Regulation Director's Office

Your ref

Rachel Fletcher
Director, Distribution
Ofgem
9 Millbank
London
SW1P 3GE

Our Ref
SM/sb

Date
21 August 2008

Contact / Extension
01698 413475

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. Ref 104/08.

SP Energy Networks (‘SPEN’), welcomes the opportunity to comment on the issues raised in this consultation on behalf of SP Distribution and SP Manweb.

1. Common Methodology Options

It is our strongly held belief that the G3 Forward Cost Pricing (FCP), methodology, which is drawn from the principles of Long Run Incremental Cost (LRIC) is currently the best available option for applying a common methodology when compared to the alternatives currently being developed and considered. The economic function that underpins FCP exhibits the most desirable economic properties including; flexibility under different assumptions e.g. growth, timely price signals and appropriate cost recovery. The model also retains sufficient flexibility to be further developed and adapted to deal with a host of market conditions and variables e.g. ranging from a more significant degree of nodal charging (currently our model incorporates 128 different locational signals) through to changes in the patterns of consumption.

When we consider the next closest alternative, the University of Bath variation of an LRIC model we are concerned by certain apparent flaws that include:

- Excessive pricing under conditions of high utilisation and low growth rate.
- Counter-intuitive charging and extremely weak signals under some conditions which are possible in localised areas of the network.

- A current failure to consider fault level costs, and uncertainty whether this can be incorporated.
- Distortion of charges and dilution of price signals as a consequence of the use of an annuity factor in the charging function that is based on the asset life.
- A model that calculates incremental / marginal charges which are then applied to full demand rather than to the incremental portion can result in charges far in excess of the expected reinforcement costs, and also far in advance of the required reinforcement. Inconsistent basis of derivation and application of charges creates significant competition law concerns.

When these flaws are taken together with the context of a challenging environment where changes in the pattern of demand are more likely, load patterns are varying across networks and there is significant uptake of distributed generation we are deeply concerned that the existing version of LRIC could act to the detriment of some customer groups without economic justification.

We also note that as yet the only two variants of the University of Bath LRIC model, which have been tabled by DNOs, contain quite fundamentally different adaptations aimed at circumventing the acknowledged weaknesses of this methodology. One variant applies a uniform growth assumption that is in stark contrast to current trends and another applies a power flow-scaling factor.

We note with some concern the fact that the Bath interpretation and adaptation of the LRIC principle seems to have evolved, in the collective minds of the industry, into the "standard" LRIC approach, to the point that it is referred to as simply "LRIC" throughout the latest consultation document. This is a misconception as there is no standard LRIC implementation. In fact, the G3 FCP approach is also derived from the LRIC principle, but corrected to avoid the main flaws and problems mentioned above.

Taking account of the problems we have highlighted, we would have to carefully consider whether it is possible for us to accept a licence modification, which prescribes the implementation of the existing Bath interpretation and adaptation of the LRIC principle as common methodology, given the implications this could have for our customers. We would take this opportunity to remind all parties that this concern does not arise as a result of vested interest, the DNOs will be largely cash-flow neutral regardless of what common methodology is applied, rather a deeply held concern over the economic consequences for customers and other stakeholders living, working and striving for economic growth and success within our franchise areas.

We cannot stress enough therefore the importance of choosing an appropriate common charging methodology that is capable of being applied to all network conditions and structures, current and future, as well as accommodate particular "local" conditions (such as high as well as low growth rates, “interconnected” networks etc). G3 FCP has developed an approach which has been demonstrated to deliver appropriate charges across three groups, comprising six DNO areas, which differ in customer characteristics, topology and network architecture. It is also believed that the approach can be implemented across the rest of the DNOs without the fear of unreasonable or unexpected results from the model.

2. Implementation Costs

In terms of implementation costs, we believe that it is necessary to conduct a full impact assessment on the costs to the DNOs, once the methodology has been chosen and scope of the project are known.

It is important that funding mechanisms consider both the cost of implementing a common methodology and also those costs relating to the significant investment made since the beginning of the Structure of Charges project, from around 2003.

SPEN has been working together with the rest of the DNOs in the development of the Structure of DUoS Charges, initially as part of the COG working group and later with the G3 companies to develop the G3 approach. These sunk costs are significant and are ignored in the weak financial assessment highlighted in Ofgem’s decision letter.

It is also of some concern to us that in taking this decision, Ofgem appear not to have quantified the value of the benefits to stakeholders in their document.

Depending on the scope of the common methodology, we believe that implementation costs will be higher than the figure of £7 million pounds (£500k per DNO) quoted in the consultation document. For instance a methodology, which prescribes a tariff structure and impacts billing systems, would trigger system costs (possibly impacting suppliers’ billing systems as well). Another example would be the instruction to perform “nodal” power flow analysis (depending on what is meant by nodes), which would generate costs and add to the complexity involved in implementation. It is also necessary to consider what the ongoing governance resources and processes will be as well as their associated operational costs.

It is therefore vitally important that Ofgem lay out clearly what funding arrangements are to be put in place and confirm that there will be full recovery of costs incurred to date and during the remainder of this project, at an early stage.

3. Governance of the project

It is also important to point out that the form of the licence obligation and guidelines document must specify in detail what methodology is required and the scope of the requirements. This is particularly important given the tight timelines allocated to this process.

We believe that the best approach to governance of the project is to establish an arrangement similar to the Distribution Code. It is important that the decision on change proposals should rest with the distribution companies, to avoid the promotion of vested interests from non-neutral participants. We agree as well that there needs to be a forum for proposals and concerns to be raised by other stakeholders, which should be duly examined and considered by the DNOs, without undermining the capacity to decide when to bring forward a modification to the common methodology. We think that the existing DCMF could provide the starting point for such a forum.

Finally, It will be important that suppliers and other stakeholders expectations are matched against what benefits a common methodology can actually deliver. A common DUoS charging methodology does not mean common tariffs (unless specified) or a common tariff structure (fixed, unit and capacity split). It would not eliminate the differences in the level of charges across DNO areas, as these are mostly due to the derivation of allowed revenue, or the overall balance between different customer groups (again, this tends to be a function of the balance of the inputs, which depend on the individual characteristics of the DNO areas). Finally, it does not necessarily eliminate price volatility: in fact, it is possible that a forward looking methodology *increases* volatility in some instances, for example as a result of the reinforcement programme taking place, changes in that programme or load churn across the network.

The main body of our response follows this letter. It focuses on the following main points: choice of methodology, costs and cost recovery, governance arrangements and timetables.

I would also take this opportunity to emphasise that SP Energy Networks acknowledges the importance of the decision outlined by Ofgem in the consultation, we are fully committed to driving forward towards a common methodology and we look forward to engaging in a successful project.

I hope this response is helpful. Please do not hesitate to contact me should you wish to discuss any of the points raised in this document.

Yours sincerely

Scott Mathieson
Regulation Director

1. Common DUoS Charging Methodology

1. One of the core aspects in delivering a common methodology is the choice of methodology itself. In this section we present some comments and analysis on the different methodologies being considered at the moment. Before going into the details of the analysis, however, we would like to make a point of clarification with regards to the notion of an LRIC model.

1.1. Notion of "LRIC"

2. We note the use of the term "LRIC" in the consultation to refer to the Bath University interpretation of the Long Run Incremental Cost principle. We would like to make the point that the LRIC principle is confined to the determination of the change in Present Value caused by an incremental change in demand (£/kVA).

