Rachel Fletcher
Director, Distribution
Ofgem

19 August 2008

Dear Rachel,

Delivering the electricity distribution structure of charges project: decision on a common methodology for use of system charges from April 2010, consultation on the methodology to be applied across DNOs and consultation on governance arrangements

I am responding on behalf of Central Networks to the above consultation document.

In summary we argue against mandating a common methodology at this stage, but believe the G3 methodology is uniquely suited to this role if the decision to proceed in this way is carried through.

We are surprised by your decision to change the basis of the structure of charges project at this very late stage, particularly given the investment and effort expended by the DNOs and the very significant progress that has been made.

The DNOs have developed methodologies in line with the guiding principles set out by Ofgem and many have either submitted these for approval, or are on the verge of doing so. In our view it would be wasteful and probably ultimately sub-optimal to set aside this work in favour of a yet to be defined common methodology. Some two years ago Ofgem decided not to proceed down the route of a common methodology, but instead encouraged DNOs to develop their own methodologies. We believe this was the right decision, and one which should be followed through.

We have previously argued that there is no proven 'right answer' for a charging methodology. Given the above, and that a number of quite different methodologies have been developed and proposed, it would be appropriate for Ofgem to now work closely with DNOs to finalise, implement and test the various methodologies on offer, before assessing their relative merits and finally settling on a common methodology for the longer term. This approach would reveal and provoke best practice through real experience of the operation of different methodologies and allow a more informed, optimal decision to be reached in due course.

We believe that other stakeholders are primarily seeking commonality in respect of the *structure* and *application* of the tariffs themselves, rather than the methodology used to set the prices. If this is their real goal, they would not be satisfied by a common methodology alone. We would therefore urge Ofgem to be clear on this point before commencing on a common methodology.

However, if you do follow through on the decision to opt for a common charging methodology, the proposed collective licence modification and any project set up to develop and implement a common methodology should be led by Ofgem. You would need to set clear terms of reference, agree high level principles and specify the chosen 'common methodology' in detail. It would not be sufficient to rely on high level principles or general descriptions of the methodology - precise details would have to be specified if commonality is to be achieved. It is important to recognise that competition law constrains DNOs from jointly agreeing pricing approaches, and that details missing from the specification could therefore compromise the desired commonality of outcome. In light of this, you would need to consider the extent to which you are able to direct a common methodology and, therefore, the degree of commonality that would be achievable.

Given the current situation, it as yet difficult to assess the extent of change to our methodology and reassess the timetable involved. We would therefore find it difficult to commit to a deadline within a licence modification at this stage without fully understanding the implications of a common methodology.

We support the ENA's response to the consultation and believe this aligns well with our views set out above.

While we do not favour adoption of a common methodology at this time, we believe the G3 have developed a robust and integrated package which would be well fitted to this role. We set out below the attributes of the methodologies on offer that lead us to believe the G3 methodology is uniquely suitable.

The G3 companies have consistently invited other DNOs to share their methodology and, if Ofgem decide to adopt G3 as the common methodology, we are willing to do everything possible to help the four other DNO groups implement this. As well as making available all of our models and documentation, we would be happy to share the practical experience that we have built up through the project.

In addition to the above, we address the specific questions raised in your letter below and in the appendices to this letter and other documents referred to and attached:

Whether respondents agree that we should specify the common methodology to be applied across DNOs

No, we do not agree that Ofgem should specify the common methodology to be applied across all DNOs.

The pros, cons and impacts of each model

The G3 methodology, jointly developed by SP, SSE and CN, has been formally proposed by Scottish Power and 'informally' proposed by Scottish and Southern and Central Networks. Thus, this proposed methodology is ready to implement in six DSAs, covering a substantial proportion of all GB customers. We strongly believe that this methodology satisfies the charging principles set out for the structure of charges project.

In formulating the G3 methodology it was considered essential that it could be implemented by the G3 companies with different computer systems in different stages of development, and yet provide a platform for further development, individually or collectively, as appropriate. In this context we believe the G3's common methodology constitutes the ideal basis for a future common charging methodology. The desirable properties of the G3 methodology are:

- It uses an approach that is both forward looking and incremental;
- It provides different locational price signals to existing and potential EHV demand and generation customers
- It employs granular data on growth rates for network groups at all levels, taken from published sources;
- It recognises and reflects both the costs imposed and benefits afforded by demand and generation customers in these different groups;
- It uses AC load flow analysis, including both thermal capacity and fault level considerations;
- It ties differential price signals firmly to the recovery of anticipated network reinforcement costs within an appropriate time horizon;
- It assesses generator-prompted reinforcement using test size generators and takes account of national targets for DG, using a probabilistic approach;
- It uses a common tariff model to pull together demand and generation charges at all voltage levels;
- It takes reinforcement cost information for the EHV network as an input to the tariff model for HV and LV customers;
- It takes other cost information from appropriate sources in an auditable way;
- It uses allocation based on appropriate cost drivers, rather than simple scaling, to recover allowed income, as far as possible;
- Any distortion of price signals is minimised by finally scaling tariffs using a fixed adder for each different voltage level - reflecting each voltage level's share of the, largely historic, costs not allocated within the tariff model;
- It carries much reduced risk in relation to potential allegations of abusive pricing in comparison to the other methodologies on offer;
- It is a fully common methodology, tested using real network and customer data in six different DNO service areas; and
- It is relatively easy to understand and has low implementation costs.

We firmly believe the G3 methodology represents a major improvement over current methods, and is significantly superior to any other, either currently in use, or in preparation.

As with all other methodologies, concerns have been raised about the potential shortcomings of the G3 methodology. However, some of these concerns arise from misconceptions of the methodology, while others do not deflect from the fulfilment of the overall charging objectives, as follows:

- The concern that the FCP approach only considers assets above 87% utilisation is simply a misunderstanding. As stated in paragraph 3.10 of our methodologies "*The base network demand is then incremented in small steps, up to a level that is able to encapsulate the expected growth in the network over the next ten years above their current maxima*". In the case of Central Networks there are reinforcements which feed into the incremental cost calculation for assets with current utilisations lower than 20%;

- There has also been a concern that the FCP approach only considers reinforcements within a 10-year horizon. This horizon was selected as we view this as an appropriate balance between ensuring the forecasts on which costs are derived are likely to be reasonably accurate and providing enough time for customers to respond to the resultant locational signals. Whilst this is the current view of the G3 companies, it would require little additional effort to extend the timeframe over which costs are considered if this was the consensus view of the industry in developing a common methodology. Such flexibility underscores the superiority of the G3 methodology; and

- A further concern of the G3 methodology is that its locational signals are diluted because of the aggregation to network group level. It should be pointed out that such aggregation still provides a large amount of locational variation (over 80 different locational charges in our recent 'submission' for CNE) and we strongly argue that this is the correct level of aggregation for the purposes of charging. Network groups reflect the way in which engineers actually plan network developments and it is intuitive to calculate charges on the same basis. Nodal charges may give a greater number of locational signals but are not truly cost reflective if they are not based on all relevant costs (e.g. including fault level) and include network contingency analysis. In addition to this, they are not truly locational unless local growth rates are employed. As Frontier Economics point out with regard to the FCP approach "*Charges are derived for the higher voltages of the network at a zonal level and therefore vary to reflect the underlying infrastructure conditions in each part of the network. In our view this represents an enhancement of the cost reflectivity criterion. At the same time, the use of zones (rather than nodes) and limiting the locational variations in charges to the higher voltage levels represents a sensible boundary. More granular locational signals would, in our view, substantially increase the complexity and unpredictability of the charging regime (and also require more engineering-based judgement to derive charges) with minimal incremental benefit arising from the additional cost reflectivity that this would create*".

In the case of the G3 methodology, we do not regard any of the potential concerns as deflecting from fulfilling the overall objectives. Some of these potential concerns can be addressed by relatively minor and easy adjustments to the methodology, while others may be the result of unavoidable trade-offs between competing objectives.

In contrast, we believe that the concerns relating to the LRIC methods, either currently in place or proposed, to be sufficiently significant to demonstrate that these methods fail to meet the overall objectives, as follows:

- The current LRIC charging functions in place or proposed simply do not work for highly utilised/low growth networks with charges tending to infinity as the growth rate tends to zero. The result is potential abusive prices being calculated for some areas of the network. It is noteworthy that EDF's attempt to resolve this flaw involves simply scaling the power flows used to derive reinforcements but this invalidates the cost reflectivity of the resulting marginal costs;

- WPD's method ignores the problem by using an average growth rate. This is wholly inappropriate and severely compromises locational signals. It seems very likely that the historic long term average growth rate may no longer be appropriate going forward (see chart 2) and it is possible that the scenario of highly utilised/low growth areas of the network will increasingly become the norm. Ofgem acknowledges the importance of growth rates on marginal costs in their recent consultation on EDF's proposal;

- None of the LRIC methods fully takes account of all relevant reinforcement costs. They ignore fault level costs and therefore can not claim to be truly reflective of forward costs. Academics are in agreement that the inclusion of fault level costs is a significant step forward in charging methodologies. It is not clear whether the LRIC approach on a nodal basis is capable of including fault level costs;

- The use of an annuity factor in the charging function which is based on the asset life further distorts the resulting charges. If the asset life is 40 years then this will result in diluting the economic message of any reinforcement required before 40 years;

- There are potentially significant risks of competition law breaches with any method which calculates an incremental or marginal charge but then applies this charge to 'total' demand (rather than to the incremental demand). This has the potential to cause charges that recover in a single year of charges many times the potential reinforcement cost, that may or may not occur a long way off in the future. It is important that the basis on which charges are applied to users (over total or incremental demand) is consistent with the way in which the charges are derived. This risk is real for very real with the LRIC methods, as highlighted in paragraph 54 of Reckon's paper delivered to the DCMF in June 2008 and attached as Appendix 3, where they state that:

> *"We therefore find that none of the variants of LRMIC described in this paper appear capable of providing an objective justification in circumstances such as those of the above example where charges exceed the relevant measure of stand-alone cost."*

We set out a more detailed analysis of the pros and cons of the various methodologies on offer in the appendices to this letter.

