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Assessing the impact of increasing shares of variable generation on system operations in South Africa

Flexibility Study

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Abbreviations

CCGT	Combined Cycle Gas Turbine
OCGT	Open Cycle Gas Turbine
GDC	Gross Dependable Capacity
IRP	Integrated Ressource Plan
VRE	Variable Renewable Energies (wind and solar-PV)
EFOR	Equipment Forced Outage Rate
LCOE	Levelised Cost of Energy
C&M (costs)	Capital Replacement costs and Maintenance costs

Glossary

Term	Definition
Operating Reserve	According to the South African Grid Code – System Operations Code [1], "Operating Reserves are required to secure capacity that will be available for reliable and secure balancing of supply and demand within ten minutes and without any energy restrictions. Operating Reserves shall consist of: Instantaneous Reserve, Regulating Reserve and Ten Minute Reserve."
10-Minute Reserve	According to the South African Grid Code – System Operations Code [1], "Ten-minute reserve is required to balance supply and demand for changes between the day-ahead market and real time such as load forecast errors and unit unreliability. Ten-minute reserve is used to restore regulating reserve when required. Ten-minute reserve must be activated, on request, within ten minutes and must be sustainable for two hours." Additionally, the following definitions can be found in [1]: "Frequently used more than once a week, 10 minute activation – sustained for 2hrs Can be dispatched via telephone or Direct Control Hourly contract based on bid price for capacity, dispatched on energy price"
Regulating Reserve	According to the South African Grid Code – System Operations Code [1], "Regulating reserve is reserve that is under AGC and can respond within ten seconds and be fully active within ten minutes of activation. This reserve is used for second-by-second balancing of supply and demand. The reserve is also used to restore instantaneous reserve within ten minutes of the disturbance." Additionally, the following definitions can be found in [1]: "Start response in 10 seconds and 10 minute full activation – sustained for 1 hour. Must be on "AGC" Contracted on Energy Bid Price cheapest first"
Instantaneous Reserve	According to the South African Grid Code – System Operations Code [1], "The System Operator shall ensure instantaneous reserve is available as needed to arrest the frequency at acceptable limits following a contingency, such as a unit trip or a sudden surge in load. A sudden increase in frequency is not included as part of instantaneous reserve. (Generating units are required to respond to high frequencies (above 50 Hz) by means of governing.)" Additionally, the following definitions can be found in [1]: "10 second full activation - sustained for 10 minutes Direct control according to the frequency Contracted on Energy Bid Price after Regulation"
Supplemental Reserve	According to the South African Grid Code – System Operations Code [1], "Supplemental reserve is used to reduce the short-term risk. This reserve is available for at least two hours. It is contracted to ensure an acceptable day-ahead risk."
Emergency Reserve	According to the South African Grid Code – System Operations Code [1] the following definitions are given: "(1) Emergency reserve is typically made up from contracted interruptible load, gas turbines and emergency generation (EL1 and EL2). (2) Emergency reserve is a less frequently used reserve and is used when the IPS is not in a normal condition and to return the IPS to normal conditions while slower reserves are being activated. The reserve can be used by the System Operator for supply and demand balancing, network stability and voltage constraints. This reserve shall be activated, on request, within ten minutes and shall be sustainable for two hours."

Term	Definition
Imbalance Requirement	Term used in this study for quantifying the mismatch between planned and actual generation, whereas "planned" generation relates to day-ahead operational planning. The Imbalance Requirement has to be compensated by intra-day dispatch of generation, Supplemental Reserve and 10-Minute Reserve. In situations with an exceptionally high Imbalance Requirement, Emergency Reserve can be used additionally.
Operating Requirement	Term used in this study for quantifying the required amount of Operating Reserve for compensating short term variability (variations within any 1-hour dispatch cycle). Operating Requirement only refers to variability, not to contingencies. Operating Reserve must be allocated for securing the system against variability and contingencies. Therefore, an increased Operating Requirement does not necessarily lead to increased Operating Reserve.
Regulating Requirement	Term used in this study for quantifying the required amount of Regulating Reserve for compensating variability within any 10-minute cycle. Regulating Requirement only refers to variability, not to contingencies.
Cycling	Cycling refers to the operation of power plants at varying load levels. Frequent changes of load cause stress to boilers, steam lines, turbine and auxiliary components. Therefore, frequent cycling of thermal power plants leads to fatigue, shorter lifetime of relevant components or even the whole power plant. In this study, cycling is expressed by: • Load following ramps: Ramping of power plants for load following • Start-ups
Demand	Demand is the total amount of energy or power, which is required by all consumer for satisfying their needs. Demand can either be "Power Demand" in GW (typically equivalent to peak Demand) or energy Demand in TWh. In this study, Demand includes network losses.
Load	Load is the sum of actual power or energy that flows from generation to the load. In a system with adequate generation (no planned load shedding required), Load is the same as Demand.
Residual Load	Residual Load is Load minus the power generated by VRE. Residual Load must be supplied by conventional power plants (thermal and large hydro).

1 EXECUTIVE SUMMARY

1.1 Introduction

This report presents the methodology and results of a study assessing increased flexibility requirements to the South African power system resulting from increased levels of renewable generation in the time frame until 2030. The study further analyses whether the existing and planned power plants will be able to cope with these requirements. Finally, the study quantifies costs associated to increased flexibility requirements imposed by variable renewables (wind and photovoltaic solar).

1.2 Approach and Methodology

1.2.1 What is Flexibility?

The term Flexibility covers a wide range of aspects. Flexibility requirements arise out of the fact that demand is not constant but varies over time. This in turn requires power plants to adjust their power output to demand, either by starting and stopping or just by varying their power output while being synchronized (load following ramping).

Because there are constraints on the flexibility of power plants (e.g. start-up times, shut-down times, minimum up-times, ramp-rate limits, minimum stable operation level etc.) and costs associated with it (e.g. increased O&M cost resulting from frequent ramping or starting, increased CAPEX for enhanced flexibility capabilities), the dispatch of power plants must be planned and optimized in advance (e.g. at day-ahead time scales and re-adjusted at hours-ahead time scales). This in turn requires predicting load variations at day-ahead and hours-ahead time scales.

Because such predictions can never be fully accurate (because of inaccuracies of load forecast, continuous load variations and generator outages) balancing reserve is needed for compensating the mismatch between predicted and actual load and generation.

Balancing reserve must be highly flexible and activation times must be short. Because it is difficult to realize very short response times with thermal power stations, different types of balancing reserve are defined and classified in terms of their response and activation time (see also **section 3.1**):

- Instantaneous Reserve: Fully available within 10s, activated locally by automatic governors;
- Regulating Reserve: Responds within 10s, fully active within 10min, activated centrally by Automatic Generation Control (AGC);
- 10-Minute Reserve: fully available within 10min, activated manually by the System Operator;
- Emergency Reserve: Same technical characteristics as 10-Minute-Reserve but used less often;

The sequence of activation of the different reserves in case of a sudden generator outage is depicted in **Figure 1**. As shown

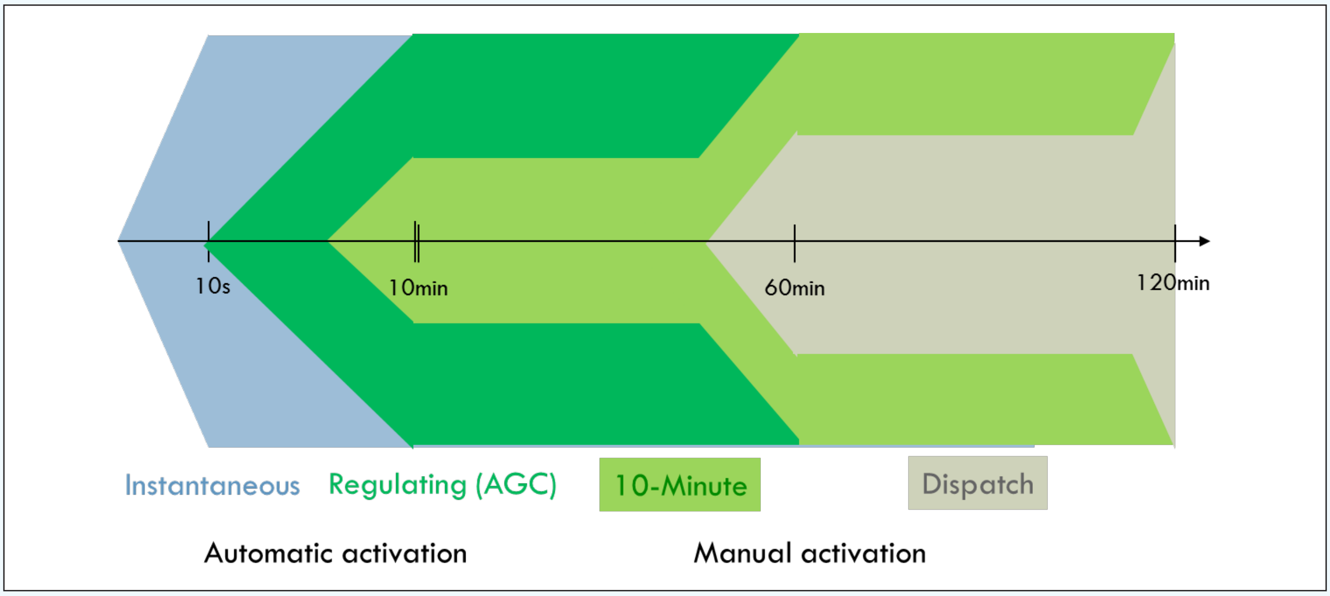

Figure 1: Operating Reserve in South Africa

by this figure, Instantaneous Reserve compensates for the lost generation within 10s. Within the next 10 minutes, Instantaneous Reserve is substituted by Regulating Reserve (controlled by the Automatic Generation Control (AGC) System) and manually activated 10-Minute Reserve. After one hour, 10-Minute Reserve is replaced by a readjustment of the generator dispatch (either partly, as shown in **Figure 13** or completely).

1.2.2 Variable Renewable Energies and Flexibility

When adding Variable Renewable Energies (VRE), like wind or PV plants to the system, another source of variability is added.

The impact of VRE on flexibility requirements can best be understood by considering VRE as being negative load. In fact, there are many similarities between VRE and load:

- VRE and load vary over time;
- VRE and load cannot be planned but only predicted;
- VRE and load are not constant within a dispatch interval likewise dispatchable generation but vary continuously;

With respect to system balancing, the only difference between VRE and load is the sign (negative sign for VRE and positive sign for the load).

When subtracting VRE from load the resulting quantity is the Residual Load of the system. **Figure 2** shows load, wind generation, PV generation and Residual Load (dark blue) for three consecutive days. The Residual Load (dark blue) is simply obtained by subtracting wind generation and PV generation from the actual load (light blue).

The importance of Residual Load can best be understood by comparing typical operational planning process (day-ahead process) of a system with VRE and a system without VRE as shown in **Figure 3**. Integrating VRE into the day-ahead operational planning process means replacing load (demand) by Residual Load. In order to obtain sufficiently accurate day-ahead predictions of the Residual Load, professional tools for short-term VRE forecast (wind and PV) will be required.

The actual (conventional) generation dispatch is then prepared on basis of the predicted Residual Load instead of the actual load (or demand).

In a system with VRE, conventional generation must provide the required flexibility for meeting flexibility requirements arising out of variability (and limited predictability) of load and VRE, which is combined into the Residual Load.

By comparing variability and predictability of Residual Load and actual load (or demand), the impact of VRE on flexibility requirements can be studied.

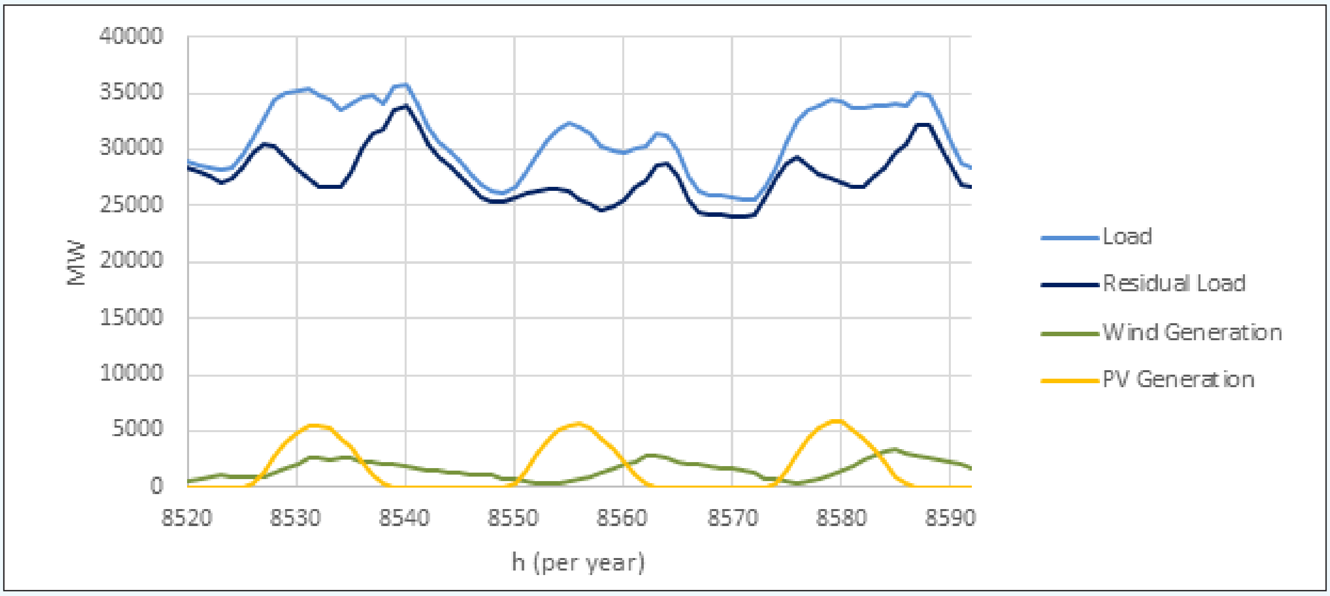

Figure 2: Load, wind generation, PV generation and Residual Load on three consecutive days (example)

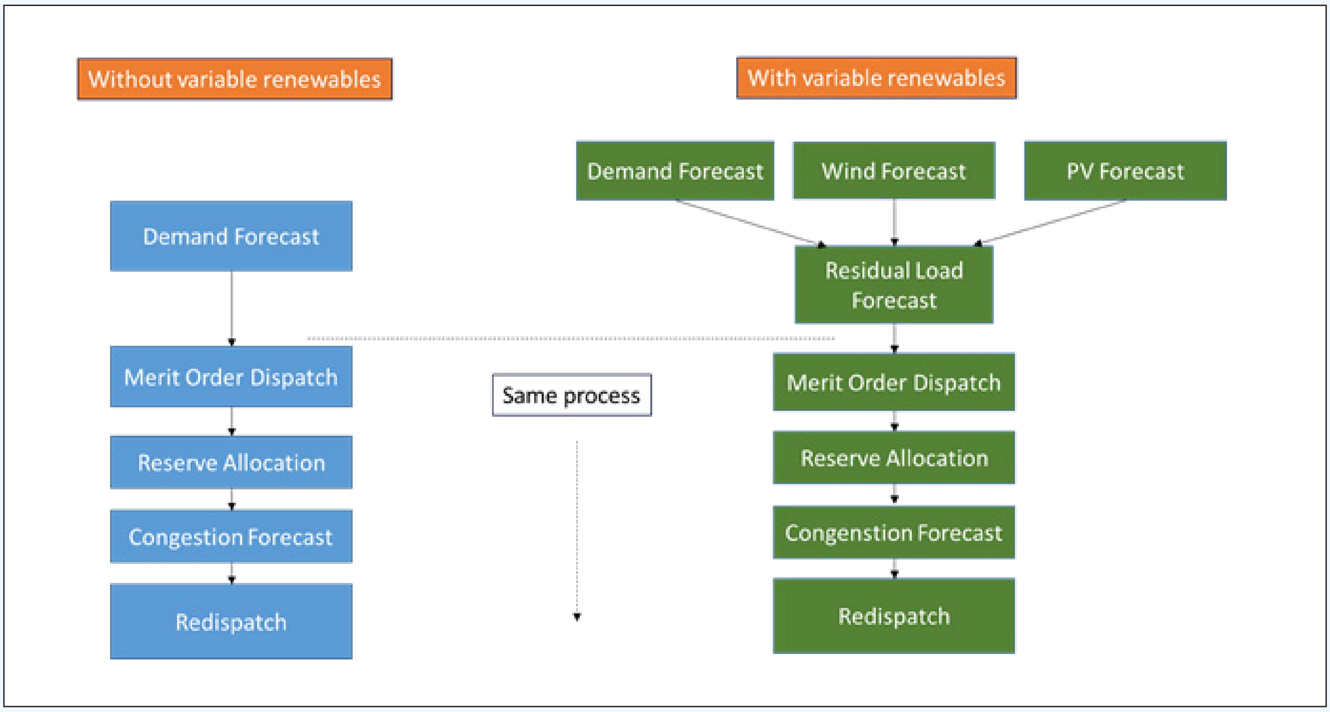

Figure 3: Typical day-ahead process of a system without and with VRE

1.2.3 Quantifying Flexibility

This study focuses on the following two flexibility aspects:

- **System balancing:** Impact of VRE on day ahead forecast errors (Imbalance) and required Operating Reserve.
- **Cycling:** Impact of VRE on load following events and start-ups of conventional power plants.

Balancing power is required for compensating day-ahead prediction errors ("Imbalance"), variability of the Residual Load within a dispatch cycle of one hour and contingencies (e.g. trip of a generator). In more detail, the study analyses the following aspects:

- **Imbalance:** Difference between the hourly average of Residual Load and the day-ahead prediction error of Residual Load.
- **Operating Reserve:** Impact on the different types of Operating Reserve (Instantaneous, Regulating, 10-Minute Reserve and Emergency Reserve), which is required for balancing the system within a one-hour dispatch cycle.

Cost of balancing power is difficult to quantify in South Africa because there is no well-defined market in place for the procurement of balancing power. Therefore, the impact on balancing power is just expressed in technical quantities (MW).

Cycling is quantified considering the following metrics:

- **Number of start-ups** of every power plant, whereas the study further distinguishes hot, warm and cold starts.
- **Number of significant load following cycles:** A significant load following cycle is change in active power (ramping event) by more than 20% of the Gross Dependable Capacity (GDC) of a power plant. This definition is in-line with the definitions used in [2].

Cost of increased cycling is estimated considering direct and indirect cycling costs. Direct cycling costs incur directly during a start-up event of a thermal power plant (e.g. cost of start-up fuel). Indirect cycling costs are caused by increased stress of different components of a power plants due to increased cycling. Increased stress results in accelerated fatigue and finally to increased O&M costs (see also [2]).

To quantify future cycling costs, a production cost model simulating the operation of the South African power system for a complete year with a resolution of 1 hour has been implemented. This allows the number and cost of load following and start-up cycles of every power plant to be quantified.

1.2.4 Scenarios

The scenarios for demand and generation expansion are based on the IRP2016 base case scenario, which was published by the Department of Energy in November 2016

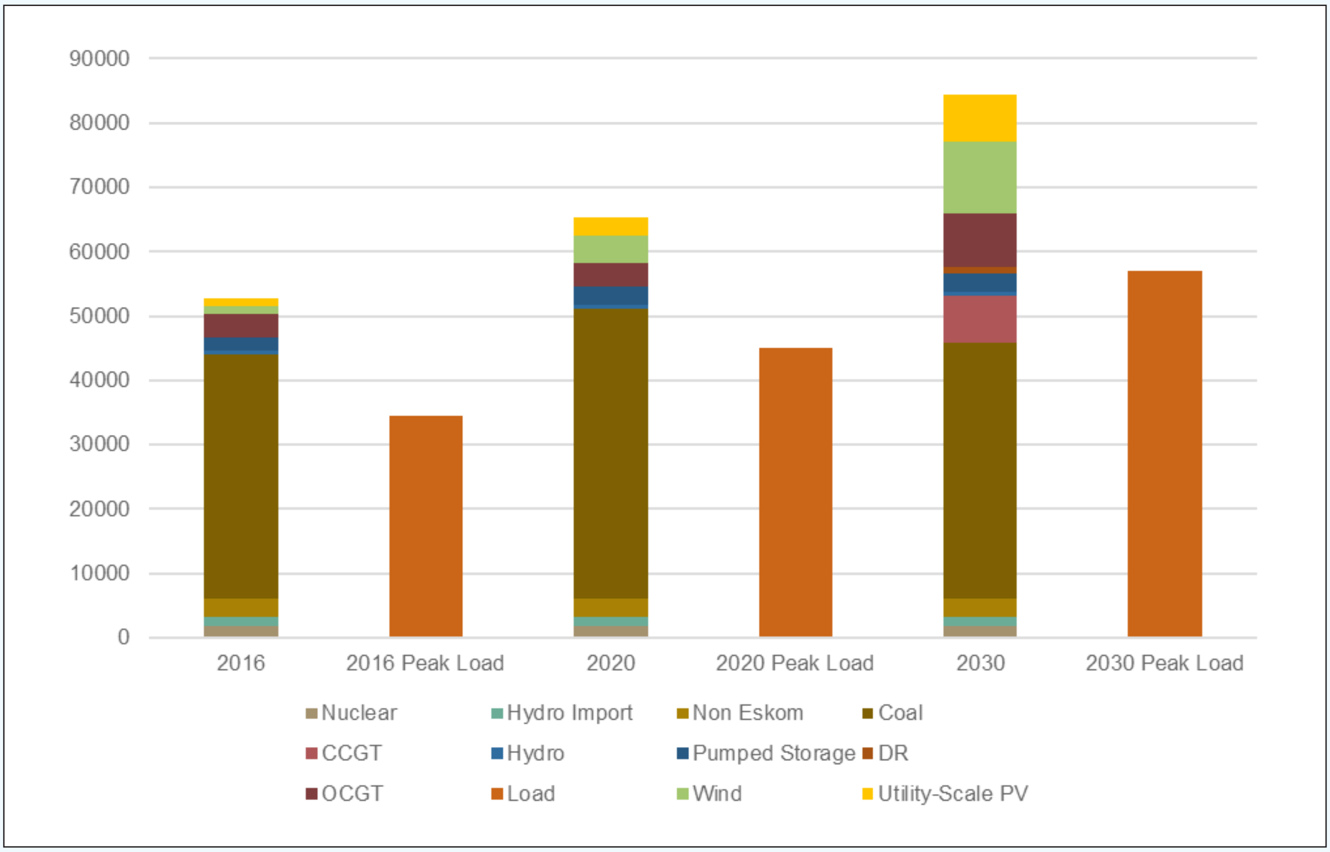

Figure 4: Installed Capacity in 2016 and assumed capacities in 2020 and 2030

[3]. **Figure 4** provides an overview about generation capacity and peak load of the different spot years analysed by in this study. The actual numbers are summarized in **Table 1**.

Table 1: Installed Capacity in 2016 and assumed capacities in 2020 and 2030

Spot Year:	2016	2020	2030
Power Station	**Installed Capacity in MW**		
Nuclear	1840	1840	1840
Non Eskom	2800	2800	2800
Hydro Import	1440	1440	1440
Coal	37865	45085	39805
CCGT	0	0	7320
Hydro	600	600	600
Pumped Storage	2068	2736	2736
Demand Response	0	0	1000
OCGT	3800	3800	8439
Total non VRE	**50413**	**58301**	**65980**
Wind	1100	4200	11100
utility-scale PV	1200	2800	7400
Total	**52713**	**65301**	**84480**

In addition to the installed capacities of wind and PV foreseen by the IRP2016 base case scenario [3], this study optionally considers different scenarios for rooftop PV. In the absence of any credible scenario for the development of rooftop PV in South Africa, this study looks at the impact of different assumed rooftop development scenarios, named “moderate rooftop”, with 5GW of additional rooftop PV capacity by 2020 and 10GW by 2030 and a “high rooftop” scenario with 10GW by 2020 and 20GW by 2030.

This study further analyses the impact of the allocation of utility-scale PV farms on Flexibility Requirements. The allocation scenarios considered in this study are based on the study “Analysis of Options for the future Allocation of PV farms in South Africa” [4]:

- **Scenario A:** High concentration of utility-scale PV farms in the solar corridor (see **Figure 19**). Scenario is based on actual applications of PV project developers in South Africa, as they were available to ESKOM by the time of the study [4].
- **Scenario B:** As much utility-scale PV in the solar corridor as the transmission grid in this area can absorb. Remaining PV capacities are distributed and allocated close to load centres (see **Figure 20**).

1.3 Results

1.3.1 Impact of VRE on Balancing Power

1.3.1.1 Year 2020

The impact of VRE on Imbalance for the spot year 2020 is depicted in **Table 2**. As shown by these figures, the integration of 4.2GW of wind generation and 2.8GW of utility-scale PV capacity increases maximum credible day-ahead prediction errors by around 9%. When further adding up to 10GW of rooftop PV, Imbalance resulting from day-ahead prediction errors is around 13% higher than without wind and PV.

The impact of the allocation of utility-scale PV on Imbalance is only very small.

Table 2: Impact of VRE on Imbalance in 2020

Scenario	Imbalance
No PV/Wind	100,00%
Scenario A	109,28%
Scenario B	109,19%
Scenario A, +5GW rooftop	110,28%
Scenario B, +5GW rooftop	110,40%
Scenario A, +10GW rooftop	112,91%
Scenario B, +10GW rooftop	113,30%

The impact of increased variability on Operating Reserve is shown in **Table 3**. As shown by these numbers, the integration of 4.2GW of wind and 2.8GW of solar PV by 2020 has almost no impact on Operating Reserve (see **Table 3**, Scenario A and Scenario B). When adding up to 10GW of rooftop PV, there is a visible impact on the variability component of Operating Reserve. However, because Operating Reserve required for balancing variability of Residual Load is less than Operating Reserve required for compensating the worst-case contingency event, there is no impact on the required Operating Reserve in any of the analysed scenarios for 2020 (including scenarios with up to 10GW of rooftop PV in addition to utility-scale PV according to the draft IRP2016 base case scenario [3]).

1.3.1.2 Year 2030

The impact of VRE on Imbalance for the spot year 2030 is depicted in **Table 4**. As shown by these figures, the integration of 11.1GW of wind generation and 7.4GW of utility-scale PV capacity increases maximum credible day-ahead prediction errors by around 25%. When further adding up to 20GW of rooftop PV, Imbalance resulting from day-ahead prediction errors is around 35% higher than without wind and PV.

Table 4: Impact of VRE on Imbalance in 2030

Scenario	Imbalance
No PV/Wind	100,00%
Scenario A	125,58%
Scenario B	125,37%
Scenario A, +10GW rooftop	128,23%
Scenario B, +10GW rooftop	128,64%
Scenario A, +20GW rooftop	135,42%
Scenario B, +20GW rooftop	136,82%

The impact of the allocation (locational aspects between Scenario A and B) of utility-scale PV on Imbalance is very small.

The results according to Table 4 show that wind generation has a substantially higher impact on Imbalance than PV. Imbalance increases quite considerably when adding

Table 3: Impact of VRE on Imbalance in 2020

Scenario	Operating in MW		Instanta-neous in MW	Regulating in MW	10-Minute in MW
	variability	contingency			
No PV/Wind	1541	2166	800	406	960
Scenario A	1574	2166	800	420	946
Scenario B	1571	2166	800	416	950
Scenario A, +5GW rooftop	1606	2166	800	431	935
Scenario B, +5GW rooftop	1594	2166	800	429	937
Scenario A, +10GW rooftop	1741	2166	800	459	907
Scenario B, +10GW rooftop	1730	2166	800	458	908

Table 5: Impact of VRE on Operating Reserve in 2030

Scenario	Operating in MW		Instantaneous in MW	Regulating in MW	10-Minute in MW
	variability	contingency			
No PV/Wind	1968	2166	800	519	847
Scenario A	2120	2166	800	576	790
Scenario B	2084	2166	800	570	796
Scenario A, +10GW rooftop	2385	2166	800	631	954
Scenario B, +10GW rooftop	2357	2166	800	624	933
Scenario A, +20GW rooftop	2868	2166	800	750	1318
Scenario B, +20GW rooftop	2848	2166	800	745	1303

11.1GW of wind and 7.4GW of PV. However, when adding another 20GW of rooftop PV, Imbalance increases by a relatively small amount.

The impact of increased variability on Operating Reserve in 2030 is summarized in **Table 5**. As shown by these figures, the integration of 11.1GW of wind and 7.4GW of solar PV by 2030 has only a minor impact on the variability component of Operating Reserve (see Table 5, Scenario A and Scenario B). With VRE penetration levels according to the draft IRP2016 base case [3], there is no impact of VRE on operating reserve, because the required reserve power is dominated by worst-case contingency criteria.

However, when adding 10GW or even 20GW of rooftop PV, variability starts dominating and the required Operating Reserve increases. In the scenario with 10GW of additional rooftop PV, the required Operating Reserve is around 10% higher than without wind/PV. In the scenario with 20GW of additional rooftop PV, Operating Reserve will be around 30% higher than without wind/PV.

The large impact of PV on Operating Reserve in 2030 can be explained by the variation of PV within a one-hour interval, which is a direct result of the daily variation of sunlight. Because there is no diversity with respect to this variation, the resulting variability increases in proportion to the installed PV capacity.

However, this is a predictable effect (and not a stochastic effect) and therefore, it is possible to consider this effect by the day-ahead planning process by reducing the length of a dispatch interval.

This is illustrated by the example according to **Figure 5**, in which the variation of PV within a dispatch interval of 30 minutes is compared against a dispatch interval of 15 minutes. As confirmed by this example, the amount of power, which is required to compensate this variation reduces in proportion to the length of the dispatch interval.

In the South African context, this means that the impact of PV on Operating Reserve could be reduced by reducing the length of a dispatch interval from one hour to e.g. 30 minutes or even 15 minutes. In Germany, the electricity market is organized by 15 minute intervals. In Texas or Australia, the market is even organized by 5 minute intervals.

Such a modification to the operational process could be an option for South Africa when PV penetration levels go beyond the 2030 levels and the variation of PV within a dispatch interval requires an increased Operating Reserve.

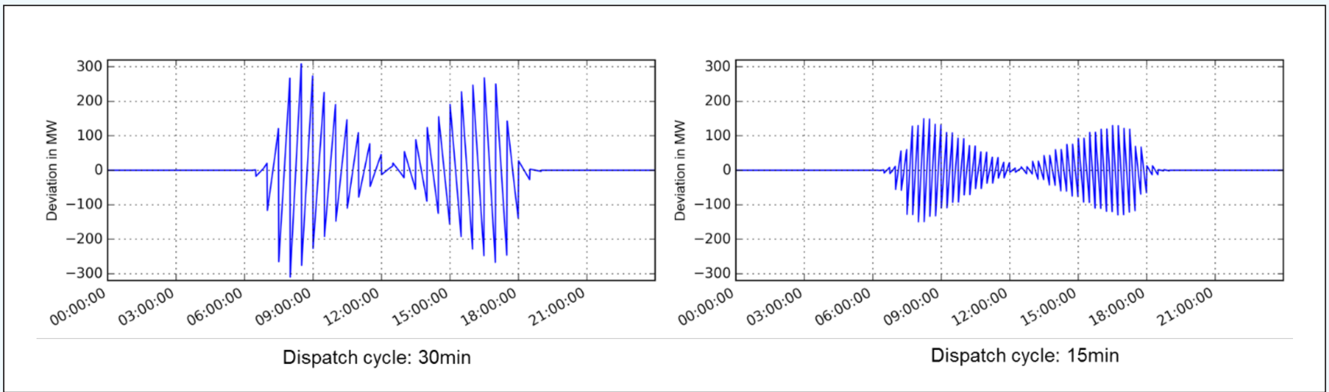

Figure 5: Example: Impact of the length of a dispatch interval on the required Operating Reserve

1.3.2 Impact of VRE on Cycling

1.3.2.1 Year 2020

In 2020, the South African power system will mostly be supplied by baseload power plants (mainly coal and some nuclear), which will perform most of the required load following. Only during peak load situations, hydro, pumped-storage, and OCGT plants are added (see **Figure 6**). This type of operation essentially corresponds to today's situation.

The addition of 10GW of rooftop PV leads to more frequent and steeper load following ramping of baseload power plants, as demonstrated by **Figure 7**.

