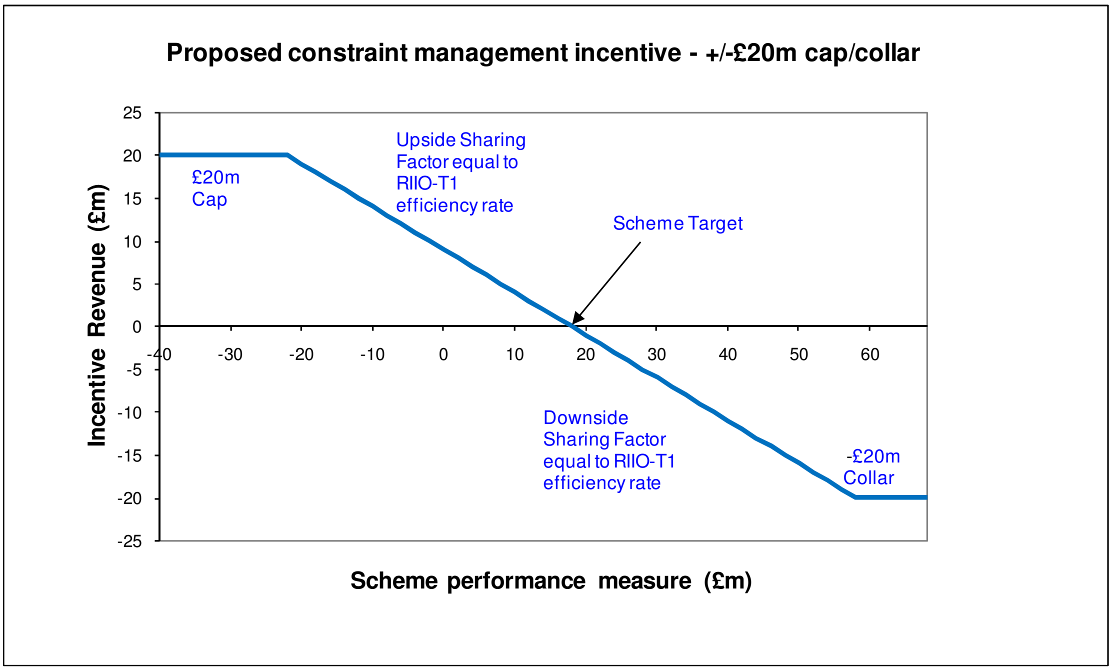
Proposed scheme for constraint management

Proposed parameters

121 Our proposed scheme parameters (ex-ante target level, sharing factors and caps/collars) for the elements of the constraint management scheme in each year are as outlined in the table below:

	Annual constraint management scheme parameters (09/10 prices)							
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Collar (£m)	-20	-20	-20	-20	-20	-20	-20	-20
Cap (£m)	20	20	20	20	20	20	20	20
Target (£m)	**17.9**	**24.5**	**21.1**	**27.1**	**21.6**	**18.5**	**56.7**	**24.3**
Sharing factors	RIIO-T1 efficiency rate 40%-50%							

122 The following illustrates how the scheme would operate in each year (based on the parameters suggested for the first year of the RIIO-T1 period):



123 The incentive performance under this scheme is as indicated in the following table. It shows that the expected performance under the scheme over the RIIO-T1 period (£18.7m) is commensurate with the proposed performance of £18.79m as indicated in paragraph 110 above:

	Incentive Revenue (£m) - Case 3 costing, 50% sharing factors, £20m cap/-£20m collar for scheme with target set to include risk premium								
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total over RIIO-T1 period
Minimum	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	**-113.4**
Maximum	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	**107.0**
Mean	**2.3**	**2.5**	**2.5**	**2.5**	**2.1**	**2.2**	**2.4**	**2.3**	**18.7**
10%	-6.0	-7.9	-6.6	-7.0	-4.4	-5.0	-10.6	-5.7	**-20.0**
50%	3.5	3.7	3.8	3.6	3.0	3.1	3.3	3.2	**20.9**
90%	9.0	11.2	9.8	10.8	7.9	8.3	13.9	9.4	**54.5**
Std Dev	**6.7**	**7.8**	**7.1**	**7.6**	**5.5**	**5.7**	**9.3**	**6.5**	**29.0**
2.5%	-19.0	-19.6	-19.1	-20.0	-12.0	-12.4	-20.0	-15.5	**-43.5**
97.5%	11.3	14.1	12.6	14.0	10.0	10.7	18.4	12.3	**69.2**

124 We note that the scheme still includes a wide variation in performance, but that the downside exposure over the RIIO-T1 period is reduced with the 95% confidence interval now showing the lower limit equal to a loss of £43.5m with the upper limit now equal to a profit of £69.2m. The difference between the figures in this table and those in the table in paragraph 102 is the uplift which is necessary to fund the SO risk premium.

125 As noted in paragraph 80 above, as we expect that the impacts of potential incremental capacity release would be considered by the application of the relevant uncertainty mechanism, we have not factored this into this analysis.

126 We noted in paragraph 81, however, that before start of the RIIO-T1 period, the July 2012 exit application window and the March 2013 QSEC auction could result in incremental capacity release which could lead to incremental constraint risk.

127 Within our 'Delivering connections and capacity' annex, we suggest that the existing arrangements could be amended[27] to cover the interim period until such time as the proposed change to the commercial regime in relation to connection and capacity processes may be implemented via the UNC governance process. If accepted, this change would also apply for the rollover year and therefore mitigates some of the risks which relate to capacity release obligations within the March 2013 QSEC auction.

Scheme length

128 If our proposed approach to mitigating the risks associated with the March 2013 QSEC auction were to be agreed, we could set all the parameters of this scheme (including the target) for the first four years of the RIIO-T1 control period with the expectation that it would be subject to the mid-period review.

129 If this were not to be the case, due to the risks posed by the current arrangements concerning the March 2013 QSEC auction, we would propose that the target level for the scheme is only set for the first three years of the RIIO-T1 period as we would need to factor in potential risks from October 2016 onwards.

[27] Via either the revision of the existing permits scheme or by modification of the relevant methodology statements

130 The analysis in this annex does not take account of RPI. We would therefore expect this to be appropriately reflected in the resultant licence drafting for the incentive scheme.

Proposed scheme for transmission support services

131 We propose that there should be a separate incentive scheme to cover Transmission Support Services (TSS)[28] (which are defined in our Safety Case as a substitute for pipeline capacity at high demands to support a 1 in 20 peak day). We currently have two different forms of TSS available to us; contracts under the Long Run Contracting Incentive and Constrained LNG (CLNG).

132 We are proposing that the existing exit schemes entitled ‘Long Run Contracting incentive’ and ‘Constrained LNG incentive’ are merged to create a combined scheme in the RIIO-T1 period[29]. This incentive should continue until the pipeline solution has been delivered to replace the Avonmouth LNG storage facility (proposed to be delivered in October 2018).

133 This is consistent with our proposal that an ex-ante allowance within the TO control should be provided to fund these investments. If this were not the case, then we would need to this incentive to carry on into the RIIO-T1 period.

134 As outlined within our ‘Detailed Plan’ annex of the March submission, we propose the following Transmission Support Services annual target:

Incentive scheme	£m (09/10 prices)	Sharing factor
CLNG	3.33 (2012/13 annual target)	100%
Long Run Contracting Incentive	3.90 (annual target starting Oct 2012)	50%
Proposed TSS annual target	**7.23 (RIIO-T1 period annual target)**	**RIIO-T1 efficiency rate 40%-50%**

[28] For details, see the ‘Provision of Operating Margins and Constrained LNG for the South West’ section of the ‘Detailed plan’ annex
[29] For details, see the ‘Provision of Operating Margins and Constrained LNG for the South West’ section of the ‘Detailed plan’ annex

Addendum 1 - March 2012 RIIO-T1 business plan submission

This is an unchanged extract from the 'Buybacks/Constraint Management' section of our 'Managing Risk and Uncertainty' Annex of the March 2012 RIIO-T1 business plan submission and for convenience we have used the same paragraph numbering as was used within that submission.

Introduction

63 The workings of the existing capacity regime leave us with an inherent level of constraint risk on the system to manage. Additionally, our RIIO-T1 business plan will bring new challenges going forward due to the increased system access requirements driven by maintenance, asset health investment, statutory work (such as to comply with requirements under the Dangerous Substances and Explosive Atmospheres Regulations (DSEAR) and Industrial Emissions Directive ("IED")), and construction activities relating to the provision of incremental capacity or Network Flexibility being envisaged. We propose to address each of these areas separately.

64 Our main focus has been on articulating the level of inherent risk which exists on the system and to that end we provide our current view of the quantification of this inherent level of constraint management risk.

65 We note that we have only currently investigated inherent risk for the 2012/13 and 2020/21 formula years so we also include our thoughts as to how that work can be taken forward to inform our May 2012 SO external incentives submission in which we will be proposing scheme designs and parameters.

66 We consider the impact that the levels of required system access identified within the RIIO-T1 business plan (in terms of both the more traditional Asset Health type work and the increased level of work due to environmental legislation, such as under IED) will mean for forecast constraint management costs and present our findings in this area.

67 We also note the effects of the potential levels of incremental spend which could be seen on the system due to either changes in the use of existing capacity (Network Flexibility) or requests for additional capacity (Incremental Entry and Exit). Furthermore, we note the potential for material consequences on the constraint risk profile driven by European-led change (such as the Nomination rules under the EU Balancing code). Given the uncertainty surrounding all these requirements into the future, we propose that it is not reasonable to try to set ex-ante allowances to deal with these and that the effects on constraint costs should be explicitly considered as part of the relevant uncertainty mechanisms.

Interactions between the TO business plan and constraints

68 The key interactions between the TO plan and constraints on the NTS are:

(a) Asset health – whilst necessary to ensure on-going network reliability, this ex-ante funded investment results in reduced capability during the activity.

(b) Compressor investment related to environmental legislation (specifically the Industrial Emissions Directive, which will incorporate the Large Combustion Plant Directive and the Integrated Pollution Prevention and Control regulations) – this ex-ante funded investment requires compressor station outages whilst construction activities are completed and tied into the NTS, and specific gas flows to commission the new compressor units. Creating these flows may require curtailment of, or increases to, prevailing gas flows (thereby potentially incurring capacity buyback or locational action costs).

(c) Incremental capacity – if investment is undertaken to address incremental capacity requirements, the ongoing capability of the system will be changed and this needs to be taken into account. The construction activity will lead to reduced capability for a limited period of time during construction and commissioning[30]. If alternative solutions (such as a commercial solution) are chosen, then the underlying level of risk on the system could change.

(d) Network Flexibility investment – the need case for this type of investment is likely to identify increased future constraint costs should investment not be the agreed solution to an issue brought forward under the Network Flexibility uncertainty mechanism. Conversely, investment options should enhance the ongoing capability of the system mitigating upward cost pressure but it will lead to reduced capability for a limited period of time during construction and commissioning.

(e) Additional environmental legislative requirements – if triggered by the IED uncertainty mechanism, these additional investments will impact on network operation in the same manner as our baseline IED investments; i.e. they will require system access to construct, tie-into the NTS and commission, thereby restricting capability during the activities, and may potentially incur capacity buyback or locational action costs.

(f) EU requirements – possible changes under the EU Balancing code or Capacity Allocation Methodology to the nomination rules have the potential to change the constraint risk profile of the GB market. Additionally the impact of the Congestion Management Principles (CMPs) and greater TSO to TSO cooperation will also need to be considered.

69 Note that the modelling included within this annex has not taken any account of unplanned outages on the system. The level of network risk as defined by the Network Output Measures (NOMs) at the end of the RIIO-T1 period is expected to be comparable to the level that is experienced today, therefore it is reasonable to assume that the unplanned outage level will also be comparable.

[30] We note there are some provisions in new Network Entry Agreements which can secure User compliance for certain commissioning activities; however this will be insufficient to manage the wider issue.

We will undertake further work on this to be included within the May SO external incentives submission.

Drivers of constraint risk

70 There are two different dimensions we need to consider for constraints; whether we can predict the driver on an ex-ante basis or not, and whether the modelled constraints are caused by operational issues on the day or by investment activities. We therefore propose two different, but complimentary, approaches to constraint management schemes:

	Funded ex-ante in RIIO-T1 settlement	Driven by uncertainty mechanism
Operational constraints Driven by the inherent risk on the network which results from changing flow conditions from existing supply and demand capabilities (i.e. with no incremental capacity or capability of either the NTS or connected parties) and by unplanned maintenance	Ex-ante operational constraint management	Incremental operational constraint management
Investment constraints Driven by construction and commission activities (such as pipeline tie-ins) and commissioning activities (such as in-line inspections and compressor commissioning) related to investments proposed in our TO investment plan	Ex-ante investment constraint management	Incremental investment constraint management

71 It is useful to consider that the key difference between investment and operational constraint risk is that the former is transitory (i.e. for a defined period only). The operational constraint risk in an ongoing step change to the level of risk.

72 There are a number of different drivers of constraints on the NTS which we detail further in this section and summarise below, along with how we intend to manage them. Note there will be a degree of overlap in mapping; for example the optimum solution to a Network Flexibility issue may be to face constraint risk rather than investment, in which case this would form part of the incremental operational constraint risk rather than the incremental investment constraint risk.

Driver of constraint	Treatment
Inherent risk Risk inherent in the network, driven by changes in existing gas supplies and demand expected over the RIIO-T1 period. To also include unplanned outages. Note this does not include any incremental supplies or demands on the NTS.	**Proposed to be included as operational buyback (ex-ante)** (to be proposed in the May SO external incentives submission)

Driver of constraint	Treatment
Unforeseeable asset health events Events triggered under the Asset health uncertainty mechanism have the potential to affect the constraint risk going forward.	**Proposed to be included as investment buyback (incremental)** (as defined in the Asset health uncertainty mechanism)
Maintenance Planned maintenance and asset health investment which requires system access (including outages) to complete. This activity is expected to increase as large parts of the network ages beyond its design life over the RIIO-T1 period.	**Proposed not to be included in the buyback scheme** Propose that risk is primarily managed through extension of 'maintenance days' to Entry[31]
Impact of known IED requirements The Industrial Emissions Directive requires us to replace a number of our compressor units. This exceptional event will drive a significant number of compressor station outages over the RIIO-T1 period, far in excess of those required for maintenance and asset health investment.	**Proposed to be included as investment buyback (ex-ante)** (to be proposed in the May SO external incentives submission)
Impact of additional IED requirements The Industrial Emissions Directive may require us to replace further compressor units over and above those in the known IED requirements above. Investment triggered by the IED uncertainty mechanism will drive similar system access requirements to Incremental capacity.	**Proposed to be included as investment buyback (incremental)** (as defined in the IED uncertainty mechanism)
Incremental capacity Delivery of triggered incremental capacity will require system access for construction activities (such as pipeline tie-ins) and commissioning activities (such as in-line inspections and compressor commissioning, which both require specific gas flows to complete).	**Proposed to be included as investment buyback (incremental), however could be included as operational buyback (incremental) should the solution not be totally asset-based** (as defined in the Incremental entry and exit capacity uncertainty mechanism)
Network Flexibility Delivery of solution triggered by the Network Flexibility uncertainty mechanism, if investment related, will drive similar system access requirements to Incremental capacity (above).	**Proposed to be included as investment buyback (incremental), however could be included as operational buyback (incremental) should the solution not be totally asset-based** (as defined in the Network Flexibility uncertainty mechanism)

[31] See the 'System access requirements' section of this annex for further details. Note that there could be an impact on operational buy backs if the agreed number of 'maintenance days' have been used and work is still required on the network.

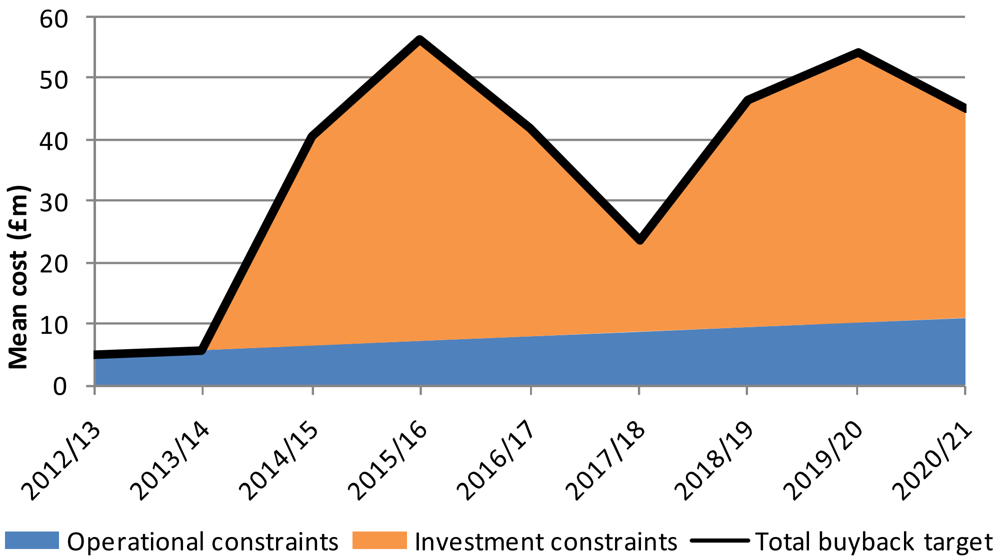
Driver of constraint	Treatment
Impact of European regulatory change Regulatory changes resulting from the implementation of the Third Energy Package (such as nomination rules under the EU Balancing code) have the potential to change constraint risk.	**Proposed to be included as operational buyback (incremental)** (as defined in the IED uncertainty mechanism)

73 We therefore believe that there are four distinct categories of constraint management costs which need to be factored into the relevant year's target. This will therefore be calculated as follows:

Constraint management target = Ex-ante operational constraints + Ex-ante investment constraints + Incremental operational constraints + *Incremental investment constraints*

74 We therefore propose a one scheme covering entry and exit capacity and believe appropriate caps and collars should be determined. We do not believe it appropriate to propose two separate schemes (i.e. one for operational and one for investment) as it is unlikely that we will be able to identify one driver for the need to take a constraint management action – the need to take an action is likely to be as a result of a number of different factors. We will present our proposals in detail in our May 2012 SO external incentives submission.

75 The detail presented in this section is shown in the graph below. We have a view of the inherent operational risk we face as existing supplies and demands evolve on the network (ex-ante operational constraints), and a view on the modelled investment buyback risk resulting from the extensive programme of compressor outages required to deliver the known IED requirements included in our ex-ante baseline plan (ex-ante investment constraints). The two incremental constraint categories in the above equation for the constraint management target are zero as they will only be triggered by the relevant uncertainty mechanisms.



