2015 Asset Management Plan

www.topenergy.co.nz

TOP ENERGY®
Te Puna Hihiko

Introduction

It gives me great pleasure to present this 2015 Asset Management Plan Update to Top Energy's 2014-2024 Network Asset Management Plan (AMP). This 2015 AMP Update follows on from the full 2014 AMP, and documents the material changes to Top Energy's Asset Management Strategies, Levels of Service, Network Development, and Lifecycle Asset Management Plans described in that AMP.

Our 2014 AMP, as updated by this 2015 AMP Update, is the core asset management planning and operations document for our electricity transmission and distribution network and details planned inspection, maintenance and capital replacement strategies for the next ten years, as well as the service level targets that we intend to deliver to our customers.

In compiling this AMP Update, emphasis has been placed not only on ensuring compliance with the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012, but also on providing details of material changes to the 2014 AMP. Further, while there is no change to the internally set reliability targets detailed in the 2014 AMP (apart from additional planned transmission line interruptions due to the delay in commissioning the second 110kV line) the reliability forecasts presented in the 2015 AMP Update Schedule 12d now follow the Commission's requirement for unplanned outage information to be presented before normalisation, and planned outage information to be presented before the 50% reduction in impact that the Commission has introduced when assessing compliance with the reliability threshold for the FY 2016-20 default price-quality path regulatory period.

The most significant change presented in this 2015 AMP Update is a revision to the construction schedule and subsequent commissioning date for the Wiroa-Kaitaia 110kV line to FYE 2026. In the 2014 AMP, commissioning was forecast for FYE 2018; however, over the past year three key developments have occurred that have necessitated a revision to that commissioning date:

- Progress on the acquisition of property rights for the line route has been far slower than anticipated due to the time it takes to obtain Maori Land Court approval, a process that cannot be accelerated, and a small number of landowners along the proposed route who are strongly opposed to construction of the line across their land. In these circumstances it may be necessary to resort to compulsory acquisition under Section 186 of the Resource Management Act 1991. We now estimate that it will take until at least FYE 2018 before property rights over the full route can be secured and consider that it would not be prudent to commence construction of the line prior to this.
- The forecast cost for this line in the 2014 AMP was a high level estimate based on the budgeted costs for Stage 2 of the Kaikohe-Wiroa 110kV line. Out-turn costs for this project are now available, and it is apparent that the initial project budget was too low. In addition, the Wiroa-Kaitaia line section is now known to have higher property rights acquisition costs and also additional construction costs due to the more difficult terrain. Hence, the forecast total project cost is now estimated to be $44.2 million, compared to $33.7 million in the 2014 AMP.
- Given our forecast revenues and the amount of our available debt facility, construction of the full line length immediately after the securing of property rights in FYE 2018, would require the deferral of other projects designed to improve the reliability of the distribution network. Following a review of the network development plan, we now consider that it would be unwise to focus all our resources on a single project and that a more balanced approach to developing the network is required.

The delay in completing the second 110kV line construction project will allow us to accelerate the construction of the Kaeo substation, which is now scheduled for completion in FYE 2018 and also the reinforcement of the supply to Russell, which is now expected to be completed by FYE 2020. Completion of these two projects will improve the reliability of the distribution network in the affected areas by reducing the number and duration of unplanned supply interruptions. We remain committed to improving the reliability of our network and to this end over the FY2016-20 regulatory period there has been a small increase in the capital expenditure forecast presented in the 2014 AMP. However, the need to re-optimise this expenditure and put more focus on the reduction of unplanned supply interruptions, which are of most concern to consumers, has meant changes to the way in which planned capital expenditure has been allocated.

INTRODUCTION

We recognise that many consumers in the north of our supply area will be frustrated by the delay in the completion of the second 110kV circuit, as it means that planned supply interruptions for maintenance of the existing circuit will need to continue through to FYE 2025. The decision to delay the completion of this project was not taken lightly, but reflects the difficulties experienced by all New Zealand lines businesses in securing routes for large transmission projects in the present legal environment, the need to prudently manage future price increases and ensure the long term sustainability of the business for the benefit of all our consumers. A robust programme of continued maintenance and investment in the existing 110kV line is in place to ensure its ongoing reliability and minimise the risk of faults on this line causing widespread unplanned supply interruptions to consumers in the north of our supply area.

FYE 2015 has been an exceptionally difficult year for us. In April 2014, our network was hit by the remnants of Tropical Cyclone Ita, which on a single day resulted in a total of 32 high voltage supply interruptions with a total SAIDI impact of 82.9 minutes. Only three months later, in July 2014, we were hit by a second severe weather event that remained stationary for several days and caused winds well in excess of gale force and extensive flooding, which intensively damaged not only our network but also roads and other public infrastructure. Over the month of July, we experienced a total of 87 unplanned high voltage interruptions with a total SAIDI impact of 1,362 minutes or almost 23 hours. Finally, just prior to Christmas 2014, we discovered a land slip on the top of the Maungataniwha Ranges, which caused a tower on the 110kV Kaikohe-Kaitaia transmission line to move almost 10 metres and some of the tower members to break. An unanticipated planned outage of this line to replace the damaged structure, with a SAIDI impact of 72 minutes, was necessary in March 2015.

It is a great disappointment to everybody at Top Energy that, having made good progress over the last five years in improving the reliability of the network, during FYE 2015 the average connected consumer will have been without an electricity supply for more than 30 hours. Despite this setback, efforts to improve the reliability of the network over time will continue unabated, During FYE 2015 progress to schedule has been made in the delivery of the Network Development Plan and we have completed the replacement of the Kaikohe zone substation and the installation of a new, larger 110/33kV transformer at Kaitaia.

We hope that you find this Asset Management Plan Update a succinct summary of the material changes to our 2014 AMP. We welcome your feedback on the update or any other aspect of Top Energy's business and performance. Feedback can be provided through the Top Energy website at http://www.topenergy.co.nz/contact-us-feedback.shtml or emailed to info@topenergy.co.nz.

Russell Shaw

Chief Executive, Top Energy Ltd

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1. Asset Management Strategy and Delivery

1.1 Asset Management Strategies

Our corporate mission statement is outlined in our Statement of Corporate Intent (SCI) and is:

> *To operate a successful and responsible business and to maximise the value of the Group in the long term, for the benefit of the Shareholders.*

We strive to continually improve our management structure and the manner in which we operate in order to better achieve this objective. Consistent with this strategy of continuous improvement, the following material changes were made during FYE 2015 to the way in which the company manages its network assets.

