Appendix A
Summary of Responses to the Common Distribution Charging Methodology Consultation June/July 2009
August 2009

energynetworks association

Summary of Responses to CDCM Consultation

The Common Distribution Charging Methodology Consultation was published on 12th June 2009. Following a new “minded to” decision from Ofgem on 30th June a supplementary consultation paper was issued, together with illustrative charges, showing the effects of this.

A total of twenty responses were received to both the original and supplementary consultation papers. These came from a range of sources including three DNOs, four IDNOs, ten suppliers, an IDNO Association, a Generation Association and an academic.

Below is a summary of these responses with some reactions from the working groups. The appendix contains a table with all the responses categorised according to the respondent and detailed comments when appropriate.

General Comments

There was general support for a move to a common methodology across distribution networks, however suppliers expressed concerns regarding, price disturbance and stability in charges year on year.

We agree that predictability and commonality are desirable in the retail market. However, DNOs need to balance a number of sometimes conflicting requirements, such as delivering methodologies that are cost reflective and yet provide stable and predictable charges. We believe implementing the CDCM produces a consistent, transparent and cost reflective methodology which benefits all stakeholders. Any significant price disturbance will be more likely to occur on initial introduction of the CDCM.

Several respondents commented that some input elements of the CDCM could be set for a fixed period of time.

A greater number of generic inputs would lead to less cost reflective pricing. Key inputs should not change dramatically once the common methodology is implemented. The group understands however the appetite for reducing or managing price volatility and will follow any guidelines that Ofgem issues in this area.

There were mixed view from suppliers with regard to implementation, some were suggesting a phasing of up to three years others felt it essential that all DNOs implement for April 2010.

Changes to billing systems to achieve all aspects of tariff application in the CDCM should not be underestimated but all DNOs are fully committed to delivering the CDCM by April 2010 in line with their licence requirement. However, in the event of a derogation being sought for all or part of the CDCM, it will be for the DNO to justify this to Ofgem.

<u>Initial Consultation Paper Questions</u>

Q1. Is the proposed tariff structure for demand capable of implementation in April 2010? If not, what specific changes are needed to permit implementation?

In general, there was reasonable support for the tariff structure proposed, for implementation in 2010. None of the respondents identified areas of concerns regarding implementation.

Q2. Should the CDCM place restrictions on the freedom of DNOs to define and update their distribution time bands? If yes, what should the restrictions be and why are they necessary?

Some respondents suggested that the time bands should be common for all areas. The group notes these comments, however the view is that the time bands need to reflect the usage, and therefore costs, in each distribution services area. However, the option of fixing the time bands for the price control period will be considered if Ofgem instructs us to do so.

Q3. Is the proposal to make a charge for breach of agreed import capacity on the basis of the capacity charge applied for one month an appropriate way of charging for unauthorised use of the network?

And

Q4. Should other remedies for breach of agreed import capacity be specified in the CDCM?

Views were mixed on the issue of whether other remedies for breach of agreed import capacity should be included in the CDCM. Some respondents supported the proposal whilst others stated that DNOs should manage capacity through connection agreements rather than DUoS charges. One respondent suggested that the charge for excess should be applied for a longer period than one month. The group agrees that DNOs should manage connection agreements proactively, and do so; however it is also fair that customers who use more capacity than their agreed amount should pay the costs associated with that excess. The group did consider at great length the option of applying the charge for a period longer than one month but the consensus was that one month should be adopted across all DNOs. This brings a greater level of commonality across the industry.

Q5. Is the proposed approach to generator credits capable of implementation in April 2010? If not, what specific changes are needed to permit implementation?

No respondent raised serious concerns. Areas such as treatment of VAT, payments of credits and governance are being considered by the CMG and the resurrection of BSC modification proposal P224 is being monitored.

Q6. Do you agree with the proposal to apply single-rate tariffs for intermittent half hourly settled generation and three-rate tariffs for non-intermittent half hourly settled generation?

And

Q7. If both single-rate and three-rate tariffs are used for half hourly settled generation, should each half hourly metered generator be entitled to choose between them? If not, what exact criteria should determine which tariff applies?

There were mixed views across the respondents and nobody specified single or three-rate tariffs should apply to everyone.

Some respondents felt generators should be allowed to choose their tariff.
The group's proposal is that the tariff is not a choice of the generator, but that the generation type will be allocated by reference to the P2/6 definitions for generators.

Q8. Is the proposal to use portfolio billing for all embedded networks capable of implementation in April 2010?

The respondents were generally supportive for portfolio billing for an April 2010 implementation.

Q9. Is the proposed method for reconciling the boundary metered data appropriate?

There were considerable concerns raised by IDNOs. Boundary metering will be consulted on by Ofgem, however the group are developing a billing proposal which is capable of working with or without boundary metering in some or all cases and is currently consulting on it.

Q10. Are the proposed cost and revenue allocation rules suitable for use for setting 2010/2011 tariffs? If not, what practical steps can be taken, within the constraints of the timetable and the need for the method to be common to all DNOs and to provide an objective justification for all tariffs, to develop acceptable allocation rules for April 2010?

The IDNOs were concerned about how appropriate it was to use the same method for both 'all-the-way' and IDNO charges. The group has developed a separate methodology for IDNO tariffs as part of the final submission.

Q11. Is the rationale for the replacement annuity factor correct, and are the assumptions underpinning the proposed 45.3 per cent figure reasonable? If not, what should be done instead? Is there any basis to use a different discount factor?

There was no support for this proposal.

Q12. Should some or all of indirect operating expenditure be stripped out of the model? If yes, which part and how could charges in which this expenditure has been allocated through revenue matching be objectively justified?

There were mixed views in response to this question with some respondents commenting all costs should be included and others not. More analysis was carried out in this area and the final submission proposes to strip out some of the operating expenditure.

Q13. Is the concept of operating expenditure intensity multipliers appropriate? Have we overlooked relevant information that could help determine these multipliers?

The responses showed a supplier versus IDNO/DNO split. The suppliers are not in favour whilst the IDNOs/Dons are. Those in support assumed that the CDCM would *be used to calculate IDNO tariffs. A new approach for calculating IDNO tariffs has been used for the final submission.*

Q14. Should the proportion of LV network included in tariffs for LV connected embedded networks be common or specific to each DNO licence area?

This area is still under discussion within the Ofgem facilitated IDNO/DNO steering group.

Q15. Should a fixed adder be used instead of an annuity scaler for revenue matching? If yes, how can charges that include the fixed adder be justified?

The majority of respondents supported a fixed adder. The final submission uses a fixed adder approach.

Q16. Are there any other issues that threaten the finalisation of the common cost and revenue allocation method, or its implementation on 1 April 2010? If yes, what should be done to mitigate these risks?

No respondent identified any additional issues.

Q17. Should the rate of return and annuity period be specified in the CDCM? If not, what should be the process for modifying them?

And

Q18.Should the replacement annuity factor be specified in the CDCM? If not, what should be the process for modifying it?

And

Q19. Should the operating expenditure intensity multipliers be specified in the CDCM? If not, what should be the rules for updating them and who should be responsible for doing so?

And

Q20. If a single GB-wide proportion of LV network included in tariffs for LV-connected embedded networks is used, should the figure be specified in the CDCM? If not, what should be the rules for determining that proportion and who should be responsible for doing so?

There was support for specification of the financial parameters in the CDCM.
There was some support for specification of a single GB-wide proportion of LV network in the CDCM, but process not commented on.

In their general comments to the consultation a supplier commented that coincidence factors should be fixed for the price control period. The group sees merit in this approach and will speak to Ofgem with regard to which elements of the model it is appropriate to fix for a period of time, if appropriate.

Q21. Are there any other parameters or rules which should be taken out of the CDCM and subject to a different governance process?

No respondent suggested a different approach.

Supplementary Consultation Paper Questions

QS1. Is the inclusion of replacement costs in the modelling necessary to provide an objective justification of the charges?

In general IDNOs think they should be included, whilst suppliers generally feel it is not appropriate.

QS2. Would the inclusion of replacement costs in the modelling help provide appropriate incentives for capacity release by customers?

There was no support for the notion of providing incentives for capacity release.

QS3. Should expenditure in 40 years affect decisions to be made now?
Should the analysis of customers' incentives focus on short-term cash flow rather than on profit or earnings measures?

And

QS4. Should the analysis focus on incentive effects on new customers and on customers who wish to increase their capacity, rather than on customers who are facing decisions to reduce capacity or to disconnect?

There was no support for analysis which takes long term expenditure into account.

QS5. If objective justification based on cost is not achievable for all the way tariffs, what principles should be used to set charges for embedded networks?

Some respondents questioned the appropriateness of the use of the DRM approach and suggested a separate model. The group is now working on this.

QS6. Could an annuity scaler be justified if replacement costs have been excluded from the model? If yes, how?

And

QS7. Is a fixed adder least distortive to the cost signal? Which cost signal?

The majority of respondents supported the fixed adder.

QS8. Is the essential feature of a fixed adder approach to revenue matching that it should collect the same amount of money from a customer with a given capacity and load irrespective of whether the user is supplied at HV or at LV?

Most respondents agreed that this was an essential feature of the fixed adder approach.

