APPLICATION NOTICE

PROPOSED AUGMENTATION OF GEELONG TERMINAL STATION

November 2008

Contents

Executive Summary

Background and Purpose

This document ("Application Notice") sets out Powercor's application to establish a fourth 220/66 kV transformer at Geelong Terminal Station (GTS). This Application Notice has been prepared in accordance with, and meets the requirements of clause 5.6.6 of the National Electricity Rules (NER). It explains the rationale for the proposed fourth transformer at GTS with reference to the requirements of the regulatory test.

Given that the proposed fourth transformer at GTS is a transmission connection investment, the regulatory test and the provisions in clause 5.6.6 of the NER are not strictly applicable to the proposed investment. Nevertheless, this Application Notice is intended to provide a further opportunity for interested parties to comment on the proposed investment, which has been foreshadowed in the Victorian distributors' annual Transmission Connection Planning Report since 2005.

GTS currently consists of three 150 MVA 220/66 kV transformers and is the main source of supply for over 127,500 customers in Geelong and the surrounding area. The area supplied by the station includes Geelong, Corio, Little River, Meredith, North Shore, Drysdale, Waurn Ponds and the Surf Coast. Growth in summer peak demand at GTS has averaged around 18.5 MW (6.5%) per annum over the last 5 years. The peak load on the station reached 412.9 MW in summer 2008.

The need for investment at GTS

The sustained increase in summer peak demand at GTS exposes customers to reliability risks. It is these reliability risks that give rise to the need for investment at GTS.

The bar chart in Figure 1 below depicts the energy that would not be supplied ("energy at risk") with one transformer out of service at GTS, for a demand forecast that has a 50% probability of being exceeded (the "50th percentile" demand forecast). It also shows the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to customers of the expected (probability-weighted) unserved energy in each year, for the 50th percentile demand forecast.

Figure 1: Annual energy at risk and customer value of expected unserved energy at GTS

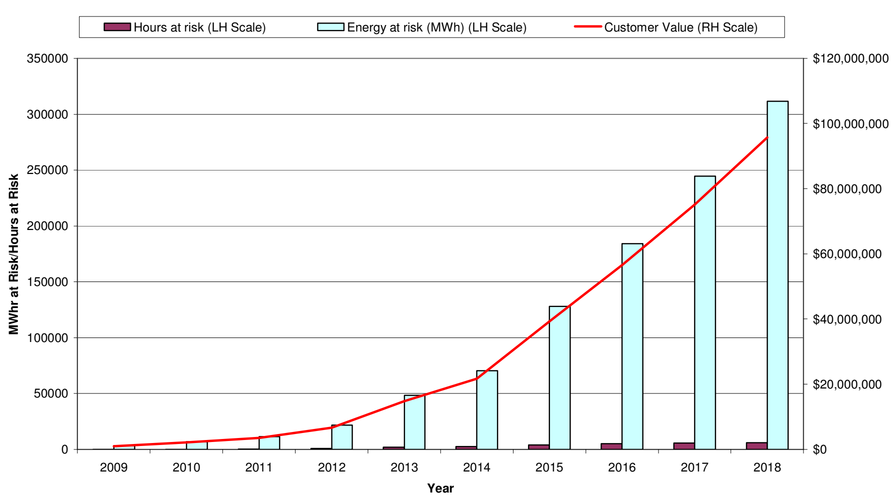


Figure 1 depicts energy at risk if there is a major outage[1] of one of the three transformers at the station. Based on the historical performance of these assets, the risk of a major outage occurring is small (at approximately 1% per annum per transformer) and the expected annual unavailability of each transformer is therefore 0.217%. Given the very low level of expected unavailability of each transformer, the expected value of unserved energy is substantially lower than the energy at risk shown in the bar chart in Figure 1. Nevertheless, using central (median) demand forecasts and weather estimates, the expected value of unserved energy will be more than $2 million per annum by 2010, which is self-evidently a substantial exposure.

In light of the growing demand at GTS and the existing load at risk, Powercor believes that an additional terminal station supply point will eventually need to be established to supply the Powercor distribution area in East Geelong. This additional terminal station will service the significant growth to the south of Geelong and in the Armstrong Creek and Torquay areas. The key issue in this Application Notice is whether the investment to establish a new terminal station should be brought forward to address the more immediate load at risk issues at GTS, or whether an alternative interim measure - namely the installation of a fourth transformer at GTS - is more cost effective.

Net market benefits of proposed augmentation

The possible options to address the reliability issues at GTS are:

- Option 1: Do nothing.

- Option 2: Install a fourth 220/66 kV transformer at GTS.

- Option 3: Establish a new 220/66 kV terminal station in the East Geelong area on an existing vacant terminal station site.

In addition to the above options, Powercor has considered whether demand reduction and embedded generation could provide non-network solutions to the reliability issues at GTS. No proposals from proponents of non-network alternatives have been received, even though Powercor first foreshadowed the need for investment at GTS in the 2005 Transmission Connection Planning Report. Non-network solutions are therefore not considered to be feasible and are not examined further in this Application Notice.

Table 1 below sets out a comparison of the present value of net market benefits of each option over the 10 year horizon adopted for the purpose of this study. Seven scenarios are presented: a “base case” or most likely scenario, and six other scenarios, which represent plausible combinations of upper and lower bound assumptions on the key variables of capital cost, operating cost, discount rate and demand growth.

[1] For the purpose of this analysis, a “major outage” is defined as one that has a mean duration of 2.6 months

Table 1: Results- Economic evaluation of options under various scenarios (Net present value in $ million)

Scenario	Option 1 Do nothing	Option 2 Fourth transformer	Option 3 East Geelong	Net market benefit of Option 2	
				compared to Option 1	compared to Option 3
Base case	-$169.7	-$23.2	-$29.4	**$146.4**	**$6.2**
Scenario A • Upper bound capital cost • Upper bound operating cost • Lower bound discount rate • Central demand growth	-$188.3	-$30.6	-$35.7	**$157.7**	**$5.1**
Scenario B • Upper bound capital cost • Upper bound operating cost • Lower bound discount rate • Lower bound demand growth	-$115.6	-$29.6	-$33.1	**$86.0**	**$3.4**
Scenario C • Upper bound capital cost • Upper bound operating cost • Upper bound discount rate • Lower bound demand growth	-$90.2	-$25.2	-$34.6	**$65.0**	**$9.4**
Scenario D • Lower bound capital cost • Lower bound operating cost • Lower bound discount rate • Central demand growth	-$188.3	-$18.9	-$22.7	**$169.4**	**$3.7**
Scenario E • Lower bound capital cost • Lower bound operating cost • Lower bound discount rate • Lower bound demand growth	-$115.6	-$18.0	-$20.1	**$97.6**	**$2.1**
Scenario F • Lower bound capital cost • Lower bound operating cost • Upper bound discount rate • Lower bound demand growth	-$90.2	-$16.3	-$20.9	**$73.9**	**$4.6**

The results of this analysis demonstrate that the proposed option (Option 2 - installation of a fourth transformer at GTS) maximises net market benefits under all scenarios considered. SPI PowerNet has advised that the earliest possible time by which the fourth transformer could be installed and commissioned is late 2011. Further analysis has demonstrated that deferral of the installation of the fourth transformer beyond the proposed commissioning date of November 2011 would reduce net market benefits.

In light of these results, it is proposed to install a fourth 220/66 kV transformer at GTS, for commissioning into service by late 2011.

Description of the proposed project

The project which is the subject of this Application Notice involves the establishment of a fourth 220/66 kV transformer, to be operated initially on “normal open, auto-close” duty. Under this arrangement, the fourth transformer will operate on “hot stand-by”, and it will be automatically switched into operation if there is a forced outage of any one of the other three normal-running transformers. The transformer is to be double-switched at 220 kV and single switched to the No 2 66 kV bus.

Following the installation of the fourth transformer, Powercor’s network development plans envisage a second stage of works involving the permanent switching of the transformer on load, the creation of an open point between 66 kV buses 2 and 3, and the re-arrangement of 66 kV feeders to balance loads and reduce fault levels at the station. On present demand forecasts, these works are expected to be required in 2012. For the purpose of this Application Notice the estimated costs of the second stage works form part of the proposed project.

The proposed works have no material inter-network impact, so an augmentation technical report (pursuant to clause 5.6.5(c)(5) of the National Electricity Rules) is not required to be included with this Application Notice.

Detailed design and construction of the project is planned to commence in February 2009. The fourth transformer is expected to be placed into service in November 2011.

1 Background and purpose

This document ("Application Notice") sets out Powercor's application to establish a fourth 220/66 kV transformer at Geelong terminal station (GTS). This Application Notice has been prepared in accordance with, and meets the requirements of clause 5.6.6 of the NER. It explains the rationale for the proposed fourth transformer at GTS with reference to the requirements of the regulatory test.

Under the present Victorian regulatory arrangements governing the planning and development of transmission connection facilities Powercor is not strictly required to apply the regulatory test to the proposed investment at GTS. In addition, given that the proposed fourth transformer at GTS is a transmission connection asset, the regulatory test and the provisions in clause 5.6.6 of the NER are not strictly applicable to the proposed investment. Nevertheless, this Application Notice is intended to provide a further opportunity for interested parties to comment on the proposed investment.

In Victoria the five Distribution Businesses ("the DBs") are responsible for planning and directing the augmentation of the transmission facilities that connect their distribution systems to the shared transmission network. Accordingly, clause 3.4 of the Victorian Electricity Distribution Code requires the Victorian DBs to publish an annual Transmission Connection Planning Report setting out, amongst other things:

- details of how the distributors plan to meet the predicted demand for electricity supplied into their distribution networks from transmission connections (terminal stations) over a ten year planning horizon; and
- an assessment of the magnitude, probability and impact of loss of load at each terminal station over that planning horizon.

In the 2005 Transmission Connection Planning Report, Powercor noted the need to address emerging constraints at GTS. That report (and subsequent Transmission Connection Planning Reports) identified the installation of a fourth transformer at GTS as Powercor's preferred network-based solution, and noted that the additional capacity from that augmentation would not be required before 2009. In the 2005 report, Powercor:

- invited proponents of non-network solutions to submit, by 30 September 2006, proposals to alleviate the emerging constraints at GTS;
- provided a period of nine months to enable proponents to research and prepare their proposals; and
- provided an indication of the maximum contribution from Powercor which may be available to embedded generators and/or customers to reduce forecast demand and defer or avoid the transmission connection component of the proposed GTS augmentation.

The 2005 Transmission Connection Planning Report sought proposed solutions from non-network service providers in practically the same manner as specified in the provisions relating to requests for information on alternative options (set out in clause 5.6.5A(c)(4) of the NER and clauses 24 to 29 of versions 3 of the regulatory test). No offers from proponents of non-network alternatives were received. This Application Notice therefore does not consider that there are any feasible non-network solutions that should be examined further.

Accordingly, this paper sets out Powercor's assessment of the network investment options at GTS, prepared in accordance with the principles underpinning the regulatory test. In accordance with the consultation process set out in clause 5.6.6 of the NER, Powercor will consider all submissions made in response to this paper before publishing a final report detailing its plans for addressing the emerging constraint at GTS.

It is widely known in the electricity industry that the regulatory test is a form of cost-benefit analysis for assessing alternative investment options. The current version of the test comprises two distinct limbs:

- the 'reliability limb', which is intended for use in assessing network investments to be undertaken to meet minimum network performance requirements, and which is set out in clause (1)(a) of the test; and
- the 'market benefits limb', for use in assessing other network investments, set out in clause (1)(b).

The investment options at GTS will be assessed in this Application Notice in accordance with the market benefits limb of the regulatory test (clause (1)(b)), which states that an option satisfies the regulatory test if:[2]

> "in all other cases - the option maximises the expected *net economic benefit* to all those who produce, consume and transport electricity in the national electricity market compared to the likely *alternative option/s* in a majority of *reasonable scenarios*. *Net economic benefit* equals the *market benefit* less *costs."*

The italicised terms are defined in the regulatory test.

The proposed investment at GTS is relatively small in scale, and therefore the application of the regulatory test is relatively straightforward when compared with major augmentations. Nevertheless, as already noted, this Application Notice has been prepared in accordance with the concepts and principles underpinning the regulatory test.

---

[2] Clause 1 of Version 3 of the regulatory test as published by the Australian Energy Regulator in its *Final Decision: Regulatory Test version 3* and in the accompanying *Application Guidelines*, in November 2007.

2 Overview of GTS and rationale for the network investment

GTS is a 220/66 kV transmission connection asset owned by SPI PowerNet. It is situated in Norlane, in the Greater Geelong area. The station currently consists of three 150 MVA 220/66 kV transformers and is the main source of supply for over 125,000 customers in Geelong and the surrounding area. The station supply area includes Geelong, Corio, Little River, Meredith, North Shore, Drysdale, Waurn Ponds and the Surf Coast.

Figure 2 below provides an overview of the location and characteristics of GTS.