Governance arrangements

We favour governance based on cross industry engagement through a forum such as the DCMF, where proposals can be put forward, debated and analysed with a view to the DNOs proposing modification of the common methodology. We believe this would avoid the uncertainty, instability, risk and resource pressures associated with the code type governance described below, while ensuring proper joint development of the methodologies over time. Suppliers would be reassured by the presence of Ofgem representatives at the forum, and would have the option to appeal to Ofgem if they felt that the forum was responding unreasonably to proposed changes.

It is superficially attractive to submit DNOs' charging methodologies to more formal governance, on lines similar to that in the BSC, CUSC or DCUSA where all individual parties are free to propose any modification they may wish. In our view, application of such governance to DUoS charging would invite modification proposals motivated by the narrow self interest of individual suppliers, rather than genuine concern for the common good. Our experience with other governance arrangements makes us very aware that proposals lacking broad consensus support can, nevertheless, eat up industry resources. Such proposals would increase uncertainty, instability and risk in relation to DUoS charges and have serious resource implications for both the industry and the Authority, without any real benefit to customers.

The proposed processes

Our overall impression of the proposed process is that the timescales are extremely tight. If DNOs are to stand any chance of achieving what is required within the timescales envisaged, we would need clear and consistent leadership from Ofgem throughout the project with an early decision on the common methodology and a very clear and detailed specification of this methodology.

Whether there are any other matters we need to consider in light of our decision on a common charging methodology

In parallel to the specification of the common methodology, we believe it would be necessary for Ofgem to review and tighten up on the definitions and rules around the connection charging boundary. This will be particularly important if we are to ensure commonality going into the DR5 process.

As requested the appendices to this letter contain evidence in support of the points made above.

I hope that this information is helpful to you.

Yours sincerely,

Andrew Neves
Tariff and Income Manager

Appendix 1 - Impacts, Pros and Cons of EHV level models

LRIC (WPD, EDF & CE)

Pros:

(1) Simple cost reflective method to value spare capacity on the EHV level network.

We do not agree that the LRIC methods in place or proposed to date are fully cost reflective since they ignore costs associated with fault level which are a significant element of future costs including for demand reinforcements (see chart 3 at the back of this appendix). EDF also change the power flows of the network to produce charges which compromises cost reflectivity and the WPD LRIC uses a historic average growth rate in its implementation. The use of an average growth rate also has the effect of significantly compromising the resulting locational message and it is questionable as to whether the long term historic growth rate will remain appropriate for use in forward cost pricing (see chart 2). Given current uncertainties surrounding growth of both demand and generation we also believe that the LRIC approaches use too long a time horizon and therefore may produce what turn out to be misleading signals. It is our strong view that any methodology that does not take account of these issues can not be considered to be reflective of true costs.

(2) Enhanced cost reflectivity from utilising power flow modelling

We agree that utilising power flow modelling is one step forward in enhancing cost reflectivity. However, as explained above, the WPD and EDF LRIC methods do not consider fault levels (WPD & EDF), change the actual power flows on the network (EDF) or ignore local growth rates (WPD). For these reasons the methods are not truly reflective of the costs of electricity distribution.

(3) Flexibility for future development

Firstly, it should be pointed out that, unlike the FCP approach which is common across six DNO areas, there is no single common LRIC proposal. We note that WPD, in their recent response to the consultation on EDF's modification proposal, are of the opinion that the EDF implementation should be vetoed and therefore it is not clear as to which of the different implementations of the LRIC approach Ofgem feels is flexible for future development. Certainly, the current methods on offer would have to be flexible to future development in order to overcome the flaws in their existing forms. The enduring charging methodology should:

- Take account of location specific growth rates – WPD's LRIC does not and whilst we note that EDF attempt this it is not at the nodal level and is therefore inconsistent;
- Take account of fault level – WPD & EDF methods do not;
- Properly take account of network contingencies – we are not sure either WPD's or EDF's method does this;
- Use an appropriate annuity factor – an annuity factor based on asset life in the charging function compromises the economic rationale behind the approach in our view and will lead to under charging where reinforcements are imminent.

- Produce robust and non abusive charges under all scenarios – the problem of high charges produced in highly utilised / low growth nodes has still not been overcome by any of the methods on offer. Also, by applying the resulting charges over total demand rather than incremental demand the LRIC approaches have the real potential to lead to abusive charges. Reckon's paper and presentation to the DCMF in June found that "*none of the variants of LRMIC described in this paper appear capable of providing an objective justification in circumstances such as those of the above example where charges exceed the relevant measure of stand-alone cost.*" (paragraph 54 Reckon June DCMF paper attached as appendix 3 with supporting spreadsheet.)

These issues need addressing before a methodology would be properly fit for purpose – they do not, in our opinion, fall into the category of 'future development'. Furthermore, we doubt whether it is feasible to modify the current LRIC approaches on offer to overcome these issues in the timescales indicated in the consultation.

(4) Significantly improved cost reflectivity with strong incentives to promote economic efficiency

We do not agree with the strength of this assertion. By undertaking power flow analysis we believe the LRIC methods attempt to improve cost reflectivity however for the reasons explained above (fault level, growth rates, scaling of power flows), the LRIC methods as implemented or proposed to date do not 'significantly' improve cost reflectivity. They 'slightly' improve cost reflectivity and only within a limited range of scenarios. Also due to the use of an annuity factor based on asset life in the charging formula and because the resulting charges are applied to total demand rather than incremental demand only, the promotion of economic efficiency is fatally compromised.

(5) Strong locational message from nodal study

In principle Central Networks would agree that a properly implemented LRIC approach based on a nodal study with individual nodal growth rates could be a feasible alternative to the G3's FCP methodology however it would be much more complex. There are two main variables that determine the present value of a given future reinforcement investment. One is the current spare capacity and the other is the current growth rate and we believe both are equally important. WPD assume a single average growth rate in their implementation and EDF try to improve this by applying individual GSP growth rates to nodes connected to that GSP. As Ofgem point out on page 32 of their recent consultation on EDF's proposal "*The growth rate assumption has a significant impact on the level of the marginal cost charge. The figure* [in the consultation document] *shows a pronounced change to nodal marginal cost following a departure from an average growth rate assumption. The growth rate assumption [also] has a significant impact on the relative marginal cost charges for site specific nodes*". It follows from Ofgem's analysis that using an average growth rate invalidates the resulting marginal charges and therefore WPD's method is unsuitable for the enduring common methodology. EDF attempt to improve locational signals by applying GSP level growth rates to individual nodes. This is a step in the right direction however the resultant locational messages are inconsistent since reinforcements are based on nodes yet growth rates are based on network groups.

(6) Treats demand and generation the same

We believe that only where there are valid reasons should demand and generation be treated differently. Conversely, however, if there are valid reasons for demand and generation to be treated differently then it would be wholly wrong to treat them the same. By not recognising the differences in 'lumpiness' of demand and generation and the differences in relative effects of demand and generation on the cost drivers we believe the existing LRIC methods listed above are unsuitable for any enduring common methodology.

(7) Model implemented in two DSAs

This is an important point to note, the WPD LRIC method is only implemented in two DSAs and the other LRIC methods proposed are quite different to it. Inconsistencies in the LRIC methods listed in the consultation include:

- Growth rates (WPD use constant whilst EDF use GSP level growth rates;
- Size of increment (WPD use 0.1MVA whilst EDF use 1MVA)
- Power Flows (WPD do not scale power flows whilst EDF do)
- Asset Values (WPD use a conventional asset value whereas EDF use "*the sum of the weighted average MEAV costs for reinforcing the generic asset types that make up each node*" – note we are unclear as to what the EDF approach actually means.

We also note that WPD, in their recent response to the consultation of EDF's modification proposal, are of the opinion that the EDF LRIC implementation should be vetoed. This shows that even amongst the supporters of LRIC there are disagreements over how it should be implemented. Therefore, in our view, it would be an unachievable task to agree a common LRIC corrected for the faults and deficiencies highlighted above and get it implemented in all DSAs within the timescales indicated. In contrast to this, the G3's FCP approach has already been developed for six DSAs and truly is common among those. Therefore the effort involved in rolling it out to the industry, even allowing for any desired developments, is substantially lower and is more achievable within the timescales indicated in the consultation.

LRIC (WPD, EDF & CE)

Cons:

(1) Potentially less stable tariffs

It is clear that charges derived on a nodal basis will be more volatile than those that are aggregated at a higher level. The WPD method uses a uniform growth rate and ignores important aspects of costs (fault level) and if left uncorrected in these regards can not claim to produce true cost reflective tariffs. However, if corrected to take account of these issues it is likely that volatility (not to mention the complexity of the analysis) will significantly increase again. If potential users can not judge where prices are likely to go in future years then the effect on their investment decisions may be significantly compromised. By aggregating to network group level, the FCP approach simplifies the analysis enough to be able to include all relevant costs and produces more stable costs over the medium term.

