21st Century Power Partnership: September 2016 Fellowship Report

Prudence Rambau & Sipho Mdhluli

Energy Planning and Market Development
Eskom
Pretoria, South Africa

National Renewable Energy Laboratory/
21st Century Power Partnership Fellows

Eskom

Technical Report

NREL/TP-6A50-69085
September 2017

Contract No. DE-AC36-08GO28308

CLEAN ENERGY MINISTERIAL
Accelerating the Transition to Clean Energy Technologies

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Acknowledgements

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A multitude of NREL technical experts and staff must also be thanked for their efforts and guidance during the Fellowship Term, namely Erol Chartan and Greg Brinkman, who served as mentors throughout the process. Matt O'Connell, Aaron Bloom, Owen Zinaman, Ali Ehlen, Debbie Meixner, Jeff Logan and Tim Reber also deserve thanks for all they did to make the Fellowship possible.

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Background

This Fellowship is a follow-up to the "Technical Audit of Eskom's Medium- and Long-term Modelling Capabilities," conducted by U.S. National Renewable Energy Laboratory (NREL) in April 2016. The prospect and role of variable renewable energy (vRE) in South Africa poses new modelling-related challenges that Eskom is actively working to address by improving the fidelity of PLEXOS LT and ST models, which are primarily used in:

- Long-term energy plans for large-scale generation expansion investments (conducted in PLEXOS LT)
- Medium-term System Adequacy Outlook (MTSAO), a biannually conducted 5-year outlook on the capacity adequacy of South Africa's power system (conducted in PLEXOS ST)

The focus areas of the 21st Century Power Partnership Eskom Fellowship are listed below, the details of which can be found in Section 3:

- Exploring techniques to reduce model run time
- Comparing long term expansion plans produced using Chronological Sampling, Load Duration Curve (LDC), and Split Optimizations techniques
- Identifying and assessing power system flexibility metrics
- Incorporating transmission considerations into the long term expansion planning model

Fellow Profile

Ms. Prudence Rambau is a professional with well-developed analytical and problem solving skills coupled with a host of knowledge of relevant electrical engineering standards. She holds a Bachelors of Engineering in Electrical Engineering from the University of Pretoria, followed by 7 years' experience in the power system industry. Her career covers both customers perspective from a building services and network upgrades standpoint, as well as the utility perspective on high voltage transmission planning and operational issues.

She is registered with the Engineering Council of South Africa as a professional engineer competent in building services, power system simulations (load flow, fault levels and network stability) and energy planning (short-, medium- and long-term). Her skills are in the use of *DigSilent PowerFactory* and *PSSE* software packages, performing feasibility and network integration studies for cross-border transmission and generation strategic projects as well as studying the network from an operational perspective to determine power transfer limits and identify suitable opportunities to expedite the mitigation of outages. Her current role makes use of Energy Exemplar's PLEXOS software to appraise adequacy between supply and demand in the short to medium-term and to influence the expansion of electricity generation in the long-term. Further, she conducts research and tests Integrated Energy Planning methods, developing new techniques for adaptation in future studies

Dr. Sipho Mdhluli is a mathematician by training with a robust understanding of linear programing and optimization methodologies. He joined Eskom's Energy Planning and Market Development unit in August 2008 as a Senior Scientist, and was promoted to a position of Chief Scientist in 2012. Dr. Sipho Mdhluli is registered with the South African Council for Natural Scientific Professions (SACNASP). His current responsibility at Eskom includes training junior staff and producing the Medium Term System Adequacy Outlook and the Integrated Resource Plan for South Africa, as well as conducting *ad-hoc* studies for Eskom.

Through Eskom's Energy Planning & Market Development department, Dr. Mdhluli has provided strategic advice on the following projects:

- Prefeasibility studies on the Koeberg's upgrade
- Value assessment of the 100MW Aggreko project
- Prefeasibility assessment of converting an OCGT to CCGT and the optimal take-or-pay natural gas volumes

Dr. Sipho Mdhluli enjoys investigating new methods for improving the quality of the work that Eskom's Energy Planning conducts for the company and on behalf of the Department of Energy.

Fellowship Focus Areas

Model Run Time Reduction

Improving the fidelity of models sometimes results in longer run times. The first focus of the Fellowship was to explore any "low hanging fruit" for reducing model run time without significantly impacting model fidelity. More generally, exploring how various model improvements impacted run time, and contrasting them with the value they provided, was a theme throughout the Fellowship.

Exploring the Efficacy of Sampled Chronology versus LDC Methods in Long-term Planning

The main goal of this exercise is to understand the differences between results that are produced using Sampled Chronology Method and Load Duration Curve (LDC) Method through assessing adequacy and flexibility of each system. Specifically, the assessment entailed:

- Quantifying model run time
- Comparing unserved energy and vRE curtailment of PLEXOS LT results in PLEXOS ST
- Assessing the flexibility of the forecasted power system by dispatching PLEXOS LT results in PLEXOS ST. This analysis becomes particularly important as vRE, with its time- and location-varying nature, plays an increasing role in the power system.

Split Optimization

As a possible option for reducing model run time, PLEXOS LT can be solved in a series of sequential time steps, rather than in one single (and often times computationally intensive) step. Specifically, a split optimization method splits the time period of interest into a series of smaller time steps, but with an overlap period in time which makes up for "model end effects." For example, a model simulation from 2016 – 2050 can be solved in a single time step, or from 2016-2030, 2026 – 2040, and 2036 – 2050. The results of the previous time step, during the 4-year overlap period in this example, are thrown away before the next time-step starts.