Figure 2: Overview of GTS

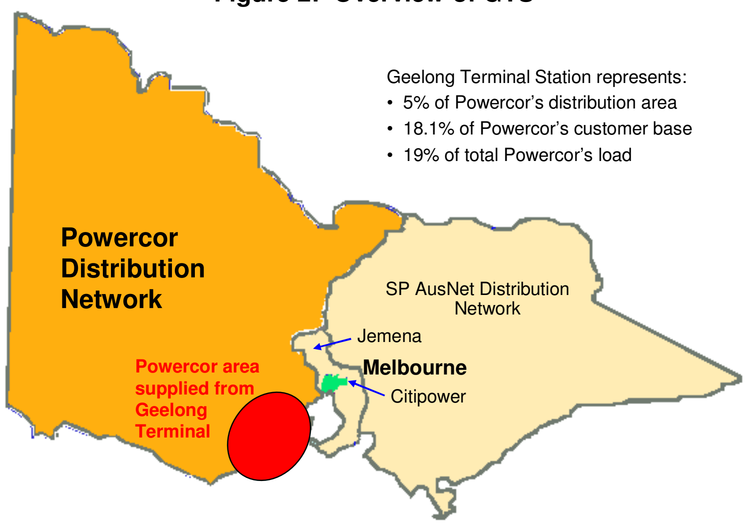
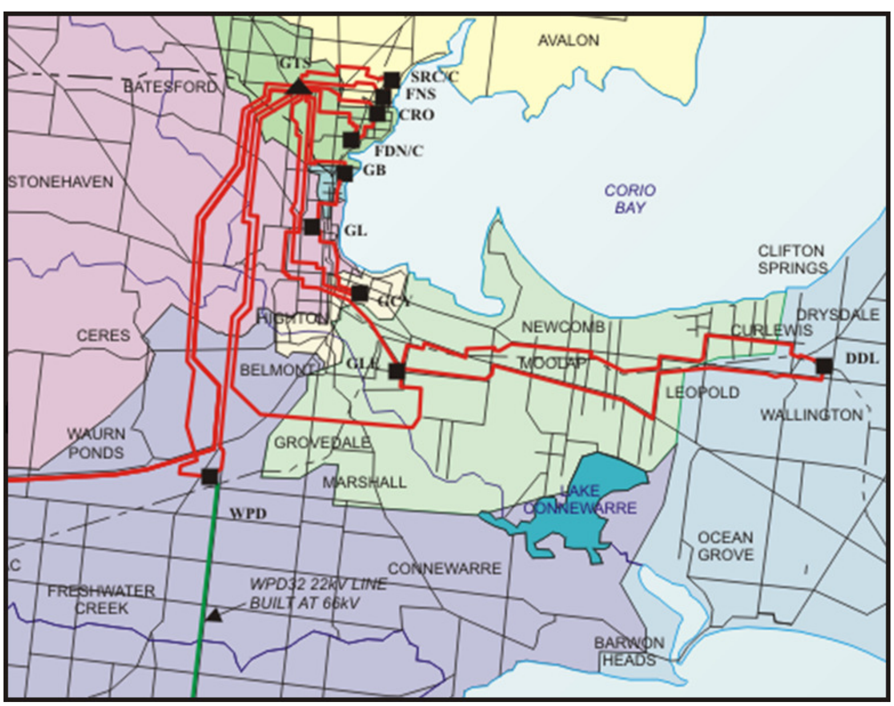


Figure 3 below shows the present 66 kV supply arrangements in the Geelong area.

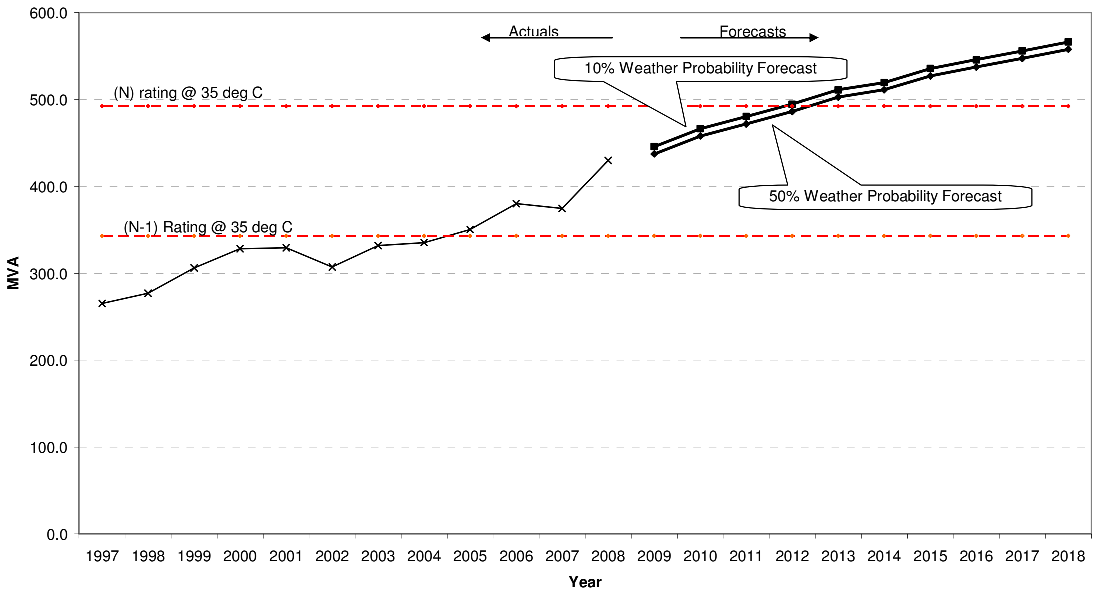
Figure 3: Existing 66 kV supply arrangements in Geelong



Peak demand at GTS occurs in the summer. Growth in peak demand at GTS has averaged around 18.5 MW (6.5%) per annum over the last 5 years. The peak load on the station reached 412.9 MW in summer 2008.

Figure 4 below depicts the 10th and 50th percentile[3] summer maximum demand forecast together with the station's operational "N" rating (all transformers in service) and the "N-1" rating (one transformer out of service) at an ambient temperature of 35°C.

Figure 4: GTS summer peak demand forecasts and installed capacity



The (N) rating shown in Figure 4 indicates the maximum load that can be supplied from GTS with all transformers in service. Exceeding this level will initiate automatic load shedding by SPI PowerNet's automatic load shedding scheme.

The sustained increase in summer peak demand at GTS exposes customers to supply reliability risks, particularly if a major transformer outage[4] occurs over the summer period. It is these reliability risks that create the need for investment in additional capacity at GTS.

Figure 5 below depicts the energy at risk[5] with one transformer out of service at GTS for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand

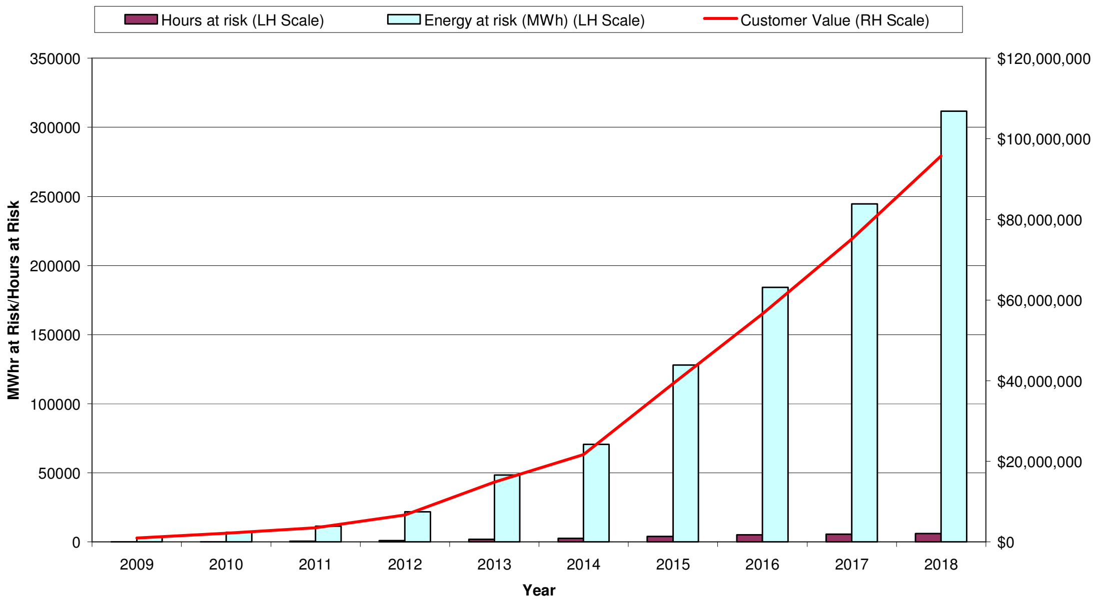
3 The 50th percentile forecast represents the demand forecast at a temperature that has a 50% chance of being exceeded in any one year. The 10th percentile forecast represents the demand forecast at a temperature that has a 10% chance of being exceeded in any one year. This represents the estimated maximum demand that would occur under more extreme (that is, one in ten-year) Summer temperatures.

4 For the purpose of this analysis, it is estimated that on average, 2.6 months is required to repair a transformer and to return it to service following a major failure, during which time, the transformer would not available for service. On this basis, a "major outage" is defined as one that has a mean duration of 2.6 months.

5 "Energy at risk" is, for a given forecast of demand, the total energy that would not be supplied from the terminal station if: a major outage of a transformer occurs at that station in a specified year; the outage has a mean duration of 2.6 months; and no other mitigation action is taken. This statistic provides an indication of the magnitude of loss of energy that would arise in the unlikely event of a major outage of a transformer.

forecast is expected to exceed the N-1 capability rating. The line graph shows the value to customers of the expected unserved energy in each year, for the 50th percentile demand forecast.

Figure 5: Annual energy at risk and customer value of expected unserved energy at GTS



For a major outage of one transformer at GTS during the summer period, there will be insufficient capacity at the station to supply all demand at the 50th percentile temperature for about 198 hours in 2010. The energy at risk at the 50th percentile temperature under N-1 conditions is estimated to be 6,933 MWh in 2010.

An estimate of the value that customers ascribe to unserved energy is required in order to assess the potential costs to customers from the energy at risk[6]. In this regard it is noted that in September 2008 VENCorp published a consultation paper, titled *The Value of Customer Reliability Used by VENCorp for Electricity Transmission Planning*[7], which stated:

> "The VCR [Value of Customer Reliability] for electricity is a measure of the cost of unserved energy and is used in regulatory test assessments for planned augmentations for the Victorian electricity transmission system. The VCR is determined through a customer survey approach that estimates direct end-user customer costs incurred from power interruptions at the sector and state levels."

In September 2008, VENCorp also published a report prepared by Charles River Associates (CRA) and titled *Assessment of the Value of Customer Reliability*[8]. The CRA report provides

---

6 It is noted that clause 4(c) of the regulatory test states that: "In determining the market benefit, the analysis may include the present value of … changes in involuntary load shedding using a reasonable forecast of the value of electricity to consumers".

7 A copy of the consultation paper is available from VENCorp's website at: http://www.vencorp.com.au/index.php?action=filemanager&folder_id=1047&pageID=7742&sectionID=7720

8 A copy of the CRA report is available from VENCorp's website at the address shown immediately above.

an updated estimate of the composite or average value of customer reliability in Victoria for all electricity consumers, being approximately $47,600 per MWh. This estimate of VCR is a weighted average of estimated sector-specific VCRs for residential, commercial, agricultural and industrial customers. For a particular terminal station such as GTS, it is appropriate to apply the sector-specific VCR estimates based on the known composition of customers served by that terminal station. In the case of GTS, this approach produces a VCR estimate of $47,255/MWh. This value is a reasonable forecast of the value of electricity to consumers in accordance with the requirements of clause 4(c) of the regulatory test.

Using the estimated VCR at GTS, the estimated value to consumers of the 6,933 MWh of energy at risk in 2010 is approximately $327.6 million. In other words, at the 50th percentile demand level, and in the absence of any other operational response that might be taken to mitigate the impact of a forced outage, a major outage of one transformer at GTS over the summer period in 2010 would be anticipated to lead to involuntary supply interruptions that would cost consumers $327.6 million.

It is emphasised however, that the probability of a major outage of one of the three transformers occurring over the year is very low, at about 1% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (6,933 MWh) is weighted by this low unavailability, the expected unsupplied energy in 2010 is estimated to be around 45.1 MWh. This expected unserved energy is estimated to have a value to consumers of around $2.1 million (based on a value of customer reliability of $47,255/MWh).

It should also be noted that the above estimates of energy at risk and expected unserved energy are based on an assumption of moderate summer temperatures occurring in each year, and central estimates of demand growth. Under more extreme summer temperature conditions (that is, at the 10th percentile level), the energy at risk in 2010 is estimated to be 9,312 MWh. The estimated value to consumers of this energy at risk in 2010 is approximately $440 million. The corresponding value of the expected unserved energy is around $2.8 million.

These key statistics for the year 2010 under N-1 outage conditions are summarised in Table 2 below.

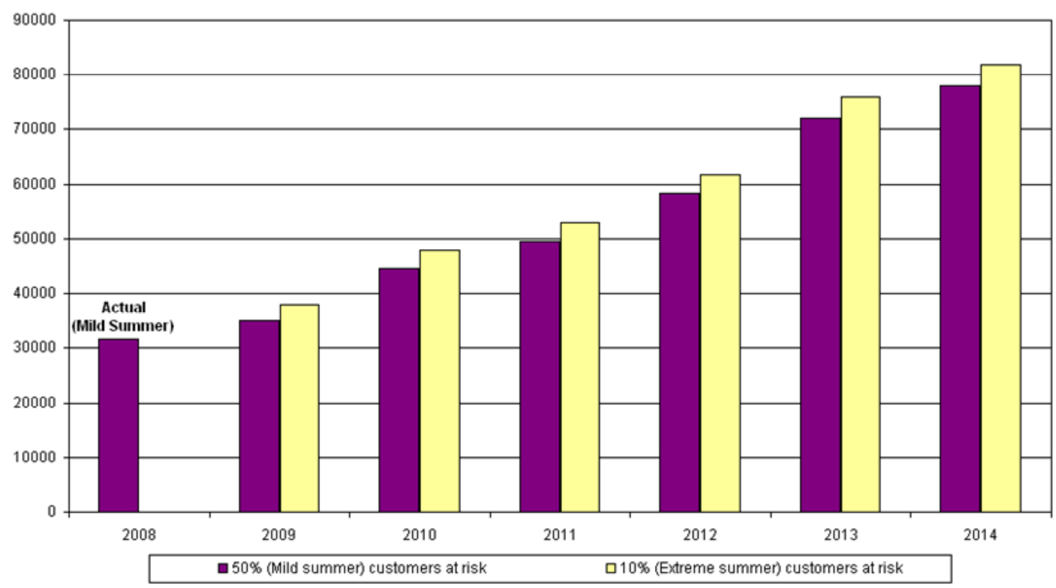
Table 2: Energy at risk and expected unserved energy under N-1 conditions at GTS in 2010

	MWh	**Valued at consumer interruption cost**
Energy at risk, at 50th percentile demand forecast	6,933	$327.6 million
Expected unserved energy at 50th percentile demand	45.1	$2.1 million
Energy at risk, at 10th percentile demand forecast	9,312	$440 million
Expected unserved energy at 10th percentile demand	60.5	$2.9 million

Appendix 1 provides more detailed data on the station rating, demand forecasts, energy at risk and expected unserved energy at GTS for each year to 2018.

