Modelling Retrofitting Options for Autonomous Island Power Systems to Maximize Penetration of Variable Renewable Electricity

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Abstract - The installation of variable renewable electricity sources (VRE) in existing autonomous island power systems promises high potential for fuel, cost and emission reduction [15]. At medium to high penetration levels however, the volatile nature of wind and solar limits VRE's maximum feasible penetration. To maintain a secure and reliable system, the operator has the option to limit the VRE installation, curtail excessive amounts of electricity from VRE or deploy measures to increase the system's acceptance for VRE; e.g. by installation of storage capacities. These countermeasures are herein categorized as "Retrofit options". This paper presents a simulation model for a techno- economic analysis of autonomous island power systems in terms of the optimum system retrofit to accommodate high shares of VRE. It is separated into three sequential time series which allows an adequate pre-determination of the required spinning reserve as well as an assessment of the short term operation considering aspects like ramping abilities of the conventional generation units. The model is applied to a case study on the island Suðuroy of the Faroe Islands.

Keywords- variable renewable electricity, autonomous island power systems, modelling

I. INTRODUCTION:

Variable renewable energy (VRE) sources are characterized by an intermittent production since their output depends on the real time availability of their primary energy resource [14]. Power systems have to balance generation and varying demand at all times. Increasing VRE deployment increases the variability and rate of changes of the residual load, the remaining load portion carried by the conventional generation units [3]. At certain shares of VRE penetration the integration becomes challenging.

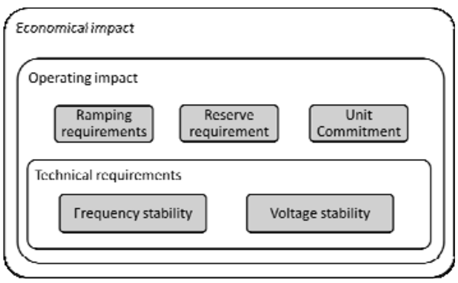

Figure 1. Schematic of VRE integration impact on autonomous island power systems

The fundamental technical requirements of a power system are to provide electrical energy within predefined frequency and voltage ranges. Variable generation impacts the systems in different time scales as well as in different width of area of the grid [1]. Some impacts are relevant on a local scale such as power quality or the voltage management [8][9], whereas others are concerning the whole system such as the reserve requirements [10]. These aspects are directly connected and interact each other; increasing the capacity of wind power within a power system for example leads to higher demand for spinning reserve in order to fulfill the technical system requirement of frequency stability [12][4]. This causes a change in the unit dispatch of the conventional power plants and therefore to the system operation. A change in the system operation, however affects the penetration, capacity factors and therefore the economy of the system [7]. Another aspect of VRE integration is the impact on the rotational inertia and frequency stability. VRE units, particular inverter-connected, do not provide rotational inertia and thereby reduce the overall inertia of the system [2][11]. Assuring sufficient amounts of generation is dispatched to fulfill these system requirements at all times is critical. Scheduling these generation resources by unit commitment planning is prepared by the system operator. The objective is to make available the correct combination of units for reliable and economic operation of the system, taking into account fuel cost and reserves required. Autonomous island power systems in particular are affected by increased VRE penetration [6]. Due to their limited size high VRE penetration levels are reached fast, Spinning reserve shares are high and the amount of conventional generation units for frequency and voltage control are limited. Following assumptions are made for the herein presented simulation model:

- Variable renewable electricity sources:
  - non-dispatchable renewable energy sources,
  - not contributing to Spinning reserve,
  - non-synchronous, not contributing to inertia,
  - contributing to Voltage control by supply of reactive power.
  - considered VRE sources: wind turbine generators (WTG), photovoltaic (PV), run-

off-river hydroelectricity.

- Autonomous island power system:
    - no Interconnection to neighboring or continental systems,
    - Aggregated power model.