1.1.1 Organisational Structure

In April 2014 we modified our organisational structure to give Top Energy Networks (TEN) greater control over the implementation of the AMP. In particular:

- The asset inspection function has been transferred from Top Energy Contracting Services (TECS) to TEN and asset inspectors are now employed directly by TEN.
- All network design is now being undertaken in-house by TEN. Previously TECS was responsible for the design of upgrades and modifications to the 11kV and low voltage networks.

1.1.2 Transmission Asset Condition Assessment and Maintenance

In addition, we have contracted Northpower for the condition assessment and maintenance of the 110kV substation and transmission line assets acquired from Transpower. Northpower is a Transpower approved service provider and has access to Transpower's maintenance standards and to condition assessment technologies not readily available to TECS. The contract requires Northpower to maintain the assets to a level no less rigorous than would normally be applied to similar Transpower assets. While this will reduce the amount of work available for TECS, the strategy is designed to maximise the reliability of the existing assets in view of the delay to the commissioning of the second 110kV circuit. This delay is discussed in Section 3.

1.1.3 Planned Supply Interruptions

We have also modified our approach to the management of planned outages. In order to minimise the SAIDI impact of planned outages, in recent years we used generators to maintain supply during the interruption to downstream consumers not directly affected by the outage work. While this strategy has been effective in reducing planned SAIDI, it was driven solely by a desire to minimise SAIDI, as measured by the Commission for information disclosure and DPP assessment. We do not consider this cost effective, since in the longer term the reliability of the network would be enhanced if the cost of operating generators during planned outages was diverted to projects designed to reduce the impact of unplanned interruptions to supply. This view was supported by our consumer satisfaction survey undertaken in April 2014, where a majority of respondents indicated an acceptance of longer and more frequent planned interruptions if this meant that funding on initiatives designed to reduce the probability of unplanned interruptions could be increased.

1.2 ISO 9001 Certification

Following the certification of our public safety management system we have been working towards certification of our quality management system to ISO9001:2008. A certification audit is planned for April 2015.

1.3 Asset Management Maturity Assessment

The organisational restructure described above and the systems and processes that are currently being implemented as part of our initiative to obtain ISO 9001 certification will result in significant improvements to our broader asset management system. We are planning to reassess the maturity of our asset management system as we prepare our 2016 AMP, by which time we hope that the new processes will be bedded into the organisation and their benefits can be assessed in a more meaningful way.

The reassessment will use the Commission's asset management maturity assessment tool (AMMAT) and will be based on the *Guide to Commerce Commission Asset Management Maturity Assessment Tool* published by the Electricity Engineers' Association in May 2014.

We will then work towards developing those areas of our asset management system where scope for improvement is identified in this updated AMMAT assessment, in line with our philosophy of continuously improving our business systems. Strategies and improvement implementation plans will be set out in our 2016 AMP.

2 Levels of Service

As discussed in Section 3, completion of the second 110kV circuit between Kaikohe and Kaitaia has been delayed and commissioning of the full circuit length is not now expected until FYE 2026. Until the full length of the circuit has been commissioned, annual planned shutdowns of the existing 110kV line will continue to be required and the impact of this has been reflected in the forecast impact of planned interruptions shown in Schedule 12d.

The forecast levels of reliability shown in Schedule 12d are unrelated to the regulated quality thresholds that have been determined by the Commerce Commission under its default price-quality path (DPP). These DPP quality thresholds are based on the historic performance of the network and reflect a supply reliability that is significantly lower than the reliability of supply that we have consistently provided consumers in recent years, with the exception of FYE 2015 as discussed below. We expect, given normal weather patterns, to continue to meet the Commission's regulatory requirements notwithstanding the adoption of a revised network development plan.

FYE 2015 has been an exceptionally difficult year for us. On 17 April 2014 our network was hit by the remnants of Tropical Cyclone Ita, which on a single day resulted in a total of 32 high voltage supply interruptions with a total SAIDI[1] impact of 82.9 minutes. Then, on 8 July 2014, our supply area was hit by a further severe weather event that caused winds well in excess of gale force and extensive flooding, which intensively damaged not only our network but also roads and other public infrastructure. While this storm was not categorised as a cyclone, a blocking high pressure area to the south east of New Zealand caused it to remain stationary over the Far North and persist for several days. State Highway 1 was closed for a number of days by a slip south of Kawakawa that has still to be permanently repaired. Over the month of July, we experienced a total of 87 unplanned high voltage interruptions with a total SAIDI impact of 1,362 minutes or almost 23 hours. Finally, just prior to Christmas 2014 we discovered a land slip on the top of the Maungataniwha Ranges, which caused a tower on the 110kV Kaikohe-Kaitaia transmission line to move almost 10 metres and some of the tower members to break. An unanticipated planned outage of this line to replace the damaged structure, with a SAIDI impact of 72 minutes, was necessary in March 2015. The damaged tower supported long spans and was located in isolated and difficult terrain. It was not possible to engineer and fabricate a replacement in time for the planned outage that occurred on 1 February 2015.

The SAIDI minutes noted above directly measure the impact of these extreme events as experienced by consumers. For regulatory assessment purposes, the Commission has specified a normalisation methodology that reduces the impact of such events in order to better measure reliability outcomes that are within management's control. However, the number, severity and duration of these extreme events in a single year means that, even after normalisation, it is likely that we will breach the Commission's SAIDI threshold. The consequences of this could be an investigation by the Commission and a possible inquiry into our performance. We are confident that any such inquiry will find that the breach was due to factors outside our control and that no further action will be taken.

In managing the reliability of the network we will focus on minimising the impact of unplanned interruptions because this is what our consumers have indicated they would prefer. Figure 1 shows the SAIDI impact of unplanned interruptions from FYE 2011 when the current normalisation regime was instituted. The figure shows the impact of the April and July 2014 storms on the reliability of the network and the impact the normalisation process will have on the reliability as reported to and assessed by the Commission. It shows the reliability the current network can deliver in the benign weather conditions of FYE 2013 and the reliability levels currently experienced under more normal weather patterns.

