Transmission Price Control Review 4

Review of the Electricity Transmission Asset Management Policies and Processes as adopted by National Grid Electricity Transmission (NGET) within England & Wales

and

Assessment of Implications for Capex for 2007/08-2011/12

DRAFT Final Report

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Transmission Price Control Review 4

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Revision History

Rev.	Date	Description	Author	Checker	Approver
	23 Dec 05	Initial Progress Report: Tasks 1& 4 (all TOs)	MW	KvO	
	10 Feb 06	2nd Progress Report (all TOs).	MW	KvO	
	10 Apr 06	3rd Progress Report - NGET Only	MW	KvO	
1.0	09 Jun 06	Final Draft Report - NGET	MW	DP	LP
2.0	06 Jul 06	Amended Draft Final Report	MW	SS	DP
3.0	25 Sept 06	Final amendments post NGET comments	MW	DP	LP

Executive summary

This report outlines the results, findings and conclusions of (i) KEMA's assessment of the asset management practices of National Grid Electricity Transmission (NGET) and (ii) KEMA's assessment of NGET's Non-Load Related Expenditure (NLRE), in support of Ofgem's ongoing 2007/08 – 2011/12 Transmission Price Control Review (TPCR4). The report encompasses a review of NGET's NLRE activities for both the current (2000/01 – 2006/07) and forthcoming (2007/08 – 2011/12) price control periods, including the related Engineering Operating Expenditures. It also provides KEMA's opinion regarding an appropriate level of NLRE for both periods.

Asset management processes and historic NLRE

NGET has developed a asset management organisation and procedural framework which has been enhanced over the current price control period. NGET has also implemented a range of dedicated asset management IT systems to support long-term asset replacement modelling and replacement prioritisation. NGET's condition monitoring processes are comprehensive and are captured within a robust asset knowledge system which is widely accessible. NGET's long-term asset replacement modelling is sophisticated, with some of the main assets groups being modelled at a disaggregated level to reflect the differing asset lives of individual components. The capital planning processes employed appear robust and should be capable of authorising the appropriate asset replacement schemes in a timely manner although it is recognised that NGET's forward programme represents a step change in volume.

KEMA has identified some inconsistencies regarding the application of NGET's asset management processes during the formulation of the capital plan. KEMA also notes that NGET's NLRE capital planning processes is not wholly driven by asset management considerations and could be subject to non-asset management related influences from GB System Operator and the wider National Grid Group.

Analysis of NGET's Non-Load Related Expenditure

KEMA's analysis indicates that the volumes for overhead line conductors (OHL) replaced by NGET during the historic price control period align with KEMA modelling. Similarly, the replacement volumes for 132 kV switchgear also align with KEMA's calculations. NGET's replacement volumes for 275 kV switchgear are below that suggested by KEMA's modelling. However, NGET's replacement volumes for 400 kV switchgear and switchgear <132 kV are higher than those indicated by modelling. The unit cost information provided by NGET for the replacement of overhead lines and switchgear during the historic price control period are lower than KEMA estimates. Furthermore, KEMA has not identified any aspect of NGET's historic NLRE capital expenditure that has been incurred inefficiently.

With respect to NGET's forecast NLRE requirements, KEMA is not convinced that all of the proposed NLRE schemes are supported by comprehensive condition-based evidence, in particular for overhead line conductors and switchgear. Furthermore, NGET may be underestimating the asset lives of particular asset categories and thus overestimating some asset replacement volumes. NGET's adoption of route specific overhead line refurbishment strategies combined with the use of circuit breakers as the lead asset when determining substation replacement priorities inevitably increases NLRE forecasts.

KEMA anticipates that NGET's proposed 'Alliance' approach to procurement and capital plan delivery could address some procurement deficiencies and deliver cost savings across the full range of NLRE schemes when compared to the projections submitted to Ofgem. Overall KEMA estimates that NGET's NLRE projection for the period 2007 – 2012 could be reduced by 19%.

NGET asset management policies and practices

KEMA's review of NGET's asset management procedures has confirmed a number of areas where NGET performs strongly and in a number of cases exhibits best practice relative to its GB peers and the wider international network community; in particular:

(i) asset management policies, procedures and governance framework;

(ii) establishment and use of a corporate Asset Health Review system; and

(iii) disaggregated asset replacement modelling incorporating feedback from the asset base, especially with respect to asset lives.

However there are some areas in which NGET's approach to asset management could be improved, which also have implications for NLRE. These include:

(i) Capital plan formulation

i. matching of theoretical asset replacement volumes derived from top-down modelling with actual asset replacement schemes;

ii. opaque and potentially unjustified network betterment, apparently influenced by undocumented GBSO operational preferences embedded within scheme development processes;

iii. lack of granularity with respect to substation asset replacement;

iv. divergence between NGET and DNO replacement priorities for fundamentally similar equipment types, where NGET assumes a more urgent replacement requirement;

v. lack of systematic assessment of network risk, its linkage to network performance and its usage in determining appropriate investment requirements;

vi. the non-transparent influence of other NG Group portfolio objectives constraining asset management policy implementation (e.g. capital constraints restricting planned NLRE); and

vii. Capital Plan instability at the network, asset replacement, asset category and scheme levels.

(ii) High cost of asset replacement

i. Expensive, broad-scope substation replacement schemes;

ii. the application of high additional cost factors to equipment costs, resulting in upward pressure on aggregate scheme costs;

iii. reliance on ‘all-or-nothing’ asset replacement strategies (e.g. complete lines of route and entire substations); and

iv. limited reassessment of options post-tender where costs increase beyond expectation.

(iii) Procurement effectiveness

i. the involvement of the procurement group appears predominantly towards the end of asset replacement process in a remote service provider capacity;

ii. short-term, sequential and scheme specific approaches which do not fully deliver economies of scale;

iii. sub-optimal long-term procurement strategy and asset replacement contracts;

iv. inability to exploit purchasing power given the scale of expenditure.

With respect to procurement, it is important to note that an Alliance approach to capital plan delivery is currently being implemented. Whilst there is a lack of detailed understanding as to how Alliances will operate, KEMA anticipates the initiative will address at least some of the areas of concern outlined above. The Alliance initiative should be expected to deliver material savings across the full range of NLRE projects in addition to securing plan delivery.

Formulation of KEMA’s view of NGET’s forecast NLRE requirements

(i) NGET’s approach to condition assessment is generally robust although examples have been identified where scheme justification is not compelling for all asset categories, implying a degree of plan ‘back-filling’.

(ii) NGET’s assumptions regarding future unit costs appear high. This seems partly due to some self-imposed policies which incur additional time and costs. These high costs estimates are also partly driven by the Project Definition Document modelling assumptions where (i) the increase in OHL volumes towards the latter part of the HBPQ period may have influenced future assumptions and (ii) complexity costs relating to site-specific issues sometimes appear overstated.

Scheme Assessments

KEMA assessed 24 NGET schemes in detail. These schemes did not represent a random sample, being selected on the basis of financial materiality and scope of work. Generally the data supplied was of good quality, albeit sometimes brief.

The total cost of the selected NGET schemes, based on NGET cost estimates was £623M, of which historic schemes comprised £111M and future schemes approximately £512M. The future schemes selected for the FBPQ period represented approximately 16% of NGET's FBPQ total NLRE submission. From its assessments of the 24 schemes, KEMA's own cost estimates for the historic schemes were broadly aligned with NGET's actual expenditure. However, KEMA's assessment of future schemes was that these could potentially be delivered at a cost of as low as £274M compared with NGET's projected £512M (i.e. as much as 45% lower).

Site Visits

In total 17 forecast NLRE schemes have been assessed during 8 site visits. These site visits comprised an equal mixture of substation (i.e. switchgear, transformers etc) and OHL site visits. From the 4 substation site visits, KEMA found evidence that:

(i) NGET is scheduling some switchgear replacements in shared substations before the relevant DNO deems necessary;

(ii) Operational betterment associated with the proposed change from 4 switch mesh to a double busbar layout is proposed where the rationale is not yet compelling;

(iii) the ageing mechanisms for outdoor switchgear is also declared applicable in indoor environments;

Consequently, KEMA concluded that there was evidence of potential over-forecasting within NGET's proposed NLRE for substation assets.

KEMA conducted 4 "site" visits relating to OHL and towers in different parts of England & Wales for routes where NGET intend to undertake full refurbishment or fittings-only work. From these visits KEMA confirmed:

(i) Asset condition varied along routes and in some cases parts of routes appeared to be in good condition, yet these sections formed part of the overall asset replacement scheme.

(ii) In one case, the justification for refurbishment of a given route was mainly predicated on forensic data of an adjacent route. KEMA is not convinced that this is sufficient justification for asset replacement requirement.

(iii) In another case, the KEMA engineers stated that the primary driver for asset replacement appeared to be more related to a need for betterment than a need to address deteriorating condition of the route.

KEMA recognises the small sample size of the selected OHL routes. Nevertheless, KEMA could not always confirm the poor condition of the assets identified for replacement or the scale of refurbishment required. Consequently, KEMA concludes that there is insufficient evidence to conclude that NGET's proposals for OHL refurbishment are justified.

KEMA Assessment of appropriate future NGET NLRE capital expenditure

On the basis of the assessments, it appears that reductions in both asset replacement volumes and costs are achievable whether viewed from a top-down or bottom-up perspective with particular focus on OHLs (mainly cost) and switchgear (mainly volume).

KEMA's conclusions is that NGET's NLRE requirements for the period 2005/06 - 2011/12 could be reduced by 19%. KEMA's estimate regarding the reduction in forecast NLRE per asset category is outlined below:

Table 1 – Overview Capital expenditures NGET

Asset Category	NGET forecast £M	KEMA estimate £M	KEMA Comment
Transformers	209.6	178.2	Volume (400/275 IB) and unit costs overstated
Switchgear	654.6	556.4	Volumes and unit costs
Reactors	57.7	57.7	Close alignment with forecast
Substation Other	108.0	91.8	Based in Switchgear analysis
Overhead lines	871.6	566.6	Unit costs high
Underground cables	595.7	565.9	Highly route and tunnel specific
Protection and Control	244.3	207.6	High-level analysis based on circuit breaker volumes
Total	**2741.5**	**2224.2**	**c.£500M reduction**

The increasing investment profile o effectively results in the majority of the savings applying to the later years of the TPCR4 period. For each primary asset category, KEMA concludes that NGET is overestimating forecast NLRE requirements as follows:

- Transformers: the estimated level of over-forecasting is 15%, due to excessive 400/275 kV transformer volumes and some high unit costs.

- Switchgear: KEMA estimates a 15% over-forecasting due to both high volumes and some unit costs. NGET's unit costs are 10% above those expected by KEMA (assuming full bay replacement, although circuit breaker-only replacement opportunities may emerge). KEMA has assumed that some 275kV mesh substations will be replaced to double busbar arrangements.

- Overhead lines: NGET appear to be overestimating capital requirements for overhead lines by approximately 35%. This is predominantly attributable to unit costs but also the proposed conductor replacement volumes appear high.

- Cables: In general, KEMA agrees with NGET's stated cable volume replacement requirement. Some cable schemes include provision for tunneling works and the related costs are recognised to be variable. However, based on procurement efficiencies, KEMA estimates that a cost reduction of 5% is possible overall.

- Protection & Control: Based on a high-level estimation, it appears that NGET is overestimating protection & control requirements by approximately 15%. The figure for Protection and Control does not include adjustments for asset replacements arising from BT's 21st Century network initiative. KEMA understands that this item is under separate review by Ofgem.

1. Introduction

1.1 General

The Office of Gas and Electricity Markets (Ofgem) appointed KEMA Limited (KEMA) to asses the asset management policies, processes, systems and practice of the three electricity transmission licensees (TL's) in Great Britain – National Grid Electricity Transmission Ltd (NGET), Scottish Power Transmission Ltd (SPT), and Scottish Hydro-Electric Transmission Ltd (SHETL).

This report lays out the results, findings and conclusions of KEMA's assessment of the asset management practices of NGET in support of Ofgem's ongoing 2007/08 – 2011/12 Transmission Price Control Review (TPCR4). This includes reviews of all the activities which result in the prediction, management and implementation of Non-Load Related Capital Expenditure (NLRE).

1.2 Aim of this assessment

The key aims and objectives of this assessment are to establish the **overall efficiency and effectiveness of transmission licensees' asset management systems and processes** over the current and next regulatory price control periods. This final report brings together the results, findings and conclusions, in respect of NGET, of each of the following work streams:

(i) **The asset management system**. Evaluation of the underlying asset management policies and strategies as adopted by NGET;

(ii) **Implementation of the asset management system**. Assess the extent to which these policies and strategies are applied at a working level by NGET, i.e. transmission licensee practice;

(iii) **Asset condition and system impact.** Evaluate the net impact of these policies, systems, processes and practices on asset condition profiles and network performance metrics; and

(iv) **International / GB comparisons.** Assess extent of leading international practice adoption and whether scope exists to further improve the transmission licensee's asset management systems.

(v) **Appropriateness of NGET's historic and proposed future NLRE Capex.** Assessment of the asset replacement volumes for each transmission asset category over the periods 1999/00 - 2006/07 (historic) and 2007/08 - 2011/12 (forecast), based on KEMA's top-down asset replacement modelling adjusted according to relevant asset management related inputs. These volumes were subsequently used to estimate NLRE requirements using KEMA estimates of unit costs.

2. KEMA's approach

This chapter provides an overview of the approaches adopted by KEMA during the assessment of NGET's asset management practices for each of the five main work streams identified (in 1.2) above.

2.1 Review of the asset management system

The overall objective of this task was to assess the asset management systems and processes adopted by NGET with respect to NLRE. The following methodology and approach was applied:

- Detailed assessment of the responses from NGET to HBPQ;
- Submission of KEMA questions as a follow up on NGET's narrative HBPQ submission to clarify the features of its asset management policies and procedures;
- Assessment of the answers provided by NGET on KEMA's HBPQ questionnaire submission;
- A clarification meeting between NGET, Ofgem's Capex team and the Capex consultants (KEMA and PB Power) in Warwick on 13 December 2005;
- Detailed assessment of the responses from NGET to Ofgem's FBPQ;
- Fourteen Workshops in Warwick facilitated by NGET. These covered the following topics: overview of asset replacement requirements; condition assessment practices and observations; asset lives and asset replacement modelling; network performance; network risk; strategic spares; benchmarking; capital planning; engineering operational expenditure; and procurement;
- Submission of KEMA's questions in response to NGET's FBPQ narrative submission;
- Assessment of the answers provided by NGET on KEMA's FBPQ questionnaire; and
- KEMA's modelling of NGET's asset replacement volumes in historic and future periods.

2.2 Assessment of the implementation of the asset management system

Having reviewed the asset management policies, processes and systems, the second key task was to review implementation. This enabled KEMA to compare asset management practice versus policy to identify any discontinuities. KEMA applied the following methodology and approach:

- Seek evidence from NGET to confirm that the stated policies and processes are implemented and used within the relevant different parts of the organisation of NGET; This included;
    - Use of Written questions;

- Use of workshops to enable NGET to present evidence e.g. condition assessment reports; and
- On-site investigation of NGET Asset Health Review process and associated asset management practices.

- Review of a representative sample of individual capital expenditure schemes, selected by KEMA, in detail for both completed and planned projects. This review sought to follow the asset management process from “cradle to grave” and thus to verify the applied practices for that scheme. This included the identification of need (condition assessment, risk & criticality etc), appropriateness and cost effectiveness of the chosen solution; assessment of the prioritisation, and decision making/planning processes and of NGET’s cost control and delivery performance; and the interaction with the procurement process.

2.3 Assessment of asset condition and system impact

The third task was to undertake an assessment of the condition of NGET’s electricity transmission asset base. This task provided insights into the overall condition of network assets within each of the asset categories. To enable this KEMA applied the following approach:

- Seek evidence from NGET of asset condition and performance at a “micro” and asset family level plus wider “macro” metrics of network condition and performance, to prove the asserted condition and performance of both the assets and network of NGET. This included;
    - Use of specifically focused Written questions;
    - Use of Workshops to enable NGET to present and discuss such evidence e.g. condition assessment reports; and
    - On-site investigation of NGET Asset Health Review process and associated asset management practices.
- Targeted site visits for a selection of sites covering a representative sample of planned future asset replacement (as identified in NGET’s FBPQ) to assess and verify asset condition, relevant scheme need and the choice of scheme option for conducting the asset replacement;
- A review of key external and internal system reliability and performance records relevant to asset/network condition, e.g. the unplanned unavailability;
- Review of any internally applied asset and network KPIs and examination of any risk metrics applied by NGET;
- Examination of NGET’s records of overall asset age and asset life profiles, and identification of any emergent patterns for asset replacement in the next price control period taking into account the findings of asset condition and wider impact on system performance

2.4 Review of international and GB comparisons

This fourth task was to assess the extent to which NGET have adopted leading practice asset management processes and systems at both the aggregate system level and for each of the different network asset categories. KEMA applied the following approach in this fourth task:

- Overview of leading practices adopted by transmission system operators (TSOs) and distribution companies in other European countries and in the USA;
- Review of internal and external benchmarking as conducted by NGET e.g. ITOMS; and
- Comparison of the asset management policies, procedures and practices of the three GB transmission licensees e.g. comparison of asset lives assumptions, unit costs, condition assessment practices etc.

2.5 Assessment of NGET's NLRE capital expenditure

This final task, was to provide Ofgem with KEMA's views as to the efficiency of NGET's historic NLRE expenditure; and to provide an estimate of an appropriate future level of NLRE for the period 2007/2008 - 2011/12. KEMA applied the following approach to delivery of this final task:

- KEMA's assessment of NGET's NLRE requirements was conducted from different perspectives; (i) volumes and cost, and (ii) top-down and bottom-up processes, as illustrated below:

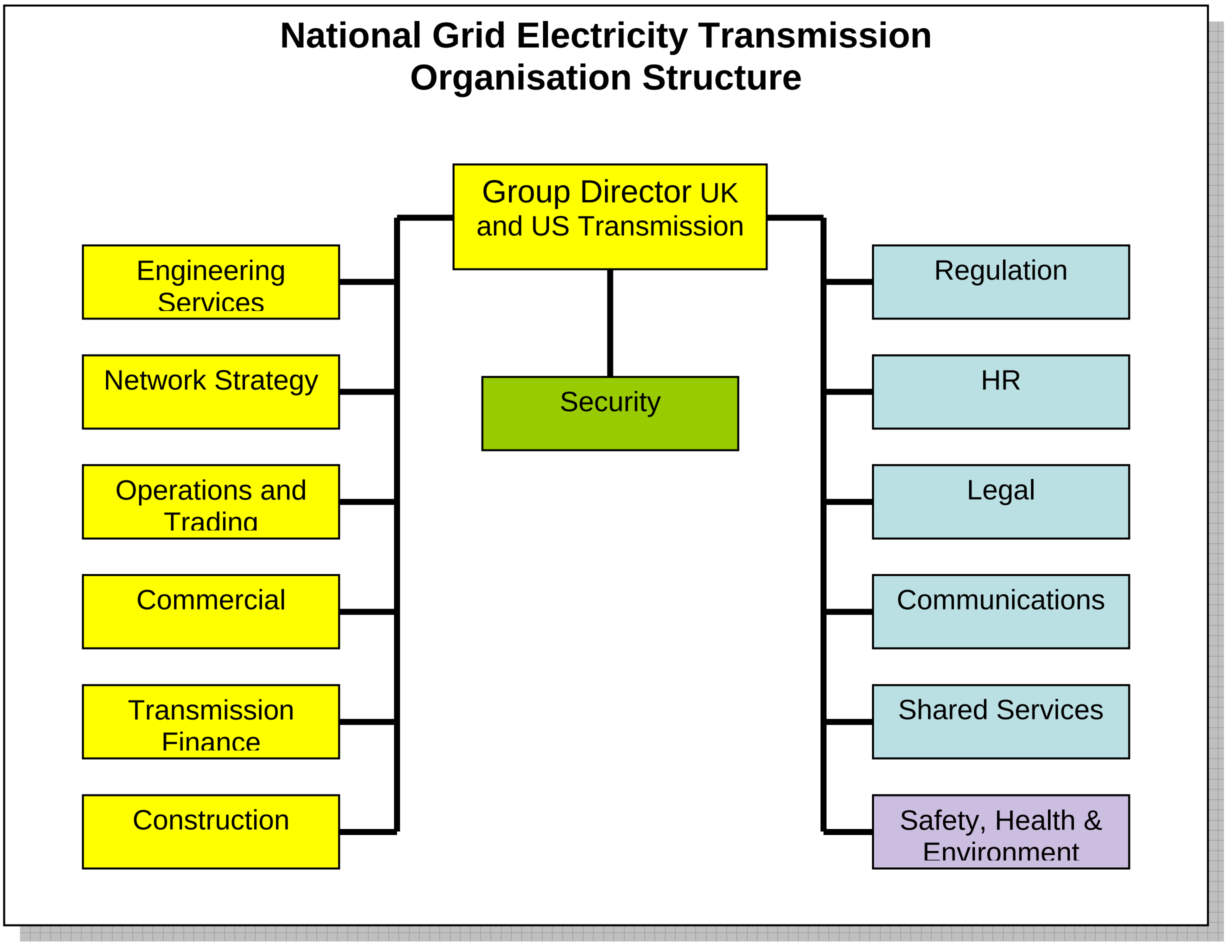
	Volumes	**Costs**
Top Down Approach	Review Aspect: Asset Replacement Modelling Key Issues: Asset Lives Review Method: Workshops, Q&A, review of ALERT, KEMA's own modelling, benchmarking, KEMA knowledge	Review Aspect: Unit Costs Key Issues: Equipment + Other Factor costs Review Method: Workshops, Q&A, review of PDD model, scheme assessment, benchmarking, KEMA knowledge
Bottom up approach	Review Aspect: Asset Condition Assessment Key Issues: Need (evidence) and granularity Review Method: Workshops, Q&A, review of AHR, scheme assessments, site visits, KEMA knowledge	Review Aspect: Scheme Costs Key issues: need, design choice and costing Review Method: scheme assessments, benchmarking, KEMA knowledge, Q&A, Workshops

3. An overview of NGET relevant to asset management

NGET is the largest of the three GB transmission licensees, with the largest asset base and associated asset management organisation. An outline of the relevant company structure and the asset base NGET manages is provided below.

3.1 Organisation

NGET forms part of a portfolio of companies in the UK and US comprising NG Group. The UK structure is illustrated below:



There has been organisational change over the last 5 years, one key event being the merger with Transco in 2002 such that UK Transmission is now an integrated electricity and gas utility. Although Procurement (part of Shared Services) and Operations & Trading (which contains the majority of the function of the GBSO) each play a role, the two primary Directorates associated with asset management of the transmission network are Network Strategy and Engineering Services. Until 2005 Construction formed part of Network Strategy but has now been separated as a specific Directorate given the increasing volume of construction activity on NGET's transmission network. Furthermore, during the latter part of 2006, the (majority) remainder of Network Strategy and Engineering Services will merge into a single Asset Management Directorate. At present Network Strategy (exc. Construction) and Engineering Services;

(i) employ over 1500 UK electricity transmission staff,

(ii) account for the majority of NGET's controllable Opex (>£100m per annum requested for the FBPQ period); and

(iii) are responsible for all asset management activities from "cradle to grave" i.e. are responsible for the identifying, planning and implementing the vast majority of NGET's Capex (>£790m per annum average requested for FBPQ period)

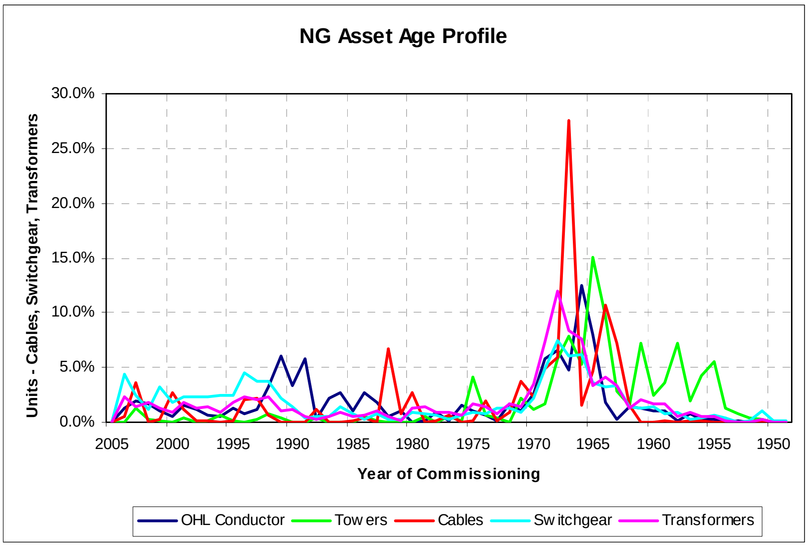
3.2 Asset base

As noted above, NGET has the largest asset base of the three GB Transmission Licensees and is the dominant owner of 400kV assets (SPT only having some and SHETL none). The magnitude of this asset base as at 2005/06 (from NGET's FBPQ submission) is illustrated below:

Table 2 – Overview NGET transmission assets

Asset category	Unit	400 kV	275 kV	132kV
Overhead line	ct km # tower	10,507 16,672	3,283 4,744	207.5 486
Cable	ct km	178.5	423.4	64.1
Substations	#	150	133	162
Transformers	#	626 (with 400kV or 275kV as highest winding)		6

A key point to establish is that a large part of NGET's asset base was commissioned in the 1960's when national energy demand rose rapidly and needed to be supported by an associated rapid expansion in generation and network assets. Thus many of NGET's primary assets (overhead line, cables, transformers, and switchgear) are approaching the latter stages of traditional asset life assumptions (typically 40 years) and this is illustrated below:



Thus it can be seen why, for the forthcoming Price Control period (2007/8-2011/12), there is a focus placed on asset replacement by NGET and Ofgem. Therefore key considerations centre around;

(i) the condition and performance of NGET's asset base;

(ii) what are appropriate asset life assumptions for NGET assets; and

(iii) what are the appropriate programme and costs for asset replacement for the FBPQ period.

These central issues have been examined by KEMA within its review of asset management policies and practices at NGET and relevant observations and conclusions are provided in this document.

4. The asset management system

This chapter outlines the evaluation of the underlying asset management policies and strategies as adopted by NGET. The following sections focus on the strategies, policies, systems and procedures to deal with Non Load Related Expenditure replacements mainly triggered by ageing equipment.

4.1 Asset management organisation and structure

KEMA has developed a thorough understanding of NGET's organisation in relation to performance of its asset management function covering policies and practices. The organisation has changed over the timeframe of the HBPQ period. This is especially true of Engineering Services.

Currently the Network Strategy and Engineering Services directorates appear to interact reasonably effectively together in performing NGET's asset management activities but improvements could be made by ensuring policy makers and practitioners work closely together. NGET has identified the benefits of unification of these two directorates under a single (reorganised) Asset Management function. This appears to represent a sensible development and it should lead to both enhanced performance and increased efficiency in the FBPQ period.

The separation of Construction into a separate unit reflects the increasing capital programme and need for dedicated focus on delivery of the associated construction programme. However, it is unclear what role Construction will play in NGET evolving organisational structure.

KEMA has also examined how Network Strategy and Engineering Services interface with the GBSO and other NG Group functions such as procurement. This has led to the following concerns:

(i) the non-transparent interaction of the GBSO with (and within) Network Strategy and Engineering Services activities, e.g. capital and outage planning, which can lead to higher asset management costs than those a Transmission Owner (TO) might incur;

(ii) the basic role and limited degree of integration of Procurement within the asset management organisation, which leads to ineffective purchase of capital equipment and delivery of construction programme;

(iii) insufficient in-house resource for certain core activities and the degree of reliance on external outsourcing of engineering activities.

KEMA views these issues as important in the context of analysing whether NGET are formulating and delivering its capital plan as well as its asset maintenance activities in the most efficient and economic manner.

Looking forward, NGET have initiated substantive organisational change in relation to asset management, some of which have been highlighted above. KEMA's understanding is that within the next year the following key organisational changes will take place:

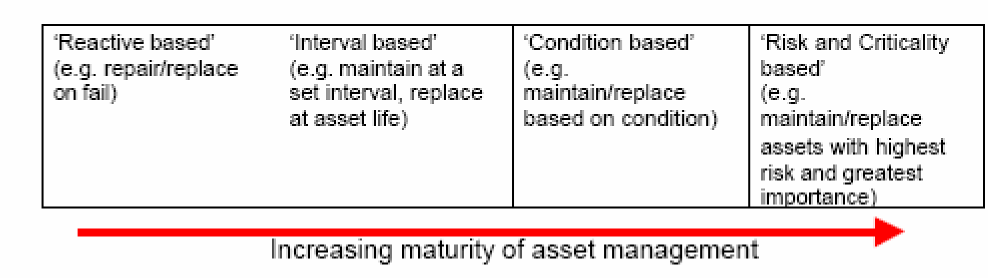
(i) Unification of the Network Strategy and Engineering Services directorates to create a single Asset Management directorate. Whilst the structure will be rolled out by the end of 2006 (with some staff rationalisation expected), KEMA has been made aware of the high level structure which indicates greater integration of Network Strategy and Engineering Services within more separated electricity and gas functions. This initiative should deliver enhanced asset management performance and cost reduction.

(ii) There will be increased interaction between the Procurement and asset management functions. The role of Procurement should evolve into a broader “Supply Chain Management” function. These should represent positive steps enabling more effective and efficient delivery of both Opex and Capex.

(iii) The adoption of an Alliance based approach to capital plan delivery will impact on the capital planning process. There is currently a lack of clarity regarding Alliance implementation and the implications for capital planning processes so it is difficult comment in detail on the potential benefits.

4.1.1 NGET’s asset management philosophy

NGET has emphasised that its assets are ageing and that this requires an evolving approach to asset management as illustrated below:



The key message here is that NGET claim to be adopting a Risk and Criticality based approach to both maintenance and replacement of assets and this has developed from less sophisticated interval and condition-based asset management practice previously adopted and prevalent at the time of the last Price Review. However, answers to questions suggest that NGET is in transition from interval based asset management to condition based asset management in many areas. Whilst it is beginning to progress to risk and criticality based asset management for its primary assets, KEMA’s observation as discussed later is that this latter approach is not yet widely understood, well defined and coherently applied across all primary asset categories.

In terms of a guiding philosophy for its asset management strategy, NGET’s key statement which it emphasised in its HBPQ Submission was that it seeks to “replace assets in a timely manner before failure in service occurs”. This implies that all of NGET’s policies and procedures are driven by this philosophy although it is not yet clear how this is applied. Following questioning of the “replace assets in a timely manner before failure in service occurs” philosophy NGET has softened its commitment to this statement to “NGET seeks to minimise within reason the chances of such events”. However, KEMA has concerns how NGET translates its policy into practice.

4.1.2 Asset Management Policy and Procedure Documents

NGET has provided extensive policy documents as part of Appendix 6 of its HBPQ Submission. The existence of these well documented procedures and policies is a aspect of NGET’s asset management framework. It reflects the importance and scale of asset management within the UK transmission business and also reflects NGET’s procedural culture.

Following the 2002 ARM Report, and in preparing for PAS 55 accreditation as discussed below, NGET established an overarching UK Transmission Asset Management Policy, designated PS(T) AM-001. PS(T) AM-001 (revised in June 2005) established the three principal document suites within Asset Strategy, namely Engineering Policy Statements, Engineering Technical Specifications and Technical Guidance Notes and the relationship between them.

(i) **Engineering Policy Statements** (EPS) – are statements of need or intent, based on safety and/or environmental implications, business needs, international policy, legislation and supplier market.

(ii) **Engineering Technical Specifications** (ETS) – define the technical requirements for equipment and services being provided to NGET. Technical Specifications continue to be aligned with International Standards.

(iii) **Technical Guidance Notes** – provide advice and guidance on how policy is to be applied or the specification used, referencing the policy statement, technical specification or other relevant documents as appropriate.

These documents are produced for all asset categories and NGET have a Transmission Procedure TP101 which requires Asset Strategy to undertake annual reviews of Policy Statements, Technical Guidance Notes and Technical Specifications to ascertain if the documents are fit for purpose, identifying whether any further course of action is required.

4.1.3 PAS 55 asset management standard

NGET has contributed to the development of the BSI’s Publicly Available Specification for Asset Management (PAS 55-1). The objective was to establish a common and widely accepted framework for assessing whether companies are adopting good practices for asset management. This has now been completed and NGET was the first UK utility to achieve PAS 55-1 certification in autumn 2005.

PAS-55 provides a basis for verifying the existence of sound asset management processes across the business and also ensuring that processes link together. NGET stated that PAS-55 certification provides confirmation of good asset management practice and also provided details of the PAS-55 assessment process and findings. KEMA acknowledges PAS-55 certification to be a useful confirmation of asset management capability. For clarity, NGET did not use the PAS-55 certification to confirm the accuracy of its asset replacement expenditure forecasts.

4.1.4 Some key policy trends/changes

4.1.4.1 GIS vs. AIS substation build

NGET has explicit policy documents relating to substation design, namely NGET policy PS(T) 070 *'Optimised strategies for asset replacement of substations'* which sets out the framework within which off-line build decisions are made; and where off-line build is selected, NGET's policy, PS(T) 023 which examines whether gas (GIS) or air (AIS) insulated is the most appropriate solution. PS(T) 023, expresses preference for AIS where circumstances allow, but there are a number of circumstances wherever GIS may be applied. GIS is adopted where land availability, visual amenity or pollution issues require the use of an alternative solution to AIS.

NGET's forecast proportions of GIS equipment (based on volumes) to be installed over the period to 2011 under asset replacement are included in the table below along with average separate unit costs for GIS and AIS.

	Proportion GIS	Average AIS Costs (£k)	Average GIS Costs (£k)	Average Total Costs (£k)
400kV	12%	[redacted]	[redacted]	[redacted]
275kV	31%	[redacted]	[redacted]	[redacted]
132kV	49%	[redacted]	[redacted]	[redacted]

NGET subsequently provided analysis, including both LRE and NLRE switchgear volumes, as shown below:

Voltage	% GIS 01/02 - 05/06	%GIS 06/07 – 11/12
400kV	31%	40%
275kV	17%	35%
132kV	34%	48%

NGET was keen to highlight that the above costs relate purely to the equipment and that it always seek to construct the most economic practical scheme. NGET state that in considering 'extra costs' of GIS over AIS, the difference is often hypothetical, as the AIS option could not be constructed in the available location

NGET state that in order to facilitate switchgear replacement with minimal operational and safety risk and with a reduced outage programme, it is often necessary to build a new substation 'off-line' adjacent to the existing site and transfer circuits in on completion. NGET states that, without this approach, system access would prevent delivery of the necessary programme.

NGET indicates its preference would be to use an off-line AIS solution, rather than GIS. However, where GIS is required, a GIS off-line solution can be delivered at lower cost than an AIS in-situ replacement. As the greatest proportion of these decisions is at the 132kV interface with the DNOs, NGET is not alone in using GIS solutions to deliver efficient asset replacement.

Nevertheless, NGET is increasingly adopting GIS offline build, perhaps to simplify network operation during and after completion of construction, i.e. operational considerations appear be influencing substation scheme design and development. This may be appropriate and efficient although increased transparency would be beneficial in this area.

4.1.4.2 Shunt reactor replacement

NGET indicated in its 1999 Price Control Review submission, that its replacement policy for shunt reactors was to replace on failure, as safety and operational risks associated with the loss of a shunt reactor was generally considered to be acceptable.

However, NGET notes that there are a number of shunt reactors, mostly in the London area, to maintain voltage compliance and planned replacement is considered appropriate. NGET has stated that these reactors are showing signs of ageing. Hence NGET has changed its policy from “replace after failure” to “replace before failure”.

This change in policy preceded the London supply incident in which the shunt reactor at Laleham (NGET source information) was a contributory part. NGET state the change in policy was driven by the perception of increased risk of multiple coincident failures as assets age and condition deteriorates and refer to internal paper (PSC567) which addressed Wimbledon, Tottenham and Hurst substations (1 shunt reactor each) and 2 strategic spares. NGET states that shunt reactors are required at periods of low demand; that all are showing signs of advanced ageing; and that failure of any one shunt reactor would lead to voltage constraints. NGET state 12 weeks would be required to replace a shunt reactor with a 12 month lead time if no spares were available.

It remains unclear whether the importance and risks associated with shunt reactors has changed materially since the London incident or whether the change in shunt reactor replacement policy with is justified. This policy change is material in that NGET’s FBPQ submission contains provision for shunt reactor replacement.

4.1.5 KEMA’s views

NGET has comprehensive documentation providing detailed descriptions of its asset management strategy and policies. There is evidence that these documents are updated on an ongoing basis to reflect changing asset knowledge and evolving experience. Furthermore, a number of NGET’s asset management documents relating to asset specific engineering and maintenance policies are used by the other TOs which further lend credence to their robustness. The documentation of asset management strategy and policies is extensive and thorough but some documents are cross-referenced undermining user-friendliness.

NGET's adoption of intranet based documentation and information suites relating to asset management (e.g. Transmission Procedures and the Asset Health Review Process, as covered later) is a positive development. This provides an effective basis for maximising access to asset management policies and procedures and here NGET's approach represents leading practice.

Whilst NGET's documentation is extensive and accessible, this does not guarantee that the strategy and supporting policies are robustly applied in the derivation of asset replacement forecast for the capital plan. A key aspect is the progression from condition assessment via asset replacement prioritisation to the "unconstrained" and "constrained" capital plans.

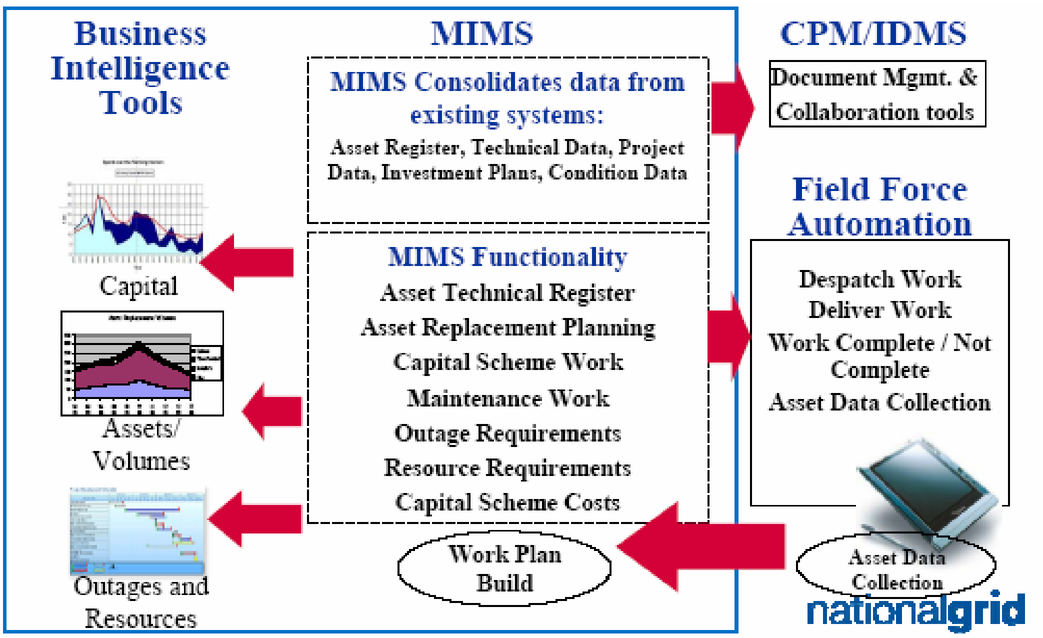
KEMA has noted an example of a policy versus practice inconsistency. Specifically the policy of replacing Category 1 transformers within 5 years was not implemented within the HBPQ period and this was not attributable to asset re-categorisation.

Whilst the development of asset management strategy and policies are areas of strength for NGET, there is scope to improve the detailed application of asset management strategy with respect to the linkages between investment requirements and network risks.

4.2 NGET's supporting IT systems for asset management

4.2.1 Overview of IT framework

NGET employs a number of systems as part of its asset management framework. The current high level NGET asset management systems landscape is shown below:



NGET provided a high level description of these systems and the associated benefits in its HBPQ submission and subsequent presentations. NGET has also provided online demonstrations of the asset management systems such as MIMS and Office in The Hand (OITH), covering their content, functionality and role within NGET's asset management.

The objectives of the asset management "System Landscape" are to capture and centralise all asset data, enable effective centrally coordinated planning and support activities, support peripatetic working in the field and to ensure a standard set of processes is applied throughout NGET in all its asset management activities.

The diagram above shows the central role MIMS plays. Under the Work Asset Management (WAM) Project it was developed to consolidate data from other systems and acts as a central data source for all parties in Engineering services, Network Strategy or others involved in the asset management process, including project data and asset condition data.

The OITH Field force Automation Devices, are linked to MIMS, providing two way information transfers. OITH is used by Engineering Services to conduct asset inspections and maintenance. OITH is also used to collect basic condition assessment data which is uploaded centrally into MIMS. OITH information also updates Engineering Services' own Maintenance Plans throughout the year.

The integration of Technical Asset Register information in MIMs (from a previous system known as AMIS) with the asset information already held supports the activities identified above. It is now also being used to feed into developing Business Intelligence Tools to enable more effective planning of the capital programme, maintenance outages and resource planning.

It is important to note that this asset management "systems landscape" has been developed during the HBPQ period and thus a number of IT systems have been implemented within the current Price Control period. For example, the improved functionality of MIMS delivered under implementation of the WAM project was a fundamental initiative central to this systems landscape. Originally sanctioned at c. £10m the costs of implementation have outturned at approximately £21m. Similarly the OITH system which facilitates mobile field force working was also originally sanctioned for approximately £10m implementation cost but has outturned at c.£21m, including anticipated 2005/06 expenditure. The first two WAM Business Intelligence applications 'Aggregated Scheme and Asset Data' and 'Project Scoping Model' were delivered in August 2005.

Further WAM Business Intelligence Solutions, integrating asset performance and condition data, have been delayed pending the outcome of the Transmission Business Process Review but delivery is expected towards the end of 2006/7. There are also planned further enhancements for MIMS and OITH. NGET's FBPQ Submission indicates that this systems landscape continues to evolve and develop and it is noted that some £30m of IT expenditure on asset management systems is planned in the FBPQ period.