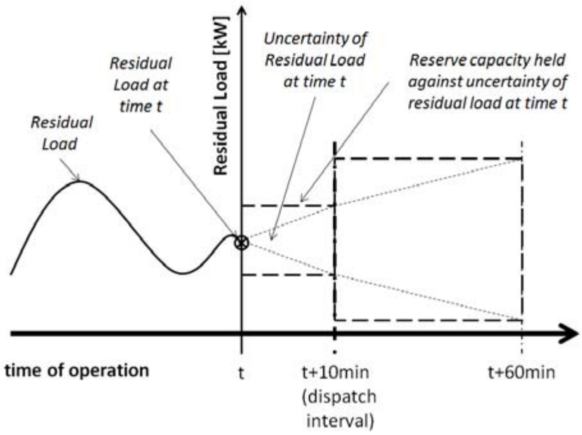

Figure 2. Addressing uncertainty in residual load using regulating reserve (herein defined as capacity to follow residual load from the forecasted 10 minute dispatch interval) and load following reserve (herein defined as capacity required to follow hourly load forecast to 10 minute dispatch interval) [13]

II. MODELLING APPROACH:

A. Modell Structure

The simulation model herein proposed may be devided into three technical sub-models as well as one economic model:

A. Reserve model (Fig.2):
Time intervall: 1hour, 10minutes, 30seconds
Methodology: Reserve calculated as difference of forecasted to actual value in each time step (1hour-forecast to 10minute-actual as Load following, 10minute-forecaste to 30second-actual for regulation). Data set generation by randomly generated forecast errors added to an underlying linear interpolated time series [5], Forecast error derived from Probability density function
Output: Regulation and Load-following reserve, Spinning reserve setting

B. Operation model (Actual dispatch):
Time intervall: 10minuntes
Methodology: Energy balance in each time step, Unit prioritization: VRE (penetration limits apply), Storage, Conventional generation,
Output: Capacity factors all generation units, Thermal start-up, VRE curtailment, Fuel consumption, Residual ramping reserve

C. Short-term Operation model:
Time intervall: 30seconds
Methodology: see Operation model
Output: Residual ramping reserve, Ramping speed, Additional VRE curtailment, Load curtailment

D. Economic model:
Methodology: Discouted cashflow calculation, VRE integration cost considdered: thermal unit start-up, VRE curtailment, partial loading of thermal units, cost-benefit calculation
Output: LCOE (each unit), System- LCOE, net benfit curves, retrofit benefit curves

All the models described above were implemented in MATLAB 7.10.0 (R2010a)).

B. Applied penetration limits for variable renewable electricity

To maintain secure system operation the amount of VRE within power systems needs to be constrained in relation to generation units that provide ancillary services. Following system constraints for VRE penetration are enforced in the simulation model:

- Conventional generation units loading limits: demand for ancillary services such as reactive power control and primary power control may require a certain amount of conventional generation unit dispatch, the operation of these units is constrained by their loading limits. Fig. 3 illustrates the relation between the conventional generation loading

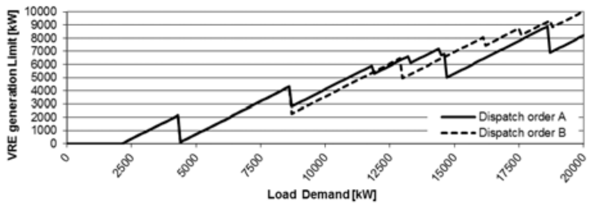

Figure 3. Example of VRE penetration limit as per Conventional generation units loading limits and two different dispatch order (with minimum Conventional generation loading of 50%)

- Spinning reserve requirement: Spinning reserve needs to be dispatched to the grid by conventional or storage units in order to provide capacity and/or ramping reserves. If conventional generation units have to be dispatched to provide spinning reserve the corresponding loading limits for these units apply. The spinning reserve requirement is herein calculated as the maximum regulating reserve required during one year of operation.

