NECEC 1-1

Request:

Please provide functioning spreadsheet versions, with formulae intact, of all charts and tables contained in:

a. National Grid Joint Pre-Filed Direct Testimony;

b. National Grid Joint Direct Testimony, Book 1 of 3;

c. National Grid Joint Direct Testimony, Book 3 of 3; and

d. Appendices 10.1 to 10.11 of National Grid Joint Direct Testimony, Book 2 of 3.

Response:

All files are being provided on a USB flash drive due to size.

In the Company's responses to DIV 19-8 and 27-13, certain Grid Mod revenue requirements were updated. These updates are not reflected in the documents provided in responses a through d. Therefore, the Company is providing these files as well to supplement the response.

a. Attachment NECEC 1-1 contains a list of the workpapers in support of the charts and tables contained in the National Grid Joint Pre-Filed Testimony. With the exception of the Exhibits outlined in Attachment NECEC 1-1-1, all charts and tables in National Grid's Joint Pre-filed Testimony are reproduced from National Grid's Direct Testimony, Books 1-3. See responses to parts b. through d., below.

Attachment 1, Table A	Attachment NECEC 1-1-1
Attachment 1, Table B	Attachment NECEC 1-1-1
Appendix 10.1 Revenue Requirements Summaries REVISED	Attachment NECEC 1-1-2
Appendix 10.2 Grid Mod Stand Alone REVISED	Attachment NECEC 1-1-3
Appendix 10.3 Grid Mod Shared REVISED	Attachment NCEC 1-1-4

Prepared by or under the supervision of: Kayte O'Neill

Appendix 10.4 AMI Stand Alone REVISED	Attachment NECEC 1-1-5
Appendix 10.5 AMI Shared REVISED	Attachment NECEC 1-1-6
Appendix 10.6 Electric Transportation REVISED	Attachment NECEC 1-1-7
Appendix 10.7 Electric Heat REVISED	Attachment NECEC 1-1-8. Please note the table included herein reflects revisions from the November 2017 filing, as presented in the Company's response to Division 32-16.
Appendix 10.8 Energy Storage REVISED	Attachment NECEC 1-1-9
Appendix 10.9 Solar REVISED	Attachment NECEC 1-1-10

b. Attachment NECEC 1-1-2containsa list of the workpapers in support of the charts and tables contained in the National Grid Joint Direct Testimony, Book 1 of 3:

Table 3-1 System Data Portal Cash Flow	Attachment NECEC 1-1-11
Table 3-2 Feeder Monitoring Sensors Cash Flow, RI only	Attachment NECEC 1-1-11
Table 3-5 DSCADA & ADMS Cash Flow Estimate, Multi-Jurisdiction	Attachment NECEC 1-1-11
Table 3-6 RTU Separation Cash Flow Estimate, RI only	Attachment NECEC 1-1-11
Table 3-7 GIS Data Enhancement Cash Flow Estimate for IS Resources, RI only	Attachment NECEC 1-1-11
Table 3-8 GIS Data Enhancement Cash Flow Estimate for IS Resources, Multi-Jurisdiction	Attachment NECEC 1-1-11
Table 3-9 GIS Data Enhancement Cash Flow Estimate for Non-IS Resources	Attachment NECEC 1-1-11

Table 3-10 Enterprise Service Bus Cash Flow Estimate, RI only	Attachment NECEC 1-1-11
Table 3-11 Enterprise Service Bus Cash Flow Estimate, Multi-Jurisdiction	Attachment NECEC 1-1-11
Table 3-12 Data Lake Cash Flow Estimate, RI only	Attachment NECEC 1-1-11
Table 3-13 PI Historian Cash Flow Estimate, RI only	Attachment NECEC 1-1-11
Table 3-14 Advanced Analytics Cash Flow Estimate, RI only	Attachment NECEC 1-1-11
Table 3-15 Data Lake Cash Flow Estimate, Multi-Jurisdiction	Attachment NECEC 1-1-11
Table 3-16 PI Historian Cash Flow Estimate, Multi-Jurisdiction	Attachment NECEC 1-1-11
Table 3-17 Advanced Analytics Cash Flow Estimate, Multi-Jurisdiction	Attachment NECEC 1-1-11
Table 3-18 Telecommunications Cash Flow Estimate, RI only	Attachment NECEC 1-1-11
Table 3-19 Telecommunications Cash Flow Estimate, Multi-Jurisdiction	Attachment NECEC 1-1-11
Table 3-20 Cybersecurity Cash Flow Estimate, RI only	Attachment NECEC 1-1-11
Table 3-21 Cybersecurity Cash Flow Estimate, Multi-Jurisdiction	Attachment NECEC 1-1-11
Table 3-23 Power Sector Transformation Cash Flow Estimate, RI only	Attachment NECEC 1-1-11
Table 3-24 Power Sector Transformation Cash Flow Estimate, Multi-Jurisdiction	Attachment NECEC 1-1-11

Table 4-1 Estimated Costs for the Rhode Island Only Scenario	Files to support Table 4-1 were provided under confidential treatment in DIV 5-1-1.
Table 4-2 Estimated Costs for the Multi-Jurisdiction Scenario	Files to support Table 4-2 were provided under confidential treatment in DIV 5-1-2.
Table 4-6 Rhode Island Only Implementation Societal Test Benefits and Costs	Files to support Table 4-6 were provided under confidential treatment in DIV 5-1-1.
Table 4-7 Rhode Island and New York Joint Implementation Societal Test Benefits and Costs	Files to support Table 4-7 were provided under confidential treatment in DIV 5-1-2.
Table 5-4 Total Costs by Program Type (Electric Transportation)	Attachment NECEC 1-1-18
Table 5-5 Program Costs by Type of Expense (Electric Transportation)	Attachment NECEC 1-1-18
Table 5-6 Societal Cost Test Benefits and Costs (Electric Transportation)	Please see the Company's response to DIV 5-1-3.
Table 5-7 Rate Impact Measure Benefits and Costs (Electric Transportation)	Please see the Company's response to DIV 5-1-3.
Table 6-2 Costs by Program (Electric Heat)	Attachment NECEC 1-1-12. Please note the table included herein reflects revisions from the November 2017 filing, as presented in the Company's response to DIV 25-18.
Table 6-4 Societal Cost Test Benefits and Costs (Electric Heat)	Please see the Company's response to DIV 5-1-3.
Table 6-5 Rate Impact Measure Benefits and Costs (Electric Heat)	Please see the Company's response to DIV 5-1-3.
Table 7-2 Energy Storage System Program Costs by Year	Attachment NECEC 1-1-20.

Table 7-3 Societal Cost Test Benefits and Costs (Energy Storage)	Please see the Company's response to DIV 5-1-3.
Table 7-4 Rate Impact Measure Benefits and Costs (Energy Storage)	Please see the Company's response to DIV 5-1-3.
Table 8-2 Solar Program Costs by Year	Attachment NECEC 1-1-21.
Table 8-3 Societal Cost Test Benefits and Costs (Income Eligible)	Please see the Company's response to DIV 5-1-3.
Table 8-4 Rate Impact Measure Benefits and Costs (Income Eligible)	Please see the Company's response to DIV 5-1-3.
Table 9-1 Overview of Proposed Performance Incentive Mechanisms and Maximum Earnings Opportunity in Basis Points	Attachment NECEC 1-1-13
Appendix 2.2 Economic Development	Attachment NECEC 1-1-14

c. Attachments NECEC 1-1-3 contains a list of workpapers in support of the charts and tables contained in the National Grid Joint Direct Testimony, Book 3 of 3:

Workpaper 3.1 Modern Grid Costs, RI only	Attachment NECEC 1-1-15 and NECEC 1-1-16. Attachment NECEC 1-1-15 was provided in the Company's response to DIV 8-4-1. Additional files to support Workpaper 3.1 were provided under confidential treatment in DIV 8-4-2.
Workpaper 3.2 Modern Grid Costs, Multi Jurisdiction	Attachment NECEC 1-1-15 and NECEC 1-1-16. Attachment NECEC 1-1-15 was provided in the Company's response to DIV 8-4-1. Additional files to support Workpaper 3.2 were provided under confidential treatment in DIV 8-4-2.
Workpaper 4.1 AMF Costs REDACTED	Attachment NECEC 1-1-17

Workpaper 5.1 Electric Transport Costs/Assumptions	Attachment NECEC 1-1-18
Workpaper 6.1 Electric Heat Costs/Assumptions	Attachment NECEC 1-1-19
Workpaper 7.1 Energy Storage Costs/Assumptions	Attachment NECEC 1-1-20
Workpaper 8.1 Solar Costs/Assumptions	Attachment NECEC 1-1-21
Workpaper 9.1 Peak Demand Reduction Targets	Attachment NECEC 1-1-22
Workpaper 9.2 Electric Heat Initiative Targets	Attachment NECEC 1-1-12. Please note the table included herein reflects revisions from the November 2017 filing, as presented in the Company's response to DIV 25-18.
Workpaper 9.3 Electric Vehicle Targets	Attachment NECEC 1-1-23
Workpaper 9.4 Incentive Benefits	Attachment NECEC 1-1-24

d. Attachment NECEC 1-1-4 contains a list of the workpapers in support of the charts and tables for Appendices 10.1 to 10.11 of National Grid Joint Direct Testimony, Book 2 of 3:

Appendix 4.1 AMF Technology and BCA REDACTED	Please see the Company's response to DIV 5-1-1 and DIV 5-1-2.
Appendix 4.2 AMF BCA Methodology	Please see the Company's response to DIV 5-1-1 and DIV 5-1-2.
Appendix 10.1 Revenue Requirement Summaries	Attachment NECEC 1-1-25
Appendix 10.2 Revenue Requirement Modern Grid, RI only	Attachment NECEC 1-1-26

Appendix 10.3 Revenue Requirement Modern Grid, Multi Jurisdiction	Attachment NECEC 1-1-27
Appendix 10.4 Revenue Requirement AMF, RI only	Attachment NECEC 1-1-28
Appendix 10.5 Revenue Requirement AMF, Multi Jurisdiction	Attachment NECEC 1-1-29
Appendix 10.6 Revenue Requirement Electric Transportation	Attachment NECEC 1-1-30
Appendix 10.7 Revenue Requirement Electric Heat	See Attachment NECEC 1-1-8. Please note the table included herein reflects revisions from the November 2017 filing, as presented in the Company's response to DIV 32-16.
Appendix 10.8 Revenue Requirement Energy Storage	Attachment NECEC 1-1-31
Appendix 10.9 Revenue Requirement Solar	Attachment NECEC 1-1-32

NECEC 1-2

Request:

Refer to National Grid Joint Direct Testimony, page 83 of 102, lines 9-14:

> *Although today's regulatory framework supports cost-recovery and earnings on investment deemed prudent by regulators, it is not sufficient to drive innovative utility performance in delivering these new objectives. To best encourage utilities to innovate and to align their financial interests with broader policy goals and customer outcomes that expand beyond core performance obligations, new compensation mechanisms are needed.*

a. What is meant by "new compensation mechanisms?"

b. Would "new compensation mechanisms" include rate base rate of return regulation? Why or why not?

c. Would "new compensation mechanisms" include cost of service regulation? Why or why not?

d. (For witnesses McGuinness and Roughan). Please state each and every reason that supports the statements in this quoted testimony.

e. If not addressed in response to the previous question, what are the shortcomings of the current "compensation mechanisms?"

Response:

a. By "new compensation mechanisms," the Company is referring to incentive structures that would support utility innovation in support of delivery of regulatory and state policy goals and provision of new benefits to customers.

b. The Company intends that new compensation mechanisms would be combined with traditional cost of service regulation, including the opportunity to earn a fair rate of return on capital investments. This combined framework would provide comprehensive and fair compensation to utilities and the greatest value to customers. Cost of service regulation will benefit customers by ensuring the Company is able to raise necessary capital at reasonable costs and on reasonable terms. Carefully designed incentives can address barriers to innovation and encourage utilities to devote resources to endeavors that may not be within their normal responsibilities but that have the potential to provide substantial benefits to customers.

Prepared by or under the supervision of: Meghan McGuinness and Timothy Roughan

c. See response to part b.

d. As the Company notes in PST Book 1 of 3 (see Bates page 162), integration of new objectives around sustainability, system efficiency, resiliency, grid modernization, distributed energy resource integration, and customer engagement into the utility business environment requires electric distribution utilities to perform new functions that are materially different from the functions that support traditional utility business functions, and will require innovation with regard to technology adoption and deployment, business and management practices, and the customer relationship.

A regulatory environment that can foster such innovation is necessary to enable the utility to deliver the objectives described above in a way that maximizes benefits to customers. Two key shortcomings of the current regulatory framework impede this necessary innovation:

- **Under the current regulatory framework, the innovation necessary in support of these new objectives introduces regulatory risk for utilities.** Malkin and Centolella (2014)[1], included as Attachment NECEC 1-2, describe this risk:

  > "If a new system fails to perform as expected, the utility might face a risk of its costs being disallowed. Alternatively, if an innovative project succeeds, the utility might be challenged for not implementing the improvement more broadly or rapidly" (Attachment NECEC 1-2, page 7).

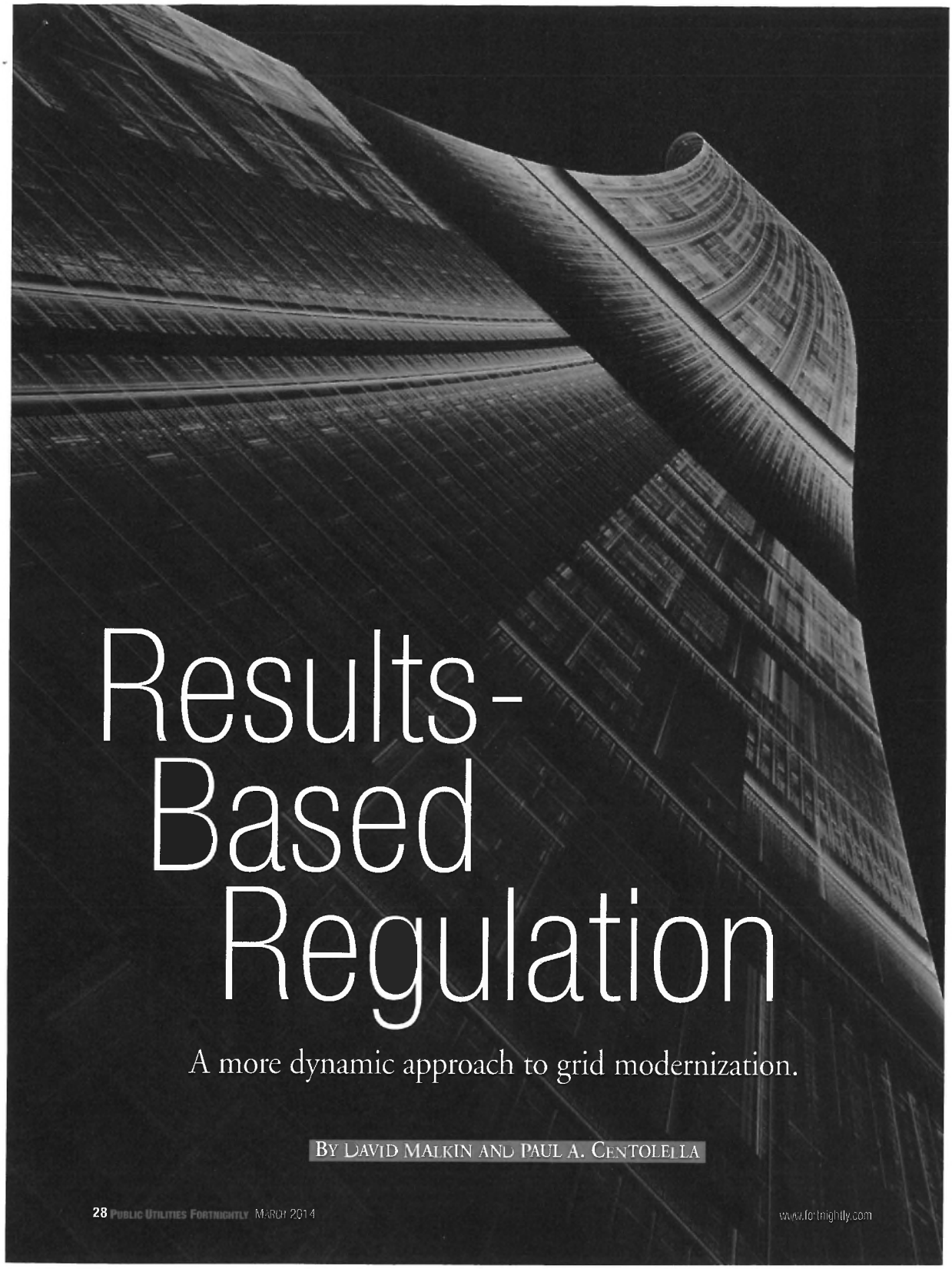
- **The current regulatory framework fails to reward the utility for successful innovation that generates customer value.** Malkin and Centolella (2014) describe a second key limitation of the current regulatory framework. While the discussion below focuses primarily on efficiency, the same arguments apply to innovation by the utility in support of regulatory or state policy goals.

  > "In competitive markets, firms have an opportunity to earn higher profits when innovation delivers greater value to their customers. Whether utilities actively seek to operate more efficiently or deliver greater value to customers will depend on whether regulation provides the incentive to innovate. Regulators never have sufficient information on all the available opportunities to reduce costs or improve service. It's thus virtually impossible for regulators to mandate that a firm actively seek out and discover such improvements. Incentives therefore play an indispensable role in promoting dynamic efficiency improvements. However,

[1] Malkin, David and Paul A. Centolella, Results-Based Regulation, Public Utilities Fortnightly 29-36 (2014).

even when the results exceed expectations, utilities are seldom rewarded for assuming the risks associated with innovation" (Attachment NECEC 1-2, page 7).

e. Please see the response to part d., above.



Results-Based Regulation

A more dynamic approach to grid modernization.

By David Malkin and Paul A. Centolella

Today's electric distribution companies face a dilemma. Increasingly, they are expected to modernize their networks: replace aging infrastructure, improve resilience during severe weather, integrate distributed and variable renewable generation, and secure systems against cyber and physical attacks. Yet these expectations arise at a time of slow-growing, flat, or even declining sales – a trend that discourages capital investment.

This problem is rooted in an outdated cost-of-service model of regulation that reviews costs as if the functions and activities of the modern distribution utility were little changed from those of yesterday. This model of regulation can slow the pace of innovation and defer investment that could otherwise deliver significant net benefits to customers. Yes, cost-of-service regulation helped support the 20th-century expansion of electric service, but it did so largely during periods of falling costs and increasing sales.

Building a 21st-century power system that's affordable, resilient, and environmentally sustainable will require a regulatory model that enables investment in new technologies and supports business models that deliver greater value to customers. However, cost-of-service regulation offers little incentive for utilities to improve performance beyond minimum levels required by regulators and may delay the pace the grid modernization.

Some regulators have experimented with alternative models – including capital trackers or multi-year revenue caps – to provide either greater support for new investments or stronger incentives for utilities to reduce costs. Yet rarely have these models simultaneously supported both objectives.

An alternative is emerging in the form of a new forward-looking regulatory and incentive framework: Results-Based Regulation. This regulatory model supports utility business plans that deliver long-term value to customers, rewards utilities for exceptional performance, and maintains affordable rates by encouraging operational efficiencies and sharing the cost savings with customers. One example of this new approach is the United Kingdom's recently adopted "RIIO" model, or "revenue set to deliver strong incentives, innovation and output." (*See, Peter Fox-Penner, Dan Harris, Serena Hesmondhalgh, "A Trip to RIIO in Your Future?" Fortnightly, October 2013.*) Its major components include: revenues set based on the regulator's review of a forward-looking utility business plan; a multi-year revenue cap that provides an incentive for cost reductions; an earnings-sharing mechanism that enables customers to benefit from utility cost savings; clearly defined performance metrics and incentives for delivering value to customers; and funding set aside for innovative projects.

A window of opportunity now exists to rethink regulation and seek a new approach to support needed investments.

Creating the Modern Grid

Across the economy – from aircraft to automobiles and from manufacturing to entertainment – industries have adopted digital controls and technologies to drive down costs and, in many cases, improve the quality of products and services provided to customers. Electric utilities are starting a similar transition: from delivering power produced in distant facilities to a model that integrates resources located closer to the customer and provides enhanced levels of service.

The integration of modern information and communications technologies into distribution utility operations is central to creating a modern grid, often called a "smart" grid. And just as these technologies have produced material benefits in other sectors, a smart grid can produce significant benefits in the power sector.

The Electric Power Research Institute estimated in 2011 that nationwide deployments of smart grid technologies could produce net economic benefits over the 20-year period through 2030 of $1.3 to $2.0 trillion. To deliver these benefits, utilities would need to invest roughly $17 to $24 billion per year, with an average benefit-to-cost ratio between 2.8 to 1 and 6 to 1.[1]

While the United States remains in the early stages of modernization, utilities across the country are reporting promising results.

Distribution systems are becoming more reliable and resilient as utilities become better able to minimize the effects of power outages. The monitoring and control capabilities of fault detection, isolation, and restoration schemes, as well as advanced

David Malkin is the director of government affairs and policy for GE's Digital Energy business. **Paul A. Centolella** is a vice president with the Analysis Group, and formerly was a commissioner on the Public Utilities Commission of Ohio.

1. Electric Power Research Institute, *Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid* (March 2011).

feeder restoration systems, are enabling utilities to isolate outages while maintaining service to surrounding customers. Initial results from the implementation of such self-healing systems on 1,250 distribution feeders at four utilities, funded through investment grants from the U.S. Department of Energy, have identified a reduction in the average frequency of customer outages of 11 percent to 49 percent, as well as reductions in the average duration of customer outages of up to 56 percent.[2] The development of advanced distribution management systems should further enhance the ability of operators to minimize the effects of outages. (*See "Toward a 21st Century Grid: Producing value with advanced distribution management systems," p. 44*). Outage restoration is being accelerated by the combination of improved outage management systems and advanced metering. Advanced metering infrastructure (AMI) provides real-time visibility on when customers are affected by an outage and when their service is restored. Historically, utilities had to wait for customers to report an outage, and then visually inspect their lines to determine which portions of a circuit were affected. By bringing data on outages and service restoration into an advanced outage management system, the utility can deploy its personnel more efficiently to restore service and provide customers better estimates of when service will be restored. These capabilities can cut days off of the time required to restore service following a severe weather event.

Voltage levels can be monitored and controlled in real time throughout the distribution system. By providing only as much voltage as the system requires, volt-VAR optimization systems have enabled utilities to reduce the amount of generation required to serve some circuits by as much as 2.5 percent to more than 5 percent. In a comprehensive national deployment, this would be expected to result in a 3.2-percent reduction in annual energy consumption and a 5.2-percent reduction in CO_2 emissions from electric generation.[3]

Advanced meters and time-differentiated pricing have enabled some utilities to achieve significant reductions in peak demand. When accompanied by enabling technologies in the home, these programs have produced reductions of 30 percent or more in customer demand during critical peak periods. When implemented at scale such programs might enable utilities to reduce peak demand by more than 20 percent, reducing the need for power plants as well as transmission and distribution investments.[4] The flexibility provided by intelligent end-use devices and dynamic price signals also would allow for easier integration of variable renewable resources.

Finally, consider recent advances in monitoring and data analytics. Such improvements allow utilities to improve load forecasts, reduce line losses and theft of service, and cut costs by moving from scheduled maintenance to more reliable condition-based maintenance. Monitoring and analytics also play key roles in ensuring the security of both existing and new information systems.

A New Business Model

Today's electric grid isn't just a means to deliver power. Rather, today's grid is expected to provide services that mitigate the effects of storms, integrate renewable energy, and secure the electric sector against cyber and physical attacks. But slowly growing or declining sales are leading some utilities to defer needed investments. This trend could leave us with an outdated power system and prove costly to consumers.

The distribution utility will become an active real-time system operator, integrator, and defender.

Much of our electric infrastructure was built more than 40 years ago and is in need of replacement and modernization. For a typical utility, as many as three-quarters of wooden poles and half of transformers could be approaching or beyond the end of their expected service lives. The American Society of Civil Engineers (ASCE) estimated in 2011 that maintaining the U.S. electric infrastructure will require $673 billion in new investment by 2020. The ASCE forecasts significant economic consequences if the electric sector fails to close the investment gap:

"As costs to households and businesses associated with service interruptions rise, GDP will fall by a total of $496 billion by 2020. The U.S. economy will end up with an average of 529,000 fewer jobs than it would otherwise have by 2020… In addition, personal income in the U.S. will fall by a total of $656 billion from expected levels by 2020."[5]

To put these investment requirements into context, as of Dec. 31, 2012, the total market capitalization of U.S. shareholder-owned electric companies was $463.9 billion. In its 2013 report on the state of America's infrastructure, the ASCE noted a recent decline in investment in electric distribution systems. It found

2. U.S. Department of Energy, *Reliability Improvements from the Application of Distribution Automation Technologies* – Initial Results (December 2012).
3. U.S. Department of Energy, *Application of Voltage and Reactive Power Management Systems – Initial Results* (December 2012); Electric Power Research Institute, *Briefing on Volt-VAR Control for Electric Distribution Systems for the Public Utilities Commission of Ohio* (Jan. 18, 2012); and Pacific Northwest National Laboratory, *Evaluation of Representative Smart Grid Investment Grant Project Technologies: Summary Report* (November 2012), hereafter: PNNL (2012).
4. PNNL (2012).
5. American Society of Civil Engineers, *Failure to Act: The Economic Impact of Current Investment Trends in Electricity Infrastructure* (2011).

that aging equipment has resulted in an increasing number of power disruptions and that, "significant power outages have increased from 76 in 2007 to 307 in 2011."[6] More than 90 percent of customer service interruptions can result from distribution outages.

Electric utilities have increased their total capital expenditures since 2007. However, that has had a negative effect on cash flow. In 2012, capital expenditures and dividend payouts of investor-owned electric companies (IOU) exceeded net cash from operations by $26.7 billion. Over the period from 2007 to 2012, IOUs posted a net cash deficit of more than $132 billion. Although utilities have been able to finance this deficit during a period of relatively favorable interest rates, it's unclear whether the industry will be able to sustain the required pace of investment. Currently, 58 percent of electric utilities have a Standard and Poor's credit rating of BBB or lower;[7] 20 years ago, only about one in five electric utilities had such low ratings.

Electric utilities also are facing slow-growing, flat, or declining sales. Total U.S. electricity sales declined by 1.8 percent in 2012, by 0.7 percent in the first 10 months of 2013, and – including results so far reported from 2013 – have fallen in five of the last six years. Despite a moderate economic recovery, electricity sales remain below pre-recession levels. The U.S. Energy Information Administration and many utility load forecasters are predicting less than 1 percent growth in electricity deliveries in coming years. This represents the continuation of a long-term decline in the growth of electricity demand that began in the 1950s.

