ACER

Agency for the Cooperation of Energy Regulators

Publishing date: 16/04/2014

Document title:

We appreciate your feedback

Please click on the icon to take a 5' online survey
and provide your feedback about this document

ACER
Agency for the Cooperation of Energy Regulators

OPINION OF THE AGENCY FOR THE COOPERATION OF ENERGY REGULATORS No 09/2014

of 15 April 2014

ON THE APPROPRIATE RANGE OF TRANSMISSION CHARGES PAID BY ELECTRICITY PRODUCERS

THE AGENCY FOR THE COOPERATION OF ENERGY REGULATORS,

HAVING REGARD to Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging[1], and, in particular, point (5) of Part B of the Annex thereof,

WHEREAS:

(1) Pursuant to Recital (10) of Regulation (EU) No 838/2010, the values of annual average transmission charges faced by producers ("G-charges") across the EU should not undermine the internal market and should be kept within a range which helps to ensure that the benefits of harmonisation are realised. Pursuant to Article 18(2) of Regulation (EC) No 714/2009 of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003[2], guidelines may also determine appropriate rules leading to a progressive harmonisation of the underlying principles for the setting of charges applied to producers under national tariff systems, including the provision of appropriate and efficient locational signals. When assessing the appropriateness of the current range of G-charges, the Agency took those objectives into account.

(2) Pursuant to point 4 of Part B of the Annex to Regulation (EU) No 838/2010, the Agency has to monitor the appropriateness of the ranges of G-charges, taking particular account of their impact on the financing of transmission capacity needed for Member States to achieve their targets for the promotion of energy from renewable sources and their impact on system users in general. The results of this monitoring for the years 2011 and 2012 were also considered in defining the appropriate range of G-charges and are presented in Annex A to this Opinion.

[1] OJ L 250, 24.9.2010, p. 5.
[2] OJ L 211, 14.8.2009, p. 15.

(3) Furthermore, the Agency's proposal for the appropriate range of G-charges builds upon an economic assessment of G-charges at national and transnational level which is presented in Annex B to this Opinion. According to this economic assessment, the market impact of G-charges strongly hinges on the basis on which the charges are applied (i.e. energy-based charges vs. power-based charges) and the appropriate range of G-charges depends on the unit they are based on,

HAS ADOPTED THIS OPINION:

For the purpose of this Opinion, the following definitions of G-charges apply:

- Energy-based G-charges are charges payable on every unit of energy produced and/or injected into the grid (€/MWh);
- Power-based G-charges are charges payable on the capacity connected to the grid, on yearly or multi-year peak output or output under peak conditions (€/MW);
- Lump-sum G-charges are charges that are fixed at the start of the relevant charging period and do not depend on capacity connected, on yearly or multi-year peak output or on output under peak conditions, unless these are taken into account in the form of an average over a past period of at least 5 years. Moreover, lump-sum G-charges may take into account the average annual load factor or the average of other output related factors, as long as such averages are calculated over a minimum of 5 years. The level of the lump-sum G-charge may be differentiated between small and large plants, or based on generator characteristics.

Based on its G-charge monitoring activity (Annex A) and on the economic assessment of G-charges at national and transnational level (Annex B), the Agency has come to the following conclusions as to the appropriate range of G-charges for the period after 1 January 2015:

- The increasing interconnection and integration of the European market[3] implies an increasing risk that different levels of G-charges distort competition and investment decisions in the internal market.
- In order to limit this risk, the Agency deems it important that G-charges are cost-reflective, applied appropriately and efficiently and, to the extent possible, in a harmonised way across Europe.
- In particular, the Agency considers that:

[3] The ongoing and future integration process determines the availability of new interconnectors, the convergence of supply cost/price curves and the increase of spare capacities on interconnectors. These conditions favour the possibility of merit order switch (and less efficient dispatch) across countries.

