To generators, distributors, suppliers, customers and other interested parties

Promoting choice and value for all customers

Ref: 95/08
Direct Dial: 020 7901 7194
Email: rachel.fletcher@ofgem.gov.uk

2 July 2008

Dear colleague,

Consultation and impact assessment on EDF's proposal (UoS Mod 21) to introduce a LRIC[1]-based UoS charging method at EHV[2] and a revised HV/LV[3] generator charging methodology for its south-east power network (SPN)

As of 1 April 2005, Electricity Distribution Network Operators (DNOs) have licence obligations[4] to have in place three charging statements: i) a statement of its use of system (UoS) charging methodology, ii) a statement of its UoS charges, and iii) a statement of its connection charging methodology. The statement of UoS charging methodology outlines the method by which DNOs calculate their UoS charges.

In accordance with standard licence condition (SLC) 13.2, DNOs are required to keep their charging methodologies under review and to bring forward proposals (as are necessary) to modify them for the purpose of better achieving the relevant objectives[5].

Before making a modification to a charging methodology a DNO must submit to the Gas and Electricity Markets Authority (the Authority)[6] a report that sets out the terms of the proposal to modify their methodology, how the proposal better achieves the relevant objectives and a timetable for implementing the modification. The DNO then makes the modification unless within 28 days of submitting the modification report the Authority either directs the DNO not to make the modification or notifies the DNO that it intends to consult, and then within three months directs the DNO not to make the modification.

[1] Long-run incremental cost.
[2] Extra-high voltage.
[3] High voltage/low voltage.
[4] Standard electricity distribution licence conditions (SLC) 13 and 14.
[5] The relevant objectives for both the connection and use of system charging methodologies, as contained in paragraph 3 of SLC 13 of the distribution licence:

- that compliance with the use of system charging methodology facilitates the discharge by the licensee of the obligations imposed on it under the Act and by the licence;
- that compliance with the use of system charging methodology facilitates competition in the generation and supply of electricity, and does not restrict, distort, or prevent competition in the transmission or distribution of electricity;
- that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable (taking account of implementation costs), the costs incurred by the licensee in its distribution business; and
- that, as far as is consistent with the sub-paragraphs above, the use of system charging methodology, as far as is reasonably practicable, properly takes account of developments in the licensee's distribution business.

[6] Ofgem is the office of the Authority. The terms 'Ofgem' and the 'Authority' are used interchangeably in this letter.

EDF Energy Networks (SPN) plc submitted proposals to modify their UoS charging methodology to introduce a new methodology for calculating charges for demand and generation customers connected to the EHV portion of their SPN network. The proposals also change HV/LV generator UoS charges along with other minor changes to the existing HV/LV demand methodology.

These proposals represent substantive changes for calculating UoS charges in the SPN distribution services area (DSA). The Authority has therefore decided to consult on the proposed modification and notified EDF of this on 13 June 2008.

This consultation letter summarises EDF's proposals in **Annex 1**, provides details of issues we have identified following preliminary analysis in **Annex 2** and seeks views on these issues. **Annex 3** contains an impact assessment and the supporting **schedules** to this letter provide additional analyses and commentary on the proposals.

Background

In May 2005, we published a consultation on the longer term charging framework[7]. This called for DNOs to overhaul their charging methodologies to make them significantly more cost reflective and provide a baseline methodology which will endure for years to come. These new charging frameworks are intended to replace interim arrangements put in place at the beginning of the current price control period[8]. The document stated that the methodology should be:

- Cost reflective;
- Transparent;
- Predictable;
- Simple (at the point of use); and should
- Facilitate competition

An update detailing the progress of the structure of charges project was published in April 2007[9]. It outlined areas for development, along with each DNO's progress and target implementation for a long term framework. To date, one distribution company (Western Power Distribution (WPD)) has submitted and implemented a long term framework based on the high level principles above[10]. We are currently consulting on a proposal from Scottish Power regarding proposals for its longer term charging framework[11].

In April 2008, we published a consultation inviting views on the way forward for the structure of charges project[12]. The consultation document stressed the importance of all DNOs putting in place long term charging methodologies ahead of the start of the next price control period in April 2010 and offered two alternative licence modifications to

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[7] 'Structure of electricity distribution charges: consultation on the longer term charging framework', Ref 135/05,May 2005, available on our website at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=187&refer=Networks/ElecDist/Policy/DistChrgs.
[8] Interim charging arrangements took effect on 1 April 2005 based on the outcome of a consultation process which began in December 2000. A decision document was published in November 2003 proposing that by April 2005 the clearest problems with the current structure would be addressed through interim arrangements, while work would continue in parallel on the development of a longer term solution.
[9] 'Structure of electricity distribution charges: Update on progress and next steps', Ref 78/07, April 2007, available on our website at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=177&refer=Networks/ElecDist/Policy/DistChrgs.
[10] Our non-veto decision letter on WPD's proposed methodology can be found at http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Documents1/16857-20a07.pdf.
[11] 'Consultation on Scottish Power's (SP) proposal for a longer term charging methodology: FCP model' Ref 86/08, June 2008, available on our website at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=432&refer=NETWORKS/ELECDIST/POLICY/DISTCHRGMODS.
[12] 'Delivering the structure of charges project' Ref 36/08, April 2008, available on our website at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=396&refer=Networks/ElecDist/Policy/DistChrgs.

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achieve this deadline. We also set out the role long term charging methodologies play in facilitating the efficient development of the network and ensuring that networks do not provide a barrier to meeting climate change targets. In the document we also suggested how the high level principles from our May 2005 document could be amplified in order to guide the DNOs as they develop their methodologies. A DNO working group is currently discussing the drafting of these clarifying principles and the associated licence conditions.

EDF's proposed modification

EDF propose to replace their current EHV UoS methodology with a new methodology based on a LRIC model. The new LRIC methodology will apply to the derivation of demand and generation charges at EHV only and, by producing relevant cost signals, will feed EHV costs into the existing HV/LV methodology. The LRIC model calculates nodal incremental costs. These costs represent the brought forward (or deferred) reinforcement costs caused by the addition of an increment of demand or generation at each network node. The method attempts to model the impact changes in users' behaviour have on system costs.

EDF also propose to introduce revised arrangements for HV/LV generator charging along with a few changes to HV/LV demand charges.

The proposal is described in detail in EDF's modification report and proposed charging methodology, which are published on our website[13], and is summarised in **Annex 1** to this letter.

Prior to submitting their modification report, EDF consulted the industry on the EHV aspects of their proposed methodology in June 2007 and January 2008. The original consultation documents and subsequent responses have been published on EDF's website[14].

Initial assessment

We consider that this proposal represents a significant development in EDF's UoS charging methodology. In particular, it seeks to introduce enhanced cost reflectivity:

i) *At EHV level*, which:
    a. applies to the derivation of demand and generation charges;
    b. is a forward-looking incremental cost model; and
    c. uses nodal power flow modelling.

ii) At HV/LV level where generator charges have been modified to reflect both costs and benefits.

We have identified some initial concerns[15] in relation to the proposed methodology. These concerns are detailed in **Annex 2** and are centred on:

i) *Power flow scaling* – EDF scale the load flow data derived from their power flow model by a factor of 0.6. They do this because utilisation on their SPN network is generally high which produces high charges. Scaling is a way of avoiding this. We are concerned that this approach dilutes all incremental cost signals and alters their relativity;

ii) *Counterintuitive results for some kWh unit charges* - the conversion of incremental cost signals into capacity and unit charges means that the relativity of kWh unit

[13] See http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=426&refer=NETWORKS/ELECDIST/POLICY/DISTCHRGMODS.
[14] http://www.edfenergy.com/products-services/networks/knowledge-centre/public-information.shtml.
[15] Please note that where in this document we refer to the views of Ofgem or the Authority, this is a reference to our provisional views, and is subject to further consideration of any points raised over the course of or in response to this consultation.

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charges between time bands does not always reflect the relativity of the original incremental cost signals; and

iii) *The transparency of EDF's methodology* – we have some concerns over the extent to which users are able to understand EDF's proposed method as set out in its revised UoS charging methodology statement. We are keen to determine views on this.

Views sought

We welcome views on the extent to which the issues and effects we have highlighted are material and whether, overall, EDF's proposals represent an appropriate balance of the charging principles to provide a baseline methodology for years to come.

We stress again the importance of making a step change improvement in the cost reflectivity of distribution charging methodologies so that investors have an appropriate basis on which to assess the business case for different generation projects, so that current distribution connected generators are rewarded where they relieve network constraints and so that customers can see the network benefits associated with demand side management measures they may be considering. We recognise however, the need to take a proportionate approach to achieving this new baseline and the importance of ensuring transparency and predictability as well as cost reflectivity.

With regard to EDF's proposal we invite views specifically on:

- The transparency of the model and the level of cost reflectivity[16];
- Whether the model treats distributed generation in an appropriate manner;
- The extent to which the proposals take account of long term, incremental, avoided costs from distributed generation and demand side management[17];
- Whether the proposals facilitate the discharge by the licensee of the obligations imposed on it under the Act and by the licence[18];
- The extent to which the proposals are more cost reflective; transparent, predictable and simple (at the point of use) than the current methodology;
- Whether EDF demonstrate that its proposals facilitate competition in generation and supply and do not restrict, distort or prevent competition in transmission and distribution[19]; and
- The extent to which the proposals take account of developments in the licensee's distribution system[20].

You are also asked to consider whether we have correctly captured the main issues raised by, and the impacts of, EDF's modification proposal in **Annex 2** and **3**. We welcome any quantification of impacts as part of responses where possible.

IDNO charging

We note that as part of their proposal, EDF have not proposed any IDNO-specific tariffs. However, some of the proposed changes to their method may impact on IDNOs, as set out in **Annex 2**. We urge all DNOs to continue developing their UoS charging methodologies to take account of IDNO and longer term charging arrangements. In addition, we are keen to hear the views of IDNOs on any particular impacts EDF's proposals might have on them.

[16] Standard condition 13(3)(c) of the electricity distribution licence.
[17] Recital 18 of EU Directive 2003/54/EC says that charging methodologies should take account of incremental and avoided costs.
[18] Standard condition 13(3)(a) of the electricity distribution licence.
[19] Standard condition 13(3)(b) of the electricity distribution licence.
[20] Standard condition 13(3)(d) of the electricity distribution licence.

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Responses to this consultation letter

Views are invited **by 13 August 2008** on the issues raised by EDF's proposals from interested parties, including DNOs, IDNOs, suppliers, customers, generators and their representatives.

Where possible responses should be sent electronically to Nicholas Rubin via e-mail to distributionpolicy@ofgem.gov.uk.

In accordance with SLC 13, we have until 13 September 2008 to decide whether to veto EDF's proposed modification. As the Authority's decision is time bound, please ensure that your comments are received by us by 13 August so they can be fully considered. It may not be possible to consider responses received after this date.

All responses will be held electronically by Ofgem. They will normally be published on our website unless they are clearly marked confidential. Respondents should put confidential material in appendices to their responses where possible. We prefer to receive responses electronically so that they can easily be placed on our website.

A copy of this document is available on our website under the distribution charging modifications area of work[21].

Please contact Nicholas Rubin on either 0207 901 7176 or at nicholas.rubin@ofgem.gov.uk if you have any queries in relation to the issues raised in this letter.

Yours faithfully,

Rachel Fletcher
Director, Distribution

[21] http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Pages/DistChrgMods.aspx.

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Annex 1 – EDF's proposals

EDF's proposals relate to their SPN network and do not apply to their eastern (EPN) and London (LPN) networks. For the SPN network, EDF propose to replace their current EHV UoS methodology with a new methodology based on a LRIC approach. The new methodology applies to the derivation of demand and generation charges at EHV level. EHV costs then feed into EDF's existing HV/LV methodology. EDF propose changes to the method for calculating generator UoS charges as well as a few changes to HV/LV demand charging.

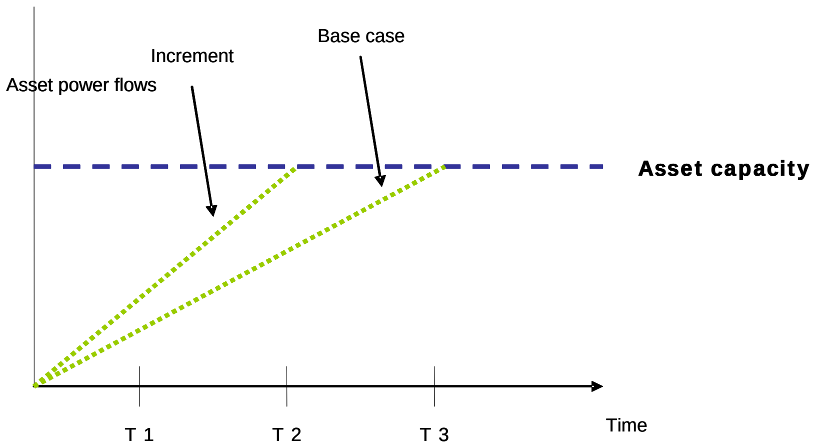
The proposed method considers the impact of thermal costs and does not consider fault level costs.