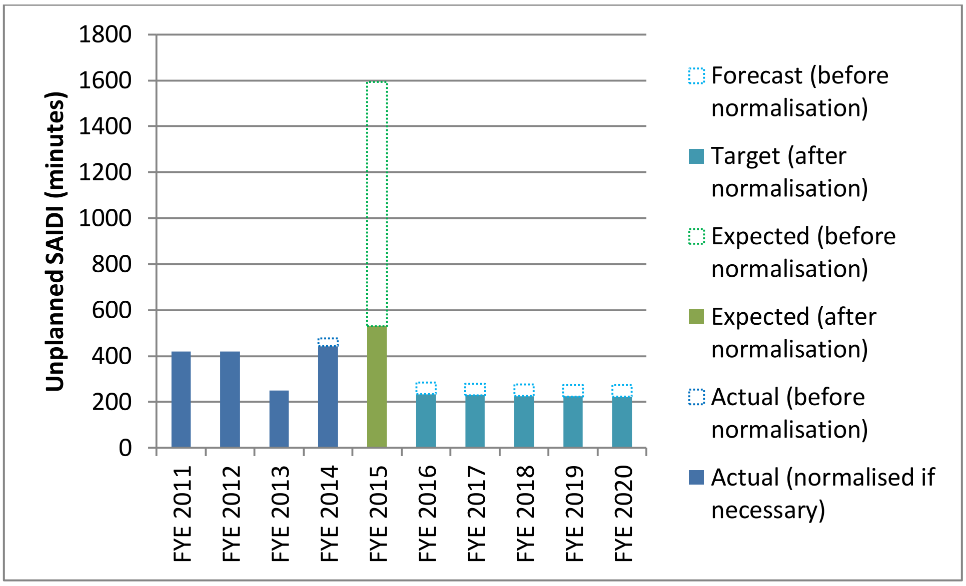
Figure 1 also shows the forecast unplanned SAIDI over the FYE 2016-20 regulatory period both before and after normalisation. The unplanned SAIDI before normalisation reflects the expected performance of our network assuming normal weather patterns (and is consistent with s12d), while the unplanned SAIDI after normalisation reflects the targets we use for internal management purposes[2]. While Top Energy's unplanned reliability targets

[1] SAIDI in an acronym for System Average Interruption Duration Index and measures the cumulative time that the average consumer is without an electricity supply over a measurement period (which for regulatory purposes extends from 1 April until 31 March the following year).

[2] We set network reliability targets using normalised measures on the basis that the normalisation process is designed to lessen the impact of factors that are outside management's ability to control.

for the FYE 2016-20 period appear challenging in comparison with our historic performance, our current network reliability is adversely impacted by interruptions caused by the 33kV network. These interruptions are expected to reduce significantly after the completion of the 33kV protection upgrade in FYE 2016.

Figure 1: Actual and Target Unplanned SAIDI



3 Network Development

3.1 Uncertainties in the Demand Forecast

We have been in discussions with representatives of the new owner of the Peppers Carrington Resort on the Karikari Peninsula, who is currently seeking resource consent for a significant expansion to the existing development. Should this expansion proceed, demand will exceed the capacity of the 11kV feeder that currently supplies the peninsula, but the extent of any capacity expansion required is not clear. Initially the installation of one or more voltage regulators may suffice but should the magnitude of the development approach the level envisaged by the owner a new 33kV subtransmission line and substation could be required.

At this point, resource consent for the proposed development has not been granted and no provision has been made in our capital expenditure forecast or works programme for any expansion of the supply capacity to the peninsula. We will continue to monitor the situation and should the development proceed, provision for any necessary capacity expansions will be included in future AMP forecasts.

3.2 Changes to the Network Development Plan

3.2.1 Wiroa-Kaitaia 110kV Line

In the 2014 AMP, commissioning of the Wiroa-Kaitaia 110kV line was forecast for FYE 2018. However, over the past year a number of developments have occurred, which have necessitated a revision to the construction schedule. In particular:

- Progress on the acquisition of property rights for the line route has been far slower than anticipated. The line will need to cross Maori land and, notwithstanding any agreement by the beneficial owners, approval of the Maori Land Court will be needed before easements can be granted. Our experience in securing the route for the Kaikohe-Wiroa line is that obtaining Maori Land Court approval is a very lengthy process that cannot be accelerated. Furthermore, a small number of landowners along the proposed route are strongly opposed to construction of the line across their land and it may be necessary to resort to compulsory acquisition under Section 186 of the Resource Management Act 1991. We now estimate that it will take until at least FYE 2018 before property rights over the full route can be secured and we consider that it would not be prudent to commence construction of the line prior to this.
- Our forecast cost of this line in the 2014 AMP was a high level estimate based on the budgeted costs for Stage 2 of the Kaikohe-Wiroa 110kV line. Out-turn costs for this project are now available, and it is apparent that the initial project budget was too low. In addition, further costs that were not incurred in the Kaikohe-Wiroa project have been identified, including additional property rights acquisition costs and additional construction costs due to the difficult terrain. Hence our forecast total project cost is now $44.2 million, compared to the estimated $33.7 million in the 2014 AMP. Nevertheless, this updated estimate still benchmarks well against the costs of similar projects elsewhere in the industry.
- Given our forecast revenues and the amount of our available debt facility, construction of the full line length immediately after the securing of property rights in FYE 2018, would require the deferral of other projects designed to improve the reliability of the distribution network. Following a recent review of the network development plan, we now consider that it would be unwise to focus all our resources on a single project and that a more balanced approach to developing the network is required. Of particular concern are the consequences of delaying the installation of an alternative supply to feed the Russell township and delaying the construction of the Kaeo substation. The need for these two projects is discussed in the following sections.

Given these changes and the need to optimise the capital investment programme across all parts of the network, we have now decided to stagger the construction of the Wiroa-Kaitaia line over the seven year period FYE 2019-2026. At this stage we anticipate that the line will be constructed in three sections. The section between Wiroa and the Kaeo tee-off will be constructed first and operated at 33kV to provide a second incoming supply to the Kaeo substation. Likewise, as discussed further below, the section between Kaitaia and Taipa will be constructed and operated initially at 33kV to provide a second incoming supply to the new Taipa substation. The middle section between Kaeo and Taipa is likely to be the last of the three sections of the project to be built.

3.2.2 Kaeo Substation

Supply to the coastal belt north of Waipapa, as well as the inland rural area to the north-west, is becoming increasingly constrained. The area served is large and development of the coastal strip between Matauri Bay and Whangaroa is becoming more intensive. Continuing to supply this area through three long heavily loaded 11kV feeders is no longer tenable in terms of either supply capacity or reliability. While the construction of the planned new substation at Kaeo is categorised as system growth because it will increase the capacity of the incoming supply to this area, it will also improve the reliability of the 11kV network it supplies by increasing the number of feeders and significantly reducing the number of customers on each feeder. This will improve both SAIDI and SAIFI[3] by reducing the number of customers impacted by an individual fault.

In the 2014 AMP, completion of the substation was scheduled for FYE 2022, although we hoped that one transformer would be commissioned in FYE 2021. We now plan to advance this schedule by four years and to complete the substation in FYE 2018. Initially there will be only one incoming 33kV circuit, as it will not be possible to provide a second incoming supply until the southern section of the new 110kV line is completed, hopefully by FYE 2022. However, even with only one incoming supply, we anticipate that supply reliability in the area will improve significantly once the new substation has been completed.

