Report

Multi-Nodal Generation Expansion Planning Tool

(Rapid Response Modelling: Phase 1)

Submitted to:

Eskom Integrated Strategic Electricity Planning

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Executive Summary

This document reports on how TIMES is used in conjunction with Excel to do multi-node generation expansion planning. The 3 aspects that are focused on are the handling of planned and unplanned outages, characterization of demand and representation of transmission lines. Current versions of some of the more important components of the user interface (in Excel) are also presented.

A two-stage benchmark test was performed on a single node model with EGEAS. In the first stage, the fixed investment plan generated using EGEAS was forced in TIMES and an analysis was conducted on the production plan. The results obtained show that TIMES report similar production levels as reported by EGEAS. The unserved energy levels obtained using the MC approach seem to correlate well with that obtained using the equivalent load duration curve used by EGEAS.

In the second stage, the investment problem was solved using the master-slave iteration approach with TIMES and Excel. This approach yields a range of suitable solutions, some of which resemble closely those obtained using EGEAS. It was demonstrated in the report, how the planner may decide on a preferred plan given a trade-off between unserved energy and system costs. The results of this two-phase benchmark test are notable given that the two approaches (EGEAS and TIMES) are significantly different.

A second case study involving a 6 node version of the model was also performed. The input data provided by Eskom for this study was limited and therefore the parameters used may not replicate the Eskom system for the regions studied. A range of suitable plans were obtained using an approach similar to the one used for a single node. The amount of data generated for the multi-node problem was large and some areas still need to be explored. Results obtained are however within what was expected for the model at hand:

- Transmission lines at bottle-necks use the higher capacity-higher losses transmission blocks (B2).

- Some transmission lines switch direction within the study period, while others are used to carry electricity in two different directions within a single year but never in the same time-slice.

A direct comparison between generation planning with and without transmission constraints on the problem presented here is difficult given the range of solutions obtained in both cases. The generation expansion plans do overlap. One notable difference is that in the multi-node case, some of the generation expansion decisions are delayed by the investment of new transmission lines.

The framework developed in this project is a work in progress. It is demonstrated how this methodology can been used to generate insightful expansion plans that integrate transmission into the decision framework. This framework is customised specifically for ISEP's requirements, based on the format of their input data as well as their output templates. Further work can add to this existing framework and further develop and customise it according to Eskom's and ISEP's changing needs and growing requirement for integrated generation and transmission planning.

The 6 nodal model prepared as proof of concept requires further expansion (27 nodes excluding imports) and refinement both from a methodology, model configuration and user interface perspective. Furthermore, modelling the total Eskom (and National) system will require a high degree of involvement of Eskom planners (ISEP-generation, Nodal demand forecasters and transmission) so as to ensure adequate empowerment of Eskom staff in the application and use of the model and appropriate data collation and input.

The model implemented so far has some shortcomings and areas that can be improved. Some of the more significant issues are elaborated below:

Processing time: Master-iteration runs can take significant amounts of time to solve. Some suggestions on how this can be improved are given later in the report.

Interface: The input interface is almost entirely based in Excel with links to Eskom data tables and some of the results are output using standard Eskom templates. The flexibility of Excel allows for the interfaces to be tailored to Eskom requirements. However they also need to be made more robust to user error. This involves extensive data validation and data checking both of which require significant programming effort.

This being said; having established how TIMES in conjunction with Excel would be used for multi-nodal power sector expansion planning opens up numerous possibilities, namely:

All energy carriers: power sector planning can be performed within the context of the complete energy system, with components both upstream (e.g. refineries) and downstream (demand modelling e.g. electric geyser vs. solar water heaters)

Analysis of uncertainty: Currently the only uncertain parameters handled via Monte Carlo is the unplanned outages of stations and transmission lines. However, having this framework in place, other uncertain parameters such as demand growth could be included into the *master-slave* methodology as well. Other uncertain input parameters such as investment and operating costs of future options, fuel costs, as well as lead time uncertainty could be modelling using MC and a full robustness analysis could be done on preferred plans demonstrating their performance based on the uncertain distributions of the input parameters.

TIMES has the functionality that allows for a few uncertain parameters to be expressed in a stochastic programming with recourse framework. Stochastic programming models with recourse are used for near term modelling in light of long term uncertainties through the development of short term strategies with inherent flexibility towards long-term uncertainties, as well as long term contingency plans once more information becomes available about the uncertain parameters. Another possibility is to combine this tool with the Decision Tree tool developed last year for Eskom, where specific decisions in the context of some of the uncertain parameters can be evaluated.

Multiple-objectives

Within the TIMES framework it is also possible to define the objective function for optimization in terms of more than one objective, e.g. costs, emissions, unserved energy. In this way a range of solutions could be generated, optimised for multiple objectives, from which decision makers could select preferred alternatives. This could be combined with a multi-objective robustness analysis such that a set of plans could be compared based on their performance in terms of each of multiple objectives given the uncertainty in input data (such as investment and operating costs of future options and fuel costs).

Sophisticated graphic user interfaces and reports: as mentioned before, an interface based in Excel offers a number of possibilities, the information generated in a multi-nodal optimization run is substantial and analysis needs to be facilitated via the use of appropriate graphics. Expansion plans reported in Excel could be formatted in such a way so as to seamlessly integrate with other analysis tools such as Pro-Mod.

Multi-regional Generation Expansion Planning Tool

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1 INTRODUCTION

1.1 BACKGROUND

The ISEP process in Eskom has increasingly been requested to undertake studies beyond the capabilities of the computer models currently in use. The current model used for capacity expansion studies was developed some years ago by the Electricity Power Research Institute of the USA, and does not provide for opportunity to develop new features or make alterations as are required in a continually changing environment. These include capabilities such as optimizing expansion plans taking into account concurrent transmission expansion, or to include emissions constraints and penalties.

In addition "what if", sensitivity analyses are required by Management, with increasing frequency. These studies require a more rapid response than can be achieved with the current models.

Further electricity generation is a component of the total energy market and given the interaction that other fuels may have on the demand for electricity, it would be useful to have a methodology that could be expanded to include "all energy" planning.

At present, the electricity expansion planning tool of choice, the "Electric Generation Expansion Analysis System (EGEAS)", solves the system problem for one demand and one supply "node". EGEAS is a multi area planning tool, but it can expand the system (build new stations) in 1 node only. For the other nodes, it simulates the load and the operation of the stations only. Transmission "credits" are granted to generation that occurs close to loads far from the Mpumalanga Highveld where the bulk of South Africa's base-load electricity is generated. Emissions penalties or constraints are not included in the determining the optimal choice of new plant. The tool though powerful, is user intensive requiring time for any data additions, this is not automated. Access to the source code is restricted, and it is not possible to consider fuels other than electricity.

Eskom contracted the Energy Research Centre of Cape Town University (ERC) to investigate various resource planning tools (models) on the International market and recommend a model for future implementation in Eskom. Further ERC contracted to benchmark the model against EGEAS.

After extensive literature survey and analysis, ERC recommended The Integrated Markal-Efom System (TIMES) for use in Eskom as the most appropriate option for future ISEP's needs.

1.2 TIMES

TIMES is an economic model generator for local, national or multi-regional energy systems. It provides a technology-rich basis for estimating energy dynamics over a long-term, multi-period time horizon.

TIMES is a bottom-up optimization model which can simulate large energy systems and provide least-cost solutions to the expansion planning problem. The objective function for the optimization is a linear function of capacity and activity/flow variables. The optimization is subject to a set of linear constraints and is solved by linear programming[1].

TIMES being very flexible and versatile in its basic form is not configured specifically for multi-regional generation expansion planning. It requires some pre-configuration both in the actual model structure and interface.

The main technical stumbling blocks to using a model like TIMES for multi-regional power expansion planning are:

- Representation of outages
- Load representation
- Representation of transmission lines

Another area that has required some effort is customizing/tailoring the interface with TIMES for the multi-regional generation expansion planning problem. While this has taken some effort, the flexibility of TIMES has allowed us to explore various alternatives for overcoming the technical stumbling blocks and tailoring the interface.

[1] See http://www.etsap.org for more detailed technical information on TIMES

1.3 OBJECTIVE

The objective of the work reported in this document is to show how TIMES could be used to do multi-nodal generation expansion planning, given the above-mentioned stumbling blocks, and whether its results can be benchmarked against another well established platform (EGEAS).

1.4 OVERVIEW OF DOCUMENT

The rest of this document is structured as follows:

Section 2 gives a description of how **outages** are handled

Section 3 gives a description of how **demand** is characterised

Section 4 gives a description of how **transmission lines** are modelled

Section 5 gives a description of the **user interface**

Section 6 describes a **case study done for a one-node model** based on the West and Eastern Cape regions of South Africa

Section 7 describes a **multi-node** representation of the same regions

We **conclude** and make some **recommendations** for a way forward in section 8

2 REPRESENTATION OF OUTAGES

In this section the representation of outages is discussed in detail.

2.1 MODEL STRUCTURE

An unserved energy plant was included so that the model could decide, given the cost of not serving energy, whether it would be optimal to build new capacity or not serve energy. This trade-off is particularly pertinent when demand is only marginally higher than supply capacity and therefore only a small amount of energy would not be served if new generation capacity was not built. The model was then separated into a *master* (investment) and *slave* (operational) problem so as to model uncertainty in plant outage. See Figure 1 below:

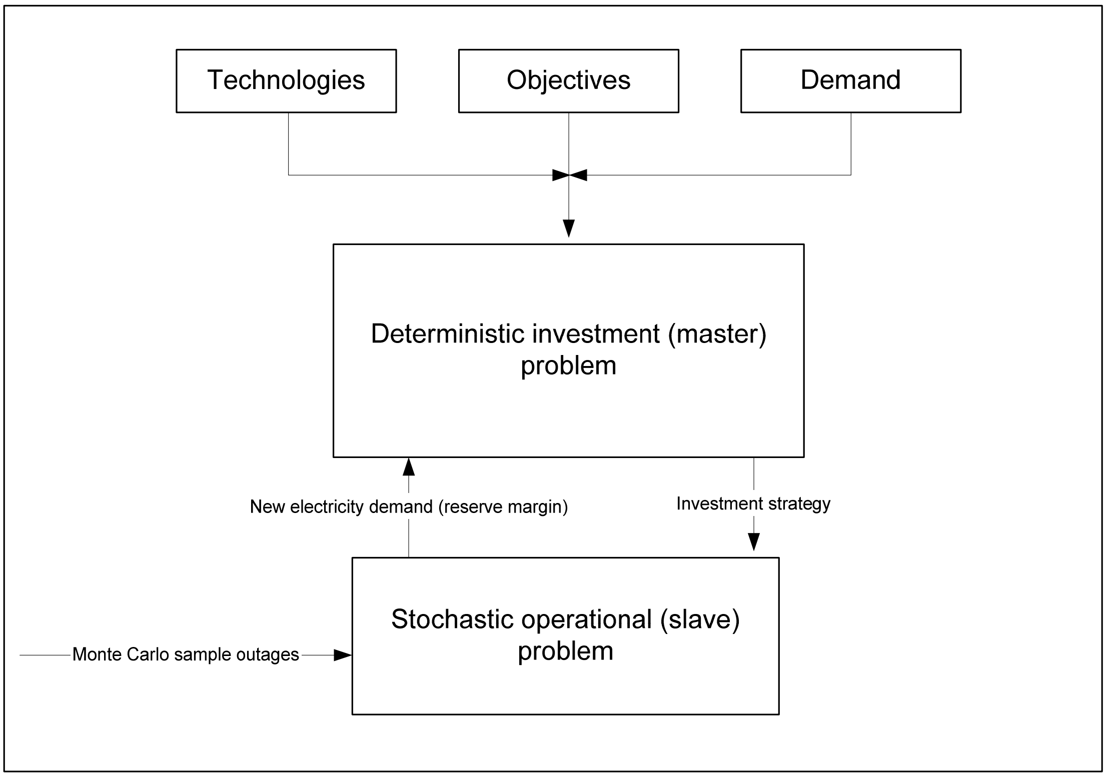

Figure 1 - Representation of master slave feedback for reserve margin calculation

The *master* problem is essentially a complete model in itself as TIMES is setup to solve both the investment and operation of the power plants for a specified demand simultaneously (similarly to MARKAL-described in chapter 4). However, in order to model uncertainty in plant availability an operational *slave* sub-model was created that uses the fixed investment "skeleton" from the *master* problem.

The *master problem* is solved to generate an initial solution, and then the *sub-problem* is solved for the investment strategy generated in the *master problem* for each random sample of plant outages (described in section 3.4).

Unlike in the Benders decomposition method, the dual multipliers of the *slave* problem are not used as the new cuts for the *master* problem. Instead, for each random set of outages generated using Monte Carlo sampling, the unserved energy of the system given the demand and the investment strategy from the *master* problem is recorded. After the slave problem has been rerun for each of the Monte Carlo samples, the distribution of unserved energy over the sample set is calculated for each year in the time horizon and compared to the "optimal" amount of unserved energy calculated in the *master* problem for that year. If the distribution of unserved energy in the *slave* problem is greater than the unserved energy in the *master* problem (for a specified tolerance e.g. 90 %), then the demand for that year in the master problem is increased.

This forces the *master* problem to invest in more capacity in that year (if possible given the constraints of the model) which will in turn result in less energy going unserved in the *slave* problem. If the distribution of unserved energy in the *slave* problem is less than the unserved energy in the *master* problem then the demand inflation level that year remains unchanged. This methodology is carried out iteratively until unserved energy objectives as reported in the slave runs are achieved over the entire study period[2].

Using this methodology on a national model based on the NIRP 2 data, the following results were observed:

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[2] The master-slave problem would have to be setup separately for each alternative in the case where a portfolio of preferred alternatives exists. The initial investment strategy sent to the slave problem would then be the investment strategy of each of the preferred alternatives selected previously.

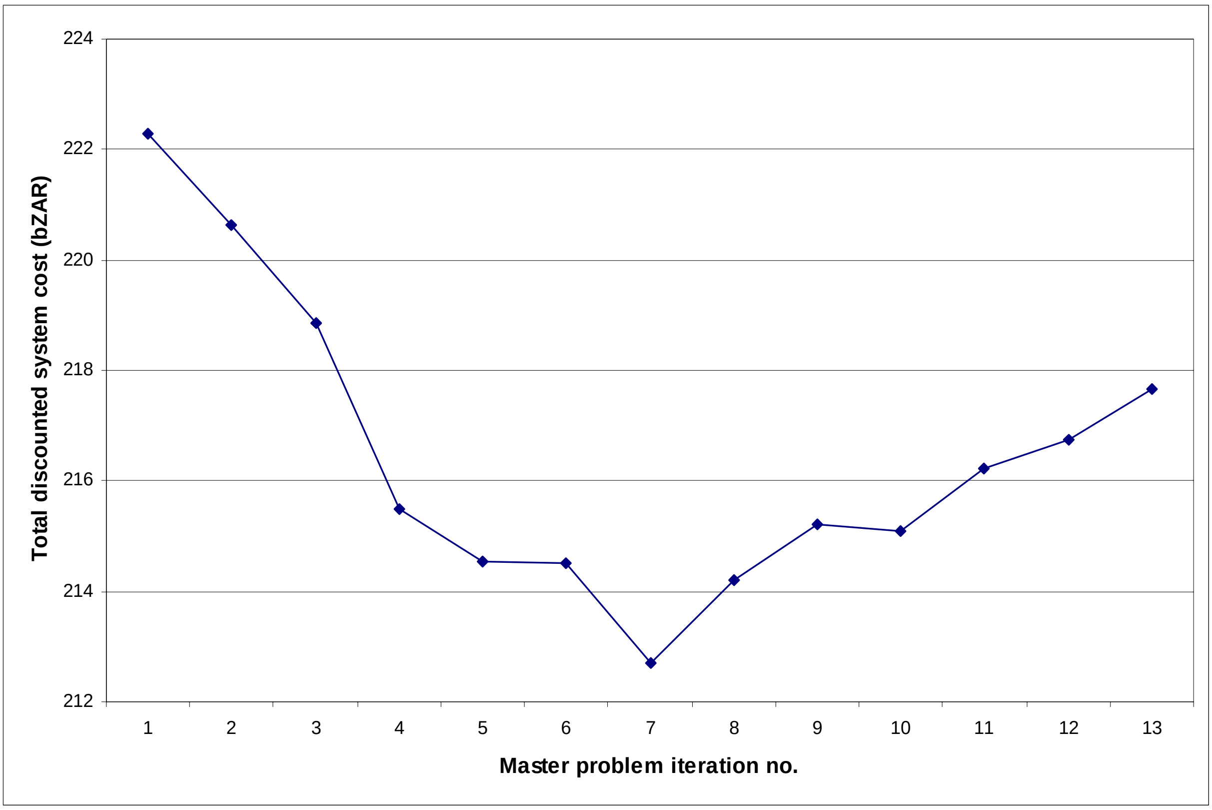


Figure 2 - Graph of total discounted system cost as a function of master problem iteration number - National model-NIRP2 data (Heinrich (2007))

Figure 2 shows that total discounted system cost decreases as the demand is incrementally increased in years where the convergence criterion is not met. A minimum is reached before total convergence is achieved.

The behaviour seen in Figure 2 is due to the trade-off between the avoided costs of unserved energy by building more capacity to account for plant outage and the investment cost and fixed O&M cost of that extra capacity. Up to the point where the minimum is reached, the avoided cost of unserved energy outweighs the extra investment and fixed O&M cost of the new capacity. Beyond that point it is more expensive to build the extra capacity than it is to not serve small amounts of electricity. This can be simplified to an example where in a particular year; the demand for electricity would be very slightly above the capacity to supply (e.g. 0.01 PJ or 2.78 GWh). In this case it would probably be cheaper to pay the high cost per unit of unserved energy and not supply that small demand than it would be to build a 120 MW gas turbine an run it for less than 1 % of the year.

Reserve margin or inflated demand?

The question of whether to use a minimum reserve margin or an inflated demand to increase capacity investment in the master problem was considered. Deration combined with a reserve margin is a common method used in ESI modelling. The problem with this method is in the way the model interprets a reserve margin. To the model, the minimum reserve margin represents a minimum capacity constraint that must be met. Therefore the model invests in plants that have low investment costs; irrespective of their running costs due to the fact that they will not be run as they are built to meet capacity constraints. In reality the excess capacity built to account for unforeseen unit outage will be run as other plant fail and therefore their running costs must be considered. One way of doing this is to set minimum utilisation constraints in the model forcing stations that are built to be run at a minimum utilisation rate (e.g. 5 % for OCGTs). This does however constrain the optimisation skewing the results.

Another way of doing this is to use an inflated demand, thereby forcing the model to build stations for a hypothetical demand that must be met (instead of a capacity constraint). This method more closely resembles reality as running costs (as well as investment costs) are considered. A complication of this approach is that the operating or running costs calculated in the *master* problem are inflated. However, using the approach presented here, the correct operating costs (taking plant outage into account) can be calculated from the *slave* problem.

2.2 PLANNED OUTAGE

Planned outage is typically modelled using the derating method, whereby an annual constraint on the availability of each station limits its operation to never exceed the annual availability rate (1-POR), in any timeslice. While this is a fair approximation that has been used in energy modelling, in reality planned outage is optimised such that maintenance occurs outside of the peak demand time periods. This can be modelled using summation constraints that specify an annual bound on activity for each station without a bound on the activity of each station in each timeslice. In this way a station can run to its' full capacity when it is online, but can be partially in planned outage, for a specified amount portion of the year. One of the potential limitations of this approach is that planned outage will not necessarily occur in discrete blocks (i.e. a unit may go for two weeks over the period of a year rather than for a period of 2 weeks at a time). This approach is still a significant improvement over limiting the load factor of a station to (1-POR) in every timeslice.

2.3 FORCED OUTAGE

Forced outage is more complicated to model than planned outage as it is random, not optimised, and can even occur in a timeslice allocated to planned maintenance. The methodology adopted here was to simulate the random forced outage of stations using Monte Carlo sampling in the *slave* problem, such that each unit of a station would either be available or out, for any given timeslice, and that the total time that a station would be forced out in any year would converge to the average annual force outage rate of this station (over all MC iterations) as specified in the data. Appendix A and B give some details on how the required number of MC iterations for a given problem are estimated. Forced outages were not explicitly handled in the *master* problem, but instead accounted for by inflated demand.

The starting point for the Monte Carlo sampling was to examine the probabilities of units going out. Table 1 below illustrates the probability of 0, 1, 2 or 3 units of a station going out (using a FOR of 0.05) as a function of the number of units in that station. Firstly, the number of combinations for which 0, 1, 2 or 3 units could go out given the number of units making up a station was calculated. Next the probability of the event of 0, 1, 2 or 3 going out was calculated. Finally by multiplying the number of combinations for each event by the probability of each event, the actual probability of 0, 1, 2, 3 or more units going out for each station could be calculated.