If one of the transformers at GTS is taken off line during peak loading times and the N-1 station rating is exceeded, the “OSSCA”[9] automatic load shedding scheme which is operated by SPI PowerNet’s Transmission Operation Centre will automatically reduce load in blocks to within safe loading limits[10]. By 2011, supply to as many as 73,000 Powercor customers could interrupted initially for at least one hour due to insufficient capacity at GTS. Figure 6 below shows the number of customers exposed to the risk of supply interruption in the event of an unplanned outage of a transformer at GTS.

Figure 6: Number of customers exposed to risk of supply interruption for a transformer failure at GTS



In light of the growing demand at GTS and the existing load at risk, Powercor’s strategic network development plan envisages that an additional terminal station supply point at East Geelong is expected to be required in 2023 to supply the Powercor distribution area. This additional terminal station will service the significant growth to the south of Geelong and in the Armstrong Creek and Torquay areas. A question considered in this Application Notice is whether the establishment of the proposed East Geelong Terminal Station should be brought forward to address the more immediate load at risk issues, or whether an alternative interim measure - namely, the installation of a fourth transformer at GTS - is more cost effective.

In broad terms the analysis presented in this Application Notice examines whether net market benefits are maximised by:

- Incurring the additional costs (approximately $13.5 million) of installing a fourth transformer at GTS by late 2011 and subsequent works in 2012 (costing approximately $2 million); constructing the new terminal station at East Geelong in 2023 (at a cost of

---

9 Overload Shedding Scheme of Connection Asset.

10 The OSSCA scheme will automatically open the CLC/WIN 66 kV tie line, and then load shed WPD, GLE, and DDL zone substations.

approximately $60 million including shared transmission network augmentation costs); and thereby minimising the expected costs of unserved energy; or

- Avoiding the costs (approximately $13.5 million) of installing a fourth transformer at GTS by late 2011 and subsequent works in 2012 (costing approximately $2 million); bringing forward the investment at East Geelong Terminal Station (approximately $60 million including shared transmission network augmentation costs) from 2023 to the earliest commissioning date of late 2012; and incurring additional expected unserved energy costs as a result of this later commissioning date.

3 Investment Options

The market benefits limb of the regulatory test requires the assessment of a proposed investment option relative to a number of alternative options, where the term "alternative option" is defined as:[11]

(a) a genuine alternative to the option being assessed, in that it:

(i) delivers similar outcomes to those delivered by the option being assessed; and

(ii) would become operational in a similar timeframe to the option being assessed;

(b) a practicable alternative to the option being assessed in that it is technically feasible.

In determining whether an alternative option is likely, a network service provider must consider a range of matters, including whether the alternative option has a genuine proponent and whether it is commercially feasible.[12] However, the absence of a proponent will not in itself exclude a project from being a likely alternative option for the purpose of the regulatory test.[13]

Clause 11 of the regulatory test requires consideration of whether any option provides prescribed network services as well as other services, and where this is the case, the costs and benefits associated with the other services should be disregarded, and the allocation of costs between prescribed and other services must be consistent with the cost allocation principles in clause 6A.19.2 of the NER, or the relevant jurisdictional guideline, as applicable. For the purpose of clause 11, it is noted that the transmission investment options described below (namely, Options 2 and 3) provide only prescribed transmission services.

In view of these requirements, the remainder of this section outlines both the proposed and alternative options for addressing the reliability issues at GTS.

3.1 Option 1: Do nothing

The first option is to "do nothing". The net cost of this option is the present value of the estimated costs of unserved energy as a result of the emerging reliability issues at GTS. As indicated in Figure 5 in section 2 of this Application Notice, the value of energy at risk rises rapidly as demand continues to grow at GTS. As also shown in Figure 5, it follows that the expected value of unserved energy (which takes account of the low probability of an outage at GTS) will similarly increase.

3.2 Option 2: Proposed Option - Install a fourth transformer

The proposed project involves the establishment of a fourth 220/66 kV 150 MVA transformer at GTS, for operation initially on "Normal Open Auto-close" duty. Under this arrangement, the fourth transformer will operate on "hot stand-by", and it will be automatically switched into operation if there is a forced outage of any one of the other three normal-running

---

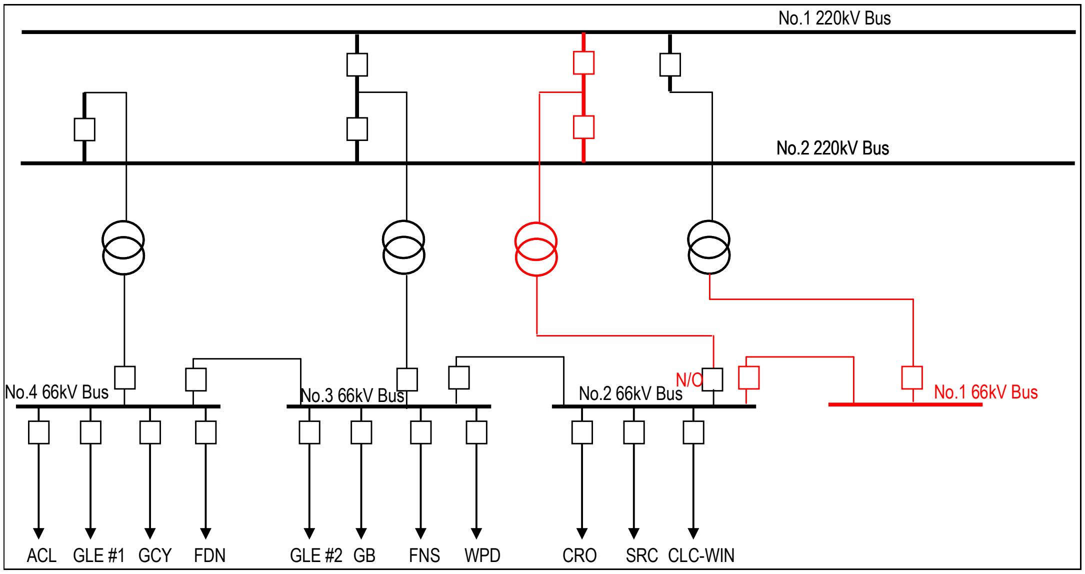
[11] Clause 16 of the Regulatory Test.

[12] Clause (17)(b) and (17)(c) of the Regulatory Test. The extent to which an alternative option is commercially feasible is to be demonstrated by determining whether an objective operator, acting rationally according to the economic criteria prescribed by this test, would be prepared to construct or provide the alternative option.

[13] Clause (17)(b) of the Regulatory Test.

transformers. The transformer is to be double-switched at 220 kV and single switched to the No 2 66 kV bus. The proposed layout is shown in Figure 7 below.

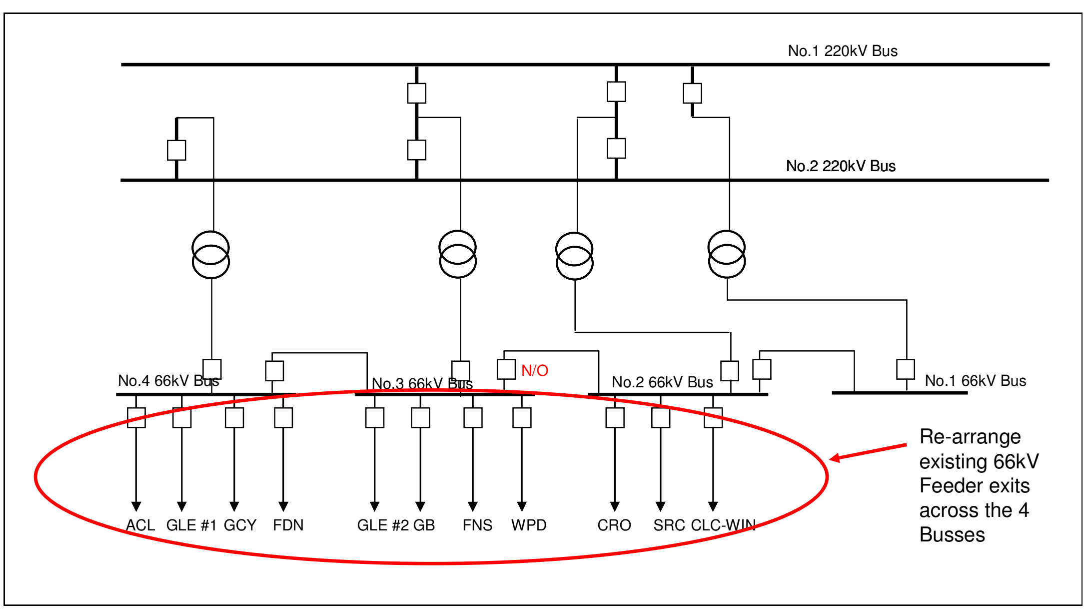
Figure 7: Proposed layout of GTS following installation of fourth transformer (operating on hot standby)



With this transformer operating arrangement, the N-1 rating is increased to be approximately equal to the present N rating at the station.

This option also allows for the N rating at the station to be increased as part of a future "stage 2", which would involve re-arranging 66 kV lines and switching the fourth transformer on load permanently. On present demand forecasts, these works are expected to be required in 2012. For the purpose of this Application Notice the second stage works in 2012 form part of the proposed project. Figure 8 shows the proposed layout of GTS following completion of stage 2 works.

Figure 8: Proposed layout of GTS following completion of stage 2 works



SPI PowerNet has provided an estimate of the capital cost for the first stage of the proposed works (including supply and installation of the transformer), which is $13.5 million. This estimate is SPI PowerNet's preliminary estimate of the final price, and for the purpose of this Application Notice the final price is assumed to be subject to variation within a range of plus or minus 10%. Powercor estimates the capital cost of the second stage works to be $2 million (within a range of plus or minus 30%).

Powercor expects the fourth transformer to be installed and in operation by the end of 2011, with stage 2 works completed by the end of 2012.

3.3 Option 3: New terminal station at East Geelong

As noted already in section 2, the growing demand at Geelong and in the surrounding areas, together with the load at risk at GTS will create a longer-term need for an additional terminal station to supply the Powercor distribution area in and around Geelong (and particularly to the south of Geelong). The third option is therefore to bring forward the development of the new terminal station proposed at East Geelong to the earliest possible commissioning date, which is late 2012.

This option would offload the GTS network by establishing a new East Geelong Terminal Station and undertaking associated 66 kV and 22 kV line works. It is a much higher cost option than the preferred option as it would require significant 66 kV line works to offload GTS. It would also require significant new investment in the shared transmission network. A further consideration is that this option cannot provide any additional capacity to address the load at risk at GTS in the summer of 2011/12.

3.4 Other options considered

As noted earlier, Powercor is not currently aware of any proponents of embedded generation or demand side management that would be capable of providing services to alleviate the reliability issues at GTS.

Details of the proposed network investment at GTS have been published in the Transmission Connection Planning Report since 2005, and no proposals for non-network solutions have been forthcoming in response. As a consequence, non-network solutions such as embedded generation or demand side management are not considered to be viable alternative options, and are not considered further.

4 Range of Reasonable Scenarios

Under the market benefits limb of the regulatory test, an investment option will satisfy the test if it maximises the net present value of the market benefit, compared with a number of alternative options in a majority of reasonable scenarios. For the purpose of the test, reasonable scenarios are defined as scenarios incorporating reasonable and mutually consistent:[14]

(a) forecasts of:

  (i) electricity demand (modified where appropriate to take into account demand-side options, economic growth, weather patterns and price elasticity);

  (ii) the efficient operating costs of supplying energy to meet forecast demand from existing, *committed, anticipated* and *modelled proje*cts including demand side and generation projects;

  (iii) the avoidable costs of *committed, anticipated* and *modelled projects* including demand side and generation projects and whether all avoidable costs are completely or partially avoided or deferred;

  (iv) the cost of providing sufficient ancillary services to meet the forecast demand to support the relevant option or *alternative option*; and

  (v) the capital and operating costs of other regulated network and market network service projects that are augmentations consistent with the forecast demand and generation scenarios;

(b) *market development scenarios*, which must include, for each relevant option or *alternative option* :

  (i) all *committed projects*;

  (ii) *anticipated projects*, to the extent they are likely to be commissioned within the modelling period;

  (iii) *modelled projects*; and

  (iv) any other technically feasible projects identified during the consultation process; and

(c) sensitivity testing.

The rationale for assessing the costs of alternative options across a number of reasonable scenarios is to test the robustness of the results. Where the analysis relies on forecasts or uncertain assumptions, the outcome should be tested against plausible variations in these forecasts or assumptions.

Given that the regulatory test considers only direct costs and benefits, market development scenarios are relevant only to the extent that they affect the nature, timing and level of such costs and benefits. In light of this consideration, this Application Notice considers a range of scenarios for particular variables where they have the potential to affect the ranking of the options.