QS9. Are there other ways of applying a fixed adder? If so what are they?

There was support for a voltage level adder and for a utilisation related adder. The final submission uses a fixed adder approach.

Appendix – Table of Responses

Issue / comment	**Raised by**	**Our response**
General		
GDF SUEZ Energy UK welcomes the move to a common charging methodology and to common charging structures across the Distribution Networks.	GDF suez	
GDF Suez Energy UK believes that the objectives should be a completely common charging methodology which delivers stability in the level of charges.	GDF suez	We agree that predictability and commonality are desirable in the retail market. However, DNOs need to balance a number of sometimes conflicting requirements, such as deliver methodologies that are cost reflective and also provide stable and predictable charges.
The calculation of Reactive charges should be based upon a standard formula e.g. a single rate and as with the calculation of kVA DNO's must agree that only kVArh lag is used and not both kVArh lag and lead.	GDF suez	The formula for reactive charges is common under the CDCM, as proposed in the tariff application paper. The correct formulation must reflect lead and lag power factors.
The REA are generally in favour of cost reflective charging.	REA	
The REA are disappointed that the charging methodology has not been able to agree on a common EHV charging methodology or even to move in 2010 to one of the two methodologies that it is intended will be allowed from April 2011.	REA	
It should be possible for whatever methodology is selected for EHV and to apply to HV and LV as well, if necessary using "typical" rather than actual network models at these lower voltage levels.	REA	It is not clear to us how what the REA proposal is. Should the HV/LV charges be based on power flow modelling on typical networks? The DRM is a representation of a typical network.
The REA is particularly disappointed that proposed HV/LV models will not even use more cost reflective EHV models to calculate EHV components of HV and LV charges.		

The REA supports the adoption of this methodology from April 2010. This is conditional upon Ofgem allowing a single pot approach for the allowed revenues from DNOs from that date	REA	Ofgem have already allowed one single pot.
CDCM "more transparent and consistent"	Scottish and Southern Energy	Generally this has been achieved as a product of the development of the CDCM within WS2
Concerns about pricing disturbance	Scottish and Southern Energy	DNOs need to change to the common pricing model under the common methodology, from different starting positions. Once implemented, future price disturbances should be more limited. This has been Ofgem guidance since 2005.
Regulation on large price increases proposed	Scottish and Southern Energy	
Variation in key inputs result in uncertainty and instability	Scottish and Southern Energy	A greater number of generic inputs would lead to less cost reflective pricing. Key inputs should not change dramatically once the common methodology is implemented.
Proposes that key inputs are fixed for a defined period	Scottish and Southern Energy	There are some inputs that could be fixed for a defined period. However, fixing inputs reduces cost reflectivity in future years. The group is open to guidance from Ofgem in this area.
NHH tariff structure is too simple and lacks cost reflectivity particularly when considering the onset of smart metering	Scottish and Southern Energy	There are areas where the CDCM would appear too simplistic, particularly in regards to time bands. However the current WS2 time bands do represent a current pragmatic solution.
Support for the de-linking proposal	Scottish and Southern Energy	WS3 will be progressing the de-linking proposal later this year.
Highlights support for robust governance and stability	Scottish and Southern Energy	The governance does need to be robust. We understand why suppliers would seek stability, but

		this must not be to the detriment of improvements to the methodology.
It is not yet clear how the NH charges will be applied to some of the two/three rate supply tariffs that exist or to any new supply tariffs that will be created.	Scottish and Southern Energy	WS3 are currently populating a table to allow suppliers to determine which tariff rate will apply to each of the market domain data SSC/TPR combination. This will be made available to the industry once finalised. WS3 will also be progressing the de-linking proposal later this year.
Margin available to an embedded operator is halved by the removal of one element of cost in supplementary consultation. The fact that this results from the alternative treatment of one single element of cost model raises alarms for future volatility of LDNO margins.	ESPE	Replacement costs had considerable weight in the original CDCM consultation, as they are real costs incurred by the DNO
Questions remain outstanding as to the necessity, provision and funding of boundary meters. ESPE believes a common charging methodology must not rely on boundary metering,	ESPE	We understand Ofgem is going to consult on this issue soon.
Supportive of this project but needs to be implemented in a controlled way and price disturbances kept to a manageable level	Haven Power	We welcome your support.
The indicative proposals result in a very significant disturbance to DUoS charges in the SME segment. Price increases in excess of 30% in 6 regions and over 50% in 3 regions. This is a highly material increase to distribution costs which will impact these customers dramatically. It will damage small suppliers disproportionately since, unlike the major suppliers we will not receive the counterbalancing reductions in charges associated with other profile classes.	Haven Power	The charges derived from the CDCM reflect the costs imposed by the SME users on the distribution system. The group contacted Haven Power to correct their analysis as all charges impacted on SME segment were reduced.
This is a highly material increase to distribution costs which will impact small business users dramatically. It will also damage small suppliers disproportionately since, unlike the major suppliers we will not receive the counterbalancing reductions in charges	Haven Power	Noted

associated with other profile classes.		
As our customer supply contracts are typically 12 to 36 months we suggest the application of the revised costs is delayed 3 years.	Haven Power	We believe implementing a CDCM produces a consistent, transparent and cost reflective methodology which benefits all stakeholders. We do not believe delaying by 3 years is appropriate. This is a decision for Ofgem
Supportive of standardisation of the methodology across all DNO regions. The level charge increases presents a significant challenge.	IPM Energy Retail	Noted
The charge increases together with price control outcome uncertainties represents a significant risk to our business and a barrier to growth. The tariff increases have a material impact on costs and delivered margins.	IPM Energy Retail	The charges derived from the CDCM reflect the costs imposed by users on the distribution system.
The changes proposed together with price control outcome uncertainties exposes us especially for customers on fixed price, fixed term products. Updating each DNO's illustrative charges based on Ofgem's Initial Proposal for DPCR5 at the end of July would be extremely useful. We would like to suggest implementing a cap to the level of charge increases that can occur for any individual customer in any year to reduce the risk premium required in tariffs and provide lower end price to customers.	IPM Energy Retail	Noted
We are deeply disappointed that the CMG appears to have ignored guidance provided by competition case law: that the margin available should be that which the DNO's own notional downstream business would require in order to operate the downstream business and make a normal profit. Therefore, we do not support the methodology that underpins the tariffs to IDNOs. We are of the view that the margins made available to IDNOs by this methodology fall far short from what is required. We have highlighted key guidance documents published by the Office of Fair Trading and provided	GTC	Whether a notional downstream business would be able to operate with a normal profit might be relevant to the question of whether charges have an exclusionary effect, but is not the be all and end all of competition law. The approach put forward in the 12 June 2009 consultation was to develop an objective justification based on cost for all charges, without

references to the relevant case law.		regard to the finances of downstream businesses.
Such a wide range of margins questions whether the DRM approach is capable of delivering charges to IDNOs that are consistent with the requirements of competition law.	GTC	The charges published with the consultation were illustrative. It should also be pointed out that due to the fact that different network areas will have different topography and customer characteristics, different margins are to be expected.
The cost of operating downstream networks did not halve between the June consultation and the July consultation. Therefore, when by the apparent click of a mouse on a spreadsheet the margins available to IDNOs are slashed, the use of the CDCM as a credible model for determining the costs of operating downstream networks must be seriously questioned.	GTC	It is not surprising that changing the principles of the model should change the results. We pointed out in the supplementary consultation that the changes made affected the usability of the method to set IDNO tariffs.
[Boundary metering and billing arrangements] are upstream activities and have the potential to significantly impact on the margins available to IDNOs. We believe that the costs for these activities falls within the scope of the price control and should be recovered through the DUoS charge.	GTC	
Network rates are different to profit taxes. They are a fixed and unavoidable cost. Neither is true of profit taxes. Where IDNOs own and operate downstream networks the effect will be that DNO will avoid additional rates it would have had to pay if it owned and operated the downstream network and the IDNO will pick up the expense. Clearly the tariff methodology must make allowance to cover this bona fide operating cost that IDNOs face.	GTC	In the 12 June 2009 CDCM, the proposal was to allocate the cost of network rates alongside other asset-related revenue through the operation of the annuity scaler. If the annuity scaler is not used, as proposed for the 8 July 2009 scenarios, then the argument is correct; the group has now included a provision for network rates explicitly in the model.