4.2.2 NGET's Asset Health Review System

The Asset Health Review system is the backbone of the NGET asset management process, as it essentially collates all knowledge about the assets on NGET's transmission network including any current and/or emerging asset issues.

NGET indicates that, historically, the Asset Health Review (AHR) was published annually as a set of 9 Engineering documents consisting of 8 Equipment group documents and a Summary document. In 2002, NGET established the AHR process as it is applied currently. A key feature is that the AHR process is now web-based. The AHR now has its own dedicated site within NGET's intranet which KEMA has extensively examined on-site. This enables easy (and controlled) access throughout the company. Within the AHR website, there are two distinct categories of information, namely;

> REVIEW – this section contains current information on asset health issues in seven generic sections, namely (i) equipment condition and performance, (ii) maintenance, (iii) refurbishment, (iv) issue management, (v) contingency management, (vi) asset replacement and (vii) action list; and

> KNOWLEDGE – this section contains "knowledge-based" information specifically relating to the equipment group and was originally compiled with the help of technical specialists from around NGET but is now maintained and updated by Asset Strategy, within the Network strategy directorate.

The AHR website is "owned" by Network Strategy and it is its responsibility to manage it to ensure that it is comprehensive, accurate and current on an ongoing basis. Within Asset Strategy there are nominated individuals specifically responsible for managing sections of the AHR website, for example a designated equipment group.

Whereas the AHR website is a continuous process, underlying this is a stream of AHR meetings by equipment group. These are regular meetings at varying frequencies by equipment group depending on the amount of prevailing issues which need to be addressed. These AHR meetings review asset condition assessments and asset replacement scheme prioritisations within the equipment group.

A monthly AHR report is provided to the Transmission Performance and Assurance Group (TPAG) which is currently chaired by a direct report to the Director of Network Strategy, although the chairmanship of this group rotates across Network Strategy, Engineering Services and the GBSO on a six monthly basis.. This monthly AHR report identifies the latest issues arising across the equipment groups in that month. Where major issues arise within the AHR Report, such as when OHL fittings failures were first recognised as being widespread, these can be further escalated to the Transmission Operation Committee (TOC - a committee covering all asset management issues) and/or the Transmission Project Sanctioning Committee (TPSC - a committee covering all asset investment decisions) where there are implications for either Capex or Opex. These committees report to the Transmission Executive Committee, where any major issues are resolved.

4.2.3 Office in the Hand (OITH) and Work Asset Management (WAM)

NGET's asset management processes and systems have been developed during the current Price Control period. Two important Information Systems were implemented including Office in the Hand (OITH) and functionality improvements to MIMS as part of the Work Asset Management (WAM).

Given the high costs of implementation and the degree of over-forecasting against sanction, KEMA asked for quantification of the value and benefit WAM and OITH have provided to NGET in terms of improving its asset management and related capital investment performance. NGET indicated that the implementation of OITH and WAM as part of its 'Staying Ahead' and 'Ways of Working' initiatives in 2002-04 contributed to NGET's ability to shed 244 Engineering Services staff delivering a cost saving of £9.6m (per annum presumably) but also has improved the effectiveness of asset management processes to which it has not sought to put a financial figure.

In the relevant sanction paper obtained for OITH, dated December 2002, NGET was projecting 4 year NPV benefits of £3.3m (at 15% discount rate) for OITH on an expenditure of £8m-£9.5m. However to note that the selection of OITH implementation option was primarily driven by a need to meet a March 2003 delivery date i.e. to enable delivery of cost savings for Financial Year performance following the NGET/Transco merger. This was a challenging timeframe for an IT and organisational change of such magnitude.

Implementation of OITH was subject to problems as demonstrated by the late delivery in August 2003 (98% implementation). A re-sanction paper raised in May 2004 for an additional £5.2m to enhance OITH after 8-10 months operational experience demonstrated the need for functionality improvements. The impact was a 4 year Net Present Value loss of £1m.

In the relevant sanction paper obtained for WAM, dated March 2003, NGET was projecting 5 year NPV benefits of £6.5m (at 15% discount rate) for WAM on a mid-point expenditure of £9.8m (within a range of £8.8m - £10.8m plus £1.6m risk contingency). This was to be delivered from £6.6m of productivity gains, £0.4m of improved revenue capture from connection assets and 2% capital efficiencies from more stable capital planning and more efficient outages/works.

As for OITH, it was necessary to re-sanction WAM in May 2004. The re-sanction paper indicates NGET required an additional £5.4m above the initial upper sanction value including contingency (£12.4m) for WAM. This was predominantly for Opex required to secure system integration resource for ongoing development of WAM. The impact of this re-sanction (as granted) was to reduce the NPV benefit to £5.4m.

Looking forward NGET indicates in its FBPQ that it intends to commit £19.4m on OITH, £18.1m of which is to replace mobile and central system hardware, £1.3m of which is to improve functionality of the field devices to align with latest NGET asset management working practices.

Similarly NGET indicates that it intends to commit £13.3m on WAM of which £9.7m is hardware related to maintain existing service, £1.2m is to put in place more effective system interfaces relating to (a) long, medium and short-term outage planning and change management and (b) scheme document management, asset data collection and supplier collaboration, and £2.4m is to introduce new business intelligence tools; namely (a) Capital Monitoring & Reporting, (b) “What If” analysis on Capital Plan, (c) Asset Performance & Condition Analysis, (d) Work and Capital prioritisation based on multi-condition asset criticality, (e) Resource Management for maintenance & capital work, and (f) Capital & maintenance risk assessment & mitigating action management.

4.2.4 KEMA’s views

In terms of asset management processes and systems, NGET’s Asset Health Review (AHR) process and “system landscape” represent a good approach and provide the basis for effective asset management. However, the robustness of the different parts of the “system landscape” varies and that the detailed architecture, functionality, and interactions are evolving. Capital investment is required simply to maintain the robustness of the architecture in relation to OITH and WAM and relatively little investment is being made in further evolving the functionality of these two systems to increase the effectiveness of NGET’s asset management.

NGET’s AHR process is a positive development which makes core asset management information widely accessible. There is evidence that AHR underpins NGET’s asset management activities from information gathering on asset families, and coordinating condition assessment of assets to identification of prioritised candidates for asset replacement. The process is not simply an IT system but also incorporates working practices which should ensure most effective capture and use of asset information in the key asset management decision processes. NGET’s adoption of this AHR process puts it to the forefront of TO practice.

NGET’s OITH and WAM systems are each, in principle, important and positive developments in supporting NGET’s asset management activities. Each provides information and capability which should enable more effective asset management in the areas of condition assessment and outage planning but also, given future enhancements in functionality, capital planning. However, KEMA is concerned that, whilst the underlying principles and objectives behind OITH and WAM are sound, the chosen solution and implementation costs associated with OITH and WAM are less satisfactory.

In the case of OITH, there is evidence in the sanction paper to suggest that the solution adopted was driven by an artificial timeframe requirement. Specifically it seems that that targeted delivery of OITH by FY2003/04 was to enable Opex savings to be realised via reorganisation and associated headcount reduction initiatives. This desired timeframe precluded alternative and arguably better OITH options from a purely asset management perspective and overlooked key organisational and practical issues. It also required a high risk rapid deployment of OITH without any pre-testing. In combination with an apparently flawed initial reorganisation of Engineering Services which needed correction within 12-18 months, this meant that the implementation of OITH was not only costly at almost double original estimate and ironically late but also ineffective leading to a direct impact on NGET’s maintenance activities (although some of this reduction is attributable to post Transco merger financial target issues)

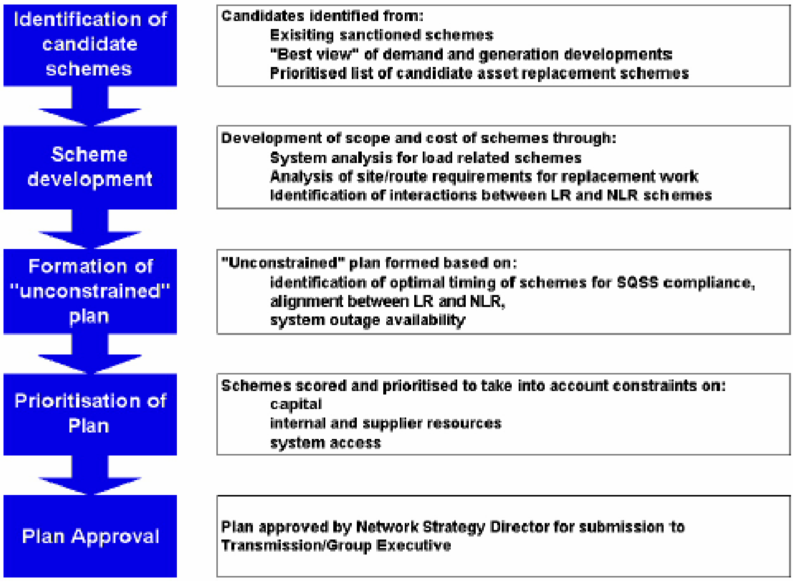
Also for WAM, NGET's choice of solution appears complex and bespoke and has thus occurred high costs, almost double originally expected. Continued high cost of maintaining functionality of hardware and interfaces are evident in the FBPQ.

4.3 Capital planning

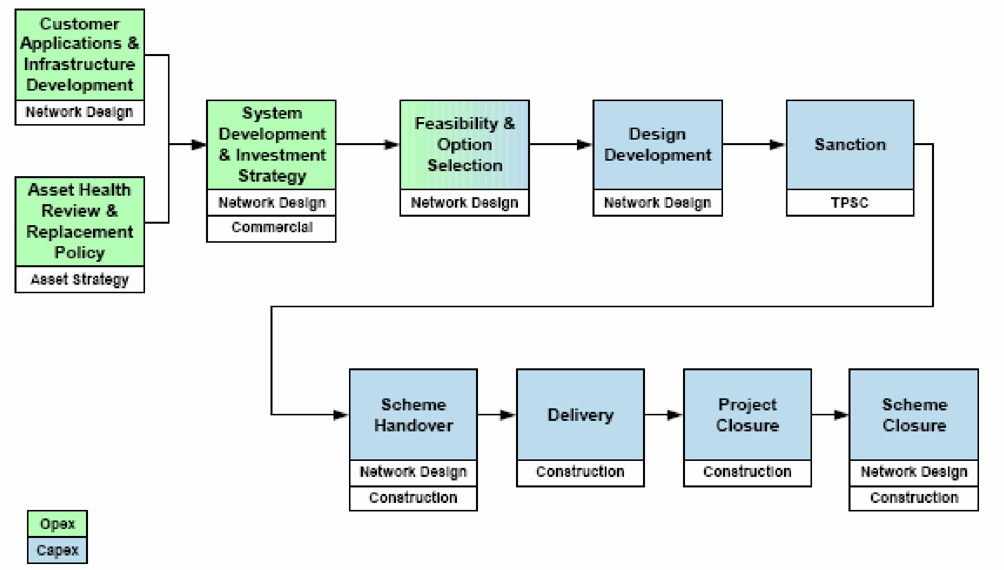
The capital planning process should seek to optimise the timing of asset replacement.

4.3.1 Outline of NGET's capital planning and scheme process

NGET characterises its capital planning process in 5 stages from scheme identification through to the formalisation of the final Capital Plan. These stages and their elements are illustrated below.



NGET indicate this process is in practice a live process which carries on throughout the year and the "live" Capital Plan is updated on a monthly basis, as discussed later. Nevertheless, each year an annual Capital Plan is established to underpin the NGET Business Plan and it is this which would be used as a benchmark for monitoring internally by NGET and in the case of the December 2005 Capital Plan is used as the basis for NGET's FBPQ Submission. Underpinning this capital planning process is the scheme process as illustrated below:

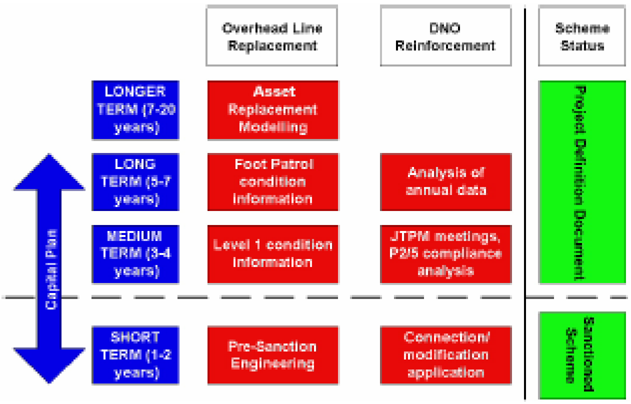


The key point to note from this chart is the sequential nature of the process. KEMA accepts it is an illustrative high level diagram, and NGET's relevant capital planning procedure TP146 does indicate feedback loops exist but these are predominantly within each high level stage or between adjacent stages. Workshop discussion confirmed that further feedback loops could be introduced to refine the process, e.g. where a scheme design choice is based on a projected cost which turns out to be inaccurate (and thus may validate alternative options). KEMA believes there could be greater feedback and/or iteration between stages and management tiers without imposing unduly onerous governance requirements or excessive timeframes. KEMA is concerned that the process as outlined is overly reliant on the initial integration of area and/or equipment strategies (if any) with individual scheme assessments and on the accuracy of initial scope and cost estimates proposed for sanction. KEMA also has some concerns about the concise/brief and sequential nature of scheme sanction papers (without a view of scheme inter-relationships readily available) which may impair the ability of the sanctioning body to challenge the proposed solution and alignment with network development strategies.

Each stage of the Capital Planning process is now discussed in more depth below:

4.3.1.1 Scheme identification

At this stage the ongoing top-down asset replacement modelling and bottom-up condition assessment of assets is used to (a) anticipate likely replacement volumes and (b) identify the candidates within those volumes. How NGET's integrated approach works on an iterative basis has been described, but as an example of how this works in practice, the full scheme identification (and development) process for OHL and DNO reinforcement (typically 132kV switchgear) schemes is illustrated below:



Here it can be seen how replacement volumes identified at the earliest stages by top-down modelling in ALERT begin to be verified by Foot Patrol condition assessments and as timeframes shorten and condition knowledge improves for potential scheme candidates more detailed Level 1 condition assessments are used to confirm (or drop) the need for these. At this stage the estimated cost for these schemes is based on NGET's Project Definition Document (introduced in 2004).

NGET indicate that in the medium term a quarterly meeting is held with representation from Engineering Services Overhead Lines staff, Operations and Trading (O&T) to provide a view on circuit criticality, Network Design for an overview of the capital plan, and Asset Strategy. The AHR meetings review the most recent condition data on a national, route-by-route basis. Using the views of NGET's experts, together with condition and performance information for the lines, the AHR meeting prioritises the lines for replacement and makes an initial assessment of the likely scope of works (for capital planning purposes). NGET indicate it is not uncommon for the relative priority of schemes to change, for example, as a result of storm damage pushing various routes higher up the priority list, or new condition data indicating that a route's condition is better than anticipated.

Divergence has been identified between NGET and DNO views regarding replacement priorities for 132kV switchgear. NGET appears to assume a more urgent replacement requirement and such divergence is relevant given the proposed volumes of 132 kV switchgear to be replaced.

As highlighted above for OHL, NGET indicate that within the AHR process they prioritise scheme need in parallel with identification of schemes.

NGET indicate that condition and performance ranking algorithms have been developed to assist prioritisation within equipment groups, with the transformer model being the most mature. However, the translation from asset condition scoring to replacement prioritisation requires expert intervention. The process for each primary asset group is described below:

> OHL – NGET prioritises overhead line replacement through the Asset Health Review process. All available condition information is considered by the relevant experts in order to rank schemes for delivery. The condition scoring is done by a subset of those people involved in the Asset Health Review process.

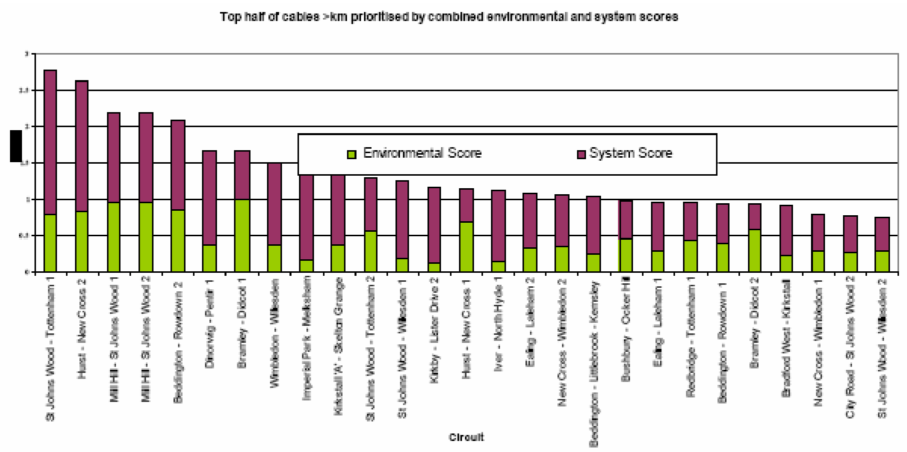
Switchgear – NGET prioritises switchgear replacement primarily with reference to the condition and performance of the associated circuit breaker type, with families exhibiting generally poor condition and performance being targeted for replacement. Within a family, the local operating conditions (duty and environmental exposure) and maintenance regime, refine the priority and associated scoring. In addition, the substation condition assessment programme will evaluate the condition of the general substation infrastructure at the associated site and this assessment will further inform prioritisation scoring.

Cables – a range of cable condition and performance data is gathered into a prioritisation tool which calculates a system performance and environmental performance score for each transmission cable. This scoring is used to inform the order and relative prioritisation of cable replacement and refurbishment schemes included in the plan.

Transformers – all transformers, reactors and quad-boosters have condition scores based upon current and historic dissolved gas and other oil analysis results, family history and electrical test data (where available). This scoring is used to filter the high priority transformers in order to target more detailed condition assessment and risk management. All transformers are assigned a replacement priority, and the condition information available in general increases with priority (and proximity of planned replacement date). Scheme prioritisation scoring is based upon (but not directly derived from) this detailed condition analysis.

Protection and Control – Replacement priorities (scores) are assigned to particular families of protection and control equipment. The scheme prioritisation system utilised by NGET is not optimised for prioritising P&C schemes, which cover a large range of equipment type and a large number of sites. These schemes are more likely to be scaled back rather than entirely deferred as a result of prioritisation. The equipment replacement priority scores would be utilised to identify priorities within the scheme, and thus reduce extent of replacement work covered by a scheme if necessary.

As an example, the chart below shows the ranking approach adopted for cable replacement schemes and illustrates the top 30 priority schemes.



The above chart shows that NGET use a combination of environmental scoring (to reflect the risk and impacts of cable oil leaks on nearby water aquifers for example) and system scoring (to reflect the reliability and impact on system operation) to rank cable replacement candidates.

KEMA has seen similar ranking approaches for all the primary asset categories although each differs slightly to reflect the pertinent drivers of asset replacement. KEMA has also seen how the schemes are scored within the different asset categories and thus ranked.

4.3.1.2 Scheme development

Having identified potential schemes, initial costings are made and consideration of any load related and non-load related interactions are made. All unsanctioned schemes which ultimately lie in the capital plan have these outline costs estimates. This estimation will typically be undertaken by the appointed scheme team which consists of a mixture of representation form across the electricity transmission business but is led by a Network Strategy design engineer. It is important to note that all scheme teams have a GBSO representative i.e. the GBSO and its considerations is integrated into the TO planning process.

NGET has experienced difficulties in the determination of accurate outline costs and introduced a new Project Definition Document (PDD) process in 2004 to address this. Immediately preceding implementation of PDD, cost deviations of closed schemes from their initial outline cost estimates averaged 14% and NGET claim that since PDD this has fallen to 3% (although this does not indicate the range of outcomes).

In the shorter term, more intensive pre-sanction cost estimation is undertaken, especially for OHL schemes. Such schemes are now subjected to further Pre-Sanction Engineering (PSE) cost estimation if included within the Capital Plan (sometimes referred to as “Level 2 condition assessment”). OHL contractors are engaged to consider the available condition information (collecting more if required) and assess the design implications of the proposals in order to arrive at a scope of works, programme and costs for sanction. This process produces an extensive suite of documentation, which is used by the Scheme Team to make decisions such as whether a route requires full refurbishment or whether it is suitable for a fittings only scheme. There is concern that the potential beneficiary of replacement works is involved in establishing the scope of requirement.

NGET’s approach to asset replacement is predominantly route-specific for OHLs and substation-specific for switchgear. An OHL example, is the Walham-Rassau-Cilfynydd Tee route where condition varies considerably from one end of the line to the other. NGET also classifies entire switchgear families collectively with limited inputs regarding individual asset condition, duty or environment. Consequently, there is scope for NGET to increase the granularity of asset replacement decision-making to improve the targeting of investment.

Where scheme tenders are more costly than anticipated, there is an opportunity for NGET to review the effectiveness of the initial scope of work and reconsider the viability of alternative options. In this respect improved feedback mechanism may be beneficial.

4.3.1.3 Formation of "unconstrained plan"

As outlined in Section 4.3.1.1, NGET indicate that scheme prioritisation/ranking is carried out within the AHR process coincidently with scheme identification. NGET further indicate they compile the unconstrained plan from all identified schemes (which have been prioritised within each asset category). Thus NGET develops a long-list of schemes (by asset category) for potential inclusion on an unconstrained basis in the capital plan. Constraints could relate to finances, resourcing and/or outage availability.

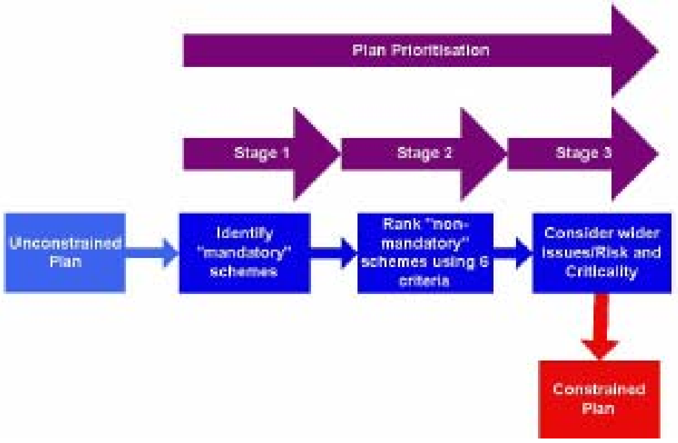
Whilst the development of the unconstrained plan involves selection of potential schemes to be implemented, NGET was not able to clearly explain how the ranked lists of schemes included in the unconstrained plan are rationalised from the original long-list of potential schemes, i.e. it has not been fully explained how NGET decides which schemes will ideally require to be progressed within the time horizon of the plan period (at the scheme identification stage).

Furthermore, NGET indicate the identified and prioritised schemes are entered into an unconstrained plan in line with their optimum placement. However, NGET have not clearly explained how this optimum placement has been determined – it does not automatically flow from scheme identification and prioritisation (and for the latter part of the plan period not all schemes will have been developed).

4.3.1.4 Scheme prioritisation for placement in the constrained plan

At this stage, it is recognised that the unconstrained plan represents a list of schemes felt necessary to be done within the plan period and does not take into account relative scheme priorities, any inter-relationships and dependencies, or the practicalities of resourcing and system access.

Consequently NGET states that it formulates the final constrained plan recognising all these real life factors as illustrated below:



Firstly it identifies all mandatory schemes; these are typically customer driven (i.e. load related) but can be non-load related where there are safety issues. The remaining non-mandatory schemes are then prioritised using a scoring system defined by a policy document known as IM4 - Capital Scheme

Prioritisation Process for which NGET initially provided KEMA with extracts of and subsequently the full current version. The criteria NGET adopts in its scoring system is as follows;

- Condition
- Criticality
- Safety
- Environment
- System Compliance and Capacity
- Finance

A common 0 – 4 (highest priority) scoring system is applied across each criteria for all schemes and then combined to create a total score for each scheme. NGET indicate that when originally adopted in 2003 following sanctioning of PSC291 the 6 criteria scores were combined using the following weightings; Condition = 1/3, Criticality – 1, Safety = 1/3, Finance = 1, Environment = 1/3, and System Compliance & Capacity = 1. Subsequently, when IM4 was revised/updated in Dec 2004 the following weightings were adopted; Condition = 1, Criticality = 1, Safety = 1, Finance = 1/2, Environment = 1, and System Compliance & Capacity = 1. In other words NGET boosted the weighting of Condition, Safety and Environment and reduced the weighting of finance. It is these weightings NGET indicate that were applied in deriving the FBPQ capital plan submission.

Given that condition information is not yet robust across NGET's asset population, when questioned NGET indicates that it use condition information from alike assets if none available specific to a given asset. NGET also indicates that it does not rigidly/mechanistically follow IM4. It indicates that the scoring process is used to initiate debate and decisions to be undertaken in a focussed manner and that there is not a "Line" that can be drawn to delineate between schemes that will or will not be in the Constrained Plans. Whilst NGET accepts that it can be expected that schemes with higher overall scores will be in the "constrained" plan compared to those scoring lower it highlights that care needs to be taken with apparent low scores, where any individual high component score needs to be reviewed, (e.g. a 4 in the Safety category).

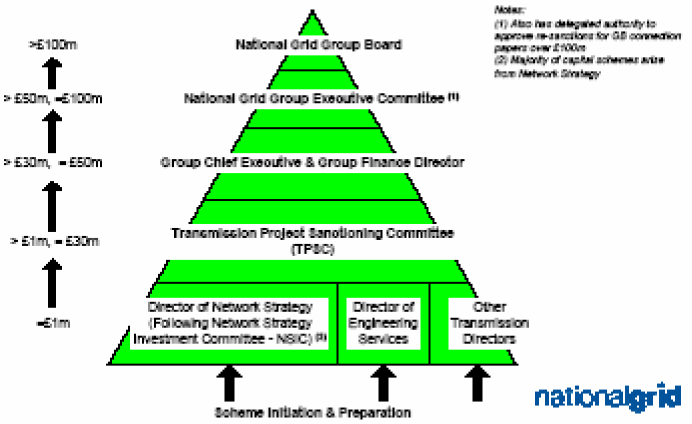
Furthermore NGET indicate that in the case of asset replacement schemes, each scheme will have a condition based driver for replacement, and therefore, the scheme is required. It is therefore usually a case of not "what" scheme is in the constrained plan but "when" will it be in the constrained plan and that the case by case consideration of the scoring and associated risks is about determining scheme placement not inclusion/exclusion. This highlights the fact that there is pre-selection before the unconstrained plan and reinforces KEMA's concern that it unclear as to how this initial stage is carried out as noted earlier.

Finally NGET indicate that wider issues such as resourcing, system access constraints and any scheme inter-dependencies are considered to determine the final constrained plan which will detail not just which schemes will take place during the period but also when.

4.3.1.5 Authorisation of the Plan and sanctioning procedures for constituent schemes

The annual Capital Plan as used to underpin NGET's overall Business Plan is formulated within Network Strategy. It is first signed off by the director of Network Strategy before submission to the Transmission Project Sanctioning Committee (TPSC) for approval. It is subsequently submitted to the NG Group Board by the UK transmission CEO for final approval.

It is important to note that a Capital Plan consists of a mixture of sanctioned schemes (typically at the front end and/or of high value) and unsanctioned schemes (typically at the back end of the plan period). For those schemes within the capital plan which have not yet been sanctioned these are submitted to scrutiny and escalating approval process as shown below:



Essentially the majority of NGET's Capex schemes will require approval at the TPSC after first being approved by the relevant NGET Director. However larger schemes (29 for the FBPQ period) will require sign off by the NG Group CEO and Finance Director. A small proportion of schemes (11 for the FBPQ period) need further sign off from the NG Group Executive Committee and in a select number of cases (3 for the FBPQ period) the full NG Group Board must ultimately sanction the scheme.

It is worth noting that 90% of schemes are generated by Network Strategy and typically comprising the larger schemes. Nearly 10% of schemes arise from Engineering Services generally under "Substation Other". Most of these fall under £1m so are sanctioned by the Engineering Services Director, the remainder requiring TPSC sanctioning. KEMA understands that prioritisation and coordination of Engineering Services schemes is done at working level between Engineering Services and Network Strategy.

This same sanctioning authorisation procedure applies for any schemes which subsequently require re-sanctioning (this will capture deferral or advancement of expenditure). The Investment Scheme Procedure details triggers for a re-sanction, which is required where:

(i) it is believed likely that the outturn cost will exceed the sanctioned range (KEMA notes that from its review of scheme papers the sanctioned range often represents in excess of +/-10% around the target value;

(ii) scheme costs remain within range but there material change in the method of achieving objectives, the level of achievement (what this means in practice is unclear) and the extent of work required;

(iii) it is believed likely that scheme completion will suffer > 3 months delay;

(iv) there is a material change to commercial or contractual arrangements as sanctioned; and/or

(v) there is a material change to method of recovery of costs from the customer.

This authorisation procedure applies regardless of the size of any cost deviation or the re-submitted cost for sanctioning unless it breaches the upper financial authorisation threshold of the original sanctioning body. The table below outlines the volume of re-sanctioned schemes since 2001 – it is important to note that, for example Load Related scheme papers typically consist of connection and infrastructure schemes (i.e. at least 2 schemes), which is why the number of scheme papers is lower and rises less sharply.

Number of Re-sanctions over Price Control Period (to January 2006)

	01/02	02/03	03/04	04/05	05/06	***Total***
Schemes Re-sanctioned	89	63	60	73	103	388
Re-sanction Papers	51	33	38	44	44	210

It is also important to highlight that all the schemes that NGET deliver are subject to a scheme closure paper upon their completion which is escalated to the appropriate sanctioning level. This paper highlights all changes from the sanctioned (or where relevant re-sanctioned) scheme and identifies any lessons which have been learned and thus may need revisions to NGET asset management policy for example.

There does not appear to be a summary available to the TPSC (or other relevant authorising body) providing an overview for a number of schemes completed over a given time period. As the process is sequential, it is unclear how the TPSC is able to take a strategic overview of related schemes and to form a judgement regarding optimisation.

KEMA also notes that the scheme papers reviewed were generally concise and it is not clear that from an engineering solution or network strategy perspective the sanctioning authorities have sufficient information to challenge what is presented. This highlights a clear dependency on the start of the scheme process and the assumptions made by Network Strategy and scheme teams.

4.3.1.6 NGET's monitoring of plan performance and managing changes to the Capital Plan

NGET regards its capital plan as a live document updated by the annual Capital Plans used in the wider NGET business planning. Consequently as part of a quarterly agenda at the monthly TPSC, there is a review of the current status of the capital plan and movements since the previous month. NGET states that this ensures senior management monitor how delivery of the plan is progressing within year and future expectations of the plan evolve over time.

NGET indicate that the Monthly Capex Report includes the latest forecast of total capital expenditure for the current year and over the business planning period (normally the following 5 years). Comparisons are provided of the latest forecast against the Business Plan and budget (current year) positions. A comparison against the regulatory settlement is also included in the report.

Various indicators of plan progress are used in the report to monitor progress. These include traffic light KPIs based on sanctioned levels of work, committed levels of work and actual values of work done. The Monthly Capex Report facilitates TPSC discussion of the overall plan position and development of plan management actions where necessary. The report also provides a summary of how each month's set of sanction papers will impact the overall plan position.

Substantial Changes

NGET note that where changes to the live plan begin to amount to differences from the initial annual Capital Plan this will trigger a need for the TPSC to make the Group Executive aware of the underlying factor(s) and request endorsement to plan revisions. NGET highlighted this was the case in 2004 when the scale of the emergent OHL refurbishment need became apparent.

4.3.2 Allocation of investment between NLRE and LRE

NGET indicates that is generally adopts a simple approach to allocation of schemes to LRE or NLRE Capex categories. It claims the majority of schemes can be relatively easily allocated to LRE or NLRE as the drivers for the investment in the timeframe being proposed are either:

- **Load related** - as a result of entry or exit connection applications and/or resultant infrastructure modifications or uprating, or;
- **Non load related -** condition driven asset replacement schemes.

NGET indicate that for load related (LR) schemes, the resulting work will generally involve the installation of new assets and for the non load-related (NLR) schemes, the resulting work will generally involve the replacement of existing assets.

NGET state that many Load Related schemes will result in the replacement of existing assets before end-of-life. In these cases, for example the replacement of an existing overhead line conductor system to provide increased circuit capacity, all of the work will be categorised as LRE. Likewise, NGET state that many NLR asset replacement schemes will result in provision of additional transmission capacity even though this is not required to meet changes in the generation of demand background. For example, the replacement of an existing ACSR (Aluminium Conductor Steel Reinforced) conductor system with the modern equivalent AAAC (All Aluminium Alloy Conductor) conductor system may provide increased capacity (this will depend on the rating of other elements of the transmission circuit). In these cases, the work will be categorised as NLRE.

NGET indicates that in some cases, it acknowledges schemes have both LRE and NLRE investment drivers. Here, the overall scheme to be taken forward will be a combination of LRE and NLRE work and where practical, elements of the work will be categorised using different scheme numbers.

NGET indicate that where LR and NLR scheme drivers have been identified, the scheme would go forward for sanction in its totality so that the overall proposal can be considered by the sanction authority. Where practical, the costs attributable to the individual LR and NLR elements would be separated out in the Capital Plan according to the predominant driver, specifically;

1) the elements of the scheme driven by the need to uprate the network to accommodate changes in generation and demand would be allocated to the load related scheme; and

2) the elements of the scheme driven by the need to replace assets based on condition information would be allocated to the non-load related scheme.

NGET state that the extent to which work on an individual site or circuit can be separated into LR and NLR schemes is limited by the nature of the work. For example, where a circuit is uprated to meet load related drivers, but the work is aligned with the need to replace the circuit according to condition, NGET claim it is not practical to separately identify an element of cost for the uprating, and an element for replacement. However, where substation works driven by load related drivers are aligned with condition based replacement of a discrete set of assets (such as a number of circuit breakers) NGET indicate it is possible to identify a separate NLR scheme.

NGET indicate that following scheme approval, the costs of the different elements of the work will continue to be updated and reported in the Capital Plan. The individual LR and NLR elements will be individually monitored as the scheme is delivered. The project engineers and project accountants responsible for delivering the scheme will allocate elements of the actual scheme costs to the different scheme numbers.

4.3.3 Asset replacement undertaken within load related scheme expenditure

NGET indicate that whilst quantifying the volumes of asset decommissioning completed under load related schemes is relatively straightforward, it is difficult to convert this into a capital cost allocation. NGET state that LRE schemes often involve a high degree of substation reconfiguration, and it is difficult to identify the proportion of the scheme cost which is strictly a consequence of the assets being replaced and what proportion of the cost is due to the reconfiguration.

4.3.4 Asset replacement which has delivered system betterment

NGET indicate that as part of non-load related schemes, some degree of betterment is commonly achieved, as assets are rarely replaced with assets of an exactly equal capacity or rating i.e. replacement of assets with their modern equivalent often results in an increase in capacity or capability. Furthermore NGET state that where there are load related drivers for increasing capacity, assets are purposely replaced with assets of a higher rating.

4.3.5 Coordination of 132kV asset replacement plans with DNOs

NGET indicate that it provides information on its long-term intentions for the replacement of connection assets on an on-going basis, usually discussed at Joint Technical Planning Meetings. Where NGET claims that the replacement of a connection asset is necessary, it can enforce this under section 2.17 of the CUSC but NGET indicates that alignment of replacement programmes with DNO and directly connected customers is the preferred industry solution and reaching early agreement between parties is always its intention. NGET states that it would seek to enforce its rights under the CUSC only as a result of failure to agree a coordinated approach.

Furthermore NGET indicated that in advance of DPCR4 NGET met with all DNOs with the aim of aligning investment at the 132kV interface, to optimise delivery of substation replacement works planned during this period. Consequently NGET instigated a series of workshops with the DNOs, typically titled “Asset Investment 2004-2010” and that the aim of the workshops was to review asset replacement drivers and strategy and specific investment priorities over the period.

NGET indicate that these workshops were in general in addition to normal JTPM discussions with broader representation on both sides and that to meet DPCR4 submission timescales these sessions were targeted early 2003. NGET claim that this work building on the JTPM framework was generally well received and as a result progress has been made at a number of sites (e.g. Littlebrook 132, Walpole 132).

4.3.6 Capital plan delivery

Sanctioned schemes become the responsibility of Construction to project manage implementation from thereon according to cost and schedule. NGET has noted that it faces 3 key constraints in terms of capital plan delivery:

(i) capital allowance (i.e. Price Review Capex allowance)

(ii) resourcing (both internal and external)

(iii) system access (covering both outage congestion and SO Balancing Services Incentive Scheme) considerations

NGET indicates that in the HBPQ period, the principal constraint was the capital allowance constraint which ultimately was exceeded. NGET has indicated that the unconstrained plan highlighted resource constraints.

4.3.6.1 Outage Planning

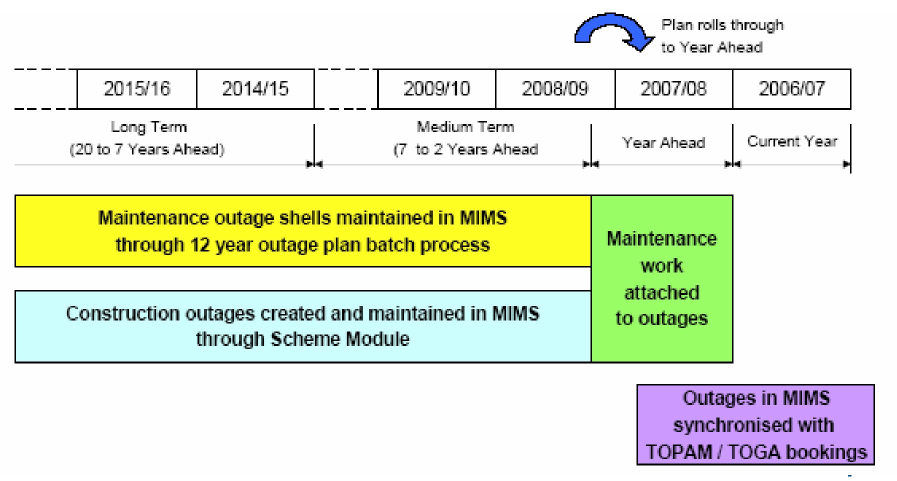
NGET indicate that the management of the outage plan (which is directly linked to the capital planning and resource planning processes) can be considered in terms of the following timescales:

(i) years ahead and longer timescales

(ii) year ahead

(iii) current year including real time control timescales

This is illustrated in the chart below:



Whilst construction and maintenance outages are considered separately, these are coordinated in parallel via MIMS.

In the 2 years ahead and longer term timescales, scheme outages are identified but detailed outage definition and placement are not carried out. The primary decision is the year in which the scheme and the associated outages will be delivered. This activity is led by Network Strategy as part of the capital planning process. NGET state that in the 2 years ahead and longer timescales, outage movements are mainly caused by revised requirements for capital schemes. Often, these will come to light during the detailed development of the schemes. The GBSO representative on the scheme team determines the acceptability of the outage programme.

In the year ahead timescales, there is a high degree of certainty about the capital schemes that will be delivered within the following year and the primary decision is the placement of outages within the year. The main constraint on the phasing of these schemes is the impact of the outages on system security and therefore this process is led by the GBSO, specifically the Operations & Trading (O&T) Directorate. The outage placement also takes account of other factors including scheme completion dates, and internal and external resource constraints. In exceptional cases, more up to date information about the outage requirements for a scheme, or detailed analysis of system security, may lead to the conclusion that, for example, the total outage requirement for a particular system boundary cannot be granted. In these circumstances the first stage is to investigate whether there is scope to reduce the outage requirements for some or all of the relevant schemes. The next stage is to consider the priority of the schemes and decide which scheme should be advanced or deferred.

Within the current year, changes to the outage plan can be initiated for a number of reasons.

(i) System changes, including market behaviour (generation and interconnector flows), demand forecasts

(ii) Scheme changes, including manufacturing delays, site access issues

(iii) Plant and equipment issues including system faults, defects, found on inspection work

(iv) Internal and external resource issues

(v) Third parties including directly connected customers and DNOs

The GBSO manage the outage change process and ensure that at all times the transmission system will be operated securely within the Security and Quality of Supply Standard (SQSS). The available contingencies (including rescheduling maintenance or construction work) are discussed and agreed with Engineering Services and Construction as appropriate. This process is supported by more regular ‘Schemes at Risk’ and ‘Demand at Risk’ cross functional review meetings attended by senior managers..

NGET indicate that within Control timescales, immediate response may be required to ensure that the Transmission system is operated securely. Such actions may include delaying the start of planned outages and returning circuits to service. All circuit outages have an assigned emergency restoration time (ERT) to help manage such emergency situations. Operations and Trading control staff take these decisions, supported if necessary by the Duty Manager who is usually a senior manager. Following such an emergency event, the options available will be reviewed by Operations and Trading planning staff and the current year process described above will be followed to re-optimise the overall plan.

In general, NGET indicate that the processes for decision making in relation to planning and movement of outages in the different timescales are described above and are cross-functional in order to manage the wide range of issues to be considered. However as a rule it indicates that the main criteria are as follows.

- System security;
- BSIS constraint cost;
- Priority of particular schemes, including Customer requirements;
- Asset risks (i.e. plant condition); and
- Availability of internal and external resources.

4.3.6.2 Adoption of the Alliance approach to delivery of the capital programme

NGET are currently in the process of establishing a fundamental new organisational approach to ensure delivery of the capital programme. Known as the Alliance approach it is intended to mirror the approach adopted by NG Gas Distribution. This initiative was commenced in March 2006 following endorsement by the NG Group Board and was a direct outcome of NGET's Transmission Business Process Review between May 2005 and March 2006.

