COMMISSION FOR ENERGY REGULATION

GAS TRANSMISSION AND DISTRIBUTION REVENUE CONTROL

OUTPUTS, INCENTIVES AND UNCERTAINTY MECHANISMS

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IMPORTANT NOTICE

1. INTRODUCTION

A consortium of CEPA, GL Noble and PKF have been engaged by the Commission for Energy Regulation (CER) to advise on Bord Gais Network's (BGN) allowed revenue control for Price Control period 3 (PC3). This report provides an initial view on some aspects of possible outputs, incentive regimes and approaches to managing uncertainty that might form part of the next allowed revenue control of BGN's gas transmission and distribution businesses.

1.1. Context

In Price Control period 2 (PC2), the CER sought through its price control to provide strong regulatory incentives for BGN to make efficiency savings in the day to day operation of its networks business, and through efficient and timely investment in the network infrastructure and systems. Therefore, incentive based regulation formed the core of its PC2 decision and regime. In the longer term this was considered to be the way in which customers would obtain the greatest benefit through lower prices, as BGN improved its efficiency.

The CER also noted the importance of ensuring that BGN was accountable for spending the revenue allowed under the PC2 determination appropriately, and in particular, to deliver the outputs that were expected delivered with the revenue. Therefore, in both its transmission and distribution decisions, CER specifically set out the outputs and outcomes that BGN were expected to deliver with its allowed revenue, and the incentive arrangements that applied to the costs related to the delivery of those outputs. Those outputs were a combination of specific observable outputs and standards to be achieved by BGN.

1.2. Objectives and approach

The objectives of this paper are threefold.

Primarily the objective is to review the performance of the outputs and incentives regime in PC2, and the approach adopted by CER for managing uncertainty, and what lessons might be learned for PC3 from the PC2 experience.

We have then also assessed the options for incentives and performance in relation to transmission and distribution for PC3. This has involved a review of explicit and implicit outputs and objectives that CER might wish to establish for BGN in PC3 and how these could be linked to an incentive regime. We have focused our comments in this area on BGN's own proposals for outputs in PC3.

We have approached our review of the options for possible incentive regimes and uncertainty mechanisms by considering the following:

- principles of regulatory incentive regimes;
- current framework;
- BGN's proposals for PC3 (where they exist);

- performance of PC2 arrangements;
- regulatory precedent, specifically Ofgem and CER; and
- possible options for PC3.

With our approach to incentives including an assessment of the current framework and guidance for PC2 – in particular, incentives created through the treatment of expenditure in the price control – there is a link to other analysis prepared by the consortium on BGN's outturn expenditure and performance in PC2. This includes issues around the guidance CER provided at the previous price review on efficient management of opex and capex.

In this paper we have sought to comment on the *principles* of the current framework, whether at a high level it has achieved the objectives it set out to achieve and whether aspects of the current regime should be retained. The review of price control outturn, and the implications for allowed revenue in PC3, is addressed in our historical transmission and distribution capex and opex reports. However, reference is made to those reports throughout this paper.

1.3. Structure of paper

This rest of this document is structured as follows:

- Section 2 provides a general overview on some principles for incentive regimes;
- Section 3 summarises the outputs and incentives regime in PC2;
- Section 4 considers BGN proposed outputs in PC3;
- Section 5 reviews operating expenditure incentives;
- Section 5 reviews capital expenditure incentives;
- Section 6 considers pass-through costs;
- Section 7 considers the connections incentive;
- Section 8 considers market development
- Section 9 considers innovation funding;
- Section 10 reviews sources of uncertainty in PC3;
- Section 11 provides conclusions.

2. PRINCIPLES

2.1. Focus for establishing incentives

When considering what incentives to establish in a regime it is important to prioritise as it is likely that only a limited number of incentives will be established – in part because it is better to provide a limited, and achievable, set of objectives and in part because there may be unintended consequences from incentives and these multiply as additional incentives are established.

When prioritising it is useful to consider:

- the materiality of the incentive / issue in question;
- the degree of control exercised by management over the underlying cost/activity;
- the emphasis that customers place on this activity; and
- the experience with incentives in this area to date.

The answers to each of these points will help design appropriate incentives. In output based regulation (which is increasingly the approach adopted in the UK) regulatory incentives are linked to outputs the regulated company is expected to deliver over the regulatory period.

In our view, it is particularly important to understand how a regulated company (in this case BGN) has responded to incentives in the past and role of ownership and managerial incentives in the company's responsiveness to incentives. When setting a price control it is also important to not to forget that while service performance or behavioural incentives can be used to support delivery of targeted outputs and performance measures, often the strongest regulatory incentives for the company are created through the treatment of expenditure in the price control and the guidance provided by the regulator when setting price control allowances.

2.2. Treatment of expenditure in the price control

Various aspects of the price control can create incentives for the regulated company. For example, whether types of activities are treated as capital or operating expenditure, the speed of cost recovery in either case and whether the regulator will review the outturn expenditure and its treatment at a later price control period. The treatment of investment, in particular, can create strong incentives on the network operator over the course of the price control.

For example, whether or not assets are included in the Regulatory Asset Base (RAB) and value assigned to these assets for the purposes of inclusion in the RAB, can create strong incentives for whether to invest or not invest. Guidance on methodologies the regulator expects to follow when reviewing outturn expenditure can also incentivise and affect the way the firm goes about network planning and running of its business.

2.3. Incentive strength and incentive caps

The power of incentives (for example, the length of retention period for any efficiency savings) and specific design parameters around any marginal or behavioural incentives (such as the performance measure used and the revenue at risk under the scheme) are all also likely to be key issues relevant to the incentivisation framework. In particular, there is always a concern about the strength of incentives, especially when there is uncertainty about whether the base line target value for expenditure or a performance measure has been set correctly.

Two issues need to be considered:

- the strength of specific incentives; and
- whether individual and/or overall incentives are capped.

When setting the strength of a specific or behaviour incentive there are several issues to take into account. For example:

- The value that customers place on the service/activity. This is the most powerful basis on which to set incentives as direct evidence from customers shows how they value the service or the improvements being offered.
- The interaction with the base target. It can be argued that to limit the risk of windfall gains/losses for a company it is appropriate to link the incentive strength to the degree of certainty about the target value. If a very certain target value can be set then it may be appropriate to give strong incentives around the target since any deviation is clearly attributable to management. If the target is less certain then a weaker incentive is likely to be appropriate as the outcome could be due to other factors, such as mis-measurement of the target, rather than management actions.
- Maintaining a level strength. A lesson from the 1990s is that companies respond to incentives and if the strength of an incentive declines over time then a company will, rationally, maximise the effect of the early years. Consequently regulators have either used rolling incentives to ensure a constant incentive strength or have set a separate time independent incentive strength.
- Length of retention period. This affects the proportion of the present value of efficiency savings retained by the regulated company. In the case of fixed timings for the price control *review* (in the case of BGN's price control, every five years) how efficiency savings are treated at the point of the price control *review* can affect the incentive strength at different points over the price control period.

An alternative approach when there is uncertainty about target levels rather than reducing the strength of the incentive is to place a cap/collar on the revenue at risk through the incentive. So, a strong incentive can then exist for initial savings/over-spend but as the scale of the saving grows the impact is reduced and then negated. Many regulators, including CER, Ofgem and NIAUR, have used caps and collars in the past.

In addition, it is possible to place an overall cap/collar on the aggregate revenue at risk from incentives – again something many regulators have done in the past. The rationale for this (and in part for individual incentive caps and collars), as opposed to helping address uncertainty about targets, is to limit the risk that companies and customers face. Companies may face risk that they will seek to recover through the WACC if the risk exposure is such that investor returns are materially affected by penalties. Customers face the risk that significant out-performance of the targets would lead to large incentive payments to the company that increase the prices paid by consumers.

2.4. Degree of symmetry

Another issue in incentive design that needs to be considered is whether the incentive is symmetric. Decisions about this depend on several factors, including:

- The desired outcome – is the target something that should not be breached but customers do not benefit from (or value the benefit of) beating the target?
- The ease of beating/failing the target – if the actions needed to beat the target are very different to those required to maintain the target then either asymmetric incentives, or at least different strength incentives, may be needed.

Our presumption is that incentives ought to be symmetric but that a case-by-case approach to deviations from this can be appropriate, especially for the reasons given above. Symmetry is likely to have the least impact on the required WACC.

In general, we consider a regulator would move away from a symmetrical incentive because:

- the activity being incentivised is one where a minimum level of quality is required but higher levels are not valued by consumers; or
- the implications for the financeability of the company are such that limiting the downside is important but still retaining a greater upside is of benefit to consumers.

Moving to an asymmetric incentive could also have implications for the allowed WACC. Symmetry should have no impact on the WACC but asymmetry might, especially if it is a greater downside risk than potential upside benefit. However, consideration of whether the risk is associated with general market conditions or management actions should also influence the decision as to whether there is an impact on the WACC – if the cause of the risk is the former (general market conditions) then an impact is possible but if it is the latter (management actions) then there should be no impact.

2.5. Managing uncertainty

Various frameworks exist for assessing risk and uncertainty and how this should be captured by a price regulatory regime. One approach is to consider what is controllable by the network company (and so an ex ante revenue allowance and incentive can be set to promote the management of risk) and what is not controllable (either because the network company is unable to "opt out" of the activity, or the network operator cannot predict with certainty the expenditure over the price control period). Other considerations that should be taken into account include whether particular types of uncertainty can be separated from the overall commercial framework of the price control, and do risks in one area of the price control, impact on others.

Our analytical framework is summarised in Figure 2.1 below. It illustrates our differentiation of network risk and uncertainty according to price, volume/outputs and timing. We also differentiate whether costs and risks are controllable, partially controllable or non-controllable by the network company in order to assess who is best placed to manage the impacts of uncertainty and the appropriate regulatory treatment of expenditure.

Figure 2.1: Framework for assessing network risk and uncertainty

Controllable ↔ *Non-Controllable*

Uncertainty	Ex-ante allowance / incentive	Uncertainty mechanisms	Cost pass-through
Price	Unit costs	Inflation	Business rates or gas price
Volume / Outputs	Repairs / New connections	Smart metering	ISO establishment (PC2)
Timing	Reinforcement (required over 5-years)	Large project Reinforcements (e.g. SWOSS)	ISO establishment (PC2)

Source: CEPA

Figure 2.1 illustrates different components of the price control that might be captured by our risk assessment framework. So for example, unit costs are a price risk that can be managed by the network company and so an ex-ante allowance / incentive can be set. In contrast, business rates and the gas price incurred from shrinkage gas are less controllable by the network company and require an alternative form of regulatory treatment.

More generally understanding the sources of uncertainty, their implications for companies and customers and the different mitigation options (and the linked implications for companies and customers) is likely to be key to designing an appropriate uncertainty regime in PC3. Obviously there is a transparency / complexity trade-off to consider but it should be possible to better understand the causes of risk and uncertainty and so implement appropriate responses.

2.6. Summary

This section has considered certain principles associated with the design of incentive regimes for regulated companies. The section which follows reviews at a relatively high-level BGN's incentive and price control regime in PC2.

3. PRICE CONTROL PERIOD 2

This section reviews the outputs and incentives regime put in place for PC2 for both transmission and distribution controls.

3.1. Summary of regime

Table 3.1 provides a summary of the regulatory incentive regime put in place by the Commission for the PC2 period for both transmission and distribution.

Table 3.1: Key aspects of BGN distribution price control and incentive regime

Element	Distribution	Transmission
Form of control	Revenue-cap	Revenue-cap
Length of control	5-years	5-years
Headline control	CPI-0%	CPI-0%
Cap/Com split	80:20	90:10
Pass-through	Some 50:50 sharing	Some 50:50 sharing
Incentives	Rolling capex Connections incentive Volume of gas shrinkage Safety initiatives Rates	Rolling capex Rates CO2
Additional Opex efficiency	0.5%	0%
Other elements	Guidance for PC2 on: - Opex clawback; - Capex clawback; - Incentive retention; and - Reopeners	Guidance for PC2 on: - Opex clawback; - Capex clawback; - Incentive retention; and - Reopeners and triggers

Source: CEPA

3.2. Price control outputs

BGN was also set a number of outputs in PC2. These outputs were directly or indirectly linked to the incentives created by the treatment of expenditure in the price control, or specific incentive regimes put in place by CER for the networks businesses. In the case of distribution, these included a number of specific *observable* outputs for example the connection of 150,000 new customers, the addition of over 1,500km of mains to the network the introduction of gas to a number of new towns including those in Mayo-Galway and the role out prepayment metering to the rest of the country (then only available in Dublin).