Many factors are likely to continue limiting growth in electricity sales, including: expanded energy efficiency programs; revisions to state and federal efficiency codes and standards; the falling cost and associated growth in customer-sited photovoltaic (PV) generation; potential growth in gas-fired combined heat and power generation; and fuel switching from electricity to natural gas for certain heating, cooling, and industrial process applications.

Most electric distribution utility costs are fixed and represent investments in poles, wires, and other equipment or systems. In the conventional regulatory model, most fixed costs are recovered through volumetric rates charged on a per-kilowatt-hour basis. Slowly growing or declining sales remove a key source of revenue for new investment and tend to increase customer rates. These higher prices could further depress sales, nibbling away at and eventually creating a self-reinforcing cycle that undermines a utility's business model.

Some utilities might respond by cutting operating expenses, deferring investments, or hoping for a resumption of robust growth in sales. However, this strategy fails to address the significant challenges facing the industry and could prove costly to customers in the long-term. As a result, our country faces a fundamental question: how to structure a regulatory model that both supports needed investment and drives efficiency improvements so that service remains affordable for customers.

Cost-Based Regulation: A History

In 1898, Samuel Insull, the first president of Commonwealth Edison in Chicago, proposed a grand bargain in which local electric companies would receive exclusive franchise service territories, "coupled with the conditions of public control, requiring all charges for services fixed by public bodies to be based on cost plus a reasonable profit."[8] By the early 20th century, state regulation of public utilities became a common practice, as distribution companies accepted the obligation to provide service and regulation of the rates that they could charge. Regulation would protect customers from utility monopolies charging unreasonably high or discriminatory prices, and would ensure that these companies provided satisfactory service.

Focusing on incremental costs assumes the utility will continue providing the same fixed set of services.

Since the 1940s, regulation has been based on providing utility investors the opportunity to earn a return on the historical costs of their investments commensurate with returns on investments having similar risks. As specified in state statutes, commissions set rates designed to recover prudent and reasonable costs used in providing service to customers. In some states, regulators review historical costs, while in others, the utility can file an application based on a near-term forecast of its costs.

Over time, policymakers have sought to maintain a balance between utility and consumer interests by adjusting the cost-of-service model. For example, an increase in interest rates and a decline in sales growth in the 1970s led some regulators to allow their utilities to begin recovering the costs of large projects while construction work was still in progress. However, significant overruns in the cost of generating facilities in the 1980s led regulators to disallow recovery of more than $15 billion.

In the 1980s, regulators initiated integrated resource planning proceedings and began requiring utilities to implement energy efficiency programs. With the success of efficiency programs,

6. American Society of Civil Engineers, *2013 Report Card for America's Infrastructure* (2013).
7. Edison Electric Institute, *2012 Financial Review: Annual Report of the U.S. Shareholder-owned Electric Utility Industry* (2013).
8. Insull, Samuel. "Standardization, Cost System of Rates, and Public Control" (1898). Reprinted in S. Insull, *Central-Station Electric Service,* 34-47. Chicago: Privately Printed, 1915.

14 states have implemented rate adjustment mechanisms that decouple electric distribution company revenues from sales.

Early experiments with market-based rates for generation and continuing dissatisfaction with prices in high-cost jurisdictions helped spur industry restructuring in the 1990s. Restructuring included the development of organized wholesale generation and transmission markets serving more than 60 percent of U.S. electricity consumers and competitive retail access to generation services for some or all customers in 21 jurisdictions.

Some jurisdictions have experimented with performance-based regulation and earnings sharing mechanisms. Many of the experiments with performance-based ratemaking adjusted rates based on changes in a price index for the broader economy, less a commission-determined benchmark for productivity improvements based on past productivity gains at comparable firms. These experiments focused on incentives for reducing utility operating expenses. They typically didn't address the need for greater capital expenditures, which continued to be recovered based on cost-of-service principles.

More recently, a few jurisdictions have adopted tracker mechanisms to facilitate selected investments or formula rates that track utility costs more generally.

Taken together, these changes illustrate the capacity of regulators and legislatures to develop innovative approaches to regulation. However, with the exceptions of revenue decoupling and the use of alternative rate mechanisms in selected jurisdictions, most of the major policy changes of the last few decades have addressed the regulation of generation, transmission, and retail services, as well as the opening of these portions of the industry to competition. On the distribution front, most utilities continue to recover their costs through traditional cost-of-service regulation.

Regulation and Litigation

Cost-of-service regulation focuses on minimizing utility costs and preventing the undue exercise of utility monopoly power. While minimizing the effects of market power is important, discovering more efficient ways to operate and deliver value to customers can create much larger economic benefits. The question facing regulators and policymakers is how to realize both objectives.

Although an innovative regulator can find ways within the conventional model to reward superior performance and innovation, commissions are constrained by their statutory authority, judicial precedents, and the fact that they must decide cases based on the record presented in each proceeding. A commission can open an investigation to explore an emerging issue. However, limited resources and a docket filled with conventional cases can present practical limitations on the ability of regulators to explore new issues or develop alternative approaches.

Additionally, rates typically are set through time-consuming, quasi-judicial proceedings in which the utility files a lengthy application and testimony detailing the cost basis for a requested increase in rates. In some cases, the parties reach an agreement stipulating to a result that is recommended to the commission. While such agreements can provide parties greater flexibility, if one or more parties don't agree, the case can revert back to a litigated process.

Litigation can work well when the relevant questions can be answered based on historical facts. But it might not be ideal for gathering broad public input and making the type of risk and value judgments that utilities and regulators increasingly face: How reliable and resilient should the power system be, given increasingly frequent and severe weather events? What's an appropriate level of cyber and physical security for different systems and facilities? What is the utility's responsibility for accommodating distributed and renewable resources? How should the distributed resource owner help pay for the distribution system?

'As costs to households and businesses associated with service interruptions rise, GDP will fall by a total of $496 billion by 2020.'

–ASCE

Such judgments need to evolve with an ongoing grid modernization planning process as issues are explored and technologies develop.

The Status Quo Fallacy

Utilities often are asked to justify any significant changes from the status quo – from practices previously accepted by the regulator. To do so, they must demonstrate that the new practice will reduce utility costs. But this focus on incremental costs assumes the utility will continue to provide the same fixed set of services. In reality, distribution utilities are increasingly expected – and many cases, required – to perform fundamentally new functions:

- *Ensuring the grid is resilient to severe weather and disruptive events:* With greater dependence on digital technologies, customers need a power system that can quickly rebound from service disruptions. Replacing aging infrastructure and hardening the grid can reduce the probability of service interruptions. A local network also can become more resilient if it can reconfigure around a failure; depend on distributed resources and self-islanding microgrids to maintain service to high-value loads; or accelerate service restoration through more efficient outage management and using advanced meters that identify in real time when a customer's service is interrupted and has been restored.
- *Integrating distributed and variable renewable generation:* Historically, the grid was designed to move power in one direction – from central station generators located on high-voltage transmission lines to customers at the end of distribution wires,

extending radially from the substations that step down voltages to distribution levels. Utilities didn't plan for customer-owned generation on the distribution system, which requires changes in distribution planning, control, and protection systems. Moreover, as PV generation becomes more widely deployed, the power system will need to manage large, rapid shifts in load and generation. For example, the California Independent System Operator has estimated that by 2020 the combination of evening peak loads and simultaneous reductions in customer-sited PV generation in some months could increase net load across the state (load in excess of customer-sited resources) from less than 14,000 MW to more than 26,000 MW in just a three-hour window.[9]

■ *Securing the grid from cyber and physical attacks:* Transmission, generation, and certain distribution protection systems are covered by North American Electric Reliability Corp. (NERC) Critical Infrastructure Protection standards. However, compliance with these standards is only a first step toward making the grid secure. Electric utilities have become the front-line defenders of critical national infrastructure. As the recent Presidential Executive Order on Improving Cyber Security states, "The cyber threat to critical infrastructure continues to grow and represents one of the most serious national security challenges we must confront."[10] Utilities also must consider the possibility of physical or combined physical and cyber attacks. The National Academy of Sciences has found that, "Economic costs from a carefully designed terrorist attack on the U.S. power delivery system could be as high as hundreds of billions of dollars."[11] Protecting the grid from both threats of deliberate sabotage and the risk of introducing inadvertent errors into increasingly complex control systems will require a substantial, ongoing security program.

Meeting these new needs will require changes in grid design and control systems. The distribution utility will become an active real-time system operator, integrator, and defender. Creating the modern distribution grid involves more than installing advanced meters. If advanced meters and sensor networks can be likened to additional nerve endings, advanced communications, back office, and operational systems represent the evolution of a central nervous system that makes the grid intelligent. The utility will deliver greater value to customers, but at a potentially higher cost to the distribution utility.

These changes go beyond a simple extension of baseline expenditures or business-as-usual practices. They require analyzing new sets of risks and benefits: the value of uninterrupted electric service to different classes of customers; the loss of options from selecting lower-end technologies; environmental and societal costs; opportunities for innovation; and how to design incentives for delivering greater long-term value.

Misaligned Incentives

Rate regulation is intended to mirror the "pressures of competitive markets, to prevent regulated companies from becoming high cost-plus companies."[12] Indeed, "the single most widely accepted rule for the governance of the regulated industries is to regulate them in such a way as to produce the same results as would be produced by effective competition, if it were feasible."[13]

Over 90 percent of customer service interruptions result from distribution outages.

In the current environment of increasing costs and slow growth, cost-of-service regulation often fails to provide comparable incentives for investment, efficiency, and innovation.

In cost-of-service regulation, there's a lag between the time a utility makes a capital expenditure and when it begins to recover its costs following a subsequent rate case. This lag has a negative effect on cash flow, and, to the extent the utility isn't accruing a return equal to its cost of capital, it can reduce the utility's earnings. During a period of rising costs and investment requirements but slowly growing or declining sales, this can impair a utility's ability to earn its authorized return. If earnings are significantly impaired, the utility could be spurred to defer discretionary investments that would otherwise benefit customers.

Yet simply shortening this lag period can reduce the incentive for efficient operations. A fundamental assumption of cost-of-service regulation is that the interval between rate cases creates an efficiency incentive because the utility retains any firm-wide cost savings realized during that period. When a utility has to file frequent rate cases, it has little opportunity to benefit from any cost savings that might result from efficiency improvements. Cost reductions would be rapidly passed on to consumers through reduced revenue requirements in the next rate proceeding. To the extent the regulator relies on historical costs, the utility's expenditures in one year can become the basis for its allowed revenue in the next.

9. M. Rothleder, California ISO, Long Term Resource Adequacy Summit (Feb. 26, 2013).
10. White House, "Improving Critical Infrastructure Cybersecurity, Executive Order," Feb. 12, 2013.
11. National Research Council of the National Academy of Sciences Committee on Enhancing the Robustness and Resilience of Future Electrical Transmission and Distribution in the United States to Terrorist Attack, *Terrorism and the Electric Power Delivery System* (2012).
12. *Democratic Central Committee of the Dist. Of Columbia v. Washington Metropolitan Area Transit Comm'n,* 485 F. 2d 786 (1973).
13. Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions, Vol. I* (New York: John Wiley & Sons, 1970), at 17.

Innovation Barriers and Solutions

The development of a modern grid will require learning by doing and experimentation. However, innovation can introduce regulatory risk. If a new system fails to perform as expected, the utility might face a risk of its costs being disallowed. Alternatively, if an innovative project succeeds, the utility might be challenged for not implementing the improvement more broadly or rapidly.

In competitive markets, firms have an opportunity to earn higher profits when innovation delivers greater value to their customers. Whether utilities actively seek to operate more efficiently or deliver greater value to customers will depend on whether regulation provides the incentive to innovate. Regulators never have sufficient information on all the available opportunities to reduce costs or improve service. It's thus virtually impossible for regulators to mandate that a firm actively seek out and discover such improvements. Incentives therefore play an indispensable role in promoting dynamic efficiency improvements. However, even when the results exceed expectations, utilities are seldom rewarded for assuming the risks associated with innovation.

The design of traditional utility regulation affects the very nature of the process of innovation. While firms in competitive markets can rapidly innovate, learn, and, if necessary, redirect their efforts, a regulated utility might need to cycle through a lengthy regulatory review process and justify changes from previously approved practices.

If a utility wants to implement an improvement, it will need to make a case for the new way of doing things. That could entail a lengthy series of time-consuming steps: gathering data on where the proposed system has been implemented elsewhere; testing to demonstrate compatibility with legacy systems; proposing a pilot program for regulatory approval; securing approval for the costs of the pilot in one rate case; implementing and evaluating the pilot program, during which time one or more additional rate-case cycles might have occurred; presenting the results of the pilot and proposing rollout of the system in one or more subsequent proceedings; securing approval for the costs of rolling out the proposed system in these subsequent rate proceedings; and thereafter implementing the system.

The time between when the utility identifies a valuable commercial innovation and full implementation can stretch to as long as a decade. Such delays can impose significant costs and deter the pursuit of innovation that would benefit customers.

Some alternative regulatory models tend to provide greater support for new investment. These approaches might involve prior regulatory review of utility plans. They also might be conditioned on utility commitments to make specific improvements. Such alternative models include:

■ *Annual rate cases with a forecast test year:* In some jurisdictions, the utilities forecast their investment expenditures based on prior planning reviews. By using these forecast values in annual rate proceedings, the utilities and their regulators can minimize the effect of regulatory lag. However, frequent regulatory involvement can make this approach administratively burdensome. Examples in which this approach has supported investment include the Public Service Commission of Wisconsin with its biennial Strategic Energy Assessment and annual rate cases, and the Iowa Utilities Board's pre-construction approvals of new generation.

■ *Capital expenditure trackers:* A tracker is a separate rate-adjustment mechanism that allows for the recovery of specific costs outside of the conventional rate case process. Historically, tracker mechanisms were reserved for significant and volatile costs, such as fuel, which are largely outside of the utility's control. More recently, some states have permitted accelerated recovery of specific capital expenditures outside of a cost-of-service rate case. For example, Pennsylvania's Distribution System Improvement Charge allows accelerated recovery of costs associated with improved service reliability.

Higher prices could depress sales, eventually creating a self-reinforcing cycle that undermines a utility's business model.

■ *Formula rates:* In this approach, a specific formula for setting rates is established in advance by statute or a prior commission order. The utility then files its cost data and the information used to determine its allowed rate of return in a standard format. Costs can be subject to review based on whether the expenditures were prudent. Examples of formula rates include the Federal Energy Regulatory Commission's transmission rates and the Illinois Energy Infrastructure Modernization Act.

These approaches can support investment in instances where there's a constructive relationship between the utility and its regulator. However, they can involve a high level of regulatory oversight. They also offer limited incentives for the utility to reduce its costs and share any cost savings with consumers. For example, cost trackers have been criticized for diminishing incentives to reduce waste and cost inefficiency. Similarly, formula rate statutes have been opposed by regulators on grounds that they limit regulators' ability to balance the interests of utilities and consumers and discourage cost efficiency and productivity improvements.[14]

Other alternative models are designed to provide strong incentives for electric utilities to reduce costs. These include

14. K. Costello, "How Should Regulators View Cost Trackers," National Regulatory Research Institute (September 2009); Statement by Illinois Commerce Commission Chairman Doug Scott on Senate Bill 1652, Illinois Commerce Commission (May 27, 2011).

multi-year revenue and price caps. Under these models, changes in utility revenues or rates can be indexed to inflation and adjusted for a targeted rate of productivity improvements and any extraordinary costs. Alternatively, the regulator might set annual step changes or freeze revenues or rates for the duration of the rate plan. These multi-year rate plans can promote cost reduction by enabling the utility to share in any cost savings during the years covered by the plan. However, in the absence of strong reliability standards or incentives, they've been associated with a reduction in spending on operations and maintenance and an increase in the average duration of customer outages.

In addition, unless the multi-year plan is tied to a reasonable utility business plan for new investment and changes in its operations, the revenue or rate cap won't support needed capital investments. Accordingly, some commissions have experimented with caps and then returned to more conventional cost-of-service regulation.

Designing a Results-Based Model

Modern regulation should balance utility and consumer interests while providing incentives for utilities to improve efficiency, innovate, and invest to deliver long-term value to customers.

Today's electric utilities have average asset utilization rates below 50 percent,[15] spend 0.2 percent of revenues on research and development,[16] and are experiencing major service outages at a rate more than double their historical frequency.[17] These aren't the characteristics of successful companies in competitive markets. Asset utilization rates in the electric sector are far below the levels typical of other capital intensive industries, which are often 75 percent or greater. The rate of utility spending on research and development is less than one-tenth the average rate for all sectors of the U.S. economy and a much smaller fraction of the rate in the most productive sectors.

If policymakers wish to ensure an affordable, resilient, secure, and sustainable energy future, then they should consider how regulation can evolve to address a broader set of economic and policy objectives. A policy review might start with the widely accepted premise that regulation should seek to produce results comparable to those that would emerge from an efficient competitive market – were such a market feasible. This implies a regulatory model that: supports investments and expenditures that deliver greater value to customers; incentivizes efficiency while returning a portion of the resulting cost savings to customers; and encourages innovation and adoption of innovative practices from other sectors. Other implications might include:

- *Service-level options:* Service classifications that reflect the ability to deliver higher levels of reliability in portions of the grid and that would allocate the costs to customers who value and are willing to pay for more reliable or resilient service.
- *Valuing distributed energy resources:* A balanced treatment of customer-owned energy systems that reflects the system and reliability benefits of integrating these distributed resources into the planning and operation of networked distribution systems, and yields distribution rates that appropriately allocate fixed distribution costs to customers based on their contribution to local and circuit peak requirements.
- *Price-responsive demand:* Dynamic competitive prices that are transparent and made available in a manner that facilitates efficient automated responses by intelligent devices in customers' homes and businesses.

Litigation can work well when the relevant answers can be based on historical facts. It might not be ideal for the value judgments utilities increasingly face.

Efficient, competitive, real-time wholesale power markets exist across much of the United States. Significant benefits could be gained by making expected prices in these markets – together with any adjustments needed for the operation of local distribution – available to any device, anywhere, all the time, and at a minimal cost. Most devices that use electricity either have thermal inertia (*e.g.,* heating, cooling, water heating, and refrigeration) or operating flexibility (*e.g.,* industrial pumping loads and batch processes, pool pumps, dishwashers, clothes dryers, electric vehicle chargers, and battery-powered devices) and could automatically adjust the timing of their electricity use without materially affecting the consumer's experience. Existing low-cost technology could enable devices to receive, authenticate, and select a broadcast price signal that's appropriate for each device's location or to connect to cloud-based energy management applications. Influencing the timing of electricity use in this way could improve asset utilization, reduce investment requirements and customer costs, enhance system resilience, and facilitate the integration of variable renewable resources.Regulation also should account for the system and public benefits associated with a distribution grid that can effectively integrate renewable and distributed generation. Customer-sited generation might directly benefit the host customer and, if properly configured, provide that customer

15. U.S. Energy Information Administration, *2012 Electric Power Annual* (2013) at Tables 3.1A and 4.7A.
16. R. Lester and D. Hart, *Unlocking Energy Innovation: How America Can Build a Low-cost, Low-carbon Energy System* (2012); Battelle Memorial Institute and *R&D Magazine*, 2012 Global R&D Funding Forecast (December 2011) at 21.
17. Executive Office of the President, "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages" (August 2013).

with backup service in the event of an outage. Meanwhile, the integration of such generation into distribution operations can also provide reliability and system benefits. Integrating these resources provides additional options for serving loads when parts of the system reach capacity or lines are out of service. In some circumstances, a local generator could permit a distribution circuit serving multiple customers to function as a microgrid and remain operational if separated from the larger system. As the role of distributed generation increases, regulators should consider the development of markets that extend locational pricing into the distribution system.

Moreover, to the extent distributed generation permits high-value loads (*e.g.*, public safety, medical care, telecommunications, water, fuel) to remain operational during an outage, the utility will be able to more efficiently restore service for other customers. Finally, a distribution system that's able to efficiently integrate rooftop PV and distributed, high-efficiency combined heat and power applications provides important options for transitioning to a low-carbon economy.

To promote greater integration of renewable and distributed generation, utilities and their regulators will need to agree on a mechanism that supports needed investments and provides distribution utilities a reasonable opportunity to recover their largely fixed costs. That could involve a greater portion of costs being recovered through fixed customer or demand charges in combination with rate adjustments that decouple fixed-cost recovery from sales.

Regulation also will need to address emerging public policy issues, such as cyber security. Across each of North America's three large interconnections, electricity is produced, transmitted, and consumed in virtually the same the instant. As a result, the cyber security of a single utility's systems can affect the security a larger regional power grid. The 2003 Northeast blackout, while "not linked to malicious activity," was an example of "the failure of a software program," which left operators unaware of current system conditions and "significantly contributed" to a region-wide power outage.[18] The 2003 blackout affected more than 50 million people and cost the U.S. economy an estimated $6 billion, thereby demonstrating how an isolated incident can have wide effects across the grid.[19]

Lastly, as the industry moves to address new challenges, regulators can and should engage stakeholders more directly. Regulators can encourage broad public input; convene public workshops; initiate collaborative processes through which citizens and stakeholders can gain a common understanding of issues; and discuss alternatives in an informal setting prior to having to take a position in a regulatory proceeding. Regulators also will want to ensure that utilities educate their customers about new services as they become available.

A model that meets these objectives would provide utilities the opportunity to earn reasonable returns on investments that deliver value to customers. It would remain affordable by encouraging improved efficiency and innovation, and it would incorporate incentives for both cost savings and performance on multiple customer and public policy metrics. Results and innovation would translate into earnings.

As the role of distributed generation increases, regulators should consider the development of markets that extend locational pricing into the distribution system.

That's not to suggest that a results-based model would ignore costs. A review of utility costs could be a central part of setting rates in a results-based approach. However, a results-based model would be forward-looking and take into consideration the forecasted costs for meeting new objectives. It would place a greater emphasis on providing the right incentives for cost savings, efficiency, and performance, recognizing that regulators will seldom have enough information to effectively review whether a utility's management has made the best possible decisions.

In considering how to update the regulatory model, policymakers can draw on regulatory experience with capital investment cost trackers – in which the utility presents and the regulator approves an investment plan – and other planning reviews. Policymakers also can consider lessons from multi-year revenue caps that have provided significant incentives for cost savings. A results-based model would contain elements of each.

While variations will emerge in different jurisdictions, an effective results-based model might well feature five key components:

- *Revenues set to support a forward-looking utility business plan:* The plan would include investments needed for grid modernization and to meet specific performance objectives.
- *A multi-year revenue cap:* The multi-year period provides an incentive for the utility to pursue efficiency improvements by providing an opportunity to retain a portion of any cost savings.
- *A mechanism for sharing any cost savings with customers:* An earnings-sharing mechanism or a sharing of variances from cost

18. U.S. – Canada Power System Outage Task Force, *Final Report on the Aug. 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (August 2004) at 131.

19. The U.S. Department of Energy estimated costs of $6 billion and this is near the $6.4 billion mid-range estimate prepared by Anderson Economic Group. For a summary of estimates of the blackout's costs see: Electric Consumers Resource Council (ELCON), *The Economic Impacts of the August 2003 Blackout* (Feb. 9, 2004).

targets allows customers to benefit from cost savings achieved during the multi-year plan.

■ *Output-based performance incentives:* These performance incentives are a counterweight to the incentive for cost reduction and can be selected to reflect different consumer preferences and public policies in each jurisdiction. Different incentives might be considered, based on: 1) the value of the uninterrupted service from outages avoided; 2) savings from energy efficiency programs, dynamic pricing, and voltage optimization; 3) results of customer satisfaction surveys; 4) improvements in environmental performance; 5) independent assessments of cyber governance; 6) interconnecting distributed generation and integrating electric vehicles; and 7) implementing programs that enable economically disadvantaged customers to afford service. Each should be based on clearly defined metrics. To better match the incentives found in competitive markets, bi-directional incentive mechanisms could permit the utility to earn higher returns for superior performance.

■ *Support for innovation:* In a competitive market, multiple firms innovate simultaneously as they compete to deliver value to customers. This combination of competition and innovation can

produce improvements in efficiency and customer value that are difficult to approximate in a regulated environment. However, a results-based model could include competitive solicitations that allow third parties to propose innovative projects, long-term funding for research and development, and support for the demonstration and implementation of new technologies that reduce costs, improve performance, or advance policy objectives.

The results-based model is a forward-looking approach for achieving the net economic and societal benefits of a modern grid.

New Ways of Thinking

Overall, results-based regulation shifts the focus from the reasonableness of historically incurred costs to the pursuit of long-term customer value. It enables utilities to meet today's challenges.

By contrast, cost-of-service regulation was developed more than a century ago to support the build-out of the basic electric infrastructure for an industrializing economy, but was never designed for meeting the demands of today's customers.

With the low cost of natural gas holding down generation prices, and with the beginning of an economic recovery, a window of opportunity now exists to rethink regulation and seek agreement on a new approach that can support making needed investments.

A results-based regulatory model can incent innovation. It can enable utilities to complete the transition from an industrial model of distributing electricity as a commodity, to a service-based model in which the distribution system operator becomes a guardian of critical infrastructure, an efficient integrator of variable and distributed resources, a trusted advisor to its customers, and a potential provider of additional energy services.

In results-based regulation, the regulator is effectively contracting with the utility for the achievement of specific objectives. To achieve those objectives, the regulator provides both efficiency and performance incentives to the utility, returns a portion of cost savings to customers, and limits its own backward-looking cost review.

In making the transition to a results-based approach, policymakers should gather input from a broad range of stakeholders. The Massachusetts Department of Public Utilities, for example, recently engaged stakeholders through a Grid Modernization Working Group to consider needed investments and changes in the state's regulatory framework. While the working group didn't reach consensus on every issue, it identified stakeholder concerns and outlined new approaches for the department to consider. Moreover, two-thirds of participating organizations agreed on the broad outline of a new "Utility of the Future, Today" regulatory model to advance grid modernization.[20] Additionally, customer surveys and voice-of-customer interviews can be used in setting or periodically adjusting various performance metrics, such as the value of uninterrupted service.

In implementing a results-based model for the first time, regulators could mitigate risk for both customers and the utility through a progressively tiered earnings-sharing mechanism. With tiered earnings sharing, the percentage of earnings shared with customers could increase with the amount by which the utility's actual return on equity exceeds authorized levels. Similarly, a symmetrical approach might protect the utility from a confiscatory result by having consumers pay an increasing percentage of any reasonable, unanticipated costs to the extent actual earnings fall below authorized levels.

The results-based model is a forward-looking approach for achieving the net economic and societal benefits of a modern grid.

