# Common Arrangements for Gas (CAG) - Transmission Tariff Methodology and Regulation

Consultation Response

**15th August 2008**

## Table of Contents

## 1. EXECUTIVE SUMMARY

Bord Gáis Networks (BGN)[1] summarises below its response to the consultation paper on "Transmission Tariff Methodology and Regulation in Ireland and Northern Ireland" dated 27 June 2008. In turn, we summarise our views on the constraints on the viable options, the appropriate criteria for discrimination amongst the options and our preferred option based on these criteria. We also summarise our views on some further issues. Finally, we comment on some quantitative analysis of our preferred option.

Our proposal is primarily based on Entry/Exit with LRMC and results customers in both the ROI and NI benefiting as the average gas cost at the Irish Balancing Point falls considerably due to adopting capped interconnector charges. Under our preferred charge structure, a typical residential customer would see a reduction of an average of some 15% in ROI and some 4% in NI.

At the outset, we emphasise our full support for the objective expressed in the Memorandum of Understanding signed by the Regulatory Authorities in February 2008 which is "to establish All-Island Common Arrangements for Gas whereby all stakeholders can buy, sell, transport, operate, develop and plan the natural gas market north and south of the border effectively on an all-island basis" so that "variations in the price and conditions on which gas is bought and sold will be determined by market conditions and economics, not by variations in regulatory arrangements."

Further consideration will need to be given to the timing and phasing of implementation of any new charge structure once all elements of the CAG have been finalised. We stress, however, that any new charge structure should not be implemented until the next price control period to avoid adverse impact on the investment climate in Ireland. At that time, there should be greater clarity as to which development scenario will eventuate.

### 1.1. Constraints

In determining viable options for the tariff regime, we consider the following are constraints:

- tariffs must **comply with European legislation** which emphasises the need for tariffs to recover efficiently incurred costs and an appropriate return on investment and to facilitate efficient competition;
- tariff **levels must not be amended** outside of price control reviews as any adverse amendment within a price control period would undermine the investment climate in Ireland adversely impacting not only on the gas sector but also on the electricity and other regulated sectors; and, ideally,
- tariffs should **avoid significant financial transfer** across jurisdictions which would be difficult to implement.

### 1.2. Criteria

In assessing the viable options, we use criteria which differ from the four broad criteria suggested in the consultation paper as we emphasise:

[1] Bord Gáis Networks is responding to this consultation as a licensed asset owner in ROI, on behalf of BGE(UK) - an asset owner and TSO in NI, and as a service provider to all of the TSOs on the island north and south

- cost recovery as a primary criterion while the consultation paper states that prices should at least allow cost recovery under its “protecting customers” criterion and mentions cost orientation under its “developing the industry” criterion; and
- efficiency achieved through appropriate price signals as a primary criterion while the consultation paper mentions appropriate price signals under its “developing the industry” criterion and notes that a key role for tariffs is to send the right signals under its “security of supply” criterion.

We list below our criteria in broad order of priority from highest priority to lowest priority and, in parenthesis, we cross-reference them to the broad criteria included in the consultation paper:

- **cost recovery**: the harmonised tariff regime should allow the network asset owners sufficient revenue to cover efficiently incurred investment and operation costs, including an appropriate return commensurate with the risks of their businesses (“developing the industry”, “security of supply”);

- **efficiency:** the harmonised tariff regime should promote efficient development and operation of the gas system through appropriate price signals (“developing the industry”, “security of supply”). The tariff structure should reflect underlying marginal costs of gas transmission, allowing producers and consumers to allocate resources efficiently in response to tariff price signals. For example, with interconnector charges and thus the Irish Balancing Point (IBP) price reflecting marginal transmission costs, there would be more efficient signals for investment in the face of declining interconnector utilisation than are provided by the current tariff structure. However, we stress that efficient development of the industry is impacted by many broader issues which are outside the scope of the tariff regime (eg tax policy or other incentives for producers);

- **equity**: the harmonised tariff regime should promote equity by:
  - maintaining regulatory commitments particularly concerning recovery of agreed allowed revenues (“developing the industry”, “security of supply”);
  - avoiding inequitable payments for security of supply (“promotion of competition”). In particular, while the interconnector assets provide security of supply to all customers, it is not clear that it is equitable for the Moffat shippers alone to bear their costs;
  - ensuring a level playing field for efficient competition among suppliers irrespective of the location of their customers (“promotion of competition”);
  - avoiding undue cross-subsidy between network users and between jurisdictions (“promotion of competition”);
  - appropriately balancing the interests of the network asset owners and network users (“protecting customers”);

- **stability**: the harmonised tariff regime should be relatively stable and predictable across a range of scenarios to give producers and consumers confidence to make investment decisions based on the tariff price signals and there should be no step changes in tariffs (“developing the industry”, “protecting customers”). We are concerned that choices made are robust under a range of development scenarios rather than the single development scenario discussed in the consultation paper. In particular, there is uncertainty around the timing of the Corrib gas flows and the Shannon LNG facilities which would have significant impacts on the interconnector flows. However, we recognise that on a small system where new facilities cause relatively large changes in flows, tariffs cannot be fully stable across all development scenarios; and

- **practicality** (“protecting customers”) the harmonised tariff regime should:
  - be reasonably easy to implement;
  - avoid undue complexity so that it can be understood by customers; and
  - result in benefits that exceed the transaction costs.

These criteria conflict. For example, tariffs that are stable across a range of scenarios will likely have somewhat weakened price signals. Accordingly, the harmonised regime will inevitably represent a compromise which depends on the weighting attached to the various criteria. In using these criteria to discriminate among the options, we apply the highest weight to the cost recovery criterion (as this is essential for investor confidence not just in networks but throughout the energy sector) and, thereafter, while there is a degree of overlap, we apply the second highest weight to the efficiency criterion (as this is likely to ensure lowest overall costs to customers in the short and long term) and we then apply broadly equal weights to the equity, stability and practicality criteria.

Using these criteria, in circumstances where economic efficiency is most important and thus price signalling is required, particularly in interconnector charging, we consider that an approach to charging based on long run marginal cost (LRMC) represents the best compromise among the competing objectives as:

- **cost recovery**: it achieves the required transmission revenue through fairly straight-forward adjustments (a uniform addition or subtraction to charges is often used to maintain appropriate differentials and hence price signals);
- **efficiency**: it promotes economic efficiency over the medium-term through appropriate price signals;
- **equity**: it results in prices which are likely to be acceptable to users as the prices demonstrably:
  - correspond to the (forward looking) costs of transmission capacity;
  - avoid cross-subsidy;
- **stability**: it results in prices that are likely to be relatively stable; and
- **practicality**: it results in a regime that is reasonably easy to implement.

Our focus is to achieve efficient charges for the interconnectors because of the important impact these have in determining the price at the Irish Balancing Point.

### 1.3. Preferred structural option

We propose the following entry/exit charge structure:

- **entry**:
  - structure: combined Moffat entry point (i.e. southern interconnectors and SNIP) and separate entry points for Inch and Corrib and for any LNG or storage facilities that emerge;
  - charges: for the combined Moffat entry point and, possibly, for other entry points, entry point charges to be the lower of charges that recover the cost of the entry point regulatory asset base (RAB) or charges equal to the equilibrium level of long run marginal costs

(with any under recovery of the cost of the entry point RAB recovered through exit charges). For the combined Moffat entry point, long run marginal costs would be approximated by the lowest of the long run average incremental costs of expansion along each of the existing interconnector pipeline routes;

- **exit**:
  - structure: two exit zones corresponding to the relevant jurisdictions;
  - charges: exit zone charges to recover the cost of the exit zone regulatory asset base and any under recovery of entry charges. Any under-recovery of the combined Moffat entry point costs would be recovered by adjustments to the exit zone charge for each jurisdiction in proportion to their share of the combined allowed revenue (thus avoiding cross-subsidy between jurisdictions)..

We make this proposal because we consider that:

- the Moffat interconnectors should be combined as they provide a common service of entry from the GB system and the interconnector charges should provide economic efficient price signals that are essential to deal with the declining flows on the interconnectors. Combining the interconnectors:
  - ensures that the prices faced by shippers reflect the optimum cost of transporting gas from the GB market, irrespective of the actual route taken by the gas to the all-Ireland market;
  - ensures that there is no artificial incentive to use one Moffat interconnector rather than another (for example, due to the different depreciation rates of the various assets);
  - increases the robustness of the charging approach under scenarios in which utilisation of the interconnectors vary significantly;
  - provides mechanisms to allow NI to reduce mutualisation risk and to smooth SNIP charges across years;
  - provides a transparent single tariff for delivery of gas from GB that facilitates non-discriminatory access to the available transmission capacity;

- the interconnector charges should be capped at the equilibrium level of the long run marginal cost to provide a stable and practical charge regime with appropriate price signals;

- the other entry points should be treated separately to retain the possibility of separate price signals as they each provide a unique entry service though further consideration is needed as to whether such charges should be capped at LRMC; and

- the two exit zone option is most practical, both on social grounds and because it offers the possibility of reducing the need for financial transfers across the jurisdictions. We reject the alternatives as we consider that options:
  - with many exit points are unlikely to be practical and, with the relatively small networks on the island, we are not convinced that they will bring commensurate benefits in terms of increased efficiency and equity;
  - under which exit charges vary within the jurisdictions, or there is cross-subsidy from one jurisdiction, to another are unlikely to be acceptable on social grounds.

Further consideration to be given to the timing and phasing of implementation of any new charge structure once all elements of the CAG have been finalised. We stress, however, that any new charge structure should not be implemented until the next price control period to avoid adverse impact on the investment climate in Ireland.

### 1.4. Further issues

We summarise below our views on four further issues concerning tariff structure raised in the consultation paper:

- we recognise that a **revenue transfer and currency risk mechanism** will need to be devised if the Moffat interconnectors (or other elements of the tariff structure) are combined. Such a mechanism should be used not only for transfer of transmission revenues but also for any other necessary transfers (such as might be required in respect of system balancing). We see merit in devising mechanisms that are congruent with the SEM regime which spreads default and currency risk across the market;

- we support **harmonisation of non annual gas capacity products** as this brings significant benefits to users in terms of transparency, simplicity and ease of use and we can see no significant drawbacks. Accordingly, we suggest that inventory, short term and back-up products currently available in the ROI should be made available in NI and that interruptible products should be made available in both jurisdictions with the (non-price) product terms for each product harmonised across the jurisdictions. If further products are developed, for example, the peaking plant capacity product currently under consideration in the ROI, these should also be harmonised across jurisdictions;

- we would support **harmonisation of the capacity/commodity split** to promote stability and practicality if cost reflective capacity/commodity splits were similar (say within 5%). If harmonisation is to be imposed, we would prefer harmonisation at a level which minimises the projected (volume weighted) differences from the cost reflective splits which is likely to be around the 90/10 split currently applied in the ROI; and

- we are happy with the current arrangements in the ROI for **smoothing within a price control** period. However, we understand that there may be constraints on such smoothing in NI as the tariff regimes for assets under mutualised companies anticipate annual charging not smoothing.

### 1.5. Quantitative analysis

We have conducted some illustrative quantitative analysis to demonstrate that our proposal that caps interconnector charges at the equilibrium level of LRMC has significant merit in mitigating the impact of declining interconnector flows. Our proposal leads to **relatively stable interconnector entry, exit and end user charges for both the ROI and NI under the three development scenarios considered**. In the table below, we show our estimate of the range and average of end user charges, across all three development scenarios we have considered, which would emerge under the current charge structure and under our preferred option.

| | | ROI | | | NI | | |
|---|---|---|---|---|---|---|---|
| | | Min | Ave | Max | Min | Ave | Max |
| **Current** | Capacity (EUR/peak day MWh) | 552 | 707 | 977 | 508 | 539 | 637 |
| | Commodity (EUR/MWh) | 0.289 | 0.434 | 0.841 | 0.219 | 0.242 | 0.282 |
| **Preferred Option** | Capacity (EUR/peak day MWh) | 558 | 609 | 664 | 453 | 516 | 635 |
| | Commodity (EUR/MWh) | 0.287 | 0.310 | 0.336 | 0.224 | 0.258 | 0.320 |

Notes:
(1) The illustrative ROI end user charges are based on interconnector entry and onshore ROI exit. "Current" charges comprise IC entry and ROI exit; and "Preferred Option" charges comprise combined IC/SNIP entry and ROI exit
(2) The illustrative NI end user charges are based on interconnector entry and onshore NI exit (including SN pipeline). "Current" charges comprise SNIP entry and NI exit; and "Preferred Option" charges comprise combined IC/SNIP entry and NI
(3) If other entry points were used for the illustration other charges would results.

Finally, we note that, **overall, the customers in both the ROI and NI benefit from the proposed charge structure as the average gas cost at the Irish Balancing Point falls considerably due to adopting capped interconnector charges**. Under our preferred charge structure, a typical residential customer would see a reduction of an average of some 15% in ROI and some 4% in NI.

We look forward to discussing this response and other proposals further with the Regulatory Authorities.

## 2. INTRODUCTION

In this document, Bord Gáis Networks (BGN) sets out its response to the consultation paper on "Transmission Tariff Methodology and Regulation in Ireland and Northern Ireland" dated 27 June 2008. This response includes our views on the criteria for choosing among the options, the viable options, and our preferred option.

At the outset, we emphasise our full support for the objective expressed in the Memorandum of Understanding signed by the Regulatory Authorities in February 2008 which is "to establish All-Island Common Arrangements for Gas whereby all stakeholders can buy, sell, transport, operate, develop and plan the natural gas market north and south of the border effectively on an all-island basis" so that "variations in the price and conditions on which gas is bought and sold will be determined by market conditions and economics, not by variations in regulatory arrangements."

We note that the consultation paper raises matters related to both the level and the structure of tariffs. Our strong view is that matters relating to the level of tariffs should be addressed only in scheduled transmission price control reviews with the relevant Regulatory Authority.

We also note that the quantitative analysis in the consultation paper is potentially confusing as it is based on input data which has been revised in the Common Arrangements for Gas (CAG) model circulated more recently.

Finally, we note that our response deals only with transmission use of system charge structure and not with matters related to connection charge policy.

We have set out the remainder of our response as follows:

- Section 3 describes the **context** to our response to the consultation;
- Section 4 describes the hard and soft **constraints** on the harmonised tariff options and our views on the objectives of the harmonised tariff regime and the weighting we attach to the various criteria for choosing among the options;
- Section 5 deals with matters relating to the **structure of tariffs** including our assessment of the options against our view of the objectives and our preferred option;
- Section 6 includes some comments on the modelling intended to allow users to examine the magnitude and direction of the impact on tariffs of varying the key assumptions and our **quantitative assessment** of our preferred option for tariff structure.

The response includes four annexes:

- Annex 1 provide more detail on the value of the interconnectors to the Irish gas system;
- Annex 2 provides a response to each specific question raised in the consultation paper to facilitate consolidation of responses;
- Annex 3 provides further details of our modelling; and
- Annex 4 includes indicative estimates of long run marginal cost (LRMC) at the interconnector (IC) entry points.

## 3. CONTEXT OF CONSULTATION

In this section we describe certain contextual issues which should be taken into account by the regulators, and which shape our response to the consultation.
BGN has recently completed a price review for the next five years with the CER and similar price control reviews have been completed in Northern Ireland (NI). The **regulatory agreements** resulting from these reviews must continue to be respected. The BGN review determined allowed revenue as the sum of allowances in respect of operational costs, depreciation and return on the regulatory asset base (RAB). Accordingly, the review included a thorough examination of the efficiency of operational and investment costs, the appropriate depreciation rates and the appropriate cost of capital. Indeed, the review gave explicit consideration to depreciation rates for the interconnectors and the CER concluded that IC2 should continue to be depreciated over 100 years given the CER's view that Corrib will commission in 2009 and reduce flows on IC2. Thought was also given to the impact of Shannon LNG (e.g. in relation to new investment requirements) during the review. Consideration of these factors should therefore be outside the scope of the CAG programme of work.

It should be recognised that the **interconnectors are a critical asset** for the Irish gas system that allow development of the gas system and provide security of supply, access to the GB market, price stability and environmental benefits. Without the interconnectors, major users, such as potential power station investors, would be reluctant to invest as they would not enjoy security of supply and might be exposed to undue market power exerted by Irish producers. As a result, there would be significantly adverse impacts on Irish competitiveness. Further the interconnectors allow annual savings of the order of €200M-€250M in the costs of carbon emission permits.

**Tariff volatility** has been and will continue to be an important consideration within the Irish market. The arrangements for tariffs put in place as part of CAG should be robust to various potential gas development scenarios. The tariff regime must accommodate and operate effectively under various potential development scenarios. For example, while interconnector flows are projected to decline under scenarios with Corrib gas and Shannon LNG commissioned, the tariff regime should be robust to alternative scenarios where flows do not decline significantly such as:

- delay in Corrib gas flow; and/or
- postponement (or even cancellation) of the Shannon LNG project; and/or
- postponement (or cancellation) of either or both of the Larne storage projects[2].