Asset replacement cannot be avoided in the long run and so clearly allowance must be made. Replacing assets typically incurs higher costs because the activity involves excavating and reinstating of roads and pavements.	GTC	
The process for charging for invalid combinations is still being discussed and we would have appreciated the opportunity to respond to the options here. Happy with the current option of billing on a default tariff linked to the domestic rate but believe much work needs to be carried out to resolve invalid LLFCs currently assigned.	SPERL	
The respondent has concerns over the potential future development of de-linking	TGP	
Concerns over level of price disturbance	WPD	
Concerns over use of the 'in the month charging' approach for billing excess capacity charges over the 'twelve month rolling' approach	ENW	
We are able to implement the majority of changes to our IT systems for billing the new tariffs but we expect to seek derogation for a limited number of small changes that would be implemented during 2010/11. We would welcome some clarification on the application process for derogations and asks that the CMG consider discussing the detail with Ofgem so that there is a consistent approach taken by those DNOs expecting to apply.	ENW	The CMG will discuss this with Ofgem.
CDCM heralds significant change to the structure of distribution charges and we should review the threshold for the application of half hourly metering. ENW suggests that all HV tariffs should be half-hourly metered and believes that the artificial boundary determined as 100kW at the onset of deregulation due to the costs of metering equipment should now be reviewed in light of the developments and reduced costs in digital metering technology.	ENW	

Our main concern on changes to distribution charging is the disturbance (or variation) which any new methodology could cause. We are led to believe that the disturbance associated with this round of changes could be very significant indeed. In the half hourly market contracts are typically struck for 12 or 24 months, and 36 month contracts are not unheard of. The vast majority of contracts which we enter into are all inclusive i.e. the DUoS element is fixed using an estimate of likely increases in the future. From our view of the competitive market, we do not believe that suppliers are factoring in increases for the year 2010-2011 and beyond which are greater than the levels of change we have seen in recent years. This is because suppliers have had little insight until now into how much of an increase to expect. It is, therefore, vital that any changes to the methodology include a phasing (or preferably a delay to any out-of-the-ordinary cost recovery until April 2012 followed by a phasing) otherwise suppliers could face a significant financial loss.	SmartestEnergy	We believe implementing a CDCM produces a consistent, transparent and cost reflective methodology which benefits all stakeholders. We do not believe delaying by 3 years is appropriate.
As well as concerns for the risk suppliers are facing, we are also very concerned about overall increases which customers may see year on year. Over the last two to three years we have seen national average increases in the half hourly tariffs of the order of 4 to 5%. Obviously, there has been a great deal of variation between areas; some tariffs staying the same (or even reducing) in some areas from one year to the next and some moving up by as much as 20%.	SmartestEnergy	Charges across DNO areas will always be different due to the differences in the underlying network model and the allowed revenue to be recovered. This model should bring more stability to charges cross the industry.
This comment may be more appropriately directed at Ofgem but we do not believe that customers should be exposed on average to percentages year on year which are significantly above the rate of inflation. The United Kingdom is currently in recession; DUoS bills make up a significant element of an electricity bill; and there are many other environmental initiatives which will push up the cost of electricity to end-users over the coming	SmartestEnergy	Ofgem do scrutinise our plans during the price review process - this is currently underway

years. Ofgem should scrutinise very closely and challenge any plans for investment in infrastructure. Ofgem are in the best position to do this on behalf of the industry.		
We are also concerned that there has been insufficient control over the most recent round of tariff increases for 2009/2010. We are led to believe that there have been examples of increases above the agreed formula on the grounds that there were "income adjusting events," "one-off corrections," "allowances for reductions in usage" and even the need for "additional tree-lopping." We would suggest to Ofgem that there needs to be more stringent application of their "controls."	SmartestEnergy	DNOs set charges to reflect the usage of the network by different types of customers. The amount of income is fixed for five years at the start of a price control period. Ofgem's drafting of the final proposal in the last price control made provision for DNOs to recover any exceptional costs over and above those that had been agreed. These increase/income adjusting events are not done in isolation DNOs have to consult with and justify to Ofgem any such requests.
There is no justice in a regulatory framework which allows suppliers to take all of the risk in the variations of distribution charging while distributors can adjust their incomes at will.	SmartestEnergy	Note that DNOs have income adjusting factors that can reduce income, such as the growth incentive that reduce the allowed income for network operators due to lack of growth. This reduction will be passed on in the same way as any potential increases.
On a final note in this preamble we would suggest that as many parameters/issues as possible are brought under the Price Control Reviews.	SmartestEnergy	
ESPE does not accept level of LDNO margins available in S100 or S80 models as appropriate.	ESPE	We agree
The methodology might not produce tariffs in all DNO areas that satisfy competition tests	CNA	The approach put forward in the 12 June 2009 consultation was to develop an objective justification based on cost for all charges.

Where there is a substantial mismatch between the total allowed revenue and that directly attributed by the DRM model, then consideration needs to be given to the underlying cause of the difference.	MCM	
Support for de-linking and longer term products. Would like to seem them developed as soon as possible after implementation.	BGT	The group remains supportive of de-linking and will be considering this and other long term products later in the year. Agree that prescribing de-linking to apply from April 2010 would have seriously jeopardised delivery.
Important that DNOs keep to the agreed timetable and do not seek derogations from their licence obligations.	BGT	The changes to billing systems to achieve all aspects of tariff application in the CDCM should not be underestimated however DNOs are fully committed to delivering the CDCM by April 2010 in line with their licence requirement. However, In the potential event of a derogation being sought for all or part of the CDCM, it will no doubt be for the DNO to justify this to Ofgem.
Thinks that too many costs are placed in the 500MW model and has concerns about the range of over-/under-recovery	BGT	The group has done further work to improve the commonality of the 500MW models underpinning the tariff model.
Questions the allocation of opex towards LV networks and the inclusion of some categories of opex that are unrelated to network size	BGT	The group has done further work in this area. The final proposal does not include the use of intensity multipliers and it makes an allowance for indirect/direct opex costs.
Model should be independently audited before implementation	BGT	We agree that this is a sensible suggestion. As mitigation however, the model has been available for scrutiny by industry participant for some time and will continue to make the model available as it develops.

The methodology applied to the tariffs published in the secondary consultation does not reflect Ofgem's thinking in respect of LDNO tariffs	IPNL	That is true. Ofgem's guidance was in reference to the ATW tariffs and they intimated that LDNO tariffs could be derived from a separate model. LDNO tariffs in the secondary consultation were included for illustration purposes only.
IPNL does not consider that an identical method is necessarily appropriate for both ATW tariffs and LDNO tariffs	IPNL	This is consistent with Ofgem's latest view.
Question 1 Is the proposed tariff structure for demand capable of implementation in April 2010? If not, what specific changes are needed to permit implementation?		
To implement these proposals will require major system changes for Suppliers, incurring significant cost and risk. Billing Systems need to take account of both historic and new methodologies for the application of DUoS charges. To allow proper staged implementation an implementation date beyond April 2011 would be needed to reduce supplier risk.	GDF suez	DNOs have a licence obligation to implement changes from April 2010.
Proposed changes will pose problems but with reasonable notice April 2010 implementation could be achieved	Energetics	
ESPE fully supports decision to adopt portfolio approach to charging IDNOs but suggests further consideration of separation in treatment of end user tariffs and LDNO – may be useful to look at existing non-vetoed methodologies which incorporate IDNO charging.	ESPE	
We anticipate applying for derogation for a delayed implementation of some aspects of billing functionality.	ENW	
We support the proposed structure and see no reason why this could not be implemented in April 2010	IPM Energy Retail	We agree.
In respect of DUoS tariffs to suppliers we expect to be able to implement the proposed tariff structures. In respect of the IDNO tariffs, further work is required to develop an agreed enduring solution for the DUoS billing of IDNOs. Even if an enduring solution is not in place for the 1 April 2010, based on the information currently available to us, we believe we will be	GTC	

able to develop work round arrangements with DNOs for an interim period.		
Adopting an approach [where boundary and portfolio tariffs coexist, as in ENW's interim proposals] (even if only as a transitional arrangement) could mitigate the effects of a billing solution not being in place on time.	GTC	
Ready for the April 2010 implementation date though significant work would be required. However, totally dependent on all information being made available well in advance by all DNOs and implement all changes at the same time. Following discussions at WS3 and the CDCM workshop have serious concerns regarding the implementation date. It has been suggested that DNOs will not implement everything in April and will instead go live in stages. This will force suppliers to update systems but still leaves the requirement to continue with the "as is" process (including settlement run off of up to 28 months). This is totally unrealistic and unfair on both suppliers and end users. Recommend that if any DNO cannot meet any part the April 2010 date, all changes should be held back until they can, implementing across all DNOs in stages if required. This should include transferring NHH site-specific billing to super-customer billing.	SPERL	
No issues. However request if any changes, enough notice given.	RWE npower	
From what we have heard from Distributors it seems highly unlikely they will be able to implement a full structure by April 2010. This would mean suppliers having to cope with many different structures which is not acceptable.	e.on	All DNOs will endeavour to implement the new common structure by April 2010. We are in the process of carrying out an impact assessment to identify what changes are required to billing systems and whether or not these can be delivered in time. Once this is know we will communicate this to the industry.

