National Grid Metering Pricing Consultation

For: National Grid Metering

November 2012

Engage Consulting Limited

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Executive Summary

In July 2012 Ofgem published their document "Decision and further consultation on the regulation of traditional gas metering during the transition to smart metering". This confirmed that a Licence Condition to provide a Back-stop Metering Provider of Last Resort (B-MPoLR) service and a National Metering Management (NMM) service would be placed on National Grid Gas (NGG); and that National Grid should lead a pricing consultation with stakeholders on the regulated gas metering tariffs.

National Grid Metering (NGM) enlisted the services of Engage Consulting Limited (Engage) to provide independent support to this consultation process – and obtain Stakeholder feedback through workshops and bilateral meetings. This report provides the stakeholder feedback obtained through this process.

Consultation Questions

Q1: Do you believe that competition is already effective in the I&C market? What, if any, regulatory controls do you think are appropriate?

- Most Stakeholders considered that competition in the I&C market is not effective.
- Most felt that the "I&C market" needs a more specific definition - based around customer rather than meter types; and that more certainty is required regarding the numbers in each category for competition to be assessed meaningfully.
- Most considered that a light touch regulatory oversight on I&C pricing, as is currently the case, was appropriate.
- Most considered that the I&C portion of the RAV should not be the basis of this regulation.
- Several thought that the NGM's I&C market share would need to be reduced via asset sale – either voluntarily or via regulation – if effective competition is to be realised in the foreseeable future.

Q2: Do you agree that the retention of tariff caps remains an appropriate approach to regulating domestic metering charges?

- Most Stakeholders considered that tariff caps are an appropriate way to regulate domestic metering charges.
- Many did not consider it appropriate that there is a single price cap based around the NGM portfolio and commercials - as the situation for other GDNs is materially different.
- Several did not consider it appropriate to include commercial MSA contracts or associated assets in the derivation of this regulated tariff cap.

Q3: Do you agree that adjustments should be made only to the domestic credit meter tariff cap and that the tariff cap for prepayment metering should continue to be constrained in line with the current price control?

- Many Stakeholders were concerned that the PPM cross subsidy will result in misplaced incentives and inappropriate or unintended commercial outcomes.
- They felt that this could result in unnecessary risk premiums and / or unfair GDN losses.
- They also felt that this situation could be exacerbated by delays in the DCC support for the

smart prepayment infrastructure.

Q4: Do you agree with our descriptions of the B-MPoLR and NMM obligations and assessment of their likely duration?

- Most Stakeholders were in broad agreement with what was included in the descriptions of the B-MPoLR and NMM obligations.
- However, they felt that these descriptions were not complete enough, leaving key areas of ambiguity that need to be addressed; several in relation to smart meter obligations and several in relation to PEMs services.
- Most also felt B-MPoLR and NMM durations and the 6 month sunset periods were reasonable; although many thought that there would still be a significant traditional meter stock post 2020 and that this should be recognised.
- Whilst outside the consultation, most GDNs felt that the B-MPoLR arrangements should replace the MPoLR arrangements – rather than simply giving a route for them to be discharged.
- Most Stakeholders felt that the scope and processes in relation to the "regulated transfer" of assets into the NMM were not sufficiently clear.
- This included whether it applies just to MPoLR regulated assets or whether it extends to commercially provided domestic assets (and if so why); and whether it is a one off opportunity or whether such transfers could be effected at any point to the end of the NMM obligation.
- Many anticipate significant commercial issues in the event that the transfer applies to all domestic assets – particularly if the NMM does not disaggregate MAP and MAM services and costs – as Suppliers will be subject to different and unexpected contractual terms / prices.
- Some wanted assurance that the principle of asset transfer into the NMM role had been reviewed by Ofgem lawyers with regard to Competition Law.
- Several wanted assurances that the regulation would ensure that advantage would not be taken of a "distressed seller" – particularly one who holds the assets through regulatory obligations.
- Most felt that principles applied for the transfers need clarification – and that their eventual application would need to be consistent and transparent.

Q5: Do you consider our use of the DECC Lower bound-case for meter displacement rates to be reasonable? Is there any basis for assuming any other displacement rate and if so, why? Do you think that the roll-out will specifically identify particular meter types for early displacement and if so why?

- Most Stakeholders felt that the DECC lower bound-case for meter displacements was too high and that the outturn would be a slower start and a back loaded finish.
- However, most were of the view that NGM had to use an authoritative rollout scenario – and the DECC lower bound case was the best available.
- Most felt that a re-opener assessment in 2018 would be too late. Various alternatives were put forward including: 2016, upon a percentage rollout completion, upon breach of a tolerance around the base rollout profile; and an annual recalibration of the price cap based on variance from the base rollout profile.

- Key factors that could influence the rollout timing for particular meters include: displacement of the electricity meter; communication coverage; PPM later due to the cross subsidy or delays to the smart payment infrastructure; PPM early to recover bad debt; meters with technical or installation issues later.

Q6: Which of the RAV allocation methodologies described do you believe is the most appropriate? Please indicate your reasons if a preference is expressed.