For transmission, the CER did not specifically propose "outputs" but highlighted a number of benefits for the transmission customer over the life of the price control period. These included facilitating the connection of large I/C, development of new products (including short term products and development of the interconnector storage product), facilitating ongoing cost efficiencies and continuing to meet pipeline safety standards and address risks associated with disruption of supplies from onshore network issues.

3.3. Regulatory incentives

In PC2 the CER sought through its price control to provide strong regulatory incentives for BGN to make efficiency savings in the day to day operation of its networks business, and through efficient and timely investment in the network infrastructure and systems. This was primarily achieved through the treatment of expenditure in the price control. However, in addition to creating incentives by the treatment of expenditure in the price control, CER also put in place specific performance and behavioural incentives for the network businesses outputs, for example connections and the volume of gas shrinkage.

3.4. Investment triggers

For transmission, CER put in place arrangements to manage the uncertainty relating to the timing of the Corrib gas field production and significant uncertainty about both the timing and cost of any connection of any connection for an LNG terminal at Shannon. Triggers were utilised as the uncertainty mechanism. In the case of Corrib, a negative trigger was used. This meant that transmission tariffs were set with the assumption the project would go ahead as planned but revenues would be reduced or re-profiled if the project was delayed. The arrangements for Shannon were in contrast a positive trigger. This meant that revenues would be increased if the project was undertaken during the price control period.

3.5. Summary

The later sections of this report review the PC2 arrangements in more detail and assess what lessons might be learned for PC3 from the PC2 experience.

4. PRICE CONTROL PERIOD 3

BGN's business plan proposes a series of outputs which it proposes to deliver in PC3 and the revenue allowance is requires for those outputs. The associated capex and opex requirements are discussed in our other working papers while the context for the output areas proposed by BGN are discussed in the subsections below.

4.1. Proposed outputs

BGN has proposed seven outputs for PC3:

- promoting competitiveness – operating the networks efficiently and effectively;
- maintaining a strong customer focus;
- delivering a safe and secure network;
- promoting innovation and sustainability;
- successfully delivering the European Third Directive unbundling and market arrangements;
- financing its activities efficiently; and
- embedding the ITO and High Performance Utility Model (HPUM) structure.

We discuss the context to these outputs in the subsections below. Note that as the financial arrangements for PC3 are considered elsewhere in the price control review, we have not sought to comment on BGN's proposals in this area.

4.1.1. Organisational change

BGN highlights in its BPQ response that its networks business underwent major organisational change in PC2. This was focused on: "*significantly enhancing the work delivery and asset management capabilities within BGN* [following implementation of the NTP]. *BGN now operates a high performance utility model (HPUM), which places asset management at its centre*."[1]

BGN also established a separate ITO structure, systems and processes in PC3 to ensure it fully complies with the requirements of the European Third Gas Directive. This has meant BGN will now be separated from its parent company (BGE) subsidiaries of which provides retail services to the Irish gas market, amongst other business activities.

Amongst BGN's proposed outputs for the PC3 period is embedding this new organisational structure. Through the HPUM – including the outsourced contract model BGN has operated in the past – the company expects to operate efficiently in the PC3 period and to optimise the HPUM

[1] BGN (2011): 'PC3 Executive Summary – PR068'

model to the benefit of "the Network, Customers and Regulatory authorities, by ensuring management of the network is proactive, timely and efficient."[2]

4.1.2. Changes in gas markets

Changes *within* BGN's networks business have also taken place during a period of major change in the Irish gas market.

The Irish gas market is now open to competition and the entrance of Airtricity and Electric Ireland has resulted in a major boost to gas domestic retail competition.

As BGN highlight in their BPQ response, there are also potential changes to the gas market arrangements in PC3, emerging from the requirements of the European Third Gas Directive (development of European gas codes) and joint work between the CER and NIAUR in shaping the Common Arrangements for Gas (CAG) framework.

4.1.3. Sustainability, competitiveness and security of supply

The Irish Government has put in place a strategic energy framework for Ireland that states amongst its objectives, sustainability, competitiveness and security of energy supply.[3]

BGN's PC3 business plan suggests certain reinforcement activities on both the transmission and distribution networks are required to contribute to the security of supply objective. It also highlights promotion of safety as a "leading company value".

BGN has also proposed an innovation funding scheme for the PC3 and included the fast rollout of smart meters in its business plan, both of which are expected to contribute to the environmental targets and sustainability of the Irish economy. As discussed in the later sections of this report, BGN has proposed that a Gas Innovation Group be established and an associated governance and funding mechanism for innovation in PC3.

4.1.4. Customer focus

BGN also highlights its intention to maintain a strong focus on customers in PC3. This includes an objective to outperform its customer charter targets and achievement of customer service Key Performance Indicators (KPIs). BGN also proposes to help customers in financial difficulties through its customer engagement programme, prepayment meters and roll out of smart meters. Finally, BGN plan to grow the network through significantly increasing its "sales effort and market development activities over PC3 in order to increase our customer base."

4.1.5. Incentives and price control mechanisms

[2] BGN (2011): 'PC3 Executive Summary – PR068'

[3] DCNER (2006): 'Delivering a sustainable energy future for Ireland'

While BGN has not made a proposal on the overall structure of the price control, and the overall opex and capex incentives, it has commented on specific incentives for certain areas of expenditure, for example gas shrinkage costs. Specific incentive arrangements BGN has proposed are discussed in the sections which follow.

There is also uncertainty around the timing of certain impacts on BGN's networks business and what BGN believes it may need to deliver in PC3. For example, uncertainty over the volume of work that may be needed to implement changes to the gas market arrangements.

For these items, it is seeking uncertainty mechanisms, including the capacity for price control reopeners or more specific investment triggers in certain cases. The case for investment triggers is based on the precedent of their use in PC2 and BGN's view that there is uncertainty of the timing of certain events and investments.

There are also a number of activities and costs that might be considered outside BGN's control. These are termed pass-through items, as aspects of the price and/or volume of work is considered not to be controllable by BGN. In its business plan, BGN has retained items that were deemed by the Commission to be pass-through in PC2 as pass-through in PC3.

4.1.6. Summary

Given this context, BGN has linked its future capex and opex requirements in PC3 to high-level outputs that support the delivery of identified objectives or programmes within these broad areas. The key points to note (in our view) are that BGN has proposed to implement a HPUM within an ITO structure in PC3 that focuses on asset management *and* customers / users of the gas networks in Ireland.

4.2. Precedent

BGN's price review needs to be considered within the specific context and objectives of the gas sector in Ireland. However, while there are unique circumstances affecting its networks business, this does not prevent lessons potentially being learnt from other network operator price controls in Ireland and other parts of European.

Annex A summarises the outputs Ofgem is seeking to put in place for the GB GDNs in the forthcoming gas distribution price control. Annex B illustrates the incentives already in place for the current gas distribution price control in GB.

Perhaps the key point to note as regards the GB GDNs is that the outputs and incentives regimes proposed by Ofgem are focused on asset management strategy to deliver objectives such as network reliability, safety and availability. Incentives are linked to GDN delivery of *outcomes* rather than just successful delivery of investment plans. A good example is for safety related activities where Ofgem is seeking to target "removal of risk" through the price control arrangements rather than replacement of "x km's of pipe".

The complexity and feasibility of such approaches of course also needs to be considered. However, what the RIIO approach illustrates, is that for network businesses where the focus is asset management rather than a targeted rollout of investment in infrastructure, careful thought is needed from the regulator about how it can create the right incentives on the network operator to manage these activities through asset management functions but also consider possible alternative (in some cases more cost effective) solutions to network investment.

4.3. Consortium views

There have been two previous multi-year determinations of revenue requirement for the Irish gas transmission and distribution networks, with the current one (PC2) operating until 2011/12. The gas industry in Ireland is one where the bulk of the infrastructure is now in place and while this does not mean that there will be no proposed investment, what it does mean is that the investment plans for PC3 need careful analysis to ensure that they are appropriate. An ITO structure is also now in place while previously BGN was more closely integrated with BGE.

The activities the CER might expect BGN to deliver for customers in PC3, and the regulatory incentives and price control arrangements used support delivery, may as a result need to change to accommodate these changes. For example, with the bulk of infrastructure in place, CER might expect BGN to maintain and develop an economic and efficient network through greater consideration of the alternative solutions to investment (through system operation measures) and the impacts and trade-offs of not undertaking investment.

This raises issues such as the role of IT in network operation and management, and the types of expenditure and incentives that might be needed to support an asset management capability. GDNs in GB underwent similar network IT and investment projects to BGN following the GDN sales in 2005.[4] As well as by network sales, this was driven by the need for an asset management capability for a mature network asset base, a capability BGN highlight as important for its networks business in the future.

Many of the high-level outputs BGN has proposed in its business plan for the PC3 period are, in our view, wholly appropriate for a gas ITO business seeking to operate as a HPUM similar to the GDNs. In particular, we note:

- Given the organisational change and the investment BGN has made in its systems and processes in PC2 to enhance work delivery and asset management capability, BGN's commitment to ongoing efficiency across its network business.
- We are supportive in principle of an innovation funding scheme for the Irish gas industry provided it is focused on innovation, for example research and development, involves a range of industry stakeholders and demonstrates value for money for the consumer.

[4] See for example:
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=19&refer=Networks/GasDistr/GDPCR7-13

- We are also supportive of BGN's focus on asset management capability given the rollout of the gas network in Ireland and the HPUM structure. It continues to be important for BGN to deliver a safe and secure gas network for Ireland.

However, as illustrated by the case of the GB GDNs, CER needs to apply careful thought to how BGN's changing network activities and outputs are captured by the service performance and behavioural incentives it creates for the networks business. This includes the more general incentives created through treatment of different types of expenditure in PC3.

As we explore in the later sections of this paper, given the HPUM structure has only recently been implemented, it would be sensible in the large part to retain the PC2 incentive regime (where elements remain appropriate). This can allow the management processes to bed down within BGN's business and more data to be collected on actual performance of the HPUM.

However, looking forward to PC4, the CER may wish to consider how the incentive regime created through the price control arrangements could be linked much more closely to the objectives and outputs of BGN's HPUM. The experience of the GDNs under Regulatory Incentives Innovation and Outputs (RIIO) GD1[5] may provide useful lessons in this regard.

What we have sought to achieve in this paper however, is to provide a high-level review of the incentive regime in PC2, and given BGN's PC3 business plan, and our own analysis of future capital and operating expenditure, how the current incentive arrangements can support the changing network activities and regulatory outputs in PC3.

4.4. Summary

In this section we have considered the outputs BGN has proposed for PC3. This forms the basis for our assessment of the incentive arrangements in place for PC2 and their continuing applicability in the PC3 period.

[5] RIIO-GD1 will be the first gas distribution price control review to reflect the new regulatory framework resulting from Ofgem's RPI-X@20 review.

5. OPERATING EXPENDITURE INCENTIVES

Opex is a key element of the cost base. Therefore, the price control regime needs to create the right incentives for BGN to manage its opex activities effectively.

5.1. Objectives

What is the desired outcome from an opex incentive? Ideally, a company should be delivering its services as cost effectively as possible while doing this in a sustainable manner. It should also be doing this in a way such that appropriate decisions about the mix of capex and opex is based on the lowest life-time cost of the solution, rather than an arbitrary effect of different incentive rates.

An opex incentive also has an informational role within the price control framework. When developing a network monopoly price control, there is an asymmetry of information between the regulated network company and the regulator, with the regulated company having an informational advantage over the regulator.

The asymmetry of information problem makes developing a forward-looking (ex-ante) price control challenging for the regulator. An opex incentive can help to incentivise the regulated company to reveal its actual operating costs (given established regulatory outputs and deliverables) necessary to establish a business as usual or base year level of costs at the next price control review.

Apart from the general incentive to reduce operating costs, there can also be specific incentives linked to specific cost items. For example, cost items where there is a great deal of uncertainty over aspects of the cost base or the output being delivered. Aspects of the cost item may also be largely outside the control of the regulated network company.