LRIC approach

EDF's LRIC model calculates nodal incremental costs, which are the brought forward (or deferred) reinforcement costs caused by the addition of a 1MVA increment of demand or generation at each network node.

The incremental cost for a node is the sum of the change in brought forward reinforcement costs triggered by a change in the power flow at the node, for example the addition of an increment. A summary of this approach is shown in Figure 1 below. The change in power flows from an increment in load triggers the need for reinforcement to move from year T3 to T2.

Figure 1



Source: Ofgem

The underlying principle of an LRIC approach is that each modelled asset will have a net present value (NPV) of reinforcement based on the expected future timescale of when the reinforcement will be required and the cost of the method of reinforcement. An incremental cost signal can be calculated from the change in the present value of future reinforcement cost as the result of the increment or decrement in demand.

The key calculations for a base case scenario are as follows:

$$\text{Number of years until reinforcement} = \frac{\log(\text{rated capacity}) - \log(\text{current utilisation})}{\log(1+\text{growth of utilisation})}$$

$$\text{Present value (base)} = \frac{\text{Cost of reinforcement solution}}{(1+\text{DiscountRate})^{\text{Number of years until reinforcement}}}$$

The number of years until reinforcement is the time it will take, given forecast growth rates, to use up any spare usable capacity in the asset at which point the asset will need to be reinforced.

The NPV calculations are then repeated once an increment or decrement is applied to the system. The charging model establishes the 'new' number of years until reinforcement for each branch asset once the power flows are adjusted to take account of the effect of an increment or decrement.

The difference in present values then provides the incremental cost of reinforcement.

$$\text{Marginal Cost of reinforcement} = \text{Present Value (Inc)} - \text{Present Value (Base)}$$

For charging purposes EDF annuitises the difference in incremental costs over 40 years.

Time bands

A significant element of EDF's proposed methodology is in the use of five time bands[22]. In particular, EDF intend to derive a demand and generation cost signal for each of the time bands described in Table 1 below. Consequently, an EHV demand or generation tariff will consist of five unit rates, one for each time band.

Table 1

Time band	**Description**
Night	Between midnight and 07:00 hours all year
Winter Peak	Between 16:00 and 20:00, Monday to Friday, November to February
Winter Shoulder	Between 07:00 and 16:00, Monday to Friday, November to February and between 07:00 and 20:00, Monday to Friday in March
Summer Peak	Between 07:00 and 20:00 Monday to Friday, June to August
Other	All other times

Source: EDF

EDF consider that using five time bands to calculate UoS tariffs will provide time of day and seasonal cost signals and more effectively encourage and discourage use of their network at given times of the day and year.

Figure 2 below illustrates the key components of EDF's proposed methodology.

Power flow model

The power flow model calculates the load on each branch of EDF's EHV network under N-1 conditions. For example, if a network has two branches the model therefore sets out what the load on branch 1 would be if branch 2 was offline, for example as a consequence of a fault. Load flows for all nodes and branches are calculated under these conditions under base conditions and with a 1MVA increment.

EDF perform AC power flow analysis and calculate load flows using Siemens' PSS™E software. EDF have recreated SPN's network in the software. The software produces individual node and branch active and reactive power load flows under N-1 conditions, with and without an additional increment of load. EDF determine the amount of energy to pass

[22] EDF currently charge all HH demand customers based on the five time bands they intend to use as part of their proposed methodology.

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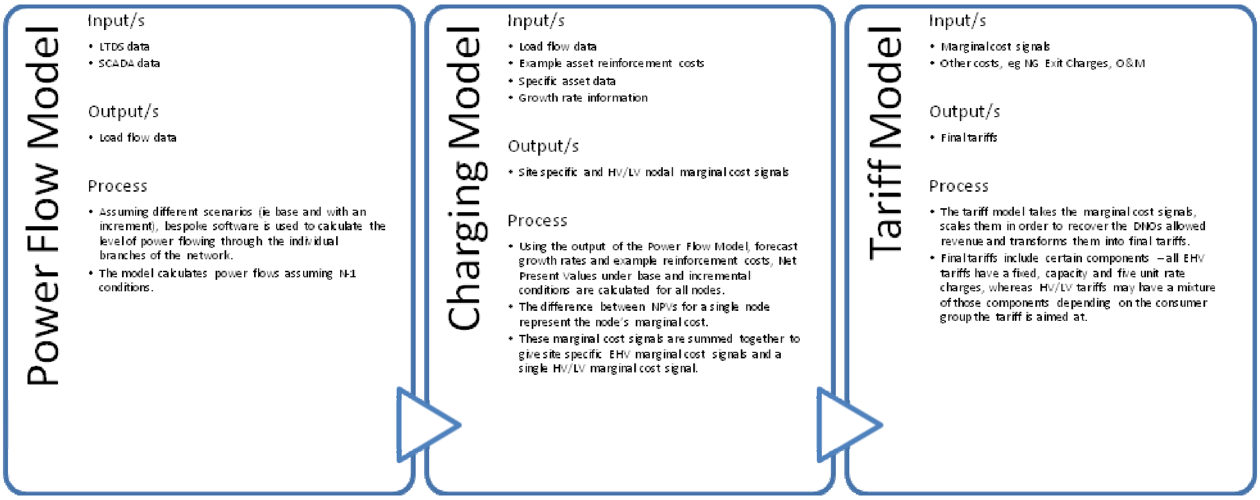
over the modelled SPN network by analysing historical GSP[23] group take data and demand data taken from their SCADA[24] system database.

EDF use GSP group take data to determine the dates and times of the three maximum and minimum levels of demand that occurred in each time band over the last year. Specific nodal load data is then extracted from EDF's SCADA database on the dates and times that correspond with the dates and times of the three maximum and minimum GSP group demands in each time band. This approach is similar to National Grid's 'Triad' method. Maximum and minimum demand data sets are then averaged to give a final maximum and minimum demand value for each node in each time band. Maximum and minimum demand levels are calculated for the purpose of deriving, respectively, demand and generation UoS charges. This is because EDF consider these levels of demand represent the overall cost drivers for reinforcing the network in each time band, depending on the type of network use (i.e. demand or generation).

Figure 2



Source: Ofgem

In order to avoid some nodal charges, which in EDF's view are high and caused by a combination of either i) high network utilisation and low growth rate or ii) negative time to reinforcement, they propose to scale all power flows used in their power flow model by a factor of 0.6. The reasons for and impacts of using this scale factor are considered below in Annex 2 and Schedule 1.

To improve the efficiency of their load flow analysis, EDF propose to use sensitivity coefficients. These have been developed to avoid running the power flow model multiple times (once for each node) and incurring unavoidable but fractional statistical errors.

Charging model

The fundamental elements of the LRIC approach are in the charging model. It is this part of the methodology that takes the load flow analysis (calculated by the power flow model), reinforcement cost data, specific asset data and forecast network growth rates, and calculates demand and generation incremental cost signals for each time band, for each node.

Whilst the key formulae used to determine nodal incremental costs are summarised above, an important component of those formulae is expected network growth. In order to recognise varying levels of growth across their network, EDF propose to use zonal growth rates. In particular, EDF propose to use different rates depending on the GSP a node is

[23] Grid supply point.
[24] Supervisory control and data acquisition.

connected or related to, as set out in Table 6 of their modification report and replicated in Table 2 below:

Table 2: SPN Zonal Growth Rates

GSP	Annualised Growth Rate
Beddington	2.1%
Bolney	1.0%
Kemsley	1.3%
Canterbury	1.3%
Sellindge	1.3%
Chessington	0.4%
Kingsnorth	0.9%
Laleham	1.3%
Ninefield	0.5%
Northfleet & Littlebrook	1.7%
West Weybridge	0.5%
Average	1.2%

These growth rates are based on expected levels of demand, which are outlined in EDF's long-term development statement (LTDS). They are calculated by finding the percentage change between the level of demand at the time the LTDS is published and expected demand in five years' time. The LTDS is published annually and our understanding is that EDF will update growth rates used in their charging model on a yearly basis.

Depending on the configuration of a node (i.e. the combination of assets), the reinforcement cost used in each NPV calculation represents a sum of the weighted average MEAV[25] costs for reinforcing the generic asset types that make up each node.

Tariff model

The tariff model annuitises EHV nodal incremental costs over 40 years at a 6.9% discount rate and converts them into capacity and unit charges that make up EHV final tariffs. The tariff model passes aggregated incremental costs into EDF's existing DRM[26] model as an additional cost input.

Allowed revenue will be split between demand and generation according to the price control allowances, and divided across voltage levels for demand in proportion to the MEAVs of the EHV and HV/LV networks and for generation according to the relative proportions of effective metered generation on the EHV and HV/LV networks.

EHV incremental cost signals are scaled using a fixed adder to derive the EHV allowed revenue. EDF's model uses a goal-seek function[27] to calculate the fixed adder necessary to ensure final charges recover the correct amount.

Treatment of National Grid exit charges

EDF allocate exit charges to the time band unit rate which coincides with peak GSP demand (winter peak time band). This is a change from their current method which recovers the exit charge through capacity charges. Generators are provided a credit for the whole amount of the exit charge where they are generating within the winter peak time band.

HV/LV demand charging

Under this proposal the existing DRM charging model is continuing to be used for charges at HV and LV. However, we understand that EDF propose to use outputs from the LRIC

[25] Modern equivalent asset value.
[26] Distribution reinforcement model.
[27] This is needed due to the split of charges between capacity and unit charge elements.

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model at EHV to calculate HV/LV tariffs and derive the split between timebands within the DRM.

In particular, as mentioned above, EDF's LRIC model proposes to calculate a single set of demand and generation incremental costs (ie 10 cost signals; five demand and five generation) for the HV/LV networks' use of the EHV network. HV/LV fixed charges comprise of 100% of the costs at the point of connection and for LV connections 50% of the costs of the assets above, while HV connections' fixed charges comprise 20% of the EHV marginal cost. Remaining costs are recovered through unit rates depending on the tariff group's average consumption and the kW:kWh conversion ratio for each time band.

EDF also propose to introduce a new LV HH substation tariff and increase the granularity of the fixed charge for profile class 5-8 tariffs by allocating costs based on individual profile class average demand levels, as opposed to a single aggregate demand value for all profile classes 5-8.

HV/LV generator charging

EDF propose the introduction of more cost reflective generator UoS charges at HV and LV level. They propose to allocate charges using the same principles as those that are used for demand tariff groups, but where HV/LV demand marginal costs are offset or deferred by generators, the charge will be seen as a credit.

Schedule 4 provides a summary of EDF's proposed methodology for HV/LV generator charges and is based on reviewing EDF's tariff model and their March 2008 paper on principles for HV/LV Generation tariffs[28]. In summary:

- EDF assume the SPN network will continue to be demand dominated and appropriately sized and sited generation will offset the need to reinforce this network for demand users. They propose to continue to use the five usage time bands to present a cost reflective signal to generator tariff groups;

- EDF propose to set HV/LV level generation network time band costs equal to the negative of demand network time band costs. This approach results in a credit placed on generators based on offset demand costs;

- EDF propose to further credit generation with long term savings from offsetting £/kW National Grid exit charges. The value of this credit is aligned to generators production at time of system demand peak;

- Reinforcement benefit is fully credited for network costs above a 0.433 kV level, while only half of the reinforcement benefit is credited for network costs at the 0.433 kV level; and

- The apportionments of offset costs for final tariff group charges are based on a tariff group's coincidence factor for each time band:

    - Non-half hourly (NHH) tariff groups receive a charge (credit) based on a generic time band coincidence factor (0.4 for all time bands).

    - Half hourly (HH) metered tariff groups receive a charge (credit) based on metered time band coincidence factor data. The coincidence factors used for all HH tariff groups for all five usage time bands are shown in Table 7 (see Schedule 4). Generators will only receive an offset reinforcement cost credit - based on the Table 7 tariff group coincidence factors - if they show metered generation during the usage time bands.

[28] EDF Energy Networks, 'HV/LV Generation tariffs principles paper', March 2008 – this paper is attached to this document as Appendix 1.

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We believe that EDF's proposal removes their existing +/- 10% cap on annual changes in generator charges as it no longer appears in their methodology, although we have not found anything in EDF's modification report that discusses or confirms this.

