Gas Transmission Charging Methodologies Forum

Draft Meeting Report: 26 April 2006

This report outlines the key discussions of the fourth Gas TCMF meeting held at The Radisson Grafton Hotel, Tottenham Court Road, London on 26th April 2006. All supporting material can be found at www.nationalgrid.com/uk/gas

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ATTENDEES

Tim Davis (Chair)	TD	Joint Office of Gas Transporters
Chandima Dutton	CD	National Grid NTS
David Howdon	DH	Ofgem
Eddie Blackburn	EB	National Grid NTS
Eric Sleutjes	ES	Ofgem
Hydreace Ali	HA	RWE
John Bradley	JB	Joint Office of Gas Transporters
Mike Young	MY	BGT
Paul Roberts	PR	National Grid NTS
Steve Rose	SR	RWE
Yasmin Sufi	YS	ENI

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1. Report of Previous Meeting

The meeting report of the Forum 5 April 2006 was agreed as accurate.

2 Actions and Issues from previous meetings

6 *National Grid NTS to conduct further analysis of Transport Model Variants 1 to 3 plus Variant 5 suggested at the working group meeting.*

This analysis will be discussed at the Forum to be held on 25 May 2006

Action Carried Forward

7 *National Grid NTS to arrange meeting to discuss issues identified by Ofgem in its Third Consultation document.*

This meeting was arranged and the date advised through the Joint Office **Action Closed**

2. Ofgem – UCA Consultation

ES gave this presentation on behalf of Ofgem. There had been a number of requests for UCAs for large new Entry points. ES pointed out that there is no existing methodology for large new Entry Points. He also pointed out that the current linkage between reserve prices and UCAs would not continue from April 2007.

He then summarised the issues identified by Ofgem. The proposed starting point for the UCAs would be the flow rate requested by the applicant. The base transmission network would be that established for 2008/9. Ofgem was considering use of a one year model based upon Graphical Falcon output. The adoption of flow bands for which different UCAs would be established was being considered so that some flexibility was available but, outside those bands, the UCA would need to be recalculated. SR pointed out that aspects of this approach had been used at Milford Haven. Ofgem's initial view was that supply substitution would be more appropriate as load absorption might take flows above the 1 in 20 level. Four approaches for supply substitution had been identified. Ofgem asked the meeting to consider whether a 50:50 cost allocation approach was appropriate – for a new Entry point an argument could be put forward for 100% cost allocation to Entry.

SR raised the relationship between new UCAs and existing in the context of consistency and non-discrimination. TD expressed the belief that UCAs for Milford Haven had been set based on the same underlying cost estimates. National Grid NTS volunteered to establish the unit pipeline cost assumptions underlying the Milford Haven UCAs.

Action National Grid NTS

ES stated that Ofgem was considering whether the Milford Haven approach was a suitable precedent. Also, Ofgem was considering the view that storage sites should be treated differently. Its initial view was that, for discrimination reasons, storage should not be treated differently.

TD suggested that there would be no linkage between UCAs and reserve prices for new Entry points. ES confirmed this. CD pointed out that the UCA would, however, go into the NPV test.

Ofgem were asked how a large entry point would be defined. TD pointed out that, under the existing criteria, Milford Haven definitely would be considered large and wondered whether Aldborough would be large or small and hence which UCA methodology would have applied. DH responded that some ambiguity might be helpful as Ofgem would not wish applications to be determined purely by avoidance of thresholds.

TD asked for comments on Ofgem's assumptions. For example, was there agreement to setting UCAs based on planned flow rates? There had been confidentiality concerns amongst shippers as a result of setting ranges for UCAs and prices that reflected development intentions. MY recognised this but could not see any reasonable alternative to use of developer's intentions in UCA setting. SR responded that developers would not have confidentiality concerns as their intentions would probably be known, particularly for a situation such as Milford Haven. SR queried whether there was greater uncertainty at exit. PR related this to the user commitment principle, which would establish assumptions through the ARCA process. CD stated that 1 in 20 DN load growth was the dominant feature in exit growth assumptions. PR also pointed out that NTS and the DNs were in reasonable agreement on the figures. TD asked whether there was agreement on single year modelling. There was no disagreement on this principle. TD suggested that separate treatment connecting pipelines of the order of 100 km or more should be encouraged for large sites. CD suggested that responses to the consultation could identify the maximum length that should be considered. TD pointed out Ofgem would not wish to inhibit a developer that wished to build its own connecting pipeline or, say, supply a power station in the vicinity of the Entry point. This was recognised. TD also pointed out that the UCA would determine the revenue driver and that this would apply into the next price control period. Ofgem confirmed the general principle. DH stated that a worked example on this principle had been published in 2003 for Milford Haven and this would still apply. As a principle, it was agreed that recent cost data was appropriate for UCA determination.

