Cost Reflectivity in Transmission Charging

Does it matter?

What does it mean?

Introduction

This note contains some of the thoughts accumulated over the past twenty years or so of thinking about the subject. It gives a view on whether cost reflectivity is important and then discusses what it might mean, with illustration from five different actually or potentially used methodologies. It is written with the emphasis on electricity charging for generation although the same principles should generally be applied to demand with respect at least to any element of the charge that leads to locational differentials. Although "transmission" is in the title it is really applicable to any network with generation and demand connected and indeed two methodologies currently being developed for distribution charging in Great Britain are considered as candidate methodologies for the transmission system. After all there is no reason in principle why one network with generation and demand connected to it would be better charged for using a different methodology from another network purely because one operates at different voltages from the other.

Clearly there is much discussion at present on appropriate charges for non traditional types of generation, particularly those that are intermittent. This is not discussed further as different methods of dealing with this may be applied to any of the methodologies considered in Part III and this is a matter of application of a particular methodology rather than the basic philosophy of any of them.

The assumption is made that for any pattern of generation and demand connected to a network there are rules as to what that network is required to comprise i.e. that there are some network planning standards (which for the avoidance of doubt could be based on operational standards and a cost benefit analysis). Clearly for transmission in GB there is a fundamental review of the relevant standards in progress and all that will be said is that any fundamental change to the standards could impact significantly on both the total network investment required and individual parties' charges, assuming that these are calculated on some sort of a cost reflective basis. Getting some sort of timely closure to this review might therefore be considered expedient at a time when the next transmission price control review is being worked on and there is a fundamental review of charging for transmission. I will say no more about this.

The views in this are purely my own and have not been written to promote commercial advantage for any particular party or generation technology type.

Part I Why cost reflective charging?

The area of cost reflective charging being considered is that of locational differentials i.e. the difference between connecting a power station (or a demand) in one place rather than another. It does not deal with the total revenue that a network company is allowed to collect nor to how much of that revenue is collected from generation as opposed to demand. The former two areas can be dealt with independently from the question of locational differentials. For example if it is decided to collect no revenue from generation (or demand) then there can still be locational differentials between generation (or demand) by virtue of having negative tariffs so that the sum of all the income recovered from generation (or demand) is zero. Of course the sum of all the income recovered from generation or demand or indeed the total if it is not desired to set a target income from each can be set to any value, irrespective of the existence or size of locational differentials between generators (or demand).

In any network that has generation and demand connected to it power stations at different locations may have different station gate costs to the same type of power station located somewhere else (and some types of power stations may have a very limited number of locations at which they are viable). Different fleets of power stations (and demand locations) will result in the need for different transmission networks that will have different costs. In order to provide the most economic power (of whatever carbon intensity / renewable or other content that is required) delivered to the final customer it is self evident that the total cost of generation and transmission should be minimised.

There are three approaches to power station site decision making, two of which potentially achieve this.

Central Planning

If a single body plans and develops all power stations (and possibly but not necessarily the transmission system as well) then they obviously have the capacity in theory to optimise the total cost of generation and transmission. Leaving aside how this would cope with the vast number of much smaller projects that are hoped for it clearly would not be compatible with anything resembling a liberalised market.

It is sometimes argued that there can be some central intervention in station locational decisions relative to the transmission network via the planning regime. For example when granting section 36 consent account could be taken of the location of the proposed power station and the consequences for transmission expenditure if it goes ahead. My feeling is that this would be mixing up two processes in a potentially opaque way and in any event the authorities would not be privy to the detailed economics of the generation project so could not perform a proper optimisation. I have worked in a European country where the transmission owner is invited to submit a view as part of the equivalent of our section 36 process but this does not really constitute any type of effective optimisation of generation plus transmission costs.

A central buyer system where the central purchaser received offers for energy from potential new power stations and could then select which outputs to purchase, having taken account of the transmission cost, could in theory provide an optimum system. It would of course be subject to the judgement of the single purchasing agency and would not be able to cope with a large number of smaller projects.

