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Research Article

Cost Optimization For The 100% Renewable Electricity Scenario for the Java-Bali Grid

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ABSTRACT. A 100% renewable electricity supply is no insurmountable technical problem anymore after the respective technologies to harvest the energy from multiple renewable energy sources have been developed and have reached a high level of maturity. A problem may rather be suspected to reside on the economic side of an exclusively renewable electricity supply. The present study examines the economic implications of a renewable energy scenario for the Java-Bali grid. Based on given energy supply scenarios, the costs of an electricity supply from renewable energy sources alone are determined. Economic optimum configurations are determined for which the annual system costs and accordingly the power generation costs are minimized. First the system running costs are considered, i.e. the operation and maintenance costs as well as the costs of the continuous renovation of system components, while capital costs are not taken into account. After this the capital costs are taken into consideration, and total system costs and power generation costs are determined. One result is a specification of economic optimum system configurations. Another important result is that a future electricity supply from renewable resources alone is not more expensive than the current power generation in developed countries. A further result is that the integration of special long-term storage into the Java-Bali grid, like for instance methane storages, besides pumped storages and batteries, is not economically favorable if further moderate battery cost reductions are reached.

Keywords: energy system modeling, electricity cost, cost optimization, energy scenario

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1. Introduction

In the paper "A 100% Renewable Electricity Scenario for the Java-Bali Grid" (Günther, 2018) a consumption and load scenario for the Java-Bali grid for the year 2050 was developed as well as an electricity generation scenario according to which the modeled load would be covered exclusively with electricity from renewable resources. The scenario specified power generation shares of the different renewable sources as well as power plant and storage capacities that are necessary and sufficient to supply the needed power. However, an economic evaluation of the different system configurations, of the different possible combinations of power plant and storage capacities, was not included in that study. The task of the present study is to deliver such an economic evaluation.

The scenario developed in (Günther, 2018) considers an electricity demand of 640 TWh in the Java-Bali grid for the year 2050, compared to a demand of about 152 TWh in 2015 (PLN, 2016). According to the scenario, 90% of this demand is covered by solar energy (PV), 6% by geothermal power, 3% by hydropower, and 1% by biopower. The installed power plant capacities amount to 5.8 GW for hydropower, and to 5.5 GW for geothermal power. The installed capacity was not defined for bioenergy, and it is an open parameter for PV. The PV capacity is related to the storage capacity. The larger the storage capacity is, the smaller the PV capacity can get, and vice versa (with a minimum PV capacity of around 410 GW, and a minimum storage capacity of around 960 GWh).

Three system logics (I, II, and III) are distinguished in (Günther, 2018). All logics have the following in common: geothermal power is used as permanently running baseload power; solar energy is used whenever it is available, and stored in case it exceeds the power demand; hydropower is used for load peak shaving. System logic I and II are distinguished by the allocation of bioenergy: while in system logic I bioenergy is used for further peak load shaving (with the objective to reduce the peak load that has to be covered by the storage), it is used for seasonal balancing in system logic II (balancing partially the fluctuations of solar electricity generation between dry and rainy season). In both system logics, the storage (a combination of pumped storages and batteries)

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is used to fill the remaining supply gaps. System logic III is analogue to system logic II with the difference that a second storage system is integrated, a long-term storage based on synthetic methane.

The distinction between short-term and long-term storages is reasonable in the following sense: Some storage types have high capacity costs (due to high capacity component costs or due to high self-discharge rates), but low charging and discharging costs, others have low capacity costs, but high charging and discharging costs (due to a costly charging and discharging infrastructure or due to high charging or discharging losses). Pumped storages and batteries belong to the first type, synthetic gas storages belong to the second type. Contrary to system logics I and II, system logic III integrates a long-term storage into the power supply system.

The most important result in (Günther, 2018) is a three-parameter space of possible power supply system configurations with the following parameters: PV capacity, storage I capacity (a combination of pumped storages and batteries), and storage II maximum charging power (methane storage, if existent). The main result is represented in Fig. 1 with the PV capacity on the ordinate, the storage I capacity on the abscissa, and the storage II charging capacity as discrete parameter.

