Northern Ireland Electricity plc

Transmission and Distribution Price Control for RP5

Response to the Utility Regulator's Strategy Paper

Reference 001
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Executive Summary

Northern Ireland Electricity plc (NIE) welcomes the opportunity to comment on the Utility Regulator's Strategy Paper on the price control for the fifth regulatory period (RP5) to be applied to NIE from 1 April 2012.

Now that the Department of Energy, Trade and Investment (DETI) has published its Strategic Energy Framework (SEF), it is certain that a major factor in this price control review will be DETI's target for 40% of electricity consumed in Northern Ireland (NI) to be generated from renewable sources by 2020. Without a very substantial investment in NIE's network, there will be insufficient capacity to facilitate this significant increase in renewable generation. However, inevitably there will be delays in obtaining planning consents for a significant part of this investment and in our view it is very unlikely that all the necessary transmission infrastructure can be put in place in the timescale envisaged by DETI's target.

NIE agrees with the Utility Regulator that the objectives for RP5 should be:

- To ensure value for money for customers for the service provided;
- To ensure security of supply by maintaining and developing a network which is fit for purpose; and
- To facilitate sustainability in the generation and consumption of electricity.

In addition the following objectives should be priorities when considering the form of the price control:

- An appropriate regulatory regime that does not introduce unnecessary risk to investment;
- Appropriate incentive mechanisms to promote value for money outcomes for customers; and
- Maintenance of a simple and transparent network modus operandi consistent with the urgent need to execute an extensive transmission capital programme in NI.

NIE believes that a coherent regulatory package can be developed that can meet these objectives so long as particular care is taken in the choice and calibration of the parameters of the regulatory regime in order that they achieve the desired effect.

Value for money for customers

Value for money for customers is best achieved in an appropriate incentive-based regulatory environment. This has been demonstrated by the response by NIE (and other utilities in general) to the incentives in price controls since privatisation to reduce controllable operating costs to the extent that NIE has had for some time a very lean and efficient cost base. With limited opportunities for further savings in controllable operating expenditure (opex), capital expenditure (capex) will be the dominant driver of transmission and distribution prices going forward. Therefore it will be particularly important to optimise asset utilisation and capex efficiency through suitable incentive mechanisms. The evolving nature of the transmission and distribution system will benefit from the innovation and efficiency stimulus that an effective incentive regime can provide. It is for this reason that Ofgem has recently re-committed itself (in its RPI-X@20 recommendations published in July 2010) to incentive-based arrangements as the most effective way of protecting customers' interests.

Consequently, NIE proposes to work with the Utility Regulator to agree suitable incentives that produce benefits for customers. It is envisaged this will involve moving towards a greater equalisation of opex and capex incentives. In doing so NIE does not think it is necessary to replicate the complexity of the information quality incentive (IQI) as applied by Ofgem in Great Britain (GB) - since this approach is more suited to a multi-firm industry - but would seek to discuss with the Utility Regulator how to reproduce the economic effect of this incentive more simply.

NIE believes it would also be in customers' interests to introduce incentives in areas such as reducing the amount of energy dissipated when electricity is transported through the network (i.e. network losses) and improving network performance and customer service. Care will be needed to ensure that mechanisms are properly designed as regards incentive rates and targets, with appropriate caps and collars on rewards and penalties. There will also be a need for investment in new IT systems and processes for measurement, analysis and reporting and hence an appropriate timeline will be required for the introduction of certain incentives.

There are also areas of the price control where consideration will have to be given to the extent to which NIE has any control over the associated costs. NIE's view is that uncontrollable costs should be recovered on a pass-through basis. For example, the current pensions deficit is a result of factors outside NIE's control which have arisen mainly as a result of the pension scheme's investment returns being lower than anticipated and increases in life expectancy. The recovery in full of deficit repair costs is supported by Ofgem precedent.

Security and sustainability

Security of supply requires a stable price control framework which provides the necessary incentives to encourage long term investment and stewardship of network assets.

Meeting NI government targets for sustainable generation of electricity will require some modifications to the existing regulatory framework to accommodate the uncertainty associated with network developments to facilitate renewable generation, particularly with respect to the transmission network. In this response NIE proposes a way forward for the treatment of these costs that effectively manages that uncertainty, ensures the outputs are delivered, and provides appropriate incentives for innovation and efficiency.

NIE believes that its approach represents a more effective remedy to the problem of uncertainty than the Utility Regulator's suggestion of separate transmission and distribution price controls or shorter price control periods for transmission. Indeed, these options would be detrimental to customers' interests.

Separate price controls would impose an arbitrary boundary in the operation of a transmission and distribution (T&D) business that is effectively run on an integrated basis to capture efficiencies and synergies between T&D (e.g. as regards network development, maintenance, procurement, supply chain management and project management). NIE believes that unbundling of T&D is not necessary to comply with the IME3 Directive. It would add transaction costs for customers and would be practically difficult. In short, it would be unnecessary and inefficient, particularly on a small network like NIE's where transmission accounts for only 18% of use of system costs.

The uncertainty associated with transmission investment to facilitate renewable generation cannot be managed through a shorter, three year, price control which would only add to the regulatory burden, add costs and introduce further and unnecessary investment uncertainty. Instead, NIE has proposed a method whereby project uncertainty can be handled with minimal adjustments to the existing price control framework.

NIE is concerned about the Utility Regulator's suggestion that alternative financing models could be applied to new transmission developments. The equity model has a number of advantages over an alternative such as a highly geared mutual model, for instance the ability to combine it with incentive arrangements to encourage efficient and innovative delivery.

New transmission developments will be embedded in the existing transmission network and cannot readily be separated from the rest of the system which would be necessary if they were to be owned and managed by a third party under a mutual model for example. It is for these reasons that there are only limited instances of the contestable ownership model for embedded assets (rather than for standalone interconnectors) worldwide.

In any case, the bulk of the uncertainty around transmission investment to facilitate renewable generation relates to 275kV assets and arises due to timing constraints likely to be imposed by the planning system. Given the probable timeline for obtaining planning consents for large overhead line projects, it is very unlikely that these assets will be constructed in RP5. NIE's view is that there is no need to consider alternative ownership and financing models during the RP5 price control.

NIE would support the continued use of Ofgem precedent for the weighted average cost of capital conditional upon a recognition of Ofgem's new holistic approach in the fifth distribution price control review (DPCR5) in GB, which implicitly allowed an uplift to the baseline WACC and took into account the additional returns available to Distribution Network Operators (DNOs) through incentives. An incentives package which brings customer and environmental benefits to NI should offer the opportunity for NIE to earn similar returns.

Finally, NIE believes that the application of smart technologies provides a means to address some of the challenges in delivering an increased asset replacement programme in an optimised manner, facilitating Government's targets for sustainability and moving towards a low carbon network. NIE has outlined ideas for the application of smart technology across a range of its activities and looks forward to developing these proposals with the Utility Regulator.

1 Background and context for RP5

Network investment

Government's low carbon agenda and associated targets for renewable generation have transformed the context under which electricity networks will be planned, constructed and operated going forward. The targets for NI set out in DETI's SEF give rise to the requirement for a very significant investment in NIE's network over the course of the next decade and beyond to facilitate renewable generation.

However there is uncertainty over the exact magnitude and timing of this investment.

- There will be an accumulation of renewable generation requiring access to the transmission network. In practical terms, it is expected that most of this will be onshore windfarms. Much of this new capacity will be geographically dispersed and located in areas not currently well served by transmission infrastructure. The location of some new generation is known, but the timing over which it will be commissioned is uncertain. While it is not yet clear where all future renewable build might be located it is the uncertainty of the planning consent process for large-scale transmission projects that gives rise to the greatest uncertainty. Given this, transmission investment to facilitate renewable generation represents the most material source of uncertainty to be addressed during the RP5 review. NIE has developed a proposal for a set of regulatory arrangements through which the Utility Regulator and NIE can agree how best to manage this uncertainty on a project-by-project basis in the interests of all stakeholders.
- At the distribution level, growth in the numbers of micro-generation units, small to medium sized individual wind generators, windfarms and other renewable generation such as anaerobic digesters will require network reinforcement and present new challenges for operation of the distribution network. There is also an emerging consensus that electricity will become a key fuel for transport as electric vehicle usage increases. The speed of some of these transitions is difficult to forecast and the benefits they bring in terms of a low carbon economy may require a material increase in distribution costs.

Given this uncertainty there is a strong public policy rationale to design arrangements for the RP5 price control that encourage relevant innovation and early action, in order to ensure networks do not act as a barrier to the delivery of DETI's environmental goals.

This ‘renewables investment’ will coincide with the need to expand the programme for replacing assets since a significant proportion of NIE’s asset base was installed between the 1950s and 1970s and is reaching the end of its serviceable life. Ofgem has recently agreed large increases in capital expenditure for the DNOs in recognition of the corresponding position in GB. Since NIE is at a similar point in its investment cycle, it is right to anticipate a similar need for increased investment in asset replacement in NI.

Incentives

Alongside the requirement for increased investment in the network will be the need to ensure that the capex programme is adequately funded and that there are incentives for work to be undertaken efficiently and innovatively. In order to keep costs down to the benefit of customers, clear and appropriately strong incentives should be established to encourage best practice and innovation. A regime based on weak incentives and unwarranted ex post assessment creates the risk that there is no payback for innovation, which is likely to lead to higher costs in the long run, harming the interests of customers. Given that the RP5 investment programme will be a key driver of prices going forward, there will be merit in strengthening the incentive for NIE to outperform its capex allowance.

NIE will be required to support proactively those network-related aspects of Government policy for the decarbonisation of electricity supply in NI. NIE will also support moves to improve further any areas of customer service for which there is a customer mandate. To deliver against a potentially wide range of targets and obligations, NIE will need to excel in many areas. In areas where NIE is able to drive further improvements NIE believes that it should be appropriately rewarded for delivering increased and new benefits to customers and the environment. NIE will bring forward proposals for new and enhanced incentives to encourage it to meet and beat current levels of performance.

Financing investment

The balance between incentives and risk will need very careful analysis in RP5. NIE will need to compete in order to secure funding for a large capex programme and investors will need confidence that, with effective operational management, reasonable returns will be forthcoming.

Given the need to attract investment, and to incentivise the efficient and timely delivery of the investment programme, NIE believes that the alternative financing structures for new transmission investment mentioned by the Utility Regulator in the Strategy Paper are inappropriate, including the mutual model. Transition to such a model would carry material risk, reduce efficiency incentives and have clear drawbacks. The specific factors that can contribute

to the sustainability of a mutual structure in certain specific cases are not present in NIE.

Given this, NIE strongly advocates the retention of the more traditional equity financing model, with an appropriately sized equity component. This model has a proven ability to deliver value for money for customers.

The WACC will have to be set at an appropriate level that ensures financing for the investment programme will be forthcoming.

All the points raised above are fully consistent with the key messages coming out of Ofgem's RPI-X@20 review. In its latest recommendations (published in July 2010), Ofgem has clearly re-asserted its strong preference for an incentive-based system within its RIIO framework. This framework emphasises the need to ensure that operators earn the **R**evenues necessary to achieve the key policy objectives of value for money and sustainability, within an **I**ncentive-based system that encourages **I**nnovation in the delivery of a clear set of **O**utputs. Our view is that the system of regulation applied to NIE should move in this direction, appropriately tailored to the specific environment in NI.

2 Performance under RP4

Continued focus on customer service

NIE has continued to maintain customer service as a key priority in RP4. For example:

- All the Overall Standards have been met and there have been no defaults against Guaranteed Standards.
- There were only three Stage 2 complaints to the Consumer Council during 2009/10.
- As measured by fault CMLs, last year customers received the best level of distribution network performance since privatisation.
- NIE continues to maintain a very effective and well managed emergency response to storm damage on the network, as evidenced most recently during the March 2010 ice storm.

Delivery of the capex programme

During RP4 NIE has continued to invest in the electricity network with a major focus on the replacement of assets that have come to the end of their serviceable life. This is in response to the need to begin to ramp-up the asset replacement programme as a result of the age and condition of equipment installed as part of the significant development of the network between the 1950s and 1970s. Other investment drivers include the development of the network to allow new customers to be connected and to reinforce parts of the network to continue to comply with the relevant technical standards.

NIE aims to comply with its statutory and licence obligations to manage network risks while at the same time containing capex within the budget agreed with the Utility Regulator for RP4. This has become more challenging during the course of RP4 because of additional costs that were not assumed in setting the agreed budget. In particular, a significant increase in global raw material prices has impacted on the price of copper and steel, the primary raw materials used in the manufacture of cables, transformers and other network assets.