76 Note there is no risk allowance shown for routine maintenance and asset health investment as we are assuming successful extension of the concept of 'maintenance days' to entry. Should this not be accepted, clearly we will need to revisit our modelling to include an allowance for this work.

77 For spend which will be triggered by the relevant uncertainty mechanism (i.e. will not be included as ex-ante funding), the proposals under the relevant mechanisms include the ability to reflect any incremental constraint risk which should be included in the investment constraint management target in the relevant years.

Background to the existing capacity regime

78 The current regulatory and commercial frameworks oblige us on every day of the year to release obligated levels of capacity significantly in excess of peak demand at both entry and exit. Flows of gas commensurate with these levels of capacity cannot occur concurrently, so we take a view of the likely combinations of supply and demand patterns we could experience and an assessment of the most efficient solution to meet them (consider the rules, tools and asset options available to us).

79 In the instances where we cannot accommodate a user's flow requirements associated with booked capacity, we undertake constraint management actions in accordance with the Uniform Network Code (UNC) and System Management Principles Statement[32].

80 Following a formal 'trigger', the capacity regime provides us with the discretion to undertake investment, enter into contracts or to take the buyback risk. The investments included within our baseline plan, which if triggered will be funded through revenue drivers, have been chosen to ensure that optimisation of this trade off has been considered.

81 The regulatory capacity regimes determine the level of capacity which NGG must offer for sale on each day (subject to using reasonable endeavours). It should be noted that over all the entry points on the system, the current level of entry capacity obligations is 10,956 GWh/d which is approximately twice forecast peak demand[33]. However, the level of capacity that is booked by shippers, whilst potentially being indicative of peak flows at specific points, does not necessarily provide a good indication of gas flows that will actually be seen across the network[34] on any gas day.

82 Whilst the incentive arrangements surrounding constraint management actions are contained within our licence in respect of the NTS, the risks we face are also highly dependent on the commercial framework outlined within the UNC. Different arrangements apply at entry and exit (both within the licence and the UNC) and these are outlined at a high level below.

Entry capacity regime

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[32] For details, see http://www.nationalgrid.com/uk/Gas/OperationalInfo/operationaldocuments/ProcurementSystemManagementServicesStatementsReports/doc_req_by_SCC8D/Stmt_Ent_Cap_Const_MGMT

[33] Forecast peak demand for 2010/11 is 5007 GWh/d as shown within Table 5.3 accompanying this submission.

[34] Note that capacity provides shippers with an option but not an obligation to flow gas.

83 For entry, the licence currently includes incentive schemes[35] covering:

(a) Entry capacity operational buyback; and

(b) Entry capacity constraint management relating to the release of incremental obligated entry capacity (relating to late delivery).

84 The entry capacity operational buyback incentive is a sliding scale incentive, with a target, sharing factors and a cap and collar.

85 The performance measure under the entry capacity operational buyback scheme is calculated based on the difference between certain costs we incur and specific revenues we receive relating to entry capacity. Costs relate to the buying back of entry capacity (including the costs of forwards or options) plus the cost of locational buy actions[36]. Revenues are received from the sale of particular types of entry capacity products (on-the-day sales of firm entry capacity, sales of interruptible entry capacity and non-obligated incremental firm entry capacity), from overrun charges and from locational sales[37].

86 The entry capacity incremental buyback incentive relates to costs of late delivery of incremental obligated entry capacity on the system. The incentive is a downside only scheme which provides both a monthly cap and an annual cap[38] on our exposure to the associated costs[39]. As such, it implicitly assumes the efficient level of constraints is zero. It is arguable whether this assumption is correct now and will undoubtedly be incorrect into the future.

87 The licence also currently obliges[40] us to use reasonable endeavours to continue to release previously unsold entry capacity up to the prevailing obligated levels within the gas day to which it relates ("the clearing allocation obligation"). Given the present amount of obligated capacity on the system and the current zero reserve price which on the day capacity attracts, this has led to more shippers securing their capacity requirements on the day, with the consequence that we have relatively poor medium to long term user signals of required capacity.

88 We note that the obligation to release capacity does not reduce within the gas day as time unfolds, and have already raised this as an issue with Ofgem that we believe this should be reviewed.

89 Our ability to accurately forecast flow patterns on the network is highly dependent on the quality of the flow information which is received from the different users of the system and the predictability of their behaviour in response to external factors (such as price). We have set out in the 'Detailed plan' annex the variety of change drivers impacting on supplies into the UK

[35] There is also a specific incentive surrounding the delivery of the incremental entry capacity up to 650 GWh/day at the Milford Haven ASEP, but this has now expired.

[36] Locational buys and sells are when we enter into transactions via the On-the-day commodity market to manage capacity at particular points of the network

[37] The inclusion of locational actions within the entry capacity buyback scheme was introduced by Ofgem as part of its review of the SO incentives in February 2004. This was in accordance with the views expressed in the decision letter issued relating to Network Code modification 0592.

[38] There is also an overall annual collar on our exposure to the aggregate of entry capacity operational buyback costs, entry capacity incremental buyback costs and exit capacity incremental buyback costs.

[39] Whilst the incentive is downside only, there is clearly a link back to the current delivery incentive or permits scheme which provides a further incentive surrounding the delivery of incremental capacity.

[40] The changes being driven by the Capacity Allocation Methodology and Congestion Management Principles under the European Third Package may change this obligation or the associated price.

(UKCS decline, increasing reliance on LNG importation and interconnectors, the increase of fast cycle storage responding to CCGT operation in response to greater levels of wind generation on the electricity network) and the material surplus of supply capacity over peak demand flows. This therefore means we have reduced certainty as to where the gas is likely to flow.

Capacity bookings

90 The figures in Appendix A show the capacity bookings (split into before the day Firm, within day Firm and Interruptible (both Use It Or Lose It (UIOLI) and discretionary) capacity) which have been seen over the last two winters[41] at five Aggregated System Entry Points (ASEPs): Bacton, Easington, Isle of Grain, Milford Haven and St Fergus. The obligated levels are also shown on the figures together with the actual levels of gas flow experienced.

91 The figures provide a clear indication that the levels of capacity (both firm and interruptible) being bought do not provide any suggestion or certainty regarding the level of gas flows which will ultimately be seen on the day. Therefore when planning and operating the system, we need to take a judgement as to the likely range of flow patterns which could be seen and hence we carry the risk that actual flows could be very different on the day. Given the potential diversity of future supply/demand flow patterns and difficulty in forecasting supply and demand (as discussed above), coupled with the high number of permutations of supply for any given demand level, this has the potential to lead to considerable levels of constraint management costs until such a time as an alternative solution (if appropriate) can be implemented, which could be either rules, tools or asset based.

92 Additionally, any changes to the commercial regime (on Gas or Electricity) could change the balance of risk and therefore have a marked impact on the likely level of costs we could face. We therefore believe that major changes to the framework (such as changes to the Gas regime driven by the European Third Package, or to the electricity regime from the Electricity Market Reform) should automatically trigger a re-assessment of the appropriate incentive structure.

93 In the next section we consider the correlations which have been seen between outturn end of day flow level and demand.

Demand levels

94 Given that the majority of supplies are currently being provided through five entry points on the system (Bacton, Isle of Grain, Easington, St. Fergus and Milford Haven), we provide details below of the level of supply volatility that has been seen over recent years. Note that the different entry points do not all respond to changes in demand in the same way (in fact, to varying levels they react more to regional or global market economics than demand), which means it is difficult to forecast the likely level of supply through these entry points on any given day.

95 The current level of capacity obligations at these entry points is as per the following table:

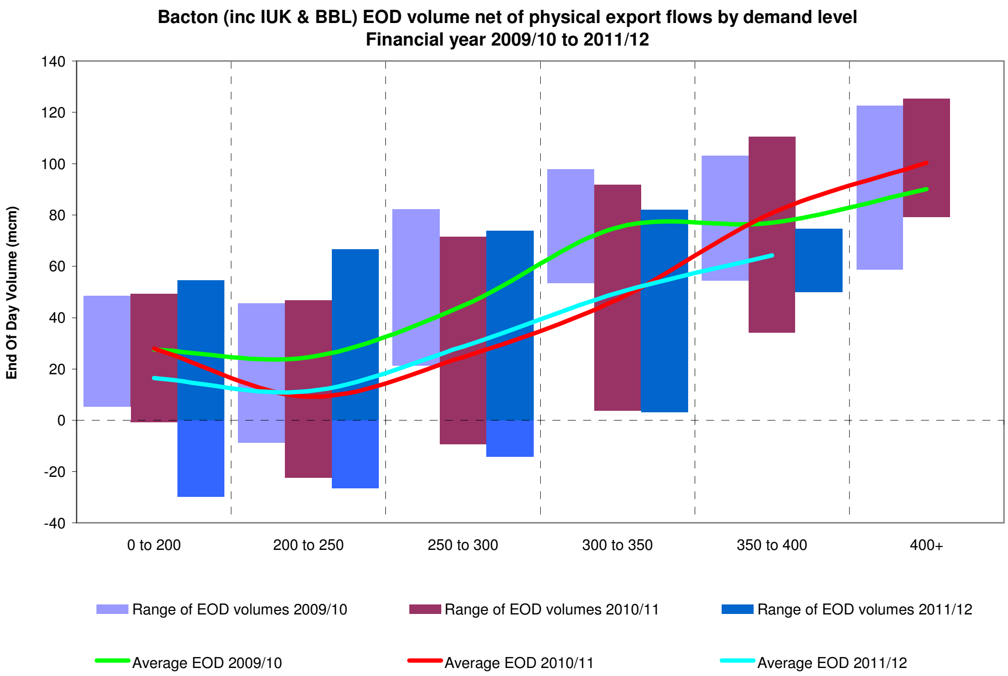
[41] Note for the current winter, data is only included up to 31 January 2012.

Entry Point	Obligated level (GWh/d)	Obligated level (Mcm/d)[42]
Bacton	1,783.4	162.1
Easington	1,407.2	127.9
St Fergus	1,670.7	151.9
Isle of Grain	699.7	63.6
Milford Haven	950.0	86.4
Total over these 5 entry points	**6,510.9**	**591.9**

96 The following table shows the ranges of demand that have been seen over the last three formula years:

Demand Range (mcm/d)	Number of days per year		
	2009/10	2010/11	2011/12[43]
0 to 200	81	19	46
200 to 250	76	89	137
250 to 300	74	103	81
300 to 350	45	94	37
350 to 400	66	40	5
400+	23	20	0
Total	**365**	**365**	**306**

97 Using these demand ranges, we have examined the range of End of Day (EOD) flows (and the average level of flow) that has been seen at these entry points over the last three formula years[44].

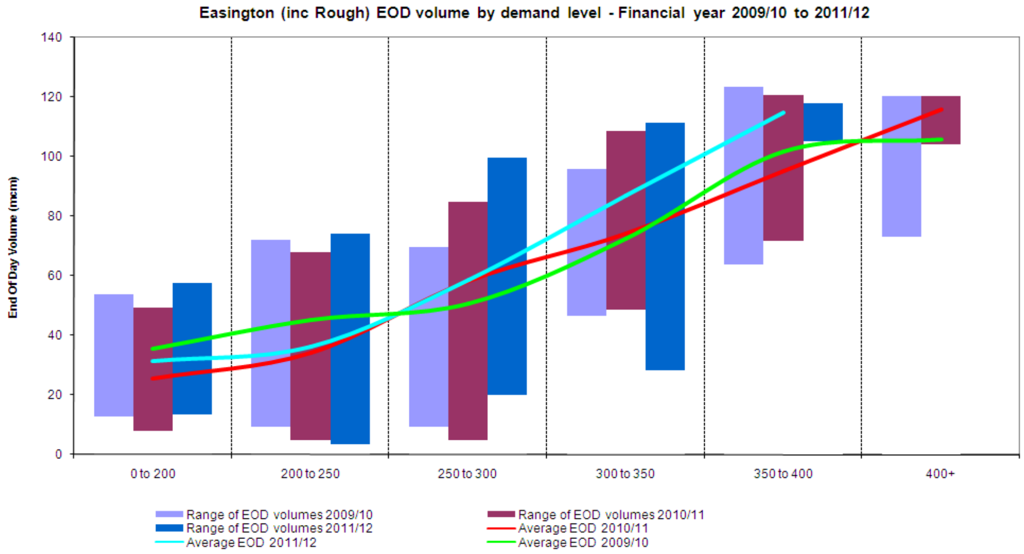


[42] Calculated using an assumed Calorific Value of 39.6MJ/m^3 which means that 1 Mcm/d equals 11 GWh/d or 1 GWh/d equals 0.0909 Mcm/d

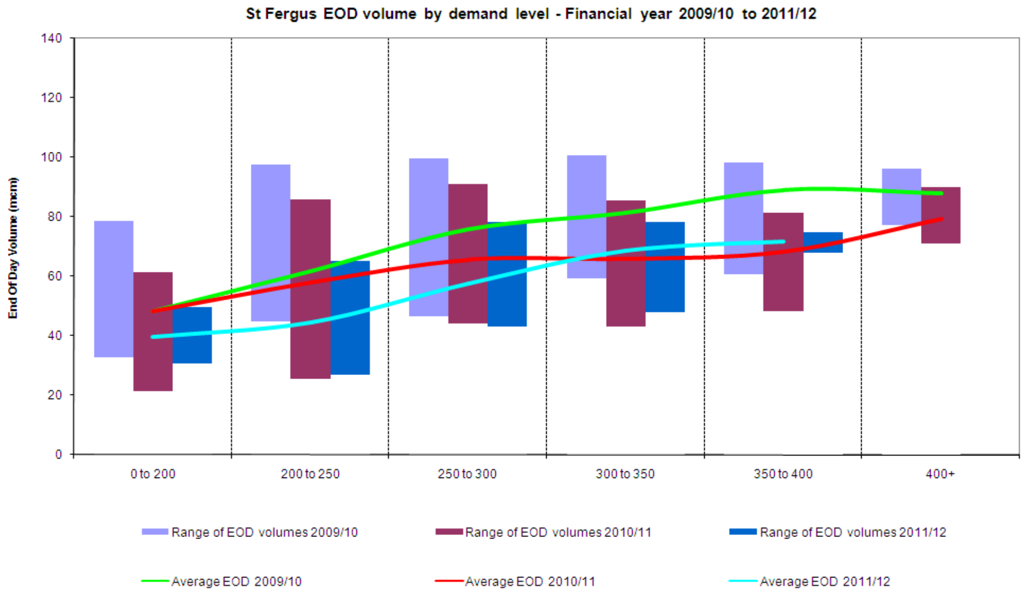
[43] Note for the current formula year, data is only included up to 31 January 2012.

[44] A summary of this supply data can be found in Appendix C at the end of this annex.

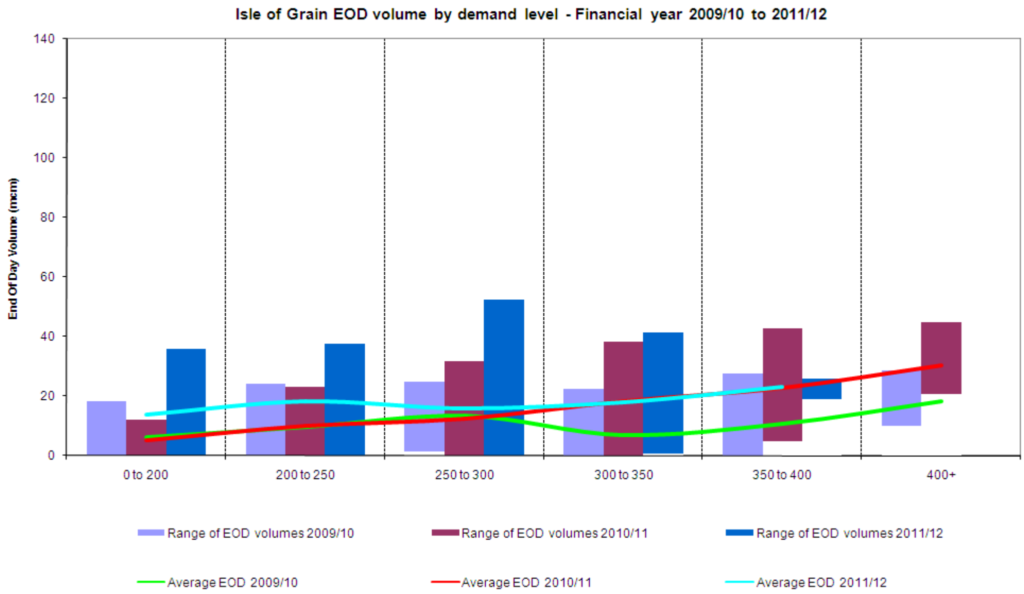
98 The graph shows that average flows at Bacton tend to increase linearly with demand levels meaning that forecast levels of demand can provide some indication of likely flow. However, given the range between the minimum and maximum levels of flow which have been seen at the various demand levels, it is clear that any such forecast would be subject to a large degree of error. For example, during the last formula year the average supply for the 350 to 400 mcm/d demand level was 81 mcm/d, but given the minimum flow seen was 34 mcm/d and the maximum 110 mcm/d, the range between these was 76 mcm/d. Additionally, due to the bi-directional nature of IUK, net exports can occur on some days, as seen within the 0 to 200, 200 to 250 and 250 to 300 mcm/d demand ranges above, which makes the range of potential flows even wider.



99 Easington supplies also tend to follow demand levels, but the range of supplies (particularly for the 200 to 250 mcm/d and 250 to 300 mcm/d ranges) is much larger than that seen at Bacton (for the 250 to 300 mcm/d demand range, the range between the maximum and minimum flows which were seen in 2010/11 was 80 mcm/d).

