FOREWORD

ITP 2016 is our second standalone Integrated Transmission Plan (ITP). Building on ITP 2015, it provides an update on our business transformation process and provides our current, best view of our RCP2 expenditure programmes.

We recently published an update to our Transmission Tomorrow strategy. It looks at the challenges and opportunities facing the electricity industry over the next forty years.

It sets out our view that, over the long term, new technologies installed within homes and businesses, and by distributors, may alter how the power system is operated.

While the changes may lead in the longer term to the grid playing a different role, it will always be beneficial for New Zealand to have a strong, resilient transmission network. We therefore still need to prudently and safely manage the long-lived assets and complex systems that provide this essential service.

We are continuing to transform our business to meet our efficiency targets, and are mid-way through a multi-year transformation programme. We have made significant progress and are beginning to see the benefits. These include increased cost-effectiveness in our activities and fewer workplace injuries.

We are making progress with the foundations of our RCP3 proposal. This includes further development of our service performance measures, on which we soon plan to engage with stakeholders.

We trust you will find ITP 2016 a useful resource. If you want to engage with us on how we should set our performance measures from 2020 we recommend you look out for our engagement process later this year.

Alison Andrew
Chief Executive
August 2016
TABLE OF CONTENTS

FOREWORD ......................................................................................................................... II

1. INTRODUCTION ........................................................................................................ 1
   1.1. Purpose ................................................................................................................ 1
   1.2. Structure of the ITP ............................................................................................ 2
   1.3. ITP Narrative Content ........................................................................................ 3

2. OUR BUSINESS ............................................................................................................. 4
   2.1. Our Role in the Electricity Sector ....................................................................... 4
   2.2. Our Stakeholders ................................................................................................. 5
   2.3. Strategy Framework ............................................................................................ 6
   2.4. Transmission Tomorrow ..................................................................................... 7
   2.5. 2016/17 Focus Areas .......................................................................................... 9

3. SERVICE PERFORMANCE ........................................................................................... 11
   3.1. Background ......................................................................................................... 11
   3.2. Current Service Measures and Targets ............................................................... 11
   3.3. Future Refinements ............................................................................................ 13

4. EXPENDITURE OVERVIEW ....................................................................................... 14
   4.1. Expenditure Categories ...................................................................................... 14
   4.2. Major Capex ....................................................................................................... 15
   4.3. Base Capex ......................................................................................................... 16
   4.4. Operating Expenditure ....................................................................................... 17

5. ENHANCEMENT AND DEVELOPMENT .................................................................... 19
   5.1. Development Outlook ....................................................................................... 19
   5.2. E & D Capex ...................................................................................................... 20

6. ASSET LIFECYCLE MANAGEMENT .......................................................................... 24
   6.1. Background ....................................................................................................... 24
   6.2. R & R Capex ...................................................................................................... 24
   6.3. Grid Opex .......................................................................................................... 26

7. ICT AND BUSINESS SUPPORT ............................................................................. 29
   7.1. ICT Capex .......................................................................................................... 29
   7.2. ICT Opex .......................................................................................................... 30
   7.3. Business Support Capex ................................................................................... 31
   7.4. Corporate Opex ................................................................................................. 32
1. INTRODUCTION

This chapter introduces our Integrated Transmission Plan (ITP) and its supporting documents. The chapter:

− sets out the overall purpose and aims of the ITP
− explains that the ITP comprises four related documents and a set of supporting schedules
− sets out the structure of this document, the ITP Narrative.

1.1. PURPOSE

The ITP sets out our plans for our regulated transmission business during the current and subsequent regulatory periods. It provides an overview of our business and the strategies and goals that inform our decision-making. A key element of our strategic framework is the recently published Transmission Tomorrow document.\(^1\) We discuss its role in Chapter 2.

The ITP has been developed to align with regulatory requirements\(^2\) and to make it easier for stakeholders to understand and engage with our business.

Our first ITP was completed in 2013 as part of our proposal for the five-year regulatory control period beginning 1 July 2015 (known as RCP2). Subsequent to this we published our first standalone ITP in September 2015 (ITP 2015). This ITP provides an update to the ITP 2015, setting out our refined forecasts up to 2025 (ITP Period).

Building on ITP 2015, we have focused on the following aspects when preparing ITP 2016:

− providing our current, best view of our RCP2 investment programmes
− signalling our RCP3 investment needs
− providing updates on our business transformation processes
− starting to incorporate Transmission Tomorrow into our plans
− reflecting feedback on ITP 2015 from stakeholders including the Commence Commission.

ITP 2018 will form part of our proposal for the regulatory period between 2020 and 2025 (RCP3).

**Note on Forecasts**

ITP 2016 reflects the forecasts produced during our 2016/17 business planning round. The projects and activities described are our best view of our asset management and investment intentions.

Much of our planned works are still subject to further internal governance processes, including final financial approvals and in some cases customer consultation. They may be subject to further review and refinement, which may alter their scope, timing and cost.

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\(^1\) This can be downloaded from [https://www.transpower.co.nz/transmission-tomorrow-publication](https://www.transpower.co.nz/transmission-tomorrow-publication).

\(^2\) The Transpower Capital Expenditure Input Methodologies Determination (Capex IM) requires us to prepare ITP documents and specifies the timing and frequency of their publication.
1.2. **Structure of the ITP**

As illustrated below, the ITP includes this document (the ITP Narrative), three supporting documents, and a set of supporting schedules.

Figure 1: Structure of the ITP

![ITP Structure Diagram]

**Asset Management Plan**

The Asset Management Plan (updated in 2016) sets out our overall asset management framework. It provides background information on our assets and describes the strategies we have in place to manage them throughout their lifecycle.

**Services Report**

The Services Report (produced in 2015) describes the service performance framework for our regulated transmission business. It sets out our service performance measures, which we are progressively introducing into our investment decision-making. We developed the measures as part of ITP 2013. We plan to undertake further stakeholder engagement on refinements to the measures and targets for RCP3 and beyond (see Chapter 3).

**Transmission Planning Report (TPR)**

The TPR (produced in 2015) identifies potential developments to the capability and configuration of the grid. It identifies where future enhancement and development (E & D) investments may be required. Chapter 5 provides an update on our E & D analysis.

**ITP Schedules**

The ITP includes a number of schedules that summarise our expenditure forecasts. These also set out related deliverables including forecast volumes of asset replacements.

1. Expenditure overview
2. Base capital expenditure
3. Base capital expenditure—deliverables
4. Operating expenditure
5. Major capital expenditure—approved projects
6. Major capital expenditure—outputs
7. Major capital expenditure—projects under development
8. Output measures
1.3. ITP Narrative Content

The remainder of the ITP Narrative (this document) is structured as follows.