3. Supply/Demand Planning Assumptions – Load Absorption and Supply Substitution

EB gave this presentation. The aim was to inform the industry on how the alternative methods of maintaining a Supply and Demand match including the new Entry Point and allocating identified costs might be adopted and to set out National Grid NTS view. The methodology for calculating the UCAs in 2002 was based upon Transcost and route costs but the proposal was to base UCAs on "system costs". Route costs might not be modelled accurately by Transcost with large new Entry points, as modelling the corresponding Exit flow at a single Exit point might more than double flows in the vicinity of many of the Exit points. If additional flows at new Entry points were balanced by compensating adjustments at a number of other points, a more reflective cost would be derived – this was the basis of the system cost approach. With a route cost approach, there would be no balancing decision to be taken as the analysis started from a balanced central case network and considered route costs i.e. matched increases in Entry/Exit pairs. However, with a system cost approach, system balancing assumptions had to be made such as load absorption, supply substitution or a combination of the two.

With load absorption, there were a number of alternatives such as reflecting known locations of load growth, scaling firm demand or including interruptible demand. Offtake related costs might be identified so this would make a 100% cost allocation to Entry inappropriate. This could either be overcome by use of engineering judgement, which would not be a transparent process, or by imposing a 50:50 split,which would be expected to underestimate true investment costs in some cases. Both these alternative assumptions (engineering judgement or 50:50 split) were agreed to be problematical.

With supply substitution, the decision would become which Entry points to scale down to allow for the additional flow at the new Entry point. There were a number of alternatives such as scaling all supplies; excluding those within a 50 km radius or scaling the supplies that had the least impact on capacity for the new Entry approach. EB noted that some entry points that were close had little impact on each other due to being connected on different sides of local compressors or different feeders whereas some entry points that were separated by distances greater than 50km shared common feeders and compressors and hence were interrelated. One approach would be a “merit” order that reduces Entry flows, based on the commercial order that Shippers might use supplies to balance demand. Experience indicated that typically the order in which supplies were used to match demand was beach gas first then a mix of long range storage, Interconnector and LNG importation followed by mid range storage and LNG only at the highest demands. This order could be used in reverse to reduce flows.

EB believed there was a strong argument for 100% cost allocation to Entry for load absorption as it would be consistent with a process where only Entry flow levels were changed and Exit flows remained unchanged. A 50:50 split would underestimate the share of the investment costs. Ofgem suggested there would be benefits through exit capacity creation and so 100% allocation of costs to entry might be inappropriate. TD suggested that this methodology was only relevant for Entry – a single approach would not be suitable for estimating exit and entry charges consistently. For exit, a load absorption approach may be more applicable. This was recognised by the meeting. DH stated that the correct answer would only be derived from a full Monte Carlo simulation which would not be practicable. There would however be some benefits to exit points from new Entry points even if not 50:50. EB responded that the costs identified would be those incurred for the new Entry point if the demand forecast was accurate and on that basis 100% Entry cost allocation was appropriate. If there were increased demands then the benefit in terms of reducing the entry cost would only occur if the Exit flows occurred every day of the Gas Year on which the new Entry point was at maximum flow.

EB recognised that a hybrid approach might be adopted but it might not be transparent and would be complex. TD suggested that this might incorporate the problems of both. It might be simpler to do both calculations then average the results.

National Grid NTS had concluded that supply substitution using a “merit order” approach starting with those Supply Points furthest from the new Entry Point was the most appropriate basis for UCA calculation at Entry. It had also concluded that 100% Entry cost allocation was appropriate as it was consistent with a System modelling approach where only Entry flows were varied. This did not affect National Grid NTS’s view that, for the LRMC methodology purposes, a 50:50 split remained appropriate as it was consistent with the modelling of route costs where equal Entry and Exit flow increases are considered.

TD asked whether any meeting attendee favoured a load absorption approach for a large new Entry point. Nobody favoured this approach. TD pointed out that the merit order suggested seemed to be more price order based than geographic, which felt correct. MY suggested that sense checks should be adopted such as whether the model reflected known developments at Entry e.g. less St Fergus, more Easington. EB pointed out that decisions on a merit order would need to reflect the demand level but, with lower demand levels, the assumptions would become increasingly subjective. For this reason the 1 in 20 demand level was being suggested by National Grid NTS.

TD suggested that any decision should seek to embody the objective that transparency should be retained where possible.

In terms of the timetable, notice would need to be given in August if the auctions for new entry points were to coincide with the September auctions for existing Entry points. However, the UNC provides for two months notice to be given of price changes. Attendees suggested there would be a concern if the auctions were delayed. SR stated that he would prefer having different auction dates to delaying the auctions. ES said that developers wanted to have the position resolved within the 2005/6 Gas Year. TD suggested that Ofgem might helpfully make a decision in June rather than July 2006 if this target were to be achieved. This was recognised by Ofgem.