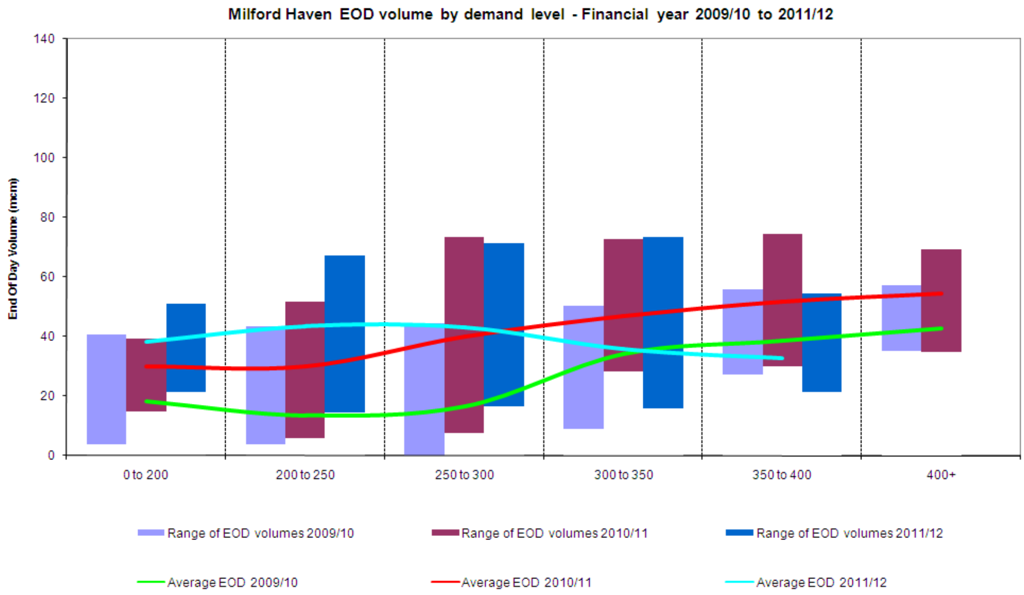


100 Supplies at St. Fergus, which are largely UKCS-led, are far more stable and (subject to local maintenance or unplanned outages) predictable than the other major entry points. These supplies tend to increase linearly with demand levels, and the level of variability of supply flows at each of the demand levels is lower than that seen at Bacton or Easington, particularly at the higher demand levels, meaning that demand is a greater predictor of supply than for the other two entry points. However it is interesting to note that the graph shows that the average level of flow at St. Fergus is reducing year on year.



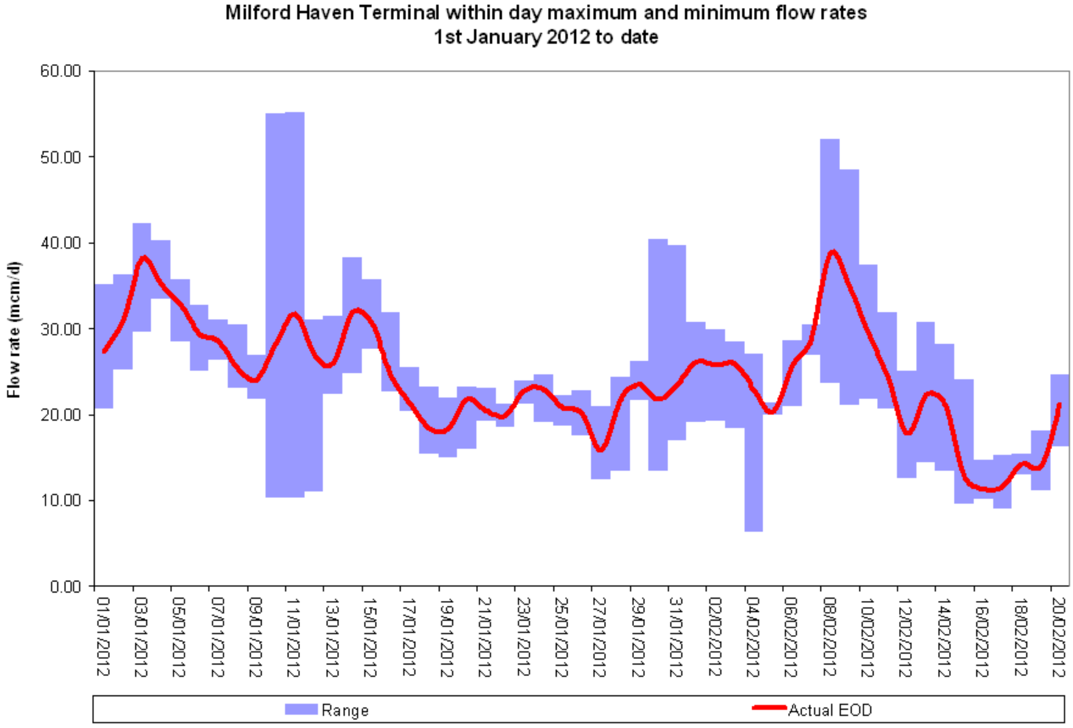
101 The supply flows at Isle of Grain tend to be at a lower level than the other entry points considered above, and the correlation between average flow and demand level is less defined. This means that the ability to predict supply levels based on an assumption of demand level is less certain, reflecting the global nature of the market for LNG supplies. This is compounded by the fact that the LNG importation facility at Isle of Grain (along with those at Milford Haven) has the ability to ramp up from zero flow to maximum within a couple of hours – a rate far greater than we have seen historically from UKCS field-based supplies. This ability may bring benefits for system balancing through this price responsiveness, however, recent operational experience (for example the very low flows seen from Milford Haven throughout winter 2011/12 even during periods of high prices) illustrates that these supplies do not always behave in a predictable manner. This reduced predictability of response can in itself drive greater challenges in balancing the system, and make planning of system access far more difficult.

102 Whilst the absolute range of variation in the supplies (i.e. in mcm/d) is lower than that shown at Bacton, Easington and St. Fergus, when the range is compared with the average levels of supply, the variability in percentage terms is much greater (for the 300 to 350 mcm/d demand range the percentage of supply range to average flow is over 300%).



103 Supply flows at Milford Haven show even less correlation with the level of demand. This has been most pronounced over the current formula year 2011/12, where average flows have actually been lower at the 300 to 350 mcm/d and 350 to 400 mcm/d demand levels than at both the 0 to 200 mcm/d and 200 to 250 mcm/d demand levels. Again this makes the prediction of supply based on forecast demand levels very difficult. As with Isle of Grain, whilst the absolute range of variation in the supplies is lower than that shown at Bacton, Easington and St. Fergus, when the range is compared with the average levels of supply, the variability in percentage terms is much greater (for the 200 to 250 mcm/d demand range the percentage of supply range to average flow is just under 300%).

104 Therefore, using either predicted demand levels or capacity bookings provides us with little certainty as to where the gas is ultimately likely to flow. It also provides no information relating to the profile of supply we can expect during the day – a factor which can drive material system management issues should supplies be heavily weighted to a particular point in the day. The graph below shows the range of within day flow levels over recent months, and plots the end of day demand level for comparison. It can be seen that on some days there is a high range of flows as Shippers take the opportunity to respond to external stimuli (such as price) to profile their flows.



105 This approach is also not capable of providing information relating to the expected behaviour of storage sites which may respond quickly to price signals in either the gas or electricity markets. This means we cannot ensure the system has been configured in the optimal manner to support the flow patterns which ultimately transpire on the system[45].

Other entry considerations

106 Within the UNC, the costs associated with entry capacity constraint actions (and locational buys) and the associated relevant revenues (including locational sells) are subject to the entry capacity neutrality scheme, meaning that they are shared amongst industry participants and we are not directly exposed to these costs or revenues. However, as noted above, we are subject to incentive arrangements around these costs and revenues, via the schemes contained in our licence. The revenues associated with the incentive schemes form part of the allowed revenue within the SO form of control in the licence and are therefore recovered from shippers via the SO commodity charge.

107 There are no specific arrangements at entry concerning maintenance and construction activities within the UNC. This means that any costs which are incurred due to maintenance are captured within the relevant capacity costs terms. We note that when Ofgem re-set the parameters of the entry capacity operational buyback incentive in 2009, it recognised that an appropriate allowance of £2m should be included within the annual scheme target relating to unplanned outages and £0.5m for planned outages.[46] Given this treatment under the commercial framework, maintenance activities provide an additional

[45] Note that users provide anticipated flow information via the OPN/DFN route (as discussed later in this section), but this information is only available close to the relevant gas day and sometimes can be quite inaccurate – see paragraph 122 for further details.

[46] For details, see http://www.ofgem.gov.uk/Networks/Trans/GasTransPolicy/EntryCapacity/Documents1/Decision%20letter_buy-back.pdf

source of risk for the entry capacity scheme and this risk needs to be considered in the design of an incentive scheme. Our proposal to extend maintenance days to entry negates much of the risk relating to system access requirements for general maintenance and asset health; however the risks driven by the need to replace a large number of our compressors to comply with the IED will go beyond what can reasonably be managed in this way.

108 Therefore, in order to set suitable parameters for the incentive schemes, we need to be able to agree forecasts both for the likely level of constraint volume and price, however it needs to be recognised that these are highly dependent on the prevailing commercial framework and external factors beyond our control with respect to user behaviour and flows at both entry and exit.

Exit capacity regime

109 For the enduring exit period (1st October 2012 onwards), the licence currently includes incentive schemes covering:

(a) Long run contracting

(b) Exit capacity constraint management relating to NTS obligated incremental exit flat capacity

(c) Revenue from the sale of non-obligated exit capacity

110 The long run contracting incentive[47] relates to the costs incurred associated with the provision of firm exit capacity at certain sites in the south west of the country which were previously booking interruptible exit capacity prior to the implementation of UNC mod 0195AV (Exit Reform). It is a sliding scale incentive with a target level of costs and a sharing factor. Unlike the entry capacity operational buyback scheme, the incentive does not include any forms of revenue (for example from the sales of certain exit capacity products) and therefore whilst the scheme does not include an explicit cap or collar, by definition there is an implicit cap on the upside which is set at 50% of the target level. However it should be noted that our exposure to the costs included within the incentive is unlimited.

111 The exit capacity incremental buyback incentive covers costs incurred relating to the late delivery of incremental obligated exit flat capacity on the system. As per the corresponding scheme on entry it is, in effect, a downside only scheme[48] which provides both a monthly cap and an annual cap on our exposure to the associated costs[49].

112 Revenue from the sale of non-obligated exit capacity relates to capacity sales both from firm NTS exit flat capacity over and above the licence defined obligated levels and off-peak NTS Exit Capacity. The scheme is an upside only scheme with a sharing factor of 50% and a cap of £20m (subject to indexation). We retain these revenues as the release of non-obligated capacity increases the capacity levels we are managing on the system and therefore

[47] We are proposing the Long Run Contracting Incentive is merged with the Constrained LNG incentive in the RIIO-T1 period. See the ‘Provision of Operating Margins and Constrained LNG for the South West’ section of the ‘Detailed plan’ annex for further detail.

[48] As with entry, there is a corresponding delivery incentive for incremental capacity releases.

[49] As noted above, there is also an overall annual collar on our exposure to the aggregate incentive costs of entry capacity operational buyback costs, entry capacity incremental buyback costs and exit capacity incremental buyback costs.

increases the level of risk. We note that charges relating to capacity overruns also apply at exit but that there is no commensurate increase in our allowed revenue; we have proposed that similar arrangements should apply as at entry.

113 The licence also obliges us (subject to reasonable endeavours) to release exit capacity up to the prevailing obligated level within the gas day to which the capacity relates on all days of the year. This obligation is particularly onerous with regards to bi-directional sites (such as storage or interconnectors) where traditional planning assumptions would have assumed that such sites would be entering gas on peak days. In the future, these assumptions may need to be amended to take account of changing user behaviour (including any assumptions over the demand levels at which storage sites would inject[50]).

114 There is currently no incentive scheme relating to operational buybacks on exit. Additionally, within the UNC, there is no concept of a neutrality scheme covering the costs and revenues associated with exit capacity as there is for entry, so we are currently fully exposed to the costs of any exit constraint management actions (with the exception of a small number of specified categories[51] of costs that were allowed to be recovered via the implementation of UNC modification proposal 0195AV which enacted enduring exit reform).

115 We propose that exit costs and revenues should be included in any future incentive scheme design (and within a neutrality mechanism) as discussed within our proposals for the incentive mechanism. We recognise that implementation of such a change would require UNC code modifications and IT system changes. Costs for this are not expressly included within our SO capex submission and therefore, if material, would be captured under our proposed 'GB and EU market facilitation' uncertainty mechanism.

116 The UNC does, however, include the concept of planned maintenance days at exit. This provides us with the right to reduce exit capacity to NTS users on a pre-determined number of days for maintenance purposes without needing to buy back any associated capacity rights.

117 The original rationale for this treatment being different at exit to that at entry include:

(a) Maintenance at exit is largely a statutory activity

(b) There is generally limited competition to respond to the constraint (often a single site with one shipper and exit points are often reliant on a single feeder, limiting the opportunity to seek alternative sources of flow modification)

118 It should be noted that during the process of initialisation of the enduring exit arrangements, we released incremental exit capacity on the NTS and did not seek any additional funding to support this. Within a presentation provided to the 7 May 2009 Transmission Workstream[52], we noted that this would be likely to result in increased levels of risk above the TPCR4 settlement level and suggested that there should be "an agreement in principle to revisit this issue

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50 As part of the network analysis undertaken to support SE revenue drivers for storage sites, we have only considered storage injection at 350 mcm/d and 400 mcm/d demand levels, however recent evidence does exist of both storage sites injecting, and interconnectors exporting, on days with higher demand levels than these assumptions.

51 Those relating to users exceeding the maximum permitted offtake rate, overruns and planned maintenance

52 For details, see http://www.gasgovernance.co.uk/sites/default/files/ExitManagingincrementalsignals1_05_09.ppt

as part of the next Price Control Review (PCR) and to provide appropriate funding to manage the increased risks".

119 Within its decision letter which enacted the corresponding changes to the exit capacity baselines[53], Ofgem acknowledged our request and stated that, in principle, they agreed that this should be considered as part of the next price control – *"we regard the request to be reasonable and so we agree with the principle, but reiterate that the burden of proof for demonstrating the appropriateness of levels of funding going forward will rest with NGG NTS".*

120 Therefore, as for entry, we also need to be able to agree forecasts both for the likely level of constraint volumes and prices and the likely level of revenues to be experienced in future in order to set suitable parameters for the incentive schemes.

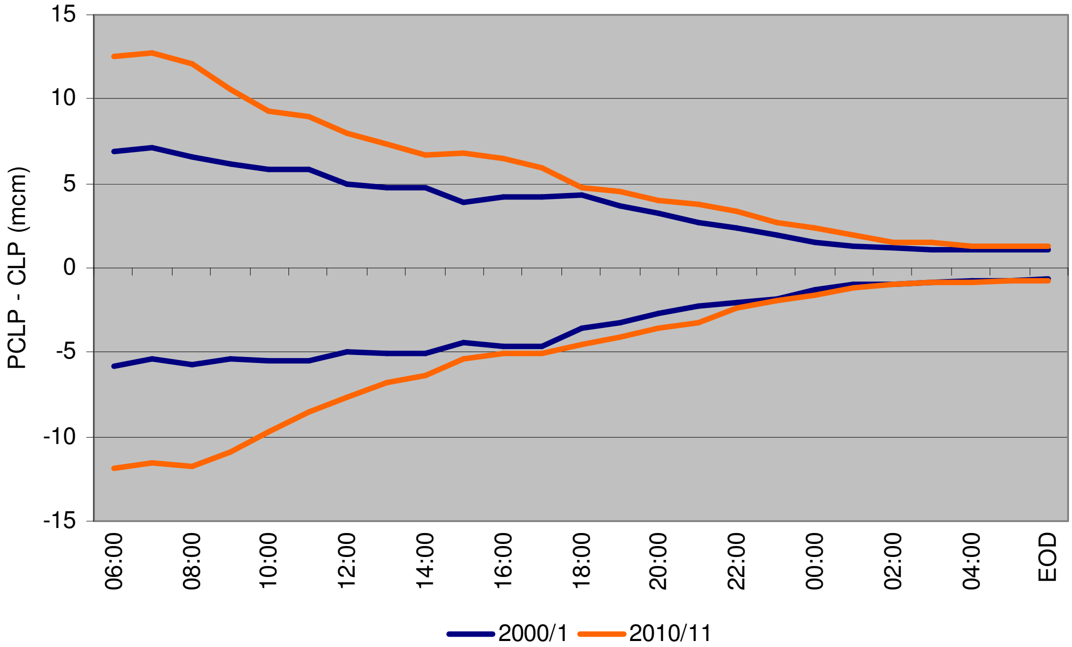
121 Additionally, our ability to accurately forecast flow patterns on the network is highly dependent on the quality of the flow information which is received from the different users of the system (shippers, Distribution Network Operators (DNOs) and Delivery Facility Operators (DFOs)). Demand is dominated by space heating and electricity generation, which in turn are weather and electricity market dependent and are therefore difficult to forecast.

122 As part of the information shared with Ofgem relating to the review of the SO incentives (relating to the Demand Forecasting incentive), we provided details[54] of the quality of the indicative flow information which we receive at various times leading up to the gas day (i.e. 1300 D-1, 1900 D-1 0600 on D) compared with actual flows. This clearly showed that across all users of the system (i.e. at LDZs, Power Stations, Industrial sites, Storage sites and Interconnectors) the quality of this information was poor. This therefore means we have a reduced level of certainty as to where the gas is likely to flow.

123 As evidence of this, the chart below shows the underlying market imbalance at the start of the gas day and the time taken for the network to balance (note this is impacted by the combination of both entry and exit flows for 2000/01 and 2010/11). It shows on average the Predicted Closing Linepack (PCLP) at the start of the gas day is around twice as far out of balance compared to ten years ago. Furthermore the time taken for the system to come into balance has also increased with PCLP – Actual Closing Linepack (CLP) values not converging to similar levels until around midnight.

[53] For details, see: http://www.ofgem.gov.uk/Networks/Trans/Archive/GasTrans/OfftakeReview/Documents1/Con%20on%20exit%20baselines%20090603.pdf

[54] Information provided to Markets division within Ofgem on 30/9/11 and subsequent information following a teleconference on 3/10/11.



124 The factor which will have the greatest impact on the volume of constraints likely to be seen on the system is the outturn supply and demand pattern annually, inter-day, within-day and against the operational forecast. We believe, in terms of level of influence, supply variability generally has a much greater impact on outturn constraint costs than demand patterns.

125 The following section includes our current view of this baseline level of risk, but note that we have only currently investigated the 2012/13 and 2020/21 formula years and so will continue to develop this work further such that we can provide more details in the SO external incentives submission in May 2012.

System access requirements

Maintenance

126 Maintenance in relation to both entry and exit is primarily driven by statutory requirements. Historically in entry there were generally multiple parties at any one ASEP and therefore competition. Exit sites on the other hand tended to be single shipper sites with no competition. Historically, therefore, maintenance has been dealt with differently within the two regimes with the existence of maintenance days on exit being a reflection of the lack of competition reducing the likelihood of competitive buyback prices being put forward. The situation on entry is now changing, however, with the reliance on a number of key entry points and reduction in number of shippers at those sites.

127 As noted above, the maintenance that we plan to carry out going forward, which impacts entry capacity, is mainly due to safety and environmental statutory reasons and given the reliance on a number of key entry points and shippers going forward, there is little competition to optimise the cost of compensation in the event of an outage.

128 For these reasons, we believe the concept of “maintenance days” should be extended to cover both entry and exit. This would entail changes to the UNC (which would clearly need industry consultation and Ofgem approval) and

contracting arrangements between Delivery Facility Operators (DFOs) and their Shippers, but would provide a better reflection of the ability we have to control these outages and could be linked to an incentive (on both ourselves and others) regarding the scheduling of maintenance.

