Integration of Renewable Energy and the Benefit of Storage from a Grid and Market Perspective – Results from Morocco and Egypt Case Studies

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***Abstract*—This paper presents results from case studies of the future power systems in Morocco and Egypt, with a high increase in renewable generation capacity. Datasets representing 2030 scenarios have been generated and studied with a simplified grid–market model that takes into account variable renewable generation, energy storage and electricity grid constraints. Simulation results for Morocco and Egypt are studied and compared, with emphasis on the benefit of energy storage.**

***Index Terms*—Power system modeling, Power system simulation, Power system planning, Energy storage, Solar energy, Wind energy**

I. Introduction

Large scale deployment of renewable energy sources such as wind and solar energy gives rise to multiple challenges from a grid and power system integration point of view. This study addresses hour-by-hour energy balancing, the impact of altered power flow patterns on grid congestion, and the benefit of energy storage.

A flow-based market model approach that represents an idealised electricity spot market respecting the power flow equations is applied for hour-by-hour determination of generation dispatch and power flow. This approach, implemented as an open source software package called PowerGAMA, has been found useful in particular for simulating scenarios for renewable energy integration and systems with energy storage.

Datasets have previously been made for Europe and recently been extended to Morocco and Egypt. These include reduced models for the main transmission grid, parameters and geographical distribution of generators and loads, energy storage systems, and time-series providing the variability of renewable energy and power demand.

The paper presents results from analyses applying the grid–market model method with these datasets for Morocco and Egypt. The main emphasis is on grid congestions, and computations of reduction in the system cost of generation arising from the addition of energy storage systems. Different operational strategies for storage utilisation and their effect on alleviating grid congestion and price variation are compared and discussed.

An earlier paper [1] introduced a Western Mediterranean case study, with validation of simulation results against actual power flow and energy mix data for a 2014 case, and with preliminary results from a 2030 scenario analysis. This 2030 scenario dataset was subsequently improved and studied with the main aim on identifying cost-efficient grid upgrades in Morocco [2]. In this analysis, simulations were combined with investment cost analysis in an iterative process to determine beneficial grid upgrades. A recent publication [3] gives a detailed description of the underlying modelling approach and assumptions of the PowerGAMA simulation tool, and further results from the Western Mediterranean case study.

The present study extends previous work related to Morocco by analysing in more detail the impact of different storage utilisation strategies. The present paper also includes early results from similar analysis for Egypt, and a comparison between these countries.

II. Modelling approach

The present analysis is based on linearised optimal power flow analysis done time-step by time-step. The linear optimisation finds the generation dispatch and power flow that gives the lowest overall cost of generation whilst respecting the constraints of the system, including the physical power flow equations. This optimisation is performed in a sequential way, where demand, available renewable generation and energy storages are updated between each time-step. The interpretation of this approach is that it represents an idealised flow-based electricity market with nodal pricing, where all power is traded in a single hour-ahead market.

This approach has been applied in several studies in the past, and has been described in detail in a recent paper [3]. A software implementation has been made available as an open source Python package called PowerGAMA[1]. For the sake of readability of the present paper, a brief outline of key elements of this modelling approach is given below.

A. Variable demand and renewable generation

Time-series data are used to provide the variability in power demand and generation. For demand, this has been based

[1] Bitbucket: https://bitbucket.org/harald_g_svendsen/powergama

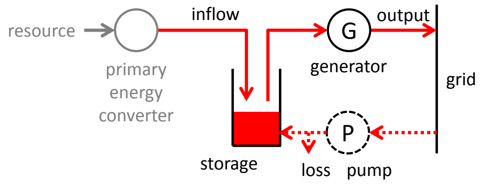

Fig. 1. Generator model

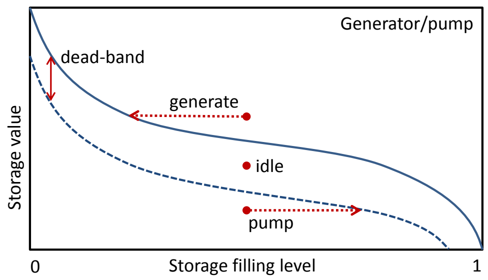

Fig. 2. Storage value principle. The solid line is the storage value curve, and the dotted line is the pumping threshold curve. The red dots represent situations with different cost of alternative generation.

on present load profiles and scaled according to the total demand in the studied scenarios. The time-series include daily variations, the differences between weekdays and weekends, and the seasonal variation.