Figure 2: ITP Narrative Content

<table>
<thead>
<tr>
<th>Chapter 2</th>
<th>Service Performance</th>
<th>Chapter 3</th>
<th>Expenditure Overview</th>
</tr>
</thead>
<tbody>
<tr>
<td>Our Business</td>
<td>Explains our service performance measures and our plans to refine these in the lead-up to RCP3.</td>
<td>Provides an overview of our ITP 2016 expenditure forecasts and compares them with ITP 2015.</td>
<td></td>
</tr>
</tbody>
</table>

Throughout these chapters we include references to the supporting documents to help direct readers to further information.

1.4. 1.4 Information Disclosure Determination

The Transpower Information Disclosure Determination 2014 requires us to publish a set of schedules or information “in or as a companion to the integrated transmission plan”. Three of those schedules, Schedule G6 (a detailed breakdown of asset ages, remaining lives and additions, disposals and other movements) and Schedules G7 and G8 (details of our asset management maturity assessment), fitted more naturally in our main Information Disclosure document, with the other disclosures required by the Determination. The Commerce Commission has therefore given us an exemption from providing those disclosures in this document, on the basis that they will be provided in our main Information Disclosure document.
2. OUR BUSINESS

This chapter provides an overview of our business and our strategic framework, including Transmission Tomorrow. The chapter:

- explains our role in the New Zealand electricity sector
- describes some of our key stakeholders
- outlines our strategic framework
- discusses our recently published strategy document, Transmission Tomorrow
- summarises our company focus areas for 2016/17.

2.1. OUR ROLE IN THE ELECTRICITY SECTOR

We are a state-owned enterprise, with two main roles in the New Zealand electricity sector: grid owner and system operator. The ITP covers our role as grid owner. As such, it excludes services delivered by, and costs funded through, our system operator service.

The following diagram illustrates our place in the New Zealand electricity industry.

Figure 3: Our place in the New Zealand electricity industry

As depicted above, there are a number of stakeholders that we interact with in our roles as grid owner and system operator, including the Commerce Commission and the Electricity Authority. We discuss our key stakeholders in Section 2.2.
2.1.1. Financial Overview

The provision of regulated transmission services accounts for around 90 per cent of our revenue. The system operator service and customer-funded grid connections account for a further 4 per cent each. The balance of our business involves non-regulated services, such as income from our emsTradepoint natural gas market.

We own and manage over $5bn of transmission assets, and plan to invest over $2.6bn on these and additional assets during the ITP Period.

2.1.2. Network Overview

We have 169 substations across the North and South Islands and 11,066 km (route length) of overhead transmission lines. We have approximately 88 km (route length) of underground transmission HVAC cables and 114 km of submarine HVDC cables. Our telecommunications assets include 1,923 km of fibre optic cables.

Further information on our grid assets can be found in Part 3 of our Asset Management Plan.

2.2. Our Stakeholders

Being open and consulting effectively with our stakeholders is a key aim of our business. Below we set out an overview of our main external stakeholders.

- Customers: our ultimate customers are electricity consumers across New Zealand. These customers include residential, commercial and industrial users that are served through the networks of 29 distribution companies. These distributors make up most of our direct customers. In addition, we have 6 grid-connected generator customers and 11 large industrial customers.

- Communities: our assets can have a significant impact on the communities in which we operate. It is important that we consult effectively with communities at an early stage when planning our activities so we can better understand potential impacts and mitigate these as far as practicable.

- Landowners: we often require access to private land to undertake work on our assets. Constructive relationships with landowners are therefore essential. We are committed to working openly and honestly with landowners and occupiers when undertaking our activities.

- Service Providers: we outsource field maintenance, capital project construction and a number of other technical roles to a group of ‘service providers’. They are key stakeholders in the maintenance and development of the grid.

- Our Regulators: our activities are mainly regulated by two bodies. The Commerce Commission regulates our transmission service revenues, works with us to set service measures, and governs incentive arrangements. The Electricity Authority sets reliability standards, governs our pricing methodology and grid access framework.

- Our Shareholders: our investors seek confidence that financial returns will be commensurate with investment risk and reflect the preservation of business value. Working with our Board and executive team they seek to ensure that we are an effectively managed business with appropriate governance processes.
2.3. **Strategy Framework**

We use a strategic framework across our business to support a structured way of aligning our long-term plans and everyday priorities with stakeholder interests.

This year we updated Transmission Tomorrow, which provides a key connection between our enduring purpose and our ongoing strategies and plans.

A simplified version of our high-level framework, highlighting key grid-focussed documentation, is illustrated below.

![Simplified strategy framework](image)

**Figure 4: Simplified strategy framework**

### 2.3.1. **Our Purpose**

Our business operates at the heart of New Zealand, powering our economy and way of life. Our purpose reflects this and emphasises safety, our drive to find smart solutions, and our long term perspective.

*We connect New Zealanders to their power system, through safe, smart solutions for today and tomorrow.*

### 2.3.2. **Transmission Tomorrow**

We recently published a comprehensive update to our Transmission Tomorrow report. First developed in 2011, Transmission Tomorrow is our long-term view of possible futures for the New Zealand electricity sector. In Section 2.4 we discuss strategic priorities identified in Transmission Tomorrow, while later sections explain how we are incorporating these priorities into our plans.

### 2.3.3. **Our Grid Strategies**

In July 2014, we became one of the first electricity companies in New Zealand to achieve certification against the international asset management specification PAS 55. In 2015 PAS 55 was withdrawn and replaced with the ISO 55000 standard. We are currently moving towards certification against the ISO 55000 standard.
Embedded within our strategic framework is our suite of enduring, grid–related asset management documents.

- **Grid Asset Management Framework**: sets out the scope of our asset management system and provides the high-level direction for our asset management activities.
- **Strategic Asset Management Plan (SAMP)**: we are evolving our current asset management document suite into a more integrated SAMP. It will set out and explain the objectives of our asset management activities, and the strategies in place to achieve them. The SAMP will inform the development and implementation of our Asset Class Strategies and Asset Management Plan.
- **Asset Class Strategies (ACS)**: set out objectives and strategies specific to the management of particular assets. They provide the direction required to develop our Asset Management Plan.

### 2.3.4. Our Plans for the Grid

There are a number of grid-related planning documents that form part of our overall strategic framework.

- **Transmission Planning Report**: identifies potential developments to the capability and configuration of the grid. It identifies where future E and D investments may be required.
- **Asset Management Plan (AMP)**: sets out our approaches to managing our various asset classes throughout their lifecycle. This includes E & D Investments, operational plans and individual programmes that focus on particular asset classes.

Further details on our asset management framework, including our over-arching asset management objectives and standards, can be found in Chapters 2-4 of the Asset Management Plan.