Despite these additional costs, NIE has been able to manage investment requirements such that the level of expenditure currently planned on network programmes during RP4 remains in line with the regulatory budget.

Renewable generation integration

NIE has co-operated with the Utility Regulator during RP4 to progress the development of identified major projects that have necessitated expenditure outside the RP4 price control (e.g. the 400kV Tyrone-Cavan Interconnector and the Renewable Integration Development Programme (RIDP).

However, the present ad hoc treatment of the costs of projects like these through the D_t term of the price control is unsatisfactory because it introduces additional uncertainty regarding development and delivery timelines. Furthermore, there is a need to address the significant step change in the requirement for engineering resources and funding brought about by the growth in renewable generation. The RP5 price control should incorporate a mechanism to address these matters and this is dealt with later in this response.

Fuel poverty and sustainability

NIE is delivering on its commitment to make available in RP4 funding of £1m for each of the Vulnerable Customer Programme and the Sustainable Networks Programme. NIE's programme of Sustainable Management of Assets and Renewables Technology (SMART) continues to promote key technologies associated with the sustainability agenda.

- The Vulnerable Customer Programme aims to help combat fuel poverty by assisting low income households to maximise their incomes by identifying unclaimed benefits. By 2009/10 £13m of unclaimed benefit had been identified. This represents a potential additional household income of approximately £43 per week. This can make a significant difference to a household when it is considered that £10 should cover a typical weekly electricity bill.
- The targeted research carried out under the Sustainable Networks Programme has produced a number of initiatives (such as dynamic line rating) that are finding practical application as NIE seeks to find ways of accommodating significant increases in renewable generation requiring connection to the network. NIE's ideas for carrying forward this work are set out in chapter 7.
- Against an overall SMART budget of £2m for RP4 a total of thirty two projects representing a financial commitment of £1.26m has been made in the period up to April 2010. Funding of photovoltaics continues to be an important aspect with three discrete programmes being progressed. SMART continues to support new technologies (e.g. anaerobic digestion) and remains at the forefront of new technology trials and specific monitoring programmes. It has encouraged collaboration between large UK renewable equipment suppliers and installers in NI. This partnership approach has helped to secure competitive prices for community group

projects throughout NI. Small-scale hydro-electric generation continues to require significant investment and SMART is recognised as providing valuable support to installations across the province. Despite the ending of Government grants for electricity renewable energy technologies in 2010, the SMART programme continued to provide support for local industry.

Business excellence

Employees

NIE has a strong HR strategy which is intrinsically linked to the needs of the business. A number of employee development programmes are embedded across the many disciplines within the organisation. These drive performance and productivity initiatives enabling the company to operate with the minimum resources in each area. A varied programme of management development initiatives is in place, designed to ensure managers maintain a focus on efficiency and that resources are managed effectively. These programmes include performance management, leadership skills and negotiating skills etc.

Time-based progression has been replaced by skills-based progression in some instances and all salary levels are externally benchmarked against the local employment market. Staff turnover is less than 2% which means that retraining and recruitment costs have recently been low. However, the current age profile of staff means that a significant number of experienced employees will retire over the next ten years and successors will need to be put in place in a timely manner.

NIE is Investors in People accredited and 34% of all employees in NIE and NIE Powerteam are professionally qualified. The company was awarded the Department of Employment and Learning's (DEL) Employer Award 2008 and a second year jointing apprentice won the DEL Modern Apprentice of the Year in 2007.

In 2009/10 the sickness absenteeism rate within NIE and NIE Powerteam was 2.47% which compares well with the UK private sector average of 3.9%.[1]

ISO accreditation

NIE promotes a high level of standards throughout its business and holds a number of ISO accreditations. These accreditations are independently

[1] CBI: On the path to recovery - Absence and workplace health survey 2010.

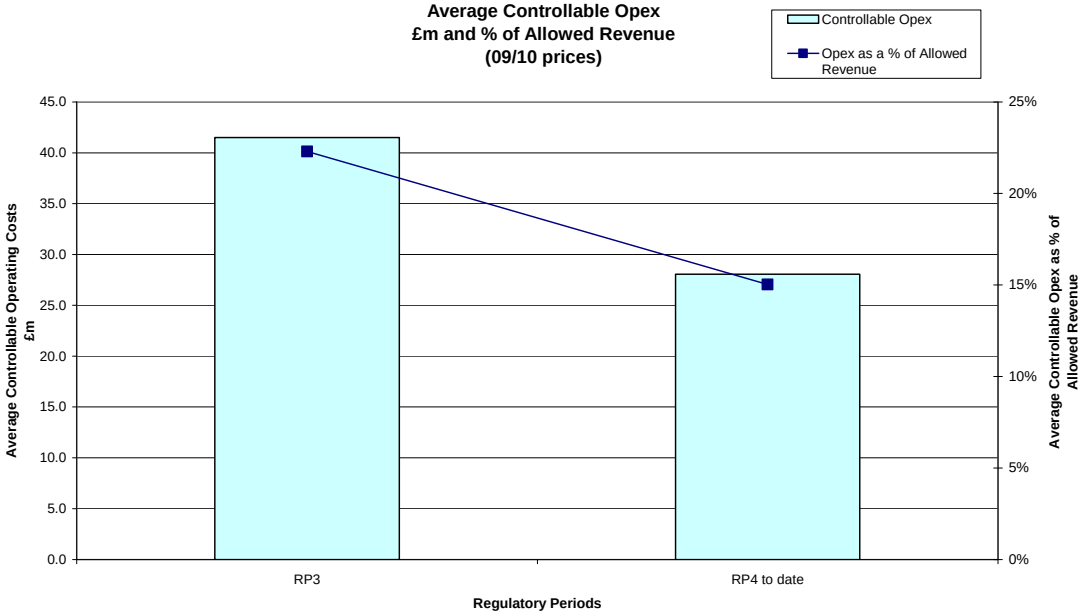
reviewed on an annual basis and a major audit is carried out every three years. The accreditations are in respect of: Metering Support (retained since 1996); Environmental Management (retained since 1997); the Plant Workshop (retained since 1997); Customer Standards Administration (retained since 1998); Plant Maintenance/Substation Inspections (retained since 2000); Revenue Protection and the Meter Test Station (retained since 2000); Transmission Technical Services (retained since 2001); Training Services (retained since 2002); Live Line Working (retained since 2003); Underground Cable Jointing (retained since 2003); and Tree Cutting Operations (accredited in 2010).

Awards

NIE places high importance on safety and in 2009 was awarded the RoSPA Level Four Quality Safety Audit. In the 2009 Environmental Management survey conducted by ARENA Network, NIE was positioned in the first quintile achieving a score of 88% compared with the Northern Ireland average of 67% and a utilities sector average of 72%. In 2008, NIE's Switched on Schools programme, funded through the SMART programme, received an award for the best use of renewable energy at the Sustainable Ireland Awards. Switched on Schools, which works in partnership with the Department of Agriculture and Rural Development and the Education and Library Boards, has installed photovoltaics and renewable energy streetlights at schools across rural NI. In the last two years NIE has been awarded the top grade for its training services in the Department of Education's annual Improving Quality, Raising Standards (IQRS) audit.

Efficiency savings passed to customers

All of the above has been achieved whilst NIE has continued to exercise strict control over its operating costs. The figure below shows that average annual controllable operating costs in RP4 to date are 32% lower (in real terms) than they were in RP3. These savings are mainly as a result of NIE's 'customer aligned' programme of efficiency measures that was introduced in RP3. The rolling opex mechanism operating in RP4 automatically passes through to customers savings achieved in RP3.



In 2009/10 actual controllable operating costs were equivalent to only 15% of allowed revenue (in RP4 they were 22% on average).

NIE believes that it is an efficient organisation and the scope for further savings in RP4 and into RP5 is limited by the absence of opportunity to remove costs from what is already a very efficient cost base.

3 Forecast expenditure during RP5

This chapter provides a high level description of what will be the key drivers of expenditure in RP5. It begins with the requirements for capital investment in what have been the conventional categories of capex, i.e. load related, asset replacement, connections, IT and metering. It briefly describes the role that smart technology may play in mitigating future increases in expenditure. This is followed by a short discussion of the very significant increase in network investment that will be needed to accommodate the rapidly increasing amounts of renewable generation seeking access to the network. Opex is dealt with at the end of the chapter.

Detailed information on expenditure forecasts will be provided in NIE's response to the Business Plan Questionnaire (BPQ).

Capex (conventional)

Context

Historically the requirement for investment in the T&D network has been driven mainly by (i) increased demand for electricity and (ii) the need to replace assets that have reached the end of their serviceable life. Increasing demand for electricity has to be met by increasing network capacity. Deterioration in the condition of network assets has the potential to increase the risk of failure, compromise the safety of NIE staff and the public, impact on the performance of the network, create adverse environmental impacts and compromise compliance with legislative requirements.

Load related requirements

The level of growth in demand during the next regulatory period will depend in part on the rate of recovery from the current economic downturn. While load growth is not expected to be the primary driver of expenditure in RP5, the relatively modest level of load related investment during RP4 means that a number of sections of the network are now at their electrical limit, necessitating investment. For example:

- On the transmission network there is a need to make significant investment in voltage support, complete the uprating of transformer capacity at Castlereagh grid supply substation, replace switchgear and cabling that are at the limit of their fault ratings, establish three new 110/33kV substations and improve the security of a fourth 110/33kV substation. A number of smaller schemes will also be included in the RP5 programme.

- On the distribution network there is a need for up to twenty individual 33kV developments including the works associated with the proposed 110/33kV transmission substations mentioned above. There are also over twenty specific instances on the 11kV network where there is a risk of overload and/or inadequate voltage levels. In addition, a significant number of town centre low voltage networks require reinforcement due to the previous build-up of demand. The replacement of overloaded HV/LV ground-mounted distribution transformers and the resolution of voltage issues at customers' premises will also need to be undertaken.

Asset replacement requirements

The number and type of assets on the network range from a small number of large 275/110kV transformers costing in excess of £2m each, to a very large number of individual service cable terminations in domestic dwellings costing a few pounds each. The consequences of a deterioration in the condition of assets to the point of failure depend on the nature of the asset. For example, in the case of the large transformer a failure can give rise to the risk of a major substation fire and the real risk of interruption of supplies to tens of thousands of customers. In the case of domestic cable terminations the risk is one of electrocution or a house fire.

An investment programme must properly identify and prioritise the investment needs of all categories of network assets. While increasing age can be an indicator of the need for investment, NIE's approach is fundamentally condition-based using a range of condition indicators. For each asset category, NIE takes into account not only the risk of failure but also the consequence of failure. The quantum of investment is then dictated primarily by the number of units identified through the application of these risk/consequence criteria.

The expected life of network assets is typically forty years or more. Whilst age alone is not a driver of individual investment decisions it is a useful indicator of overall investment requirements and with large parts of the network having been constructed between the 1950s and the 1970s NIE is moving towards a peak period during which many assets will be approaching the end of their serviceable life. This upward trend in the requirement to replace assets began in RP4 when NIE began ramping-up investment and a further ramp-up will be required in RP5 to ensure the network in NI continues to be fit for purpose.

A range of T&D plant replacement programmes, all ongoing in RP4, will need to continue through RP5 including, for example, the requirement to replace approximately eighty transmission and primary distribution transformers, five hundred units of transmission switchgear and primary distribution switchgear

and associated outdoor structures, and a significant quantity of secondary distribution plant. With respect to overhead lines NIE has identified the need to refurbish or re-conductor a number of transmission towerline circuits, continue the cyclical refurbishment of the high voltage distribution woodpole network (taking account of lessons learned from the March 2010 ice storm) and commence a major programme of refurbishment of the LV network with a proposal to replace portions of overhead line with aerial bundled conductor and to underground sections of line which are not amenable to refurbishment due to access restrictions. The need to apply a more proactive approach to the replacement of underground cable has also been identified.

Connections

The early years of RP4 saw a significant and unforeseen increase in demand for new connections with a subsequent falling-off due mainly to the recent economic downturn. However, following the recent increase in the Government ROC scheme applicable to renewable generation up to 250kW in capacity, there has been a significant increase in the volume of connection applications for small scale wind generators, CHP plant and anaerobic digesters and NIE currently expects to be required to process around thirty applications each month. In RP5 we expect the rate of development of small-scale renewables and micro-generation to increase, perhaps substantially, and we expect the general economic recovery to re-establish a higher level of demand for connections to new premises.