Transmission Representation

Incorporating a transmission element into generation expansion planning is vital as network constraints are practical factors that can significantly impact the fidelity of planning and operational models. Such a consideration enables (1) computation of the economic dispatch and optimal power flow in ST dispatch models, *i.e.* taking into account the output levels of all plants that minimize total production cost and respect thermal limits of the transmission network, and (2) consideration of transmission costs and constraints when optimizing generation resource expansion in PLEXOS LT such that the cost of building additional transmission capacity to transport lower cost power can be weighed against a more expensive generation option built near load centers.

Methodology

Sampled Chronology vs Load Duration in LT plan

The LDC method sorts the chronological load profile from the highest value to the lowest value, and then creates time slices to simplify the 8760 hourly values for the year into manageable steps that can be solved in a reasonable amount of time. The LDC exercise used 18 blocks per month to create the load, as well as generators with an existing production profile. Sampled Chronology, on the other hand, samples hour-to-hour dispatch within the expansion optimization framework for 9 representative days using a statistical filtering algorithm that groups similar days/weeks together. Generators with predefined profiles are similarly sampled to obtain representative days/weeks.

The PLEXOS LT database that was used to produce an LT plan using LDC and Sampled Chronology techniques both used the same data and inputs, with the exception of the above mentioned changes when choosing blocks in LDC and samples in Sampled Chronology.

Split Optimization

The time period was split into three 14-year periods with a 4-year overlap period. Even though a perpetuity function was activated, the optimal result was different from when the time period was lumped. By splitting the time period, constraints are not carried over in totality; Energy Exemplar has declared this is a bug in PLEXOS, version 7.300 R04. The most recent release of PLEXOS, version 7.400 R01 states the bug is fixed (see snapshot showing part of notes released that accompanied version 7.400 R01). However, this is yet to be tested by the Eskom Fellows as of November 2016.

Execution – Split Run	Implement quarterly reporting support with the split/stitch feature.
Execution – Split Run	Added stitching support for splitting by planning horizon with look ahead.

Transmission Representation

For Energy Planning processes, it is a key factor to align the transmission representation to that used by network data custodians, namely Eskom Grid Planning and the System Operator. The current methodology breaks up the South African transmission system into nine regions plus the high-voltage direct current circuit from Mozambique. The regions are allocated a number of substations and lines which are further broken down into Customer Load Networks (CLN) made up of a fewer number of substations and associated lines. CLN groupings, termed Aggregated Zonal Representation by the modeling staff are used to aggregate a spatial network for various study purposes in a more manageable manner without compromising the integrity of the results.

With knowledge of locations and performance of energy resources, a transmission model can be configured spatially with multiple nodes such that generation expansion accounts for limitations in the transmission network. The base model would typically consider the transmission network as existing and take into account any expansion plans in future years. In this instance, no attempt is made to optimize expansion of the transmission network as part of the generation optimization, and violation of transmission power transfer limits is not allowed. Power transfer limits are determined by considering the permissible voltage regulations (typically ±5% for high voltage lines) and the associated electrical phase shift[1] (Morgan, 1983). Another option is to introduce a penalty for violating transmission thermal limits, an R/MWh shadow price for expanding the network to carry extra MW. In this case, a constraint would be imposed on build capacity to ensure a typical transmission substation capacity is not exceeded. The Fellowship studied the use of penalties with the constraints, which may be added at a later stage.

Alternatively, existing generation and transmission expansion could be co-optimized in the model to create a more holistic expansion plan. The results would be followed up by load flow studies in a suitable software package such as *PSSE* to ensure compliance to applicable grid security codes. Non-compliance would require further iterations with additional constraints imposed wherein compliance takes precedence.

It was agreed that although modeling of losses could increase credibility of the model, for long term planning purposes losses constitute a small percentage (less than 1%) and thus decision variables would not be affected much. In the ST however, it may change dispatch pattern and as a consequence affect pricing policies.

[1] Phase shift occurs between two ends of a transmission line when power flows through it. An increase in the phase shift makes the network vulnerable to instability.

Outcomes

Model Run Time Reduction

With model run times currently in excess of three (3) days when employing certain high fidelity methods, several proposals were explored to reduce run time without substantively compromising the fidelity of modelled results.

Hardware Setup

The first step was to use NREL's computational hardware to achieve a baseline. A model run time reduction of 24 hours (~30%) was immediately achieved with NREL's hardware and it became evident that Eskom's existing computational hardware is not setup effectively. Although Eskom's hardware is sufficiently scoped, it is suspected that running PLEXOS on a local network results in back and forth transfer of data, which slows down the process.

Perpetuity

A comparison of annual build was done for a simulation horizon up to 2050 with perpetuity and another up to 2054 also with perpetuity to test the modeling "End Effects". Without considering perpetuity, the end of time effect is not considered hence the annuitized cost is perceived as higher. It was proven that the differences were not due to renewable constraints or retirement of existing fleet or even emission constraints. The two approaches yielded plans similar in their large scale annual builds through 2045 but diverged significantly towards the end of the period. It is clear that performing studies until 2054 instead of 2050 does not give any more confidence in the result as there is uncertainty in the inputs and assumptions. Sharing of results should thus emphasize the years where results are credible.

The results on model run times were not conclusive due to different loads experienced by different computing machines, though it is expected that elimination of model years 2051-2054 may reduce run time.

Aggregation of Generation

The goal of this exercise was to aggregate all existing generators of the same type with available generation profiles, including those with future known implementation dates, thereby reducing the number of optimization variables. This was successfully implemented for CSP, PV and wind generators. Conventional generators were not aggregated out of concern that this would negatively impact the convolution calculation used in the determination of reserves in the LT framework. The aggregation was tested with two model runs: (1) one where existing CSP, PV and wind are netted against the load to create a residual load and (2) a second where generators are not consolidated. Results showed a reduction in model run time of 4 hours (~30%) when CSP, PV and wind are consolidated and netted against demand compared to the case when they are not consolidated which took 13 hours.