### 2.3.5. Our Values

Our values capture our view of how we operate when we are at our best. They provide a common language and a foundation for promoting the best aspects of the culture within our organisation.

The values above emphasise that we need to work hard and efficiently to keep the lights on for our fellow Kiwis. To do so we strive to deliver excellence by changing, adapting, and improving what we do. We come together to make things happen, focusing on the needs of the communities we serve and the need to keep everybody safe.

### 2.4. Transmission Tomorrow

Transmission Tomorrow looks at the challenges and opportunities facing the electricity industry over the next five to forty years. It acts as a key connection between our purpose and our grid strategies and activities.
It reflects our views on long-term possible futures for the electricity industry. It recognises that electricity consumers have an expanding range of options for meeting their energy needs as new technologies become more affordable. This combined with changing societal factors, continual changes in electricity generation, and relatively flat demand growth leads to increasing uncertainty in the near future.

To capture and consider these issues we undertook a wide range of analysis and research to inform Transmission Tomorrow. This included the following elements.

- **Environment scan** – review of key trends, our value proposition and critical elements of our social licence to operate.
- **Scenario testing** – modelling the New Zealand power system to 2050 under a wide range of possible futures.
- **Planning trajectory** – developing a storyline of how we see the sector developing, with a view to providing a ‘least-regret’ basis for our planning.
- **Strategic priorities** – identifying six priority areas for our business, with supporting rationale and guidance on actions we should take.

Below we summarise the strategic priorities informed by this analysis and outline how these flow through to other parts of our strategic framework.

**Ensure competitive costs and services** – New Zealand’s traditional electricity supply chain faces increasing competitive pressure, so we need to reduce our costs while ensuring we target the right services and performance levels. Our plans will be underpinned by good asset management and customer engagement.

**Play an active role in shaping our industry** – there are new challenges and opportunities due to uncertainties in demand, carbon policy, and uptake of new technologies. We have a strong stake in the successful adaptation of the industry and a role to play in enabling a renewable future. We plan to play an active and constructive role in shaping the future of the industry.

**Sustain our social licence to operate** – it is essential that we maintain public support for our activities. We will continue to place a priority on safety, grid security and reliability, transmission corridors, sustainability, and good corporate citizenship. One of the key focuses is on sustaining our commitment to worker and public safety.

**Match build to need** – our planning trajectory indicates a need to anticipate and respond to change more rapidly. We plan to undertake careful and cautious management of capacity investment pressures over a longer timeframe, and swiftly adapt to a new mode of operation in the long term.

**Improve asset management** – we manage hundreds of thousands of assets valued at more than $5bn and requiring approximately $400m in total expenditure each year, making asset management central to our business. We will continue to improve our competencies, systems and processes to ensure we provide valued, cost-effective services that meet our customers’ changing needs.

**Increase organisational effectiveness** – to support our other priorities, we need to continuously improve our organisational effectiveness. We will continue to embed and refine operational approaches across the business.

The future New Zealand electricity sector may be dramatically different to what it is today. Over a long-term horizon, battery or other storage technologies installed within homes and businesses, electric vehicles, and distribution networks may fundamentally alter how the power system is operated.

These changes may lead to the grid playing a different role, however, it will always be beneficial for New Zealand to have a strong, resilient transmission network. We will therefore still need to
prudently and safely manage the long-lived assets and complex systems that provide this essential service.

### 2.5. 2016/17 Focus Areas

Each year we identify a number of focus areas within our Annual Business Plan that will help us advance our strategic goals. The focus areas help guide divisional operating plans and are used to inform our investment decision-making.

For 2016/17 we have selected six key focus areas aligned with ensuring organisational effectiveness. We summarise these below and explain how they support the strategic priorities set out in Transmission Tomorrow.

**Health and Safety**

Operating safely remains our top focus.

For the coming year, our focus is on investing in improved identification and mitigation of high consequence risks and making it easy for people to work safely through consistent, simple processes and safe behaviours.

This focus area assists with our strategic priority to sustain our social licence to operate.

**Transformation**

Transformation refers to our preparations for a changing environment and ensuring that the organisation is effective in meeting the changing expectations of our customers, stakeholders, and regulators.

In the coming year we will continue work on operational initiatives. A key area is strengthening the focus on leadership capability and embedding behaviours that support these initiatives. Our revised grid operating model will continue to be embedded and refined to support our objectives, including these focus areas.

The revised model will help support our strategic priorities to improve asset management and ensure competitive costs and services.

**Increased Service Orientation**

In December 2018 we will be putting forward a revenue proposal to support our provision of transmission services during RCP3. The proposal will set out the service performance we aim to deliver, and our view of the efficient cost of delivering those services.

The coming year is important for putting in place strong foundations for our proposal, including engaging with our customers and other stakeholders on what transmission services they value. This includes exploring what attributes of our service are important; how we should measure performance; and whether we should be holding, lifting or easing our performance. This is discussed further in Chapter 3.

This focus area assists with our strategic priority to ensure competitive costs and services.

**Network Pricing**

Network pricing will be a big focus for the industry in the coming year, and there are clear benefits to ourselves and the wider sector in successfully addressing pricing design challenges.

This focus area includes engaging on the transmission pricing methodology review to improve certainty for planning and investment decisions. This will be a key focus, particularly as the review
moves into detailed design and implementation. Other areas include proposals for changes to
generation funding approaches and the need to refresh our approach to contracting for new grid
connections (and customer-driven enhancements to existing connections).

Efforts to increase consistency and to introduce more cost-reflective methodologies into distribution
pricing regimes will also be an important initiative for the wider industry.

This focus area assists with our strategic priority to play an active role in shaping the industry’s
future.

Adaptation

Transmission Tomorrow describes a need to lift our awareness and agility to navigate a changing
electricity sector. Issues such as low growth, tight security margins and the prospect of emerging
technologies may require significant operational changes in the medium term.

This focus area brings together several items relating to the development of the grid. These include
development of plans to deliver reliable power to, within, and through Auckland in the short and
long term.

We plan to evolve the way we forecast investment needs (e.g. demand and generation changes) and
how we manage our forward investment programme. This will include increasing our understanding
of the potential impacts of emerging technologies, and understanding how to use these to improve
our services.

This focus area assists with our strategic priority to match build to need.

Grid Works Delivery

Improving the systems and processes we use to deliver work will help ensure that our stakeholders
can be confident in our ability to complete the work cost-effectively.

This requires that we continually revise and optimise our work plans to ensure these works can be
delivered cost-effectively and as planned. We have revised our programme for 2016/17 to smooth
work flow and brought works forward from 2017/18. Smooth, predictable workflows allow our
service providers to optimise their resource levels, reducing overall delivery costs.