Here the objective (or outcome) might be provide an incentive on the regulated company to manage an element of its cost base (where it has some ability to influence the level of costs) but also have in place arrangements that limit the company's exposure to large variations in cost. For example, through within price control sharing arrangements with customers.

5.2. PC2 incentive arrangements

CER set a revenue cap for BGN's distribution activities in PC2. As was noted by the Commission in the PC2 decision paper, in theory an overall revenue cap provided a strong regulatory incentive for BGN to make efficiency as it retains the savings for the remaining period of the price control.

CER also increased the length of the price control from a four year control in PC1 to a five year control in PC2. This increased the incentive strength (compared to PC1) by providing more certainty to BGN and increasing the retention period for any opex efficiency savings the company was able to make over the PC2 period.

The overall revenue cap was supplemented by regulatory guidance provided by CER for the price control period. This sought to clarify incentive arrangements for opex. CER proposed for overall operating costs, i.e. other than for pass-through items (see below), it was for BGN to manage actual outturns within its revenue allowance. CER proposed it would not in general expect to clawback overall or individual items for which there was under spends of opex.

However, neither did CER expect to allow BGN to recover higher costs at an overall or individual level. Consistent with the revenue cap for opex allowances, BGN was expected to manage overspends within the overall revenue allowance. Overall, this provided a relatively strong incentive to control costs and make efficiency savings.

While the majority of BGN's operating costs were include in the revenue cap for PC1, a different incentive was created around a small number of pass-through items. Following the structure of the price control in PC1, these cost items were treated as pass-through because they were considered largely outside the control of BGN.[6] These are discussed in Section 8. There was also a connection incentive / revenue driver outside the revenue cap.

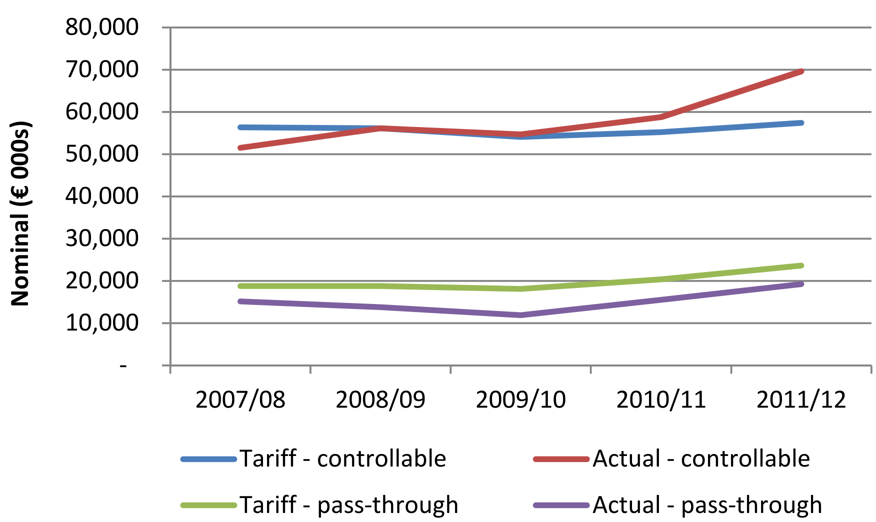
5.3. Lessons learned from PC2

The consortium's working papers on historical distribution and transmission opex reviews outturn in detail. Here we focus on general evidence BGN has responded to the incentives put in place in PC2 and the value the incentive arrangements have provided in PC2.

5.3.1. Outturn - distribution

Figure 5.1 sets out BGN's total controllable and non-controllable opex allowance for each of the gas years in PC2, as well as BGN's outturn expenditure.

Figure 5.1: Outturn distribution opex vs. PC2 targets



[6] Which items were treated as pass-through in PC2, and should continue to be treated as pass-through in PC3, is discussed in Section B. Here we focus quite generally on the incentive structure for pass-through costs.

BGN is projecting to under-spend relative to its opex allowances in four of the five years of the PC2 period, resulting in under-spend of €12.9m for the period as a whole. The overall under spend was driven by savings on pass-through (non-controllable) costs, while there is predicted to be an *overspend* against other parts of the opex allowance in PC2 (controllable opex).

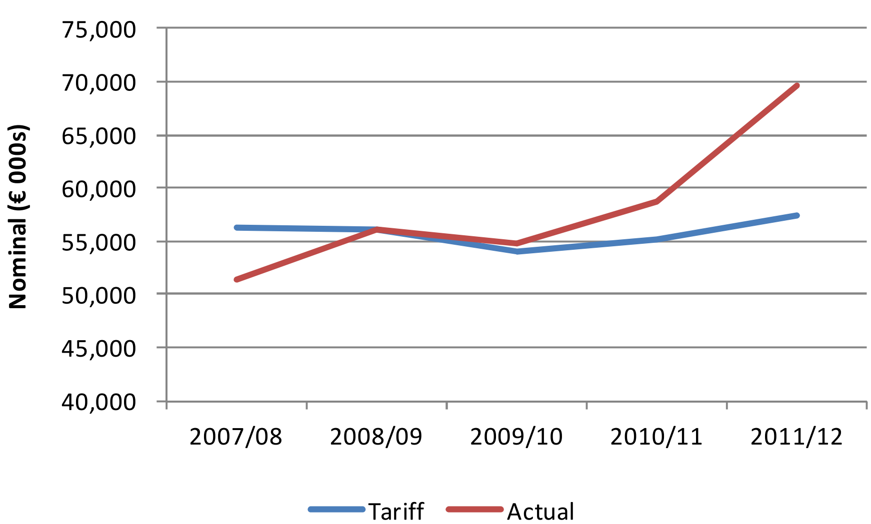
Under the regulatory incentive arrangements for PC2, BGN are not seeking to recover the over-spend on the direct opex allowances. Consumers have benefitted from the savings BGN has made against pass-through item allowances in PC3 – the share of savings (i.e. incentivised in a number of cases) have been returned to consumers through the K-factor mechanism.

5.3.2. Discussion - distribution

The outturn for opex overall illustrates that there is some evidence that BGN has responded to the overall opex incentive created by CER through the revenue cap. As discussed in the historical distribution opex report, the variation in the expenditure profile shows that BGN is capable of delivering to the required service standards at varying levels of annual operating expenditure. The arrangements have also provided protection for consumers given the overspend in controllable opex relative to the revenue cap.

The periodicity of the price reviews may also have had an incentive effect on BGN's business. As illustrated by Figure 5.2 below, BGN's *controllable* opex came in below the tariff allowance in the first two years of the price control period while the company has over spent in the remaining years. Although this observed trend may also be due to cost drivers highlighted by BGN in their historical BPQ submission for PC2.[7]

Figure 5.2: Outturn controllable distribution opex (excluding Gaslink costs)



[7] BGN state that the overspend is driven by a step up in maintenance activities as a result of moves towards condition based maintenance and the identification of a number of unforeseen maintenance requirements.

As is explained further in the other working papers, it is not clear the overall opex incentive has been as successful (in the PC2 look back) in helping to facilitate setting a base year opex target. Partly this is due to significant restructuring of BGN's distribution business linked to the NTP and the establishment of the ITO which has meant selecting a base year that accounts for the step up in costs has been more difficult than in the past.

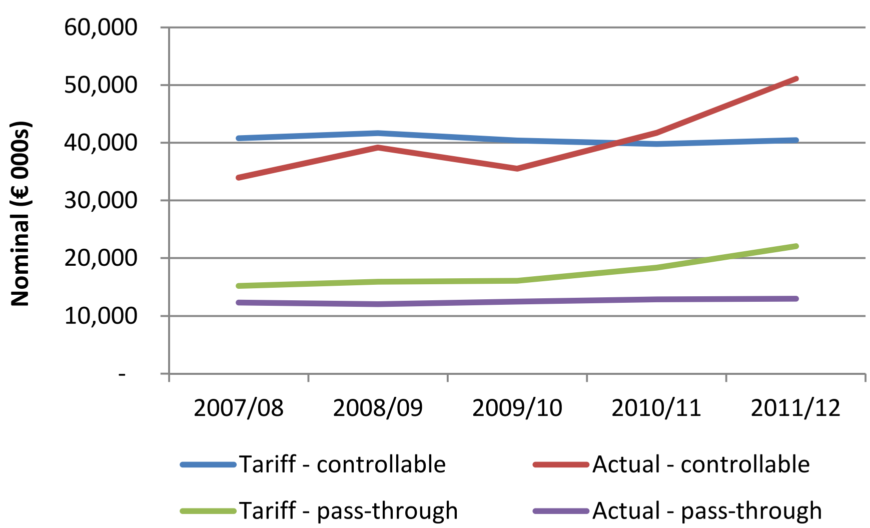
Perhaps the key lesson from the outturn for direct controllable opex is that during the initial two-three year period of PC2 (pre-implementation of the major restructuring programmes and before the economic downturn) BGN demonstrated an ability (and willingness?) to respond to the opex incentive target, or at minimum control costs within the revenue cap set by CER at the price control. With the ITO and HPUM restructuring, this means more than ever care needs to be given to the base year opex target selected for PC3.

One way to address this is issue is through benchmarking of BGN operating expenditure against similar gas ITO businesses, such as the GB GDNs. How BGN benchmarks against the GDNs is discussed in our separate benchmarking report.

5.3.3. Outturn - transmission

Figure 5.3 sets out BGN's total controllable and non-controllable opex allowance for each of the gas years in PC2, as well BGN's outturn expenditure.

Figure 5.3: Outturn transmission opex vs. PC2 targets



Source: BGN and CEPA

Total opex is projected to be 9.1% lower than the CER allowance for PC2. Total opex before pass-through and Gaslink costs was 0.5% lower than BGN's allowance for the PC2 period meaning the majority of opex savings have been through pass-through (non-controllable) expenditure (part of which is incentivised in PC2).

5.3.4. Discussion - transmission

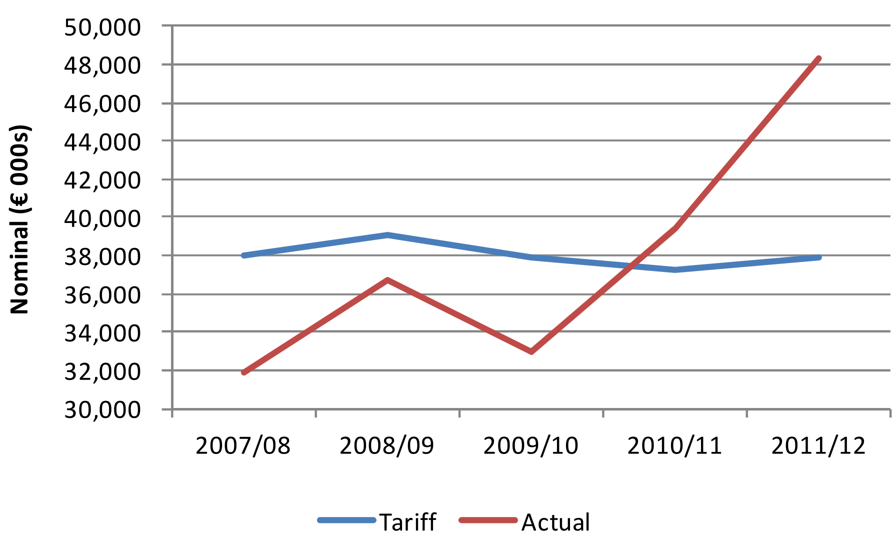
Figure 3.3 illustrates similar trends as the distribution control. The under spend relative to the allowance is principally driven by savings on pass-through (non-controllable) expenditure (discussed later in this report) and therefore we have also reviewed outturn transmission expenditure before Gaslink and pass-through items (see Figure 5.4).

Again, as with distribution, the outturn expenditure shows that BGN is capable of delivering to the required service standards at varying levels of annual opex, although we note that transmission opex (as compared to the distribution business) is more lumpy by nature, which creates a natural variation in year on year spend as illustrated by Figure 3.3.

Overall though BGN has managed its transmission business expenditure within the revenue cap driven by an under spend against its allowance for the first three years of PC2. As for distribution, the trends in actual expenditure demonstrate the importance - given the incentive regime for opex - of setting an efficient base year level of costs.

There is an interdependency here with BGN's HPUM. The PC2 period has seen significant IT investments and organisational restructuring to allow BGN to operate its networks more efficiently and effectively and the need to develop a greater asset management capability. Our papers on transmission and distribution opex and capex note these investments should deliver value for money for the gas consumer in *PC3* through an *efficient baseline allowance* for the forthcoming price control period, potentially including an ongoing efficiency target for the different components of the networks business. The incentive arrangements for opex in PC3, however, should be used to incentivise BGN to identify further *unanticipated* savings in PC3.