Freedom for developers to site projects combined with cost reflective network charges

Here developers are free to site new projects wherever they want, subject to normal planning / consenting and the network charges that they face vary by location in a manner that is meant to be “cost reflective” i.e. differs by location in some manner that is related to the different costs that the new project imposes on the transmission network. Leaving aside for later what “cost reflective” might mean this is what is said to apply currently in Great Britain and has the potential (provided the cost reflectivity is actually cost reflective!) to promote a least cost combination of generation and transmission.

Freedom for developers to site projects with no locationally differentiated network charge

Basically if there are no locationally differentiated transmission charges project developers have no need to take any account of the network expenditure related to their project and there is no reason for the resulting system to yield the lowest possible generation plus network cost. It could only be justified on the grounds of simplicity if it could be demonstrated that in no case would a cost reflective variation in network charging make any difference to generator locational decisions. It is thought unlikely that this condition could be demonstrated in any territory of significant size. Despite this it has been adopted in a number of countries, often due to the desire not to charge generation for using the network and not considering that this could be achieved on average with a mixture of positive and negative charges.

Commonly used arguments against cost reflective network charging

The most commonly used targets made against cost reflective charging are that:

- Generators have little or no choice where to locate and / or charging cost reflectively discriminates against certain generation technologies

- Other factors overwhelmingly determine generation location and network charges makes so little difference to project economics that it is a pointless complication of the market

The second objection may be true for the majority of projects but is unlikely to be the case for those where the economic case is marginal. The first part of the first objection is true in terms of individual projects at specific locations. A project for a station at location X is just that and if it were to be proposed for a different location would become a different project. However what network charges may have an effect on is whether individual projects go ahead or not. It is of course unfortunate for a specific project developer if cost reflective network charging makes its particular project uneconomic. On the other hand there may be other developers projects (or other projects of the same developer) that only become economic because of cost reflective network charging.

It may be that for the majority of projects the second point is true i.e. network charges will not have an effect on whether they go ahead or not. However for those at the margin they will either stop projects going ahead or allow others to proceed that otherwise would not. They should therefore affect the overall fleet of generation that emerges in a way that minimises the total cost of that generation plus transmission. Yes some projects may go not go ahead when they would have done with uniform (non locationally varying) charging but others may go ahead when they would not have done with uniform charges. As to the argument that locationally differentiated network charging discriminates unduly against certain generation technologies, if the government wants to encourage particular technologies then it should provide appropriate incentives for that technology which should be sufficient to account for typical cost reflective network charges that that technology may face. For example by their nature far offshore wind farms are likely to require more transmission expenditure than technologies that can be built nearer to demand centres and it is up to the government, to the extent that it wishes to encourage such technology, to ensure that the incentives to build it are adequate.

Overview on cost reflective network charging

On the assumption that one does not want to spend more than necessary in total generation and transmission costs to achieve a desired generation fleet (in terms of carbon intensity / types of technology or whatever) there appear to be two alternatives i.e. either

1. Central planning of generation locations with the central planner having full site of both the generation and transmission economics or
2. Freedom of generation to locate where they choose with cost reflective network charging.

Clearly whether Government wishes to adopt the first option is a matter for them. I would just make the point that it would become rather unwieldy with the large numbers of relatively small / community / micro scale generation that are envisaged. It is important to recognise that with the current arrangements in England and Wales even the smallest distribution connected micro generator that has no direct liability for transmission charges sees approximately the same locational differentials in transmission charges as a multi GW transmission connected project. For the purposes of this note I will therefore assume that generators will continue to be free to choose their locations and that cost reflective network charges will remain an essential feature of optimising the overall generation and transmission system.

What exactly however might cost reflectivity in transmission charging mean?

What is cost reflectivity?

Part II some general issues – lumps and cost assignment

On a simple level one could say that if a party takes an action and that causes £x network related cost then the cost reflective charge is £x and it should be paid by the party that took the action. That is certainly a view on cost reflectivity (and the predominant one behind the so called “deep connection” charging methodology). It begs the question though as to what is meant by taking an action? For example does continuing to behave as you have done previously count? Who owns any spare capacity created?

These and other issues will be discussed later when a few methods that some people would consider cost reflective are discussed. First however there are two general overarching issues that need to be given thought in any consideration of what is meant by cost reflective charges.

