2023-27 Transmission Revenue Reset

Customer Advisory Panel #5

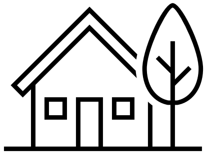
2 September 2020

Keeping in touch during times of loneliness is important for our mental health

AusNet services

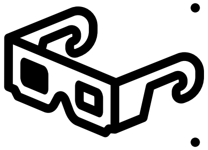
Impact of loneliness

The current COVID19 restrictions can lead to many of us feeling lonely. Loneliness can have major negative effects on our health as a whole, so it is important we keep in touch with our friends and family the best we can during these times.



Effective social activities to minimise the feelings of loneliness

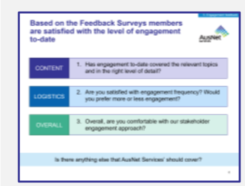
Some lockdown social activity ideas that can be done virtually are:



- Movie/Sports Night
  - Set a time to watch a movie or sports event with friends. Use a video call or messaging app to chat while you're watching.
- Quiz Night
  - Use online quiz platforms such as Kahoot while on a video call with friends.
- Gratitude Group
  - Set up a messaging group where everyone shares something that they are grateful for on a regular basis.

It is important to look after your own health in other ways by maintaining your regular routines, set aside some time for your hobbies (or find some new ones!), and reach out for help when you need to.

Meeting to agree how Deep Dive 1 and 2 feedback should be reflected in the proposal and seek feedback on engagement process

#	Topic	Presenter	Time	Content
1	Safety topic	Danielle Johnstone	*1:30 PM (5 mins)*	
2	Agenda and meeting purpose	Adrian Hill	*1:35 PM (5 mins)*	
3	Summary of Deep Dive 1 and 2 outcomes	Rob Ball	*1:40 PM (10 mins)*	 Summary of key Deep Dive 1 outcomes Summary of key Deep Dive 2 outcomes
4	Adjustments to operating and capital expenditure forecasts to address stakeholder feedback	Rob Ball	*1:50 PM (20 mins)*	 We have adjusted our operating and capital expenditure forecasts to address stakeholder feedback Operating expenditure
5	Feedback on engagement to-date • Deep Dives • Customer Advisory Panel • Briefing Sessions	Danielle Erzetic-Graziani	*2:10 PM (10 mins)*	 Based on the Feedback Surveys members are satisfied with the level of engagement to-date
6	Post-lodgement engagement	Danielle Erzetic-Graziani	*2:20 PM (10 mins)*	 Post-lodgement, the business will continue to engage and reflect customer feedback in our proposal
	Meeting Close		*2:30 PM*	

3. Summary of Deep Dive 1 and 2 outcomes

Summary of key Deep Dive 1 outcomes

Section	Observations	Outcome
Choice of base year	• Attendees heard that AusNet Services remains revenue neutral to the choice of base year due to the operation of the EBSS, however FY21 is preferred over FY20 as it is the latest year for which actuals will be available • While noting that AusNet Services' stated preference for FY21 was driven by updated actuals, attendees also questioned whether the impacts of COVID-19, updated benchmarking results and further FY21 actuals would affect the choice of base year. • AusNet Services' Revenue Proposal will include updated forecasts of FY21 opex and our proposed approach to address COVID-19 impacts, including the further consultation we intend to undertake	• **Maintaining FY21 as base year**
Cyber security step change	• Attendees acknowledged that networks should continue developing cyber security capabilities (despite delays to legislation) but noted there must be a clear narrative explaining how customers will benefit • Given this is a highly technical area, attendees noted it is difficult to comment on the reasonableness of the proposed expenditure • Stakeholders queried why the provision of a secure system is not part of a business as usual 'duty of care'	• **Addressing issues and questions raised by stakeholders in the Revenue Proposal**
Transformer oil step change	• Stakeholders queried how costs and risks should be allocated between consumers and the business and whether the business could recoup expenditure through the supplier or insurer • While AusNet Services considers that managing this risk will increase costs, we will absorb this to address stakeholder feedback and improve the affordability of our proposal	• **Absorbing step change to address affordability concerns**

For more information see Seed Advisory, Deep Dive Workshop One – *Summary Report: AusNet Services Transmission Revenue Reset 2023 – 2027 (July 2020).*

Summary of key Deep Dive 2 outcomes (1/2)

