Comments on CEPA's draft conclusions in relation to European transmission tariffs

ACER commissioned CEPA to review harmonisation of transmission tariffs in Europe, and specifically to:

- assess whether increased harmonisation of electricity transmission tariff structures would be beneficial; and if this were the case; and
- to recommend the most appropriate policy option.

CEPA presented their draft conclusions at an ACER workshop. In essence their work has concluded that:

- The *status quo* may potentially prevent the efficient least cost development of the European electricity system, though they note that they have found more evidence for distortions in relation to operational than investment decisions;
- In the short term, existing policies and specifically the requirements of Regulation 838/2010 should be sufficient to prevent potential negative effects, and in particular the removal of generation (G) charges or the imposition of a common generation:load (G:L) split would not be appropriate; and
- In the longer term, the establishment of a common set of principles for transmission tarification would be the most beneficial way forward, as they suggest the biggest problems stem from an absence of agreement on such principles.

Energy Norway has asked Frontier Economics to comment on CEPA's findings, and in particular to:

- consider whether CEPA's suggestions for the short term are beneficial and whether they could be improved; and
- consider whether CEPA's suggestions for the longer term are appropriate.

Short term: 838/2010 should be maintained and improved

In general, we agree with CEPA's findings that the *status quo* arrangements are capable of resulting in inefficient outcomes in relation to both investment and operational decisions[1]. To address any potential distortions, 838/2010 provides ranges within which "annual average transmission charges" paid by producers in each Member State must fall (Annex A, Part B, paragraph 2). The range that applies to Denmark, Sweden and Finland also in practice applies to Norway, i.e. 0 to 1.2€/MWh.

These ranges were not set with reference to a detailed study on cost reflectivity and hence do not necessarily represent a move in the direction of CEPA's long term vision. However, neither is there time in the short term for such a study. In this sense, we agree with CEPA that the maintenance of the ranges set out in 838/2010 would be a reasonable interim step – this would at least ensure that bigger differences between tariffs faced by producers do not emerge, even if it will not lead to the "progressive harmonization" referred to in Regulation 714/2009 (Article 18(2)). We certainly agree that this would be preferable to the removal of G charges completely (generators are likely to contribute at least something to forward looking costs) or to the specification of a common G:L split (which would still leave the potential for large variances in absolute G charges, which is what matters from the perspective of creating distortions).

However, we do not believe that CEPA has explored all of the options for improvement on the requirements set out in 838/2010. Specifically, we do not believe sufficient attention has been paid to the issue of exemptions from the charges constrained by 838/2010.

Generic issues associated with exemptions

As noted above, 838/2010 sets specific ranges for "annual average transmission charges" paid by producers. However, it also provides for explicit exemptions from these ranges, specifically for:

- charges paid by producers for physical assets required for connection to the system or the upgrade of the connection (para 2(1));
- charges paid by producers related to ancillary services (para 2(2)); and
- specific system loss charges paid by producers (para 2(3)).

It is not clear why these charges were exempted. It may be because it was assumed that charges for these items would be more likely to be cost-reflective, or it may be that it was felt difficult to estimate appropriate ranges for them.

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1 We note that CEPA has found more evidence in relation to operational decisions. However, we would suggest that conclusions from the lack of evidence in relation to investment decisions are drawn with caution. We agree with CEPA that many wider factors (e.g. tax and subsidy policies) drive investment decisions. It is precisely for this reason that it is difficult to assess how investment decisions may have been different had tariffs been more harmonised, and hence why it is difficult to provide concrete evidence of investment based distortions. Given this, the lack of evidence should not be taken to be clear proof that the distortions do not exist.

However, their existence provides a source of distortions that is not constrained by 838/2010. Ambiguities or differences in the definition of these excluded charges (or laxity in policing of their interpretation) provides scope for TSOs and NRAs to move costs which should more properly fall under harmonized charges into these charges (and *vice versa*).

This should be a concern even in the short term. Issues of interpretation arise in each of the three exclusions set out in 838/2010.