Figure 3.4: Outturn transmission opex vs. PC2 targets (excluding Gaslink costs)



Source: BGN and CEPA

5.4. Assessment and proposal

BGN has not made a proposal on the structure of the price control, including the revenue cap and opex incentive, as this is determined by the CER.

We continue to believe that a revenue cap provides strong regulatory incentives for BGN to make efficiency savings. Therefore, in line with CER's PC3 position paper, we propose the CER retain a revenue cap for the vast majority of BGN's controllable transmission and distribution opex. The exception to this is the connections incentive discussed in Section 5.

We note the major restructuring of BGN's business in PC2, notably the organisational change and IT investment from the NTP.

BGN's own BPQ submission highlights a key objective of the programme was to drive efficiencies and business benefits for its networks business. These benefits should be clearly reflected in the *baseline allowance* set for both transmission and distribution PC3 and potentially an ongoing efficiency target for the different components of the networks business. The objective of the opex incentive regime, however, should be to incentivise BGN to control costs within its allowance and to realise *unanticipated* savings in PC3 that can be shared with consumers in future periods.

Given BGN's outturn in PC2 relative to the incentive regime and allowances set by CER, careful thought must be given to setting a baseline level of costs moving forward into PC3, given the proposed opex incentive regime. Benchmarking of BGN relative to similar gas ITOs has an important role to play in setting that baseline.

6. CAPITAL EXPENDITURE INCENTIVES

One of the most important elements of cost for a regulated network utility is that linked with capex. This section briefly reviews issues around capex incentives including the guidelines that the CER provided to BGN for PC2.

6.1. Objectives

What is an incentive for capex trying to achieve? Ideally the best outcome for customer is that the company is incentivised to provide a sustainable service as cost effectively as possible. This means that focusing on the service provided to customers is the key while ensuring that appropriate long-term approaches are being employed.

6.2. PC2 incentive arrangements

Under PC2 regulatory arrangements, BGN is rewarded for making savings against their capex budgets through their Regulatory Asset Base (RAB). Prices were set at PC2 on the basis of an opening RAB value together with a stream of projected capex figures (set out in PC2 decision) for projects approved by the CER.

In general terms, where BGN was able to achieve a saving compared to its projected investment PC2 allowance in a given year, then it would be allowed to earn the rate of return plus a depreciation payment on the expenditure saved. It would retain this benefit for five years, at which point the RAB and depreciation payments are recalculated on the basis of actual investments.

The capex incentive is thus a rolling incentive mechanism that allows BGN to retain the savings from cost savings for the same length of time (i.e. five years) regardless of when the savings on investment were made in the price control. This arrangement was put in place to avoid adverse incentive effects that are created if the networks business was only able to retain the efficiency savings up to the point of the next price control review.

As with operational costs, CER supplemented this regime with specific guidance on how it expected to approach assessing under and over spends of capex. This was to provide clarity to BGN on how CER expected to approach these issues in PC3 both for efficiency savings (i.e. where projects went ahead as planned) but also where specific projects were not carried out or deferred by BGN. In summary, this guidance included:

- Where a capex underspend arises because a project was completed at lower cost than anticipated when the control was set, then BGN would retain the benefits of this underspend for five years from the date of inclusion in the notional RAB, but the actual rather than forecast capex incurred would be put in the RAB at the end of the five years.

- Where the underspend arises because BGN had not carried out or deferred a project, CER will reach a view on whether this was an efficient deferral. Where the deferral is deemed efficient BGN will in general retain the depreciation and return earned for the project in PC2, but *no value for the project* will be added to the starting RAB for PC3.

- Where an overspend arises because a project has been completed at higher cost than anticipated when the control was set, CER would not generally expect to remunerate BGN for financing these higher capex costs in PC2, but would consider whether all the actual capex incurred should be included in the starting RAB for PC3.

This guidance provided an incentive for BGN to *efficiently defer* projects where these were considered unnecessary by the networks business in addition to the rolling capex incentive for efficiency savings (i.e. where projects went ahead). In providing this guidance, CER noted that its objective was to improve certainty for BGN and thereby improve the company's incentives to make efficient savings and investment decisions.

6.3. Lessons learned from PC2

6.3.1. Outturn – distribution

BGN define six categories of distribution capital expenditure in PC2:

- Original tariff allowance – this is the capex allowance for PC2 set by the CER.
- Inflated allowance – this is the original tariff allowance inflated.
- Flexed allowance – this the CER allowance realigned to actual quantity delivered.
- Actual – this actual expenditure incurred by BGN in the price control period.
- Scope Variance – the difference between the Tariff Allowance and the Flexed Allowance.
- Efficiency Variance – the difference between the Flexed Allowance and Actual.

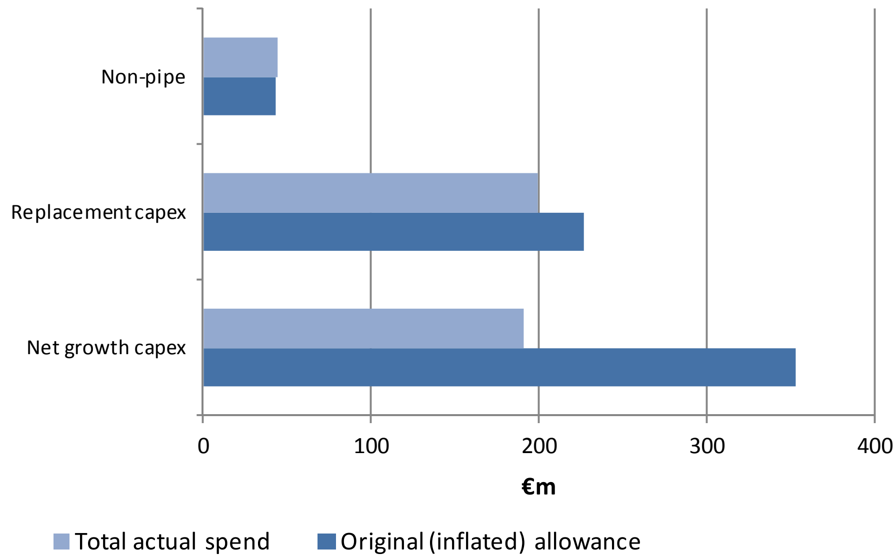
In distribution, growth capex items (connections) are managed through the annual K-factor process and so any Scope Variances against customer connections targets (on which the original allowed revenues were based) have already been accounted for by BGN in their annual tariff review and K-Factor adjustment process (see Section 7).

For those areas outside the K-Factor process (e.g. replacement expenditure) BGN has chosen to present its PC2 expenditure by rebasing the original tariff quantities to the actual (flexed quantity) delivered[8], valuing these quantities at the tariff unit cost (to derive a flexed allowance) and then comparing this to the actual spend to give the Efficiency Variance. The difference between the inflated tariff allowance and the flexed allowance gives the Scope Variance for growth (non-connections) and replacement expenditure.

[8] For example, km of main or units of services and meters delivered.

The outturn of BGN distribution capex spend has been significantly less than the PC2 allowances. BGN has under-spent 30% or €188m of its total allowance of €624m. This is driven by an under-spend of 46%, or €161m in growth related capex, and by an under-spend of 12%, or €27m in replacement related capex, and an over-spend of 1% or €0.6m in non-pipe capex. This is shown in the figure below.

Figure 6.1: Outturn distribution capex [9]



Source: BGN and CEPA

While an under spend in distribution capex is observed at the total allowance level, at a distribution capex category level, the PC2 outturn has been a lot more variable. There have been categories of capex where BGN has under spent against the allowance, either because the scope of work undertaken was significantly less than that at envisaged at the price control review or BGN was able to find efficiency savings on work actually completed.

There have however also been categories of capex where BGN has over spent the allowance either because of an increase in scope (for example, the pre-payment metering programme approved by CER) or the business was unable to achieve the unit cost targets set for the price control period because of factors under and outside the control of the operator.

BGN's own analysis concludes that €12.23m of revenue will need to be refunded to customers as a result of the unspent capex outside of the K-factor process. BGN expect to offset this by the allowed revenue to be earned beyond the PC2 period under the 5 year rolling incentive (amounting to €2.52m). The net position amounts to a €9.7m give back to consumers (additional to the amounts already given back under the annual K-Factor process).

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[9] Growth related capex is net of customer contributions.

6.3.2. Outturn – transmission

Outturn expenditure variances on transmission capex was analysed and allocated by BGN according to four pots / categories:

- Pot A identified the actual spends on Transmission capex during PC2. All approved capital spend goes into the BGN RAB on the commissioning date of the project.
- Pot B identified the expenditure variances attributable to capital projects that were Efficiently Deferred.
- Pot C identified the variances attributable to efficiency savings achieved on projects that have been completed or are under construction.
- While Pot D identified the variances that were classed as Non-Spend and where revenue was not proposed to be retained on outturn variances.

The outturn of BGN's transmission capex spend has also been considerably less than the allowances. Total transmission capex spend in PC2 is estimated to be €159.9m compared to an allowance of €235.1m. BGN argue a large part of the under-spend relates to a combination of efficiency savings and efficient deferral of projects resulting from changes in circumstances across its transmission business (BGN's definitions of spend are discussed below).

Of the total capex variance (€75.2m under-spend) BGN has identified €17.9m as Non-spend and are proposing to return the full revenue earned in the period associated with these monies (c. €4.3m). The remaining €57.25m they argue was delivered through optimising the Scope, finding Efficiency savings (on projects that went ahead) or Efficient Deferral of capex projects as illustrated below.

Figure 6.2: Outturn transmission (PC2 and 2006/7) – actual prices (€m)

	Tariff	Actual	Variance	Scope	Efficiency	Efficient deferral	Non-spend
Onshore	189.6	113.1	76.5	8.9	21.3	27.3	18.9
Inch	1.6	0.1	1.5	-	-	1.5	-
IC	14.0	11.4	2.5	-	0.2	3.3	-1.0
Total - pipe	**205.1**	**124.7**	**80.5**	**8.9**	**21.5**	**32.1**	**17.9**
Non-pipe	29.9	35.2	-5.3	-5.3	-	-	-
Total	**235.1**	**159.9**	**75.2**	**3.6**	**21.5**	**32.1**	**17.9**

Source: BGN

For transmission, BGN expect to offset the €4.3m returned to customers from Non-spend capex by the revenue to be earned beyond the PC2 period for efficiency savings under the 5 year rolling incentive (this amounts to €1.75m). The net position on transmission capex (as proposed by BGN) therefore amounts to a €2.52m give back to customers in PC3.

6.3.3. Outturn – overspend

As discussed above, captured within an overall under spend against both the transmission and distribution allowances there are also a number of examples of overspends against the CER's original allowances. There are examples where BGN argues there has been a *negative scope* variances (i.e. where BGN delivered greater volumes in PC2 than was envisaged at the price review) and there are examples where BGN has also delivered the expected volume of work but overspent compared to what it proposed was required at the price control review (negative efficiency variances).

6.3.4. Discussion – distribution and transmission

There are a number of ways BGNs outturn expenditure against the regulatory allowance for capex could be interpreted at PC3.

On the one-hand "an incentive is an incentive" and while BGN has been able to outperform the allowances through efficiency savings *and* deferral of specific capex projects, consumers in the long run will benefit from these savings - this is the objective of the incentive. The guidelines and rolling incentive were put in place to incentivise BGN to find efficiency savings and avoid growing the RAB where a deferral would have been more sensible. The regulatory guidelines appear to have achieved both those objectives.

On the other hand, some of the benefits from deferrals in particular, which BGN proposes to retain in PC2, relate to the economic downturn and events where the project sponsor, i.e. the customer, made a commercial decision not to proceed with a particular project. While avoiding these works has been efficient, it may be arguable whether the savings were all *controllable* by BGN's businesses.

Perhaps the most interested point highlighted by BGN's PC3 submission (from an incentives perspective) is the company argues it has actively carried out its activities in PC2 in *response to* the capex guidelines set by CER. This is illustrated in both the historic transmission and distribution capex working papers where BGN has sought to analyse variance on capex for specific projects against the criteria that were set by CER at PC2. This in part demonstrates that BGN has actively sought to respond to the regulatory incentives put in place by CER for PC3.