  - energy-based G-charges (€/MWh) shall not be used to recover infrastructure costs; and, therefore,
  - except for recovering the costs of system losses and the costs related to ancillary services, where cost-reflective energy-based G-charges could provide efficient signals, energy-based G-charges should be set equal to 0 €/MWh.
- Different levels of power-based G-charges (€/MW) or of lump-sum G-charges, as long as they reflect the costs of providing transmission infrastructure services to generators, can be used to give appropriate and harmonised locational signals for efficient investments in generation, e.g. to promote locations close to load centers or where the existing grid can accommodate the additional generation capacity with no or minimal additional investments.
- The Agency therefore considers it unnecessary to propose restrictions on cost-reflective power-based G-charges and on lump-sum G-charges.
- The Agency notes that even power-based G-charges may have significant distortive effects on investment decisions if they are not cost-reflective, lack proper justification or are not set in an appropriate and harmonised way. Therefore, the Agency will continue to monitor the appropriateness of G-charge levels, with a view of contributing to potential future amendments of the guidelines on transmission charging in Part B of the Annex to Regulation (EU) No 838/2010.
- To this aim, the Agency considers it important that reasonable reporting requirements are defined in future legislation to support the Agency's monitoring. In particular, the Agency believes that each NRA should:
  - report to the Agency, by 31 July of each year, the level and structure of G-charges in its jurisdiction and the average G-charge value for the previous year;
  - notify to the Agency, without delay, any proposal (e.g. public consultations) or decision taken to amend the national G-charging methodology, submitting relevant information such as a detailed reasoning and evidence of cost reflectivity.

The proposed G-charge levels should be applied from 1 January 2015 to 31 December 2018. Transitional arrangements may be put in place for Member States where substantial changes to the current level of charges are required, as long as these arrangements apply over a period not exceeding 2 years.

Done at Ljubljana on 15 April 2014.

For the Agency:

Alberto Pototschnig
Director

ACER
Agency for the Cooperation of Energy Regulators

Annex A: Results from G-charge Monitoring

1 Sources of information

The Agency, in the framework of cooperation with National Regulatory Authorities (NRAs), prepared and distributed to NRAs in June 2012 a questionnaire to monitor the ranges of transmission charges paid by producers ("G-charges") in each Member State. NRAs provided their replies in summer 2012.

In June 2013, an expanded questionnaire on G-charges in 2012 was circulated to the NRAs of the 27 Member States. The Norwegian NRA also participated in this activity. Out of the 28 NRAs which received the questionnaire, 26 NRAs replied. The NRAs of Bulgaria and Malta did not respond.

2 Yearly average G-charges and compliance with Annex Part B of Regulation (EU) No 838/2010

10 NRAs reported that a G-charge according to the definition of Annex Part B, point 2, of Regulation (EU) No 838/2010[4] was applied in their jurisdictions[5] in 2012. The annual average G-charges (calculated by dividing the annual total transmission tariff charges paid by producers by the annual total energy injected by producers into the transmission system) show in 2012 a range from 0.19 to 1.96 €/MWh across Member States (and Norway), as shown in Table 1. The share of the total transmission revenues collected from G-charges ranges between 2% and 41%.

Table 1: Non-zero national annual average G-Charges in 2011 and in 2012

Country	Average G-Charges 2011 [€/MWh]	Average G-Charges 2012 [€/MWh]	Share of Transmission revenue 2012
Denmark	0.40	0.40	3%
Finland	1.00	0.50	7%
France	0.19	0.19	2%
Great Britain	1.93	1.68	27%
Ireland	Approx.1.5	1.77	17%
Northern Ireland	1.06	1.77	17%
Norway	1.06	1.02	12%
Portugal	-	0.50	8%
Romania	1.90	1.96	41%
Spain	0.50	0.50	8%
Sweden	0.33	0.64	32%

[4] OJ L 250, 24.9.2010, p. 5.
[5] In the case of United Kingdom, the data for Great Britain and those for Northern Ireland are separately presented.

The yearly average G-charges of all Member States comply with the ranges set by Annex Part B of Regulation (EU) No 838/2010.

3 G-charge setup in Member States

G-charges may be applied on the energy produced or on the power connected to the grid. Out of the 9 Member States[6] applying G-charges, in 6 Member States the charge is based on the energy produced, while 3 apply G-charges on the power connected to the grid. Table 2 shows the yearly average G-charges applied on an energy basis and a power basis in 2012.

Table 2: G-charge Setup

Country	energy produced [€/MWh]	power connected [€/MW]
Denmark	0.40	-
Finland	0.50	-
France	0.19	-
Great Britain	-	6,994
Ireland	-	5,590
Northern Ireland	-	5,590
Portugal	0.50	-
Romania	1.93	-
Spain	0.50	-
Sweden	-	4,090

Individual G-charges may vary across Member States based on the location, time and voltage level of generation (Table 3).

Table 3: G-Charge variation basis

Country	Location	Time	Voltage Level
France			X
Great Britain	X		X
Ireland	X		
Northern Ireland	X		
Portugal		X	X
Romania	X		
Sweden	X		

[6] For Norway, see the description of the national G-charge calculation methodology provided by the Norwegian NRA in Section 4 of this Annex.