Table 1- Probability of unit outage as a function of number of units per station

Unit per station		**No of combinations**			**Probability of event**				**Probability of combination**				**Probability of more than 3 units out**
No. units out	**0**	**1**	**2**	**3**	**0**	**1**	**2**	**3**	$\mathbf{P_0}$	$\mathbf{P_1}$	$\mathbf{P_2}$	$\mathbf{P_3}$	
1	1	1	0	0	95.00%	5.00%	0.00%	0.00%	95.00%	5.00%	0.00%	0.00%	0.00%
2	1	2	1	0	90.25%	4.75%	0.25%	0.00%	90.25%	9.50%	0.25%	0.00%	0.00%
3	1	3	3	1	85.74%	4.51%	0.24%	0.01%	85.74%	13.54%	0.71%	0.01%	0.00%
4	1	4	6	4	81.45%	4.29%	0.23%	0.01%	81.45%	115%	1.35%	0.05%	0.00%
5	1	5	10	10	73.8%	4.07%	0.21%	0.01%	73.8%	20.36%	2.14%	0.11%	0.00%
6	1	6	15	20	73.51%	3.87%	0.20%	0.01%	73.51%	23.21%	3.05%	0.21%	0.01%
7	1	7	21	35	69.83%	3.68%	0.19%	0.01%	69.83%	25.73%	4.06%	0.36%	0.02%
8	1	8	28	56	66.34%	3.49%	0.18%	0.01%	66.34%	293%	5.15%	0.54%	0.04%
9	1	9	36	84	63.02%	3.32%	0.17%	0.01%	63.02%	29.85%	6.29%	0.77%	0.06%
10	1	10	45	120	59.87%	3.15%	0.17%	0.01%	59.87%	31.51%	46%	1.05%	0.10%
15	1	15	105	455	46.33%	2.44%	0.13%	0.01%	46.33%	36.58%	13.48%	3.07%	0.55%
20	1	20	190	1140	35.85%	1.89%	0.10%	0.01%	35.85%	374%	18.87%	5.96%	1.59%
30	1	30	435	4060	21.46%	1.13%	0.06%	0.00%	21.46%	33.89%	25.86%	12.70%	6.08%
50	1	50	1225	19600	7.69%	0.40%	0.02%	0.00%	69%	20.25%	26.11%	21.99%	23.96%
60	1	60	1770	34220	4.61%	0.24%	0.01%	0.00%	4.61%	14.55%	22.59%	22.98%	35.27%
70	1	70	2415	54740	2.76%	0.15%	0.01%	0.00%	2.76%	10.16%	18.45%	22.01%	46.61%
80	1	80	3160	82160	1.65%	0.09%	0.00%	0.00%	1.65%	6.95%	14.46%	19.78%	57.16%
90	1	90	4005	117480	0.99%	0.05%	0.00%	0.00%	0.99%	4.68%	10.97%	16.94%	66.42%
100	1	100	4950	161700	0.59%	0.03%	0.00%	0.00%	0.59%	3.12%	8.12%	13.96%	74.22%

It can be seen from Table 1 above that the probabilities of more than 3 units of a station going out simultaneously only become significant (i.e. greater than 1 %) for stations with more than 15 units. Therefore it could be said that provided the stations in the model have less than 15 units, only the probabilities of 0, 1, 2 and 3 units going out need to be taken into account when calculating forced outage. This enables some significant saving of computing time when doing thousands of model runs.

With this in mind a logical procedure was developed to decide the availability of each station in every timeslice. This is outlined below:

- Draw a random number between 0 and 1
- If the number is less than P_0 then 0 units of that station are offline and availability =1 , else:
- if the number is greater than (1- P_3) then availability of the station = 1-3/(number of units). Note the case >3 units out are included in this case, else:
- if the number is greater than (1- (P_3 + P_2)) then availability of the station = 1-2/(number of units), else:
- the number is greater than (1- (P_3 + P_2 + P_1)) then availability of the station = 1-1/(number of units),

In this way the availability of each station for each timeslice could be decided for a single model run. This is illustrated in Table 2 below for an example station with 6 units using a demand resolution containing 2 seasons (s01 and s02), 2 weekparts (w1 and w2) and 7 dayparts (h1-h7):

Table 2 - Forced outages for an example station

Timeslice	2005	2006	2007	2008	2009
s01w1h1	1	1	1	1	1
s01w1h2	1	0.5	1	0.8333	0.8333
s01w1h3	1	0.6667	1	1	1
s01w1h4	1	1	1	0.8333	1
s01w1h5	1	1	1	1	1
s01w1h6	1	1	1	1	0.8333
s01w1h7	0.8333	1	0.8333	1	0.8333
s01w2h1	1	1	1	1	0.8333
s01w2h2	1	0.8333	1	1	1
s01w2h3	1	1	1	1	1
s01w2h4	1	0.8333	1	1	0.8333
s01w2h5	1	0.8333	1	0.8333	0.8333
s01w2h6	1	1	1	0.8333	1
s01w2h7	1	0.6667	1	1	1
s02w1h1	1	1	0.8333	1	1
s02w1h2	1	1	1	1	1
s02w1h3	1	1	1	1	1
s02w1h4	1	1	1	1	1
s02w1h5	1	1	0.8333	1	1
s02w1h6	0.8333	0.8333	0.8333	1	0.6667
s02w1h7	1	1	1	1	1
s02w2h1	1	1	1	1	1
s02w2h2	0.8333	1	1	1	1
s02w2h3	1	1	1	1	1
s02w2h4	1	0.8333	1	1	1
s02w2h5	1	0.6667	1	1	1
s02w2h6	1	1	0.8333	0.6667	1
s02w2h7	1	1	1	1	1

In Table 2 above, “1”s represent when the station is available to run and values less than 1 represent the degree to which the station is forced out or how many of the units of that station are forced out. This information is generated using production variables for each station and not for each unit (except where stations have non-identical units), given their forced outage rates using the procedure described above. This outage information is then fed into the operational *slave* problem and solved for the investment strategy generated in the *master problem*. The solution represents the optimal operational strategy for the objectives defined. This process is repeated for the specified number of sample sets used to represent forced outage (varies depending on the size of the system and the number of samples necessary to adequately represent the outage for that system. The operational variables of each of the power stations as well as the amount of unserved energy for each sample set are recorded. The distribution of unserved energy over all the sample sets is then calculated and used as feedback to the *master* problem as described previously in section 3.2. This methodology is demonstrated in section 9.

3 DEMAND

Raw hourly data is averaged according to user defined time slices. These time slices are divided into seasonal, week-part and day-part breakdowns. Chronology of demand is retained such that DSM and multi-regional load variation can be captured. This representation allows the planner to decide on how to aggregate demand such that the shape of the load is sufficiently captured. The trade-off between representing demand in greater detail and reducing model run time is therefore left to the planner.

Given hourly load data for the entire study period (as available at Eskom in the form of EEI files), the planner has 3 sets of parameters to define this level of detail:

1. The number of seasons, their timing and duration,
2. The number of day types (e.g. 2 day types would be a "weekday" and a "weekend"), and their relative duration, and
3. The number of day-parts within each day type, their timing and duration.

The number of Time slices[3] processed is then equal to:

nSeasons x nDayTypes x nDay-Parts.

This input is used to produce 2 sets of necessary input data for TIMES.

- Time slice duration (as a time fraction of the year)
- Sum of energy demand in each time slice

These energy sums are then processed into energy fractions as required by TIMES. This is done so as to ensure peak power information as well as total energy information is consistent with input data from Eskom.

Figures 2 and 3 below show the representation of demand using containing 3 seasons (s01, s02 and s03), 2 weekparts (w1 and w2), one for typical weekdays and another for typical weekends (weighted according to their time fractions) and 7 dayparts (h1-h7). Figure 3 shows demand chronologically while Figure 4 represents demand using a LDC (although the LDC representation is not used by the model). It must be noted

[3] A Time Slice in TIMES represents the smallest time unit within a period (a year) for which production variables must be solved. One activity/flow variable value is found for each production unit in each Time Slice.

that the energy fractions are solved such that the MW peak in the peak timeslice is equal to the actual MW peak from the raw demand data.

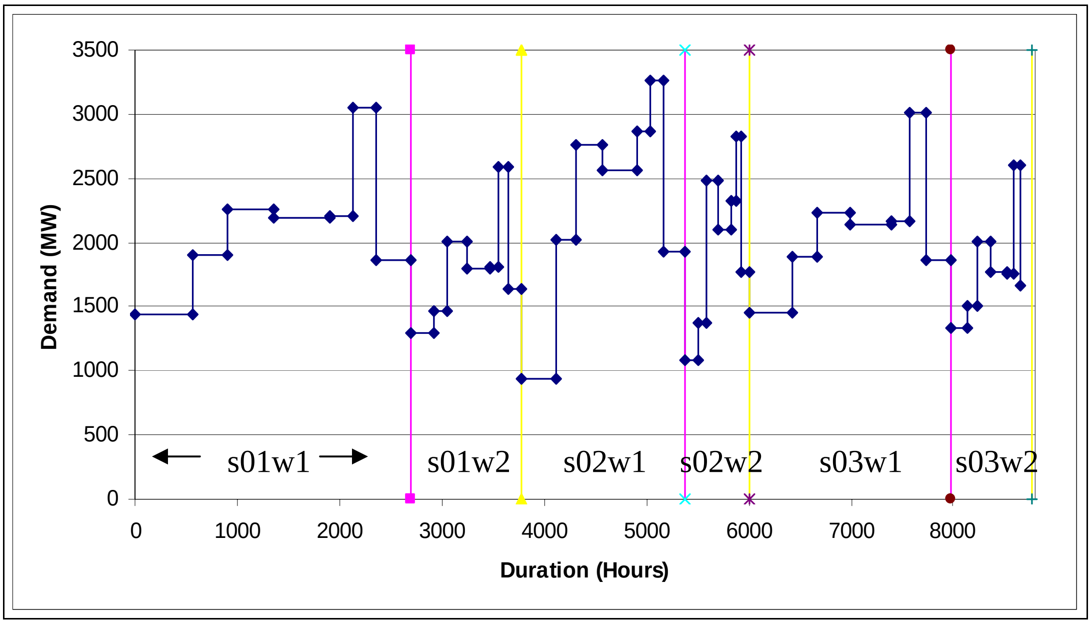


Figure 3 - Chronological representation of demand

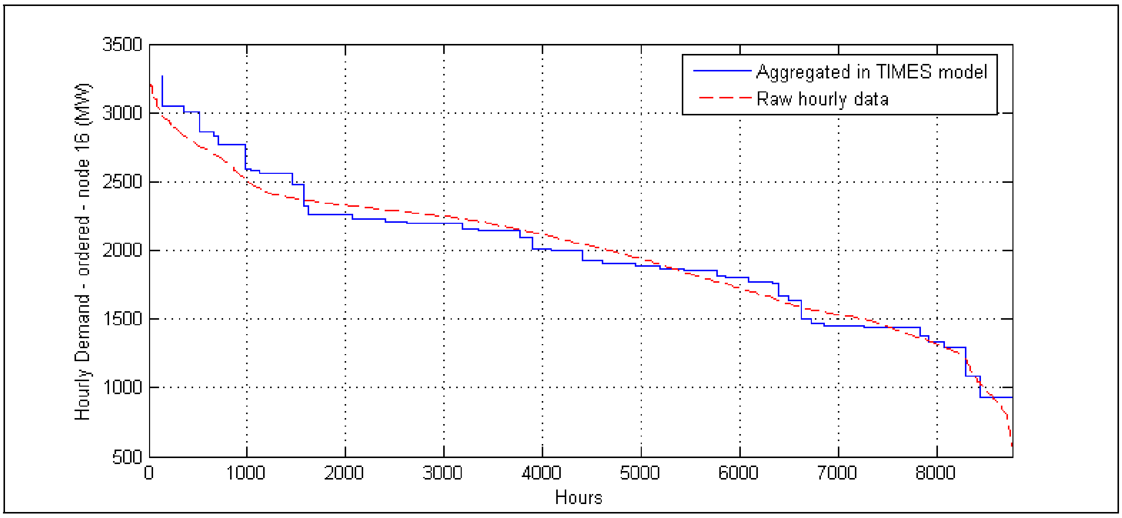


Figure 4 - LDC representation of demand

4 MODELLING TRANSMISSION LINES IN THE TIMES MULTI-NODAL MODEL

4.1 BACKGROUND

To simulate a multi-nodal power system for generation expansion planning, the transport of energy from node to node needs to be accounted. Transmission line capacity represents a maximum constraint on the power flow on the line, either related to the thermal rating, voltage drop or network stability. In our modelling framework we cannot explicitly model these constraints as they are dynamic and non-linear.

4.2 METHODOLOGY

The non-linearity of the losses has been simulated with a loss curve made of two (or more) linear sections (as done in [1]). If configured correctly, this approach would allow the model to capture in a simplistic way the thermal rating limit and possibly a voltage drop limit of transmission lines.

Figure 5 shows a two-component representation of a 400kV transmission line, where we assume that low losses are experienced up to a capacity of 600MW and higher losses are experienced for up to a maximum capacity of 1100MW (these numbers could be further refined and specified for each line).

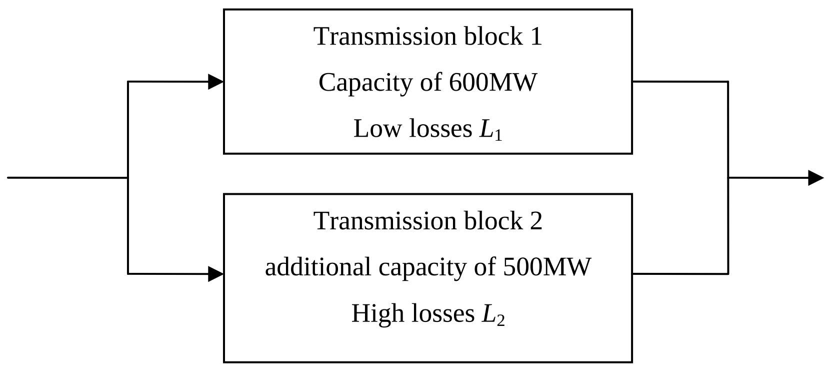


Figure 5 - 2-block model for a 400kV line

Since operating block 1 is cheaper (because of lower losses), the system will choose to first transmit power using block 1. It will do so up to the maximum capacity of the block, after which it will start using block 2 for additional capacity (up to its maximum), if it is required.

The losses as seen by the system for the line is then

$$L = (L_1\xi_1 + L_2\xi_2)/(\xi_1+\xi_2),$$

Where

L (%) is the power loss as seen by the system for the line (combination of the 2 blocks),

$L_{1/2}$ (%) is the power loss if power is transmitted only through block 1/2,

$\xi_{1/2}$ is the power input into block 1/2.

Figure 6 shows the losses in MW as seen by the system using a 2-linear-block model. We compare it to the theoretical losses given by

$$L \text{ (MW)} = (R / |V^2|).D.\xi^2,$$

Where

R is the line resistance per km (ohms/km) in this case 0.012 (maybe a bit high),

V is the voltage (kV) in this case 400,

ξ is the power input (MW) into the line,

D is the distance in km.

These loss models were calibrated on the following assumptions (which can be easily refined and adapted for different lines):

- Line voltage: 400kV
- Distance: 1750km (from Alpha to the Peninsula)
- Losses at 600 MW: 8%
- Losses at 1100 MW: 15%

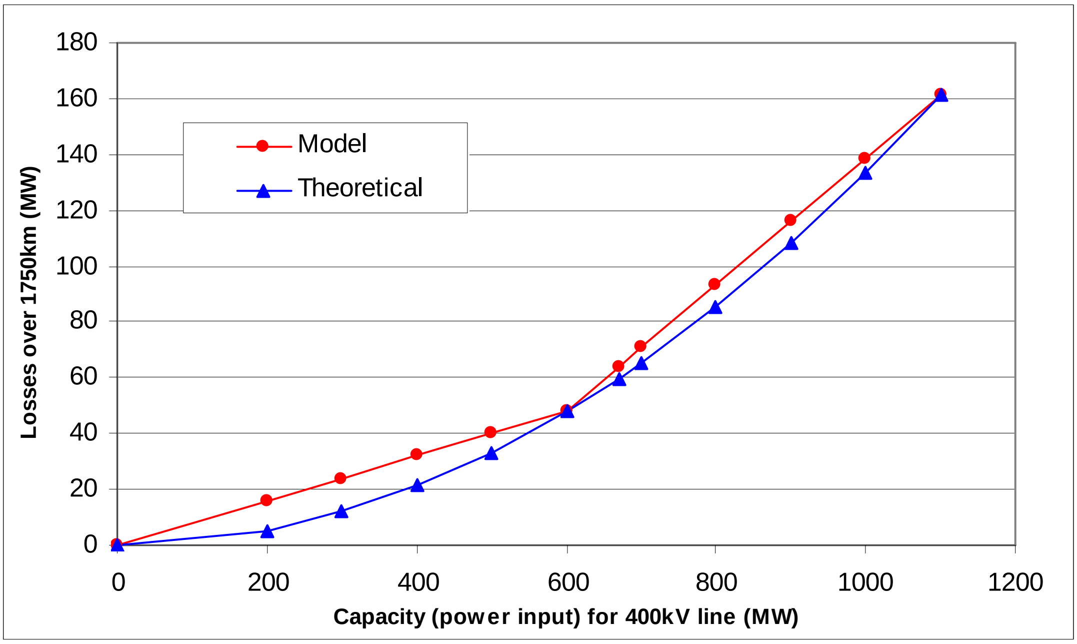


Figure 6 - Losses (MW) using a 2-block model for a 400kV line.

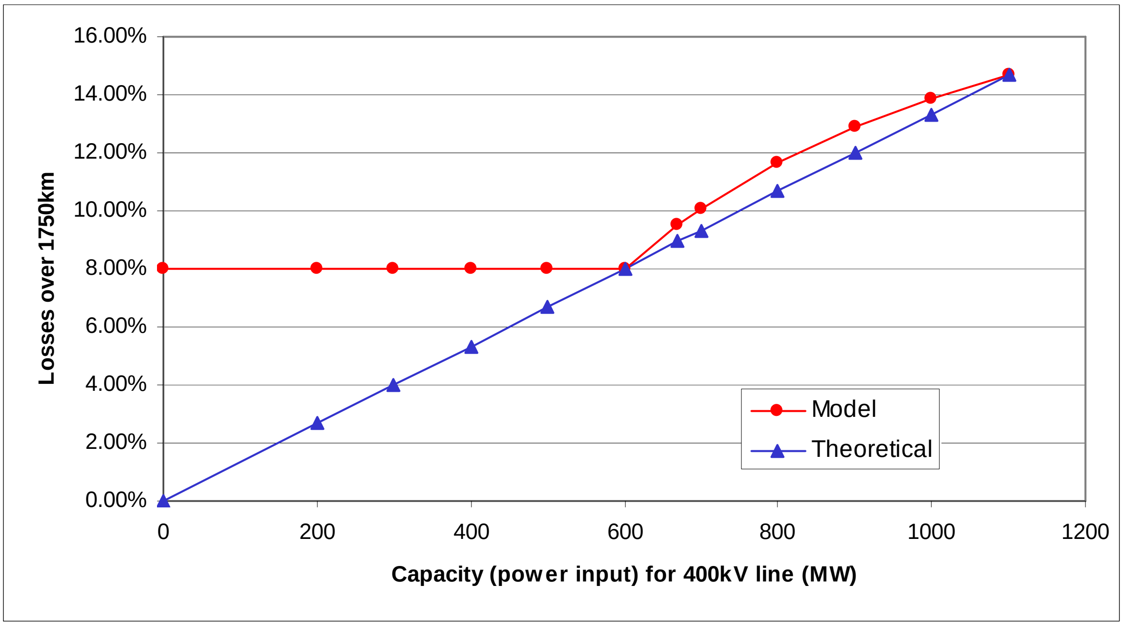


Figure 7 - Losses (fraction of input %) using a 2-block model for a 400kV line.

More accurate representations of the loss curve can be achieved by using more blocks. The decision is then a trade-off between accuracy and model complexity/computation time. By using the same approach power flow can be modelled in reverse direction, when such an event is anticipated.

5 THE USER INTERFACE

This section gives a description of the current version of the input and output user interfaces.

5.1 INPUT INTERFACES

5.1.1 INTERFACE FOR DEMAND PARAMETERS

Figure 8 shows a screen shot of the user interface for specifying demand parameters.
In the first table the dates for the different seasons are entered. The day-parts are specified in the 2nd table. The day-types are specified in the 3rd table.
The 4th table enables to specify for which years should a different load shape be defined.