---

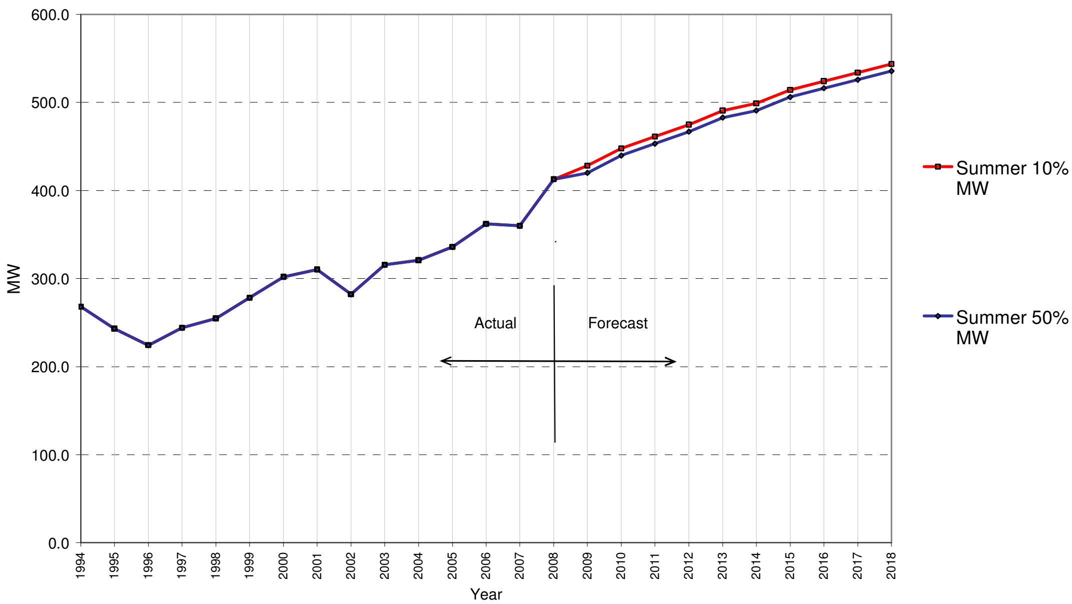
[14] See Clause 19 of the Regulatory Test. Italicised terms are defined in the regulatory test.

4.1 Demand forecasts

Under Clause 19(a)(i) of the regulatory test, the analysis must consider reasonable forecasts of electricity demand (modified where appropriate to take into account demand-side options, variations in economic growth, variations in weather patterns and price elasticity).

Forecasts of the 50th and 10th percentile summer maximum demand for GTS are presented in Figure 9 below, based on Powercor's central estimate of annual demand growth.

Figure 9: 10th & 50th percentile Summer maximum demand forecasts- GTS



The effective annual growth rates underpinning the demand forecasts are summarised in Table 3 below.

Table 3: Forecast annual growth rates in demand (central estimates)

Period	Growth rate in 10th percentile demand forecast	Growth rate in 50th percentile demand forecast
2004 to 2008 (actual)	6.41% per annum	6.41% per annum
2008-2012 (forecast)	3.56% per annum	3.12% per annum
2008-2018 (forecast)	2.79% per annum	2.64% per annum

4.2 Capital and operating costs of options

Under clause 19(a) of the regulatory test, reasonable forecasts of costs of each option under each scenario must be included in the analysis. Capital and operating cost assumptions for each of the three options considered in this analysis are summarised in Table 4 below.

Table 4: Capital and operating cost assumptions

Option	Capital cost (and basis of estimate)	Operating cost (and basis of estimate)
Option 1: Do nothing	Nil	Unserved energy valued at $47,255 per MWh (in accordance with the findings of the CRA report on VCR published by VENCorp[15].
Option 2: Install a fourth transformer	$13.5 million ± 10% for stage 1 in 2011 (SPI PowerNet price estimate, October 2008) plus $2 million ± 30% in 2012 for stage 2 (Powercor estimate)	1% per annum in real terms of the capital cost (Powercor estimate)
Option 3: Establish new station at East Geelong	$60 million ± 30% for new terminal station and associated 66 kV works, and shared transmission network augmentation in 2012 (Powercor estimate, based on recent costs of developing Wemen Terminal Station)	1% per annum in real terms of the capital cost (Powercor estimate)

4.3 Market development scenarios

Under clause 19(b) of the regulatory test, reasonable market development scenarios must be considered.

In the case of this particular analysis, different assumptions regarding generation and other transmission developments are not expected to have any impact on the assessment of the alternative options to the proposed investment at GTS.

It is noted however, that under Option 2, demand growth in the Geelong area will necessitate the establishment of the proposed Geelong East Terminal Station in 2023. An allowance for the capital and operating cost of this investment in 2023 has therefore been included in the evaluation of Option 2.

4.4 Sensitivity Testing

In relation to sensitivity testing, clause 23 of the regulatory test states:

> *Reasonable scenarios* under this test must encompass sensitivity testing on key input variables. Sensitivity testing may be carried out on the following, and should be appropriate to the size and type of project:
>
> (a) testing reasonable forecasts of the value of electricity to consumers.
>
> (b) price elasticity of demand.
>
> (c) capital and operating costs of *alternative options*.

[15] Charles River Associates, *Assessment of the Value of Customer Reliability*, August 2008. A copy of the report is available from VENCorp's website at: http://www.vencorp.com.au/

(d) discount rate (the lower boundary should be the regulated cost of capital).

(e) market demand.

(f) generation bidding behaviour using:

  (i) short run marginal cost; and

  (ii) approximates of realistic bidding.

(g) commissioning dates of:

  (i) the option being assessed;

  (ii) *alternative options*;

  (iii) *committed projects*; and

  (iv) *anticipated projects*

(h) inclusion or exclusion of particular *anticipated projects* based on their degree of likelihood of being commissioned within the modelling period;

(i) *modelled projects* based on a market-driven market development modelling approach

(j) market based regulatory instruments that may be used to address greenhouse and environmental issues and

(k) other sensitivity testing determined to be relevant and material to the case concerned.

For the purpose of this analysis, it is appropriate to apply sensitivity testing to the following variables:

- demand forecasts;
- capital costs;
- operating costs; and
- discount rate.

Sections 4.4.1 to 4.4.4 below provide details of the sensitivity testing undertaken in respect of these key variables.

4.4.1 Demand forecasts

For the purpose of sensitivity testing, the central estimate of the annual growth rate in the demand forecast was reduced by 15%. To manage the number of scenarios presented in this Application Notice, a detailed consideration of an upper bound estimate for demand growth is not provided. Nevertheless, it is possible to draw clear inferences regarding the impact of a higher demand growth forecast on the ranking of the options. As discussed in section 5.2, it is found that a higher demand forecast would not affect the ranking of the options.

The annual growth rates for the central estimate and the lower bound 50th percentile demand forecast are shown in Table 5 below.

Table 5: Annual growth rates for central estimate and lower bound 50th percentile demand forecasts

Period	Growth rate for central estimate demand forecast	Growth rate for lower bound demand forecast
2004 to 2008 (actual)	6.41% per annum	6.41% per annum
2008-2012 (forecast)	3.12% per annum	2.65% per annum
2008-2018 (forecast)	2.64% per annum	2.24% per annum

4.4.2 Capital costs

As noted in section 4.2 above, SPI PowerNet has estimated that the final price for the capital works of the first stage of the proposed option will be $13.5 million. The final price is assumed to be subject to variation of ±10%. Powercor's estimate of the cost of stage 2 works of the proposed option (to be undertaken 1 year after the fourth transformer comes into service) is $2 million ±30%. For the purpose of sensitivity testing, a range of ±30% is assumed to define the upper and lower bounds of the capital costs of Option 3. Accordingly, the range of capital costs assumed for each option for sensitivity testing purposes is set out in Table 6 below.

Table 6: Capital costs of options for sensitivity testing ($ million at 2008 prices)

Option	Capital costs		
	Lower bound	Mid point	Upper bound
Option 1: Do nothing	Nil	Nil	Nil
Option 2: Install a fourth transformer[16]	$13.6 M	Total of $15.5 M, being $13.5 M for initial "hot standby" configuration in 2011 plus $2 M for stage 2 works in 2012	$17.5 M
Option 3: Establish new station at East Geelong and undertake necessary shared network augmentations	$42 M	$60 M	$78 M

4.4.3 Operating costs

For the purpose of this analysis it has been assumed that the operating and maintenance costs associated with all network investments will be 1 per cent per annum (in real terms) of

16 The model outputs provided in Appendices 2 and 3 show slightly different capital expenditure amounts. The values shown in the Appendices are equivalent (in present terms) to those shown in Table 6. They reflect the present value of the estimated cost of stage 2 works which are assumed to be implemented 1 year after the installation of the fourth transformer.

the capital cost. Since this is a generic estimate that may not reflect actual costs, sensitivity analysis has been undertaken with operating costs at ±50 per cent of this estimate.

4.4.4 Discount Rate

To compare cash flows of options with different time profiles, it is necessary to use a discount rate to convert the future cash payments and receipts into present value terms. The choice of discount rate will impact on the estimated present value of costs and may affect the ranking of alternative options.

Clause 13 of the regulatory test states:

> The present value calculations must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. The discount rate used should be consistent with the cash flows being discounted.

A real pre-tax discount rate of 8 per cent has been applied for the purpose of this analysis. This is consistent with the discount rate applied by VENCorp in three recent assessments of new transmission investments.[17]

The regulatory test requires that sensitivity analysis using alternative discount rates be carried out, and that the lower boundary should be the regulated cost of capital.[18] The Essential Services Commission's estimate of the real pre-tax regulatory weighted average cost of capital is 6.6 per cent.[19]

Accordingly, for the purpose of sensitivity testing, real discount rates of 6.6 per cent and 10 per cent are applied.

4.4.5 Alternative timing of options

The ranking of options may be affected if there is a greater risk of delay in the delivery of one project compared to the other. All capital projects face some risk of delay, with larger or more complex projects typically being subject to a greater risk of extensive delays. For the purpose of sensitivity analysis, therefore, it may be reasonable to assume that Option 3 is subject to greater risk of delay or protracted delays than Option 2.

At this stage, however, it would be highly speculative to estimate the extent of any such difference in the risk of delay. For the purposes of the analysis presented in this Application Notice, therefore, it is assumed that Option 2 and 3 can be completed without delay or with an equal risk of delay. On this basis, no specific sensitivity analysis has been undertaken in relation to the impact of project delays on the net market benefits of the options.

A further issue arises in relation to the optimal timing of the project that is identified as maximising the net present value under the majority of scenarios examined. In particular, it

---

17 VENCorp, *New Large Transmission Network Asset: Additional 500/220 kV Transformation to Support West Metropolitan Melbourne and Geelong Area Load Growth*, September 2005, p27; VENCorp, *New Large Network Asset: Additional 500/220 kV Transformation to Support Melbourne Metropolitan Load Growth*, July 2005, p48; and VENCorp, *Consultation Notice Small Network Augmentation Rowville to Richmond Transfer Capacity Upgrade*, March 2005, p13.

18 Clause 23(c) of the regulatory test.

19 This is the "Officer" real pre-tax WACC derived using the WACC parameter values contained in the ESC October 2005 Final Decision in the Electricity Distribution Price Review for 2006-10.

is reasonable to assess whether the proposed timing is optimal or, alternatively, whether further net benefits could be obtained by deferring the proposed investment. This issue is addressed in section 5.2 below.

4.5 Summary of Reasonable Scenarios

In light of the approach to sensitivity testing explained in section 4.4, Table 7 below lists the variables and ranges of values for those variables adopted for the purpose of defining scenarios.

Table 7: Variables and ranges adopted for the purpose of defining scenarios

Variable for sensitivity testing	Lower Bound	Base Case	Upper Bound
Capital cost	- 10% for stage 1 of Option 2; - 30% for all other capital costs	SPI PowerNet and Powercor estimates, as appropriate	+ 10% for stage 1 of Option 2; + 30% for all other capital costs
Network operating costs	- 50%	Powercor Estimate	+ 50%
Discount Rate (real pre-tax)	6.6%	8%	10%
Annual growth rate of forecast demand	15% reduction from base	Powercor Estimate	Not examined

Clause 19 of the regulatory test requires the application of reasonable scenarios incorporating reasonable and mutually consistent forecasts of demand, costs and market development paths. In light of this requirement, the analysis presented in section 5:

- assesses the sensitivity of the base case net market benefit of the proposed option to upper and lower bound variations in each individual variable (as shown in Table 7 above); and also

- evaluates the net market benefit of the proposed option under six scenarios that represent plausible combinations of assumptions. These scenarios are described in Table 8 below.

Table 8: Scenarios considered in the economic evaluation

	Capital cost	Operating cost	Discount rate	Demand growth
Scenario A	Upper bound	Upper bound	Lower bound	Central estimate
Scenario B	Upper bound	Upper bound	Lower bound	Lower bound
Scenario C	Upper bound	Upper bound	Upper bound	Lower bound
Scenario D	Lower bound	Lower bound	Lower bound	Central estimate
Scenario E	Lower bound	Lower bound	Lower bound	Lower bound
Scenario F	Lower bound	Lower bound	Upper bound	Lower bound

5 Methodology and results of analysis

5.1 Methodology and approach

The economic evaluation considered the costs of the three options over a ten-year time horizon. A study horizon of 10 years was chosen because:

- By the tenth year of the analysis, the effective annual cost of expected unserved energy under Option 1 ("do nothing") is extremely high, indicating that the net market benefit of any option that would alleviate constraints would be assessed as being very high. Extending the period of analysis beyond 10 years would simply increase the net market benefits of Options 2 and 3 by equal amounts, but the investment decision signal provided by the analysis would be unaffected.

- A 10 year study period is consistent with the planning horizon for transmission networks required under Clause 5.6.2(d) of the National Electricity Rules.

