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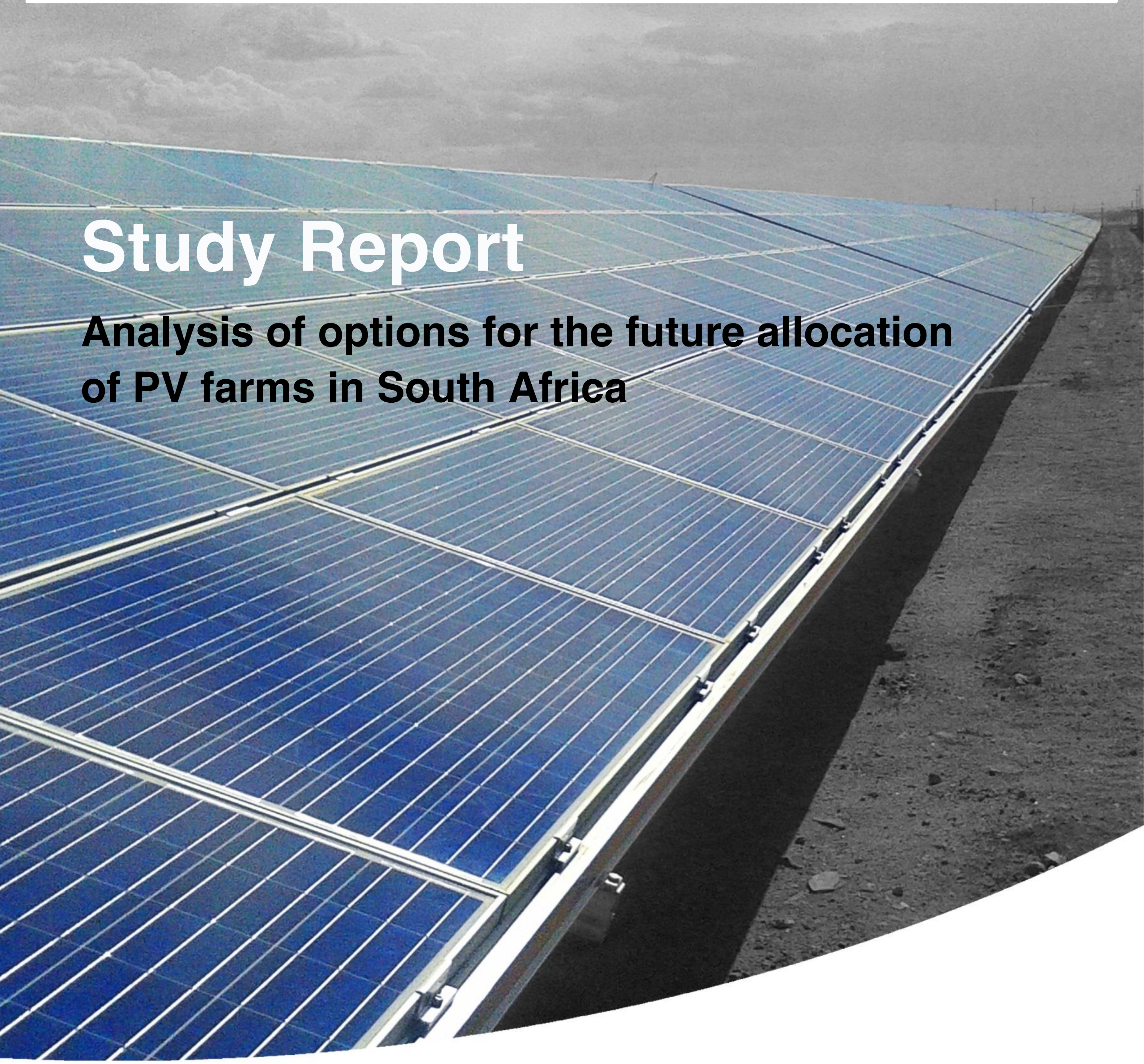

Study Report

Analysis of options for the future allocation of PV farms in South Africa

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1 Executive Summary

Objective and Scope of Studies

The aim of the studies presented in this report is to quantify the economic impact of different strategies for the deployment utility scale PV farms in South Africa. These are referred to as 'allocation strategies'.

Three different allocation strategy scenarios for a total of 8,4GW of utility scale PV farms in South Africa have been considered. These are summarized as follows:

- **Scenario A:** "**As planned**"
  This scenario is according to the existing applications for PV farms where there is a total of, 6,4GW of PV in the 'Solar Corridor' (see Figure 2), and 2GW distributed elsewhere in the country.
- **Scenario B:** "**Close to load centers**"
  Here, only 2,6GW of PV is considered in the Solar Corridor, the remaining 5,8GW is distributed across the country.
- **Scenario C:** "**According to REDZs** [1]"
  For this scenario, PV farms have been allocated in the Renewable Energy Development Zones (REDS), as identified by CSIR and DEA within the SEA project [1]. In this scenario, 2,8 GW is considered in the Solar Corridor, and 5,6GW is distributed predominantly in the REDZs.

For assessing the overall economic impact of the different allocation strategies, the following techno-economic studies have been carried out:

- Calculation of levelized cost of electricity (LCOE) of utility-scale PV farms in various South African regions.
- Load flow and contingency analysis for identifying any required transmission system upgrades. Plus a high level assessment of any required distribution system reinforcements.
- Load flow simulations using time series data of substation loads and PV infeed with a time resolution of 30min for calculating the impact of PV on transmission system losses over the period of 1 year.

The cost impact of all of the above aspects has been expressed in levelized form on basis of units of produced electricity from PV. Hence, the key results are:

- LCOE: Levelized cost of electricity of PV farms considering all investments up to the point of connection (POC)
- LCOT: Levelized cost of transmission grid upgrades (per kWh of generated PV electricity)
- LCOD: Levelized cost of distribution grid upgrades (per kWh of generated PV electricity)
- LCOL: Levelized cost of losses (cost of losses per kWh of generated PV electricity).

The overall cost impact of the three scenarios for allocating PV farms in South Africa is finally expressed by the sum of all of the above listed cost indices.

The main results and conclusions of the studies are summarized in the following sections.

Levelized Cost of Electricity of planned PV farms

The resulting average LCOE (at POC) of utility scale PV farms in South Africa is shown for each allocation scenario in Table 1 below.

Table 1: Average LCOE of utility scale PV farms in South Africa per Allocation Scenario

	Scenario A	Scenario B	Scenario C
LCOE in USD/kWh, static systems	0,1198	0,1244	0,1229
LCOE in USD/kWh, tracked systems	0,1116	0,1171	0,1153

As it could be expected, Scenario A leads to the lowest overall LCOE of the three analyzed scenarios because this is the scenario with the highest energy yield per kW installed.

These numbers are higher than recently published round three bids. However, one should consider that the figures according to Table 1 represent average values of LCOE for utility scale PV farms with a total installed capacity of 8,4GW, including many PV farms outside the Solar Corridor. When only looking at the Northern Cape, the calculated LCOE gets much closer to the published round three figures (see Table 17, Table 18 and Table 19).

Transmission and Distribution Grid Upgrades

For identifying the required transmission grid upgrades, load flow and contingency analysis studies were performed using a model of the complete South African transmission system including 765kV, 400kV, 275kV, 220kV voltage levels. PV generation was modelled by equivalent infeed into the nearest transmission substation. Transmission upgrades mainly include:

- Transmission line upgrades (e.g. additional lines, upgraded voltage levels)
- Substation upgrades (additional transformers and switch bays)

Cost of required distribution upgrades have been calculated based on a high level assessment, considering the capacity of existing 132kV or 88kV grids and the average distance of planned PV farms from the nearest transmission substation in each region. The result of this assessment is the total length of additionally required distribution lines.

The most relevant grid upgrades of each scenario are summarized in Table 2.

Table 2: Required Transmission and Distribution Upgrades of Scenario A, B and C

	Scenario A	Scenario B	Scenario C
Transmission Lines (400kV/275kV) in km	1105	136	235
Number of Substation Transformers	32	15	15
Distribution Lines (132kV/88kV) in km	1772	1130	1192

CAPEX of grid upgrades have been calculated using unit costs, as provided by ESKOM. OPEX of grid upgrades was generally be considered to be equal to 3% of CAPEX, which is in-line with ESKOM's standard assumptions.

The economic impact of grid upgrades, expressed as levelized cost on the basis of annually generated energy from PV, is depicted in Table 4 (static PV systems) and Table 5 (tracked PV systems).

Table 3: CAPEX of required grid upgrades

	Scenario A	Scenario B	Scenario C
CAPEX of Transmission grid upgrades in Mio. USD	554,73	135,27	165,13
CAPEX of Distribution grid upgrades in Mio. USD	670,76	423,03	445,73
Total CAPEX of grid upgrades in Mio. USD	**1.225,49**	**558,30**	**610,86**

Table 4: Levelized cost of transmission and distribution upgrades, static PV systems

static systems	Scenario A	Scenario B	Scenario C
LCOT in USD/kWh	0,0042	0,0011	0,0013
LCOD in USD/kWh	0,0051	0,0033	0,0034
Total (LCOT+LCOD) in USD/kWh	**0,0093**	**0,0044**	**0,0047**

Table 5: Levelized cost of transmission and distribution upgrades, tracked PV systems

tracked systems	Scenario A	Scenario B	Scenario C
LCOT in USD/kWh	0,0036	0,0009	0,0011
LCOD in USD/kWh	0,0044	0,0029	0,0030
Total (LCOT+LCOD) in USD/kWh	**0,0080**	**0,0038**	**0,0041**

Impact on Losses

In order to calculate the impact of utility scale PV in South Africa on transmission losses, the load flow model has been expanded by time series data of PV generation and substation loads. For considering the impact of PV generation on the dispatch of conventional power plants, a rule based economic dispatch algorithm has been implemented.

Table 6 below summarizes the impact of PV generation according to Scenario A, Scenario B and Scenario C on transmission system losses. The results of this table show, that PV generation according to Scenario A, B and C will reduce transmission network losses by a similar amount.

Table 6: Impact of PV generation on transmission system losses

	Base Case	Scenario A	Scenario B	Scenario C
Av. Power Losses in MW	887	795	789	788
Annual Energy Losses in GWh	7767	6964	6910	6907
Difference, Power in WM		-92	-98	-98
Difference, Energy in GWh		-802,938	-857,624	-860,848

In order to assess the impact of avoided losses on cost, ESKOM has provided maximum and minimum limits of the Long Run Marginal Costs (LRMC). The corresponding cost figures, also expressed in the form of levelized costs on basis of the electrical energy produced by PV farms, are summarized in Table 7. These figures are all negative, because transmission system losses will be reduced when PV generation displaces conventional generation.

When comparing these figures to the results of Table 4 and Table 5 it can be concluded that cost of grid upgrades will be paid partly (Scenario A) or even completely (Scenario B and C) by the reduction of transmission system losses. Please note that the impact of PV on distribution system losses has not been evaluated.

Table 7: Levelized cost of (avoided) losses

	Scenario A	Scenario B	Scenario C
LCOL, max LRMC in USD/kWh	-0,0057	-0,0063	-0,0062
LCOL, min. LRMC in USD/kWh	-0,0029	-0,0031	-0,0031
LCOL, average LRMC in USD/kWh	-0,0043	-0,0047	-0,0047

Conclusions and Recommendations

The resulting levelized cost of energy of static and tracked PV systems, allocated according to Scenario A, B and C are depicted in Figure 1. These figures include the actual LCOE of utility scale PV systems at the POC, transmission and distribution upgrades (LCOT and LCOD) and the impact of losses (LCOL).

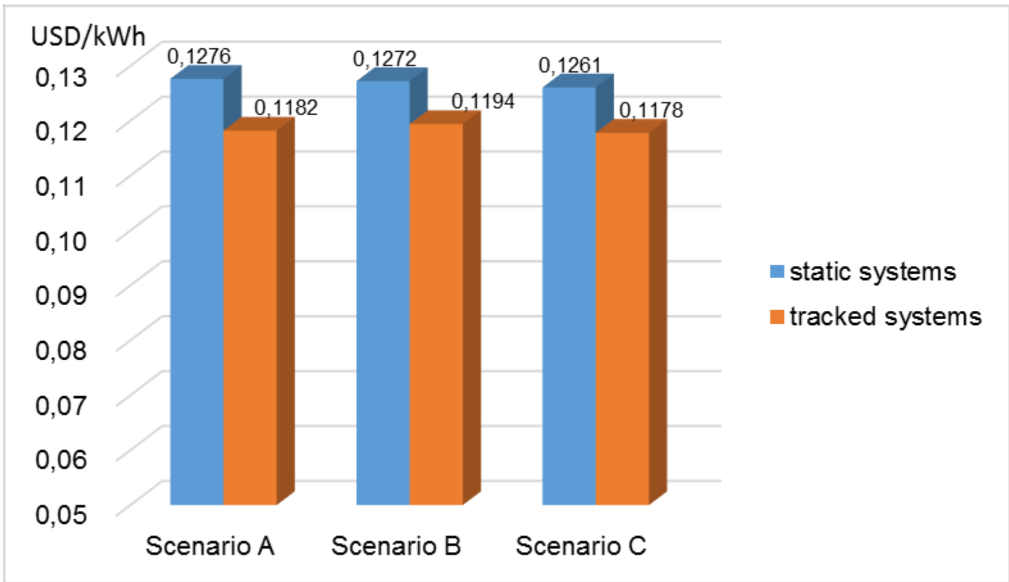


Figure 1: Total levelized cost of electricity of PV generation

Based on these results, the main conclusions are:

- All three PV allocation scenarios analysed in the presented studies result in very similar economic impact, and each could therefore be justified from a cost point of view (see Figure 1).

- In Scenario A, where the cost of PV production is lower (higher energy yield) compared to the two other scenarios, there are higher transmission and distribution expansion costs, which even out the advantage of a higher energy yield of PV farms in this Scenario.
- In all three Scenarios, system losses are reduced compared to the Base Case Scenario without PV generation. The amount of (energy) loss reduction is almost identical for all three scenarios.

Following these conclusions, the main recommendations for the allocation of PV farms in South Africa are summarized as follows:

- As the overall cost of the three scenarios are almost identical, decisions with respect to the future strategies for allocating PV farms in South Africa should consider additional criteria such as the risks associated with each allocation strategy. Specifically, the timely realization of transmission grid upgrades are considerable. Therefore Scenario B and Scenario C (more heavily distributed PV) would be more favorable than Scenario A (large concentration of PV in the Solar Corridor requiring significant transmission upgrades).
- Consequently, the most economical approach will be to use the available transmission grid capacity in the Solar Corridor up to its full extent for PV generation. This limit will be at around 2,8GW of installed PV capacity, as shown by the results in Scenario B and C.
- PV capacity above this limit should be distributed across the country. Besides solar irradiation/energy yield, other criteria such as required transmission and distribution upgrades, socio-economic impact, environmental impact etc. should also be considered when deciding upon the allocation of these capacities.

Future rules and regulations in South Africa, especially those relating to the South African Renewable Energy IPP Procurement Program, should consider these aspects in order to ensure the most successful and cost efficient deployment of utility scale renewable PV generation for the country as a whole.

2 Background

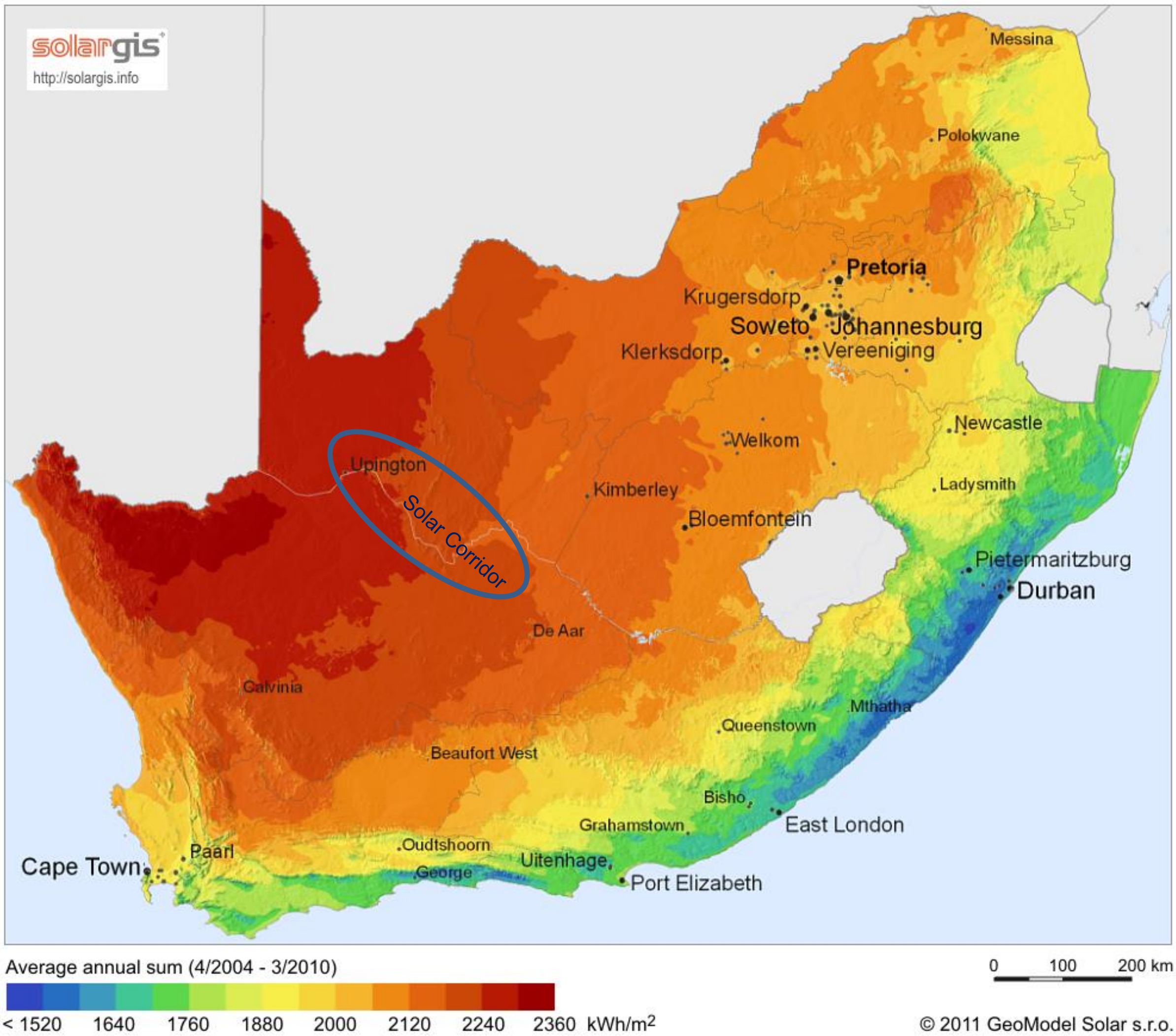


Figure 2: Global horizontal solar irradiation in South Africa

Within the next 10 to 20 years there is a high possibility that up to 8400MW of PV generation will be installed in South Africa. This is based on the plans contained in IRP 2010 and applications already received.

At present, most developers of utility scale PV farms are planning their projects in areas with the highest solar irradiation, mainly in the Northern Cape, in the so-called “Solar-Corridor” as shown in Figure 2. Constructing PV farms in areas such as this with very high solar irradiation leads to the lowest cost of energy generation which subsequently allows the developers to submit bids with low generation tariffs. However, a high concentration of PV in areas with low population density will typically require substantial grid reinforcements, including long transmission lines at main transmission voltage levels.

It should be noted however, that compared to world-wide figures, there are excellent conditions for PV generation in most regions of South Africa, including those which are relatively close to load centers and therefore close to a very strong electricity grid.

Allocating PV farms closer to load centers would slightly increase cost of generation due to the comparatively lower solar irradiation, but at the same time it would reduce grid expansion costs.

These considerations triggered a debate about the overall cost of PV in South Africa and the optimum location of those projects.

For this reason, in the context of the RE Grid Advisory Sub-Component of GIZ-SAGEN, the DoE and ESKOM, together with GIZ-SAGEN, initiated techno-economic studies for assessing the impact of PV allocation in South Africa based on overall costs, including cost of electricity production, cost of transmission grid expansion and cost of losses.

The studies were supported by a working group with members of ESKOM, DoE, SAPVIA, CSIR, DEA and GIZ, who provided very valuable input and comments, especially with respect to the definition of realistic allocation scenarios, grid models and financial parameters.

This report presents the methodology and outcome of these studies.

3 Approach and Methodology

3.1 General

The studies presented in this report are based on three different scenarios for the allocation of PV which are detailed in section 3.2 below. These scenarios are based on realistic assumptions with regard to the allocation of PV in South Africa.

The economic assessment of these studies analyses the overall economic impact of PV generation considering:

- LCOE: Levelized cost of energy of PV at the point of connection (POC)
- LCTD: Levelized cost of additionally required grid assets (transmission and distribution)
- LCOL: Levelized cost of losses (evaluating the difference between annual energy losses in the transmission system with and without PV generation for each scenario).

3.2 Scenarios

For the purpose of the studies, three scenarios have been defined with respect to the allocation of PV farms in South Africa. The scenarios, realised by lumped PV infeed into each transmission substation, have been defined by ESKOM, considering the work of DEA and CSIR with regard to Renewable Energy Development Zones (“REDZs”) [1], and reflect actual applications and environmental constraints:

- **Scenario A:** “**As planned**”
  According to existing applications for PV farms, 6,4GW of PV in the solar corridor, 2GW distributed.
- **Scenario B:** “**Close to load centers**”
  Only 2,6GW in the Solar Corridor, the rest (5,8GW) distributed across the country.
- **Scenario C:** “**According to REDZs**”
  2,8 GW in the Solar Corridor, the rest (5,6GW) distributed (predominantly in the REDZs [1]) and more concentrated than Scenario B.

The allocation of PV infeed per substation for each of the three scenarios is depicted in Figure 3, Figure 4 and Figure 5. The diameter of the circles is in proportion to the PV infeed per substation. Additionally, these maps show global solar irradiation and population density.

Table 8 provides a summary of the allocation of PV capacity per province for each of the three scenarios. Details about the installed PV capacity feeding into each substation is listed in Annex 1.

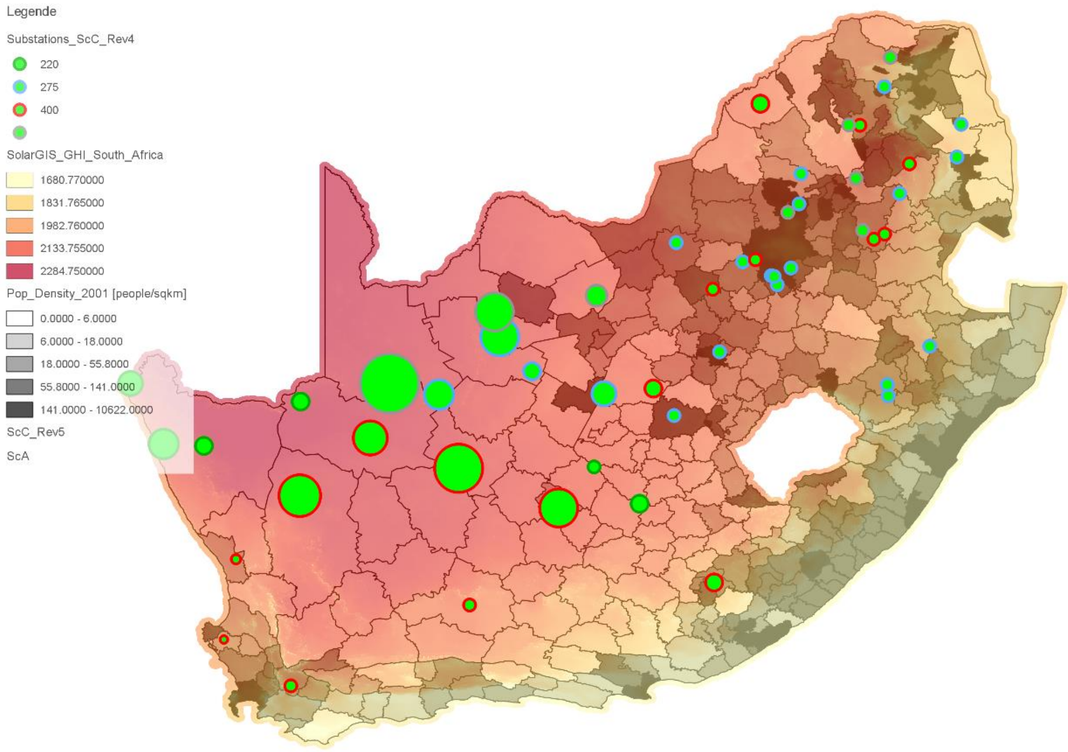


Figure 3: PV Allocation per substation for Scenario A

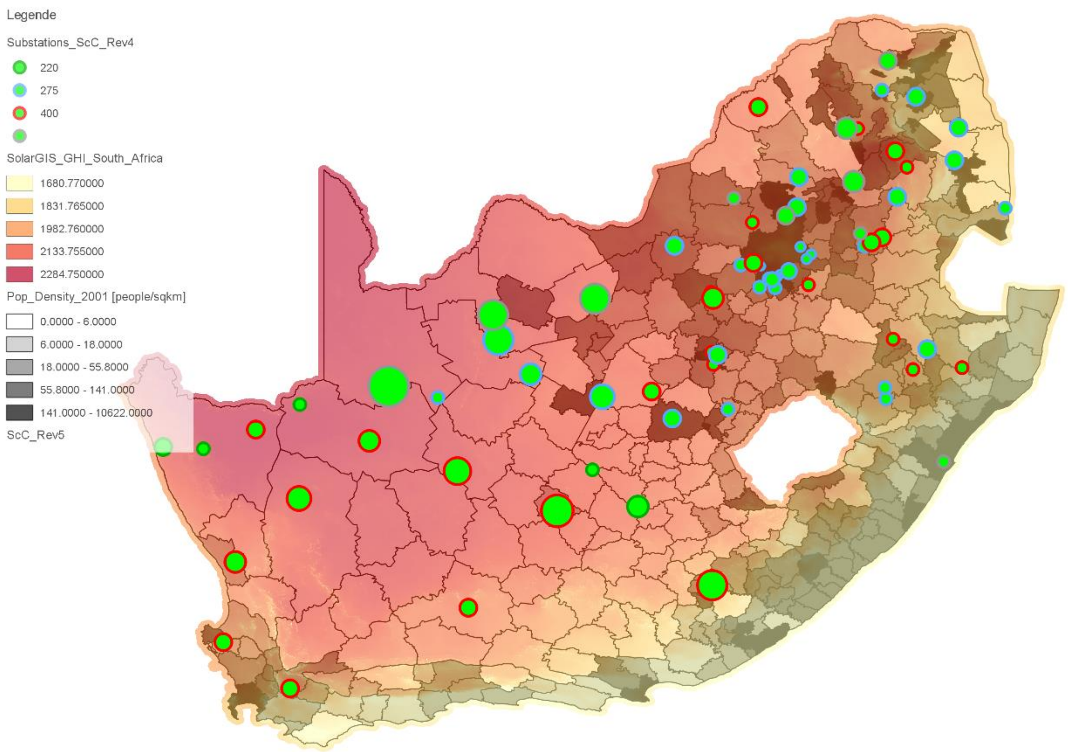


Figure 4: PV Allocation per substation for Scenario B

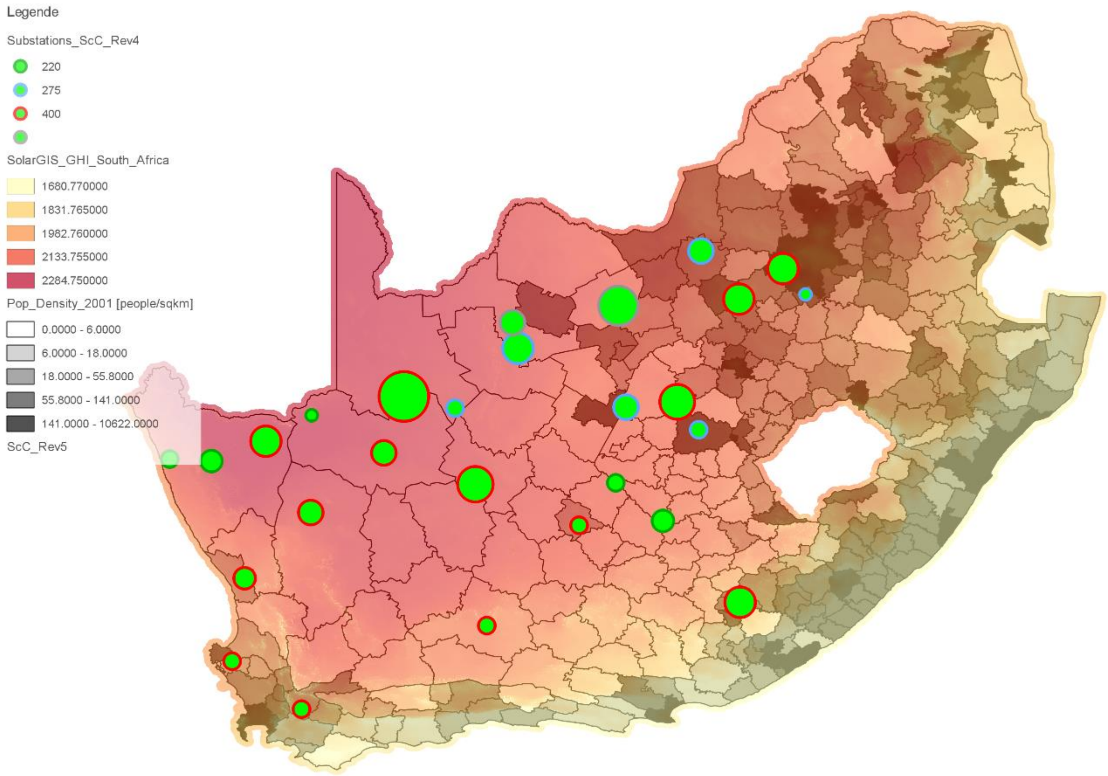


Figure 5: PV Allocation per substation for Scenario C

Table 8: Allocation of PV capacity per province for Scenario A, B and C

Province	Scenario A [MW]	Scenario B [MW]	Scenario C [MW]
Northern Cape	6000	2600	2800
North West	350	750	2100
Free State	500	950	2100
Mpumalanga	250	600	0
Limpopo	500	1050	0
KwaZulu Natal	150	400	0
Gauteng	300	650	0
Eastern Cape	200	750	750
Western Cape	150	650	650
Total	**8400**	**8400**	**8400**

3.3 Cost of PV Generation

3.3.1 Levelized Cost of Electricity

For quantifying the cost of electricity production, the LCOE (Levelized Cost of Electricity) approach has been applied. LCOE is equivalent to a fixed tariff per kWh, which has to be paid over the entire time of use of the plant so that the Net Present Value (NPV) of income breaks even with the NPV of costs (including the expected return of equity) of the plant (e.g. [1]).

Hence, LCOE is defined by the equation below:

$$\sum_{t=1}^{n} LCOE \frac{E_t}{(1+WACC)^t} = I_0 + \sum_{t=1}^{n} \frac{C_t}{(1+WACC)^t}$$

with:

- n: time of use (in number of years)
- t: time (in years)
- LCOE: Levelized Cost of Electricity
- WACC: Weighted Average Cost of Capital (real)
- E_t: Energy yield in year t
- I_0: Initial investment cost (CAPEX at year t=0)
- C_t: Cost in year t (O&M and reinvest)

The LCOE approach has been taken for evaluating cost of PV production because it represents a widely accepted methodology and works well in the South African context, where the RE procurement process requires the submission of fixed tariffs per MWh.

3.3.2 CAPEX and OPEX of PV installations

Typical investment costs of PV have been assessed on basis of interviews with South African developers of PV projects. The objective of this survey has been to identify typical values of installed PV costs (turn-key) in South Africa.

The cost breakdown considers the following components of a PV farm:

- Modules: Cost of PV modules
- Tracker: Cost of single axis tracker systems (only in case of “tracked” systems)
- Inverter: Cost of PV inverter
- Construction: All on-site works
- Logistics: Roads, water supply during construction, housing of staff, transportation etc.
- Services: Planning, studies, project management, tests, commissioning etc.
- Other: anything else (e.g. land use etc.)

The resulting CAPEX and OPEX for static and tracked PV-systems which have been based on the survey and used for the economic assessment are summarized in Table 9.

The corresponding cost breakdown (tracked systems) is depicted in Figure 6.

Site-specific cost aspects (e.g. land price etc.) have not been considered because it became apparent that these differences are not significant in comparison to the total costs (especially when compared to site-specific variations of the energy yield).

Table 9: Assumed CAPEX and OPEX of utility scale PV farms in SA

PV CAPEX and OPEX	
PV Plant (static) [USD/kWp]	$ 1.850,00
PV Plant (tracked) [USD/kWp]	$ 2.000,00
Substation [USD/kVA]	$ 15,00
Annual operation costs (static) [USD/kWp]	$ 31,50
Annual operation costs (tracked) [USD/kWp]	$ 35,00

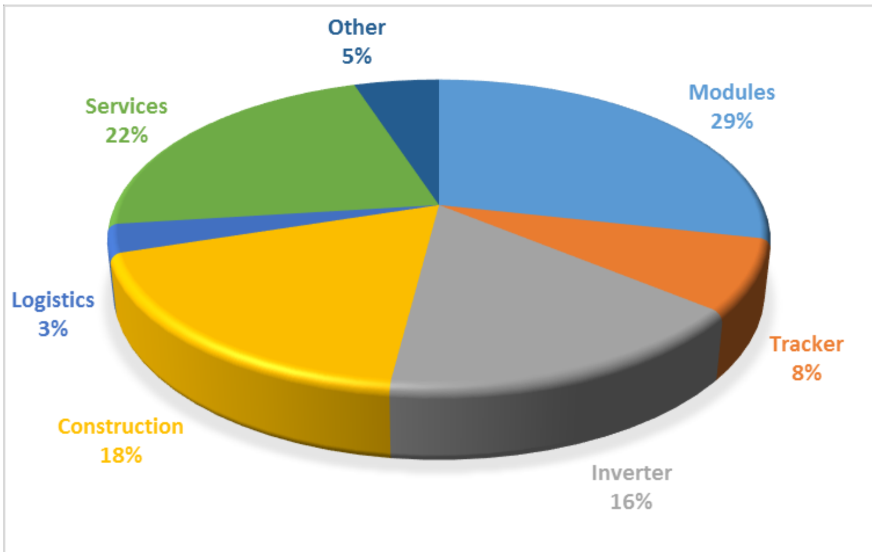


Figure 6: Cost break down of utility scale PV farms in SA - tracked systems

3.3.3 Energy Yield

For the purpose of these studies the modelling resolution of PV farm allocations is substation-specific and not site-specific. Hence, for estimating the average annual energy yield of all PV farms of each scenario, the location of each transmission substation, at which PV infeed is modelled, is considered to be representative for the energy yield of all PV farms feeding into this particular substation.

The average annual energy yield at the substation locations has been extracted from the Environment GIS (EGIS) website of the South African Department of Environmental Affairs (DEA) [2] and [3]. These references provide energy yield data for static and tracked PV systems. Additionally they calculate the annual average electrical energy yield considering effects like inverter losses, impact of temperature on inverter efficiency, etc.

For considering efficiency decrease of PV modules over time, an annual reduction of the electricity output of 0,5% per year was also considered.

3.3.4 Financial Parameters

Table 10: Financial Parameters

Financial	
Share of equity	25,0%
Share of dept	75,0%
Return on equity (nominal)	17,0%
Interest rate on dept (nominal)	13,0%
Credit period [years]	16
WACC nominal	14,0%
Inflation	5,7%
WACC real (year 1 to 16)	**8,3%**
WACC real (year 17 to 20)	**11,3%**
Time of Use [years]	**20**

The relevant financial parameters have been defined on the basis of feedback from South African PV project developers. These are summarized in Table 10.

3.4 Grid Expansions

3.4.1 Transmission Modelling

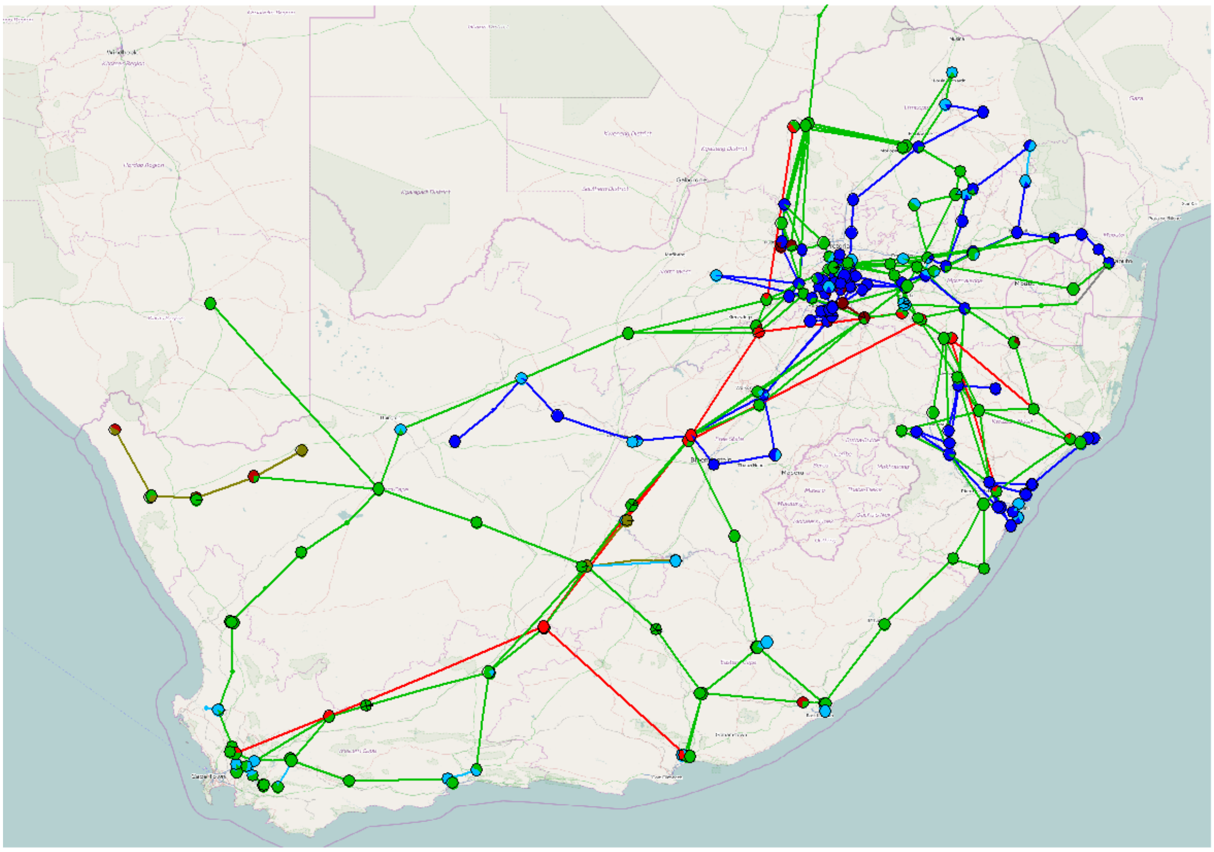


Figure 7: Model of the South African Transmission System (red: 765kV, green: 400kV, blue: 275kV, brown: 220kV)

For identifying required transmission grid expansions, ESKOM provided a model of the South African transmission grid to the consultants. This model contains all planned transmission and generation expansions according to the transmission development plan for the year 2020 (see Figure 7).

The used model consists of 2359 nodes and represents the complete South African transmission grid, including 765kV, 400kV, 275kV, 220kV levels and reduced models of the underlying 132kV networks. Besides existing and planned thermal and hydro generation, the model contains planned wind generation until 2020 but no PV generation.

The generator dispatch contained in this model is for the predicted peak load hour of the year 2020 (around 51,5GW). In addition to the model itself, ESKOM provided time series data of all substation loads with a resolution of 30min. This load data has been scaled up to the 2020 peak load of around 51,5GW. Using this information, together with the provided Merit Order Table [4] it was therefore possible to generate a load flow model for any half hour period during the year 2020, including time series data of load and PV generation and an integrated algorithm for calculating an optimized dispatch of conventional generation for every 30min time step.

Because the existing transmission development plan has been produced without considering PV, all transmission expansions, which are required in addition to already planned transmission expansions, can be accounted for and applied to the overall cost of PV generation.

3.4.2 Transmission Expansion Planning

In order to determine required transmission grid expansions, the planned PV generation has been modelled for each scenario as equivalent infeed into the corresponding transmission substation as per Scenario A, B and C and Annex 1: 'Installed capacity and energy yield per substation'.

However, in reality, most PV farms will be connected to distribution levels (mostly 132kV). Since the resolution of this study is only substation-specific and not site-specific, only transmission grid expansions can be identified (in 765kV, 400kV, 275kV, 220kV grids, including substation transformers), but it is not possible to predict sub-transmission and distribution network reinforcements and expansions, which will be required at 132kV or below. A reliable assessment of distribution expansion costs would require site-specific information about each individual PV farm, which is simply not yet available at this early stage of the planning and development process. Therefore, it is appropriate (and in-line with international practice) to limit the results of this study to transmission grids.

It should be noted however, that the cost of distribution reinforcements can be considerable. Therefore, a high level cost estimate of required distribution network reinforcements and expansions was performed and added to the results sections of this report (see also section 3.4.3). However, it must be kept in mind that the accuracy of this estimate is much below the accuracy of all other results presented in this report.

For working out required transmission reinforcements and expansions the following worst case load/generation dispatch scenarios have been extracted from the time series data of the substation loads (year 2020):

- Peak load during daytime: 47GW
- Low load during daytime: 34GW

For balancing off thermal and hydro generation, thermal and hydro power plants have been reduced and switched off according to the Merit Order Table and the additional constraints and rules, which ESKOM described in [4].

The key parameters of the resulting worst-case generator-load dispatch cases are shown in Table 11 and Table 13 below:

Table 11: Generation dispatch for "High Load during Day Time" cases with one Koeberg unit available

Case	Load	Hydro/Thermal	No. Koeberg	Wind	PV	Apollo HVDC
	GW	GW		GW	GW	GW
Base Case	47,000	46,118	1	0,657	0,000	1,464
Scenario A	47,000	37,801	1	0,657	8,400	1,464
Scenario B	47,000	37,602	1	0,657	8,400	1,464
Scenario C	47,000	37,552	1	0,657	8,400	1,464

Table 12: Generation dispatch for "High Load during Day Time" cases with two Koeberg units available

Case	Load	Hydro/Thermal	No. Koeberg	Wind	PV	Apollo HVDC
	GW	GW		GW	GW	GW
Base Case	47,000	45,966	2	0,657	0,000	1,464
Scenario A	47,000	37,673	2	0,657	8,400	1,464
Scenario B	47,000	37,457	2	0,657	8,400	1,464
Scenario C	47,000	37,470	2	0,657	8,400	1,464

Table 13: Generation dispatch for "Low Load during Day Time" cases with one Koeberg unit available

Case	Load	Hydro/Thermal	No. Koeberg	Wind	PV	Apollo HVDC
	GW	GW		GW	GW	GW
Base Case	34,000	32,731	1	0,945	0,000	1,464
Scenario A	34,000	24,832	1	0,945	8,400	1,000
Scenario B	34,000	24,602	1	0,945	8,400	1,000
Scenario C	34,000	24,656	1	0,945	8,400	1,000

Table 14: Generation dispatch for "Low Load during Day Time" cases with two Koeberg units available

Case	Load	Hydro/Thermal	No. Koeberg	Wind	PV	Apollo HVDC
	GW	GW		GW	GW	GW
Base Case	34,000	32,584	2	0,945	0,000	1,464
Scenario A	34,000	24,820	2	0,945	8,400	1,000
Scenario B	34,000	24,632	2	0,945	8,400	1,000
Scenario C	34,000	24,662	2	0,945	8,400	1,000

For identifying required transmission reinforcements the following constraints have been considered:

- No thermal violation of any branch rating in any worst case operating condition (see Table 11 and Table 13), based on the continuous branch rating ("Rating A") for normal system situations (n-0 condition).
- In case of n-1 contingencies, the transmission grid must be able to handle power flows without any post-fault action when considering emergency ratings of all branches ("Rating B").
- Generator connections generally don't have to be n-1 secure with respect to the connecting substation transformers. However, in the case of too large transformer infeed, system security could be endangered. Therefore, for the purpose of these studies, it has been assumed that if the total feed-in capacity is below 400MW there is no requirement for n-1 security. Otherwise, substation transformers connecting generation must be n-1 secure too.
- Load connection have to be n-1 secure. This has to be considered when rating substation transformers.

For calculating the substation transformer capacities required for integrating PV farms, load has been ignored, meaning that the available capacity of substation transformers must at least be equal to the sum of all PV infeed's into a transmission substation.

Of course the capacity of substation transformers must always be sufficient for providing n-1 secure supply of the maximum substation load (considering zero infeed). However, this constraint is independent from the installed PV capacity and therefore, it can be considered that this constraint was already considered by the Base Case models (without PV generation).

In the case that substation reinforcements are required, ESKOM's standard transformer ratings (250MVA and 500MVA at 400kV and additionally 125MVA at 275kV) have been chosen.

The rules for selecting the appropriate number and size of substation transformers is further illustrated in Figure 8:

- In example 1, two transformers with 125MVA each are chosen for connecting a total of 200MW of PV generation. Because the total infeed is below 400MW, n-1 security is not required with respect to the substation transformers.
- In example 2, 500MW of PV infeed has to be connected. Because the total infeed capacity is >400MW, an n-1 secure connection is required. The installation of three 250MVA transformers would provide an n-1 secure connection.

In both examples, the substation load is not considered when selecting the appropriate size and number of substation transformers.

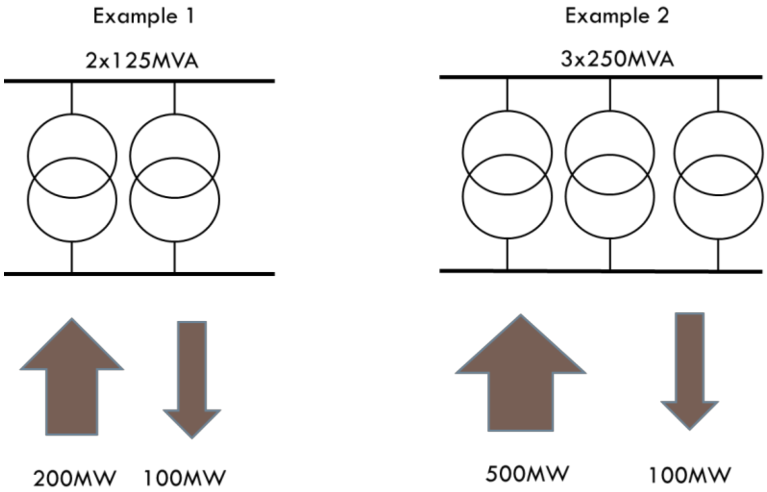


Figure 8: Examples for the selection of substation transformers

3.4.3 Distribution Reinforcements

As mentioned earlier, the actual technical studies focus is on the transmission grid only. However, cost of distribution reinforcements can be significant, and therefore, an attempt was made to estimate distribution expansions and associated costs.

The procedure for estimating distribution expansions is as follows:

- If no 132kV grid exists, all PV farms have to be connected directly to the main 132kV busbar.
- If 132kV (or 88kV etc.) networks exist and transformer capacity is sufficient, it is assumed that all PV farms can be connected to existing distribution grids.
- If transformer capacity is insufficient, it is assumed that 132kV line capacity must be upgraded so that the total line capacity corresponds to the upgraded transformer capacity.
- For each additional distribution line (132kV), a capacity of 125MVA was assumed.
- For each area, the average distance of planned PV farms from the nearest substation has been calculated on basis of available GIS data and assigned to the corresponding distribution line.

3.4.4 Cost of transmission and distribution expansions

For assessing cost of transmission and distribution grid reinforcements, ESKOM's standard unit costs for grid assets [5] have been used. For O&M, 3% of the investment cost for grid assets per year have been assumed.

In order to compare these costs with the cost of PV generation, the NPV of all transmission assets has been calculated and expressed in a levelized form basis ("per kWh of PV production") using the financial parameters according to Table 15, which were provided by ESKOM, and the annual energy yield of planned PV farms according to Scenario A, B and C. This results in a "Levelized cost of T&D assets" (named LCTD in this report) and can be added to LCOE of PV production for assessing the overall economic impact.

Table 15: Financial parameters for transmission and distribution assets

WACC real grid assets	7,80%
time of use	25 years

3.5 Energy Losses

3.5.1 Loss Assessment

In order to analyse annual energy losses, a load flow model with a time resolution of 30 minutes has been setup using the load time series data provided by ESKOM (year 2012, scaled to 2020 peak load).

PV infeeds have been model-based using the data derived within the DEA project (see reference [3]). This model considers various aspects (including solar irradiance, air temperature, PV farm internal losses etc.) and generates time series data with a resolution of 15 minutes.

This data has been linked to the transmission grid model resulting in a model (in space and time) of the complete South African transmission grid to give an overall resolution of 30 minutes.

For simulating wind generation, no time series data was available. For this reason, each scenario has been simulated four times, with the different constant wind generation levels of 0%, 30%, 60% and 90%.

Because of the high sensitivity of losses against import flows into the Cape Corridor, the influence of the availability of the two Koeberg units has been specifically taken into consideration.

Finally, each year has been simulated eight times, to cover the different assumptions with regard to wind generation and the availability of Koeberg power station. The average annual energy losses have been calculated using a weighted average of these eight results.

The assumed distribution of different wind generator levels is depicted in Figure 9. According to this chart, the average production is equal to 30% of the installed capacity (average load factor of 30%).

With regard to Koeberg power station, the following assumptions have been made:

- 2 Koeberg units in service: 7 months (58,3%) per year
- 1 Koeberg unit in service: 5 months (41,7%) per year

The resulting probabilities of each of the eight cases is shown in Table 16.

With regard to actual loss evaluation, only transmission system losses have been considered. The calculation of the impact of PV on distribution network losses would require a model of the future distribution networks, which was out of the scope of these studies here as already explained in section 3.4.3.

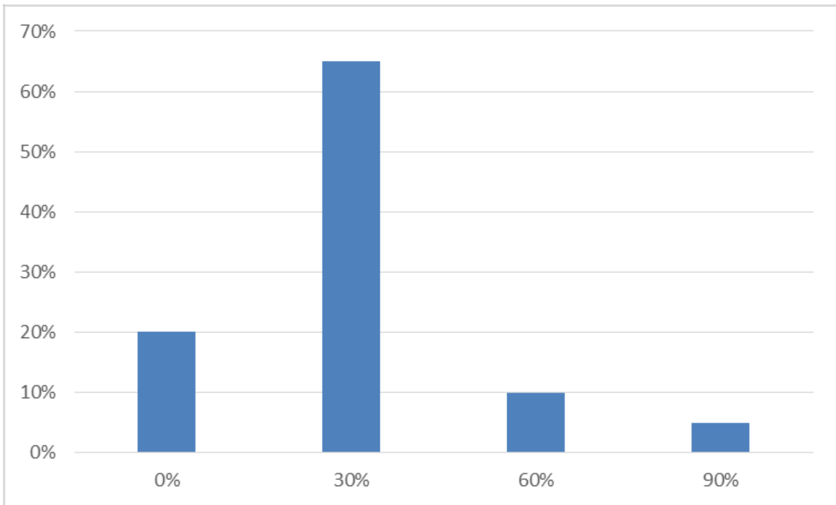


Figure 9: Approximate distribution of wind generation

Table 16: Probability table for loss assessment

	Wind generation level			
	0,00%	**30,00%**	**60,00%**	**90,00%**
1 Koe	8,33%	27,08%	4,17%	2,08%
2 Koe	11,67%	37,92%	5,83%	2,92%

3.5.2 Avoided Generation Costs

By injecting electricity generated by PV plants into the systems, cost of conventional energy production will be avoided. Avoided cost will depend on:

- Time of PV generation
- Impact on system losses (positive or negative)

With respect to the first aspect, different PV allocation scenarios would lead to different avoided cost of generation if their special distribution would show a very different spread along the West-East direction. This would be due to the different time-zones influencing the correlation of PV generation with peak load hours. In South Africa, there is a time delay of approximately one hour between West and East. Therefore, the sum of all PV farms of each scenario show a very similar time distribution and it can be considered that the first aspect is only of minor importance in the South African case, even if it’s visible when comparing total solar generation of the three scenarios (see Figure 20).

Therefore, only the impact of the different PV allocation scenarios on losses has been evaluated.

It should be noted even the inclusion of losses in the economic assessment is complex as the cost of losses must be evaluated using marginal cost, which are time dependent. Therefore, a maximum and minimum value of the Long-Run Marginal Costs (LRMC) have been provided by ESKOM and considered in the economic evaluation of losses using the method outlined below.

For comparing cost of losses with all other cost factors, losses have been expressed in levelized form on basis of the energy produced by PV.

$$LCOL = LRMC \frac{\Delta E_{lt}}{E_t}$$

with:

- LRMC: Long run marginal cost
- ΔE_{lt}: Difference between annual energy losses with PV generation and without PV generation for the year t (only transmission system losses).
- E_t: Energy yield of PV during the year t.

It has been assumed that ΔE_{lt} is in proportion to the annual energy yield E_t. In this case, LCOL is a constant annual figure, even if the energy yield of PV will reduce over time because of aging.

Please note that LCOL can also be negative because PV generation can either increase or decrease transmission system losses. In fact it has been shown to be negative in this case due to a decrease of system losses.

For estimating LRMC, ESKOM has provided the following upper and lower limits:

- $LRMC_{max}$ = 1200ZAR/MWh = 113,50USD/MWh
- $LRMC_{min}$ = 600ZAR/MWh = 56,75USD/MWh

3.6 Overall economic evaluation

For evaluating the overall economic impact of the three PV allocation scenarios A, B and C, the three cost components have been added:

$$LCOE_{tot} = LCOE + LCTD + LCOL$$

with the following definitions:

- $LCOE_{tot}$: Total levelized cost of electricity from PV considering all aspects
- LCOE: Levelized cost of electricity from PV (at the POC)
- LCTD: Levelized cost of transmission and distribution reinforcements
- LCOL: Levelized cost of system losses

The $LCOE_{tot}$ represents a measure for the overall cost impact of PV generation. Even if different components of $LCOE_{tot}$ have to be financed by different organizations (PV project developer, transmission system operator / dispatcher), $LCOE_{tot}$ is an excellent measure for representing the impact that PV generation may have on the electricity tariff in South Africa.

3.7 Assumptions

The study approach is based on a number of appropriate assumptions and simplifications (likewise for any study). The most important of these are listed below:

- The analysis evaluates one target year only, i.e. no grid or PV development over several years were considered. This approach is valid, as the purpose of the analysis was to assess different scenarios for the allocation of PV and not different grid development plans.
- Actual avoided costs resulting from displacing conventional thermal generation with PV was not considered. Only the impact of the change in system losses was calculated. This is appropriate as the daily profile of PV generation is similar for the three allocation scenarios. In this case, the difference between the cost savings is virtually the same, and the dominant factor is the impact on power losses resulting from different line loadings of the three scenarios. Because the focus of this study is on differences between the three PV allocation scenarios, cost effects, which influence the three scenarios in the same way, have been considered with less accuracy.
- All cost figures published in this report are estimates of typical costs. Actual project costs can deviate considerably from the published figures (because of different financial parameters at the time, differences with regard to actual installation costs, and site-specific aspects etc.).

Nevertheless, the most important aspects for evaluating the overall economic impact of different PV allocation scenarios in South Africa are covered by the presented studies.

4 Results

4.1 LCOE of PV Farms at POC

The Levelized Cost of Electricity (LCOE) has been calculated for each modelled PV substation infeed based on the parameters and the methodology described in section 3.3. The corresponding results, summarised at provincial level, are depicted for Scenario A, Scenario B and Scenario C in Table 17, Table 18 and Table 19 respectively. More detailed results (per substation) can be found in Annex 1.

According to this assessment, the LCOE of utility-scale PV farms in South Africa varies for tracked systems between 0,109 USD/kWh (Northern Cape) and around 0,135 USD/kWh (KwaZulu Natal).

As it could be expected, average cost of electricity generation from PV is the lowest in Scenario A (LCOE of 0,112USD/kWh, tracked systems). In Scenario B, the average LCOE of PV generation is the highest of the three scenarios (0,117 USD/kWh, tracked systems). In scenario C, PV generation costs are in-between the two other scenarios (average LCOE=0,115 USD/kWh, tracked systems).

Table 17: LCOE of PV Generation, Scenario A

Scenario A		Fixed		Tracked	
Province	**Inst. Capacity [MW]**	**Yield [GWh]**	**LCOE [USD/kWh]**	**Yield [GWh]**	**LCOE [USD/kWh]**
Northern Cape	6000	11509	$ 0,117	13471	$ 0,109
North West	350	638	$ 0,123	734	$ 0,116
Free State	500	925	$ 0,122	1066	$ 0,114
Mpumalanga	250	436	$ 0,129	498	$ 0,123
Limpopo	500	855	$ 0,131	986	$ 0,124
KwaZulu Natal	150	251	$ 0,134	280	$ 0,131
Gauteng	300	533	$ 0,127	609	$ 0,120
Eastern Cape	200	358	$ 0,126	406	$ 0,120
Western Cape	150	265	$ 0,127	305	$ 0,120
Total	**8400**	**15771**	**$ 0,120**	**18354**	**$ 0,112**

Table 18: LCOE of PV Generation, Scenario B

Scenario B		Fixed		Tracked	
Province	**Inst. Capacity [MW]**	**Yield [GWh]**	**LCOE [USD/kWh]**	**Yield [GWh]**	**LCOE [USD/kWh]**
Northern Cape	2600	4977	$ 0,117	5820	$ 0,109
North West	750	1364	$ 0,124	1569	$ 0,117
Free State	950	1742	$ 0,123	2002	$ 0,116
Mpumalanga	600	1035	$ 0,130	1179	$ 0,124
Limpopo	1050	1787	$ 0,132	2057	$ 0,125
KwaZulu Natal	400	649	$ 0,139	721	$ 0,135
Gauteng	650	1157	$ 0,126	1321	$ 0,120
Eastern Cape	750	1329	$ 0,127	1501	$ 0,122
Western Cape	650	1146	$ 0,128	1324	$ 0,120
Total	**8400**	**15186**	**$ 0,124**	**17494**	**$ 0,117**

Table 19: LCOE of PV Generation, Scenario C

Scenario C		Fixed		Tracked	
Province	Inst. Capacity [MW]	Yield [GWh]	LCOE [USD/kWh]	Yield [GWh]	LCOE [USD/kWh]
Northern Cape	2800	5383	$ 0,121	6309	$ 0,112
North West	2100	3789	$ 0,125	4354	$ 0,118
Free State	2100	3877	$ 0,122	4466	$ 0,115
Mpumalanga	0	0	$ -	0	$ -
Limpopo	0	0	$ -	0	$ -
KwaZulu Natal	0	0	$ -	0	$ -
Gauteng	0	0	$ -	0	$ -
Eastern Cape	750	1329	$ 0,127	1501	$ 0,122
Western Cape	650	1146	$ 0,128	1324	$ 0,120
Total	**8400**	**15523**	**$ 0,123**	**17955**	**$ 0,115**

4.2 Transmission Reinforcements

4.2.1 Before Reinforcements

Figure 10 shows the transmission system in the Cape (765kV, 400kV and 275kV levels) in the Base Case situation (year 2020) prior to any system reinforcement due to PV generation.

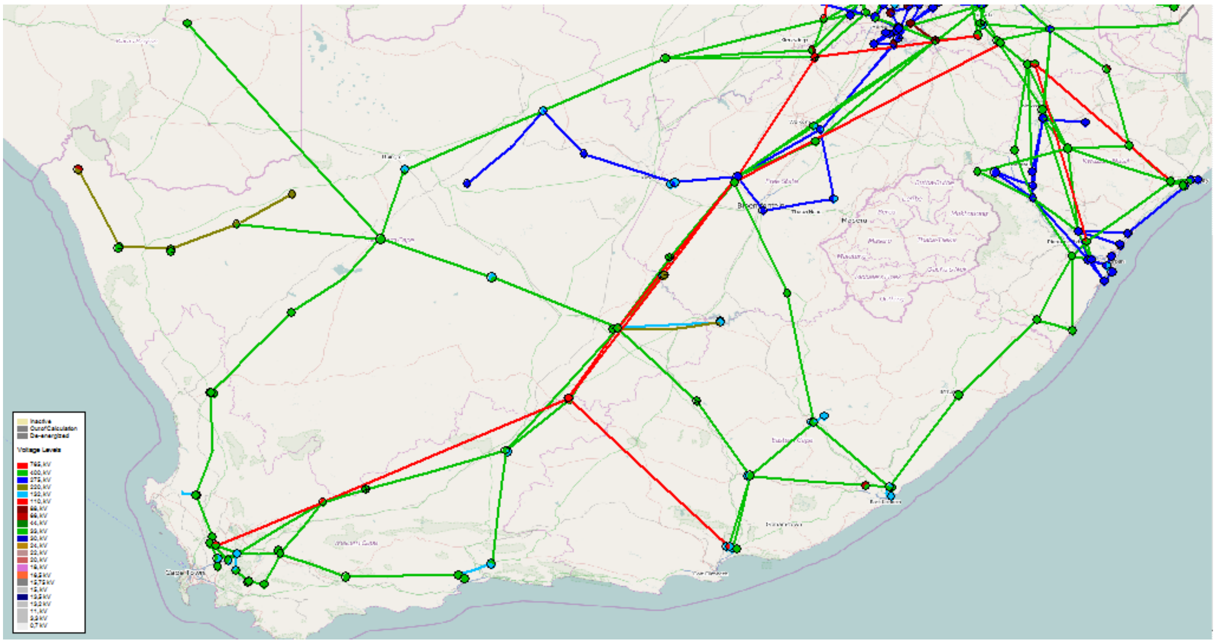


Figure 10: Transmission System in the Cape, Base Case (before reinforcements), showing 765kV (red) 400kV (green), 275kV (blue) and 220kV (brown) grids.

4.2.2 Scenario A

When connecting PV generation onto the transmission system according to Figure 10, the transmission system will show severe grid congestions under normal operating conditions (n-0 situation, see Figure 11).

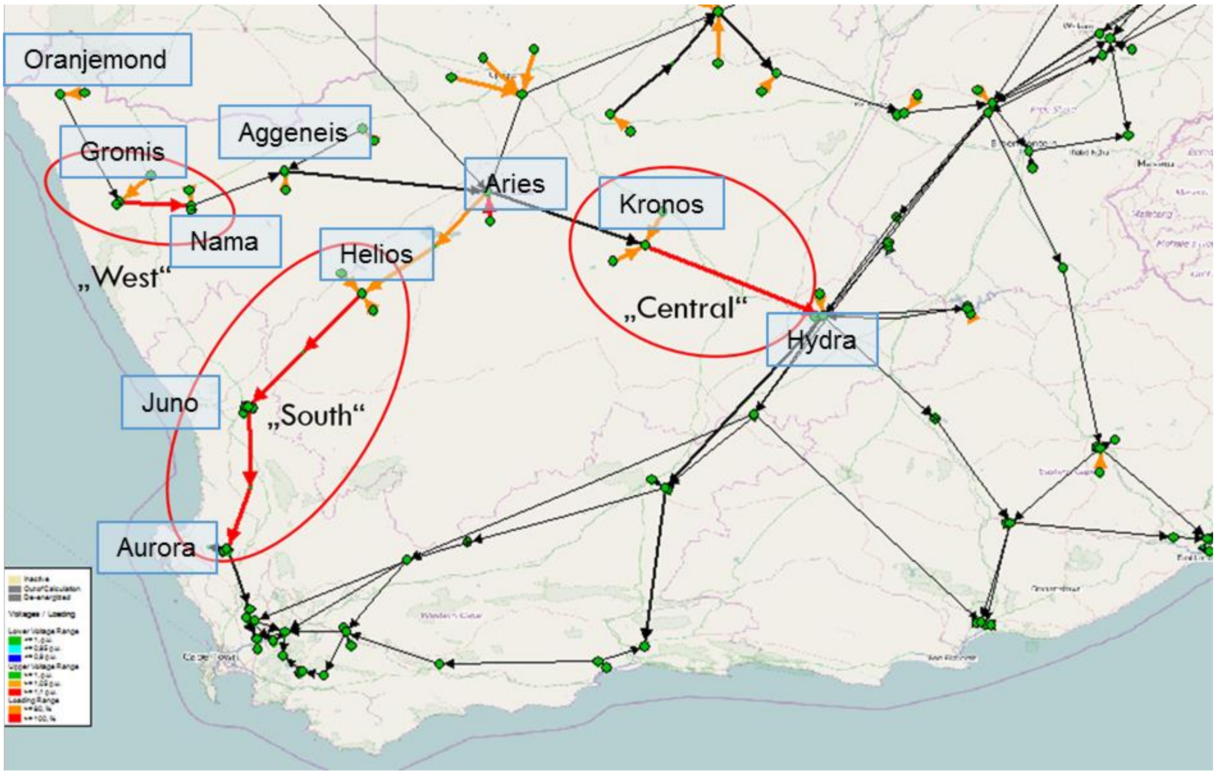


Figure 11: Transmission system in the Cape, Scenario A, prior to system reinforcement (orange: loading >80%, red: loading >100%)

These congestions are named “Central”, “West” and “South”:

- “Central”: Thermal overload on 400kV line “Hydra-Kronos”
- “West”: Thermal overload on the 220kV lines “Gromis-Nama”
- “South”: Thermal overload on the 400kV lines connecting the substations Helios-Juno-Aurora

In order to resolve the congestion “West”, the following major transmission grid reinforcements are required (see also Figure 12):

- Upgrade of the substations Oranjemond, Gromis and Nama from 220kV to 400kV
- Upgrade of the following lines to 400kV:
  - Oranjemond-Gromis (130km)
  - Gromis-Nama (76km)
  - Nama-Aggeneis (98,5km)
- New line between Oranjemond and Aggeneis (250km)
- Additional line between Aggeneis and Aries (200km)

The lines Oranjemond-Aggeneis and the additional line between Aggenieis and Aries are required for making this part of the 400kV grid n-1 secure. N-1 security is necessary in this area because the maximum net-generation that could be lost because of a trip of the line Aggeneis-Aries is equal to 1370MW (1100MW PV, 500MW wind, 230MW load/minute during daytime, see Figure 12). Even when considering that there will be a considerable diversity factor, especially between wind and PV generation, this amount of generation requires n-1 secure connection to the rest of the grid because otherwise a sudden trip of one of the transmission lines in this area could lead to a very large generation outage that would exceed the outage of the largest unit in the South African system at present (Koeberg), and would therefore endanger system frequency stability.

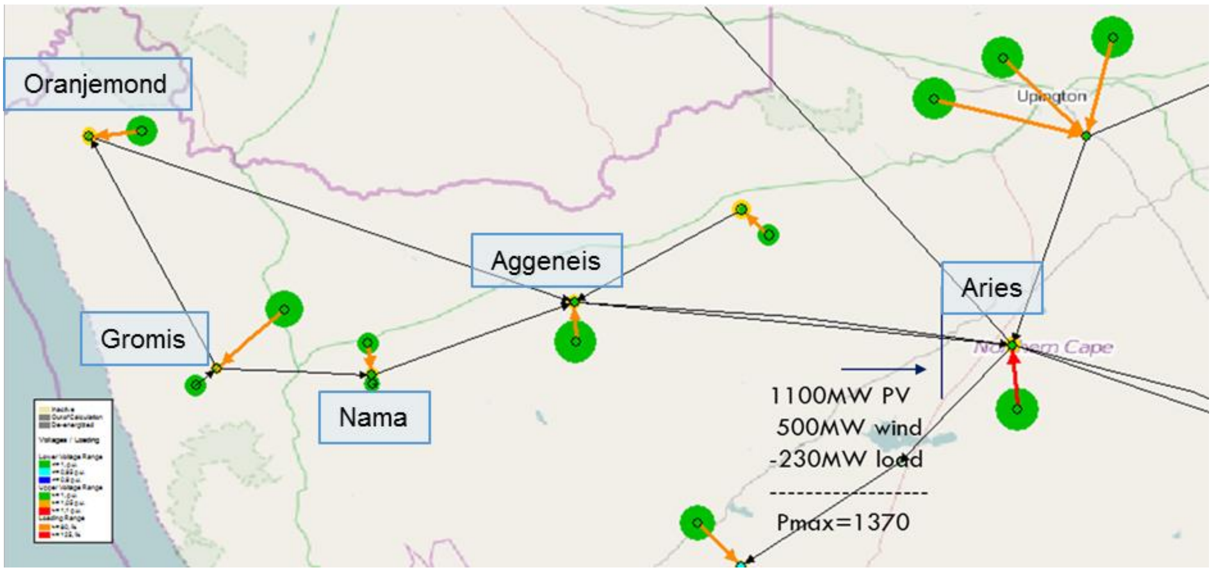


Figure 12: Reinforcements "West" (orange: loading >80%, red: loading >100%)

For resolving the congestions on the corridor “Central”, there are additional 400kV lines required in parallel to the following existing lines:

- Aries-Kronos (163km)
- Kronos-Hydra (187km)

Figure 13: Reinforcements "Central" (orange: loading>80%, red: loading >100%)

It is assumed that the existing series compensation for the following lines will be removed:

- Aries-Kronos
- Kronos-Hydra
- Aries-Helios
- Helios-Juno
- Juno-Aurora
- Aries-Kronos
- Kronos-Hydra

Additionally, numerous substations require reinforcement. These substation reinforcements have been identified according to the rules described in section 3.4.2 (see also Figure 8).

The resulting transmission grid was tested for n-1 security (considering n-1 line outages) by carrying out AC-load flow calculations, commonly known as contingency analysis. In case of all simulated contingencies thermal loadings of all lines were within either continuous or emergency limits ("Rating A" or "Rating B") and all voltages were within the required band of operation.

An overview about all transmission reinforcements required for Scenario A and the corresponding costs (CAPEX based on unit costs according to [5] and OPEX assumed to be 3% of CAPEX) is depicted in Table 20 below.

Table 20: Number and cost of transmission reinforcements, Scenario A

Transmission Costs			
Lines	Number	CAPEX in Mio USD	OPEX in Mio. USD/year
400kV Line [MUSD/km]	1105	$ 344,78	$ 10,34
275/220kV Line [MUSD/km]		$ -	$ -
Substations			
400kV Bus Bar [MUSD/unit]	3	$ 3,00	$ 0,09
132kV Bus Bar [MUSD/unit]	10	$ 10,00	$ 0,30
400kV Feeder Bay [MUSD/unit]	14	$ 18,66	$ 0,56
275kV Feeder Bay [MUSD/unit]	0	$ -	$ -
400kV Transformer Bay [MUSD/unit]	30	$ 58,15	$ 1,74
275kV Transformer Bay [MUSD/unit]	2	$ 3,46	$ 0,10
400kV/132kV, 500MVA Transformer [MUSD/unit]	1	$ 4,92	$ 0,15
400kV/132kV, 250MVA Transformer [MUSD/unit]	19	$ 75,45	$ 2,26
Other 400kV or 275kV Transformer [MUSD/unit]	12	$ 36,31	$ 1,09
Total Transmission Assets		**$ 554,73**	**$ 16,64**

4.2.3 Scenario B

In Scenario B, PV farms are more distributed than in Scenario A, leading to substantially less grid congestions compared to Scenario A.

Even without any transmission grid reinforcement, there is no overload of any transmission component under normal operating conditions (n-0 situation).

Under n-1 conditions, only one problem has been identified: there are two lines between Ruigtevallei and Hydra, one 220kV line and one 132kV line. In case of an outage of the 220kV line, the parallel 132kV line will be overloaded (150%) during high PV infeed (see Figure 14). Therefore, in order to make the connection between Ruigtevallei and Hydra n-1 secure, the 132kV line Hydra-Ruigtevallei has to be upgraded to 220kV, in which case the connection will be n-1 secure (see Figure 15).

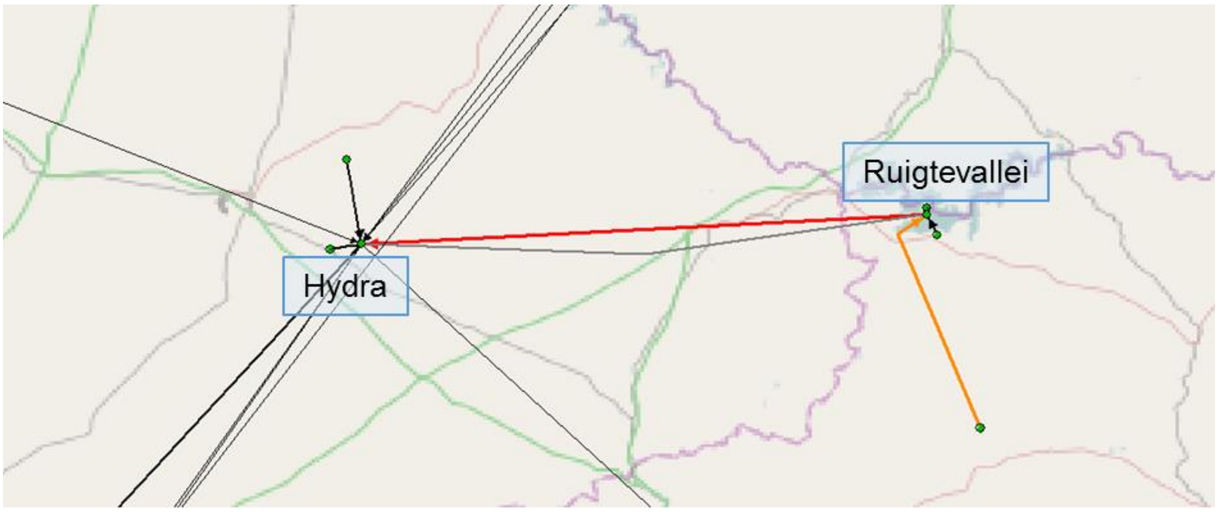


Figure 14: n-1 contingency of 220kV line Ruigtevallei-Hydra, before reinforcement (orange: loading>80%, red: loading >100%)

Figure 15: n-1 contingency of 220kV line Ruigtevallei-Hydra, after reinforcement (orange: loading>80%, red: loading>100%).

For analysing whether additional transmission lines will be required in the western part of the Northern Cape, which is not n-1 secure at present, the maximum generation that could be lost because of a single line outage is calculated:

As shown in Figure 16, the maximum net generation capacity that could be lost following a trip of the line Aries-Aggeneis (which is the worst case line contingency with this regard) is equal to 570MW. This is in the order of magnitude of many large units of thermal power plants in South Africa and therefore acceptable. Consequently, there is no transmission upgrade required in this western part of the Northern Cape transmission system.

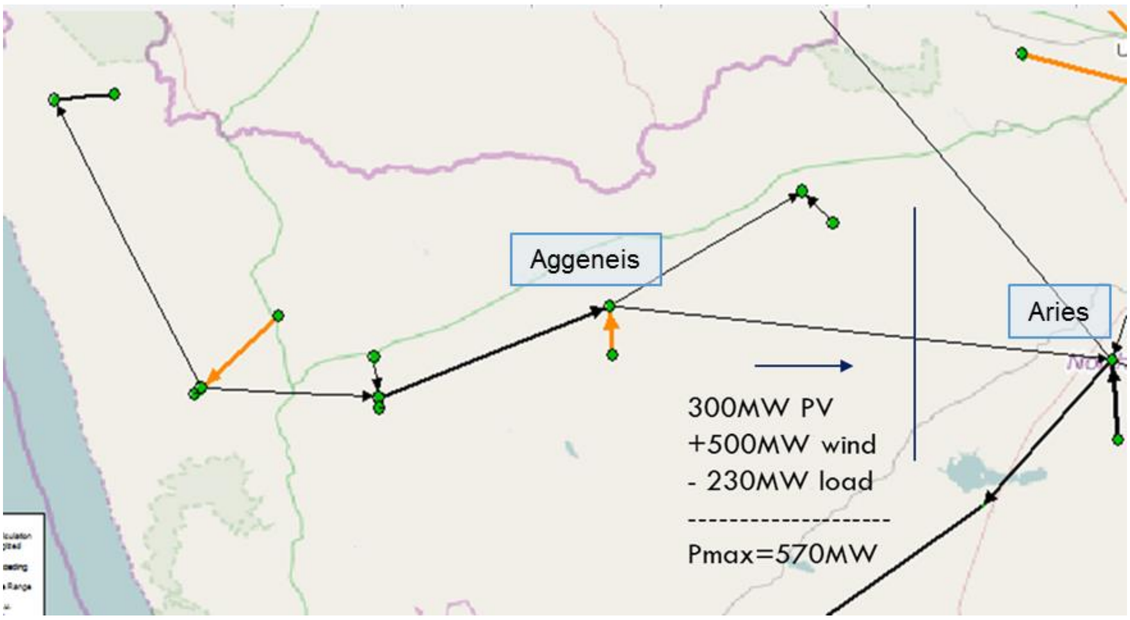


Figure 16: n-1 security Aries-Aggeneis, Scenario B (orange: loading >80%, red: loading>100%)

In addition to the described transmission line upgrade (Ruigtevallei-Hydra), Scenario B requires numerous substation reinforcements for supporting the PV infeeds into the 132kV distribution grids. As shown in Table 21, compared to Scenario A, there are considerably less substation reinforcements required in Scenario B. This is because of the more distributed allocation of PV farms in Scenario B and the closer proximity of PV farms to load centers where stronger distribution grids are available.

Table 21: Number and cost of transmission reinforcements, Scenario B

Transmission Costs			
Lines	Number	CAPEX in Mio USD	OPEX in MioUSD/year
400kV Line [km]	0	-	-
275/220kV Line [km]	136	38,69	1,16
Substations			
400kV Bus Bar [unit]	0	-	-
132kV Bus Bar [unit]	10	10,00	0,30
400kV Feeder Bay [unit]	0	-	-
275kV Feeder Bay [unit]	2	2,55	0,08
400kV Transformer Bay [unit]	11	21,32	0,64
275kV Transformer Bay [unit]	4	6,92	0,21
400kV/132kV, 500MVA Transformer [unit]	0	-	-
400kV/132kV, 250MVA Transformer [unit]	11	43,68	1,31
Other 400kV or 275kV Transformer [unit]	4	12,10	0,36
Total Transmission Assets		**135,27**	**4,06**

4.2.4 Scenario C

Similar to Scenario B, PV farms of Scenario C are substantially more distributed across the country than in Scenario A

However, compared to Scenario B, there is considerably more PV capacity installed in the Namaqualand area in the western part of the Northern Cape. As a result, it can happen that the line Nama-Aggeneis is overloaded, even under normal operating conditions (n-0 conditions, see Figure 17).

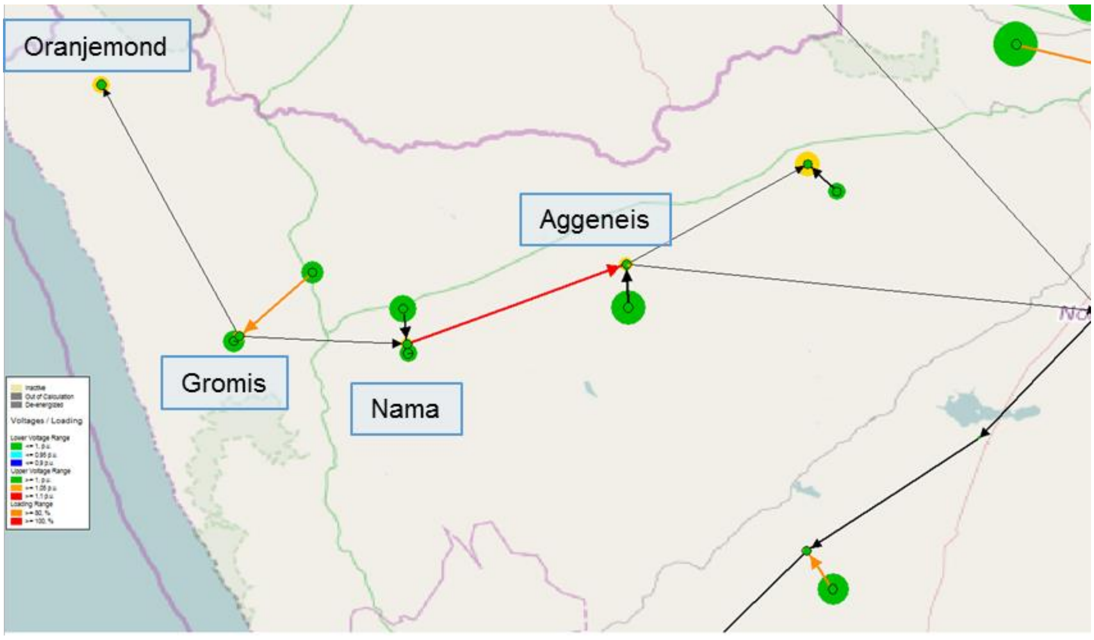


Figure 17: Overloaded line Nama-Aggeneis during normal operation (orange: loading>80%, red: loading>100%)

The maximum loading of that line under n-0 conditions is around 110%. This is not a heavy overloading and one could argue that because PV-farm losses and diversity is not considered in the model, an overload of around 110% could still be accepted. But there is also a wind farm feeding into the 220kV substation Nama and this overload of 110% occurs even during times, when the wind farm infeed is at its average value of around 30% of installed capacity. When considering that there will be times with strong wind generation and PV generation at the same time, this line might be loaded up to 150%, which would definitely be inacceptable. Therefore, it has been decided to consider an upgrade of the line Nama-Aggeneis by a second circuit of 98,5km, which runs in parallel to the existing 220kV circuit (see Figure 18).

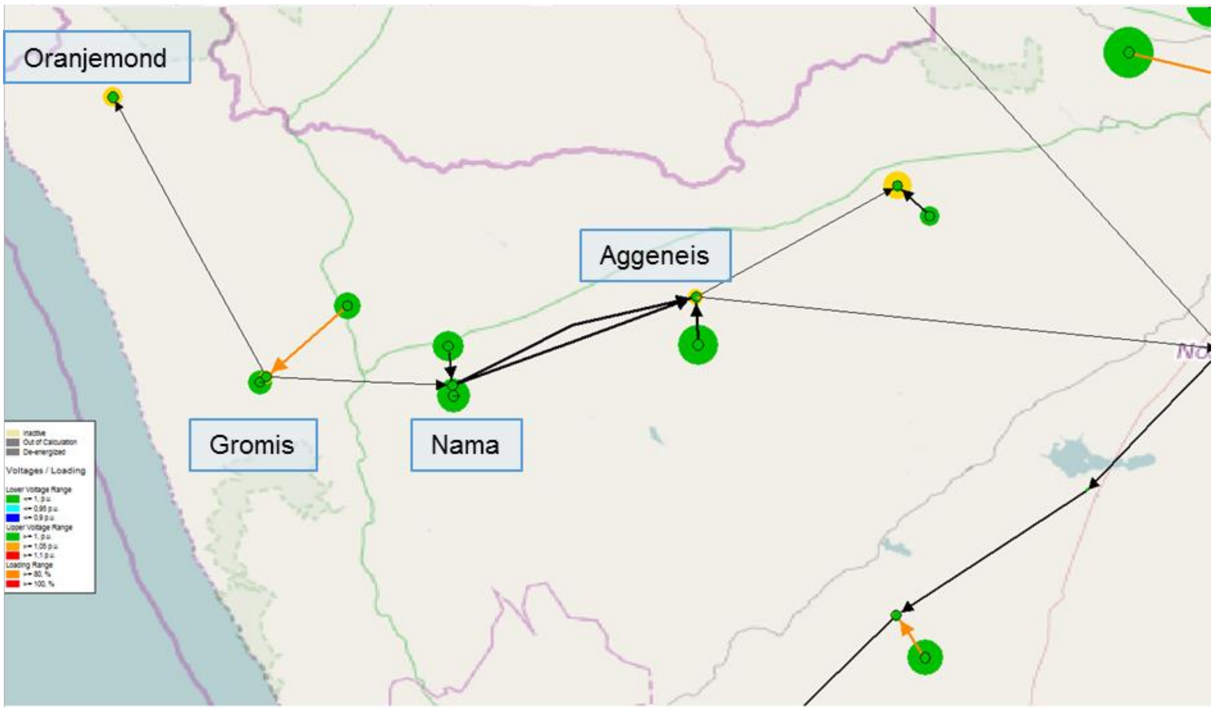


Figure 18: Upgrade of the line Nama-Aggeneis by a parallel 220kV circuit (orange: loading>80%, red: loading>100%)

Under n-1 situations, there is a problem with the two parallel lines between Ruigtevallei and Hydra, as it has been described for Scenario B. Consequently the same type of grid reinforcement for that line as described for Scenario B is required (see also Figure 14 and Figure 15) for resolving this issue.