This is confirmed by the cycling costs (estimated cost range) according to **Figure 8**. These figures show cycling costs compared to a (theoretical) system with a constant load not requiring any flexibility and includes direct and indirect cycling costs. They include annual cycling costs of all power plants in South Africa on the basis of the annually generated electrical energy. As shown by these numbers, cycling costs in 2020 are generally very low and are in a range of far less than 0.5% of overall generation costs (assuming an average

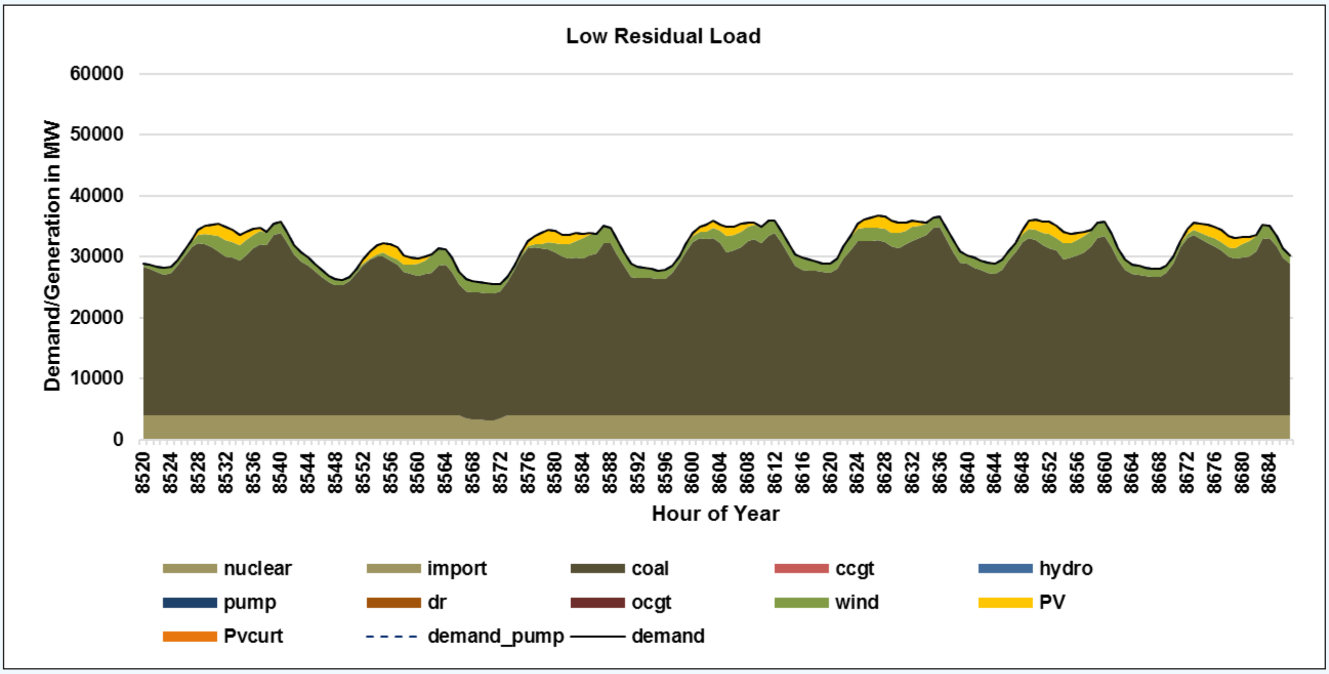

Figure 6: Scenario A, year 2020: generator dispatch, week of lowest Residual Load

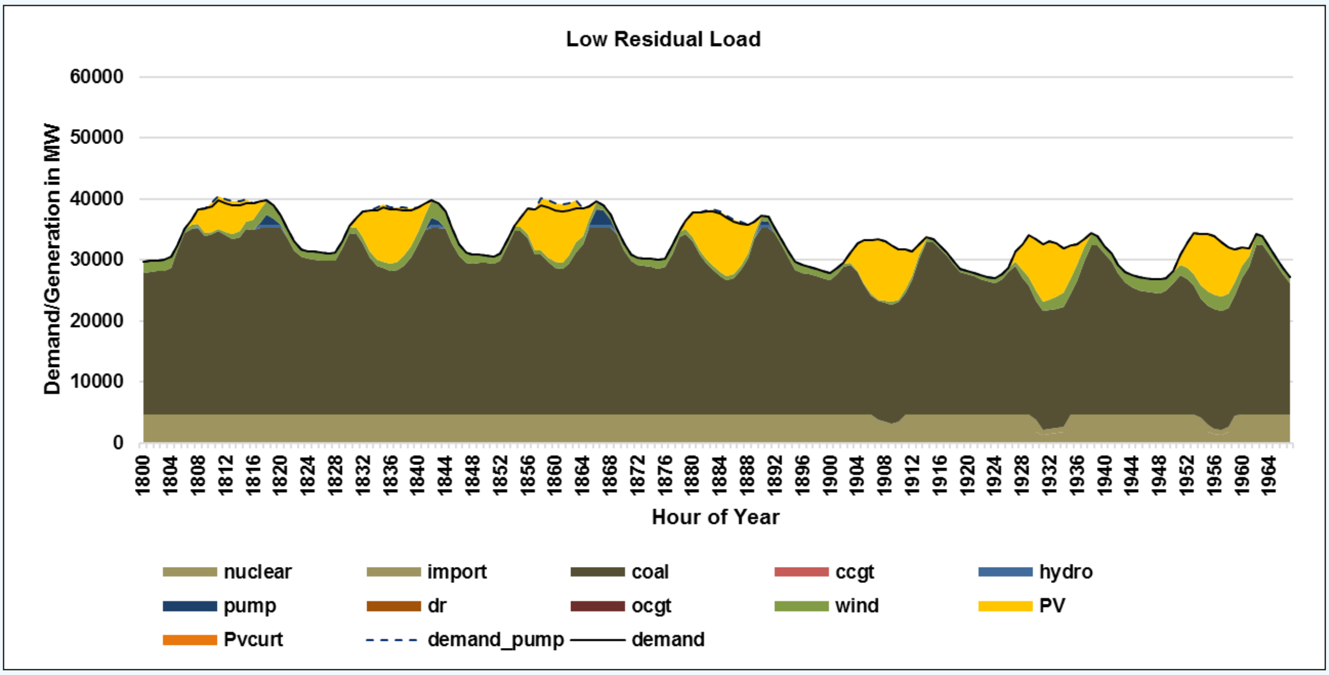

Figure 7: Scenario A +10GW of rooftop PV, year 2020: generator dispatch, week of lowest Residual Load

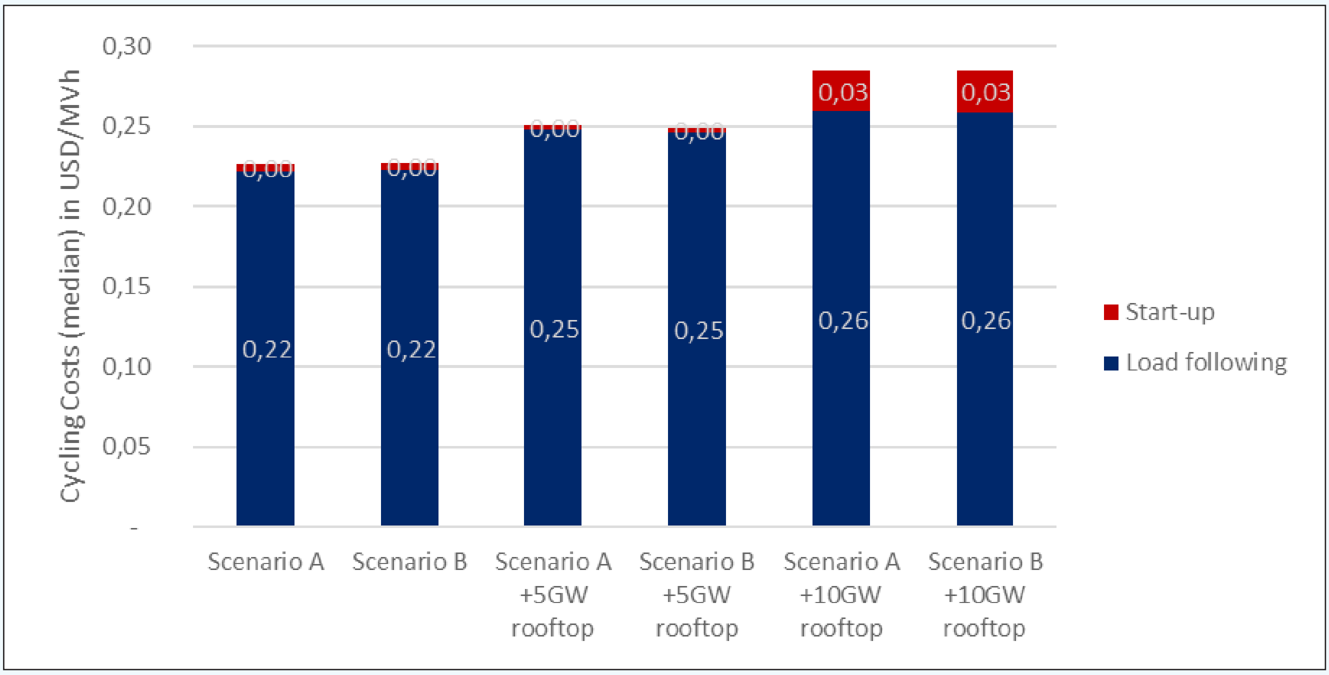

Figure 8: Cycling costs in USD/MWh of annually generated electrical energy in South Africa, year 2020

LCOE of around 60 USD/MWh). The impact of up to 10GW of rooftop PV on cycling costs is in a range of around 0.05% of overall generation costs. In 2020 cycling costs are mainly defined by costs of load following cycling of coal fired power stations (see **Figure 8**).

1.3.2.2 Year 2030

Until 2030, the characteristics of the South African generation fleet will change considerably compared to 2020 (and compared to 2016). In the time frame between 2020 and 2030 numerous CCGTs and OCGTs will be added (see also **Figure 4**) operating as mid-merit plants (CCGTs) and peaking plants (OCGTs).

As shown by the generator dispatch according to **Figure 9**, load following requirements of coal fired power stations are substantially reduced compared to 2020, because the newly built CCGTs will deliver most of the load following requirements.

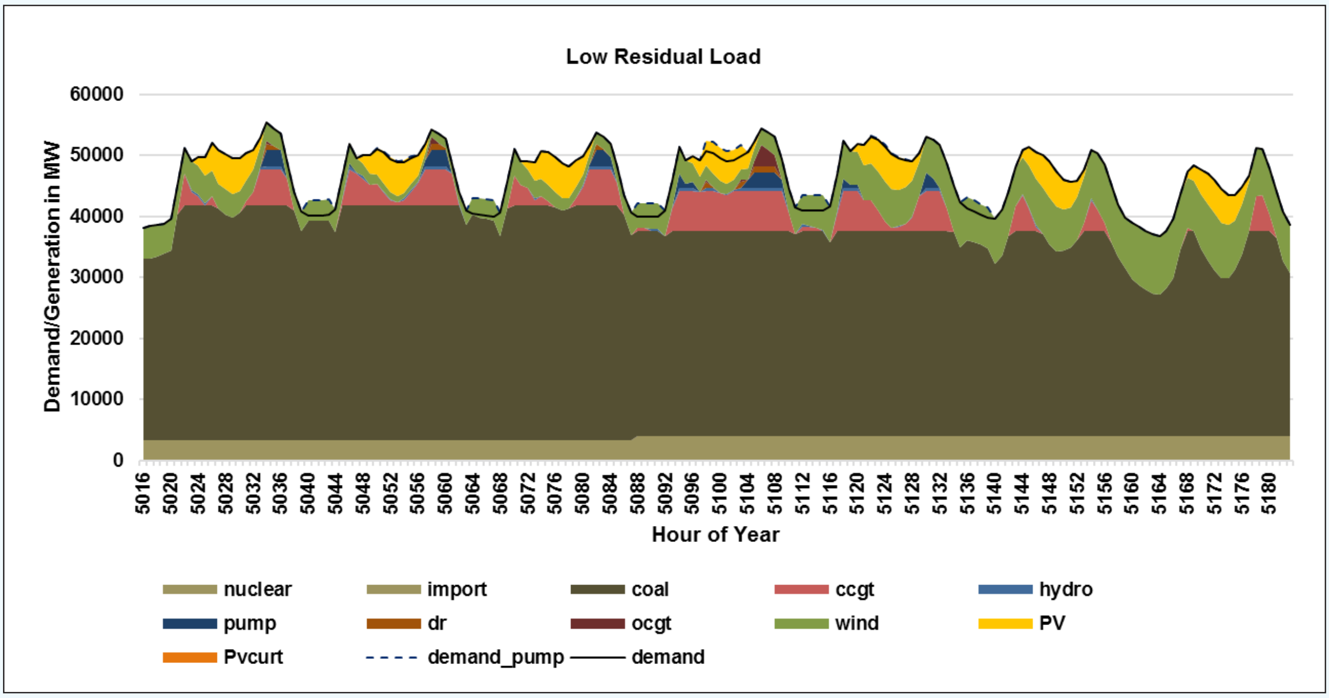

Figure 9: Scenario A, year 2030: generator dispatch, week of lowest Residual Load

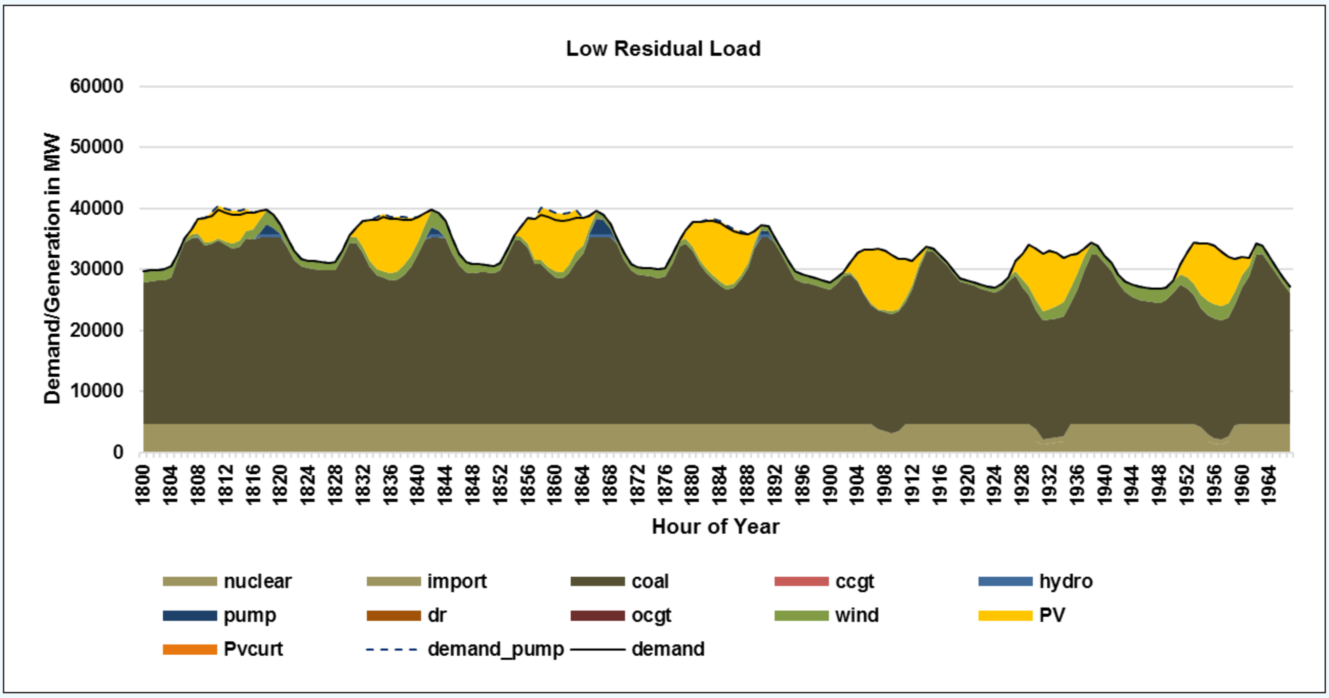

Figure 10: Scenario A +20GW of rooftop PV, year 2030: generator dispatch, week of lowest Residual Load

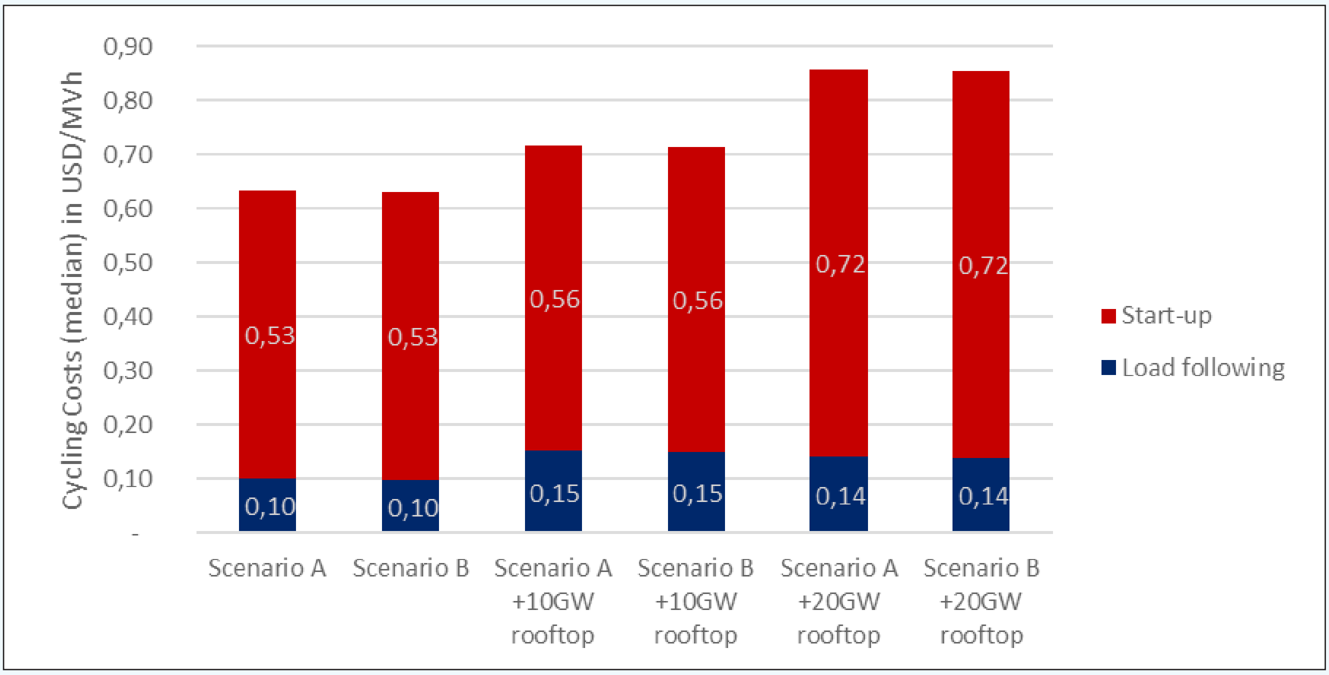

Figure 11: Cycling costs in USD/MWh of annually generated electrical energy in South Africa, year 2030

To support the system under minimum Residual Load scenarios, pumping of pumped-storage power plants should shift from night to day-time, especially during days with high solar generation.

The addition of up to 30GW of rooftop PV will increase load following requirements to coal fired power stations again, but not above the levels of 2020. The number of start-ups of CCGTs will increase due to the addition of up to 30GW of rooftop PV because during many days, CCGTs will have to start and stop twice per day instead of once per day (see also **Figure 9** and **Figure 11**).

Despite the fact that load following requirements of coal fired power stations will decrease, overall cycling costs will increase during the time frame between 2020 and 2030 (see **Figure 11**). By 2030 cycling costs are dominated by start-up costs of CCGTs and OGCTs and will be in a range of around 0.60 USD/MWh (no rooftop PV) and 0.85USD/MWh (with 20GW of rooftop PV). This is in a range between around 1% and 1.4% of the average cost of electricity generation.

1.4 Summary Conclusions and Recommendations

The study presented in this report confirm that the South African power system will be sufficiently flexible to handle very large amounts of wind and PV generation, especially when considering the addition of CCGTs and OCGTs according to the IRP-2016-Base-Case [5]. To cope with increased flexibility requirements resulting from the installation of 4,2GW of wind generation and up to 12,8GW of PV by 2020, and 11GW of wind and 27,5GW of PV by 2030, flexibility requirements can be handled by existing and planned power plants at moderate additional costs.

In 2030, the addition of CCGTs will even reduce cycling requirements of coal-fired power stations, even with 20GW of additional rooftop PV.

In the case of very high PV installations (10GW in 2020, 20GW in 2030), it is recommended to move pumping operation of pumped-storage power plants from night to midday, when Residual Load is at its minimum value. This relaxes Residual Load Requirements and allows coal fired power plants to operate at higher levels. It can also help reduce the amount of curtailed PV energy.

Until 2020, the allocated Operating and Emergency Reserve does not need to be increased, even when adding 10GW of additional rooftop PV.

Until 2030, Operating and Emergency Reserve, according to [6], is still sufficient to balance increased variability of wind and PV generation capacities according to the IRP-2016-Base-Case [5].

When installing 10GW or 20GW of rooftop PV in addition to utility scale VRE proposed by the IRP-2016-Base Case [5], Operating and Emergency reserve must be increased to balance increased variability. However, the required additional Operating and Emergency Reserves are in a moderate range.

To ensure secure and cost-efficient operation of the South African power system even with very high levels of wind and PV generation, we can make the following recommendations:

- Application of professional short-term forecast tools/services for wind and PV prediction, including a system for short-term prediction of rooftop PV.
- In the case of very high PV installations (e.g. 27GW by 2030): Allocation of higher levels of Operating Reserve and Emergency Reserve in afternoon hours.
- In the case of very high PV installations (e.g. 27GW by 2030): Operate pumped-storage power plants in pumping mode during mid-day (and not during night time) when Residual Load is at its minimum value.

Other modifications to operational procedures (day-ahead planning, intra-day planning, real-time operations) are not required in the studied time frame and the studied levels of wind and PV.

This study confirms that very large penetration levels of wind and PV could be handled by the system, from an active power balancing point of view, at moderate additional costs for balancing services (Reserve and increased cycling of thermal power plants).

Other aspects, like voltage issues resulting from the operation of the South African power system with very high levels of distributed PV and potentially required additional reactive power compensation equipment (and/or new strategies for reactive power and voltage control at distribution levels) was not subject to these studies. However, it is recommended that this should be analysed in follow-up work to this study.

2 Introduction

2.1 Power System Flexibility - Background

One key task of system operations is to balance load and generation at any moment in time. For this reason, it is essential that the operator has sufficient flexibility resources (e.g. flexible power plants) in the power system to be able respond to predicted and unpredicted variations of load and variable generation. In addition to power plants, modern power systems can utilise storage (e.g. pumped or battery storage), HVDC interconnection with other asynchronous power systems, and controllable loads (demand response), to deliver balancing services. These, therefore, all fall under the category of 'flexibility resources' as shown in **Figure 12**.

In a system without considerable share of VRE, variability and predictability of the load predominantly defines the flexibility requirements, and power plants deliver the required balancing services (flexibility resources). But also, the grid itself, especially strong interconnectors to other countries (AC or DC) can considerably increase the flexibility of a power system because they allow accessing new flexibility resources.

When adding variable renewable energies (VRE) to a power system, predicted and unpredicted variations of VRE impose additional flexibility requirements. In addition to the added variability, VRE will displace conventional, dispatchable power plants and consequently reduce the amount of available flexibility resources during times of high wind and solar irradiation. Consequently, VRE have an impact on both flexibility requirements and flexibility resources.

Besides the technical characteristics of a power system, the amount and type of required balancing services and the associated costs highly depend on operational concepts and the market design (including ancillary service markets).

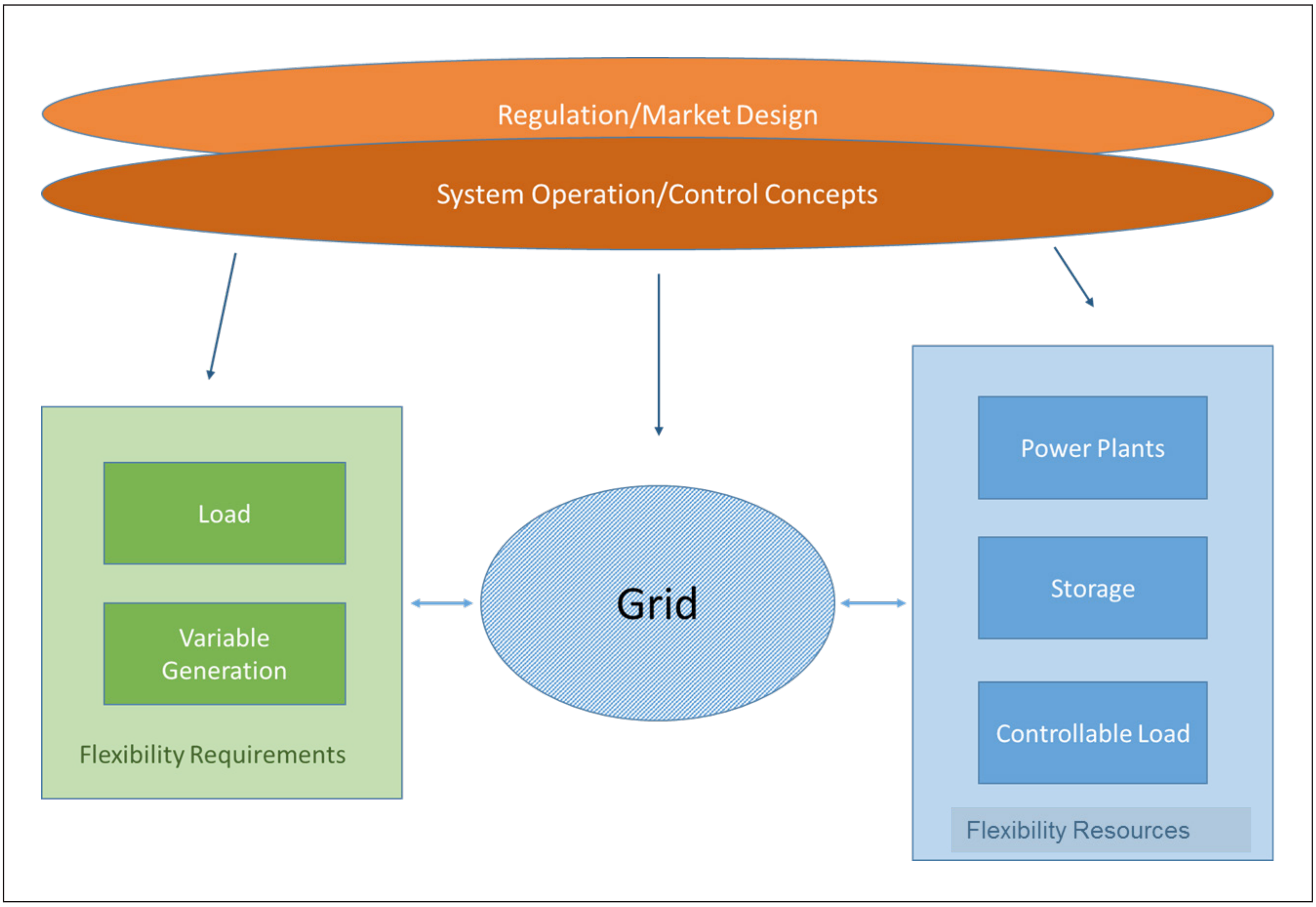

Figure 12: Power System Flexibility - requirements, resources and other factors influencing flexibility

2.2 Scope of Studies

According to the IRP2016-Base Case Scenario [5], there are plans to install around 18,5GW of utility-scale VRE power plants in South Africa until 2030.

In addition to the volumes of VRE identified by the IRP2016-Base case [5], there are predictions that the use of rooftop PV in South Africa could potentially grow significantly in future. In contrast to utility-scale PV, rooftop PV systems are installed by consumers. It is therefore significantly more difficult to plan and control the amount of installed rooftop PV capacities, in contrast to utility scale PV plants.

These studies consider scenarios with 10GW and 20GW of rooftop PV installations in South Africa (in addition to the utility-scale PV mentioned above).

In 2011, GIZ, DoE and ESKOM carried out capacity credit and flexibility studies of wind generation in South Africa [7]. Besides capacity credit, the impact of up to 10 000MW of installed wind capacity in the Cape on the residual load in South Africa has been analyzed in [7]. According to these studies, the impact of up to 10 000MW of wind generation in South Africa on Flexibility Requirements of conventional power plants can be expected to be rather low.

However, the IRP2016-Base Case [5] deviates substantially from the assumptions of the studies carried out back in 2011 [1], especially with regard to absolute penetration levels of VRE. Besides this, the grid integration of PV was not considered by the studies [7].

The main objective of the studies presented in this report is to answer the following questions:

Topic: Increased flexibility requirements:

- What is the impact of planned VRE installations on ramping requirements?
- What is impact of planned VRE installations on required operational reserve?

Topic: Capability of the existing and the planned system:

- Are existing and planned conventional power plants capable of meeting future ramping requirements?
- Are existing and planned conventional power plants capable of delivering the required additional operational reserve?

Topic: Cost of increased flexibility requirements:

- What is the cost of increased cycling?
- What is the cost of additional operating reserve?

An additional objective of this study is to identify whether there are any technical requirements, which must be considered by renewable generators, and/or conventional power plants, in the future for ensuring that the system will be able to operate efficiently with high levels of VRE penetration.

3 Approach and Methodology

3.1 System Operations in South Africa

The ‘Operations Code’ (part of the Grid Code) [1], and ESKOMs technical report for identifying operational reserve requirements [6], describe the main operational concepts applied to the South African power system.

The South African power system is operated at a dispatch cycle of one hour. Imbalance introduced by day-ahead forecast errors are either compensated by an updated intra-day-dispatch of generation (if sufficient lead time is available) or by reserve (10-Minute Reserve or Supplemental Reserve).

According to the Operations Code [1], Operating Reserve is subdivided into different types of reserve, either spinning or stand-by, which can be activated within different time scales:

- Instantaneous Reserve
  - Fully activated within 10 seconds
  - Sustained for at least 10 minutes
  - Activated locally by local speed governors
  - Used for instantaneous control of frequency (primary frequency control)
- Regulating Reserve
  - Responds within 10 seconds
  - Fully activated within 10 minutes
  - Activated centrally by the Automatic Generation Control (AGC) system
  - Used for second-by-second balancing of generation and demand
  - Additionally, used for restoring Instantaneous Reserve within 10 minutes after a frequency disturbance (secondary frequency control)
- 10-Minute Reserve
  - Fully activated within 10 minutes
  - Sustained for at least 2 hours
  - Activated centrally by the System Operator (manual activation)
  - Used for compensating imbalance between load and supply, e.g. resulting from load forecast errors
  - Built by Demand response

In addition to Operating Reserve, the system operator can use additional reserve for emergency situations (Emergency Reserve):

- Fully activated within 10 minutes
- Sustained for at least 2 hours
- Activated centrally by the System Operator (manual activation)
- Used less frequently than 10-Minute Reserve, only in emergency situations
- Built by interruptible load, generator emergency capacity, and gas turbine generators (in particular OCGTs)
- For longer term balancing tasks (with several hours' notice) the system operator can activate Supplemental Reserve:
- Must be available within 1-6 hours (according to the contract)
- Must be sustained for at least 2 hours
- Used for risk mitigation (contingencies, day-ahead risks, substitution of 10-Minute reserve)
- Mainly built by interruptible load and gas turbine generators

The sequence of activation of the different reserves in case of a sudden generator outage is depicted in **Figure 13**. As shown by this figure, Instantaneous Reserve compensates for the lost generation within 10s. Within the next 10 minutes, Instantaneous Reserve is substituted by Regulating Reserve (controller by the Automatic Generation Control (AGC) System) and manually activated 10-Minute Reserve. After one hour, 10-Minute Reserve is replaced by a readjustment of the generator dispatch (either partly, as shown in **Figure 13**) or completely.

On an annual basis, ESKOM calculates the required active power reserve requirement for each of the different types of reserve described above (e.g. [8], [9], [6]). The methodology of calculating these reserves, especially for Emergency and Supplemental Reserve, has changed over the years and, therefore, the reserve requirements have varied considerably between the evaluation from 2012 [8] and the last evaluation in 2016 [6].

Operating Reserve needs to cover both, worst-case contingencies (e.g. trip of a generator or power plant) and variability. For most types of reserve, independent assessments based on worst-case contingencies and variability are performed. The larger of the resulting values finally defines the required amount of reserve.

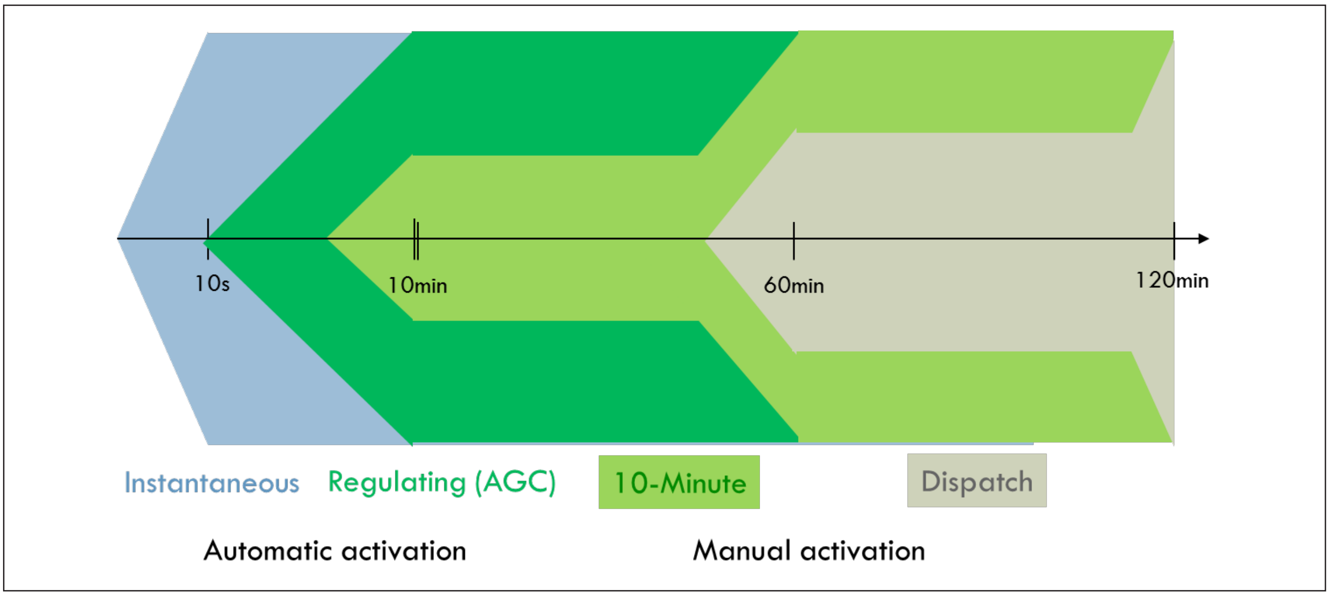

Figure 13: Operating Reserve in South Africa

Because the integration of VRE should not have any impact on worst-case contingencies (e.g. trip of Largest Unit), only the variability aspect, and the corresponding impact on Operating, Emergency and Supplemental reserve will be analysed in these studies. This approach is valid provided it is assumed that the design of connections for VRE is suitably coordinated so that one system event (e.g. a secured transmission line fault outage) cannot cause a loss of VRE generation greater than the trip of the Largest Unit (see also the study "Options for the allocation of PV in South Africa" [10].

3.2 Load and Residual Load

To quantify the impact of VRE on flexibility requirements, and to evaluate the capacity and capability of flexibility resources to meet these requirements, it is necessary to introduce a set of parameters (metrics).

Flexibility requirements can best be evaluated by analysing the Residual Load, which is defined by the actual load minus VRE generation. This definition of Residual Load is illustrated by **Figure 14**, which shows, as an example, Load, PV generation, Wind Generation and Residual Load for three consecutive days in a future scenario in South Africa with 4.2GW of wind capacity and 7.8GW of PV capacity.

The Residual Load defines the requirements to the system in terms of:

- Cycling (start-up, shut-down and load following) of conventional power plants
- Provision of balancing services (Operating Reserve, Emergency Reserve, Supplemental Reserve)
- Need for intra-day updates of the generator dispatch for compensating Imbalance.

Some of these requirements refer to variability, some other requirements relate to predictability aspects.

Variability relates to fact that load is not constant over time and can be quantified by:

- Load factor (ration between average load and peak load)
- Ramping (in terms of power variations between two consecutive dispatch cycles, expressed by hourly ramp rates)
- Short-term variability (variations within one dispatch cycle, which must be compensated by regulating reserve and 10-minute reserve)

Predictability is mainly quantified by the day-ahead prediction error of the Residual Load (difference between the day-ahead prediction of Residual Load and its actual

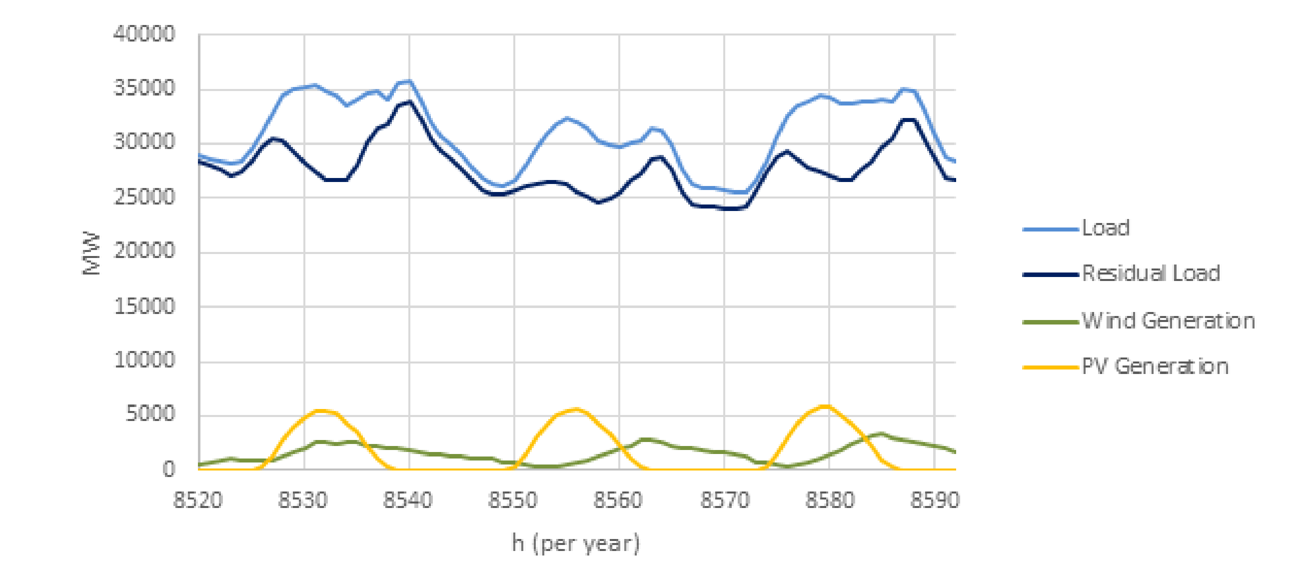

Figure 14: Residual Load (year 2020, Scenario A with 5GW of additional PV capacity, see also 3.7)

(hourly) average). This introduces an Imbalance between generation and load, which must be compensated by intra-day update of the generator dispatch or by Reserve.