The aim of the Alliance approach is to put in place a number of regional consortia who will become the monopoly provider (in a primary contractor sense) of services and supplies to enable delivery of the capital plan over the FBPQ period. NGET indicate it is driven by;

(i) the rapidly increasing construction workload associated with the capital plan;

(ii) the need to be an attractive client (NGET being a small player in a global market);

(iii) the focus on safety performance;

(iv) the increasing complexity of outage and DNO management; and

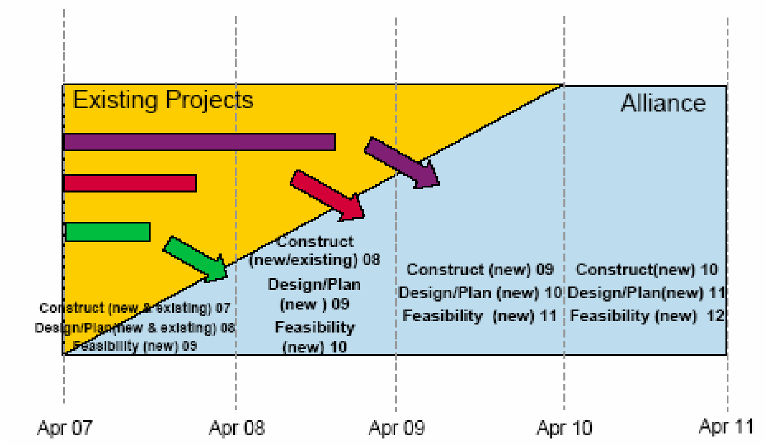
(v) increasing planning consent issues.

NGET has not commented on cost savings as a driver for Alliances although KEMA notes that this initiative resulted from NGET's 12 month Transmission Business Process Review (TBPR) as instigated by the Board to identify major cost efficiencies.

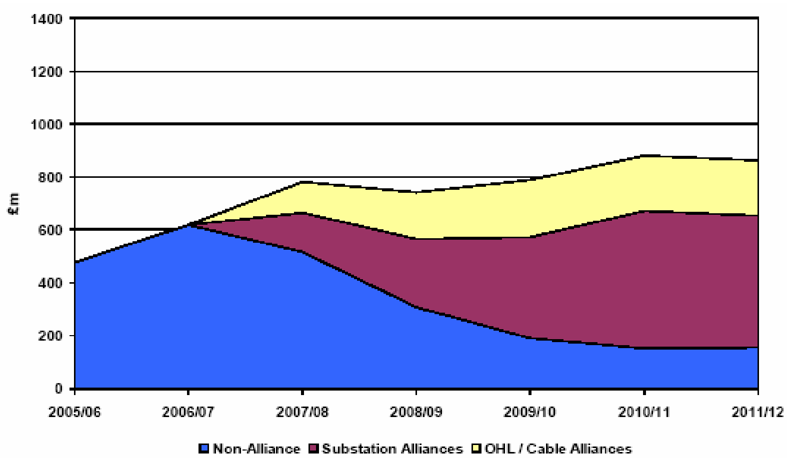
Essentially each Alliance (2 for networks and 4 for substations) will operate as an integrated entity, including NGET staff i.e. Front End Engineers. These area Alliances will be subject to a supervisory board which will in turn report to NGET. The intention is that the Alliances will be able to gain a longer line of sight of NGET's capital plan (say 3 years ahead) and will be asked to plan delivery accordingly. Each year a final budget for the year ahead is set. NGET indicate it envisages that this will be for 75% of the required capital programme in the region, with the remaining 25% being open to competitive tender and/or allocation to strongest performing Alliances (regardless of whether it represents work out of their normal region).

NGET outlines that each Alliance will have performance targets for delivery and that this will include cost related targets. To enhance delivery NGET will also put in place an overarching pan-Alliance set of performance targets. NGET claim this encourages Alliance members to support other members who are under-performing to ensure a collective gain of reward.

NGET indicates its intention to phase Alliances into its capital plan delivery process over three years from 2007/08 i.e. to be in place by 2010/11, as shown below:

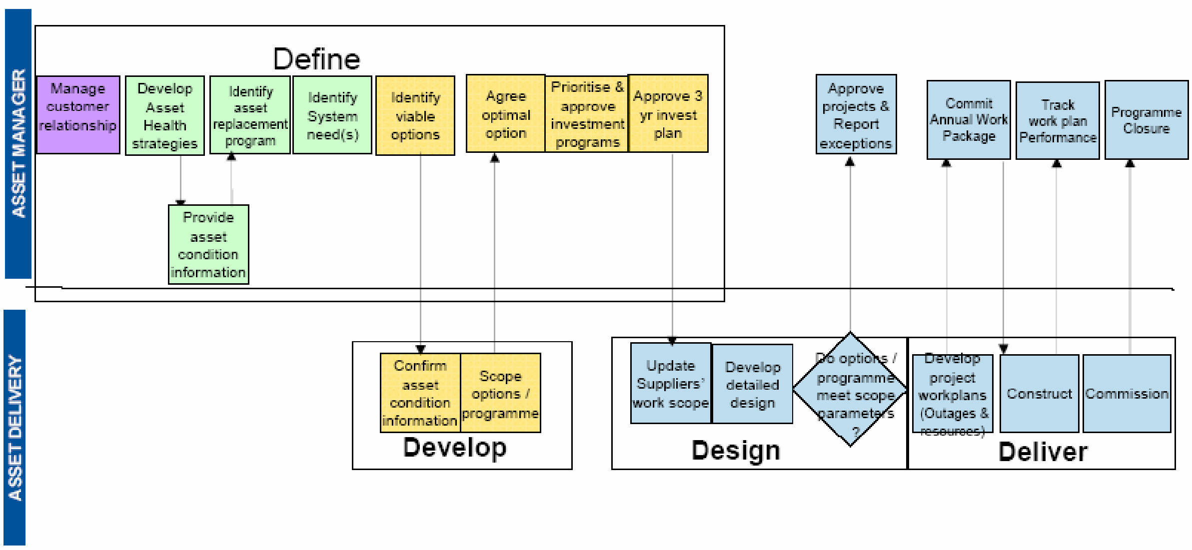


NGET's projected impact on how this will translate into the management of the capital programme rolling forward is shown below:



This chart shows that a residual amount of capital expenditure would be provided to non-Alliance parties, although Workshop discussion suggests that Alliance parties from outside the region could win such work based on competitive tenders and evidence of performance of their core work (and thus it is possible all capital delivery will be retained within Alliance members).

The role and operation of Alliances to deliver the capital programme is under development. The following diagram was presented to illustrate NGET's role as Asset Manager and the Alliances as "Asset Delivery" functions within the capital and scheme planning process.



The process diagram above seeks to show that NGET will retain the role of defining the requirement but that the suppliers within Alliances will become involved in the planning and delivery process at an earlier stage. This diagram raises the following questions;

(i) how extensive is the "Develop" function within Alliance Asset Delivery, eg. does it encompass scheme optioneering?

(ii) how will "rejected" projects at the end of the Design stage feedback into the process?

(iii) who will be responsible for decisions regarding network design within an Alliance area, asset (e.g. substation) design, bulk/long term equipment purchases, and any strategic decisions?

(iv) how embedded will the Alliances and their representatives be within NGET's governance processes for capital planning?

(v) what will be the working relationships and responsibilities of NGET (front end engineering) staff allocated to work within Alliances?

(vi) how will Construction and Procurement function in NGET interface with the Alliances?

(vii) who will drive working practices within Alliance areas?

(viii) what will the relationship be between the Alliances and (a) the GBSO – outage planning, (b) DNOs – coordination of works, (c) manufacturers – purchase of assets/equipment. (d) local authorities – planning permission, environment etc, and (e) land owners – access, wayleaves?

Given the late notification of the Alliance initiative, KEMA is not clear how Alliances will work in practice or how it will impact on the existing processes and resourcing. The Alliances represent a fundamental change and will impact a number of parts of NGET's asset management organisation.

However, if the Alliance initiative is effectively implemented, it should deliver meaningful cost savings across the whole of the capital plan. Therefore, in the context of previous poor price leverage, this is a positive development, although KEMA wonders whether the same cost impact might have been achieved by adopting more sophisticated long term purchase contracts rather than such a fundamental change to NGET's organisation in relation to capital planning and delivery. Nevertheless, in the context of the ongoing Price Review, it is important to recognise that this Alliance approach should deliver procurement efficiencies across the full FBPQ period.

4.3.7 KEMA's views

NGET appears to have a well defined and structured capital planning process. It is not clear how NGET formulate the unconstrained plan as an input into the Capital Plan. Information received suggests that the constrained plan may not be constrained.

In the context of NGET's FBPQ Submission, the issue of capital planning and delivery is of importance and KEMA's assessment of this area from an asset management perspective has highlighted the following:

(i) The scheme and capital planning processes are sequential and is dependent on the quality of inputs at the start of the process. Improved feedback loops would refine the process;

(ii) It is not clear that the sanctioning bodies are provided with sufficient information to effectively challenge scheme engineering solutions or their fit within a wider network strategy;

(iii) There is lack of transparency of the role of the GBSO in determining TO scheme design selection;

(iv) There is a lack of transparency within non-load related schemes with respect to betterment and appropriate allocation of scheme costs;

(v) It is unclear how NGET determines for each primary asset category which schemes should initially be placed within the unconstrained plan;

(vi) Similarly, the process by which the unconstrained plan is converted into the Capital Plan could be more transparent, including identification of which schemes can be deferred beyond the plan period;

(vii) the Capital Plan that is ultimately approved by the NG Group Board appears to be impacted by non-asset management considerations unrelated to UK transmission;

(viii) divergence between NGET and DNO replacement priorities for fundamentally similar equipment types, sometimes located at the same site, where NGET assumes a more urgent replacement requirement;

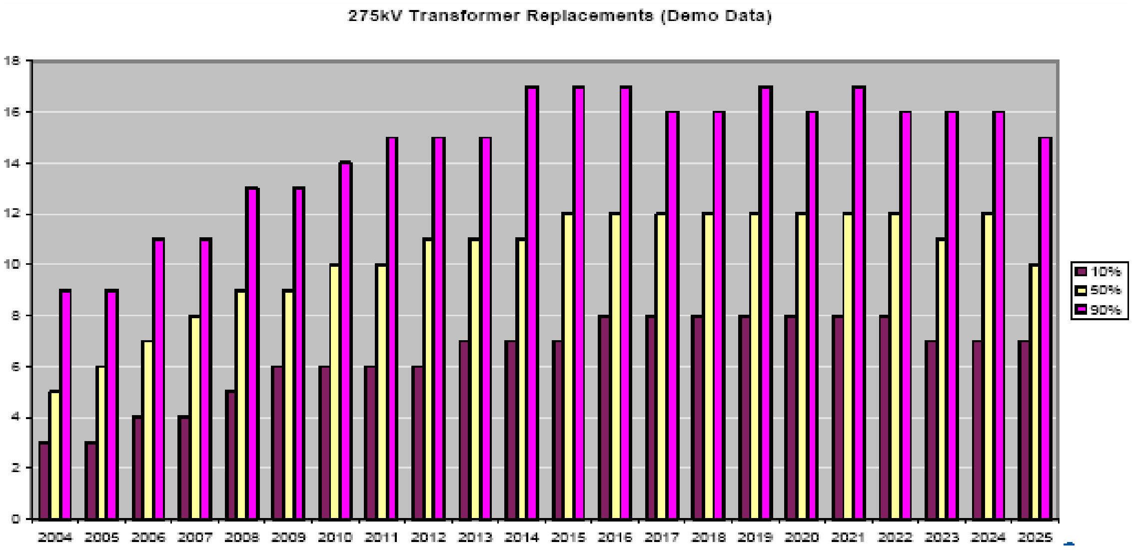
(ix) there is scope for NGET to increase the granularity of asset replacement decision-making to improve the targeting of investment;

(x) the introduction of Alliances for delivery of the capital plan is a fundamental change and it is clear that full implication and details of how this approach will work have yet to be thought through even whilst roll-out is proceeding.

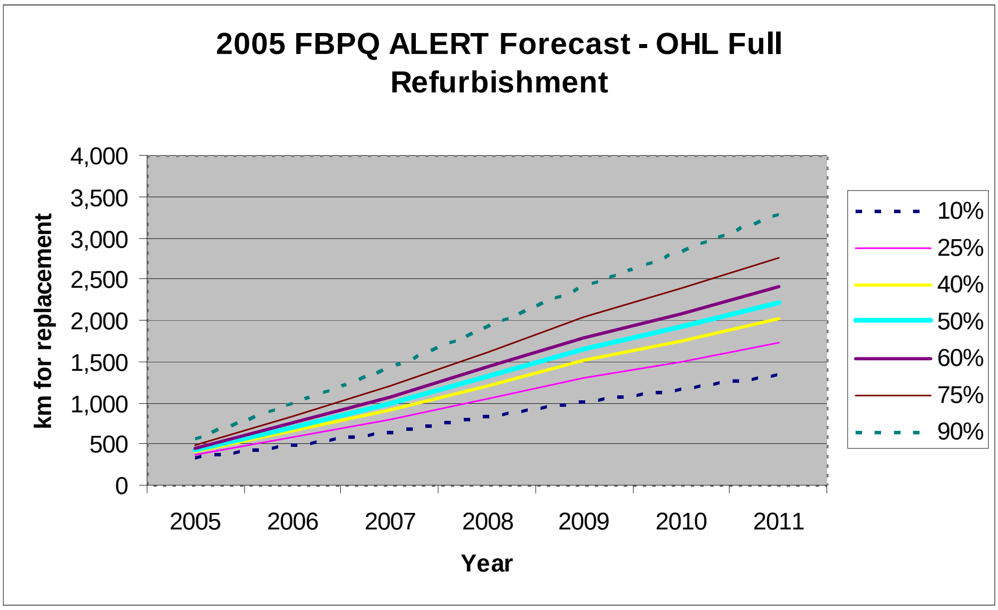
It is noted that, although NGET's ongoing Alliance initiative is at an early stage so that there is an apparent lack of understanding of the detail of how it will operate when implemented, such an approach should not just secure delivery of NGET's expanding capital programme but should enable realisation of meaningful cost savings across the board.

4.4 Asset replacement modelling

NGET uses ALERT for top down asset replacement modelling. ALERT is a Monte Carlo based simulation model, which uses the asset life assumptions to generate a large number of potential asset replacement paths over an extended time period. The user can choose how many paths (or simulations) to run and it is easily practicable to run up to 10,000 simulations which would give confidence in the full range of possibilities is being adequately captured in the modelling. It then considers the asset replacement outcomes each year across all paths to derive a percentile view of likely asset replacement need in that year. As an example, the chart below shows a typical output which can be derived – here it shows the most likely (50%) together with the 10%ile and 90%ile asset replacement likelihoods across the time period.



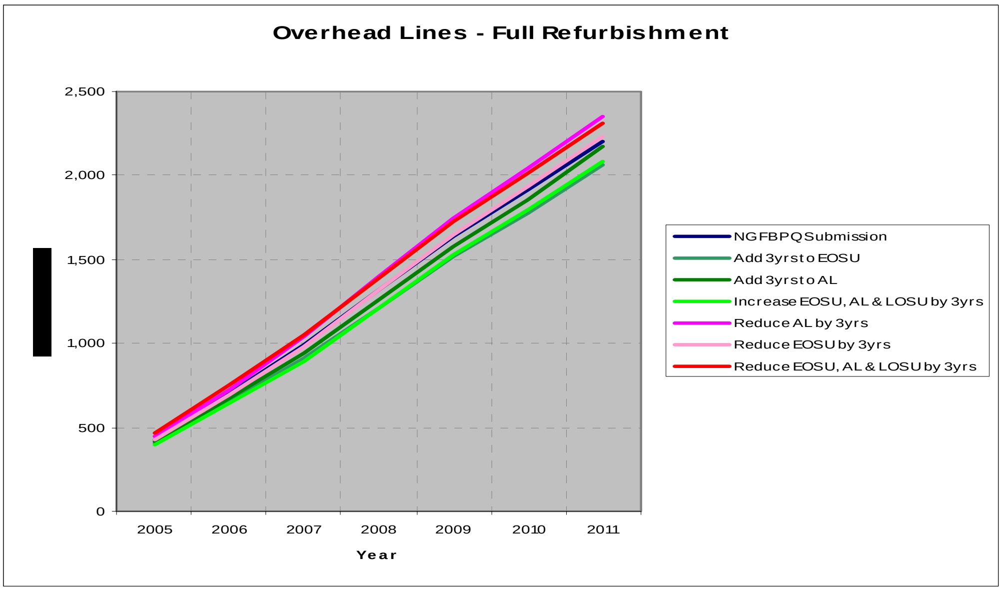
It is important to note at this point that NGET only chooses to use the Median or 50% projection arising from its ALERT modelling. NGET suggests that this is on the basis that there is a 50/50 chance of more or less replacement being required and the bigger the deviation the lower the likelihood. However, KEMA feels it is important to understand the range and shape of the “envelope of uncertainty” that surrounds the Median forecast. KEMA raised a FBPQ question on this issue relating to the range of potential outcomes per primary asset (per annum and over the next price control period). NGET provided answers in tabular which have been converted into charts as shown below:



Such charts provide insightsinto the relationship between the Median forecast used by NGET and the potential range ALERT indicates could arise (and arguably the risks faced by allowing a lower volume of replacement in the first instance). Comparison of these charts highlights the greater uncertainty regarding the volume of OHL work compared to switchgear.

The structure and nature of NGET's input assumptions increases level of sophistication of the modelling process. In this respect NGET have the most sophisticated input structure of any of the 3 GB TOs and is probably demonstrating leading international practice in this area. This does not mean that all input assumptions are necessarily correct. Also it is possible to adjust how inputs are reflected in ALERT e.g. recognising the uncertainty of certain key asset lives assumptions.

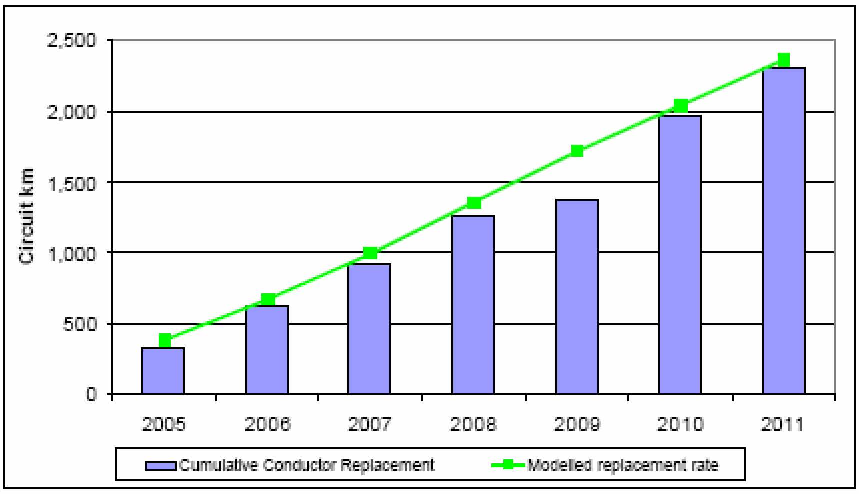
In terms of results and their use, ALERT enables a variety of different analyses of outputs, especially given the sophistication of the input structures. However, it not clear to KEMA as yet that NGET utilise the range of output analyses that could be applied to understand future asset replacement needs and strategies. For example an assessment is to consider the sensitivity of the ALERT forecast to changes in asset lives assumptions. This is important given that NGET adopts a "to the nearest multiple of 5" rounding approach to setting Anticipated Lives (ALs), Earliest Onset of Significant Unreliabilties (EOSU)s and Latest Onset of Significant Unreliabilties (LOSU)s (these factors are explained in section 4.5.2 below). Whilst KEMA has reservations regarding this approach, the derived chart below does illustrate the principle.



This chart would suggest NGET's median ALERT forecast is relatively stable to changes in asset lives assumptions although the credibility of this chart is slightly undermined by the fact that adding 3 yrs to the AL alone has a bigger impact than adding 3yrs to the full asset life distribution.

4.4.1 NGET's emphasis on asset replacement modelling in its planning process

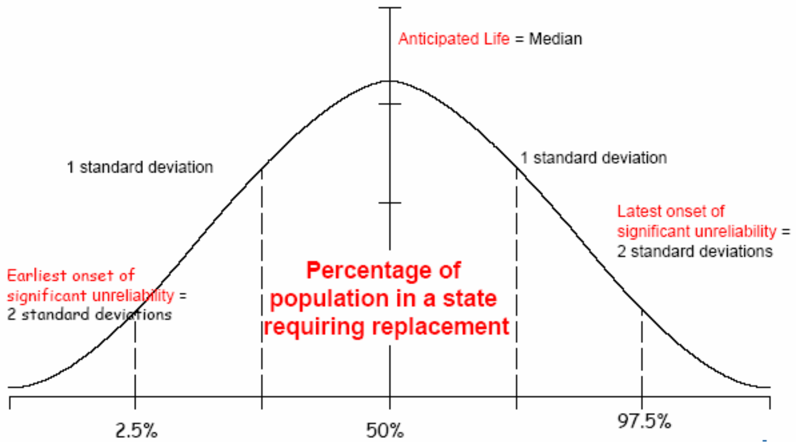
NGET place emphasis on the results from ALERT as a guide to its future investment needs. For each asset category NGET show the 50% ALERT forecast vs. its proposed replacement and use it as a means of justifying asset replacement projections. Furthermore, there is some evidence that some FBPQ schemes have been included to fit the projections arising from the top-down modelling as asset condition information does not align with replacement need. The chart below as contained in the FBPQ for OHL Full Refurbishment is an example.



NGET's FBPQ Submission provides a chart similar to the above for each primary asset category and explains asset replacement projections in the context of the ALERT (Median) projection. As a general rule NGET claim that the ALERT Median line gives the required smooth profile for asset replacement as it takes into account all condition information it retains regarding its asset populations. Consequently, any deviations are typically explained as being due to lumpiness of scheme investments and/or ability to schedule asset replacement in the context of outage congestion issues.

4.4.2 NGET's development of its asset lives

For all asset lives used within ALERT for top down asset replacement modelling a common structure is adopted as illustrated below:



The above diagram is an idealised representation, and NGET claim the actual asset life distributions assumed have been generated from condition based assessments and asset research conducted at Leatherhead. These bespoke distributions can be unusually shaped e.g. skewed. However the diagram does illustrate the 3 key points used by NGET in its ALERT modelling, namely;

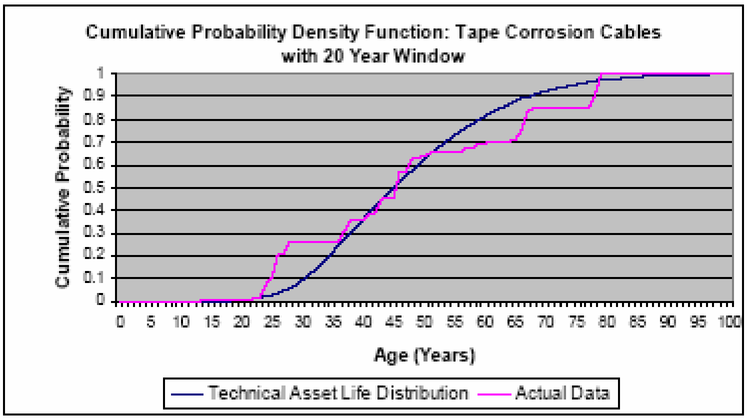
(i) the AL, which represents the age at which NGET expects 50% of those assets to need replacing

(ii) the EOSU, which represents the age at which 2.5% of those assets need replacing; and

(iii) the LOSU, which represents the age at which 97.5% of those assets need replacing

The choice of values for EOSU and LOSU represent standard mathematical practice for capturing the reasonable range of outcomes and NGET has used these to indicate in the HBPQ the status of the primary asset populations. NGET have demonstrated and explained how the values for AL, EOSU and LOSU have been derived from various asset analyses conducted since the mid-1990s. KEMA has investigated NGET's asset life assumptions in greater detail.

An example of type specific asset life information is shown for cables below, which shows a "lumpy" asset life distribution derived from actual condition data examining the degree of tape corrosion for a sample of cables. For the purposes of ALERT modelling a smooth asset life distribution was fitted to this lumpy curve taking into account the sample size and some engineering judgement.



Whilst this seems a reasonable step KEMA notes that a smooth profile does not match actual data especially for a relatively small dataset. Thus there is a risk of over and under replacement expectation of asset replacement at different points in the curve and this reinforces the importance of good asset condition information, condition monitoring and understanding of deterioration mechanisms.

In general, initially set asset lives analyses have been refined and augmented over the intervening years to accommodate new information gathered from condition assessment of asset populations and the emergence of new key asset life drivers and/or components (the exception is transformers which have not changed). To this extent the structure of input assumptions has developed over 15 years into a disaggregated and refined structure.

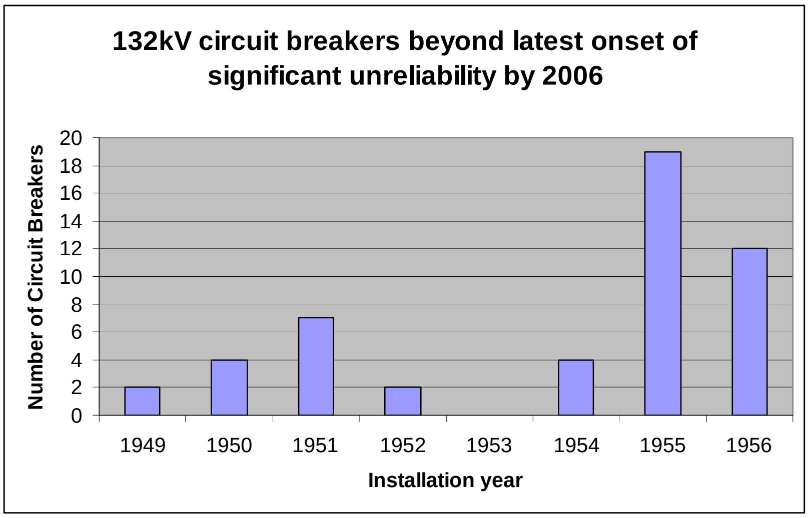
It is important to note that in generating the asset life distributions for ALERT a degree of tolerance is applied. In other words it is recognised that it is not possible to establish asset live values with 1 year of accuracy. Hence NGET has generally rounded asset life parameters to the nearest 0 or 5 figure (e.g. a derived 42 year figure would be rounded to 40years and a 43 year figure to 45 years), giving a maximum tolerance of $\pm$2.5 years.

4.4.3 NGET's asset lives compared to other GB TOs and KEMA's views

Representative asset life assumptions are important for accurate asset replacement modelling and NGET has developed an increasingly disaggregated level (e.g. foundations, towers, insulators, conductors, clamps, fittings, spacers and dampers for OHLs). Furthermore, as indicated above for OHL conductor, it has also further disaggregated, where relevant, a number of asset groups in ALERT by condition factors which have an impact on the life expectancies of those assets (e.g. for towers, (i) degrees of pollution, (ii) wind exposure and (iii) whether painted to policy over lifetime).

This level of disaggregation and input sophistication that NGET adopts is greater than adopted by the other 2 GB TOs, who typically assume only standard lives per asset type.

A comparison of NGET asset lives with those of the other GB TOs and KEMA's assumptions was undertaken. Two examples are provided below where NGET appears to be out of alignment with KEMA's views of asset lives and/or actual asset performance. Here, it can be seen that NGET asset life assumptions are narrower in range than those of KEMA and for non-reconditioned switchgear is at the lower end of the spectrum of potential asset lives. It is these circuit breakers which form a large part of NGET switchgear replacement plans and thus asset life assumptions for these circuit breakers are a determinant of future asset replacement volume requirements. In response to a written question (KE4005), NGET indicate that 34% of 132kV circuit breakers will have reached anticipated asset life by the end of the FBPQ period. In fact at 132kV, approaching 16% of the population has already reached asset life with 6% (50 circuit breakers) now operating beyond latest onset. The age profile of this subset is shown below:

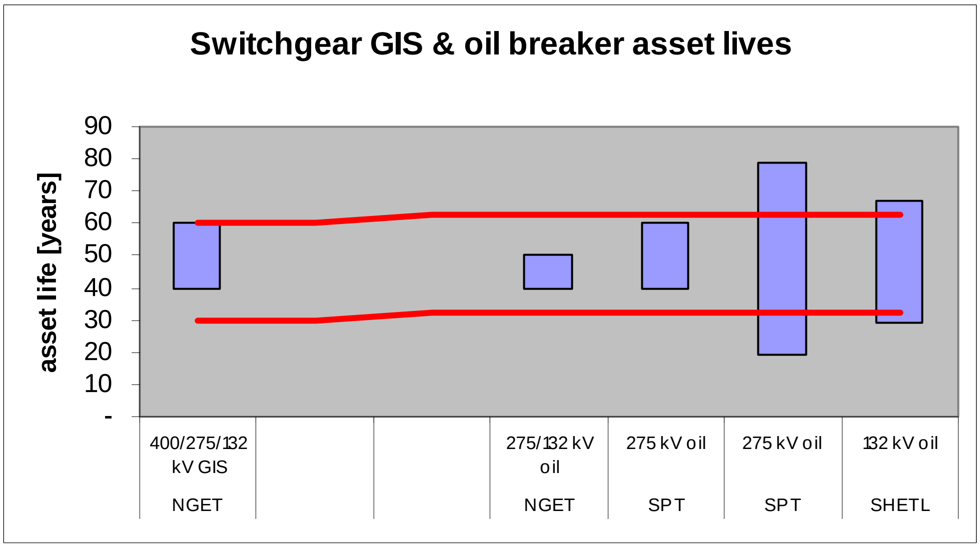


By definition the LOSU for the 132kV switchgear must be incorrect (and it also suggests the AL and EOSU need revisiting) as otherwise half of these assets would be at risk of immediate failure, should have failed. Furthermore, from material provided by NGET there is clear evidence that at least one asset family of 132kV air blast switchgear (OB14s) have low asset lives assumed in NGET's asset replacement modelling given nearly half have reached the nominal LOSU age without evidence of poor performance as highlighted in the table below.

132kV Circuit Breaker Type	Number > LOSU	Total Population
OW410	4	88
XOPR60	1	21
HG6MA	1	7
OFA11	5	43
Frame 'g'	5	63
CA10	1	1
OB14	33	68

The second family of switchgear are oil filled circuit breakers. These are a large proportion of the switchgear that NGET intends to replace in the FBPQ period and there is evidence from material provided that NGET is unclear that the current asset lives assumed for 275kV bulk oil circuit breakers are robust – 21% of 275kV oil circuit breakers having reached anticipated life by the end of the FBPQ period. Over a third of its switchgear replacement programme relates to circuit breakers on which it is undertaking forensic analysis (in the course of removal) to confirm replacement timing need over the FBPQ period. A comparison of NGET asset lives assumptions and those of KEMA are shown below.

The chart below compares TO asset life assumptions with KEMA's. The blue bars show the range of asset lives for each asset family as assumed by the TO. The top of the bar is the TO's Latest Onset of Significant Unreliability (LOSU) assumption, i.e. maximum expected life for asset replacement purposes. Similarly the bottom end of the blue bar is the TO's Earliest Onset of Significant Unreliability (EOSU) assumption, i.e. minimum expected life for asset replacement purposes. In terms of defining the distribution of asset lives for specific assets within an asset family the LOSU represents 97.5% and EOSU represents 2.5% i.e. 97.5% of the assets in the family will become unreliable by the LOSU and only 2.5% would be expected to become unreliable by the EOSU (For a symmetrical distribution, this would represent + 2 standard deviations around the mean). The red lines represent KEMA's view of the LOSU and EOSU for each asset family. Thus in the chart below, for 275/132kV oil switchgear NGET assumes an EOSU of 40yrs and an LOSU of 50yrs which contrasts with KEMA's view that EOSU could be 30 years and the LOSU could be 60 years i.e. in this case KEMA's view is that there is a wider range of potential asset lives for this type of switchgear and that some assets in this family could last up to 10 years longer than NGET assumes.



For oil circuit breakers, NGET asset lives assumptions are tighter in range than the views of KEMA. The red lines in the diagram represents KEMA's view, the blue bars represent the asset lives provided by the licensees. These oil circuit breakers represent a large proportion of the switchgear to be replaced in the FBPQ period and there is evidence the current asset lives assumed for such circuit breakers may not be robust – 21% of 275kV oil circuit breakers having reached anticipated life by the end of the FBPQ period. Over a third of NGET's switchgear replacement programme relates to circuit breakers on which it is undertaking forensic analysis (in the course of removal) to confirm optimal replacement timing.

However, KEMA does acknowledge the systematic and comprehensive procedures adopted by the skilled NGET staff within the Leicester Refurbishment Centre in conducting switchgear refurbishment for certain families of circuit breakers (e.g. OBR60 circuit breakers) which enable asset lives to be extended for these assets.

4.4.4 KEMA's views

NGET's top-down asset replacement modelling is well developed and sophisticated, in particular in its use of disaggregated input structures and bespoke asset life distributions incorporating condition based asset life assumptions.

ALERT is the most sophisticated tool utilised by any of the three TOs and is actively used by NGET in assessing its future asset replacement needs in the medium to long term. It is also equally clear that NGET does revise the structure and level of asset lives assumptions over time as experience of its ageing asset bases continues and it becomes more informed about drivers of performance deterioration and potential asset failure.

However, whilst ALERT is sophisticated this does not mean that it could not be further improved e.g. introduction of uncertainty around AL, EOSU, and LOSU assumptions to reflect for example the $\pm$2.5 years rounding NGET employs. Also, it should be noted that outputs will depend upon the validity of input data and there is evidence that some of the condition based asset lives are apparently out of step with the reality on the network, particularly 132kV switchgear but also 275kV switchgear and transformers.

KEMA notes that throughout the review, NGET has not undertaken any sensitivity analysis of its ALERT modelling. This may be an aspect it has not explored or NGET may be concerned at the insights this may provide. There is also a suggestion that generating ALERT forecasts is a manual process reliant on input structures created by key individuals within the asset management organisation. It remains unclear to KEMA whether NGET utilise the range of analyses available from running ALERT. It also seems that NGET's use of outputs is based on examination of the median forecast. KEMA sought more evidence that sensitivity analyses were undertaken when forecasting asset replacements requirements.

Furthermore, NGET chooses to emphasise its ALERT projections as a validation of its proposed asset replacement in the FBPQ period. There is clear evidence in the case of transformers that these have acted as target lines for the identification of relevant scheme candidates regardless of the condition based need for asset replacement. Consequently there is an underlying concern that NGET's development of the capital plan, in some areas, at least for the purposes of the Price Review, may be influenced by the outputs of ALERT and may insufficiently base its formulation on robust condition based assessment and identification/prioritisation for replacement.

4.5 Condition assessment

4.5.1 Input from inspection & maintenance

Inspection and routine maintenance is undertaken by Engineering Services staff (and in some instances contractors). Until 2002/03 this area of work was carried out under a regional structure and thus inspection and maintenance practices varied between different parts of the country. It was also largely divorced from bottom-up condition assessment of the asset base by the relevant responsible staff within NGET (now Network Strategy).

However, since the emergence of a national Engineering Services structure during the HBPQ period, the implementation of NGET's Office in the Hand (OITH) devices and the evolution of NGET's asset systems under the Work Asset Management (WAM) project, there is now a clear linkage between asset inspection and maintenance activities and bottom-up condition assessment activity managed and/or carried out by Network Strategy.

For example embedded within the electronic maintenance scripts held on OITH are a few key condition assessment questions. These are used by Network Strategy to enhance its understanding of the current and evolving condition of the asset population(s).

WAM has delivered a central system(s) linking the technical asset register to maintenance and condition history. It is accessible by Network Strategy who are responsible for setting asset strategies and policies (including maintenance), and by Engineering Services, who are responsible for undertaking the inspections and maintenance to develop a common view of the state of the asset base. It also facilitates communication and coordination between Network Strategy and Engineering Services in understanding and addressing key issues in relation to asset condition.

KEMA understands that, whilst OHL inspection and maintenance is predominantly driven by condition assessment and thus the status of particular routes, the remaining primary assets are typically inspected and maintained on an interval based policy, albeit informed by the general condition of the asset population or major sub-families.

4.5.2 Asset condition assessment techniques used by NGET

The nature of detailed condition assessment varies by asset category. NGET undertakes a number of different condition assessment techniques for each primary asset category and varying associated frequencies. Details of the condition assessment techniques applied are provided below for each primary asset group. (We highlight that the information for OHL is the most extensive).

4.5.2.1 OHL

Prior to 2002, overhead line inspections consisted of foot patrol and helicopter patrols only. These patrols were carried out to meet statutory requirements and to identify defects. Decisions regarding refurbishment were based on asset age and local knowledge, not on information from these inspections. Since this time, the role and content of inspections has been reviewed and the output built into the Asset Health Review process. The current range of in-house overhead line inspections are:

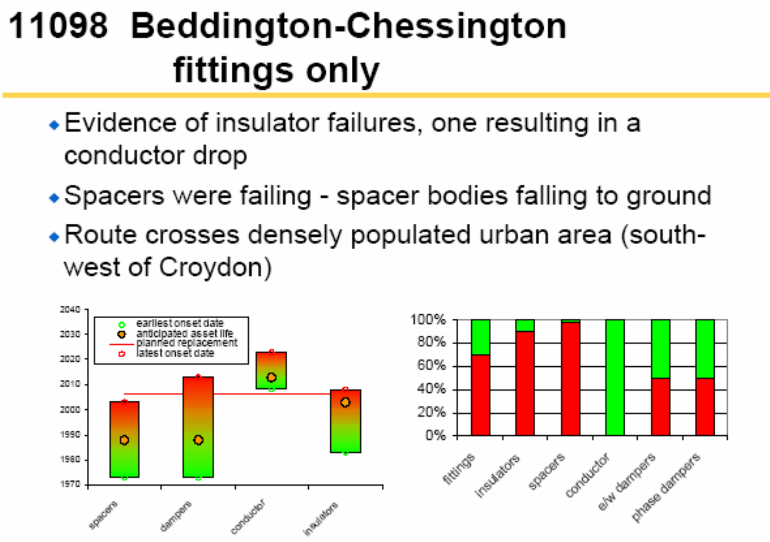
- **Foot Patrols**
- **Level 1 Condition Assessment (**non-outage climbing inspections)
- **Helicopter Patrols**

NGET also undertake further “hands-on” condition assessment:

- **Conductor Corrosion Monitoring**
- **Conductor Sampling**

Also, in addition to the above, NGET indicate that the opportunity is taken during selected capital schemes to examine the condition of components that are removed. Finally, “Research & Development” projects are undertaken to advance NGET’s understanding e.g. one current project is to confirm a technical asset life for AAAC conductor.

The outcome of the detailed condition assessments allows NGET to formulate an understanding of complete circuit routes as shown below.



This example shows a route where the fittings required replacement whereas the conductor was in good condition, resulting in a Fittings Only OHL refurbishment scheme.

For OHL such analysis would identify the scheme need priority. Subsequently NGET commissions an additional detailed Pre Sanction Engineering (PSE) exercise by external contractors to assess the detailed scope and cost of associated works for that scheme. It is this PSE determined scope of works and costing which is then submitted in the relevant scheme paper for sanctioning. NGET initiated the PSE stage in 2003 due to emergent scale of OHL refurbishment needs and a need to avoid over-expenditure. PSE work is expensive at c. £0.5m per scheme but does enable cost savings from improved scoping of replacement and refurbishment works.

Although NGET has reinforced OHL condition assessment during the historic price control period, NGET has not yet assessed the condition of the entire network. Good examples of this are the Bolney – Lovedean (full refurbishment 2010-2012) and Bramford-Norwich (fittings only - 2011/12) routes where conductor type/condition is not fully documented. Such details are important as NGET acknowledges that asset lives for fully greased conductor are some 5-10 years longer than core-greased and such information determines the timing and scope of related asset replacement. Simple swapping between a full refurbishment scheme and a fittings-only scheme is material – for quad conductor routes the cost ratio is c. 3:1 and for twin conductor routes is c.2.5:1 (these ratios essentially being valid for short, medium and long lengths of route) - and the implications for outage planning are significant.

KEMA notes here that it is apparent that whereas NGET does try to develop a refined condition assessment of an OHL route, it adopts a relatively unrefined approach to associated OHL asset replacement. For example, for OHL, NGET generally apply a full route approach to associated replacement irrespective of route length and variable condition along the route.

4.5.2.2 Towers

Towers lend themselves to visual inspection by Foot and Climbing Patrols, the latter being prioritised within the overall prioritisation of OHL routes for potential asset replacement. Corrosion is the principle driver of limiting tower life and is dependent on the degree of pollution (industrial and/or saline) and exposure which a tower faces in its local environment. NGET use a sophisticated assessment of pollution provided by an external provider. Towers are graded from 1 to 6 based on the state of the steelwork i.e. the amount of rusting apparent, according to clear criteria supplemented by pictorial examples as shown below:

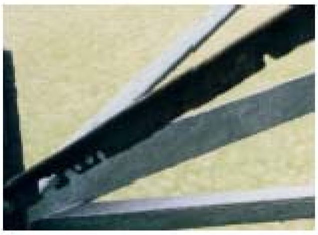
Grade 1

Grade 2

Grade 3

Grade 4

Grade 5



Grade 6

NGET also undertake loading analysis which, in conjunction with the assessed state of the steelwork for each strut of the tower, can determine the risk of failure and component criticality to provide an overall view of the tower strength. This allows NGET to undertake partial refurbishment of towers rather than simply undertake wholesale replacement of the towers, thus minimising expenditure and also outage durations and thus circuit disruptions especially for routes from a system operation perspective.

It appears that NGET is applying leading practices in relation to condition assessment of its towers, and whilst tower replacement is not a major feature of the future capital plan, it is notable that the condition information that NGET is acquiring facilitates an efficient and sophisticated approach to determining required wholesale or partial tower refurbishment and tower maintenance (e.g. painting) in a timely manner.

4.5.2.3 Cables

As would be expected, cable condition assessment is more difficult due to the cables typically being directly buried and thus not easily accessible.

The primary drivers of deterioration in cable performance and ultimately failure are tape corrosion, oil leaks and stop joint failure. An example of tape corrosion is shown below:

NGET indicates that tape corrosion in particular is an issue which causes it problems for lengths of pre-1973 BICC and AEI cables it installed. However NGET also indicates that in recent years it is seeing an increasing trend in stop joint failures. Cable outages are disruptive and typically lengthy in duration as the pictures below of an investigation into a stop joint failure on a 400kV cable demonstrate.

Thus NGET aims to avoid overly-frequent outages simply for condition assessment. This approach is reinforced by the fact that many of the HV cables on NGET's network are important in securing power flows into London. Consequently, typically condition assessment is only conducted during outages for mid-life refurbishment or required to remedy a fault

Clearly oil leaks are an indicator of deteriorating performance and NGET now monitor closely cable oil leaks both to seek to minimise their impact and to identify any signs of an escalating problem. Cable faults are another sign of deterioration in performance. It is these two factors in combination with the environmental and operational consequences which are used to identify candidates for asset replacement.