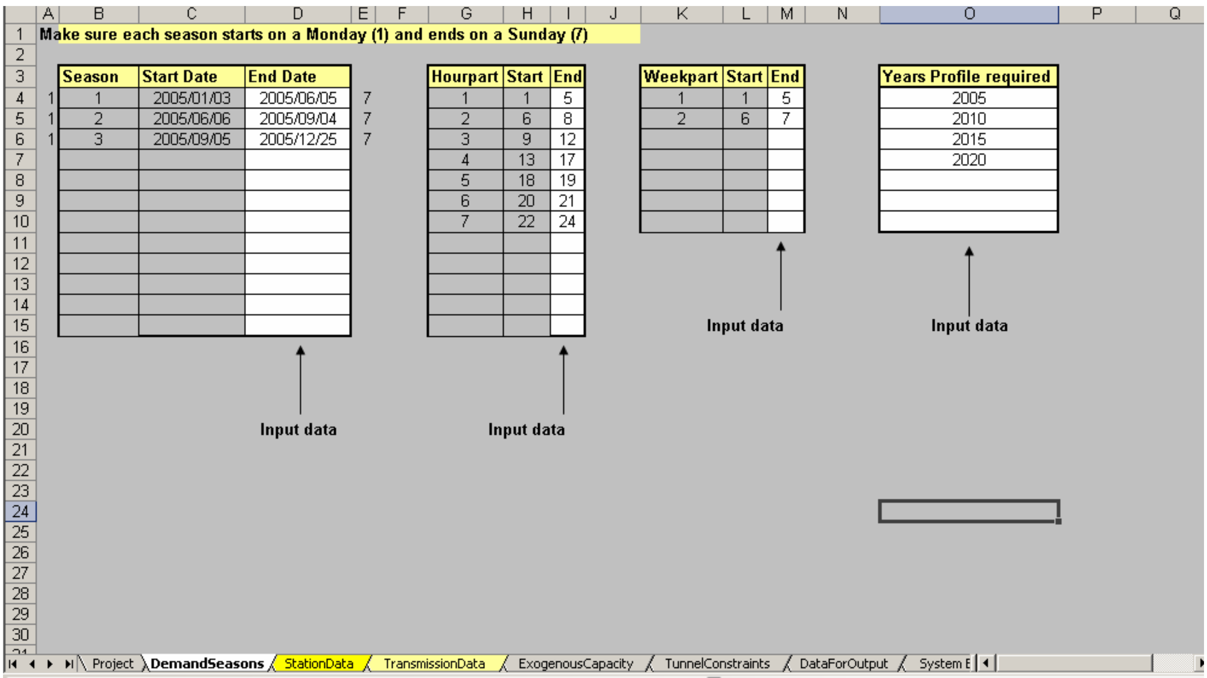
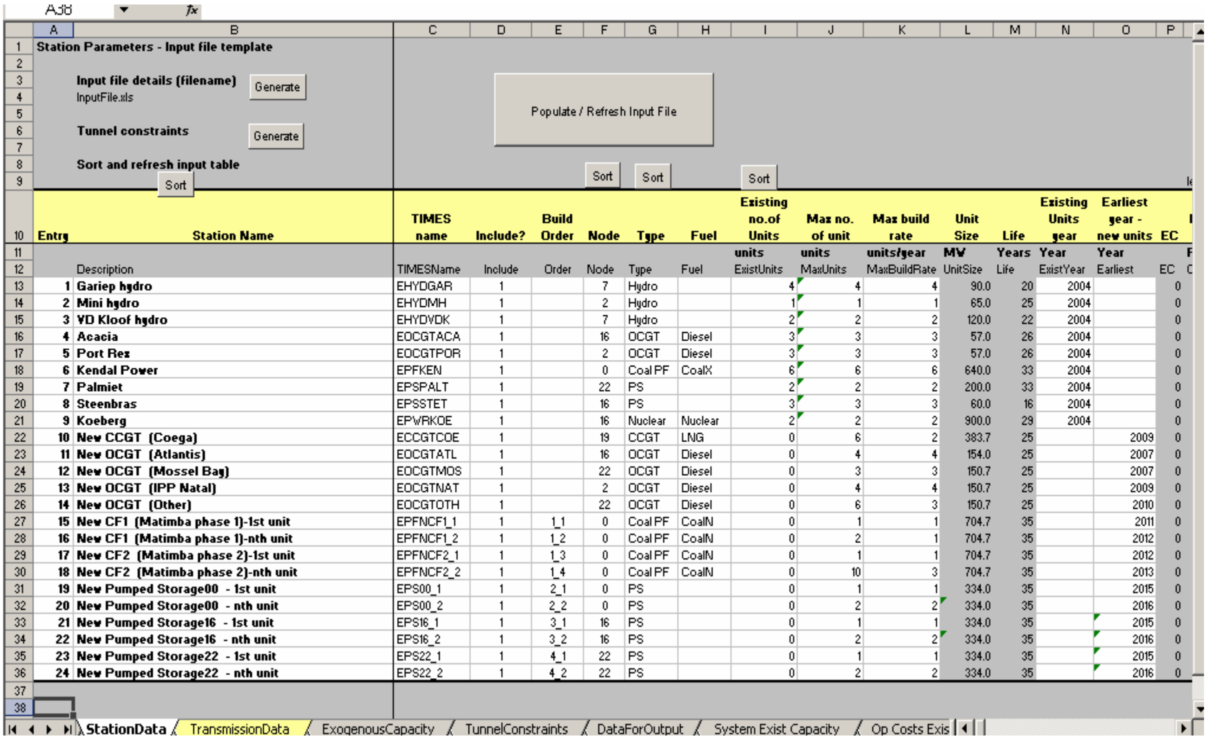


Figure 8 - Interface for demand parameters

5.1.2 INTERFACE FOR GENERATION CAPACITY

The existing Eskom supply side technology database was linked to a master table which contains all of the key input parameters for the TIMES model. This table contains information relating to costs, performance parameters, fuels, nodes as well as technology life times and decommissioning dates. This table is then used to generate the necessary input parameters required by TIMES in a separate workbook. In this way the planner can easily detect errors in input data as well as compare the costs and performance parameters of power stations.



Station Parameters - Input file template

Input file details (filename) Generate

InputFile.xls

Tunnel constraints Generate

Sort and refresh input table Sort

Populate / Refresh Input File

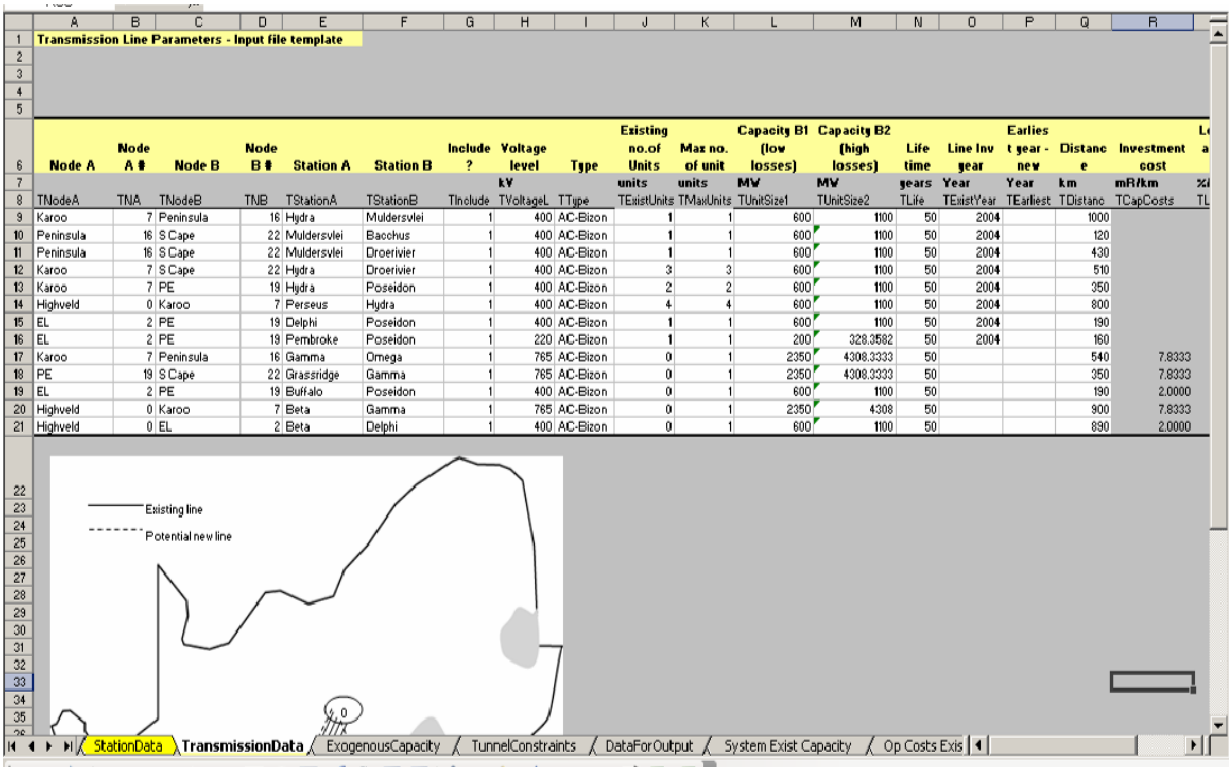
Entry	Station Name	TIMES name	Include?	Build Order	Node	Type	Fuel	Existing no.of Units	Max no. of unit	Max build rate	Unit Size	Life	Existing Units year	Earliest year - new units	EC
								units	units	units/year	MW	Years	Year	Year	
	Description	TIMESName	Include	Order	Node	Type	Fuel	ExistUnits	MaxUnits	MaxBuildRate	UnitSize	Life	ExistYear	Earliest	EC
1	**Gariep hydro**	EHYDGAR	1		7	Hydro		4	4	4	90.0	20	2004		0
2	**Mini hydro**	EHYDMH	1		2	Hydro		1	1	1	65.0	25	2004		0
3	**VD Kloof hydro**	EHYDVDK	1		7	Hydro		2	2	2	120.0	22	2004		0
4	**Acacia**	EOCGTACA	1		16	OCGT	Diesel	3	3	3	57.0	26	2004		0
5	**Port Rex**	EOCGTPOR	1		2	OCGT	Diesel	3	3	3	57.0	26	2004		0
6	**Kendal Power**	EPFKEN	1		0	Coal PF	CoalX	6	6	6	640.0	33	2004		0
7	**Palmiet**	EPSPALT	1		22	PS		2	2	2	200.0	33	2004		0
8	**Steenbras**	EPSSTET	1		16	PS		3	3	3	60.0	16	2004		0
9	**Koeberg**	EPWRKOE	1		16	Nuclear	Nuclear	2	2	2	900.0	29	2004		0
10	**New CCGT (Coega)**	ECCGTCOE	1		19	CCGT	LNG	0	6	2	383.7	25		2009	0
11	**New OCGT (Atlantis)**	EOCGTATL	1		16	OCGT	Diesel	0	4	4	154.0	25		2007	0
12	**New OCGT (Mossel Bay)**	EOCGTMOS	1		22	OCGT	Diesel	0	3	3	150.7	25		2007	0
13	**New OCGT (IPP Natal)**	EOCGTNAT	1		2	OCGT	Diesel	0	4	4	150.7	25		2009	0
14	**New OCGT (Other)**	EOCGTOTH	1		22	OCGT	Diesel	0	6	3	150.7	25		2010	0
15	**New CF1 (Matimba phase 1)-1st unit**	EPFNCF1_1	1	1_1	0	Coal PF	CoalN	0	1	1	704.7	35		2011	0
16	**New CF1 (Matimba phase 1)-nth unit**	EPFNCF1_2	1	1_2	0	Coal PF	CoalN	0	2	1	704.7	35		2012	0
17	**New CF2 (Matimba phase 2)-1st unit**	EPFNCF2_1	1	1_3	0	Coal PF	CoalN	0	1	1	704.7	35		2012	0
18	**New CF2 (Matimba phase 2)-nth unit**	EPFNCF2_2	1	1_4	0	Coal PF	CoalN	0	10	3	704.7	35		2013	0
19	**New Pumped Storage00 - 1st unit**	EPS00_1	1	2_1	0	PS		0	1	1	334.0	35		2015	0
20	**New Pumped Storage00 - nth unit**	EPS00_2	1	2_2	0	PS		0	2	2	334.0	35		2016	0
21	**New Pumped Storage16 - 1st unit**	EPS16_1	1	3_1	16	PS		0	1	1	334.0	35		2015	0
22	**New Pumped Storage16 - nth unit**	EPS16_2	1	3_2	16	PS		0	2	2	334.0	35		2016	0
23	**New Pumped Storage22 - 1st unit**	EPS22_1	1	4_1	22	PS		0	1	1	334.0	35		2015	0
24	**New Pumped Storage22 - nth unit**	EPS22_2	1	4_2	22	PS		0	2	2	334.0	35		2016	0

StationData / TransmissionData / ExogenousCapacity / TunnelConstraints / DataForOutput / System Exist Capacity / Op Costs Exis

Figure 9 – Master table for generation technologies

This table also generates a “tunnel constraint sheet” whereby technologies can be forced in, where decisions have already been made. It also allows the planner to specify minimum and maximum activity levels for all technologies.

5.1.3 INTERFACE FOR TRANSMISSION PARAMETERS



Transmission Line Parameters - Input file template

Node A	Node A #	Node B	Node B #	Station A	Station B	Include ?	Voltage level	Type	Existing no.of Units	Max no. of unit	Capacity B1 (low losses)	Capacity B2 (high losses)	Life time	Line Inv year	Earliest year - new	Distance	Investment cost
							kV		units	units	MW	MW	years	Year	Year	km	mR/km
TNodeA	TNA	TNodeB	TNB	TStationA	TStationB	TInclude	TVoltageL	TType	TExistUnits	TMaxUnits	TUnitSize1	TUnitSize2	TLife	TExistYear	TEarliest	TDistanc	TCapCosts
Karoo	7	Peninsula	16	Hydra	Muldersvlei	1	400	AC-Bizon	1	1	600	1100	50	2004		1000	
Peninsula	16	S Cape	22	Muldersvlei	Bacchus	1	400	AC-Bizon	1	1	600	1100	50	2004		120	
Peninsula	16	S Cape	22	Muldersvlei	Droerivier	1	400	AC-Bizon	1	1	600	1100	50	2004		430	
Karoo	7	S Cape	22	Hydra	Droerivier	1	400	AC-Bizon	3	3	600	1100	50	2004		510	
Karoo	7	PE	19	Hydra	Poseidon	1	400	AC-Bizon	2	2	600	1100	50	2004		350	
Highveld	0	Karoo	7	Perseus	Hydra	1	400	AC-Bizon	4	4	600	1100	50	2004		800	
EL	2	PE	19	Delphi	Poseidon	1	400	AC-Bizon	1	1	600	1100	50	2004		190	
EL	2	PE	19	Pembroke	Poseidon	1	220	AC-Bizon	1	1	200	328.3582	50	2004		160	
Karoo	7	Peninsula	16	Gamma	Omega	1	765	AC-Bizon	0	1	2350	4308.3333	50			540	7.8333
PE	19	S Cape	22	Grassridge	Gamma	1	765	AC-Bizon	0	1	2350	4308.3333	50			350	7.8333
EL	2	PE	19	Buffalo	Poseidon	1	400	AC-Bizon	0	1	600	1100	50			190	2.0000
Highveld	0	Karoo	7	Beta	Gamma	1	765	AC-Bizon	0	1	2350	4308	50			900	7.8333
Highveld	0	EL	2	Beta	Delphi	1	400	AC-Bizon	0	1	600	1100	50			890	2.0000

Figure 10 - Master table for transmission

This table contains similar cost and performance information to the generation technology master sheet. Once again this table provides a single point where the planner can compare input data and detect errors.

5.2 OUTPUT INTERFACES

An output interface was developed to display the key model results to the planner. This interface has been modelled on the existing ISEP templates but can easily be changed if need be in the future.

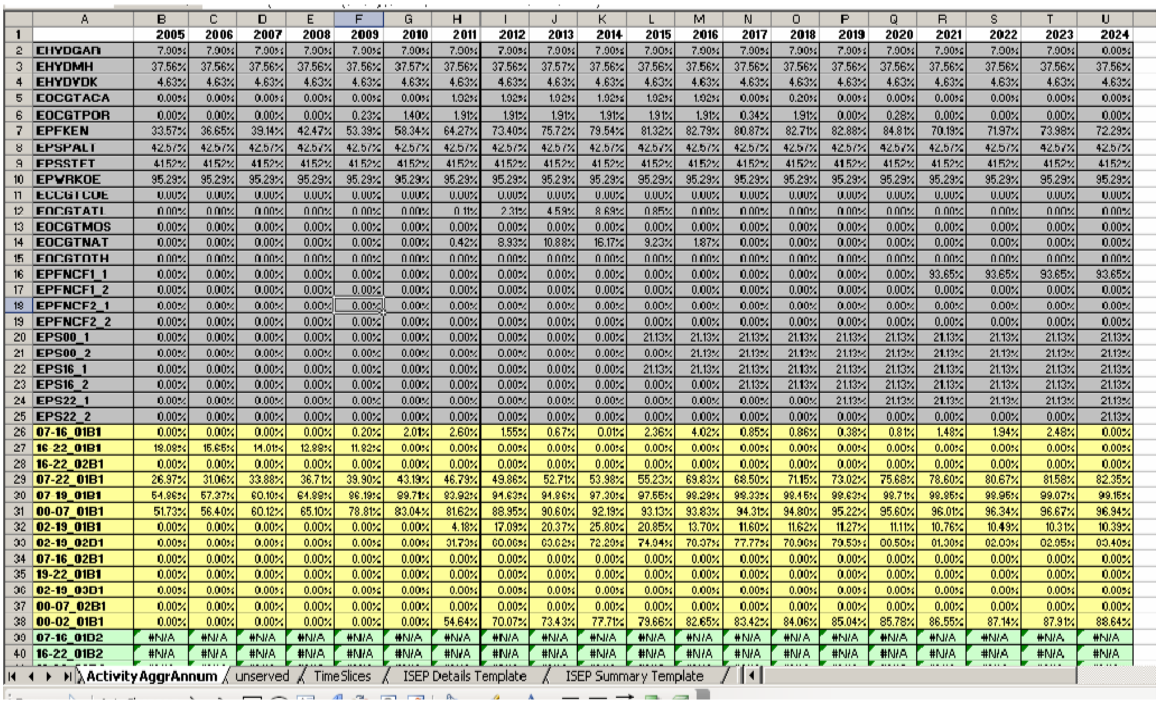
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1																
2	Western and Southern Cape Expansion Plan					Colour code		Node 0	Node 2	Node 7	Node 16	Node 19	Node 22			
3	Annual Added Capacity															
4		Gas					Coal				Pumped Storage					
5	YR	New CCGT (Coega)	New OCGT (Atlantis)	New OCGT (Mossel Bay)	New OCGT (IPP Natal)	New OCGT (Other)	New CF1 (Matimba phase 1)-1st unit	New CF1 (Matimba phase 1)-nth unit	New CF2 (Matimba phase 2)-1st unit	New CF2 (Matimba phase 2)-nth unit	New Pumped Storage00 - 1st unit	New Pumped Storage00 - nth unit	New Pumped Storage16 - 1st unit	New Pumped Storage16 - nth unit	New Pumped Storage22 - 1st unit	New Pumped Storage22 - nth unit
6	2005															
7	2006															
8	2007		462	452												
9	2008		154													
10	2009				452											
11	2010				151											
12	2011															
13	2012															
14	2013															
15	2014															
16	2015										334		334			
17	2016											668				
18	2017													668		
19	2018															
20	2019														334	
21	2020															
22	2021						691									
23	2022															
24	2023															
25	2024															668
26	TOTAL		616	452	603		691				334	668	334	668	334	668

	New transmission				
YR	Karoo-Peninsula (Gamma-Omega)	PE-S Cape (Grassridge-Gamma)	EL-PE (Buffalo-Poseidon)	Highveld-Karoo (Beta-Gamma)	Highveld-EL (Beta-Delphi)
2005					
2006					
2007					
2008					
2009					
2010					
2011					600
2012					
2013					
2014					
2015					
2016		2350			
2017					
2018					
2019					
2020					
2021					
2022					
2023					
2024					
TOTAL		2350			600

Figure 11 – Investment summary sheet

A summary of the primary output information is displayed for all new investment (generation and transmission) in the ISEP summary template sheet of the output workbook.

A summary of the activity information for all stations and lines is shown in the ActivityAggAnnum sheet. This is shown below.