For wind and solar generation, time-series have been obtained from numerical weather model reanalysis data [4] for an arbitrarily chosen historical weather year. In this study, year 2012 has been used. For wind power, wind speeds were converted to electrical power using a wind power curve representing the smoothed power output from many wind turbines distributed over a large geographical area [5]. For solar power, daily irradiation has been converted to hourly solar power by accounting for the trajectory of the sun on the sky, including how it varies with time latitude and time of year [6].

Generators are described using a single model illustrated in Fig. 1.

B. Energy storage

The generator model in Fig. 1 includes the possibility of energy storage. The power *inflow* represents energy added to the storage from a primary energy source such as rainwater or solar radiation. Storage is also possible without any inflow, in which case it takes energy from the grid via a *pump* or charger. It is not necessary in this model to specify the type of storage, whether a water reservoir, thermal storage, battery or something else. What matters are the parameters; storage capacity, generator and pump capacities, and the *storage value* curves that provide the operational strategy for how the storage is used, i.e. when to generate, when to remain idle, and when to pump.

The method of storage values [7], [8] provides a computationally effective way to incorporate storage systems with

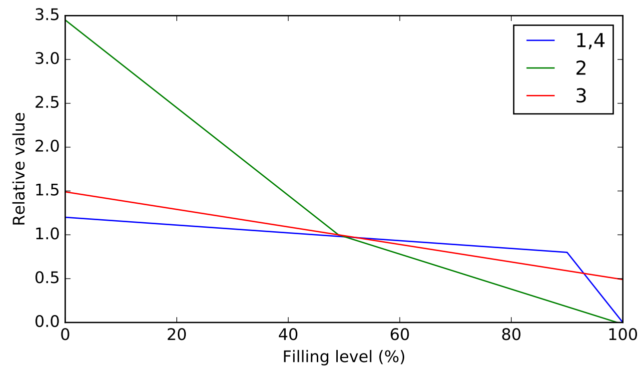

Fig. 3. Storage values – filling level dependence, $\hat{v}_{\text{filling}}$

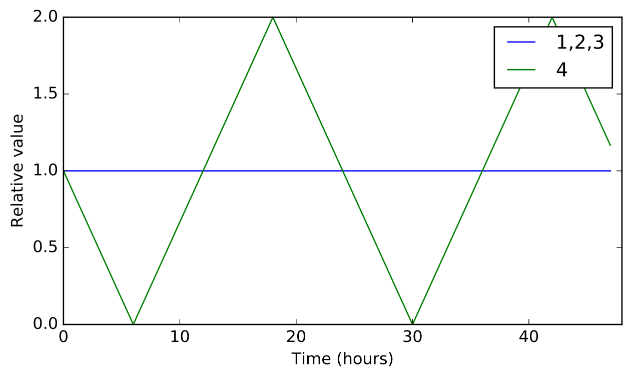

Fig. 4. Storage values – Time dependence, $\hat{v}_{\text{time}}$ (showing only 48 hours)

realistic behaviour in the simulation. Storage value curves are provided as user input and specify how storage values depend on storage filling level, and on time. Storage values are therefore updated for each storage between each time step, and give the cost of the generator in the objective function of the optimisation. This is not the real marginal cost of generation, which is typically very low for renewable generation. Instead it reflects the expected value of keeping energy in the storage. If this expected value is lower than the cost of alternative generation, the generator should produce. This is exactly what is obtained by setting the generator cost equal to the storage value. This behaviour is illustrated in Fig. 2. At each time step t, the storage value $v(f,t)$ is computed as

