Bridging the Power Gap in Africa: Testing options to manage constrained short to medium term system operations

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Abstract—Although significant historical investment in power system capacity placed African countries in a strong position to meet increasing demand, this capacity has been absorbed by significantly increased levels of demand as a result of economic growth and intensive electrification programmes. Even though long term capacity expansion is planned, system operators face increasingly constrained system operations in the short to medium term with available capacity. Adding to this, ageing capacity is requiring increased levels of maintenance with increasing outage durations. Performing the required maintenance is not always possible as a result of the abovementioned constraints resulting in further increases in maintenance required as well as increased levels of forced outages. This paper presents options for system operators to use in an attempt to prevent and stop what seems like a downward spiral of system adequacy in the short to medium term. A model is developed which assesses a number of supply and demand side options for system operators to use to help weather the storm in the short to medium term. These options include:

- Demand side:
  i. Non-selective load-shedding
  ii. Demand Side Participation (DSP)
  iii. Introduction of country/regional time zones
  iv. Introduction of labour shifts

- Supply side:
  i. Improvement in generation availability
  ii. Leveraging existing but unused distributed generation
  iii. Fast-tracked emergency power generation
  iv. Strategic energy storage in adjacent countries/regions
  v. Security constrained operations

The paper is structured to include an overview of the model developed, the presentation of the effect each supply and demand side option can have followed by a concluding section.
around the globe primarily for energy market optimisation and analysis in short, medium and long term.

The model developed uses mathematical programming (Quadratic Programming (QP) and Mixed Integer Programming (MIP)) focusing on short to medium term constrained system operations. In one fully integrated environment, the model includes the optimal placement of maintenance events (excluding forced outages), decomposition of any medium-term constraints to short-term constraints and a complete production cost model including unit commitment and economic dispatch. The analysis is performed over a representative one year time horizon to assess the effects of the various supply and demand side options in the short to medium term that the system operator could use to mitigate constrained system operations. Hardware/software configuration to run the required simulations include a 64-bit architecture in a Windows environment with two Intel® Xeon® E5-2670 processors operating at 2.6 GHz (8 cores each) and 100 GB RAM.

The supply side of the model includes a mix of generation capacity technologies including steam turbines, Open Cycle Gas Turbines (OCGT), hydraulic turbines, wind turbines, solar Photovoltaic (PV) and Concentrated Solar Power (CSP). These technologies are fired by a number of fuels including coal, nuclear, gas/diesel, water, solar and wind. Each generation technology is modelled with specific assumed technical and financial parameters as summarised in Appendix A. Hydro generation capacity is energy constrained on a monthly basis based on an assumed annual rainfall seasonality profile. Maintenance parameters chosen have been intentionally increased from typical maintenance rates and forced outage rates in order to present a constrained system. A supply side with installed capacity of 46 711 MW (rated capacity of 43 119 MW) has been modelled with a total of 598 units and unit sizes ranging from 1.3 MW to 900 MW.

The demand side of the model is built up using sector specific participation in the overall demand profile as well as daily, weekly and seasonal variations. Pertinent characteristics of the demand model are summarised in Appendix A. The annual seasonality of the demand model is shown in Figure 1 where the hourly demand profile over a typical week is given in Figure 3 while the hourly demand profile over a typical week is shown in Figure 2. As can be seen, demand is dominated by the industrial sector dominates with residential, mining an commercial sectors having quite similar shares while the agricultural sector has a small demand requirement. The demand side has a peak demand of 35 850 MW and minimum demand of 19 775 MW with an annual energy requirement of 247 141 GWh.

The annual supply-demand balance of the model is shown in Figure 4 where the effect of constrained system operation is clearly seen via the unserved energy required to maintain the supply-demand balance. Unserved energy is penalised heavily in the objective function by a parameter known as Cost of Unserved Energy (COUE). The COUE can be interpreted to be the value placed on a unit of energy not supplied and can be sector specific. There are many detailed methods available to determine COUE but an estimate of USD 7 000/MWh is used in this model for all sectors.

The annual supply-demand balance of the model is shown in Figure 5 where the effect of constrained system operation is clearly seen via the unserved energy required to maintain the supply-demand balance. The supply stack for a typical week is given in Figure 4 where the available generation capacity is shown along with all supply resources against the demand. As can be seen, nuclear and coal generation capacity are dispatched first as base-load. Hydropower is energy constrained and thus provides mid-merit and sometimes peaking capacity while renewables are dispatched at their rated capacity as they are self-dispatched (based on assumed wind and solar profiles). The thermal (gas/diesel) generation capacity is typically dispatched as peaking capacity but due to the constrained nature of the system it is dispatched as both mid-merit and peaking generation capacity. The effect of not having sufficient available generation capacity is clear where loadshedding is required at a number of times during the week shown. It should be noted that even when there appears to be sufficient available generation capacity to meet the demand, certain technical constraints of the available generation capacity necessitate loadshedding.
B. Demand Side Participation (DSP)