The definition of connection costs varies significantly around Europe. ACER itself, in Table 8 of their 2014 Opinion on producer transmission charges, presented evidence suggesting that the costs which were defined as "required for connection to the system" varied widely depending on whether a shallow or deep connection policy is adopted. Nine countries were reported as having a deep connection policy, where connection charges recovered some main system grid reinforcement costs, whereas 16 countries had a shallow connection policy, where such reinforcement costs were covered by the charges which are constrained by 838/2010.

If one country has a shallow connection charging policy and locational transmission charges to reflect deep system reinforcement costs, and its neighbour has a deep connection charging policy and non-locational transmission charges, in principle it is possible for both to be cost reflective. However, if 838/2010 constrains the locational transmission charges of the first country but does not constrain the deep connection charges of the second, an outcome which is not consistent with a cost-reflective pattern of *relative* charges may result.

The approach taken to defining ancillary services costs may also vary. Take as an example the provision of reactive power by generators (and potentially certain loads). The cost of this provision is frequently recovered through ancillary services charges. However, it is also possible for TSOs to invest in equipment (e.g. shunt capacitive compensation) to provide reactive power. Investments in network equipment may either be defined as part of "average annual transmission charges" and hence be constrained by 838/2010, or may be charged as ancillary services and be unconstrained.

So again, if one country included reactive compensation equipment in transmission charges and these are constrained by the levels in 838/2010, but another country includes them in (unconstrained) ancillary services charges, the *relative* overall charges faced by producers may not be consistent with a cost reflective outcome.

Finally, there is significant variance in the costs recovered relating to transmission losses. In many systems, the losses charge simply represents average transmission losses. However, in some systems, charges to generators are based on marginal transmission losses. Because of the way losses vary with line loading, marginal losses tend to be higher than average losses, meaning that charges based on marginal losses will recover more than the average cost of losses. The surplus is typically used to reduce "average annual transmission charges". Put another way, in some countries some part of the costs which are meant to be covered by the charges constrained by 838/2010 are recovered through high losses charges.

So, within the constraints of 838/2010, for two otherwise identical countries, producers in a system with marginal losses charges could face higher grid costs than those in a system with average losses.

Beyond these three exclusions, there is a fourth implicit exclusion from "average annual transmission charges", namely the cost of congestion.

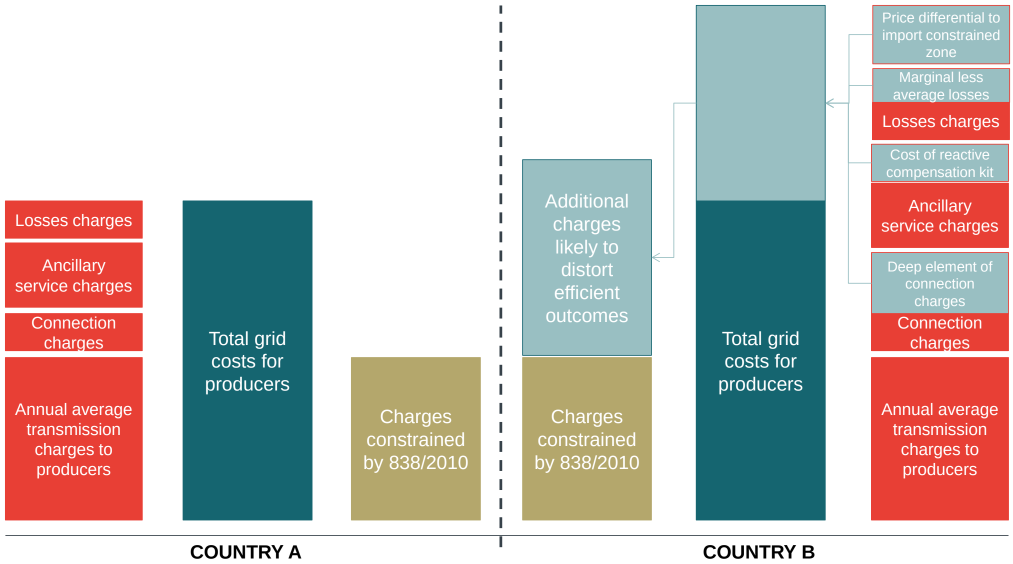
In a number of countries, market splitting creates price zones for energy. Generators in export constrained price zones pay transmission charges, and also receive a lower price for their energy. One could say that they face a further charge related to the short run marginal cost of congestion on the grid, which is equal to the difference between zonal energy prices (or the difference between the system energy price and the zonal energy price where they are located). This "charge" is in many ways analogous to the difference between locational transmission charges which are present in some other systems, and which would be constrained by 838/2010.