Lumps

Lumps are a very important feature in charging cost reflectively for any network that cannot usually be expanded in small increments. Firstly it is useful to note that electricity network investment is generally lumpier than gas network investment.

Obviously bringing either an electricity or a gas network to an area that does not have an existing one will require a “lump” of discrete investment. However once the network exists it is often possible to expand the capacity in the case of gas incrementally to a greater extent than is usually possible for electricity.

This is because gas flows are I understand generally limited by the pressure drop along the pipe. If the pressure drop is too great then it is possible to reduce it and thus increase the capacity of the pipe by enlarging the diameter of the pipe along an incremental part of its length. Thus for a 100km pipe one could increase its capacity by increasing the diameter of 10km, 11km, 12km or any proportion of its length that is required. One could also of course fit a compressor station. It is therefore possible to increase gas network capacity more or less incrementally (although obviously there may come a point when another pipe will be required).

In the case of electricity the capacity of a circuit is generally limited by its current carrying capacity. To increase this one has to fit a larger conductor (which may or may not require new towers) or adjust the tension of the existing conductor but to get any increase in capacity this has to be done for the whole length of the circuit. Hence the cost of expansion of electricity networks tends to come in a lumpier pattern than that for a gas network.

Of course electricity network capacity is sometimes limited by voltage or stability considerations rather than current carrying capacity and in those cases the capacity may be increased other than be increasing the current carrying capacity of a circuit involving work on its entire route. However it is generally the case that increasing capacity in areas where networks already exist is lumpier for electricity networks than gas ones.

Why lumps are important

The cost characteristic of lumps are that they each cost a discrete amount and provide a discrete amount of capacity. If therefore demand for capacity is increasing continuously it is essentially cost free to provide additional capacity in between each lump of investment. One could therefore argue that cost reflective charging should consist of alternating periods of low charges when there is spare capacity and high ones when another lump of network investment is required.

Clearly if the increase in capacity required and the size of the lumps was such that a similar lump of investment was regularly required every few years it would be pointless alternating between low and high charges and a steady charge reflecting the smoothed network investment pattern would provide a cost reflective stable signal reflecting the steady investment required. On the other hand if a lump is of significant size and not an investment that is needed on a regular basis every few years then there is a good argument that it is important to have a pricing methodology that does signal the difference between not having to make the investment for the foreseeable future and the investment being necessary.

Looking at this another way, it is efficient that spare capacity is used and a low charge is likely to promote this, whilst when the need for investment is imminent charges should reflect this. Charges that fluctuate regularly between high and low as similar lumps of investment are made every few years serve no useful purpose but if the lumps are sufficiently rare (relative for example to the life of a typical power station) and large it may become more important and indeed cost reflective to signal when all the spare capacity has been used up and the rare and significant lump of network investment is actually required.

How smooth over time required investments in a network are likely to be, as opposed to how irregular, non inevitable and lumpy they are expected to be, should be a prime consideration when considering whether cost reflective charges should be smoothed reflecting a continuous and regular pattern of network investment or allowed to vary according to the level of spare capacity / how imminent a new required lump of investment is.

Cost assignment

Many charging methodologies involve assigning causation of flows (or changes in flows) in network elements to particular demand and generation as part of the process of setting charges. It is important to be aware that there are at least two philosophically different ways of doing this that can produce quite different results. These are what I will refer to as an incremental flow method and a flow tracing method. Any network charging methodology that requires circuit flows (absolute or incremental) to be assigned to particular demand and generation ought to be absolutely clear on which method it is using and why.

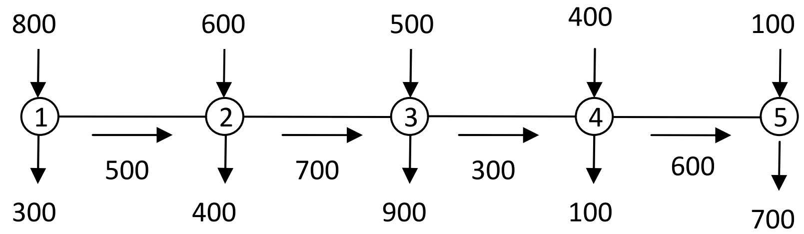
Incremental flow methodology

This essentially looks at an increase in demand or generation at a node and measures how much the flow increases or decreases on all circuits in the network and uses this as a measure of the incremental use of those circuits by the incremental change at the node and hence in some way the share of the reinforcement cost (if any) of the relevant circuit.