As part of NGET's drive to improve environmental performance of its cables and given the impact on operations, cables have become a prime focus for NGET with the establishment of a National Cables Manager to focus exclusively on all cable issues and thus is an area which has improved in the last few years. KEMA has seen a number of actual documents, reports, analyses etc for some cables across the NGET network which leads to the view NGET has reasonable condition assessment information for its cable population.

4.5.2.4 Switchgear

NGET conducts detailed reviews of switchgear operational performance using internal and external technical specialists. Such reviews are then documented to produce a comprehensive reference source for performance of all types of switchgear. Using this document, NGET conduct targeted substation condition assessments to review and document infrastructure condition. Since 2005, this has been supplemented by embedded condition assessment scripts within the electronic maintenance scripts in OITH used by Engineering Services field staff. Approximately 50 substation assessments have been undertaken since 2001 and 14 are planned for 2006. These substation assessments are comprehensive and entail detailed condition assessment for switchgear and site infrastructure such as civil engineering structures, air systems etc. These detailed substation assessments are used to identify the need for investment and to assign relative priority i.e. condition scoring to enable NGET to prioritise investment.

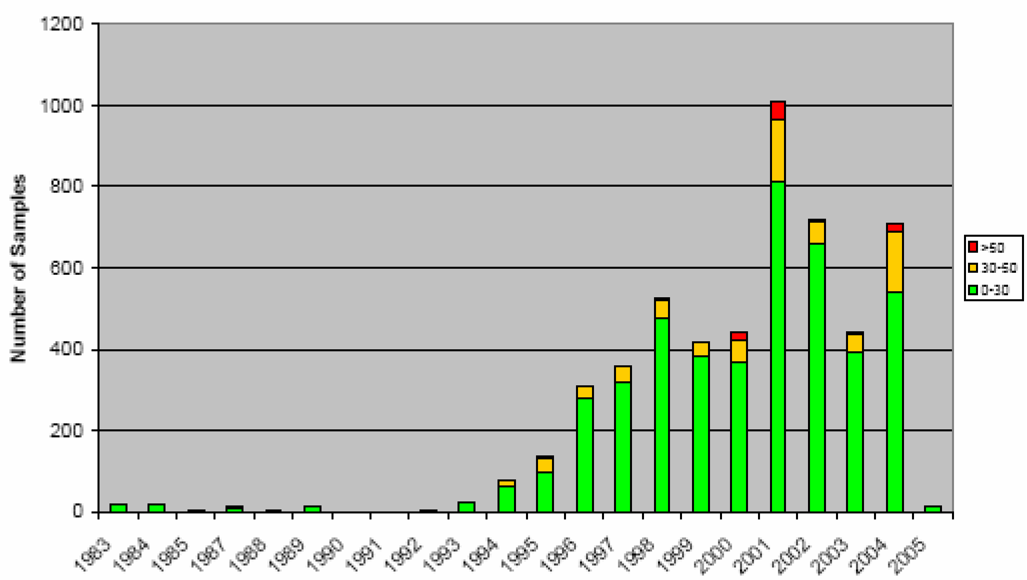
NGET indicates that there is a dedicated team that carry out substation condition assessment. The condition of each asset is assessed and corresponding replacement dates are allocated. Network Strategy will use this information to derive a refurbishment and/or replacement strategy for the whole site. The substation condition assessment may also lead to an enhanced maintenance regime being implemented to mitigate any performance and safety risk in advance of asset replacement.

NGET also indicates that, where appropriate, only selected components are replaced. However, NGET do indicate that, due to increasing outage congestion, the standard practice is to replace all the assets in a bay at the time of replacement of the primary asset. In a number of cases, ageing substations are being replaced completely, which addresses the needs of all site assets, the deliverability of the solution and the need to facilitate any necessary rating enhancement.

In addition, NGET conduct extended forensic investigations of switchgear. This has been carried out for switchgear which failed in service but also (more recently) where switchgear has been removed from service as part of asset replacement schemes. This has included air, oil and SF6 circuit breaker assessments, although NGET now claims it has sufficient knowledge of older switchgear that it is focusing such forensic investigation on the newer switchgear families. NGET state that the information captured from these detailed strip-downs will help to inform future replacement/refurbishment policy and further validate asset life models. As can be seen from the table below, these families represent a significant proportion of NGET's proposed switchgear asset replacement expenditure (c.40% of proposed FBPQ investment).

Switchgear Family	Proposed Replacement Volume	Total modelled Replacement Cost
JW420	68	£120.5m
Frame r	39	£69.1m
OHBR140	0	£0
OHBR60	19	£33.7m
300SPL	7	£12.4m
300FE2	0	£0
FQ4 & Committee design	0	£0

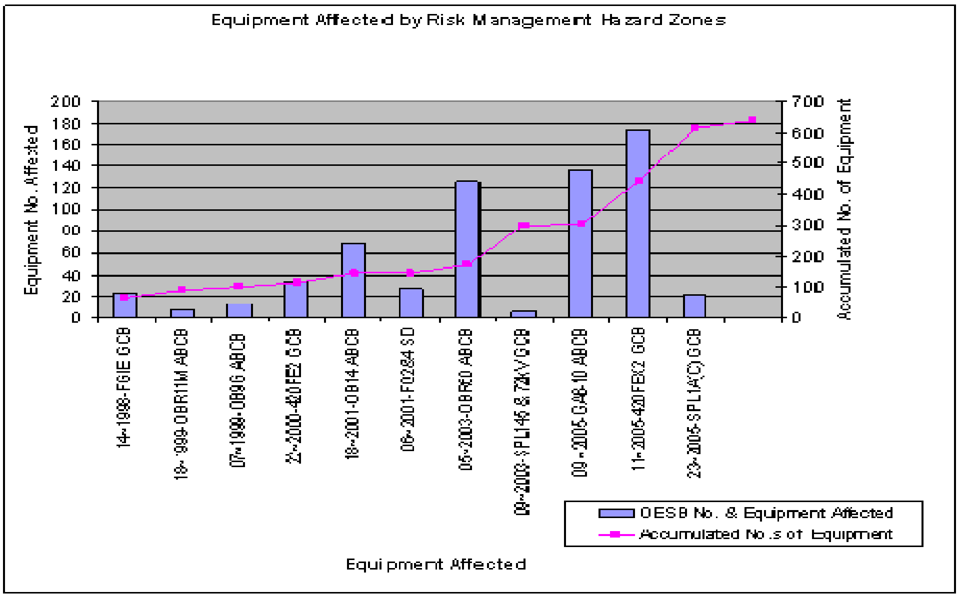
In addition, NGET has increased the sampling of circuit breaker bushings for moisture content (parts per million) over the HBPQ period, as shown below.



The chart above, as provided by NGET during KEMA's review, represents the position in early 2005 and thus does not give a proper indication of results from sampling conducted by 2005. NGET were unable to provide a more recent chart.

Finally NGET has also conducted extensive invasive condition assessment of its earliest GIS switchgear at Littlebrook in order to gain an early insight into the end of life processes for this newer technology.

At the extreme end of switchgear condition assessment is the possible creation of safety Risk Management Hazard Zones (RHMZs) where it is considered by NGET that the safety risk associated with working in the vicinity of operational plant is considered to be unacceptable and therefore access needs to be restricted. The chart below shows the current number of RMHZs, and the associated population affected.



All of this bottom-up condition assessment feeds into NGET's view of asset lives for switchgear families and thus informs top-down modelling. NGET note that in the majority of cases condition assessment means that switchgear is replaced within the window of its useful life but some disruptive failures are experienced each year.

KEMA has seen an extensive number of actual documents, reports, analyses etc for different switchgear across the NGET network leading to confidence that there is condition assessment information retained by NGET for switchgear. However, it is not clear that the condition information is appropriately fed into asset life assumptions within the top-down modelling and in the case of 132kV switchgear there is clear evidence that asset lives used in top down modelling do not align with experience on the network.

There is also evidence that the number of RMHZs has been allowed to escalate without remedial action having been taken and, given the implications for asset management at substations, the reasons for this remain unclear. Furthermore, it appears that the determination of the RMHZs is done on a family wide basis and thus there is potential that the allocation of RMHZs following an incident may not be proportionate to the risk as identified through poor condition or failure of a particular switchgear asset.

In summary, NGET has conducted condition assessments on its switchgear population and that this has developed over the HBPQ period. NGET also has extensive condition information on different switchgear families in its Asset Health Review system. However, NGET appears to apply family (long term) indicators of condition rather than asset specific (short term) indicators of condition in determining, for example, RHMZs.

There is some evidence of misalignment of between condition assessment and asset replacement priority. In general, NGET appears to adopt a cautious approach in interpreting the implications of condition assessment of individual switchgear assets. Furthermore, statements and associated metrics put forward by NGET regarding switchgear condition do not always appear to translate into actions in terms of remedial work (to remove RMHZs), nor replacement nor enforcement of CUSC rights (at 132kV level).

Consequently, this primary asset category is one where NGET could demonstrate a more refined (asset specific) approach to condition assessment and improve the alignment of replacement with condition based need.

4.5.2.5 Transformers

NGET indicates that of all the asset groups, transformers has the most mature condition assessment regime and related condition scoring system. It states that since Vesting it has developed a comprehensive family history for all transformer design groups and KEMA has been shown extensive examples of this on the AHR web site and from detailed technical reports on specific assets. The family history ensures NGET understands the varying life limiting processes but also records known defects or design shortfalls which can lead to failure.

Common failure modes include dielectric faults and the inability of the transformer to withstand high loads or through-faults.

NGET states that it works in partnership with external service providers to apply detailed condition assessments such as Dissolved Gas Analysis (DGA), furfuraldehyde assessments, acidity, moisture and degree of polymerisation (DP); as well as forensic analysis of transformers. Forensic analysis is conducted both for transformers that fail in service and for transformers removed from services as part of asset replacement. The diagrams below show the investigation of a transformer which failed in May 2005. The right hand picture demonstrates the winding collapse which contributed to failure.

The combination of condition assessment and forensic analysis is used to validate expected condition and confirm any relevant family defect (NGET prioritises asset replacement based on known transformer family defect or design shortfalls which present safety, environmental or operational risk). This is used to continue to build a family history for transformer types.

For problematic oil filled transformers the DGA will be the key condition assessment technique to monitor the deterioration in capability. This is because transformer design defects usually lead to or allow increasing HV arcing occurring in the transformer and for oil transformers this generates gases such as hydrogen and ethylene. The type and extent of the gases detected coupled with trend information enables transformer degradation to be monitored. This informs NGET which transformers are the highest priority (Category 1) transformers for replacement.

NGET indicates that transformers are assigned a technical replacement priority on a four-point scale according to their known condition and the service history of other similar transformers. Associated with each priority level there is a recommended timescale within which the units should be considered for replacement. The four basic numerical codes can be interpreted as follows:

Priority	Condition Information	Recommended Action
1	Definite evidence exists of a serious problem. The problem can be identified and it is known that it will lead to failure in a relatively short period (less than 5 years). Alternatively a problem exists which is likely to lead to a failure post-fault overload or short-circuit event. This category of transformers is considered to have reached a state requiring replacement	Replacement within 5 years. Test results combined with other factors may indicate that replacement should be planned as soon as possible using a spare unit if required.
2	Some evidence exists of developing problems giving rise to uncertainty regarding long term health. These transformers would be expected to deteriorate to a state requiring replacement within 5-10 years.	Replacement within 10 years, but may be deferred if not priority 1 at scheme preparation stage. Consider requirements for refurbishment work.
3	No evidence of problems, but transformer is of a family of known problems and therefore a higher risk of failure can be anticipated.	Placed in plan for replacement before anticipated asset life, but may be deferred if not priority 1 or 2 five years prior to planned replacement. Increased frequency of monitoring and condition assessment to be considered.
4	Good condition – no known specific or general problems.	No requirement to place in replacement plan prior to anticipated life. Condition assessment testing to be considered at 40 years.

Owing to the large number of priority 2 transformers, NGET further subdivides these into three categories – 2a, 2b and 2c. These can be interpreted as follows:

2a Likely to degrade to priority 1 within 5 years.

2b Likely to degrade to priority 1 in between 5 and 10 years.

2c Problems have ceased developing. (This includes cases where a problem has been “fixed” by changes to operational practices, rather than “cured” by corrective maintenance).

Category 2b and 2c transformers have some further leeway in the timing of their replacement than Category 2a transformers but ultimately NGET indicate excessive deferral would not be allowed if this led to an increase in the historical level of unplanned failures and hence system reliability. NGET further indicate that increased frequency Dissolved Gas Analysis of oil samples and in some circumstances continuous on-line monitoring allow the population of priority 2b and 2c transformers to be best managed to control the risk versus timeframe relationship.

NGET indicates that the process by which transformers are assigned to priority group relies firstly on service history and failure rates specific to particular designs of transformers, secondly on routine test results such as those obtained from Dissolved Gas Analysis of oil samples and thirdly on forensic examination of units taken out of service and the investigation of random failures. When any of these considerations gives rise to concern, then where practical, special condition assessments tests (which usually require an outage) are performed to determine if assigning category 1 or 2 is appropriate. A transformer with no design problems would be expected to be in category 4 at least up to its anticipated asset life.

Furthermore NGET highlights that life limiting processes for transformers (i.e. insulating paper ageing, failure of insulation fixings, insulation shrinkage/loose clamping and increasing moisture in insulation) affect transformer performance in the following ways:

- Reduction in dielectric strength (ability to withstand lightning and switching impulses)
- Reduction in mechanical strength (ability to withstand through faults)
- Reduction in thermal capacity (ability to withstand overloads)

Therefore the ultimate failure of a transformer is likely to be precipitated by a system event and as such the risk versus timeframe relationship is not clear-cut.

NGET's HBPQ submission indicates that NGET replaced 27 transformers for "non-load related issues" alone in the HBPQ period. Five transformers were allocated "Category 1" (although arguably the Iver transformers were load-related, as these related to demand at Heathrow Terminal 5) and 9 were the Category 2 transformers. However, it would appear that 13 NLRE transformer replacements were from transformers in categories 3 and 4 as at 2000. This raises the question as to why NGET replaced so many "non-urgent" transformers, and so few urgent ones. 12 out of 17 (70%) of the Category 1 transformers were not replaced during the price review period and 2 of the 5 that were replaced, were replaced after a fault and examination of the other 3 appears to indicate that the categorisation decision was correct.

It should also be noted that, of the 12 original category 1 transformers remaining on the system, 8 (66%) have been reclassified as category 2 although these are apparently showing signs of internal defects, given the inferred condition of the transformer by a Category 1 status. If these are now category 2, the classification means that these should deteriorate to a condition requiring replacement in 5 – 10 years. However, NGET states that such transformers "will all be replaced during TPCR4", suggesting category 1 classification, i.e. replacement within 5 years.

There is further evidence of instability in NGET's view of transformer condition (and need for replacement) between the Ofgem's Mini Review and the FBPQ submission. In response to a Written question (KE4012), NGET confirmed that was a net increase of 10 transformers included in the capital plan since the interim price control review, with 3 transformers being deferred out of the plan period since the Mini Review submission. In other words 13 new candidates for replacement had materialised within the space of 6 months and 3 were deferred. Also in its response (to KE4012)

NGET indicated that 22 specific transformers had been identified for replacement in place of a generic allowance for the appropriate volume of transformer replacement (presumably to align with NGET's top-down ALERT modelling) made in the Mini Review submission. This is a clear sign of a lack of comprehensive and robust understanding of the condition of the transformer fleet and hence stability of view of the priority replacement candidates and is concerning.

In summary, NGET has conducted condition assessments on its transformer fleet and this may have developed over the HBPQ period. Further, NGET has extensive condition information on different transformer families in its Asset Health Review system. However, it appears that NGET's understanding of the individual transformers could be improved and that it relies on family (long term) indicators of condition rather than asset specific (short term) indicators of condition in determining replacement priorities, until close to the date of potential replacement itself.

KEMA notes the apparent volatility of the condition status of transformers, given the large number of Category 1 transformers downgraded to Category 2 and even Category 3. This volatility leads to consequent changeability of transformer replacement candidates and calls into question both presumed asset lives and future transformer replacement proposals. A clear second cause for concern is NGET's inability to meet its policy of replacing all "Category 1" transformers (where these remained Category 1) within 5 years. This undermines the robustness of NGET's condition assessment of transformers. Of all the primary asset families this is perhaps the one where NGET has demonstrated poorest asset management performance.

4.5.2.6 Protection and Control

Condition assessment as applied to the above four primary asset groups is not readily applied to Protection and Control. Clearly, deterioration in performance and reliability of Protection and Control equipment will drive asset replacement as for other primary assets. KEMA's view is that NGET appears to apply a comprehensive overview of performance data and condition information on a function and type basis together with information on support availability from the equipment supplier and internal resources to determine actions to be taken. This information also demonstrably feeds into the determination of asset lives and plans for replacement and remedial action and thus "condition" assessment appears to operate appropriately within this primary asset category. However, KEMA does note that much of Protection and Control replacement is driven by equipment obsolescence, lack of maintenance support and diminishing of equipment expertise (in the case of older electro-mechanical systems).

4.5.3 KEMA's views

NGET has been forthcoming in addressing bottom-up condition assessment and, as indicated earlier, has provided evidence of detailed condition assessment information. NGET has demonstrated how its condition assessment techniques have developed and improved over the HBPQ period. NGET's understanding of overhead line condition required improvement and NGET has actively sought to rapidly and thoroughly improve its condition information for overhead lines (and towers).

In recent years, NGET has developed a comprehensive range of techniques to assess the condition of its asset base, although the extent to which these are employed varies by asset category. The centralisation and accessibility of asset condition data within the Asset Health Review intranet system represents a positive component of the overall asset management framework.

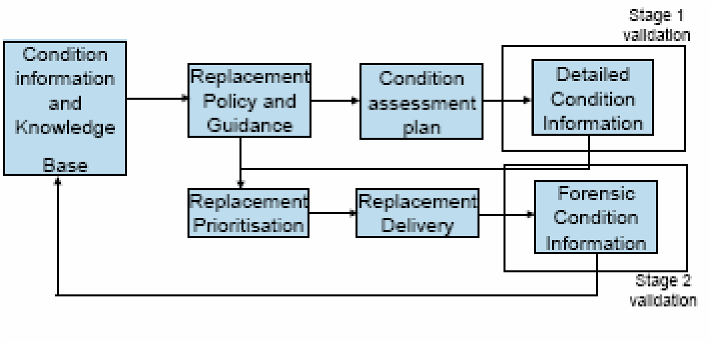
KEMA is also concerned by some evidence of instability (e.g. in the case of transformers) or uncertainty (e.g. in the case of OHL and switchgear) of condition assessment at an asset specific level. There is also evidence that classification of substation assets (i.e. switchgear and transformers) whether it be in terms of condition, replacement priority or even safety risk is made on too low a granular basis. In other words there is the tendency to apply a family based status judgement without being able to, or seeking to, apply a more refined status assessment of specific assets within these families. This suggests there is a need for NGET to further extend and develop its condition assessment practices.

KEMA has conducted a number of site visits examining a number of NGET proposed future asset replacement schemes driven by asserted condition. On the whole KEMA found reasonable correlation between asserted condition (and associated need for replacement) and actual on-site condition observed. There were, however, examples where the condition NGET stated was driving replacement need in the FBPQ period was not evident and deemed to be potentially overstated by the KEMA engineers conducting the site visits. This is discussed more in the relevant KEMA NGET Site Visits Report. However it does reinforce KEMA's view that NGET are cautious in translating condition assessment of specific assets into safety and replacement needs for the wider population.

Finally, KEMA is not reassured that the information captured within this bottom-up condition assessment process has been applied appropriately within capital planning processes used to generate NGET's proposed NLRE forecast and underlying asset replacement volumes for the FBPQ period. The difficulty KEMA has faced in obtaining a clear picture from NGET of how in practice the FBPQ submission resulted from the relevant snapshot condition assessment of the asset population, means that based on other evidence, KEMA has some concerns that, for the Price Review process at least, the capital plan may not be a reflection of prioritised (and constrained if necessary) candidates identified from condition assessment within the various primary asset categories.

4.6 Residual asset life assessment techniques employed by NGET

As broadly indicated under top-down modelling, NGET employs a mixture of top-down (ALERT) and bottom-up (condition assessment) techniques to determine residual asset lives at a collective and individual asset level. KEMA also understands that NGET uses its Asset Health Review process to consider the implication of bottom-up residual asset life assessment of individual assets on its assumptions and modelling approach to determining the residual asset lives of groups of assets on NGET's system. The diagram below illustrates this process:



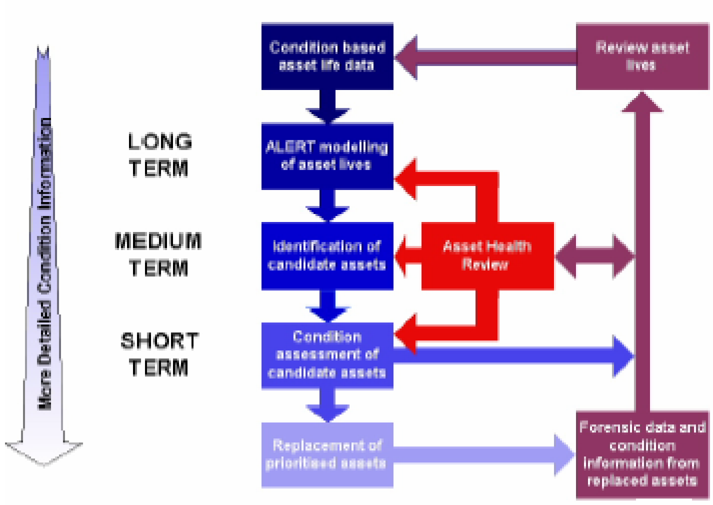
4.6.1 KEMA's views

In principle NGET applies a robust approach to the determination and evolution of its understanding of residual asset lives. However, in practice some residual lives assessments are based on potentially outdated analysis of key drivers of asset deterioration and failure, in particular OHL conductor fatigue. Consequently NGET would be expected to take the opportunity of asset decommissioning to validate and/or amend its residual asset lives assumptions. Furthermore as noted under "condition assessment" above it would be expected that NGET continues to seek to refine its understanding at an asset specific level of the residual life from a bottom up perspective rather than globally apply a top-down asset life assumption which is broadly applied purely for modelling reasons.

Finally, it is not certain that the information captured within NGET's iterative process has been applied appropriately in deriving the asset life input structures and assumptions used in top-down modelling for the FBPQ period as presented in the Price Review. It is noted that NGET uses such modelling to support its proposed Capital Plan for the FBPQ period, and there is some evidence that, in some cases, reality of asset performance/life on the network is not reflected in the ALERT modelling assumptions.

4.7 Integration of top-down and bottom-up approaches by NGET

One aspect of NGET's integration of top-down and bottom-up asset management processes has been demonstrated above. However, NGET has highlighted and demonstrated the overall process it follows to ensure full integration of its top-down and bottom-up asset management approaches. This is illustrated below.



It can be seen that in the long term (i.e. long lead time ahead) the top down modelling is the dominant factor but is informed by the existing state of knowledge from bottom-up condition assessment. Thus, as understanding of condition evolves, this is used to inform changes to top-down asset management processes including modelling of residual asset life as discussed above via the updated knowledge in the Asset Health Review system.

As timeframes enter the medium term, NGET state that top-down modelling is used in conjunction with bottom-up condition assessment to determine asset replacement plans which are populated by prioritised replacement candidates. In these timeframes, ongoing information capture via the Asset Health Review system and from detailed condition assessment of the candidate assets for replacement should be used to refine the replacement plan. This refinement will involve advancement or deferral of replacement candidates and potential reduction or addition of overall volumes as some candidates are deferred beyond timeframe or newly introduced into the timeframe.

In the shorter term, ongoing asset replacement will give rise to new information via forensic and other less intrusive examination of removed assets. This can lead to changes in the top-down asset management approaches employed in the longer and medium terms (e.g. changed asset lives) and to bottom-up asset management processes in the short – medium terms (e.g. asset maintenance and condition assessment).

Overall NGET appears to have developed a well structured approach to integrating top-down and bottom-up asset management process and KEMA has been shown a number of examples illustrating how this has worked in practice, from the adoption of OHL Fittings Only asset replacement through to the use of condition prioritised records to generate the Capital Plan.

4.7.1 KEMA's views

In principle, NGET appears to have established a robust framework for effective integration of bottom-up and top-down processes. However, there appear to be instances where the feedback loops have not operated effectively and that the information captured within this iterative process may have been applied inappropriately in generating the Capital Plan.

4.8 Unit costs and scheme costs

4.8.1 KEMA's view of NGET unit costs

4.8.1.1 General Points

NGET states that the price for supply and installation of the majority of types of transmission equipment has increased at, or below, the rate of inflation since 1999. This appears reasonable except for overhead lines for which there appears to be an increase over the price review period.

NGET states that scheme costs are built up of a number of components of which equipment unit costs is one, albeit large, component. KEMA accepts that material costs are one component of scheme costs and that the contribution of equipment costs to overall scheme costs is variable and depends on the type of scheme and the issues encountered and hence it is difficult to make a sensible generalisation.

NGET states that other components of scheme costs, predominantly project management and engineering costs, have risen over the price review period and list a number of factors. In KEMA's experience, project management and engineering costs typically amount to approximately 5% of contract values. This is relatively insignificant in terms of overall scheme costs. This labour cost has been rising at approximately the rate of inflation and so it is unclear why management and engineering design costs should be higher than anticipated and have such an impact on scheme costs.

4.8.1.2 Substation Components

NGET states that GIS and AIS bay supply and install costs include all switchgear, bay civil works and structures, bay protection and control, bay design, engineering and project management and that the supply and install costs break down into 40% for electrical equipment, 40-50% labour and 10-20% civil works. KEMA has been advised that traditionally NGET has contracted for supply and install contracts. Within these contracts, the price for supply includes the labour for manufacture but it is presented as part of the supply cost. The labour cost within a supply and install contract only refers to the site installation labour which has normally been about 10-20% of the supply and install value. Within this range it would be about 10% for GIS due to the higher capital value of equipment and towards 20% for AIS equipment.

NGET claim that transformer supply and install costs are down over the price review period due to the purchasing strategy. Nevertheless NGET claim "transformer" schemes have increased due to "other" costs as transport costs which NGET indicates can be up to £250k and are a part of scheme cost. KEMA accepts that costs such as transport make a transformer scheme more expensive than the unit cost but costs such as transport are "not a surprise". NGET have long experience with transformer and heavy load transport thus the cost of £250k for transformer transport should not be unexpected and already included in scheme estimates. Thus if the reduced cost of transformer units is correct, scheme estimates for transformer schemes should be lower than estimates from previous business plans.

NGET have identified 31 substation schemes in the price review period that have outturned at 26% above estimate. As this is a subset of schemes, KEMA is wary about drawing any conclusions as these form part of a wider portfolio of schemes some of which will have outturned at or below scheme estimate

4.8.1.3 Cables

NGET state that cost of cables has decreased despite the large rise in copper prices but, where tunnels have been employed, the cost is variable. KEMA would expect that NGET are only likely to adopt a tunnelling solution where direct bury is impractical. Recent experience of tunnelling in London should enable NGET to make reasonable capital cost estimates. This is relevant to scheme 15494 St John's Wood – Tottenham cable replacement in the FBPQ which has an assessed value plus a "x 2" complexity factor to account for the tunnel.

4.8.1.4 Overhead Lines

NGET has provided a chart of contract costs for a basket of supply and installation costs for overhead line contracts and state that the costs of Aluminium has risen 92% since 1999 and 40% in the last year. Unfortunately the chart does not distinguish between voltage and conductor type or configuration and it also does not indicate whether the £k/km refer to circuit or route kilometres. Hence it is difficult for KEMA to draw clear conclusions. However if KEMA uses a similar approach and assumes a similar mix of projects in each year then the following conclusions may be drawn:

(i) OHL supply and installation costs have risen by almost 400% from 1999 to 2005. The majority of this rise being between 1999 and 2004. NGET have stated that the aluminium cost increase was predominantly in 2004-2005.

(ii) The stated OHL cost per route km for 2005 is just under [redacted]. The estimated average scheme costs in the schemes studied by KEMA for the FBPQ period were over [redacted].

(iii) NGET states that market conditions are different for OHL when compared with switchgear and transformers with there being more switchgear and transformer manufacturers. KEMA infers that NGET is suggesting that lack of competition is driving prices up, as NGET states that there are three OHL contractors although one has limited capability. However, in comparison, there are really only three switchgear manufacturers as VATech have been taken over by Siemens (ABB, Siemens, GEC/Areva), two or three transformer manufacturers and a similar number of cable suppliers. Hence KEMA is not convinced that lack of competition would justify cost increases for OHL but not other primary assets.

NGET has provided a subset of OHL schemes that outturned in excess of estimate suggesting a 74% increase in costs. This list does not include the schemes that were at or below estimate so no conclusions can be drawn.

Furthermore, NGET states that improved Pre-Sanction Engineering coupled with OHL framework agreements has stabilised costs. KEMA is not convinced that this is the case. Pre-Sanction Engineering has reduced the need for re-sanction of schemes as it has determined a more detailed scope of work before sanction and as such is a good and sensible process. For example, Pre-Sanction Engineering would have avoided the massive scope change on the Dungeness – Ninfield scheme that has been examined by the KEMA team. However, Pre Sanction Engineering does not keep cost increases in contracts down as the chart provided by National Grid demonstrates.

4.8.1.5 Price movement - anticipated trends

NGET states in the FBPQ submission that the average labour component of unit cost is in the order of 37.5% and so suggests that changes in the labour market will have a large impact on its business. Given this high weighting of manpower costs in driving capital expenditure, the forecast increase in these costs is important.

It is not clear to KEMA that the factor should be so high. KEMA accepts that OHL schemes might have a 40% labour value in a supply and install contract but this is not the case for 400kV cable contract. KEMA's view is that transformer supply and install contracts are also material intensive and the labour element relatively small. KEMA asserts that labour costs affect some types of works more than others and estimates that in supply and install contracts labour elements are likely to be as follows:

(i)	Overhead lines	30-50%
(ii)	Transformers	6-12%
(iii)	Switchgear	10-20%
(iv)	Cables	1-2%
(v)	Protection	40 – 50%

4.8.2 NGET's PDD model and its use for scheme costing in the FBPQ period

4.8.2.1 Overview of the PDD model process for scheme costing

The PDD process is a scheme desk top study to establish the scope of work and how it is likely to be constructed in consideration of any safety or outage restrictions. NGET indicate that the study utilises:

(i) substation layout drawings

(ii) Geographic Image Satellite pictures

(iii) Operational diagrams

(iv) Local knowledge

(v) Known future system design requirements

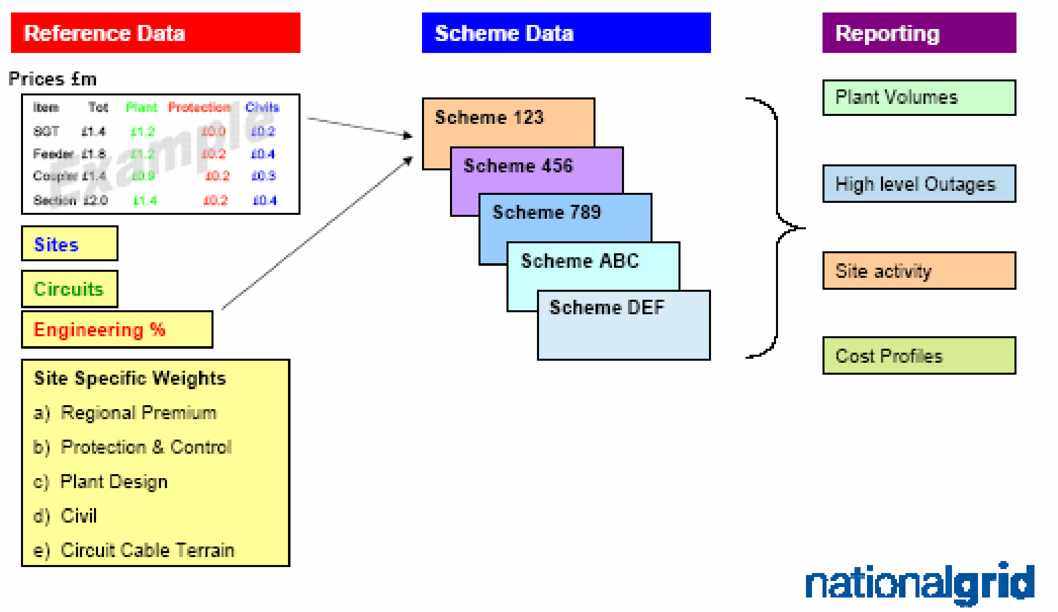
NGET explains that the PDD process identifies equipment volumes for equipment at 400kV to below 66kV and that the basic costs are derived through automatic application of data derived from a single source approved and monitored by Procurement. The PDD process incorporates an Excel spreadsheet based model (the PDD model) which captures scheme specific data used for medium to long term and financial planning purposes. NGET claims that the PDD model provides;

(i) a quick, consistent and improved method of estimating the preliminary high level scheme costs for Business Plan entry,

(ii) enables an impact assessment and costing of scheme specific site conditions; and

(iii) places responsibility for the provision of scheme cost estimating on a single department

The PDD process of which the PDD model forms the core part is illustrated below in a slide provided by NGET:



This highlights that in deriving scheme costs using the PDD process there are 3 basic cost elements;

(i) supply and installation of equipment ("prime" costs);

(ii) complexity factors recognising site specific situation for 5 different aspects; and

(iii) (project) engineering costs

Each of these aspects is discussed in more detail in following 3 sub-sections.

4.8.2.2 Derivation of the base unit costs

NGET indicates (in KE4048) that the basis of the scheme base unit costs are determined by using a number of sources of data and then aggregated dependent on the most frequent application. The data sources NGET states that it uses are:

a) Historic contracts (contracts from the last 5 years) at bay level

b) Recent (and live) contracts e.g. Bulk Purchase Transformer contract, OHL Framework or NICAP.

c) Informed estimations where little recent cost evidence exists.

NGET indicates that most PDD unit costs are stated at bay level that simplifies the process and the tendering price schedules are also set at bay level that makes data extraction easier. KEMA notes that this automatically assumes that all switchgear replacement is conducted on a full bay basis and there is no allowance for replacement of the circuit breaker only. Whilst this may reflect NGET policy, it is clear that the PDD model should at least allow for the “circuit breaker only” replacement option to be costed in case policy or requirements change.

In discussion at the 9 May Workshop, NGET indicated that the base unit costs are revised on an annual basis - presumably aligned with the capital planning process. However, it appears that in the event of a change in costing, whether upwards or downwards, that NGET does not take the opportunity to revise its PDD base unit costs. This probably reflects the fact the PDD is used as a general estimate for schemes 3-5 years away and thus is less important from an internal NGET process point of view. However, it is a point worthy of note given that PDD cost estimates underpinning Table 9.9 of the FBPQ are likely to be 12-18 months out of date by the time of final determination.

KEMA is not clear how this basic cost data is checked to ensure it does not incorporate implicit complexity factors within contract costs for particular historic schemes. Furthermore there is a risk that where market circumstances are such or NGET’s need is such (e.g. in the case of OHL schemes in 2004/05) that it drives costs above what would be recognised as equilibrium levels, the PDD process may work in a way that allows these costs to feature in the base unit cost data. KEMA’s assessment of OHL unit costs suggests that, short notice high volume requirements from the historic period have set the baseline within the PDD model leading to an over-estimate of costs for some FBPQ OHL schemes.

4.8.2.3 Derivation of PDD Complexity Factors

The percentiles (complexity multipliers) were established by a multi-discipline group with experience in the detailed development, procurement of schemes and who possessed working knowledge of cost variances that can arise from the impact of site-specific conditions/risks such as the ‘regional premium’. This can apply to sites with access problems that increase the transportation costs of heavy loads such as transformers into the site or the removal of spoil/redundant equipment. These problems are not restricted to sites within specific geographical areas.

NGET indicates that the application of the High/Medium/Low etc. complexity rating is based upon experienced engineering assessments made from a desktop study and any local knowledge of the site. However in questioning at the 9 May Workshop NGET indicated that these preset values for the different levels (e.g. High/Medium/Low) of the complexity factors were established when PDD was introduced in 2004 and have not been changed since. Whilst KEMA would be worried if these complexity factor levels changed it would nevertheless expect some evolution as experience of the accuracy of the PDD process has grown when comparing against both scheme sanction costs and asset or site specific contract costs being observed over the last 2 years.

Another important aspect is the determination of the levels of complexity factors to be applied to the different schemes. Whilst it is clear that it is a step forward for all scheme engineers to reference a single source and for there to be a central overview of the factors, there does seem to be evidence of high complexity factors being applied for some schemes. This has become apparent in KEMA's analysis of a sample of NGET schemes. Consequently, whilst the process may be more structured it is susceptible to inappropriate input decisions leading to inappropriate cost outputs.

4.8.2.4 Determination of scheme project engineering costs within the PDD process

NGET clarifies (in KE4048) that engineering costs include: design, project management, safety from the system, consents, legal, commissioning etc. To improve the cost estimation for budgetary Business Plan purposes, NGET adopted a range of engineering assessment values. NGET explain that the 'Lo' (5%) range encompasses schemes with a high monetary value and relatively low engineering (e.g. cables/long overhead lines) and the 'Hi5' (25%) schemes with a low monetary value and relatively high engineering (e.g. small-scale protection replacement). The percentage values used for the 'Lo' to 'Hi5' ranges are based upon engineering values that have previously been realised on these particular types of scheme. It is not clear to KEMA if these, like the complexity factor values have remained unchanged since introduction of the PDD process in 2004 or have evolved over the last 2 years. NGET indicates that an Engineering Assessment rating between these upper and lower levels is selected based upon site complexities, the type of work, number of years required for scheme construction and total assessed scheme costs.

As for the complexity factors, whilst the approach to allocation of engineering costs is sound, the robustness of the cost estimation is dependent on the assumptions made for each scheme and how valid these are.

4.8.2.5 Accuracy of the PDD process

As noted previously NGET indicates that the introduction of the PDD process has improved its cost estimation accuracy for sanctioned schemes to 3% below sanction value on average, compared to a figure of 14% previously. NGET state that this is the appropriate comparison as the PDD is meant to be the medium to long term predictor of scheme costs and that post-sanction cost deviation is more about delivery performance than cost estimation. KEMA is not sure this is a sound argument.

NGET did not provide the range of deviation of PDD cost estimates from sanction values obtained over the past 2 years. KEMA is thus unable to form a view as to the accuracy of PDD across different types of schemes. NGET did provide a chart suggesting the PDD process was performing well in 2006 but this only covered 19 schemes most of which were load related.

4.8.3 NGET's derivation of unit costs as in Table 9.8 of the FBPQ

NGET indicates that the unit costs in Table 9.8 of the FBPQ have been derived from its PDD model.

NGET indicates (in KE4047) that the PDD cost components have been combined and weighted to provide a manageable set of costs for Table 9.8, reflecting the general mix of equipment and configurations it is using in its projects as listed in Table 9.9 of the FBPQ.

i) **Supply and installation of materials ("prime" costs)** – NGET indicates these costs have been taken from the cost components in the PDD, and weighted to reflect typical asset configurations. NGET provide the results for the main asset groups in KE4047

To derive the figures in Table 9.8, NGET applied deflation of 0.974659 (to get to 2004/05 prices). The percentages described in (ii) and (iii) below have been applied to the deflated cost.

ii) **Project management and engineering** – NGET indicates that based on exercises undertaken for last year's Mini Review, a mean percentage loading for these activities was identified as 10%. This figure was selected following analysis of a number of recently closed schemes, and from assessing percentage levels applied by development engineers using PDDs. NGET suggests that the figure of 10% is considered to be a conservative estimate for some schemes – e.g. Protection and Overhead Line schemes in particular may be nearer to 20-30%.

iii) **Other expenditure** – NGET indicates in terms of the PDD costing model, this area covers those costs assessed within the "complexity" weighting. The figure used to support the costs in Table 9.8 has been derived from a similar exercise to that in (ii) above. NGET indicates that it conducted statistical analysis of 581 scheme costs in PDDs for the Mini-Review deriving a mean complexity percentage at 18% and this was retained for its FBPQ submission, as the overall mix of projects has not changed materially in the last year. As with (ii) above, there is some variation in this figure dependent upon the type of work being undertaken. However, for substation schemes (370 of the 581 total), and the group for which the most assessment by development engineers had been applied, NGET indicates the mean result was 18% and the use of 18% is a good estimate overall.

NGET indicates that the PDD does not differentiate between new build and asset replacement at the unit cost level, but rather uses complexity weighting to reflect specific design, integration and differing civils needs for each project. Project management and engineering costs are added to the PDD costs as a variable percentage. However, NGET indicated that to keep the list of costs reasonable, a single assumption of average complexity and project management / engineering costs, as derived in (ii) and (iii) above was used in Table 9.8.

4.8.4 NGET cost indices for external "uncontrollable" factors

Clearly, in delivering its capital plan NGET is exposed to certain key cost components, an example being the cost of external labour, highlighted previously. NGET indicates (in KE4050 and KE4051) that it is really only realistic to cost these elements for price levels up to one year ahead, as the unit costs do not reflect any assumptions on changes in market costs of materials and labour. Thus to look further ahead NGET has conducted an analysis of these factors with assistance from an external consultancy Gardiner & Theobald Fairway ("Fairways")

NGET indicates that its analysis of the capital plan identified that around 80% of the capital plan value was supported by 50 components. Fairways analysed the 50 components to establish the main cost drivers associated with them, and settled on 7 key elements, namely; Civils, General (RPI), Manpower, Oil, Copper, Aluminium alloy and fabricated steel. The weighted, plan-level view of each driver, based on the total cost accumulated against each cost component in the schemes in the capital plan is shown below:

Index	Proportion of capital plan	Elements of capital plan covered by Index
Civils	12.5%	i.e. rock, sand, gravel, concrete, plastic pipe, timber and concrete reinforcing bars
Manpower	37.0%	Wage costs based on JIB ("approved electrician") and NAECI ("advanced craftsman-mechanical")
General (RPI)	20.5%	Used to reflect activities influenced by general economic inflation, including larger manufactured items (reflecting the higher cost control possible within a factory environment)
Oil	7.0%	Oil cost affects many of our costs, and especially in transformers and cables.
Copper	10.0%	Large component in cables and heavy wound plant, and an influence in many others
Aluminium alloy	4.0%	Main component for overhead line conductors
Steel (fabricated)	9.0%	Large influence on heavy wound plant and towers

Fairway identified publicly available indices to predict the costs of the 6 non-RPI components above. NGET indicates Civils and Manpower were selected for inclusion in Table 9.9 as these are the two largest cost drivers (other than RPI) and that these indices were firmer forecasts than the others. The methodology NGET adopted derived figures of £20.5m for NLRE Civils Uplift and £96.5m for Manpower Uplift as included in Table 9.9:

This methodology appears reasonable, however, KEMA has not verified the analysis put forward by NGET and Fairway in determining these values. if these Uplift costs are included as normal schemes in the capital allowance it will be necessary to adjust them accordingly in line with any adjustment to NGET's typical capital scheme based allowance e.g. if less schemes are implicitly accepted then these

Uplift Factors should be smaller. The fact that NGET separates out these costs also means it is important that the unit costs and PDD driven scheme costs in the FBPQ submission do not include any element of future cost growth.

