Gas Transmission Charging Methodologies Working Group

Draft Meeting Report: 09 March 2006

This report outlines the key discussions of the Working Group meeting of the TCMF held at Elexon Offices, 350 Euston Road, London on 09th March 2006. All supporting material can be found at www.nationalgrid.com/uk/gas

ATTENDEES

Tim Davis (Chair)	TD	Joint Office of Gas Transporters
Colin Dickens	CD	ExxonMobil
Charles Ruffell	CR	RWE npower
Christiane Sykes	CS	E.ON UK
Dominic Harrison	DH	National Grid NTS
Dan Roberts	DR	Frontier Economics
Eddie Blackburn	EB	National Grid NTS
Erik Sleutjes	ES	Ofgem
Fiona Lewis	FL	EDF Energy
John Bradley	JB	Joint Office of Gas Transporters
Jeff Chandler	JCh	Scottish and Southern Energy
Andy Scott	AS	Gaz de France ESS
Julie Cox	JCo	AEP
Merel Van Der Neut Kolfscholten	MVDNK	British Gas Trading
Mick Curtis	MC	$e=mc^2$
Mike Young	MY	British Gas Trading
Nick Wye	NW	Waters Wye Associates
Shelley Rouse	SR	Statoil UK

1. Introduction and Key Objectives of the Meeting

TD welcomed attendees to the meeting and suggested that the key objectives of this meeting were to go through the options within the Tariff Model, as described previously, evaluating advantages and disadvantages of options within this model and consolidating options as appropriate.

2. Charging Methodology Assessment Criteria

At the working group on the "Transport Model", EB had summarised the objectives within National Grid NTS's licence and its charging methodology statement objectives, which can be related to the Licence objectives. These objectives represent the principles against which any changes to the pricing methodology must be assessed. This working group accepted that these general principles would be appropriate.

3. LRMC Methodology Tariff Model Enhancement Options

EB highlighted that this working group was being held to discuss the Tariff Model and the questions to be discussed:

3.1 How should entry and exit costs be disaggregated?

EB identified three alternatives: reference node, solver with non-negative constraint and solver with 50:50 constraint. EB demonstrated the principles with a simplified

network with 3 entry points (A, B and C) and four exit points (1 to 4). In the first example, for flow from Entry Point C to Exit Point 4, the costs associated with the backhaul sections were considered to be zero.

The next example considered backhaul and allowed for a negative cost.

The third example ignored all flows that did not physically occur.

Thus three different route cost matrices were produced to go into the solver. This produced 3 sets of fitted entry and exit point costs.

The solver solution with backhaul and a 50:50 constraint gives a statistically perfect fit. The same applies with the flow only assumption. JC asked whether this outcome was a characteristic of the numbers chosen or of the models themselves. MC suggested it might not apply to a complex network. DR stated that it was possible to prove mathematically that if backhauls were taken into account the position of the reference node became irrelevant which would indicate a systematic relationship. EB stated that National Grid hadn't completed checks with a complex network but, at the very least, the fit would be better if backhaul was assumed. TD stated that a statistically better answer would normally be expected where additional factors, such as backhaul, were taken into account. This did not necessarily mean that the results were more appropriate for charge setting, for example backhaul might not be consistently available in practice.

EB then inserted a reference node at point x2 in the system and demonstrated the effect of a backhaul assumption. EB noted that with a reference node approach, the only costs that were considered were those associated with flow paths from the Entry points to the reference node and from the reference node to the Exit points

In summarising the models, EB suggested that a 50:50 split be taken as an ongoing assumption. This was agreed.

TD pointed out that selecting the position of the reference node could be important for a complex network since it could move the cost allocation between exit and entry.

3.2 How should negative costs be treated?

If, due to better fitting, backhaul were included, negative incremental costs could result. These costs could be removed by the solver or be removed as the last step in the methodology. Alternatively, they could be retained, if associated with an obligation to flow, and become a capacity payment or form part of a commodity charge.

In considering negative costs, EB pointed out that some beach terminals flow at peak for 100 days or more. It would therefore be over this type of period that assurance of back-flow would be required. MC requested National Grid NTS to find out how many current exit points would have negative costs. **Action EB**

NW raised the issue of system points with bi-directional flows. EB suggested that the magnitude of the entry and exit charges should be the same but with the opposite sign applying.

3.3 Should capacity charges be adjusted to 50:50 entry:exit and if so how?

EB stated if backhaul and a 50:50 split were assumed there would be a perfect fit between derived entry and exit costs and the route costs and therefore such

assumptions were appropriate, when considering cost reflectivity. For the lack of a better assumption, it was agreed to retain a 50:50 split. MC suggested that it seemed simpler to build-in the 50:50 to the solver as other approaches were more complex with no apparent advantages. This view was generally supported.