- As explained in further detail below, in evaluating the costs of long-lived options over a shorter (10 year) period, a particular approach was applied to ensure that the analysis would provide a valid investment decision signal.

In evaluating the cost of the proposed option (Option 2) it was considered important to recognise that in effect, the installation of a fourth transformer at GTS enables the deferral of the development of EGTS. Therefore, in order to make a valid comparison of the costs of Options 2 and 3 over a 10 year study horizon, an allowance was made in the evaluation of Option 2 to provide for the cost, in present value terms, of the development of the East Geelong Terminal Station (EGTS) in 2023 (notwithstanding the application of a 10 year study horizon in relation to all other costs and benefits).

The costs attributable to the network augmentation options are included in the discounted cash flow analysis as a real annuity (or an 'equivalent annual cost'). The annuity of the network capital cost is calculated by amortising the capital cost at the discount rate over an assumed asset life of 45 years. The annual operating costs for the network assets are then added to the equivalent annual capital cost to derive an estimate of the total effective annual cost for each year of the 10 year study period. Under this approach:

- The capital-related costs of the network options are apportioned uniformly across all years of the relevant asset's life, and the analysis therefore need not be extended to include the whole of each asset's 45 year life.

- The total present value cost for each option (over the 10-year study period) can be calculated in a manner that takes into account the fact that, under Options 2 and 3, the transmission assets will have remaining service potential at the end of the study period.

This approach provides a reasonable means of ensuring that the costs of all options will be compared on a like-for-like basis over the 10 year study horizon.

5.2 Results of the analysis

The results of the analysis of the base case, and sensitivities to variations in individual variables are set out in Table 9 below. The net present value of each option under the base case scenario is shown in the first row of the table, and then results are presented reflecting the base case changed for one variable only (in turn: capital cost, network operating costs, discount rate and demand growth rate).

Table 9: Summary of results- Sensitivity testing of individual variables (Net present value in $ million)

	Option 1 Do nothing	**Option 2** Fourth transformer	**Option 3** East Geelong	**Net market benefit of Option 2**	
				compared to Option 1	**compared to Option 3**
Base Case	-$169.7	-$23.2	-$29.4	**$146.4**	**$6.2**
Capital cost sensitivity					
Upper Bound (Base + 30%)	-$169.7	-$27.5	-$35.0	**$142.2**	**$7.6**
Lower Bound (Base - 30%)	-$169.7	-$19.0	-$23.7	**$150.7**	**$4.7**
Operating cost sensitivity					
Upper Bound (Base + 50%)	-$169.7	-$24.2	-$30.4	**$145.5**	**$6.2**
Lower Bound (Base - 50%)	-$169.7	-$22.3	-$28.3	**$147.4**	**$6.1**
Discount rate sensitivity					
Upper Bound (10% real)	-$146.7	-$21.4	-$29.8	**$125.3**	**$8.4**
Lower Bound (6.6% real)	-$188.3	-$24.5	-$28.9	**$163.8**	**$4.4**
Demand forecast sensitivity					
Central demand forecast	-$169.7	-$23.2	-$29.4	**$146.4**	**$6.2**
Lower bound (base annual growth rate reduced by 15%)	-$104.2	-$22.3	-$26.9	**$81.9**	**$4.6**

Copies of the output of the model used to calculate the results shown above are provided in Appendix 2.

Table 10 below presents the results of the analysis under the scenarios.

Table 10: Results- Economic evaluation of options under various scenarios (Net present value in $ million)

Scenario	Option 1 Do nothing	Option 2 Fourth transformer	Option 3 East Geelong	Net market benefit of Option 2 compared to Option 1	Net market benefit of Option 2 compared to Option 3
Scenario A • Upper bound capital cost • Upper bound operating cost • Lower bound discount rate • Central demand growth	-$188.3	-$30.6	-$35.7	**$157.7**	**$5.1**
Scenario B • Upper bound capital cost • Upper bound operating cost • Lower bound discount rate • Lower bound demand growth	-$115.6	-$29.6	-$33.1	**$86.0**	**$3.4**
Scenario C • Upper bound capital cost • Upper bound operating cost • Upper bound discount rate • Lower bound demand growth	-$90.2	-$25.2	-$34.6	**$65.0**	**$9.4**
Scenario D • Lower bound capital cost • Lower bound operating cost • Lower bound discount rate • Central demand growth	-$188.3	-$18.9	-$22.7	**$169.4**	**$3.7**
Scenario E • Lower bound capital cost • Lower bound operating cost • Lower bound discount rate • Lower bound demand growth	-$115.6	-$18.0	-$20.1	**$97.6**	**$2.1**
Scenario F • Lower bound capital cost • Lower bound operating cost • Upper bound discount rate • Lower bound demand growth	-$90.2	-$16.3	-$20.9	**$73.9**	**$4.6**

Copies of the output of the model used to calculate the results shown above are provided in Appendix 3.

The results set out in Table 9 and Table 10 show that the proposed option (Option 2 - installation of a fourth transformer at GTS) maximises net market benefit under all scenarios considered.

It is noted that clause 23(g) of the regulatory test states that sensitivity testing should be carried out in relation to the commissioning dates of the proposed options and alternative options, while clause 4(d)(iv) states:

> In determining the *market benefit*, the analysis may include the present value of benefits [including] changes in costs caused through differences in the timing of transmission investments.

Accordingly, as noted in section 4.4.5 above, this analysis has examined the economics of deferring the proposed installation of a fourth transformer at GTS. It is evident that deferring the proposed project would lead to a reduction in the net benefit of the proposed project (Option 2) because:

- deferring the installation of the transformer for one year (from 2011 to 2012) would lead to savings of approximately $1.4 million[20]; however
- Appendix 1 shows that the cost of deferring the project (in terms of expected unserved energy at the 50th percentile lower bound estimate of demand) is approximately $2.8 million in 2011 and $4.5 million in 2012.

This analysis confirms that installation of the fourth transformer at GTS by the earliest possible date (2011) will maximise net market benefits.

As noted in section 4.4.1, the sensitivity analysis presented in this Application Notice only considered two demand forecasts – a central case and a lower bound in which the annual growth in demand is 15% lower than the central case. Whilst a higher forecast was not adopted in the sensitivity analysis presented in this paper it is noted that:

- a higher demand forecast would increase the net present value of Option 2 and Option 3 when compared to the 'do nothing' option; and
- as Option 2 delivers a more economic solution to the reliability issues at GTS, a higher demand forecast will further improve the net present value of Option 2 relative to Option 3.

[20] This is the sum of: the annuity for one year of the total capital cost of the proposed option (calculated over 45 years at a discount rate of 8% real) and the annual operating and maintenance costs (of 1% per annum in real terms of the initial capital cost).

6 Conclusion

The results of this analysis demonstrate that the proposed option (Option 2 - installation of a fourth transformer at GTS) maximises net market benefit under the base case set of assumptions and all six scenarios considered. As noted in section 2, in broad terms the analysis presented in this Application Notice has found that net market benefits are maximised by: incurring the additional costs (approximately $13.5 million) of a fourth transformer at GTS by late 2011 and subsequent works in 2012 (approximately $2 million); constructing the new terminal station at East Geelong in 2023 (at a cost of approximately $60 million including shared transmission network augmentation costs); and thereby minimising the expected costs of unserved energy.

It follows that the proposed works provide a better outcome for customers when compared against the alternative options of:

- Avoiding the costs (approximately $13.5 million) of a fourth transformer at GTS by late 2011 and subsequent works in 2012 (approximately $2 million); bringing forward the investment at East Geelong Terminal Station (approximately $60 million) from 2023 to the earliest possible commissioning date of late 2012; and incurring additional expected unserved energy costs as a result of this later commissioning date; or

- Doing nothing.

The analysis has also demonstrated that deferral of the proposed installation of the fourth transformer beyond the proposed commissioning date of late 2011 would reduce net market benefits.

The proposed works have no material inter-network impact, so an augmentation technical report (pursuant to clause 5.6.5(c)(5) of the National Electricity Rules) is not required to be included with this Application Notice.

Detailed design and construction of the project is planned to commence in February 2009. SPI PowerNet has advised that the earliest possible time by which the fourth transformer could be installed and commissioned is late 2011. Accordingly, the fourth transformer is expected to be placed into service in November 2011. The subsequent works described in this Application Notice as “stage 2” are expected to be completed in late 2012.

Appendix 1: Station rating data and expected unserved energy calculations

Geelong Terminal Station
Detailed data: Magnitude and probability of loss of load for central (median) demand forecast

Distribution Businesses supplied by this station:	Powercor (100%)		
	MW	MVA	
Normal cyclic rating with all plant in service		493	via 3 transformers (Summer peaking)
Summer N-1 Station Rating:	322	343	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating:	374	390	

Station: GTS	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
50th percentile Summer Maximum Demand (MVA)	437.4	458.0	471.9	486.2	502.9	511.2	527.2	537.5	547.6	557.8
Summer % Overload [See Note 2 below]	27.52	33.53	37.59	41.75	46.61	49.04	53.70	56.70	59.64	62.64
50th percentile Winter Maximum Demand (MVA)	370.3	378.0	396.2	408.7	421.5	437.1	444.4	458.6	467.6	476.5
Winter % Overload [See Note 2 below]	Nil	Nil	1.58	4.80	8.06	12.08	13.95	17.59	19.89	22.17
Annual energy at risk (MWh) [See Note 3 below]	3339.9	6933.3	11527.2	21727.7	48271.7	70551.0	127913.6	184171.8	244647.4	311681.9
Annual hours at risk [See Note 4 below]	107.0	198.3	379.0	892.3	1830.8	2532.5	4003.8	5018.8	5638.3	6152.0
Expected Annual Unserved Energy (MWh) [See Note 5 below]	21.71	45.07	74.93	141.23	313.77	458.58	831.44	1197.12	1590.21	2025.93
Expected Annual Unserved Energy valued in accordance with the value of customer reliability as estimated in the August 2008 commissioned by VENCorp. [See Note 6 below]	$1,025,877	$2,129,606	$3,540,639	$6,673,764	$14,826,880	$21,670,049	$39,289,237	$56,569,201	$75,144,559	$95,734,512

Notes:

1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. This is the percentage by which the 50th percentile forecast maximum demand exceeds the N-1 capability rating.
3. “Annual energy at risk” is the amount of energy that would not be supplied in a year during which the 50th percentile demand forecast exceeds the N-1 capability rating, if there is a major outage of a transformer (see Note 5 below), and no other mitigation action is taken.
4. “Annual hours per year at risk” is the number of hours in a year during which the 50th percentile demand forecast exceeds the N-1 capability rating.
5. “Expected annual unserved energy” means “Annual Energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with a duration of 2.6 months. The outage probability is derived from historical data.
6. The value of unserved energy is derived from the sector values given in Table 24 on page 34 of the VCR report prepared by CRA in August 2008, weighted in accordance with the composition of the load at this terminal station.

Geelong Terminal Station
Detailed data: Magnitude and probability of loss of load for lower bound demand forecast

Distribution Businesses supplied by this station: Powercor (100%)

	MW	MVA	
Normal cyclic rating with all plant in service		493	via 3 transformers (Summer peaking)
Summer N-1 Station Rating:	322	343	[See Note 1 below for interpretation of N-1]
Winter N-1 Station Rating:	374	390	

Station: GTS	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
50th percentile Summer Maximum Demand (MVA)	436.3	453.8	465.5	477.4	491.4	498.3	511.5	520.0	528.3	536.7
Summer % Overload [See Note 2 below]	27.20	32.29	35.71	39.20	43.25	45.27	49.13	51.60	54.03	56.48
50th percentile Winter Maximum Demand (MVA)	370.3	378.0	396.2	408.7	421.5	437.1	444.4	458.6	467.6	476.5
Winter % Overload [See Note 2 below]	Nil	Nil	1.58	4.80	8.06	12.08	13.95	17.59	19.89	22.17
Annual energy at risk (MWh) [See Note 3 below]	3199.9	5989.5	9054.8	14647.4	28609.3	41535.1	73535.1	107891.1	148979.4	198271.0
Annual hours at risk [See Note 4 below]	104.0	171.5	279.5	540.0	1224.8	1717.8	2701.0	3805.8	4734.0	5467.0
Expected Annual Unserved Energy (MWh) [See Note 5 below]	20.80	38.93	58.86	95.21	185.96	269.98	477.98	701.29	968.37	1288.76
Expected Annual Unserved Energy valued in accordance with the value of customer reliability as estimated in the August 2008 report commissioned by VENCorp. [See Note 6 below]	$982,853	$1,839,697	$2,781,237	$4,499,016	$8,787,465	$12,757,685	$22,586,628	$33,139,247	$45,759,699	$60,899,832

Notes:

1. “N-1” means cyclic station output capability rating with outage of one transformer. The rating is at an ambient temperature of 35 degrees Centigrade.
2. This is the percentage by which the 50th percentile forecast maximum demand exceeds the N-1 capability rating.
3. “Annual energy at risk” is the amount of energy that would not be supplied in a year during which the 50th percentile demand forecast exceeds the N-1 capability rating, if there is a major outage of a transformer (see Note 5 below), and no other mitigation action is taken.
4. “Annual hours per year at risk” is the number of hours in a year during which the 50th percentile demand forecast exceeds the N-1 capability rating.
5. “Expected annual unserved energy” means “Annual Energy at risk” multiplied by the probability of a major outage affecting one transformer. “Major outage” means an outage with a duration of 2.6 months. The outage probability is derived from historical data.
6. The value of unserved energy is derived from the sector values given in Table 24 on page 34 of the VCR report prepared by CRA in August 2008, weighted in accordance with the composition of the load at this terminal station.

