Optimising Expenditure in Asset Management

E.S. Cornwall Memorial Scholarship

Final Report

2014-2016

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28/08/2016

Disclaimer

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Acknowledgements

The author of this report acknowledges the support of UK Power Networks, Commonwealth Edison, and their respective employees. Without their assistance and willingness to share knowledge this report would not have been possible. The author would also like to thank: the E. S. Cornwall Memorial Scholarship and its Board for the personal, professional, and technical development opportunity that this scholarship affords; his family (Heather, Allan and Hayley) for their ongoing support and encouragement; and his friends and colleagues, both old and new.

Executive Summary

The focus of my tenure on the E.S. Cornwall Memorial Scholarship was to gain an understanding of how utilities in an international setting are working to optimise expenditure in asset management, particularly in the face of challenges posed by today's ever changing electrical industry. In conducting this research, I undertook two, nine-month placements, the first of which was based with UK Power Networks (a distribution utility that operates in the south eastern corner of the United Kingdom), and the second based with Commonwealth Edison (a transmission and distribution utility that operates in northern Illinois in the United States of America). My work with these utilities provided me with wide-ranging exposure and learnings; however, this report focuses particularly on the development and optimisation of the asset management function and where my experience may be of value to the Australian Electricity Industry.

Central to my time abroad, the structure of this report, and my subsequent recommendations is the belief that optimising the asset management function relies heavily on three themes. They are:

1. Establishing a robust asset management system;
2. Leveraging increased data availability to create tools and information that can enable prudent and timely decision making; and
3. Understanding the impact of new technologies on existing assets, and the additional value that these assets provide.

To address these themes and align with my Scholarship experience this report is structured in three sections:

1. Developing the Asset Management System
2. Information Enablement
3. Understanding the role of Regulation

Developing the Asset Management System

Utilities, particularly those within the Australian Electricity Industry, are under increasing pressure to sustain or improve network performance, while reducing cost to customers; all during a period of significant technological change. Coping with these demanding conditions, in an industry that is reliant on the performance of their assets, will require that utilities have a strong asset management foundation. Industry specifications and standards, like Publicly Available Specification (PAS) 55 (PAS55:2008) and the International Standards Organisation's (ISO's) 55000 series standard (ISO55000:2014) provide guidelines and requirements for developing this strong foundation. These documents provide a catalyst for self-assessment and review that will help to optimise the asset management function, even within well-established utilities.

As such, utilities should consider, at a minimum, undertaking a self-assessment against the requirements of PAS55:2008 or ISO55000:2014 to identify gaps and opportunities for development of their asset management system. Moreover, regulatory bodies should consider requiring organisations under their jurisdiction to achieve compliance with ISO55000:2014.

Detailed recommendations pertaining to the development of the asset management system are available in Table 3 of Section 4.4.

Information Enablement

Many of prevailing technologies that are affecting the electricity industry have the ability to improve network and asset monitoring, making data available with previously inconceivable frequency and granularity. However, data in its own right presents little value, and if captured unnecessarily, inefficiently, or ineffectively could negatively impact the organisation. As such, it is important that organisations explicitly identify their present and future data requirements and use this data to

develop information that in turn adds value (i.e. informs decision-making, and drives improvement and optimisation) within the organisation. To enable creation of information from data, it is important that utilities invest in developing skillsets, tools, and systems that are capable of managing and analysing "big data".

Detailed recommendations pertaining to information enablement in a utility setting are available in Table 6 of Section 5.6.

Understanding the role of Regulation

Regulatory bodies, like the Australian Energy Regulator, play an important role in incentivising optimisation of the asset management function within regulated utilities. In many instances, it is the regulatory framework that they enforce, which nurtures the environment around innovation and development within the industry. Regulatory frameworks that are constricting or too prescriptive may stifle innovation, while those lacking adequate mechanisms may fail to challenge and incentivise utilities to develop.

Internationally, the Revenue equals Incentives, Innovation, and Outputs (RIIO) framework developed by the UK's regulator, the Office of Gas and Electricity Markets (Ofgem), has gained attention as a framework that challenges utilities to optimise and reduce expenditure, while also supporting innovation. Regulatory bodies should consider the mechanisms inherent within the RIIO model, namely: the upfront and ongoing efficiency incentives, output incentives, and innovation incentives, for use in their own regulatory models.

Detailed recommendations pertaining to role of regulation in optimising expenditure in asset management are available in Table 9 of Section 5.6.

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1 Glossary, Abbreviations & Definitions

Table 1: List of acronyms, abbreviations, and technical terminology

Terminology / Acronym / Abbreviation	Definition
AER	Australian Energy Regulator
ARP	Asset Risk and Prioritisation (Tool)
Asset Group	A collection of assets that are defined by certain fundamental and operational similarities. In the case of the ARP tool, an asset group is generally defined by type of asset (e.g. circuit breaker, cable, wood pole, transformer) and the operating voltage.
Asset Management System	Encapsulates all policies, standards, systems, processes, and activities that guide the management of assets at all stages of their lifecycle.
BCM	Bronzeville Community Microgrid
BMCS	Broad Measure of Customer Satisfaction
BSI	British Standards Institution
CAPEX	Capital Expenditure
CBRM	Condition Based Risk Management
CDF	Cumulative Density Function
CI	Criticality Index
CI Ranking	A standardised, four-tier ranking system calculated from the CoF.
CoF	Consequence of Failure
ComEd	Commonwealth Edison (Company)
CYMDIST	A distribution system modelling and analysis software developed by CYME International.
DER	Distributed Energy Resource
DG	Distributed Generation
DIKW	Data, Information, Knowledge, Wisdom *As used when referring to the DIKW hierarchy.*
DNO	Distribution Network Operator
DNV	Distribution Network Visibility (tool)
DPCR	Distribution Price Control Review
EELG	Element Energy Load Growth (model)
EPN	Eastern Power Networks *One of UKPN's three licensed distribution networks.*
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
HC	Hosting Capacity
HI	Health Index
HI Ranking	A standardised, five-tier ranking calculated from the HI score.
HI Score	A calculated, continuous, numeric, score ranging between 0 and 10 that identifies the health of an asset – 0 being as new and 10 being end of life.
IAM	Institute of Asset Management
ICL	Imperial College London
IFI	Innovation Funding Incentive
IPEC	Independent Power Engineering Consultants
ISO	International Standards Organisation
ISO55000:2014	Refers to a suite of documents that comprises the international standard for asset management.
KPI	Key Performance Indicator
LCNF	Low Carbon Networks Fund
LPN	London Power Networks *One of UKPN's three licensed distribution networks.*
LRE	Load Related Expenditure (Model)
MSE	Mean Squared Error
Ofgem	Office of Gas and Electricity Markets
OPEX	Operational Expenditure
PAS	Publicly Available Specification
PAS55:2008	Refers to suite of documents that comprises the specification for the optimised management of physical assets.
PCFM	Price Control Financial Model

	As used when referring to the RIIO framework.
PD	Partial Discharge
PDF	Probability Density Function
PoF	Probability of Failure
RF	Risk Factor
RI	Risk Index
RIG	Regulatory Instructions and Guidance
RIIO	Revenue equals Incentives, Innovation, and Outputs
RTU	Remote Terminal Unit
SCADA	Supervisory Control And Data Acquisition
SMART	Specific, Measurable, Achievable, Relevant, and Time-bound *As used when referring to a set of criteria or objectives.*
SPN	South Eastern Power Networks *One of UKPN's three licensed distribution networks.*
TOTEX	Total Expenditure
TWPL	The Woodhouse Partnership Limited
UK	United Kingdom
UKPN	UK Power Networks
USA	United States of America
WACC	Weighted Average Cost of Capital
WPD	Western Power Distribution

2 Introduction

2.1 Overview of the Scholarship

The E.S. Cornwall Memorial Scholarship (referred to as "the Scholarship" from this point forward) was established in 1955 in commemoration of Edward Satchwell Cornwall, an Irish-born Australian migrant who played an influential role in the development of Queensland's electricity industry during the early 20th century. The Scholarship, which is open to engineering graduates of Queensland universities, provides the successful applicant(s) the opportunity to undertake a period of international research or employment in an area that is beneficial to the Australian Electricity Supply Industry.

Since its inaugural award, the Scholarship has afforded almost 30 young engineers the opportunity to work within international settings and learn from industry leaders on topics that traverse the power sector. For more information on the Scholarship, past scholars, scholarship rules, and future calls for applications see the Scholarship's website (http://escornwall.com.au/).

2.2 My Scholarship Experience

The electricity supply industry is currently undergoing a period of substantial change. At its core, this change is being driven by the need to improve industry sustainability, adapt to new technologies, and respond to the changing roles and expectations of energy consumers. These factors are already impacting the day-to-day business of energy markets, generators, and transmission and distribution utilities; highlighting the need for the industry to be agile and responsive in adapting to these changing conditions. In an industry that is characterised by significant investment in primary assets with long lifetimes, keeping pace with these changes will rely on (among other things), the ability to:

- Derive additional value from its existing asset-base; and
- Integrate new technologies that add value to the existing assets base.

During my tenure on the Scholarship I investigated these issues in an asset management setting, seeking to understand how:

- International standards for best-practice in asset management can be used to drive efficiency and increased performance;
- Improvements in data availability made possible through the deployment of new technologies can assist in understanding asset performance and drive more informed decision making around asset investment; and
- How new technologies and ideologies can be applied to improve network performance and derive additional value from existing assets.

As part of this research, I undertook two placements with utilities based in the UK and USA, namely:

- **UK Power Networks (UKPN)** – a DNO servicing the south eastern region of England in the United Kingdom, where I worked within the Engineering Standards and Assurance team; and
- **Commonwealth Edison (ComEd)** – a transmission and distribution network operator servicing the northern Illinois area in the USA, where I worked within the Smart Grid and Technology team.

The following subsections provide a brief overview of each placement and the work that I was involved in during my respective nine-month placements.

2.2.1 UK Power Networks (UKPN)

Between the 1st September 2014 and 31st May 2015 I worked as an Engineer based predominantly within the Engineering Standards and Assurance team at UKPN. In this role I worked with a small team of engineers and consultants on UKPN's transition from Publicly Available Specification 55 (PAS55:2008) to International Standards Organisation 55000 (ISO55000:2014). While on this project I was responsible for developing UKPN's first "Asset Management Manual", a cross-cutting document

that provided an end-to-end detailed overview of UKPN's approach to asset management in alignment with the requirements of ISO55000:2014. In authoring this document, I gained wide-ranging exposure to UKPN's asset management standards, systems, and processes, while working with consultants to identify possible gaps and opportunities for development of UKPN's asset management practices.

In addition to my work with the Engineering Standards and Assurance team, I sought a number of placements within other teams, working on projects and systems that aligned with my research topic and that maximised the benefit from my time at UKPN. These placements included working within:

- Asset Strategy – focusing on the Asset Risk and Prioritization (ARP) tool, a tool that utilizes data about assets (e.g. condition, operating environment, and age) and risk-based analysis (i.e. considering likelihood of failure and consequence of failure) to build a prioritised asset replacement or refurbishment plan.
- Future Networks – investigating information-enablement tools like the Distribution Network Visibility (DNV) tool, and leading practices in asset condition monitoring like online partial discharge (PD) testing and diagnosis.
- Network Design Standards – gaining exposure to the Imperial College of London load related expenditure (LRE) model and reliability-based analysis.
- Strategy and Regulation – understanding the various mechanisms inherent within the Revenue equals Incentives, Innovation, and Outputs (RIIO) model and their impact on the UK utility environment.

2.2.2 Commonwealth Edison (ComEd)

Between the 17th August 2015 and the 6th May 2016 I worked as an Engineer based within the Smart Grid and Technology team. My key focus during this time was the development of a modelling tool that was capable of estimating the capacity (in Watts) of distributed energy resources (DERs) ComEd's distribution network could accommodate without negatively impacting feeder performance (also known as "hosting capacity" (HC)). The resultant tool, which became known as the Automated Distribution Hosting Capacity Assessment Tool (ADHCAT), was developed in Matlab and VB.NET programming languages and integrated big data analysis techniques (e.g. k-means clustering) and probabilistic analysis (e.g. Monte Carlo simulation) alongside ComEd's chosen distribution modelling environment (CYMDIST) to perform a system-wide analysis of the DER HC of ComEd's distribution network.

Although focused on the development of the ADHCAT tool, I was also involved in a number of other DER-related works, which included, working on the planning for the Bronzeville Community Microgrid (BCM) and documenting the challenges of widespread DER integration and their impact on power quality.

2.2.3 Site visits, Tours and Other Experiences

The Scholarship provides a unique opportunity to attended events, such as conferences and site visits, the like of which may not be possible within Australia's boarders. To take advantage of these opportunities while working in the USA and UK I attended a number of events and tours either privately organised or as part of engineering professional bodies (e.g. CIGRÉ, IEEE, IET or ComEd's GrADS). These events included:

- Attending the 2014 CIGRÉ Paris Session in Paris, France;
- A site visit arranged by the CIGRÉ Next Generation Network to the Culham Centre for Fusion Energy in Culham, Oxfordshire, England;
- Attending the CIGRÉ Next Generation Network's Distribution Innovation Challenge in York, Yorkshire, England;
- Site visits to a number of UKPN substations, including:
    - A number of underground secondary substations (11kV / 400V) in the immediate area surrounding the Bank underground station;
    - The Guildford 123 / 33 / 11 / 6.6kV Grid Supply Point and Substations complex;
    - The West Ham 400 / 132 / 66 / 11kV and Bow 132 / 11kV substation sites;

- Visiting UKPN's Primary Control Centre based in Fore Hamlet, Ipswich, England;
- Visiting UKPN's Smarter Network Storage facility in Leighton Buzzard, Bedfordshire, England;
- Visiting the E.ON Energy Research Centre and touring the RWTH Aachen university in Aachen, Germany;
- Presentations by the Institution of Engineering and Technology (IET) on: the London Array wind farm and Future of the Large Hadron Collider;
- Site visits to S&C Electrics Chicago headquarters in Chicago, Illinois, as well as their Power Quality Products factory in Franklin, Wisconsin; and
- A site visit to the Braidwood Nuclear Generating Station in Will County, Illinois.

I would like to thank those who made my attendance at these events and site visits possible.

3 Document Structure

My tenure on the E.S. Cornwall Memorial Scholarship provided me with a diverse experience covering the field of asset management and new technologies. As is highlighted in Section 2.2, in investigating how to "optimise expenditure in asset management" I sought to gain exposure in three key areas. These areas related to:

1. **Establishing a robust asset management system**; that is, developing a strong set of policies, standards, systems, processes, and activities that guide the handling of assets at all stages of the asset lifecycle.
2. **Leveraging increased data availability to create tools and information that can enable prudent and timely decision making** at all levels of the organisation.
3. **Understanding the impact of new technologies on the assets** and how these technologies may be used to derive additional value from the asset base.

To align with these themes, the report hereafter is structured as follows:

> **Section 4**: Developing the Asset Management System, covers my experience with PAS55:2008 and ISO55000:2014, particularly within the setting of UK Power Networks. This section provides an overview of both documents, their value in assessing an organisation's asset management system, and factors to consider when doing so.
>
> **Section 5**: Information Enablement, covers my experience with a range of systems and technologies that are designed to inform decision making at all levels of the organisation. Tools documented within this section include the:
>
> 1. Asset Risk and Prioritisation (ARP) Tool – UKPN
> 2. Distribution Network Visibility (DNV) Project – UKPN
> 3. Online Partial Discharge (PD) Monitoring System – UKPN
> 4. Long-term Planning and Scenario Assessment – UKPN
> 5. Distributed Generation (DG) Hosting Capacity (HC) Assessment – ComEd
>
> The first three of these are focus on optimising the management of existing assets, while the latter two aim to understand how new technologies and other changes impacting the electricity industry can be understood and managed.

During my tenure on the Scholarship I also sought to understand the role of regulatory bodies in influencing optimisation of expenditure in asset management. Regulatory bodies play a vital role in driving optimisation not just within asset management but across an organisation. Their goal should be to create an environment that constructively and sustainably incentivises utilities to innovate and evolve, while meeting the needs and the expectations of customers. To this end:

> **Section 6**: Understanding the role of Regulation, covers my experience with the UK's Revenue equals Incentives, Innovation, and Outputs (RIIO) regulatory model, which has gained notoriety for its innovative and incentive-based approach to regulation.
>
> Finally, **Section 7**: Closing, offers my closing thoughts and acknowledgements.

Table 2 provides a visualisation showing the alignment of the three key sections of this report and the three proposed themes inherent in optimising expenditure in asset management.

Table 2: Alignment of report sections with key themes

		Section		
		Developing the Asset Management System	Information Enablement	Understanding the role of Regulation
Theme	Establishing a robust asset management system	✓	✓	✓
	Leveraging increased data availability	✓	✓	✓
	Understanding the impact of new technologies	-	✓	-

This report should be considered in conjunction with my quarterly reports, which are available on the Scholarship's website at http://escornwall.com.au/index.php/category/study-topics/optimise-expenditure-on-asset-management/.

4 Developing the Asset Management System

Organisations that utilise assets in their day-to-day business will undertake asset management in one form or another. Highly performing organisations are those that are actively aware of the asset management challenges they face and work to derive the greatest benefit (be that income, efficiency, quality of service, or customer satisfaction) from their assets. Within the Electricity Sector, the high-value and traditionally long lifespan of assets generally drives a strong focus on asset management; irrespective of the size or value of an organisation's asset inventory, it is important to ensure that their asset management system has a solid foundation. PAS55:2008 and ISO55000:2014 offer a framework and guidance to developing the fundamental components of the asset management system.

The following subsections provide an overview of the structure and general requirements of PAS55:2008 and ISO55000:2014, while also detailing my experience with these standards, concluding with my recommendations regarding their application.

4.1 Publicly Available Specification 55 (PAS55)

First published by the British Standards Institution (BSI) in 2004, Publicly Available Specification 55 (PAS55:2003) established a framework and set of key requirements for the "optimised management of physical assets". PAS55 takes a top-down approach to building an asset management system, aiming to ensure continuity and alignment between high-level organisational policy and strategy, and day-to-day asset management activities, while placing particular emphasis on the value of whole-of-lifecycle asset management.

Following the widespread success of PAS55:2003 the specification was revised in 2008 with input from stalwarts of the UK asset management industry and participation from 10 countries. The resulting publication, PAS55:2008, is underpinned by two key principles:

1. Line of sight, which is targeted at developing a clear and consistent set of goals. All aspects of the asset management system should have clear linkage to these core goals or organisational objectives. Performance measures should then be derived from, and directly mapped to these objectives (as demonstrated in Figure 1).
2. The plan, do, check, act cycle, which recognises the need for continual evolution of the asset management system. Development of a highly performing asset management system requires a process of conscious monitoring and review, particularly in adapting to new challenges. Figure 2 shows the "plan, do, check, act" cycle and how the 28 requirements of PAS55-1 align with this cycle.

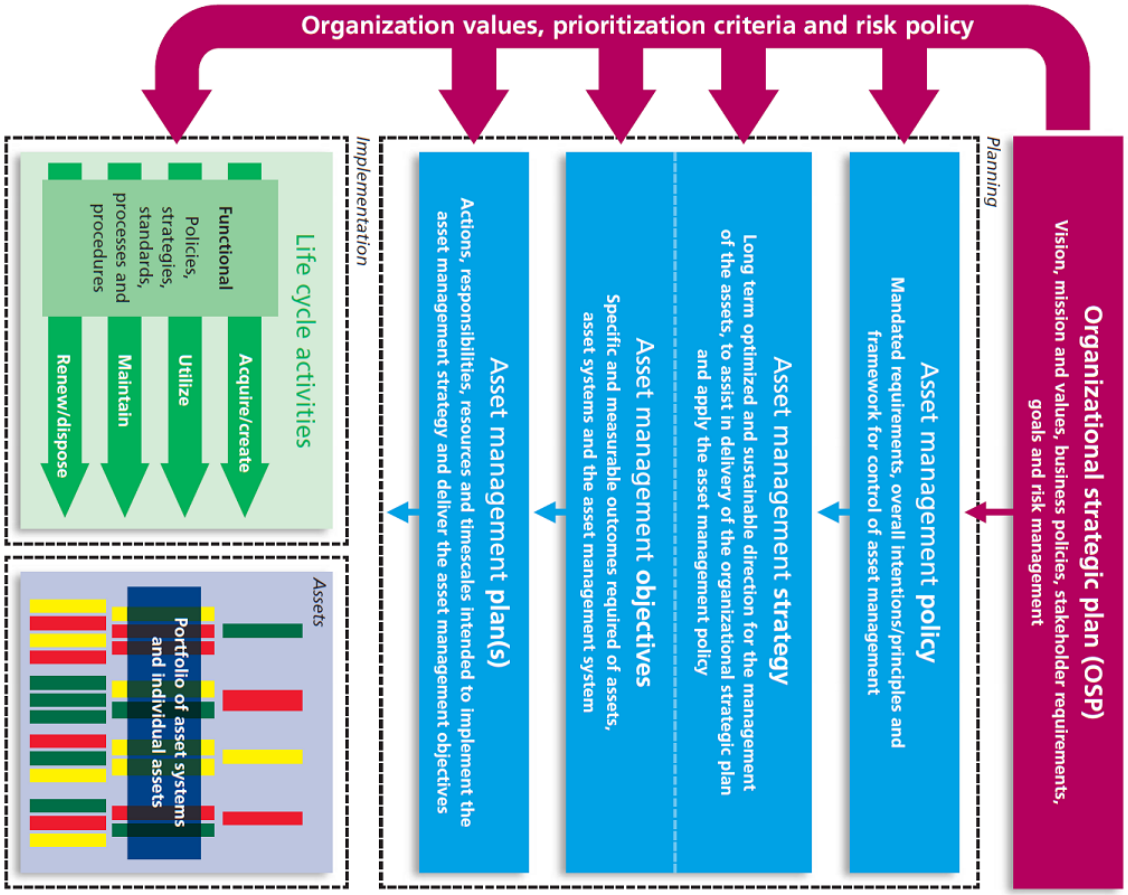


Figure 1: Overview of elements of an asset management system [1]

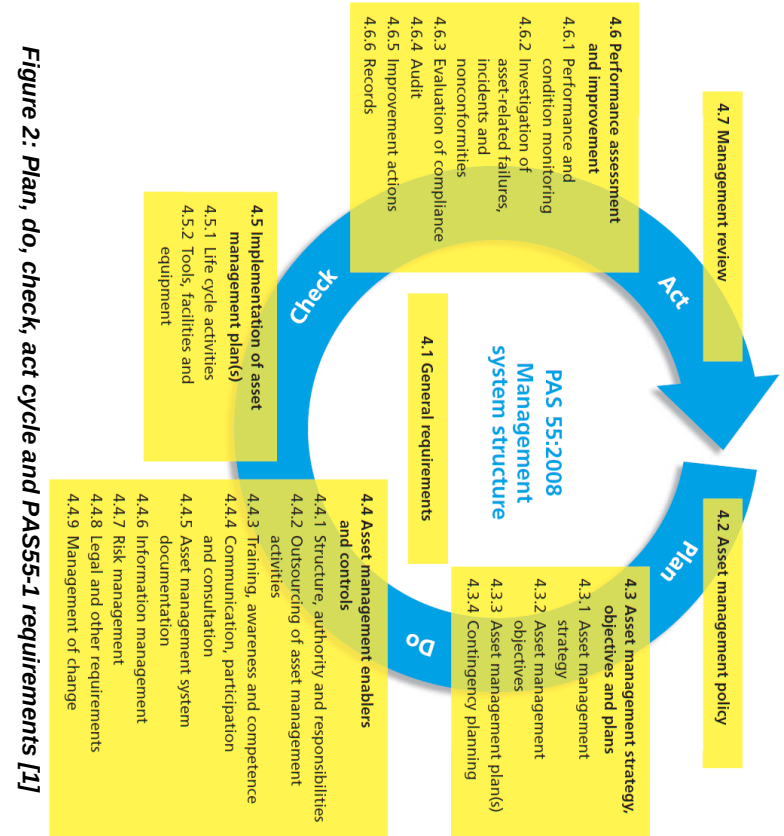


Figure 2: Plan, do, check, act cycle and PAS55-1 requirements [1]

The PAS55:2008 series comprises of two documents:

- PAS55-1, titled “Specification for the optimised management of physical assets”; and
- PAS55-2, titled “Guidance for the application of PAS55-1”.