IPNL believes that its existing billing system is capable of implementing the new structures and charges without any significant modification. We are however concerned about reactive unit charging where some changes may be necessary to implement a slightly different method than that currently employed and generation charging where we believe that the method employed by the EDF group is slightly different to that used by other DNOs.	IPNL	In relation to reactive charges, in order to achieve a common approach, those companies that do not already apply that approach will need to implement changes. This is true for DNOs, IDNOs and suppliers. EDF are not proposing a different approach to generation charging, all DNOs will comply with the CDCM
Question 2 Should the CDCM place restrictions on the freedom of DNOs to define and update their distribution time bands? If yes, what should the restrictions be and why are they necessary?		
All time bands should be common, without this, benefits to suppliers and customers are severely dampened. We would propose that the change of time band requires a significant lead time (say 2 years) or that those DNOs be prevented from making changes to their time bands for the duration of each price control. This is driven by the fact that Suppliers forward contract with customers based on the current rate structures. In terms of Billing, significant work is required to update billing systems and explain to customers the changes in their charges.	GDF suez	Different time bands per DNO are necessary to reflect network usage and therefore cost reflective. We do not agree with the argument of excessive costs to suppliers' billing systems: the benefits in terms of cost signals are likely to offset the work required to reflect the time bands of 14 licensees.
Time bands should be common across all DNOs; any proposed changes would be subject to governance considerations	Energetics	
CDCM should not place restrictions on the freedom of DNOs to define and update their distribution time bands.	EDFEN	The WS2 development of the three time bands offers a pragmatic starting point, but should not restrict the development of time bands to deliver more economic pricing signals.
All DNOs should use the same methodology for determining the time bands for the CDCM. The results of the application of that methodology will be based on the network information for each DNO. ENW expects its time bands will change over time as the distribution network develops and how	ENW	

it is used changes (i.e. from the impact of smart metering on consumer behaviour).		
We would support further restrictions on the number of time bands Reducing the complexity of and the number of changes to tariff structures would reduce workload for suppliers and reduce the risks associated with the uncertainty	IPM Energy Retail	We are not convinced that reducing the number of time bands further would be cost reflective particularly for the Half Hourly metered customers market. This would also not be appropriate with the planned introduction of Smart Meters.
The CDCM should place restrictions on the freedom of DNOs to define and update their distribution time bands.	GTC	
We oppose strongly the de-linking proposals put forward by work stream 3. (Explains why it would not work without new SSCs.) Such an approach may be more plausible with the advent of smart metering. In the meantime if DNOs wish to introduce more time bands then they should do so through working with suppliers to introduce SSCs with multiple TPRs.	GTC	The practicalities of introducing many new SSCs and reflecting them in new DUoS tariff are complex; this is why de-linking is still worth considering.
Appreciate the need for distribution time bands to highlight peak periods and that each area has different demands. DNOs must be realistic in times they set. Must follow the normal charging statement update process timescales to provide suppliers and end users enough notice.	SPERL	
No. However, in practice expect time bands to be relatively stable on a year-by-year basis as underlying changes in consumption patterns are likely to be gradual in nature. Generally, the CDCM should outline the principles for determining time bands, which, if properly set, could be followed without causing unnecessary disturbance.	RWE npower	
Restrictions should be in place and a minimum time period in advance of changes	TGP	
Would prefer 2 unit rates not 3 for HHM sites	WPD	

We understand the desire for DNOs to define and update their time bands, but don't believe this is good customer service. One of the main drivers as far as we are concerned for a common methodology has come from customers who operate in different DNO areas and cannot understand why charges differ in each. Having different time bands does not rectify this problem and it is left to the supplier to field the calls to customers with these queries.	e.on	The actual times where each time band might need to change to reflect network usage and therefore give appropriate costs signals. DNOs do not think that the impact of changing the time bands will be significant in the billing systems. Charges across DNO areas will always be different due to the differences in the underlying network model and the allowed revenue to be recovered. This model seeks to align tariff structures.
A Common Distribution Charging Methodology should be precisely that: common. As a Supplier we see advantages in aligning the definitions of day and night with the generally used supply definitions where night is from 00:00 to 07:00. Bringing all of the DUoS charging in line with this should lead to greater clarity on customers' bills in the HH market.	SmartestEnergy	The actual times where each time band might need to change to reflect network usage. One of the main drivers for introducing the time bands is to reflect network usage having simple day/night tariffs does not address this.
Yes. Enough notice should be given	IPNL	The tariff structure is unlikely to change year on year, but the actual times where each time band might need to change to reflect network usage. DNOs do not think that the impact of changing the time bands will be significant in the billing systems.
Question 3 Is the proposal to make a charge for breach of agreed import capacity on the basis of the capacity charge applied for one month an appropriate way of charging for unauthorised use of the network?		
The consultation paper does not state the rationale behind a one month charge therefore it is difficult to see how the charge of 1 month of capacity charge reflects the costs incurred for breach of network use. It is important that there should be a deterrent but in practice this approach may over penalise someone who has a short breach, and under penalise someone	GDF suez	

who consistently breaches.		
Principle is appropriate but consideration should be given to singular events where the increase above the agreed capacity is not material	Energetics	
Does not agree with the proposal to make a charge for breach of agreed import capacity on the basis that a normal capacity charge is applied for only one month.	EDFEN	The group believes the approach is cost reflective.
Yes , support the proposal.	IPM Energy Retail	Noted.
The charge for a month is not appropriate on its own. [The connection] agreement normally has a provision for either of the parties to the agreement to propose a variation. For persistent offenders the DNO could raise a variation to change the agreed capacity. For customers who do not have a connection agreement, Section 21 of the Electricity Act 1989 permits an electricity distributor to require any person who requires a connection to accept "...any terms which it is reasonable in all the circumstances for that person to be required to accept".	GTC	The group believes the approach is cost reflective.
Yes. Will help customers who have often been confused by the variation in charge rules across DNOS. The charge seems reasonable and fair method and will also been seen as such by customers.	SPERL	
Charging for excess capacity maybe viewed as a method of policing connection agreements and, as such, concerned it blurs the distinction between connection and use of system. It appears unlikely a customer exceeding its agreed capacity on a single occasion causes a DNO to incur extra costs, so it could be argued excess capacity should not be charged for and those who repeatedly exceed be dealt through active management of the connection. If excess capacity if to be charged for, we support this proposed method as the preferred option.	RWE npower	
Yes	TGP	
Yes we believe it is far better arrangement than the mixture that	e.on	We welcome your support

exists today.		
If the ‘in the month’ approach is deemed the most sensible approach moving forward for charging for exceeded capacity then ENW suggests that the Workstream should consider the approach that the capacity charge applicable for the exceeded amount is determined as the capacity charge from the CDCM, without the removal of the deemed customer contributions percentages for appropriate network levels.	ENW	.
It is not clear from this wording whether the charge applies to *all* the half hours in the month or only those in which the import capacity was exceeded. The former interpretation would seem a little draconian and would not be the fairest approach. We understand, however, that the charge itself would be lower in this situation and would be easier to administer and reconcile.	SmartestEnergy	The charge would apply to all HH periods in the given month.
Yes. Customer should be asked to re-declare capacity	IPNL	
Question 4 Should other remedies for breach of agreed import capacity be specified in the CDCM?		
GDF SUEZ Energy UK would like to see a simple and uniform charge introduced that customers could readily understand and would be simpler to implement.	GDF suez	The charges need to be DNO-specific to be cost reflective. Otherwise the approach proposed is common.
The increased capacity charge should be levied for a duration, or charge which at least matches the duration or cost that is faced by a customer who legitimately applies for an increase in their capacity requirements.	EDFEN	
Support the proposed changes and do not feel any remedies are necessary.	IPM Energy Retail	Noted.
DNOS must manage customers connected to their network constantly and not expect suppliers to highlight agreed capacity issues. Any requirements should be written into the capacity agreements not the CDCM.	SPERL	
It is not appropriate to manage connection agreement issues through use of system charges.	RWE npower	
We believe that other remedies should remain specified in the Distribution Connection and Use of System Agreement (DCUSA) and the Bilateral Connection Agreement and/or National	ENW	

Terms of Connection.		
Would prefer it if DNOs all charged for capacity breaches on the same basis	TGP	
Yes	e.on	We would be keen to hear what you think these may be
No	SmartestEnergy	Noted
the issue of exceeding capacities should be address outside the CDCM	BGT	We agree that breaches in agreed import capacities (or export capacities) can have significant consequences and should be primarily dealt with outside of the charging arrangements. However it is also important that users pay for the cost they impose on the network through the charging arrangements as otherwise the burden of this cost will fall on other customers. Charges for exceeded capacity should never replace the management of the network and connection agreements but we believe that they complement it well.
Yes	IPNL	
Question 5 Is the proposed approach to generator credits capable of implementation in April 2010? If not, what specific changes are needed to permit implementation?		
There is no problem with implementation	REA	
There are three areas for consideration with the proposed approach to generator credits being capable of implementation in April 2010: Technical, VAT, Governance.	EDFEN	This is currently being progressed.
Yes. However would like to seek assurances on a few points not detailed in the consultation document. Currently sites with import & export capacity (split across two suppliers) can unfairly penalise the import supplier due to the way reactive (RI&RE) is allocated during periods of export. A potential solution this , BSC Modification P224, was rejected though discussions have started again. It should be noted that one DNO	SPERL	

company already has a solution, which although is not perfect, is very similar to the P224 solution. The CDCM provides an excellent provides an excellent opportunity to ensure the incorrect allocation of reactive charges is discontinued. The consultation document is also silent on the process DNOs will follow if no reactive data is available. We should appreciate the opportunity to review and comment on any estimation techniques.		
Based on our prioritisation of the changes ENW is expecting to deliver generator tariffs and the corresponding IT changes to accommodate the billing of such tariffs in line with the current proposal by April 2010.	ENW	
Have no issues.	RWE npower	
We do not feel sufficiently involved to offer an opinion on this question.	SmartestEnergy	Noted
IPNL have been advised that the approach in EDF is different.	IPNL	EDF are not proposing a different approach to generation charging, all DNOs will comply with the CDCM
Question 6 Do you agree with the proposal to apply single-rate tariffs for intermittent half hourly settled generation and three-rate tariffs for non-intermittent half hourly settled generation?		
A single methodology should be used for generator credits and it is unfair to differentiate between intermittent and continuous. It is not clear why this methodology has been adopted or how “intermittent” of “continuous” would be derived.	GDF suez	Methodology has been adopted to encourage generators that can control their output "continuous" to provide network benefit when it's most valuable. Apologies for the use of jargon: "intermittent" generators refers to wind farms and hydro generators. "Continuous" means mostly thermal generators, nomenclature is consistent with P2/6 recommendation.
Both three rate and single rate tariffs should be available for all half hourly metered generation and it should be up to the generator to choose between the tariffs.	REA	

