Constraint Cost Minimisation Options

A Consultation Paper
By
The Commission for Energy Regulation

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1 INTRODUCTION AND BACKGROUND

There has been a 160% increase in constraint costs, from an average of €2½ million a month in the first half of 2005 to €6¾ million a month in the first half of 2006. Indications are that this trend will continue, thereby increasing transmission use of system charges for all suppliers in 2007 and later years.

This paper briefly examines the causes of that increase, the reasonableness of the increase and, to the extent that these increases do not reflect an increase in the underlying cost of resolving constraints, options for minimising future constraint costs.

In the existing bilateral contracts market, generators are obliged to submit offers for the subsequent trading day indicating their preferred output (ANOMs) and a series of prices for incrementing or decrementing their output from the preferred position (INC/DEC prices). The energy market is cleared based on an ex post unconstrained schedule (EPUS), which adjusts ANOMs to match actual demand. Actual dispatch will differ from ANOMs owing to the need to provide operating reserve and to alleviate transmission constraints.

Whenever a generator is dispatched away from its preferred output level as determined by EPUS, the generator is kept financially whole in the energy market. This is achieved by allowing the generator to sell (in the energy market) the output it would have produced had it not been constrained on or off (the generator's XNOM). Any generator that the transmission system operator (TSO) dispatches up is paid an instructed imbalance payment at its incremental offer (INC) price; and any generator the TSO dispatches down pays the TSO an instructed imbalance payment at its decremental bid (DEC) price. The generator is kept whole if the incremental price it bids adequately reflects the incremental costs it incurs in being dispatched above its preferred output; and if the decremental price offered reflects the cost the generator avoids in being dispatched below its preferred output.

The differential between what the TSO pays generators and what it receives from them is the cost of constraints. Since incremental offer prices (used to price the positive difference between instructed quantities and nominations) are greater than decremental price bids (used to price the negative difference between instructed quantities and nominations), there is a net payment from the TSO to the generators.

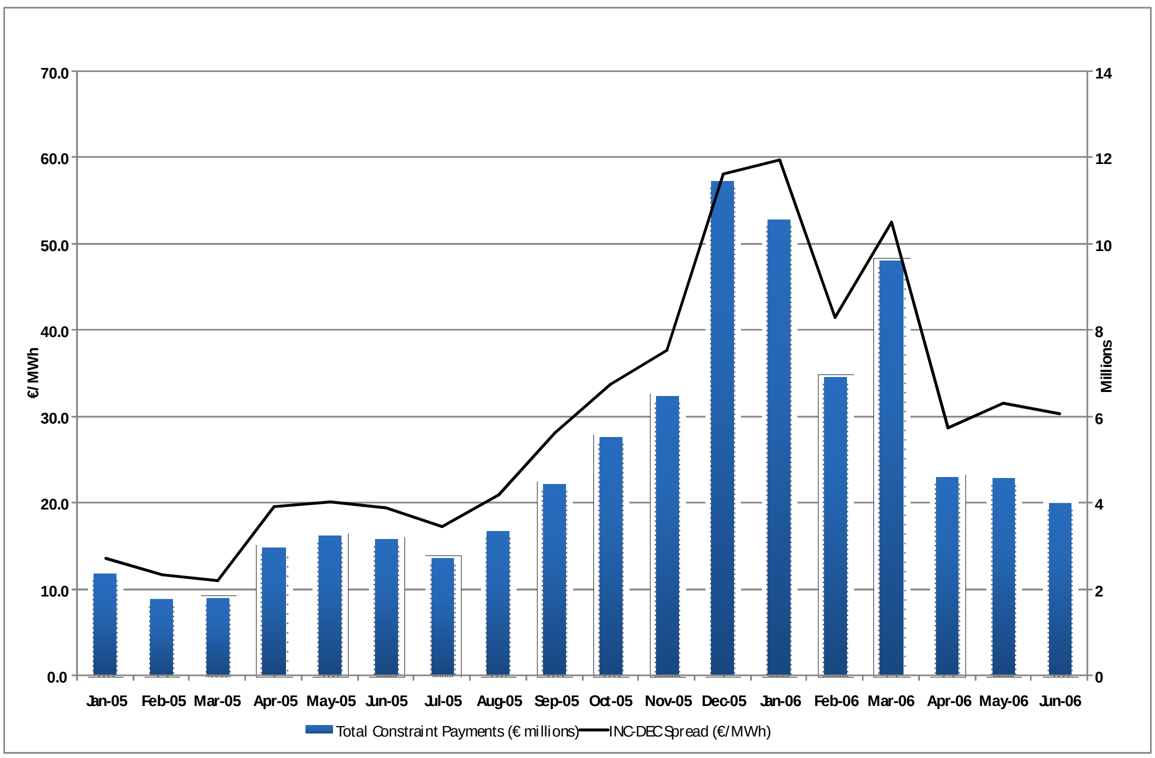
Paragraph 8 of S.I. No. 445 (European Communities (Internal Market in Electricity) Regulations, 2000) requires the transmission system operator " to operate … a safe, secure, reliable, economical and efficient transmission system …" In carrying out this function, and to minimise the costs of constraints, the TSO chooses generators with the cheapest incremental price and generators with the most expensive decremental price, to provide reserve and to manage congestion whilst maintaining the generation-supply balance.