(2) Sharp incremental cost signals on low growth / highly utilised network assets

This is a feature of the LRIC charging functions implemented or proposed to date and is fatal flaw in our view. Charts 1 and 2 at the back of this appendix show the utilisation rates of substations in the CNE area and the underlying units distributed since 1996 which has shown a considerable shift form long term trend in recent years. It is likely therefore that low growth / highly utilised nodes will represent an increasing proportion of the network in the future. In their implementation WPD try to address this problem by assuming a constant growth rate but this simply ignores the fundamental issue of the derivation of the charging function whilst also severely compromising the locational element of charges. EDF in their proposed implementation attempt to address the problem by scaling the power flows so that no networks are highly utilised however, in our view, this is simply an admission of the underlying fault whilst the fix has no theoretical basis and distorts the marginal costs as highlighted by Ofgem's own analysis in their recent consultation on EDFs proposal.

(3) Use of an annuity factor

The use of an annuity factor based on asset life to convert an incremental cost (£/kVA) to an annual charge (£/kVA/Yr) significantly compromises the underlying economic message inherent in the original analysis. It will have the effect of diluting cost messages where time to reinforcement is less than the asset life and inflating cost messages where the time to reinforcement is greater than the asset life. Any annuity factor must be based on the time to reinforcement rather than asset life. Note that none of the implemented or proposed LRIC methods produce a valid incremental cost in the first place due to the reasons already highlighted.

(4) Fault level costs are not included

Fault level costs are a significant driver of reinforcement costs, particularly for generation though they are also relevant for demand. Chart 3 shows the relative importance of switchgear reinforcements (fault level related) for demand as submitted informally to Ofgem recently. The graph shows quite clearly that fault level is an important cost driver and therefore any method which ignores it will not produce appropriate forward looking costs. Given the significance of fault level to demand and generation reinforcements, we also disagree with the view that fault level messages should be left to connection charges as such an view could equally apply to all forward cost messages which is not the desired outcome of this project. Frontier Economics (on page 39 of their report on the FCP approach) say of the inclusion of fault level analysis "*Our view is therefore that the inclusion of such analysis represents a notable strength of the EHV generation charging regime and an enhancement relative to other charging regimes*." Dr Furong Li and David Tolley in their recent response to the consultation on the Scottish Power FCP proposal comment that the "*recognition of fault level costs, which will be more significant for generation than demand, is* *a useful step forward*". None of the LRIC methods include fault level analysis.

Further Cons:

(5) Reinforcements only evaluated after power flows have been scaled

A further 'con' with regard to the LRIC methods proposed to date which Ofgem has failed to recognise in their consultation is that in relation to EDF's proposal reinforcements are only considered after first scaling network power flows which had no theoretical basis and in our view invalidates the resulting marginal costs.

(6) Incremental cost applied to total demand – potential for abusive pricing

Ofgem has also failed to highlight the inconsistency and potential abusive charging implications of a regime which calculates marginal or incremental charges and then applies these charges to total demand. There should be consistency between the derivation and application of charges for the economic message to remain valid. Applying an incremental charge over total demand will penalise past decisions of network users rather than send a forward looking message to them.

LRIC (WPD, EDF & CE)
Impacts
Efficiency of decision making

(1a) Strong locational signals from nodal charges

This is compromised because the costs that are feed into the charging function ignore fault level. Also in the case of WPD a uniform growth rate is applied which further compromises the locational signal.

(1b) Less tariff stability

It is clear that charges derived on a nodal basis will be more volatile than those that are aggregated at a higher level, especially properly calculated nodal prices which should include contingency analysis and use local growth rates.

(1c) Long term forward cost signals

For the reasons detailed above the LRIC methods implemented or proposed to date produce cost signals that are poorly cost reflective, volatile and economically unsound in their current format. There are also potential concerns in relation to abusive pricing with regard to how the charging function behaves under certain scenarios and with how a supposed incremental charge is then applied to total demand.

Competition Assessment

(2a) Positive impacts for competition, particularly for the connection of cost efficient DG, from more cost reflective tariffs

Properly calculated and applied cost reflective tariffs will boost competition and will boost the connection of cost efficient DG. The LRIC methods 'on the table' however have fatal flaws meaning they can not be considered to give appropriate cost reflective tariffs in all cases and the application of an incremental charge to total demand (or generation) could lead to abusive pricing. Reckon's paper to the DCMF in June 2008 stated that “*none of the variants of LRMIC described in this paper appear capable of providing an objective justification in circumstances such as those of the above example where charges exceed the relevant measure of stand-alone cost*.” (paragraph 54 Reckon June DCMF paper attached as appendix 3 with supporting spreadsheet)

(2b) Possible negative impacts on competition from more volatile cost signals

We are not convinced that volatility itself would have negative impacts on competition providing charges are predictable – it is the level of charge that may be anti-competitive. Notwithstanding this however, nodal prices will be more volatile than aggregated prices and we believe that properly implemented nodal prices will be an order of magnitude more complex than the current WPD method and therefore likely to result in even greater volatility. It is difficult to see how users could predict such complex and volatile prices and therefore take account of them when making long term decisions on where to connect to the network.

Suppliers

(3a) More cost reflective EHV and lower voltage level tariffs for power flow incremental cost study

(3b) Potential for DUoS charges to change at nodal locations

Suppliers are best placed to comment on the impacts of the various models.

Generators

(4a) Potential for negative charges where UoS facilitates the deferral or avoidance of future reinforcement costs

This is a positive development, however the future reinforcement costs should be accurate and include all relevant costs including those from contingency analysis and for fault level and their derivation and application should be consistent.

(4b) Valuation of generator costs and benefits consistent with demand

This should be the case where the cost and/or benefit drivers are consistent, however if there are valid reasons for demand and generation to be treated differently then it would be wholly wrong to treat them the same.

Other impacted parties

EHV Demand customers

(5) Potential for abusive charges on existing/new demand customers

Ofgem have failed to highlight the potential impact on existing demand customers, where under all the LRIC methods on the table the incremental cost is applied over total demand. It is important that the basis on which charges are calculated is consistent with the basis on which they are applied otherwise there is a real possibility of abusive charges. Due to the issue of high charges on highly utilised and low growth nodes the possibility of abusive charging is very real for new customers also.

Impacts, Pros and Cons of EHV level models

FCP (CN. SSE & SP)
Pros:

(1) **Robust empirical approach to forecast and charge for EHV level costs that are likely to be incurred over next 10 years**
The FCP approach has been designed to overcome to shortcomings of the LRIC charging functions in place or proposed to date. It can handle highly utilised / low growth circuits as well as any other scenario. The G3 companies have chosen 10 years with a pragmatic mindset. We feel it is an appropriate balance between ensuring the forecasts on which costs are derived are likely to be reasonably accurate and providing enough time for customers to respond to the resulting locational signals. Whilst this is the current view of the G3 companies, it requires little additional effort (if agreed up front) to extend the timeframe over which costs are considered if this was the consensus view of the industry in developing a common methodology. However due to the uncertainty around long term growth rates we would argue that the timeframe be limited to a maximum of 20 years.
Insofar as the G3 method is an empirical approach, it is worth noting that the FCP charging formula can also be derived from a corrected LRIC approach as detailed in appendix 4.

(2) **Enhanced cost reflectivity from utilising power flow modelling**
We agree that utilising power flow modelling is one step forward in enhancing cost reflectivity in setting charges. However FCP goes further than this by including fault level analysis and by analysing costs under various network contingency conditions. Without these further steps we do not believe a method can be truly cost reflective. Note that the FCP approach does NOT scale power flows prior to undertaking network analysis.

(3) **Extensive use of public information**
One of the main problems in implementing a common methodology will be ensuring that it is implemented in a consistent way amongst DNOs – unless this is the case the resulting charges may not actually be derived on a common basis, will be less predictable and the economic messages will not be comparable across DNOs. It is important that where possible, inputs into the models that calculate the charges are taken from auditable or publicly available data. Frontier Economics, in assessing the FCP approach, conclude that the extensive use of publicly available data and third-party assumptions is a notable strength of the approach – "*An overriding feature of the G3 approach has been to minimise the use of internally-based assumptions and engineering-based judgements in deriving charges. Therefore, wherever possible, inputs into the models that calculate the charges are taken from publicly available data (for example the Long Term Development Statement) or from third party assumptions (for example, National Grid's Seven Year Statement). The overall effect of this is to ensure that the methodology is, in relative terms, transparent and that charges are, to a large extent, predictable*." (Frontier report, p.2 - see appendix 2 for full report).

(4) Improved cost reflectivity to promote economic efficiency

We agree that the FCP approach improves cost reflectivity and will promote economic efficiency. It is more cost reflective than any other method because it takes account of fault level and network outage conditions. Cost reflectivity is further enhanced by ensuring that charges as applied will only recover the forward looking costs identified which contrasts with the LRIC methods which can in some circumstances recover many times more than the actual forward looking costs. See chart 5 and accompanying spreadsheet for a comparison of FCP and LRIC recoveries under different growth scenarios. We believe the FCP will also promote economic efficiency to a greater extent than any other method because it is robust enough to deal with any scenario of growth or utilisation and will produce more stable price signals than nodal analysis which in turn will give users the confidence to incorporate the resulting charges into their investment decisions.