$$v(f,t) = v_0 \cdot \hat{v}_{\text{filling}}(f) \cdot \hat{v}_{\text{time}}(t), \quad (1)$$

where f is storage filling level, v_0 is the base value of the storage, $\hat{v}_{\text{filling}}$ is the relative value dependent on filling level and $\hat{v}_{\text{time}}$ is the relative value dependent on time. The base value v_0 should be similar to the cost of alternative generation. The storage value curves $\hat{v}$ are given as input. Curves that are used in the present study are shown in Fig. 3 and 4.

Four different storage utilisation strategies are evaluated in this study. These are given as four different combinations of $\hat{v}_{\text{filling}}$ and $\hat{v}_{\text{time}}$, numbered 1 to 4.

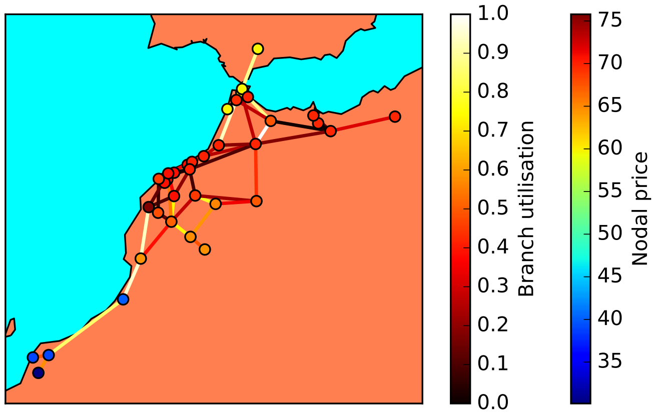

Fig. 5. Morocco 40 bus grid model (case 6h_1)

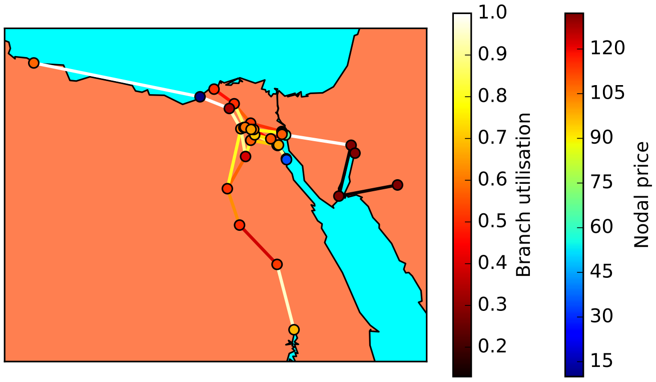

Fig. 6. Egypt 30 bus grid model (case 6h_1)

III. 2030 Scenario datasets

A. Morocco

A reduced, equivalent grid model for Morocco has previously been created from detailed 2016 grid data using a two-step algorithm based on similarity of power flow characteristics in the full and reduced models [9]. The 2030 scenario dataset is based on this grid model, with added wind and solar power generators according to expectations, and otherwise up-scaled demand and generation capacity per generator type to agree with 2030 projections.

Because of the very large demand increase and added generation capacity, the grid requires reinforcements in order to avoid high degree of load shedding and curtailment of renewable energy generation. Cost-effective grid reinforcements have been identified in a previous study, and a 2030 base case grid model has been established with these reinforcements included [2].

The Morocco grid model is shown in Fig. 5.

B. Egypt

A reduced model the the Egyptian grid has been modelled by including the 500 kV grid and key parts of the 220 kV grids [10]. The resulting model has 33 buses, including boundary buses representing neighbouring countries, i.e. Libya, Jordan and Saudi Arabia. Branch capacity and impedances have been derived from more detailed grid models. Generators and loads have been aggregated to the nearest high voltage bus, such that the total demand and total generation capacity equals the total for all of Egypt.