The ranges of the different individual G-charges are shown in Table 4 and Table 5.

Table 4: Ranges for energy-based G-Charges

Country	Min [€/MWh]	Max [€/MWh]
Denmark	0.40	0.40
France	0.00	0.19
Portugal	0.43	0.55
Romania	1.12	2.29
Spain	0.50	0.50

Table 5: Ranges for power-based G-Charge

Country	Min [€/MW]	Max [€/MW]
Great Britain	- 16,380	27,060
Ireland	4,076	10,500
Northern Ireland	4,076	10,500
Sweden	2,500	6,300

4 G-charge Calculation Methodologies

The methodologies for calculating the G-charges vary greatly across countries. In general, G-charges calculation methodologies can be classified into the following categories (more than one category may be applied at the same time):

1. G-charge to cover a certain share of total costs;
2. G-charge to cover a specific cost element;
3. G-charge to cover costs implicitly or explicitly caused by the generation unit;
4. Other.

Table 6 provides an overview of the methodologies in different jurisdictions.

Table 6: Methods of G-Charge calculation

Country	Category 1	Category 2	Category 3	Category 4
Denmark	X			
Finland	X			
France		X		
Great Britain			X	
Ireland			X	
Northern Ireland			X	
Norway	X			
Portugal*				X
Romania	X		X	
Spain	X			
Sweden	X		X	

* Harmonised with Spain

The following description of the national G-charge calculation methods was provided by the NRAs of the countries concerned:

Denmark: The G-charge is calculated to cover a share of 2-5% of the total tariff income and not to exceed the upper bound set in Regulation (EU) No 838/2010.

Finland: Fixed Charge on energy basis (0.5 €/MWh) also applied to generators on Distribution System Operator level.

France: The G-charge covers the costs for the Inter-Transmission System Operators (TSO) Compensation mechanism. Consequently, only generation on the high voltage level is charged.

Great Britain: The G-charge is calculated to cover the long-run incremental costs of transmission investment. The cost scalar in that model is based on the indexed historic asset cost for generic technology types along with an overhead factor to represent asset maintenance and a security factor which represents the cost of maintaining a Security Standard-compliant network.

Ireland: The revenues that feed into tariffs are based upon the Commission for Energy Regulation's 5 year ex-ante review process for the Transmission Business. This revenue consists of controllable costs sometimes referred to as "wires"-related costs, (which include costs associated with capital expenditure, deprecation, rate of return, transmission maintenance and a portion of TSO's operating expenditure costs) and external costs or "non-wires" costs (which include costs associated with ancillary services, interconnector services and a portion of EirGrid's operating expenditure costs). 25% of the controllable costs are recovered from generation (through G-charge). The remaining 75% of the controllable costs and 100% of the external costs are recovered from demand users.

Norway: The G-charge covers a small portion of the TSOs capital and operational expenditures, new transmission investments, renewable energy sources transmission investments etc. However, the G-charge is not linked to individual investment costs or operating costs. The G-charge is a lump-sum payment that is fairly stable over time and covers a portion of the TSOs allowed revenue. The tariffs are based on a 10-year historical average of production and have been designed in order to be neutral with respect to short-run production decisions and long-run capacity investment decisions. The charge applied to each generator is each year calculated from the average production in previous years (the charge for 2014 is based on average production during the years 2003-2012). For hydro power the charges paid by producers can, to a large extent, be considered as fixed, depending on the amount of precipitation and inflows to the reservoirs on average during the previous years. The generators cannot influence the annual cost by altering the operational decisions as the yearly amount is given at the start of the year.

Portugal: The G-charge was set at the same level as in the Spanish market.

Romania: Transmission tariffs differ by nodes (zones) depending on the impact of electricity injections or withdrawals into/from the nodes of the transmission grid. This impact is expressed as the nodal marginal cost of transmission. In any node of the transmission network, the short term marginal cost is the sum between the marginal cost of the network losses and the marginal cost of congestions in the transmission network. These marginal costs do not recover fully the total transmission cost. This is obtained by adding an average cost component calculated as the difference between the regulated revenue and the revenue provided by the marginal costs. The average cost is evenly allocated to transmission network nodes. Marginal costs and electricity quantities injected or withdrawn into/from the transmission network during a calendar year are determined using a number of 24 to 48 characteristic operational regimes of the National Power System. Each characteristic regime has the following items identified:
a) Generation nodes (G) are transmission network nodes in which electricity is injected into the grid (the generation-consumption balance is positive);
b) Consumption nodes (L) are transmission network nodes from which electricity is withdrawn from the grid (the generation-consumption balance is negative).
The characteristic of generation or of consumption node can change from one regime to another. Any of the nodes can be both a generator and a consumer node.