3.2.3 Reinforcement of the Supply to Russell

There is an increasing level of consumer dissatisfaction over reliability of supply on the Russell peninsula, and in particular within the Russell township.

Under normal operating conditions almost all load on the Russell peninsula is supplied through the Russell express feeder and the submarine cable across the Waikare Inlet. There is a second submarine cable between Opua and Okiato Point but, as this is connected to the heavily loaded Opua feeder, the load that can be transferred through this feeder is limited and is much lower than the rated capacity of the cable. Under normal operating conditions the load supplied through this second cable is limited to the area around Okiato Point. A further problem is that the termination point for both submarine cables is at Okiato Point and there is no alternative point of injection into the 11kV network. This means that, should a fault occur between Okiato Point and Russell, the township will lose supply until the fault is repaired as there is no way to restore supply around the fault to consumers not directly affected.

What is needed is a second point of injection into the distribution network at the north end of the Russell township and a reconductoring of the distribution network within the town so that, if necessary, the load on the peninsula can be supplied from this injection point. Two possibilities for this second point of injection are currently being considered:

- Installation of a third submarine cable, which would be routed between Paihia and Russell. This would be rated at 33kV to provide for the eventual construction of a zone substation at Russell but would initially be operated at 11kV. This solution would have the additional advantage of taking supply from the Haruru Falls zone substation, which would offload Kawakawa, which is becoming increasingly heavily loaded.
- Construction of an 11kV underground cable between Okiato Point and Russell to provide an alternative feed into Russell and enable the newer submarine cable from Opua to be better utilized. This alternative would also involve some reconductoring of the distribution network around Opua to relieve constraints on the supply side of the submarine cable.

In the 2014 AMP reinforcement of the supply to Russell was not planned until FYE 2020-23. We now plan to reconductor the 11kV network within Russell township during this coming year, FYE 2016, and to complete the second point of injection by FYE 2020. Planning studies will be undertaken in the coming year to determine the preferred reinforcement alternative with detailed design to follow. Construction work on the second injection point will commence in FYE 2019, following completion of the Kaeo substation.

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[3] SAIFI is an acronym for System Average Interruption Frequency Index, which is a measure of the number of supply interruptions experienced during a measurement period by the average consumer connected to the network.

Expenditure on this project is categorised as network growth capex as it will increase the supply capacity into the peninsula, particularly if a third submarine cable is installed.

3.2.4 Existing Transmission Assets

As discussed in Section 3.2.1, full completion of the Wiroa-Kaitaia 110kV line is not now expected until FYE 2026, just beyond the end of the planning period of this AMP Update. This means that most consumers in the northern part of the supply area will continue to be subjected to annual planned supply interruptions, lasting around 8 hours, through until FYE 2025.

There will also be a continuing risk of unplanned interruptions arising from a fault on the existing transmission circuit between Kaikohe and Kaitaia. We have examined this risk in some detail and found that:

- Historically the reliability of this line has been good, and most widespread unplanned supply interruptions in the northern area resulting from transmission system events have been due to faults occurring outside our supply area. An exception was an extended supply interruption on 21 April 2013 lasting more than three hours, which was due to a lightning strike rather than an equipment failure or tree contact. There have been no unplanned interruptions due to faults on our 110kV system so far in FYE 2015, notwithstanding the two abnormally severe storms described in Section 2. The landslip, also described, in Section 2, did not cause an unplanned supply interruption and was found during a routine asset inspection.
- It is not possible to completely eliminate the risk of unplanned outages of any electricity transmission line. However the probability of such outages can be reduced if enhanced inspection and maintenance practices are put in place. To this end, as discussed in Section 1.1.2, we have contracted Northpower to inspect and maintain our 110kV assets. Northpower is a Transpower certified transmission asset maintenance contractor and will be required to maintain the assets in full compliance with Transpower's maintenance standards. Northpower also has access to condition assessment technologies not readily available to us and a scheduled condition assessment of these assets, with all identified defects prioritized by risk, was completed in December 2014.

We will continue to invest in the maintenance of these assets, with the aim of gradually improving their condition. Over the last year five supporting structures have been replaced using live line methodologies and two further structures were replaced during the recent planned outages. Planning is underway for the replacement of 17 further structures over the next two years. We will continue to ensure that the level of maintenance on our existing 110kV assets will be sufficient to ensure an ongoing improvement in the condition of these assets over time and, where possible, will use live line maintenance techniques to minimise disruption to consumers.

3.2.5 Moerewa Substation Rebuild

The 2014 AMP provided for a progressive rebuild of the Moerewa substation, involving the replacement of the outdoor 33kV and 11kV switchboards and the subsequent replacement of the existing transformers with 9/15MVA units occurring progressively over the period FYE 2015-2022. This work has been accelerated. A new 11kV switchboard was installed in a new switchgear building in FYE 2015. Installation of a new 33kV switchboard and replacement transformers is now planned for completion in FYE 2016. This will release the mobile substation for installation elsewhere.

Previous AMPs identified potential new meat or dairy processing industrial load at Moerewa. We now consider it very unlikely that this load will materialise and as incremental load growth in this area is flat or negative, 3/5MVA transformers will now be installed.

3.2.6 Other Changes

Other changes to the network development plan as set out in the 2014 AMP are relatively minor. There have been small changes to the timing of some other larger subtransmission projects and some reprioritisation of distribution network upgrade and renewal works.

3.2.7 Budgetary Impact

The overall budgetary impact of these changes has been small as expenditure allocated to the construction of the 110kV line between Wiroa and Kaitaia will now be used to accelerate the Moerewa and Kaeo substations and the upgrade of the supply to Russell. Table 1 compares the forecast capital expenditure on network assets in s11a of this AMP Update with the corresponding forecast in the 2014 AMP and shows that over the FYE 2016-20 this expenditure is now expected to be marginally higher than the forecast in the 2014 AMP.

Table 1: Capital Expenditure on Network Assets ($000 in nominal dollars)

FYE	2016	2017	2018	2019	2020
2015 AMP Update	16,318	19,665	19,656	17,092	19,147
2014 AMP	16,730	19,478	18,269	16,779	18,919
Change	(412)	187	387	313	228
Change (%)	(2.5%)	1.0%	2.1%	1.9%	1.2%

4 Lifecycle Asset Management

The delay in the construction of the 110kV Wiroa-Kaitaia line has permitted some increase in maintenance expenditure over FYE 2016-18. However, with the commencement of line construction in FYE 2019, the increases in maintenance expenditure beyond FYE 2019 that were forecast in the 2014 AMP have had to be scaled back. The overall impact of this reprioritisation over the total AMP planning period is minor.