Transmission Representation

Testing was performed comparing the Full Nodal Representation Scheme against an Aggregated Zonal Representation of transmission in the PLEXOS ST that assesses adequacy of the network. The Aggregated Zonal Representation presented a relative ~75% reduction in run time. This type of aggregation is useful where one zone of interest is modelled in detail while the rest of the network is aggregated, such as performing detailed analysis of areas dominated by embedded generation at the distribution level to investigate the effects of thermal loading more closely or evaluate power flow in higher detail.

Load Duration vs Sampled Chronology in LT Plan

Two methodologies for representing time dimensions of the power system were systematically compared to better understand their relative value. The analysis compared the actual load profiles seen by PLEXOS LT in the LDC and Sampled Chronology techniques as shown in Figure 1 below. The Sampled Chronology technique produces a substantially more robust representation of system load.

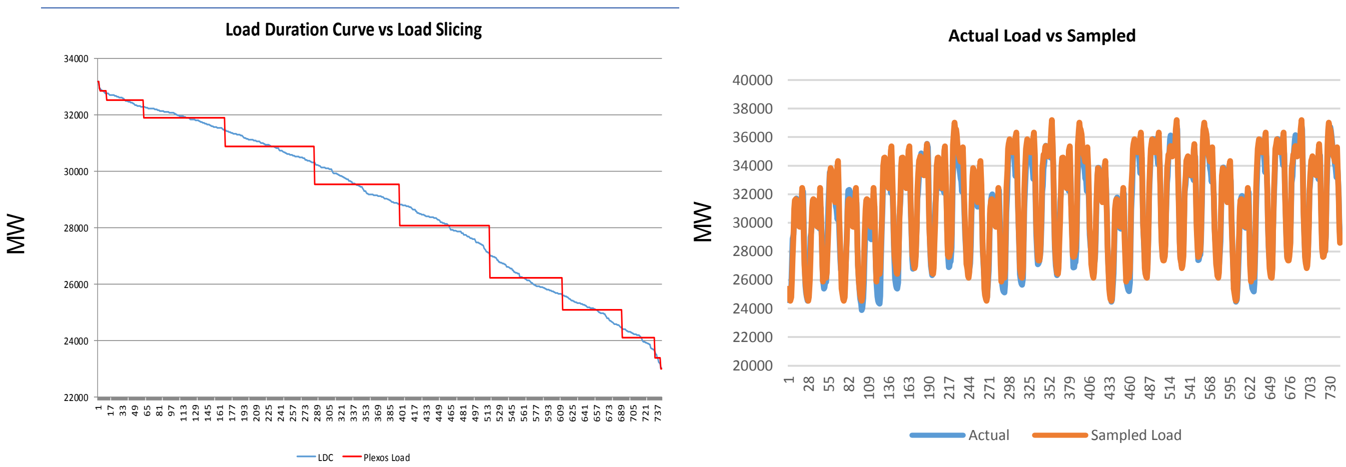

Figure 1. Load Profile in LDC and Sampled Chronology

Figure 2 and Figure 3 below show how an actual generator's production profile is transformed by the LDC, as well as the Sampled Chronology technique, into a simplified profile. The output of both PV and wind in LDC aggregation does not ramp to full potential. Also, the PV generator shows some residual production outside of sunlight hours. Although the Sampled Chronology samples actual hours of operation and shows a much stronger representation of time-varying vRE resources in comparison to LDC, some periods with over- and under-generation of the actual profile are still observed. This is to be expected, given that even the detailed Sampled Chronology method is still a model simplification.