Figure 15 shows Load and Residual Load over two example sunny days in a future scenario in South Africa with high VRE capacities. In this example, the worst-case ramp-rate of

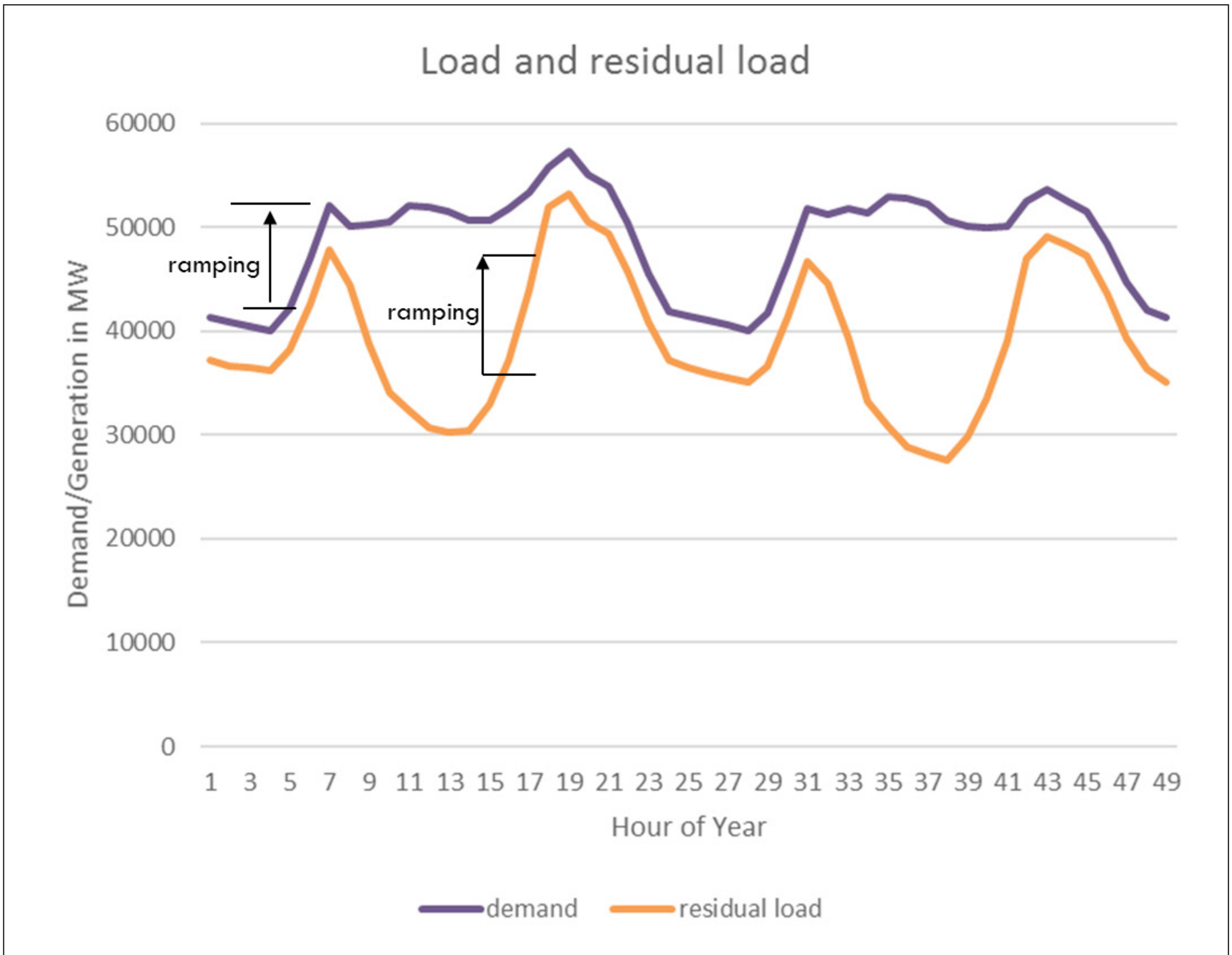

Figure 15: Ramping of Load and Residual Load

the Load occurs in the morning, whereas worst-case ramp rates of Residual Load can occur in the evening, when sun sets and load increases.

To quantify the impact of VRE on ramping requirements, the study calculates hourly ramp rates of load and Residual Load and evaluates the results in the form of cumulative distribution curves (duration curves) so that both impact on worst-case situations and frequency of occurrence of significant ramp rates can be evaluated.

In a second step, the cost impact of increased variability will be evaluated using a time domain model of the South African power system and a unit commitment/economic dispatch algorithm for simulating the operation of the South African power system with different levels of VRE.

The model will consider all existing power stations and future power plant additions and retirements according to the recently published IRP2016 Base-Case scenario [5].

3.3 Impact of VRE on Balancing

3.3.1 Requirements/Metrics

Regarding the impact of VRE on Operating Reserve (Instantaneous Reserve, Regulating Reserve, 10-Minute Reserve), the impact of VRE on the accuracy of the day-ahead prediction error of the Residual Load (predictability assessment) and short-term variability of VRE (variations within a one-hour dispatch cycle) are analysed.

The impact on the different types of reserve is assessed using the following metrics (see also **Figure 16**, which shows Imbalance and Variations that define the Operating Requirement):

- **Imbalance Requirement:** Difference between the day-ahead prediction of Load or Residual Load and the actual value of the load or Residual Load for the same time interval. Since the dispatch cycle in South Africa is one hour, Imbalance is evaluated on the basis of one-hour-average values of predictions and actual values of Load and Residual Load.
- **Operating Requirement:** Difference between the instantaneous value of the load (minimum resolution of this study is 1 minute) and the hourly average.
- **Regulating Requirement:** Difference between the instantaneous value of Load and Residual Load (minimum resolution in this study: 1 minute), and the 10-minute average of Load and Residual Load.

The Time Frame of Instantaneous Reserve is too short for being considerably influenced by variability of load, wind or PV. The maximum required Instantaneous Reserve is defined by the worst-case credible generator outage event (e.g. one Koeberg unit or large coal fired power station as in [6]) and this value will not be affected by VRE). Therefore, Instantaneous Reserve is not part of this report.

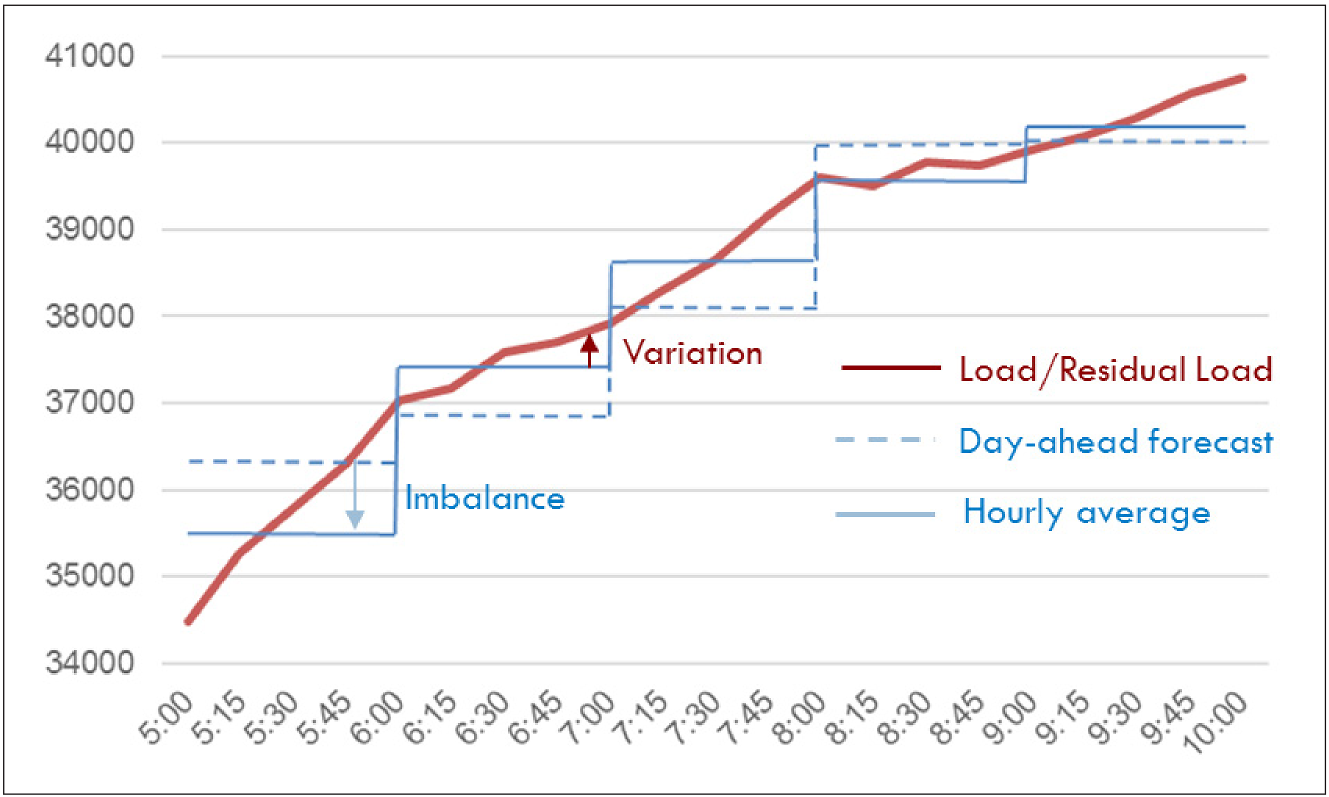

Figure 16: Definition of Imbalance and Variation (Operating Requirement)

3.3.2 ESKOM's approach for predicting required Operating Reserves

ESKOM's approach for predicting the required amount of Operating, Emergency and Supplemental Reserve is described in [6] and is based on the following approach:

- The total required Operating Reserve must compensate either worst-case contingencies or short-term variability (but it is assumed that worst-case contingency and short-term variability do not occur simultaneously).
- The sum of Instantaneous Reserve, Regulating Reserve and 10-Minute Reserve add to the total Operating Reserve. The total Operating Reserve must be adequate to compensate a worst-case credible multiple contingency event (see [6]), which is defined by the simultaneous outage of the largest three coal fired units, which is from 2017/2018 on 3x722MW=2166MW. Regulating Reserve and 10-Minute Reserve do not substitute Instantaneous Reserve in case of a contingency (Regulating Reserve is lower than Instantaneous Reserve in [6]) but add to each other.
- Emergency Reserve is only used occasionally but has similar characteristics to 10-Minute Reserve.

3.3.3 Approach of this study

In this study, the focus is on the impact of variability on required Reserves, which are calculated as follows:

- **Operating Reserve** is calculated by the 99% percentile of the Operating Requirement and by considering the worst-case multiple-contingency as defined by ESKOM's study [6] (simultaneous trip of three large units), whichever leads to the higher value.
- **Regulating Reserve** is calculated by the 99% percentile of the Regulating Requirement.
- **10-Minute Reserve** is calculated by subtracting Regulating Reserve and Instantaneous Reserve from the Operating Reserve.
- **Emergency Reserve** is assessed by the difference between the worst-case value of the Operating Requirement (99,9% percentile) and the 99% percentile.

Imbalance introduced by the day-ahead prediction error is usually compensated by intra-day updates to the generator dispatch (e.g. based on 4h-ahead predictions, which are considerably more accurate than day-ahead predictions). Additionally, Supplemental Reserve can be used for compensating imbalance. For compensating remaining prediction errors (e.g. 4h-adhead or 2h-ahead prediction errors), 10-Minute Reserve must be used (or Emergency Reserve in worst-case situations).

Because Imbalance is compensated by many different concepts (intra-day dispatch, Supplemental Reserve, 10-Minute Reserve), we will report the impact of VRE on Imbalance without assessing its impact on Supplemental Reserve or 10-Minute Reserve.

3.4 Methodology for Assessing Prediction Errors

To assess the impact of VRE on Imbalance, representative time series data of day-ahead prediction errors of load, wind generation and PV generation are calculated. The main input data for these calculations are time series data of load, wind speed (at every modelled site), and solar irradiation (at every modelled site). This data is obtained from various data sources (see section 3.6). Time series of the relevant day-ahead prediction errors are then calculated using the methods described in the following sections.

3.4.1 Day-ahead prediction error of load

Time series data of the load prediction error is generated by first calculating a 24 hours' persistence error (difference between the load at the same hour on two consecutive days). For considering the change of load from working day to week-end and back, a typical "week-end reduction factor" is assumed.

This approach considers that load prediction errors are higher in the case of irregularities of the load and very low in case of a regular variation.

To reflect the accuracy level of actual short-term load prediction algorithms (compared to a simple persistence method) the time series of day-ahead persistence errors were scaled to obtain a typical value for the Mean Average Error (MAPE) of 2%. This approach produces time series data of day-ahead load prediction errors with very realistic stochastic parameters.

3.4.2 Day-ahead prediction error of wind generation

The estimated time series of day-ahead wind prediction errors mainly considers the phase error of wind prediction. Phase error means that short-term wind forecasts can very well predict the occurrence of a rise or fall of wind speeds, however, it is much more difficult to predict the precise time of such an event.

Based on these considerations, we assume that the day-ahead prediction error of wind generation is in proportion to the rate of change of wind generation, which is calculated using 4-hours-ramps.

It is further assumed that the typical accuracy of the day-ahead prediction error of a single wind farm is in the range of an nRMSE of 20% (Root Mean Square Error). Therefore, the time series of 4-hour-ramps is scaled so that the resulting nRMSE of the time series vector is 20%. This value of 20% was confirmed to be typical for South African wind farms by evaluating the accuracy of the day-ahead prediction errors of the first South African wind farms, which are in operation. Summing up the time series data of day-ahead wind prediction errors of all sites results in a vector of time series data representing the total day-ahead prediction error of the entire wind generation in South Africa.

For verifying this approach, especially with regard to the appropriate representation of cross-correlation between wind farms at different sites, an analytical approach, as proposed by U. Focken and M. Lange [11] was used. According to [11], the cross-correlation of wind prediction errors is only in function of their distance (see **Figure 17**).

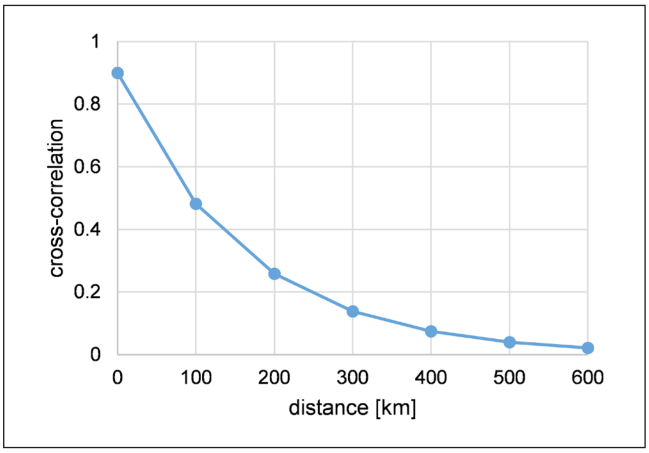

Figure 17: Cross-correlation coefficient r_{xy} of the day-ahead prediction error of two wind farm sites in function of distance between these sites

For calculating the resulting prediction error (nRMSE) a matrix of cross-correlation coefficients of any two wind farms sites (see also **Figure 18**) was prepared and the resulting nRMSE was calculated using the following formula:

$$nRMSE_{ensemble} = \sqrt{\frac{1}{P_{total}^2} \sum_x \sum_y RMSE_{single,x}\, RMSE_{single,y}\, r_{xy}}$$

With:

- $nRMSE_{single}$: Wind forecast error, nRMSE at a single site
- $nRMSE_{ensemble}$: Wind forecast error, calculated as nRMSE of all sites
- P_{total}: Total capacity of all windfarms
- r_{xy}: Cross-correlation coefficient in function of the distance between two single sites

The analytically calculated value of $nRMSE_{ensemble}$ was compared to the numerically generated $nRMSE_{ensemble}$ and it was found that this was almost a perfect match between the two.

3.4.3 Day-ahead prediction error of utility-scale PV

Simulated day-ahead prediction errors of utility-scale PV are based on 24-hours' persistence errors (difference between the load at the same hour on two consecutive days). This approach reflects that the day-ahead prediction error of PV is very small in the case of very stable weather conditions with clear sky and full sunshine, and that prediction errors will be higher in the case of varying weather conditions.
Secondly, the vector of 24-hours' persistence errors is scaled so that the nRMS of simulated day-ahead prediction errors is equal to a typical value of 6%, which is a value that has been found to be typical for South African PV farms (when assuming that all systematic errors, like modelling errors, have been rectified, and the prediction has been well calibrated).

Finally, the vectors of PV prediction errors of all PV farms have been summed, and the resulting vector represents the day-ahead prediction error of all utility-scale PV farms in South Africa for the different scenarios.

3.4.5 Day-ahead prediction error of rooftop-PV

The approach for simulating the day-ahead prediction error of rooftop PV installations is basically the same as for utility-scale PV. However, because it is not possible to calculate prediction errors for all sites, it has been assumed that the nRMSE of the day-ahead prediction error of rooftop PV in South Africa will be 3%, which is a typical value, and can be expected from a set of largely diversified PV installations.

3.4.6 Day-ahead prediction error of Residual Load

The day-ahead prediction error of the Residual Load is finally obtained by summing the vectors of time series data of prediction errors of load, wind generation, utility-scale PV and rooftop PV.

3.5 Methodology for Assessing the Impact of VRE on Cycling

3.5.1 Cycling of coal and gas-fired power plants

Cycling refers to the operation of power plants at varying load levels. Frequent changes of load cause stress to boilers, steam lines, turbine and auxiliary components. Therefore, frequent cycling of thermal power plants leads to fatigue, shorter lifetime of relevant components or even the whole power plant.

In these studies, the impact of increased cycling of coal-fired power plants, CCGT and OCGT, caused by the integration of VRE, is assessed using time domain simulation of the South African power system at a resolution of one hour.

Load, wind speed and solar irradiation is considered by time series data of wind speed and solar irradiation, considering the different scenarios, as described in **section 3.6** and **section 3.7**.

For modelling the dispatch of conventional power plants, a unit commitment/economic dispatch algorithm was applied, and an optimal dispatch over a complete year was calculated for every scenario (see **section 3.7**), at an hourly resolution. In this model, all existing South African power plants are modelled considering relevant parameters like: fuel cost, heat rate (efficiency), minimum level of operation, and maximum level of operation. The model further considers which plants can be started and stopped for operational purposes (CCGT, OCGT, hydro, pumped-storage), and those plants, which are operated as base load plants (coal, coal-IPP and nuclear) and are only started and stopped for maintenance purposes. The model further considers the technical availability of the different types of power stations, as per the IRP-2016-Base Case report [5] (see also **Table 6**).

Table 6: Technical availability of South African power plants

Power Plant	Technical availability
Import	88%
Nuclear	94%
Coal existing	80%
Coal new	90%
CCGT	88%
OCGT	88%
Hydro	88%
Pumped Storage	88%
Non-ESKOM	80%
Demand Response	100%

Ramp-rates of thermal power plants during load following were not constrained during the actual simulation. Technical limits of thermal power plant ramping are usually significantly above that required for load following. However, increasing these ramping rates leads to increase costs due to the higher thermal stress on critical parts of the plant such as the boiler or turbine. Verification that the technical ramping capabilities of South African power plants were above that required for managing the Residual Load was carried out by post-processing the simulation results. For cases where larger ramp rates than normal would be required, increased costs for load following cycling are applied[1].

To quantify the impact of VRE on power plant cycling, precise definitions of cycling events are required. This study mainly follows the definitions of the Intertek Aptech report [2] (prepared for NREL). This study evaluates the following types of cycling events:

- Significant load follow cycle: Load follows ramps of MW range greater than 20% of GDC (Gross Dependable Capacity).
- Hot start-up events
- Warm start-up events
- Cold start-up events

The report [2] further provides typical costs of power plants for different types of cycling events.

Cycling costs vary significantly between different individual units. Therefore, we use a range of costs, as determined for typical power plants of each category based on the research of Intertek Aptech/NREL [2]. Direct start-up costs are taken from [12].

Start-up costs used in these studies include both, direct and indirect start-up costs. Direct start-up costs include cost for start-up fuel and auxiliary services. Indirect start-up costs include capital replacement costs and maintenance costs due to start-ups (C&M costs). Especially for gas turbines, indirect start-up costs substantially exceed direct start-up costs.

Besides the costs of ramping, direct and indirect start-up costs, cycling has an impact on EFOR (Equipment Forced Outage Rate) and heat rate. Increased cycling leads to increased outage frequency, which must be compensated by other units in the system. This study considers increased capital replacement and operation costs of cycling, but not the cost of energy not delivered or energy replacement costs during forced outages, nor lowered efficiency due to cycling (increased heat rate), because these effects highly depend on maintenance practice and are therefore very difficult to quantify.

[1] However, the evaluation has shown that there are no such events in any of the analysed scenarios

Table 7: Typical cost of cycling and other cost for various types of power plants in South Africa

Power Plant		Coal (super-critical)	CCGT	OCGT (large frame)
load following (typical ramp rate) in USD[2] per inst. MW (C&M cost)	median	1.96	0.64	1.59
	25% percentile	1.52	0.30	0.94
	75% percentile	2.38	0.74	2.80
Typical ramp rate during load following in %/min		0.5 (old) to 1.0 (new)	3.00	3.00
Multiplying factor for faster ramping		2 to 8	1,2 to 4	1,2 to 4
Typical minimum operation level in % of GDC		50 (old) to 70 (new)	55	55
Typical hot start in USD per inst. MW (C&M cost)	median	54.00	35.00	32.00
	25% percentile	39.00	28.00	22.00
	75% percentile	63.00	56.00	47.00
Typical warm start in USD per inst. MW (C&M cost)	median	64.00	55.00	126.00
	25% percentile	54.00	32.00	26.00
	75% percentile	89.00	93.00	145.00
Typical cold start in USD per inst. MW (C&M cost)	median	104.00	49.00	103.00
	25% percentile	73.00	46,00	31,00
	75% percentile	120.00	101.00	118.00
Cost of fuels and auxiliaries during start-up in USD per inst. MW		30.00	5.00	2.50
Typical warm start offline hours		12 to 72	5 to 40 (ST different)	2 to 3

Table 7 provides an overview of cost and other cycling related parameters as they are used in this study.

3.5.2 Operation of pumped-storage power plants

Pumped-storage power plants are in pumping operation during times of low electricity tariffs, which is usually at night when the load is low. In the future, with high levels of PV, pumping will be more effective during midday, when Residual Load is at its minimum value.

This study assumes that pumped-storage power plants will pump during times of lowest Residual Load. With no or moderate PV capacity, this will be at night time. In the 2020 and 2030 scenarios, with 10GW and 20GW of rooftop PV respectively, pumping operation is shifted predominantly to midday. Pumping during midday reduces flexibility requirements at the same time, because base load power plants can operate at higher levels (with better efficiency).

3.6 Data Sources

3.6.1 Load

ESKOM provided time series data of the load (resolution: 30mins) from the year 2013, which was up-scaled to meet the predicted peak demand (according to IRP2016-Base-Case [5]) of the years 2020 and 2030.

3.6.2 Wind Generation

CSIR provided time series data of wind speed at hub heights of 80m, 100m and 150m with a resolution of 15mins for a large number of sites of existing wind farms and sites, at which the installation of wind farms could be possible in future (see **Figure 18**).

ESKOM provided a list of prospective wind farm sites and capacities at these sites, which is in-line with the assumptions of the Transmission Development Plan Update 2016 [13].

[2] All costs in this chapter are expressed in USD2011
[3] Council for Scientific and Industrial Research

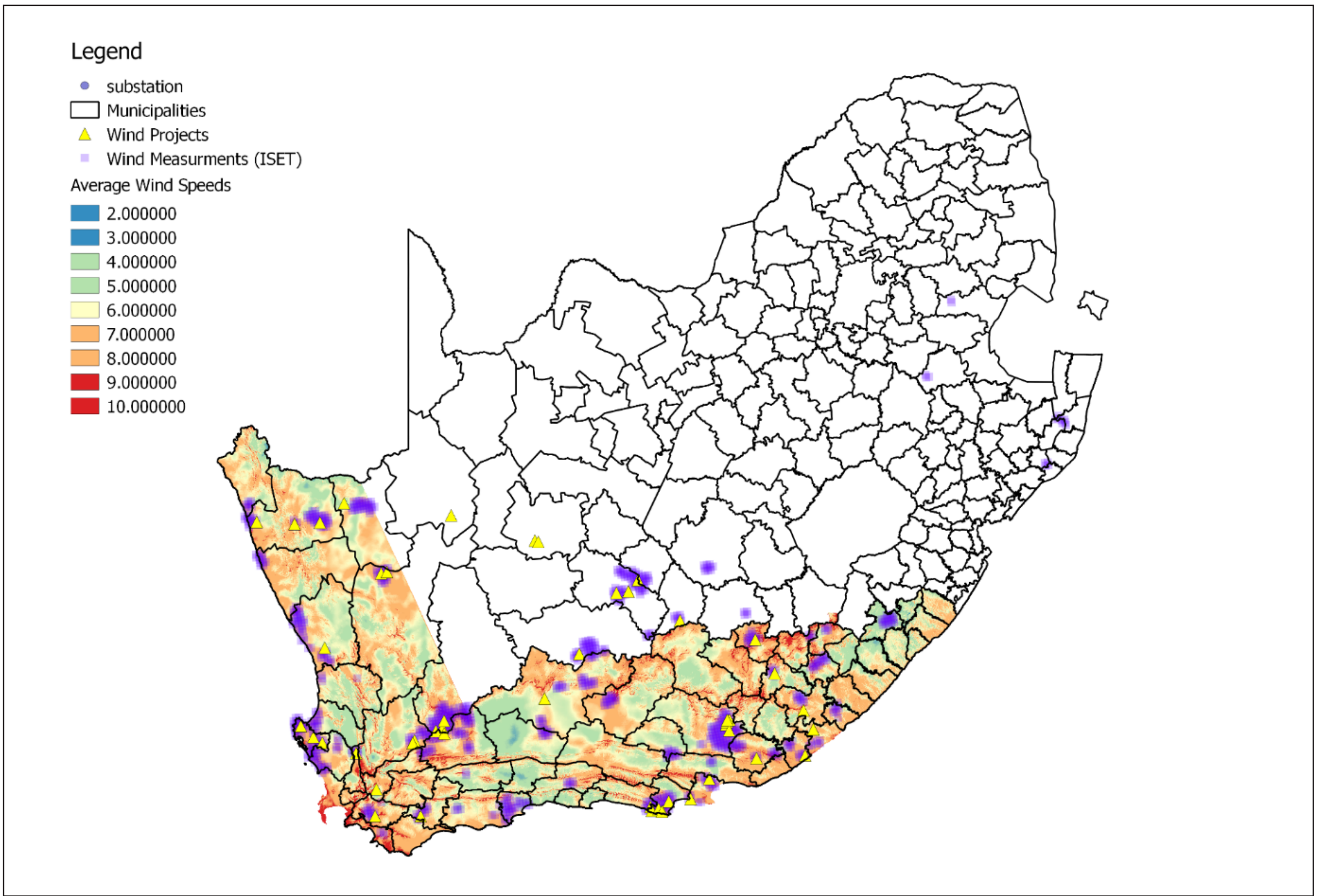

Figure 18: Available wind speed measurements and considered wind farm sites

Figure 18 shows a map of South Africa with locations at which wind speed data was available, and locations at which wind farms have been considered. At sites where no wind speeds were available, time series data of the nearest location have been used, and scaled to the average wind speed at the prospective site.

For each wind farm, a power curve of a typical wind turbine generator (WTG) for the corresponding IEC wind speed class (IEC I, II or III) was selected, and hub heights of either 100m or 120m, depending on average wind speed at the individual site, was chosen (strong wind: lower hub height; weaker wind: higher hub height). For the selection of realistic power curves and hub heights, MPE's experience with the electrical planning of approximately 30 wind farms per year, was called upon.

The wind farm model further considers typical values for park efficiency in function of wind park size (considering wake effects), and adjusts the representative power curve of an individual wind turbine generator for reflecting the power versus wind characteristic of a complete wind farm.

Using these wind farm power curves, time series data of wind generation (in MW) have been calculated for every considered wind farm location with a time resolution of 15 minutes.

3.6.3 Utility-Scale PV Farms

The assumed distribution of utility-based PV farms is in-line with the assumptions of the study "Options for the Allocation of PV in South Africa" [10]. In this study, the impact of allocating PV in South Africa on transmission reinforcements, losses and Levelized Cost of Electricity (LCOE) was analysed.

For this purpose, the study analysed three scenarios for the allocation of utility-scale PV:

- Scenario A: Realistic Scenario: In-line with existing applications and plans of project developers. Allocation of utility-scale PV farms mainly in areas with highest solar irradiation (see **Figure 19**).
- Scenario B: Distributed Scenario: Fewer PV farms in the Northern Cape (only up to the existing transmission capacity in the Northern Cape), the rest is spread over the country and allocated close to load centers (see **Figure 20**).
- Scenario C: PV allocation mainly in Renewable Energy Zones (defined by DEA study).

This study analysis the impact of different PV allocations on flexibility using Scenario A and Scenario B of the PV Allocation Study [10].

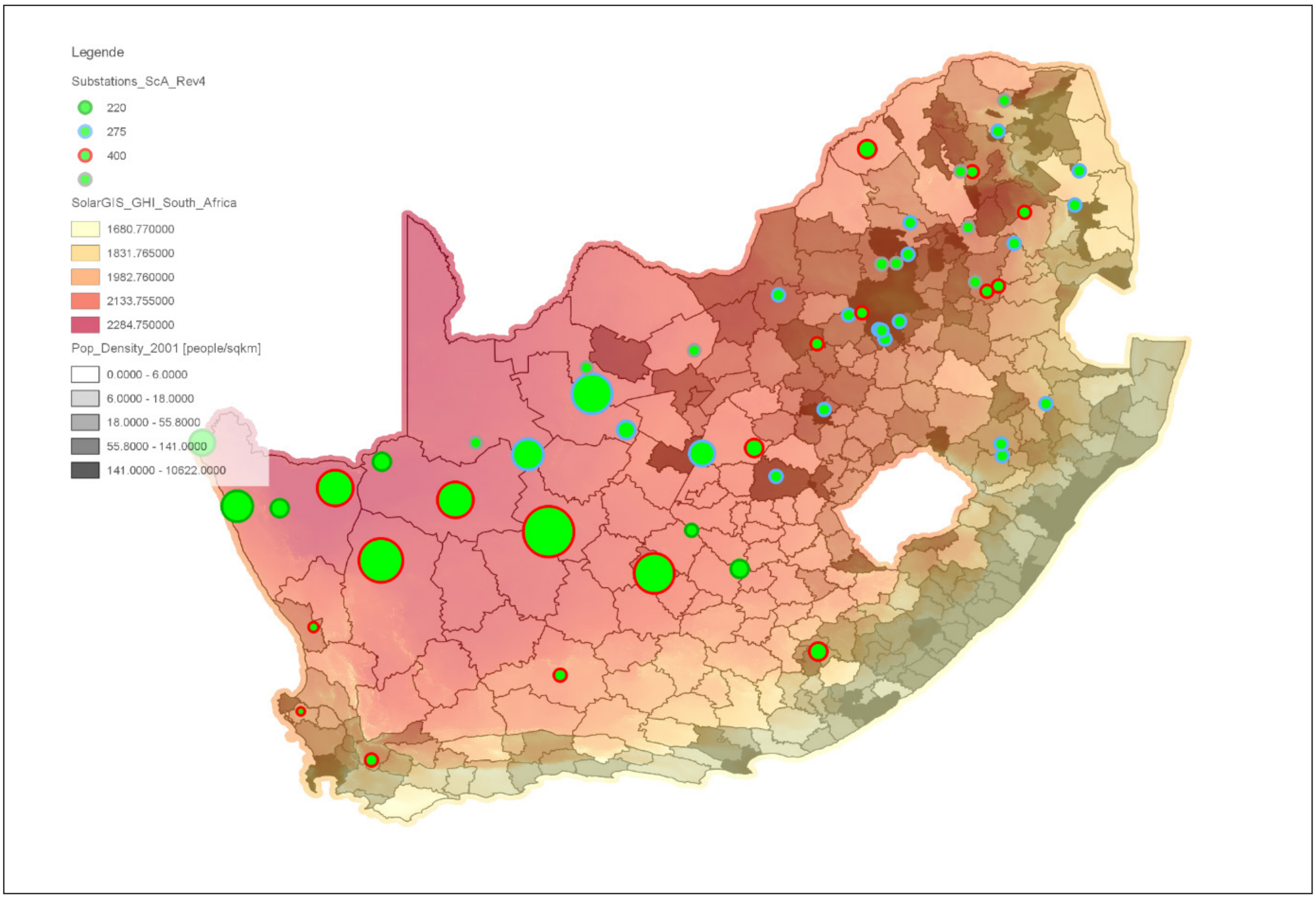

Figure 19: Allocation of PV farms (substation infeeds) according to Scenario A

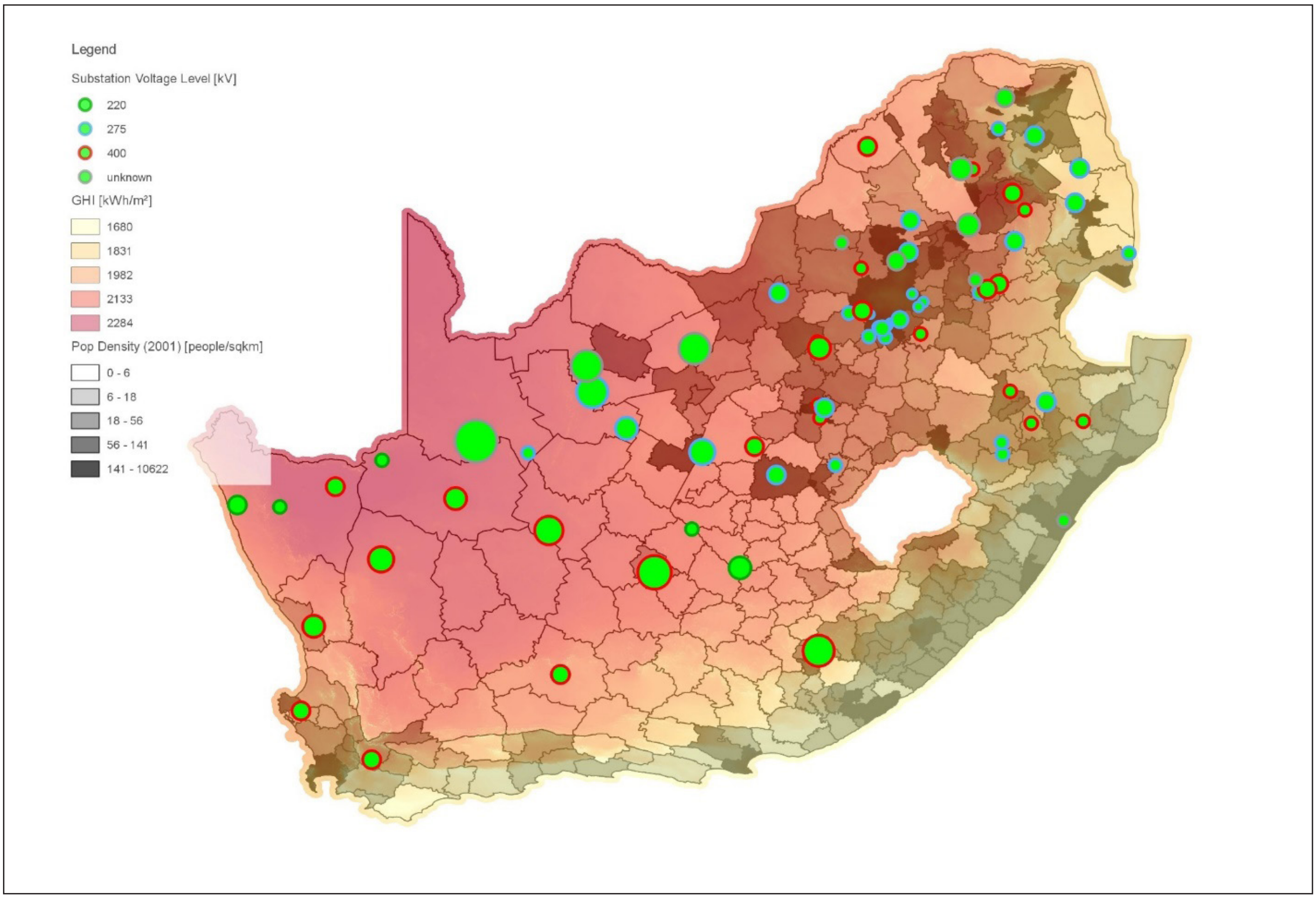

Figure 20: Allocation of PV farms (substation infeeds) according to Scenario B

The study uses time series data of PV generation (calculated on the basis of time series data of solar irradiation, ambient temperature and wind speed, and the characteristics of typical PV modules) at the nearest substation of every PV farm location (SolarGIS[4]-data, resolution: 15 mins). The time series data at every location is then scaled to the total installed PV capacity which is considered to feed into the corresponding substation.

Additional data points with a resolution of 1min have been calculated using a model-based approach that considers the cloud-index and typical cloud patterns of each site and have been inserted for generating time series data with 1min resolution.

The distribution of utility-scale PV farms is visualized by **Figure 19** and **Figure 20**, where substation locations with modelled PV infeeds are highlighted by green circles. The diameter of every circle is in proportion to the considered PV infeed capacity.

For modelling the installed PV capacities according to IRP 2016-Base Case [5] for the years 2020 and 2030, the installed capacity at every substation was scaled so that the total installed utility-scale PV capacity corresponds to the assumptions of IRP-2016-Base Case [5] (see also **section 3.7**).

3.6.4 Rooftop PV

For modelling rooftop PV, a database with time series data of solar irradiation in South Africa (resolution 50kmx50km), and a time resolution of 30mins, has been used.

Additional data points with a resolution of 1min have been calculated using a model-based approach that considers typical cloud patterns and have been inserted for generating time series data with 1min resolution.

The distribution of rooftop PV was modelled to be in proportion to the population density (see **Figure 21**) and the solar irradiation. For this purpose, a population density index, and a solar irradiation index were calculated. Rooftop PV was considered to be allocated in proportion to the product of both indices. Different scenarios with regard to the total installed rooftop PV capacity have been modelled by scaling all considered rooftop PV installations up and down equally, so that the specific distribution of rooftop PV across South Africa is the same in all scenarios.