4. Ofgem – Charging Arrangements from April 2007

ES gave a presentation explaining that this was essentially a repeat of one given at the incentives seminar. He identified a number of issues with the current regime that linked reserve prices with UCAs. This included the increasing lack of cost reflectivity of reserve prices with time. The solution therefore was to delink UCAs and reserve prices. This would involve National Grid NTS developing a new charging methodology. Ofgem would set the high level objectives for this methodology. More frequent updating of reserve prices would enhance cost reflectivity but at a risk of instability. However, resetting UCAs at the end of a price control period would involve a less frequent but potentially larger reserve price change. ES summarised the areas on which Ofgem would welcome views including charging methodology objectives, the role of Ofgem, requirements on information disclosure, consultation and change governance.

SR asked whether all UCAs would be reset including those recently calculated for new Entry points. ES confirmed that this would be the case but the magnitude might not be that great for new Entry points. PR expressed a concern in adopting a formal annual review. He pointed out that there were already requirements within the Transporter’s licence. EB reminded the meeting that this forum had essentially agreed the methodology objectives, which had been linked to the licence objectives. MY identified the need to increase understanding and this would be promoted by moving away from use of a Transcost type approach. The meeting concluded that the current pricing consultation process was appropriate and change in this was not required. TD didn’t believe that the licence should set out in detail the information required. A more useful route was for shippers to put forward what information would be helpful. MY agreed and suggested that this would promote agreement during the consultation phase.

5. Proposed Data Format for Sharing Alternate LRMC Modelling Results

EB presented a sample spreadsheet. This would include the supply/demand information, and the LRMC and ten years of cost matrices for the different models, identified at previous meetings of this forum. SR asked which of the assumptions identified within the Ten Year statement had been used. PR agreed that, when the spreadsheet was populated, this aspect would be clarified in an accompanying document. **Action National Grid NTS**

PR also identified that some confidentiality issues had to be resolved particularly on the demand side with issuing data at a nodal level, which might mean that the some data would need to be aggregated.. SR asked what increment size would be used for the analysis. EB confirmed that the standard increment of 2.834 mcm would be applied.. It was also clarified that the weighting of prices would be based on the discount factors for each year used within the existing LRMC.

PR asked whether this format was satisfactory. The meeting confirmed that it was. TD asked whether the latest Transcost model would be placed on its website. PR stated that there were some licensing issues with Advantica that currently prevented this but National Grid NTS were seeking to address these.

TD suggested issuing this spreadsheet with a period of about a week for comments. EB suggested that it was best to place this on the website. **Action National Grid NTS**

6. Capacity Release Mechanisms and Implications for Pricing – Estimation of Long Run Capacity Costs

TD referred to the hand-outs on this topic and suggested that the presentation be made at the end of the Transmission Workstream meeting to be held on 4 May 2006. This was agreed.

7. IECR Consultation

As this presentation had been made at the UNC Transmission Workstream it was agreed that this agenda item was not required

8. Way Forward

PR indicated proposals for further meetings as set-out below. This would mean that 4 May could be used to go through the Estimation of Long Run Capacity Costs.

9. AOB

None

10. Dates of Next Meetings

The next meetings were set for:

Thursday 4 May 2006, after UNC Transmission Workstream at Elexon Offices

- Capacity Release Mechanisms and Implications for Pricing – Estimation of Long Run Capacity Costs

Thursday 25 May 2006, 10.00 at Elexon Offices (Full day including lunch)

- Outcome of LRMC Analysis
- Reserve Pricing
- Flexibility Pricing
- TO Exit commodity charge

Thursday 15 June 2006, 13.30 at Elexon Offices

- Impact of Exit Reform

- Re-balancing of NTS Exit Capacity prices
- Commercial Framework

Action Log

No.	Date Raised	Description	Status	Comments
6	02/03/2006	National Grid NTS to conduct further analysis of Transport Model Variants 1 to 3 plus Variant 5 suggested at the working group meeting.	Carried Forward	Full analysis to be circulated a week prior to TCMF meeting now set for 25 May 2006
10	05/04/2006	National Grid NTS to arrange meeting to discuss issues identified by Ofgem in its Third Consultation document.	Closed	Meeting arranged through Joint Office
11	26/04/2006	National Grid NTS to identify the assumptions behind the determination of Milford Haven UCAs and the relationships with existing Entry points		
12	26/04/2006	National Grid NTS to include with the spreadsheet a summary of planning assumptions from which the flows were established.		
13	26/04/2006	National Grid NTS to place the indicative spreadsheet on its website and notify the Joint Office of the hyperlink details. Also to place presentations from this meeting on the website.		
14	26/04/2006	National Grid to arrange for the presentation “Capacity Release Mechanisms and Implications for Pricing – Estimation of Long Run Capacity Costs” to be given after the Transmission Workstream 4 May 2006.		