Demand Side Participation (DSP) is an alternative to peaking generating capacity as it is the reduction of demand by certain end-users (compensated accordingly) when the power system supply-demand balance is constrained. Many governments, utilities and energy service companies around the world have implemented successful DSP programs with varying levels of end-user participation including International Energy Agency (IEA) countries like Spain, Denmark, USA, Canada, Sweden, Germany and Netherlands being very active [14] while local African examples include Eskom (South Africa) [15] and Nampower (Namibia) [16].

DSP is included in the model by defining a certain level of capacity, number of hours of operation per day, number of activations per day and number of activations per year. DSP is included with a total capacity of 1 000 MW. The number of activations per day is one, number of hours per operation is two hours while the number of activations per year is assumed to be 150. The cost of activating DSP is assumed to be slightly higher than the typical large end-user tariff level (so as to incentivise the participation in DSP).

Similar to Figure 4, Figure 5 shows a typical week of operations but includes DSP. As can be seen, DSP assists the system operator at times of peak demand and reduces the amount of loadshedding required to maintain the supply-demand balance. However, the constraints of only being allowed to operate DSP once a day, for 2 hours and activating it 150 times throughout the year are clear as significant loadshedding is still required.

C. Time Zones

Constrained operations in a specific country with one time zone could be assisted by the introduction of time zones. This is relatively easy to do (even if only temporary until other capacity is available or existing generation performance improves).

In the model, certain components of demand in the model is shifted by 2 hours to assess the effect on the constrained system. The share of demand in each of the two time zones is as shown in Table I.

The resultant supply for a typical week is shown in Figure 6. As can be seen, there is a flattening of the demand profile as a result of the shifting in demand by 2 hours. It is interesting to note that peak demand is reduced from 35 392 MW to 34 653 MW (739 MW) while minimum demand increased slightly (as expected) from 20 253 MW to 20 605 MW (352 MW) even though the same energy is supplied over the course of the year.

D. Labour Shifts

An option that could be available to a country experiencing significantly constrained system operations is the introduction of labour shifts in certain sectors of the economy that do not typically have labour shifts i.e. the commercial sector. Although extreme, this may assist significantly in managing the demand profile and allowing for the system operator to better serve end-users.

The model tests the above by introducing three eight hour labour shifts in the commercial sector of the economy with the residential load profile assumed to follow similarly. The mining and industrial sector are assumed to remain as-is...
(they already use labour shifts) while the agricultural sector is assumed to be inflexible to labour shifts.

The resultant supply for a typical week is shown in Figure 7. The significant change in the demand profile is clear with the demand profile flattening significantly and a reduction of the system peak demand from 35 392 MW to 32 964 MW (2 428 MW). As can be seen in Figure 7, this results in less loadshedding but it should be noted that the flatter demand profile does increase the minimum demand significantly and thus reduces the opportunity to perform maintenance in what were lower demand periods when labour shifts were not introduced.

E. Improvement in generation availability

In the developed model, the amount of generation capacity available to meet demand is relatively low (compared to the installed capacity) as a result of degraded generating capacity performance i.e. higher maintenance rates and forced outage rates. With improved generation capacity performance, there would be more available capacity to meet demand and thus a less constrained power system. In order to test this, maintenance rates and forced outage rates were reduced by 10%.

The annual supply-demand balance is shown in Figure 8 and can be contrasted to Figure 3 where degraded plant performance resulted in significant loadshedding throughout the year. The supply for a typical week is shown in Figure 9. The improved generation capacity performance allows for more available capacity and thus no loadshedding in the week presented in Figure 9. Although what seems like a simple solution to a constrained system, the improvement of generation capacity performance by 10% requires significant planning and investment in labour and capital by the generating capacity owners and thus the effort required in pursing this solution to relieve a constrained system should not be underestimated.

F. Unused distributed generation

Unused distributed generation is typically sourced from standby small generators typically used by end-users as back-up for when an outage does occur on their premises/plant/site. Under the circumstances of a constrained power system, the system operator may be able to use these distributed standby generators to supply power at certain times throughout the year.

To simulate the use of unused distributed generation, it is assumed that these generators can be operated once a day for 4 hours at a time with a maximum of 150 operations per year (1000 MW is assumed to be available for the system operator to use). The cost of using this capacity is assumed to be in line with typical diesel engine technology and fuel.