(5) Cost drivers are extensive (include fault levels)

This is a strength of the FCP approach. Frontier Economics (page 39) say of the inclusion of fault level analysis "*Our view is therefore that the inclusion of such analysis represents a notable strength of the EHV generation charging regime and an enhancement relative to other charging regimes.*" Dr Furong Li and David Tolley in their recent response to the consultation on the Scottish Power FCP proposal comment that the "*recognition of fault level costs, which will be more significant for generation than demand, is a useful step forward*". We agree with the academics and would further state that fault level is a significant cost driver for demand also (see chart 3).

(6) Potential practical and transparent approach to the uncertainty of DG connections

There is undoubtedly a significant amount of uncertainty surrounding the extent of DG connections in the foreseeable future, an order of magnitude more so than for demand. There are also significant differences in both the 'lumpiness' of EHV generators compared to demand and on the effect on future reinforcements that EHV connections may cause (for CN the range of EHV capacities for generation is 3MW to 406MW and EHV generators will represent all of the generation on the EHV network and will drive virtually all of reinforcement costs. However, for demand, the range of EHV capacities is much smaller at 0.1MW to 37MW and EHV demand customers represent only around 2% of the demand on the EHV network). Where appropriate there should be no difference in the treatment of demand and generation in any charging methodology however where differences are significant, it would be wrong not to consider different treatments in the charging regime. The FCP method considers all relevant cost for both demand and generation and in this sense treats them similarly. However due to the increased 'lumpiness' and uncertainty surrounding DG connections the G3 have developed a probabilistic approach to costing future increments of generation. The Frontier report highlights this as a notable strength of the approach – "*The use of a probabilistic 'test-size' generator analysis to estimate reinforcement costs for EHV generation constitutes a significant step up in sophistication from* *the methodology currently in use. By notionally installing test generators, the FCP methodology promises to arrive at locationally accurate cost estimate, while the probability analysis constitutes a sensible way of accounting for the inherent uncertainty that exists about 'lumpy' future generation connections. While alternative methods do theoretically exist – for example Monte Carlo analysis could be used to derive a probability density function for generation connections – these could not be implemented without incurring a significant increase in methodological complexity and potential loss of transparency*" (Frontier Economics report page 40)

(7) Model developed for six DSAs

This is indeed a large positive in favour of the FCP approach. Given the timescales involved in concluding the structure of charges project, the fact that the common FCP approach is at a proposal stage for six DSAs means that the method is 'on the shelf' and ready to roll out to the industry. No LRIC model which has been implemented or proposed has this strength and all are different. We have already highlighted some of the inconsistencies between the LRIC methods listed in the consultation and we would point out that the time required for the debate and compromise involved in getting to a common position among a number of DNOs should not be understated. The G3 companies have been through this process and have arrived at a common position and therefore it is likely that we will have already arrived at something close to a consensus industry view on many of the major decisions that would be needed in the development of a common FCP approach for the industry. The G3 remains open to further industry views and should the consensus change for any aspect of FCP then the method should change with it.

FCP (CN. SSE & SP)

Cons:

(1) Weak forward-looking message

We disagree with the assertion that FCP provides a weak forward looking message – we believe it provides the correct forward looking message. It may well be the case that in some instances FCP produces lower charges than with the LRIC methods but this is not a weakness of FCP but rather it is a result of the flaws of the LRIC calculations proposed in the consultation (described in detail above) and also in how those LRIC charges are then applied to customers. It is important that the basis on which charges are derived is consistent with the way in which they are implemented. The LRIC approaches derive charges by dividing cost by the increment of demand but then apply these charges to total demand – this is a fatal flaw as the effect is to penalise customers for their past decisions as well as attempting to influence future decisions. As a result the messages given to new customers and existing customers are different and will result in inefficient decision making by existing customers. The forward cost message for FCP is rooted to the actual forward reinforcement costs of incremental demand and individual customers' contribution to those costs and we believe it therefore produces the correct forward cost message in a regime where charges are to be applied to total demand. Chart 5 compares the recoveries of a future reinforcement cost on a LRIC and FCP basis and the accompanying spreadsheet (FCP v LRIC analysis.xls) shows the workings behind this.

(2) Weak locational message with average pricing within each network group

Network groups define how engineers actually plan the network and therefore it seems appropriate to calculate charges on this basis. Nodal charges may give a greater number of locational signals but unless these signals are based on all relevant costs, include network contingency analysis and use appropriate growth rates then they are not truly locational. In their recent consultation on EDFs proposal Ofgem have acknowledged the importance of local growth rates on the level and relativity of marginal costs and therefore it is wholly inappropriate to assume a constant growth rate across all nodes (as WPD have done) or, to a lesser extent, to assume GSP growth rates across nodes (as EDF have done – whilst this a step forward on the WPD approach it now produces charges that are based on inconsistent assumptions i.e. costs on nodal basis and growth on GSP basis). The FCP approach is truly locational as it calculates costs on a network group basis and also, in a consistent manner, calculates growth rates on a network group basis. The aggregation to network group is a necessary simplification to include all relevant costs and to include network contingency analysis. As Frontier Economics point out with regard to the FCP approach "*Charges are derived for the higher voltages of the network at a zonal level and therefore vary to reflect the underlying infrastructure conditions in each part of the network. In our view this represents an enhancement of the cost reflectivity criterion. At the same time, the use of zones (rather than nodes) and limiting the locational variations in charges to the higher voltage levels represents a sensible boundary. More granular locational signals would, in our view, substantially increase the complexity and unpredictability of the charging regime (and also require more engineering-based judgement to derive charges) with minimal incremental benefit arising from the additional cost reflectivity that this would create*" (Frontier Report p.2). Furthermore, chart 4 showing the 83 different locational costs derived for the EHV network under FCP for Central Networks East, would lead us to assert that the locational message is not weak.

(3) Model considers assets above 87% utilisation only

This is not the case, although the G3 must perhaps accept some liability for the confusion around this area as we have not been clear on how the method has developed from initial proposals in 2007. The driver for reinforcements is whether or not the reinforcement is required within 10 years given the current utilisation and growth rate. The wording of the FCP methodology as submitted formally by Scottish Power and informally by Central Networks and Scottish and Southern makes this clear in paragraph 3.10 "*The base network demand is then incremented in small steps, up to a level that is able to encapsulate the expected growth in the network over the next ten years above their current maxima.*" Chart 6 shows the range of utilisations considered in Central Networks recent informal submission.

(4) Different approach for generation and demand charging

As explained above, because of the uncertainty surrounding generation connections and growth, the increased 'lumpiness' of generation connections and the relative significance of EHV connections on reinforcements of the EHV network especially with regard to fault level, we believe it is appropriate to treat demand and generation differently. Due to fault level considerations small increments of generation can cause significant reinforcement costs (much more so relative to demand). Therefore, under an amended LRIC approach which takes account of fault level, the addition of a small increment of generation can cause the same change in reinforcement NPV as a much larger increment except that the use of a smaller increment would of course result in significantly larger marginal costs. If these large marginal costs are applied to total generation then this will lead to unreasonably large, unfair and uneconomic charges in some areas of the network.

With regards to the FCP approach to generation charging we refer again the conclusion of Frontier Economics, who on page 40 of their report state "*The use of a probabilistic 'test-size' generator analysis to estimate reinforcement costs for EHV generation constitutes a significant step up in sophistication from the methodology currently in use. By notionally installing test generators, the FCP methodology promises to arrive at locationally accurate cost estimate, while the probability analysis constitutes a sensible way of accounting for the inherent uncertainty that exists about 'lumpy' future generation connections.*"

FCP (CN. SSE & SP)

Impacts:

Efficiency of decision making

(1a) Weaker locational signals from zonal charges

Charging on a zonal basis is necessary because:

(a) it represents how networks are designed and operated by our engineers and therefore represents the appropriate level of granularity for locational charges;

(b) it allows for the inclusion of all relevant costs (e.g. fault level) thereby strengthening the locational signal without over complicating the analysis;

(c) it does this whilst maintaining a large degree of locational message (83 EHV zonal charges for CNE).

(1b) More tariff stability

Charges derived on a zonal basis will be more stable than nodal charges (especially properly calculated nodal prices which include fault level and contingency analysis and use local growth rates) and therefore will encourage users to respond to the economic signals.

(1c) Forward cost message limited to 10 years

As previously explained the G3 companies have chosen 10 years with a pragmatic mindset. We feel it is an appropriate balance between ensuring forecast accuracy and providing enough time for customers to respond however as previous stated we remain open to industry views in this regard. .

Competition Assessment

(2a) Positive impacts for competition, particularly for the connection of cost efficient DG, from more cost reflective tariffs

Properly calculated cost reflective tariffs will boost competition and will boost the connection of cost efficient DG. We believe that the FCP approach pragmatically delivers this whilst avoiding the fatal flaws on the LRIC methods ‘on the table’.

(2b) More stable long term cost signals

Charges derived on a zonal basis will be more stable than nodal charges and therefore will encourage users to respond to the resulting economic signals.

Suppliers

(3a) More cost reflective EHV and lower voltage level tariffs for power flow incremental cost study

(3b) Potential for DUoS charges to change at network group locations

Suppliers are best placed to comment on the impacts of the various models.