Section	Observations	Outcome
Overview of indicative capex forecast and proposed major station projects	• Attendees queried the scope of major station projects and whether they involve targeted replacements or entire rebuilds. • Attendees keen to understand interactions between Integrated System Plan projects and AusNet Services' major station replacement projects • Stakeholders questioned how AusNet Services accounts for uncertainty in its investment planning, given the rapid rate of change in the energy sector and lengthy asset life (40+ years)	• **Confirmation that the economic assessment framework ensures the most efficient option is progressed, most projects are staged replacements, and sensitivity analysis is conducted to manage uncertainty of key inputs.** • **To explore ISP interactions at AST/AEMO Briefing Session**
Economic assessment framework for major station projects	• Attendees sought clarification and detailed information on baseline risk and data/evidence supporting key assumptions. • Stakeholders queried whether AEMO's Reliability Standard, the value of DER and reputational risk are inputs into AusNet Services' economic assessment. • Attendees engaged in meaningful discussion on non-network options. • Strong interest in refinements made recently by AusNet Services to its safety risk quantification approach • Acknowledgement from some stakeholders that ageing/poor condition assets must be replaced eventually and AusNet Services' approach to deciding this timing appears reasonable	• **Clarification of which inputs are considered within the economic assessment framework (e.g. VCR, DER (through demand forecasts), safety risks) and which are not (e.g. Reliability Standard, reputational risk)** • **Confirmation that the Revenue Proposal and supporting documents will provide detailed information on key assumptions and inputs, including changes made to safety risk approach.**

Summary of key Deep Dive 2 outcomes (2/2)

Section	Observations	Outcome
Major station project case studies	• General comment from stakeholders regarding the need for meaningful discussion on non-network options. • Strong interest in understanding interactions with ISP projects (e.g. impact of project 'Energy Connect' specifically with Red Cliffs project) • Some queried the trade-off between lowest cost overall and the extent to which costs can be spread out? For example, Option 1 and Option 2 for KTS, how does their timing feed into the optimisation strategy • Further detailed queries in relation to the analysis and assumptions, e.g. discount rates, failure rates	• **Confirmation that AST is required to explore non-network options as part of RIT-T process and is investigating (with UED) whether demand management can be used to defer significant upgrades of the Cranbourne Terminal Station** • **ISP interactions would be explored at AST/AEMO Briefing Session, e.g. Sydenham Terminal Station project interaction with Western Vic augmentation** • **Confirmation that the lowest NPV option is generally selected as the preferred solution, regardless of timing of expenditure, to minimise long-term costs to customers** • **Confirmation that the Revenue Proposal and supporting documents will provide detailed information on key assumptions and inputs**
Capex profile and deliverability considerations	• Stakeholders generally acknowledged that some smoothing may be required and the need to consider the trade-offs involved, including which locations and customers could be impacted by deferrals • Ranking projects based on NPV of each project was raised as a possible way to smooth the forecast • Further information was sought on the precise risk impacts, e.g. where and who would they experienced by, what is the baseline risk • One larger user noted it is easier to respond to a high price signal than an unplanned outage that could trip lines and possibly cause damage • Clarify was sought on what deliverability risk actually means in practice for customers	• **Clarified that baseline risk is very close to zero as transmission supply interruptions are rare and the minutes off supply are probably-weighted values** • **Confirmation that any smoothing adjustment could consider a combination of network wide and location specific deferrals.** • **Noted that some projects and programs can be driven by both market and supply risk, though one risk can be a stronger driver than the other** • **Smoothing approaches to be explored, having regard to feedback around price and reliability preferences and relative NPVs of various projects**

Feedback during the session

Topic	Comment/question	Internal response
Deep Dive 1 Base Year	In light of Covid-19, is it too early to state AST will maintain FY21 as its base year?	• As part of the Proposal, AST must nominate a base year (currently F21). AST is not anticipating material impacts to opex in FY21 as a result of COVID and, therefore, no need to change the base year post-lodgement. Furthermore, any changes between forecast and outturn FY21 opex will be offset by the EBSS. Nonetheless, the choice of base year will be a matter for the AER to consider as part of its assessment.
Joint AEMO/AST Briefing Session	Appreciative of the session and found the content very helpful as it addressed AST's responses to the ISP.	• N/A