3.6.5 Conventional Generators

The study uses models of all existing power plants in South

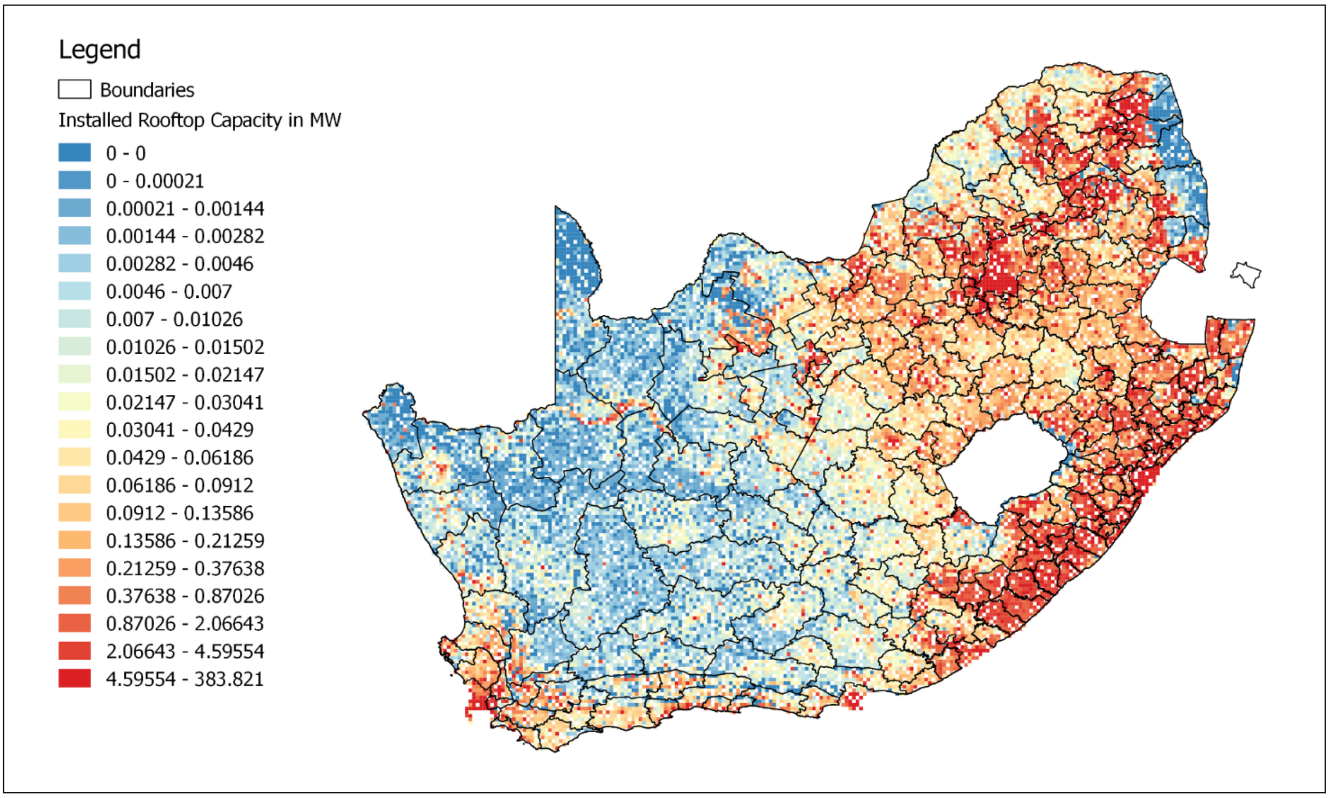

Figure 21: Distribution of rooftop PV in South Africa (assumption of this study)

[4] SOLARGIS: http://solargis.com/

Africa, and all power plants foreseen by the IRP2016 base-case [5], for the years 2020 and 2030 (see also **section 3.6.5**). This includes all coal-fired power stations, nuclear, CCGT, OCGT, hydro and pumped storage power plants.

3.7 Scenarios

The scenarios, which are subject to the analysis, are based on the following assumptions:

- Spot Years: 2020 and 2030
- System expansion (peak demand, conventional generation capacity, installed wind generation capacity, installed utility-scale PV capacity): according to the IRP2016-Base-Case scenario [5]
- Additional rooftop PV (installed capacities):
  - Year 2020: +0GW, +5GW, +10GW
  - Year 2030: +0GW, +10GW, +20GW
- Allocation pattern of wind generation: according to the TDP2016 update [13]
- Allocation pattern of utility-scale PV: Scenario A and Scenario B according to [10] (see also **Figure 19** and **Figure 20**).

A total of six scenarios is defined for each of the two spot years (2020 and 2030). The maximum installed VRE capacity is 27.5GW of PV, and 11GW of wind in 2030.

More detailed information about load and installed generation capacity are shown in **Figure 22** and **Table 8**.

Table 8: Installed Capacity in 2016 and assumed capacities in 2020 and 2030

Spot Year:	2016	2020	2030
Power Station	**Installed Capacity in MW**		
Nuclear	1840	1840	1840
Non Eskom	2800	2800	2800
Hydro Import	1440	1440	1440
Coal	37865	45085	39805
CCGT	0	0	7320
Hydro	600	600	600
Pumped Storage	2068	2736	2736
Demand Response	0	0	1000
OCGT	3800	3800	8439
Total non VRE	**50413**	**58301**	**65980**
Wind	1100	4200	11100
utility-scale PV	1200	2800	7400
Total	**52713**	**65301**	**84480**

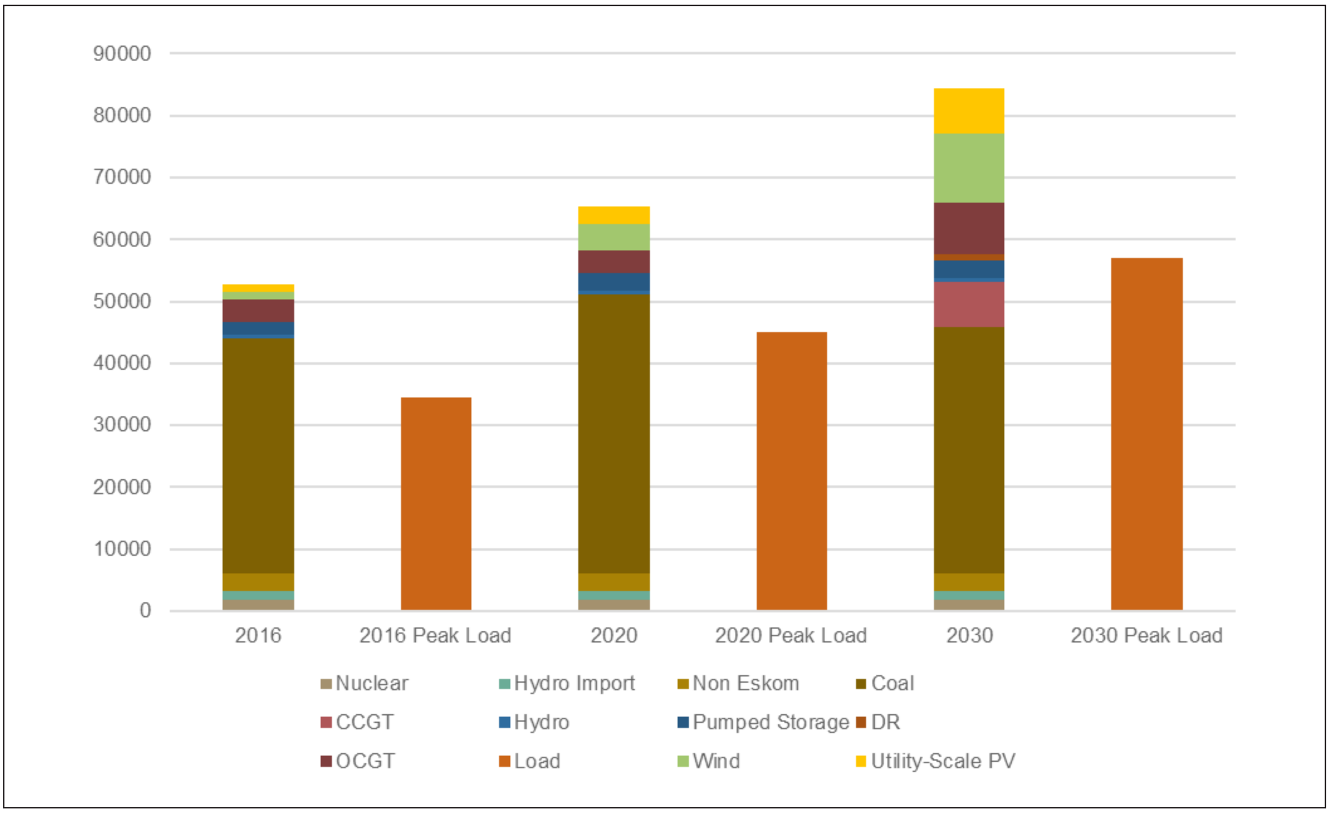

Figure 22: Installed Capacity in 2016 and assumed capacities in 2020 and 2030

Duration curves of utility-scale PV, rooftop PV and wind generation for spot years 2020 and 2030 (and 5GW/10GW/20GW of rooftop PV) are depicted in **Figure 23**, **Figure 24** and **Figure 25**.

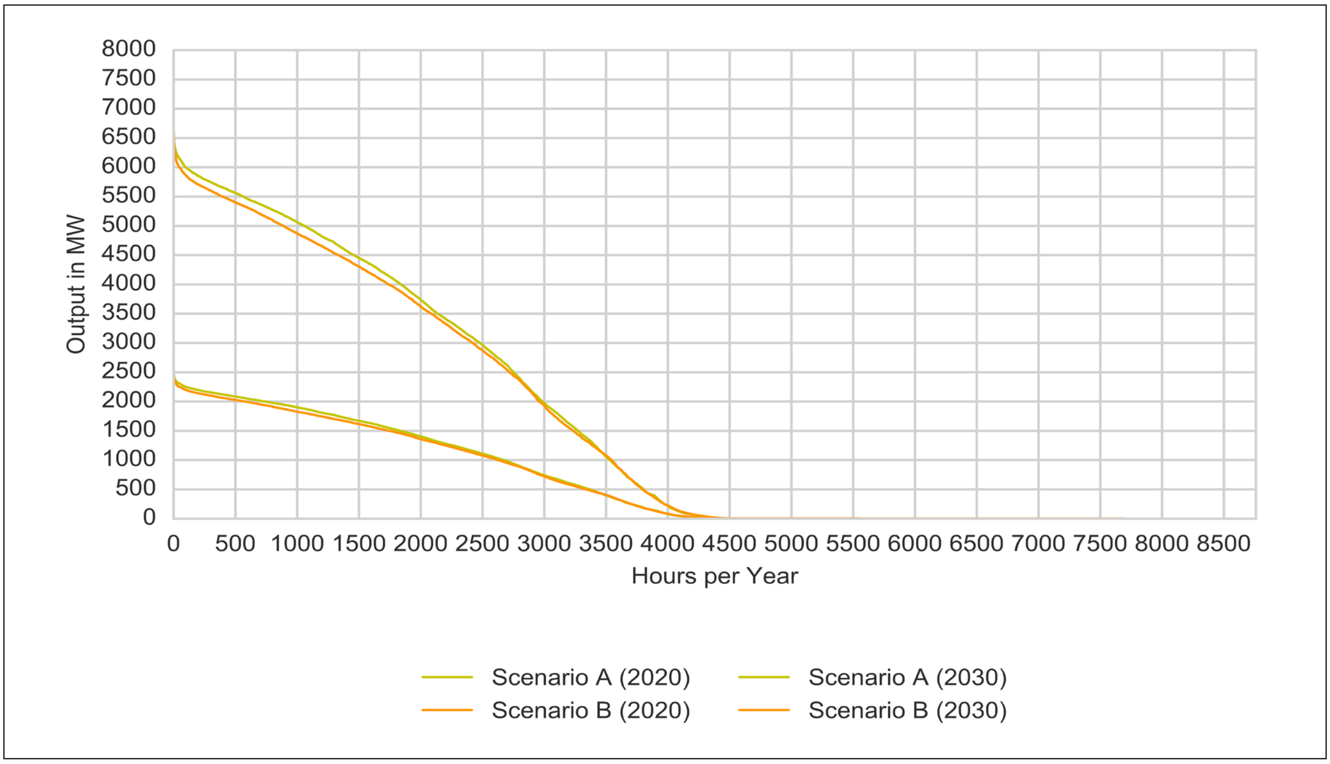

Figure 23: Duration curves of utility-scale PV generation

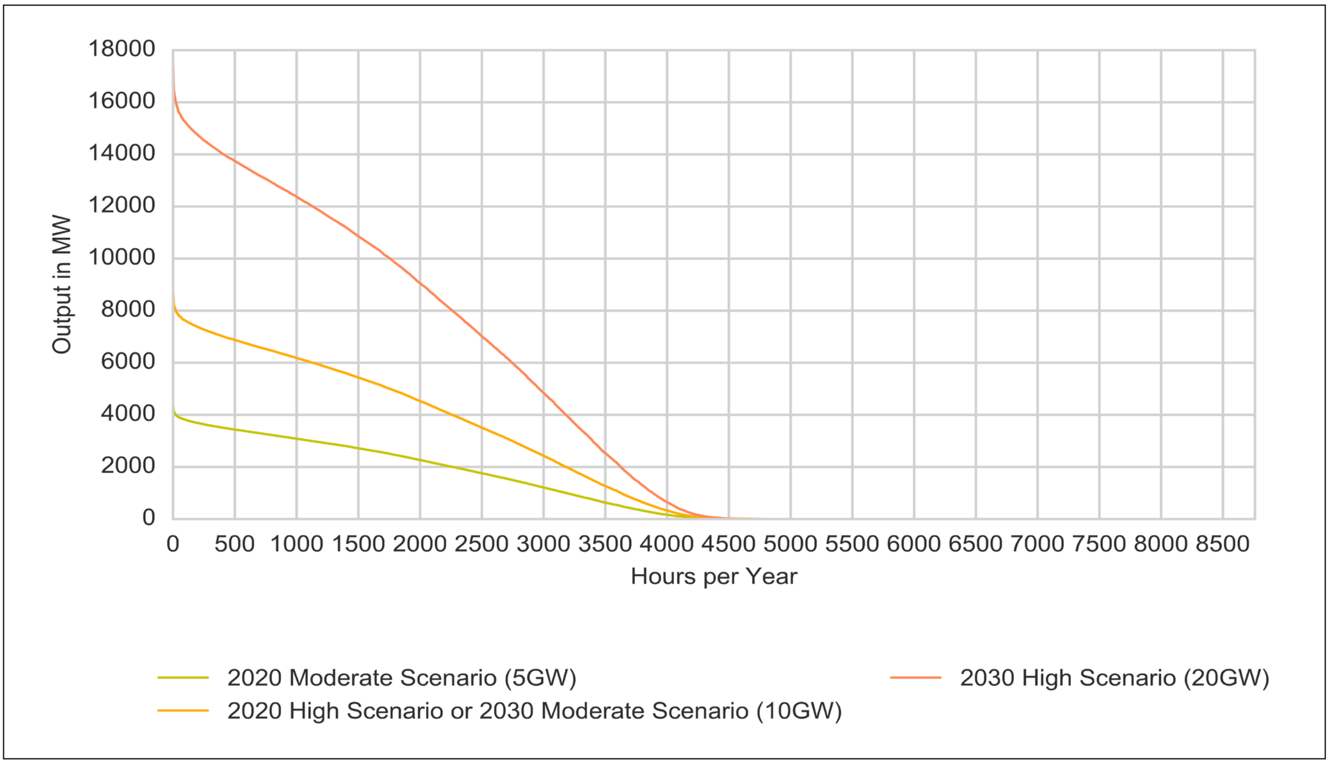

Figure 24: Duration curves of rooftop PV generation

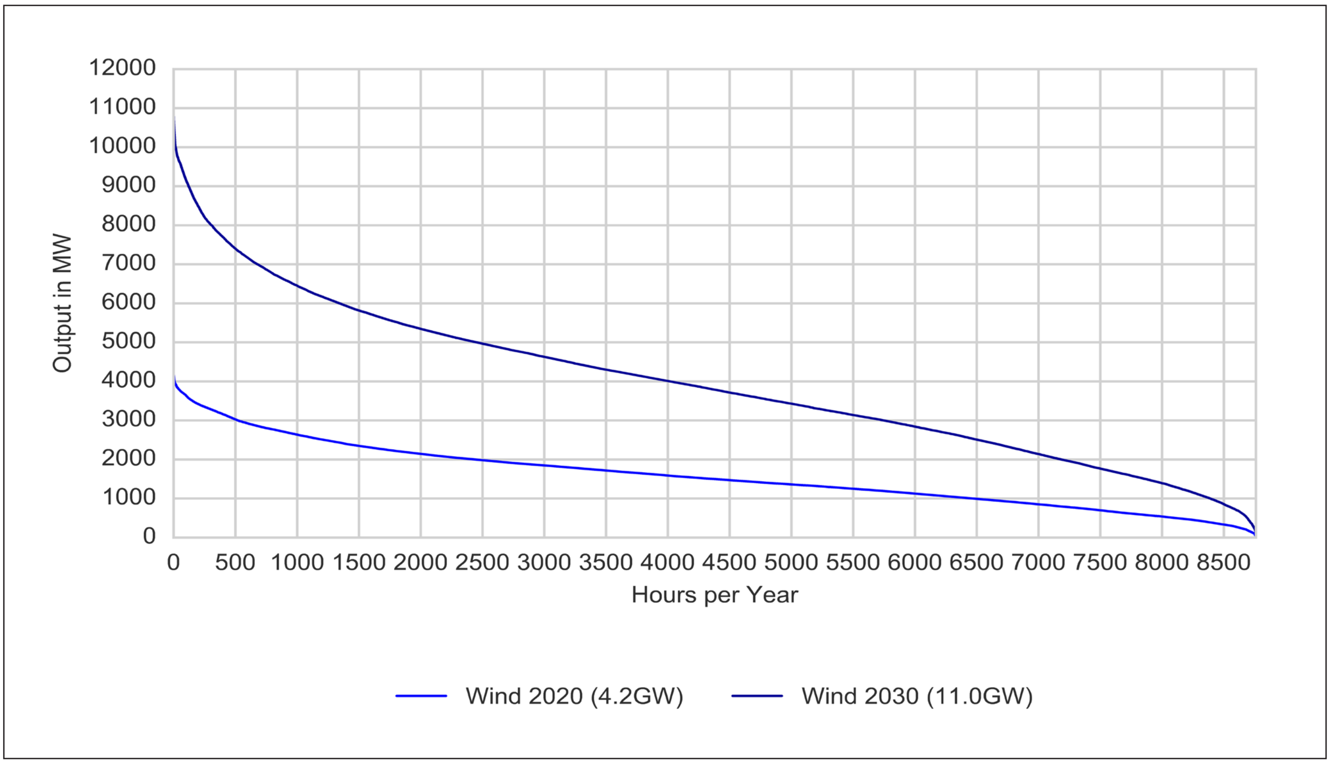

Figure 25: Duration curves of wind generation

4 Results

4.1 Impact on Balancing Power

4.1.1 Imbalance

4.1.1.1 Year 2020

As explained in **section 3.3** and **section 3.4**, Imbalance is calculated based on the day-ahead prediction error of load, wind generation and solar generation. In actual system operations in South Africa, the day-ahead prediction error will partly be compensated by intra-day dispatch, Supplemental Reserve and Operating Reserve. The required amount of each type of reserve will depend on the accuracy of the day-ahead prediction error, which varies in function of load, wind speed and solar irradiation.

In this study, the day-ahead prediction error of load, wind generation, utility-scale PV and rooftop PV is assessed for every hour of the year. The methodology of this study (see also **section 3.4**) considers all diurnal and seasonal correlation effects, and takes the stochastic nature of prediction errors fully into account.

Figure 26 shows 90%, 95%, 99% confidence levels and the worst-case of the day-ahead prediction error of the Residual Load ("Imbalance Requirement"). Due to the integration of wind and utility-scale PV (Scenario A and Scenario B), the Imbalance Requirement increases by around 9% (based on 99% confidence levels).

When integrating up to 10GW of rooftop PV additionally, the impact on the Imbalance Requirement increases by another 3% (13% higher than without VRE).

The contribution of load, wind generation, utility-scale PV and rooftop PV to the overall day-ahead prediction error (Imbalance Requirement) for the year 2020 is depicted in **Figure 27**. This figure shows that the wind prediction error is contributing the most to the day-ahead prediction error. The impact of utility-scale PV and additional rooftop PV is rather small because the day-ahead prediction error of PV is considerably smaller than wind prediction errors. This figure also shows that the impact of the individual prediction errors (utility-scale PV, rooftop PV and wind) is considerably less than the sum of the individual predictions errors. This is because of natural averaging effects, i.e. worst-case wind,

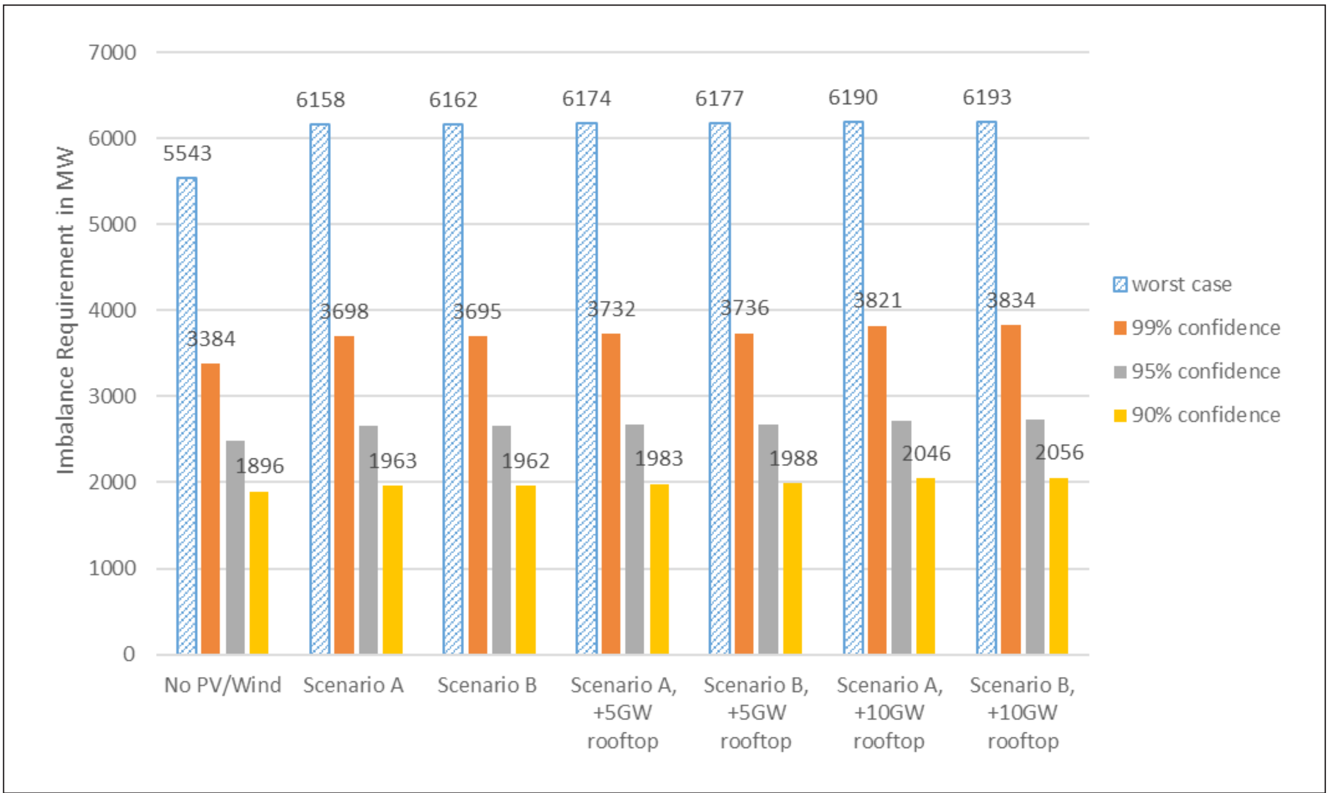

Figure 26: Imbalance Requirement, all scenarios, 2020

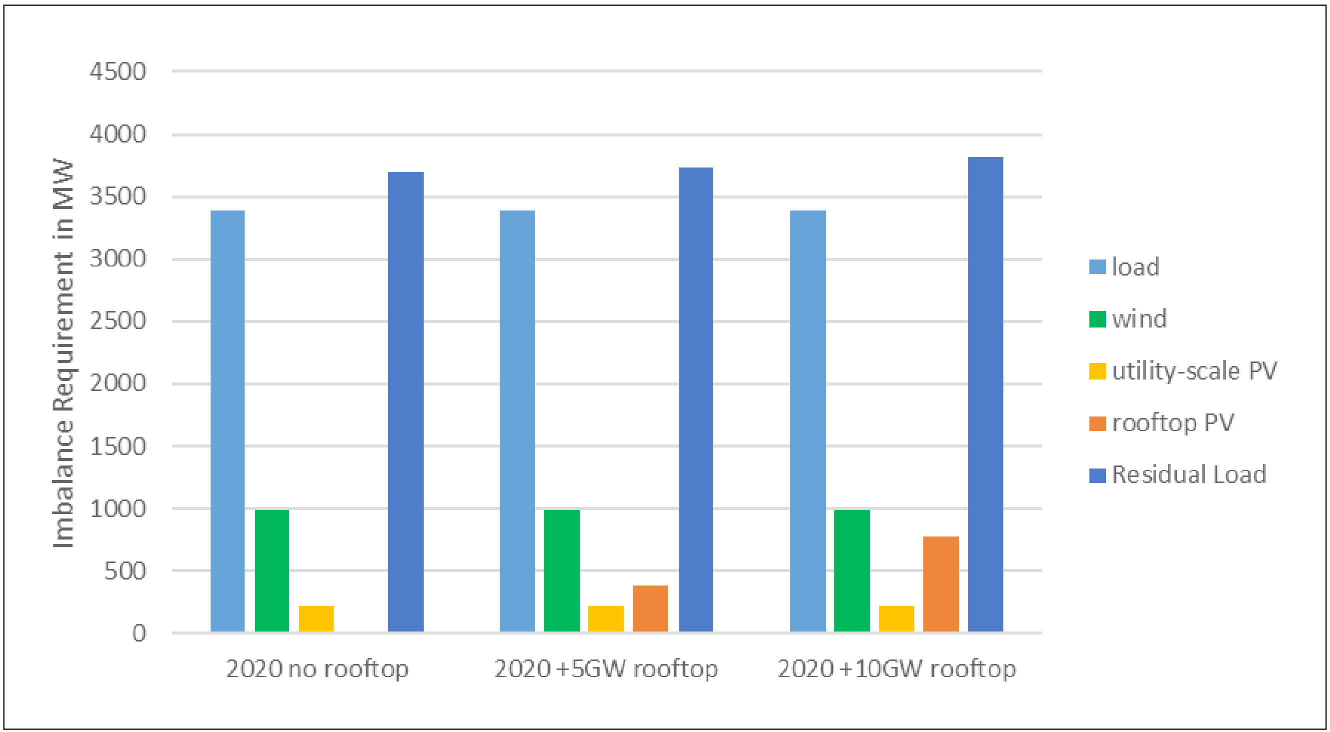

Figure 27: Imbalance Requirement, Scenario A plus rooftop PV, 2020 (99% percentile)

utility-scale PV, rooftop-PV prediction errors and worst-case load prediction errors do not occur simultaneously.

Differences between Scenario A and Scenario B (different allocation scenarios for utility-scale PV) are very low in all cases.

4.1.1.2 Year 2030

The Imbalance Requirement for the year 2030 is depicted in **Figure 28**. In 2030, absolute levels of day-ahead prediction errors increase considerably because of the assumed load growth.

The addition of utility-scale wind and PV farms according to IRP2016-Base Case (year 2030) lead to an increased Imbalance Requirement of around 26%. The addition of up to 20GW of rooftop PV leads to a further increase of the Imbalance Requirement of around 7%. The overall impact of 11GW of wind and 27,5GW of PV is in a range of 35% (compared to zero VRE).

The contribution of day-ahead prediction errors of load, wind generation and PV generation to the overall day-ahead prediction error (Imbalance Requirement) is depicted in **Figure 29**. Wind generation once again has the largest impact on the day-ahead prediction error.

4.1.2 Operating Reserve

4.1.2.1 Year 2020

For determining the additional amount of Operating Reserve (Regulation and 10-Minute Reserve), which is required for compensating the variability of wind and PV within shorter time frames (up to one hour), the maximum deviation of the instantaneous value of the Residual Load and the corresponding 1-hour average is analysed.

This approach assumes that variations, which are faster than a dispatch cycle of 1 hour can only be compensated by Operating Reserve.

Based on 99% percentiles, the required Operating Reserve increases by only 2% due to the integration of wind generation and utility-scale PV generation and increases by another 10,5% due to the addition of up to 10GW of rooftop PV. In the scenario with 10GW of rooftop PV, the required

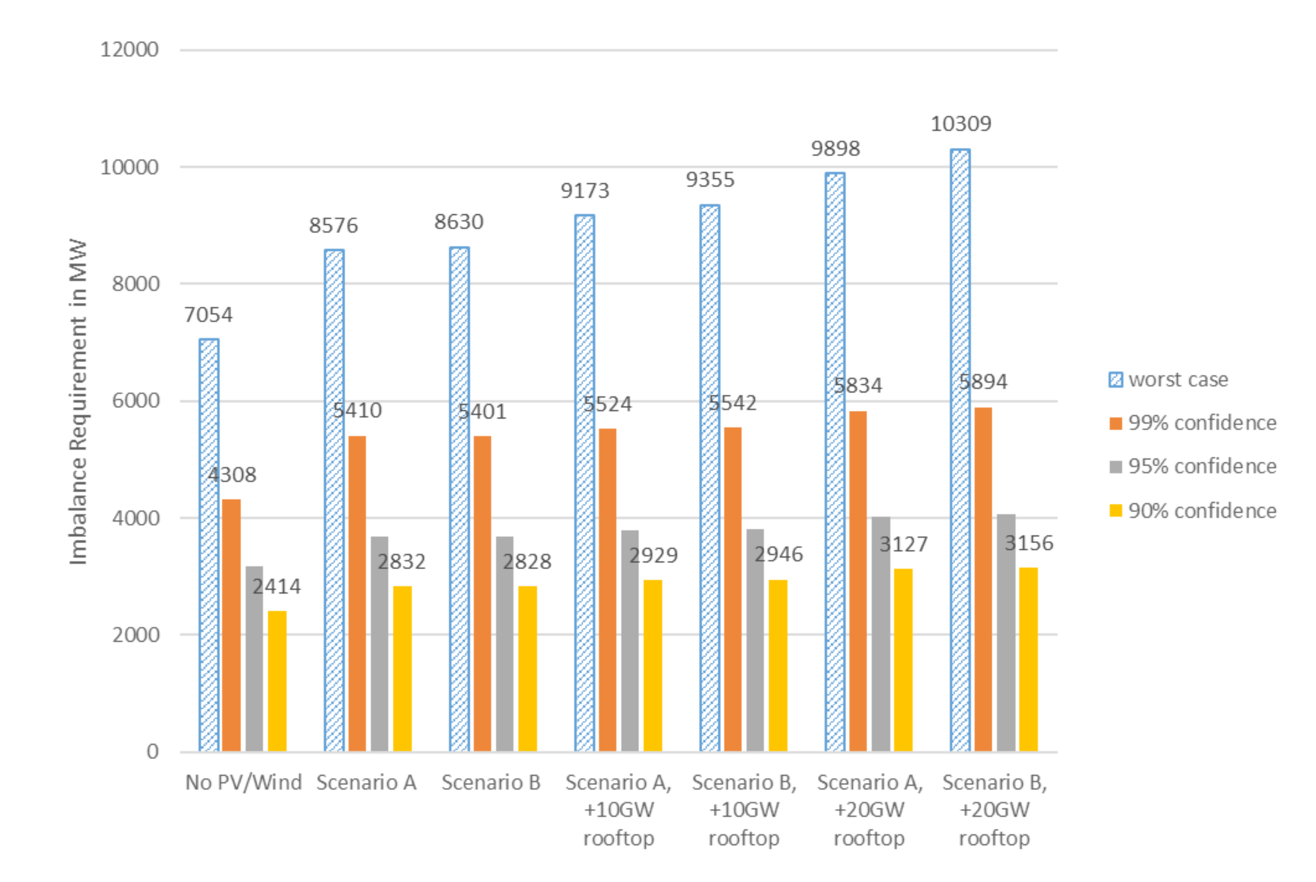

Figure 28: Imbalance Requirement, all scenarios, 2030

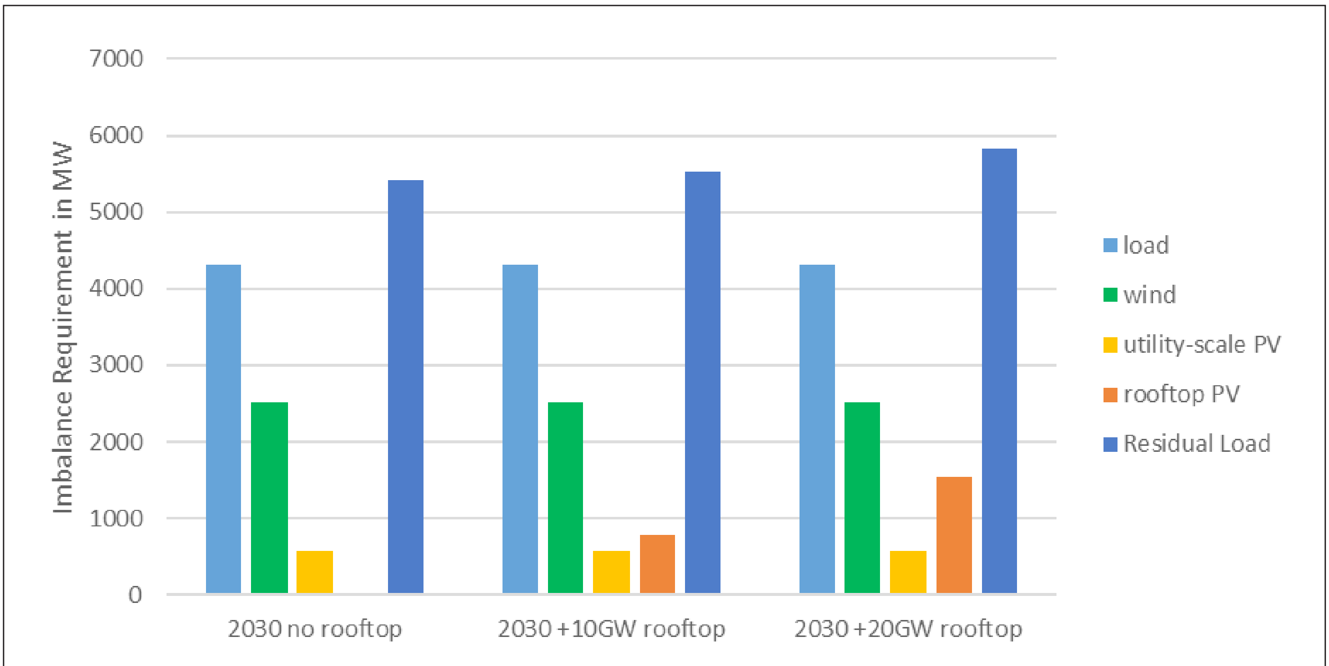

Figure 29: Imbalance Requirement, Scenario A plus rooftop PV, 2030 (99% percentile)

operating reserve is 13% higher than in case of no VRE (see **Figure 30**).