Built upon the principles of line of sight and the plan, do, check, act cycle, PAS55-1 is a concise document that defines 28 specific recommendations (or requirements) outlining the structure and supporting framework of an optimal asset management system. These recommendations are grouped into seven overarching themes[1]; namely:

1. **General requirements** – a somewhat generic and overarching clause that requires that:
    a. The organisation develop, maintain, and improve an asset management system that is suitably equipped when considering the size and complexity of the organisation;
    b. The scope of the asset management system is explicitly defined;
    c. The asset management system seamlessly interfaces with other necessary systems (e.g. environmental management and health and safety systems)

2. **Asset management policy** – that outlines a number of requirements around the establishment and ongoing management of an asset management policy document. This asset management policy should be developed by upper management in consideration of the organisation’s strategy (i.e. their mission statement, values, goals, stakeholder requirements, and appetite for risk) and should guide the development of the asset management system as a whole.

3. **Asset management strategy, objectives, and plans** – one of the more intensive sections that sets out requirements for a set of documents, which collectively: define the approach (strategy), goals and their measures (objectives), high-level plans and contingency plans for asset management. In particular, the latter of these, the asset management plans should not be confused with annual or program of work planning, but rather refers to the need to establish plans for the management of assets throughout each stage of their life (i.e. procurement and commissioning, operation and maintenance, and decommissioning and disposal).

4. **Asset management enablers and controls** – defines the requirements for elements that support the asset management system in its day-to-day operation in achieving the asset management objectives. These elements include:
    a. Implementation of a suitable organisational structure and clearly defined responsibilities;
    b. Scope and clarity around the use and management of outsourced work;
    c. Controls around the competency and necessary training or qualification of employees;
    d. Suitable avenues for communication within the organisation (internally) and with stakeholders (externally);
    e. The establishment and maintenance of documentation and information management systems; and
    f. Clearly defined process for assessing and managing risk, legal and regulatory obligations, and change management.

5. **Implementation of asset management plans** – which deals with the day-to-day work processes and procedures that describe how the asset management plans are put into practice. As with the asset management plans, these documents are targeted at detailing how assets are managed throughout each stage of their lifecycle and capturing the tools and equipment required in completing these day-to-day activities.

6. **Performance assessment and improvement** – that focuses on establishing the necessary systems to: monitor the performance and current state (or condition) of the assets, investigate asset failures and non-conformities, evaluate compliance with legal and regulatory requirements and internal policies and standards (auditing). Each of these components should

[1] Within PAS55-1 and PAS55-2 these seven themes and their associated requirements are captured as subsections in Section 4: Asset management system requirements.

then drive continual improvement of the asset management system, particularly where failures or deficiencies are identified.

7. **Management review** – that completes the "loop" (as outlined in Figure 2) and provides upper management with the opportunity to review the holistic performance of the asset management system. These reviews provide an opportunity for upper management to address poor performance and risks within the asset management system.

Each of these subsections and their inherent 28 recommendations are built upon in PAS55-2, which provides more detailed guidelines for the application of PAS55:2008 and how these requirements might be realised in practice.

4.2 International Standards Organisation 55000 (ISO55000)

In an effort to broaden the scope of PAS55:2008 and create a standard suitable for an international audience, the BSI worked with the Institute of Asset Management (IAM) to launch the development of the International Standards Organisation (ISO) standard 55000 in 2010. After approximately four years of development, with input from representatives from across 31 countries, the ISO55000 series of standards for asset management was officially released in January 2014 (ISO55000:2014). The series consists of three documents:

- ISO55000, titled "Overview, principles and terminology";
- ISO55001, titled "Management system requirements"; and
- ISO55002, titled "Management system – guidelines for the application of ISO55001".

In addition to aligning to the standard ISO document structure, the scope of ISO55000:2014 was broadened to encapsulate all assets, shifting away from the PAS55:2008 focus on physical assets. As a result, the ISO550000:2014 series places greater emphasis on:

- Understanding stakeholder expectations and requirements (both internal and external to the organisation) and the inclusion of these requirements in developing targeted organisational objectives;
- The roles of organisational leaders in developing the asset management systems; and
- The various facets of risk related to the asset management system.

In its final format, the ISO55000:2014 series has a similar, but slightly different, set of 29 requirements as documented in ISO5001. These 29 requirements are grouped in seven sections[2]; namely:

1. **Context of the organisation** – that is targeted at understanding the circumstances surrounding the organisation and how these circumstances impact the asset management system. It requires that the organisation identify key stakeholders and document their expectations and requirements; as well as any internal and external issues that may impact the asset management system in achieving its objectives. Moreover, the organisation is required to explicitly define the scope of the asset management system and how it interfaces with other systems within the organisation (similar to the "general requirements" section of PAS55-1.

2. **Leadership** – that sets the need for organisational leadership to be actively engaged in ensuring that the asset management system achieves its desired objectives. This includes taking a role in: establishing the asset management objectives, developing policy, assigning roles and responsibilities, ensuring that the business is enabled at all levels to achieve the asset management objectives, and regularly reviewing the performance of the asset management system.

3. **Planning** – that covers the need to define a set of asset management objectives and detailed plans around how these objectives will be met. These plans should allow the business to

[2] Within ISO55001 and ISO55002 these seven sections and their associated requirements are captured in Section 4 (Context of the organisation) through Section 10 (Improvement).

manage assets through the entirety of their lifecycle (similar to the "implementation of asset management plans" section of PAS55-1) and include methodology and criteria for decision making to prioritise activities and expenditure in the day-to-day operation of the asset management system.

4. **Support** – that emphasises the importance of supporting functions in achieving the asset management objectives. These supporting roles include the need for:
    a. Suitable resourcing (both staff and equipment);
    b. Training and the necessary level of competence of staff;
    c. Communication and awareness to ensure that staff are adequately informed to undertake their role;
    d. A clearly defined set of information requirements that are capable of supporting the asset management system in reaching its objectives; and
    e. Systems and processes for use in the capture and control of documented information.

5. **Operation** – that sets requirements around the delivery of the asset management plans and helps to ensure success in achieving the asset management objectives. These include the development of:
    a. Operational planning and control processes that document how plans (established as part of the "Planning" section) are put into practice and risks related to these activities will be monitored and managed;
    b. Change management functions that are capable of assessing and mitigating the impact of changes internal or external to the organisation; and
    c. Explicit controls and performance measures around outsourced activities.

6. **Performance evaluation** – that focuses on understanding how the asset management system and the assets themselves are performing. In particular, the organisation should utilise a number of asset performance indicators (e.g. percent utilisation, condition, reliability, cost per unit of production) that should be regularly reported and reviewed. In addition, the organisation should utilise internal or external audits as a means to review the performance of its assets and asset management system, and ensure conformance with internal and external requirements.

7. **Improvement** – that highlights the need for continual improvement within an organisation's asset management system. The organisation should consider periodical (e.g. audits and management reviews) and ongoing (e.g. performance monitoring) means for identifying improvement opportunities. Moreover, these review or monitoring points should be capable of instigating improvement at any level within the asset management system.

Figure 3 shows the various components of these seven sections, demonstrating how they fit within the structure of the asset management system. While ISO55000 does not explicitly refer to the same "plan, do, check, act" cycle or "line of sight" utilised in PAS55:2008, both of these principles are engrained within the ISO55000 methodology evident in Figure 3.

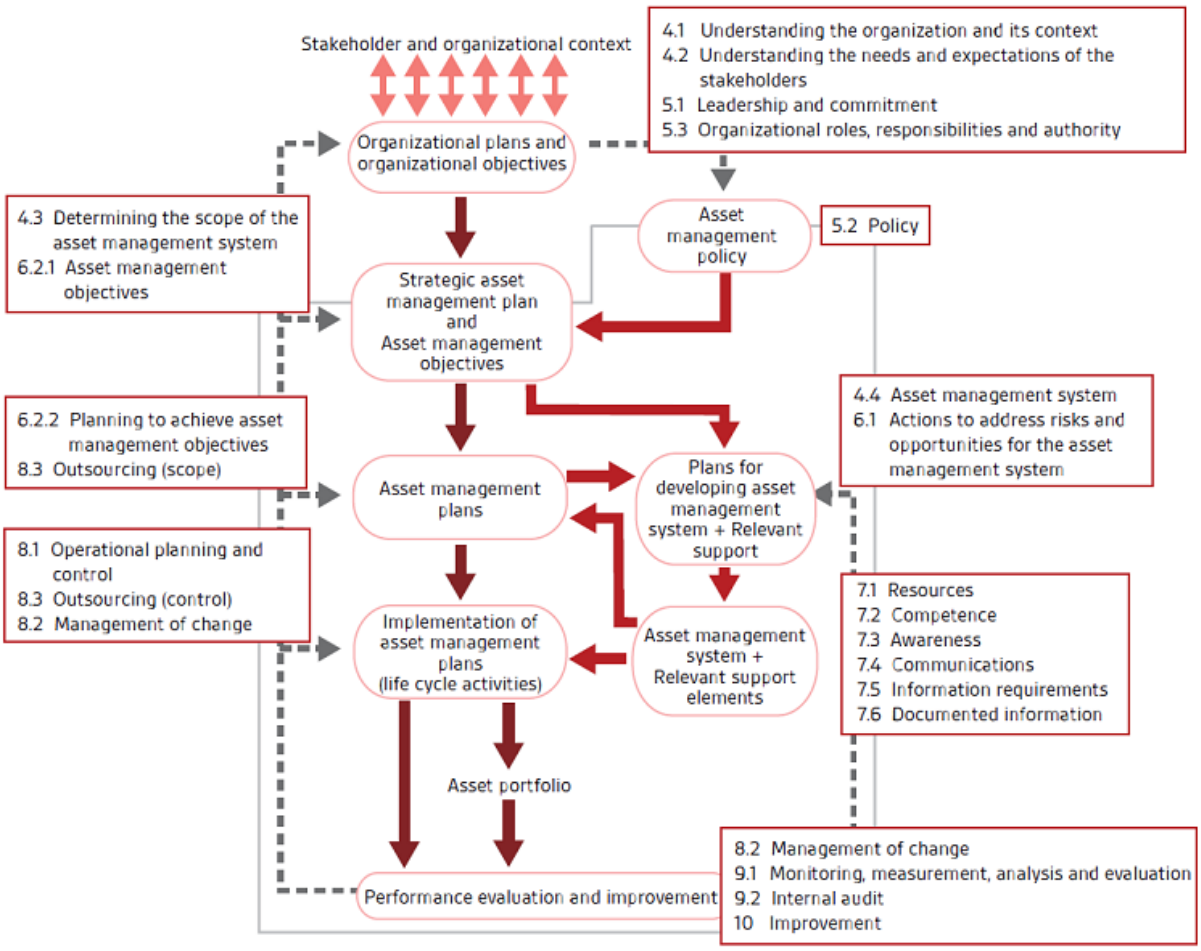


Figure 3: Sections and requirements from ISO55000:2014 [2, 3]

4.3 PAS55 and ISO55000 in Practice

As the birthplace of PAS55:2003, utilities within the UK have a long standing history with the implementation and ongoing operation of PAS55-acredited asset management systems. Initially, a number of utilities in the UK moved to voluntarily adopt PAS55, using it as a catalyst to reviewing and improving their asset management practices. However, in 2006, the UK's national regulator, the Office of Gas and Electricity Markets ("Ofgem") provided strong guidance that utilities should aim to achieve PAS55 certification by April 2008 [4]. In doing so, Ofgem was able to ensure that utilities were adapting, applying, and maintaining compliance with industry best practice in asset management, thus allowing them to take a hands-off approach to regulating the asset management function within the utility sector.

During my tenure with UKPN the UK electricity industry was in the midst of transitioning from PAS55:2008 to ISO55000:2014 accreditation. As such, this period provided me with significant exposure to the structure, requirements, and application of both documents. Although specifically focused on UKPN's transition project, through my engagement with consultants from The Woodhouse Partnership Limited (TWPL)[3] and through research of my own I was able to gain an understanding of how utilities within the UK and internationally have approached asset management under the guidance of PAS55:2008 and ISO55000:2014.

[3] TWPL is a leading asset management consultancy that was active in the development of PAS55:2003, PAS55:2008, and ISO55000:2014.

From this research it was evident that, although organisations may be compliant with PAS55:2008, their strategy and methodology for managing assets may be fundamentally different. Even within the relatively close geographical confines of the UK I became aware of a number of different approaches to asset management. Although every organisation will have subtle differences in their approach I found that most utilities I had exposure to fit loosely in one of the three following approaches:

1. An "innovator" approach, where utilities invested in building a sophisticated asset management system, and who were driven by a desire to be at the "bleeding edge" of innovation. These organisations used this innovation to drive change within their business in search of more efficient and effective ways of operating.
2. A "close follower" approach, where utilities had well established asset management systems, but who didn't seek to be at the "bleeding edge" of innovation, instead learning from those who were and move quickly on opportunities that had demonstrated value.
3. A "slim and responsive" approach, where utilities had simple but efficient asset management systems, and who took a very targeted approach to innovation.

Although each of these approaches manifest themselves in the form of differing organisational structures and resultant asset management systems, each of the UK's electricity transmission and distribution utilities were successful in receiving PAS55:2008 accreditation and will likely be certified against ISO55000:2014. As such, it is evident that, in spite of these differing approaches, it is still possible to meet the requirements of PAS55:2008 and ISO55000:2014. Moreover, PAS55:2008 and ISO55000:2014 don't deal with the detailed "how to" around managing assets, rather they set requirements that define the structure and framework of the asset management system. If followed, these requirements minimise the opportunity for gaps within the asset management system but do not necessarily guarantee optimal asset management.

Ultimately the value of PAS55:2008 and ISO55000:2014 lies in:

- Providing a standardised structure that can be used:
  - To guide the development of asset management systems, particularly for small or fledgling organisations; or
  - As a catalyst for subjective review and self-reflection for larger organisations with substantial asset management systems;
- Emphasising a top-down approach to asset management, and ensuring that each component of the asset management system plays a role in achieving the organisations objectives;
- Enforcing the continual need for review and improvement within the asset management system; and
- Driving a whole-of-lifecycle approach to asset management, particularly within technically focused industries (like the electricity industry) where there is a risk of focusing predominantly on management during an assets operational or installed life at the expense of other stages.

4.4 Recommendations

From my experience with PAS55:2008, ISO55000:2014, their implementation at UKPN, and my exposure to the different approaches to asset management, this section proposes a number of recommendations for organisations engaged in asset management, particularly for utilities within to the Australian Electricity Industry. These recommendations are listed in Table 3.

Table 3: Recommendations relating to asset management and the application of PAS55:2008 and ISO55000:2014

#	Recommendation
1	Regulatory bodies should consider taking a similar approach to the UK regulator (Ofgem) in suggesting, or even requiring, that regulated utilities operating within their jurisdiction achieve certification against ISO55000:2014. This would help to ensure that utilities are operating in alignment with industry best practice and enable an arm's-length approach to regulating and monitoring asset management.
2`	Where accreditation with ISO55000:2014 and PAS55:2008 is not mandated, organisations will likely still benefit from self-evaluation against the requirements of wither document. As such, organisations should strongly consider undertaking a self-evaluation of their asset management systems against these requirements.
3	Organisations should have a clear and documented understanding of their organisational and asset management objectives. The need for this understanding is explicitly listed in the requirements of ISO55001, namely sections: 4.1 Understanding the organisation and its context; 4.2 Understanding the needs and expectations of stakeholders; and 4.3 Determining the scope of the asset management system. While these clauses deal with high-level detail, they are core to determining an organisation's objectives and their plans to fulfil these. Failure to understand these drivers will likely result in an asset management system that is inefficient or ineffective. Moreover, it is this understanding that should drive the development of "SMART"[4] objectives and key performance indicators (KPIs) at all levels of the asset management system.
4	All components of an organisation's asset management system should be regularly reviewed. These reviews should critically assess the need for, suitability, and applicability of each component of the asset management system. Moreover, these reviews should consider the possibility that some components may add little value, become irrelevant or outdated, or even impede efficiency. Where this occurs it may be necessary to make these components redundant.
5	Organisations should strongly consider developing an "Asset Management Manual" or "Guide to Asset Management" document that shows how each level of the asset management system and other management systems integrate to fulfil the role of asset management. This document need not replicate existing documentation, but rather act as a central hub, linking to relevant documentation. Moreover, it should demonstrate how the "line of sight" and "plan, do, check, act" principles are embedded within the organisation's asset management system. Indeed, it is likely that this "document" may be best suited to an interactive website or graphic, rather than a static document. Development of such a document is not a trivial task; however, it provides an ideal opportunity for organisational self-reflection and assessment (as suggested in Recommendation 2). This undertaking will also help to identify duplication, unnecessary complexity, or gaps within the asset management system.
6	Although PAS55:2008 has been superseded by ISO55000:2014, utilities should still consider PAS55:2008 a valuable reference in self-assessments. Owing to its focus on the management of physical assets, PAS55:2008 still holds value in a utility setting, and in some instances may be more readily applied than ISO55000:2014, which, at times, relies on generality to allow its application to non-physical assets.

[4] SMART objectives are those that are: specific (i.e. well defined without need for interpretation), measurable (i.e. clear, ideally numerically-based, and that can be easily reported upon), achievable (i.e. challenging but reasonable and realistic), relevant (i.e. linked to the organisation's or asset management system's objectives), and time-bound (i.e. providing a set timeframe in which the objective is to be achieved).

5 Information Enablement

Advances in communication and monitoring systems have made data (e.g. information about assets, their performance, and the performance of the network) available with previously unimaginable granularity and regularity. This increased data availability represents an opportunity for the electricity industry to revolutionise core organisational functions. For example, increased data availability can enable improved:

- Understanding around the current condition of assets and their performance;
- Control and operation of the electricity network;
- Planning and development of the electricity network;
- Accuracy of forecasting; and
- Awareness in changing customer trends and electricity usage.

However, data in its own right presents little value to the organisation. Indeed, if captured unnecessarily, inefficiently, or ineffectively, data could result in additional burden and wasted effort. For this reason, it is important that:

1. The data requirements of the organisation are explicitly identified (as per the requirements of PAS55:2008 and ISO55000:2014); and
2. That this data is utilised to develop information that provides value to the organisation.

This second component, termed “information enablement” is captured by the Data, Information, Knowledge, Wisdom (DIKW) Hierarchy [5] (also known as the Information Hierarchy). The DIKW Hierarchy is a construct widely used in the field of information science that provides a simple representation of the various levels of data maturity and their relationship. Figure 4 shows an amended version of this hierarchy, demonstrating the increased value achieved with each subsequent tier and the actions required to transition in maturity.

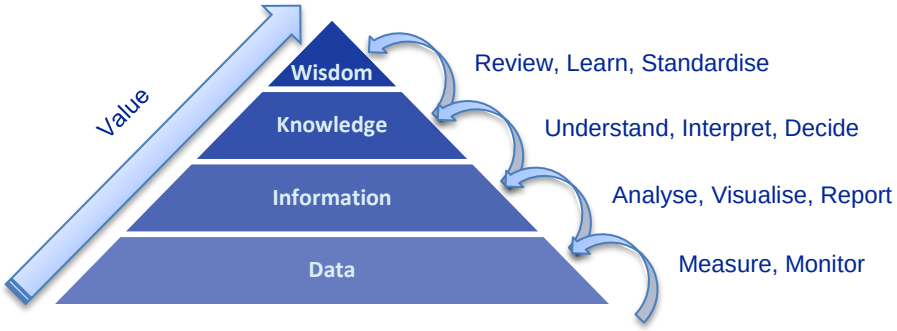


Figure 4: DIKW Hierarchy [5]

It is the first step, transitioning data to usable information, that I believe is the most challenging but that provides the greatest value. As such, utilities should be investing in:

- Developing or employing personnel that are familiar with “big data” analysis techniques; and
- Tools and systems that are capable of managing and analysing “big data”, or improving existing tools and systems to meet this need.

To this end, this section focuses on tools and systems that I worked with during my tenure on the Scholarship, and that utilise data from a diverse range of sources to create valuable information. These tools and systems are empowering the respective utilities in their drive to optimise expenditure within asset management and make informed decisions within the wider organisation. I believe these specific tools offer examples of how data, if captured in a meaningful way, can offer significant and tangible value to an organisation.

The following subsections discuss the:

5.1 Asset Risk and Prioritisation (ARP) Tool – that takes a data-driven, risk- and condition based approach to optimising the refurbishment and replacement of assets against a range of real-world constraints.
5.2 Distribution Network Visibility (DNV) Project – that was targeted at leveraging existing and new distribution monitoring capability, using these data sources to optimise: network planning, control, and configuration of the distribution network.
5.3 Online Partial Discharge (PD) Monitoring System – that applied advanced monitoring technologies and analysis techniques in monitoring and assessing the condition of assets to identify high risk assets.
5.4 Long-term Planning and Scenario Assessment – that discusses a number of modelling techniques used in developing long-term (30+ year) planning and scenario assessment of load growth and load-related expenditure.
5.5 Distributed Generation (DG) Hosting Capacity (HC) Assessment – that details the advanced and "big" data analysis techniques that were applied in an attempt to understand the impact of DG technologies on the distribution network and quantify feeder HC.

5.1 Asset Risk and Prioritisation (ARP) Tool

The Asset Risk and Prioritisation (APR) tool, which was developed by EA Technology Limited[5] and customised for use within UKPN, is an extension of EA Technology Limited's Condition Based Risk Management (CBRM) tool[6]. At its heart, the ARP tool has been developed to understand how finite capital and operational budgets can be optimally deployed to minimise risk exposure and maintain reliability of the network. It does this by integrating data from field and office based sources into bespoke modelling techniques to understand the current and forecast health of individual assets and taking a risk-based approach to identifying the optimal refurbishment or replacement time of each asset.

The following subsections provide an overview of the approach of the ARP tool, examples of the data used in its models, and the concepts applied in calculating the risk profile of an asset. Given the commercially sensitive nature of many parts of this tool, I am not able to discuss the details of specific ARP tool models and related calculations.

5.1.1 Overview of the ARP Tool

The ARP (and CBRM) tool exists as a large database consisting of:

- Input data – a diverse range of input data and settings, including, but not limited to, data on: each asset covered by the ARP tool, configuration and settings for risk assessment and aging models, and historical failure data;
- Calculations – that are used in calculating the condition of assets;
- Models – that detail how data is fed into the numerous calculations that make up an asset group model (e.g. power transformer, circuit breaker, cable, distribution transformer) and how these in turn are combined to produce the final single value results; and
- Thresholds or rankings – that convert the output of the model (and their inherent calculations) into simple and easily comparable rankings.

These components are utilised to calculate current and forecast asset health, criticality and risk profile, which is in turn used in generating an overall refurbishment or replacement priority ranking. In taking this data-driven approach the ARP tool is able to make an objective assessment of estimated refurbishment and replacement quantities and how associated budgets should be utilised to best mitigate risk to the network.

[5] EA Technology Limited (formerly the Energy Research Council Centre) was founded following the privatisation of the previously nationally owned electricity network, which began in 1990. EA Technology Limited are known for their work in the field of asset management, particularly in understanding the condition of assets and optimising investment in asset maintenance and replacement.
[6] See http://www.eatechnology.com/products-and-services/optimise-network-operations/cbrm for more information.

There are five key stages that the ARP tool employs in calculating the optimal asset replacement or refurbishment plan:

1. Calculation of the asset health in relation to a defined health index (HI);
2. Calculation of the probability of failure (PoF);
3. Modelling future degradation of asset health;
4. Calculation of asset PoF over time, identifying the optimal intervention time; and
5. Optimisation of the asset refurbishment or replacement program (across all assets) using criticality.

These stages are shown graphically in Figure 5, which demonstrates the flow of the calculation from input asset data through to optimised asset refurbishment and replacement program. It is important to note that stages one through four relate to the calculation for a single asset while the final stage (Optimise Program) is undertaken across all assets covered by the ARP tool. The following subsections discuss each of these stages in more detail.