3. The transformation of these costs into annual rates (£/kVA/annum) are not part of the standard form of the LRIC method. It is in this part of the derivation of the pricing formula where the "Bath/WPD LRIC" and the "G3" Forward Cost Pricing (FCP) approaches differ.

4. Appendix 1 gives more detail on this point[1]. We believe that these differences between the "Bath LRIC" and the G3 FCP correct the problems associated with the first, as will be explained in more detail below. However, the FCP method is also based on the LRIC principle, and in our view the FCP approach could be termed the "Corrected LRIC" method.

5. Despite some commonality in the terminology, the Bath method is quite different in its structure and its objectives from the telecommunications network cost modelling. In the Bath method, the calculations reflect the actual network structure (not a notional scorched-node or scorched-earth network), and the focus is on a small load increment (not on an increment defined as a whole network-wide service as in telecommunications modelling). There is, therefore, no industry-wide standard for the application of the LRIC method to the utilities sector.

1.2. EHV level models, demand

Bath LRIC method

6. The Bath LRIC formula presents a series of problems and shortcomings, which have been analysed and documented on numerous occasions by different industry participants and consultants. These problems arise from the derivation of the method, and can be summarised as follows:

   a) The pricing function behaves in a counter-intuitive way. The charge rates increase as the growth rate decreases and vice-versa, when the opposite should be expected. Lower growth rates would push the time for reinforcement further into the future and therefore one would expect the charges to be lower than with steeper growth rates.

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[1] This was presented as Appendix 3 of SPEN's modification proposal to implement the G3 FCP method, May 2008, available at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=419&refer=Networks/ElecDist/Policy/DistChrgMods

b) The use of an annuity factor over the life of the asset. We believe there is no economic justification for using the nominal asset life (40 years) as a fixed annuity period to recover the incremental costs (i.e., convert the £/kVA costs into £/kVA/year). Any annuity factor for cost recovery should be calculated for the payment period (or cost recovery period). Otherwise, the price signals that customers face, in present value terms, do not reflect the cost of reinforcement incurred, as they often will be paying these annual charges for less than the assumed life of 40 years.

c) The pricing formula can lead to excessive charges (deriving from excessive cost recovery) under conditions of low growth and high utilisation rates. This is a consequence of point (b) above and of using an approach where costs are determined per incremental kVA but then charged to the entire demand existing in the network. This clearly leads to over recovery.

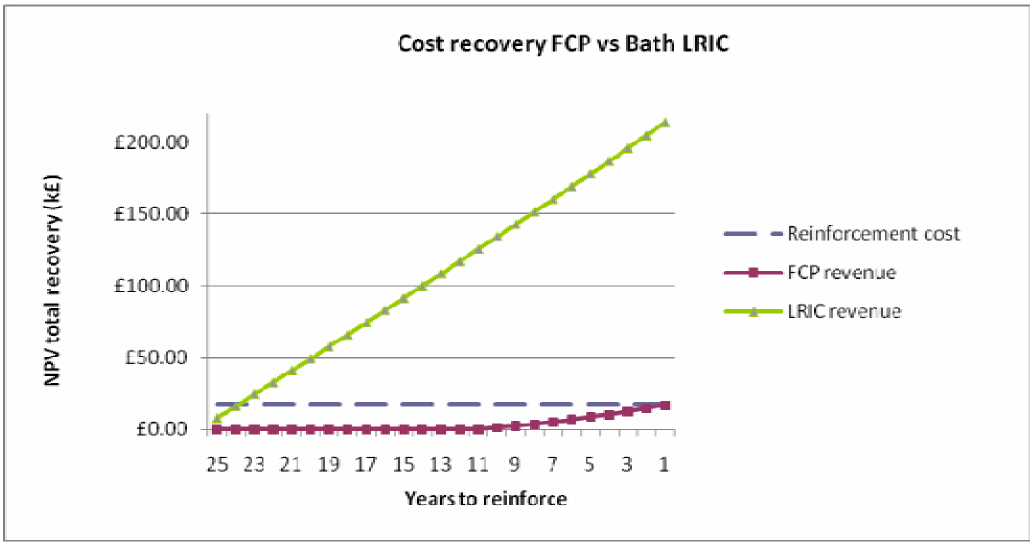
d) As growth rates tend to zero the charge rates tend to infinity. This is an extension of point (c) above, but it is of particular relevance in today's environment of high energy prices and where energy efficiency and environmental awareness are playing an important role in consumers' behaviour. Zero or even negative growth rates are no longer a theoretical scenario: recent growth rates are negative for the industry as a whole. The year on year changes are -2.4% for 2006/07 and -0.17% for 2007/08, as per the distribution units and losses percentage summary recently published by Ofgem[2]. We struggle to find an economic justification for cost signals tending to infinity as growth rates tend to zero. A charging function that cannot work under these conditions clearly cannot be considered an enduring solution.

e) The opposite of the problem mentioned in (c) above is also true: In situations where the growth rate is large the Bath LRIC formula would lead to under recovery of the costs. Although high growth rates are increasingly unlikely on average (for the reasons mentioned above), it could well be possible that in certain locations of the network a high growth rate is experienced. In order to appropriately model locational signals at the nodal level (whatever the "node" is chosen to be), the power flow analysis must use real growth rates at this node. It clearly is a key priority in choosing a common methodology that it can be applied in every single scenario that could present itself in the networks.

7. The following figure illustrates the point made in c) above. It shows the total cost achieved by the Bath LRIC method (and compares it with the G3 FCP method). This scenario assumes a reinforcement is due in 25 years at a cost of £100k at the time of reinforcement. The FCP method is designed to recover the NPV of the value of the reinforcement whereas the Bath LRIC method recovers roughly 12 times the NPV of the reinforcement at 1% growth.

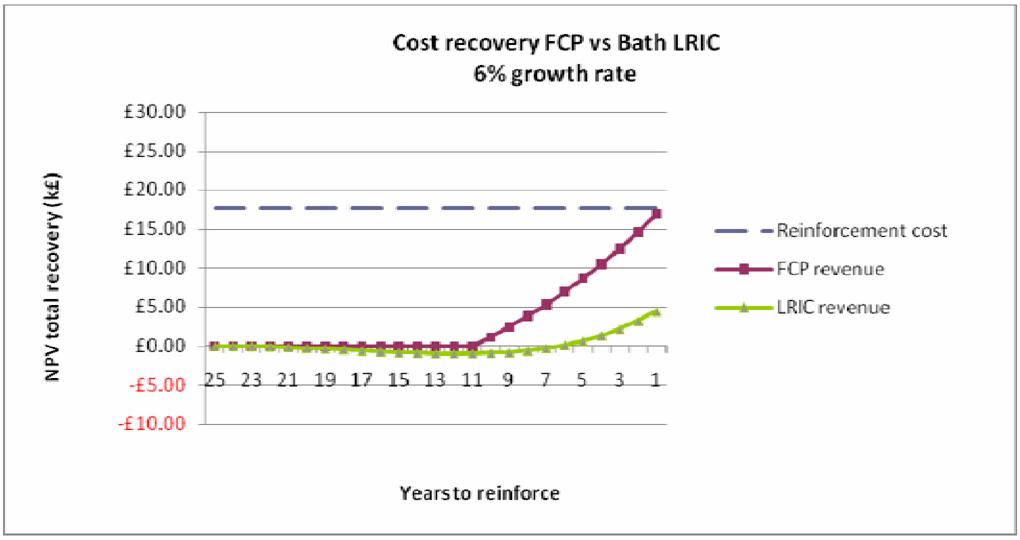
[2] Available at http://www.ofgem.gov.uk/Networks/ElecDist/Documents1/Electricity%20Distribution%20Units%20and%20Loss%20Percentages%20Summary.pdf

Figure 1. Cost recovery FCP vs Bath LRIC method, 1% growth



8. The total recovery under the Bath LRIC is very dependent on the growth rate. The following figure illustrates a scenario where this method under recovers the cost of reinforcement, under a high growth rate. This is the scenario detailed in point e) of paragraph 6 above.