It would be damaging to confidence in the overall market arrangements if the tariff regime has to be reviewed quickly after having been put in place due to changes in the out turn development scenario. However, we recognise that on a small system where new facilities cause relatively large changes in flows, tariffs cannot be fully stable across all development scenarios

Finally, BGN believes it is important that the tariff regime should draw on the **experience of the Single Electricity Market** (SEM) on common issues. As examples, we understand that the SEM arrangements deal with issues such as financial transfers between system operators,

[2] The two potential Larne storage projects are under consideration: one by Bord Gáis Strategic Investment Division and the other by Portland Gas/Premier Transmission Limited. In the most recently presented modelling, the Regulatory Authorities assume that one project commissions.

differential VAT rates in the Republic of Ireland (ROI) and NI and currency risk- all of which are likely to arise in the CAG also. Lessons learned in the development of the SEM should, where relevant, be applied in the development of all-island gas tariff arrangements.

## 4. CONSTRAINTS, OBJECTIVES AND CRITERIA

In defining new tariff arrangements, BGN believes there are significant constraints that will need to be taken into account. The objectives of the tariff arrangements and therefore the criteria against which different proposals are judged should take account of these constraints.

Therefore, in this section, we set out our view of the hard and soft constraints on the tariff regime, and we then set out the objectives (and hence criteria for choice) we consider appropriate for the harmonised tariff regime.

### 4.1. Constraints

In determining viable options for the tariff regime, we consider there are two hard constraints which must not be violated and one soft constraint which ideally should not be violated when selecting the appropriate tariff regime.

#### 4.1.1. Hard constraints

The first hard constraint is the need to comply with **European legislation**. EC 1775/2005 Article 3 Tariffs for Access to Networks requires that tariffs or the methodologies used to calculate them:

- "shall take into account the need for system integrity and its improvement and reflect actual costs incurred, insofar as such costs correspond to those of an efficient and structurally comparable network operator and are transparent, whilst including appropriate return on investments";
- "shall facilitate efficient gas trade and competition, while at the same time avoiding cross-subsidies between network users and providing incentives for investment and maintaining or creating interoperability for transmission networks"; and
- "shall not restrict market liquidity nor distort trade across borders of different transmission systems".

Critically, we note the emphasis placed by European legislation on:

- an appropriate return on investments; and
- economically efficient transmission tariffs which facilitate efficient competition.

The second hard constraint is that **tariff levels should not be amended outside of price control reviews**. We strongly believe that all matters relating to overall allowed revenue and hence the average level of tariffs should be dealt with only at a price control review.

During the recent price control review in the ROI, a comprehensive review of BGN's cost base and risk profile was undertaken and reported in the document "Bord Gáis Networks Revenue Review 2007/8-2011/2 Transmission Decision Paper". This resulted in a price control settlement for a five year price control period, including a clear statement on the appropriate level of our cost of capital which will allow ongoing investment in the business. In its decision paper the

CER stated that "Consistency is a key regulatory requirement. Investment in a regulated environment requires certainty about the future treatment of key elements, particularly the return on and return of any funds invested". Such sentiments apply to all regulated businesses.

Any adverse amendment to a price control within its price control period would undermine the investment climate in Ireland adversely impacting not only on the gas sector (production, LNG and storage facilities) but also on electricity and other regulated sectors. It would signal that the regulators were willing opportunistically to claw back efficient revenue from companies and, in doing so, impact the economic feasibility of existing and new investments.

This would be likely to have two effects:

- **deterring new investment in infrastructure projects**: new developers would not have confidence that the relevant regulator would allow them to make returns within a stable regulatory framework without the risk of profits being clawed back. This should be a major consideration for the regulators as a large number of new capital projects are currently under construction[3] or being considered in the Irish energy sector; and
- **causing higher costs**: where new investment does take place, developers will demand a higher cost of capital to compensate for the risk of opportunistic regulatory action. This will increase costs to customers, who in the end pay for all infrastructure.

Among the measures that would demonstrate regulatory opportunism and thus undermine investor confidence are:

- reduction in the value of existing assets in the RAB; and
- reduction in the allowed cost of capital (whether through a formal option such as adopting a different model for rewarding investment or through an informal option such as government guarantees).

Furthermore, it is unclear how any such moves would be consistent with the requirement under European law that tariffs include an appropriate return on investments. Indeed, arguably since the price control settlements, any attempt to estimate "the costs… of an efficient and structurally comparable network operator" would indicate an <u>increase</u> in financing costs as market interest rates have increased.

Neither should a regulator arbitrarily seek to reprofile revenues or amend agreed depreciation lifetimes even if this does not change the present value of revenues. Having agreed its price control, a regulated business will optimise its ongoing operating and investment activities and financial structure against the revenues implied by the review. Any re-profiling of revenues subsequent to the price control review will necessitate re-optimisation and incur additional costs. This will adversely affect the business and again increase the perception of regulatory opportunism within the market, impacting on customers in the long term.

As an example, we have scheduled major elements of capital expenditure to be confident that, given our projected cash flows, we will maintain our credit ratings and key financial ratios within acceptable levels. If our revenues are re-profiled, our costs are likely to increase because, with materially altered cash flows during the regulatory period, we will need to either re-

[3] For example, the East West electricity interconnector.

optimise our activities at potentially increased cost or we will risk a deterioration in our financial position (potentially leading to breach and costly renegotiation of our loan covenants).

As we argued in relation to reductions in revenue, the appropriate time to consider the profile of recovery is at a price control, where a holistic view can be taken on an "efficient" level of costs and on the issues for individual businesses in relation to financing their activities over the coming price control period. Having set revenue and profile, there should be no changes – the business should be allowed to optimise efficiently its activities against a clear and stable set of revenue requirements, and in so doing, maximise benefits to customers over the long term.

While the above constraint rules out options that involve a reduction in the allowed cost of capital, including mutualisation, we wish to emphasise here that **mutualisation poses other risks** which have not been identified in the consultation paper. For reasons explained below, while mutualisation may result in short term (financing) cost savings, it may also result in **long term cost increases**. Mutualisation also places **greater risks on customers**. Further, mutualisation **inhibits investment** as without equity and with limited free cash flow any new investment must be funded through new debt with corresponding needs to negotiate with lenders.

Mutualisation involves the transfer of a joint stock company (funded by a mixture of equity and debt) to a not-for-dividend company limited by guarantee (CLG), which has no shareholders. This may lead to cost savings if the operating and financing costs of the CLG are lower than those of the joint stock company. However, the reverse may easily occur as, while the regulatory regime on a joint stock company imposes pressure on the management to control both operating and financing costs, the regulatory regime on the CLG is unlikely to impose pressure on the management to control operating costs (because to achieve the low cost, long term debt necessary to justify mutualisation, the regulatory regime must allow the CLG to pass-through to customers its operating costs

#### 4.1.2. Soft constraint

In addition to the hard constraints, ideally, we believe that there should be no cross-subsidy across jurisdictions as we consider mechanisms that cause significant financial transfer across jurisdictions will be difficult to implement.

This soft constraint does not necessarily rule out regimes that imply a significant reduction in payments by customers in one jurisdiction and an increase in payments by customers in the other jurisdiction. For example, if payments in one jurisdiction did increase, but this was balanced by commensurate present or future benefits, then the regime could be acceptable. Such benefits could include:

- avoided future investment, that arises, for example, because of reduced or removed barriers to gas flow across the island allowing access to a greater volume of gas within the existing all-island network;
- formal arrangements that increase security of supply and that are not always recognised in the current regime;
- risk reduction, that arises, for example, through reduced price volatility due to recovering revenues over a larger sales volume; and
- access to different sources of gas, for example, access to Corrib gas in NI.

4.2. Objectives and criteria

The Regulatory Authorities have, in their consultation document, suggested four criteria for evaluating options for the tariff regime. While these criteria are a useful starting point, we believe they miss some key points. In particular, we do not believe they capture clearly the hard constraints above – while they are relevant for some of the criteria, this relies on specific interpretation.

For example, in the consultation paper, it is not clear whether there is a particular costing approach which is believed to be appropriate for tariff structure (in previous CER tariff consultations (for example, CER/04/182), significant emphasis has been placed on marginal cost). Rather, as a result of the "developing the industry" and "protecting customers" criteria, much of the discussion concerns whether regimes will result in high prices (good for developing the industry) or low prices (good for customers) rather than whether regimes will result in the right prices (though this is mentioned under the "security of supply" criterion).

We therefore believe the criteria in the consultation document should be refined. We propose the following objectives and hence criteria which line up more closely with those used elsewhere, for example:

- in the discussion paper on options for the gas operational regime;
- in the evaluation of the options for the single electricity market; and
- in the CER's 2004 paper on tariff structures (CER/04/182).

We list the criteria in broad order of priority from highest priority to lowest priority and, in parenthesis, cross-reference them to the broad criteria included in the consultation paper:

- **cost recovery**: in line with European legislation, the harmonised tariff regime should allow the network asset owners sufficient revenue to cover efficiently incurred investment and operation costs, including an appropriate return commensurate with the risks of their businesses ("developing the industry", "security of supply");
- **efficiency**: in line with European legislation, the harmonised tariff regime should promote efficient development and operation of the gas system through appropriate price signals ("developing the industry", "security of supply"). In particular, it should remove pricing barriers to gas flowing around the island[4]. The tariff structure should reflect underlying marginal costs of gas transportation, allowing producers and consumers to allocate resources efficiently in response to tariff price signals. For example, with interconnector charges and thus the Irish Balancing Point (IBP) price reflecting marginal transport costs, there would be more efficient signals for investment in the face of declining interconnector utilisation than are provided by the current tariff structure. However, we stress that efficient development of the industry is impacted by many broader issues which are outside the scope of this review of the tariff regime (eg tax policy or other incentives for producers);
- **equity**: the harmonised tariff regime should promote equity by
  - maintaining regulatory commitments particularly concerning recovery of agreed allowed revenues ("developing the industry", "security of supply");
  - avoiding inequitable payments for security of supply ("promotion of competition"). In particular, while the interconnector assets provide security of supply to all customers, it is not clear that it is equitable for the Moffat shippers alone to bear their costs;

[4] Unless those flows can be shown to result in significant incremental cost.

- ensuring a level playing field for efficient competition among suppliers irrespective of the location of their customers ("promotion of competition");
- avoiding undue cross-subsidy between network users and between jurisdictions ("promotion of competition"). Cross-subsidy arises when customers face prices which do not reflect the costs they impose. Clearly, some cross-subsidy between network users is a consequence of introducing tariffs that reflect the cost drivers (such as location, peak demand and utilisation) of an average user rather than charges that reflect the cost drivers of each user. However, some cross-subsidy can be avoided by suitable structure of charges, for example, cross-subsidy between customers of varying utilisation can be avoided by use of a cost reflective capacity/commodity split;
- appropriately balancing the interests of the network asset owners and network users ("protecting customers"):

- **stability**: the harmonised tariff regime should be relatively stable and predictable across a range of scenarios to give producers and consumers confidence to make investment decisions based on the tariff price signals and there should be no step changes in tariffs ("developing the industry", "protecting customers"). We are concerned that choices made are robust under a range of development scenarios rather than the single development scenario discussed in the consultation paper. In particular, we have noted above that there is uncertainty around the timing of the Corrib gas flows and the Shannon LNG facilities which would have significant impacts on the interconnector flows. However, we recognise that on a small system where new facilities cause relatively large changes in flows, tariffs cannot be fully stable across all development scenarios; and
- **practicality** ("protecting customers") the harmonised tariff regime should:
  - be reasonably easy to implement;
  - avoid undue complexity so that it can be understood by customers; and
  - result in benefits that exceed the transaction costs.

These criteria conflict. For example, tariffs that are stable across a range of scenarios will likely have somewhat weakened price signals. Accordingly, the harmonised regime will inevitably represent a compromise which depends on the weighting attached to the various criteria. In using these criteria to discriminate among the options, we would apply the highest weight to the cost recovery criterion (as this is essential for investor confidence not just in networks but throughout the energy sector) and, thereafter, while there is a degree of overlap, we would apply the second highest weight to the efficiency criterion (as this is likely to ensure lowest overall costs to customers in the short and long term) and we would then apply broadly equal weights to the equity, stability and practicality criteria[5].

While we recognise that the four broad criteria suggested in the consultation paper are intended to encompass many of the above criteria, there are some key differences, particularly of emphasis:

- we emphasise cost recovery as a primary criterion while the consultation paper states that prices should at least allow cost recovery under its "protecting customers" criterion and mentions cost orientation under its "developing the industry" criterion; and
- we also consider efficient development and operation achieved through appropriate price signals should be a primary criterion while the consultation paper mentions appropriate price

[5] Note that "security of supply" arises from regulatory requirements (e.g. to design the gas system to meet severe cold weather demands and to promote diversity of supply) and is best promoted by ensuring that transmission tariffs allow recovery of costs efficiently incurred to meet these regulatory requirements.

signals under its “developing the industry” criterion and notes that a key role for tariffs is to send the right signals under its “security of supply” criterion..

## 5. TARIFF STRUCTURE PROPOSALS

In this section, we set out our views on the broad approaches to interconnector charging for tariff purposes, our preferred approach to tariff structure that maintains entry and exit charges and our views on some further issues raised in the consultation paper.

### 5.1. Interconnector charging approaches

Concerning tariff structure, BGN considers that the main issue is providing a mechanism to deal appropriately with southern interconnector and SNIP charges under all scenarios. Specifically, the interconnector charges must encourage economic efficiency to avoid distorting investment decisions by producers and consumers (e.g. encouraging inefficient indigenous production rather than imports through the interconnector). In this regard, there are two broad approaches to charging that will provide appropriate signals which have been discussed extensively in the context of reforms in other countries:

- long run marginal cost (LRMC): transmission tariffs are based on the forward-looking incremental costs of the optimal response to a sustained increment of demand for the transmission service. The optimal response in the long run is typically investment in new compression or transmission capacity and little or no increase in the probability of failure to supply (i.e. failure to meet the 1 in 50 peak day demand). Hence the incremental costs typically comprise incremental transmission investment costs and little or no increase in the costs of failure to supply; and
- auctions: transmission tariffs are determined by competitive auction.

Within each broad approach there are various different methodologies which can be used to derive charges – however, we summarise our assessment of the broad approaches below.

| | LRMC | Auction |
|---|---|---|
| Cost recovery | ●● | ● |
| Efficiency | ●●● | ●●● |
| Equity | ●●● | ●● |
| Stability | ●●● | ● |
| Practicality | ●● | ● |

Key: ●●● good ●● fair ● poor

Using our criteria, in circumstances where economic efficiency is most important, such as in interconnector charging, we consider that an approach to charging based on LRMC represents the best compromise among the competing objectives as:

- **cost recovery**: it achieves the required transmission revenue through fairly straight-forward adjustments (a uniform addition or subtraction to charges is often used to maintain appropriate differentials and hence price signals) as compared with auction approaches (which may require more complex arrangements to deal with a more volatile shortfall or surplus of revenue);

- **efficiency**: it promotes economic efficiency over the medium-term through appropriate price signals as do auction approaches;
- **equity**: it results in prices which are likely to be acceptable to users as the prices demonstrably:
  - correspond to the (forward looking) costs of transmission capacity;
  - avoid cross-subsidy;
- **stability**: it results in prices that are likely to be relatively stable as compared with auction approaches; and
- **practicality**: it results in a regime that is reasonably easy to implement as compared with auction approaches.

Our focus is to achieve efficient charges for the interconnectors because of the important impact these have in determining the price at the Irish Balancing Point. Assuming an LRMC approach to interconnector charging, we turn to an assessment of the viable options for tariff structure. As cost recovery must be achieved under all viable options, we consider only criteria relating to efficiency, equity, stability and practicality.

## 5.2. Entry tariffs

We consider that the range of entry options set out in the consultation paper is broadly appropriate. However, we rule out the entry option that separates the southern interconnectors because, as we explain later, we consider that the interconnectors provide a common service as a single transport system for gas from the GB market and should be charged as such. Accordingly, we consider the following structural options for entry:

- single entry point (combining all existing (and future) entry points);
- single Moffat entry point (combining SNIP and the southern ICs) and single other entry point (combining all other existing (and possibly all future) entry points);
- single Moffat entry point (combining SNIP and the southern ICs) with all other existing (and future) entry points separate; and
- all existing (and future) entry points separate (as now).

Below we provide our thoughts on:

- the application of the LRMC concept to interconnector charges within the framework of these options; and
- the choice of entry point definitions.

### 5.2.1. Application of the LRMC concept to interconnector charges

We believe that further thought needs to be given to the methodology for determining charges at each entry point.

Under the current charging methodology, there will be very different charges for the interconnector – and other entry points – depending on the overall development of the gas market. Interconnector charges vary significantly depending on the assumption made in relation to Shannon LNG's entry into the market – something which remains uncertain. Therefore, it is not clear that the current methodology would be robust against different developments, even if entry points were combined.