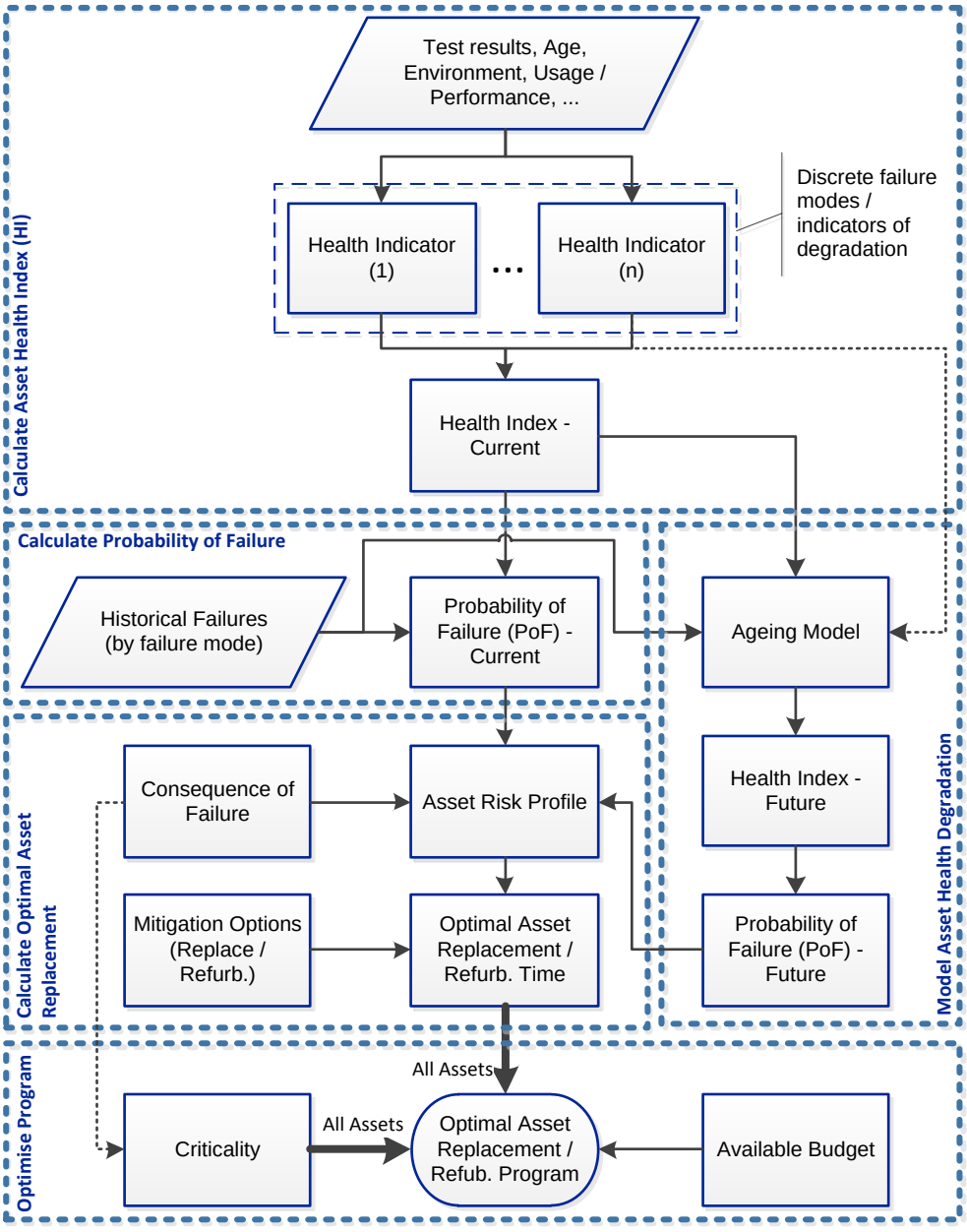


Figure 5: Process flow of ARP (CBRM) methodology

5.1.2 Input Data

The ARP tool integrates a variety of asset specific data that ranges in complexity. Depending on the asset being modelled, data incorporated in the asset health and criticality model can include: asset age, installed location, environmental factors, operational data and statistics (e.g. loading or operations), nameplate data, inspection results, and test results, and monitoring data. In addition to this asset specific data, models take into account: historical failures and failure rates for asset groups (particularly in fine tuning the PoF and ageing models), consequence of failure and risk assessment settings, and mitigation options and associated costs. These datasets are integrated throughout the ARP tool and directly impact the output of each model; as such, it is important to have data that is accurate and complete. Where data is incomplete assumed values or worst-case values are applied.

5.1.3 Asset Health Index (HI) Model

The HI is used as a simplistic and standardised method for describing the condition of an asset based on a variety of indicators of asset health (i.e. input datasets). The calculation of HI within the ARP tool occurs at an individual asset level using discrete data (e.g. locational or environmental data) and continuous data (e.g. historical loading or test results). Internal to the HI model is the calculation of one or more health indicators. Each health indicator is generally linked to a mode of failure for the asset group and may consist of a relatively simple calculation (e.g. scaling of input datasets) or could incorporate a number of layers of calculations.

The level of sophistication of the overall HI model is largely dependent on the complexity, value, and the availability of data for an asset group. However, each model within the ARP tool is fully customisable and can be updated with additional health indicators if suitable and relevant data sources are identified. The final step in calculating the current HI of an asset involves aggregating the individual health indicators (generally with relevant weighting factors) into a single HI score that is a continuous scale ranging between 0 (for an asset in good health) and 10 (for an asset in poor health) these values are then converted to a five-tiered HI ranking system (shown in Table 4).

Table 4: Ofgem HI rankings and definitions [6, 7]

HI Ranking	Definition
HI1	New or as new
HI2	Good or serviceable condition
HI3	Deterioration requires assessment and monitoring
HI4	Material deterioration, intervention requires consideration
HI5	End of serviceable life, intervention required

It is important to note that, although Table 4 provides textual definitions of each HI ranking (as defined in [7]), each HI ranking has a distinct HI score range that was developed as part of the Common Network Asset Indices Methodology document [6]. The Common Network Asset Indices Methodology was authored at the request of Ofgem by a working group with participants that spanned each of the transmission and distribution utilities within the UK. Its purpose is to develop a unified approach to assessing HI, PoF, consequence of a failure (CoF), criticality index (CI), and resultant risk for a number of key asset groups.

These standardised values are reported to Ofgem periodically (twice per regulatory period), allowing the regulator to understand the risk reduction achieved by the various utilities maintenance and refurbishment programs (i.e. the return on investment). Moreover, it allows benchmarking between utilities to compare reduction in risk per amount of investment, and tracking of HI and CI over time.

5.1.4 Probability of Failure (PoF)

The PoF provides a statistical estimate of how likely an asset is to fail at a given point in time. Calculation of the PoF, which occurs at an individual asset level, is intrinsically linked to the derivation and calculation of the asset HI. This relationship between HI and PoF is estimated within the ARP tool using a third-order polynomial of the form shown in Equation (1). Where possible, the coefficients of

this curve are tuned using historical failure data. If accurate and reliable failure data is not available, this polynomial relationship is tuned using past experience and best estimate.

$$\text{PoF} = \text{K} \times \left(1 + (C \times H) + \frac{(C \times H)^2}{2!} + \frac{(C \times H)^3}{3!}\right) \quad (1)$$

Where:

- K is a constant that defines the scale of the PoF;
- C is a constant that defines the shape of PoF curve and how it varies with increasing HI score; and
- H is the HI score which has a lower bound of four (4) (i.e. for all values of HI score less than four, a value of four is used).

For completeness, the ARP model takes account of the overall PoF; that is the PoF including the likelihood of a non-condition-related fault (e.g. exceptional weather conditions, or third-party damage). However, when assessing investment options, the impact of different types of mitigation on the PoF must be considered (e.g. refurbishment or replacement will not change the risk of failure from lightning strike).

5.1.5 Modelling Future Asset Health ("Ageing Model")

The process of calculating HI and PoF provides a snapshot of risk at a single point in time. To understand how this HI and PoF changes over time, the future health of assets must be estimated using ageing modelling. Application of this modelling allows an organisation to calculate:

- The optimal time for replacement or refurbishment in an asset's lifecycle;
- How the health of its asset portfolio will change over time and hence the organisation's risk exposure; and
- The improvement in risk profile achieved by intervention (i.e. maintenance, refurbishment, or replacement).

In building this ageing model, the ARP tool utilises the assumption that the health of an asset tends to degrade more quickly as it reaches the end of its serviceable life, predicting an exponential decay in health (and therefore increase in HI score). The ageing model has two phases:

1. From "as new" to "end of normal life." This phase models the HI score over the asset's normal operating life and is predominantly determined by the present and future age of the asset. Beyond this point it is expected that the HI score and associated PoF of the asset will rise substantially.
2. Beyond "end of normal life." Once an asset has exceeded its normal operating life the HI score is estimated using condition and reliability information to extrapolate the exponential health degradation curve. In particular, it looks at how assets of similar type and operating conditions have performed, using this data to predict HI score deterioration.

This HI ageing model is estimated for each individual asset covered by the ARP model. As a result, the ageing model takes account of the different physical operating environments (e.g. indoor, outdoor, and geographical location) and the operating conditions (e.g. loading and load duration) of the asset to fine tune the rate-of-change of the HI. Where possible the ageing curves are cross referenced with historical data to ensure accuracy and validity.

5.1.6 Risk Profile and Optimal Replacement Time

To provide a meaningful and quantifiable measure of risk the ARP tool applies widely accepted risk assessment techniques in associating a monetary value (pound sterling (£) within UKPN) to the CoF. CoF is classified in four key areas, they are: network performance, safety, financial, and environmental. Each asset covered by the ARP model is analysed against these four CoF categories. This provides an understanding of the direct or indirect financial loss in the event of a fault or failure of that asset.

The CoF and PoF can then be used to calculate the risk exposure from an asset at a given point in time. This risk can be extrapolated using the ageing model to give a PoF profile and hence a risk profile. Comparison of this risk profile and the diminishing cost of mitigation allows for the calculation of the optimal replacement time for an asset. In economic terms, the algorithm calculates the point where the marginal cost reduction of mitigation becomes less than the marginal increase in risk that can be mitigated; thus identifying the optimal replacement time for the asset.

5.1.7 Optimising the Program

The final element of the ARP model develops an optimised asset replacement and refurbishment plan. Although the ARP tool identifies the technically optimal asset replacement time, budgeting, time, and resourcing constraints limit the work that can be undertaken. As a result of these real-world constraints it is inevitable that not all assets will be able to be refurbished or replaced at the optimal time. To take account of this, it is important to understand the criticality of each asset; particularly when compared with assets of a different type.

To resolve this issue, the ARP tool (and Ofgem) use standardised CI rankings (developed by the Common Network Asset Indices Methodology [6]) for reporting and comparison purposes (see Table 5). As with the HI rankings (see Table 4), the CI ranking is defined both textually and numerically [6]. Each of the four tiers of CI ranking provided in Table 5 have an associated numerical banding, which is applied to the CoF of an asset as a percentage of the average CoF for that asset group. The calculation of CI ranking and CoF for each individual asset and for the asset group average allows for comparison of the criticality of assets within the same asset group and across different asset groups. Thus providing the ability to understand which asset replacements or refurbishments should be prioritised across the asset base.

Table 5: Ofgem CI rankings and definitions [6, 7]

CI Ranking	Definition
C1	Low Criticality
C2	Average Criticality
C3	High Criticality
C4	Very High Criticality

Using these HI and CI rankings Ofgem defines a standardised and monetised risk index (RI) that is calculated using a risk matrix, specific to each asset group. This RI is being used during RIIO-ED1 for utilities to report their proposed and achieved network risk throughout the regulatory period. Organisations that fail to reach their proposed risk score without suitable justification may be exposed to revenue penalties. Therefore, the underlying goal of utilities should be to minimise their risk score by prioritising high risk assets (i.e. those with a high RI) within their budget, time, and resourcing constraints.

5.2 Distribution Network Visibility (DNV) Project

The Distribution Network Visualisation (DNV) project, undertaken by UKPN and project partners PPA Energy[7] and Capula[8], was a Low Carbon Networks Fund (LCNF) and Innovation Funding Incentive (IFI) funded project. It was targeted at leveraging new and existing distribution monitoring and control systems (namely remote terminal units (RTUs) installed at distribution transformers across UKPN's network) to:

- Improve utilisation of existing monitoring systems (remote terminal units (RTUs));
- Explore various data sources and monitoring systems, investigating collection methods and frequencies;

[7] PPA Energy is an energy and management consultancy specialising in issues relating to the power sector.
[8] Capula is an IT consultancy with a core focus on implementing control, automation, real-time solutions.

- Understand the benefits that could be derived from the analysis and visualisation of this data; and
- Use smart software packages to better understand network performance.

As this project was funded under the LCNF and IFI[9], information pertaining to this project is publicly available on UKPN's Innovation website [8].

Figure 6 provides an overview of the work undertaken as a part of this project. The project focused initially on documenting high-level user requirements and deconstructing these into data sources and monitoring requirements. The end result is a library of valuable tools and reports that deliver benefits to the business by enhancing: decision making capabilities, modelling capability and accuracy, and the understanding of network performance.

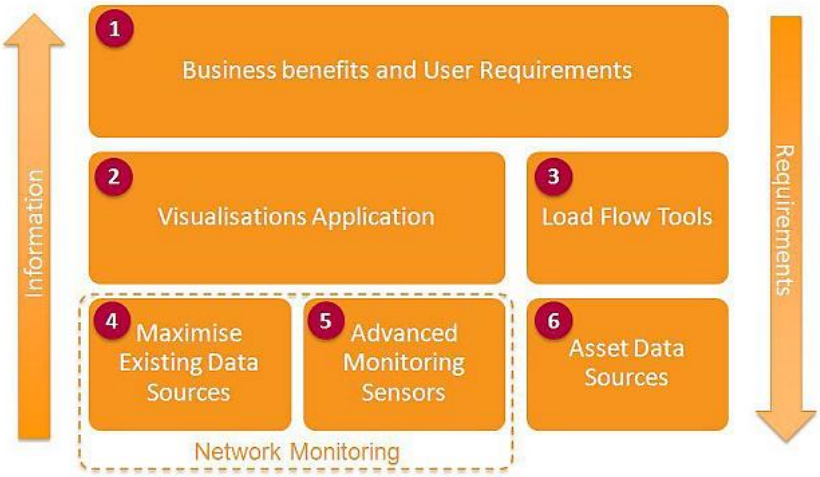


Figure 6: Components addressed in the DNV project [9]

Given the size and complexity of the DNV project, this section will not discuss each component of Figure 6 in detail; rather, it will focus on specific components of the project that relate to my area of research. More information regarding key findings and supporting documentation is made available on UKPN's website [8].

5.2.1 Network Monitoring

UKPN's distribution network is monitored and controlled via RTUs at all primary substations (132/11kV, 33/11kV) and, within UKPN's London Power Network (LPN)[10], at approximately 45% of secondary (distribution) substations (11kV/415V) [9]. The level of existing monitoring and control capability within the LPN licence area made it the ideal test location for many of the DNV project's monitoring initiatives.

Historically, collection of data made available from these secondary substation RTUs was constrained by the speed and reliability of the telecommunications infrastructure and was limited to four core measurements. However, advances in telecommunications and data storage capabilities have allowed for the transfer and storage of large amounts of information, making the collection of previously inaccessible data a possibility. To this end, approximately 10,000 secondary RTUs were

[9] The LCNF and IFI were two funding incentives established by Ofgem to promote innovation within the UK's highly competitive electricity distribution industry. LCNF was specifically targeted at research to enable the uptake of low carbon and energy saving technologies; while the IFI (which was replaced by the Network Innovation Allowance (NIA) in 2015) was targeted at innovation in all aspects of electricity distribution.
[10] LPN is one of UKPN's three licensed distribution areas.

upgraded to report 10 new network measurements, making a total of 14 measurements per RTU. The resultant measurements captured following this upgrade were[11]:

1. Apparent (S) power
2. Red Phase voltage
3. Power Factor (PF)
4. Substation ambient temperature
5. *Red Phase current*
6. *White Phase current (Yellow in the UK)*
7. *Blue Phase current*
8. *White Phase voltage (Yellow in the UK)*
9. *Blue Phase voltage*
10. *Real (P) power*
11. *Reactive (Q) power*
12. *Total Harmonic Distortion – Red Phase*
13. *Total Harmonic Distortion – White Phase*
14. *Total Harmonic Distortion – Blue Phase*

These additional measurements were derived following a period of consultation within the business to understand requirements and resulting benefits. Using this increased monitoring capability and consolidated data from existing systems (e.g. SCADA and the asset register), a number of tools and analysis techniques were explored to leverage value for the organisation.

It is worth noting that the DNV project also investigated a number of advanced monitoring systems and sensors; however, these are not discussed in this report.

5.2.2 Knowledge and Information from Data

As outlined in Figure 4, simply collecting this additional data would provide little (if any) benefit to the organisation. Further analysis, reporting and understanding was required to generate usable information and knowledge. Some of the areas investigated by UKPN included:

- The development of the DNV tool in partnership with Capula;
- Load profiling at a secondary substation level;
- Improved / real-time load flow modelling; and
- Dynamic rating of assets.

It was also important to consider data quality as part of the project deployment and ongoing management. Given the scale of additional data generated, automated scripts were developed to assist in highlighting and resolving data errors. This will not be covered in this report, but is available in Section 5.3 of [9].

The DNV Tool

The DNV tool, was initially prototyped by UKPN but later redeveloped by a consultancy as a web-based tool. At the core of the DNV tool is a geographical view of the network. This view is overlaid with dynamically generated reports and analysis. These reports allowed users to view and analyse data in a variety of ways, including: raw data timescale charts, load duration curves, calculated load at risk, and planning reports.

As a business tool, the DNV tool demonstrated how improved data availability can be leveraged to produce useful information that is of benefit to engineers, decision makers, and customers. The ability to readily generate and view this information presents opportunities for: streamlining processes, informing planning and operation, and improving the understanding of how the network is performing. For asset management, the availability of this information will enable more informed decision making to drive investment in areas of greatest need.

Load Profiling

One such application was understanding the impact of new customer connections and improving transformer capacity utilisation. Rather than applying an assumed diversity figure for new connections, load profiles (depending on the type of connection) could be used to directly model the impact of new load on a transformer's existing load profile. Furthermore, documentation of the load profile over time will allow for the identification and exploration of changes in customer consumption and usage trends.

[11] Added measurements in highlighted in *italics*

This information is particularly valuable in understanding the impacts of new technologies and changing trends on customer electricity usage.

Improved / Real-time Load Flow Modelling

The availability of secondary substation loading data in near real time provided an opportunity for improving the accuracy of load flow modelling and the investigation of "real-time" modelling. To enable this functionality, UKPN investigated two commercial load flow tools: *GE Distribution Power* low and *CGI DPlan* with varying levels of success. In both instances, software limitations restricted the accuracy of the final solution[12]. This highlighted the need for end users (i.e. DNOs) to work with software developers to ensure that products are providing the required functionality. The final finding was that improving load flow accuracy and achieving real-time modelling was a promising prospect, but that it was not viable at present.

Dynamic Rating of Assets

The improved data availability achieved during the DNV project allowed for the dynamic rating of distribution transformers being investigated[13]. While dynamic rating is not a new practice for high-value primary assets (e.g. power transformers or high criticality cables), it does not normally occur with lower value assets (e.g. distribution transformers). Dynamic rating of distribution transformers would deliver obvious benefits for network operations, allowing short-duration overloading of transformers during a contingency or load transfers with an acceptable loss of life. In addition, asset management would benefit if this was monitored over a long duration. The resulting history could provide an estimate of the remaining life (or condition) of a transformer. This would assist the prioritisation of asset replacement, particularly when considering that low-value assets typically don't receive the same level of monitoring, testing and maintenance as their high-value counterparts.

5.3 Online Partial Discharge (PD) Monitoring System

The application of PD testing for insulated assets is not a particularly new idea. However, UKPN's application of online partial discharge monitoring on critical cable and switchgear assets demonstrates how developments in test and monitoring techniques, alongside advanced analysis, visualisation, and reporting can assist in the targeted management of assets.

UKPN, working with industry partners IPEC[14], have long been involved in the development of PD monitoring systems and analysis techniques. In particular, UKPN undertook an Innovation Funding Incentive project [10] to test the use of online PD monitoring in pre-emptively identifying and rectifying faults on switchgear and cables. This project, which was closed-out in March 2012, is now been adopted as business as usual within UKPN. During part of my tenure with UKPN I sought exposure to this system where I worked with the Future Networks team in collaboration with the Asset Strategy and Performance team.

My involvement with the online PD monitoring system focused on: better embedding the PD monitoring system within the business by progressing a number of cable investigations, coordinating with the PD service provider, and reviewing and providing feedback on a number of "LOT 5" innovation proposals. The "LOT 5" call for innovations was published by UKPN to seek input from industry on innovative developments in PD monitoring and condition assessment of cables [11]. Owing to the confidential nature of the "LOT 5" innovation proposals, I am not able to discuss this work in more detail. However, this section provides a brief overview of the application of online PD monitoring within UKPN and the benefits and challenges inherent within this system.

[12] See Section 5.5 of [9] for more information on the issues experienced with the load flow software.
[13] See Section 5.8 of [9] for more information on the dynamic rating model applied to secondary transformers.
[14] Independent Power Engineering Consultants (IPEC) are a consultancy based in Manchester in the UK who specialise in PD testing and monitoring of cable and switchgear assets.

5.3.1 Overview of Partial Discharge

In its most common form, PD is known as corona discharge, which predominantly occurs on EHV or HV overhead networks at points of high electromagnetic stress (e.g. on the live electrode of an arc gap). The occurrence of corona discharges within air presents little concern to the health of assets themselves as the insulating medium (air) is quickly refreshed. However, in applications using solid or contained insulation (e.g. gas or oil) where the insulating medium is not easily refreshed, PD is more of a concern as it can actively degrade the insulation.

PD may occur as a result of manufacturing defect, pollution, damage, ageing of material, or overvoltage, whereby the insulation has reduced breakdown strength or the insulation is under increased electromagnetic stress. In these circumstances the dielectric strength of small portions of the insulating material is exceeded, resulting in PD arc. This process of arcing reduces the insulating properties of the arcing medium by tracking, treeing, or general degradation; thus making it more prone to future PD. Over a prolonged period of time this degradation will compromise the insulation and likely result in disruptive failure due to flashover.

Each PD creates a small impulse signal that is transferred through the surrounding insulation, normally to the metallic housing or, in the case of cables, the earth sheath. PD testing and monitoring techniques aim to identify and locate these discharge signals by monitoring the metallic casing of assets, earth sheath terminations, or within the insulating medium.

For a more detailed overview of PD theory and models, including some applications of testing see [12].

5.3.2 Online Monitoring and Fault Identification

The ability to detect and locate the source of PD aids in identifying assets that may be prone to failure, in turn enabling proactive maintenance and replacement. The system developed by IPEC and employed by UKPN in online monitoring of their cable and switchgear assets consists of three components:

- A range of online monitoring sensors, processing, and communication equipment;
- A web-based analysis and reporting tool; and
- On-site testing systems.

The use of these components in the detection, location, and prevention of faults is outlined in Figure 7 and discussed in more detail below.

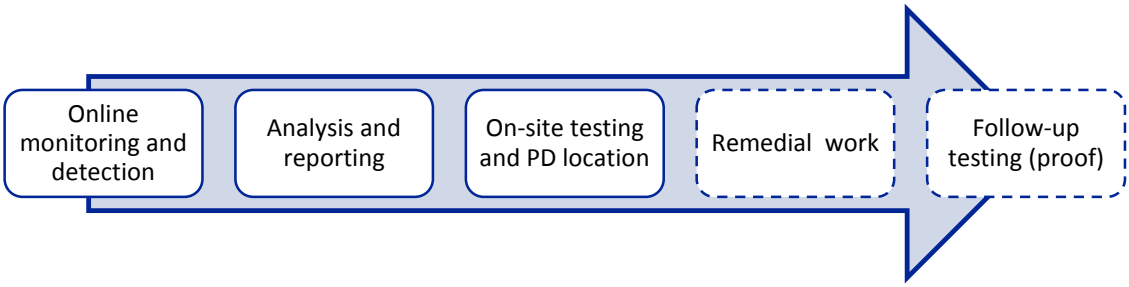


Figure 7: IPEC / UKPN online PD monitoring process

The online monitoring component of the system that is responsible for measuring and recording PD uses three IPEC sensors: an ultrasonic acoustic sensor (for switchgear monitoring), a transient earth voltage (TEV) sensor (for switchgear monitoring), and high frequency current transformers (HFCT) (for switchgear and cable monitoring). UKPN has employed approximately 2,000 of these sensors across its network covering 60 primary substations predominantly focused in LPN. The two most commonly used sensors, the TEV and high frequency CT, work by detecting electrical PD pulses (in the order of mV peak) which are created on the casing of metal clad switchgear or on the earth sheath of cables.

Accurately measuring and recording these PD pulses not only enables the identification of PD (particularly from noise), but also enables advanced analysis and location of specific discharges.

The data collected from the monitoring system is communicated to a central server that is responsible for processing and analysis. Fundamental to the processing algorithm is the resolution of actual PD activity from noise. A summary of some of the common signal processing techniques used to remove noise from PD signals is covered in [13]. Once actual PD activity has been resolved from noise, the amount (count) of PD activity and PD magnitude (in pC[15]) are calculated. Using this information IPEC's proprietary analysis system provides a range of reports for use in manual analysis and understanding detected PD activity. These include:

- Asset criticality ranking (based on PD activity);
- Polar and phase-resolved plots of PD activity, showing the point of occurrence of PD on the voltage cycle;
- Correlation of PD activity with load, as well as a number of other environmental variables (e.g. temperature and humidity); and
- Identification and classification of PD activity by pulse signature, enabling the identification of different PD sources and their level of activity.