4.8.5 Scheme costs – KEMA's analysis of a sample of NGET schemes

As part of the remit of KEMA's Review of Asset Management practices for TPCR4, KEMA was required to provide an assessment of a representative sample of NGET capital investment schemes covering both historic and future proposed schemes focussing on non-load related capital expenditure schemes.

24 NGET schemes have been analysed in detail. The total expenditure for these schemes is £623M based on NGET's costs. Of the selected schemes, the historic schemes have a total cost of £111M and future schemes approximately £512M.

4.8.5.1 Key themes from KEMA's analysis of NGET schemes

Based on the analysis of the 24 schemes, it is possible to identify three general themes of concern. These are considered below.

(i) **Substation Design:** Historically, NGET has generally used double busbar and mesh substation designs. However, going forward NGET is increasingly adopting a double busbar design. Whilst it is more secure, and is operationally more flexible, than a mesh substation, a double busbar substation is more expensive than a mesh substation. For example, for air-insulated substations (excluding the cost of transformers) a 400 kV double busbar substation is [redacted] while a 4-switch mesh is [redacted] and a 275 kV double busbar substation is [redacted] while a 4-switch mesh is [redacted].

NGET's policy for replacing mesh substations with double busbar substations is based on the premise that a double busbar is only marginally more expensive than a mesh substation. However, KEMA's experience of substation costs and its analysis of NGET schemes do not support this basic premise.

One of the justifications for using double busbar substation designs as opposed to a 4-switch mesh is if the site requires more than 4 transformers, then a mesh design can introduce operational complexity. One alternative to using 5 transformers is to adopt units rated at more than 240 MVA and KEMA's view is that 15% higher MVA rating can be achieved at little cost and use of 300MVA units could be economic. Finally, in addition to the above NGET appears to specified more bus couplers/sections than either Scottish TO.

(ii) **OHL refurbishment costs:** NGET's HBPQ submission suggests that the cost of towers and conductors increased at about 0.8% per year below RPI. However, in March 2006 NGET provided the chart below, which indicates an enormous rise in the cost of overhead line refurbishment.

[Commercially sensitive table removed]

KEMA therefore compared historic costs for completed overhead line refurbishment schemes (Dungeness – Ninfield and Blyth – Harker) with estimates for future schemes in the FBPQ. Using these two schemes as benchmarks, it is possible to compare with the costs of all the other NGET schemes, as well as those of SPT and SHETL. This is shown diagrammatically below:

[Commercially sensitive table removed]

It can be seen that the four future NGET schemes, namely Bolney – Lovedean, Aberthaw – Tremorfa, Bramley – West Weybridge and Cilfynydd Tee – Rassau, are more expensive than either the historic NGET schemes or any of the SPT schemes. It should be noted that NGET have identified a 92% increase in overhead line material costs (steel and aluminium) since 1999. However the Dungeness – Ninfield scheme that has been used for comparison purposes was delivered in the period 2000 – 2003 so it is expected that the costs are representative and will have seen at least a proportion of that “large increase”.

(iii) **NGET cost estimation.** For the previous Price Review NGET used a document called “TR3” for estimating scheme costs. This document was, essentially, a standardised “Price List” – schemes were split into the basic building blocks (substation bays, transformers, overhead lines etc.) which were then individually costed using the TR3 document. Any special costs (e.g. due to contaminated land, transport costs, etc) had to be specifically estimated. NGET has now dropped TR3in favour of a Project Definition Document or “PDD” form introduced in 2004 and which has been used for estimating costs of schemes in the FBPQ.

For the PDD the system designer has to input details of the scheme components, as with TR3, and then has to select a number of complexity factors which are used to adjust the component prices. NGET have supplied (in KE4048) a list of standard PDD component costs, which appear to be the “Price List” equivalent to TR3, but there are a number of anomalies. Unfortunately, it appears that these costs are effectively “hidden” within the PDD process, so will not be visible to users hence preventing the possibility of feedback as these errors are discovered.

Complexity factors are then specified in 5 areas and under each of these factors there are 5 options. Each of these will result in multiplying part of the costs by a given factor. However, NGET indicate that there are no guidance notes. Thus, for all schemes, there is a 5x5 complexity matrix, with the possibility that different design engineers will input different factors without an obvious audit trail.

The results which are visible to the design engineer are uplift costs determined under three separate headings which do not bear any direct relationship to the input data. This is compounded by the absence of a diagram showing what the scheme involves, or any indication of the input data used in the costing. This internal process appears to be opaque even to the design engineer; and ostensibly minor factors can result in uplift costs. For example, the Bramley – West Weybridge scheme has been allocated “High” factors for regional, civil and plant design complexity, “neutral” for Protection and Control, and “light urban” for terrain – all decisions which NGET have individually justified – but this results in plant costs being uplifted by 50%, protection costs by 10% and civil engineering costs by an enormous 170%.

It is difficult to know how NGET are using these factors; there may a large area of judgement involved. In some cases NGRT introduces regional factors for plant items and in other cases a large “plant design complexity” factor is introduced where the rationale is questionable. The justification for the values selected is not transparent.

In summary, NGET has replaced a transparent “price list” approach (TR3) with an opaque “black box”. This latter approach appears to give rise to unjustifiably high costs, but due to the opacity of the process it is impossible to see how those costs are derived.

4.8.5.2 KEMA’s assessment of the costs of the analysed NGET schemes

The tables below summarise NGET’s cost estimates, together with those of KEMA for the 24 NGET schemes which KEMA reviewed in detail. It should be emphasised that this is given as an indication rather than as a definitive estimate. However, KEMA’s indicative estimates are broadly in alignment with NGET historic schemes (and also with all Scottish TO schemes selected for detailed assessment).

Scheme Number	Title	Need	Year	NGET Cost £M	KEMA Estimated Cost £M	Potential Saving	Comments
Overhead Lines							
005811	Dungeness – Ninfield Refurbishment	✓	2000-4	[redacted]	[redacted]	0	Justification for refurbishment of inland section unclear. Outturn costs 25% greater than original sanction, justified by additional work. KEMA's estimate excludes huge steelwork replacement and costs of Foot & Mouth which are impossible to assess. Cost of basic refurbishment is assessed as reasonable and has been used as benchmark in other analysis
08651L	Blyth – Harker refurbishment	✓	2000-3	[redacted]	[redacted]	0	HBPQ value differs from original sanction and final outturn by approx £4m (25%). KEMA's estimate similar to original sanction
14557 and 14295	Pembroke – Swansea OHL refurbishment	✓	2003-5	[redacted]	[redacted]	-0.6	Close cost correlation
11642	BOLN - LOVE (4VF)	?	2009-12	[redacted]	[redacted]	21.2	Scheme justification questionable – documentation states condition to be relatively good. Costs excessive
4732	ABTH-TREM (LL) OHL FULL REFURB	✓	2007-9	[redacted]	[redacted]	2.4	Scheme costs excessive for a single twin conductor circuit
4742	Bramley – West Weybridge OHL refurbishment	✓	2006-9	[redacted]	[redacted]	15.8	Scheme costs excessive compared with other twin conductor routes
11260	Cilfynydd T – Rassau OHL	✓ ?	2008-11	[redacted]	[redacted]	14.1	Scheme costs appear excessive
			Total (2000 – 2005)	[redacted]	[redacted]	**0**	
			Total (2005 – 2012)	[redacted]	[redacted]	**53.5 (-40%)**	
			Total (2000 – 2012)	[redacted]	[redacted]		

Scheme Number	Title	Need	Year	NGET Cost £M	KEMA Estimated Cost £M	Potential Saving	Comments
Switchgear and Substations							
008034	Carrington 132 kV	✓	2000-5	[redacted]	[redacted] [redacted]	0 6.5	Final outturn costs [redacted] but HBPQ gives £8.4m. Two estimates (a) new GIS substation (NG solution), (b) equivalent AIS double busbar substation. GIS solution justified only if space constraints applied. * Note HBPQ states [redacted] during period.
10342C 10342I	Penwortham	✓	2003-6	[redacted]	[redacted]	0	Costs seem reasonable
9609	Hams Hall	✓	2000-6	[redacted]	[redacted]	0	Costs seem reasonable
11030	Rugeley 132 s/gear repl. &bb prot'n.	?	2009-12	[redacted]	[redacted]	3.9	Scheme costs excessive. Condition of indoor equipment good. Case for replacement during next price control period questionable.
11122	Walpole 132 kV switchgear Replacement	✓	2006-9	[redacted]	[redacted]	1.2 (within tolerance)	The sanctioning paper was for [redacted] which included an additional transformer. This scheme could have been cheaper if it had been properly planned. The FBQ shows [redacted] whereas the scheme was sanctioned for [redacted] which is comparable to KEMA's estimate

11143 and 11143C	Hurst 275 kV switchgear replacement	?	2007-12	[redacted]	[redacted]	28.8	It is only necessary to replace the circuit breakers.
15143I	HACK4-4 Bay GIS Substn. and Add SGT-Infra	?	2009-12	[redacted]	[redacted]	4.3	Double busbar substation not justified but cost estimate based on DBB substation anyway
15140	West Melton 275 kV GIS	✓	2009-12	[redacted]	[redacted]	-2.9	Some doubt over justification for double busbar solution but if appropriate cost estimate looks reasonable.
11228	Nechells 275 kV SWGR replacement	?	2007-11	[redacted]	[redacted]	34.1	It is only necessary to replace the circuit breakers at this time.
	Total (2000 – 2005)			[redacted]	[redacted]	**0**	
	Total (2005 – 2012)			[redacted]	[redacted]	**67.9 (-53%)**	Note: Reduction factor becomes 10.6% if Hurst and Nechells are excluded
	Total (2000 – 2012)			[redacted]	[redacted]		

Scheme Number	**Title**	**Need**	**Year**	**NGET Cost £M**	**KEMA Estimated Cost £M**	**Potential Saving**	**Comments**
	Transformers and Reactors						
14353	Elstree Series Reactor	✓	2003-5	[redacted]	[redacted]	0	Scheme includes Gas Insulated Line + Circuit Breaker
10299	Rochdale SGT 2, 3 and 4 replacement	✓	2001-5	[redacted]	[redacted]	0	Costs seem reasonable
20041	Pitsmoor SGTs 1, 3 & 4 Replacement	✓	2006-9	[redacted]	[redacted]	0	Costs seem reasonable
11134	Uskmouth SGT1, 2A and 4A Replacement	✓	2009-12	[redacted]	[redacted]	3.1	Cost for this part of the scheme excessive. Total scheme costs including 3 transformers are [redacted] investment overall, which is also excessive.
15140C	West Melton 275 kV GIS 5 Tx + 5 bays	✓	2009-12	[redacted]	[redacted]	1.1	Transformer scheme with accompanying bays. Some doubt over justification for double busbar solution but if appropriate cost estimate looks reasonable.
15143	Hackney additional SGT	✓	2009-12	[redacted]	[redacted]	3.6	Costs within tolerance although doubt regarding scope of scheme
	Total (2000 – 2005)			[redacted]	[redacted]	**0**	
	Total (2005 – 2012)			[redacted]	[redacted]	**7.7 (-22%)**	Note: Reduction factor becomes -15% should impact of Uskmouth be excluded (where no transformers are costed in scheme
	Total (2000 – 2012)			[redacted]	[redacted]		

Scheme Number	Title	Need	Year	NGET Cost £M	KEMA Estimated Cost £M	Potential Saving	Comments
Cables							
9473	Dartford Tunnel Cable	✓	2001-06	[redacted]	[redacted]	15.1	Costs appear excessive
11414	SJOW-WISD cable replacement	?	2007-12	[redacted]	[redacted]	7.3	Basis of estimates: Elstree – St John's Wood outturn. However, KEMA is not necessarily persuaded that these two schemes represent the cheapest way of replacing these cables (not costed).
15494	SJOW-TOTT cable replacement	?	2006-12	[redacted]	[redacted]	42.6	
Total (2000 – 2005)				[redacted]	[redacted]	**15.1**	
Total (2005 – 2012)				[redacted]	[redacted]	**49.9 (-28%)**	
Total (2000 – 2012)				[redacted]	[redacted]		

* A further £50m falls into the following TPCR period

Total - All Asset Categories in sample (2005 – 2012)	[redacted]	[redacted]	**187.9 (-40%)**	Note: Reduction factor becomes 31.6% if Nechells and Hurst are excluded

[The total cost of the selected NGET schemes is £623M based on NGET's cost estimates. Of the selected schemes, the historic schemes have a total cost of £111M and future schemes approximately £512M. KEMA's estimate of the cost of undertaking the is £238M, or 38% lower than NGET's estimate. The majority of the over expenditure is covered by future schemes, where KEMA estimates that NGET's predicted costs of £512M could be delivered at a cost of £274M (i.e. NGET's predicted expenditure is around 45% too high).]

The largest area of excess expenditure lies in overhead line refurbishment schemes. Overhead Line Refurbishment seems to be showing unjustified cost increases, and in some cases the justification for undertaking the work is not compelling: it is estimated that there is an overestimate of £60M.

A second cause of excessive forecasting is over-specification of substations. In some cases NGET has specified double busbar substations when a cheaper mesh design would meet the GB Security and Quality of Supply Standard, and in other cases NGET is proposing a new substation when the circuit breakers could be replaced in situ. This is estimated to account for around £100M of the excess expenditure.

A third area of excess expenditure lies within London and the Home Counties. NGET appears to have taken a piecemeal approach to Asset Replacement, without considering the network as a whole. The future replacement of a large number of underground cables in London gives a "once in a lifetime" opportunity to rethink the London transmission network. KEMA is not in a position to identify what should be the appropriate future London network, but it seems unlikely that this will be given by like-for-like asset replacement, and it is estimated that savings in a range of £50M - £80M might be made in this area.

The remaining excess expenditure lies with individual scheme cost estimation, generally associated with the PDD process.

4.8.6 KEMA's views

NGET has stated that the costs of transmission equipment has risen at or below the rate of inflation over the price review period and has produced charted evidence of this claim. The charts seem to agree with this statement except for overhead lines which appear to have increased by some 400% over the period and the reasons why this should be the case are not clear to KEMA although the suspicion is it relates to NGET's sudden need to carry out extensive OHL work in 2004-2006 following realisation of the poor condition of some parts of the network.

NGET has stated project management and engineering costs have risen over the price review period. However, NGET has not explained what it considers to be project management costs but, assuming that both project management and engineering costs are labour related, increases should be closely linked to inflation. Also, the scope of the activities associated with project management and engineering of schemes should not have changed significantly over the period.

NGET has stated that "other costs" i.e. site specific costs are adding to scheme costs and that it has developed a series of complexity factors to improve its scheme estimates with its new PDD process. There is some evidence that the "other costs" may be driven by the new working practices adopted by NGET. In addition, from KEMA's scheme assessment it appears that these complexity factors have been emphasised.

NGET has presented a selection of schemes that outturned higher than estimate as a justification for its "complexity factor" approach. However, KEMA is wary of drawing simple conclusions from these statistics as examination of the full portfolio may give a different picture.

KEMA has had the opportunity to discuss the PDD process with NGET and on this basis (and from Written questions – KE4047 and KE4048) has a good understanding of how it is applied. The adoption of single sourced consistent process is welcome but the process is susceptible to the quality of usage. For example, a key input is the base unit cost data and it may be that atypical cost factors have not been excluded from the reference data used in the PDD model, especially for overhead lines. Also KEMA's review of certain schemes and based on its own local knowledge of the site suggests that, for the Price Review FBPQ submission at least, complexity factors have been applied on a basis which has not been explained.

NGET indicates the accuracy of the PDD process is shown by closeness to sanction values. However it is not clear to KEMA whether this is a actually an appropriate measure and NGET has only been willing to provide average figures and not the range of PDD estimation vs. sanction value deviations seen for the schemes the PDD has been used for over the last 2 years.

KEMA has assessed in detail a representative sample of 24 NGET NLRE schemes. The total cost of the selected NGET schemes is £623M based on NGET's cost estimates. Of the selected schemes, the historic schemes have a total cost of £111M and future schemes approximately £512M. KEMA's estimate of the appropriate costs for undertaking the necessary future work is £238M, or 38%, lower than NGET's costs. The majority of the over expenditure is covered by future schemes, where KEMA estimates that NGET's predicted costs of £512M could be delivered at a cost of £274M (i.e. NGET's predicted expenditure is around 45% too high).

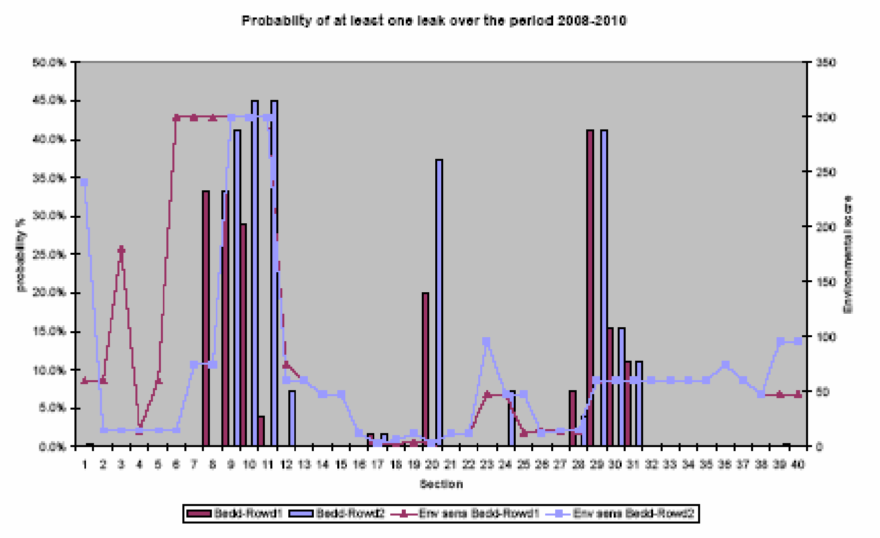
The largest area of excess forecasting lies in overhead line refurbishment schemes where cost increases appear unjustified, and in some cases the requirement is not compelling. A second cause of excessive forecasting is over-specification of substations. A third source of excess expenditure lies with individual scheme cost estimation, generally associated with the PDD process.

4.9 Risk and performance measurement

Risk is probably one of the most misunderstood aspects of asset management. KEMA is of the opinion that proper risk assessments should be carried out at two levels: equipment and system level. Equipment risk considerations include the risk of impaired performance and increased operation and maintenance cost. System risk considerations include the risk of reduced reliability, reduced quality of supply and the impact of the outages required for refurbishment or replacement.

4.9.1 Equipment risk

There is evidence that at the asset specific level, risk metrics are applied within asset management and to some decisions regarding asset replacement. One example shows for a specific scheme, in this case Beddington – Rowdown HV cable replacement, a risk analysis has been applied in terms of judging the likelihood of leaks. This is shown below:

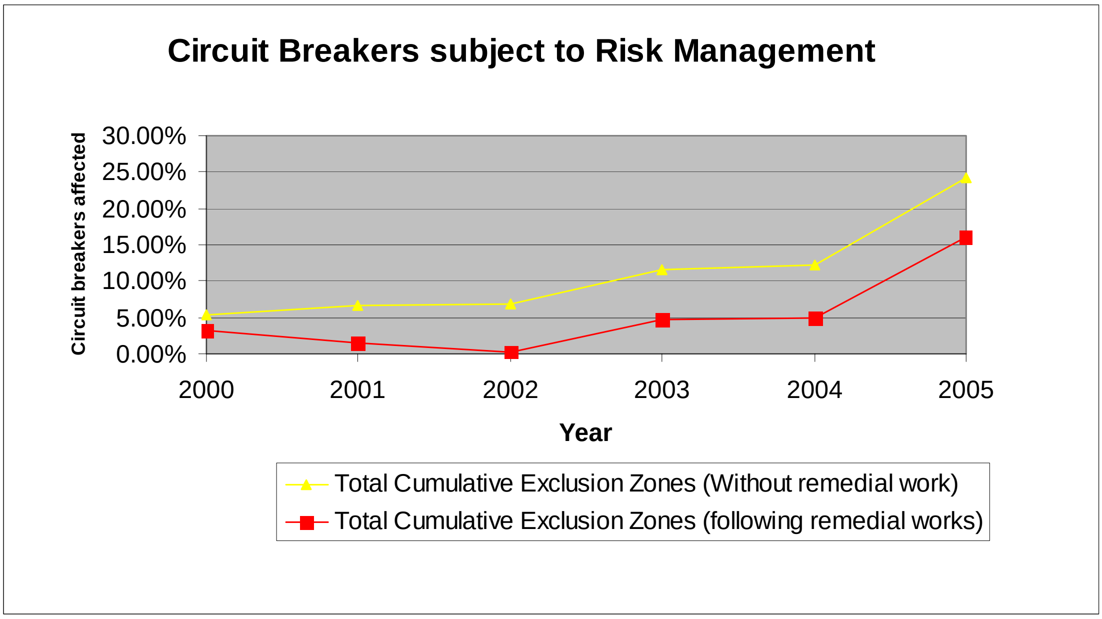


Within the cable scheme prioritisation process there is a risk and consequence assessment undertaken and scored for each potential cable replacement scheme for each of the environmental issues (as covered by the chart above) and system operation issues. In this case it shows that some clear risk metrics have been applied in assessing the need for asset replacement.

The above is one example of a "fragmented" or "embedded" application of risk metrics at the asset specific level. KEMA has seen a number of others embedded within various condition assessment reports and during the review of the Asset Health Review system.

4.9.1.1 Risk Management Hazard Zones

NGET stare that one indicator of asset specific risk is given by the number of safety zones it has in place around switchgear, the growth in which is illustrated below:

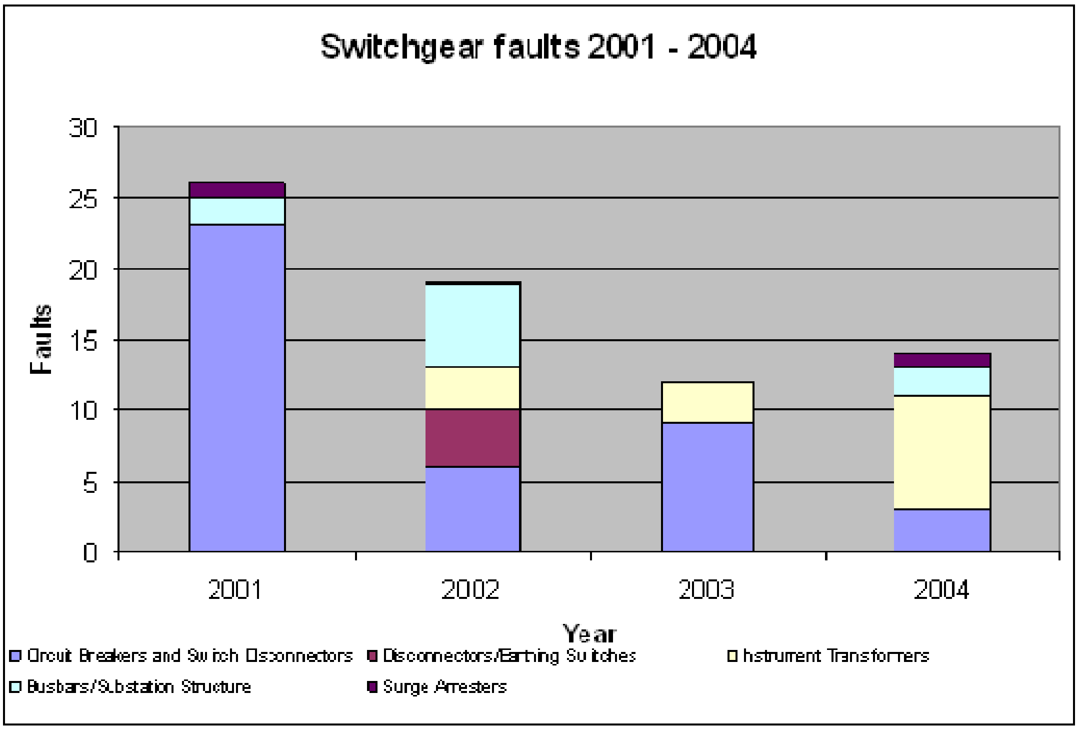


The total number of circuit breakers subject to risk management has risen from 88 to 442 over the period, or 3% to 16% expressed in percentage terms as requested. KEMA highlights these statistics for two reasons:

(i) the step jump in number indicates block implementation of risk management hazard zones for whole families of switchgear at a time based on assessment of a selection from that family. It is not clear whether the blanket application of such zones is appropriate for these assets; and

(ii) Since 2002 it would appear that only limited remedial action has taken place which is surprising given the emphasis on safety and the operational restrictions such zones impose on maintenance and site operation.

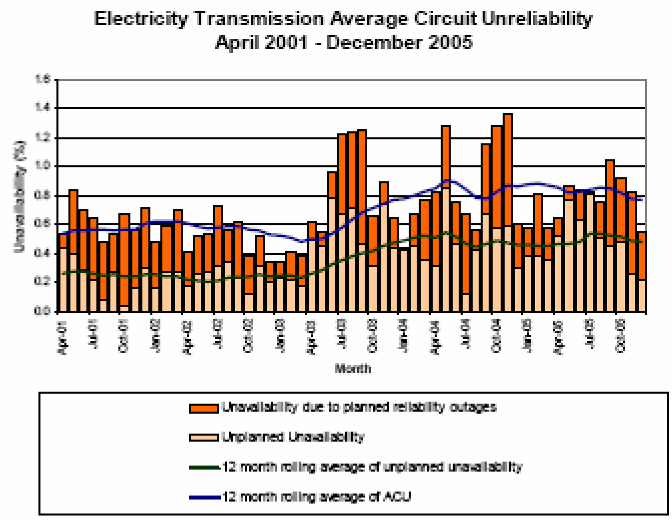
KEMA's concern raised in the first point is further emphasised by the chart below as provided by NGET:



This chart shows reducing faults (defined as: "An event which causes plant to be automatically disconnected from the HV system for investigation and further action if required.") for circuit breakers at a time when the number of safety zones is escalating. NGET state that 2005 has seen an increase in faults but nevertheless there is no apparent correlation between switchgear faults (or failures which are a very small subset) and the substantial increase in RMHZs. In the absence of apparent remedial action, these two issues would appear incompatible, given safety zones do not remedy switchgear reliability or performance. KEMA would expect that, given the high proportion of circuit breakers (c. 16%) deemed to be unsafe, and given the lack of intervention, the number of faults and asset failures should rise. In KEMA's view such a lack of any correlation can only be explained by (a) the trigger for implementing an RMHZ being set at a low level of risk and/or (b) applied at an insufficiently disaggregated level.

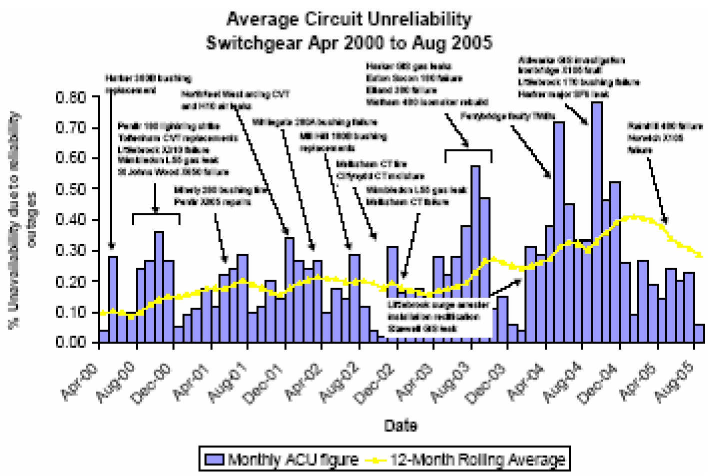
4.9.2 System risk

NGET has frequently referred to “risk” as a key consideration in its determination of NLRE Capex in its HBPQ submission, meetings and workshops and in their FBPQ response. However, KEMA has not seen how risk is defined, measured and applied quantitatively in determining asset replacement and capital investment requirements in a coordinated manner from an asset management perspective. This is especially the case at the Macro level. One “risk metric” that NGET has put forward as a key one is Unplanned Unavailability. This is shown below.



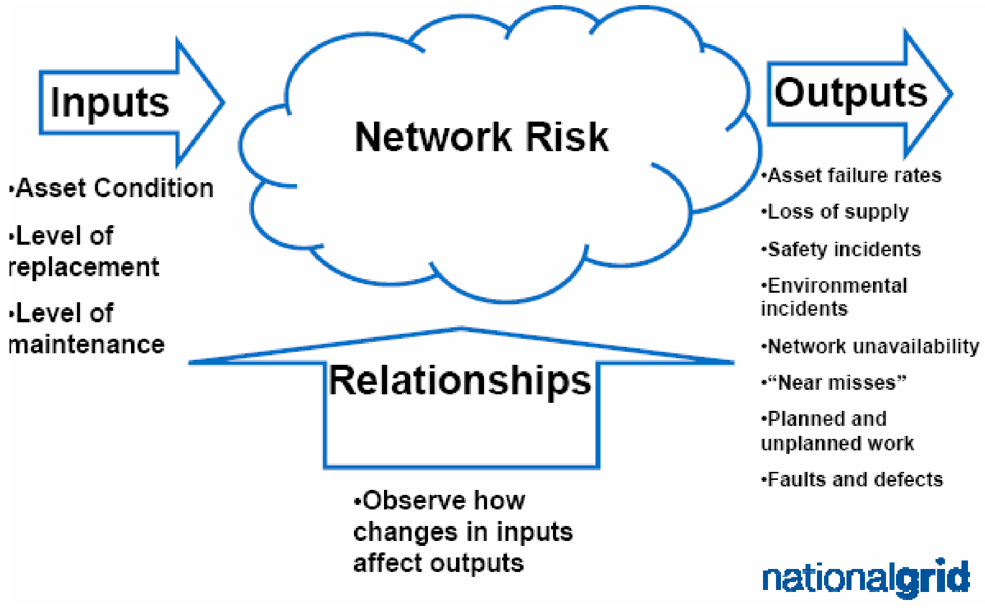
In the above chart each total bar shows total unavailability. The distinction is then drawn between those unavailabilities caused by planned outages to address reliability issues and those unplanned outages that arise due to faults etc, which then cause unavailability.

NGET indicates that it had noted the increasing trend shown and are continuing to seek to understand it but as yet are unable to identify a cohesive explanatory factor(s). For example, NGET have looked at each plant category such as switchgear shown below but apart from the prolonged nature of more recent outages cannot identify a common factor.



However, in Q&A correspondence NGET indicated that it had not looked at the unplanned unavailability driven by faults by primary asset category, although it did indicate it would take it 2 man weeks to retrospectively do so.

NGET held a one day Workshop on 21 February 2006 solely devoted to the issues of network performance and asset risk. At this Workshop NGET presented a conceptual framework regarding the definition, measurement and monitoring of network performance and risk. This is illustrated by the diagram below which was presented at the Workshop:



This diagram provides a good conceptual framework although NGET was unable to demonstrate how this conceptual framework had been applied, was currently applied or was to be applied in future. In particular, it was clear that understanding of network performance and risk issues resides with a limited number of individuals within NGET. KEMA therefore believes there is scope for NGET to assess system risks in a more comprehensive, coherent and effective manner.

4.9.2.1 Capex KPIs

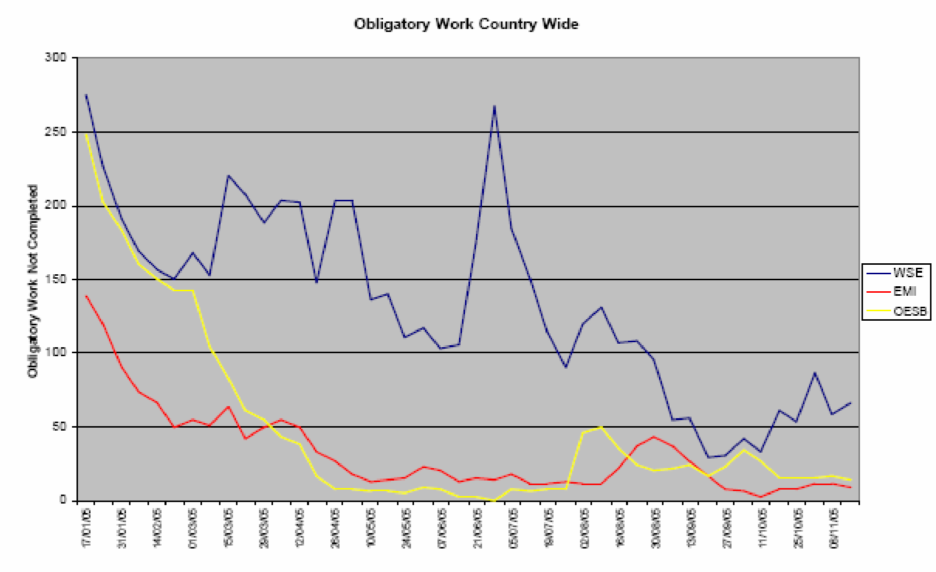
In answer to written questions KEMA has received details of Capex KPIs monitored by the TPSC on a monthly basis. In all there are 12 KPIs for electricity.

For each of these a more detailed individual KPI sheet is provided to TPSC for review illustrating recent performance, outlining reasons for poor performance and noting intended actions to redress performance.

These 12 KPIs represent a subset of a larger basket of KPIs monitored by TPAG on a monthly basis primarily focusing on different aspects of the transmission business performance.

4.9.2.2 Opex KPIs

Also Engineering Services appear to apply a well defined set of performance KPIs at managerial level with 6 KPIs that are specific to the activities of field staff and can be used to assess performance in the field from an overall national level down to a more local level. One example is given below:



This KPI shows for three different types of statutory inspection and maintenance activity the amount of tasks uncompleted first time. It can be seen that over the period since early 2004 Engineering Services has driven an improvement in performance in this area.

4.9.3 KEMA's views

NGET's use of risk metrics within the asset management processes, especially at the network level, could be improved with respect to asset replacements. There are some performance focused capex KPIs monitored by TPAG and Engineering Services does appear to have robust set of Opex related KPIs which have been in place since 2004.

It is evident that some risk metrics (whether quantitative or qualitative) are applied at a micro level but the application of such risk metric appears inconsistent. There is also evidence, despite the monthly TPAG review of KPIs that NGET is not maximising the use of available risk metric data which has in its possession. Coordinated and effective use of risk metrics could be improved at the macro level.

Furthermore, there is some evidence that in the case of safety zones there is an inconsistency between risks and performance data. Such safety zones have a major impact on both Opex activities and forecast Capex requirements. KEMA acknowledges the importance of safety issues, reinforcing the requirement to understand risks and reflect these in asset management decisions.

4.10 Engineering Opex and NLRE optimisation

4.10.1 Engineering Opex

Engineering Services are the primary driver of (controllable) Engineering Opex and headcount. Network Strategy now encompasses most of the remaining Engineering Opex activities under a structure that has radically changed since the last Price Review. There are potentially less Engineering

Opex issues to explore for Network Strategy (compared with Engineering Services) during the HBPQ period, with the possible exception of closure of the R&D facilities at Leatherhead and loss of some associated skills.

Inspection and routine maintenance is undertaken by Engineering Services staff (and in some instances contractors). Until 2002/03 this area of work was carried out under a regional structure and thus inspection and maintenance practices may have varied between different parts of the country. Following the “Staying Ahead” and “Ways of Working” initiatives and the emergence of the national Engineering Services structure, KEMA understands that inspection and maintenance whilst undertaken at a regional level is now done on a consistent basis nationally in accordance with relevant NGET policy documentation and central coordination and monitored.

Furthermore, since the implementation of peripatetic working through adoption of Office in the Hand (OITH) and the evolution of NGET’s asset systems under the Work Asset Management (WAM) project, there is now a more robust supporting IT infrastructure and allied business processes in place than there were as recently as 3 years ago.

OITH allows field engineers to enter inspection and maintenance information directly into prescribed electronic scripts on hand held devices. This information is then transmitted back to centre where it is used to update the information held on assets and their condition but also to identify further maintenance or potential replacement requirements. Embedded within these electronic maintenance scripts are key condition assessment questions and these are used by Network Strategy to enhance their understanding of the current and evolving condition of the asset population(s). These processes are already established for substation plant although detailed condition assessment of OHL continues to be paper based, collated regionally before being input into an Excel spreadsheet centrally.

WAM has delivered a central system(s) linking the technical asset register to maintenance and condition history. As it is accessible by Network Strategy, who are responsible for setting asset strategies and policies including for maintenance, and by Engineering Services, who are responsible for undertaking the inspections and maintenance, this ensures a common view of the state of the asset base. It also facilitates communication and coordination between Network Strategy and Engineering Services in addressing key issues in relation to asset condition and/or necessary changes to both asset (and thus maintenance) policy and actual inspection and maintenance activity.

KEMA understands that, as a general rule, whilst OHL inspection and maintenance is wholly driven by condition assessment and thus status of particular routes, the remaining primary assets are typically inspected and maintained on an interval based policy, albeit informed by the general condition of the asset population or major sub-families.

As previously highlighted, Network Strategy and Engineering Services are to be merged to form a single Asset Management directorate. This merger is ongoing at present with only the high level structure finalised at the time of the report. However it is already clear that gas and electricity are to be separated in some areas whilst activities under Network Strategy and Engineering Services are combined within these commodity specific functions.

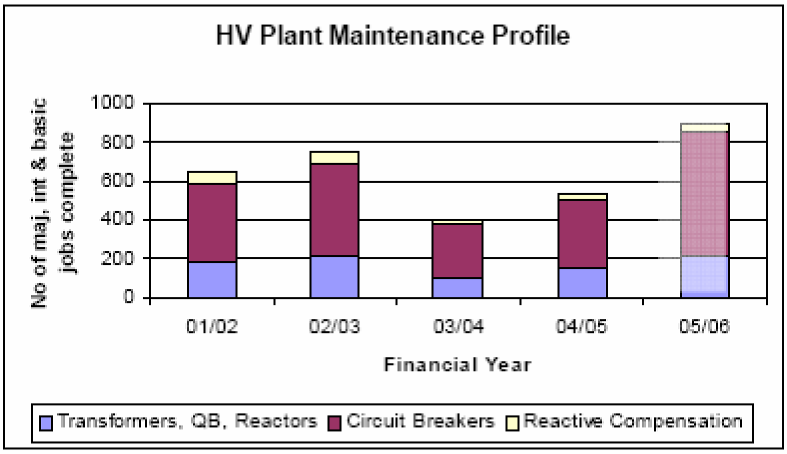
Essentially, the rationale for the merger put forward by NGET is that it represents a natural evolution which will further integrate and improve the effectiveness of asset management activities by establishing single accountability for assets including cost accountability for asset policy decisions. NGET also suggested this development will help meet the needs of the escalating capital plan, including providing a more sophisticated approach to supplier management, which indicates dissatisfaction over procurement activities in relation to both Capex and Opex activities.

It was clear from Workshop discussion with the new Director of Asset Management, and a leading member of the TBPR team that there were clear objectives to bring policy makers and practitioners closer together and to introduce greater cost control.

Whilst this merger will roll out over the next 6 months, the final form has yet to be confirmed in terms of FTE reductions (although there is provision in the FBPQ for such headcount reduction company wide) and in terms of effectiveness of performance.

4.10.2 Engineering Services' Routine Maintenance Activity in the HBPQ period

Discussions with Engineering Services revealed a fall in maintenance activity during the HBPQ period. This is illustrated below:



4.10.2.1 Review of the 2003/04 "exceptional low" activity year

It can be seen from the above chart that maintenance activity in 2003/04 was low and Engineering Services have explained this was due to difficulties in the implementation of both the new Engineering Services organisation and new IT technology such as OITH. Specifically NGET explained that the decrease in 2003/04 was greater than anticipated as a result of the combination of factors set out below:

- The field force adjusting to organisational changes and different working methods;

- Problems encountered implementing day to day work plans that achieved the right balance between application of detailed local knowledge and appropriate regard for competing national priorities;
- Initial reliance on an interim intranet based work management system until summer 2003 when the new Office in the Hand (OITH) system was launched;
- Initial difficulties with obtaining GPRS connections between OITH and the Planning function.

NGET also highlighted that, following the loss of supply incidents in London and Birmingham in August and September 2003, there was a temporary diversion of field staff activity onto asset audit and site integrity checks that contributed to the reduction in routine maintenance tasks. However, a further reason may be associated with Group financial objectives and thus pressures to keep costs down immediately post merger with BG Transco. This is discussed in more depth later under Capital Planning.

During this period of reduced productivity, NGET claim that its normal risk assessment processes were used to prioritise activities. The decisions to defer maintenance activities were made in line with NGET's maintenance policy, and therefore did not impact on asset risk or network performance. This is because this maintenance policy sets minimum and maximum time intervals for each asset type, along with a target date within this range for maintenance to occur. The minimum interval is usually target minus one year, the maximum usually target plus one year. NGET states that this flexibility in the maintenance intervals allows assets associated with the same circuit to be maintained at the same time thus maintaining high system performance without prejudicing asset performance. Furthermore, NGET states that this "bundling" of work improves system availability by optimising the amount of time circuits are out of service for maintenance works.