In the Northern Cape, a verification is required, whether n-1 secure operation of the system in the Namaqualand-area is required in Scenario C. The results of this verification is as follows:
Figure 19 below shows, that even under worst case conditions with full wind generation capacity, full PV generation capacity and minimum load (during daytime) the maximum power across the relevant boundary would be 820MW, which is below the size of one Koeberg unit. Considering that this is a very conservative estimate (with regard to the maximum simultaneous generation of wind and PV in this area), the decision is that no upgrade of the line between Aggeneis and Aries is required for Scenario C.

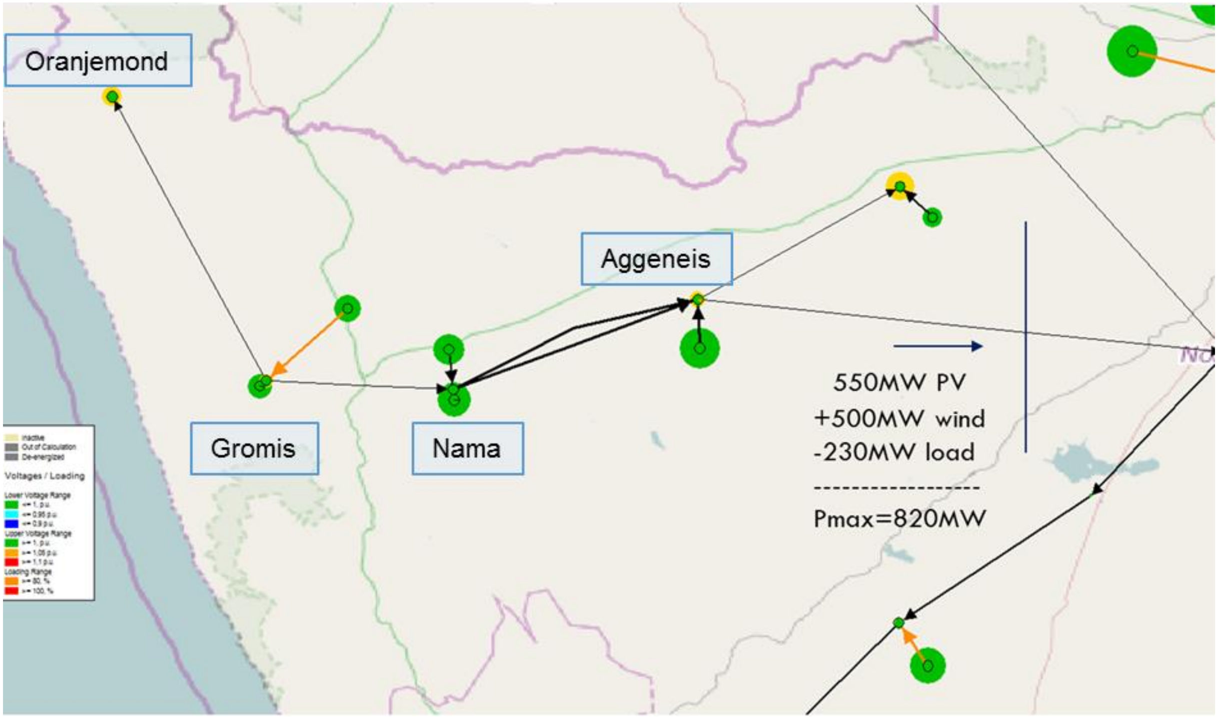


Figure 19: N-1 security Aries-Aggeneis, Scenario C (orange: loading>80%, red: loading>100%)

The overall amount of required transmission system upgrades for Scenario C, including line and substation upgrades is depicted in Table 22: Number and cost of transmission reinforcements, Scenario CTable 22. This table shows that the cost of transmission grid reinforcements in Scenario C are slightly higher than in Scenario B, which is because of the second 220kV circuit between Nama and Aggeneis.

Table 22: Number and cost of transmission reinforcements, Scenario C

Transmission Costs			
Lines	Number	CAPEX in Mio USD	OPEX in Mio USD/year
400kV Line [km]	0	-	-
275/220kV Line [km]	235	66,85	2,01
Substations			
400kV Bus Bar [unit]	0	-	-
132kV Bus Bar [unit]	8	8,00	0,24
400kV Feeder Bay [unit]	0	-	-
275kV Feeder Bay [unit]	4	5,11	0,15
400kV Transformer Bay [unit]	12	23,26	0,70
275kV Transformer Bay [unit]	3	5,19	0,16
400kV/132kV, 500MVA Transformer [unit]	0	-	-
400kV/132kV, 250MVA Transformer [unit]	12	47,65	1,43
Other 400kV or 275kV Transformer [unit]	3	9,08	0,27
765kV/400kV Transformer [MUSD/unit]		-	-
Total Transmission Assets		**165,13**	**4,95**

4.2.5 Levelized Cost of Grid Reinforcements

As described in section 3.4.4, cost of transmission and distribution grid reinforcements will be expressed in levelized form, using the NPV of grid reinforcements (with the financial parameters according to Table 15, considering the first 20 years of use only) and the average annual energy yield of PV of each scenario.

The overview according to Table 23 confirms that:

- Cost of transmission grid upgrades are substantially larger in Scenario A compared to Scenario B and C.
- The difference of levelized cost of transmission upgrades between Scenario C and Scenario B is only marginal.

Table 23: Levelized costs of transmission reinforcements (LCOT)

	Scenario A	Scenario B	Scenario C
NPV of Transmission Grid upgrades in Mio. USD	687,87	167,73	204,77
LCOT in USD/kWh, static systems	0,0042	0,0011	0,0013
LCOT in USD/kWh, tracked systems	0,0036	0,0009	0,0011

4.3 Losses

4.3.1 General impact of PV generation on transmission losses

In all three scenarios, the generation of electricity by PV farms reduces transmission system losses. Under normal operating conditions there is a large import of power into the Cape, through the Cape Corridor. Because most PV farms are located in the Cape in all three scenarios (especially in the Northern Cape), the power import into the Cape is reduced, and therefore power losses will be reduced during times with high solar infeed.

Within these studies, complete time series of losses considering load, PV generation and conventional generation with a resolution of 30min were calculated for every day of the year. Based on these time series data, annual energy losses have been calculated and used for evaluating the cost impact of losses. Annex 3 shows profiles of load, PV generation, residual load and losses for each scenario for three different days of the year.

Figure 20 shows transmission system losses over one example day for the Base Case (no PV Generation, red curve) and the three scenarios (green, blue and brown). As this comparison shows, during midday, when PV generation is at its peak, Scenario C (brown) and Scenario B (blue) show larger loss reduction than Scenario A (green). However, during morning hours and evening hours, Scenario A shows larger loss reduction than the two other scenarios. But all three scenarios with PV generation always show lower losses than the Base Case without PV generation.

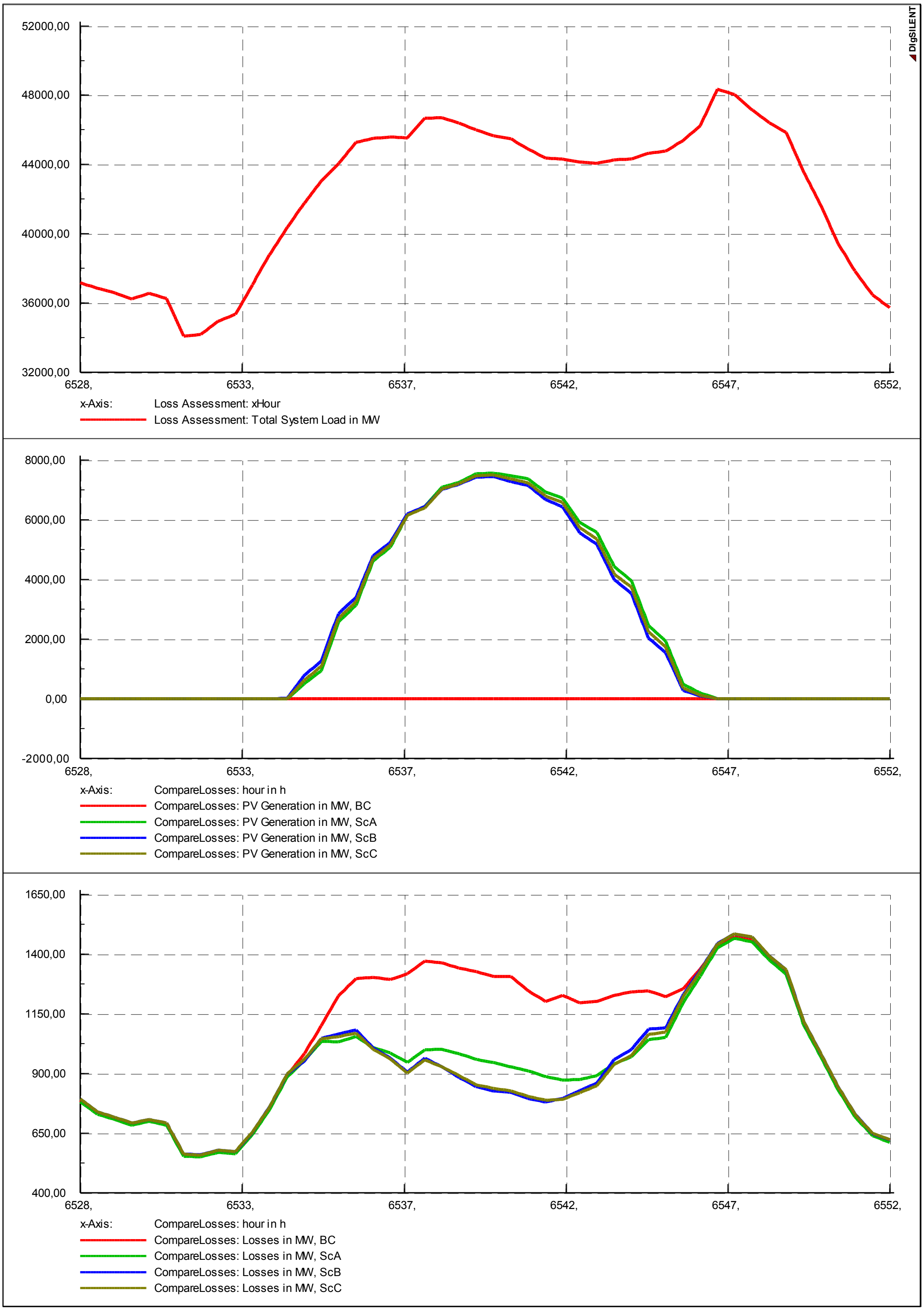


Figure 20: Load, PV generation and losses for Base Case, Scenario A, Scenario B and Scenario C

4.3.2 Loss Evaluation

As described in section 3.5, annual energy losses have been calculated for different levels of wind generation and for situations with one Koeberg unit in service and two Koeberg units in service. On the basis of the results of these eight cases per scenario, the resulting average annual energy losses have been calculated using the probabilities according to Table 16.

The results according to Table 24 and Table 25 show that reduced import into the Cape leads to reduced losses, consequently:

- Increased levels of wind generation reduce losses
- Increased levels of PV generation reduce losses
- Operation with two Koeberg units leads to less losses than operation with one Koeberg unit only.

Table 24: Transmission loss table, Base Case

Average Transmission Line Losses [MW]		
Wind [%]	1x Koeberg	2x Koeberg
0%	1107	938
30%	964	817
60%	854	730
90%	780	676
Weighted Average	972	826
Total Losses	**887**	

Table 25: Transmission loss table (Average annual losses in MW), Scenarios A, B and C

Average Transmission Line Losses [MW]						
	Scenario A		Scenario B		Scenario C	
Wind [%]	1x Koeberg	2x Koeberg	1x Koeberg	2x Koeberg	1x Koeberg	2x Koeberg
0%	973	826	982	825	973,6	820,0
30%	860	737	857	725	854,7	725,8
60%	774	674	768	661	772,0	667,4
90%	713	635	716	631	725,4	642,3
Weighted Average	867	744	866	734	863,7	734,6
Total Losses	**795**		**789**		**788**	

Table 26: Summary of the impact of PV generation on transmission losses

	Base Case	**Scenario A**	**Scenario B**	**Scenario C**
Av. Power Losses in MW	887	795	789	788
Annual Energy Losses in GWh	7767	6964	6910	6907
Difference, Power in WM		-92	-98	-98
Difference, Energy in GWh		-803	-858	-861

The results according to Table 25 and the summary according to Table 26 allow for the following conclusions with respect to losses:

- The average loss reduction resulting from PV generation is around 100MW.
- Energy loss savings are between 803GWh and 861GWh per year, depending on the scenario.
- The differences between the three scenarios with regard to loss savings are very small.
- Scenario B and Scenario C behave almost equal with respect to losses.

4.3.3 Cost of Losses

Based on the loss savings shown in Table 25 and Table 26, the levelized cost of losses (LCOL) can be calculated using minimum and maximum long run marginal costs (LRMC) as described in section 3.5.1. The results are shown in Table 27 below. Note that the figures are all negative because in all scenarios losses are lower compared to the Base Case without PV generation leading to loss savings resulting from displacing conventional thermal generation by PV.

Table 27: Levelized Cost of Losses (LCOL) in USD/kWh for max. and min. LRMC

	Base Case	Scenario A	Scenario B	Scenario C
LCOL, max LRMC in USD/kWh		-0,0057	-0,0063	-0,0062
LCOL, min. LRMC in USD/kWh		-0,0029	-0,0031	-0,0031
LCOL, average LRMC in USD/kWh		-0,0043	-0,0047	-0,0047

4.3.4 Correlation between PV generation and load

As described in the methodology section (section 3.5.2), avoided cost will not only depend on the impact on losses but on the overall cost of (conventional) generation, which can be avoided due to PV generation.

As Figure 20 shows, the correlation between PV generation and peak-load hours is not exactly the same for the three scenarios. Therefore, there will be an additional impact on avoided cost resulting from the different times of PV production. As shown in this figure, in Scenario A, PV generation will be slightly better correlated with peak load hours than Scenario B. It should be noted that this advantage is not considered in the results of this report but that its influence on the overall results and conclusions of this study is considered to be small.

4.4 Overall Economic Evaluation

The overall economic evaluation considers all three cost components:

- Levelized cost of PV production at the POC (LCOE)
- Levelized cost of transmission reinforcements (LCOT)
- Levelized cost of losses (LCOL)

The resulting cost figures, including avoided cost of losses for the three scenarios are summarised in Table 28 and Table 29. Levelized cost of losses are expressed on basis of average LRMC.

Table 28: Levelized cost of electricity production from PV, static systems

static systems	Scenario A	Scenario B	Scenario C
LCOE in USD/kWh	0,1198	0,1244	0,1229
LCOT in USD/kWh	0,0042	0,0011	0,0013
LCOL in USD/kWh	- 0,0043	- 0,0047	- 0,0047
Total in USD/kWh	**0,1197**	**0,1207**	**0,1195**

Table 29: Levelized cost of electricity production from PV, tracked systems

tracked systems	Scenario A	Scenario B	Scenario C
LCOE in USD/kWh	0,1116	0,1171	0,1153
LCOT in USD/kWh	0,0036	0,0009	0,0011
LCOL in USD/kWh	- 0,0043	- 0,0047	- 0,0047
Total in USD/kWh	**0,1110**	**0,1133**	**0,1117**

Examination of these tables results in the main conclusion that PV allocation according to all three scenarios will have very similar overall economic impact. The increased energy yield resulting from the installation of PV farms predominantly in the Northern Cape (Scenario A) can justify the increased costs of required transmission grid expansions.

When additionally considering distribution reinforcements (noting the distribution simplifications explained previously), the main conclusions are not substantially altered (see Table 30 and Table 31).

As there will be less distribution reinforcements required in Scenario B and Scenario C these scenarios are now more competitive to Scenario A. Considering the large uncertainty of the distribution cost assessment, it is possible that in reality, the advantage of stronger existing distribution grids and the better distribution of utility scale PV farms requiring less reinforcements of distribution grids is even higher than shown in these studies, which would make Scenario B and Scenario C even more competitive.

Table 30: Levelized cost of electricity production from PV, including distribution upgrades, static systems

static systems	Scenario A	Scenario B	Scenario C
LCOD in USD/kWh	0,0051	0,0033	0,0034
Total in USD/kWh	**0,1248**	**0,1240**	**0,1229**

Table 31: Levelized cost of electricity production from PV, including distribution upgrades, tracked systems

tracked systems	Scenario A	Scenario B	Scenario C
LCOD in USD/kWh	0,0044	0,0029	0,0030
Total in USD/kWh	**0,1153**	**0,1162**	**0,1147**

5 Conclusions and Recommendations

The main conclusions from the results of the presented studies are:

- All three PV allocation scenarios analysed in the presented studies result in very similar economic impact, and each could therefore be justified from a cost point of view (see Figure 21).
- In Scenario A, where the cost of PV production is lower (higher energy yield) compared to the two other scenarios, there are higher transmission and distribution expansion costs, which even out the advantage of a higher energy yield of PV farms in Scenario A (compare Figure 22).
- In all three Scenarios, system losses are reduced compared to the Base Case Scenario without PV generation. The amount of (energy) loss reduction is almost identical for all three scenarios.

In general it can be stated that using the available transmission capacity in the Solar Corridor up to its full extent, and distributing additional PV capacity across the country without requiring additional transmission line upgrades, will be the most economic strategy for allocating utility scale PV farms in South Africa.

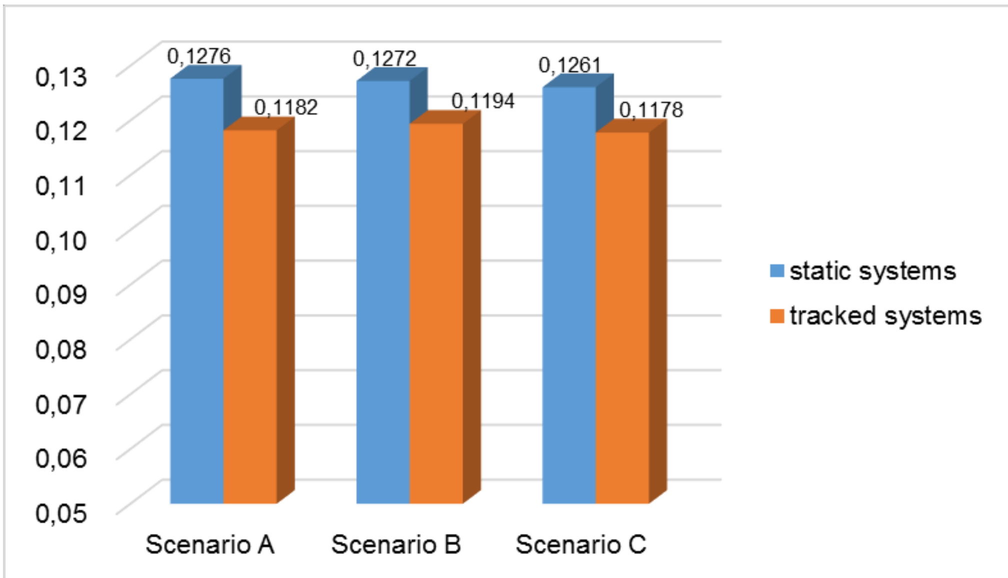


Figure 21: Levelized cost of PV production, including cost of T&D upgrades and avoided cost of losses in USD/kWh

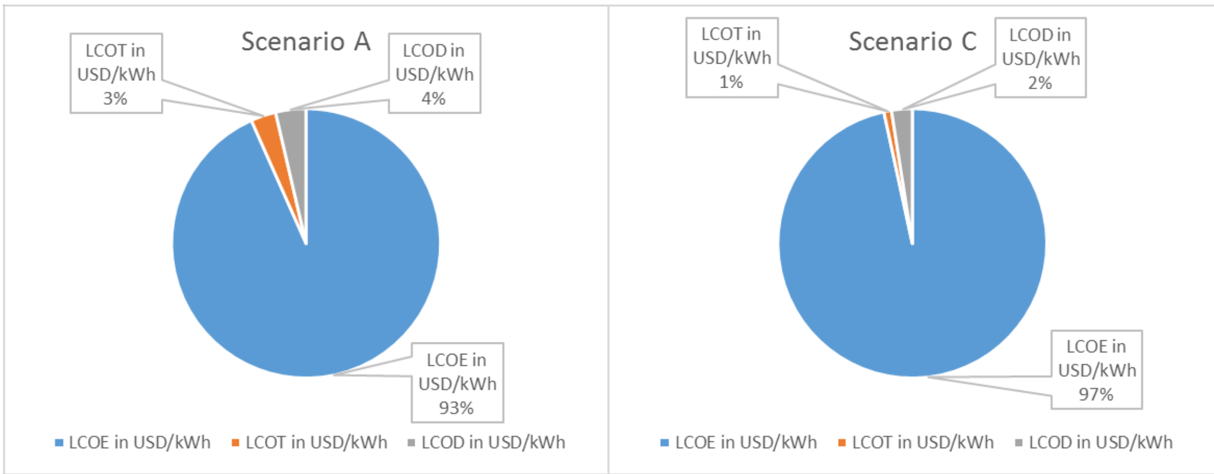


Figure 22: Cost breakdown considering LCOE of PV farms at POC and T&D upgrades

Following these conclusions, the main recommendations for the allocation of PV farms in South Africa are summarized as follows:

- As the overall cost of the three scenarios are almost identical, decisions with respect to the future strategies for allocating PV farms in South Africa should consider additional criteria such as the risks associated with each allocation strategy. Specifically, the timely realization of transmission grid upgrades are considerable. Therefore Scenario B and Scenario C (more heavily distributed PV) would be more favorable than Scenario A (large concentration of PV in the Solar Corridor requiring significant transmission upgrades).
- Consequently, the most economical approach will be to use the available transmission grid capacity in the Solar Corridor up to its full extent for PV generation. This limit will be at around 2,8GW of installed PV capacity, as shown by the results in Scenario B and C.
- PV capacity above this limit should be distributed across the country. Besides solar irradiation/energy yield, other criteria such as required transmission and distribution upgrades, socio-economic impact, environmental impact etc. should also be considered when deciding upon the allocation of these capacities.

Future rules and regulations in South Africa, especially those relating to the South African Renewable Energy IPP Procurement Program, should consider these aspects in order to ensure the most successful and cost efficient deployment of utility scale renewable PV generation for the country as a whole.

6 Annexes

6.1 Annex 1: Installed capacity and energy yield per substation

6.1.1 Scenario A

Substation Name	Province	PV Allocation [MW]	PV Yield [kWh/kWp]		PV Yield [GWh]	
			Static	Tracker	Static	Tracker
Northern Cape						
Aggeneis	NC	400	1978	2339	791.2	935.6
Aries	NC	400	1945	2285	778.0	914.0
Ferrum	NC	500	1898	2209	949.0	1104.5
Garona	NC	300	1911	2236	573.3	670.8
Gromis	NC	300	1865	2181	559.5	654.3
Helios	NC	600	1935	2275	1161.0	1365.0
Hotezal	NC	500	1889	2197	944.5	1098.5
Hydra	NC	500	1914	2226	957.0	1113.0
Kronos	NC	800	1927	2257	1541.6	1805.6
Nama	NC	100	1952	2324	195.2	232.4
Olien	NC	100	1888	2198	188.8	219.8
Oranjemond	NC	200	1891	2194	378.2	438.8
Paulputs	NC	100	1952	2297	195.2	229.7
Upington Solar Park	NC	1200	1914	2241	2296.8	2689.2
Sub Total Northern Cape		**6000**			**11509.3**	**13471.2**
North West						
Bighorn	NW	0	1780	2036	0.0	0.0
Dinaledi	NW	50	1784	2043	89.2	102.2
Hermes	NW	50	1792	2051	89.6	102.6
Midas	NW	50	1791	2047	89.6	102.4
Mookodi	NW	150	1852	2140	277.8	321.0
Ngwedi	NW	0	1769	2038	0.0	0.0
Watershed	NW	50	1837	2118	91.9	105.9
Sub Total North West		**350**			**638.0**	**734.0**
Free State						
Boundary	FS	200	1862	2153	372.4	430.6
Everest	FS	50	1835	2106	91.8	105.3
Harvard	FS	50	1841	2117	92.1	105.9
Leander	FS	0	1819	2086	0.0	0.0
Luckhoff	FS	0	1881	2181	0.0	0.0
Makalu	FS	50	1781	2027	89.1	101.4
Merapi	FS	0	1832	2100	0.0	0.0
Mercury	FS	0	1799	2061	0.0	0.0
Perseus	FS	100	1855	2138	185.5	213.8
Roodekuil	FS	50	1884	2184	94.2	109.2
Scafell	FS	0	1790	2041	0.0	0.0
Theseus	FS	0	1819	2084	0.0	0.0
Sub Total Free State		**500**			**925.0**	**1066.1**
Mpumalanga						
Acornhoek	MP	50	1598	1810	79.9	90.5

Substation Name	Province	PV Allocation [MW]	PV Yield [kWh/kWp]		PV Yield [GWh]	
			Static	Tracker	Static	Tracker
Arnot	MP	50	1794	2047	89.7	102.4
Hendrina	MP	50	1778	2024	88.9	101.2
Komati	MP	0	1778	2026	0.0	0.0
Komatipoort	MP	0	1530	1725	0.0	0.0
Malelane	MP	0	0	0	0.0	0.0
Rockdale B	MP	50	1782	2034	89.1	101.7
Simplon	MP	50	1775	2038	88.8	101.9
Sub Total Mpumalanga		**250**			**436.4**	**497.7**
Limpopo						
Foskor	LM	50	1559	1780	78.0	89.0
Leseding	LM	0	1739	1986	0.0	0.0
Marble Hall	LM	50	1778	2040	88.9	102.0
Merensky	LM	50	1746	1993	87.3	99.7
Borutho	LM	50	1732	2000	86.6	100.0
Nzhelele	LM	50	1709	1995	85.5	99.8
Spencer	LM	0	1561	1789	0.0	0.0
Tabor	LM	50	1653	1909	82.7	95.5
Warmbad	LM	50	1755	2018	87.8	100.9
Matimba	LM	100	1726	1998	172.6	199.8
Witkop	LM	50	1720	1983	86.0	99.2
Sub Total North West		**500**			**855.2**	**985.7**
KwaZulu Natal						
Bloedrivier	KZ	50	1673	1874	83.7	93.7
Bloukrans	KZ	50	1669	1849	83.5	92.5
Danskraal	KZ	50	1680	1869	84.0	93.5
Incandu	KZ	0	1695	1895	0.0	0.0
Klaarwater	KZ	0	1378	1490	0.0	0.0
Pegasus	KZ	0	1659	1851	0.0	0.0
Umfolozi	KZ	0	1553	1722	0.0	0.0
Sub Total KwaZulu Natal		**150**			**251.1**	**279.6**
Gauteng						
Benburg	GP	0	1766	2010	0.0	0.0
Bernina	GP	0	1806	2068	0.0	0.0
Carmel	GP	50	1774	2028	88.7	101.4
Grootvlei	GP	0	1786	2033	0.0	0.0
Kookfontein	GP	0	1785	2034	0.0	0.0
Nevis	GP	0	1775	2020	0.0	0.0
Olympus	GP	50	1764	2009	88.2	100.5
Pelly	GP	50	1790	2054	89.5	102.7
Phoebus	GP	50	1787	2048	89.4	102.4
Pieterboth	GP	0	1760	1997	0.0	0.0
Rigi	GP	50	1757	1999	87.9	100.0
Snowdon	GP	50	1792	2044	89.6	102.2
Verdun	GP	0	1780	2027	0.0	0.0
Sub Total Gauteng		**300**			**533.2**	**609.1**
Eastern Cape						
Delphi	EC	100	1704	1896	170.4	189.6

Substation Name	Province	PV Allocation [MW]	PV Yield [kWh/kWp]		PV Yield [GWh]	
			Static	Tracker	Static	Tracker
Burgersdorp (New)	EC	0	0	0	0.0	0.0
Ruigtevallei	EC	100	1873	2161	187.3	216.1
Sub Total Eastern Cape		**200**			**357.7**	**405.7**
Western Cape						
Aurora	WC	20	1712	1994	34.2	39.9
Bacchus	WC	50	1696	1939	84.8	97.0
Droerivier	WC	50	1835	2107	91.8	105.4
Juno	WC	30	1798	2089	53.9	62.7
Lainsburg (New)	WC	0	0	0	0.0	0.0
Sub Total Western Cape		**150**			**264.7**	**304.9**

interpolated values

6.1.2 Scenario B

Substation Name	Province	PV Allocation [MW]	PV Yield [kWh/kWp]		PV Yield [GWh]	
			Static	Tracker	Static	Tracker
Northern Cape						
Aggeneis	NC	100	1978	2339	197.8	233.9
Aries	NC	150	1945	2285	291.8	342.8
Ferrum	NC	300	1898	2209	569.4	662.7
Garona	NC	50	1911	2236	95.6	111.8
Gromis	NC	100	1865	2181	186.5	218.1
Helios	NC	200	1935	2275	387.0	455.0
Hotezal	NC	300	1889	2197	566.7	659.1
Hydra	NC	350	1914	2226	669.9	779.1
Kronos	NC	250	1927	2257	481.8	564.3
Nama	NC	50	1952	2324	97.6	116.2
Olien	NC	150	1888	2198	283.2	329.7
Oranjemond	NC	0	1891	2194	0.0	0.0
Paulputs	NC	50	1952	2297	97.6	114.9
Upington Solar Park	NC	550	1914	2241	1052.7	1232.6
Sub Total Northern Cape		**2600**			**4977.5**	**5820.0**
North West						
Bighorn	NW	50	1780	2036	89.0	101.8
Dinaledi	NW	100	1784	2043	178.4	204.3
Hermes	NW	50	1792	2051	89.6	102.6
Midas	NW	100	1791	2047	179.1	204.7
Mookodi	NW	300	1852	2140	555.6	642.0
Ngwedi	NW	50	1769	2038	88.5	101.9
Watershed	NW	100	1837	2118	183.7	211.8
Sub Total North West		**750**			**1363.9**	**1569.1**
Free State						
Boundary	FS	200	1862	2153	372.4	430.6
Everest	FS	100	1835	2106	183.5	210.6
Harvard	FS	100	1841	2117	184.1	211.7
Leander	FS	50	1819	2086	91.0	104.3
Luckhoff	FS	0	1881	2181	0.0	0.0
Makalu	FS	50	1781	2027	89.1	101.4
Merapi	FS	50	1832	2100	91.6	105.0
Mercury	FS	150	1799	2061	269.9	309.2
Perseus	FS	100	1855	2138	185.5	213.8
Roodekuil	FS	50	1884	2184	94.2	109.2
Scafell	FS	50	1790	2041	89.5	102.1
Theseus	FS	50	1819	2084	91.0	104.2
Sub Total Free State		**950**			**1741.6**	**2002.0**
Mpumalanga						
Acornhoek	MP	100	1598	1810	159.8	181.0
Arnot	MP	100	1794	2047	179.4	204.7
Hendrina	MP	100	1778	2024	177.8	202.4
Komati	MP	50	1778	2026	88.9	101.3
Komatipoort	MP	50	1530	1725	76.5	86.3

Substation Name	Province	PV Allocation [MW]	PV Yield [kWh/kWp]		PV Yield [GWh]	
			Static	Tracker	Static	Tracker
Malelane	MP	50	1720	1958	86.0	97.9
Rockdale B	MP	50	1782	2034	89.1	101.7
Simplon	MP	100	1775	2038	177.5	203.8
Sub Total Mpumalanga		**600**			**1035.0**	**1179.1**
Limpopo						
Foskor	LM	100	1559	1780	155.9	178.0
Leseding	LM	100	1739	1986	173.9	198.6
Marble Hall	LM	150	1778	2040	266.7	306.0
Merensky	LM	50	1746	1993	87.3	99.7
Borutho	LM	150	1732	2000	259.8	300.0
Nzhelele	LM	100	1709	1995	170.9	199.5
Spencer	LM	100	1561	1789	156.1	178.9
Tabor	LM	50	1653	1909	82.7	95.5
Warmbad	LM	100	1755	2018	175.5	201.8
Matimba	LM	100	1726	1998	172.6	199.8
Witkop	LM	50	1720	1983	86.0	99.2
Sub Total North West		**1050**			**1787.4**	**2056.9**
KwaZulu Natal						
Bloedrivier	KZ	100	1673	1874	167.3	187.4
Bloukrans	KZ	50	1669	1849	83.5	92.5
Danskraal	KZ	50	1680	1869	84.0	93.5
Incandu	KZ	50	1695	1895	84.8	94.8
Klaarwater	KZ	50	1378	1490	68.9	74.5
Pegasus	KZ	50	1659	1851	83.0	92.6
Umfolozi	KZ	50	1553	1722	77.7	86.1
Sub Total KwaZulu Natal		**400**			**649.0**	**721.2**
Gauteng						
Benburg	GP	30	1766	2010	53.0	60.3
Bernina	GP	20	1806	2068	36.1	41.4
Carmel	GP	50	1774	2028	88.7	101.4
Grootvlei	GP	50	1786	2033	89.3	101.7
Kookfontein	GP	20	1785	2034	35.7	40.7
Nevis	GP	30	1775	2020	53.3	60.6
Olympus	GP	50	1764	2009	88.2	100.5
Pelly	GP	100	1790	2054	179.0	205.4
Phoebus	GP	100	1787	2048	178.7	204.8
Pieterboth	GP	30	1760	1997	52.8	59.9
Rigi	GP	70	1757	1999	123.0	139.9
Snowdon	GP	80	1792	2044	143.4	163.5
Verdun	GP	20	1780	2027	35.6	40.5
Sub Total Gauteng		**650**			**1156.7**	**1320.5**
Eastern Cape						
Delphi	EC	300	1704	1896	511.2	568.8
Burgersdorp (New)	EC	300	1788	2028	536.4	608.4
Ruigtevallei	EC	150	1873	2161	281.0	324.2
Sub Total Eastern Cape		**750**			**1328.6**	**1501.4**

Substation Name	Province	PV Allocation [MW]	PV Yield [kWh/kWp]		PV Yield [GWh]	
			Static	Tracker	Static	Tracker
Western Cape						
Aurora	WC	100	1712	1994	171.2	199.4
Bacchus	WC	100	1696	1939	169.6	193.9
Droerivier	WC	100	1835	2107	183.5	210.7
Juno	WC	150	1798	2089	269.7	313.4
Lainsburg (New)	WC	200	1760	2032	352.0	406.4
Sub Total Western Cape		**650**			**1146.0**	**1323.8**

interpolated values

6.1.3 Scenario C

Substation Name	Province	PV Allocation [MW]	PV Yield [kWh/kWp]		PV Yield [GWh]	
			Static	Tracker	Static	Tracker
Northern Cape						
Aggeneis	NC	250	1978	2339	494.5	584.8
Aries	NC	200	1945	2285	389.0	457.0
Ferrum	NC	300	1898	2209	569.4	662.7
Garona	NC	100	1911	2236	191.1	223.6
Gromis	NC	100	1865	2181	186.5	218.1
Helios	NC	200	1935	2275	387.0	455.0
Hotezal	NC	200	1889	2197	377.8	439.4
Hydra	NC	100	1914	2226	191.4	222.6
Kronos	NC	350	1927	2257	674.5	790.0
Nama	NC	150	1952	2324	292.8	348.6
Olien	NC	0	1888	2198	0.0	0.0
Oranjemond	NC	0	1891	2194	0.0	0.0
Paulputs	NC	50	1952	2297	97.6	114.9
Upington Solar Park	NC	800	1914	2241	1531.2	1792.8
Sub Total Northern Cape		**2800**			**5382.8**	**6309.4**
North West						
Bighorn	NW	200	1780	2036	356.0	407.2
Dinaledi	NW	200	1784	2043	356.8	408.6
Hermes	NW	300	1792	2051	537.6	615.3
Midas	NW	300	1791	2047	537.3	614.1
Mookodi	NW	500	1852	2140	926.0	1070.0
Ngwedi	NW	400	1769	2038	707.6	815.2
Watershed	NW	200	1837	2118	367.4	423.6
Sub Total North West		**2100**			**3788.7**	**4354.0**
Free State						
Boundary	FS	200	1862	2153	372.4	430.6
Everest	FS	0	1835	2106	0.0	0.0
Harvard	FS	100	1841	2117	184.1	211.7
Leander	FS	100	1819	2086	181.9	208.6
Luckhoff	FS	500	1881	2181	940.5	1090.5
Makalu	FS	50	1781	2027	89.1	101.4
Merapi	FS	0	1832	2100	0.0	0.0
Mercury	FS	200	1799	2061	359.8	412.2
Perseus	FS	400	1855	2138	742.0	855.2
Roodekuil	FS	100	1884	2184	188.4	218.4
Scafell	FS	0	1790	2041	0.0	0.0
Theseus	FS	450	1819	2084	818.6	937.8
Sub Total Free State		**2100**			**3876.7**	**4466.4**
Mpumalanga						
Acornhoek	MP	0	1598	1810	0.0	0.0
Arnot	MP	0	1794	2047	0.0	0.0
Hendrina	MP	0	1778	2024	0.0	0.0
Komati	MP	0	1778	2026	0.0	0.0
Komatipoort	MP	0	1530	1725	0.0	0.0

Substation Name	Province	PV Allocation [MW]	PV Yield [kWh/kWp]		PV Yield [GWh]	
			Static	Tracker	Static	Tracker
Malelane	MP	0	1720	1958	0.0	0.0
Rockdale B	MP	0	1782	2034	0.0	0.0
Simplon	MP	0	1775	2038	0.0	0.0
Sub Total Mpumalanga		**0**			**0.0**	**0.0**
Limpopo						
Foskor	LM	0	1559	1780	0.0	0.0
Leseding	LM	0	1739	1986	0.0	0.0
Marble Hall	LM	0	1778	2040	0.0	0.0
Merensky	LM	0	1746	1993	0.0	0.0
Borutho	LM	0	1732	2000	0.0	0.0
Nzhelele	LM	0	1709	1995	0.0	0.0
Spencer	LM	0	1561	1789	0.0	0.0
Tabor	LM	0	1653	1909	0.0	0.0
Warmbad	LM	0	1755	2018	0.0	0.0
Matimba	LM	0	1726	1998	0.0	0.0
Witkop	LM	0	1720	1983	0.0	0.0
Sub Total North West		**0**			**0.0**	**0.0**
KwaZulu Natal						
Bloedrivier	KZ	0	1673	1874	0.0	0.0
Bloukrans	KZ	0	1669	1849	0.0	0.0
Danskraal	KZ	0	1680	1869	0.0	0.0
Incandu	KZ	0	1695	1895	0.0	0.0
Klaarwater	KZ	0	1378	1490	0.0	0.0
Pegasus	KZ	0	1659	1851	0.0	0.0
Umfolozi	KZ	0	1553	1722	0.0	0.0
Sub Total KwaZulu Natal		**0**			**0.0**	**0.0**
Gauteng						
Benburg	GP	0	1766	2010	0.0	0.0
Bernina	GP	0	1806	2068	0.0	0.0
Carmel	GP	0	1774	2028	0.0	0.0
Grootvlei	GP	0	1786	2033	0.0	0.0
Kookfontein	GP	0	1785	2034	0.0	0.0
Nevis	GP	0	1775	2020	0.0	0.0
Olympus	GP	0	1764	2009	0.0	0.0
Pelly	GP	0	1790	2054	0.0	0.0
Phoebus	GP	0	1787	2048	0.0	0.0
Pieterboth	GP	0	1760	1997	0.0	0.0
Rigi	GP	0	1757	1999	0.0	0.0
Snowdon	GP	0	1792	2044	0.0	0.0
Verdun	GP	0	1780	2027	0.0	0.0
Sub Total Gauteng		**0**			**0.0**	**0.0**
Eastern Cape						
Delphi	EC	300	1704	1896	511.2	568.8
Burgersdorp (New)	EC	300	1788	2028	536.4	608.4
Ruigtevallei	EC	150	1873	2161	281.0	324.2
Sub Total Eastern Cape		**750**			**1328.6**	**1501.4**

Substation Name	Province	PV Allocation [MW]	PV Yield [kWh/kWp]		PV Yield [GWh]	
			Static	Tracker	Static	Tracker
Western Cape						
Aurora	WC	100	1712	1994	171.2	199.4
Bacchus	WC	100	1696	1939	169.6	193.9
Droerivier	WC	100	1835	2107	183.5	210.7
Juno	WC	150	1798	2089	269.7	313.4
Lainsburg (New)	WC	200	1760	2032	352.0	406.4
Sub Total Western Cape		**650**			**1146.0**	**1323.8**

interpolated values

6.2 Annex 2: Results of contingency analysis

6.2.1 General

This Annex summarizes the results of contingency analysis studies that have been carried out for verifying the transmission grid after reinforcement of each Scenario.

The resulting tables summarize the results of 511 contingency cases, which have been processed for each case, including n-1 contingencies of all 765kV, 400kV, 275kV and 220kV transmission lines.

For each scenario, load flow and contingency analysis studies have been carried out for the following four cases, which are supposed to represent worst-case conditions:

- Maximum load during day-time (47GW), max. PV production, 1 Koeberg unit in service
- Maximum load during day-time (47GW), max. PV production, 2 Koeberg units in service
- Minimum load during day-time (34GW), max. PV production, 1 Koeberg unit in service
- Minimum load during day-time (34GW), max. PV production, 2 Koeberg units in service.

The coloring within the tables is according to the following definitions:

- Percentage loadings are expressed on basis of the maximum permanent current rating of each line (Rating A), under both, n-0 and n-1 conditions.
- Lines colored in orange represent lines, which show problems already in the Base Case, without PV generation. These overloads represent problems with the grid model, as provided by ESKOM for the purpose of these studies, and are independent from PV generation. For this reason, these overloads are not relevant within the context of the PV allocation studies.
- Each table shows all lines having a loading above 100% either under normal operating conditions (n-0 condition) or in any n-1 contingency case.
- N-0 loadings are colored in red if the line loading under normal operating conditions (n-0 condition) is above 100%.
- N-1 loadings are colored in red if the maximum n-1 loading is above 125%. Hence, an emergency rating of 125% of the maximum continuous rating is generally considered.

6.2.2 Base Case

Table 32: Base Case (no PV), 51GW of load, 1 Koeberg unit in service

Name	Grid	Max. n-1 Loading	n-0 Loading	Rtd. Voltage
		%	%	kV
lne_LAMBDA4_MAJUB4_1	17 NEWCSTLE	138,8	74,9	400
lne_LAMBDA4_MAJUB4_2	17 NEWCSTLE	138,8	74,9	400
lne_DUVHA4_MATLA4_1	3 HVLD_NRT	133,1	78,2	400
lne_VULCN4_DUVHA4_1	3 HVLD_NRT	107,9	73,6	400
lne_FGROVE4_PALMT4_1	24 S_CAPE	103,5	78,6	400
lne_OTTAWA_2_BNDR1_1	18 PINETOWN	238,8	129,0	275
lne_OTTAWA_2_BNDR2_1	18 PINETOWN	238,8	129,0	275
lne_KLRWT2_HECTR2_1	18 PINETOWN	163,6	126,7	275
lne_KLRWT2_HECTR2_2	18 PINETOWN	114,5	54,3	275
lne_VENUS2_BLKRN2_2	16 LADYSMTH	112,6	45,4	275

6.2.3 Scenario A

Table 33: Scenario A (8,4GW of PV), 47GW of load, 1 Koeberg unit in service

Name	Grid	Max. n-1 Loading	n-0 Loading	Rtd. Voltage
		%	%	kV
lne_LAMBDA4_MAJUB4_1	17 NEWCSTLE	119,6	64,5	400
lne_LAMBDA4_MAJUB4_2	17 NEWCSTLE	119,6	64,5	400
lne_HYDRA4_KRONS_SC_2	23 NAMAQUA	114,8	73,5	400
lne_BLANC4_DROER4_1	24 S_CAPE	107,4	87,1	400
lne_OTTAWA_2_BNDR1_1	18 PINETOWN	227,3	122,8	275
lne_OTTAWA_2_BNDR2_1	18 PINETOWN	227,3	122,8	275
lne_KLRWT2_HECTR2_1	18 PINETOWN	140,7	109,0	275
lne_GLOCK2_LETHB2B_2	9 VAAL_TRI	104,0	65,0	275
lne_OLIEN2_FERRM2_2	13 KIMBERLY	101,6	65,5	275

Table 34: Scenario A (8,4GW of PV), 47GW of load, 2 Koeberg units in service

Name	Grid	Max. n-1 Loading	n-0 Loading	Rtd. Voltage
		%	%	kV
lne_HYDRA4_KRONS_SC_1	20 KAROO	104,6	77,9	400
lne_HYDRA4_KRONS_SC_2	23 NAMAQUA	124,8	77,9	400
lne_LAMBDA4_MAJUB4_1	17 NEWCSTLE	119,6	64,5	400
lne_LAMBDA4_MAJUB4_2	17 NEWCSTLE	119,6	64,5	400
lne_OTTAWA_2_BNDR1_1	18 PINETOWN	226,7	122,5	275
lne_OTTAWA_2_BNDR2_1	18 PINETOWN	226,7	122,5	275
lne_KLRWT2_HECTR2_1	18 PINETOWN	140,8	109,1	275

Table 35: Scenario A (8,4GW of PV), 34GW of load, 1 Koeberg unit in service

Name	Grid	Max. n-1 Loading	n-0 Loading	Rtd. Voltage
		%	%	kV
lne_HYDRA4_KRONS_SC_1	20 KAROO	104,3	78,2	400
lne_HYDRA4_KRONS_SC_2	23 NAMAQUA	125,2	78,2	400
lne_KLRWT2_HECTR2_1	18 PINETOWN	110,0	85,2	275
lne_OTTAWA_2_BNDR1_1	18 PINETOWN	119,4	64,5	275
lne_OTTAWA_2_BNDR2_1	18 PINETOWN	119,4	64,5	275

Table 36: Scenario A (8,4GW of PV), 34GW of load, 2 Koeberg units in service

Name	Grid	Max. n-1 Loading	n-0 Loading	Rtd. Voltage
		%	%	kV
lne_HYDRA4_KRONS_SC_1	20 KAROO	103,9	79,1	400
lne_HYDRA4_KRONS_SC_2	23 NAMAQUA	126,7	79,1	400
lne_KLRWT2_HECTR2_1	18 PINETOWN	111,0	86,0	275

6.2.4 Scenario B

Table 37: Scenario B (8,4GW of PV), 47GW of load, 1 Koeberg unit in service

Name	Grid	Max. n-1 Loading	n-0 Loading	Rtd. Voltage
		%	%	kV
lne_LAMBDA4_MAJUB4_1	17 NEWCSTLE	116,5	62,8	400
lne_LAMBDA4_MAJUB4_2	17 NEWCSTLE	116,5	62,8	400
lne_SISHENA_JUNO4_KA_1	25 W_COAST	102,0	85,8	400
lne_SISHENA_AUROR4_1	25 W_COAST	102,0	85,8	400
lne_BLANC4_DROER4_1	24 S_CAPE	100,4	79,1	400
lne_OTTAWA_2_BNDR1_1	18 PINETOWN	226,8	122,5	275
lne_OTTAWA_2_BNDR2_1	18 PINETOWN	226,8	122,5	275
lne_KLRWT2_HECTR2_1	18 PINETOWN	136,1	105,4	275
lne_GLOCK2_LETHB2B_2	9 VAAL_TRI	103,5	65,0	275
lne_HYDRA1_RGTVL1_2	20 KAROO	109,2	59,6	220

Table 38: Scenario B (8,4GW of PV), 47GW of load, 2 Koeberg units in service

Name	Grid	Max. n-1 Loading	n-0 Loading	Rtd. Voltage
		%	%	kV
lne_LAMBDA4_MAJUB4_1	17 NEWCSTLE	119,8	64,6	400
lne_LAMBDA4_MAJUB4_2	17 NEWCSTLE	119,8	64,6	400
lne_VULCN4_DUVHA4_1	3 HVLD_NRT	108,8	70,5	400
lne_OTTAWA_2_BNDR1_1	18 PINETOWN	228,2	123,3	275
lne_OTTAWA_2_BNDR2_1	18 PINETOWN	228,2	123,3	275
lne_KLRWT2_HECTR2_1	18 PINETOWN	140,4	108,7	275
lne_HYDRA1_RGTVL1_2	20 KAROO	107,5	58,7	220

Table 39: Scenario B (8,4GW of PV), 34GW of load, 1 Koeberg unit in service

Name	Grid	Max. n-1 Loading	n-0 Loading	Rtd. Voltage
		%	%	kV
lne_OTTAWA_2_BNDR1_1	18 PINETOWN	117,8	63,7	275
lne_OTTAWA_2_BNDR2_1	18 PINETOWN	117,8	63,7	275
lne_KLRWT2_HECTR2_1	18 PINETOWN	108,6	84,1	275
lne_HYDRA1_RGTVL1_2	20 KAROO	111,4	60,7	220

Table 40: Scenario B (8,4GW of PV), 34GW of load, 2 Koeberg units in service

Name	Grid	Max. n-1 Loading	n-0 Loading	Rtd. Voltage
		%	%	kV
lne_OTTAWA_2_BNDR1_1	18 PINETOWN	118,3	63,9	275
lne_OTTAWA_2_BNDR2_1	18 PINETOWN	118,3	63,9	275
lne_KLRWT2_HECTR2_1	18 PINETOWN	107,7	83,4	275
lne_HYDRA1_RGTVL1_2	20 KAROO	111,8	60,9	220

6.2.5 Scenario C

Table 41: Scenario C (8,4GW of PV), 47GW of load, 1 Koeberg unit in service

Name	Grid	Max. n-1 Loading	n-0 Loading	Rtd. Voltage
		%	%	kV
lne_LAMBDA4_MAJUB4_1	17 NEWCSTLE	124,7	67,3	400
lne_LAMBDA4_MAJUB4_2	17 NEWCSTLE	124,7	67,3	400
lne_SISHENA_JUNO4_KA_1	25 W_COAST	120,5	96,8	400
lne_SISHENA_AUROR4_1	25 W_COAST	120,5	96,8	400
lne_HYDRA4_KRONS_SC_1	20 KAROO	118,9	51,9	400
lne_HELS4_SISHENB_1	25 W_COAST	113,6	89,9	400
lne_SISHENB_JUNO4_KB_1	25 W_COAST	113,6	89,9	400
lne_VULCN4_DUVHA4_1	3 HVLD_NRT	109,9	68,8	400
lne_BLANC4_DROER4_1	24 S_CAPE	104,9	80,8	400
lne_ARIES4_SISHENC_1	23 NAMAQUA	100,5	76,8	400
lne_HELS4A_SISHENC_1	25 W_COAST	100,5	76,8	400
lne_OTTAWA_2_BNDR1_1	18 PINETOWN	230,4	124,5	275
lne_OTTAWA_2_BNDR2_1	18 PINETOWN	230,4	124,5	275
lne_KLRWT2_HECTR2_1	18 PINETOWN	145,9	113,1	275
lne_KLRWT2_HECTR2_2	18 PINETOWN	102,1	48,4	275
lne_GLOCK2_LETHB2B_2	9 VAAL_TRI	101,9	60,9	275
lne_NAMA2_AGGNS2_1	23 NAMAQUA	104,4	52,2	220

Table 42: Scenario C (8,4GW of PV), 47GW of load, 2 Koeberg units in service

Name	Grid	Max. n-1 Loading	n-0 Loading	Rtd. Voltage
		%	%	kV
lne_LAMBDA4_MAJUB4_1	17 NEWCSTLE	124,2	67,0	400
lne_LAMBDA4_MAJUB4_2	17 NEWCSTLE	124,2	67,0	400
lne_HYDRA4_KRONS_SC_1	20 KAROO	111,8	57,3	400
lne_VULCN4_DUVHA4_1	3 HVLD_NRT	111,2	72,1	400
lne_SISHENA_JUNO4_KA_1	25 W_COAST	104,9	78,8	400
lne_SISHENA_AUROR4_1	25 W_COAST	104,9	78,8	400
lne_OTTAWA_2_BNDR1_1	18 PINETOWN	229,7	124,1	275
lne_OTTAWA_2_BNDR2_1	18 PINETOWN	229,7	124,1	275
lne_KLRWT2_HECTR2_1	18 PINETOWN	145,5	112,7	275
lne_KLRWT2_HECTR2_2	18 PINETOWN	101,8	48,3	275
lne_NAMA2_AGGNS2_1	23 NAMAQUA	104,6	52,3	220

Table 43: Scenario C (8,4GW of PV), 34GW of load, 1 Koeberg unit in service

Name	Grid	Max. n-1 Loading	n-0 Loading	Rtd. Voltage
		%	%	kV
lne_HYDRA4_KRONS_SC_1	20 KAROO	112,3	59,0	400
lne_SISHENA_JUNO4_KA_1	25 W_COAST	103,9	76,9	400
lne_SISHENA_AUROR4_1	25 W_COAST	103,9	76,9	400
lne_LAMBDA4_MAJUB4_1	17 NEWCSTLE	100,7	54,3	400
lne_LAMBDA4_MAJUB4_2	17 NEWCSTLE	100,7	54,3	400
lne_OTTAWA_2_BNDR1_1	18 PINETOWN	119,3	64,5	275
lne_OTTAWA_2_BNDR2_1	18 PINETOWN	119,3	64,5	275
lne_KLRWT2_HECTR2_1	18 PINETOWN	113,8	88,1	275
lne_NAMA2_AGGNS2_1	23 NAMAQUA	110,8	55,4	220

Table 44: Scenario C (8,4GW of PV), 34GW of load, 2 Koeberg units in service

Name	Grid	Max. n-1 Loading	n-0 Loading	Rtd. Voltage
		%	%	kV
lne_HYDRA4_KRONS_SC_1	20 KAROO	111,5	62,7	400
lne_LAMBDA4_MAJUB4_1	17 NEWCSTLE	103,5	55,9	400
lne_LAMBDA4_MAJUB4_2	17 NEWCSTLE	103,5	55,9	400
lne_KLRWT2_HECTR2_1	18 PINETOWN	114,5	88,7	275
lne_NAMA2_AGGNS2_1	23 NAMAQUA	110,9	55,4	220

6.3 Annex 3: Generation, load and losses for selected days

Overview

1 Base Case

1.1 1x Koeberg Unit(s) Online

1.1.1 00% Wind

1.1.2 30% Wind

1.1.3 60% Wind

1.1.4 90% Wind

1.2 2x Koeberg Unit(s) Online

1.2.1 00% Wind

1.2.2 30% Wind

1.2.3 60% Wind

1.2.4 90% Wind

2 Scenario A

2.1 1x Koeberg Unit(s) Online

2.1.1 00% Wind

2.1.2 30% Wind

2.1.3 60% Wind

2.1.4 90% Wind

2.2 2x Koeberg Unit(s) Online

2.2.1 00% Wind

2.2.2 30% Wind

2.2.3 60% Wind

2.2.4 90% Wind

3 Scenario B

3.1 1x Koeberg Unit(s) Online

3.1.1 00% Wind

3.1.2 30% Wind

3.1.3 60% Wind

3.1.4 90% Wind

3.2 2x Koeberg Unit(s) Online

3.2.1 00% Wind

3.2.2 30% Wind

3.2.3 60% Wind

3.2.4 90% Wind

4 Scenario C

4.1 1x Koeberg Unit(s) Online

4.1.1 00% Wind

4.1.2 30% Wind

4.1.3 60% Wind

4.1.4 90% Wind

4.2 2x Koeberg Unit(s) Online

4.2.1 00% Wind

4.2.2 30% Wind

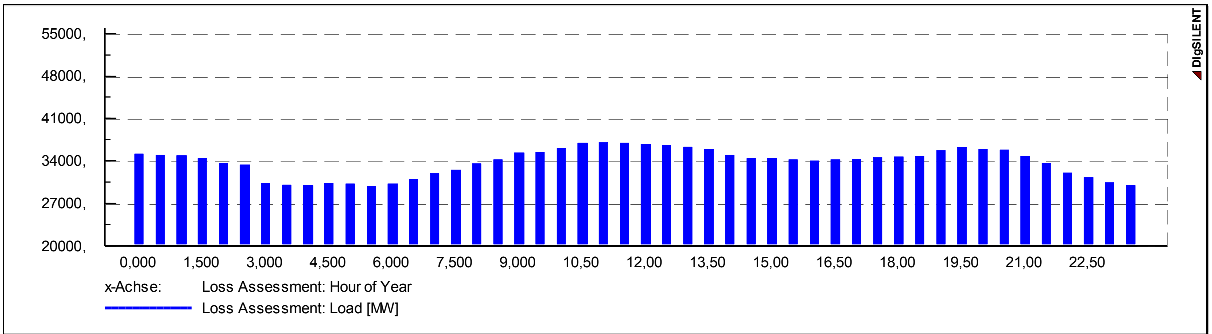
4.2.3 60% Wind

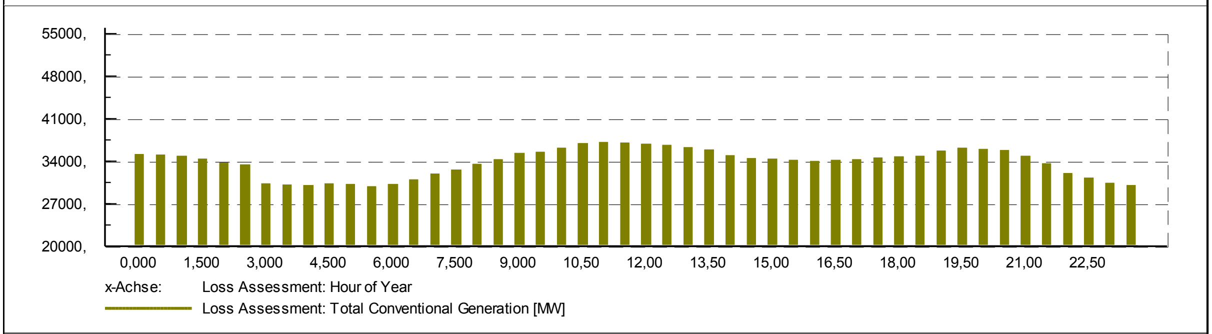
4.2.4 90% Wind

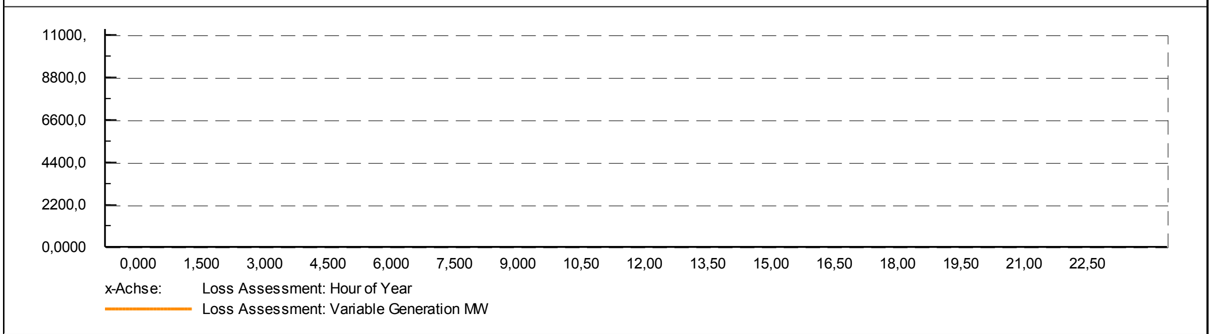
1 Base Case

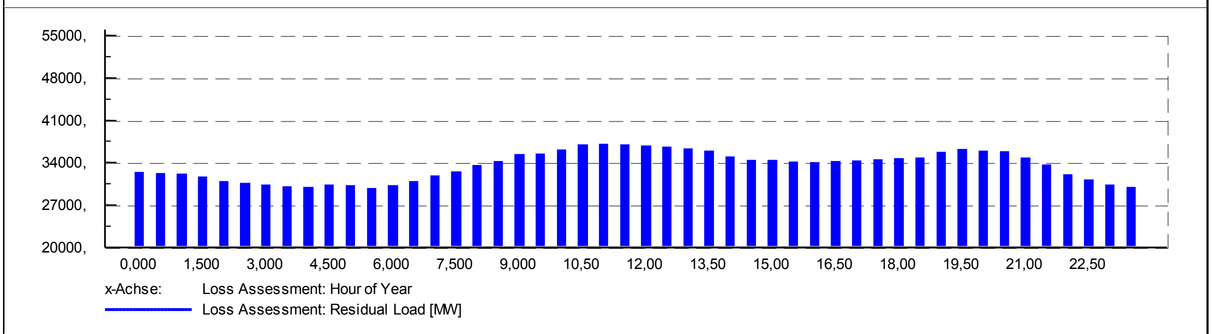
1.1 1x Koeberg Unit(s) Online

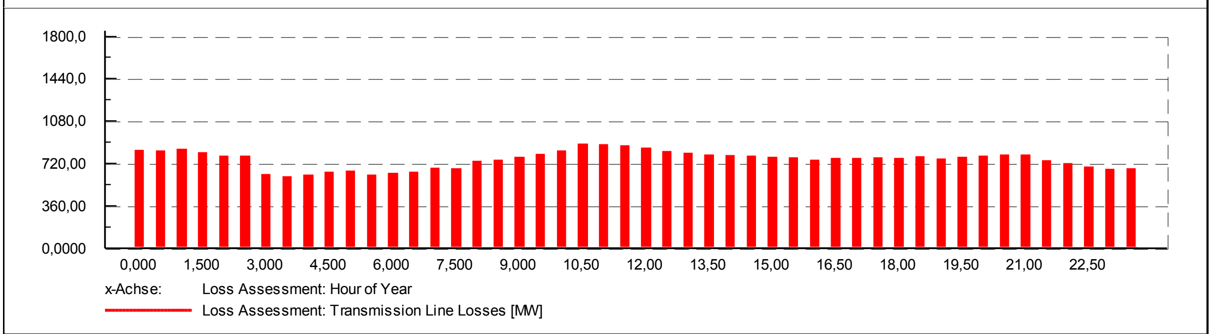
1.1.1 00% Wind



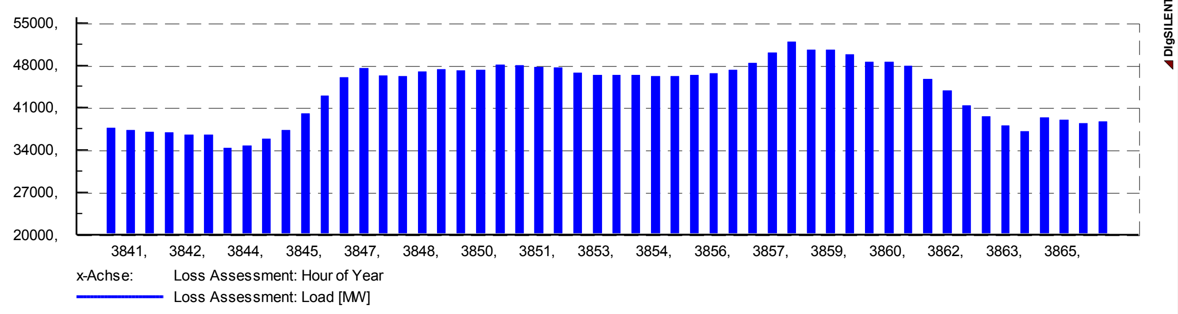


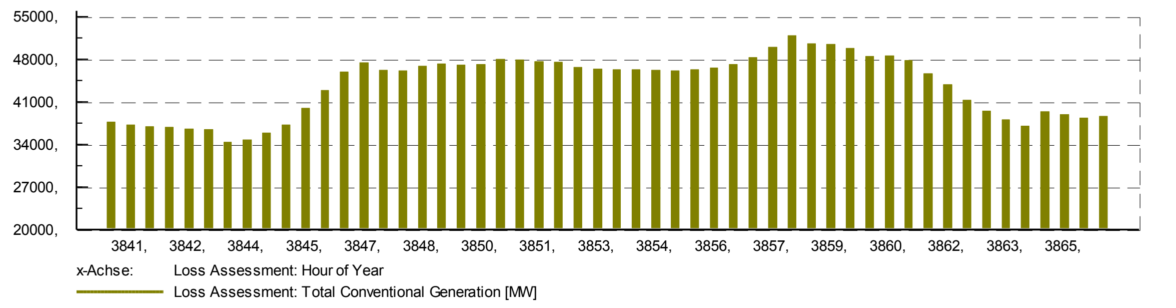


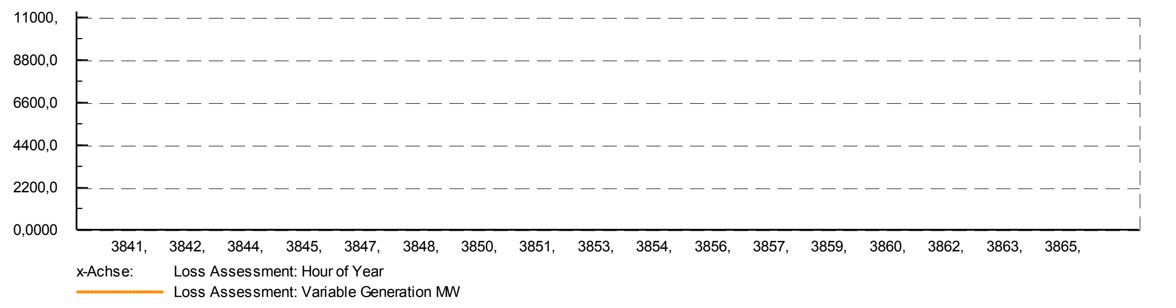


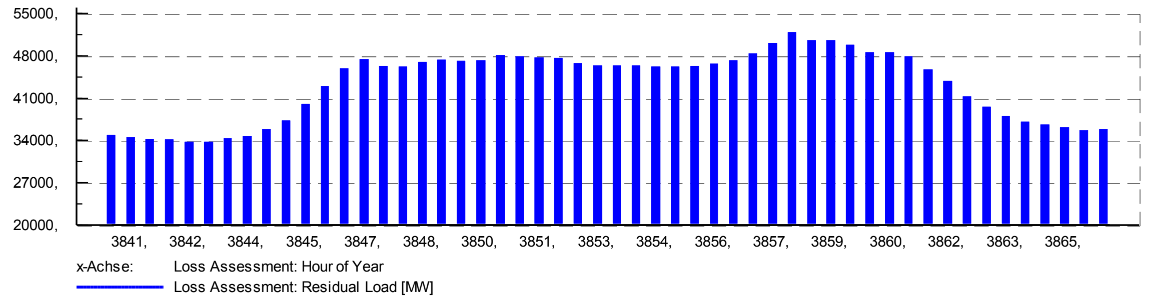


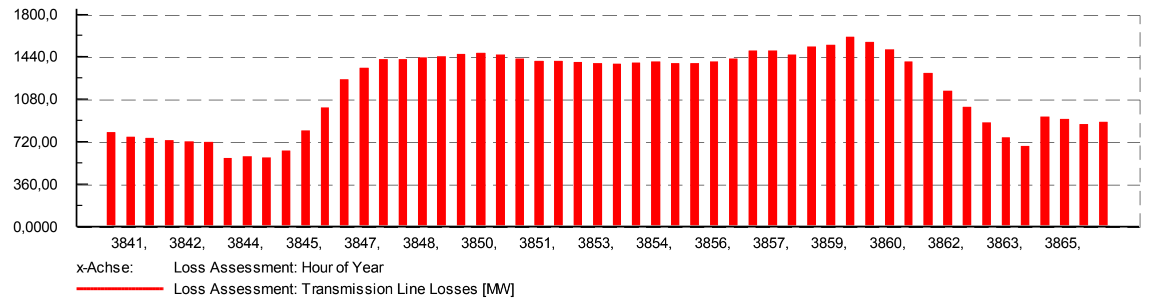
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	Low Load (1st January)	Datum: 16.02.2015
	00% Wind	2x Koeberg Unit(s) Online	Anhang: 1.1.1 /1



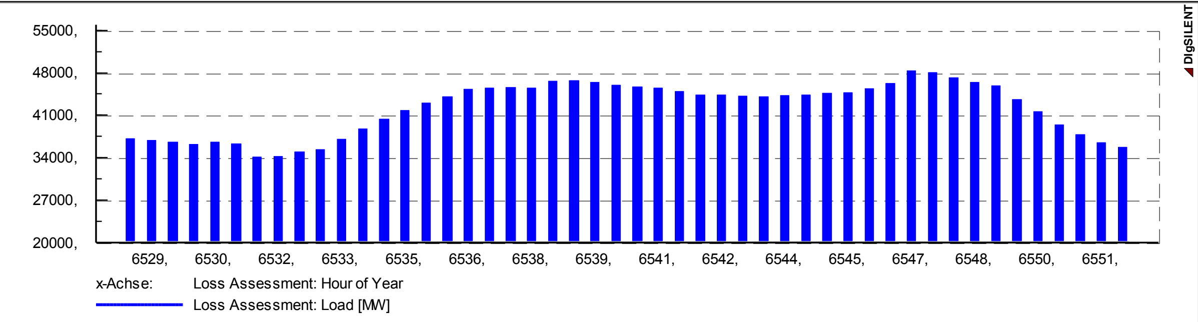


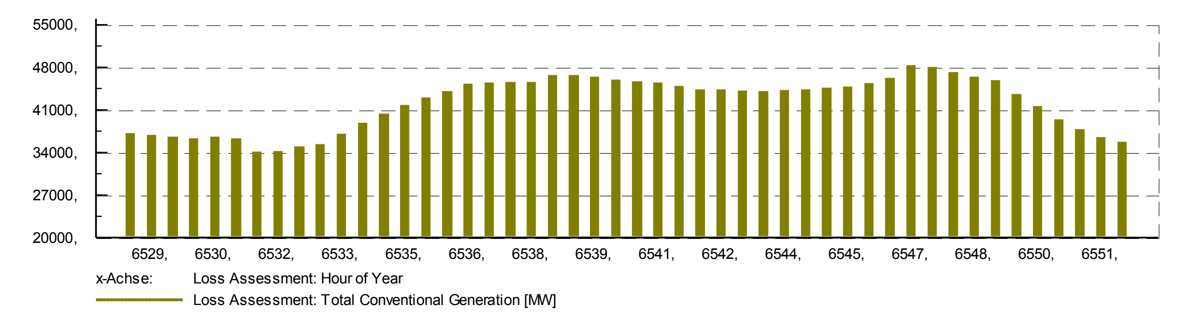


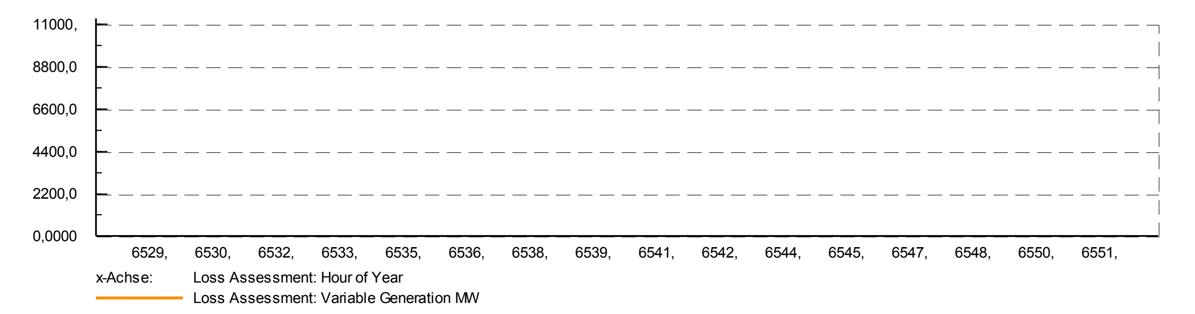


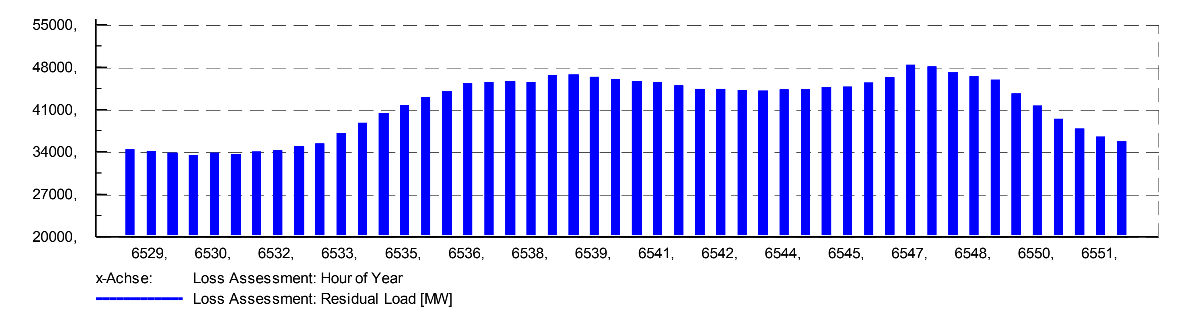


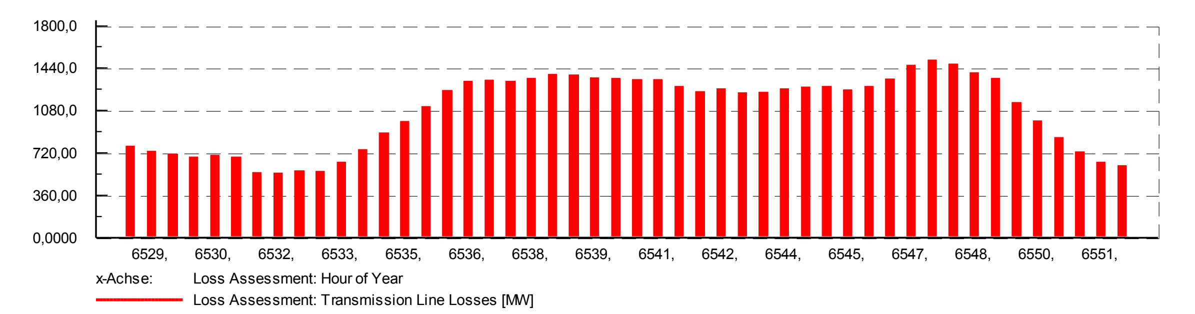
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	High Load (9th June)	Datum: 16.02.2015
	00% Wind	2x Koeberg Unit(s) Online	Anhang: 1.1.1 /2





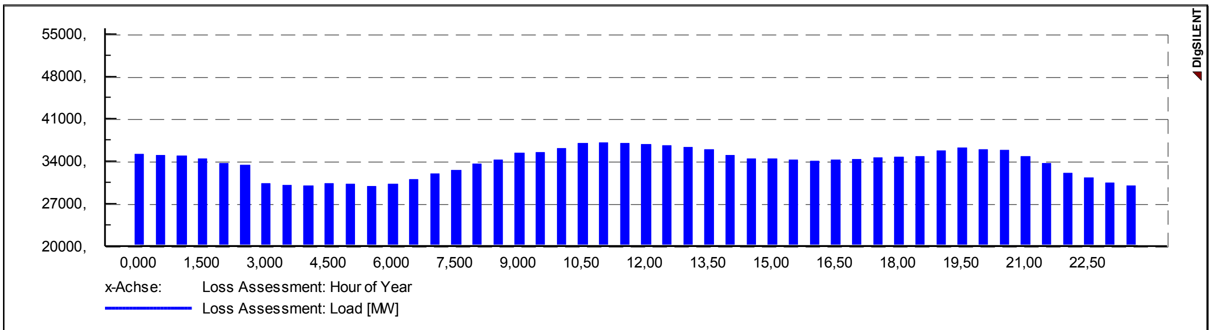


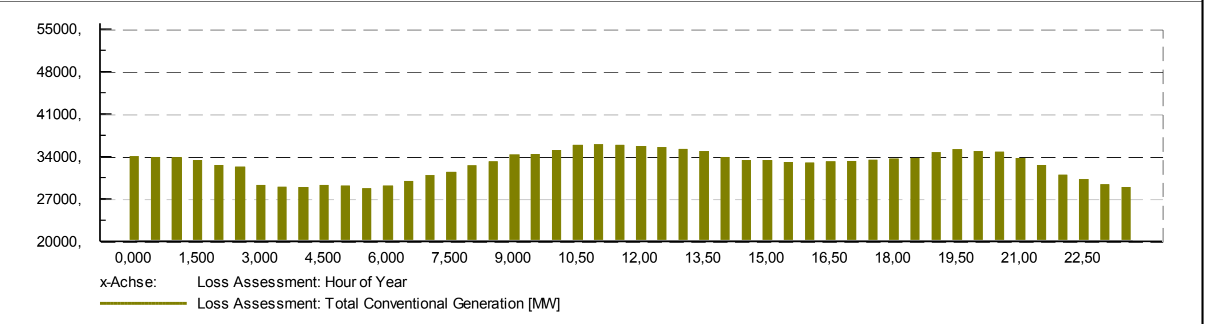


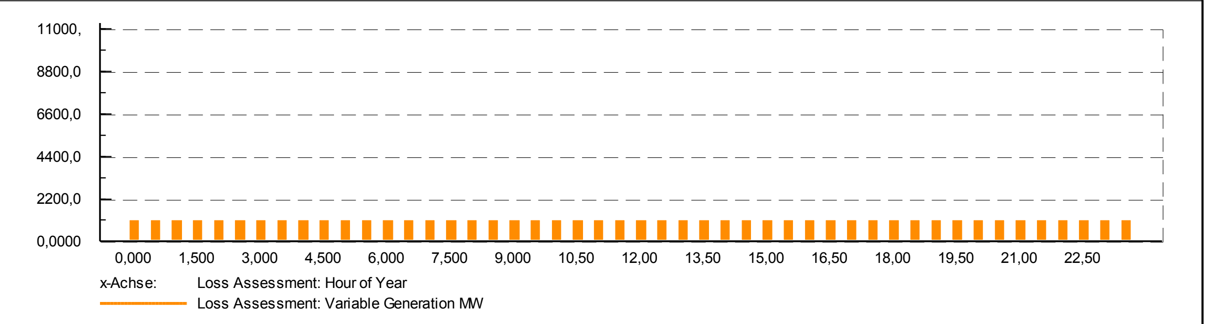


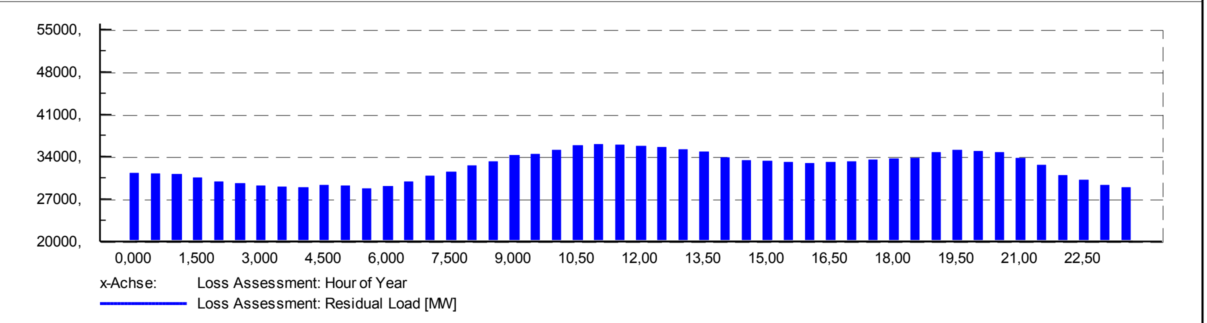
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	High PV (29th September)	Datum: 16.02.2015
	00% Wind	2x Koeberg Unit(s) Online	Anhang: 1.1.1 /3