	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
1		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2	EHYDGAR	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	0.00%
3	EHYDMH	37.56%	37.56%	37.56%	37.56%	37.56%	37.57%	37.56%	37.56%	37.57%	37.56%	37.56%	37.56%	37.56%	37.56%	37.56%	37.56%	37.56%	37.56%	37.56%	37.56%
4	EHYDVDK	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%
5	EOCGTACA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	0.00%	0.20%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
6	EOCGTPOR	0.00%	0.00%	0.00%	0.00%	0.23%	1.40%	1.91%	1.91%	1.91%	1.91%	1.91%	1.91%	0.34%	1.91%	0.00%	0.28%	0.00%	0.00%	0.00%	0.00%
7	EPFKEN	33.57%	36.65%	39.14%	42.47%	53.39%	58.34%	64.27%	73.40%	75.72%	79.54%	81.32%	82.79%	80.87%	82.71%	82.88%	84.81%	70.19%	71.97%	73.98%	72.29%
8	EPSPALT	42.57%	42.57%	42.57%	42.57%	42.57%	42.57%	42.57%	42.57%	42.57%	42.57%	42.57%	42.57%	42.57%	42.57%	42.57%	42.57%	42.57%	42.57%	42.57%	42.57%
9	EPSSTET	41.52%	41.52%	41.52%	41.52%	41.52%	41.52%	41.52%	41.52%	41.52%	41.52%	41.52%	41.52%	41.52%	41.52%	41.52%	41.52%	41.52%	41.52%	41.52%	41.52%
10	EPWRKOE	95.29%	95.29%	95.29%	95.29%	95.29%	95.29%	95.29%	95.29%	95.29%	95.29%	95.29%	95.29%	95.29%	95.29%	95.29%	95.29%	95.29%	95.29%	95.29%	95.29%
11	ECCGTCOE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
12	EOCGTATL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.11%	2.31%	4.59%	8.69%	0.85%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	EOCGTMOS	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
14	EOCGTNAT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.42%	8.93%	10.88%	16.17%	9.23%	1.87%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
15	EOCGTOTH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
16	EPFNCF1_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	93.65%	93.65%	93.65%	93.65%
17	EPFNCF1_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
18	EPFNCF2_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19	EPFNCF2_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20	EPS00_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%
21	EPS00_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%
22	EPS16_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%
23	EPS16_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%
24	EPS22_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	21.13%	21.13%	21.13%	21.13%	21.13%	21.13%
25	EPS22_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	21.13%
26	07-16_01B1	0.00%	0.00%	0.00%	0.00%	0.20%	2.01%	2.60%	1.55%	0.67%	0.01%	2.36%	4.02%	0.85%	0.86%	0.38%	0.81%	1.48%	1.94%	2.48%	0.00%
27	16-22_01B1	18.08%	15.65%	14.01%	12.89%	11.82%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
28	16-22_02B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	07-22_01B1	26.97%	31.06%	33.88%	36.71%	39.90%	43.19%	46.79%	49.86%	52.71%	53.98%	55.23%	69.83%	68.50%	71.15%	73.02%	75.68%	78.60%	80.67%	81.58%	82.35%
30	07-19_01B1	54.86%	57.37%	60.10%	64.88%	96.19%	99.71%	93.92%	94.63%	94.86%	97.30%	97.55%	98.29%	98.33%	98.45%	98.63%	98.71%	98.85%	98.95%	99.07%	99.15%
31	00-07_01B1	51.73%	56.40%	60.12%	65.10%	78.81%	83.04%	81.62%	88.95%	90.60%	92.19%	93.13%	93.83%	94.31%	94.80%	95.22%	95.60%	96.01%	96.34%	96.67%	96.94%
32	02-19_01B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	4.18%	17.09%	20.37%	25.80%	20.85%	13.70%	11.60%	11.62%	11.27%	11.11%	10.76%	10.49%	10.31%	10.39%
33	02-19_02D1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	31.73%	60.06%	63.62%	72.20%	74.04%	70.37%	77.77%	70.96%	79.53%	80.50%	81.30%	82.03%	82.95%	83.40%
34	07-16_02B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
35	19-22_01B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
36	02-19_03D1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
37	00-07_02B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
38	00-02_01B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	54.64%	70.07%	73.43%	77.71%	79.66%	82.65%	83.42%	84.06%	85.04%	85.78%	86.55%	87.14%	87.91%	88.64%
39	07-16_01D2	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
40	16-22_01B2	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A

ActivityAggrAnnum / unserved / TimeSlices / ISEP Details Template / ISEP Summary Template

Figure 12 – Annual activity summary sheet

This sheet displays the annual activity of each station and transmission line in each year of the study period. The direction of flow and activity of the transmission lines can be observed in this sheet.

More detailed sheets are available for the activity variables of each station ad transmission line for each timeslice of the model.

6 CASE STUDY: SINGLE NODE CAPE MODEL

6.1 CASE STUDY DESCRIPTION

The first case study was a single node model of the Cape, whereby no transmission was represented. It was essentially made up of the 6 nodes making up the Cape, grouped into one single node. This was done to compare results with the equivalent EGEAS model (which could not model transmission). The comparison was done in two stages:

- Stage 1: The EGEAS plan[4] was "forced in" the TIMES frame work and for a series of MC samples, the slave problem was solved to compare costs and production plans.
- Stage 2: The planning problem was solved completely using only TIMES and resultant plans are compared with the one obtained using EGEAS.

The Single Node Cape Model problem can be summarised as follows:

An annual demand starting at about 28,300GWh in model year 2005, increasing to 50,400GWh in 2024, with peak demand starting at 5427MW and increasing to 9791MW[5] had to be met at the least cost using the following existing and new supply options:

Existing options:

Eskom Coal-fired plants (Kendal): 3840 MW,

Eskom Nuclear (Koeberg): 1800 MW,

Eskom Pumped Storage (Palmiet): 400 MW,

Eskom Hydro (Gariep, VD Kloof): 600 MW,

Eskom Gas Turbines (Acacia, Port Rex): 342 MW,

Non-Eskom Pumped Storage (Steenbras): 180 MW,

Non-Eskom Hydro (mini hydro): 65 MW.

[4] The EGEAS plan is the one obtained using EGEAS for the planning problem described on this page.

[5] The demand that is input into the model is characterized in much more detail: hourly data, but this would be hard to represent on a single page, and wouldn't add much to this report.

New options:

CCGT – Coega: up to 6 units of 384 MW each, earliest 2009.

Coal fired 1 (Matimba brown super critical with FGD): up to 3 units of 705MW each, earliest 2011.

Coal fired 2 (Generic super critical with FGD): up to 3 units of 705 MW each, earliest 2013.

PS A (Braamhoek): up to 3 units of 333MW, earliest 2015

OCGT (Atlantis): up to 4 units of 154MW, all in 2007.

OCGT (Mossel Bay): up to 3 units of 151MW, all in 2007.

OCGT (IPP Natal): up to 4 units of 151MW, all in 2009.

OCGT (Other): up to 6 units of 151MW, earliest 2010.

The cost of unserved energy is assumed to be R75,000 per MWh.

The EGEAS plan

The Table below depicts the generation capacity expansion plan obtained using EGEAS for the planning problem described above.

Table 3 – Investment summary for EGEAS plan

YR	PF (1)	PF (2)	OCGT Atlantis	OCGT Mossel Bay	OCGT IPP	OCGT New GT	CCGT Coega	PS (A)	Unserved Energy (GWh)	Reserve on Moderate Forecast
2005									5	33%
2006									5	29%
2007			616	452					1	44%
2008									1	39%
2009					603				0	34%
2010									1	28%
2011	705								0	31%
2012	705								1	29%
2013									1	25%
2014	705								1	28%
2015									2	26%
2016									2	23%
2017								1002	0	33%
2018									0	31%
2019									0	29%
2020									1	28%
2021									1	26%
2022							384		0	29%
2023									1	25%
2024									1	24%
TOTAL	2115		616	452	603		384	1002		

6.2 STAGE 1 COMPARISON

The EGEAS plan[6] was "forced in" the TIMES frame work and for a series of MC samples, the slave problem was solved to compare costs and production plans.

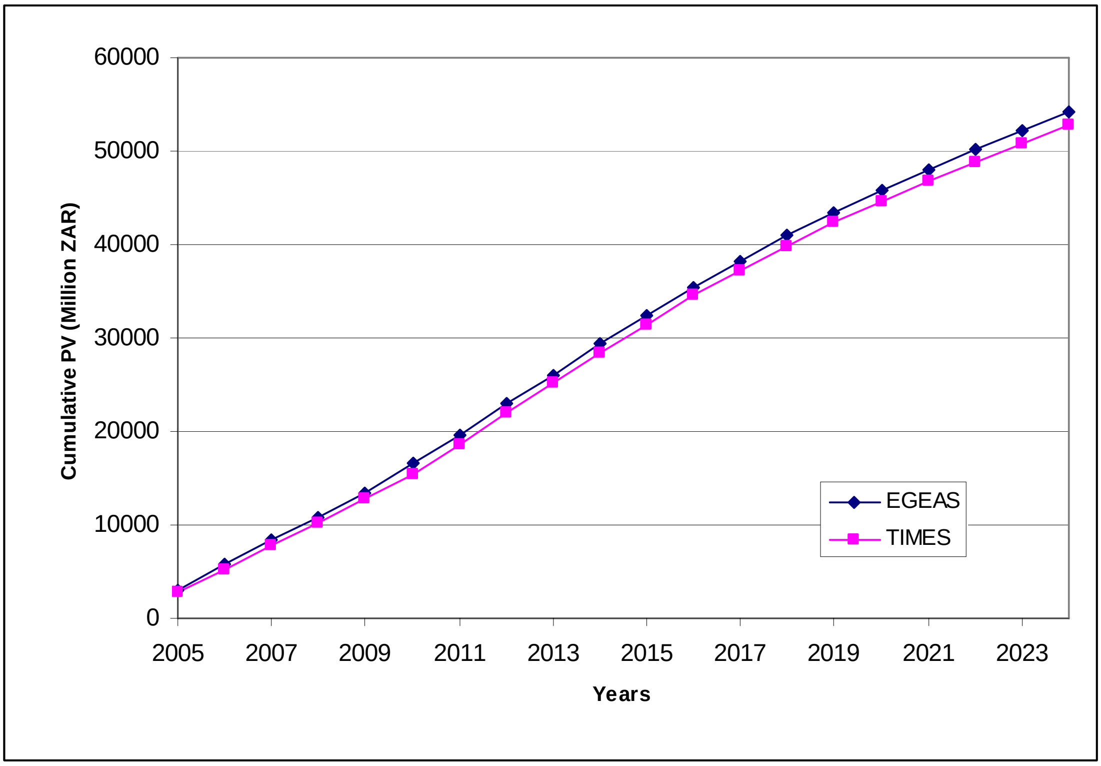


Figure 13 - Stage 1 comparison of costs

6.2.1 COMPARISON OF COSTS

Figure 13 shows a graph of the cumulative present worth of the plan as calculated by EGEAS and TIMES[7]. The EGEAS costs are reported to be slightly higher. The two figures that follow help explain this difference.

In Figure 14, we see that the production costs as calculated by EGEAS are higher in 2010 and 2022, when OCGT's (as seen is the production tables) are allowed a capacity factor of up to around 20%, when much lower limits were imposed in TIMES (This difference was noticed too late to re-run the TIMES model).

In Figure 15, we see that there is more unserved energy calculated by EGEAS in the earlier years. There is no clear explanation for this difference other than in EGEAS there is a minimum production level on Kendal, a constraint that was not imposed in the TIMES model.

[6] The EGEAS plan is the one obtained using EGEAS for the planning problem described on this page.
[7] Note that these costs do not include costs incurred after the study period.

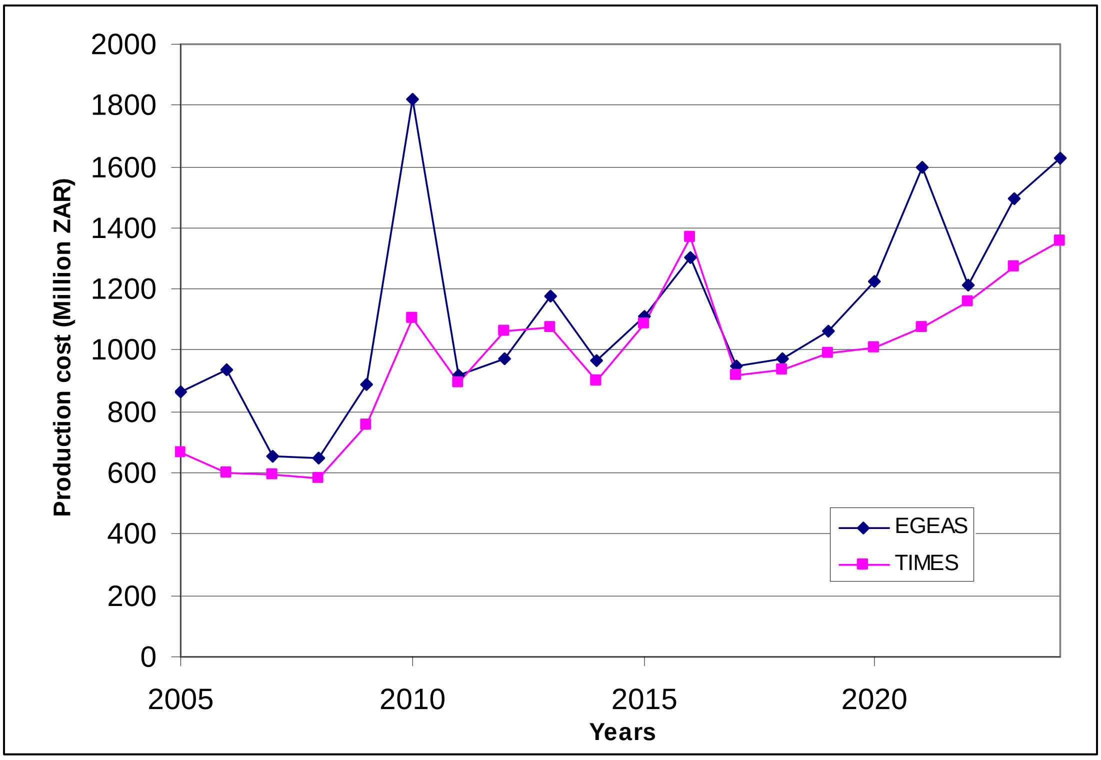


Figure 14 - Comparison of production costs

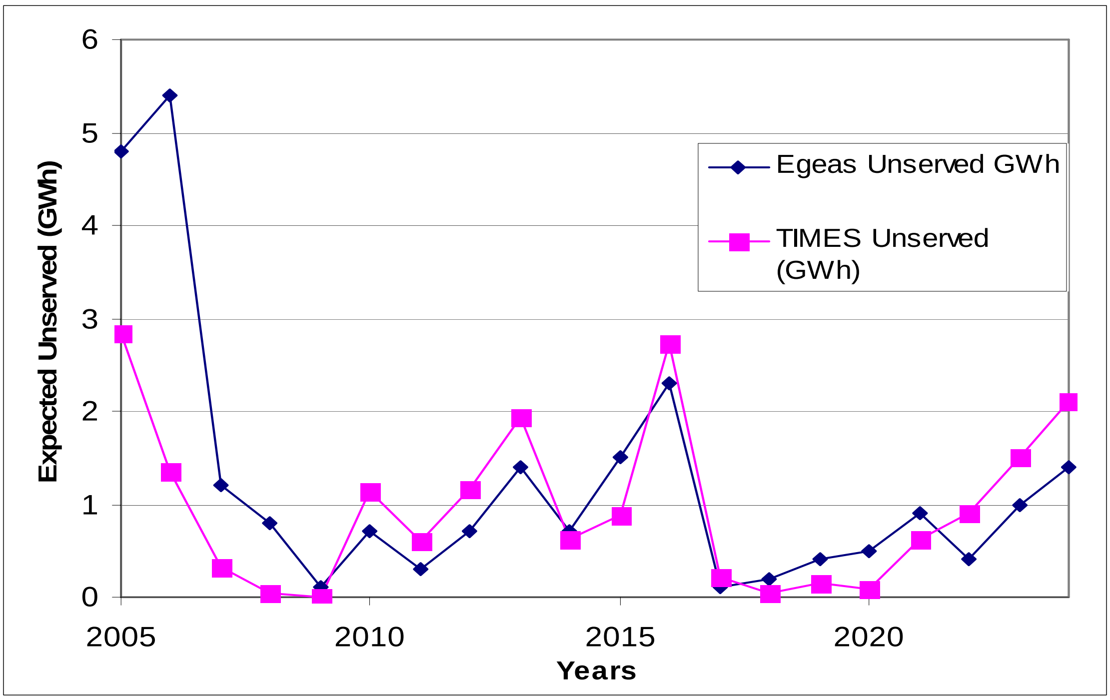


Figure 15 - Comparison of Unserved Energy

6.2.2 Comparison of Production Plans

Table 4 and Table 5 show the annual capacity factors for the investment plan presented above as calculated using EGEAS and TIMES for the first 8 years of the study period. There are a few differences that can be noted. As mentioned before the OCGT's in EGEAS are allowed to run harder and they only seem to do so in 2010. The PS stations also run a bit harder in EGEAS. When we compare the production of the other stations, and the unserved energy, they are both close. The difference in PS could possibly be explained by the capacity factor of the 2 methods being calculated differently.

Table 4 - Excerpt of production plan according to EGEAS

EGEAS	2005	2006	2007	2008	2009	2010	2011	2012	2013
EHYDGAR	7.63%	7.87%	7.93%	7.39%	7.33%	7.30%	7.21%	7.63%	7.63%
EHYDMH	26.48%	30.21%	31.78%	29.38%	35.32%	35.32%	35.32%	35.32%	35.32%
EHYDVDK	4.09%	4.45%	3.92%	4.40%	4.49%	4.54%	4.54%	4.49%	4.50%
EOCGTACA	0.13%	0.18%	0.18%	0.20%	2.71%	18.62%	2.38%	1.50%	4.06%
EOCGTPOR	0.21%	0.28%	0.27%	0.29%	9.24%	22.32%	5.61%	4.21%	8.27%
EPFKEN	44.98%	47.79%	50.16%	53.11%	62.90%	64.60%	61.71%	60.34%	62.20%
EPSPALT	14.12%	14.77%	16.15%	17.01%	20.74%	11.05%	23.17%	20.63%	21.85%
EPSSTET	13.79%	14.42%	15.78%	16.83%	20.25%	10.80%	22.63%	20.15%	21.34%
EPWRKOE	82.61%	82.63%	82.65%	82.67%	82.71%	82.71%	82.71%	82.71%	82.71%
ECCGTCOE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EOCGTATL	0.00%	0.00%	0.01%	0.01%	0.04%	0.07%	0.05%	0.05%	0.07%
EOCGTMOS	0.00%	0.00%	0.07%	0.08%	0.40%	10.16%	0.42%	0.38%	0.94%
EOCGTNAT	0.00%	0.00%	0.00%	0.00%	0.12%	0.20%	0.13%	0.12%	0.17%
EOCGTOTH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPFNCF1_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	65.87%	70.93%	73.28%
EPFNCF1_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	55.40%	58.49%
EPFNCF2_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPFNCF2_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPS00_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPS00_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 5 - Excerpt of production plan according to TIMES

TIMES	2005	2006	2007	2008	2009	2010	2011	2012	2013
EHYDGAR	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%
EHYDMH	37.55%	37.55%	37.55%	37.55%	37.55%	37.55%	37.55%	37.55%	37.55%
EHYDVDK	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	5.39%	4.63%
EOCGTACA	0.07%	0.07%	0.17%	0.21%	0.84%	1.75%	1.25%	1.27%	1.68%
EOCGTPOR	0.11%	0.13%	0.21%	0.30%	0.95%	1.85%	1.45%	1.40%	1.78%
EPFKEN	43.75%	46.65%	48.90%	51.78%	62.10%	66.47%	57.00%	51.14%	54.19%
EPSPALT	0.29%	0.28%	0.51%	0.83%	3.98%	8.90%	4.43%	3.91%	5.59%
EPSSTET	2.52%	1.95%	2.04%	2.87%	8.43%	11.58%	7.93%	5.90%	8.70%
EPWRKOE	82.71%	82.68%	82.71%	82.69%	82.68%	82.71%	82.69%	82.65%	82.69%
ECCGTCOE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EOCGTATL	0.00%	0.00%	0.04%	0.02%	0.01%	0.18%	0.07%	0.14%	0.14%
EOCGTMOS	0.00%	0.00%	0.14%	0.13%	0.49%	2.26%	1.15%	1.20%	1.91%
EOCGTNAT	0.00%	0.00%	0.00%	0.00%	0.41%	1.74%	0.61%	0.89%	1.31%
EOCGTOTH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPFNCF1_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	84.44%	84.56%	84.60%
EPFNCF1_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	84.56%	84.56%
EPFNCF2_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPFNCF2_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPS00_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPS00_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

6.3 STAGE 2 COMPARISON

Having established that production plans calculated by the 2 packages are similar we then solved the investment planning problem using only TIMES and resultant plans are compared with the one obtained using EGEAS.

6.3.1 EXPLORING THE SOLUTION SPACE

The problem was set up such that the initial demand would be set at 4 % above the actual projected demand in the master problem and then increased in small steps. The 4% was used as we were confident that it would be below the optimal level.