The expectations and requirements that customers and policymakers place on utilities are changing. The development of an affordable, resilient, and sustainable power system to meet these requirements will take time. Its development will require the use of innovative technologies and new approaches to system operations. A forward-looking, incentive-driven, and results-based regulatory model is needed to provide utilities with clear objectives, the flexibility to efficiently meet those objectives, and sufficient support for the development of an efficient, modern power grid.

20. Raab Associates, Ltd. and Synapse Energy Economics, Inc., *Massachusetts Electric Grid Modernization Stakeholder Working Group Process: Report to the Department of Public Utilities from the Steering Committee* (July 2, 2013).

NECEC 1-3

Request:

Refer to National Grid Joint Direct Testimony, page 84 of 102, lines 14-17:

> *The Company's proposal for two capital efficiency performance incentives represents an initial step toward a framework that provides a more equal incentive for the delivery of operating and capital cost-savings.*

a. Illustrate with at least one example what such a "framework" would be.

b. After this "initial step," what is the next step toward such a "framework?"

c. Will the Company's proposals for "capital efficiency" in this case provide incentives for the Company to substitute non-capital solutions for capital solutions? Why or why not?

d. Will the Company's proposals for "capital efficiency" in this case provide incentives for the Company to evaluate "non-wires alternatives?" Why or why not?

Response:

a. There are multiple potential frameworks that could provide for more equal incentives for the delivery of operating and capital cost savings. One might involve development of a broader portfolio of incentives around capital savings to align with regulatory objectives – for example, providing opportunities for the utility to not only deliver ongoing capital projects more efficiently, but to reward the utility for proactively seeking alternative non-capital solutions that have the potential to cost-effectively avoid or defer capital investments. A total expenditure (totex) approach represents another framework that could support more similar treatment of capital and operating expenses – however, as the Company discusses in its response to NECEC 1-8, the PUC and interested stakeholders would need to fully evaluate and consider the implications of any alternative cost-recovery models with respect to the objects they aim to achieve as well as potential unintended consequences on utility operations. This evaluation should consider how the objectives of a totex model could be met through incremental, measured refinements to the existing model in order to optimize between the benefits to be gained for customers and the regulator lift required to transition to a full totex model.

b. A next step might involve an evaluation of additional gaps in the Company's incentive structure, where new incentives might lead to incremental capital savings for customers. For example, one of the Company's approved incentives in the 2018 SRP would allow the Company to share 20% of the net benefits (using the Utility Cost test) of distributed

energy resources installed due to SRP initiatives. The Company is interested in proposing additional incentives for non-wires alternatives (NWAs) in the future and expects to continuously evaluate opportunities to propose such mechanisms in future proceedings.

c. The Complex Capital Projects Capital Cost Incentive would reward the Company for the efficient delivery of approved complex capital projects. As these projects are in the Company's annual ISR filings, they have all been vigorously reviewed for non-capital, or NWA, opportunities in the study processes leading up to an annual ISR filing, and were found not to be eligible for NWA treatment as per the Company's NWA criteria. The Construction Costs per Mile Productivity Incentive focuses specifically on the efficient delivery of overhead distribution line construction projects. These projects are not eligible for non-capital, or NWA treatment as per the NWA criteria.

d. Please refer to (c) above.

NECEC 1-4

Request:

Refer to National Grid Joint Direct Testimony, page 94 of 102, lines 14-17.

a. Will the revenue requirement associated with the "eligible investments" be net of any cost savings realized by the Company due to the investment? Why or why not?

b. If the answer is "yes," where in the cost recovery process will the savings offset be calculated?

Response:

a. The revenue requirements associated with the "eligible investments" are not net of any O&M cost savings realized by the Company due to the investment. Any O&M cost savings realized as a result of the Power Sector Transformation (PST) investments will be included in the next general rate case. At this time, the Company did not include the O&M cost savings as the estimates were considered de minimis and speculative prior to implementing the PST initiatives.

b. Please see response to part a.

Prepared by or under the supervision of: Melissa Little

NECEC 1-5

Request:

The Company has described its capital efficiency incentive as applying to complex capital investment projects. For each year of incentive plan,

a. Please state the Company's total projected capital investment in each year.

b. Please estimate of the amount of the capital investment budget in each year that would be considered "complex" and eligible for the incentive plan.

Response:

a. The Company included a five-year capital budget projection as Attachment 4 of its Electric Infrastructure, Safety, and Reliability (ISR) Plan Fiscal Year 2019 Proposal, which is comprised of the proposed Fiscal Year 2019 budget and preliminary budgets for Fiscal Year 2020 through Fiscal Year 2023 and is provided here as Attachment NECEC 1-5. The Rhode Island Public Utilities Commission reviews and approves capital spending in the Company's ISR Plan for one fiscal year at a time, and the approved budget levels for a given fiscal year will affect capital budgeting for the fiscal years that follow. In addition, preliminary budget values are subject to change as the Company's plans are further developed and refined.

b. The metric for the proposed incentive is not the level of capital spending on complex projects in a given fiscal year, but rather the total spend over the lifecycle of complex projects closing in a given fiscal year. The level of the capital investment budget that would be considered complex for a given fiscal year, therefore, is not a useful indicator of the level of capital expenditures that will be relevant to the incentive. However, for reference, the capital budget for complex projects for Fiscal Year 2019 comprises about 52 percent of the approved FY 2019 ISR capital budget.

Prepared by or under the supervision of: Meghan McGuinness and Timothy Roughan

Spending Rationale	Budget Class Codes	FY2018 ISR Budget	FY2019 Proposed Capital Budget	FY2020 Prelim Budget	FY2021 Prelim Capital Budget	FY2022 Prelim Capital Budget	FY2023 Prelim Capital Budget
Customer Request/Public Requirement	3rd Party Attachments	204	81	83	85	87	89
	Distributed Generation	1,106	(692)	(500)	(500)	(500)	(500)
	Land and Land Rights	223	225	230	235	240	246
	Meters - Dist	1,786	2,247	2,364	2,487	2,616	2,752
	New Business - Commercial	8,183	7,061	7,273	7,655	8,049	8,456
	New Business - Residential	5,616	5,247	5,517	5,831	6,150	6,485
	Outdoor Lighting - Capital	153	123	126	129	132	135
	Public Requirements	2,520	2,454	2,438	3,495	3,608	2,540
	Transformers & Related Equipment	2,060	2,259	2,373	2,493	2,619	2,752
Customer Request/Public Requirement Total		**21,853**	**19,005**	**19,904**	**21,910**	**23,001**	**22,955**
Damage/Failure	Damage/Failure	9,828	12,074	12,845	13,171	13,494	13,825
	Major Storms - Dist	1,550	1,600	1,650	1,700	1,750	1,800
Damage/Failure Total		**11,379**	**13,674**	**14,495**	**14,871**	**15,244**	**15,625**
Asset Condition - South St	Asset Replacement	25,773	3,720	1,800	-	-	-
Asset Condition - South St Total		**25,773**	**3,720**	**1,800**	**-**	**-**	**-**
System Capacity & Performance	Load Relief	21,079	35,849	26,390	18,585	17,590	9,061
	Reliability	3,422	9,916	6,079	8,055	10,097	13,285
System Capacity & Performance Total		**24,501**	**45,765**	**32,469**	**26,640**	**27,688**	**22,346**
Asset Condition	Asset Replacement	14,544	24,047	34,644	39,361	41,568	45,993
	Asset Replacement - I&M (NE)	1,600	1,700	4,625	5,150	5,425	6,200
	Safety	417	300	-	-	-	-
Asset Condition Total		**16,561**	**26,047**	**39,269**	**44,511**	**46,993**	**52,193**
Non-Infrastructure	Corporate/Admin/General	-	-	-	-	-	-
	General Equipment - Dist	378	306	312	318	324	331
	Telecommunications Capital - Dist	175	250	250	250	250	250
Non-Infrastructure Total		**553**	**556**	**562**	**568**	**574**	**581**
Grand Total		**100,620**	**108,767**	**108,500**	**108,500**	**113,500**	**113,700**

NECEC 1-6

Request:

For each year of the incentive plan, please state the amount of total expenditures that are projected to be considered in the Construction Costs per Mile Productivity Incentive.

Response:

The total expenditures that would be included in the Construction Costs per Mile Productivity Incentive will depend on the approved Infrastructure, Safety and Reliability (ISR) budget for the relevant fiscal year. The cost per mile of construction metric will cover all overhead distribution line work within the Company's work management system. Because the Company has indicated the incentive would be proposed formally for FY 2020, the Company cannot yet indicate the level of expenditures that would be considered in the incentive. However, as the Company noted in PST Book 1 of 3, Bates Page 164, the Company expects that the incentive would apply to roughly $45 million of "routine" capital expenditures per year.

NECEC 1-7

Request:

Refer to National Grid Joint Direct Testimony, page 95 of 102, beginning on line 17 and continuing to line 10 on page 96.

a. Is the Company representing that the proposed categorization of costs is the same as the categorization approved by the Commission in the Company's last rate case involving cost allocation? Explain any differences.

b. What are the implications, if any, of the proposed categorization for rate design in residential and small commercial customer classes?

Response:

a. Please refer to the response to NERI 27-5, part c. Yes, the categorization of costs, specifically related to the expansion of grid modernization and including Advanced Metering Infrastructure (AMI), is consistent with the categorization of similar costs and investments in the Company's 2012 general rate case in RIPUC Docket No. 4323. The allocation of grid modernization and AMI costs to rate classes as part of the Company's PST proposal is based on the proposed Allocated Cost of Service Study (ACOSS) presented in Mr. Gorman's testimony in Book 12, which was prepared consistent with the allocation of costs to rate classes in RIPUC Docket No. 4323.

b. Please refer to the response to NERI 27-5, part c. The proposed design of the PST factors for the recovery of grid modernization and AMI-related costs is intended to be consistent with the allocation of these costs in an ACOSS in a subsequent general rate case. Specific to AMI-related costs, the Company's proposal is intended to result in PST factors that are reflective of cost causation by aligning, to the greatest extent possible, the allocation of AMI costs to the rate classes in a way consistent with when such costs are included in a revenue requirement and ACOSS in a future rate case. If an alternative allocation methodology were used to develop the PST factors and then recovery of the AMI costs was transferred to base distribution rates, the allocation of costs among rate classes in an ACOSS would likely result in a significant shift in cost responsibility among the rate classes as result of allocating the costs in a different way in an ACOSS than through the reconciling mechanism. Therefore, the Company's proposal is intended to minimize the shifting of cost responsibility among the classes, for AMI specifically and grid modernization generally, at the time of the Company's next general rate case.

Prepared by or under the supervision of: Robert Sheridan

NECEC 1-8

Request:

The PST Phase 1 report contained the following recommendation:

> **1.5 Assess the existing split-treatment of capital and operating expenses.**
> *The Division should convene a collaborative of stakeholders to consider opportunities for a total expenditure approach for future implementation to remove capital bias of the regulatory framework that currently drives cost increases.*

Please explain in detail whether the Company's incentive proposals advance or retard a movement toward a "total expenditure approach" addressed in the report.

Response:

As the Company noted throughout the Power Sector Transformation proceedings, the characterization of the current regulatory framework as biased toward capital investment is not consistent with the Company's actual history in the state. Attachment NECEC 1-8, which contains the comments submitted by the Company in response to the October 13, 2017 Draft Rhode Island Power Sector Transformation Report, elaborates on this point (See Bates Page 2 of the Attachment).

Any definitive statement regarding a move to a "total expenditure approach" is premature. As the Company notes in Attachment NECEC 1-8, "The PUC and interested stakeholders need to fully evaluate and consider the implications of any alternative cost-recovery models with respect to the objectives they aim to achieve as well as potential unintended consequences on utility operations. In undertaking such evaluation, the PUC should consider how the objectives of a 'total expenditure model' could be met through incremental, measured refinements to the existing model in order to optimize between the benefits to be gained for customers and the 'regulatory lift' required to transition to a full total expenditure model" (Bates Page 3).

In light of the pending questions about the desirability of a total expenditure approach and the need for a collaborative process to further evaluate it, the Company's proposed capital efficiency incentives neither advance nor impede movement toward such an approach. That said, the Company's proposed capital efficiency incentives would provide an incremental step toward a regulatory framework that provides a more equal incentive for the delivery of operating and capital cost savings, to the benefit of customers.

Prepared by or under the supervision of: Meghan McGuinness and Timothy Roughan

nationalgrid

Jennifer Brooks Hutchinson
Senior Counsel

October 26, 2017

VIA ELECTRONIC MAIL

Rhode Island Power Sector Transformation Initiative
c/o Rhode Island Division of Public Utilities and Carriers and Office of Energy Resources
DPUC.powertransformation@dpuc.ri.gov

RE: Rhode Island Power Sector Transformation Initiative
Request for Stakeholder Comments on the Draft Recommendations
National Grid's Comments

Dear Members:

On behalf of National Grid,[1] I enclose the Company's comments in response to the draft recommendations outlined in the request dated October 16, 2016 from the Division of Public Utilities and Carriers, the Office of Energy Resources, and the Public Utilities Commission (PUC), and discussed at the PUC offices on October 23, 2017.

The Company looks forward to future discussions on this important topic. If you have any questions, please contact Kayte O'Neill at 781-907-1790, Tim Roughan at 781-907-1628, or me at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

280 Melrose Street, Providence, RI 02907
T: 401-784-7288 ■ jennifer.hutchinson@nationalgrid.com ■ www.nationalgrid.com

nationalgrid

Public Utilities Commission, Division of Public Utilities and Carriers, and
Office of Energy Resources

Power Sector Transformation

National Grid's Comments on October 13, 2017 Draft Rhode Island Power Sector Transformation Report

---

National Grid appreciates the opportunity to submit written comments on the draft Rhode Island Power Sector Transformation (PST) Report (Draft Report) released to stakeholders on October 16, 2017, and discussed at the Rhode Island Public Utilities Commission (PUC) offices on October 23, 2017. National Grid has welcomed the opportunity to provide feedback to the PUC, the Rhode Island Division of Public Utilities and Carriers (Division), and the Rhode Island Office of Energy Resources (OER) in the context of their efforts to develop for Governor Raimondo a package of PST regulatory frameworks, proposals, or deployment strategies, as appropriate, pursuant to her March 2, 2017, correspondence to the agencies.

As was discussed at the October 23, 2017 PST stakeholder meeting, National Grid is in the latter stages of preparing a request to the PUC for approval of new base distribution rates, which will include several PST initiative proposals. The Company is pleased that a large part of its upcoming PST initiative proposal appears to be directionally consistent with many of the initiatives addressed in the Draft Report (e.g., beneficial electrification initiatives, electric vehicles, performance metrics). National Grid will provide a comprehensive PST plan in its upcoming rate filing describing the proposals in detail and noting alignment in several areas with the principles and recommendations included in the Draft Report.

Upon review of the Draft Report, however, there are several instances where National Grid seeks reconsideration of some draft recommendations, and some draft language providing inaccurate context for such recommendations, as addressed below.[1] In addition, the Company takes the opportunity to reiterate in these comments a few issues addressed in the Company's previous PST stakeholder comments (on September 8 and 12, 2017, respectively) prior to the efforts by the PUC, Division, and OER to finalize the report to Governor Raimondo.

1) **The Utility Business Model (UBM) Principles and Recommendations Unfairly Conclude That the Utility Compensation Framework Needs Reform.**

Of all the topics addressed in the Draft Report, the draft conclusions in the UBM Principles and Recommendations are the most concerning because many are based on inaccurate or misleading premises. The Company addresses several issues with this module from the Draft Report below:

---

[1] The Company has not addressed each and every recommendation in the Draft Report in these comments. Rather, the Company is focusing its comments on particular draft recommendations and, in some instances, the context of those draft recommendations, in order to provide PST stakeholders with feedback from the Company in the near term on what it has identified as key areas of interest to the Company.

The Draft Report Inaccurately Concludes that the Company's Electric Distribution Business Has Over-Earned During 2014 and 2015

The UBM module of the Draft Report states that, in calendar years 2014 and 2015, National Grid in Rhode Island reported earnings to shareholders that met or exceeded its allowed return on equity (ROE) for both its electric and gas distribution businesses (UBM Draft Report at 7). However, this is not an accurate way to portray the Company's reported earnings. As noted in the Company's recent annual electric earnings reports filed with the PUC, in each year, the Company's reported earnings were *below* its allowed returns.

In addition, the comparison of earnings reported to shareholders and those reported in regulatory reports misrepresents the Company's allowed earnings for those years. The Company's earnings reports to the PUC include *both* earnings with and without energy efficiency performance incentives. In comparison, at the request of the Division, the Company provided information for purposes of the Draft Report comparing its actual earnings including energy efficiency performance incentives to allowed earnings. The Company was not asked to compare its actual earnings to allowed earnings without energy efficiency performance incentives. The latter provides a more accurate comparison of the Company's actual-to-allowed earnings. The Company is allowed to keep energy efficiency performance incentives as a tradeoff for earning revenue from electric sales, which energy efficiency has been successful in reducing. Accordingly, observations drawn in the Draft Report regarding the Company's earnings need to be revised to provide a more accurate assessment of the Company's financial status before drawing any conclusions about potential changes to utility compensation.

The Company Does Not Have a "Bias" Toward Building Infrastructure

The characterization in the UBM Draft Report that electric utilities have an inherent "infrastructure bias" unfairly implies that the Company is subject to the same proclivities (see UBM Draft Report at 3). On the contrary, the Company's actual history in Rhode Island leads to a different conclusion. First, as noted in the Company's September 8, 2017 comments submitted to PST stakeholders, the discussion overlooks the regulatory obligation of the Company to have the infrastructure in place to serve customer-driven peak loads safely and reliably and the underlying economic and weather considerations that encourage customers to use electricity in the patterns observed. Finally, this draft conclusion ignores the significant efforts that the Company has already undertaken, and is continuing to develop, to engage customers in demand response and reduce peak demand. Further, the Company has a long history of making investment and operational decisions to the benefit of customers under the current regulatory framework. Regulatory oversight of capital and operating expenditures ensures their prudency, thus requiring the Company to demonstrate alignment with customer interests and regulatory standards. Accordingly, the draft conclusions about a "bias" toward infrastructure investment, without a more comprehensive discussion about the regulatory context for investment decisions, provides a misleading context for potential future regulations and should be revised.

That said, the Company has recognized throughout this proceeding that the current regulatory framework can create a disincentive for utilities to take on the risk associated with innovation, and may not sufficiently align utility interests with broader policy goals or desired customer outcomes that expand beyond the utility's core performance obligations. To that end, the Company agrees there is value in exploring how reforms, such as the development of new utility performance incentives, can align utility interests with state policy objectives and generate new benefits for customers.

Although the Company Supports Inclusion of Potential Performance Incentives in its Overall Compensation, They Must Not Be Deemed a Substitute for an Approved ROE

The Company's allowed ROE is an important signal to investors and credit ratings agencies. An adequate authorized ROE is essential to the Company's ability to raise capital at a reasonable cost and on reasonable terms. Particularly in the early years of performance incentive mechanisms (PIMs), there is likely to be significant uncertainty involved in the definition of appropriate metrics, setting of targets, and determining the potential earnings levels at given targets, making it difficult to calibrate expected (as opposed to potential) earnings from PIMs to a level that would offset a given reduction in ROE. A lower authorized ROE combined with uncertain incentive earnings has the potential to increase the Company's risk profile, and could potentially put the Company at risk of credit downgrades, ultimately to the detriment of customers.

Any contemplation of adjustments to the authorized ROE in the presence of new incentives needs to evaluate the full portfolio of potential upside and downside incentives. The presence of downside incentives in this portfolio, for example, has not, to the Company's knowledge, led to contemplation of an offsetting increase in the authorized ROE. The Company suggests that the potential value of new incentive earnings opportunities would have to be substantially more than any corresponding reduction in ROE in order to maintain the requisite investor confidence.

As an alternative to an ROE adjustment, a more beneficial approach would be to include an earnings sharing mechanism that will ensure that total earnings (ROE + PIMs) do not exceed a certain level, with excess earnings shared with customers as they are today.

The Company considers any definitive statement regarding a move to a "total expenditure" cost recovery model, as contemplated with the Draft Report, as premature. The PUC and interested stakeholders need to fully evaluate and consider the implications of any alternative cost-recovery models with respect to the objectives they aim to achieve as well as potential unintended consequences on utility operations. In undertaking such evaluation, the PUC should consider how the objectives of a 'total expenditure' model could be met through incremental, measured refinements to the existing model in order to optimize between the benefits to be gained for customers and the 'regulatory lift' required to transition to a full total expenditure model.

Changes to Rate Case Filing Requirements are Not Warranted.

Finally, the Draft Report recommends that the Company file a three-year Business Plan covering all initiatives and costs over a three-year period (including ISR, SRP, etc.). However, the legal, regulatory, and operational impacts of such a recommendation are significant and require more analysis. Until such time in the future when this issue can be addressed in more detail, the Company will continue the development of its base distribution rate filing for presentation to the PUC in the next several weeks.

2) The Company Agrees With the Draft UBM Recommendation Regarding the Exploration of Partnership Models.

The Draft Report addresses several areas where the Company may seek to leverage PIMs, in combination with existing capabilities, to develop new initiatives to advance intelligent infrastructure (UBM Draft Report at 23). As noted in the Company's September 8, 2017 comments submitted to PST stakeholders, the Company agrees with the Division that there is value in exploring new partnership models to advance development of intelligent infrastructure to support development of new system and customer benefits. The Company is working to evaluate how such partnerships could be implemented in a manner that delivers maximum value to our customers over an expeditious timeframe.

National Grid has a long history of working with vendors in order to be able to access specific capabilities and resources that the Company is not able to cost-effectively provide, but that benefit our customers. Of course, the Company understands the Innovative Partner Models being considered by the Division represent greater partner involvement than might occur under a traditional vendor-customer relationship. For example, the partner to the utility might be expected to contribute capital or take on some level of risk, with the goal of ultimately providing new services and opportunities to customers at a lower cost than might otherwise occur if the Company were to undertake such investments independently. With these considerations in mind, the Company has begun to consider how partnerships might appropriately be structured in the areas below in order to most effectively benefit customers. As noted in prior comments, the Company suggests that the Division consider the following points in evaluating the potential partnership models:

- Partnerships with third parties should be designed to maximize net benefits to customers through the outcomes achieved and the combination of revenue sharing and any cost-sharing on the part of third parties.

- Potential incremental earnings to the utility from any partnership should be commensurate with the level of risk borne by shareholders.

- Specific system needs will likely limit the ability of the Company to engage in a partnership, particularly where reliance on partner performance might impact the reliability and safety of the electric distribution system.

- Development of potential partnerships must address potential interactions with existing regulations governing utility procurement as well as utility standards of conduct.

3) The Distribution System Planning (DSP) Draft Report Provision Recommending Coordinated DSP Filings Ignores the Sequencing Necessary to Develop the Company's System Reliability Procurement (SRP) Plan and Infrastructure, Safety, and Reliability (ISR) Plan.

The DSP Draft Report states that the SRP and ISR plans represent critical and complementary areas of utility investment, and concludes that the PUC and stakeholders should be able to consider investments made in both these processes in an integrated manner (DSP Draft Report at 8). However, this draft recommendation ignores the independent purposes of the SRP and ISR plans, and the resulting sequencing necessary to develop these plans. To inform the selection of projects proposed for the ISR plan, the Company, through DSP, forecasts loads, identifies distribution system needs, and proposes infrastructure or NWA solutions. Accordingly, the Company develops these plans at different intervals, typically 1-3 years apart, because the SRP plan (or non-wires) investments must be analyzed during or at the end of a localized planning study, which must focus in the first instance on identifying possible "wires" alternatives to meet the Company's obligation to provide safe and reliable electric service to customers. The development of "wires" projects must take priority because these types of projects are known and proven solutions to address system reliability, system condition and/or system operational needs. Once the identification of "wires" alternatives is completed, the analysis of "non-wires" alternatives can then be performed to determine if such non-wires options can meet the same goals as the "wires" alternative in providing safe and reliable distribution service at a lower cost to customers. In addition, in the event a non-wires project delivers less load relief than needed, the Company must stand ready to deliver a wires solution in short order if need be, and thus parallel development of the wires solution must occur.

In Rhode Island, the Company has 11 different planning areas that are rotated every 5-8 years to determine what the Company's long term (15 year) loads/system condition may be at the end of that term. This analysis allows the Company to better determine potential capital investment changes it may need to implement in that time horizon. Once the Company determines those investments, and based on the Company's overall infrastructure improvement needs and allowed budget, it includes them in its annual ISR plans for potential future implementation.

Because of the difference in time when a non-wires option is developed and when a project is selected for inclusion in an annual ISR Plan (approximately 1-3 years in most cases), it would be challenging for the PUC to consider investments in both of these processes in an integrated manner as recommended in the Draft Report. Nonetheless, the Company acknowledges these

investments complement each other. Thus, one option could be that, if a non-wires proposal moves forward, the Company could include reference to that project in a future ISR plan filing, and mention that the equivalent wires solution of a certain amount is, therefore, being excluded from the filing. In addition, as is already done in the SRP plan filing, the Company could include a discussion of the equivalent wires solution. As the SRP plan process now includes looking at hybrid non-wires opportunities (i.e., some of the need is met with a smaller wires investment, and the remainder met with a non-wire option), reference in both filings would be made to reflect how the Company is meeting the total need in an area. This requires an understanding that the discussion of the corresponding wires solution that a non-wires investment could replace, either in full or partially, which is included in an SRP plan filing, would not be seen in an ISR plan for 1-3 years later

4) **With Regard to the Grid Connectivity and Meter Functionality (GCMF) Draft Report, the Company has Been Actively Researching Issues Associated with Third-Party Access to Company Advanced Metering.**

The GCMF Draft Report addresses several issues associated with the deployment of advance meters. The Company's upcoming PST initiative proposal will provide an assessment of the potential costs and benefits of advanced meter deployment in Rhode Island. In the meantime, the Company wishes to restate in these comments its efforts to research issues specifically associated with third-party access to advanced metering.

As noted in the Company's September 12, 2017 PST stakeholder comments, National Grid is actively researching opportunities and challenges associated with a multi-user shared network operation model through three different venues: 1) research from a major telecommunications provider; 2) a venture capitalist that has reached out to the Company; and 3) a collaborative forum being established by PST leadership.

Based on the Company's research thus far, there are four important challenges to the development of a multi-user network operating model that must be addressed. The first is finding a model or development model that can be successfully deployed while demonstrating lower communication costs for the end-user.

The second challenge that must be addressed is cybersecurity. A shared network must support the Company's obligation to provide for a safe, secure, and reliable energy delivery system. Introducing a multi-user network could pose additional cybersecurity risks that could impact distribution and transmission utility operations. There will be mission-critical aspects of distribution and transmission utility operations where it may not be prudent to use a shared network if cybersecurity issues cannot be clearly and efficiently addressed.