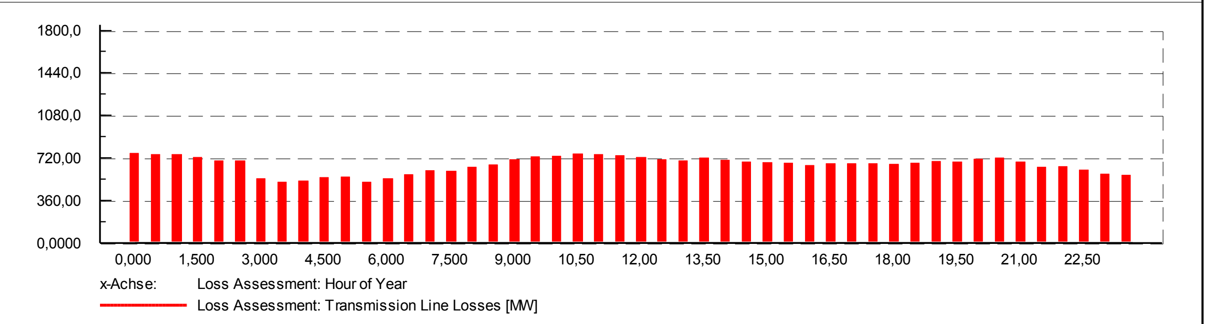
1.1.2 30% Wind



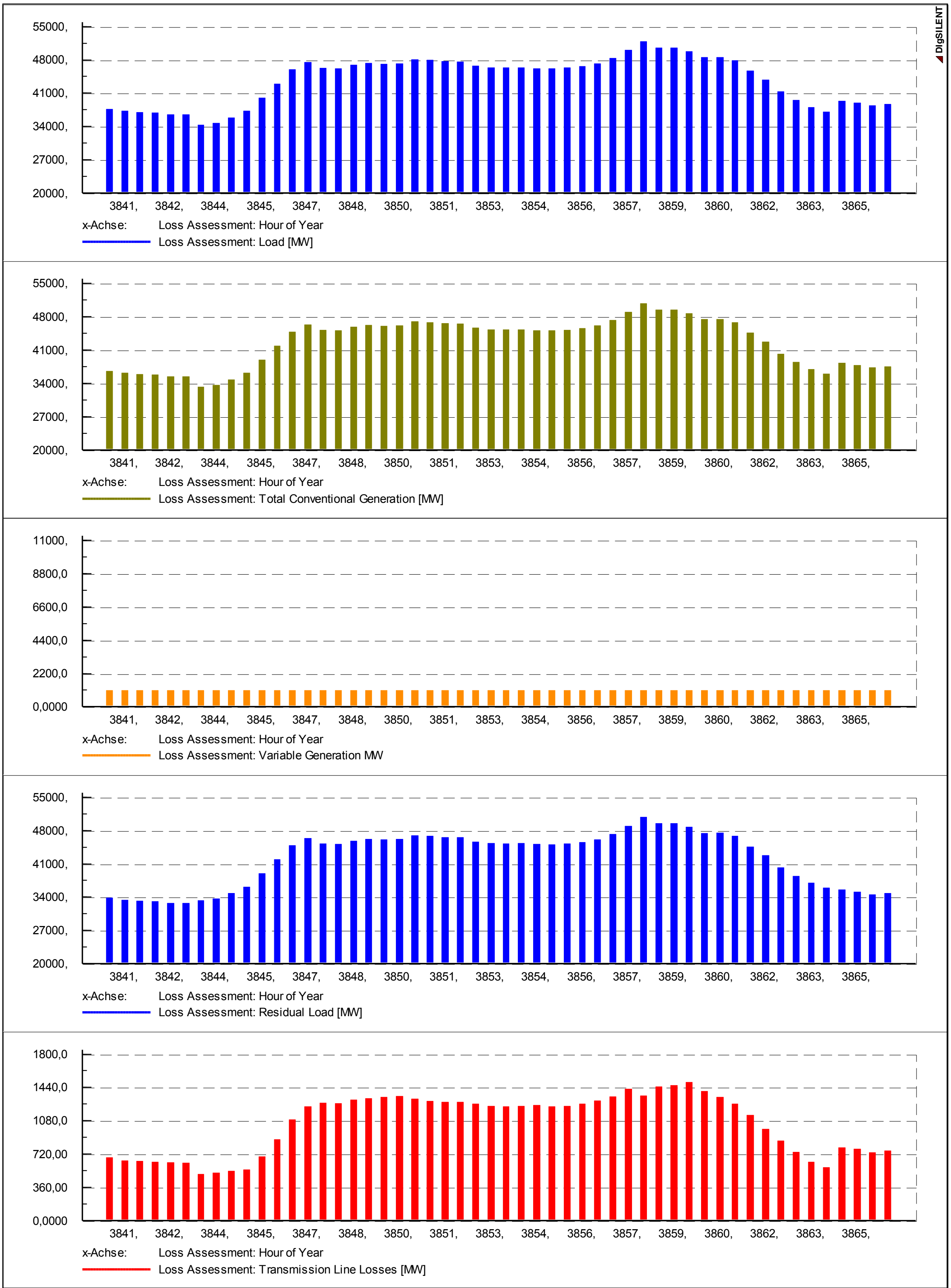




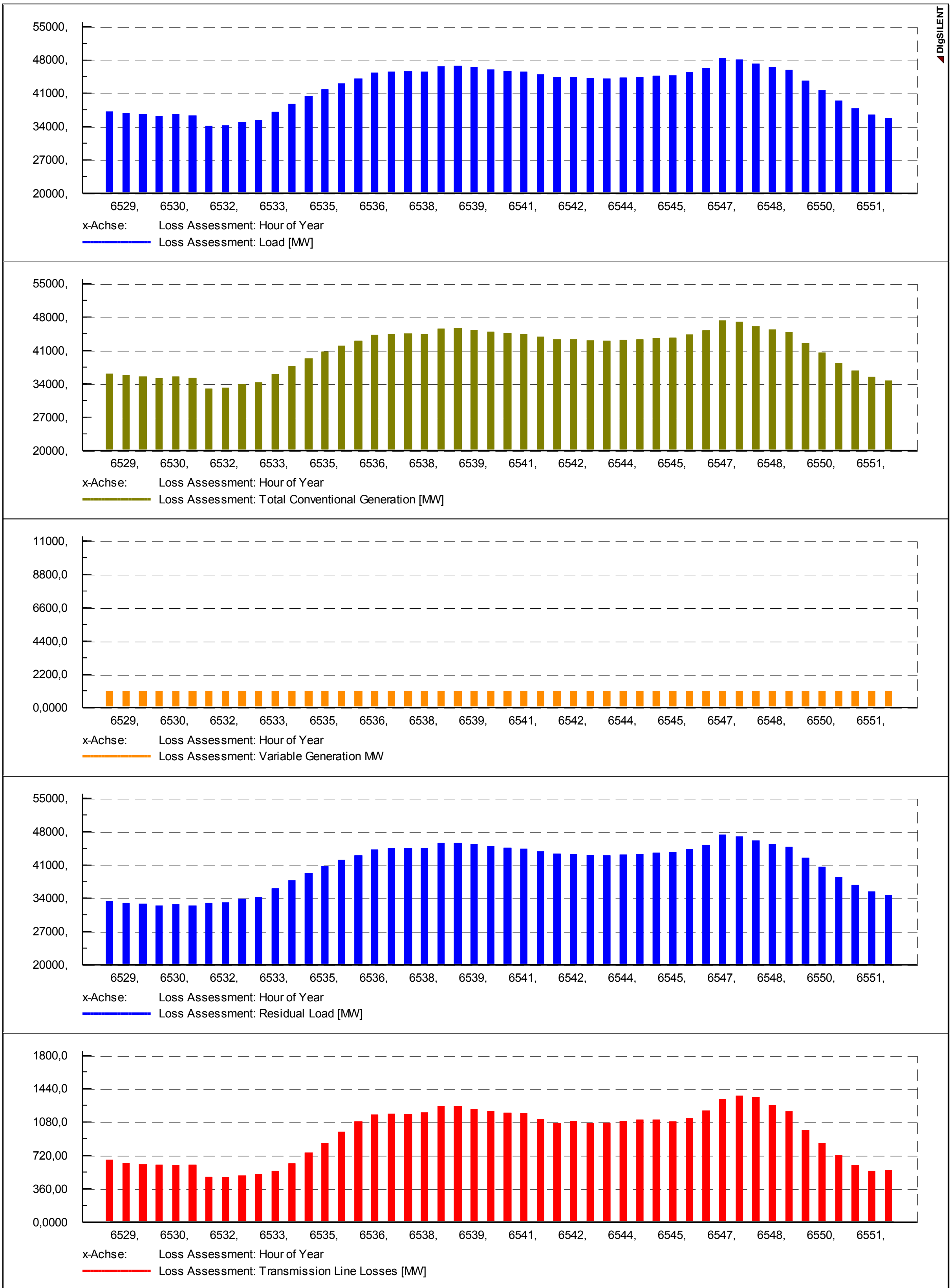




M.P.E. MOELLER & POELLER ENGINEERING	Base Case	Low Load (1st January)	Datum: 16.02.2015
	30% Wind	2x Koeberg Unit(s) Online	Anhang: 1.1.2 /1

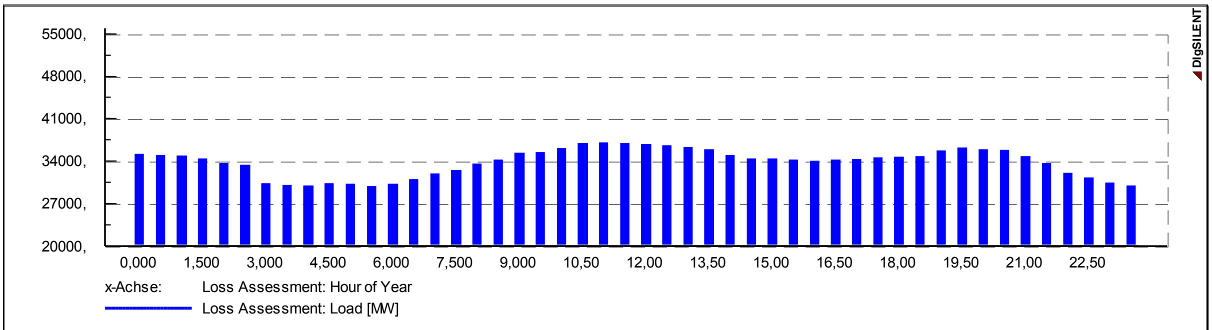


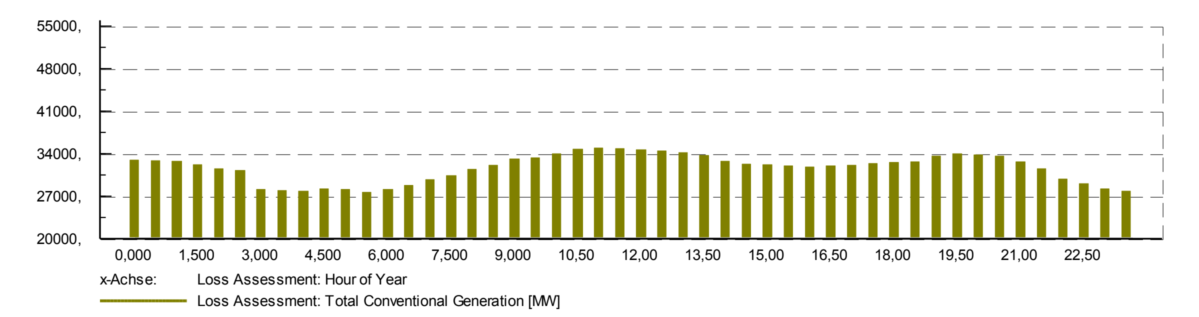
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	High Load (9th June)	Datum: 16.02.2015
	30% Wind	2x Koeberg Unit(s) Online	Anhang: 1.1.2 /2

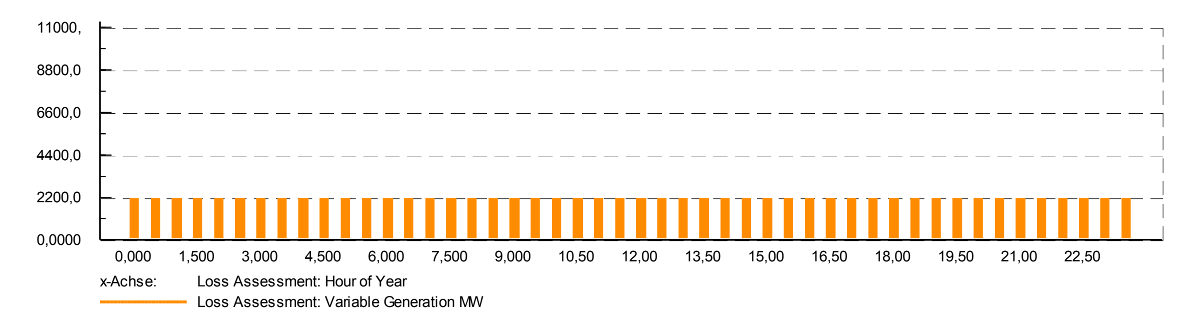


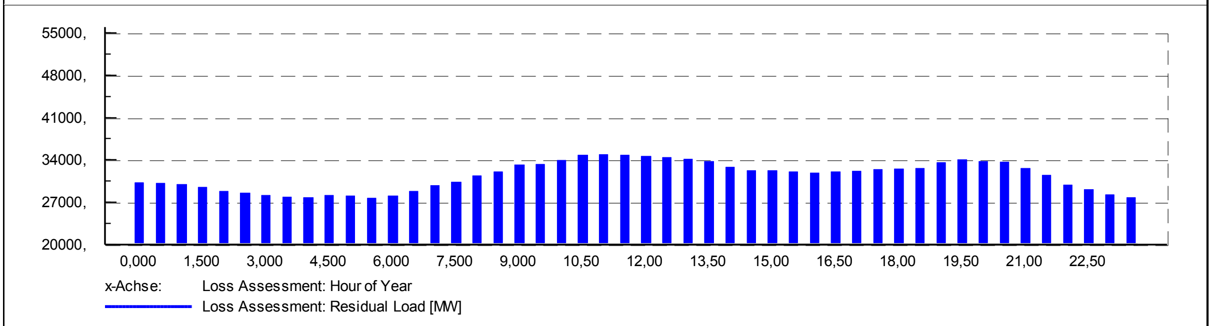
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	High PV (29th September)	Datum: 16.02.2015
	30% Wind	2x Koeberg Unit(s) Online	Anhang: 1.1.2 /3

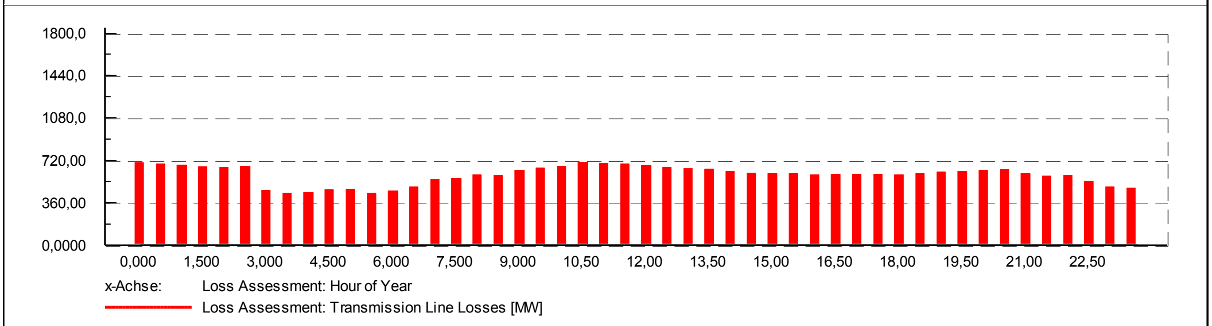
1.1.3 60% Wind



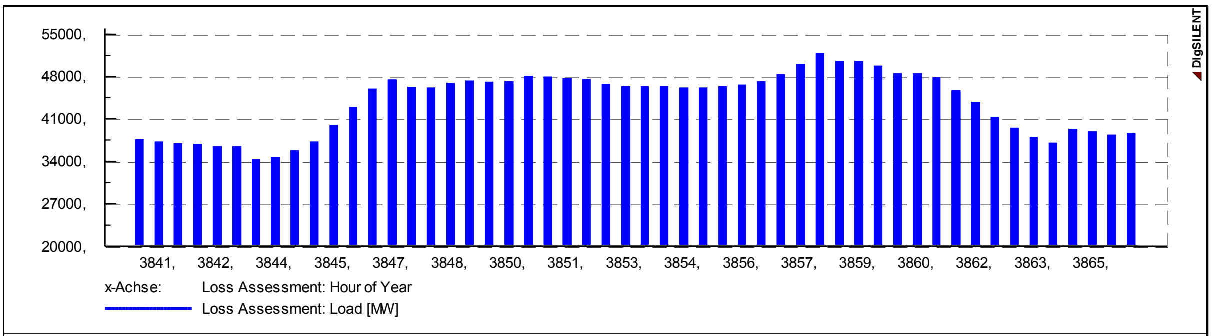


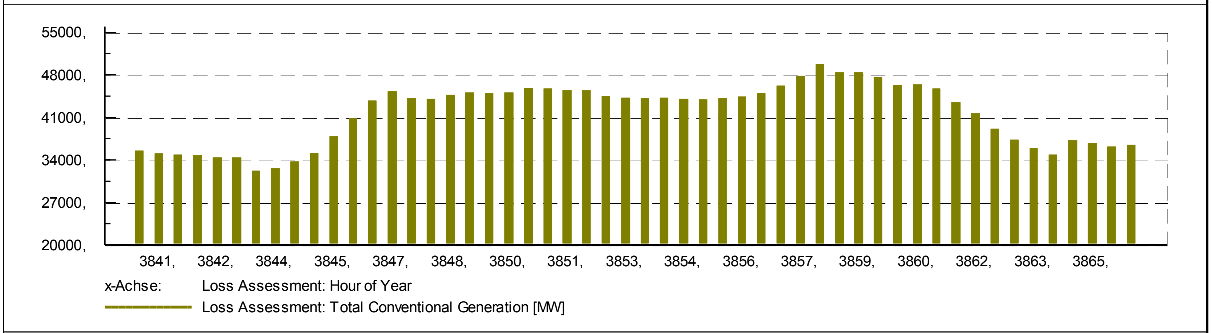


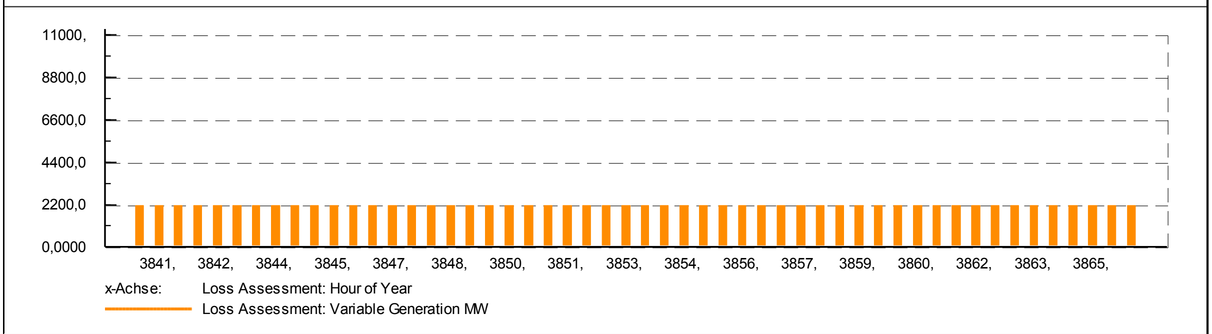


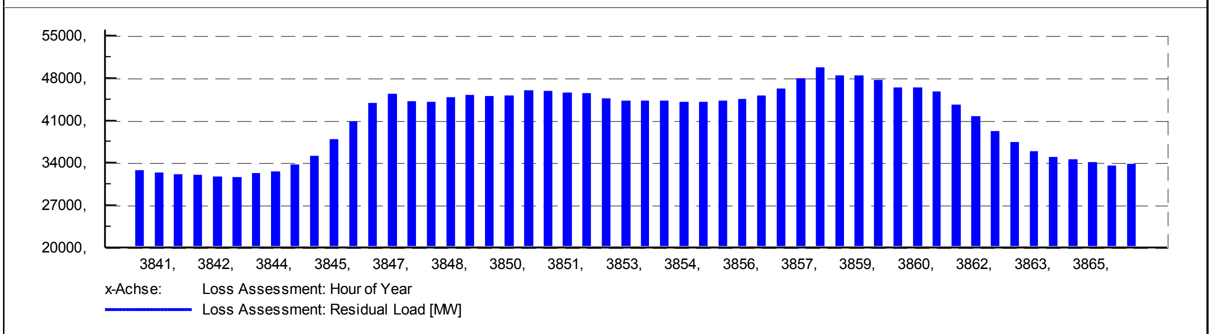


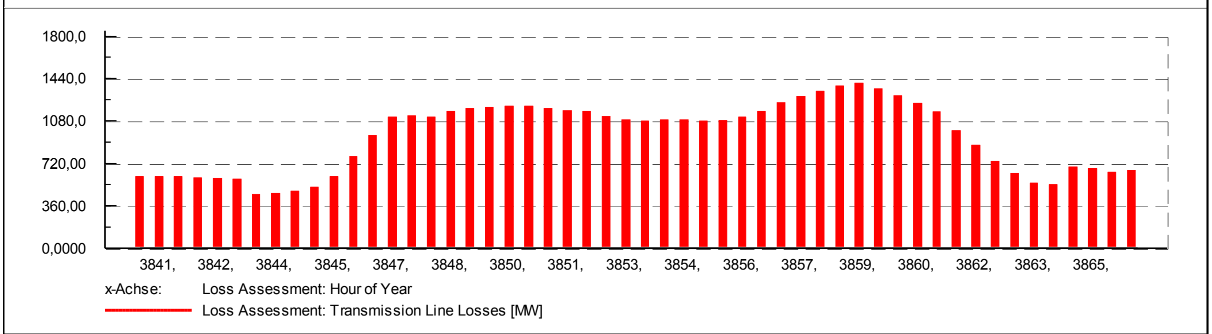
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	Low Load (1st January)	Datum: 16.02.2015
	60% Wind	2x Koeberg Unit(s) Online	Anhang: 1.1.3 /1



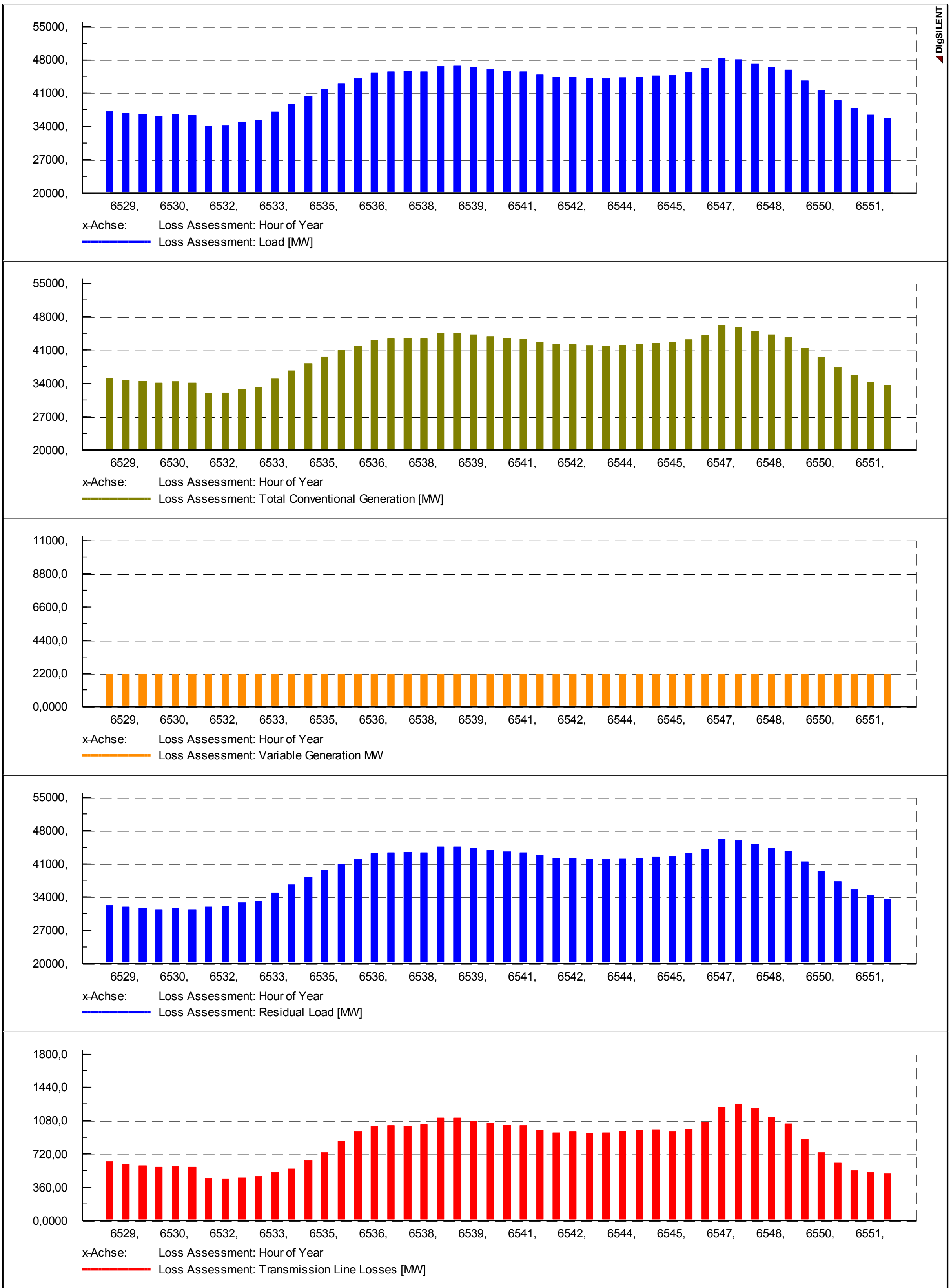






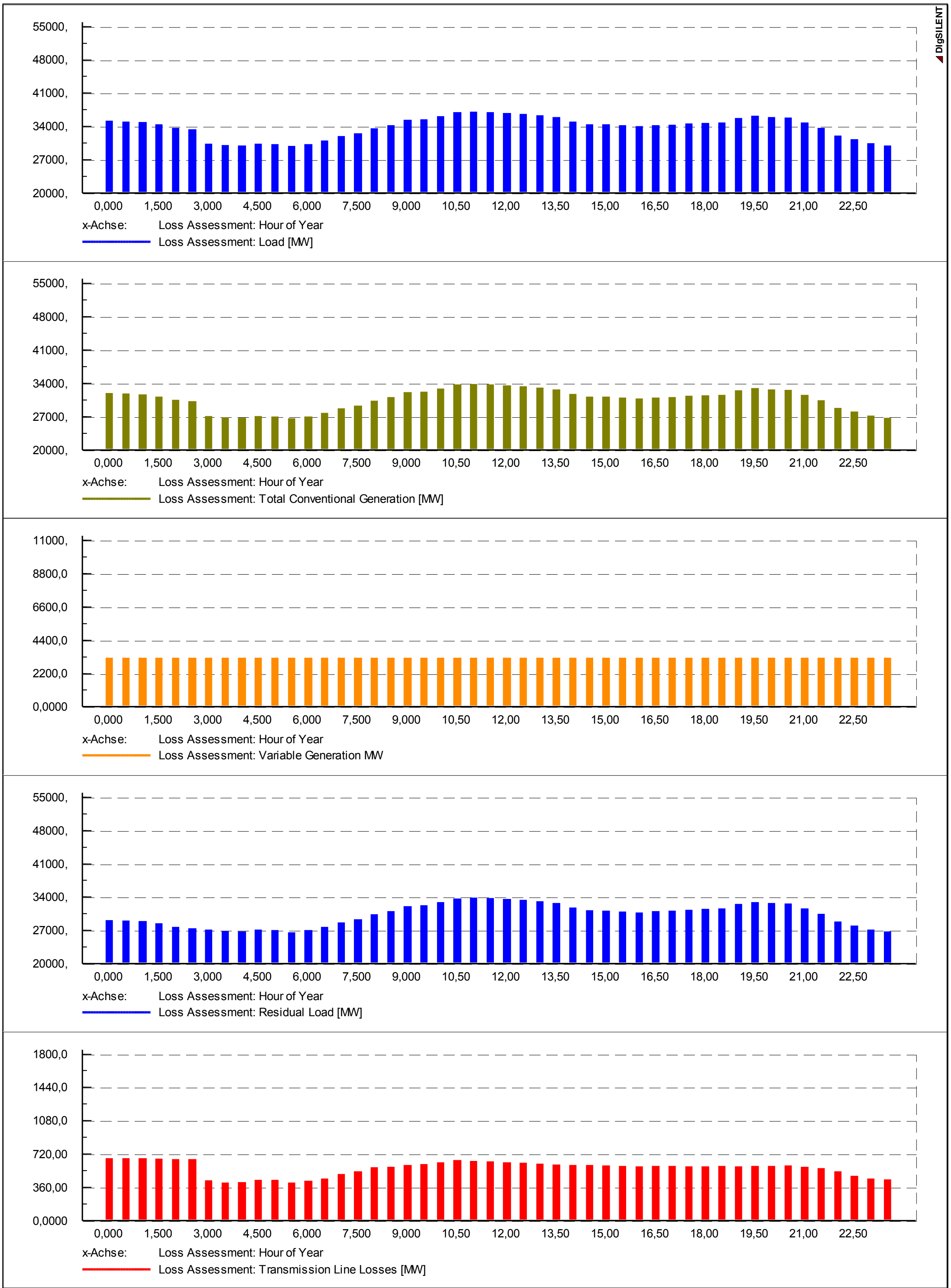


M.P.E. MOELLER & POELLER ENGINEERING	Base Case	High Load (9th June)	Datum: 16.02.2015
	60% Wind	2x Koeberg Unit(s) Online	Anhang: 1.1.3 /2

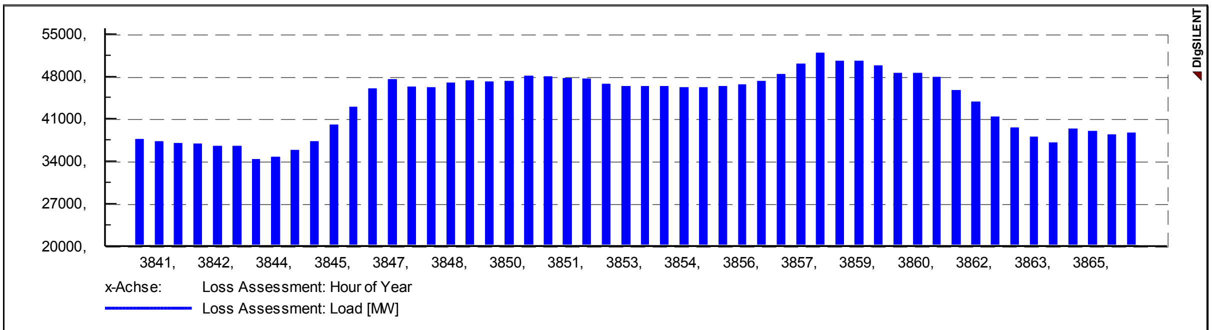


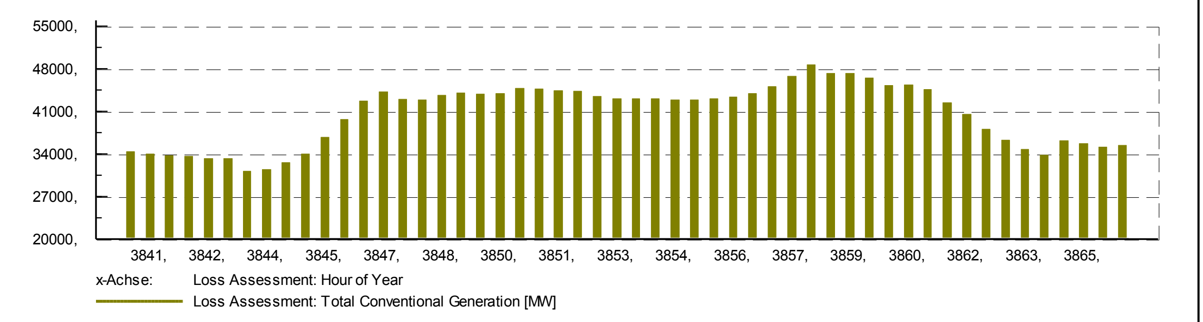
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	High PV (29th September)	Datum: 16.02.2015
	60% Wind	2x Koeberg Unit(s) Online	Anhang: 1.1.3 /3

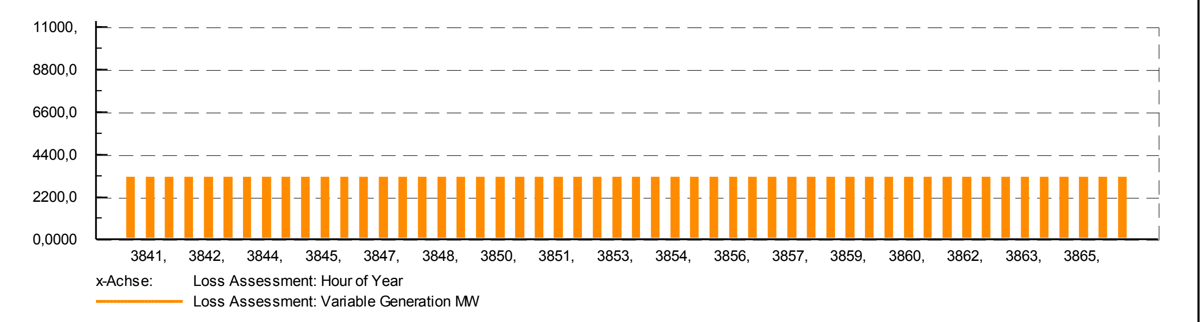
1.1.4 90% Wind

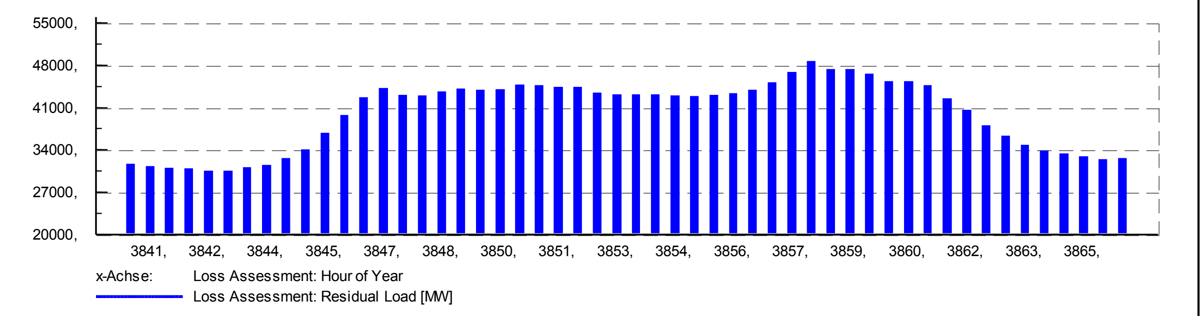


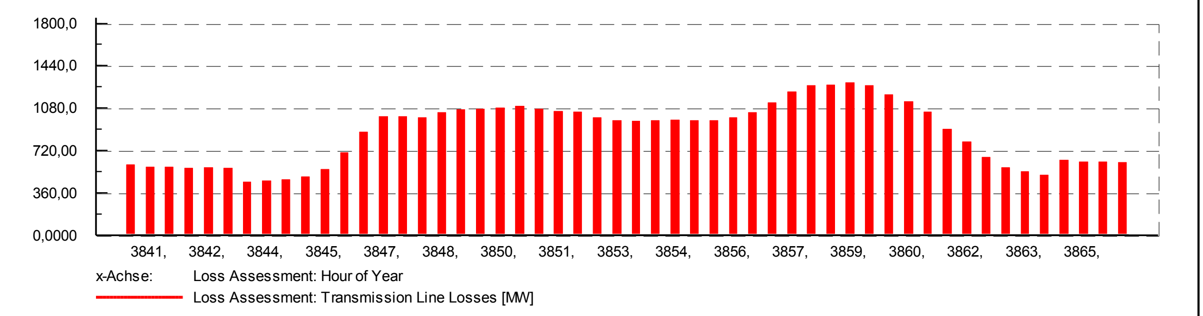
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	Low Load (1st January)	Datum: 16.02.2015
	90% Wind	2x Koeberg Unit(s) Online	Anhang: 1.1.4 /1



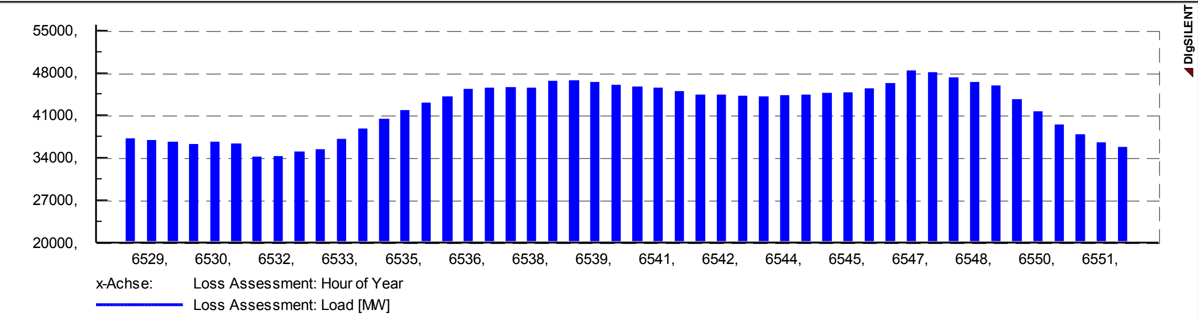


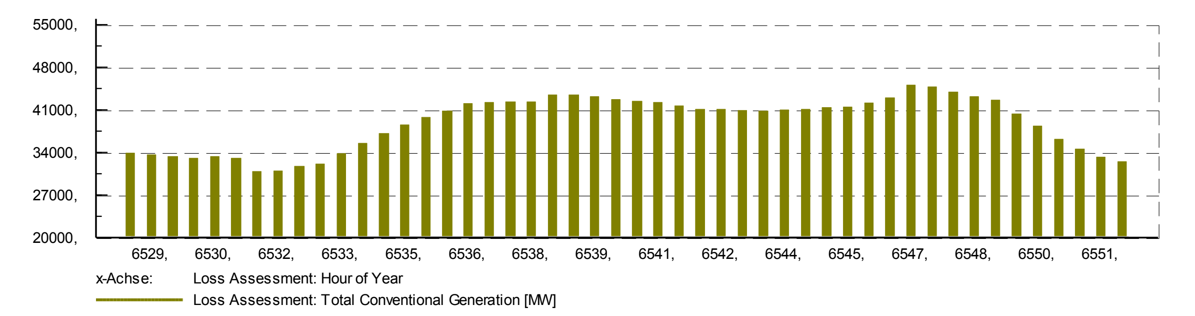


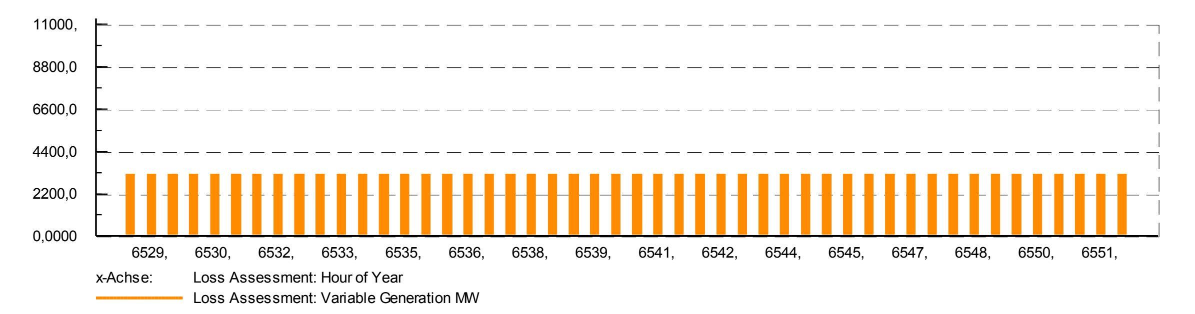


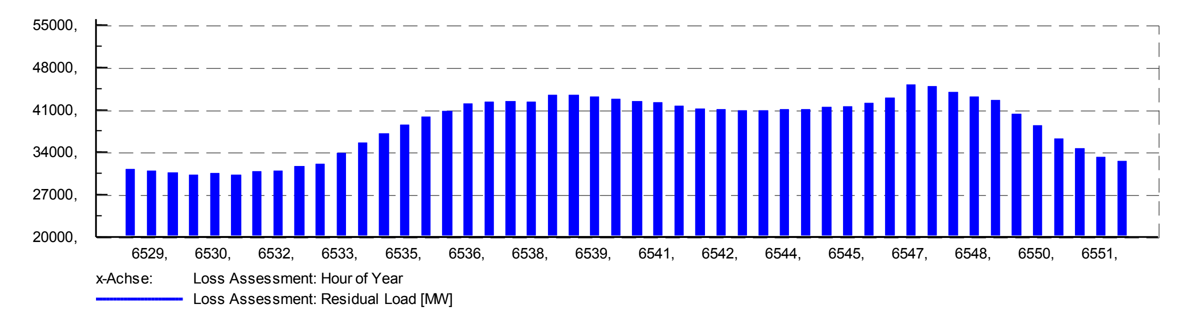


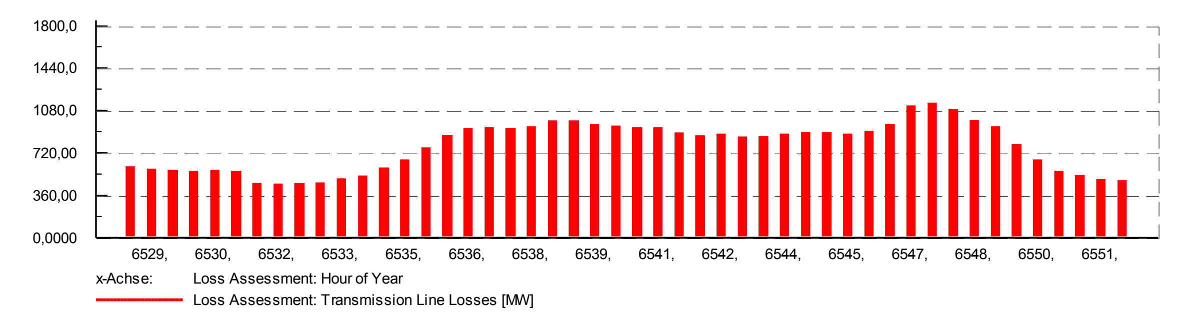
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	High Load (9th June)	Datum: 16.02.2015
	90% Wind	2x Koeberg Unit(s) Online	Anhang: 1.1.4 /2







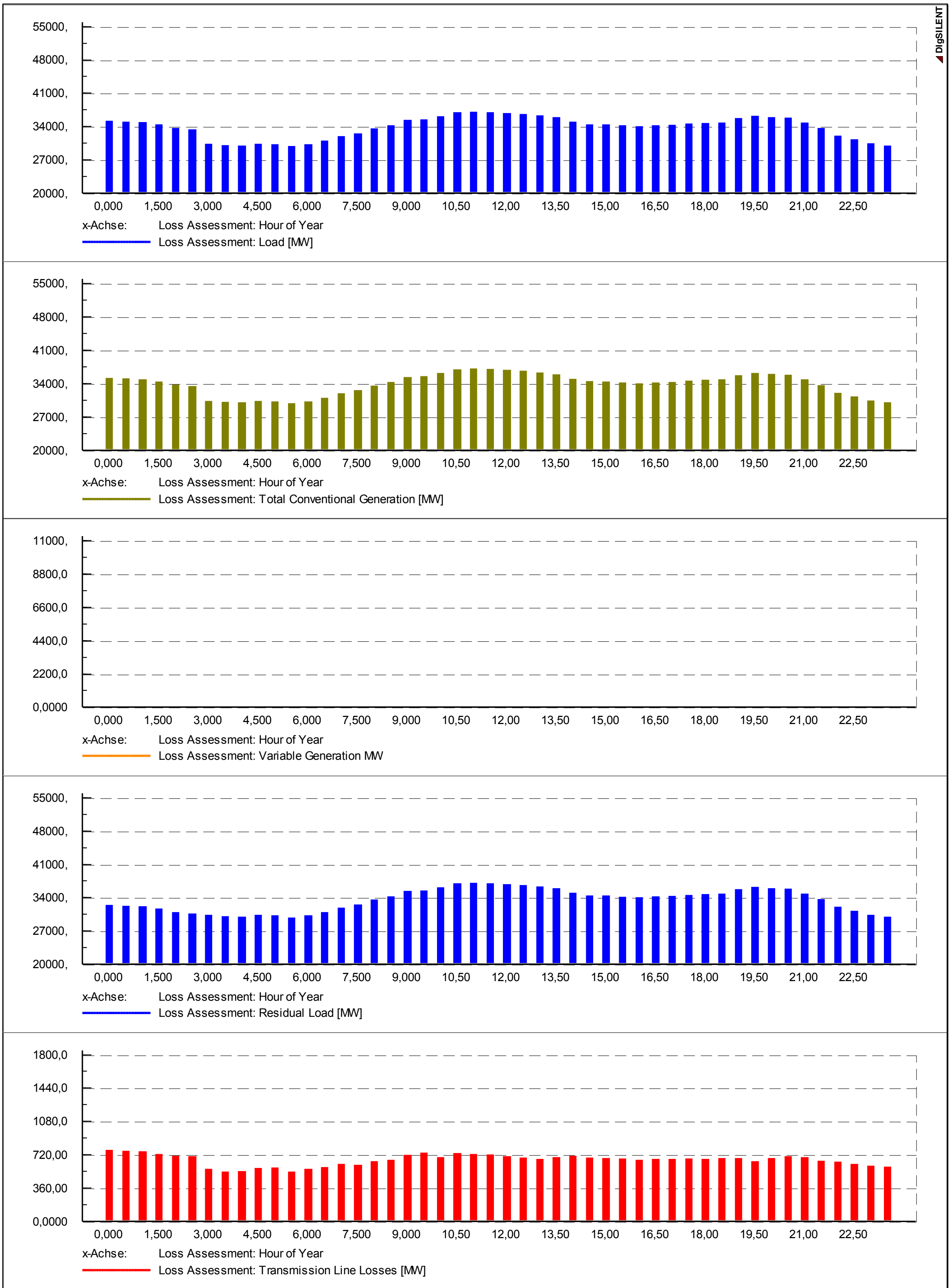




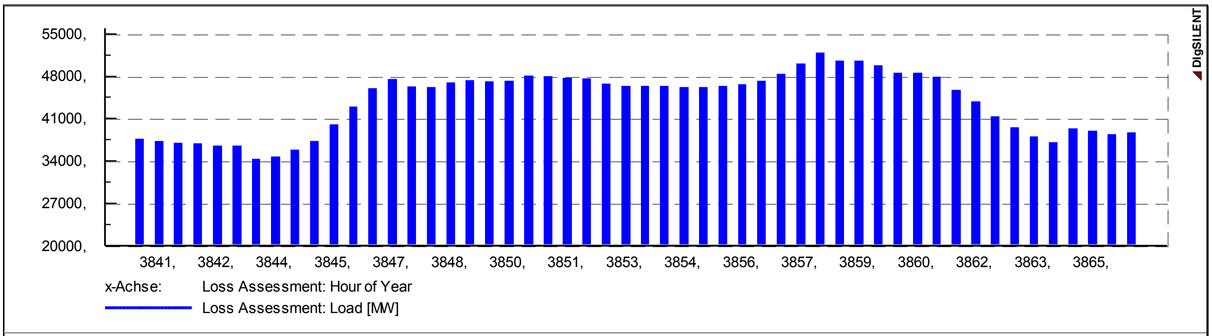
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	High PV (29th September)	Datum: 16.02.2015
	90% Wind	2x Koeberg Unit(s) Online	Anhang: 1.1.4 /3

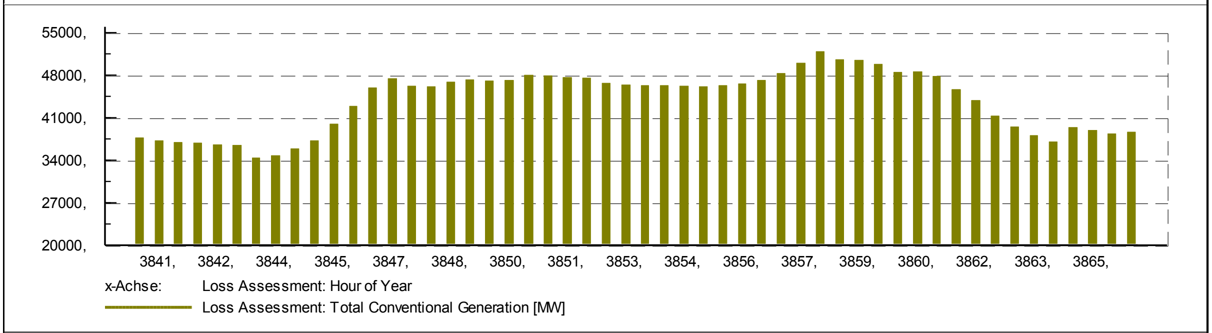
1.2 2x Koeberg Unit(s) Online

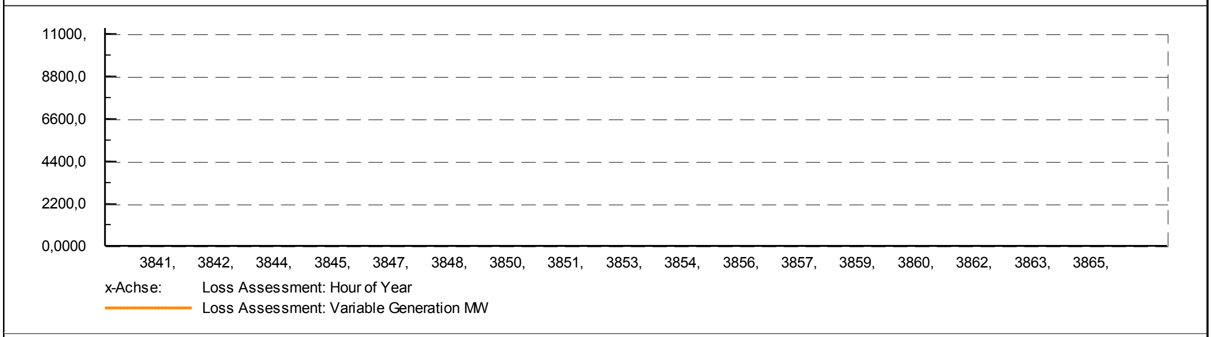
1.2.1 00% Wind

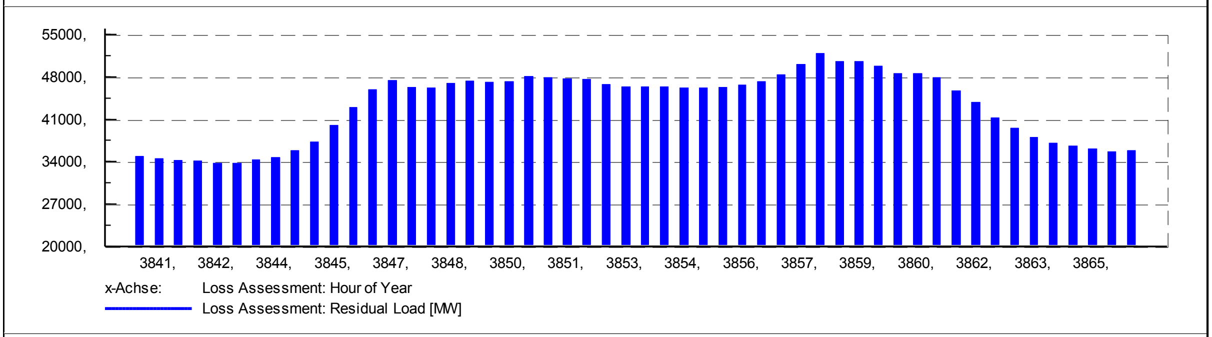


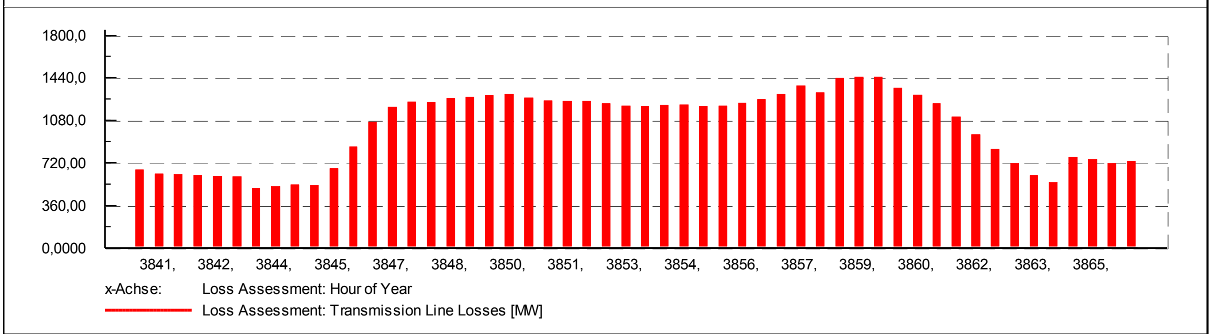
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	Low Load (1st January)	Datum: 16.02.2015
	00% Wind	2x Koeberg Unit(s) Online	Anhang: 1.2.1 /1



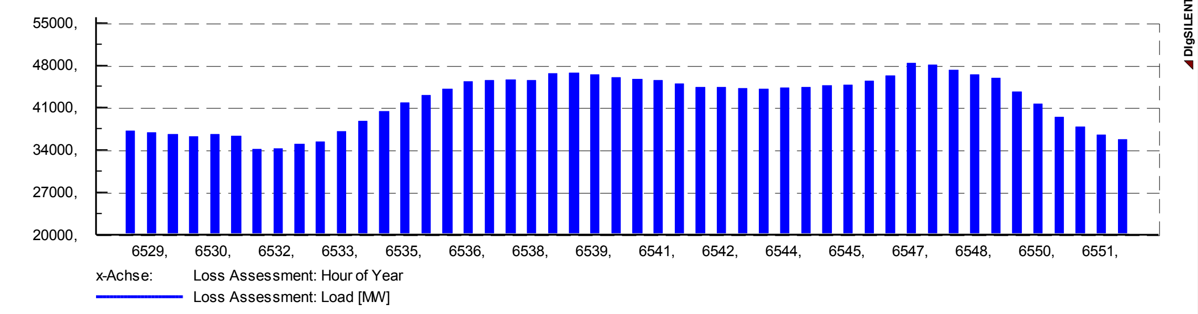


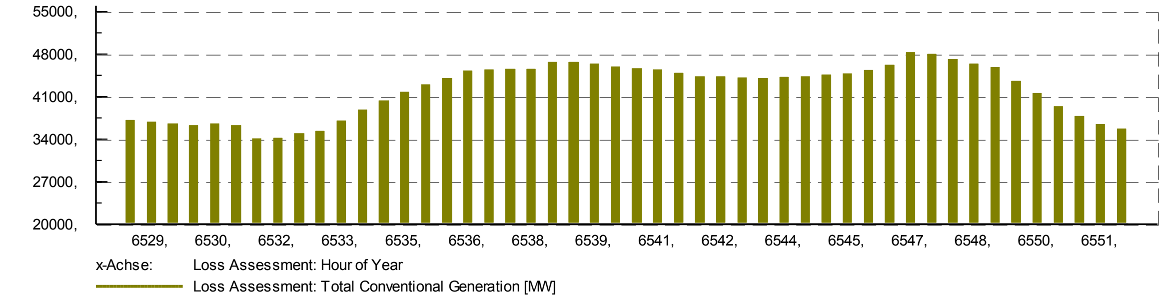


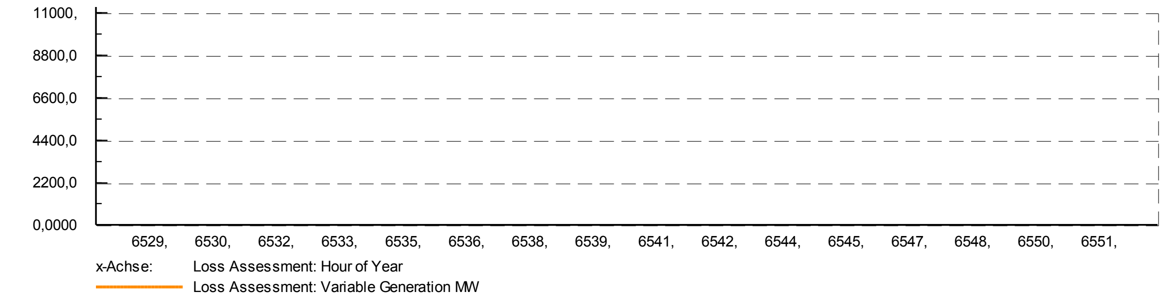


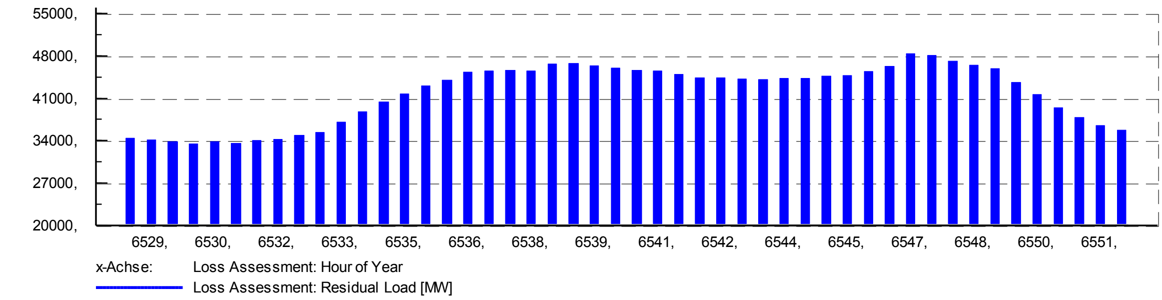


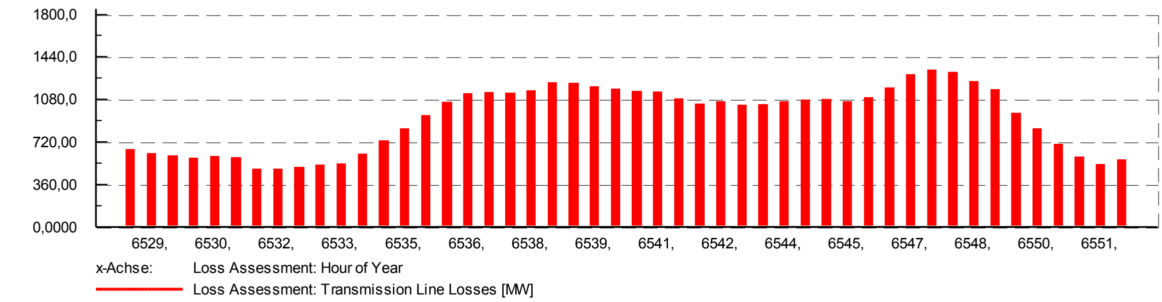
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	High Load (9th June)	Datum: 16.02.2015
	00% Wind	2x Koeberg Unit(s) Online	Anhang: 1.2.1 /2





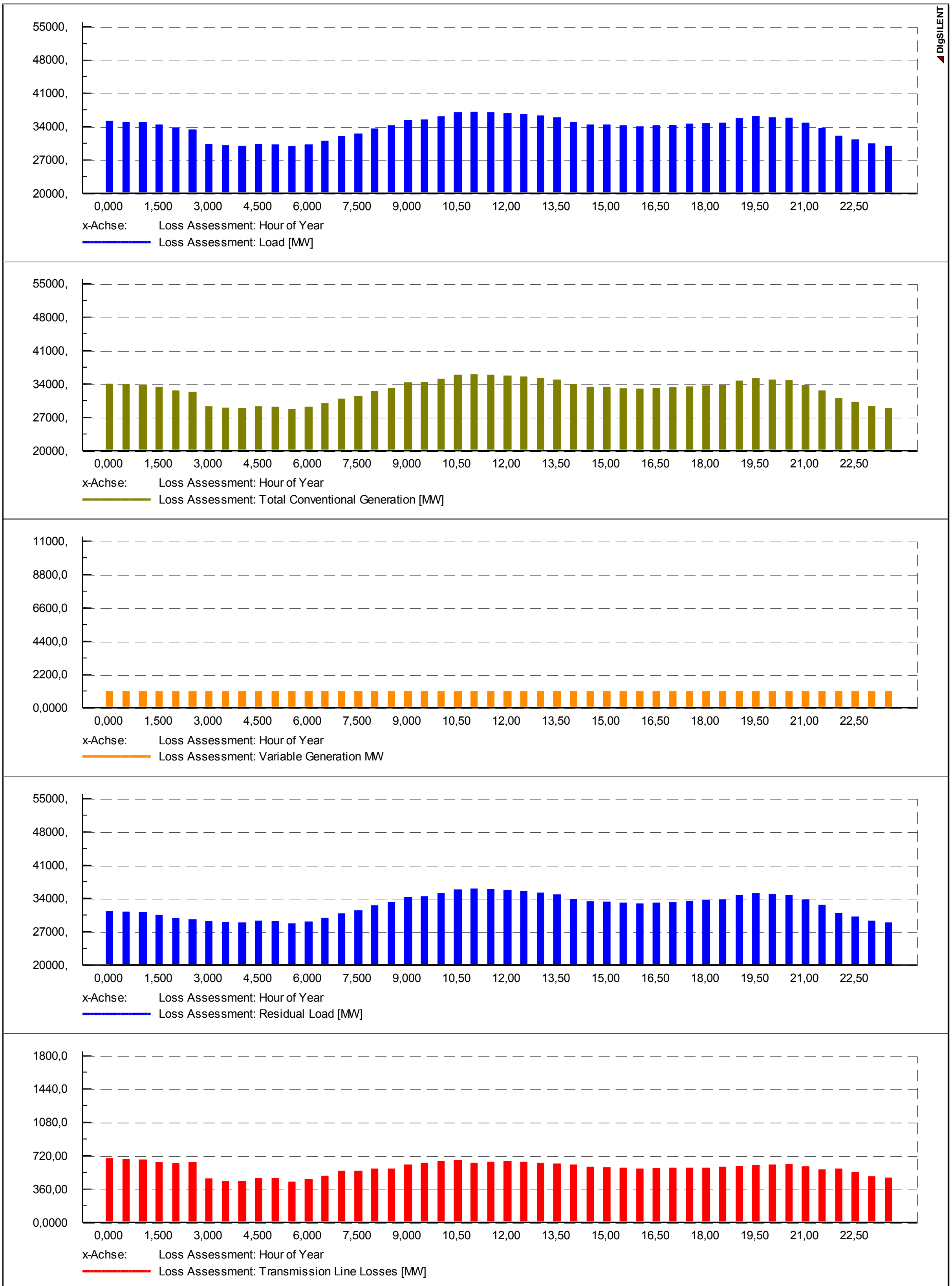






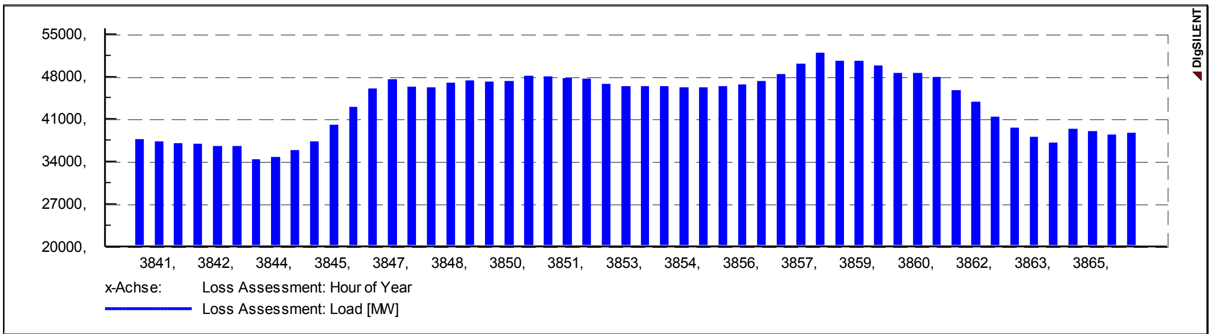
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	High PV (29th September)	Datum: 16.02.2015
	00% Wind	2x Koeberg Unit(s) Online	Anhang: 1.2.1 /3

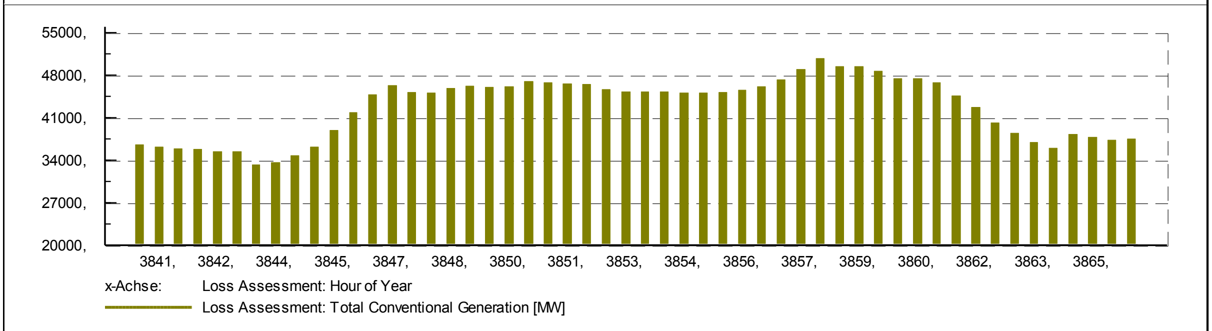
1.2.2 30% Wind

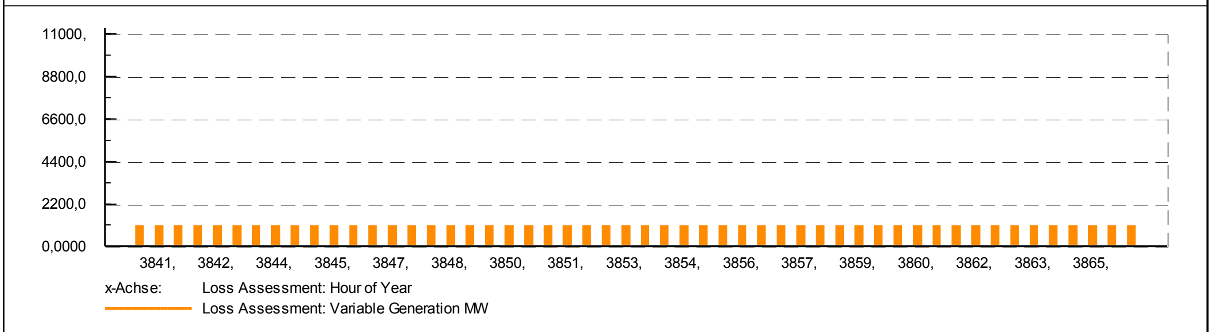


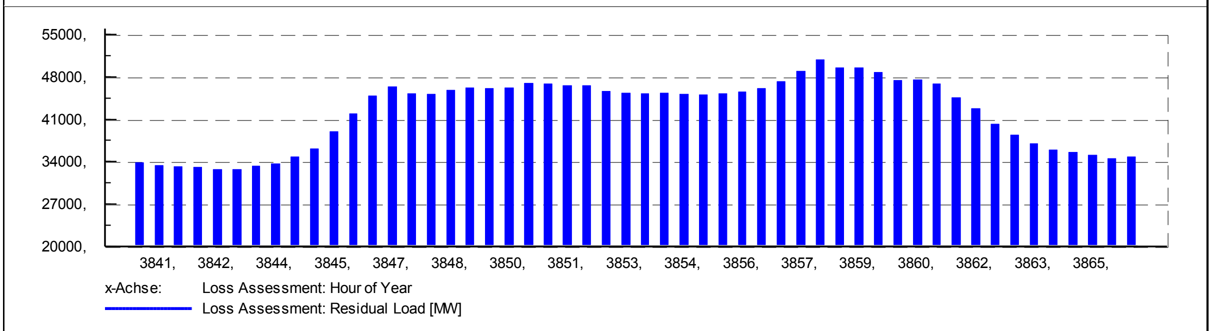
M.P.E. MOELLER & POELLER ENGINEERING

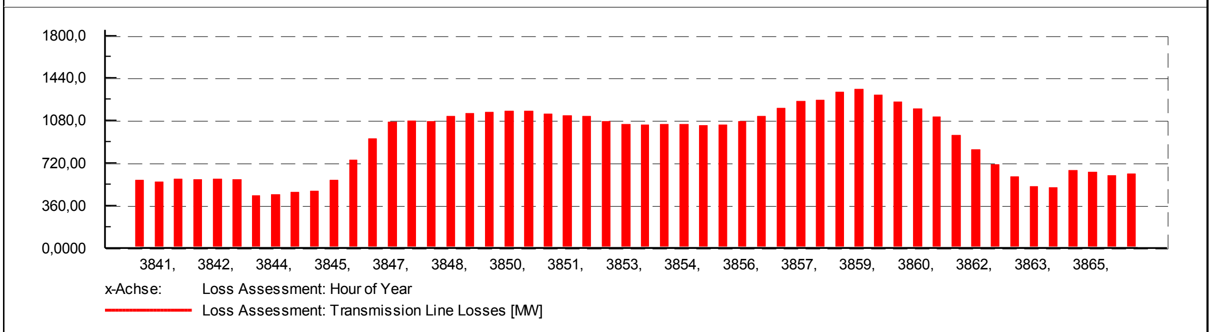
Base Case		Low Load (1st January)	Datum: 16.02.2015
30% Wind		2x Koeberg Unit(s) Online	Anhang: 1.2.2 /1



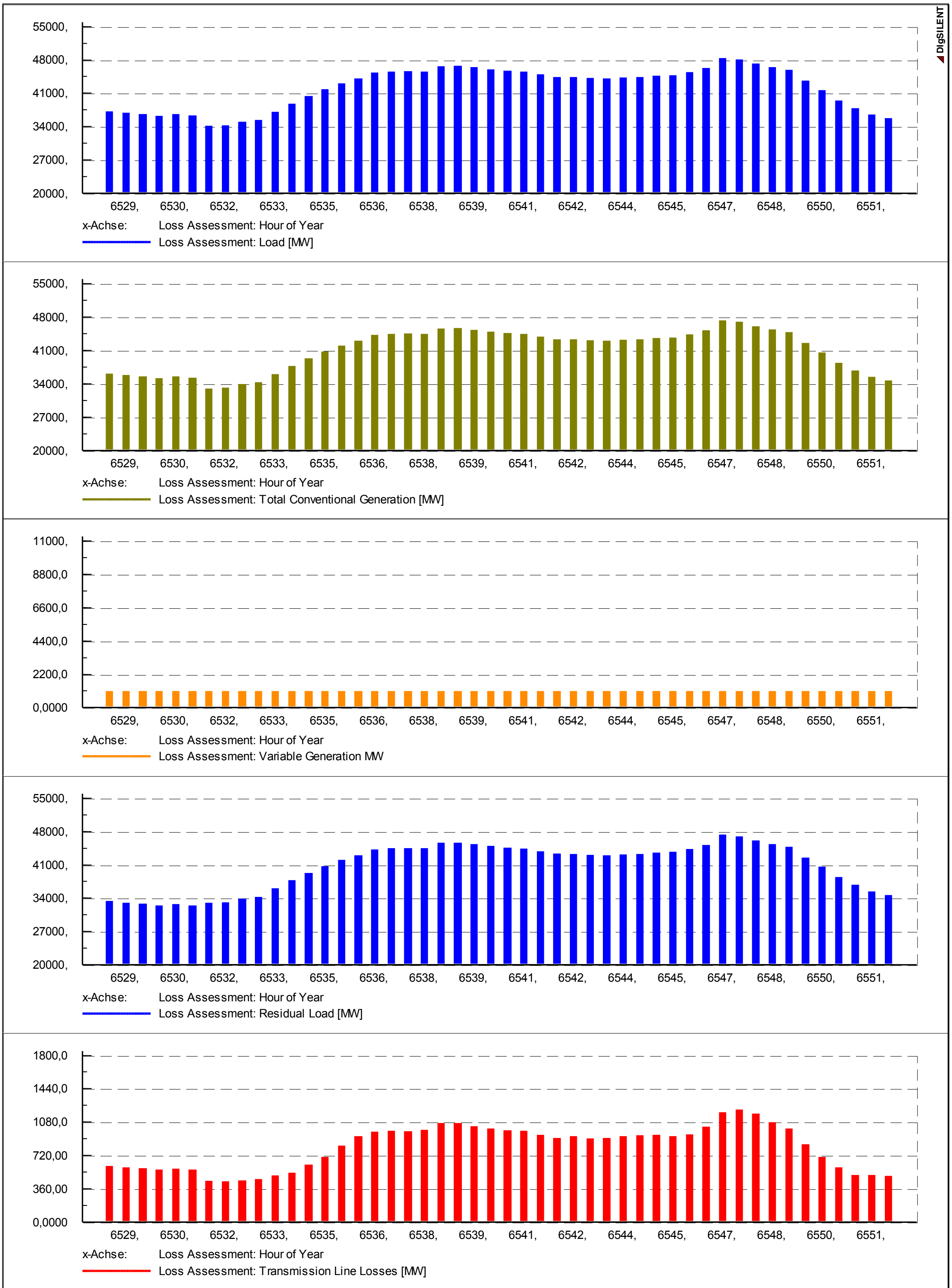






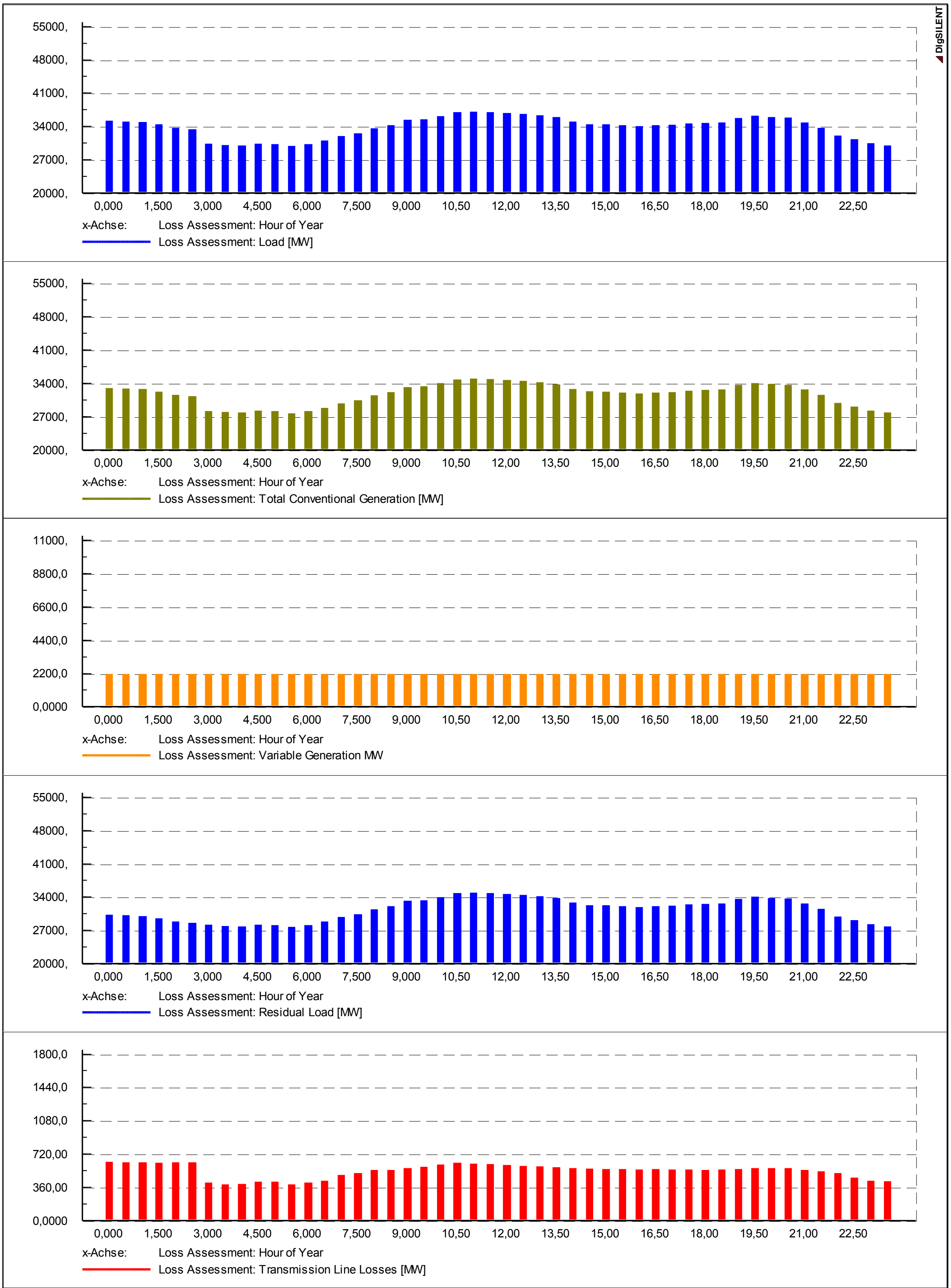


M.P.E. MOELLER & POELLER ENGINEERING	Base Case 30% Wind	High Load (9th June) 2x Koeberg Unit(s) Online	Datum: 16.02.2015 Anhang: 1.2.2 /2

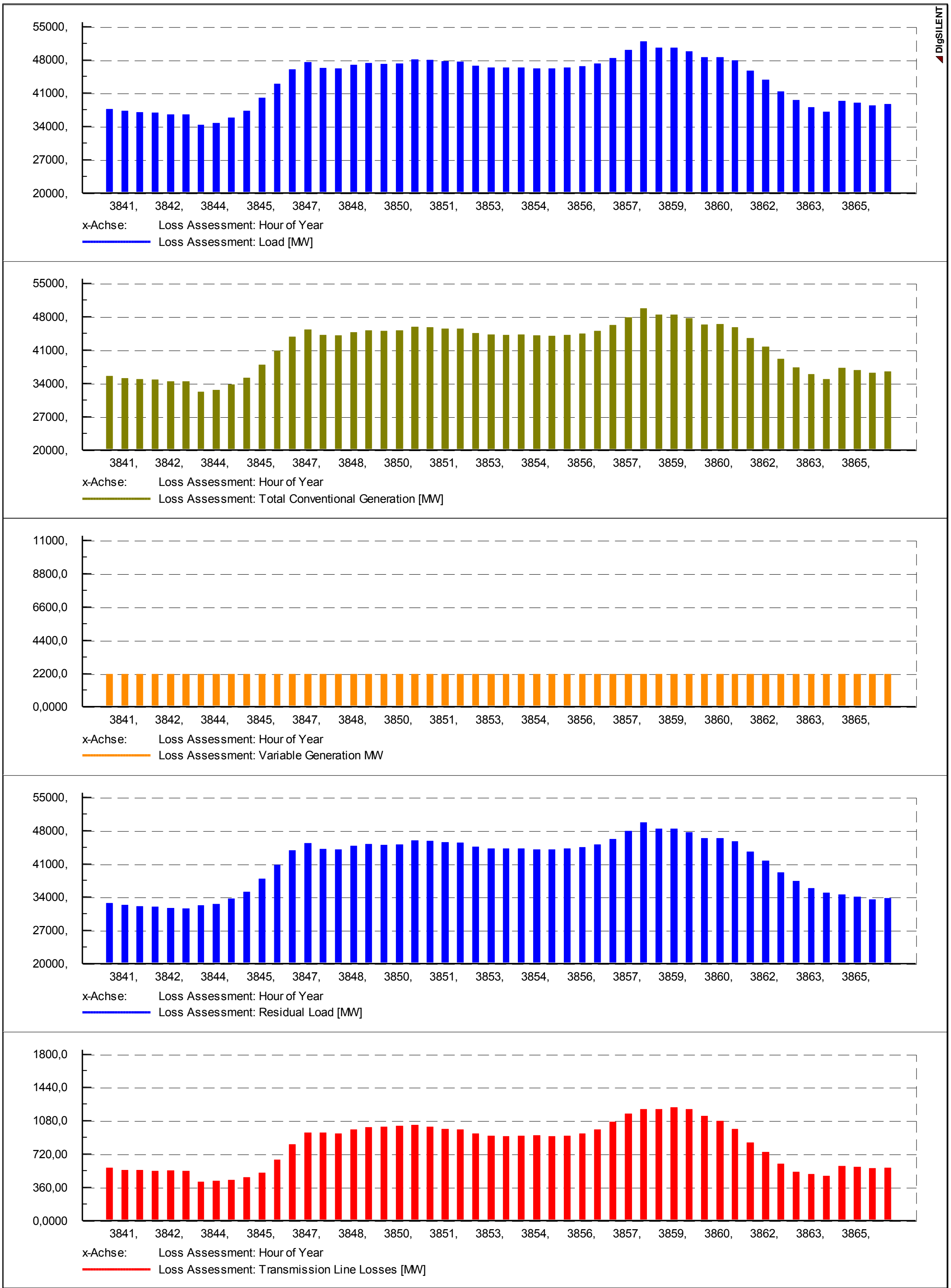


M.P.E. MOELLER & POELLER ENGINEERING	Base Case	High PV (29th September)	Datum: 16.02.2015
	30% Wind	2x Koeberg Unit(s) Online	Anhang: 1.2.2 /3

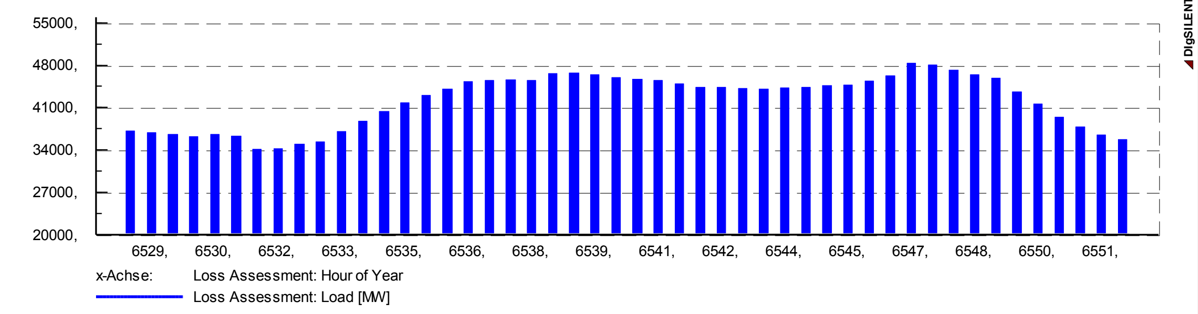
1.2.3 60% Wind

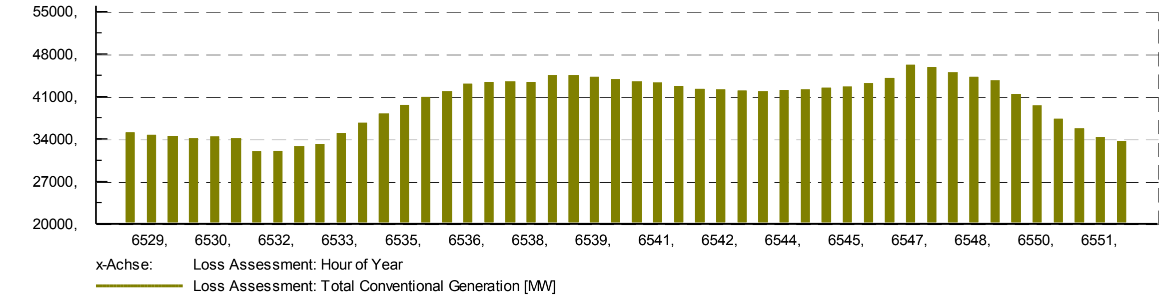


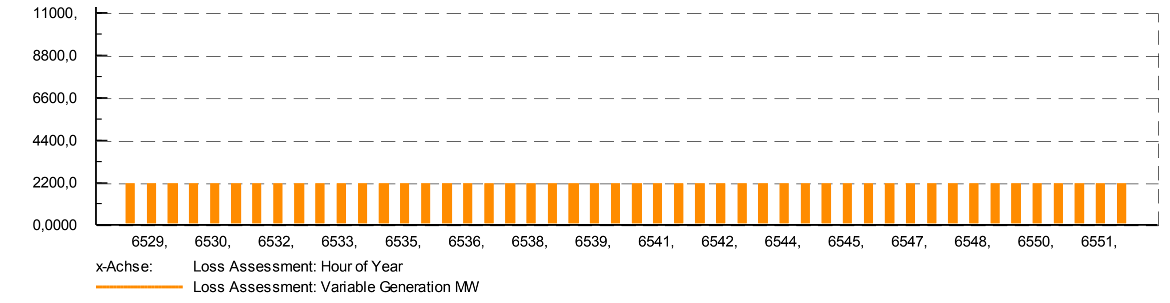
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	Low Load (1st January)	Datum: 16.02.2015
	60% Wind	2x Koeberg Unit(s) Online	Anhang: 1.2.3 /1

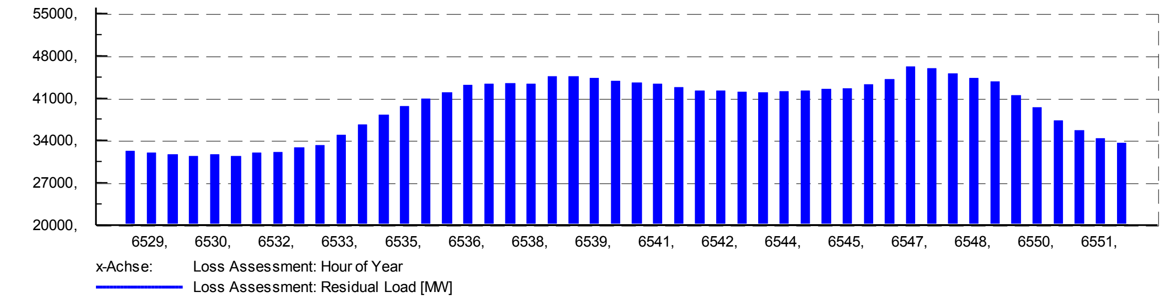


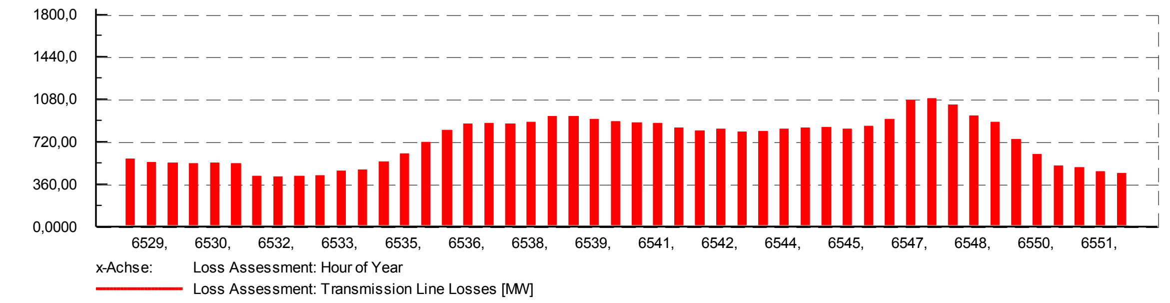
M.P.E. MOELLER & POELLER ENGINEERING	Base Case 60% Wind	High Load (9th June) 2x Koeberg Unit(s) Online	Datum: 16.02.2015 Anhang: 1.2.3 /2