When asked by KEMA in a written question about the impact on planned activities for 2003/04 NGET provided the analysis below:

2003/04 Records	Transformers, QB, Reactors	Circuit Breakers	Reactive Compensation	Total
Total number of basic, intermediate & major main tasks	244	671	20	935

NGET indicated that out of the total of 935 tasks, some 474 were completed. There are a variety of circumstances pertaining to the balance of 461 tasks that were created but not completed. These include:

a) Tasks that were deemed not to be required for various reasons. Such as:

- unwanted tasks erroneously raised on assets that may have recently been decommissioned
- to avoid undertaking invasive maintenance on an asset that was scheduled to be replaced later the same year;
- other tasks raised in error.

b) Tasks which were precluded from being completed because of constraints such as system access limitations, field force capability and weather. NGET acknowledges that 2003/04 suffered from poor field force productivity but are keen to highlight that remedial actions have been put in place through the "Ways of Working" review that have brought productivity improvements evident in 2005/06 performance data.

c) Tasks that were deferred (e.g. for a complete maintenance cycle) following risk assessment considerations. In these cases risk mitigation or substitute tasks may have been performed, but are not necessarily captured in these results (e.g. additional inspections or oil samples taken).

"Work Not Done" & Risk Assessment

NGET states that to defer maintenance work beyond the time intervals prescribed within NGET's maintenance policy a risk assessment is applied. NGET indicates that prior to the implementation of the improved "Ways of Working" (WoW) processes in 2005 the application of risk assessment was administered through 2 methods.

b) The application of generic and localised risk assessments. The generic assessment ensures that the deferred maintenance conducted at the next scheduled date (normally 3 years) can be of a higher specification to the original requirement where necessary. The plant specific checks ensured that work was not deferred on assets with outstanding defects, technical limitations or design modification requirements under TDCs/EMIs. Consideration is given to 3rd party access to areas exposed to plant with deferred maintenance.

c) In instances where previous issues have resulted in 'work not being done' a further localised risk assessment was applied by experienced engineers with a comprehensive understanding of the condition and defects history of each item of equipment. Deferral was always to the next planned outage, nominally 3 years. If an interim task was deemed to be necessary this one off job would have been classified as an additional task and therefore not as planned maintenance policy. To enable deferral of maintenance additional checks may be required to take place in lieu of the maintenance activity (additional oil sampling, additional trip or operational tests).

NGET noted that by virtue of deferring maintenance this does not necessarily result in an increased number of tasks to be undertaken in the deferred year. NGET acknowledges that this deferral of maintenance may however result in the subsequent task being of a higher level to that originally deferred and hence the number of tasks to be completed in any one year could remain consistent.

4.10.2.2 Review of 2004/05 – a low activity year

Whilst NGET claimed 2003/04 was an "Exceptional Low Year" KEMA further noted that maintenance activity in 2004/05 had also remained at a low level (if slightly higher than 2003/04). NGET accept that following the low year in 2003/04 a degree of recovery would be expected in 2004/05. However NGET indicated that this level of recovery remained low caused by the following contributory factors;

(i) The preparatory "year ahead plan build" for 2004/05 took place between January 2003 through to March 2004.

(ii) The plan build process focussed upon creation of a deliverable plan based on data provided from the Field Force to the Central Planning Team. The planning of detailed resource schedules and the organisational culture and processes to support a peripatetic workforce had not developed sufficiently to replace regional focus with nationally prioritised delivery. Due to the prime focus upon maintenance work that was becoming due for delivery there was reduced consideration on recovering tasks that were due in the previous year.

(iii) In addition during the 04/05 delivery year the new processes under WoW were being settled in resulting in some planned work being further frustrated.

NGET claim that implementation of WoW has now improved national planning, national management information, supervision and delivery effectiveness to enable work to be delivered and overdue work continually managed at low level. NGET also refers to the Overdue Work KPI.

4.10.3 NGET's outsourcing of Engineering Opex activities

NGET currently outsources some network design work, specifically those activities that previously lay within the skill set of the 'Front End Engineer' activity in scheme development. However, NGET note that as these activities are performed after establishing the scheme need case these are capitalised.

A framework arrangement has been put in place with PB Power, Mott Macdonald, KBR and WS Atkins to call off these services. NGET indicates that these outsourcing costs are currently on a par with the costs had the role been undertaken internally. Also NGET claims that the current arrangement has the additional benefit of having a pool of expertise available to NGET through consultants, with an increasing likelihood of innovative solutions, the ability to match requirements both in terms of rising design work volumes and peak lopping, all at competitive rates and with no adverse effects on the management of the network.

4.10.3.1 NGET's outsourcing of technical engineering activities

NGET outsources a number of technical engineering activities and these are listed, together with the incurred costs for 2004/05 in the table below:

Item	Outsourced Service	2004/5 Costs
A	Site HV Electrical Testing	£500k
B	HV Testing & Calibration	£40k
C	Oil Analysis	£860k
D	Oil Analysis Interpretation	£165k
E	Forensic Analysis	£71k
F	Pressure System Safety Regulations Compliance	£377k
G	Network Mapping	£636k
H	Substation Equipment Maintenance	£5,815k
I	Substation Site Care	£8,475k

Activities A-E were outsourced by NGET following the closure of Leatherhead which was a strategic decision, made as part of 'Staying Ahead'. NGET recognised that these laboratory services were needed, but conducting them in-house was not the most cost-effective option. Some laboratory staff chose not to move and instead left the company whilst others moved to companies which subsequently became suppliers of laboratory services to National Grid. Similarly, some of the Leatherhead laboratory equipment was transferred to the new suppliers (oil analysis equipment to Nynas, site electrical testing equipment to Doble and HV testing equipment to BSTS and Manchester University). NGET claim that the benefits of outsourcing these laboratory services were:

- improving testing services through competitive tendering, process development and innovation in partnership with suppliers. All contracts are tendered on a regular basis to ensure price competitiveness;
- freeing National Grid staff to concentrate more on asset management activities; and
- making full use of suppliers' knowledge in their specialist area.

Results from the outsourced contracts play a key part in National Grid's asset management activities. NGET indicates that although the laboratory services themselves are not a core competency for NGET, staff with specialist engineering knowledge associated with these laboratory services work within Network Strategy. These staff make decisions based on the results from the outsourced contracts and also act as informed buyers of these services. For example, transformer oil analysis is conducted under an outsourced contract. Analysis of the oil provides condition monitoring of both the transformer and the oil itself. Interpretation of the results from oil analysis, as part of another contract, allows NGET to understand the health of transformers and may result in, for example:

- changes to the frequency of oil sampling;
- identification of the need for planned condition assessment tests (electrical testing);
- immediate withdrawal from service for internal inspection or bushing replacements;
- replacement or refurbishment of the oil; and
- feed into the transformer asset replacement prioritisation process.

NGET states that transformer condition assessment tests conducted as part of the Site Electrical Testing contract allow NGET to better understand the health of its transformers and also feed into the transformer asset replacement prioritisation process.

4.10.3.2 Overview of NGET's outsourcing of engineering activities and skill retention

For the Network Design 'Front End Engineer' activities and outsourced laboratory services where NGET Grid has lost internal capability, the decision to outsource these activities was the result of strategic decisions associated with 'Staying Ahead' with Network Strategy keeping its informed buyer capability.

For Network Mapping, NGET adopted the technology and developed the overhead line services using the Aerial Laser Survey data. As NGET states that this is not a core activity for it, a strategic decision was taken to create a subsidiary NGET company. This company sells these services to other utilities worldwide to leverage the combination of the technology and the overhead lines services as NGET's requirements alone would not have ensured full utilisation of the equipment.

External resources compliment Engineering Services in the delivery of field activities. However, in general these are not contracted in on a "head by head" basis but rather contracts are let for specific tasks as outlined in the previous section. Thus the number of FTEs involved in delivery of such tasks is the primary concern of the supplier whereas the cost charged to NGET is Engineering Services' prime concern. NGET indicate that FTE information for external resources is therefore not available and it would be difficult to form a meaningful top-down proxy relating to the balance of "internal" to "external" FTEs. However, NGET asserts that there has been no adverse consequence on the management of its assets and network as a result of the strategic decisions to outsource these activities.

In the meantime in areas of core business activity NGET is undertaking a number of parallel activities to retain skills in house including:

- Recruitment of graduates and apprentices who are trained to undertake core business activities

- Recruitment of staff with specific skill sets (e.g. protection and control)

- Targeted skill improvement through identification of current staff skills and development of areas requiring enhanced skills

4.10.4 KEMA's views

For the purposes of this report it is sufficient to highlight that:

(i) the impact of headcount reduction impaired the effectiveness of Engineering Services in undertaking its core maintenance duties [for a time;]

(ii) it is clear that NGET is increasingly heavily reliant on external providers for a number of key engineering/asset management activities. Until recently, procurement of these activities has been uncoordinated and costly and this should be expected to improve in the future under reorganisation of the procurement activity;

(iii) Engineering Services level of performance following reorganisation initiatives has been inconsistent over the HBPQ period but in the last year has improved but there remain some key issues such as outage planning;

(iv) the impact of increasing use of technology and the evolution of OITH and WAM was not properly thought out at first and aggravated difficulties arising from organisational change. These are now beginning to add real value but there is a question mark over the cost effectiveness of the solutions/approaches chosen; and

(v) the merger of Network Strategy and Engineering Services directorates into a single directorate should realise cost efficiencies not just from rationalisation of headcount but in realising greater coordination, cost accountability and efficiency of asset management activities.

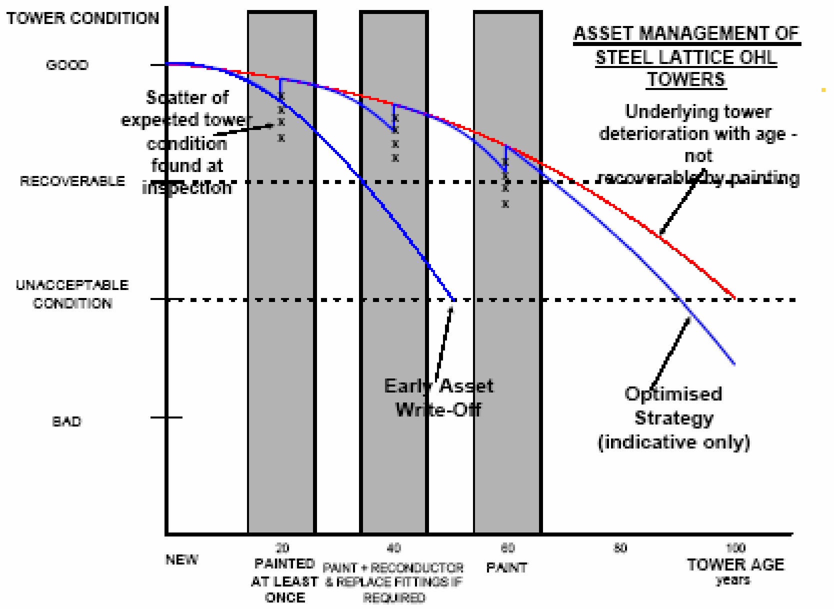
Further detailed review of engineering Opex is contained in a separate report including views on appropriate Opex allowance for engineering activities in the FBPQ period.

4.10.5 Trade off between Opex and Capex

NGET have provided extensive information indicating NGET's definition of which activities/costs are regarded as Capex or Opex (this is provided in KEMA's Engineering Opex report for NGET). NGET has been equally clear that the Opex and Capex plans have been developed together so that a change to one cannot be made without impacting the other.

The NGET's price control submissions and workshop material did not clearly explain how the trade-off between Capex and Opex is optimised when making asset management decisions. However KEMA has seen a number of examples of where this Capex/Opex asset management choice is occurring.

One example provided to KEMA by NGET, is in the context of asset life extension in relation to towers. Here NGET have undertaken a comprehensive cost benefit analysis of the timing and frequency of tower painting on asset life and thus deferred need for tower refurbishment or replacement (see chart below).



Other examples of Opex/Capex interactions which NGET state to be embedded in asset replacement plans include the choice to undertake circuit breaker refurbishment (especially of OBR60s), oil replacement in transformers, and Littlebrook substation site refurbishment. NGET have also demonstrated maintenance cost changes as the asset population and mix of assets changes as a result of the capital programme.

4.10.6 KEMA's views

As shown above, there are good examples of specific asset related Capex/Opex trade off analysis leading to a national strategy being applied. However, a systematic approach does not appear to have been adopted for considering other Capex/Opex trade-offs.

4.11 The role of procurement

4.11.1 Interaction with the main asset management organisation

In an answer to a written question, NGET provided an outline of the role of procurement within its asset management activities as a whole.

(i) Network Design (ND);

- Lead and jointly develop within the scheme team the Contract Strategies on an individual basis;
- Regularly look for opportunities to package work differently, bulk up or bundle schemes to gain efficiencies in costs and delivery;
- Supported ND on developing the PDD scheme outline costing tool based on current contract prices, regular reviews ongoing;
- Provide support on scheme cost budgets/verification of costs prior to sanction (may involve suppliers);

(ii) Construction

- Jointly develop and agree contract strategies going forward;
- Deliver the tendering programme to support all capital projects, including construction contracts, consultancy services, survey works;
- Once contracts awarded, provide commercial support on variations, claims, disputes, general advice on the contract;
- Facilitate & administer the Supplier Development programme using the CLASS database;
- Act as the “Employer” or “Purchaser” on behalf of the company – provide protection & impartial viewpoint;

(iii) Asset Strategy

- Influence strategy for supplier selection of key strategic suppliers
- Support on QA / Expediting on equipment manufacturing

(iii) Engineering Services Planning

- Ensuring that all outages and Early Restoration to Service (ERTS) details are named within the tender documents and that the tenderers/suppliers are able to meet the requirements.

- Ensure that during the tender process tenderers/suppliers demonstrate sufficient resources are available to meet the project requirements.

(iv) Engineering Services Delivery (ESD)

- Liaison with the Delivery teams on site records (e.g. Underground services) and preparation of Pre Tender SHE Plans for input into the tender documents.

- Ensure that ESD provide a valuable input into the tender documents and during the tender evaluation so that any tenderers solution is deliverable on site.

KEMA notes from the above that the role of Procurement is secondary to and driven by the asset management organisation, mainly acting as an interface between NGET and suppliers for the administration of contracts and tender processes.

4.11.2 Relationship of Procurement with suppliers

NGET seeks to indicate that Procurement play a key role in Supplier strategy and maintenance of relationships.

KEMA enquired, in the context of escalating investment needs and thus equipment supply requirements how NGET and Procurement in particular seek to secure in an effective manner future requirements with Suppliers. NGET indicates that a relationship approach has been adopted to encourage information sharing with Suppliers to provide an indication of future workload. KEMA notes that this does not entail any contractual commitments and thus in the case where suppliers proactively invest in capacity, they do so at their own risk.

The level of detail NGET provides to suppliers with respect to its procurement requirement increases the closer it approaches the tender stage.

In the longer term (5 to 10 years out) NGET indicates that high level Business Plan volume requirements are shared with suppliers, with the caveat that its ability to proceed will be tempered by Price Control determinations.

In the medium term (3 to 4 years out) scheme specific details, with respect to volumes and need are shared with suppliers, based on NGET’s medium term identification of asset replacement candidates. Framework agreements, made on the basis of volumes of work coming forward, also help ensure that suppliers can identify and plan for future workload whilst providing cost benefits to NGET. NGET claims its OHL Pre Sanction Engineering (PSE), and substation Joint Activity Solutions (JAS), also provide suppliers with a deeper insight into its requirements and help provide firmer contractual arrangements.

NGET indicates that specific schemes in the short term (1 to 2 years out) are then tendered for before or after sanction as each case merits, or awarded on the basis of framework or other longer term arrangements already in place.

4.11.3 Value added by procurement

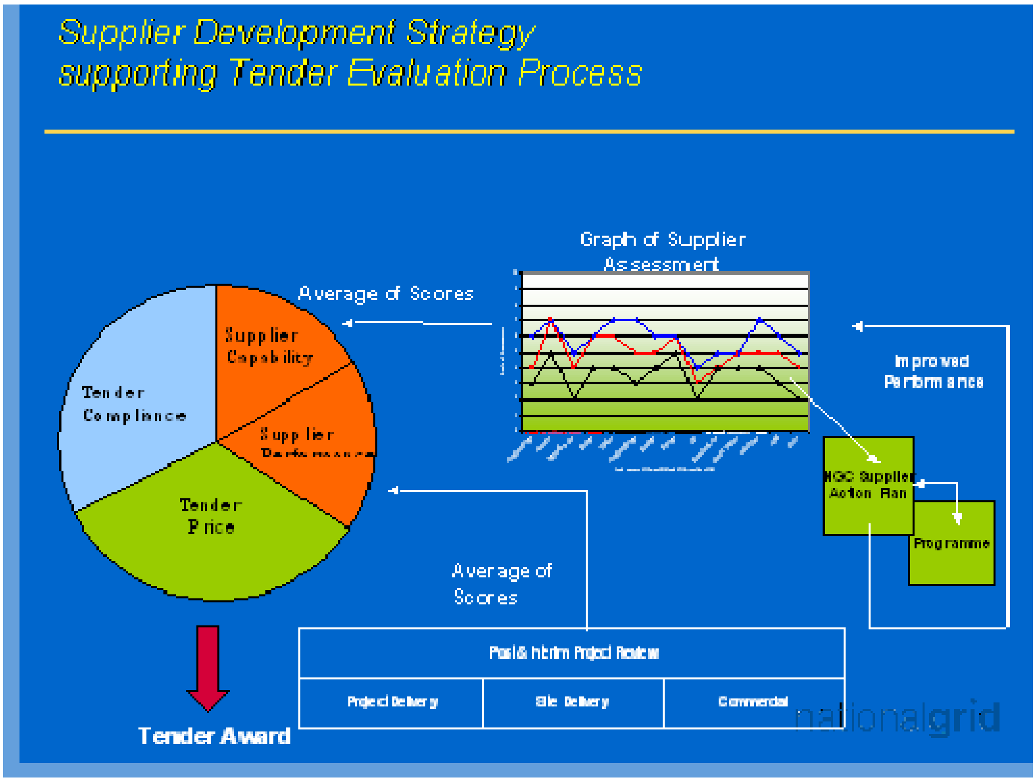
NGET provided an example where it claims Procurement has delivered a business benefit with respect to the 400 kV HV XLPE cable market for cable tunnel projects where Elstree / Dartford experience highlighted need to expand the supplier market. This involved supplier capability assessments, selling the vision, agreeing the strategy internal to NGET. The result is 4 key suppliers in a competitive market, nearly all Type Registered with new products, expanding portfolio. As a result NGET claim Unit Cost / km has reduced (<25%).

Furthermore NGET highlighted that two of the major longer term procurement strategies that are currently in place are the Bulk Purchase SGT contract, and the NICAP protection and control framework, which NGET claim produced 9-12% savings on transformers 10-30% savings on bay prices for protection & control.

However, in answer to a Written question (KE4075), figures for Protection & Control PDSAs provided by NGET indicate the real cost per bay has not dropped since 2002/03 despite a doubling of protection & control bays covered and will only fall slightly (<10%) by 2011/12 compared to 2004/05, with 2005/06, the first year of the new contract actually being the highest per cost for the full period since PDSAs were introduced. Given the recent receipt of the answer, KEMA has been unable to clarify the conflicting evidence provided by NGET.

4.11.4 The current role of procurement in securing plan deliverability

NGET indicate that Procurement also manage the Supplier development programme which monitors the contractor performance and provides feedback on potential improvement areas. This is fed into the CLASS tender assessment criteria to ensure that the suppliers are continually improving. NGET provided a diagram illustrating the supplier development strategy as shown below:



NGET indicates that regular assessments are made on capacity and capability to ensure the right resources are available for the future projects going forward. For example, civil subcontractor management has been a poor scoring area over recent years and this has been fed back through the Supplier development loop. All suppliers now have in-house civil expertise in order to better manage the technical, programme and commercial aspects of most areas of civil works.

NGET has further highlighted its strategy to focus on a relatively small number of key strategic suppliers. NGET outlines the benefits of having a small number of key suppliers as:

- Close working relationship / increased collaboration;
- Supplier Quarterly Forums;
- Providing more visibility of capital plan and imminent schemes;
- Discuss contract strategies going forward;
- Feedback on tendering / contracts;
- Streamlining tendering and contract process.
- Moving away from “confrontational” contract delivery. Examples include, risk sharing, open book methods and involving suppliers at the design stage; and

- Working with its suppliers to develop contract strategies.

Within this key strategic supplier approach NGET indicates that it applies a drive for continuous improvement and has focused on understanding its suppliers better going forward to meet the rising capital plan expenditure for the FBPQ period. It is noted that this does not entail any contractual commitments and thus in the case where a supplier proactively develops supply capacity it is exposing itself to risks if NGET were not to follow through on indicated work levels underpinning that supply expansion.

4.11.5 Implications of the Alliance approach for capital plan delivery

Procurement indicates that their role will change in the FBPQ period as result of the outcome of NGET's review of its UK Shared Services functions. In the future Procurement is to be relabelled as Supply Chain Management. The intention is that Supply Chain Management will perform an end-end procurement function typical of that found in other major companies

This will mean that the procurement function will take a more active role with the business and in the context of the asset management organisation will take a more active role in the procurement of services. NGET further indicates that a Procurement Council is to be established and that this will have subsidiary councils reporting in, one of which will be an Engineering Council. This governance structure will drive procurement strategy and seek to maximise purchasing leverage.

In the context of engineering Opex, NGET has indicated that it anticipates the increased role, improved sophistication, and greater business interaction of the Supply Chain Management function to deliver c.5% procurement savings. Thus, barring other changes, KEMA would expect the new Supply Chain Management function to equally be able to deliver similar savings for engineering Capex. Historic examples of more strategic purchasing for Protection and Control (NICAP scheme) and transformers (bulk purchase agreements) have delivered estimated cost savings well in excess of 10%.

In addition, NGET is implementing the Alliance approach to capital plan delivery as explained in section 4.4.6. Consequently, as this represents a fundamental change of organisational approach and without doubt provides greater long term security to suppliers for NGET's capital delivery programme, KEMA expects that this will reinforce and should enhance the costs savings achievable by Supply Chain Management.

The primary relationship in terms of the day-to-day supervision and oversight of Alliances would fall to Construction and that Procurement would effectively have a limited role once the Alliances had been established other than to monitor compliance with the Alliance contract and handling of related financial transactions.

Thus, whilst the Procurement function will become more sophisticated going forward it is likely to be primarily in relation to NGET Opex activities and that its role in Capex activities under the Alliance approach will be little changed. Consequently the successful adoption of Alliances to deliver NGET's capital programme will be driven more by the asset management organisation rather than Procurement. Procurement's main involvement will be in setting the commercial terms and incentives but its input is likely to be generic and will rely on the asset management organisation to tailor such terms appropriately to the objective of effectively and efficiently delivering the capital programme.

4.11.6 KEMA's Views

The role of Procurement within NGET currently appears to be subsidiary to the asset management organisation, acting as an interface between NGET and suppliers for the administration of contracts and tender processes.

NGET seeks to adopt a relationship based approach to share information with suppliers to reduce contract volume uncertainty. However, this does not entail any contractual commitments and thus where suppliers proactively increase supply capacity, they do so at their own risk. This effectively increases NGET's exposure to short term supplier pricing as seen in OHL scheme costs. There is scope for NGET to adopt a longer term and more integrated approach to procurement.

NGET have provided some limited examples to date that demonstrate where Procurement initiatives have generated cost savings to the business. However, the relationship of Procurement with asset management and the approach to contracting, provides scope to realise further efficiencies in future.

The changing role of Procurement post-TBPR and with the adoption of Alliances, should improve and it is realistic to expect procurement savings across the whole range of assets included in capital plan.

5. Implementation of asset management

KEMA's review identified that NGET largely implements its asset management strategies and policies into practice. However, KEMA has identified inconsistencies with respect to implementation in the following areas:

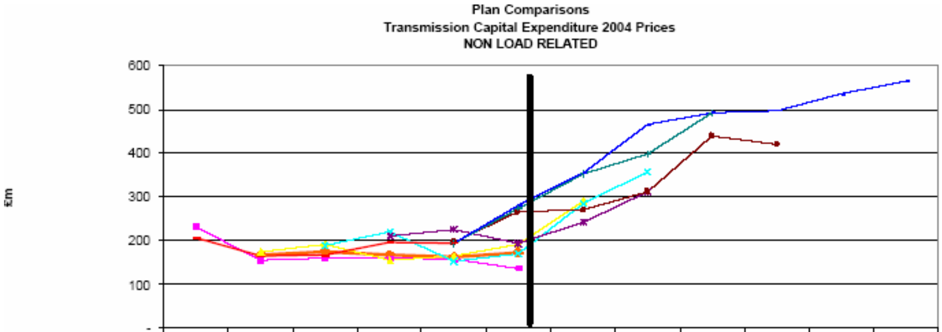
- efficacy of the capital planning process;
- the non-transparent influence of the GBSO in scheme design; and
- coordination of 132kV asset replacement with the DNOs.

5.1 Efficacy of capital planning

NGET has sought to explain the reasons for the Capex overspend for the historic price control period. The following charts were provided by NGET. It is clear from the chart below that there was a step change in 2004 for the year ahead forecast and beyond and that since then more recent forecasts have been similar.

	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12
Allowance	397.9	349.6	333.4	308.1	277.3	258.8						
2000 Dev Plan	385.4	408.1	395.2	329.8	240.6	210.2						
2001 Dev Plan		376.5	421.7	331.0	230.8	218.2	325.8					
2002 Dev Plan			397.8	406.1	243.6	215.8	406.5	488.4				
2003 Dev Plan				395.9	318.4	241.2	362.6	443.4				
2004 Dev Plan					351.1	498.4	566.3	653.0	741.6	651.0		
2005 Mini Review					352.3	464.8	614.1	668.7	760.9	748	767.4	785.3
2005 FBPQ					353.0	475.8	603.9	766.7	684.6	773.5	874.7	861.8
Actuals	373.8	374.4	376.1	364.2	353.0							

NGET provided a workshop to explain the evolution the capital plan. In summary, the synopsis was that up to 2003 NGET were seeking to operate within the capital constraint set by the Price Review. Then following the Transco merger, group financial objectives combined with lack of acceptance regarding the condition of the network and a limited DNO indication of exit schemes meant that the need for increased expenditure was not recognised in 2003, although this Business Plan was rejected by the Group Board. In 2004 NGET claims that unavoidable new mandatory exit schemes and urgent OHL asset refurbishment requirements resulted in a step change in forecast expenditure.



	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12
Allowance		165.8	174.0	166.3	160.6	172.5						
2000 Dev Plan	229.7	153.5	158.7	157.8	157.0	136.3						
2001 Dev Plan		174.4	191.4	152.9	163.6	191.1	289.7					
2002 Dev Plan			187.8	218.9	151.9	169.3	285.5	355.3				
2003 Dev Plan				208.6	226.0	193.6	241.6	310.2				
2004 Dev Plan					196.1	265.0	270.0	310.1	438.9	418.0		
2005 Mini Review					193.5	274.1	352.2	397.3	491.3			
2005 FBPQ					193.5	280.1	354.8	464.6	492.0	496.2	533.7	562.2
Actuals	205.2	164.2	165.5	196.3	193.5							

This chart shows a sudden step change in anticipated NRLE in 2004 but only for the year ahead, with long term expectations in line with previous forecasts. However, NGET’s Mini Review submission fell across the overlapping forecast period and KEMA notes that following the outcome of the Mini Review, the FBPQ submission shows a c.£80m increase in NLRE in 2007/08. Also, changes of 50% or more have been presented within 1-2 year time periods. This is a key focus in the context of considering stability and robustness of NGET’s FBPQ submission for NLRE.

KEMA requested the breakdown of the above chart by primary asset category. NGET has provided this as a series of tables from the 2001 Capital Plan to the 2004 Capital Plan. It is not clear why the tables for all years were not provided, especially as the breakdown provided differs from the HBPQ/FBPQ Table 9.9 formats, such that only OHL, Cables, Switchgear and Transformer Capex forecasts can be compared. KEMA notes that the initially forecast OHL investment increased in 2004 and has since eased; perhaps due to improved understanding of both condition and refurbishment needs. At the same time, forecast switchgear expenditure fell sharply in 2004 before rising sharply during the course of 2005.

Furthermore in the HBPQ period, OHL schemes have been the source of overspend against the TPCR3 capital allowance. However of the 33 schemes submitted by NGET in its 1999 BPQ, only 10 proceeded within the HBPQ period, 10 start (and some complete) within the Extension period 05/06-06/07, 6 have been deferred to the FBPQ period for this Price review (2 of which are forecast to start in 09/10 or later) and 6 do not appear to have or be taking place.

In the case of transformers, NGET indicates that in Aug 2000 there were 17 Category 1 transformers, 3 Category 1/2 and 31 Category 2 (consisting of 2a, 2b and 2c subdivisions). Of these, 5 Category 1 transformers and 9 Cat 2 were replaced in the HBPQ period with 3 Category 1 transformers delayed to 2005 or 2006 . From an answer to a written question it is clear that 8 (i.e. nearly half) of Category 1 transformers, as at August 2000, were subsequently downgraded (only two due to change in use given an additional SGT being put in place i.e. at Wylfa). NGET indicates that all of the originally identified

Category 1 transformers are due to be replaced in FBPQ period most by 2008 even though some were lowered in Category from 1 to as low as 2c.

The above information illustrates that in recent years, NGET's capital expenditure forecasts have not been stable, have been influenced by non-asset management related issues and were subject to a step change in 2004. It also highlights issues at the latter stages of the capital planning process, namely Stage 4 – Scheme Prioritisation and Selection (i.e. formulation of constrained plan) and Stage 5 – Plan Approval.

Clearly, this issue has implications regarding the role and robustness of NGET's asset management processes in formulating the asset replacement capital expenditure requirements for the FBPQ period.

5.2 Non-transparent role of the GBSO in scheme design

Within NGET, the GBSO influences scheme development and the TO capital planning process, more than appears to be the case for the Scottish TO. In particular, GBSO representatives participate in NGET scheme teams. This enables the GBSO to discuss and influence design solutions and scheme, timing etc. There is some evidence from review of schemes that this has led to high cost switchgear/substation replacement e.g. at Hurst and Nechells.

NGET has explicit policy documents relating to substation design, namely NGET policy PS(T) 070 *'Optimised strategies for asset replacement of substations'* which sets out the framework within which off-line build decisions are made; and where off-line build is selected, NGET's policy, PS(T) 023 which examines whether GIS or AIS is the most appropriate solution. PS(T) 023, expresses preference for AIS where circumstances allow, but GIS is adopted where land availability, visual amenity or pollution issues require the use of an alternative solution to AIS. NGET indicates that its preference is to use an off-line AIS solution, rather than GIS.

However, NGET's forecast proportions of GIS equipment (based on volumes) to be installed over the period to 2011 under asset replacement (as provided in KE1069v2), including both LRE and NLRE switchgear volumes, are rising as shown below:

Voltage	% GIS 01/02 - 05/06	%GIS 06/07 – 11/12
400kV	31%	40%
275kV	17%	35%
132kV	34%	48%

The relevant NLRE volumes for the equivalent future period are shown in the table below along with average separate unit costs for GIS and AIS.

	Proportion GIS	Average AIS Costs (£k)	Average GIS Costs (£k)	Average Total Costs (£k)

400kV	12%	[redacted]	[redacted]	[redacted]
275kV	31%	[redacted]	[redacted]	[redacted]
132kV	49%	[redacted]	[redacted]	[redacted]

It can be seen that the cost of GIS exceeds AIS in general although NGET highlighted that the above costs relate purely to the equipment and that it always seeks to construct the most economic practical scheme. Also NGET states that the difference is often hypothetical, as the AIS option could not be constructed in the available location. Also NGET states that in order to facilitate switchgear replacement with minimal operational and safety risk and with a reduced outage programme, it is often necessary to build a new substation ‘off-line’ adjacent to the existing site and transfer circuits in on completion. NGET further states that without this approach, system access would prevent delivery of the necessary programme.

NGET indicates its preference is be to use an off-line AIS solution, rather than GIS. Nevertheless, the evidence of the figures is that NGET is increasingly adopting GIS offline build. Thus it appears that, partly due to incorporation of the GBSO within scheme development team process there is an implicit policy of GIS build which is not purely based on the costs and benefits from a TO perspective and that it is possible that some asset replacement relating to switchgear or substation replacement is over-specified, driven by GBSO considerations which are not made explicit.

Whilst it is reasonable and arguably more efficient overall for NGET to act as an integrated TO and SO (for England & Wales only), nevertheless there is need for transparency of decision making where the costs and benefits sit on different sides of the SO/TO divide. KEMA has been unable in all its review activities, including Workshops, Written questions and analysis of scheme documentation etc, to find such clarity of reporting.

5.3 Coordination of 132kV asset replacement plans with DNOs

There is evidence of discrepancy in views regarding 132kV switchgear and the need for replacement between NGET and the DNOs. This is an area of concern for KEMA given the volume of such replacement identified for the FBPQ period.

In Written question responses (KE4036, KE4040 and KE4079) NGET indicated that it provides information on its long-term intentions for the replacement of connection assets on an on-going basis, usually discussed at Joint Technical Planning Meetings. Where NGET states that the replacement of a connection asset is necessary, it can enforce this under section 2.17 of the CUSC.

NGET indicates (in workshop discussion and Written question responses) that alignment of replacement programmes with DNO and directly connected customers is the preferred industry solution and reaching early agreement between parties is always its intention. NGET states that it would seek to enforce its rights under the CUSC only as a result of failure to agree a coordinated approach.

Furthermore NGET claims (in KE4040) that there is not disagreement about the case for investment, although this is not consistent with the claimed under-investment in 132kV switchgear during the HBPQ period, and the stated intension to “catch up” within the FBPQ period. NGET also indicates a joint approach to replacement is the industry preferred solution and there are many examples of this approach being taken in the current period. It suggests though that whilst companies may agree on the technical case for investment, the priority of taking forward this investment is dependent on competing priorities within respective businesses and the interaction with broader strategies. This can result in differences between companies regarding the timing of replacement schemes.

NGET states that it is not the case that its view of replacement timing is always sooner than that of DNOs, indicating there are examples (not given) where the DNOs have proceeded in advance of NGET and also where DNOs are requesting that the priority of particular replacement works be increased. However in the FBPQ (Section 5.1 Para 315) NGET highlights that the DNOs allocate an asset life of some 3yrs more than that assumed by NGET for equivalent switchgear (48yrs c.f. 45yrs).

Furthermore, NGET indicated (in KE4040) that in advance of DPCR4 NGET met with all DNOs with the aim of gaining alignment in investment at the 132kV interface. NGET has stated that alignment of investment priorities at the DNO interface is critical to optimise delivery of substation replacements. Consequently NGET states (in KE4079) that it instigated a series of workshops with the DNOs, typically titled “Asset Investment 2004-2010” and that the aim of the workshops was to review asset replacement drivers and strategy and specific investment priorities over the period.

NGET indicates that these workshops were in general in addition to normal JTPM discussions with broader representation on both sides and that to meet DPCR4 submission timescales these sessions were targeted early 2003. NGET claims that this work building on the JTPM framework was generally well received and as a result progress has been made at a number of sites (e.g. Littlebrook 132, Walpole 132).

NGET underspent on 132kV switchgear in the HBPQ period and indicates that this was due to inability to align investment with the DNOs (HBPQ Appendix 4 Para 171 and 173). Furthermore, it indicates a need to catch up on this investment in the FBPQ period based on “compelling” safety requirements (as evidenced by numbers of RMHZs) and are willing to enforce CUSC rights if necessary to ensure replacement of this catch up 132kV switchgear volume (FBPQ Section 5 Para 330-332) – this seems at odds with previous suggestions of alignment of NGET and DNO views.

It also seems strange given the escalating RMHZs since 2002 that, as discussed in section 5.1.2 above, NGET did not see a safety driven need to aggressively replace 132kV switchgear or to seek to enforce CUSC until beyond the HPBQ period – and this may reflect the fact NGET faced an unavoidable capital overspend in the HBPQ period. Historically, NGET has not chosen to enforce CUSC rights potentially undermining its statement of the urgency of the replacement need.

Finally the fact that the 132kV switchgear remains operating without any evidence of seriously eroded performance, reliability or safety both on the NGET and DNO sides of the substations (e.g. nearly

50% of OB14s are operating at an age above NGET's nominal LOSU for the family) does seem to accord more with the DNO viewpoint that the replacement need is not as urgent as NGET appears to suggest (but is not backing up with action).

6. Asset condition and system impact

The following sections outline the evaluation of the net impact of these policies, systems, processes and practices on asset condition profiles and network performance metrics.

6.1 Network performance

This section reports on the reliability and performance records of the transmission networks of Great Britain that are considered relevant to asset condition, with particular emphasis on NGET. The purpose is to confirm (or otherwise) the existence of evidence that there has been a change in network reliability and performance caused by deteriorating asset condition. Such deterioration could support the requirement to increase expenditure on asset monitoring, refurbishment and replacement. Statistics and analysis for SPTL and SHETL have been included in this section for comparative purposes.

The section reviews performance in a general sense, analysing primarily the publicly available performance data. The reason for this is that the majority of specific asset related conditions are assumed to have been identified individually in the company submissions.

This section addresses the following issues:

- A view on the expectation and acceptability of a deterioration in performance
- Records examined and a list of data available from them
- Discussion of which data is relevant to the task.
- Examination of the relevant data
- Discussion of trends in that data and conclusions

6.1.1 Should deterioration in network performance be expected?

It is generally reasonable to expect the reliability performance of transmission plant to follow the classic pattern over time of a number of problems emerging in equipment that is of new design relatively early in its life followed by a higher settled down level of reliability over the bulk of its life and finally a deterioration in this level as the life limiting mechanisms start to take effect. Although it is essentially evidence of the "end of life decrease in reliability" that is being searched for there are a number of reasons why one should not expect any evidence of this.

Firstly a number of failure mechanisms have safety implications, for example overhead lines falling down and anything resulting in catastrophic failure of primary substation plant. It is important therefore that wherever possible remedial work is undertaken before such failures occur i.e. it is not acceptable, where the risk of these types of failure is known, to wait for failure to occur.

Secondly there is a level of redundancy designed into the system, by means essentially of the Security and Quality of Supply Standard and similar historic Scottish standards, which assumes historic levels of circuit reliability and availability. If these were to drop then the redundancy provided by these standards would not continue to deliver the same level of security and quality of supply. Assuming that this would be unacceptable no reductions in levels of reliability or availability should be deemed acceptable.

Thirdly because of the age profile of the transmission network there is a risk that should life ending failure mechanisms start to become evident, this could happen across much of the system at a similar time because of its common age that it will be impossible to rectify the situation in an orderly manner due to resource constraints. Essentially one will suffer from a lack of sufficient materials, manpower and outage opportunities to address the proportion of transmission system components that may fail essentially at the same time. If this situation, which has been recognised since the 1980's, is reached the transmission licensees will have "lost control" and at this stage it will be impossible, even by allowing unlimited expenditure, to avoid a reduction in security and reliability performance.

Therefore increases in unplanned unavailability should not be expected. If such increases were to be observed, the licensees would essentially be "too late" to accelerate their asset replacement and refurbishment activities and would have entered the area where there is a deterioration in performance of the transmission system that impacts its customers in a noticeable and adverse way.

Records examined and data available

The following reports have been reviewed:

- National Grid Reports on Electricity Transmission System Performance (LC AA2) for 2004/5 and 2003/4;
- Scottish Hydro-Electric Transmission Ltd Transmission System Performance reports for 2004/5 and 2003/4;
- Scottish Power Transmission Ltd Transmission System Performance reports (LC D3) for 2004/5, 2003/4 and 2002/3;
- Distribution and Transmission Performance reports for 1997/98, 1998/9, 1999/2000 and 2000/01;
- additional material supplied by the companies as part of the price control review process; and
- responses to enquiries of NGET on equipment fault data and unplanned unavailability.

Data in these reports provides the following information:

- System availability by month for current and previous year;
- average annual and winter peak availability for the past ten years (5 years for Scottish companies);

- o monthly breakdown for current and previous (NGET only) year between various categories of planned and unplanned unavailability;
- o data on interconnector (s) availability;
- o data for last ten years (5 years for Scottish companies) on transmission system incidents causing a loss of supply with description of current year's events; and
- o data on incidents causing voltage and frequency excursions.

The older Distribution and Transmission performance reports give for transmission:

- Current year monthly unavailability and annual unavailability since 1991/92;
- Monthly breakdown of reasons for unavailability for current year in graphical form;
- Interconnector availability data; and
- Basic data on voltage and frequency excursions.

6.1.2 Data relevant to reliability performance

It was decided that a detailed analysis of data on incidents that affected customers was not directly relevant to the task as:

- There are few transmission incidents each year that cause a loss of supply;
- many of those that do are caused by bad weather rather than equipment failure; and
- many of the incidents relate to customer chosen supply arrangements e.g. a large direct transmission network connected customer that has chosen to be connected via a single circuit and thus will be off supply for any outage of that circuit.

Data on planned and unplanned unavailability appears to be most relevant to the task, of which that regarding unplanned unavailability is the key. This is because there is by definition control over planned unavailability i.e. one can determine within limits when it takes place and therefore avoid it at times when it would deplete the system beyond the level to which it is normally secured. this would no longer be the case if the backlog of work reached the stage where outages that would normally be planned became unplanned due to the deterioration of asset conditions to the point requiring removal from service without delay or tripping. Setting aside the possibility of this undesirable situation, the risk to supplies arises in a general sense from overlapping unplanned unavailability of two or more circuits in the same part of the system. Increasing unplanned unavailability therefore represents an indicator of the most serious (for system security) forms of asset deterioration.