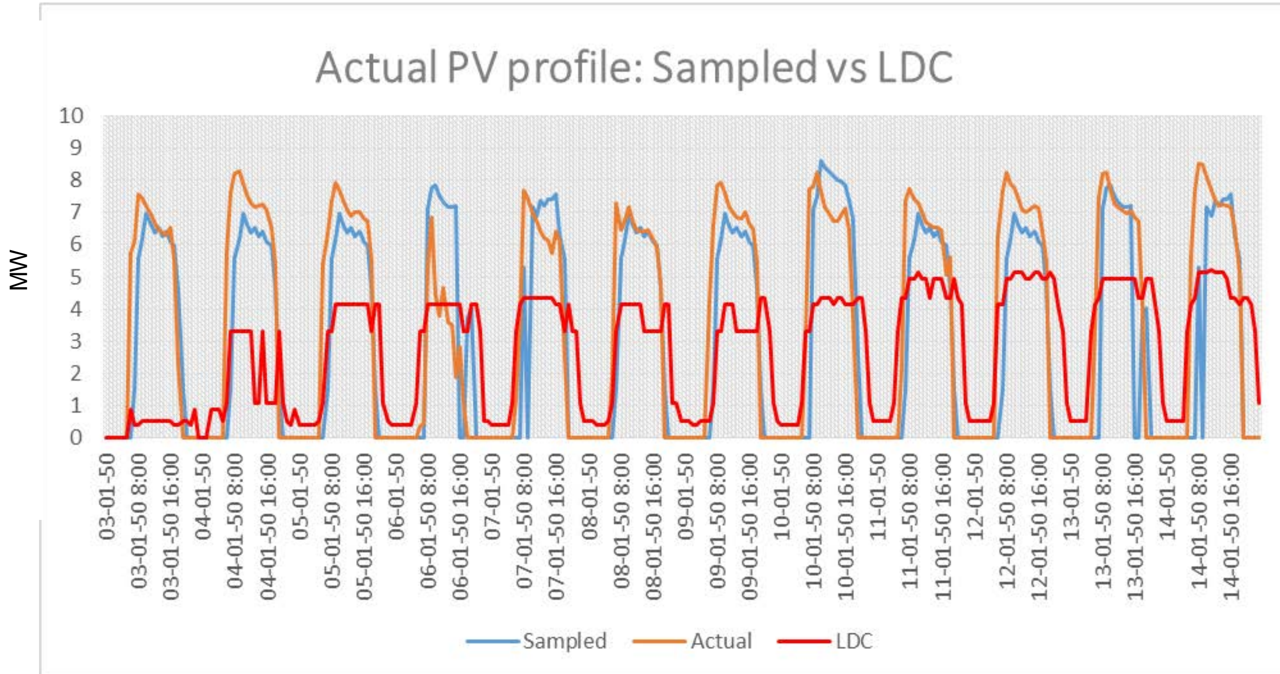

Figure 2. PV generation profile in LDC and Sampled Chronology

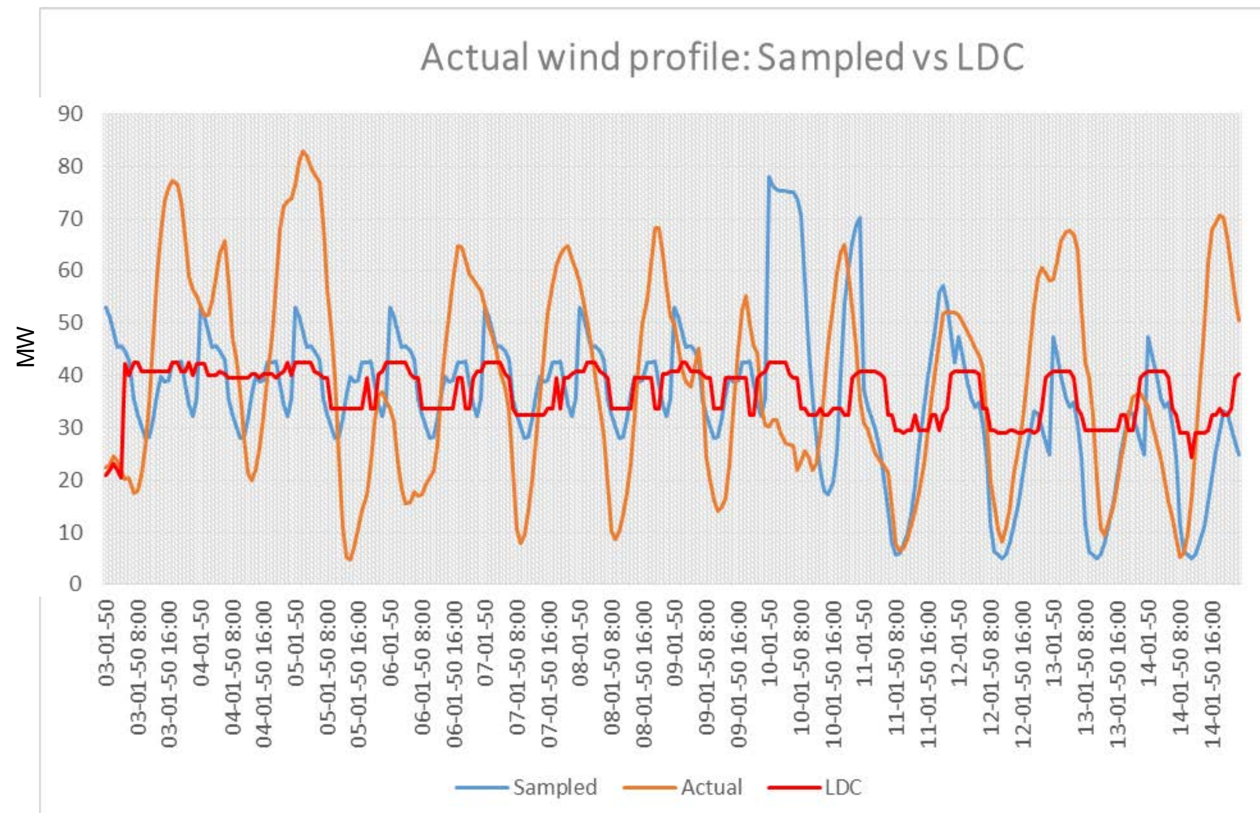

Figure 3. Wind generation profile in LDC and Sampled Chronology

The *Load Duration Curve (LDC) Method*, being a more traditional modelling practice, has significantly shorter run times due to mathematical simplification (the model run time for this test case is 2hrs43min). The optimal result when using an LDC technique yields a significant amount of wind, PV, OCGT and CCGT in the annual capacity built by the system, instead of conventional base load power plants, due to the type of aggregation that distorts the generator's actual output. The amount of vRE curtailment in PLEXOS ST reported by the LDC plan is significantly higher than that reported by the Sampled Chronology.

The *Chronological Sampling Method* experiences much longer run times (the model run time for the same test case as LDC is 15hrs10min). Compared to the LDC, Sampled Chronology built less PV and wind. Of note is the distribution between the OCGT and CCGT: the LDC builds a significant amount of OCGT compared to CCGT whereas the Sampled Chronology builds more CCGT compared to OCGT. This implies that more support for a Sampled Chronology plan is sought from a mid-merit CCGT plant than a peaking OCGT plant.

It is seen in Figure 4 that the Sampled Chronology technique optimizes at more sites than the LDC. Since the Sampled Chronology has a stronger representation of time-varying vRE resources, it has a better correlation to the load and closely mimics real life conditions, the decision variables used are more robust.