Generators

(4a) Potential for negative charges where UoS facilitates the deferral or avoidance of future reinforcement costs

This is a positive development however the future reinforcement costs should be accurate and include all relevant costs, including those from contingency analysis and for fault level.

(4b) Valuation of generator costs and benefits are different to demand. Model assumes different cost drivers are relevant for generators.

It is not true to say that the model assumes different cost drivers as the FCP approach analyses fault level for demand users also. However because of the different relative impacts on reinforcements between demand and generation (especially for fault level) and because of the significantly different uncertainties surrounding the growth of demand and generation it is necessary to treat the two differently. The FCP method has come up with a pragmatic way of calculating the network group costs for generation and Frontier Economics have concluded that the approach “*represents an appropriate balance between cost reflectivity and transparency*” (page 3, Frontier Report).

Other impacted parties

EHV Demand customers

(5) Reduced potential for competition law infringements (abusive charges on existing/new demand customers)

Ofgem has failed to recognise the potential impact on existing demand customers, where under all the LRIC methods on the table the incremental cost is then applied over total demand. It is important that the basis on which charges are calculated is consistent with the basis on which they are applied otherwise there is a real possibility of abusive charges. Due to the issue of high charges on highly utilised and low growth nodes the possibility of abusive charging is very real for new customers also. The risk of exploitative abuse is real for the LRIC methods and in paragraph 54 of Reckon's paper delivered to the DCMF in June 2008 and attached as an appendix they state that "*We therefore find that none of the variants of LRMIC described in this paper appear capable of providing an objective justification in circumstances such as those of the above example where charges exceed the relevant measure of stand-alone cost*."

The FCP approach is consistent in how it calculates the incremental charge and then applies that charge and thereby largely avoids the risk of abusive charges on existing or new customers.

Impacts, Pros and Cons of HV/LV demand models

DRM
Pros:

(1) **DRM has been used to calculate lower voltage level charges since the 1980s**
Application as part of a common methodology would maintain the status quo for lower voltage level cost modelling.
Firstly, we are aware that the DRM is not the current model in use for all DNOs and therefore it would not maintain the status quo. Also, the use of a DRM in name by most DNOs will not provide protection from huge tariff swings upon the implementation of a common DRM. Inputs to the DRM such as coincidence factors (day & night) and units/KW factors (day & night) will be calculated differently in different DNOs and approaches to non operational costs and exit charges will also differ, not to mention how tariffs are structured between unit and capacity and reactive power charges. Therefore whichever model is chosen for HV/LV charges will result in significant tariff movements and therefore this can not claim to be a 'pro' of the DRM. It is worth noting that Central Networks are one of the DNOs which currently use a DRM for charges which is a reasonably clean implementation and so we are not 'defending our own' however we feel that the G3 tariff model is a huge improvement over the DRM in terms of simplicity, transparency and consistency among DNOs.

(2) **Forward looking incremental cost model**
Since the DRM is based on a notional network it is only a notionally forward looking incremental cost model. However, such an improvement could also be made to the G3 HV/LV tariff model. In the marginal cost section of the G3 tariff model there is no reason why the £/kVA charges can not be a simple input from a notional network rather than from the RRP cost data. It should be noted however that this would slightly reduce the transparency of the model and we feel would only be warranted for the marginal cost input (not for O&M or refurbishment or customer service costs).

DRM
Cons:

(1) **Various forms of the DRM are currently in use by DNOs**
Application as part of a common methodology would require a single approach to be developed and agreed by DNOs.
This is a vitally important point. There is no 'blue print' available to use as the common DRM (unlike the G3 tariff model) and agreeing one will be very difficult given the impact on companies tariffs and commercial positions. HV/LV tariffs make up the vast majority of DNOs income and issues such as fixed vs. variable charges, capacity charges and reactive power charges all have the ability to affect companies' commercial positions and as such objections and disagreements are likely to be strong. We believe that the industry will be unable to agree on a common DRM and, even if one is provided by Ofgem. some DNOs may well be unable to accept the model proposed.

(2) **Currently less predictable and transparent relative to the proposed use of historical data as based on 500MW increment cost modelling that is unavailable to network users**
Users would be able to better understand future charges if there was public access to cost modelling
We agree that the DRM would be less predictable and transparent than the G3 tariff model.

DRM Impacts:

(1) **Industry wide development of a common DRM**
For the reasons explained above we believe that this could well prove unachievable.

(2) **No significant developments for competition**
A common method could bring benefits in terms of facilitating a common IDNO charging methodology also.

(3) **Better understanding of future charges provided public access to cost modelling**
Public access will improve understanding, but since the model will be a notional one the benefit to transparency may be limited.

Impacts, Pros and Cons of HV/LV demand models

Historic RRP Cost Data
Central Networks feel that this is a misleading title that has not come from the G3 companies. It suggests the G3 tariff model is interested in recovering historic cost, which is not the case. The G3 tariff model is a forward looking model, but in order to improve transparency and predictability and reduce subjectivity we are using historical data which can be published, is auditable and is consistent among DNOs to forecast future costs. We would note that most forecasts use this approach.

Pros:

(1) **A transparent and simple model for network users to understand**
The principles behind the G3 tariff model are clear. The inputs are transparent and auditable and the intention is that they would be published with the model. In our view this makes the model a significant improvement on current models (including our own).

(2) **Potentially delivers stable and predictable charges that reflect medium-term cost trends**
G3 have listened to consultation responses and will use average historic costs to derive forecasts. The use of averaging will greatly enhance stability and predictability. Furthermore, we would point out that any alternative forecasting technique which did not arrive at similar answers to medium term trends derived from historic data would need to be severely questioned.

Historic RRP Cost Data
Cons:

(1) **Reliance on historical trends to forecast future network developments**
This is a robust basis on which to forecast future developments. The exact approach to forecasting can be amended to suit the consensus opinion of the industry (for example the use trend analysis rather than simple averaging or by adding a productivity gain assumption and so on), but we feel that historical data is a sound and transparent footing to base any forecast on especially for costs such as O&M, customer service, refurbishment. The case for capital costs may be less clear but the G3 tariff model is easily capable of using £/kVA inputs from a notional network (as is done for the DRM) for the capital cost elements of the input data although this may slightly reduce the overall transparency.

(2) **Potential for fluctuations between yearly RRP data which may lead to volatility**
The G3 have listened to concerns expressed in this regard through our own consultation process and have modified the G3 tariff model to use a rolling average of RRP data thereby minimising volatility whilst still capturing medium term trends.

Historic RRP Cost Data
Impacts:

(1) **Industry wide revision to how HV/LV demand charges are calculated**

Whichever model is chosen there will inevitably be significant movements compared to existing charges. This will have commercial implications for each DNO and it will therefore be very difficult get agreement. The advantage of the G3 tariff model is that the 3 companies have gone through a long process of debate and compromise already and therefore it is likely that the answers we have come to would also be the consensus of the whole industry. We believe that the G3 tariff model therefore represents a robust baseline or blue print to present to the industry for a common methodology.

(2) No significant developments for competition

A common method could bring benefits in terms of facilitating a common IDNO charging methodology also.

(3) Users will potentially be able to estimate future charges provided public access to RRP data and cost modelling

The model that the G3 companies consulted on in May 2007 and also the models provided to Ofgem as either formal or informal submissions have always contained the RRP data on which any forecasts may be based and it has been the intention that these will be published. Therefore there **will** be access to that RRP data and cost modelling needed to enable users to better estimate future charges.

Impacts, Pros and Cons of HV/LV generation models

Pros:
We would agree with the first two of Ofgem's positive points:

(1) **Each of the models significantly develops existing methodologies and recognises the contribution that appropriately sized and sited generation can have for system security and the deferral of network reinforcement costs**

(2) **All the models apply transparent practical approaches to value the costs and benefits of generators connected at lower voltage levels**

With regard to the other points raised by Ofgem we believe that the use of P2/6 security factors by the G3 tariff model is an appropriate basis for valuing the contribution of generation to system security. Furthermore G3 go further than strict P2/6 guidelines by applying these security factors all the way up the network, thereby also valuing the deferral of network reinforcement cost that generation can bring. In this way the G3 approach, we believe, delivers what the other methods deliver but has a more robust grounding. It will also be flexible to future developments in the industry such as updates to P2/6 security factors for different types of generation. The WPD, EDF and ENW methods are all different and none of them have such a robust grounding as the G3 model, and we believe this makes them less suitable.

Where Ofgem state that the G3 method only recognises generator benefits where higher voltage FCP demand costs are not zero - this is not true. The G3 method applies generator benefits all the way up the network based on P2/6 security factors regardless of the demand costs. P2/6 does not recognise a benefit of LV generation which is the only reason that LV generation charges are zero. If P2/6 were to change in this regard, the G3 model would provide benefits to LV generation accordingly.

It should also be noted that the G3 model calculates HV generator costs using the same methodology as for EHV levels and as such results in more cost reflective tariffs.

Overall, we believe the G3 HV/LV generation model is the most suitable for the longer term charges because:

- It recognises the contribution that appropriately sized and sited generation can have for system security and the deferral of network reinforcement costs
- It applies transparent practical approaches to value the costs and benefits of generators connected at lower voltage levels
- It makes extensive use of industry standards and codes
- It is flexible to industry developments of these standards
- It uses the same reinforcement model (at HV) as for EHV levels and therefore calculates more cost reflective tariffs.
- It will encourage the connection of generation at lower voltages especially if the allowed revenues for demand and generation are combined from April 2010.