Comparison with WPD's EHV LRIC methodology

EDF's proposed LRIC methodology is similar to the LRIC methodology currently employed by WPD. However, there are some differences. Table 3 below provides a summary of some of these differences:

Table 3

Detail within model	**EDF (SPN area only)**	**WPD (South West and South Wales areas)**
Power flow used in charge calculations	Power flow scaled by 0.6	No scaling of power flows
Increment	1MVA	0.1MVA
Time bands	Five demand and five generation time of day and time of year time bands	No time bands within final charge. Summer and winter network conditions factored in to generator charging
Modelled network	Current network configuration	Planned network expected to be in use when the calculated charges are in force. Takes account of signed connection agreements
Growth rate	Variable rates by GSP. Current range 0.4% to 2.1%	1%
Final charge structure	Fixed, capacity, unit and excess reactive power charge	Fixed, capacity and excess reactive power charge
Allowed revenue split	Demand revenue is split depending on MEAV of EHV and HV/LV. Generation revenue is split depending on effective metered generation at EHV and HV/LV	Demand revenue is split depending on MEAV of EHV and HV/LV
Treatment of negative charges	Model allows for negative demand and generation charges	Negative demand charges capped to zero
Treatment of National Grid exit charges	Allocated to winter peak time band unit charge for demand Generation receives credit within winter peak time band.	Captured in fixed charge.

Source:Ofgem

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Annex 2 – Key issues

EDF's proposals represent a number of fundamental changes to their UoS charging methodology. These have been designed in an attempt to implement a methodology which better meets the relevant objectives.

We have identified a number of areas where we feel that the methodology may raise certain issues. This consultation seeks views from consultees on the materiality or otherwise of the issues we have identified, and any other relevant issue respondents would like the Authority to consider in reaching its final decision. Issues are set out in this annex along with analysis in the supporting schedules at the back of the document.

As set out in our cover letter, we also see this consultation as an opportunity to gather views from industry on the trade off between the charging principles which are the basis of the structure of charges project[29]. We have identified the following areas as being pivotal in the debate over the practical application of these charging principles:

1) **Application of a power flow scaling factor**
2) **Calculation of capacity and unit charges and the impact on incremental cost signals**
3) **Transparency and predictability**
4) **Further issues**
    i. LRIC pricing and the rate of load growth
    ii. Revenue reconciliation
    iii. Use and application of five network time bands throughout tariff calculations
    iv. Maximum and minimum power flow demands
    v. Calculation of HV/LV generator charges
    vi. LRIC pricing and the use of an annuity factor
    vii. Data accuracy
    viii. Size of increment
    ix. Cost drivers
    x. New HH/LV demand tariff.

Application of a power flow scaling factor

EDF are proposing to scale all power flow data used in their model to ensure that for all network branches, existing demand does not exceed usable capacity[30]. They propose to apply a scaling factor of 0.6 to all power flows derived from their Power Flow model. This issue is discussed in more detail in Schedule 1.

[29] In referring to charging principles we principally mean cost reflectivity, simplicity (at point of use), transparency, predictability, facilitating competition as well as accurately reflecting forward looking costs, incentivising the efficient use and development of the network and accommodating the introduction of generator use of system charges better than existing models. As noted previously these principles are detailed within various documents, for example the April 2008 'Delivering the electricity distribution structure of charges project' document', Ref 36/08: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=396&refer=Networks/ElecDist/Policy/DistChrgs.

[30] Usable capacity is the capacity of a branch under N-1 conditions, which is approximately the capacity described in Engineering Recommendation P2/6. DNOs are required by their licences to plan and develop their networks in accordance with P2/6.

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EDF argue that a 0.6 scale factor ensures that the highest utilisation on the SPN network is 60%[31] and so the charging model avoids producing, what are in their view, very high incremental cost charges where i) zonal growth rates are low (<1%) and utilisation is high (>60%) or ii) because of overloaded parts of the network (which result in negative years to reinforcement). EDF note that they considered some alternatives to this approach - including modelling the future network configuration or manual adjustment of demands - but that they concluded scaling power flows is the most appropriate approach.

Appendix 3 of EDF's modification proposal provides some analysis on how power flow scaling impacts on HV/LV network charges.

We are concerned that EDF's rationale for using a scale factor is not clear from their modification report or having reviewed the illustrative models (which cover the Charging and Tariff Model components of their proposed methodology) they have provided to us. As mentioned, EDF argue that the use of a scale factor is to avoid very high charges in certain circumstances, but it is not clear whether these circumstances indeed need correcting. In particular, there is no quantitative consideration of materiality or the costs and benefits of alternative solutions.

Our initial analysis of site-specific incremental £/kVA reinforcement costs at EHV level (see Schedule 1), suggests the ranking of nodal charges is distorted by applying a scaling factor. Furthermore, the scale factor will have the effect of scaling incremental cost signals where it is not needed (i.e. by scaling nodal cost signals which have average levels of utilisation and growth).

In addition to our concerns in relation to the effect

We seek views on whether scaling is appropriate, and whether it conforms with the intention of locational charging.

- ***Are EDF's proposals to scale all power flows appropriate? Is it clear why EDF propose to scale power flows using a factor of 0.6?***
- ***Does the proposal provide an effective trade-off between cost-reflectivity and practicality for the charging methodology?***
- ***Have EDF adequately considered alternative approaches to modelling for a highly loaded network? Are there alternatives that they have not considered?***

<u>Calculation of capacity and unit charges</u>

EDF's proposed methodology derives incremental cost signals that are measured in £ per kVA. The tariff model converts these signals into capacity and unit charges. Schedule 2 discusses this issue in more detail.

Our analysis shows that the unit rate charges do not always reflect the original time band incremental cost signals produced in the charging model. This suggests that in some cases the original incremental cost signals are distorted in the process of determining capacity and unit charges.

EDF acknowledge this issue in their modification report. They highlight that they have changed their methodology to utilise the same kW/kWh factor across all time bands and this method allows the unit charge to mirror the incremental cost signal. However, our analysis suggests that this has not remedied the issue for around 10% of sites.

As explained in Schedule 2, in some cases, unit charges distort time band incremental cost signals further by the incorporation of National Grid exit charges. EDF pass these costs on

[31] Our analysis does not substantiate this conclusion, as set out in Figure 4, Schedule 1.

to EHV customers by adding the exit charge to the 'unit rate less capacity' for winter peak time band charges only. This then gives the final unit rate.

- ***We ask for views as to whether EDF's approach for calculating final unit rate charges is appropriate? Is the distortion of incremental costs suitable given the objective of better cost reflection of incremental/avoidable reinforcement costs?***
- ***Does EDF's proposed approach provide an appropriate balance between achieving cost reflectivity and recovering allowed revenue and other costs in a predictable manner?***

Transparency and predictability

Respondents to EDF's past consultations highlighted difficulties in assessing the proposed modification and model. This may indicate that the level of access to the model and clear descriptions and analysis presented in previous consultations was insufficient. In writing this consultation document we have had to clarify EDF's approach in a number of areas, which are not specified clearly in the proposed methodology statement and / or the modification report. For example, in the proposed methodology statement:

- EDF's method for determing HV/LV generator charging lacks clarity; and

- EDF's approach to HV/LV demand charging does not mention retention of the DRM approach; and

In the modification proposal report:

- EDF's modification report (and cover note) initially specifies implementation of a LRIC approach at EHV only, whereas the proposals are more substantial than this, for example:
    - the introduction of a new LV HH substation tariff;
    - the improved allocation of profile class 5-8 fixed charge costs based on individual profile class demand data;
    - the introduction of HV/LV generator unit charges; and
    - changes that mean capacity charges fall.

We are concerned that EDF's proposed methodology also appears to contain errors. For example,

- The methodology for SPN states that the approach described is "only applicable to the London and East of England Distribution Systems operated by EDF Energy Networks" and that the "Use of System Charging Methodology applicable to the South Eastern Distribution System operated by EDF Energy Networks is described in a separate Statement".

Whilst EDF have said they will make publicly available a copy of their model, we note that industry participants and interested parties have had limited access to the detail of the modification proposal during its development. We are concerned that without adequate access to information, effective consultation, a clear modification report and ultimately a clear methodology, the industry and interested parties are limited in their ability to effectively assess proposed changes to that methodology and accurately understand and estimate use of system costs on the SPN network going forward.

We note that EDF state in their modification report that they consider their methodology to partially meet the charging principles of transparency and predictability. EDF state their intention to work with interested parties to deliver improvements to information and capabilities with regard to understanding and forecasting use of system costs.

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- ***We welcome views on the transparency of EDF's proposed methodology and whether it is clear from EDF's modification report how they intend to modify their current methodology?***

Further issues

We have identified some further issues with EDF's proposal that we would like consultees to consider and provide views on:

LRIC pricing and the rate of load growth

Schedule 1 considers the impact of the rate of load growth on the incremental cost charges produced by EDF's LRIC-based EHV methodology.

EDF propose to use zonal growth rates in their LRIC methodology as opposed to a global growth rate for all network assets. EDF argue this provides greater granularity to their incremental cost charges as forecast growth is based on quantitative assessments of growth. It also implies zonal growth rates could be low or even negative in the future as they are based on forecasts in the long term development statement (LTDS) for SPN.

Our analysis in Schedule 1 also highlights that EHV nodes produces some relatively high incremental cost charges when a hypothetically low growth rate (0.2%) is applied to the SPN network.

- ***We ask for views on whether the use of zonal growth rates in EDF's charging methodology is appropriate?***
- ***Do respondents consider the concerns with a LRIC charging methodology are relevant and material in relation to EDF's proposal?***

Revenue reconciliation

EDF propose to align yardstick charges with allowed revenue as follows:

1. For demand charges the allowed revenue that is to be recovered is first split between EHV network modelled yardsticks and HV & LV network modelled yardsticks. This is done in the same proportion as the MEAV of the EHV networks and the HV & LV networks. A fixed adder approach is then used to scale the modelled revenue to match the allowed revenue for the different voltage networks.

2. For generation charges the allowed revenue that is to be recovered is split between EHV and HV/LV network users. This is done by splitting the allowed generation revenue in the same proportion as the effective metered generation demand on the network. A fixed adder approach is then used to scale the modelled revenue to match the allowed revenues for the different voltage networks.

- ***We welcome views on whether the scaling approaches for demand and generation are appropriate?***

Use and application of five network time bands

EDF use five network time bands in their modelling process for demand, and five for generation[32]. The five time bands are used to define Half Hourly (HH) tariff charges for EHV site-specific and HV/LV customers. These time bands are already common throughout EDF's pricing modelling. They represent a mixture of time of day and time of year periods.

We note that for all illustrative nodal charges[33], time band 2 (winter peak) represents the maximum incremental £/kVA cost of demand reinforcement. For the purpose of EDF's

[32] See Table 1 above.
[33] Page 32 of EDF's modification report.

illustrative charges, network use during time band 2 appears to be the primary driver for reinforcement costs. However, our analysis of EDF's model shows that time band 2 may not always be the primary driver of nodal costs in all circumstances.

We also note that capacity charges are based wholly on the incremental cost signal for the time band that correlates with the overall maximum system demand, which is time band 2 (winter peak). This implies capacity reinforcement costs and charges are also driven by time band 2.

- ***We welcome views on the extent to which it is appropriate to use five time bands?*** **In particular, whether it is appropriate to differentiate between the seasons?**
- ***Do respondents consider it appropriate for capacity charges to be based on time band 2 (winter peak)?***

Use and application of nodal maximum and minimum demands

The demand data used for the power flow model is extracted for three maximum periods and three minimum periods for each of the five time bands. The dates and times that the data is extracted is determined from the three highest demands and the three lowest demands, separated by 10 complete days, in each time band, using the annual GSP group take as the reference data.

The result of EDF's approach is to populate each and every time band with a maximum (peak) power flow value used for the calculation of demand charges and a minimum power flow value used for the calculation of generation charges. As set out in EDF's modification report, the time periods used in these calculations are different for demand and generation.

We note that this approach to populating the power flow model with network data may create volatility in charges as the dates and times that the data is extracted change on an annual basis. We note that this may particularly be an issue given the dates for the three maximum demands are determined with reference to the GSP group and not each node on an individual basis.

In addition, we also note that EDF have not explained whether maximum and minimum levels of demand accurately reflect the appropriate drivers of reinforcement. For example, the effects generators have on deferring the need to reinforce as a consequence of demand growth may vary from one time band to the next. Furthermore, a network may be so demand dominated that even at minimum demand, it is demand that is driving re-inforcement costs, not generation.