Figure 2. Cost recovery FCP vs Bath LRIC method, 6% growth

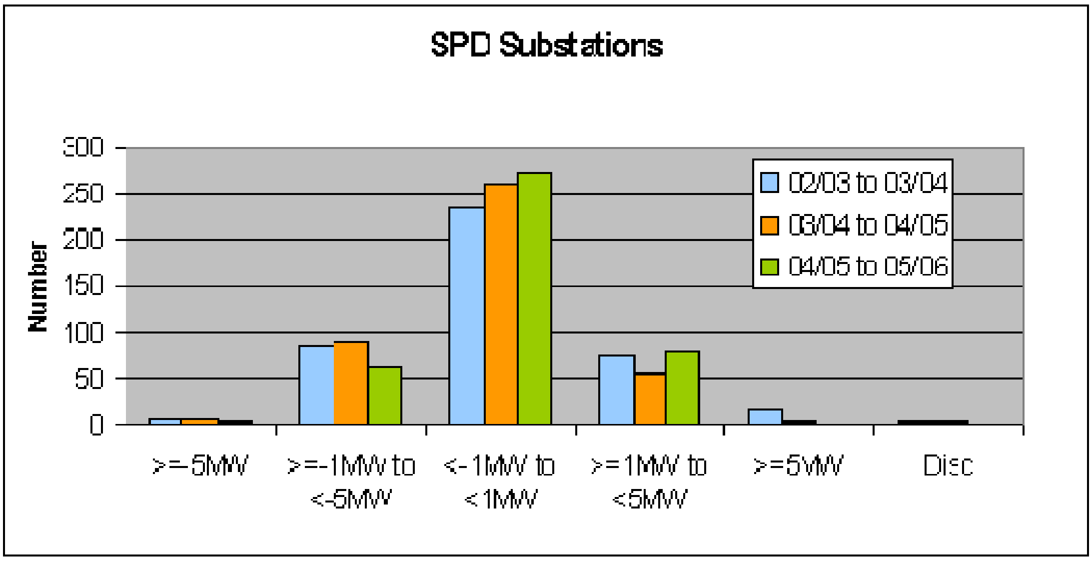


9. The dependency on the growth rate of the total recovery is further illustrated in Appendix 2. This appendix shows the backing numbers and a number of other scenarios additional to the two highlighted above. In fact, for this particular example the total recovery under the Bath

LRIC method is only “about right” at 4.5%, a number we found by trial and error. This kind of volatile methodology cannot be implemented across the industry as an enduring solution.

10. To further demonstrate the need for a methodology which adapts to all possible growth rate scenarios, and the point made in paragraph 6 (e) above about variations of load growth at the local level (as oppose to the network on average), the following figure shows the degree of load churn we have experienced at primary substation level in a period when total units consumed and network maximum demand have both been falling. The substations are grouped by the difference in demand from the previous year and this shows that typically 30 to 40% of our substations have experienced annual swings in demand in excess of 4% of substation firm capacity.

Figure 3. Load churn at primary substation level in SPD.



11. The problems mentioned above have been encountered by the two DNOs that have tried to implement (or have implemented, in the case of WPD) the Bath LRIC methodology. WPD have had to fix the growth rate used in their model at 1%, since only under that assumption it produces reasonable results. As a reference, note that SP Manweb currently has a wheeling agreement with WPD in the Aberystwyth area (132 kV connection). Before fixing the growth rate we received indications from WPD that the DUoS charges at that point would increase by 400% when implementing the Bath LRIC method. After the fix was done, the charges decreased by 20%. This illustrates the kind of swings that result from small variations to growth rates under the Bath method.

12. Even if the solution of fixing the growth rates to 1% sidesteps the problem of excessive charges, it cannot be seen neither as cost reflective nor as forward looking. The argument has been put forward that the use of 1% growth rate is justified on the grounds that this is the long run trend for growth. This does not correspond to the trend observed in all DNO areas: for

instance in our SP Distribution area the long run cost has historically been in the region of 0.7%.

13. Furthermore, we believe that a key input to a forward looking method is not the historical trend but the future trend. Few people would claim that the present growth rate will maintain into the future (due to the shifts in consumer behaviour mentioned above). Therefore this approach can only be described as “backward looking” and negates the principle of forward looking pricing.

14. EDF, on the other hand, have proposed the use of a “power flow scaling factor” which decreases the inputs (in terms of current demand) into the power flow model in order to avoid the excessive charges seen otherwise.

15. We cannot see any economic justification for the application of an arbitrary power flow scaling factor. As there is no real basis for the derivation of the factor itself (EDF propose to use 60% but do not explain the origin of that number), we believe that under this approach, as a common methodology, each DNO would be left with a trial and error process of varying the power scaling factor until obtaining “appropriate” results. Just what the level of these appropriate results would be is not clear, and this scenario is so subjective that it would be an easy target for endless challenges by customers and suppliers.

16. The use of a scaling factor also has the effect (as demonstrated in Ofgem’s consultation of the EDF method) of distorting the pricing signals, by changing the ranking order amongst nodes[3].

17. These two examples illustrate the potential problems that could be encountered by the DNOs if forced to adopt this Bath LRIC methodology. Furthermore, we believe that DNOs would be left exposed to the risk of challenges under a competition point of view, as it can be claimed that the Bath LRIC method create excessive charges that lead to abusive pricing. Reckon consulting has written a paper for the G3 analysing this problem.[4]

<u>FCP method</u>

18. The Forward Cost Pricing (FCP) approach, proposed by the G3 companies, does not present the issues exposed above. This method is also incremental and forward looking, but it has “corrected” the LRIC formula proposed by Bath to ensure that the total recovered via the charging function is equal to the change of NPV brought by the increment in demand (or generation). This solves the issue of excessive charging whilst keeping with the principle of forward looking pricing.

19. The FCP pricing formula behaves in a logical way and has a set of desirable qualities which can be summarised as follows:

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[3] Available at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=457&refer=Networks/ElecDist/Policy/DistChrgMods

[4] Available at http://www.scottishpower.com/StructureOfChargesProjectG3.htm

a) Linear variation with reinforcement costs. If the reinforcement costs doubles then the FCP rate should double, as there needs to be a stronger pricing signal for the more expensive reinforcements, to promote more efficient use of the network.
b) The FCP rate should increase as reinforcement approaches, reflecting the fact that the present value of the cost of reinforcement increases and that there is less spare capacity at that location. This means that the charge rate should be higher if expected demand growth meant that the network necessitates reinforcement, say, three years in the future than if it necessitated reinforcement, say, eight years in the future.
c) For a given demand, the FCP rate should increase with increasing growth rate to give stronger signals.
d) As the growth rate tends to zero the FCP rate also tend to zero.
e) Increasing the discount rate gives higher charge rates at closer times prior to reinforcement.