We note that the WPD method only provides a benefit if the load factor is above 60 per cent. We believe this will prevent the connection of some types of generation and is not a suitable aspect of an enduring charging regime. The ENW credits differ where load factors are above or below 50 per cent – this seems to us to be an arbitrary split which is not a suitable feature of an enduring charging regime. The EDF method assumes a credit based on the tariff group coincidence factor, however this does not take account of industry security standards.

Impacts, Pros and Cons of EHV level models

LRIC / ICRP (ENW)

Unfortunately we feel unable to comment at this stage on a model which is still in development and therefore we feel that the ENW method is not suitable for an enduring common methodology at this stage.

High Utilisation / Low growth rates may become more common – a problem for LRIC

Chart 1 – Utilisation rates in CNE is 'high' in a significant portion of the network.

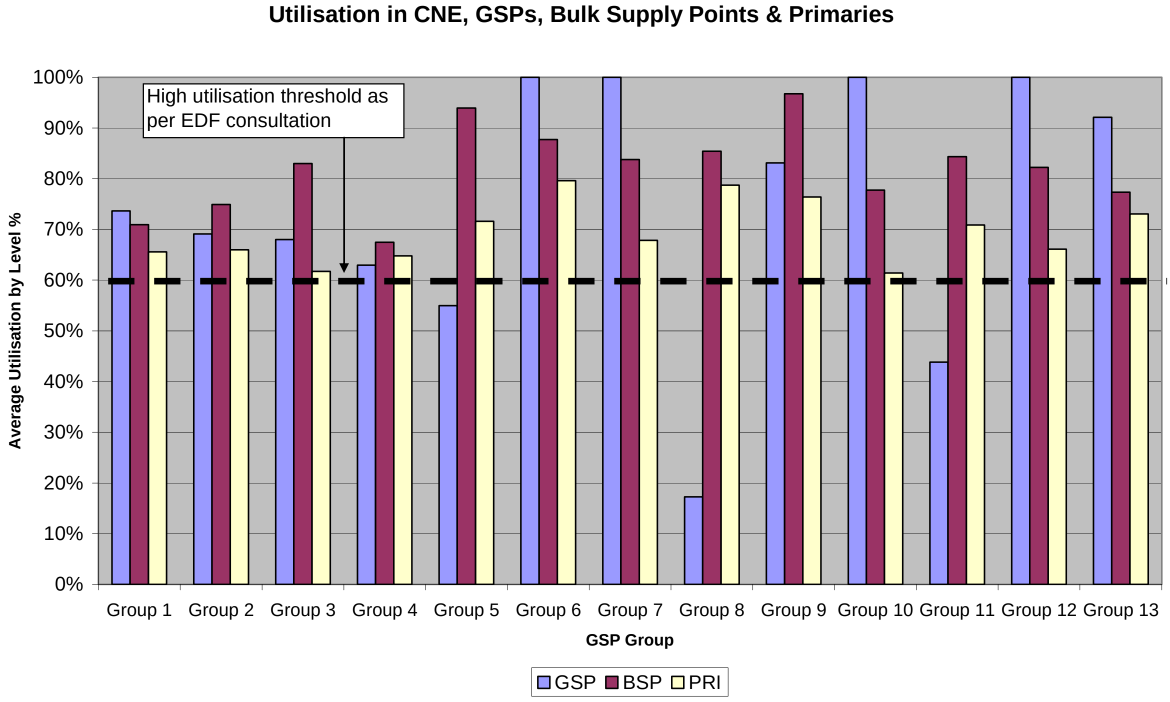


Chart 2 – underlying units distributed in CNE – low growth in recent years may translate to low demand growth

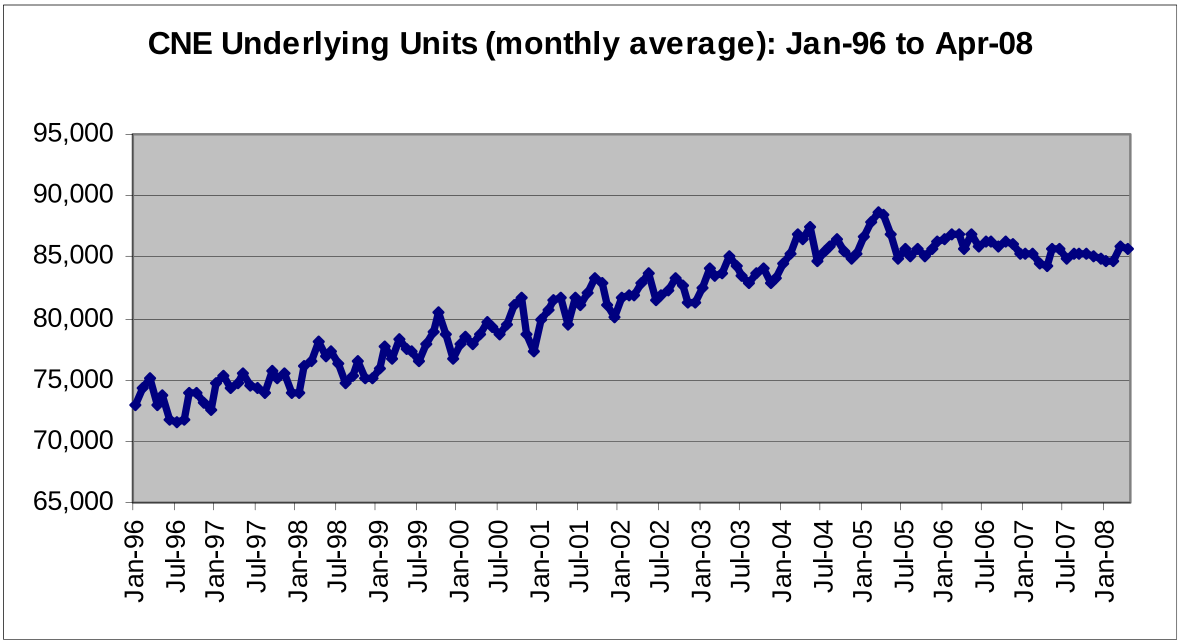


Chart 3 – Composition of reinforcement costs for Demand - Fault level (switchgear) is a significant driver for Demand also

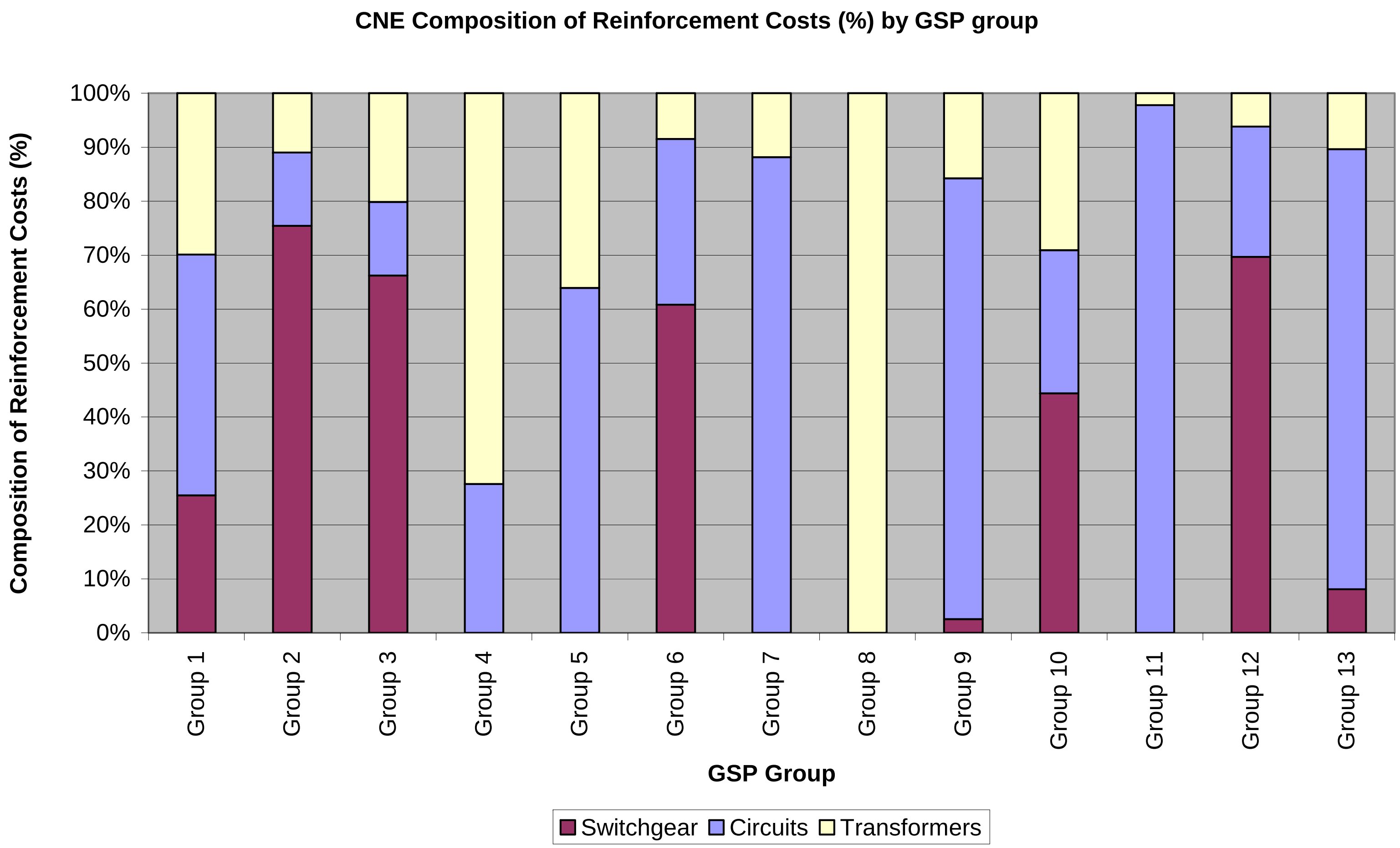


Chart 4 – 83 locational charges at EHV level for CNE – a large degree of locational message