The outcome of the Utility Regulator's forthcoming consultation on distribution connection charging policy has the potential to change the basis on which net connections capex is derived. Since net capex is funded through the price control, it will be important to have a timely decision on this. As the charging policy will also have an impact on the economic viability of small scale renewables in cases where the cost of connection is relatively high, it is likely to affect the number of schemes coming forward.

Although it is not mentioned in the Strategy Paper, NIE would support a move to introduce competition in connections. If it is considered that competition in connections has the potential to bring benefits to customers, a range of factors would need to be considered, not least the pricing strategy. There would be a need to review NIE's current pricing policy (under which certain connecting customers are charged only 60% of the cost, with the remaining 40% being recovered through use of system charges) to ensure that competing providers of connections would see a level playing field. The disaggregation of connection activities into contestable and non-contestable activities would need careful consideration as would the arrangements whereby the Utility Regulator and NIE could be satisfied that new entrants to the connections market would adhere to consistent quality and health and safety standards.

IT and metering

Network IT: Investment in network IT systems and infrastructure is critical for the operation of an efficient and customer aligned electricity network. Forecast expenditure on network IT includes investment in: SCADA systems and the associated field devices; network/outage management systems (which lie at the heart of NIE's Distribution Control Centre); and the operational telecoms network which delivers network data to the control centres. There is a need to increase investment in RP5 compared to RP4. This mainly arises from a 15-year refresh of SCADA field devices due in RP5 and the need to manage a more dynamic network (created by the increase in embedded renewable generation) through the application of smart technology.

Non-network IT: This category (which is usually treated as opex, but is noted here for completeness) includes expenditure on information and communications technology infrastructure required to support NIE's business activities. Investment is required in three main areas comprising IT infrastructure, corporate telecommunications and business applications. Many of these applications are critical to efficient business operations and customer service.

Metering: The high level objectives behind investment in metering in RP5 include the provision of metering for new connections, innovation in tariffs driven by suppliers, the replacement of life-expired metering assets and other customer requirements. In addition, the Government believes smart meters will both change our energy habits in the short term and provide an essential stepping stone to smart grids. If the cost/benefit case for a roll out of smart meters in NI is confirmed, the common services provider model which has been established here is well suited to implementing a smart metering programme by NIE with the meters being treated as a regulated asset. A timely decision by DETI on a roll-out of smart metering would assist in defining the investment requirements for RP5.

Innovation and smart technology

The increase in NIE's conventional capex requirements is mainly driven by asset replacement and, as an integral part of its capex analysis, NIE is considering the part that innovation and smart technology can play in reducing its capital requirements, thereby mitigating the impact on customers' bills. In this regard, condition assessment is an integral part of the investment decision-making process. Up to now condition assessment has been largely off-line and generally carried out during maintenance of the asset. Over the past few years NIE has installed a number of on-line condition-monitoring devices which could hold out the potential for managing risk through the

development of a more robust estimation of remaining life and also for using the information to identify actions to extend asset lives.

Wider application of this approach will require investment in increased condition-monitoring equipment, replacement of certain plant components, enhanced maintenance and some R&D etc. The benefit in terms of reduced capital investment would be expected to outweigh such costs.

With a sizeable increase in capital requirements it will be important to ensure appropriate incentives are in place to optimise all investment. NIE is keen to explore with the Utility Regulator the introduction of new incentives designed to encourage the company to seek out and apply innovation such as smart technology for the benefit of customers. We address this further in chapters 5 & 7.

Capex (to facilitate renewable generation)

The Government's 2007 Energy White Paper "Meeting the Energy Challenge" set out key energy policy goals - including specific objectives in relation to reduced CO_2 emissions. These, and other objectives associated with the environmental agenda, have transformed the context under which electricity networks will be planned and operated in the future.

DETI's SEF encourages increased levels of renewable generation and associated new infrastructure to improve security and diversity of energy supply. In addition, it sets challenging targets for renewable generation to be achieved over a relatively short timeframe. It recognises that there will be cost implications in moving NI into this new energy future and indicates the need to plan carefully to manage and minimise the cost impact on customers.

Very substantial increases in network expenditure will be needed to connect significantly more renewable generation. However, the need for this long term investment is accompanied by unavoidable uncertainty surrounding the magnitude and timing of such expenditure - driven, for the most part, by public opposition to new infrastructure and by the length and complexity of the due process for planning and environmental consents.

NIE has been developing a staged approach to increase substantially the network capacity at both 110kV and 275kV for the connection of wind-powered generation.

There are four principal stages to this approach:

- Short term actions to increase the capabilities of the existing 110kV network through measures that do not require extensive works or planning/environmental approvals (such as replacing conductors on overhead lines with conductors of higher capacity). This category of work is expected to increase the available windfarm connection capacity in NI from c340 MW to some 550MW by the end of RP4.
- Medium term actions to construct new 110kV circuits and reinforce critical parts of the existing 110kV network by upgrading substation transformers, installing replacement higher capacity conductors on overhead lines and adding additional circuits along existing routes to increase connection capacity to some 750MW by 2015. Some of this work, new overhead lines in particular, will be subject to planning consents.
- A long term strategic plan to expand significantly the capability of the 275kV transmission system. The plan is continuing to develop, with the overall objective of facilitating DETI's SEF target to achieve 40% of electricity from renewable generation sources (representing around 1,700MW in total). This part of the overall programme is highly uncertain since new 275kV overhead lines may be referred to a planning inquiry.
- NIE is developing windfarm clusters whereby groups of windfarms are connected to the network through shared assets to minimise the extent of overhead lines required. In addition, as explained in chapter 7, dynamic line ratings and special protection schemes are being applied to enable the early connection of wind powered generation where possible.

The capital costs associated with the delivery of these plans is expected to exceed £1bn, with several hundred million pounds being expended within RP5.

Our proposal for the treatment of transmission investment to support renewable generation is set out in chapter 4 of this response.

Opex

As noted in the previous chapter NIE has a very lean and efficient cost base and as a result has limited opportunities to make further efficiency gains. Indeed, there are a number of factors which will put upward pressure on opex in RP5.

NIE's operating costs during RP5 will be influenced by a combination of factors. The RP5 opex plan will be based on assumptions that take account of these factors, including:

- Growth of the network: Some opex costs are sensitive to growth in circuit length, others to growth in customer numbers. There has been continuous growth in both of these measures over RP4, and this is forecast to continue over RP5.
- Tighter customer standards: The Utility Regulator's review of standards of performance may result in tighter standards which will need to be supported by new or upgraded IT systems and additional staff.
- Workforce renewal: The DNOs receive an allowance for workforce renewal to cover the costs of recruiting and training new staff to replace retiring staff and to resource an expanded investment programme. NIE has a similar need.
- New legislation: The introduction of new legislation such as the Electricity Safety, Quality and Continuity Regulations will result in additional costs. Street Works legislation will require IT investment and more costly working practices.
- Smart networks: The development and adoption of smart technology will result in additional costs in relation to IT support services associated with the development of control room systems to manage 'active' networks and enhanced communication systems to manage the information from smart meters and wind farms.
- Smart metering: The roll out of smart metering will result in additional ongoing operational costs to support the metering, IT and communications infrastructure given the greater complexity of smart technology. The extent to which these costs will impact on NIE will depend on whatever role is defined for NIE in the smart metering operational model that is finally adopted in NI. This structure awaits clarity from DETI and the Utility Regulator.
- Market services: NIE provides registration and data services in support of the retail market in NI and the all-island Single Electricity Market (SEM). These services, which principally involve the provision of metering data for settlement purposes, are currently provided by interim arrangements that are expected to be replaced in 2012 with the completion of the Enduring Solution IT project. Business processes will also change as a result. The ongoing cost to NIE of providing these services during RP5 will reflect these changes.
- Injurious affection: Claims have been brought against the DNOs and National Grid with some success. Similar claims have been raised against NIE and based on the GB experience there could be a significant cost to NIE in RP5.
- Renewable generation integration: The substantial additional workload associated with facilitation of renewable generation requires NIE to take on new internal and external resources to carry out the range of activities under the short, medium and long term plans.

- Dt costs: It is anticipated that certain ongoing costs currently recovered through the Dt term of the RP4 price control will be consolidated within the RP5 costbase.

Further details will be provided in the response to the BPQ.

4 Form of the RP5 price control

The level of the price control depends in large part on the expenditures and the WACC that are expected over the forthcoming regulatory period. The form of the price control, on the other hand, together with the incentives embodied within it, will influence how the required outputs can best be delivered at least cost.

The RP4 price control was structured around the usual regulatory "building blocks" which come together to determine the agreed revenue allowance. NIE considers the building blocks approach remains appropriate for the RP5 price control.

The Strategy Paper has highlighted a number of specific issues for consideration in relation to the form of the next control. These include:

- Totex regulation.
- Menu regulation.
- Split of the T&D control.
- Duration of the control.
- Incentives around each building block and around other aspects of performance (which we address in detail in chapter 5).

Totex regulation

Totex regulation as discussed by the Utility Regulator in section 6.2.1 of the Strategy Paper covers two areas: first, whether cost assessment should be conducted at the total (opex + capex) cost level; and secondly whether opex and capex incentives should be equalised.

NIE supports greater equalisation of incentives between opex and capex, but does not consider that the application of totex benchmarking would be useful or informative.

As far as equalisation of incentives is concerned, as discussed in the next chapter, our view is that the capex incentive should be strengthened in order to encourage greater innovation and efficiency in future investment decisions and also to bring it closer into line with the strength of the opex incentive. As Ofgem recognised in DPCR5, there is great merit in balancing incentives to

make savings across competing cost types in order to promote efficient input choices and to optimise any capex - opex trade-offs.

In terms of how this equalisation could be achieved, there may be merit in the Utility Regulator adopting Ofgem's approach and treating network operating costs equivalently to capex for the purpose of encouraging balanced efficiency initiatives across these competing costs. In practice, however, the opportunity to do this may be constrained by the quite different ways in which the DNOs and NIE report their costs. It would be an involved and complex process to develop a new set of cost reporting rules to facilitate this end. Given the timescales for this review, a simpler and pragmatic way of progressing would be to increase the strength of the capex incentive.

As far as totex benchmarking is concerned, NIE does not believe this is a fruitful way forward for two main reasons. First, to the extent that the Utility Regulator relies on benchmarking at all, the most obvious sample it can draw upon will be the database of DNOs. Ofgem did not undertake totex benchmarking of historic data, but in DPCR5 it did undertake separate exercises to benchmark (i) operating expenditures and (ii) capex unit costs. For the purposes of benchmarking NIE, it is therefore likely to be far more practicable to re-state NIE's costs to facilitate separate benchmarking of NIE's opex and its capex unit costs against the DNOs using Ofgem's cost definitions, rather than re-state not only NIE's costs but also the costs of all the DNOs to facilitate totex benchmarking.

Secondly, in its RPI-X@20 work Ofgem has indicated that if totex benchmarking is to be used at all, it would be restricted to the analysis of forward looking plans rather than historic costs. This is essentially for two reasons. First, totex benchmarking of historic costs could result in previous investments being written off. This would run counter to established regulatory practice in the UK, and such a move in this direction would have significant implications for business risk. Secondly, at present the imperative should be on network utilities to find innovative solutions to new problems in order that the costs associated with the very large increase in the scale of investment are minimised. As Ofgem recognises, innovation has many potential benefits, but also comes with the cost that some of the ideas that could be trialled and tested could turn out, with the benefit of hindsight, to be of less value than originally expected. However, even these cases provide useful information to network companies in addition to the information from innovations that did turn out to be valuable. If totex benchmarking raises the prospects that the costs of some innovations will not be recovered, then this would undermine incentives to innovate, and lead companies to continue to apply more traditional approaches to network replacement and development.

For the above reasons, NIE would not support a move to total cost benchmarking

Menu regulation

Menu regulation can complement RPI-X regulation by enabling network utilities to trade-off the target cost they face against the profits that can be earned by beating the target. This approach has been adopted in the regulation of capex incurred by the DNOs and the gas distribution businesses in GB, and in the England and Wales water sector.