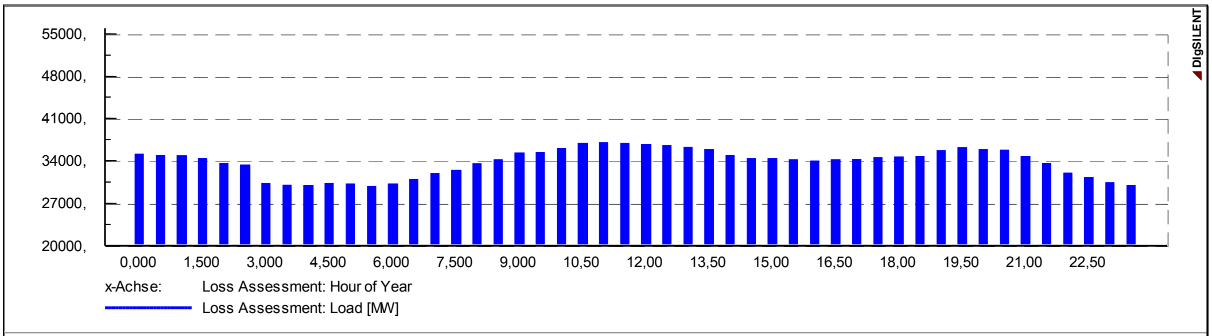


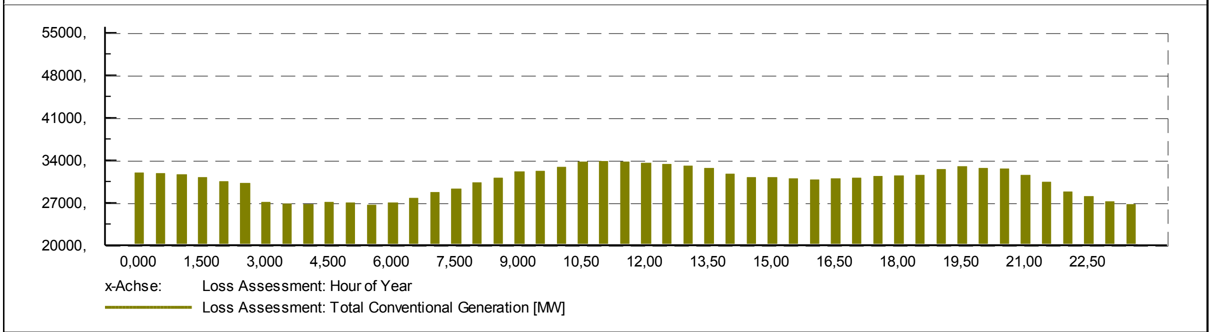


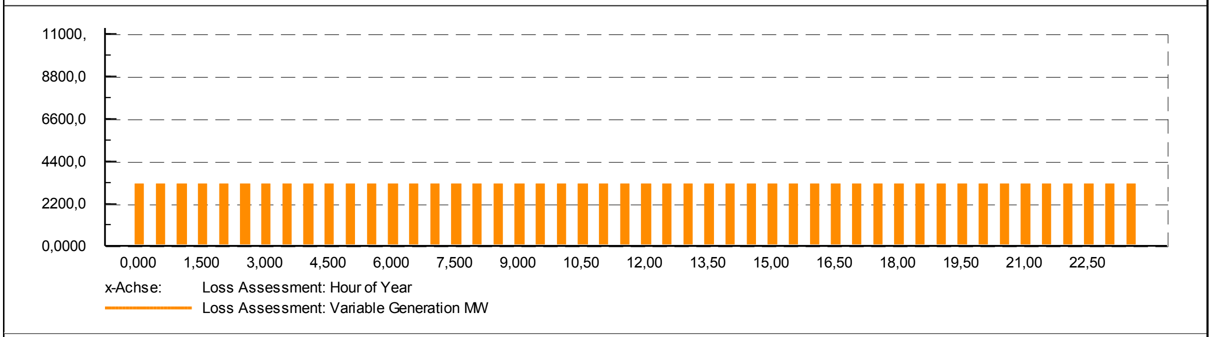


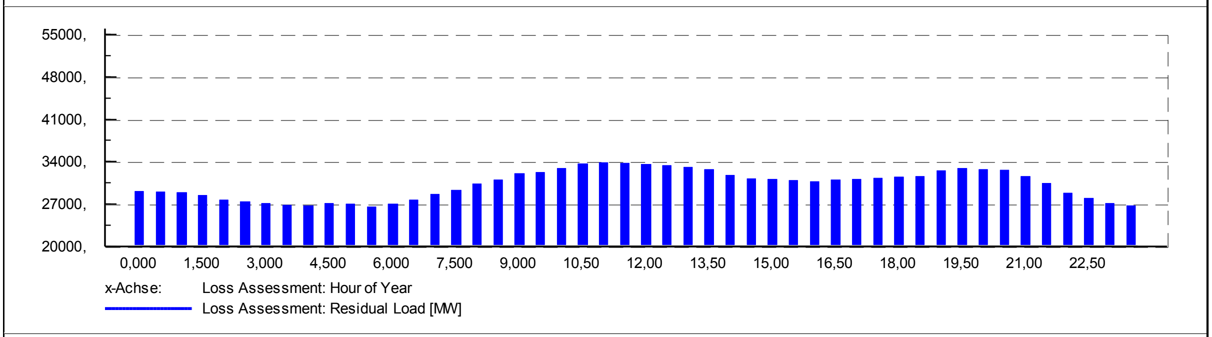
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	High PV (29th September)	Datum: 16.02.2015
	60% Wind	2x Koeberg Unit(s) Online	Anhang: 1.2.3 /3

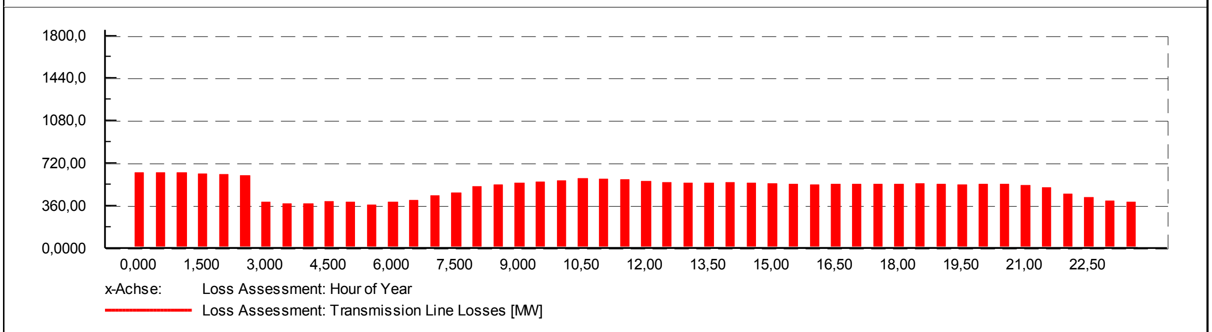
1.2.4 90% Wind



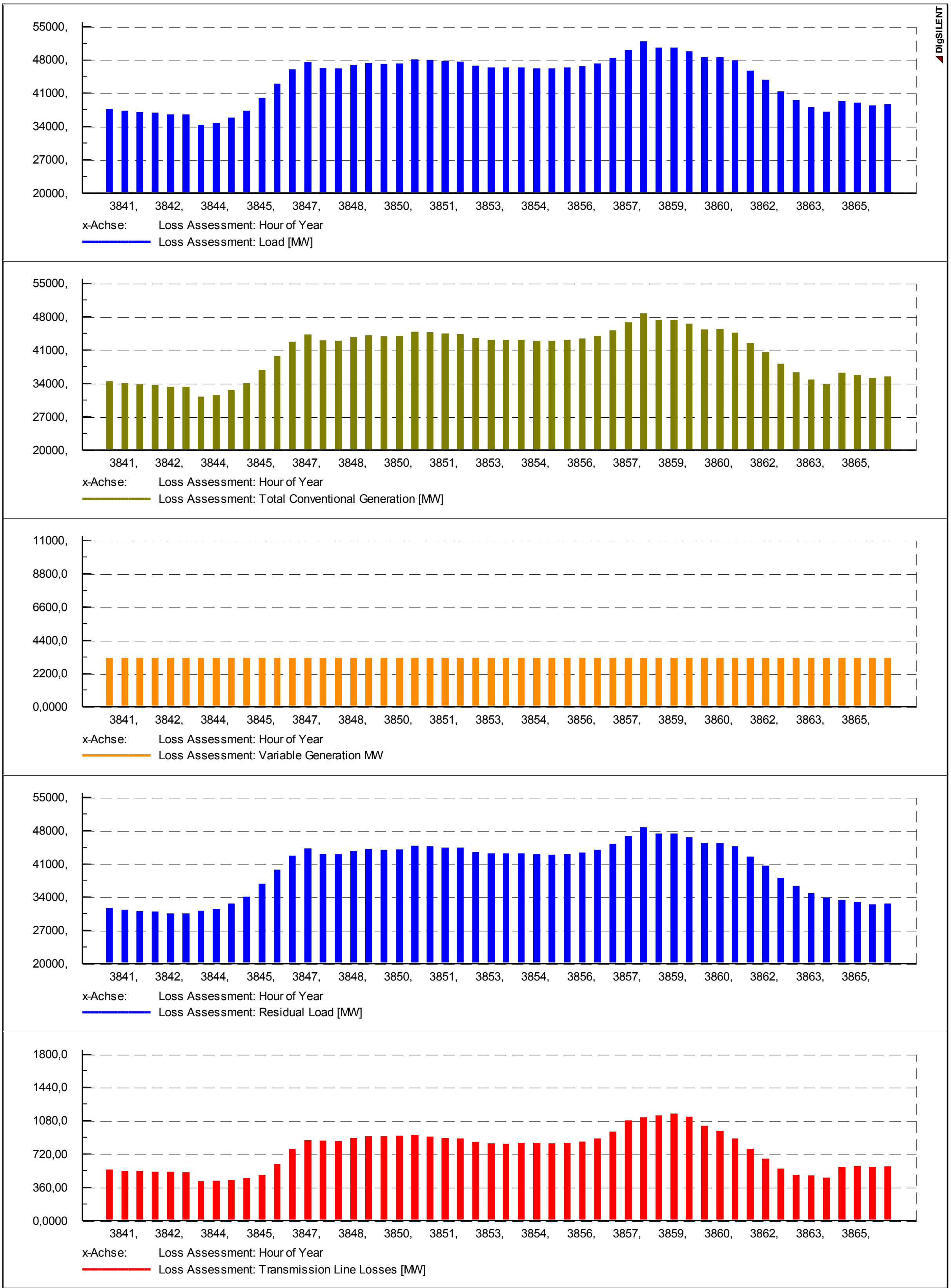




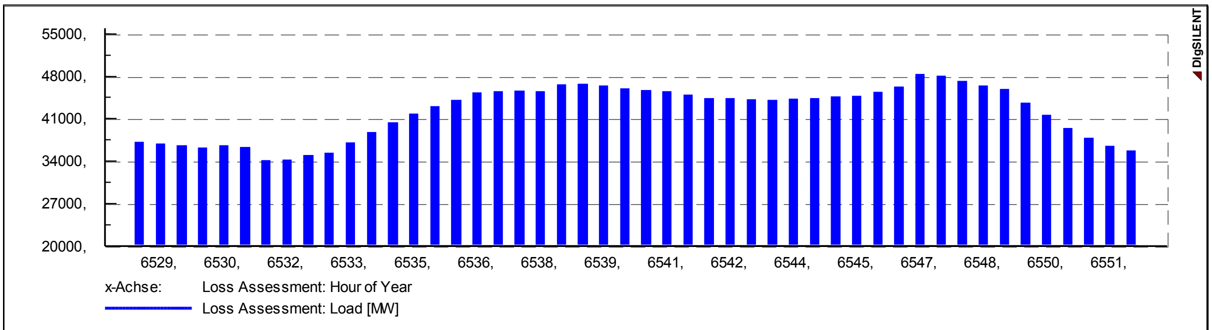


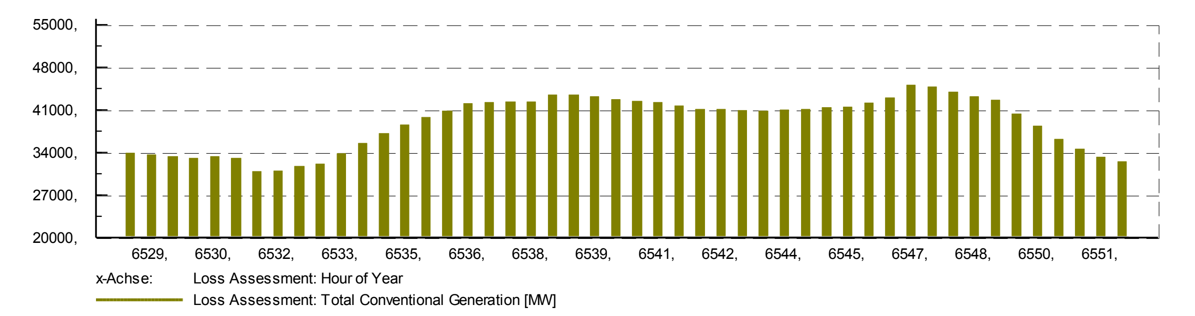


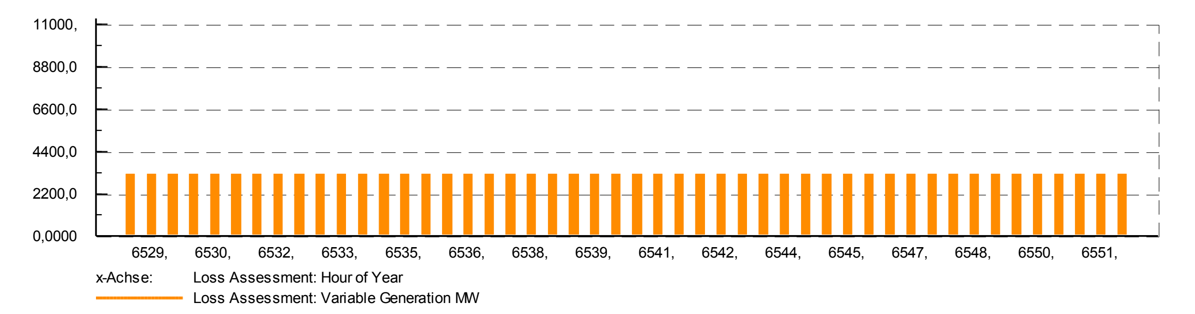
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	Low Load (1st January)	Datum: 16.02.2015
	90% Wind	2x Koeberg Unit(s) Online	Anhang: 1.2.4 /1

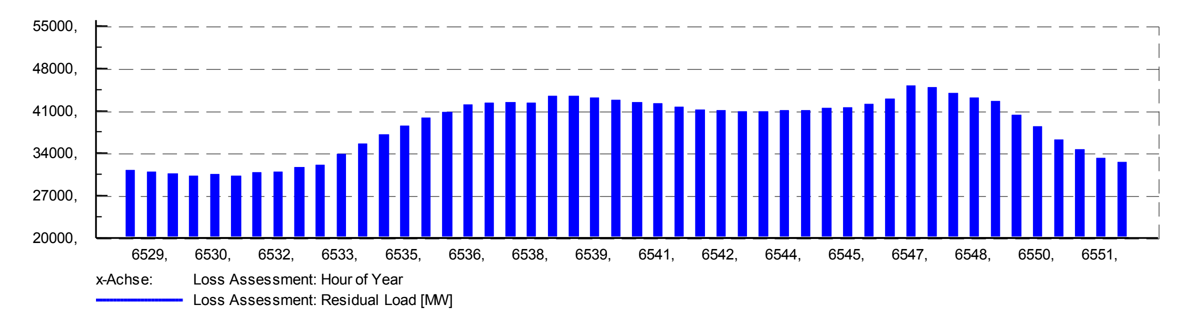


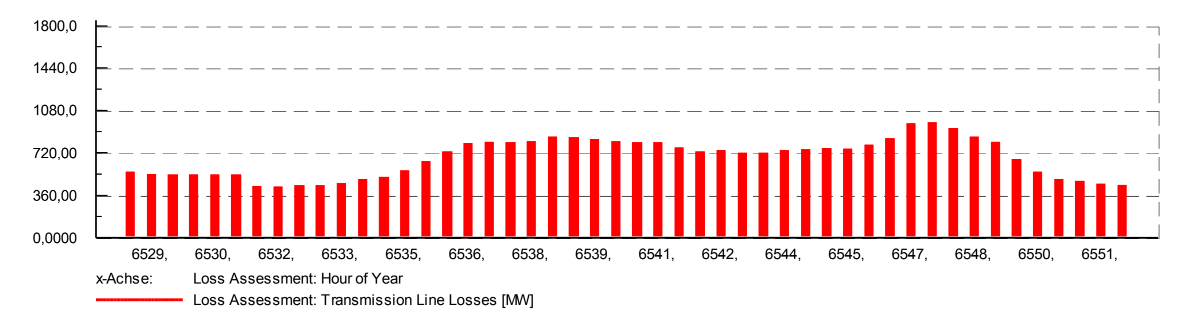
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	High Load (9th June)	Datum: 16.02.2015
	90% Wind	2x Koeberg Unit(s) Online	Anhang: 1.2.4 /2









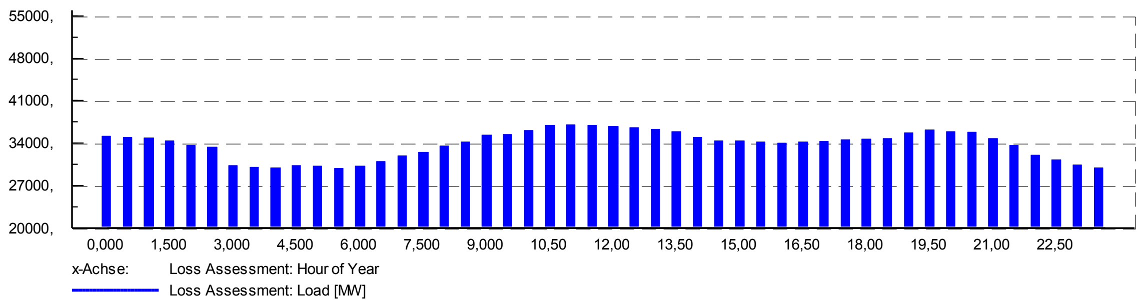


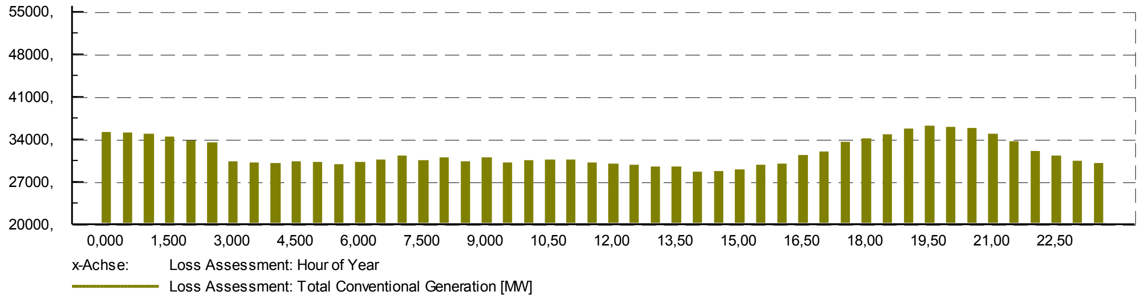
M.P.E. MOELLER & POELLER ENGINEERING	Base Case	High PV (29th September)	Datum: 16.02.2015
	90% Wind	2x Koeberg Unit(s) Online	Anhang: 1.2.4 /3

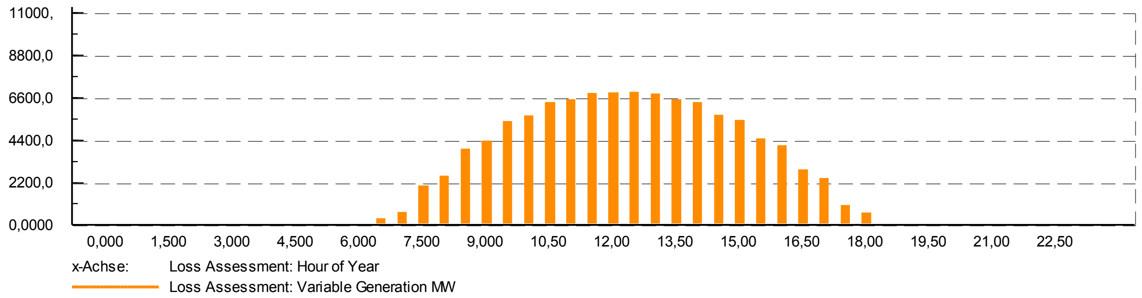
2 Scenario A

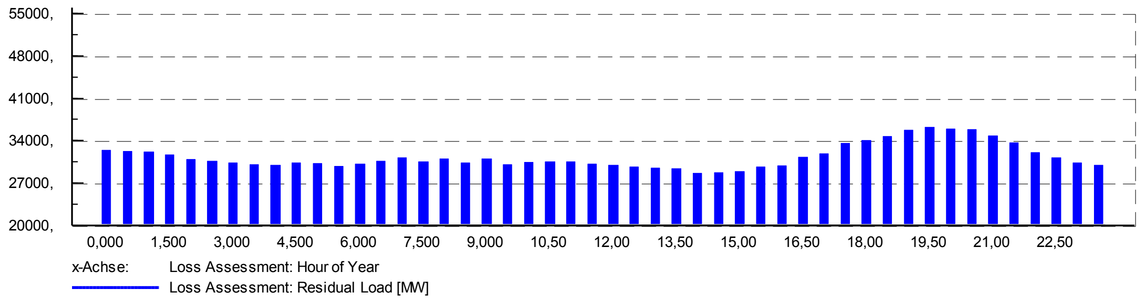
2.1 1x Koeberg Unit(s) Online

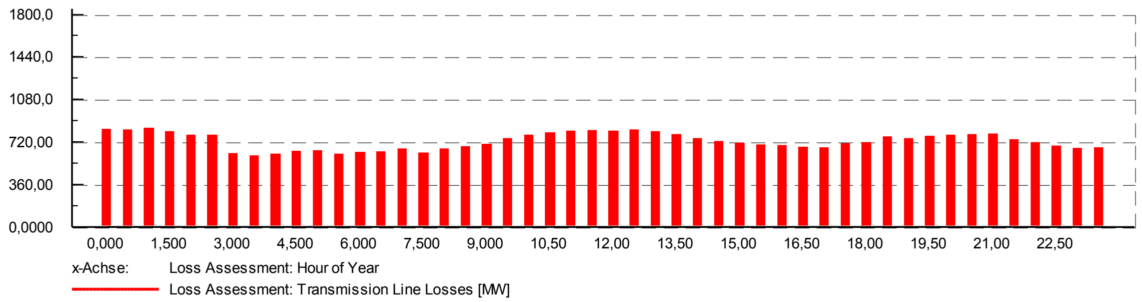
2.1.1 00% Wind



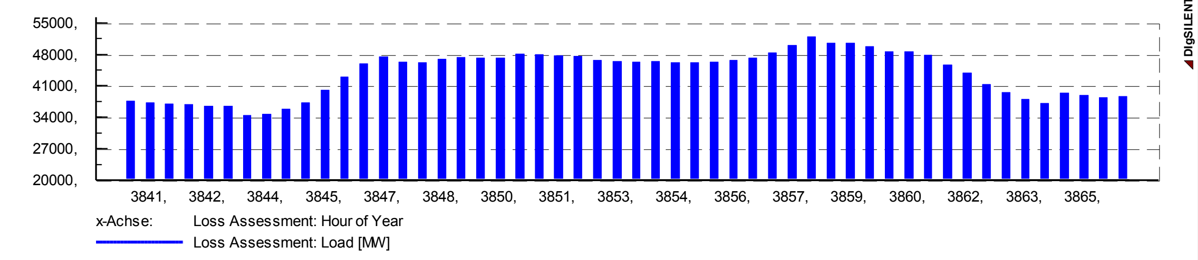


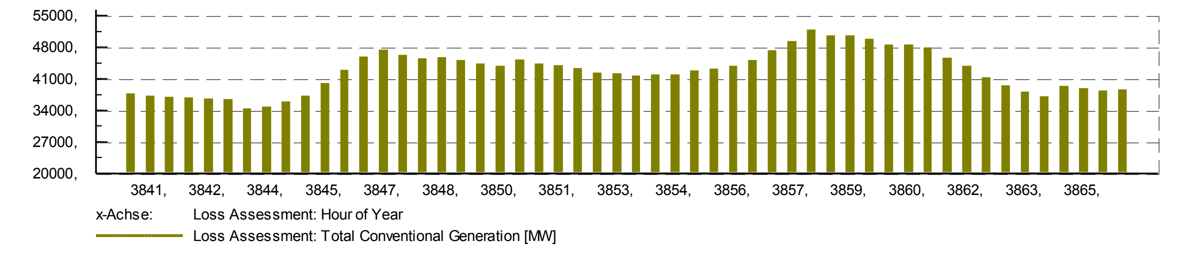


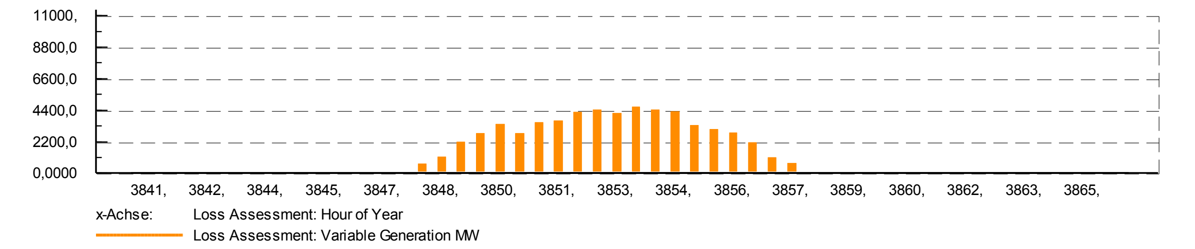


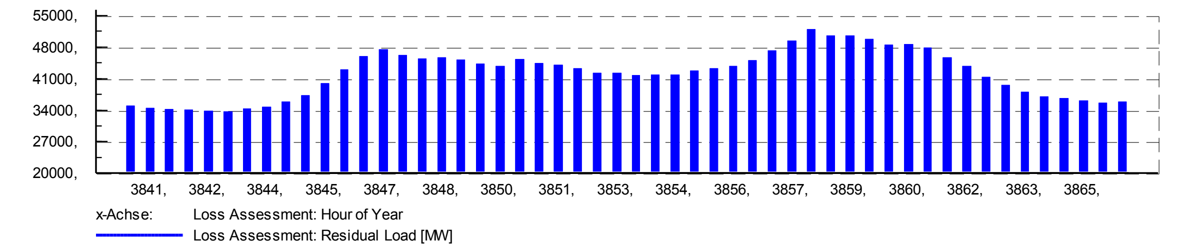


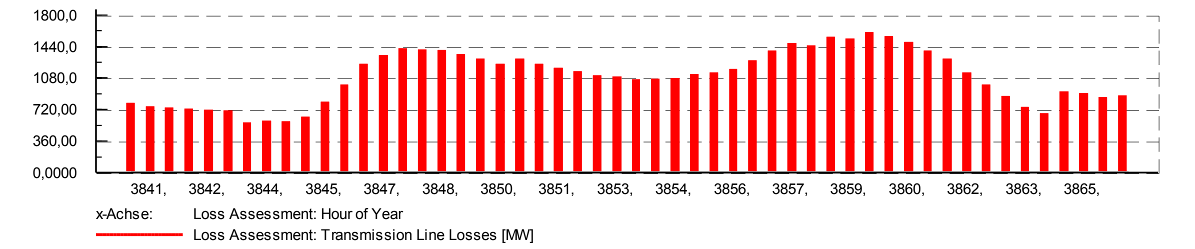
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	Low Load (1st January)	Datum: 16.02.2015
	00% Wind	1x Koeberg Unit(s) Online	Anhang: 2.1.1 /1

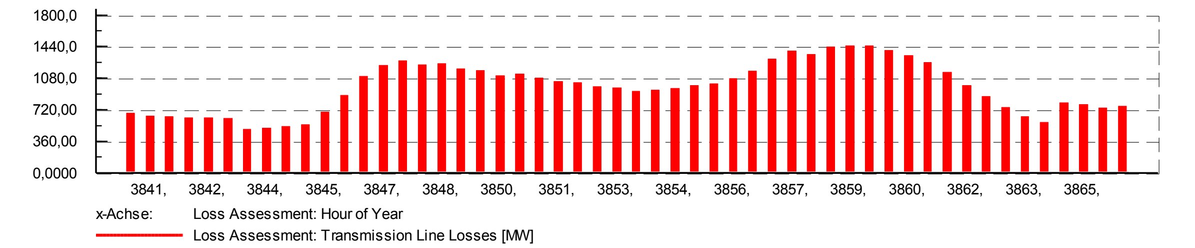




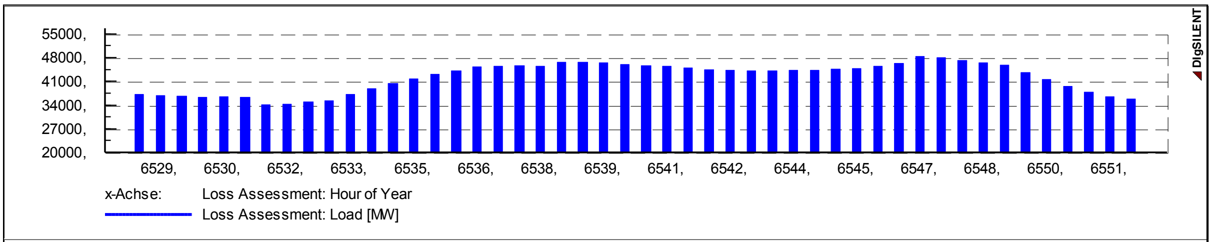


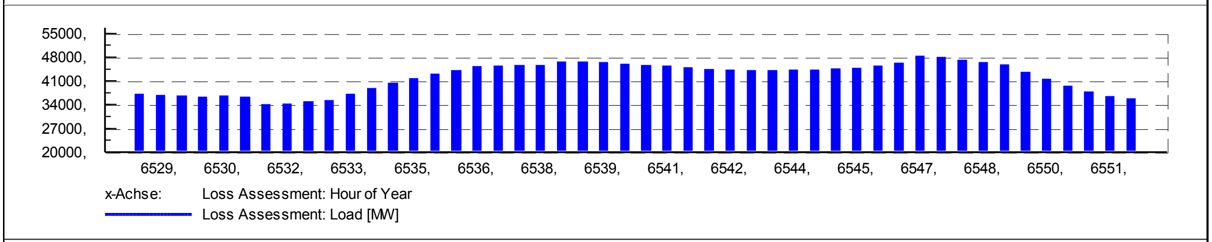


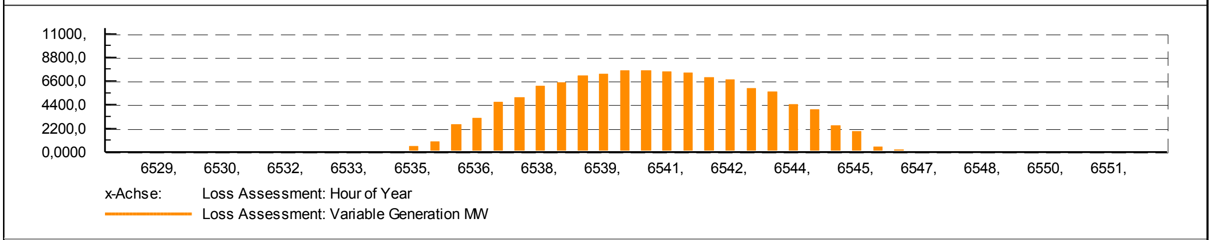


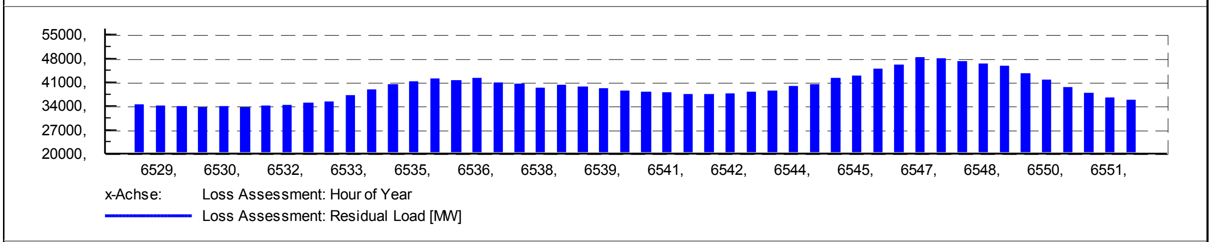


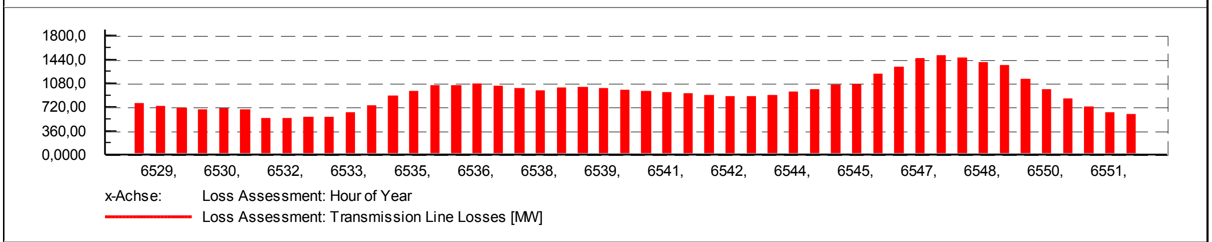
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	High Load (9th June)	Datum: 16.02.2015
	00% Wind	1x Koeberg Unit(s) Online	Anhang: 2.1.1 /2

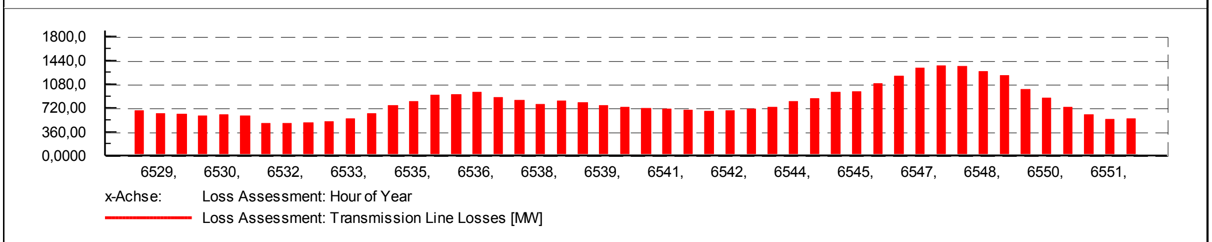


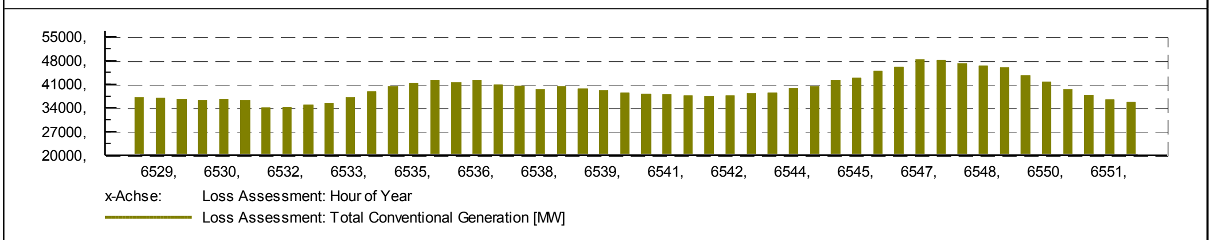






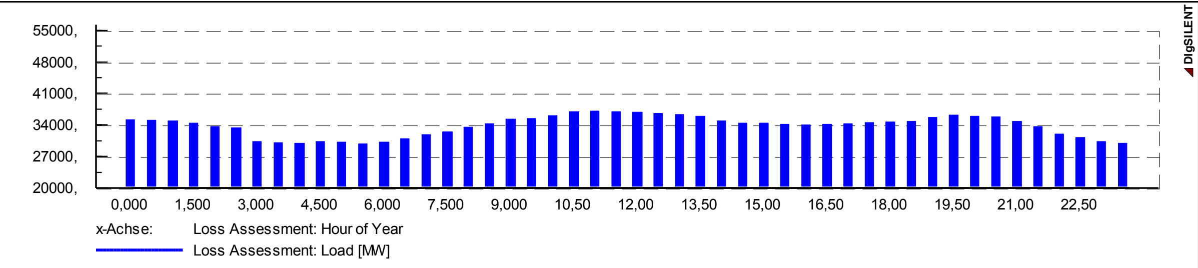


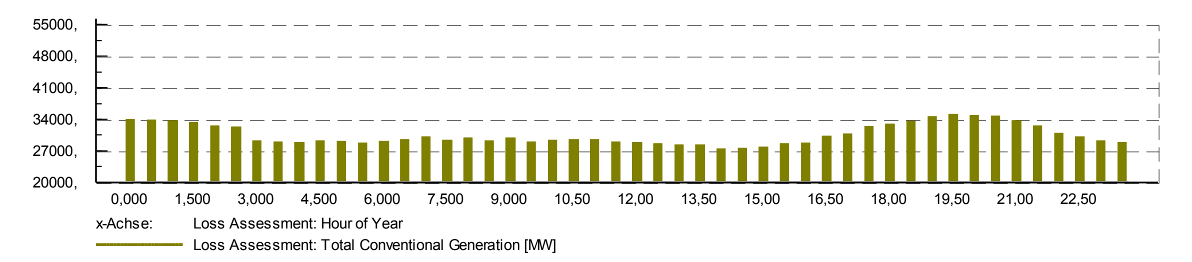


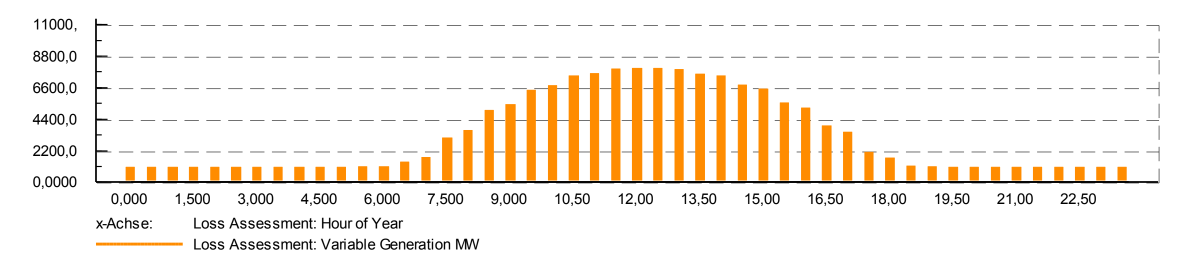


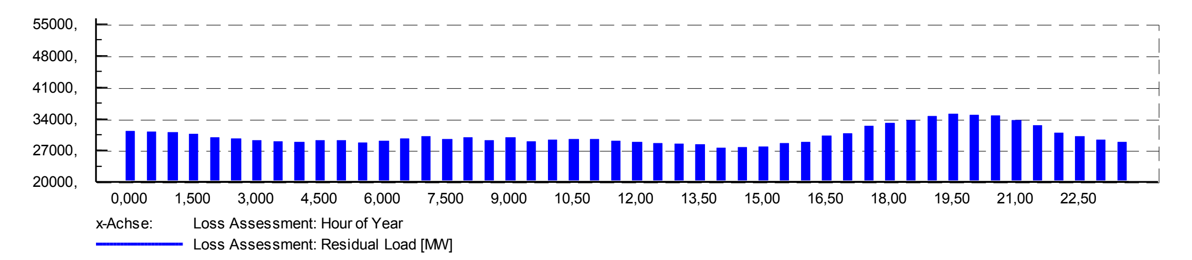
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	High PV (29th September)	Datum: 16.02.2015
	00% Wind	1x Koeberg Unit(s) Online	Anhang: 2.1.1 /3

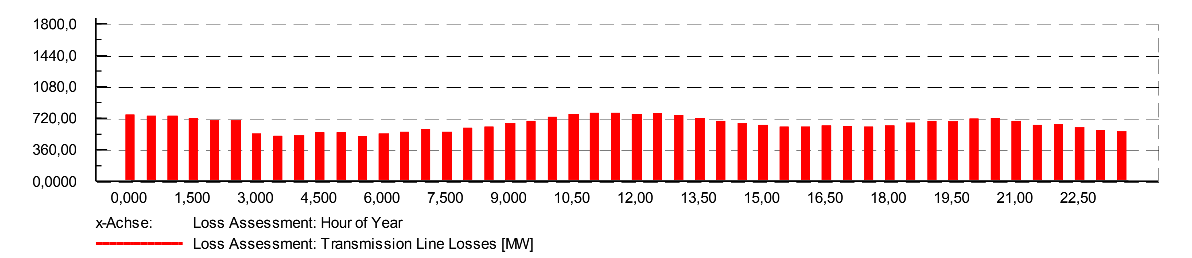
2.1.2 30% Wind

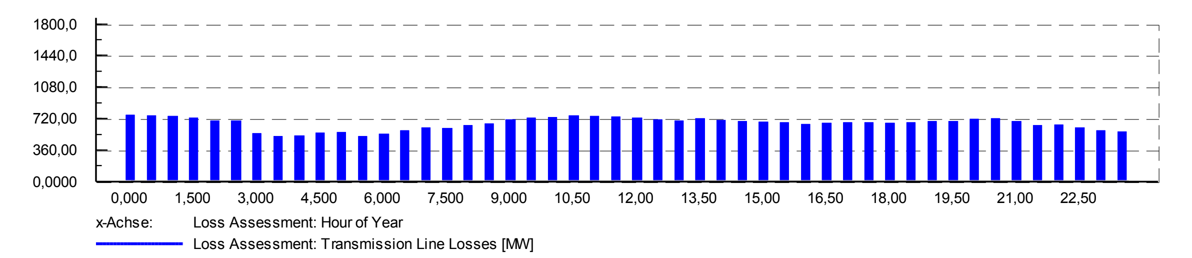




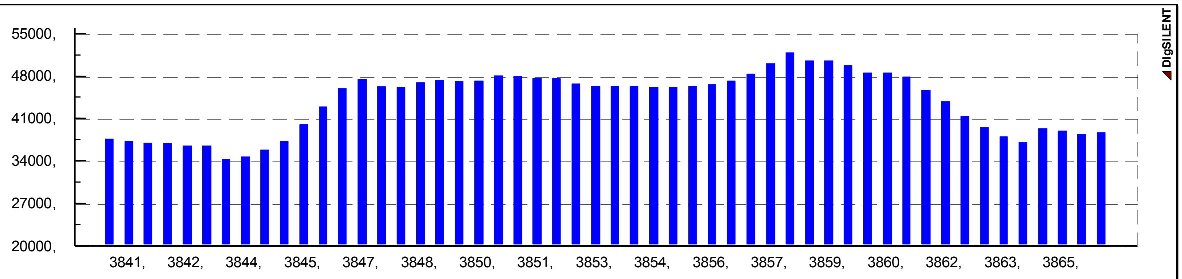




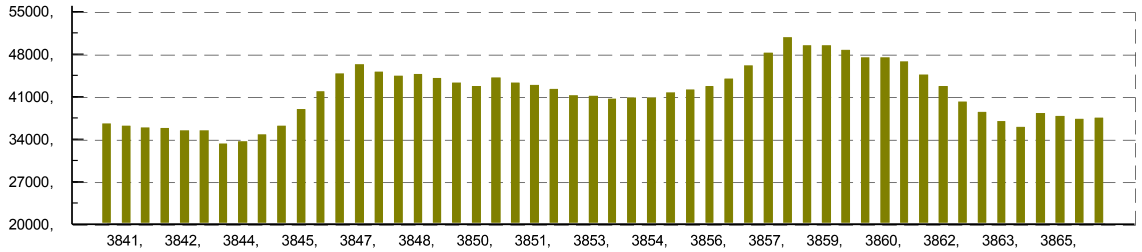




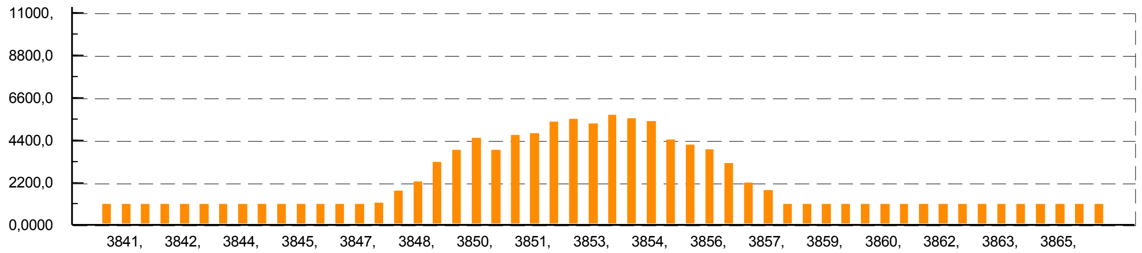
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	Low Load (1st January)	Datum: 16.02.2015
	30% Wind	1x Koeberg Unit(s) Online	Anhang: 2.1.2 /1



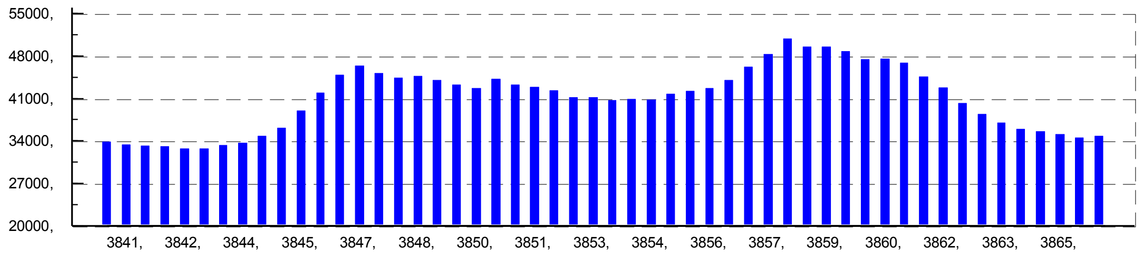
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Load [MW]



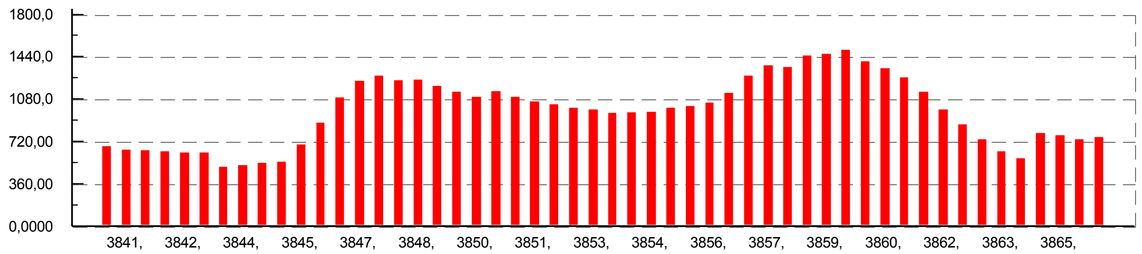
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Total Conventional Generation [MW]



x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Variable Generation MW

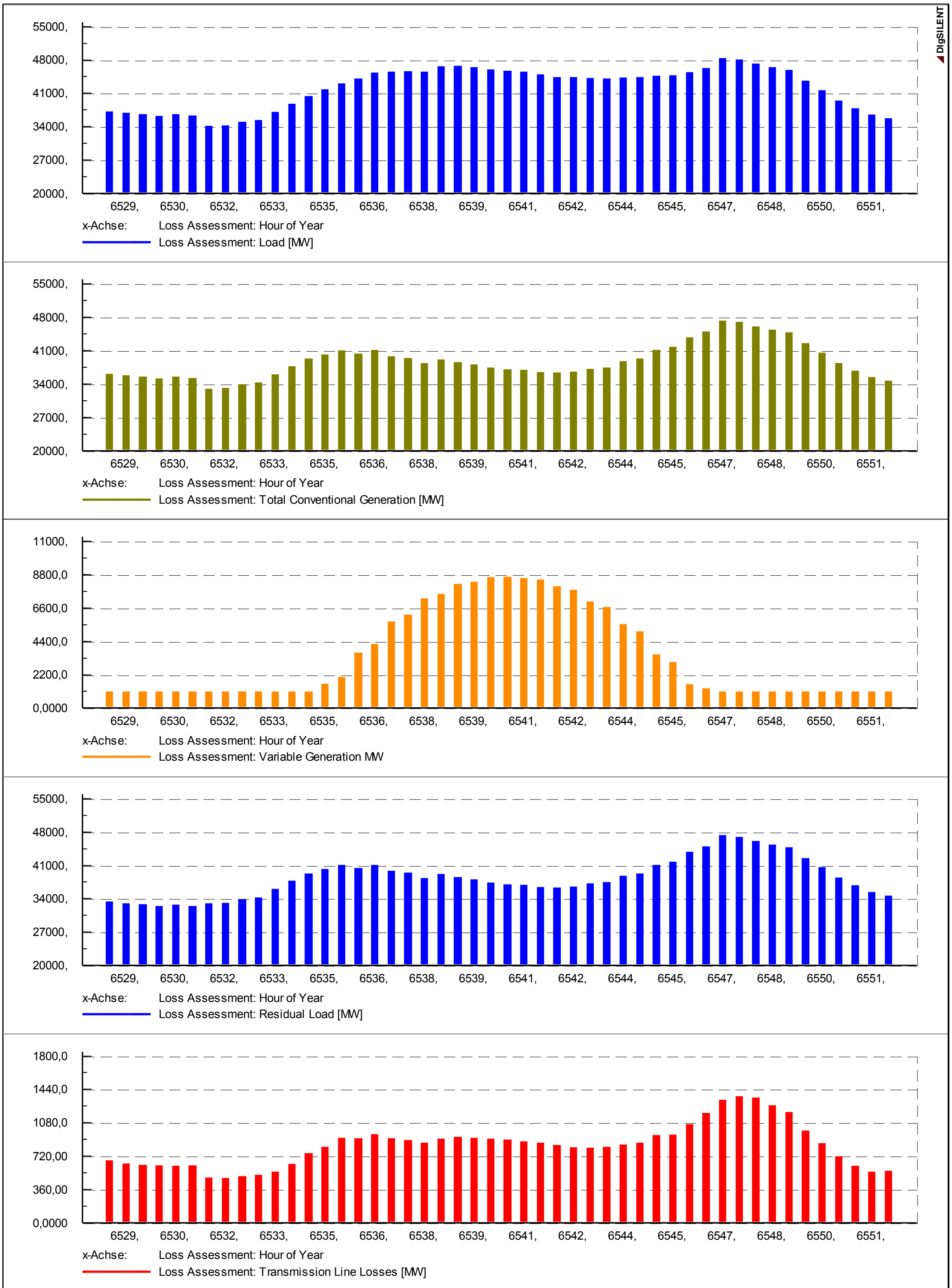


x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Residual Load [MW]



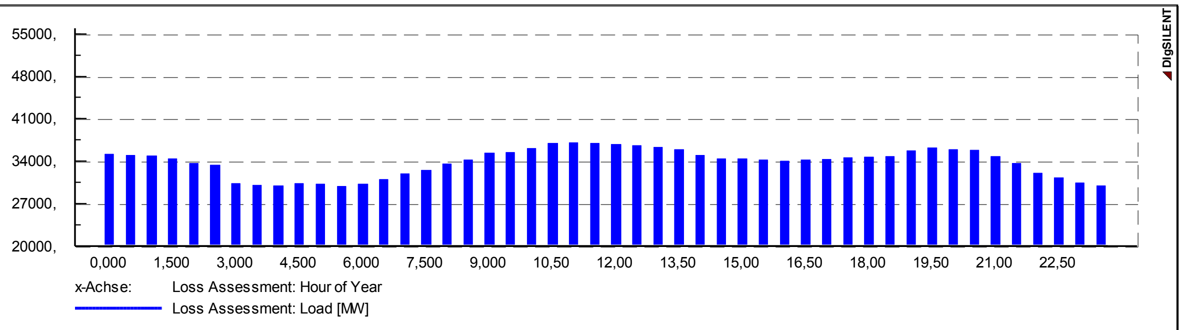
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Transmission Line Losses [MW]

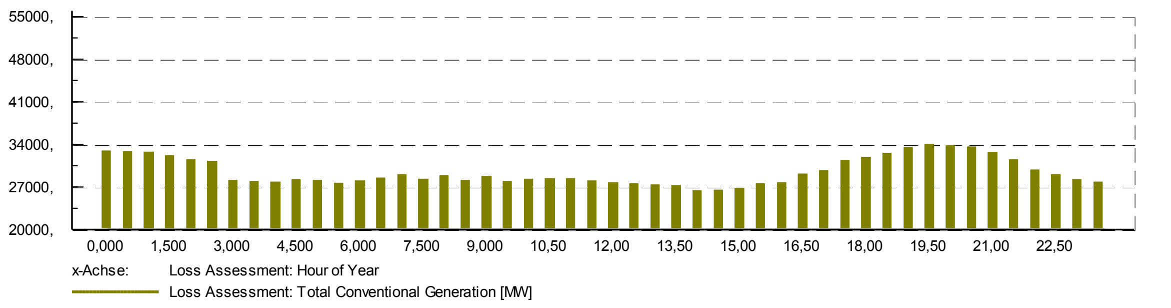
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	High Load (9th June)	Datum: 16.02.2015
	30% Wind	1x Koeberg Unit(s) Online	Anhang: 2.1.2 /2

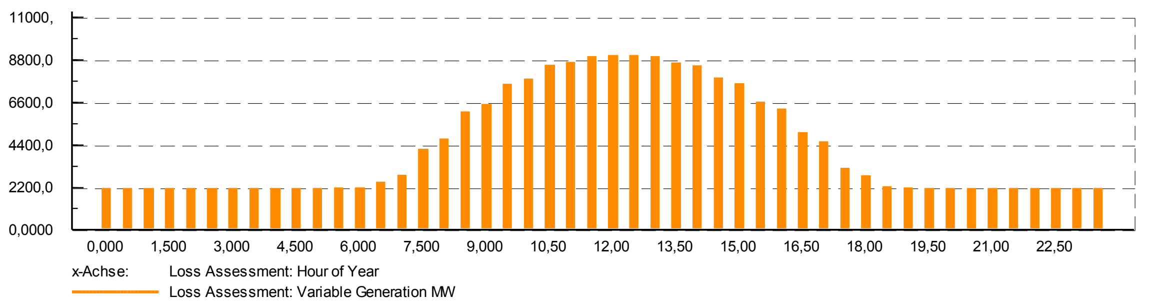


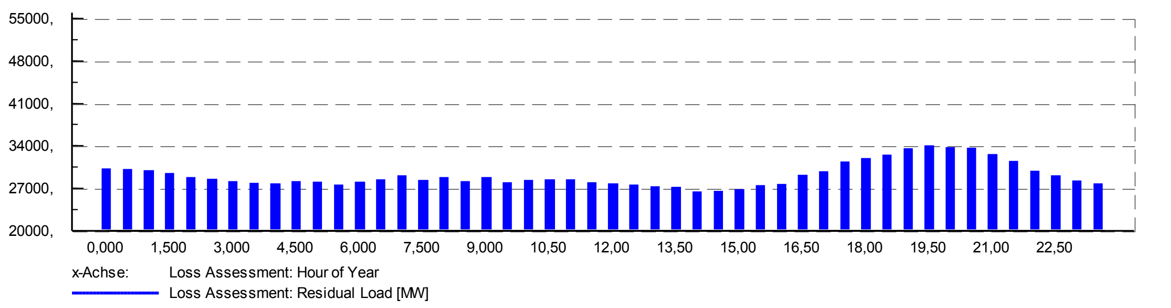
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	High PV (29th September)	Datum: 16.02.2015
	30% Wind	1x Koeberg Unit(s) Online	Anhang: 2.1.2 /3

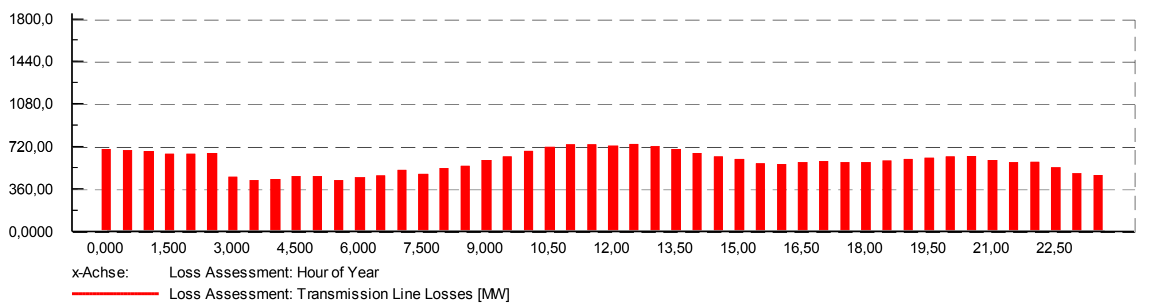
2.1.3 60% Wind



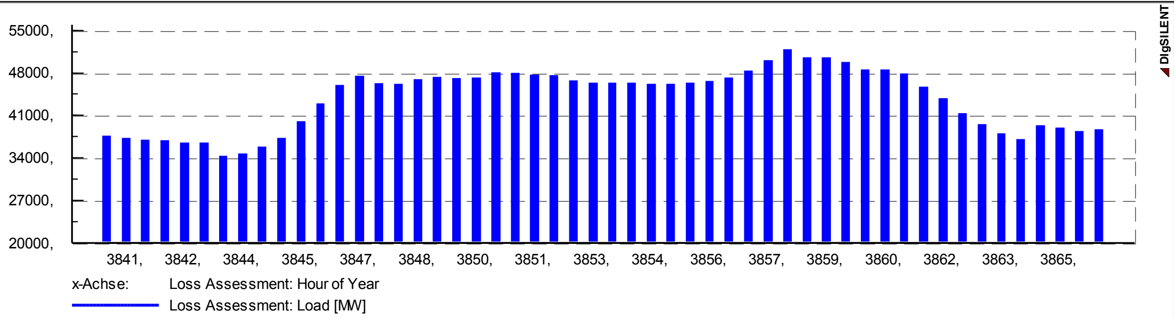


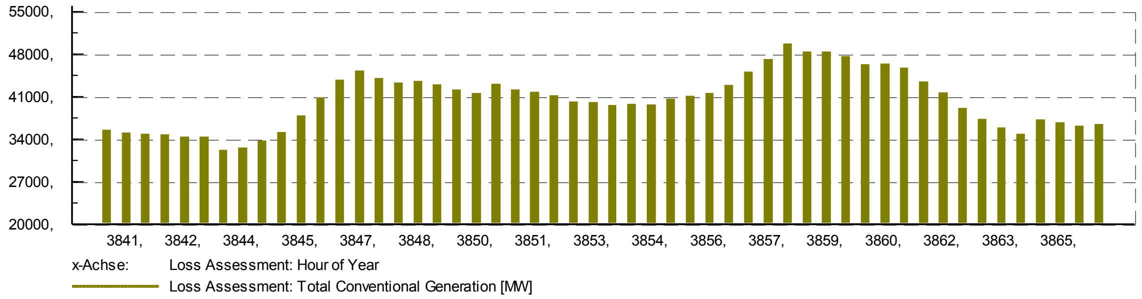


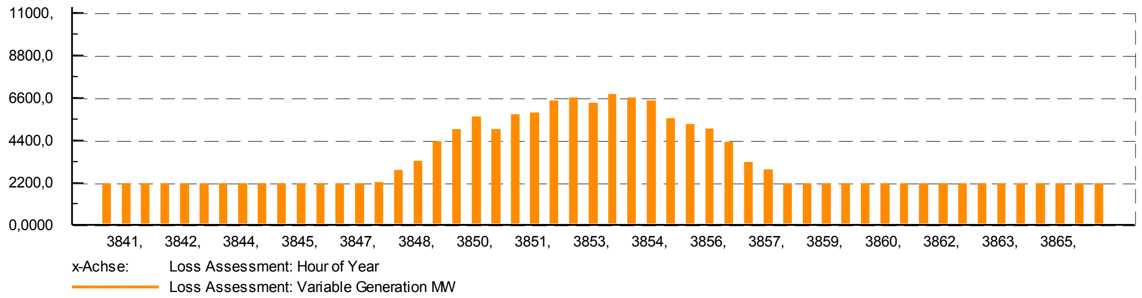


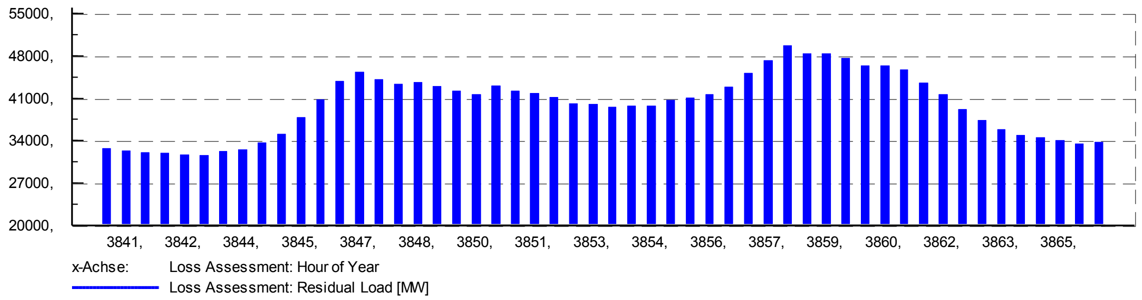


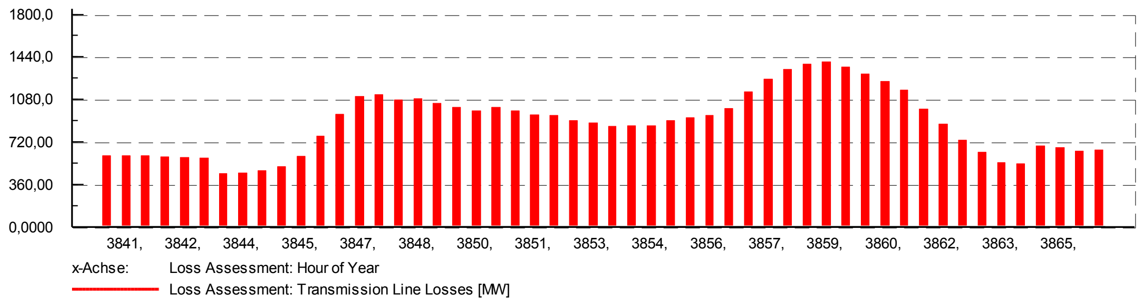
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	Low Load (1st January)	Datum: 16.02.2015
	60% Wind	1x Koeberg Unit(s) Online	Anhang: 2.1.3 /1



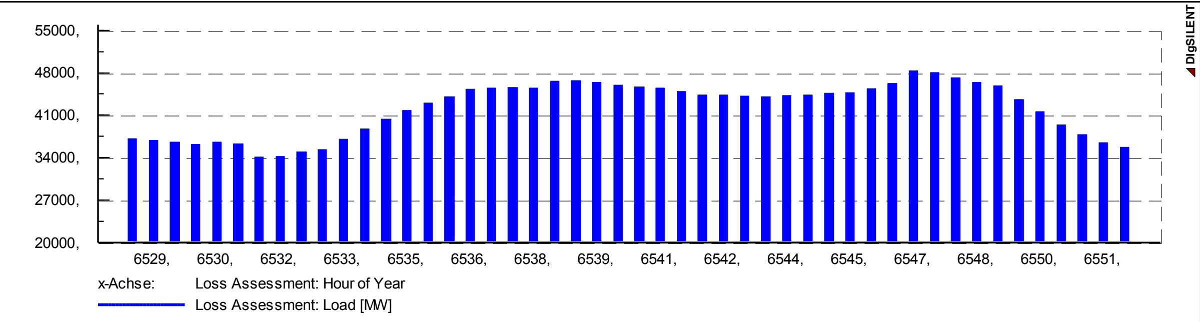


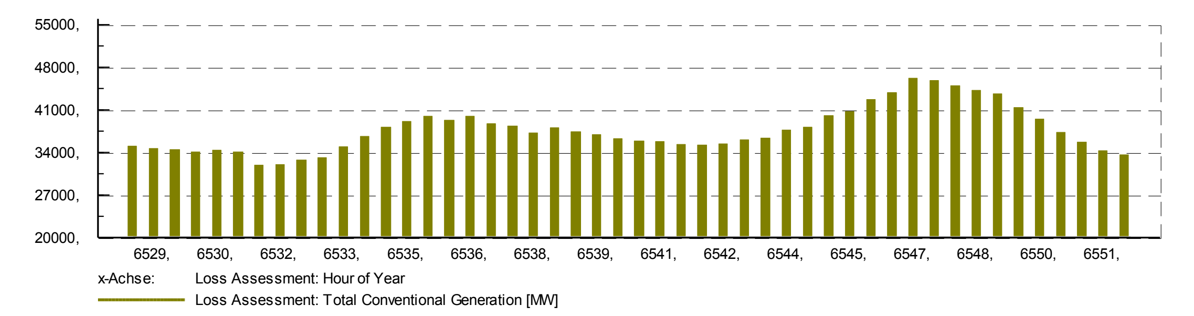


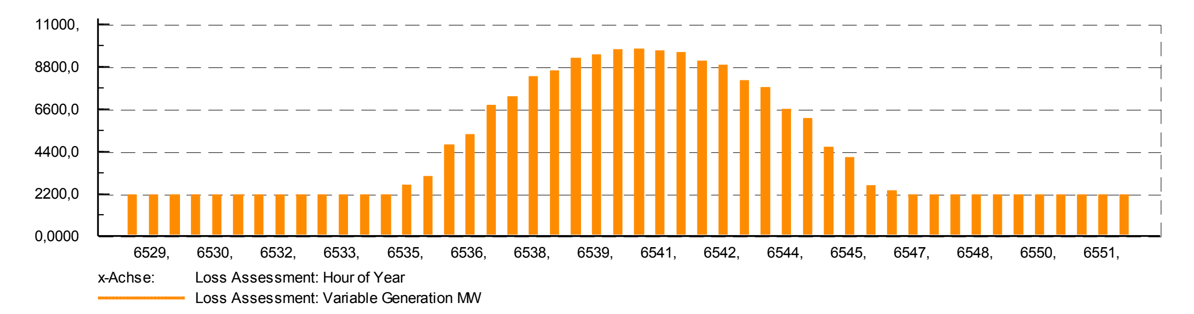


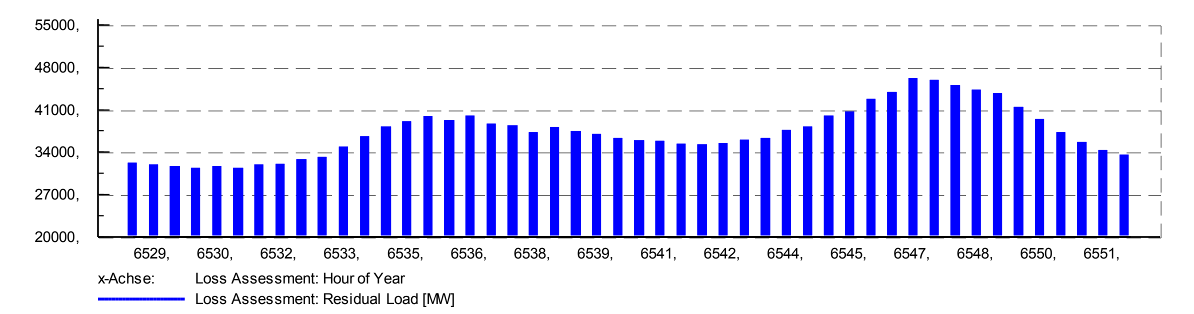


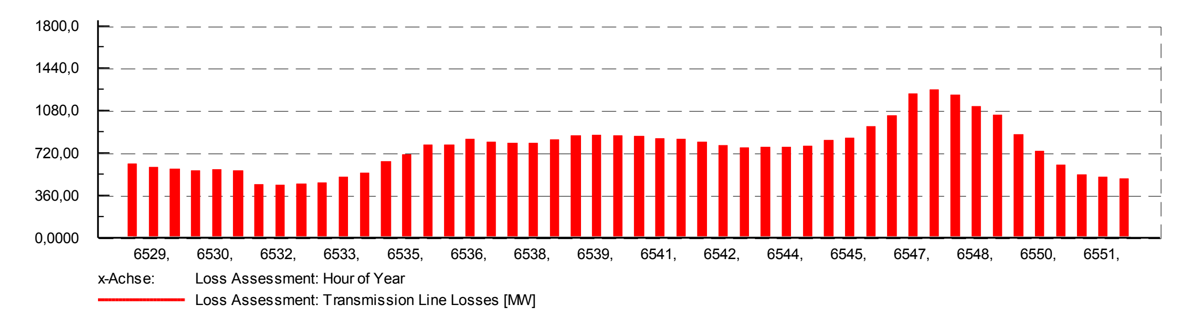
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	High Load (9th June)	Datum: 16.02.2015
	60% Wind	1x Koeberg Unit(s) Online	Anhang: 2.1.3 /2











M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	High PV (29th September)	Datum: 16.02.2015
	60% Wind	1x Koeberg Unit(s) Online	Anhang: 2.1.3 /3

2.1.4 90% Wind

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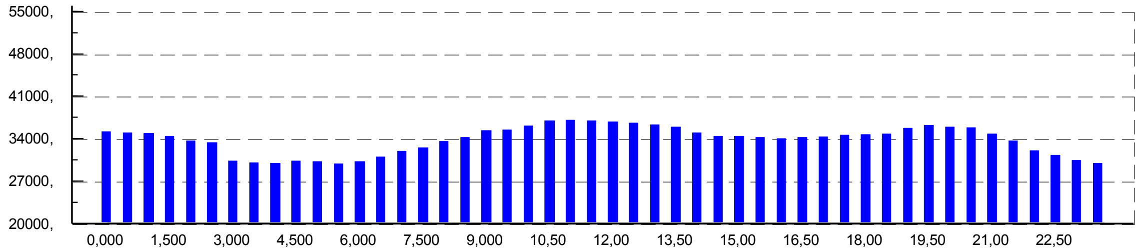
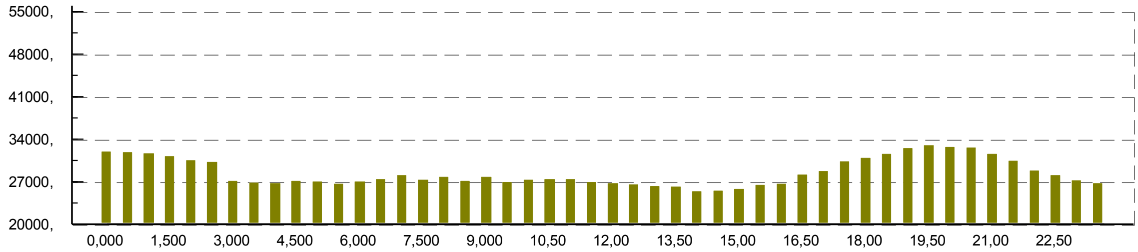
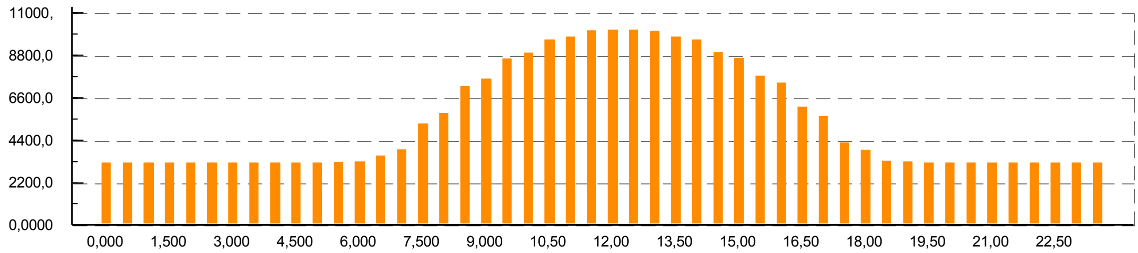


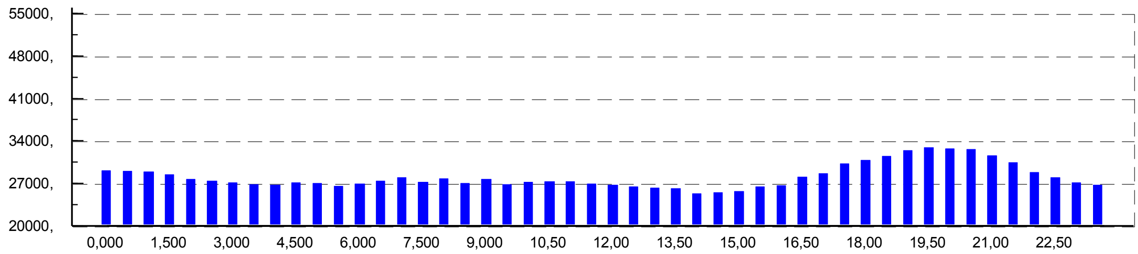
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Load [MW]



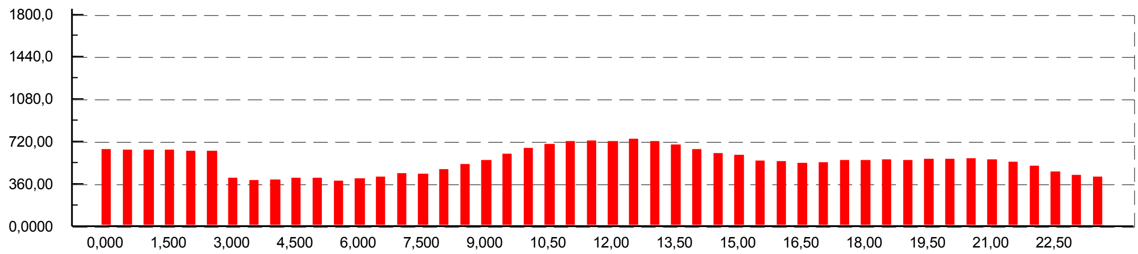
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Total Conventional Generation [MW]



x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Variable Generation MW

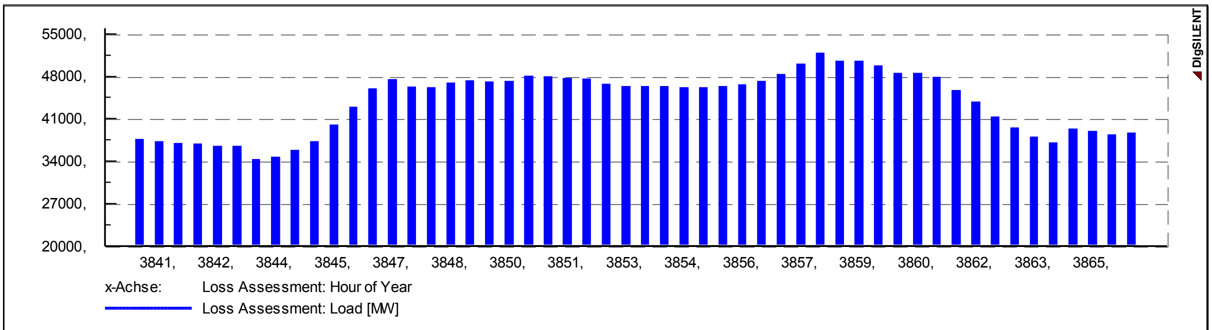


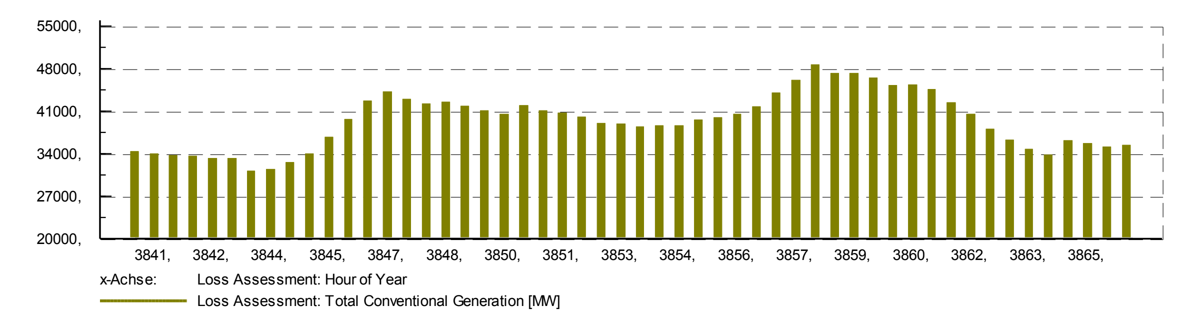
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Residual Load [MW]

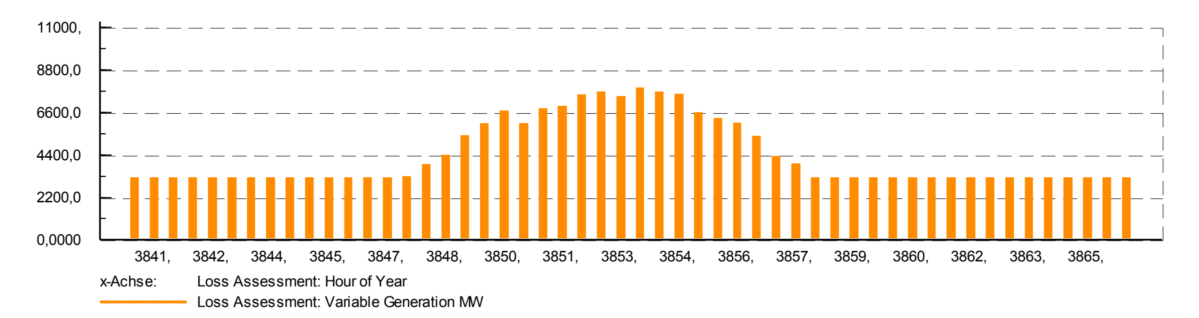


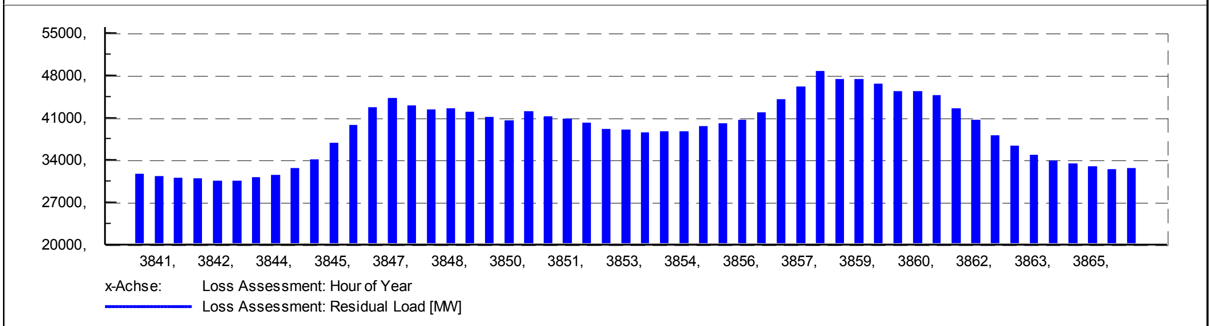
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Transmission Line Losses [MW]

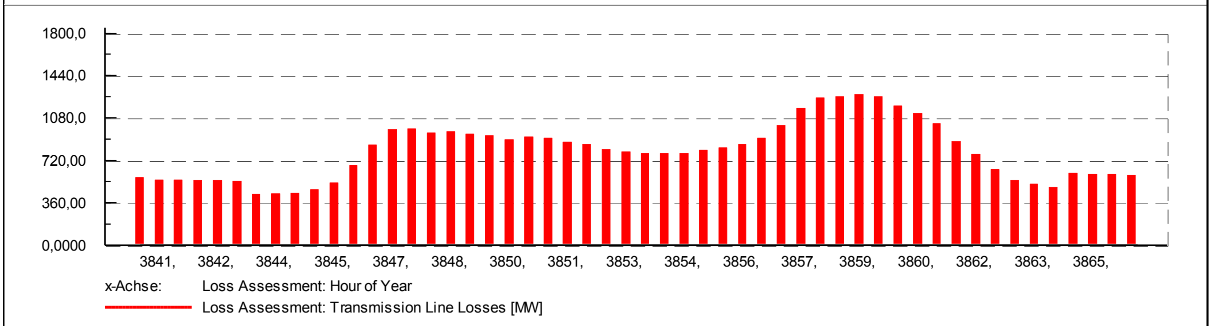
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	Low Load (1st January)	Datum: 16.02.2015
	90% Wind	1x Koeberg Unit(s) Online	Anhang: 2.1.4 /1







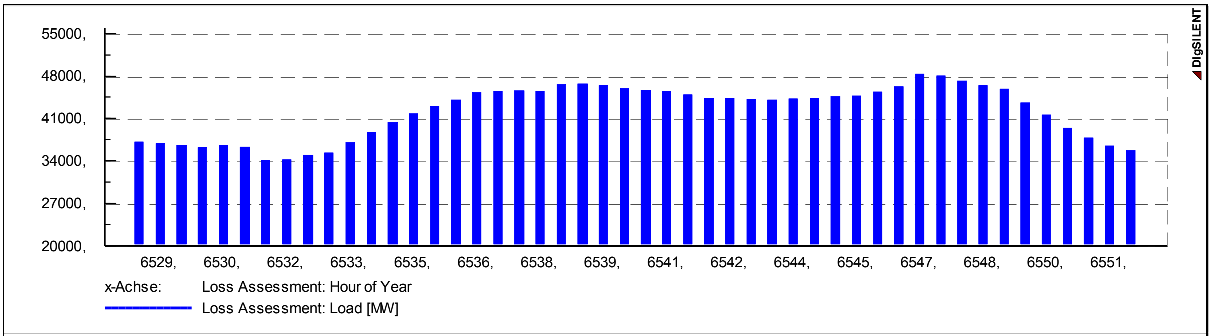


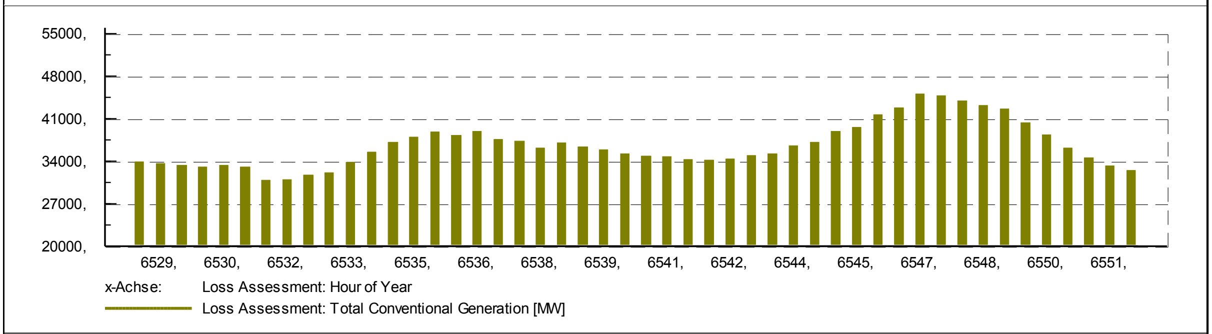


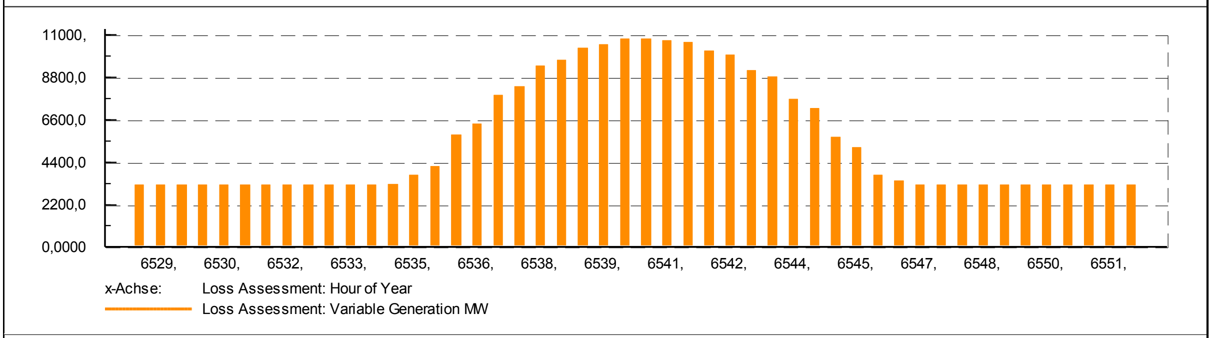
M.P.E. MOELLER & POELLER ENGINEERING

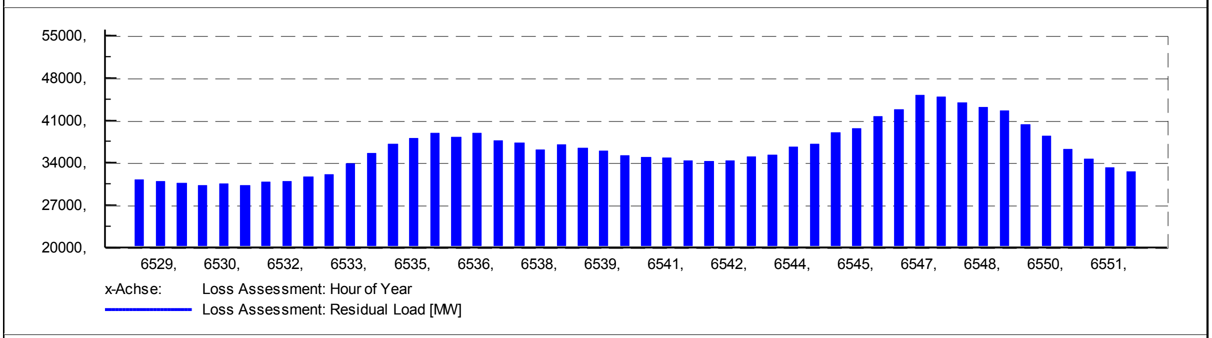
Scenario A — High Load (9th June) — Datum: 16.02.2015