This analysis system utilises automated algorithms to identify and alarm on assets exhibiting certain PD trends, such as sustained high levels of, or trending increase in PD activity. These alarms are used to flag assets for onsite investigation and PD location. On site investigations, conducted by IPEC engineers, are aimed at locating the source of the PD to a high degree of confidence and accuracy (e.g. to a single switchgear panel's cable terminations or cable box, or to within a few meters on a cable). During my time working on the project I was able to attend a PD mapping exercise with IPEC engineers, providing a valuable insight to the tools and processes used to locate the PD source.

Switchgear testing uses a combination of ultrasonic and TEV sensors placed in different locations on the switchgear casing. Ultrasonic sensors are used to locate the general vicinity of the PD, while multiple TEV sensors are used to accurately triangulate the source of PD by detecting the difference in pulse propagation or arrival times between the various sensors. Cable testing uses the principle of time-domain reflectometry to estimate the location of the fault by measuring the travel time (or time delay) of a PD impulse and its reflection(s), which travel along the earth sheath of a cable.

Mapping the source of PD on a cable requires accurate measurement of the cable length. This can be achieved by injecting known signals on the cable sheath and measuring the travel time between a pulse being injected and the reflection being received. The mapping of PD uses the same principle, but instead using the known cable length, propagation speed, and time difference between the initial PD pulse and its reflection arriving at the monitored end to pinpoint the location of the fault.

Successful PD investigations result in a fault summary report that is issued to UKPN for corrective work or continued monitoring. If an outage can be secured for remedial action to be undertaken, the identified PD location is inspected for evidence of damage (through intrusive maintenance) and is generally replaced. Where an outage cannot be secured or where workloads limit the ability for remedial work to be undertaken, sites are monitored for any changes in PD activity. Following the completion of remedial work a final "proof" investigation is undertaken (using online monitoring) to confirm that the PD source has ceased, signalling successful prevention of a fault.

[15] PD signal magnitude is measured electrically in mV; however, it is common for PD magnitude to be reported in pico-Coulombs (pC). This value represents the apparent charge of the PD and is not equivalent to the charge present within the PD itself. As defined in IEC 60270:2000, the apparent charge is the "charge which, if injected within a very short time between the terminals of the test object in a specified test circuit, would give the same reading on the measuring instrument as the PD current pulse itself."

5.3.3 Limitations

Although the online monitoring of PD in cables and switchgear provides a pre-emptive indication of insulation failure, there are a number of limitations within these monitoring systems and their subsequent analysis techniques. Foremost amongst these is the lack of means to estimate an asset's remaining life or time to failure from PD data. While there has been much research in this area [14, 15, 16] (to name a few) consensus is that there is little correlation between PD magnitude, frequency, and time to failure. This has been evident in UKPN's experience, whereby some assets have shown high levels of PD magnitude and activity for sustained periods without failure, while others have failed in relatively short timeframes after displaying lower levels of PD activity. Some analysis [16] has shown that short increases or trends in PD may be a more reliable indicator of imminent failure, however this technique has not been developed sufficiently. The lack of indication of time to failure makes the prioritisation of corrective action to avoid faults difficult, especially when considering resourcing and budgetary constraints. This is one of the issues for investigation as a part of the UK Power Networks' "LOT 5" call for innovation.

There are also a number of factors impacting the success rate of PD location, namely:

- PD signal attenuation (on cables);
- noise (on cables and switchgear); and
- variability and unpredictability in PD activity (on switchgear and cables).

Overall the use of online PD monitoring provides a valuable tool to monitor the condition of ageing assets, a challenge particularly relevant within Australia. The present lack of a predictor of time to failure makes the findings of PD monitoring difficult to manage; moreover, it makes the value of such a system difficult to demonstrate. As these systems, methodology, and analysis develop, the value provided by PD monitoring will increase.

5.4 Long-term Planning and Scenario Assessment

Historically, DNOs (and the electricity supply industry) could rely on sustained and predictable load growth when developing investment plans. The changing landscape within the electricity supply industry internationally has complicated this task significantly. Technologies such as electric vehicles, energy efficient appliances, distributed generation, and energy storage systems will change the way consumers interact with the electricity network, and the amount of energy they use. Moreover, environmental and economic concerns are increasing consumer's energy awareness, in turn driving down energy usage. The challenge for the electricity industry is to understand how this landscape will change in the long term and to best prepare for possible future scenarios.

Within the UK, and UKPN more specifically, a great deal of research and development has been undertaken to understand the different economic, environmental, and technological scenarios and model their impact on the long-term load growth and associated investment. During part of my tenure at UKPN I worked within the Network Design Standards team to gain exposure to the Element Energy Load Growth (EELG) model and the Imperial College London (ICL) Load Related Expenditure (LRE) model to understand the underlying algorithms, possible limitations, and how they have been of benefit to UKPN. Both models, along with a summary of the work that I completed, are discussed in this section.

For completeness I have provided an overview of the Transform model. In addition to this summary I recommend reviewing the final scholarship report of past E.S. Cornwall Scholar Robyn O'Connor [17], who undertook a placement with EA Technology and was involved in the implementation of the Transform model in New Zealand.

5.4.1 The Transform Model

To assist in understanding how the low carbon transition will impact future energy usage, peak demand, and network investment, Ofgem and the Department of Energy and Climate Change (DECC)

established the Smart Grid Forum in 2011, with Work Stream 3 being focused on assessing the impacts of a range of different future (low carbon) scenarios [18]. Work undertaken by this group led to the production of the Transform model by EA Technology and a consortium of contributing parties [19].

In modelling a sizable and complex network like the UK's distribution network, the Transform model applies simplified network models that are defined by key parameters, such as network: type (urban, suburban, or rural), topology (radial or meshed); and construction (overhead or underground). These simplified models are combined to build a representative model of each of the 14 license areas. In addition, data around consumer demographic (residential, commercial, or industrial; appliance usage; and energy efficiency), and technology uptake is used in understanding load growth on representative models of the network. The resulting network model and scenario growth forecast inherent in the Transform model is used to estimate load-related network investment by applying a range of traditional and "smart" solutions to mitigate network load constraints. In each case, mitigating options have been characterised to allow the Transform model to identify the most suitable and cost effective outcome. In doing so, the model is also able to represent different investment strategies (e.g. favouring traditional or "smart" investment options). The resultant output provides a summary of the investment required and investment portfolio by mitigating option; thus enabling and understanding of the:

- Potential impact of likely future scenarios on load growth and resultant network constraints;
- Financial investment required to meet the estimated load growth of these scenarios; and
- Best value long-term investment options and overall investment strategy.

Ofgem required that all UK DNOs utilise the Transform model (or suitable alternative) as a part of their RIIO-ED1 business plan justification. For a detailed overview of UKPN's application of the Transform model and its use within their RIIO-ED1 business plan see Section 6.3 and 6.4 of [20]. For the detailed report into the findings for the Transform model, as conducted by the Smart Grid Forum - Work Stream 3, see [21]. This report provides a detailed analysis of the forecast investment required to meet load growth between 2012 and 2050, as predicted by the Transform model.

Although the parameterised network representation used in the Transform model aids in reducing computational complexity, UKPN (and indeed other DNOs) found that the generalised nature of this model failed to accurately capture important network and customer demographic information that could impact the outcome of the load growth forecast. Therefore, UKPN sought the experience and expertise of Element Energy[16] and the Imperial College London[17] (ICL) to develop models that more accurately capture the operating conditions of its network. The two resulting models are outlined in the following sections.

5.4.2 Element Energy Load Growth (EELG) Model

During my time with the Network Design Standards team I was given access to the Element Energy Load Growth (EELG) model, allowing me to gain an understanding of the model inputs, underlying calculations, assumptions, and outputs, while running my own scenario assessments. Because of the confidential nature of the model I am not able to discuss its inner working in great detail; however, the following section provides an overview of key inputs and outputs of the model.

The EELG model was developed to improve the accuracy of long-term load growth forecasts for UKPN's network. One of the major improvements (in comparison to the Transform model) is the detailed consideration of customer demographics and customer characteristics. The EELG model develops a highly disaggregated model of network loading (to a secondary substation level) by:

[16] Element Energy is a consultancy based in the UK who specialise in low carbon energy analysis.
[17] The Imperial College London is public research university located in London, which is amongst the top-ranked universities internationally and is known for its strength in engineering research.

- Establishing a set of customer classifications within each consumer type (i.e. within the residential, commercial, and industrial groups). For example:
    - Residential customers, who are classified by: age of dwelling, size of dwelling, location (urban, suburban, or residential), and availability of gas.
    - Commercial customers, who are classified by their usage (retail, hospitality, leisure, education, etc.).
    - Industrial customers, who are considered as a single group.
- Classifying customers using Experian Mosaic[18] data [22], which identifies customer and housing demographic by postal code sector[19] to apply the aforementioned customer classifications. These customer classifications are used to understand localised technology and efficiency uptake trends based on affluence and type of housing.
- Aggregating these customer types using UKPN's network connectivity data.

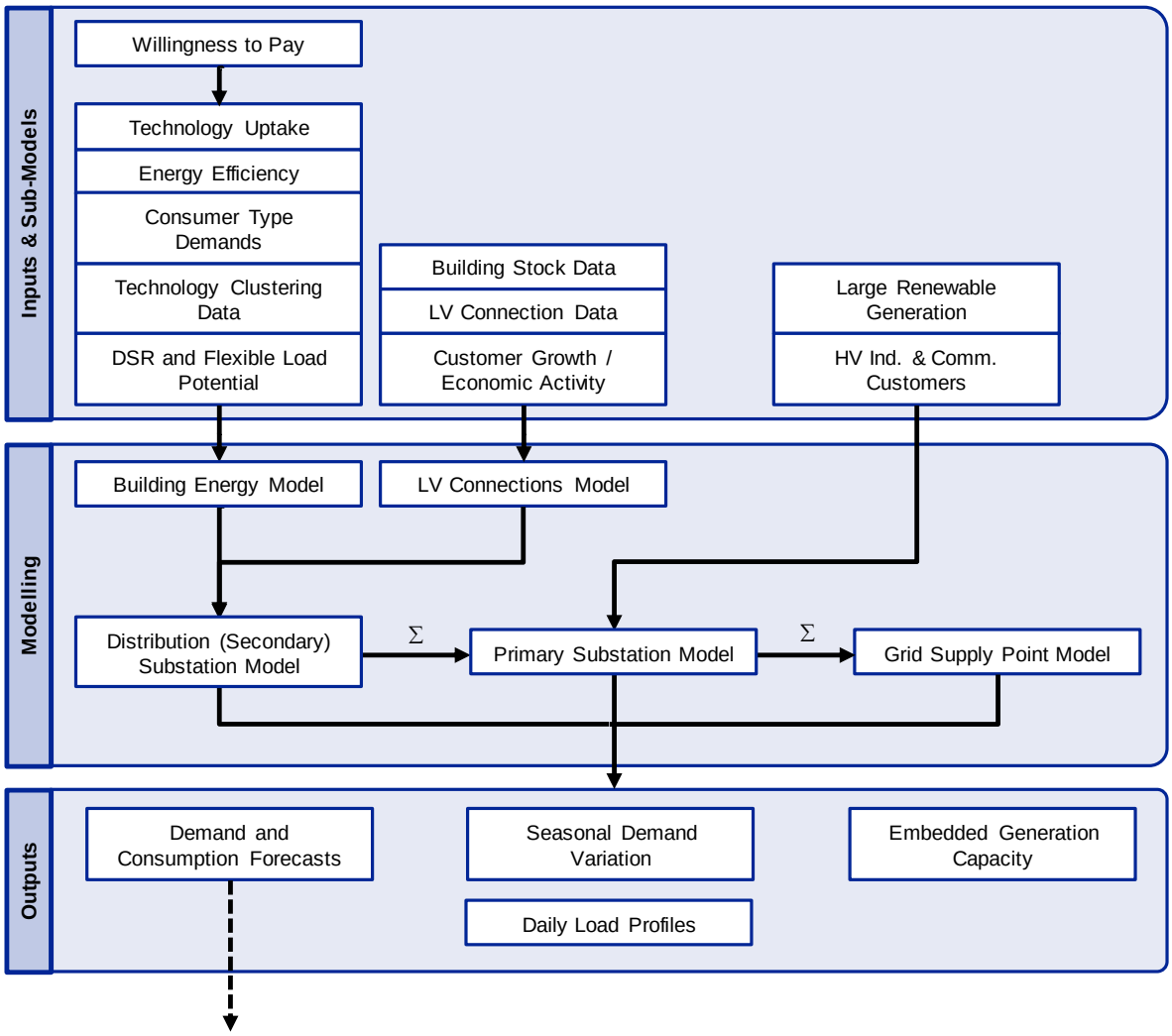


Figure 8: Overview of EELG model inputs and outputs (modified from [23])

Having established this detailed view of the customer composition of the network, the EELG model applies detailed and complex scenario analysis in estimating how the various customer group's usage will change over the study period in response to different factors. Inputs to the EELG model include:

[18] Experian is a consultancy that provides data and analytic services to businesses. Their Mosaic dataset and analysis provides market classifications and segmentations by post code sector for the UK and Scotland.
[19] The UK utilise a high resolution post code system (in comparison to that used in Australia). A complete post code, consisting of area, district, sector, and unit codes identifies on average 15 customers or postal addresses. Therefore, data on customer type by postal sector provides a detailed geographical understanding of customer composition.

- Economic growth forecasts, including growth in housing stock;
- Gains in energy efficiency for residential, commercial, and industrial customers;
- The impact of market reforms and changes to customer usage through demand management and time of use tariffs; and
- The proliferation of heat pumps and low carbon technologies such as, electric vehicles, photo-voltaic generation, and wind generation.

These scenario inputs and the subsequent modelling method are summarised in Figure 8, demonstrating how input data on customers and future scenarios (as discussed above) are integrated with network connectivity data to provide output forecasts across a number of areas and at all levels of the network.

The output of this model provides UKPN with an understanding of future growth on their network and sensitivity to the range of scenario inputs. These estimates are used alongside those of the Transform model and the work of the Future Grid Forum - Work Stream 3. However, the EELG model has a significant advantage owing to its highly disaggregated nature with load forecasts resolvable to a secondary substation level. This level of granularity enables a much more detailed assessment of how estimated load growth will impact network capacity and create constraints. To understand this, the EELG forecasts are fed into the ICL Load Related Expenditure (LRE) model discussed in Section 5.4.3.

5.4.3 Imperial College London (ICL) Load Related Expenditure (LRE) Model

As with the EELG model, which was developed as an extension to the load forecasting component of the Transform model, UKPN sought the experience and expertise of the ICL in developing a whole-of-network (i.e. EHV, HV, and LV) model of UKPN's three license areas. The resulting model is one that can be used for a number of applications, but is primarily used alongside load forecasts from the EELG model to understand the impact of this load growth on the network and to estimate required load related expenditure.

In more detail, the LRE model provides accurate network representations of UKPN's EHV and HV networks (derived from a culmination of UKPN's own network models developed in DIgSILENT Power Factory, DINIS, and GROND), while using a fractal model[20] to approximate and simplify analysis of the LV network. This network model, along with a number of other inputs outlined in Figure 9, feed ICL's optimal power flow algorithm[21] in calculating the impact of load growth on the network. Where network constraints (i.e. capacity, voltage, or fault) are identified, the model is capable of assessing a number of traditional and "smart" investment options and selecting the most cost effective. In this way, using the year-on-year load growth rate from the EELG model, the ICL LRE model is able to identify the optimal investment profile over the study period. This enables UKPN to quickly estimate their load related expenditure profile, sensitivity to different load growth scenarios, and breakdown cost and quantity by mitigating option.

[20] By definition a fractal is, "*a curve or geometrical figure, each part of which has the same statistical character as the whole.*" In this application ICL utilised fractal analysis on the LV networks of all three of UKPN's license areas to identify characteristic network types which are similar across UKPN's network. Using this methodology ICL were able to identify a set of circa 800 characteristic LV networks which accurately describe the node and load density of circa 100,000 LV networks. In doing so the ICL LRE model is only required to model circa 800 LV network models to understand the performance and expected expenditure on UKPN's entire LV network.
[21] Optimal power flow algorithms take account of network attributes like capacity, configuration, available generation, and load alongside an optimisation function to identify the optimal network operating conditions.

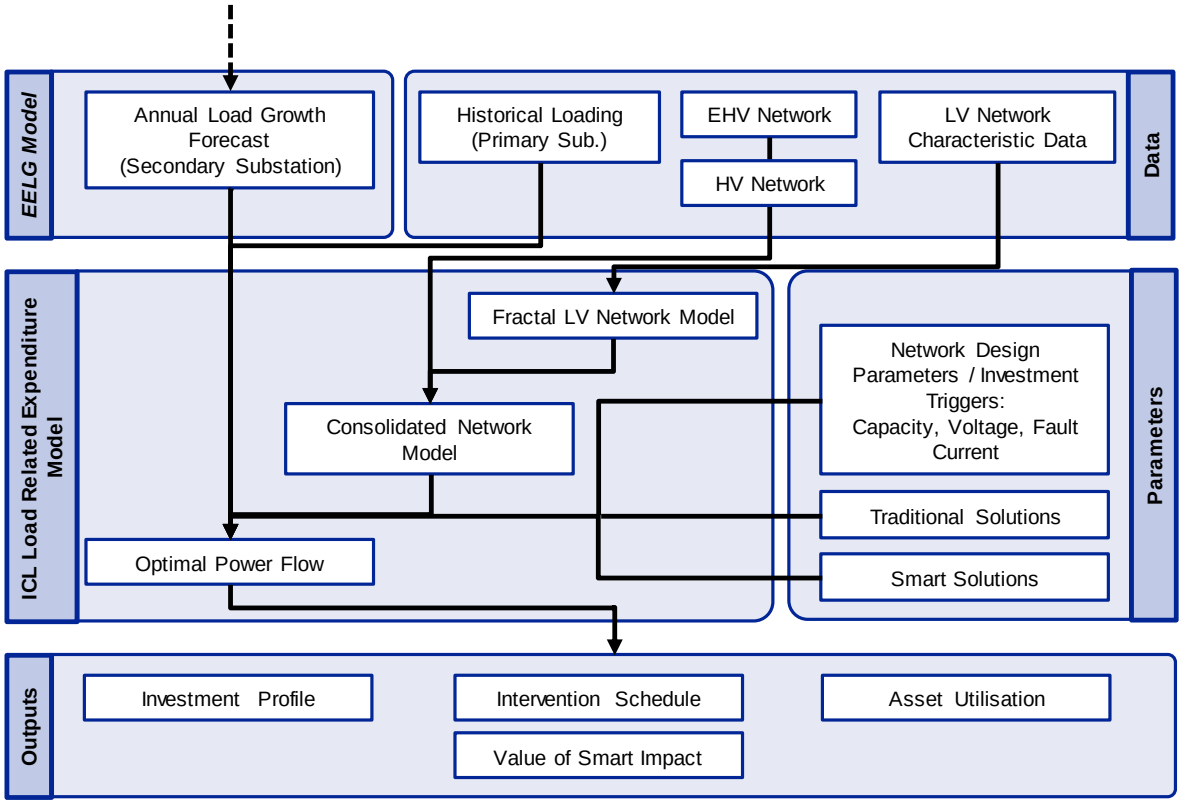


Figure 9: Imperial College London (ICL) Load Related Expenditure (LRE) model process flow (modified from [24])

5.5 Distributed Generation (DG) Hosting Capacity (HC) Assessment

Distributed generation (DG) systems, particularly renewables (solar and wind), are proliferating within Australia and internationally as a result of reducing costs, attractive incentive schemes, and legislative mandates. Understanding and quantifying the impact of these technologies on networks, which have traditionally not been designed to accommodate such technologies, is a complex and time consuming problem. In many instances it is not viable to undertake detailed manual case-by-case studies of high volume, low capacity connection requests (like those for small rooftop solar systems); however, as the penetration of these smaller systems increases, their cumulative impact can negatively affect assets and the performance of the network.

5.5.1 Screening Techniques

To expedite the interconnection assessment process, while minimising the impact of DG on assets and the network, utilities, industry groups, and regulators have worked to develop connection assessment standards. Within Australia, utilities are moving to define required performance characteristics and limitations for inverter system that can be fast tracked; see, for example, Ergon Energy and Energex's "*Connection Standard: Small Scale Parallel Inverter Systems up to 30kVA*" [25]. Within the USA, similar guidelines have been issued by the Federal Energy Regulatory Commission (FERC) [26], which resulted in the creation of the "15% rule"[22].

These documents provide a well-constructed set of requirements for screening and assessing distributed generation connection requests on a case-by-case basis. However, heuristic screens like

[22] The "15% rule" refers to the requirement set out in Section 2.2.1.2 of [26] that stipulates (in addition to other requirements), for an interconnection request to be fast tracked, "*…the aggregated generation, including the proposed Small Generating Facility, on the circuit shall not exceed 15 % of the line section annual peak load as most recently measured at the substation.*"

the 15% rule and the more recent 100% minimum daytime load rule[23] (which may prevail [27]), that are applied in the USA, fail to take account of all feeder dynamics and often impose conservative limits. As such, it is important to provide a more realistic estimate of a network's capability to accommodate distributed generation.

This topic has received substantial interest from industry organisations like the Electric Power Research Institute (EPRI). EPRI has worked extensively on developing techniques for quantifying DG hosting capacity (HC) [28, 29, 30]. DG HC, often referred to by the more general term "hosting capacity", is the amount (by kVA or MVA capacity) of DG that a feeder can accommodate without negatively impacting its performance. This research and subsequent studies have shown the relationship between network dynamics and HC to be complex and, in the case of [30], have highlighted reasons for updating existing screening processes when assessing distributed generation connection requests.

It was this limitation of existing screening techniques and the subsequent research and development of detailed HC assessment techniques that formed the core focus of my tenure with ComEd. In particular, I was tasked with developing a scalable tool that was capable of automatically calculating the HC of feeders within ComEd's network. Quantifying HC on a feeder-by-feeder basis would:

- Provide an analytical measure to use in expediting application screening process (in comparison to the current heuristic method);
- Provide a detailed understanding of feeder limitations;
- Identify the optimal distribution of distributed generation (capacity and location) that allows for maximum penetration with minimal network impact; and
- Inform other works like the development of incentives to encourage installation of distributed generation in a sustainable way.

5.5.2 Prevailing Techniques

Within literature there are two common approaches to analysing the HC of a distribution feeder:

Method 1 - The stochastic and simulation-based approach discussed in [28], which uses a network simulation tool (CYME in the case of ComEd) to model a large number of distributed generation scenarios (i.e. different locations of distributed generation on the network). In each scenario the penetration of distributed generation is iteratively increased until a network constraint is reached.

Method 2 - The streamlined approached discussed in [29], which builds on the analysis utilised in [28] to develop a set of correlations and equations that can be used to quickly estimate the HC of a feeder based on a feeder load flow and short circuit analysis.

Both of these methodologies provide a means for estimating the minimum and maximum HC (as they are commonly referred to in literature). The minimum HC is the amount of distributed generation that can be accommodated on a network without negatively impacting its performance, regardless of installed location. Conversely, the maximum HC is the maximum amount of distributed generation that can be accommodated without negatively impacting network performance, requiring optimal location of distributed generation.

These values are demonstrated graphically in Figure 10, which shows the DG penetration against maximum phase voltage on an example ComEd distribution feeder. This figure was created using the stochastic, simulation-based approach outlined in Method 1. The line between Region A and Region B is the minimum HC, this is the level of DG penetration at which the first overvoltage constraint occurs. Similarly, the line between Region B and Region C is the maximum HC, the penetration at which DG must be optimally located to avoid an overvoltage constraint. Beyond the maximum HC (i.e. within Region C) all possible distributions of DG will cause a network constraint violation.

[23] The "100% of minimum daytime load rule" is being offered by a number of industry parties as a purportedly more accurate threshold for fast tracking DG interconnection when compared with the 15% rule.