5 Appendices

5.1 Asset Management Plan Schedules

Schedule 11a	CAPEX Forecast
Schedule 11b	OPEX Forecast
Schedule 12a	Asset Condition
Schedule 12b	Capacity Forecast
Schedule 12c	Demand Forecast
Schedule 12d	Reliability Forecast
Schedule 14a	Mandatory Explanatory Notes on Forecast Information

5.2 Appendix E – Certification for Year Beginning Disclosures

TOP ENERGY®
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Certification for Year-beginning Disclosures

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure Determination 2012

We, Paul Anthony Byrnes and Gregory Mark Steed, being directors of Top Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge –

a) The following attached information of Top Energy Limited prepared for the purposes of clause 2.6.1 and subclauses 2.6.3(4) and 2.6.5(3) of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

P A Byrnes

G M Steed

31 March 2015

EDB Information Disclosure Requirements
Information Templates
for
Schedules 11a–13

Company Name	Top Energy Ltd
Disclosure Date	31 March 2015
AMP Planning Period Start Date (first day)	1 April 2015

Templates for Schedules 11a–13 (Asset Management Plan)
Template Version 3.0. Prepared 13 December 2013

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Disclosure Template Guidelines for Information Entry

These templates have been prepared for use by EDBs when making disclosures under subclauses 2.6.1(4), 2.6.1(5) and 2.6.5(5) of the Electricity Distribution Information Disclosure Determination 2012. Disclosures made under subclauses 2.6.1(4) and 2.6.1(5) must be made before the start of each disclosure year. Disclosures made under subclauses 2.6.5(5) must be made within 5 months after the start of the disclosure year. The information disclosed under 2.6.5(5) should be identical to that disclosed under 2.6.1(4) and 2.6.1(5).

Under clause 2.6.3, EDBs can elect to complete and publicly disclose before the start of the disclosure year, an **AMP update**.
EDBs can elect to complete and publicly disclose an AMP update instead of a full AMP in the following years:
- 31 March 2014
- 31 March 2015

If electing to complete an AMP update, EDBs can choose to not complete and disclose Schedule 13: Report on Asset Management Maturity Table. Schedule 13 sheet should be removed if not completed.
If disclosing a Full AMP, EDBs must complete and disclose Schedule 13.

Company Name and Dates

To prepare the templates for disclosure, the supplier's company name should be entered in cell C8, the date of the first day of the 10 year planning period should be entered in cell C12, and the date on which the information is disclosed should be entered in cell C10 of the CoverSheet worksheet.
The cell C12 entry (planning period start date) is used to calculate disclosure years in the column headings that show above some of the tables. It is also used to calculate the AMP planning period dates in the template title blocks (the title blocks are the light green shaded areas at the top of each template).
The cell C8 entry (company name) is used in the template title blocks.
Dates should be entered in day/month/year order (Example -"1 April 2013").

Data Entry Cells and Calculated Cells

Data entered into this workbook may be entered only into the data entry cells. Data entry cells are the bordered, unshaded areas (white cells) in each template. Under no circumstances should data be entered into the workbook outside a data entry cell.
In some cases, where the information for disclosure is able to be ascertained from disclosures elsewhere in the workbook, such information is disclosed in a calculated cell. Under no circumstances should the formulas in a calculated cell be overwritten.

Validation Settings on Data Entry Cells

To maintain a consistency of format and to guard against errors in data entry, some data entry cells test entries for validity and accept only a limited range of values. For example, entries may be limited to a list of category names or to values between 0% and 100%. Where this occurs, a validation message will appear when data is being entered.

Conditional Formatting Settings on Data Entry Cells

Schedule 12a columns G to K contains conditional formatting. The cells will change colour if the row totals do not add to 100%.

Inserting Additional Rows

The templates for schedules 11a, 12b and 12c may require additional rows to be inserted in tables marked 'include additional rows if needed'.
Additional rows must not be inserted directly above the first row or below the last row of a table. This is to ensure that entries made in the new row are included in the totals.
For schedule 12b the formula for column J (Utilisation of Installed Firm Capacity %) will need to be copied into the inserted row(s).

Schedule 11a & 11b

Schedule 11a requires Capital and Operational Expenditure to be expressed in both nominal and constant prices.
The differences between the nominal and constant prices should reflect EDB expectations of the impact of changes in the costs of its labour, materials and other inputs (ie, inflationary pressures).

Schedule 12b(ii)

The purpose of schedule 12b(ii) is to disclose transformer capacity as at the end of the current year. As the information may not be available in time for disclosures made under subclause 2.6.1(4), but available for disclosures made under 2.6.5(5), EDBs can choose not to disclose transformer capacity under schedule 12b(ii). EDBs who do not disclose transformer capacity under schedule 12b(ii) must disclose the information in schedule 9e(iii). Accordingly, the Excel template has been modified to allow the value "N/A" to be entered into these input cells.

Schedule 12d Report Forecast Interruptions and Duration sub-network disclosures

If the supplier has sub-networks, schedule 12d must be completed for the network and for each sub-network. A copy of the schedule 12d worksheet must be made for each sub-network.

Schedule 13 Report on Asset Management Maturity

The name of the standard applied (eg, 'PAS55') must be entered in cell K4.

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2015 – 31 March 2025**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10	Consumer connection		1,475	1,473	1,766	1,809	1,852	1,880	1,909	1,939	1,969	1,999	2,030
11	System growth		4,866	2,276	5,864	6,400	6,992	5,075	7,247	8,025	7,131	4,937	2,296
12	Asset replacement and renewal		8,469	7,830	5,843	6,728	6,657	9,095	6,195	6,928	11,495	7,770	9,458
13	Asset relocations		-	-	-	-	-	-	-	-	-	-	-
14	Reliability, safety and environment:												
15	Quality of supply		9,339	4,573	6,036	4,720	1,591	3,096	6,966	6,096	3,153	6,702	10,546
16	Legislative and regulatory			-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment		620	167	156	-	-	-	-	-	-	-	-
18	**Total reliability, safety and environment**		9,959	4,740	6,192	4,720	1,591	3,096	6,966	6,096	3,153	6,702	10,546
19	**Expenditure on network assets**		24,769	16,318	19,665	19,656	17,092	19,147	22,318	22,988	23,748	21,408	24,330
20	Non-network assets		105	150	261	267	274	278	282	286	291	295	300
21	**Expenditure on assets**		24,874	16,469	19,926	19,923	17,365	19,425	22,600	23,274	24,038	21,703	24,630
22													
23	*plus* Cost of financing		390	153	327	957	288	601	198	850	800	255	817
24	*less* Value of capital contributions		600	1,042	1,326	1,358	1,390	1,412	1,434	1,456	1,478	1,501	1,524
25	*plus* Value of vested assets		15	26	26	27	55	56	56	86	87	89	120
26													
27	**Capital expenditure forecast**		24,679	15,605	18,954	19,549	16,318	18,669	21,421	22,755	23,447	20,546	24,042
28													
29	Value of commissioned assets		23,375	13,065	9,500	29,768	11,641	24,858	11,634	23,586	31,788	12,139	20,487