2 CONSTRAINT COSTS SINCE JULY 2005

Total constraints payments were in the region of €2 million to €3 million a month (with an average monthly total of about €2½ million) for the first seven months of 2005. This was similar to the monthly average in earlier years. The monthly average then rose to more than €6 million in the last five months of 2005. Payments in December alone were €11½ million. The outturn cost for the year as a whole was more than €49 million, some 70% higher than anticipated in mid-year.

This pattern of higher constraints costs has continued into 2006. In the six months to end-June 2006, constraints costs amounted to €40.3 million, which is equivalent to more than €80 million on an annual basis. April, May and June 2006 saw total constraint costs of around €4½ million a month. This is about €2 million a month more than in the seven months up to and including July 2005 (see Figure 1 below).

Figure 1: Total Constraint Payments and INC-DEC Price Spread



Source: Eirgrid

The causes of this marked increase in constraint costs since August 2005 include:

- an increase in the volume of constraints, associated primarily with the commissioning over the winter of 2005/06 of Aughinish and Tynagh;[1]

- an increasing differential (at an aggregate or system level) between incremental (INC) and decremental (DEC) price offers submitted by generators (the INC-DEC price spread);

- a number of other structural factors, mainly involving discrepancies between the treatment of plant in EPUS and that used hitherto by the TSO. The importance of these factors have come to light only because of the increase in the INC-DEC price spread since July 2005. They are also now largely being addressed by changes to the TSO's operating procedures.

The average price differential between positive instructed imbalance payments (incurred by Eirgrid) and negative instructed imbalance payments (paid to Eirgrid) has risen sharply since July 2005, as shown by the line labelled "INC-DEC spread" in Figure 1 above. This, rather than the volume of constraints or the structural factors mentioned above, is the main cause of the higher constraint costs since mid-2005, as can be seen by the close relationship between the INC-DEC spread and the net monthly amount paid by Eirgrid in constraint payments.

The increase in the INC-DEC spread since July 2005 has coincided with a sharp rise in oil and gas prices. But higher fuel prices in themselves should not necessarily lead to an increase in the INC-DEC price spread at an individual plant level, since the avoidable cost of producing an additional MWh should be close to that of reducing output by a MWh. The increase in the spread at an aggregate level reflects:

- an increasing disparity between oil, gas and coal prices;

- an increase in INC price bids by non-ESBPG plant, reflecting higher gas prices, unmatched by similar increases in DEC prices.

Eirgrid has written to the Commission and made oral presentations about the effect of higher than anticipated constraint costs in 2005 and 2006 on its allowable revenues – and hence transmission use of system charges paid by suppliers - in 2007. The analysis and some of the mitigation measures put forward in this consultation paper draws on those representations. The issue was also raised and discussed in a Trading and Settlement Code Modification Panel meeting earlier this year.[2]

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[1] When plant is being commissioned, the TSO has to schedule more reserve against the risk of the tripping of the plant being commissioned.

[2] Code Modification PM 182, submitted by ESBPG.

3 MITIGATION MEASURES

It is not clear that the increase in constraint costs since July 2005 reflects a genuine increase in the resource costs associated with resolving transmission and reserve constraints. In other words, it is not obvious that the increase in the INC-DEC spread at an aggregate level represents an increase in the true resource costs incurred by generators in responding to Eirgrid instructions to resolve transmission and reserve constraints. The Commission is therefore considering what changes might be made to the rules governing the existing imbalance market to ensure that INC-DEC price bids more closely reflect the costs incurred by generators in responding to TSO instructions.

This is justified on two grounds:

- *efficiency:* Eirgrid can only make efficient decisions about how to resolve constraints, both in the short-term by dispatching plant, and in the medium term by making investments in the transmission system to reduce the incidence of constraints, if the prices it faces properly reflect costs;

- *equity:* suppliers (and ultimately their customers) will bear these substantially higher constraint costs through increased TUoS charges. To the extent that the increase in net payments to generators does not reflect an increase in the underlying costs incurred by them in responding to the TSO's dispatch instructions, there is an unwarranted transfer of income from the end-customer to the generators.

The Commission has identified three options. These are discussed in the following paragraphs. [3]

3.1 Changes to the rules setting top-up and spill

The first proposed option is to change the way in which top-up prices are set to give generators a better incentive:

- to bid cost-reflective INC and DEC prices; and

- to nominate their plant in a way that best reflects their bilateral contract positions.