The revenue raised through these charges (the congestion rent between zones) is typically used to reduce "average annual transmission charges". In some countries the rent may reduce the load component of annual transmission charges, and in others it may reduce both generation and load components. As with charges based on marginal losses, another way of putting this is that part of the costs which are meant to be covered by the charges constrained by 838/2010 are recovered through excluded charges.

This means that the implementation of 838/2010 may result in outcomes not consistent with cost reflective charges. This can be seen by comparing, for example, a system with locational signals sent through transmission charges (which can be constrained by the ranges set out in Regulation 838/2010) with a system with zonal pricing sending within-country locational signals which are not constrained by any regulation.

These explicit and implicit exclusions all create a potential for distortion. This is shown in Figure 1.

Figure 1. Distortionary effect of exclusions from 838/2010



Source: Frontier Economics

In Figure 1 we show two countries, both of which have equal constrained levels of "annual average transmission charges" as defined by 838/2010. However, country B charges additional costs to producers through separate and unconstrained charges relating to connection charges, ancillary services, losses, and congestion. As a result, producers in country B pay significantly higher total grid-related charges than those in country A. Even if B's additional charges are cost reflective, the fact that 838/2010 constrains transmission charges in country A (which might otherwise have been higher) means that the relativity between charges in A and B can be inefficient.

As CEPA suggests, the maintenance of 838/2010 is therefore a helpful necessary condition for the removal of distortions in the short term. However, it is not necessarily sufficient to generate the "progressive harmonization" required by Regulation 714/2009.

Manifestation of these issues in Norway

Some of the issues identified above apply to Norway. In particular, the losses and congestion aspects of grid charges in Norway are based on short run marginal costs. Hence:

- producers face charges related to marginal losses calculated weekly by the Norwegian TSO (marginal loss factor at the node to which the production is connected multiplied by the hourly spot price from Nordic power exchange – Nord Pool ElSpot); and

- producers in exporting zones face a price reduction resulting from a zonal spot price.

Both of these aspects of grid related charges for producers result in surplus revenue (the difference between marginal and average losses valued at the spot price and the zonal congestion rent respectively). This surplus is used to reduce transmission revenue, which in turn reduces the charges levied by Statnett which are constrained by 838/2010.

While Sweden also has marginal losses, these are valued on a different basis (the hourly spot price is not used) and they are capped at a different value (in Norway they are capped at 15%, whereas in Sweden they are capped at 8%). And Finland and Denmark have neither marginal losses nor zonal pricing, and so producers in those countries do not face these issues. In line with the logic set out by CEPA, this has the potential to cause distortions to efficient outcomes (because it has an impact on the equilibrium price on Nord Pool in each of the systems). The simple maintenance of the ranges set out in 838/2010 will not result in the removal or reduction of these distortions, or result in progressive harmonization in the Nordic area.

In addition, the producer charge for some ancillary services cost in Norway[2] is a set charge per unit (€0.25/MWh for all producers), with other costs being recovered through charges for being out of balance. At least the fixed variable charge is unlikely to be reflective of the incremental costs resulting from the injection of additional generation onto the system, not least since there is typically a large proportion of ancillary service costs which are a function of capacity rather than production. While this lack of cost reflectivity may not be an issue which is addressable in the short term, it again has the potential to cause distortions from efficient outcomes.