30			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
32			**$000 (in constant prices)**										
33	Consumer connection		1,475	1,443	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693
34	System growth		4,866	2,229	5,621	5,989	6,390	4,568	6,424	7,006	6,131	4,180	1,915
35	Asset replacement and renewal		8,469	7,670	5,601	6,296	6,084	8,187	5,492	6,049	9,883	6,579	7,887
36	Asset relocations		-	-	-	-	-	-					
37	Reliability, safety and environment:												
38	Quality of supply		9,339	4,480	5,785	4,417	1,455	2,787	6,175	5,322	2,711	5,675	8,794
39	Legislative and regulatory		-	-	-	-	-	-					
40	Other reliability, safety and environment		620	163	149	-	-	-					
41	**Total reliability, safety and environment**		9,959	4,643	5,935	4,417	1,455	2,787	6,175	5,322	2,711	5,675	8,794
42	**Expenditure on network assets**		24,769	15,985	18,849	18,395	15,621	17,235	19,784	20,069	20,418	18,127	20,288
43	Non-network assets		105	147	250	250	250	250	250	250	250	250	250
44	**Expenditure on assets**		24,874	16,132	19,099	18,645	15,871	17,485	20,034	20,319	20,668	18,377	20,538
45													
46	**Subcomponents of expenditure on assets (where known)**												
47	Energy efficiency and demand side management, reduction of energy losses												
48	Overhead to underground conversion												
49	Research and development												

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2015 – 31 March 2025**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref

57		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
58	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
59	**Difference between nominal and constant price forecasts**	**$000**										
60	Consumer connection	-	30	73	116	159	188	217	246	276	306	337
61	System growth	-	47	244	411	601	507	823	1,019	1,000	757	381
62	Asset replacement and renewal	-	160	243	432	573	908	703	880	1,612	1,191	1,571
63	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
64	Reliability, safety and environment:											
65	Quality of supply	(0)	94	251	303	137	309	791	774	442	1,027	1,752
66	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
67	Other reliability, safety and environment	-	3	6	-	-	-	-	-	-	-	-
68	**Total reliability, safety and environment**	(0)	97	257	303	137	309	791	774	442	1,027	1,752
69	**Expenditure on network assets**	(0)	334	817	1,262	1,470	1,913	2,534	2,919	3,330	3,281	4,041
70	Non-network assets	-	3	11	17	24	28	32	36	41	45	50
71	**Expenditure on assets**	(0)	337	828	1,279	1,494	1,940	2,566	2,955	3,371	3,326	4,091
72												

73		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
74	**11a(ii): Consumer Connection**						
75	*Consumer types defined by EDB**	**$000 (in constant prices)**					
76	All customer types	1,475	1,443	1,693	1,693	1,693	1,693
77							
78							
79							
80							
81	**include additional rows if needed*						
82	**Consumer connection expenditure**	1,475	1,443	1,693	1,693	1,693	1,693
83	*less* Capital contributions funding consumer connection	600	1,021	1,271	1,271	1,271	1,271
84	**Consumer connection less capital contributions**	875	422	422	422	422	422
85	**11a(iii): System Growth**						
86	Subtransmission	4,473	382	10	530	781	-
87	Zone substations	38	321	4,581	4,989	3,797	1,947
88	Distribution and LV lines	231	850	393	341	1,436	2,622
89	Distribution and LV cables	124	677	637	129	378	-
90	Distribution substations and transformers						
91	Distribution switchgear						
92	Other network assets						
93	**System growth expenditure**	4,866	2,229	5,621	5,989	6,390	4,568
94	*less* Capital contributions funding system growth						
95	**System growth less capital contributions**	4,866	2,229	5,621	5,989	6,390	4,568

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2015 – 31 March 2025**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref

			Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
103								
104		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**

105 11a(iv): Asset Replacement and Renewal

			$000 (in constant prices)					
106		Subtransmission	1,717	1,872	1,484	1,241	712	818
107		Zone substations	2,704	3,225	1,331	726	1,662	3,492
108		Distribution and LV lines	2,605	1,404	1,671	2,700	2,466	2,674
109		Distribution and LV cables	1,402	182	173	179	193	187
110		Distribution substations and transformers	41	806	768	1,272	856	828
111		Distribution switchgear		182	173	179	193	187
112		Other network assets						
113		**Asset replacement and renewal expenditure**	8,469	7,670	5,601	6,296	6,084	8,187
114	*less*	Capital contributions funding asset replacement and renewal						
115		**Asset replacement and renewal less capital contributions**	8,469	7,670	5,601	6,296	6,084	8,187

116 11a(v):Asset Relocations

117		*Project or programme**						
118								
119								
120								
121								
122								
123		**include additional rows if needed*						
124		All other asset relocations projects or programmes						
125		**Asset relocations expenditure**	-	-	-	-	-	-
126	*less*	Capital contributions funding asset relocations						
127		**Asset relocations less capital contributions**	-	-	-	-	-	-
128								

129 11a(vi):Quality of Supply

130		*Project or programme**						
131		Wiroa-Kaitaia 110kV line - property rights	852	2,411	4,723	3,611	392	-
132		Wiroa-Kaitaia 110kV Line - construction	10	-	-	-	-	2,294
133		Conusumer specific quality upgrade (e.g. low voltage)	-	286	286	286	286	286
134		Other subtransmission	845	187	95	-	531	-
		Other distribution	1,018	778	8	220	103	-
135		Communications, protection & SCADA	1,206	816	673	299	142	206
136		**include additional rows if needed*	-					
137		All other quality of supply projects or programmes	5,408					
138		**Quality of supply expenditure**	9,339	4,480	5,785	4,417	1,455	2,787
139	*less*	Capital contributions funding quality of supply						
140		**Quality of supply less capital contributions**	9,339	4,480	5,785	4,417	1,455	2,787
141								

142 11a(vii): Legislative and Regulatory

143		*Project or programme**						
144								
145								
146								
147								
148								
149		**include additional rows if needed*						
150		All other legislative and regulatory projects or programmes						
151		**Legislative and regulatory expenditure**	-	-	-	-	-	-
152	*less*	Capital contributions funding legislative and regulatory						
153		**Legislative and regulatory less capital contributions**	-	-	-	-	-	-