- Most Stakeholders considered that RAV should not be used to regulate the I&C market at all.
- Several felt that it was inappropriate to include assets under commercial MSA arrangements in the portion of the RAV used as the basis of setting the price cap – given that these meters would not be regulated by the cap.
- Many felt that more transparency of the underlying model, associated data and time was needed to allow the options to be assessed adequately.
- Most considered that Option 1 was not appropriate.
- They also considered that Option 2 was the purest option if RAV theory dictates that a regulated income should be obtained from the domestic portion of the delta between the RAV established initially[1] and carried forward, and the current value of underlying assets. However, the non-trivial issues with determining the value of I&C assets in particular were acknowledged.
- They also considered that Option 3 was a viable alternative for overcoming the logistical issues associated with Option 2 – but recognised that it is based on a rather subjective domestic / I&C split set in 2002.
- Many considered that new Option 6 (where the domestic RAV is determined from an assessment of the current value of the domestic assets) was the purest option if RAV theory dictates that the income should be based on the current value of the underlying assets and should not consider the delta between this and the RAV established initially and carried forward.

Q7: Do you agree that the regulatory return allowed for the Distribution business remains the most suitable basis for establishing the rate of return for metering or should a higher rate be applied?

- Most Stakeholders felt that linking to the regulatory return allowed for a gas networks business was not appropriate; and that the risk premium of 0.75% was rather arbitrary and did not have a credible basis.
- Most felt that an independent assessment of an appropriate rate of return from a suitably qualified financial management consultancy would be far more appropriate – taking into account the specific circumstances / risks of the business and matters such as the cost of capital.
- Many felt that there was a lack of clarity of what the risk premium of 0.75% represented.
- Most felt that, if NGM continued with the current approach, far more justification and rationale for it would be required – with clarity about which risks were being managed and why values chosen were appropriate.

[1] In 2002.

Q8: What requirements do you have for services to support the management of traditional meters (query handling, call management, complaint handling)? What level of service would you expect to receive?

- Most Stakeholders felt that the current scope and level of services were about right.
- This was based on assumptions that: the costs took into consideration that customer contact was more likely upon meter replacement; that additional assets could be transferred in; that services and service levels would not be withdrawn or reduced; and that the service levels provided for I&C would not be affected.

Q9: Do you agree with our assessments of future workload? If you have alternative views please outline where they differ.

- Most Stakeholders considered that the workload would be driven by displacement rates and reiterated the comments made in relation to Question 5.
- Many felt that, other than the dependency on the displacement rates, the assumptions seemed reasonable.
- Several felt that they were not in a position to comment, as they did not have full visibility of the future workload model; and some felt that there was a lack of transparency in this respect.
- Several raised the matter of potential smart meter installation workload in the scope of the B-MPoLR and NMM obligations – re-iterating the points raised in relation to Question 4.

Q10: Do you anticipate any specific requirement for changes to industry data flows or arrangements for traditional meters?

- Most Stakeholders could not foresee any significant changes being required to industry dataflows or arrangements for traditional meters; although some were a little cautious, wanting first to have further clarity on the end to end processes before being confident of this.
- Many felt that the biggest challenge to systems and processes would be the "bulk change of MAP/MAM" event – upon a wholesale asset transfer to the NMM.
- Several felt that the separate MAM and MAP roles should be recognised by the systems and processes – even though they are often fulfilled by the same organisation.

Other Matters Raised

Other relevant matters that were raised by Stakeholders during the consultation process include:

- Several Stakeholders did not feel that NGM were sufficiently open with the data they provided in support of the consultation – particularly in areas such as the RAV calculations and pricing model.
- A small number of Stakeholders were openly distrustful of NGM – considering that they take advantage of their market position to protect their interests. Some were even cynical about the nature of their relationship with Ofgem.

- Many Stakeholders did not understand why the consultation period was so brief – and several did not appreciate that the timetable was set out by Ofgem in their July decision document (Reference 2).
- Several Suppliers felt that conducting the consultation at the same time as MSA contracts were being negotiated was very unhelpful. Some were suspicious about the reasons for this; some felt that these negotiations could have motivated input into the consultation inappropriately.

Document Control

Authorities

Version	Issue Date	Author	Comments
0.1-0.5	Nov 2012	Tom Hainey	Initial Drafts
0.6-0.8	Nov 2012	Richard Cullen	Final Drafts
Version	**Issue Date**	**Reviewer**	**Comments**
0.1-0.7	Nov 2012	Engage Team	Review Initial Draft Report
0.8	Nov 2012	Gary Morris	Engage Release QA
Version	**Issue Date**	**Authorisation**	**Comments**
1.0	Nov 2012	Richard Cullen	Initial Issue

Related Documents

Reference 1	The Approach and Pricing Model - National Grid Metering 2012 Pricing Consultation (October 2012).
Reference 2	Decision and further consultation on the regulation of traditional gas metering during the transition to smart metering (July 2012).
Reference 3	Review of Metering Arrangements (December 2011).

Change History

Version	Change Reference	Description
1.0	N/A	Initial version.

Distribution

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1 Introduction

In July 2012 Ofgem published their document "Decision and further consultation on the regulation of traditional gas metering during the transition to smart metering" (Reference 2). This affirmed their plans to proceed with their "minded to" approach detailed in the "Review of Metering Arrangements" (Reference 3), published in December 2011. It confirmed that:

- A Licence Condition to provide a Back-stop Metering Provider of Last Resort (B-MPoLR) service and a National Metering Management (NMM) service would be placed on National Grid Gas (NGG);
- National Grid would be asked to lead a pricing consultation with stakeholders on the regulated gas metering tariffs; and
- Existing market-based arrangements would continue in respect of Post Emergency Metering Services (PEMS).