The two key things to note about this methodology are that firstly the answer that you get will depend entirely upon what you do to compensate for the increment at each node. For example if you balance it by an equal and opposite increment at one other node you are likely to get a different flow pattern depending on which other node you choose and this will be different to the pattern you will get if for example for an increase in generation at one node you decrease generation uniformly at all other generation nodes to compensate. This will itself be different to the answer that you get if you decrease generation at all other generation nodes in proportion to the amount of generation there originally and a different answer will also be given if you compensate for increment of generation by incrementing demand at all demand nodes.

The other feature of this methodology is that in general it is likely to show an increment of generation at one node producing a changed flow in circuits right at the opposite end of the system and some parties may for example question whether it is right to charge for example generators in Scotland for the change in flow that an increment there may be said to produce in a circuit in the South West of England.

A simple example illustrates these points.



The above shows a radial network with 5 nodes with generation flowing onto each (above) and demand being taken from each (below). The resulting left to right flows on the four circuits are shown, losses being ignored.

Consider the effect of increasing the 800MW generation at node 1 by 1MW. If node 3 is chosen as the slack node (the one that compensates for this small change) then the flows on lines 1 to 2 and 2 to 3 will each increase by 1MW with no changes to the flows on the other lines. On the other hand if node 5 had been chosen as the compensating node the flow would have increased by 1MW on all of the lines. If one decreased the generation by 1/4MW at each of nodes 2 to 5 one would get a different change in flows and if one decreased the generation at each of these nodes in proportion to the original generation there initially one would get a different result again. Furthermore increasing the demand at each node in proportion to the original demand there to total an additional 1 MW would produce yet a different change in flows in each line.

There is nothing intrinsically incorrect about any of these methods (although probably either changing all generation or all demand has most merit) but it should be recognised that the results will be different depending on which method is used.

The second effect that should be noted is that using a methodology that changes either all demand or all generation to compensate for 1MW increased generation at node 1 will change the flows in all lines including line 4 to 5. Assuming that this change in flow is used to apportion either an incremental or an actual reinforcement cost of these lines to the generator at node 1 some could argue that it is not cost reflective for the generator at node 1 to pay towards the reinforcement (real or hypothetical) of line 4 to 5. In other words is it cost reflective for a generator in Scotland to pay towards the actual or hypothetical cost of reinforcement of a line supplying demand in the South West or London?

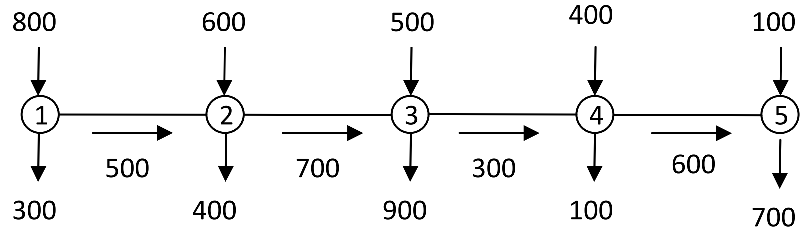
Of course one can argue that it is completely cost reflective and fair because if the demand increases at node 5 and line 4 to 5 is reinforced then all generation except that at node 5 benefits equally because it has access to a larger demand at node 5 to sell its output to. If one accepts that then the incremental flow methodology for assigning circuit related costs to demand and generation is probably acceptable so long as one also recognises its sensitivity to how one compensates for the increment at each node. If not then one might want to consider a flow tracing methodology.

Before leaving the incremental flow method it is worth mentioning that it does of course require a work around if there are direct current links in parallel with the ac system as the flows in these are controlled by human intervention rather than by the laws of physics. The flow tracing methodology does not entirely get around this issue as it would still depend on the flow in any direct current circuits running in parallel to the ac system and these have to be decided upon “manually”.