An increase in average demand from 32.3 GW in 2015 to is 76.7 GW in 2030 has been assumed, based on expected increase in population and industrial growth.

Generation capacity and new generators have been added according to planned developments in the next years. Additionally, 81 GW of solar CSP power has been added and distributed on nodes such as to reduce the amount of load shedding. This is a very optimistic projection, but as the costs of solar power are decreasing and may be the cheapest form of new generation well before 2030, it is an interesting option to consider. In our study, whether it is CSP with thermal storage, or PV with battery storage does not make a difference.

Grid reinforcements have not been considered in the present work, but is likely necessary with large amounts of new renewable production away from load centres. However, as the location of new generation this far into the future is unknown, we have chosen to place it close to the nodes where load shedding would otherwise occur.

The Egypt grid model is shown in Fig. 6.

TABLE I
Simulation cases

case	storage capacity	storage curve
0	0	–
6h_1	6h	1
12h_1	12h	1
6h_2	6h	2
12h_2	12h	2
6h_3	6h	3
12h_3	12h	3
6h_4	6h	4
12h_4	12h	4

IV. Simulation results

Simulations have been performed with the same cases for both Morocco and Egypt. There is a base case without added storage, and several cases with CSP storage added as shown in Table I.

Results indicating geographical variation in nodal prices (marginal cost of supply) as well as utilisation of connections are shown in Fig. 5 and 6 for simulation case case 6h_1. In both cases, there are clearly some grid bottlenecks with 100 % utilisation, where grid reinforcements would be beneficial for the system.

Times series for a week showing generation mix in Morocco and Egypt for case 6h_1 is shown in Fig. 7 and 8.

Key results from the different simulation cases are shown in Table II for Morocco and Table III for Egypt. *Output* is average power generation in the country; *cost* is average generation cost per output within the country; *price* is average nodal price, i.e. the marginal cost of increasing demand; *CSP* refers to

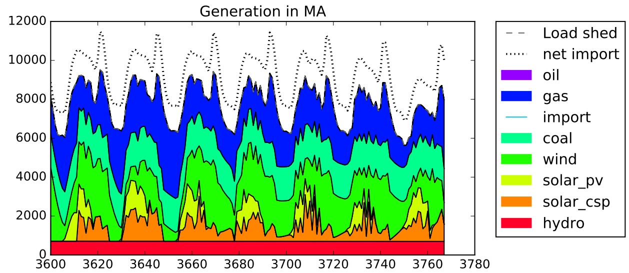

Fig. 7. Generation mix Morocco (case 6h_1)

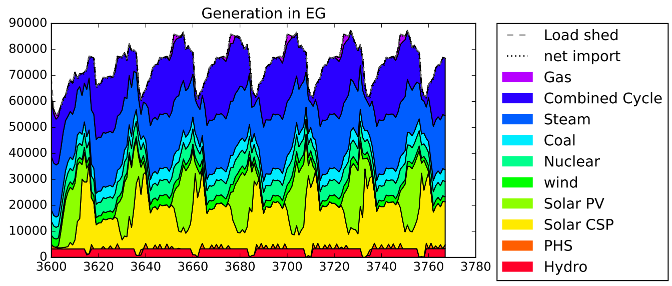

Fig. 8. Generation mix Egypt (case 6h_1)

average csp plant income, i.e. nodal price multiplied by plant output; *loadshed* is average load shedding; and *curtailed* is average curtailment of renewable energy.

Load shedding gives a high area price because of a high penalty associated with load shedding.

Both for Morocco and Egypt there is a clear benefit from adding storage, as all cases give a reduced specific cost compared to the base case without storage. This is largely due to reduced curtailment of renewable generation, which therefore replaces expensive fuel-based generators such as coal and gas.

In the case of Morocco, the case with storage value curve 4 gives the best result, with the highest reduction in generation cost and renewable generation curtailment. In other words, a storage utilisation strategy that explicitly includes a time dependence seems to work well.