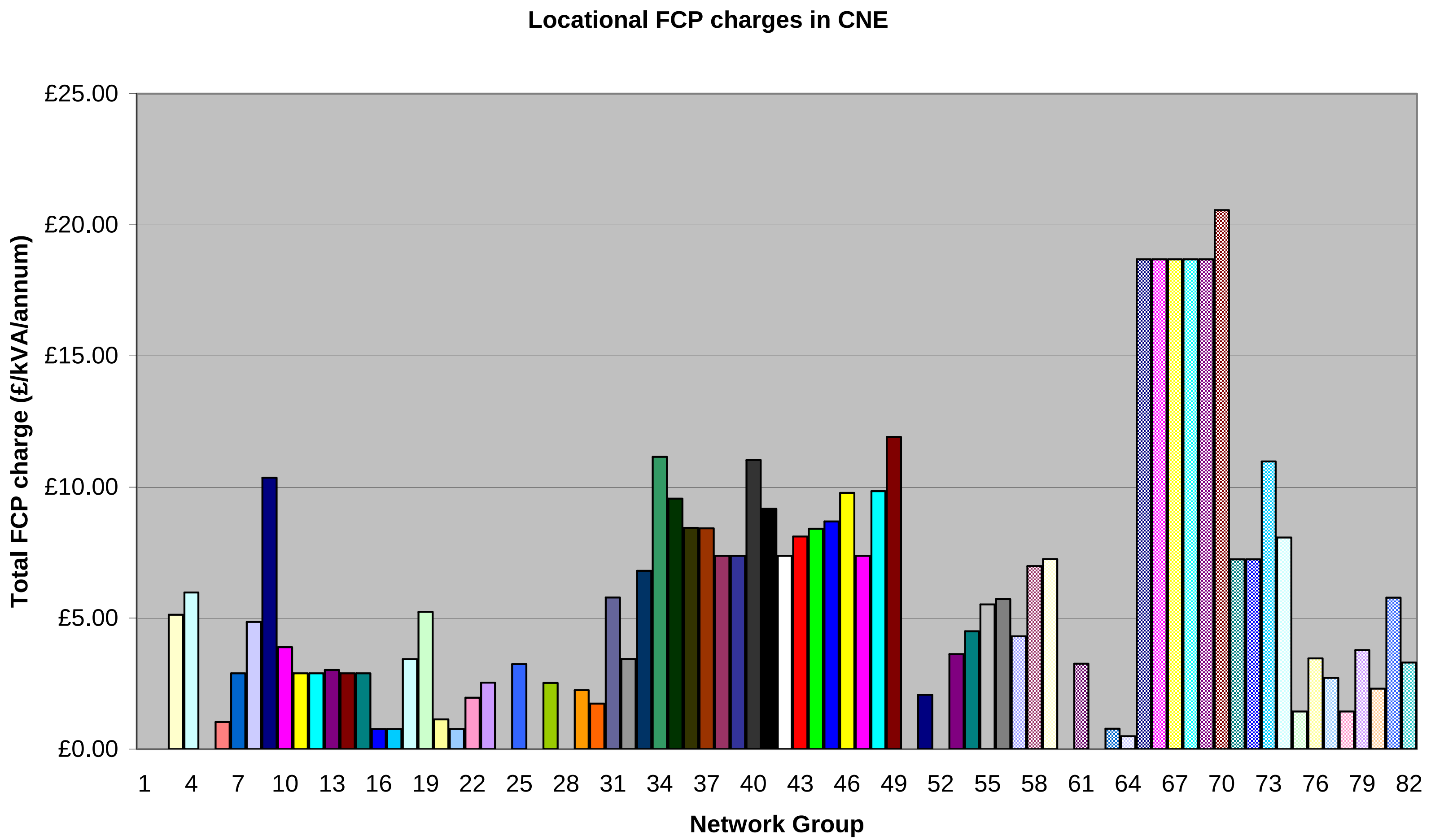
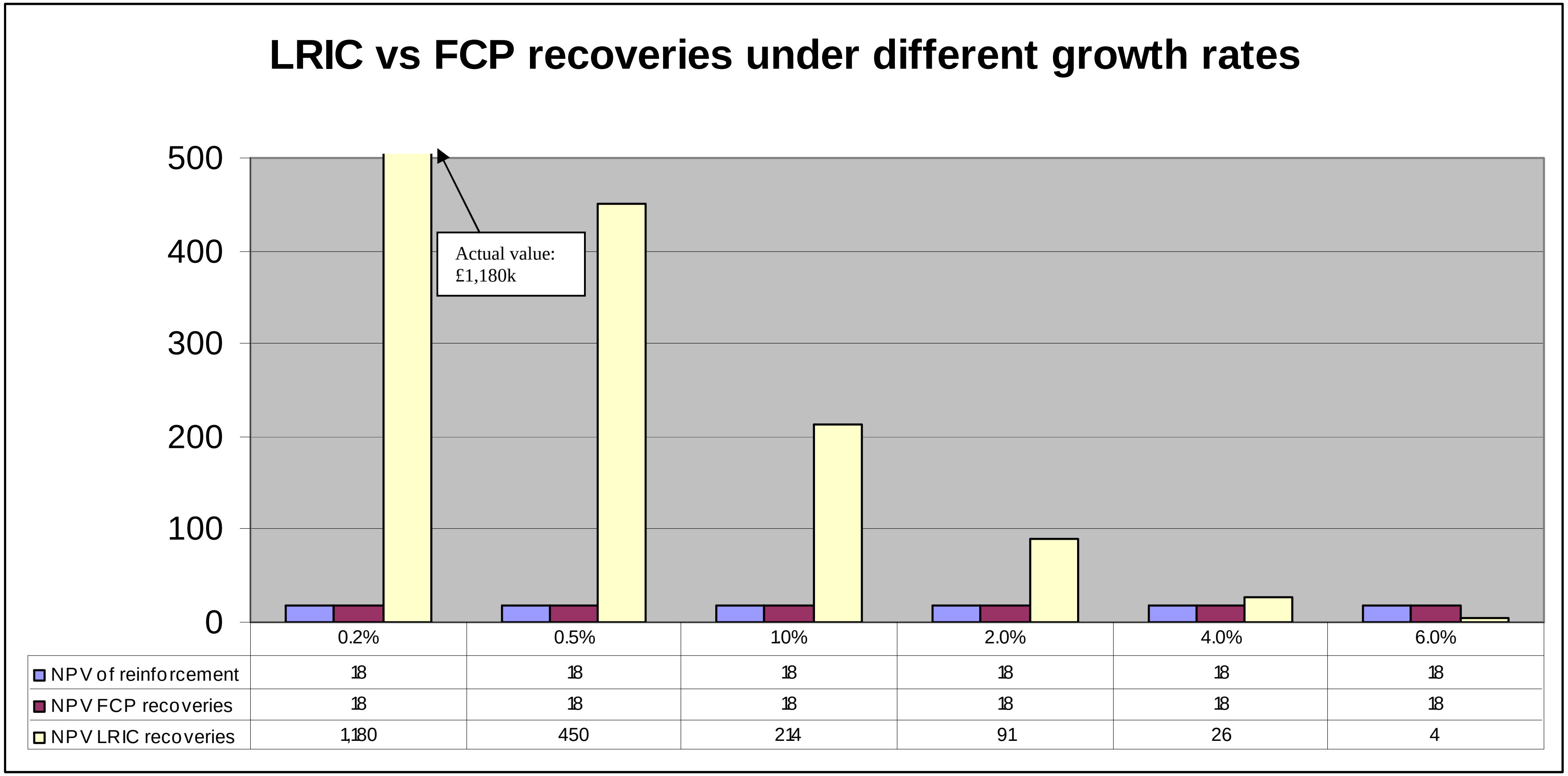


Chart 5 – A comparison of revenue recovered through charges under different growth rates: LRIC vs. FCP

Reinforcement cost - £100k
Required in 25 years
Growth rates range from 0.2% to 6%
See spreadsheet “FCP v LRIC analysis.xls” for calculations



	0.2%	0.5%	10%	2.0%	4.0%	6.0%
NPV of reinforcement	18	18	18	18	18	18
NPV FCP recoveries	18	18	18	18	18	18
NPV LRIC recoveries	1,180	450	214	91	26	4