Ofgem asked National Grid Metering (NGM) to undertake this pricing consultation on behalf of NGG; and they enlisted the services of Engage Consulting Limited (Engage), through a tender process. Engage was charged with providing independent support to the consultation process – obtaining Stakeholder feedback through workshops and bilateral meetings; and reporting the key themes and issues arising to NGM and Ofgem.

1.1 Background

In September 2012 NGM launched a Pricing Consultation (Reference 1) to address the B-MPoLR and NMM obligation placed upon NGG by Ofgem. The consultation document provided NGM's proposed approach to the various aspects arising - including the approach to pricing; and sought Stakeholder responses to the following set of ten questions:

1. Do you believe that competition is already effective in the I&C market? What, if any, regulatory controls do you think are appropriate?
2. Do you agree that the retention of tariff caps remains an appropriate approach to regulating domestic metering charges?
3. Do you agree that adjustments should be made only to the domestic credit meter tariff cap and that the tariff cap for prepayment metering should continue to be constrained in line with the current price control?
4. Do you agree with our descriptions of the B-MPoLR and NMM obligations and assessment of their likely duration?
5. Do you consider our use of the DECC Lower bound-case for meter displacement rates to be reasonable? Is there any basis for assuming any other displacement rate and if so, why? Do you think that the roll-out will specifically identify particular meter types for early displacement and if so why?

6. Which of the RAV allocation methodologies described do you believe is the most appropriate? Please indicate your reasons, if a preference is expressed.
7. Do you agree that the regulatory return allowed for the Distribution business remains the most suitable basis for establishing the rate of return for metering or should a higher rate be applied?
8. What requirements do you have for services to support the management of traditional meters (query handling, call management, complaint handling)? What level of service would you expect to receive?
9. Do you agree with our assessments of future workload? If you have alternative views please outline where they differ.
10. Do you anticipate any specific requirement for changes to industry data flows or arrangements for traditional meters?

In order to facilitate Stakeholder feedback to these questions and related matters, Engage held three workshops covering the various aspects of NGM's proposed approach[2] . These were attended by a broad range of the Stakeholder community[3]. All Stakeholders were also proactively offered a bilateral meeting with Engage to cover matters in more detail in a confidential environment. Seven organisations took advantage of this offer[4].

1.2 Purpose

The purpose of this report is to document the key themes and matters arising in the Stakeholder feedback obtained by Engage in the workshops and bi-lateral meetings held.

1.3 Scope

This report is confined to Stakeholder feedback that was provided in the workshops and bi-lateral meetings held by Engage, to matters within the scope of NGM's consultation (Reference 1). Matters raised outside the scope of the consultation are not included unless they add context.

The feedback is not attributed to any specific Stakeholder but, where appropriate and beneficial, the category of stakeholder is included.

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[2] See Appendix B.
[3] See Appendix C.
[4] Including three "big six" Suppliers (covering domestic and non-domestic); a smaller non-domestic Supplier; a GDN; and two independent MAPs.

2 Consultation Questions

NGM's consultation asked all interested Stakeholders ten specific questions in relation to their proposals for delivering the B-MPoLR and NMM obligations. The key themes and matters arising in the workshops held and bi-lateral meetings conducted are drawn out in the following sections.

2.1 Question 1

Do you believe that competition is already effective in the I&C market? What, if any, regulatory controls do you think are appropriate?

2.1.1 Competition in the I&C Market

Most Stakeholders felt that the "I&C market" is not sufficiently well defined and that this inhibits assessment of competition. Regardless, the vast majority were of the view that, overall, competition in the current I&C market is not effective.

The key points made were as follows:

1. Many Stakeholders felt that the figure quoted of 1.5 million I&C gas customers should be classified more specifically[5] – with clarity about whether this is based on meter type or by type of customer being supplied.
2. Most Stakeholders felt that "I&C market" should be interpreted as "non-domestic market" - and that this should include non-domestic customers with U6 meters.
3. Most Stakeholders acknowledged that competition is effective to different extents in various metering segments of the I&C market – as follows:
   (i) High Pressure (c. 120 customers): This sector was considered high value and competitive;
   (ii) Rotary Turbine (c. 40k customers): Stakeholders view was that the majority of customers are still with NGM;
   (iii) Large Diaphragm (U16 and above with c.400k customers): Stakeholders view was that the majority of customers are still with NGM;
   (iv) Small Diaphragm (U6): Stakeholders view was that the vast majority of customers are still with NGM, but it is not clear how many of these meters are "non-domestic".
4. Most Stakeholders felt that market share is a crude measure of competition - and so knowing the number of meters in each sub-sector

[5] DECC Smart Metering Impact Assessment document specifies 23 million gas meters and c. 1.5 million I&C gas meters, but raises the need to undertake further work to define the I&C market more clearly.

along with the number owned by NGM is necessary[6] to assess competition meaningfully.

5. Most Stakeholders felt that long asset lives means that existing market shares will only change gradually without any regulatory intervention to address this.

2.1.2 Regulatory Controls

Despite the view that, overall, competition is not effective in the I&C market, Stakeholders (particularly I&C Stakeholders) were strongly of the view that there should not be any overly intrusive pricing regulation in this sector.

Most I&C Stakeholders were acutely concerned by Ofgem statements indicating that regulation in the I&C market would be linked to the outcome of pricing regulation in the domestic sector. Particular concern was raised in relation to the splitting of the Regulatory Asset Value (RAV)[7] with the view being that the residual I&C component should not form the basis of any regulation.