1. In terms of establishing new markets we support the application of a single rate. Applying a single rate at the outset would provide a consistent pricing environment thus promoting the growth of DG uptake. 2. As the DG market matures, and DG customers gain a greater understanding of the market, the more cost reflective approach of using all available time bands as used with demand customers would be more appropriate.	EDFEN	
See no benefit in the provision of a single rate tariff and prefer just to provide a three rate tariff for this customer class so that all customers are treated consistently and it will remove the ability of the distributed generator to argue for the tariff with the best income profile.	ENW	
We do not understand the need for two tariffs. Doesn't the banding in the three rate tariff take care of the value of a unit of electricity delivered onto the distribution system from intermittent generators?	GTC	The consultation document explains (paragraph 2.31) that the purpose of the single-rate tariff for intermittent generation would be to avoid exposing these generators to the additional risks associated with banded unit rates.
Tentatively yes. However important to note that this affirmative is only within the narrow confines of the question's scope. Concerns on the methodology of the DGUOS calculation as defined by the document. How would the credits apply in practise? It appears as though they would be offset against the fixed and reactive charges applied but there is no confirmation of this within the document. Are credits to be issued to the generator, the party purchasing the power or will they be automatically deducted against charges incurred? In turn if generators are to be re-numerated which party will be responsible for settling the GDUOS invoice? Will the DNO be dealing with the embedded generator directly? b) There is concern that the methodology for calculating the	SPERL	

reactive power charges is overly complex and that this will impact on the validation and settlement of GDUOS costs. Following renewed discussions on P224 we recommend the reactive charging part of the CDCM should be removed. As a revised BSC modification will greatly impact this area any changes should now be put on hold until a well worked solution can be implemented.		
It does not appear sensible to allow generators to choose which tariff to apply. Due to tariffs necessarily being average in nature this gives an opportunity for generators to 'cherry-pick' the tariff that is most beneficial. The exact criteria to apply are not obvious and so it may be inappropriate to apply different tariffs for intermittent and non-intermittent generators	RWE npower	
Yes	e.on	We welcome your support
It would be impossible to create rules which fairly create such a distinction between intermittent and non-intermittent. We believe all generation should be treated equally.	SmartestEnergy	The rationale for having different tariffs is that for an intermittent generators they may not be able to generate at the time of system peak, and off-set any need for re-enforcement
Question 7 If both single-rate and three-rate tariffs are used for half hourly settled generation, should each half hourly metered generator be entitled to choose between them? If not, what exact criteria should determine which tariff applies?		
As stated in the answer to question 6 we believe that half hourly metered generation should be allowed to choose between tariffs.	REA	
Where there is doubt about how a generator is classified (i.e. whether "intermittent" or "non-intermittent"), then the "non-intermittent" rate should be applied. Generators defined as "intermittent" half hourly customers should be offered the option of choosing a multi rate tariff.	EDFEN	See full EDFEN response.
No, the criteria of HH intermittent = one rate band, HH non-intermittent = three rate bands is acceptable. As with Q6 concerns regarding the exact nature of		

the credits process and the issues surrounding the reactive power issue.		
Yes	e.on	We welcome your support
It would be impossible to create rules which fairly create such a distinction between intermittent and non-intermittent. We believe all generation should be treated equally.	SmartestEnergy	The rationale for having different tariffs is that for an intermittent generators they may not be able to generate at the time of system peak, and off-set any need for re-enforcement
Criteria should be specified in CDCM	IPNL	
Question 8 Is the proposal to use portfolio billing for all embedded networks capable of implementation in April 2010?		
Proposed changes will pose problems but with reasonable notice April 2010 implementation could be achieved	Energetics	
Would prefer the adoption of portfolio billing now being proposed for our interim IDNO methodology.	EDFEN	We expect this to be resolved through the CMG and WS2/3/4
We support the proposal to introduce portfolio tariffs.	GTC	
Offered portfolio billing as part of its recent Modification Proposal for the introduction of an Interim LDNO charging methodology as we see that it could be implemented in the short term if the LDNO is able to provide the data, in an agreed format, on a monthly basis. We intend to process this information manually and submit a monthly invoice to the LDNO.	ENW	
We do not feel sufficiently involved to offer an opinion on this question.	SmartestEnergy	Noted
IPNL supports the move towards portfolio billing. Proposal needs to be sufficiently firmed, the more complex the more likely implementation will be. IPNL originally envisaged settlement solution to be based on LLFCs, but believe a solution based on SSC/PC/LLFC combination could work. Agreement on methodology and governance by all parties is needed.	IPNL	WS2 has issued a consultation on IDNO billing which is currently underway.
Question 9 Is the proposed embedded network billing procedure appropriate?		
This method is not appropriate as it passes on costs to the supplier that the supplier cannot recover. Suppliers may only bill customers at the rates in force multiplied by the metered units and	GDF suez	Proposal was misunderstood: the charge is to the IDNO.

with fixed/additional charges added. If there is an adjustment to the charge on a supplier by a DNO because of an adjustment at boundary metered units, then this cannot be recovered by suppliers.		
Concerns over application of LAFs to boundary metered data. Also, if the benefits of boundary metering accrue to DNOs they should bear the cost of it	Energetics	
[Yes but] there is no common position on: the circumstances where boundary metering is required; the relevant standards for the metering; the relevant standards and protocols for metering data; the responsibilities for the provision of such metering; who should pay for such metering. We understand the Work Stream 2 considers these areas to be outside the scope of its work. Further, we understand that there is no common position among DNOs in respect of boundary metering. At least two distribution groups (representing five distribution services areas) appear to be insistent that boundary metering is fitted in all circumstances. Whilst, some DNOs acknowledge that boundary metering may not be required (LV connected networks) in certain cases, other DNO groups are still to confirm their position. Additionally, Work Stream 2 has failed to consider how and who would fund such a solution. Boundary metering brings an additional cost to the industry which must ultimately be borne by consumers.	GTC	Boundary metering is a current requirement in some areas and it seems inappropriate to describe it as an "additional" cost. Ofgem has said that it will consult on these issues.
In determining the appropriate margins available to an IDNO such costs must be considered. To illustrate the point, if the cost of metering was £100 per annum for a development of 25 properties connected at LV then the indicative cost per is £4 per MPAN per annum. Where CT metering is required annual costs will be higher, ranging from £6 per MPAN per annum (for a development of 50 properties) to £1.50 per annum.	GTC	This assumes that IDNO tariffs should be set to allow IDNOs to make a particular level of profit. The approach proposed on 12 June 2009 did not rely on that principle.

The double benefit received by DNOs (through increased units and reduced losses) is not reflected in charges to IDNOs. This benefit to the DNO equates to nearly 6p/kWh in respect of IDNO losses.	GTC	This assumes that IDNO tariffs should be set on the basis of the benefit (including avoided cost) to the DNO of not being responsible for a downstream business. This conflicts with the apparent principle underpinning the previous comment. The approach proposed on 12 June 2009 did not rely on either principle.
As long as this does not impose any more direct costs onto the Supplier. Any extra costs should be borne by the Distributors and passed on via their Duos charge and not paid directly up front by the supplier.	e.on	We note your comment and expect the impact of any associated costs to be debated in more detail in a separate IDNO consultation
Embedded network operators should neither be exposed to undue profiling errors nor avoid their proportionate share unduly. We are inclined to believe that the reconciliation to boundary flows should not be applied in a different way.	SmartestEnergy	DNOs think that boundary metering is needed in at least some circumstances, as DNOS are exposed to losses incentives. However, settlement proposal works with and without boundary metering. It is our understanding that Ofgem are planning to consult on the issue of boundary metering soon.
Remain concerned with the competition effects that the proposed reconciliation to boundary metering data may have. It is conceivable that an LDNO could be faced with negative margins due to the actions of suppliers which a 'downstream DNO business' would not face. To avoid this potential issue, we believe that this adjustment should not be applied to IDNO billing but to the reporting of distribution units by the distributor.	ENW	
IPNL believes boundary metering is not necessary and that the method will introduce costs and it is extremely complex and over elaborated. Reconciliation is not necessary.	IPNL	DNOs think that boundary metering is needed in at least some circumstances, as DNOS are exposed to losses incentives. However, settlement proposal works with and without boundary metering. It is