The *master* problem was then solved to obtain the investment strategy for that level of demand. This investment strategy was then used in the *slave* problem where plant outage would be modelled as described above using 150 model runs. The distribution of unserved energy for that investment strategy was then calculated and compared to the unserved energy value reported in the *master* problem.

The following stopping criterion was used in the model: The *slave* problem has to achieve unserved energy values equal to the *master* problem within a 90 % confidence interval for each year; else the demand is increased by 0.5 % in the year/s where this criterion was not met. This process was repeated until this criterion was met in every year.

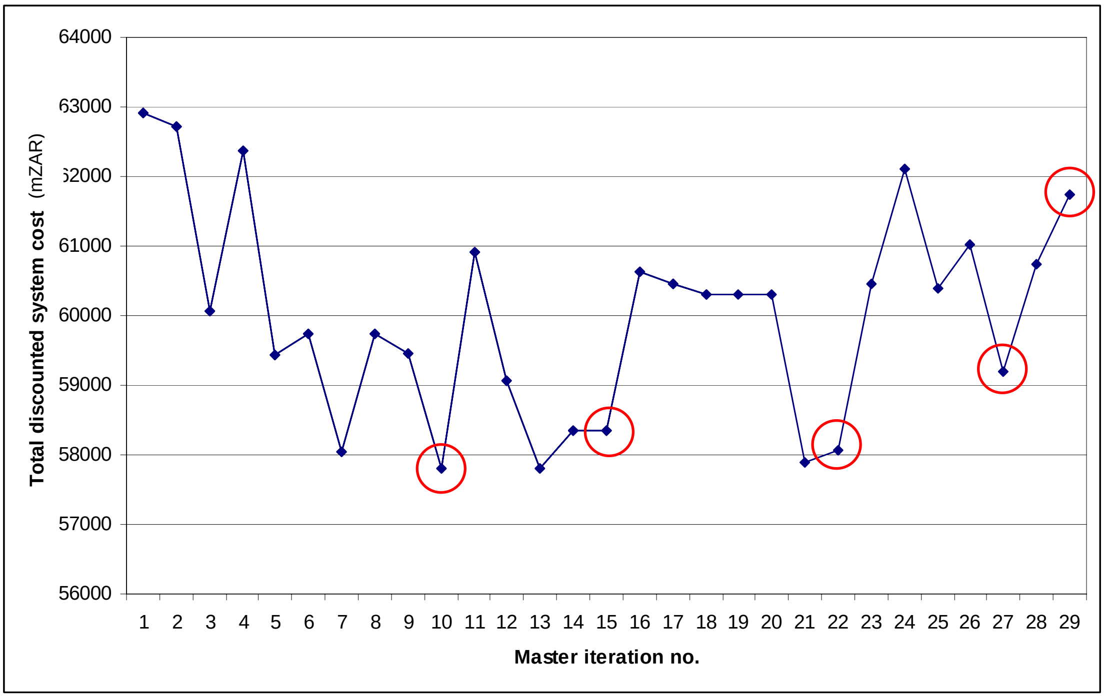


Figure 16 - Graph of total discounted system cost as a function of master problem iteration number for single node Cape model

Figure 16 shows the total discounted costs for a 29 different investment plans. The total discounted costs include investment costs, operation costs and unserved energy costs incurred over the study period, averaged over the 150 slave runs. The investment plan 1 was generated in a master run where demand was inflated by 4% in all years. Subsequent plans were generated by iterating between master and slave from this point onwards as explained before.

As can be seen in Figure 16, the Cape model behaves differently to the model demonstrated in Figure 2 in that the results are more “jaggerred”. This is due mainly to the size of the modular constraints imposed on the model by using mixed integer programming relative to the magnitude of the demand and size of the model (in terms of the total capacity required to meet the demand). Although having fewer technology options when using mixed integer programming increases the chances of obtaining a local minimum instead of a global minimum, running the *master-slave* loop until convergence is achieved, allows for a large range of the solution space to be sampled and reduces the chances of obtaining a local minimum as a final solution.

6.3.2 SHORT-LISTED PLANS

The master problem iteration numbers corresponding to the optimal inflated demand for the system could then be identified from Figure 16. The investment plans corresponding to each of the master problem iterations shown in Figure 16 was stored. 5 plans of interest were chosen from Figure 16 (circled in red) and analysed in more detail below. The probability density functions for these plans and the EGEAS plan are shown in Figure 17 for the 150 Monte Carlo runs of the *slave* problem.

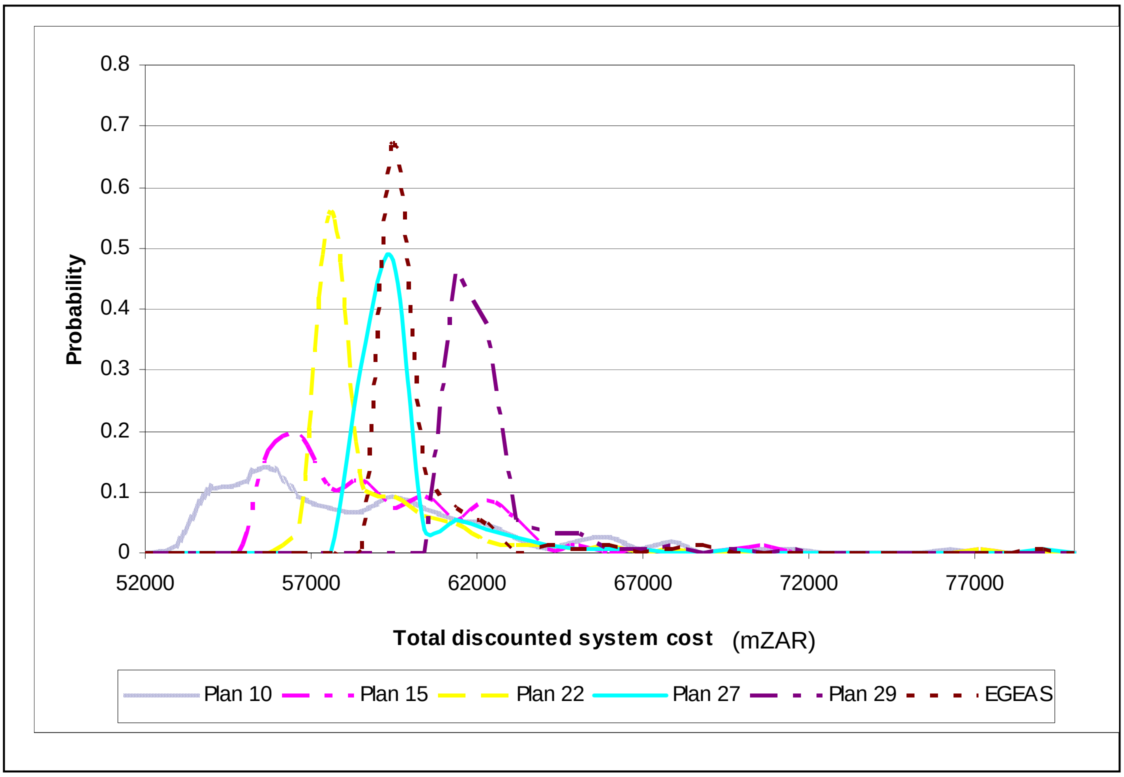


Figure 17 - Probability density functions for total discounted system cost

As can be seen in Figure 17 above, Plan 10 has the lowest average cost, but it has a wide spread. This occurs because Plan 10 has a relatively low investment cost component and a relatively high unserved energy cost component compared to the other plans (see Table 6 for the investment summary). This causes Plan 10 to be extremely sensitive to the amount of unserved energy in the system and therefore it has very high costs for the slave runs when there is a high unserved energy value and very low cost for when unserved energy has a low value.

Plan 22 has a slightly higher average cost, but has a relatively narrow spread of costs compared to Plan 10. This means that this plan is less dependant on the amount of unserved energy in the system due to more investment into generating capacity (see Table 7 below).

The EGEAS plan has higher average cost than Plan 22 but a slightly narrower spread of costs due to its more aggressive investment strategy (see Table 8 below).

Table 6 – Investment summary table for Plan 10 – single node

Annual Added Capacity

	Coal-Fired				**Gas**					**Pumped Storage**			
YR	New CF1 (Matimba phase 1)-1st unit	New CF1 (Matimba phase 1)-nth unit	New CF2 (Matimba phase 2)-1st unit	New CF2 (Matimba phase 2)-nth unit	New OCGT (Atlantis)	New OCGT (Mossel Bay)	New OCGT (IPP Natal)	New OCGT (Other)	New CCGT (Coega)	New Pumped Storage - 1st unit	New Pumped Storage - nth unit	Reserve on Moderate Forecast	Average unserved energy (GWh)
2005												28%	2.4
2006												24%	1.1
2007					616	452						38%	0.5
2008												34%	
2009							603					29%	
2010												24%	1.3
2011												18%	1.6
2012	705											18%	10.7
2013												16%	8.2
2014												11%	18.3
2015										334		13%	22.6
2016											668	18%	6.1
2017												16%	6.0
2018												15%	5.9
2019		705										21%	1.5
2020												20%	2.1
2021												18%	5.9
2022												17%	14.0
2023												14%	19.9
2024												12%	21.5
TOTAL	705	705			616	452	603				668		149.9

Total cost		**58087**

Total discounted unserved energy	**62.6**

Table 7 - Investment summary table for Plan 22 – single node

Annual Added Capacity

	Coal-Fired				**Gas**					**Pumped Storage**			
YR	New CF1 (Matimba phase 1)-1st unit	New CF1 (Matimba phase 1)-nth unit	New CF2 (Matimba phase 2)-1st unit	New CF2 (Matimba phase 2)-nth unit	New OCGT (Atlantis)	New OCGT (Mossel Bay)	New OCGT (IPP Natal)	New OCGT (Other)	New CCGT (Coega)	New Pumped Storage - 1st unit	New Pumped Storage - nth unit	Reserve on Moderate Forecast	Average unserved energy (GWh)
2005												28%	2.4
2006												24%	1.1
2007					616	452						38%	0.5
2008												34%	
2009							603					29%	
2010												24%	1.3
2011	705											28%	0.5
2012		705										26%	1.9
2013												24%	0.6
2014												20%	2.5
2015										334		21%	5.7
2016											668	25%	2.0
2017												24%	0.2
2018												22%	0.7
2019												21%	1.5
2020		705										27%	
2021												26%	0.4
2022												24%	2.9
2023												21%	4.9
2024												19%	5.8
TOTAL	705	1409			616	452	603				668		34.9

Total cost		**58321**

Total discounted unserved energy	**16.2**

Table 8 - Investment summary table for EGEAS plan – single node

Annual Added Capacity

	Coal-Fired				Gas					Pumped Storage			
YR	New CF1 (Matimba phase 1)-1st unit	New CF1 (Matimba phase 1)-nth unit	New CF2 (Matimba phase 2)-1st unit	New CF2 (Matimba phase 2)-nth unit	New OCGT (Atlantis)	New OCGT (Mossel Bay)	New OCGT (IPP Natal)	New OCGT (Other)	New CCGT (Coega)	New Pumped Storage - 1st unit	New Pumped Storage - nth unit	Reserve on Moderate Forecast	Average unserved energy (GWh)
2005												28%	2.4
2006												24%	1.1
2007					616	452						38%	0.5
2008												34%	
2009							603					29%	
2010												24%	1.3
2011	705											28%	0.5
2012		705										26%	1.9
2013												24%	0.6
2014		705										28%	0.2
2015												25%	1.3
2016												22%	3.8
2017										334	668	32%	
2018												30%	0.1
2019												29%	0.1
2020												27%	
2021												26%	0.4
2022									384			28%	1.3
2023												25%	1.8
2024												23%	2.8
TOTAL	705	1409			616	452	603		384		668		20.2

Total cost		**59924**

Total discounted unserved energy	**10.8**

TIMES plans

As mentioned above Plan 10 has the lowest average cost of all the plans in Figure 16. This is due to its relatively low level of investment in generating capacity. It only builds two units of CF1, with the first coming online in 2012. It builds all three units of pumped storage, with the first unit coming online in 2015 and the next two coming online in 2016. It also builds the OCGT stations that are forced in (Atlantis, Mossel Bay and IPP Natal). It does not build any units of CF2 or CCGT or OCGT (other).

Plan 22 build all three units of CF2 with the first coming online in 2011 and the second following in 2012. All other investments are identical to Plan 10. By investing in CF1 unit 1 earlier and following it with unit 2 in the next year, the amount of unserved energy from 2011 to 2015 is significantly reduced. The additional investment results in Plan 22 being 0.4 % more expensive than Plan 10; however it has much less unserved energy.

The fact that plans can yield similar overall costs with significantly different investment levels and unserved energy costs highlights the trade-offs that decision makers need to be aware of and also highlights the need for planners to be able to compare a range of plans with a thorough analysis of unserved energy.

6.3.3 Comparison of TIMES plans with EGEAS plan

The EGEAS plan and TIMES Plan 10 lie on opposite extremes in terms of investment strategies. The EGEAS plan is aggressive in its investment and therefore has lower unserved energy cost, however Plan 10 is significantly cheaper than the EGEAS plan (more than 3 %). Decision makers may however not be satisfied with Plan 10 as its performance is highly dependant on the amount of unserved energy (demonstrated in Figure 17) and they may find the absolute annual values of unserved energy unacceptable high. Plan 22 may be more acceptable to decision makers. Although it is slightly more expensive than Plan 10, it is less dependant on the amount of unserved energy and also has lower absolute annual unserved energy values.

Comparing the EGEAS plan to Plan 22, the third unit of CF1 comes in earlier in EGEAS than Plan 22 (2014 instead of 2020). The first unit of pumped storage station is built in 2016 instead of 2015. EGEAS also builds one unit of CCGT in 2022, while Plan 22 builds none. These differences result in EGEAS having a higher reserve margin from 2014-2015 as well as 2017-2019 and 2022-2024 and therefore lower unserved energy in those years. The total cost of the EGEAS plan is however more than 2.5 % more expensive than Plan 22.

6.4 MARGINAL COSTS OF SERVING ELECTRICITY

One of the outputs of TIMES, is the marginal costs of producing each of the commodities in a particular model. For each of the 42 TimeSlices used in the single node problem described above TIMES reports the marginal cost of producing electricity, how much would the total system cost be increased by if demand were to increase by one unit of energy for each of the TimeSlices, for each of the periods.

From this, a weighted average marginal cost of producing electricity for each year can be calculated as follows:

$$\text{ElecAnnualMarginal} = \sum_{i=1}^{nTS} TSMarginal_i \times TSFrac_i \ ,$$

Where $TSMarginal_i$ is the marginal cost of electricity in $TimeSlice_i$,

And $TSFrac_i$, is the fraction of the total energy demand in the year that is to be served in $TimeSlice_i$.

Figure 18 below shows how the annual marginal costs varies over the study period for a particular solution of the problem considered in this case study. Note that this costs does include the possibility of not serving electricity, hence, as the reserve starts dropping, the marginal costs start increasing. The costs reported are slightly inflated and cannot at this stage be directly interpreted as the projected marginal costs. This is because the plan is generated using inflated demand and not true demand. This issue can nevertheless be addressed, but was not because of time constraints.

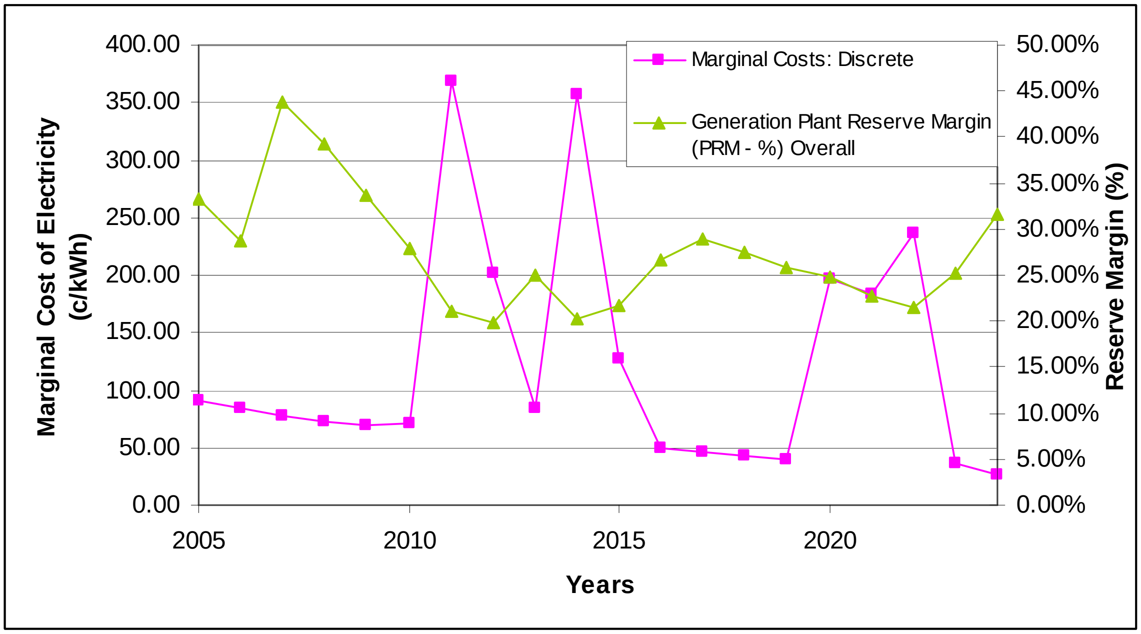


Figure 18 - Marginal costs of electricity

7 CASE STUDY: MULTI-NODE CAPE MODEL

7.1 CASE STUDY DESCRIPTION

Figure 19 shows how the 6 nodes that are included in the Cape model.

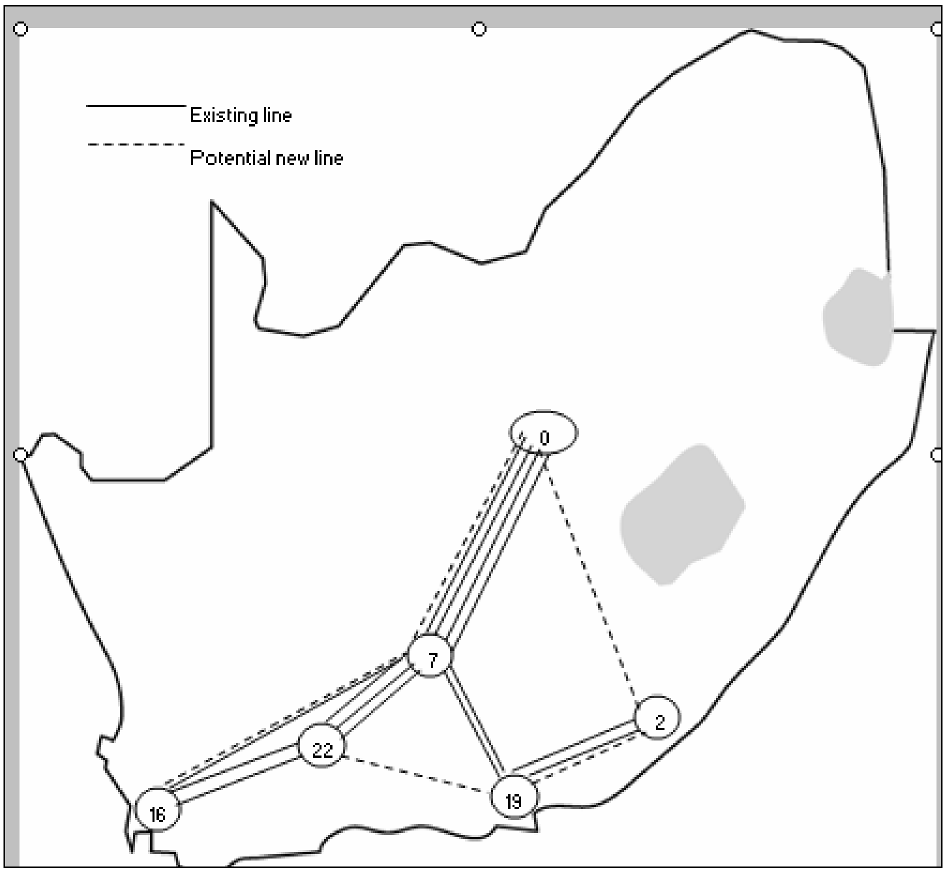


Figure 19 – Map of nodal breakdown for Cape model

The multi-node model was developed based on the single node model except that transmission lines were integrated into the model such that the transport of electricity between nodes could be explicitly modelled as discussed in section 6. Additional pumped storage options for each node were also included at the request of ISEP.