The third challenge is the allocation of administrative and technical ownership and accountabilities. For example, which party should administrate service levels, costing, security, the network operation center, system configuration, and other relevant factors? Should it be the party with the biggest risk? Should this party be a regulated entity?

The fourth challenge is any restrictions posed by utility regulation or the Telecommunications Act of 1996. The Act was the first comprehensive rewrite of the Communications Act of 1934 and dramatically changed the ground rules for competition and regulation in virtually all sectors of the communications industry, from local and long-distance telephone services, to cable television, broadcasting, and equipment manufacturing.

In conclusion, the Company looks forward to continued engagement with the PST stakeholders, and respectfully requests that the Division, OER, and PUC consider the above comments in preparation of the final PST Report that will be submitted to Governor Raimondo pursuant to her March 2, 2017 letter to the agencies.

NECEC 1-9

Request:

The UK subsidiary of National Grid is regulated under a system called RIIO in Britain.

a. Does the UK subsidiary of National Grid have experience with investment programs for network modernization?

b. Please describe how a program such as PST would be evaluated, authorized, paid for and monitored under the UK regulatory regime.

Response:

a. National Grid Electricity Transmission in the UK operates under the RIIO price control, which provides funding for expanding the transmission network and renewing its aging assets. .

b. To understand how Power Sector Transformation and all of the initiatives that fall under it (Grid Mod, AMI, Performance Incentive Mechanisms, Electric Vehicles, Electric Heat, Solar and Storage) would be evaluated, authorized, paid for and monitored under RIIO requires a detailed explanation of RIIO, which can be found in the Company's attachments to NECEC 1-12. At a high level, in the UK, Ofgem runs a public consultation process to solicit input from interested stakeholders on network operators' business plans and proposed incentives and outputs, similar to the input provided from stakeholders during a rate case process on incentives such as the proposed performance incentive mechanisms. Allowed revenues, outputs, and incentives are then set by Ofgem's Final Proposals, which is similar to an order from a Commission and detailed in Attachment NECEC 1-9. Achieved incentives are ultimately paid for by end customers and monitored through progress reports. Additionally, RIIO provides forward-looking revenue allowances for eight year price controls, based on network operator's business plans, and as reviewed and judged by Ofgem. The performance incentive mechanisms as proposed in Rhode Island would be evaluated, authorized, paid for and monitored in a similar way under the UK regulatory regime.

As noted in NECEC 1-3, a total expenditure (totex) approach, which is another aspect under RIIO, represents another framework that could support more similar treatment of capital and operating expenses – however, as the Company discusses in its response to NECEC 1-8, the PUC and interested stakeholders would need to fully evaluate and consider the implications of any alternative cost-recovery models with respect to the objects they aim to achieve as well as potential unintended consequences on utility operations.

Prepared by or under the supervision of: Kayte O'Neill

Promoting choice and value
for all gas and electricity customers

RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas

Outputs, incentives and innovation Supporting Document

Reference: 169/12

Publication date: 17 December 2012

Contact Grant McEachran

Team: RIIO-T1

Tel: 0141 331 6008

Email: grant.mceachran@ofgem.gov.uk

Overview:

This Supporting Document sets out further detail on our Final Proposals on the outputs, incentives and innovation within the next transmission price control (RIIO-T1) for National Grid Electricity Transmission (NGET) and National Grid Gas (NGGT) from 1 April 2013 to 31 March 2021.

Alongside this document we are publishing two other Supporting Documents on Cost assessment and uncertainty, and Finance.

This document and the other Supporting Documents are aimed at those seeking a detailed understanding of the Final Proposals. Stakeholders wanting a more high-level overview should refer to the Overview Document.

Ofgem/Ofgem E-Serve 9 Millbank, London SW1P 3GE www.ofgem.gov.uk

RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas

Contents

Associated documents

Main consultation paper

RIIO-T1: Final Proposals for NGET and NGGT- Overview
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/1_RIIOT1_FP_overview_dec12.pdf

Supporting Documents

RIIO-T1: Final Proposals for NGET and NGGT – Cost assessment and uncertainty
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/3_RIIOT1_FP_Uncertainty_dec12.pdf

RIIO-T1: Final Proposals for NGET and NGGT – Finance
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/4_RIIOT1_FP_Finance_dec12.pdf

Other Relevant Documents

RIIO-GD1: Final Proposals – Overview
http://www.ofgem.gov.uk/Networks/GasDistr/RIIO-GD1/ConRes/Documents1/1_RIIOGD1_FP_overview_dec12.pdf

RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd
RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd

Decision on strategy for the next transmission price control - Overview paper
Decision on strategy for the next transmission price control – RIIO-T1

Glossary
Glossary for all the RIIO-T1 and RIIO-GD1 documents

1. Introduction

Chapter Summary

This chapter explains the structure and purpose of this document, and of the associated documents published alongside it. The chapter also summarises our approach to setting outputs, incentives, and providing for innovation in setting our Final Proposals for National Grid Electricity Transmission (NGET) and National Grid Gas (NGGT).

Purpose of this document

1.1. Under the RIIO process, network companies are required to take into account the needs and views of stakeholders in order to submit well-justified business plans to us. Our March Strategy Document for RIIO-T1[1] set out decisions on the key aspects of the regulatory framework. It also set out what we expected to see in a well-justified business plan, and the criteria against which we would assess such a plan. We used five broad criteria to assess the plans:

- Process: has the company followed a robust process?
- Outputs: does the plan deliver the required outputs?
- Resources (efficient expenditure): are the costs of delivering the outputs efficient?
- Resources (efficient financial costs): are the proposed financing arrangements efficient?
- Uncertainty/risk: how well does the plan deal with uncertainty and risk?

1.2. This document aims to provide further detail to support the Final Proposals Overview Document in relation to the second of those criteria - the outputs that the companies have to deliver and the incentive arrangements around delivery. It also details the elements of the framework intended to encourage innovation.

1.3. Alongside this document and the Overview Document[2] we have published two other Supporting Documents:

[1] Decision on strategy for the next transmission price control: RIIO-T1 – Ofgem, 31 March 2011 Ref:46/11 Decision on strategy for the next transmission price control – RIIO-T1

[2] RIIO-T1 Final Proposals for National Grid Electricity Transmission and National Grid Gas, Overview Document – Ofgem 17 December 2012 Ref 171/12 (http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/1_RIIOT1_FP_overview_dec12.pdf)

- RIIO-TI: Final Proposals for NGET and NGGT – Cost assessment and uncertainty[3]
- RIIO-T1: Final Proposals for NGET and NGGT – Finance.[4]

1.4. The Supporting Documents are aimed primarily at network companies, investors and those who require a more in-depth understanding of the proposals.

1.5. This document sets out our Final Proposals for the outputs to be delivered and the associated incentives that will apply around delivery for NGET and NGGT for the next transmission price control, RIIO-T1. This price control will cover the eight-year period from 1 April 2013–31 March 2021. This document also outlines the proposed arrangements to support innovation by the companies.

1.6. This document does not set out Final Proposals for the outputs to be delivered by SP Transmission (SPTL) or SHE Transmission (SHETPLC). This is because the price control packages put forward by SPTL and SHETPLC were subject to "fast-tracking".[5] We published Final Proposals for those companies in April 2012.[6] Two aspects of the outputs and incentives framework where we required further work from SPTL and SHETPLC, as well as from NGET and NGGT, were:

- the SO:TO alignment work involving development of a network access policy to enhance joint planning, coordination and communication and set out transmission owner (TO) accountabilities
- the work to implement the stakeholder satisfaction output.

1.7. We will provide clarification in relation to the final position for SPTL and SHETPLC in these areas in a separate letter due to be published alongside our statutory consultation on licence drafting for RIIO-T1.

1.8. We are also publishing details (including statutory consultation on licence modifications) of the gas system operator (SO) incentives to be applied from 2013.[7]

[3] RIIO-T1 Final Proposals for National Grid Electricity Transmission and National Grid Gas, Supporting Document on Cost assessment and uncertainty – Ofgem 17 December 2012 Ref 169/12 http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/3_RIIOT1_FP_Uncertainty_dec12.pdf

[4] RIIO-T1 Final Proposals for National Grid Electricity Transmission and National Grid Gas, Supporting Document on Finance – Ofgem 17 December 2012 Ref 169/12 http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/4_RIIOT1_FP_Finance_dec12.pdf

[5] Where business plans are of sufficient quality, fast-tracking provides a process whereby we can reach early settlement of a company's price controls, ie its business plan may be "fast-tracked".

[6] RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd (now Plc) 58/12, April 2012. This is available on our website at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=190&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes.

[7] Gas System Operator incentive schemes from 2013 Final Proposals – Ofgem 17 December 2012 Ref 171/12 http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/Gas%20SO%20incentives%202013%20final%20proposals%20consultation.pdf

These have been established through a parallel project, and we have worked closely with the teams involved to facilitate alignment of the incentives where applicable.

Requirement to deliver outputs and setting the incentives

1.9. RIIO is an outputs-led framework. It is important that throughout the RIIO-T1 period the transmission owners (TOs) understand what they are expected to deliver, and are held to account for delivery.

1.10. Our March Strategy Document set out the outputs we expected NGET and NGGT to deliver in the RIIO-T1 period. We developed these through written consultation and stakeholder workshops.

1.11. The outputs set out in the March Strategy Document provided the context for NGET's and NGGT's July 2011 and March 2012 business plans. We explicitly stated that TOs could propose departures from our March Strategy Document on particular outputs. In such cases, the TO would be required to describe its proposed approach clearly. It would also need to justify why the alternative was likely to improve expected outcomes for consumers, compared to the position set out in our Strategy Document.

Assessing performance against outputs

1.12. Under RIIO, we will generally consider NGET's or NGGT's performance against its outputs on an annual basis. We will set out in our Regulatory Instructions and Guidance (RIGs) information requirements and further detail on the reporting and monitoring arrangements. We consulted on draft RIGs on 30 October 2012. We intend to consult on the final RIGs in February 2013.

1.13. In RIIO, non-delivery of these outputs is not just a matter for the applicable financial incentives. NGET and NGGT are also accountable for delivery through their licence. We may take enforcement action where applicable where there is delivery failure. This means that even where there is a limit to the financial incentive associated with poor delivery, for example in the case of reliability, the licence enforcement process remains as a backstop. This provides additional protection for consumers in the case of significant underperformance on output delivery. Where both enforcement and financial incentives apply, the enforcement decision would take account of any financial incentives applied.

1.14. For the avoidance of doubt, we confirm that NGET's or NGGT's revenues or allowances can be adjusted downwards if it does not deliver the level of outputs for

which it has been funded. We will make an allowance adjustment for the amount of underdelivery after an assessment of actual outputs against the expected level of output delivery set out in Final Proposals or NGET's/NGGT's licence, or derive an allowance adjustment using the parameters of an output volume driver if one is operating in respect of the output.

Setting the level of incentives

1.15. Under RIIO it is not possible to set out the actual level and profile of annual allowed revenue that NGET and NGGT can collect. This is due, in part, to within period revenue flexing mechanisms that will adjust the opening base revenue allowances. Examples of mechanisms that can alter allowed revenue over the price control period include the uncertainty mechanisms, the Strategic Wider Works (SWW) mechanism and the application of the efficiency incentive rate.

1.16. In order to maintain strong output incentives we intend to make sure that where caps and collars apply to these, they do not just reflect the starting position on revenue called the opening base revenue allowance. Instead, we propose that they adjust in response to ongoing, but uncertain, changes in revenue in order to reflect more accurately the true change in network total expenditure (totex) and other in-period adjustments over the price control period.

1.17. To do this, we propose that the maximum caps and collars will be linked to a combination of the opening base revenue allowance plus within-period adjustments captured through annual iteration of the financial model and, for NGET, the revenue from Transmission Investment in Renewable Generation (TIRG).[8] This will include all extra totex that is triggered during the RIIO-T1 price control period.

1.18. In Final Proposals the Totex Incentive Mechanism will apply to those incentive rates that have been set to equal the economic value of the output, ie the incentive rates for sulphur hexafluoride and energy not supplied. This is necessary to ensure that NGET faces the appropriate economic incentives to take decisions on the level of outputs it delivers that are in the interests of consumers. For the same reason, we have decided to include a tax adjustment on these incentives to address the different tax treatment of any over or under spend and output incentive reward/penalty. Note that this issue does not arise in relation to any of NGGT's output incentives. Lastly, we will preserve the economic value of these incentives during the price control period by adjusting for the rate of RPI inflation.

Managing charging volatility

[8] TIRG is a mechanism designed to fund transmission projects specific to connecting renewable generation outside of the price control allowance to minimise delays. TIRG is comprised of four projects: Beauly-Denny, Sloy, South West Scotland and the Anglo Scottish Interconnector.

1.19. While we do not determine charges, the changes in allowed revenue at the start and during the RIIO-T1 period impacts on the network companies' customers through the network charges. We recognise that our proposals can add to volatility in these charges and that the degree of notice before significant changes are made to charges is a critical issue to network companies' customers and to end consumers. When setting the RIIO-T1 framework we have considered how we might manage the volatility that necessarily results from an incentive regime that rewards outputs, penalises under-performance and provides a flexible regulatory framework that can cope robustly with uncertainty.

1.20. In April 2012 we consulted on five options for managing charging volatility:

- Improved information for suppliers and customers
- Restricting the frequency of intra-year charge changes
- Increasing the lag on incentive rewards/penalties that networks recover through allowed revenues
- Increasing the lag on adjustments to allowed revenues from uncertainty mechanisms
- Imposing a cap and collar on changes to allowed revenues.

1.21. In September 2012, we published our decision which proposed to implement the first three options. While rejecting the imposition of a cap and collar on changes to allowed revenues, we also proposed to increase the lag on adjustments to allowed revenues from uncertainty mechanisms in some cases. In relation to the financial incentives discussed in this document, this means that we are planning to manage their impact on charging volatility. This will generally be through a lag in the impact they have on allowed revenues and/or significant advance knowledge about changes.

1.22. We will reflect this decision in the statutory consultation on the licence conditions to be published on Friday 21 December 2012.

Funding RIIO-T2 outputs

Our Initial Proposals

1.23. In Initial Proposals we proposed to disallow the baseline allowances that NGET requested in its business plan for outputs which may be required in the next transmission price control period, RIIO-T2 (circa £425m), after adjustments such as for unit cost efficiencies. We did not consider it appropriate to include baseline allowances for this expenditure in view of the uncertainty about what might turn out to be required. This is in line with the RIIO principle of matching expenditure to outputs.

1.24. Instead, we proposed that any expenditure made by NGET in RIIO-T1 for outputs delivered in RIIO-T2 would be treated initially as apparent overspend and

covered by the totex incentive mechanism. We also set out the principle that NGET would be remunerated for the total efficient costs it incurred in RIIO-T1 for outputs delivered in RIIO-T2. We proposed that we would assess this as part of setting the price control for the next period, also taking into account any totex incentive mechanism adjustments.

Responses to Initial Proposals

1.25. NGET has said that under these arrangements it would incur significant costs in advance of funding, and that these costs did not seem to be reflected in our financeability modelling.

1.26. NGET also noted that we said in the RIIO Handbook[9] that expenditure for the delivery of outputs in future price control periods could be included as part of the price control, subject to the company providing evidence that the benefits of this expenditure will be observed in future price controls, and is related to delivering long-term value for money.

Our Final Proposals

1.27. In response to NGET's concerns, we have further assessed the financial implications of the RIIO-T2 expenditure as per our Initial Proposals under different scenarios. We set out the assumptions we used in these stress tests in our Supporting Document on Finance. Overall, we find that our proposals are robust to a range of downside scenarios, including expenditure relating to outputs delivered in RIIO-T2.[10]

1.28. Although our analysis confirms that the approach set out in Initial Proposals is financially sustainable for the company, we have also considered other potential implications of this approach on NGET in carrying out work for delivery of outputs in future price control periods. For example, we recognise that without clarity on the efficient costs of delivering outputs there is a risk that NGET may seek to defer load-related projects into RIIO-T2 to fund more expensive projects through the baseline. As a result, we consider it is in existing and future consumers' interests, and in line with the RIIO principles generally, to ensure that the company has strong incentives to deliver these customer-driven outputs efficiently and in a timely manner.

1.29. Accordingly we intend to change our proposals in this area. However, given the level of uncertainty about what might turn out to be required,we retain our position of not including baseline allowances in RIIO-T1 for RIIO-T2 outputs. Instead we are including in Final Proposals an additional funding mechanism for NGET to trigger a funding adjustment to cover this expenditure should it be needed. This will work through the respective volume drivers in each load-related area, using the unit cost allowances agreed for RIIO-T1 and the generic spend profile that is also

[9] Handbook for implementing the RIIO model – Ofgem 4 October 2010 http://www.ofgem.gov.uk/Networks/rpix20/ConsultDocs/Documents1/RIIO%20handbook.pdf.
[10] Further detail of our analysis in set out in the Finance Supporting Document.

included as part of the volume drivers. The benefit of this approach is that there will be a much clearer link between the costs NGET has incurred in the RIIO-T1 period and outputs that the company can be held to account to deliver during RIIO-T2. More details about how and when this funding adjustment will be triggered and when it will take effect are set out in the Cost assessment and uncertainty Supporting Document.

Structure of this document

1.30. The remainder of this document is structured as follows:

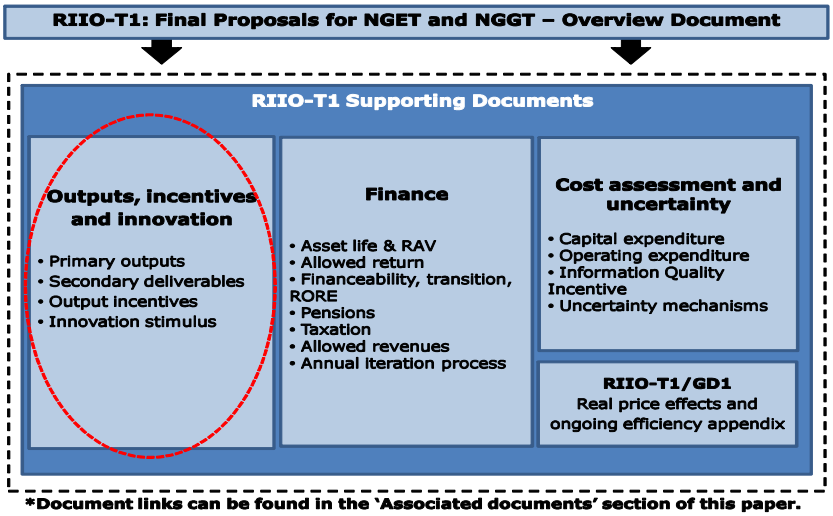
- Chapter 2 sets out our Final Proposals for the outputs and incentives that will apply to NGET
- Chapter 3 sets out our Final Proposals for the outputs and incentives that will apply to NGGT
- Chapter 4 sets out the proposed arrangement that will apply to encourage NGET and NGGT to innovate and to meet the requirements of their innovation strategies.

1.31. We intend to publish licence modifications for statutory consultation on Friday 21 December 2012.

1.32. All monetary amounts in this document are in 2009-10 prices unless otherwise stated. There may be slight differences between tables due to the rounding of numbers.

1.33. Figure 1.1 provides a map of the RIIO-T1 Final Proposals documents.

Figure 1.1 – RIIO-T1 Final Proposals document map


RIIO-T1: Final Proposals for NGET and NGGT – Overview Document
RIIO-T1 Supporting Documents
Outputs, incentives and innovation
• Primary outputs
• Secondary deliverables
• Output incentives
• Innovation stimulus
Finance
• Asset life & RAV
• Allowed return
• Financeability, transition, RORE
• Pensions
• Taxation
• Allowed revenues
• Annual iteration process
Cost assessment and uncertainty
• Capital expenditure
• Operating expenditure
• Information Quality Incentive
• Uncertainty mechanisms
RIIO-T1/GD1
Real price effects and ongoing efficiency appendix
*Document links can be found in the 'Associated documents' section of this paper.

2. NGET: Outputs and incentives Final Proposals

Chapter Summary

This chapter sets out our Final Proposals in relation to outputs and incentives that will apply to NGET.

Introduction

2.1. This chapter considers each output area in turn and considers what we are requiring NGET to deliver over RIIO-T1. It also sets out the detail of associated incentives that apply around NGET's delivery during RIIO-T1.

Outputs we are requiring NGET to deliver over RIIO-T1

Safety

Our Initial Proposals

2.2. Our Initial Proposals in relation to safety were for NGET to be compliant with its legal safety requirements. These are requirements monitored by the Health and Safety Executive (HSE), as the safety regulator.

2.3. In addition, our Initial Proposals also required NGET to maintain and report annually on a suite of network output measures (NOMs) on criticality, replacement priorities (or risk), system unavailability, average circuit unreliability (ACU), faults and failures. These measures inform both the safety and reliability of NGET's network. The measures are important despite not involving direct financial incentives. Performance against them informs us about the ability of NGET to continue to deliver a safe and reliable network both into, and throughout, the next price control period.

Responses to Initial Proposals

2.4. We received no specific responses in this area. NGET confirmed its support for the proposal for the safety primary output. NGET had comments on the secondary measures on asset health and condition, and we explore these under the reliability section below.

Our Final Proposals

2.5. Our Final Proposals reflect our Initial Proposals in this area. A more detailed discussion of our approach to NOMs is set out in the discussion on reliability below.

Reliability

Our Initial Proposals

2.6. In our Initial Proposals, we proposed that NGET be held to account for delivering an output on the level of energy not supplied (ENS) each year. A target level of 316MWh per annum would apply during the RIIO-T1 period. The incentive rate would be £16,000 per MWh, with the company gaining reward for delivering a lower level of ENS and incurring a penalty for each MWh worse than the 316MWh target. We proposed to maintain the level of the incentive rate in real terms for the price control period. The incentive has a natural cap, as NGET cannot reduce ENS below zero. Our Initial Proposals proposed to limit the downside risk from this incentive by applying a 3 per cent collar, which is consistent with our assessment of the risk of NGET's overall package.

2.7. These Initial Proposals also envisaged the ENS incentive being subject to a number of exclusions. These were to completely exclude ENS related to customer-choice connections and events lasting less than or equal to three minutes. In other cases, such as extreme weather events, we proposed that it will be a matter for Ofgem to understand the specific circumstances of the case before deciding whether to exclude any ENS from this incentive.

2.8. The NOMs are secondary deliverables that provide us with a measure to monitor and assess transmission owners (TO)s' asset renewal performance over the longer-term. They are a leading indicator of asset performance.

2.9. For Initial Proposals we set out the detail on how we reconcile asset replacement volume and NOMs under the non-load-related (NLR) investment programme. We proposed that we will take the NOMs target of RIIO-T1 as the opening position from which a TO will be funded to deliver the NOMs target of RIIO-T2. Under this approach any under or over delivery in RIIO-T1 would either require catch-up or carry-forward by the TO in order to meet its RIIO-T2 NOMs target.

2.10. We proposed a two tier approach to assessing the NOMs performance of RIIO-T1 as part of the RIIO-T2 price control review, and outlined the high level reviewing process. When assessing the actual NOMs, we consider a delivery of an equivalent NOMs target is on target. We also said we would consider using a dead-band around the NOMs target to take into account inherent uncertainties in the assessment methodology.

2.11. To encourage TOs to make the most appropriate asset management decisions in the best interests of consumers, we proposed to introduce financial incentives on the TOs based on our assessment of their actual NOMs' performance against their target. We proposed a financial reward for justified over and under delivery and a financial penalty for unjustified over and under delivery. We indicated that the size of the incentive is likely to be linked to the cost associated with over and under delivery, and that we would set out the parameters during the RIIO-T2 price control review.

2.12. We also proposed to implement a true-up process to reconcile the financial incentives after the completion of RIIO-T1.

Responses to Initial Proposals

2.13. NGET supported our primary output of ENS and the associated financial incentive. Another respondent questioned the level of the value of lost load (VOLL), highlighting how difficult it was to reflect a level that was appropriate to the impact on different types of energy consumer.

2.14. NGET commented on our Initial Proposals for NOMs. We summarise the key points below.

2.15. NGET agreed in general with our Initial Proposals on the NOMs' assessment principles and welcomed our Initial Proposals for the two tier assessment approach for the NOMs. It noted that a dead-band around the NOMs' target was appropriate.

2.16. NGET expressed its concern on our proposed treatment of under and over delivery as it was worried that marginal reward and penalty could skew the cost benefit analysis used for asset management decision-making.

2.17. NGET was also concerned about Ofgem not setting out the details of the strength of incentives until the RIIO-T2 price control, as it felt that it would not be able to make fully informed investment decisions without understanding the parameters of any reward or penalty.

2.18. NGET proposed a mechanistic dead-band of minus and plus 5 per cent around the Replacement Priority Four (RP4) target, and requested further clarification of the trade-off between asset categories.

Final Proposals

2.19. Our Final Proposals confirm ENS as the primary output in this area and all other elements of Initial Proposals without change. We agree that the VOLL is necessarily an average level that does not reflect the impact on particular consumers. However, our proposed range was derived through a review of a number of studies (described in detail in our Strategy Document (31 March 2011)). We are content that it balances the different impacts, and we have deliberately incorporated the RIIO sharing factor to guide NGET to make the right balance when considering the costs incurred in reducing the incidence of ENS.

2.20. Since publication of our Initial Proposals we have further consulted our stakeholders via industry workshops and bilateral meetings. We considered the feedback from stakeholders in developing our Final Proposals.

2.21. We will set out the agreed NOMs targets as binding secondary deliverables in the licence. TOs will be obliged to deliver these targets (or an equivalent taking into account trade-offs described below) for consumers. We propose to link the NOMs condition with the NOMs methodology condition, such that the targets will need to be rebased should significant changes be made to the NOMs methodology.

2.22. We expect TOs to make asset management decisions which are based on the latest information, and in the best interest of consumers. TOs can trade-off between asset categories in order to deliver an equivalent or better outcome to the NOMs target. We will not limit these trade-offs. It is for TOs to justify why they need to over-deliver in one asset category and under-deliver in another, and how the overall delivery equates to an equivalent or better level of the network risk. In the longer term we expect TOs to develop a monetisation approach to justify the trade-off.

2.23. We propose to review the performance of NOMs following the two-tier approach in our Initial Proposals. The first tier of this process is to compare the outturn NOMs against the NOMs targets, and determine if a TO delivers the NOMs targets or not. We do not think a mechanistic dead-band of plus or minus 5 per cent around the RP4 target is appropriate, because the assets in different RP groups have different impacts on the network risk and TOs have the scope to trade-off against asset categories. Therefore, we do not propose to set out a mechanistic dead-band around the NOMs targets. We will ask TOs to provide evidence to justify their achievement of the NOMs target when we compare the outturn NOMs against the NOMs targets. Where a TO is on target, we will take no further action following the first tier review.