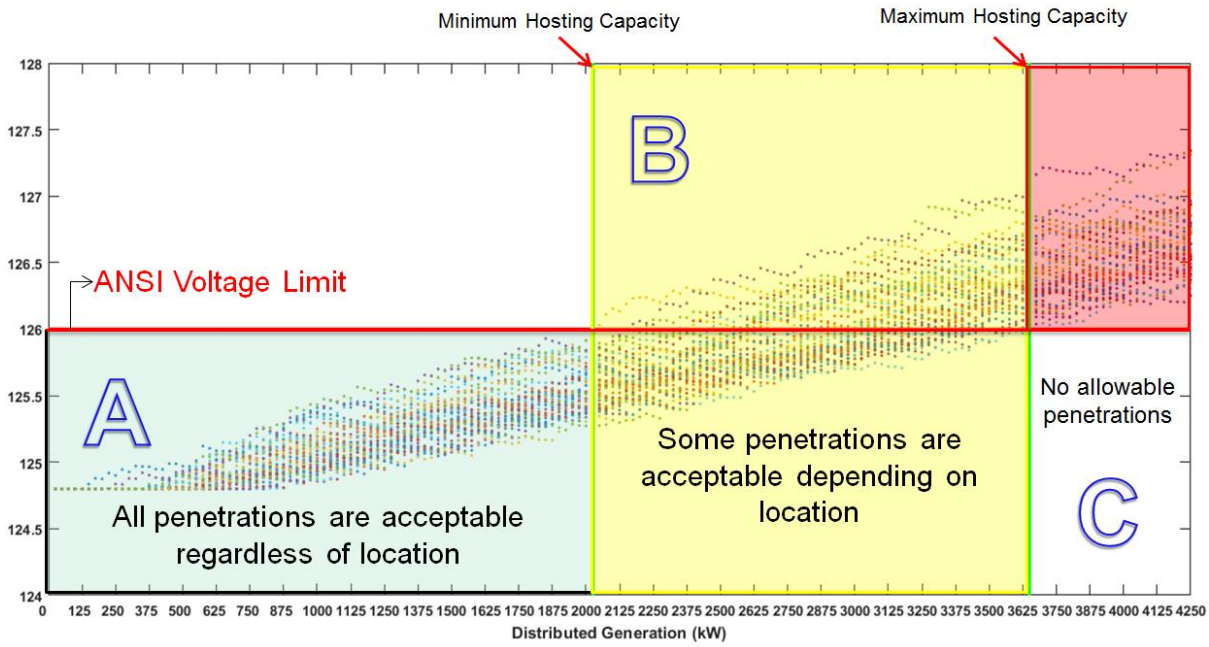


Figure 10: Comparison of distributed generation penetration (in kW) and maximum network phase voltage (at LV[24]) for a range of scenarios on an example ComEd feeder [31]

Although either scenario is unlikely to eventuate as a result of random customer uptake of DG, it is this region near the minimum HC that is of most interest, as it identifies the level of penetration below which DG will not likely have a negative impact on the performance of the network regardless of location. Such a limit could be used to more accurately assess when to fast track connection requests and would offer an analytical alternative to existing screening techniques. For the purpose of this report and from this point forward, the term "hosting capacity" will be used to refer to the single value at which the network will not likely experience a network constraint (i.e. the area around the minimum HC). This value can be determined by combining the desired level of organisational risk and probabilistic nature of network constraints occurring. This principle is discussed in more detail in the following subsection.

5.5.2.1 Analysis Algorithm

After reviewing both of the aforementioned methodologies for estimating HC it was decided that Method 1 would be implemented as the preferred means for estimating the HC of ComEd's network. This method has been shown to provide a more accurate assessment of HC at the expense of being slower and more computationally complex [29]. Moreover, this method built upon other work already undertaken by -members of the Smart Grid and Technology team [31, 32, 33].

The final algorithm that I implemented is outlined in Figure 11. This process was coded in VB.NET which controlled CYME's[25] component object model[26] (COM) interface to automate the iterative adding of distributed generation to network model and running of load flows inherent in the stochastic method. In more detail, the modelling process applies and object-oriented programming approach and consists of two key components: a Feeder Study, and Feeder Scenario. A Feeder Study is the structure that drives the Monte Carlo HC analysis for one feeder; in this way one Feeder Study is

[24] Nominal household service voltage (low voltage, line to neutral) within Illinois is 120V. ANSI C84.1 requires that, during normal network operation (i.e. non-fault or contingency conditions), voltage is regulated ±5% of nominal (i.e. 126V-114V).
[25] CYME is a power system modelling and analysis software developed by Cooper Power Systems. ComEd uses CYME to model the performance of its distribution network.
[26] The component object model (COM) is a standard interface for Windows native applications that is used for communication and automation between otherwise independent applications and processes.

created for each feeder to be studied. The Feeder Scenario is the structure that iteratively adds DG to a feeder, modelling the impact of each DG unit (or group of DG units) added on the feeder until the point at which a network constraint occurs. In this way the Feeder Scenario studies one possible limiting distribution and penetration of DG. This relationship is demonstrated in Figure 12, showing how the overarching Monte Carlo simulation (Feeder Study) is constructed of many Feeder Scenarios, which in turn incorporates many CYME models of DG location and penetration.

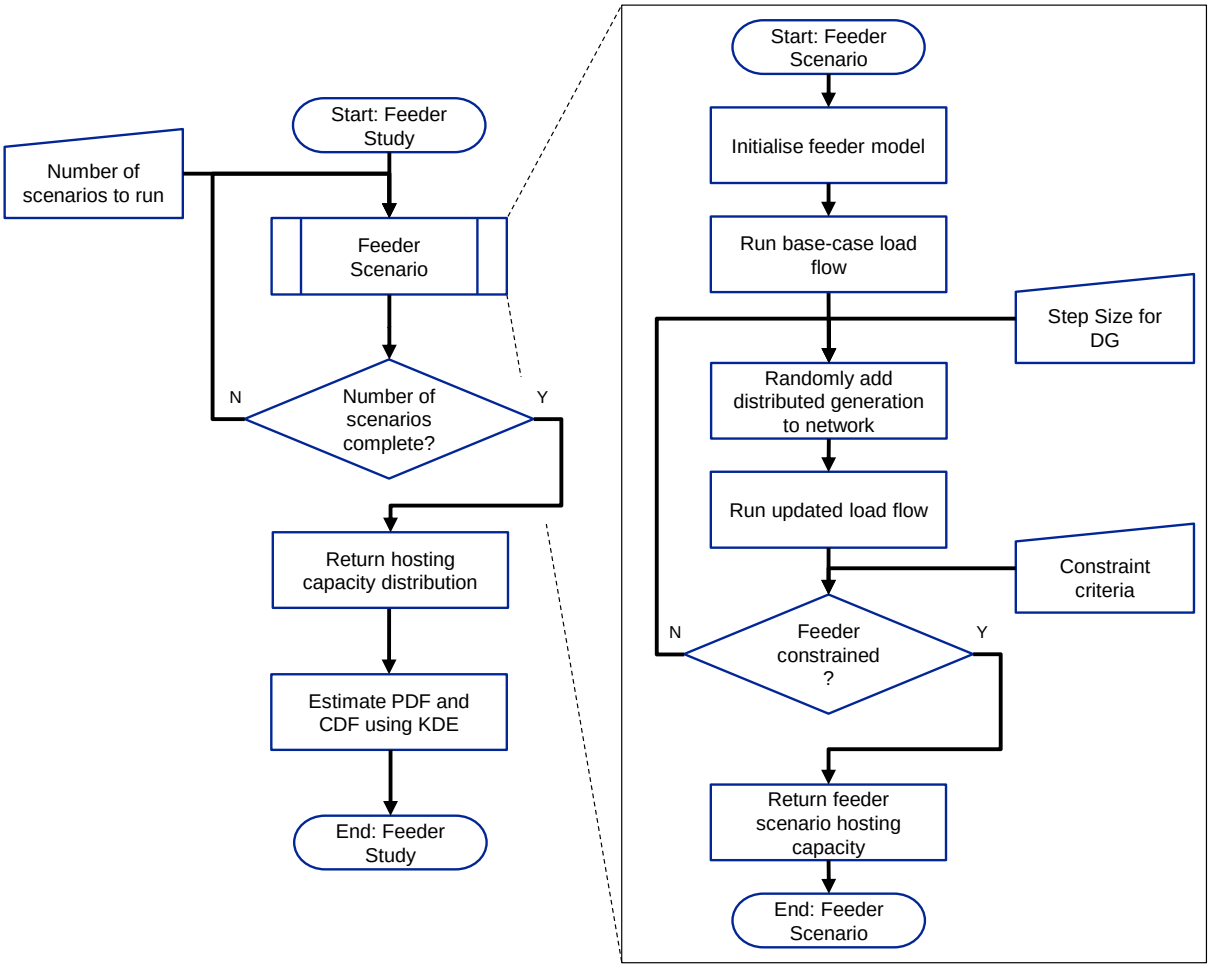


Figure 11: High-level overview of stochastic hosting capacity estimation process

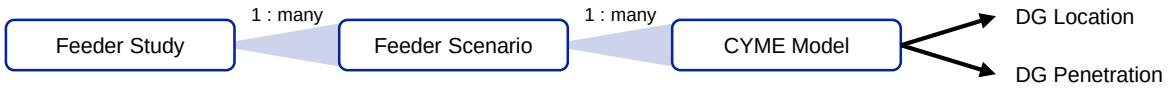
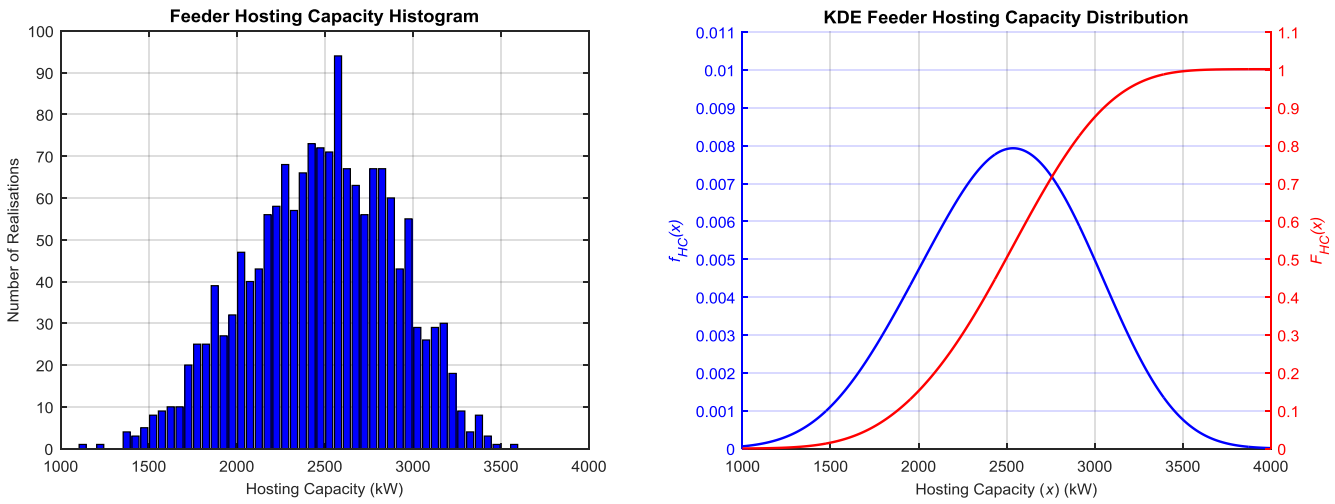


Figure 12: Relationships within stochastic hosting capacity estimation process

Figure 13 (a) shows the HC distribution histogram for a representative distribution feeder in ComEd's network that was produced using the algorithm documented in Figure 11 with 1,200 modelled Feeder Scenarios. Figure 13 (b) shows the feeder's HC probability density function (PDF) (in blue) and cumulative density function (CDF) (in red). These curves were calculated using the kernel density estimation[27] (KDE) method applied to the simulated data (shown in Figure 13 (a)). With this information it was possible to calculate a single HC capacity for the feeder by taking a probabilistic, risk-based approach.

[27] Kernel density estimation is a non-parametric method for estimating the probability density function (and hence the cumulative density function) of a finite set of samples.



(a) ***(b)***

Figure 13: Hosting capacity for representative ComEd feeder
(a) Histogram of stochastic hosting capacity simulation results for 1600 scenarios
(b) Hosting capacity PDF (blue, $f_{HC}(x)$) and CDF (red, $F_{HC}(x)$) calculated using kernel density estimation

This approach required the definition of a risk factor (RF) (or risk of a network constraint) that the organisation was willing to be exposed to in setting the feeder HC. The predefined RF was applied to the calculated CDF ($F_{HC}(x)$) shown in Figure 13 (b) and used to calculate the penetration of DG that could be accommodated with the defined percentage risk of causing a network constraint. For example, by setting a RF of 0.5 ($F_{HC}(x) = 0.5$) it is evident that the feeder represented in Figure 13 (b) will accommodate approximately 2,500kVA of DG with a 50% likelihood that there will be no constraint. Similarly, for a RF of 0.1 ($F_{HC}(x) = 0.1$) the feeder will accommodate approximately 1,900kVA of distributed generation with a 90% likelihood that there will be no constraint.

This probabilistic approach provides a means of directly relating an organisation's "appetite for risk" to a value for feeder HC. Given the traditionally risk adverse nature of the electricity industry, and the potential use of HC in fast-tracking applications it is expected that the RF should be set suitably low (i.e. between 0.05 and 0.15), however this should be determined on an organisation-by-organisation basis.

5.5.2.2 Feeder Classification

Owing to the computational complexity of this modelling technique, it would not be feasible to conduct this level of analysis for each feeder in a distribution system. In ComEd's case, their distribution network consists of approximately 5,000 feeders. This is a common challenge in "big data" analysis where the sheer quantity of data often calls for techniques to compress or simplify the data to make analysis possible. To this end I investigated the use of big data analysis techniques, namely clustering algorithms that could reduce the scale of analysis required by identifing a characteristic set of feeders within ComEd's network. Indeed, this is a technique that has already found application in a number of network analysis problems within the electricity industry [34, 35] (to name a few).

By identifying a smaller and unique set of characteristic feeders it is possible to undertake detailed HC studies (as outlined in Section 5.5.2.1) on this subset of feeders and extend the findings to the larger population. The clustering algorithm selected for this application is a common partitioning method known as k-means clustering. K-means clustering works by iteratively locating centroids (or means) in a way that minimizes the cost or error function, which is normally chosen to be the Euclidian distance between the centroid and its associated data points (feeders)[28]. Figure 14 provides an overview of the

[28] For an overview of the k-means clustering algorithm see http://mnemstudio.org/clustering-k-means-introduction.htm

clustering process that was utilised in scaling the HC analysis to a whole-of-network analysis. Each of these steps is discussed in more detail below.

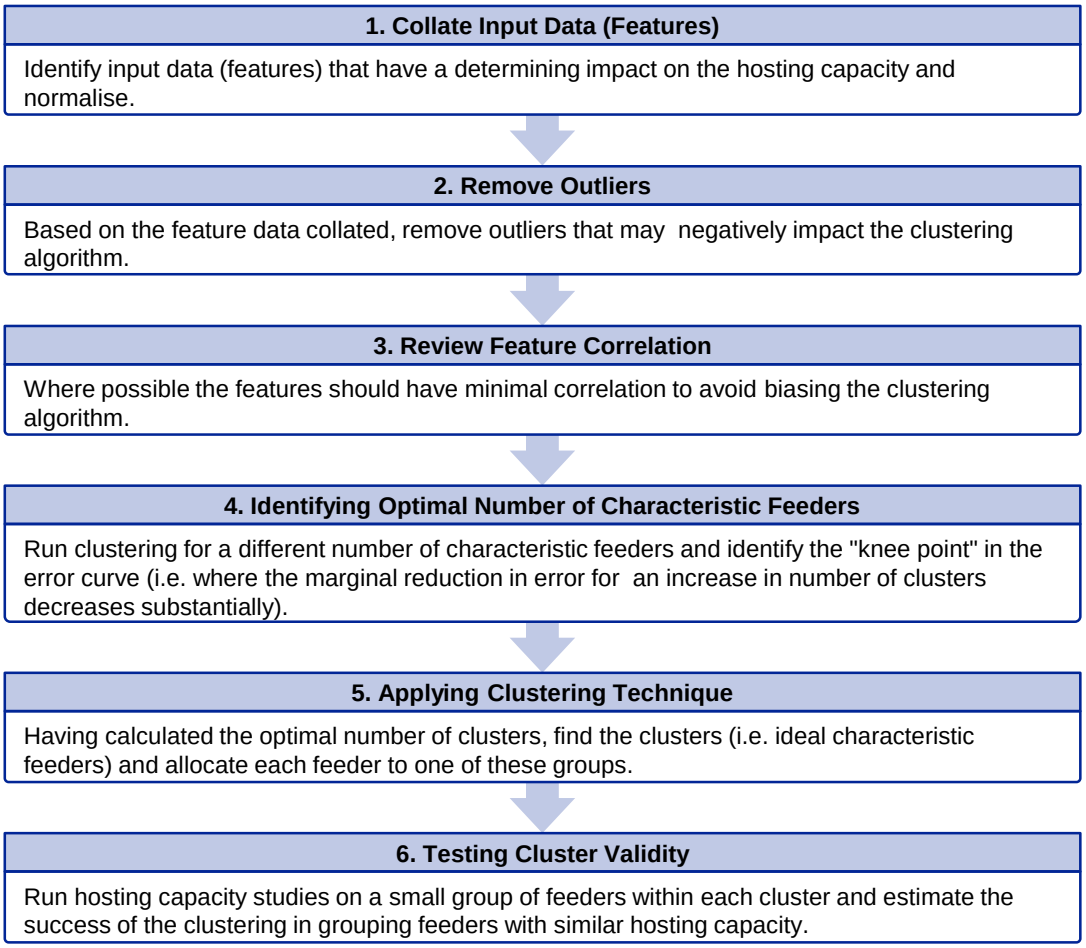


Figure 14: Overview of clustering methodology

Input Data (Features)

The underlying assumption in this process is that the clustering methodology successfully groups feeders of similar HC. To ensure this holds true it is important that the inputs (referred to as features) in some way describe a feeder's ability to host DG. Feeder characteristics which impact HC are discussed in Section 2 of [36]. For this application I investigated a large number of different features for use in feeder characterisation; these features included:

- Total line length
  - One phase
  - Two phase
  - Three phase
- Number regulators
- Reactive compensation (kVAR)
- Number tee points
- Total secondary transformer connected capacity (kVA)
- Minimum Demand (kVA)
- Maximum demand (kVA)
- Average pos. sequence resistance (Ω / mi)
- Average pos. sequence reactance (Ω / mi)
- Customer Count
  - % Residential
  - % Commercial
  - % Unknown
- Voltage regulation
  - Source voltage (PU)
  - Max node voltage (PU)
  - Min node voltage (PU)
- Nodal Thevenin equivalent impedances
  - R, X ,and |Z|, mean, min, and max for all matrix elements (PU)

It is important to note that this is not an exhaustive list and that more features may be incorporated to improve the accuracy of the clustering algorithm in grouping feeders with similar HC. However, these

features were investigated because they were readily accessible and thought to have an impact on feeder HC.

Once selected, these features are normalised to a similar range and order of magnitude. This avoids biasing of the clustering algorithm by features with comparably large magnitude or range. In this instance a simple normalisation function was used, as set out in Equation (2), where D is the $m \times n$ matrix of feeder data with m feeders and n features describing each feeder. It follows that d_i is the i^{th} feeder feature vector, d_{ij} is the element relating to the j^{th} feature of the i^{th} feeder, and $\widehat{D}$ is the normalised feeder data matrix. Using this normalisation transformation in this way ensures that each feature covers the same magnitude and range (0 to 1).

$$\widehat{D_j} = \frac{[d_{1j}, d_{2j}, d_{3j}, \dots, d_{mj}] - \min([d_{1j}, d_{2j}, d_{3j}, \dots, d_{mj}])}{\max([d_{1j}, d_{2j}, d_{3j}, \dots, d_{mj}]) - \min([d_{1j}, d_{2j}, d_{3j}, \dots, d_{mj}])} \quad \text{for } j = 1, \dots, n \tag{2}$$

Outliers

Outliers and data errors are an unavoidable consequence of analysing a real-world data set. These anomalies are not generally representative of the group as a whole and including them in the clustering algorithm may act to bias the algorithm and generally degrade the quality of the resultant characterisation. In the case of distribution feeder characterisation for use in HC analysis it was important to minimize the impact of outlier feeders. To this end, two methods were applied to identify and remove them from the dataset, they are:

1. Identifying obvious outliers and data errors by inspection. For example, feeders with no customers were removed from the study dataset. While it is entirely feasible that a distribution network would have feeders with no customers (e.g. an interconnecting feeder), it is unlikely that these feeders will have DG connected and therefore need an estimate of HC[29].
2. Measuring the Euclidian distance of any feeder to its nearest neighbour (or in this case the average distance to the 10 closest neighbours). This provides a more analytical means for identifying feeders that are on the "fringe" of the dataset. Although these feeders should still be subject HC studies, they're unlikely to be good fits to the estimated HC calculated on a characteristic feeder (as they themselves would be significantly dissimilar to the characteristic feeder).

   This process is outlined in Equations (3) and (4), where V is the $m \times x$ matrix that holds the x smallest Euclidian distances between each feeder (i) and the other $m-1$ feeders in $\widehat{D}$ (termed the neighbor distance). It follows that $\bar{V}$ is the vector of length m that holds the mean of the x smallest neighbor distances for all feeders in $\widehat{D}$. An example of the outcome of this is shown in Figure 15, where the threshold distance for outliers was selected by visual inspection and set at 0.25.

$$V_i = \min_x([\|\hat{d}_i - \hat{d}_1\|, \|\hat{d}_i - \hat{d}_2\|, \dots, \|\hat{d}_i - \hat{d}_m\|]) \quad \text{for } i = 1, \dots, m \tag{3}$$

$$\overline{V_i} = \frac{1}{x}\sum_{k=1}^{x} V_{i,k} \tag{4}$$

[29] In the instance of interconnecting feeders, ideally they should be considered as a part of the wider network as they may still impact the final HC (e.g. through overvoltage or capacity constraints).

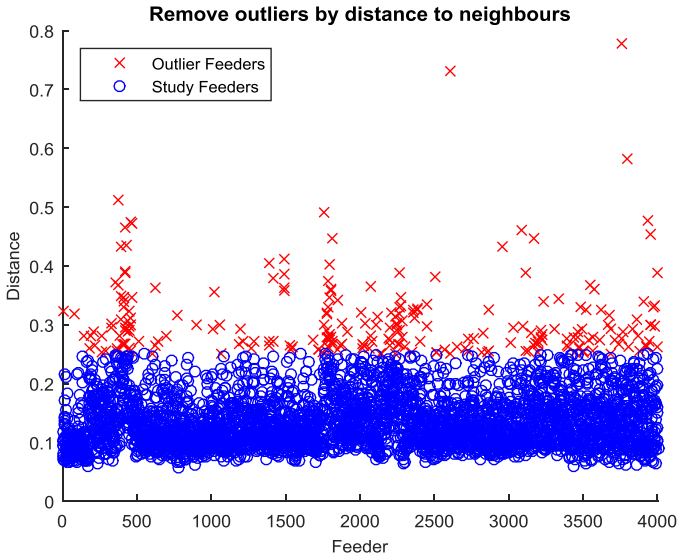


Figure 15: Example of removing outliers by their Euclidian distance to neighbouring feeders' features

Feature Correlation

Once outliers have been removed it is important to test for correlations between features in the dataset. Strong correlation (either positive or negative) between features is undesirable as it will bias the resultant cluster locations. To avoid correlation in outputs, two possible solutions are:

- To remove features with a high level of correlation, as shown in Figure 16; or
- To use transformations like principal component analysis (PCA) that takes the initial features as inputs and generates a new set of features that are uncorrelated.

Both of these methods will help to improve the quality of the final clusters.

Figure 16 (a) shows a correlation heat map for a set of example features, while Figure 16 (b) identifies features that have a positive or negative correlation above a defined threshold (in this case 0.7). In this instance the features identified in Figure 16 (b) could be considered for exclusion from the clustering data set.

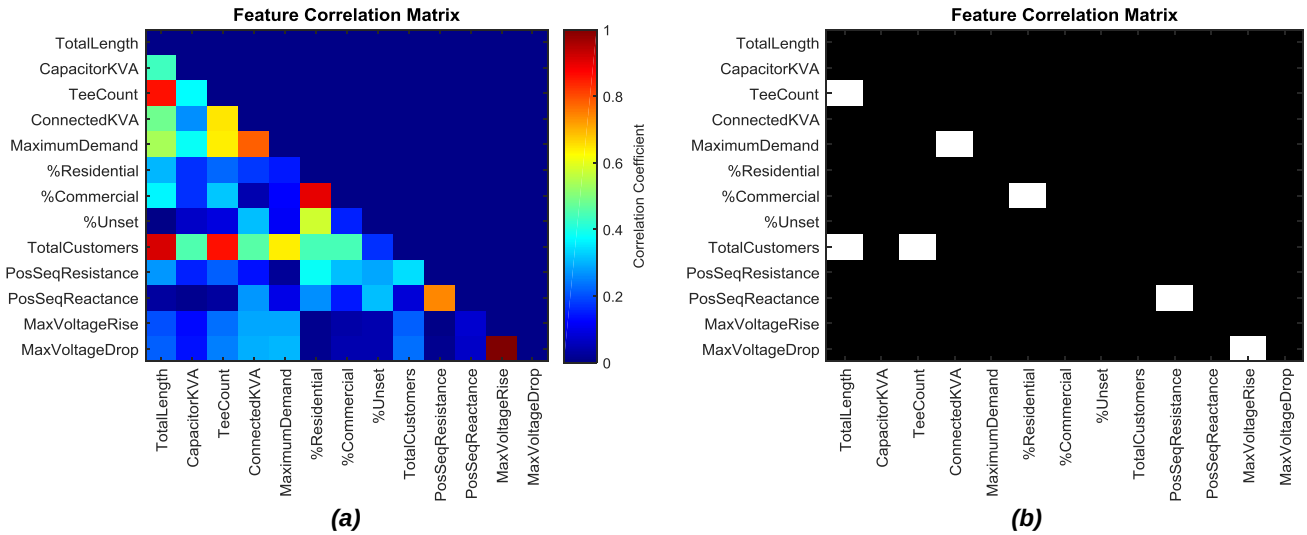


Figure 16: Example of feature correlation
(a) Showing correlation across all features
(b) Showing features with a correlation magnitude greater than 0.7

Optimal Number of Characteristic Feeders

K-means clustering, like many clustering techniques, requires that the user nominate the desired number of clusters to be allocated. Although this may sound somewhat counter intuitive, it is possible to estimate the optimal number of clusters via a number of means, for example the mean squared error (MSE) or cubic clustering criterion. For this application the MSE approach was utilized.