Spain: In Spain, there exists an excess of capacity in generation and hence, incentives to invest in generation are not a priority. Moreover, there is no congestion in the transmission networks and hence, G-charges are not aimed at providing locational signals to generators, but to contribute, jointly with charges on load, to the financing of transmission costs up to the limit set by Regulation (EU) No 838/2010 (i.e. 0,5 €/MWh).

Sweden: All depreciation and operation and maintenance should be covered by the power charge. It has been decided that the G-part shall be approximately 30% of the total power charge. This 30% is allocated among producers. The charge acts as a locational signal and is linear on location from north to south. Highest in the north since the general power flow is from north to south. The more generation in the north, the larger is the need for additional investments.

5 Additional charges to producers

The definition of G-charge according to Annex Part B of Regulation (EU) No 838/2010 excludes:

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

5.1 Ancillary services and system losses

5 NRAs reported that they apply charges related to ancillary services and/or losses. The average levels of these charges in these jurisdictions are presented in Table 7.

Table 7: Charges related to ancillary services and losses (€/MWh)

Country	Losses	ancillary services
Austria	0.50	1.53
Belgium		0.91
Great Britain		0.38
Romania	0.35	
Sweden	0.41	

5.2 Connection charges

24 NRAs reported that connection charges are paid by producers in their jurisdictions. Connection charges can be calculated based on "shallow" or "deep" costs. Shallow connection charges are based on costs for connecting a party to the transmission network not including reinforcement of the core grid. If grid reinforcement measures are included into the cost base, the connection charges are calculated on a "deep" basis. The method for setting connection charges in the different jurisdictions is displayed in Table 8.

Table 8: Connection charges

Country	Shallow	Deep	No
Austria	X		
Belgium	X		
Cyprus	X		
Czech Republic	X		
Denmark			X
Estonia		X	
Finland	X		
France		X	
Germany	X		
Great Britain	X		
Greece	X		
Hungary	X		
Ireland	X		
Italy		X	
Latvia		X	
Lithuania		X	
Luxembourg	X		
Netherlands	X		
Northern Ireland	X		
Norway	X		
Poland	X		
Portugal		X	
Romania		X	
Slovakia		X	
Slovenia			X
Spain	X		
Sweden		X	

Connection charges are calculated in most countries on a case-by-case basis. Hence an assessment of the charging levels was not possible.

Annex B: Economic assessment of G-charges at national and transnational level

1 Introduction

This Annex seeks to provide an overview of the economic implications for implementing G-charges, as well as their effects on the European electricity market. Chapter 2 of this Annex presents a short theoretical overview of why G-charges are applied and why they may vary in different Member States. Chapter 3 then describes how G-charges affect the electricity market at the transnational level. Finally, Chapter 4 provides some additional remarks on topics related to G-charging.

2 Reasons for implementing G-charges

This chapter describes the main reasons for implementing a G-charge. Although G-charges are not implemented in the majority of Member States, they can be an important instrument in the tariffication schemes of the transmission system.

2.1 Application of locational signals

Locational signals induce market participants to trade-off transmission charges against other cost considerations and operating efficiencies which are likely to vary by locations. The signals can be used to internalise costs of transmission investments and to promote location of generators where the existing grid can accommodate the additional generation capacity with no or minimal additional investments. Besides, locational signals can also be a tool to incentivise the dispatch of close-to-load production facilities if there are different levels of costs for losses, congestion and ancillary services, in different areas of the transmission grid. At the same time, generation costs are dependent, *inter alia*, on the local availability and prices of fuels and other primary energy. The locational differences of generation costs are often especially high for intermittent renewable generation, like wind and solar, where the local climate conditions are the driving locational factors. As wholesale power prices inside market areas do not reflect the different costs of the transmission system, a G-charge can be an important tool for achieving system efficiency. The efficient levels of locational signals are, *inter alia*, strongly related to the grid topology and the distribution of generation and load. Different levels of charges are used to provide locational signals.