Table 9 – Nodal breakdown and new station data

Geographic Nodes	Geographic Areas	Stations
2	East London	
		Port Rex (Buffalo)
		Colley Wobbles
		IPP OCGT
0 (Dummy)	Highveld	
		Kendal Power Station
		New CF1
		New CF2
		New Pumped Storage
7	Karoo	
		VanDer Kloof
		Gariep
16	Peninsula	
		Acacia
		Koeberg
		Atlantis OCGT
		Steenbras
		New Pumped Storage
19	Port Elizabeth	
		Coega CCGT
22	Southern Cape	
		Palmiet
		New OCGT
		Mossel Bay OCGT
		New Pumped Storage

7.2 EXPLORING THE SOLUTION SPACE

As with the single node model, the solution space of the multi-node model was explored by running the *master-slave* loop using the following convergence criterion: The *slave* problem had to achieve unserved energy values equal to the *master* problem within a 95% confidence interval for each year; else the demand was increased by 0.5 % in the year/s where this criterion was not met. This process was repeated until this criterion was met in every year.

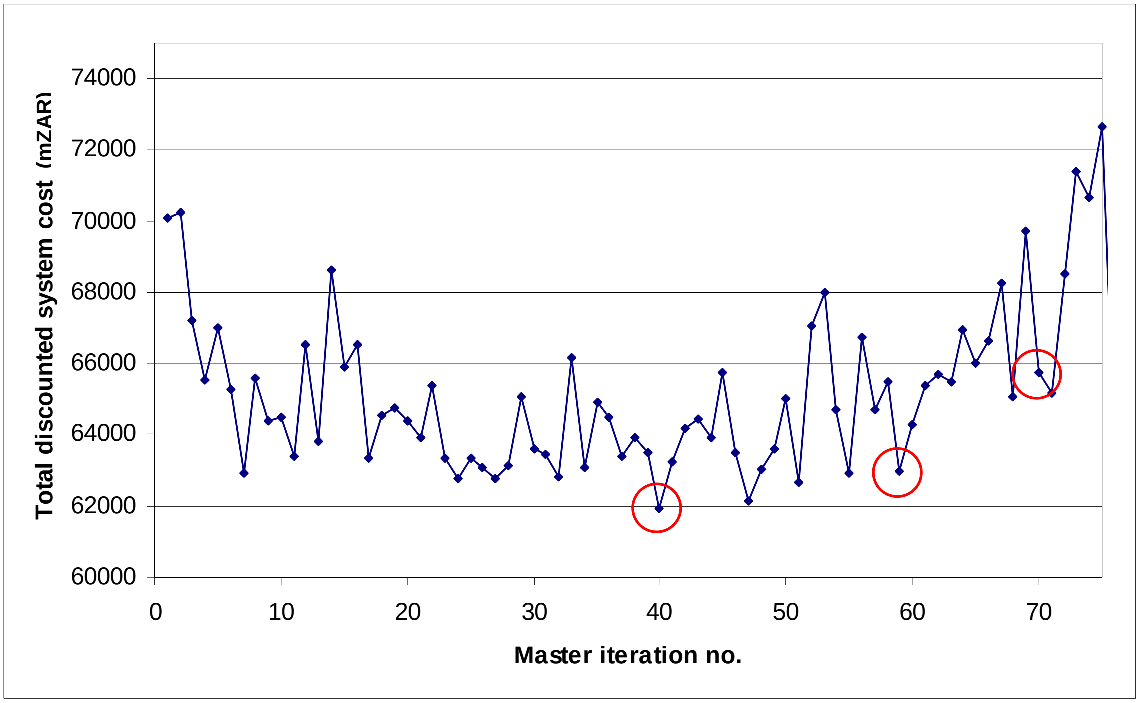


Figure 20 - Graph of total discounted system cost as a function of master problem iteration number for multi-node Cape model

Figure 20 shows the total discounted costs for 75 different investment plans. The total discounted costs include investment costs, operation costs and unserved energy costs incurred over the study period, averaged over the 150 slave runs. The investment plan 1 was generated in a master run where demand was inflated by 4% in all years in all nodes. Subsequent plans were generated by iterating between master and slave from this point onwards as explained before.

The multi-node model required many more iterations as demand was increased in each year for each node individually. This process could be significantly accelerated by doing a cursory scan of the solution space by increasing demand in larger increments and then focusing on a particular region of the solution space once an area of interest had been identified.

7.3 SHORT-LISTED PLANS

Three plans were selected form different areas of the solution space for more detailed analysis. The probability density function of the total discounted system cost for these plans is shown below:

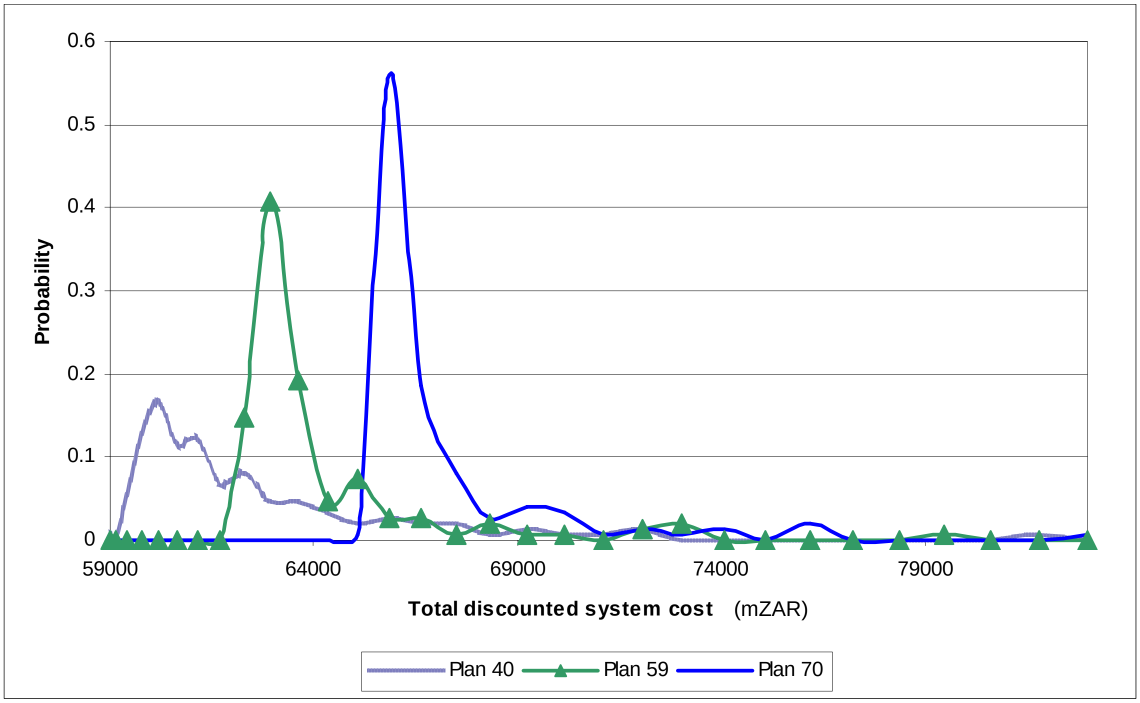


Figure 21 - Probability density functions for total discounted system cost – multi-node

As can be seen above, Plan 40 has the lowest average cost but has a wide spread. This occurs because Plan 40 has a relatively low investment cost component and a relatively high unserved energy cost component compared to the other plans (see Table 10 for the investment summary). This causes Plan 40 to be more sensitive to the amount of unserved energy in the system than the other plans shown above and therefore it has very high costs for the slave runs when there is a high unserved energy value and very low cost for when unserved energy has a low value.

Plan 59 has a slightly higher average cost, but has a relatively narrow spread of costs compared to Plan 40. This means that this plan is less dependant on the amount of unserved energy in the system due to more investment into generating capacity (see Table 11 below).

Plan 70 has a slightly higher average cost than Plan 59 as well as a marginally narrower spread.

Plan 40 and Plan 59 are compared and discussed in more detail in terms of investment strategies, reserve margin, unserved energy and the activity levels of generation and transmission capacity:

Table 10 – Generation investment summary table for Plan 40 –multi-node

Colour code	Node 0	Node 2	Node 7	Node 16	Node 19	Node 22

Annual Added Capacity

	Gas					Coal				Pumped Storage					
YR	New CCGT (Coega)	New OCGT (Atlantis)	New OCGT (Mossel Bay)	New OCGT (IPP Natal)	New OCGT (Other)	New CF1 (Matimba phase 1)- 1st unit	New CF1 (Matimba phase 1)- nth unit	New CF2 (Matimba phase 2)- 1st unit	New CF2 (Matimba phase 2)- nth unit	New Pumped Storage00 - 1st unit	New Pumped Storage00 - nth unit	New Pumped Storage16 - 1st unit	New Pumped Storage16 - nth unit	New Pumped Storage22 - 1st unit	New Pumped Storage22 - nth unit
2005															
2006															
2007		616	452												
2008															
2009				603											
2010															
2011															
2012						705									
2013															
2014							705								
2015															
2016												334	668		
2017															
2018															
2019															
2020															
2021															
2022															
2023															
2024							705								
TOTAL		616	452	603		705	1409					334	668		

Table 11 – Generation investment summary table for Plan 59 –multi-node

Colour code	Node 0	Node 2	Node 7	Node 16	Node 19	Node 22

Annual Added Capacity

	Gas					Coal				Pumped Storage					
YR	**New CCGT (Coega)**	**New OCGT (Atlantis)**	**New OCGT (Mossel Bay)**	**New OCGT (IPP Natal)**	**New OCGT (Other)**	**New CF1 (Matimba phase 1)- 1st unit**	**New CF1 (Matimba phase 1)- nth unit**	**New CF2 (Matimba phase 2)- 1st unit**	**New CF2 (Matimba phase 2)- nth unit**	**New Pumped Storage00 - 1st unit**	**New Pumped Storage00 - nth unit**	**New Pumped Storage16 - 1st unit**	**New Pumped Storage16 - nth unit**	**New Pumped Storage22 - 1st unit**	**New Pumped Storage22 - nth unit**
2005															
2006															
2007		616	452												
2008															
2009				603											
2010															
2011															
2012						705									
2013							705								
2014															
2015												334			
2016													668		
2017															
2018															
2019															
2020															
2021														334	
2022							705								334
2023															
2024															
TOTAL		616	452	603		705	1409					334	668	334	334

From Table 10 and Table 11 above it can be seen that Plan 40 and plan 59 differ mainly in that Plan 59 builds 2 units of pumped storage in node 22 and Plan 40 does not build any. Plan 59 builds the first unit of pumped storage in node 16 one year earlier than Plan 40 (in 2015). Plan 59 also builds the second unit of CF1 a year earlier than Plan 40 and the third unit of CF1 two years earlier (in 2022).

Table 12 – Transmission investment summary table for Plan 40 –multi-node

	New transmission				
YR	**Karoo-Peninsula (Gamma-Omega)**	**PE-S Cape (Grassridge-Gamma)**	**EL-PE (Buffalo-Poseidon)**	**Highveld-Karoo (Beta-Gamma)**	**Highveld-EL (Beta-Delphi)**
	07-16_02	**19-22_01**	**02-19_03**	**00-07_02**	**00-02_01**
2005					
2006					
2007					
2008					
2009					
2010					
2011					
2012		**2350**			
2013					
2014					
2015					
2016					
2017					
2018					
2019					**600**
2020					
2021					
2022					
2023					
2024					
TOTAL		**2350**			**600**

Table 13 – Transmission investment summary table for Plan 59 –multi-node

	New transmission				
YR	**Karoo-Peninsula (Gamma-Omega)**	**PE-S Cape (Grassridge-Gamma)**	**EL-PE (Buffalo-Poseidon)**	**Highveld-Karoo (Beta-Gamma)**	**Highveld-EL (Beta-Delphi)**
	07-16_02	**19-22_01**	**02-19_03**	**00-07_02**	**00-02_01**
2005					
2006					
2007					
2008					
2009					
2010					
2011					**600**
2012					
2013		**2350**			
2014					
2015					
2016					
2017					
2018					
2019					
2020					
2021					
2022					
2023					
2024				**2350**	
TOTAL		**2350**		**2350**	**600**

From Table 12 and Table 13 above it can be seen that Plan 59 invests in the Highveld-EL transmission line earlier than Plan 40, as well is investing in the Highveld-Karoo line in 2024 (which is not built at all in Plan 40). Plan 40 does however invest in the PE-S Cape line earlier than Plan 59.

Table 14 – Unserved energy and reserve margin table for Plan 40 –multi-node

YR	Unserved Energy (GWh) Node 2	Unserved Energy (GWh) Node 7	Unserved Energy (GWh) Node 16	Unserved Energy (GWh) Node 19	Unserved Energy (GWh) Node 22	Generation Plant Reserve Margin (PRM - %) node 2	Generation Plant Reserve Margin (PRM - %) node 7	Generation Plant Reserve Margin (PRM - %) node 16	Generation Plant Reserve Margin (PRM - %) node 19	Generation Plant Reserve Margin (PRM - %) node 22	Generation Plant Reserve Margin (PRM - %) Overall
2005			4.1	0.3		-46%	1199%	-16%	144%	372%	32%
2006			1.5			-47%	1177%	-19%	132%	361%	28%
2007	0.1		0.8			-51%	1166%	-2%	123%	412%	43%
2008	1.4		0.1			-53%	1120%	-4%	103%	402%	38%
2009			0.6	0.6		65%	1115%	-6%	28%	391%	33%
2010			0.1	4.9		60%	1100%	-9%	16%	377%	27%
2011	0.0		2.1	4.9		58%	1095%	-11%	0%	371%	20%
2012			1.8	3.4		53%	1081%	-13%	-22%	637%	19%
2013	0.0		4.2	7.0		50%	1072%	-15%	-24%	620%	16%
2014			1.3	5.3		48%	1072%	-16%	-31%	613%	20%
2015			4.0	8.0		45%	1058%	-18%	-32%	592%	18%
2016	0.1			4.9		44%	1063%	6%	-35%	588%	26%
2017			0.1	2.4		42%	1054%	4%	-36%	573%	24%
2018			0.7	7.4		40%	1045%	3%	-37%	559%	23%
2019			0.1	1.5		137%	1045%	2%	-38%	545%	21%
2020			0.8	2.7		135%	1041%	-3%	-38%	534%	18%
2021			0.3	3.5		131%	1024%	-5%	-39%	520%	16%
2022			2.3	3.0	0.3	128%	1019%	-6%	-40%	510%	15%
2023			0.8	5.1		125%	1011%	-6%	-41%	499%	14%
2024			0.9	3.4		124%	878%	-7%	-41%	490%	16%
TOTAL	1.6		26.7	68.3	0.3						
Discounted Total	1.2		16.0	31.5	0.1						

Table 15 – Unserved energy and reserve margin table for Plan 59 –multi-node

YR	Unserved Energy (GWh) Node 2	Unserved Energy (GWh) Node 7	Unserved Energy (GWh) Node 16	Unserved Energy (GWh) Node 19	Unserved Energy (GWh) Node 22	Generation Plant Reserve Margin (PRM - %) node 2	Generation Plant Reserve Margin (PRM - %) node 7	Generation Plant Reserve Margin (PRM - %) node 16	Generation Plant Reserve Margin (PRM - %) node 19	Generation Plant Reserve Margin (PRM - %) node 22	Generation Plant Reserve Margin (PRM - %) Overall
2005			4.1	0.3		-46%	1199%	-16%	144%	372%	32%
2006			1.5			-47%	1177%	-19%	132%	361%	28%
2007	0.1		0.8			-51%	1166%	-2%	123%	412%	43%
2008	1.4		0.1			-53%	1120%	-4%	103%	402%	38%
2009			0.6	0.6		65%	1115%	-6%	28%	391%	33%
2010			0.1	4.9		60%	1100%	-9%	16%	377%	27%
2011			2.3	0.3		170%	1095%	-11%	0%	371%	20%
2012	0.0		1.9	4.8		163%	1081%	-13%	-22%	358%	19%
2013			1.5	0.2		158%	1072%	-15%	-24%	620%	25%
2014			0.3	0.4		155%	1072%	-16%	-31%	613%	20%
2015			0.0	0.2		149%	1058%	-10%	-32%	592%	21%
2016				0.1		148%	1063%	6%	-35%	588%	26%
2017			0.1	0.5		143%	1054%	4%	-36%	573%	24%
2018			0.5	0.9		140%	1045%	3%	-37%	559%	23%
2019			0.1	1.5		137%	1045%	2%	-38%	545%	21%
2020			0.8	2.7		135%	1041%	-3%	-38%	534%	18%
2021			0.0	0.5		131%	1024%	-5%	-39%	553%	20%
2022			0.7	0.3		128%	1019%	-6%	-40%	576%	29%
2023			0.2	0.1		125%	1011%	-6%	-41%	563%	28%
2024				0.2		124%	1748%	-7%	-41%	554%	23%
TOTAL	1.4		15.7	18.5							
Discounted total	1.2		11.2	10.0							

The differences in investment into generation and transmission discussed above result in Plan 59 having significantly lower unserved energy levels in node 19 than Plan 40. Unlike in a single node model, this cannot be directly attributed to an increased generating reserve margin for that node. As can be seen in Table 14 and Table 15 above, the generating reserve margin for node 19 is identical. The differences are caused mainly by the additional investment of generating capacity in node 22 and the timing of the CF1 units, as well as the timing of the first unit of the node 16 pumped storage station.

The operation of the generating plants as well as the transmission lines can be examined to yield more insight into the plans considered:

Scale: 0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%

Table 16 – Excerpt of generation activity results for Plan 40 – multi-node

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
EHYDGAR	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	0.00%
EHYDMH	37.56%	37.56%	37.56%	37.56%	37.56%	37.56%	37.56%	37.56%	37.56%	37.56%
EHYDVDK	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%
EOCGTACA	1.92%	1.80%	1.91%	1.92%	1.59%	1.92%	1.92%	1.92%	1.92%	1.92%
EOCGTPOR	1.91%	1.90%	1.91%	1.91%	1.63%	1.91%	1.91%	1.91%	1.91%	1.91%
EPFKEN	69.26%	77.28%	79.04%	80.82%	81.85%	83.32%	85.49%	86.98%	87.86%	76.38%
EPSPALT	21.39%	9.68%	12.57%	16.05%	8.16%	14.74%	19.65%	21.87%	19.63%	11.28%
EPSSTET	26.13%	17.37%	19.70%	21.19%	13.44%	0.00%	0.00%	0.00%	0.00%	0.00%
EPWRKOE	82.71%	82.70%	82.70%	82.62%	82.66%	82.69%	82.65%	82.70%	82.65%	82.71%
ECCGTCOE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EOCGTATL	4.93%	0.65%	0.96%	1.36%	0.79%	1.41%	1.94%	2.38%	3.21%	2.40%
EOCGTMOS	1.51%	0.14%	0.16%	0.25%	0.10%	0.24%	0.38%	0.53%	0.68%	0.49%
EOCGTNAT	13.66%	3.61%	5.19%	7.07%	2.35%	4.22%	5.78%	7.21%	12.01%	4.49%
EOCGTOTH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPFNCF1_1	84.52%	84.59%	84.45%	84.52%	84.53%	84.61%	84.47%	84.61%	84.61%	84.58%
EPFNCF1_2	84.56%	84.58%	84.60%	84.47%	84.48%	84.46%	84.42%	84.45%	84.60%	84.64%
EPFNCF2_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPFNCF2_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPS00_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPS00_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPS16_1	0.00%	20.44%	20.77%	21.04%	19.86%	20.88%	20.93%	21.01%	20.99%	19.10%
EPS16_2	0.00%	20.54%	20.80%	20.97%	19.66%	20.20%	20.65%	21.03%	20.96%	18.98%
EPS22_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPS22_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 17 –Excerpt of generation activity results for Plan 59 – multi-node

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
EHYDGAR	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	0.00%
EHYDMH	37.56%	37.56%	37.56%	37.56%	37.56%	37.56%	37.56%	37.56%	37.56%	37.56%
EHYDVDK	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%	4.63%
EOCGTACA	1.82%	1.02%	1.33%	1.49%	1.59%	1.92%	1.65%	0.73%	0.94%	1.02%
EOCGTPOR	1.88%	1.29%	1.45%	1.56%	1.63%	1.91%	1.72%	0.80%	1.02%	1.28%
EPFKEN	70.56%	75.48%	77.46%	79.59%	81.85%	83.32%	86.27%	72.87%	75.10%	74.71%
EPSPALT	10.28%	3.31%	4.52%	5.80%	8.16%	14.74%	10.33%	1.64%	2.00%	2.42%
EPSSTET	15.91%	6.88%	8.98%	10.95%	13.44%	0.00%	0.00%	0.00%	0.00%	0.00%
EPWRKOE	82.71%	82.70%	82.70%	82.62%	82.66%	82.69%	82.65%	82.70%	82.65%	82.71%
ECCGTCOE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EOCGTATL	1.52%	0.27%	0.45%	0.52%	0.79%	1.41%	1.03%	0.18%	0.17%	0.28%
EOCGTMOS	0.24%	0.04%	0.11%	0.08%	0.10%	0.24%	0.21%	0.03%	0.01%	0.03%
EOCGTNAT	2.54%	0.71%	1.10%	1.60%	2.34%	4.22%	3.69%	0.38%	0.44%	0.75%
EOCGTOTH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPFNCF1_1	84.52%	84.59%	84.45%	84.52%	84.53%	84.61%	84.47%	84.61%	84.61%	84.58%
EPFNCF1_2	84.56%	84.58%	84.60%	84.47%	84.48%	84.46%	84.42%	84.60%	84.64%	84.64%
EPFNCF2_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPFNCF2_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPS00_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPS00_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EPS16_1	19.25%	16.03%	17.55%	18.94%	19.80%	20.83%	20.32%	15.40%	16.19%	14.30%
EPS16_2	0.00%	16.39%	17.51%	18.40%	19.69%	20.23%	19.61%	13.09%	13.97%	12.90%
EPS22_1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	20.15%	11.52%	11.38%	10.36%
EPS22_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	10.08%	12.41%	12.88%

It can be noticed from the activity results shown above that many of the generating stations in Plan 40 are generally run harder than those in Plan 59 (e.g. EPFKEN (Kendal), EPS16_1 (New pumped storage – node 16 unit 1), EPSSTET (Steenbras)). This is due to the additional generating capacity in Plan 59.