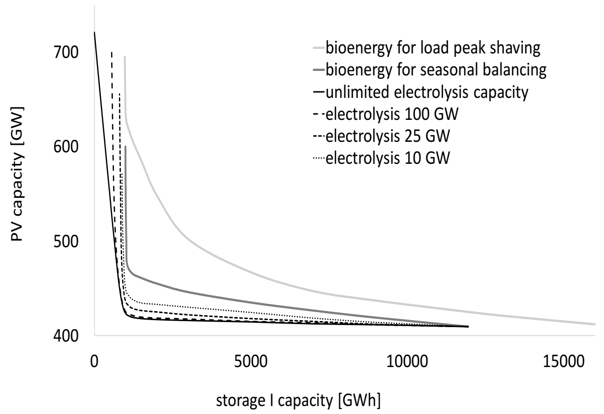

Fig. 1 Installed PV and storage I capacities in the different system logics

There is an important difference between the definition of the size of the two storage types: While the size of storage I is characterized by the amount of storable energy (storage capacity), the size of storage II is characterized by the maximum charging power. The reason for this difference is that the storage capacity is expensive for storage I, and it is the economically decisive quantity, while for storage II the storage capacity itself is cheap and the charging infrastructure (electrolyzer and methanation units) is rather expensive.

The combinations of installed capacities of the three system components (PV, storage I capacity, storage II charging capacity), defined in the scenario and represented in Fig. 1, are minimum configurations that allow the supply of the required electricity.

The questions to be tackled are what system configurations are economically preferable, i.e. what configurations allow the most economic generation of the needed electricity, and what is the cost of the system and the generated power.

2. Methodological Considerations

The economic comparison of the different system configurations is done with respect to the electricity generation cost only. Transmission and distribution are not considered. Furthermore, a static system will be considered, i.e. a system that is not modified over time. System components are only replaced after their lifetime ends, and infrastructure is modernized in regular intervals. And we assume that the system components, power plants and storages, are represented in a homogeneous age continuum so that every year a constant share of the components has to be replaced. For instance, if the lifetime of a system component is 20 years, then 5% of the installed capacity is replaced every year. The approach of assuming a static system has the advantage that the annual expenses are constant. Every year is exactly the same in terms of operation, maintenance and modernization expenses, which simplifies the calculation considerably.

In a first step, capital costs are neglected. That means, only operation and maintenance expenses are considered as well as the costs of the replacement of the system components, but no capital costs. We call the set of the costs taken into account the running costs.

The objective function, the minimum value of which has to be determined is the following:

$$COST_{syst\_run} = \sum_i \left[\left(\frac{cost_{cap_i}}{t_i} + O\&M_i \right) \cdot cap_i \right], \tag{1}$$

where $COST_{syst\_run}$ is the annual system cost, $cost_{capi}$ the specific cost of the installation of component i (e.g. the cost per installed kWp of PV, or the cost per installed kWh battery storage), $O\&M_i$ the specific annual operation and maintenance costs of component i, t_i the lifetime of component i, and cap_i the installed capacity of component i. The components are PV power plants, geothermal power plants, hydropower plants, biopower plants, combined-cycle power plants, storage systems, or subsystems of these systems (for instance inverters in the PV power plants or the electrolyzes that are an integral part of the methane storage systems).

The magnitudes that have to be determined such that the target function reaches its minimum are the installed capacities cap_i of the system components. There are several constraints with respect to the installed capacities. First, some of the installed capacities are fixed: 5.8 GW hydropower, 5.5 GW geothermal power, 4 GW biopower, 60 GW PV rooftop power, 100 GW pumped storages. Second, some installed capacities are interrelated and define a space of possible configurations. This space is represented in Fig. 1: the parameters are storage I capacity, storage II charging capacity, and PV capacity. Third, some parameters are strictly related to the combination of the installed capacities of the latter three components: the needed methane storage capacity, and the combined-cycle power plant capacity.

The economic parameters that characterize the components, i.e. their future cost and their lifetimes, are no parameters for the optimization. In general, they are fixed, with the exception of the battery cost for which a sensitivity analysis is done. A major challenge for an economic evaluation of future energy supply systems is indeed the estimation of the future cost of components and their lifetime. As we consider the year 2050, the cost and lifetime assumptions are more or less vague, at least for some of the system components. For mature technologies like combined-cycle power plants and hydropower plants, costs can be reasonably assumed to be constant and equal to the current costs. However, for components the costs of which underlie a dynamic development as is the case for batteries and PV systems, the estimation cannot be but vague. For components that are critical for the economic evaluation in the sense that they generate a big share of the system costs and that they experience a dynamic cost development, a sensitivity analysis should therefore be added that shows how strongly the optimum system configuration depends on their prices. We will conduct such a sensitivity analysis for the particularly important case of the battery costs. Details of the economic assumption concerning the system components are given in chapter 3.