The primary purpose of menu regulation, through the IQI applied to the GB DNOs, is to encourage operators to reveal quality information about future costs and risks. The IQI has had mixed results in practice, with commentators arguing that it does not adequately encourage operators to submit accurate forecasts, and may continue to encourage gaming. In response to this, Ofgem, through the signals it sent in DPCR5 and in the RPI-X@20 review, has increased the pressure on companies to provide accurate forecasts, not through the parameters of the IQI, but through the increased emphasis on the submission of "well-justified business plans".

The two key parameters of the IQI are the sharing factor associated with over-spend and under-spend (which defines the strength of incentives on the company), and the additional income that it receives for producing a quality forecast - the greater the confidence the regulator has in the forecast, the higher the payment. In the context of NI, it is questionable whether the Utility Regulator needs to explicitly set out an IQI matrix for the purposes of establishing these two parameters for NIE. One of the principal advantages of the IQI is that it provides a common framework within which all companies in a multi-firm industry can be treated on an equal basis, which is not relevant in the NI situation. NIE would hope to be able to satisfy the Utility Regulator that its business plan is robust and well-justified, and be able to engage in a constructive dialogue around the incentive rate that should apply. In other words, NIE would hope to be able to reproduce the economic effect of the IQI without introducing unnecessary complexity.

In doing so, it should be noted that the "additional income" which all the DNOs receive and which is not conditional on performance, is one of the reasons why the effective WACC of 4.3% (real, post tax) for the DNOs is higher than the baseline WACC of 4.0%. But for the existence of the IQI, this additional income would have found its way into the WACC, and this should be factored into the Utility Regulator's calculations of the WACC at RP5, as discussed in more detail in chapter 6.

Separate T&D controls, and the duration for the price control

The Utility Regulator sets out two reasons why the present T&D price control should be split into separate controls. The first relates to the uncertainty surrounding the investment in the transmission network to facilitate renewable generation; and the second to compliance with the IME3 Directive (IME3). The first of these is also given as the primary reason for suggesting a shorter price control period for transmission.

NIE does not support a move to introduce separate transmission and distribution price controls, and does not support a shorter regulatory period for transmission.

For the reasons discussed below, the uncertainty of the transmission investment to facilitate renewable generation cannot be managed under the umbrella of a short term price control. NIE believes there is a solution by which the costs that are most subject to uncertainty can be treated in an appropriate manner while retaining investment confidence in the longer investment horizon for the conventional assets. This is consistent with the proposals emerging from Ofgem's RPI-X@20 review.

IME3 provides for compliance with the requirements for independence of the transmission function in a number of ways that do not require full ownership unbundling, including for example through article 9(9). Given this, IME3 is not a reason for splitting the price control and additionally NIE does not see any good reason why IME3 considerations would justify a short-run price control. As explained below, NIE regards the splitting of the control and/or the shortening of its duration as detrimental to customers' interests.

Managing new build uncertainty

The primary source of uncertainty over transmission expenditure relates to new build in support of renewable generation. Conventional transmission investments (e.g. asset replacement) face no more or less uncertainty than in previous price reviews.

As regards support for renewable generation, NIE's medium term plan (which will be undertaken throughout RP5 and which will facilitate c50% of DETI's renewable generation target) is focused on the delivery of a range of 110kV transmission network projects, together with the 400kV Tyrone-Cavan Interconnector.

The longer term RIDP is focused on extending the 275kV network and is intended to deliver the network capacity required to facilitate the full extent of DETI's target. The RIDP expenditures and their timing are extremely uncertain at this stage, particularly given the extent of new 275kV overhead line to be built. Inevitably there will be delays in obtaining planning consents for new 275kV works, and with the possible exception of the Tyrone-Cavan Interconnector, it is increasingly likely that the only new assets actually built and operational within RP5 will be the 110kV assets from the medium term plan.

There is also uncertainty around the medium term plan, albeit less so. This uncertainty will be largely resolved as each project (or group of projects) within the plan is properly scoped and costed during its pre-construction phase. The scoping and costing process for both the medium and long term plans will occur throughout the period leading up to RP5 and into RP5 itself.

For each of the projects (or groups of projects) within both the medium term and long term plans, the work required to completion can be characterised as falling into three phases:

- A "preliminary development phase" associated with planning, developing and proposing a range of transmission projects directly associated with renewable generation expansion. The preliminary development phase will require additional internal and external resources to be put in place to work on the 400kV Tyrone-Cavan Interconnector, the 275kV RIDP programme, the 110kV "short" and "medium" term infrastructure expansions programmes, and the 110kV windfarm clustering programme. This is a 'baseline' resource needed to bring projects to the next stage. This phase of work would deliver all the background work necessary to bring forward for approval project specific development proposals for (i) the strategic need for the project (if not already approved) and (ii) a defined further budget estimate for "pre-construction" costs.
- The "pre-construction phase", which begins once the strategic "need" for the project and the associated specific pre-construction budget estimate have been confirmed by the Utility Regulator. This phase would include specific detailed engineering design, environmental impact assessment, planning consents, and relevant procurement - and would conclude with all information necessary to establish robust capital proposals for the third and final phase.
- The "construction" phase (which as noted above may only apply for 110kV projects within the timeframe of RP5) would involve the management and delivery of identified capital programmes for construction and commissioning of specified assets.

In the majority of cases a firm view of the cost of any individual project or group of projects will only be available some time after the RP5 price control has been set. In order to reflect the impact of the forthcoming investment on the level of the price control, whilst still protecting customers from the costs of uncertainty, we propose that an *indicative* capex allowance for these projects is set at the outset. As due diligence is completed on each project (or group of projects) and as RP5 progresses, this indicative allowance would be updated with the budgeted costs from the due diligence process. The impact on tariffs of any difference between the indicative allowance and the updated allowance would be addressed through a true-up arrangement.

This approach would enable the Utility Regulator to scrutinise these key investment plans just as it would do with the plans for more conventional investments, but because the former are and will be uncertain at the outset of RP5, due diligence will be undertaken *during* RP5. This approach therefore has many of the features of the 'Transmission Investments for Renewable Generation' (TIRG) model already adopted in GB for National Grid and the Scottish transmission owners.

The key regulatory ingredients of this approach are therefore as follows.

- For conventional operating and capital expenditure, (and for transmission projects in support of renewable generation that have been through the pre-construction phase and for which a robust capital budget is available) set the price control allowances as usual.
- For the transmission expenditure in support of renewable generation relating to projects that have not been through the pre-construction phase (and so the capex requirement is uncertain), set the price control on the basis of:
    - an allowance for the internal 'baseline' resources and the external resources needed for the preliminary development phase - these costs should be relatively straightforward to forecast;
    - pass through of the pre-construction costs - these costs are much less controllable by NIE; and
    - an indicative capex allowance, but this would be adjusted following the due diligence undertaken as the projects are progressed throughout RP5.
- The capex incentive would apply to performance relative to the budgeted spend for the construction phase arising out of the due-diligence process, and not the indicative spend established for the purposes of setting the price control at the outset.

This approach effectively deals with the uncertainty associated with transmission expenditure to support renewable generation in a targeted way, whilst maintaining capex incentives. NIE believes that this approach will be far more effective at managing uncertainty than simply splitting the price control or setting a price control of shorter duration.

IME3 implementation

NIE has presented its position to DETI and the Utility Regulator that the current arrangements for transmission in NI satisfy article 9(9) of IME3 which provides a derogation from transmission ownership unbundling. Although the decision has yet to be made as to which of several models will be adopted in NI, apart from a full ownership unbundling solution none of the models would require separate price controls. Indeed, the Directive provides that where article 9(9) applies, transmission and distribution may co-exist as a combined business (the 'combined operator') and separate price controls are not specified.

If it were found to be the case that the current arrangements do not satisfy the article 9(9) derogation, then an alternative model would have to be adopted. However, it should not be assumed that regulatory unbundling (by way of separate price controls) is synonymous with either ownership unbundling or the ISO model. It would be wrong to assume that separating the price controls now could seamlessly facilitate an ISO model or ownership unbundling later without additional work. As we discuss below, there is a complex set of boundary issues between T&D that would need to be resolved, and simply having separated for regulatory purposes would not rule out having to undertake the exercise again to establish the permanent boundaries required for any further change required under IME3. Consequently, regulatory unbundling now would be inefficient, and would not materially alter the cost of further change if that were to be required. It would be better to proceed now with setting the RP5 price control as a combined T&D control and, if necessary in the light of the final decision on IME3, make the appropriate adjustment to those elements of allowed revenue which relate to transmission.

Separation and shorter duration of control are detrimental to customers' interests

In the light of the points made above, there is no persuasive rationale for separation of price controls or the adoption of controls of a shorter duration. Indeed, both measures could be expected to work against the interests of customers in the longer term.

Separate price controls

Separate price controls would impose an arbitrary boundary on the operations of a business that is effectively run on an integrated transmission and distribution basis. Splitting the integrated business in two would inevitably give rise to new costs because of the additional transaction arrangements. In such a small jurisdiction as NI, there are many costs and activities that are shared across T&D, and great care would need to be taken by the Utility Regulator to ensure that the treatment of these costs and activities for price control purposes does not distort sensible commercial decision-making, that would then result in unnecessary higher costs for customers.

The current management of the T&D networks as an integrated business captures efficiencies and synergies. For example, decisions on maintenance of the T&D networks are taken by the same group of specialist staff using common skills, information systems and analytical tools.

Similarly, decisions on network development are currently taken jointly between the transmission system planners and the distribution system planners and this provides opportunities to optimise investment decisions to achieve project objectives at lowest overall cost. The effective co-ordinated development and application of smart technologies that have the potential to play an important part in the network of the future is likely to be hindered if the integrated business is sub-divided.

A third example is that network maintenance and development involves the specification of materials and services, procurement activity, supply chain management and project management. Currently, beneficial economies in overheads are achieved by jointly managing the needs of both networks and economies of scale are achieved from the combined volume of the work.

At present, therefore, total costs are optimised within internal cost exchanges that exist between the T&D networks, and this enables efficient and flexible operation of the combined T&D business. Separate price controls would properly require a formal, administered set of transfer prices to be determined between these networks, which would never be able to optimise costs to the degree already established. The creation of an arbitrary boundary between the networks coupled with an administered set of transfer prices would sacrifice many synergies that are presently exploited. Furthermore, the transfer prices could become so out of line with reality that they could distort behaviour and create further inefficiency.

Separation in organisational terms would have an adverse impact on the response to major incidents on the network e.g. storm damage.

There would be an increased regulatory burden in having to review, monitor and report against two separate price controls.

Finally, new costs would be incurred to develop the systems that would enable costs and activities to be divided and reported, however arbitrarily, between the two networks.

Ofgem recognised similar concerns in its assessment of the merits of the sale of a number of gas networks by National Grid. After careful consideration it took the view that it would be reasonable to allow the costs of business separation, including the creation of interface arrangements between gas transmission and distribution. However, the balance of costs and benefits is very different in NIE's case. First, the GB gas transmission and distribution businesses are large businesses in their own right, so the lost synergies across the business were regarded as smaller than the potential efficiency gains that could be achieved on the sizeable core businesses. Secondly, in GB Ofgem's intended route to promoting greater efficiency was through a fragmented ownership structure at the distribution level that would allow for more effective comparison between companies of operational performance and costs. In the case of NIE, the synergies are large relative to the size of the businesses themselves; and secondly, there is nothing to be gained by way of distribution comparators. Consequently, the fragmentation of T&D would create significant additional costs without the creation of any obvious countervailing benefits.

In summary, regulatory unbundling between transmission and distribution is both unnecessary and inefficient, particularly on a small network like NIE's, and would be detrimental to customers' interests.

Shorter price control

As far as a three year period for the transmission price control is concerned, this would have a number of serious efficiency defects;

- First, it would have weaker incentive properties than the existing five year period. As the transmission business increases in size over the next 15 years, there will be an imperative to encourage efficiency and innovation in the delivery of the transmission plan, which will require stronger incentives than at present, not weaker ones.

- Second, the divergence between price control periods applicable to each business would introduce further risks of incentive distortion between the businesses.
- Third, a three year control would increase unnecessarily the burden of regulation on both the business and the Utility Regulator.
- Fourth, these arguments have been recognised by Ofgem. As part of RPI-X@20 it is considering whether there is merit in increasing, rather than decreasing, the length of some price control periods.

If there is a need to introduce separate transmission and distribution price controls for whatever reason, then only accounting separation should be required as full organisational unbundling would be very inefficient. Even accounting unbundling could be expected to introduce an additional administrative cost that would need to be borne by customers, which would only be justified if price control separation was absolutely necessary

For the reasons set out, NIE is strongly opposed to both a separation of price controls (particularly if organisational separation is required) and a shortening of the duration of the transmission control.