- ***We welcome views on EDF's proposed 'Triad' approach.***
- ***Is the use of maximum levels of demand appropriate for calculating demand and the use of minimum levels of demand for generation charges?***

Calculation of HV/LV generator charges

EDF propose to allocate HV/LV generator charges using the same principles as those that are used for demand tariffs groups, but where HV/LV marginal costs are offset or deferred by generators, the charge will be seen as a credit. In addition, EDF also propose to provide a full credit for generators at peak time for National Grid exit charges.

We note that this approach assumes the SPN network is demand dominated. We also note that EDF propose to continue to use five usage time bands for HV/LV generator charges and to apportion offset reinforcement costs based on tariff group coincidence factor values for each time band.

For NHH customers charges (credits) are based on a generic time band coincidence factor. HH generator customers receive an offset reinforcement credit – based on tariff group time

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band coincidence factors - if they show metered generation during the five usage time bands.

- ***We welcome views on whether EDF's proposals for HV/LV generator charging are appropriate.***
- ***Do respondents consider it appropriate for a credit to be given against unit charges for National Grid exit charges?***

LRIC pricing and the use of an annuity factor

EDF propose to annuitise EHV incremental costs at the regulatory rate of return over an average expected asset life of 40 years to derive an annual £/kVA incremental cost charge. The annuity factor is therefore a pricing approach to recover costs in a set of annual charges. Schedule 4 discusses this issue in more detail.

- ***We welcome views on the appropriateness of a 40-year annuity factor.***

Data accuracy

Some respondents to EDFs January 2008 consultation document raised concerns with the use/collation of certain data used as inputs to the proposed model. A summary of these concerns is provided below.

<u>Growth rates</u> - EDF propose to use zonal growth rates in their charging model. These growth rates are based on data contained in the LTDS for the SPN network. It was noted by a couple of respondents that the use of this data - which is based on development of the network over a five year period - may not be appropriate for calculating nodal costs that potentially occur many more years into the future.

However - as EDF note in their modification report - the use of the LTDS provides a publicly available source for forecast growth rates. The use of forecast growth rates from the LTDS should assist users with transparency and predictability of information used.

<u>Collation of load flow data</u> – Respondents noted two things in relation to the collation of load flow data. First, that EDF propose to use only a year's worth of data and second, that collated load flow data does not exclude known outages. Respondents considered that these issues could significantly affect the calculation of maximum and minimum power flow demand levels which are fundamental to the subsequent calculation of incremental cost signals.

- ***We welcome respondents' views on data accuracy in EDF's proposed methodology.***
- ***Does the use of forecast growth rates from the LTDS represent an appropriate trade off between cost reflectivity, transparency and predictably?***

Size of increment

EDF propose to use a 1MVA increment / decrement to calculate EHV network incremental cost charges. We note that WPD use a smaller 0.1MVA incremental value in their LRIC based EHV charging methodology.

Appendix 4 of EDF's modification report provides a comparison of the effect of using a smaller 0.1MVA incremental value as opposed to the proposed 1MVA increment in their model. Tariffs for various customer groups have then been recalculated to the same allowed revenue. EDF suggest that their analysis shows that the final differences observed are very small and are likely to be due to the calculation rounding differences.

We note that EDF proposed to use the same size of increment for both generation and demand. EDF argue that the choice of increment size and their charging methodology in general, is designed to measure the impact of demand and generation on the EHV network on an equitable and consistent basis.

- ***We welcome views on the extent to which it is appropriate to use a 1MVA increment in the context of a LRIC based charging methodology.***
- ***Do respondents consider it appropriate to measure the impact of demand and generation on a consistent basis?***

Cost drivers

We note that EDF's charging methodology considers thermal capacity and not fault level costs. EDF are best placed to understand the cost drivers on their network and by not incorporating fault levels indicate that they do not consider fault levels to be a significant driver of costs on the SPN network.

- ***We welcome views on whether it is appropriate for EDF's model to ignore fault level driven costs.***

New HH LV demand tariff

EDF propose to introduce a new HH LV demand tariff for LV customers connected directly to an LV substation. They consider the new tariff will better cater for a number of customers on their network who are connected to LV substations.

- ***We welcome views on whether this new tariff is appropriate.***

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Annex 3 – Impact assessment

The Authority will make its decision on EDF's modification proposal in light of the relevant licence objectives set out in the electricity distribution licence (standard licence condition (SLC) 13), the Authority's principal objective and its statutory duties and obligations[34].

In accordance with the SLC 13 a DNO may modify its current charging methodology if within 28 days it has not been notified of the Authority's intention to veto the modification or consult.

The Authority has taken the decision to consult on the EDF model to establish the extent to which the methodology achieves what it sets out to do in terms of the high level principles and ultimately the relevant licence conditions. These issues are set out in Annex 2 with further analysis provided in the schedules to this Annex.

The purpose of this consultation is to seek views on the proposed modification and its associated impacts. To assist this process, we have included analysis of the impact of this proposal to help respondents understand the potential consequence of the modification. The schedules attached to this document provide some context and analysis to build upon the issues highlighted in Annex 2.

Background

EDF's proposed modifications are designed to implement a methodology which better meets the relevant objectives. It also recognises and responds to the need to replace the existing UoS charging methodology with a long term solution in line with the high level principles[35]:

- Cost reflectivity;
- Facilitation of competition;
- Predictability;
- Simplicity at the point of use; and
- Transparency.

EDF's proposed modification seeks to amend their existing UoS charging methodology in their SPN region. In particular, their proposal aims to replace their existing methodology at EHV, which derives site specific charges based on historical data, with a Long Run Incremental Cost (LRIC) model. It will also alter the way in which EHV costs are used in deriving tariffs for HV and LV connected customers.

Specifically, EDF's objectives in carrying out this work are:

- To implement cost reflectivity based on the expected impact of customer actions on future network reinforcement costs; and
- To calculate the charges applied to both demand and generation users of the network on an equitable basis.

EDF consider that the proposed methodology is more cost reflective in a number of ways, including:

- The LRIC approach for calculating EHV network charges. This enables locational price signalling by using power flow modelling to take into account the extent that

[34] The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. The Authority also has other statutory duties in respect of the environment, as set out in various other Acts, for example the Environment Act 1995 and the Countryside and Rights of Way Act 2000.
[35] See 'Structure of electricity distribution charges: consultation on the longer-term charging framework' (Ref 135/05), available on our website.

assets are used to supply a node on the network, as well as the spare capacity that exists in those assets;

- Zonal growth rates rather than a single universal growth rate which should more accurately reflect zone specific demand curves and therefore clearer signals regarding utilisation and headroom capacity;

- Five time bands to improve the calculation and allocation of costs to all users of the network. This allows for more effective energy demand management by reflecting customers' coincidence to peak demand. The incorporation of time of day and/or seasonal influences can help encourage more efficient utilisation of the network;

- EDF's model allows demand and generation charges to be determined on the same basis within the LRIC model. This enables clearer signals than currently to reflect the benefits that generation brings to the network and should encourage more efficient network operation; and

- EDF state their belief that the proposed methodology statement provides improved details of the methodology, formulae and data used to attribute charges, which should lead to increased transparency and predictability. If this is the case, this increased transparency should better facilitate competition in supply and generation.

Impacts on customers

Non Half Hourly (NHH) HV and LV Customers

The proposed modifications represent significant changes to EDF's charging methodology for EHV. As EHV costs are used in deriving HV and LV tariffs, these too will be impacted. This includes tariffs for domestic customers, small and large businesses. An analysis of current and proposed charges for NHH customers is set out in Table 4[36].

The filtering of the LRIC model incremental costs into the yardstick allocations calculations has meant that costs have been transferred from EHV to HV and LV. Consequently, fixed costs (we understand that these cover local assets and some of the costs of the network above) have increased, whilst unit rates for non-half hourly customers have fallen.

Half Hourly (HH) HV and LV Customers

Table 5 shows the tariff analysis for HV and LV HH customers. It illustrates that HH unit price disturbances are extremely high, with some unit charges changing by up to 671%. These individual spikes are somewhat diluted when applied to the final tariff charges, with the end result being that LV HH customers can expect an 18% increase, whereas HV HH customers can expect a 2% decrease. The night and unit charges are dampened as their contribution to the final tariffs is relatively minimal, i.e. the night charge makes up only 2% of the total charge.

[36]Assumptions in this analysis are based indicative consumption data for EDF's SPN network. All LV capacities are taken as 100kVA and all HV capacities are taken as 800kVA.

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Table 4 – Tariff Analysis for SPN NHH demand customers

Oct 07 Tariff Rates - Total	Unit Charge Day (p/kWh)	Unit Charge Night (p/kWh)	Fixed Rate (p/MPAN/day)	Current sample tariff (£/annum)		
Domestic Unrestricted	0.78	0.00	5.64	51.75		
Domestic Two Rate	0.96	0.37	5.64	65.74		
Small Business Unrestricted	0.81	0.00	7.72	101.08		
Small Business Two Rate	0.74	0.28	7.72	156.16		
Business Profile 5 - Standard	0.76	0.00	193.50	1258.89		
Business Profile 6 - Standard	0.71	0.00	193.50	1346.18		
Business Profile 7 - Standard	0.56	0.00	193.50	1472.11		
Business Profile 8 - Standard	0.49	0.00	193.50	1626.71		
Business Profile 5 - Two Rate	0.78	0.21	193.50	1313.18		
Business Profile 6 - Two Rate	0.69	0.19	193.50	1316.46		
Business Profile 7 - Two Rate	0.55	0.16	193.50	1403.76		
Business Profile 8 - Two Rate	0.47	0.13	193.50	1495.52		
Proposed Tariff Rates - Total	**Unit Charge Day (p/kwh)**	**Unit Charge Night (p/kwh)**	**Fixed Rate (p/MPAN/day)**	**Proposed sample tariff (£/annum)**	**Difference (£)**	**Difference (%)**
Domestic Unrestricted	0.63	0.00	7.47	52.51	£0.76	1.47%
Domestic Two Rate	0.76	0.33	7.47	64.15	-£1.58	-2.41%
Small Business Unrestricted	0.66	0.00	11.44	100.80	-£0.28	-0.28%
Small Business Two Rate	0.60	0.26	11.44	147.00	-£9.16	-5.87%
Business Profile 5 - Standard	0.63	0.00	219.24	1,258.67	-£0.22	-0.02%
Business Profile 6 - Standard	0.60	0.00	239.70	1,411.31	£65.13	4.84%
Business Profile 7 - Standard	0.47	0.00	249.93	1,553.40	£81.30	5.52%
Business Profile 8 - Standard	0.41	0.00	260.15	1,722.56	£95.85	5.89%
Business Profile 5 - Two Rate	0.64	0.21	219.24	1,310.03	-£3.15	-0.24%
Business Profile 6 - Two Rate	0.57	0.18	239.70	1,387.30	£70.84	5.38%
Business Profile 7 - Two Rate	0.45	0.16	249.93	1,499.80	£96.05	6.84%
Business Profile 8 - Two Rate	0.39	0.13	260.15	1,615.20	£119.68	8.00%

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Table 5 – Tariff analysis for SPN HV and LV HH demand customers

	Fixed Charge 1 (p/MPAN/ day)	Day Unit Charge 1 (p/kWh)	Day Unit Charge 2 (p/kWh)	Day Unit Charge 3 (p/kWh)	Night Unit Charge 1 (p/kWh)	Other Unit Charge 1 (p/kWh)	Capacity charge (p/kVA/ month)	Total sample tariff (£/ annum)		
Oct 07 Tariff Rates - Total Unit Charges										
LV HH	69.46	1.22	0.27	0.08	0.04	0.07	184.60	£3341.82		
HV HH	148.85	0.46	0.09	0.03	0.01	0.03	109.80	£13476.07		
Proposed Tariff Rates - Total Unit Charges									Diff. (£)	Diff. (%)
LV HH	69.46	0.90	0.61	0.32	0.30	0.53	88.80	£3942.96	601.14	17.99%
HV HH	130.77	0.39	0.16	0.05	0.07	0.14	74.50	£13194.06	-282.01	-2.09%
LV HH Diff. %	0%	-26%	127%	321%	634%	671%	-52%	18%		
HV HH Diff. %	-12%	-16%	78%	89%	400%	386%	-32%	-2%		

EHV Customers

Table 6 replicates EDF's modification report showing the impact of the new methodology on EHV demand charges. The majority of EHV customers can expect substantial decreases in their tariffs as a result of the introduction of an LRIC approach coupled with MEAV-driven revenue scaling.