We are increasing the level of certainty around the works required in later years of RCP2. This is
being achieved by improving our condition assessment regime and refining the way we make
investment decisions. Improved stability across our works plan will provide opportunities to further
reduce costs.

This focus area assists with our strategic priority to improve asset management. In particular it will
help ensure we develop the capability needed during RCP3.
3. SERVICE PERFORMANCE

This chapter explains our service performance measures and our plans to refine these in the lead-up to RCP3. The chapter:

- provides background on how our service performance framework has developed
- sets out our current service measures and our recent performance against them
- discusses our process to update and refine these measures in the lead up to RCP3.

3.1. BACKGROUND

As part of ITP 2013 we developed a new service measures framework to apply during RCP2. This included a new set of measures and targets that were developed through a stakeholder consultation process. The measures were formalised as part of the RCP2 reset process.

We have now completed one full year of RCP2 and the measures and associated targets are now in effect. We are therefore better placed to begin considering how these can be refined and more effectively embedded into our decision-making processes.

We are now planning to engage with stakeholders on potential refinements. This process is discussed in Section 3.3 below.

Our performance against the measures is discussed in the following section. We successfully met the majority of our targets during 2015/16. While these annual performance results provide an indication of our performance and that of our assets, a review of results over a number of years (once available) will allow us to more fully assess our underlying performance.

Further background on our current service performance measures can be found in ITP Schedule 8 and Chapter 3 of the Services Report.

3.2. CURRENT SERVICE MEASURES AND TARGETS

Our service measures and targets are summarised in the following tables. Our performance for the 2015/16 year can be compared with the respective targets.

The current measures are based on:

- the frequency and duration of interruptions experienced by customers and by relative priority of points-of-service
- availability targets for 27 HVAC circuits having the biggest impact on the energy market
- forward-looking targets for HVDC energy availability.

The basis for the targets, caps, and collars is discussed in Chapter 3 of the Services Report.

3 The measures and targets exclude interruptions due to the Automatic Under-Frequency Load Shedding (AUFLS) system.
We successfully met our number of interruption targets for all categories during 2015/16.

In some instances, we exceeded the performance level set by the ‘cap’, for example the Important and Standard categories above. A number of factors led to this good performance including relatively benign weather during the year and fewer equipment-related interruptions.

We successfully met our average duration targets for the majority of categories during 2015/16. However, our performance for generator and N-security sites didn’t meet the respective targets.

The GP2 Generator target was missed mainly due to equipment-related interruptions at one site. The main reason for not achieving the N-security targets for GP2 and GP3 (below) was an extended outage at Ohakune in December 2015 resulting from a tripped supply transformer. Following an investigation of the incident we have put in place additional preventive maintenance targeted at reducing the potential for similar future incidents.

We successfully met our P90 duration targets for the majority of categories during 2015/16. The N-security target wasn’t met due to the supply transformer interruption at Ohakune, discussed above.
Table 4: Performance 15/16 — circuit availability

<table>
<thead>
<tr>
<th>Availability (%)</th>
<th>15/16 performance</th>
<th>RCP2 targets</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Target</td>
</tr>
<tr>
<td>AP1: HVDC</td>
<td>98.9</td>
<td>98.5</td>
</tr>
<tr>
<td>AP2: HVAC</td>
<td>99.0</td>
<td>99.6</td>
</tr>
</tbody>
</table>

We successfully met our HVDC availability target during 2015/16. However we did not meet our HVAC availability target. This was due to the volume of scheduled maintenance and project work required on key South Island circuits.

3.2.1. **How we use the measures**

The service performance measures are an important part of our day-to-day activities. We use the reliability targets as part of our renegotiation of service provider contracts, and are factoring the reliability and availability targets into our works planning processes.

At a high level, we use the measures:

- **to discuss our services with customers**: as the measures should reflect what is important to customers. Having clear measures helps support discussions with our customers, including commercial and operational negotiations.

- **as inputs into asset management decisions**: in particular, the measures are being used to prioritise our work and we are working through how we can sensibly shift from traditional economic decision-making to a more strongly services-driven approach.

3.3. **Future refinements**

As discussed above, we plan to review our service performance measures in the lead-up to RCP3. This will be done through engagement with the industry and other stakeholders over the coming months. We will publish an engagement paper on this topic in October 2016.

At the time of completing this ITP, we envisage that the engagement process will focus on a range of issues, including:

- the overall purpose of service performance measures
- reviewing the service attributes that customers value
- comparing our service measures with other jurisdictions
- refinements to measures; allocations across categories; and service levels.

Further information on our engagement approach and how to provide feedback will be provided via an engagement paper, due to be published in October 2016.
4. EXPENDITURE OVERVIEW

This chapter provides an overview of our ITP 2016 expenditure forecast. The chapter:
- explains our expenditure categories
- sets out our forecast for Major Capex and Listed Projects and a comparison with ITP 2015
- summarises our forecast for Base Capex and provides a comparison with ITP 2015
- summarises our total Opex forecast, compared against the ITP 2015 forecast.

4.1. EXPENDITURE CATEGORIES

This chapter presents expenditure using the categories illustrated below. Further detail on the make-up of each category is provided within the chapter.

Figure 5: Expenditure categories

The ITP schedules include further detail on our forecast expenditure. The Asset Management Plan provides information on our work plans, including information on key Capex works.

Note on Forecasts and Expenditure Charts
All forecast information in the ITP was prepared as part of our 2016/17 business planning round, which was completed in June 2016. They are presented in 2015/16 prices.
Charts compare the forecasts included in this ITP with equivalent ITP 2015 forecasts. For reference, they also include our Base Capex allowance for the RCP2 period.\(^{4}\) Capex charts present the value of assets we expect to commission each year, rather than the amount we expect to spend.

4.1.1. MAIN EXPENDITURE CATEGORIES

We use a large number of expenditure portfolios during our day-to-day management of the grid. These fall under the following three main categories.
- **Major Capex and Listed Projects**: includes E & D projects with an expected value of more than $20 million and several large reconductoring projects (referred to as “Listed Projects”).\(^{5}\)
- **Base Capex**: refers to all Capex incurred in providing regulated transmission services, excluding Major Capex and Listed Projects. In addition to network expenditure, Base Capex includes ICT Capex and Business Support Capex.
- **Opex**: includes expenses related to activities that support our management of the grid.

\(^{4}\) The Commission set a total allowance only (i.e. there are no category allowances). Our forecast charts show a derived, proportional allowance for reference. The allowance is updated for the difference between forecast and actual CPI.

\(^{5}\) Listed Projects were excluded from Base Capex during the RCP2 reset process. This reflected their size large relative to our underlying level of Capex and their relatively large scope uncertainties. We need to apply to the Commerce Commission to have these projects added to Base Capex.
The following subsections set out our current forecasts for the ITP Period in each of the above categories. These forecasts are compared with equivalent forecasts from ITP 2015. Where relevant we also include a comparison against our RCP2 allowance.