In the case of Egypt, the base case has a high amount of load shedding, and the addition of storage helps reducing this by shifting generation to peak demand. The reduction in

TABLE II
MOROCCO RESULTS

caes	output MW	cost €/MWh	price €/MWh	CSP €/MWh	loadshed MW	curtailed MW
0	7814	35.5	67.6	26.9	0.0	547
6h_1	7760	33.7	68.3	55.8	0.0	344
12h_1	7759	34.0	68.5	59.1	0.0	306
6h_2	7777	34.0	67.3	41.0	0.0	366
12h_2	7763	34.1	67.5	47.3	0.0	313
6h_3	7768	33.8	67.7	57.1	0.0	343
12h_3	7764	34.1	68.1	60.8	0.0	302
6h_4	7721	33.5	67.1	46.0	0.0	324
12h_4	7715	33.6	66.7	42.4	0.0	295

TABLE III
EGYPT RESULTS

case	output MW	cost €/MWh	price €/MWh	CSP €/MWh	loadshed MW	curtailed MW
0	69225	55.7	382.9	78.2	5337.2	12030
6h_1	74422	52.7	104.9	91.4	48.2	1664
12h_1	74203	53.5	106.0	103.5	48.2	694
6h_2	74720	52.3	138.0	112.2	48.2	1370
12h_2	74581	53.0	120.7	108.2	48.2	681
6h_3	74589	52.1	110.2	102.4	48.2	1250
12h_3	74351	53.0	108.7	105.3	48.2	662
6h_4	74493	52.2	127.5	106.9	105.5	1175
12h_4	74531	52.8	124.1	107.0	61.7	911

specific generation cost is highest with 6 hour storage, whilst curtailment reduction is highest with 12 hour storage. Load shedding is not entirely eliminated in any of the cases. In this case, the explicit time dependence in storage curve 4 gives poorer results than the other cases without time dependent storage values.

In addition to the benefit of reduced generation cost, energy storage associated with CSP plants also increases the income from the plant, by allowing power to be sold when prices are higher. In this regard, the value of storage is clear, however, it is difficult to make firm conclusions regarding optimal storage capacity and storage utilisation strategies.

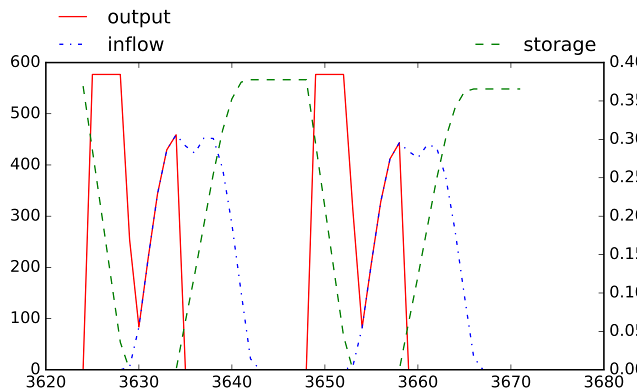

Fig. 9. Morocco CSP plant generation (MW) (case 12h_4)

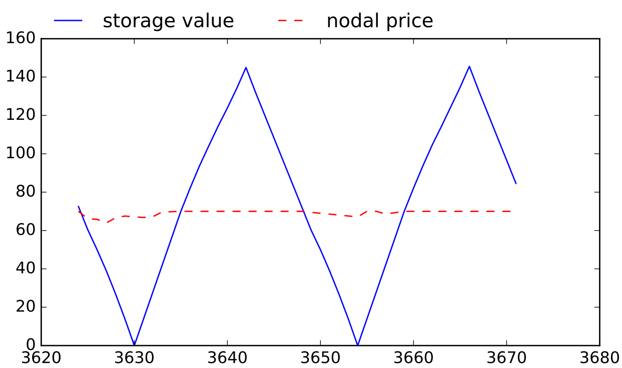

Fig. 10. Morocco CSP plant storage value (€/MWh) (case 12h_4)