4. Adjustments to operating and capital expenditure forecast to address stakeholder feedback

We have adjusted our operating and capital expenditure forecasts to address stakeholder feedback

Operating expenditure

- **Transformer oil step change.** Stakeholders expressed concern at Deep Dive 1 about the need for this step change and whether it could be funded instead as a BAU activity. We remain of the view that this is an efficient cost that the regulatory framework allows networks to recover. However, we have chosen to absorb this cost to address stakeholder feedback and improve the affordability of our proposal. This has reduced our forecast opex by **$2.5M**

- **RIT-T step change.** We have also withdrawn a step change for a potential resourcing uplift required for new RIT-T obligations relating to major station projects, following earlier stakeholder concerns around the need for this step change. This has reduced our forecast opex by **$1.8M**

- **Productivity.** Customer Advisory Panel members considered that our forecast should account for expected improvements in productivity. We propose to base our forecast of productivity on the long-term industry trend of 0.31%[1] p.a., consistent with the AER's historical approach. This has reduced our forecast opex by a further **$2.5M** ($4.6M decrease in opex in total) compared to our previous assumption of 0.14%

- We will present our **final opex forecast** at the next CAP meeting on **14 October.**

1. Reflects a preliminary estimate provided by the AER. This will be confirmed when the AER releases its 2020 Transmission Benchmarking Report in November 2020

These adjustments are additional to the efficiency savings we have made in the current period, which we expect to reduce our opex forecast by $90M compared to what would otherwise have been the case

We have adjusted our operating and capital expenditure forecasts to address stakeholder feedback
Capital expenditure (1/4)

- The profile of the network capex forecast is driven by the **optimal economic timing of each project and program**, as determined by our economic assessment framework. However, this framework **does not take into account overall program deliverability considerations** (e.g. the availability of resources, the ability to schedule the necessary planned outages on the transmission network etc.)

- As a result, the **unsmoothed** capex forecast is heavily front-loaded due to the economic timing for several large major station projects falling at the start of the next regulatory period. This exposes the forecast to deliverability risk, which could result in the **unplanned deferral of expenditure** and, therefore, **misalignment between actual and forecast costs** (with customer bills reflecting forecast costs)

- At Deep Dive 2, two alternative, **indicative** capex profiles, each with their own cost and risk implications, were presented to stakeholders:
  - **Major projects smoothed:** Major station projects at South Morang (switching station), Shepparton (connection station) and Keilor Terminal Stations (switching station) are deferred by two years to minimise deliverability risk
  - **Programs smoothed:** Asset replacement programs are back-ended to smooth the overall capex forecast and minimise deliverability risk

- Feedback was sought on each scenario's cost and risk implications, to help **inform which smoothing adjustments, if any, should be applied to the forecast** to address deliverability risk. This feedback is summarised on slides **6** and **7.** A more detailed Deep Dive Summary Report will also be circulated to stakeholders in the coming weeks.

We have adjusted our operating and capital expenditure forecasts to address stakeholder feedback

Capital expenditure (2/4)

- Following Deep Dive 2, we identified smoothing the forecast by deferring selected **major station projects** (rather than deferring **replacement programs**) as the most effective and appropriate way of managing deliverability risk, as it is these projects that are driving the front-loaded profile and, therefore, creating the deliverability risk
- In light of the stakeholder feedback received at Deep Dive 2 regarding the high value placed on both reliability and affordability, it was decided that smoothing the forecast in a way that priorities addressing **supply risk** and **market impact risk** over other risks would best reflect customer views (see **Appendix A** for further information on our economic risk assessment framework)
- Accordingly, **the projects selected for deferral were ranked based on the impact on customers**, where the impact on customers was measured by the **supply risk** and **market impact risk** addressed by each project:
  - **Supply risk.** The risk of supply being lost to customers due to an asset failure
  - **Market impact risk.** The risk that due to an outage the lowest cost generators cannot supply the NEM, resulting in higher wholesale prices.
- Because AusNet Services **will not compromise on the safety of its employees and the general public**, we also included safety risk in this ranking process. However, this did not change the outcome of the ranking process as safety risk is not a material driver for any of the projects
- Other factors we had regard to when selecting projects for deferral included:
  - **Committed projects.** These projects, which account for 7% of proposed major stations capex, are currently being delivered and on track for completion by the first year of the next regulatory period. Timing for these projects was therefore left unchanged
  - **Projects going through RIT-T.** Projects for which RIT-T processes are underway have largely been kept at their economic timing
  - **Interactions with the ISP.** Projects where coordination with ISP projects is necessary to minimise total costs to customers have been timed to coordinate with the relevant ISP project (e.g. SYTS project).