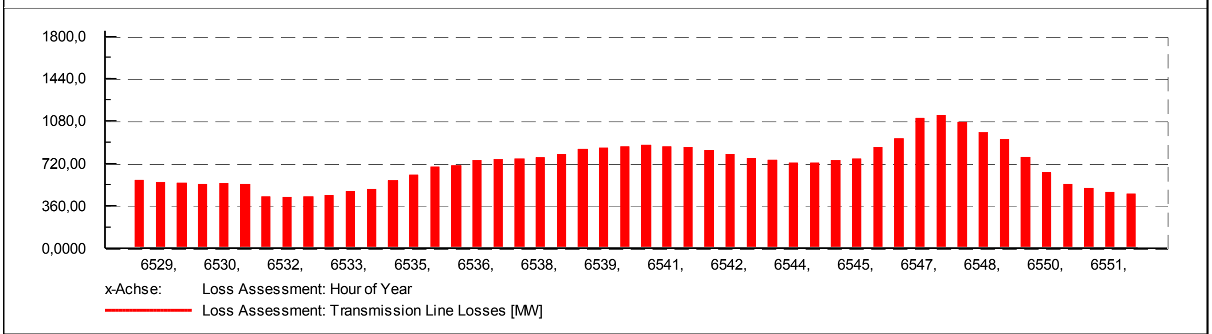
90% Wind — 1x Koeberg Unit(s) Online — Anhang: 2.1.4 /2







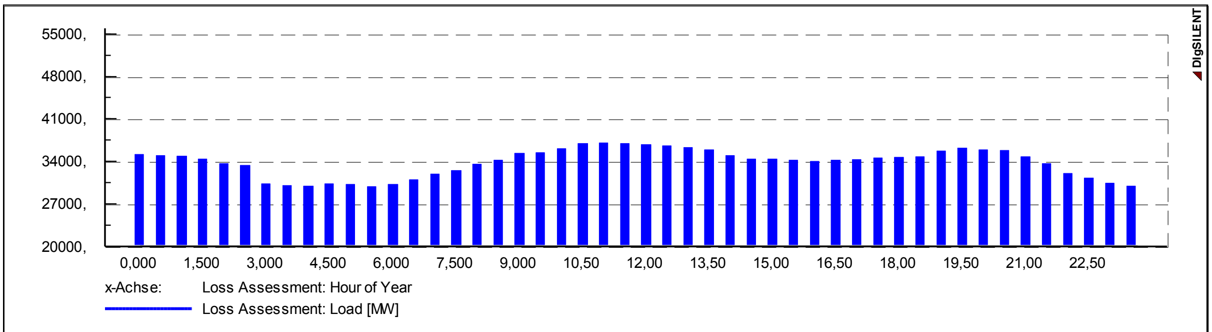


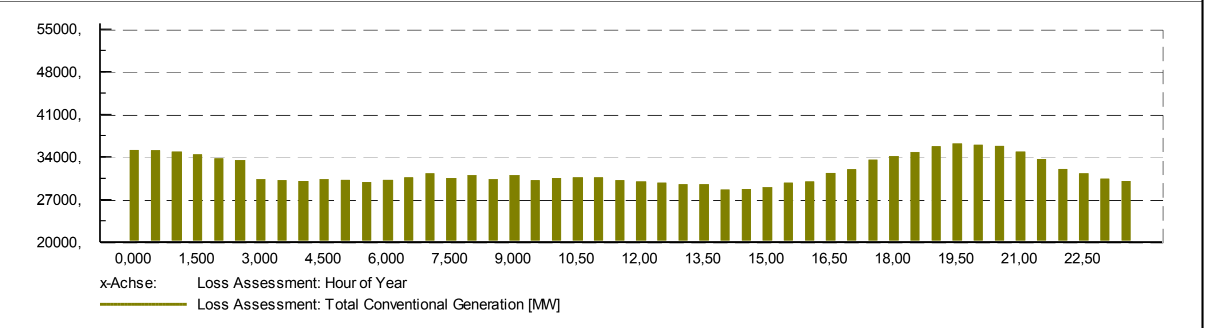


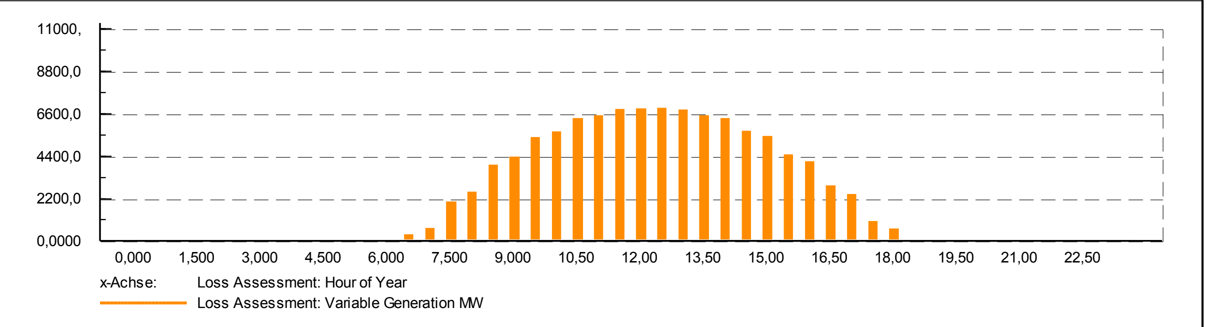
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	High PV (29th September)	Datum: 16.02.2015
	90% Wind	1x Koeberg Unit(s) Online	Anhang: 2.1.4 /3

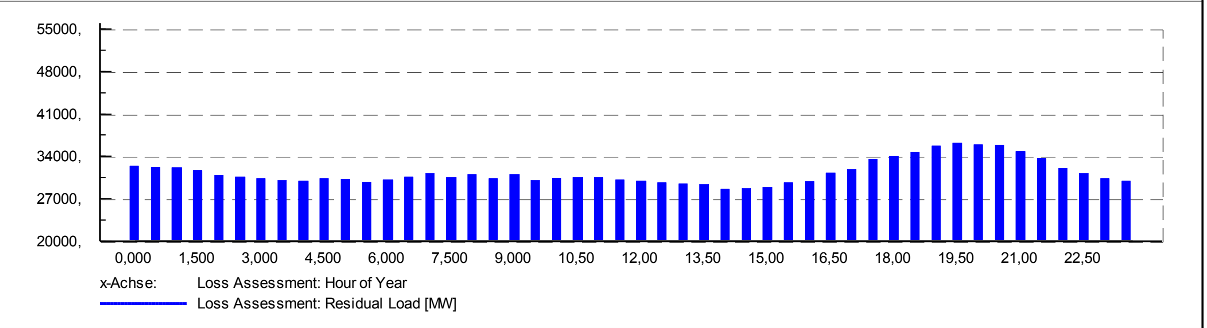
2.2 2x Koeberg Unit(s) Online

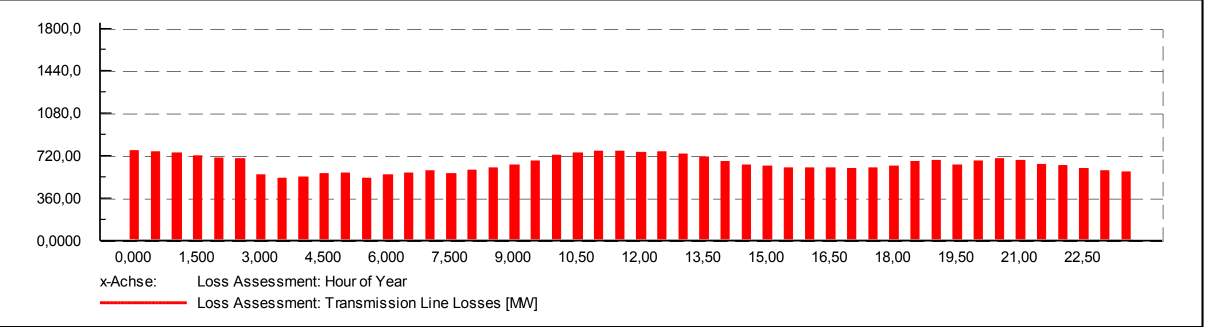
2.2.1 00% Wind



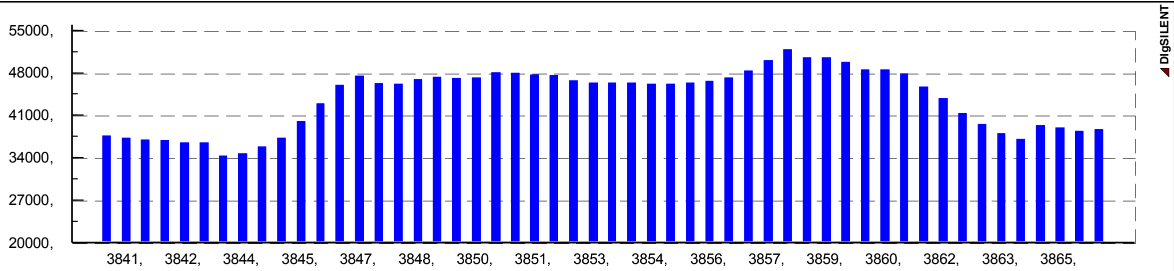




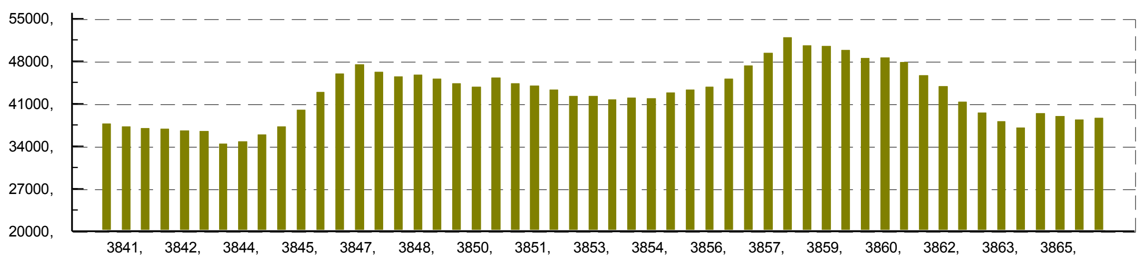




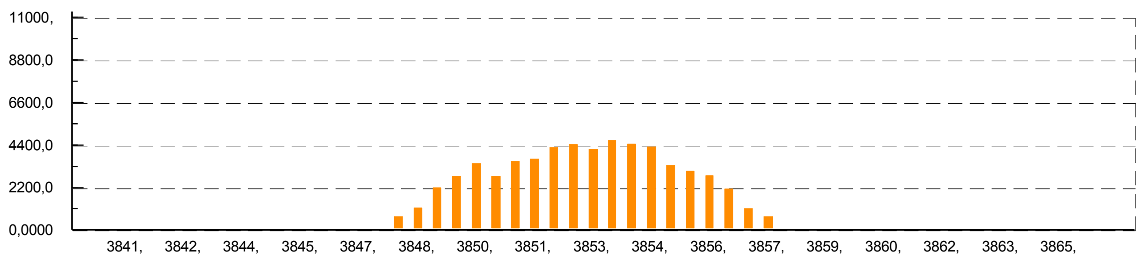
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	Low Load (1st January)	Datum: 16.02.2015
	00% Wind	2x Koeberg Unit(s) Online	Anhang: 2.2.1 /1



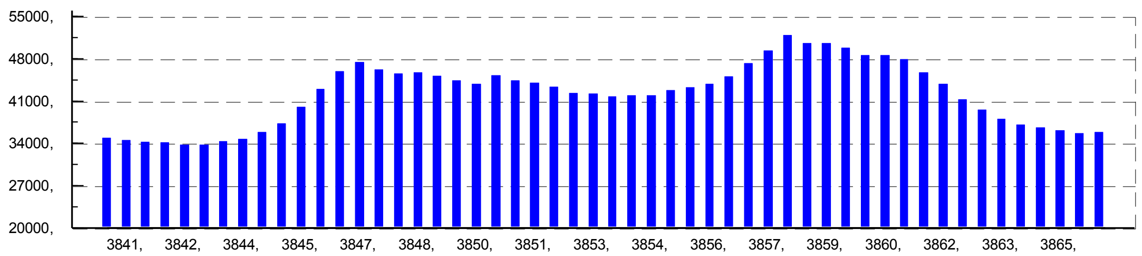
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Load [MW]



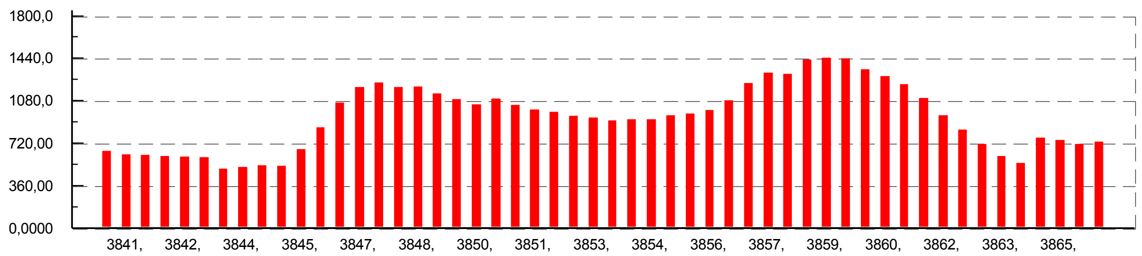
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Total Conventional Generation [MW]



x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Variable Generation MW

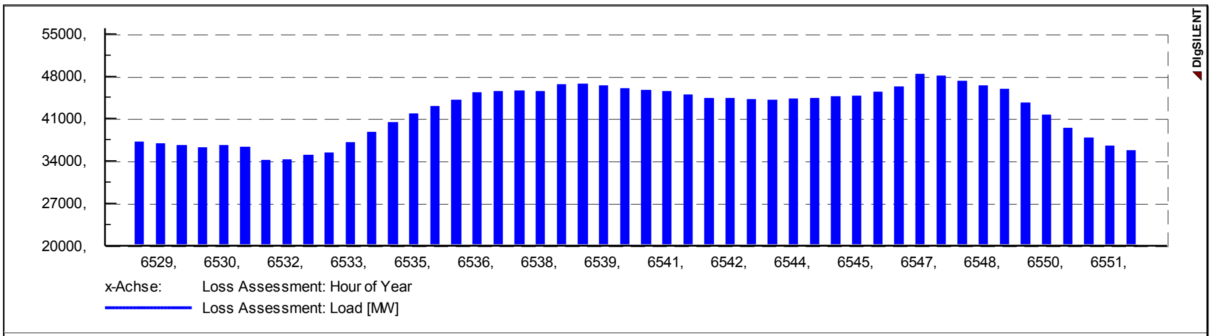


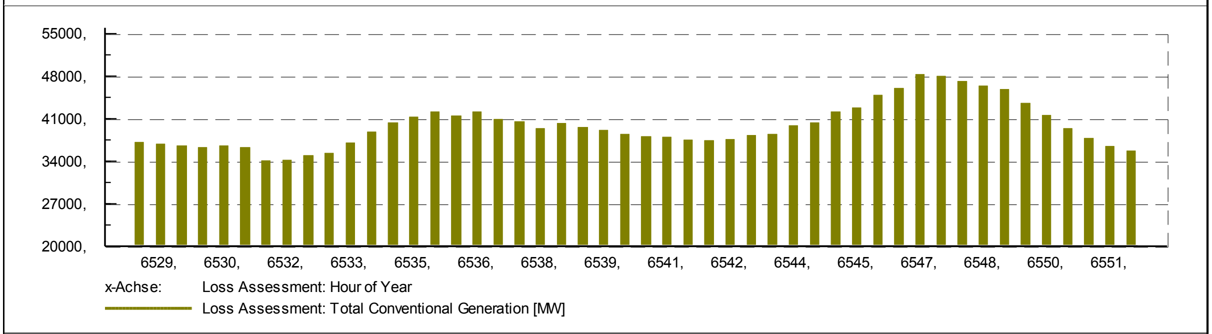
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Residual Load [MW]

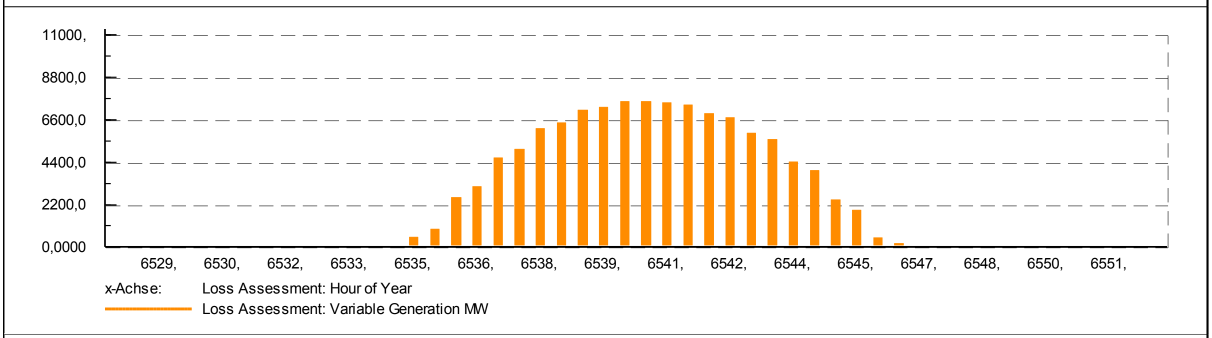


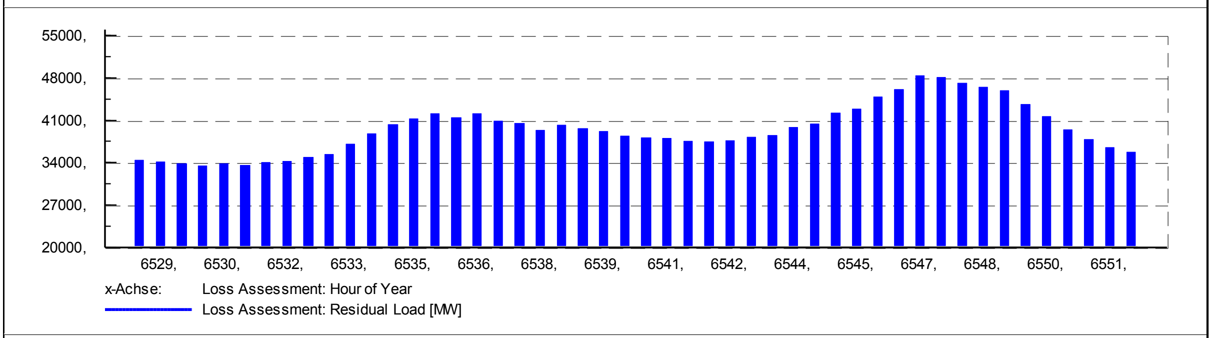
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Transmission Line Losses [MW]

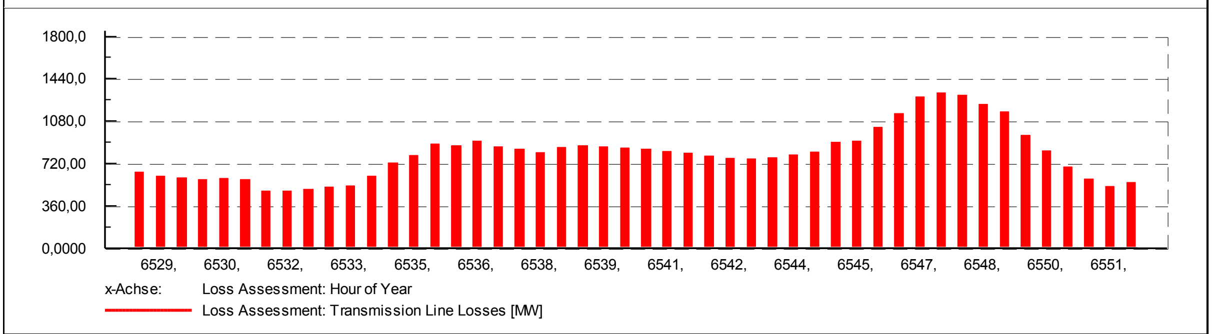
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	High Load (9th June)	Datum: 16.02.2015
	00% Wind	2x Koeberg Unit(s) Online	Anhang: 2.2.1 /2





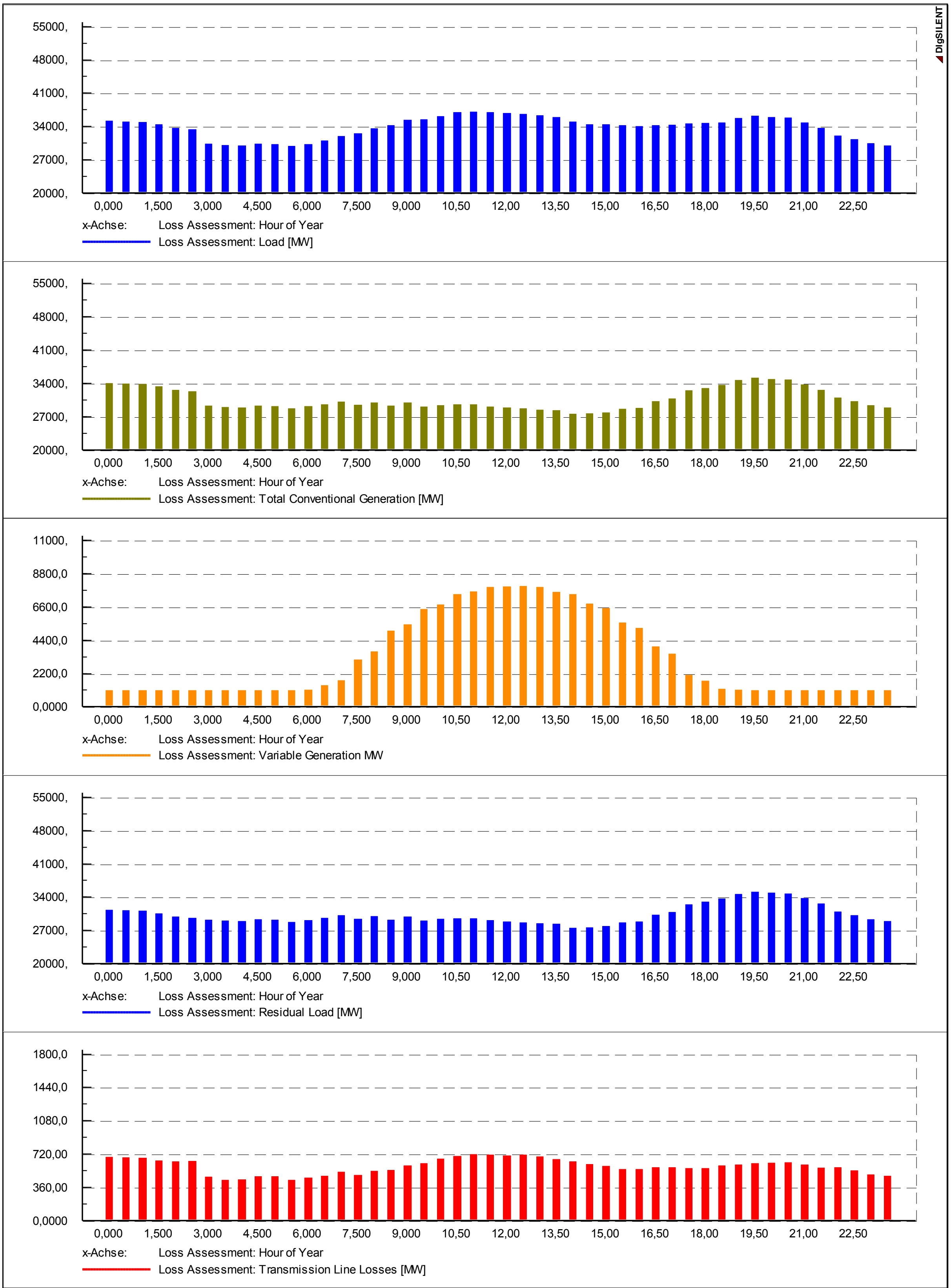




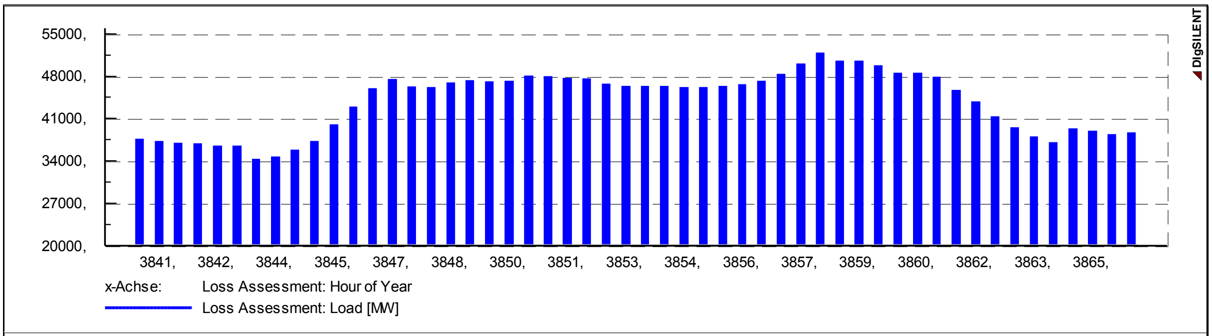


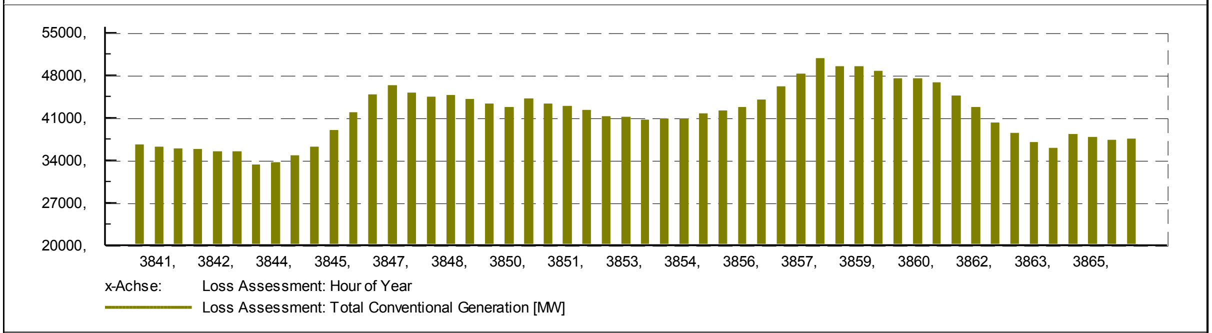
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	High PV (29th September)	Datum: 16.02.2015
	00% Wind	2x Koeberg Unit(s) Online	Anhang: 2.2.1 /3

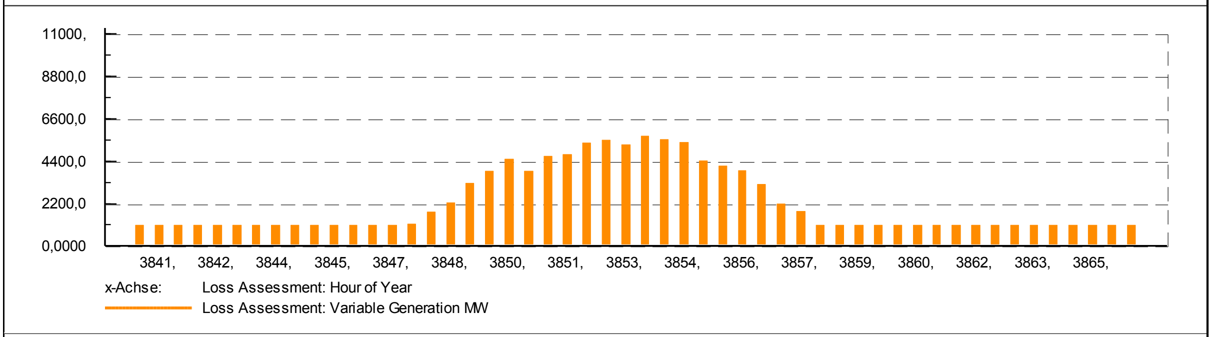
2.2.2 30% Wind

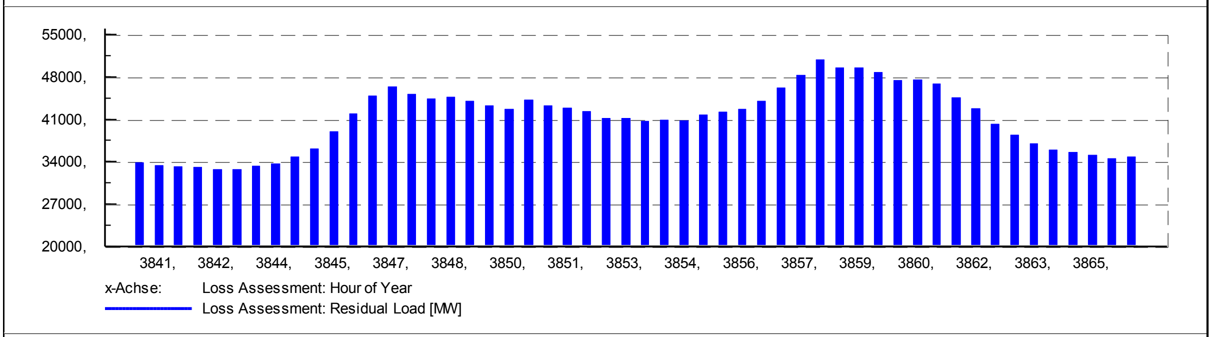


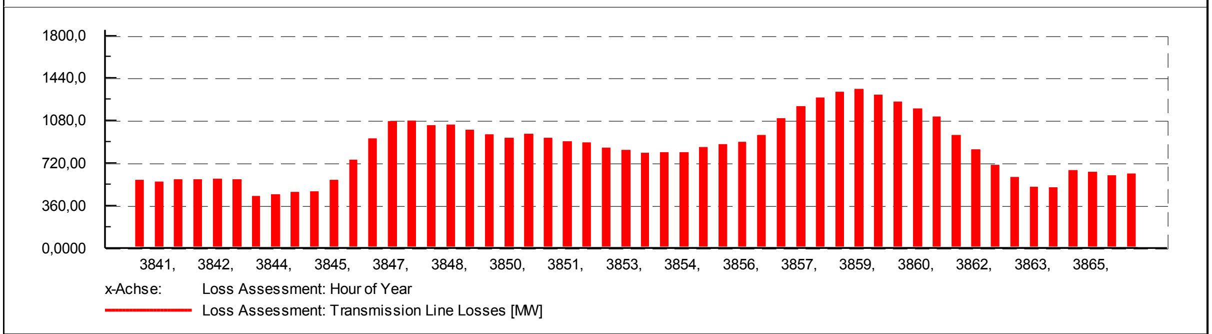
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	Low Load (1st January)	Datum: 16.02.2015
	30% Wind	2x Koeberg Unit(s) Online	Anhang: 2.2.2 /1



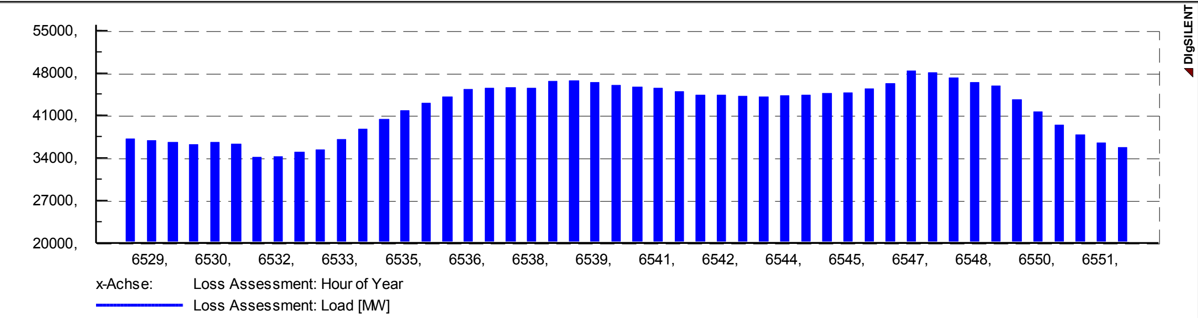


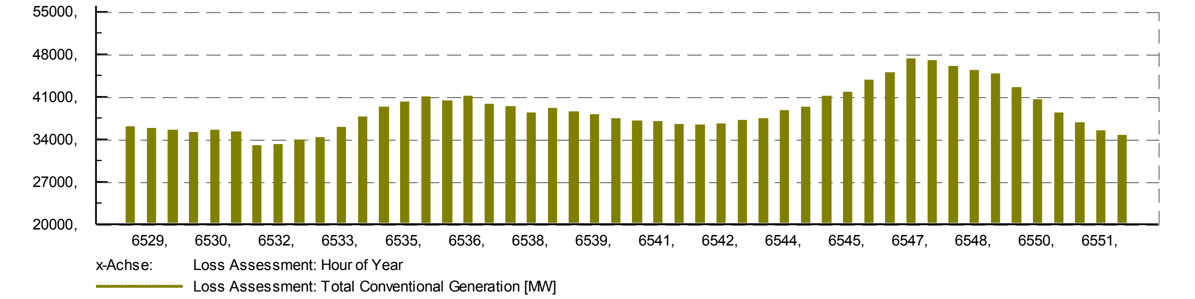


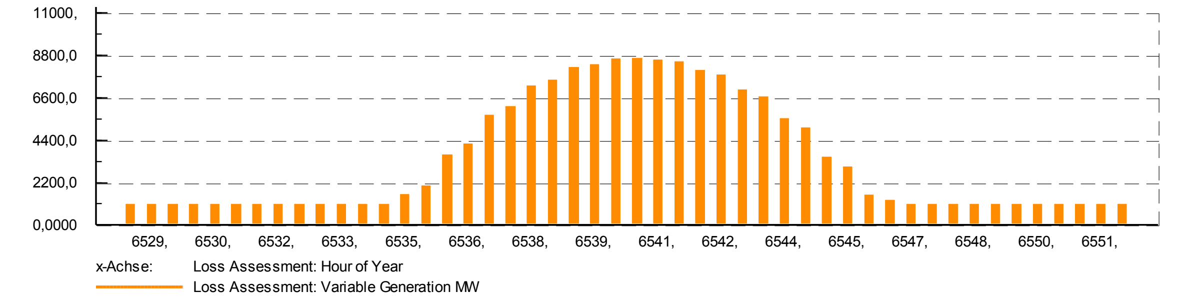


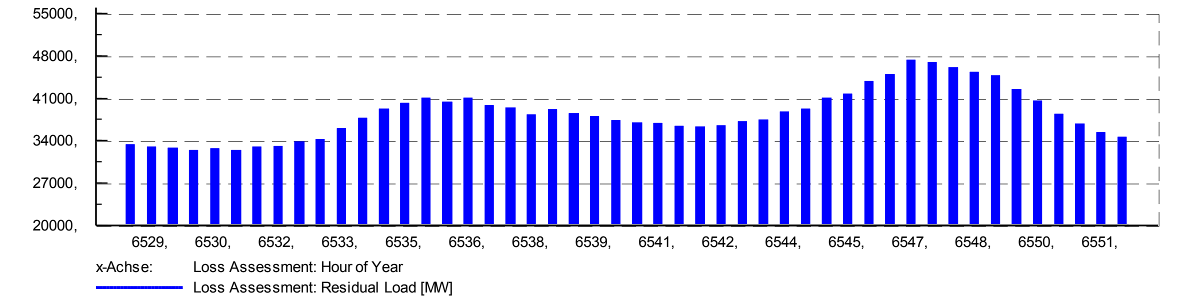


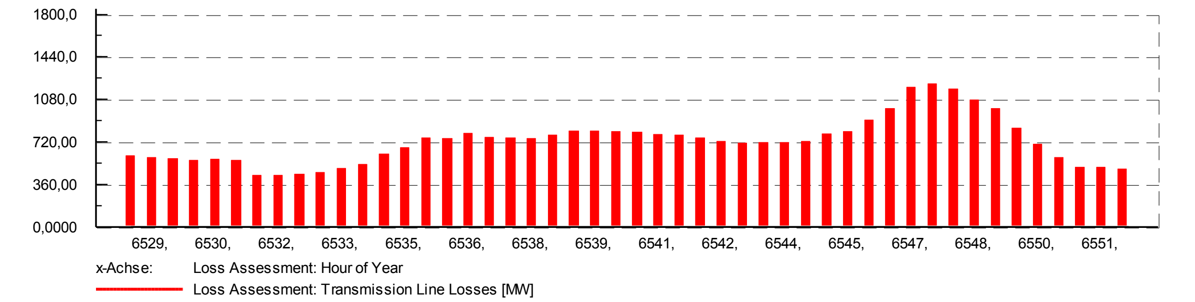
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	High Load (9th June)	Datum: 16.02.2015
	30% Wind	2x Koeberg Unit(s) Online	Anhang: 2.2.2 /2





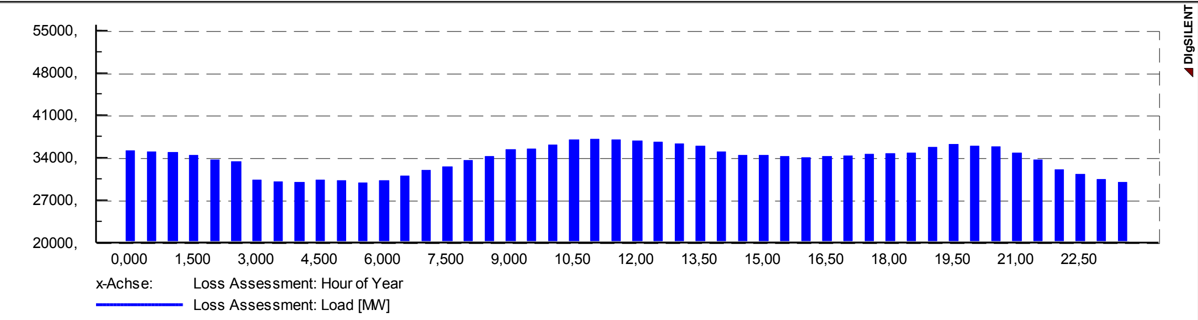


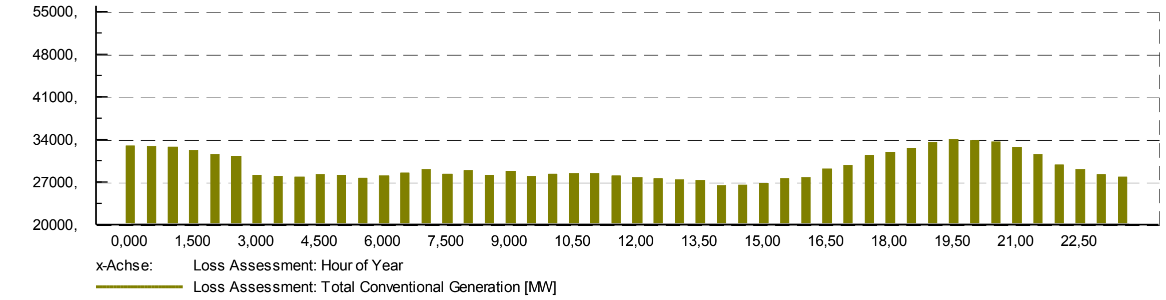


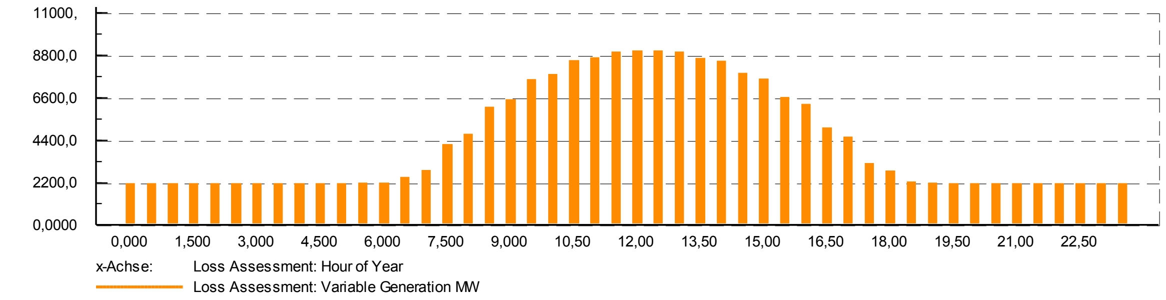


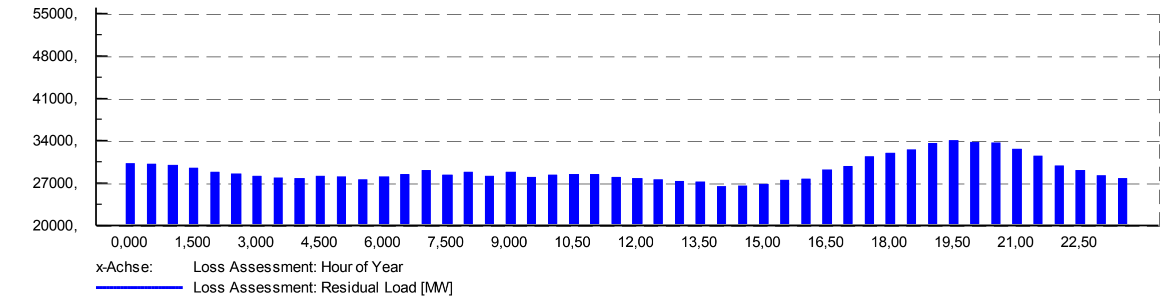
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A 30% Wind	High PV (29th September) 2x Koeberg Unit(s) Online	Datum: 16.02.2015 Anhang: 2.2.2 /3

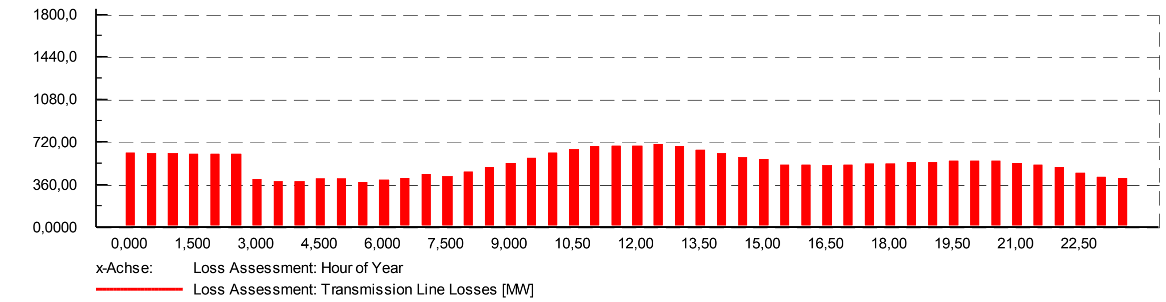
2.2.3 60% Wind



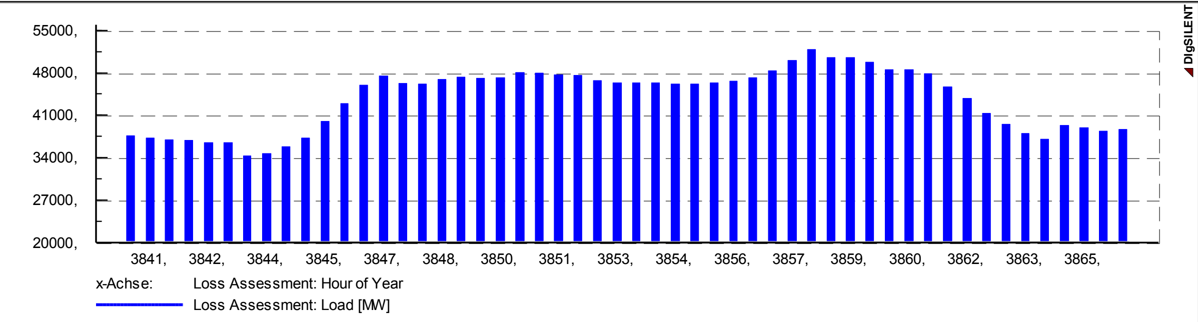


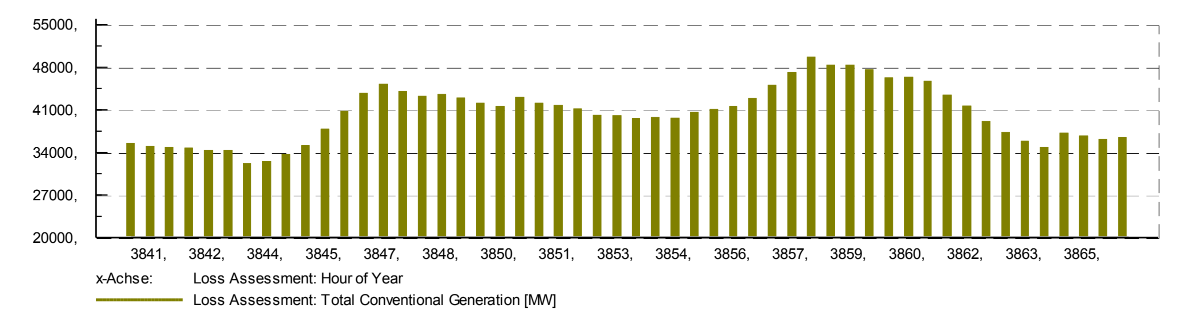


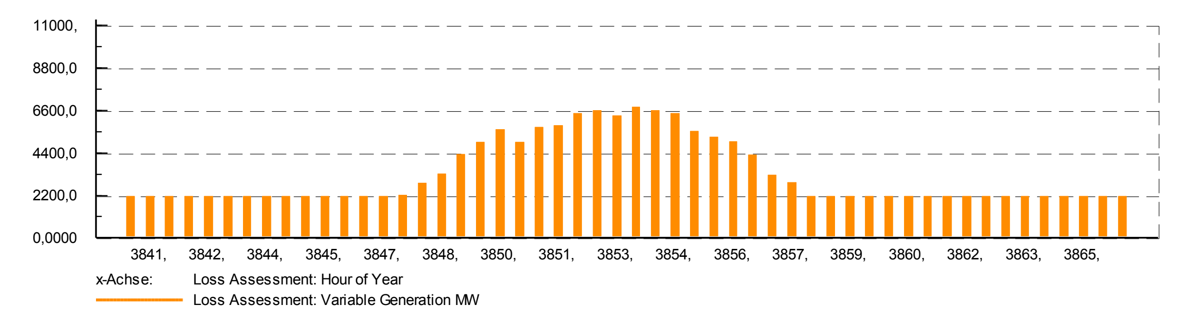


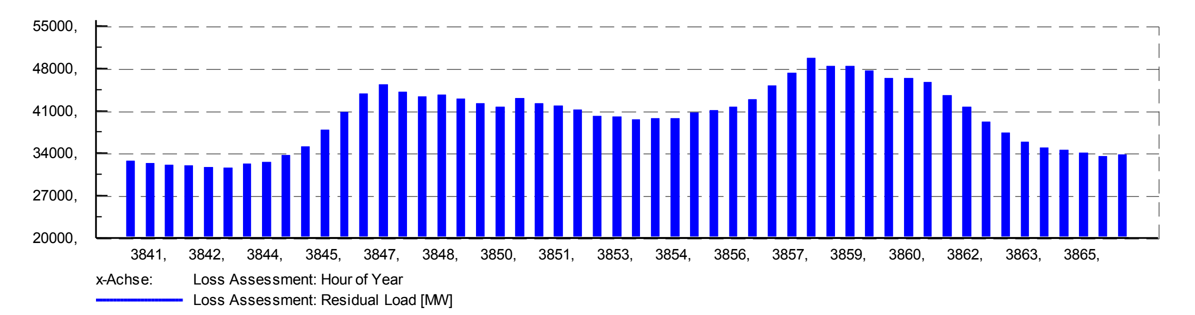


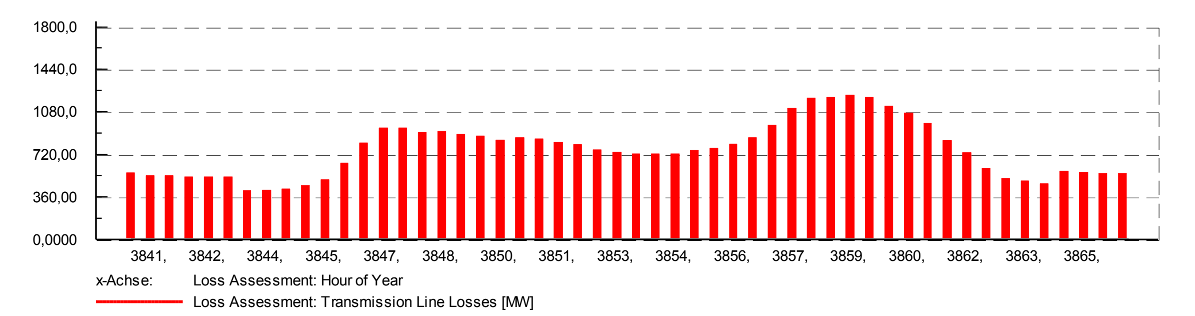
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	Low Load (1st January)	Datum: 16.02.2015
	60% Wind	2x Koeberg Unit(s) Online	Anhang: 2.2.3 /1



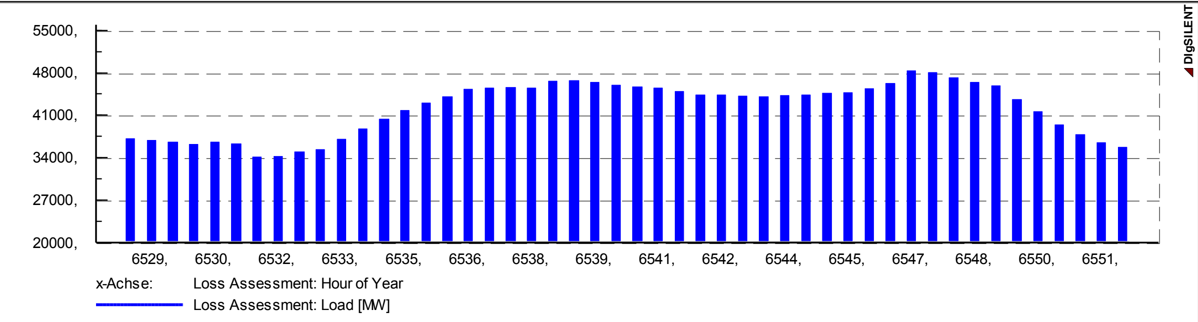


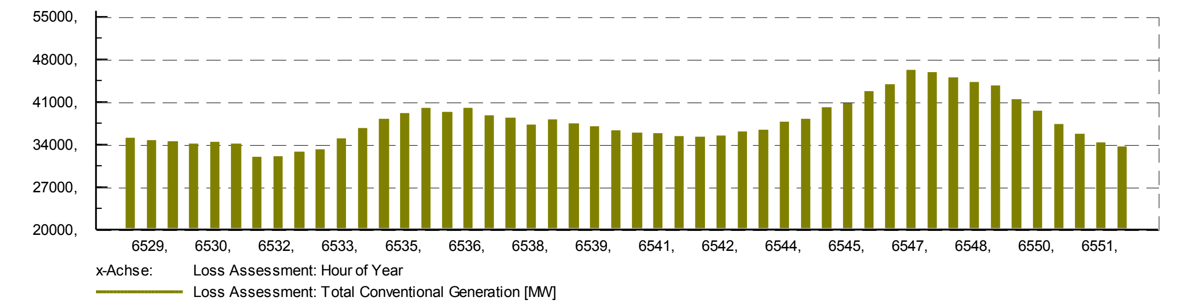


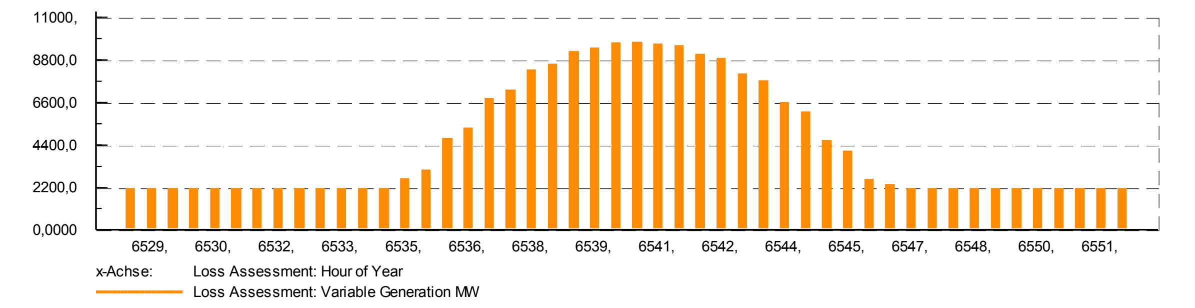


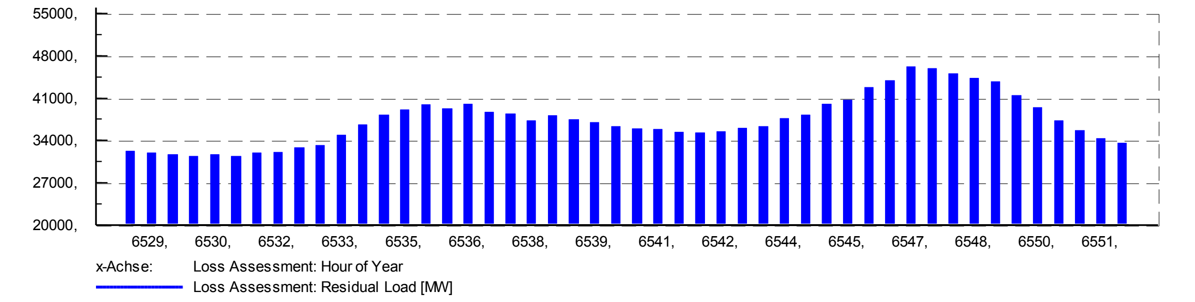


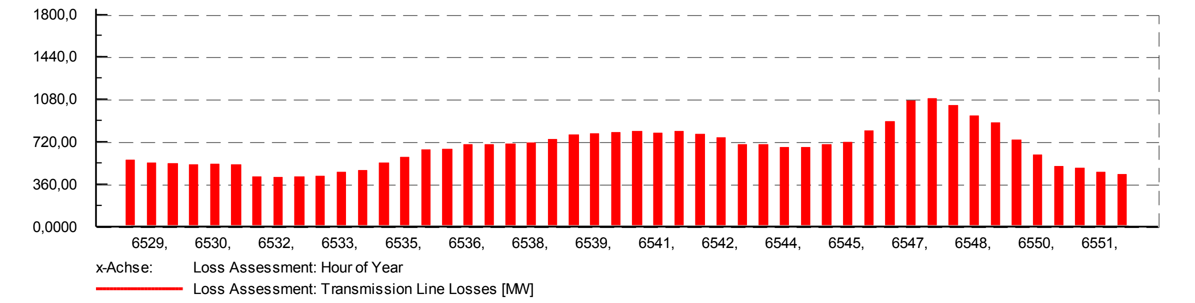
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	High Load (9th June)	Datum: 16.02.2015
	60% Wind	2x Koeberg Unit(s) Online	Anhang: 2.2.3 /2





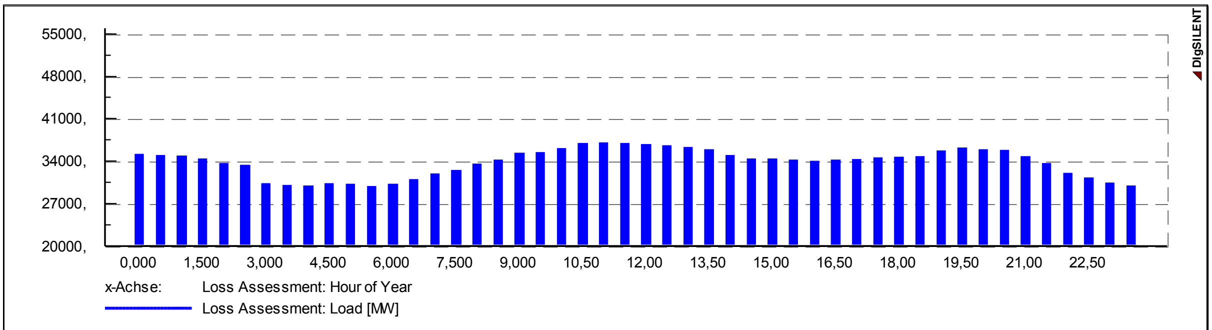


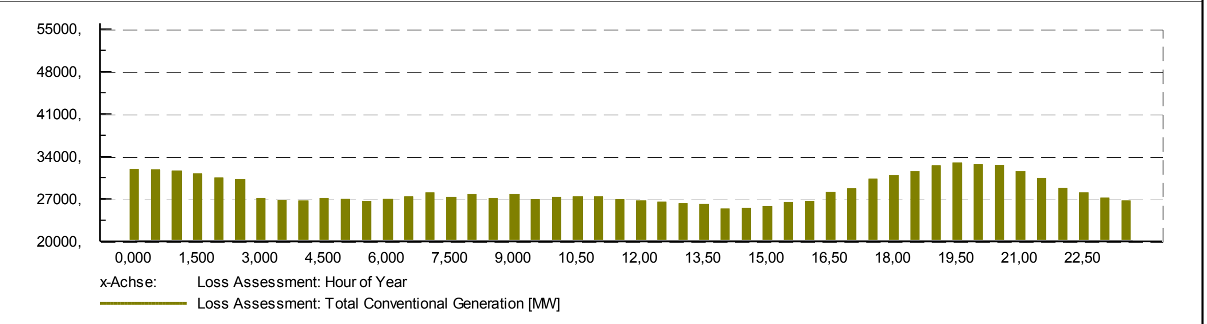


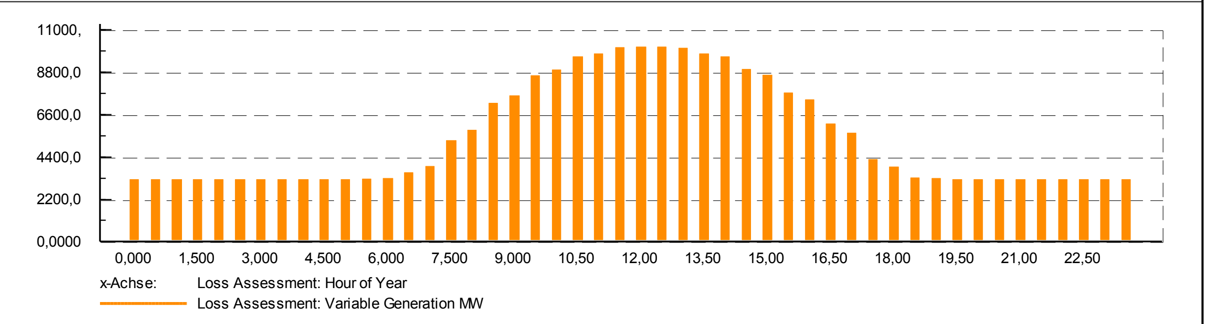


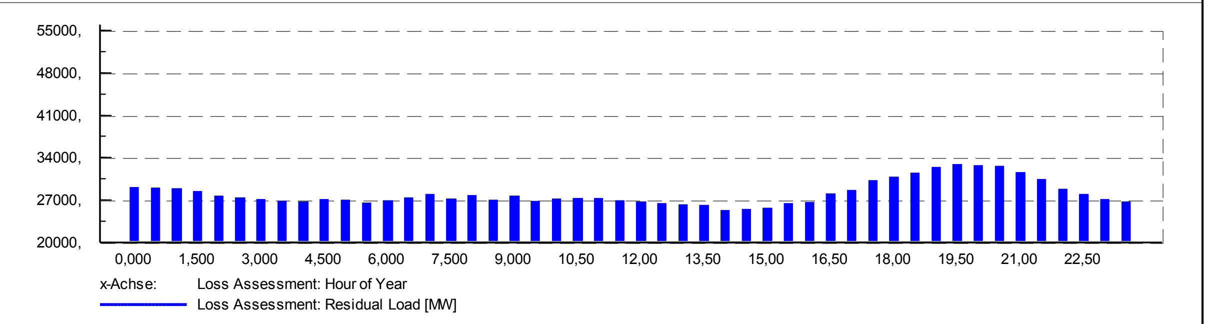
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A 60% Wind	High PV (29th September) 2x Koeberg Unit(s) Online	Datum: 16.02.2015 Anhang: 2.2.3 /3

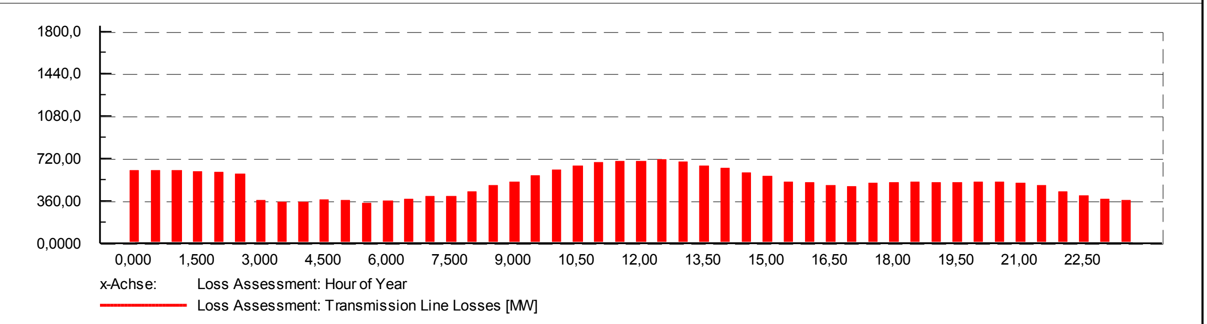
2.2.4 90% Wind



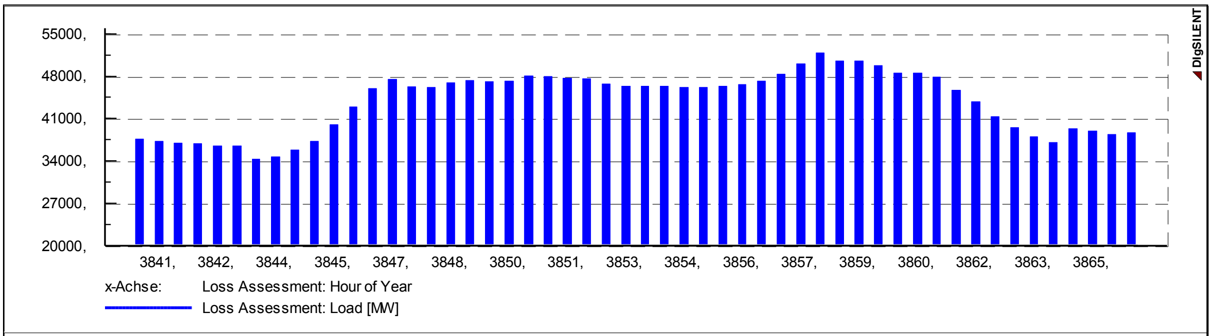


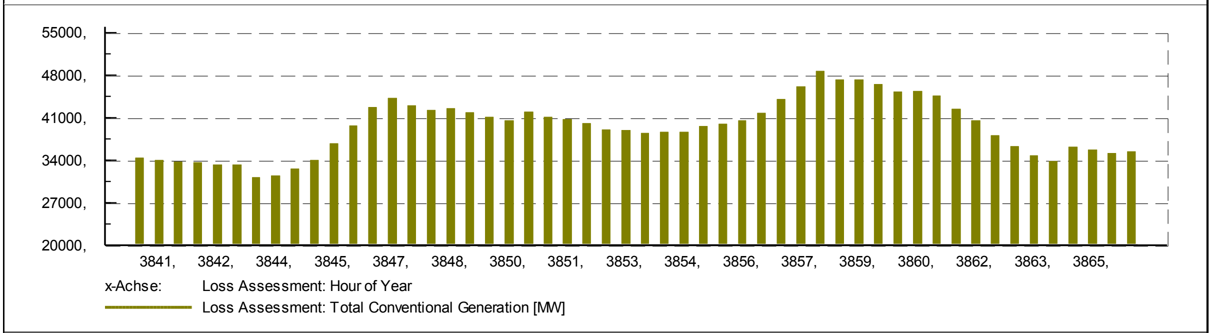


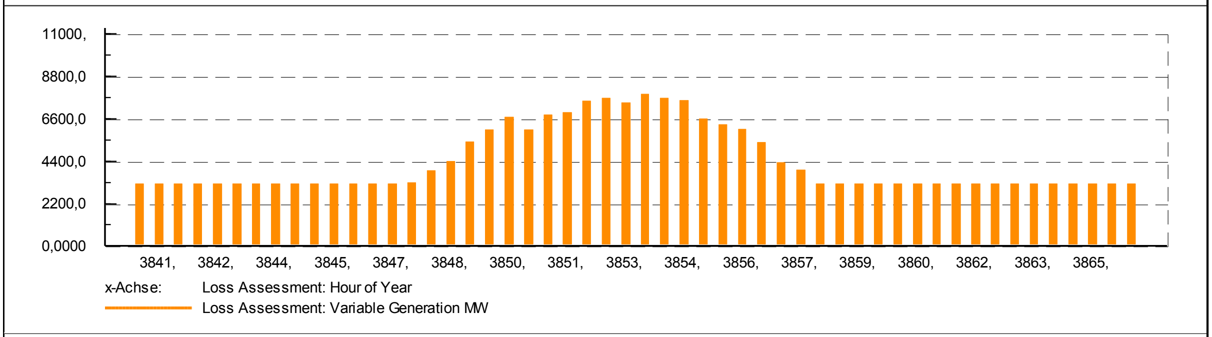


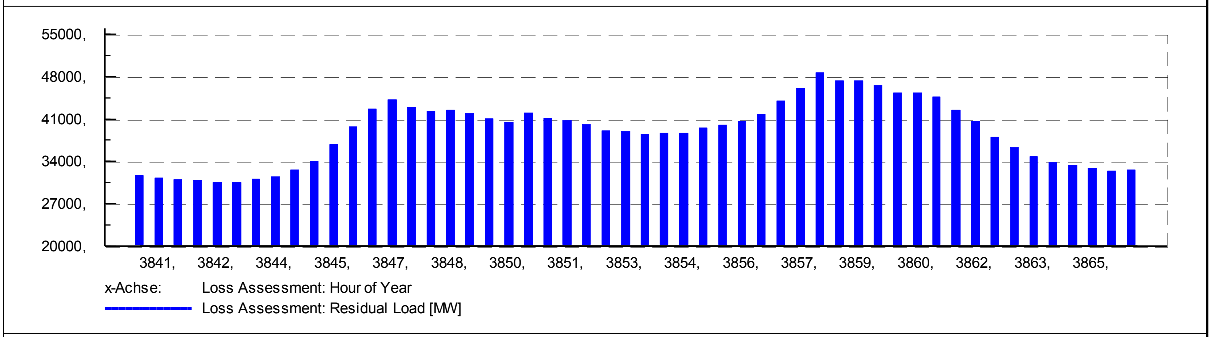


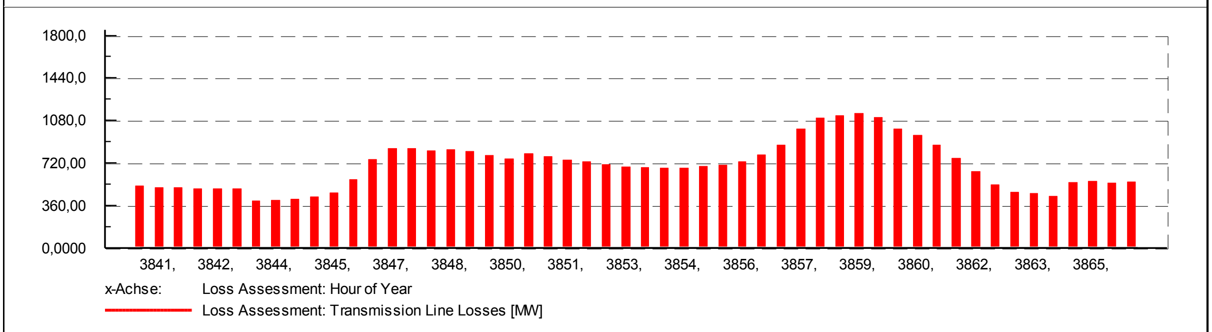
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A 90% Wind	Low Load (1st January) 2x Koeberg Unit(s) Online	Datum: 16.02.2015 Anhang: 2.2.4 /1



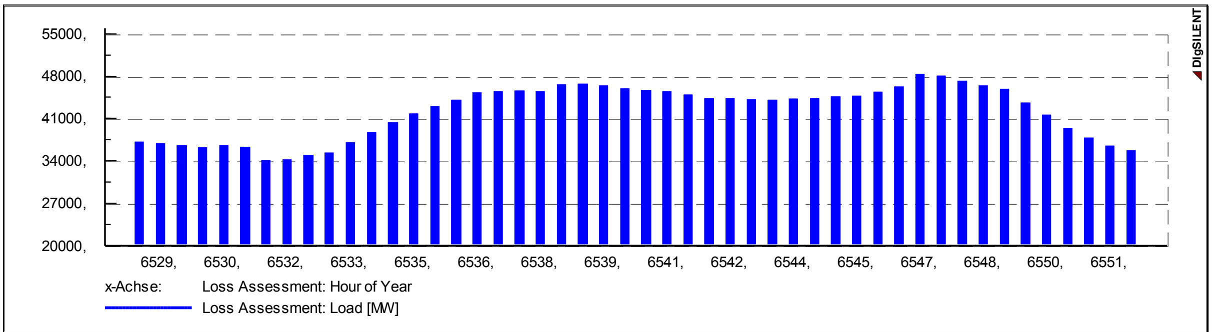


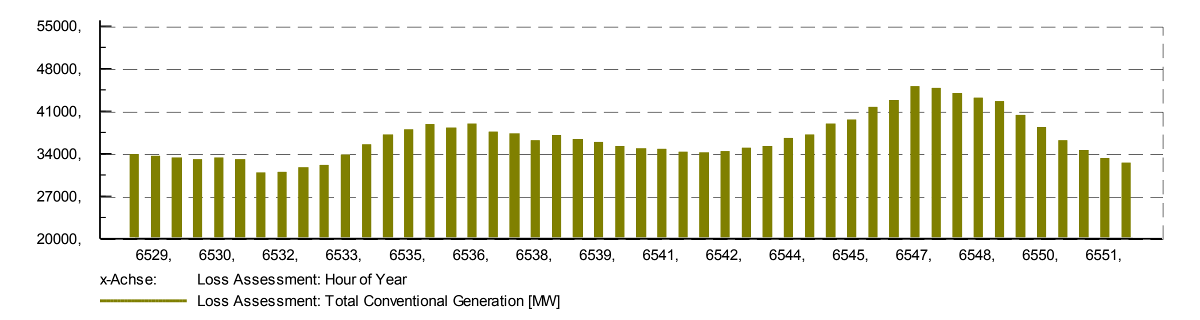


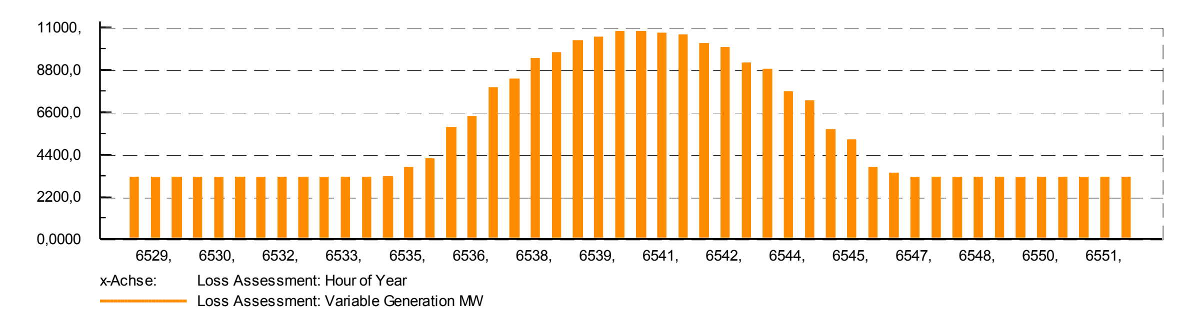


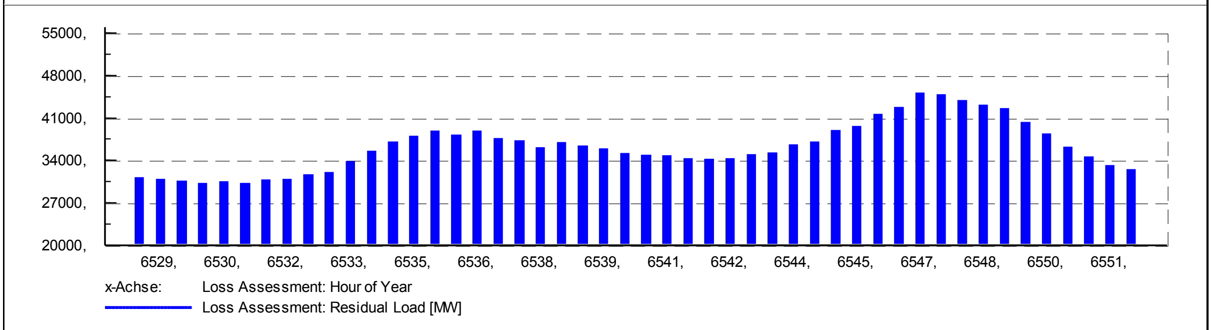


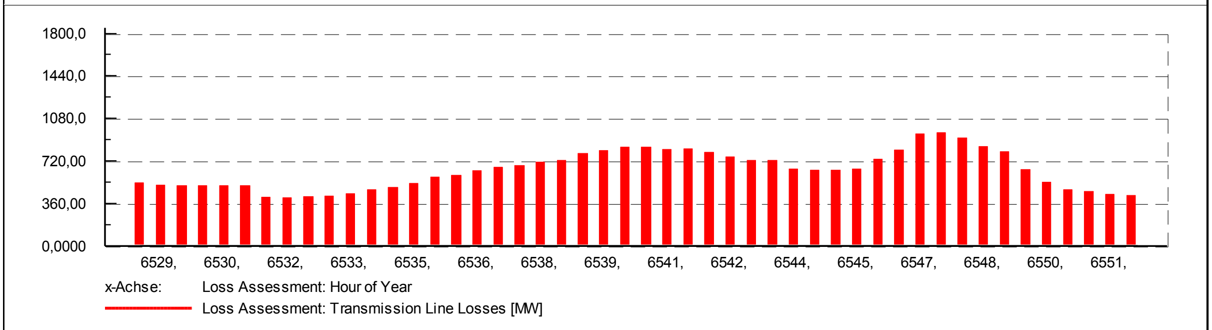
M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	High Load (9th June)	Datum: 16.02.2015
	90% Wind	2x Koeberg Unit(s) Online	Anhang: 2.2.4 /2









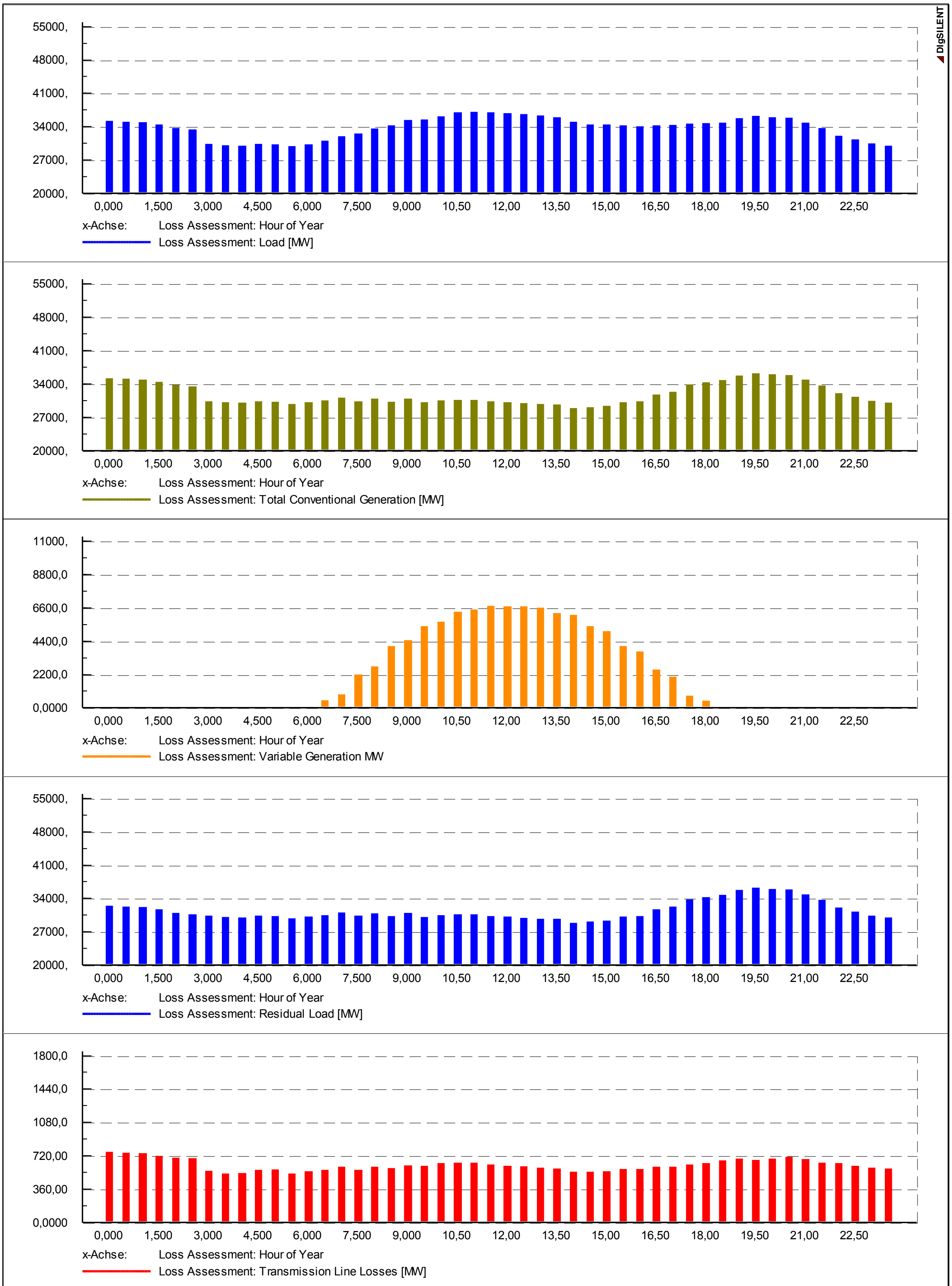


M.P.E. MOELLER & POELLER ENGINEERING	Scenario A	High PV (29th September)	Datum: 16.02.2015
	90% Wind	2x Koeberg Unit(s) Online	Anhang: 2.2.4 /3