5 Incentives

Incentives provide a means of ensuring that network companies deliver the outcomes that customers value and that support relevant government policy objectives. NIE believes that incentives should play a significantly increased role in the regulatory regime for RP5.

The benefits to customers from incentive schemes are clear. Incentive-based regulation has been applied successfully to numerous monopoly network businesses around the world for many years. There is widespread acceptance that they have typically delivered very material benefits to customers and have a proven track record of delivering improvements in efficiency and standards of performance. In its RPI-X@20 review, Ofgem found that:

> "The upfront incentive-based nature of the existing framework has encouraged network companies to reduce operating costs, improve quality of service and undertake considerable investment."[2]

Ofgem has consequently made incentives one of the cornerstones of its proposed new regulatory framework, RIIO, which stands for Revenue set to deliver strong Incentives, Innovation and Outputs.

In developing new or enhanced incentive schemes for NIE, there will be a need to ensure that incentive rates applied to different performance measures reflect the appropriate value that stakeholders place upon those measures. Enhanced incentive scheme could have desirable benefits in the following principal areas:

- efficient delivery of the capex programme;
- improvements in customer service;
- environmental improvements; and
- encouragement to maintain and where possible improve upon existing levels of excellent performance.

[2] Ofgem, 2010, RPI-X@20 recommendations, page 29, para 5.1

Targets should be set to ensure that there is an appropriate balance of risk and reward. Ofgem reflected the need to ensure a fair and proper calibration of the regulatory regime, including incentive mechanisms, in its RORE analysis in DPCR5.

The introduction of new or enhanced incentives is likely to require investment in systems and processes for measurement, analysis and reporting. It may also be necessary to limit the risk of excessive rewards and penalties through the application of caps and collars until the application of new incentives here is more mature.

The Utility Regulator has invited views on the RP4 incentives and whether they should continue into RP5. NIE is working on a set of proposals for incentive mechanisms in RP5 for further consideration and looks forward to discussing these with the Utility Regulator. These are outlined briefly as follows.

Capex

The capex arrangements in place at RP4 place relatively weak incentives on NIE to develop innovative approaches that could aid the delivery of capex programmes at lower overall cost to customers. This is a consequence of the mechanistic approach taken to assessing capex efficiency during RP4. While it is not unreasonable that the company is required to demonstrate efficiency gains conclusively through a detailed ex post calculation, this bottom-up approach is limited in the scope of activities under which efficiencies are rewarded since it only covers productivity and procurement activities. The result is that large elements of efficiency have gone unrewarded, particularly those which have been achieved through innovation in planning and design.

Given the increases in capital expenditure to support asset replacement and facilitate renewable generation that will be required in RP5 and beyond, maintaining the current approach to capex incentives is unlikely to be in the long run interests of customers. To bring it more into line with the DNOs' capex incentives, the scope of the incentive should be widened to cover all aspects of the delivery of the overall capex programme for RP5 and encourage innovative approaches such as the wider application of smart technology.

This could be achieved by implementing a capex incentive scheme for RP5 under which NIE bears a set proportion of any over or under spend relative to the capex allowances.

Where appropriate, and as indicated in chapter 4, the arrangements for incentivising capex associated with the transmission programme in support of renewable generation may differ from those for conventional investment.

The capex incentive regime (for both conventional and investment in support of renewable generation) should recognise the uncertainty associated with setting targets for specific outputs many years in advance of the actual investment being made.

Opex

A rolling opex mechanism was originally introduced in water regulation (the 'glidepath') to incentivise companies to seek savings over the entire regulatory period. For similar reasons the rolling opex mechanism was introduced at RP4 to strengthen the incentive on NIE to manage controllable opex and to pass savings to customers automatically. The substantial cost reductions achieved in RP3 are automatically passed to customers in the corresponding years in RP4.

As identified in chapter 3, a number of factors will tend to put upward pressure on operating costs in RP5. These will need to be taken into consideration in deciding if the rolling opex mechanism should continue and NIE will put forward its ideas on this.

The efficiency measures implemented since privatisation ensured that NIE became and has remained an efficient organisation. Given that opex will be a relatively modest driver of T&D prices in RP5 compared to capex, the greater effort should be focused on ensuring that the efficient and timely delivery of the increased capex programmes (both conventional and in support of renewable generation) is properly incentivised as discussed above.

Network losses

NIE supports the objective of reducing network losses.

However, in common with the situation in GB, there is a high degree of uncertainty in the measurement of losses. Due to limitations in the current arrangements for metering at the exit points on the distribution system, the scope for errors in the measurement of distribution losses is large compared to the absolute scale of losses. This is compounded by the relatively limited scope for the company to influence the level of losses which are ultimately determined by system design and the location of generating plant and its

dispatch profile. As a result, it is unlikely that improvements would be distinguishable from the background margin for error in the measurement of losses.

Therefore, it is likely that variations in measured losses will be as a consequence of measurement variations and other factors rather than influences brought to bear by NIE which will tend to lead to either windfall rewards or penalties rather than providing a meaningful incentive mechanism. This means that simply adopting the Ofgem incentive scheme, which mechanistically applies an incentive rate to measured losses, would be inappropriate.

Whilst smart metering will improve measurement and help solve many of these issues, a full roll out will take at least another two price control periods. Therefore, instead of adopting the GB arrangements, we propose that an incentive scheme should be developed for RP5 which directly encourages NIE to seek ways of reducing losses on specific sections of the distribution network (e.g. as defined by voltage level) on which a more robust system for measuring losses can be implemented in a cost effective and timely manner. This would enable improvements in losses to be measured and rewarded and thereby provide a meaningful incentive for the company to reduce losses to the benefit of customers.

In parallel, and to ensure a losses incentive applies to the development of the entire T&D network, consideration should also be given to providing direct incentives to procure low-loss equipment when carrying out network investments.

Customer service

NIE would wish to explore with the Utility Regulator the extent to which further incentives should be introduced during RP5 aimed at improving other elements of customer service. We note that Ofgem has proposed the introduction of a ‘composite measure of customer experience’ consisting of three key elements: customer satisfaction, complaints and DNO engagement with customers and other stakeholders. Ofgem proposes to develop these arrangements for introduction in GB in April 2012.

Network performance

From the recent customer survey work carried out by the Utility Regulator’s consultants it is clear that customers regard reliability of supply as a key

priority. This suggests there would be customer support for an incentive around network performance.

A scheme based on customer interruptions and customer minutes lost (CI and CML) would be appropriate, with the incentive strength associated with improvements (or reductions) in reliability informed by the arrangements in GB, where such a scheme has been established for some time and subject to consultation.

The baseline targets would need to be set taking into account the characteristics of the network in NI which differentiate it from most other UK electricity networks, in particular, the extent of overhead line and relative sparsity of the rural population.

NIE proposes the application of caps and collars to limit the risk of exceptional gains or losses. Furthermore, there would need to be some mechanism (as in GB) to ensure that the incentive arrangement excludes exceptional events which are essentially outside NIE's control such as those resulting from severe weather.

Low carbon network innovations

In addition to putting in place a range of incentives for DNOs, Ofgem has recognised explicitly the need to provide network companies with incentives to undertake targeted R&D and to trial new technology and network solutions that will enable the transition towards a low carbon energy sector. Ofgem has recognised that, given the risks inherent in undertaking such activity, it would be difficult to encourage the DNOs to engage in it within normal price control allowances. It has therefore established a series of separate funding mechanisms within the DNOs' price control arrangements, specifically the Low Carbon Networks Fund (LCNF) and Innovation Funding Incentive (IFI). These mechanisms allow for the possibility of companies receiving additional reward where innovation delivers benefits to customers.

There are similar strategic energy themes in NI in which NIE is keen to engage as explained in chapter 7. This will require funding mechanisms that will enable NIE to build on the success of its Sustainable Network Programme during RP4. NIE therefore welcomes the Utility Regulator's commitment to consider the introduction of a LCNF for RP5. NIE proposes that arrangements similar to those in GB should be in place during RP5 to stimulate innovation in the development of low carbon networks in NI.

Recognition of efficiency as part of allowances

In DPCR5, Ofgem rewarded those companies it found to be the most efficient by setting allowances which built in expected outperformance.

- Companies performing at the efficiency frontier were awarded an additional allowance within Ofgem's return on regulatory equity (RORE).
- In its capex unit cost benchmarking process, Ofgem applied uplifts to the allowances it provided for three DNOs, compared with the allowances they would have received had their own capex unit costs been used.[3]
- In setting network performance targets for CI and CML, Ofgem allowed additional revenue for five DNOs which were already operating at superior levels compared to Ofgem's benchmarks.[4]

NIE is a very efficient company and this delivers significant ongoing benefits to customers. There may therefore be areas in the RP5 price control where a similar approach to rewarding outperformance would be warranted.

NIE Powerteam

Finally, NIE firmly believes that the incentive arrangement around the charges from NIE Powerteam (which provides network services to NIE only) is encouraging a commercial culture within NIE Powerteam by incentivising the business to drive down its costs through subjecting its cost base to on-going challenge. The arrangement is working in customers' interests and should continue into RP5.

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[3] Ofgem, 2009, DPCR5 final proposals cost assessment appendices, page 23, para 1.79

[4] Ofgem, 2009, DPCR5 final proposals incentives and obligations, page 87, para 16.12

6 Financial issues

There are four key financial issues to be established for RP5:

- the WACC and the appropriate methodology for its determination;
- the depreciation profile for NIE assets in light of potential financeability issues;
- whether alternative financial structures should be adopted for new transmission developments; and
- the treatment of pensions costs.

We discuss each of these areas below.

WACC

NIE is supportive of applying Ofgem precedent in the setting of the effective WACC for NIE, recognising that this precedent not only takes into account the baseline WACC that Ofgem allowed, but also the additional income that the DNOs are able to earn that is not conditional on performance within the DPCR5 period.

The DPCR5 WACC was set in a holistic manner. The revenue allowances include non-conditional "additional income", and in the absence of these additional returns Ofgem would have had to set a higher baseline WACC in order to achieve the same expected returns for investors.

> "In this review we have said that we will take a more holistic approach to determining the allowed return for DPCR5 taking into consideration a number of factors including the market evidence, the incentive packages, our assessment of the potential returns on regulated equity, consultants' views, the investors' survey and our financeability tests."[5]

Taking into account this non-conditional "additional income", the average actual allowed rate of return for the DNOs is 4.3% (real, post tax), compared with the 4.0% allowed in the baseline WACC. The range across companies is from 4.2% to 5.0%. In order to achieve these levels of return, DNOs need only to match Ofgem's allowances.

[5] Ofgem (2009), 'Electricity Distribution Price Control Review - Final Proposals', December, para. 3.79.

In addition, highly performing DNOs can be expected to outperform this level through:

- the incentive arrangements for opex and capex;
- the interruptions incentive scheme (where the DNO is incentivised to beat targets for customer interruptions and customer minutes lost);
- the losses scheme; and
- customer satisfaction incentives.

In line with the holistic nature of Ofgem's approach, as indicated in the previous chapter, NIE is keen to explore with the Utility Regulator the scope for further customer and environmental benefits to be secured through the introduction in RP5 of a wider package of incentives compared to the current arrangements. The incentives package should offer the opportunity for NIE to earn the same level of 'expected return' as the best performing DNOs.

WACC methodology

In general, NIE believes that the overall approach to the WACC adopted by Ofgem - in particular the equity model and use of the CAPM to determine the appropriate WACC at each price control review - remains the correct one.

In its RPI-X@20 review, Ofgem has also confirmed its continued use of the CAPM to set the cost of equity at each price control review (supplemented by other evidence such as a dividend growth model).[6]

There are many difficulties surrounding any move away from the equity model, which are discussed below, meaning that the cost of capital should continue to be set on the basis of a weighted average of the cost of debt and equity.

Potential alternatives to setting a WACC at each price control review, such as a long term WACC, do not appear to offer any benefits over the current approach. For instance, under the current approach there is no constraint on regulated network utilities from accessing long term forms of debt finance, and they choose to do so when debt market conditions make this appropriate.