2.2 Sharing of costs between Generation and Load

Both generators and electricity consumers use the transmission grid and consequently share its benefits. Hence, in some Member States, a G-charge is applied to share the costs between generation and load. Reflecting that aim, G-charges may be used to recover a certain percentage of the total transmission revenues. In addition to that, they might cover specific cost elements that can be directly linked to the generation side. For instance, a positive G-charge can finance the inter-TSO compensations, especially in mainly exporting countries. The percentage or amounts charged to generators can differ between countries due to different total cost levels, different views on the fair or optimal distribution of costs, or simply by different cost elements that are being charged for. Moreover, the effective share of the costs which is ultimately born by generation is highly dependent on the possibility for generators to pass costs onto consumers. This may differ depending on the charging setup, the level of competition or the generation portfolio. If G-charges directly translate to an increased market price, effectively no cost sharing can be achieved. As will be discussed in Chapter 3, energy-based G-charges will lead to a short-term passing of costs onto consumers, as electricity prices are likely to increase. Power-based G-charges, on the other hand, can only be rolled over in the long run[7].

2.3 Provision of time signals

Grid or transmission infrastructure that is built to cope with peak load is relatively more expensive, and less efficient, per unit of electricity carried, than transmission infrastructure which is built to serve base load. Peak-load charging may be used to provide signals to users/consumers that serving peak-load demand is more expensive, which will reduce the quantity demanded at peak times. In the long term, this may reduce the amount of transmission (and generation) investment required to meet demand.

3 Effects of G-charges on the Electricity Market

In this chapter the effects of G-charges on the European electricity market are discussed from an economic point of view. In this context, the effects of G-charges on the efficient power plant dispatch and power prices, as well as on investment signals for power plants are analysed.

The European Market is split into different pricing zones, mostly corresponding to Member States. For analytical purposes, the effects of G-charges on the market are initially assessed in a uniform market area without bottlenecks and one pricing zone.

---

[7] According to economic theory, generation costs in the long run are borne by the consumers.

Subchapter 3.3 discusses how the findings in a uniform market are affected when the market is split into different price zones with transmission bottlenecks.

The effect of the charges on the behaviour of market participants can fundamentally differ depending on the charges' setup. Apart from the levels of G-charges, the main determining factor is the "unit" which is effectively charged. Consequently, the evaluation of effects of energy- and power-based G-charges are discussed separately below. The initial assumption for the analysis is a high level of competition within the electricity markets, but the key conclusions are also applicable to markets with a low to mid level of competition.

3.1 Effects on efficient dispatch and short term pricing

In this subchapter, the effect of G-charges on the efficient dispatch and short-term pricing is analysed. Before the effects of energy-related and power-related G-charges are assessed, a short description of the price-setting mechanism in electricity spot markets and the requirement for efficient dispatch in these markets is given.

3.1.1 Spot market pricing and dispatch

In competitive electricity markets, the dispatch is mainly determined by the spot market price. Generators base their running decisions on the short-run marginal costs (SRMC) of production (i.e. costs that directly vary with production). For fuel-based generation, these consist, *inter alia*, of fuel costs, costs for CO_2-allowances (where a CO2 allowance scheme operates, as in the EU) and costs associated with wear and tear of plant and equipment. Fixed costs, on the other hand, are not part of the dispatch decision, as they can be considered as sunk at the time of such a decision.

If no constraints exist for a plant, the generator will usually only run the plant if the price received for the produced electricity is as at least equal to SRMC. Hence, in fully competitive markets, the price at which the generator offers its production into the spot market equals its SRMC. The spot market price is then determined by the price where the offered amount of electricity equals electricity demand[8]. In the process, plants are implicitly sorted by their SRMC and the plants needed for meeting demand with the lowest costs are dispatched. An efficient dispatch is reached if the load is met by the plants which cause the lowest possible (short-term) costs to the system. Even if a market is not fully competitive, prices would still reflect SRMC, but possibly with a mark-up. Consequently, efficient dispatch can only be achieved by electricity markets if the relation of SRMC between the power plants is reflected in the actual relation of short-term system costs caused by the production of the power plants. A charge which

[8] As demand is relatively price inelastic in the short term.

changes this relation may distort the short-term electricity markets and should therefore be avoided.

3.1.2 Energy-based G-charges

An energy-based G-charge can affect the dispatch decision of generators as an increase in production directly increases payments for the use of the transmission system. Hence, the SRMC of power plants is increased by the level of the G-charge. Different levels of energy-based G-charges applied to different plants may affect the relation of SRMC between the plants. If the different levels of G-charges resemble the differences in short term costs (e.g. losses, congestion, ancillary services) imposed by the plant's generation onto the transmission system, the G-charge does not affect efficiency (see Chapter 2.2). If, on the other hand, different levels of G-charges unrelated to the generation costs - for instance, charges related to different levels of fixed costs of the transmission system - are applied, the efficiency of the dispatch may be harmed. It is indeed possible that production from efficient plants facing relatively high G-charge levels is replaced by less efficient plants facing relatively low G-charge levels. Due to the increase in SRMC, the spot market prices will increase according to the level of G-charges charged to the price-setting power plant(s) (e.g. the one(s) which at a specific time have the highest SRMC among those needed to meet demand).