It also highlights the importance of the definitions and boundaries of different categories of expenditure categories given the different incentive arrangements that apply in each case. As discussed in the transmission and distribution capex and opex reports, we believe the boundaries between the allocations of non-spend, scope changes, efficient deferrals and efficiency savings have been 'blurred' by BGN in some cases. This is a key point to note when considering the arrangements for PC3 in our view.

The rolling capex incentive seems to have worked reasonably effectively at helping to remove the well known regulatory time distortion effect of 5-year price review processes. BGN has sought efficiency savings on its capex projects for both transmission and distribution over the course of the price control period.

It is also important to pause and recall the objectives of this incentive. While BGN has made significant efficiency savings in some categories of expenditure, and this has contributed to the returns the operator has achieved within the price control, reviewing detailed project proposals for capex is notoriously difficult for the regulator although the volume / requirement for the work can be more easily assessed. The rolling incentive provides a mechanism for BGN to benefit from efficiency savings and so seek out such reductions, while allowing consumers to benefit over the longer term through adjustment to the RAB.

The fact efficiency savings have been achieved in PC2 should be considered a success given without such an incentive arrangement, the network operator would primarily be incentivised to grow the RAB as large as possible.

6.4. Assessment and proposal

6.4.1. Review of outturn

The objectives of the rolling capex incentive and guidance at PC2 were to strengthen BGN's incentives to make efficient savings and investment decisions in PC2. The PC2 framework, in part, seems to have achieved this. In our view, BGN should be rewarded for making efficient decisions and, therefore, where it has demonstrated that savings made against its capital allowances were indeed efficient, then a clawback should not be sought at PC3.

For example, for efficiency savings, we believe it would be inconsistent to seek to a clawback from BGN given the guidance provided at PC2, and that in these cases the capital projects actually went ahead. Users of BGNs networks can expect to benefit from these savings in PC3 through the rolling incentive arrangement.

Similarly given the regulatory guidance put in place, BGN *should not* be remunerated for financing higher capex costs in PC2 where there has been an overspend on capex categories or projects (whether a negative scope or efficiency variance).[10] CER put in place a revenue cap in PC2 to provide an incentive for BGN to find efficiency savings *and* control capex costs.

Indeed BGN was allowed a pre-tax return on capital of 5.2 per cent by the CER in PC2 to reflect the financing and operational risks of its transmission and distribution networks businesses including the delivery of capital projects.

The overspend on capex should also only be included in the RAB where BGN has clearly demonstrated to CER that the actual capex was efficient. We provide our view on such overspends in our opex and capex reports.

Our view on efficient deferral is that the burden of demonstration, that the deferred expenditure is 'efficient', lies with BGN and must be justified.

[10] We believe the regulatory guidance for PC2 is clear that CER would take a cost category approach to assessing under and overspends in distribution and a project by project approach to assessing under and overspends in transmission.

Again as outlined in our opex and capex reports, we do not consider that project sponsors, i.e. the customer, who make a commercial decision not to proceed with a particular project amounts to efficient deferral by BGN. Neither can the outturn for PC2 be divorced from the reality of the unanticipated macro-economic environment in Ireland and the impact this has had on both BGN's gas transmission and distribution businesses in PC2.

We have, therefore, sought to analyse BGN's proposals for efficient deferral according to the following assessment criteria:

- Controllability – was the deferral driven by BGN decision making or events outside of BGN's control?
- Proportionality – are project savings (and the revenue benefits) proportionate given the operating environment and regulatory framework in PC2?

For the controllability criteria, we have focused on the customer role – i.e. how did network users or specific project sponsors affect the project deferral decision;

A review of outturn transmission capex against these criteria is provided in the opex and capex report. In general, we conclude BGN should retain part of the benefit (c. 41% of BGN's total request) received in PC2 from efficient deferral, given the regulatory framework put in place at PC2. Where we have disallowed efficient deferrals, and propose the CER seek a clawback of the revenue, this is generally because we believe the project was intricately linked to a customer decision rather than BGN demonstrating efficient decision making.

6.5. Proposal

Strong capex incentives are important for capital intensive businesses such as BGN. We therefore propose that CER seek to retain the rolling capex incentive mechanism for both transmission and distribution revenue controls in PC3.

While certain aspects of the regulatory guidance on capex incentives have worked better than others, partly we believe this is a result of the challenging operating environment that we have reviewed BGN's outturn capex against.

In our view, the regulatory guidance and incentives for capex have gone part of the way to meeting their stated objectives in PC2 and should, therefore, in principle be retained in PC3. We believe this is particularly important in the context of the significant changes to BGN's networks business since the PC2 review. In particular, the move to a HPUM and asset management capability. Strong capex incentives need to be maintained on BGN to:

i. find efficiency savings when capital projects do go ahead (for example, large and uncertain capital projects like smart metering); and
ii. seek long term solutions which may or may not involve capex to deliver the desired outcomes by consumers and the CER.

CER may wish to revisit aspects of the capex incentives and guidance (for transmission and distribution) to provide greater clarity particularly around the criteria and boundaries of different definitions of expenditure. For example:

- whether overspends are managed and assessed at a project (transmission) or category level (distribution) or managed as a large 'bucket' in PC3;
- ensuring the regulatory incentive arrangements provide appropriate and balanced incentives for capex and opex;
- clearer definitions of what constitutes an efficient deferral (the criteria above provide our view of the types of issue that need to be accommodated here); and
- a clearer definition of the boundaries between variance categories such as scope and true efficiency savings.

7. CONNECTIONS INCENTIVES

In this section we consider the connections incentives in the gas distribution control.

7.1. Objectives and PC2 incentive arrangements

At PC2, CER wanted to ensure that appropriate incentives were maintained for BGN to connect new customers to the distribution network, whether as one-off connections or new housing developments. All gas customers on the distribution network in Ireland benefit from additional connections to the system as there are more users and units of capacity and throughput over which to spread the largely fixed costs of running the network.

Therefore, CER decided to retain the positive incentive introduced in PC1 for BGN to maximise the number of new connections to its systems. This involved setting a capex allowance for a forecast number of new connections in the determination. Any additional connections beyond this baseline were then expected to be subject to a *single* unit cost incentive. The allowed revenue formula for the distribution control also enabled BGN's revenue to "flex" depending on actual capex incurred for new connections.

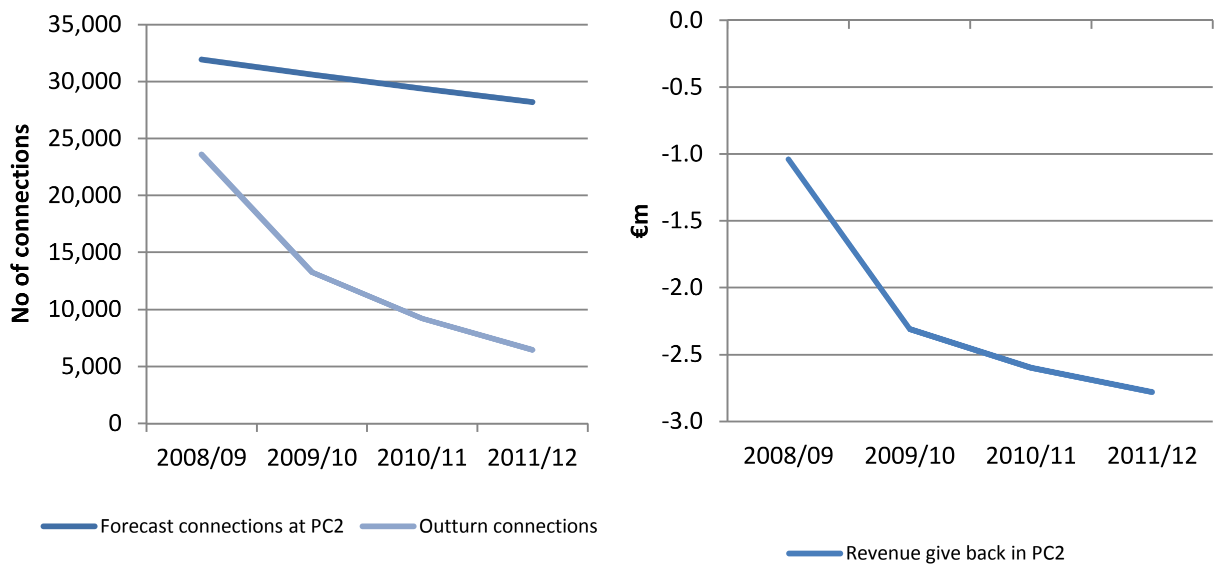
7.2. Lessons learned from PC1 and PC2

At the PC2 decision, the Commission noted that in its view the incentive for new connections that had been in place during PR1 had worked reasonably well and as intended, as BGN sought out additional connections. It also noted that BGN had responded to the unit cost incentive by focusing on lower average cost connections, e.g. for new housing developments, rather than more expensive one-off connections.

In PC2, the connections incentive has not been effective as a *positive incentive* because of the macro environment in Ireland and its impact on the gas market. As BGN note in their PC2 look back, significant network growth for the gas network had been projected in the domestic sector as a result of new build activity (reflected in the outputs and allowances set for the distribution control). There was instead a dramatic fall off in housing completions during the period. This means BGN has largely been unable to respond to the positive incentive set by CER in PC2.

Instead the incentive arrangements have worked closer to a price control uncertainty mechanism. Decreases in new customer connections have resulting in a decrease in BGN's revenue allowance as the actual connections fell below the connection projections on which the original (PC2) allowed revenue were based. Each tariff year BGN has determined a revised allowance based on the revised connections against the PC2 projections. This is illustrated in Figure 6.1 in both number of connections and allowed revenue terms.

Figure 6.1: Connections incentive in PC2



Source: CER and CEPA

7.3. Assessment

Does a similar incentive and revenue control arrangement for connections continue to be appropriate for PC3? In principle yes, since all consumers benefit from sharing the largely fixed costs of the network. The arrangement has also allowed under spend in capex (in revenue terms) to be returned to customers in a timely manner within the PC2 period.

There are however, a number of issues to consider here:

- Firstly, what is the objective of the connections incentive? In PC2, the arrangement has largely operated as an uncertainty mechanism rather than incentive for BGN. Do both those objectives continue to be appropriate in PC3?
- Secondly, what has BGN proposed for customer connections in PC3? What are the principle drivers of network development from a connections perspective in PC3 and what does this mean for the connections incentive arrangements in the price control?
- Finally, what changes might be considered for the connections incentive assuming the arrangement is retained? At PC2 CER considered whether a single unit cost incentive distorted BGN's incentives given different actual unit costs for types of connection.

We consider each of these issues below.

7.3.1. Objectives of a PC3 connections incentive

BGN note in the PC3 submission that the emphasis of the networks growth strategy for the PC3 period will be on increasing penetration of the existing network footprint. This includes the development of a programme of infill projects over the course of the PC3 period, a modest recovery in terms of new housing connection numbers, a few new towns and maintaining annual I&C connection levels.

Given the uncertainty around these connections, and therefore the capex of BGN in PC3, it seems sensible to retain an arrangement that requires the operator to flex its allowed revenue depending on actual connections versus projections. As regards the positive incentive arrangements for new connections above the price control baseline, again we consider this to be a sensible arrangement.

Therefore, in our view, while it remains sensible to retain the connections incentive, going forward we believe that the incentive should be used with the objective of a "revenue driver" as new connections come forward through the gas market, rather than a arrangement to support a wider opex allowance for market development activities.

7.3.2. What changes might be proposed in PC3?

We have considered the option of adopting different unit cost incentives for different types of new connection. Our analysis of is summarised in Table 6.1. It highlights pros and cons with both the existing approach and the alternative (i.e. range of unit costs). On balance, as the CER concluded at PC2, we believe a single unit incentive should be retained for PC3, mainly because of the complexity an alternative approach would create for the price control and the likelihood this may create other distortions in behaviour.

Table 6.1: Analysis of changes to the connections incentive

Option	Pros	Cons
Single unit cost incentive	Simple to implement	Not cost reflective
Different unit cost incentives by type of connection	Evidence from PC2 and proposals for PC3 suggest BGN undertakes a wider range of new connections.	Relatively complex May create its own distortions

Source: CEPA

7.4. Proposal

In summary, we propose CER seek to retain the connections incentive in PC3 with a single unit cost incentive.