Both methodologies work using a similar principle whereby the k-means clustering algorithm is run for a range of different cluster numbers (or values of k)[30]. From the resultant clusters the desired metric (i.e. MSE) is calculated and compared graphically across the range of cluster numbers. In the case of MSE the rule of thumb is to pick the "knee point" in the error curve; that is where the marginal reduction in error for an increase in the number of clusters decreases substantially. This is demonstrated on a two dimensional artificially constructed set of data in Figure 17 (a) and (b).

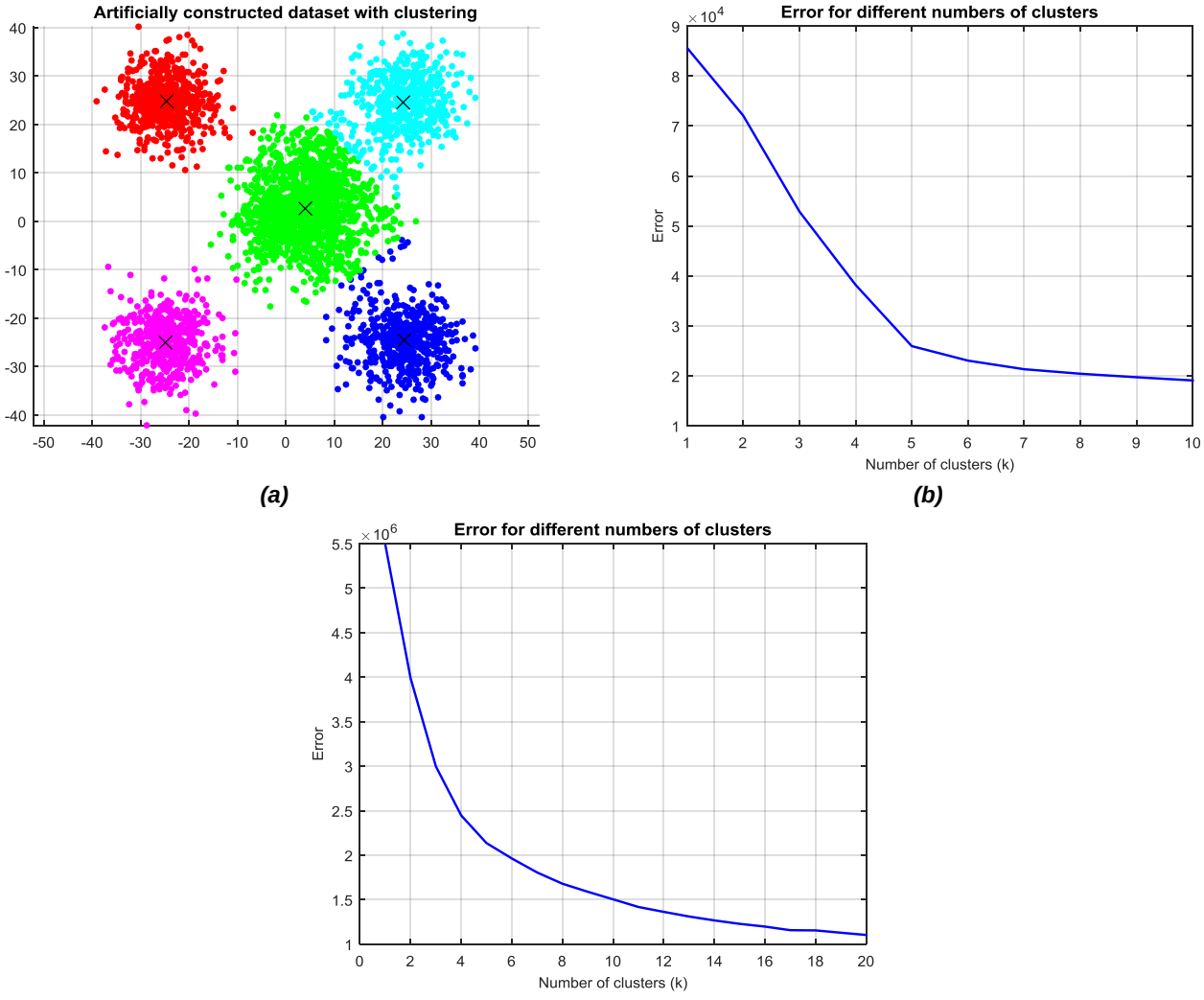


Figure 17: Demonstration of selecting the optimal number of clusters
(a) An artificially constructed test dataset with clustering (coloured) and means
(b) The error curve for different numbers of clusters using the k-means algorithm on the test data
(c) The error curve for different numbers of clusters using the k-means algorithm on the actual feeder dataset

[30] It is important to note that the k-means clustering algorithm does not guarantee convergence to a global minimum. Therefore, it is important to run the algorithm multiple times for each cluster number (i.e. value of k) using different initialisations. The global minimum would be identified by selecting the best error performance across the multiple iterations.

From Figure 17 (a) using a simple visual inspection it can be deduced that there are five natural clusters within the data. However, for complex higher-dimensional datasets, like the one used in this application, visual inspection is not an option. By calculating the cluster MSE for a number of clusters and finding the knee point in the MSE curve (see Figure 17 (b)) it is also possible to identify the optimal number of clusters. In a more complex example, like the application of k-means clustering to characterizing feeders, the knee point is likely to be less prevalent. This is shown in Figure 17 (c), which demonstrates the MSE curve for k-means clustering that is applied to a high-dimensional feeder feature dataset. Given the decrease in marginal reduction in error (i.e. the "knee point") between 4 and 8 clusters it is possible to conclude that the ideal number of clusters falls somewhere in this region.

Clustering

The final step in identifying the characteristic feeders is to utilize the optimal number of clusters (identified in the previous step) and re-run the k-means clustering algorithm to solve for the characteristic feeders. As mentioned previously, it is important that the clustering algorithm is run a number of times with different initialisation, as k-means clustering does not guarantee convergence to a global minimum. Figure 18 shows an example of cluster centroids calculated using eight clusters and a small number of feeder features. It is important to note that these cluster centroids do not directly represent a real world feeder, but rather the characteristics of a feeder that would be optimally representative of the cluster. A real-world representative feeder is identified by selecting the feeder that is closest (by Euclidian distance) to the cluster centroid. This real-world representative can then be analysed using the HC analysis algorithm (see Section 5.5.2.1) to calculate the representative HC for the cluster.

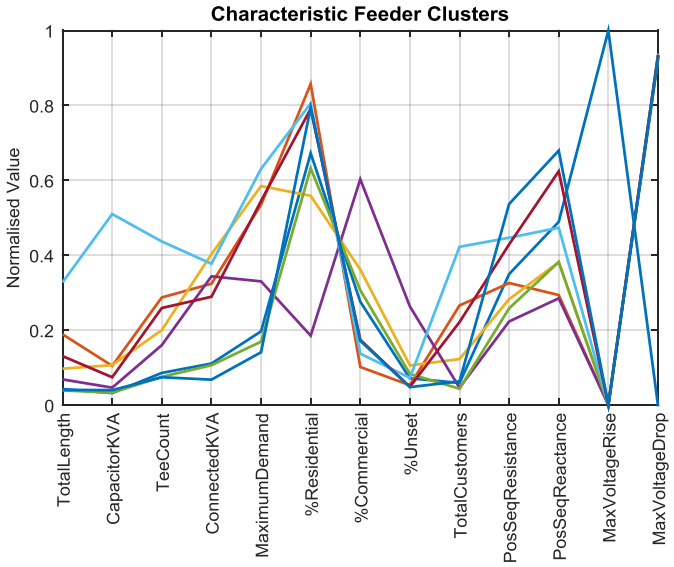


Figure 18: Example characteristic feeder clusters for eight clusters

Cluster Validity

Once the feeders have been clustered it is important to test the validity of the resultant groupings. To do so the HC for a subset of feeders must be calculated. If the k-means clustering has achieved its desired goal it should group feeders with similar HC. Therefore, by comparing the HC for the subset of feeders the validity of the resultant clusters can be tested.

5.5.2.3 Limitations

Given the diverse nature of the study data set (i.e. distribution feeders), the complexity of HC and the analysis algorithm, and the inherent application of assumptions and generalisations to scale this analysis, there are a number of limitations, considerations, and challenges with this approach. For the

HC analysis algorithm, there are five core considerations that I believe, from my experience, can significantly impact the accuracy, validity, and speed of the modelling process:

1. **Model accuracy versus speed** – as with most stochastic modelling algorithms there is a compromise between computational complexity and level of accuracy or confidence. As such, it is important to consider the number of scenarios to be modelled to ensure statistical validity of the outcome. Failing to consider a sufficient number of scenarios could result in feeder HC being overestimated, while incorporating too many scenarios would substantially extend modelling time, particularly when taking into account the compounding relationships shown in Figure 12. From experience I found that at least a few hundred scenarios were required to provide an accurate estimate of HC.
2. **The number of network constraints considered** – high penetrations of distributed generation can cause a wide-variety of network issues and constraints; for example:
    - Voltage-related (overvoltage, voltage imbalance, voltage swing);
    - Capacity-related (overloading, phase current imbalance);
    - Protection-related (reduction of reach, mal-coordination, reverse power flow, anti-islanding);
    - Harmonics-related (total harmonic distortion)

    Some of these constraints lend themselves to being more easily identified as a part of basic network analysis (e.g. overvoltage, voltage imbalance, and overloading), while others require more detailed and complex analysis (e.g. protection- and harmonics-related constraints). As a result, it may not be possible to consider every type of network constraint in calculating the HC. For the most part, literature tends to identify voltage-, capacity-, and protection-related constraints as being the predominant limiting factors [29, 37]; therefore, these constraints should be considered wherever possible to ensure validity of the calculated HC.
3. **Dynamic feeder elements and characteristics** – within a feeder there are a number of dynamic or controllable elements and characteristics that can significantly impact the HC. For example: tap changer set point voltage (at the substation and, if applicable, on line regulators), feeder loading (minimum and maximum), phase loading imbalance (under normal operation), and the presence and operation of switched capacitors. It is important that these characteristics are well captured and accounted for as a part of the modelling process as variations in feeder load, set point voltage, or other controlled elements can significantly impact feeder HC.
4. **Model and data accuracy** – as with all big datasets (like one that comprises a utility's network and asset data), there exist data errors that occur as a result of incorrect, outdated, or missing data. Implementing a large-scale modelling algorithm like this one is reliant on having good data readily available (i.e. requiring no manual updates or modification). Although data errors are normally identifiable and feeders with data errors can be excluded from the algorithm, instances were these errors are not identified may reduce the accuracy of any analysis undertaken.
5. **Statistical limitations** – although the stochastic nature of this modelling technique attempts to account for the diversity in distributed generation uptake, both in size and location, the number of possible permutations (or Feeder Scenarios) is so large that modelling each scenario is not viable. As a demonstration, even for a relatively simple feeder with 100 secondary transformers[31], assuming average incremental DG step sizes of 5kW, where the feeder HC is approximately 500kW, the number of permutations can be calculated as shown in Equation (5). The resultant network would have approximately 10^{200} different possible scenarios, without taking into account the possibility for different phasing of single phase connections. Although considering practical network limitations, such as constraining the maximum amount of distributed generation connected on any one distribution transformer to the rating of that transformer would reduce the possible permutations, this number would still be substantial.

    Considering this, it is unlikely, given the finite (and comparably small) number of simulations conducted that this stochastic method will capture the single worst or single best case scenario for location of distributed generation. However, giving a large enough number of scenarios and resultant HC calculations, a representative probabilistic distribution can be

[31] This assumes that the network model only considers to the HV terminal of the secondary substation and does not model the LV network. Considering the impact of distributed generation on the LV network would further increase the computational complexity of this task.

approximated. Using this statistical approach, it is possible to understand the feeder's response to DG and subsequent HC without having to model every possible permutation.

$$Permutations = Customers^{\frac{Hosting\ Capacity}{Step\ Size}} \quad (5)$$

Similarly, the feeder classification technique that provides scalability to the HC analysis algorithm has a number of underlying assumptions and limitations. The fundamental assumption of this technique is that feeders with similar HC can be grouped by applying k-means clustering to a dataset of features that describe these feeders. While this would appear to be a reasonable assumption, and one that has been used by others when analysing HC [38, 39, 40], as well as in other power system analysis problems [41, 42, 43, 44], my experience analysing ComEd's network and the experience of others (namely EPRI [45]) has shown that there are some limitations and challenges with this approach.

These limitations and challenges are discussed in detail in Section 5.2.2 and 5.2.3 of [46], and stem largely from the apparent inaccuracy of the k-means clustering algorithm in grouping feeders with similar HC. This is demonstrated in Figure 19 (a), which shows a scatterplot of modelled HC (shown as blue dots) for 350 12kV distribution feeders grouped by cluster, alongside the associated representative feeder HC (shown as red crosses). Moreover, Figure 19 (b) uses box plots[32] to provide a clear statistical comparison of the modelled HC data presented in Figure 19 (a). Viewing the data in this way highlights some of the challenges with the performance of the feeder classification technique; in particular:

1. **The spread of HC values within a cluster** - in an ideal situation the clustering algorithm should group feeders with similar hosting capacities, so it follows that each cluster should only have a small spread. From Figure 19 (a) and (b) it is evident that there are a number of clusters that cover a large spread of modelled feeder HCs (e.g. cluster 5).
2. **How representative the characteristic feeder is of the cluster** - if the characteristic feeder is representative of the group, it should have a HC that is close to the group median (red line on the box plot) and well within the 25th and 75th percentiles (upper and lower blue lines). From Figure 19 (b) it is evident that there are a number of clusters where the representative feeder has a HC that is not representative of the group and may even be considered an outlier (e.g. cluster 15).

As a result of these findings (and the findings of others [45]) it may be concluded that k-means clustering is not suitable for this application; however, the performance of this algorithm is predominantly limited by the quality of the dataset (i.e. the feeder features) that are used in the clustering technique. For this reason, I believe that additional characteristics, be they topological, electrical, sociological, or a mathematical blend of a number of these, will unlock vastly improved accuracy in clustering feeders with similar HC. This is an area which will benefit from additional investigation and analysis.

[32] Box plots (also known as box and whisker plots) provide a visual representation of five key statistical values (from top to bottom) the: maximum value, 75th percentile, median (or 50th percentile), 25th percentile, and minimum value. Statistical outliers, which are points that are 1.5 times the inter-quartile range above or below the 75th or 25th quartile (respectively), are also shown on these boxplots (represented as circular points).

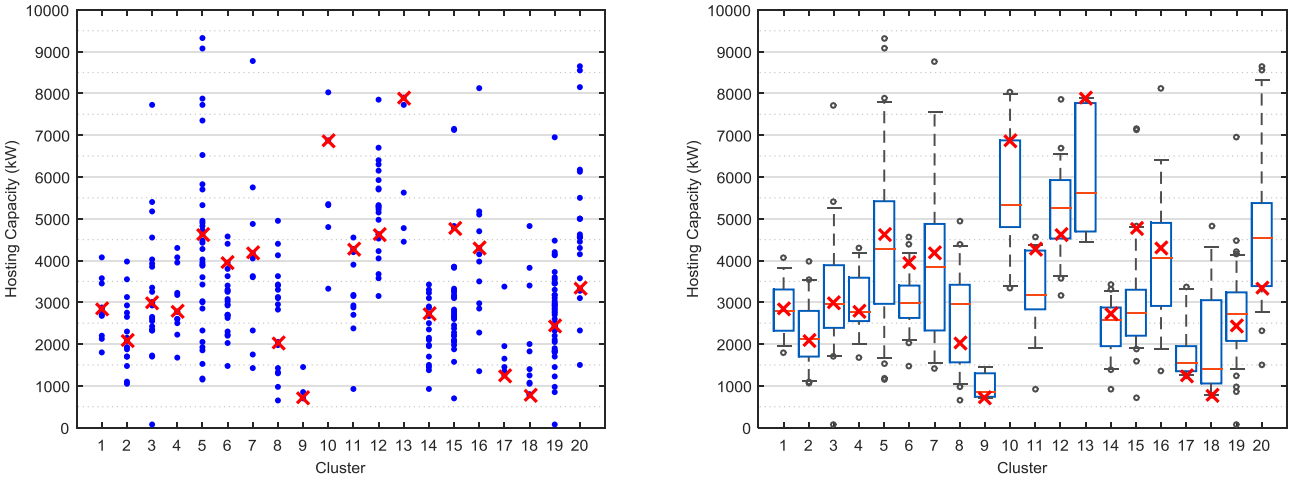


Figure 19: Example of inaccuracy in clustering of feeder hosting capacity (350 12kV feeders, 20 clusters) (a) Scatter plot of modelled hosting capacity (blue dot) and characteristics feeders (red cross) by cluster (b) Box plot of modelled hosting capacity and characteristic feeders (red cross) by cluster

5.6 Recommendations

It is evident, from my experience with these tools, systems, and analysis techniques, that they provide substantial and often tangible value to the respective organisations, enabling savings, improved performance, and informed decision making. As such, this section proposes a number of recommendations to guide and develop similar levels of information enablement within asset management and more generally within organisations. These recommendations are captured in Table 6.

Table 6: Recommendations relating to information enablement

#	Recommendation
7	Given the growing availability of data (e.g. monitoring, test, and office-based data) there is a strong need for organisations to: 1. Be proactive in identify data that is of value to their organisation now and in the future. These requirements should be explicitly recorded and periodically reviewed. 2. Capture and store the data in ways that make them accessible to the those who can derive value from this data. 3. Manage and maintain this data to ensure its quality and completeness.
8	In consideration of Recommendation 7, it is vital that this data be used to create information that can: empower decision making, identify process improvements, and assist in managing assets more effectively. To assist in this process organisations should invest in: 1. Developing or employing personnel that are familiar with “big data” analysis techniques; and 2. Tools and systems that are capable of managing and analysing “big data” or improving existing tools and systems to incorporate this data. Section 5 provides a small number of examples of the types of information enabling tools and systems that can be developed in an environment that is data enabled and has the skillsets to apply this data in meaningful ways. Organisations should seek to develop environments that are supportive of this form of development.

#	Recommendation
9	In many instances the development of condition-based analysis techniques, particularly in understanding modes of failure (as used in the ARP tool and online PD monitoring), is reliant on the availability of "good" historical data around asset failure and monitoring. It is therefore important that organisations share information, particularly in relation to asset failure and indicators of failure (e.g. through forums like EPRI, ENA's NEDeRS, and CIGRÉ). To aid in this sharing of information, I believe regulators should encourage organisations to participate in building relevant libraries of asset failure data. This would be particularly advantageous in Australia, where networks are often subject to different environmental challenges to those of their North American or European counterparts.
10	Regulatory bodies, particularly those in asset-intensive industries (like the electricity industry), should consider requiring organisations under their jurisdiction to apply and report against a standardised framework of asset HI, CI, and RI ranking. As well as encouraging utilities to apply these techniques, which encourage good asset management practices. Such a system provides a measure for regulators to benchmark and monitor performance of organisations throughout a regulatory period.
11	Organisations should consider taking a risk- and condition-based approach to managing their assets. The ARP tool provides an example of how this approach can be applied to managing the refurbishment and replacement of assets; however, this could be further extended to include the condition-based maintenance of assets.
12	Organisations should look beyond traditional modelling and analysis capabilities to leverage advances in big data analysis and processing to develop whole-of-network modelling tools (like those demonstrated in ICL LRE model and DG HC analysis) to understand how changing environmental, economical, technological, and customer changes will impact their network and manage these impacts in a sustainable way.

6 Understanding the role of Regulation

Regulatory bodies, particularly within the electricity industry, play a key role in driving optimisation within asset management and across regulated organisations. The regulatory framework that they enforce challenges regulated organisations to deliver their product or service in a way that is cost effective and that meets the needs and expectations of customers. Within the UK, the primary regulatory body for the electricity and gas industry, Ofgem, has worked to establish a regulatory framework that delivers on these objectives. The resultant RIIO framework aims to incentivise gas, transmission, and distribution utilities to [47]:

> *"…put stakeholders at the heart of their decision-making process; invest efficiently to ensure continued safe and reliable services; innovate to reduce network costs for current and future consumers; and play a full role in delivering a low carbon economy and wider environmental objectives."*

During my tenure with UKPN I undertook a placement within the Regulation arm of the Strategy and Regulation directorate, where I sought to understand the impact of this regulatory model in incentivising prudent and sustainable expenditure in asset management and the wider organisation. This section details my experience and findings during this placement, with a particular focus on key developments, and the output- and incentive- based mechanisms of the RIIO model.

6.1 Overview of Key Developments

The concept of RIIO, initially put forward following the RPI-X@20 review and subsequent decision paper [48], proposed a number of fundamental changes to the existing distribution price control review (DPCR) (for electricity distribution utilities) framework. Figure 20 provides an overview of the pillars of the RIIO model, highlighting the direct linkage to the delivery of outputs and the financial mechanisms to incentivise efficiency and innovation. The left pillar shows the mechanisms for baseline revenue calculation and revision, while the central pillar shows revenue adjustment mechanisms that are incentivised by performance-, innovation-, and efficiency-based incentives. The right pillar covers revenue adjustment mechanisms that allow for uncertainty within the regulatory period.

The following sub-sections provide a high level overview of many of these elements, discussing key changes between DPCR and RIIO, and highlighting points of interest. It is not intended to provide readers with a complete understanding of the RIIO model. Where possible references are provided to more detailed explanation and documentation; in addition to these references, Ofgem's RIIO publication library [49] is an invaluable source of information.

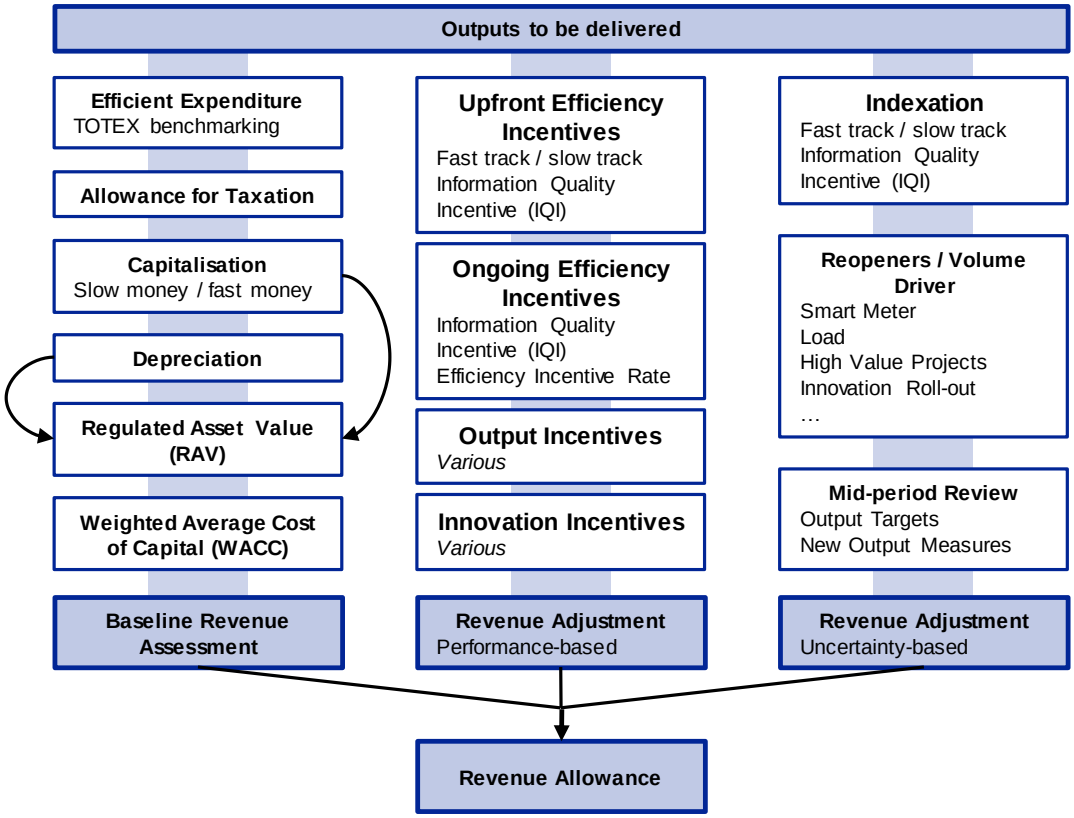


Figure 20: RIIO elements of sustainable regulation (adapted from [50])

Fast track and slow track determination

The establishment of a fast track assessment with the introduction of RIIO was a significant change to the regulatory submission process. The fast track process was established to encourage the submission of high-quality cost efficient business plans at first submission. If the business plan of a DNO (and its license area(s)) met Ofgem's criteria, Ofgem could choose to provide an early determination, prior to the beginning of the traditional price control period while also rewarding the DNO with a number of financial benefits. The incentives offered by Ofgem were a:

- 2.5% increase applied to the DNO's proposed TOTEX; and
- 70% efficiency incentive rate (or sharing factor) (discussed later in this section).