129 We publish information about our maintenance programmes twice a year and provide details of the work to be undertaken in the forthcoming months. Where relevant, we also provide information on the effect that this maintenance will have on entry and exit capacity capability. Whilst we work closely with our customers to ensure (with reasonable endeavours) that our maintenance programme has a minimum impact on entry and exit obligations and that we coordinate with users when arranging outages[55], the absence under the current arrangements of "maintenance days" at entry mean there is a risk that significant levels of cost could be incurred if gas flows at entry and exit are not as expected.

130 We therefore propose that the concept of "maintenance days" should be extended to cover both entry and exit in order to minimise the expected cost to the end consumer. This change to the arrangements at entry means that (providing the number of days agreed is appropriate) we would not seek to include any extra costs relating to routine maintenance (as described under the Asset Health category of spend within our 'Detailed Plan' annex) within the target level for the operational buyback incentive scheme, and therefore avoid socialising such costs across the industry.

131 It is important to recognise that this is a core assumption underpinning our risk analysis, and if the arrangements concerning maintenance activities at entry were to remain unchanged, we would have to revisit our modelling assumptions.

132 In order to ensure an appropriate number of "maintenance days" are set, we are considering proposing an incentive surrounding the use of maintenance days at both entry and exit (covering both the use of such days and the re-scheduling of any maintenance programmes). We will continue to develop our thinking in this area and will include it within our May 2012 SO external incentives submission.

Construction and commissioning activities

133 Delivery of triggered incremental capacity will require system access for construction activities (such as pipeline tie-ins) and commissioning activities (such as compressor commissioning).

134 Planned maintenance activities are generally set actions that are carried out year-on-year in accordance with established procedures, requiring relatively short timescales to complete. They generally require no gas flow at all, or a reduced flow below a defined level in order for the maintenance to be carried out safely.

135 Construction and commissioning activities on the other hand generally require a specific level of gas flow to be maintained for defined periods of time, which can be over several consecutive days.

[55] Note that historically, changes to maintenance outages have been predominately driven by user requests (68% users, 32% NG).

136 The scale and frequency of construction and commissioning activities means it is not appropriate for maintenance days to be used and therefore buybacks and/or contractual solutions will be required to make the necessary arrangements for required flows with the affected parties.

137 We therefore propose that when these activities are required, which will be in relation to triggered incremental capacity, the cost of any actions necessary to achieve required flows from affected parties should be covered by the incremental entry and exit capacity uncertainty mechanism and factored into our costs of delivering that incremental capacity (and therefore feed into the capacity buyback target as incremental investment buybacks).

138 In a similar manner, the impact on constraint management costs of investment relating to either Network Flexibility or IED will need to be assessed. The relevant uncertainty mechanism should propose the appropriate adjustment to the constraint management target.

Current view of the baseline level of risk on the system

139 The modelling which was outlined within the July RIIO-T1 submission only focussed on entry capacity constraints. Due to the interconnected nature of the network in reality a constraint on the network could be addressed via a combination of actions at entry and exit points. Therefore further work has been undertaken to develop this modelling further such that risks over the system as a whole are now considered. An overview of this revised methodology (including the supply/demand assumptions used) is outlined within Appendix B.

140 The new modelling approach therefore uses a probabilistic range of supplies and demands to create a forecast of the likely level of risks due to capacity constraints on the system (i.e. it covers both entry and exit capacity) within a distribution curve. The physical capability of the network is a function of both entry and exit flows, within the constraints of allowable pressures and flow rates. Given the modelling is now based on constraint management risk on the system as a whole, we believe that any future incentive schemes should be developed to cover constraint management costs as a combined scheme (i.e. it should cover both entry and exit capacity).

141 Note that the results from the modelling need to be considered in the context of the simplifying assumptions which have been employed, such as:

(a) The range of supply/demand conditions used in the modelling

(b) It is based on end of day flow patterns only at an assumed hourly flow rate of 1/24th end of day position (i.e. it does not cover transient or within-day analysis) or inter-day transitions[56]

(c) It does not assume any outages on the system (i.e. for maintenance or construction activities)

(d) It assumes Assured Offtake Pressures are met.

[56] The current modelling is based on steady state analysis. This was the first stage in the capacity modelling process, and we plan to develop this capability to model both static and transient analysis in the future. This will require a significant amount of development due to the increased complexity associated with the transient methodology, and we expect this to take 12-18 months to develop.

142 The second point above, relating to intra- and inter-day flow patterns, is fundamental to Network Flexibility. Rather than attempting to cost this material risk into the incentive target, where our network analysis (coupled with operational experience and wider information from such sources as TBE) indicate such gas flow patterns (and changes in patterns) are likely to cause operational issues in the future, we will bring this forward for consideration under the Network Flexibility uncertainty mechanism.

143 The last point above, relating to maintenance, is exacerbated by work required to meet the requirements of the Industrial Emissions Directive. The legislative timescales dictate that this work is condensed into very tight timescales which do not allow for any slippage and therefore cannot in most cases be deferred to avoid causing a constraint. In addition, the tight timescales mean that if a project takes longer than planned, multiple compressor stations could be on concurrent outages in addition to within-year planned and unplanned maintenance.

144 The impact of this programme of work has been included in the analysis, however, given the risks around delivery in such a tight timeframe, the outturn levels of costs are likely to be higher. Given the location of the compressor stations and the interactions between them, we have developed an optimised outage plan in order to minimise the impacts of this work on the network. *[text deleted]*

145 The costs associated with securing required system outages to complete construction activities required to deliver incremental capacity have, however, not been included in this analysis. We propose that, should an incremental capacity signal be received, the incremental risk associated with the required construction and commissioning activities are considered as part of the proposed incremental entry and exit uncertainty mechanism.

146 Note that constraints the model identified can be resolved via a combination of actions, either at entry or exit. Where possible we have chosen to resolve constraints in our modelling at entry as this allows us to use established methods to calculate volumes and costs. At entry points the current choices are between buybacks (prompts, forwards or options) or locational actions and clearly this affects the costs that the model produces. In order to assess the sensitivity of the outturn costs to these assumptions we have included three potential outturn cost options based on:

(a) Case 1: an assumption that 100% of the constraints identified are resolved by buyback actions and that the price of these is 1p/kWh[57;]

(b) Case 2: an assumption that 25% of the constraints identified are resolved by locational sell actions[58] and 75% buyback actions (again using the price of 1p/kWh).

(c) Case 3: an assumption that 50% of the constraints identified are resolved by locational sell actions (but again that only 50% of these

[57] This price assumption is based on previous experience of buyback actions. It also allows the resultant costs to be easily scaled if other price assumptions are used.

[58] Note that Locational Sell actions may result in a revenue into both Entry Capacity Neutrality and the current operational Buyback scheme, however this may be negated by costs relating to any corresponding locational buys to keep the system in balance. In this modelling, we have assumed that only 50% of the locational sell actions need a corresponding locational buy action. The Locational actions have been priced relative to an assumption for SAP of 50p/th (1.71 p/kWh).

actions also require a corresponding locational buy) and 50% buyback actions (again using the price of 1p/kWh).

147 To date, locational actions have been used in situations where they were felt to be the most economic and efficient response to the constraint. The benefit of these actions has been shared with the industry via the capacity neutrality scheme and the sharing factor within the incentive under the licence[59]. Given the limited operational experience of the use of locational actions, there is no certainty that these will continue to be used into the future.

148 We look to resolve constraints at the least cost to the community (and therefore aim to have incentives which align to this). We will look to employ management actions if possible to reduce costs (such as using locational sell actions, which will need to be balanced with a locational buy option to avoid creating a supply/demand imbalance on the network).

149 As a starting position, we believe that the Case 3 assumption above (i.e. 50% locational sell actions and 50% buyback actions) represents a reasonably balanced view of likely outcome costs, but clearly if we find that the market is not responsive in the future to tenders for such actions (as has been seen in the past when tenders for Operating Margins have been issued), we may be forced to employ more constraint cost actions and this assumption would need to be reviewed.

150 We also recognise that our ability to utilise locational sell actions may also depend on the number of days we need to take action and the volume of constraint being addressed, as repeated locational trades at a specific point on the network may potentially open the market to abuse. We will therefore continue to develop our thinking with regards to this such that we can provide a more informed position within the May SO external incentives submission.

151 In our current modelling, we have allowed for capacity buybacks to procure through unused 'space' in capacity holdings before assuming an effect on flows. We have also modelled locational actions (by using our experience to date) that locational sells have tended to cost 0.7 times System Average Price (SAP) and locational buys 1.6 times SAP, and also assumed that 50% of locational sell actions will need to be balanced by a locational buy. We will also continue to review these assumptions for our May 2012 SO external incentives submission.

152 This year we have been able to manage system constraints through a combination of bi-lateral contracts and locational actions. As the system has frequently been long (i.e. supply outweighing demand), we have sold gas on a locational basis without the need to buy on a locational basis to balance the network (i.e. the act of selling to manage the constraint helped to balance the system). Into the future, we cannot assume a long system each time we need to manage a constraint, therefore have assumed that on 50% of occasions we will need to perform a locational buy to balance the location sell.

[59] For details of the actions taken so far in 2011/12, see http://www.nationalgrid.com/NR/rdonlyres/C25F1ADE-DB8A-4E20-A969-15205E475B07/51688/OperationalOverview_Feb2012.pdf

153 Using the costing assumptions under Case 3, performance for the current formula year to date (April 2011 to December 2012 inclusive)[60], would be as per the following table:

Cost element	Cost (£m)
Capacity management agreements	1.5
Revenue from Locational sell actions	(1.2)
Other revenue (WDDSEC/DAI/Overruns/Non-obligated)[61]	(0.5)
Total net cost	**(0.2)**
Calculated cost of balancing locational buy actions[62]	1.8
Calculated total net cost	**1.6**

154 This demonstration provides a reasonable comparator to the results of the analysis shown below for the 2012/13 formula year for Case 3.

155 The initial set of modelling analysis has been conducted based on two formula years; 2012/13 and 2020/21 but we plan to provide further evidence within the May 2012 SO external incentives submission relating to modelling of other years within the RIIO-T1 period.

156 The following sections provide an initial indication of the potential range of the underlying constraint management risk expected for the 2012/13 and 2020/21 formula years, but should be considered in conjunction with the assumptions outlined above (i.e. that the modelling is based on the particular range of supply/demand scenarios considered, end of day flow patterns and takes no account of any plant failure or maintenance activities).

2012/13 formula year

157 The initial analysis of the 2012/13 formula year indicates the potential level of underlying constraint management risk (and associated cost under the three different cost options) is as per the following table:

	Forecast number of constraint days for 2012/13 formula year	Volume (mcm)	Volume (GWh)	Total Cost[63] (£m)		
				Case 1	Case 2	Case 3
Minimum	0	0	0	0	-3	-55
Maximum	71	1055	11609	116	116	167
Mean	**5**	**80**	**875**	**9**	**7**	**5**
10%	0	0	0	0	0	0
50%	3	44	486	5	4	2
90%	14	203	2230	22	16	11

60 Current formula year to date data is available at http://www.nationalgrid.com/NR/rdonlyres/C25F1ADE-DB8A-4E20-A969-15205E475B07/51688/OperationalOverview_Feb2012.pdf and shows a net revenue position of £154k.
61 WDDSEC: Within Day Daily System Entry Capacity. DAI: Day Ahead Interruptible
62 Calculated by applying the assumption that locational sell actions receive 0.7*SAP, and locational buy actions cost 1.6*SAP, this gives a calculated cost of ((£1.2m/0.7)*1.6)=£3.5m is all locational sell actions were balanced by locational buy actions. We are assuming 50% locational sell actions will require balancing, therefore the calculated cost shown in the table is (£3.5m*50%)=£1.8m
63 Note that the Total Cost is the net position of costs less revenues (where relevant)

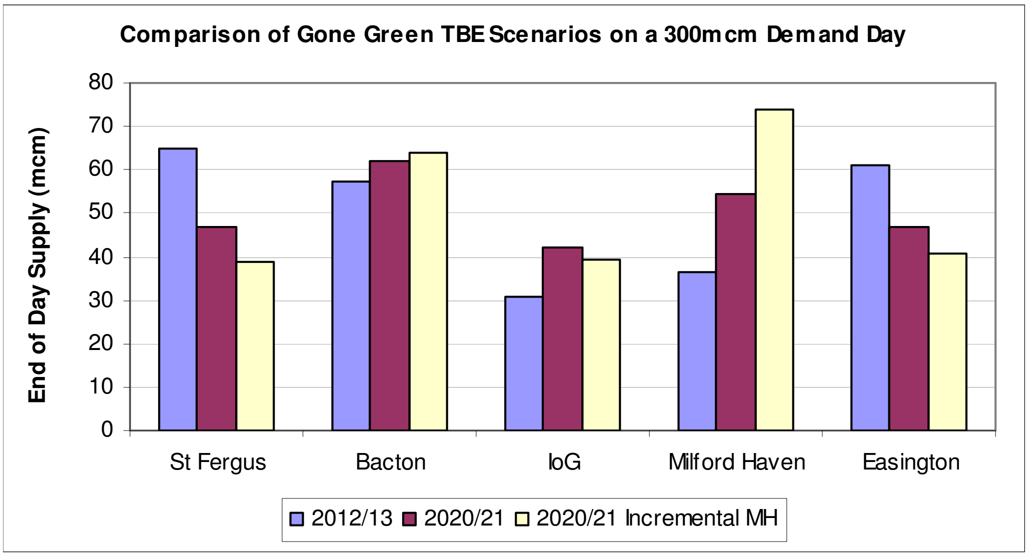
158 The figure above shows that there is an expectation of 5 days (in the range 0 to 14 days with 80% confidence) when constraints are likely to be seen within the year and that the expected constraint volume over those days would be 80 mcm or 875 GWh (i.e. 175 GWh/d on average). Using the three cost options outlined above (Case 1, Case 2 and Case 3), this indicates that the expected cost for 2012/13 could be between £4.5m (with the 80% range between -£0.1m to £11.2m) and £8.8m (with the 80% range between zero to £22.3m) depending on the assumption regarding the constraint volume which would be resolved via buyback actions and which would be by locational action, and the price which was ultimately paid.

159 This analysis provides an indication of the inherent level of risk within the system for the 2012/13 year, under steady state conditions with an intact network, and shows the wide range of uncertainty of constraints, which is a direct consequence of the uncertainty of supply location. In order to examine how the level of risk could change over the RIIO-T1 period, analysis has also been undertaken for the 2020/21 formula year. However, we recognise that in order to form a more complete picture, further work will also be needed to perform extra analysis on intervening years and this is planned to take place in the period leading up to the SO external incentives submission in May 2012.

2020/21 formula year with current network capability

160 We have undertaken further analysis to derive an initial view of the level of risk expected during the 2020/21 formula year assuming that no extra capability is provided on the system, assuming demands consistent with the Ten Year Statement and supplies consistent with data from our Gone Green Transporting Britain's Energy (TBE) scenario. Further detail on the supply and demand assumptions used within the analysis is included in Appendix B of this annex.

161 The graph[64] below shows, for a 300mcm/d demand day (i.e. an 'average' day) the changing supply mix over the period at each of the five main supply points. Our analysis has been completed assuming no incremental capacity on the network, and has also investigated the sensitivities around incremental capacity at Milford Haven (as an example) – these are discussed below.



[64] The data in the graph is based on the Gone Green TBE scenario and does not include the range of uncertainty that is generated by the methodology used for forecasting entry and exit capacity constraint volumes and costs.

162 This analysis indicates that the potential level of underlying constraint management risk (and associated cost under the three different cost options) is as per the following table:

	Forecast number of constraint days for 2020/21 formula year	Volume (mcm)	Volume (GWh)	Total Cost (£m)		
				Case 1	Case 2	Case 3
Minimum	0	0	0	0	-1	-139
Maximum	89	1501	16507	165	201	178
Mean	**12**	**184**	**2028**	**20**	**16**	**11**
10%	3	46	509	5	3	1
50%	9	134	1476	15	11	6
90%	25	376	4138	41	32	24

163 For this scenario, the figure above shows that there is an expectation of 12 days within the year when constraints would occur (in the range 3 to 25 days with 80% confidence) and that the expected constraint volume within the year would be 184 mcm or 2028 GWh (i.e. 169 GWh/d on average). Using the three cost options outlined above (Case 1, Case 2 and Case 3), this indicates that the expected cost for 2020/21 could be between £11.0m (with the 80% range between £0.8m to £24.0m) and £20.3m (with the 80% range between £5.1m to £41.4m) depending on the assumption regarding the constraint volume which would be resolved via buyback actions and which would be by locational action, and the price which was ultimately paid.

164 The analysis shows that the average level of constraint volume is slightly greater in 2020/21 than in the 2012/13 year. Under very high demand (550mcm/d) conditions, the highest Milford Haven supply in the TBE data in gas year 2012/13 is 70.8mcm/d, but this increases to 83.7mcm/d in gas year 2020/21. Correspondingly, the highest supply at St Fergus decreases from 87mcm/d to 66mcm/d over the same timeframe. This analysis does not assume any incremental investment in network capability. It is unsurprising, therefore, that the mean number of days on which constraints could be seen over the period increases from 5 to 12 (in the range 3 to 25), and that the likely level of constraint costs is likely to increase over the RIIO-T1 period. This increase is primarily driven by the assumption of a more varied supply/demand mix.

165 Given that we expect the supply/demand patterns to change within the RIIO-T1 period, we believe that the analysis of this year is more representative of the level of risk that we face during the period. However, as noted above, we plan to undertake further analysis of more years within the RIIO-T1 period to inform the May 2012 SO external incentives submission to validate this assumption.

2020/21 formula year - the effect of one large supply project – *[text deleted]* with no additional investment to support incremental capacity

166 A further sensitivity has been performed to examine how the level of risk could change over the RIIO-T1 period if an incremental capacity signal were to be seen on the system. For this scenario, the 2020/21 formula year has been analysed assuming that no extra capability is provided on the system (i.e. no incremental investment has been made), but that extra supplies of 300 GWh/d

are seen *[text deleted]*. We have made the same supply and demand assumptions as above, and have also assumed Shippers will attempt to make use of the incremental capacity.