In a uniform market area without bottlenecks, a flat energy-based G-charge for all plants will have no effect on the dispatch of power plants. As SRMC increase by the same amount, the relations of SRMC are not affected. Still, SRMC and therefore also the spot market price is increased by the level of the applied G-charge.

3.1.3 Power-based G-charges

In markets with a high level of competition, power-based G-charges have no effect on the dispatch of power plants, as they do not increase the generation costs for the generators and hence SRMC remain unchanged.

In markets with a low level of competition, it is possible that part of a power-based G-charge is passed, as a mark-up, onto the price at which the generators offer their production and thus the spot market price increases[9]. This price increase might however be limited by the possibility of market (new entrants and - to a probably limited extent - demand) and regulatory responses. Nevertheless, an increase of power-based G-charges (with different levels of energy-equivalent charges) can be

[9] This can be simply explained by a full-cost approach of generators in an environment of low competition. Economic theory suggests that an incumbent producer will set prices to a level where outside competition (investment in new capacity) will not enter the market. If the (long) term costs for generation rise due to a G-Charge the incumbent producer can defend higher prices.

expected to have an effect on short-term dispatch and prices in markets with low competition. The regulators' role in these markets is to evaluate which part of a power-based G-charge is passed onto the spot market price and how much this pass-through effect is distorting the short-term electricity market.

3.1.4 Lump-sum G-charges

Lump-sum G-charges (charges per power plant, turbine or generator for instance, the level of which is however not related to output or capacity) will tend to be neutral with regard to operational decisions. The tariff level may be differentiated between small and large plants, or based on generator characteristics, reflective of costs imposed by these different sizes or technologies on the system or of specific policy objectives.

Where lump-sum charges are calculated taking into account the historical average annual load factor, or other historical output-related factors, the time period considered should be sufficiently long in order to minimise impact on the dispatch decision.

3.2 Effects on investment signals and long term prices

In this subchapter, the effects of G-charges on investment signals are discussed. First, a short theoretical description of the investment decision and long-term prices is given. Then the effects of G-charges on investment signals are described.

3.2.1 Investment decision and long term prices

Investment decisions are based on a total-costs approach. If the total expected revenues for the plant exceed the total expected costs of investment (including e.g. investment and production costs), the investment will be realised. Hence an increase/decrease in costs imposed on generators will decrease/increase the incentive to invest to the extent that generators cannot fully pass these costs onto consumers.

In energy-only markets, revenue-related investment signals are mainly given by long-term energy prices (expected revenues) which reflect the expectation of the market on spot price developments. In economic theory, investment signals are efficient if the (long-term) marginal costs of capacity additions equal their marginal benefits. The rules for "efficient" investment signals are therefore a different issue than efficient dispatch. The determination of the optimal level of investment or the ability of energy only markets to generate sufficient incentives for investment, for example, are outside the scope of this document. Since the beginning of the liberalisation, the argument about the ability of energy only markets to generate sufficient incentives for investments has persisted. The effect of G-charges on the efficiency of investment signals will therefore only be evaluated in terms of "where to invest". The general rule applied for the evaluation of G-charges on investment signals may, for the purpose discussed here, be characterised as such: if different levels of G-charges reflect (distort) the differences of the total costs of adding a generation unit to the system, G-charges improve (deteriorate) the investment (locational) signals.

3.2.2 Energy-based G-charges

Energy-based G-charges lead to an increase in power prices equal to the charge on the price setting power plants (see subchapter 3.1.2). As long-term prices indicate the expectation of the market on spot price developments, long-term prices will increase to a similar extent. Investment decisions are based on the difference of expected costs and expected revenues. Thus the increase in price and costs compensate each other. Hence flat charges should not have an effect on investment signals[10].

Investment signals may however be affected by energy-based G-charges that are different between power plants, or types of power plants. Power plants with lower G-charges will benefit from the higher prices - reflecting the higher level of G-charges imposed on other power plants which may set the market price - and hence investment incentives for these types of power plants will increase.