Our analysis suggests that within the decreasing charges, capacity charge components are decreasing most significantly. Further analysis suggests that the current methodology comprising EHV fixed and capacity charges only, means that the capacity charge makes a significant contribution to the the total charge. EDF's proposed modification introduces five unit charge rates as well as a capacity charge. Consequently, the total charge is now driven mainly by the unit rate for the period of maximum demand.

Generation

The proposed methodology will split EHV and HV/LV HH generator charges between five time band charge rates and an availability (capacity) charge for HH customers. This is a change from their existing charging structure which at present only charges based on a capacity charge.

Appendix 1 of EDF's Modification report provides illustrative HV/LV charges. As a consequence of recovering costs through capacity and unit rate charges, these illustrative tariffs will have their capacity charges reduced by about 78%. As noted above, EDF intend to pass on National Grid exit charges to generators as a full credit. Consequently, all final winter peak time band unit rates will credit generators for exporting. All other time band rates are positive and will debit the generator for use of the network.

IDNOs

There are no IDNO-specific charge rates. However, we note that proposed changes may have an impact on IDNOs, for example EDF's proposal to introduce a new LV HH substation tariff and changes to profile class 5-8 standing charges.

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Table 6 – EHV tariff movements under proposal

Site ID	Proposed Total Charge per annum	Oct 07 Total Charge per annum	Difference (£)	Difference (%)
1	£126,099	£875,677	-£749,578	-86%
2	£3,865	£9,270	-£5,405	-58%
3	£39,466	£38,810	£656	2%
5	£90,930	£739,631	-£648,701	-88%
6	£85,133	£399,362	-£314,229	-79%
7	£242,310	£693,802	-£451,492	-65%
8	£3,085	£2,551	£535	21%
9	£26,257	£30,577	-£4,320	-14%
10	£229,045	£199,243	£29,802	15%
11	£4,875	£4,365	£510	12%
12	£167,974	£336,006	-£168,032	-50%
13	£56,104	£306,416	-£250,312	-82%
14	£79,825	£291,094	-£211,270	-73%
15	£70,515	£236,528	-£166,014	-70%
16	£78,160	£223,991	-£145,831	-65%
17	£41,691	£70,062	-£28,371	-40%
18	£172,445	£374,316	-£201,872	-54%
19	£72,388	£212,533	-£140,145	-66%
20	£31,770	£130,448	-£98,677	-76%
21	£26,174	£168,688	-£142,514	-84%
22	£37,761	£41,881	-£4,120	-10%
23	£49,065	£186,884	-£137,819	-74%
24	£105,509	£231,161	-£125,652	-54%
25	£64,181	£155,696	-£91,515	-59%
26	£4,309	£13,062	-£8,753	-67%
27	£62,781	£230,878	-£168,097	-73%
28	£40,124	£209,019	-£168,895	-81%
29	£589,071	£423,258	£165,813	39%
30	£50,157	£208,684	-£158,527	-76%
31	£42,739	£120,835	-£78,097	-65%
32	£53,520	£304,694	-£251,173	-82%
33	£6,389	£16,729	-£10,341	-62%
34	£290,928	£421,791	-£130,863	-31%
35	£108,449	£520,614	-£412,165	-79%
36	£217,134	£279,804	-£62,670	-22%
37	£90,026	£115,493	-£25,467	-22%
Total	**£3,460,254**	**£8,823,853**	**-£5,363,601**	**-61%**

Impacts on competition

The proposed modification will have an impact on suppliers, generators, IDNOs and ultimately, end customers. Charging methodologies should be developed and designed to encourage the efficient use of the network. In Annex 2 we have asked for views on whether EDF's proposal achieves this. Developments in the methodology may also cause suppliers to offer more innovative products to customers. In particular, the introduction of incremental costs for five time bands may encourage more representative pricing or metering structures.

EDF's proposed charging methodology leads to a majority of customers seeing reduced charges. In Annex 2 we have asked for views on whether our concerns with EDF's approach are both relevant and material.

We note that whilst EDF is not proposing IDNO-specific tariffs, the changes being proposed to charges can be expected to have an impact on all customers, including IDNOs.

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Transparency and predictability are key elements in allowing generators and suppliers to calculate and quote costs to their existing and potential customers and therefore, in promoting competition. EDF propose using LTDS data to calculate growth rates and network asset capacities in order to increase the transparency and predictability of inputs (and therefore outputs) to their model. However, as set out in Annex 2 several respondents have commented on the data accuracy and integrity of certain data used in the model.

Impacts on sustainable development

Environment

Whilst we have not attempted to quantify the environmental costs and benefits of the proposed modifications, a qualitative evaluation suggests that charging frameworks which accurately reflect locational costs and a customer coincidence to peak demand encourage high utilisation of the network at all times and at all locations. This in turn would generate benefits to the environment and may also lead to lower fixed losses associated with network equipment. We welcome views on the extent to which EDF's proposed modifications accurately reflect both coincidence and locational charges.

Similarly, more cost reflective charges for generators and the recognition of generation benefit is expected to encourage more distributed generation. A large proportion of this is expected to come from renewable, low carbon sources thus facilitating a transition to a low carbon economy.

Security of supply

Electricity distribution networks are designed to meet security standard P2/6. Where possible, EDF's proposed methodology uses P2/6 in the power flow model to both determine reinforcement needs and identify the reinforcement types. Using P2/6 in this way is likely to ensure the charging methodology improves the security of supply.

Energy Savings

The use of five time bands may allow for more effective demand side management, (assuming the time band charges are cost reflective) which would enable customers to better control their usage patterns. This should lead to more efficient network demand overall, theoretically producing a more even spread of use across the five periods.

Impacts on health and safety

We consider that the effects of this proposal have no health and safety implications.

Risks and unintended consequences

The main risk comes from the possibility that the proposed modifications are implemented and do not better meet the relevant licence objectives. It is for this reason that a full consultation and analysis is being carried out ahead of possible implementation. This process allows the Authority to consider all issues in an informed way ahead of making a decision based on the licence objectives. In this way, this risk is minimised.

Risks can arise if methodologies containing assumptions regarding emerging industry trends are implemented and these trends are subsequently not realised. Where possible, the EDF methodology has based such assumptions on industry standards such as LTDS data. As these sources change, it is expected that the methodology would be updated to reflect these changes. Therefore risks in this area may be limited under the proposal. It is also desirable that a methodology attempts to account for expected future developments by adopting a forward looking approach.

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Other impacts, costs and benefits

DNO Costs

EDF is not expected to incur significant additional costs in implementing these proposals. The models have already been developed and applied to EDF's SPN region. We are not aware that any significant costs would be associated with implementing the new tariffs in the settlement system.

Benefits

In attempting to build a model which better meets the relevant licence objectives a number of benefits are expected in line with what the licence conditions and structure of charges project is striving to achieve. A more cost reflective methodology would mean customers and generators pay charges which are more representative of the costs incurred by the DNO which result from their use of the distribution network. In addition, the way in which these costs are allocated and charged for are designed to create signals to customers encouraging a more efficient use of the network. A cost reflective methodology attempts to create a network which is efficiently utilised by influencing the behaviour of those for whom UoS charging is an active consideration in setting their demand profile and location. EDF try to achieve this using the LRIC model to encourage expansion of EHV demand in locations which will not trigger reinforcement. Annex 2 asks for views on the extent to which EDF achieve such benefits in their proposals.

Post-implementation review

Licensees have an obligation to keep their charging methodologies under review and make changes which will better achieve the relevant objectives. Furthermore, Ofgem and the industry are committed to developing charging methodologies as part of the ongoing structure of charges project.

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Schedule 1 – Power flow scaling, utilisation and growth rates

Introduction

The network configuration EDF use for modelling EHV incremental costs is a snapshot of the current operational network and does not take into consideration reinforcement schemes that are under construction when the snapshot is taken. As such, some modelled branch flows are higher than the modelled branch assets capacity.

EDF state in their modification report that if their model included branches where the demand appears to exceed the capacity, this would result in the model forecasting negative years to reinforcement which would cause excessively high incremental costs. This would have the consequent effect of creating high and unstable final charges. In addition they also note in their report that the LRIC approach also produces very high charges when hight network utilisation (>60%) is coupled with very low network growth (<1%)

This schedule analyses how EDF propose to address these perceived issues and the implications arising from their approach.

Power flow scaling

EDF are proposing to scale all power flow data (derived from their Power Flow model) to ensure that for all network branches, existing demand does not exceed capacity. They propose to apply a scaling factor of 0.6 to all power flows. This impacts on the derivation of EHV demand and generation charges.

EDF had considered some alternatives to this approach - including modelling the future network configuration or manual adjustment of demands - but conclude that scaling power flows is the more appropriate approach. However, we note that any assessment of alternatives was not described in EDF's modification report.

The LRIC method can produce high charging rates where an increment is added to a highly utilised network with a low rate of load growth or where the assets on a network are overloaded. Utilisation on SPN's network is shown in Figure 6. EDF highlight in their modification report that the scaling of power flows helps address these concerns with the LRIC charging methodology because the level of and range of cost signals are reduced by the scaling of power flows by 60%. In addition, and as discussed in Schedule 3, EDF's annuitisation of costs over 40 years further scales incremental cost outputs.

EDF's Analysis

EDF propose to introduce a revised charging methodology which they argue is more forward-looking and enables charges to reflect the incremental costs and benefits that users place on the network. Modelling EHV costs on a nodal basis allows these charges to vary by location.

Nodal locational charging provides potential customers with a merit order of the costs and benefits of using the distribution network at each network node. The resulting relativity in nodal charges then incentivises customers to locate where there is maximum headroom on the SPN network.

EDF propose to calculate EHV charges on a locational basis. However, the weighted average of all the EHV nodes where there is an connection to the HV/LV network are used in tariff yardsticks for HV/LV charges. Appendix 3 of EDF's modification report presents analysis on how HV/LV network charges are influenced by the power flow scaling factor described above.

The key points to note from EDF's modification report analysis are:

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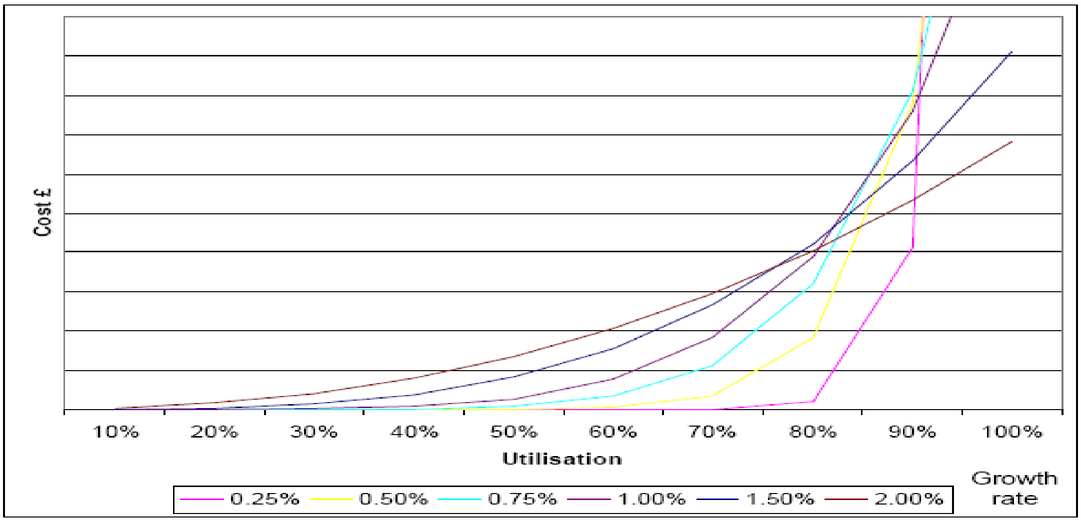
- Where EHV incremental costs are recalculated using a power flow scaler of 0.8, all LV and HV half hour tariffs fall (range 2 – 9%) while all the other reported tariffs increase (range 11 – 1%).

- Where incremental costs are recalculated without a power flow scaler, changes to tariffs follow the same direction as the 0.8 scaler but the movements are more substantial.

- EDF's published analysis illustrates only the impact of power flow scaling on HV and LV customer tariffs. The analysis does not show the impact on EHV site specific £/kVA incremental costs and how scaling impacts on the relativity of nodal charges.

Additional analysis in EDF's modification proposal (provided below as Figure 3) shows that as power flows exceed 60% utilisation under various growth rate assumptions then the level of cost rises exponentially. EDF argue that this issue is addressed in their model by scaling all power flows.

Figure 3: EDF's load growth rate analysis



Source: EDF Energy Networks

Ofgem analysis

We have recalculated the EHV incremental costs without a power flow scaler and when using a 0.8 power flow scaler. Table 7 below shows the results for a sample of SPN EHV site-specific nodes.