Company Name **Top Energy Ltd**
AMP Planning Period **1 April 2015 – 31 March 2025**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
161							
162	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
163	**11a(viii): Other Reliability, Safety and Environment**						
164	*Project or programme**	**$000 (in constant prices)**					
165	Substation security upgrades	500	158	-	-	-	-
166	Lower KWA transformers to ground and install bunding	120	5	149	-	-	-
167							
168							
169							
170	**include additional rows if needed*						
171	All other reliability, safety and environment projects or programmes						
172	**Other reliability, safety and environment expenditure**	620	163	149	-	-	-
173	*less* Capital contributions funding other reliability, safety and environment						
174	**Other reliability, safety and environment less capital contributions**	620	163	149	-	-	-
175							
176							
177							
178	**11a(ix): Non-Network Assets**						
179	**Routine expenditure**						
180	*Project or programme**						
181							
182							
183							
184							
185							
186	**include additional rows if needed*						
187	All other routine expenditure projects or programmes	105	147	250	250	250	250
188	**Routine expenditure**	105	147	250	250	250	250
189	**Atypical expenditure**						
190	*Project or programme**						
191							
192							
193							
194							
195							
196	**include additional rows if needed*						
197	All other atypical projects or programmes						
198	**Atypical expenditure**	-	-	-	-	-	-
199							
200	**Non-network assets expenditure**	105	147	250	250	250	250

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2015 – 31 March 2025**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref												
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,778	1,531	1,565	1,603	1,641	1,666	1,692	1,718	1,745	1,772	1,799
11	Vegetation management	1,985	2,083	1,626	1,668	1,710	1,738	1,880	1,911	1,950	2,078	2,008
12	Routine and corrective maintenance and inspection	861	1,470	1,494	1,540	1,587	1,621	1,769	1,807	1,852	1,986	1,924
13	Asset replacement and renewal	800	1,133	1,163	1,197	1,231	1,255	1,280	1,306	1,332	1,358	1,385
14	**Network Opex**	5,424	6,217	5,849	6,008	6,169	6,281	6,622	6,742	6,879	7,194	7,116
15	System operations and network support	2,936	3,452	4,461	4,748	4,888	5,010	5,157	5,286	5,442	5,578	5,742
16	Business support	3,040	3,516	3,580	3,646	3,713	3,781	4,151	4,234	4,344	4,431	4,520
17	**Non-network opex**	5,976	6,968	8,041	8,394	8,601	8,791	9,308	9,520	9,786	10,009	10,262
18	**Operational expenditure**	11,400	13,185	13,890	14,402	14,770	15,072	15,930	16,262	16,665	17,203	17,378
19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,778	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
23	Vegetation management	1,985	2,040	1,559	1,561	1,563	1,565	1,667	1,669	1,677	1,759	1,675
24	Routine and corrective maintenance and inspection	861	1,440	1,432	1,441	1,450	1,459	1,568	1,577	1,592	1,682	1,604
25	Asset replacement and renewal	800	1,110	1,115	1,120	1,125	1,130	1,135	1,140	1,145	1,150	1,155
26	**Network Opex**	5,424	6,090	5,606	5,622	5,638	5,654	5,870	5,886	5,914	6,091	5,934
27	System operations and network support	2,936	3,381	4,276	4,443	4,468	4,510	4,571	4,615	4,679	4,723	4,788
28	Business support	3,040	3,444	3,431	3,412	3,394	3,403	3,680	3,696	3,735	3,752	3,769
29	**Non-network opex**	5,976	6,825	7,707	7,855	7,861	7,913	8,251	8,311	8,414	8,475	8,557
30	**Operational expenditure**	11,400	12,915	13,313	13,477	13,499	13,567	14,121	14,197	14,328	14,566	14,491
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses											
34	Direct billing*											
35	Research and Development											
36	Insurance	225	241	245	248	252	252	252	252	252	252	252
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	31	65	103	141	166	192	218	245	272	299
43	Vegetation management	-	43	68	107	147	174	213	243	273	318	334
44	Routine and corrective maintenance and inspection	-	30	62	99	137	162	201	229	260	304	320
45	Asset replacement and renewal	-	23	48	77	106	125	145	166	187	208	230
46	**Network Opex**	-	127	243	386	531	627	752	856	965	1,103	1,182
47	System operations and network support	-	71	185	305	420	500	586	671	763	855	954
48	Business support	-	72	149	234	319	378	471	538	609	679	751
49	**Non-network opex**	-	143	334	539	740	878	1,057	1,209	1,372	1,534	1,705
50	**Operational expenditure**	-	270	577	924	1,271	1,506	1,809	2,065	2,337	2,637	2,887

Company Name	**Top Energy Ltd**
AMP Planning Period	**1 April 2015 – 31 March 2025**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8												**% of asset forecast to be replaced in next 5 years**
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**		
10	All	Overhead Line	Concrete poles / steel structure	No.	-	1.00%	93.00%	6.00%	-	2	4.00%
11	All	Overhead Line	Wood poles	No.	-	12.00%	87.00%	1.00%	-	2	15.00%
12	All	Overhead Line	Other pole types	No.	-	-	-	100.00%	-	4	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	87.00%	13.00%	-	2	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	100.00%	-	-	2	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	3.00%	97.00%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	NA	NA	NA	NA	NA	N/A	NA
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	NA	NA	NA	NA	NA	N/A	NA
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	NA	NA	NA	NA	NA	N/A	NA
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	NA	NA	NA	NA	NA	N/A	NA
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	NA	NA	NA	NA	NA	N/A	NA
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	NA	NA	NA	NA	NA	N/A	NA
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	NA	NA	NA	NA	NA	N/A	NA
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	NA	NA	NA	NA	NA	N/A	NA
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-		100.00%		-	4	10.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	100.00%	-	-	4	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	75.00%	25.00%	-	4	10.00%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	43.00%	37.00%	20.00%	-	3	20.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	NA	NA	NA	NA	NA	N/A	NA
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	5.00%	9.00%	48.00%	38.00%	-	3	15.00%
30	HV	Zone substation switchgear	33kV RMU	No.	NA	NA	NA	NA	NA	N/A	NA
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	NA	NA	NA	NA	NA	N/A	NA
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	20.00%	60.00%	20.00%	-	4	20.00%
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	13.00%	-	69.00%	18.00%	-	3	13.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	4.00%	67.00%	29.00%	-	3	16.00%