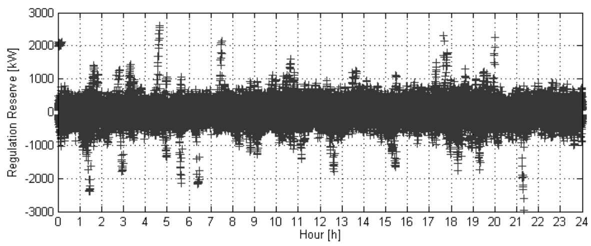

Figure 4. Boxplot of simulated regulating reserve (one year plotted in 24 hours, WTG installation of 3,000kW)

- Ramp rate of conventional generation units: An increasing share of VRE power in the grid usually increases the residual Load changes within the system. In order to maintain the energy balance within the system conventional or storage units need to provide the residual power in a certain timeframe. Ramp rate limits of the generation units might limit the ability to follow the load changes.

- Dynamic limit (based on critical Rate-of-change-of frequency (ROCOF)): With increasing VRE penetration rotating mass that is contributing to system inertia (H) is replaced; according to the aggregated swing equation [2] the ROCOF (df/dt) and consequently the frequency drop will increase. In order to limit the maximum ROCOF ($(df/dt)_{max}$) in relation to a maximum expected load drop (p_{max}) the share of VRE is limited to (c_{Dyn}):

$$c_{Dyn}=(1-p_{max}/(2*H_{noVRE}*(df/dt)_{max})*f_0) \quad (1)$$

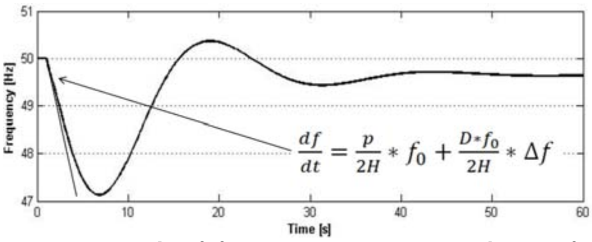

Figure 5. Example of frequency response event with Rate-of-change-of-frequency (df/dt) after a Load change p on system with Inertia H, Damping D and frequency f_0

- Reactive power balance: As real power, reactive power needs to be balanced within the power system at all times. Since reactive power supply by VRE units is limited, conventional generation units or storage units need to be dispatched to provide the remaining reactive power. This share of conventional generation units or storage units within the system limits the maximum VRE penetration.

C. *Retrofit Benefit calculation*

As the last step of the simulation approach the results of the operating analysis are used to determine the economic parameters of the simulated system setup. Therefore the cost of electricity for the generation units are calculated using discounted cash flow calculation. Furthermore the following VRE integration cost are considered:

- Thermal unit start-up: The increase in residual load variation effects the demand for thermal unit start-ups. Starting up a thermal generation unit such as a diesel or a heavy fuel generator requires a certain amount of fuel as well as it increases wear and tear of the units.

- Load reduction of thermal units: Allowing a higher share of VRE power within the power system usually reduces the loading of the thermal units since they still have to provide the spinning reserve. This load reduction of the thermal units can lead to a less efficient operating point for the thermal units. In order to capture these cost on a system level the cost difference to a system operation without VRE installation to the system using VRE is calculated.

- VRE curtailment: Maintaining the must-run-capacity of thermal generation units and meeting the penetration limit requirements might require curtailing a certain amount of VRE. Since the production cost of electricity remain no matter if the energy is curtailed or penetrated to the grid, curtailing VRE creates additional cost to the overall system. These cost can also be understood as the cost for overproduction of VRE.

The levelized cost of electricity (LCOE) for the overall system (sLCOE) is calculated considering the generation cost for the generation units as well as the system level integration cost. These results are used for a cost-benefit analysis which is based on the concept of net benefit calculation [16]. The net benefit is calculated as the annual difference of system cost subtracted by the benefits. The cost are calculated as present values over the span of the power plants' lifetimes of summed development capital expenditures (CAPEX), operating expenditure (OPEX) for the VRE deployment and retrofit as well as the VRE integration cost. The benefits are the system level savings generated due to the VRE installation like CAPEX savings for planned capacity deployment, Fuel savings and saved emission cost. To compare retrofit options among each other net benefits of two cases may be compared by calculating retrofit benefit as follows:

$$RetrofitBenefit_{A-B,j}=NetBenefit_{CaseA,j} - NetBenefit_{CaseB,j} \quad (2)$$

III. CASE STUDY:

The proposed simulation model is applied to the autonomous island power system of Suðuroy, the southernmost of the Faroe Islands with a size of 163.7 km^2 and almost 4,700 inhabitants (as per 2012). It is powered by two thermal power plants using heavy oil and diesel combustion generator sets (2MW diesel; 2x 2.7MW, 4.15MW heavy fuel) as well as one hydro power plant (1MW Pelton-; 2MW Francis-turbine).