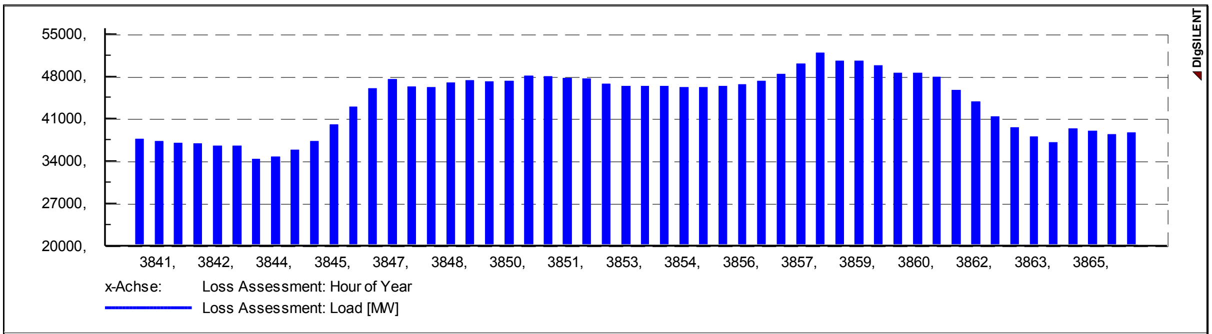
3 Scenario B

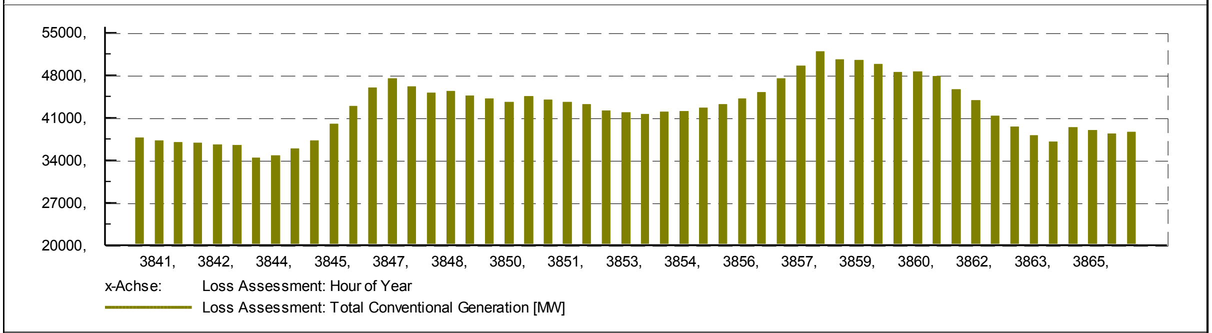
3.1 1x Koeberg Unit(s) Online

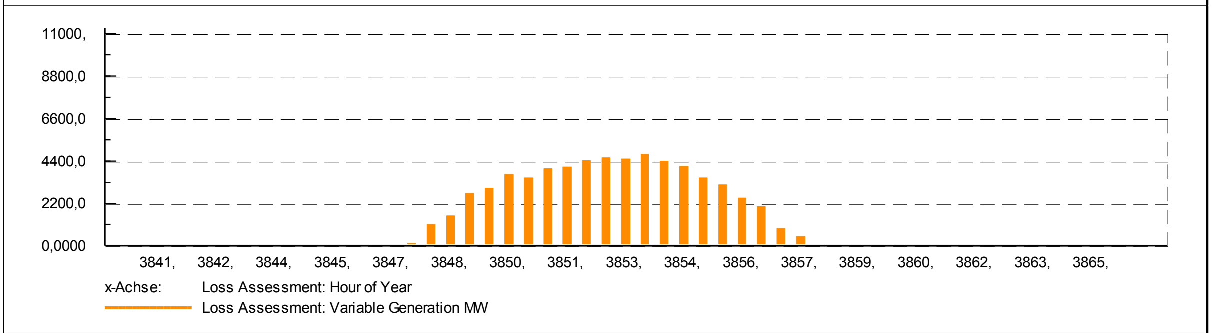
3.1. 00% Wind

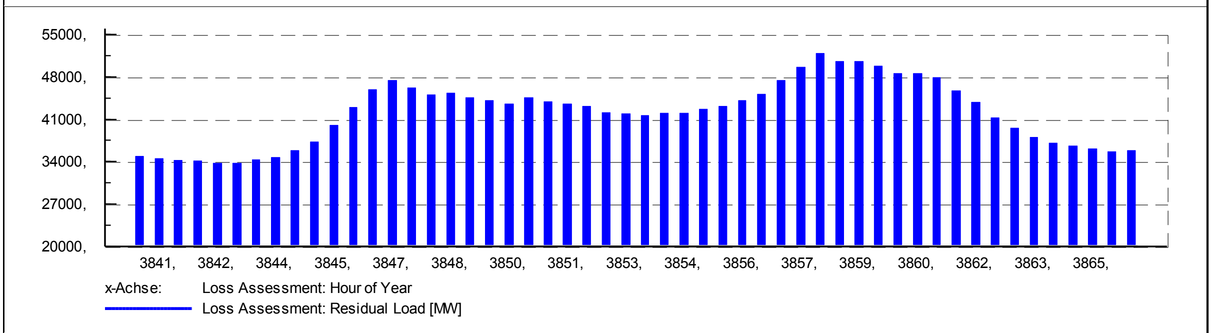


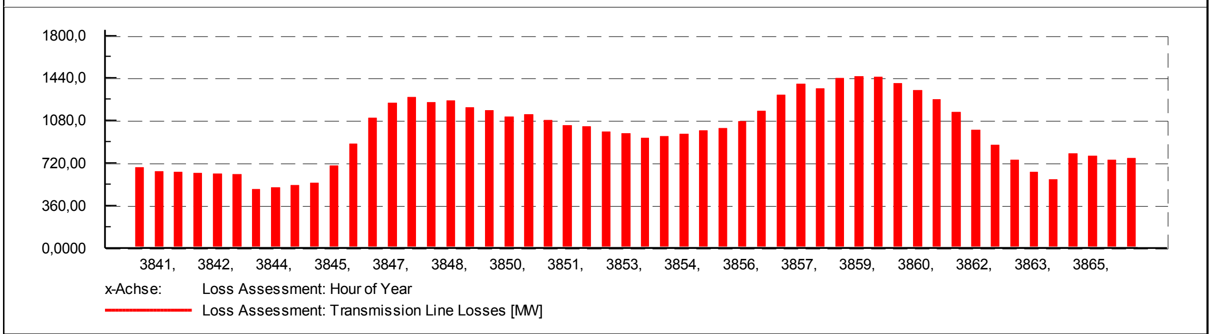
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	Low Load (1st January)	Datum: 16.02.2015
	00% Wind	1x Koeberg Unit(s) Online	Anhang: 3.1.1 /1



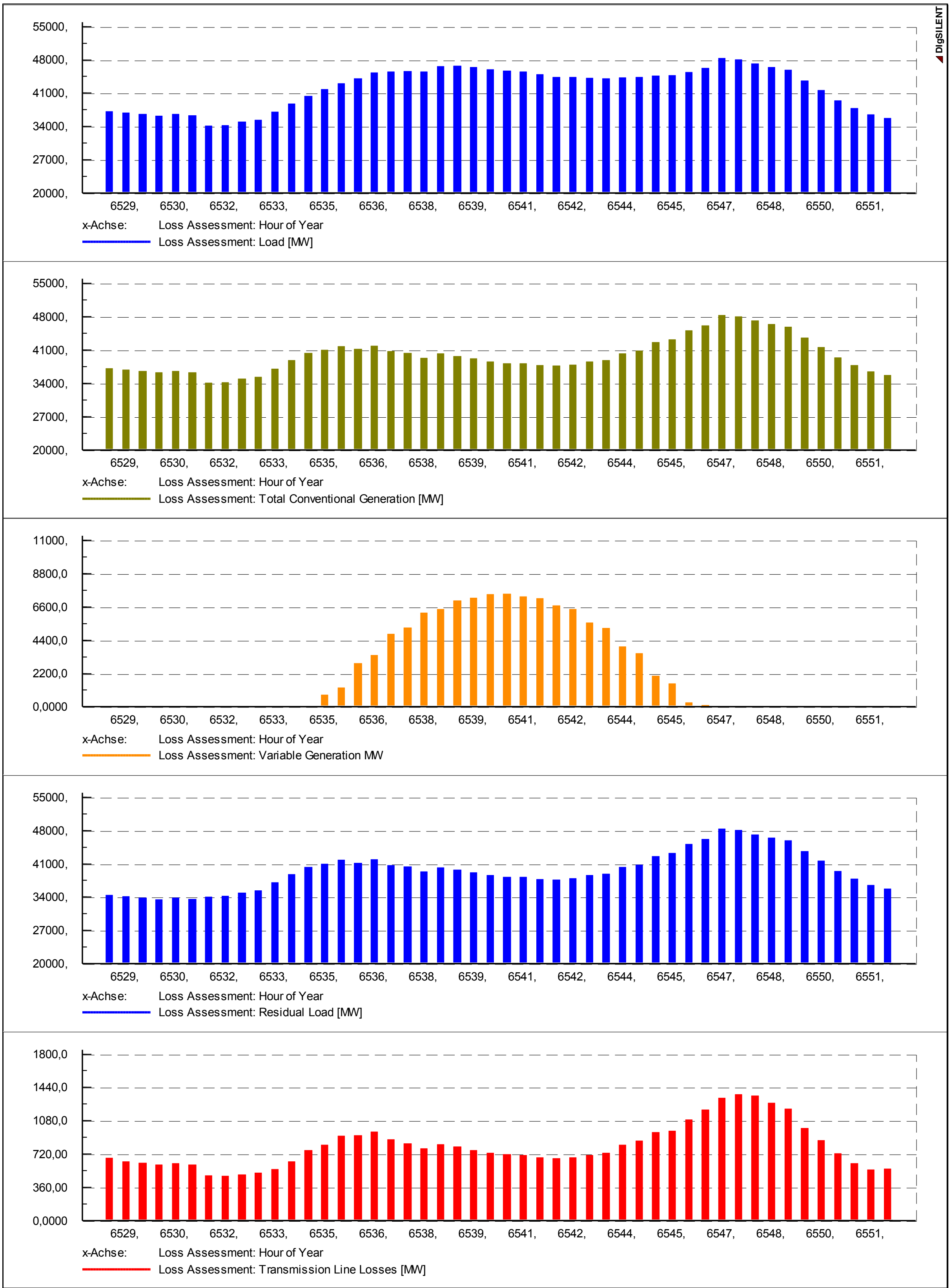








M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	High Load (9th June)	Datum: 16.02.2015
	00% Wind	1x Koeberg Unit(s) Online	Anhang: 3.1.1 /2



M.P.E. MOELLER & POELLER ENGINEERING

Scenario B

High PV (29th September)

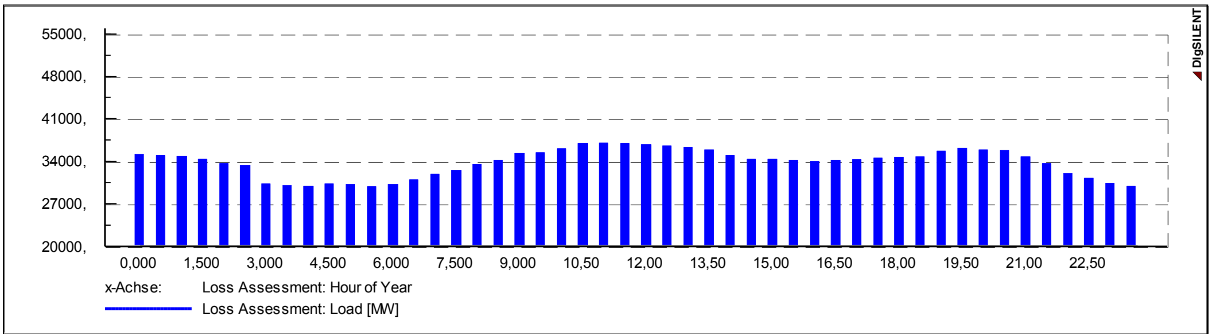
Datum: 16.02.2015

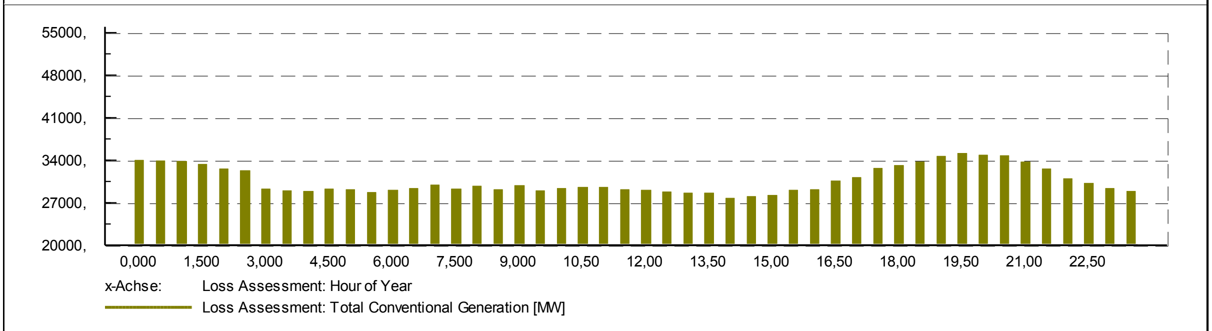
00% Wind

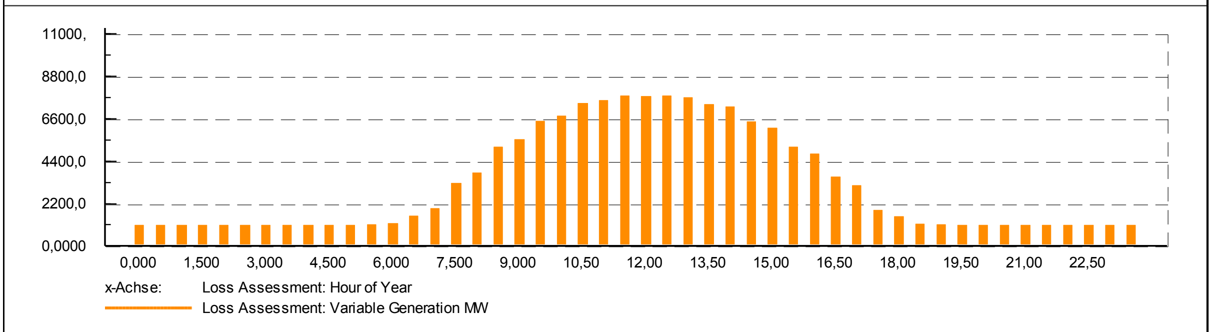
1x Koeberg Unit(s) Online

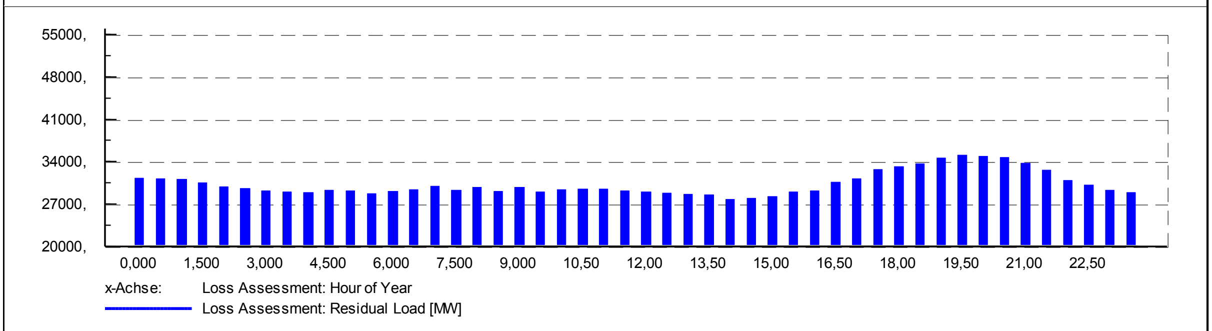
Anhang: 3.1.1 /3

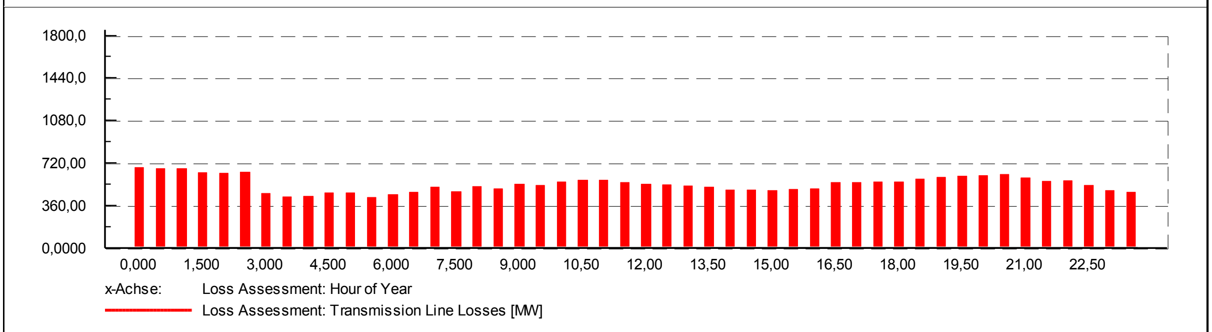
3.1.2 30% Wind



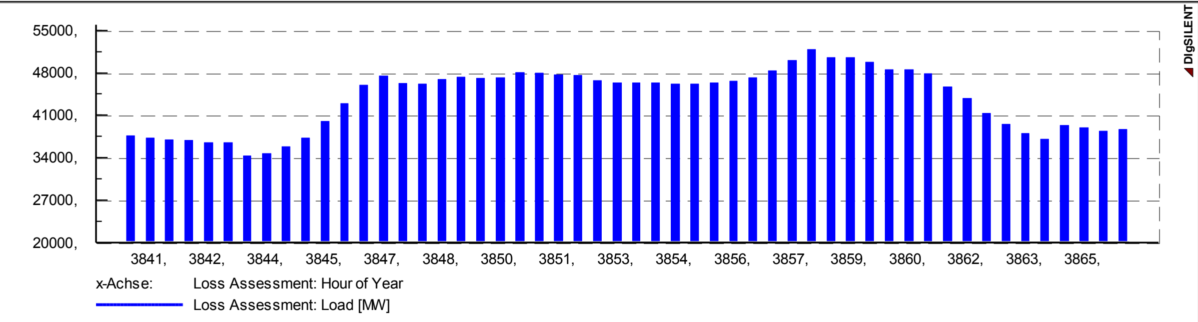


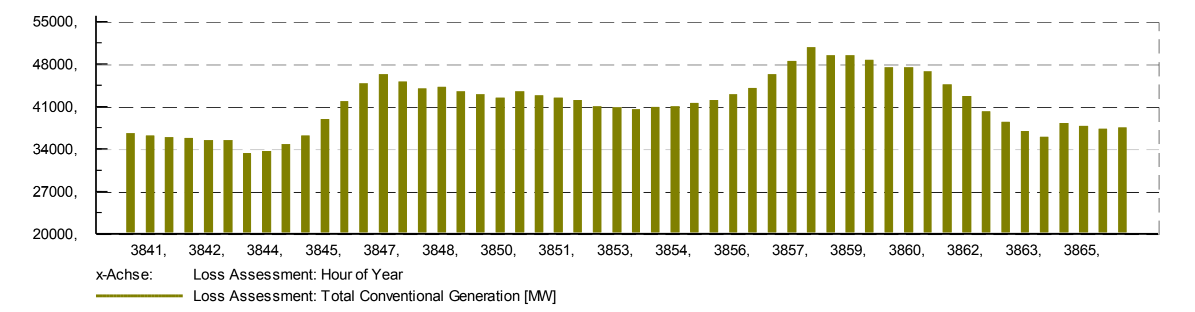


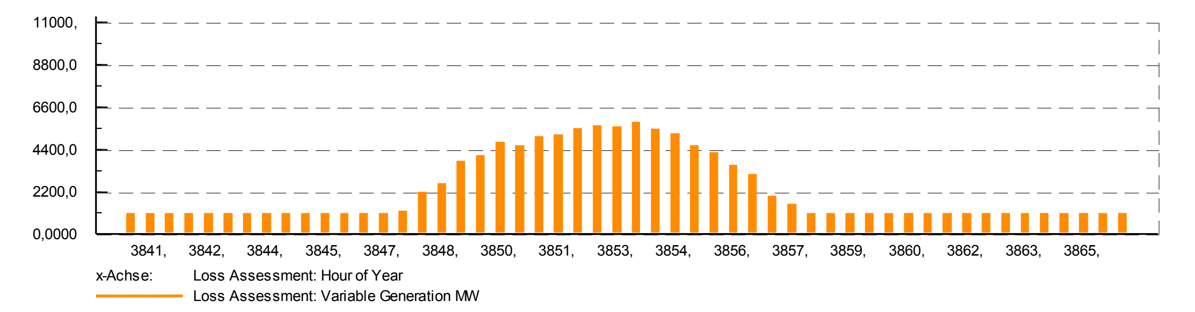


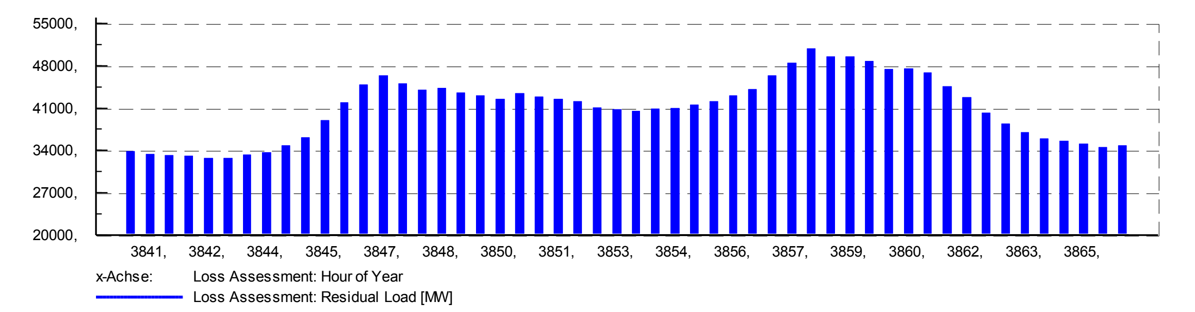


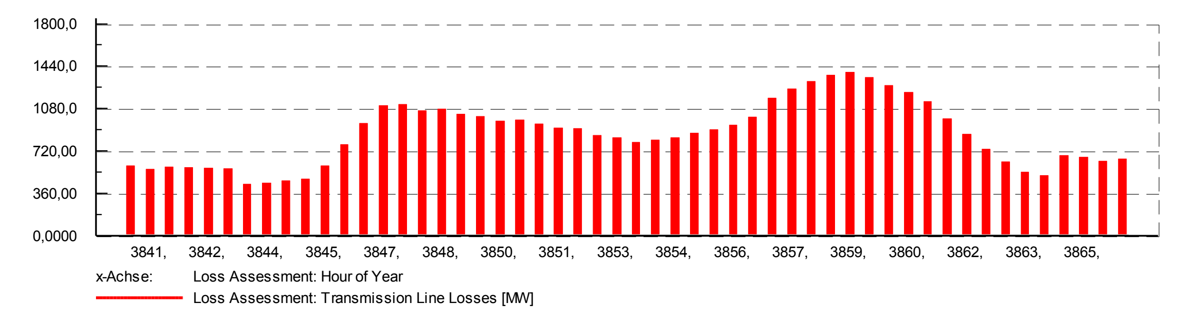
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	Low Load (1st January)	Datum: 16.02.2015
	30% Wind	1x Koeberg Unit(s) Online	Anhang: 3.1.2 /1



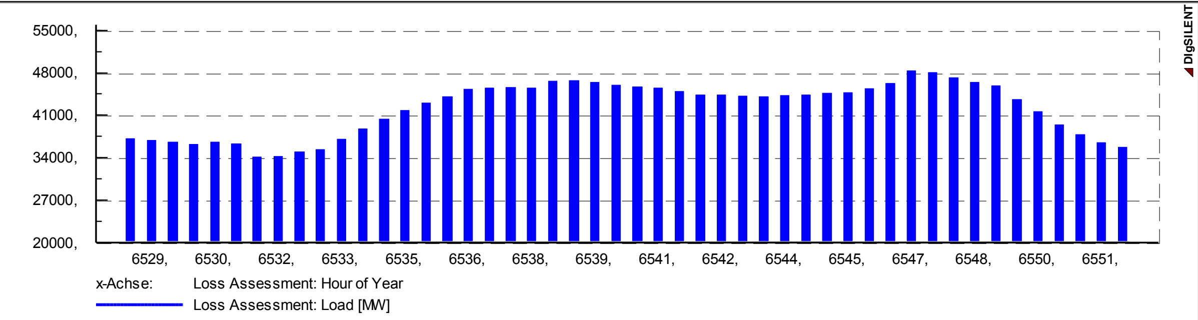


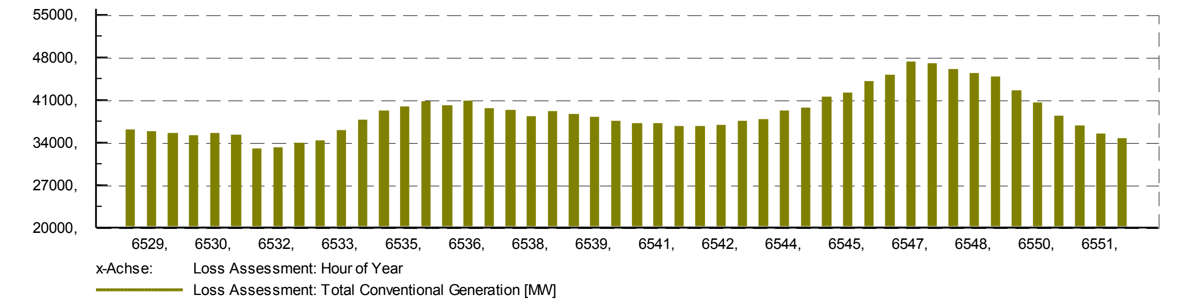


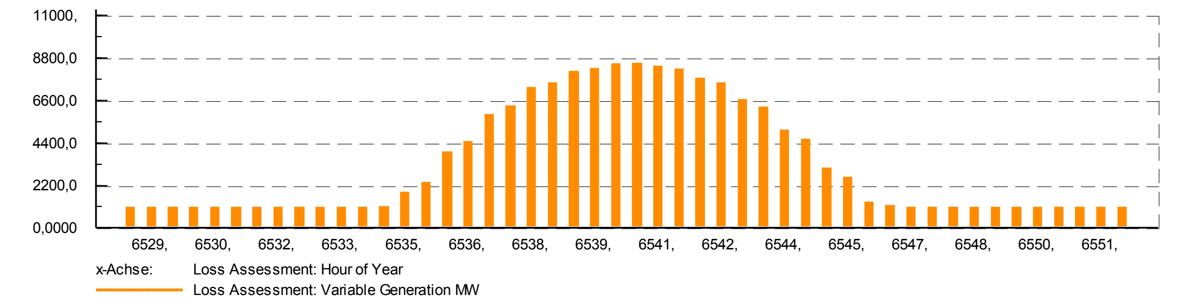


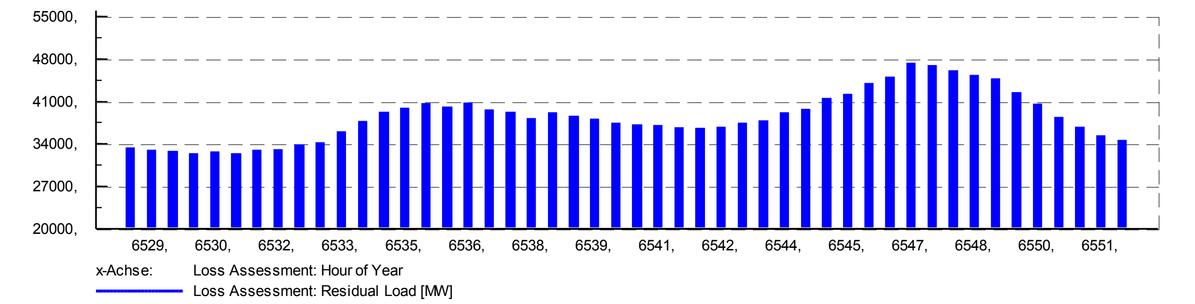


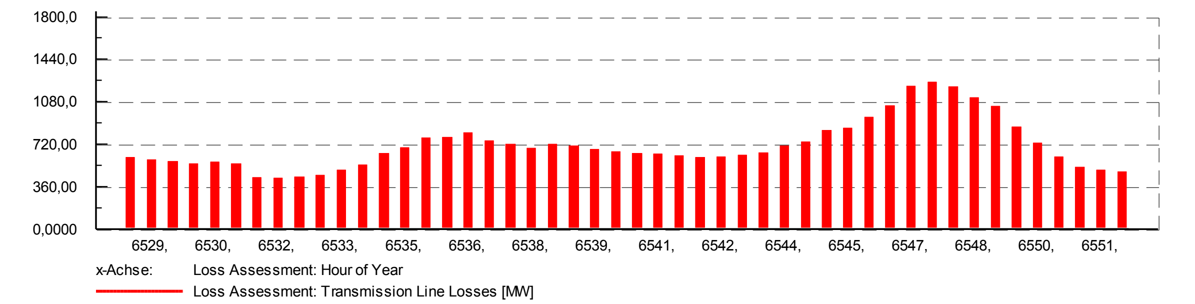
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	High Load (9th June)	Datum: 16.02.2015
	30% Wind	1x Koeberg Unit(s) Online	Anhang: 3.1.2 /2





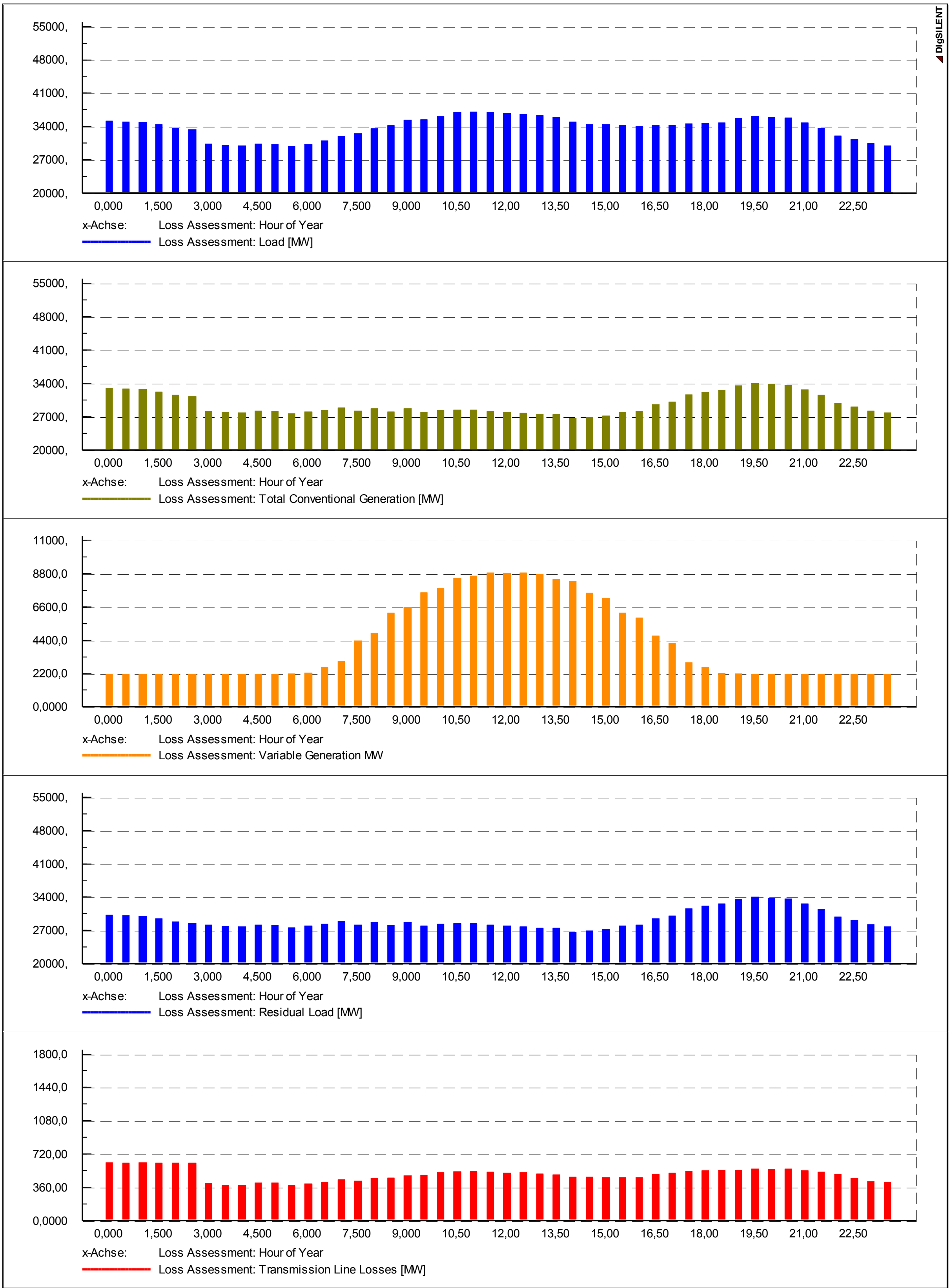




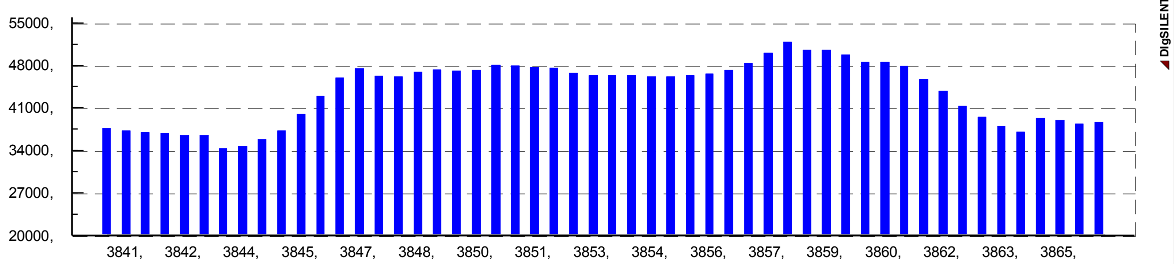


M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	High PV (29th September)	Datum: 16.02.2015
	30% Wind	1x Koeberg Unit(s) Online	Anhang: 3.1.2 /3

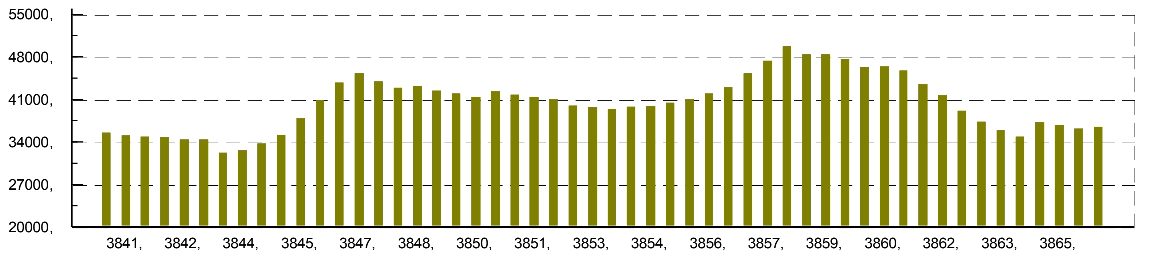
3.1.3 60% Wind



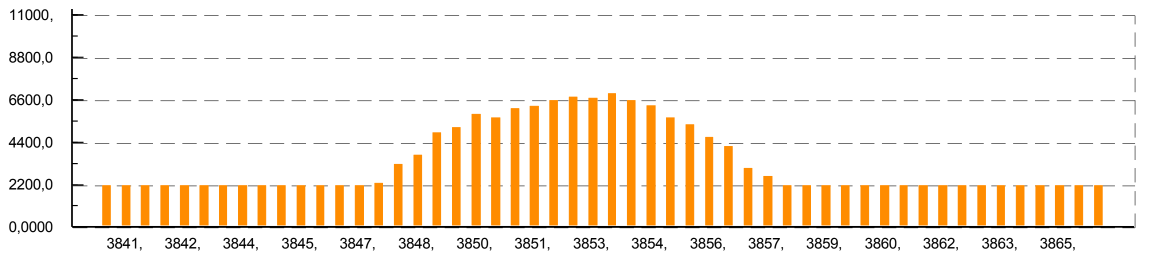
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	Low Load (1st January)	Datum: 16.02.2015
	60% Wind	1x Koeberg Unit(s) Online	Anhang: 3.1.3 /1



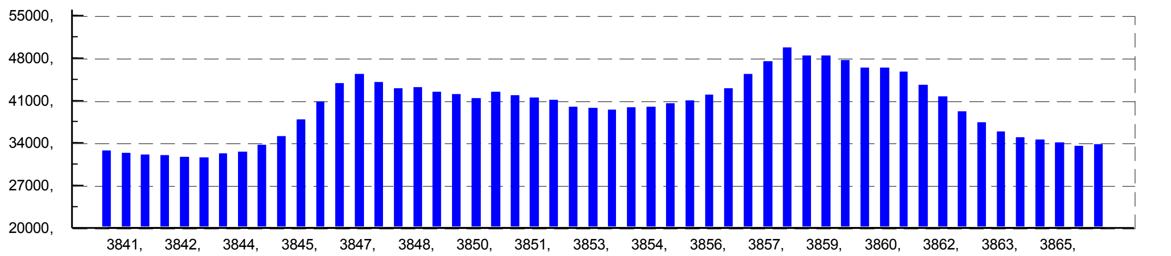
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Load [MW]



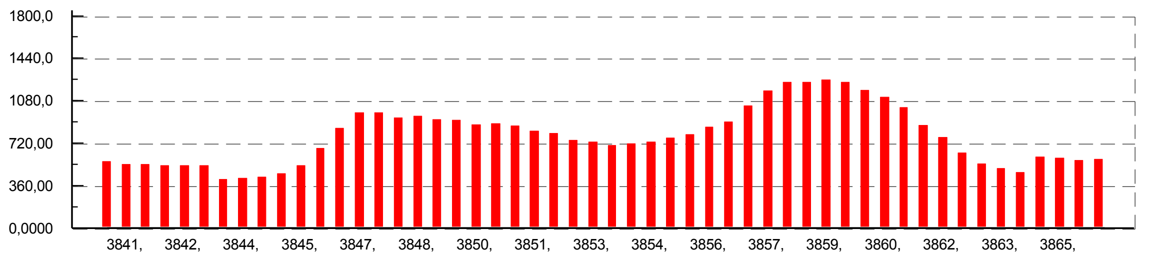
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Total Conventional Generation [MW]



x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Variable Generation MW

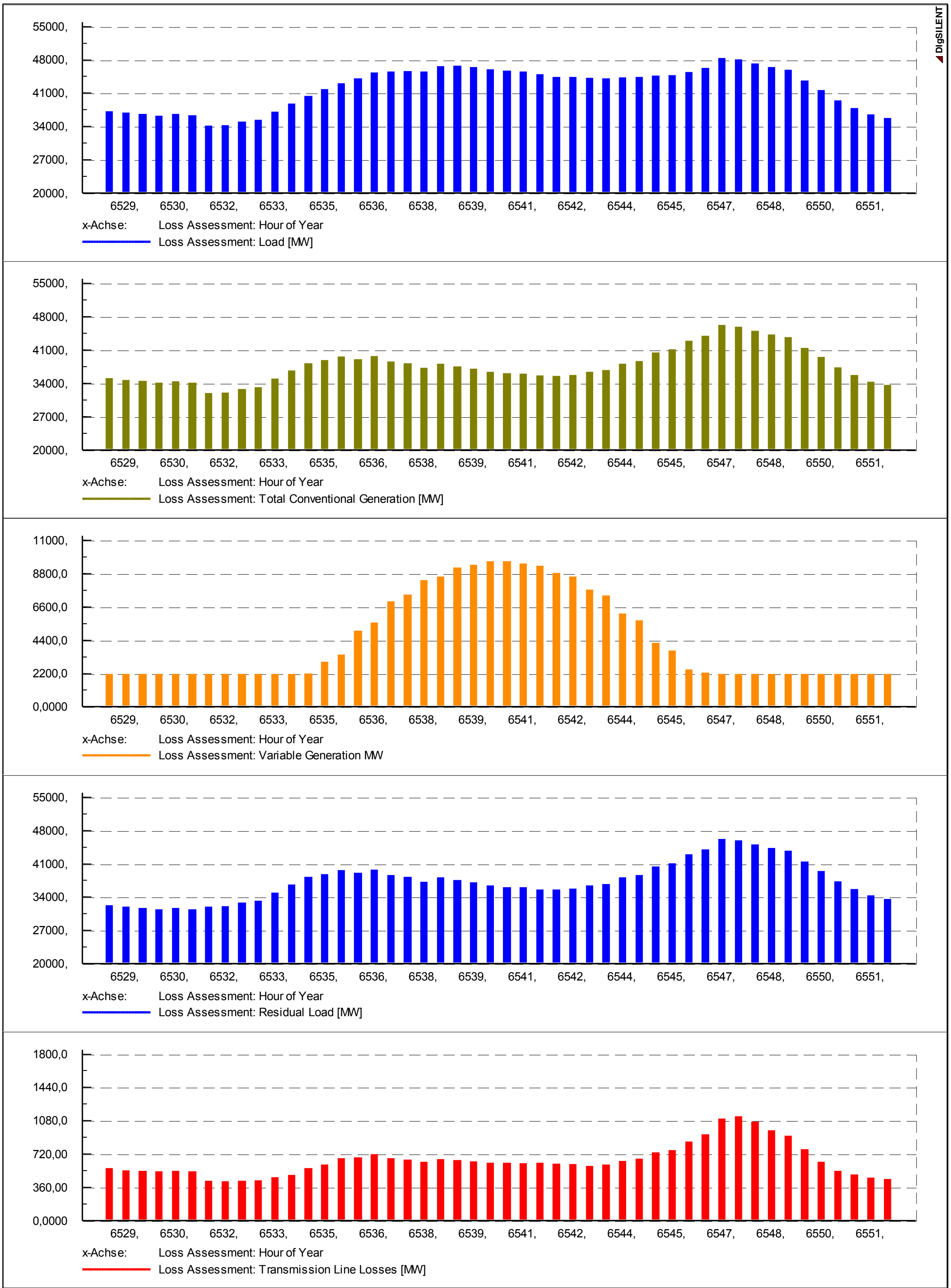


x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Residual Load [MW]



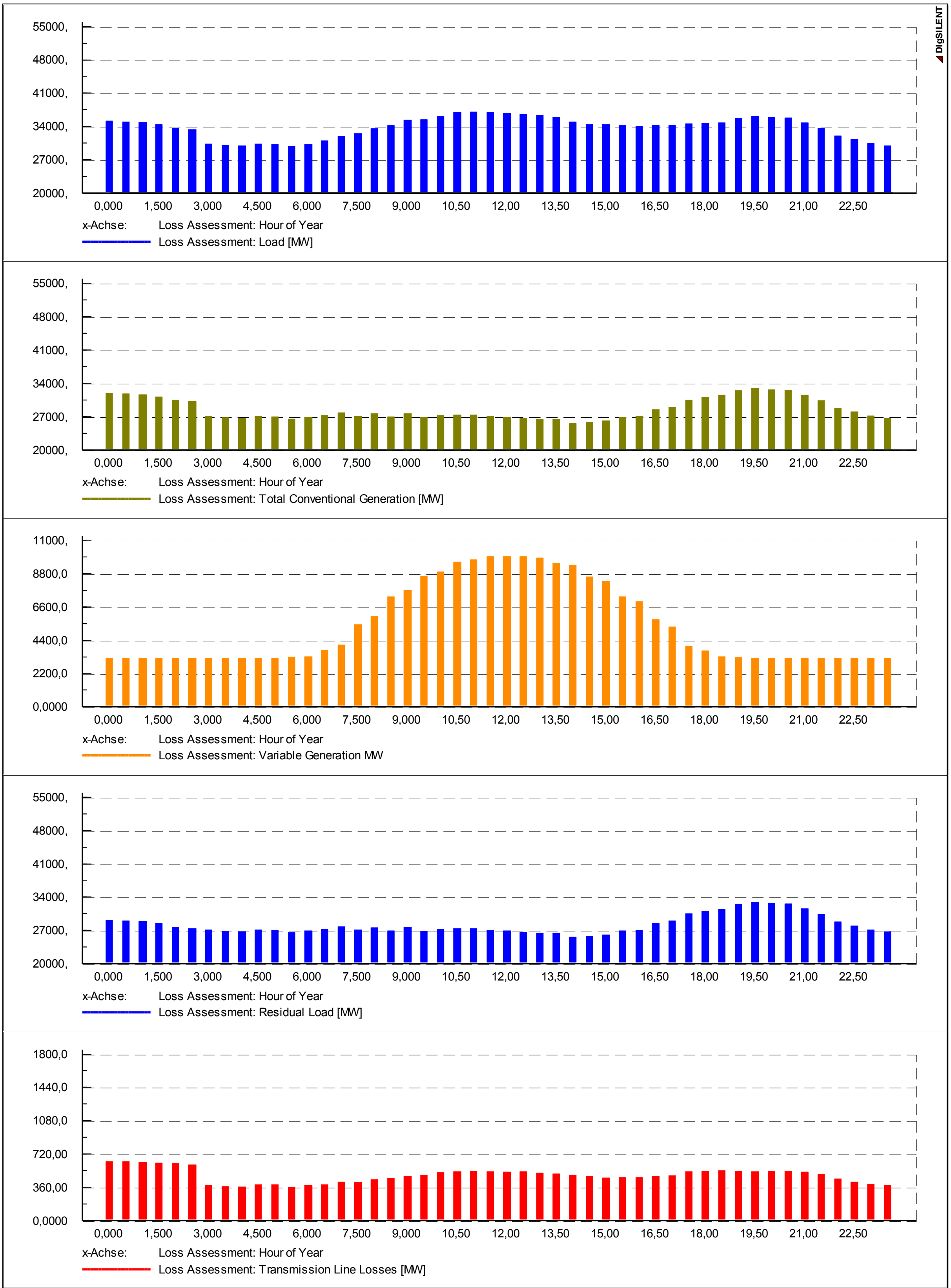
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Transmission Line Losses [MW]

M.P.E. MOELLER & POELLER ENGINEERING	Scenario B / 60% Wind	High Load (9th June) / 1x Koeberg Unit(s) Online	Datum: 16.02.2015 / Anhang: 3.1.3 /2

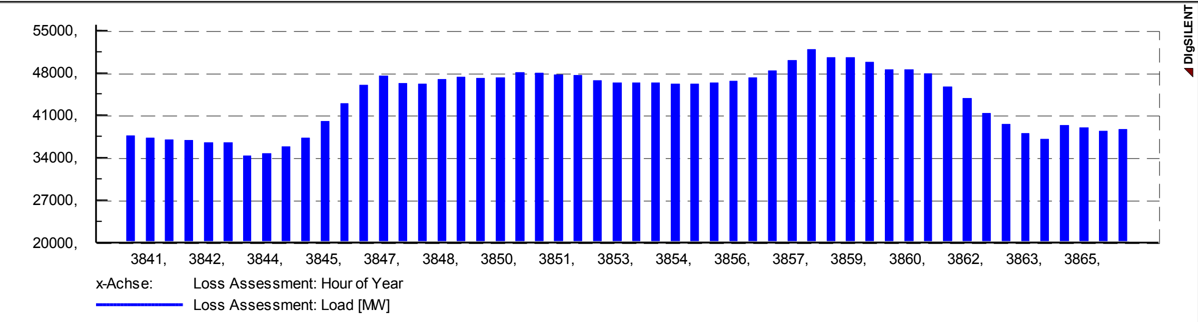


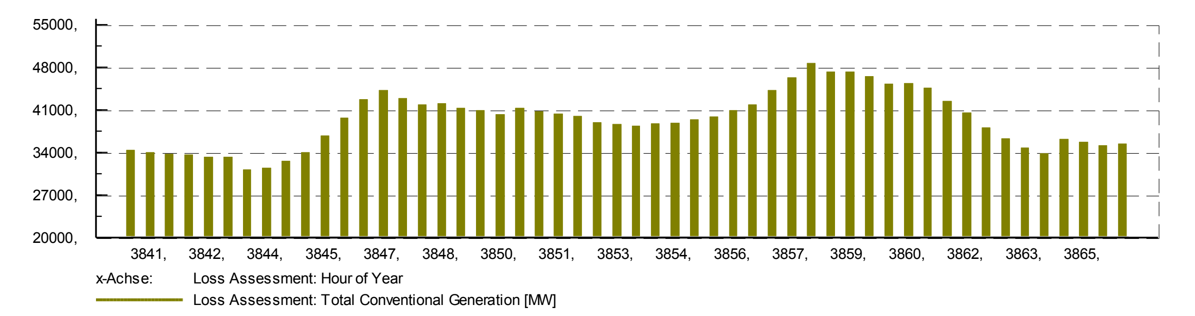
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	High PV (29th September)	Datum: 16.02.2015
	60% Wind	1x Koeberg Unit(s) Online	Anhang: 3.1.3 /3

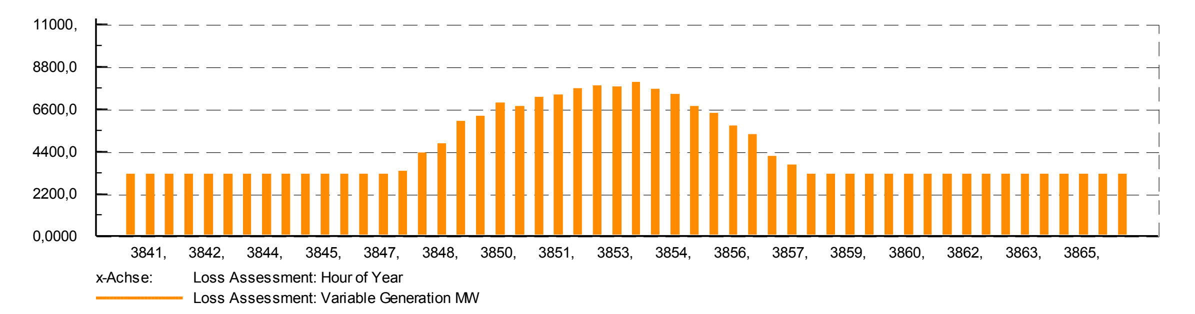
3.1.4 90% Wind

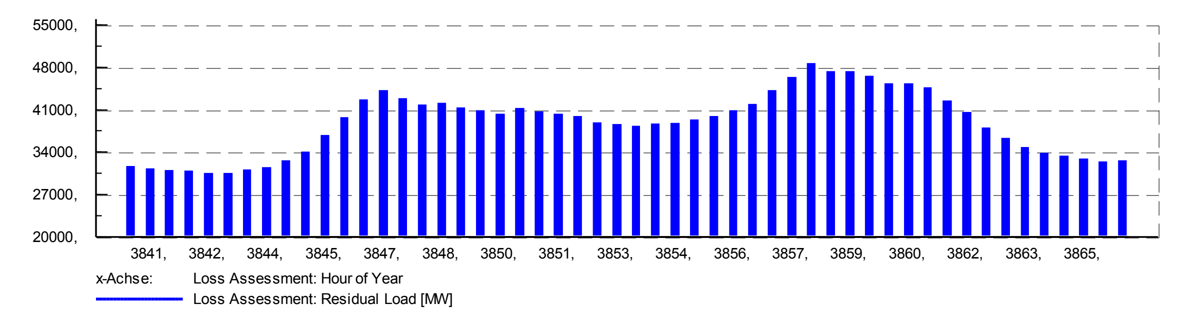


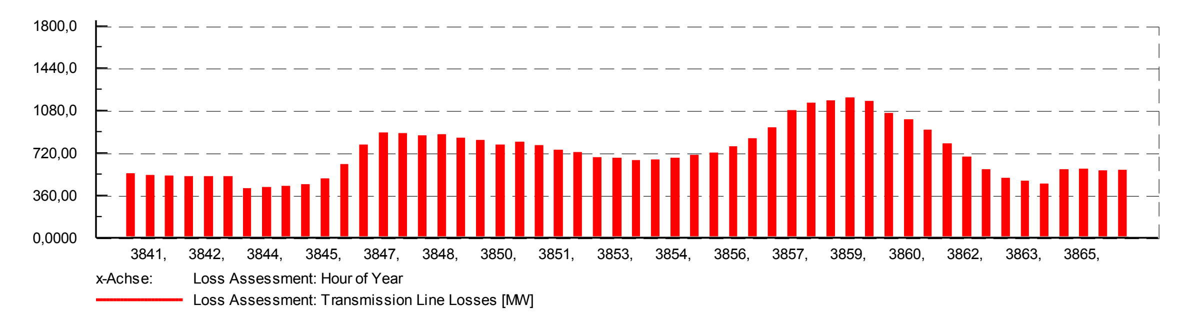
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	Low Load (1st January)	Datum: 16.02.2015
	90% Wind	1x Koeberg Unit(s) Online	Anhang: 3.1.4 /1



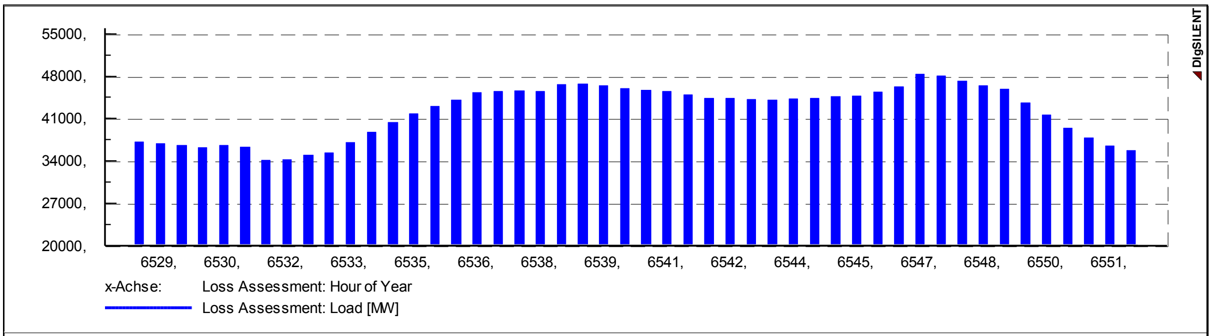


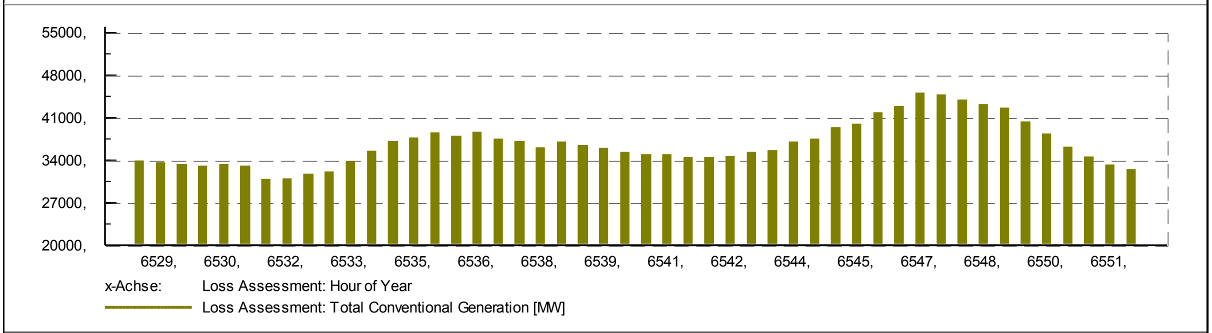


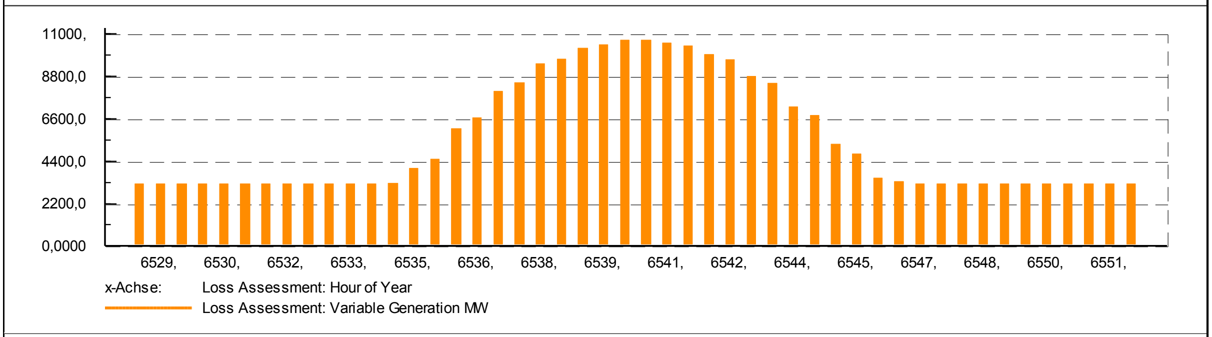


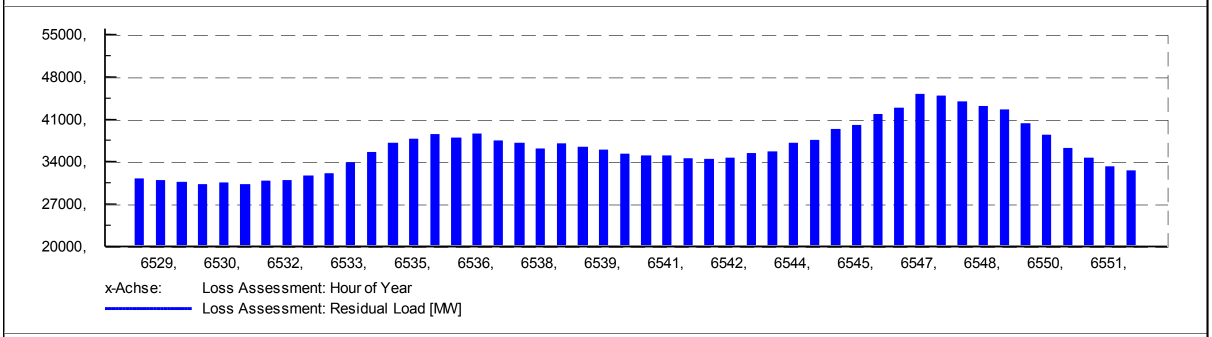


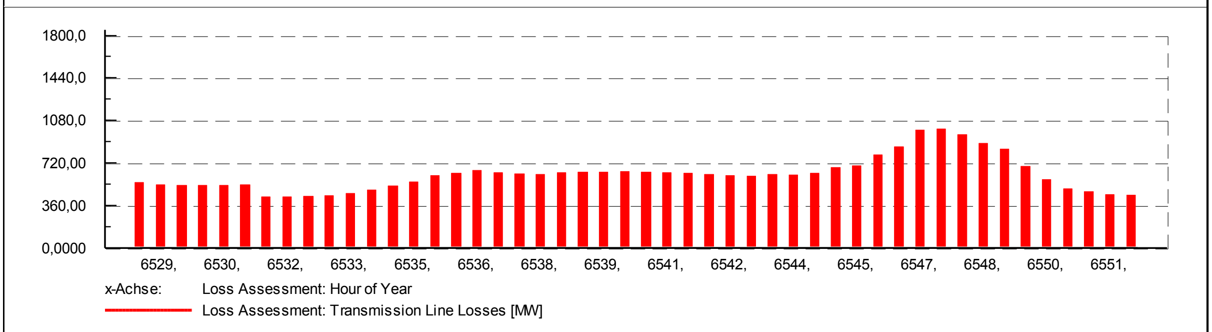
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	High Load (9th June)	Datum: 16.02.2015
	90% Wind	1x Koeberg Unit(s) Online	Anhang: 3.1.4 /2







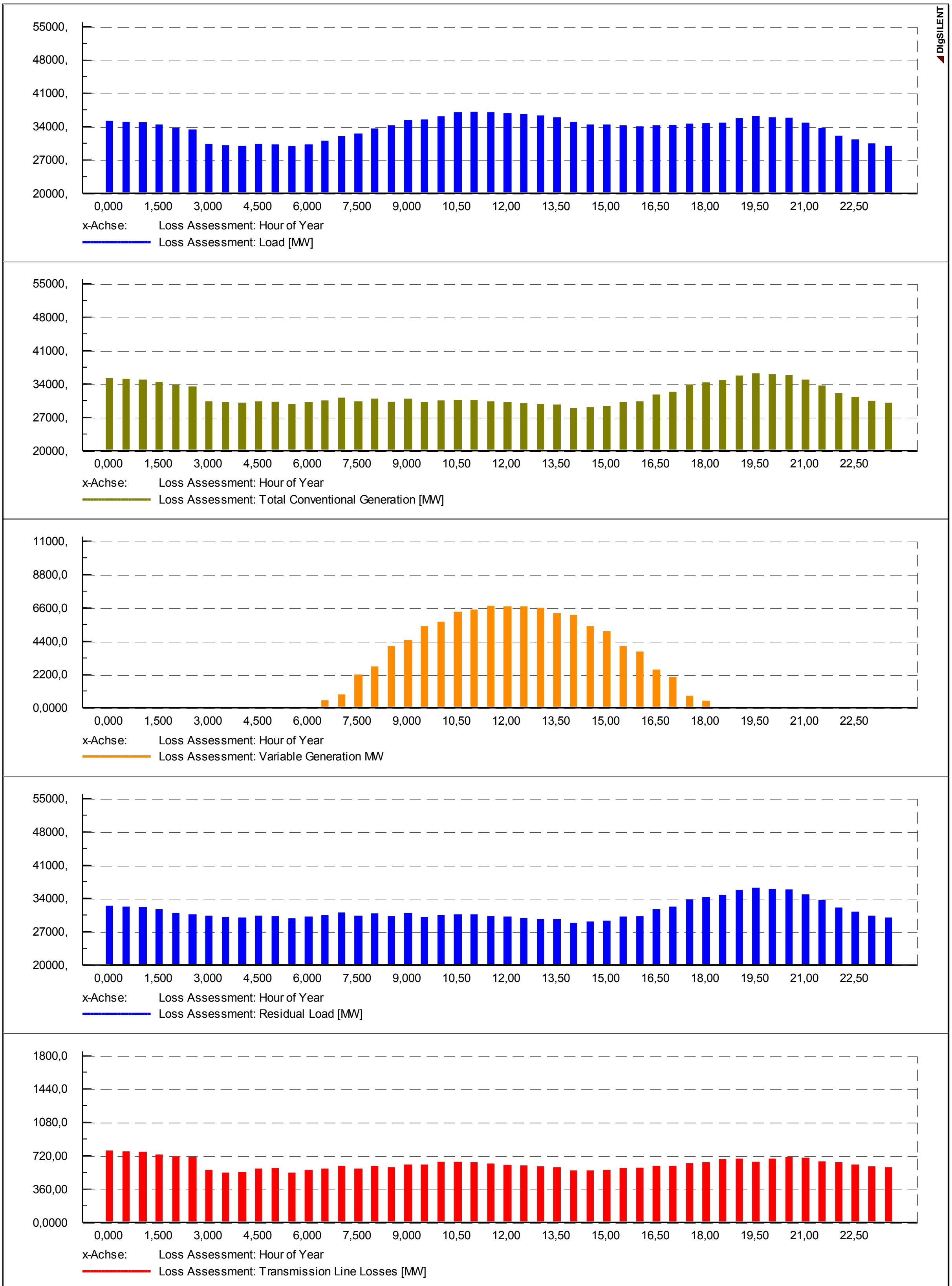




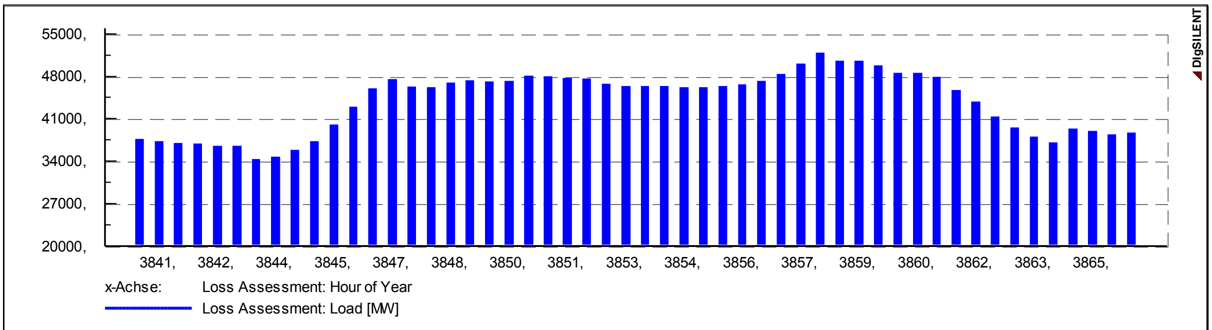
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	High PV (29th September)	Datum: 16.02.2015
	90% Wind	1x Koeberg Unit(s) Online	Anhang: 3.1.4 /3

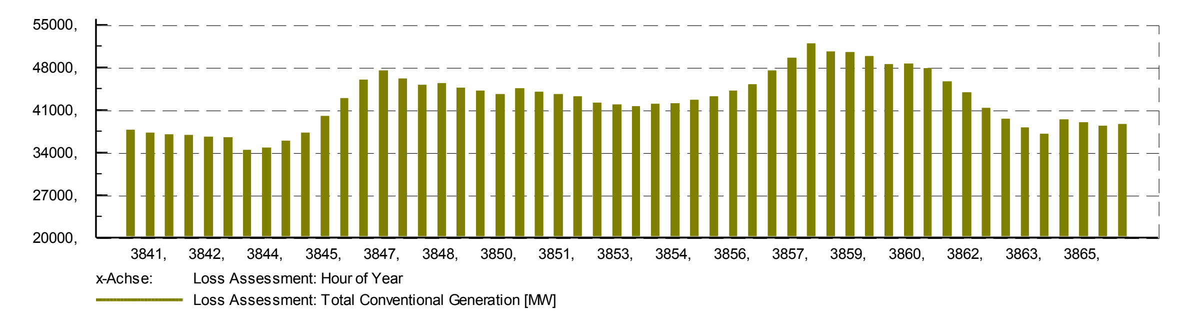
3.2 2x Koeberg Unit(s) Online

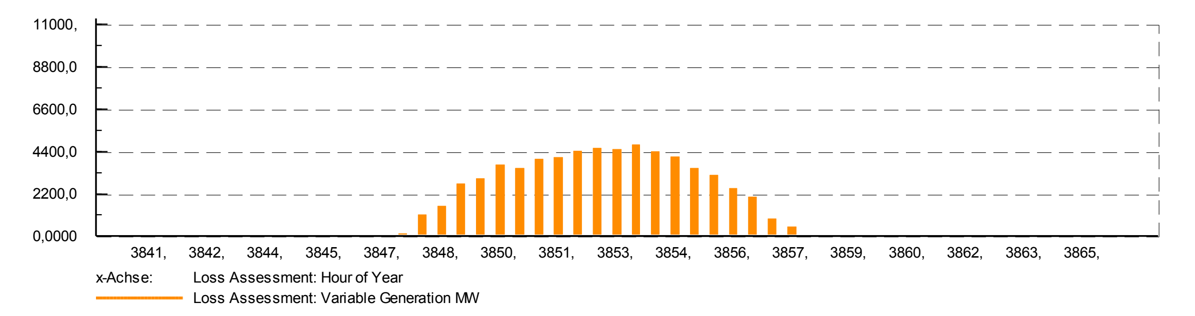
3.2.1 00% Wind

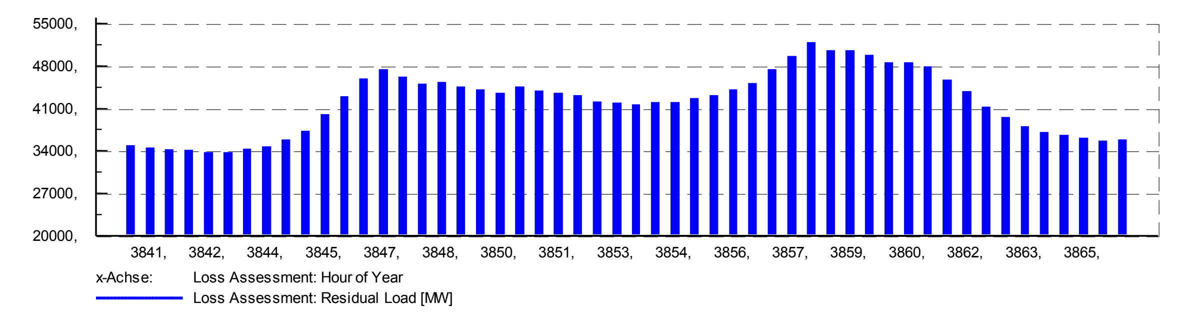


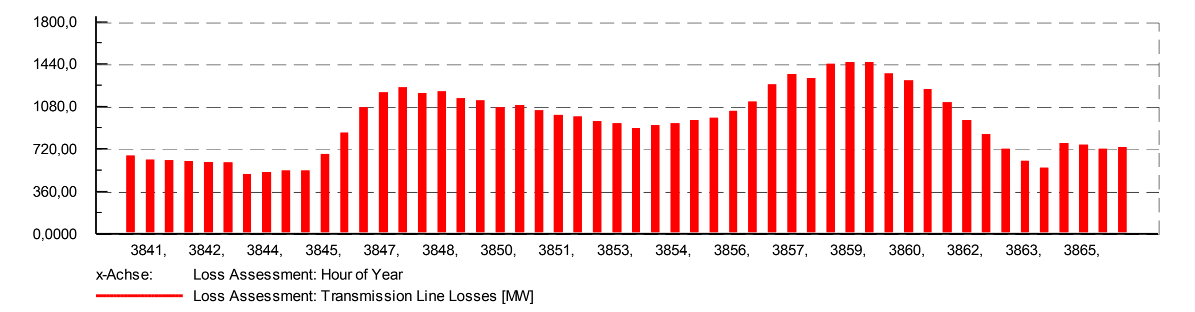
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	Low Load (1st January)	Datum: 16.02.2015
	00% Wind	2x Koeberg Unit(s) Online	Anhang: 3.2.1 /1



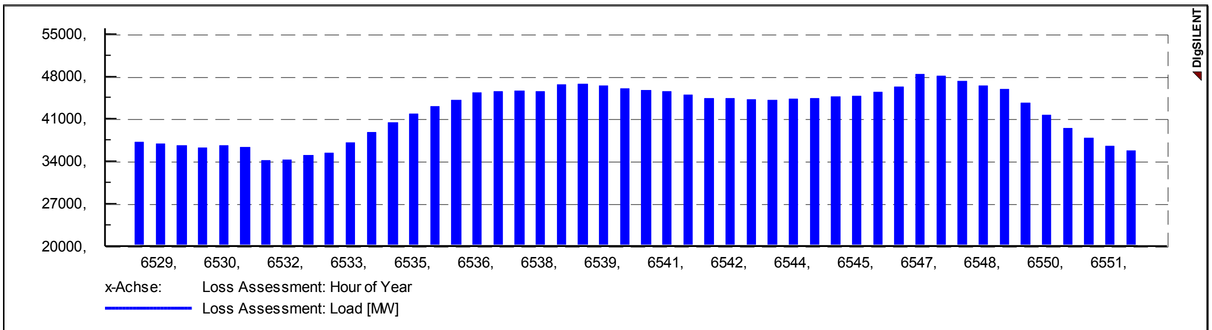


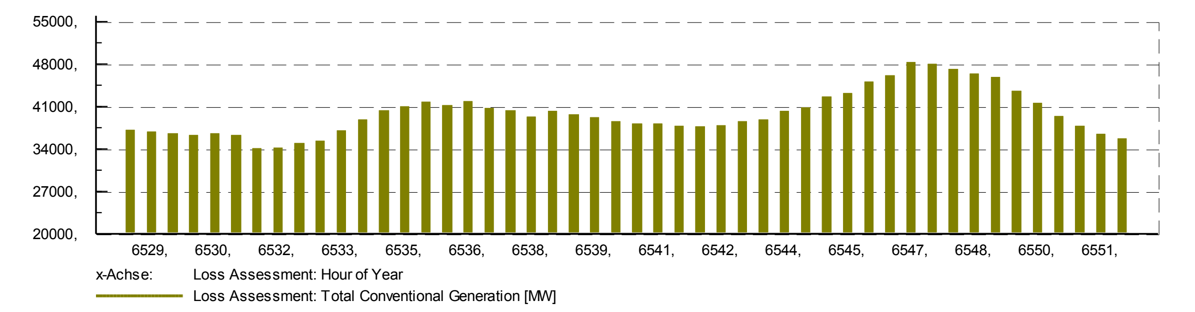


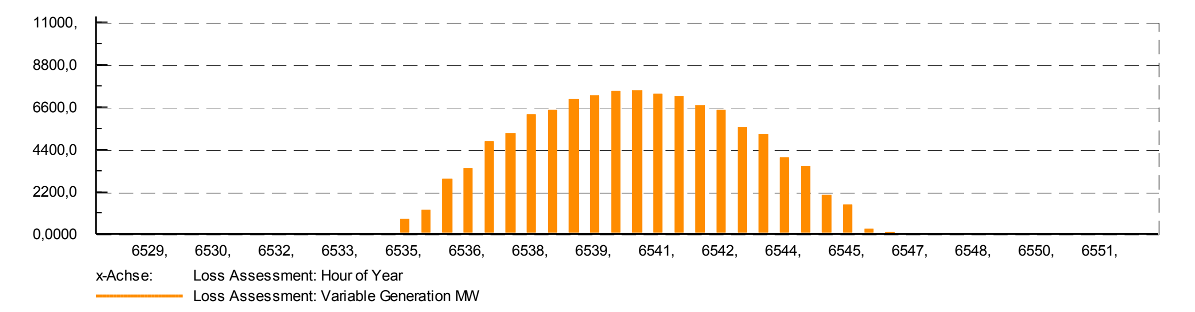


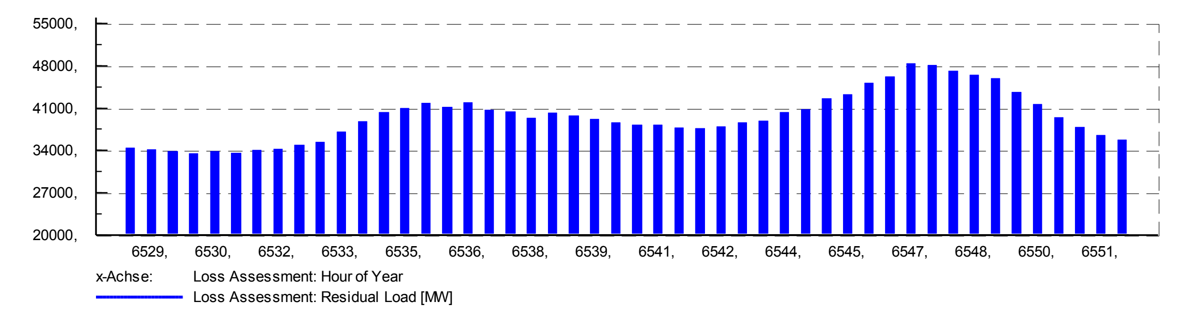


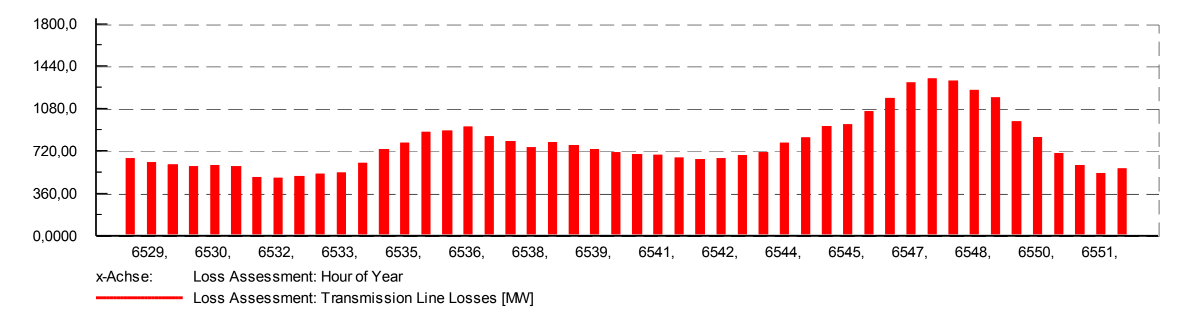
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	High Load (9th June)	Datum: 16.02.2015
	00% Wind	2x Koeberg Unit(s) Online	Anhang: 3.2.1 /2





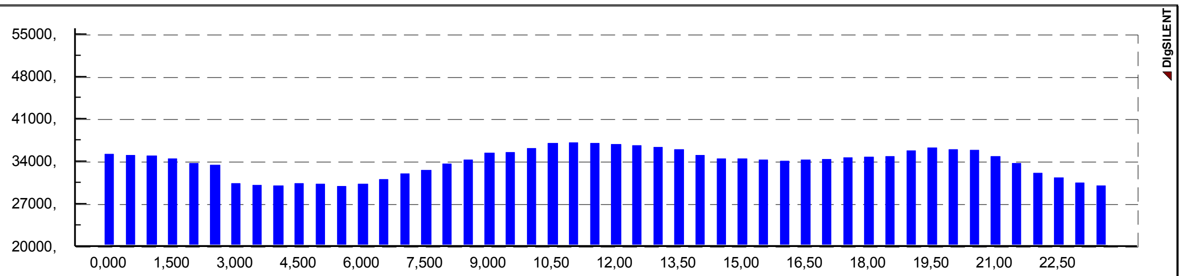




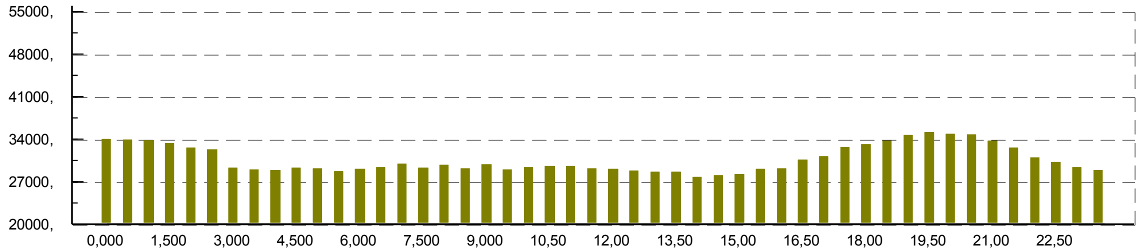


M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	High PV (29th September)	Datum: 16.02.2015
	00% Wind	2x Koeberg Unit(s) Online	Anhang: 3.2.1 /3

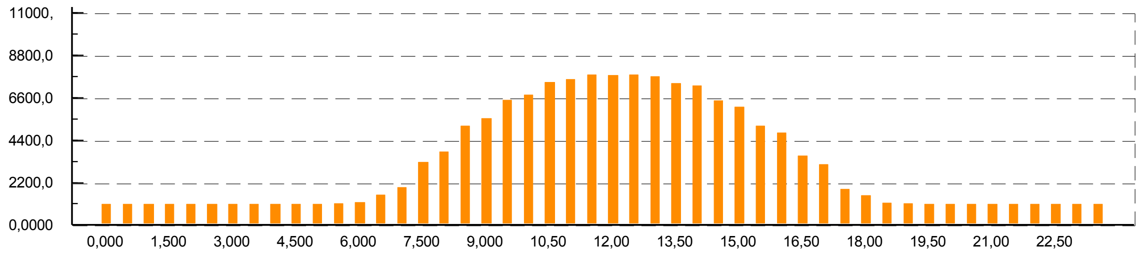
3.2.2 30% Wind



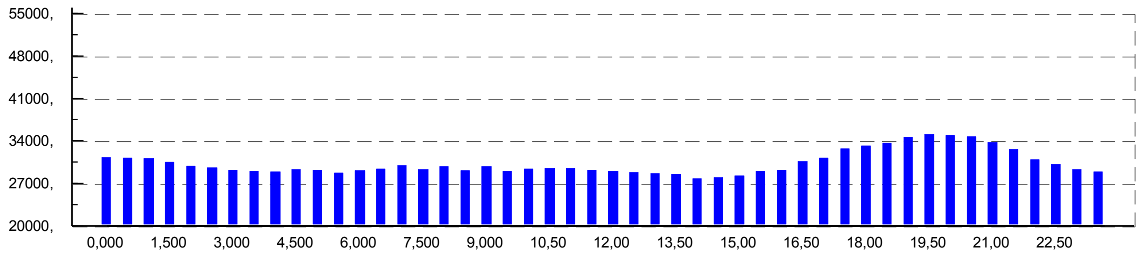
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Load [MW]



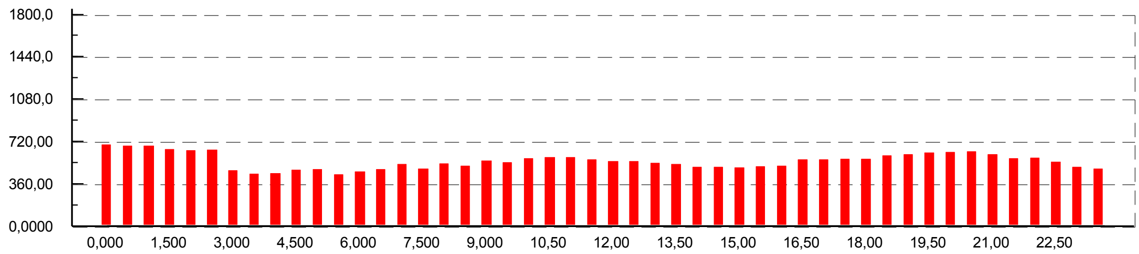
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Total Conventional Generation [MW]



x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Variable Generation MW

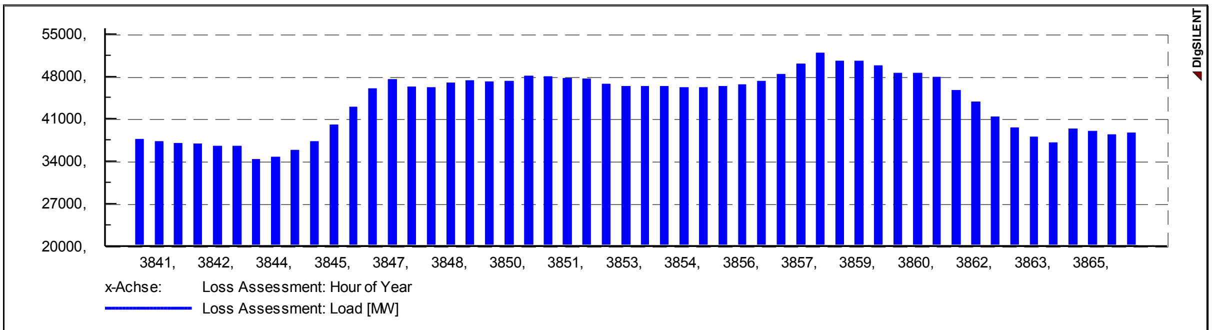


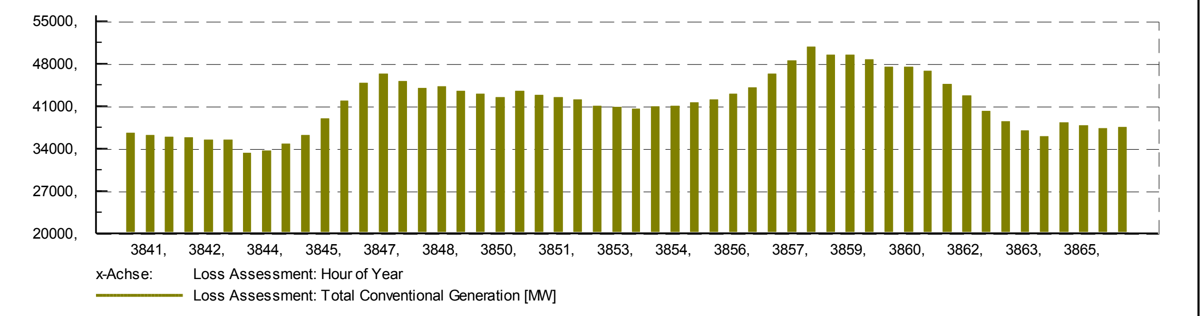
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Residual Load [MW]

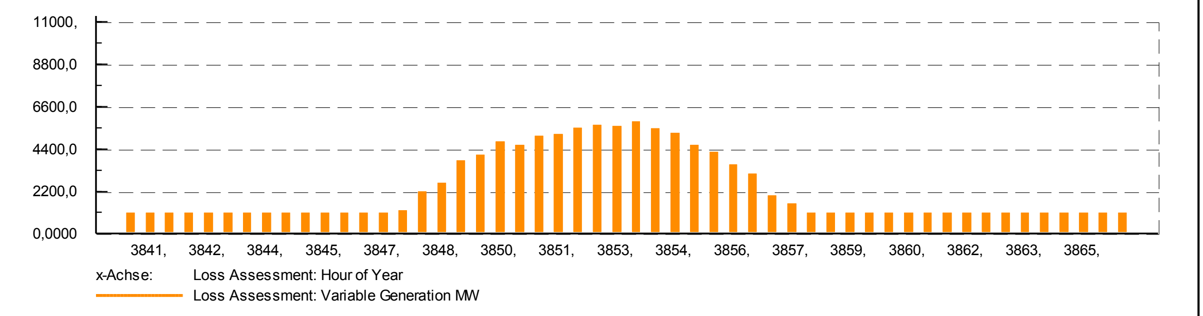


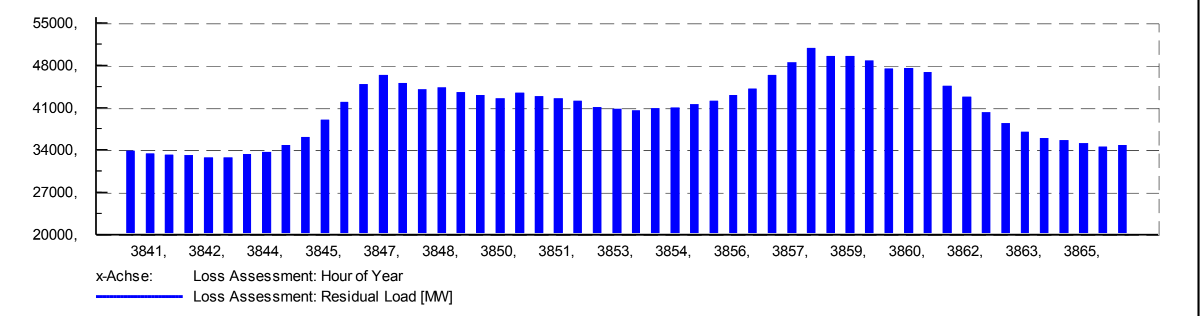
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Transmission Line Losses [MW]