In contrast to Imbalance, the required Operating Reserve is mainly influenced by PV because short-term variations of wind are relatively small and stochastically uncorrelated between different wind farms, whereas short-term variations of solar irradiation of PV farms at different sites have a large correlation (due to the movement of the sun). This is confirmed by the results according to **Figure 30**, in

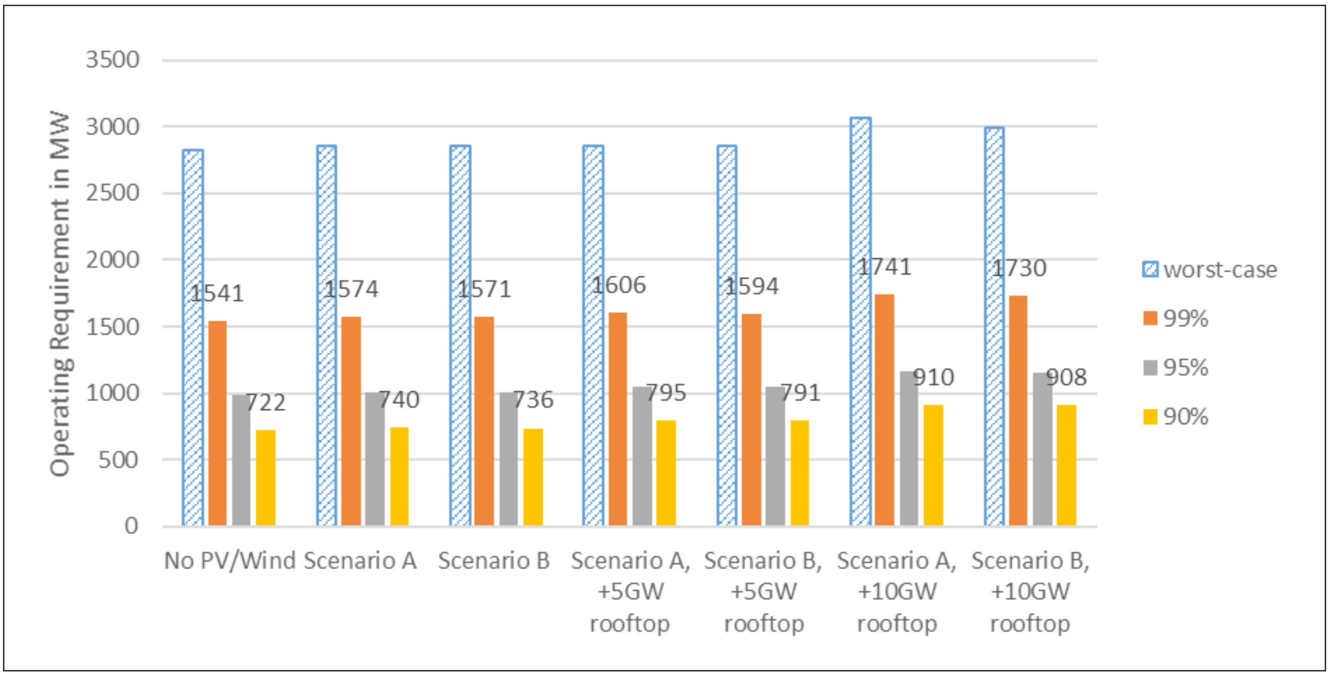

Figure 30: Operating Requirement, all scenarios, 2020

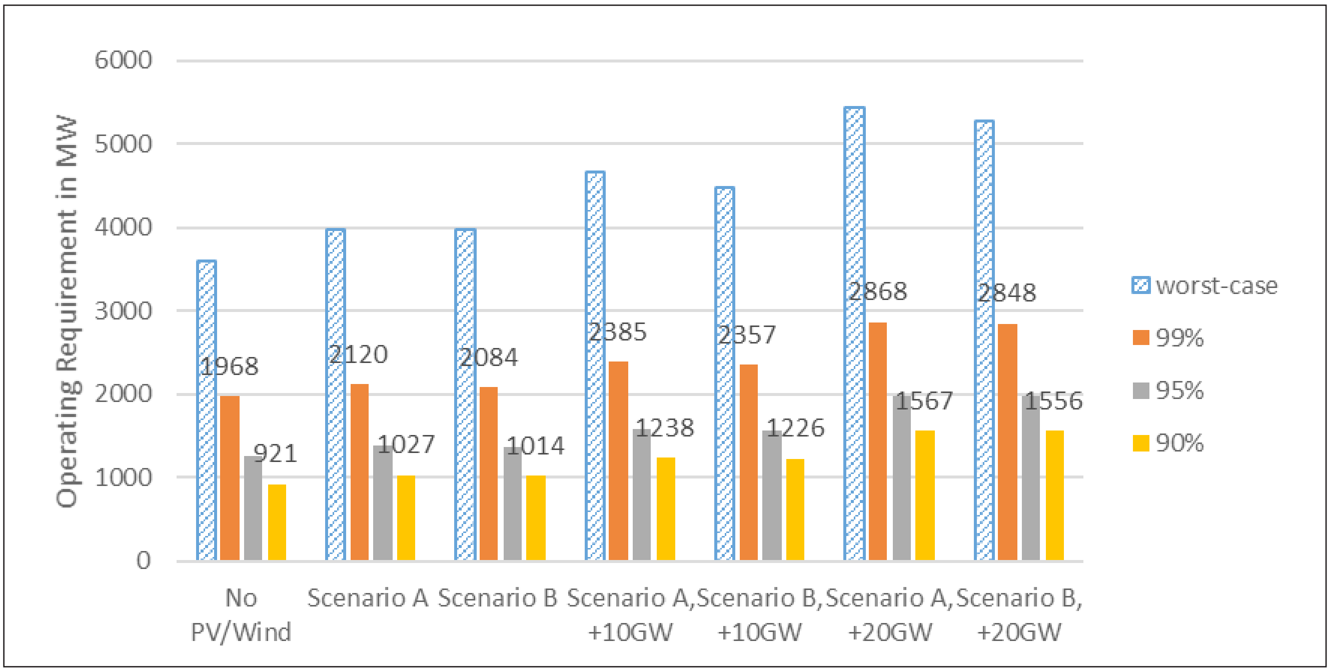

Figure 31: Operating Requirement, all scenarios, 2030

which the difference between Scenario A (no rooftop PV) and the case without any VRE is very small, whereas Operating Requirements considerably increase with increased levels of PV.

4.1.2.2 Year 2030

In 2030, Operating Requirements increase by around 8% due to the addition of wind and utility-scale PV as per IRP-2016-Base Case [5] (see **Figure 31**).

With the addition of rooftop PV (up to 30GW) this value further increases by 35% (compared to the corresponding scenarios with utility-scale PV but without rooftop PV) and is 46% higher than in a scenario without any wind or PV generation.

4.1.3 Regulating Reserve

4.1.3.1 Year 2020

For determining the additional amount of Regulating Reserve, which is the fast part of the overall Operating Reserve and which is required for compensating the variability of wind and PV within short time frames (up to 10 minutes), the maximum deviation of the instantaneous value of the Residual Load and the corresponding 10-minute-average is evaluated.

This approach assumes that variations, which are faster than 10 minutes, can only be compensated by Regulating Reserve, and that slower variations will be balanced using 10-Minute Reserve.

As shown in **Figure 32**, the impact of VRE on Regulating Reserve is very small. For Scenario A, Regulating Reserve, which is required because variability only increases by 3% or 14MW compared to a scenario without any VRE.

The addition of up to 10GW of rooftop PV requires a further

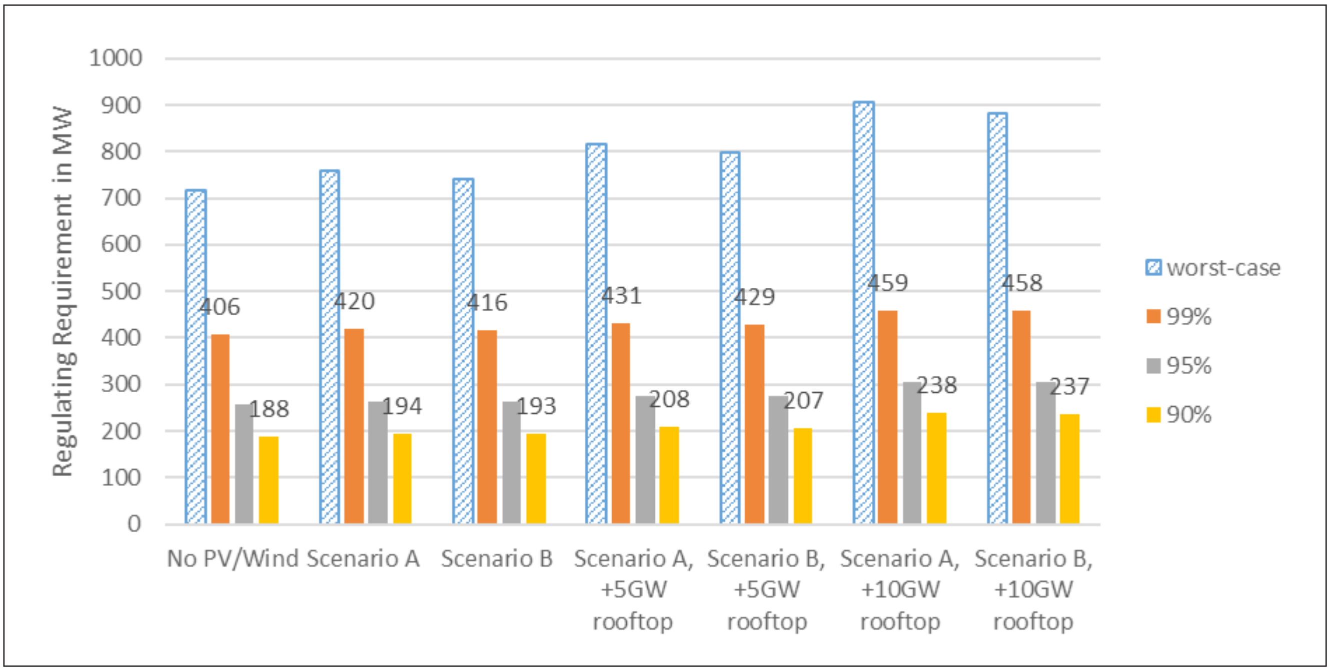

Figure 32: Regulating Requirement, all scenarios, 2020

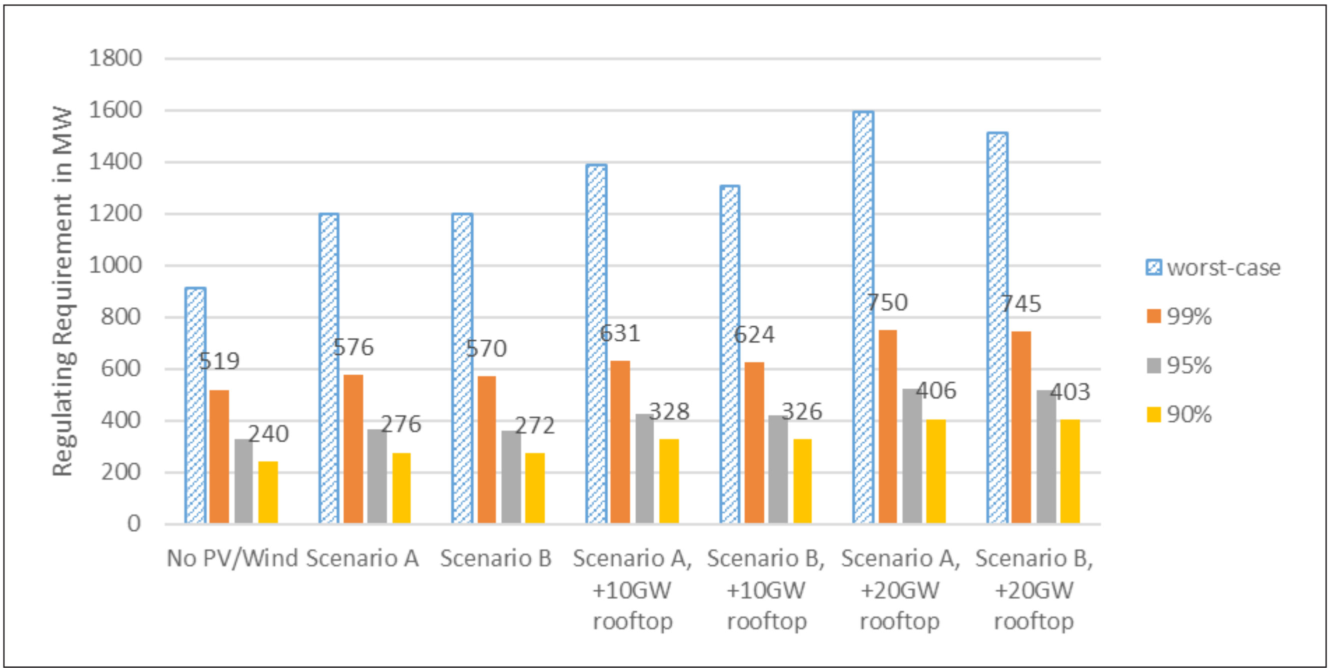

Figure 33: Regulating Requirement, all scenarios, 2030

increase of Regulating Reserve of 10% (113% increase in total).

The value of 420MW for 2020 is very much in-line with the corresponding value according to the ESKOM study [6]. However, according to the System Operation Code [1], Regulating Reserve is also required for restoring Instantaneous Reserve. Because Instantaneous Reserve should be sufficiently large for backing up the largest single outage (800MW according to [6]), Regulating Reserve would have to be at least equal to the value of Instantaneous Reserve.

4.1.3.2 Year 2030

In the year 2030, the Regulating Requirement goes up from 406MW to 519MW due to load growth (without VRE). The addition of wind and PV generation according to IRP-2016-Base Case causes the Regulating Requirement to increase by 11% (see **Figure 33**). The integration of up to 20GW of additional rooftop PV lets the Regulation Requirement increase by another 29% (43% higher than without VRE).

4.1.4 Balancing Power – Summary

4.1.4.1 Year 2020

Table 9 summarizes the percentage increase of Imbalance, total Operating Reserve and Regulating Reserve due to increased variability introduced by VRE.

As this table shows, Imbalance Requirements increase by around 9% due to the addition of wind and utility-scale PV. The addition of rooftop PV leads to a relatively small further increase of the day-ahead prediction error (Imbalance Requirement) of around 4%.

The required Operating Reserve only increase by 2% due to the addition of wind and utility-scale PV in 2020. Additional installation of rooftop PV increases Operating and Regulating Requirements up to 113% (compared to the case without VRE).

Table 9: Impact of VRE on required Balancing Power (based on 99% percentiles, 2020)

Scenario	Imbalance	Operating	Regulating
No PV/Wind	100,00%	100%	100%
Scenario A	109,28%	102%	103%
Scenario B	109,19%	102%	102%
Scenario A, +5GW rooftop	110,28%	104%	106%
Scenario B, +5GW rooftop	110,40%	103%	106%
Scenario A, +10GW rooftop	112,91%	113%	113%
Scenario B, +10GW rooftop	113,30%	112%	113%

The figures according to **Table 9** only consider those components of the required balancing power, which are required for balancing the variability of load, wind and PV generation, but not those components, which are required for compensating worst-case contingencies, for example, the outage of one or several large generating units.

When applying the overall methodology for calculating the required amount of Operating Reserve considering the impact of variability and contingencies (see also **section 3.3.3**) we come to the conclusions that by 2020, Operating Reserve required for balancing worst-case contingencies is higher than Operating Reserve required for balancing variability (see **Table 10**). This is even true for all scenarios, even the scenario with 10GW of additional rooftop PV.

Thus, VRE has no impact on Operating Reserve in any of the scenarios studied for 2020.

Table 10: Impact of VRE on Operating Reserve (based on 99% percentiles, 2020)

Scenario	Operating in MW		Instantaneous in MW	Regulating in MW	10-Minute in MW
	variability	contingency			
No PV/Wind	1541	2166	800	406	960
Scenario A	1574	2166	800	420	946
Scenario B	1571	2166	800	416	950
Scenario A, +5GW rooftop	1606	2166	800	431	935
Scenario B, +5GW rooftop	1594	2166	800	429	937
Scenario A, +10GW rooftop	1741	2166	800	459	907
Scenario B, +10GW rooftop	1730	2166	800	458	908

This also means that the amount of Operating Reserve identified by ESKOM for the period until 2021/2022 [6] does not have to be increased until 2020, even if up to 10GW of rooftop PV will be added to the system.

The analysis according to **Table 9** and **Table 10** was based on 99% percentiles of the required Operating Reserve.

To compensate worst-case variations, which occur during less than 1% of all times (less than 87,6 hours per year), Emergency Reserve should be used.

Table 11 calculates the Emergency Reserve which would be required for balancing worst-case variability. As this **Table 11** shows, the resulting values are all below 900MW, which is the Emergency Reserve allocated by ESKOM for 2020 [6] (based on worst-case contingencies).

Table 11: Emergency Reserve, 2020

Scenario	Operating Requirement in MW, 100%	Required Emergency Reserve in MW
No PV/Wind	2823	657
Scenario A	2853	687
Scenario B	2853	687
Scenario A, +5GW rooftop	2853	687
Scenario B, +5GW rooftop	2853	687
Scenario A, +10GW rooftop	3064	898
Scenario B, +10GW rooftop	2997	831

These results confirm that the allocated amount of Emergency Reserve is sufficient for balancing increased variability caused by the addition of 4,2GW of wind and up to 12,8GW of solar PV generation by 2020.

4.1.4.2 Year 2030

Table 12 summarises the impact of VRE on Imbalance, Operating and Regulating requirements for all scenarios studied for 2030 (11GW of wind and up to 27,5GW of PV).

As shown by the results of this table, Imbalance resulting from day-ahead prediction errors increases by around 25% due to the integration of 11GW of wind and 7,5GW of utility-scale PV. When adding 20GW of rooftop PV (27,5GW of PV in total), Imbalance would increase by another 9% (137% compared to the case without wind/PV).

The Operating Reserve required for balancing short-term variability would increase by around 8% due to the addition of 11GW of wind and 7,5GW of utility-scale PV and by another 35% due to the addition of 20GW of rooftop PV (145% compared to the case without wind/PV).

Table 12: Impact of VRE on required Balancing Power (based on 99% percentiles, 2030)

Scenario	Imbalance	Operating	Regulating
No PV/Wind	100,00%	100%	100%
Scenario A	125,58%	108%	111%
Scenario B	125,37%	106%	110%
Scenario A, +10GW rooftop	128,23%	121%	122%
Scenario B, +10GW rooftop	128,64%	120%	120%
Scenario A, +20GW rooftop	135,42%	146%	145%
Scenario B, +20GW rooftop	136,82%	145%	144%

Based on the assumption that worst-case contingencies remain the same in 2030, as in 2020, the impact of VRE on Operating Reserve is summarized in **Table 13**.

As shown by the results according to **Table 13**, Operating Reserve does not have to be increased due to the addition of 11GW of wind and 7,5GW of utility-scale PV by 2030 (IRP2016 scenarios, Scenario A and Scenario B, see **Table 13**), compared to the values allocated for 2020 (and until 2021/2022 according to [6]).

However, when adding 10GW or 20GW of rooftop PV, Operating Reserve required for balancing variability will exceed the values required for balancing worst-case contingencies. With the addition of 20GW of rooftop PV, a total of 2868MW of Operating Reserve would be required for balancing short-term variability, which is around 30% higher than without additional rooftop PV (see **Table 13**).

However, as the box-diagram of **Figure 34** shows, the amount of required Operating Reserve would not have to be maintained permanently but only during very few hours per day. Consequently, an allocation strategy for Operating Reserve could foresee a value of 2200MW permanently (for compensating worst-case contingencies) and an increased operating reserve of 2900MW between 3:00 p.m. and 6:00 p.m.

Another option for reducing Operating Reserve Requirements resulting from short-term variability of PV is to reduce the dispatch cycle, e.g. from 1 hour to 15 minutes. With a reduced dispatch cycle, short-term variations of PV are substantially less and can be considered by the day-ahead dispatch. However, because there is only a relatively small increase of Operating Reserve Requirements in the studied

Table 13: Impact of VRE on Operating Reserve (based on 99% percentiles, 2030)

Scenario	Operating in MW		Instantaneous in MW	Regulating in MW	10-Minute in MW
	variability	contingency			
No PV/Wind	1968	2166	800	519	847
Scenario A	2120	2166	800	576	790
Scenario B	2084	2166	800	570	796
Scenario A, +10GW rooftop	2385	2166	800	631	954
Scenario B, +10GW rooftop	2357	2166	800	624	933
Scenario A, +20GW rooftop	2868	2166	800	750	1318
Scenario B, +20GW rooftop	2848	2166	800	745	1303

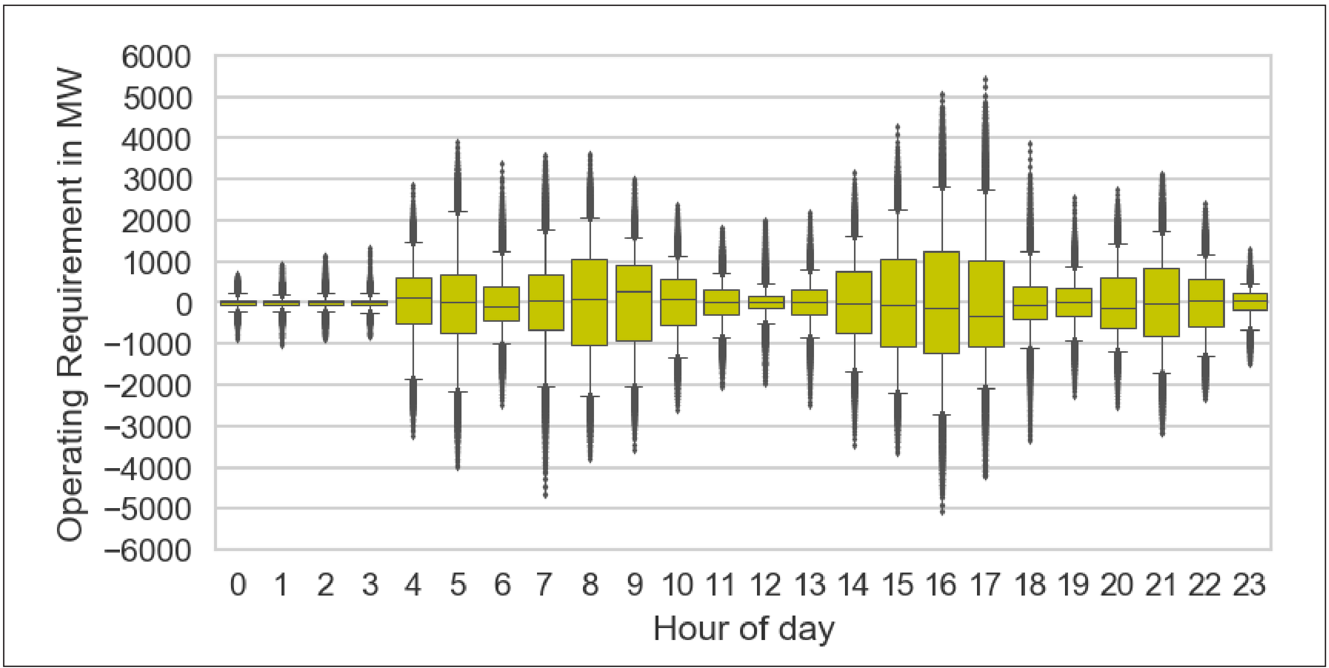

Figure 34: Required Operating Reserve in function of the hour per day, 2030, Scenario A+20GW rooftop PV[5]

scenarios, it is not recommended to enact such a severe change to the operational planning concepts currently employed.

The required amount of Emergency Reserve, which would be required for balancing worst-case short-term variability events (having a probability of less than 1%) are depicted in **Table 14**. As the results of this table show, even without VRE, Emergency Reserve would have to be increased compared to 2020.

The addition of 11GW of wind generation and 7,5GW of utility-scale PV would require 27% of additional Emergency Reserve.

The addition of 20GW of rooftop PV would be required to increase Emergency Reserve by another 42% (180% of the value required without VRE, see **Table 14**).

However, as in the case of Operating Reserve, this increased amount of Emergency Reserve would only be required for a very few hours per day. Therefore, as in the case of Operating Reserve, we recommend allocating varying amounts of Emergency Reserve during the day.

[5] The Boxplot-diagram is in-line with the standard definition (see e.g. https://en.wikipedia.org/wiki/Box_plot). The lower and upper boundary of the box represent 25% and 75% percentiles (enclosing 50% of all cases). The line in the middle of the box represents the median. The “Whiskers” represent 5% and 95% percentiles (enclosing 90% of all cases).

Table 14: Impact of VRE on Emergency Reserve, 2030

Scenario	Operating Requirement in MW, 100%	Required Emergency Reserve in MW	Required Emergency Reserve in % of "No PV/ Wind"
No PV/Wind	3599	1433	100%
Scenario A	3983	1817	127%
Scenario B	3983	1817	127%
Scenario A, +10GW rooftop	4663	2278	159%
Scenario B, +10GW rooftop	4484	2127	148%
Scenario A, +20GW rooftop	5445	2577	180%
Scenario B, +20GW rooftop	5266	2418	169%

4.2 Impact on Cycling

4.2.1 Cycling Requirements - Residual Load Assessment

4.2.1.1 Year 2020

The impact of increased levels of VRE on the Residual Load duration curve is depicted in **Figure 35**. The load duration curve of **Figure 35** is for the year 2020 with 10GW of additional rooftop PV (total of 12,8GW of PV and 4,2GW of wind).

As this diagram shows, peak load remains (almost) unchanged, while minimum load is substantially reduced.

The impact of VRE on the load factor (of the Residual Load) is depicted in **Figure 36**. As shown by **Figure 36**, the load factor (ratio between average load and peak load) decreases with increasing PV installations, as it is expected because PV reduces the Residual Load during mid-day while the evening peak remains at the same level as without PV.

Figure 37 shows minimum load and peak load for every scenario analyzed for 2020. The reduction in minimum Residual Load, caused by increased levels of VRE, means that more and more mid-merit and peaking plants and less base load power plants will be required with increasing levels of VRE,

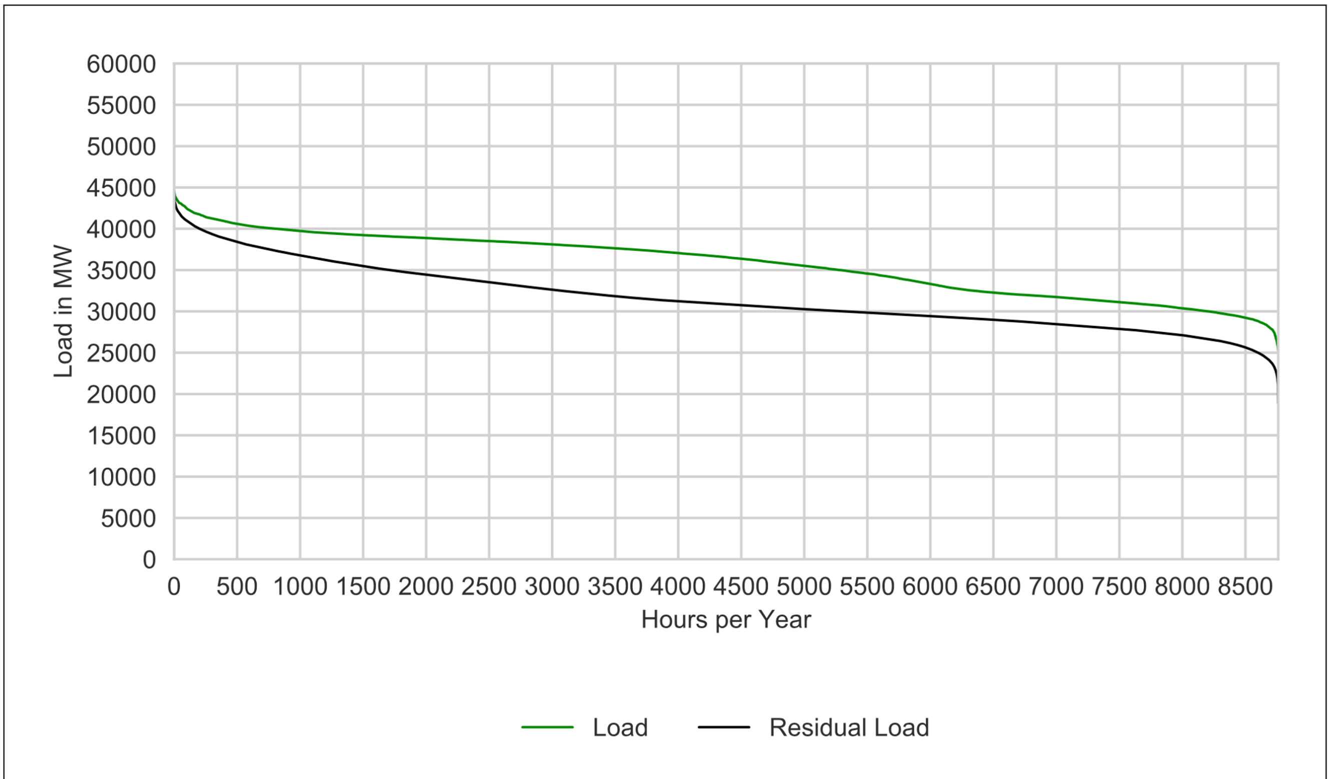

Figure 35: Impact of VRE on the Residual Load (2020, Scenario A + 10GW rooftop PV)

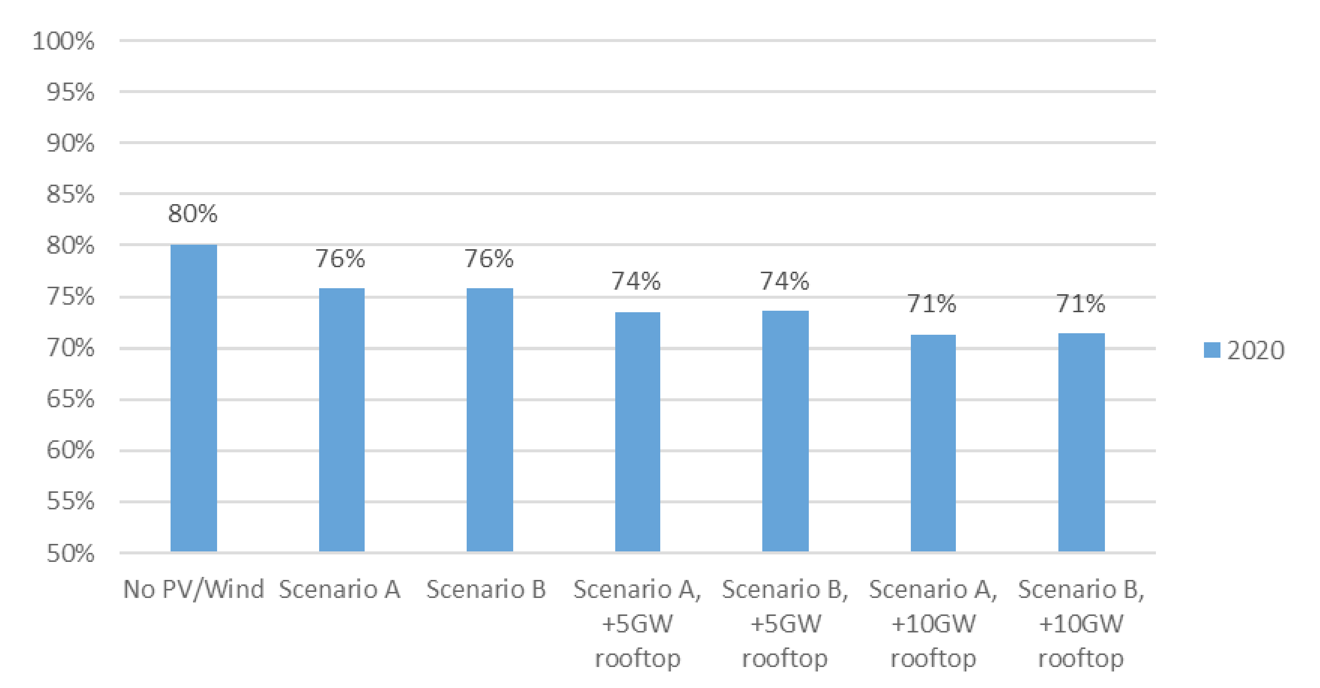

Figure 36: Impact of VRE on the Load Factor (ratio in % between average and peak of Residual Load, 2020)

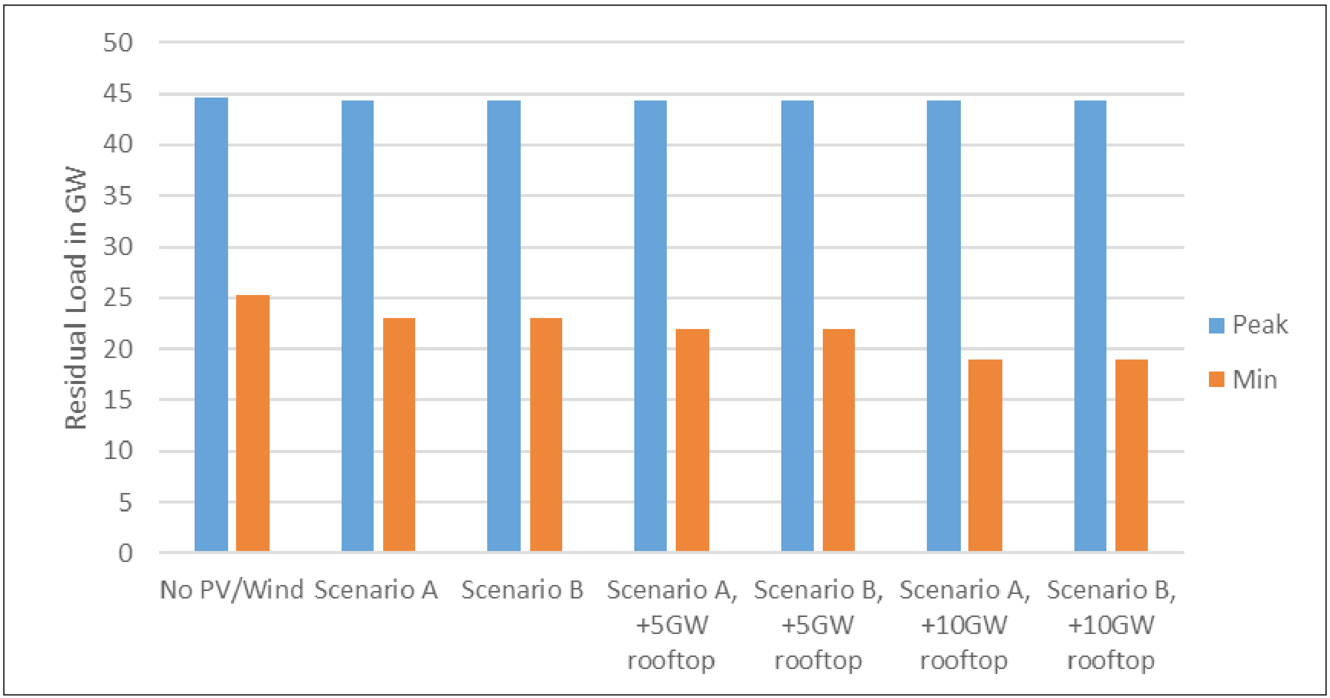

Figure 37: Peak load and minimum load, 2020

The diagrams according to **Figure 36** and **Figure 37** further show that the distribution pattern of utility-scale PV (Scenario B vs. Scenario A) don't have any noticeable impact on Residual Load.

The impact of VRE on ramp-rates is shown by **Figure 38**. This figure shows maximum credible ramp rates considering different confidence levels. Through the addition of wind, utility-scale PV and rooftop PV, worst-case ramp-rates increase by around 30%. This looks at extreme situations, which may only occur occasionally. However, when looking at more frequently occurring ramp rates (99% percentiles), maximum ramp rates only increase by 8%.

The difference between the two allocation scenarios for utility-scale PV systems (Scenario A and Scenario B) is extremely low. The impact of the distribution pattern of utility-scale PV on ramp-rates is below 1% and can therefore be ignored.

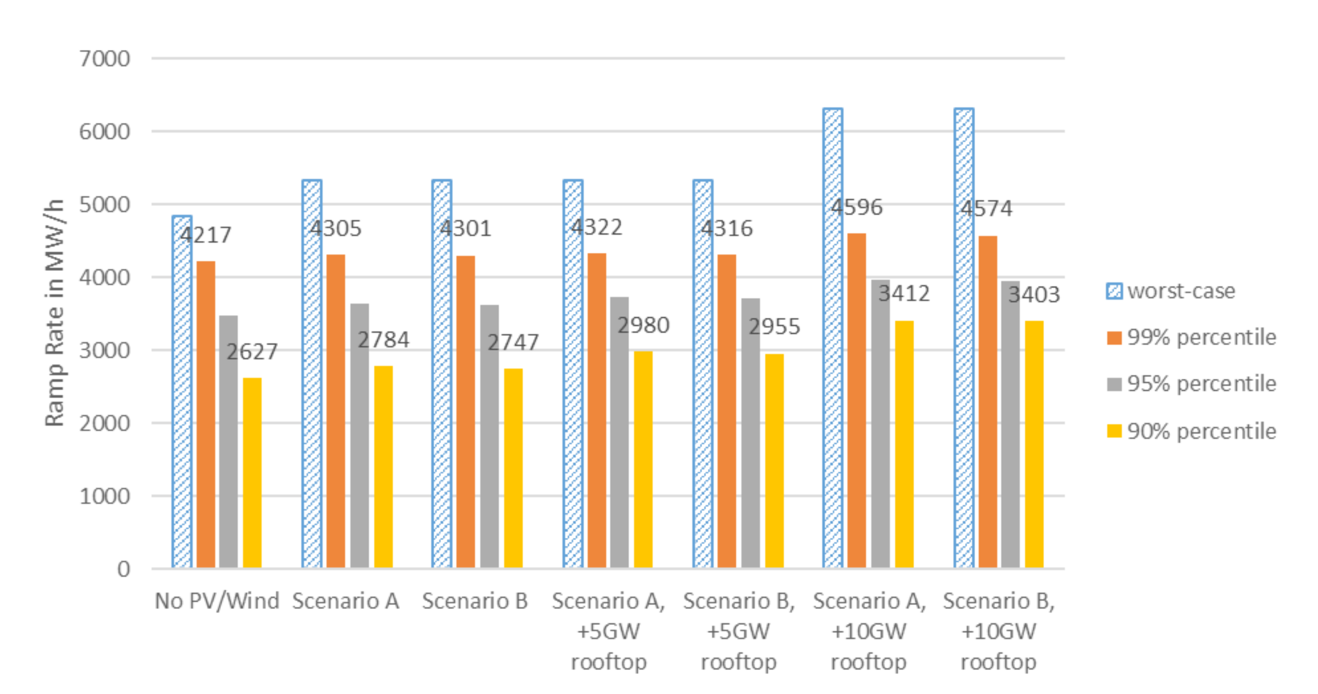

Figure 38: 60min ramp-rates, all scenarios, 2020

Due to the low impact of VRE on ramp-rates (only 8% higher), feasibility issues with respect to load following are not expected in 2020. Whether there will be issues during exceptional situations and whether there will be a considerable cost impact is analyzed later in this report using time domain simulations (see **section 4.2**).