Many Stakeholders considered that a fully effective competitive market would require maximum market shares consistent with Competition Law (e.g. 25%-40%). They considered that the long life of metering assets limited significantly the pace at which further competition could be introduced and that, for a competitive market to be reached in the foreseeable future, NGM's market share would need to be reduced via the sale of assets - either voluntarily or via regulatory intervention.

Some Stakeholders were also concerned that NGM could use the wind down of their domestic business to cross subsidise their I&C business and considered that regulation had a role to play in ensuring that this did not happen.

2.2 Question 2

Do you agree that the retention of tariff caps remains an appropriate approach to regulating domestic metering charges?

Most Stakeholders considered that tariff caps are an appropriate way to regulate domestic metering charges. However, a number of concerns were raised in relation to the manner of implementing this. These were as follows:

1. Stakeholders consider that NGM's and GDNs' portfolios are very different in terms of age of assets and PPM/DCM split (NGM 1:10; GDNs 1:1). Many Stakeholders therefore felt that applying the same cap for all is not appropriate.
2. These Stakeholders felt that this issue could be made worse if the DCC does not have the prepayment infrastructure in place for smart; as more traditional PPMs could be requested from the GDNs; and they could be left with a proportionally higher PPM stock.

[6] It was acknowledged that work has been commissioned by DECC in this area.
[7] See Question 6 in section 2.6.

3. Many Stakeholders felt that the method of setting the regulated price cap is influenced unduly by commercial Metering Services Agreements (MSA) contracts. This includes:

   (i) Proposals for splitting the RAV[8] that do not differentiate between domestic assets under regulated tariffs and those under commercial tariffs; and

   (ii) Ofgem's "six box" model[9] which has the effect of compensating for losses or gains through the commercial MSA contracts in the regulated tariffs – which could be extreme if the number of assets under regulated tariffs is proportionally low.

4. Several Suppliers felt that undertaking this pricing consultation at the same time as MSA contracts are being negotiated was unhelpful.

2.3 Question 3

Do you agree that adjustments should be made only to the domestic credit meter tariff cap and that the tariff cap for prepayment metering should continue to be constrained in line with the current price control?

The original social related rationale for the PPM cross-subsidy was well understood by Stakeholders. However, there were several concerns about the impact this is likely to have on an on-going basis – with the potential for misplaced incentives and inappropriate or unintended commercial outcomes.

Most Stakeholders agreed that the PPM tariff is priced significantly below the market rate. They also acknowledged that this has influenced call on the MPoLR regulated service in the past - with a disproportionate number of PPMs having been requested.

Many Stakeholders were concerned that the continued absence of cost reflective PPM prices will lead to selective use of the MPoLR arrangements - potentially resulting in unnecessary B-MPoLR risk premiums; or unfair GDN losses where the PPM/DCM portfolio split is materially different.

Stakeholders considered that this situation could be made worse if the DCC support for the smart prepayment infrastructure is delayed, as is likely – with a higher proportion of traditional PPMs being requested.

Most Stakeholders assumed that the 2013-14 PPM tariff cap would be increased by RPI in subsequent years.

8 See Question 6 in section 2.6.

9 See section 3.2.7 of Reference 2.

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2.4 Question 4

Do you agree with our descriptions of the B-MPoLR and NMM obligations and assessment of their likely duration?

2.4.1 B-MPoLR and NMM Obligations

Most Stakeholders were in broad agreement with what had been written in NGM's descriptions of the B-MPoLR and NMM obligations, but felt these descriptions were not complete enough and left ambiguity in too many areas. As a consequence, they could not confirm, at this stage, that they supported NGM's interpretation of the obligations. Specific questions that Stakeholders felt required addressing included:

1. What would happen in the event of a delay to the industry solution for smart PPMs? This would create a need for continuation of the B-MPoLR arrangement for PPMs – and, if so, would capped rates apply?

2. How does the B-MPoLR role and NGM's statement that they will not install smart meters align with the obligation to provide meters that are "reasonably available" if this was considered to include SMETS 1/2 meters?

3. How would the issue of "cherry-picking" be dealt with - with the B-MPoLR obligation only being called upon for high cost installations such as PPMs in difficult to access sites?

4. Does the relationship between the MPoLR and B-MPoLR obligations imply the need for a specific contractual relationship between NGM and GDNs? If so, how will this be progressed?

5. How does the NMM role and NGM's statement that they will not install smart meters align with the Supplier obligation to install smart meters post April 2014? If a meter develops a fault and is replaced by the NMM with a traditional meter, does this put the Supplier in breach of their Licence condition to install smart? If so, there is a regulatory conflict.

6. How will the PEMs service operate if it is an NMM asset but the Supplier has a different PEMs provider?

7. Under what circumstances will the capped rates apply and what is the rationale for capped rates not applying? For example, replacements due to faults and due to damage – are these treated differently and, if so, how? It would be useful to have price capped periods clearly marked on the time line diagram (Reference 2 - Section 3.2.1, page 6).

8. How will the charging mechanism work end to end?

9. How will the traditional meter stock be dealt with post 2020 as it is likely to still be significant? Will the closedown arrangements be reviewed between 2014 and 2020?

Most Stakeholders felt that the B-MPoLR and NMM durations and the 6 month sunset periods were reasonable. A minority thought the B-MPoLR sunset period was not long enough as there would probably be teething problems with the smart rollout; and a different minority felt that both sunset periods were too long. In addition, as indicated above, many Stakeholders felt that there would be a significant traditional meter stock post 2020, and that the NMM arrangements should recognise this.