In line with the general rule stated in Subchapter 3.2.1, investment signals may be improved if the differences of the additional costs of adding generation to the transmission system are charged to the respective generator. Insofar as these differences would only reflect short-term costs, an energy-based G-charge may increase dispatch efficiency. However, when differences reflect long-term costs (like investment costs for reinforcement of the grid), an energy-based G-charge may, at the same time, distort the spot markets.

3.2.3 Power-based G-charges

Power-based G-charges do not affect short-term prices. They lead, on the other hand, directly to increased costs for generators. (Positive) G-charges on power may therefore decrease the incentive to invest in capacity or incentivise generation owners to mothball existing capacity[11].

In line with the general rule in Subchapter 3.2.1, efficiency of investment signals may be improved if the differences of total additional costs of adding generation to the transmission system are charged to generators – that is contribute to the long-run marginal cost (LRMC) as perceived by generators. The investment signals may, on the other hand deteriorate, if differences in the charges reflect other purposes rather than this marginal cost of providing transmission to the generators. To avoid such deterioration, regulators' role is to evaluate the interrelations between cost recovery purposes and cost reflectivity.

---

[10] In the long run the price increase could lead to a decrease in demand which could hence lead to a decrease of prices and hence investments.

[11] This effect can even occur rather short-term as increasing the power-based G-Charges may prevent existing generators from fully recovering their fixed costs, some of them being short-term fixed costs (maintenance, operation). Some peak generator(s) may thus be mothballed instead of losing money.

3.2.4 Lump-sum G-charges

Similarly to power-based G-charges, lump-sum G-charges do not affect short-term prices. On the other hand, they lead directly to increased costs for generators.

In contrast to power based charges, lump-sum G-charges can reflect plant characteristics including load factors, load patterns and their impact on transmission investment requirements.

3.3 Effects of transmission bottlenecks and multiple pricing zones

Subchapters 3.1 and 3.2 analysed the effects of G-charges on a uniform market area with only one market price. But the European power market is split into different price zones, in most cases corresponding to Member States. In order to discuss the need for transnational harmonisation, the main findings from the first two subchapters are evaluated in relation to different national prices and limited cross-border transmission capacity. In general the findings from the previous subchapters are applicable to the European electricity market. Multiple pricing zones and transmission bottlenecks will however affect these findings mainly with regard to two aspects. Firstly, transmission bottlenecks limit the distortive effects of different levels of G-charges on the transnational market: this is shown in the next subchapter. Secondly there may be a trade-off between national and transnational cost reflectiveness: this is shown in Subchapter 3.3.2.

3.3.1. Limitation of distortive effects on markets due to transmission bottlenecks

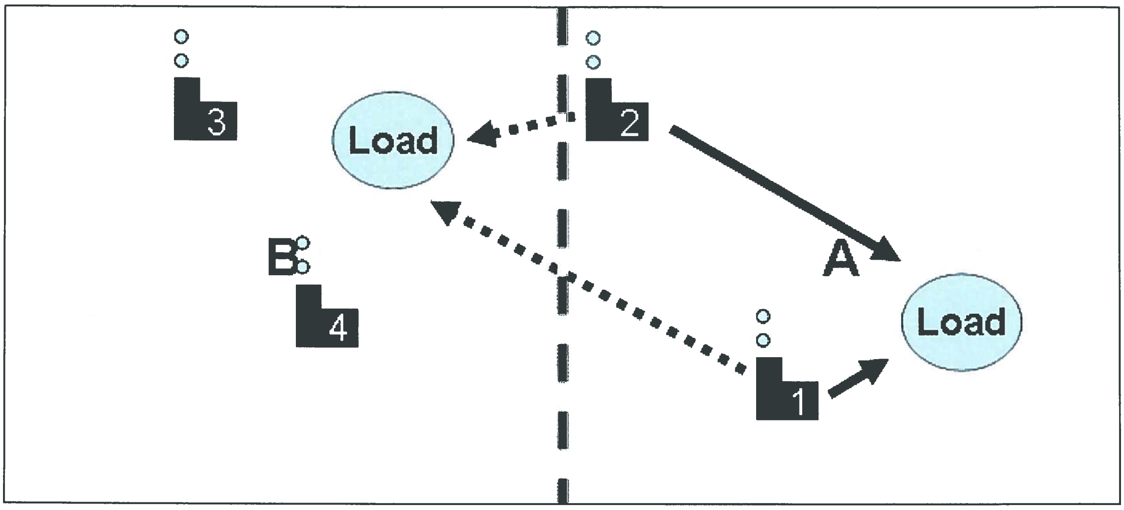
Distortive effects imposed by G-charges to cross-border trade and investment signals will of course depend on the level of possible competition of power plants between the affected countries. Consequently, different levels of G-charges will be more distortive of cross-border trade and investment signals between countries which are well connected with high transmission capacities. This is evident for the impact of G-charges on the dispatch, as the potential distortion correlate with the difference between cross-border flows before and after G-charge implementation (which is in general lower if transmission capacity is lower).