Given uncertainty in relation to projections of future flows, there is a risk that the current interconnector charging methodology will not reflect directly marginal costs and instead will allow charges which exceed the marginal cost levels as the charges are constrained to ensure cost recovery.

This would be damaging to customers over the short and long term. If interconnector charges are significantly in excess of marginal costs, then in the short term IBP prices will be higher and customers will pay more for their gas. In the longer term, inefficient investments will be made – for example, new sources of gas may be encouraged on to the system in place of gas flowing over the interconnector (which might be the cheaper option).

We therefore see merit in capping interconnector charges at the equilibrium level of the LRMC of expansion of the relevant facilities and recovering any balance of the allowed revenue in respect of the facilities in exit charges[6]. In the case of combined IC1/2 and SNIP interconnectors, we propose that the long run marginal costs of expansion are approximated by the lowest of the long run average incremental costs of expansion along each of the existing interconnector pipeline routes and that any balance of allowed revenues above the cap is recovered from exit charges in both jurisdictions in proportion to their share of the combined allowed revenue (thus avoiding cross-subsidy between jurisdictions).

Based on high level initial analysis, we estimate that the equilibrium long run marginal cost of transporting gas over the interconnector to the ROI is around €107/peak day MWh – significantly lower than the current projected interconnector charges. Obviously, capping interconnector charge at LRMC is therefore likely to lead to a corresponding fall in the gas price at the IBP which will create significant customer benefits in both ROI and NI.

Producers cannot reasonably argue that they expected the IBP price to continue to be based indefinitely on non-cost reflective interconnector charges that rise as a result of falling utilisation. They could reasonably be expected to have anticipated appropriate changes to interconnector charges in the medium term. For example, they should have been aware that the decision document for the penultimate transmission tariff review[7] in ROI indicated that "The existing tariff structure – locational entry charges and a "postalised" exit charge – will be retained for the current four-year review" but also made clear that changes were possible thereafter[8].

Nevertheless, we recognise that investments have been made against the background of current price differentials. Thus, given the scale of the change from current projected tariffs, we believe any cap on interconnector charges should be phased-in to avoid significant step changes in charges from one year to the next

[6] Charges which are based on LRMC are unlikely to recover the revenue of the network operator and thus some adjustment to LRMC charges is required. Such adjustment is often through scaling up of charges where such scaling is unlikely to distort investment and operating decisions by those facing the charges. Here, it seems likely that recovering shortfalls in LRMC based entry charges (e.g. interconnector revenues above the LRMC cap) by scaling up exit charges would be the approach which leads to the lowest distortions.

[7] CER/03/172 Commission's Decision on Transmission Use of System Revenue Requirement and Tariff Structure 1 October 2003 to 30 September 2007

[8] As the CER saw "merit in using marginal costs as the basis for transmission tariffs" and intended to conduct a review prior to the next transmission revenue review to assess whether it was "desirable to adopt marginal cost based transmission tariffs".

Clearly, the detailed mechanics of application of the caps would need to be developed. One simple scheme to deal separately with the southern interconnectors and SNIP would be as follows:

- the equilibrium LRMC would be calculated at the time of a price control review by the relevant network owner;
- the relevant regulator would review, amend if necessary, and approve the LRMC at the price control review;
- the LRMC would remain fixed for the period of the price control;
- the entry and associated exit charges (i.e. exit charges that recover any revenues above the LRMC cap) would be calculated annually by the relevant network owner based on its forecasts of demand; and
- the entry and associated exit charges would include a correction factor to allow for forecast error.

Such a scheme would need amendment to deal with combined IC1/2 and SNIP interconnectors as the network owners would need to co-operate to share the combined revenues.

The implementation of charges capped at LRMC for other entry points would need to be given further consideration, in the light of the need for appropriate price signals at these entry points, the likely level of the relevant LRMC, and the difference between this level and charges calculated under the existing methodology.

#### 5.2.2. The choice of entry point definition

In comparing each of the options set out in the consultation document (complemented by interconnector charges being capped), there are two main questions to consider:

- are there merits in combining the IC1/2 and SNIP entry points? and
- are there merits in combining all entry points?

In relation to the first question, BGN believes that there is merit in combining IC1/2 and SNIP entry points. The interconnectors provide a common service as a single transport system for gas from the GB market – if increased capacity is required for NI, it could come from an expansion of SNIP capacity or an expansion of the IC1/2 capacity and flow of gas over the SN pipeline. For any given increase in demand, the most efficient engineering solution should be adopted, and the LRMC of interconnector entry should reflect that solution.

It is therefore appropriate to set a single price for these lines – such that shippers are faced with a cost which reflects the incremental cost of an optimum expansion to transport capacity from GB.

Further combining IC1/2 and SNIP brings other benefits, particularly for NI:

- it allows NI customers to reduce some of the mutualisation risk associated with SNIP;
- it provides a mechanism that could allow NI to smooth SNIP charges across years; and
- it provides a transparent single tariff for delivery of gas from GB that facilitates non-discriminatory access to the available transmission capacity by users from both jurisdictions.

In relation to the second question (whether all entry points should be combined, either separately or with the combined IC1/2 and SNIP entry point), we believe the answer is also clear. We consider that the entry points should remain separate as each provides the unique service of entry from its associated field or facility.

To summarise, therefore, we believe that:

- the IC1/2 and SNIP interconnectors should be combined as they provide a common service of entry from the GB system and:
  - to ensure that the prices faced by shippers reflect the optimum cost of transporting gas from the GB market, irrespective of the actual route taken by the gas to the all-Ireland market;
  - to ensure that there is no artificial incentive to use one Moffat interconnector rather than another (for example, due to the different depreciation rates of the various assets);
  - to increase the robustness of the approach under scenarios in which utilisation of the interconnectors vary significantly;
  - to provide mechanisms to allow NI to reduce mutualisation risk and to smooth SNIP charges across years;
  - provides a transparent single tariff for delivery of gas from GB that facilitates non-discriminatory access to the available transmission capacity by users from both jurisdictions;
- the other entry points should be treated separately to retain the possibility of separate price signals as they each provide a unique entry service;
- the interconnector charges should be capped at the equilibrium level of the long run marginal cost to provide a robust and stable charge regime which provide appropriate price signals given the potential for significant changes in the interconnector flows depending on the development scenario. Any balance of allowed revenues above the cap should be recovered from exit charges in both jurisdictions in proportion to their share of the combined allowed revenue (thus avoiding cross-subsidy between jurisdictions); and
- the other entry point charges might be capped at the equilibrium level of the relevant LRMC depending the need for appropriate price signals at these entry points, the likely level of the relevant LRMC, and the difference between this level and entry point charges calculated under the existing methodology.

### 5.3. Exit tariffs

We consider that the range of structural options for exit set out in the consultation paper is appropriate. These structural options for exit are:

- single exit zone (combining the onshore systems);
- two exit zones (one in each jurisdiction as now); and
- multiple exit points (either zonal or nodal).

In assessing the exit options, there is a simple trade-off. Those options with more exit zones better meet the efficiency and equity criteria as there is less geographic cross-subsidy (though this is offset somewhat by the need to scale charges for entry revenue recovery) but meet less well the stability and practicality criteria.

With the relatively small networks on the island, we consider that options with many exit points are unlikely to be practical and we are not convinced that they will bring commensurate benefits in terms of increased efficiency and equity. Further, for social reasons, options under which exit charges vary within the jurisdictions are unlikely to be acceptable.

Similarly, we anticipate that the option of a single exit zone would not be acceptable as it would imply cross-subsidy from NI to the ROI or vice versa.

Accordingly, of the options with few exit points, we consider the two exit zone option is most practical, both on social grounds and because it offers the possibility of reducing the need for financial transfers across the jurisdictions.

Finally, we emphasise that the SN pipeline should remain as part of the onshore NI exit asset base. To do otherwise, would fail to recognise the benefits of increased security of supply and enhanced capacity the SN pipeline brings to all end users in NI and would lead to inefficient "pancaking" of charges. To ensure that the price of gas is determined by market conditions and economics, not by variations in regulatory arrangements, it is essential to avoid pancaking of transmission charges (e.g. to ensure a supplier located in the ROI with a customer located in NI faces entry charges in the ROI and exit charges in NI but does not face any additional transit charge for use of the SN pipeline and, similarly, that a supplier located in NI with a customer located in the ROI faces entry charges in NI and exit charges in the ROI but does not face any additional transit charge for use of the SN pipeline).

### 5.4. Further issues

We comment below on four further issues concerning tariff structure raised in the consultation paper:

- the revenue transfer and currency risk mechanisms necessary if certain elements of the tariff structure are combined;
- the non-annual gas capacity products;
- the capacity/commodity split; and
- smoothing within a price control period: whether tariffs should recover the allowances in respect of costs in each year of the price control period or whether the tariff profile should be smoothed within a price control period.

Clearly a **revenue transfer and currency risk mechanism** will need to be devised if the IC1/2 and SNIP interconnectors (or other elements of the tariff structure) are combined. Such a mechanism should be used not only for transfer of transmission revenues but also for any other necessary transfers (such as might be required in respect of system balancing). We see merit in devising mechanisms that are congruent with the SEM regime which spreads default and currency risk across the market.

We believe harmonisation of **non annual gas capacity products** would bring significant benefits to users in terms of transparency, simplicity and ease of use and we see no reason not to harmonise. Accordingly, we suggest that inventory, short term and back-up products currently available in the ROI should be made available in NI and that interruptible products should be made available in both jurisdictions with the (non-price) product terms for each product harmonised across the jurisdictions. If further products are developed, for example, the peaking plant capacity product currently under consideration in the ROI, these should also be harmonised across jurisdictions. Obviously, all products will need to meet the minimum requirements set out in the Guidelines attached to Regulation EC1775/2005 for firm and interruptible services down to the day ahead timescale. Given the difference in costs, further consideration is needed as to whether, and, if so, how, capacity transfers would be allowed.

We consider that the **capacity/commodity split** in each jurisdiction should reasonably reflect the drivers of cost in each jurisdiction – the CER undertook some analysis on this in the ROI during the last price control review – and should ideally be harmonised. While we have previously supported a non-cost reflective capacity/commodity split in NI to encourage development of the industry, we consider that a transition to a more cost reflective capacity/commodity split in NI is now appropriate. To do otherwise, would, for example, lead to distortions in the single electricity market where gas commodity charges flow through to bids (potentially inducing new power stations to locate inefficiently).

We would support harmonisation of the capacity/commodity split to promote stability and practicality if cost reflective capacity/commodity splits were similar (say within 5%). If harmonisation is to be imposed, we would prefer harmonisation at a level which minimises the projected (volume weighted) differences from the cost reflective splits which is likely to be around the 90/10 split currently applied in the ROI.

Any **smoothing within a price control period** results in less cost-reflective but more stable charges. We are happy with the current arrangements in the ROI for smoothing within a price control period. We have no strong view on arrangements in NI but we understand that the tariff regimes for assets under mutualised CLGs anticipate annual charging not smoothing and, accordingly, there may be constraints on any smoothing of such charges. However, we emphasise once again that we strongly oppose revenue smoothing across price control periods (re-profiling) primarily because it increases regulatory risk with potentially damaging consequences for investor confidence but also because of the impact on indigenous producers with relatively short lived fields noted in the consultation paper.

## 6. QUANTITATIVE ANALYSIS

In this section, we note some modelling issues and make a quantitative assessment of our preferred option for tariff structure using our own model. At the outset, we note that the quantitative analysis in the consultation paper may give a misleading impression of the differentials in tariffs between the ROI and NI as some of the input data and assumptions need to be modified. Hence, the quantitative analysis in the consultation paper should not be used to inform policy decisions[9].

[9] For example, on page 36, the consultation paper states that tariffs in the ROI are some 80% higher than those in NI. Whereas, with revised data, considering 2007/08 only and with a load factor of some 77% (appropriate for a power station), we estimate the differential is some 25% with IC1/2 and SNIP treated separately or just 16% if IC1/2 and SNIP are combined. In subsequent years, these differentials would decrease further.

## 6.1. Modelling issues

We have created a model to make a quantitative assessment of our preferred option for tariff structure as the recently circulated CAG model does not accommodate capping of charges in the manner we propose[10] and focuses on transmission tariffs alone[11].
We appreciate that the numerical analysis is intended to allow users to examine the magnitude and direction of the impact on transmission tariffs of varying the key assumptions rather than to calculate exact tariffs. We also note that the CAG model circulated more recently incorporates some changes to the input data and assumptions underlying the published analysis in the consultation paper. However, we consider that further changes to the input data and assumptions are necessary to provide a good guide as to the likely impact on tariffs.

In our modelling, we:

- use the data as published in the most recent CAG model except where we note otherwise below;
- smooth tariffs over three periods corresponding to the remaining four years of the current price control period, a further five year price control period, and the first three years of the following price control (2008/09-2011/12, 2012/13-2016/17 and 2017/18-19/20);
- use the CAG model assumptions that Inch flows cease in 2012/13, but we also assume that any residual revenues related to Inch thereafter are incorporated in onshore ROI revenues;
- adjust the revenue for the SN pipeline to reflect movement in the interconnector tariffs as we understand that the revenue for the SN pipeline relates to the cost of capacity booking and throughput on the interconnectors;
- examine three development scenarios:
  - Corrib only: we assume a Corrib profile which is consistent with the Gas Capacity Statement 2008 and the Transmission Development Statement for the period 2006/07 to 2012/13. This profile shows decreasing capacity and commodity demand in the period 2015/16 to 2019/20;
  - Corrib and Shannon LNG; we assume the above Corrib profile and we vary the Shannon LNG profile to be consistent with the Gas Capacity statement 2008;
  - Corrib and Larne: we assume the above Corrib profile and we assume a Larne capacity booking of 66 000 pd MWh which, for illustrative purposes, we assume reduces the capacity booking on IC1/2 and has no impact on capacity booking on the SNIP. We note that further analysis is necessary to provide a realistic estimate of the impact of Larne on the ROI and NI; and
- present data based on a 90/10 capacity/commodity split for both ROI and NI for ease of comparison.

---

[10] We also note that there are a couple of simplifications in the model which means that it may not provide a good guide as to the likely impact on tariffs. Firstly, the calculation of marginal asset value movement needs amendment as the transferred portion takes the depreciation lifetime and rate of return of the destination asset rather than the original asset. For example, if a proportion of the southern interconnector asset is transferred to the onshore ROI asset, the transferred portion takes an opening depreciation lifetime of 25 years (as an onshore ROI asset) rather than 45 years (as a southern interconnector asset) Secondly, the calculation of smoothing needs amendment as the smoothed tariff does not ensure that the present value of revenues under the smoothed tariff equals the present value of revenues under the unsmoothed tariffs (the smoothed tariff is simply the aggregate allowed revenue in the period divided by the aggregate volume in the period not the aggregate discounted allowed revenue in the period divided by the aggregate discounted volume in the period).

[11] We understand that the published calculation of the additional cost to customers (or benefit to Irish producers) that arises from setting the gas price at the Irish Balancing Point equal to the gas price at the UK National Balancing Point plus UK transportation charges and the Moffat entry charge is made in another model.

## 6.2. Quantitative assessment of our preferred option

Based on the above assumptions, we have used our model to estimate the likely impact on tariffs of our preferred option compared with the current structure. We stress that we provide indicative figures which should be considered merely as a guide for possible ranges of tariffs rather than definitive tariffs[12]. We summarise the results below and give more details in Annex 3.

Our proposal for capping interconnector charges at LRMC and recovering the balance of the allowed revenues in exit charges has significant merit in mitigating the impact of declining interconnector flows, leading to relatively stable and practical interconnector entry, exit and end user charges for the ROI and NI under all three scenarios considered. Of course, such charges also meet our cost recovery, efficiency and equity criteria. The table below shows the range of end user charges across all three scenarios that would emerge with the current charge structure and our preferred option.

| | | ROI | | | NI | | |
|---|---|---|---|---|---|---|---|
| | | Min | Ave | Max | Min | Ave | Max |
| **Current** | Capacity (EUR/peak day MWh) | 552 | 707 | 977 | 508 | 539 | 637 |
| | Commodity (EUR/MWh) | 0.289 | 0.434 | 0.841 | 0.219 | 0.242 | 0.282 |
| **Preferred Option** | Capacity (EUR/peak day MWh) | 558 | 609 | 664 | 453 | 516 | 635 |
| | Commodity (EUR/MWh) | 0.287 | 0.310 | 0.336 | 0.224 | 0.258 | 0.320 |

Notes:
(1) The illustrative ROI end user charges are based on interconnector entry and onshore ROI exit. "Current" charges comprise IC entry and ROI exit; and "Preferred Option" charges comprise combined IC/SNIP entry and ROI exit
(2) The illustrative NI end user charges are based on interconnector entry and onshore NI exit (including SN pipeline). "Current" charges comprise SNIP entry and NI exit; and "Preferred Option" charges comprise combined IC/SNIP entry and NI
(3) If other entry points were used for the illustration other charges would result. .