Whilst outside the B-MPoLR and NMM roles, many Suppliers were not at all clear about how the NGM PEMS service would work. Would Suppliers be in breach of their Licence condition to install smart post 2014 if NGM installed a traditional meter? If so there is a regulatory conflict with NGM's PEMs offering.

Also, whilst outside the scope of the consultation, some GDNs were firmly of the view that their MPoLR obligation should be removed with commencement of the B-MPLoR obligation. Otherwise, these parties would need to continue to manage this obligation which would be inefficient.

2.4.2 Asset Transfer

Most Stakeholders felt that the scope and processes in relation to the "regulated transfer" of assets into the NMM were not sufficiently clear.

They were unsure whether this asset transfer option applied just to MPoLR regulated assets or whether it applied to commercially provided domestic assets. If the latter, Stakeholders questioned the rationale for such regulatory intervention in commercial markets, providing commercial players, taking and managing calculated commercial risks – a regulated route to exit the market.

Many Stakeholders anticipate significant commercial issues in the event that the transfer applies to all domestic assets – particularly if the NMM does not disaggregate MAP and MAM services and costs. If a Supplier has agreed terms with a MAP for meter provision and a MAM for asset maintenance – and the MAP decides to transfer their assets to the NMM, a different set of terms / prices are likely to apply for the Supplier. In addition, in the event of the MAM being a different organisation to the MAP, the Supplier could be left with termination charges with the MAM. The commercial implications for Suppliers would be a function of the contracts they have in place with their MAPs and MAMs and the nature of the termination arrangements and charges. This could be complex commercially and resource intensive.

Some Stakeholders wanted assurance that the principle of asset transfer into the NMM role had been reviewed by Ofgem lawyers with regard to Competition Law.

Many Stakeholders were also unsure about whether this would be a one off opportunity or whether such transfers could be effected at any point to the end of the NMM obligation. Most assumed that it could apply to a subset of the transferee's portfolio and did not have to be all of it. Several questioned whether it could extend to any related spares stock.

Several Stakeholders wanted assurances that the regulation would ensure that advantage would not be taken of a "distressed seller" – particularly one who holds the assets through regulatory obligations.

Most Stakeholders felt that principles applied for the transfers need clarification – and that their eventual application would need to be consistent and transparent. They considered that the key factors would include:

a. price / value;

b. warranties;

c. timing of the transfer;

d. age profile of portfolio;

e. termination conditions; and

f. contractual liabilities.

Some Stakeholders queried whether NGM could deal with all the types of asset that could be transferred to the NMM.

Many Stakeholders reiterated points made in relation to Question 10 regarding potential issues in getting accurate records transferred via the bulk change of agent process.

2.5 Question 5

Do you consider our use of the DECC Lower bound-case for meter displacement rates to be reasonable? Is there any basis for assuming any other displacement rate and if so, why? Do you think that the roll-out will specifically identify particular meter types for early displacement and if so why?

2.5.1 DECC Lower Bound Case and Displacement Rates

Most Stakeholders felt that the DECC lower bound case for meter displacement was too high and that the outturn would be a slower start and a back loaded finish. However, most were of the view that NGM had to use an authoritative rollout scenario – and the DECC lower bound case was the best available.

In light of the considerable uncertainties associated with the displacement rate – and the sensitivity of the price cap to it – most Stakeholders felt that an early re-opener assessment or method of recalibrating the price cap based on the outturn was required. Examples cited leading to this uncertainty included:

1. Strategy of each Supplier could be very different;
2. PPMs could be back loaded (for example because of the cross subsidy); or front loaded (for example to reduce bad debt);
3. Possible delays in establishing the DCC; or associated communication issues;
4. Possible delays in the smart PPM infrastructure; and

5. Possible introduction of exemptions in the set of meters that are subject to the Supplier rollout profile obligations.

Most Stakeholders felt that a re-opener assessment in 2018 would be too late – as this could result in the set of meters giving rise to any over or under recovery being materially different from the set of meters across which this would be addressed. Various other suggestions were put forward, including:

1. A re-opener assessment in 2016 to align with the first year of the DECC published lower bound case;
2. A re-opener assessment once a certain percentage of the meters had been displaced;
3. A re-opener if the rollout profile moved outside of a certain tolerance of the DECC lower bound case;
4. A mechanism for adjusting the price cap on an annual basis to reflect the variance of the displacement rate from the basis on which the cap was set. In essence, providing a self-correcting price cap that would dispense with the need for a re-opener and would more closely correlate the set of meters giving rise to any over or under recovery with those over which this would be addressed.

2.5.2 Categories of Meter - Factors Driving Displacement

Most Stakeholders felt that each Supplier's smart roll-out strategy could be very different – and that predicting the collective outcome would be very difficult. However, views put forward that could provide insight into rollout plans included:

1. Electricity meter replacement will be a key driver for gas meter replacement – and so dual fuel customers are likely to be front loaded;
2. PPM meters could be back loaded due to the cross subsidy and delays in the DCC payment infrastructure; or could be front loaded to address bad debt;
3. Communication coverage will be a key factor in the rollout;
4. Sites likely to have technical issues or installation complications would be back loaded; and
5. NGM's HAM[10] policy could influence rollout.