For the second step, after calculating the system running costs, costs for the capital that is bound in the existing infrastructure are taken into consideration. This will be done in an exemplary way assuming a unique interest rate for the financing of all system components. The objective function is then:

$$COST_{syst\_total} = COST_{syst\_run} + z \cdot \sum_i \left(cost_{cap_i} \cdot cap_i \right) , \quad (2)$$

where z is the interest rate on the invested capital.

Monetary inflation is not taken into consideration in the calculation. All monetary values are specified in €2018. The selection of the Euro currency is arbitrary. The results of the study would not differ if any other reference currency were chosen.

3. Cost Assumptions

In the following, the most important assumptions concerning the component costs will be specified. The considered timeframe is always the year 2050.

3.1. Photovoltaics

The costs of PV power plants can be subdivided into costs for modules, costs for inverters, costs for balance of system (bearing structures, cables etc.), and costs for logistics and installation. Monocrystalline modules cost at the moment (2018) about 500 €/kWp. Learning curves were very steep in the past with 19 to 23% cost reduction per doubling of the installed capacity. According to the assumed capacity expansion until 2050 and assumptions about the steepness of the learning curve, costs between 140 €/kWh and 350 €/kWh should be considered for 2050 (Fraunhofer ISE, 2015). The cost of inverters amounts currently to around 100 €/kWp and is estimated to be between 21 and 42 €/kWp in 2050. Balance of system and installation cost are about 340 €/kWp and should come down to 210 to 120 €/kWp in 2050.

The electricity supply scenario considers a massive installation of PV power plants, i.e. it presupposes a massive PV world market. As large markets generally allow lower prices, it is reasonable to assume the future costs to be in the lower half of the mentioned ranges. For ground-mounted systems we assume 275 €/kWp for the whole system without inverter, and for roof-mounted systems 350 €/kWp. For the inverter, we calculate with 25 €/kWp. The lifetime of the systems without inverter is 25 years, and the lifetime of the inverters is 15 years. Operation costs are assumed to be 10 €/kWp per year for ground-mounted systems and 12 €/kWp per year for roof-mounted systems.

We assume a roof-top capacity of 60 GW. This number is derived from a conservative estimation of 2 m2 roof area per person.* The remaining capacity is considered to be built on ground.†

3.2. Pumped storages

For pumped storages, we assumed installation costs of 510 €/kWh (IRENA, 2015). Regular modernization costs of 75 €/kWh have to be covered every 40 years (Conrad 2014). The annual operational costs are taken to be 2% of the investment. These assumptions result in an annual average storage cost of 12.08 €/kWh.

At present (2018), a pumped storage capacity of 20 GWh is planned and partially under construction (PLN, 2017). We calculate with an installed capacity of 100 GWh. The remaining needed storage capacity is covered with electrochemical storages (batteries).

3.3. Batteries

Contrary to pumped storages, the costs of which can be taken to be quite stable, batteries are currently undergoing a very dynamic cost development, specifically the increasing importance of e-mobility has triggered a steep cost decline. At the moment (2018), battery costs amount to around 300 €/kWh, but battery producers and market observers estimate that in a medium-term perspective costs of about 100 €/kWh can be achieved (Agora Energiewende, 2014).

According to the warranties offered by battery and e-car manufacturers the lifetime of current Li-ion batteries amounts to about 8 years with about 70% remaining capacity. For e-mobility a high remaining capacity is important because lower capacities mean lower driving ranges. Batteries for stationary storage systems, in contrast, can tolerate lower remaining capacities. We assume a lifetime of 12 years with a remaining capacity of 60% of the nameplate capacity.

3.4. Methane storage

The economic evaluation of the methane storage is more complex because several subsystems have to be taken into account: electrolyzers for the electrolysis of water into oxygen and hydrogen, hydrogen storage, methanation units for the reaction of carbon dioxide and hydrogen to methane and water (in the Sabatier process), and the methane storage. The conversion of the chemical energy back into electrical energy is assumed to be done in combined-cycle power plants. The power plants are equipped with a carbon dioxide capture system that delivers the carbon dioxide back to the methanation units. Thereby a closed carbon cycle is realized.