We have adjusted our operating and capital expenditure forecasts to address stakeholder feedback

Capital expenditure (3/4)

- Applying the prioritisation approach described on the previous slide resulted in the deferral of the following major station projects (see **Appendix B** for full project listing):
  - RCTS Transformer and Switchgear Replacement (**deferred by one year**)
  - SMTS 330/220kV Transformer Replacement - Stage 2 (**deferred by two years**)
  - SMTS 500kV GIS Replacement (**deferred by two years**)
  - TTS 66kV Circuit Breaker Replacement (**deferred by one year**)
  - KTS A4 500/220kV Transformer Replacement (**deferred by two years**).

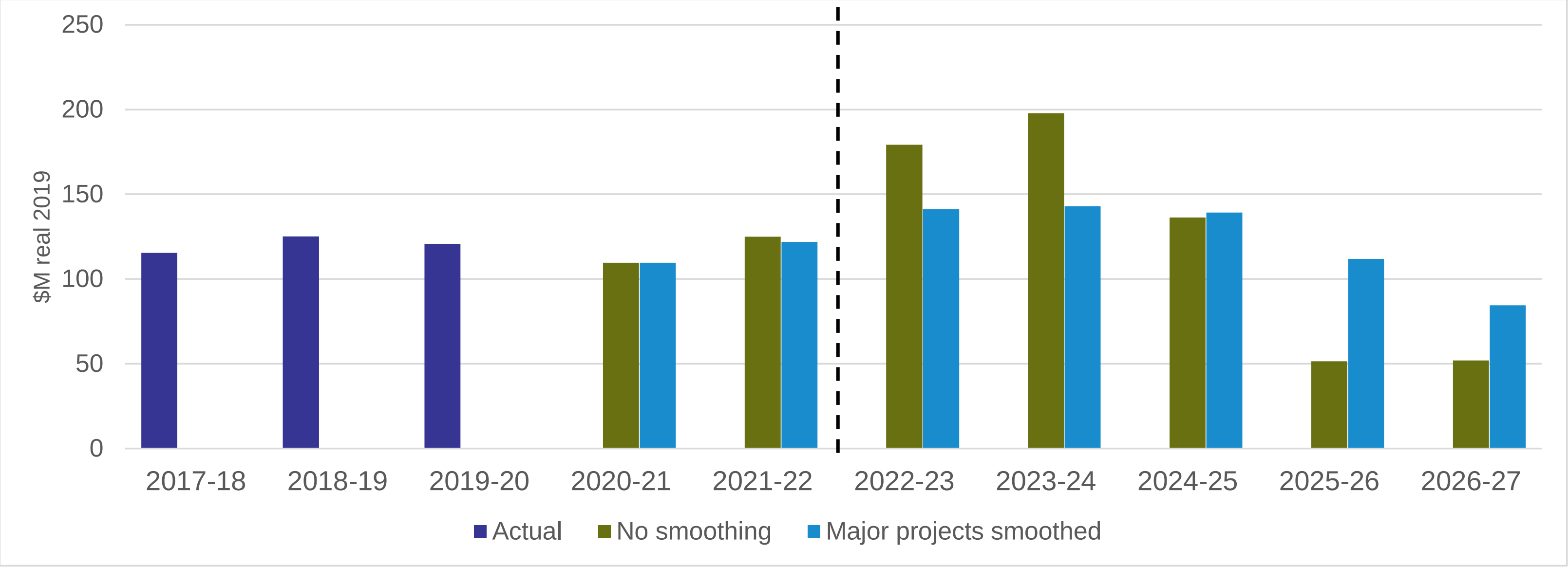
- The project deferrals outlined above have:
  - Addressed the deliverability risk associated with the capital program, **without compromising the reliability and safety of the network** and **ensuring market impact risk is addressed;** and
  - **Mitigated the risk of unplanned deferral of expenditure** and, therefore, improved the accuracy of the capex forecast which, subject to AER approval, will be reflected in customer bills in the next regulatory period.