Table 7: Power flow scaler, comparisons against 0.6 scaler baseline, winter peak timeband

Nodes	**0.6 scaler**		**0.8 scaler**			**No scaler**		
	£/kVA	**Rank**	**£/kVA**	**Rank**	**% change**	**£/kVA**	**Rank**	**% change**
1	17.4	6	94.3	5	442%	271.7	8	1462%
2	13.9	9	69.5	8	399%	158.7	14	1040%
3	24.1	5	76.1	7	216%	191.1	12	694%
4	4.7	19	15.5	25	229%	41.2	24	774%
5	13.9	9	69.5	9	399%	158.7	15	1040%
6	9.6	12	47.9	11	400%	253.6	10	2547%
7	6.4	16	15.9	23	148%	30.0	25	368%

8	8.3	13	37.2	12	350%	131.7	16	1495%
9	13.2	11	33.2	14	152%	65.9	21	400%
10	34.3	4	118.0	4	244%	273.7	7	698%
11	1.8	24	21.3	18	1114%	311.9	5	17720%
12	7.5	14	33.8	13	354%	127.1	17	1603%
13	2.0	23	16.6	21	734%	190.5	13	9472%
14	3.9	20	17.3	19	342%	52.5	22	1242%
15	15.3	8	66.9	10	338%	208.1	11	1262%
16	6.5	15	29.7	15	356%	111.5	18	1610%
17	3.5	22	16.5	22	367%	67.6	20	1811%
18	15.4	7	86.6	6	463%	260.1	9	1591%
19	5.1	18	22.0	16	329%	67.9	19	1224%
20	36.0	2	157.5	3	338%	491.9	2	1267%

Source:Ofgem

The key points to note from Table 7 are as follows:

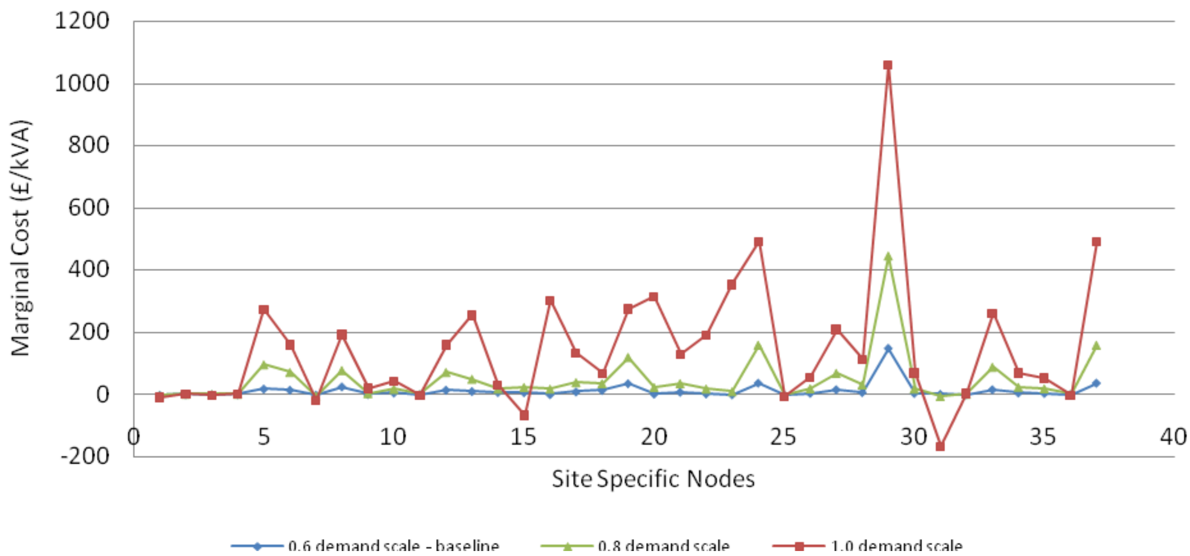
- Without the power flow scaler, a number of site-specific nodes have high incremental (unannuitised) £/kVA charges. The 0.6 scaler dampens these high charges;

- Changes to the power flow scaler produce large percentage changes to incremental cost charges relative to the 0.6 scaler proposed by EDF; and

- The rank for the sample nodes is similar for each scaling factor but there are some major changes in the relativity of charges. In particular, the ranking of sample nodes appears to be distorted by the choice of scaling factor.

Figure 4 shows the £/kVA incremental costs for all EHV site specific network nodes when 0.6, 0.8 and no power flow scalers are applied. It also shows some change in the relativity of nodal charges when a different power flow scaler is applied in the charging model.

Figure 4: Impact of power flow scaling on £/kVA incremental costs, winter peak time band



Source:Ofgem

Once incremental costs are calculated these are passed through the Tariff Model, as described above. Part of this process involved scaling the incremental costs via a fixed

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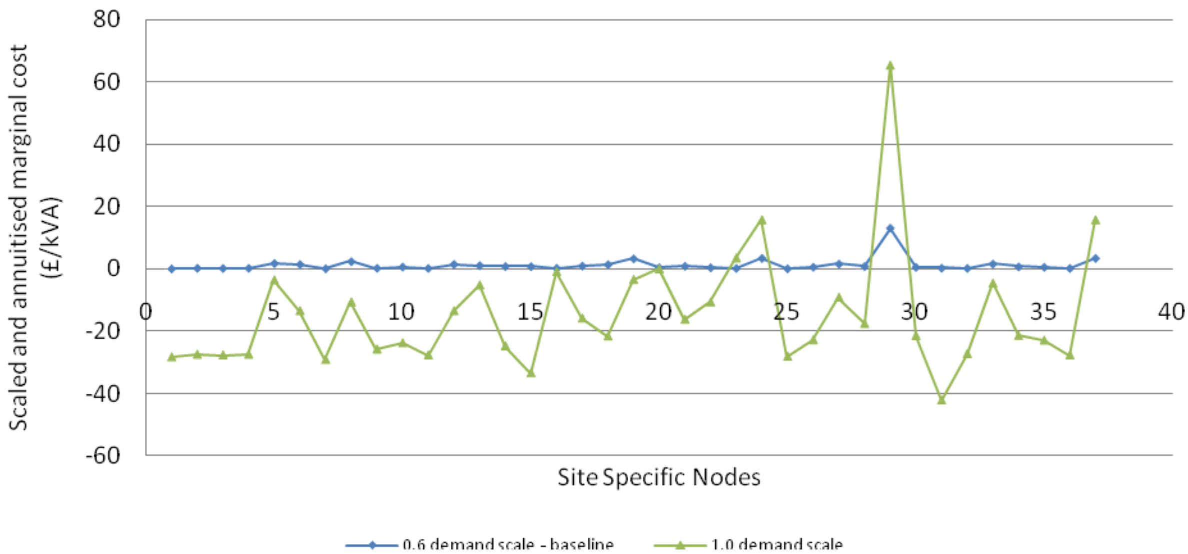
adder so that the final tariffs will recover allowed revenue. Figure 5 below shows the effect of different power flow scale factors on incremental cost once it has been scaled to recover allowed revenue and annuitised. A consequence of not applying a power flow scale factor results in a majority of negative costs post revenue scaling and annuitisation. Where the 0.6 power flow scale factor is used, cost signals are positive. In addition, the variance of charges is also relatively much larger where no scale factor is applied.

Figure 5 – Impact of power flow scale factor £/kVA incremental costs post annuitisation and scaling to allowed revenue (winter peak time band)



Source:Ofgem

The large number of negative cost signals where no power flow scaler is applied, which is illustrated by Figure 5, may be explained by the fixed adder applied to the incremental cost signal. The proposed methodology results in a modest positive fixed adder where a 0.6 scaler is used but a large negative fixed adder where no scale factor is added. The size of the fixed adder where no power flow scale factor is applied is likely to be so large in order to counteract the effect of some very large incremental cost signals as illustrated by Figure 3.

Figure 6 below shows the utilisation of SPN network assets for time band 2 where no power scaler is applied and once the 0.6 power flow scaler is applied. For illustrative purposes, a hypothetical LRIC pricing schedule for each level of utilisations is also provided.

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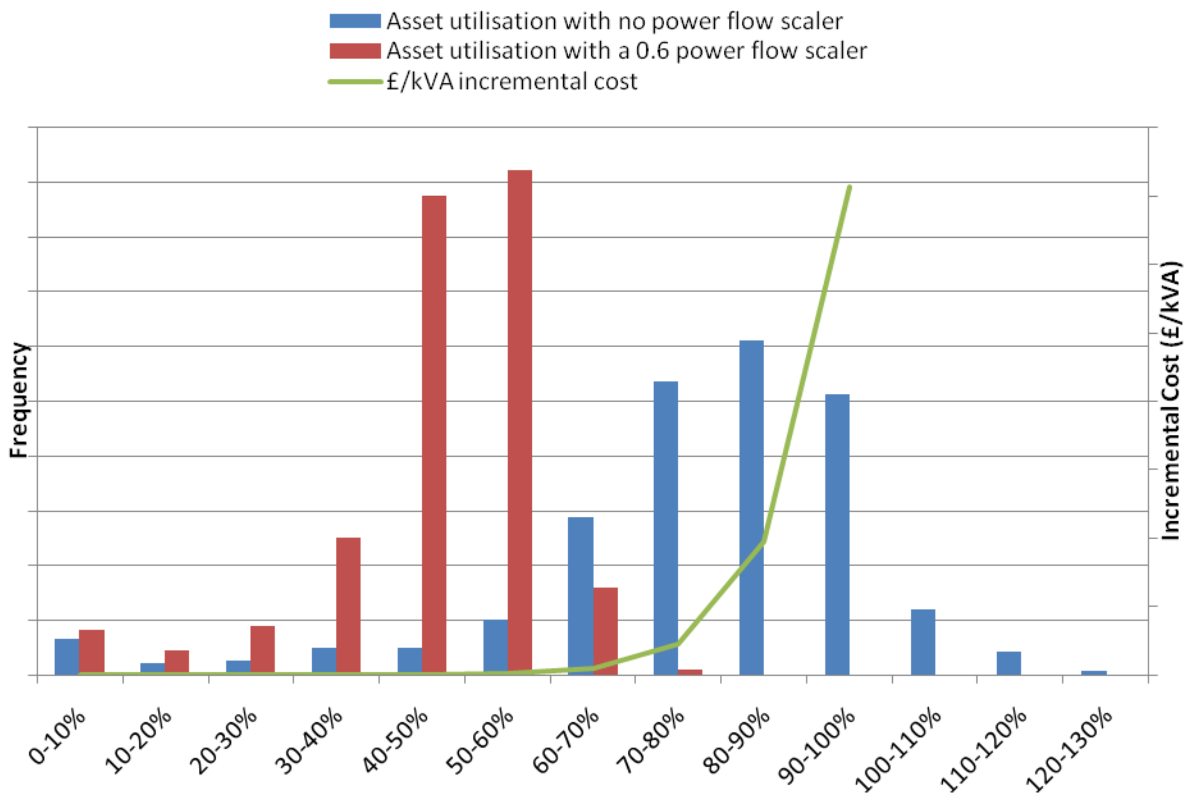
Figure 6: Asset utilisation frequency in 10% utilisation bands on SPN network, winter peak time band



Source:Ofgem

The key points to note from Figure 6 are as follows:

- Without the power flow scaler significant quantities of network assets exceed 70% utilisation;
- In the context of LRIC pricing, where utilisation is greater than 100% this will result in negative years to reinforcement and very high marginal cost charges. Where utilisation is 70% or greater this could result in high incremental costs; and
- The application of the 0.6 power flow scaler reduces asset utilisation significantly. For the majority of assets utilisation becomes 50 – 70%.

Figure 7 below contrasts the marginal £/kVA cost charges for all EHV site specific nodes when the average project growth rate is applied globally with charges when the proposed zonal growth rates are applied to site-specific nodes.

The key points to note from Figure 7 are as follows:

- The growth rate assumption has a significant impact on the level of the marginal cost charge. The figure shows a pronounced change to nodal marginal costs following a departure from an average growth rate assumption; and
- The growth rate assumption has a significant impact on the relative marginal cost charges for site-specific nodes.