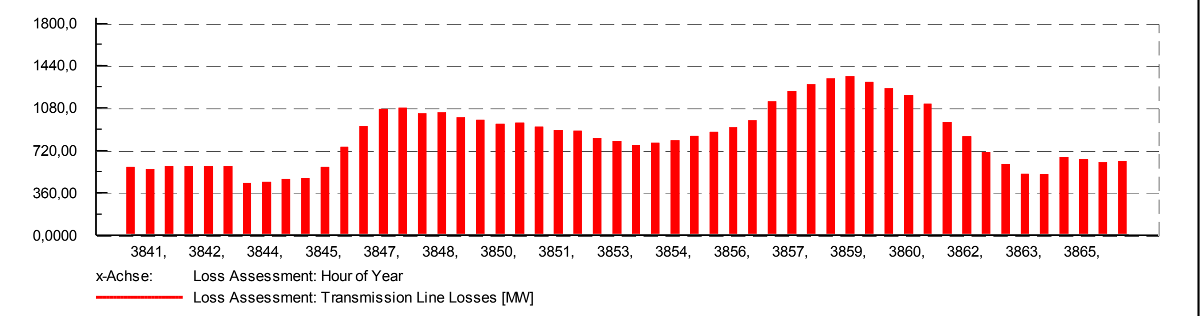
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	Low Load (1st January)	Datum: 16.02.2015
	30% Wind	2x Koeberg Unit(s) Online	Anhang: 3.2.2 /1



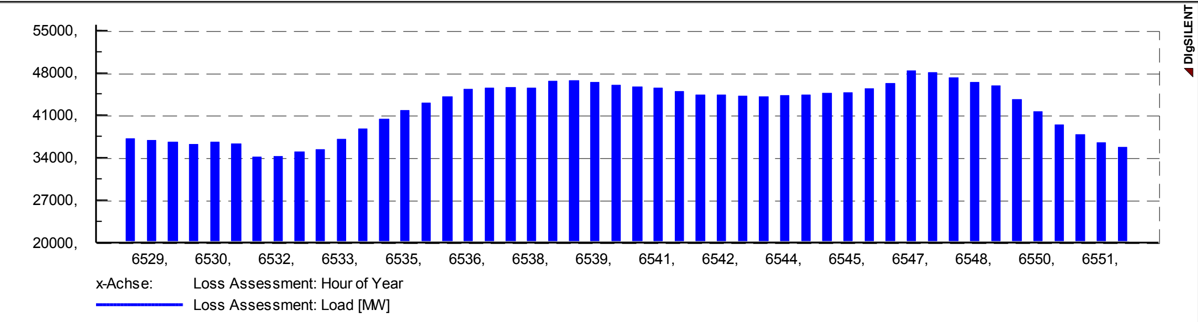


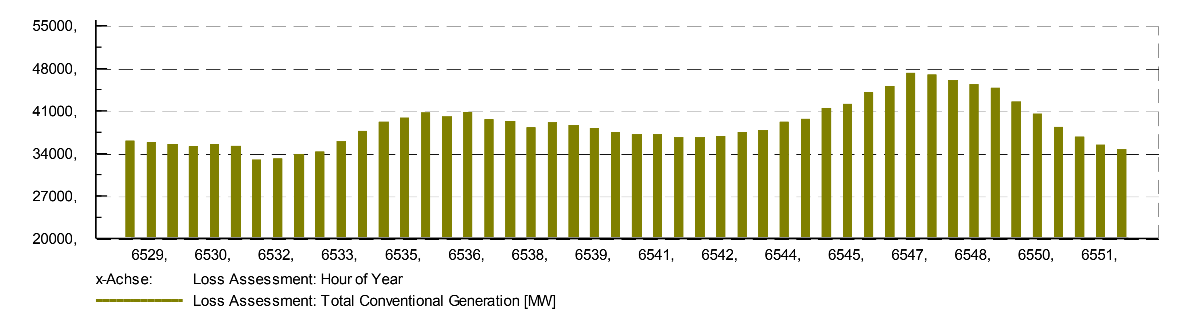


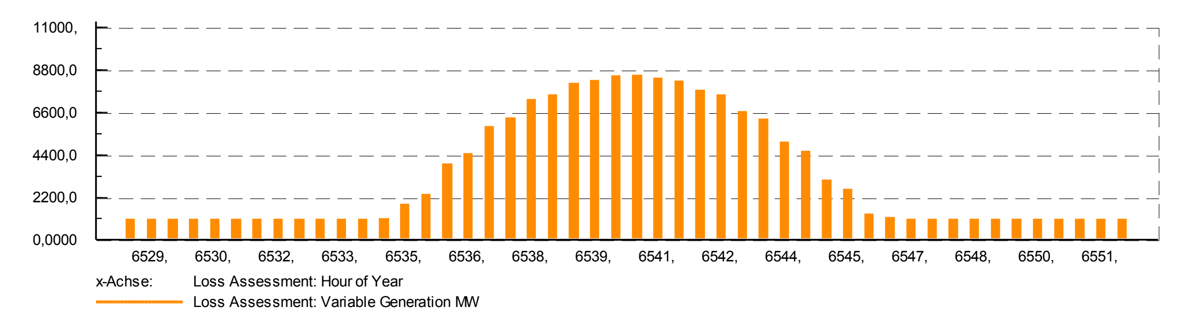


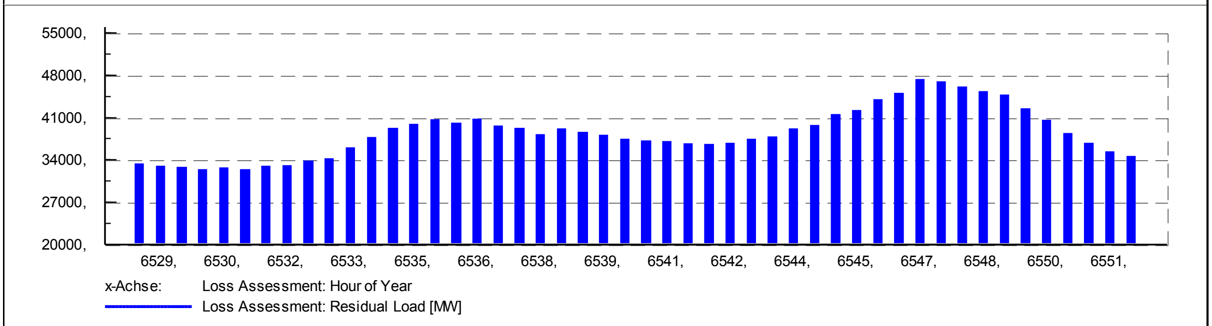


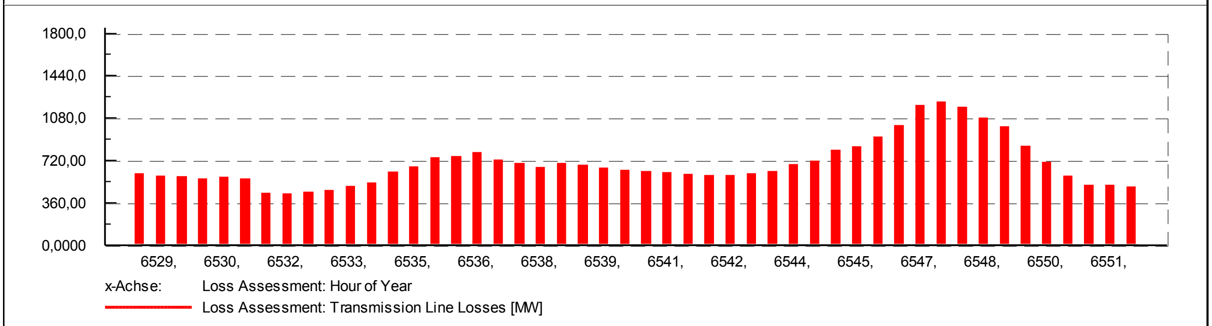
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	High Load (9th June)	Datum: 16.02.2015
	30% Wind	2x Koeberg Unit(s) Online	Anhang: 3.2.2 /2





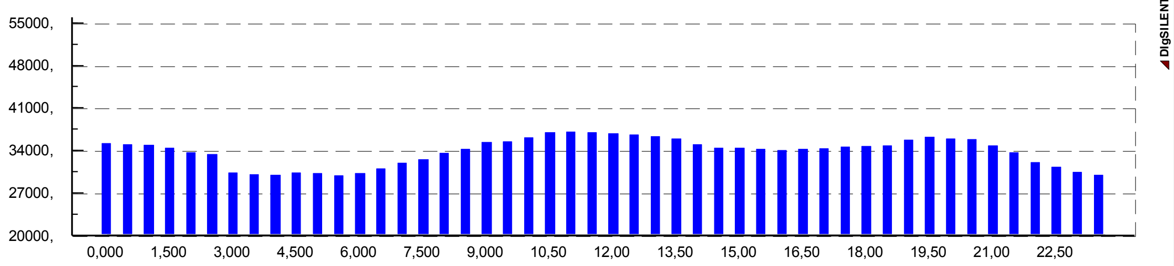






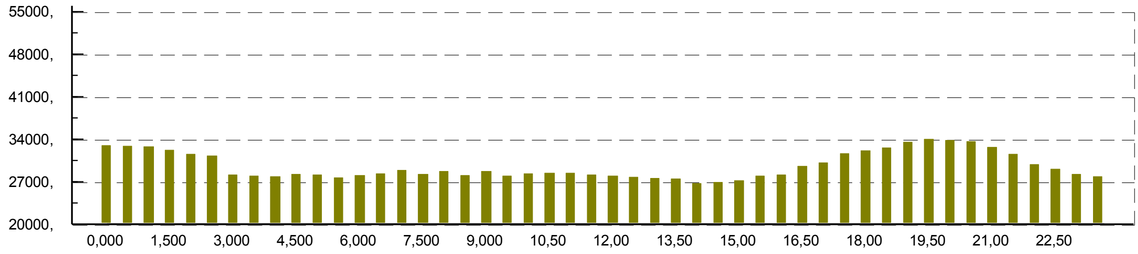
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	High PV (29th September)	Datum: 16.02.2015
	30% Wind	2x Koeberg Unit(s) Online	Anhang: 3.2.2 /3

3.2.3 60% Wind



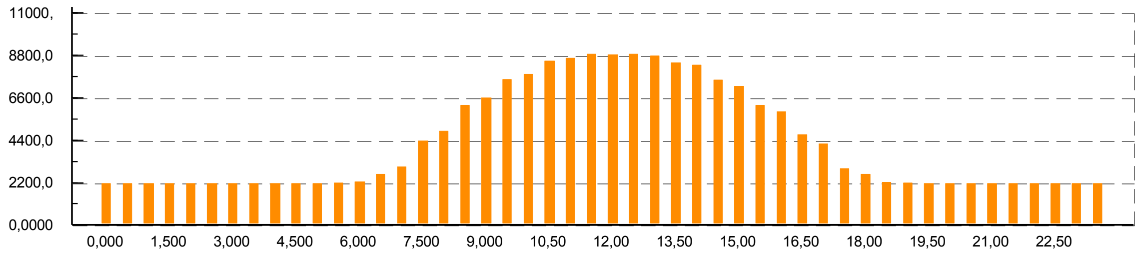
x-Achse: Loss Assessment: Hour of Year

Loss Assessment: Load [MW]



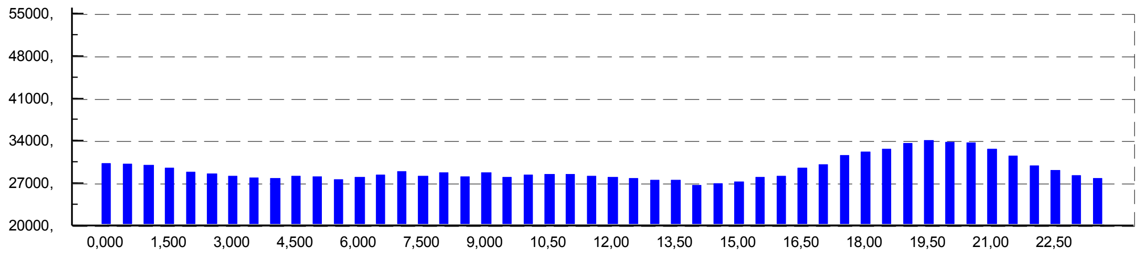
x-Achse: Loss Assessment: Hour of Year

Loss Assessment: Total Conventional Generation [MW]



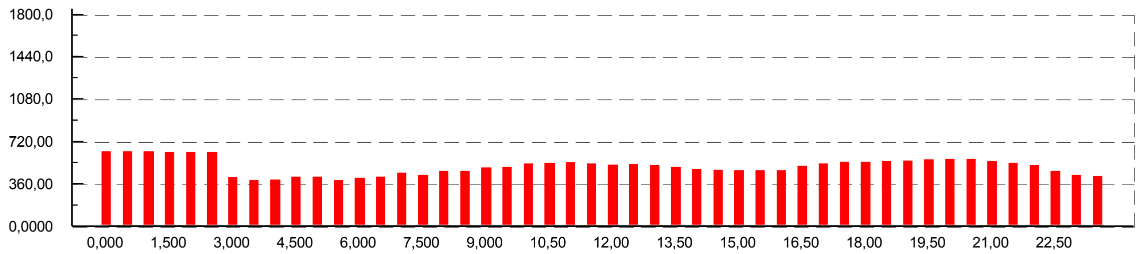
x-Achse: Loss Assessment: Hour of Year

Loss Assessment: Variable Generation MW



x-Achse: Loss Assessment: Hour of Year

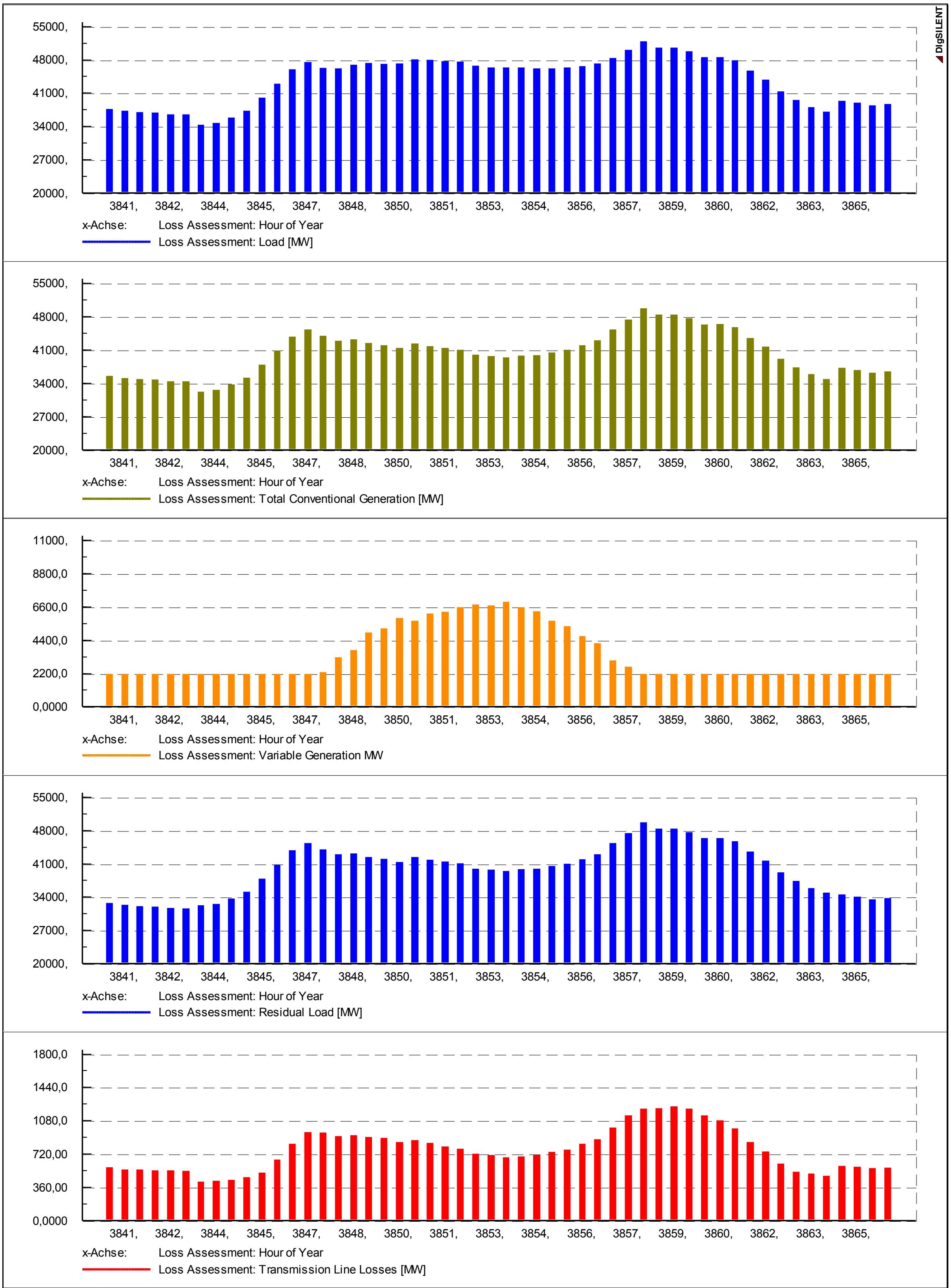
Loss Assessment: Residual Load [MW]



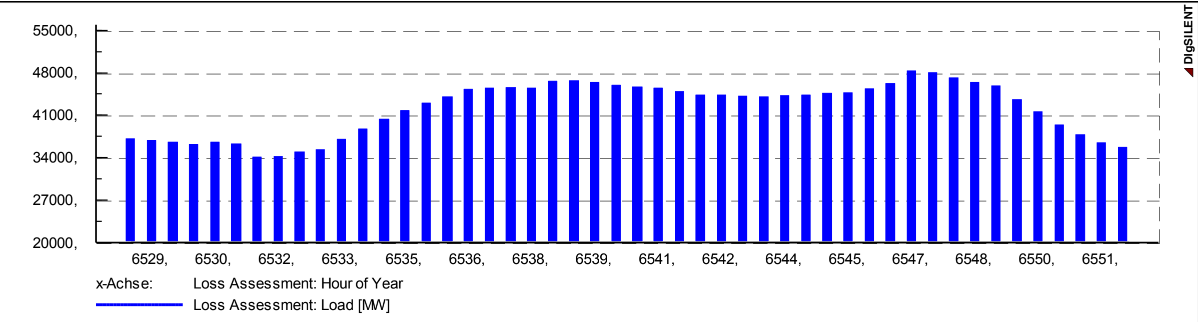
x-Achse: Loss Assessment: Hour of Year

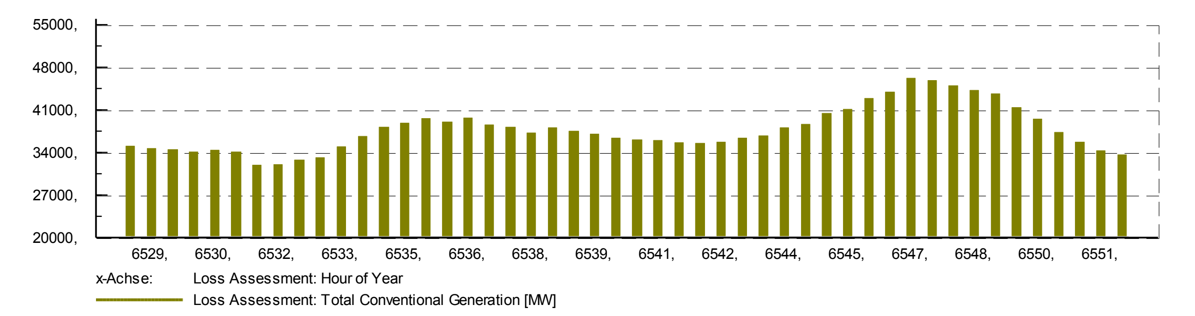
Loss Assessment: Transmission Line Losses [MW]

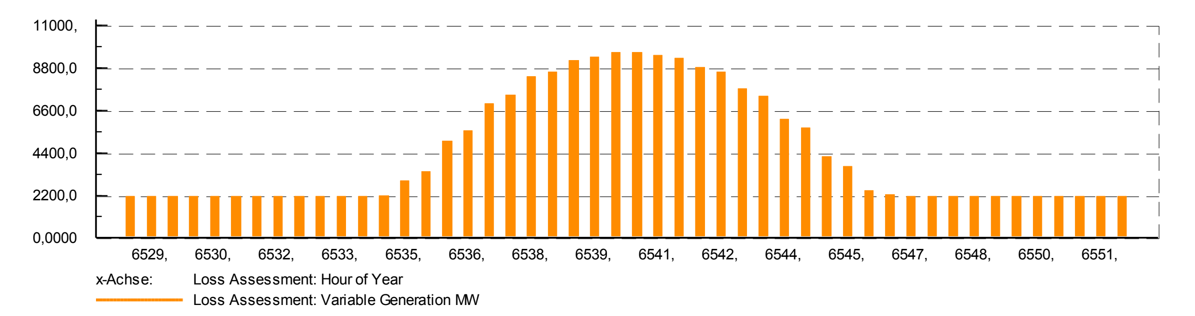
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	Low Load (1st January)	Datum: 16.02.2015
	60% Wind	2x Koeberg Unit(s) Online	Anhang: 3.2.3 /1

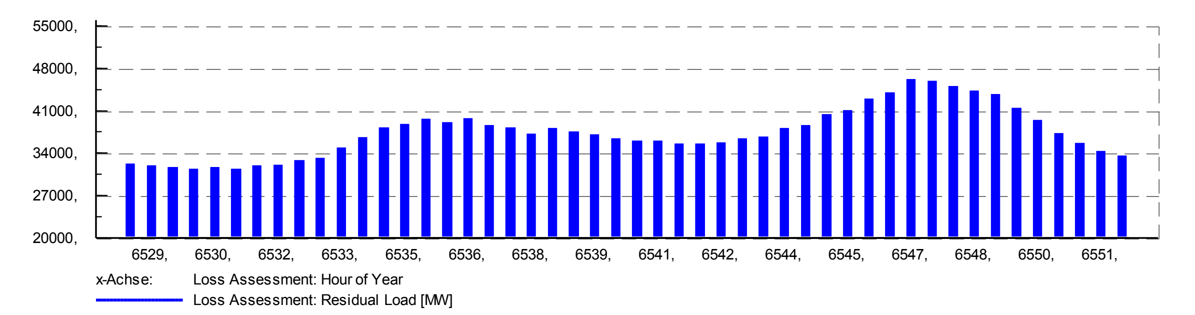


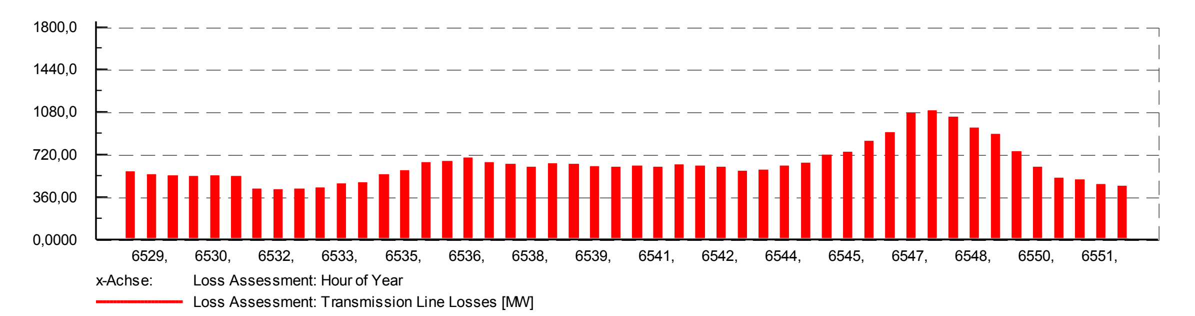
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	High Load (9th June)	Datum: 16.02.2015
	60% Wind	2x Koeberg Unit(s) Online	Anhang: 3.2.3 /2





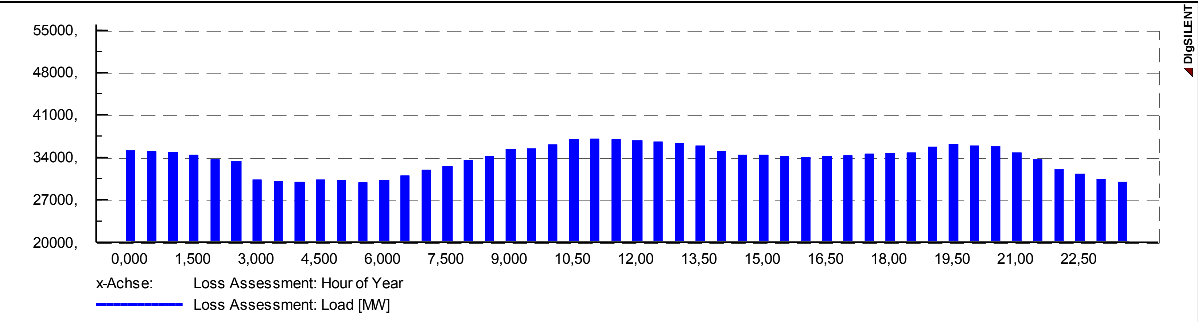


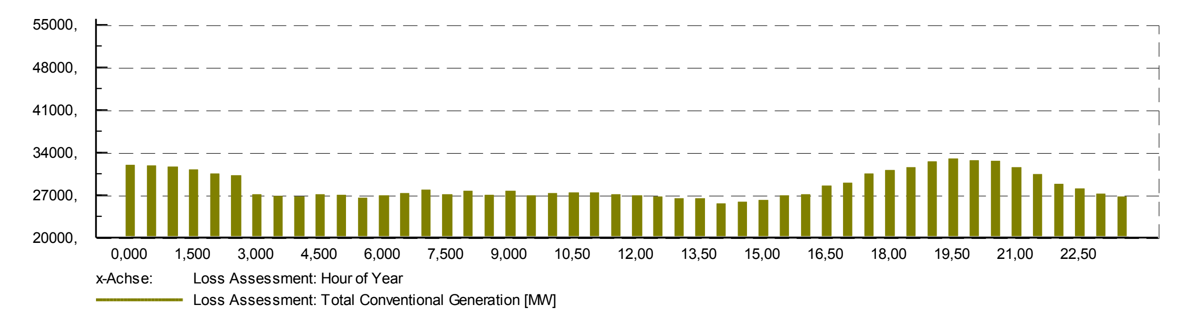


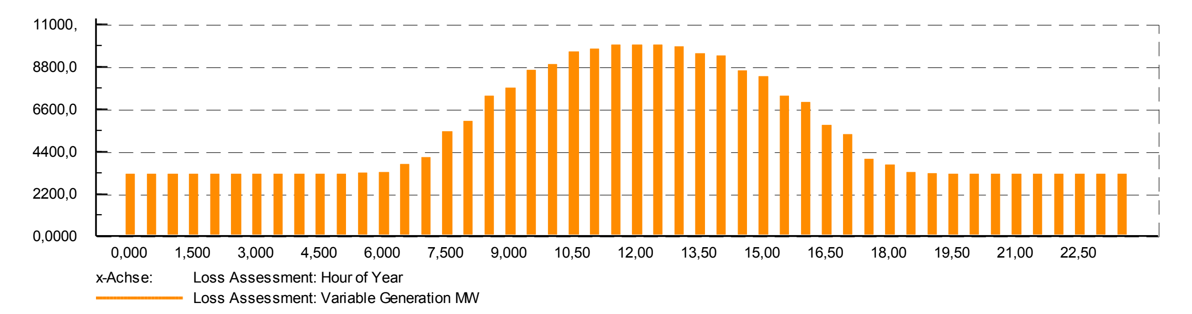


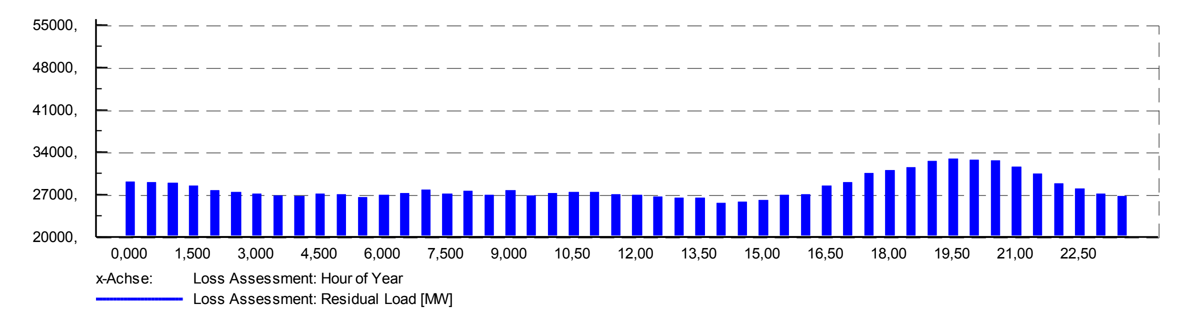
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B 60% Wind	High PV (29th September) 2x Koeberg Unit(s) Online	Datum: 16.02.2015 Anhang: 3.2.3 /3

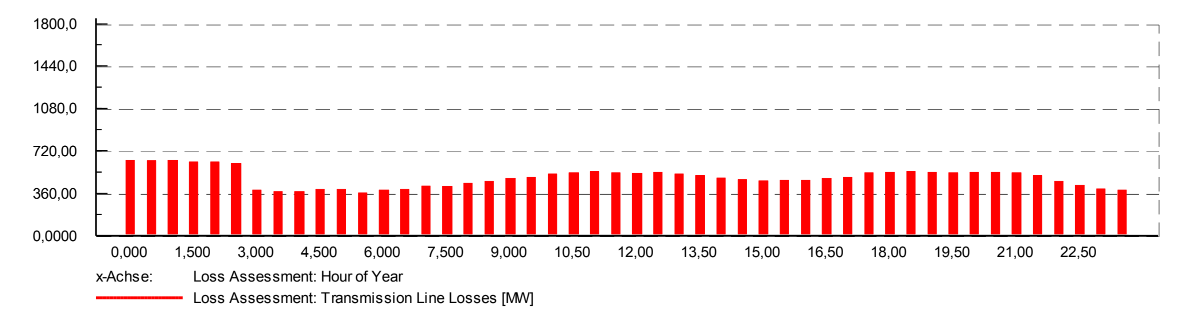
3.2.4 90% Wind



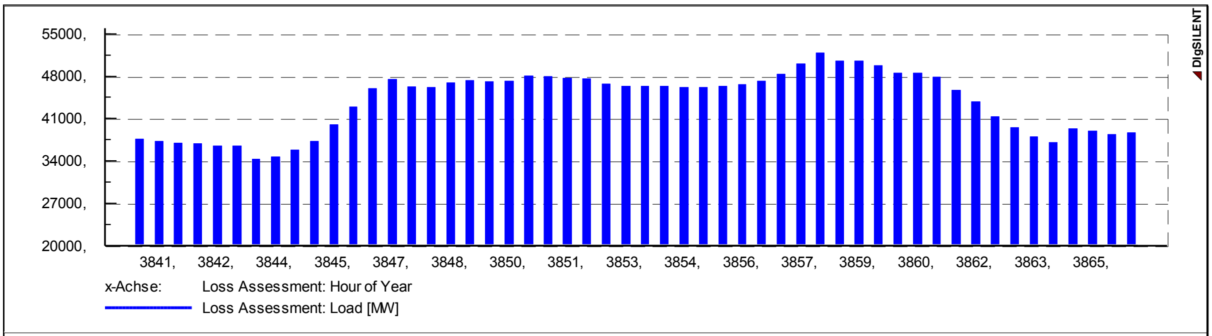


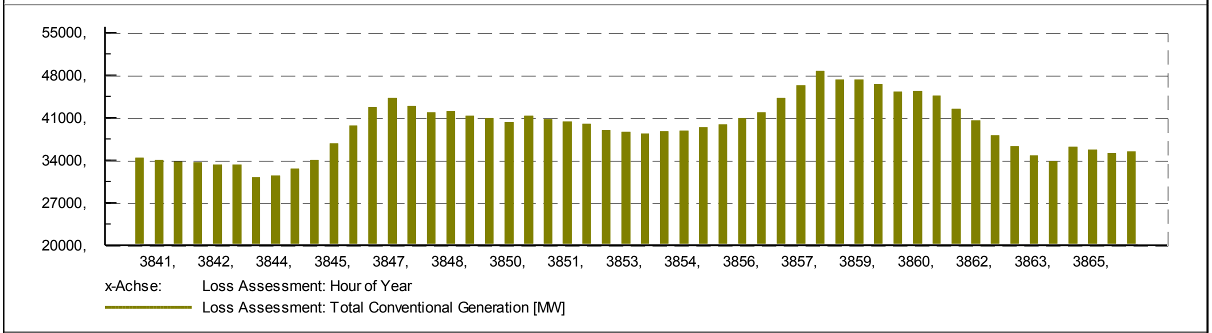


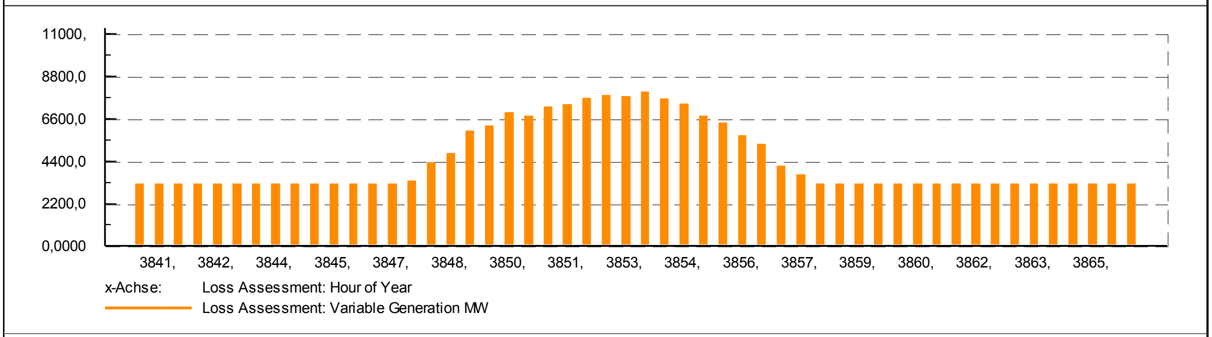


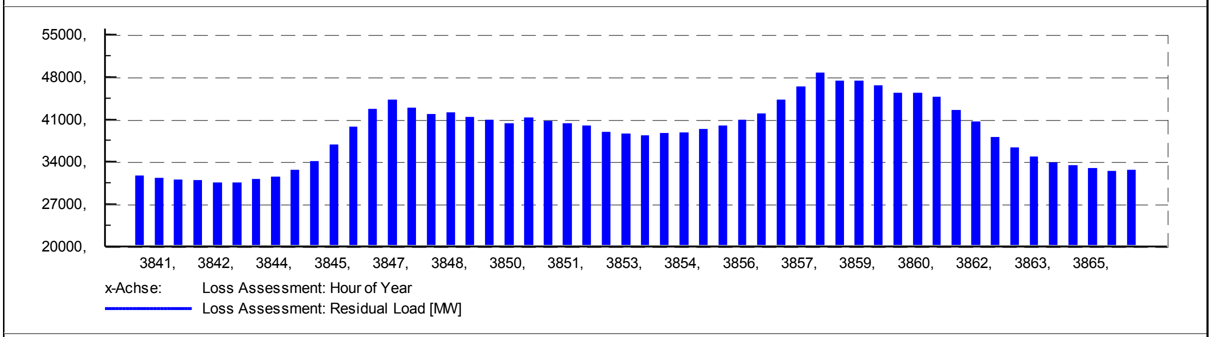


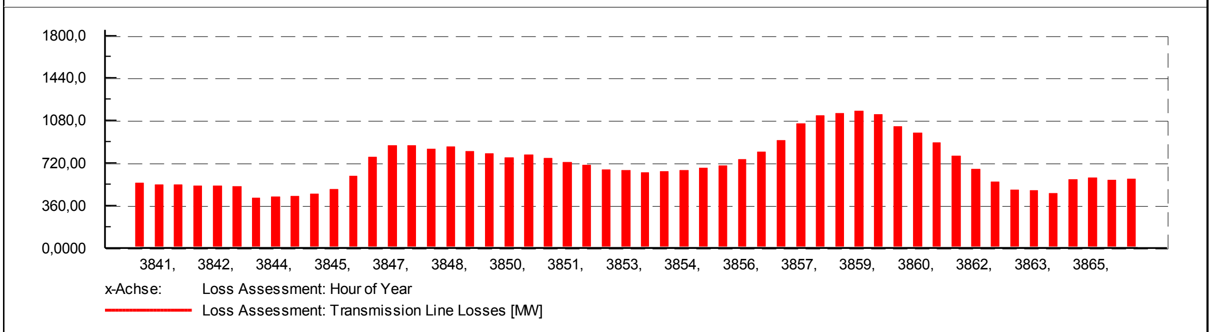
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	Low Load (1st January)	Datum: 16.02.2015
	90% Wind	2x Koeberg Unit(s) Online	Anhang: 3.2.4 /1



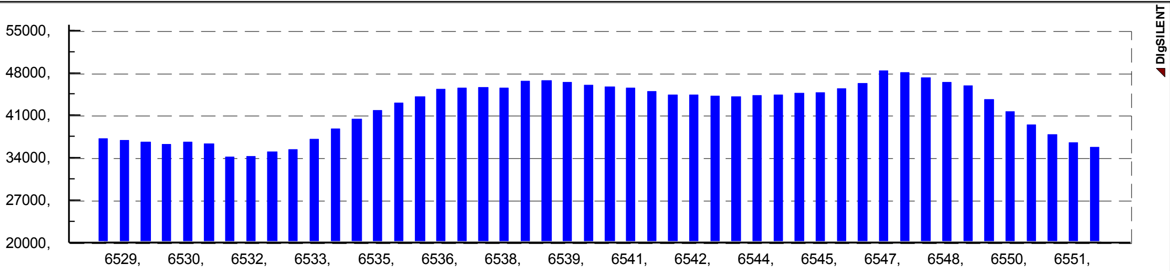




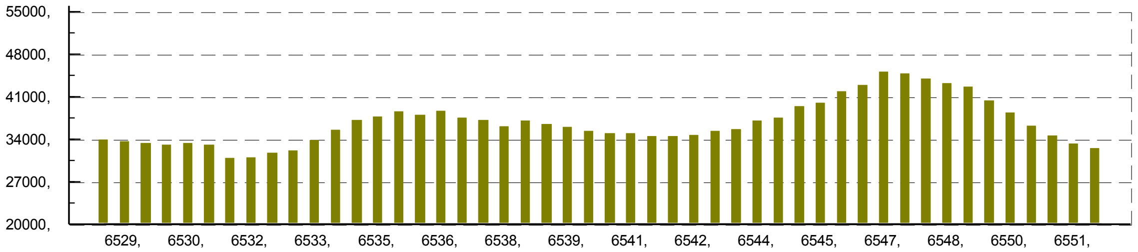




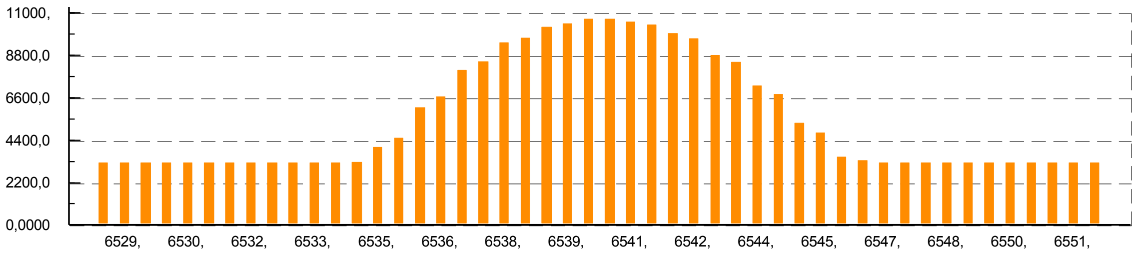
M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	High Load (9th June)	Datum: 16.02.2015
	90% Wind	2x Koeberg Unit(s) Online	Anhang: 3.2.4 /2



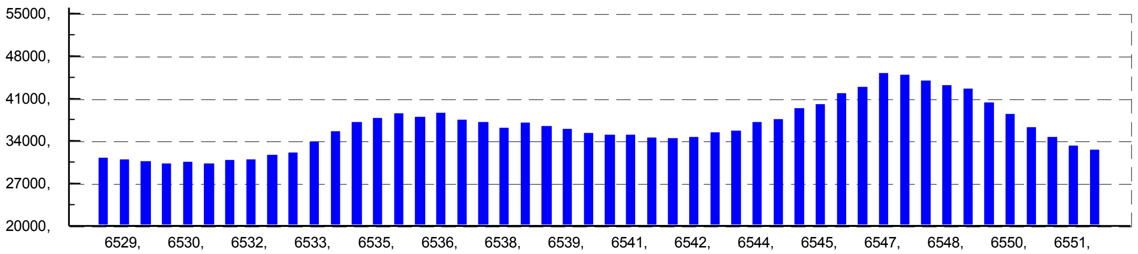
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Load [MW]



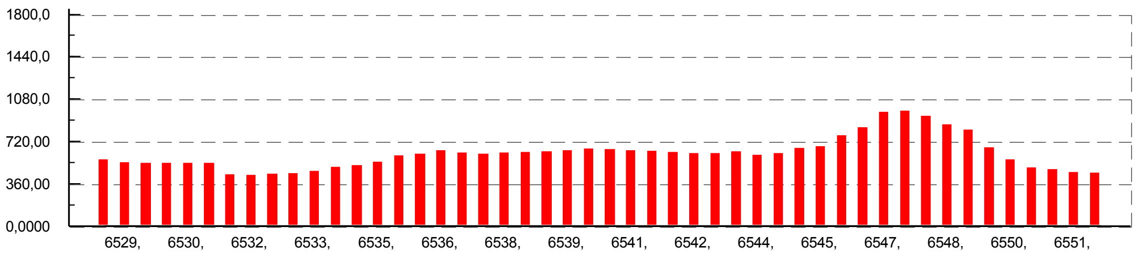
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Total Conventional Generation [MW]



x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Variable Generation MW



x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Residual Load [MW]



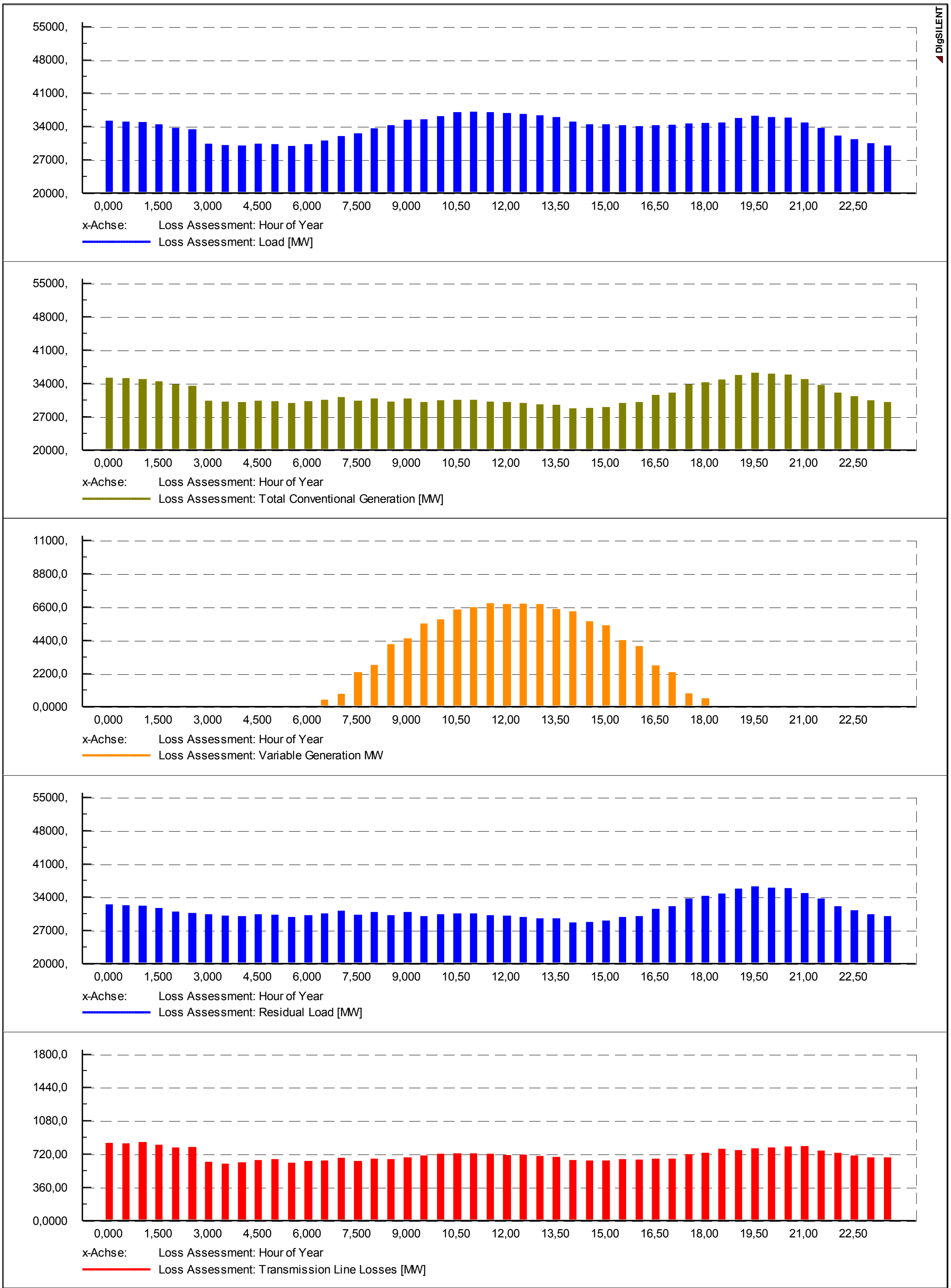
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Transmission Line Losses [MW]

M.P.E. MOELLER & POELLER ENGINEERING	Scenario B	High PV (29th September)	Datum: 16.02.2015
	90% Wind	2x Koeberg Unit(s) Online	Anhang: 3.2.4 /3

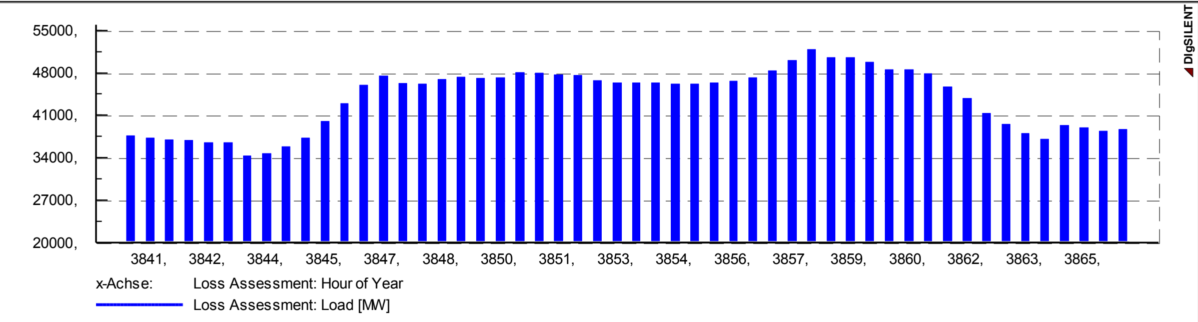
4 Scenario C

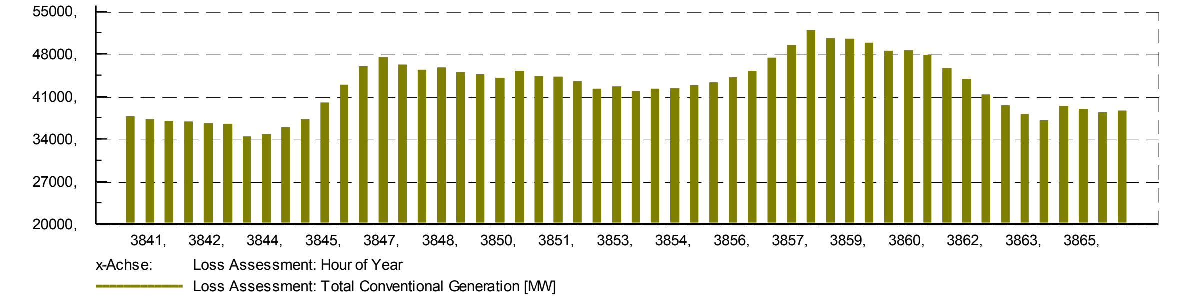
4.1 1x Koeberg Unit(s) Online

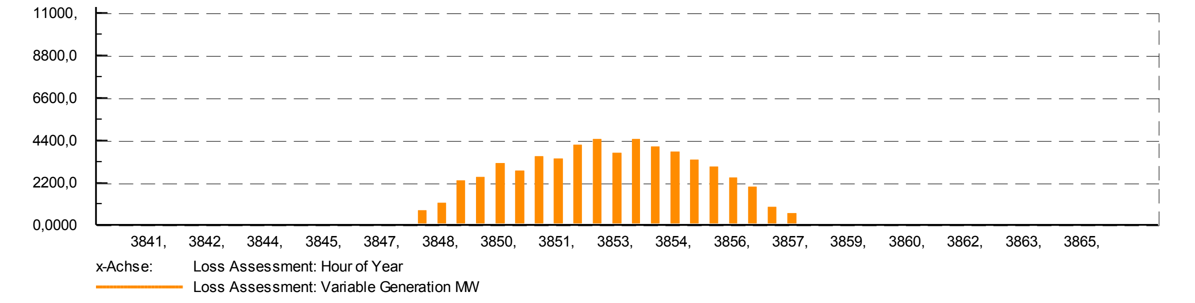
4.1.1 00% Wind

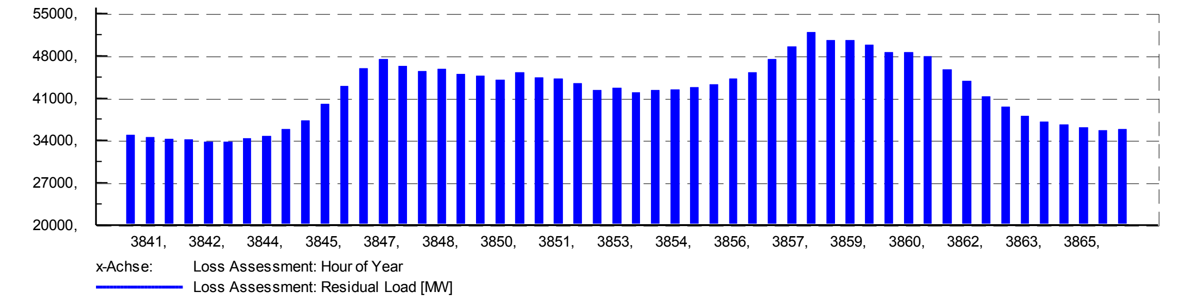


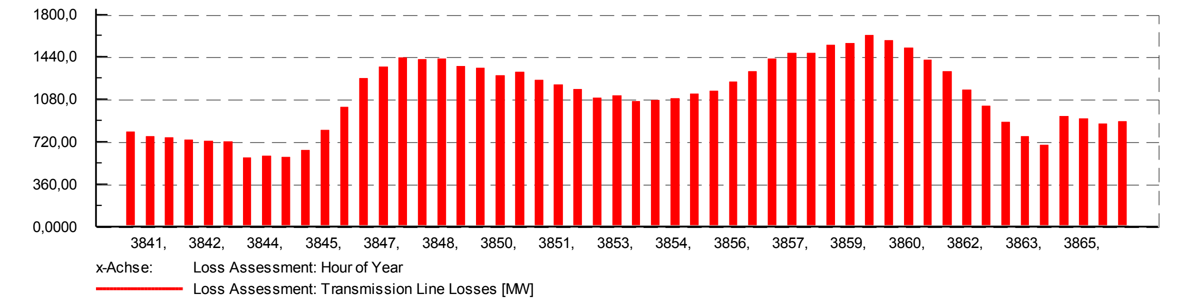
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C 00% Wind	Low Load (1st January) 1x Koeberg Unit(s) Online	Datum: 16.02.2015 Anhang: 4.1.1 /1



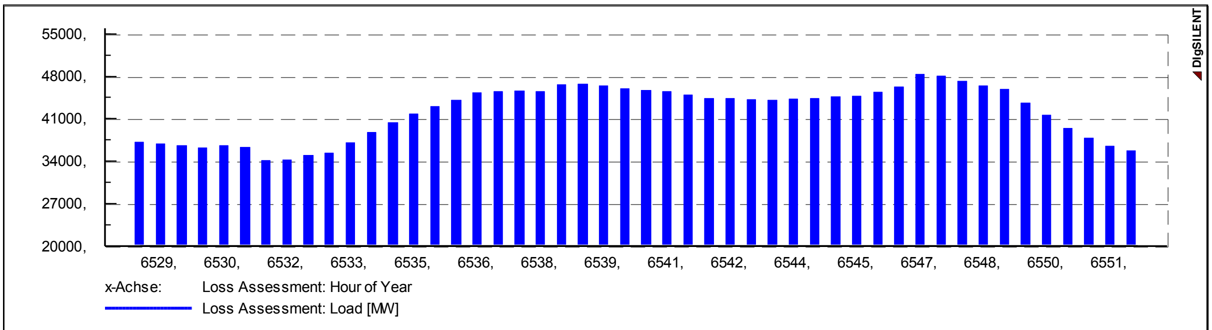


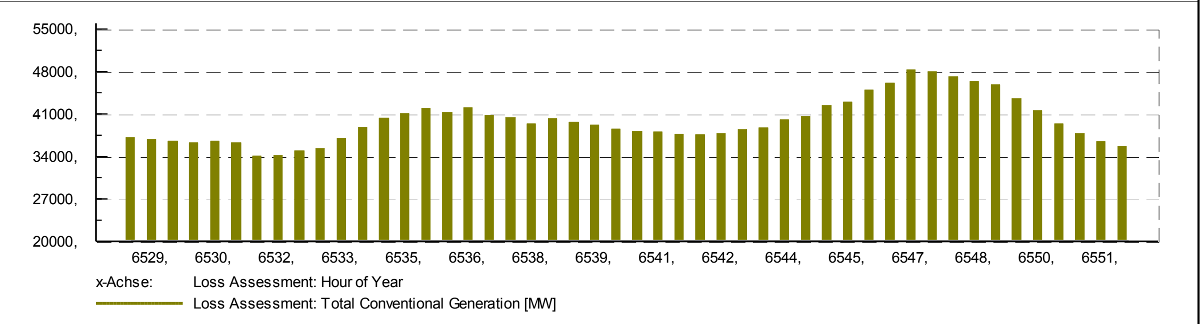


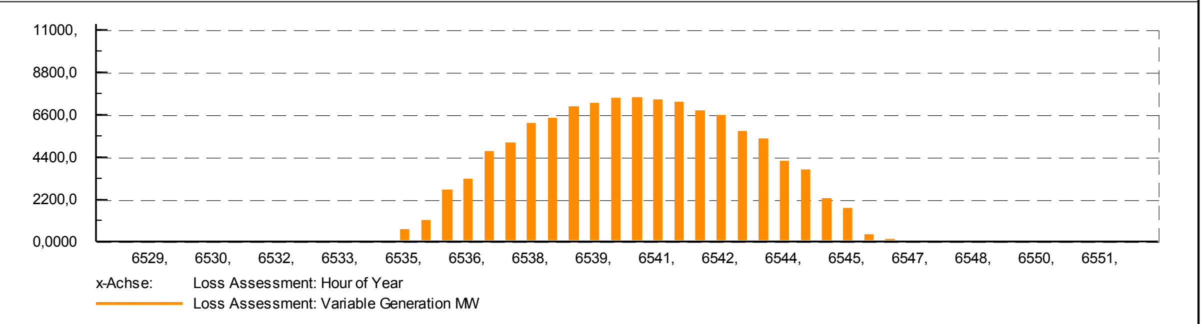


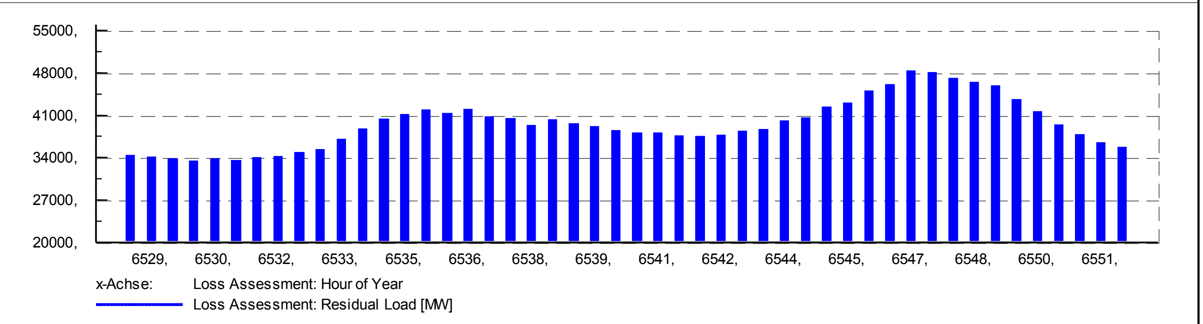


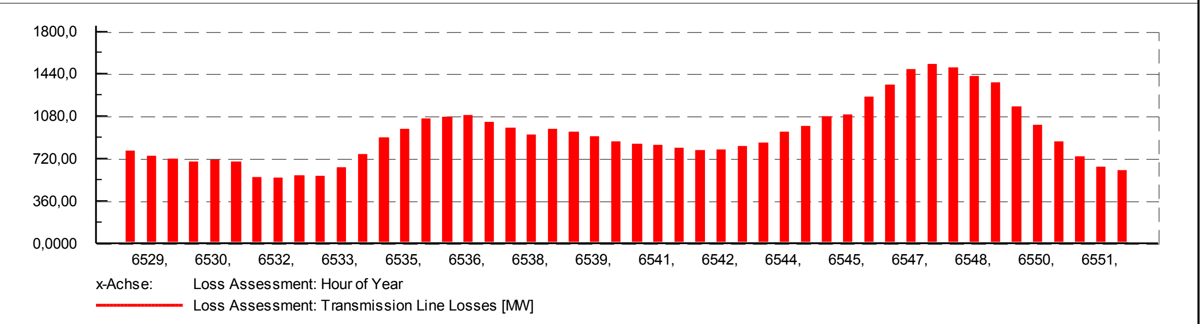
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	High Load (9th June)	Datum: 16.02.2015
	00% Wind	1x Koeberg Unit(s) Online	Anhang: 4.1.1 /2





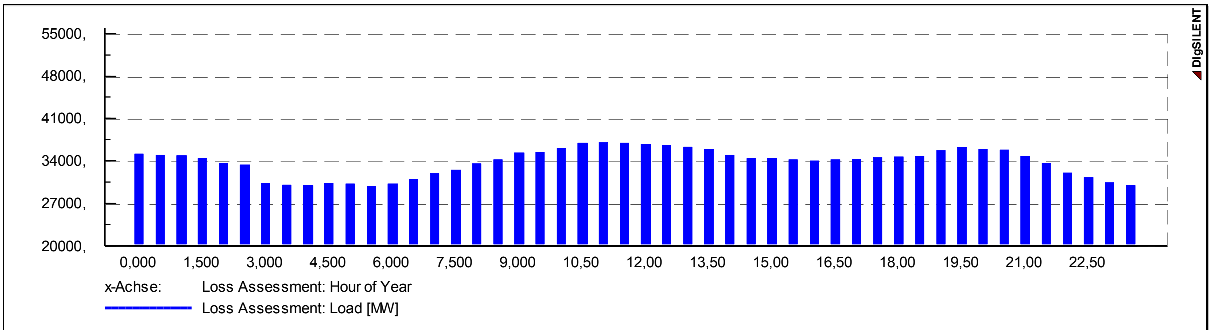


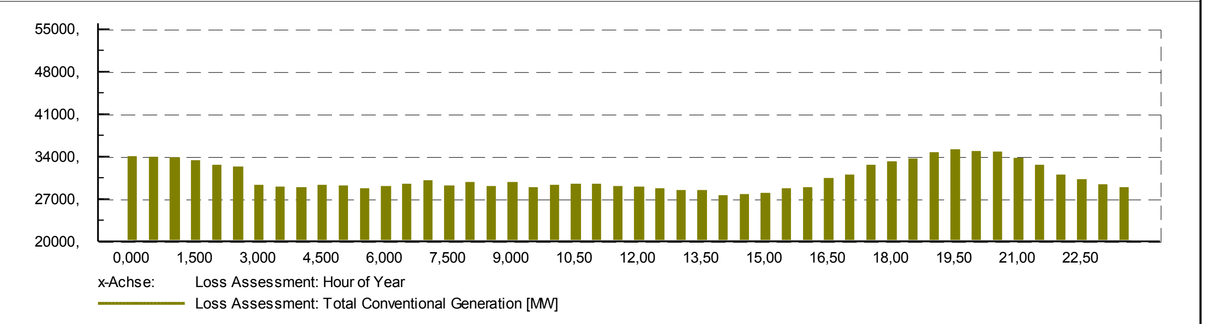


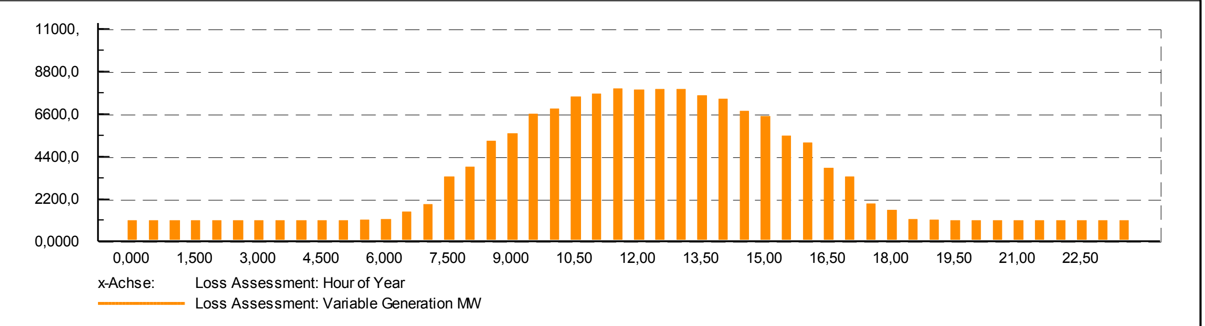


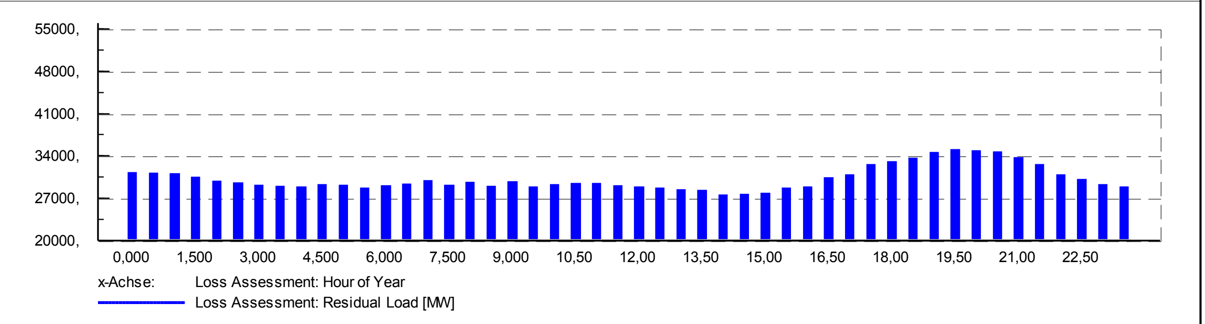
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	High PV (29th September)	Datum: 16.02.2015
	00% Wind	1x Koeberg Unit(s) Online	Anhang: 4.1.1 /3

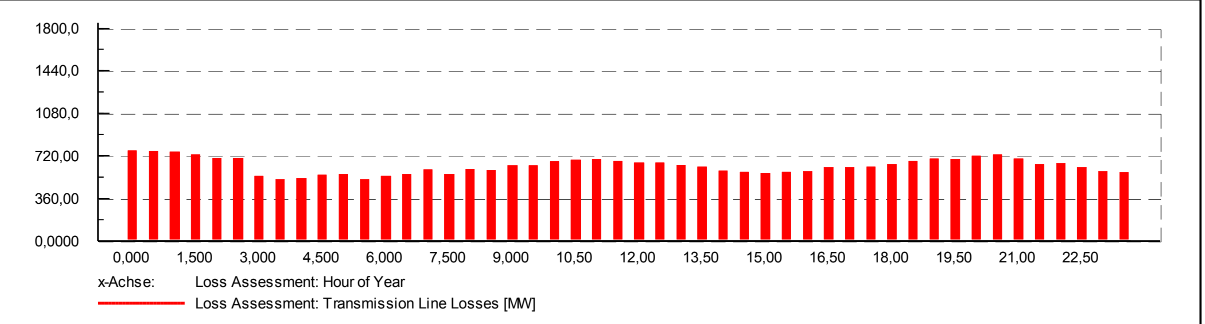
4.1.2 30% Wind



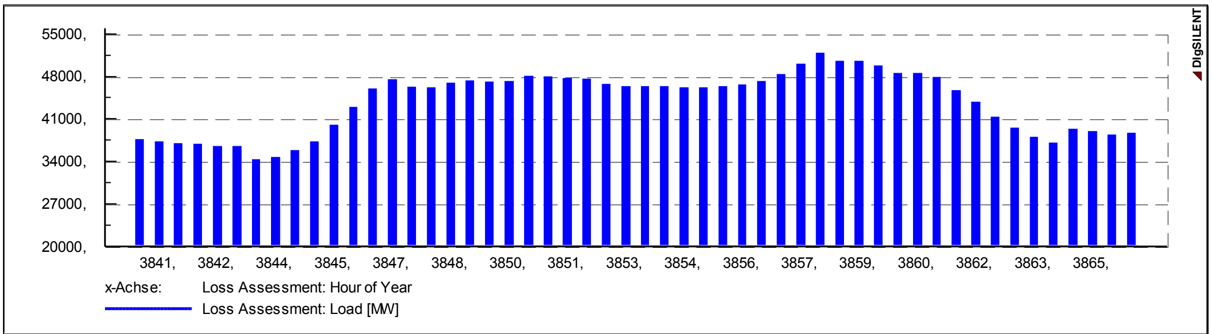


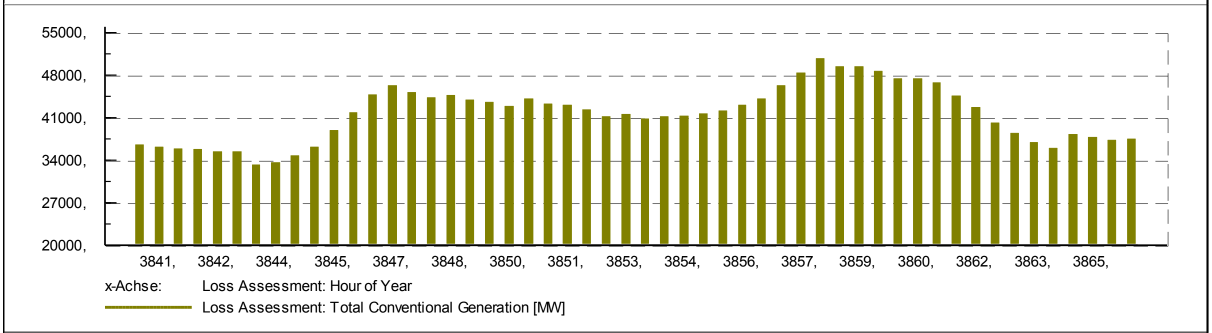


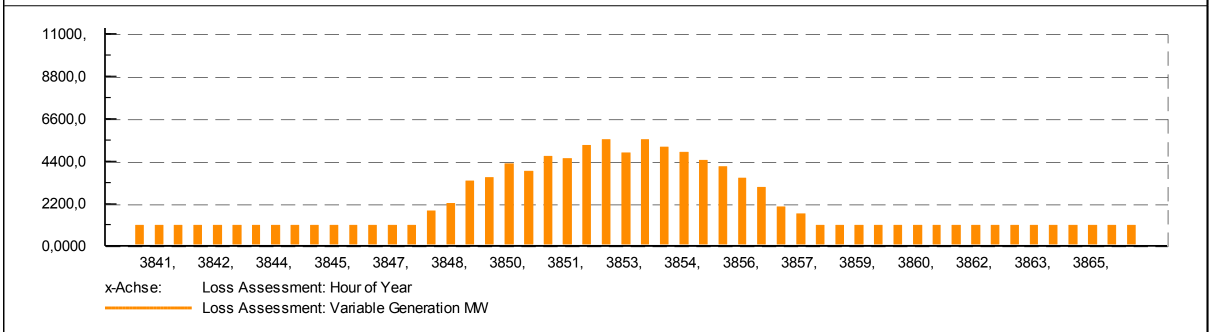


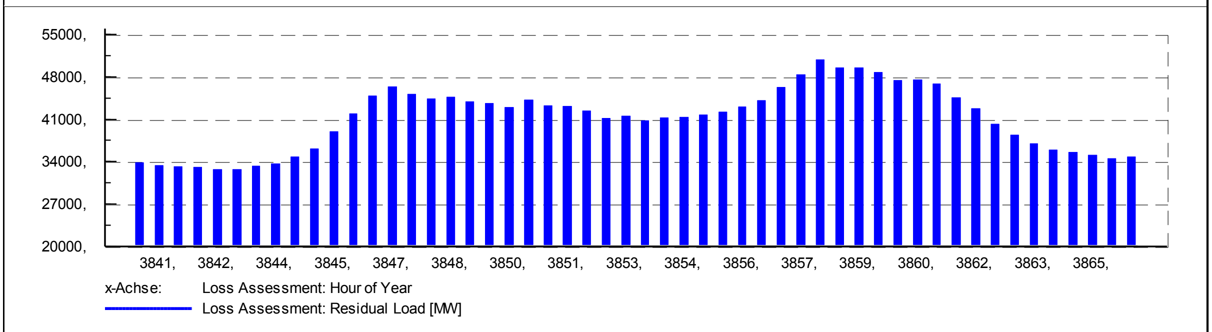


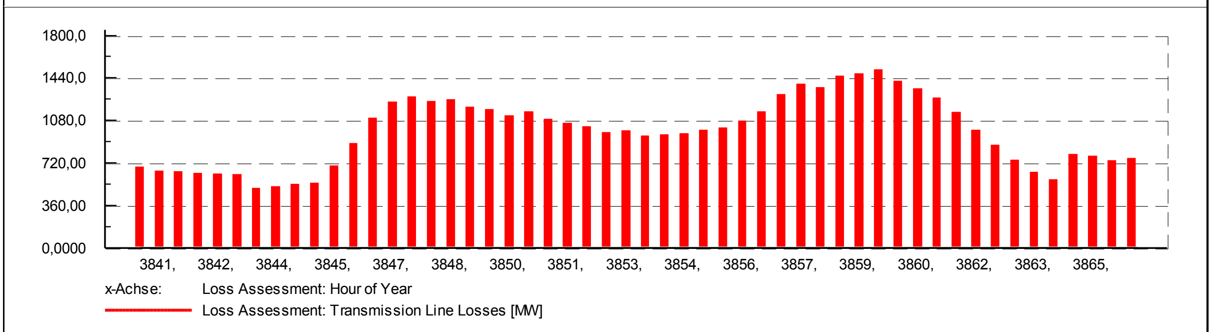
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	Low Load (1st January)	Datum: 16.02.2015
	30% Wind	1x Koeberg Unit(s) Online	Anhang: 4.1.2 /1



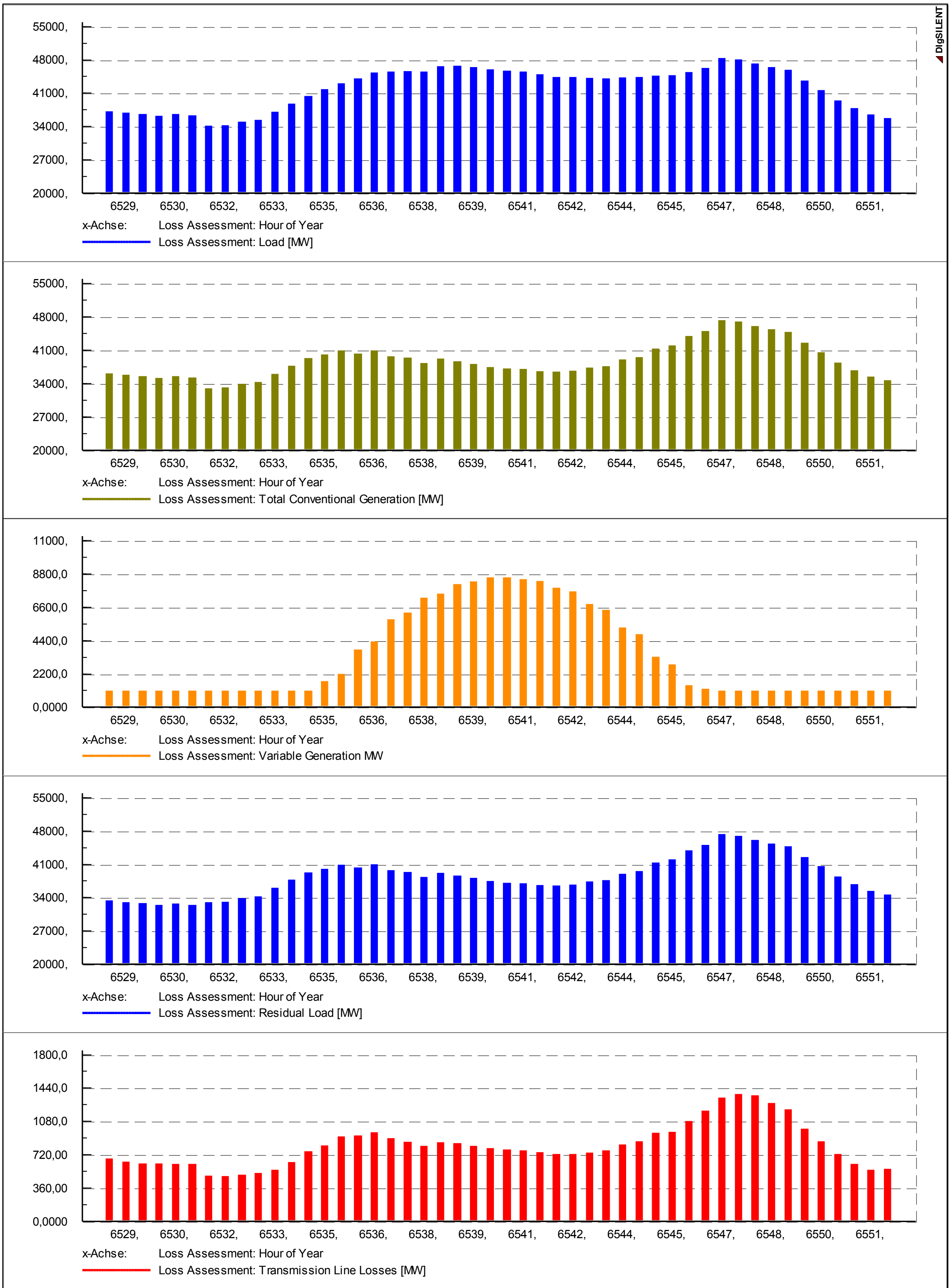






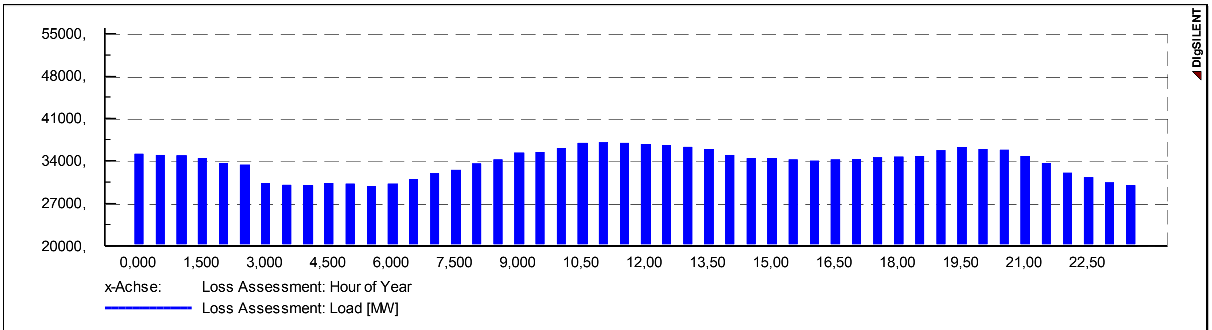


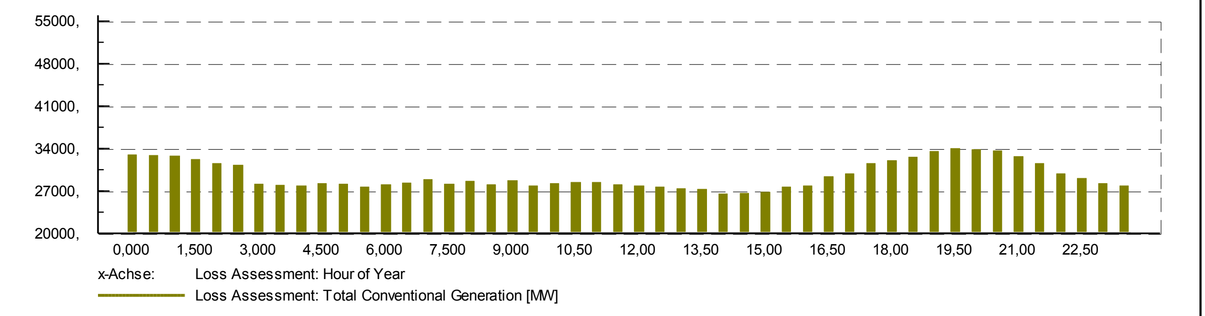
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	High Load (9th June)	Datum: 16.02.2015
	30% Wind	1x Koeberg Unit(s) Online	Anhang: 4.1.2 /2

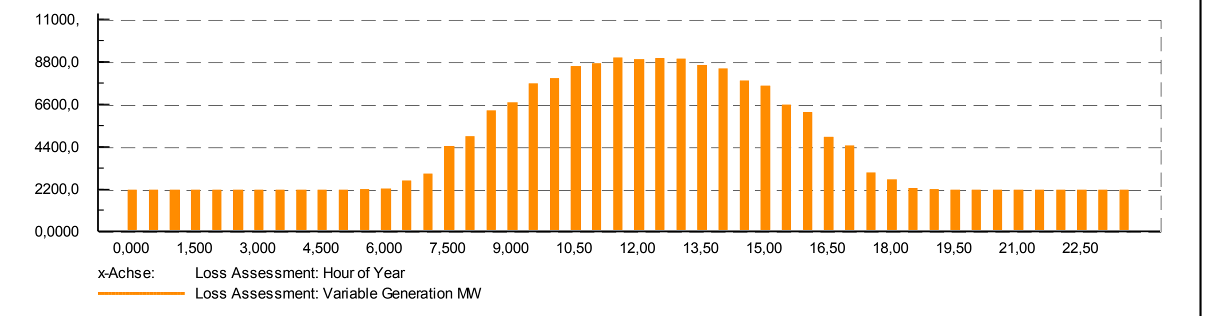


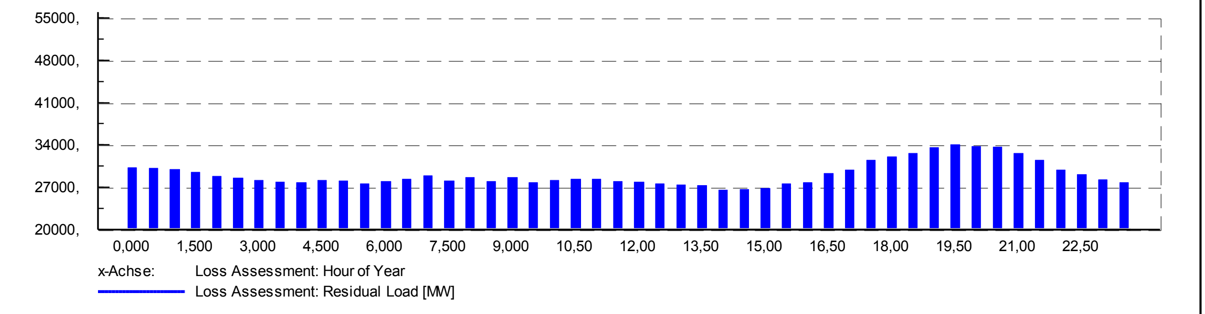
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	High PV (29th September)	Datum: 16.02.2015
	30% Wind	1x Koeberg Unit(s) Online	Anhang: 4.1.2 /3