2.24. For a TO that delivers the NOMs below or above the target, we will initiate the second tier of assessment process. We will ask the company to provide evidence to quantify the scale of the under or over-delivery, and justify whether the under or over delivery is in the best interest of consumers. When we set out the RIIO-T2 allowances for non-load related expenditure (NLRE), we will take the NOMs targets of RIIO-T1 as an opening position from which the company will deliver the NOMs targets of RIIO-T2. Therefore, for under delivery the gap between the outturn and target NOMs of RIIO-T1 will not be funded in RIIO-T2, and for over delivery this gap will be funded through the NLRE allowance for RIIO-T2.

2.25. We recognise that asset management is a continuous process and the decision-making should not be distorted by the end of the price control period, and the financial incentives on under- or over-delivery. As a result, we propose the following incentives to encourage any justified variations to the NOMs targets overall, whilst discouraging any unjustified variations. These incentives are set out in Table 2.1 below. The 'costs' and 'avoided costs' referred to in the Table are net of the amounts already funded through the efficiency incentive rate.

Table 2.1 – Financial incentives on NOMs

Incentives	Justified	Unjustified
Over delivery	• Costs of over delivery are included in the RIIO-T2 allowance. • A TO would benefit from the reduced network risk compared to the NOMs target. • A TO would be allowed to recover the financing cost of the earlier investment. • An additional reward is applied.	• Costs of over delivery are included in the RIIO-T2 allowance. • A TO would benefit from the reduced network risk compared to the NOMs target. • A TO would take the financing cost of the earlier investment. • No additional penalty is required.
Under delivery	• Avoided costs associated with under delivery are excluded from the RIIO-T2 allowance. • A TO would be exposed to the increased network risk compared to the NOMs target. • A TO would benefit from the financing cost of the delayed investment. • No additional reward is required.	• Avoided costs associated with under delivery are excluded from the RIIO-T2 allowance. • A TO would be exposed to the increased network risk compared to the NOMs target. • The benefit of the financing cost of the delayed investment would be clawed back from a TO. • Additional penalty is applied.

2.26. In addressing NGET's concern on risks of financial incentives, we propose to set a fixed level of rewards and penalties in order to provide strong incentives for TOs to deliver the NOMs target while protecting them from financial stress relating to the non-delivery. The value of any penalty or reward will be 2.5 per cent of the value of the additional or avoided costs. For the avoidance of doubt, there is substantial unjustified under delivery we may consider whether it is appropriate also to use our powers relating to enforcement of licence conditions.

2.27. To illustrate how we will apply the above methodology in assessing the performance of NOMs and applying incentives, we set out a few hypothetical scenarios and cases in Appendix 1.

2.28. In response to our Initial Proposals we have discussed the NOMs measures in detail with NGET and the other TOs. We have agreed that the average circuit unreliability is not ready for immediate use from the start of RIIO-T1, and continues instead to be an area of development for possible later addition.

Availability: Network Access and SO:TO interaction

Our Initial Proposals

2.29. Our Initial Proposals were for NGET to produce and maintain a Network Access Policy (NAP) to contribute to better SO:TO interaction and cooperation in both short-term and long-term network planning. We also proposed that NGET continues to engage with SPTL and SHET PLC in the development and maintenance of their respective NAPs both before the start of the RIIO-T1 control period and ongoing engagement through the price control period, for instance to engage on possible updates to the NAP (eg reflecting lessons learned).

2.30. Our separate work on SO incentives from 2013 is considering the external incentives for NGET as SO. We expect to publish Final Proposals for these incentives in 2013 following our further consultation that closes on 21 December 2012.

2.31. Through both RIIO-T1 and the project for setting SO incentives from 2013, we have worked to make sure that we align the incentives facing electricity TOs and the SO where choices can be made across the two functions that minimise overall costs to consumers, or where the costs caused by one can affect the other. The NAP development is the central area of interaction on the electricity side though we have also developed other proposals assessing the combined TO and SO impact, eg our proposals in relation to transmission losses.

Responses

2.32. Responses that considered this work were generally supportive of the NAP. One respondent highlighted the need for a co-ordinated approach to planning against the context of significant new investment being required to support new generation capacity. However, concerns were raised regarding both the type of incentive involved and its focus (ie whether it was targeting some of the areas of concern to generators and other stakeholders). In particular, the absence of an incentive on NGET to avoid disconnection impacting on generators was a concern. This respondent proposed that these issues should be considered in an open and transparent way in the industry.

2.33. Another respondent noted concern with the degree to which SO-TO interaction is discussed within our Initial Proposals. This respondent particularly highlighted the importance of taking a wider view of system costs.

Our Final Proposals

2.34. Our Final Proposals for NGET in relation to network availability is that it should continue to develop a NAP within a month of the start of the RIIO-T1 period, and should actively engage in the development of the equivalent document for SPTL and SHETPLC. The NAP will be a live document, and we will continue to support the electricity TOs and SO in working towards the publication of the initial documents

within a month of 1 April 2013. Our proposed new licence condition requires the NAP to be a regularly reviewed and potentially updated. While the SO has a direct role in challenging the TOs on the quality of their NAP documents, other interested stakeholders should also influence this development.

2.35. On 30 October 2012 we consulted on an initial draft of the joint NAP between SPTL and SHETPLC. NGET has played a full role in getting this draft to the stage it has reached. The principles should also provide a basis for a NAP for NGET. In this, as at Initial Proposals, we recognise the difference in NGET's NAP compared to SPTL and SHETLPLC in light of it being both TO and SO. Its document might serve to reflect best practice in some areas where it has long established coordination within the single company. In other areas, the NAP can provide useful transparency that might influence the company's approach going forward.

2.36. We agree with respondents who recognised the importance of the NAP development. We also agree with those who challenged whether its coverage was sufficiently comprehensive and whether the incentives associated with it where sufficiently strong on the TOs.

2.37. We also agree that it is important to take an overall view of system wide costs. We recognise the importance of the interaction between our work and the SO incentives post 2013. In terms of network constraint costs, the SO incentives play an important role. However, it is also important through the NAP development that TOs are incentivised to co-operate and plan together with the SO. The NAP is a live document. While we are very happy with the efforts of the companies to date, it is important that the TOs and SO continue to work on this. The NAP seeks to maintain a difficult balance. On the one hand it should be sufficiently clear so that the parties to it are held accountable for overall performance in this area. At the same time, however, this is an area where simple measures or blanket commitments are not feasible. The NAP seeks to describe not just what the TO would normally do, but circumstances where this might not be possible and what we should expect the TOs to do in such cases.

2.38. We consider that the NAP documents published within a month of 1 April 2013 should reflect continued work to understand the full range of TO activities that interact with the SO.

2.39. We recognise the different circumstance for NGET. This is because NGET, as the one company performing both SO and TO roles, faces incentives from the costs and benefits associated with both network constraints and TO costs and benefits. We continue to see value in NGET producing its own NAP. This should provide transparency about the existing interactions, and potentially demonstrate best practice that might be adopted in the more complex situation where separate TOs do not face the combined effect of direct TO and SO incentives.

2.40. We expect that the NAP proposals will encourage a step towards greater interaction between the SO and TOs and promote enhanced coordination of activities. However, we are aware of the level of potential for cost savings through

providing greater incentives for cross party communication and actions in this area. We will continue to work closely across the SO incentives and NAP development to consider further how to promote communication and coordination between the SO and TOs.

Customer Satisfaction

Our Initial Proposals

2.41. In our Initial Proposals we proposed that NGET should have a financial incentive informed directly by the results of a survey. We noted that the survey should clearly highlight the distinction between NGET's activities and the other roles that it or other companies may carry out. This incentive had the limits of plus or minus 1 per cent of the particular year's allowed revenue. Since Initial Proposals, work has continued to progress on the details of how to implement this incentive.

2.42. The second part of our Initial Proposals in this output was provision for a possible reward for using ongoing stakeholder engagement to generate a high quality outcome. We presented initial guidance on how we would assess the case for this reward in Initial Proposals. We subsequently set out a draft guidance document with our second informal licence consultation of 30 October 2012.

Responses to Initial Proposals

2.43. Those respondents who commented specifically in this area were generally supportive. NGET provided details of its view on progress towards the incentive, and proposed a way forward on some of the mechanics of the survey incentive.

2.44. In particular, NGET's response set out the parameters it proposed for the consumer element of the survey based on a number of years experience. This included a baseline of 6.9/10 for the period and points above and below this level where the incentive would be limited to reflect the extreme responses appropriately.

Our Final Proposals

2.45. Our Final Proposal is consistent with our Initial Proposal in overall form. However, it reflects our assessment of the further work that NGET has carried out.

2.46. NGET has material experience of operating a customer survey and has been able to provide sufficient evidence to set the parameters for this element of the survey in the licence condition, (due to be published shortly). This reflects a baseline score based on NGET's recent overall performance but also supported by similar surveys in other sectors.

2.47. NGET has also carried out a 'dry run' survey of its key stakeholders (other than its consumers). This is an area where it has far less experience of the likely level and variance of responses. We agree that it is appropriate that separate metrics be applied for the stakeholder survey compared to the consumer survey. The specific baseline metrics for the stakeholder element are being developed in light of evidence from the now completed dry run, and we expect NGET to propose metrics by April 2013. We may consider the stakeholder baseline and related metrics in 2016 looking at the wider evidence that we will have at that time about how stakeholders respond to this type of survey under different conditions and company performance.

2.48. We also agree with NGET's proposal to increase the proportion of the incentive driven by the stakeholder survey over the control with the aspiration of it having equal representation towards the end of the price control period when we will understand the results from this new element more fully. In the early years, the proportion of the two elements may be significantly different. We will consider and determine the proportion profile in April/May 2013 following NGET's proposal to us.

2.49. NGET noted in its response to the second informal consultation on licence modifications that it was interested in understanding if it could make use of elements of the approach SPTL and SHETPLC have followed, to make use of supporting information alongside its survey of customer and stakeholder opinions. We see merit in both types of approach, and on the condition that the supporting information or processes support the survey results by providing information that directly implies higher quality performance in meeting customer/stakeholder needs, these are consistent with the aims of this output. However, it is too late in the process for NGET to be able to implement this from 1 April 2013. Instead this is something that could be considered with relevance to the second half of RIIO-T1 if proposed as part of any review of this incentive in 2016.

2.50. We are publishing updated Stakeholder Engagement Reward Guidance with the statutory consultation on licence modifications. Otherwise this remains as per our Initial Proposals.

Connections

Our Initial Proposals

2.51. We proposed that the connections output for NGET should be the timely meeting of its existing licence obligations in relation to delivering connections. Consistent with our Strategy Document, given the importance in electricity transmission of timely connections with respect to the delivery of a sustainable energy sector, we include scope for a possible financial penalty equivalent to up to 0.5 per cent of allowed base revenue.

2.52. NGET accepted this aspect of our Strategy Document in its business plan. It has sought revenue to reflect that position.

2.53. The timely connection obligations are already present in NGET's licence. However, we have been working with NGET and other TOs to draft the financial incentive.

Responses to Initial Proposals

2.54. NGET accepted the proposed output but highlighted that these were existing licence obligations and argued that it was not appropriate to apply a financial incentive to part of an existing set of obligations for delivering timely connections.

2.55. No third party response commented specifically on this issue.

Our Final Proposals

2.56. We confirm our Final Proposals are for the output in this area to be the timely delivery of NGET's connection obligations. We recognise that NGET has a number of obligations in relation to the connections process (significantly more than the Scottish TOs because of its wider role). We also recognise that to focus a financial incentive on those obligations with specified timings where a number of others have implied but non-specific timely delivery requirements might potentially distort NGET's delivery approach. We propose to continue to set the output so that NGET considers all of its timely connection obligations. The Authority may use its general enforcement powers as the route to take action in the case of under delivery with the potential for an associated financial adjustment.

2.57. We also confirm that the RIGs in this area, in addition to the information reporting requirements set up at the conclusion of Project TransmiT, should provide a good base for understanding NGET's performance in relation to connections delivery.

2.58. To put the importance of this output in context, we set out the Best View[11] for new transmission connected generation capacity in England and Wales over RIIO-T1 in Table 2.2. Please see the Cost assessment and uncertainty Supporting Document for further details on our efficiency assessment and risk sharing arrangements

Table 2.2 New transmission connected generation capacity over RIIO-T1

New Generation Connections Capacity	Baseline funding	Uncertainty Mechanism funding	Best View total expenditure
	(£m)	(£m)	(£m)
33,000 MW	1,042.6	-	1,042.6

[11] 'Best View' is the expenditure that we consider the TO's will need to deliver the outputs under the central scenario . It comprises 'baseline' and 'uncertainty mechanism' funding.

Environmental outputs

Sulphur Hexafluoride (SF_6)

2.59. In Initial Proposals we proposed to adopt NGET's business plan submission that all new assets using SF_6, gas such as switchgear, are commissioned with a target leakage rate of 0.5 per cent per annum. This leakage rate is consistent with best practice set by the International Electrotechnology Commission standard 62271-203 for high voltage switchgear.[12]

2.60. We also proposed that the TO's baseline target for SF_6 emissions is calculated annually from adding together emissions from the previous year and expected emissions from new asset additions in the current year, less the expected emissions from asset disposals in the current year. We proposed that NGET would face a financial incentive on the difference between actual SF_6 emissions from assets on its transmission system and the baseline target. The incentive would be equal to the non-traded carbon price for the amount of carbon equivalent emissions.

2.61. In Initial Proposals we rejected NGET's proposal to adjust the baseline target each year for a marginal increase in leakage from its existing inventory, as we consider that this would not provide the right incentive.

Responses to Initial Proposals

2.62. One third-party respondent was concerned that Ofgem's proposal to calculate SF_6 incentive performance, based on differences between actual and calculated baseline emissions, was inconsistent with the principles of a good incentive mechanism, ie that it would be inappropriate to incentivise companies on estimated data.

2.63. NGET also responded on the SF_6 proposals in Initial Proposals. It made the following points:

- There is an error in paragraph 2.27 which stated that the calculated change in SF_6 emissions should be added to the "actual emissions for the previous year". NGET considered this should read the "calculated emissions target for the previous year" to have the desired effect.
- In its view, our proposal to calculate the baseline emissions target in the first year of the price control, by applying NGET's existing (TPCR4) Rollover SF_6 emissions target (1.75 per cent) to its existing inventory, is inconsistent with our Strategy Document that "companies should use existing emissions as a starting point" (currently 1.83 per cent from the last full year).

[12] The International Electrotechnical Commission prepares and publishes International Standards for all electrical, electronic and related technologies collectively known as "electrotechnology". See http://www.iec.ch/.

- By not allowing NGET's proposed adjustment for higher leakage from existing assets, it considers we had set NGET a more demanding target than that faced by the Scottish TOs and that this was not justified.
- Details around adding emissions from new assets in proportion to the amount of time they formed part of the TO's transmission system needed clarification as part of the licence drafting process.

Our Final Proposals

2.64. In our Strategy Document we considered the robustness of setting an incentive regime based on an estimated measure of the SF_6 output. We considered that it would not be efficient to set a zero baseline for TOs in relation to SF_6 emissions given the existing stock of SF_6 assets, and the various benefits of using such assets.[13] However, we did consider it appropriate to set an incentive regime that would drive companies to fully consider lifetime costs, including emissions, when appraising investment options and making operational and maintenance decisions about these assets. To do this we need to set an incentive around a baseline target that represents an operational and investment strategy that is in the interests of existing and future consumers. In the case of SF_6 emissions, we consider there is a relatively low risk from calculating a baseline target, given the available information on best practice that can be used to set the value of the parameters for this calculation.

2.65. Therefore, we retain our position in Final Proposals for a SF_6 output regime using a calculated baseline target. We consider this is in the interests of existing and future consumers as it will provide economic incentives for TOs to make decisions around investing, operating and maintaining SF_5 assets, including addressing the worst performing assets where it is economic to do so.

2.66. NGET is correct in its response to the Initial Proposals that the baseline target for SF_6 emissions should be calculated from the previous year's calculated baseline target emissions rather than the actual emissions (for all years in the price control period except the first year – see below).

2.67. In relation to NGET's second point regarding the baseline target for SF_6 emissions in the first year of the price control, we also confirm that this should be calculated as set out in the Strategy Document. NGET's initial baseline emissions target will take as a starting point its actual emissions in 2012/13.

2.68. We do not agree with NGET that its calculated baseline target for SF_6 emissions is unjustifiably more demanding than that faced by the Scottish TOs. We have not included an adjustment factor for any of the TOs' Final Proposals that would add extra emissions each year to the calculated baseline for a deterioration in the leakage of existing assets. Evidence provided during the assessment of the Scottish TOs' business plans demonstrated that the proposed leakage rates comply with the

[13] Equipment containing SF_6 provides a safe and cost efficient electrical insulation medium, while also helping to minimize substation footprint.

standards set by the IEC for assets containing SF_6 and SF_6 mixtures. We also note that one Scottish TO will add emissions to its baseline target from new SF_6 assets that form part of large transmission system reinforcements, and that these will be calculated at the manufacturers' specified leakage rate.

2.69. We have also informed our decisions on baseline targets for SF_6 for each TO through the particular TO's track record in the SF_6 leakage scheme under TPCR4. We expect a TO who has previously performed well, such as NGET, and which has developed processes and gained a lot of experience in operating and managing these assets, will continue to benefit from these under the RIIO-T1 regime. Accordingly, we also think it is appropriate that the incentive regime should provide sufficient stretch for NGET to seek further improvements in its approach where it is economic to do so. For these reasons we confirm for Final Proposals that we are not including an adjustment to NGET's calculated baseline for deterioration in the leakage from existing assets.

Business Carbon Footprint

Our Initial Proposals

2.70. In Initial Proposals we proposed that NGET report annually to stakeholders on its scope 1 and scope 2 greenhouse gas (GHG), or carbon dioxide equivalent, emissions throughout the RIIO-T1 period.[14] We also proposed that NGET face reputational incentives only on its business carbon footprint (BCF) reporting. We also said that NGET would need to report on its BCF at the business level to enable accurate reporting on its carbon equivalent GHG emissions from the transmission business.

Responses to Initial Proposals

2.71. We did not receive any specific responses in relation to our BCF proposals set out in Initial Proposals.

Our Final Proposals

2.72. We confirm that our proposals as consulted on in Initial Proposals are unchanged for our Final Proposals in this area.

Transmission Losses

Our Initial Proposals

[14] Scope 1 are direct GHG emissions that occur from sources that are owned and controlled by the company. Scope 2 are indirect GHG emissions from the generation of purchased energy consumed by the company. Scope 3 includes other indirect GHG emissions that result from the activities of the company, but are not owned or controlled by the company.

2.73. In Initial Proposals we proposed to set reputational incentives on NGET in relation to its overall approach to contributing to fewer transmission losses where it can do so and provide long term value to consumers.

2.74. We also proposed that NGET should publish its strategy for transmission losses and report to stakeholders annually on its progress in implementing its strategy. We also said that this should include an estimate of the impact this has had on transmission losses in its transmission area.

Responses to Initial Proposals

2.75. Two respondents supported the proposal to set a reputational incentive on losses because the outcome can be significantly affected by the actions of third parties. They also supported the proposed design of the mechanism.

Our Final Proposals

2.76. We confirm our proposals as consulted on in Initial Proposals are unchanged for our Final Proposals in this area.

Visual amenity

Our Initial Proposals – new transmission infrastructure

2.77. In Initial Proposals, we proposed that NGET efficiently address the visual amenity impacts of new transmission infrastructure where necessary to obtain development consent from the Secretary of State. This is consistent with NGET's requirements as a proposer of potential new developments under the Planning Act 2008, and also NGET's obligation under its transmission licence to maintain and develop its transmission system in an economical and efficient manner.

2.78. We proposed to adopt NGET's submission for a baseline allowance equivalent to the efficient costs of deploying underground cabling technologies for 10 per cent of the new transmission assets potentially required in RIIO-T1. This was a working assumption to use as a starting point. To deal with uncertainty around whether this is the actual level needed over the price control period we also proposed to include a volume driver to adjust NGET's revenue for the level of mitigation technologies needed to obtain development consent. For more information on the operation of the Planning Requirements volume driver we refer the reader to the Cost assessment and uncertainty Supporting Document.

2.79. We also proposed to make provision for the Authority to review the volume driver mechanism if it becomes clear to us that it is not delivering efficient outcomes.

Responses to Initial Proposals

2.80. We received several responses to Initial Proposals for mitigating the visual amenity impacts of new infrastructure. The overwhelming majority of third-party stakeholders supported the inclusion of baseline funding with an uncertainty mechanism to adjust allowances if more or less mitigation is required to obtain development consent during the price control.

2.81. NGET welcomed the proposals in our Initial Proposals as these were aligned with the approach set out in its business plan. NGET also sought clarification on Ofgem's process for reviewing the uncertainty mechanism and said it should also be able to trigger a review.

2.82. Third-party stakeholders also raised the following issues in relation to arrangements by which the mitigation required for new infrastructure would be determined:

- Several stakeholders said that a study into consumer willingness to pay for undergrounding new transmission infrastructure was needed, to inform both the companies, Ofgem and the Planning Inspectorate about the 'economic and efficient' level of mitigation. Stakeholders argued that without such a study there is little information available to inform NGET on how it should efficiently address the visual amenity impacts of new infrastructure proposals.
- Generally the same stakeholders argued that Ofgem should require the TOs to undertake this analysis as part of their business planning process and that it was important that this was done at a national level because it is greater than local significance.
- Several stakeholders also sought clarification on Ofgem's role as statutory consultee on new transmission infrastructure under the Planning Act 2008. There was also a similar call for further clarification on the interface between regulatory and planning regimes.
- In a similar vein these stakeholders also thought that Ofgem should provide more guidance on NGET's regulatory and legislative obligations under the Electricity Act in the context of seeking planning decisions, to ensure that the company did not place greater weight on particular solutions based primarily upon their cost as opposed to their overall sustainability.

Our Final Proposals

2.83. In light of the widespread stakeholder support for the proposal consulted on in Initial Proposals we retain this approach for Final Proposals largely unchanged.

2.84. The one area we have reconsidered with a view to amending for Final Proposals is the proposed provision for the Authority to review the volume driver mechanism during the price control period. We no longer consider it is necessary to include a re-opener provision. This is because the Totex Incentive Mechanism will

help protect consumers in the event that actual unit costs change significantly over the price control period by sharing savings between the company and its customers. We also consider that we will have sufficient opportunity as a statutory consultee under the Planning Act 2008 to prompt NGET to provide further justification that its investment proposals represent good value for existing and future consumers.

2.85. We agree with third-party stakeholders that there is a potential role for consumer willingness to pay (WTP) studies, as well as other information on landscape quality and features of special interest, to inform NGET on the efficient level of different technologies when developing its proposals. However, it is ultimately for NGET to develop its proposals and the need for mitigation on a case by case basis by working with stakeholders during the planning process rather than any fixed funding rule set through the price control.

2.86. We acknowledge stakeholders' request for further clarification on Ofgem's role as statutory consultee under the Planning Act 2008 and the interface between regulatory and planning regimes. We intend to update our Visual Amenity factsheet to address these questions including more information on the respective roles of the TOs, Ofgem and the relevant planning authorities in the development of transmission infrastructure.

2.87. We also acknowledge stakeholders' request that Ofgem should provide more guidance to NGET on its regulatory and legislative obligations under the Electricity Act. We believe that through RIIO we have given all of the network companies a very strong steer that the solutions they propose contribute to overall sustainability, and encompass a wider evaluation of value for money for existing and future consumers rather than focusing on short-term cost efficiency.

Our Initial Proposals – existing infrastructure in designated areas

2.88. In Initial Proposals we consulted on an initial expenditure cap of £100m to allow all electricity TOs to start work on mitigating impacts of existing infrastructure in designated areas at the beginning of RIIO-T1. We also said we wanted further analysis of consumer WTP from the TOs, such as median WTP estimates, to inform the amount of the total expenditure cap for RIIO-T1. We also confirmed that it was our intention that the expenditure cap would be available nationally for all electricity TOs.

2.89. In relation to the governance of the expenditure cap, we proposed that the TOs would need to develop a policy for delivering visual amenity outputs in designated areas. We also proposed that Ofgem would approve this policy before TOs can access funding under the expenditure cap.[15]

[15] The TOs could develop this policy either before the start of RIIO-T1 or during RIIO-T1 but in order to have an approved allowance for a particular project under the expenditure cap the TOs would first need to have a policy approved by the Authority.

Responses to Initial Proposals

2.90. We received 16 responses from third parties in relation to mitigation of impacts from existing infrastructure on visual amenity in designated areas. National Grid also included a section in their response on the proposals on Initial Proposals for the existing infrastructure expenditure cap.

2.91. There was overall support for the introduction of a mitigation programme as part of RIIO-T1 to reduce the visual amenity impacts of existing transmission infrastructure. However, many stakeholders raised the following issues in relation to our Initial Proposals:

- Most stakeholders (12 out of 16) were concerned that Ofgem had not adopted the £1.1bn amount NGET proposed in its business plan for the existing infrastructure funding pot. These stakeholders said the underlying analysis is a robust estimate of consumer WTP to inform the expenditure cap. In addition, stakeholders believed that NGET's proposal to set the national expenditure cap from the average WTP estimate is consistent with previous decisions by Ofgem to setting the undergrounding allowance in the fifth distribution price control.
- Two stakeholders supported Ofgem's alternative proposal of £100m for the start of the price control. One stakeholder did not think NGET had made a convincing case for a higher expenditure cap. The other stakeholder thought a smaller amount was appropriate because of affordability issues and the potential impact of higher costs on household and business finances alike.
- At least half of stakeholders wanted further clarity on Ofgem's rationale for setting an initial expenditure cap for the start of the price control at £100m. Stakeholders said that in proposing a £100m initial allowance Ofgem's interpretation of consumers' interest is too conservative and could undermine a strategic assessment of potential visual amenity improvements. Several stakeholders argued that the proposed amount of the expenditure cap is inherently conservative because it is based on measures of WTP rather than Willingness to Accept (WTA) which are generally higher and double counts affordability concerns.
- Several stakeholders expressed concerns that the expenditure cap of £100m proposed by Ofgem would not be enough to deliver meaningful visual amenity improvements, and asked for more information about how the cap could be increased if further evidence was supplied.
- More than half of stakeholders thought the intent of the policy should be to address impacts from existing infrastructure on designated areas, such that it could be used to mitigate existing infrastructure in, or in close proximity to, a designated area.
- Two stakeholders questioned why other designated landscapes or sites were omitted from the scope of the measure.