The supply for a typical week is shown in Figure 10. As can be seen, the distributed is used at times when the system is constrained but can only be used for 4 hours at a time an can only be used 150 times throughout the year (thus the reason for not being used for all days of the week resulting in loadshedding).
G. Emergency generation

From the perspective of a system operator, emergency generation would play a similar role to the unused distributed generation with the major difference being that there is an associated lead time in procuring emergency generation. Thus, the constrained system operations will continue until the emergency generation can be installed.

For the analysis, two types of emergency generation are assumed (small and large). Small emergency generation totalling 300 MW is installed in increments of 100 MW with an initial lead time of 6 months followed by 2 month intervals. Large emergency generation of 1000 MW is assumed to have a lead time of 8 months. This is feasible as outlined in [17] and many service providers are available to provide this type of fast tracked emergency generation capacity.

An annual view of the phasing in of emergency generation is shown in Figure 12 where the lead time is clearly seen (emergency generation only generates from 6 months into the year). The supply for a typical week is shown in Figure 11. The inclusion of the emergency generation helps significantly as it can generate when required by the system operators (compared to standby generation and DSP with their inherent constraints).

H. Strategic storage

A system operator could use a storage medium in an adjacent country effectively as a pumped storage generating plant. When system demand is low (overnight, early morning and weekends), the system operator can use excess generating capacity to send power to the adjacent country, allowing the country to reduce generation from their hydro capacity and keep energy in storage reservoir(s). When the system operator then requires generation capacity at times of system peak, the energy ”stored” in the adjacent country can be called upon to supply demand.

Storage capacity of 1000 MW is assumed and the model is left to determine the appropriate energy storage requirement and the effect on constrained system operations. As can be seen in Figure 13, the envelope of energy storage operation throughout the day shows how the storage charges overnight and before the evening peak while discharging for the morning and evening peaks (as expected). A similar envelope is shown in Figure 14 for the energy stored on a daily basis. As can be seen, the energy requirement is in the range of 3 600 GWh (just over 3.5 hours at full capacity) and peaks in the mornings while discharging for the rest of the day.

I. Security constrained operations

Typically, system operators operate a power system taking into consideration certain key contingencies (generators/transmission lines) and operating the power system in a manner that ensures the system unit commitment and energy dispatch meets pre and post-contingency constraints. In the
model developed, security constrained operation is simulated via the grouping of a number of hydro and gas/diesel generators and constraining their generation to their available capacity less a large contingency in the same zone of the system as these generators in order to ensure demand can still be met in that zone. The contingency assumed is the loss of a nuclear unit of 900 MW.

The result of security constrained operation is clear in Figure 15 and Figure 16 (for an example one month period in the year). The group of generators chosen is limited to their available capacity less the 900 MW contingency previously mentioned resulting in a further constrained system (increased levels of loadshedding required). From this representative example, allowing for concessions on security constrained system operations by the could help to maintain the supply-demand balance even if only applied in the short to medium term until new generation capacity or demand side alternatives are brought online.

V. CONCLUSIONS

In the context of the challenges faced by system operators to balance supply and demand in increasingly constrained power systems a model has been developed to assess various supply and demand side options to improve short to medium term operational adequacy. Using a model built The model developed was based on mathematical programming (QP and MIP) and included the optimal placement of maintenance events, decomposition of medium-term constraints to short-term constraints and a complete production cost model including unit commitment and economic dispatch in one fully integrated environment.

On the demand side, the effect of not having sufficient available generation capacity is clear when loadshedding is required to balance supply and demand by the system operator (an undesirable result). DSP can assist at times of system peak but is limited in that it can only be activated for a pre-defined number of hours per day and per year. A novel solution which could be relatively easily to implement is the introduction of two time zones into a country in order to shift demand and attempt to reduce the peaks present in the demand profile. A reasonable reduction in system peak was possible with two time zones two hours apart. A more extreme option being the introduction of labour shifts in sectors of the economy where shifts were not already in place (commercial) resulted in a significant change in the demand profile and significant reduction in system peak.

On the supply side, the use of standby distributed generation capacity by the system operator (typically by end-users as backup capacity) allowed for an improvement in the system but with limited hours of operation per day and per year (similar to DSP this does not assist in providing mid-merit or base-load capacity. The fast tracking of emergency power generation was also tested and shown to be effective when introduced (as it could provide mid-merit or base-load power as required) but with the disadvantage of a lead time required (8-12 months at least). The novel usage of a neighbouring country as an effective pumped storage station was also shown to be able to manage peak demand as energy can be stored in the neighbouring country during off-peak times and used during times of system peak. Finally, a brief demonstration of the effect of security constrained system operation was presented where a group of generators’ generation was constrained in order to cater for a the possibility of a system contingency in a specific zone of the system.