For the ROI, with combined IC1/2/SNIP interconnector entry charges capped at our estimate of equilibrium LRMC and with exit charges recovering above cap entry revenues, (“capped combined”) **the range of ROI end user charges across the three scenarios is reasonable and reduced from the range with separate IC1/2 and SNIP** charges and with no capping (“uncapped separate”). The range of end user:

- capacity charges reduces significantly as the range of interconnector entry capacity charges is much reduced and this reduction significantly exceeds the slight increase in the range of exit capacity charges. Indeed, with our estimate of LRMC for the interconnector (of €107/pdMWh if expressed as 100% capacity charge), the entry capacity tariffs, capped at LRMC, are capped under all scenarios in all years (at €96.3/pdMWh reflecting the 90/10 capacity/commodity split) and do not vary; and
- commodity charges reduces significantly as the range of interconnector entry commodity charges is much reduced and this reduction significantly exceeds the slight increase in the range of exit commodity charges. Again, the entry commodity tariffs, capped at LRMC, are capped under all scenarios in all years but they vary slightly across the years reflecting the changing utilisation.

For NI, **the range of “capped combined” NI end user charges across the three scenarios is reasonable but increased from the range of (“uncapped separate”) user charges**. However, while the average end user capacity charge falls, the average end user commodity charge rises

[12] For example, obviously, the tariff will change significantly with differing estimates of the LRMC cap on interconnector entry charges or with differing capacity and commodity demand forecasts.

which leads to a distributional effect which depends on the development scenario – lower utilisation customers always gain, while customers with very high utilisation levels gain in the Corrib only and Corrib and Larne scenarios they remain largely unaffected in the Corrib and Shannon LNG scenario. The range of end user:

- capacity charges increases slightly as while the range of interconnector entry capacity charges is reduced this reduction is outweighed by an increase in the range of exit capacity charges. However, the average capacity charge falls and we consider the resulting range is reasonable. Again, with our estimate of LRMC for the interconnector, the entry capacity tariffs, capped at LRMC, are capped under all scenarios in all years (at €96.3/pdMWh) and do not vary; and
- commodity charges increases as, while the range of interconnector entry commodity charges is reduced, this reduction is outweighed by an increase in the range of exit commodity charges. However, the average commodity charge also rises which leads to a distributional effect that depends on development scenario and level of LRMC cap[13]:
  - under the Corrib only and Corrib and Larne scenarios, all customers gain; and
  - under the Corrib and Shannon LNG scenario, customers with lower utilisation gain while customers with very high utilisation levels are largely unaffected.

Finally, we note that the introduction of more cost-reflective prices also leads to **a reduction in the gas price at the IBP to the overall benefit of customers in both the ROI and NI**. However, there is a distributional effect in NI which means that the gain is focused on lower utilisation customers. Under our preferred charge structure, a typical residential customer would see a reduction on average of some 15% in ROI and some 4% in NI.

[13] As the LRMC cap decreases, more customers benefit and vice versa.

## ANNEX 1 - INTERCONNECTORS

In this Annex, we explain in more detail why the interconnectors have been, are and will continue to be a critical asset for the Irish gas system:

- the interconnectors provided essential security of supply which was **key to the development of the Irish gas system**. Without the second interconnector, major investors, such as power station developers, could not have obtained the long term firm contracts that they needed before committing to invest;
- the interconnectors have several important roles for all Ireland. They:
  - provide **essential security of supply** and they will continue to provide such security even if their utilisation falls when other supply sources come on line. Even under scenarios with both Corrib and Shannon LNG capable of delivering gas, the interconnectors ensure that the Irish market is not exposed to the risk of production failures[14] and/or LNG cargo diversion. In this regard, we note that new facilities are less reliable in the early years of operation before sufficient experience has been accumulated. The security of supply benefits of greater interconnection have also been noted in relation to the electricity interconnector[15];
  - provide **access to the UK market** which is essential to deliver a competitive wholesale gas market. Without this access, there would be significant adverse impacts on Irish competitiveness as both gas and electricity prices would be unlikely to be competitive;
  - bring **price stability** which gives major users, such as potential power station investors, confidence to invest knowing that they will not be exposed to undue market power exerted by Irish producers;
  - allow **new products**. For example, the second interconnector provides backup capacity (e.g. it ensures that the Inch and Corrib entry points can provide a firm entry product ) and the inventory product;
- both interconnectors are **currently well used**. The booked capacity currently exceeds the capacity of the first interconnector and the throughput will exceed the capacity of the first interconnector in cold winter conditions. Indeed, if the Corrib Pipeline were to be delayed then increased investment would be required on the second interconnector and, in any event, NI will be booking capacity on the second interconnector from 2011/12 onwards when capacity will become constrained on the SNIP;
- **the second interconnector is of huge strategic and economic importance**. It both provides **additional capacity and security of supply** to Ireland and the Isle of Man and provides **environmental benefits**:
  - prior to the construction of the second interconnector, six different parties were interested in constructing gas fired power stations in Ireland but capacity constraints on IC1 meant only two parties were able to secure capacity and construct power plants;
  - subsequent to the construction of the second interconnector, there has been significant switching of fuel at power stations to natural gas bringing great environmental benefits to Ireland (in terms of reduced carbon dioxide, nitrogen oxides, sulphur dioxide and particulate emissions). Overall, the interconnectors allow annual savings of the order of

[14] Minor problems in sub-sea equipment can lead to lengthy outages, particularly in winter, due to the difficulty of obtaining access in adverse sea conditions.

[15] In the announcement of the East West interconnector, the Minister for Communications, Marine and Natural Resources said that "by providing … additional electricity capacity onto the Irish grid, the interconnectors will provide many benefits, including enhanced security of supply, increased competition in the electricity market and integrate Ireland into the wider European energy market."

€200M to €250M in the costs of carbon emission permits (significantly more than the annual costs of the interconnectors);

- the second interconnector provides a reliable source of supply in the event of disruption to IC1 or other gas supplies and ensures security of supply to at least 2025. It has brought Ireland's security of supply in line with countries such as France, Italy, Sweden and Denmark, all of which duplicated sub-sea pipelines to ensure the availability of alternative sources of natural gas; and
- in view of the above benefits, both the relevant Department and the CER have concluded that the second interconnector is a necessary asset through investment approvals and over three regulatory reviews.

## ANNEX 2 - RESPONSE TO EACH SPECIFIC QUESTION

1: Have we adequately described the differences/commonalities between the two markets?

We consider that the differences/commonalities have been adequately described though the summary should mention that there is a back-up product available in the ROI that is not available in NI.

2: Do you feel that all the relevant criteria have been covered in this document and are there other criteria you feel should be included?

We propose the following criteria which line up more closely with those used elsewhere, for example, in the evaluation of the options for the single electricity market. We list the criteria in broad order of priority (from highest priority to lowest priority) and cross-reference them to the broad criteria included in the consultation paper:

- **cost recovery**: in line with European legislation, the harmonised tariff regime should allow the network asset owners sufficient revenue to cover efficiently incurred investment and operation costs, including an appropriate return commensurate with the risks of their businesses ("developing the industry", "security of supply");
- **efficiency**: in line with European legislation, the harmonised tariff regime should promote efficient development and operation of the gas system through appropriate price signals ("developing the industry", "security of supply"). In particular, it should remove pricing barriers to gas flowing around the island[16]. The tariff structure should reflect underlying marginal costs of gas supply, allowing producers and consumers to allocate resources efficiently in response to tariff price signals. For example, with interconnector charges and thus the IBP price reflecting marginal costs, there would be more appropriate signals for investment in the face of declining interconnector utilisation. However, we stress that efficient development of the industry is impacted by many broader issues which are outside the scope of the tariff regime (eg tax policy or other incentives for producers);
- **equity**: the harmonised tariff regime should promote equity by
  - maintaining regulatory commitments particularly concerning recovery of agreed allowed revenues ("developing the industry", "security of supply");
  - avoiding inequitable payments for security of supply ("promotion of competition"). In particular, while the interconnector assets provide security of supply to all customers, it is not clear that it is equitable for the Moffat shippers alone to bear their costs;
  - ensuring a level playing field for efficient competition among suppliers irrespective of the location of their customers ("promotion of competition");
  - avoiding undue cross-subsidy between network users and between jurisdictions ("promotion of competition");
  - appropriately balancing the interests of the network asset owners and network users ("protecting customers"):
- **stability**: the harmonised tariff regime should be relatively stable and predictable across a range of scenarios to give producers and consumers confidence to make investment decisions based on the tariff price signals and there should be no step changes in tariffs ("developing the industry", "protecting customers"). We are concerned that choices made are robust under a range of development scenarios rather than the single development scenario discussed in the consultation paper. In particular, we have noted above that there is

[16] Unless those flows can be shown to result in significant incremental cost.

uncertainty around the timing of the Corrib gas flows and the Shannon LNG facilities which would have significant impacts on the interconnector flows. However, we recognise that on a small system where new facilities cause relatively large changes in flows, tariffs cannot be fully stable across all development scenarios; and

- **practicality** ("protecting customers") the harmonised tariff regime should:
  - be reasonably easy to implement.
  - avoid undue complexity so that it can be understood by customers; and
  - result in benefits that exceed the transaction costs.

These criteria conflict. For example, tariffs that are stable across a range of scenarios will likely have somewhat weakened price signals. Accordingly, the harmonised regime will inevitably represent a compromise which depends on the weighting attached to the various criteria.

While we recognise that the four broad criteria suggested in the consultation paper are intended to encompass many of the above criteria, there are some key differences, particularly of emphasis:

- we emphasise cost recovery as a primary criterion while the consultation paper states that prices should at least allow cost recovery under its "protecting customers" criterion and mentions cost orientation under its "developing the industry" criterion; and
- we also consider efficient development and operation achieved through appropriate price signals should be a primary criterion while the consultation paper mentions appropriate price signals under its "developing the industry" criterion and notes that a key role for tariffs is to send the right signals under its "security of supply" criterion.

3: Do you have a view in relation to the priority of the criteria and whether some criteria should be considered more important than others.

See above under Question 2. In using these criteria to discriminate among the options, we would apply the highest weight to the cost recovery criterion (as this is essential for investor confidence not just in networks but throughout the energy sector) and, thereafter, while there is a degree of overlap, we would apply the second highest weight to the efficiency criterion (as this is likely to mitigate the impact of declining interconnector utilisation) and we would then apply broadly equal weights to the equity, stability and practicality criteria[17].

4: Do you feel we have adequately represented the appropriate reform options at Entry and Exit? What further reform options do you feel warrant further investigation?

We consider that the range of structural options for entry set out in the consultation paper is broadly appropriate. However, we rule out the entry option that separates the southern interconnectors because we consider that interconnectors provide a common service as a single transport system for gas from the GB market and should be charged as such. Accordingly, we propose consideration of the following structural options for entry:

- single entry point (combining all existing (and future) entry points);

[17] Note that "security of supply" arises from regulatory requirements (e.g. to design the gas system to meet severe cold weather demands and to promote diversity of supply) and is best promoted by ensuring that transmission tariffs allow recovery of costs efficiently incurred to meet these regulatory requirements.

- single Moffat entry point (combining SNIP and the southern ICs) and single other entry point (combining all other existing (and possibly all future) entry points);
- single Moffat entry point (combining SNIP and the southern ICs) with all other existing (and future) entry points separate; and
- all existing (and future) entry points separate (as now).

We consider that the range of structural options for exit set out in the consultation paper is appropriate. These structural options for exit are:

- single exit zone (combining the onshore systems);
- two exit zones (one in each jurisdiction as now); and
- multiple exit points (either zonal or nodal).

We consider that within these structural options there are further options for the formulation of charges which could be developed. In particular, we consider that capping of interconnector entry charges at the equilibrium level of LRMC is appropriate to encourage economic efficiency and avoid distorting investment decisions. See below under Question 5 concerning mitigating the effect of declining interconnector utilisation.

5: In relation to mitigating the effect of declining interconnector utilisation, have all the viable options been set out? What option do you feel is missing? What level of price incentive, if any, do you feel is an adequate signal to incentivise indigenous gas production/storage?

We consider that all viable options and some non-viable options have been set out for mitigating the effect of declining interconnector utilisation. Specifically, we consider that all options which seek to reduce the recovery of the allowed revenue in respect of the interconnectors are not viable as they would have substantially damaging impact on the development of the gas industry. Equally, we consider an auction without further, potentially complex, measures to ensure recovery of allowed revenue is non-viable as it could lead to under-recovery.

We consider that, in the event of low interconnector flow, interconnector charges could be reduced by moving some portion of the interconnector regulatory asset base to another part of the regulatory asset base (most probably the onshore part) thus preserving the allowed revenue in respect of the interconnectors. We see merit in capping interconnector charges at the level of the long run marginal costs of expansion of the relevant facilities and recovering any balance of the allowed revenue in respect of the facilities in exit charges. In the case of combined interconnectors (i.e. southern interconnectors and SNIP), we propose that the long run marginal costs of expansion are approximated by the lowest of the long run average incremental costs of expansion along each of the existing interconnector pipeline routes and that any balance of allowed revenues above the cap is recovered from exit charges in both jurisdictions in proportion to their share of the combined allowed revenue (thus avoiding cross-subsidy between jurisdictions).

We consider that the question relating to price incentives for indigenous gas production/storage raises much broader issues (such as tax policy or other incentives for producers) that are outside the scope and competence of this consultation. However, focusing strictly on transmission tariffs, we consider that (efficient) cost-reflective pricing of transmission will provide appropriate incentives for efficient indigenous gas production/storage - any further incentives will by definition provide incentives for inefficient gas production/storage.

6: Do you think we should harmonise the capacity/commodity split?

We consider that the capacity/commodity split in each jurisdiction should reasonably reflect the drivers of cost in each jurisdiction – the CER undertook some analysis on this in the ROI during the last price control review – and should ideally be harmonised. While we have previously supported a non-cost reflective capacity/commodity split in NI to encourage development of the industry, we consider that a transition to a more cost reflective capacity/commodity split in NI is now appropriate. To do otherwise, would, for example, lead to distortions in the single electricity market where commodity charges flow through to bids (potentially inducing new power stations to locate inefficiently).

We would support harmonisation of the capacity/commodity split to promote stability and practicality if cost reflective capacity/commodity splits were similar (say within 5%).

7: Do you think we should aim to harmonise non annual gas capacity products? What products do you feel should be available?

We believe harmonisation of non annual gas capacity products would bring significant benefits to users in terms of transparency, simplicity and ease of use and we see no reason not to harmonise. Accordingly, we suggest that inventory, short term and back-up products currently available in the ROI should be made available in NI and that interruptible products should be made available in both jurisdictions with the (non-price) product terms for each product harmonised across the jurisdictions. If further products are developed, for example, the peaking plant capacity product currently under consideration in the ROI, these should also be harmonised across jurisdictions. Obviously, all products will need to meet the minimum requirements set out in the Guidelines attached to Regulation EC1775/2005 for firm and interruptible services down to the day ahead timescale. Given the difference in costs, further consideration is needed as to whether, and, if so, how, capacity transfers would be allowed.

8: Do you feel that we have adequately described Postalisation under the selected criteria?

Yes.

9: Do you feel that Postalisation is a viable option for the harmonisation of transmission tariffs in the two jurisdictions?

We believe that postalisation is conceptually viable though, while the consultation paper notes that postalisation implies average cost pricing, we consider that it should emphasise more that postalisation cannot therefore provide appropriate transmission price signals and will lead to inefficient competition. All options merit consideration. However, we consider combined postalisation of the ROI and NI is unlikely to be acceptable because of the implied cross-subsidy between jurisdictions.

10: How should we deal with revenue transfer between the two jurisdictions under postalisation?

Some revenue transfer (and associated currency risk) is inevitable if transmission assets, costs and revenues are combined across jurisdictions,.

We consider that the introduction of mechanisms to deal with revenue transfer or currency risk should not pose material obstacles to implementation. We see merit in devising mechanisms that are congruent with the SEM regime which spreads default and currency risk across the market.

Postalisation in each jurisdiction, rather than combined postalisation, would mitigate the need for revenue transfer and would provide a mechanism for revenue transfer and dealing with currency risk.

11: How should we deal with currency risk arising from the postalisation option?

See Question 10 above.

12: Do you feel that we have adequately described the entry options under the selected criteria?

We consider that the range of structural options for entry set out in the consultation paper is broadly appropriate. However, we rule out the entry option that separates the southern interconnectors because we consider that the interconnectors provide a common service as a single transport system for gas from the GB market and should be charged as such. Accordingly, we propose consideration of the following structural options for entry:

- single entry point (combining all existing (and future) entry points);
- single Moffat entry point (combining SNIP and the southern ICs) and single other entry point (combining all other existing (and possibly all future) entry points);
- single Moffat entry point (combining SNIP and the southern ICs) with all other existing (and future) entry points separate; and
- all existing (and future) entry points separate (as now).

We consider that the description of these structural options for entry set out in the consultation paper is adequate.