[10] Holistic Asset Management – which identifies meters for exchange based on a range of criteria; including identification of those that, on a probabilistic basis, have a higher risk of developing a fault.

2.6 Question 6

Which of the RAV allocation methodologies described do you believe is the most appropriate? Please indicate your reasons if a preference is expressed.

2.6.1 Principles of RAV Split

Most Stakeholders – but particularly I&C Stakeholders – considered that, whichever method was used to split the RAV, the non-domestic portion should not be used as the basis for regulating the I&C market (see also Section 2.1). Stakeholders considered that the RAV is a regulatory tool only appropriate for use in relation to regulated income.

Most Stakeholders recognised that there is a delta (which could be positive or negative) between RAV as determined in 2002 and carried forward, and the current value of assets (in domestic and I&C); and that each of the methods deals with this delta in a different way (as is shown in Figure 1 - Treatment of Current and Carried Forward RAV Delta, below).

Some Stakeholders felt that additional detail and results for each method of splitting the RAV were required before they could give the matter adequate consideration; several being of the view that NGM needed to be more transparent in this regard. Several also thought that the timescales associated with the consultation precluded them from undertaking sufficiently detailed analysis.

Some Stakeholders also felt that it was inappropriate to include assets under commercial MSA arrangements in the portion of the RAV used as the basis of setting the price cap – given that these meters would not be regulated by the cap. They argued that, along with the I&C sector, the MSA arrangements should not influence the regulated price caps at all – and it is the RAV associated with domestic non-MSA assets that should be used as the basis of setting the price cap.

2.6.2 RAV Split Options

Most Stakeholders agreed that Option 1 was not suitable as it was not appropriate to tie the domestic allocation of the RAV to the I&C market given the differing conditions that will prevail in each of these sectors between now and 2020.

Most Stakeholders considered that an asset replacement cost approach to splitting the RAV was more appropriate than an income related approach – as it was more consistent with the principles of a RAV.

Based on the workshops and bi-lateral meetings conducted, most Stakeholders considered that:

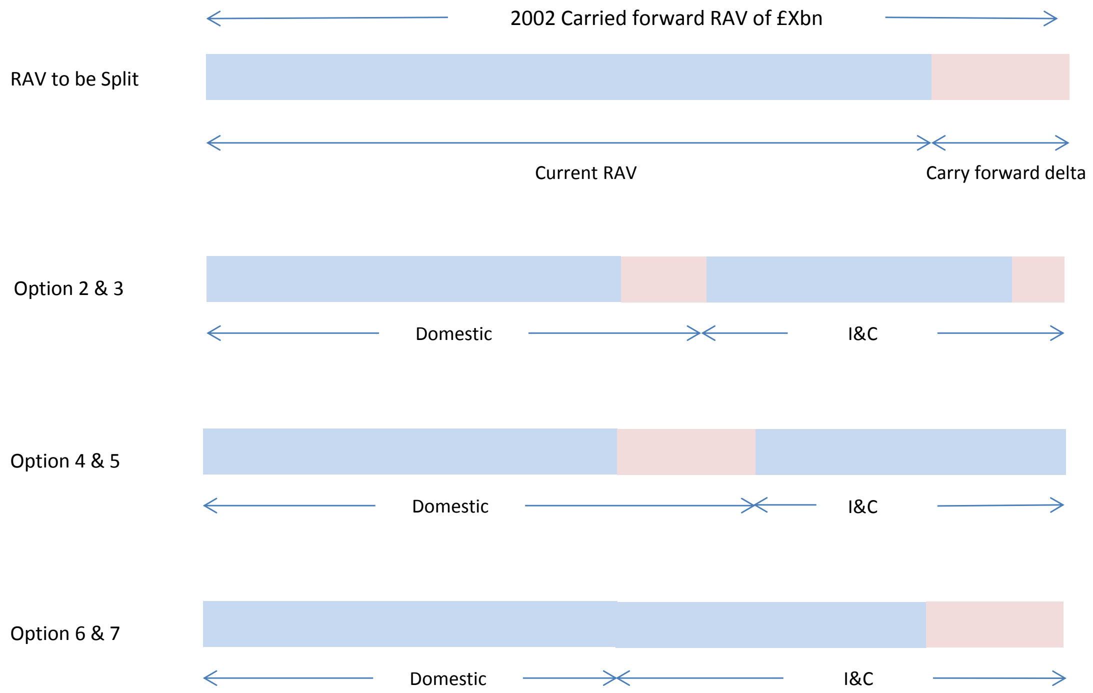
1. Option 1 was not appropriate, as described above.

2. Option 2 was the purest way of determining a domestic RAV - if RAV theory dictates that a regulated income should be obtained from the domestic related delta between the RAV established initially[11] and carried forward, and the current value of underlying assets. However the non-trivial issues associate with this method - in relation to determining the value of I&C assets in particular - were acknowledged.
3. Option 3 was considered inferior to Option 2 but perhaps a far more practical way of achieving an Option 2 like approach – and therefore had merit. Its downside is that it is based on a subjective domestic / I&C split set in 2002.
4. Options 4 & 5 – were considered inferior to Options 2 and 3 as the entire delta between RAV established initially and carried forward, and the current value of underlying assets, is attributed to the domestic sector – which is not appropriate. Option 5 was considered inferior to Option 4 as it is not consistent with asset value based RAV theory and is instead income related.
5. A new Option 6 was identified where the domestic RAV is determined from an assessment of the current value of the domestic assets; and the remainder is attributed to I&C. This was viewed as a possible method of overcoming the issues associated with Option 2 (valuing the I&C assets); and was considered a viable option if RAV theory dictates that the income should be based on the current value of the underlying assets and should not consider the delta between this and the RAV established initially and carried forward.
6. A second new Option 7 was identified where the domestic RAV is determined from an assessment of the income from the domestic assets and the remainder attributed to I&C. This was considered inferior to Option 6 as it is not consistent with asset value based RAV theory and is instead income related.