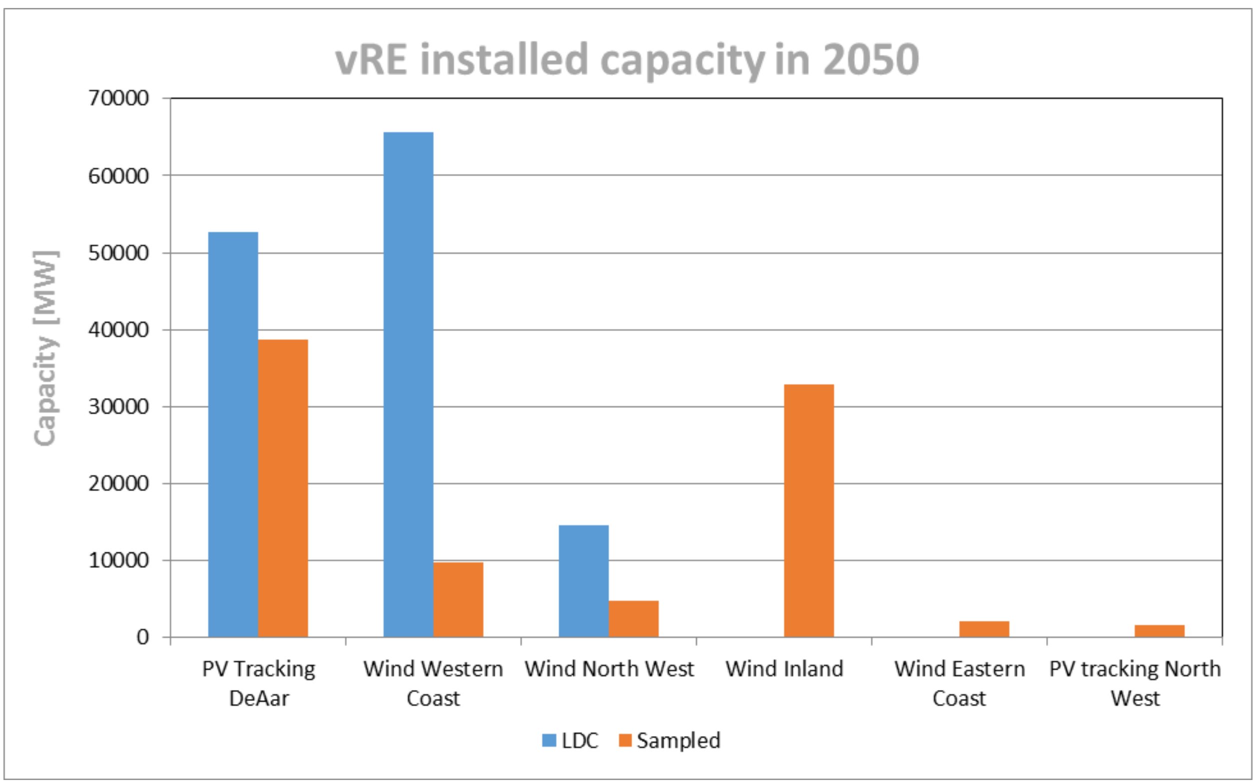

Figure 4. vRE installed capacity based on LDC and Sampled Chronology technique

The results further showed the following in the context of increased penetration of renewables:

- The resulting 2050 vRE energy share and consequential vRE curtailment are respectively 75% and 8.5% (35.4 TWh) for an LDC run compared to 46% and 0.5% (1.1 TWh) respectively from the Sampled Chronology study. This represents a substantial net reduction in total vRE curtailments, as well as significantly less vRE generation. With the Sampled Chronology providing a higher fidelity treatment of vRE resources, the model is able to more accurately perceive the extent of costly) vRE curtailment under different penetrations, and chooses to deploy less. More broadly, an observed vRE curtailment of 0.5% for a system with a 46% annual vRE energy penetration appears quite reasonable. Operating vRE resources at an average of 8.5% curtailment (with some individual generators experiencing much higher curtailments) may lead to financial complications, as vRE resources in South Africa are procured through take-or-pay contracts and curtailment would need to be paid, likely through tariff increases.

- Conventional stations ramp up and down frequently following demand fluctuations. For purposes of this study, the critical ramps were defined as those that are greater than 20% of the unit's size over the course of an hour, both positive and negative while the total ramps counts all ramps irrespective of magnitude. Unit shutdowns due to planned and unplanned maintenance were not accounted for in the total. The critical ramps (Figure 5) were 5% and 2% of the 8760 hours in year 2050 against the total (Figure 6) of 10% and 5% for LDC and Sampled Chronology respectively. These outcomes conclude that using Sampled Chronology instead of the LDC method produced a system that needed to ramp less to meet demand amidst a 46% penetration vRE compared to the 75% of LDC. A system with fewer ramps is commonly preferred, particularly for conventional stations since it has a negative effect on maintenance and operating costs. At a later stage, we will be incorporating a full representation ramping and cycling costs into the modelling framework.