Flow tracing methodology

This methodology assigns circuit related costs to demand and generation by tracing out the flows and assigning them to demand and generation at each node. Considering the simple radial network again the circuit related costs (whether hypothetical reinforcement, actual reinforcement or whatever) could be assigned as follows. Note that there is more than one possible method of flow tracing methods so what follows is purely illustrative.

For a more definitive guide to the methodology see **Bialek, J., 1996**. Tracing the flow of electricity. IEE Proceedings on Generation, Transmission and Distribution.



Generation at node 1 would have 500MW assigned to line 1 to 2. At node 2 it is assumed that the demand of 400MW is met 5/11ths by the generation at node 1 and 6/11ths by the generation at node 2. The 700MW flow on line 2 to 3 is therefore attributed between the generation at nodes 1 and 2 in proportion to what remains from that absorbed by the demand at node 2 (and in the case of the node 1 generation at node 1). So the flow in line 2 to 3 attributed to the generation at node 1 is 500-(400x5/11) = 318MW. The flow in line 2 to 3 attributable to the generation at node 2 is 600-(400x6/11) = 382MW. Another way of looking at this is assigning the flow away from node 2 of 700MW in proportion to the two flows into it, from the local generation and from node 1.

This process can be continued and it can be seen that by the time the flow on line 4 to 5 has responsibility assigned the proportion remaining from the generation at node 1 will be small.

For a meshed network the computation is of course more complex. The basic method is however to assign responsibilities for flows out of a node in proportion to the flows into it. The other aspect to be born in mind is that if it is being used to assign responsibility for changes in flows then basing the ratios on a current load flow pattern only works on the assumption that the flow pattern does not change radically i.e. incremental flows split up in a similar manner to existing flows. Obviously if one is trying to apportion the cost of an existing network equitably (as opposed to giving an economic forward looking signal about the effect of incremental flows on future reinforcement needs) then the method does not require this assumption.

In any event it is a method of assigning line flows to demand and generation that may be considered as an alternative to the incremental flow based method. Although it was originally devised to trace total flows for the purposes of apportioning total costs (either of losses or network elements) there is no reason why it should not be used (assuming that the assumption about incremental flow patterns being similar to existing flow patterns holds) to apportion incremental costs or costs of actual or hypothetical reinforcement between network users.

Part III some cost reflective charging methodologies

Having thought about lumpiness and how one might assign circuit costs (historic, future actual reinforcement if any, future hypothetical reinforcement or whatever) to individual generation and demand a number of cost reflective charging methodologies are discussed below as possible candidates.

Deep connection charging methodology

This is in principle very simple in that if a new party wishes to connect to the system or increase its maximum generation or demand and this results in network investment being required that party pays for that investment. In terms of the cost of the existing network one either recovers that on a uniform basis from whenever one starts this methodology or tries to reconstruct the development of the system (since the beginning of time?!?) and unpick what the deep charges would have been for each party as it connected. I will not comment any further on the practicality of that.

In terms of forward going deep connection charging two of the major drawbacks would appear to be whether the responsibility for the new investment is really just due to the newly connecting party or equally due to the continued presence of its neighbours and what to do about spare capacity created by investment funded by a newly connected party.

The former is an important consideration as network cost reflectivity is relevant for optimising generation closure decisions as well a new entry. Perhaps if an existing neighbour saw that due to the reinforcement required it would be subject to higher charges it would decide to close and the reinforcement to accommodate the new entry would not be required after all. In terms of spare capacity one could take the economically pure but not terribly equitable view that it is efficient to let parties use spare capacity without paying for the reinforcement that created the capacity. One could alternatively try to devise some sort of second comer regulations along the lines of the regulations applicable to distribution connection charges.

Possibly the biggest drawback with the methodology is the fact that a relatively small capacity addition may trigger a large network investment requirement creating far more capacity than is required by the new entrant and this may prevent that new entrant ever coming forward even if, if the network capacity was increased, it would be utilised by that entrant and a large number of other new parties, each one too small to contemplate paying for the reinforcement by itself.