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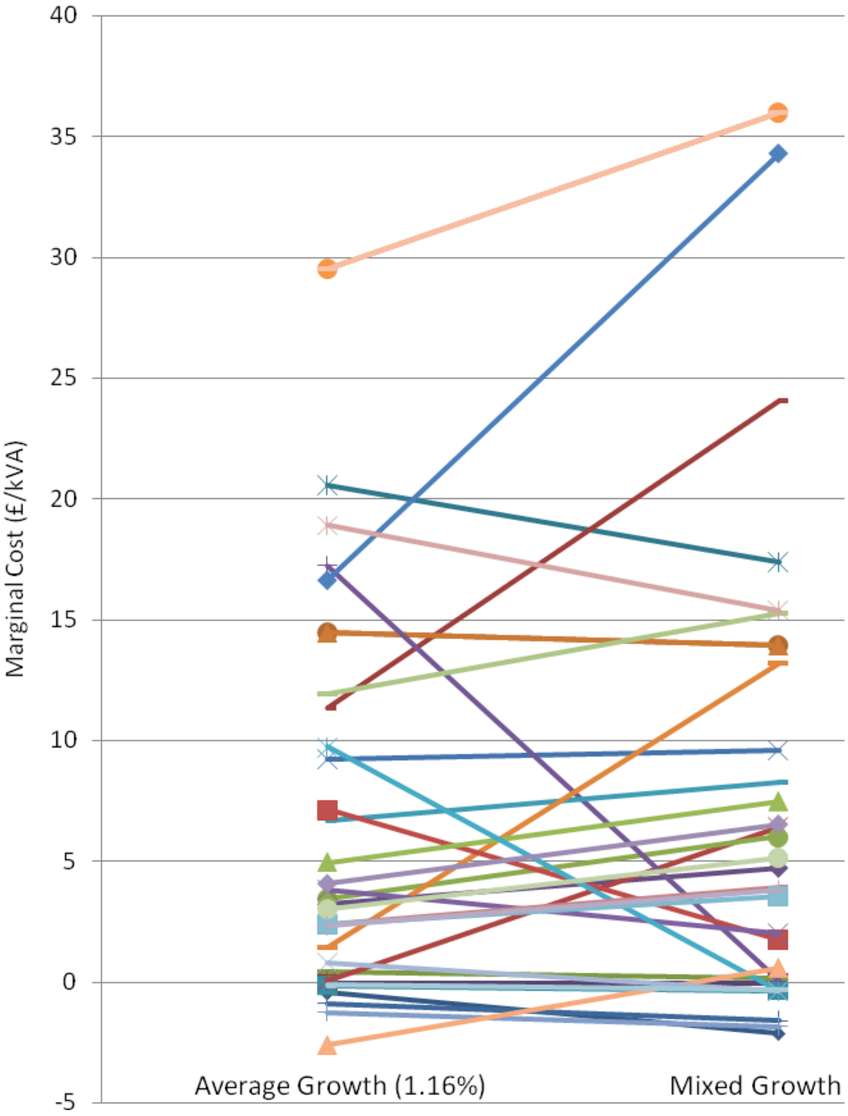
Figure 7: Load growth rate analysis (2)



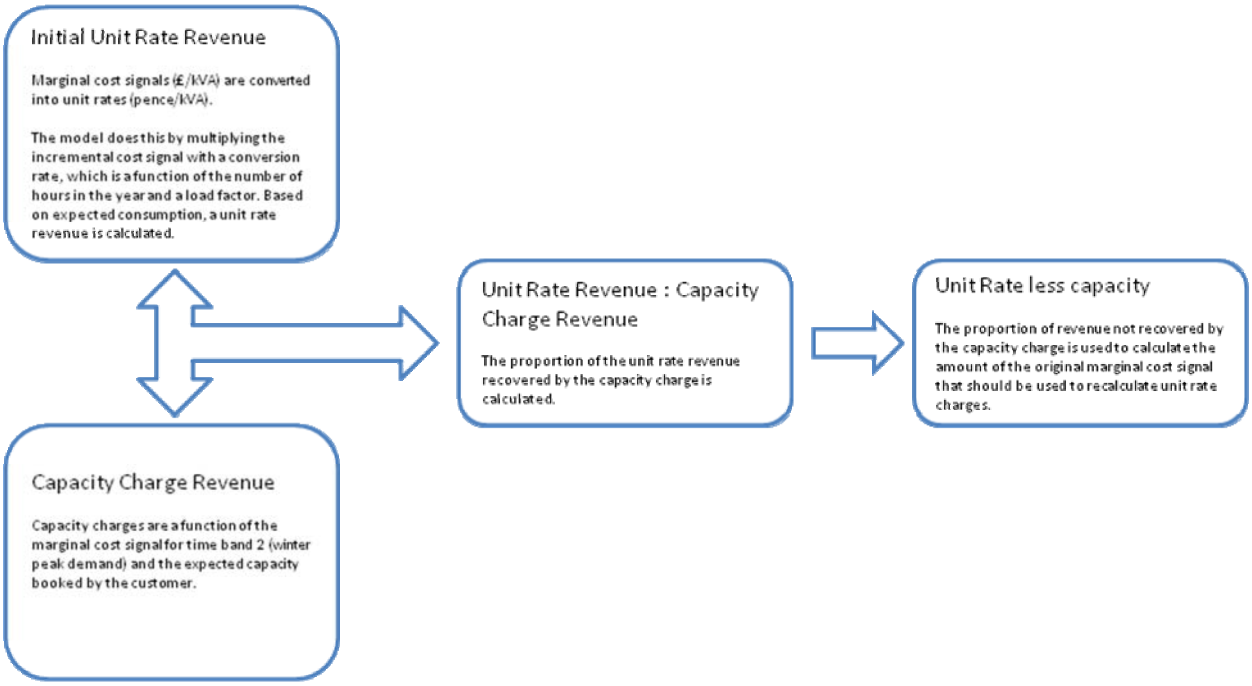
Source: Ofgem

Schedule 2 - The calculation of capacity and unit charges

Introduction

The proposed methodology derives incremental cost signals that are measured in £ per kVA. The tariff model converts these signals into capacity and unit charges, following the process illustrated in Figure 8 below.

Figure 8



Analysis

Our preliminary analysis shows that the unit rate charges less capacity do not reflect the original incremental cost signals between time bands. Despite efforts by EDF to correct this problem, the model appears to continue to distort cost signals. If the incremental cost signals for all time bands were ranked 1-5 (from highest to lowest) and compared against the ranking of unit charges less capacity, the ranks for the charges in the same time band do not always correlate. This suggests that in some cases the original incremental cost signals are distorted in the process of determining capacity and unit charges. However, we note that this is the case for only about 10% of site specific nodes.

The ranking of unit charges is more substantially changed by the incorporation of an exit charge which is levied by National Grid for transmission network connection costs. EDF pass these costs on to EHV customers by adding the exit charge to the 'unit rate less capacity' for time band 2 charges only. This then gives the final unit rate. The incorporation of exit charges in to time band 2 because this is the time band containing GSP peak demands. Consequently, it generally makes time band 2 charges much higher relative to other time band unit rates and affects the relative prices between timebands.

Figures 9, 10 and 11 below show diagrammatically how the relativity of charges for three site specific customers can change through the tariff model.

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Figure 9

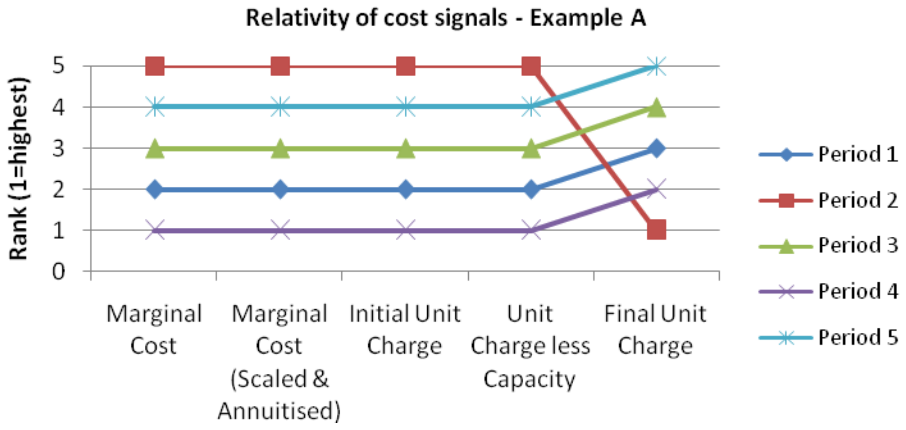


Figure 10

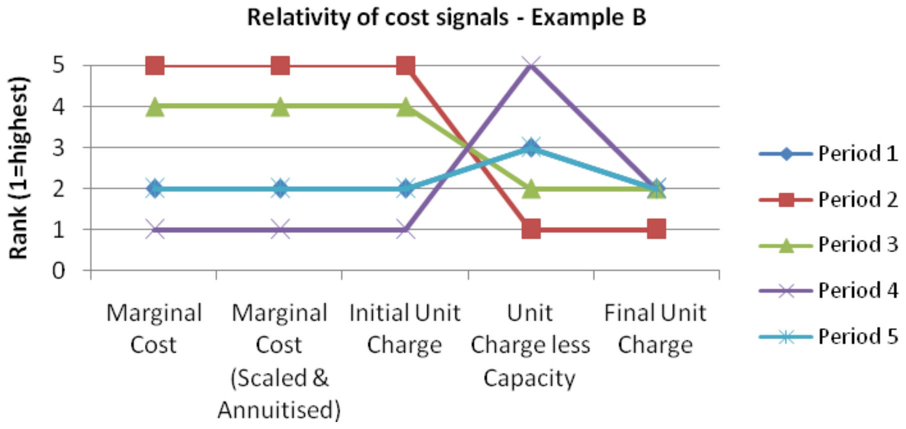
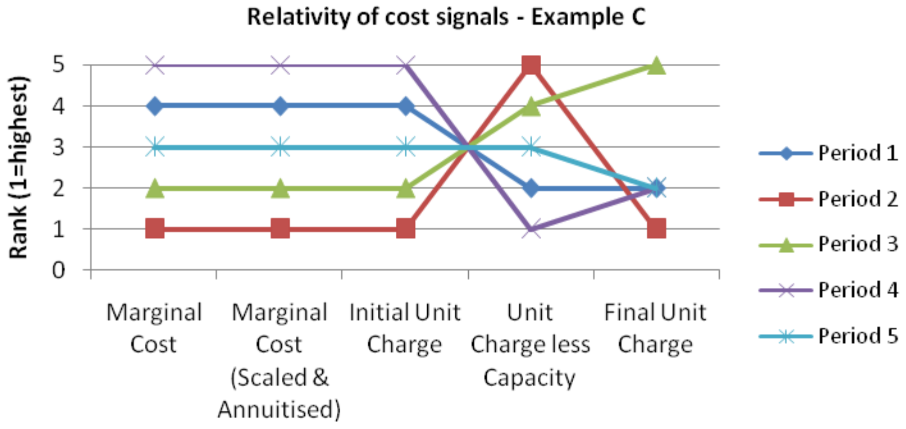


Figure 11



Source:Ofgem

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Schedule 3 – Annuity Factors

Introduction

This schedule considers EDF's proposed annuity factor and views on the appropriateness of its application.

EDF approach

EDF propose to annuitise the nodal marginal £/kVA reinforcement costs at the regulatory rate of return over an average expected asset life of 40 years to derive an annual £/kVA marginal cost charge. The annuity factor is therefore a pricing approach to recover costs in a set of annual charges.

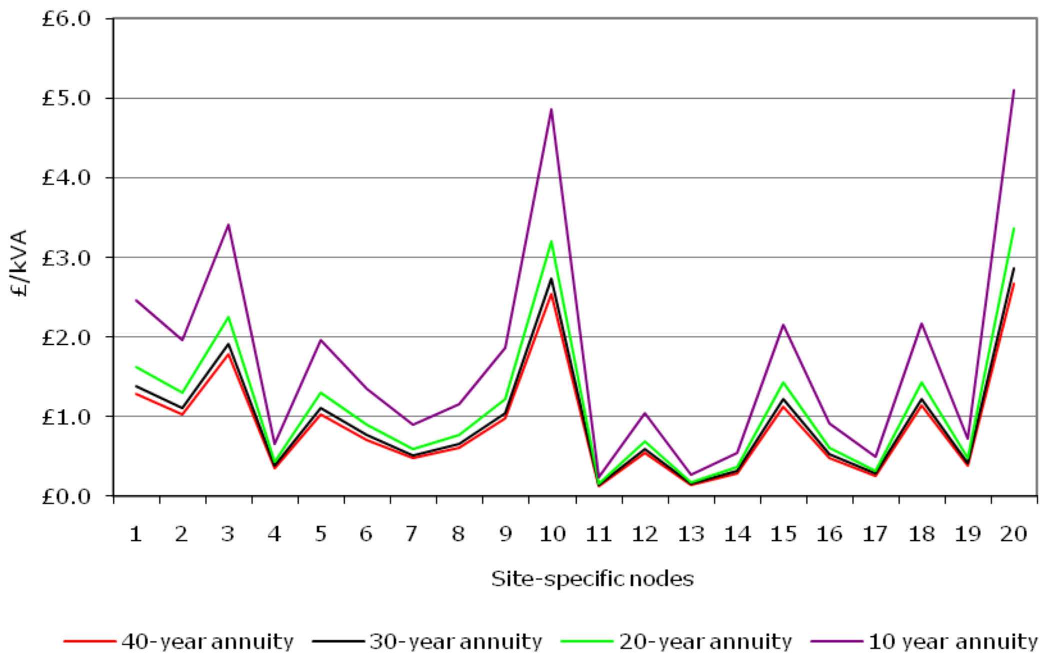
Issues highlighted during development

Some industry participants and commentators have already raised concerns in relation to EDF's proposed 40-year annuity rate. In particular, whether a 40-year period is representative of customer behaviour.