8. PASS-THROUGH COSTS

In this section we discuss pass-through costs and their treatment in PC3.

8.1. Objectives

While a majority of BGN's costs during PC2 were included in the revenue cap, a small number of items considered to be outside BGN's control were treated as pass-through items. Evidence from PC1 however, was that BGN had a greater ability than was expected at the time the price control was set to influence the level of costs for certain of the items designated as pass-through. Therefore, the CER put in place a specific form of incentive for certain pass-through items where BGN had demonstrated its ability to partly control costs and realise savings.

8.2. PC2 arrangements

Items included as pass-through in the distribution price control were as follows:

- the CER levy;
- Gaslink (ISO);
- rates;
- gas shrinkage; and
- safety advertising and safety initiatives

For transmission, pass-through items included:

- the CER levy;
- Gaslink (ISO);
- rates; and
- CO2.

The commission sought to incentivise BGN to reduce pass-through costs as much as possible by introducing a 50:50 sharing scheme for pass-through costs. The arrangements (in general terms) meant that:

- CER set an allowance for each pass-through item within the overall revenue cap for the price control ("target");
- to the extent that costs were higher or lower than forecast, 50% of the variation would be borne by BGN and 50% by consumers ("sharing factor");

- the incentive, therefore, was symmetric with BGN having a strong incentive to minimise these costs whilst also capping its exposure to the incentive;[11]
- at the same time, users of BGN's network would gain if BGN was able to reduce costs for these pass-through items.

Incentive arrangements for pass-through items meant savings made by BGN were passed directly through to consumers through the annual K-Factor mechanism. This meant consumers would benefit from savings BGN was able to make on its pass-through cost allowances *over the course* of PC2. Table 8.1 summarises the specific incentives that applied to each pass-through cost item across both controls. In some cases the arrangement was 100% pass-through (i.e. no incentive).

Table 8.1: Pass-through cost incentive arrangements in PC2

Pass-through item	Control	Incentive arrangements
Rates	T&D	▪ Allowance set in PC2 revenue cap ▪ 50% sharing factor
CER levy	T&D	▪ Allowance set in PC2 revenue cap ▪ 100% pass-through
Gaslink	T&D	▪ Allowance set in PC2 revenue cap ▪ 100% pass-through
Safety	D	▪ 100% pass-through for initial forecast and revised forecast ▪ 50% sharing factor (on close out of safety costs)
CO2	T	▪ Volume of CO2 fixed for PC2 ▪ Sharing arrangements
Gas shrinkage	D	▪ Incentive to reduce volume of gas "lost" in system ▪ Gas price is linked to spot price (100% pass-through)

Source: CEPA

Gas shrinkage incentive arrangements are different to the other pass-through cost items. Here BGN was considered to be able to influence the *volume* of shrinkage gas but had less control over the price paid, which was determined by the market price for gas in Ireland. The appropriate level of the volume target for shrinkage gas was based on comparisons with shrinkage gas used by the GB gas distribution companies and an assessment of BGN's performance in PC1.

[11] In recognition that the cost item was treated as pass-through.

For transmission, a more complicated incentive arrangement applied for CO2 costs. An agreed set of CO2 volumes was established and the CO2 cost per ton was to be estimated every year. During the annual transmission revenue setting process, a one-year forward looking estimate price is set and 100% of any saving/cost increase between the allowance and estimated cost for CO2 are passed through. When closing out however, 50% of any saving/cost increase between the estimated and actual CO2 are passed through.[12]

8.3. Lessons learned in PC2 and proposals

For each pass-through incentive we review outturn for PC2 and BGN's proposals for the PC3 period. We then conclude on whether each item a) should be retained as pass-through in PC3 and b) the incentive arrangements we propose CER seek to implement (or retain) for each pass-through item in the revenue control.

8.3.1. Shrinkage gas

PC2 outturn and BGN's proposals

Table 8.2 suggests the incentive arrangements for gas shrinkage have encouraged BGN to undertake proactive measures to reduce UAG. BGN claim the majority of the savings shown in Table 8.2 are driven by specific initiatives undertaken by BGN rather than uncontrollable or economic influences.[13] This suggests BGN has responded to the incentive arrangements.

Table 8.2: PC2 allowance vs. Calculated UAG

End of gas year	UAG Factor	Calculated UAG
GY 07/08	1.40%	0.85%
GY 08/09	1.20%	0.63%
GY 09/10	1.00%	0.43%
GY 10/11	1.00%	0.91%
GY 11/12	1.00%	Not available
Average	**1.12%**	**0.71% (incomplete)**

Source: BGN

For shrinkage gas, BGN originally proposed a UAG factor of 1.3% for PC3 as a representative predicted average UAG for the five year period. BGN note that:

- while a number of influencing factors have a supported a reduction in UAG over the PC1 and PC2 period;

[12] BGN (2011): 'PC2 Transmission pass-through expenditure analysis – PR041'

[13] For example, significant completion of mains renewal, increase in domestic meter reading cycle rates and initiates to more accurately control and set meter conversion factors.

- these measures have largely exhausted the opportunities to reduce UAG further, and the primary influences for PC3 are quite different in nature; therefore
- BGN are predicting that the PC3 period will lead to increased UAG levels, hence its proposal of a 1.3% UAG factor.

BGN goes on to note that:

"Unlike the lead in to PC2 where the influencing factors were positive towards incentivising a reduction in UAG levels, the PC3 influences may not support an incentive based approach. The Code of Operations details a process of annual UAG Factor setting based on a pass-through of the previous 12 months recorded UAG, which may be more appropriate or cost beneficial towards industry for PC3."[14]

In a revised distribution opex position, BGN has set out an alternative proposal for shrinkage gas in PC3 based on the following:

"Based on the known influencing factors, BGN included a UAG estimate of 1.3% for PC3. This forecast was based on a number of assumptions the most significant of which is the new Revenue Protection processes that are currently being progressed with industry and are to commence at the very of PC2. The processes entail BGN taking on more operational roles and costs … [with] the gas value component is in essence absorbed into UAG … BGN are willing to except an allowance of 1% for the period of PC3 provided that any additional costs associated with revenue protection is treated as a separate pass-through item."[15]

Proposal

Firstly, the continued control and reduction of shrinkage gas, in our view, has a role to play in delivering one of BGN's proposed regulatory output for PC3 – helping to promote sustainability and meet environmental targets. Secondly, we note BGN has a relatively new network and, therefore, relative to the GDNs in GB (as an example) we would expect continued control of shrinkage costs given the state of BGN's distribution asset base.

We therefore propose CER *retain* a shrinkage incentive in PC2 for BGN's distribution control. BGN's distribution average shrinkage factor for PC2 to date was 0.7%.

As discussed in our distribution opex and capex report, one approach would be that the shrinkage allowance be based on a 1.0% UAG factor reducing to 0.75% by the end of PC3. This *includes* an allowance for costs associated with revenue protection.

An alternative proposal would be to fix the UAG factor at 0.75% for the entire PC3 period with costs associated with revenue protection treated as a 100% pass-through costs. This would retain the incentive arrangement for shrinkage whilst funding BGN for the new activities it is has taken on.

[14] BGN (2011): 'Distribution Operating Expenditure – PC3 PR062'
[15] BGN (2012): 'BGN response to CER Position'

Our recommendation is the CER adopt the former proposal – i.e. a 1.0% UAG reducing to 0.75% by the end of PC3 and that this allowance includes all revenue protection costs, which are then subject to an incentive, as is appropriate. This proposal reflects the shrinkage opex allowances for PC3 shown in Table 8.3 below.

Table 8.3: Gas Shrinkage

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
BGN based on 1.3%	5,613	5,693	5,712	5,738	5,766	**28,522**
Based on 1% reducing to 0.75%	4,318	4,106	3,845	3,586	3,327	**19,181**

Source: CEPA

8.3.2. Rates

PC2 outturn and BGN's proposals

In PC2, BGN were allowed an increase in rates of 10% for the first three years and 18% and 28% respectively for the last two years of PC2.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

16 [redacted]

[redacted]

Proposal

Given BGN has demonstrated its ability to control costs in this area of spend, we propose it be retained as an incentivised item in PC2. However, there remain aspects of this cost item that are also outside the control of the network operator and, therefore, we recommend that an incentivised pass-through arrangement be retained in this case. As regards incentive design, we propose that the 50:50 sharing factor be retained. The proposed target allowances for the incentive arrangements are set out in Table 8.4.

Table 8.4: Rates

Rates	Forecast €000s				
	12/13	13/14	14/15	15/16	16/17
Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Distribution	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: CEPA

8.3.3. Safety initiatives and advertising

Outturn and BGN's proposals

Each year, in advance of the annual revenue setting process, BGN present the upcoming proposed safety advertising and initiatives to the CER Safety Committee. The updated forecast allowance is agreed and 100% of the difference between the initial forecast and revised forecast is passed through to the customer. However, when closing out safety costs for each year, 50% of the difference between the revised forecast safety costs and final actual safety costs is passed through to the customer. Table 8.5 shows the outturn to date.

Table 8.5: Safety initiatives - outturn

Activity	2007/08			2008/09			2009/10			Cumulative		
	For	Act	Pass	For	Act	Pass	For	Act	Pass	For	Act	Pass
Safety	3.71	1.33	1.19	3.33	2.49	0.42	1.99	1.91	0.04	9.03	5.73	1.65

Source: BGN

Safety initiatives costs are expected to remain static over PC3. Here again, BGN proposes to retain safety initiatives as a pass-through item, but makes no specific comments on whether an incentive arrangement continues to be appropriate for this item.

[17] BGN (2011): 'Price Control 3 Executive Summary'

Proposal

At PC2 there was uncertainty over safety related costs and so it was considered necessary to treat safety related expenditure as a pass-through item. We continue to believe that aspects of safety initiatives and advertising related expenditure should remain a priority for BGN's distribution business and given the uncertainty of the costs should remain as a pass through item.

However following direction from the CER we have approached setting the allowances for safety initiatives and advertising in PC3 differently to PC2. Our proposed allowances for PC3 (summarised in Table 8.6) are set comparatively low compared to historical expenditure trends with a relatively small upfront allowance proposed for the five year revenue control.

Table 8.6: Safety initiative and advertising allowances

Activity	Forecast €000s				
	12/13	13/14	14/15	15/16	16/17
Safety advertising	600	600	600	600	600
Safety nitiatives	90	90	90	90	90

Source: CEPA

For PC3, the proposal is the Gas Safety Promotion and Public Awareness Committee will act as the forum for individual gas safety initiative and advertising proposals and budgets to be considered. It will then be the responsibility of the CER to approve the final budget which is included in the distribution tariff for the forthcoming year. Once the budget for the forthcoming year is set a 50:50 sharing arrangement (as currently) will apply to allowances creating an incentive for BGN to control costs against the established target.

The impact of this approach is that funding of safety initiatives and advertising schemes will continue, but will need to reviewed by the Gas Safety Promotion and Public Awareness Committee (and ultimately approved by the CER) on a year-by-year basis in PC3 rather than the 5-year revenue including an allowance to cover a range of schemes to be agreed over the price control period.

8.3.4. CER levy

The Levy is a pass-through cost that is allocated evenly between the Transmission and Distribution businesses. Given this cost item remains outside the control of BGN, we propose it be retained as 100% pass-through in PC3. The proposed allowances are summarised in Table 8.7.

Table 8.7: CER levy

CER levy	Forecast €000s				
	12/13	13/14	14/15	15/16	16/17
Transmission	1,320	1,320	1,320	1,320	1,320
Distribution	1,320	1,320	1,320	1,320	1,320

Source: CEPA

8.3.5. CO2 emission

Outturn and BGN's proposals

CO2 is emitted from BGN's compressor stations in Ireland and the UK. As members of the ETS the CO2 emissions from these sites are reported on annually. An annual allowance of CO2 is issued to each participating installation and the difference in tonnes of Co2 between the allowance and the total Co2 emissions must be purchased from the open CO2 market.

BGN's PC2 look back, notes for PC2 that an agreed set of CO2 volumes was established and the CO2 cost per tonne was then estimated every year. During the annual transmission revenue setting process, a one-year forward looking estimated price is set, based on current market data and 100% of any saving/cost increase between the allowance and estimated cost for CO2 are passed through as part of the K-Factor (Kt+1) process.