There are also a number of practical difficulties with setting a long term WACC. For example:

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[6] Ofgem, 2010, RPI-x@20: Implementing sustainable network regulation, page 130, para 12.25

- Regulators are unable to bind their successors to applying the same long term WACC, or maintaining the approach. For example, the CAA explicitly recognised its inability to constrain its successors when making assumptions regarding a 10 year price path for Heathrow airport in its 2003 price control determination. [7]
- A single long term WACC applied to the whole regulatory asset base (RAB) cannot be credibly maintained, since if the actual WACC falls, successor regulators are likely to claim this benefit for customers, while the possibility that the WACC will not be reset upwards if the WACC increases will add to regulatory risk.
- Setting separate long term WACCs for investment dating from previous price control periods (i.e. different vintages) would quickly create complexity and could distort incentives for investment and asset stewardship. For example, investment plans could be arbitrarily accelerated or deferred in order to benefit from expected movements in the components of the WACC. Dealing with this potential problem would create further cause for regulatory oversight of NIE's investment decisions, which would be entirely unnecessary in the absence of such an approach for setting the WACC.

Tax

NIE believes that the proposed post tax approach to the WACC is appropriate, and we note that it is consistent with regulatory precedent. The tax allowances should be calculated on a basis that is consistent with the post tax return, again in line with regulatory precedent.

Depreciation profile

As acknowledged by the Utility Regulator in the Strategy Paper, recent volatility of financial markets and the upcoming requirements for large amounts of investment in the asset base to support renewable generation and asset replacement, mean that financeability considerations require greater attention at RP5 than has previously been needed.

NIE's RAB currently faces a relatively long depreciation profile over 40 years. This is significantly longer than the established regulatory precedent in GB, which is as follows:

- The depreciation lifetime of investments in the electricity distribution RAB has been shortened to 20 years across all assets.

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[7] CAA, 2003, Economic regulation of BAA London airports decision, page 45, para 4.68

- In electricity transmission, a decision was taken at TPCR4 to shorten the depreciation profiles on post vesting assets to 20 years, to prevent large falls in revenues when pre-vesting assets became fully depreciated.
- Depreciation on transmission investments to support renewable generation made under the TIRG and enhanced incentives frameworks starts the year after investment (rather than when the assets enter service) in light of the scale of the investments. These assets are also depreciated over 20 years.

Coupled with NIE's increased investment requirements, its relatively slow depreciation rate will lead to increased needs to raise capital on financial markets compared with the DNOs and transmission companies. This could increase the cost of finance of the business. In particular, if NIE's WACC is set to be comparable with that set by Ofgem at DPCR5 (including the return implicit in Ofgem's incentive schemes), then it may be necessary to consider shortening the depreciation profile of NIE's RAB.

Alternative financing structure

The Utility Regulator has expressed a desire to investigate potential approaches to the financing of new electricity transmission infrastructure in Northern Ireland based on alternatives to the present equity model that has applied since privatisation.

> "Other more radical solutions may also be worth considering, which could include various mutual models, risk-transfer between customers and shareholders, greater debt-financing, a split cost of capital. In different ways, these options might mean adjusting the risk and reward mechanism in a way that might improve financeability, incentives or the overall expected cost of finance."[8]

There are three main issues to consider when evaluating alternative financing models for new transmission developments: the advantages of the equity model, the practicalities of ring-fencing assets that will be embedded in the transmission network and the timing of new investments. We discuss each of these issues below:

The equity model

The appropriate level of gearing for NIE is well below the very high levels involved in some of the financing models apparently being contemplated by the Utility Regulator, such as a highly geared mutual model.

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[8] The Utility Regulator, 2010, *RP5 strategy paper*, page 31

The current equity model has a number of advantages over the alternatives that mean it is appropriate for NIE, and can be expected to ultimately deliver the greatest benefit for customers. There are seven central reasons for this conclusion:

- Financing theory shows that there are no automatic financing benefits from higher gearing, and that inappropriately high gearing can actually increase financing cost. The CAPM also means that applying a mutual model does not reduce the financing risk unless there is some associated reduction in business risk, or financial markets are mis-pricing risk under the equity model.
- The position of GB regulators including Ofgem, Ofwat and the Competition Commission is that it is not for them to impose a particular capital structure but to set price control incentives within which companies are free to optimise performance. It is not clear that an alternative financing structure could be imposed and in any case the customer benefits would need to be proven. Structures such as mutuals have not been widely promoted by market participants, suggesting that they typically do not bring clear financing benefits. Since financial markets have also undergone significant change over recent years, understanding fully the implications of choosing an alternative model could take some time.
- A highly geared mutual structure for NIE would materially reduce the Utility Regulator's ability to apply incentive regulation at a time when the need for incentives to innovate is particularly relevant, given the requirement for NIE to transform its network. The absence of strong incentives would lead to slower delivery of the investment programme, a loss of efficiency and higher costs and prices over the longer term. In effect, such a model applied to NIE is likely to transfer risk to customers in the form of higher costs.
- The Mutual Energy model is not suited to NIE's specific situation. Mutual Energy's highly geared debt structure has been achieved through a regulatory regime that passes all risk on to customers, and effectively places no cost incentives on the business. In addition, the discrete characteristics of Mutual Energy's assets means it has no development capex. This raises a key question under a mutual model for new transmission assets, namely who would take the construction risk? The incremental benefit of mutualisation is also not clear, since any perceived benefit would be countered by:
    - pass through guarantees that pass cost shocks directly to customers;
    - the need for a level of debt funding at a premium to the RAB to cover the acquisition premium (if NIE assets were to be acquired by an entity financed on a mutual basis) and the need for debt service and maintenance reserve accounts. In the equity model any acquisition premium is funded by shareholders, not customers; and

- potential requirements to increase the step-in rights of debt financiers relative to the current arrangements for most network operators.

- The Glas Cymru model is superficially more relevant to NIE's situation, since Glas faces ongoing operational, demand and investment risks and operates under regulatory incentives. However, in order to manage these risks, Glas maintains an equity-like buffer of around 30% of RAB to reflect the riskiness of a network operator under incentive-based regulation. An equity injection would be required from customers to create such a buffer and cover the acquisition premium. In addition, there is a significant risk that over time incentives on NIE would be weakened to facilitate a cost of capital that would be lower only because cost risk had been transferred to customers, and this could be of far greater long term cost than any financing benefit.
- The impressive track record of the equity model, combined with efficiency incentives, means that the potential costs of a move to a different regulatory model would be high. The equity model has also delivered an effective management and governance structure, and a radical departure from that model would bring with it material implementation risks.
- The wider relevant regulatory precedent, including Ofgem's recent findings from RPI-X @ 20, also suggests that a highly geared equity model or a mutual would not be appropriate for NIE. Regulators have implicitly recognised that a very highly geared model (mutual or otherwise) would be costly to reverse and significantly less flexible in response to credit conditions and cost shocks. The Utility Regulator also appears to have recognised the lack of flexibility that a highly geared financial model can entail, in its stated desire to implement a tax clawback mechanism for gearing in excess of regulatory assumptions.

Embedded assets are difficult to ring-fence

Much of the transmission development that will take place over the RP5 period in accordance with NIE's medium term plan will involve upgrading parts of the existing 110kV system e.g. by re-conductoring 110kV overhead lines or adding additional transformers to existing substations or adding additional circuits to existing routes. By definition these assets will be fully integrated within the existing transmission network and the practical difficulties associated with unbundling them to facilitate any separate financing structure are likely to be substantial, cumbersome and complex to the point of adding to, rather than reducing, costs - e.g. each asset would have to be separately financed and economies of scale would be lost.

The medium term plan investment is therefore not readily amenable to a form of financing that is different from the rest of the transmission network. The 110kV developments are relatively more certain (as regards their scale and

timing) than the 275kV developments and can be sensibly incorporated within the form of the price control as proposed in chapter 4.

New assets on the 275kV transmission network driven by the RIDP would also be difficult to separate from the rest of the network without giving rise to many practical difficulties and new costs to customers. Given these assets will be fully embedded in a dynamic transmission network, the management and operation of the network and its further development would become significantly more complex if ownership was fragmented - and complexity adds cost. For example, with multiple ownerships the current procedures and processes that govern the interface between the transmission system operator and the transmission system owner (as set out in the Transmission Interface Arrangements) would become increasingly complex and new contractual arrangements between asset owners would need to be established. Operational issues to be resolved would include the management and co-ordination of planned outages on the transmission network, the response to transmission faults including under storm conditions and health and safety issues. The effective application of smart technologies that have the potential to play an important part in the transmission network of the future is likely to be hindered if the network is sub-divided into different ownerships.

The proposed 400kV Tyrone-Cavan Interconnector is not regarded as a stand-alone asset. It has been specifically designed to form an integral part of the synchronised “all-island” HVAC transmission network. The observations made above in regard to new 275kV assets are therefore equally applicable to the Interconnector.

Any proposal to introduce ‘financial boundaries’ within an integrated transmission network would need to ensure that the operational, maintenance and control issues were properly understood and establish that the overall benefits were real. In our view there is no evidence to suggest that this would be the case. This probably explains why there are only limited instances of the contestable ownership model for embedded assets (excluding stand-alone interconnectors) worldwide.

Timing of investment

Furthermore, given the complexity of the arrangements that would need to be in place to overcome the practical difficulties in ring fencing embedded assets, and the fact that the 275kV (and possibly also the 400kV Tyrone-Cavan Interconnector) assets are unlikely to be constructed in RP5 due to constraints such as those imposed by the planning system, there is no need to consider alternative ownership and financing arrangements for RP5.

Pensions

There are three key issues regarding pension costs:

- the background to the current deficit;
- the appropriate treatment of pension costs incurred in RP4 but not covered by allowances; and
- the appropriate treatment of pension costs that are expected in RP5.

We discuss each of these issues in more detail below.

Reasons for the current pensions deficit

The actuarial valuation as at 31 March 2006 of the pension scheme to which NIE belongs (the "Scheme") showed a past service deficit. Contributions, including a one-off payment, were subsequently made to clear the deficit. However, subsequent to these contributions having been made a significantly larger deficit emerged. The major sources of this increased deficit were:

- lower than anticipated investment returns; and
- increases in life expectancy.

None of the deficit as at 31 March 2009 is attributable to early retirement deficiency costs, which have been fully funded by the sponsor since 1 April 2003.

As required by pension legislation, the Scheme's investment strategy is set by the Scheme's Trustees, who, with encouragement from the company, have actively followed a course of de-risking to reduce exposure to market volatility. Over the three years from 2006 to 2009, investment markets have been very volatile and equity markets in particular have lost value. Most UK pension schemes have suffered losses because of this. The Scheme has an investment strategy which is less exposed to market volatility than other schemes in the electricity industry and UK schemes overall. Hence the Scheme has suffered less adverse investment performance than many other schemes over the period.

The other major cause of the current deficit is that estimates of future life expectancy have increased since those estimated as part of the 2006 valuation, reflecting new research and the position of the Pensions Regulator. Over the three years since 2006, advice from the actuarial profession on life expectancy has moved on substantially. Guidance from the Pensions

Regulator has reinforced this, in particular its February 2008 consultation paper and September 2008 guidance regarding mortality assumptions.

The assumed life expectancy for the Scheme at 2009 is broadly in line with that of the UK electricity industry as a whole, based on the assumptions set out in the Government Actuaries Department report to Ofgem. [9]

Limits to company control of pension costs

Like other regulated network utilities with defined benefit schemes, NIE has limited ability to control its pension costs, since:

- all reasonable structural changes available to control Scheme costs have been made, in particular closure of defined benefit schemes to new members; and
- the very large majority of past and present members of the Scheme have their rights protected by primary legislation put in place at privatisation - not only in relation to benefits accrued to date but also in respect of future service.

NIE in particular acted promptly to control its pension costs. The final salary section of the Scheme was closed to new entrants in March 1998. NIE was one of the first privatised electricity companies to do so. The Government Actuaries Department report to Ofgem[10] suggests that only 3 of the 14 companies covered closed final salary membership before this.

The impact of protected persons legislation on the ability of NIE to manage the cost of the existing defined benefit scheme is also significant. Currently, protected persons represent around 97% of the Scheme's final salary members and represent a similarly high percentage of NIE's liabilities.

The issue of controllability of pensions costs has been examined at length in GB where Ofgem ran a 16 month consultation on the topic. On the role of protected persons legislation in limiting the ability to amend the benefits that accrue to members of such schemes, Ofgem found that:

> "We have reviewed the evidence submitted by DNOs in response and the protected person legislation directly. We have concluded that the protected persons legislation provides limited scope to

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[9] Government Actuaries Department, 2009, report to Ofgem England, Wales and Scotland electricity and gas distribution businesses.