To assess the performance of a pump hydro system in three retrofit scenarios are simulated. In all cases WTG installation with incremental installation increasing from 0kW to 10,000kW in 1,000kW increments are investigated. At first the base scenario, WTG installation without retrofit, was simulated. The base scenario does not consider structural adjustment to the existing grid. In the next step the system is analysed considering the installation of a pump hydro system. The capacity of the turbines is preselected to be half of the installed WTG capacity. The pump capacity equals the installed WTG capacity. Two pump hydro operation strategies are simulated; "stand-alone" operation in which the WTG power is solely used to operate the hydro pumps and "WTG to grid" operation, where WTG power that exceeds a power penetration of 25% is used to store excessive WTG generation in the upper reservoir of the pumped hydro storage. In the last scenarios a short-term storage system is simulated for both of the two pump hydro options in order to replace spinning reserve provided by the thermal generator sets with spinning reserve of the storage system.

TABLE I.

ID	***Retrofit Option***
Base	No retrofit
A1	Pumped hydro storage as "Stand-alone"

ID	*Retrofit Option*
A2	Pumped hydro storage as “WTG to grid“[a]
B	Short-term Storage for Spinning reserve

a. max. WTG to grid 25% power penetration

A. Reserve analysis:

In the first step a sequential time series analysis is performed in order to determine the system demand for regulation reserve (see Fig. 6). The demand for regulation reserve is calculated for the “WTG to grid” operation strategy of the pumped hydro system (retrofit option A2). The demand is a function of the WTG capacity installed and the “WTG to grid“ setup since it determines how much variable WTG capacity is dispatched to the grid. For the “stand-alone” application of the pumped hydro storage (retrofit option A1) which uses all WTG generation for pumping, the demand for spinning reserve is the same as for the “WTG to grid“ strategy with 0kW WTG installed. Hence the demand for spinning reserve is remaining unchanged no matter how much WTG capacity is connected to the pump hydro system. This is obvious since no WTG capacity is directly connected to the grid, hence the WTG installation does not impact the demand for regulating reserve.

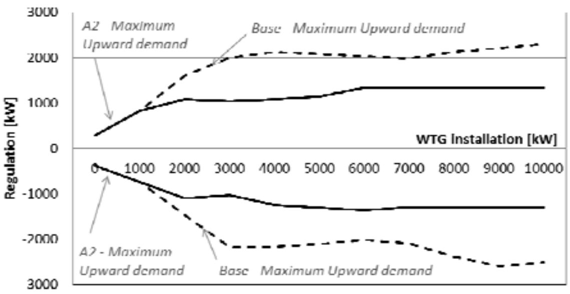

Figure 6. Regulation per WTG installation for base and retrofit scenario A2

B. Operation analysis:

In the second step the operation is simulated for the proposed retrofit options in Table I. The retrofit combination of Pump hydro storage (A) combined with a short term storage system (B) promises the highest potential for fuel savings since conventional generation units may be shut-off while no system constraints for VRE are violated (see Fig.7).