[11] In 2002.

The diagram below shows how each of the options (including the new options identified) deal with the delta (which could be positive or negative) between RAV as determined in 2002 and carried forward, and the current value of assets (in domestic and I&C) for a hypothetical RAV of £Xbn.

Figure 1 - Treatment of Current and Carried Forward RAV Delta



2.7 Question 7

Do you agree that the regulatory return allowed for the Distribution business remains the most suitable basis for establishing the rate of return for metering or should a higher rate be applied?

Most Stakeholders felt that using a rate of return established for a regulated network business[12] was not the most appropriate method of establishing the basis of a suitable rate of return for a metering business – particularly given the rather specific circumstances associated with the business, managing a metering stock that will reduce to zero by 2020. The fact that it will be the NGG network business that will hold the Licence condition to provide the B-MPoLR and NMM services was considered irrelevant.

In addition, most Stakeholders felt that the 0.75% risk premium was rather arbitrary – and did not have a credible basis. The fact that 0.75% was the risk premium used in 2002, under very different conditions, was also considered irrelevant. Many Stakeholders also considered that the biggest risk – the uncertainty in the displacement rates – was managed by the re-opener (see

[12] Via the RIIO proposals for Gas Distribution.

Section 2.5.1) and so should not be managed via this premium. Some suggested that, if the displacement risk was being managed by this premium, it should be negative on the basis that displacement rates lower than the DECC lower bound case would be more likely than displacement rates that were higher (see Section 2.5.1).

Most Stakeholders felt that an independent assessment of an appropriate rate of return from a suitably qualified financial management consultancy would be far more appropriate – taking into account the specific circumstances / risks of the business and matters such as the cost of capital. Stakeholders felt that this would not need to be an overly extensive exercise to produce materially more appropriate results than the current approach of benchmarking to a network business and adding a rather arbitrary risk premium. Several Stakeholders did acknowledge that this exercise could result in a rate of return that was higher than the one NGM has proposed.

Most Stakeholders felt that, if NGM did continue with the current approach, far more justification and rationale for it was required – with clarity about which risks were being managed and why values chosen were appropriate.

2.8 Question 8

What requirements do you have for services to support the management of traditional meters (query handling, call management, complaint handling)? What level of service would you expect to receive?

Most Stakeholders felt that the current scope and level of services were about right. This was on the assumption that the costs took into consideration that customer contact was more likely upon meter replacement; that additional assets could be transferred in; that services and service levels would not be withdrawn or reduced; and that the service levels provided for I&C would not be affected.

Specific issues raised by Stakeholders were as follows:

1. Several Stakeholders raised the concern that any reduction in service levels provided may pose a risk that they would be extremely uncomfortable with.
2. Some Stakeholders:
   (i) expressed a view that as costs for the additional services are variable, they should be reviewed annually;
   (ii) wanted to know whether the model offset the cost of the services with the reduced cost of installation as meters are displaced;
   (iii) were unsure if 24/7 services are paid for separately; and
   (iv) suggested that there was scope for NGM working with Suppliers and optimising costs through shared use of resources / infrastructure pre and post displacement.

2.9 Question 9

Do you agree with our assessments of future workload? If you have alternative views please outline where they differ.

Most Stakeholders considered that the workload would be driven by displacement rates, reiterated the comments made in relation to Question 5, and suggested that these be taken into consideration.

Many Stakeholders felt that, other than the dependency on the displacement rates, the assumptions seemed reasonable. However, several felt that, beyond that, they were not in a position to comment, as they did not have full visibility of the future workload model. Some felt that there was a lack of transparency in this respect.

Several Stakeholders raised the matter of potential smart meter installation workload in the scope of the B-MPoLR and NMM obligations – re-iterating the points raised in relation to Question 4.

2.10 Question 10

Do you anticipate any specific requirement for changes to industry data flows or arrangements for traditional meters?

Most Stakeholders could not foresee any significant changes being required to industry dataflows or arrangements for traditional meters; although some were a little cautious, wanting first to have further clarity on the end to end processes before being confident of this. Most felt that, in the absence of any material cost saving or benefit, continuation of the existing IX platform for traditional metering would be preferable to a move to the DTN used in electricity.

Many Stakeholders felt that the biggest challenge to systems and processes would be the “bulk change of MAP/MAM” event – upon a wholesale asset transfer to the NMM. They acknowledged that this business event had been used before, but considered that, if significant volumes were transferred, adequate notice would be needed and careful planning would be required between all parties involved – MAP, MAM, Supplier and NGM. There was also an assumption that the costs NGM has proposed will cover any changes required to their (NGM) systems or processes to support this event.

Several Stakeholders felt that the separate MAM and MAP roles should be recognised by the systems and processes – even though they are often fulfilled by the same organisation. The MAP role is not recognised by the IX system for example; and will not communicate MAM to MAM or MAM to MAP.