[10] Government Actuaries Department, 2009, report to Ofgem England, Wales and Scotland electricity and gas distribution businesses.

> amend benefits already accrued and payable now or in the future to a member or beneficiary, or to adversely amend either future pension rights of protected persons or their contributions. It is only possible to change benefits or increase contributions of protected members in some circumstances if a two-thirds majority of scheme members consent."[11]

In its second consultation document on pensions, Ofgem also stated that:

> "With one exception, they have mitigated these costs by closing the schemes to new members. They cannot without the consent of trustees and members amend scheme benefits or future accruals." [12]

Since pension costs are not within the control of NIE, the appropriate regulatory treatment is cost pass through. The relevant regulatory treatment of pension deficit contribution costs depends on whether these are past RP4 pension costs, or future RP5 pension costs.

RP4 pension costs

At RP4, NIE's a priori pension allowances were based on NIE's actual pension contributions made during the corresponding year of RP3, adjusted for inflation. NIE's actual pension costs will be larger than those included in its allowance during RP4, leading to an under-recovery.

Given the uncontrollable nature of these costs, and the impact of the contributions on reducing the pension deficit funding required in future periods, NIE proposes that this under-recovery should be recovered in full at RP5. This should be done through a logging-up mechanism at RP5, allowing for a rate of return to be earned on the under-recovery.

The regulatory precedent from Ofgem supports an approach that allows the full recovery of pension contributions made during the previous price control period.

> "As proposed at DPCR4, we have made a calculation to restore companies to the position they would have achieved if their actual pension payments had been forecast perfectly in the last price review. A revenue adjustment is made in DPCR5 for this true up".[13]

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11 Ofgem, 2009, DPCR5 Final Proposals, Financial Methodolgies, page 37, para 5.14

12 Ofgem, 2009, Price Control pension principles, Second Consultation, page 17, paras 3.6-3.7

13 Ofgem, 2009, DPCR5 Final Proposals, Financial Methodolgies, page 39, para 10.2

Ofgem has also ensured that the allowed return on deficit under-recoveries at DPCR4 is logged up and recovered during subsequent price control reviews on an NPV neutral basis.[14]

RP5 pension costs

NIE proposes that its pension costs during RP5 should be allowed over the same period as agreed with the trustees. As the Utility Regulator recognises in the Strategy Paper, the Pensions Regulator discourages deficit repair periods in excess of 10 years, and the trustees are in a strong position to negotiate even shorter periods than this. NIE also has limited ability to influence the actuarial assumptions adopted, with extensive use having been made of such ability to influence actuarial assumptions as the sponsor has.

At DPCR5, Ofgem allowed full recovery of pension deficits as at the end of DPCR4.

> "In our minded to position we made it clear that we are committed to allowing the network operators to recover through regulated revenues, all of the pension liabilities they have accrued to the end of the current price controls. In the case of DNOs this means we are committed to allowing the companies to recover the full value of their deficits accrued at the 31 March 2010."[15]

Although Ofgem adopted a different approach to the deficit repair period to the one NIE proposes, it was clear that in doing so any timing differences in regulatory allowances compared to actual payments by companies would need to attract the regulatory rate of return. Even so, a timing difference of this nature may be difficult to reconcile with the requirement to fund a higher level of capex in RP5.

With regard to deficit repair payments over the forthcoming period, Ofgem stated the following.

> "If DNOs agree faster repair payments with their trustees than the 15 years we use, we will adjust allowed revenues over the remaining portion of the 15 years to keep the companies whole on a Net Present Value (NPV) neutral basis."[16]

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[14] Ofgem, 2009, DPCR5 Final Proposals, Financial Methodologies, pages 39-40.

[15] Ofgem, 2009, DPCR5 Final Proposals, page 45, para 3.62

[16] Ofgem, 2009, DPCR5, Final Proposals, page 47, para 3.71

Pensions deficit in the gearing calculation

NIE does not believe it would be appropriate to reflect the pensions deficit in the gearing calculation because:

- The RAB has been funded through debt and equity, and no portion of it can be seen as having been funded through the pensions deficit.
- Pensions deficits are already taken into account when a rating agency determines an investment grade credit rating.
- The appropriate regulatory treatment of pensions deficit is as a pass through item, rather than an item for inclusion in RAB. Since the deficit should be treated as a pass through cost, there is no reason to include it in any gearing calculations.
- Including the deficit in gearing would be inconsistent with Ofgem's approach.

7 Smart Technology

Introduction

It is widely recognised across the utility industry that the application of smart technologies is necessary to address the challenges in meeting Government's targets for sustainability and moving towards a low carbon network. As noted in the Utility Regulator's Strategy Paper, in GB Ofgem has begun introducing funding incentives to the DNOs to provide a head start in trialling, developing and applying smart technologies.

Although there is no desire to duplicate research into smart technologies already taking place in GB, NIE recognises the need to carry out its own trials and development of certain technologies to address the different needs of the NI network. To achieve this, NIE is seeking support from the Utility Regulator broadly in line with the funding incentives provided by Ofgem for the DNOs.

Proposals for smart technology initiatives

As mentioned in chapter 2, NIE's Sustainable Networks Programme has provided the opportunity to gain the necessary experience in developing the structure and reporting processes associated with the management of smart technology projects as well as continuing to promote a culture of innovation within the organisation.

For RP5, NIE intends to step up its efforts to take on innovation projects that are bigger in scale to include solutions that can be applied in both the short and long-term. Progress to date in developing smart technology and proposals for future projects is outlined below. The proposals are only meant to provide an indication of the areas of interest and scale of work; a more detailed description will be included in a subsequent submission.

Renewable Generation

NIE has deployed smart technologies in the form of dynamic rating of overhead lines and special protection and control schemes.

- Applying dynamic ratings to overhead lines maximises the network's capacity to accommodate wind generation connected to the network by calculating the real current carrying capability of the line through observation of the local weather conditions in or near real-time. Dynamic ratings are currently applied to a number of lines to make available additional capacity within the existing network to connect wind generation.

- Special Protection Schemes (SPS) are schemes that automatically initiate a series of control actions to prevent the overloading of circuits after an unplanned event on the network. These schemes can enable more capacity to be connected without significant investment in infrastructure by reducing demand and/or generation output whenever such an event occurs.

Two software packages have been developed to assist planners in maximising the amount of generation that can be connected to the distribution network.

- The SPS modelling tool will be used to accelerate the design of new SPSs and ensure no unintended interaction occurs between the schemes.
- Network constraint assessment software is helping planners to quantify the cost/benefit of connecting renewable generation. So far, the software has already been used in studies to determine the future transmission network capacity requirements for the RIDP and has facilitated further connection of several wind farms which would otherwise have had to wait for network reinforcement to be completed.

Moving forward, NIE will continue to utilise smart technologies throughout RP5 to get the most from the existing network in terms of connecting windfarms while minimising the investment required. NIE will bring forward proposals to ensure the delivery of these objectives is properly incentivised through the RP5 price control arrangements.

- NIE intends to extend the application of dynamic line ratings throughout the 110kV overhead line system as required in order to maximise the network capacity available. To date, three 110kV lines have had instrumentation fitted for this purpose.
- So far NIE has deployed a number of SPSs to allow windfarms to be connected. We intend to continue to deploy this technology moving towards a position of ‘smart zones’ within the network.
- NIE will seek to utilise smart technologies to maximise the number of individual smaller scale wind turbines that can be connected to the 11kV and LV networks.
- NIE’s medium term investment plan into RP5 is targeted to accommodate around 750MW of renewable generation. By utilising smart technologies it is hoped to push this figure closer to the 1,000MW figure that DETI aspires to by around 2015.

Asset life extension

NIE already utilises smart technologies to monitor the condition of assets with a view to asset life extension. For example, monitoring equipment attached to transformers can give a real time view of the condition of the transformer. In RP5 NIE will extend the use of these technologies to get a more real time view of key assets with the aim of asset life extension and reduction in asset replacement investment.

Load related investment

NIE utilises monitoring equipment to understand load flows on the high voltage network. This information is utilised to push network assets harder and minimise load-related network investment. In RP5 the intention is to run demand side management or demand profiling pilots with a view to future deployment of smart technologies to defer load-related network investment while also contributing to a broader carbon reduction agenda.

- NIE intends to carry out a domestic smart meter trial consisting of around 200 customers to determine the possibility of influencing customer behaviour through the provision of in-home displays and application of time of use tariffs. Other smart technologies will also be included as part of this trial such as monitoring of 11kV circuits and transformer condition monitoring.
- A collaborative project between NIE, Ulster University and the Housing Executive is investigating the feasibility of utilising existing hot water tanks with immersion heaters in domestic homes as thermal storage for wind balancing (using excess wind generation as cheap heating), load shifting and demand response. If results prove positive, a trial may be carried out.

Remote control and automation

NIE deploys remote control facilities on the high voltage network and this is currently being extended throughout the 11kV rural network. This benefits customers with improved restoration times and reduced CMLs and also quicker response during storms. These smart technologies will also facilitate the management of wind turbines connected to the 11kV network. In RP5 NIE intends to further extend these facilities throughout the 11kV network, including to underground networks in cities and towns.

Control and communications

As communications is a pre-requisite for the application of smart technology its deployment will have a significant impact on the operational telecommunications networks (OTN). NIE is in the process of identifying what

development of the OTN is required during RP5 and will submit proposals to the Utility Regulator.

NIE will also investigate the requirement to upgrade the control and network management IT systems to facilitate the management and utilisation of smart technologies deployed on the network.

Electric vehicles

NIE will participate in pilots sponsored by DOE/DRD/DETI. It will be necessary for Departments, the Utility Regulator and NIE to agree the manner in which NIE should support these wider policy initiatives.

Smart meters

Similarly, any general deployment and funding of smart meters will need direction from Government and the Utility Regulator's approval. There will be some minimal deployment of smart meters in various pilot schemes that NIE plans to establish subject to agreement with the Utility Regulator.

Carbon reduction

NIE will work with the Utility Regulator or other government bodies in appropriate carbon reduction initiatives.

Approach to funding smart technology

Smart technology can be grouped into the following categories:

Smart technology at or near the end of its development cycle.

Projects in this category will consist of installing equipment or systems which will lead to benefits that can be achieved in the short-term. For example, condition monitoring which may lead to an extension in the serviceable life of transformers that would otherwise need to be replaced as part of an asset replacement programme.

For the foreseeable future, there will continue to be uncertainty over the extent of network investment that can be deferred from the utilisation of smart technology. However, it will be important to ensure that the deployment of smart technology is properly incentivised, for example, through the wider arrangements to incentivise capex efficiency.

As it provides a means of deferring conventional network investment, NIE will seek to recover the costs of installing smart technology as part of the RP5 capex allowance.

Smart technology that requires further development.

Certain areas of smart technology will have a large impact on the manner in which the network is currently operated. Such projects will require substantial development work before widespread implementation can be achieved. For example, increasing amounts of generation embedded in the distribution network will increase the complexity of how the network must be managed and this will require an increase in the level of monitoring and automation already in operation.

In relation to these types of projects, NIE will be seeking funding arrangements not dissimilar to the IFI and LCNF incentives offered to DNOs by Ofgem.

NIE will work with groups such as Smart Grid Ireland in order to seek access to other sources of funding for the deployment of smart technologies.

Communications infrastructure

The application of smart technology will call for a greater demand in communications due to increased monitoring and control requirements. It is critical that significant investment is made in RP5 to ensure that the communications infrastructure put in place over the next few years meets NIE's long-term smart grid strategy.

NIE will be submitting an investment plan for the OTN to the Utility Regulator.

Annexe: Answers to specific questions raised in the Strategy Paper

This Annex provides a short synopsis of NIE's position on each of the 21 questions on which the Utility Regulator specifically invites views. Where appropriate, the page numbers refer to sections of the main body of this response where the matter is addressed in more detail.

1. *Which aspects of the SEM arrangements do respondents believe should be taken into account for the NIE T&D RP5 price control?*

   The Strategy Paper identifies a number of policies which are now harmonised through the SEM arrangements which may influence the future operation and development of the network in NI. These include policies to encourage demand side participation, transmission connection policy, locational network signals and the promotion of regional integration.