20. Due to the problems with the Bath LRIC method explained in paragraphs 6 to 13 above, the FCP pricing function is an improvement on a so-called "pure incremental" cost pricing approach. Frontier economics has concluded[5] that this departure is needed to accommodate the "indivisibility" characteristics of network reinforcements. Reinforcement solutions are normally given by "standard sized" pieces of equipment. This is characteristic of natural monopolies, where the economies of scale dictate that the marginal cost of reinforcement is usually higher than the total costs.

21. One of the criticisms that have been put to the "FCP" method is that it gives "weak" pricing signals. We believe, however, that this is an unfounded observation. It is not known what level of pricing signal, if any, would cause customers to modify their behaviour in a way that would lead to a more efficient use of the network. Therefore the identification of "weak" or "strong" signals seems to be based solely on one method compared to the other (not on any measure of price elasticity). This certainly has no economic grounds.

22. The Bath LRIC does give higher, but also incorrect signals. This is due to the erroneous application of the incremental concept to indivisible capital assets. As said before, these charges can be deemed as excessive, especially when they come way in advance of hypothetical charges. They are not efficient either, because as a result of the stronger signals some customers could make the inefficient decision of a less preferred behaviour (be it a less preferred location or pattern of utilisation) only to avoid DUoS costs that cannot be economically justified by reference to cost recovery of capital expenditure requirements[6].

23. Another of the criticism put forward for the FCP is that it only takes into account reinforcement solutions which occur in a 10 years horizon. However we would like to make the point that this decision was taken by the G3 group as it was felt to be the best balance between forward looking and certainty. There is a need to strike a balance between allowing enough time ahead of the pricing signals (to make it possible for the customers to react) and

[5] Report available at http://www.scottishpower.com/StructureOfChargesProjectG3.htm
[6] For more detail on this point, refer to the Reckon Consulting report available at http://www.scottishpower.com/StructureOfChargesProjectG3.htm, which documents a comparative analysis between the Bath LRIC approach and the G3 FCP one.

using reliable data. Reinforcements beyond a time horizon of ten years were thought to be too speculative to be included in realistic forward cost estimates.

24. However, the 10 years assumption is not hardcoded in the model in any way. If it is felt, by the common methodology implementation group, that a horizon of, say, 20 years is more appropriate (to make it match, say, the regulatory depreciation period) it would be an easy task to adapt the model and the analysis to this new cost recovery period.

25. Figures 1 and 2 presented above, as well as appendix 2 shows a comparison of the results obtained with the Bath LRIC method vs the FCP LRIC method.

1.3. Generation

<u>Bath method</u>

26. The Bath LRIC method for treatment of generation does not adequately model generation reinforcement costs, as it takes no account of fault level and reverse power flow, which are the main cost drivers for generation connections.

27. We believe there is no justification for a "symmetrical" treatment, in terms of cost pricing formulae and modelling, for generation and demand, since the cost drivers for these two types of customers are fundamentally different and the growth characteristics are also different. The evidence to date for generation is that it is "lumpy" in nature, and we see no reasoned justification to believe that this will shift to a uniform, "smooth" growth rate in the near future.

<u>FCP method</u>

28. We believe the analysis proposed by the G3 is the most cost reflective and accurate of all of the analysis proposed to date. It performs an extensive assessment of EHV and HV generation costs by using actual transformer and generation data. This information is also transparent, as it is contained in publicly available documents.

29. The FCP approach is the only method to correctly identify and value generation cost drivers. As said previously, the evidence to date is that the generation growth is "lumpy". Therefore the test size approach proposed by the G3 is the most appropriate one.

30. We consider the advantages of properly modelling fault levels and reverse flow capacity to outweigh by a great margin the possible need for improvement of the generation model as a result of a shift in the pattern of generation growth observed in the network. This can be undertaken after initial implementation in 2010, as we believe that such shift is highly unlikely to occur in the near future.

31. It is also important to clarify at this point that the proposed "G3" approach recognises benefits from generation *over and above* those prescribed by P2/6 rules. The P2/6 recommendations do not go as far as recognising contribution in all of the voltage levels above the point of connection, whereas our pricing decision was to recognise these benefits up to the highest EHV point. The use of the P2/6 "F" factor, in this case, is a proxy for the coincidence factors

which have been discussed in different industry forums recently, as we believe the two concepts (P2/6 security of supply and coincidence factors deferring demand-triggered reinforcement needs in the higher voltage levels) are related to the probability that the generation will be generating output, represented by an "F" (probability) factor.

1.4. Nodal and zonal approach

32. We note that the consultation document makes a differentiation between the nodal approach prescribed by the Bath methodology and the Network Group approach proposed by the G3 FCP method. One of the issues we have encountered with this area is the lack of transparency in the concept of "node".

Bath method

33. We believe that the definition of "node" in the Bath approach is not entirely clear. The published version of the Bath LRIC states that these are "network components that support a nodal power injection or withdrawal of power", which does little to helping understand what physical assets of the networks are being analysed.

34. With relation to the AC load flow analysis, our understanding of the Bath method is that it carries out a full contingency analysis at the nodal level, but then it derives a sensitivity factor from the normal operating conditions (possibly to reduce computing requirements). This would appear to nullify the perceived advantages of the nodal analysis.

FCP method

35. The G3 FCP modification report defined clearly what a Network Group is: "A practical group defined by physical, operational and technical boundaries and includes all voltage levels above HV (11kV). Network Groups are defined as the network normally supplied from a Grid Supply Point (GSP) or a Bulk Supply Point (BSP). In situations where GSP/BSPs are operated in parallel, the parallel GSP/BSP groups are considered as one Network Group[7]".

36. On consulting with our own planning engineers, they have expressed uncertainty towards the concept of node. Whereas the definition of Network Groups is contained in the P2/6 recommendations and used routinely by design engineers to assess security of supply, there can be a number of different interpretations to the concept of "node".

37. The FCP implementation of the appropriate level of nodal disaggregation currently produces 128 different locational "nodal" prices in total in the two licensees' areas. It is our view that this level of disaggregation is the right balance between complexity and cost reflectivity.

38. It is the view of our engineers that the most detailed nodal analysis can drop to is the the 11kV primary substations. The power flow analysis performed for the FCP inputs already produces these results. Here, the load is increased uniformly across the primary substation points to evaluate reinforcement needs. This better reflects the load behaviour of the network, i.e., it is

[7] See SPEN's modification proposal for implementation of the FCP method in the SPD and SPM licensed areas, available at http://www.scottishpower.com/StructureOfChargesProjectG3.htm

more cost reflective especially for interconnected, or “meshed” networks such as SP Manweb. These levels are usually interconnected, therefore they do not “move” independently from each other.

39. Nevertheless, it is possible to perform the analysis at each 11kV primary substation in isolation. This however would only result in spurious accuracy since, as said before, these “nodes” do not operate in isolation.