### 4.2. Major Capex

The chart below presents our forecast for Major Capex and Listed Projects during the ITP Period. The forecast is compared with our equivalent forecast from ITP 2015. The chart presents the value of assets (in 2015/16 prices) we expect to commission each year.

Figure 6: Major Capex and Listed Projects

Based on our refined Major Capex and Listed Project forecast we expect to commission assets with a total value of $293m during RCP2. This is $107m below the ITP 2015 forecast, a reduction of 27%.

Major Capex is primarily driven by grid conditions, including demand growth, changes in the locations and capacity of generation, and distributors’ plans for their networks.

Our plans evolve through our processes as we progress solutions taking into account updated information from: demand and generation changes, options and cost analysis, consultation, and regulatory approvals. The main drivers for the changes depicted above include the following.

- Revised cost estimates following route surveys on the Bunnythorpe – Haywards reconductoring project.
- Reassessment of expected need dates:
  - Pakuranga-Whakamaru series compensation has been removed from RCP2 and RCP3, but will be considered on the long-list of options associated with our Waikato and upper North Island Voltage Management investigation.
  - Waitaki Valley project has been moved to RCP3 based on refined load forecasts changing the need date and the use of interim works, including special protection schemes.
  - HVDC works planned for 2024/25 have been deferred beyond RCP3, though this timing may be subject to further review.

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6 This total includes works under investigation that if approved would be commissioned in RCP2. Further detail can be found in Chapter 5 of the AMP.
Upper South Island Grid Upgrade Stage 2 – has been moved out of RCP3 based on updated load forecasts.

- Wairakei Ring, a generator driven investment, has been removed from RCP3 as we currently have no confirmed plans for new generator connections.

**Figure 7: Major Capex and Listed Projects**

The chart above presents our forecast of Total Capex expenditure including Major and Listed Projects, in addition to Base Capex during the ITP Periods.

Further detail on our Major Capex and Listed Project forecasts can be found in ITP Schedules 5, 6 and 7 and Chapter 6 of the Asset Management Plan.

### 4.3. **Base Capex**

The chart below presents our forecast for Base Capex during the ITP Period. The forecast is compared with the equivalent forecast included in ITP 2015 and the associated RCP2 allowance.

**Figure 8: Base Capex**

**Total Base Capex - Commissioned Value**
RCP2 Base Capex

We expect to commission assets with a value of $1,082m during RCP2. This is $86m below the ITP 2015 forecast, which equates to a reduction of 7% in expected Base Capex.

The new profile for RCP2 is generally consistent with the allowance other than an uplift in 2019/20. This uplift reflects curtailed delivery in 2015/16 and the rescheduling of works to ensure a more stable work plan with improved deliverability.

In addition to smoothing our workflow, the following aspects have led to the updated profile.

- **Refined investment decision-making:** as signalled in ITP 2015 we are improving our decision-making approach to allow improved prioritisation and more cost-effective decisions. Continued implementation of this approach will help improve overall efficiency.

- **Finding efficiency savings:** we have a programme underway to actively seek efficiency savings during RCP2. These savings are resulting from improved design, review of our strategies, and capturing savings from improvements in our decision-making approach.

- **Aligning to our new structures:** we restructured all three grid divisions in the first half of 2015/16. With the new structure in place we are steadily extending our planning horizon and capability to release a stable work plan to service providers well ahead of delivery.

- **Deferring E & D projects:** we have been able to defer some projects through further evaluation of their need date and delivery schedule, as well as through the use of lower cost interim solutions, such as variable line ratings.

Over the coming year we will use our new decision-making framework to further refine our plans for RCP3 and the remaining years of RCP2.

Further background on our Base Capex can be found in ITP Schedules 2 and 3 and in the Asset Management Plan.

RCP3 Base Capex

Our RCP3 plans are in an early stage of preparation and do not yet fully reflect our improved decision-making approach. Our preliminary view is that there is a good prospect of reducing planned work for RCP3, but we will not have a clear view until we complete further analysis.

Consistent with our Transmission Tomorrow strategy of controlling costs to remain competitive we have set a Capex target for RCP3 of $1.3bn. This total, for the five year RCP, includes Base Capex and Listed Projects. It has been set based on our RCP2 expenditure levels, with a view to holding price increases below inflation (all else being equal). Over the coming year we will test the viability of this target through our planning processes. The ITP Schedules include an indication of the Capex required to meet this target.

This approach requires further discipline in our decision-making where there are trade-offs between expenditure and risk, including potential impacts on service performance.

4.4. **OPERATING EXPENDITURE**

The ITP forecasts include Opex incurred in providing regulated transmission services. This excludes pass-through and recoverable costs, and cost related to our system operator function.

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7 Pass-through costs include regulatory levies and local government rates. Recoverable costs include instantaneous reserves availability charges and transmission alternatives costs (e.g. using demand response to defer a project).
Our Opex is categorised as:

- **Grid**: activities related to field maintenance, operations, and technical training
- **ICT**: including fibre and equipment leases, outsourced support, and software licences
- **Corporate**: activities and costs incurred in providing the transmission service. It includes network and operational support, asset management staff costs, and business support.

The chart below presents our total Opex forecast for the ITP Period. The forecast is compared with our equivalent forecast included in ITP 2015 and the associated RCP2 allowance.

Figure 9: Total Opex

We expect to incur a total of $1,240m Opex during RCP2. This is $72m below the ITP 2015 forecast and $101m below our RCP2 allowance, leading to a 5% reduction in expected Opex since ITP 2015. This reflects the significant savings we expect to make over the period on maintenance costs, ICT lease costs and building lease costs.

Further detail on our Opex forecasts is provided in the remaining chapters.

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8 We allocate costs to our system operator business where we can identify the costs as ‘avoidable’—i.e., we would not incur the costs if we did not provide system operator services. This allocation methodology means that common costs are included in the ITP.
5. ENHANCEMENT AND DEVELOPMENT

E & D investments allow us to develop the grid to cater for expected changes in demand or generation. This chapter provides an update on these investments over the ITP period. It sets out:

- the development outlook, including the context that informs our investment decisions
- our E & D forecasts and a comparison with ITP 2015.

The Transmission Planning Report (TPR) summarises how we assess whether the grid can accommodate expected changes in demand and generation. It identifies where future E & D investments may be required, and summarises these needs in the Grid Reliability Report and the Grid Economic Investment Report that identify potential reliability and economic investments respectively.

This year we have not revised our TPR, with the latest version being included in ITP 2015.