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SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref											
42					**Asset condition at start of planning period (percentage of units by grade)**						
43											
44	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.	24.00%	8.00%	56.00%	12.00%	-	4	8.00%
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2.00%	2.00%	92.00%	4.00%	-	2	2.00%
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	NA	NA	NA	NA	NA	N/A	NA
48	HV	Distribution Line	SWER conductor	km	18.00%	7.00%	73.00%	2.00%	-	2	2.00%
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	78.00%	22.00%	-	2	-
50	HV	Distribution Cable	Distribution UG PILC	km	-	-	99.00%	1.00%	-	2	-
51	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	83.00%	17.00%	-	2	-
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	4.50%	-	68.00%	27.50%	-	3	2.50%
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	NA	NA	NA	NA	NA	N/A	NA
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	10.00%	6.00%	69.00%	15.00%	-	2	2.50%
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	NA	NA	NA	NA	-	N/A	NA
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	72.50%	27.50%		2	2.00%
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	8.00%	3.00%	75.00%	14.00%	-	2	2.50%
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.50%	0.50%	86.50%	12.50%	-	2	1.00%
59	HV	Distribution Transformer	Voltage regulators	No.	-	-	77.00%	23.00%	-	3	-
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	100.00%	-	-	2	-
61	LV	LV Line	LV OH Conductor	km	1.00%	2.50%	94.00%	2.50%	-	2	3.00%
62	LV	LV Cable	LV UG Cable	km	1.00%	5.00%	91.00%	3.00%	-	2	
63	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	-	98.00%	2.00%	-	2	
64	LV	Connections	OH/UG consumer service connections	No.	2.00%	5.00%	81.00%	12.00%	-	2	
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	23.00%	26.00%	51.00%	-	3	23.00%
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	100.00%	-	-	3	20.00%
67	All	Capacitor Banks	Capacitors including controls	No.	-	20.00%	80.00%	-	-	2	9.00%
68	All	Load Control	Centralised plant	Lot	-	-	100.00%	-	-	4	-
69	All	Load Control	Relays	No.	-	-	100.00%	-	-		
70	All	Civils	Cable Tunnels	km	NA	NA	NA	NA	NA	N/A	NA

Company Name	**Top Energy Ltd**
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SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
8										
9	Kaikohe	10	17	N-1	1	59%	17	59%	No constraint within +5 years	
10	Kawakawa	6	5	N-1	3	114%	5	126%	Transformer	Sufficent transfer capacity from Moerewa and Haruru is available to accommodate a peak demand contingency.
11	Moerewa	3	8	N-1	2	45%	5	72%	No constraint within +5 years	
12	Waipapa	11	23	N-1	6	48%	23	29%	No constraint within +5 years	
13	Omanaia	2	-	N-0	0	-	-	-	Transformer	Mobile transformer available.
14	Haruru	5	23	N-1	1	23%	23	26%	No constraint within +5 years	
15	Mt Pokaka	2	-	N-0	1	-	-	-	Transformer	Sufficient transfer capacity available to supply most load. Mobile transformer is also available.
16	Kerikeri	6	23	N-1	6	28%	23	30%	No constraint within +5 years	
17	Okahu Rd	9	12	N-1	4	79%	12	83%	No constraint within +5 years	
18	Taipa	6	-	N-0	4	-	-	-	Transformer	Transfer capacity is standby diesel generation installed at the substation site
19	Pukenui	2	-	N-0	0	-	-	-	Transformer	Mobile transformer available.
20	NPL	12	23	N-1	1	51%	23	52%	No constraint within +5 years	
21	Kaikohe 110kV	48	30	N-1	25	159%	30	168%	Transformer	Transfer capacity is Ngawha generation, which is connected to the 33kV subtransmission network and which is normally in operation.
22	Kaitaia 110kV	25	-	-	4	-	-	-	Subtransmission circuit	Firm capacity limited by single incoming 110kV circuit. With the replacement of the second transformer in FYE2020 firm transformer capacity utilisation is forecast to be 64%.
23	Kaeo	-	-	-	-	-	-	-	Subtransmission circuit	New substation. +5 year transformer capacity utilisation forecast to be 50%. However there will be only one incoming subtransmission circuit until the souther section of the 110kV line is completed, expected to be in FYE2022.
24						-			[Select one]	
25						-			[Select one]	
26						-			[Select one]	
27						-			[Select one]	
28						-			[Select one]	

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

30 **12b(ii): Transformer Capacity**

sch ref		(MVA)
31		**(MVA)**
32	Distribution transformer capacity (EDB owned)	-
33	Distribution transformer capacity (Non-EDB owned)	
34	**Total distribution transformer capacity**	-
35		
36	**Zone substation transformer capacity**	280

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SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
7	**12c(i): Consumer Connections**							
8	*Number of ICPs connected in year by consumer type*				**Number of connections**			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
11	*Consumer types defined by EDB**							
12	Residential		323	250	250	250	250	250
13	Commercial		35	5	5	5	5	5
14								
15								
16								
17	**Connections total**		358	255	255	255	255	255
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		-	-	-	-	-	-
21	Installed connection capacity of distributed generation (MVA)		-	-	-	-	-	-
22	**12c(ii) System Demand**							
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)**	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
25	GXP demand		44	46	47	47	48	48
26	*plus* Distributed generation output at HV and above		25	25	25	25	25	25
27	**Maximum coincident system demand**		69	71	72	72	73	73
28	*less* Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**		69	71	72	72	73	73
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		178	192	196	196	200	203
32	*less* Electricity exports to GXPs		16	16	16	15	15	15
33	*plus* Electricity supplied from distributed generation		195	197	197	199	199	199
34	*less* Net electricity supplied to (from) other EDBs			-	-	-	-	-
35	**Electricity entering system for supply to ICPs**		357	373	377	380	384	387
36	*less* Total energy delivered to ICPs		319	339	342	345	349	352
37	**Losses**		38	34	35	35	35	35
38								
39	**Load factor**		59%	60%	60%	60%	60%	61%
40	**Loss ratio**		10.6%	9.1%	9.2%	9.2%	9.1%	8.9%

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Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	248.2	140.0	140.0	140.0	140.0	140.0
12	Class C (unplanned interruptions on the network)	1,592.3	284.0	280.0	275.0	274.0	273.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.88	0.50	0.50	0.50	0.50	0.50
15	Class C (unplanned interruptions on the network)	5.40	3.60	3.50	3.40	3.30	3.20

Company Name	Top Energy Ltd
For Year Ended	31 March 2016

Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012)

1. This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the disclosure year, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

We have derived the nominal capital expenditure forecast by escalating the constant price forecast using the escalation factors that were used by the Commission in its modelling for the *Electricity Distribution Services Default Price-Quality Path Determination 2015*.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the disclosure year, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

We have derived the nominal operational expenditure forecast by escalating the constant price forecast using the escalation factors that were used by the Commission in its modelling for the *Electricity Distribution Services Default Price-Quality Path Determination 2015*.

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