Load and Residual Load duration curves of all studied scenarios for spot year 2020 can be found in Annex.

4.2.1.2 Year 2030

Load and Residual Load duration curves for the year 2030 with 20GW of additional rooftop PV capacity (27,5GW of total PV capacity) is depicted in **Figure 39**. As the comparison with **Figure 37** clearly shows, the minimum Residual Load further drops and gets as low as 10GW in the case with 27,5GW of PV in 2030 (see **Figure 39** and **Figure 41**).

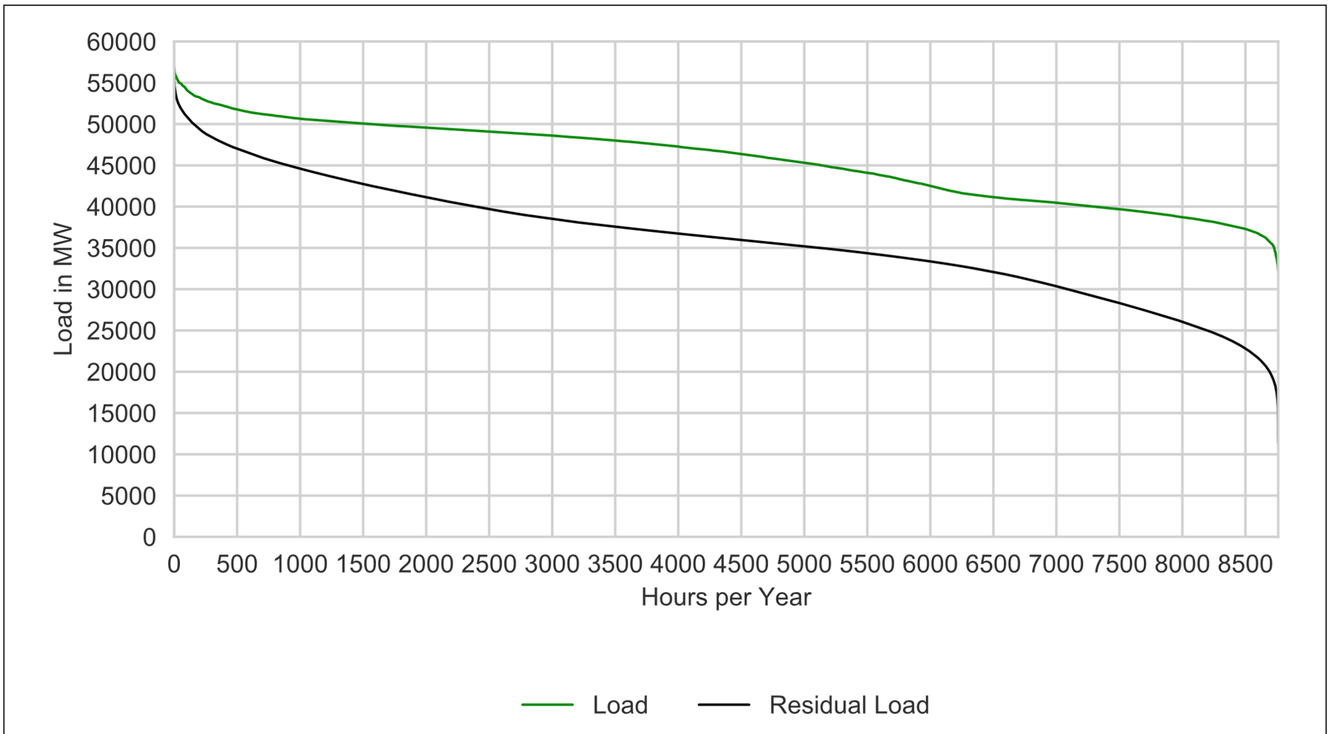

Figure 39: Impact of VRE on the Residual Load (2030, Scenario A + 20GW rooftop PV)

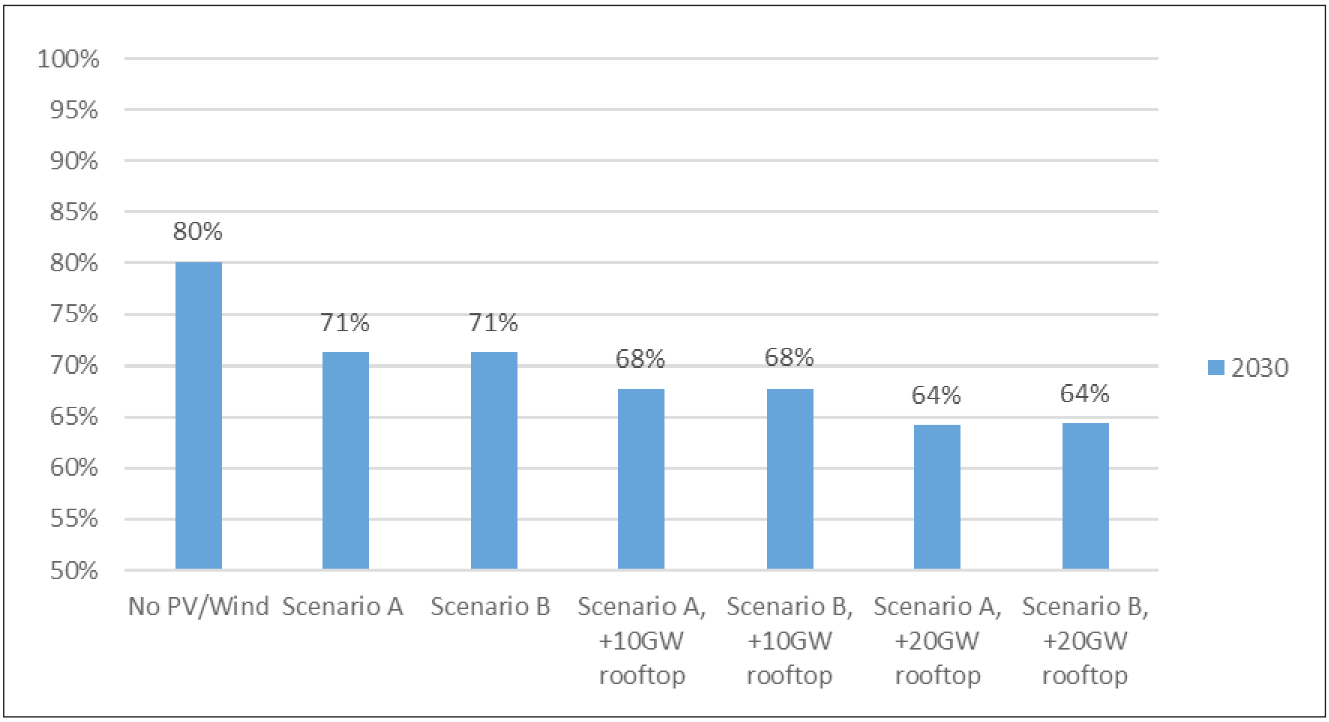

Figure 40: Impact of VRE on the Load Factor (ratio in % between average and peak of Residual Load, 2030)

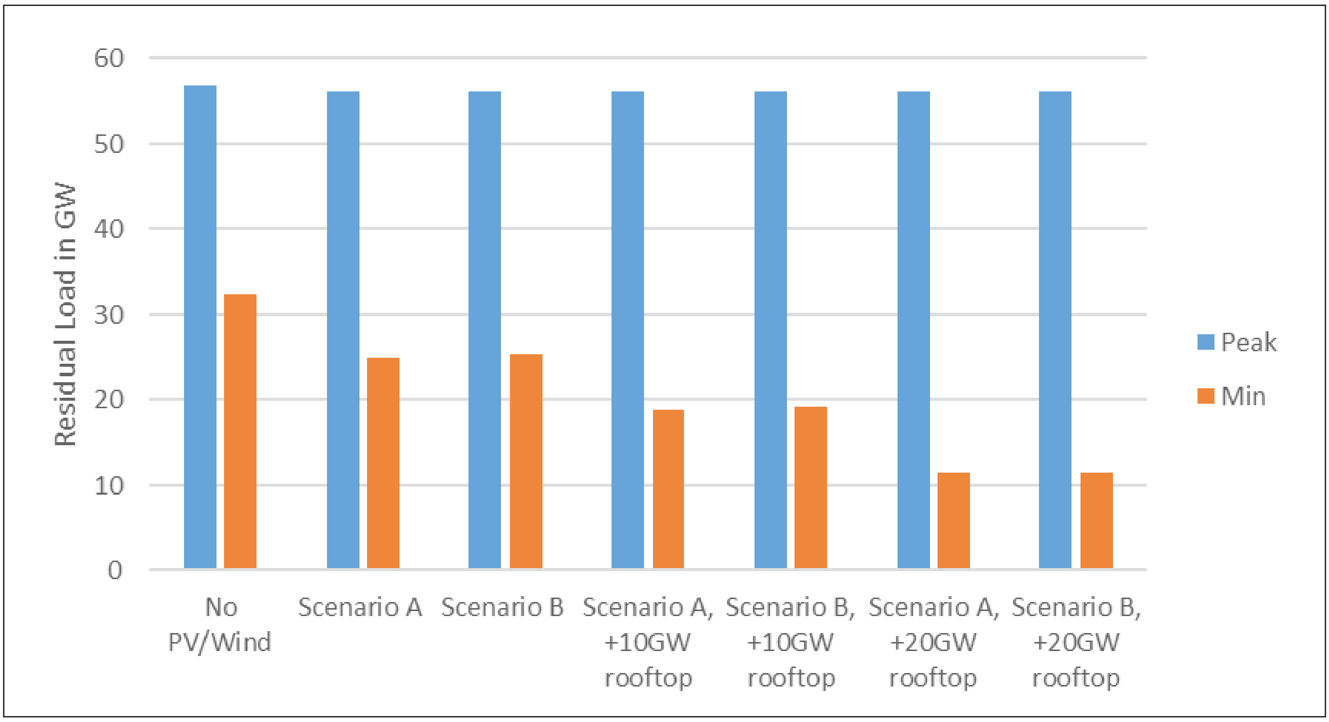

Figure 41: Peak load and minimum load, 2030

The Load Factor of the Residual Load is reducing from 80% (without VRE) to 64% (with 11GW of wind and 27,5GW of PV in total), as shown by the chart of **Figure 40**.

The impact of VRE on ramp-rates of the Residual Load is shown in **Figure 42**. As shown by **Figure 42**, the integration of VRE according to IRP2016-Base-Case [5] increases worst-case ramp rates by around 19% (see **Figure 42**, Scenario A and Scenario B). However, 99% percentiles of ramp-rates only increase by around 6%.

When adding up to 20GW of rooftop PV, worst-case ramp rates increase by around 80% (compared to the case without VRE). However, these are very few, very extreme events - the 99% percentile increases by a much more modest 47%. Therefore, it can be stated that the impact of 20GW of

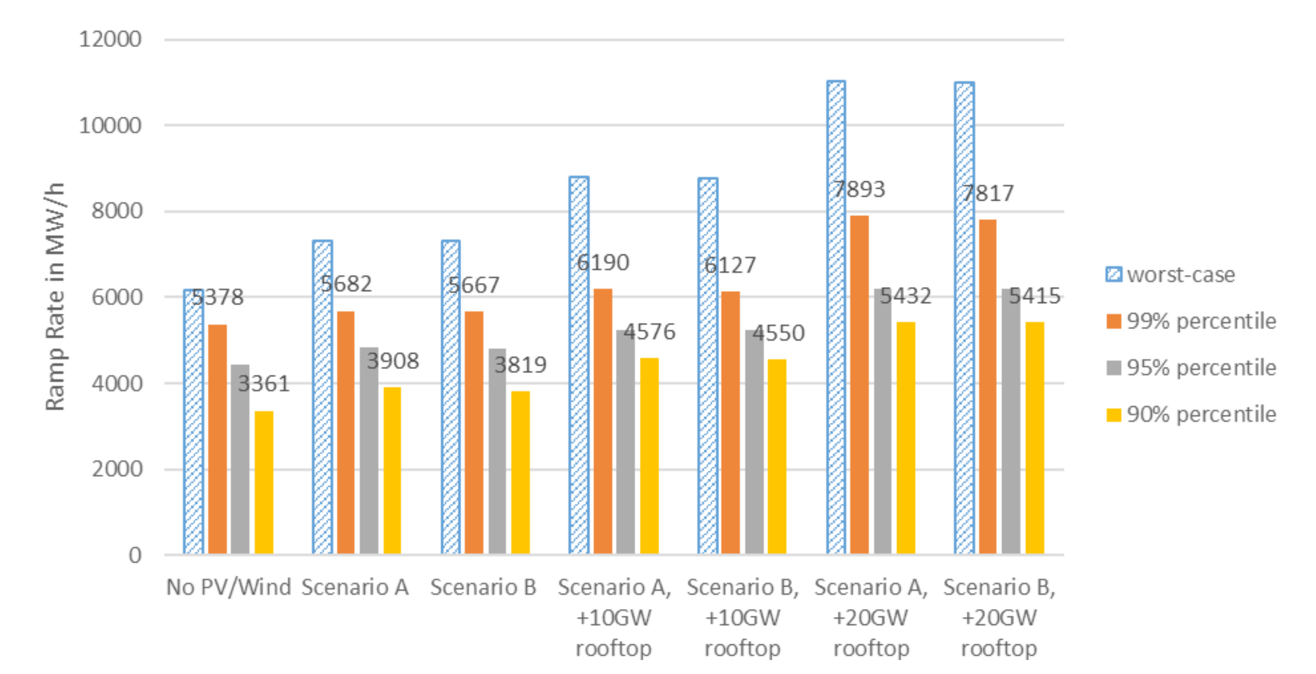

Figure 42: 60min ramp-rates, all scenarios, 2030

additional rooftop PV capacity on ramp-rates is considerable, and requires careful analysis of the ramping capabilities of conventional power plants. The analysis determining whether existing and planned power plants will be able to cope with these ramping requirements, and by how much cycling costs would increase, is presented in **section 4.2**.

As for the year 2020, the impact of the distribution pattern of utility-scale PV farms (Scenario A vs. Scenario B) on the Residual Load is negligible.

Duration curves of Load and Residual Load for all studied scenarios of spot year 2030 can be found in Annex.

4.2.2 Assessment of cycling capability and cycling costs

4.2.2.1 Results of time simulation studies

4.2.2.1.1 Year 2020

In 2020, the Residual Load will mainly be supplied from coal, nuclear and imports. During evening hours, hydro and pumped-storage power plants will make an additional contribution. OCGTs are only available for emergency situations or for balancing/reserve purposes.

Figure 44 and **Figure 46** show the generator dispatch during two weeks in 2020 for the scenario with 10GW of additional rooftop PV. As shown by these diagrams, the addition of rooftop PV reduces the Residual Load during the day considerably. With the addition of 10GW of rooftop, minimum Residual Load will occur during midday, when there is maximum PV generation, during many days of the year.

4.2.2.1.2 Year 2030

In 2030, the largest part of Residual Load will be supplied by coal, nuclear and imports, which are essentially operating as base load plants. Much of the load following cycling will then be provided by new CCGTs, which will operate as mid-merit power plants. For peak load coverage, hydro, pumped-storage, demand response and even OCGTs will be in operation (see **Figure 47** to **Figure 50**).

When adding large amounts of PV, they will displace CCGTs (and coal) during midday. Besides reduced operating hours of CCGTs, the number of start-ups of CCGTs will increase due to the addition of rooftop PV (compare the CCGT operation according to **Figure 49** and **Figure 50**).

When adding large amounts of PV, pumping operation of pumped-storage power plants should be shifted towards midday, as shown by **Figure 48** and **Figure 50**. This is the most economic operation of pumped-storage power plants because these are the hours with minimum Residual Load, and at the same time this helps thermal power plants to operate above their minimum operating level, and avoids PV being curtailed due to flexibility constraints of thermal power plants.

For situations in which the operating level of base load power plants cannot be further reduced, PV must be curtailed. In the scenario with 20GW of additional rooftop

PV, there will be 85 hours during which PV must be curtailed, because all thermal power plants, which are in operation, have reached their minimum operating level (see also **Figure 48** showing such a situation). However, in this scenario with 27,5GW of PV generation in total, only 0,33% of the energy available from PV must be curtailed. In all other scenarios (no rooftop PV and +10GW of additional rooftop PV) there is no curtailment required, and the system can take all the generated PV energy.

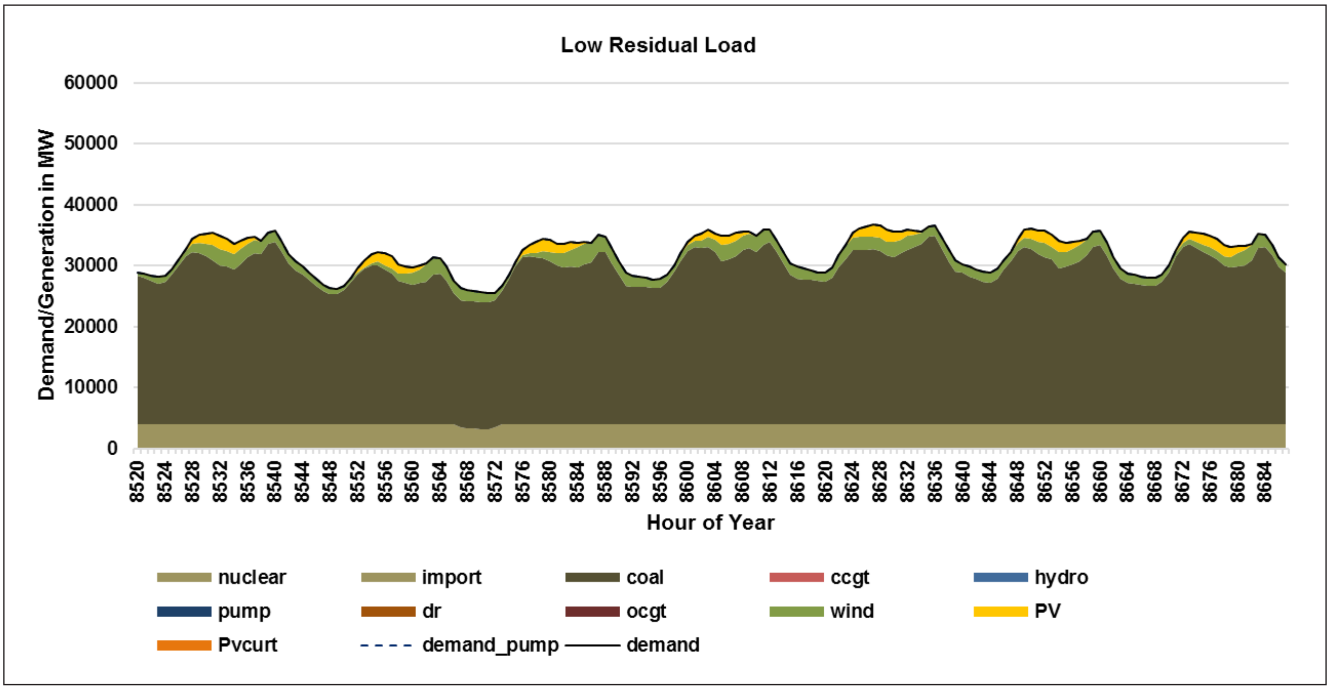

Figure 43: Scenario A, year 2020: generator dispatch, week of lowest Residual Load

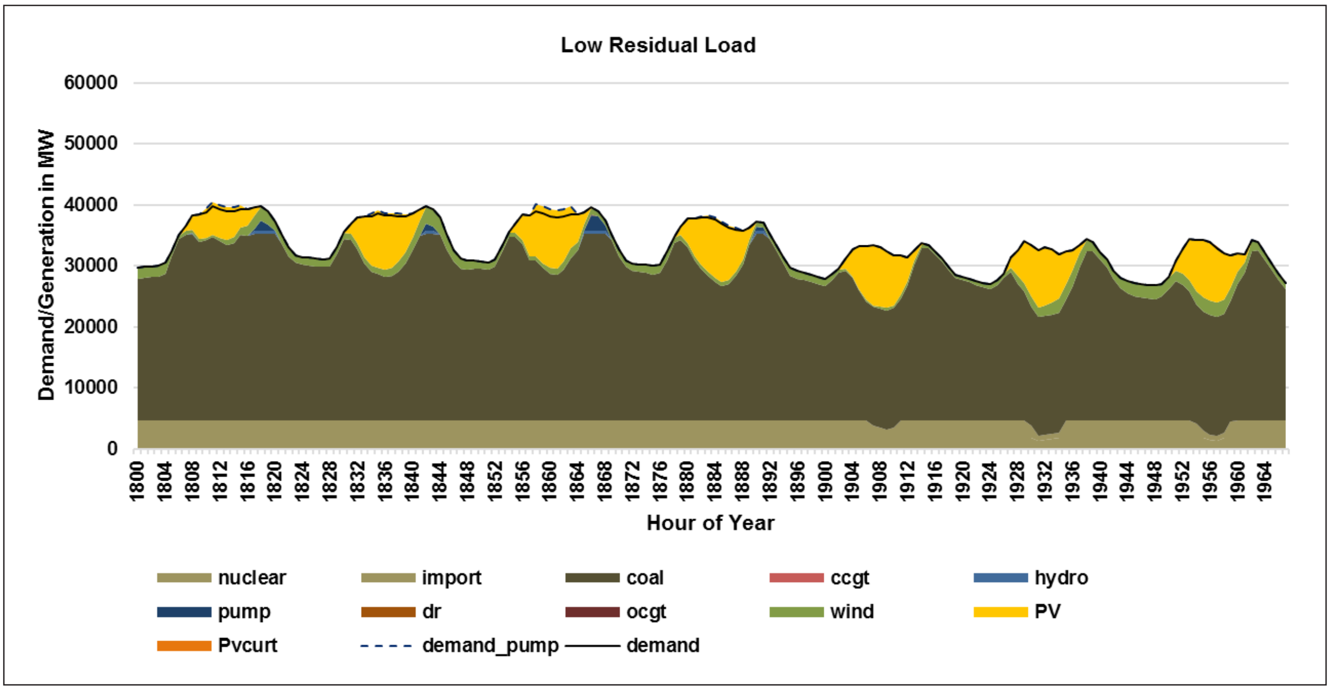

Figure 44: Scenario A +10GW of rooftop PV, year 2020: generator dispatch, week of lowest Residual Load

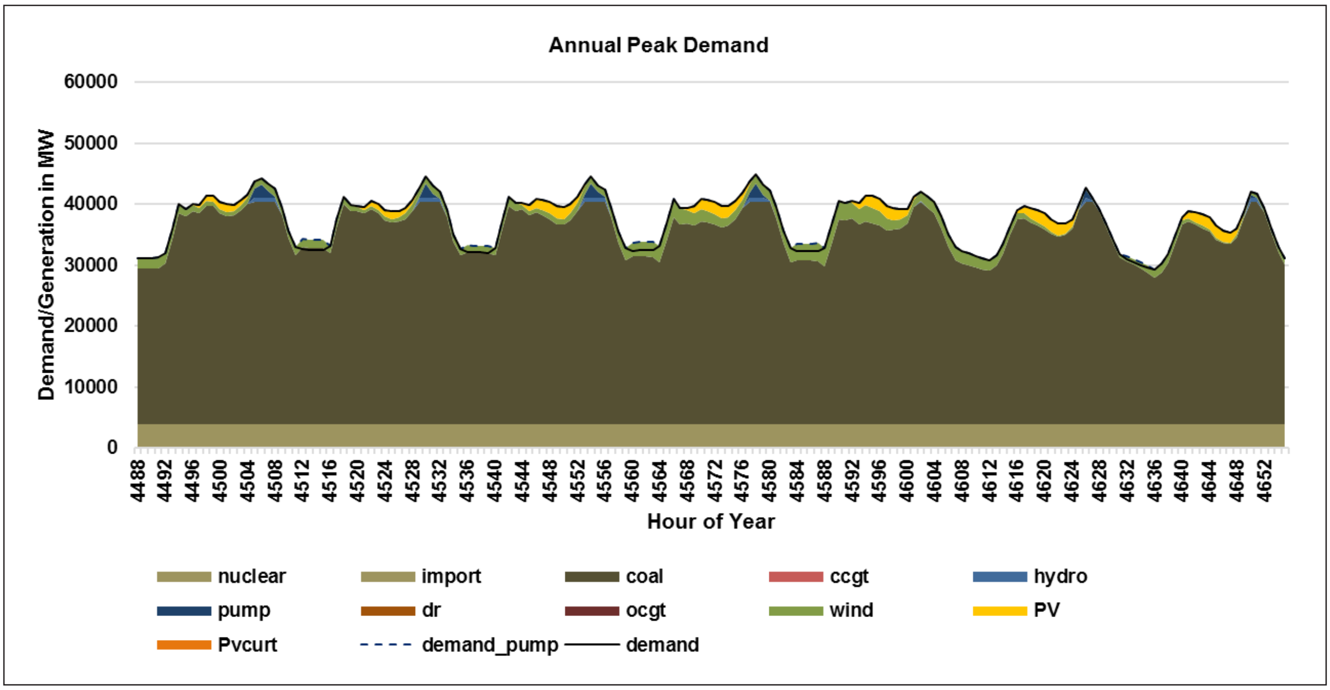

Figure 45: Scenario A, year 2020: generator dispatch during week of annual peak load

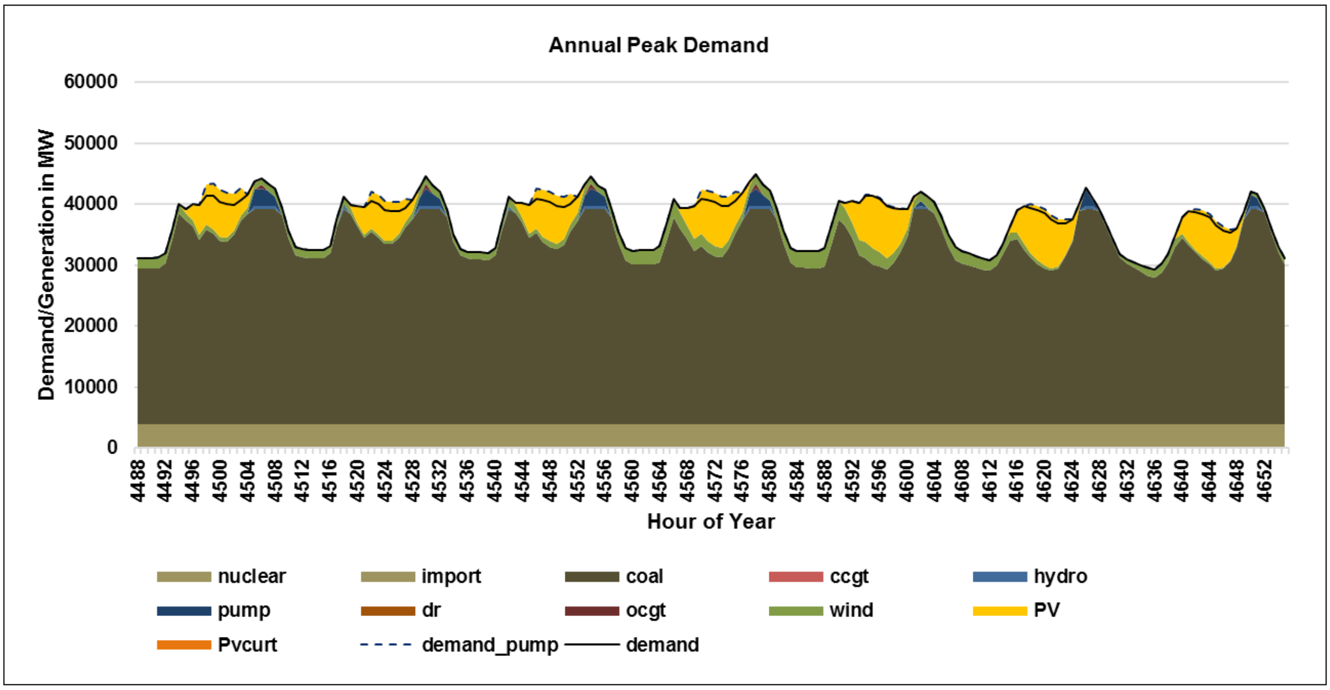

Figure 46: Scenario A +10GW of rooftop PV, year 2020: generator dispatch during week of annual peak load

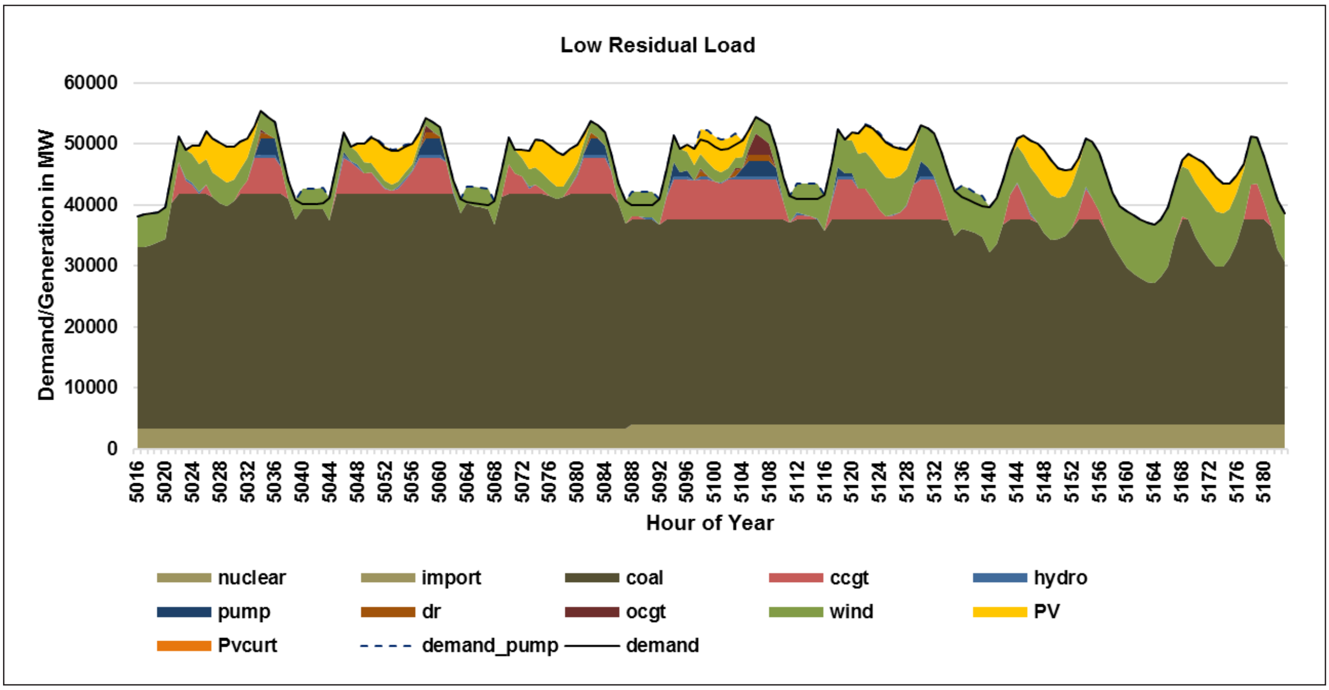

Figure 47: Scenario A, year 2030: generator dispatch, week of lowest Residual Load

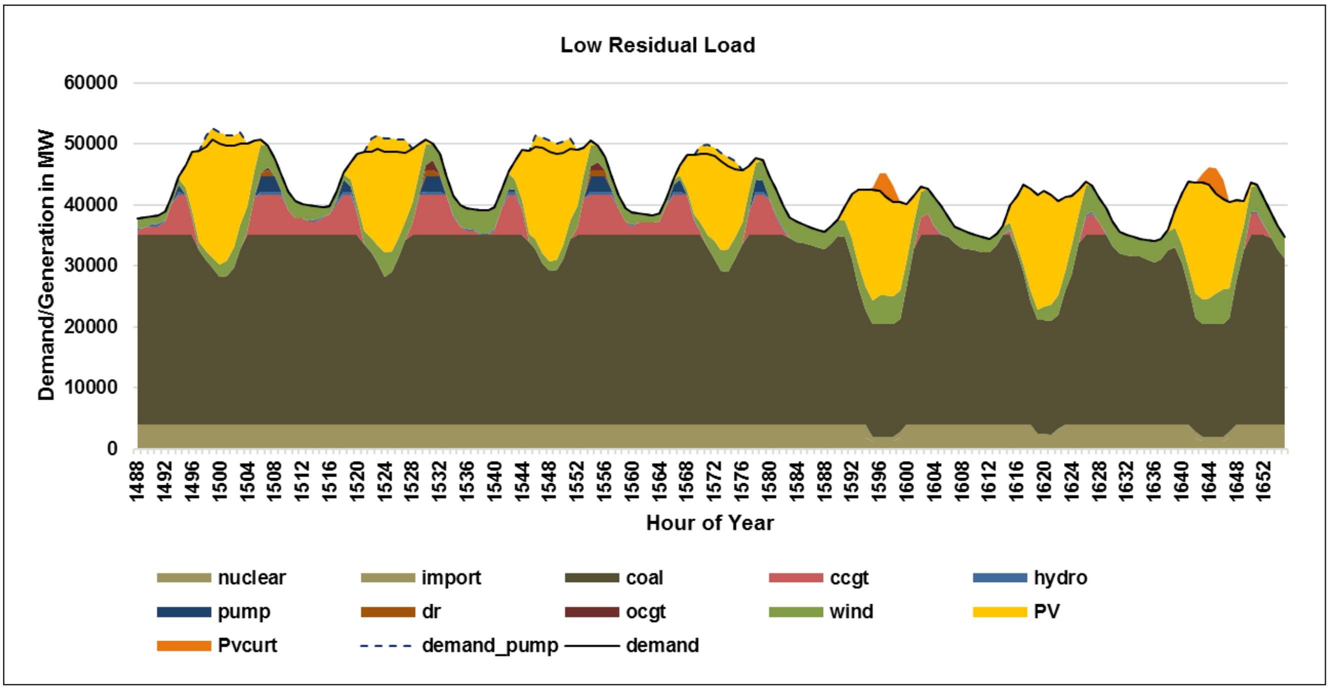

Figure 48: Scenario A +20GW of rooftop PV, year 2030: generator dispatch, week of lowest Residual Load

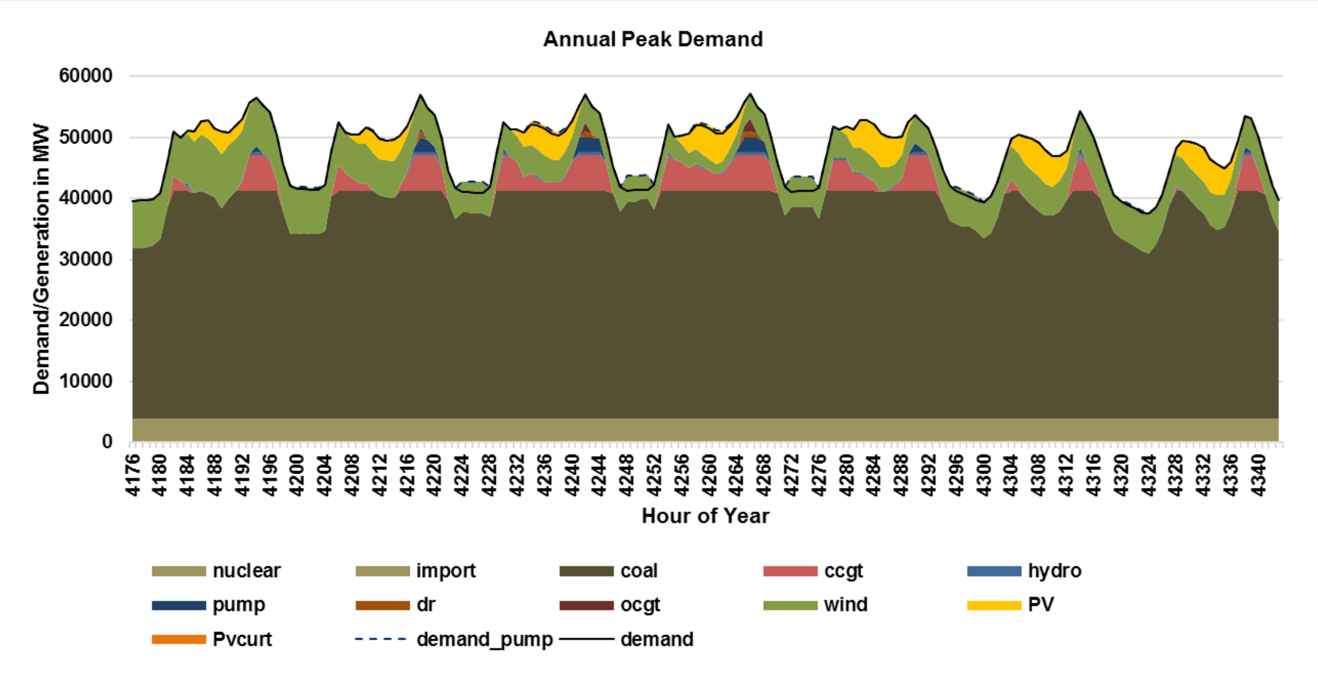

Figure 49: Scenario A, year 2030: generator dispatch during week of annual peak load

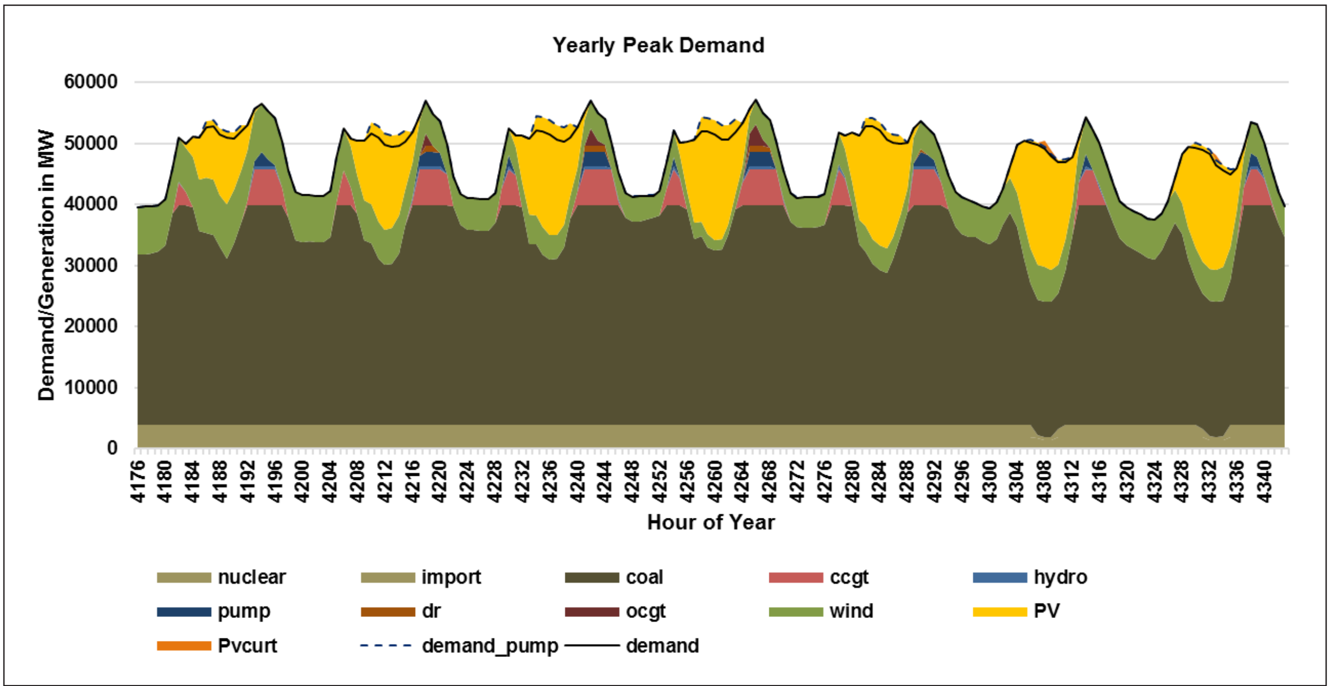

Figure 50: Scenario A +20GW of rooftop PV, year 2030: generator dispatch during week with annual peak load

4.2.2.2 Load following cycling

4.2.2.2.1 Year 2020

Based on the results of the time domain simulations for 2020, the number of significant load following ramping events per year (ramping by more than 20% GDC) has been evaluated for each of the analysed scenarios.