However, as noted previously, we consider that within these structural options there are further options for the formulation of charges which could be developed. See above under Question 5 concerning mitigating the effect of declining interconnector utilisation.

13: How should we deal with revenue transfer between the two jurisdictions under the relevant options?

Clearly a revenue transfer and currency risk mechanism will need to be devised if any elements of the tariff structure are combined (e.g. combination of the 1C1/2 and SNIP entry point tariffs). Such a mechanism should be used not only for transfer of transmission revenues but also for any other necessary transfers (such as might be required in respect of system balancing). We see merit in devising mechanisms that are congruent with the SEM regime which spreads default and currency risk across the market.

14: How should we deal with currency risk arising from the above options?

See above under Question 13.

15: Do you feel that we have adequately described the exit options under the selected criteria?

We consider that the description of the structural options for exit set out in the consultation paper is adequate:

- single exit zone (combining the onshore systems);
- two exit zones (one in each jurisdiction as now); and
- multiple exit points (either zonal or nodal).

We stress that the SN pipeline should remain as part of the onshore NI exit asset base. To do otherwise, would fail to recognise the benefits of increased security of supply and enhanced capacity the SN pipeline brings to all end users in NI and would lead to inefficient "pancaking" of charges. To ensure that the price of gas is determined by market conditions and economics, not by variations in regulatory arrangements, it is essential to avoid pancaking of transmission charges (e.g. to ensure a supplier located in the ROI with a customer located in NI faces entry charges in the ROI and exit charges in NI but does not face any additional transit charge for use of the SN pipeline and, similarly, that a supplier located in NI with a customer located in the ROI faces entry charges in NI and exit charges in the ROI but does not face any additional transit charge for use of the SN pipeline).

Further, we note that charging options which included combined charges for the IC1/2 and SNIP interconnectors with a separate charge for the SN pipeline are not good harmonisation options. If IC1/2 and SNIP interconnectors were combined, the network operators rather than the users would be better placed to optimise the flows on the interconnectors and, consequently, the SN pipeline and, accordingly, users should not be charged separately for their use of the SN pipeline (which they would not control).

16: How should we deal with revenue transfer between the two jurisdictions under the single exit option?

We consider that there should be separate exit charges in each jurisdiction. However to the extent any revenue transfers are necessary, we consider that they should use the same mechanism as that for entry charges. See above under Question 13.

17: How should we deal with currency risk arising under the existing exit option?

To the extent any currency risk arises, we consider that it should be dealt with under the same mechanism as that for entry charges. See above under Question 13.

18: Should there be any attempt to mitigate the effect of declining utilisation of the interconnectors?

We consider that there should be changes to the interconnector charge methodology which would mitigate the effect of declining utilisation of the interconnectors.

Substantial economic inefficiency results from the current charge methodology that causes the charge for interconnectors to increase when demand for use of interconnectors falls. The inefficiency arises both through transmission tariffs and, more importantly, the IBP price.

Economically efficient development of the industry, protection of customers, security of supply and economically efficient competition would all be promoted by appropriate price signals based on marginal costs. Given projections of future flows, there is a risk that the current interconnector charge methodology will not reflect directly marginal costs and instead will allow charges which exceed the marginal cost levels as the charges are constrained to ensure cost recovery.

We consider that an interconnector charging methodology which reflects more directly long run marginal costs will meet the broad criteria while mitigating the effect of declining utilisation of the interconnectors. Our proposal is to cap interconnector charges at the equilibrium level of the long run marginal costs of expansion of the relevant facilities and to recover the balance of the allowed revenue in respect of the facilities in exit charges.

19: Do you feel that we have adequately described the relevant options under the selected criteria?

We consider that the options have not been described adequately. Specifically, we consider that the damaging impact on investor confidence of adopting options which result in a reduction in the allowed revenue in respect of the interconnectors has not been addressed.

We strongly believe that any option which results in a reduction in the allowed revenue in respect of the interconnectors should not be considered because of the damaging impact on investor confidence. While lower prices will be achieved in the short term, investor perceptions of increased regulatory risk will ultimately lead them to require higher returns and thus higher prices in all elements of the gas supply chain. Any perception of increased regulatory risk in the gas sector is also likely to spill over to other regulated sectors, particularly the electricity sector, adversely impacting on prices and willingness to invest.

We further believe that the development of the gas industry may be impeded rather than promoted by such options as, while demand for gas may be stimulated, on the supply side, investment may be inhibited because investors in production, LNG and storage facilities will require higher returns.

20: Do you feel that we have adequately described the option of harmonising capacity & commodity charges under the selected criteria?

We consider that the option has been described adequately.

21: What is an appropriate level at which to harmonise?

We would support harmonisation of the capacity/commodity split to promote stability and practicality if cost reflective capacity/commodity splits were similar (say within 5%). If harmonisation is to be imposed, we would prefer harmonisation at a level which minimises the projected (volume weighted) differences from the cost reflective splits which is likely to be around the 90/10 split currently applied in the ROI.

We consider that the capacity/commodity split in each jurisdiction should reasonably reflect the drivers of cost in each jurisdiction – the CER undertook some analysis on this in the ROI during the last price control review – and should ideally be harmonised. While we have previously supported a non-cost reflective capacity/commodity split in NI to encourage development of the industry, we consider that a transition to a more cost reflective capacity/commodity split in NI is now appropriate. To do otherwise, would, for example, lead to distortions in the single electricity market where gas commodity charges flow through to bids (potentially inducing new power stations to locate inefficiently).

22: Do you agree with our analysis of the applicability of auctions?

We broadly agree with the presented analysis. Auctions would lead to volatile entry charges based on the economic value of the entry assets rather than the cost of those assets requiring further mechanisms to deal with under-recovery of costs of some assets and over-recovery of costs of other assets. For example, in GB there is a fairly complex mechanism. Over-recovery of entry charge allowed revenue above a certain level as a result of any entry capacity auction triggers the mechanism for rebate of the over-recovery. The over recovery is used, firstly, to offset the costs of any buy-back of entry capacity in the trigger month and subsequent months of the price control formula year (ending 31 March) that would otherwise be borne by shippers, effectively reducing the monthly entry capacity charges, and, secondly, if excess revenue still remains at the end of the formula year, to reduce commodity charges in the following formula year. Under-recovery of entry charge allowed revenue is recovered by introducing entry commodity charges.

23: Do you agree with our selection of viable options for further analysis?

No, see below.

- What additional options should be included for further analysis and why?

As noted above, within the entry/exit charge approaches, we consider that there is merit in capping interconnector charges at the equilibrium level of the long run marginal costs of expansion of the relevant facilities with any balance of the allowed revenue in respect of the facilities recovered through exit charges.

- What options should be excluded from further analysis and why?

We consider that the following options should be excluded:

- reprofiling linked with some cost reduction: principally because of the damaging impact on investor confidence but also because it is contrary to EU law and the duties of the regulators;
- guaranteed minimum capacity bookings: because we believe that it raises issues concerning who should be obliged to contract the minimum capacity (presumably those contracting for exit capacity) and the desired effect is achieved more simply by transferring an appropriate portion of the interconnector regulatory asset base to the onshore regulatory asset bases.

24: Which is your preferred option for entry / exit?

Our preferred option for entry/exit comprises:

- entry:
  - structure: combined Moffat entry point (i.e. southern interconnectors and SNIP) and separate entry points for Inch and Corrib and for any LNG facilities that emerge;
  - charges: for the combined Moffat entry point and, possibly, for other entry points, entry point charges to be the lower of charges that recover the cost of the entry point regulatory asset base (RAB) or charges equal to the equilibrium level of long run marginal costs

(with any under recovery of the cost of the entry point RAB recovered through exit charges). For the combined Moffat entry point, long run marginal costs would be approximated by the lowest of the long run average incremental costs of expansion along each of the existing interconnector pipeline routes;

- exit:
  - structure: two exit zones corresponding to the relevant jurisdictions;
  - charges: exit zone charges to recover the cost of the exit zone regulatory asset base and any under recovery of entry charges. Any under-recovery of the combined Moffat entry point costs would be recovered by adjustments to the exit zone charge for each jurisdiction in proportion to their share of the combined allowed revenue (thus avoiding cross-subsidy between jurisdictions).

We prefer this option because we consider that:

- the Moffat interconnectors should be combined as they provide a common service of entry from the GB system and the interconnector charges should provide economic efficient price signals that are essential to deal with the declining flows on the interconnectors. Combining the interconnectors:
  - ensures that the prices faced by shippers reflect the optimum cost of transporting gas from the GB market, irrespective of the actual route taken by the gas to the all-Ireland market;
  - ensures that there is no artificial incentive to use one Moffat interconnector rather than another (for example, due to the different depreciation rates of the various assets); and
  - increases the robustness of the charging approach under scenarios in which utilisation of the interconnectors vary significantly;
  - provides mechanisms to allow NI to reduce mutualisation risk and to smooth SNIP charges across years;
  - provides a transparent single tariff for delivery of gas from GB that facilitates non-discriminatory access to the available transmission capacity by users from both jurisdictions;
- the interconnector charges should be capped at the equilibrium level of the long run marginal cost (LRMC) to provide a stable and practical charge regime with appropriate price signals;
- the other entry points should be treated separately to retain the possibility of separate price signals as they each provide a unique entry service though further consideration is needed as to whether such charges should be capped at LRMC; and
- the two exit zone option is most practical, both on social grounds and because it offers the possibility of reducing the need for financial transfers across the jurisdictions. We reject the alternatives as we consider that options:
  - with many exit points are unlikely to be practical and, with the relatively small networks on the island, we are not convinced that they will bring commensurate benefits in terms of increased efficiency and equity;
  - under which exit charges vary within the jurisdictions, or there is cross-subsidy from one jurisdiction, to another are unlikely to be acceptable on social grounds.

25: Which is your preferred option for mitigating the effect of declining interconnector utilisation?

See Questions 18 and 24 above.

## ANNEX 3 – MODELLING OUR PREFERRED OPTION

In this annex, we present the results of our modelling using an amended model to estimate the impact on tariffs of our preferred option. We begin by describing the main features of our modelling. We then present a series of tables and figures for three scenarios which demonstrate the issue with rising interconnector charges due to declining flows on the interconnector and which show the impact of our preferred option on dealing with this issue.

### 1.1. Features of our model

In our modelling, we use the data as published in the most recent CAG model except where we note otherwise below. Specifically, in our modelling, we:

- smooth tariffs over three periods corresponding to the remaining four years of the current price control period, a further five year price control period, and the first three years of the following price control (2008/09-2011/12, 2012/13-2016/17 and 2017/18-19/20);
- use the CAG model assumptions that Inch flows cease in 2012/13 but we also assume that any residual revenues related to Inch are incorporated in onshore ROI revenues;
- adjust the revenue for the SN pipeline to reflect movement in the interconnector tariffs as we understand that the CAG model revenue for the SN pipeline relates to the cost of capacity booking and throughput on the interconnectors;
- examine three development scenarios:
  - Corrib only: we assume a Corrib profile which is consistent with the Gas Capacity Statement 2008 and the Transmission Development Statement for the period 2006/07 to 2012/13. This profile shows decreasing capacity and commodity demand in the period 2015/16 to 2019/20;
  - Corrib and Shannon LNG; we assume the above Corrib profile and we vary the Shannon LNG ramp-up profile to be consistent with the Gas Capacity Statement 2008;
  - Corrib and Larne storage: we assume the above Corrib profile and we assume a Larne capacity booking of 66 000 pd MWh which, for illustrative purposes, we assume reduces the capacity booking on IC1/2 and has no impact on capacity booking on the SNIP. We note that further analysis is necessary to provide a realistic estimate of the impact of Larne on the ROI and NI; and
- present data based on a 90/10 capacity/commodity split for both ROI and NI for ease of comparison.

### 1.2. Illustration of capped interconnector tariff

In the following, we show annual capacity and commodity charges under tariffs smoothed across price control periods and under tariffs, with interconnector entry charges capped at our estimates of LRMC and onshore exit charges including any above cap revenue. After this commentary, for each scenario we show two sets of tables and one set of figures, to demonstrate:

- the **issue of tariff stability** under declining interconnector flows, the first set of tables shows capacity and commodity charges for each entry and exit point with tariffs smoothed across price control periods and with IC1/2 and SNIP separate; and
- our **suggested solution**, the second set of tables and the figures shows a comparison of end-user charges in the ROI and NI that result from entry and exit point tariffs smoothed across price control periods with:

- IC1/2 and SNIP separate; and
- IC1/2 and SNIP combined and with interconnector entry tariffs capped (at our estimate of LRMC) with the proportionate share of above cap interconnector revenues recovered in the ROI and NI onshore exit charges.

In the second set of tables:

- we estimate end user tariffs as the sum of the relevant interconnector entry tariff and the relevant exit tariff (which for NI includes the SN pipeline revenue);
- we apply our estimate of the LRMC cap for IC1/2 set out in Annex 4 to the combined IC1/2 and SNIP interconnectors. The cap of €107/pdMWh if expressed as 100% capacity charge cap becomes a cap of €96.3/pdMWh on combined IC1/2 and SNIP interconnector capacity charges and a time varying cap of between €0.041/MWh and €0.058/MWh on the combined IC1/2 and SNIP interconnector commodity charges as we assume a 90/10 capacity commodity split. The commodity cap varies across scenarios and with time because the interconnector utilisation changes across scenarios and over time.

We comment below on the main features of the two sets of tables.

#### 1.2.1. Current charge structure

The first set of tables show clearly that, **in the absence of any mechanism to deal with declining flows on the interconnectors, IC1/2 entry charges would become high if Shannon LNG commissions**. The tables show for both capacity and commodity charges that:

- Corrib entry charges are relatively low and rise in all scenarios as Corrib flows decline;
- IC1/2 entry charges are relatively low and decline over time in the Corrib only scenario and Corrib and Larne scenarios, but are high in the second price control period in the Corrib and Shannon LNG scenario as the interconnector flows decline;
- Inch entry charges are low and rise in all scenarios as flows decline;
- Shannon LNG entry charges are very low in the relevant development scenario;
- SNIP entry charges are initially lower than IC1/2 entry charges but rise above IC1/2 entry charges in later years in the Corrib only and Corrib and Larne scenarios, SNIP entry charges are significantly lower than IC1/2 entry charges in the Corrib and Shannon LNG scenario;
- Larne entry charges are also very low in the relevant development scenario;
- Onshore Ireland exit charges are stable and similar in all scenarios; and
- Onshore Northern Ireland (including SN pipeline) exit charges are lower than Onshore Ireland exit charges in all scenarios. They are stable over time in the Corrib only scenario and Corrib and Larne scenarios, but increase in the second price control period in the Corrib and Shannon LNG scenario as the revenue requirement for the SN pipeline increases because interconnector flows decline.

#### 1.2.2. Comparison of current structure and our preferred option

The second set of tables shows how our preferred option deals with the issue of declining interconnector flows. **Under our preferred option where interconnector entry charges are capped at LRMC and revenues above the cap are recovered in onshore exit charges, the interconnector entry, onshore exit and end user charges remain broadly stable and are practical** under the three scenarios.

For the ROI, with combined IC1/2/SNIP interconnector entry charges capped at our estimate of equilibrium LRMC and with exit charges recovering above cap entry revenues, ("capped combined") **the range of ROI end user charges across the three scenarios is reasonable and reduced from the range with separate IC1/2 and SNIP** charges and with no capping ("uncapped separate"):

- the range of "capped combined" ROI end user capacity charges is from €558/pdMWh to €664/pdMWh with an average of €609/pdMWh and the range of "uncapped separate" ROI end user capacity charges is from €552/pdMWh to €977/pdMWh with an average of €707/pdMWh. Overall, the range of ROI end user capacity charges reduces significantly as the range of interconnector entry capacity charges is much reduced and this reduction significantly exceeds the slight increase in the range of ROI exit capacity charges. Indeed, with our estimate of LRMC for the interconnector (of €107/pdMWh if expressed as 100% capacity charge), the entry capacity tariffs, capped at LRMC, are capped under all scenarios in all years (at €96.3/pdMWh reflecting the 90/10 capacity/commodity split) and do not vary; and
- the range of "capped combined" ROI end user commodity charges is from €0.29/MWh to €0.34/MWh with an average of €0.31/MWh and the range of "uncapped separate" ROI end user commodity charges is from €0.29/MWh to €0.84/MWh with an average of €0.43/MWh. Overall, the range of ROI end user commodity charges reduces significantly as the range of interconnector entry commodity charges is much reduced and this reduction significantly exceeds the slight increase in the range of ROI exit commodity charges. Again, the entry commodity tariffs, capped at LRMC, are capped under all scenarios in all years but they vary slightly across the years reflecting the changing utilisation.