Chart 6 – Utilisations of network groups in CNE

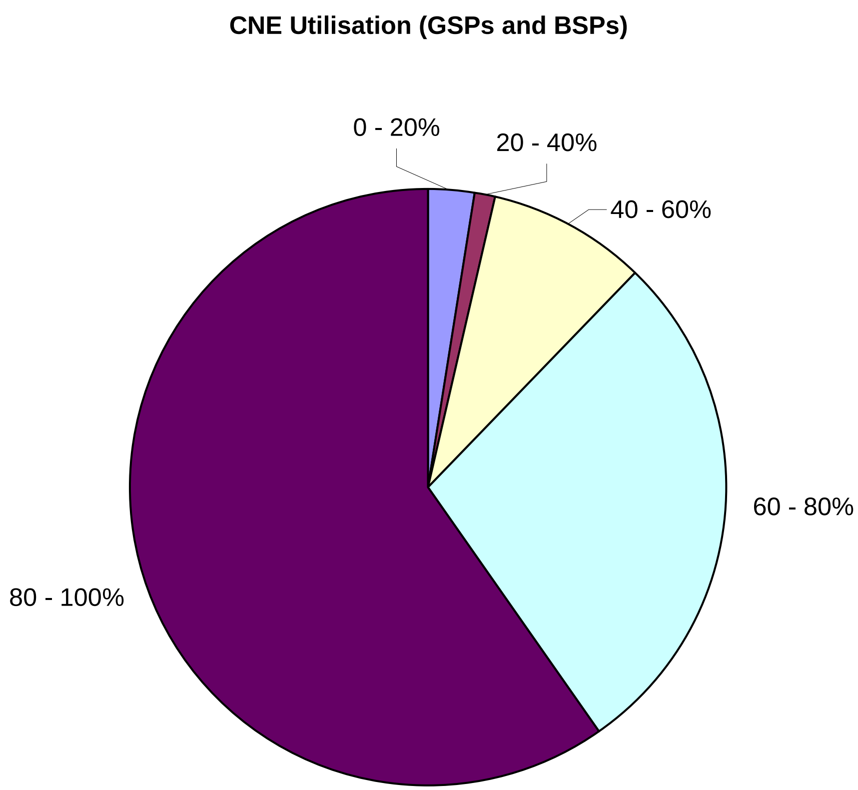
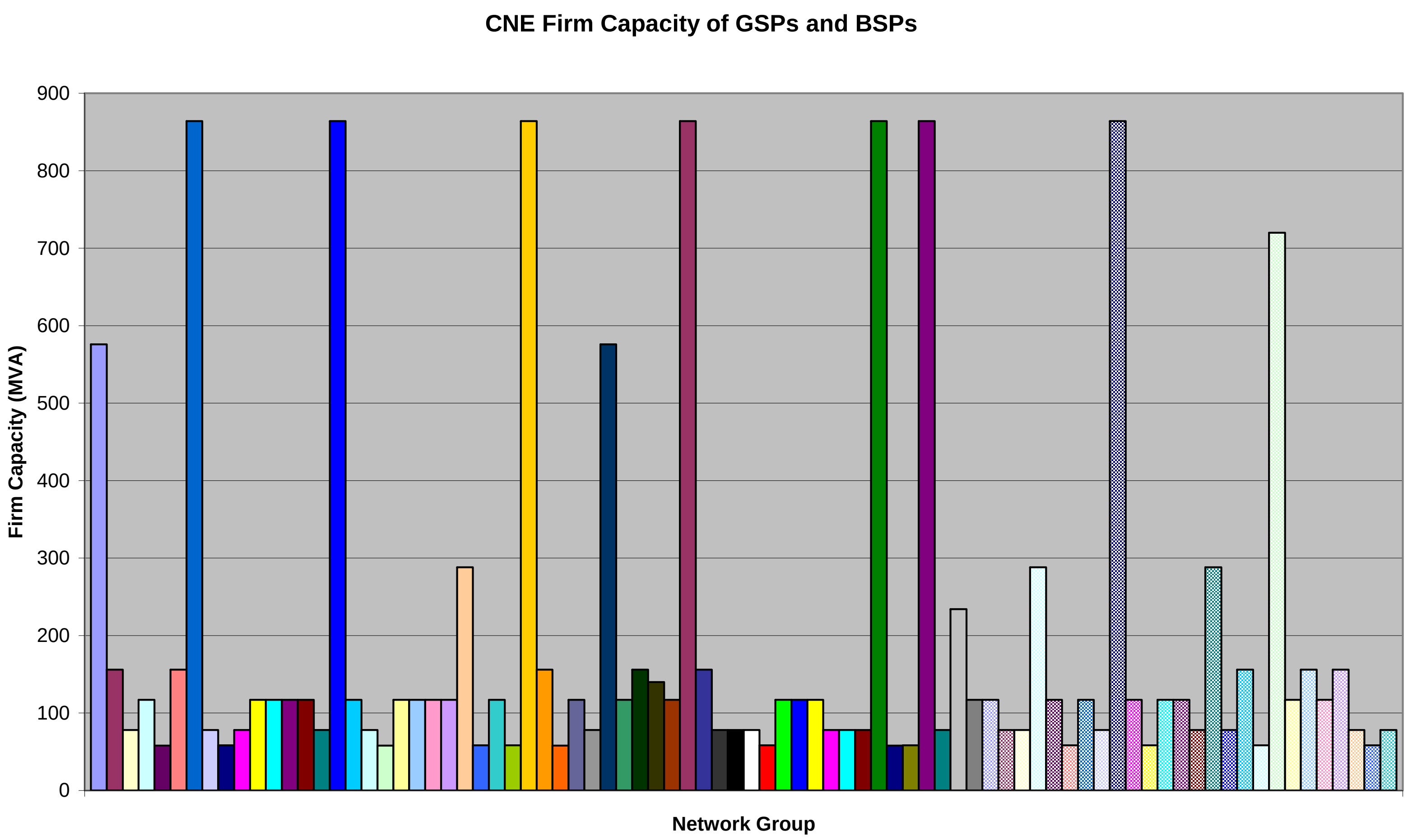


Chart 7 – CNE range of substation firm capacities (GSPs & BSPs) – uniform increments are not appropriate for all networks



APPENDIX 2 – FRONTIER REPORT – SEE SEPARATE ATTACHMENT

APPENDIX 3 – RECKON DCMF JUNE 2008 PAPER AND SPREADSHEET – SEE SEPARATE ATTACHMENTS

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APPENDIX 4. ALTERNATIVE DERIVATION OF THE FCP DEMAND ALGORITHM, LRIC APPROACH

Let the growth rate of the demand, D kVA, be denoted by g per annum.
Then, if C kVA is the capacity at which reinforcement is required, the demand at time t years prior to the capacity being reached is given by:

$$D(t) = C \exp(-g\, t) \text{ kVA}$$

The Present Value, PV, of reinforcing the asset, cost £A, at a discount rate of i per annum is:

$$PV = £\, A \exp(-i\, t)$$

The effect of a small change in D at time t is given by:

$$d(PV)/dD = A\, d(\exp(-i\, t))/dD = A\, d((D/C)^{i/g})/dD = i\,(A/C)\,(D/C)^{i/g-1}/g \text{ £/kVA}$$

This is the analytical form of the standard formula for the LRIC incremental cost of individual asset reinforcements. It can also be expressed in terms of time rather than demand as:

$$d(PV)/dD = i\,(A/C)\exp(-i\, t)\exp(g\, t)/g \text{ £/kVA}$$

Note that the units are £/kVA and in order to determine an annual rate an additional factor needs to be introduced. Applying an annuity factor based on the lifetime of the asset is incorrect, since such a value is based on the rental rate or mortgage rate assuming that constant payments can be collected over the lifetime of the asset. Here the payments are not constant and will only be paid over the cost recovery period from the time when the previous reinforcement was carried out until the time of the next reinforcement. The factor therefore needs to be based on the cost recovery period, not on the asset lifetime. Moreover, in keeping with the concept of NPV, it is more appropriate to use repayments which contribute equal amounts to the final total rather than equal instalments. Thus, denoting the cost recovery period by T years, the annuity factor is chosen to be:

$$\exp(-it)/T$$

Denoting the initial demand by D_0:

$$\begin{aligned} LRIC2 &= i\,(A/C)\exp(-2i\, t)\exp(g\, t)/gT \\ &= i\,(A/C)\,(D/C)^{2i/g-1}/\mathrm{Log}(C/D_0) \quad \text{£/kVA p.a.} \end{aligned}$$

If the additional reinforcement is assumed to double the capacity then the initial demand can be taken to be half the capacity and the numerical value of the denominator gives a multiplying factor of 1.44.

Thus, the functional form is identical to that of FCP. If the formula above is rescaled to recover the the total reinforcement cost over the 10 year period, then the FCP formula is obtained:

$$\text{FCP} = i\,(A/C)\,(D/C)^{2i/g-1}/(1-\mathrm{Exp}(-i\, T)) \quad \text{£/kVA p.a.}$$

which for T = 10 years and i = 6.9% gives a multiplying factor of approximately 2, and the formula becomes:

$$FCP = 2i(A/C)(D/C)^{2i/g-1}$$

This larger multiplying factor of 2 in FCP represents the recovery of the total cost over a 10 year period rather than the generally much longer period between the growth of demand from 50% utilisation to full capacity. As such, FCP gives sharper messages, more effectively discouraging growth in demand in the crucial period when full capacity is being approached and offering the larger incentives to generation in this period.