- One stakeholder was concerned that Scotland would not receive its fair share of the expenditure cap, and recommended that funding was allocated and ring-fenced geographically. The stakeholder also had concerns that Scotland could miss out because in its view the two Scottish TOs had shown little inclination to engage fully in this area. The stakeholder also noted that as Scotland did not have Areas of Outstanding Natural Beauty (AONB), that we should recognise Scottish designated National Scenic Areas (NSAs) under the scheme as having the same status.
- Several stakeholders expressed concern about the 'use it or lose it' nature of the allowance, arguing that delivering these works could involve protracted negotiations with landowners, and involved technical complexity that might mean not all the funding could be used over the price control period.
- Several stakeholders said that affordability in the current economic situation was a short term concern, and that Ofgem would have to balance this against more long-term considerations and duties such as contributing to sustainable development.
- Many stakeholders also set out their views for objectives and criteria to be included by the TOs in the governing policy to select and prioritise schemes.

Final Proposals

2.92. As stated in the Initial Proposals, we have confidence that the WTP survey method is robust and was designed to counter the potential biases and other issues highlighted for us by London Economics in its report setting out best practice for such studies.[16] Accordingly, we accept the results overall as evidence of domestic consumers' WTP for such benefits over the coming price control period. Nonetheless, we took a conservative approach in Initial Proposals because of the materiality of the expenditure cap NGET proposed, and because NGET had not tested its proposal with stakeholders before submission to Ofgem.

2.93. We have also further considered, since publishing the Initial Proposals, the high proportion of survey respondents who said they chose to pay for mitigation for the benefit of the country as a whole, despite the additional costs. As regulator we need to weigh this against the proportion of survey respondents who had concerns about affordability and value for money. Respondents' motivations and issues raise important questions for Ofgem about the acceptability and fairness of additional costs among the broader consumer base, alongside our duty to have regard to the sustainable development benefits that could be delivered.

2.94. Taking into account stakeholder responses, and the above considerations, we have refined our Final Proposals in this area. We retain our view that the level of expenditure should be informed by estimates of the median WTP rather than

[16] We commissioned London Economics to review NGET's July 2011 study of consumer attitudes to undergrounding. In this report they set out the key features of best practice for conducting WTP studies. A copy of London Economics report is available at: http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/visualamenity.pdf

adopting the approach in DPCR5 of setting the cap based on the average WTP. Importantly, the median represents the amount that at least 50 per cent of survey respondents are willing to pay for mitigation. Setting the cap in line with the median gives us more confidence that it would be seen as legitimate with the wider consumer base (including electricity consumers that were not covered by the survey, such as business customers and large users who together incur a large share of total transmission charges), and help to ensure support for a mitigation programme over the long term.

2.95. We have decided to increase the level of the initial expenditure cap available at the start of RIIO-T1 in Final Proposals to £500m. This amount gives a much stronger steer of our ambition for this measure to deliver significant improvements in designated areas during RIIO-T1, and also ensures that the companies have a meaningful amount of funding at the start of the price control for a wider range of potential projects.

2.96. We have set this value taking into account the results of the WTP survey. While we expect the median WTP to be less than the average WTP it is unlikely to be lower than half the value, because only 20 per cent of respondents choose to pay nothing extra for any form of mitigation, ie the final value based on the median will be greater than £500m. We also consider it is appropriate to set the initial expenditure cap at this level because this will ensure there is enough of an incentive for the TOs to undertake further analysis to inform the total value of the cap for RIIO-T1, ie we expect the median WTP to be significantly higher than £500m.

2.97. The process for updating the amount of the expenditure cap during the price control period will be triggered when one or more of the TOs request Ofgem to review the amount of the expenditure cap, and present new evidence on the median WTP of consumers. Before the Authority makes a decision, we will consult with interested stakeholders on our assessment of the request to revise the level of the cap available under the price control period. We will also publish Ofgem's decision so that all stakeholders are aware of the total funding available under the programme, taking into account consultation responses on our assessment.

2.98. We retain our position in Initial Proposals that the expenditure cap is available to SHETPLC, SPTL and NGET to progress improvements in their respective transmission areas. We note that all GB consumers will be contributing to the overall costs of the scheme. In consultation responses, stakeholders said that a programme of projects should be considered on a national basis and that all TOs should actively participate and deliver improvements if projects with sufficient merit are identified in their transmission area. Stakeholders also said that the best way to achieve this would be for the selection of projects to be based on a transparent and coordinated assessment of the benefits, costs and practical feasibility of candidate projects.

2.99. We see a lot of merit in this approach as it would ensure a level playing field for the assessment of candidate projects across GB, and help to ensure that projects with the most cost effective benefits are prioritised for delivery during RIIO-T1. Stakeholders' views will guide our assessment of the TOs' policies for delivering visual amenity outputs in designated areas. Therefore we expect the TOs to take

forward a joined up approach with each other, and relevant stakeholders, to develop both guiding principles and an open process to identify and prioritise candidate projects on a national basis.

2.100. We have also further considered stakeholders' feedback that proposals in Initial Proposals should be broadened out to include other designated landscapes such as NSA in Scotland and Heritage Coasts (HC) in England and Wales. We do not have specific positive obligations with respect to these other designations, as is the case with National Parks (NP) and AONB. However, we have looked further at this issue in the context of our duties to have regard to the promotion of sustainable development more generally.

2.101. We have decided to extend the scope of the expenditure cap to include Scottish designated NSA. We consider this is appropriate from a sustainable development perspective because NSA are the Scottish equivalent of AONB in England and Wales. With more than 35 designated NSA in Scotland that are distinct from the Cairngorms NP and the Loch Lomond & Trossachs NP this will increase the potential list of candidate projects in Scotland. The inclusion of Scottish NSA will also improve parity of opportunity in Scotland compared to England and Wales to make use of the expenditure cap.

2.102. We have decided not to extend the cap to cover any other designated landscapes at this time. For some, such as Heritage Coasts, this is largely unnecessary as the majority are already covered by virtue of being part of an AONB or NP. For other designations we do not have enough information to assess the potential suitability of extending the mitigation programme into such areas. We recognise that there could be important issues to consider such as the impact on protected wildlife or potential disturbance to sensitive archaeological or ecological features which should be explored further through consultation with stakeholders.

2.103. We also considered stakeholders' feedback that the expenditure cap and mitigation programme should also include existing infrastructure in close proximity to a designated area. While we recognise that there could be issues around the boundaries of designated areas we do not consider it would be appropriate, given the costs involved, to make a rule in Final Proposals about points visible from a designated area being the same as within it. We believe it is more appropriate that the costs and benefits of mitigation near to the boundary of a designated area are assessed alongside other candidate projects such that any tradeoffs can be fully considered by stakeholders.

Broad Environmental Measure

Our Initial Proposals

2.104. In Initial Proposals we proposed an Environmental Discretionary Reward (EDR) as part of the price control to sharpen the environmental considerations of all the

electricity TOs throughout the RIIO-T1 period.[17] The key aim of this incentive is to drive the TOs, including NGET, to adopt a proactive corporate and operational culture to facilitate the transition to a low carbon economy and improve environmental performance.

Responses to Initial Proposals

2.105. One stakeholder supported the Environmental Discretionary Reward but encouraged Ofgem to consider how its aims could be supported by a decision on the size of NGET's overall RIIO-T1 baseline allowance.

Our Final Proposals

2.106. We confirm our proposals as consulted on in Initial Proposals are unchanged for our Final Proposals in this area.

Wider system reinforcement works

2.107. Under the RIIO output framework, reinforcement works to the wider transmission system to accommodate new generation and comply with security standards are known as Wider Works (WW) outputs.

2.108. In Initial Proposals we proposed that we measure NGET's WW outputs in terms of the transfer capacity across system boundaries.[18] The available transfer capability on a given boundary depends on the limiting thermal, voltage or stability capability assessed in accordance with the National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS).

Our Initial Proposals

2.109. In Initial Proposals we proposed that we would hold NGET to account for delivery of the WW outputs in table 2.3 with scheduled delivery dates as shown.

[17] Decision on the concept for the implementation of the Environmental Discretionary Reward for the electricity transmission owners and system operator http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=210&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes

[18] A system boundary splits the transmission network into two parts across which the capability to transfer electrical power can be assessed. For the avoidance of doubt, system boundaries are not network ownership boundaries and each TO's network could contain multiple system boundaries.

Table 2.3 Scheduled Baseline Wider Works Outputs

Project	Wider Works Output (additional boundary capability)	Scheduled for delivery in Regulatory Year
Harker Hutton Re-conductoring	Boundary 7: 1,400MW increase	2013-14[1]
Series and Shunt Compensation (Anglo-Scottish Incremental schemes)	Boundary 6: 1,000MW increase	2014-15[2]
Re-conductoring Norwich-Walpole; turning-in Norwich-Sizewell circuit at Bramford; and extending Bramford substation	Boundary EC3: 1,100MW increase Boundary EC5: 1,000MW increase	2014-15[3]
Re-conductoring of Trawsfynyyd-Treuden Tee	Boundary NW3: 1,500MW increase	2015-16
Western High Voltage Direct Current link between Deeside and North-West England	Boundary B6: 2,250MW increase Boundary B7: 2,250MW increase Boundary B7a: 2,250MW increase	2016-17[4]

Notes:
1 This project is scheduled to complete in 2013-14 but the benefits of this scheme on the boundary transfer capability will not be fully realised until the Anglo-Scottish incremental schemes are completed in 2014-15.
2 This project is scheduled to complete in 2014-15 to take advantage of delivery synergies with non-load-related work. However, the benefits of this scheme on the boundary transfer capability will not be realised until sometime around 2017-18.
3 The additional transfer capability across EC5 boundary will not be realised until the Bramford-Twinstead OHL, and the installation of a Mechanically Switched Capacitor at Barking, is completed sometime around 2017-18.
4 Maximum transfer capability of the WHVDC is deemed to be 2,400MW (short-term, 6 hour rating). But the boundary transfer shown for B6, B7 and B7a reflects the continuous rating of 2.25GW.

2.110. We also confirmed that the Western High Voltage Direct Current link between Scotland and North-West England, which NGET is developing jointly with SPTL, would be included as a WW output and form part of NGET's baselines under RIIO-T1.[19]

2.111. In Initial Proposals we said that we intend to review NGET's performance in delivering WW outputs, including whether NGET had met with the timely delivery requirements specified in the licence. We said that we would assess the causes and impacts of late delivery, and determine whether or not NGET was in breach of its licence conditions. In the event we found that late delivery constitutes a breach, we said that NGET could be subject to a financial penalty which would be determined under the Authority's Statement of Policy with respect to Financial Penalties.[20]

2.112. We also proposed that in the event that NGET under or over delivers (subject to delivering economically and efficiently) in relation to the WW outputs specified in Table 2.3, we would adjust allowed revenue to match the delivered output using the WW volume driver.

2.113. We also proposed, consistent with NGET's business plan, that NGET should have more direct control over adding new WW outputs to its investment programme over the price control period. To do this we proposed that NGET should develop a Network Development Policy (NDP) setting out how it would assess the need for additional WW outputs and the optimal phasing and timing of these outputs to ensure value for money for existing and future consumers. Subject to having an NDP which is approved by Ofgem, NGET would be able to determine the requirements of any new WW outputs and advance these into its forward investment programme with minimum regulatory oversight. For outputs determined and delivered in accordance with its NDP we proposed that we would adjust NGET's baseline allowances for the efficient costs of the delivered WW outputs through a WW volume driver (for more information on our Final Proposals for the volume driver parameters and operation see the Cost assessment and uncertainty Supporting Document).

2.114. We also proposed that NGET should only advance WW outputs through the NDP where the total cost of a project is less than £500m, and has:

- a needs case with diverse potential users
- a high degree of user commitment, ie 70 per cent or more
- a relatively short lead time, ie up to three years
- a positive needs case under a range of generation and demand scenarios.

[19] Our decision letter on the ex ante allowances and risk sharing arrangements between the transmission companies and consumers for this project under TII (to end 2012-13) and RIIO-T1 (from 2013-14 onwards) is available here: http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/CriticalInvestments/InvestmentIncentives/Documents1/Jul12_WHVDC_decision_FINAL.pdf

[20] Ofgem Utilities Act Statement of policy with respect to financial penalties, October 2003. This is available on our website at http://www.ofgem.gov.uk/About%20us/Documents1/Utilities%20Act%20-%20Statement%20of%20policy%20with%20respect%20to%20financial%20penalties.pdf.

2.115. Consistent with NGET's March 2012 business plan, at Initial Proposals we proposed that very large reinforcements, ie those costing more than £500m, known as Strategic Wider Works outputs (SWW), and WW outputs not meeting its NDP criteria, would be subject to a within-period determination by the Authority. More information on the proposed SWW arrangements for taking forward these outputs is set out in the Cost assessment and uncertainty Supporting Document.

2.116. We also proposed NGET would deliver pre-construction engineering works for the SWW and WW outputs. The deliverables from these pre-engineering works would be a combination of routing, siting and optioneering studies, project design, environmental assessment, technical specifications for cost tenders, and planning consents. For more information on our Final Proposals for the baseline funding for pre-construction engineering works see the Cost assessment and uncertainty Supporting Document.

Responses to Initial Proposals

2.117. NGET was the only party to make specific responses in relation to the proposals for WW outputs. NGET's main concern was that the inclusive conditionality for taking forward WW outputs under the NDP is overly restrictive. It said most projects would fail and that it would then have to seek approval from Ofgem through the within-period arrangements which could lead to delays and be disproportionate for some outputs. NGET also said that the majority of projects identified in its business plan submission as potential WW outputs have a lead time of more than three years, and would be automatically excluded on this basis. NGET said that the criteria should be mutually exclusive, such that if any one condition is met, the development of the project would then be determined by the requirements of the NDP. NGET also said that it would be sensible to include a de-minimis cost value below which projects would automatically be determined by the requirements of the NDP. NGET proposed that this value should be set at £150m.

2.118. NGET also highlighted two errors in the WW outputs set out in Initial Proposals. NGET also disagreed with our proposal in Initial Proposals to move the Hinkley Seabank project from baseline funding into the SWW uncertainty mechanism.

Our Final Proposals

2.119. It is not our intention to restrict unnecessarily the WW outputs NGET is able to determine through its NDP and advance into its investment programme. However, we consider that WW outputs should satisfy certain conditions in order to safeguard that consumers are only paying for new infrastructure which is needed (ie to avoid stranded assets).

2.120. We have further considered the practicality of the conditions set out in Initial Proposals and we have also considered de minimis arrangements by which qualifying projects would automatically be determined by NGET through its NDP.

2.121. For Final Proposals we confirm that NGET would determine WW outputs using its NDP, if the project meets all the stipulated conditions in one of the following categories:

Category 1 WW outputs:

- the total costs of the project are less than £100m (2009-10 prices)
- the project does not require planning permissions from a local authority or a Development Consent Order from the Secretary of State.

Category 2 WW outputs:

- the total cost of the project is less than £500m (2009-10 prices)
- is supported by user commitment from more than one customer
- has a positive needs case under a range of generation and demand scenarios.

2.122. We agree with NGET that there is a practical requirement for de-minimis arrangements to progress some projects through its NDP automatically. However, we were not convinced that this should be solely based on the value of the project's total cost. We asked NGET to consider whether there were other suitable features common to these projects to set the scope of these de minimis arrangements. NGET confirmed that a common distinguishing feature of potential projects identified in its business plan that cost less than £100m was that there was no requirement for any planning permissions.

2.123. We also agree with NGET that setting a requirement for the lead time in delivering a project, as set out in Initial Proposals, would be overly restrictive and therefore we have dropped this criterion.

2.124. Our consideration and decisions on the issues raised by NGET in relation to the WW outputs specified in Initial Proposals, and the treatment of Hinkley Seabank are set out in the Cost assessment and uncertainty Supporting Document.

Other outputs - System Operator and European activities

Our Initial Proposals

2.125. In our assessment of the efficient amount of revenue that NGET needs for 2013-2021 we considered its ability to provide SO activities through our determination of the SO internal or capital expenditure costs. We also considered funding within the company's operating expenditure (opex) in relation to meeting its ongoing commitments driven by developments in European policy and its legal framework, particularly the Network Code developments.

2.126. We stated in Initial Proposals that we expected NGET to perform these functions in addition to the outputs set out in this chapter.

Responses to Initial Proposals

2.127. NGET raised concerns about the allowed expenditure in relation to its role as SO (particularly its market facilitation role) and its European activities.

Our Final Proposals

2.128. We present relevant aspects of our assessment of efficient costs in the Cost assessment and uncertainty Supporting Document. However, we confirm here that our Final Proposals continue to envisage NGET delivering in these areas.

2.129. The final form of the SO external incentives from April 2013 is still being determined in relation to electricity transmission. However, we expect NGET to play its full role responding to these incentives. We include details on our final assessment of the funding of the SO internal or capital expenditures in the Cost assessment and uncertainty Supporting Document. However, we also recognise that delivering its SO role might make use where appropriate of funding in support of innovation through the Network Innovation Competition (NIC), Network Innovation Allowance (NIA) or rolling mechanism. Performing well as SO for its stakeholders is also something that is being directly rewarded through the customer/stakeholder satisfaction survey.

2.130. We recognise that NGET also needs to play a full role in the development of European Network Codes and other legislative and regulatory changes. The Supporting Document on Cost assessment and uncertainty considers our assessment of operating expenditure. However in fulfilling its output in this area, NGET is also rewarded not just through opex items in its allowed revenue but across its whole framework. This might include lower costs across a range of activities resulting from the engagement. This might for example be because of the avoidance of a high cost solution where NGET was able to influence the agreement of a different outcome. It might also make use of potential funding from innovation and stakeholder engagement arrangements.

3. NGGT: Outputs and incentives Final Proposals

Chapter Summary

This chapter sets out our Final Proposals in relation to outputs and incentives that will apply to NGGT.

Introduction

3.1. This chapter considers each output area in turn and considers what we are requiring NGGT to deliver over RIIO-T1. It also sets out the detail of associated incentives that apply around NGGT's delivery during RIIO-T1.

3.2. In two areas our Initial Proposals package was not complete. In these cases we consulted on options. This was in relation to the implementation arrangements relating to the treatment of incremental capacity, and our proposals for setting constraint management incentives. Since July 2012, and based upon the responses to our Initial Proposals, we published a consultation letter on 30 October 2012[21] seeking further views on these areas. This chapter includes our Final Proposals in these areas as well as the rest of the Final Proposals package. It includes key points from responses received at this further consultation as well as those responding to Initial Proposals.

Outputs we are requiring NGGT to deliver over RIIO-T1

Safety

Our Initial Proposals

3.3. We proposed in Initial Proposals that NGGT's primary output in this area should be compliance with its legal safety requirements. The Health and Safety Executive (HSE), as the safety regulator, monitor these requirements.

3.4. In addition, we proposed a suite of secondary measures that inform both the safety and reliability of its network relating to asset health and condition measures known as network output measures (NOMs).

[21] RIIO-T1 (Gas): Further views sought on implementation arrangements relating to the treatment of incremental capacity and constraint management incentives – October 2012-12-02 http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIOT1_Consultation_Capacity_And_Constraint_Incentives.pdf

3.5. The NOMs are secondary deliverables that provide us with a measure to monitor and assess NGGT's asset renewal performance over the longer-term. They are a leading indicator of asset performance.

3.6. For Initial Proposals we set out the details on how we reconcile between asset replacement volume and NOMs under the non-load-related investment programme. We proposed that we will take the NOMs target of RIIO-T1 as the opening position for how NGGT will be funded to deliver the NOMs target for RIIO-T2. Under this approach any under or over delivery in RIIO-T1 would either require catch-up or be carried forward by NGGT in order to meet its RIIO-T2 NOMs target.

3.7. We proposed a two tier approach to assessing the NOMs performance for RIIO-T1 as part of the RIIO-T2 price control review, and outlined the high level reviewing process. When assessing the actual NOMs we considered delivery of an equivalent NOMs target as being representative of being on target. We said we would consider using a dead-band around the NOMs target to take into account inherent uncertainties in the assessment methodology.

3.8. To encourage NGGT to make the most appropriate asset management decisions in the best interest of consumers, we proposed to introduce financial incentives based on our assessment of its actual NOMs' performance against their target. We proposed a financial reward for justified over and under delivery, and a financial penalty for unjustified over and under delivery. We indicated that the size of the incentive would be likely to be linked to the costs associated with over and under delivery, and that we would set out the parameters during the RIIO-T2 price control review.

3.9. We also proposed to implement a true-up process to reconcile the financial incentives after the completion of RIIO-T1.

Responses to Initial Proposals

3.10. NGGT supported this proposed primary output. No other response addressed this issue. NGGT had some concerns about the application of the NOMs.

3.11. We summarise the key points below.

3.12. NGGT in general agreed with our Initial Proposals on the NOMs' assessment principles and welcomed our Initial Proposals for the two tier assessment approach for the NOMs. It noted that a dead-band around the NOMs' target was appropriate.

3.13. NGGT expressed its concern on our proposed treatment of under and over delivery as it was worried that a marginal reward and penalty could skew the cost benefit analysis used for asset management decision-making.

3.14. NGGT was also concerned about us not setting out the details of the strength of the incentives until the RIIO-T2 price control. It felt that it would not be able to

make fully informed investment decisions without understanding the parameters of any reward or penalty.

3.15. NGGT proposed a mechanistic dead-band of plus or minus 5 per cent around the Replacement Priority Four (RP4) target and requested further clarification of the trade-off between asset categories.

Our Final Proposals

3.16. We confirm the primary output as proposed at Initial Proposals which is NGGT's compliance with its legal safety requirements.

3.17. After publication of our Initial Proposals, we further consulted our stakeholders via industry workshops and bilateral meetings about the NOMs development. We considered the feedback from stakeholders in developing our Final Proposals.

3.18. We propose to set out the agreed NOMs' targets as binding secondary deliverables in NGGT's licence. NGGT will be obliged to deliver these targets (or an equivalent taking into account trade-offs described below) for consumers. We propose to link the NOMs' condition with the NOMs' methodology condition such that the targets will need to be rebased should significant changes be made to the NOMs' methodology.

3.19. We expect NGGT to make asset management decisions based on the latest information and in the best interest of consumers. NGGT can trade-off between asset categories in order to deliver an equivalent, or better outcome, to the NOMs' target. We will not limit these trade-offs. It is for NGGT to justify why it needs to over deliver in one asset category and under deliver in another, and how the overall delivery equates to an equivalent or better level of network risk. In the longer term, we expect NGGT to develop an approach to monetise this in order to justify the trade-off.

3.20. We propose to review the performance of NOMs following the two-tier approach in our Initial Proposals. The first tier of this process is to compare the outturn NOMs against the NOMs' targets, and determine if NGGT delivers the NOMs' targets or not. We do not think a mechanistic dead-band of plus or minus 5 per cent around the RP4 target is appropriate because the assets in different replacement priority groups have different impacts on the network risk, and NGGT has the scope to trade-off against asset categories. Therefore, we do not propose to set out a mechanistic dead-band around the NOMs' targets. We will ask NGGT to provide evidence to justify their achievement of the NOMs' target when we compare the outturn NOMs against the NOMs' targets. Where NGGT is on target, we will take no further action following the first tier review.

3.21. Where NGGT delivers the NOMs above or below the target, we will initiate the second tier of assessment process. We will ask the company to provide evidence to quantify the scale of the under or over delivery, and justify whether the under or

over delivery is in the best interest of consumers. When we set out the RIIO-T2 allowances for NLRE we will take the NOMs' targets of RIIO-T1 as an opening position from which the company will deliver the NOMs targets of RIIO-T2. Therefore, for under delivery the gap between the outturn and target NOMs of RIIO-T1 will not be funded in RIIO-T2, and for over delivery this gap will be funded through the NLRE allowance for RIIO-T2.

3.22. We recognise that asset management is a continuous process, and the decision-making should not be distorted by the end of the price control period and the financial incentives on under or over delivery. Therefore, we propose the following incentives to encourage any justified variations to the NOMs' targets whilst discouraging any unjustified variations.

Table 3.1 – Financial incentives on NOMs

Incentives	Justified	Unjustified
Over delivery	• Costs of over delivery included in the RIIO-T2 allowance. • NGGT would benefit from the reduced network risk compared to the NOMs target. • NGGT would be allowed to recover the financing cost of the earlier investment. • An additional reward is applied.	• Costs of over delivery included in the RIIO-T2 allowance. • NGGT would benefit from the reduced network risk compared to the NOMs target. • NGGT would take the financing cost of the earlier investment. • No additional penalty is required.
Under delivery	• Avoided costs associated with under delivery excluded from the RIIO-T2 allowance. • NGGT would be exposed to the increased network risk compared to the NOMs target. • NGGT would benefit from the financing cost of the delayed investment. • No additional reward is required.	• Avoided costs associated with under delivery excluded from the RIIO-T2 allowance. • NGGT would be exposed to the increased network risk compared to the NOMs target. • The benefit of the financing cost of the delayed investment would be clawed back from NGGT. • Additional penalty is applied.

3.23. In addressing NGGT's concern on risks of financial incentives, we propose to set a fixed level of rewards and penalties in order to provide strong incentives for TOs to deliver the NOMs target while protecting them from financial stress relating to the non-delivery. The value of any penalty or reward will be 2.5 per cent of the value

of the additional or avoided costs. For the avoidance of doubt, where there is substantial unjustified under delivery we may consider whether it is appropriate also to use our powers relating to enforcement of licence conditions.

3.24. To illustrate how we will apply the above methodology in assessing the performance of NOMs and applying incentives, we set out a few hypothetical scenarios and cases in Appendix 1 to demonstrate how our proposed approach works in practice.

Reliability and availability

Our Initial Proposals

3.25. Our Initial Proposals proposed that NGGT should be required to provide a level of network capacity sufficient to convey gas volumes at system entry and exit points in line with existing requirements under the Uniform Network Code (UNC), its Gas Transporter (GT) Licence and ultimately, the Gas Act.

3.26. This output requires NGGT to deliver, subject to Section 9 of the Gas Act, its Standard Special Condition A9 obligation to plan and develop its pipeline system capable of meeting 1 in 20 peak aggregate daily demand. It would also require NGGT, subject to the provision of other conditions within the licence, to meet its baseline entry and exit capacity obligations as established at the start of RIIO-T1.

3.27. The reliability and availability output for gas transmission also covers arrangements for NGGT to make available capacity on its network including where new or incremental capacity is needed. NGGT's March 2012 business plan proposed wide-ranging changes to the way it delivers incremental capacity. The business plan was incomplete in places and NGGT began discussing the details and implications (including possible code changes) with industry at the start of May 2012. It became apparent then that the wholesale change could not be fully discussed, consulted upon and agreed in time for implementation from 1 April 2013.