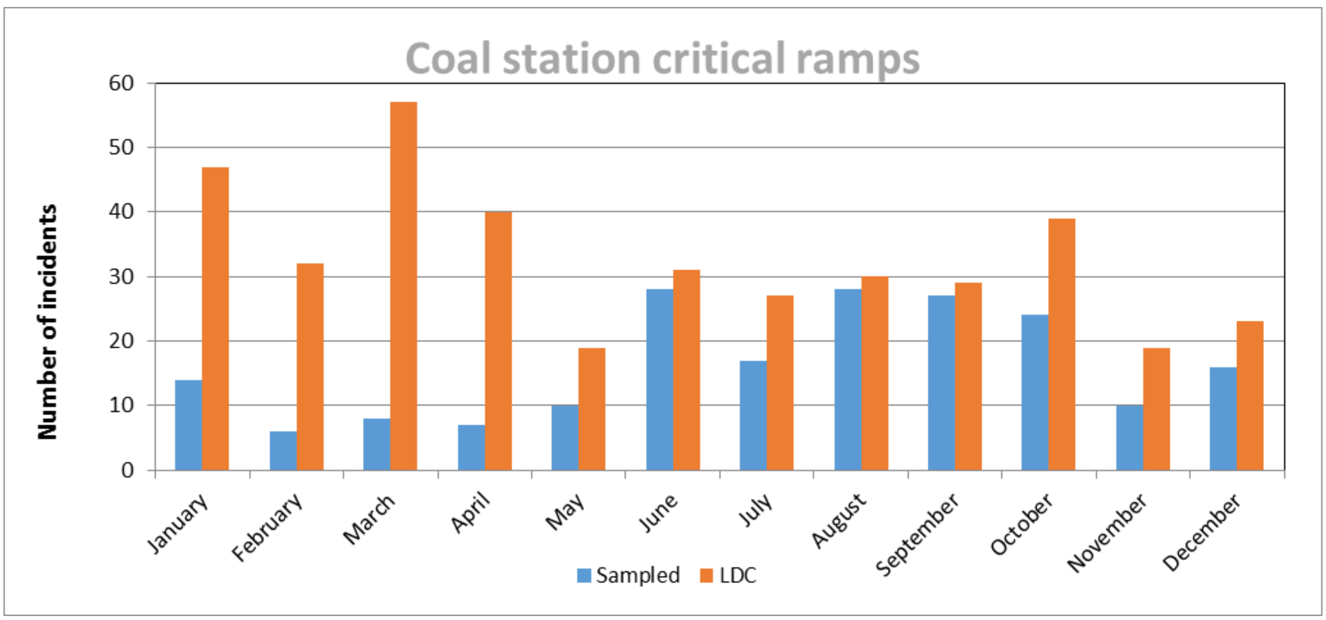

Figure 5. Number of critical ramps, positive plus negative

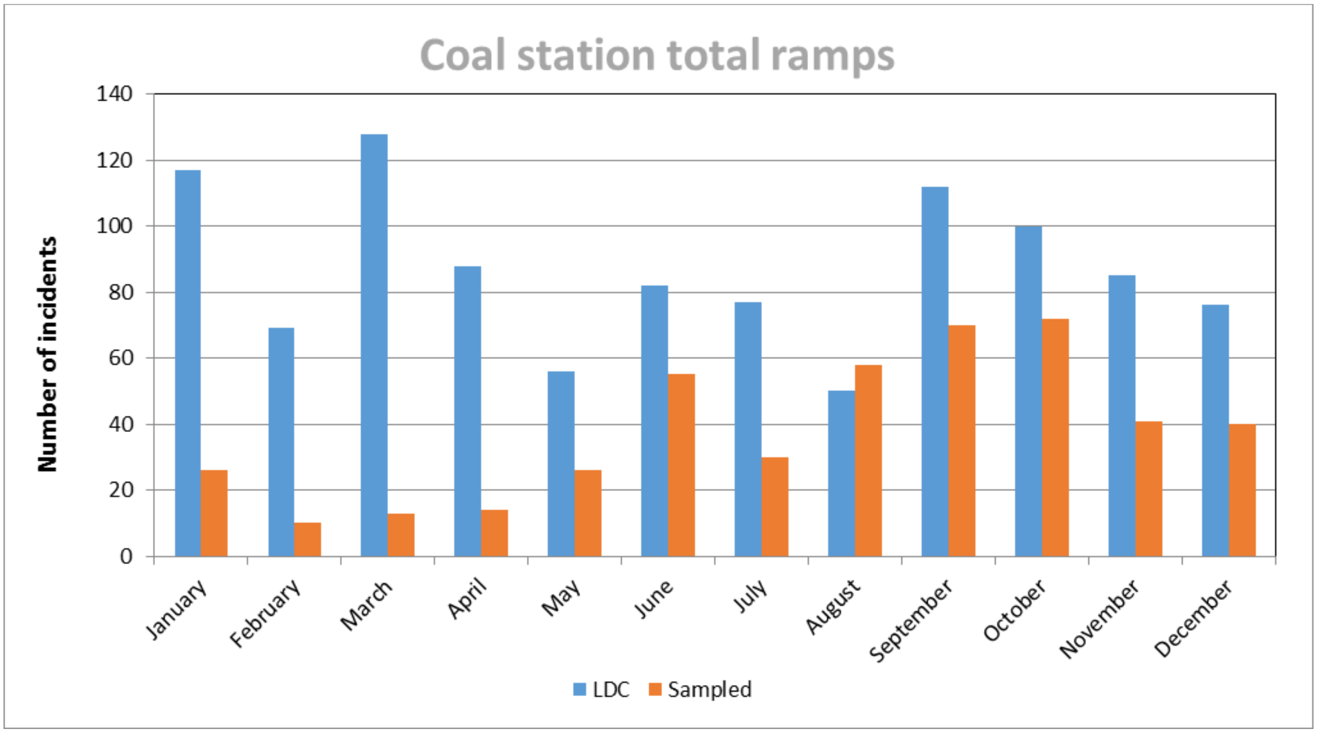

Figure 6. Total number of station ramps

- A conventional station is designed with a minimum stability level (MSL) below which it is infeasible to operate and a maximum capacity rating which provides the highest efficiency. The number of hours the base load system is run on part load, defined as the units' production which is less than the maximum capacity but great than zero was found to be higher in the LDC case than the Sample Chronology case, indicating that in the former stations are being operated less efficiently.
- The total number of shutdowns per station, in addition to planned and unplanned outages was also assessed for both techniques. This parameter affects the total cost of producing electricity since each start up and shut down of a station has a cost. Although the overall number of shutdown hours may not indicate a badly operated station, the frequency of shutdowns observed may. As can be seen in Figure 7 below, the LDC method results in substantially more shutdowns compared to the Sampled Chronology for a sample coal-fired plant. The total number of shutdowns per year for LDC amounts to 301 events compared to 29 shutdowns for Sample Chronology.