When closing out, 50% of any saving/cost increase between the estimate and actual CO2 are passed through as part of the Kt-1.

Table 8.8 shows the outturn to date.

Table 8.8: CO2 - outturn

Activity	2007/08			2008/09			2009/10			Cumulative		
	For	Act	Pass	For	Act	Pass	For	Act	Pass	For	Act	Pass
UK CO2	0.89	0.73	0.08	1.26	0.98	0.14	1.06	1.05	0.00	3.21	2.77	0.22
Inch CO2	0.19	0.16	0.02	0.37	0.19	0.09	0.18	0.18	0.00	0.75	0.53	0.11
CO2 adj						-0.32						

Source: BGN

Proposal

Although we understand that the CO2 pass-through arrangement is considered to have been relatively complicated in PC2 we propose it be retained given ETS prices are largely outside the control of BGN. The proposed allowances are summarised in Table 8.9

Table 8.9: CO2

Activity	Forecast €M				
	12/13	13/14	14/15	15/16	16/17
Transmission	665	612	309	146	361

Source: CEPA

8.4. Conclusions

Table 8.10 summarises our conclusions on pass-through items across both transmission and distribution revenue controls.

Table 8.10: Summary of proposals for treatment of pass-through costs in PC3

Pass-through item	Proposal	Change from PC2?
Rates	Retain as an incentivised pass-through cost in PC3	No
Shrinkage	Retain as an incentivised pass-through cost in PC3	Yes - update UAG factor. Much lower than PC2.
Safety	Retain as pass-through activity cost in PC3 (incentivised once budget set)	No
CER levy	Retain as a full (100%) pass-through cost in PC3	No
CO2 emissions	Retain as an incentivised pass-through cost in PC3	No

Source: CEPA

9. Innovation

9.1. Overview

BGN has developed a proposal document for Innovation (ref. PC3 PR065), which contain a number of Proposed Innovation Projects that collectively amount to c. € 12.5 m of transmission opex and capex-related costs and c. €13.5 m of distribution opex and capex-related costs. BGN has also proposed principles for a governance structure for innovation funding in PC3.

This section initially:

- reviews forecast innovation costs for PC3 in more detail following the overview provided in our forecast opex and capex papers;
- summarises the innovation themes and projects proposed by BGN, including their objectives and rationale; and
- the processes and principles that BGN have proposed for the governance of funding for innovation in PC3.

It then considers precedent from existing innovation funding programmes in the Irish and UK energy sector, including

- innovation funding available to UK DNOs and GDNs (including the structure of those programmes); and
- the allowance made by the Commission for innovation funding in ESB Network's recent price control review.

The focus of this second part is 'lessons' from the GB experiences over the last 3 to 4 years of the IFI programme launched by Ofgem in 2008.

We then provide our conclusion on the proposed innovation funding scheme for PC3 and our views on the issues that need to be considered further, particularly around the governance and incentives of the funding mechanism.

9.2. BGN proposals

A major section of the BGN Innovation Proposals revolves around the idea of forming an Innovation Group. The idea of such a group is to work with internal and external BGN stakeholders, especially the CER to share knowledge and better utilise their available resources.

The Innovation Group would be responsible for managing the resources and project selection. This would involve the creation of a standardised project appraisal methodology. The Innovation Group would also have ongoing communication with CER, govern funds as per Regulatory Innovation Allowances and report on the progress of projects to CER.

BGN is seeking continuous innovation funding of 0.5% of revenue per annum, with 1% in the early years of innovation. The specific innovation impact is stated to be up to 3% in any one year. The total innovations costs forecasts for PC3 by BGN total €25.76m. Approximately one-third of this is comprised of capex costs (€8.68m), with the remainder being categorised as opex spending (€17.09m). In terms of the distinction between capex and opex spending, the categories that fall under capex spending are network expansion, biogas expansion and the capex associated with CNG in transport. The remaining costs fall under the opex heading.

9.2.1. Innovation themes

BGN has proposed the following themes for innovation:

- to increase grid utilisation;
- to provide a reliable and secure supply of gas;
- to provide long term benefits to the customer;
- to participate in a low carbon economy and help meet environmental targets;
- to promote and enhance energy savings and reduce Fuel povery.

The innovation proposals (part of which are outlined above) are broadly based around these proposed innovation themes.

9.2.2. Governance and funding mechanism

As described above, to promote innovation in the Irish gas industry BGN proposes to create a Gas Innovation Group. BGN propose that the group include BGN, CER and relevant stakeholders "who are keen to develop the gas industry."[18] The principle actions of the Gas Innovation Group BGN propose to be as follows:

- forum for idea generation and capture;
- financial appraisal / justifation using a 'gating system';
- screening and prioritisation of proposed initiatives;
- governance of innovation funding (see below);
- team guidance;
- quality assurance;
- project follow-up / implementation / close out;
- liaise with the gas industry; and

[18] BGN (2011): 'PC3 Executive Summary – PR068'

- structured decision making; project governance.

While BGN's proposals outline a role for external stakeholders it is not totally clear the role the operator envisages for other stakeholders to make use of the innovation funding mechanism that it proposes be provided through the price control mechanism.

As regards funding (as summarised above), BGN proposes to seek on-going innovation funding of *at least* 0.5% of revenue per annum, but typically 1% in the early years of innovation. The specific innovation impact in any one year BGN propose by up to, but not to exceed 3% of annual revenue.

9.2.3. Proposed innovation projects

This section gives information on ten different projects referenced in BGN's Innovation Proposals (ref.PC3 PR065). The content for each sub-heading gives descriptions and a summary of costs for illustration rather than any critical analysis of individual projects being provided at this point.

Natural Gas in Transport – Compressed Natural Gas (CNG)

This is intended to facilitate the use of CNG in Ireland as a transport fuel following introductions across Europe and the USA. As part of this process, BGN state the supply chain will need to be developed, awareness created and cross industry co-operation encouraged. Proposed costs are as follows: [redacted] p.a. each of the five years ([redacted] extra in Yr3). CNG Capex only = [redacted]. See the tables below.

Opex Costs

	12/13	13/14	14/15	15/16	16/17
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Capex Costs

	12/13	13/14	14/15	15/16	16/17
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: BGN

Bio-methane injection into Gas Grid

The aim here is to initiate supply chain development of an emerging bio-methane production market and find an efficient cost model. BGN proposed costs are summarised below.

Opex Costs

	12/13	13/14	14/15	15/16	16/17
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Capex Costs

	12/13	13/14	14/15	15/16	16/17
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: BGN

MicroCHP Renewable Heat & Electricity

This process involves the simultaneous production of heat and electricity in individual homes. The micro CHP unit is intended to replace the gas central heating boiler. In the UK it is anticipated that micro CHP may provide up to 20% of the UK's energy generating capacity. It is 80-85% efficient compared to 30% from a large power plant. BGN's proposed costs for this category of spend are summarised below.

Field Trial Costs

	12/13	13/14	14/15	15/16	16/17
One off costs	[redacted]				
Ongoing costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Trial Opex Costs

	12/13	13/14	14/15	15/16	16/17
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: BGN

Domestic Regulator Failure

This comprises research into the chances of extreme weather causing problems for BGN in terms of regulator failure.

Research amount

	12/13	13/14	14/15	15/16	16/17
Total		[redacted]			

Network Extension/ Fuel poverty

The idea behind this plan is to allow those in fuel poverty to convert to natural gas without the up-front costs. They are required to be within 15m of the existing distribution network and funding is generally between [redacted] per household. This would be funded by a proposed [redacted] annual regulated allowance and a portion of the savings may be taken.

Opex Costs

	12/13	13/14	14/15	15/16	16/17
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Capex Costs

	12/13	13/14	14/15	15/16	16/17
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: BGN

Gas Powered Air Conditioning

Natural gas is 30-50% less energy intensive than electric air conditioning and has twice the useable life. BGN has proposed feasibility study costs for this area of expenditure.

Feasibility Study Costs

	12/13	13/14	14/15	15/16	16/17
Total			[redacted]	[redacted]	

Source: BGN

Asset Management R&D

Materials Design & Innovation (MD&I) is a large part of Asset Management. The proposed opex allowance is based on a number of projects.

The benefits of these projects would be in increased safety, decreased environmental impact and greater efficiency.

R&D Asset Management

	12/13	13/14	14/15	15/16	16/17
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: BGN

University research/ third level collaboration

To utilise emerging technologies, BGN propose working on projects with university resources. Proposals already put forward include some from the Trinity College Dublin, UCC Cork, CIT Cork & DIT Dublin. Proposed costs are set out below.

Graduate Researcher Costs

	12/13	13/14	14/15	15/16	16/17
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Capex Costs

	12/13	13/14	14/15	15/16	16/17
Total			[redacted]		

Source: BGN

Legal & Industry Standards

Legal expertise will aid market development and provide direction in cases who currently have little regulation in place.

Legal Costs

	12/13	13/14	14/15	15/16	16/17
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: BGN

International Energy Research Centre (IERC) Support

DETI announced in April 2010 the formation of the IERC and BGN wishes to be involved for their R&D access, influencing main research programmes and for development. BGN therefore requests the €150,000 annual membership fee to allow it to participate alongside firms such as IBM, General Motos, ESB Networks, Bord Gais Energy & Enterprise Ireland.

IERC Membership Costs

	12/13	13/14	14/15	15/16	16/17
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: BGN

9.3. Review of precedent

9.3.1. RD&D in Ireland's electricity networks price control

In the recent electricity transmission and distribution price control review of ESB Network and EirGrid, CER allowed €18.2m on sustainability and research, development and demonstration over 5-years for the distribution price control. For transmission, there was also a small allowance - €2m over the 5-years regulatory period. As BGN note in their business plan, projects in the electricity networks control have to be justified on value for money grounds and sign off secured from CER prior to initiating projects. The consultants when reviewing ESB Networks proposals, highlighted the importance of innovation funding being directly linked to the core activities of the *networks business* and its licence obligations.

9.3.2. Lessons learned from the GB IFI

For comparison, Ofgem's Innovation Funding Incentive (IFI) Allowances for the GDN's in GB during 2007/8 to 2012/13 are shown below.

Figure 8.1: GDN Innovation Funding Incentive allowances

GDN's Innovation Funding Incentive Allowances 2008 to 2013

GDN Owner/Operator	LDZ	(a) Average Annual Allowed Revenue £m	(b) Total 5-year Allowed Revenue £m	(c) Total Innovation Funding Incentive £m	(d) Ofgem IFI Allowance £m
National Grid Gas	East of England	430.50	2152.50	10.76	8.61
	London	282.10	1410.50	7.05	5.64
	North West	299.00	1495.00	7.48	5.98
	West Midlands	231.70	1158.50	5.79	4.63
Northern Gas Networks	Northern	290.30	1451.50	7.26	5.81
Scotia Gas Networks	Scotland	201.50	1007.50	5.04	4.03
	Southern	468.10	2340.50	11.70	9.36
Wales & West Utilities	Wales and West	267.30	1336.50	6.68	5.35
		2470.50	**12352.50**	**61.76**	**49.41**

Source: Ofgem

As BGN highlight in their innovation proposal report:

- IFI focuses on technical R&D for networks;
- funding comprises 0.5% of allowed revenue;
- there are specific targets for IFI projects which must satisfy three eligibility criteria including:
    - technical development;
    - degree of innovation;
    - customer value.

9.4. Ofgem's proposed innovation scheme for gas distribution

Network innovation is one of the principles of Ofgem's RIIO (Regulatory-Incentives-Innovation-Outputs) price control framework. For gas, Ofgem are proposing a Network Innovation Competition (NIC) mechanism.[19]

The NIC is to be introduced in 2013 for the RIIO GD1 and T1 price controls. There will be one NIC across both gas distribution and transmission, and one NIC for electricity transmission alone. Network companies will have to *compete* for funding for research, development and trials of new technologies. This will operate alongside the Network Innovation Allowance (NIA), a direct allocation of funding to each network, up to 1% of their allowed revenues, that replaces the IFI from previous network price controls.

At the time of the RIIO GD1 decision papers, the design of the NIC was not certain and an update was published on the proposed design features in January 2012.

[19] http://www.ofgem.gov.uk/Networks/nic/Pages/nic.aspx

However, the NIC is expected to work in a similar fashion to the LCN Fund that Ofgem has implemented for electricity distribution, with two tiers of competition, both intended for larger and more complex innovation projects. Funding for NIC projects is covered by all network customers (in proportion to their use of the network), raised via system operators and transferred to the implementer of the successful project. Access to the NIC for non-licensees has not been decided upon, but has been left open as a possibility.