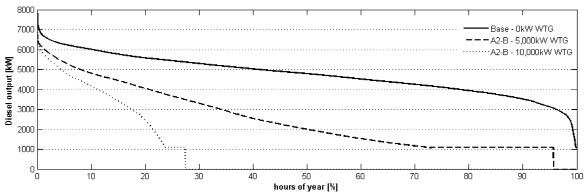

Figure 7. Diesel duration curves of base-case and retrofit cases using pumped hydro storage as “WTG to grid“ application (A2-B) for 5,000kW and 10,000kW WTG installation

In order to shut-off the thermal power plants, spinning reserve needs to be provided by sources other than the thermal generator sets. While using short-term storage to provide spinning reserve the thermal generator sets are dispatched only to follow the remaining residual load. The remaining residual load is the resulting feeder load after accounting hydro generation (by the existing hydro power plants), WTG generation (if “WTG to grid” strategy is used) and hydro generation by pump hydro turbines. If pump hydro turbine capacity or charge level are not sufficient to feed the total residual load, thermal generator sets have to be dispatched. The results of this retrofit case are summarized in table II. and III. Short-term storage for spinning reserve does significantly reduce the diesel penetration. In the “stand-alone” pump hydro operation the short-term storage has an effect on the diesel penetration if more than 3,000kW WTG are installed. In the “WTG to grid“ pump hydro operation the short-term storage has an effect on the diesel penetration if more than 2,000kW WTG are installed. An effect on the fuel consumption can be seen in all WTG installation scenarios. Another positive effect of using short-term storage is that both systems meet the ramping requirements up to the analysed WTG installation of 10,000kW. By comparing the two pumped hydro operation strategies it can be seen that allowing a direct WTG penetration to the grid results in a lower diesel penetration. At the same time the sum of energy produced is lower.

TABLE II.

WTG capacity [kW]	Penetration and fuel consumption retrofit case A1-B					
	Diesel penetration [%]	WTG Penetration [%]	WTG_{Curt} penetration [%]	PS-Turb penetration [%]	Hydro penetration [%]	Fuel consumption [10^6 l]
0	91%	0%	0%	0%	9%	9,1
1000	83%	0%	0%	8%	9%	8,5
2000	75%	0%	0%	16%	9%	7,8
3000	67%	0%	0%	24%	9%	7,1
4000	60%	0%	0%	31%	9%	6,4
5000	53%	0%	-1%	38%	9%	5,7
6000	47%	0%	-1%	45%	9%	5,0
7000	41%	0%	-2%	52%	9%	4,4
8000	35%	0%	-3%	59%	9%	3,8
9000	30%	0%	-3%	64%	9%	3,3
10000	25%	0%	-3%	68%	9%	2,7

TABLE III.

WTG capacity [kW]	Penetration and fuel consumption retrofit case A2-B					
	Diesel penetration [%]	WTG Penetration [%]	WTG_{Curt} penetration [%]	PS-Turb penetration [%]	Hydro penetration [%]	Fuel consumption [10^6 l]
0	91%	0%	0%	0%	9%	9,1
1000	79%	11%	0%	1%	9%	8,1
2000	69%	16%	0%	6%	9%	7,3
3000	61%	17%	0%	13%	9%	6,4
4000	54%	18%	-1%	20%	9%	5,7
5000	47%	18%	-2%	28%	9%	5,0
6000	41%	19%	-3%	35%	9%	4,4
7000	34%	19%	-3%	42%	9%	3,6

8000	27%	19%	-2%	47%	9%	2,9
9000	22%	19%	-1%	51%	9%	2,3
10000	18%	19%	0%	54%	9%	1,9

C. *Short term Operation analysis*

A ramp rate analysis is conducted in order to determine the maximum WTG installation scenario for retrofit case. Ramp rate analysis uses the 30 second real time interval. The maximum capacity that can be ramped upwards or downwards depends on the operating point of the operation constraints of the thermal generator sets. In order to provide sufficient ramping capacity additional spinning reserve has to be dispatched or to be provided by sources with higher ramp rates. For all storage systems it is assumed that they can provide 100% of their output capacity within the 30 second interval. In the following simulation the ramp rate analysis is not used to determine the adequate spinning reserve setup but as a determination for the maximum allowed WTG installation. The spinning reserve used for the simulation is determined based on the maximum required regulation capacity.