167 This analysis indicates that the potential level of underlying constraint management risk for this formula year is as per the following table:

	Forecast number of constraint days for 2020/21 formula year	Volume (mcm)	Volume (GWh)	Total Cost (£m)		
				Case 1	Case 2	Case 3
Minimum	1	37	412	4	0	-65
Maximum	205	8441	92848	928	901	865
Mean	**52**	**2186**	**24049**	**240**	**185**	**127**
10%	12	527	5800	58	40	19
50%	45	1880	20680	207	154	83
90%	99	4181	45986	460	375	315

168 The figure above shows that there is an expectation of 52 days within the year (in the range 12 to 99 days with 80% confidence) that constraints could be seen in 2020/21 and that the expected constraint volume within the year is 2186 mcm or 24049 GWh (i.e. 462 GWh/d on average). Using the three cost options outlined above (Case 1, Case 2 and Case 3), this indicates that the expected cost for 2020/21 could be between £127m (with the 80% range between £18.8m to £315.1m) and £240m (with the 80% range between £58m to £460m) depending on the assumption regarding the constraint volume which would be resolved via buyback actions and which would be by locational action, and the price which was ultimately paid.

169 This analysis shows that if extra supplies (i.e. gas flows) are seen *[text deleted]*, the anticipated level of constraints is likely to increase greatly (from an expectation of 12 days per year to 52 days per year). Additionally the constraint volume which is likely to be seen on each of those days increases from 169 GWh/d to 462 GWh/d (i.e. roughly by the 300 GWh/d increment which has been assumed). Given that this modelling run assumed no extra network capability being provided, this is not an unsurprising result.

2020/21 formula year - the effect of one large supply project – *[text deleted]* with future network capability

170 The final scenario which has been modelled has again assumed an incremental signal *[text deleted]*, but this time has been based on expanded network capability commensurate with the projects outlined within the RIIO-T1 plan. The total value of the projects which have been identified to support increased flows of between 150 GWh/d and 300 GWh/d *[text deleted]* is £893.2m[65] over the RIIO-T1 period. We have made the same supply and demand assumptions as above.

[65] As shown in table 5.10 – note these figures are excluding RPE

171 This analysis indicates that the potential level of underlying constraint management risk for this formula year is as per the following table:

	Forecast number of constraint days for 2020/21 formula year	Volume (mcm)	Volume (GWh)	Total Cost (£m)		
				Case 1	Case 2	Case 3
Minimum	0	0	0	0	-7	-70
Maximum	111	3780	41583	416	331	349
Mean	**9**	**324**	**3563**	**36**	**28**	**20**
10%	1	37	407	4	4	0
50%	7	240	2644	26	20	12
90%	18	645	7095	71	56	40

172 The figure above shows that there is an expectation of 9 days within the year (in the range 1 to 18 days with 80% confidence) where constraints could be seen in 2020/21 and that the expected constraint volume within the year is 324 mcm or 3563 GWh (i.e. 396 GWh/d on average). Using the three cost options outlined above (Case 1, Case 2 and Case 3), this indicates that the expected cost for 2020/21 could be between £19.8m (with the 80% range between zero to £40m) and £36m (with the 80% range between £4m to £71m) depending on the assumption regarding the constraint volume which would be resolved via buyback actions and which would be by locational action, and the price which was ultimately paid.

173 This analysis shows that with the extra investment on the system the anticipated number of days when constraints would be experienced has fallen back to levels close to those expected in 2020/21 before any extra supplies were considered (i.e. 9 in this case compared with 12 from the initial 2020/21 analysis). It also shows that the investments included within the plan reduce the expected number of constraint days greatly (from an expectation of 52 days per year to 9 days per year). Again, this is not a surprising result.

174 However, the analysis shows that the investments which have been included within the plan do not build out all of the risk of the additional *[text deleted]*. When constraints are forecast to occur, the anticipated volume which could occur on those days is 396 GWh/d. To achieve a reduction back to expected levels of risk in 2020/21 before any extra supplies were considered would require *[text deleted]* additional investment. As this investment would only reduce modelled buyback costs by £9m per annum (i.e. from £20m to £11m under Case 3 shown in the tables above), the most efficient answer for industry is to face the risk of the buyback over the certainty of funding this additional investment.

Effects of TO planned work regarding IED (LCP and IPPC)[66]

175 As noted above, we have proposed that the concept of 'maintenance days' should be introduced at entry to cover off routine maintenance and asset health investment activities hence have not included any costs relating to this activity.

[66] The Industrial Emissions Directive incorporates the Large Combustion Plant and Integrated Pollution Prevention and Control legislation

176 We recognise that the aggressive schedule of work which will need to be undertaken in response to the IED legislation will have a significant effect on the capability of the system (particularly given the location of the particular compressors being identified as needing replacement) and beyond what could be considered a 'routine' activity. We need to undertake this level of work for statutory reasons, however, it is a one off requirement that will result in a peak of activity rather than ongoing year-on-year work, therefore we propose that a suitable adjustment is made to the operational buyback target for the relevant years to cover this risk and that it is not incorporated into any 'maintenance days'.

177 To be clear this target cost relates to the activities associated with the baseline level of funding for IED (both LCP and IPPC) which is included within our TO plan (£631m and £255m respectively over the RIIO-T1 period only). Our working assumption is that the IED Uncertainty Mechanism (which relates to changes in scope of the IED itself), if triggered, would also derive suitable proposals for how the operational buyback target should be amended into the future.

178 In order to quantify the effect on system capability, we have undertaken an exercise to investigate the effect that this level of work will have on the capability of the system and as a result have devised an optimised schedule (given current information) over the RIIO-T1 period to comply with the IED legislation. It is worth noting that the phasing of compressor outages as set out in our investment plan may not represent the fully optimised schedule as we continue to refine this schedule as new information arises (such as incremental capacity signals, or better information becomes available relating to the duration of outage requirements). This is covered in more detail in the 'Compressor investment strategy' Appendix to our 'Detailed plan' annex.

179 Our planned schedule for this work covers the 2014/15 to 2020/21 years of the RIIO-T1 period. For each of these years we have used the 2020/21 formula year case (with current network capability) as a base for the level of inherent risk on the system (as shown within paragraph 162). We have then built on top of this the forecast effect of the planned maintenance using the same three costing options (Case 1, Case 2 and Case 3).

180 The results for the Case 1 costing option (i.e. 100% of constraints are resolved by buybacks) are shown in the following table[67].

	Total Cost (£m) - Case 1 Inherent risk (including IED programme)						
	2014/15	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**
Minimum	15	42	19	0	22	34	15
Maximum	219	274	219	171	225	240	219
Mean	**64**	**97**	**66**	**29**	**73**	**88**	**64**
10%	43	70	44	12	50	63	43
50%	60	94	62	24	69	84	60
90%	89	127	91	51	98	116	89

[67] It is worth noting that the only material buyback of recent years related to the construction activity to complete the Feeder 29 tie-in. This same situation would have arisen for a number of other drivers, such as in line inspections, pipeline defect resolution and commissioning activities.

181 By comparing the above with the table in paragraph 162, we can see that for the year with the lowest level of planned outages due to the IED programme (2017/18), the total cost is now £29m on average (compared with the previous £20m), hence the extra level of inherent risk on the system is forecast to be £9m on average. Conversely for the 2015/16 year (which is the one with the highest number of stations on outages), the extra costs are forecast to be £77m on average.

182 The results for the Case 2 costing option (i.e. 75% of constraints are resolved by buybacks, 25% by locational actions) are shown in the following table:

	Total Cost (£m) - Case 2 Inherent risk (including IED programme)						
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Minimum	9	18	7	-6	14	12	9
Maximum	239	275	239	210	250	261	239
Mean	**48**	**71**	**49**	**20**	**53**	**64**	**48**
10%	29	47	29	6	32	41	29
50%	44	68	45	16	49	60	44
90%	70	98	71	38	77	89	70

183 By comparing the above with the table in paragraph 162, we can see that for this costing assumption, the year with the lowest level of planned outages due to the IED programme (2017/18), the total cost is now £20m on average (compared with the previous £16m), hence the extra level of inherent risk on the system is forecast to be £4m on average. Conversely for the 2015/16 year (which is the one with the highest number of stations on outages), the extra costs are forecast to be £55m on average.

184 The results for the Case 3 costing option (i.e. 50% of constraints are resolved by buybacks, 50% by locational actions) are shown in the following table:

	Total Cost (£m) - Case 3 Inherent risk (including IED programme)						
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Minimum	-126	-122	-126	-140	-127	-119	-126
Maximum	242	255	245	185	248	261	242
Mean	**34**	**49**	**34**	**15**	**37**	**44**	**34**
10%	12	21	12	2	13	18	12
50%	29	44	29	10	32	39	29
90%	59	83	60	31	66	76	59

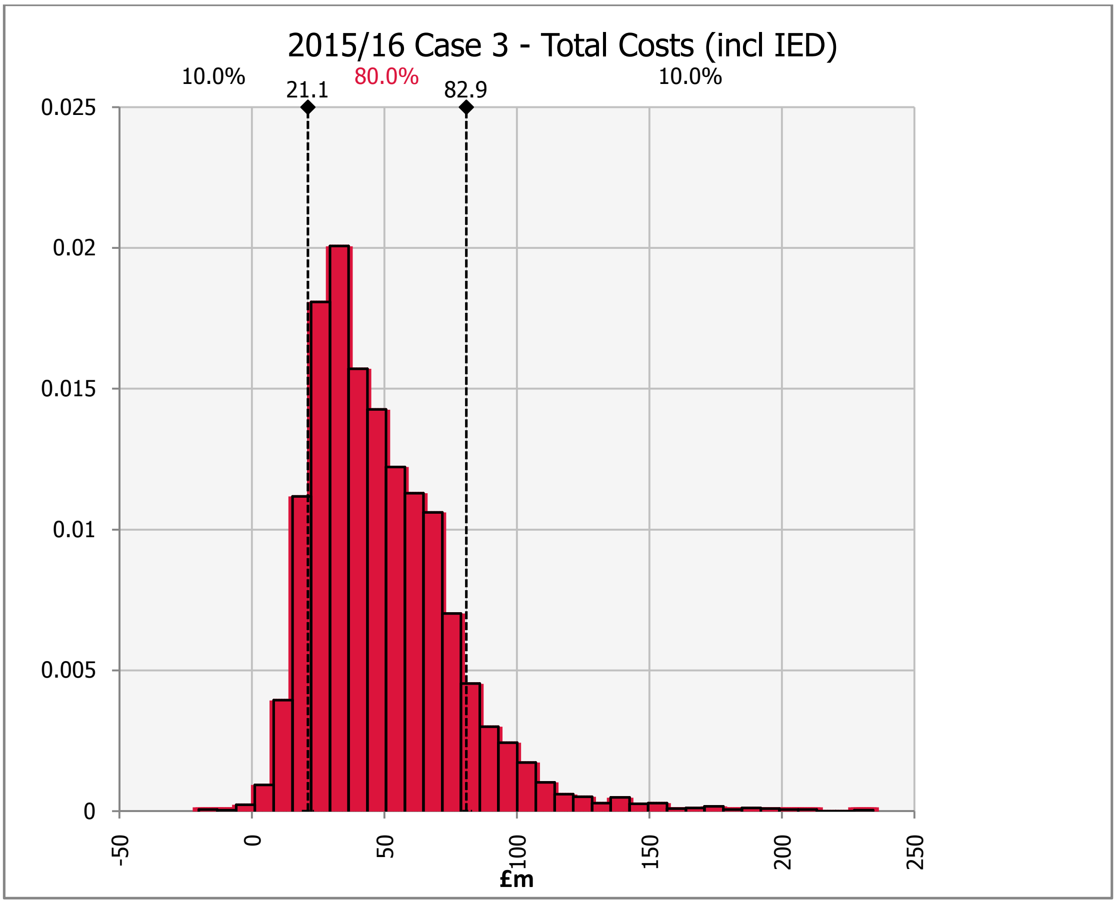
185 By comparing the above with the table in paragraph 162, we can see that for this costing assumption, the year with the lowest level of planned outages due to the IED programme (2017/18), the total cost is now £15m on average (compared with the previous £11m), hence the extra level of inherent risk on the system is forecast to be £4m on average. Conversely for the 2015/16 year (which is the one with the highest number of stations on outages), the extra costs are forecast to be £38m on average.

186 This analysis shows that the forecast impact of the IED programme on constraint costs varies greatly over the different years of the RIIO-T1 period.

Again the forecast level of costs depends on the pricing assumption that has been adopted. For example looking at the year with the lowest level of planned outages due to the IED programme (2017/18), the extra costs above the inherent risk levels on the system are forecast to be between £4m and £9m on average. Conversely for the 2015/16 year (which is the one with the highest number of stations on outages), the extra costs are forecast to be between £38m and £77m on average.

187 The results included in this annex represent our initial view of the impact of the IED workplan on constraint costs, but clearly this is a very aggressive programme and there is a risk that the work could overrun (especially given the interaction with other outages on the system), hence the profile of costs could change greatly as more assessment is done. We will therefore continue to refine our view of the impact of this programme to inform the May 2012 SO external incentives submission.

188 Note that there is a wide spread of the likely level of net cost for each of the years as shown in the following graph for the Case 3 scenario (inherent risk including the IED programme) for the 2015/16 year:



189 Given the level of uncertainty, the range of factors outside our control (such as the price Shippers will charge for capacity buybacks, and the premium they will demand for locational actions) and the associated wide range of potential outcomes, it is clear that unlimited exposure to the cost of constraint management is not appropriate. We will therefore be proposing caps and collars to the capacity buyback incentive scheme in our May 2012 SO external incentives submission.

Other revenue forecasting

190 The expected levels of revenue (primarily from the sales of the relevant capacity products which are included within the incentive framework) affect the arrangements concerning entry and exit capacity in slightly different ways. This is explored in more detail below.

191 However, notwithstanding these differences, it is impossible to forecast the levels of revenue which are likely to be received from the sale of the various types of either entry or exit capacity which are relevant to constraint management or from other sources such as overruns as these are hugely influenced by the prevailing commercial framework and the obligations contained in the licence.

Existing entry scheme

192 As noted above, under the current incentive arrangements concerning entry capacity, there are several different revenues which feed into the performance measure for the entry capacity operational buyback scheme.

193 Over the last few years, whilst there has been an increase in the volume of capacity sales seen on the day (of both firm and interruptible), the revenues due from those sales has decreased (due to the zero reserve price for these auctions).

194 The following figure provides a summary of the levels of the various revenues which are included within the entry capacity operational buyback scheme that have been experienced over the last few years:

	Formula year				
	2007/8	2008/9	2009/10	2010/11	2011/12[68]
Within day Firm	0.84	0.08	0.11	0.14	0.06
Interruptible	1.04	0.37	0.44	0.32	0.16
Non-obligated	0.08	4.41	0.12	0.71	0.40
Overruns[69]	1.66	0.82	0.82	5.29	0.15
Locational Sells	0.00	0.00	0.00	2.35	1.19
Total	**3.61**	**5.69**	**1.49**	**8.80**	**1.96**

195 The figure above clearly shows that the various revenues have been variable over the last few years and therefore it will be difficult to forecast into the future with any certainty what the likely levels of these revenues will be. In previous settlements, revenues have been explicitly included the capacity buyback target. We will consider an appropriate allowance in more detail and will outline our thinking in the May 2012 SO external incentives submission.

Management response

196 If constraint costs were forecast to be large and could be predicted at any given location, we would endeavour to enter into contracts to mitigate these costs

[68] Note for the current formula year, data is only included up to 31 January 2012.
[69] Note that the revenues from overruns relate to Shippers flowing gas without having associated capacity rights. These revenues are therefore completely outside our control.

using the range of commercial actions available to us (such as options or forwards, or other contracts to secure turn up or turn down contracts provided there is a liquid locational market).

197 We have already noted that we have little control over the outturn supply/demand conditions experienced. However, we can ensure that the levels of investment on the system and the commercial solutions we explore are appropriate to mitigate the risk of considerable constraint costs occurring (as noted for the 2020/21 scenario with the effect of one large supply project).

198 As outlined in our 'Detailed plan' annex, if certain investments in our baseline plan were omitted (most notably the ones identified as Network Flexibility, but also some under Asset Health), constraint costs could rise dramatically. Therefore there is a direct linkage between the level of investment we undertake and the costs of dealing with any potential constraints on the system (either in terms of commercial contract costs to mitigate the risks or outturn costs themselves). Additionally, it should be noted that during the construction and commissioning phases, there will be a direct impact on the capability of the system.

199 In terms of costs relating to maintenance and asset health investment, we liaise with users regarding our system access planning and constantly keep our outage schedule under review. In working with our customers to plan system access, we request outage programmes from relevant and impacted industry parties to facilitate alignment of outages where feasible and to reduce the potential impact of carrying out the work required. If flow patterns were forecast to change adversely, we would seek to amend this in order to mitigate excessive costs to ourselves, the affected users and the Industry. Our proposal to introduce an incentive scheme on Maintenance will help to ensure that we use this constraint management tool in an efficient way, balancing the commercial risk of facilitating system access against the customer impact of moving it.

Proposed risk sharing arrangements

Summary

200 We note that the risks we face relating to constraint management actions associated with the release of entry and exit capacity are not the same due to the differing treatment under both the licence and the UNC.

201 However, we believe that common arrangements should be devised such that a single incentive scheme should be created which would cover both entry and exit capacity based on the form of the current operational entry capacity buyback scheme. This means that the performance measure should capture all the relevant costs and revenues (covering both entry and exit) and this would be compared to a target level subject to sharing factors and caps and collars.

202 We have proposed that the treatment of maintenance (including ex-ante funded asset health investment) under the UNC should be amended such that there is a fixed number of "maintenance days" per ASEP applicable for entry, and we note that it may be prudent to review the number at exit. Clearly if this is not acceptable by industry, then the suggested level of costs from our analysis would need to be revisited.

203 In order to ensure the efficient use of such 'maintenance days', we are considering proposing an incentive surrounding the use of maintenance days at both entry and exit (covering both the use of such days and the re-scheduling of any system access programmes). We will continue to develop our thinking in this area and will include within our May 2012 SO external incentives submission.

Future analysis to be provided in the SO external incentives submission in May 2012

204 Given the importance of fully understanding the risks throughout the RIIO-T1 period, we will continue to investigate the likely level of underlying constraint risk on the system in order to feed into the SO external incentives submission in May.