Top-up prices are currently set *ex ante* at the BNE price (suitably profiled); or, to the extent that the spill price resets the top-up price, by the decremental price of the most expensive generator scheduled to run in EPUS (that is capable of being decremented). By design, top-up prices do not reflect the INC prices of generators. Indeed, INC price bids have a minimal impact on market signals. They predominantly affect the price paid by Eirgrid for constraints and the scheduling of plant.

[3] It is assumed in the following paragraphs that ESBPG will continue to be subject to direct regulation by the Commission of their INC/DEC price bids.

This has implications for constraint payments since a generator can, if it can anticipate occasions when its instructed quantity will be greater than its XNOM in any half hour, be assured of being paid by the TSO for the difference between its actual output and its XNOM at its INC price. If it simultaneously has to resort to top-up in that half hour to meet its contractual commitments in the market, it will do so at the top-up price. If the generator's INC price is set above its true avoidable costs, it will make a profit from being instructed to generate above its XNOM. And if its XNOM turns out below its bilateral contract quantity, it can rely on buying top-up at a price that is unrelated to its INC price.

Generators would be incentivised to bid in a cost reflective manner if the top-up price was changed to be the higher of:

1) the ex-ante top up price; or

2) the lowest INC price of a generator in the EPUS schedule whose output is capable of being incremented; or

3) the spill price.

Similarly, a generator is not exposed to the consequence of bidding low DEC prices because the spill price floor protects revenues in off-peak periods. If the spill floor price was removed, generators would be more likely to submit higher decremental prices that reflected their true avoidable costs.

The advantage of this option is that it would:

- give generators a better incentive to bid cost-reflective INC and DEC prices and to nominate their plant in accordance with their bilateral contract position, thereby creating a market-based solution to high constraint costs;

- result in imbalance prices that would better reflect real time conditions in the market and turn the existing market into something closer to a true bilateral contracts market with cost-reflective imbalance prices;

- be consistent with the view that the existing market has now outlived its design, which was drawn up when the independent sector was non-existent;

- remove regulatory influence in the setting of the top-up price;

- possibly create less of a structural break when the SEM starts.

However:

- it would fundamentally change the rules around the setting of top up prices;

- it would reverse a Commission decision on the spill price floor and other related decisions that was endorsed as recently as mid-2005 and designed to add to revenue certainty;

- create regulatory risk.

The Commission has asked Eirgrid (in its capacity as the Settlement System Administrator) for an analysis of how long it would take and what it would cost to implement the required changes to the Trading and Settlement Code to give effect to this option. There is doubt that this change can be implemented at a reasonable cost and relatively quickly (between now and the SEM go live date). Whether it can be done will depend on:

- whether EPUS can report for each trading period the required price variable (ie the lowest INC price of a scheduled generator that can be incremented)

- if it can, then the change will be relatively modest

- how much effort needs to be devoted to testing.

3.2 Caps on generator price bids

The marked increase in the INC-DEC spread at an aggregate level since July 2005 is mainly the result of an increase in the INC-DEC spread of non-ESBPG gas-fired plant. A cap on generator INC price bids would be a direct way of controlling constraint costs. The cap could either be fixed or indexed. A fixed cap would be difficult to justify in a world of increasingly volatile fuel prices.[4] If the price cap were indexed (i.e., determined by a predictable formula), the question then arises as to the necessary components of the formula. The following paragraphs set out what such a formula might look like.

Fuel

The INC price cap would in practice apply to independent generators burning gas in either single or combined cycle units. The cost of gas would be the most important element in the price cap formula. Thus, gas costs (in €/GJ) in combination with the heat rate of the unit in (GJ/MWh), would represent an important component of the bid price formula.

The true opportunity cost would be represented by the prompt price for gas. This is the price that a generator would have to pay on the day for gas or the price at which it could sell gas bought forward. But if a cap is in place, the prompt price will not be known at the time the bids are submitted (at 10am on the day before the trading day). The day ahead price would be the best proxy in these circumstances.

[4] PM 183 proposed a fixed cap of €150/MWh.

There may be case for an addition to the day ahead price to represent the risk that prompt prices will turn out higher than day ahead prices, i.e., a measure of the volatility of the day ahead and the prompt price.

The cap would apply to all the INC prices submitted by the generator. The Trading and Settlement Code specifies that price bids in respect of a unit consists of the following:

1) one each of a hot start price, a warm start price and a cold start price (given in €/start);

2) an incremental price curve, consisting of: an incremental idling price (in €/hour) and up to four incremental prices (given in €/MWh), the resulting price curve to be monotonically increasing and piece-wise linear;

3) a decremental price curve, consisting of: a decremental idling price (in €/hour) and up to four decremental prices (given in €/MWh) , the resulting price curve to be monotonically increasing and piece-wise linear;

4) the MW levels between which a given incremental or decremental price applies (the break points).