3.28. Our Initial Proposals therefore proposed a transitional measure. This was to retain current required lead times for providing incremental capacity and include an increased permits allowance for year 1 to allow NGGT to manage the risk that in some cases might arise against the backdrop of changes such as the new Planning Act 2008 arrangements in England and Wales. Permits provide a means by which NGGT can take longer than the default lead times for the release of incremental capacity. Their use enables NGGT to trade-off the risk of more difficult projects with those of other projects.[22]

3.29. We reviewed evidence submitted by NGGT and proposed that the 'first year' permits allowance value would be £19m. We sought consultees' views on the

[22] Permits have no value until the end of the period – NGGT gets to keep the cash value of any unused permits from its allocation for the period, plus any additional permits it has earned during the period for early delivery (up to the cap).

appropriate arrangements beyond 1 April 2014 as there is no guarantee that the wholesale change will be made by then. We also recognised the likelihood that new incremental capacity arrangements would be ready by 1 April 2014 and therefore further details might become redundant. NGGT had proposed having the ability to 'overdraw' its permits by 50 per cent in volume terms. Its reward/penalty related to this would be limited to £30m upside and £10m downside for NGGT. Our Initial Proposals were not to include this change to the existing arrangements.

3.30. Our Initial Proposals also considered retaining the existing approach to revenue drivers including calculating new revenue drivers where needed.

3.31. A further aspect of incremental capacity discussed in the Initial Proposals was the situation at Fleetwood. Fleetwood is a location where the need for a new entry point was triggered by the long term capacity auction in 2006 and at the time of Initial Proposals commercial rights to future capacity were held at the site. We stated in Initial Proposals that we would continue to monitor the situation and should circumstances arise which require Ofgem to take action to protect the interests of consumers, we would take the appropriate steps to ensure an economic and efficient outcome is achieved.

3.32. A further element of policy considered under reliability and availability was the treatment of the tools used by NGGT to manage constraints on the network, including the various buyback arrangements. Here NGGT had proposed a unified incentive covering these tools across entry and exit capacity and operational and incremental buyback operations. NGGT favoured a cap and collar on upside and downside from its perspective of £20m. As with other costs in RIIO, the impact would be shared in accordance with the incentive rate determined from the IQI, between 40 per cent and 50 per cent.

3.33. As we only received full details of this as part of NGGT's 30 May 2012 SO incentive plan submission, and because of stakeholder concerns raised in the initial discussions with NGGT before and after the plan was published, we decided to consult on two options:

- a variant of NGGT's proposed single unified incentive covering entry/exit and operational/incremental actions but with no caps and collars on the incentive
- the retention of the existing separate incentive schemes (see table 3.2).

Table 3.2 Existing buyback schemes

Buyback Incentive	Target (£m)	Sharing Factor	Cap (£m)		Collar (£m)	
			month	year	Month	year
Entry Capacity Operational Buyback	15.5	50 per cent	N/A	15.5	N/A	11.5
Entry Capacity Incremental Buyback	0	100 per cent	4.6	41.3	N/A	0
Exit Incremental Investment Buyback	0	100 per cent	4.6	41.3	N/A	0

An overarching cap across the schemes of £55m.

3.34. In the event of implementing the unified incentive, we had proposed no cap or collar on the incentive payments. We considered NGGT's own business plan analysis and in particular the relative risk of its preferred approach of a cap and collar on net liabilities of £20m versus other options including a cap and collar set at £48m and the no cap/collar option. We considered the evidence of potential worst case costs and the financial analysis from NGGT. We also considered the need to protect consumers from the disinterest in the level of costs that a cap and collar can bring about in parties who have at least some control in the level of total cost. This is particularly important as network users would pick up the remaining costs.

3.35. Our Initial Proposals also addressed the issue of NTS Transmission Support Services (TSS). TSS are services rendered from either long run contracts at specific exit sites or from the constrained storage facility at Avonmouth. These are used as a substitute for capacity during periods of high demand to avoid constraints on the pipeline system to which this licence relates and allow the licensee to meet its 1 in 20 peak day obligation in the safety case it has in place from time to time pursuant to the Gas Safety (Management) Regulations 1996.

Responses to Initial Proposals

3.36. Responses to the Initial Proposals focused on the arrangements for incremental capacity and on the constraint management proposals.

3.37. On incremental capacity NGGT expressed disappointment that we had decided not to provide views or propose to implement most of its new approach in this area. It considered that, apart from the change to obligated lead times to 24 months, all other elements of its proposals could be implemented for the RIIO-T1 period. NGGT considered that even in the absence of its proposed two stage revenue driver approach, appropriate up front funding would still be required for feasibility works.

3.38. NGGT argued that it was important for Ofgem to provide guidance and direction to the industry as the new commercial arrangements continue to be developed.

3.39. NGGT also opposed our Initial Proposals in respect of not providing additional permits for the current year (2012-13), and to limit the permits level we set in year 1 (ie that there was no process for NGGT to request further permits if needed). Given this view, it pointed to the need to consider the balance of risk between the permits allowance, obligated lead times and constraint management caps and collars. NGGT stressed that the removal of the collar on its potential losses from its unified scheme would be inappropriate, as these costs are not entirely within NGGT's control due to the lack of competition in some areas to respond to constraints. NGGT argued that this approach incentivises it to conduct network modelling to a lower risk tolerance to factor the unbounded risk it would then face, leading to more conservative build programmes for the provision of incremental capacity.

3.40. NGGT welcomed our approach in Initial Proposals in relation to the evolving situation at Fleetwood. It sought clarity as to whether our proposed methodology represented an acceptable way forward.

3.41. NGGT favoured the following order of preference in relation to deriving revenue drivers:

- via an approved Generic Revenue Driver Methodology, which has been consulted upon (as long as this is fully discussed and consulted on such that it is approved by 1 April 2013)
- if the Generic Revenue Driver Methodology is not achieved in time for 1 April 2013, then revenue drivers where needed would be calculated with reference to a table within the associated document which will include revenue drivers for any entry or exit points that are expected to be required during the early years of the RIIO-T1 period following discussion with industry
- if neither of the above are achieved at a point where a revenue driver is needed, then reference could be made to a table within the associated document which would include the previous transmission price control review (TPCR4) revenue drivers, amended to fit with the totex approach (ie £m/GWh) using up to date unit cost information.

3.42. Other respondents who commented in this area supported our Initial Proposal not to pre-judge or attempt to implement parts of NGGT's proposed new incremental capacity arrangements before the industry had been able to discuss and develop them through the appropriate industry fora. However, a number of these respondents urged Ofgem to play a full role in these discussions.

3.43. There was general opposition to a unified incentive across all constraint management tools due to the reduction in transparency and the absence of the case being made in terms of benefits.

Open letter (30 October 2012)

3.44. On 30 October 2012, we sought further stakeholder views on a small number of issues. These were as follows:

- the arrangements for providing incremental (extra) capacity in RIIO-T1. In particular, on the use of permits (tools to defer the provision of set capacity beyond required lead times) and implementation arrangements for the calculation of new revenue drivers (the basis on which extra revenue becomes available to NGGT in relation to providing extra capacity if required)

- the basis of the incentive arrangements for constraint management for RIIO-T1. NGGT uses constraint management tools when insufficient capacity is available or investments are delivered late. We incentivise it to minimise its constraint management costs through a range of mechanisms. In particular, we sought views on two modified versions of the options consulted on in Initial Proposals.

3.45. Within this consultation we specifically sought views on whether stakeholders supported the use of a Generic Revenue Driver Methodology. In the absence of such a methodology we sought views on whether they supported the proposed approach to retain existing revenue drivers in the licence for all entry and exit points (updated as appropriate) along with NGGT calculating new drivers where it perceived a likelihood of the need for the drivers.

3.46. On permits, we particularly sought views on whether it is appropriate to limit the way that NGGT can apply permits, eg between entry and exit projects. We also sought further views and evidence around the level of permits appropriate in years from 1 April 2014 onwards. Finally, we specifically sought views on whether NGGT should be able to cash out permits at the end of the period or before this.

3.47. On constraint management, we wanted to explore further the reasons for stakeholder concerns with the unified incentive scheme and the extent to which we could ease these concerns through maintaining transparent information. We also asked stakeholders to consider the implications of removing the cap and collar from the existing constraint management schemes.

Responses to open letter (30 October 2012)

3.48. We received five responses to this open letter.

3.49. All respondents who commented on the revenue driver proposals supported the use of a Generic Revenue Driver Methodology and argued this should be established as soon as possible. One respondent pointed out that this should streamline the dialogue between Ofgem and NGGT where a new revenue driver is needed. All who commented also supported the use of existing numbers (or newly calculated numbers where needed) ahead of the completion of the generic

methodology. However, NGGT only supported the use of existing revenue drivers as a last resort as it considered the data would not be a reliable reflection of its costs.

3.50. On permits, many respondents were concerned at the £19m value of permits in year 1 of RIIO-T1. It was considered a potential windfall to NGGT, particularly where there were no signals requiring incremental capacity release. Suggestions were made of project specific permits only useable where incremental capacity needs to be released. NGGT remained concerned about the inability to go overdrawn in year 1, ie it wanted the ability to have further permits with associated cost implications if needed.

3.51. In terms of the use of permits across entry and exit projects there was little support for limiting NGGT's flexibility except for concerns about the implications on individual projects.

3.52. For permits beyond 1 April 2014, most respondents felt that the need, if any, for such permits should be decided when more information was available. NGGT felt that it was important for it to have greater certainty in this area than our Initial Proposals had provided. It provided detailed evidence to demonstrate a continuing need for permits and a value across the three years of £40.2m.

3.53. There was general support for the timing of the cash out of the permits, ie the point at which NGGT can recover the value of any unused permits, being the end of the control period. NGGT felt that this should instead be the point at which the new incremental capacity arrangements were introduced.

3.54. On constraint management mixed views were expressed. Most respondents still saw little justification behind a unified incentive, with one respondent suggesting that the case could have been made through the operation of the new approach on a shadow basis (ie showing the effects that the unified incentive would have on NGGT but while retaining the existing incentives in terms of financial effect). One response favoured the unified approach with no cap/collar as being in the interests of consumers.

3.55. There were also different views on how the existing incentives should continue in RIIO-T1. NGGT favoured updating the caps while others favoured removing caps and collars. Also some respondents favoured retaining the arrangements whereby NGGT meets 100 per cent of the incremental buyback costs rather than moving to the RIIO sharing factor across all buyback costs.

Our Final Proposals

3.56. Our Final Proposals for this output cover:

- reliability of the existing system
- arrangements for making available extra capacity

- management of the availability of the network through the use of constraint management tools.

3.57. Our Final Proposals for reliability reaffirm our Initial Proposals requiring NGGT to deliver, subject to Section 9 of the Gas Act, its Standard Special Condition A9 obligation to plan and develop its pipeline system capable of meeting 1 in 20 peak aggregate daily demand. It also requires NGGT, subject to the provision of other conditions within the licence, to meet its baseline entry and exit capacity obligations.

3.58. Supporting network output measures also form part of Final Proposals eg asset health and conditions. These were as discussed in the previous section on safety outputs.

3.59. Our Final Proposals in relation to incremental capacity arrangements are to continue to await and not pre judge any major changes to the incremental capacity arrangements following ongoing industry discussions. We welcome progress with the discussions in response to the proposals set out in NGGT's business plan. We recognise that progress suggests a real possibility of implementation in time for 1 April 2014. We confirm that we will continue to work with the industry as it develops these proposals and encourage all stakeholders to continue to engage in this process.

3.60. While we note NGGT's disappointment that we have not provided more guidance on this, this should not be interpreted as undervaluing the significant work that it has put into develop these proposals and the active engagement it has had with stakeholders since May 2012. We also note that our proposal in this area is consistent with the view of all other respondents who responded on this aspect of our Initial Proposals.

3.61. A summary of our Final Proposals in relation to incremental capacity arrangements in light of the above decision are:

- retain existing required lead times (42 months to release entry capacity and 36 months to release exit capacity)
- provide a permits allowance initially expected to be for one year only (from 1 April 2013) with the following features:
    - permits allowance maximum cash out value is £19m
    - 3,800 x £5,000 monthly permits can be used flexibly between projects at entry or exit by NGGT to defer delivery of extra capacity when needed
    - volume of permits can increase in reward for early delivery (though the cash out maximum remains as above)

- per project limit of 24 months[23] (subject to timely process ahead of the auction process under which NGGT can seek to alter this in a specific case)
- no scope for NGGT to 'go overdrawn' (increase the number of permits other than as reward for early delivery)
- NGGT would be able to cash out any remaining permits at the end of the scheme with the current expectation that this will be 2014 (plus the lag adjustment to help with managing charging volatility).

- Consider extending the permits allowance for the second, third and fourth years of the control period if NGGT can demonstrate there is a good reason not to implement the new incremental capacity arrangements at that stage. Notional permits of £40.2m across three years with the potential to be extended year by year.

- In relation to revenue drivers that:

  - our Final Proposal is that they should be calculated consistent with the Generic Revenue Driver Methodology if available
  - in the absence of the Generic Revenue Driver Methodology,NGGT should calculate revenue drivers where it considers they are likely to be needed
  - existing revenue drivers will be retained in the licence but adjusted to provide for an appropriate revenue driver informed by our assessment of unit costs (further detail on our unit cost assessment can be found in our Cost assessment and uncertainty Supporting Document).

3.62. We recognise that stakeholders other than NGGT were concerned about the £19m, perceiving this as a potential 'windfall' particularly if there were no signals that required incremental capacity to be released. We also recognise that NGGT considers £19m represents an insufficient numbers of permits given the absence of applying it with retrospective impact to the TPCR4 roll over period and allowing it to go overdrawn. We encourage NGGT and the industry to consider the appropriate long-term incentives for early delivery of incremental capacity as part of the ongoing wider industry discussions. However, in terms of our Final Proposals, we consider that it is important to encourage NGGT to make a prudent assessment of where to apply permits. A financial incentive plays an important role in this and it is designed to reflect the real activity undertaken by NGGT in advance of auctions to provide clear proposals around potential incremental capacity.

3.63. Respondents generally supported flexibility in the way that NGGT used permits, for instance not favouring specific limits on entry or exit related signals.

[23] For clarity while we are proposing a one year permits scheme, the application of permits during this year can impact on projects over the number of years that the projects take to be delivered. It is the overall timescale that the 24 month per project limit applies.

However, there was some concern at the impact on individual projects and through this on gas investment. To provide protection to individual projects, we propose to have a limit in application to individual signals. We propose to set the per project limit at 24 months. This, added to the default lead time on exit, is toward the lower end of NGGT's view of the impact of the new planning process on project timings (5 – 8 years). NGGT will be able to seek a higher number of permits than the 24 monthly permits by writing to us. This would need to be evidenced and also need to be done in a timely manner before the relevant auction to which the application relates.

3.64. Our Final Proposal, not to introduce the ability for NGGT to go overdrawn on its permits allocation, is in part a decision to retain the existing principles consistent with what we envisage is likely to be a short term arrangement. We are also basing our limit of £19m on our assessment of NGGT's analysis of the probability of signals for incremental capacity occurring and deferral time being needed. We think this should be a real limit in terms of maximum earnings based on signals made in the first year.

3.65. Consistent with our Initial Proposals, we have not included the request made by NGGT for the allowance previously set for the rollover year to be altered by RIIO-T1. This is on the grounds that NGGT accepted the TPCR4 rollover decision, having failed to demonstrate the need for an increased level of permits.

3.66. In the event that the new arrangements for incremental capacity being discussed with the industry are not ready to be implemented by 1 April 2014, we would expect NGGT to demonstrate why this was the case and why there was good reason to continue with the permits arrangements. In that event our starting point is the evidence that NGGT has submitted in response to our open letter (30 October 2012). This totals £40.2m worth of permits (at the same rate and type as the year 1 arrangements) across three years but we would only extend the arrangements by one year at a time (so in the first instance set an extra year to 31 March 2015 while pushing back the cashout point by a year). For that one year we would start with NGGT's submission for that year but would look to NGGT to update this evidence based on experience and greater knowledge available.

3.67. Our Final Proposals on revenue drivers as summarised above are supported by all stakeholders and allow the flexibility of reflecting a Generic Revenue Driver Methodology if available but with the fallback of an effective and timely basis for calculating revenue drivers if not.

3.68. A separate aspect of incremental capacity discussed in the Initial Proposals is the situation at Fleetwood. Fleetwood is a location where the need for a new entry point was triggered by the long term capacity auction in 2006 and at the time of Initial Proposals commercial rights to future capacity were held at the site. Our understanding is that these capacity rights have been lost. At the present time it is unclear whether the future capacity as signalled will be needed. We will continue to monitor the situation and should circumstances require Ofgem to take action to protect the interests of consumers, we will take the appropriate steps to ensure an economic and efficient outcome is achieved (which might affect the treatment of

capacity at Fleetwood). This may have implications for base revenue and represents how we would expect to act in any similar situation, as we will generally consider taking steps in accordance with our principal objective to protect the interests of consumers.

3.69. Our Final Proposals in relation to constraint management tools are, in summary, to introduce a unified incentive scheme but retain some elements of the existing schemes and all the transparency of the information produced under the existing schemes. We think that this will encourage NGGT to make the best overall decisions across its range of constraint management tools. We also consider it provides certainty to network users on issues raised in response to our Initial Proposals and our further consultation.

3.70. Specifically this includes:

- a requirement for NGGT through its RIGs to provide information on all the existing scheme terms
- an additional requirement in the RIGs for NGGT to provide commentary on how its decision making has changed reflecting the unified incentive scheme
- introduction of an overall cap (set at £20m) and collar (set at £60m) to provide protection from low probability high impact cost events
- maintenance of the separate incentive rate on incremental buyback with NGGT bearing 100 per cent of the costs in the incentive mechanism (subject to the proposed cap/collar)
- include the incentive within the scope of the SO uncertainty provisions that allows the incentive mechanics to be reviewed under specific circumstances that suggest it might be introducing unintended consequences as a result of the implementation of the unified incentive or as a result of the level of the caps and collars
- possible review of constraint management targets in the event of changes through the RIIO-T1 uncertainty mechanisms eg incremental entry/exit. These mechanisms are discussed in more detail in the Cost assessment and uncertainty Supporting Document.

3.71. We will consult on the RIGs requirements in the new year but will include the existing terms reported on at present through NGGT's licence. We will seek a commentary on the workings of the incentive so that its benefits and any costs can be properly understood.

3.72. We proposed in Initial Proposals to have an incentive(s) without caps and collars. This was because we wanted to ensure that NGGT was incentivised to minimise these costs at potentially higher levels than historically (including as a

result of the incremental capacity changes and the potential impact of the new planning regime in England and Wales). We considered the overall impact across the period on NGGT. In light of NGGT's response, we recognise that the annual variance can be significant with low probability but high impact events potentially leading to significant net costs in a particular year. As set out in our further consultation letter, one option we considered was smoothing the liability across the price control period.

3.73. In the Final Proposals we think there is merit in retaining an absolute cap and collar. We propose a single cap and collar across the incentive. NGGT's maximum annual downside risk would be £60m. We will index the level of this for inflation. We have informed the level of the cap in relation to NGGT's analysis which contained 97.5 per cent and 2.5 per cent confidence limits around the constraint management costs. This should mean that the collar rarely has an impact on NGGT's share of the costs. The cap on the upside to NGGT is £20m. We will also index the level of this for inflation. This is lower because the scope for positive incentive revenues for NGGT is lower than that for possible costs. We have in this case adopted the original level of cap requested by NGGT. Given the likely level of revenues, this is again a protection for low probability but high impact occurrences.

3.74. NGGT's call for a collar on its liabilities was partly justified by an argument that we had not considered consumers sufficiently in proposing an uncapped/collared regime. It is important to be clear that our Initial Proposals were informed by the priority of protecting network users and end consumers from NGGT being indifferent in relation to costs above the collar level. This matters as these continue to fall on the network users despite the limit on the incentive mechanism.

3.75. In applying the collar, we did not think it appropriate to apply a limit on NGGT's liability while retaining the RIIO-T1 sharing factor across schemes that have, until now, carried a 100 per cent liability on NGGT up to the level of the limits (monthly as well as annual in some cases in the current schemes). We were also mindful to preserve arrangements from the existing schemes in this area given the continued stakeholder concerns about moving to a unified incentive.

3.76. The SO external incentives Final Proposals for the post 2013 incentives includes uncertainty provisions that provide for review of the incentives in specific circumstances. This provides an extra degree of flexibility around incentives where some uncertainty underpins the incentive and prolonged misalignment might have a significant impact. In part, because of the degree of historical data in this area, we propose to extend the scope of this mechanism to constraint management actions some of which have been viewed as SO activities. The specific provision allows a review where, as a result of the implementation of unified incentives or the cap and collar, the incentive is acting in a materially detrimental way to network users and consumers. We would expect any review carried out under this provision to be initiated in the light of stakeholder concerns. We would consult on any change and expect that it would be forward looking.

3.77. We propose to have the ability to review the constraint management targets in the light of changes in incremental capacity and other results of the RIIO-T1 uncertainty mechanisms. These might change the conditions within which NGGT

manages constraints. There is no automatic assumption that such changes necessarily warrant a change in targets and there is insufficient information to build any kind of automatic mechanism. Instead, we would need to review the evidence put forward at the time.

3.78. We confirm our Initial Proposals to merge the NTS Transmission Support Services (TSS) incentive schemes, the Constrained LNG (CLNG) and the Long Run Contracting Incentive, into a single scheme. At Initial Proposals we said that we would include NGGT's proposal but reserved the right to alter the targets. Having considered historical performance further, we propose that NGGT's proposed target will be applied.

Customer Satisfaction

Our Initial Proposals

3.79. In our Initial Proposals we proposed that NGGT should have a financial incentive informed directly by the results of a survey. The survey should clearly highlight the distinction between NGGT's activities. This incentive had the limits of plus or minus 1 per cent of the particular year's allowed revenue. Since Initial Proposals, work has continued to progress on the details of how we will implement this incentive. A second part of our Initial Proposals in this output was the inclusion of a provision for a possible reward for using ongoing stakeholder engagement to generate an exceptional outcome. We presented initial guidance on how we would assess the case for this reward in Initial Proposals. We subsequently set out a draft guidance document with our 30 October 2012 second informal licence consultation.

Responses to Initial Proposals

3.80. Those respondents who commented specifically in this area were generally supportive. NGGT provided details of its view on progress towards the incentive and proposed a way forward on some of the mechanics of the survey incentive.

3.81. In particular, NGGT's response set out the parameters it proposed for the consumer element of the survey based on a number of years experience. This included a baseline for the period of 6.9/10 and points above and below this level so as to reflect the extreme responses appropriately.

3.82. A number of respondents commented on the guidance for how we would apply the stakeholder engagement reward.

Our Final Proposals

3.83. Our Final Proposal is consistent with our Initial Proposals in overall form. However, it reflects our assessment of the further work that NGGT has carried out since July 2012.

3.84. NGGT has, as part of the wider company, material experience of operating a consumer survey and has been able to provide sufficient evidence to set the parameters for this element of the survey in the licence condition that we are to publish shortly. This reflects a baseline score based on NGGT's recent overall performance, but also supported by similar surveys in other sectors.

3.85. NGGT has also carried out a 'dry run' survey of its key stakeholders (other than its consumers). These are groups or individuals affected by, or with an interest in, the company's activities. This is an area where it has far less experience of the likely level and variance of responses. We agree that it is appropriate that separate metrics be applied for the stakeholder survey compared to the consumer survey. The specific baseline metrics for the stakeholder element are being developed in light of evidence from the now completed dry run, and we expect NGGT to propose metrics by April 2013. We may consider the stakeholder baseline and related metrics in 2016. In doing so we would look at the wider evidence that we will have at that time about how stakeholders respond to this type of survey under different conditions and company performance.

3.86. We also agree with NGGT's proposal to increase the proportion of the incentive driven by the stakeholder survey over the control with the aspiration of it having equal representation towards the end of the control period when the results from this new element are better understood. In the early years the proportion of the two elements may be significantly different. We will consider and determine the proportion profile in April/May 2013 following NGGT's proposal to us.

3.87. NGGT noted in its response to the second informal consultation on licence modifications that it was interested in understanding if it could make use of elements of the approach being followed by SPTL and SHETPLC. This included making use of supporting information alongside its survey of customer and stakeholder opinions. We see merit in both types of approach and, on the condition that the supporting information or processes support the survey results by providing information that directly implies higher quality performance in meeting customer/stakeholder needs, these are consistent with the aims of this output. However, if NGGT wants to consider this from 1 April 2013, then it would need to provide and commit to sufficient detail within a month of the start of RIIO-T1. We would potentially consider such arrangements for operation in later years if proposed as part of any review of this incentive in 2016.

Connections

Our Initial Proposals

3.88. We proposed in Initial Proposals that NGGT should have a primary output to meet the new obligations set out in UNC modification 373 (UNC 373). Further detail is available from our decision letter in relation to that modification.[24] There is no

[24] Ofgem: Modification proposal: Uniform Network Code (UNC) 0373: Governance of NTS connection processes. http://www.ofgem.gov.uk/Licensing/GasCodes/UNC/Mods/Documents1/UNC373D.pdf

financial incentive related to this but the new process provides a clear reputational incentive. We also stated that we would consider whether UNC 373 needs to be complemented by licence obligations on NGGT in relation to connections.

3.89. We also proposed to consider further refinement to the connections output in line with any enduring changes to the capacity arrangements.

3.90. Our March Strategy Document noted the absence of a detailed process for the provision by NGGT of connections to the gas transmission network. We recognised that industry discussions were already underway to establish a process and indicated that we expected NGGT's business plan to consider these evolving arrangements as a likely basis for the RIIO-T1 output in this area.

3.91. On 4 July 2012 the Authority directed the approval of UNC 373. For the first time in gas transmission this established a formal process for connecting to the NTS. This modification was implemented on 1 August 2012.

3.92. At the time of Initial Proposals NGGT was proposing to link up its work on connections with its work on incremental capacity. This has potential advantages but we are concerned that it should not reduce NGGT's obligations as established under UNC 373. Both our March Strategy Document and NGGT's initial business plan in July 2011 recognised that UNC 373 might not cover all the requirements of a connections output for the whole of the RIIO-T1 period.

Responses to Initial Proposals

3.93. NGGT stated that it continued to believe that the proposals relating to funding the provision of incremental capacity can be implemented from April 2013 and can utilise existing processes (such as the UNC Modification 373 process) as trigger points.

3.94. No other responses to our Initial Proposals focused on this output.

Our Final Proposals

3.95. We confirm that the primary output for NGGT in relation to connections is delivery of the process set out in UNC modification 373. We address NGGT's concerns in this area in the above section on reliability and availability.