Possible competition is also affected by the cost-relation of power plants. If (in a certain period) the plants in one country show sufficiently lower production costs than in another country, the country with the lower production costs will export to the higher-cost country up to the maximum cross-border capacity. Different levels of G-charges would in this scenario have a low effect on competition. Hence the effects may also be limited by heterogeneous power plant parks.

3.3.2. Cost reflectiveness of G-charges at national and transnational level

The identification of costs caused by a power plant to the transmission system at national level will, in most cases, be a difficult task for regulators and transmission system operators. Finding the *efficient* cost differences at both national and international levels involves multiple layers of complexity. This could lead to situations where transnational cost differences cannot be defined. One example for this is the calculation of losses imposed on the transmission system, as illustrated in Figure 1.

Figure 1: Example for G-charge loss calculation



In Country A, two power plants are situated at widely different distances (and implied losses) to the load centre. Looking at Country A alone would imply a higher energy-based G-charge for Power Plant 2 than for Power Plant 1. The load centre of Country B, on the other hand, is closer to Power Plant 2 than to Power Plant 1. Considering limited transmission capacities between Country A and Country B, two cases may arise. In the first case, transmission capacity is still available and Power Plants 1 and 2 can produce for the Load in Country A and Country B to the same extent. In this case there should be no differences between G-charge for losses charged on Power Plants 1 and 2. In the second case, the transmission capacity is limited and Power Plants 1 and 2 can only produce for Load in Country A. In this case, the optimal G-charge would again be the "Country A alone" solution, i.e. a higher energy-based G-charge for Power Plant 2 than for Power Plant 1. Hence, if restricted to a uniform system of a case-independent G-charge, there can be no efficient solution. There may be a trade-off between efficient national and transnational signals provided by the G-charge.

4 Other remarks

4.1 Exclusions from the calculation of annual average G-charges

Under Regulation (EU) No 838/2010, charges for losses and ancillary services are excluded from harmonisation. Indeed, they are closely linked to the energy price development[12]. Harmonisation should therefore not be based on a fixed range for these costs categories. As the example in Subchapter 3.3.3 showed, a transnational harmonisation on cost categories will not necessarily increase market efficiency, but can hamper cost-reflective charging at the national level. Hence, there is no point in harmonising the charges for these cost categories.

As connection charges are exempted from the allowed ranges, Regulation (EU) No 838/2010 can lead to a different treatment of costs caused by generators. If the main infrastructure costs of the transmission grid stems from the physical connection facilities to the grid, the charges are excluded from harmonisation. If the costs are imposed by the future need for reinforcement within a meshed transmission grid, the charges are limited to the set ranges. As the Agency opinion proposes not to restrict power-based charges, National Regulatory Authorities could implement a more consistent charging setup.

4.2 G-charges for generators connected to distribution level

Regulation (EU) No 838/2010 only harmonises G-charges at the transmission level. However, more and more generation is connected at the distribution level and plays a larger role for national and European-wide competition. Hence, it should be carefully considered if and how Regulation (EU) No 838/2010 should be amended to harmonise also charges for generators connected to distribution grids. The effects of different levels of charges as described in this Annex are in principle transferable to G-charges related to the distribution level. Yet, generators connected to the distribution grids, as well as the distribution grids themselves, may have different characteristics that would have to be considered.

4.3 Impact on the financing of transmission capacity needed for Member States to achieve their targets for the promotion of energy from renewable sources

The Regulatory systems in the Member States grant revenues or charges to TSOs that ensure that the financing needs for investments are met. A decrease in G-charges in a regulatory system will normally lead to a shift of costs to Load charges. The financing needs will consequently be covered independently of the level of charges collected

[12] The costs for losses should develop proportionally to the short term market prices and the price for reserve capacity and reserve energy will normally also relate to current short term market prices.

from the generation side. Nevertheless, the acceptance of charging regimes may decrease if the cost sharing between generation and load is changed especially at times of increasing system costs and, as a consequence, could be perceived as unfair by market participants.

ACER
Agency for the Cooperation of Energy Regulators

Publishing date: 16/04/2014

Document title:

We appreciate your feedback

Please click on the icon to take a 5’ online survey
and provide your feedback about this document