205 The elements of our constraint / buyback analysis and associated proposals that we will investigate further and feed into our SO submission in May are:

(a) The assumptions we have made when analysing costs arising from constraints, in particular in relation to locational buys and sells

(b) The affect of unplanned outages on the inherent level of risk in the system

(c) The impact of the work programme to comply with the IED on the level of risk on the system

(d) Further analysis on the inherent levels of risk in the years between 2012/13 and 2020/21

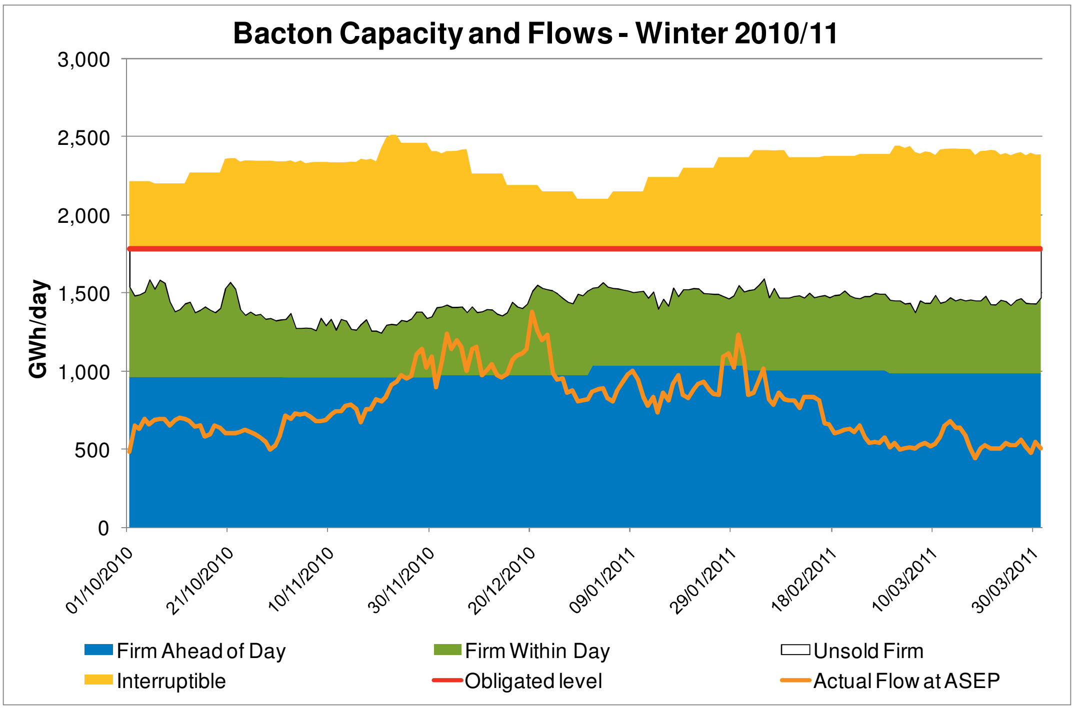
(e) Our proposals for the design and appropriate parameters of the incentive scheme

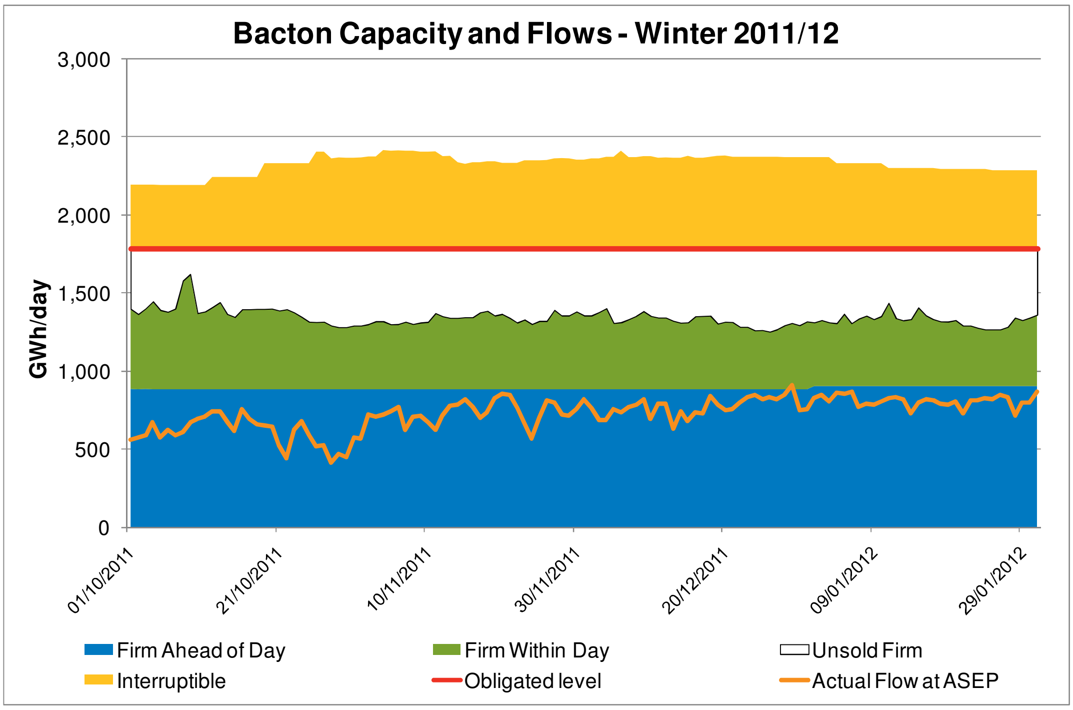
(f) Our proposals for a maintenance incentive.

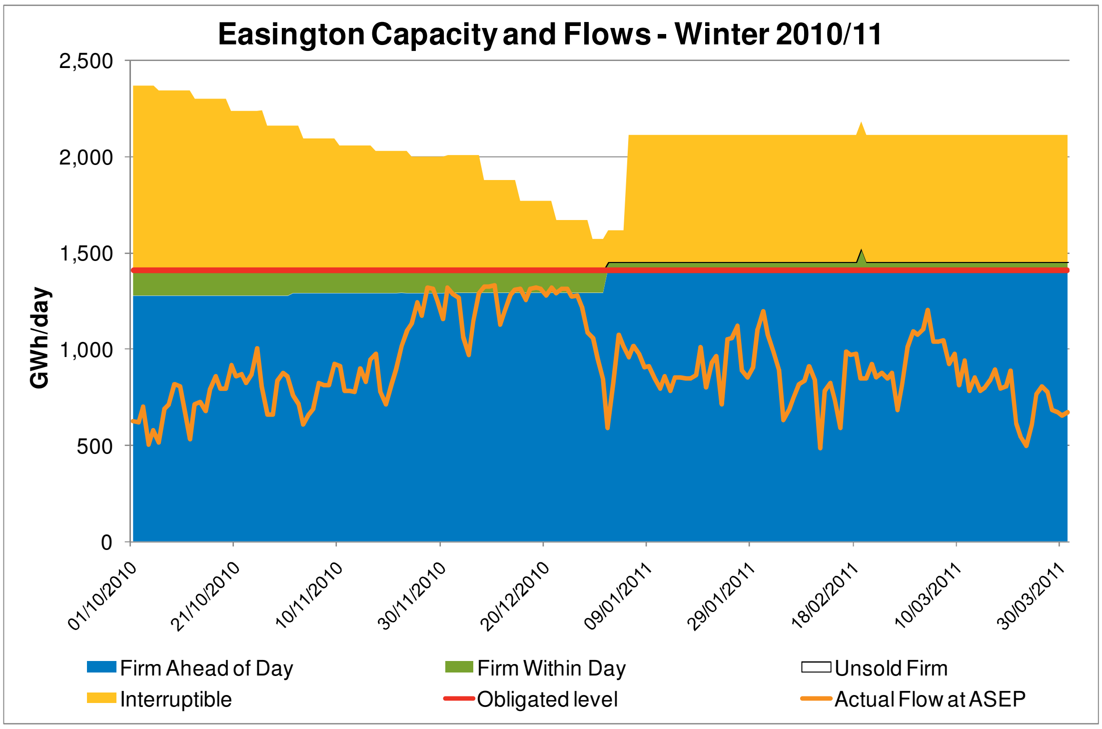
Appendix A: ASEP capacity bookings

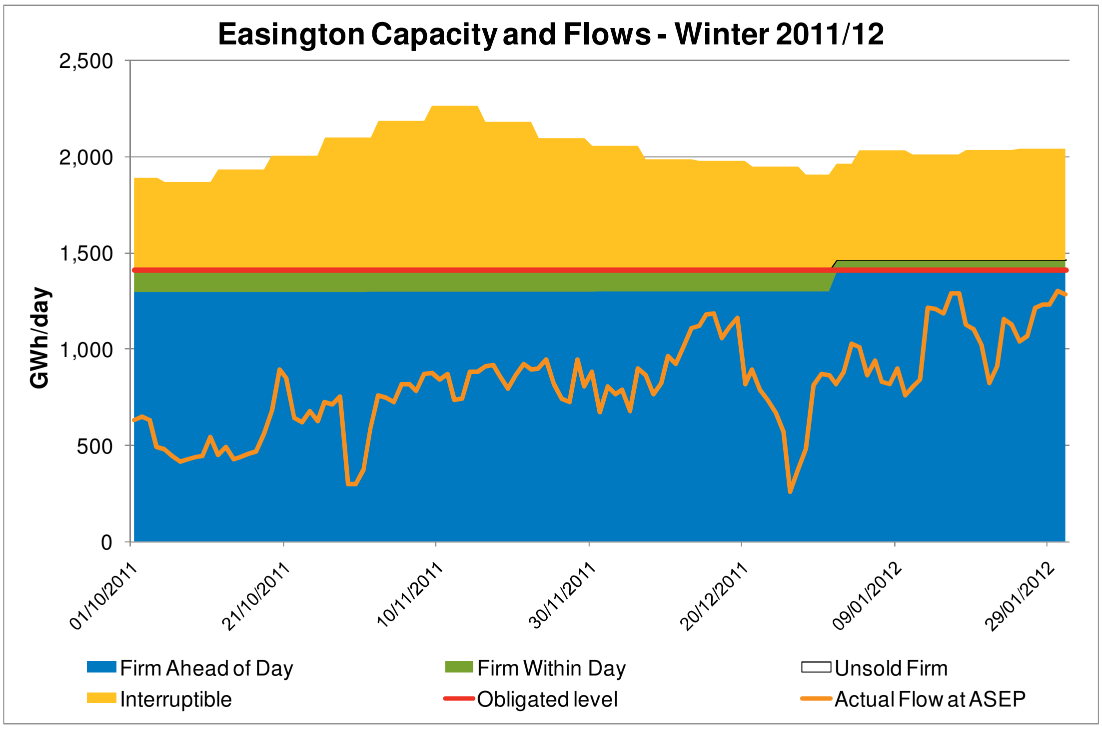
This is an unchanged extract from our 'Managing Risk and Uncertainty' Annex of the March 2012 RIIO-T1 business plan submission and for convenience we have used the same paragraph numbering as was used within that submission.

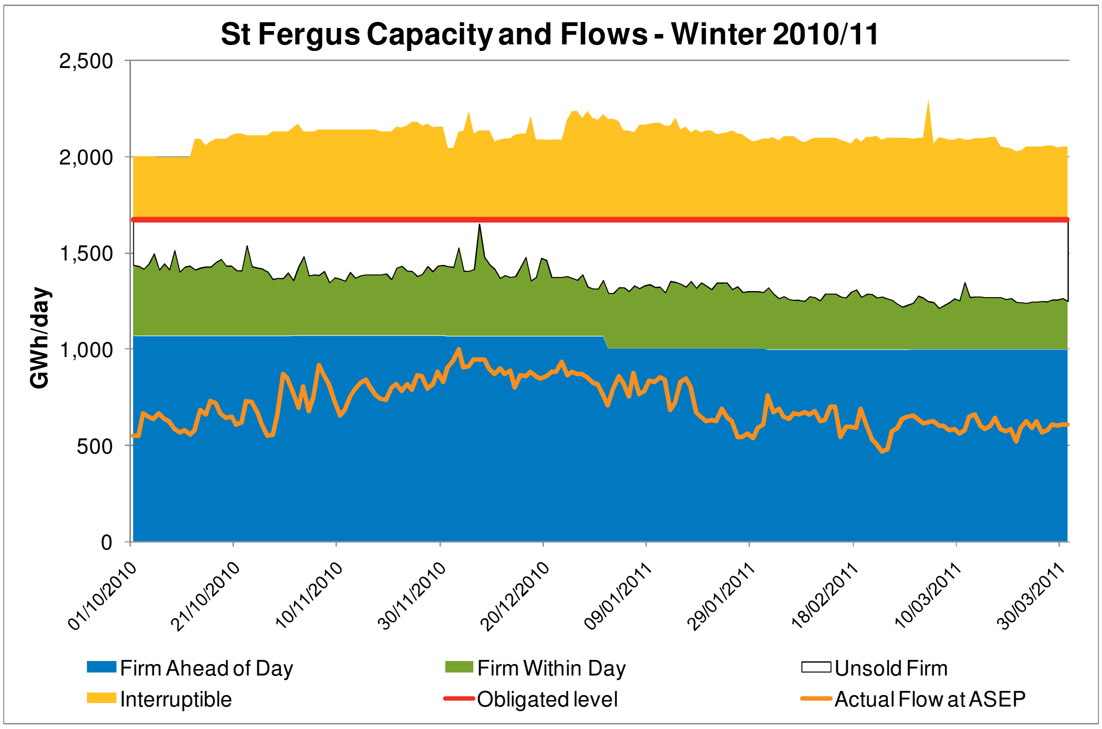
A1 The graphs below show capacity bookings at Bacton, Easington, Isle of Grain, Milford Haven and St Fergus over the past two winters together with the actual levels of gas flow experienced.

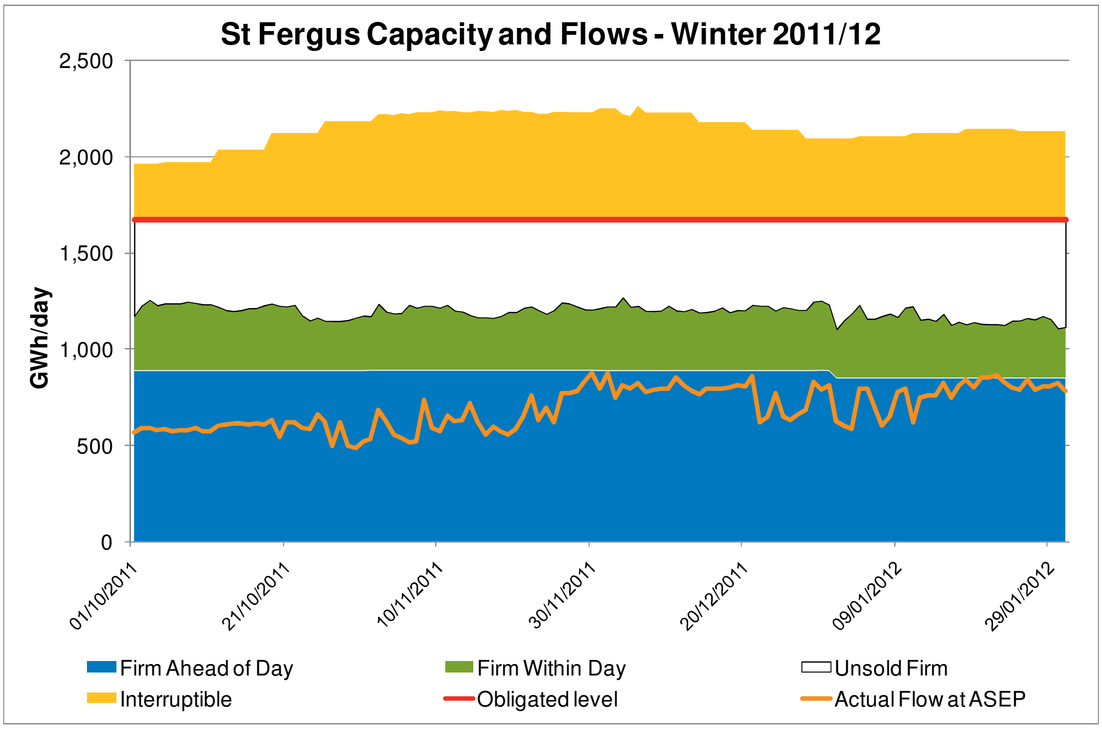


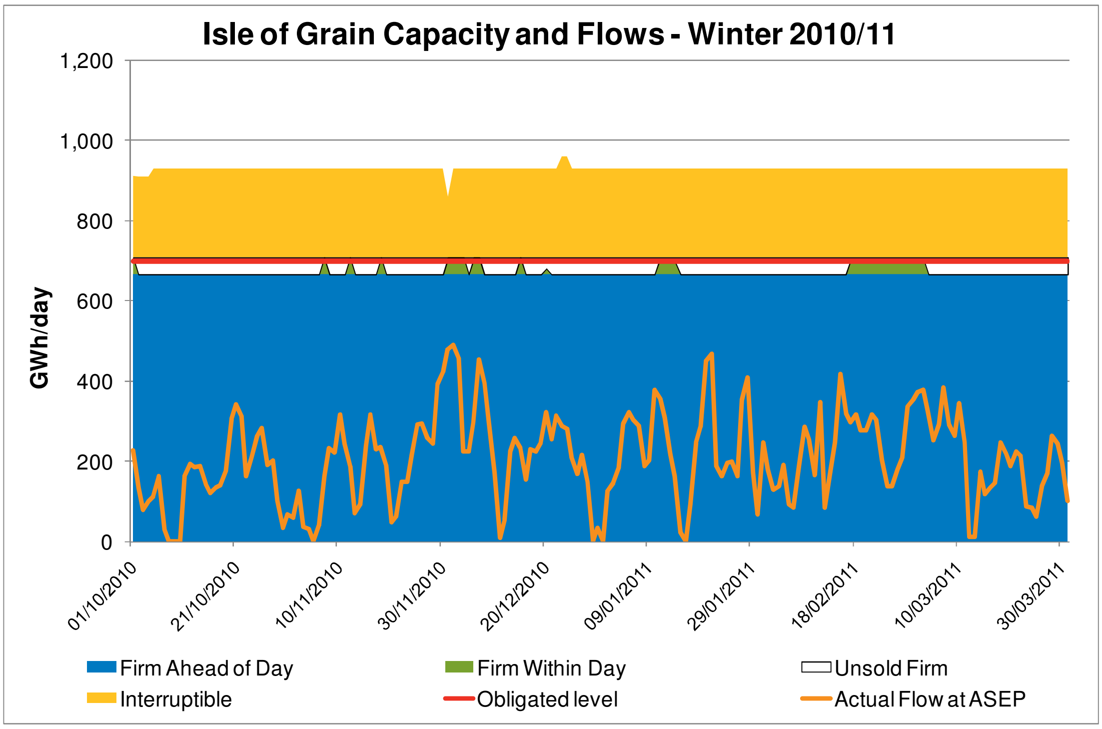


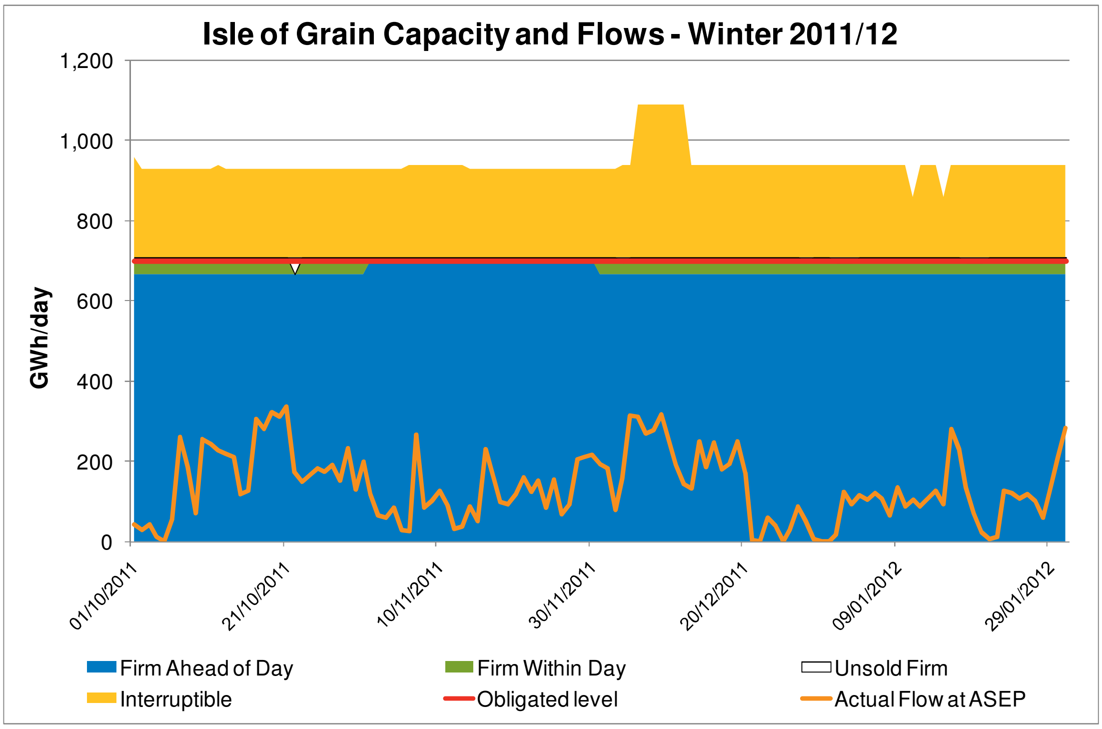

Easington Capacity and Flows - Winter 2010/11
GWh/day
2,500
2,000
1,500
1,000
500
0
01/10/2010
21/10/2010
10/11/2010
30/11/2010
20/12/2010
09/01/2011
29/01/2011
18/02/2011
10/03/2011
30/03/2011
Firm Ahead of Day
Firm Within Day
Unsold Firm
Interruptible
Obligated level
Actual Flow at ASEP