To produce comparable figures between the scenarios and spot years and because cycling costs are (approximately) in proportion to the size of a unit (installed capacity), the annual number of ramping events has been normalized to typical unit sizes of coal, CCGT and OCGT power plants.
All cycling-related results (load flowing ramping and start-up events) are therefore expressed based on the following equivalent unit sizes:

- Coal: 600MW
- CCGT: 300MW
- OCGT: 150MW

This means for example, that one load-following event of an 800MW coal fired unit counts for 800/600=1,33 load following events of an equivalent 600MW unit.

The results for 2020 are depicted in **Figure 51**. This figure confirms that in 2020, load following is mainly carried out by coal-fired power plants and only by a few OCGTs. This figure further highlights, that in 2020 the impact of additional rooftop PV on load following cycling is very low.

Cycling costs are expressed in USD_{2011} per consumed (or generated) MWh of electricity. Expressing levelised instead of absolute costs allows comparing costs of cycling between the different years.

The estimate of cost of significant load following ramping in USD per consumed MWh is depicted in **Figure 52**. The absolute numbers show that cost of load following cycling are relatively small and contribute by much less than 1% to overall cost of electricity.

The results according to **Figure 52** further show that the addition of up to 10GW of rooftop PV increases cost of load following cycling by around 20%.

4.2.2.3 Year 2030

The results according to **Figure 53** show that in 2030, load following of coal-fired power stations is reduced compared to 2020 but CCGTs, operating as mid-merit plants, contribute significantly to load following cycling.

With increased PV capacity, the number of load following ramps of coal fired power plants initially increases (scenario with 10GW of additional rooftop PV) but with further addition of PV (scenario with 20GW of additional rooftop PV), load following ramps of coal fired power plants reduce slightly and ramping of OCGTs picks up. At these high PV-penetration levels, the dispatch of coal fired power stations is reduced because of the large variability of the Residual Load and more OCGTs are in operation during peak load hours. Because less coal fired power stations are in operation, the number of significant load following events of coal fired power stations decreases too.

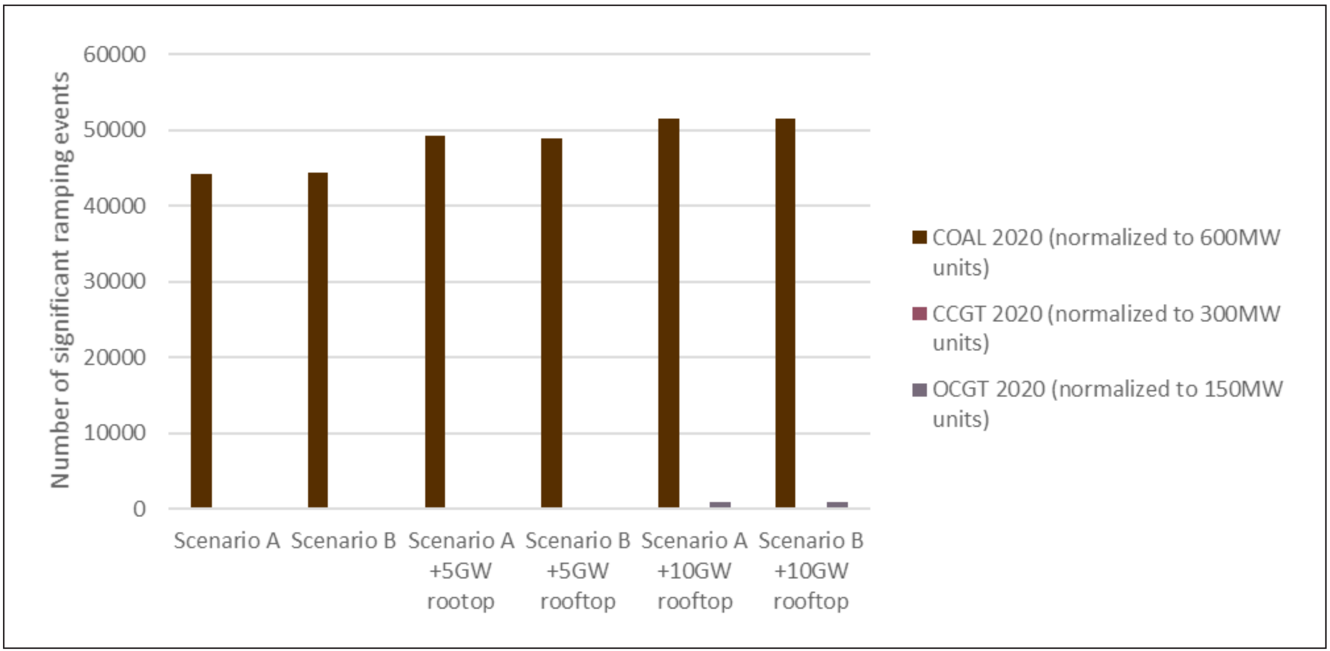

Figure 51: Number of significant load following ramping events per year, 2020

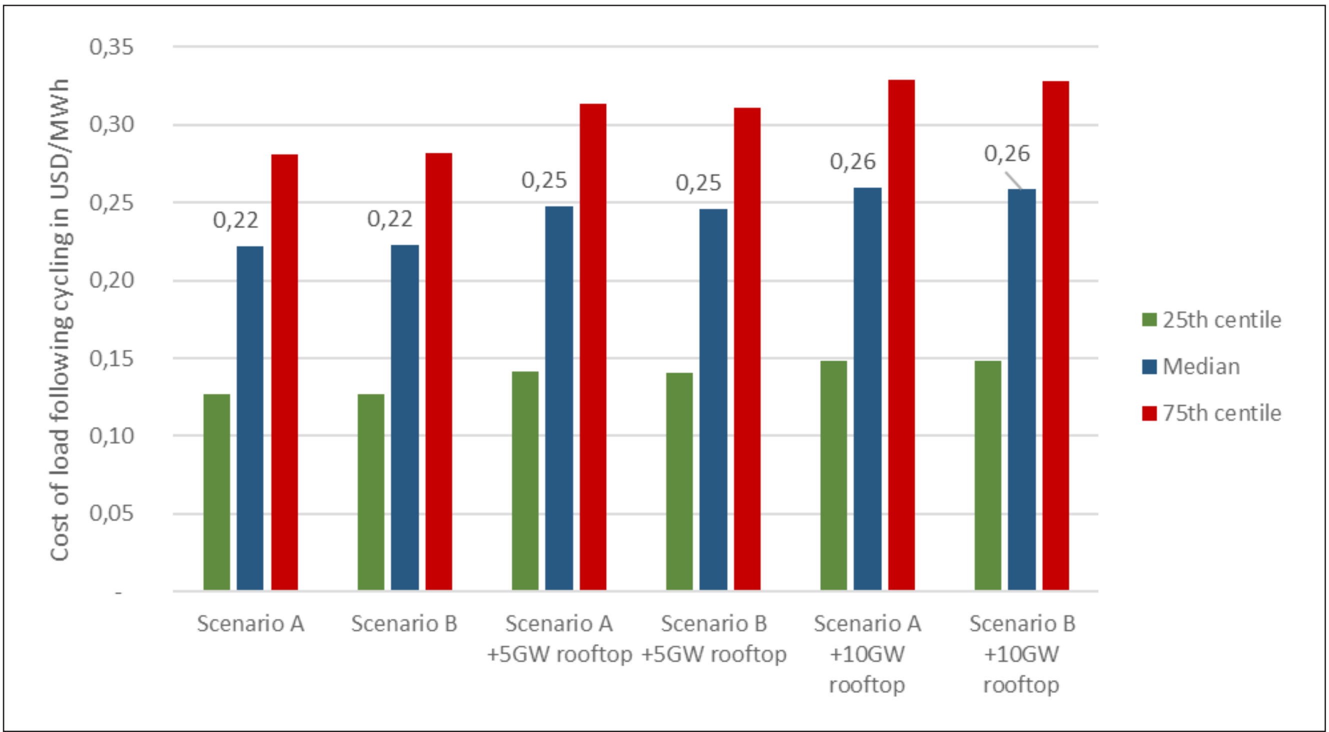

Figure 52: Cost of significant load following ramps in USD/MWh, year 2020

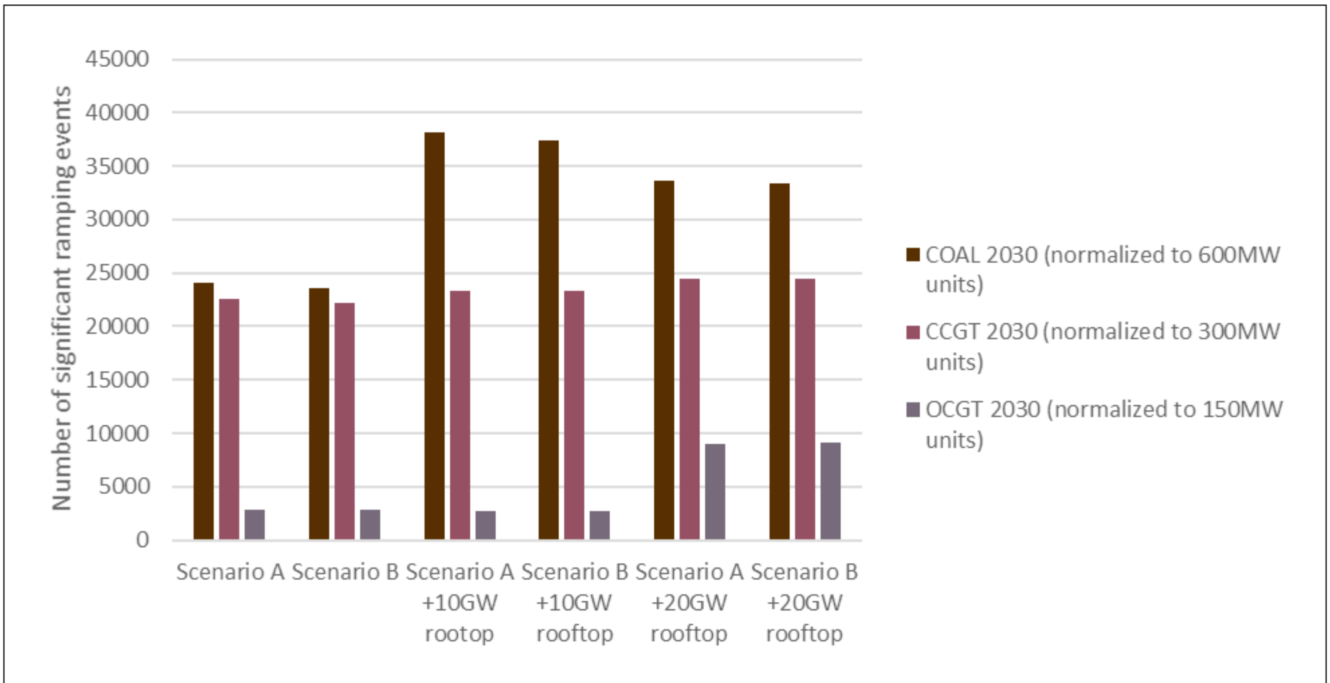

Figure 53: Number of significant load following ramping events per year, 2030

The estimated cost of load following cycling in 2030 is depicted in **Figure 54**. Comparing these costs with the corresponding figures of 2020 (see **Figure 52**), it should be noted that cost of load following ramps generally decrease between 2020 and 2030. This can be explained by added CCGT power plants, which operate as mid-merit plants, and take up a lot of load following at lower cost compared to coal-fired power stations in 2020.

When adding up to 10GW of rooftop PV in 2030 (17,5GW of PV in total), cost of load following cycling increases by around 50% compared to the scenario without rooftop PV (7,5GW of PV). When adding another 10GW of rooftop PV, cost of load following cycling is reduced because there is less load following ramping of coal fired power stations. In general, costs of load following cycling in 2030 is considerably lower than corresponding costs in 2020 with only 2,4GW of PV.

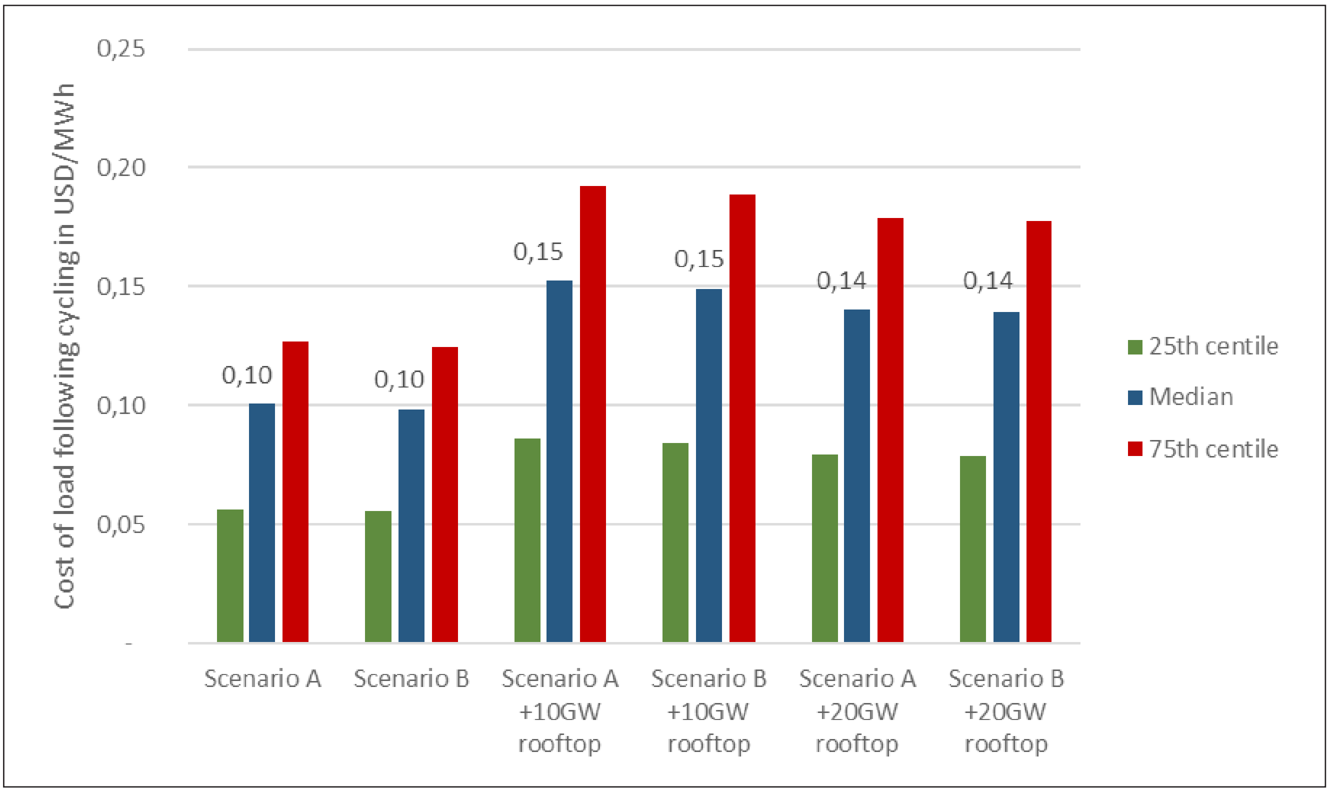

Figure 54: Cost of significant load following ramps in USD/MWh, year 2030

These results show that the addition of more mid-merit, and peaking plants decreases cost of load following cycling, and can even compensate for larger numbers of load following ramping events resulting from increased variability caused by significantly increased levels of PV. However, cost of load following cycling should not be interpreted without analyzing cost of start-up events of thermal power plants: As the analysis of the following section will show, load following ramping of base load power plants will partly be replaced by start-up cycling events of mid-merit and peaking plants.

4.2.2.4 Start-ups

4.2.2.4.1 Year 2020

In 2020, the system is mainly supplied by base load power plants (nuclear and coal), which only start and stop for maintenance but (usually) not for operational purposes. During peak-load hours, base load plants are complemented by peaking plants, which are hydro, pumped-storage and OCGTs. OCGTs are the most expensive peaking units and, therefore, they are only dispatched occasionally.

As shown by the chart of **Figure 55**, the number of annual start-ups is very low for the scenarios with only utility-scale PV (Scenario A and Scenario B), and the scenarios with 5GW of additional rooftop PV.

The number of OCGT start-ups increases significantly in the scenario with 10GW of additional rooftop PV. Most of these start-ups are cold start-ups because start-ups of OCGTs with down-times >3h are defined to be cold starts (see [2]).

However, the absolute number of OCGT start-ups and associated start-up costs are very low, as the associated costs according to **Figure 56** show (around one order of magnitude lower than cost of load following cycling).

4.2.2.4.2 Year 2030

In 2030, the system-wide number of start-ups increases significantly because a significant number of new CCGTs and OCGTs will be installed. **Figure 57** shows the annual number of starts of CCGTs (equivalent 300MW units) and Figure 58 for OCGTs (equivalent 150MW units).

However, as shown by the chart of **Figure 57**, the total number of start-up events of CCGTs is almost unaffected by the addition of up to 20GW of rooftop PV: The overall number of start-ups of CCGTs per year only increases by around 10% due to the addition of 20GW of rooftop PV (from around 1,25 start-ups per day to 1,38 start-ups per day per CCGT on average).

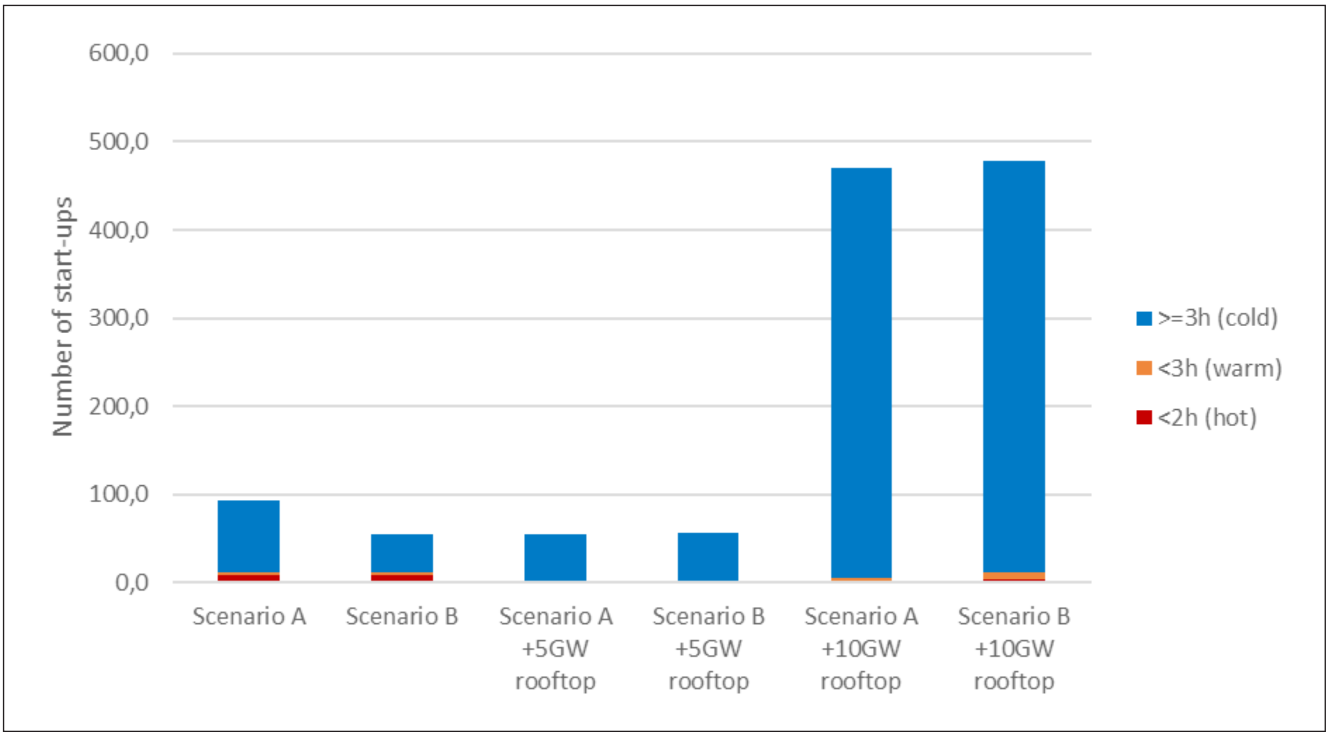

Figure 55: Total number of annual starts of OCGT units (equivalent 150MW units), 2020

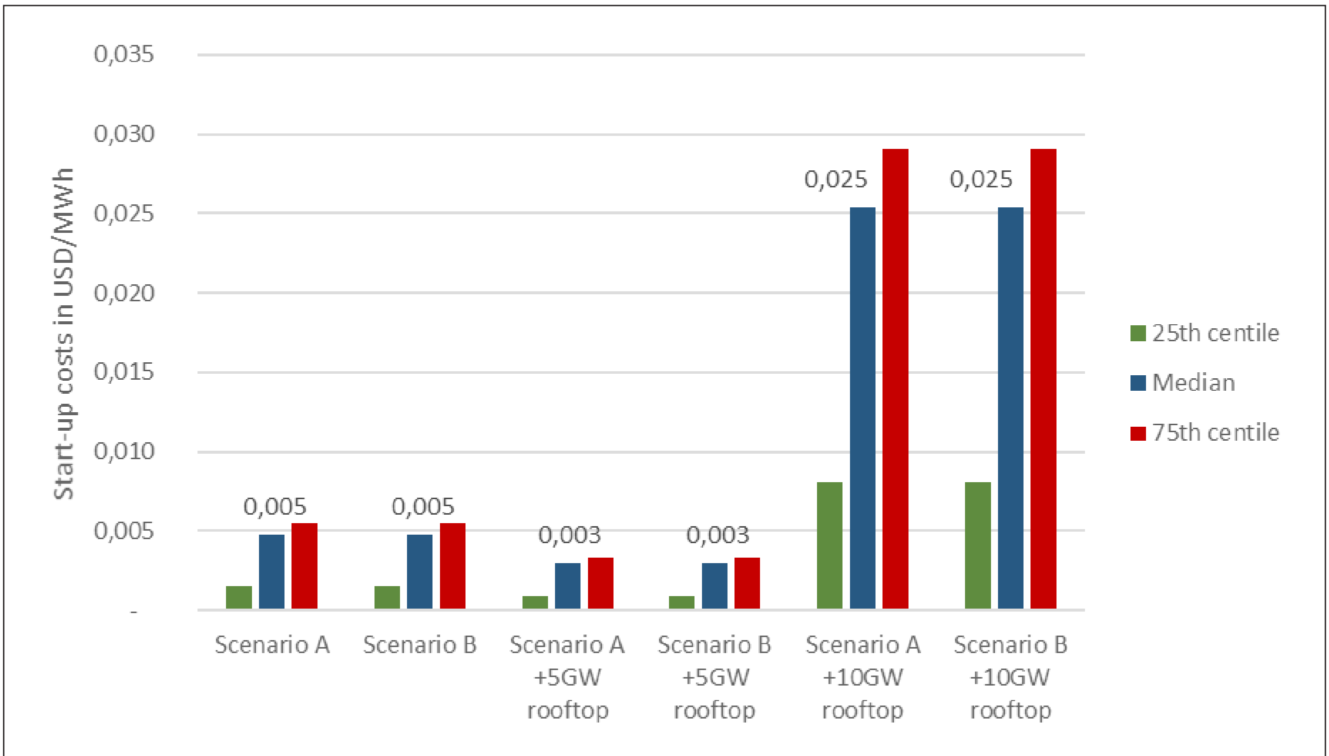

Figure 56: Start-up costs in USD/MWh, 2020

Figure 58 shows the total number of annual start-ups of OCGT units. As these results show, the addition of 10GW of rooftop PV has almost no impact on the number of OCGT start-ups. However, when adding another 10GW of rooftop PV (20GW of rooftop PV in total), the number of start-ups of OCGT units increases significantly (from 0,07 start-ups per day per unit to 0,21 start-ups per day per unit on average).

While start-up costs could almost be neglected in 2020, their contribution to cycling costs is significant and around three to four times larger than costs of load following ramping as the results according to **Figure 59** and **Figure 60** show.

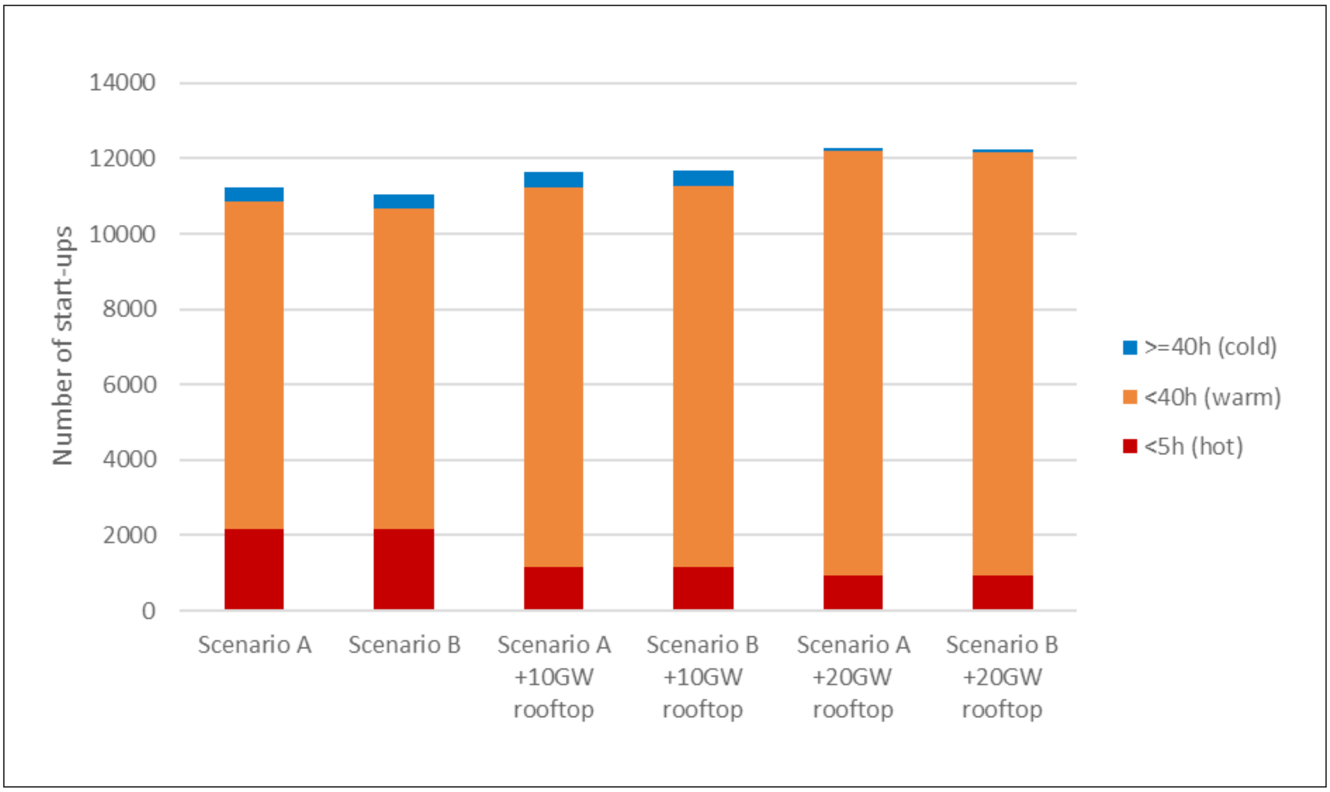

Figure 57: Total number of annual starts of CCGT units (equivalent 300MW units), 2030

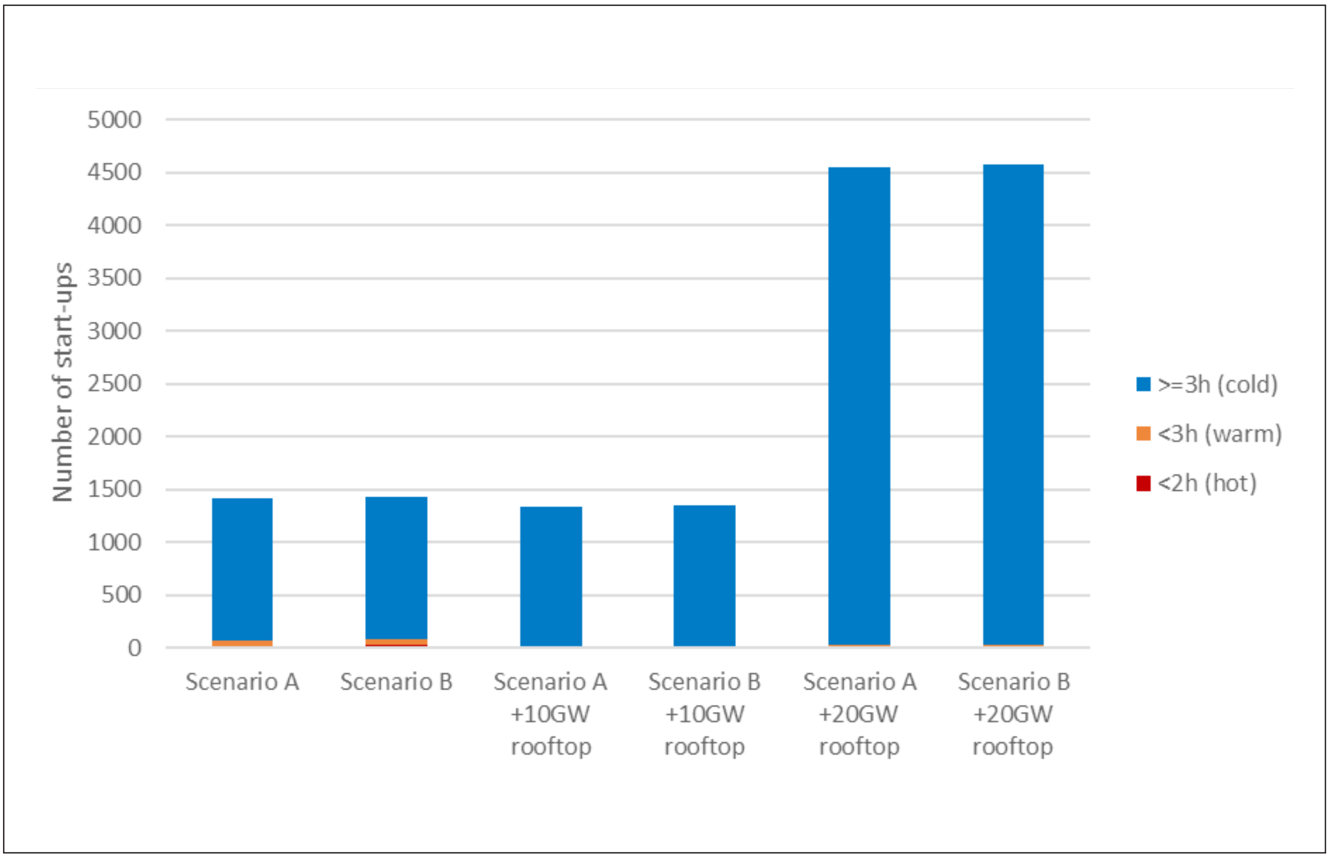

Figure 58: Scenario A +20GW of rooftop PV, year 2030: generator dispatch, week of lowest Residual Load

Through the addition of 20GW of rooftop PV, start-up costs increase from 0,53 USD/MWh to 0,72USD/MWh, which is an increase of around 37% (see **Figure 59**).

Figure 60 shows the contribution of CCGT start-ups and OCGT start-ups to the total annual start-up costs. These results confirm that CCGT units have the largest contribution to start-up costs and that the difference between the scenario with 20GW of rooftop PV and the scenario with 10GW of rooftop PV is mainly because of increased OCGT start-up costs.