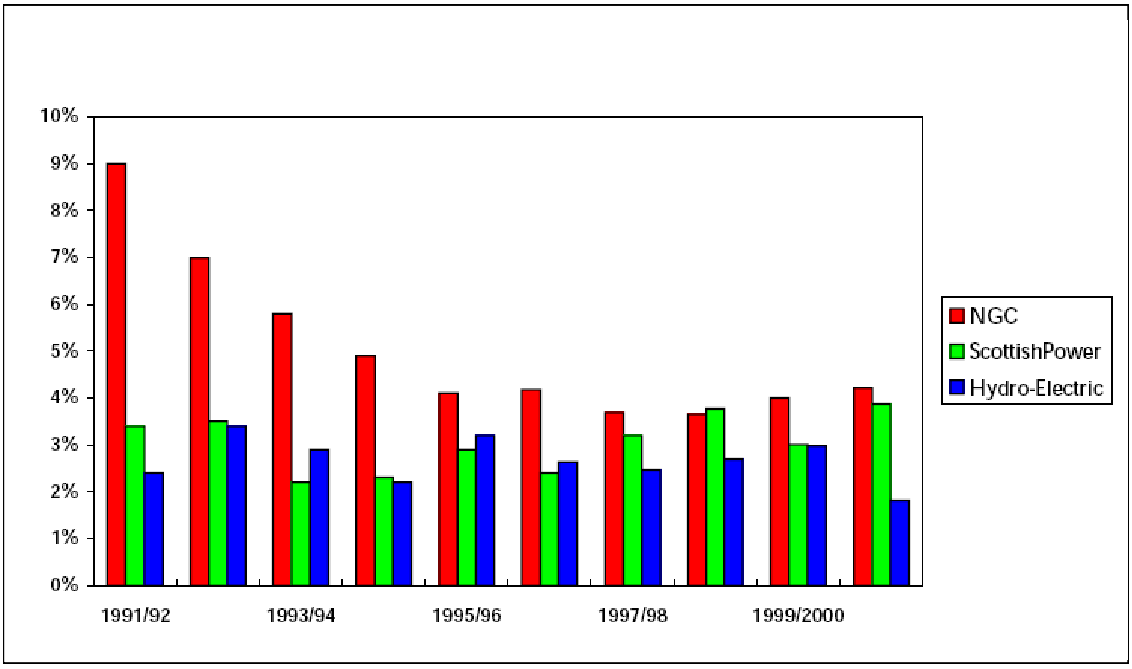
6.1.3 Relevant data

The relevant data from the sources examined is described, first for total unavailability and then for unplanned unavailability and finally for certain fault data.

6.1.3.1 Total Unavailability Data

It can be seen from from the 2000/01 Distribution and Transmission Performance report that the annual unavailability of the NGET system declined continuously and over the years 1991/92 to 1998/99 before rising at a moderate rate. It remained though generally higher than that for the Scottish companies, the unavailability for which showed no change over the period.

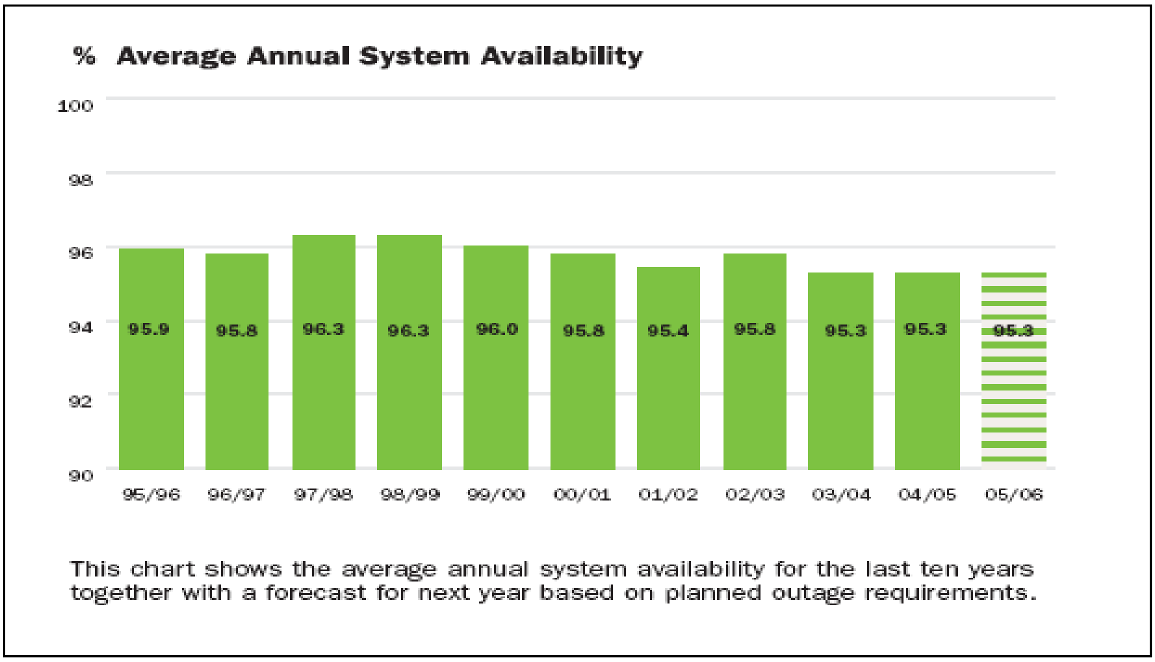
Figure 1 - Annual unavailability 1991 to 2000 for all companies



The decrease in unavailability of NGET' network until 1998/99 may have been due to efforts made to shorten outages to reduce constraint and other "uplift" costs although this trend started before the first uplift management incentive scheme.

Equivalent data for later years is presented in the original sources as availability rather than unavailability. The NGET data is given below in Figure 2.

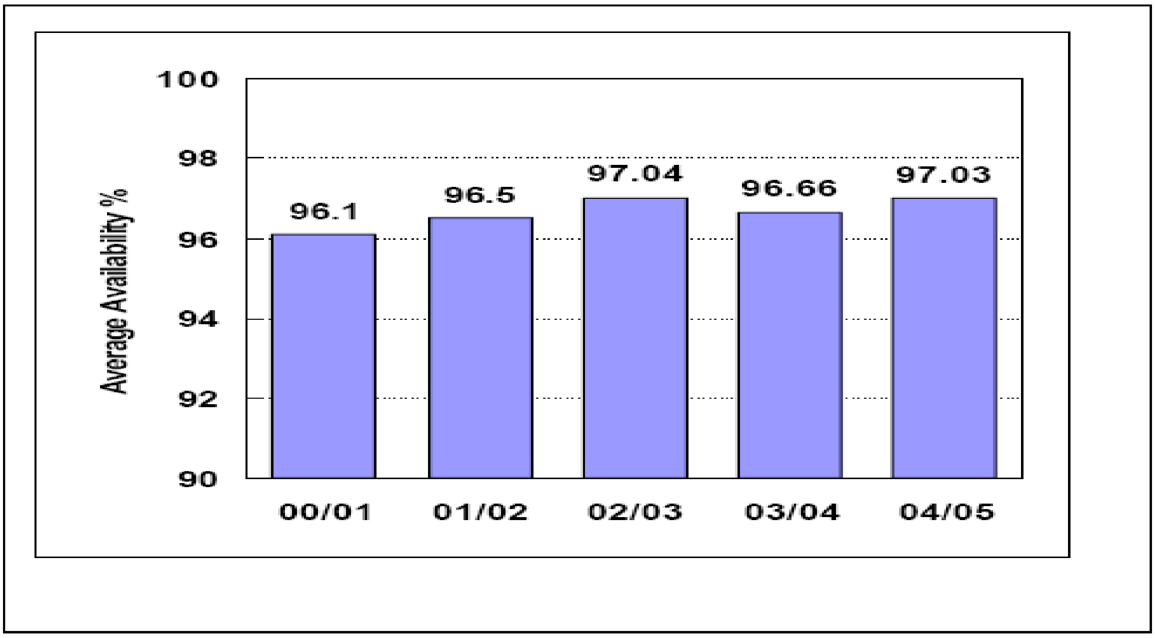
Figure 2 - NGET Average System Availability 1996 to 2005



It can be seen that the data for the common years presented in both formats is consistent and the small downward trend in availability (or upward trend in unavailability) continues from 1998/99 to 2004/05.

For Scottish Power Transmission the data from 2000/01 is presented graphically in Figure 3.

Figure 3 – Scottish Power average availability



The data for the common year of 2000/01 is consistent from both sources but the slightly increasing availability trend since 2000 reverses the generally decreasing availability over the previous five years.

For Scottish Hydro Electric Transmission the annual average availability from 2000/01 to 2004/5 is reported in Table 3.

Table 3 - Scottish and Southern annual availability

	2000/01	2001/02	2002/03	2003/04	2004/05
Annual Ave	98.13	98.65	97.85	**97.59**	**97.75**

The figure for 2000/01 is consistent with the previous data and it can be seen that the general trend of between 2% and 3% unavailability observed since 1991/92 is continued.

Comparing the levels achieved in the past two years by the different transmission owners shows that Scottish Hydro Transmission has maintained its availability relatively at over 97%, Scottish Power at between 96% and 97% with NGET's having settled at between 95% and 96%. One can not necessarily draw conclusions on the relative merits of the three companies from these figures. For example the Scottish companies' data includes that for the 132kv system which dominates the number of circuits in the case of Scottish Hydro Electric Transmission. It is also true that over the period considered NGET has had to accommodate more outage time associated with the connection of new generators than has been the case in Scotland.

This data is combined to produce annual unavailability trends for all these years in Figure 4 for NGET,

Figure 5 for Scottish Power and

Figure 6 for Scottish and Southern

Figure 4 - NGET annual unavailability

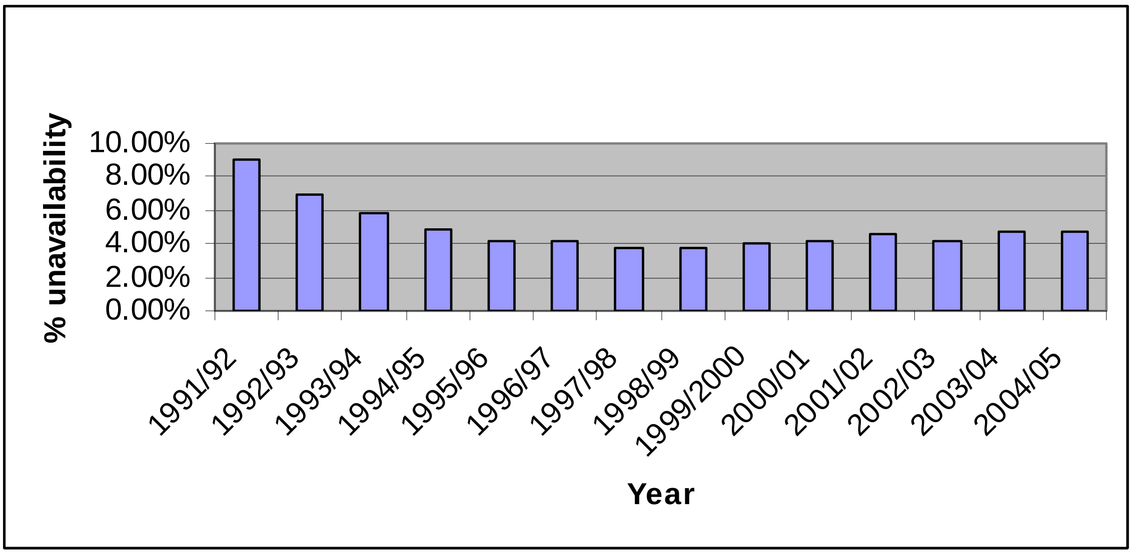


Figure 5 - Scottish Power unavailability

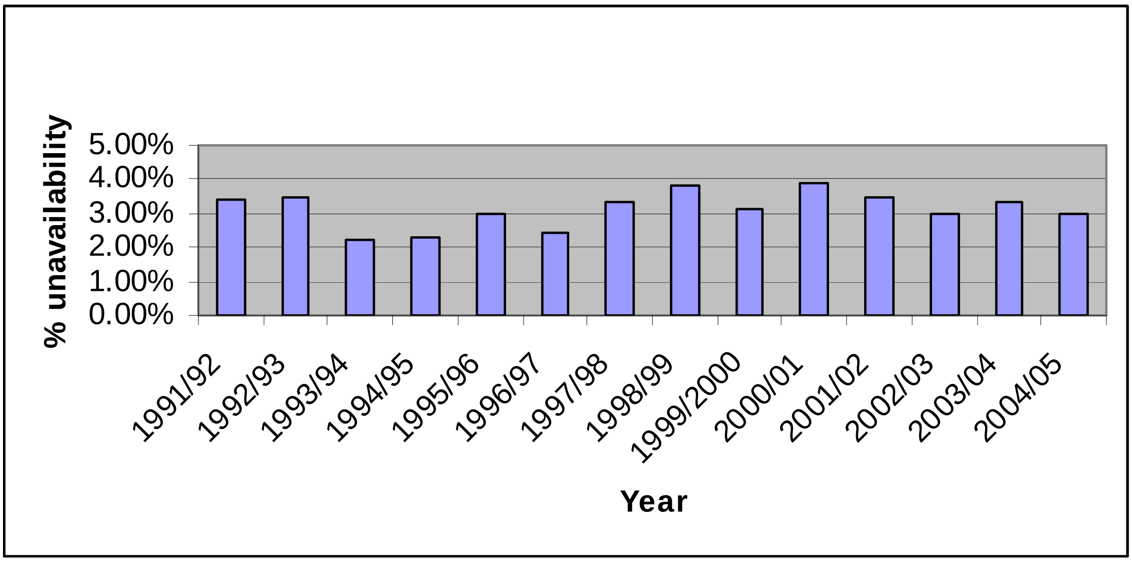
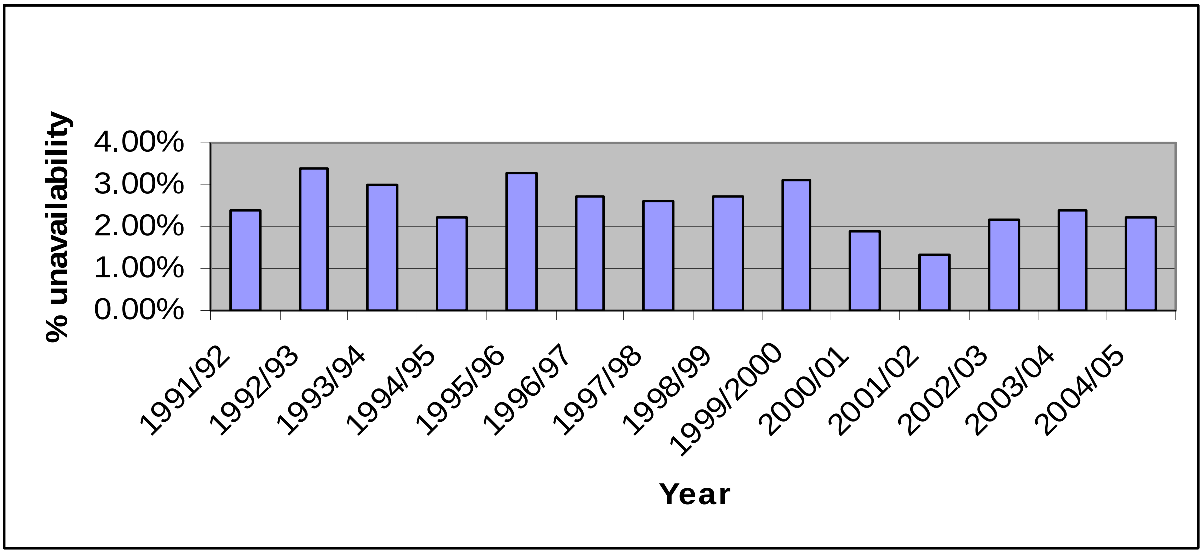


Figure 6 - Scottish and Southern unavailability



6.1.3.2 Unplanned unavailability Data

As suggested earlier it is the unplanned availability that is the most direct indicator of an increase in equipment unreliability. Although a proportion of the number of unplanned outages are due to weather related effects, the duration of these incidents tends to be short so the unavailability data is dominated by equipment failures rather than weather related faults. The unavailability data which takes outage duration into account is also important for system security as the longer forced outages last for the higher the probability that the outages are overlapped by another forced outage in the same part of the system. Table 4 comprises the unplanned unavailability data that may be extracted from the reports examined.

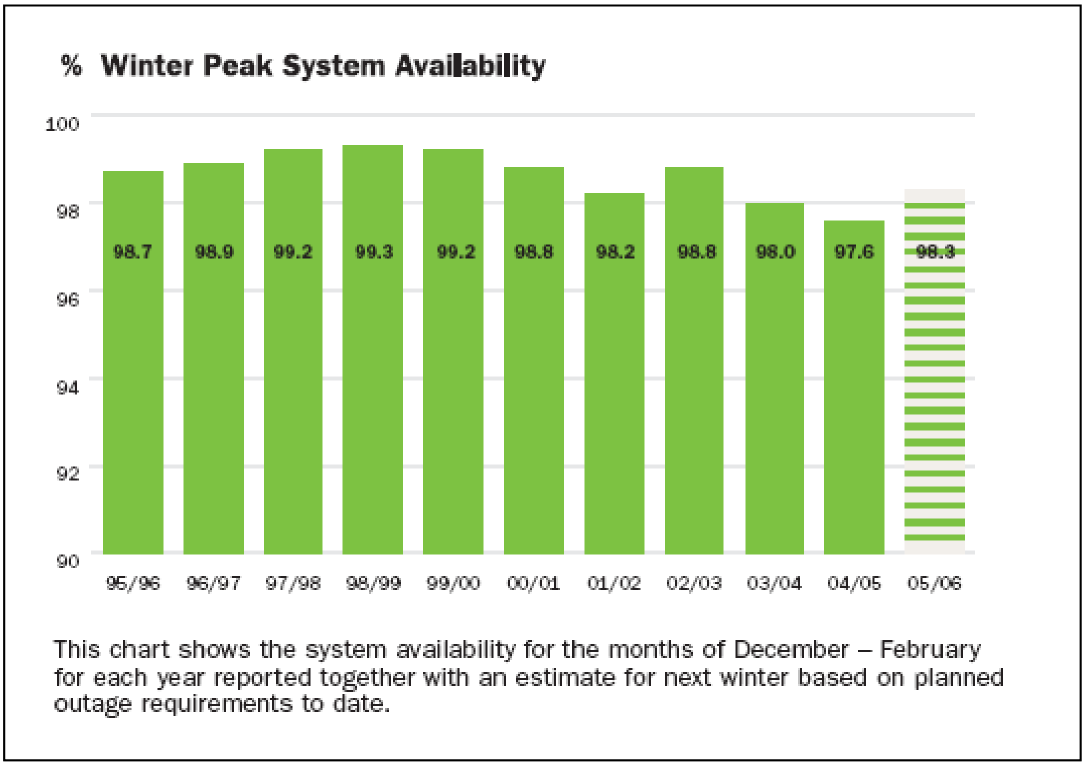
Table 4 - recent unplanned unavailability

TO	2002/03	2003/04	2004/5
NGET	0.29	0.49	0.47
Scottish Power	0.61	0.41	0.17
Scottish Hydro	-	0.19	0.04

The other data available in these reports is the ten year average for NGET. In the 2004/05 report this is 0.31%. This indicates that the NGET rate is (except for 2002/3) above the ten year average and possibly on a rising trend. The Scottish Hydro rate is low which may indicate its population of network assets (and 275 kV and above network in particular) is so small that in all observed years, it was possible to avoid any forced outages with long repair times.

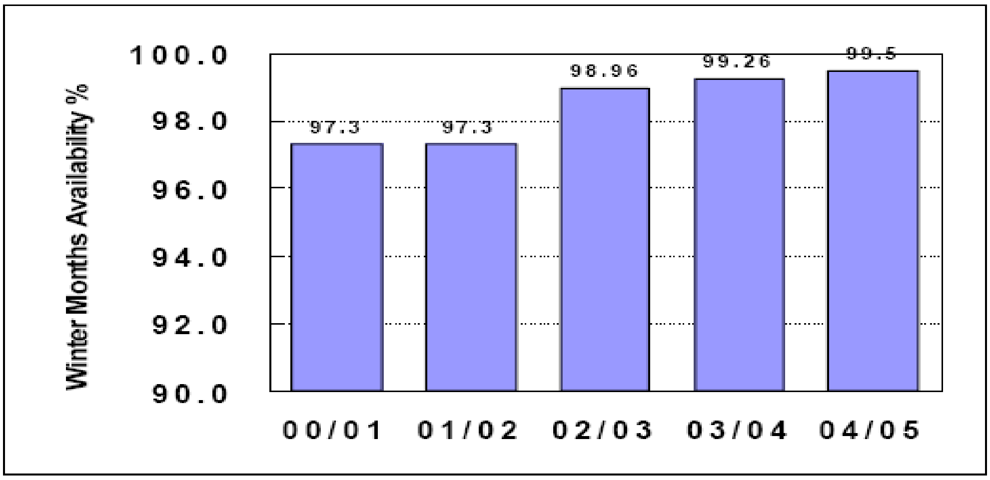
It is possible that the winter availability given in the reports for the months of December to February may be an approximate indicator of unplanned unavailability as the majority of planned unavailability is scheduled for other times in the year. NGET's 2004/5 data for this is shown in Figure 7.

Figure 7 - NGET winter peak availability



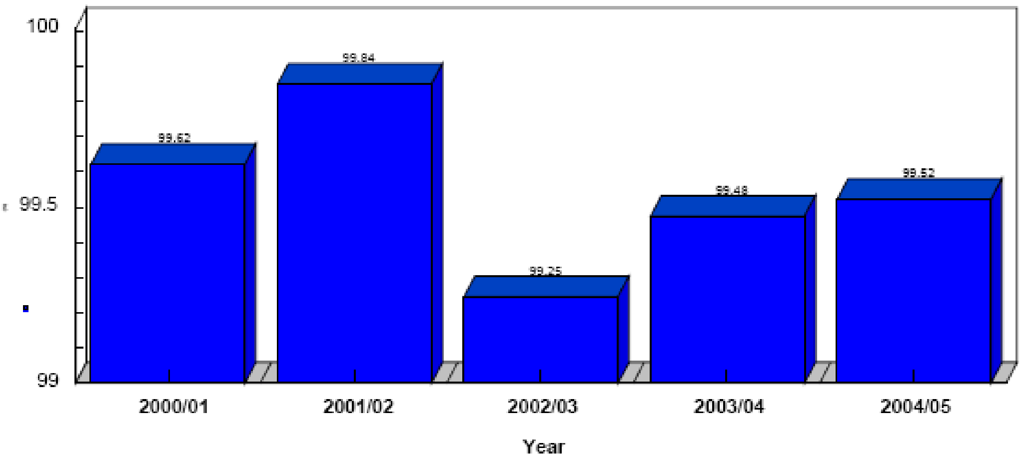
It can be seen that from 1999/2000 there has been a small downward trend in this. The Scottish Power winter availability appears from **Error! Reference source not found.** to have increased in recent years.

Error! Reference source not found. - Scottish Power winter availability



The winter availability for Scottish Hydro given in Figure 8 appears to be consistently at high levels (well above 99 %.)

Figure 8 - Scottish and Southern winter availability



Some data relating to unplanned unavailability that had been supplied as part of the price control process was examined. NGET's presentation at the January workshop shows two relevant graphs reproduced below.

Figure 9 shows that the level of unplanned unavailability has increased over the past five years. Its twelve month rolling average is now double what it was five years ago and at a level that would imply that the "average" circuit has about two days per year of unplanned outage.

Figure 10 breaks the unavailability down by plant type and it can be seen that all categories are on a rising trend. The increasing trend for switchgear must be of particular concern as unplanned switchgear outage rates may indicate a potential failure to operate when required, which is inconsistent with the assumptions which underpin network security calculations. Such calculations assume that any fault is cleared correctly with a high degree of reliability before it affects other circuits. A fall in switchgear reliability would invalidate this assumption.

Figure 9 - NGET unavailability

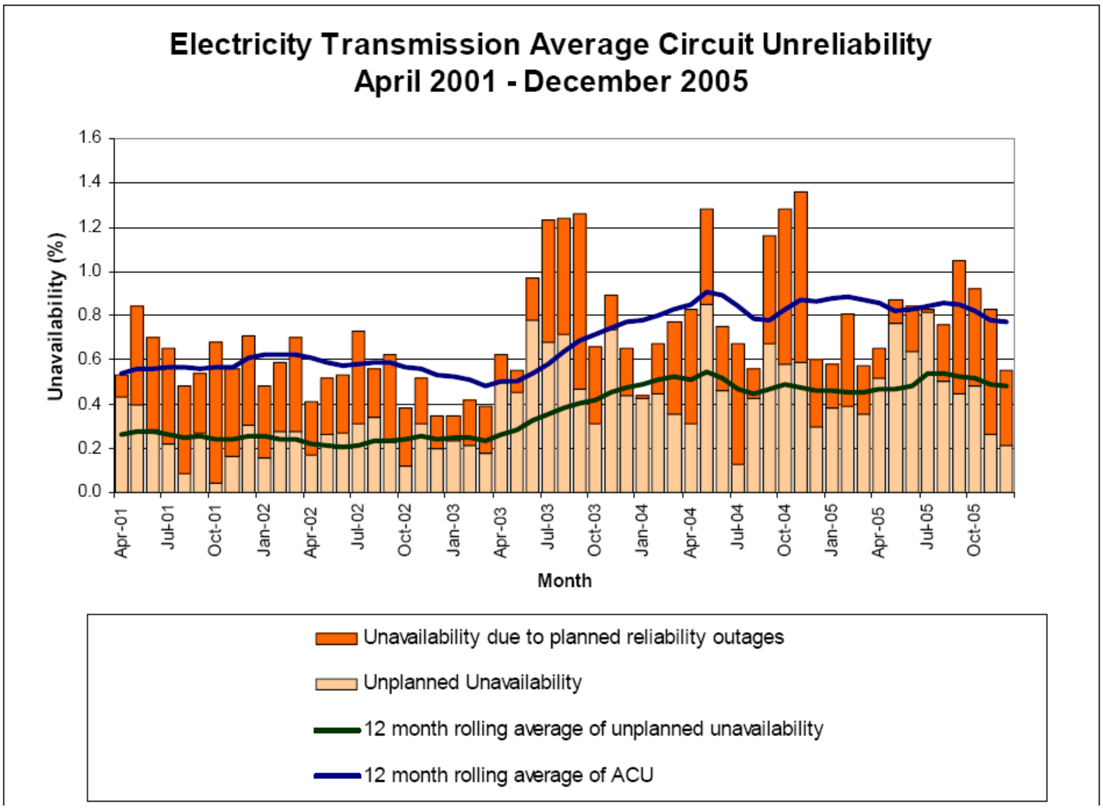
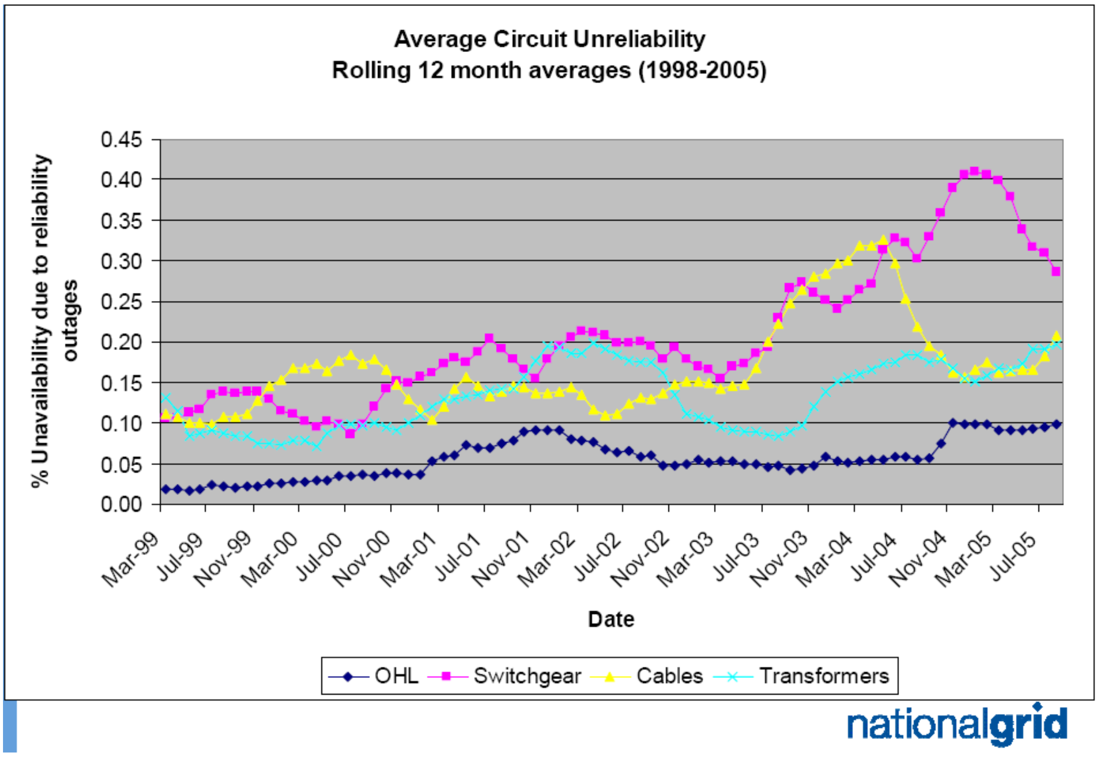


Figure 10 - NGET unavailability by equipment cause



6.1.3.3 Fault data

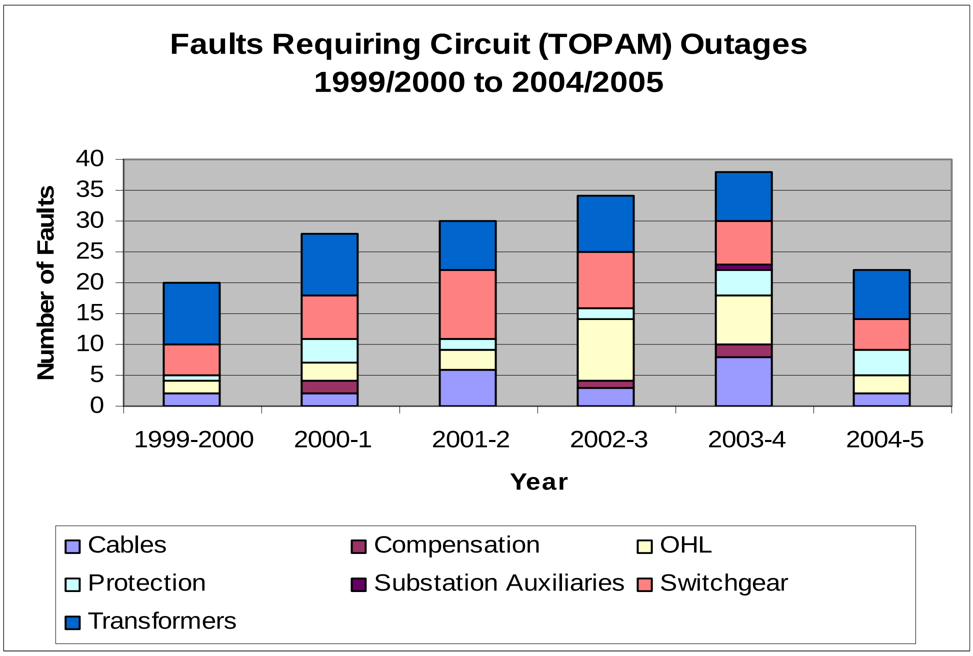
SPTL's response to question 6.5 from the historic business plan questionnaire, reproduced in Table 5, shows a modest increasing trend over the past five years in non weather related fault outages, which can be assumed to be broadly equivalent to equipment related faults.

Table 5 - Scottish Power fault data

	00/01	01/02	02/03	03/04	04/05
Weather related (no.)	166	138	19	9	15
Non-weather related (no.)	32	39	35	37	43
Total system faults (no.)	198	177	54	46	58
Incidents affecting customers	12	13	8	9	5
Capex cost of fault repair (£m)	1.0	1.3	2.2	3.3	0
Opex cost of fault repair (£m)	0.3	0.2	0.2	0.6	1.1

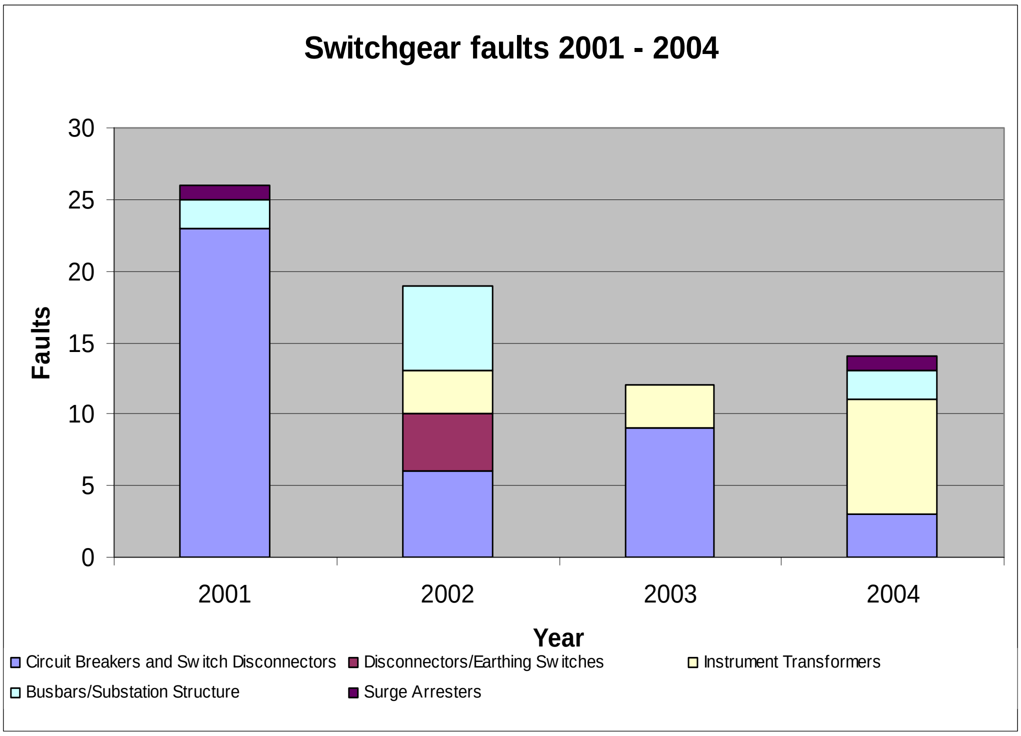
For NGET, some additional data on faults was obtained. Figure 11 below shows the number of faults that resulted in outages of at least 3 hours thus excluding many weather related trips that either reclosed successfully automatically or could be restored manually after a short inspection.

Figure 11 - NGET faults requiring outages of over 3 hours



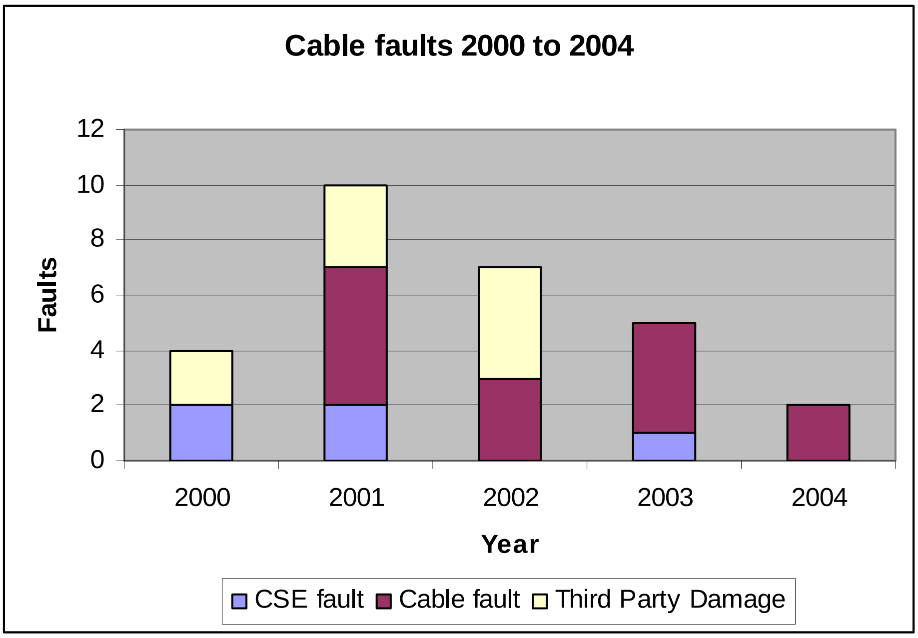
This shows an increase in the number of protection related faults and, apart from 2004-5, an increasing trend in the number of overhead line faults. Data on faults split in more detail was also obtained for a number of plant types. For example data on switchgear faults is given below in Figure 12.

Figure 12 - NGET switchgear fault data



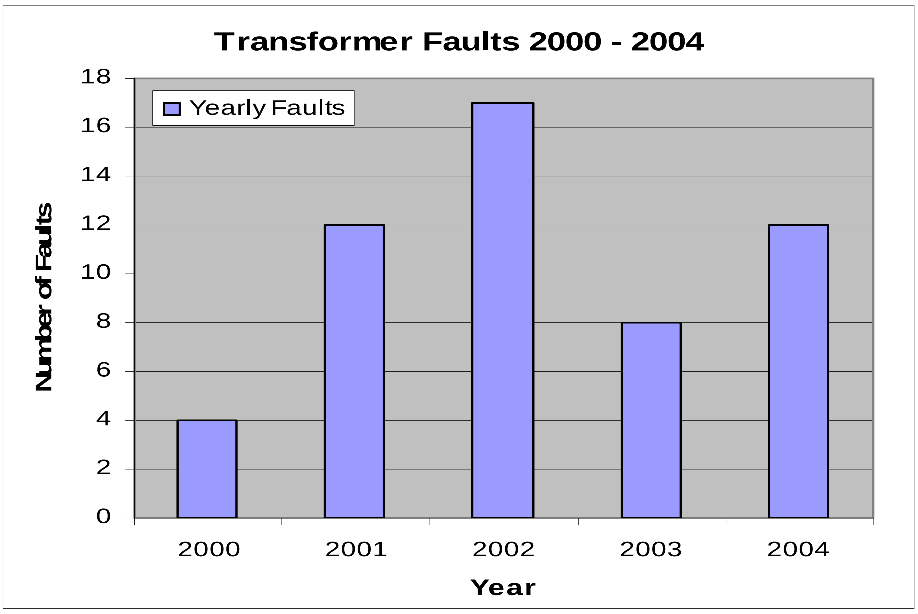
Whilst the numbers are small there does seem to be a trend of an increasing number trips caused by instrument transformer faults. Similar data for cable faults is given below in Figure 13.

Figure 13 - NGET cable fault data



Although this appears to show a falling fault rate it can be seen that the majority of this trend is due to the elimination of third party damage faults in the past two reported years so no conclusions can be drawn about the state of cables. There is no detectable trend in the incidence of transformer faults shown below as Figure 14.

Figure 14 - NGET transformer fault data



6.1.4 Discussion of trends in data and conclusions

Whilst the trends observed for total availability are of interest it is clear that these can not be regarded as a primary indicator of deterioration in asset conditions or otherwise. The increase in NGET total system availability over the first decade after privatisation and its levelling off in the past five years is noteworthy. There is a paucity of data readily available on unplanned unavailability by asset class from all of the transmission owners.

SPTL's unplanned unavailability appears to have reduced over the past three years although the non weather related faults appear to have increased slightly. SHETL's unplanned unavailability is too low for any meaningful conclusions relating to equipment deterioration to be drawn from it. The network performance from both the Scottish licensees has been consistent.

It is only in the case of NGET that the unplanned unavailability data, the winter peak availability and the unplanned unavailability provided specifically for the price control review show a rising unplanned unavailability trend that would be consistent with deterioration in the condition of the asset base.

Some data on fault outages was reviewed as a substitute for more detailed unplanned unavailability data. Whilst this data is on the number of faults rather than the resultant circuit unavailability, these give an indication of incidents which result in some unplanned unavailability. Whilst there was a small increase in non weather related faults in SPTL's area and a specific increase in fault numbers for NGET for instrument transformers and protection, there was certainly no particular evidence from this that the asset base has deteriorated to an extent that it is causing increased faults.

The primary indicator of need for increased asset refurbishment or replacement should be from investigation of the condition of assets before failure in service, rather than an observable increased failure rate. Notwithstanding this an increased unplanned unavailability is taking place within NGET's assets and, if supported by appropriate explanation of the individual failure mechanisms, this provides at least secondary evidence of the need to increase asset refurbishment and replacement activity.

6.2 Conclusions from NGET site visits

6.2.1 Substations

In total 17 NLRE schemes of NGET have been assessed during 8 site visits. All selected schemes were part of NGET's FBPQ submission. In addition KEMA also paid a visit to the Leicester switchgear refurbishment facility.

A part of the proposed replacement schemes for substation equipment (switchgear, transformers and reactors) investigated by KEMA are justified by the condition and age of the equipment. The following issues have been identified which could be interpreted to indicate over-forecasting:

- Two Walpole reactor schemes were not recognised. According to NGET staff there will be no replacements;

- NGET tends to replace switchgear in combined substations (NGET & DNO) earlier than the DNO claim is necessary;

- Ageing mechanism for outdoor switchgear are declared applicable to indoor; and

- The explanation given by NGET for the replacement of the Nechells 275 kV substation is not yet compelling.

6.2.2 OHL and towers

KEMA conducted 4 “site” visits relating to OHL and towers in different parts of England & Wales for routes where NGET intend to carry out refurbishment and/or fittings work. Whilst KEMA did find evidence of condition as outlined by NGET as drivers for asset replacement need, this cannot be considered comprehensive and conclusive justification for the size of the refurbishments as proposed by NGET. The following issues have been identified which might be interpreted to indicate over-forecasting:

- KEMA engineers conducting site visits were presented with various qualitative assessments and justifications for replacement need but did not see any quantitative evidence of key condition assertions relating to actual strength and reliability of insulators, fittings and conductor, which would underpin asset risk and replacement timing.

- Condition assessments varied considerably along the routes and in some cases parts of routes appeared to be in good condition and in particular with respect to conductor and yet these sections formed part of the overall asset replacement scheme. It is not clear to KEMA that an asset replacement approach to OHL at a low level of granularity (all or nothing) is necessary or appropriate.

- In one case justification for refurbishment of a given route was mainly predicated on forensic data of an adjacent route and KEMA is not convinced that this is sufficient justification for asset replacement requirement.

- In another case, the KEMA engineers stated that the primary driver for asset replacement appeared to be more related to a need for betterment (i.e. increased route capacity) than a need to address deteriorating condition of the route.