The ramping capabilities may limit the maximum installed WTG capacity the grid can accommodate. In order to bypass this constraint, short-term storage systems should provide spinning reserve instead. This would allow diesel-off operation and therefore a further reduction of diesel penetration. To reveal further fuel saving potential, the power system is simulated using pump hydro storage and short-term storage systems. The simulation is performed for both pump hydro operation strategies. The short-term storage capacity is determined based on the amount of spinning reserve capacity required. For the retrofit case using “stand-alone” pump hydro storage and short-term storage (retrofit case A1-B), the installed short-term storage capacity is 500kW for all WTG installation scenarios. For the retrofit case using “WTG to grid” pump hydro storage and short-term storage (retrofit case A2-B), the installed short-term storage capacity is adjusted to the installed WTG capacity depending on the demand for spinning reserve.

TABLE IV.

ID	***Maximum WTG installation based on short term Ramping ability of the system [kW]*** [b]
Base	2.000
A1	9.000
A2	4.000
B	>10.000
A1-B	>10.000
A2-B	>10.000

b. Setup: maximum change in conventional generation of 25% rated capacity per Minute

D. *Economic analysis*

The cost-benefit analysis is conducted on three retrofit options: first, the installation of short-term storage system where the capacity of the storage is determined by the amount of spinning reserve required (retrofit case B). Second, in addition to the short-term storage system a pumped hydro storage is considered where the storage system operates as a “stand-alone” system with the VRE units (retrofit case A1-B). This means that the VRE generation is solely used to operate the pumps of the pumped hydro storage. The third retrofit option is a pumped hydro storage system which operates in “WTG to grid“ mode. In this mode the VRE units feed up to 25% of the system load into the grid. All generation exceeding this penetration threshold is used to operate the pumps of the pumped hydro storage.

In order to compare the proposed retrofit options the retrofit benefit is calculated. As shown in figure 6.8 the retrofit benefit of the retrofit options B, A1-B and A2-B is calculated in relation to the base-case scenario (emission cost of carbon dioxide are not considered). It shows that the retrofit option A1-B is not beneficial compared to the base-case scenario up to a WTG installation of 4,000kW. Up to a WTG installation of 8,000kW, retrofit case B is the most beneficial retrofit option among the base-case scenario. At installation levels higher than 8,000kW, option A2-B becomes the most beneficial option. Based on these results it can be seen that the pumped hydro storage system reveals its best potential at high WTG installation levels. At moderate and low WTG installation levels it is more beneficial to install short-term storage systems to provide spinning reserve. Fig. 9 summarizes Penetration levels and the net benefit in relation to the installed VRE capacity for the optimum retrofit case. The optimum retrofit case is determined by the maximum retrofit benefit in relation to the Base scenario.

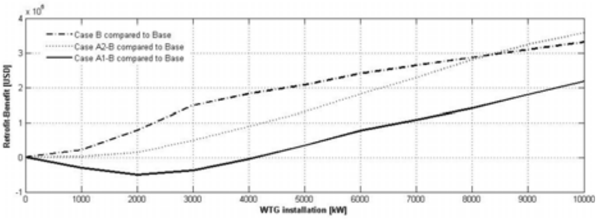

Figure 8. Retrofit-benefit curves of retrofit case B, A1-B and A2-B compared to the base-case scenario

IV. CONCLUSION:

This paper presented a simulation model which allows to determine best practice retrofit and VRE deployment for an autonomous island power system. At all times system reliability and security is maintained by enforcing technical and operational limits. Regulation and load-following reserves can be pre-determined; high resolution time-series allow to assess impacts of VRE’s short term variability on ramping reserve and speed. Existing methods consider hour-level wind/solar statistic data, but cannot reflect the random nature of VRE. The determined capacities may be over- or under-sized for system requirements at short time scales. A special focus is applied to the retrofit options which can act as an enabler for increased VRE penetration. Additionally a cost-benefit analysis has been proposed allowing to study different retrofit options in regard to their net benefit. Multiple retrofit options can be compared and their benefit among each other can be quantified using the "retrofit benefit" benchmark. The proposed model is applied to a case study. Fig. 9 shows its optimum retrofit case in terms of maximum net benefit in relation to the installed VRE capacity.