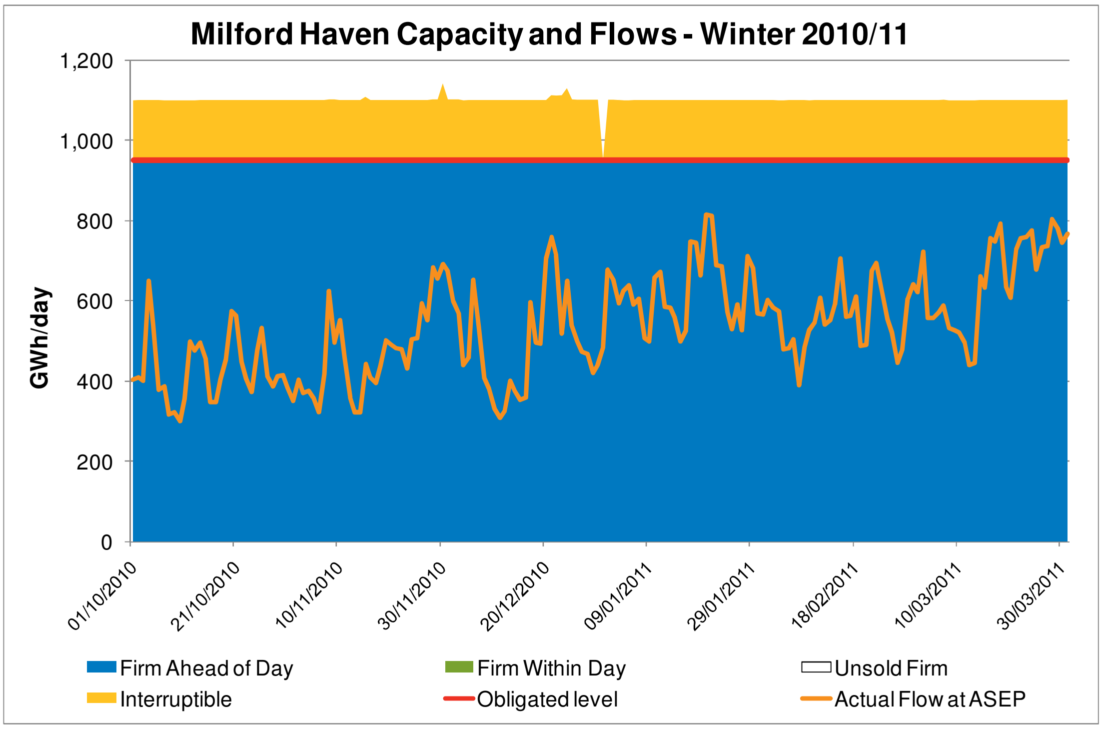

Easington Capacity and Flows - Winter 2011/12
GWh/day
2,500
2,000
1,500
1,000
500
0
01/10/2011
21/10/2011
10/11/2011
30/11/2011
20/12/2011
09/01/2012
29/01/2012
Firm Ahead of Day
Firm Within Day
Unsold Firm
Interruptible
Obligated level
Actual Flow at ASEP

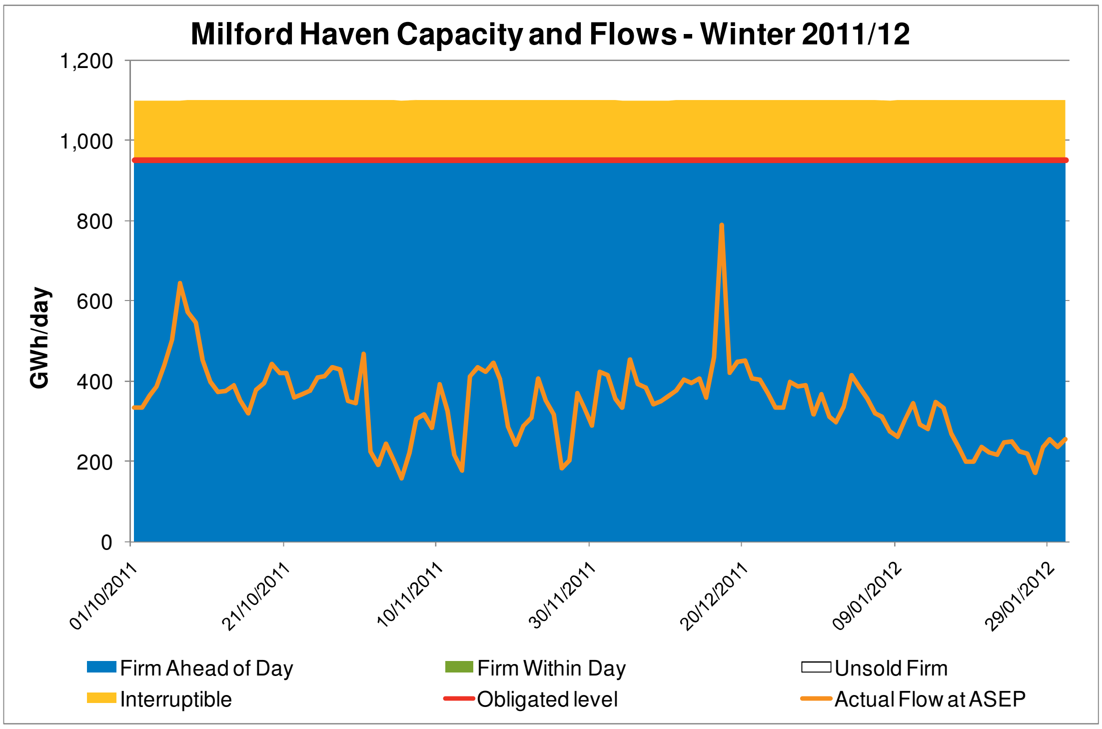

St Fergus Capacity and Flows - Winter 2010/11
GWh/day
2,500
2,000
1,500
1,000
500
0
01/10/2010
21/10/2010
10/11/2010
30/11/2010
20/12/2010
09/01/2011
29/01/2011
18/02/2011
10/03/2011
30/03/2011
Firm Ahead of Day
Firm Within Day
Unsold Firm
Interruptible
Obligated level
Actual Flow at ASEP


St Fergus Capacity and Flows - Winter 2011/12
GWh/day
2,500
2,000
1,500
1,000
500
0
01/10/2011
21/10/2011
10/11/2011
30/11/2011
20/12/2011
09/01/2012
29/01/2012
Firm Ahead of Day
Firm Within Day
Unsold Firm
Interruptible
Obligated level
Actual Flow at ASEP


Isle of Grain Capacity and Flows - Winter 2010/11
GWh/day
1,200
1,000
800
600
400
200
0
01/10/2010
21/10/2010
10/11/2010
30/11/2010
20/12/2010
09/01/2011
29/01/2011
18/02/2011
10/03/2011
30/03/2011
Firm Ahead of Day
Firm Within Day
Unsold Firm
Interruptible
Obligated level
Actual Flow at ASEP


Isle of Grain Capacity and Flows - Winter 2011/12
GWh/day
1,200
1,000
800
600
400
200
0
01/10/2011
21/10/2011
10/11/2011
30/11/2011
20/12/2011
09/01/2012
29/01/2012
Firm Ahead of Day
Firm Within Day
Unsold Firm
Interruptible
Obligated level
Actual Flow at ASEP


Milford Haven Capacity and Flows - Winter 2010/11
GWh/day
1,200
1,000
800
600
400
200
0
01/10/2010
21/10/2010
10/11/2010
30/11/2010
20/12/2010
09/01/2011
29/01/2011
18/02/2011
10/03/2011
30/03/2011
Firm Ahead of Day
Firm Within Day
Unsold Firm
Interruptible
Obligated level
Actual Flow at ASEP


Milford Haven Capacity and Flows - Winter 2011/12
GWh/day
1,200
1,000
800
600
400
200
0
01/10/2011
21/10/2011
10/11/2011
30/11/2011
20/12/2011
09/01/2012
29/01/2012
Firm Ahead of Day
Firm Within Day
Unsold Firm
Interruptible
Obligated level
Actual Flow at ASEP

Appendix B: Entry capacity constraint forecasting

This is an unchanged extract from our 'Managing Risk and Uncertainty' Annex of the March 2012 RIIO-T1 business plan submission and for convenience we have used the same paragraph numbering as was used within that submission.

B1 We have developed two methodologies for forecasting capacity constraint volumes and costs on the NTS. The entry capacity constraint forecasting methodology outlined in Appendix A within the July submission (the "original methodology") is appropriate for analysis of entry capacity constraints and can quickly analyse a large number of supply patterns (357,000 supply patterns in approximately 3 hours). However this original methodology could not be adapted to forecast exit constraints for two main reasons:

(g) The large number of NTS exit points compared to NTS entry points (there are approximately ten times more exit points than entry points).

(h) The need to model network topology changes to 2020/21.

B2 A new model and methodology has therefore been developed to forecast exit constraints on the NTS.

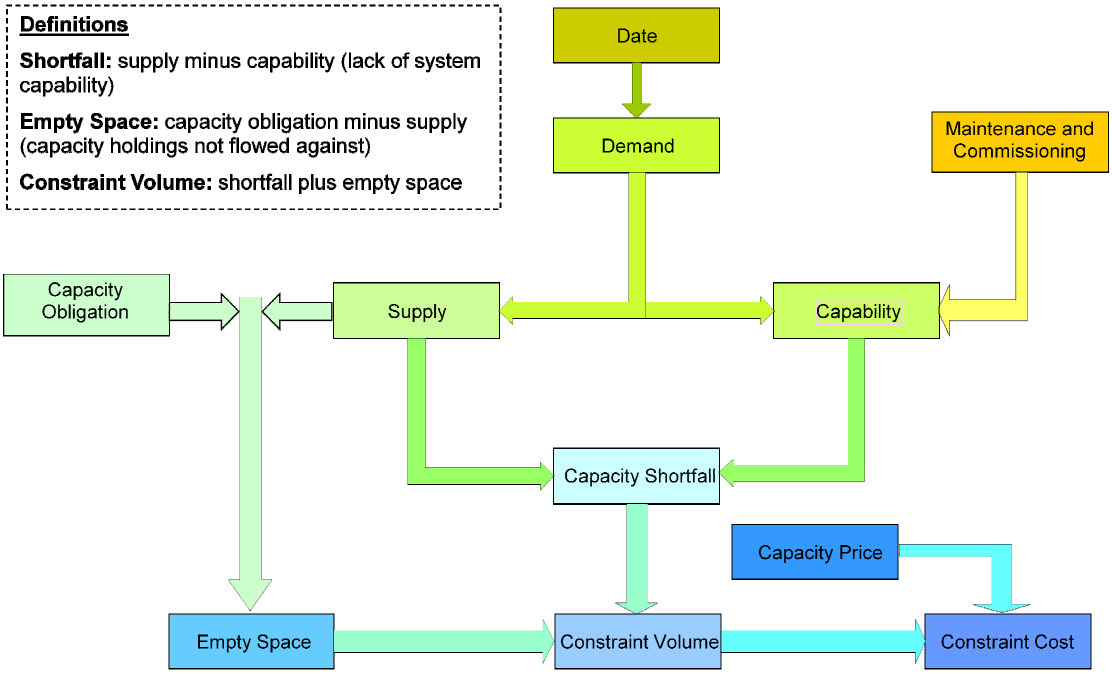
B3 The development of the new model exemplified the hypothesis that entry and exit constraints are interlinked e.g. solving an exit constraint can generate an entry constraint and vice versa. The new model and associated methodology will therefore be referred to as the entry and exit capacity constraint forecasting model / methodology (the "EECC forecasting model / methodology").

B4 As with the original methodology, the new EECC forecasting model and associated methodology provides a probabilistic forecast (a range of potential outcomes along with their likelihoods) of expected constraint volumes and associated costs for a period.

B5 There are two key differences between the original methodology and the new EECC forecasting methodology:

	Original Model	EECC Model
Demand Modelling	Probabilistic range of total NTS demand	Probabilistic range for each exit point
Capability of the NTS	Approximated using actual supply and demand patterns and a small number of results from network analysis	Calculated using a combination of automated and manual network analysis of thousands of supply and demand patterns

B6 The key elements of the modelling process are the same as those shown in paragraph A2 in the original methodology with slightly different interactions to reflect that capabilities are calculated for each supply / demand pattern being considered:



Demand (Excluding Bacton Interconnector and Storage Demand)

B7 The EECC forecasting methodology creates a range of demands at each exit point i.e. a range of potential demand patterns, while the total demand is based on the Gone Green TBE scenario.

B8 In the original methodology end user consumption demand, Bacton interconnector demand and storage demand are aggregated to one "total NTS demand" figure. For the purposes of the EECC forecasting methodology, demand needs to be specified at a nodal level (each "node" being a system exit point) and different methodologies are applied to each demand category to do this. The different methodologies reflect the different relationships and behaviours associated with each demand category.

B9 End user consumption demand is provided by our Demand Forecasting team who produce 980 different demand levels for each day in the year (357,700 demands in a non-leap year). For each of the 357,700 forecasts are made of the aggregated end user consumption demand and a breakdown into aggregated LDZ demand, aggregated power station demand, Moffat demand and industrial demand by site. Composite Weather Variable (CWV) relevant to each of the 357,700 demands are also calculated. The demands provided by the Demand Forecasting Team are based on the Gone Green TBE scenario.

B10 LDZ demand is split to nodal level using regression analysis of CWV. This calculation typically results in the sum of demand at the LDZ nodes no longer equalling the aggregated LDZ demand provided by our Demand Forecasting team. To correct this imbalance the demand at each of the LDZ nodes is adjusted so that the sum of the nodes equals the aggregated LDZ demand. The adjustment also creates "noise" around the demand at each LDZ node which produces a realistic indication of uncertainty around the demand associated with a specific CWV.

B11 Power station demand is split to site level by sampling from appropriate distributions which have been fitted to historic data. As with the LDZ demand, a result of the sampling is that the sum of demand at each power station will no longer equal the aggregated power station demand and so each power station demand is adjusted to correct the imbalance.

Supply (Excluding Bacton Interconnector and Storage Supply)

B12 The EECC forecasting methodology uses the Gone Green TBE scenario provided by our Supply Forecasting team. The scenario covers supply patterns for each demand level from 1100GWh/d to 6050GWh/d. Look-up tables are used to match total demand (end user consumption + Bacton interconnector + storage) to the corresponding supply pattern. "Noise" is then created around each supply point using historic supply data to produce a realistic indication of uncertainty around the central supply forecast that varies with demand. This results in 357,700 different supply patterns being produced for each year.

B13 *[text deleted]*

Bacton Interconnector and Storage Supply and Demand

B14 Increasingly, storage site flows are driven as much by gas prices (prompt and forward contracts) and expectations of future market and network conditions as they are by weather and demand. A wide range of flows is therefore required to model this uncertainty.

B15 Supply and demand at Bacton interconnector and at the Rough storage site is modelled using regression analysis as the sites have a strong correlation with CWV. For the remaining storage sites, supply and demand is modelled by sampling from appropriate distributions which have been fitted to historic data. Future sites are modelled on existing sites with a similar behaviour.

B16 "Noise" is created around storage and Bacton interconnector supply and demand when the adjustments are made to ensure the sum of the supplies matches the sum of the demands.

System Capability

B17 System capability is the ability of the pipeline and other infrastructure to cope with varying supply and demand patterns. System capability is very difficult to assess; it is dependent on many interrelated variables and the result is only applicable to that specific set of values.

B18 In the original methodology the convex hull utilised existing network analysis and actual supplies to analyse thousands of supply / demand scenarios and approximate system capability. This methodology works well for a small number of points and a consistent network topology but for a large number of exit points and a changing topology the best way to assess system capability is via network analysis. National Grid Gas Transmission uses a bespoke network analysis software package called Simone.

The EECC Forecasting Model

B19 The EECC forecasting model has been developed to automatically determine if the NTS has sufficient capability to cope with a wide range of supply and demand patterns. A constraint is identified when network analysis indicates that the forecast supply / demand pattern would result in either pressures at entry points exceeding pre-determined limits (e.g. operational / safety limits) or pressures at exit points being lower than pre-determined limits (e.g. assured / agreed limits).