		our understanding that Ofgem are planning to consult on the issue of boundary metering soon.
Question 10 Are the proposed cost and revenue allocation rules suitable for use for setting 2010/2011 tariffs? If not, what practical steps can be taken, within the constraints of the timetable and the need for the method to be common to all DNOs and to provide an objective justification for all tariffs, to develop acceptable allocation rules for April 2010?		
Concern over whether the DRM is suitable for embedded networks	Energetics	
Whilst the DRM apportions reinforcement costs to different voltage levels of the network and, through the use of coincidence factors, to different consumer groups. We believe the CDCM fails to allocate correctly the other significant costs of operating networks. This is particularly important in setting IDNO tariffs. Placing a reliance on average network lengths to determine costs may play a significant part to in the model's failings. Costs of operating downstream network have a high fixed cost component. Such fixed costs cannot be properly apportioned using an incremental average network length approach.	GTC	We agree that the network model can only capture costs associated with network length or capacity. The costs that are not associated with network length or capacity are captured in the CDCM through the use of service models, and none of these costs are included in IDNO charges on the 12 June consultation.
DNOs receive funding through the price control to replace assets; IDNOs should similarly be funded.	GTC	It is not for DNOs to decide how IDNOs should be funded.
We are concerned that the CDCM is incapable of satisfying key principles set out by competition law tests and that the margins made available are as a consequence of avoided costs at the margin.	GTC	We are not clear about the relevance of "avoided costs at the margin".
Incremental OPEX only should be included; Indirect overheads should be excluded	WPD	
We do not feel sufficiently involved to offer an opinion on this question.	SmartestEnergy	Noted
The cost and revenue allocation rules are appropriate for setting all-the-way and LDNO tariffs for April 2010.	ENW	
The DRM should not be used to derive IDNO tariffs. Use of the common methodology to derive end user and IDNO tariffs is contrary to OFGEM's guidance	CNA	The rationale for using the same model for standard and IDNO tariffs was to develop an objective justification based on cost for all charges. We are

		considering this further in the light of Ofgem's 'minded to' decision to remove replacement costs from the model.
IPNL does not accept that the same methodology should necessarily apply in respect of the calculation of DNO tariffs to its traditional end customers and in its calculation of tariffs to LDNOs in respect of embedded networks.	IPNL	This is consistent with Ofgem's latest view.
Question 11 Is the rationale for the replacement annuity factor correct, and are the assumptions underpinning the proposed 45.3 per cent figure reasonable? If not, what should be done instead? Is there any basis to use a different discount factor?		
We recognise that some academics have put forward arguments for the use of a split cost of capital in price control mechanisms for regulated businesses. To date such arguments are not supported by Ofgem, nor are they reflected in the current price control where a single cost of capital figure is used. Using different annuity factors for different activities of the distribution business appears to treat IDNOs differently from the DNOs own notional downstream business activities.	GTC	Proposal was misunderstood.
In setting charges for IDNOs, DNOs should use the cost base of their own notional downstream businesses, not the hypothesised costs (and cost of capital) for IDNO business; these are the relevant costs that must be considered in setting IDNO charges.	GTC	Reflecting the DNO's own actual rate of return on capital is the principal purpose of the annuity scaler proposed in the 12 June 2009 consultation. The 12 June 2009 proposals for replacement costs do not amount to using the risk-free rate as a rate of return for IDNOs.
In setting tariffs for IDNOs it is the total costs that must be considered; therefore the cost of replacing assets must be included in determining the downstream margins.	GTC	This comment conflicts with the comment that IDNOs should be funded in the same way as DNOs to replace assets, since DNOs receive no income through the price control in respect of assets that have not yet been replaced.

Replacement annuity factor should be used and share Ofgem’s concerns with the value of the annuity multiplier of 45.3 percent. We believe that the factor should be determined by calculating the amount of revenue that needs to be collected annually to fund the replacement of the asset in 40 years time.	ENW	
Integral from 0 to T of (A/T^2) Exp(-i(T - t)) dt = A/(iT^2) = 0.9% of A.	MCM	The value of the integral stated is actually A/(iT^2)*(1-exp(-iT)) which is approximately 0.85% of A.
Suggests that replacement costs should be accounted for on the basis of 1/40th of the asset replacement cost, multiplied by the average discount factor at a rate of 6.9% considering periods of between 0 and 40 years.	MCM	A notional business responsible for asset replacement (or a notional downstream business) does not have access to discretionary investment opportunities returning 6.9 per cent above RPI. The response does not explain why the discount factor should be calculated as a straight average of discount factors taken over periods of between 0 and 40 years (rather than, say, as an annuity).
Ofgem’s recent ‘minded to’ decision in this area and our general position on replacement costs is outlined in our Supplementary Consultation response (below).If it is decided to include replacement costs it would seem most appropriate to employ the 6.9% rate of return to calculate the discount factor to give, coincidentally, a replacement annuity factor of 6.9%. This is the rate of return the DNO is expected to earn and so should apply to revenues ‘received early’	RWE npower	
Discount rate on replacement should not be 45.3%	WPD	
Risk free rate should be 2.5%, not 2%	WPD	
This should be consistent with any regulatory settlements which are made in price control determinations.	SmartestEnergy	Replacements costs have now been removed from the model. The impact of this was detailed in the supplementary consultation

IPNL thinks that allowance for replacement costs should be made within the model, but not convinced that the same factor should apply for ATW tariffs and LDNO tariffs	IPNL	We agree that replacement cost should be included in the model.
Question 12 Should some or all of indirect operating expenditure be stripped out of the model? If yes, which part, and how could charges in which this expenditure has been allocated through revenue matching be objectively justified?		
Some operational costs should be included. Therefore, we would support the notion used in the S80 example included in supplementary consultation	IPM Energy Retail	Noted.
In setting charges for IDNOs it is the total costs of operating downstream networks that must be considered.	GTC	
Network rates should be included. We understand that rates are currently charged on a £/meter based (i.e. based on the number of metering points. A review of network rating is currently taking place by HMRC with the intention to levy rates on IDNOs from 2010. It is likely rates costs will be circa £4 per domestic connection per year. Therefore, the model should accommodate such costs.	GTC	
Operating costs that are not asset-related should not be included as any price signal should be reflecting future incremental costs. We would be happy if these costs were defined as the Indirect Costs outlined through the Regulatory Reporting information (RRP data).	RWE npower	
Do not share Ofgem's concerns with using the full DNO operating costs in the model as we do not believe these should be adjusted to match a 500MW increment as the CDCM should be a whole cost model to allow the derivation of LDNO tariffs. If this is done the model will be unable to derive cost justified LDNO tariffs	ENW	
We believe all indirect operating expenditure be stripped out of the model.	SmartestEnergy	Some operating costs were removed in and the impact of this was detailed in the supplementary consultation. The final proposal uses an approach for including an appropriate level of indirect costs.

Believes that only those opex categories that vary with network size should be included in the model since the current approach skews costs to lower network levels	BGT	The final proposal uses an approach for including an appropriate level of indirect costs.
There should be no arbitrary decision to exclude costs from the model, in particular for LDNO tariffs.	IPNL	
Question 13 Is the concept of operating expenditure intensity multipliers appropriate? Have we overlooked relevant information that could help determine these multipliers?		
Believes the use of opex intensity multiplies unduly discriminates against LV customers. Their analysis conflicts with the view that direct opex as a proportion of estimated asset value is higher at LV than at EHV network levels	BGT	The final proposal uses an approach for including an appropriate level of indirect costs. No intensity multipliers are used.
This methodology will increase significantly the charges on LV customers, and these are the customers most likely to wish to fix DNO charges. Contractual risk on suppliers. Whilst we do not dispute that there may be evidence that Opex is higher at LV than EHV, we believe that it would be prudent to either phase this multiplier in slowly over time or to introduce it further into the future so suppliers have time to manage their risk position.	GDF suez	
Yes	Energetics	
Supports the use of operating expenditure intensity multipliers, but a DNO specific solution is preferred.	EDFEN	The final proposal does not include the use of intensity multipliers
The approach to using intensity multipliers would appear to be more cost reflective than for the smearing operational costs to be based solely on asset values. However, we question whether such multipliers offer an appropriate mechanism for determining the fixed costs of operating a business.	GTC	The reference to fixed costs appears to be to costs unrelated to network length or capacity. The operating expenditure intensity multipliers determine fixed operating expenditure in this sense as they are used in conjunction with service models.
The yardstick model allocates reinforcement costs on a £/KW of demand.	GTC	In the methodology and model, £/user costs from service models are used alongside £/kW costs from the 500 MW model to allocate operating expenditure. This is to

		take account of expenditure that is not related to network length or capacity.
We are concerned that these multipliers do not appear to be forward looking and so will cause operating expenditure allocation to reflect current/historic levels. Ideally, further work is required to ensure these levels are relevant looking forward.	RWE npower	
We agree with Ofgem	SmartestEnergy	Noted
IPNL agree with the concept of opex intensity multipliers for all tariffs. It believes that the use of these multipliers needs careful checking in relation to LDNO tariffs.	IPNL	
Question 14 Should the proportion of LV network included in tariffs for LV-connected embedded networks be common or specific to each DNO licence area?		
Too arbitrary - on the assumption that a more objective measure can be put in place, then this proportion should be common	Energetics	
LV network included in tariffs for LV connected embedded networks should be specific to each DNO licence area so as to allow for regional differences.	EDFEN	
This approach appears to apportion all costs based on network length and on the avoided (marginal) cost of the upstream business. A significant proportion of the cost of operating a downstream business is fixed (and is not included in service models cost).	GTC	We do not understand which costs are fixed and not included in service model costs. If the reference is to administrative or overhead expenditure that might appear to be fixed in the short run, we are not clear how you propose that they should be allocated. One possibility, which we did not take forward on account of its potential adverse effects on IDNOs, would be to treat some of the DNO's costs as fixed and recover them through a fixed adder applied to all users (including IDNOs) rather than allocating to different network levels.