Scale: 0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%

Table 18 – Excerpt of transmission forward lines activity results for Plan 40 – multi-node

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
07-16_01B1	15.09%	20.23%	23.83%	29.02%	21.61%	25.90%	31.87%	35.77%	39.41%	38.31%
16-22_01B1	0.01%	0.73%	0.56%	0.36%	0.15%	0.07%	0.02%	0.02%	0.01%	0.03%
16-22_02B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-22_01B1	96.29%	98.22%	98.48%	98.47%	97.23%	97.46%	97.86%	98.10%	97.98%	98.02%
07-19_01B1	98.65%	98.69%	98.74%	98.74%	91.99%	92.57%	93.39%	93.86%	94.29%	94.31%
00-07_01B1	97.94%	97.94%	98.01%	97.92%	97.96%	97.95%	97.91%	97.99%	97.93%	97.92%
02-19_01B1	0.65%	0.17%	0.20%	0.32%	23.24%	24.21%	25.11%	25.88%	29.45%	31.99%
02-19_02B1	9.57%	1.95%	2.66%	3.86%	95.39%	95.67%	95.74%	96.09%	97.17%	97.09%
07-16_02B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-22_01B1	0.07%	0.64%	0.77%	0.94%	0.80%	0.83%	1.18%	1.24%	1.11%	1.46%
02-19_03B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
00-07_02B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
00-02_01B1	0.00%	0.00%	0.00%	0.00%	97.26%	97.17%	97.05%	97.21%	97.41%	97.18%
07-16_01B2	0.05%	0.00%	0.01%	0.00%	0.00%	0.01%	0.01%	0.01%	0.02%	0.02%
16-22_01B2	0.00%	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
16-22_02B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-22_01B2	0.16%	0.46%	0.33%	0.39%	0.17%	0.13%	0.14%	0.15%	0.12%	0.22%
07-19_01B2	41.31%	60.62%	63.77%	66.30%	30.39%	31.66%	33.09%	34.64%	35.11%	37.99%
00-07_01B2	62.91%	76.68%	79.58%	82.72%	56.09%	58.71%	62.33%	64.83%	66.47%	69.22%
02-19_01B2	0.00%	0.00%	0.00%	0.00%	0.05%	0.07%	0.06%	0.07%	0.11%	0.36%
02-19_02B2	0.00%	0.00%	0.00%	0.00%	0.77%	0.82%	1.00%	0.86%	1.00%	1.90%
07-16_02B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-22_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
02-19_03B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
00-07_02B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
00-02_01B2	0.00%	0.00%	0.00%	0.00%	2.33%	2.19%	2.56%	2.49%	2.20%	15.51%

Table 19 – Excerpt of transmission forward lines activity results for Plan 59 – multi-node

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
07-16_01B1	14.59%	16.01%	17.25%	18.72%	21.61%	25.90%	33.68%	33.03%	38.35%	42.56%
16-22_01B1	0.01%	0.14%	0.14%	0.17%	0.15%	0.07%	0.02%	0.01%	0.01%	0.00%
16-22_02B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-22_01B1	88.78%	92.75%	94.47%	96.00%	97.23%	97.46%	97.93%	97.59%	97.69%	97.73%
07-19_01B1	88.49%	90.12%	90.67%	91.32%	91.99%	92.57%	93.82%	93.05%	93.97%	94.49%
00-07_01B1	97.93%	97.91%	97.99%	97.89%	97.96%	97.95%	97.91%	97.99%	97.93%	97.91%
02-19_01B1	23.42%	22.80%	22.65%	22.70%	23.24%	24.21%	23.41%	28.40%	28.54%	17.54%
02-19_02B1	95.49%	95.13%	95.60%	95.52%	95.39%	95.67%	94.91%	96.23%	96.50%	93.37%
07-16_02B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-22_01B1	0.27%	0.35%	0.49%	0.69%	0.80%	0.83%	1.59%	1.27%	1.58%	1.81%
02-19_03B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
00-07_02B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	60.94%
00-02_01B1	95.53%	96.78%	97.10%	97.26%	97.26%	97.17%	97.06%	97.20%	97.36%	97.14%
07-16_01B2	0.03%	0.01%	0.03%	0.02%	0.00%	0.01%	0.01%	0.07%	0.04%	0.08%
16-22_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
16-22_02B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-22_01B2	0.11%	0.16%	0.15%	0.14%	0.17%	0.13%	0.17%	0.27%	0.23%	1.57%
07-19_01B2	18.60%	23.89%	25.63%	27.87%	30.39%	31.66%	33.85%	35.57%	37.87%	44.77%
00-07_01B2	37.69%	45.60%	48.77%	52.37%	56.09%	58.71%	63.65%	63.61%	67.21%	3.47%
02-19_01B2	0.02%	0.03%	0.01%	0.03%	0.05%	0.07%	0.05%	0.02%	0.04%	0.02%
02-19_02B2	0.42%	0.54%	0.35%	0.72%	0.77%	0.82%	0.95%	0.53%	0.57%	0.19%
07-16_02B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-22_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
02-19_03B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
00-07_02B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
00-02_01B2	1.11%	1.77%	1.76%	2.07%	2.33%	2.19%	2.62%	13.94%	14.78%	0.32%

The activity results of the forward lines show that the dummy lines[8] for 07-19_01 and 00-07_01 are run relatively hard; implying that the lines are heavily loaded (beyond their lower capacity levels). Dummy line 00-02_01 is also run relatively hard in the last few years of the study period. The lines in Plan 40 are run harder than the lines in Plan 59 due to the extra transmission and generation capacity in Plan 59.

[8] Normal capacity lines are denoted by “B1” while dummy lines representing loading beyond normal capacity (see section 4.2 (transmission)) are denoted with a “B2”

Scale: 0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%

Table 20 – Excerpt of transmission reverse lines activity results for Plan 40 – multi-node

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
16-07_01B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22-16_01B1	98.13%	93.81%	93.90%	94.28%	96.78%	97.62%	97.59%	98.19%	98.33%	98.24%
22-16_02B1	7.97%	9.15%	9.65%	8.92%	10.75%	8.59%	8.74%	7.92%	7.78%	8.56%
22-07_01B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-07_01B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-00_01B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-02_01B1	7.06%	10.72%	10.68%	10.60%	0.13%	0.15%	0.12%	0.13%	0.11%	0.14%
19-02_02B1	80.91%	92.59%	90.99%	89.12%	1.51%	1.41%	1.41%	1.29%	1.02%	1.35%
16-07_02B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22-19_01B1	10.72%	9.50%	8.68%	8.16%	4.11%	3.84%	3.92%	3.59%	3.08%	2.57%
19-02_03B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-00_02B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
02-00_01B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
16-07_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22-16_01B2	51.12%	72.84%	74.25%	74.41%	82.10%	81.49%	80.37%	80.80%	80.69%	84.12%
22-16_02B2	0.05%	0.03%	0.03%	0.06%	0.10%	0.03%	0.08%	0.09%	0.02%	0.11%
22-07_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-07_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-00_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-02_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-02_02B2	0.04%	0.12%	0.15%	0.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
16-07_02B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22-19_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-02_03B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-00_02B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
02-00_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 21 – Excerpt of transmission reverse lines activity results for Plan 59 – multi-node

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
16-07_01B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22-16_01B1	98.61%	96.82%	96.83%	96.49%	96.78%	97.62%	98.18%	99.18%	99.08%	99.05%
22-16_02B1	5.31%	5.50%	6.73%	9.13%	10.75%	8.59%	7.73%	6.41%	7.22%	7.50%
22-07_01B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-07_01B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-00_01B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-02_01B1	0.16%	0.15%	0.17%	0.10%	0.13%	0.15%	0.15%	0.17%	0.17%	0.20%
19-02_02B1	1.56%	1.61%	1.43%	1.20%	1.51%	1.41%	1.55%	1.51%	1.33%	1.63%
16-07_02B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22-19_01B1	4.09%	4.97%	4.69%	4.28%	4.11%	3.84%	4.33%	3.06%	2.95%	4.18%
19-02_03B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-00_02B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
02-00_01B1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
16-07_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22-16_01B2	61.26%	74.35%	78.67%	81.55%	82.10%	81.49%	79.40%	83.12%	81.69%	78.45%
22-16_02B2	0.04%	0.10%	0.14%	0.29%	0.10%	0.03%	0.04%	0.23%	0.19%	0.25%
22-07_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-07_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-00_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-02_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-02_02B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
16-07_02B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22-19_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-02_03B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-00_02B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
02-00_01B2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Examining the reverse line activity results it can be seen that some lines are always run in only one direction (e.g. lines 07-19_01 (19-07_01 does not run) and 00-07_01 (07-00_01 does not run) mentioned above for both plans) while other lines switch direction midway through the study period (e.g. 02-19_02 switches to 19-02_02 in Plan 40) as generation capacity and demand levels in the nodes change. There are also cases were lines are run in both directions within a single year (e.g. 22-19_01 in both plans). This anomaly can be due to units being forced out as well as demand peaks occurring at different times in the different nodes.

Scale: 0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%

Table 22 – Excerpt of transmission losses for Plan 40 – multi-node

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
07-16_01	4.61%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
16-22_01	0.55%	0.57%	0.56%	0.55%	0.56%	0.55%	0.55%	0.55%	0.55%	0.55%
16-22_02	0.00%	1.98%	0.00%	1.98%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-22_01	2.35%	2.35%	2.35%	2.35%	2.35%	2.35%	2.35%	2.35%	2.35%	2.35%
07-19_01	1.98%	2.09%	2.11%	2.12%	1.92%	1.92%	1.93%	1.94%	1.95%	1.97%
00-07_01	4.83%	4.98%	5.00%	5.03%	4.74%	4.77%	4.82%	4.85%	4.87%	4.90%
02-19_01	0.87%	0.87%	0.87%	0.87%	0.87%	0.88%	0.88%	0.88%	0.88%	0.88%
02-19_02	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%
07-16_02	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-22_01	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%
02-19_03	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
00-07_02	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
00-02_01	0.00%	0.00%	0.00%	0.00%	5.93%	5.92%	5.96%	5.95%	5.92%	7.17%
16-07_01	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22-16_01	0.70%	0.74%	0.74%	0.74%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%
22-16_02	1.99%	1.98%	1.98%	1.99%	1.99%	1.98%	1.99%	1.99%	1.98%	2.00%
22-07_01	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-07_01	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-00_01	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-02_01	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%
19-02_02	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%
16-07_02	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22-19_01	2.24%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%
19-02_03	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-00_02	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
02-00_01	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 23 – Excerpt of transmission losses for Plan 59 – multi-node

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
07-16_01	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.61%	4.60%	4.60%
16-22_01	0.55%	0.55%	0.55%	0.55%	0.56%	0.55%	0.55%	0.55%	0.55%	0.55%
16-22_02	0.00%	0.00%	0.00%	1.98%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-22_01	2.35%	2.35%	2.35%	2.35%	2.35%	2.35%	2.35%	2.35%	2.35%	2.37%
07-19_01	1.82%	1.87%	1.88%	1.90%	1.92%	1.92%	1.94%	1.95%	1.97%	2.01%
00-07_01	4.48%	4.60%	4.64%	4.69%	4.74%	4.77%	4.83%	4.83%	4.87%	3.77%
02-19_01	0.87%	0.87%	0.87%	0.87%	0.87%	0.88%	0.87%	0.87%	0.87%	0.87%
02-19_02	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%
07-16_02	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-22_01	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%
02-19_03	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
00-07_02	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	5.74%
00-02_01	5.80%	5.87%	5.87%	5.91%	5.93%	5.92%	5.96%	7.04%	7.11%	5.72%
16-07_01	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22-16_01	0.72%	0.74%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.74%
22-16_02	1.99%	2.00%	2.01%	2.02%	1.99%	1.98%	1.98%	2.03%	2.01%	2.02%
22-07_01	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-07_01	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-00_01	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19-02_01	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%
19-02_02	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%	0.74%
16-07_02	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
22-19_01	2.24%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%
19-02_03	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
07-00_02	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
02-00_01	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 22 and Table 23 above show the transmission losses for each of the lines and reverse lines for Plan 40 and Plan 59. These losses take both the lines and dummy lines into account and therefore account for the higher losses experienced by lines running above their normal capacity.

The losses are similar for the two plans except that Plan 59 experiences losses for 00-02_01 much earlier as it is built in 2011 instead of 2019 as in Plan 40. Higher losses occur where lines are run harder. This can be seen for lines 07-19_01 and 00-07_01.

In summary, the activity data can be used to determine how hard lines each of the lines are running, whether they are running beyond their lower rated capacity and of so, by how much, as well as the direction of flow of electricity through the lines. The losses for different plans can also be compared.

8 CONCLUSIONS AND RECOMMENDATIONS

8.1 CONCLUSIONS

In this report, it was demonstrated how TIMES, in conjunction with Excel could be used to do multi-node generation expansion planning. The three aspects that were focused are the handling of planned and unplanned outages, characterization of demand and representation of transmission lines. Current versions of some of the more important components of the user interface (in Excel) were also presented.

A two-stage benchmark test was performed on a single node model with EGEAS. In the first stage, the fixed investment plan generated using EGEAS was forced in TIMES and an analysis was conducted on the production plan. The results obtained show that TIMES report similar production levels as reported by EGEAS. There seem to be some differences in the way the capacity factors for PS stations are reported. This should be investigated in more detail. The unserved energy levels obtained using the MC approach seem to correlate well with that obtained using the equivalent load duration curve used by EGEAS.

In the second stage, the investment problem was solved using the master-slave iteration approach with TIMES and Excel. This approach yields a range of suitable solutions, some of which resemble closely those obtained using EGEAS. It was demonstrated in the report, how the planner may decide on a preferred plan given a trade-off between unserved energy and system costs. The results of this two-phase benchmark test are notable given that the two approaches (EGEAS and TIMES) are significantly different.

A second case study involving a 6 node version of the model was also performed. The input data provided by Eskom for this study was limited and therefore the parameters used may not replicate the Eskom system for the regions studied. A range of suitable plans were obtained using an approach similar to the one used for a single node. The amount of data generated for the multi-node problem was large and some areas still need to be explored. Results obtained are however within what was expected for the model at hand:

- Transmission lines at bottle-necks use the higher capacity-higher losses transmission blocks (B2).
- Some transmission lines switch direction within the study period, while others are used to carry electricity in two different within a single year.

A direct comparison between generation planning with and without transmission constraints on the problem presented here is difficult given the range of solutions obtained in both cases. The generation expansion plans do overlap. One notable difference is that in the multi-node case, some of the generation expansion decisions are delayed by the investment of new transmission lines.

The framework developed in this project is a work in progress. It has been demonstrated how this methodology has been used to generate insightful expansion plans that integrate transmission into the decision framework. This framework has been customised specifically for ISEP's requirements, based on the format of their input data as well as their output templates. Further work can add to this existing framework and further develop and customise it according to Eskom's and ISEP's changing needs and growing requirement for integrated generation and transmission planning.

8.2 RECOMMENDATIONS – PHASE 2

The 6 nodal model prepared as proof of concept requires further expansion (27 nodes excluding imports) and refinement both from a methodology, model configuration and user interface perspective. Furthermore, modelling the total Eskom (and National) system will require a high degree of involvement of Eskom planners (ISEP-generation, Nodal demand forecasters and transmission) so as to ensure adequate empowerment of Eskom staff in the application and use of the model and appropriate data collation and input.

The model as it evolves over time will continuously require reviewing and checking. It is also required to ensure that assumptions are reasonable, comprehensive and accurate, results are informative to the planning process, and that the model remains an adequate user-friendly tool.

8.2.1 SCOPE OF PHASE 2

- Together with ISEP staff, benchmark the TIMES model with EGEAS based on a single node configuration of the South African Electricity System using updated data supplied by Eskom under confidentiality agreement.

- Together with ISEP staff, further develop and configure the TIMES model for multi-Nodal generation expansion planning of the entire South African Electricity System, including for National imports / Exports of electricity.

- Compare all resultant plans and Report

8.2.2 ACTIVITIES AND MILESTONES

The project activities and milestones are summarised as follows:

- **Inception/kick-off (Milestone 1)**
  - Presentation and description of existing 6 nodal model as currently configured under Phase 1 of the project.
  - Agree on the methodology for development and configuration of the national model.
- **Development of 1-node reference national database with ISEP station data**
  - Data collection on existing stations and new options
  - Further development of interface for station data
  - Benchmark with EGEAS for 1 node National System. The benchmark exercise includes some sensitivity test with respect to some key variables: e.g. discount rate, cost of coal, outage rates and unserved energy

- **Development of multi-nodal system**
    - Node configuration
    - Collection of transmission data relevant to nodal configuration, existing and new options
    - Calibration of transmission data to TIMES representation
    - Further development of interface for node configuration and transmission data
    - Thorough test of model
    - Presentation of first pass of multi-nodal Reference system results **(Milestone 3)**
- **Refinement of multi-nodal system and sensitivities**
    - Adjustments to transmission data and node configuration
    - Sensitivity studies
    - Further refinements of interface
    - Presentation of sensitivity studies results **(Milestone 4)**
- **Final reporting and documentation**
    - Report of multi-node national expansion plan
    - Model documentation
    - User Manual
    - Final hand over + Agreement of mechanisms for future technical support and provision for upgrades **(Milestone 5)**

8.3 POTENTIAL IMPROVEMENTS FOR THE FUTURE

The model implemented so far has some shortcomings and areas that can be improved. Some of the more significant issues are elaborated below:

8.3.1 PROCESSING TIME

Processing time needs to be improved (currently it can take more than 24hrs to generate a set of solutions for the 6 node problem). This could be achieved in a few different ways:

1. A more thorough evaluation of the number of Times Slices to achieve the required level of accuracy must be established, (42 Time Slices may be too many).
2. A first pass of the master problem with larger increments in inflated demand in the master problem should avoid unnecessary evaluations of slave problems.
3. Another possibility for setting up a better starting point for the *master-slave* iterations is to de-rate the stations by the forced outage rate in the *master* problem.
4. Intelligent feedback mechanism between slave and master (e.g. make the demand increments proportional to unserved energy reported in the slave problem).
5. Certain constraints such as stations with units that have different characteristics could be eliminated by combining them (minor simplification).
6. There exists a feature in GAMS[9] that allows solutions from an earlier solve to be saved and used for subsequent solves. This feature was not used in producing the results presented in this report. It could potentially reduce some of the computation time.

8.3.2 INTERFACE

The interface is almost entirely based in Excel. There are some minor operations that are currently required using the ANSWER interface. This adds to the complexity faced by the user, which could be avoided if these operations are automated.

[9] GAMS: General Algebraic Modeling System (GAMS) is a high-level modeling system for mathematical programming and optimization. TIMES optimization components is in GAMS.

Excel allows significant flexibility, however in light of this input templates need to be made more robust to user error. This involves extensive data validation (ensuring the magnitude, sign etc… of each entry is allowed) and data checking (making sure that no infeasibilities are introduced in the model). Both of these require substantial programming effort.

The master-slave iterations are currently automated but again the interface could be improved and the process made smoother.

There is no facility currently to handle different scenarios within the Excel interface. This is something that would have to be programmed as well (currently scenarios are still possible, yet the process is not user friendly).

Emissions are not included in the current version of the model. However, the capacity to handle emissions and tax on emissions in TIMES already exists, therefore implementing this into the model should not present any major hurdles.

The output interfaces can easily be further tailored to meet Eskom’s needs. Further analysis can be automated from within Excel to accelerate the report generation process. The data produced from a set of master-slave iterations is considerable. Data visualization tools (graphic) could significantly help the planner. With Excel and visual basic, the possibilities here are only limited by imagination (and programming time).

There is no facility for the user to impose a reserve margin, should he wish to do so. This feature could easily be included in the next version of the software.

8.3.3 FURTHER ANALYSIS

Better representation of Planned Outages

A more realistic representation of planned outages in TIMES needs to be explored further and implemented on the systems analyzed in this report. Appendix C describes a method that would be possible to implement in TIMES.