We have adjusted our operating and capital expenditure forecasts to address stakeholder feedback

Capital expenditure (4/4)

- The unsmoothed and smoothed network capex forecasts are shown in the figure below
- Subject to feedback from the Customer Advisory Panel, and the implications of Deep Dive 3, **the smoothed forecast will be reflected in the Revenue Proposal**
- We will present our **final capex forecast** at the next CAP meeting on **14 October.**

Network capex, smoothed and unsmoothed forecasts ($M, real 2020, direct costs only)



Feedback during the session

Topic	Comment/question	Internal response
Potential opex step change – network support (contracted embedded generation)	Would it be cheaper for customers if AEMO or AST took this on? Has AST considered a cost pass-through? Is this a short or long term consideration?	• AEMO has the cost pass-through built in to their process. AST is exploring whether network support could be procured by AEMO instead, to ensure the lowest cost to customers overall • Long-term as it's unlikely to be a transitional issue due to continued growth in renewable energy and impacts on system security. • AST to explore whether cost pass-through arrangements could be used instead of opex step change.
Productivity assumption	What was the source of AST's 0.31% productivity assumption?	• Based on the indicative data provided by the AER on the transmission industry productivity trend, which the AER will release publicly in November 2020.
Program/Project deferral process	Is there risk to regional areas if certain projects are deferred? Ultimately, trying to gauge impact on Victoria as a whole versus localised risks.	• Our probabilistic planning approach means there will always be some some residual risk on the network. While deferral of projects does invariably increase this risk in some locations, this will not result in supply disruptions unless there is an unplanned outage of an asset.

5. Feedback on engagement to-date

Based on the Feedback Surveys members are satisfied with the level of engagement to-date

CONTENT	1. Has engagement to-date covered the relevant topics and in the right level of detail?
LOGISTICS	2. Are you satisfied with engagement frequency? Would you prefer more or less engagement?
OVERALL	3. Overall, are you comfortable with our stakeholder engagement approach?

Is there anything else that AusNet Services' should cover?

Feedback during the session

Topic	Comment/question	Internal response
Content	Appreciate the detail presented in Deep Dive sessions, contrasted with broad engagement through Customer Advisory/Briefing sessions and one-one engagement sessions. Good opportunity to air grievances individually but then also engage with broader group.	N/A
Logistics	Comfortable with engagement to date.	N/A
Overall	Comfortable with engagement to date. Encouraging post-lodgement engagement and appreciate AST's lead as conduit with AEMO.	• Section 6: Post lodgement engagement was appreciated by Panel members. • Indicative timeline for Deep Dives post lodgement works well with AER timelines.
Other	What regional engagement has AST created in light of all the projects out West? Keen to hear feedback from regional customers.	• AST is engaging regional Victorians, including through recent discussions with our Customer Consultative Committee. There's also been engagement with C&I's through the Customer Advisory Panel process. In Western Victoria there has also been lots of engagement for the Western Victoria Transmission Project, which is a greenfield project being delivered by Mondo.
	Keen to hear detail regarding the ICT forecasts at the next Deep Dive session. In particular, comparison of plans/delivery and associated benefits.	• Material will be made available next Wednesday (9/10). • AST is following the AER's ICT expenditure guidelines, as it did with the EDPR. • Comparison of plans/delivery and associated benefits will be discussed.

6. Post-lodgement engagement

Post-lodgement, we will continue to engage and reflect customer feedback in our proposal

Recent / upcoming engagement activity	
Deep Dive 2 • *Major station projects* • *Capex profile and deliverability considerations*	***11 August***
Briefing Session 2 • *Final 2020 ISP – changes since the draft ISP, implications for Victorian transmission customers* • *Customer bill impacts of ISP projects*	***26 August***
Customer Advisory Panel meeting 5 • *To agree implications of Deep Dives 1 and 2 for the Revenue Proposal*	***2 September***
Deep Dive 3 • ICT capex – transmission-specific programs (Intelligent Networks) • Ground-wire replacement program	**14 September**
Customer Advisory Panel meeting 6 • To agree implications of Deep Dive 3 for the Revenue Proposal • Briefing on Revenue Proposal highlights	**14 October**
Post-lodgement engagement	
One-on-One meetings with stakeholders • To discuss Revenue Proposal highlights and key customer outcomes	**Nov-Feb**
Briefing Session 3 • To inform Deep Dives and highlight implications of new information for our plans	**February**
Further Deep Dives • Topics to be agreed with stakeholders	**April-May**
Customer Advisory Panel meeting 7 • To agree how new information and insights from Deep Dives should be reflected in our Revised Revenue Proposal	**June**