For NI, **the range of "capped combined" NI end user charges across the three scenarios is reasonable but increased from the range of ("uncapped separate") user charges**. However, while the average end user capacity charge falls, the average end user commodity charge rises which leads to a distributional effect which depends on development scenario – lower utilisation customers always gain, while customers with very high utilisation levels gain in the Corrib only and Corrib and Larne scenarios they are largely unaffected in the Corrib and Shannon LNG scenario:

- the range of "capped combined" NI end user capacity charges is from €453/pdMWh to €635/pdMWh with an average of €516/pdMWh and the range of "uncapped separate" NI end user capacity charges is from €508/pdMWh to €637/pdMWh with an average of €539/pdMWh. Overall, the range of NI end user capacity charges increases slightly as while the range of interconnector entry capacity charges is reduced this reduction is outweighed by an increase in the range of NI exit capacity charges. However, the average capacity charge falls and we consider the resulting range is reasonable. Again, with our estimate of LRMC for the interconnector, the entry capacity tariffs, capped at LRMC, are capped under all scenarios in all years (at €96.3/pdMWh) and do not vary; and
- the range of "capped combined" NI end user commodity charges is from €0.22/MWh to €0.32/MWh with an average of €0.26/MWh and the range of "uncapped separate" NI end user commodity charges is from €0.22/MWh to €0.28/MWh with an average of €0.24/MWh. Overall, the range of NI end user commodity charges increases as, while the range of interconnector entry commodity charges is reduced, this reduction is outweighed by an increase in the range of NI exit commodity charges. However, the average commodity

charge also rises which leads to a distributional effect that depends on development scenario and level of LRMC cap:[18]

- under the Corrib only and Corrib and Larne scenarios, all customers gain; and
- under the Corrib and Shannon LNG scenario, customers with lower utilisation gain while customers with very high utilisation are largely unaffected.

Finally, we note that the introduction of more cost-reflective prices also leads to **a reduction in the gas price at the IBP to the overall benefit of customers in both the ROI and NI**. However, there is a distributional effect in NI which means that the gain is focused on lower utilisation customers. Under our preferred charge structure, a typical residential customer would see a reduction of an average of some 15% in ROI and some 4% in NI.

[18] As the LRMC cap decreases, more customers benefit and vice versa.

# Scenario 1 – Corrib only

# Current charge structure

**ILLUSTRATIVE CAPACITY AND COMMODITY CHARGES** **Scenario: Corrib only**

**CAPACITY CHARGES (EUR/peak day MWh)**

| **Year** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gas year** | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | Minimum | Maximum | Average |
| **Entry** | | | | | | | | | | | | | | | |
| Corrib | - | 143 | 143 | 143 | 286 | 286 | 286 | 286 | 286 | 593 | 593 | 593 | 143 | 593 | 331 |
| IC1&2 | 295 | 331 | 317 | 282 | 216 | 214 | 215 | 216 | 217 | 187 | 187 | 188 | 187 | 331 | 239 |
| Inch | 64 | 64 | 63 | 62 | 84 | - | - | - | - | - | - | - | 62 | 84 | 68 |
| SLNG | - | - | - | - | - | - | - | - | - | - | - | - | 0 | 0 - | |
| SNIP | 219 | 229 | 221 | 233 | 235 | 225 | 239 | 229 | 243 | 233 | 247 | 243 | 219 | 247 | 233 |
| Larne | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Exit** | | | | | | | | | | | | | | | |
| Onshore Ireland | 403 | 429 | 450 | 421 | 389 | 388 | 389 | 389 | 388 | 365 | 365 | 365 | 365 | 450 | 395 |
| Onshore NI (includes SN pipeline) | 290 | 293 | 294 | 302 | 285 | 284 | 284 | 284 | 283 | 275 | 275 | 274 | 274 | 302 | 285 |

**COMMODITY CHARGES (EUR/MWh)**

| **Year** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gas year** | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | Minimum | Maximum | Average |
| **Entry** | | | | | | | | | | | | | | | |
| Corrib | - | 0.044 | 0.044 | 0.044 | 0.087 | 0.087 | 0.087 | 0.087 | 0.087 | 0.180 | 0.180 | 0.180 | 0.044 | 0.180 | 0.101 |
| IC1&2 | 0.125 | 0.205 | 0.211 | 0.182 | 0.123 | 0.129 | 0.124 | 0.121 | 0.119 | 0.102 | 0.101 | 0.100 | 0.100 | 0.211 | 0.137 |
| Inch | 0.069 | 0.075 | 0.078 | 0.081 | 0.114 | - | - | - | - | - | - | - | 0.069 | 0.114 | 0.083 |
| SLNG | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| SNIP | 0.112 | 0.116 | 0.084 | 0.087 | 0.087 | 0.083 | 0.087 | 0.082 | 0.087 | 0.083 | 0.087 | 0.085 | 0.082 | 0.116 | 0.090 |
| Larne | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Exit** | | | | | | | | | | | | | | | |
| Onshore Ireland | 0.195 | 0.203 | 0.226 | 0.217 | 0.200 | 0.201 | 0.200 | 0.200 | 0.201 | 0.190 | 0.190 | 0.190 | 0.190 | 0.226 | 0.201 |
| Onshore NI (includes SN pipeline) | 0.148 | 0.151 | 0.143 | 0.148 | 0.140 | 0.140 | 0.140 | 0.140 | 0.140 | 0.137 | 0.137 | 0.137 | 0.137 | 0.151 | 0.142 |

# Comparison of charges under the current structure and our preferred option

**ILLUSTRATIVE CAPACITY AND COMMODITY CHARGES** **Scenario: Corrib only**

**CAPACITY CHARGES (EUR/peak day MWh)**

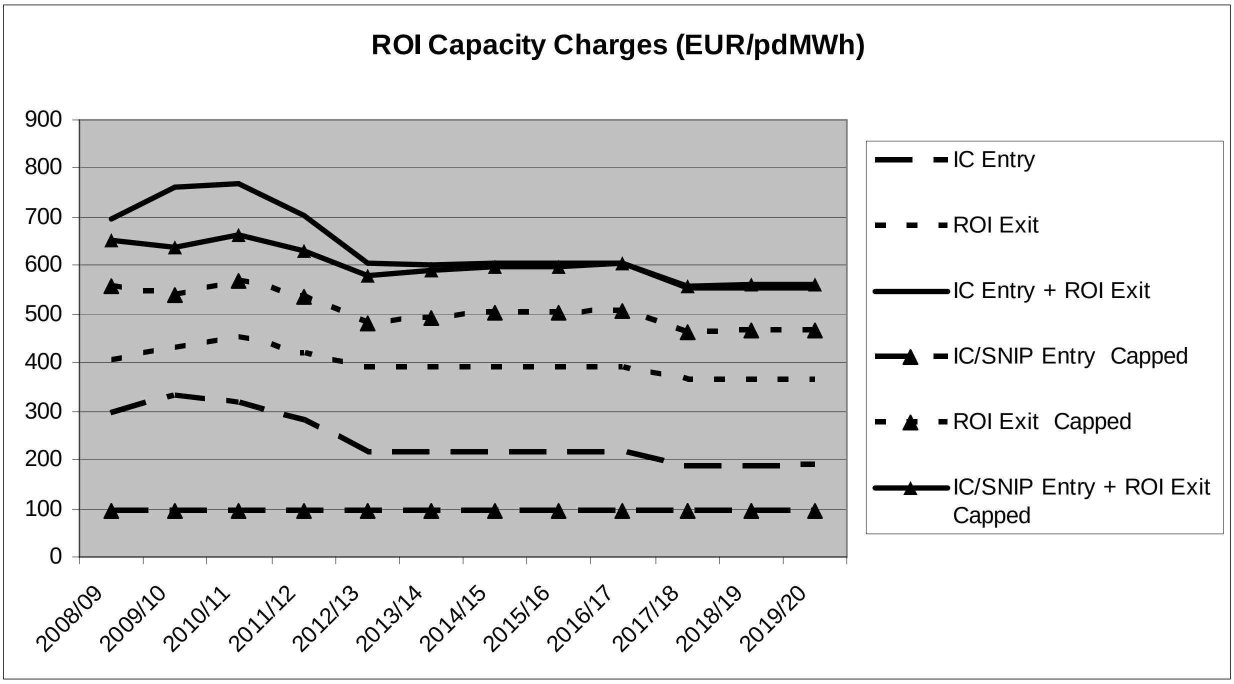
| **Year** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gas year** | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | Minimum | Maximum | Average |
| **Smoothed and Separate:** | | | | | | | | | | | | | | | |
| IC Entry | 295 | 331 | 317 | 282 | 216 | 214 | 215 | 216 | 217 | 187 | 187 | 188 | 187 | 331 | 239 |
| ROI Exit | 403 | 429 | 450 | 421 | 389 | 388 | 389 | 389 | 388 | 365 | 365 | 365 | 365 | 450 | 395 |
| IC Entry + ROI Exit | 698 | 760 | 767 | 703 | 604 | 603 | 604 | 605 | 605 | 552 | 553 | 553 | 552 | 767 | 634 |
| SNIP Entry | 219 | 229 | 221 | 233 | 235 | 225 | 239 | 229 | 243 | 233 | 247 | 243 | 219 | 247 | 233 |
| NI Exit | 290 | 293 | 294 | 302 | 285 | 284 | 284 | 284 | 283 | 275 | 275 | 274 | 274 | 302 | 285 |
| SNIP Entry + NI Exit | 509 | 523 | 515 | 536 | 520 | 510 | 523 | 513 | 526 | 508 | 521 | 517 | 508 | 536 | 518 |
| **Capped and Combined:** | | | | | | | | | | | | | | | |
| IC/SNIP Entry Capped | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| ROI Exit Capped | 557 | 540 | 567 | 536 | 482 | 494 | 501 | 502 | 507 | 462 | 465 | 466 | 462 | 567 | 507 |
| IC/SNIP Entry + ROI Exit Capped | 653 | 637 | 664 | 632 | 578 | 590 | 597 | 598 | 604 | 558 | 562 | 562 | 558 | 664 | 603 |
| IC/SNIP Entry Capped | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| NI Exit Capped | 458 | 416 | 395 | 407 | 369 | 380 | 386 | 387 | 391 | 363 | 367 | 367 | 363 | 458 | 391 |
| IC/SNIP Entry + NI Exit Capped | 554 | 512 | 491 | 503 | 466 | 476 | 482 | 483 | 488 | 460 | 464 | 464 | 460 | 554 | 487 |

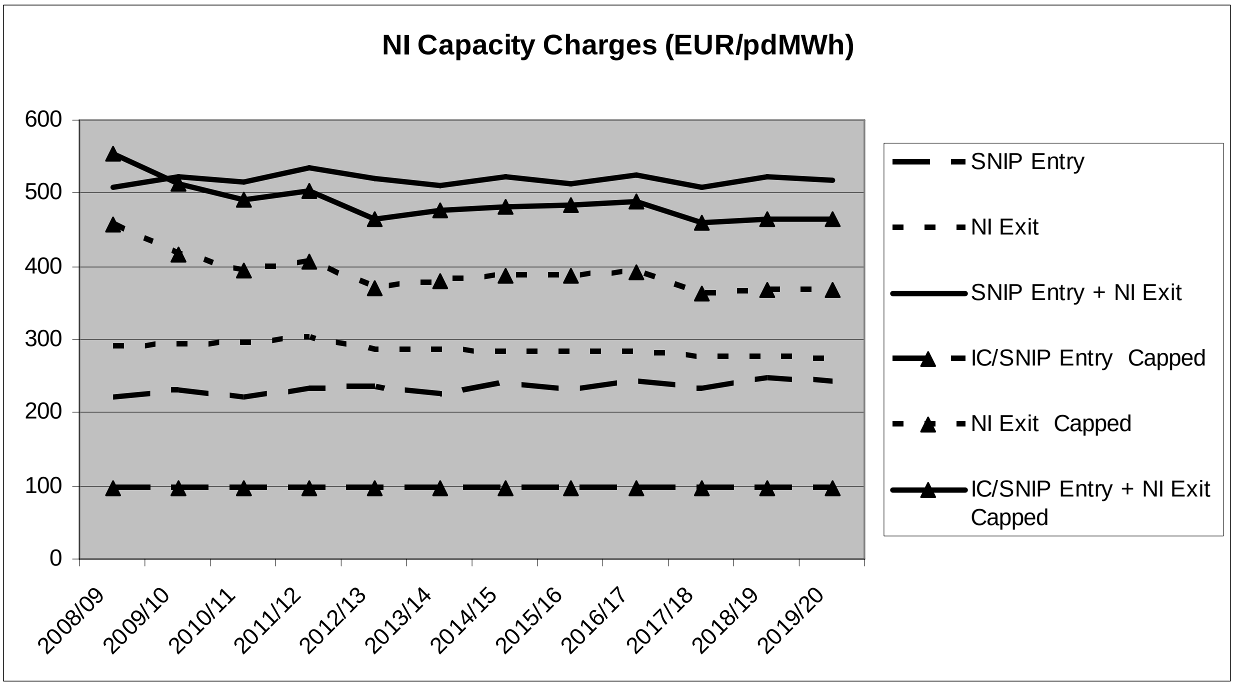
**COMMODITY CHARGES (EUR/MWh)**

| **Year** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gas year** | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | Minimum | Maximum | Average |
| **Smoothed and Separate:** | | | | | | | | | | | | | | | |
| IC Entry | 0.125 | 0.205 | 0.211 | 0.182 | 0.123 | 0.129 | 0.124 | 0.121 | 0.119 | 0.102 | 0.101 | 0.100 | 0.100 | 0.211 | 0.137 |
| ROI Exit | 0.195 | 0.203 | 0.226 | 0.217 | 0.200 | 0.201 | 0.200 | 0.200 | 0.201 | 0.190 | 0.190 | 0.190 | 0.190 | 0.226 | 0.201 |
| IC Entry + ROI Exit | 0.320 | 0.408 | 0.437 | 0.400 | 0.323 | 0.330 | 0.325 | 0.321 | 0.320 | 0.291 | 0.291 | 0.289 | 0.289 | 0.437 | 0.338 |
| SNIP Entry | 0.112 | 0.116 | 0.084 | 0.087 | 0.087 | 0.083 | 0.087 | 0.082 | 0.087 | 0.083 | 0.087 | 0.085 | 0.082 | 0.116 | 0.090 |
| NI Exit | 0.148 | 0.151 | 0.143 | 0.148 | 0.140 | 0.140 | 0.140 | 0.140 | 0.140 | 0.137 | 0.137 | 0.137 | 0.137 | 0.151 | 0.142 |
| SNIP Entry + NI Exit | 0.261 | 0.267 | 0.226 | 0.235 | 0.227 | 0.223 | 0.226 | 0.222 | 0.227 | 0.219 | 0.224 | 0.222 | 0.219 | 0.267 | 0.232 |
| **Capped and Combined:** | | | | | | | | | | | | | | | |
| IC/SNIP Entry Capped | 0.043 | 0.055 | 0.050 | 0.050 | 0.047 | 0.050 | 0.048 | 0.048 | 0.047 | 0.047 | 0.046 | 0.046 | 0.043 | 0.055 | 0.048 |
| ROI Exit Capped | 0.269 | 0.256 | 0.284 | 0.277 | 0.249 | 0.255 | 0.258 | 0.259 | 0.262 | 0.240 | 0.242 | 0.242 | 0.240 | 0.284 | 0.258 |
| IC/SNIP Entry + ROI Exit Capped | 0.312 | 0.311 | 0.334 | 0.327 | 0.296 | 0.305 | 0.307 | 0.307 | 0.309 | 0.287 | 0.289 | 0.288 | 0.287 | 0.334 | 0.306 |
| IC/SNIP Entry Capped | 0.043 | 0.055 | 0.050 | 0.050 | 0.047 | 0.050 | 0.048 | 0.048 | 0.047 | 0.047 | 0.046 | 0.046 | 0.043 | 0.055 | 0.048 |
| NI Exit Capped | 0.234 | 0.214 | 0.192 | 0.199 | 0.181 | 0.187 | 0.190 | 0.191 | 0.194 | 0.181 | 0.183 | 0.184 | 0.181 | 0.234 | 0.194 |
| IC/SNIP Entry + NI Exit Capped | 0.277 | 0.268 | 0.241 | 0.249 | 0.228 | 0.237 | 0.238 | 0.238 | 0.241 | 0.227 | 0.230 | 0.230 | 0.227 | 0.277 | 0.242 |

Note: Here and later, we do not repeat the Corrib, Inch, Shannon LNG and Larne charges which do not change from those under the current charge structure.