   We consider that three of these are likely to require some degree of consideration in setting the RP5 price control: Demand side management is one aspect of smart technology that NIE intends to explore in RP5. The policy for charging for connecting windfarms to cluster substations will have a bearing on the proportion of costs to be funded by windfarm developers rather than through the price control, and the 400kV Tyrone-Cavan interconnector is a key element for regional integration.

2. *Are there any other legislative or policy developments that the Utility Regulator should take into consideration for the RP5 price control?*

   The Strategy Paper identifies the IME3 Directive, the Renewable Energy Directive and DETI's Strategic Energy Framework as three areas where policy and legislative developments are likely to impact on the RP5 price control. To these NIE would add the introduction of the Electricity Safety, Quality and Continuity regulations and street works legislation.

3. *The Utility Regulator welcomes respondents' views on the depreciation policy and profile used for the current NIE T&D price control. Do respondents agree with the current profile and are there alternatives we should consider?*

   The 40 year depreciation period applied to NIE's RAB is currently twice as long as that for electricity transmission and distribution RABs in the rest of the UK. This difference should be taken into account in any WACC comparisons between NIE and the DNOs. Given the significant increase in investment that NIE expects to make in RP5, a shortening of the depreciation period to aid financeability should be considered. (Pages 35 - 36).

4. *Currently, rates, wayleaves and licence fees are classed as "uncontrollable opex". Do respondents agree with this classification?*

   In its 1997 review of NIE's RP2 price control the MMC (now the Competition Commission) regarded rates and wayleaves as costs which are essentially or largely uncontrollable and, in addition to licence fees, that has continued to be the view under successive price controls. NIE sees no reason to change this established treatment.

5. *The Utility Regulator welcomes views on the treatment of the proportion of a pension scheme deficit which has arisen due to early retirement deficiency costs. How do respondents think this should be funded?*

   None of the pension deficit as at 31 March 2009 is attributable to early retirement deficiency costs. (Page 40).

6. *The Utility Regulator welcomes any comments on the current incentive mechanisms in place for RP4. Do respondents think that these incentive mechanisms should continue for RP5?*

   As capital expenditure will be the dominant driver of transmission and distribution prices going forward, it will be particularly important to optimise the use of network assets and capital efficiency through suitable incentive mechanisms for both conventional investment and investment to facilitate renewable generation. The current capex incentive is relatively weak and should be strengthened. Consideration should also be given to introducing new incentives in areas such as network losses, network performance and customer service. Appropriate incentives will provide a means of ensuring that NIE is encouraged to innovate to provide the outcomes that customers value and that support relevant government policy objectives, notably DETI's target for renewable generation. In developing new or enhanced incentive schemes it will be important to ensure that incentive rates applied to the various performance measures reflect the appropriate value that stakeholders place upon these measures. NIE expects the GB arrangements to provide a useful guide. (Pages 27 - 32).

7. *Do respondents agree on the continued RPI-X approach for the RP5 price control, or do they support developments in incentive regulation such as Totex or Menu regulation?*

   For a number of reasons, not least the lack of a comparable data set between NIE and the DNOs, NIE would not support a move to total cost benchmarking. The equalisation of opex and capex incentives (which the Strategy Paper lists as one of the objectives of totex) can be achieved by other means and NIE supports that aim.

As regards menu regulation, this has been implemented in GB through the IQI arrangement which is intended to reveal quality information about future costs. The two key parameters of the IQI are the sharing factor associated with over-spend and under-spend (which defines the strength of incentives), and the additional income that the company receives for producing a quality forecast - the greater the confidence the regulator has in the forecast, the higher the payment. In the context of NI, it is questionable whether the Utility Regulator needs to explicitly set out an IQI matrix for the purposes of establishing these two parameters for NIE. One of the principal advantages of the IQI is that it provides a common framework within which all companies in a multi-firm industry can be treated on an equal basis, which is not relevant in the NI situation. NIE would hope to be able to satisfy the Utility Regulator that its business plan is robust and well-justified, and be able to engage in a constructive dialogue around the incentive rate that should apply. In other words, NIE would hope to be able to reproduce the economic effect of the IQI without introducing any unnecessary complexity. (Pages 17 - 19).

8. *Are respondents aware of any other alternative approaches to incentive regulation, other than RPI-X, Totex or Menu regulation which they feel is appropriate for RP5, taking into account changing circumstances and the integration of renewables?*

The key challenge for the RP5 price control is how the investment to facilitate renewable generation should be assessed and incentivised in light of the uncertainty as to its scale and timing. The proposal outlined in this response provides a means to manage this uncertainty, ensures the outputs are delivered, and provides appropriate incentives for innovation and efficiency. (Pages 21 - 23).

9. *The Utility Regulator welcomes views on whether it should continue to use a 'rolling mechanism' for controllable Opex in RP5, or alternatively a bottom-up approach supported by benchmarking?*

The rolling opex mechanism introduced in RP4 is automatically passing through to customers savings made in the previous regulatory period. However, a number of factors will tend to put upward pressure on costs in RP5. These will need to be taken into consideration when deciding if the rolling opex mechanism should continue and NIE will put forward its ideas on this. (Page 29).

10. *For RP5 should there be an allowance for Capex or should it be recoverable on an actual (pass-through) basis?*

The current capex incentive is a relatively weak one, not least because its scope is limited to productivity and procurement. The result is that large elements of efficiency go unrewarded, particularly savings that

have been achieved through innovation in planning and design. Given the expected increases in capital investment in RP5 in asset replacement and facilitating renewable generation, maintaining the current approach is unlikely to be in the interests of customers. NIE will work with the Utility Regulator to develop more effective incentives for both conventional capex and capex to support renewable generation. The RP5 price control should provide a clear mechanism for dealing with a situation where, in order to meet statutory and licence obligations, it becomes necessary to exceed the regulatory allowance or budget. (Pages 28 - 29).

11. *Do respondents have any views on any other incentive mechanisms that should be considered for RP5?*

As indicated in the response to question 6, consideration should be given to introducing new incentives in areas such as network losses, network performance and customer service. Considerations will include (i) the application of caps and collars to limit excessive rewards and penalties and (ii) the supporting investments in systems and processes for measurement, analysis and reporting. NIE will submit proposals to the Utility Regulator. (Pages 27 - 32).

12. *The Utility Regulator is interested to hear views on the proposal that two separate price controls could be implemented in 2012 for Transmission and Distribution. What are respondents' views on this possibility?*

The basis for the Utility Regulator's proposal is uncertainty relating to (a) the investment in the transmission network to facilitate renewable generation and (b) the IME3 Directive. NIE has proposed an approach to transmission investment that represents a more effective remedy to the problem of the uncertainty around transmission developments without having to separate the price controls. This avoids the risk of introducing new costs arising from (i) the introduction of new interface arrangements between T&D (ii) making changes to cost reporting processes and systems and (iii) the loss of synergies between T&D (in activities such as network development, project management, maintenance and procurement). As regards the IME3 Directive, NIE believes there is a strong case for applying the article 9(9) derogation which would not require separate price controls. In summary, separation of the price controls is unnecessary and would be inefficient, particularly on a small network like NIE's. It would be better to proceed now with setting the RP5 price control as a combined T&D price control and, if necessary in the light of the final decision on IME3, make the appropriate adjustment to those elements of allowed revenue which relate to transmission. (Pages 20 - 26).

13. *The Utility Regulator welcomes views on changing the duration of the price control to 3 years for Transmission, while maintaining a 5 year price control for Distribution. Interested parties who believe the Utility Regulator should maintain the 5 year duration for Transmission are invited to lay out specific reasons in their response as to why we should do so.*

    A three year price control would not resolve the problem of the uncertainty around transmission developments (the uncertainty is confined to transmission investments in support of renewable generation, not conventional capex). It would have weaker incentive properties than a five year price control, it would increase the burden of regulation and it would run counter to the trend in GB where Ofgem is considering longer price controls. (Pages 20 - 26).

14. *The Utility Regulator wishes to ascertain respondents' opinions on using Ofgem's WACC as precedent for NIE T&D. Do respondents think the Utility Regulator should continue to do this for RP5?*

    NIE is supportive of applying GB precedent in the setting of the effective WACC for NIE, conditional upon recognising that this precedent not only takes into account the baseline WACC that Ofgem allowed, but also the additional income that the DNOs are able to earn that was not conditional on performance within the DPCR5 period. This treatment would reflect the fact that the DPCR5 WACC was set in a holistic manner, and, in the absence of the non-conditional additional income, Ofgem would have had to set a higher baseline WACC in order to achieve the same expected returns for investors. (Pages 33 - 35).

15. *The Utility Regulator welcomes views on the treatment of a pension scheme deficit as part of the price control. What are respondents' views on the appropriate duration of a deficit recovery plan?*

    The current pensions deficit is a result of factors outside NIE's control which have arisen mainly as a result of investment returns being lower than anticipated and higher life expectancy. There is only limited scope to control pension costs - the final salary element of the scheme of which NIE is a member was closed to new members in 1998 and around 97% of the scheme's final salary members have their rights protected by primary legislation. The under-recovery of pension costs in RP4 should therefore be recovered in full in RP5 through a logging-up approach which allows a rate of return, while pension costs during RP5 should be allowed on a pass-through basis. The full recovery of deficit repair costs is supported by Ofgem precedent. The recovery of pension costs should be over the same period agreed with the scheme's trustees. (Pages 40 - 44).

16. *The Utility Regulator welcomes views on whether the current pension deficit in respect of NIE T&D employees should be treated as debt as part of the company's gearing calculation.*

It would not be appropriate to reflect the pensions deficit in the gearing calculation. (Pages 40 - 44).

17. *The Utility Regulator welcomes respondent's opinions on continuing with setting the rate of return on a post-tax basis for the next price control. Are respondents in agreement with this?*

NIE believes that the proposed post tax approach to the WACC is appropriate. (Page 35).

18. *The Utility Regulator welcomes views on the use of a Reporter for the NIE T&D RP5 price control. Do respondents think this would be beneficial?*

NIE appreciates that it will have to develop a well-justified business plan, and be subject to appropriate regulatory monitoring of the delivery of that plan. In most jurisdictions, the regulator evaluates the robustness of company plans for the purposes of setting a price control, perhaps with the support of expert advisors; and also monitors the company's costs and output provision, again potentially with external support.

In a small number of jurisdictions, most significantly the water industry in England and Wales, a different approach has been applied, in which a reporter has been appointed for each company since privatisation. These reporters both critically assess the business plan, and undertake ongoing monitoring. However, their role is advisory, in the sense that Ofwat can choose to apply other considerations when setting prices. It is worth noting that Ofwat chose this approach at a time when the water industry was about to incur significant capital expenditures, and when Ofwat had yet to develop the capacity and expertise to assess these plans for over thirty companies. The Utility Regulator is at a more mature stage in its development, so perhaps might consider itself to be better equipped at undertaking these tasks for a single operator such as NIE. In any case, the question of whether or not there is a reporter is but one part of a wider question of the framework the Utility Regulator would adopt for the purposes of evaluating plans and monitoring against those plans, which we look forward to developing with the Utility Regulator.

NIE believes that the current annual reviews of capex, supported by advisors if necessary, provides an appropriate balance between periodic price control reviews and the risk of undue regulatory intrusion on the business. NIE is also of the view that such a step would not be consistent with an incentive-based approach.

19. *The Utility Regulator welcomes views on encouraging additional consumer expertise for RP5?*

The Utility Regulator notes that it will work with the Consumer Council to ensure consumer views are considered in setting the RP5 price control. NIE will be pleased to discuss its perspective with the Consumer Council and with any additional consumer representation that might be brought on board.

20. *Do respondents support a smart metering roll out as part of RP5?*

If the cost/benefit case for a roll out of smart meters in NI is confirmed, the common services provider model which has been established here is well suited to implementing a smart metering programme by NIE with the meters being treated as a regulated asset. A timely decision by DETI on a roll-out of smart metering would assist in defining the investment requirements for RP5. (Page 12).

21. *The Utility Regulator is interested to hear respondents' views on the possible introduction of a fund similar to Ofgem's Low Carbon Networks Fund as part of RP5. Do respondents think this would be beneficial on a Northern Ireland/all Ireland basis?*

The application of smart technologies is necessary to address the challenges in delivering an increased asset replacement programme, meeting Government's targets for sustainability and moving towards a low carbon network. NIE has outlined ideas for the application of smart technology across a range of its activities and looks forward to developing these proposals with the Utility Regulator. The introduction of a Low Carbon Networks Fund and an IFI or similar arrangements would be a helpful facilitator. (Pages 31 and 45 - 49).