Appendix A

Economic risk assessment framework

We rely on a robust assessment framework to determine the preferred option and its economic timing

Step 1:
Establish Baseline Risk

= **Supply risk** + **Safety risk** + **Environmental risk** + **Market risk** + **Financial risk**

Step 2:
Formulate options to address risk

OPTION 1
OPTION 2
OPTION 3
OPTION 4

Step 3:
Quantify and compare options against Baseline Risk

Conduct sensitivity analysis of assumptions e.g. discount rate, VCR, Asset failure rate, demand growth

Step 4:
Select Preferred Option

Select the option which delivers the greatest net benefits to customers

Step 5:
Determine optimal timing

Conduct sensitivity analysis to determine economical timing to undertake of Preferred Option

Step 1: Establish the baseline risk (I/II)

- **Baseline Risk is defined as the risks that our network and customers would be exposed to under a 'Business As Usual' approach**
- **Establishing Baseline Risk reveals the benefits of alternative options when implementing network or non-network solutions and to consider these alternative options on an equal footing. The AER has commented that this approach reflects best industry practice**
- **The components that make up the Baseline Risk are shown below**
  - The magnitude of each type of risk, and therefore the benefits of implementing a solution, varies from project to project depending on the nature and location of the assets

Risk component	Definition	Approach
Supply Risk	The risk of supply being lost to customers due to an asset failure	• Unserved energy is calculated using AEMO's demand forecasts to estimate the weighted probability of various forced outage scenarios • VCR is sourced from the latest AER data, and weighted by customer groups specific to each project
Safety Risk	The risk of explosion and fire due to asset failures (e.g. design issues), causing injury/fatality to employees or the public.	• Uses a value of statistical life,[2] value of lost time injury[3] and applying a disproportionality factor of 3 (see next slide for more information).
Environmental Risk	The risk arising from oil spills from plant (e.g. power transformers), resulting in costs due to clean-up and environmental impact costs.	• Potential oil spills are valued at $30,000 per event while risks from transformers with poly-chlorinated biphenyls (PCB) oil are valued at $100,000 per event
Market risk	The risk lower cost generators cannot supply the NEM, resulting in higher wholesale prices	• Value of substitute generation costs based on market modelling
Financial Risk	The failure rate-weighted cost of undertaking reactive maintenance or replacing failed assets given the ongoing need for energy	• Uses the cost of emergency asset replacements when major asset failures occur

1. Department of the Prime Minister and Cabinet, "Best Practice Regulation Guidance Note: Value of statistical life' (October 2018)
2. Safe Work Australia, "The Cost of Work-related Injury and Illness for Australian Employers, Workers and the Community: 2012-13 (November 2015)

Step 1: Establish the baseline risk (II/II)

Updated safety assumptions

- **As detailed on the previous slide, the Safety Risk of explosive failure makes up one element of Base Risk. This is calculated by determining the safety risk cost discounted by the likelihood of the following consequences:**
  - Probability x Cost of Lost Time Accident (LTA)
  - Probability x Cost of Death/Serious Injury to the Public
  - Probability x Cost of Death/Serious Injury to Staff.[1]
- **We have updated the assumptions in these two elements since the last reset as follows:**

Probability of safety risk

- Previously, in estimating this probability we assumed that there was a 100% probability that someone was struck and seriously injury in the event of an explosive failure.
- AusNet Services conducted joint analysis with other Victorian distribution networks and determined that the most appropriate probabilities for safety risk for distribution network assets were in the UK Methodology.[1] As there is no published equivalent for transmission assets, we have applied the 132kV values to our transmission network, which are set out below for each asset type and consequence.