Believe that the proportion of LV network utilised in the LDNO tariff methodology should be specific to each DSA, as this reflects the use of the network by LDNOs on each distribution network operator. But we recognise that this may be inappropriate for those DNOs that have little competition in distribution within their DSA. Where this occurs then the default value should be the industry average.	ENW	
A third method [besides Ramsey pricing and single fixed adder] is the use of the voltage level adder. This lies between Ramsey pricing and the single fixed adder approaches. It allocates the residual revenue between voltage levels in proportion to the assets at each voltage level excluding that proportion paid for by customers. It provides wider margins for IDNOs and should avoid competition issues.	MCM	The response does not explain how the proposed voltage level adder would avoid competition issues.
It may require 2 models to produce IDNO charges	WPD	This is the way the final proposal works.
Surely the correct thing to do is a DNO specific average on a large sample of sites and to update this parameter on a regular basis. A GB-wide calculation *might* be more reflective of future embedded network design, but then again, it might not. This wording seems to imply that there is no desire to revisit the calculation.	SmartestEnergy	This is still the subject of discussion and once a decision is made it will need to be re-visited in the future to ensure it is still appropriate.
IPNL do not therefore consider LV network usage figures calculated on the current IDNO project base to necessarily be robust. They are not convinced network length is a good guide for allocation of costs as many costs are fixed.	IPNL	
Question 15 Should a fixed adder be used instead of an annuity scaler for revenue matching? If yes, how can charges that include the fixed adder be objectively justified?		
Concerns over whether an annuity scaler would give a reasonable rate. It could be that the rate is formally reviewed and subject to governance	Energetics	
The fixed adder is a better theoretical mechanism for revenue matching, but the annuity scaler is currently preferred as there are a number of outstanding issues with the fixed adder within the	EDFEN	

present CDCM model.		
We strongly support the fixed adder approach due to the non distortive cost signal and simplicity	IPM Energy Retail	
If the difference between the CDCM outputs and the price control income are significant then the adequacy of the model needs to be seriously questioned.	GTC	
Preference is for a fixed adder scaler; concerns over applying scaler to only one element of tariff	WPD	
If Ofgem are correct then the fixed adder is preferable.	SmartestEnergy	The supplementary consultation includes analysis on one option for using a fixed adder. The final proposal uses a fixed adder approach.
Previously argued that the annuity scalar is an appropriate mechanism for revenue matching. Concerned that the fixed adder can lead to unjustifiable results when considered against the wider Competition Act tests	ENW	
Choice of scaling method should be revisited. Fixed adder seems simple and may be least distortive to cost signal but annuity scaler also has merits especially if variations in implied annuity rates are reduced.	BGT	We considered both options.
Method for scaling should be the one that produces the least distortion to price signals	IPNL	
Question 16 Are there any other issues that threaten the finalisation of the common cost and revenue allocation method, or its implementation on 1 April 2010? If yes, what should be done to mitigate these risks?		
Concerns over the clarity of the impact of the proposed methodology on embedded networks. The next release of the CDCM must address the variability of net margins across the DNOs. Issues surrounding boundary metering	Energetics	Final proposal uses a separate method to determine IDNO tariffs.
Not aware of any other issues. It is realised there remains a number of particular unresolved issues that may affect charges. Outside of the impact of these issues, it is expected that efforts should be made to ensure the impact of the final implementation of the CDCM follows closely the impacts indicated within the latest	RWE npower	

(supplementary) consultation. To not do so would severely limit the usefulness of the consultation potentially to the point of being detrimental		
Not that we are aware of.	e.on	Noted
We do not feel sufficiently involved to offer an opinion on this question.	SmartestEnergy	Noted
IPNL does not believe the margins published in the supplementary consultation meet the requirements of competition act.	IPNL	We agree.
Question 17 Should the rate of return and annuity period be specified in the CDCM? If not, what should be the process for modifying them?		
Yes	Energetics	
Rate of return and annuity period be specified in the CDCM.	EDFEN	In line with the current CDCM
Yes	GTC	
The CDCM should detail the principles over how all parameters are set. This should include any calculations, definitions of any inputs and prescribe how often inputs are refreshed etc. The CDCM does not necessarily need to hold specific values are these will be available in the published charging models but should endeavour to provide users with sufficient information to replicate their calculation	RWE npower	
Rate or return, annuity period, opex multiplier, time bands should fall within governance. Coincidence factors should be fixed over the price control period if not included in governance	BGT	
This should be determined by Ofgem in its price control determinations.	SmartestEnergy	We considered the possibility of referring to Ofgem price control documents as the source for the rate of return, but concluded that it was impractical as the price control now uses primarily a “vanilla” rate of return rather than a “pre-tax” rate of return. It would in any event be inappropriate to make the CDCM dependent on any particular way of deriving price controls.
The rate of return and the annuity period should be specified in the CDCM and fall within the modification	ENW	

process as it is common for all distribution network operators.		
Yes but they don't necessarily need to be the same parameters for ATW tariffs and LDNO tariffs	IPNL	
Question 18 Should the replacement annuity factor be specified in the CDCM? If not, what should be the process for modifying it?		
If there are to be replacement annuity factors (see supplementary questions) then we agree that they should be specified in the CDCM.	EDFEN	We expect this to be resolved through WS2
The replacement annuity factor should be specified in the CDCM as it is common for all distribution network operators.	ENW	
This should be determined by Ofgem in its price control determinations.	SmartestEnergy	Replacement cost have now been removed from the model
Question 19 Should the operating expenditure intensity multipliers be specified in the CDCM? If not, what should be the rules for updating them and who should be responsible for doing so?		
This should be determined by Ofgem in its price control determinations	SmartestEnergy	Total operating expenditure is determined via the price control settlement, however allocations within the CDCM has to be agreed between the DNOs and Ofgem
Question 20 If a single GB-wide proportion of LV network included in tariffs for LV-connected embedded networks is used, should the figure be specified in the CDCM? If not, what should be the rules for determining that proportion and who should be responsible for doing so?		
Yes	Energetics	
Yes	e.on	Noted
The proportion of LV network should not be specified in the CDCM as these values should be company specific.	ENW	
This should be determined by Ofgem in its price control determinations.	SmartestEnergy	We do not believe this is something that can be determined by the price control.
Question 21 Are there any other parameters or rules which should be taken out of the CDCM and subject to a different governance process?		
Not that we are aware of.	e.on	Noted
QS1. Is the inclusion of replacement costs in the modelling necessary to provide an objective justification of the charges?		

If there is an agreed method for determining future replacement costs then the total costs should be included	Energetics	
ESPE believes replacement costs are a cost for legitimate inclusion in DNO's modelling, but significance of these costs may be over-stated in proposals to the detriment of other (fixed) operating costs. This would seem to be borne out by the steep reduction in margin available to embedded operators upon removal of replacement costs.	ESPE	
We would be comfortable if the model included these costs, but support Ofgem's stance that they should be excluded	IPM Energy Retail	Noted.
In respect of margins available to IDNOs to operate downstream businesses it is the total costs of operating the notional downstream business that must be considered. It is wholly inappropriate to exclude a subset of the total costs. We do not comment as to whether the replacement costs are modelled as the correct proportion of the total costs. We question whether operational costs are understated and replacement costs overstated in determining charges to IDNOs.	GTC	
Since it is a real cost, it is desirable to include it. However, as is shown in the above analysis, the value needs to be checked.	MCM	
Not appropriate. Whilst the asset model of the network provides an "objective justification" for the allocation of the permitted revenues it does not reflect the actual system and therefore cannot interact directly with the capital contributed at the time a new connection is made. Some adjustment to the asset model may be appropriate under the current connection charging policy.	RWE npower	