B20 The EECC forecasting model is built around an Access database and Simone and the interaction between the two software packages is as follows:

(a) The Access database stores all of the inputs and outputs (i.e. supplies, demands, plant settings, pressure settings, results from the analysis etc).

(b) Simone is used to carry out the network capability assessments.

(c) The whole process is controlled using Visual Basic programming to bring the Access database and Simone elements together and automate the process.

B21 The EECC forecasting model methodology is based on the premise that network analysis provides the best view of forecasting network capability and that previous network analysis studies can be used to analyse new networks with similar supply / demand patterns. The model works as follows:

(a) A forecast supply / demand pattern is loaded into the Access database, which contains network analysis results from previous studies.

(b) The forecast supply / demand pattern is converted into vectors to allow the closest match with previously solved networks to be found.

(c) The forecast supply / demand pattern is loaded into Simone along with the plant configuration settings from the closest matching previously solved network.

(d) Simone assesses if there is sufficient network capacity to accommodate the forecast supply / demand pattern without causing any entry or exit constraints.

(e) The model assesses each forecast supply / demand pattern in turn and records all of the results.

(f) When all the forecast supply / demand patterns have been assessed the results are examined by the user.

(g) Any failed networks are manually examined using traditional network analysis techniques.

(h) If the networks can be solved manually then the results are stored in the Access database to enable future studies to utilise the additional information.

The Monte Carlo Constraint Evaluation

B22 The EECC forecasting model can assess approximately 120 networks per hour and so analysing the entire population of 357,700 supply / demand patterns per year is not practical. To overcome this, a representative sample of supply / demand patterns is tested and the results from this sample are used to forecast the constraint volumes for the population as a whole.

B23 Palisade @risk software is used to determine the most appropriate probability distributions to approximate the likelihood of a constraint based on the sample data.

B24 The probability distributions representing the likelihood of a constraint are used in conjunction with Monte Carlo techniques to build an appropriate model. The model works at a daily resolution using probability functions to determine the supply, demand and capability on any given day in the period being considered.

B25 The probability functions of supply, demand and capability are used to forecast constraint events, constraint shortfalls (supply minus capability) and constraint volumes (baseline minus capability).

B26 The output data is combined to form monthly summary statistics of event risk, volume and costs. These are in turn used to determine distributions of potential constraint events and the associated volumes and costs.

Resolving Constraints

B27 National Grid Gas Transmission can use different mechanisms to resolve constraints on the NTS, some of the more common commercial actions are:

(a) Scale back of interruptible capacity

(b) Locational actions can be used to sell gas from the NTS (generating revenue) and buy gas onto the NTS (resulting in a cost).

(c) Capacity buybacks can be used to purchase capacity rights from Shippers.

(d) Forward and option contracts can be taken out to mitigate against future constraint risk.

Scenarios

B28 Four scenarios have been considered by the modelling carried out to date:

(a) Financial year 2012/13

(i) Latest constraint probability assumptions based on a sample of 2269 supply / demand patterns

(ii) Based on supply / demand data for gas years 2011/12 and 2012/13

(b) Financial year 2020/21 (Non Incremental)

(iii) Latest constraint probability assumptions based on a sample of 2269 supply / demand patterns

(iv) Based on supply / demand data for gas years 2019/20 and 2020/21

(c) Financial year 2020/21 (Incremental Supply)

(v) Latest constraint probability assumptions based on a sample of 2269 supply / demand patterns

(vi) Based on supply / demand data for gas years 2019/20 and 2020/21 with 300GWh incremental supply *[text deleted]*

(d) Financial year 2020/21 (Incremental Build)

(vii) Latest constraint probability based on network analysis carried out on a Simone topology including proposed infrastructure changes to support *[text deleted]* incremental supplies and a sample of 260 supply / demand patterns

(viii) Based on supply / demand data for gas years 2019/20 and 2020/21 with 300GWh incremental *[text deleted]*

B29 All analysis has been carried out assuming an intact network i.e. no planned or unplanned outages.

Appendix C: Supply data statistics

This is an unchanged extract from our 'Managing Risk and Uncertainty' Annex of the March 2012 RIIO-T1 business plan submission and for convenience we have used the same paragraph numbering as was used within that submission.

C1 The following tables show summaries of the supply data for the five ASEPs: Milford Haven, St Fergus, Isle of Grain, Bacton and Easington.

Average supply flow (mcm/d)

Milford Haven

Identifier	2009/10	2010/11	2011/12
0 to 200	18	30	38
200 to 250	13	30	43
250 to 300	16	40	43
300 to 350	34	47	36
350 to 400	38	52	33
400+	43	55	

Supply Ranges (mcm/d)

Milford Haven

Identifier	2009/10	2010/11	2011/12
0 to 200	37	25	30
200 to 250	40	46	53
250 to 300	44	66	55
300 to 350	41	45	57
350 to 400	29	45	33
400+	22	34	

Supply range as a percentage of average

Milford Haven

Identifier	2009/10	2010/11	2011/12
0 to 200	200%	82%	78%
200 to 250	295%	153%	122%
250 to 300	271%	165%	127%
300 to 350	121%	95%	161%
350 to 400	74%	86%	102%
400+	52%	63%	

St Fergus

Identifier	2009/10	2010/11	2011/12
0 to 200	48	48	39
200 to 250	62	58	45
250 to 300	76	66	58
300 to 350	81	66	69
350 to 400	89	68	72
400+	88	79	

St Fergus

Identifier	2009/10	2010/11	2011/12
0 to 200	46	40	19
200 to 250	53	60	39
250 to 300	53	47	35
300 to 350	41	42	31
350 to 400	38	33	7
400+	19	19	

St Fergus

Identifier	2009/10	2010/11	2011/12
0 to 200	95%	83%	48%
200 to 250	85%	104%	87%
250 to 300	70%	72%	61%
300 to 350	51%	64%	45%
350 to 400	42%	48%	9%
400+	22%	24%	

Isle of Grain

Identifier	2009/10	2010/11	2011/12
0 to 200	6	5	14
200 to 250	10	10	18
250 to 300	13	12	16
300 to 350	7	18	18
350 to 400	11	23	23
400+	18	30	

Isle of Grain

Identifier	2009/10	2010/11	2011/12
0 to 200	18	12	36
200 to 250	24	23	37
250 to 300	23	32	53
300 to 350	22	38	41
350 to 400	28	38	7
400+	19	24	

Isle of Grain

Identifier	2009/10	2010/11	2011/12
0 to 200	295%	233%	261%
200 to 250	253%	233%	205%
250 to 300	176%	254%	329%
300 to 350	323%	208%	226%
350 to 400	257%	166%	30%
400+	102%	80%	

Bacton

Identifier	2009/10	2010/11	2011/12
0 to 200	39	40	38
200 to 250	48	48	49
250 to 300	65	57	60
300 to 350	80	64	66
350 to 400	80	82	70
400+	91	100	

Bacton

Identifier	2009/10	2010/11	2011/12
0 to 200	40	21	47
200 to 250	49	32	52
250 to 300	39	30	41
300 to 350	30	54	35
350 to 400	37	67	8
400+	56	46	

Bacton

Identifier	2009/10	2010/11	2011/12
0 to 200	103%	52%	123%
200 to 250	101%	67%	106%
250 to 300	59%	52%	69%
300 to 350	37%	84%	53%
350 to 400	46%	82%	12%
400+	62%	46%	

Easington

Identifier	2009/10	2010/11	2011/12
0 to 200	36	26	31
200 to 250	45	34	36
250 to 300	51	58	59
300 to 350	72	74	87
350 to 400	102	95	115
400+	106	116	

Easington

Identifier	2009/10	2010/11	2011/12
0 to 200	41	41	44
200 to 250	63	63	71
250 to 300	60	80	79
300 to 350	49	60	83
350 to 400	60	49	13
400+	47	16	

Easington

Identifier	2009/10	2010/11	2011/12
0 to 200	115%	162%	141%
200 to 250	138%	185%	196%
250 to 300	119%	137%	135%
300 to 350	68%	81%	95%
350 to 400	59%	51%	11%
400+	45%	14%	

[text deleted]

[text deleted]

Addendum 2 – Entry and exit capacity constraint forecasting – May 2012 update

Overview

The following outlines the details of the changes that have been applied to the modelling undertaken to inform this submission from that used to underpin our March 2012 RIIO-T1 business plan submission.

Introduction

2-1 The entry and exit capacity constraint (EECC) methodology outlined in Appendix B of the March 2012 submission assumed an intact NTS network (i.e. planned and unplanned outages were not accounted for, although the IED / IPPC programme was considered separately as outlined in Appendix D of the March 2012 submission) and only considered financial years 2012/13 and 2020/21. To build a more complete picture of the entry and exit capacity constraint risk during the RIIO-T1 period, the analysis included in the May 2012 submission has been extended to consider planned and unplanned outages on the NTS and additional years of the RIIO-T1 period. *[text deleted]*.

2-2 Three discrete constraint forecasting elements of the model have been developed for the May 2012 submission, with the output from each combined into an overall forecast. The three discrete elements of the model are:

(a) Intact network – assumes an intact NTS (i.e. no planned or unplanned outages) and uses the methodology described in the March 2012 submission.

(b) Compressor outages – builds on the model described in *[text deleted]* the March 2012 submission, which included the impact of IED / IPPC compressor outages, and has been updated to include the impact of unplanned compressor outages.

(c) Pipeline impact – this part of the model forecasts the impact of feature inspections resulting from Inline inspections[70] (ILIs) on the entry / exit capabilities of the NTS.

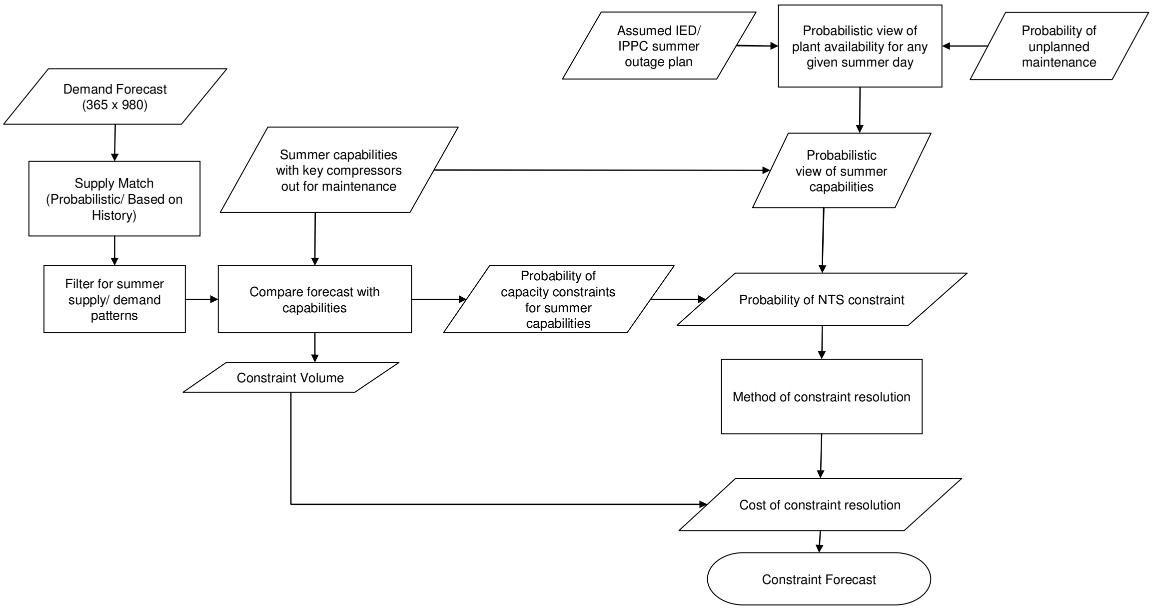
[70] An inline inspection (ILI) is a method of testing the integrity of given sections of pipe. This is undertaken using a series of tests performed by PIGs (Pipeline Inspection Gauges) which are passed through the pipe. The pipe data is recorded as the PIG passes through the pipe and this data is analysed after the event to determine the state of the pipe.

Intact Network

2-3 The intact network element assumes an intact NTS (i.e. no planned or unplanned outages) and uses the methodology described in the March 2012 submission.

Compressor Outages

2-4 The flow diagram below shows the methodology used in the compressor outage element:



Assumptions

2-5 The following assumptions have been made:

(a) The analysis has been carried out assuming that planned compressor outages only occur in the summer as historically this has been the case. The model assumes that unplanned compressor outages could occur in summer or winter.

(b) The entry capabilities are based on a combination of network analysis and historical experience.

(c) The model uses an indicative IED / IPPC compressor outage schedule.

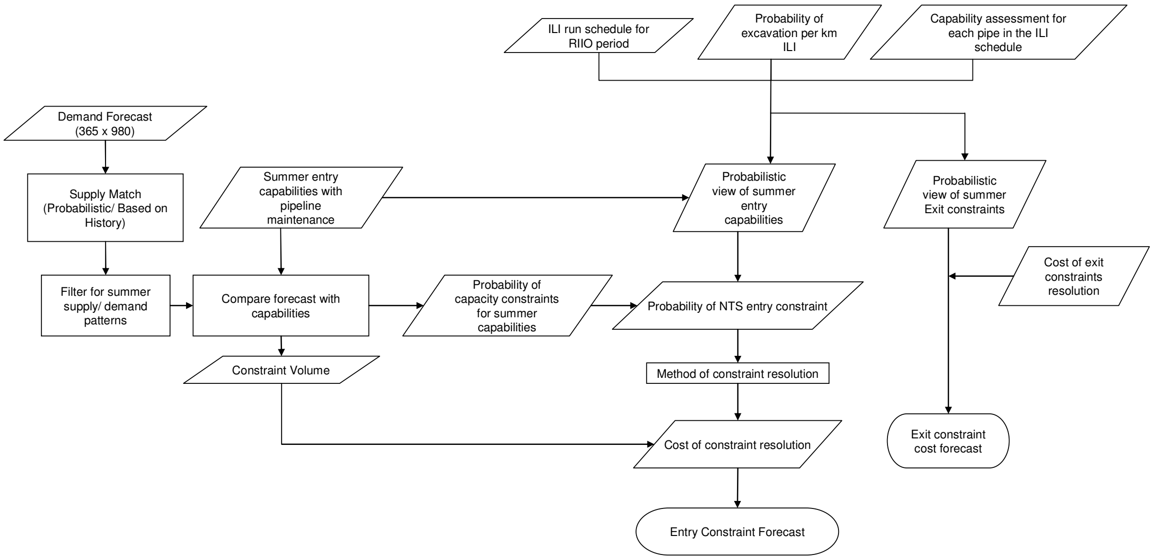
(d) The probability of an unplanned compressor outage is based on historical availability statistics for NTS compressors.

(e) Only outages at key NTS compressor sites are considered.

(f) Only entry capacity constraints are considered as it is assumed that in general at summer demand levels exit capacity constraints could be resolved using alternative compression.

Pipeline impact

2-6 The flow diagram below shows the methodology used in the pipeline impact element:



Assumptions

2-7 The following assumptions have been made:

(a) The analysis has been carried out assuming that feature inspections resulting from ILI runs only occur in the summer, as historically this has been the case.

(b) The summer entry capabilities are based on a combination of network analysis and expert opinion.

(c) An indicative ILI schedule for the RIIO-T1 period has been used. This schedule is based on the most up to date information regarding ILI intervals.

(d) Maintenance days are used to carry out ILI runs.

(e) The probability of an ILI run resulting in one or more pipeline features that require excavation (and so have the potential to cause constraints) is based on historic data detailing the number of features found per kilometre of pipe inspected.

(f) An excavation would require a pipe to be isolated (where possible).

(g) *[text deleted]*.

Supply and Demand

2-8 For each of the three elements the supply and demand patterns are created using the same methodology described in Appendix B of the March 2012 submission. Due to time constraints supply and demand patterns have only been produced for financial years 2012/13, 2014/15, 2016/17, 2018/19 and 2020/21 and each forecast is then used to calculate the entry and exit capacity constraint risk for 2 years.

Resolving Constraints

Entry Capacity Constraints

2-9 The modelling assumes that an entry capacity constraint can be resolved using one of the following methods:

(a) Entry capacity buybacks – the constraint is resolved by purchasing capacity rights from Shippers, from the obligated level down to system capability. The cost of a buyback is assumed to be 1p/kWh/day (this price assumption is based on previous experience of buyback actions and it also allows the resultant costs to be easily scaled if other price assumptions are used).

(b) Locational sell - the constraint is resolved by selling gas from the NTS (generating revenue). The volume of the locational sell is calculated as the difference between the forecast supply and capability. A SAP price of 58p/th (1.98p/kWh) is assumed, which is consistent with recent market information and that used in the modelling of SO costs for NGET. A discount of 30% is then applied (i.e. selling at 70% of SAP) based on previous experience of locational sells.

(c) Locational sell and associated locational buy - the constraint is resolved using a locational sell, as above, however in this case an associated locational buy (buying gas onto the NTS at another location) is also carried out to balance the system. The SAP price is assumed to be the same as above (58p/th) with the sell at 70% SAP and the buy at 160% SAP. The cost of resolving the constraint is the difference between the revenue from the locational sell and the cost of the locational buy.

2-10 The modelling assumes that 50% of the constraints identified are resolved using capacity buybacks and that 50% of the constraints are resolved using locational sell actions. Additionally the modelling assumes that 50% of the locational sell actions are matched by corresponding locational buy actions.

Exit Capacity Constraints

2-11 The modelling assumes that exit constraints can be resolved using one of three methods, depending on the type / location of the exit point:

(a) CCGTs - Historically there have been very few examples of exit capacity constraints at CCGT connections to the NTS. As a result, limited historic costs exist to use as a guide. As the electricity network is a constrained network the constraint costs used by NGET (as part of their RIIO submission) have been used as a proxy for exit capacity constraints at CCGT connections to the NTS. The cost used is the difference between NGET's assumed bid and offer prices for CCGTs on the electricity balancing market, which is £45.35/MWh. This cost is then scaled based on the generation capabilities of each individual site (based on Transmission Entry Capacity (TEC) data). For example, a 1000MW CCGT would cost 45.35 x 1000 = £45,350 per hour or ~£1.1m per day of constraint.

(b) Industrial users - the costs have been based on limited information provided by a small number of customers indicating the likely costs to them of being constrained off the NTS.

(c) NTS offtakes – the modelling assumes that to prevent an exit constraint at an NTS offtake, a locational buy action at a local supply point could be used. The volumes and costs are generated as follows:

   i. Volume - a distribution of summer flows at each affected offtake is used with Monte Carlo techniques to calculate the volume of the constraint and so the volume of the locational buy.

   ii. Cost - In line with the entry capacity constraint cost assumptions a figure of 1.98p/kWh/day (58p/th) is used with a 60% premium to calculate the cost of the locational buy.