It is recognised that the KEMA engineers were only examining limited samples of selected OHL routes. However, in general, they did not always witness a compelling case for large=scale refurbishment. Consequently the KEMA engineers were unsure of the need for the proposed scope of works for some schemes. Inevitably OHL replacement strategy needs to consider outage issues but it is not clear that an “all or nothing” approach is optimal.

7. International / GB comparisons

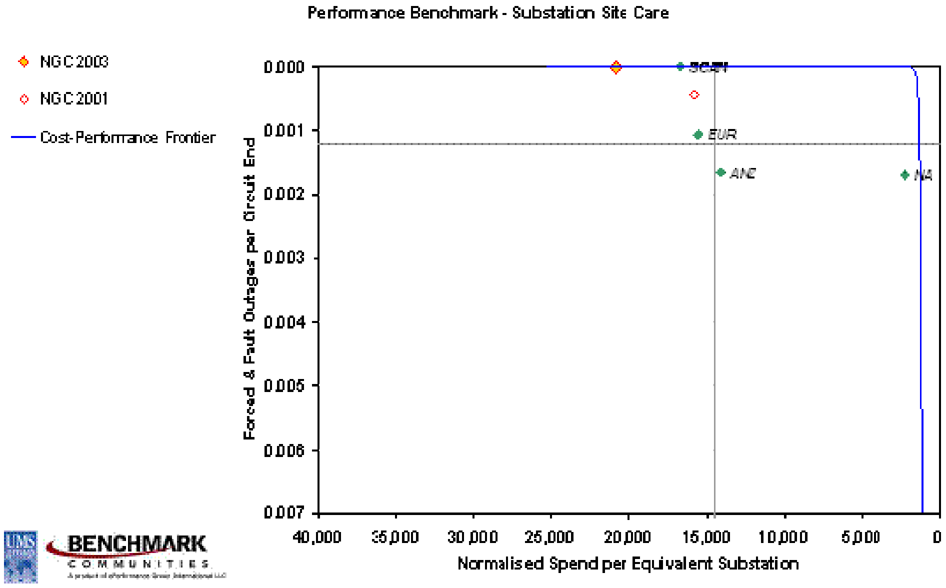
This chapter presents the results of the assessment as to what extent NGET leads international practices and whether scope exists to further improve its asset management systems.

7.1 Benchmarking (external)

NGET indicates that cross-utility benchmarking is problematic due to variable business operating environments between different utilities which can encompass a number of different economic, environmental and other issues. Examples of this are network topology and climate. Consequently, the scope of benchmarking activity is relatively limited and confined to one active (ITOMS) and one passive area (CIGRE Asset Lives)

7.1.1 ITOMS Benchmarking

Notwithstanding the reservations expressed above, NGET participate in an international utility benchmarking exercise denoted ITOMS which compares maintenance performance/practices and seeks to identify best transmission industry practices worldwide. The study takes place every two years and an example of the output received is shown below:



This shows NGET to be at the efficiency frontier in substation site care, although this has required more expenditure than other TOs, partly due to more stringent legislation.

NGET has been unable to confirm the constituency of the ITOMs benchmarking group of companies, other than to provide generic comparison data as follows:

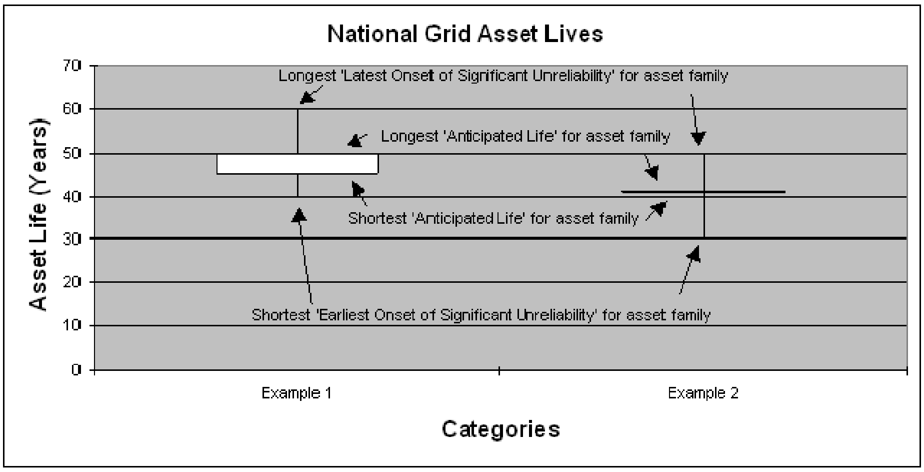
(i) NGET has an energy delivery of 297,000GWHr, a service territory of 151,189km^2 and 21,721 OHL structures above 100kV.

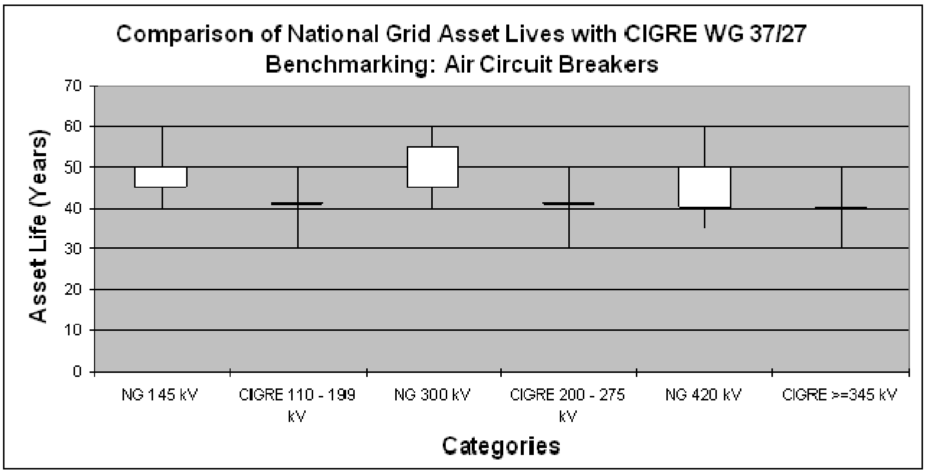
(ii) The corresponding group averages were 86,818GWHr energy delivered, a service territory of 258,586km^2 and 34,252 structures. The maximum group values were 310,369GWHr energy delivered, 1,221,037km^2 service territory and 90,381 structures.

This indicated that the ITOMS membership was disparate in nature, which may lead to the issues identified by NGET above in terms of relevance of comparison. Furthermore given NGET's statement that it is at or near best practice across the various benchmarking categories, and hs not implemented meaningful changes to its practices as result of ITOMS it is questionable whether participation provides any real value.

7.1.2 CIGRE Asset Lives Benchmarking

One other area NGET has benchmarked is asset lives, where it compared its asset life assumptions with those determined by CIGRE in 2000. An explanation of the comparison and an actual example is shown below:





In general NGET's current asset life assumptions appear to be favourable vs. the CIGRE study i.e. longer.

7.1.3 Examples of best practice applied by NGET

NGET claims to apply best practice in a number of areas such as;

- The Asset Health Review process
- Condition Based Replacement
- The understanding of asset condition and prediction of asset longevity
- The capital prioritisation process
- Asset replacement planning tools
- The adoption of standard equipment specifications/ solutions

NGET has presented extensively on these areas at the various January workshops, seeking to demonstrate best practice, without explicitly seeking to compare and contrast with the practices of other utilities (UK or internationally). In most cases, NGET's approach to asset life estimation is close to leading practice, certainly in terms of a defined asset management processes.

7.1.4 Potential for other benchmarking

Currently NGET does not benchmark with the Scottish TOs. The Scottish TOs do not participate in ITOMS. The Scottish TOs regard the sample as unrepresentative, preferring to undertake more restricted comparisons with one or more of the Scottish companies.

Furthermore, when asked which 3 international utilities were regarded as most comparable, NGET could not provide one on grounds that no other utility (when considered as an overall entity) is sufficiently similar for the purposes of benchmarking. As a leading practitioner of international utility benchmarking, KEMA does not regard this to be an argument.

7.2 Benchmarking (internal) – lessons learnt

Due to the evolution of Engineering Services from a collection of regionally managed areas, to a centralised body, NGET has taken the opportunity to benchmark internally. Specifically due to the autonomous nature of the pre-Engineering Services structure, each area adopted subtly different working practices to its core maintenance and capital plan support activities.

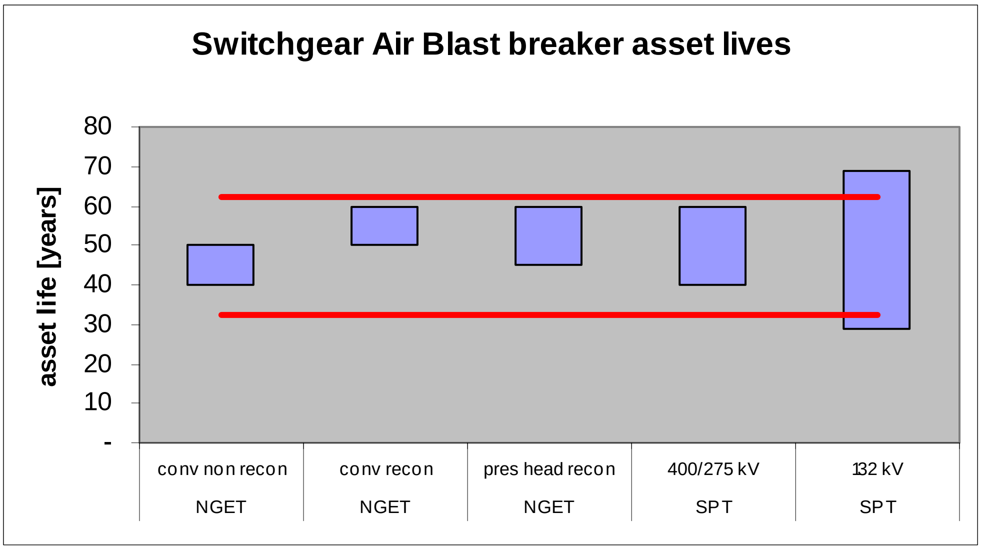
NGET have indicated some examples of where such benchmarking identified regional best practices which were subsequently rolled out on a national basis under the new unified Engineering Services structure.

7.3 KEMA's own benchmarking of NGET

KEMA has been able to make some comparisons of key aspects between NGET and the other TOs. Two important areas, namely asset lives and scheme/unit costs are highlighted below.

7.3.1 Asset lives

KEMA has developed a typical range of asset lives that should be anticipated for different types of transmission equipment. During this review, KEMA has been able to compare these with those put forward by NGET and the other TOs. An example is shown below:



In this example for conventional and pressurised head air blast switchgear, it can be seen that some of NGET's asset lives assumptions for conventional air blast switchgear are pessimistic relative to KEMA's views and those of the other TOs. This also supported views of the DNOs, which are not shown in this chart but are known from DPCR4. This is a good example of benchmarking that KEMA conducted in its detailed review of asset lives assumptions and associated modelling for NGET and the other TOs. Such analysis has supported its formulation of its views of the appropriate levels of future NLRE capital expenditure for NGET.

7.3.2 Scheme/Unit costs

During this review KEMA has been able to compare these with those put forward by NGET and the other TOs. KEMA's analysis of unit costs is highlighted in Section 8. NGET's costs of proposed future OHL schemes such as Bolney-Lovedean diverge from broadly equivalent OHL schemes proposed by SPT. Some NGET OHL unit costs are twice SPT's which cannot be explained by regional differences.

7.4 KEMA's views

NGET could adopt more benchmarking activities with the other GB TOs. However, it is not evident that the external benchmarking that is undertaken assists NGET to improve its asset management practices, given that NGET appears to exhibit leading practice in those benchmarking activities it does undertake. The value of such benchmarking expenditure is therefore questionable.

NGET's initiative, to conduct an internal benchmarking exercise following the creation of Engineering Services to adopt regional best practice across the organisation represents a positive development.

8. KEMA's assessment of NGET's NLRE capital expenditure

8.1 Overview of KEMA's approach

KEMA's assessment of NGET's NLRE requirements has conducted from two different perspectives, namely (i) volumes and cost, and (ii) top down and bottom up, which generates as 2 x 2 assessment matrix as illustrated below:

	Volumes	Costs
Top Down Approach	Review Aspect: Asset Replacement Modelling Key Issues: Asset Lives Review Method: Workshops, Q&A, review of ALERT, KEMA's own modelling, benchmarking, KEMA knowledge	Review Aspect: Unit Costs Key Issues: Equipment + Other Factor costs Review Method: Workshops, Q&A, review of PDD model, scheme assessment, benchmarking, KEMA knowledge
Bottom up approach	Review Aspect: Asset Condition Assessment Key Issues: Need (evidence) and granularity Review Method: Workshops, Q&A, review of AHR, scheme assessments, site visits, KEMA knowledge	Review Aspect: Scheme Costs Key issues: need, design choice and costing Review Method: scheme assessments, benchmarking, KEMA knowledge, Q&A, Workshops

Taking each in turn:

(i) NGET's asset replacement modelling methodology is comprehensive and robust. Some key asset life assumptions appear conservative, e.g. 132kV switchgear, 275kV oil switchgear and OHL conductors.

(ii) NGET's approach to condition assessment is generally robust although examples have been identified where scheme justification is not compelling in all asset categories, implying a degree of plan back filling to fit top-down model projections (particularly with respect to transformers). The condition assessment of substations appears insufficiently disaggregated between different asset types. Instability has been identified with respect to the condition status of individual transformers. Gaps in knowledge of both the type and condition of OHL routes are apparent.

(iii) NGET's assumptions regarding future unit costs appear high. This seems partly due to some self-imposed policies which incur additional time and costs but is also due to an ineffective procurement strategy. These high costs estimates are also partly driven by NGET's Project Definition Document modelling assumptions where (i) the ramping of OHL volumes towards the latter part of the HBPQ period may have influenced forward views via the model and (ii) complexity costs relating to site-specific issues may be sometimes overstated.

(iv) NGET future scheme costs also appear high, especially for OHL and switchgear due to a combination of internal policies, unnecessarily broad scopes of work, elements of betterment, 'over-design' for operational flexibility (possibly GBSO driven) and ineffective procurement.

8.2 Asset replacement modelling methodology

KEMA has modelled the NLRE asset replacement plans of each of the GB TLs in order to verify both the projected volumes and costs. The asset replacement model considers the following asset categories in turn:

- Transformers;
- Switchgear;
- Overhead line towers;
- Overhead line conductors;
- Underground cables; and
- Protection and Control equipment.

NLRE is driven by a number of factors such as asset condition, age and the useful remaining service life of components, systems and asset categories employed within transmission networks. The assets to be replaced within a price control period are predominantly driven by the condition (ageing). As transmission assets have long service lives combined with the fact that only a limited number of assets have actually been replaced due to ageing (globally), average asset life assumptions cannot be 100% accurate.

KEMA's asset replacement model compensates for uncertainties in asset service lives by varying the average service life expectancy as well as standard deviation between predefined limits. The replacement model is based on a double loop probabilistic calculation (varying both the asset service lives and standard deviation between upper and lower limits).

The main inputs for the asset replacement modelling are:

- The age profile of the asset categories deployed within each network as provided by the respective licensees via regulatory submissions and answers to Capex consultant questions; and
- The asset life expectancies (average asset life expectancy and standard deviation) based on KEMA's best view of transmission asset lives gained from international experience and expert knowledge.

The output of the model provides an estimate of asset replacement volumes based on these age profiles and asset life expectancies. This information was then compared with the volumes provided by the licensees in their HBPQ and FBPQ submissions (Table 9.5 asset add_disp).

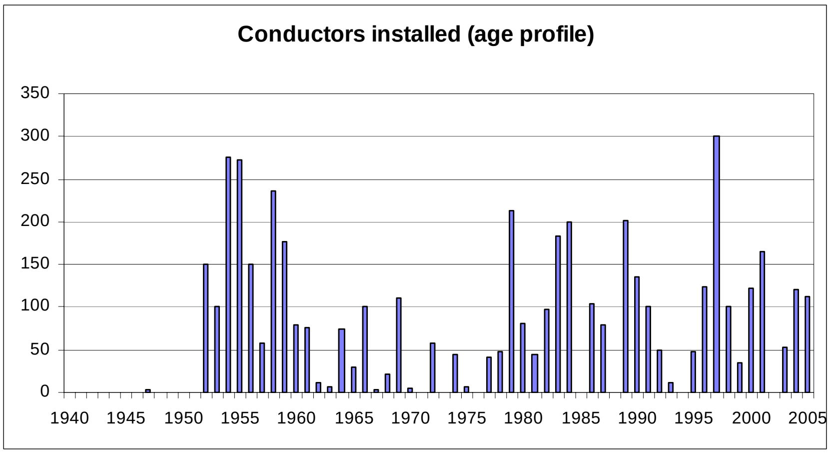
Replacement model description

This section presents a schematic overview of KEMA's replacement model showing the stages from data input up to and including the comparison of the model output and volumes provided by the licensees. The examples shown below are based on indicative conductor data.

Step 1: Loading the asset age profile

Using the asset age profiles for the various asset categories as provided in Table 9.6 of the HBPQ as the input for the modelling of the forecast period (2005/06 – 2011/12). In addition the licensees have provided the age profiles as per 2000. This data has been used to model asset replacement in the historic period (2000/01 – 2004/05). The example below presents the age profile of conductor at the start of the forecast period.

Figure 15 – Conductor age profile



Step 2: Loading asset life expectancies

KEMA's asset life assumptions for each of the main transmission asset categories were used as inputs. For example the asset life characteristics assumed for conductors are:

- Average life expectancy (mean): 52.5 years
- Standard deviation: 7.5 years.

In order to compensate for uncertainties in the average life assumption and standard deviation, KEMA set an additional standard variation beyond the initial average life and the standard deviation assumptions allowing the model to generate upper and lower limits for asset replacement volumes. The following additional standard deviations have been applied:

- Standard deviation on average life expectancy: 1.25

- Standard deviation on the standard deviation: 1.00.

The results from such a model run are presented in Figure 16 and Figure 17. Figure 16 shows an intermediary product of a model run and presents the mean value of the asset volumes to be replaced but has not been compensated for uncertainties in the average life assumptions and standard deviation. Figure 17 shows the median and the 50% and 95% certainty bands based on the additional standard deviations regarding both average life and standard deviation of conductors. It should be noted that the model replaces each asset only once.

Figure 16 – Conductor replacement volume, mean

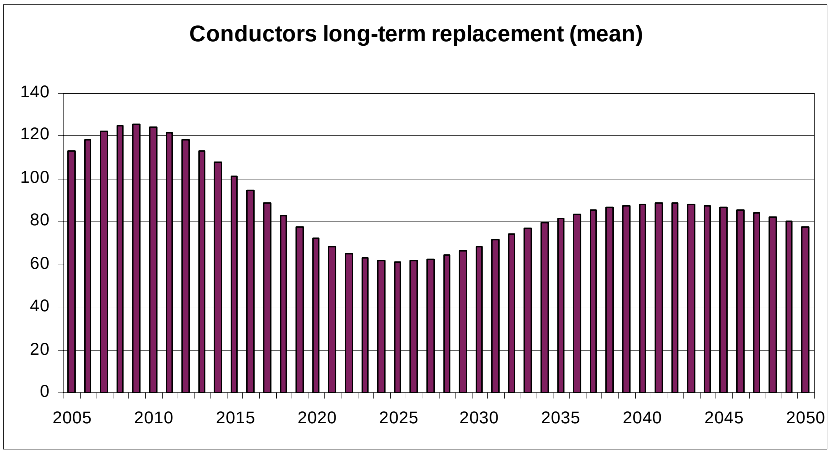
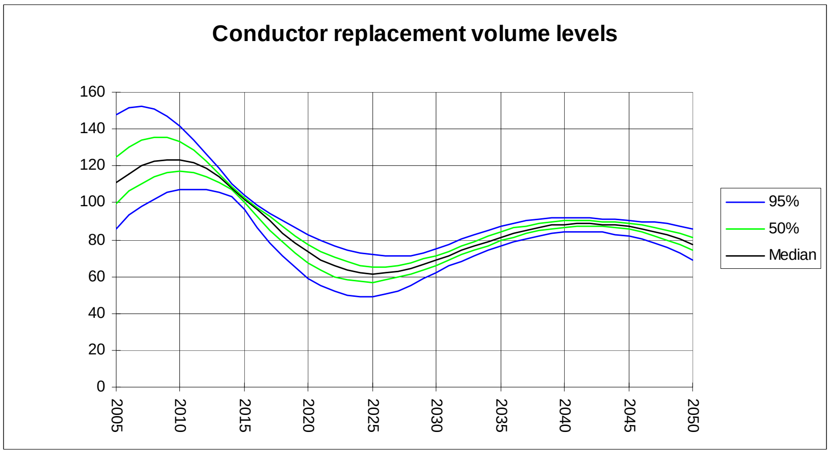


Figure 17 - Conductor replacement volume, median – 50% and 95% certainty bands

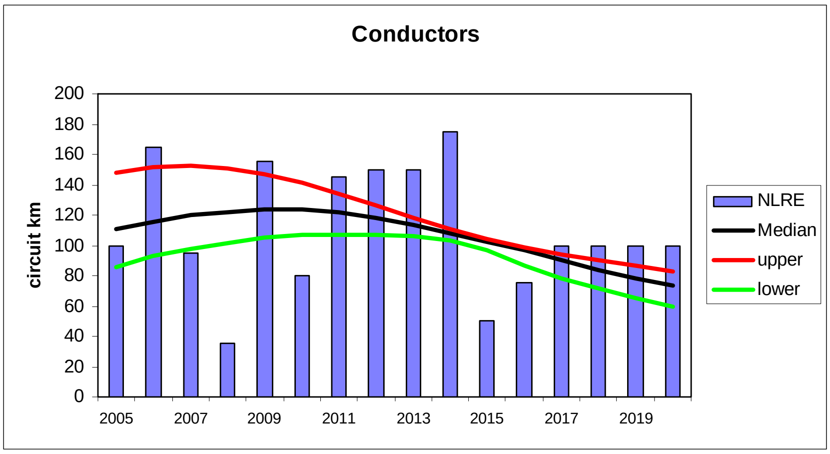


The median is used as the most appropriate asset replacement volume. The median is the middle observation in the distribution and thus half of the observations are greater than the median and half are smaller. The lower and upper limits are set equal to boundaries of the 95% certainty band and thus leaving out the outliers. Lower limit is equal to the median minus 47.5% of the observations; the upper limit is equal to the median plus 47.5% of the observations.

Step 3: Combining licensees' replacement volumes and model output

In step three of the model the model output (median and lower / upper limit) is combined with the asset replacement volumes predicted by the licensees. An example is presented in Figure 18. Comparing the volumes predicted by each TL with model outputs enables a more comprehensive assessment of the asset replacement levels proposed for the period under consideration.

Figure 18 – predicted asset replacement volumes versus model output



Step 4: Review predicted asset replacement volumes

KEMA reviewed the predicted asset replacement volumes per licensee within the upper and lower limits of the volumes calculated. Ideally, the asset replacement volumes as forecast by the TLs should fall between the upper and lower limits calculated by the model. However specific circumstances may reasonably explain deviations from the model output. The predicted and modelled asset replacement volumes are then reviewed including an assessment of the Non Load Replacement Expenditures (volumes multiplied by unit cost).

8.3 NGET asset replacement modelling results

This section describes:

- The asset life expectancies KEMA applied in the modelling exercise. KEMA's asset lives are compared with the asset lives NGET use in its replacement models.
- The replacement volumes predicted by NGET in comparison with the model output. Based on these comparisons followed by assessments KEMA established the appropriate replacement volumes for the forecast period per asset category.
- In addition KEMA multiplied volumes and unit costs to make a statement on the total level of Non Load Related Expenditures for the forecast period.

Asset life expectancies

Table 6 presents the asset lives KEMA applied in the replacement model and the asset lives used by NGET in its replacement models. Note that the asset lives KEMA applied for transformers 132 kV and switchgear 132 kV align with the asset lives used for DPCR4.

Table 6 – asset lives

Asset category	NGET		KEMA	
	Median	EOSU (2.5%) / LOSU (97.5%)	Mean	Standard deviation
Transformers 400/275 kV 500 MVA – 750 MVA	45	30 / 70	50 (1.25)	7.5 (1.00)
Transformers 400/275 kV 1000 MVA	55	40 / 80	50 (1.25)	7.5 (1.00)
Transformer 400/132 kV GSP / GSP EE 240	55	40 / 80	50 (1.25)	7.5 (1.00)
Transformer 400/132 kV GSP FER 240	50	35 / 75	50 (1.25)	7.5 (1.00)
Transformers 275 kV	55	40 / 80	52,5 (1.25)	10 (1.00)
Transformers 132 kV	55	40 / 80	55 (1.25)	10 (1.00)
Shunt reactors	45	25 / 60	45 (1.25)	7.5 (1.00)
Series reactors	55	40 / 80	55 (1.25)	7.5 (1.00)
Capacitor bank	30	20 / 40	35 (1.25)	7.5 (1.00)
Static Var comp	30	15 / 40	25 (1.25)	5 (1.00)
Switchgear 400 kV GIS outd	40	25 / 60	35 (1.25)	5 (1.00)
Switchgear 400 kV GIS ind	50	40 / 60	45 (1.25)	7.5 (1.00)
Switchgear 400 kV SF6	50	40 / 60	47.5 (1.25)	7.5 (1.00)
Switchgear 400 kV PAB R	50	45 / 60	47.5 (1.25)	7.5 (1.00)
Switchgear 400 kV PAB N	40	35 / 45	47.5 (1.25)	7.5 (1.00)
Switchgear 275 kV bulk oil	45	40 / 50	47.5 (1.25)	7.5 (1.00)

Asset category	NGET		KEMA	
	Median	EOSU (2.5%) / LOSU (97.5%)	Mean	Standard deviation
Switchgear 275 kV GIS outd	40	25 / 60	40 (1.25)	7.5 (1.00)
Switchgear 275 kV GIS ind / SF6	50	40 / 60	47.5 (1.25)	7.5 (1.00)
Switchgear 275 kV PAB	40	35 / 45	47.5 (1.25)	7.5 (1.00)
Switchgear 275 kV CAB Reconditioned	55	50 / 60	47.5 (1.25)	7.5 (1.00)
Switchgear 275 kV CAB Normal replacement	45	40 / 50	47.5 (1.25)	7.5 (1.00)
Switchgear 132 kV bulk oil	45	40 / 50	47.5 (1.25)	7.5 (1.00)
Switchgear 132 kV GIS outd	40	25 / 60	40 (1.25)	7.5 (1.00)
Switchgear 132 kV GIS ind	50	40 / 60	47.5 (1.25)	7.5 (1.00)
Switchgear 132 kV SF6	50	40 / 60	47.5 (1.25)	7.5 (1.00)
Switchgear 132 kV PAB	50	45 / 60	47.5 (1.25)	7.5 (1.00)
Switchgear 132 kV CAB	45	40 / 50	47.5 (1.25)	7.5 (1.00)
Switchgear <132 kV	45	40 / 50	50 (1.25)	10 (1.00)
Conductor Zebra fully greased	45	40 / 55	55 (1.25)	7.5 (1.00)
	50	45 / 60		
	55	50 / 65		
	45	40 / 55		
Conductor Zebra core greased	35	30 / 45	45 (1.25)	7.5 (1.00)
	45	35 / 55		
	50	40 / 60		
	45	40 / 50		

Asset category	NGET		KEMA	
	Median	EOSU (2.5%) / LOSU (97.5%)	Mean	Standard deviation
Conductor Lynx fully greased	35	30 / 40	55 (1.25)	7.5 (1.00)
	40	30 / 45		
	50	45 / 55		
Conductor Lynx core greased	25	20 / 35	45 (1.25)	7.5 (1.00)
	35	25 / 40		
	45	40 / 55		
Tower steel 400, 275 & 132 kV	40 → 85	30 → 120	80 (2.50)	10 (2.00)
Wood poles	40	10	40 (2.50)	7.5 (1.25)
Cables 400 kV oil (old)	45 → 50	25 → 80	50 (2.50)	7.5 (1.25)
Cables 400 kV oil (new)	55	45 → 80	60 (2.50)	7.5 (1.25)
Cables 400 kV XLPE	40	25 / 50	30 (2.50)	5 (2.00)
Cables 275 kV oil (old)	45 → 50	25 → 80	50 (2.50)	7.5 (1.25)
Cables 275 kV oil (new)	55	45 → 80	60 (2.50)	7.5 (1.25)
Cables 275 kV XLPE	40	25 / 50	50 (2.50)	7.5 (1.25)
Cables 132 kV	30 →55	20 → 80	55(2.50)	7.5 (1.25)

KEMA's asset life assumptions were applied to the NGET transmission asset base to determine asset replacement volumes over the current and forthcoming price control periods for each category of transmission asset. The resultant asset replacement volumes were then compared with NGET's volume submission for the HBPQ and FBPQ periods with any difference being highlighted. By including information obtained during KEMA's asset management investigation, the model outputs were then adjusted based on engineering judgement to provide KEMA's estimate of appropriate asset replacement volumes per asset category at a disaggregated level.

8.3.1 NGET Non Load Related Expenditures

8.3.1.1 Historic price control period

KEMA has modelled the main asset categories (transformers, switchgear, overhead line conductors, cables and protection & control) in order to verify the volumes and cost of NGET's NLRE asset replacement submission for the historic period (2000/01 – 2004/05). KEMA had to make the following assumptions for this modelling exercise:

- Transformers: As NGET did not provide asset age profiles for the beginning of the historic period (2000), KEMA simulated the transformer age profile by combining the age profile at the start of the forecast period (2005) with the transformer assets removed from the network during 2000/01 – 2004/05. KEMA assumed that the transformers removed from the transmission network dated from:
    - 400 kV mid and late fifties
    - 275 kV mid fifties until early sixties
    - 132 kV late fifties.
- Cables: As NGET did not provide the age profile of the underground cables at the start of the historic period, KEMA simulated this age profile at the start of the historic period. KEMA applied the same approach as for transformers. KEMA assumed that all cables removed from the network in the years 2000/01 – 2004/05 dated from the mid fifties until the mid sixties.

Table 7 provides the results of multiplying KEMA's estimated replacement volumes with KEMA unit costs to enable comparison with NGET's incurred NLRE as submitted to Ofgem. Divergences are analysed by asset category below.

Table 7 – Non Load Related Expenditure overview [historic 2000/01 – 2004/05]

Asset category	KEMA estimated Volume (Units)	KEMA Total (£M)	NGET incurred Volume (Units) NLRE/other	NGET HBPQ Total (£M)
Transformer	22	45.2	17 / 24	21.3
Switchgear	124	105.0	215 / 332	70.0
Overhead line conductor	649	130.0[1]	711 / 793	130.8

[1] KEMA did not include cost for respectively fittings only and tower steel refurbishment

Cables	14	43.4	14 / 15	89.6
Protection & Control	401	132.7	N/A	133.5

Transformers: The cost delta between KEMA and NGET is explained by unit cost differences for predominantly 275 kV transformers. The replacement volumes align. It should be noted that KEMA's unit cost parameters (2005 price level) include increases in transformer cost that have occurred in 2005 and the beginning of 2006.

Switchgear: NGET replaced more switchgear than the output of KEMA's model predicted. However, NGET invested less than KEMA's estimate. Therefore NGET's approach to switchgear bay replacement during the historic period can be considered reasonable.

Overhead line conductors: The replacement volumes delivered by NGET and the volumes calculated by KEMA's model are comparable. It should be noted that KEMA only modelled conductors. Fittings-only and tower steel refurbishment are not included in KEMA's cost estimate. KEMA's estimates the cost range for fittings-only and tower steel refurbishment at 25 – 40 million GBP for the period 2000/01 – 2004/05. KEMA concludes that NGET has not been overspending on overhead line replacement.

Cables: The underground cable replacements realised by NGET closely align with KEMA's model output. NGET's cost level is higher than the cost level estimated by KEMA. The cost difference must therefore be explained by different unit costs. In general, the cost of cable routes is dependent on route specific factors such as the number of obstacles, soil, urban versus rural, tunnels etc. These specific factors can incur addition costs which can only by estimated by detailed knowledge of the routes involved.

Protection & Control: The replacement volumes for protection and control have not been modelled. Instead KEMA has assumed the asset life for protection and control equipment to be 25 years. This means that such assets will be replaced once during the asset life of a switchgear bay. NGET's replacement cost for protection and control aligns with KEMA's view.

Summary:

- The replacement volumes of the reviewed asset categories are closely aligned with KEMA's estimates
- NGET's approach to asset replacement during the historic period is considered cost effective.

The level of NGET's NLRE investment from 2000/01 – 2004/05 appears reasonable.

8.3.1.2 Forecast price control period

Table 8 provides the disaggregated results of multiplying KEMA's asset replacement volumes (derived from modelling and adjusted in line with asset management information) with KEMA unit cost data to enable comparison of NGET's forecast NLRE forecast as submitted to Ofgem. Differences in proposed levels of expenditure are analysed by asset category below.

Table 8 – Non Load Related Expenditure overview

Asset category	KEMA				NGET	
	Vol.	Unit cost	Sub-total	Total	Total	Delta in %
Transformer 400/275 kV	10	3.2	32	181.4	209.6	13%
Transformer 400/132 kV	17	3.2	54.4			
Transformer 275 kV	52	1.8	93.6			
Transformers 132 kV	2	0.7	1.4			
Shunt reactors	35	1.2	42	58.7	57.7	-2%
Series reactors	3	1.6	4.8			
Capacitor Bank	7	1.7	11.9			
Static Var compensation	0	6.8	0			
Switchgear 400 kV GIS	0	2.4	0	570.5	654.6	15%
Switchgear 400 kV AIS	36	2.05	73.8			
Switchgear 275 kV GIS	4	1.7	6.8			
Switchgear 275 kV AIS	197	1.55	305.4			
Switchgear 132 kV	198	0.8	158.4			
Switchgear <132 kV	87	0.3	26.1			
Conductor Zebra fully greased	531	0.2	106.4	560.9	871.6	36%
Conductor Zebra core greased	1172	0.2	234.7			

Asset category	KEMA				NGET	
	Vol.	Unit cost	Sub-total	Total	Total	Delta in %
Conductor Lynx fully greased	47	0.2	9.4			
Conductor Lynx core greased	74	0.2	14.8			
Fittings only Quad	1089	0.085	92.6			
Fittings only Twin	667	0.075	50.0			
Tower steel refurb all kV	912	0.05	45.6			
Tower steel all kV	37	0.2	7.4			
Wood poles	0		0			
Cables 400 kV	12	3.6	43.2	264.9	595.7	56%
Cables 275 kV	67	3.1	207.7			
Cables 132 kV	14	1	14			
Protection & Control 400 kV	238	0.47	109.5	210.7	244.3	14%
Protection & Control 275 kV	125	0.44	62.0			
Protection & Control 132 kV	179	0.2	42.4			
Protection & Control <132 kV	80	0.1	9.2			

Transformers: The transformer cost difference between NGET's forecast and KEMA's modelling and costing exercises is largely attributable to the volumes of the 400/275 IB transformers. In addition, NGET's unit costs are slightly higher than KEMA's

Switchgear: In six instances the outcome of KEMA's modelling differed from NGET's proposals. NGET proposals are lower for 400 kV PAB breakers, and KEMA is lower with respect to 275 kV SF6, 275 kV PAB, 145 kV bulk oil, 132 kV SF6 and 132 kV CAB. The asset lives used for the 132 kV breakers are consistent with those adopted Ofgem/PB Power for DPCR4. In general NGET unit costs are 10% higher than KEMA's. KEMA adjusted 275 kV circuit breaker volumes by +30% to account for the number of mesh substations to be replaced by double busbar substations.

Overhead lines: The cost difference for overhead lines between NGET’s forecast and KEMA’s estimate predominantly caused by different unit costs. There is a slightly different view on the number of overhead line conductors which need to be replaced, but this is of marginal importance.

Cables: The cost difference for underground cables is explained by different unit costs. In general, the cost of cable routes is dependent on route specific factors such as the number of obstacles, soil, urban/rural, tunnels etc. Some of NGET cable schemes include tunneling. Such additional costs cannot be estimated without detailed knowledge of these routes. However KEMA estimates that a cost reduction of 5% on NGET proposed cable requirement can be realised.

Protection & Control: NGET’s NLRE cost figures are higher than KEMA’s estimate.

Summary all asset categories - NGET: KEMA’s concludes that NGET is overestimating NLRE over the forecast price control period by the following factors:

- Transformers: calculated level of over-forecasting is 15%, mainly due to 400/275 kV transformer volumes.

- Switchgear: 15% over-forecasting due to volumes and unit cost. NGET’s unit costs are in general 10% above KEMA’s. Note that the switchgear replacement costs applied by KEMA is based on full bay replacement. KEMA supports the upgrade of some 275 kV mesh substations to double busbar arrangements.

- Overhead lines: NGET appear to be overestimating capital requirements for overhead lines by approximately 35%. This is predominantly attributable unit costs. There are also some minor discrepancies regarding conductor replacement volumes.

- Cables: Some of the NGET cable schemes include tunneling. Such additional costs cannot be estimated without detailed knowledge of these routes. However KEMA has the impression that a cost reduction of 5% on NGET proposed cable requirement can be realised.

- Protection & Control: Based on the high-level calculation NGET is overestimating protection & control requirements by approximately 15%.

9. Conclusions

KEMA's review of NGET asset management policies and processes has confirmed a number of areas where NGET performs strongly and in a number of cases exhibits best practice relative to its GB network peers and the wider international network community; in particular:

- **Asset management policies and procedures**. Over the historic price control period, NGET has reinforced and enhanced its approach to asset management which has resulted in a comprehensive range of policies and procedures.

- **Organisation, control and governance**. The centralisation of asset management functions coupled with the development of company-wide asset databases has provided a consistent platform for decision making with respect to the whole asset base.

- **Asset Health Review system**. The development of a widely accessible web-based repository for the most current technical and operational asset-related information provides a useful input to the investment prioritisation process.

- **Asset replacement modelling**. NGET's ALERT based asset replacement modelling is the most sophisticated of GB TOs assessed. NGET has refined and disaggregated asset types over the historic price control period to improve understanding of future asset replacement volumes.

- **Condition assessment techniques**. The type and frequency of condition assessment activities has been increased over the historic price control period to the extent that NGET has now improved its (centralised) understanding of asset condition.

- **Integration of top-down and bottom-up asset management activities**. NGET has established processes to interface information collated from bottom-up condition assessment with top-down replacement modelling more successfully than the other TOs. Examples have been provided showing how asset lives have evolved in light of operational experience.

- **Evolution of asset management approach**. Over the historic price control period, NGET's organisational structure and systems have evolved to improve asset management capabilities. In many instances, there are linkages between policy and practice.

However, there are also some areas in which NGET's approach to asset management could be improved, namely;

- **Further disaggregation of asset replacement decision-making**. With respect to overhead lines and switchgear, NGET tends to adopt route and substation specific refurbishment/replacement programmes which can lead to high schemes costs. Whilst this approach can be valid, KEMA would expect to see more disaggregation with respect to asset replacement decision-making. KEMA also notes that NGET has a tendency to specify high-cost gas-insulated, double-busbar substations to be built off-line when replacing existing arrangements. KEMA acknowledges the validity of such an approach in some instances although has doubts that it always represents the least-cost solution.

- **Feedback loops within the scheme process**. KEMA has concerns that design related asset replacement decisions are fixed early in the scheme selection process and are not necessarily subject to review when costs differ from expectation.

- **Stability of the capital plan**. KEMA has become aware of a number of year-on-year changes to NGET's capital plan with respect to asset replacement priorities. These changes sometimes appear to be driven by non-asset management related considerations.

- **Procurement effectiveness**. There is evidence of high scheme and unit costs (especially with respect to overhead lines) which suggests that aspects of procurement could be better integrated within the asset management process to deliver cost savings. The adoption of the Project Definition Document approach to project costing appears sometimes to deliver inflated scheme cost estimates due to inappropriate inputs and weightings.

- **Network risk**. NGET has demonstrated a clear understanding of asset risk at a micro-level although does not appear to monitor system risk as comprehensively and the linkages to network performance and investment prioritisation. Such risk measurement techniques will become increasingly relevant as the asset base continues to age.

The merger of NGET's Network Strategy and Engineering Services directorates to form a combined "Asset Management" department should further improve asset management effectiveness by establishing closer links between policy and practice.

It is noted that NGET is initiating an 'Alliance' based approach to procurement, capital programme delivery and securing supplier capacity. Whilst it is not entirely clear how NGET intend to implement Alliances at a detailed level, the initiative should address some of the procurement weakness and thus delivery cost savings.

Assessment of historic and forecast NLRE requirements

KEMA's analysis of NLRE during the historic price control period revealed a close correlation between KEMA estimates and actual NGET expenditure both in terms of asset replacement volumes and unit cost. Consequently, KEMA concludes NGET's historic NLRE appears appropriate.

With respect to the forthcoming price control period, reductions to both NGET's asset replacement volumes and costs are appropriate whether viewed from a top-down or bottom-up perspective, with particular focus on OHLs (cost) and switchgear (volume).

KEMA's conclusions, supported by the evidence accumulated from review activities and modelling, is that NGET's NLRE requirements for the period 2005/06 - 2011/12 could be reduced by 19% in total. However, KEMA expects cost savings to be achieved across all asset categories from the Alliance initiative. KEMA's view on the NLRE reduction per asset category is outlined in the table below:

Table 9 – Overview Capital expenditures NGET

Asset Category	NGET forecast £M	KEMA estimate £M	KEMA Comment
Transformers	209.6	178.2	Volume (400/275 IB) and unit costs overstated
Switchgear	654.6	556.4	Volumes and unit costs
Reactors	57.7	57.7	Close alignment with forecast
Substation Other	108.0	91.8	Based in Switchgear analysis
Overhead lines	871.6	566.6	Unit costs high
Underground cables	595.7	565.9	Highly route and tunnel specific
Protection and Control	244.3	207.6	High-level analysis based on circuit breaker volumes
Total	**2741.5**	**2224.2**	**c.£500M reduction**

The above table implies that KEMA's proposed reduction in NLRE for NGET should apply equally across the seven year period. KEMA sought to identify the discount applicable for the seven year period 2005/06 – 2011/12 as a whole. In reality, the majority of the proposed reduction should be applied to the TPCR4 period, namely 2007/08 – 2011/12.