Asset Category	Lost Time Accident (LTA)	Death or Serious Injury	Death or Serious Injury (Staff)
132kV Tower	0.014%	0.001%	0.003%
132kV Fittings	0.054%	0.002%	0.011%
132kV OH Tower Line Conductor	0.054%	0.002%	0.011%
132kV UG Cable	0.000%	0.000%	0.000%
132kV CB	0.042%	0.006%	0.314%
132kV Transformer	0.042%	0.006%	0.314%

1. Based on the UK 'DNO Common Network Asset Indices Methodology' (Version 1.1)

Safety cost

- Previously, we used a safety cost of $20 million (including a disproportionate factor) based on the value of statistical life in an Australian Government guidance note, however, the specifics of how this amount was calculated was not transparent.
- We have refined this approach by estimating the cost of the safety consequence using the following :
  - LTA cost of $162,780 (2012-2013 dollars) using the Safe Work Australia, "The Cost of Work-related Injury and Illness for Australian Employers, Workers and the Community: 2012-13 (November 2015)
  - Death/Serious Injury cost of $4.5m using The Australian Government Value of Statistical Life (Department of the Prime Minister and Cabinet, "Best Practice Regulation Guidance Note: Value of statistical life' (October 2018))
- Under the joint analysis with other Victorian distribution networks we have used a disproportionate factor of 3 (representing a single fatality).

Step 2: Formulate options to address risk

- **Once the Baseline Risk is established, we analyse different options in order to identify the Preferred Option**
  - As part of this process, planning is done in conjunction with AEMO and Victorian distributors, taking into account the long term requirements of the network
- **The options that we typically consider for individual projects are shown below**

Option	Description
Baseline / Business as Usual	Used as a reference to quantify the relative benefits of options that address the baseline risk.
Deferred replacement	Defer replacement through asset refurbishment or operational measures. Develop contingency plans for asset failure events e.g. temporary load transfers, holding spares which can be used across a number of stations.
Integrated replacement	Conduct like-for-like replacement of all assets with poor condition score in a single project. In cases where a number of assets require replacement, major station rebuild takes advantage of project synergies not available for single asset replacement.
Staged replacement	Replace highest risk/poorest condition assets, followed by replacement of other deteriorated assets in subsequent years (e.g. 5-10 years later) as separate projects.
Non network alternatives	Use embedded generation and/or demand side response alternatives in combination with network options (hybrid options).

Steps 3 and 4: Compare options against Baseline Risk and select Preferred option

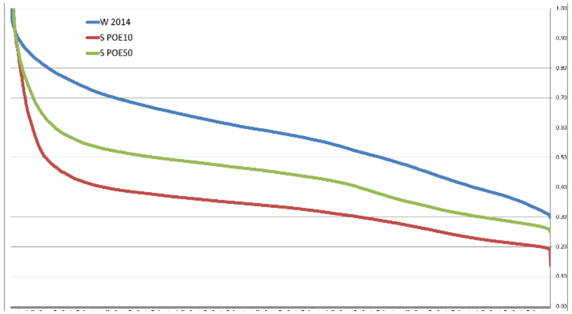
Step 3

- **After identifying all options in Step 2, we quantify their costs and benefits**
  - Costs are determined by:
    - Developing a technical scope of works
    - Applying our standard cost estimating process that utilises standard unit rates (based on recent projects and contracted procurement costs)
  - Benefits (avoided costs) are probability weighted and may include:
    - Supply: the value of energy not supplied to customers
    - Safety: risk cost of injury or death due to explosion
    - Market: risk of increased generation costs
    - Environmental: risk cost of oil spills requiring clean-up
    - Financial: risk costs associated with emergency asset works
    - Avoided costs: reduced maintenance expenditure from replacing existing assets
- **We then conduct net present value (NPV) analysis in order to compare options on an equal basis**

Step 3 cont.

- **To account for uncertainty, we conduct sensitivity analysis on the options:**
  - We do this by comparing the PV cost of each option for different input assumptions
  - Inputs tested include discount rate, VCR, Asset failure rate, demand growth, load profiles etc