For the RIIO-ED1 price control period only one DNO was successful in securing a fast track determination – Western Power Distribution (WPD) and its four license areas: South West, South Wales, East Midlands, and West Midlands. As an unintentional benefit of receiving the early determination WPD also:

- Secured a higher cost of equity (6.4% compared to 6.0% for slow track)[33];
- Avoided additional real price effects (RPE) and smart grid cuts; and
- Avoided the Information Quality Incentive (IQI) assessment process (discussed later in this section).

This was in addition to the obvious reputational benefit and increased certainty of receiving an early determination. Overall, if a DNO was able to meet the strict fast track requirements it stood to receive substantial tangible and intangible benefits.

[33] Ofgem reviewed this figure to ensure alignment with a ruling by the Competition Commission on the cost of equity for Northern Ireland Electric in November 2013.

It is worth noting that, as a result of their early determination, WPD were in some respects financially disadvantaged in comparison to other DNOs. During the longer, slow track negotiation process, DNOs were able to secure minor changes to the RIIO financial model. In particular WPD:

- Did not receive the "trombone" rolling average[34] on their cost of debit, instead receiving a standard 10 year rolling average; and
- On average, over the price control period, received a marginally lower WACC.

Eight-year price control period and uncertainty mechanisms

One of the fundamental changes introduced with the RIIO model was the change from a five- to eight-year regulatory period. The move to the longer price control period is intended to encourage utilities to develop longer-term plans, while also providing a greater level of continuity, certainty, and stability. The obvious risk with longer duration price control periods is the possibility for change (e.g. economical, consumer, technology, or legislative) beyond that predicted by DNOs, Ofgem, and stakeholders.

The diverse and ever-changing nature environment surrounding the electricity industry means that best estimates for load growth, usage trends, and economic development (to name a few) could change substantially with in the space of eight years. In an attempt to mitigate this risk Ofgem has allowed flexibility within the RIIO model through a number of uncertainty mechanisms. This is coupled with the requirement for annual reporting on expenditure and outputs, which drive revisions in TOTEX and annual revenue allowances through the Annual Iteration Process (discussed later in this section).

The uncertainty mechanisms that Ofgem has developed provide scope for:

- Reopeners and volume drivers relating to a number of different investment drivers or expenditure elements. These mechanisms provide Ofgem with a means to re-evaluate the TOTEX allowance of licences based on DNOs reaching a defined level of over- or under-expenditure (e.g. ±20% of allowance) in the case of a reopener, or seeing increased volumes above forecast in the case of volume drivers. To provide some certainty to DNOs, Ofgem has established defined timeframes for when reopeners and volume drivers will be assessed throughout the regulatory period.
- A mid-period review, which will reassess the validity of existing output targets and the need for any additional output measures. To avoid the possibility of the mid-period review becoming a significant review of the determination, effectively splitting the price control period, Ofgem has limited the scope of this mid-period review to outputs.

Output tracking and revenue adjustment

As one of the three core components of the RIIO model, the setting and continual monitoring of output targets enables Ofgem to track the DNOs' performance in delivering their plan throughout the price control period. This approach incentivises DNOs to optimise their costs (i.e. the cost to deliver components of their plan) and volumes (i.e. the amount of work undertaken to achieve their outputs) throughout the regulatory period. Where DNOs can deliver their outputs with reduced costs and volumes they stand to be rewarded. Conversely where DNOs are not able to reasonably justify under-delivery on outputs or over-expenditure they will be penalised. (See later sub-section on output, efficiency, and innovation incentives).

To ensure that DNOs are tracking against their outputs throughout the regulatory period Ofgem has established the requirement for an annual review of DNOs performance. This annual review requires that DNOs provide a suite of reports known as Regulatory Instructions and Guidance (RIG) reports[35]. These reports drive Ofgem's assessment of DNO performance and enable the adjustment of DNO's

[34] The term "trombone" rolling average is used by Ofgem to refer to an incremental duration rolling average, in this instance starting at 10 years and increasing annually reaching a maximum of 20 years.
[35] The use of standardized RIG reports is not new to RIIO-ED1; however, the format and content of the RIG reports is being reviewed and updated prior to the start of RIIO-ED1

TOTEX and revenue through the Annual Iteration Process (discussed later in this section). These reports are also made publicly available on Ofgem's website, providing an additional reputational incentive for DNOs to perform well.

Annual Iteration Process

The Annual Iteration Process (AIP) is one of the core financial uncertainty mechanisms introduced by Ofgem to provide flexibility during the eight-year price control period. It also places increased emphasis on DNOs to ensure they perform against their output targets (i.e. expenditure and delivery of outputs) throughout the price control.

Fundamentally the AIP involves re-evaluation the RIIO-ED1 Price Control Financial Model (PCFM), the model used to calculate the opening allowable annual base revenue for each license area (and subsequently each DNO). With each iteration a number of variables may be updated within the PCFM to align with latest data on performance, expenditure, economic conditions, and incentives. Where variables are linked to economic conditions or legacy issues, DNOs will have little or no means of impacting the PCFM; for example: taxation, pensions, cost of debit, and (to a lesser extent) the close out of schemes and mechanisms from past price control periods. However, a number of the variables (particularly those included in the TOTEX Incentive Mechanism) compare actual and allowed expenditure, making adjustments to TOTEX to account for under or overspending and the resultant penalty or reward on allowed base revenue. This process is summarised in Figure 21.

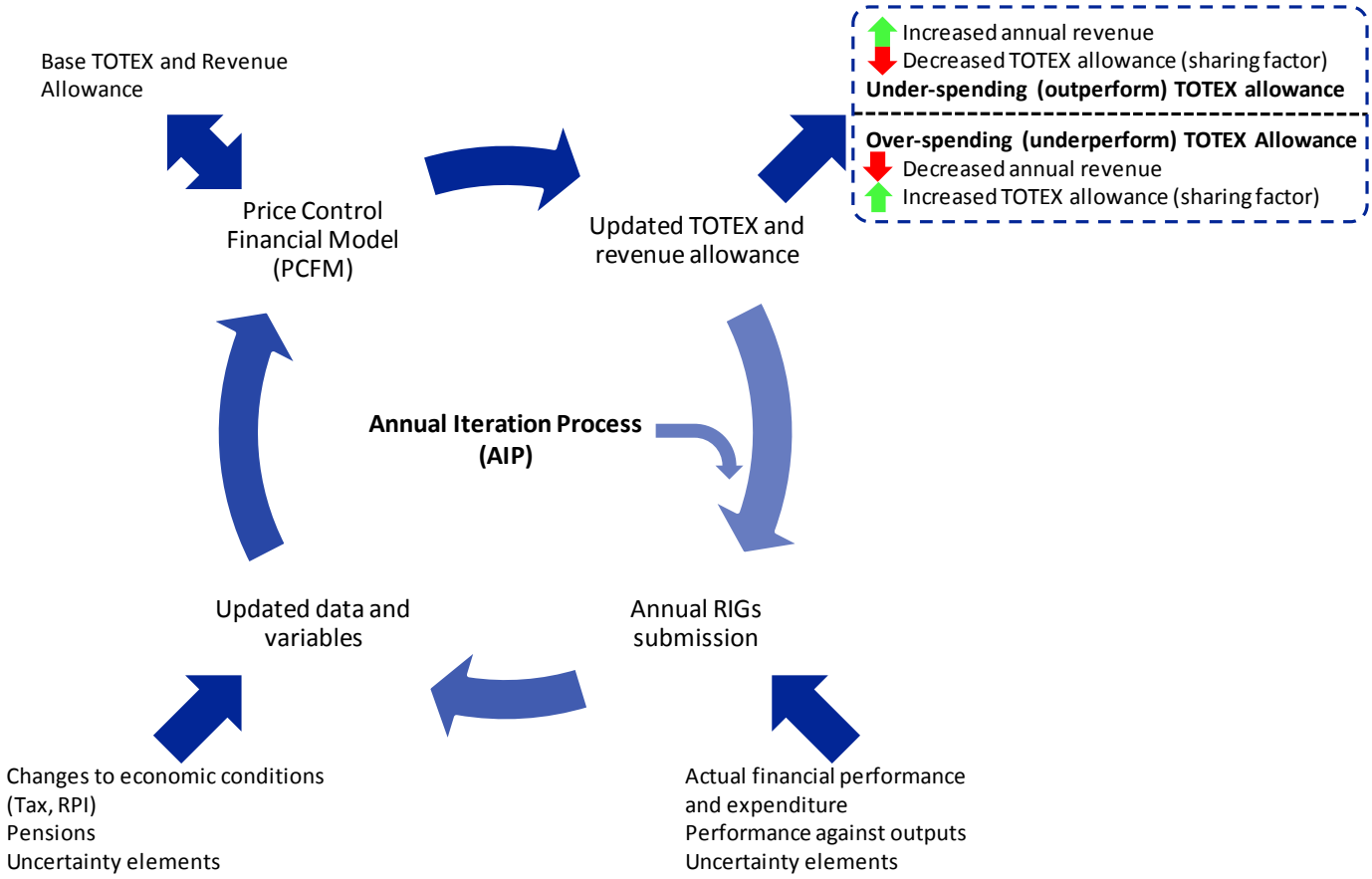


Figure 21: Summary of Annual Iteration Process (AIP)

To ensure awareness and transparency in this process, Ofgem has made the PCFM available to DNOs (and gas and transmission network operators) through their website. This model is updated annually following the latest revision of the AIP.

TOTEX cost assessment and benchmarking

Rather than utilising a CAPEX and OPEX split as the basis for cost estimation and benchmarking (as in DPCR5), Ofgem has utilised TOTEX (where TOTEX = CAPEX plus OPEX). In doing so, Ofgem aimed to:

- Utilise a method of benchmarking that focused on overall business efficiency;
- Avoid possible manipulation of CAPEX / OPEX cost categorisation; and
- Better consider the different CAPEX / OPEX trade-offs that DNOs face.

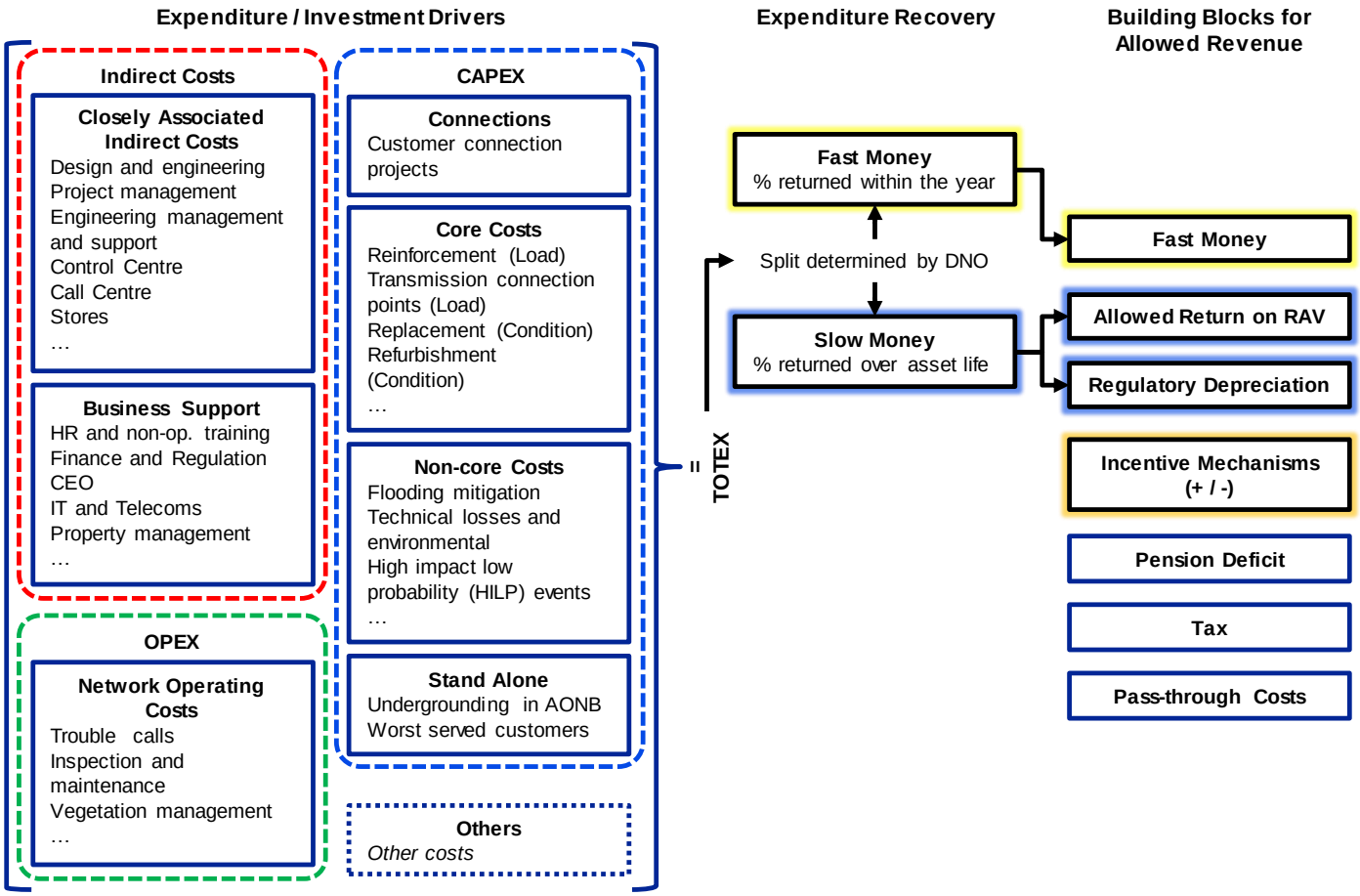


Figure 22: Overview of Ofgem's calculation of allowable revenue (adapted from [51])

Figure 22 shows a summary of the expenditure and investment drivers that Ofgem considers in the development of its cost assessment[36] (as documented in the RIGs reporting requirements). These cost drivers are used in Ofgem's benchmarking calculations, which estimate the efficient cost for DNOs using three models:

- The top-down TOTEX model, which provides a high-level cost assessment;
- The bottom-up TOTEX model, which uses a more detailed, but still high level cost breakdown; and
- The disaggregated activity-level model, which uses a highly detailed cost breakdown that is aggregated to calculate TOTEX.

The final calculation of Ofgem's view of efficient costs is a combination of these three calculations being weighted 25% for the top-down and bottom-up TOTEX models, and 50% for the disaggregated model. This is then "interpolated" against the DNOs cost assessment, with the final allowed TOTEX consisting of 75% from Ofgem's view of efficient costs and 25% from DNO's proposed costs.

[36] For a full list of investment drivers and populated example see Pages 13 and 14 of [60].

Figure 22 also shows the two means of expenditure recovery, termed fast and slow money (discussed later in this section) and how the allocation of fast and slow money feeds into the calculation of allowed revenue.

Fast and slow money

With the move away from using CAPEX- and OPEX-based cost assessment and benchmarking, Ofgem utilised the concept of "fast money" and "slow money" to determine how costs are recovered by DNOs. Fast money is that which is paid within a financial year, generally required to cover its running (or OPEX) costs; while slow money is added to the DNO's regulatory asset value (RAV) and paid out over the defined asset life[37].

Considering these definitions, it is evident that fast and slow money is not a new concept and that the expected proportions of CAPEX and OPEX would largely determine the split of fast and slow money. The interesting and inherently new concept is that Ofgem allows DNOs to define their fast / slow money split (as highlighted in Figure 22). Historically, Ofgem calculated this based on the DNO's cost submission. For example, the proportion of fast money was historically calculated as the sum of business support costs, non-operational CAPEX, and 15% of all other expenditure, with the remainder being allocated to slow money [52].

6.2 Outputs and Incentives

The output incentives mechanisms utilised in RIIO-ED1 have similarities to those used under DPCR. In some instances, incentives have been reviewed and rationalised, others have been halted and new incentives put in place. With the strong output-driven focus of RIIO-ED1, each of these incentives have been linked to one of six core output areas. These incentive mechanisms are outlined in Table 7, which provides an overview of the various outputs and related Ofgem incentives (or requirements). More detail on these incentives is available on Ofgem's website[38] or as referenced.

Table 7: RIIO-ED1 primary and secondary output incentives

	Incentive / Requirement	Max Exposure (+ / -)
Safety	Health and Safety Executive[39] regulation and legislation	*None*
	Ofgem requires that all DNOs are compliant with the relevant legislative requirements of the Health and Safety Executive. There is no financial incentive associated with this output as Ofgem felt that doing so would act to duplicate functionality of the Health and Safety Executive, while also having possible detrimental impact to safety [53]. For more information on Ofgem's requirements for safety see Section 5 of [53].	
Environmental Impact	• Electrical Losses • Electrical Theft • Business Carbon Footprint • Sulphur Hexafluoride (SF_6) • Fluid-Filled Cables • Noise Reduction • Undergrounding in Areas of Natural Beauty and National Parks	*See incentives*
	Ofgem has established a number of incentives and requirements against the environmental impact output. These include: • The **Electrical Losses incentive**, that has been used in the past[40], is aimed at encouraging DNOs to reduce network losses (estimated between 5-8% of total electrical energy [54]). The losses incentive consists of four components:	

[37] Previously the expected economic asset life had been set at 20 years. In RIIO-ED1 this asset life will transition from 20 to 45 years on a sliding scale to be applied to all new assets.
[38] www.ofgem.gov.uk
[39] The Health and Safety Executive is a non-departmental public body responsible for regulation of workplace health and safety in the UK (excluding Northern Ireland).

<table>
<tr><th></th><th>Incentive / Requirement</th><th>Max Exposure (+ / -)</th></tr>
<tr><td></td><td>

License requirements to design and operate their network in a way that would minimise losses as much as reasonably practicable (i.e. using cost benefit analysis).
The inclusion of strategies for fulfilling the aforementioned license requirement in DNO's business plans. Ofgem requires that business plans identify loss reduction work and expense with an accompanying cost and benefit analysis. Furthermore there is the requirement that business review this work throughout the price control period to ensure that their approach to loss reduction remains relevant and in alignment with industry best practice.
Annual reporting on completion of loss reduction work comparing performance against proposed cost and benefit analysis. This is a significant change from the DPCR4 model that required DNOs to report on loss volumes and reduction achieved.
Losses Discretionary Reward, which consists of a maximum £32m to be shared across all DNOs to encourage loss reduction work in excess of that identified in a DNOs business plan(s). The money available for this incentive will be awarded using a scorecard based on proposals received from DNOs. (The criterion for this assessment process is yet to be finalised).

Electricity Theft requirements, whereby Ofgem has introduced more stringent license conditions clearly defining the responsibility of DNOs. These license conditions require DNOs to be more active in monitoring, detecting, and preventing electricity theft (above and beyond the role of suppliers)[41].
The Business Carbon Footprint, SF_6, Fluid-Filled Cable, and Noise Reduction incentives, which all require DNOs to report on their current state and performance. These reports are published on Ofgem's website and are devised as a reputational incentive for DNOs. The level of reputational incentive varies from: direct competition in the case of the Business Carbon Footprint incentive that consists of a league table of DNO performance including actions undertaken to reduce their footprint; to public awareness in the case of fluid-filled cables and noise reduction.
The Undergrounding incentive, which was utilised in DPCR4 and DPCR5, provides funding for DNOs to underground overhead lines in areas of outstanding natural beauty or national parks to minimise visual and environmental impacts. Funding is provided by license area and is calculated on the basis of willingness to pay, impacted km of overhead line, and number of customers. The total funding allocated in RIIO-ED1 across all license areas is £103.6m.

For more information on Ofgem's environmental impact incentives and requirements see Section 5 of [53].
</td><td></td></tr>
<tr><td rowspan="2">Customer Satisfaction</td><td>Broad Measure of Customer Satisfaction (BMCS):

Customer Satisfaction Survey
Complaints
Stakeholder Engagement
</td><td>±1.5% (base annual revenue)</td></tr>
<tr><td colspan="2">The BMCS, which was utilised during DPCR5, incentivises DNOs to provide good customer experience beyond that of the customer interruption (CI) and customer minute lost (CML) reliability incentives. The BMCS consists of three underlying incentive mechanisms:

The Customer Satisfaction Survey, which polls a random sample of customers who have had dealings with DNOs in connections, interruptions, and general enquiries asking them to rank their experience. Depending on the resultant ranking DNOs can be rewarded or penalised to a maximum of ±1% of base annual revenue.
The Complaints metric, which aims to ensure customer complaints are resolved in a timely manner. DNOs are measured against the percentage of total complaints that are: outstanding after one day, outstanding after 31 days, repeat complaints, and where an Energy Ombudsman makes a finding against the DNO (with each having different weightings). Unlike the Customer Satisfaction Survey, there is no reward for reaching or outperforming targets; rather this incentive penalises DNOs to a maximum of -0.5% of base annual revenue for underperformance.
The Stakeholder Engagement incentive, which encourages DNOs to actively involve stakeholders in the long-term planning of their business. Metrics around this incentive appear somewhat qualitative, with the possibility of a +0.5% reward of base annual revenue at Ofgem's discretion.

For more information on Ofgem's customer satisfaction incentives see Section 6 of [53].</td></tr>
</table>

[40] The Electrical Losses incentive was used in DPCR4, but issues with reporting and data quality resulted in disproportionate rewards and penalties for DNOs. As a result, this incentive was deactivated in DPCR5 pending review and planned reintroduction in RIIO-ED1 [54, 68].

[41] Ofgem has established additional requirements and incentives impacting electricity suppliers (retailers); however, given that they do not directly impact DNOs I have not covered them in this report.

<table>
<tr><th></th><th>Incentive / Requirement</th><th>Max Exposure (+ / -)</th></tr>
<tr><td rowspan="2">Social Obligations</td><td>Vulnerable Customers</td><td>None</td></tr>
<tr><td colspan="2">Ofgem has not identified a specific output incentive relating to social obligation[42]; however, Ofgem has provided strong guidance that DNOs should be active in addressing social issues like vulnerable customers and fuel poverty. In particular, Ofgem has indicated that there will be heavy linkage between performance in this area and that of the BMCS incentive (namely stakeholder engagement). DNOs are required to document (as a part of their business plan) how they propose to identify and assist vulnerable customers.

For more information on Ofgem’s social obligation requirement see Section 7 of [53].</td></tr>
<tr><td rowspan="2">Connections</td><td>Customer Satisfaction Survey (included in BMCS for connections)
Time to Connect (for minor connections)
Incentive on Connections Engagement (for major connections)
Guaranteed Standards of Performance (GSoP)</td><td>+0.4% / -0.9%[43] (base annual revenue)</td></tr>
<tr><td colspan="2">Ofgem found that the incentive system used during DPCR5 did not sufficiently encourage DNOs to provide a timely connection service. As a result they have reviewed the connections incentives providing three mechanisms, two for minor (low voltage) and one for major (high voltage) connections. These incentives are:
A component of the Customer Satisfaction Survey (minor connections), as incorporated in the BMCS. The connections component of the BMCS was increased from +0.32% / -0.2% base annual revenue exposure in DPCR5 to ±0.5% in RIIO-ED1 to encourage DNOs to provide a prompt, high-quality connection service for customers.
Time to Connect (for minor connections), which measures the time from initial contact to issuing of quotation and connection of customer. Ofgem has issued performance targets covering both of these milestones (i.e. time to quote and connection) and where DNOs are able to outperform these targets they stand to receive a reward of +0.4% of base annual revenue. These targets will be reviewed (and likely reduced) half way through RIIO-ED1. For more information on the targets set by Ofgem see [55].
Incentive on Connections Engagement (for major connections), which is targeted at improving the level of service for major connection customers. DNOs are required to document (in their business plans) their proposed plans for engagement and delivery of major connections. This is to be accompanied by routine evidence-based reporting to Ofgem demonstrating a DNO’s performance on major connections across different market sectors (e.g. metered, unmetered, and distributed generation). These submissions will be reviewed by Ofgem and assessed against a set of minimum performance standards. Where a DNO is found to have not met these minimum performance standards they may be penalised to a maximum of -0.9% of base annual revenue.
Guaranteed Standards of Performance (GSoP), was established as a license condition in DPCR5 to encourage prompt, high-quality service for non-contestable customer connections. It stipulates maximum allowable timeframes for DNOs to provide quotation, design, and energisation to a customer. Failure to meet these timeframes or where a deliverable is found to be inadequate results in set penalties for the DNO (payable to the customer) dependant on the type of connection.
For more information on Ofgem’s connections incentives see Section 8 and Appendix 3 (GSoP payments) of [53].</td></tr>
</table>

[42] This does not preclude an incentive from being established in the future.
[43] This figure does not include the ±0.5% incentive for customer satisfaction (minor connections) (as it is already incorporated in the BMCS) or penalties accrued through the GSoP license requirement (as this is applied on a case-by-case basis).