40. We also believe that to perform a true forward looking analysis of reinforcement needs, local growth rates should be used. This information is not often easily available at the 11 kV primary level, but it is available at the Network Group level (it is normally published in the licensees’ Long Term Development Statements). This is another reason why the G3 consider that it is more appropriate to perform the analysis at the Network Group level.

41. In summary, it is possible to do a more detailed (albeit not necessarily more accurate) “nodal” power flow analysis under the FCP approach.

1.5. HV/LV demand models

DRM

42. We note that the consultation lists as a “pro” of the DRM approach the fact that it has been in use since the 1980s. However this, on itself, cannot be an advantage. A major deficiency of the DRM is that it does not deal appropriately with generation. This was identified by Ofgem in their 2005 Structure of Charges paper[8].

43. The perception of the DRM as an “industry standard” is a misconception, and probably at present there are as many versions and interpretations of the DRM approach as there are DNOs (with the exception of the two SPEN licensees, SP Distribution and SP Manweb, which do not use the DRM). We do not agree, therefore, that application of the DRM as part of a common methodology would maintain the status quo for lower voltage charging, since the effort required for harmonising the approaches (if done properly) would almost be equivalent to a totally new methodology, in terms of tariff disturbances, cost inputs, etc.

44. Another disadvantage of the DRM approach is the lack of transparency in the inputs to the model. There is no standard at present on how the cost information will be sourced or verified, and it is not clear to us how we can comply with the principle of transparency without using historical data which is published and audited.

“Historic” RRP cost data

45. This method, proposed by the G3, uses a set of historical and transparent data to derive a forward view of costs. We believe that this approach is more representative of costs than the DRM approach.

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[8] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/10763-13505.pdf

46. In terms of flexibility, it is possible to adapt this approach to use business forecast data instead of historical RRP data, which is not possible under the DRM approach. For example, we have recently completed and submitted to Ofgem data related to the Financial Business Forecast Questionnaire, for the DPCR5. This data could provide an appropriate input under this methodology. The advantages of this option was put forward to the G3 by Ralph Turvey as part of the Frontier consultancy work.

47. The consultation highlights the potential for fluctuations between yearly RRP data leading to volatility. This has been dealt with by proposing an approach which uses trends to forecast future costs, taking into account several years (not only the previous one). It is not clear to us either how this would be different to the DRM approach: any variations to the inputs on the DRM would cause volatility, with the difference in this case that the inputs would be subjective and not apt for verification and challenges.

1.6. Conclusion

48. In summary, the FCP model should be taken as the chosen methodology as it strikes the right balance between the applicable objectives and relevant principles, in particular:

a) Has a pricing function which produces logical results and has a set of desirable properties from the pricing point of view. The pricing function is based on the LRIC principle (it can be termed a “corrected LRIC), and it is both forward looking and incremental.
b) It does not have the risks of excessive charging which can arise from the Bath LRIC approach.
c) It works on every growth scenario, including very low and negative growth rates or even very high growth rates which could be experienced in certain areas of the networks.
d) It recognises in the appropriate manner the costs and benefits of demand and generation, modelling the cost drivers appropriately (including fault level and reverse power capacity costs for generation).
e) It is cost reflective as it uses Network group contingency analysis to determine reinforcement costs. It also uses granular, local, growth rates, which are published in the LTDS, to derive locational charges.
f) It makes extensive use of publicly available information such as the LTDS and the RRP.
g) It does not carry the risk of allegation of abusive (or excessive) pricing, unlike the next alternative – the Bath LRIC.
h) It already is a common methodology, tested and implemented in 6 DNO areas and with the capability of adapting to all existing network conditions.
i) It relies on network analysis at the Network Group level, which strikes the right balance of cost reflectivity and complexity.
j) Able to extend the existing nodal charging to lower voltage levels if this is considered necessary, although we believe the current level of nodal charging provides the most effective balance of cost and benefit.

2. Costs and cost recovery

49. We note the two indications of costs made in the consultation document, and are puzzled by the differences in costs and benefits quoted for suppliers and DNOs.

50. We note that the number which apparently has been quoted as the implementation costs for DNOs are in the region of £7m in total, whereas saving for suppliers are “multiple millions of pounds” (although there is no indication on the magnitude of this number). We doubt the veracity of the suppliers’ estimation of large savings arising from the implementation of a common charging methodology, and question whether this is rather the result of a misconception on what will be delivered by this project. See section 5 of this document for more detail.

51. We believe that the quoted implementation costs were provided to Ofgem after a specific request at a DCMF meeting, and are sure that they are very rough estimations based on the knowledge available at the time.

52. We believe it is extremely difficult to indicate with any accuracy the cost associated with a common methodology implementation without knowing in detail what will be the form and extent of this commonality.

53. The level and nature of the power flow required, i.e. nodal vs zonal “network group” and full contingency analysis vs “scenario analysis” under normal operating conditions would generate different engineering (or consultant) costs for each DNO.

54. Another area to consider in the costs is the tariff structure: if the common methodology extends to the tariff structure in a way that it impacts the existing billing systems it would again have an impact which is necessary to take into consideration

55. It is important to have a full impact assessment on the effects and costs on each DNO <u>after</u> the decision on which common methodology is known with the greater possible level of detail. This information will allow the licensee to evaluate risks and benefits of the common licence modification before making a decision on whether to accept the licence modification.

56. Finally there is the issue of governance. Any ongoing governance arrangements will have associated costs.

57. There needs to be clarity with regards to the funding of these costs (for instance, whether there will be a price control allowance for these costs or if any governing body will be funded by membership).

3. Governance arrangements

58. We believe that it is inappropriate to allow suppliers, generators or other stakeholders other than the DNOs themselves to have voting rights in the modification proposals for DUoS charging. Unlike DNOs, suppliers are not necessarily “cash flow neutral” in terms of DUoS charges, as their level of interest on one outcome or the other will depend on their customer portfolio and the structure of the contracts they have in place with customers – this is, the capacity and speed they have to “pass through” DUoS costs into the final retail tariffs. Therefore it could be argued that suppliers have vested interests in DUoS tariffs as much as generators and IDNOs do.

59. We think that there needs to be a forum for proposals and concerns raised by other stakeholders, which should be duly examined and considered by the DNOs, without undermining the capacity to decide when to bring forward a modification to the common methodology. We think that the existing DCMF could provide the grounds for such forum.

60. In terms of formal governance, the best option is something similar to the Distribution Code, where only DNOs have voting rights on what modifications to bring forward for consideration by the Authority. Otherwise we believe that the potential number of modifications brought forward could escalate to a point where it would not be the most efficient use of regulatory resources.

4. Timetables

61. We are convinced that the timelines allowed for this implementation are extremely challenging. We would request to Ofgem that the decision, in a form as detailed as possible, on what methodology has been chosen needs to be known sooner rather than later (we propose mid September).

62. It is important to know the extent of the modification (will it dictate the power flow to use, tariff structure, etc), so that the DNOs have a chance to perform a full impact assessment and consider this when responding to the statutory consultation on the licence modification and considering accepting the proposed change.