One of the evaluation criteria is that the innovative project must have the potential to be rolled out across GB, so this would be restrictive for non-licensees unless there is an amendment. For RIIO licensees a sliding cap between 5% and 10% has been proposed for the proportion of the NIA that can be put towards NIC bid costs. Ofgem are investigating how this would work for non-licensees.

Consultation on the NIC is still ongoing. However, the proposals illustrate that Ofgem is seeking to significantly increase the level of innovation funding that it is allowed and promoted at previous price control reviews.

9.5. Assessment and proposal

Aspects of innovation funding are discussed across our transmission and distribution opex and capex reports. In principle, the consortium is supportive of a form of Innovation Funding Scheme for the Irish gas industry. BGN have proposed a wide range of Innovation Projects in their PC3 submission and we do not propose to comment on each individual project. However, some important general points for CER to consider (drawing from the lessons of the GB IFI experience above) are as follows.

Innovation for networks should in our view be about research and development, and gas network operator and stakeholder "risk-taking" rather than market development activities.[20] As highlighted by the discussion around the innovation funding mechanism for ESB Network's transmission and distribution control, funded innovation activities should also be closely linked with the technical and licence activities of BGN's gas networks business.

Innovation as an activity is, in our view, also not incentivised effectively through a large upfront funding allowance for the duration of a price control without specific outputs and projects approved. The role of external stakeholders (i.e. other than the network operator) in scoping, approving, sponsoring, potentially delivering and approving projects is also important.

Therefore, having reviewed BGN's proposals, and precedent in other sectors, we conclude that CER *should* seek to implement a form of innovation funding in PC3. However, the allowances proposed by BGN are significant and so the scope of funding and proposed projects should be reviewed and prioritised by CER, and detailed governance arrangements developed with industry for approval by CER, including project approval and monitoring and evaluation.

[20] For example, while there may be benefits from use of natural gas as a transport fuel in Ireland, we question whether the infrastructure to support the industry's development should be funded this way. Rather funding within the price control linked to market demand for infrastructure services to support the industry.

While BGN's innovation submission begins to outline how some of these governance issues for an innovation fund might be addressed, key issues such as incentives around the revenue allowance, the focus and definition of innovation projects and the role of external stakeholders in the process require further consultation.

We therefore propose the following should CER decide to go ahead with an innovation funding mechanism for PC3:

- the concept of an innovation fund should be consulted on with the gas industry before the structure of the fund is confirmed;
- BGN should only be able to access funding where it has proposed specific projects that are agreed and signed off by an industry innovation group or the CER (or both);
- capped allowances should be set for individually approved projects to incentivise BGN to find efficiency savings;
- BGN would be expected to develop projects that involve wider stakeholders who would receive part of the innovation funding provided through the network tariff;
- BGN should be expected to make a minimum financial contribution to an innovation project from its own resources; and
- appropriate monitoring and evaluation processes should be developed and approved by the CER.

We propose CER seek to provide an innovation allowance within the price control revenue cap of €8m (80:20 split for T&D) subject to the specific governance controls and criteria for the release of funding set out above. Given our views on the focus of innovation funding and to avoid complications of including small capital projects in the RAB, we recommend that the €8m be funded purely as opex.

10. SOURCES OF UNCERTAINTY

This section considers other sources of uncertainty in the price controls.

10.1. Drivers of uncertainty

BGN's PC3 submission highlights continued uncertainty over actual timing of Corrib starting production in PC3 and the implications this may have for the optimal IC tariff profile and the CO2 volume allowances used to set its revenue allowances.

It also notes that while the Shannon LNG terminal will not be operational in PC3, in the event Shannon is developed and modifications are required to the network in PC3, it would like CER to include an investment trigger in the price control to allow BGN to "engage with the CER to determine the approach to the treatment of recovery of resultant investments."

BGN also highlight:

- Compliance with the 2nd Directive EC Regulation 1775;
- Common Arrangements for Gas; and
- 3rd Directive Market

as other sources of uncertainty in PC3. The operator is seeking confirmation from CER that costs related to these activities would be recoverable as part of PC3 revenues.

We note the requirement and timing for twinning of the SWOSS system in the PC3 period is also a source of uncertainty in PC3. This would be the case should the CER adopt our proposed approach to the SWOSS system capex allowances. Note that twinning of the SWOSS system is not considered a source of uncertainty by BGN as the operator has proposed that the project take place at the start of PC3 in its business plan submission.

Although in our view there is a compelling case for the twinning of the SWSOS pipeline in the longer term (as Corrib supplies begin to decline) we do not believe that there is a need to construct the pipeline in the short term. However we do believe remedial measures should be taken by the CER and BGN to overcome the potential issues ahead of Corrib starting production. While there remain questions of the practicality and timing of these alternative measures, this adds additional uncertainty to the price control period.

10.2. Proposals

There is timing and investment uncertainty related to a number of key transmission infrastructure projects in PC3 including the connection of Shannon LNG, twinning of the SWSOS and the start date of Corrib.

From our discussions with CER and BGN, we understand there is now increasing *certainty* of when Corrib is likely to start production. From the perspective of setting CO2 allowances (which is partly why a negative investment trigger was included in the PC2 decision), we *would not* propose CER implement a negative trigger in PC3. If there is a change in the CO2 volumes from a year or more delay in Corrib production, we believe in this case, the issue is better addressed through BGN logging-up the variances in costs. CER may still wish to consider a trigger for tariff purposes. As this is outside our terms of reference, we have not considered the issue further.

Since there is continuing uncertainty with regard to the Shannon LNG terminal we propose the CER adopt the same approach as for PC2 – i.e. a positive trigger included in the transmission price control whereby revenues will be increased if the project is undertaken during the control period. For the SWSOS system we propose the CER exclude BGN's proposed reinforcement costs from the revenue allowances but include a positive trigger in the determination so that should the project need to go ahead BGN would be able to recover those costs.

We have not sought to examine other sources of uncertainty identified by BGN in detail. For example:

- Compliance with the 2nd Directive EC Regulation 1775;
- Common Arrangements for Gas; and
- 3rd Directive Market

While these items appear reasonable as *additional* outputs/deliverables beyond what is included in the PC3 business plan, CER will need to take a view whether these activities should be undertaken by BGN within the regulatory and commercial allowances we have proposed for the revenue cap.

BGN has proposed Inch Refurbishment spend of €2.89m associated with refurbishment of Middleton compressor station to cater for reduced flows through the Inch Entry Point as a result of the decommissioning of the PSE Kinsale Gas Storage Facility post-2013/14. Our view is that the €2.89m forecast should be allowed at this stage but captured by a negative investment trigger. This will mean that were a decision taken not to de-commission the Kinsale Gas Storage Facility then revenues would be reduced to reflect the impact of this.

11. CONCLUSIONS

This section summarises the key issues outlined in this paper and the proposals we have made across each of the areas covered by the report.

11.1. Summary of proposals

Table 11.1 summarises our proposals for outputs, incentives and uncertainty mechanisms. Key dependencies with other areas of the price control are also highlighted.

Table 11.1: Outputs, incentives and uncertainty mechanisms proposals

Element	Proposal
Regulatory Outputs	Regulatory outputs proposed by BGN appear broadly appropriate for a gas ITO. Clearer definition of specific deliverables may be required for final PC3 decision.
Opex incentive	Seek no clawback on opex Retain revenue cap Careful assessment of base year costs
Capex incentive	Seek some clawback on items of PC2 efficient deferral which were deferred due to 3rd party decisions Retain capex rolling incentive Review drafting of guidance
Connections incentive	Retain incentive in current form Clearer definition of connections incentive objective i.e. revenue driver for new connections
Pass-through items	Retain rates and CO2 emissions as incentivised pass-through. Retain incentive for gas shrinkage. Retain safety initiatives and advertising as incentivised pass-through. Retain CER Levy as 100% pass-through.
Innovation incentives	Provide for an innovation funding scheme – open to all stakeholders with governance arrangements to be approved by CER upfront Allow €8m as opex for innovation funding Approval of projects before initiation
Other sources of uncertainty	Positive trigger for Shannon Positive trigger for SWOSS reinforcement Reopener for other cost items Negative trigger for Inch refurbishment spend

Annex A: Review of proposed GDN outputs in RIIO-GD1

Outputs	Overview	Incentives
Environment	Companies should work on the broader objective of encouraging reduced carbon emissions, whilst focussing on their own 'narrow' carbon footprint. The introduction of bio-methane is an objective and other measures that will contribute to the environmental output, although these will be contained in a different output category. Estimate a total value of £380m for environmental incentives.	Discretionary Reward Scheme (DRS) Gas Shrinkage Incentive Environmental Emissions Incentive (EEI) Network Innovation Competition (NIC)
Customer Satisfaction	Ofgem require effective stakeholder engagement in RIIO-GD1 and reflect these views in their business plans. Customer satisfaction includes interruption to the service, handling of complaints and suitable engagement with stakeholders.	Customer Satisfaction Survey Complaints handling penalty Stakeholder engagement reward
Connections	This encourages networks to connect customers to networks in a timely and efficient manner. Connection margin arrangements were not altered for RIIO-GD1. Gas performance standards in the current price control period have largely been met (99% of cases).	None given
Social objectives	Extending gas networks to respond to the needs of the fuel poor and address cases of carbon monoxide poisoning. Funding from this comes from the fuel poor networks connection scheme. A review will take place in 2014 to see if it is still a suitable method of assisting vulnerable consumers.	Discretionary Reward Scheme (DRS)
Safety	Safe networks, compliant with HSE safety standards and improved asset knowledge to justify their investment plans, are given as the most important objective for GDNs in Ofgem's view. The safety standards imposed means that additional penalty/reward measures would not be necessary.	Risk-removed Revenue Driver
Reliability and availability	Networks should be reliable over the longer terms, adapted for climate change and with minimal interruptions. Proposals require GDNs to develop a broad asset management strategy. Primary output measure is the 1 in 20 peak day network capacity standard.	Guaranteed Standards primary output incentive Secondary output ex-post review

Annex B: Review of incentives in current GB gas distribution price control

Incentive	Overview
Information Quality Incentive (IQI)	Provides ex-ante incentives to submit accurate forecasts of expected expenditure and for efficiency improvements.
Incentive rate e.g. for Capex	Intended to expose the company to a fixed percentage of the different between Ofgem's forecast expenditure and their actual expenditure.
Capacity Outputs Incentive	Idea is for GDNs to make the most efficient choices regarding the management of network efficiency e.g. network reinforcement, procurement of interruption services and NTS capacity bookings.
Gas Shrinkage Incentive	This intends to reduce gas lost by leakage, gas used by GDNs and gas stolen.
Innovation Funding Incentive (IFI)	Funding made available to support a company's investment in research & development.
Revenue of volume drivers	Links revenue allowances to measurable outputs, factors or volume changes that may influence costs. In gas distribution, this might relate to the loss of metering work.
Specific re-opener	A specific adjustment may be made in the price control period if a certain condition is met.
Pass through	Uncontrollable costs for the GDNs are passed onto consumers e.g. Ofgem licence fee & business rates.
Supply restoration	If an unplanned interruption occurs for over 24hrs, penalty of £30 (domestic)/ £50 (non-domestic).
Re-instatement of consumers' premises	GDNs must reinstate customer's premises within 5 days or compensate £50 (domestic)/£100 (non-domestic).
Discretionary Reward Scheme (DRS)	Reward initiatives that are difficult to measure or not covered by other mechanisms e.g. customer care.
Environmental Emissions Incentive	Reduce environmental damage e.g. emissions of methane due to leakage or venting etc.
Connections	Connection services must be accurately quoted and delivered in reasonable time, with compensation from £10 to £9000 for repeated failure on high value quotes.
Priority domestic consumers	Alternative cooking and heating arrangements for priority customers given or fine of £24.
Timeframe for compensation payments	Compensation must be paid in a certain time, or a further £20 fine is levied.
Notification of planned interruption	Consumers must have a minimum of 5 working days notice for planned interruptions or a £20 (domestic)/£50 (non-domestic) fine applies.
Responding to complaints	A response required in 10 or 20 working days. If not, compensation for non-response capped at £100.