Appendix 2: Model output - Sensitivity testing of individual variables

GTS Regulatory Test evaluation: Base case

All amounts expressed in real $ M

Discount rate	8.0%	real, pre-tax
Opex rate	1%	per annum
Transmission asset life	45	years

SUMMARY - Base case	NPV	Net benefit
Option 1 - Do nothing	-$169.7	$0.0
Option 2 - 4th Transformer	-$23.2	$146.4
Option 3 - EGTS	-$29.4	$140.3
Net benefit of Option 2 exeeds Option 3 by		$6.2

	Yr ending Dec =>	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
	t=	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
	Discount factor	1.000	0.926	0.857	0.794	0.735	0.681	0.630	0.583	0.540	0.500	0.463
Option 1: Do nothing (Central demand f/c)												
Expected Unserved energy value ($)			1025877	2129606	3540639	6673764	14826880	21670049	39289237	56569201	75144559	95734512
Expected Unserved energy value ($M)			1.0	2.1	3.5	6.7	14.8	21.7	39.3	56.6	75.1	95.7
Total cash flow			**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-14.8**	**-21.7**	**-39.3**	**-56.6**	**-75.1**	**-95.7**
PV cash flow		0.0	-0.9	-1.8	-2.8	-4.9	-10.1	-13.7	-22.9	-30.6	-37.6	-44.3
NPV=	-169.7											
NPV=	-$169.7											
Option 2: GTS 4th TFRM then EGTS in 2023												
PV of EGTS 2023 capex	-18.9											
Annuity from today of this PV	-$1.6											
Opex annuity from today	-$0.2											
Capital cost, 4th TFMR (stages 1 & 2)	-15.4											
Annuity of capital cost	-1.2679					-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3
Annual Opex	-0.1535					-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Annuity of future cost of EGTS 2023	-1.8		-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8
Unserved energy			-1.0	-2.1	-3.5							
Total cash flow		**0.0**	**-2.8**	**-3.9**	**-5.3**	**-3.2**	**-3.2**	**-3.2**	**-3.2**	**-3.2**	**-3.2**	**-3.2**
PV cash flow		0.0	-2.6	-3.3	-4.2	-2.3	-2.2	-2.0	-1.9	-1.7	-1.6	-1.5
NPV=	-23.2											
NPV=	-$23.2											
Option 3: EGTS in 2012												
Capital cost, EGTS	-60.0											
Annuity of capital cost	-5.0						-5.0	-5.0	-5.0	-5.0	-5.0	-5.0
Annual Opex	-0.6						-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
Unserved energy			-1.0	-2.1	-3.5	-6.7						
Total cash flow		**0.0**	**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-5.6**	**-5.6**	**-5.6**	**-5.6**	**-5.6**	**-5.6**
PV cash flow		0.0	-0.9	-1.8	-2.8	-4.9	-3.8	-3.5	-3.2	-3.0	-2.8	-2.6
NPV=	-29.4											
NPV=	-$29.4											

GTS Regulatory Test evaluation: High capital cost

All amounts expressed in real $ M

Discount rate	8%	real, pre-tax
Opex rate	1%	per annum
Transmission asset life	45	years

SUMMARY: High capital cost		
	NPV	Net benefit
Option 1 - Do nothing	-$169.7	$0.0
Option 2 - 4th Transformer	-$27.5	$142.2
Option 3 - EGTS	-$35.0	$134.6
Net benefit of Option 2 exeeds Option 3 by		$7.6

	Yr ending Dec =>	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	t=	0	1	2	3	4	5	6	7	8	9	10
	Discount factor	1.000	0.926	0.857	0.794	0.735	0.681	0.630	0.583	0.540	0.500	0.463
Option 1: Do nothing (Central demand f/c)												
Expected Unserved energy value ($)			1025877	2129606	3540639	6673764	14826880	21670049	39289237	56569201	75144559	95734512
Expected Unserved energy value ($M)			1.0	2.1	3.5	6.7	14.8	21.7	39.3	56.6	75.1	95.7
Total cash flow			**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-14.8**	**-21.7**	**-39.3**	**-56.6**	**-75.1**	**-95.7**
PV cash flow		0.0	-0.9	-1.8	-2.8	-4.9	-10.1	-13.7	-22.9	-30.6	-37.6	-44.3
NPV=	-169.7											
NPV=	-$169.7											
Option 2: GTS 4th TFRM then EGTS in 2023												
PV of EGTS 2023 capex	-24.6											
Annuity from today of this PV	-$2.0											
Opex annuity from today	-$0.2											
Capital cost, 4th TFMR	-17.3											
Annuity of capital cost	-1.4252					-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4
Annual Opex	-0.1726					-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Annuity of future cost of EGTS 2023	-2.3		-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3
Unserved energy			-1.0	-2.1	-3.5							
Total cash flow		**0.0**	**-3.3**	**-4.4**	**-5.8**	**-3.9**	**-3.9**	**-3.9**	**-3.9**	**-3.9**	**-3.9**	**-3.9**
PV cash flow		0.0	-3.1	-3.8	-4.6	-2.8	-2.6	-2.4	-2.3	-2.1	-1.9	-1.8
NPV=	-27.5											
NPV=	-$27.5											
Option 3: EGTS in 2012												
Capital cost, EGTS	-78.0											
Annuity of capital cost	-6.4						-6.4	-6.4	-6.4	-6.4	-6.4	-6.4
Annual Opex	-0.8						-0.8	-0.8	-0.8	-0.8	-0.8	-0.8
Unserved energy			-1.0	-2.1	-3.5	-6.7						
Total cash flow		**0.0**	**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-7.2**	**-7.2**	**-7.2**	**-7.2**	**-7.2**	**-7.2**
PV cash flow		0.0	-0.9	-1.8	-2.8	-4.9	-4.9	-4.6	-4.2	-3.9	-3.6	-3.3
NPV=	-35.0											
NPV=	-$35.0											

GTS Regulatory Test evaluation: Low capital cost

All amounts expressed in real $ M

Discount rate	8%	real, pre-tax
Opex rate	1%	per annum
Transmission asset life	45	years

SUMMARY: Low capital cost		
	NPV	Net benefit
Option 1 - Do nothing	-$169.7	$0.0
Option 2 - 4th Transformer	-$19.0	$150.7
Option 3 - EGTS	-$23.7	$146.0
Net benefit of Option 2 exeeds Option 3 by		$4.7

	Yr ending Dec =>	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
	t=	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
	Discount factor	1.000	0.926	0.857	0.794	0.735	0.681	0.630	0.583	0.540	0.500	0.463
Option 1: Do nothing (Central demand f/c)												
Expected Unserved energy value ($)			1025877	2129606	3540639	6673764	14826880	21670049	39289237	56569201	75144559	95734512
Expected Unserved energy value ($M)			1.0	2.1	3.5	6.7	14.8	21.7	39.3	56.6	75.1	95.7
Total cash flow			**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-14.8**	**-21.7**	**-39.3**	**-56.6**	**-75.1**	**-95.7**
PV cash flow		0.0	-0.9	-1.8	-2.8	-4.9	-10.1	-13.7	-22.9	-30.6	-37.6	-44.3
NPV=	-169.7											
NPV=	-$169.7											
Option 2: GTS 4th TFRM then EGTS in 2023												
PV of EGTS 2023 capex	-13.2											
Annuity from today of this PV	-$1.1											
Opex annuity from today	-$0.1											
Capital cost, 4th TFMR	-13.4											
Annuity of capital cost	-1.1105					-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1
Annual Opex	-0.1345					-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Annuity of future cost of EGTS 2023	-1.2		-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2
Unserved energy			-1.0	-2.1	-3.5							
Total cash flow		**0.0**	**-2.3**	**-3.4**	**-4.8**	**-2.5**	**-2.5**	**-2.5**	**-2.5**	**-2.5**	**-2.5**	**-2.5**
PV cash flow		0.0	-2.1	-2.9	-3.8	-1.8	-1.7	-1.6	-1.4	-1.3	-1.2	-1.1
NPV=	-19.0											
NPV=	-$19.0											
Option 3: EGTS in 2012												
Capital cost, EGTS	-42.0											
Annuity of capital cost	-3.5						-3.5	-3.5	-3.5	-3.5	-3.5	-3.5
Annual Opex	-0.4						-0.4	-0.4	-0.4	-0.4	-0.4	-0.4
Unserved energy			-1.0	-2.1	-3.5	-6.7						
Total cash flow		**0.0**	**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-3.9**	**-3.9**	**-3.9**	**-3.9**	**-3.9**	**-3.9**
PV cash flow		0.0	-0.9	-1.8	-2.8	-4.9	-2.6	-2.5	-2.3	-2.1	-1.9	-1.8
NPV=	-23.7											
NPV=	-$23.7											

GTS Regulatory Test evaluation: High opex

All amounts expressed in real $ M

Discount rate	8%	real, pre-tax
Opex rate	1.5%	per annum
Transmission asset life	45	years

SUMMARY: High network operating cost		
	NPV	Net benefit
Option 1 - Do nothing	-$169.7	$0.0
Option 2 - 4th Transformer	-$24.2	$145.5
Option 3 - EGTS	-$30.4	$139.3
Net benefit of Option 2 exeeds Option 3 by		$6.2

Yr ending Dec =>		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
t=		0	1	2	3	4	5	6	7	8	9	10
Discount factor		1.000	0.926	0.857	0.794	0.735	0.681	0.630	0.583	0.540	0.500	0.463
Option 1: Do nothing (Central demand f/c)												
Expected Unserved energy value ($)			1025877	2129606	3540639	6673764	14826880	21670049	39289237	56569201	75144559	95734512
Expected Unserved energy value ($M)			1.0	2.1	3.5	6.7	14.8	21.7	39.3	56.6	75.1	95.7
Total cash flow			**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-14.8**	**-21.7**	**-39.3**	**-56.6**	**-75.1**	**-95.7**
PV cash flow		0.0	-0.9	-1.8	-2.8	-4.9	-10.1	-13.7	-22.9	-30.6	-37.6	-44.3
NPV=	-169.7											
NPV=	-$169.7											
Option 2: GTS 4th TFRM then EGTS in 2023												
PV of EGTS 2023 capex	-18.9											
Annuity from today of this PV	-$1.6											
Opex annuity from today	-$0.3											
Capital cost, 4th TFMR	-15.4											
Annuity of capital cost	-1.2679					-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3
Annual Opex	-0.2303					-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Annuity of future cost of EGTS 2023	-1.8		-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8
Unserved energy			-1.0	-2.1	-3.5							
Total cash flow		**0.0**	**-2.9**	**-4.0**	**-5.4**	**-3.3**	**-3.3**	**-3.3**	**-3.3**	**-3.3**	**-3.3**	**-3.3**
PV cash flow		0.0	-2.7	-3.4	-4.3	-2.5	-2.3	-2.1	-2.0	-1.8	-1.7	-1.5
NPV=	-24.2											
NPV=	-$24.2											
Option 3: EGTS in 2012												
Capital cost, EGTS	-60.0											
Annuity of capital cost	-5.0						-5.0	-5.0	-5.0	-5.0	-5.0	-5.0
Annual Opex	-0.9						-0.9	-0.9	-0.9	-0.9	-0.9	-0.9
Unserved energy			-1.0	-2.1	-3.5	-6.7						
Total cash flow		**0.0**	**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-5.9**	**-5.9**	**-5.9**	**-5.9**	**-5.9**	**-5.9**
PV cash flow		0.0	-0.9	-1.8	-2.8	-4.9	-4.0	-3.7	-3.4	-3.2	-2.9	-2.7
NPV=	-30.4											
NPV=	-$30.4											

GTS Regulatory Test evaluation: Low opex

All amounts expressed in real $ M

Discount rate	8%	real, pre-tax
Opex rate	0.5%	per annum
Transmission asset life	45	years

SUMMARY: Low network operating cost		
	NPV	Net benefit
Option 1 - Do nothing	-$169.7	$0.0
Option 2 - 4th Transformer	-$22.3	$147.4
Option 3 - EGTS	-$28.3	$141.3
Net benefit of Option 2 exeeds Option 3 by		$6.1

Yr ending Dec =>		**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
t=		**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Discount factor		1.000	0.926	0.857	0.794	0.735	0.681	0.630	0.583	0.540	0.500	0.463
Option 1: Do nothing (Central demand f/c)												
Expected Unserved energy value ($)			1025877	2129606	3540639	6673764	14826880	21670049	39289237	56569201	75144559	95734512
Expected Unserved energy value ($M)			1.0	2.1	3.5	6.7	14.8	21.7	39.3	56.6	75.1	95.7
Total cash flow			**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-14.8**	**-21.7**	**-39.3**	**-56.6**	**-75.1**	**-95.7**
PV cash flow		0.0	-0.9	-1.8	-2.8	-4.9	-10.1	-13.7	-22.9	-30.6	-37.6	-44.3
NPV=	-169.7											
NPV=	-$169.7											
Option 2: GTS 4th TFRM then EGTS in 2023												
PV of EGTS 2023 capex	-18.9											
Annuity from today of this PV	-$1.6											
Opex annuity from today	-$0.1											
Capital cost, 4th TFMR	-15.4											
Annuity of capital cost	-1.2679					-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3
Annual Opex	-0.0768					-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Annuity of future cost of EGTS 2023	-1.7		-1.7	-1.7	-1.7	-1.7	-1.7	-1.7	-1.7	-1.7	-1.7	-1.7
Unserved energy			-1.0	-2.1	-3.5							
Total cash flow		**0.0**	**-2.7**	**-3.8**	**-5.2**	**-3.0**	**-3.0**	**-3.0**	**-3.0**	**-3.0**	**-3.0**	**-3.0**
PV cash flow		0.0	-2.5	-3.2	-4.1	-2.2	-2.0	-1.9	-1.8	-1.6	-1.5	-1.4
NPV=	-22.3											
NPV=	-$22.3											
Option 3: EGTS in 2012												
Capital cost, EGTS	-60.0											
Annuity of capital cost	-5.0						-5.0	-5.0	-5.0	-5.0	-5.0	-5.0
Annual Opex	-0.3						-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
Unserved energy			-1.0	-2.1	-3.5	-6.7						
Total cash flow		**0.0**	**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-5.3**	**-5.3**	**-5.3**	**-5.3**	**-5.3**	**-5.3**
PV cash flow		0.0	-0.9	-1.8	-2.8	-4.9	-3.6	-3.3	-3.1	-2.8	-2.6	-2.4
NPV=	-28.3											
NPV=	-$28.3											