5. Cost savings expectations from suppliers

63. Finally, we consider it worthwhile to make a point of clarification. We notice that some suppliers have signalled that a common methodology would decrease charging uncertainty and "seemingly arbitrary" charging differences amongst DNO areas. It is important to keep in mind that a common charging methodology does not mean common tariffs in terms of tariff structure (fixed, unit, and capacity charges) unless specifically prescribed by the methodology. It certainly does not eliminates difference in levels of charges across DNO areas (which are mostly due to differences in price control arrangements). Also, a common methodology does not necessarily decrease price volatility (in fact, it can be argued that a forward looking approach does in fact increase volatility and fluctuations as reinforcements fall in or out of the pricing analysis).

Appendix 1. 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:

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

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:

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

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.

Appendix 2. Comparison of the Bath LRIC and FCP method.

The following spreadsheets give a comparison of the Bath LRIC and the FCP LRIC method. It is based on a base scenario where a reinforcement is due in 25 years (in year 26 of the analysis) at different growth rates.

The first case shows a growth rate of 1%. In this case the Bath LRIC recovers roughly 12 times the NPV of the reinforcement. This is the full backing data for the graph shown in Figure 1 of the main body of the response.

The second case is for a growth rate of 6%, as presented in the graph shown in Figure 2 of the main response. In this case the Bath LRIC only recovers about a quarter of the reinforcement cost.

The third case is the only one where both methods recover an amount which is "about right" (i.e., close to the NPV of the recovery). This occurs at 4.5% in this example, a number which was found by trial and error. We believe the actual growth rate where Bath LRIC charges are "about right" is different for each scenario.

Cases four and five illustrate the situation for lower growth (which, as explained in the main body of the response, is the situation where all DNOs are at the moment, on average). In case four, 0.5% growth, the recovery is 25 times greater than the reinforcement cost.

Case five is possibly an extreme (but not impossible) scenario of growth rate being 0.2%. In this case the recovery is almost 70 times greater than reinforcement cost. The vertical axis on the graph has had to be expanded to an extent that it is not possible to observe the FCP or the actual recovery curve.

In all cases the FCP recovers an amount practically identical to the reinforcement cost.

The backing spreadsheet used for this analysis is available to interested parties on request to commercial@sppowersystems.com

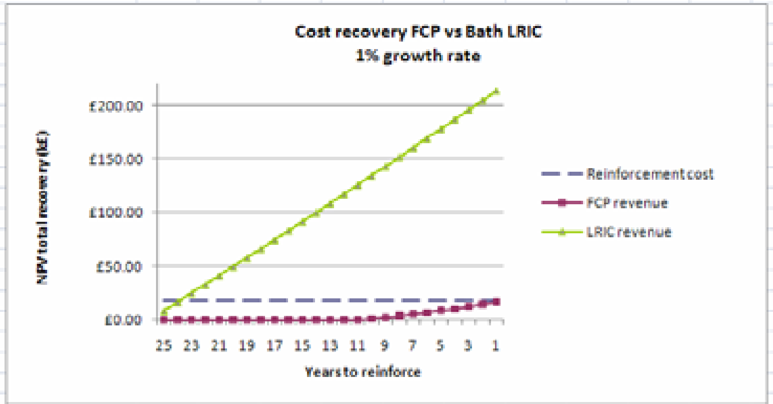
Case 1. 1% growth

FCP/ Bath LRIC COMPARISON

Reinforcement Cost	£100	k
Discount Rate	6.90%	
FCP Cost Recovery Period	10	years
LRIC Annuity Period	40	years

	Years to reinforce																									
	25	24	23	22	21	20	19	18	17	16	15	14	13	12	11	10	9	8	7	6	5	4	3	2	1	0
Demand (kVA)	7,788	7,866	7,945	8,025	8,106	8,187	8,270	8,353	8,437	8,521	8,607	8,694	8,781	8,869	8,958	9,048	9,139	9,231	9,324	9,418	9,512	9,608	9,704	9,802	9,900	10,000
Reinforcement Cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	£100
Capacity (kVA)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Growth Rate	**1.0%**																									
FCP																										
FCP Charge/kVA	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.4	£0.4	£0.5	£0.6	£0.6	£0.7	£0.8	£0.9	£1.1	£1.2	£1.4
FCP Revenue (£k)	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£3.5	£4.0	£4.6	£5.3	£6.0	£6.9	£8.0	£9.2	£10.5	£12.1	£13.8
NPV FCP Revenue, cumulative (£k)	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£1.2	£2.5	£3.9	£5.3	£6.9	£8.7	£10.5	£12.5	£14.6	£16.9	£19.3
LRIC																										
New Years to reinforce (+100kVA)	23.8	22.9	21.9	20.9	19.9	18.9	17.9	16.9	15.9	14.9	13.9	12.9	11.9	10.9	9.9	8.9	8.0	7.0	6.0	5.0	4.0	3.0	2.0	1.0	0.0	0.0
LRIC Charge/ kVA	£1.1	£1.2	£1.3	£1.3	£1.4	£1.5	£1.6	£1.7	£1.8	£1.9	£2.0	£2.2	£2.3	£2.5	£2.6	£2.8	£2.9	£3.1	£3.3	£3.5	£3.8	£4.0	£4.3	£4.5	£4.8	£0.0
LRIC Revenue (k)	£8.7	£9.4	£10.1	£10.8	£11.6	£12.4	£13.3	£14.3	£15.3	£16.4	£17.6	£18.9	£20.3	£21.8	£23.4	£25.1	£26.9	£28.9	£31.0	£33.3	£35.8	£38.4	£41.3	£44.3	£47.4	£0.0
NPV LRIC Revenue (cumulative) (£k)	£8.2	£16.4	£24.6	£32.9	£41.2	£49.5	£57.8	£66.2	£74.6	£83.0	£91.5	£100.0	£108.5	£117.0	£125.6	£134.3	£142.9	£151.6	£160.4	£169.2	£178.0	£186.8	£195.7	£204.7	£213.6	£213.6

NPV Cost	£17.64	k
NPV FCP Revenue	£19.29	k
NPV LRIC Revenue	£213.60	k



Case 2. 6% growth

SP ENERGY NETWORKS

FCP/ Bath LRIC COMPARISON

Reinforcement Cost	£100	k
Discount Rate	6.90%	
FCP Cost Recovery Period	10	years
LRIC Annuity Period	40	years

	Years to reinforce																									
	25	24	23	22	21	20	19	18	17	16	15	14	13	12	11	10	9	8	7	6	5	4	3	2	1	0
Demand (kVA)	2,231	2,369	2,516	2,671	2,837	3,012	3,198	3,396	3,606	3,829	4,066	4,317	4,584	4,868	5,169	5,488	5,827	6,188	6,570	6,977	7,408	7,866	8,353	8,869	9,418	10,000
Reinforcement Cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	£100
Capacity (kVA)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000