Incremental Cost Related Pricing (ICRP)

As the methodology that has been in use in England and Wales since the mid 1990s and in Scotland since 2005 it is obviously the one with which most players in the GB market will be most familiar. It may be characterised as an ultra long run incremental pricing methodology based on the assumption that there is no spare capacity and increased flows on all circuits require incremental reinforcement of those circuits. In fact there is some provision for an adjustment for circuits with significant spare capacity but this is not a part of the core methodology.

A major strength is therefore that it is relatively stable in that charges do not vary according to whether a line is about to require reinforcement or not. It can of course be argued that on the cost reflective scale that is also a major weakness in that no difference is made in principle to charges relating to reinforcing a circuit whether it does actually require reinforcement or it is many years away and may in practice never need reinforcing.

I have a significant concern as well with the use of the expansion factor based on the indexed historic costs of building 400kv overhead lines for predicting the future cost of expansion. It is notable that the cost used (around £100/MWKM capital cost equivalent to about £10/MWKM annuity) is a factor of 10 below the estimated typical cost of future expansion as used for the ENSG 2020 work and the SQSS review intermittent generation assessment. This may be due to some of the methods by which increased capacity will be obtained in the future being more expensive than building new 400kv lines. The methodology allows an adjustment to the expansion factor being made in some cases. However there must be a question to be asked about the cost reflectivity of a methodology that is anchored on an expansion factor which could be argued to be inaccurate or in doubt by a factor of ten.

Some of the outcomes that the ICRP methodology produces appear to be counter intuitive. For example because the cost per MWKM is significantly higher at 132kv than at 400kv the result of uprating a certain line in Scotland from 132kv to 400kv will be that the differential of charges between one end of it and the other will decrease. It has been argued that this is perfectly cost reflective because there will be far more generators on the sending end of the line and so there will be far more people paying the lower differential than there were paying the higher differential for the 132kv line and the “differential income” collected will increase making the result cost reflective. It can also be argued that the effect is forward looking i.e. having uprated the line to 400kv the costs of providing future incremental capacity is less than previously and therefore the forward looking charges should be lower.

I find it odd however describing a situation as cost reflective where after spending money in order to increase capacity in an area the charges for the users in that area for whom the capacity was increased becomes closer to the users not in that area than they were before. Whilst it is reflective of forward looking incremental costs and may affect the inclination of parties prior to the reinforcement to exit the system it is not clear that it sends a sensible and efficiency maximising message to parties considering joining the system. For example it could send the message “Build a project of size x and no network upgrading is required. Build a project of size 2x and we need to upgrade the network as a result of which your charges will be lower relative to other generators than if we had not decided to upgrade the network.”

Long Run Incremental Cost Pricing (LRIC)

I make no apology for including a methodology that has been developed to be used for EHV distribution networks. It assumes both generation and demand on the network and thus there is no reason why it could not be considered as a potential transmission pricing methodology. Indeed the ICRP methodology was considered as a potential methodology to be applied to distribution networks and one DNO actually proposed an ICRP / LRIC hybrid methodology. The big advantage (though some people could argue that this is a disadvantage) of LRIC over ICRP from a cost reflectivity point of view is that it does take into account how near circuits are to needing reinforcement.

In the brief description of it I will concentrate on the principle of how the locational element of charges are derived – what are then done with these in order to generate the final tariff is left to one side as possibly not currently being relevant for transmission as they way in which revenue to be collected is split between generation and demand is currently completely different in transmission and distribution networks. In addition for distribution networks the generalisation can often be made that demand driven reinforcement generally occurs at peak demand periods whilst generator driven reinforcement often (but not always) occurs at minimum demand periods, which is not generally the case for a transmission system.

Briefly however one set of “future reinforcement related” costs are associated with peak demand conditions (assumed to be demand driven) and are applied to demand and as a credit to generation. Another set of “future reinforcement related costs” are associated with minimum demand conditions and assumed to be generation driven. They are applied to generation. There are then further stages including assigning the cost of sole use assets, other cost apportionment and scaling to produce the final charges. These steps are generally common between the LRIC and FCP methodology below. However it is the basic method of deriving the forward looking cost components of the charges that are of interest here.