Other points made by Stakeholders included:

- Controls would be required to ensure a successful technical and commercial asset transfer – with no gaps / overlapping charging periods; and
- It is possible that changes to the systems and processes supporting traditional metering might arise from further development of smart industry arrangements.

3 Other Matters Raised

This section deals with other relevant matters that were raised by Stakeholders during the workshops and bilateral meetings conducted that do not relate directly to the ten questions posed by NGM in their consultation.

3.1 Openness and Trust

Several Stakeholders did not feel that NGM were sufficiently open with the data they provided in support of the consultation. Several would have expected to have been provided with the RAV calculations for all options; and some would have expected all non-commercially sensitive aspects of the pricing model to have been provided.

A small number of Stakeholders were openly distrustful of NGM – considering that they take advantage of their market position to protect their interests. They were therefore sceptical of much of the substance of the proposals being consulted upon. Some were even cynical about the nature of the relationship between NGM and Ofgem.

3.2 Consultation Haste

Many Stakeholders did not understand why the consultation period was so brief and would have welcomed additional time to attend workshops, take advantage of the bi-lateral meetings on offer and consider matters raised more thoroughly within their organisations. Several of these did not appreciate that the consultation timetable was set out by Ofgem in their July decision document (Reference 2).

3.3 Parallel MSA Negotiations

Several Suppliers felt that conducting the consultation at the same time as MSA contracts were being negotiated was very unhelpful. Some were suspicious about the reasons for this; some felt that these negotiations could have motivated input into the consultation inappropriately.

Appendix A - Acronyms

Acronym	Explanation
B-MPoLR	Backstop Meter Provider of Last Resort
DCC	Data Communication Company
DCM	Domestic Credit Meter
DECC	Department of Energy and Climate Change
GDNs	Gas Distribution Networks
HAM	Holistic Asset Management
I&C	Industrial and Commercial
iGTs	Independent Gas Transporters
MPoLR	Meter Provider of Last Resort
MSA	Metering Service Agreements
NGG	National Grid Gas
NGM	National Grid Metering
NMM	National Metering Manager
PEMS	Post Emergency Metering Services
PPM	Pre-Payment Meter
RAV	Regulatory Asset Value
RoR	Rate of Return
SMETS	Smart Metering Equipment Technical Specification – Version 1 & 2

Appendix B- Workshop Dates & Topics Discussed

Workshop 1: 2nd October

Topic	Scope
NMM and B-MPoLR obligations and durations	Discussion of the assumed obligations and durations of the B-MPoLR and NMM roles as described by NGM. Do these align with stakeholder views? What are key issues/uncertainties that need to be captured?
Asset transfer from GDN's to NMM	Gather stakeholders views regarding this proposal: • Is this an option that relevant stakeholders would be likely to use? • Views about NGM's proposal of a mechanism that balances technical and commercial requirements to enable an appropriate value to be agreed for the asset transfer and for future contractual arrangements for use of those assets.
Sunset assumptions, links to smart timeframe and duration of control period	Due to the fluidity of smart roll-out timescales NGM have opted for a suggested sunset date for the end of the provision of each of the B-MPoLR and NMM services. This was discussed to gather stakeholders' views on the suggested dates.
Traditional meter displacement rates	Gather stakeholder views on: • The use of the lower bound roll-out rates set by DECC in the model; • If any alternative to the lower bound roll-out rate is proposed then the supporting logic and evidence needs to be captured; • Any views regarding identifying particular meter types for early displacement and if so why?
Assessment of Future Workloads	Gather stakeholder views on assumptions regarding future workload discussed in the consultation document.

Workshop 2: 3rd October

Topic	Scope
RAV assessment and allocation	• Review the pros and cons of the 5 proposed options by Ofgem; • Which methodology do stakeholders view as most appropriate and why? • Capture any additional points stakeholders have regarding the assessment and allocation of the RAV.
Rate of return	• Gather stakeholders views regarding the use of the regulatory return for Distribution Businesses as the basis for establishing a rate of return for metering

Topic	Scope
	(RIIO-GD1); • What other approaches are there that might be suitable and why? • Obtain stakeholders views regarding the proposed risk premium aspect of the rate of return.
Derivation of tariff caps & revenue requirement equation	Gather stakeholders views regarding: • the methodology for setting tariff caps and revenue requirements; • Only adjusting credit meter rental in Domestic revenue requirement.

Workshop 3: 9th of October

Topic	Scope
Future for I&C	Gather stakeholders views regarding: • How effective competition is now in the I&C market; • What, if any, regulatory controls do you think are appropriate?
Requirements for additional services (Query handling, complaint handling, contact management, etc.)	Gather stakeholder views regarding their requirements for: • Specific services currently available; • What level of service would stakeholders expect to receive for each required service?
Uncertainty treatment	Review of the uncertainties covered in the previous workshops and a discussion on a way forward to minimise the resulting risk associated with each.

Appendix C - Organisations Attending Workshops

The following organisations attended the workshops:

Workshop	Organisation
Workshop 1	• British Gas • Dong Energy • Energy Assets • EON • Npower • Ofgem • Scotia Gas Networks • Wales & West Utilities
Workshop 2	• British Gas • Corona Energy • Dong Energy • Energy Assets • EON • Gazprom • National Grid Gas - Distribution • Northern Gas Networks • Npower • Ofgem • Scotia Gas Networks
Workshop 3	• Dong Energy • Energy Assets • EON • Gazprom • Npower • Ofgem • Scotia Gas Networks