5.1. DEVELOPMENT OUTLOOK

The TPR and the E & D portfolio are heavily influenced by changes in demand and generation. From the mid-1990s to the mid-2000s peak system demand growth was strong. However, since 2008 system demand growth has flattened. This has resulted in significant reductions in our forecasts over the last 6 years.

System demand growth is expected to be 1.1% per annum to 2030. However, as shown below, we also consider that the plausible range of future demand growth is wide, as illustrated by the high and low bounds, and this could be further influenced by the uptake of battery storage not explicitly considered in this figure. Further information on these forecasts and our approach to deriving them can be found on our website.9

While system demand growth has been low we expect higher levels of growth in some regions. South Canterbury, for example, is a region where planned irrigation and dairy factory expansion continues to place pressure on existing grid capacity.

Recent and planned decommissioning of generation in the Upper North Island will significantly affect power flows and the need for voltage support on the network. These may result in the need for investment in the grid. This issue is currently the subject of a major capex investigation.10

Accurately forecasting demand and generation expansion (and contraction) continues to be a challenge. Future influences on demand growth are difficult to predict. A recent example is the proposed changes to the Transmission Pricing Methodology that may affect incentives for consumers to manage demand at peak times, although the extent of this effect is unclear. In addition, both consumers and generators can announce and implement plans at short notice that can significantly impact demand and power flows.

Over the long-term, Transmission Tomorrow highlights a wide variety of factors that could significantly impact future demand and generation although the scale and timing of the effect is not yet clear. Examples include: solar photovoltaic panels, battery storage, energy use changes, smarter grid, urbanisation, and electrification. While we will continue to develop our ability to anticipate

9 https://www.transpower.co.nz/about-us/our-purpose-values-and-people/planning-inputs
these changes, we see a need to develop the acuity and ability of our planning approaches so that we are agile in our response.

Figure 10: System Peak Electricity Demand Forecasts

5.2. E & D CAPEX

As discussed in Chapter 4, our E & D Capex is split into two categories, Major and Base. Below we discuss these forecasts over the ITP Period and how these vary from ITP 2015.

Further information on our E & D forecasts can be found in ITP Schedules 2, 3, 5, 6 and 7 and in Chapter 6 of the Asset Management Plan.

5.2.1. MAJOR E & D CAPEX

If the value of an E & D investment exceeds $20m it is treated as a Major Capex Project. These projects require individual regulatory approval outside of our five-yearly reset proposals. The approval process for major capex projects involves multiple stages of public consultation designed to test the need date for investment and to support selection of the investment option that provides the greatest benefit over the life of the investment.

Our Major Capex forecast is discussed in Section 4.2. The remaining sections of this chapter include discussions on future grid needs and potential E & D investments to address them.
5.2.2. BASE E & DCAPEX

Below we discuss our Base E & D forecasts for the ITP Period and how these have been refined since we published ITP 2015.

Figure 11: Base E & D Capex

Base E & D Capex - Commissioned Value

Based on our refined Base E & D Capex forecasts we expect to commission assets with a total value of $53m during RCP2. This is $49m below the ITP 2015 forecast, leading to a 48% reduction in excepted Capex. Adjustments to the forecast relate mainly to the deferral of works that were due to be commissioned in 2018/19, revised project estimates, and the introduction of additional projects.

The primary variance drivers include the following.

- The schedule for the North Taranaki Transmission Capacity project has been revised based on a commissioning date in early RCP3. We are continuing our investigation, and discussions about options with customers and other stakeholders. These may lead to further timing revisions (including commissioning in late RCP2) and, based on the eventual solution, it may become a Major Capex project.

- The Otahuhu—Wiri Transmission Capacity project has been deferred from RCP2 to RCP3. We identified that variable line rating (VLR) could be applied to the circuits if protection issues were resolved. With the required protection changes made and VLR applied, the circuit rating has been increased, shifting the need date from 2015 to 2021. This will continue to be monitored closely due to rapid urban and industrial development in the region. Further detailed investigation into the preferred solution for resolving the constraint is ongoing.

- Further detailed economic investigation resulted in a number of needs not progressing to a preferred solution until it is clear that sufficient benefits will be realised (e.g. bus security improvements at Bunnythorpe and Masterton).

- Identification of additional constraints has advanced the need date for some projects. (e.g. a voltage stability constraint in the Timaru region has brought the need date forward to RCP2).

- Identification of additional needs has resulted in additional projects (e.g. special protection schemes to facilitate demand connections).

We anticipate that Demand Response will play a role in managing risks associated with the delivery of projects, such as in the lower Waitaki Valley.
As illustrated by the above variances, E & D expenditure can be challenging to forecast over the medium-term. This is particularly the case due to varying external factors such as changing underlying grid conditions (e.g. changes in demand and generation) and the actions and preferences of connected (or connecting) parties. At a time of low overall demand growth, timing or scope changes to the few, relatively large projects in this category, can occur and lead to significant forecast volatility in and across RCPs.

5.2.3. KEY ASSUMPTIONS

We expect to make further refinements to our forecasts over the ITP Period. Examples of key uncertainties that could influence our forecasts include:

- persistent low demand growth leading to further reductions in our forecasts
- changes in demand driven by changes to the Transmission Pricing Methodology
- a commitment to close the Tiwai aluminium smelter
- a commitment to change the decommissioning date for the Rankine units at Huntly.

In addition to changing demand patterns, we will undertake further investigations of investment needs and consider alternative investment options.

5.2.4. UPDATE ON OUR E & D INVESTIGATIONS

This year we have not revised our TPR, with the latest version being included in ITP 2015. An updated report will be included as a supporting document in ITP 2017.

Below we describe E & D issues currently under investigation, which could result in changes to the forecasts we expect to include in ITP 2017.

Grid Needs that are currently under investigation

We are currently investigating solutions to the following issues. If pursued, we would expect these to lead to Base Capex investments.

- Timaru Interconnecting Transformers Capacity Upgrade: this project considers an increase in interconnection capacity at Timaru and is driven by the need to ensure the region does not suffer from voltage instability following an outage of a 220 kV circuit or interconnecting transformer.
- Otahuhu-Wiri Transmission Capacity: this project considers increases in the transmission capacity into Bombay and Wiri and is driven by load growth in the region. The use of variable line ratings has deferred the need for this work to RCP3. This project has the potential to become a Major Capex Project depending on the preferred solution.
- Otahuhu and Penrose Interconnection Capacity: this project considers the replacement of interconnecting transformers in Auckland and relates to the long term development of supply into Auckland.
- North Taranaki Transmission Capacity: this project considers the development of the grid in Taranaki related to the future of the New Plymouth site. As discussed in Section 5.2.2 the timing of this project is under review and may move forward in RCP2. It is also possible the project cost may make this a Major Capex Project.
- Southland Reactive Power Support: this project considers providing additional reactive support in Southland.
- Upper South Island High Voltage Management: this project is related to the future of reactive equipment at Islington and the upper South Island.
In addition, we are currently investigating the following need that we expect to lead to a Major Capex investment.