The methodology that determines the locational element of charges comprises load flow studies at both peak and minimum demand conditions. These are both repeated with an increment of demand or an increment of generation at each relevant node. Contingency analysis is undertaken to establish a set of security factors that are based on the most onerous outage condition for each branch and will be the condition that eventually drives the need for its reinforcement.

For each base case condition with a background 1 % a year growth rate the number of years until each branch requires reinforcement is calculated and then the net present value of the cost of undertaking that reinforcement is calculated. This is repeated with the increment of generation or demand and the time until the branch requires reinforcement will become either more or less and the difference between the net present values of the reinforcement cost of each branch with and without the increment can be calculated.

Each branch incremental cost is then calculated as the difference in the net present value of reinforcing that branch with and without the increment of generation and demand, multiplied by an annuity rate. A branch incremental cost can be determined for each branch, for an increment at each node and for maximum demand and minimum demand conditions. Branches can be divided into those where maximum demand conditions drive the reinforcement and those where minimum demand conditions are the driver.

For each relevant node (where there is generation or demand) for the minimum and / or maximum demand conditions a marginal cost can be derived by summing the branch incremental costs of those branches where reinforcement is driven by that condition. The nodal incremental charge is then derived by dividing the nodal incremental cost by the magnitude of the increment (of demand or generation) used.

The above is a gross simplification of the process. It is perhaps easiest thought of as calculating how much increments of demand or generation advance or postpone reinforcement in network branches and looking for each node at the net present value of that advancement or postponement.

Disadvantages of this methodology include its complexity and that it does require an assumption about a background rate of network growth, which some people may consider either arbitrary or something that should not need to be assumed. On the other hand, comparing it with the other incremental methodology, namely ICRP, it explicitly takes into account the spare capacity in each branch network and the charges are weighted to give more importance to increments that bring reinforcement significantly nearer and also where the reinforcement is imminent.

Forward Cost Pricing (FCP)

This is the alternative method under development that may be applied instead of LRIC for ehv distribution charging. As far as generator driven reinforcement costs in particular go the big difference between it and LRIC is that it looks at discrete “possible” future generator additions and if these were to drive a reinforcement there would be an appropriate forward looking charge, if not there would not be. It thus could be said to take more account of the lumpiness of network investment. It is however still driven by future “hypothetical” generator investments of discrete sizes rather than actual network investment plans.

The basic method of calculating the forward looking element of generator driven investment is to divide the network into groups of Grid Supply Points and Bulk Supply points that normally run as interconnected networks via distribution network circuits at the same voltage. Each of these network groups is analysed separately. For generator driven investment a “test sized generator” is applied in turn to all points on the network where such a generator could connect and it is established whether this results in the requirement for any reinforcement and if so what. Different “test sizes” are used according to the location (voltage level and whether substation or circuit connected) to which the hypothetical new generator is being applied.

If a test size generator does precipitate the need for an investment then the “headroom” is established before that investment would be required by looking at the amount of generation at that location that would require reinforcement compared to the test size of generator appropriate for that location. The ratio of the size required to precipitate investment to the size of the test generator is used to determine how many years ahead (out of ten) the reinforcement would be required: the cost of that reinforcement is then discounted by the number of years ahead it has been assumed to be needed.

There are several other stages to the process including looking at the total volume of test sized generators applied at each voltage level and then comparing that to the total amount of generation anticipated to connect at those levels to determine a probability of each test sized generator connecting which modifies the costs built up from the total of the individual applications of each test sized generator.

The total generator precipitated cost component is determined for each network group by dividing the “expected and discounted” reinforcement costs in that network group by the total generation in that group expected to exist.

As for LRIC, generator driven investment is assumed to occur at minimum demand conditions. The system is also modelled for maximum demand conditions primarily to determine demand charges but in this case rather than use the equivalent of test sized generators to determine whether reinforcement is required in the ten year ahead window, each of those ten years is modelled separately and if reinforcement is required its cost is established and discounted back to the first year of the study (the one for which charges are being evaluated). If a reinforcement is required in year x it will also be in year x+1 but it is only charged at the discounted rate of implementation in year x, as it will not have to be done again the following year. Non intermittent generation is given a credit for the demand driven reinforcements calculated in this way.