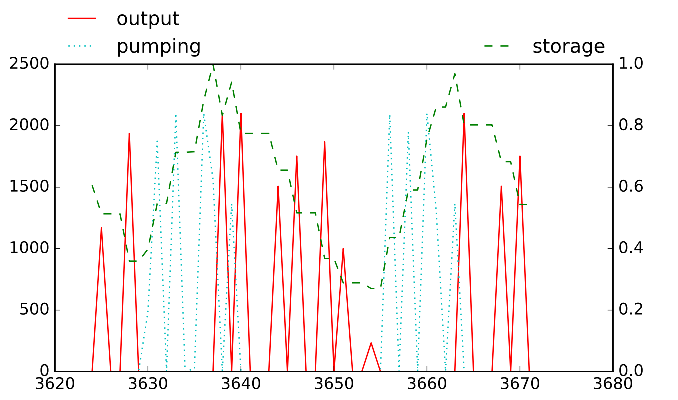

Fig. 11. Egypt PHS generation (MW) (case 6h_1)

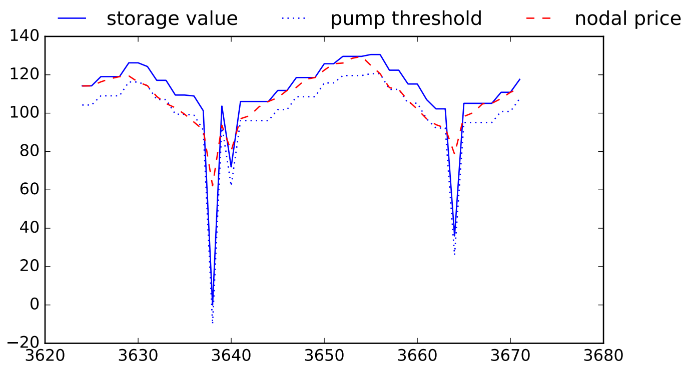

Fig. 12. Egypt PHS storage value (€/MWh) (case 6h_1)

The behaviour of CSP plant with storage in Morocco is shown in Fig. 9 and 10 for a period of 48 hours. The figure shows how output is time-shifted relative to the inflow (solar irradiation in the middle of the day). This is achieved via the explicit time-dependence in the storage value, as the nodal price does not vary very much.

The behaviour of the pumped hydro storage plant in Egypt is shown in Fig. 11 and 12 for a period of 48 hours. The figure shows a daily pattern of pumping when the nodal price is low and then generating to meet peak demand in the afternoon, when the nodal price is high.

V. Conclusion

This study has explored future scenarios with high amounts of renewable energy integration in Morocco and Egypt, and assessed the benefit of energy storage in these systems. Energy storage is treated in the simulations by means of storage values, where different storage value curves represent different storage utilisation strategies. Different curves were implemented and tested in simulations. Which one is best differs between the two countries. In the Morocco case, with little daily variation in nodal prices, forcing a time-shifting of energy production via storage curves with explicit time-dependence was found beneficial.

The results show that the systems are able to cope with large amounts of renewable generation, in an hour-by-hour energy balance sense, provided that grid reinforcements are made and/or energy storage is added.

More work is needed in order to establish realistic 2030 scenario datasets, especially for Egypt. There is uncertainty in several factors: Demand increase is very dependent on economic development and difficult to project; generation capacity mix can to some extent be derived from policy targets for renewable energy, but these are not provide a detailed breakdown for 2030; the location of future generation plants is very uncertain, however we can assume they will be placed where resources are good and need for grid reinforcements are kept minimal.

Large-scale integration of variable renewable energy requires fundamental re-thinking of how the electricity grid and market functions. Due to the long time horizons for investments and planning of grid upgrades, it is important to investigate how the future energy system will behave at an early stage, before all details are known. The approach and results presented in this paper is a contribution in this direction.

Acknowledgements

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