3.96. We recognise that this area might be enhanced during the RIIO-T1 period if NGGT's new incremental capacity arrangements are introduced. However, we do expect the key principles of the new process to be the starting point for the measure of NGGT's performance in this area.

3.97. While not including data in the consultation on the RIGs in this area in our informal consultation on 30 October 2012, we do intend to include data on the meeting of key milestones to inform on NGGT's delivery against this output.

Environmental outputs

Business Carbon Footprint (BCF)

Our Initial Proposals

3.98. In line with our Strategy Document, we proposed that NGGT be required to report annually to stakeholders on its Scope 1 and Scope 2 greenhouse gas (GHG) or carbon dioxide equivalent emissions at a business level throughout the RIIO-T1 period. We note that NGGT set out similar commitments in its March business plan. We proposed that NGGT would only face reputational incentives on its BCF reporting.

3.99. NGGT provided better information in its March 2012 business plan about its BCF when compared to its July 2011 plan. In particular, NGGT provided more context on the issues it faces around operating compressors on its network, the key sources of emissions at the business level, and how its proposals sit in relation to its relevant legislative requirements.

3.100. NGGT forecast that its Scope 1 and Scope 2 emissions (as TO and SO) will fall from nearly 700,000 tonnes in 2013 to around 385,000 tonnes at the end of the price control. This will depend on the number of compressors it needs to replace at sites that are emitting high levels of NOx emissions (to comply with legislative requirements) with more efficient technologies and electric powered compressors.[25] We noted that the reduction in NGGT's BCF would also depend largely on the rate at which the UK's electricity generation mix decarbonises as the electricity used to power the new compressors will create indirect (scope 2) carbon dioxide emissions at source. NGGT also will achieve some emission reductions through improved energy use in buildings.

3.101. We noted that NGGT proposals are consistent with stakeholder feedback that it should invest in the minimum to ensure legislative compliance.

3.102. We reiterated our position that NGGT should be required to report on its BCF at the business level to enable accurate reporting and monitoring on its BCF from the transmission business.

Responses to Initial Proposals

3.103. No responses focused on this aspect of Initial Proposals

[25] NOx is a generic term for mono-nitrogen oxides NO and NO2 (nitric oxide and nitrogen dioxide). They are produced from the reaction of nitrogen and oxygen gases in the air during combustion, especially at high temperatures. NOx reacts to form smog and acid rain. NOx are not a greenhouse gas.

Our Final Proposals

3.104. We reiterate our position that NGGT is required to report on its BCF at the business level to enable accurate reporting and monitoring of its BCF from the transmission business.

Other outputs - System Operator and European activities

Our Initial Proposals

3.105. In our assessment of the efficient amount of revenue that NGGT needs for 2013-2021 we considered its ability to provide SO activities through our determination of the SO internal or capital expenditure costs. We also considered funding within the company's operating expenditure (opex) in relation to meeting its ongoing commitments driven by developments in European policy and its legal framework, particularly the Network Code developments.

3.106. We stated in Initial Proposals that we expected NGGT to perform these functions in addition to the outputs set out in this chapter.

Responses to Initial Proposals

3.107. NGGT raised concerns about the allowed expenditure in relation to its role as SO (particularly its market facilitation role) and its European activities.

Our Final Proposals

3.108. The detail of relevant aspects of our assessment of efficient costs is presented in our Cost assessment and uncertainty Supporting Document. However, we confirm here that our Final Proposals continue to envisage NGGT delivering in these areas.

3.109. The SO external incentives from April 2013 are being published today and we expect NGGT to meet the challenges set by these incentives. Details on our final assessment of the funding of the SO internal costs are included in the Cost assessment and uncertainty Supporting Document. However, we also recognise that delivering the SO outputs might involve funding in support of innovation through the mechanisms described in Chapter 4 of this document. A good performing SO in the interests of its stakeholders is also likely to be directly rewarded through the customer/stakeholder satisfaction survey output incentive.

3.110. Similarly, NGGT is rewarded for playing a full role in its European activities not just through opex in its allowed revenue but across its whole framework. This might include lower costs across a range of activities resulting from this engagement. This might be because of the avoidance of a high cost solution where NGGT was able to influence the agreement of a different outcome.

4. Encouraging Innovation

Chapter Summary

This chapter sets out the arrangements that will apply to encourage the TOs to innovate to drive improved outcomes for consumers in RIIO-T1 and beyond.

4.1. Many elements of the RIIO framework are intended to encourage innovation. These include a strong emphasis on delivering outputs and lengthening the price control period to provide companies with more certainty of the rewards for successful innovation. The framework provides a strong incentive to innovate and for companies to adopt a range of innovative and conventional approaches across all aspects of their business.

4.2. In addition, the framework includes a time-limited innovation stimulus package to fund innovation where the commercial benefits may be uncertain, and therefore stakeholders are unwilling to fund research and development projects speculatively. The innovation stimulus consists of the following:

- **Network Innovation Allowance (NIA)** - The NIA is a set allowance that each of the RIIO network licensees will receive to fund smaller scale innovative projects as part of their price control settlement.

- **Network Innovation Competition (NIC)** - The NIC is an annual competition for funding larger more complex projects which have the potential to deliver low carbon and/or wider environmental benefits to consumers. The NIC will comprise of two competitions - one for gas and one for electricity.

- **Innovation Roll-out Mechanism (IRM)** – The IRM is a revenue adjustment mechanism that enables companies to apply for additional funding within the price control period for the rollout of initiatives with demonstrable and cost effective low-carbon and/or environmental benefits.

Summary of Initial Proposals

NIA

4.3. Our Strategy Document required each network operator to include an innovation strategy as part of their business plan, explaining the company's approach to innovation, its motivation and objectives. We set out in the Strategy Document that the level of funding available through the NIA would be linked to the innovation strategy. We also set out that the NIA would be between 0.5-1 per cent of base revenue, and that companies wishing to spend more than 0.5 per cent of base revenue should request that higher amount in their innovation strategy (up to a

maximum of 1 per cent of base revenue). In making such a request the companies were required to provide justification for the additional funds. We set out that such requests would be judged by the quality and content of the innovation strategy as well as the company's justification for requiring those allowed funds.

4.4. In their second business plans, both NGET and NGGT requested the maximum allowance of 1 per cent. At Initial Proposals we stated we did not consider that either company's strategy merited the level of funding requested. However, we did consider that both of their strategies merited some additional funding, and we proposed a conservative level of additional funding of 0.6 per cent for both TOs.

NIC

4.5. In Initial Proposals, we set out an expected delay to the commencement of the Gas NIC as a result of an ambiguity in the Gas Act which prevents the use of our desired mechanism for raising and transferring funds. In light of this delay, we proposed two options: delay the competition until we get the required amendment to the Gas Act, or implement an alternative funding mechanism where funding is raised from the winning companies own customers only (rather than socialised across customers).

SO innovation

4.6. At Initial Proposals we also proposed that NGET or NGGT should be able to access the TO innovation funding, under the NIC and NIA, in relation to innovations across both SO and TO activities.

Summary of respondent's views

4.7. Of those who responded to our RIIO-T1 Initial Proposals, seven respondents explicitly responded to questions on innovation.

General responses

4.8. In general respondents were supportive of the overall innovation stimulus package, although some had specific comments on aspects of the funding that would be provided.

NIA

4.9. We received seven responses on our proposals on the level of NIA funding. One respondent stated that a NIA of 0.6 per cent was appropriate. Three respondents said that NGET and NGGT should receive a NIA of closer to 1 per cent, and three other respondents thought we should provide an NIA of sufficient size to allow NGET and NGGT to deliver their innovation programmes.

4.10. National Grid was disappointed with the proposed levels of funding. In its response, National Grid highlighted that in addition to replacing historic IFI funding of 0.5 per cent (provided for TPCR4) the NIA would be utilised for elements of SO innovation. It also stressed that the delivery of their operational capital efficiency programme would be dependent on access to additional innovation funding. It considered that it had demonstrated stronger stakeholder engagement than our Initial Proposals assessment had suggested, through multiple stakeholder events. National Grid also felt that it had adequately delineated between business as usual innovation and scheme funding.

4.11. We also note some of the comments we received in response to the GD1 Initial Proposals. Several respondents noted that – while they agreed with our assessment of those strategies which were stronger – the level of reward for a strong strategy could have been higher.

NIC

4.12. In considering the options for dealing with the potential delay to the NIC we have considered views submitted to both the GD1 and T1 Initial Proposals consultations. This is because the issue will impact on all gas transporters.

4.13. Seven respondents provided views on their preferred option for running the gas NIC. Three supported Option 1: Run the NIC and raise the required funds from the winning licensees customers (ie this could be from either NGGT's or GDNs' customers). The other four supported Option 2: No NIC in 2013, and no replacement funding in that year. The lost funds would be rolled-over into subsequent years such that the overall level of funding in RIIO-GD1 is unchanged.

4.14. Those who supported Option 2 did so because they felt that Option 1 was against the philosophy of the competition, or they felt that the rollover of the funds would produce improved innovation projects through longer development time and an improved choice by the networks.

Our Final Proposals

4.15. Based on the responses that we have received we continue to believe the RIIO framework provides strong incentives for innovation as part of each company's normal course of business. We also consider that the overall innovation stimulus package of the NIC, NIA and IRM provides a strong additional incentive for riskier

innovation that TOs otherwise would not do as part of business as usual. Specific elements of our Final Proposals are set out below.

4.16. We note that the Treasury introduced tax relief for innovation spending in 2008. The innovation stimulus provides funding for companies to trial innovative techniques and approaches, and companies can pass through up to 90 per cent of these costs to consumers (subject to the NIC and NIA governance arrangements). We are mindful of companies receiving excessive gains through this tax relief, given this level of consumer funding. Therefore we intend to monitor its use during RIIO-T1 and may consider consulting on further action in the future.

NIA

4.17. At Initial Proposals we assessed the quality and content of the innovation strategies provided by NGET and NGGT against the minimum requirements set out in the March Strategy Document. In addition, to justify funding beyond the default of 0.5 per cent we expected NGET and NGGT to provide innovation strategies that went beyond these minimum requirements, clearly justifying why funding beyond the default of 0.5 per cent was warranted, demonstrating how additional funding would provide value for money for consumers and demonstrating how learning would be effectively disseminated into the TO's normal business activities during T1 and beyond.

4.18. Following receipt of Initial Proposals responses, we have further reviewed NGET's and NGGT's innovation strategies. We remain of the view that the strategies and justification do not warrant funding either NGET or NGGT at their requested level of 1 per cent. However, we consider that they have produced innovation strategies that go beyond the minimum requirements set out in the March Strategy Document and respondents agreed that additional funding is warranted.

4.19. Further, in the additional information provided as part of Initial Proposals we consider that National Grid and other stakeholders have highlighted a number of points which strengthen the case for an increased allowance. These are:

- responses have demonstrated that the stakeholder engagement undertaken by NGET and NGGT to inform their innovation strategies was stronger than we had understood in making our initial assessment

- further evidence has been provided for the use of NIA funding by NGET and NGGT for SO innovation.

4.20. We also note that respondents across both RIIO-T1 and GD1 have stressed the need to provide adequate reward to those companies which have developed relatively stronger innovation strategies. We consider there to be merit in this view. However, we also consider that should be tempered with the absolute performance of the companies against our assessment criteria.

4.21. On balance we consider that it would be appropriate in light of consultation responses, and in line with our assessment framework, to increase the level of both NGET's and NGGT's NIA to 0.7 per cent in Final Proposals.

NIC

4.22. Since Initial Proposals, we have been actively working with DECC to resolve the expected delay to the Gas NIC. On the 18 October 2012 the Secretary of State for Energy and Climate Change announced that the Government would propose the necessary amendment to the Gas Act as part of the Department for Communities and Local Government's Growth and Infrastructure Bill.[26]

4.23. If the clause is included in the legislation and the Bill progresses to schedule, we believe that it would be possible for us to introduce licence conditions in a manner that would allow the Gas NIC to commence in 2013 under our desired funding mechanism ie funding would be recovered from all customers and transferred to the GDNs. We will include the NIC licence conditions in the December statutory consultation on this basis. If subsequently there is an unexpected material delay to the legislative timetable that prevents the amendment being delivered in time, we would not award funding in 2013. In this instance, GDNs would still be able to recover their efficiently incurred bid preparation costs through the NIA and the unawarded funds would be rolled-over into subsequent years such that the overall level of funding in RIIO-GD1 is unchanged. This is the same as our preferred option at Initial Proposals that was supported by the majority of the respondents.

4.24. The NIC governance documents and the licence conditions have been developed in conjunction with the Legal Drafting and Innovation Working Groups and draft versions of these documents have been publically consulted on throughout October and November 2012.[27] On 21 December 2012, both will undergo the requisite statutory consultation to enable them to take effect by 1 April 2013, the start of RIIO-T1 and GD1.

IRM

4.25. The IRM is a revenue adjustment mechanism that enables companies to apply for additional funding within the price control period for the rollout of initiatives with demonstrable and cost effective low carbon or environmental benefits. There will be two reopener windows and it will be subject to the materiality threshold. The IRM licence condition sets out the conditions for the awarding and determining revenues through the IRM. This condition was consulted on as part of the first and second informal licence consultations.[28]

[26] See DECC press release: 'Ed Davey tells CBI: Coalition will unlock energy investment'
[27] Two versions of a NIC licence condition have been consulted on: one where funds are recovered from all customers and one where funding is only recovered from the winning licensees own customers. See here for further information.
[28] See here for further details.

SO access to Innovation Funding

4.26. We confirm that NGET and NGGT can access the TO innovation funding, through the NIC and NIA, in relation to innovations across both SO and TO activities.

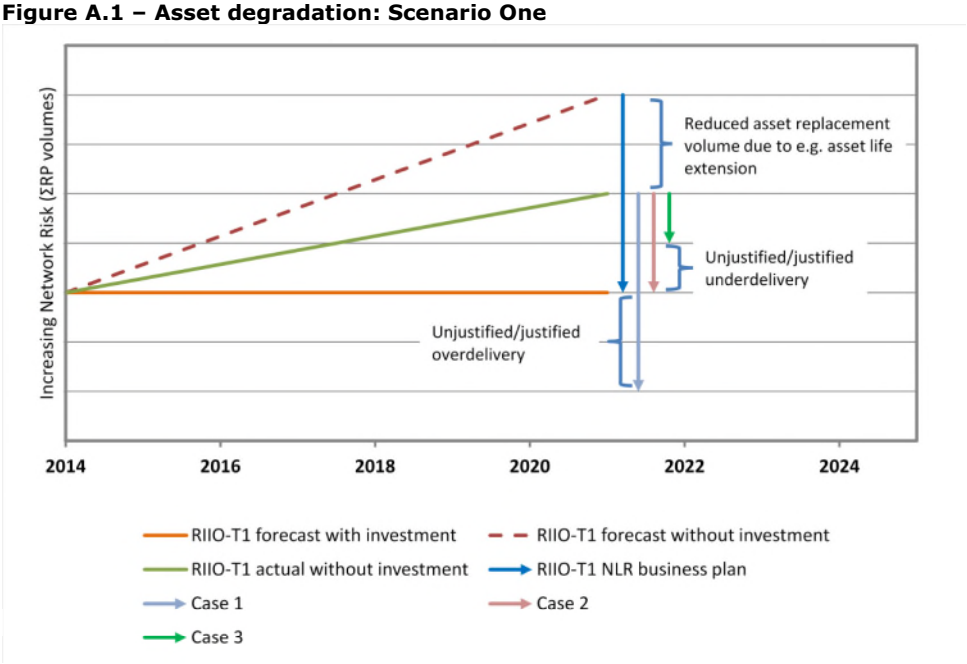
Appendix 1: Detail underpinning Final Network Output Measures (NOMs) Proposals

1.1. In this appendix we set out two hypothetical asset degradation scenarios and under each scenario we assume three cases of NOMs delivery as a result of different asset management strategies. We generally describe how we may assess the NOMs and what incentive is likely to be applied for each case.

Scenario One

1.2. Scenario One assumes the actual asset degradation is slower than the forecast as expected by TOs at the time when the NOMs target was set out. In this scenario there may be three cases arising from different asset management strategies as shown in Figure A.1.

Figure A.1 – Asset degradation: Scenario One



1.3. The red line 'RIIO-T1 forecast with investment' is the RIIO-T1 NOMs target. The dashed line showing forecast without investment illustrates how the assets can degrade further without investment during the period.

Case 1: Above target (overdelivery)

1.4. A TO carried out the asset replacement volume consistent to its RIIO-T1 business plan forecast, as illustrated by the vertical light blue arrow. Therefore, the company achieved a lower network risk than if it had not done this because the slow-down of asset degradation means the asset replacement volume is required to reach the agreed NOMs target, which is lower than the forecast in its business plan. The lower network risk is reflected by the over delivery of NOMs against the NOMs target.

1.5. We will ask the company to provide both qualitative and quantitative evidence and justify why it has delivered more than the NOMs target. For the justified over delivery we expect the company to demonstrate that the over delivery is in the best interest of consumers.

1.6. We will set out the NLRE allowance for RIIO-T2 based on the assumption that the NOMs target of RIIO-T1 is the opening position from which the company will deliver the NOMs target of RIIO-T2. In this case, the over delivery of NOMs will be carried over to the RIIO-T2.

1.7. Where the company can justify its over delivery, we will allow the company to recover the financing cost of the early investment in RIIO-T1 and apply an additional reward. Otherwise, for the unjustified over delivery, we will not apply an additional penalty but the company will incur the higher financing cost of the early investment.

Case 2: On target (equal or equivalent delivery)

1.8. A TO carried out less volume of asset replacement than its RIIO-T1 business plan forecast, as illustrated by the vertical red arrow. Although the company delivered less volume of asset replacement, it achieved the target network risk, for example, by asset management innovations.

1.9. We will ask the company to provide evidence to demonstrate how it managed to deliver the NOMs target through their asset management actions, and what benefits it will bring to consumers in the longer term.

1.10. We will take the actual outturn NOMs as the opening position for setting out the RIIO-T2 allowance for NLRE. We will not apply any financial penalty or reward.

Case 3: Below target (under delivery)

1.11. A TO carried out significantly less volume of asset replacement than its RIIO-T1 business plan forecast, as illustrated by the vertical green arrow on the diagram. The company delivered a higher network risk because the risk of significant reduction to asset replacement volume outweighed the benefit of the slow-down of asset degradation. The higher network risk is reflected by the under delivery of NOMs against the NOMs target.

1.12. We will ask the company to provide both qualitative and quantitative evidence and justify why it under delivered the NOMs. For the justified under delivery we expect the company to demonstrate that the under delivery is in the best interest of consumers.

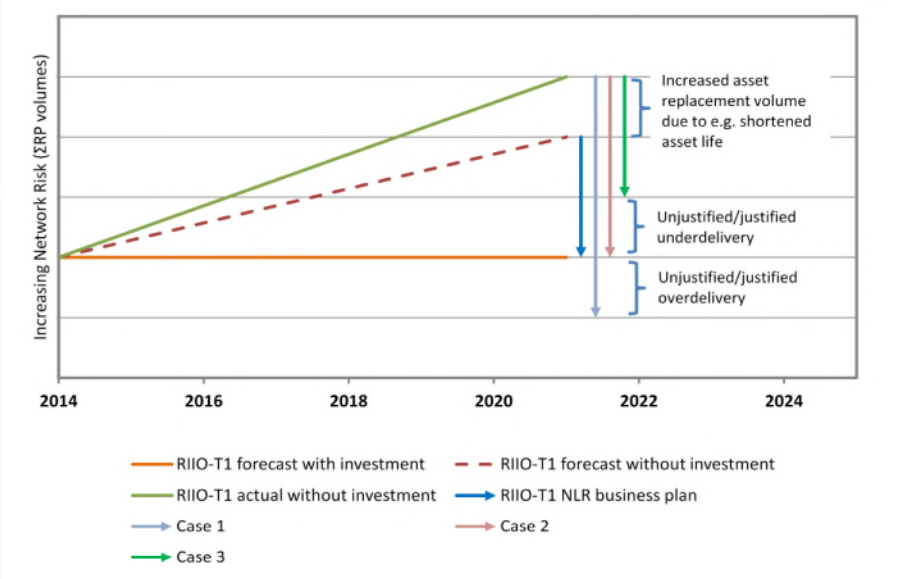
1.13. We will set out the NLRE allowance for the RIIO-T2 based on the assumption that the NOMs target of RIIO-T1 is the opening position from which the company will deliver the NOMs target of RIIO-T2. In this case the company will need to catch up the backlog of the under delivery during the RIIO-T2.

1.14. Where the company can justify its under delivery, we will allow the company to benefit from the financing cost of avoided investment in RIIO-T1, and will not apply an additional reward. However, for the unjustified under delivery, we will not only clawback/disallow the benefit from the financing cost but also apply an additional penalty to remove the undesirable incentive impact.

Scenario Two

1.15. Scenario Two assumes the actual asset degradation is faster than the forecast as expected by TOs at the time when the NOMs target was set out. In this scenario there may be three cases arising from different asset management strategies as shown in Figure A.2. The difference between forecast and actual degradation is a risk borne by the TO.

Figure A.2 – Asset degradation: Scenario Two



Case 1: Above target (over delivery)

1.16. A TO carried out the significantly higher volume of asset replacement than its RIIO-T1 business plan forecast, as illustrated by the vertical light blue arrow. The company achieved a lower network risk because the higher volume of replacement outweighed the impact of the faster asset degradation on the network risk. The lower network risk is reflected by the over delivery of NOMs against the NOMs target.

1.17. We will ask the company to provide both qualitative and quantitative evidence and justify why it delivered more than the NOMs target. For the justified over delivery we expect the company to demonstrate that the over delivery is in the best interest of consumers.

1.18. We will set out the NLRE allowance for the RIIO-T2 based on the assumption that the NOMs target of RIIO-T1 is the opening position from which the company will deliver the NOMs target of RIIO-T2. In this case the over delivery of NOMs will be carried over to RIIO-T2.

1.19. Where the company can justify its over delivery, we will allow the company to recover the financing cost of the early investment in RIIO-T1 and apply an additional reward. Otherwise, for the unjustified over delivery, we will not apply an additional penalty but the company will incur a financing cost of the early investment.

Case 2: On target (equal or equivalent delivery)

1.20. A TO carried out higher volume of asset replacement than its RIIO-T1 business plan forecast, as illustrated by the vertical red arrow. Because the higher volume of asset replacement fully offset the adverse impact of the faster asset degradation on the network risk, the company achieved the target network risk.

1.21. We will ask the company to provide evidence to demonstrate how it managed to deliver the NOMs target and what benefits it will bring to consumers in the longer term.

1.22. We will take the actual outturn NOMs as the opening position for setting out the RIIO-T2 allowance for NLRE. We will not apply any financial penalty or reward.

Case 3: Below target (underdelivery)

1.23. A TO carried out asset replacement volume consistent with its RIIO-T1 business plan forecast, as illustrated by the vertical green arrow shown in the above diagram. The company delivered a higher network risk because of the adverse impact of the faster asset degradation on the network risk. The higher network risk is reflected by the under delivery of NOMs against the NOMs' target.

1.24. We will ask the company to provide both qualitative and quantitative evidence and justify why it under delivered the NOMs. For the justified under delivery we

expect the company to demonstrate that the under delivery is in the best interest of consumers.

1.25. We will set out the NLRE allowance for RIIO-T2 based on the assumption that the NOMs target of RIIO-T1 is the opening position from which the company will deliver the NOMs target of RIIO-T2. In this case the company will need to catch up the backlog of the under delivery during the RIIO-T2.

1.26. Where the company can justify its under delivery, we will allow the company to benefit from the financing cost of avoided investment in RIIO-T1 and will not apply an additional reward. However, for the unjustified under delivery, we will not only clawback/disallow the benefit from the financing cost but also apply an additional penalty to remove the undesirable incentive impact.

NECEC 1-10

Request:

Refer to Bates page 165 of Book 1 of 3 and the following quoted language:

> *For each portfolio of closed projects, the Company will report to the PUC, as part of its annual PST Reconciliation Filing, as well as its ISR Reconciliation Filing, its actual capital expenditures relative to the total capital cost estimate, with a calculation of the value of the incentive payment the Company has earned. The Company proposes that any positive incentives earned in a given fiscal year would be collected through the PST Provision in the following fiscal year.*

a. What occurs if the actual capital expenditures exceed the total cost estimate?

b. Will the Company have recourse to include capital cost overruns in future rates through a rate case or other cost recovery mechanism such as ISR?

Response:

a. If actual capital expenditures exceed the total capital cost estimate, the Company will not earn an incentive.

b. The Company would, as is currently the case, be permitted to file for recovery of cost overruns in the next rate case or other cost recovery mechanisms such as ISR. Recovery of such overruns would be subject to PUC review and approval.

NECEC 1-11

Request:

Refer to Schedule PST-1, Table 9-1, Bates page 168 of Book 1 of 3.

a. Please state the value of 75 basis points of ROE in terms of pre-tax revenues and post-tax operating income using the rate year ending August 2019. Please provide details of the calculation.

b. State the current earnings per share of common equity attributed to National Grid's electricity operations in Rhode Island. Please provide details of the calculation.

c. Please state the value of 75 basis points of ROE in terms of earnings per share of common equity attributed to National Grid's electricity operations in Rhode Island. Please provide details of the calculation.

Response:

a. As the Company noted in PST Book 1 of 3, Bates page 167, footnote 9, the Company calculates the value of a basis point for the purpose of assigning value to its proposed performance incentive mechanisms as equal to 1 basis point of electric distribution common equity grossed up for taxes. For the rate year ending August, 2019, the Company estimates the value of 75 basis points to be $3,517,248. Attachment NECEC 1-11 shows this calculation. Note that the value of a basis point has been updated from the value cited in footnote 9.

b. The question is unclear as to what is meant by "current earnings per share" in terms of the timeframe requested and subsidiary referenced. Given that the Company is a wholly-owned subsidiary of National Grid plc, the concept of earnings per share of common equity for the Company is not applicable, and therefore not an analysis the Company has performed. To perform the calculation, certain assumptions would be required such that the resulting calculation would not be meaningful.

c. Please see the response to part b.

Basis Point Calculation for Narragansett Electric Co
Based on Rate Year Ending August 2019

1 Basis Point = 1/100 of 1% (i.e. .0001)

Narragansett - Electric

	RYE Aug 2019
Ratebase	$726,438,184
Common Equity %	51.00%
Common Equity	$370,483,474
1 Basis Point Equals	0.0001
1 Basis Point of Common Equity before Taxes	$37,048
Approximate Tax Rate (State and Federal)	21.0000%
Tax Rate Gross Up Factor (1-21.0000%)	79.0000%
1 Basis Point of Common Equity Grossed up for Taxes	**$46,897**
100 Basis Points	$4,689,664
75 Basis Points	**$3,517,248**