- Waikato and upper North Island Voltage Management: this project considers the need for voltage support via grid investments and/or non-transmission solutions in the Waikato and upper North Island regions. This project is driven by demand growth and thermal generation retirements in the upper North Island. This could require both Base and Major Capex investments.

We also plan to further investigate the following needs that if pursued could lead to Major Capex investments.

- Pakuranga-Whakamaru Series Compensation: this project considers the need to improve sharing of power flows between circuits supplying Auckland. This investigation is dependent on the Waikato and upper North Island Voltage Management investigation.
- Waitaki Valley: this project relates to the need to increase transmission capacity in the lower Waitaki Valley driven by load growth in dairying and irrigation.
- Increased HVDC capacity: we are considering the need date for additional capacity, as driven by generation and demand changes.
- Upper South Island Grid Upgrade Stage 2: this is the next phase of the Upper South Island Grid Upgrade Major Capex Project and will reconsider the need date for further investment and the preferred long-term development plan to resolve this issue.

Grid Needs identified but not yet investigated

There a number of issues that have not been investigated that may be reconsidered for the ITP 2017. These include the following.

- Additional generation in the Wairakei Ring and Taranaki requiring grid capability to be increased. These needs are dependent on potential generation connections.
- Capacity constraint for the Waitaki interconnecting transformers. This is linked to a potential new GXP in the region.
- Capacity constraint for the Hamilton interconnecting transformers. This is impacted by any investment or identification of a preferred solution to the Waikato and upper North Island Voltage Management investigation.
- Investigation to relieve generation constraints in the Roxburgh/Clyde/Twizel region.
- Voltage and capacity constraints in the 66 kV network on the West Coast.
- New generation connections may require special protection schemes to protect assets from overloading during specific operating conditions.
6. ASSET LIFECYCLE MANAGEMENT

Effectively managing grid assets through their respective lifecycles is one of our key functions. Recurrent maintenance and asset renewal are significant components of our expenditure. This chapter provides an update on these investments over the ITP period. It sets out:

- our approach to maintaining and renewing our assets
- Renewals and Refurbishment (R & R) Capex forecasts and a comparison with ITP 2015
- grid Opex forecast and a comparison with ITP 2015.

6.1. BACKGROUND

Maintaining a safe and reliable service while managing costs are key drivers in our approach to asset lifecycle management. Total lifecycle cost is a key consideration in our decision-making and requires us to make trade-offs between Capex and Opex.

When making decisions on asset intervention, we assess total required Capex and Opex, including:

- the impact of maintenance activities on asset life and performance
- all significant lifecycle costs
- benefits (such as reduced failure risk) of replacing or refurbishing the asset.

Our approach to lifecycle-based asset management is discussed in Chapter 3 of the Asset Management Plan.

6.2. R & R CAPEX

Below we discuss our Base R & R Capex forecasts for the ITP Period and how these have been refined since we published ITP 2015. This Capex relates to replacing existing assets, or refurbishing them to extend their useful life.

Further detail on our renewal programmes are included in Chapters 8 to 21 of the Asset Management Plan. It also discusses how we identify, prioritise and schedule these works.
Based on our refined Base R & R Capex forecasts we expect to commission assets with a total value of $832m during RCP2. This is $19m below the ITP 2015 forecast, which equates to a 2% reduction in expected Capex. Changes to the expenditure profile relate mainly to works being deferred from the 2015/16 work programme to later in RCP2 and changes to individual asset class forecasts. Examples of these asset class changes are set out below.

- **Power transformers**: planned expenditure in the period is lower following detailed review of replacement criteria and associated needs.
- **Grillages**: forecast expenditure associated with the concrete encasement of steel grillages has increased slightly as we begin to address more remote and difficult to access sites.
- **Outdoor to indoor conversions**: forecast expenditure in the period is lower following a re-prioritisation of some sites between RCP2 and RCP3 as well as lowering the cost of the buildings through better designs.
- **Insulators**: based on updated condition information and modelling we have reduced our forecast expenditure on insulator replacements. We have also achieved a lower cost per unit.
- **Substation fencing**: planned expenditure is lower than forecast due to improvements in standardising condition assessment of substation security fencing as well as applying a risk based approach in deciding when electrical fences should be installed.

Determining the optimum renewal timing for complex assets is difficult. There will always be an element of variance in the health of assets due to varying environmental conditions, component renewals, maintenance, and changes to asset use. Reflecting these issues we will continue to refine our forecasts over the coming year.
6.2.1. **Long-term CAPEX Forecasts**

As part of our mid-RCP ITP we are providing a set of extended forecasts for asset classes that have the potential to have large ‘lumpy’ expenditures. These forecasts are set out below by RCP.

<table>
<thead>
<tr>
<th>Asset Type</th>
<th>RCP4</th>
<th>RCP5</th>
<th>RCP6 and beyond</th>
</tr>
</thead>
<tbody>
<tr>
<td>HVDC</td>
<td>164</td>
<td>TBC</td>
<td>TBC</td>
</tr>
<tr>
<td>Power Transformers</td>
<td>127</td>
<td>20</td>
<td>TBC</td>
</tr>
<tr>
<td>HV Cables</td>
<td>TBC</td>
<td>TBC</td>
<td>TBC</td>
</tr>
<tr>
<td>Dynamic Reactive Support</td>
<td>26</td>
<td>TBC</td>
<td>TBC</td>
</tr>
<tr>
<td>Reconductoring</td>
<td>75</td>
<td>70</td>
<td>TBC</td>
</tr>
</tbody>
</table>

These forecasts reflect our current best view on likely expenditure in these asset classes. Given the period of these forecasts they should be considered indicative only. For a number of classes we have yet to develop a specific forecast. These are denoted as “TBC”. Beyond RCP5 we currently do not have specific asset class forecasts.

We are continuing to refine our longer-term forecasts and will provide further updates on the above expenditure categories as part of ITP 2018.

6.3. **Grid Opex**

The grid Opex category includes expenditure on activities undertaken by our field service providers and external training providers.\(^\text{11}\) Specifically, it includes costs related to the following activities.

- **Routine maintenance**: includes scheduled activities that keep assets in an appropriate condition and ensure that they operate as required. Routine maintenance seeks to proactively manage failure risk (preventive) as well as responding to actual failures as these occur (reactive).

- **Maintenance projects**: are time-bound programmes that address prevalent asset condition issues. They typically consist of programmes of small repairs or replacements of components of larger assets.