This constraint cost mitigation option would apply only to the first and second elements – the unit's start prices and INC prices. Generators would continue to be free to set DEC prices and break points.

The capped incremental fuel bid prices would be determined using regulated incremental heat rate curves in conjunction with the gas price. Start prices would be capped separately.

Carbon

Another component of the INC price is the avoidable cost of carbon. As with gas, the spot market price of allowances (EUAs) is the opportunity cost to be credited, not the cost at which permits were acquired. The day ahead cost of carbon (in €/tonne CO_2), adjusted by a constant to convert from tonnes of CO_2 to MWh, would be added to the incremental gas cost at each load point.

Exchange rate

The day ahead sterling/euro exchange rate would be used in the formula to convert gas prices from pounds sterling into euros.

Variable gas transmission charges

A constant amount would need to be added to the incremental fuel and carbon cost to cover the variable cost of gas transmission. The 2007 BNE estimate includes a figure of €0.4/MWh.

Variable Operating and Maintenance Cost

Some aspects of plant operations other than fuel vary relative to output. While the Commission acknowledges that it is difficult to make hard-and-fast rules about the categorisation of O&M costs into variable and fixed components, a number would have to be chosen. The 2007 BNE estimate includes a figure of €0.5/MWh in respect of variable O&M costs.

The advantage of a cap on generators bid prices is that it would directly address what is a major contributor to high constraints costs, i.e. INC prices that may not genuinely reflect incremental avoidable fuel and other costs faced by generators.

On the other hand it would go only some way to minimising the INC-DEC spread, since it would do nothing about the bidding of low DEC prices.

Implementation need not be costly or difficult, if the capped INC prices were used only for the purposes of determining constraint payments *ex post* in settlement and not for running EPUS. If they were used only for that purpose, there would be no need to check the compatibility of bids with the formula before the trading day starts. Verification could follow in the period between the end of the trading day and the running of settlement.

On the other hand, using capped bid prices only for settlement purposes would expose the TSO, since it would not know what the potential cost of an action on its part to resolve a constraint or to schedule reserve was in real time. It would find out only after the event. Whether capping bid prices according to an indexed formula would be feasible in the period between 10am on the day before the trading day to which the bids refer and 12 noon, when the TSO needs to know what the INC and DEC prices are to draw up its indicative dispatch schedule is a moot point.

3.3 Limitation of the INC-DEC price bid spread

Generators currently submit a series of INC and DEC price offers. There is often a marked difference between the series of INC and DEC prices bid in by non-ESBPG generators. Since a generator's individual constraint payments are quite well correlated with the size of its INC-DEC bid price spread, an option would be to limit the size of the differential between the two.

It is not clear what cost justification exists for such a wide INC-DEC spread. While gas-fired generators may have take-or-pay contracts in place for gas, it is not obvious that that gas cannot be sold in the market in the event that a generator is turned down by the TSO, though the price received would admittedly depend on the liquidity of the gas market on the day.

Nonetheless, the Commission is of the opinion that current INC-DEC spreads expose Eirgrid (and ultimately the end-customer) to significantly greater risks than that faced by the generators. A limitation on the INC-DEC spread of generators would significantly reduce the cost to Eirgrid of instructed imbalances.

The limit would have to be expressed in absolute terms (e.g. €100/MWh), to allow DEC price bids of zero. And to avoid negative DEC price bids, the rule would have to be expressed in terms of a DEC price plus the fixed differential.

Caps (either fixed or floating) on start and idling costs would also need to be imposed under this option. The spill price floor would also need to be removed to expose non-ESBPG generators to the effect of low price DEC bids.

The advantage of this option is that it would:

- directly address what the Commission believes is a major contributor to high constraints costs, i.e. the INC-DEC spread of individual generators;
- be relatively simple to implement and monitor.

On the other hand it would:

- reverse a Commission decision on the spill price floor that was endorsed as recently as mid-2005;
- possibly require partial exemptions in the case of CHP plant, where the avoidable costs of running at zero output may be considerably lower than the costs of running at a higher than desired level (because of the need to replace the heat using a stand-alone boiler).

4 NEXT STEPS / CONSULTATION

The Commission invites comment on this consultation on options to minimise constraint costs in the period until the SEM is operational.

Comments should be sent, preferably in electronic format, to Garrett Fitzgerald at the Commission. Comments are to be delivered to the Commission by no later than 5.00pm on Friday, 25th August 2006. The contact details are:

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The Commission is planning to make these comments public and would encourage respondents to do the same. Any information that respondents wish to submit in confidence may be submitted separately, clearly marked as such. However, the Commission would prefer public comment wherever practicable.