The method effectively splits the network into groups and for each group looks at whether a generator of the size that one would typically expect to connect at a voltage level, connected there, reinforcement would be required. If yes a reinforcement related charge is applied for generators at that voltage level in that group, modified by an "expected time to reinforcement" (dependent on headroom) and the "probability" of that test sized generator actually connecting (based on the total volume of the test sized generators used in a group at each voltage level compared to the volume expected to be connected).

The methodology moved away from the "continuous (positive or negative) reinforcement required" approach of ICRP and the "reinforcement will be advanced or deferred" assumption of LRIC by saying that if a test sized generator at a location causes no requirement for reinforcement then there will not be any associated reinforcement related charge. The charges are of course still related to hypothetical reinforcement costs.

Some thought would need to be given to how to apply the methodology to a single completely meshed transmission system. It is judged though that if it was thought appropriate the basic methodology of applying test sized generators to various system nodes and testing whether reinforcement was precipitated could be adapted for use on a transmission system.

"Possible future Irish methodology"

The methodology described here has been developed for possible future use on the transmission network in Ireland (the Republic and Northern Ireland). At the time of writing it is not clear whether it will be adopted and if so when but it is certainly worth considering as a candidate methodology.

The key feature of the methodology is that locational differentials are determined by actual network reinforcement costs (planned or recently carried out) rather than hypothetical ones, whether based on the assumption of continuous reinforcement or the probability of discrete events happening. It differs however from a deep connection charging methodology as all parties that use a reinforced circuit whether new or existing are subject to the associated locational differential and the new assets are only charged for on a locationally differentiated basis to the extent that they are utilised i.e. spare capacity is charged on a locationally non differentiated basis. In addition the locational differential charge out of reinforcements only applies for a period before and after they are commissioned.

The locational charges for generators in year x are determined by modelling the system for year x+5 and measuring the use of all circuits that are planned to be constructed or reinforced over that period. In addition the use is also measured of the circuits that have been newly built or reinforced over the past seven years. The “use” of these circuits can be positive or negative depending on whether an increment of generation increases or decreases the flow in each planned or newly reinforced circuit.

A charge relating to the annualised actual cost of the planned or recent network investment is made according to this use. The remainder of the network costs, for example the costs relating to circuits that have no requirement to be upgraded and the costs of circuits that were upgraded more than seven years ago are recovered on a non locationally varying basis.

The logic for continuing to charge locationally on circuits that have been commissioned in the past seven years (which is therefore not forward looking) is so that newly connecting parties who precipitate investment do see the cost implications of their actions even though they may connect after the circuits have been commissioned. If existing parties that utilise positively “planned” reinforcements and therefore see increased charges wish as a result to leave the system it is possible that the planned investments do not have to be made. In these circumstances at the time that they cease to be a “planned in the next five years” requirement they are removed from the locational charging pot.

The methodology is clearly potentially subject to a potentially greater variation of charges from year to year than either the ICRP or LRIC methodologies as actual reinforcement schemes are planned, commissioned and seven years later drop out of the locationally charged out pot. Locationally differentiated charges are however related to actually implemented or actually planned reinforcement schemes and some of the main shortcomings with a deep connection methodology are overcome as both new and existing users pay (either positively or negatively) for reinforcements that they “use” and any spare capacity created due to the natural lumpiness of electricity transmission investment is charged for on a non locational basis. In terms of recognising lumpiness it does also incentivise parties to utilise spare capacity but not collectively behave so as to require reinforcement.

Conclusions on charging methodologies

All of the methodologies described (and many more that have not been described) have some advantages and disadvantages. They can all be said to be in some sense cost reflective. When considering their relative merits it is worth starting by considering the relative importance attached to locational differentials being related to actual costs rather than either continuous or lumpier hypothetical future costs that may or may not actually arise. In addition the importance of lumpiness should be considered i.e. how important is it to incentivise full utilisation of an asset but avoid the need for reinforcing it. Finally the stability of charges over time (not to be confused with their predictability) may be considered more or less important by some parties. It is the relative importance of these factors that will probably determine what flavour of cost reflective network charging methodology you prefer.

Tim Russell 2nd November 2010