- **Operating**: activities relate to field maintenance switching, including requests for feeder isolation, and switching following customer faults.

- **Training**: includes expenses related to our management of skills and competencies particularly in technical areas.

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\(^{11}\) The internal staff costs related to the management and specification of these activities are included in Corporate Opex, discussed in Section 7.4.
6.3.1. Grid Opex Forecasts

Below we discuss our Grid Opex forecasts for the ITP Period and how these have been refined since we published ITP 2015.

Further detail on our Grid Opex forecasts can be found in ITP Schedule 4.

Figure 13: Grid Opex

We expect to incur a total of $464m Opex during RCP2. This is $35m below the ITP 2015 forecast, which equates to a 7% reduction. Our forecast is below our RCP2 allowance and reflects the savings we expect to make over the period, particularly in grid maintenance works.

The key drivers for these reductions include the following.

- **Routine maintenance**: expenditure will continue to reduce as we realise the benefits of our savings initiatives. These savings initiatives include preventive maintenance optimisation, changes to our vegetation strategy, improvements in work-order prioritisation, and the reset of prices with service providers. Preventive maintenance savings have been realised by rationalising the timeframes in which we carry out our scheduled tasks enabling us to reduce our forecasts across both RCP2 and RCP3. It has allowed us to further optimise work and concentrate on more critical assets.

- **Maintenance project**: activity is expected to be lower as we can defer programmed work based on improved accuracy in our asset condition information. Through optimisation and improved prioritisation of work, we are more effectively addressing deterioration leading to a reduced need for invasive maintenance projects and reduced contact with each asset. We expect to further improve this optimisation as we move toward a reliability centred maintenance approach and implement improvements to our condition assessment process.

- **Operating**: we expect to reduce expenditure on these activities in-line with the lower maintenance work volumes discussed above. As we reduce the number of interventions, our switching and associated expenditure will reduce. Additionally, as our remote monitoring capability increases we expect lower levels of on-site activity, reducing overall cost.

- **Training**: expenditure on technical training will decline over both RCP2 and RCP3. This is due to an increased emphasis on e-learning, ensuring training is targeted and effective, and through skills and knowledge retention leading to lower level of re-training. This means that while training standards, particularly safety related, are being maintained, reduced re-training
will lower overall costs. A important enabler of this is reduced service provider turnover facilitated by improved work certainty and longer-term planning.
7. ICT AND BUSINESS SUPPORT

This chapter includes the remainder of our ITP Period forecasts. It sets out:

- Capex and Opex forecasts for our ICT functions and a comparison with ITP 2015 forecasts
- Business Support Capex and Corporate Opex and a comparison with ITP 2015 forecasts.

7.1. ICT CAPEX

We continue to improve the processes with which we manage our ICT expenditure. During the ITP period, our investment focus has shifted from building new capability to ensuring continued support and maintenance of our existing systems. The main exception to this is the continuing investment in developing our asset management capability.

Further detail on our ICT programmes is included in Part 4 of the Asset Management Plan. It discusses our approach to making these investments and our key RCP2 investments.

Figure 14: ICT Capex

ICT Capex - Commissioned Value

Based on our refined ICT Capex forecasts we expect to commission assets with a total value of $166m during RCP2. This is $9m below the ITP 2015 forecast, a 5% reduction in expected Capex. The changing profile is mainly due to timing changes in large projects and emerging requirements, including the need for increased security. Examples are set out below.

- **SCADA:** our SCADA\(^{12}\) and energy management systems will require upgrades in 2019/20.
- **Cyber security:** we will enhance the protection of critical ICT infrastructure from potential intrusion.

While the overall trend in RCP2 is downward, we expect expenditure to increase through to the middle of RCP3, due to the ‘lumpy’ nature of certain large projects and their timing during the

\(^{12}\) Supervisory Control and Data Acquisition system.
period. This includes the renewal of our TransGO communications network, and lifecycle replacement of our undersea fibre cables. We expect that RCP3 will see a reduction in infrastructure refresh expenditure as we increase the use of cloud-based services for non-critical functions.

In some areas it is difficult to predict with certainty what technologies we will commission over the ITP period or the exact techniques that we will use to deliver them. Maintaining a degree of flexibility has the advantage of allowing us to consider emerging, cost-effective technologies and to adopt them if they are sufficiently mature. Reflecting this we will continue to refine our forecasts over the period.

7.2. ICT Opex

ICT Opex includes telecommunications and equipment leases, outsourced support and maintenance fees, and software licences.

Further detail on our ICT Opex forecast can be found in ITP Schedule 4.

Figure 15: ICT Opex

We expect to incur a total of $204m ICT Opex during RCP2. This is $11m below the ITP 2015 forecast, which equates to a 5% reduction. Our forecast is well below our RCP2 allowance and reflects the savings we are realising in the following areas.

- **Network lease costs**: expenditure will reduce as we realise the benefits of successful contract renegotiation and scope rationalisation.
- **Data-centre costs**: have been reduced below previous forecasts due to infrastructure rationalisation.
- **Licensing**: we are focusing on improving our capacity planning and licensing management, and on the introduction of open source technologies in appropriate areas.

We expect that RCP3 expenditures will be broadly constant from the end of RCP2 despite upward cost pressures. This reflects the cost reduction efforts which will continue through the remainder of the ITP Period.
7.3. **Business Support Capex**

Our Business Support category covers the balance of our Capex, including items such as office buildings, office furniture, and vehicles.

Further detail on our Business Support assets are included in *Part 5 of the Asset Management Plan*.

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Based on our refined Business Support Capex forecast we expect to commission assets with a total value of $30m during the remainder of RCP2. This is $9m below the ITP 2015 forecast, which equates to an reduction of 23%. Our revised forecast is below our RCP2 allowance.

The main variance is due to not going ahead with the Islington logistics supply depot and lower costs associated with the Wellington head office and Palmerston North office relocations.
7.4. **CORPORATE OPEX**

Our Corporate Opex forecast includes expenditure on activities that support the provision of transmission services. It includes direct staff costs and external specialist advice, investigation costs, insurance, travel, accommodation, and ancillary services. It includes staff costs associated with network and operational support, and asset management.

Further detail on our Corporate Opex forecast can be found in [ITP Schedule 4](#).

Figure 17: Corporate Opex

![Corporate Opex Chart]

We expect to incur a total of $572m Corporate Opex during RCP2. This is $26m below the ITP 2015 forecast, which equates to a 4% reduction. As part of our transformation programme, we have successfully targeted and realised a number of efficiencies across our operations. Reflecting these and our expectations for further savings during the period we have reduced our forecast below the RCP2 allowance.

We expect that RCP3 expenditures will be broadly in-line with our 2019/20 expenditure. This reflects our continuing cost reduction efforts.