Sensitivity analysis input



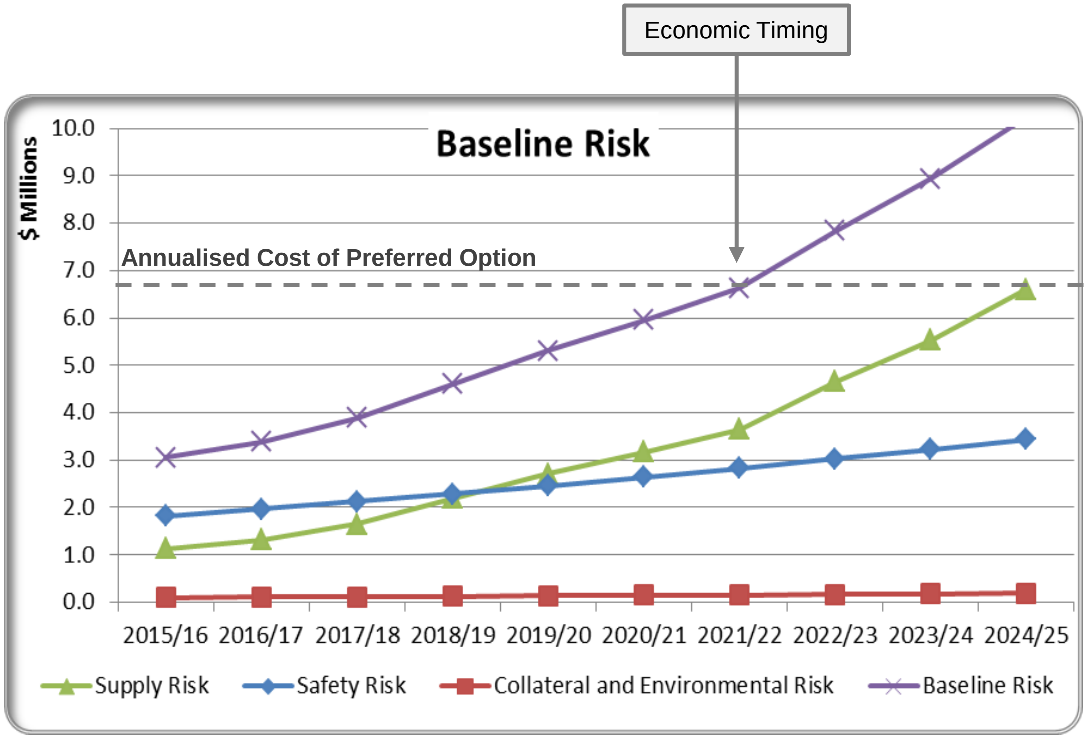
Load profiles of:
- Summer POE10,
- Summer POE50
- Winter load

Step 4

- **We then compare the options and determine which option has the highest NPV (i.e. offers most benefit to customers) in order to identify the Preferred Option**

Step 5: Determining the optimal timing of the Preferred Option

- **We determine the economic timing to complete the Preferred Option project by identifying when the Baseline Risk is equal to the cost of implementing the preferred option**
  - This is the point at which the benefits of the preferred option outweigh the annualised cost of the project[1]
- **Following this, we conduct analysis to test the sensitivity of the economic timing of the Preferred Option**
  - e.g. according to failure rate, demand growth, VCR and the project's capital cost



1. Annualised cost refers to the cost of the project discounted to its present value and spread out over the life of the asset. This allows a comparison of projects with different lifespans on an equal basis.

Appendix B

Major station project listing

Major station projects
Project expenditures

Project name	Station type	Proposed expenditure in 2023-27 ($M real 2020)
Brooklyn Terminal Station Circuit Breaker Replacement	Connection	12.6
East Rowville Terminal Station Redevelopment - Stage 2	Connection	15.2
Frankston Terminal Station Circuit Breaker Replacement	Connection	2.5
Glenrowan Terminal Station Circuit Breaker Replacement	Connection	3.3
Horsham Terminal Station Static VAR Compensator Replacement	Connection	28.5
Horsham Terminal Station Circuit Breaker Replacement	Connection	3.3
Keilor Terminal Station Transformer Replacement	Switching	***61.3***
Moorabool Terminal Station Circuit Breaker Replacement	Switching	16.4
Red Cliffs Terminal Station Transformer and Switchgear Replacement	Connection	***19.7***
Shepparton Terminal Station Transformer Replacement	Connection	15.4
South Morang Terminal Station Transformer Replacement - Stage 2	Switching	37.5
South Morang Terminal Station Switchgear Replacement	Switching	15.4
Sydenham Terminal Station Switchgear Replacement	Switching	58.2
Templestowe Terminal Station Transformer and Circuit Breaker Replacement	Connection	41.8
Thomastown Terminal Station Circuit Breaker Replacement	Connection	12.1
Wodonga Terminal Station - Purchase Spare Transformer	Connection	3.5
Total		**346.7**

**** Case study projects from Deep Dive 2***

Note: Direct costs only (i.e. excludes capitalised overheads)