GTS Regulatory Test evaluation: High WACC

All amounts expressed in real $ M

Discount rate	10.0%	real, pre-tax
Opex rate	1%	per annum
Transmission asset life	45	years

SUMMARY- High WACC	NPV	Net benefit
Option 1 - Do nothing	-$146.7	$0.0
Option 2 - 4th Transformer	-$21.4	$125.3
Option 3 - EGTS	-$29.8	$116.9
Net benefit of Option 2 exeeds Option 3 by		$8.4

	Yr ending Dec =>	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	t=	0	1	2	3	4	5	6	7	8	9	10
	Discount factor	1.000	0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424	0.386
Option 1: Do nothing (Central demand f/c)												
Expected Unserved energy value ($)			1025877	2129606	3540639	6673764	14826880	21670049	39289237	56569201	75144559	95734512
Expected Unserved energy value ($M)			1.0	2.1	3.5	6.7	14.8	21.7	39.3	56.6	75.1	95.7
Total cash flow			**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-14.8**	**-21.7**	**-39.3**	**-56.6**	**-75.1**	**-95.7**
PV cash flow		0.0	-0.9	-1.8	-2.7	-4.6	-9.2	-12.2	-20.2	-26.4	-31.9	-36.9
NPV=	-146.7											
NPV=	-$146.7											
Option 2: GTS 4th TFRM then EGTS in 2023												
PV of EGTS 2023 capex	-14.4											
Annuity from today of this PV	-$1.5											
Opex annuity from today	-$0.1											
Capital cost, 4th TFMR	-15.3											
Annuity of capital cost	-1.5531					-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6
Annual Opex	-0.1532					-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Annuity of future cost of EGTS 2023	-1.6		-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6
Unserved energy			-1.0	-2.1	-3.5							
Total cash flow		**0.0**	**-2.6**	**-3.7**	**-5.1**	**-3.3**	**-3.3**	**-3.3**	**-3.3**	**-3.3**	**-3.3**	**-3.3**
PV cash flow		0.0	-2.4	-3.1	-3.9	-2.3	-2.1	-1.9	-1.7	-1.5	-1.4	-1.3
NPV=	-21.4											
NPV=	-$21.4											
Option 3: EGTS in 2012												
Capital cost, EGTS	-60.0											
Annuity of capital cost	-6.1						-6.1	-6.1	-6.1	-6.1	-6.1	-6.1
Annual Opex	-0.6						-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
Unserved energy			-1.0	-2.1	-3.5	-6.7						
Total cash flow		**0.0**	**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-6.7**	**-6.7**	**-6.7**	**-6.7**	**-6.7**	**-6.7**
PV cash flow		0.0	-0.9	-1.8	-2.7	-4.6	-4.1	-3.8	-3.4	-3.1	-2.8	-2.6
NPV=	-29.8											
NPV=	-$29.8											

GTS Regulatory Test evaluation: Low WACC

All amounts expressed in real $ M

Discount rate	6.6%	real, pre-tax
Opex rate	1%	per annum
Transmission asset life	45	years

SUMMARY- Low WACC

	NPV	Net benefit
Option 1 - Do nothing	-$188.3	$0.0
Option 2 - 4th Transformer	-$24.5	$163.8
Option 3 - EGTS	-$28.9	$159.5
Net benefit of Option 2 exeeds Option 3 by		$4.4

	Yr ending Dec =>	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
	t=	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
	Discount factor	1.000	0.938	0.880	0.826	0.774	0.726	0.681	0.639	0.600	0.563	0.528
Option 1: Do nothing (Central demand f/c)												
Expected Unserved energy value ($)			1025877	2129606	3540639	6673764	14826880	21670049	39289237	56569201	75144559	95734512
Expected Unserved energy value ($M)			1.0	2.1	3.5	6.7	14.8	21.7	39.3	56.6	75.1	95.7
Total cash flow			**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-14.8**	**-21.7**	**-39.3**	**-56.6**	**-75.1**	**-95.7**
PV cash flow		0.0	-1.0	-1.9	-2.9	-5.2	-10.8	-14.8	-25.1	-33.9	-42.3	-50.5
NPV=	-188.3											
NPV=	-$188.3											
Option 2: GTS 4th TFRM then EGTS in 2023												
PV of EGTS 2023 capex	-23.0											
Annuity from today of this PV	-$1.6											
Opex annuity from today	-$0.2											
Capital cost, 4th TFMR	-15.4											
Annuity of capital cost	-1.0754					-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1
Annual Opex	-0.1538					-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Annuity of future cost of EGTS 2023	-1.8		-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8
Unserved energy			-1.0	-2.1	-3.5							
Total cash flow		**0.0**	**-2.9**	**-4.0**	**-5.4**	**-3.1**	**-3.1**	**-3.1**	**-3.1**	**-3.1**	**-3.1**	**-3.1**
PV cash flow		0.0	-2.7	-3.5	-4.4	-2.4	-2.2	-2.1	-2.0	-1.8	-1.7	-1.6
NPV=	-24.5											
NPV=	-$24.5											
Option 3: EGTS in 2012												
Capital cost, EGTS	-60.0											
Annuity of capital cost	-4.2						-4.2	-4.2	-4.2	-4.2	-4.2	-4.2
Annual Opex	-0.6						-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
Unserved energy			-1.0	-2.1	-3.5	-6.7						
Total cash flow		**0.0**	**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-4.8**	**-4.8**	**-4.8**	**-4.8**	**-4.8**	**-4.8**
PV cash flow		0.0	-1.0	-1.9	-2.9	-5.2	-3.5	-3.3	-3.1	-2.9	-2.7	-2.5
NPV=	-28.9											
NPV=	-$28.9											

GTS Regulatory Test evaluation: Low demand

All amounts expressed in real $ M

Discount rate	8.0%	real, pre-tax
Opex rate	1%	per annum
Transmission asset life	45	years

SUMMARY - Base case with Low demand forecast	NPV	Net benefit
Option 1 - Do nothing	-$104.2	$0.0
Option 2 - 4th Transformer	-$22.3	$81.9
Option 3 - EGTS	-$26.9	$77.3
Net benefit of Option 2 exeeds Option 3 by		$4.6

	Yr ending Dec =>	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	t=	0	1	2	3	4	5	6	7	8	9	10
	Discount factor	1.000	0.926	0.857	0.794	0.735	0.681	0.630	0.583	0.540	0.500	0.463
Option 1: Do nothing (Low demand f/c)												
Expected Unserved energy value ($)			982853	1839697	2781237	4499016	8787465	12757685	22586628	33139247	45759699	60899832
Expected Unserved energy value ($M)			1.0	1.8	2.8	4.5	8.8	12.8	22.6	33.1	45.8	60.9
Total cash flow			**-1.0**	**-1.8**	**-2.8**	**-4.5**	**-8.8**	**-12.8**	**-22.6**	**-33.1**	**-45.8**	**-60.9**
PV cash flow		0.0	-0.9	-1.6	-2.2	-3.3	-6.0	-8.0	-13.2	-17.9	-22.9	-28.2
NPV=	-104.2											
NPV=	-$104.2											
Option 2: GTS 4th TFRM then EGTS in 2023												
PV of EGTS 2023 capex	-18.9											
Annuity from today of this PV	-$1.6											
Opex annuity from today	-$0.2											
Capital cost, 4th TFMR	-15.4											
Annuity of capital cost	-1.2679					-1.3	-1.3	-1.3	-1.3	-1.3	-1.3	-1.3
Annual Opex	-0.1535					-0.2	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Annuity of future cost of EGTS 2023	-1.8		-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8	-1.8
Unserved energy			-1.0	-1.8	-2.8							
Total cash flow		**0.0**	**-2.7**	**-3.6**	**-4.5**	**-3.2**	**-3.2**	**-3.2**	**-3.2**	**-3.2**	**-3.2**	**-3.2**
PV cash flow		0.0	-2.5	-3.1	-3.6	-2.3	-2.2	-2.0	-1.9	-1.7	-1.6	-1.5
NPV=	-22.3											
NPV=	-$22.3											
Option 3: EGTS in 2012												
Capital cost, EGTS	-60.0											
Annuity of capital cost	-5.0						-5.0	-5.0	-5.0	-5.0	-5.0	-5.0
Annual Opex	-0.6						-0.6	-0.6	-0.6	-0.6	-0.6	-0.6
Unserved energy			-1.0	-1.8	-2.8	-4.5						
Total cash flow		**0.0**	**-1.0**	**-1.8**	**-2.8**	**-4.5**	**-5.6**	**-5.6**	**-5.6**	**-5.6**	**-5.6**	**-5.6**
PV cash flow		0.0	-0.9	-1.6	-2.2	-3.3	-3.8	-3.5	-3.2	-3.0	-2.8	-2.6
NPV=	-26.9											
NPV=	-$26.9											

Appendix 3: Model output - Economic evaluation of options under different scenarios

GTS Regulatory Test evaluation: Scenario A

All amounts expressed in real $ M

Discount rate	6.6%	real, pre-tax
Opex rate	1.5%	per annum
Transmission asset life	45	years

SUMMARY: Scenario A

	NPV	Net benefit
Option 1 - Do nothing	-$188.3	$0.0
Option 2 - 4th Transformer	-$30.6	$157.7
Option 3 - EGTS	-$35.7	$152.6
Net benefit of Option 2 exeeds Option 3 by		$5.1

	Yr ending Dec =>	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
	t=	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
	Discount factor	1.000	0.938	0.880	0.826	0.774	0.726	0.681	0.639	0.600	0.563	0.528
Option 1: Do nothing (Central demand f/c)												
Expected Unserved energy value ($)			1025877	2129606	3540639	6673764	14826880	21670049	39289237	56569201	75144559	95734512
Expected Unserved energy value ($M)			1.0	2.1	3.5	6.7	14.8	21.7	39.3	56.6	75.1	95.7
Total cash flow			**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-14.8**	**-21.7**	**-39.3**	**-56.6**	**-75.1**	**-95.7**
PV cash flow		0.0	-1.0	-1.9	-2.9	-5.2	-10.8	-14.8	-25.1	-33.9	-42.3	-50.5
NPV=	-188.3											
NPV=	-$188.3											
Option 2: GTS 4th TFRM then EGTS in 2023												
PV of EGTS 2023 capex	-29.9											
Annuity from today of this PV	-$2.1											
Opex annuity from today	-$0.4											
Capital cost, 4th TFMR	-17.3											
Annuity of capital cost	-1.2092					-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2
Annual Opex	-0.2593					-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
Annuity of future cost of EGTS 2023	-2.5		-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5
Unserved energy			-1.0	-2.1	-3.5							
Total cash flow		**0.0**	**-3.6**	**-4.7**	**-6.1**	**-4.0**	**-4.0**	**-4.0**	**-4.0**	**-4.0**	**-4.0**	**-4.0**
PV cash flow		0.0	-3.3	-4.1	-5.0	-3.1	-2.9	-2.7	-2.6	-2.4	-2.3	-2.1
NPV=	-30.6											
NPV=	-$30.6											
Option 3: EGTS in 2012												
Capital cost, EGTS	-78.0											
Annuity of capital cost	-5.5						-5.5	-5.5	-5.5	-5.5	-5.5	-5.5
Annual Opex	-1.2						-1.2	-1.2	-1.2	-1.2	-1.2	-1.2
Unserved energy			-1.0	-2.1	-3.5	-6.7						
Total cash flow		**0.0**	**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-6.6**	**-6.6**	**-6.6**	**-6.6**	**-6.6**	**-6.6**
PV cash flow		0.0	-1.0	-1.9	-2.9	-5.2	-4.8	-4.5	-4.2	-4.0	-3.7	-3.5
NPV=	-35.7											
NPV=	-$35.7											

GTS Regulatory Test evaluation: Scenario B

All amounts expressed in real $ M

Discount rate	6.6%	real, pre-tax
Opex rate	1.5%	per annum
Transmission asset life	45	years

SUMMARY: Scenario B		
	NPV	Net benefit
Option 1 - Do nothing	-$115.6	$0.0
Option 2 - 4th Transformer	-$29.6	$86.0
Option 3 - EGTS	-$33.1	$82.5
Net benefit of Option 2 exeeds Option 3 by		$3.4

	Yr ending Dec =>	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
	t=	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
	Discount factor	1.000	0.938	0.880	0.826	0.774	0.726	0.681	0.639	0.600	0.563	0.528
Option 1: Do nothing (Central demand f/c)												
Expected Unserved energy value ($)			982853	1839697	2781237	4499016	8787465	12757685	22586628	33139247	45759699	60899832
Expected Unserved energy value ($M)			1.0	1.8	2.8	4.5	8.8	12.8	22.6	33.1	45.8	60.9
Total cash flow			**-1.0**	**-1.8**	**-2.8**	**-4.5**	**-8.8**	**-12.8**	**-22.6**	**-33.1**	**-45.8**	**-60.9**
PV cash flow		0.0	-0.9	-1.6	-2.3	-3.5	-6.4	-8.7	-14.4	-19.9	-25.7	-32.1
NPV=	-115.6											
NPV=	-$115.6											