The removal of replacement costs would be inappropriate for the derivation of LDNO tariffs as the replacement costs would be allocated through the revenue reconciliation process which would potentially inappropriately allocate costs across the customer/ tariff types and it could not be cost justified. Replacement cost is an important cost which needs to be taken into consideration for the derivation of LDNO tariffs so that these costs can be allocated in manner that is cost justified.	ENW	
We believe a truly objective justification of charges is not achievable. Some customers may have a clear view of the future, the DNO, anticipating changes on behalf of other customers, may not. The reality in either situation may change. It is also unclear to what extent a customer may take advantage of existing (and paid for) infrastructure just because of where he is, in contrast to a new customer on a new or needing-to-be replaced part of the network.	SmartestEnergy	Replacement costs have now been removed form the model in line with Ofgem's "minded to" decision.
QS2. Would the inclusion of replacement costs in the modelling help provide appropriate incentives for capacity release by customers?		
Their experience of the rationale for encouraging customers to free unused capacity is purely theoretical	Energetics	
Replacement costs are actual costs incurred which are recovered through price control income. Therefore the costs of replacement are recovered through the tariffs irrespective of whether they are included in the charging model. We fail to see how any incentive could be created for customers to reduce capacity. HH customers already have incentives through capacity charges.	GTC	We agree that these incentives arise from capacity charges. The consultation referred to the basis on which capacity charges should be set, in particular how replacement costs should be taken into account.
The arguments put forward seem to support this. However, if the costs don't appear here, then they will be picked up elsewhere. If they are part of the kVA charges then they may have the same effect?	MCM	
Do not think the inclusion of replacement costs in the modelling will impact the incentive for the customer to release capacity if its circumstances change. This is more likely to be a	RWE npower	

function of the charge-out arrangements. The avoidance of a service capacity charge will be an incentive for customers to optimise their capacity subject to their assessment of their future plans.		
It would not be appropriate. DNOs should not be making investment decisions purely on the basis of what a current site-holder is doing/planning	SmartestEnergy	Replacement costs have now been removed form the model in line with Ofgem's "minded to" decision.
QS3. Should expenditure in 40 years affect decisions to be made now? Should the analysis of customers' incentives focus on short-term cash flow rather than on profit or earnings measures?		
Too academic	Energetics	
We don't understand how including or excluding costs replacement costs creates customer incentives (or disincentives). The CDCM is a mechanistic model for allocating DNO use of system revenues that have been derived by another process. The question is how costs are recovered. Is it through the raising of debt, funded by future DUoS; or is it from reserves that have been built up from historical DUoS – or is it a combination of both. If cost of replacement is to be funded through debt, the period for recovery of such debt should be shorter. The presumption of the methodology is that it is funded through reserves – hence the use of a risk free rate (although we disagree with this as a notion). We are not convinced that this presumption aligns with assumptions in the price control.	GTC	We agree that the CDCM is a model for allocating revenue derived by another process. The allocation affects the incentives faced by individual customers, for example by affecting the level of capacity charges.
Since all costs need to be included and recovered, it is desirable to take into account replacement costs in general, albeit that some will not need replacement for 40 years.	MCM	
If the expenditure in 40 years time is certain then it should impact today's decisions but the future use of a supermarket, for example, or any other customer's site in that timescale is unlikely to have a bearing on today's engineering decisions.	RWE npower	
Answer to first question: No. Answer to second question: This question and the background to it illustrate the need for distributors to make sensible centralised decisions and not try to	SmartestEnergy	

incentivise customers.		
QS4. Should the analysis focus on incentive effects on new customers and on customers who wish to increase their capacity, rather than on customers who are facing decisions to reduce capacity or to disconnect?		
Yes	Energetics	
We are not convinced how incentives will be given to customers. Will they given reduced tariffs (compared to others) or a cash payment as an incentive? Given that total income is determined by the price control and recovered through the price control period we don't understand how customers will be incentivised other than through differential tariffs.	GTC	For example, capacity charges provide incentives for customers, as you mention. The CDCM affects customers' incentives even in the absence of differential tariffs.
The aim should be to do both.	MCM	
The analysis tries to create a linkage between the asset model and capital contribution policy that is not appropriate. Capital contributions at the time of connection should encourage both DNO and customer to design their systems economically. Use of system charges should equitably allocate revenue recovery to each class of customer. The design of the use of system tariff may create an incentive for how the customer behaves under future circumstances.	RWE npower	
Distribution licensees are, in effect, managers of long lived network assets. Decisions made today affect the future network design, construction, reliability and operation of the network throughout its life. It is vitally important that we develop use of system charging models for the distribution network that takes due regard to future costs, especially those that could be avoided due to a change in customer behaviour.	ENW	
Neither.	SmartestEnergy	In order to manage an efficient network DNOs need to take into account the level of capacity that is currently utilised and whether there is headroom for new customers to connect without the need for reinforcement costs.
QS5. If objective justification based on cost is not achievable for all the-way		

tariffs, what principles should be used to set charges for embedded networks?		
Concerns over margins once objective justification is not achieved. Is DRM suitable?	Energetics	
Initial proposed CDCM gives indicative LDNO margins from around £20 to £70. This would therefore permit IDNOs to compete with host in some DNO areas but not others.	ESPE	Some variations were due to inconsistencies in model population, which have been addressed. Some variations are due to the differences in allowed revenue for the companies.
ESPE questions the fundamental suitability of the DRM model for treating embedded networks.	ESPE	The CDCM included all costs, therefore making it suitable for calculating tariffs for all customers. With the exclusion of replacement and some opex costs, we agree it is no longer appropriate.
ESPE believes a complete re-think may be required – it may not be necessary or possible to determine the costs of a notional downstream business using the same model as that to recover price control from groups of customers.	ESPE	This is consistent with Ofgem's latest indications
In respect of setting IDNO charges we have already provided significant input to how charges should be set. We have also raised concerns on many occasions about whether the DRM is an appropriate model for setting IDNO charges.	GTC	
The use of the voltage level fixed adder for revenue which cannot be cost justified provides a fair allocation of costs and the offsetting of costs for embedded generators.	MCM	
The "Objective Justification" of the model is in respect of the allocation of the price control revenue to classes of customer. It will not necessarily reflect the costs of serving an individual customer. Since the IDNO acts as an intermediary between the DNO and the end user the principles for the charging of these organisations should be the same as for the end user. The charges to the IDNO should reflect the proportion of the overall network it provides.	RWE npower	

It is possible to make a distinction between use of replacement costs and objective justification for the relationship between DNOs and IDNOs but not between customers and these entities. This is because an IDNO is making investment decisions based on a time span of the order of 40 years. The same cannot be expected of an individual customer or their supplier.	SmartestEnergy	
The margins available to LDNOs should meet the requirements of competition law and meet the basic test that the margins available to a downstream business are those which the incumbent DNO's notional downstream business would require to operate those networks and make a normal profit.	IPNL	
QS6. Could an annuity scaler be justified if replacement costs have been excluded from the model? If yes, how?		
Difficult to see	Energetics	
If the scaling is large then it is preferable to change to an alternative approach.	MCM	
We do not think the treatment of any shortfall or surplus between the revenue generated from the model and that allowed under the price control should be dependent upon the recognition of any specific costs in the model. The model should provide an equitable basis for the allocation of the price control revenues. In its current exposition it should also indicate the economic relativities of transporting energy at different voltages within each DNO area. If the revenues naturally generated by the model are significantly different to those permitted by the price control then the first step should be to ascertain why there is a major disparity. Scaling should be undertaken in such a way so as not to distort the underlying relativities of a (properly calculated) model. A kWh scaler would appear to have the best prospects of achieving this. An annuity scaler would effectively scale the charges according to the demand of a customer or the capacity it requested. This would appear to be a second best solution	RWE npower	
The annuity scalar will deliver a	ENW	

consistent rate of return for the use of the assets for all customers.		
Probably not.	SmartestEnergy	We agree
QS7. Is a fixed adder least distortive to the cost signal? Which cost signal?		
Yes, but can have negative impact on cost reflectivity	Energetics	
Only in the most simplistic terms ignoring the real factors and costs which influence decisions.	MCM	
The model should reflect the expected relativities in the costs of transporting energy at different voltages to different classes of customer. Although rough and ready these relativities have some economic justification and should be retained when charges are scaled to match the price control revenue. We think that the apparent sophistication suggested in the treatment of replacement costs is misplaced in the construction of the model. A fixed adder would appear the best way to preserve these relativities.	RWE npower	
This is Ofgem's view. Presumably it is to customers in general.	SmartestEnergy	Following discussion the group are considering further ways of applying a fixed adder.
QS8. Is the essential feature of a fixed adder approach to revenue matching that it should collect the same amount of money from a customer with a given capacity and load irrespective of whether the user is supplied at HV or at LV?		
Essential feature should be that at any voltage level the sums collected are the same for a given capacity and load	Energetics	
This follows from the definition of the fixed adder and the interpretation of 'distortion'. It does not follow that it gives the implied economic benefits.	MCM	
An approach to revenue matching that only considers the capacity of a customer will distort the cost message as the scale and time of use of the network is ignored.	ENW	
This may well be a consequence. We would doubt the efficacy of the model if this represented a significant proportion of the overall charge to any customer	RWE npower	
This sounds like a sensible principle.	SmartestEnergy	The group will be considering this.
QS9. Are there other ways of applying a fixed adder? If so what are they?		
Weigh the scaling factors by MEAV as per G3 proposal	Energetics	

Yes, the voltage level fixed adder is preferable.	MCM	
The use of a £/kW fixed adder creates an assumption that the revenue recovery should be associated with peak demand and thus implies that it is investment related. This may be a consequence of the treatment of the recovery of operating costs in the model. Our view would be that a utilisation related fixed adder might be a better mechanism for the recovery of missing revenue or even a simple surcharge or discount to a customer's bill since it is essentially a tax or rebate for all customers	RWE npower	
We do not feel sufficiently qualified to offer an opinion on this question.	SmartestEnergy	Following discussion the group are considering further ways of applying a fixed adder.