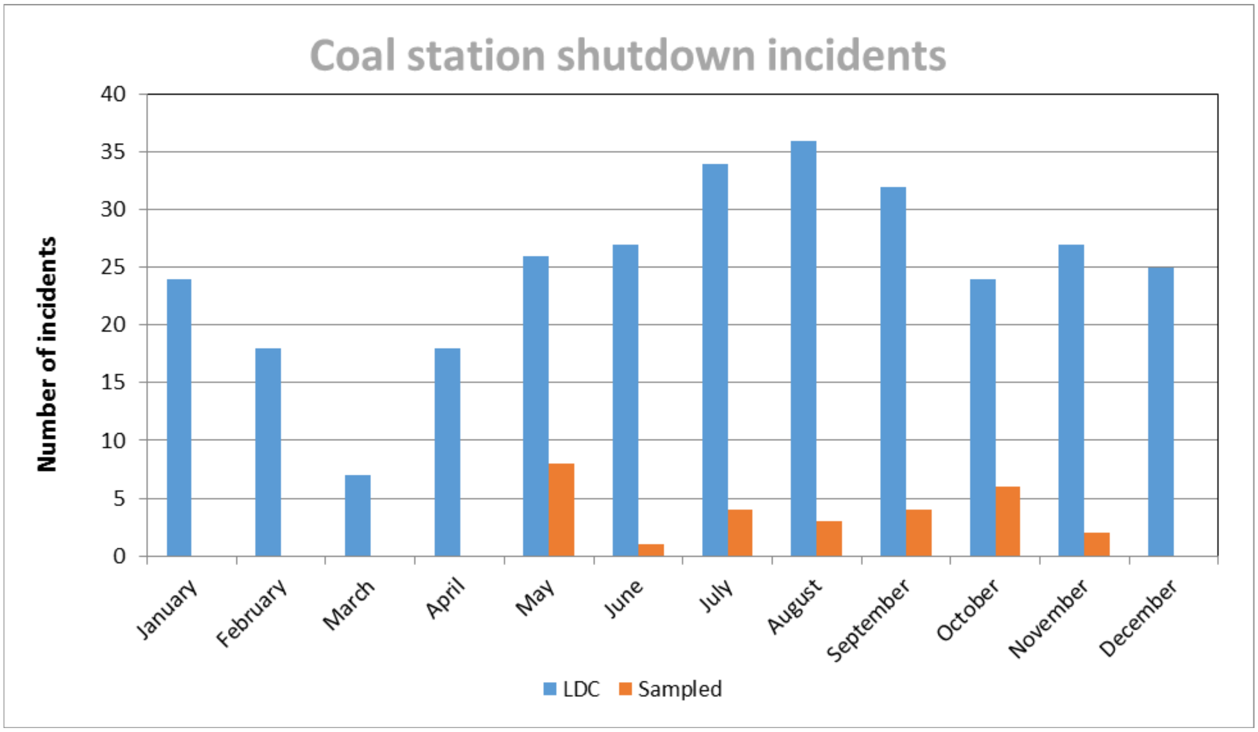

Figure 7. Total number of shutdowns per station

Assessing the Flexibility of Power Systems

First, appropriate "triggers" or signs that a flexibility assessment might be necessary were identified. They included substantial amounts of unserved energy, a projected system that is dominated by non-dispatchable generation, and/or spikes in generation costs or congestion at a single node (when transmission constraints are included). The following flexibility metrics were identified in consideration of the expected dominance of time-varying energy sources, identifying and assessing flexibility metrics on the overall power system is critical:

- Station ramp frequency and size for conventional generators to meet net load. The frequency of station ramps directly reflects the frequency of support needed from conventional power stations, which merits the question of whether these conventional plants are capable of such ramps.
- Hours in zero/partial/full load for conventional generators, with focus on "must run" units
- Number of conventional generator shutdowns/startups, with focus on "must run" units
- vRE curtailment (%)

The proposed flexibility metrics based on the identified triggers are as follows:

- A threshold on the ramping frequency in a year/day by technology type. The challenge is that plant technical information may be inaccessible due to an ageing fleet, and requesting information from the System Operator may result in acquisition of more institutionally-imposed thresholds (reflecting habitual operational practice) rather than the technical design limitations of plants.

- A threshold on the number of hours in part/full load. This criterion needs to be further validated for conformance with emissions constraints in LT, as the efficiency of a station is highest at its full output. However, the number of hours a station is completely shut down may reverse this negative outlook.
- Levels of acceptable vRE curtailment (on a percentage basis) need to be determined in light of expected higher penetrations of vRE. This is especially relevant as many conventional many power stations are effectively operated as “must-run” due to Take or Pay fuel contract arrangements.
- A threshold on the number of shutdowns and start-ups in a year of an individual conventional plant operation. In this regard, the PLEXOS ST model must be augmented to incorporate accurate shutdown costs and starting conditions declared (i.e. cold, warm and hot)

Transmission Representation into PLEXOS ST and LT

A basic visualization tool, as shown in Figure 8, was developed in RStudio to understand geographic aspects of power system behavior and validate the model augmentation, including line loadings, power flow direction and zonal power flow against already known load flow results in DigSilent PowerFactory and PSSE. As such, the functionality allows for better understanding of how generation expansion decisions are impacted by the realities of transmission grid in the PLEXOS LT. The visualization also has the added benefit of serving as a diagnostic tool. For example, it quickly allowed identification of some erroneously incorporated islanded transmission, which was then able to be promptly rectified before any further transmission exercises were completed.