Growth Rate	**6.0%**

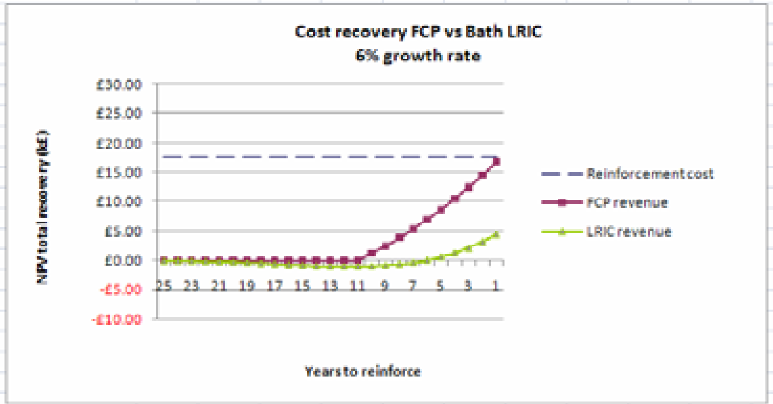
FCP

FCP Charge/kVA	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.6	£0.7	£0.7	£0.8	£0.9	£0.9	£1.0	£1.1	£1.2	£1.3	£1.4
FCP Revenue (£k)	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£3.5	£4.0	£4.6	£5.3	£6.0	£6.9	£8.0	£9.2	£10.5	£12.1	£13.8
NPV FCP Revenue, cumulative (£k)	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£1.2	£2.5	£3.9	£5.3	£6.9	£8.7	£10.5	£12.5	£14.6	£16.9	£19.3

LRIC

New Years to reinforce (+100kVA)	25.0	24.0	23.0	22.0	21.0	20.0	19.0	18.0	17.0	16.0	15.0	14.0	13.0	12.0	11.0	10.0	9.0	8.0	6.9	5.9	4.9	3.9	2.9	1.9	0.8	0.0
LRIC Charge/ kVA	£0.0	-£0.0	-£0.0	-£0.0	-£0.0	-£0.0	-£0.1	-£0.1	-£0.1	-£0.1	-£0.1	-£0.0	-£0.0	-£0.0	£0.0	£0.0	£0.1	£0.1	£0.2	£0.2	£0.3	£0.4	£0.5	£0.6	£0.7	£0.0
LRIC Revenue (k)	£0.0	-£0.0	-£0.0	-£0.1	-£0.1	-£0.1	-£0.2	-£0.2	-£0.2	-£0.2	-£0.2	-£0.2	-£0.2	-£0.1	£0.0	£0.2	£0.4	£0.7	£1.0	£1.5	£2.1	£2.9	£3.9	£5.1	£6.6	£0.0
NPV LRIC Revenue (cumulative) (£k)	£0.0	£0.0	£0.0	-£0.1	-£0.1	-£0.2	-£0.3	-£0.4	-£0.6	-£0.7	-£0.8	-£0.9	-£0.9	-£0.9	-£0.9	-£0.9	-£0.8	-£0.5	-£0.3	£0.1	£0.7	£1.4	£2.2	£3.2	£4.5	£4.5

NPV Cost	£17.64 k	
NPV FCP Revenue	£19.29 k	
NPV LRIC Revenue	£4.48 k	0.2539



Case 3. 4.5% growth

FCP/ Bath LRIC COMPARISON

Reinforcement Cost	£100	k
Discount Rate	6.90%	
FCP Cost Recovery Period	10	years
LRIC Annuity Period	40	years

Years to reinforce

	25	24	23	22	21	20	19	18	17	16	15	14	13
Demand (kVA)	3,247	3,396	3,552	3,716	3,887	4,066	4,253	4,449	4,653	4,868	5,092	5,326	5,571
Reinforcement Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity (kVA)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000

	12	11	10	9	8	7	6	5	4	3	2	1	0
Demand (kVA)	5,827	6,096	6,376	6,670	6,977	7,298	7,634	7,985	8,353	8,737	9,139	9,560	10,000
Reinforcement Cost	0	0	0	0	0	0	0	0	0	0	0	0	£100
Capacity (kVA)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000

Growth Rate	**4.5%**

FCP

	25	24	23	22	21	20	19	18	17	16	15	14	13
FCP Charge/kVA	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0
FCP Revenue (£k)	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0
NPV FCP Revenue, cumulative (£k)	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0

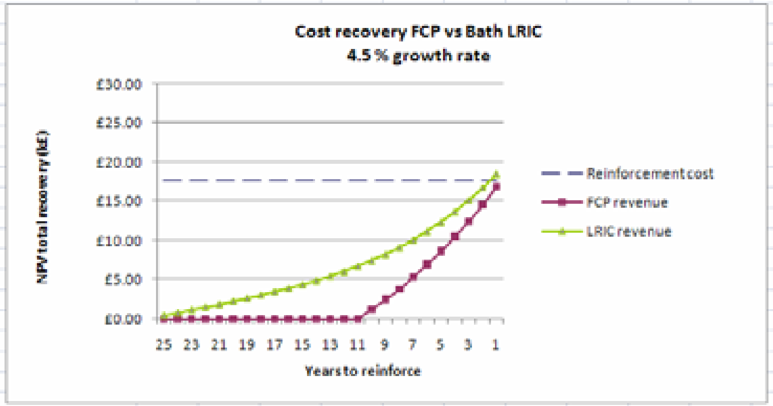
	12	11	10	9	8	7	6	5	4	3	2	1	0
FCP Charge/kVA	£0.0	£0.0	£0.5	£0.6	£0.7	£0.7	£0.8	£0.9	£1.0	£1.0	£1.1	£1.3	£1.4
FCP Revenue (£k)	£0.0	£0.0	£3.5	£4.0	£4.6	£5.3	£6.0	£6.9	£8.0	£9.2	£10.5	£12.1	£13.8
NPV FCP Revenue, cumulative (£k)	£0.0	£0.0	£1.2	£2.5	£3.9	£5.3	£6.9	£8.7	£10.5	£12.5	£14.6	£16.9	£19.3

LRIC

	25	24	23	22	21	20	19	18	17	16	15	14	13
New Years to reinforce (+100kVA)	24.9	23.9	22.9	21.9	20.9	19.9	18.9	17.9	16.9	15.9	14.9	13.9	12.9
LRIC Charge/ kVA	£0.1	£0.1	£0.1	£0.1	£0.1	£0.1	£0.1	£0.2	£0.2	£0.2	£0.2	£0.2	£0.2
LRIC Revenue (k)	£0.4	£0.4	£0.4	£0.5	£0.5	£0.6	£0.6	£0.7	£0.8	£0.9	£1.0	£1.1	£1.3
NPV LRIC Revenue (cumulative) (£k)	£0.4	£0.7	£1.1	£1.5	£1.8	£2.2	£2.6	£3.0	£3.4	£3.9	£4.3	£4.9	£5.4

	12	11	10	9	8	7	6	5	4	3	2	1	0
New Years to reinforce (+100kVA)	11.9	10.9	9.9	8.9	7.9	6.8	5.8	4.8	3.8	2.8	1.8	0.8	0.0
LRIC Charge/ kVA	£0.3	£0.3	£0.3	£0.4	£0.4	£0.5	£0.5	£0.6	£0.7	£0.8	£0.9	£1.0	£0.0
LRIC Revenue (k)	£1.5	£1.8	£2.1	£2.5	£2.9	£3.5	£4.1	£4.9	£5.8	£6.8	£8.1	£9.5	£0.0
NPV LRIC Revenue (cumulative) (£k)	£6.0	£6.7	£7.4	£8.2	£9.1	£10.1	£11.2	£12.4	£13.7	£15.2	£16.8	£18.6	£18.6

NPV Cost	£17.64 k
NPV FCP Revenue	£19.29 k
NPV LRIC Revenue	£18.58 k



Case 4. 0.5% growth.