Ofgem analysis

We have calculated annual £/kVA marginal cost charges for a sample of SPN network site specific nodes using a series of annuity factor assumptions. Figures 12 and 13 below compare the marginal costs for the sample of site-specific SPN network nodes with annual charges using 40, 30, 20 and 10-year annuity factors.

Figure 12: Annuity factor comparisons



Source: Ofgem

The key points to note from Figures 12 and 13 are that the use of a 40-year annuity factor results in customers paying a small annual marginal cost charge relative to the full incremental cost, and there is some difference in annuitised charge depending on the time period of the annuity.

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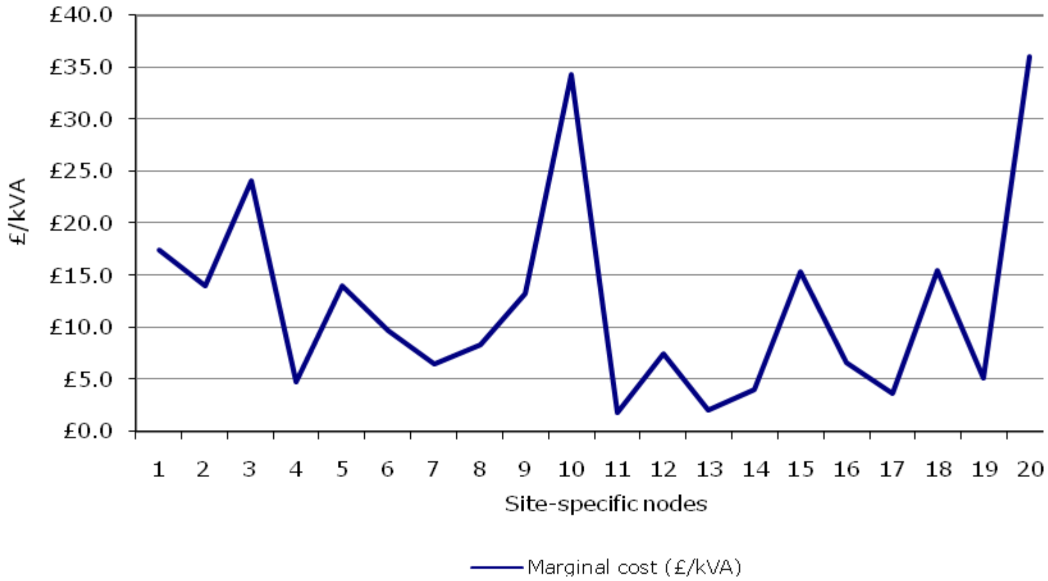
Figure 13: Marginal (£/kVA) reinforcement cost



Source: Ofgem

Schedule 4 – HV/LV generator charging

Introduction

This schedule sets out EDF's proposals for generator UoS charges at HV and LV levels. As set out in Annex 1, EDF propose to allocate charges using the same principles as those that are used for DRM demand tariff groups.

This schedule is based on reviewing EDF's Modification Proposal and the accompanying Excel tariff model, as well as EDF's March 2008 paper on principles for HV/LV Generation tariffs[37].

Proposals

EDF assume the SPN network will continue to be demand dominated and appropriately sized and sited generation will therefore offset the need to reinforce the SPN network for demand users.

They propose to set HV/LV level generation network time band costs equal to the negative of demand network time band costs. This approach results in a credit placed on generators based on their offset demand costs. In order to provide the most effective cost reflective signal to generators, EDF propose to continue to use the five usage time bands to charge for these network costs (benefits).

The offset reinforcement costs (benefit) are fully credited for network demand costs above the 0.433 kV network. Half of the offset costs are credited for network demand costs at the 0.433 kV LV network. EDF also propose to credit generation with long term savings from offset £/kW National Grid exit charges. The value of this credit is aligned to generators production at time of system demand peak, i.e. within the winter peak time band.

These network costs (benefits) are then allocated to charges for generation tariff groups based on tariff time band coincidence, network diversity and losses. The following charging formula is used to allocate network costs (benefits) based on these principles:

> Tariff group annual time band cost = tariff group time band coincidence * network diversity * network time band costs * losses

The accreditation and apportionment of offset costs (benefit) for tariff group charges is based on the tariff group's coincidence factor for each time band.

For non-half hourly (NHH) customers, EDF propose to credit offset cost based on a 0.4 coincidence factor for all tariff groups and all usage time bands.

For half hourly (HH) metered tariff groups, EDF propose to use the time band coincidence factor data provided in Table 7. Generators will only receive an offset reinforcement cost credit - based on these tariff group coincidence factors - if they show metered generation during the usage time bands.

The key point to note is that HH customers – provided they show metered generation during the usage time bands – receive a more significant offset reinforcement cost credit relative to NHH customers.

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[37] EDF Energy Networks, 'HV/LV Generation tariffs principles paper', March 2008. A copy of this letter is provided on our website alongside this consultation document.

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Table 7: NHH and HH generator tariff group coincidence factors

Time band	All NHH	LV HH	LV Sub HH	HV HH
Night	0.4	0.99	0.99	0.87
Winter peak	0.4	1	1	1
Winter shoulder	0.4	0.91	0.91	0.91
Summer peak	0.4	0.92	0.92	0.67
Other	0.4	0.95	0.95	0.99

Source: EDF Energy Networks

The key points to note from Table 7 are as follows:

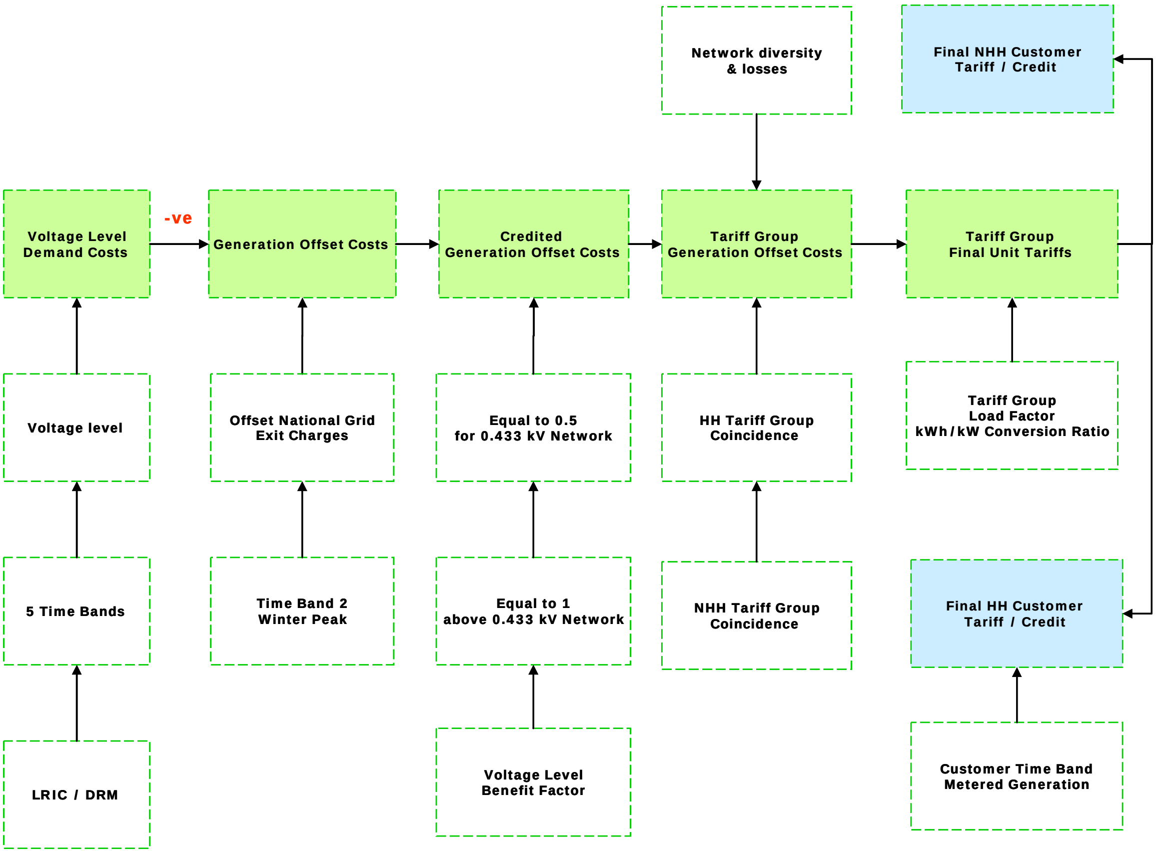
- NHH customers are allocated a generic coincidence factor value. As a result, the benefit accredited to generation is also generic for all time bands.

- HH customers are allocated a variable coincidence factor value for each time band and each tariff group. Relative to NHH customers, a more significant benefit is allocated to HH customers. However, to be credited with this benefit, generators must show metered generation during the relevant usage time band.

Final p/kWh generation tariff group charges are then calculated based on tariff group load factor kWh/kW conversion ratios and tariff group annual time band cost.

The key stages from EDF's proposed HV/LV generator charging arrangements are summarised in Figure 14 below.

Figure 14: EDF HV/LV Generator Charging Methodology



Source: Ofgem

Schedule 5 – Summary of consultation questions

1) Application of a power flow scaling factor

1. Are EDF's proposals to scale all power flows appropriate? Is it clear why EDF propose to scale power flows using a factor of 0.6?

2. Does the proposal provide an effective trade-off between cost-reflectivity and practicality for the charging methodology?

3. Have EDF adequately considered alternative approaches to modelling for a highly loaded network? Are there alternatives that they have not considered?

2) Calculation of capacity and unit charges and the impact on incremental cost signals

4. We ask for views as to whether EDF's approach for calculating final unit rate charges is appropriate? Is the distortion of incremental costs suitable given the objective of better cost reflection of incremental/avoidable reinforcement costs?

5. Does EDF's proposed approach provide an appropriate balance between achieving cost reflectivity and recovering allowed revenue and other costs in a predictable manner?

3) Transparency and predictability

6. We welcome views on the transparency of EDF's proposed methodology and whether it is clear from EDF's modification report how they intend to modify their current methodology?

4) Further issues

LRIC pricing and the rate of load growth

7. We ask for views on whether the use of zonal growth rates in EDF's charging methodology is appropriate?

8. Do respondents consider the concerns with a LRIC charging methodology are relevant and material in relation to EDF's proposal?

Revenue reconciliation

9. We welcome views on whether the scaling approaches for demand and generation are appropriate?

Use and application of five network time bands throughout tariff calculations

10. We welcome views on the extent to which it is appropriate to use five time bands? In particular, whether it is appropriate to differentiate between the seasons?

11. Do respondents consider it appropriate for capacity charges to be based on time band 2 (winter peak)?

Maximum and minimum power flow demands

12. We welcome views on EDF's proposed 'Triad' approach.

13. Is the use of maximum levels of demand appropriate for calculating demand and the use of minimum levels of demand for generation charges

Calculation of HV/LV generator charges

14. We welcome views on whether EDF's proposals for HV/LV generator charging are appropriate.

15. Do respondents consider it appropriate for a credit to be given against unit charges for National Grid exit charges?

LRIC pricing and the use of an annuity factor

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16. We welcome views on the appropriateness of a 40-year annuity factor.

Data accuracy

17. We welcome respondents' views on data accuracy in EDF's proposed methodology.

18. Does the use of forecast growth rates from the LTDS represent an appropriate trade off between cost reflectivity, transparency and predictably?

Size of increment

19. We welcome views on the extent to which it is appropriate to use a 1MVA increment in the context of a LRIC based charging methodology.

20. Do respondents consider it appropriate to measure the impact of demand and generation on a consistent basis?

Cost drivers

21. We welcome views on whether it is appropriate for EDF's model to ignore fault level driven costs.

New HH/LV demand tariff

22. We welcome views on whether this new tariff is appropriate.

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