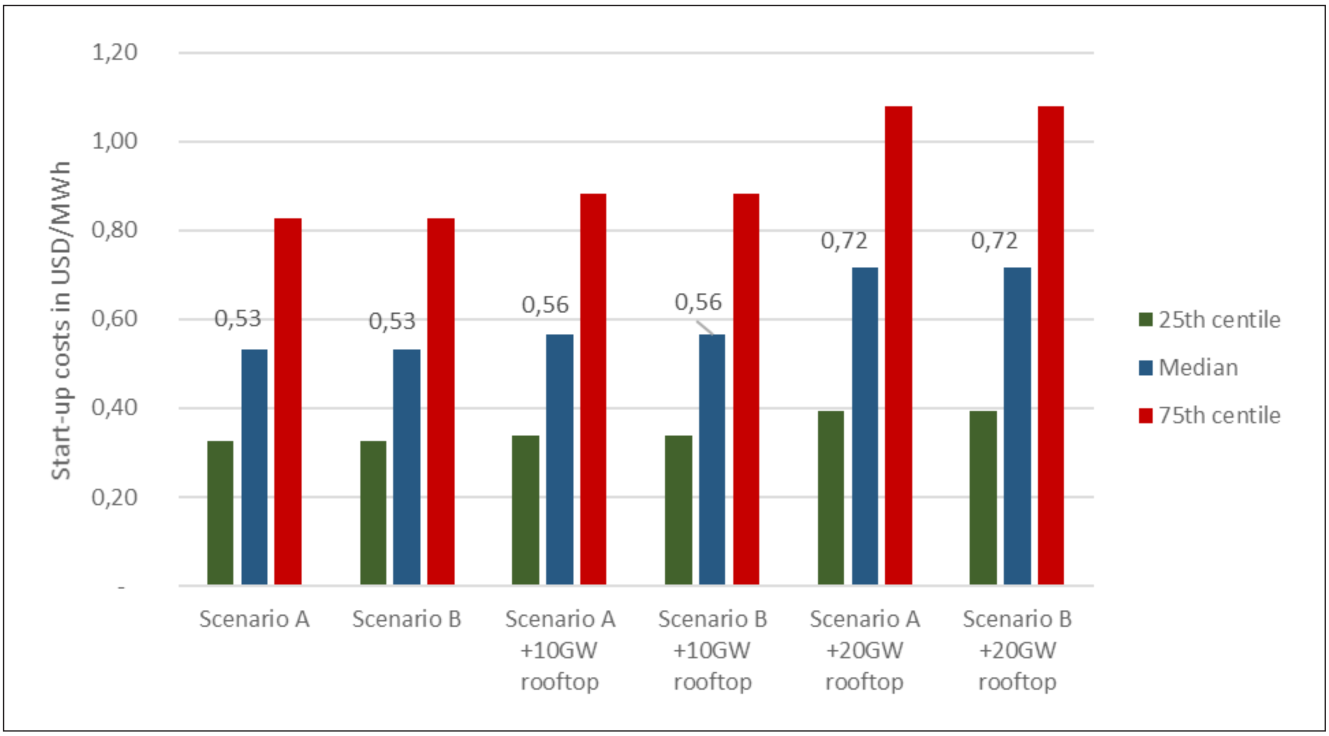

Figure 59: Start-up costs in USD/MWh, 2030

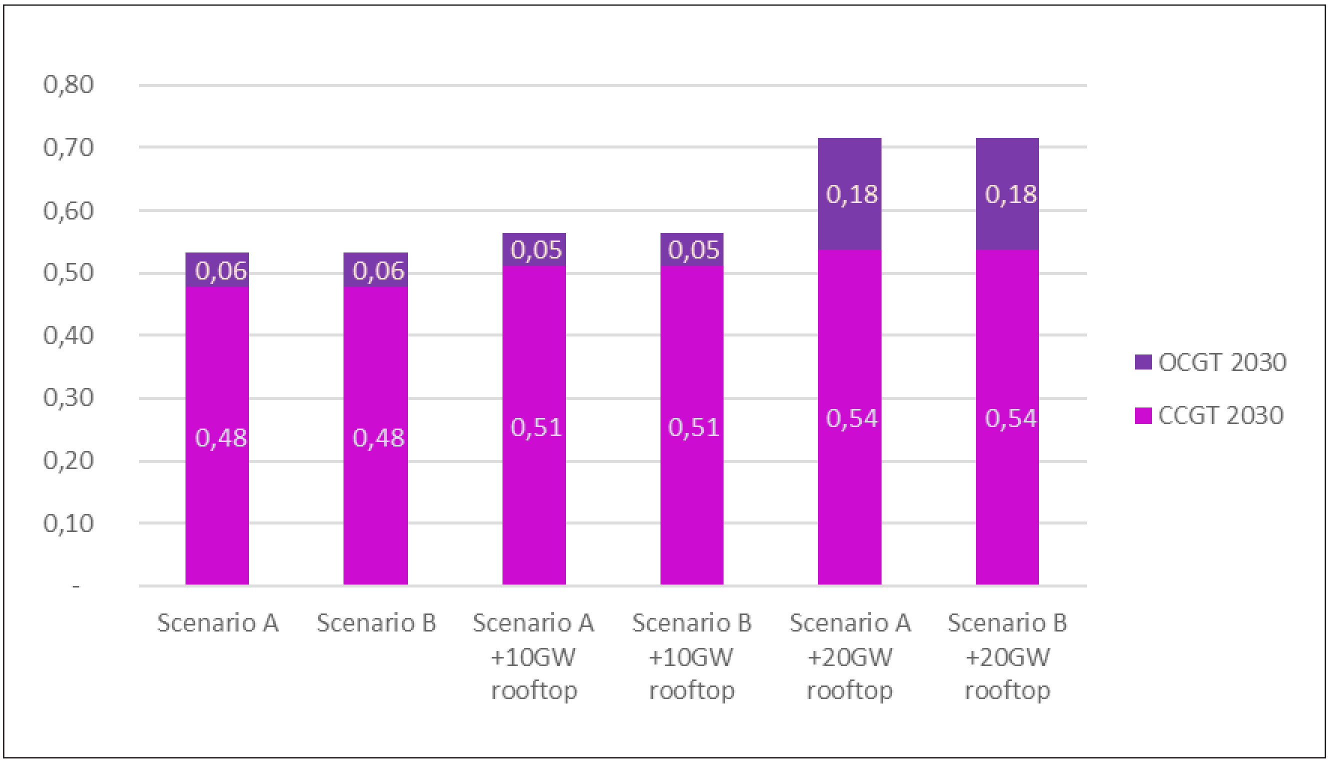

Figure 60: Start-up costs in USD/MWh (median), break down into CCGT and OCGT, 2030

4.2.3 Cycling – Summary

4.2.3.1 Year 2020

The results according to **Figure 61** summarize the impact of increased levels of PV on cycling costs (direct start-up costs, indirect start-up costs and load following ramps). As shown by this figure, the addition of 10GW of rooftop PV in 2020 would let cycling costs grow from 0,23USD/MWh to 0,28USD/MWh (median), which is an increase of around 21%.

The results according to **Figure 62** break down these costs into load following cycling and start-ups. As shown by these results, the contribution of start-up costs to cycling costs can almost be neglected in 2020.

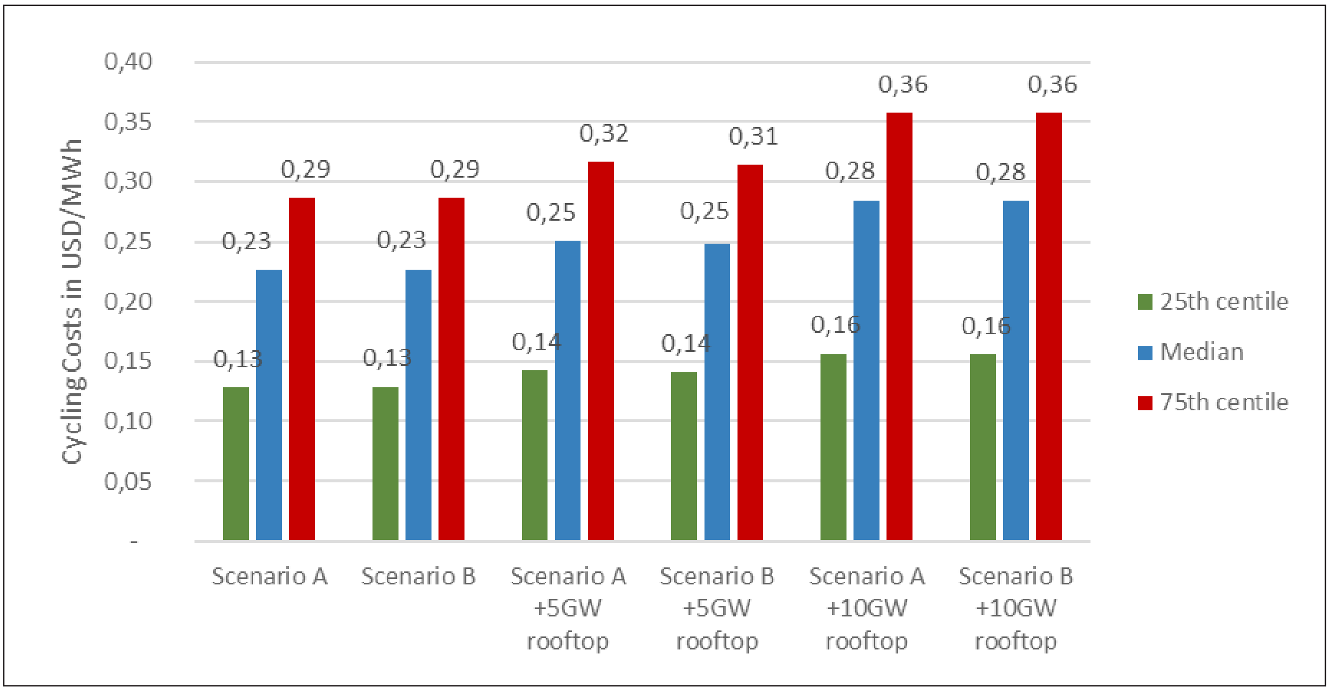

Figure 61: Cycling costs (range) in USD/MWh, 2020

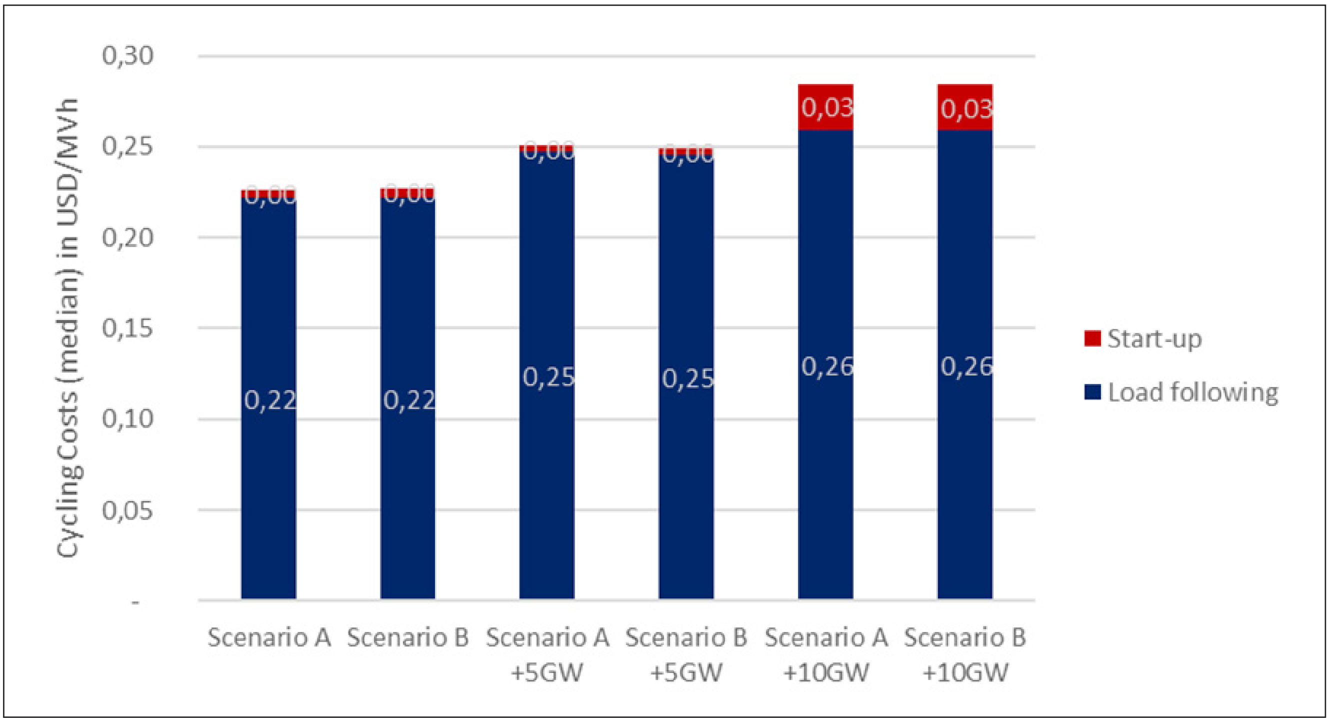

Figure 62: Cycling costs, break down into start-up and load following ramps, year 2020

The results according to **Figure 63** break down cycling costs into power plant types. This diagram shows that coal-fired power plants have the largest contribution to cycling costs in 2020 and that the contribution of OCGTs increases very slightly due to the addition of rooftop PV.

4.2.3.2 Year 2030

In 2030, cycling costs are generally higher than in 2020 because of the addition of CCGTs and their operation as mid-merit power plants with start-ups on a daily basis.

The impact of additional rooftop PV installations, however, is still moderate as the results according to **Figure 64** confirm. Due to the addition of 10GW of rooftop PV, cycling costs increase by around 14%. The addition of 20GW of PV lets cycling costs grow by 33% compared to Scenario A (without rooftop PV).

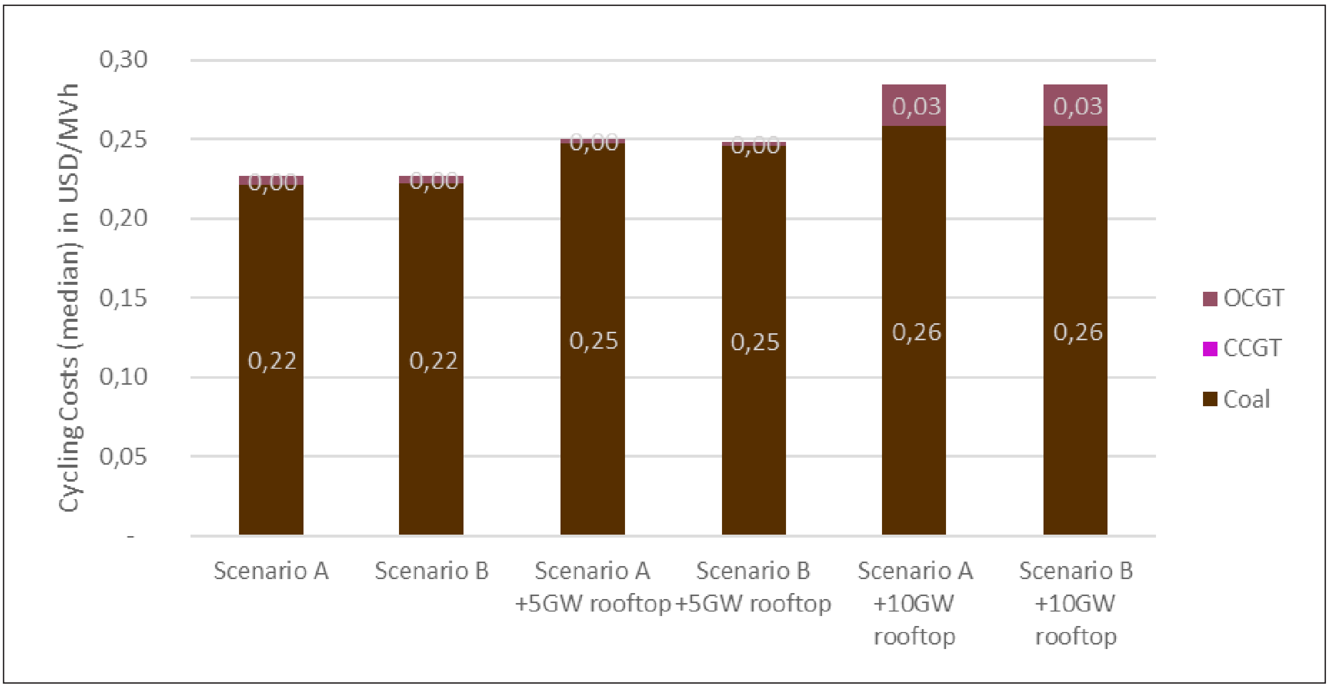

Figure 63: Cycling costs, break down into power plant types, year 2020

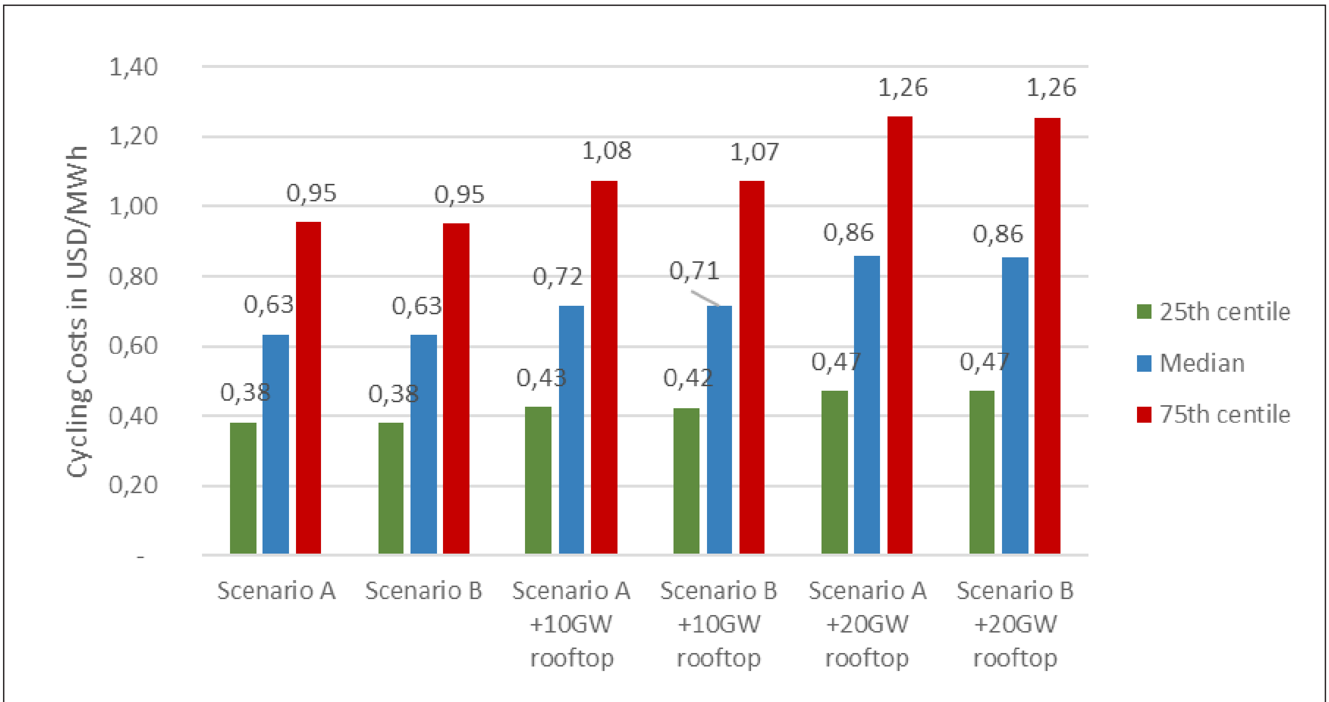

Figure 64: Cycling costs (range) in USD/MWh, 2030

In total, cycling costs are in a range between 0.5% and 2% of total LCOE of electricity production in 2030, depending on the assumed unit costs of cycling and the PV penetration level.

The breakdown of start-ups and load following ramps, according to **Figure 65**, shows that the cost of load following cycles decrease considerably in 2030 compared to 2020, but that the addition of CCGTs and OGCTs results in the cost of start-up cycles increasing significantly.

The breakdown of power plant types, as shown by **Figure 66**, confirms that increased cycling costs are mainly due to the addition of CCGTs, which are started on a daily basis. Increased cycling requirements resulting from the addition of 20GW of rooftop PV are met by OCGTs, which operate more frequently due to the increased variability of the system.

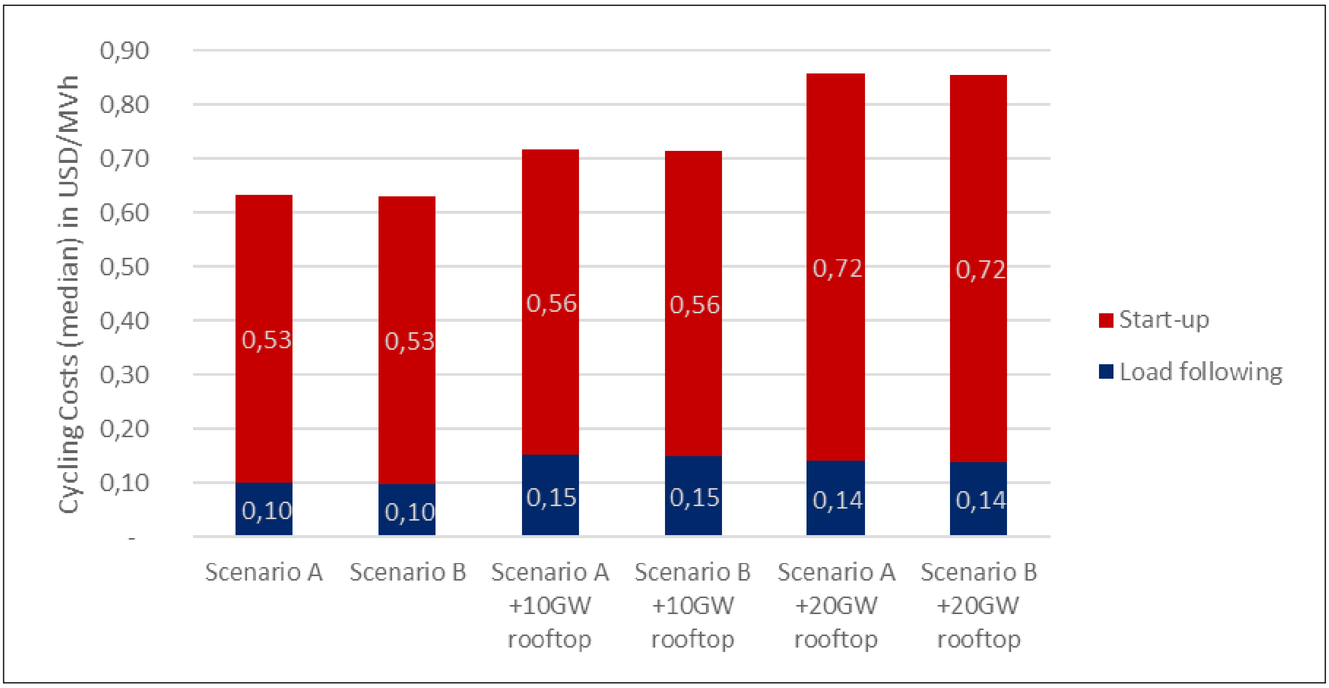

Figure 65: Cycling costs, break down into start-up and load following ramps, year 2030

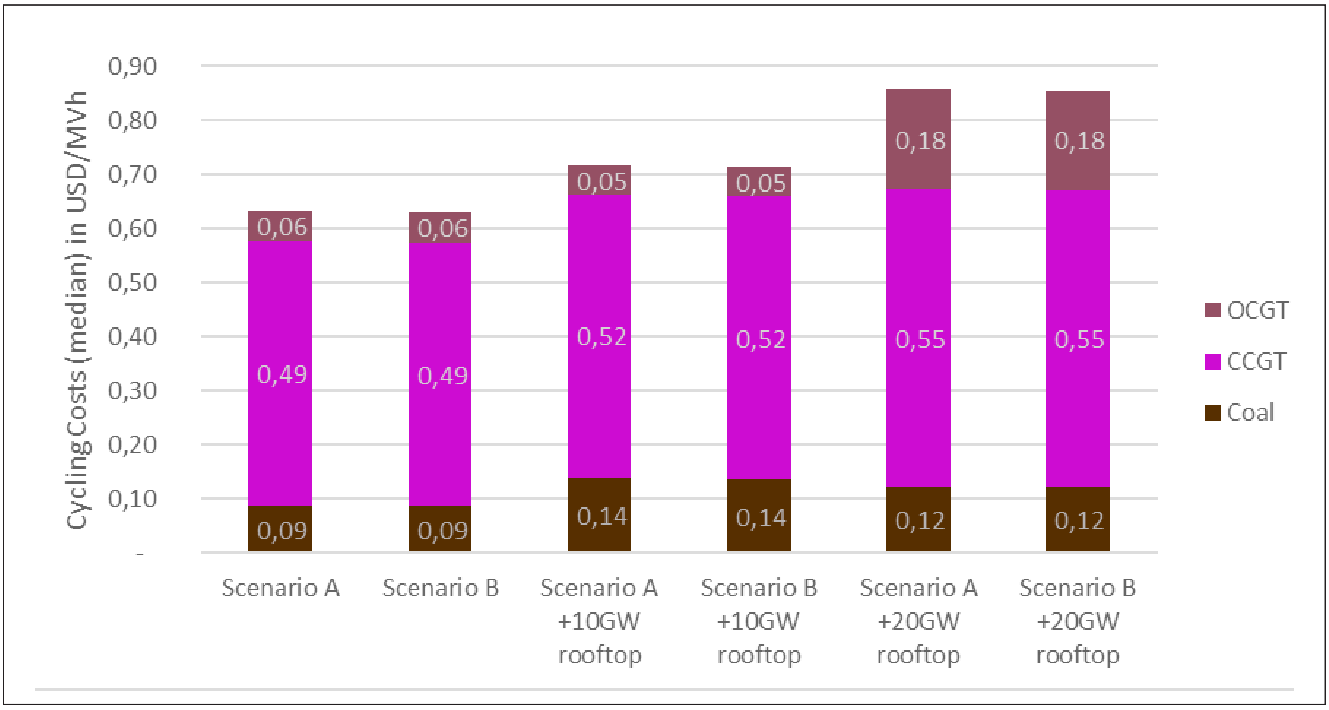

Figure 66: Cycling costs, break down into power plant types, year 2030

5 Conclusions and Recommendations

5.1 Balancing Power

It can be stated that by 2020, increased variability resulting from the addition of 4,2GW of wind and up to 12,8GW of solar PV (2,8GW utility-scale and up to 10GW of additional rooftop PV) does not require increasing Operating Reserves when compared to the levels allocated by ESKOM in 2016 (see [6]). Most reserves will be determined by worst-case contingencies and not by variability.

Imbalance Requirements resulting from day-ahead prediction errors increase by up to 13% because of wind and PV (including 10GW of rooftop PV) in 2020. This Imbalance must be compensated by either updated intra-day dispatch of conventional generation, Supplemental Reserve or 10-Minute Reserve or a combination of them.

In 2030, the standard scenarios considering installed wind and PV capacities according to the draft IRP-Base-Case-2016 [5] do not require increased Operating Reserve compared to the values which ESKOM allocated for 2020 according to [6]. If worst-case variability (situations with probability less than 1%) can be covered by Emergency Reserve, as suggested by this study, Emergency Reserve would have to be increased by around 27% compared to the levels allocated for 2020 by [6]. With the addition of up to 20GW of rooftop PV, the variability of the system will further increase and the allocation of Operating Reserve must more and more take variability aspects into account and cannot only be based on requirements resulting worst-case contingencies. As shown by **Table 13**, the total amount of Operating Reserve would have to be increased by around 10% for adding 10GW of rooftop PV by 2030 and by around 32% for adding 20GW of rooftop PV (see **Table 13**).

To balance worst-case short-term variability with Emergency Reserve, it would be necessary to increase Emergency Reserve by 80% compared to the situation without wind or PV.

Because of the predictable time variance of PV, increased amounts of Operating Reserve and Emergency Reserve would not have to be maintained permanently. Instead, it is recommended to maintain sufficient Operating and Emergency Reserve for backing-up credible contingencies permanently, and to increase Operating Reserve and Emergency Reserve between 3pm and 6pm every day for securing the system against high variability.

In 2030, Imbalance Requirements would increase by up to 37% compared to a system without wind and PV. This includes Imbalance introduced by up to 20GW of additional rooftop PV (27,5GW of PV in total).

Overall, we can conclude that balancing requirements increase moderately when adding up to 11GW of wind generation and 27,5GW of PV generation. When adding 10GW of rooftop PV until 2020, the amount of allocated Operating Reserve and Emergency Reserve would not have to be increased at all, compared to the values according to [6]. When adding 20GW of rooftop PV until 2030, a moderate update of Operating Reserve and Emergency Reserve would be required.

However, besides physical aspects, the amount of Operating Reserve depends also on operational procedures: In principle, it would be possible to reduce Operating Reserve Requirements by reducing the dispatch cycle (e.g. from 1 hour to 15 minutes), as it is done in Europe, the US or Australia (some states of USA and Australia even have dispatch cycles of 5 minutes). But because Operating Requirements only increase moderately until 2030, even when adding much more PV than foreseen by the IRP-2016-Base Case [5], we do not see the need for changing operational practice within the studied time frame.

5.2 Cycling

Until 2020, increased variability will mainly be compensated by increased load following cycling of coal fired power stations.

As shown by **Table 15**, the addition of 10GW of rooftop PV would increase cycling cost by around 22% or around 0,05USD/MWh (median) of generated energy[6]. In this study, cycling costs include direct and indirect effects, such as C&M costs resulting from load following cycling and start-ups and direct start-up costs (start-up fuel and start-up costs of auxiliaries). Not delivered energy resulting from increased EFOR and efficiency decrease resulting from increased cycling is not included in these costs[7].

[6] Cost of cycling are based on total energy demand in MWh

[7] Other studies in this area (e.g. [10]) confirm that the cost components considered in this study cover at least 80% of overall cycling cost and cost of EFOR and efficiency decrease du to frequent cycling increases in proportion to the number of load following ramping events and start-up events.

Table 15: Cost of cycling in USD/MWh in 2020

		Scenario A	Scenario B	Scenario A +5GW rooftop	Scenario B +5GW rooftop	Scenario A +10GW rooftop	Scenario B +10GW rooftop
25th centile	Load following	0,13	0,13	0,14	0,14	0,15	0,15
	Start-up	0,00	0,00	0,00	0,00	0,01	0,01
	Total	**0,13**	**0,13**	**0,14**	**0,14**	**0,16**	**0,16**
Median	Load following	0,22	0,22	0,25	0,25	0,26	0,26
	Start-up	0,00	0,00	0,00	0,00	0,03	0,03
	Total	**0,23**	**0,23**	**0,25**	**0,25**	**0,28**	**0,28**
75th centile	Load following	0,28	0,28	0,31	0,31	0,33	0,33
	Start-up	0,01	0,01	0,00	0,00	0,03	0,03
	Total	**0,29**	**0,29**	**0,32**	**0,31**	**0,36**	**0,36**

Table 16: Cost of cycling in USD/MWh in 2030

		Scenario A	Scenario B	Scenario A +5GW rooftop	Scenario B +5GW rooftop	Scenario A +10GW rooftop	Scenario B +10GW rooftop
25th centile	Load following	0,06	0,06	0,09	0,08	0,08	0,08
	Start-up	0,33	0,33	0,34	0,34	0,39	0,39
	Total	**0,38**	**0,38**	**0,43**	**0,42**	**0,47**	**0,47**
Median	Load following	0,10	0,10	0,15	0,15	0,14	0,14
	Start-up	0,53	0,53	0,56	0,56	0,72	0,72
	Total	**0,63**	**0,63**	**0,72**	**0,71**	**0,86**	**0,86**
75th centile	Load following	0,13	0,12	0,19	0,19	0,18	0,18
	Start-up	0,83	0,83	0,88	0,88	1,08	1,08
	Total	**0,95**	**0,95**	**1,08**	**1,07**	**1,26**	**1,26**

In 2030, the IRP-2016-Base-Case [5] foresees the installation of numerous CCGTs and additional OCGTs for dealing with increased flexibility requirements. CCGTs will operate as mid-merit power plants with typically one, or even two, start-ups per day. Consequently, start-up costs become significantly more important (**see Table 16**).

The addition of 20GW of rooftop PV would increase cycling costs by around 36%. This is equivalent to 0,23USD per MWh of generated electricity.

5.3 Overall Summary and Conclusions

The studies presented in this report confirm that the South African power system will be sufficiently flexible to handle very large amounts of wind and PV generation, especially when considering the addition of CCGTs and OCGTs according to the IRP-2016-Base-Case [5]. To cope with increased flexibility requirements resulting from the installation of 4,2GW of wind generation and up to 12,8GW of PV by 2020, and 11GW of wind and 27,5GW of PV by 2030, flexibility requirements can be handled by existing and planned power plants at moderate additional costs.

In 2030, the addition of CCGTs will even reduce cycling requirements of coal-fired power stations, even with 20GW of additional rooftop PV.

In the case of very high PV installations (10GW in 2020, 20GW in 2030), it is recommended to move pumping operation of pumped-storage power plants from night to midday, when Residual Load is at its minimum value. This relaxes Residual Load Requirements and allows coal fired power plants to operate at higher levels. It can also help reduce the amount of curtailed PV energy.

Until 2020, the allocated Operating and Emergency Reserve does not need to be increased, even when adding 10GW of additional rooftop PV.

Until 2030, Operating and Emergency Reserve, according to [6], is still sufficient for balancing increased variability if wind and PV generation is installed, as foreseen by the IRP-2016-Base-Case [5].

When installing 10GW or 20GW of rooftop PV in addition, Operating and Emergency reserve must be increased for balancing increased variability. However, the required additional Operating and Emergency Reserves are in a moderate range.

To ensure secure and cost-efficient operation of the South African power system even with very high levels of wind and PV generation, we can make the following recommendations:

- Application of professional short-term forecast tools/ services for wind and PV prediction, including a system for short-term prediction of rooftop PV.
- In the case of very high PV installations (e.g. 27GW by 2030): Allocation of higher levels of Operating Reserve and Emergency Reserve in afternoon hours.
- In the case of very high PV installations (e.g. 27GW by 2030): Operate pumped-storage power plants in pumping mode during mid-day (and not during night time) when Residual Load is at its minimum value.

Other modifications to operational procedures (day-ahead planning, intra-day planning, real time operations) are not required in the studied time frame and the studied levels of wind and PV.

This study confirms that very large penetration levels of wind and PV could be handled by the system from an active power balancing point of view at moderate additional costs for balancing services (Reserve and increased cycling of thermal power plants).

Other aspects, like voltage issues resulting from the operation of the South African power system with very high levels of distributed PV and potentially required additional reactive power compensation equipment (and/or new strategies for reactive power and voltage control at distribution levels) was not subject to these studies and should be analysed in follow-up work to this study.

6 Outlook

When looking at the time frame beyond 2030 with even larger penetration levels of wind and PV than considered in this report, flexibility requirements will further increase and the following mitigation measures should be considered for ensuring cost efficient operation of the South African power system.

- Generation mix: When expanding the use of VRE, retiring coal-fired power plants should be replaced by flexible mid-merit and peaking plants (e.g. CCGTs, OCGTs and if possible additional pumped-storage plants). This is in line with the results of the IRP2016 base case scenario [3].
- To reduce Operating Reserve requirements, the dispatch cycle could be reduced from 1h to 15min (or even 5 minutes, as it is current practice in some systems in the USA and in Australia). With shorter dispatch cycles, short-term variability introduced by PV is substantially reduced.
- In the longer term, when cost of battery storage further decreases, distributed battery storage that is coordinated with PV would help to reduce Operating Reserve requirements and cycling costs by storing power during mid-day and feeding it into the system during evening hours.
- To compensate increasing Imbalance Requirements resulting from the limited predictability of wind and PV (especially wind), additional pumped-storage power plants with storage capacities of more than 24 hours could help.

When integrating large amounts of VRE (beyond the levels analysed in this study) other aspects relating to the operation of power systems with large amounts of non-synchronous generation (e.g. potential grid constraints or stability issues) should be studied carefully and the available technologies for mitigating these issues must be taken into consideration (see also [14]). This is required for ensuring that no grid or stability constraints could prevent South Africa from transforming the South African power system into a wind-solar-gas system successfully, which is currently under discussion as being a least-cost scenario for the future development of the South African power system (e.g. see “Base Case + Carbon Budget + No Annual Constraints on RE” according to [3]).

7 References

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