**Scenario 1 – Corrib only**



# Scenario 2 – Corrib and Shannon LNG

# Current charge structure

**ILLUSTRATIVE CAPACITY AND COMMODITY CHARGES** **Scenario: Corrib & SLNG**

**CAPACITY CHARGES (EUR/peak day MWh)**

| **Year** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gas year** | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | Minimum | Maximum | Average |
| **Entry** | | | | | | | | | | | | | | | |
| Corrib | - | 143 | 143 | 143 | 286 | 286 | 286 | 286 | 286 | 593 | 593 | 593 | 143 | 593 | 331 |
| IC1&2 | 295 | 331 | 317 | 282 | 566 | 578 | 578 | 570 | 566 | 382 | 381 | 381 | 282 | 578 | 436 |
| Inch | 64 | 64 | 63 | 62 | 84 | - | - | - | - | - | - | - | 62 | 84 | 68 |
| SLNG | - | - | - | - | 21 | 15 | 14 | 15 | 15 | 13 | 13 | 13 | 13 | 21 | 15 |
| SNIP | 219 | 229 | 221 | 233 | 235 | 225 | 239 | 229 | 243 | 233 | 247 | 243 | 219 | 247 | 233 |
| Larne | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Exit** | | | | | | | | | | | | | | | |
| Onshore Ireland | 403 | 429 | 450 | 421 | 399 | 399 | 399 | 399 | 399 | 388 | 388 | 388 | 388 | 450 | 405 |
| Onshore NI (includes SN pipeline) | 290 | 293 | 294 | 302 | 385 | 388 | 390 | 392 | 394 | 341 | 342 | 342 | 290 | 394 | 346 |

**COMMODITY CHARGES (EUR/MWh)**

| **Year** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gas year** | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | Minimum | Maximum | Average |
| **Entry** | | | | | | | | | | | | | | | |
| Corrib | - | 0.044 | 0.044 | 0.044 | 0.087 | 0.087 | 0.087 | 0.087 | 0.087 | 0.180 | 0.180 | 0.180 | 0.044 | 0.180 | 0.101 |
| IC1&2 | 0.125 | 0.205 | 0.211 | 0.182 | 0.635 | 0.527 | 0.525 | 0.590 | 0.627 | 0.445 | 0.455 | 0.454 | 0.125 | 0.635 | 0.415 |
| Inch | 0.069 | 0.075 | 0.078 | 0.081 | 0.114 | - | - | - | - | - | - | - | 0.069 | 0.114 | 0.083 |
| SLNG | - | - | - | - | 0.009 | 0.008 | 0.007 | 0.007 | 0.006 | 0.005 | 0.005 | 0.005 | 0.005 | 0.009 | 0.007 |
| SNIP | 0.112 | 0.116 | 0.084 | 0.087 | 0.087 | 0.083 | 0.087 | 0.082 | 0.087 | 0.083 | 0.087 | 0.085 | 0.082 | 0.116 | 0.090 |
| Larne | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Exit** | | | | | | | | | | | | | | | |
| Onshore Ireland | 0.195 | 0.203 | 0.226 | 0.217 | 0.206 | 0.206 | 0.206 | 0.206 | 0.206 | 0.201 | 0.202 | 0.201 | 0.195 | 0.226 | 0.206 |
| Onshore NI (includes SN pipeline) | 0.148 | 0.151 | 0.143 | 0.148 | 0.189 | 0.191 | 0.192 | 0.193 | 0.195 | 0.169 | 0.170 | 0.171 | 0.143 | 0.195 | 0.172 |

# Comparison of charges under the current structure and our preferred option

**ILLUSTRATIVE CAPACITY AND COMMODITY CHARGES** **Scenario: Corrib & SLNG**

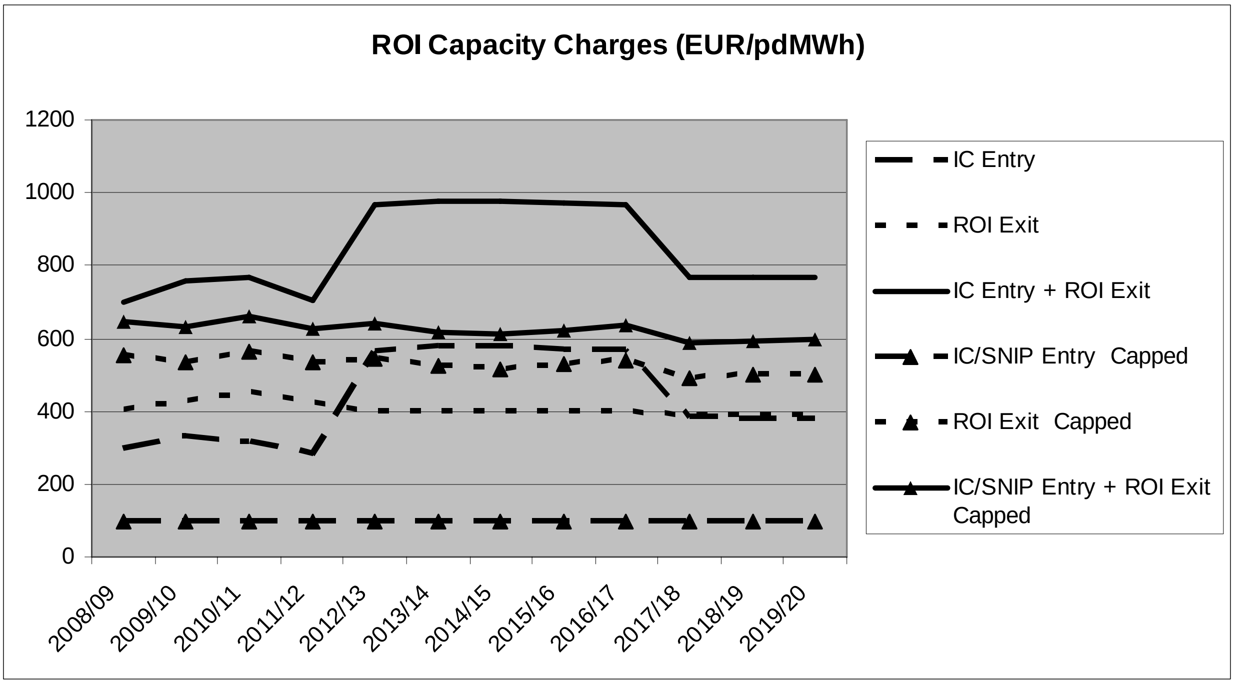
**CAPACITY CHARGES (EUR/peak day MWh)**

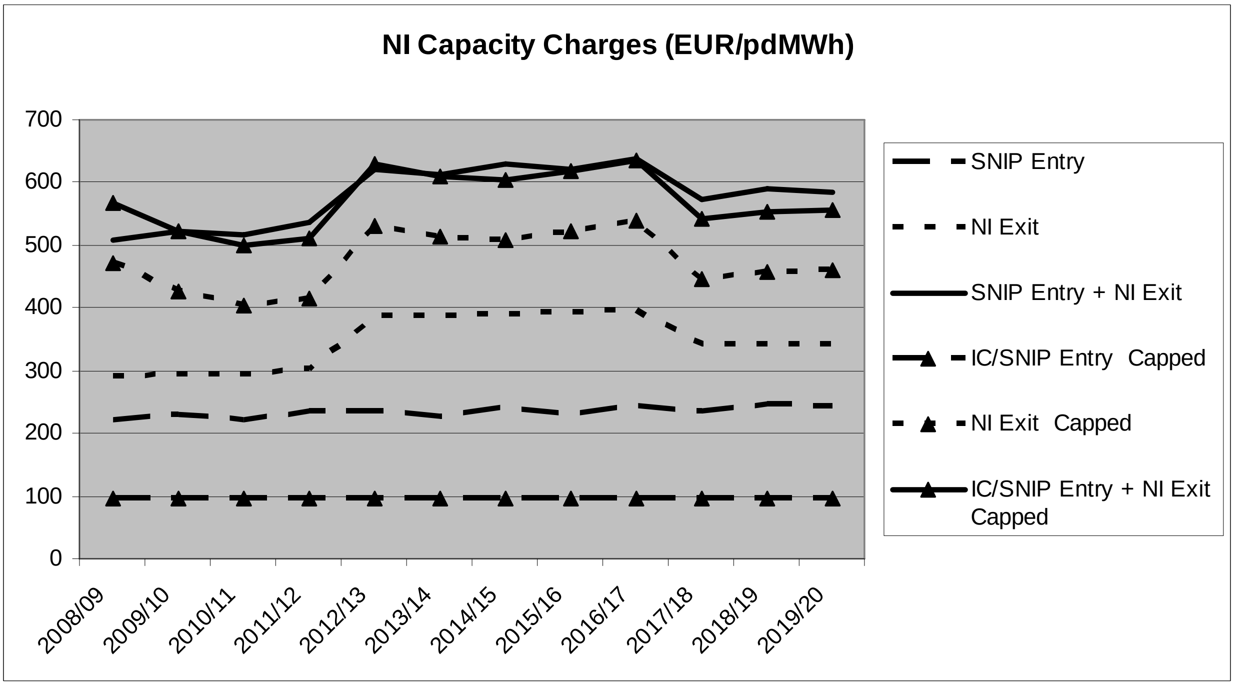
| **Year** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gas year** | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | Minimum | Maximum | Average |
| **Smoothed and Separate:** | | | | | | | | | | | | | | | |
| IC Entry | 295 | 331 | 317 | 282 | 566 | 578 | 578 | 570 | 566 | 382 | 381 | 381 | 282 | 578 | 436 |
| ROI Exit | 403 | 429 | 450 | 421 | 399 | 399 | 399 | 399 | 399 | 388 | 388 | 388 | 388 | 450 | 405 |
| IC Entry + ROI Exit | 698 | 760 | 767 | 703 | 965 | 977 | 977 | 969 | 966 | 770 | 769 | 769 | 698 | 977 | 841 |
| SNIP Entry | 219 | 229 | 221 | 233 | 235 | 225 | 239 | 229 | 243 | 233 | 247 | 243 | 219 | 247 | 233 |
| NI Exit | 290 | 293 | 294 | 302 | 385 | 388 | 390 | 392 | 394 | 341 | 342 | 342 | 290 | 394 | 346 |
| SNIP Entry + NI Exit | 509 | 523 | 515 | 536 | 621 | 613 | 629 | 621 | 637 | 574 | 589 | 585 | 509 | 637 | 579 |
| **Capped and Combined:** | | | | | | | | | | | | | | | |
| IC/SNIP Entry Capped | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| ROI Exit Capped | 552 | 537 | 564 | 532 | 544 | 523 | 516 | 527 | 541 | 491 | 499 | 502 | 491 | 564 | 527 |
| IC/SNIP Entry + ROI Exit Capped | 649 | 633 | 660 | 628 | 640 | 619 | 613 | 624 | 638 | 587 | 595 | 598 | 587 | 660 | 624 |
| IC/SNIP Entry Capped | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| NI Exit Capped | 472 | 426 | 404 | 415 | 532 | 513 | 508 | 522 | 539 | 447 | 456 | 461 | 404 | 539 | 474 |
| IC/SNIP Entry + NI Exit Capped | 568 | 522 | 500 | 512 | 628 | 609 | 605 | 618 | 635 | 543 | 553 | 557 | 500 | 635 | 571 |

**COMMODITY CHARGES (EUR/MWh)**

| **Year** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gas year** | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | Minimum | Maximum | Average |
| **Smoothed and Separate:** | | | | | | | | | | | | | | | |
| IC Entry | 0.125 | 0.205 | 0.211 | 0.182 | 0.635 | 0.527 | 0.525 | 0.590 | 0.627 | 0.445 | 0.455 | 0.454 | 0.125 | 0.635 | 0.415 |
| ROI Exit | 0.195 | 0.203 | 0.226 | 0.217 | 0.206 | 0.206 | 0.206 | 0.206 | 0.206 | 0.201 | 0.202 | 0.201 | 0.195 | 0.226 | 0.206 |
| IC Entry + ROI Exit | 0.320 | 0.408 | 0.437 | 0.400 | 0.841 | 0.733 | 0.731 | 0.796 | 0.833 | 0.647 | 0.657 | 0.655 | 0.320 | 0.841 | 0.621 |
| SNIP Entry | 0.112 | 0.116 | 0.084 | 0.087 | 0.087 | 0.083 | 0.087 | 0.082 | 0.087 | 0.083 | 0.087 | 0.085 | 0.082 | 0.116 | 0.090 |
| NI Exit | 0.148 | 0.151 | 0.143 | 0.148 | 0.189 | 0.191 | 0.192 | 0.193 | 0.195 | 0.169 | 0.170 | 0.171 | 0.143 | 0.195 | 0.172 |
| SNIP Entry + NI Exit | 0.261 | 0.267 | 0.226 | 0.235 | 0.277 | 0.274 | 0.278 | 0.276 | 0.282 | 0.252 | 0.257 | 0.256 | 0.226 | 0.282 | 0.262 |
| **Capped and Combined:** | | | | | | | | | | | | | | | |
| IC/SNIP Entry Capped | 0.043 | 0.055 | 0.050 | 0.050 | 0.055 | 0.050 | 0.048 | 0.051 | 0.054 | 0.056 | 0.058 | 0.058 | 0.043 | 0.058 | 0.052 |
| ROI Exit Capped | 0.267 | 0.254 | 0.282 | 0.275 | 0.281 | 0.270 | 0.266 | 0.272 | 0.280 | 0.255 | 0.259 | 0.261 | 0.254 | 0.282 | 0.268 |
| IC/SNIP Entry + ROI Exit Capped | 0.310 | 0.309 | 0.332 | 0.325 | 0.336 | 0.320 | 0.314 | 0.323 | 0.333 | 0.311 | 0.317 | 0.319 | 0.309 | 0.336 | 0.321 |
| IC/SNIP Entry Capped | 0.043 | 0.055 | 0.050 | 0.050 | 0.055 | 0.050 | 0.048 | 0.051 | 0.054 | 0.056 | 0.058 | 0.058 | 0.043 | 0.058 | 0.052 |
| NI Exit Capped | 0.242 | 0.219 | 0.196 | 0.203 | 0.261 | 0.253 | 0.250 | 0.258 | 0.267 | 0.222 | 0.227 | 0.230 | 0.196 | 0.267 | 0.236 |
| IC/SNIP Entry + NI Exit Capped | 0.285 | 0.274 | 0.245 | 0.253 | 0.316 | 0.303 | 0.298 | 0.309 | 0.320 | 0.278 | 0.285 | 0.289 | 0.245 | 0.320 | 0.288 |

## Scenario 2 – Corrib and Shannon LNG



# Scenario 3 – Corrib and Larne

## Current charge structure

**ILLUSTRATIVE CAPACITY AND COMMODITY CHARGES** **Scenario: Corrib & Larne**

**CAPACITY CHARGES (EUR/peak day MWh)**

| **Year** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gas year** | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | Minimum | Maximum | Average |
| **Entry** | | | | | | | | | | | | | | | |
| Corrib | - | 143 | 143 | 143 | 286 | 286 | 286 | 286 | 286 | 593 | 593 | 593 | 143 | 593 | 331 |
| IC1&2 | 295 | 331 | 317 | 282 | 227 | 225 | 231 | 230 | 228 | 187 | 186 | 185 | 185 | 331 | 244 |
| Inch | 64 | 64 | 63 | 62 | 84 | - | - | - | - | - | - | - | 62 | 84 | 68 |
| SLNG | - | - | - | - | - | - | - | - | - | - | - | - | 0 | 0 - | |
| SNIP | 219 | 229 | 221 | 233 | 235 | 225 | 239 | 229 | 243 | 233 | 247 | 243 | 219 | 247 | 233 |
| Larne | - | - | - | - | - | - | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| **Exit** | | | | | | | | | | | | | | | |
| Onshore Ireland | 403 | 429 | 450 | 421 | 395 | 395 | 396 | 395 | 395 | 388 | 388 | 388 | 388 | 450 | 404 |
| Onshore NI (includes SN pipeline) | 290 | 293 | 294 | 302 | 288 | 287 | 287 | 287 | 286 | 275 | 275 | 274 | 274 | 302 | 286 |

**COMMODITY CHARGES (EUR/MWh)**

| **Year** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gas year** | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | Minimum | Maximum | Average |
| **Entry** | | | | | | | | | | | | | | | |
| Corrib | - | 0.044 | 0.044 | 0.044 | 0.087 | 0.087 | 0.087 | 0.087 | 0.087 | 0.180 | 0.180 | 0.180 | 0.044 | 0.180 | 0.101 |
| IC1&2 | 0.125 | 0.205 | 0.211 | 0.182 | 0.129 | 0.136 | 0.107 | 0.113 | 0.119 | 0.105 | 0.111 | 0.117 | 0.105 | 0.211 | 0.138 |
| Inch | 0.069 | 0.075 | 0.078 | 0.081 | 0.114 | - | - | - | - | - | - | - | 0.069 | 0.114 | 0.083 |
| SLNG | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| SNIP | 0.112 | 0.116 | 0.084 | 0.087 | 0.087 | 0.083 | 0.087 | 0.082 | 0.087 | 0.083 | 0.087 | 0.085 | 0.082 | 0.116 | 0.090 |
| Larne | - | - | - | - | - | - | 0.038 | 0.019 | 0.013 | 0.009 | 0.008 | 0.006 | 0.006 | 0.038 | 0.015 |
| **Exit** | | | | | | | | | | | | | | | |
| Onshore Ireland | 0.195 | 0.203 | 0.226 | 0.217 | 0.204 | 0.204 | 0.204 | 0.204 | 0.204 | 0.201 | 0.202 | 0.201 | 0.195 | 0.226 | 0.205 |
| Onshore NI (includes SN pipeline) | 0.148 | 0.151 | 0.143 | 0.148 | 0.141 | 0.142 | 0.141 | 0.141 | 0.142 | 0.137 | 0.137 | 0.137 | 0.137 | 0.151 | 0.142 |