<table>
<tr><th></th><th>Incentive / Requirement</th><th>Max Exposure (+ / -)</th></tr>
<tr><td rowspan="2">Reliability and Availability</td><td>Interruption Incentive Scheme (IIS)
Guaranteed Standard of Supply
Worst-Served Customer
Health, Criticality, Risk and Load Indexes
Resilience</td><td>See incentives</td></tr>
<tr><td colspan="2">Ofgem has established a number of network-focused incentives to ensure that DNOs operate and maintain networks in a sustainable way, ensuring a good service for customers, capacity (availability), and reliability in the short- and long-term. These incentives are:
The Interruption Incentive Scheme, which was utilised in DPCR5, benchmarks DNO's network reliability performance in terms of planned and unplanned customer interruptions (CIs) and customer minutes lost (CMLs). DNO performance is compared to the industry benchmark using two years (trailing) historical data with a total exposure of ±250 return on regulatory equity[44] (RORE) basis points per annum.
Guaranteed Standard of Supply, which was utilised in DPCR5 with some revisions for RIIO-ED1, provides a means for customers to seek monetary compensation (as defined by Ofgem) from DNOs when they experience sustained outages.
The Worst-Served Customer mechanism, which was utilised in DPCR5 with some revisions for RIIO-ED1, provides DNOs with a "use it or lose it" allowance to improve the quality of supply to their worst-served customers. Ofgem provides a total allowance of £76.5m to be shared across all DNOs based on the percentage of total affected customers.
The Health, Criticality, Risk, and Load Indexes (secondary deliverables), which were utilised in DPCR5 with the inclusion of criticality in RIIO-ED1, are utilised by Ofgem to: monitor network availability, ensure prudent short- and long-term management of networks, and monitor performance of DNOs in delivering planned targets. The use of these indexes is core to the RIIO model. Rather than taking a hands-on, detailed approach to monitoring (e.g. tracking completion of projects and costs), Ofgem is able to track the performance of these indexes against a DNO's business plan. In doing so, Ofgem provides scope for DNOs to innovate and drive efficiency in achieving these targets without prescribing how targets are achieved. As a secondary deliverable there are no direct incentives around these indexes; however, their performance is tracked as a part of annual reporting and revenue adjustment (as well as being publicly published). Failure to deliver on planned index performance will be addressed in revenue adjustments as a part of this process.
Resilience (secondary deliverable), which is a measure of the risk from events in three core areas relating to flooding, black start, and overhead lines faults. DNOs are required to report on their risk exposure in these three areas with the aim of reducing exposure over the price control period. As a secondary output there is no direct incentive applied to the resilience measure; however, given that the reports are published publically there is some reputational incentive to ensure improving network resilience.
For more information on Ofgem's reliability and availability incentives see Section 4 of [53] and [56].</td></tr>
</table>

Overview of Efficiency and Innovation Incentives

In addition to the output incentives, Ofgem has established a set of mechanisms to drive efficiency and encourage innovation. While the drive for efficiency and cheaper delivery usually exists in competitive markets, research and innovation often suffer in light of cost cutting and efficiency measures. Therefore, Ofgem has provided separate incentive mechanisms to encourage progress in both areas.

It is important to note that research funded by the innovation incentives is expected to deliver better, more affordable service for customers. This was highlighted throughout the RIIO-ED1 submission process and cemented at the slow track determination, where Ofgem found that DNOs did not present sufficient cost savings through innovation. To correct this Ofgem introduced the smart grid saving in its final determination.

[44] RORE is defined by Ofgem as, "*The financial return achieved by shareholders in a licensee during a price control period from its out-turn performance under the price control.*"

Table 8: Overview of Ofgem efficiency and innovation incentives

<table>
<tr><th></th><th>Incentive</th><th>Max Exposure (+ / -)</th></tr>
<tr><td rowspan="2">Efficiency</td><td>• Information Quality Incentive (IQI)
• Efficiency Incentive Rate (Sharing Factor)</td><td>See incentives</td></tr>
<tr><td colspan="2">Ofgem’s efficiency mechanisms provide an upfront incentive for DNOs to develop efficient business plans (in comparison to Ofgem’s view of efficient costs), and an ongoing incentive to outperform during the price control period. The two efficiency mechanisms are:
• The Information Quality Incentive (IQI), which was utilised in DPCR5, encourages DNOs to develop accurate and efficient plans as a part of the regulatory submission process. In it’s simplest form the IQI provides an upfront reward or penalty to DNOs based on the cost and volume efficiency of their proposed plan in comparison with Ofgem’s view. Throughout the price control period if the DNO manages to outperform their TOTEX allowance they are rewarded through the Efficiency Incentive Rate (as discussed below). DNOs that are seen as being more efficient as a part of the IQI assessment are given a higher Efficiency Incentive Rate throughout the price control period.
• The Efficiency Incentive Rate (or Sharing Factor) forms a portion of the IQI assessment. It designates the percentage of under or over expenditure (from the TOTEX allowance) that a DNO is exposed to, with the remainder being shared by customers. In the event a DNO is able to deliver their outputs while underspending their TOTEX allowance, they retain a percentage of this underspend. Conversely, if a DNO overspends their TOTEX allowance to deliver outputs, they are required to fund the same percentage of overspend. Therefore the Efficiency Incentive Rate provides a two-sided incentive for DNO’s to outperform their proposed cost allowance through efficiency and innovation, while avoiding overspending. This rate is also an integral part in the calculation for the Annual Iteration Process, which adjusts base annual revenue throughout the RIIO-ED1 price control period.
For the RIIO-ED1 price control period Ofgem has set the efficiency incentive rate between 53-58% for slow track DNOs and 70% for fast track [57]. In the event of significant (unreasonable) under or overspend, Ofgem reserves the right to undertake a re-opener, where the level of under or overspend meets pre-defined thresholds [58].

For more information on Ofgem’s efficiency incentives see Section 9 of [53].</td></tr>
<tr><td rowspan="2">Innovation</td><td>• Network Innovation Competition (NIC)
• Network Innovation Allowance (NIA)
• Innovation Roll-out Mechanism (IRM)</td><td>See incentives</td></tr>
<tr><td colspan="2">Although a number of the previously discussed incentive mechanisms encourage innovation, Ofgem has recognised that there are areas of research and development that may not provide sufficient benefit for DNOs but that may be of benefit to society. Historically, innovation has been funded (in part) through two schemes: the Innovation Funding Incentive, and Low Carbon Networks Fund. These schemes have been replaced under the RIIO model, with Ofgem developing three new incentive mechanisms:
• The Network Innovation Competition (NIC), which is an annually awarded, competition-based incentive to promote large-scale research projects that will deliver low carbon or environmental benefit. DNOs can request a maximum of 90% of funding to be provided through NIC, with a total of £90m per annum available for the first two years of RIIO-ED1.
• The Network Innovation Allowance (NIA), which is a fixed “use it or lose it” allowance to fund small-scale innovation projects. Funding is allocated on a per license area basis depending on the strength of each DNOs innovation strategy (submitted as a part of their business plan). For RIIO-ED1 Ofgem has awarded allowances between 0.5-0.6% of base annual revenue with a maximum of 90% project funding to be provided from the NIA.
• The Innovation Roll-out Mechanism (IRM), which is aimed at enabling the integration of innovations in business as usual. Where an innovation delivers viable and proven low carbon or environmental benefits, DNOs can seek redress for the cost of roll-out through revenue adjustment twice within the price control period. This level of adjustment is limited to 1% average base annual revenue.

For more information on Ofgem’s innovation incentives see Section 10 of [53].</td></tr>
</table>

6.3 Recommendations

From my experience with international regulatory frameworks, in particular the RIIO framework that has been developed and applied in the UK, this section proposes a number of recommendations

particularly focused at regulatory organisations and the Australian Electricity Industry. These recommendations are listed in Table 9.

Table 9: Recommendations relating to the development of regulatory frameworks

#	Recommendation
13	Regulatory bodies should look to integrate a dynamic set of incentives within their regulatory framework that encourage regulated organisations to continually innovate, improve, and identify efficiencies within their business. In Australia, the Australian Energy Regulator (AER) already has four key incentives to promote prudent and efficient expenditure: the Efficiency Benefit and Capital Expenditure Sharing Schemes (similar to Ofgem's Efficiency Incentive Rate), the Service Target Performance Incentive Scheme (a combination of Ofgem's BMCS, GSoP, and IIS), and the Demand Management Incentive. However, there is an opportunity to compare and develop these incentives against those of the RIIO model.
14	Where a regulatory body oversees a number of utilities, the regulatory body should seek to create a healthy level of competition between utilities through mechanisms like benchmarking and leader boards. These competitive incentives should focus on core outcomes; for example, level of customer service or customer satisfaction, cost of delivery (where suitable), delivery timeframes, or efficiency.
15	Regulatory bodies should consider implementing a fast and slow track determination mechanism to encourage regulated organisations to provide a well-developed and lean business plan at first submission. Rewards for receiving a fast track submission should be sufficient to encourage utilities to come with their "best offer first," with criteria that is challenging but achievable.
16	Regulatory bodies should consider implementing an AIP-style mechanism that will encourage utilities to deliver against their business plans year-on-year. This mechanism would also act to "ratchet down" expenditure over time, encouraging efficiency improvements on a more continual basis (rather than the step change being seen in the most recent round of AER determinations).
17	Regulatory bodies should utilise clearly defined output measures and targets to monitor (and possibly reward or penalise) the performance of utilities throughout the regulatory period. This should be done in a way that is not so prescriptive that it stifles innovation or over performance in the delivery of work and targets.

7 Closing

Changes, be they customer-based, technological, environmental, or economical, have already begun to impact the day-to-day business of utilities. While it is difficult to predict the eventuality of many of these trends, it is inevitable that these changes will continue for the foreseeable future. As such, it is important that the industry keeps pace with and adapts to these changes, or there is a risk that large sectors of the industry could become irrelevant. Similarly, asset management, which is a fundamental function of many organisations within the industry, must be forward thinking and responsive to change.

In opening this report and my tenure on the Scholarship, I proposed three components that would be vital in realising an optimised asset management system; they were:

- Establishing a robust asset management system;
- Leveraging increased data availability to create tools and information that can enable prudent and timely decision making; and
- Understanding the impact of new technologies on the assets and how these technologies may derive additional value.

My tenure on the Scholarship, which enabled me to work with two leading international utilities, and my subsequent recommendations have supported this proposal. I believe that the Australian Electricity Industry is well placed to capitalise in these three areas, and, in some instances, is at the forefront of innovation and development.

In closing, there are a number of people that I would like to acknowledge for their contributions to my time abroad and for making this experience possible:

- To the many people that I have had the pleasure to work, learn, and explore with along the way, thank you. It is the people that make an experience like this so valuable and enjoyable. My time abroad has been filled with many memories, but it is those memories shared with friends and colleagues that I will remember most fondly.
- To Ergon Energy, my Australian employer, thank you for allowing me this time to work, research, and explore the international utility environment. I am excited to work for an organization that has a history of supporting, and continues to support engineers developing themselves through opportunities like this.
- To the benefactors who support the E.S. Cornwall Memorial Scholarship, thank you. Your philanthropy enables learning that goes far beyond those scholars who are fortunate enough to undertake a tenure on the Scholarship. The opportunity that this Scholarship affords is instrumental in driving innovation and development within the Australian Electricity Industry.
- To the E.S. Cornwall Memorial Scholarship Board, thank you, it is your time spent facilitating, guiding, and supporting engineers like myself that makes all of this possible.
- And lastly, but most importantly, to my family, who have taken on the somewhat undesirable role of “Report Vetters”. Thank you for your love, support, and words of encouragement.

For having received the E.S. Cornwall Memorial Scholarship and the wealth of experience it has provided me, I am humbled and forever grateful.

Finally, to those young, Queensland-graduate engineers who are considering applying for the E.S. Cornwall Memorial Scholarship - do! While I can assure you that it’s not always easy, it’s worth it. The experiences and challenges you will face during your time on the scholarship will grow you as a person, develop you as an engineer, and leave you with a collection of life-long memories. I’m more than happy to share my experience and advice with anyone who is considering applying for the scholarship and can be contacted by email (matthew.zillmann@gmail.com).

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9 Appendix

A1. Overview of UK Power Networks (UKPN)

UKPN is a privately-owned[45] DNO that manages three of the fourteen service areas in the UK: Eastern Power Networks (EPN), London Power Networks (LPN), and South Eastern Power Networks (SPN) (as shown in Figure 23). These service areas encapsulate 29,000km^2 of the UK, providing electricity to 8.1 million customers, via almost 186,000km of overhead lines and cables [59].

Figure 23: Distribution network areas of the UK, highlighting UKPN's service areas [60]

In 2013 UKPN's regulated asset base was valued at £5.23 billion (depreciated value), with capital and operating expenditures of £632.5 million and £440.3 respectively. Of the £632.5 million in capital expenditure, £115.1 million related to reinforcement work while £320.1 million related to asset replacement [59]. This expenditure is regulated by the Office of Gas and Energy Markets ("Ofgem"), who are responsible for determining the allowable revenue of monopolies operating in the UK electricity and gas market.

A2. Overview of Commonwealth Edison (ComEd)

Commonwealth Edison (commonly known as ComEd) is one of three utility companies owned by the Exelon Corporation. ComEd was founded in its current form in 1907, but traces its roots back to the Western Edison Lighting Company, which was established in 1882 by Thomas Edison. In 1887 the Western Edison Lighting Company was absorbed by the Chicago Edison Company, which came under the leadership of Samuel Insull (a long-time Edison employee and past Vice President of General Electric) in 1892. Insull led the company to a merger with Commonwealth Electric Light and Power Company in 1907, which saw the creation of Commonwealth Edison [61, 62].

[45] UKPN are owned by Chinese infrastructure investment company Cheung Kong Infrastructure (CKI).

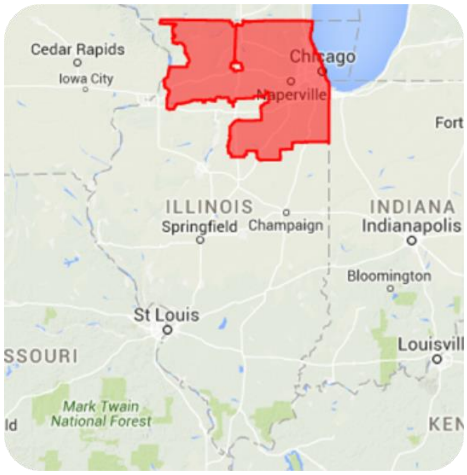


***Figure 24: Map of Illinois showing ComEd's service territory [63]*[46]**

In its present form ComEd has grown beyond its Chicago-beginnings and is now the transmission and distribution network owner for Chicago and northern Illinois (with the other major network operator for southern Illinois being Ameren). ComEd now services a network that supplies approximately 3.8 million customers (70% of Illinois population) and covers a territory of 29,500 km^2 (11,400 mi^2). Figure 24 shows a map of the extents of ComEd's service territory. In 2014 ComEd's property, plant, and equipment asset value was estimated to be $15.8 billion (USD) (2014 depreciated asset value), of which the electricity and transmission and distribution network makes up circa 98% [64].

A3. Overview of Exelon Corporation

Exelon Corporation is a holding company that was established in 2000 as a result of the merger of PECO Energy Company (formerly Philadelphia Electric Company) in Philadelphia, Pennsylvania and Unicom Corporation, the then owner of ComEd in Illinois. Since then Exelon Corporation has acquired a number of businesses spanning the gas and electricity energy sector, growing its operations across the USA and Canada. Exelon Corporation's holdings fall within three predominant areas of the energy sector: generation, transmission and distribution (for gas and electricity), and competitive energy sales (wholesale and retail). Figure 25 shows the structure of Exelon Corporation and its subsidiary companies.

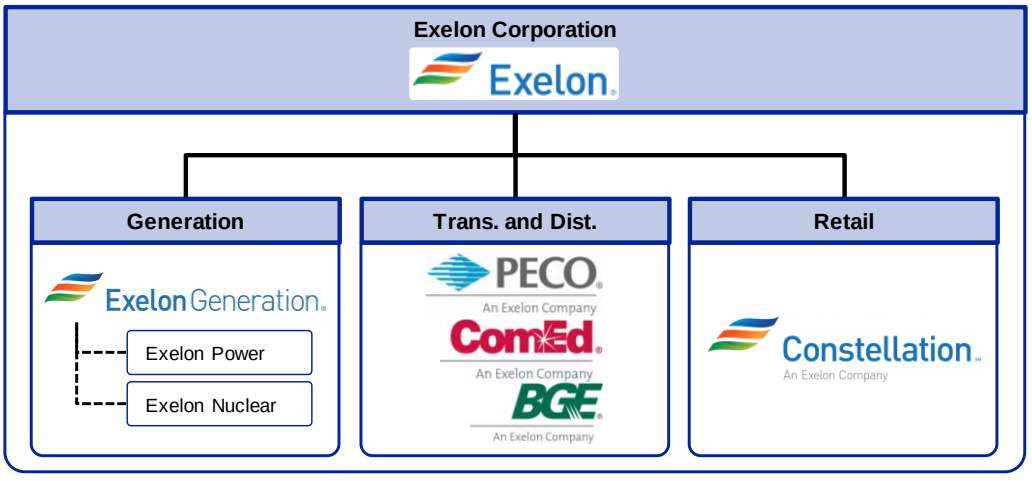
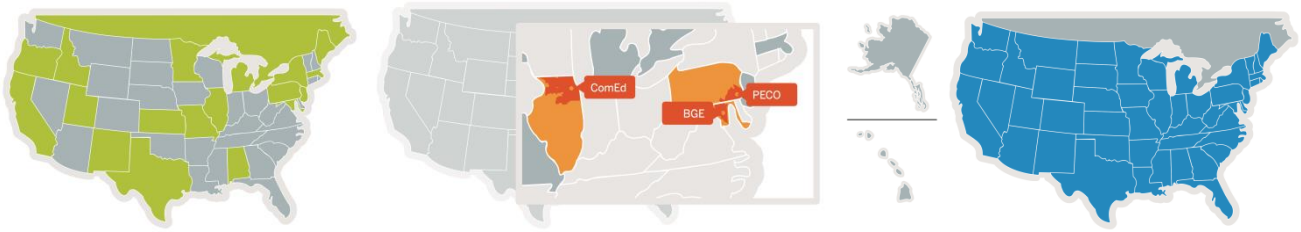


Figure 25: Exelon Corporation and its subsidiary companies

[46] The small region in central north Illinois that is not included in ComEd's service territory is the city of Rochelle, Ogle County. Rochelle has its own municipal utility (Rochelle Municipal Utility) that is responsible for providing electricity, water, waste water treatment, and communications services.

Through its subsidiaries Exelon Corporation boasts an impressive company portfolio; for example, Exelon Generation (specifically the Exelon Nuclear division of Exelon Generation) is the largest owner of nuclear generation in the USA; Constellation, Exelon Corporation's competitive energy retail business, services one of the largest customer portfolios in the USA including more than two thirds of the Fortune 100 companies. In total Exelon Corporation and its subsidiaries are active in 48 states of the USA, the District of Columbia (DC), and Canada with an asset holdings valued at $86 billion (USD), and employing circa 29,000 people [65]. Table 10 provides a brief overview of each of the Exelon Corporation subsidiaries.



(a) ***(b)*** ***(c)***

Figure 26: Maps of Exelon Corporation's Operating Areas [66]
(a) States with Exelon Generation (Power and Nuclear) assets
(b) Exelon Corporation's utility (gas and electricity transmission and distribution) utilities
(c) Exelon Corporation's (Constellation's) energy retail service states

Given Exelon Corporation's interests that traverse the electricity sector (i.e. generation, transmission, distribution, and retail), it is in a unique position to understand and, where possible, optimise the value chain from generation to end user, something that was lost as a part of the dissolution of vertically integrated companies. For this reason Exelon Corporation provides a guiding vision that drives each of its subsidiaries and, within legal limitations[47], utilises partnerships and collaboration across its business to ensure the best value outcome.

Table 10: Overview of Exelon Corporation's subsidiaries [66, 67, 64]

Exelon Corporation Subsidiaries Statistics (2014)				
Exelon Generation[48]	An electricity generation business, which consists of two divisions: **Exelon Nuclear**, who own and operate Exelon Corporation's nuclear generation fleet; and **Exelon Power**, who own and operate Exelon Corporation's fossil fuel, landfill gas, hydro, wind and solar generation fleet.			
	Headquarters:	Baltimore, Maryland		
	Operating States:	18 states of the USA and Canada (see Figure 26 (a))		
	Generating Capacity:	35,137 MW (2013)		
	Generation Mix:	54.8% Exelon Nuclear, 45.2% Exelon Power (see [67] for detail)		
	Operating Revenue:	*$17.4 billion (USD)*	% Exelon Total	*62%*
	Net Income:	*$1.02 billion (USD)*		*51%*
	Total Asset Value:	*$45.3 billion (USD)*		*51%*
	Prop., Plant & Equip.:	*$22.9 billion (USD)*		*44%*
PECO	A utility business that provides electricity and gas transmission and distribution service to consumers in south-eastern Pennsylvania, particularly focused on the city of Philadelphia and surrounding counties.			
	Headquarters:	Philadelphia, Pennsylvania		
	Employees:	2,400		
	Service Area:	5,400 km^2 (2,100 mi^2) in south-eastern Pennsylvania		
	Customers:	1,600,000 electric, 506,000 gas		
	Operating Revenue:	$3.09 billion (USD)	% Exelon Total	11%
	Net Income:	$0.211 billion (USD)		18%
	Asset Value:	$9.94 billion (USD)		11%
	Prop., Plant & Equip.:	$6.80 billion (USD)		13%

[47] Legislation and regulatory requirements like the Federal Energy Regulatory Commission's (FERC's) Standards of Conduct, which sets legal boundaries within companies like Exelon Corporation, have been put in place to avoid collusion and anti-competitive behaviour within companies that have interests spanning the electricity sector (e.g. generation and transmission).
[48] Exelon Generation's financial figures include that of Constellation (Exelon Corporation's retail subsidiary)

ComEd	A utility business that provides electricity transmission and distribution service to customers in northern Illinois, including the city of Chicago.			
	Headquarters:	Chicago, Illinois		
	Employees:	5,400		
	Service Area:	29,500 km^2 (11,400 mi^2)		
	Customers:	3,800,000		
	Operating Revenue:	$4.56 billion (USD)	% Exelon Total	16%
	Net Income:	$0.408 billion (USD)		20%
	Asset Value:	$25.4 billion (USD)		29%
	Prop., Plant & Equip.:	$15.8 billion (USD)		31%
BGE	A utility business that provides electricity and gas transmission and distribution service to customers in central Maryland, including the city of Baltimore.			
	Headquarters:	Baltimore, Maryland		
	Employees:	3,400		
	Service Area:	6,000 km^2 (2,300 mi^2)		
	Customers:	1,200,000 electric, 655,000 gas		
	Operating Revenue:	$3.17 billion (USD)	% Exelon Total	11%
	Net Income:	$0.211 billion (USD)		11%
	Asset Value:	$8.08 billion (USD)		9%
	Prop., Plant & Equip.:	$6.20 billion (USD)		12%
Constellation[49]	A competitive energy retail business which sells electricity, natural gas, and energy services (e.g. energy efficiency, load response, building energy management) for wholesale and retail customers.			
	Headquarters:	Baltimore, Maryland		
	Employees:	≈10,000		
	Service Area:	48 states of the USA and the District of Columbia (DC)		
	Customers:	2,500,000 across all sectors		

[49] For the United States Securities and Exchange Commission Form 10K [64], reporting of Constellation's financial performance is incorporated in those of Exelon Generation.