		2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Option 2: GTS 4th TFRM then EGTS in 2023												
PV of EGTS 2023 capex	-29.9											
Annuity from today of this PV	-$2.1											
Opex annuity from today	-$0.4											
Capital cost, 4th TFMR	-17.3											
Annuity of capital cost	-1.2092					-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2
Annual Opex	-0.2593					-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
Annuity of future cost of EGTS 2023	-2.5		-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5
Unserved energy			-1.0	-1.8	-2.8							
Total cash flow		**0.0**	**-3.5**	**-4.4**	**-5.3**	**-4.0**	**-4.0**	**-4.0**	**-4.0**	**-4.0**	**-4.0**	**-4.0**
PV cash flow		0.0	-3.3	-3.9	-4.4	-3.1	-2.9	-2.7	-2.6	-2.4	-2.3	-2.1
NPV=	-29.6											
NPV=	-$29.6											

		2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Option 3: EGTS in 2012												
Capital cost, EGTS	-78.0											
Annuity of capital cost	-5.5						-5.5	-5.5	-5.5	-5.5	-5.5	-5.5
Annual Opex	-1.2						-1.2	-1.2	-1.2	-1.2	-1.2	-1.2
Unserved energy			-1.0	-1.8	-2.8	-4.5						
Total cash flow		**0.0**	**-1.0**	**-1.8**	**-2.8**	**-4.5**	**-6.6**	**-6.6**	**-6.6**	**-6.6**	**-6.6**	**-6.6**
PV cash flow		0.0	-0.9	-1.6	-2.3	-3.5	-4.8	-4.5	-4.2	-4.0	-3.7	-3.5
NPV=	-33.1											
NPV=	-$33.1											

GTS Regulatory Test evaluation: Scenario C

All amounts expressed in real $ M

Discount rate	10.0%	real, pre-tax
Opex rate	1.5%	per annum
Transmission asset life	45	years

SUMMARY: Scenario C	NPV	Net benefit
Option 1 - Do nothing	-$90.2	$0.0
Option 2 - 4th Transformer	-$25.2	$65.0
Option 3 - EGTS	-$34.6	$55.6
Net benefit of Option 2 exeeds Option 3 by		$9.4

	Yr ending Dec =>	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
	t=	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
	Discount factor	1.000	0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424	0.386
Option 1: Do nothing (Central demand f/c)												
Expected Unserved energy value ($)			982853	1839697	2781237	4499016	8787465	12757685	22586628	33139247	45759699	60899832
Expected Unserved energy value ($M)			1.0	1.8	2.8	4.5	8.8	12.8	22.6	33.1	45.8	60.9
Total cash flow			**-1.0**	**-1.8**	**-2.8**	**-4.5**	**-8.8**	**-12.8**	**-22.6**	**-33.1**	**-45.8**	**-60.9**
PV cash flow		0.0	-0.9	-1.5	-2.1	-3.1	-5.5	-7.2	-11.6	-15.5	-19.4	-23.5
NPV=	-90.2											
NPV=	-$90.2											
Option 2: GTS 4th TFRM then EGTS in 2023												
PV of EGTS 2023 capex	-18.7											
Annuity from today of this PV	-$1.9											
Opex annuity from today	-$0.3											
Capital cost, 4th TFMR	-17.2											
Annuity of capital cost	-1.7453					-1.7	-1.7	-1.7	-1.7	-1.7	-1.7	-1.7
Annual Opex	-0.2582					-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
Annuity of future cost of EGTS 2023	-2.2		-2.2	-2.2	-2.2	-2.2	-2.2	-2.2	-2.2	-2.2	-2.2	-2.2
Unserved energy			-1.0	-1.8	-2.8							
Total cash flow		**0.0**	**-3.2**	**-4.0**	**-5.0**	**-4.2**	**-4.2**	**-4.2**	**-4.2**	**-4.2**	**-4.2**	**-4.2**
PV cash flow		0.0	-2.9	-3.3	-3.7	-2.9	-2.6	-2.4	-2.1	-1.9	-1.8	-1.6
NPV=	-25.2											
NPV=	-$25.2											
Option 3: EGTS in 2012												
Capital cost, EGTS	-78.0											
Annuity of capital cost	-7.9						-7.9	-7.9	-7.9	-7.9	-7.9	-7.9
Annual Opex	-1.2						-1.2	-1.2	-1.2	-1.2	-1.2	-1.2
Unserved energy			-1.0	-1.8	-2.8	-4.5						
Total cash flow		**0.0**	**-1.0**	**-1.8**	**-2.8**	**-4.5**	**-9.1**	**-9.1**	**-9.1**	**-9.1**	**-9.1**	**-9.1**
PV cash flow		0.0	-0.9	-1.5	-2.1	-3.1	-5.6	-5.1	-4.7	-4.2	-3.9	-3.5
NPV=	-34.6											
NPV=	-$34.6											

GTS Regulatory Test evaluation: Scenario D

All amounts expressed in real $ M

Discount rate	6.6%	real, pre-tax
Opex rate	0.5%	per annum
Transmission asset life	45	years

SUMMARY: Scenario D		
	NPV	Net benefit
Option 1 - Do nothing	-$188.3	$0.0
Option 2 - 4th Transformer	-$18.9	$169.4
Option 3 - EGTS	-$22.7	$165.6
Net benefit of Option 2 exeeds Option 3 by		$3.7

	Yr ending Dec =>	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	t=	0	1	2	3	4	5	6	7	8	9	10
	Discount factor	1.000	0.938	0.880	0.826	0.774	0.726	0.681	0.639	0.600	0.563	0.528
Option 1: Do nothing (Central demand f/c)												
Expected Unserved energy value ($)			1025877	2129606	3540639	6673764	14826880	21670049	39289237	56569201	75144559	95734512
Expected Unserved energy value ($M)			1.0	2.1	3.5	6.7	14.8	21.7	39.3	56.6	75.1	95.7
Total cash flow			**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-14.8**	**-21.7**	**-39.3**	**-56.6**	**-75.1**	**-95.7**
PV cash flow		0.0	-1.0	-1.9	-2.9	-5.2	-10.8	-14.8	-25.1	-33.9	-42.3	-50.5
NPV=	-188.3											
NPV=	-$188.3											
Option 2: GTS 4th TFRM then EGTS in 2023												
PV of EGTS 2023 capex	-16.1											
Annuity from today of this PV	-$1.1											
Opex annuity from today	-$0.1											
Capital cost, 4th TFMR	-13.46											
Annuity of capital cost	-0.9416					-0.9	-0.9	-0.9	-0.9	-0.9	-0.9	-0.9
Annual Opex	-0.0673					-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Annuity of future cost of EGTS 2023	-1.2		-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2
Unserved energy			-1.0	-2.1	-3.5							
Total cash flow		**0.0**	**-2.2**	**-3.3**	**-4.7**	**-2.2**	**-2.2**	**-2.2**	**-2.2**	**-2.2**	**-2.2**	**-2.2**
PV cash flow		0.0	-2.1	-2.9	-3.9	-1.7	-1.6	-1.5	-1.4	-1.3	-1.2	-1.2
NPV=	-18.9											
NPV=	-$18.9											
Option 3: EGTS in 2012												
Capital cost, EGTS	-42.0											
Annuity of capital cost	-2.9						-2.9	-2.9	-2.9	-2.9	-2.9	-2.9
Annual Opex	-0.2						-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Unserved energy			-1.0	-2.1	-3.5	-6.7						
Total cash flow		**0.0**	**-1.0**	**-2.1**	**-3.5**	**-6.7**	**-3.1**	**-3.1**	**-3.1**	**-3.1**	**-3.1**	**-3.1**
PV cash flow		0.0	-1.0	-1.9	-2.9	-5.2	-2.3	-2.1	-2.0	-1.9	-1.8	-1.7
NPV=	-22.7											
NPV=	-$22.7											

GTS Regulatory Test evaluation: Scenario E

All amounts expressed in real $ M

Discount rate	6.6%	real, pre-tax
Opex rate	0.5%	per annum
Transmission asset life	45	years

SUMMARY: Scenario E		
	NPV	Net benefit
Option 1 - Do nothing	-$115.6	$0.0
Option 2 - 4th Transformer	-$18.0	$97.6
Option 3 - EGTS	-$20.1	$95.5
Net benefit of Option 2 exeeds Option 3 by		$2.1

	Yr ending Dec =>	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
	t=	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
	Discount factor	1.000	0.938	0.880	0.826	0.774	0.726	0.681	0.639	0.600	0.563	0.528
Option 1: Do nothing (Central demand f/c)												
Expected Unserved energy value ($)			982853	1839697	2781237	4499016	8787465	12757685	22586628	33139247	45759699	60899832
Expected Unserved energy value ($M)			1.0	1.8	2.8	4.5	8.8	12.8	22.6	33.1	45.8	60.9
Total cash flow			**-1.0**	**-1.8**	**-2.8**	**-4.5**	**-8.8**	**-12.8**	**-22.6**	**-33.1**	**-45.8**	**-60.9**
PV cash flow		0.0	-0.9	-1.6	-2.3	-3.5	-6.4	-8.7	-14.4	-19.9	-25.7	-32.1
NPV=	-115.6											
NPV=	-$115.6											
Option 2: GTS 4th TFRM then EGTS in 2023												
PV of EGTS 2023 capex	-16.1											
Annuity from today of this PV	-$1.1											
Opex annuity from today	-$0.1											
Capital cost, 4th TFMR	-13.5											
Annuity of capital cost	-0.9416					-0.9	-0.9	-0.9	-0.9	-0.9	-0.9	-0.9
Annual Opex	-0.0673					-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Annuity of future cost of EGTS 2023	-1.2		-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2	-1.2
Unserved energy			-1.0	-1.8	-2.8							
Total cash flow		**0.0**	**-2.2**	**-3.0**	**-4.0**	**-2.2**	**-2.2**	**-2.2**	**-2.2**	**-2.2**	**-2.2**	**-2.2**
PV cash flow		0.0	-2.1	-2.7	-3.3	-1.7	-1.6	-1.5	-1.4	-1.3	-1.2	-1.2
NPV=	-18.0											
NPV=	-$18.0											
Option 3: EGTS in 2012												
Capital cost, EGTS	-42.0											
Annuity of capital cost	-2.9						-2.9	-2.9	-2.9	-2.9	-2.9	-2.9
Annual Opex	-0.2						-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Unserved energy			-1.0	-1.8	-2.8	-4.5						
Total cash flow		**0.0**	**-1.0**	**-1.8**	**-2.8**	**-4.5**	**-3.1**	**-3.1**	**-3.1**	**-3.1**	**-3.1**	**-3.1**
PV cash flow		0.0	-0.9	-1.6	-2.3	-3.5	-2.3	-2.1	-2.0	-1.9	-1.8	-1.7
NPV=	-20.1											
NPV=	-$20.1											

GTS Regulatory Test evaluation: Scenario F

All amounts expressed in real $ M

Discount rate	10.0%	real, pre-tax
Opex rate	0.5%	per annum
Transmission asset life	45	years

SUMMARY: Scenario F		
	NPV	Net benefit
Option 1 - Do nothing	-$90.2	$0.0
Option 2 - 4th Transformer	-$16.3	$73.9
Option 3 - EGTS	-$20.9	$69.3
Net benefit of Option 2 exeeds Option 3 by		$4.6

Yr ending Dec =>		**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
t=		**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Discount factor		1.000	0.909	0.826	0.751	0.683	0.621	0.564	0.513	0.467	0.424	0.386
Option 1: Do nothing (Central demand f/c)												
Expected Unserved energy value ($)			982853	1839697	2781237	4499016	8787465	12757685	22586628	33139247	45759699	60899832
Expected Unserved energy value ($M)			1.0	1.8	2.8	4.5	8.8	12.8	22.6	33.1	45.8	60.9
Total cash flow			**-1.0**	**-1.8**	**-2.8**	**-4.5**	**-8.8**	**-12.8**	**-22.6**	**-33.1**	**-45.8**	**-60.9**
PV cash flow		0.0	-0.9	-1.5	-2.1	-3.1	-5.5	-7.2	-11.6	-15.5	-19.4	-23.5
NPV=	-90.2											
NPV=	-$90.2											
Option 2: GTS 4th TFRM then EGTS in 2023												
PV of EGTS 2023 capex	-10.1											
Annuity from today of this PV	-$1.0											
Opex annuity from today	-$0.1											
Capital cost, 4th TFMR	-13.4											
Annuity of capital cost	-1.3609					-1.4	-1.4	-1.4	-1.4	-1.4	-1.4	-1.4
Annual Opex	-0.0671					-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Annuity of future cost of EGTS 2023	-1.1		-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1
Unserved energy			-1.0	-1.8	-2.8							
Total cash flow		**0.0**	**-2.1**	**-2.9**	**-3.9**	**-2.5**	**-2.5**	**-2.5**	**-2.5**	**-2.5**	**-2.5**	**-2.5**
PV cash flow		0.0	-1.9	-2.4	-2.9	-1.7	-1.6	-1.4	-1.3	-1.2	-1.1	-1.0
NPV=	-16.3											
NPV=	-$16.3											
Option 3: EGTS in 2012												
Capital cost, EGTS	-42.0											
Annuity of capital cost	-4.3						-4.3	-4.3	-4.3	-4.3	-4.3	-4.3
Annual Opex	-0.2						-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Unserved energy			-1.0	-1.8	-2.8	-4.5						
Total cash flow		**0.0**	**-1.0**	**-1.8**	**-2.8**	**-4.5**	**-4.5**	**-4.5**	**-4.5**	**-4.5**	**-4.5**	**-4.5**
PV cash flow		0.0	-0.9	-1.5	-2.1	-3.1	-2.8	-2.5	-2.3	-2.1	-1.9	-1.7
NPV=	-20.9											
NPV=	-$20.9											