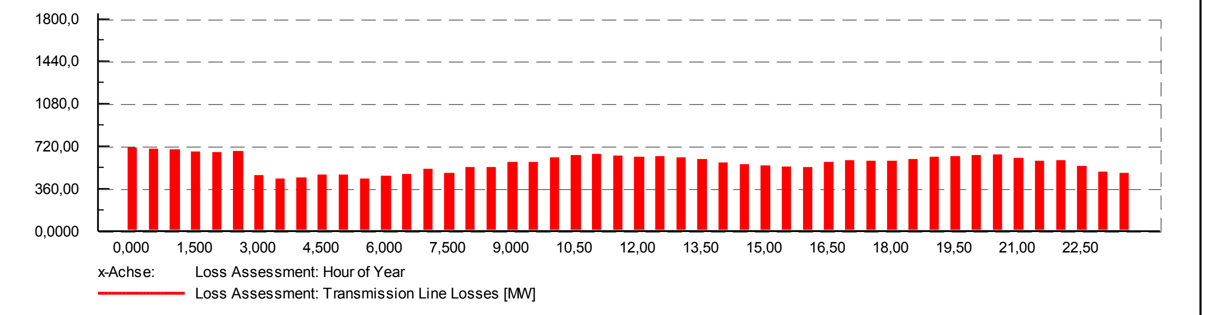
4.1.3 60% Wind



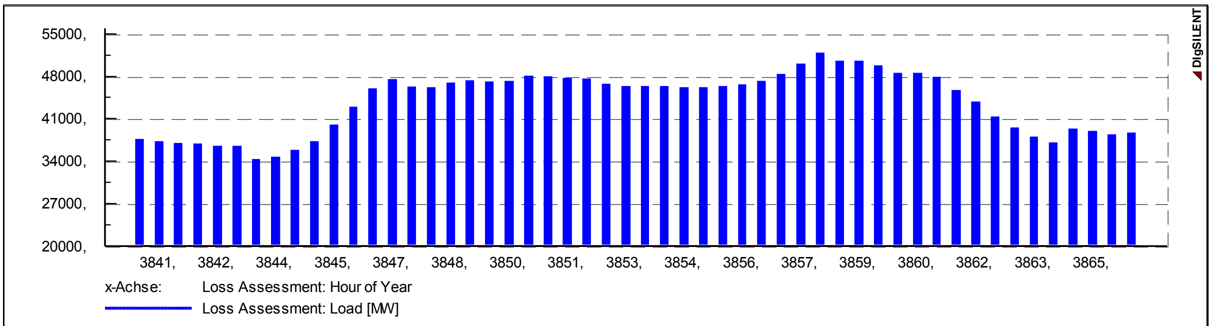


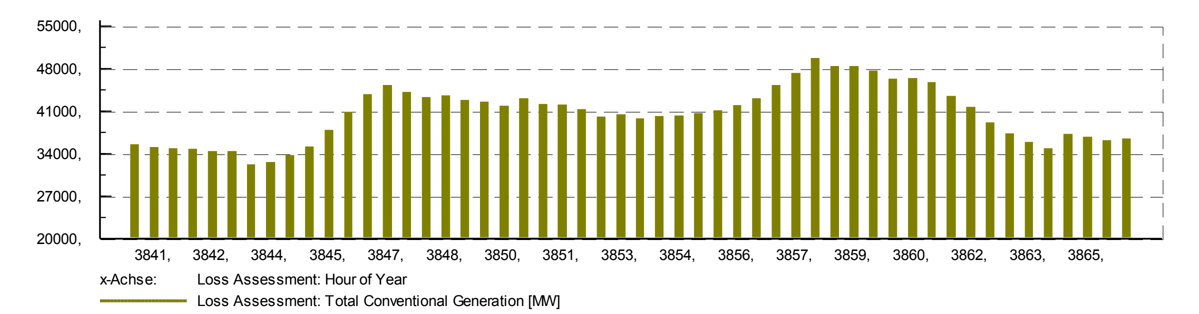


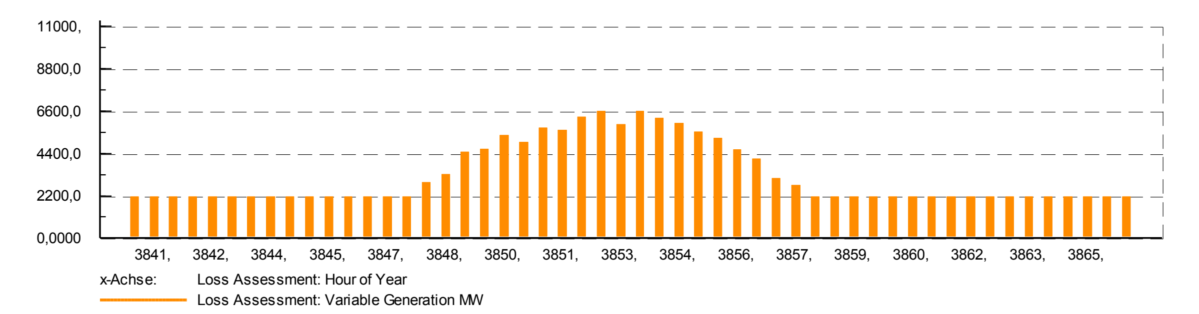


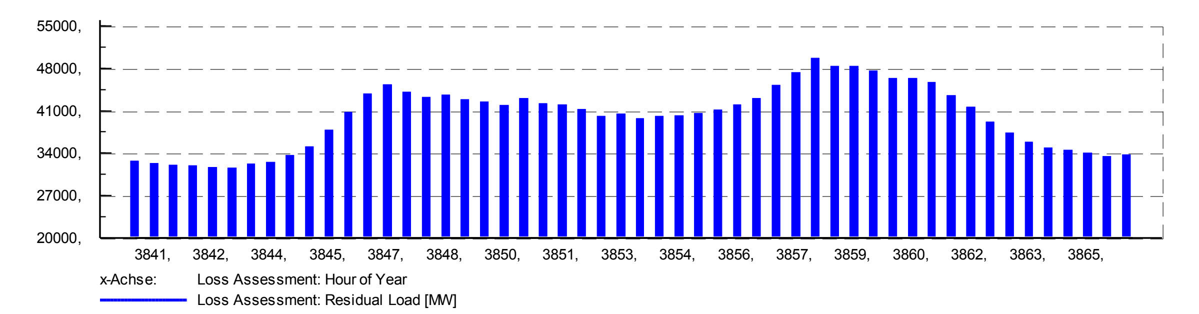


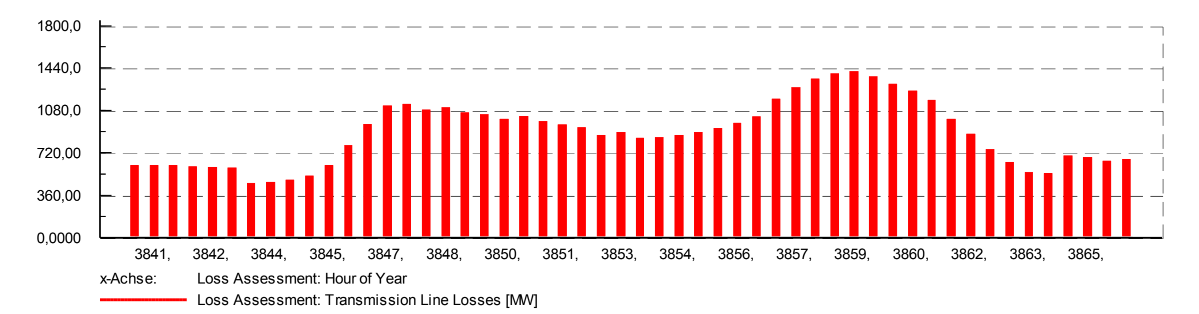
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	Low Load (1st January)	Datum: 16.02.2015
	60% Wind	1x Koeberg Unit(s) Online	Anhang: 4.1.3 /1



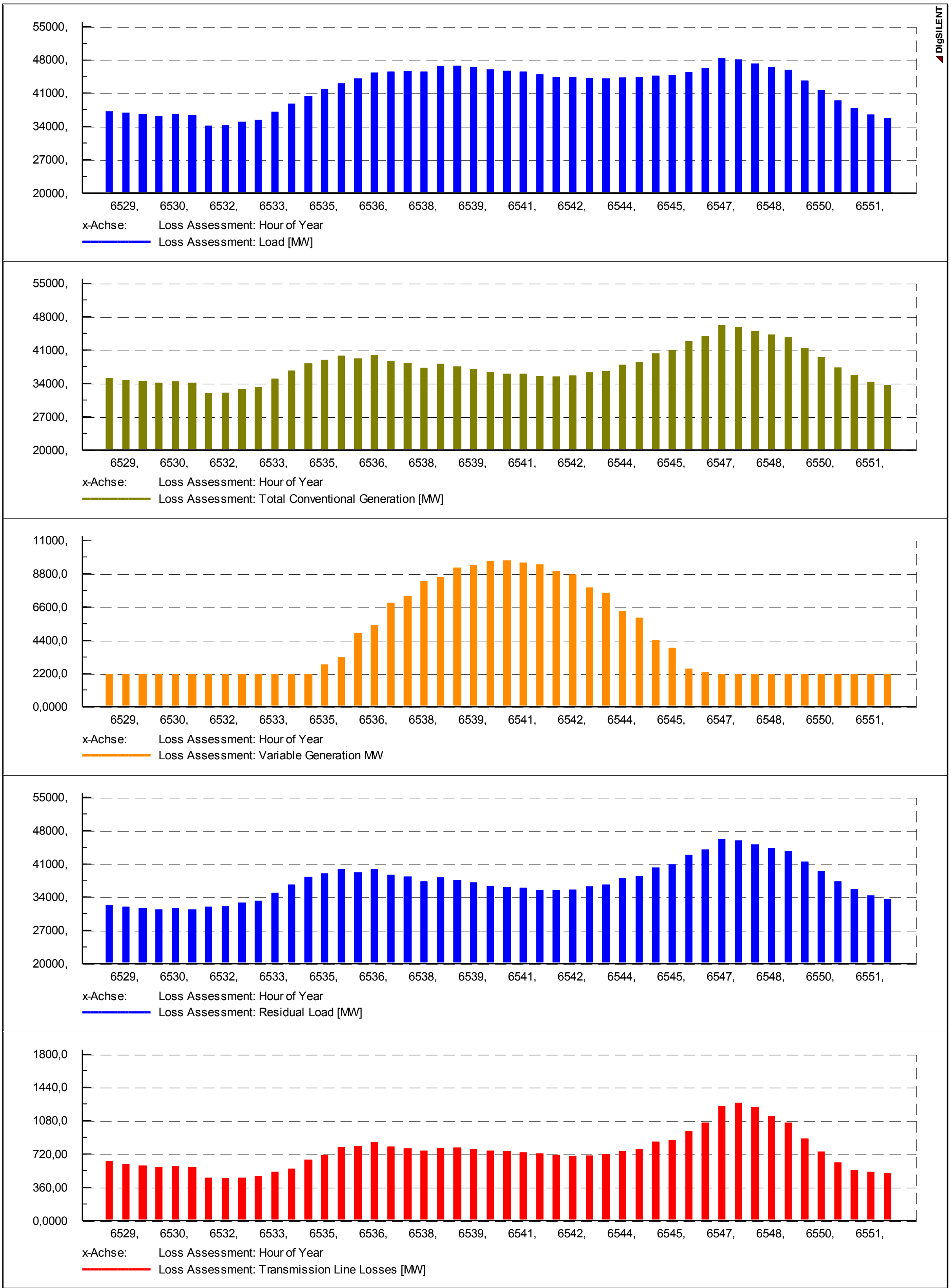






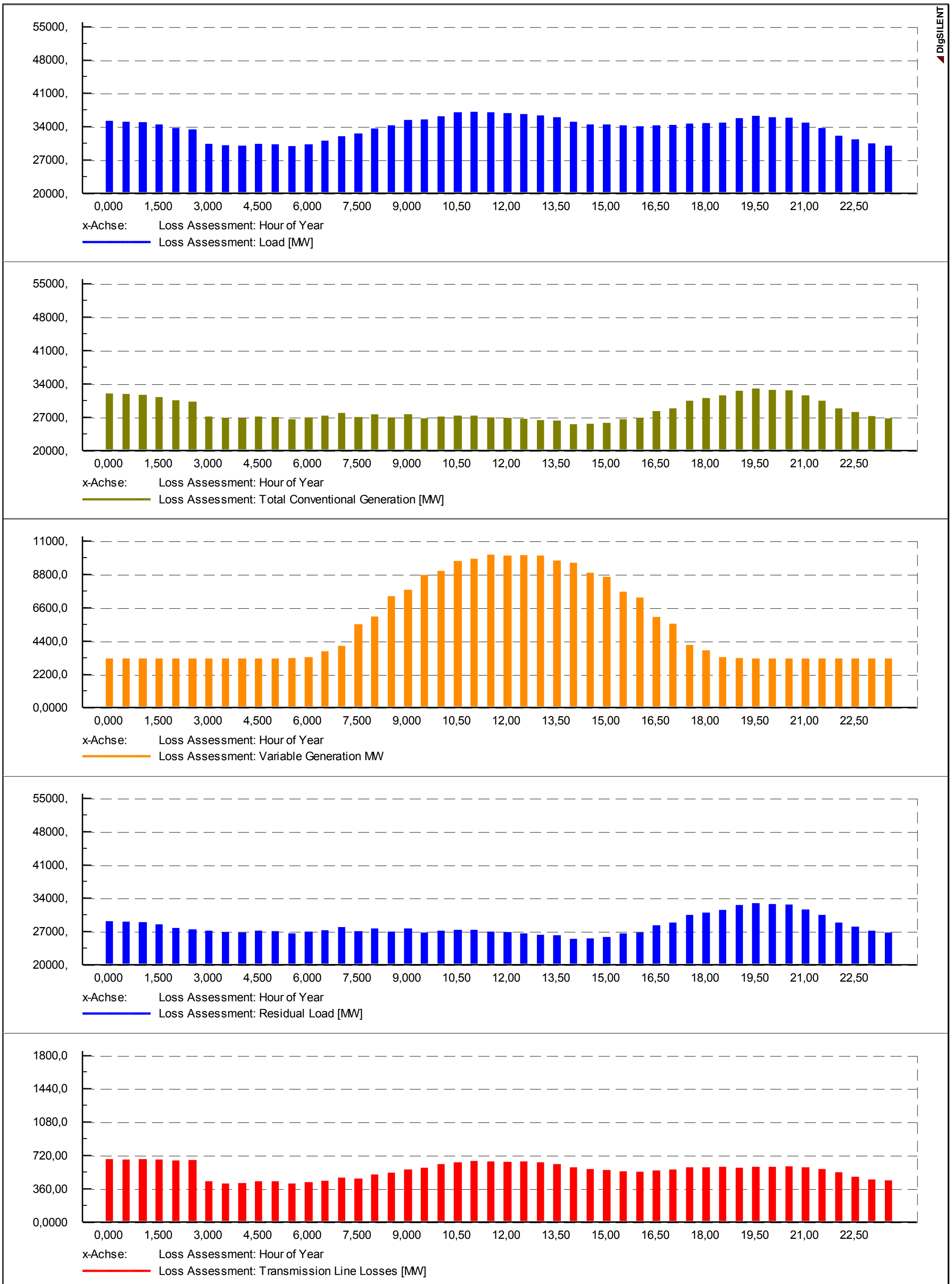


M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	High Load (9th June)	Datum: 16.02.2015
	60% Wind	1x Koeberg Unit(s) Online	Anhang: 4.1.3 /2

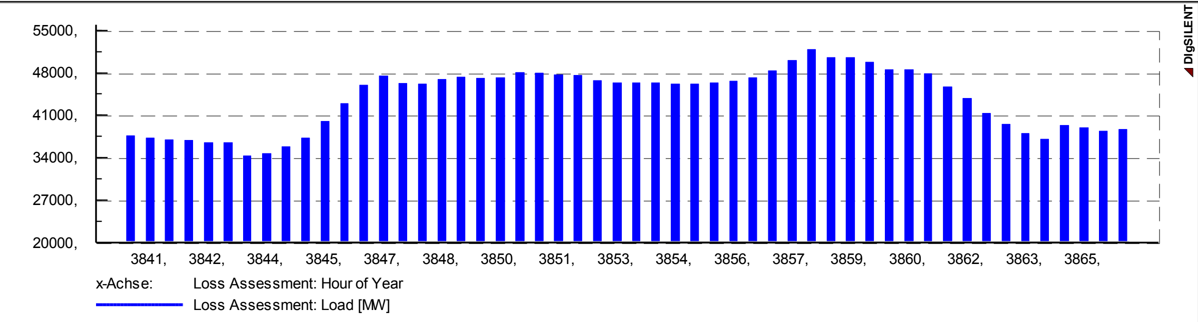


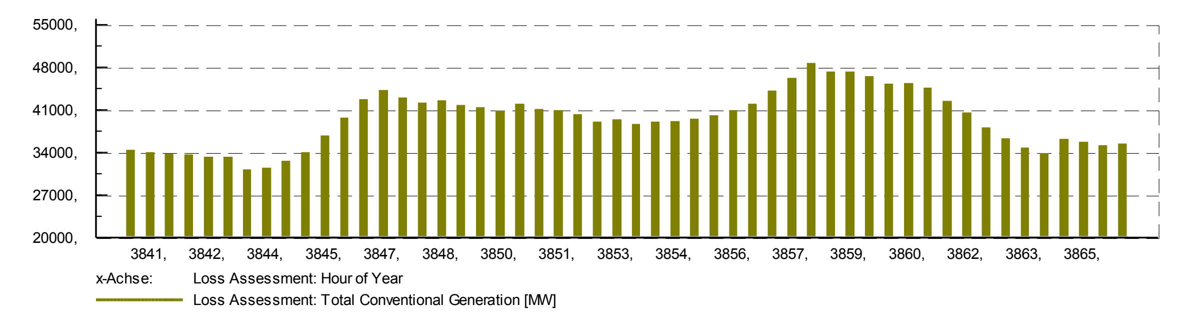
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	High PV (29th September)	Datum: 16.02.2015
	60% Wind	1x Koeberg Unit(s) Online	Anhang: 4.1.3 /3

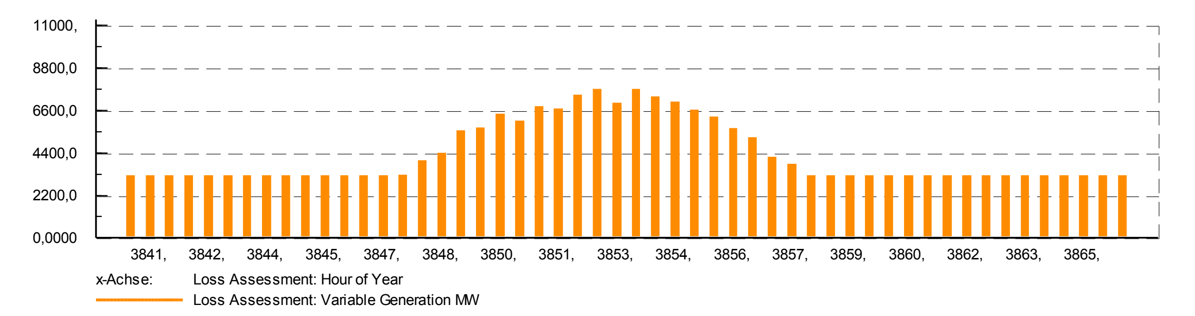
4.1.4 90% Wind

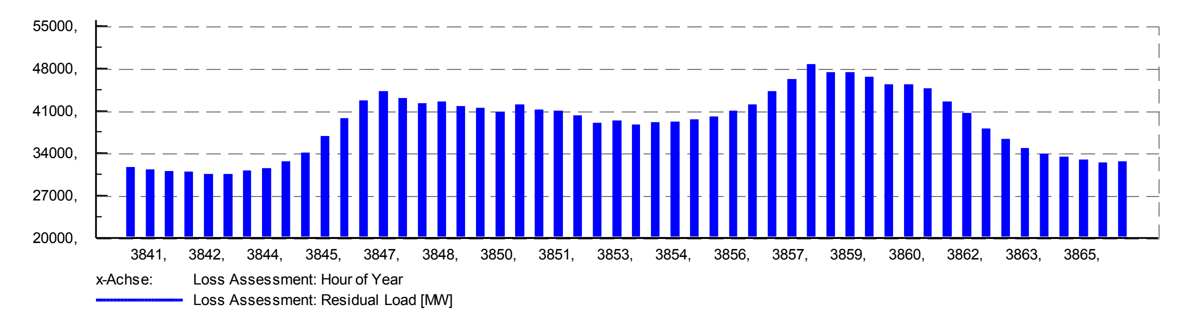


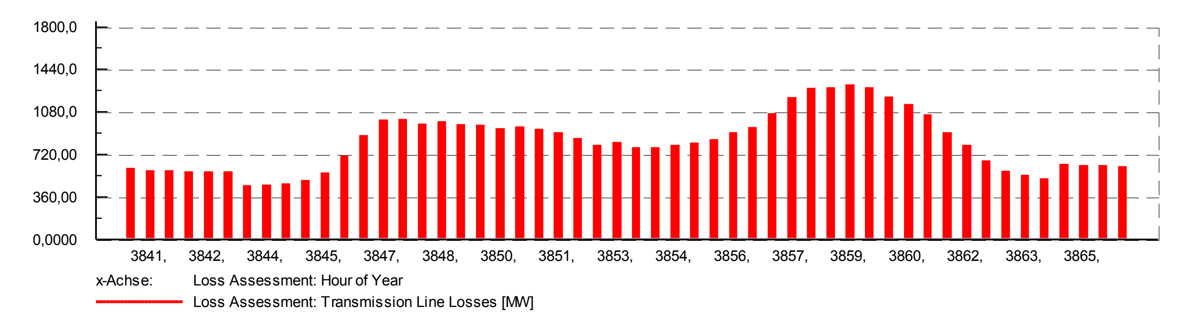
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	Low Load (1st January)	Datum: 16.02.2015
	90% Wind	1x Koeberg Unit(s) Online	Anhang: 4.1.4 /1



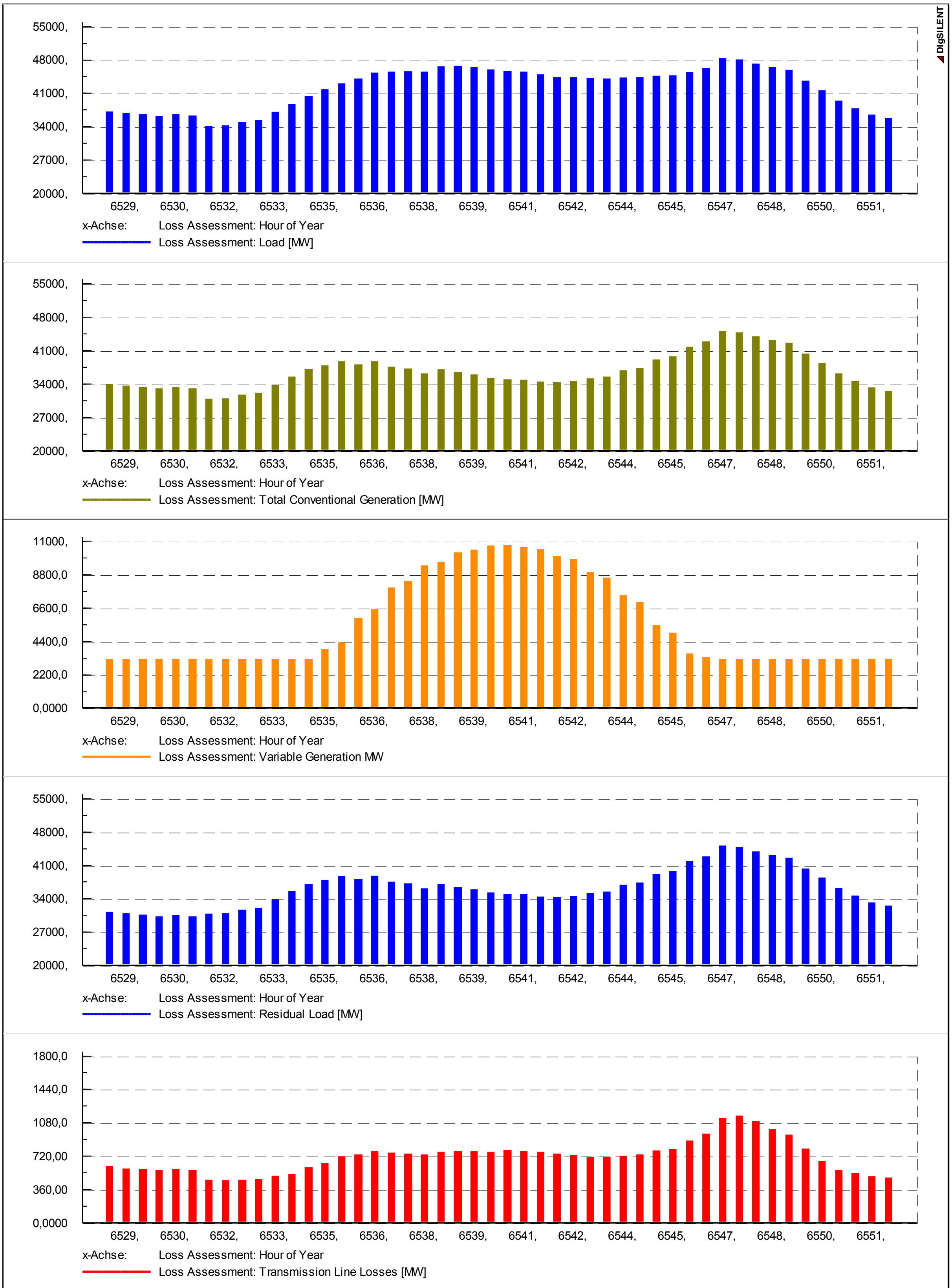








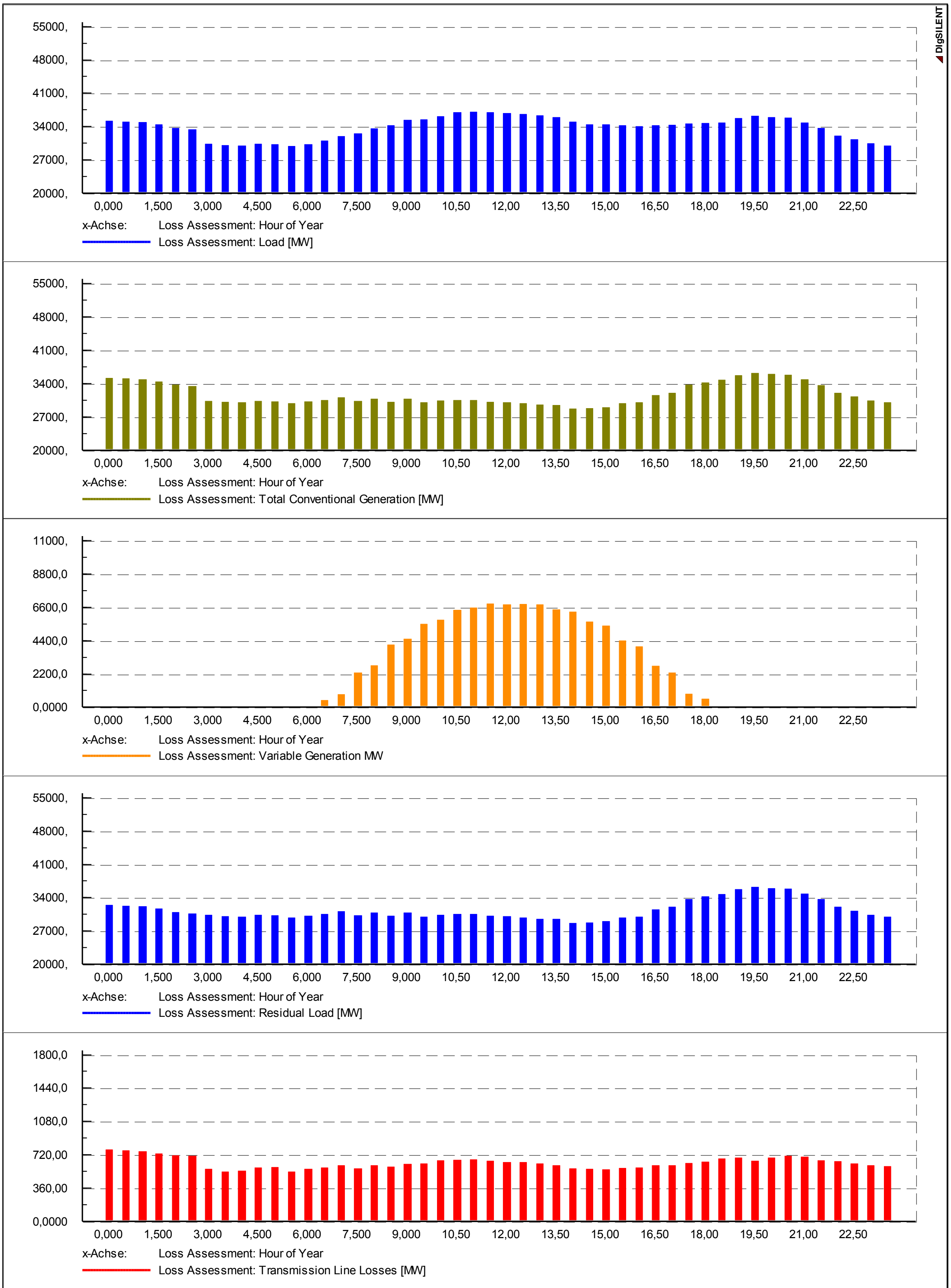
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	High Load (9th June)	Datum: 16.02.2015
	90% Wind	1x Koeberg Unit(s) Online	Anhang: 4.1.4 /2



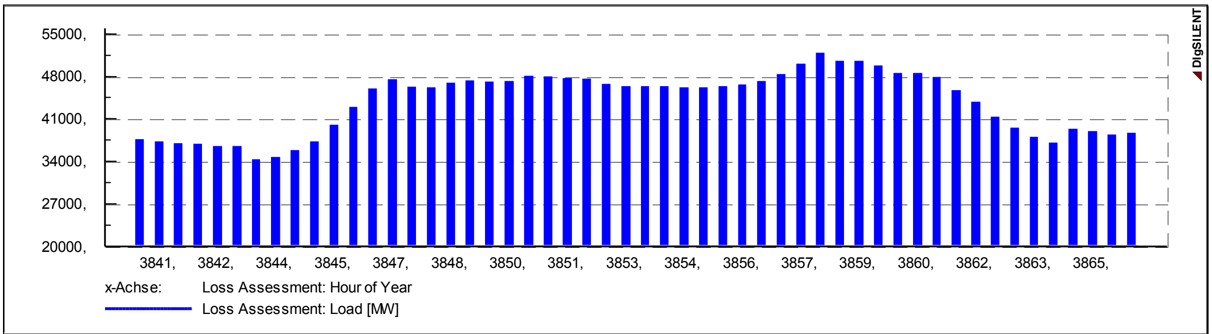
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	High PV (29th September)	Datum: 16.02.2015
	90% Wind	1x Koeberg Unit(s) Online	Anhang: 4.1.4 /3

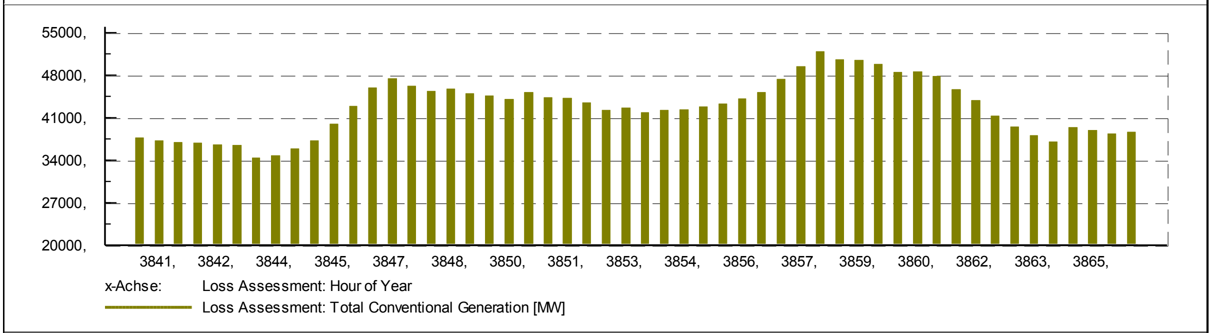
4.2 2x Koeberg Unit(s) Online

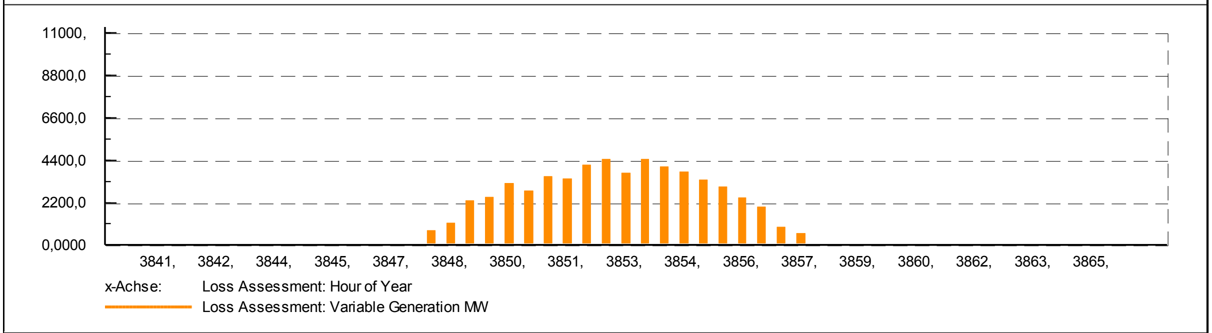
4.2.1 00% Wind

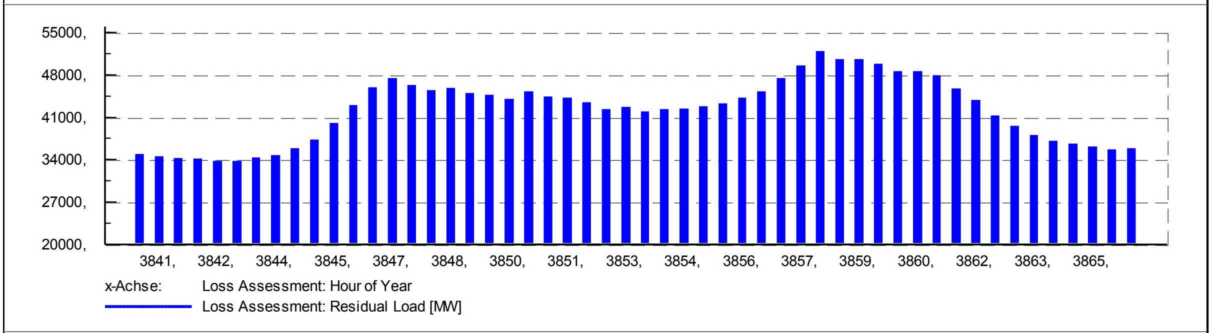


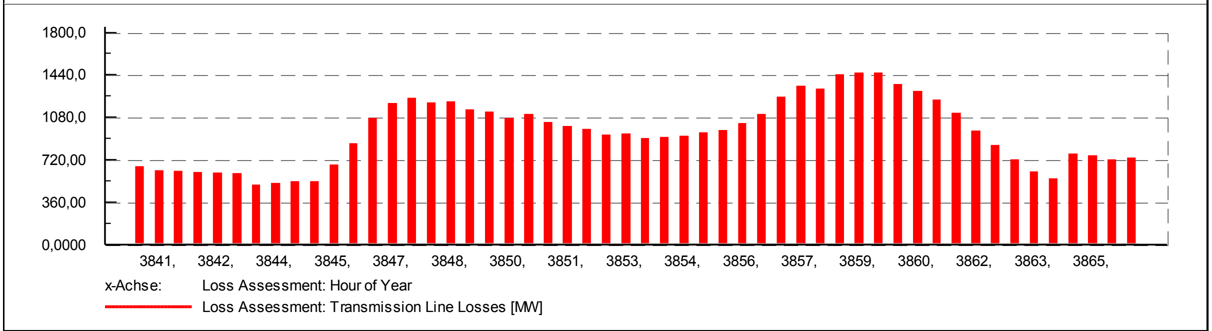
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	Low Load (1st January)	Datum: 16.02.2015
	00% Wind	2x Koeberg Unit(s) Online	Anhang: 4.2.1 /1



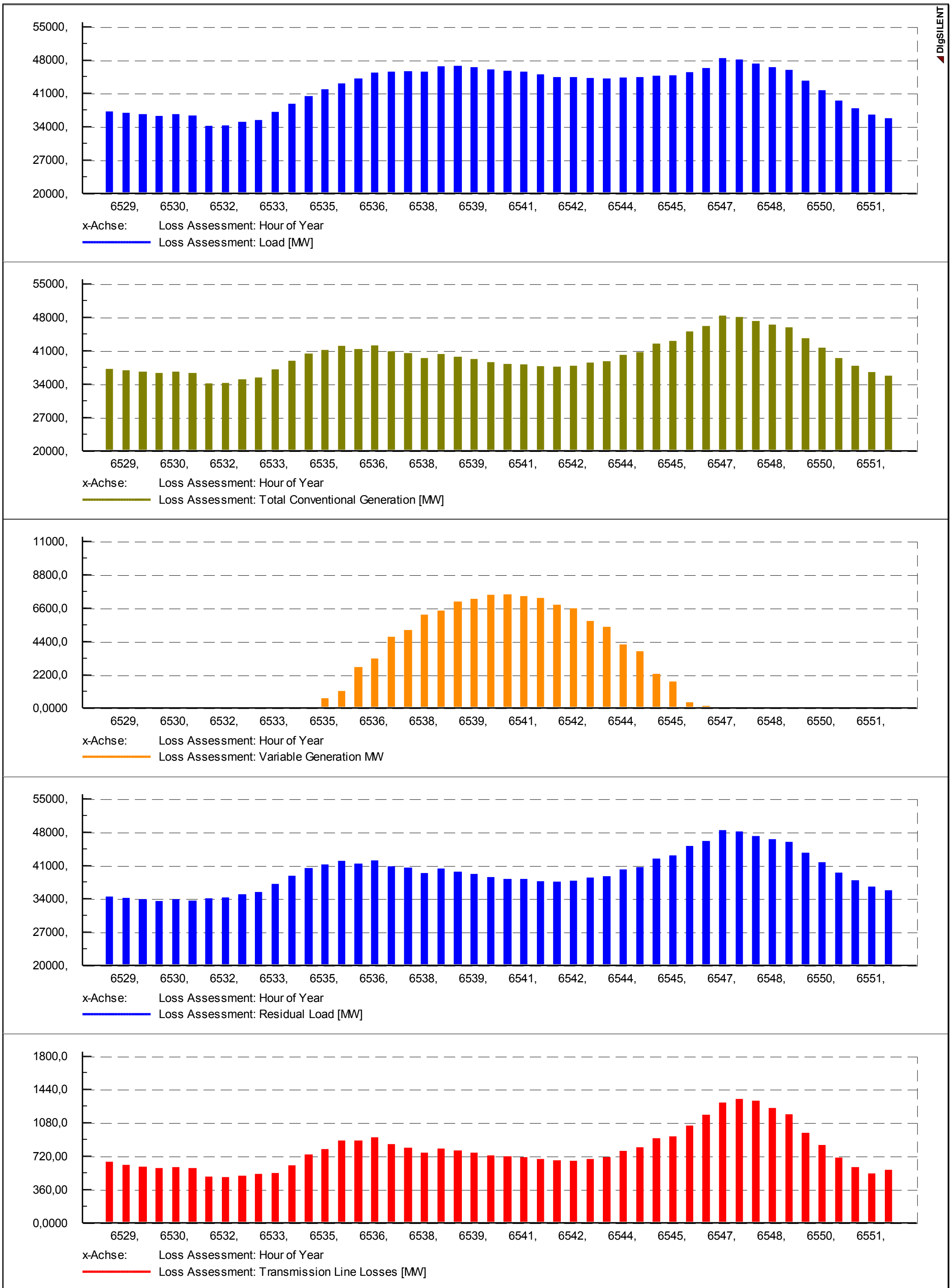






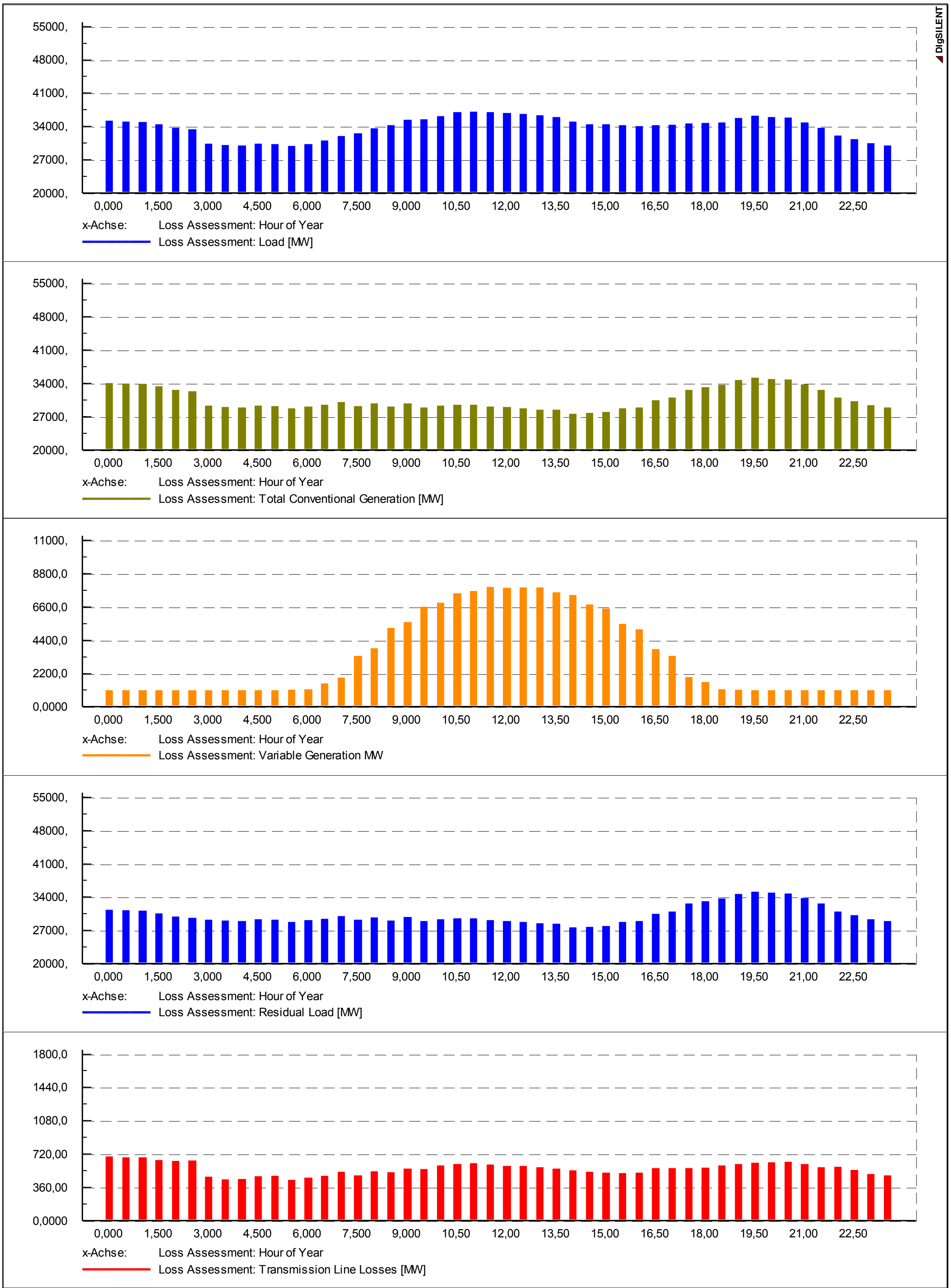


M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	High Load (9th June)	Datum: 16.02.2015
	00% Wind	2x Koeberg Unit(s) Online	Anhang: 4.2.1 /2

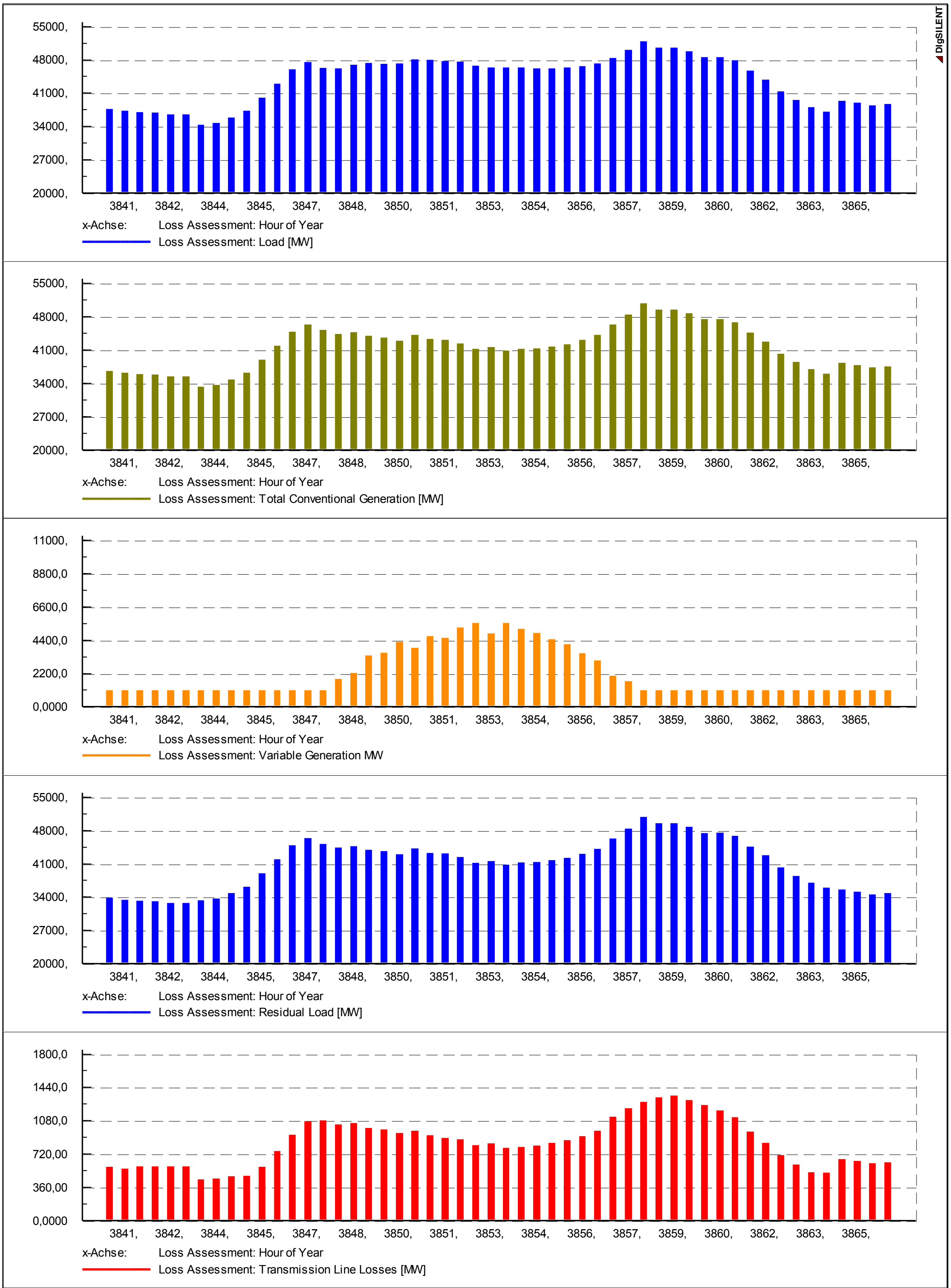


M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	High PV (29th September)	Datum: 16.02.2015
	00% Wind	2x Koeberg Unit(s) Online	Anhang: 4.2.1 /3

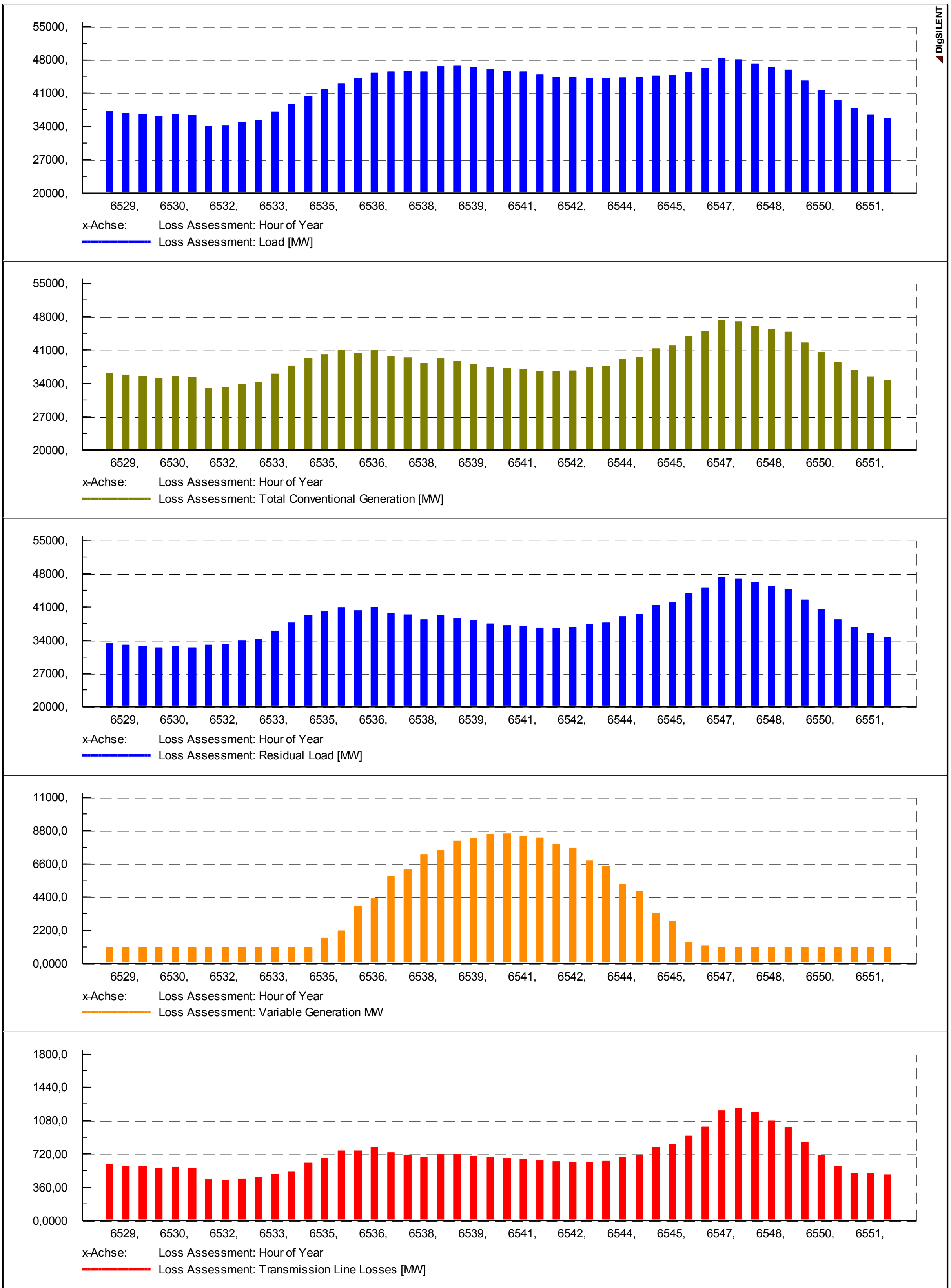
4.2.2 30% Wind



M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	Low Load (1st January)	Datum: 16.02.2015
	30% Wind	2x Koeberg Unit(s) Online	Anhang: 4.2.2 /1

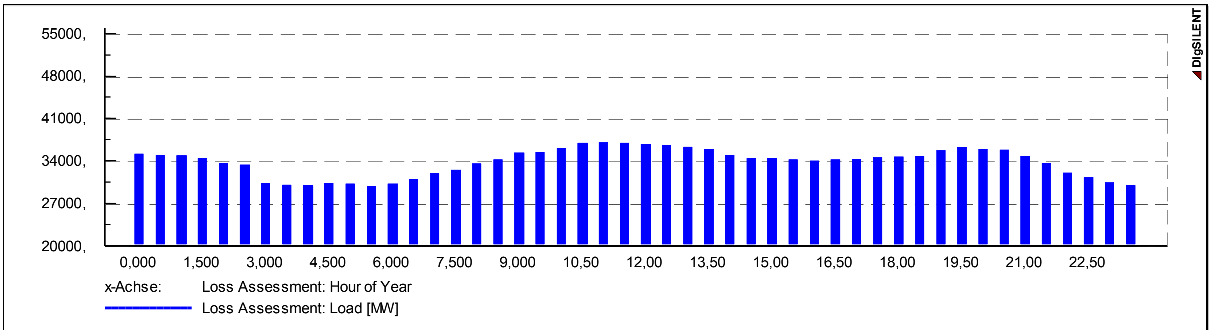


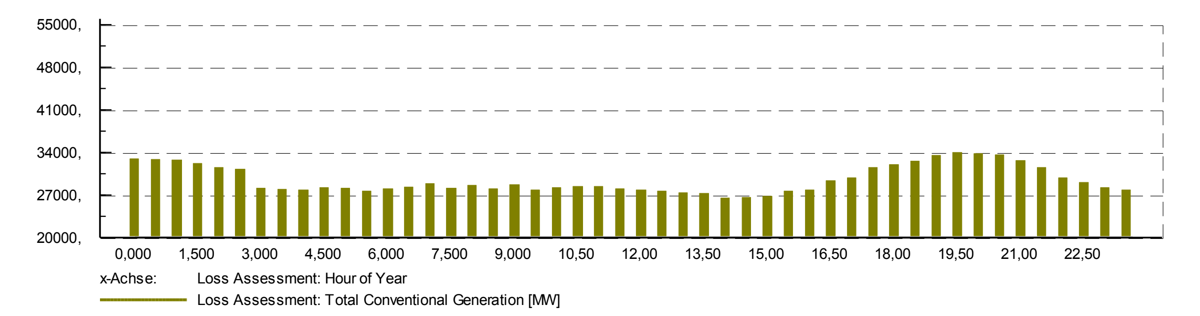
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	High Load (9th June)	Datum: 16.02.2015
	30% Wind	2x Koeberg Unit(s) Online	Anhang: 4.2.2 /2

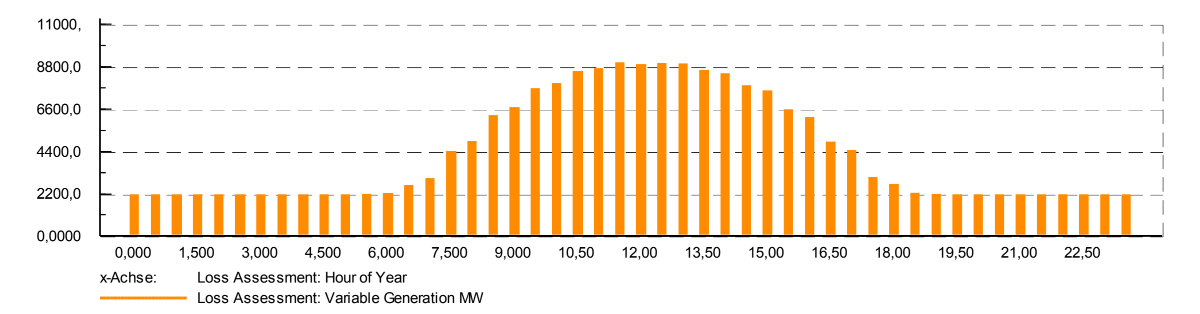


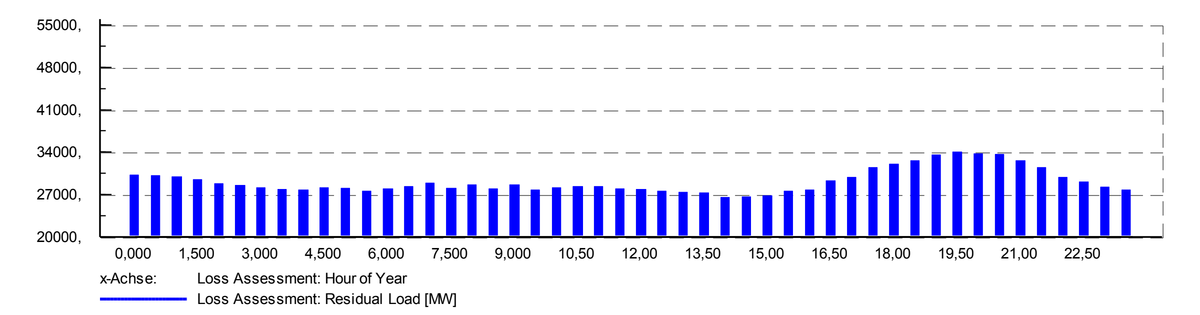
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	High PV (29th September)	Datum: 16.02.2015
	30% Wind	2x Koeberg Unit(s) Online	Anhang: 4.2.2 /3

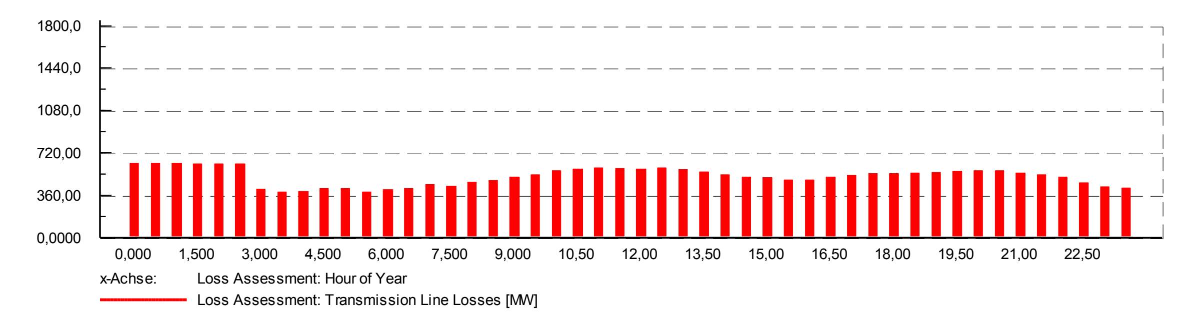
4.2.3 60% Wind



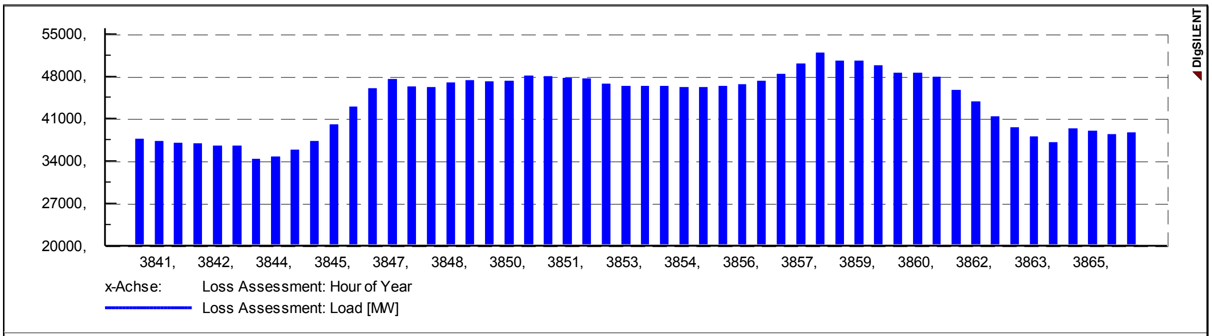


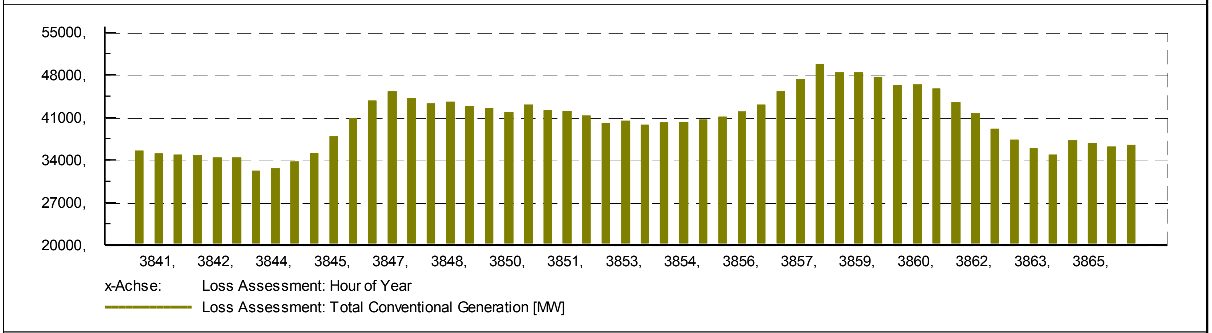


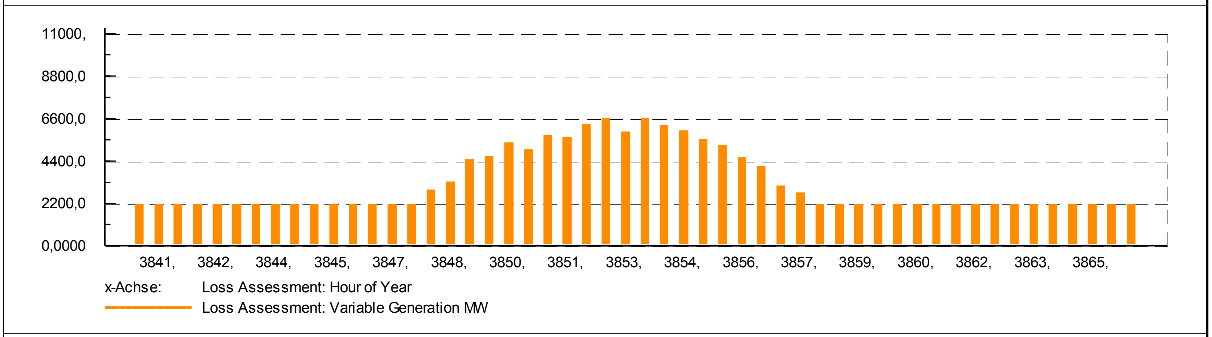


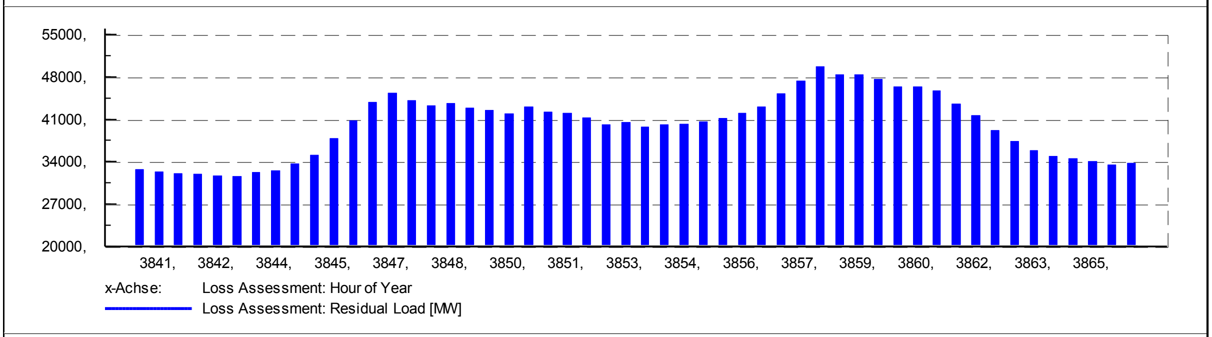


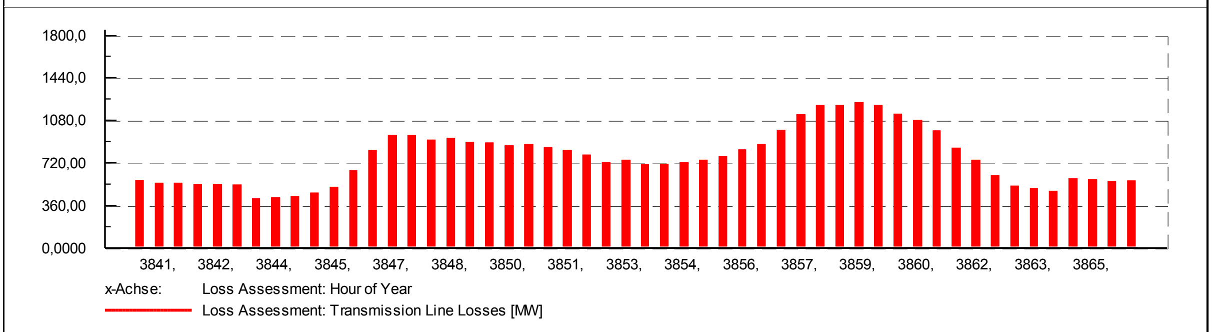
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	Low Load (1st January)	Datum: 16.02.2015
	60% Wind	2x Koeberg Unit(s) Online	Anhang: 4.2.3 /1



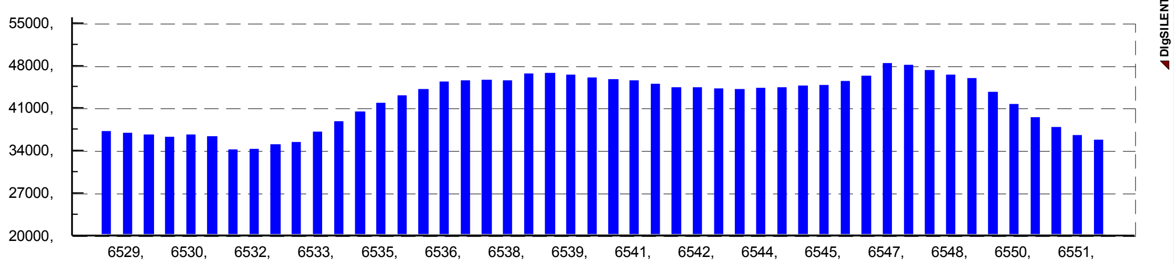




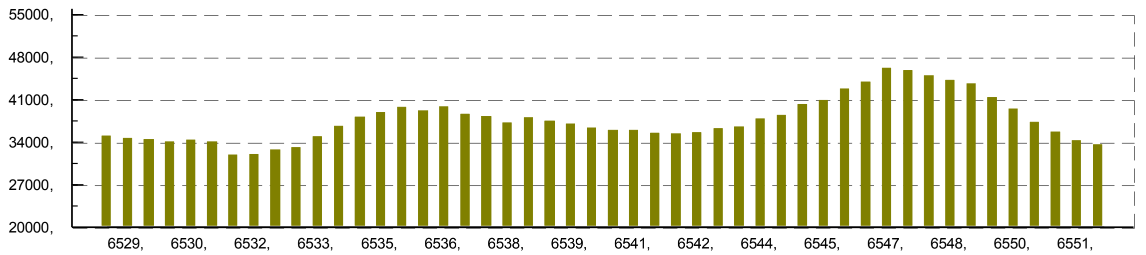




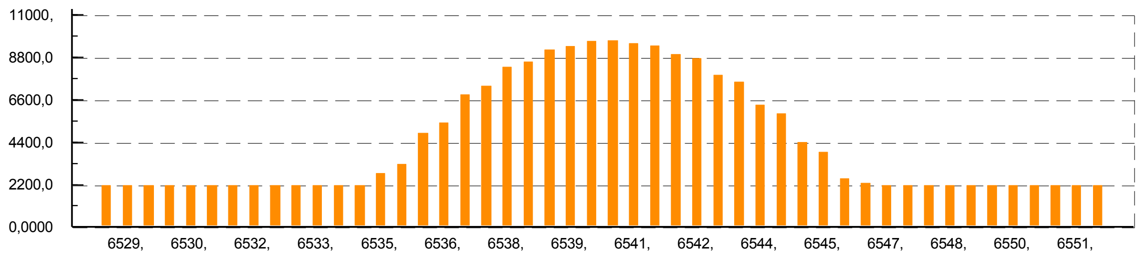
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	High Load (9th June)	Datum: 16.02.2015
	60% Wind	2x Koeberg Unit(s) Online	Anhang: 4.2.3 /2



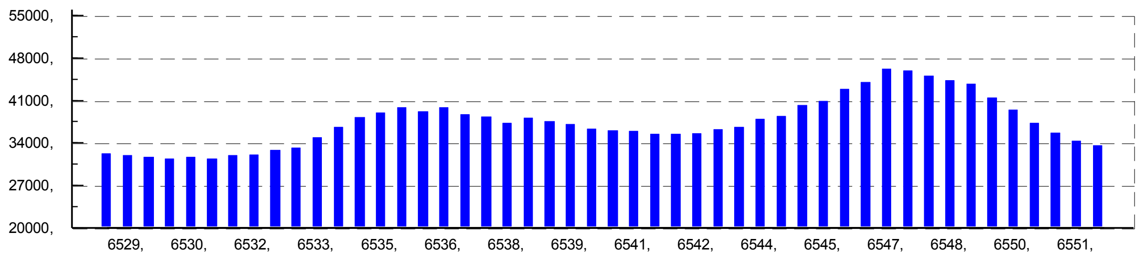
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Load [MW]



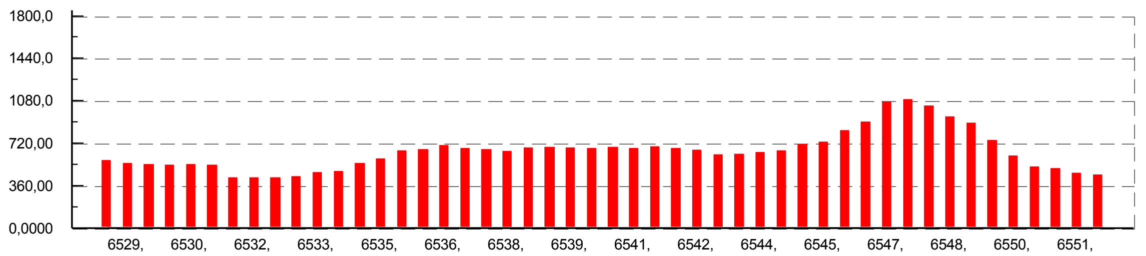
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Total Conventional Generation [MW]



x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Variable Generation MW



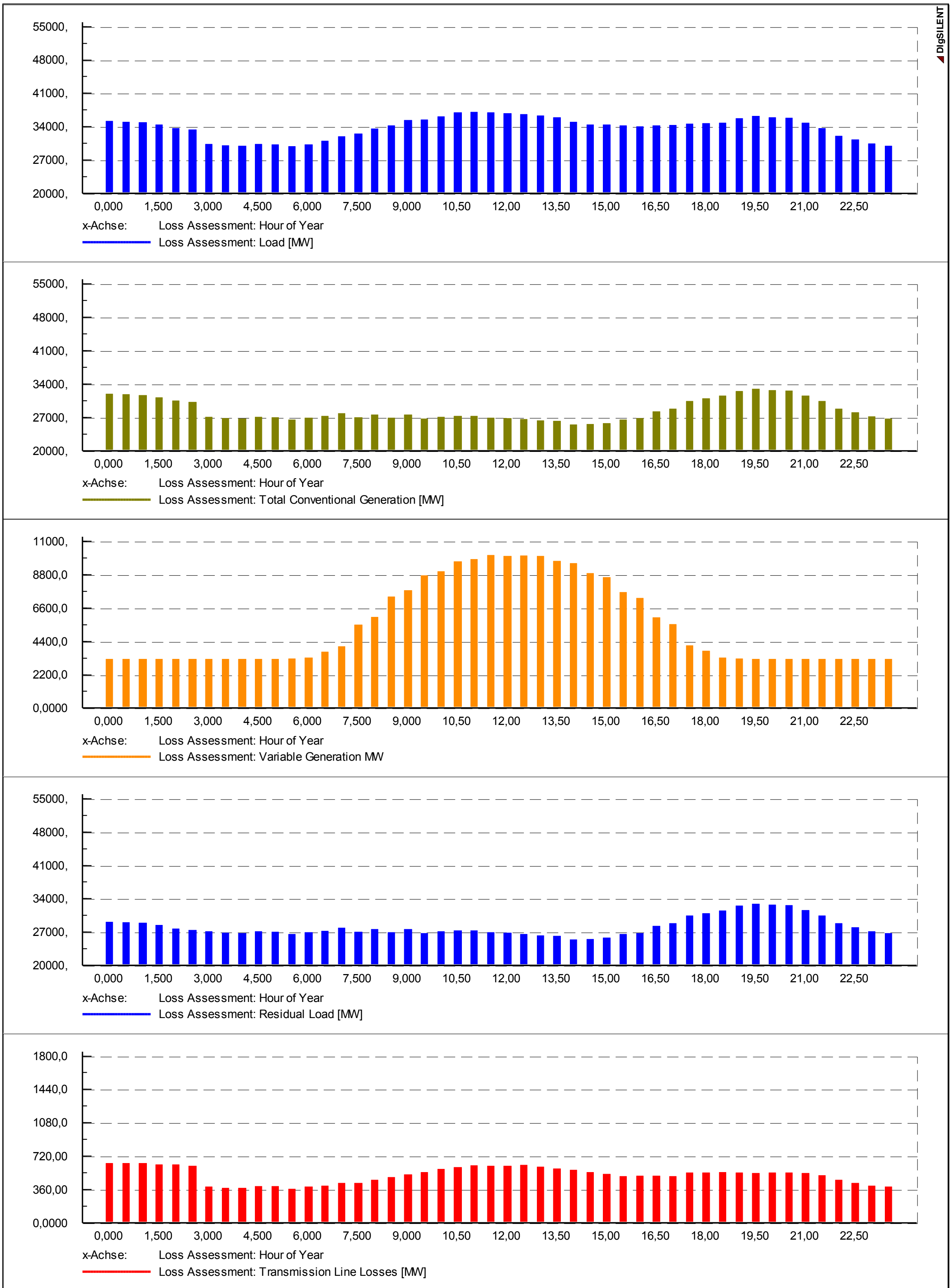
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Residual Load [MW]



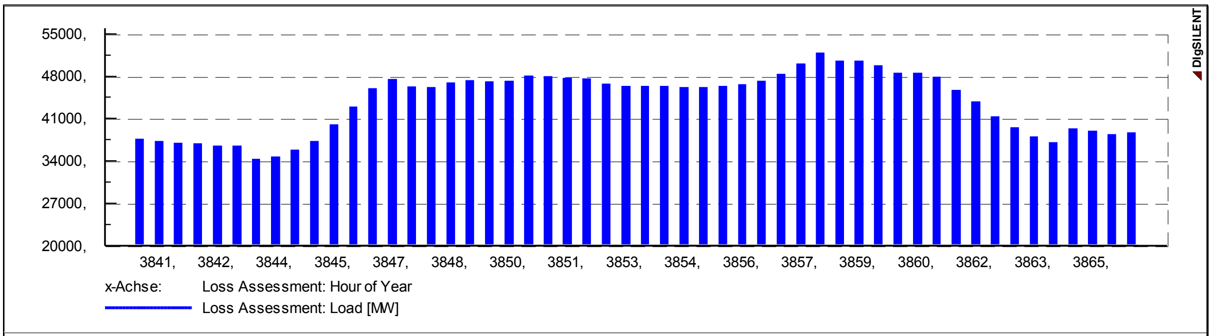
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Transmission Line Losses [MW]

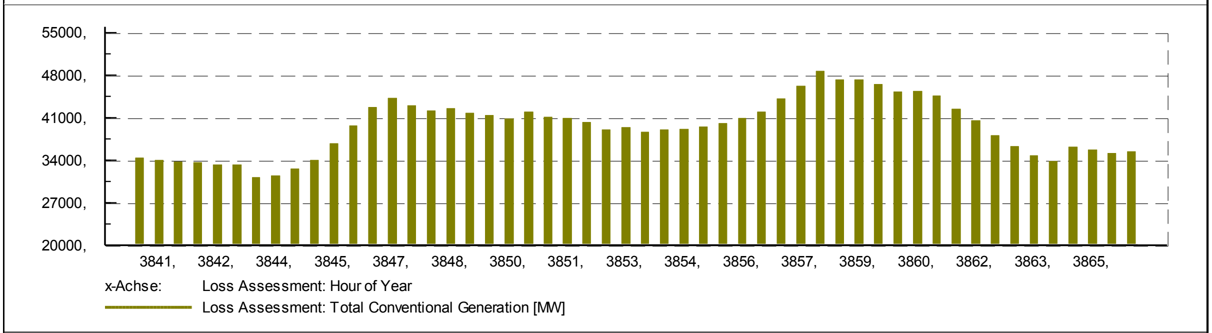
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	High PV (29th September)	Datum: 16.02.2015
	60% Wind	2x Koeberg Unit(s) Online	Anhang: 4.2.3 /3

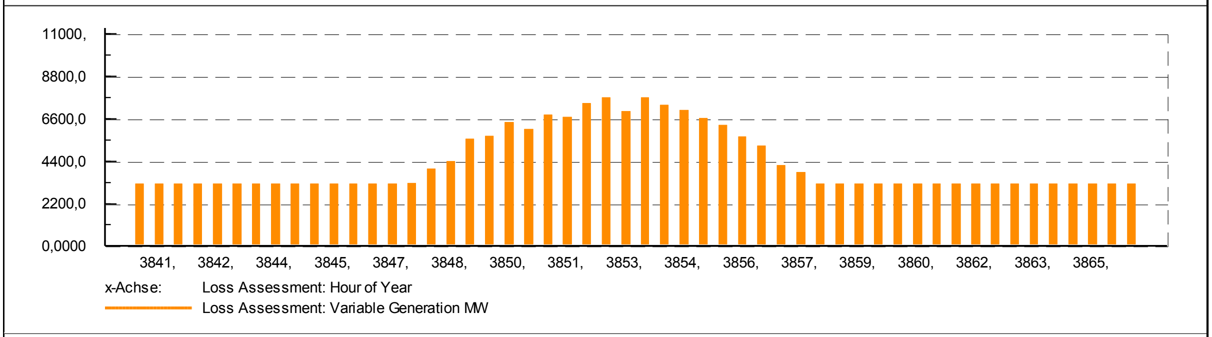
4.2.4 90% Wind

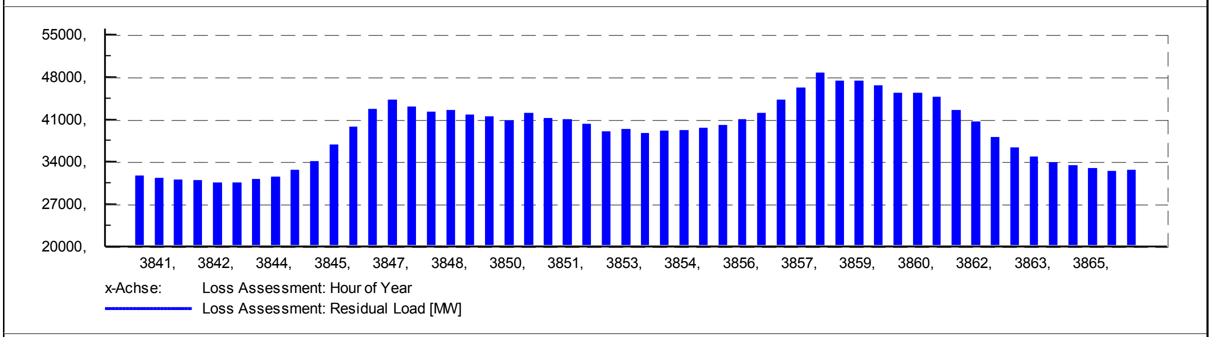


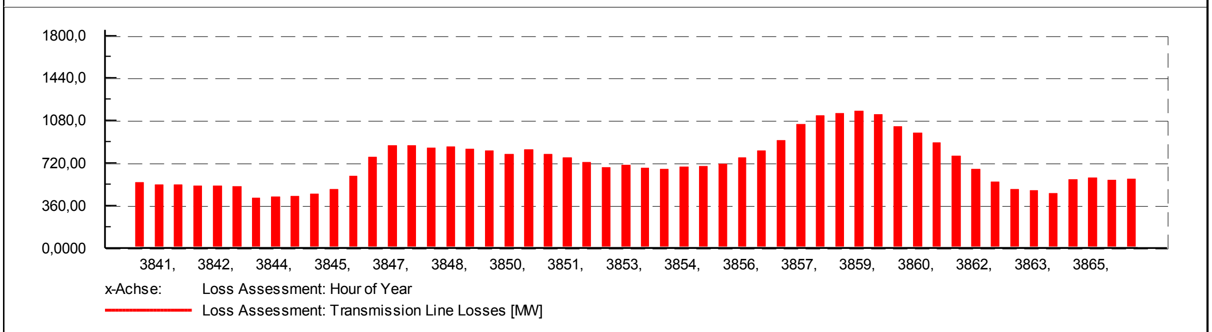
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	Low Load (1st January)	Datum: 16.02.2015
	90% Wind	2x Koeberg Unit(s) Online	Anhang: 4.2.4 /1



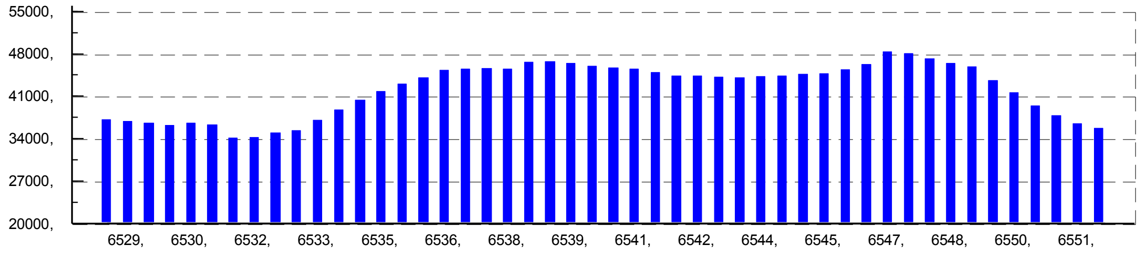




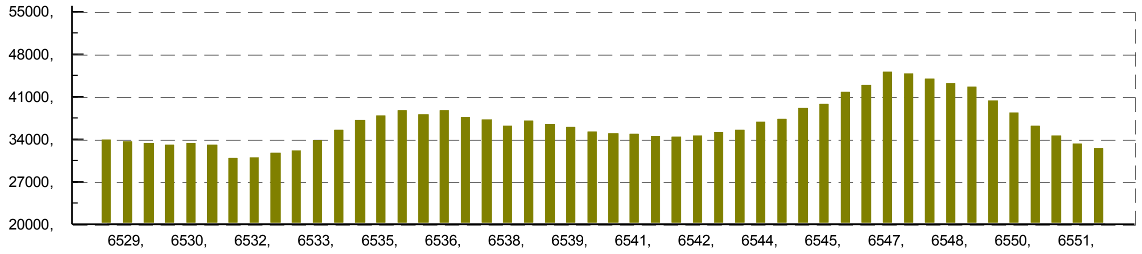




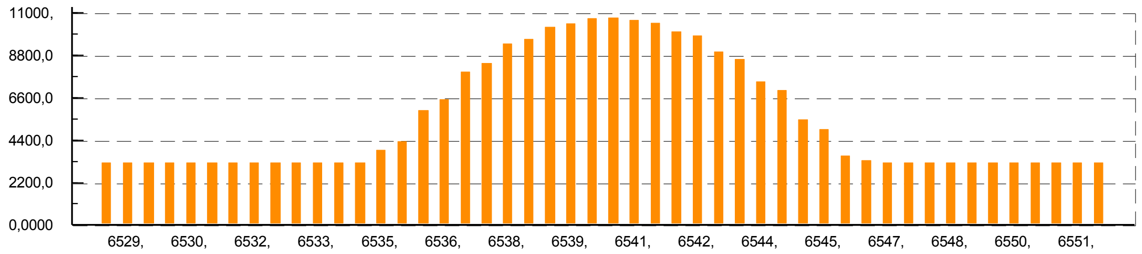
M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	High Load (9th June)	Datum: 16.02.2015
	90% Wind	2x Koeberg Unit(s) Online	Anhang: 4.2.4 /2



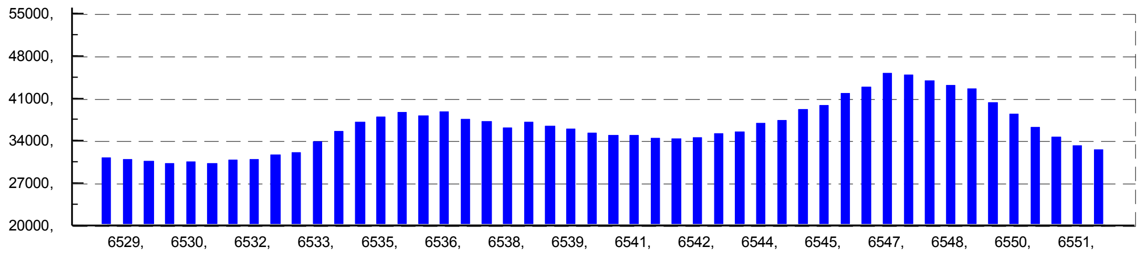
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Load [MW]



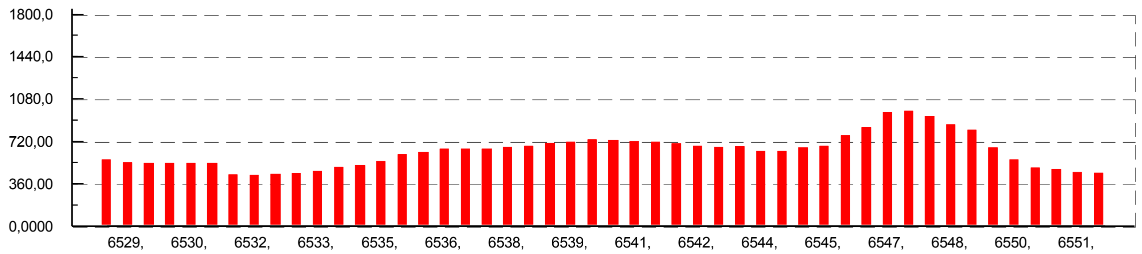
x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Total Conventional Generation [MW]



x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Variable Generation MW



x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Residual Load [MW]



x-Achse: Loss Assessment: Hour of Year
Loss Assessment: Transmission Line Losses [MW]

M.P.E. MOELLER & POELLER ENGINEERING	Scenario C	High PV (29th September)	Datum: 16.02.2015
	90% Wind	2x Koeberg Unit(s) Online	Anhang: 4.2.4 /3

7 References

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[2] South African Department of Environmental Affairs, "Renewable Energy EIA Application Database for SA," 2014. [Online]. Available: http://egis.environment.gov.za/Download.aspx?m=25.

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[4] ESKOM, "Power Station Ranking per Running Cost," 2014.

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8 List of Figures

9 List of Tables