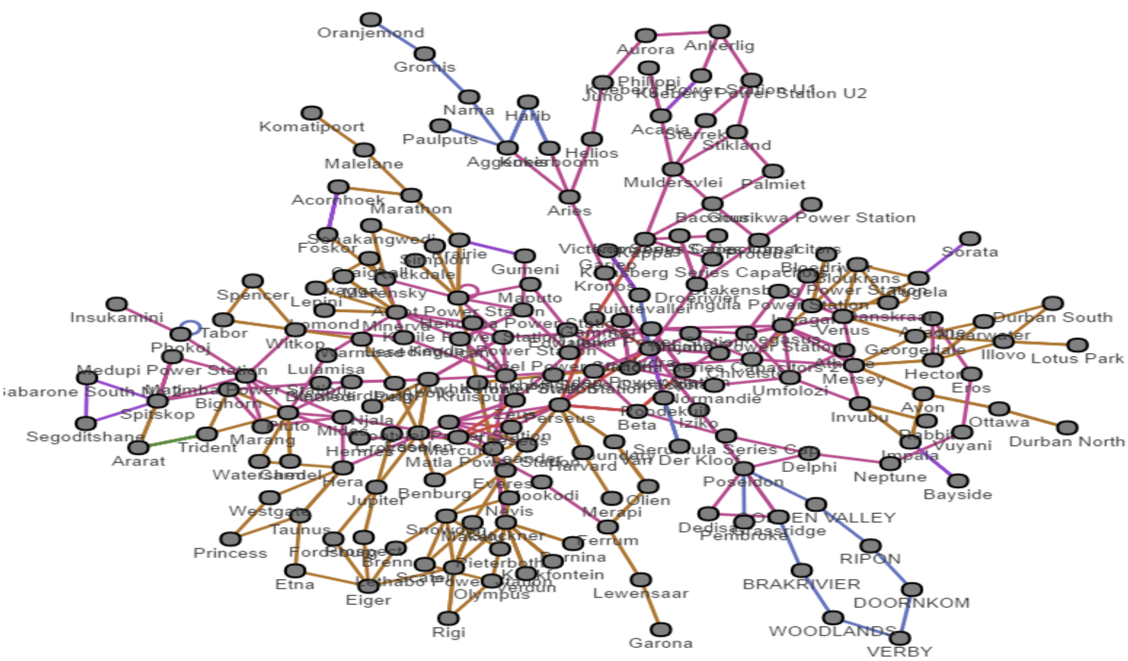

Figure 8. Full nodal transmission representation

The following conclusions were evident from the results of the ensuing transmission exercises:

- When hard transmission limits are enforced, rather than simply building the lowest LCOE technology, generation expansion shifts to areas with available transmission capacity, often resulting in a higher generation cost. This model improvement will allow for the production of geographically specific technology deployment targets which are more holistically grounded in the realities of the grid.
- When a penalty is applied to enable violation of transmission thermal limits, the lower generation cost in an area without transmission capacity is in some case outweighed by the additional penalty. This information could become useful feedback into the optimization of transmission development plans and could be incorporated into the transmission expansion planning process.

Conclusion and Follow-Up

The tools and skills developed during the Fellowship enhanced current modelling practices in both the PLEXOS ST & LT. Configuration of the network on which the model is run was found to be the easiest and most impactful on run times, with a staggering reduction of ~30%. It was further determined that aggregation of generators of the same type did not have an adverse effect on the result and reduced run times by an average 30% (with coal and gas remaining fully disaggregated). Similarly, aggregating the transmission network resulted in model run time reduction of as much as ~75%.

Although all modeling techniques have their own unique balance of costs and benefits, it is conclusive that a long-term plan developed utilizing the LDC technique will lead to a system that is not only more expensive to build, but more challenging to operate reliably and from a flexibility standpoint, with higher operational costs and higher plant failure rates compared to systems developed using the Sampled Chronology technique. Hence a fine balance needs to be sought on the level of fidelity required from each study to determine which technique is appropriate, considering the longer model run times associated with Sampled Chronology.

It was demonstrated that a least cost plan needs to incorporate the flexibility criterion that accounts for the cost curtailment, start/shut down costs, ramp up/down and station efficiency in order to produce a plan that can be operated sensibly.

Producing a long-term generation expansion plan based purely on the principal of least cost technology/site selection, without taking into the realities of the transmission system, will very likely lead to sub-optimal outcomes. When accurately formulated, a model that includes both generation and transmission would at the very least provide transmission grid planners with insight on the areas to target for strengthening opportunities, in line with the generation expansion. Further, this approach allows for expansion planning of both generation *and* transmission infrastructure; of course, this future process would need to be iterative and well-linked to load flow analyses, in order to further ground expansion results in the many technical realities of the grid.. It has also become clear that an improved, automated visualization tool will become a vital instrument for both model diagnosis and presentation of the results to less technically-oriented stakeholders in the public.

Expanding upon the issues explored during the Fellowship, Eskom and the 21st Century Power Partnership have identified several areas for continued follow-up and collaboration, including:

- Detailed examination of the costs and benefits of various operational flexibility aspects.
- Development of location-dependent spatially aggregated wind and solar resource supply curves for South Africa, including estimates of spur line transmission costs and statistically representative hourly output profiles for each resource.
- Further explorations on the merits of various spatial representations of renewables in PLEXOS LT, given data availability, run-time impacts, transmission constraints and spatial diversity of vRE resources.

- Exploration of the efficacy of various transmission transport models, including inclusion of thermal constraint violation penalties and transmission-generation co-optimization exercises
- Testing the efficacy of consolidation of existing conventional generation fleet, in light of impact on reserves determination calculations and overall results
- Production of a joint Eskom-NREL technical publication addressing a pertinent, forward-looking power systems research question for South Africa

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V.T. Morgan, “The thermal rating of overhead-line conductors, Part II. A sensitivity analysis of the parameters in the steady-state thermal model”, Electr. Power Syst. Res. 6 (1983) 287-300