EB then outlined five variants A to E and demonstrated the effect on unscaled LRMCs and LRMCs scaled to 50:50 for each variant. JC asked how the signs had changed from positive to negative for option E. EB agreed to establish the reason for this and correct any errors before the slides are published. **Action EB**

[Post Meeting Note (EB): The average exit costs for option E were negative and hence the scaling factor calculated to recover allowed revenue was also negative, resulting in all the costs being switched. This supports the view that adjusting charges (i.e. adding a constant to one set of costs and subtracting a constant from the other) is more appropriate that scaling costs.]

EB suggested that adjusting LRMCs to 50:50 retained absolute cost differentials, which was preferable to scaling which maintained percentage differentials. TD concluded that scaling was inappropriate if negative costs were permitted. This was agreed.

EB concluded that Variant C or E seemed the most appropriate. MC pointed out that inclusion of the reference node didn't seem to achieve anything – the results for C and E were the same. EB agreed and his later slides reflected this.

Looking at these four variants against the objectives agreed:

Variant A: No backhaul, solver with a non-negative constraint, scaled to 50:50 and revenue recovery

This was the status quo. EB suggested that cost differentials were more important than cost ratios when considering the impact of making a connection to the NTS and hence, from a cost reflectivity standpoint, the other variants might be more appropriate. EB concluded from this that National Grid NTS' view was that it should move from this status quo.

Variant B: No backhaul, solver adjusted to 50:50 and revenue recovery, negative costs removed as a final step.

This used the economically more appropriate absolute cost differential approach. EB also believed it would generate more stable charges than the status quo.

Variant C: Backhaul, solver with 50:50 constraint (or ref node - originally Variant E) adjusted for revenue recovery, negative costs removed as a final step.

This retained the appropriate cost differentials throughout the process and therefore, in National Grid NTS' opinion, was the most cost reflective of the variants.

Variant D: No backhaul, reference node adjusted for 50:50 revenue recovery, negative costs removed as a final step.

EB stated that without backhaul, the selection of the reference node critically affected cost reflectivity. TD suggested for this reason that National Grid NTS excluded this variant from future analysis. This was agreed.

3.4 Are zones required?

EB stated that whilst zones might increase stability, it was at the expense of cost reflectivity. JC suggested it was not worth debating this further whilst the enduring exit arrangements were being developed. It was agreed that this should be revisited when product definition was clearer.

3.5 Should capacity charges be adjusted to recover allowed revenue and if so how?

On this question, JC again suggested that a view should only be made when the exit debate had reached more of a conclusion. TD suggested that if capacity were sold by auction, the commodity route should be followed. Scaling was only used previously as a one-off when there was over-recovery from entry auctions. TD suggested that commodity charge adjustments were consistent with the user commitment principle. It was noted that auctions might still be required with a user commitment model for capacity released within the planning horizon. EB stated that National Grid NTS's preferred option was to adjust the capacity charges where auctions were not involved.

3.6 Should year on year price changes be capped?

EB stated that capping erodes cost reflectivity and, as noted at the previous TCMF meeting, if a regime could be designed to produce more stable prices the reasons for capping should be reduced. If capping were to be introduced it should be on the basis of deviation from forecast rather than a year-on-year change. JC wished to see prices gradually moving towards the result of major changes to the system. TD stated that this assumed that these changes could be predicted and he questioned whether this would always be the case. JC raised the issue of forecasting accuracy in regard to the ten year supply and demand (S&D) forecast and asked if modelling multiple S&D scenarios might be an option to counter forecasting uncertainty particularly in the later years. EB stated that discussions on the Transport model had been tending towards the adoption of shorter periods e.g. one year or 3 or 4 years up to the planning horizon. This was acknowledged by other members of the working group. JC preferred to retain capping but was prepared to be persuaded that it was no longer required. EB repeated that capping should be based on variation against prediction. JC asked whether, in that case, National Grid NTS were prepared to publish predictions. EB expressed the hope that sufficient information would be available to Users to generate these predictions themselves.

EB then summarised the pros and cons of National Grid's suggestion of options 8 to 10.

4. AOB

National Grid NTS would advise the date of the next forum meeting **Action PR**

End of Report

Action Log

No.	Date Raised	Description	Status	Comments
7	09/03/06	National Grid NTS to advise on which of the current entry and exit points would become negative.	Open	
8	09/03/06	National Grid NTS to establish why scaling produces negative LRMCs on exit with the reference node option where the unscaled LRMC is positive.	Open	
9	09/03/06	National Grid NTS to advise date of next meeting of the forum	Open	