FCP/ Bath LRIC COMPARISON

Reinforcement Cost	£100	k
Discount Rate	6.90%	
FCP Cost Recovery Period	10	years
LRIC Annuity Period	40	years

	Years to reinforce																									
	25	24	23	22	21	20	19	18	17	16	15	14	13	12	11	10	9	8	7	6	5	4	3	2	1	0
Demand (kVA)	8,825	8,869	8,914	8,958	9,003	9,048	9,094	9,139	9,185	9,231	9,277	9,324	9,371	9,418	9,465	9,512	9,560	9,608	9,656	9,704	9,753	9,802	9,851	9,900	9,950	10,000
Reinforcement Cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	£100
Capacity (kVA)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000

Growth Rate	**0.5%**

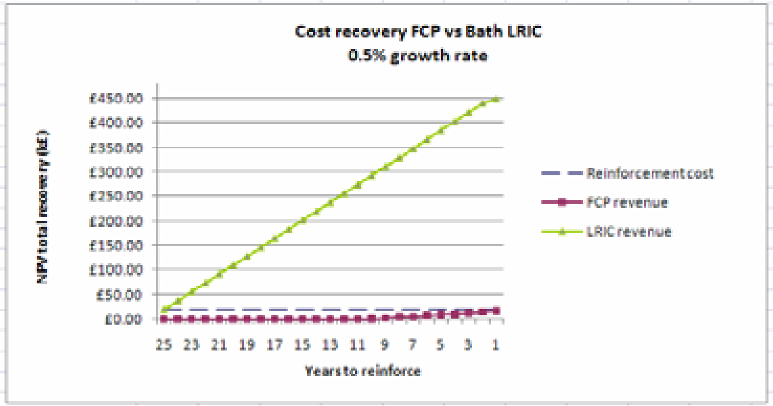
FCP

FCP Charge/kVA	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.4	£0.4	£0.5	£0.5	£0.6	£0.7	£0.8	£0.9	£1.1	£1.2	£1.4
FCP Revenue (£k)	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£3.5	£4.0	£4.6	£5.3	£6.0	£6.9	£8.0	£9.2	£10.5	£12.1	£13.8
NPV FCP Revenue, cumulative (£k)	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£1.2	£2.5	£3.9	£5.3	£6.9	£8.7	£10.5	£12.5	£14.6	£16.9	£19.3

LRIC

New Years to reinforce (+100kVA)	22.8	21.8	20.8	19.8	18.8	17.8	16.9	15.9	14.9	13.9	12.9	11.9	10.9	9.9	8.9	7.9	6.9	5.9	5.0	4.0	3.0	2.0	1.0	0.0	0.0	0.0
LRIC Charge/ kVA	£2.2	£2.3	£2.5	£2.7	£2.8	£3.0	£3.2	£3.4	£3.6	£3.9	£4.1	£4.4	£4.7	£5.0	£5.3	£5.6	£6.0	£6.4	£6.8	£7.2	£7.7	£8.2	£8.7	£9.3	£4.8	£0.0
LRIC Revenue (k)	£19.5	£20.8	£22.3	£23.9	£25.5	£27.3	£29.2	£31.2	£33.4	£35.8	£38.3	£40.9	£43.8	£46.9	£50.1	£53.6	£57.4	£61.4	£65.7	£70.3	£75.2	£80.5	£86.2	£91.7	£47.6	£0.0
NPV LRIC Revenue (cumulative) (£k)	£18.2	£36.5	£54.7	£73.0	£91.3	£109.5	£127.8	£146.2	£164.5	£182.9	£201.2	£219.6	£238.0	£256.4	£274.8	£293.3	£311.8	£330.2	£348.7	£367.2	£385.8	£404.3	£422.9	£441.4	£450.4	£450.4

NPV Cost	£17.64	k	
NPV FCP Revenue	£19.29	k	
NPV LRIC Revenue	£450.37	k	25.526



SP ENERGY NETWORKS

Case 5. 0.2% Growth

FCP/ Bath LRIC COMPARISON

Reinforcement Cost	£100	k
Discount Rate	6.90%	
FCP Cost Recovery Period	10	years
LRIC Annuity Period	40	years

	Years to reinforce												
	25	24	23	22	21	20	19	18	17	16	15	14	13
Demand (kVA)	9,512	9,531	9,550	9,570	9,589	9,608	9,627	9,646	9,666	9,685	9,704	9,724	9,743
Reinforcement Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity (kVA)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000

	12	11	10	9	8	7	6	5	4	3	2	1	0
Demand (kVA)	9,763	9,782	9,802	9,822	9,841	9,861	9,881	9,900	9,920	9,940	9,960	9,980	10,000
Reinforcement Cost	0	0	0	0	0	0	0	0	0	0	0	0	£100
Capacity (kVA)	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000

Growth Rate	0.2%

FCP

	25	24	23	22	21	20	19	18	17	16	15	14	13
FCP Charge/kVA	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0
FCP Revenue (£k)	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0
NPV FCP Revenue, cumulative (£k)	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0	£0.0

	12	11	10	9	8	7	6	5	4	3	2	1	0
FCP Charge/kVA	£0.0	£0.0	£0.4	£0.4	£0.5	£0.5	£0.6	£0.7	£0.8	£0.9	£1.1	£1.2	£1.4
FCP Revenue (£k)	£0.0	£0.0	£3.5	£4.0	£4.6	£5.3	£6.0	£6.9	£8.0	£9.2	£10.5	£12.1	£13.8
NPV FCP Revenue, cumulative (£k)	£0.0	£0.0	£1.2	£2.5	£3.9	£5.3	£6.9	£8.7	£10.5	£12.5	£14.6	£16.9	£19.3

LRIC

	25	24	23	22	21	20	19	18	17	16	15	14	13
New Years to reinforce (+100kVA)	19.8	18.8	17.8	16.8	15.8	14.8	13.8	12.9	11.9	10.9	9.9	8.9	7.9
LRIC Charge/ kVA	£5.8	£6.2	£6.6	£7.1	£7.5	£8.0	£8.6	£9.1	£9.7	£10.4	£11.1	£11.8	£12.6
LRIC Revenue (k)	£55.3	£59.1	£63.2	£67.5	£72.2	£77.1	£82.4	£88.1	£94.2	£100.7	£107.6	£115.0	£122.9
NPV LRIC Revenue (cumulative) (£k)	£51.7	£103.4	£155.1	£206.8	£258.5	£310.2	£361.9	£413.5	£465.2	£516.8	£568.5	£620.1	£671.8

	12	11	10	9	8	7	6	5	4	3	2	1	0
New Years to reinforce (+100kVA)	6.9	5.9	4.9	3.9	2.9	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
LRIC Charge/ kVA	£13.5	£14.4	£15.3	£16.3	£17.4	£18.6	£19.8	£21.0	£17.4	£13.4	£9.3	£4.8	£0.0
LRIC Revenue (k)	£131.4	£140.4	£150.1	£160.5	£171.5	£183.3	£195.9	£208.2	£172.3	£133.7	£92.3	£47.8	£0.0
NPV LRIC Revenue (cumulative) (£k)	£723.4	£775.0	£826.6	£878.2	£929.8	£981.4	£1,033.0	£1,084.3	£1,124.0	£1,152.8	£1,171.4	£1,180.4	£1,180.4

NPV Cost	£17.64	k	
NPV FCP Revenue	£19.29	k	
NPV LRIC Revenue	£1,180.44	k	66.906