* How conservative this estimation is shows the comparison to the result of a study that was done about Germany where 12 m^2 usabel roof area per person are estimated (Lödl, 2010).
† The placement of the required PV capacity is challenging. Besides ground-mounted systems, offshore systems can reasonably be considered even if there are hardly any offshore PV systems until now, and none in the open sea.

Electrolyzers are not yet common in energy supply systems, and methanation units are practically inexistent. Cost estimations for these technologies are therefore vague. With reference to (Albrecht, 2013) we assume future electrolyzer costs of 700 €/kW with annual operational costs of 4% of the investment and a lifetime of 30 years, and methanation unit costs of 550 €/kW with annual operational costs of 2% of the investment costs and a lifetime of 25 years.

Hydrogen storages are expensive compared to methane storages. That's why we assume that the produced hydrogen is converted quite directly into methane and that large hydrogen storage capacities are not needed. There may be only small hydrogen buffer storages for leveling the methanation process. Methane storages are inexpensive. The recent (2012) construction of an underground tube storage in Switzerland cost 0.027 € per kWh chemical energy (Limattaler Zeitung, 2012). This is several orders of magnitude below the cost of pumped storages and batteries. Taking into account additionally that gas storages are very durable, the methane storage costs can be neglected in the context of our calculation.

For combined-cycle power plants we assume investment costs of 750 €/kW and a lifetime of 30 years. The annual operational costs are 17 €/kW (Agentur für Erneuerbare Energien, 2012). The carbon dioxide sequestration requires an additional investment of 450 €/kW and annual operational costs of 20 €/kW (Hartmann, 2014).

3.5. Hydropower plants

For hydropower plants, we assume investment costs of 2000 €/kW and annual operational costs of 2% of the investment cost. Additionally, we assume modernization costs of 270 €/kW every 40 years (IRENA 2012a).

3.6. Geothermal power plants

The investment costs for geothermal power plants vary enormously according to the given site conditions. In accordance with existing geothermal power plants in Indonesia we assume costs of 4000 €/kW as well as modernization costs of 500 €/kW every 30 years. Annual operational costs are considered to be 2% of the investment costs (IRENA 2015).

3.7. Biomass power plants

Biopower is taken to be generated in steam power plants that are fed with solid biomass, in particular with the agricultural waste that is predominant on Java and Bali, i.e. with the waste from rice and sugar production. Additionally, biogas can be produced from the palm oil mill effluent from the few palm oil production sites in Banten and West Java, which, however, account for very small energy amounts. For biomass power plants, we assume investment costs of 2000 €/kW, annual operational costs of 6% of the investment cost, and a lifetime of 20 years (IRENA 2012b). While in (Günther, 2018) the biopower plant capacity was not defined, it has to be defined now in order to take into account the costs of the biopower plant infrastructure. As biomass is used for seasonal balancing (more specifically peak shaving in the rainy season), a relatively low capacity factor of 20% is assumed. Considering the assumed 7.2 TWh biopower per year, this renders an installed biopower plant capacity of about 4 GW.

4. Configuration-Specific System Running Costs

There are different system configurations, i.e. sets of installed capacities of power plants and storage systems that are able to supply the needed electricity. The task is now to figure out which configurations come along with the lowest annual system costs and, hence, with the lowest electricity generation costs.

For comparing the annual system costs it is sufficient to compare the costs of the components the capacity of which varies between the different configurations. The installed capacities of biopower plants, hydropower plants and geothermal power plants are constant for all configurations and do not need to be taken into consideration for an economic comparison of the different configurations. What varies are the capacities of PV plants, battery storages, and the gas storage infrastructure (if applicable).

4.1. System logics I and II

For system logic, I the economic optimum is at an installed PV capacity of around 630 GW and a storage capacity of 990 GWh. The configuration-specific cost amounts to about 27.3 bn € per year. For system logic II the optimum is at an installed PV capacity of around 475 GW and a storage capacity of 1040 GWh. The configuration-specific cost amounts to about 24.4 bn € per year. There is hence a considerable cost effect of the usage of bioenergy for seasonal balancing. The reduction of the needed storage capacity comes with a reduction of the configuration-specific costs by roughly 3 bn €, i.e. by more than 10%. This cost reduction is basically due to the reduction of PV capacity (less solar energy has to be generated in the rainy season so that the installed capacity can be smaller).