The power sector in the context of the complete energy system

Having a power sector planning tool that meets the required standard within the TIMES framework opens a lot of possibilities in terms of energy systems modeling, both upstream (e.g. refineries, mines, etc.) and downstream (demand modeling e.g. electric geyser vs solar water heaters).

The power of MC

Currently the only uncertain parameters handled via Monte Carlo is the unplanned outages of stations and transmission lines. However, having this framework in place, other uncertain parameters such as demand growth could be included into the *master-slave* methodology as well.

Other uncertain input parameters such as investment and operating costs of future options, fuel costs, as well as lead time uncertainty could be modelling using MC and a full robustness analysis could be done on preferred plans demonstrating their performace based on the uncertain distributions of the input parameters. The lack of this type of analysis is a weakness of many commercial planning tools.

Stochastic programming with recourse

TIMES has the functionality that allows for a few uncertain parameters to be expressed in a stochastic programming with recourse framework. Stochastic programming models with recourse are used for near term modeling in light of long term uncertainties through the development of short term strategies with inherent flexibility towards long-term uncertainties, as well as long term contingency plans once more information becomes available about the uncertain parameters. The recourse problem is formulated with different future states of the world coming into being after designated points in the time horizon. This is different to stochastic programming without recourse, which outputs a single strategy for the entire time horizon which is optimal, on average, for all scenarios. The recourse solution is then optimized such that each stage of the model is best positioned to meet the multiple future conditions, thus including an aspect of flexibility in the solution. Two-stage stochastic programming is best suited for modeling future uncertainties that have a definite date of resolution (such as legislation associated with emission limits) but it can also be used to model demand growth and fuel price uncertainties. Stochastic modeling with recourse has also been used to generate flexible least cost solution strategies for global climate change.

Another possibility is to combine this tool with the Decision Tree tool developed last year for Eskom, where specific decisions in the context of some of the uncertain parameters can be evaluated.

Multiple-objectives

Within the TIMES framework it is also possible to define the objective function for optimization in terms of more than one objective, e.g. costs, emissions, unserved energy. In this way a range of solutions could be generated, optimised for multiple objectives, from which decision makers could select preferred alternatives. This could be combined with a multi-objective robustness analysis such that a set of plans could be compared based on their performance in terms of each of multiple objectives given the uncertainty in input data (such as investment and operating costs of future options and fuel costs).

APPENDIX A: DETERMINATION OF SAMPLE SIZE FOR THE SINGLE NODE MODEL

Initially the sample size or number of runs needed for the *slave* problem needed to be determined. This number should be large enough to adequately represent plant outage and therefore unserved energy but should also be minimised to reduce computation time.

Figure 22 below illustrates the average amount of unserved energy in the *slave* problem for each year as a function of sample size for the single node model:

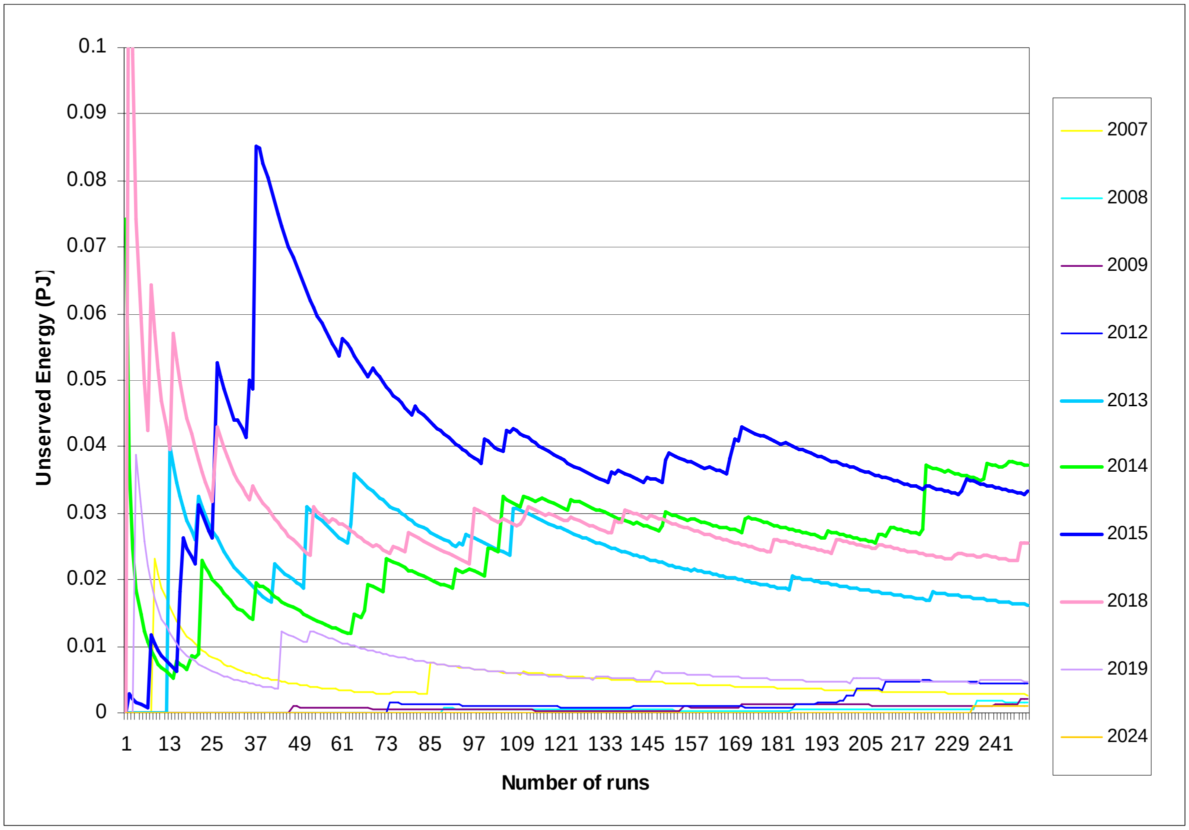


Figure 22 - Graph of average unserved energy as a function of no. of runs of slave problem for a demand inflated by 4 % for single node model for selected years

There is generally more unserved energy in the *slave* problem at a low level of inflated demand compared to a higher level of inflated demand due to the increased capacity in the system. Therefore the decision on how many runs of the *slave* to do would best be made based on the relationship between unserved energy and no. of runs at a low level of inflated demand.

Using 2015 as an example, it can be seen from Figure 22 that the average unserved energy values stabilize (with minor fluctuations) from about 120 runs of the *slave* problem. The same can be said for other years where the average value of unserved is high, relative to other years (e.g. 2013, 2014, 2018).

It was therefore decided that running the *slave* problem 150 times for each iteration of the *master* problem would be sufficient to represent plant outage and therefore unserved energy for this electricity supply system.

APPENDIX B: DETERMINATION OF SAMPLE SIZE FOR THE MULTI NODE MODEL

Figure 23 below illustrates the average amount of unserved energy in the *slave* problem for each year as a function of sample size for node 19 of the multi-node model:

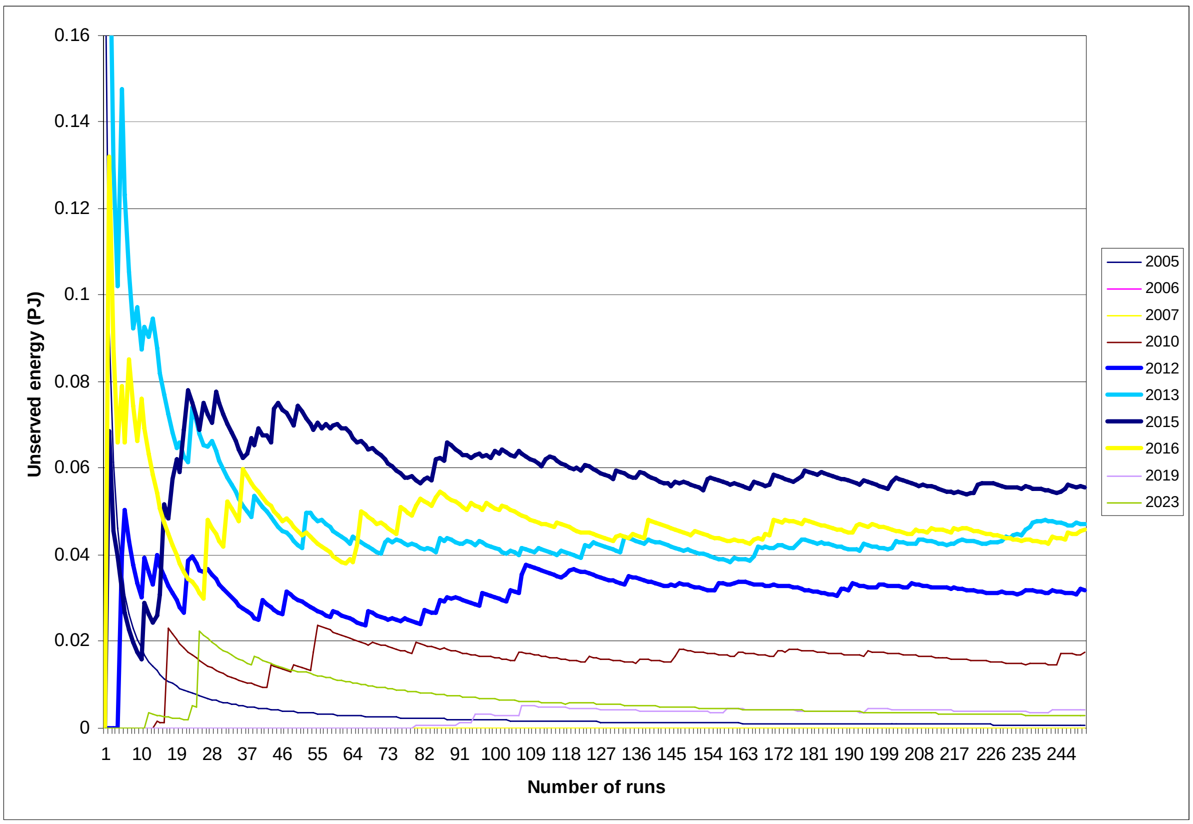


Figure 23 - Graph of average unserved energy as a function of no. of runs of slave problem for a demand inflated by 4 % for node 19 of multi-node model for selected years

Using 2015 as an example, it can be seen from Figure 23 that the average unserved energy values stabilize (with minor fluctuations) from about 120 runs of the *slave* problem (similarly to the single node model). The same can be said for other years where the average value of unserved is high, relative to other years (e.g. 2012, 2013 and 2016).

It was therefore decided that running the *slave* problem 150 times for each iteration of the *master* problem would be sufficient to represent plant outage and therefore unserved energy for the multi-node model.

Appendix C: Alternative for Planned Outage in TIMES

Background

The planned outage method described in section 2.2 is often used in energy modelling but may not be suitable to power expansion planning. In this method, planned maintenance is scheduled optimally with the only constraint being that annual production must not exceed (1-POR) x (1-FOR) x (Capacity x Hours in a year). The problem with this approach is that it allows for maintenance to occur at night throughout the year, when demand is low. This is not a very realistic way of simulating downtime that generally lasts several weeks and includes daytime periods of higher demand.

The approach commonly used by ESI software is to de-rate stations in one of the "seasons". The de-ration season would be chosen in the optimization process.

This is a discrete/integer type decision. In TIMES, the only decision variables that can be discretized are capacity additions – and so there isn't a simple implementation of this additional constraint.

Methodology

The proposed alternative method for planned outage representation for the system described throughout this document is as follows:

For each station a dummy process is created for each season. Each of the dummy processes is de-rated in a different season and are placed (in the system topology) between the station and the grid via a dummy commodity, as shown in Figure 24 below.

A dummy will never operate at a level higher than the de-ration level in the season it is de-rated, but is allowed to operate up to 100% in the other seasons. The de-ration level is calculated such that the station and dummy can operate for up to a maximum of (1-*POR*) x (Capacity x Hours in a year).

The capacities of the dummy processes are constrained as follows:

1. $\sum DCap_i = SCap$
2. $DCap_i = k \times UCap,\ k \in \{0,1,2,...,n\},\ SCap = n \times UCap,$

where $DCap_i$ is the capacity of a dummy process for season i,

SCap and *UCap* are the capacities of the station and the units that make up the station.

The life-time of a dummy is equal to 1 year, has no losses and has no costs.

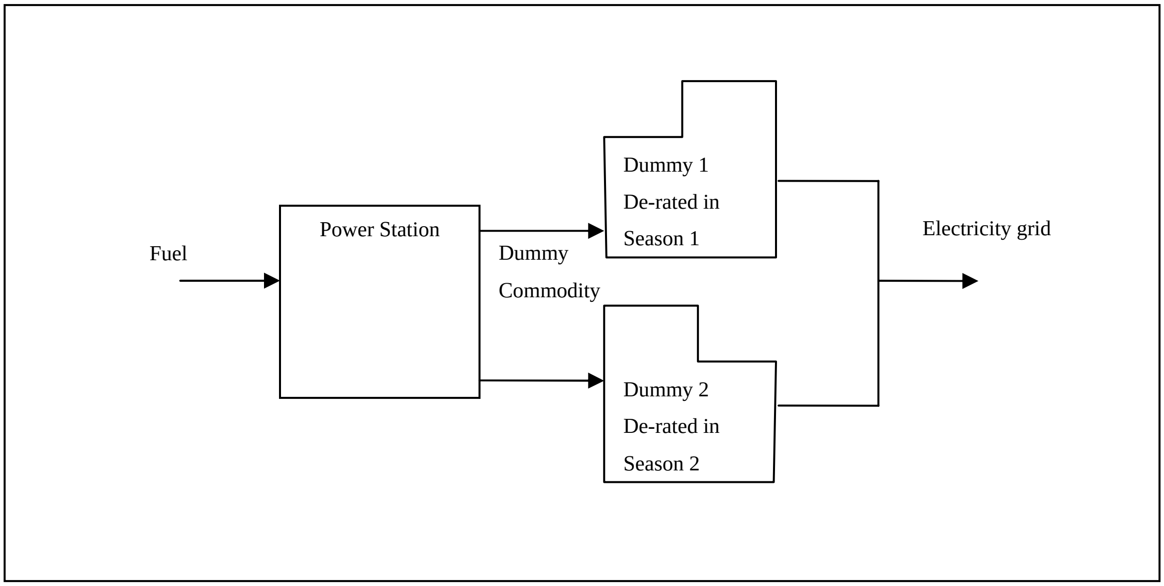


Figure 24 - Planned outage representation with dummy processes

The system is forced to ‘build’ dummy processes each year to connect the station to the grid. The constraints are such that for a single-unit station only one dummy process can be ‘built’ each year. By choosing which dummy to ‘build’, the system effectively chooses when to schedule the planned maintenance. In the case of a multi-unit station, the system can schedule the maintenance of different units in different seasons.

In the context of the master-slave system presented earlier in this document, the capacity decisions for the dummy processes are part of the *master* problem which is solved with mixed integer programming. Like the capacity decisions for stations, the capacity decisions for the dummy processes are fixed in the *slave* problem such that the same maintenance schedule is used for all the MC draws.

TESTED SYSTEM

This approach has not been tested yet on the Cape model. Instead a smaller system consisting of 2 stations and 4 time-slices was used to demonstrate the concept for the *master* problem.

The smaller system can be described as follows:

- Study Period: 2005 to 2010.
- 4 - Time-slices:
    - The year is split in 2 Seasons: summer and winter each lasting half a year
    - Each season is split into 2 blocks: 1 day block and 1 night block each lasting half the season.
- The load starts at about 8300GWh growing at 10% per annum. It is split between the 4 time slices as follows:
    - 26% in Summer day ~ 1GW in 2005,
    - 20% in Summer night ~ 0.76GW in 2005,
    - 30% in Winter day ~ 1.14GW in 2005,
    - 24% in Winter night ~ 0.91GW in 2005.
- There is one existing station of 2 units of 500MW each, and 1 station with 1 existing unit of 500MW that can be expanded by adding further units of 500MW.
- Both stations have a planned outage rate of 10%.

RESULTS

The resulting capacity and maintenance plan obtained using the method described above is shown in Figure 25. The bars on the chart represent the available capacity (darker colours) and capacity under maintenance (lighter colours) for each of the stations. The red line represents the load/demand for each of the time-slices in the study period. From the graph, it can be seen that maintenance for both stations are scheduled in Summer in 2005 and 2006; in 2007 the maintenance for station 2 is scheduled in Winter; a new unit is added to Station 2 in 2008, the maintenance of one of the units is in Winter – the rest being in Summer and so on.

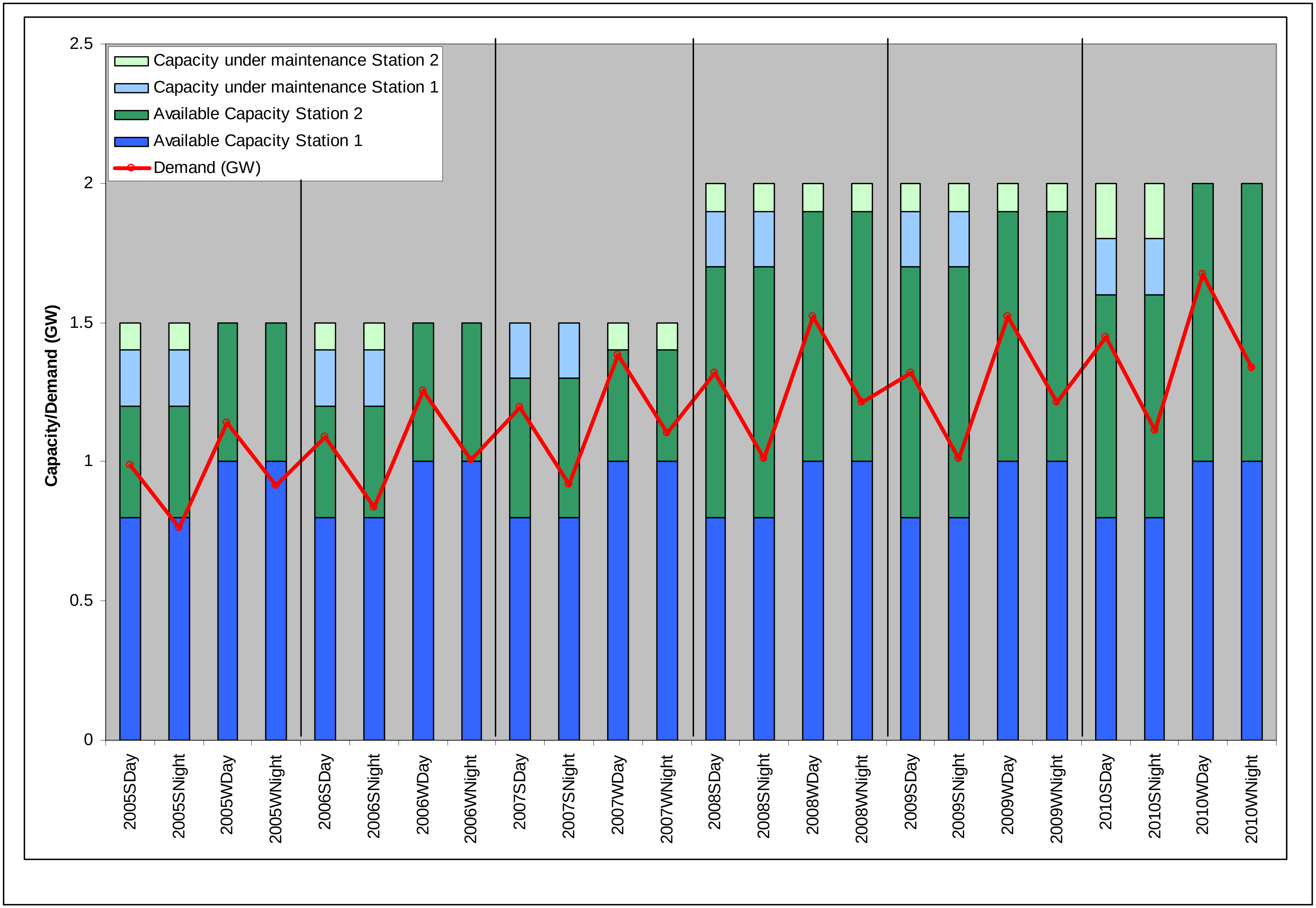


Figure 25 - Investment and maintenance schedule for small system

CONCLUSIONS

What can be concluded is that this approach for simulating planned maintenance has successfully been implemented in TIMES. The results obtained are as expected; maintenance is scheduled for one of the seasons in an optimal manner, which should more accurately describe reality. What has not been tested is the additional computational burden that results in using this method when applied to larger systems. It should be applied to the Cape Model and again compared with EGEAS to see if there are indeed significant improvements.

The interface can be set-up such that the user can choose which maintenance method to apply. This would leave the trade-off between accuracy and computational time to the user.