# Comparison of charges under the current structure and our preferred option

**ILLUSTRATIVE CAPACITY AND COMMODITY CHARGES** **Scenario: Corrib & Larne**

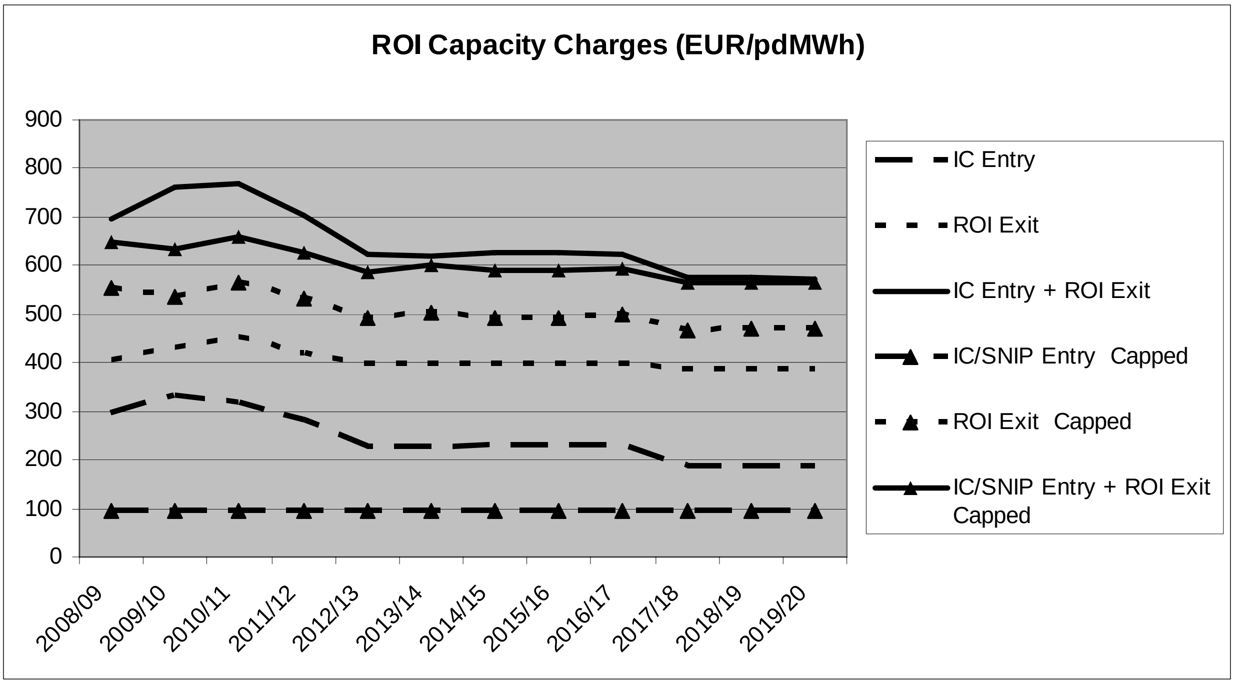
**CAPACITY CHARGES (EUR/peak day MWh)**

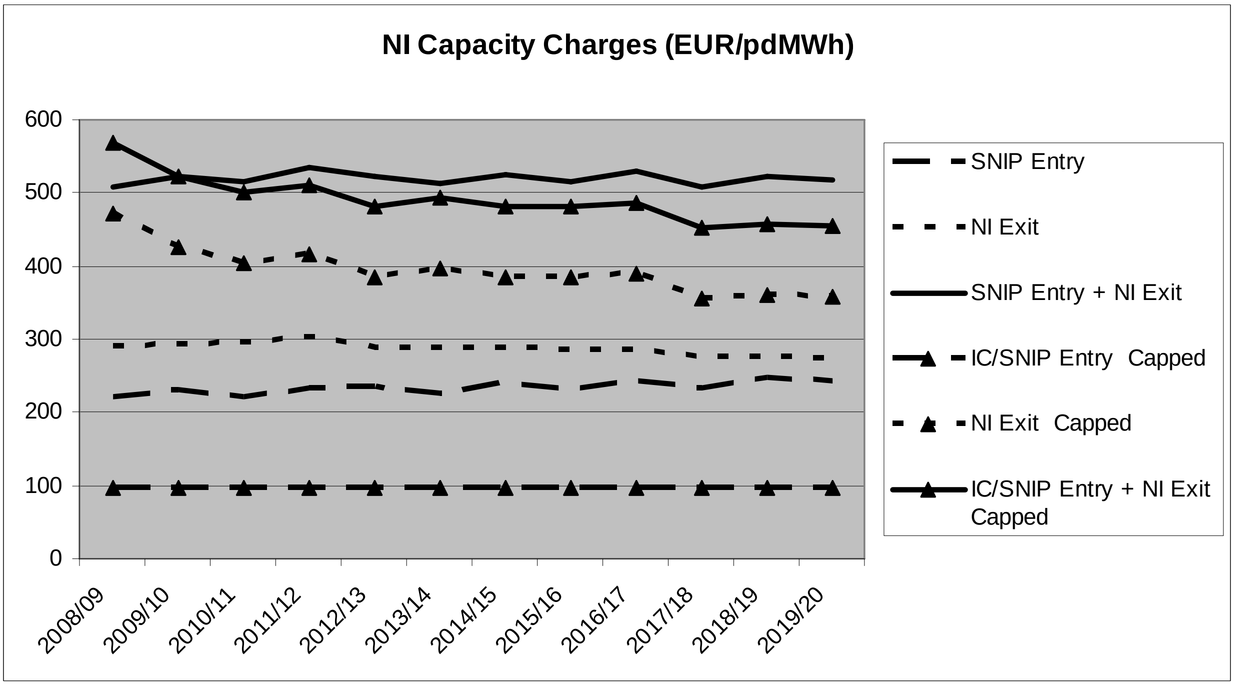
| **Year** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gas year** | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | Minimum | Maximum | Average |
| **Smoothed and Separate:** | | | | | | | | | | | | | | | |
| IC Entry | 295 | 331 | 317 | 282 | 227 | 225 | 231 | 230 | 228 | 187 | 186 | 185 | 185 | 331 | 244 |
| ROI Exit | 403 | 429 | 450 | 421 | 395 | 395 | 396 | 395 | 395 | 388 | 388 | 388 | 388 | 450 | 404 |
| IC Entry + ROI Exit | 698 | 760 | 767 | 703 | 622 | 621 | 627 | 625 | 624 | 575 | 574 | 573 | 573 | 767 | 647 |
| SNIP Entry | 219 | 229 | 221 | 233 | 235 | 225 | 239 | 229 | 243 | 233 | 247 | 243 | 219 | 247 | 233 |
| NI Exit | 290 | 293 | 294 | 302 | 288 | 287 | 287 | 287 | 286 | 275 | 275 | 274 | 274 | 302 | 286 |
| SNIP Entry + NI Exit | 509 | 523 | 515 | 536 | 523 | 513 | 526 | 516 | 529 | 508 | 522 | 518 | 508 | 536 | 520 |
| **Capped and Combined:** | | | | | | | | | | | | | | | |
| IC/SNIP Entry Capped | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| ROI Exit Capped | 552 | 537 | 564 | 532 | 491 | 504 | 492 | 493 | 497 | 467 | 470 | 469 | 467 | 564 | 506 |
| IC/SNIP Entry + ROI Exit Capped | 649 | 633 | 660 | 628 | 587 | 600 | 589 | 589 | 594 | 563 | 566 | 566 | 563 | 660 | 602 |
| IC/SNIP Entry Capped | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 | 96 |
| NI Exit Capped | 472 | 426 | 404 | 415 | 385 | 397 | 385 | 385 | 390 | 356 | 360 | 359 | 356 | 472 | 395 |
| IC/SNIP Entry + NI Exit Capped | 568 | 522 | 500 | 512 | 481 | 494 | 482 | 482 | 487 | 453 | 456 | 455 | 453 | 568 | 491 |

**COMMODITY CHARGES (EUR/MWh)**

| **Year** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gas year** | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 | 2019/20 | Minimum | Maximum | Average |
| **Smoothed and Separate:** | | | | | | | | | | | | | | | |
| IC Entry | 0.125 | 0.205 | 0.211 | 0.182 | 0.129 | 0.136 | 0.107 | 0.113 | 0.119 | 0.105 | 0.111 | 0.117 | 0.105 | 0.211 | 0.138 |
| ROI Exit | 0.195 | 0.203 | 0.226 | 0.217 | 0.204 | 0.204 | 0.204 | 0.204 | 0.204 | 0.201 | 0.202 | 0.201 | 0.195 | 0.226 | 0.205 |
| IC Entry + ROI Exit | 0.320 | 0.408 | 0.437 | 0.400 | 0.333 | 0.340 | 0.311 | 0.317 | 0.323 | 0.306 | 0.312 | 0.318 | 0.306 | 0.437 | 0.344 |
| SNIP Entry | 0.112 | 0.116 | 0.084 | 0.087 | 0.087 | 0.083 | 0.087 | 0.082 | 0.087 | 0.083 | 0.087 | 0.085 | 0.082 | 0.116 | 0.090 |
| NI Exit | 0.148 | 0.151 | 0.143 | 0.148 | 0.141 | 0.142 | 0.141 | 0.141 | 0.142 | 0.137 | 0.137 | 0.137 | 0.137 | 0.151 | 0.142 |
| SNIP Entry + NI Exit | 0.261 | 0.267 | 0.226 | 0.235 | 0.229 | 0.225 | 0.228 | 0.224 | 0.228 | 0.219 | 0.224 | 0.222 | 0.219 | 0.267 | 0.232 |
| **Capped and Combined:** | | | | | | | | | | | | | | | |
| IC/SNIP Entry Capped | 0.043 | 0.055 | 0.050 | 0.050 | 0.047 | 0.050 | 0.041 | 0.043 | 0.044 | 0.047 | 0.049 | 0.050 | 0.041 | 0.055 | 0.047 |
| ROI Exit Capped | 0.267 | 0.254 | 0.282 | 0.275 | 0.253 | 0.260 | 0.254 | 0.254 | 0.257 | 0.242 | 0.244 | 0.244 | 0.242 | 0.282 | 0.257 |
| IC/SNIP Entry + ROI Exit Capped | 0.310 | 0.309 | 0.332 | 0.325 | 0.300 | 0.310 | 0.295 | 0.297 | 0.301 | 0.289 | 0.293 | 0.294 | 0.289 | 0.332 | 0.305 |
| IC/SNIP Entry Capped | 0.043 | 0.055 | 0.050 | 0.050 | 0.047 | 0.050 | 0.041 | 0.043 | 0.044 | 0.047 | 0.049 | 0.050 | 0.041 | 0.055 | 0.047 |
| NI Exit Capped | 0.242 | 0.219 | 0.196 | 0.203 | 0.189 | 0.196 | 0.189 | 0.190 | 0.193 | 0.177 | 0.179 | 0.179 | 0.177 | 0.242 | 0.196 |
| IC/SNIP Entry + NI Exit Capped | 0.285 | 0.274 | 0.245 | 0.253 | 0.236 | 0.246 | 0.230 | 0.233 | 0.238 | 0.224 | 0.228 | 0.230 | 0.224 | 0.285 | 0.243 |

## Scenario 3 – Corrib and Larne



## ANNEX 4 – LRMC ESTIMATES

In this annex, we describe the long run average incremental cost (LRAIC) approximation to long run marginal cost (LRMC) and we set out an estimate of the equilibrium LRMC at the IC1/2 entry point using the LRAIC approximation. We stress that this estimate is to illustrate the principle of capping of interconnector charges and, accordingly, is based on simple assumptions rather than detailed engineering analysis which may lead to a significantly different estimate. Tariffs set at the LRMC encourage economic efficiency as they give producers and consumers the correct price signals on which to make investment and operational choices. However, usually, such tariffs require some adjustment to ensure that the required revenue is recovered and, often, a simple additive adjustment is made to preserve LRMC differentials and hence retain the correct price signals.

### 1.1. LRAIC approximation

The LRMC of a service is the additional economic cost imposed by the least cost means of meeting a sustained marginal increment in demand for the service assuming that capacity to provide the service can be increased marginally to accommodate the increment in demand. Clearly, it is not usually possible to make marginal increases in capacity as investment is lumpy, and, accordingly, the LRMC varies depending on whether there is a surplus or shortage of capacity to provide the service. If there is a shortage of capacity, then the economic costs of meeting a sustained increment in demand will include the costs of an immediate investment to increase capacity together with increased operating costs and the costs of any increase in probability of failure of to supply the service. Whereas, if there is surplus capacity, then the economic costs of meeting a sustained increment in demand will include the costs of an delayed investment to increase capacity together with increased operating costs and the costs of any increase in probability of failure of to supply the service. Thus, with lumpy investment, the LRMC cycles from a low value immediately following an investment that results in surplus capacity to a high value when there is shortage of capacity immediately prior to investment. However, in practical applications, the LRMC is usually taken to be the equilibrium value when there is neither a surplus nor a shortage of capacity.

In practical calculations, the LRAIC approximation to LRMC is usually adopted as it is not usually possible to estimate the cost imposed by a (small) marginal increment in demand. In making the calculation:

- a suitably sized increment in demand is chosen to result in sensible changes to the base case investment and operating costs;
- engineering judgement is used to determine the appropriate scheme for increasing the capacity at the least cost;
- the timing and lifetime of the investment is taken into account and the timing of associated operating costs is taken into account through discounting at the cost of capital;
- the construction time is taken into account recognising that investment must be completed before the sustained increment in demand can be accommodated[19]; and
- a long time horizon is used to ensure calculations are not sensitive to end effects.

The LRAIC is calculated as follows

[19] Prior to the construction, the sustained increment in demand causes increase in probability of failure to provide the service with associated economic costs (eg the costs of loss of production).

$$LRAIC = \frac{\sum_{t=0}^{n} \frac{\Delta I_t + \Delta O_t}{(1+d)^t}}{\sum_{t=0}^{n} \frac{\Delta D_{t+k}}{(1+d)^{t+k}}}$$

Where:
$\Delta I_t$ is the additional investment cost in year $t$ (being the sum of the annuitised additional investments made in all years up to and including year $t$, with the annuities made over the economic lifetime of the investments at the relevant cost of capital);
$\Delta O_t$ is the additional operating cost and the additional costs of any increase in probability of failure to supply the service in year $t$;
$\Delta D_{t+k}$ is the demand increment in year $t+k$ which causes to an investment requirement in year $t$
$d$ is the discount rate (which should equal the cost of capital); and
$n$ is the time horizon.

The LRAIC has the property that if charges are set equal to the LRAIC, then, on a present value basis, the revenue recovered to the time horizon will exactly equal the appropriate portion of the investment costs, the operating costs and the additional costs of any increase in probability of failure of to supply the service to the time horizon.

### 1.2. LRMC estimate

Expressed as a 100% capacity charge, we estimate the equilibrium LRMC at the IC1/2 entry point to be some €107/peak day MWh using the above LRAIC approximation. This comprises some €42.4/pdMWh for capex, €10.2/pdMWh for general opex and €54.4/pdMWh for gas use in compressors.

We note that this estimate is significantly below the current entry charges which are some €274/peak day MWh and €0.126/MWh suggesting that current interconnector charges are providing artificial barriers to using the interconnectors.

We stress again that our estimate is for illustrative purposes and is not based on any detailed engineering analysis or costing. For illustrative purposes, we have made the following assumptions:

- the background is an equilibrium scenario under which increased demand on the IC1/2 interconnector requires immediate capex [similar to assuming that Shannon LNG does not come on stream];
- the capex comprises an additional spend of €80M on pipelines spread over the gas years 2013/14 to 2015/16 and €90M on compressors spread over the gas years 2012/13 to 2019/20;
- the opex comprises:
  - annual maintenance of €0.4M on the additional pipelines and €2.55M on the additional compressors from the start of gas year 2017/18;
  - gas used by additional compressors at Beattock and Brighouse, with gas cost being based on the forward gas prices at the GB National Balancing Point provided by ICIS Heren and with gas use being 1% of compressor throughput (assuming the additional

compressors operate at 42% annual load factor being the average of the load factors of the current compressors at Beattock and Brighouse);
  - the probability, and hence cost, of failure to supply due to transmission failure does not change due to the demand increase;
- the above capex and opex realises an additional interconnector capacity of 25Mscm on the peak day available from the start of gas year 2017/18;
- the economic lifetime of:
  - pipelines is 50 years;
  - compressors is 25 years;
- the discount rate is equal to the current allowed cost of capital of 5.2%; and
- the exchange rate is 1.25€/£.