Conclusions on the short term

CEPA's conclusions for the short term appear to be reasonable, but perhaps do not go far enough. The maintenance of 838/2010 would still provide the freedom for TSOs and/or NRAs to use the provisions for exempted charges (and the failure to take into account charges related to congestion) to create a distorted playing field for producers.

Within the framework of the current requirements of 838/2010, the situation would be improved if ACER or the EC took action to clarify, through guidelines or another interpretive document, the specific items which are permitted to be included in each of the exempted charges, and how cost-reflective levels of these charges could be assessed. This would reduce significantly the scope for TSOs

2 Statnett has stated that they would like this charge to recover as much as 50% of the system services costs (excluding ITC costs, and certain costs recovered via the balance settlement).

and/or NRAs to implement different treatments of cost and hence the potential for inefficient outcomes. This could also help ensure that differences in producer charges reduce over time, rather than them simply getting no bigger.

Long term: principles are necessary but not sufficient

CEPA's recommendations for the long term are based on the conclusion that the biggest problems stem from the absence of a common set of principles for transmission tarification.

It is clear that a common set of principles would be helpful. We agree with CEPA's suggestion that these principles should include:

- a definition of cost reflectivity; and
- an approach to cost recovery where cost reflective charges do not recover cost (ideally, through charging load which is less price sensitive than generation).

To CEPA's suggested principles, we would add:

- **simplicity**: it is important that investors can understand the price signals which transmission tariffs are sending, otherwise there is a risk that they will not be able to respond (meaning that they are bearing risk for no real purpose); and
- **predictability**: it is important for investors to be able to predict with reasonable certainty the way in which regulated charges will evolve.

If tariff solutions are not simple and predictable, the cost of capital which investors charge to be exposed to regulatory risk (volatility in transmission tariffs) will increase, and with it costs to customers overall.

Any harmonized principles would have to be reasonably detailed. For example, consider the hypothetical principle that "tariffs should be based on forward looking marginal costs". This can be argued to be consistent with economic principles associated with tariff setting, because it would ensure that grid users faced tariffs linked to the additional costs which their connection to and use of the grid caused. But this hypothetical principle is too ambiguous. As we have noted above, tariffs could be based on long run marginal costs or short run marginal costs and still be consistent with this principle. And, as has been seen in the debates associated with the TAR Network Code in the gas sector, multiple different methodologies can be argued to be consistent with long run marginal costs, even though they may produce markedly different tariff outcomes.

Finally, we would argue that ACER and the EC need to go beyond harmonized principles. Under the existing Regulation, it is clear whether a given set of charges is consistent with the Regulation[3]. Any party wishing to check would have a simple calculation to perform. If the quantitative aspects of 838/2010 were removed and replaced with a set of principles, this would not be the case. This in turn would have two implications:

- market participants would have less transparency over the level of generator charges which they might expect. This would result in greater uncertainty as to the cost base of generation investments, and therefore a greater perception of risk for generation investors. This would eventually feed through to lower volumes of investments (with a threat to security of supply) and/or higher wholesale energy or capacity prices as investors charged more to bear this risk; and
- there would be fewer "checks and balances" on TSOs and regulators in defining generation tariffs. Assessing whether tariffs are based on incremental costs will not be a trivial undertaking, and so verifying whether charges have been set correctly will have a material cost. This may deter participants from attempting such verification, which may in turn allow TSOs and regulators to set tariffs in a way which is not consistent with the Regulation in order to provide an advantage to their own national generation assets or customers (unless verification efforts by the EC or some other authority stepped up to compensate).

All these arguments point in the direction of the need for a more prescriptive Network Code, setting out both harmonized principles and details of harmonized tariff methodologies or charge levels. The implementation of such a Network Code could ensure that "progressive harmonization" and reducing differences between producer charges becomes a reality.

Experience of the TAR Network Code in the gas sector suggests that agreeing such a prescriptive set of guidelines will be difficult. Hence, it may be that a regional approach to harmonization, which harmonises in a step-wise process regional practices may be a practical first step.

3 Although as we note above 838/2010 itself needs clarification as to the specific items that are permitted to be included in each of the exempted charges.