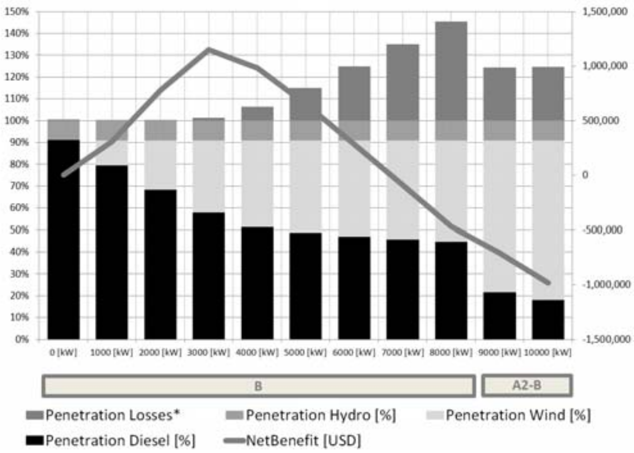

Figure 9. Retrofit option providing maximum annual net benefit depending on the installed capacity of wind power including corresponding penetration levels (*losses are considered here as pumped hydro losses and wind curtailment)

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APPENDIX:

Input Data Case study, Suðuroy,

Coordinates:	61°32′N 6°51′W
State	Kingdom of Denmark
Constituent country	Faroe Islands

Simulation Input Data – Technical:

➢ Data set generation:

WTG 30sec forecast error STDEV []:	0.05
WTG 1h forecast error STDEV []:	0.1
Load 1h forecast error STDEV[]:	0.05

➢ Wind power:

Height factor (calculated per Logarithmic wind profile law):

- WTG head height/ h2 [m] 50
- Anemometer height/ h1 [m] 10
- Roughness factor /z0 [] 0.15

WTG power curve per: ENERCON E33

➢ Conventional generation units

Diesel ramping [1/60s]:	0.25
Diesel minimum loading [kW/kW$_{rated}$]:	40
Thermal efficiency at full load []:	0.47
Heat rate [kJ/kWh] (CAT MAK 9M32)	7600
Specific fuel oil consumption [g/kWh]	CAT MAK 9M32

TABLE V.

Generator set	*Dispatch order*	
	Rated power [kW]	***Order []***
Plant 1 - Gen1	2700	1
Plant 1 - Gen2	4150	2
Plant 1 - Gen3	2700	3
Plant 2 - Gen1	2000	4

➢ Storage:

Pumped hydro round cycle efficiency [] 0.75

➢ VRE constraints:

Dynamic Penetration limit WTG:

- Intertia w/o VRE/ H_{NoVRE} [s] 3.5
- Load change (max.)/ p_{max} [kW/kW] 0.1
- Grid Frequency/ f_0 [Hz] 50
- ROCOF/ $(df/dt)_{max}$ [Hz/s] 1.5

Reactive Power limit:

- Power Factor Load [] 0.92
- Power Factor VRE [] 0.95
- Min. Power Factor Diesel [] 0.80

Simulation Input Data - Economic:

Inflation rate [1/a]:	0.02
WACC [USD/USD]:	0.1

➢ Wind power:

WTG derating [1/a]:	0.001
WTG CAPEX [USD/kW$_{peak}$]:	3000
WTG OPEX [USD/kW$_{peak}$]:	30
WTG lifetime [a]:	25

➢ Conventional generation units

Diesel price [USD/l]:	0.856
Diesel price increase [1/a]:	0.02
Diesel derating [1/a]:	0.001
Diesel CAPEX [USD/kW$_{peak}$]:	350
Diesel OPEX [USD/kW$_{peak}$]:	50
Diesel lifetime [a]:	25

➢ Storage

Short-Term Storage derating [1/a]:	0.001
Short-Term Storage CAPEX [USD/kW$_{peak}$]:	1500
Short-Term Storage OPEX [USD/kW$_{peak}$]:	0.15
Short-Term Storage lifetime [a]:	30
Pump Hydro Storage derating [1/a]:	0.001
Pump Hydro Storage CAPEX [USD/kW$_{peak}$]:	6500

Pump Hydro Storage OPEX [USD/kW_{peak}]: 0.0001
Pump Hydro Storage lifetime [a]: 30