REFERENCES

[1] East African Power Pool (EAPP) - SNC Lavalin Inter-


APPENDIX A
MODEL PARAMETERS
The parameters used in the PLEXOS® model developed are shown for the supply and demand side in Table II and Table III respectively.
### Table II
#### SUPPLY MODEL SUMMARY

<table>
<thead>
<tr>
<th></th>
<th>Hydro</th>
<th>Nuclear</th>
<th>Renewables</th>
<th>Thermal (gas/diesel)</th>
<th>Coal</th>
<th>Overall</th>
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<tbody>
<tr>
<td>Installed Capacity (MW)</td>
<td>2 228</td>
<td>1 800</td>
<td>1 474</td>
<td>2 005</td>
<td>39 204</td>
<td>46 711</td>
</tr>
<tr>
<td>Rated Capacity (MW)</td>
<td>2 228</td>
<td>1 800</td>
<td>1 474</td>
<td>1 984</td>
<td>36 857</td>
<td>43 119</td>
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<tr>
<td>Units</td>
<td>26</td>
<td>2</td>
<td>419</td>
<td>35</td>
<td>116</td>
<td>598</td>
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<tr>
<td>Unit sizes (MW)</td>
<td>2.1-333</td>
<td>900</td>
<td>1.3-138</td>
<td>9.7-167.5</td>
<td>30-800</td>
<td>1.3-900</td>
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<td>MSL (%)</td>
<td>33</td>
<td>50</td>
<td>-</td>
<td>50</td>
<td>40</td>
<td>-</td>
</tr>
<tr>
<td>MUT (hrs)</td>
<td>-</td>
<td>168</td>
<td>-</td>
<td>2</td>
<td>12</td>
<td>-</td>
</tr>
<tr>
<td>MDT (hrs)</td>
<td>-</td>
<td>168</td>
<td>-</td>
<td>1</td>
<td>16</td>
<td>-</td>
</tr>
<tr>
<td>Ramp rate (%/min)</td>
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<td>5</td>
<td>-</td>
<td>20</td>
<td>2</td>
<td>-</td>
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<tr>
<td>Heat rate (USD/MWh)</td>
<td>-</td>
<td>11.1</td>
<td>-</td>
<td>9.9-14.7</td>
<td>9.5-13.8</td>
<td>-</td>
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<tr>
<td>Fuel price (USD/GJ)</td>
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<td>0.5-0.6</td>
<td>-</td>
<td>7.2-7.4</td>
<td>28.9-31.9</td>
<td>1.4-1.5</td>
</tr>
<tr>
<td>VOM &amp; M (USD/MWh)</td>
<td>-</td>
<td>1</td>
<td>-</td>
<td>2.9-27.9</td>
<td>0.3-1.9</td>
<td>-</td>
</tr>
<tr>
<td>Planned Maintenance (%)</td>
<td>12.6-14.2</td>
<td>9.6</td>
<td>-</td>
<td>0.9-3.4</td>
<td>7.2-13.0</td>
<td>-</td>
</tr>
<tr>
<td>Planned Maintenance (%)</td>
<td>2.9-3.4</td>
<td>0.5</td>
<td>-</td>
<td>2.2-2.3</td>
<td>2.5-4.1</td>
<td>-</td>
</tr>
<tr>
<td>Forced Outage Rate (%)</td>
<td>6.0-12.9</td>
<td>4.7</td>
<td>-</td>
<td>7.4-10.3</td>
<td>7.2-15.2</td>
<td>-</td>
</tr>
</tbody>
</table>

*a MSL = Minimum Stable Level  
*b MUT = Minimum Up Time  
*c MDT = Minimum Down Time  
*d Natural gas  
*e Diesel  
*f Long duration  
*g Short duration

### Table III
#### DEMAND MODEL SUMMARY

<table>
<thead>
<tr>
<th></th>
<th>Peak demand (MW)</th>
<th>Minimum demand (MW)</th>
<th>Energy (GWh)</th>
<th>Energy share (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial</td>
<td>15 556</td>
<td>9 819</td>
<td>110 550</td>
<td>44.7</td>
</tr>
<tr>
<td>Mining</td>
<td>4 940</td>
<td>4 693</td>
<td>42 010</td>
<td>17.0</td>
</tr>
<tr>
<td>Commercial</td>
<td>7 810</td>
<td>1 077</td>
<td>36 775</td>
<td>14.9</td>
</tr>
<tr>
<td>Agricultural</td>
<td>1 235</td>
<td>617</td>
<td>7 888</td>
<td>3.2</td>
</tr>
<tr>
<td>Residential</td>
<td>11 111</td>
<td>2 695</td>
<td>49 917</td>
<td>20.2</td>
</tr>
<tr>
<td>Overall</td>
<td>35 850</td>
<td>19 775</td>
<td>247 141</td>
<td>100</td>
</tr>
</tbody>
</table>