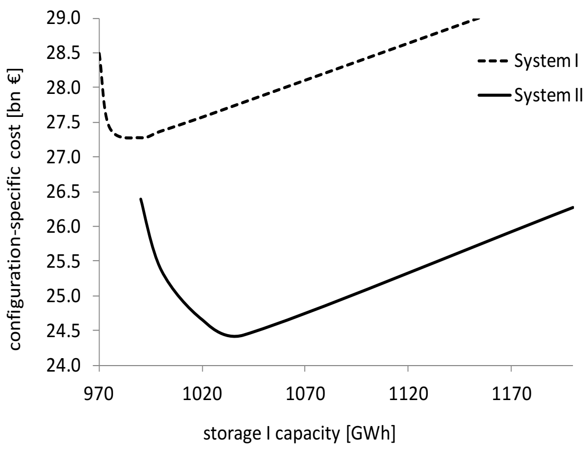

Fig. 2 Configuration-specific system cost according to system logics I and II

Fig. 2 shows the annual system cost as a function of the installed storage I capacity (pumped storages and batteries). It shows the minimum annual costs in dependence on the storage I capacity, i.e. the cost with the minimum PV capacity (which varies with the storage I capacity) that is required to cover the load at any time (according to Fig. 1).

4.2. System logic III

For system logic III the open parameter of charging capacities for storage II, the gas storage, is added. In accordance with the assumption that no large hydrogen storages are integrated into the system, it is also assumed that the electrolyser and methanation unit capacities are more or less strictly correlated. Even if the methanation process might fluctuate slightly less than the electrolysis due to a certain smoothing effect of small hydrogen buffer storages, the calculation takes the methanation unit capacities to be linked to the electrolyzer capacities. The only open parameter is, therefore, the electrolyzer capacity. As stated above, the methane storage capacity itself is economically negligible compared to the cost of the charging and discharging infrastructure.

A main result is that, at the assumed battery cost of 100 €/kWh, a small storage II charging capacity of less than 10 GW is economically preferable (Fig. 3).

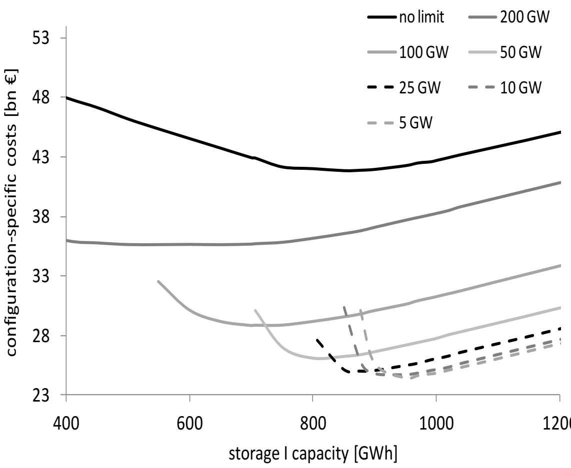

Fig. 3 Configuration-specific system cost according to system logic III with different installed electrolyser capacities

The storage I capacity is about 950 GWh for the economic minimum configurations. The installed PV capacity is about 465 GW for an electrolyser capacity of 10 GW and 480 GW for an electrolyser capacity of 5 GW.

A comparison to system logic II shows that the minimum configuration-specific costs for system logic III are in the same range of around 24.4 bn €. This means that the saved cost due to the reduced storage I capacity in system logic III just compensates for the additional cost for the methane storage infrastructure. For the cost-efficiency of the power supply system the integration of a gas storage system is not necessary under the given assumptions.

5. System Running Costs

In addition to the configuration-specific costs, the non-variable generation costs have to be considered if the total running costs of the system are to be determined. Non-variable costs are caused by the hydropower plants, the geothermal power and the biopower plants. The installed capacities of these power plants are constant for all considered system configurations. The cost associated with these system components is about 2.6 bn € per year. This amount has to be added to the variable generation costs shown in Fig. s 2 and 3 to calculate the total system running costs.

The minimum annual system running costs are, hence, about 27 bn € for system logic II and for system logic III with small electrolyzer capacity. The breakdown of the costs for the different system logics is represented in Fig. 4.

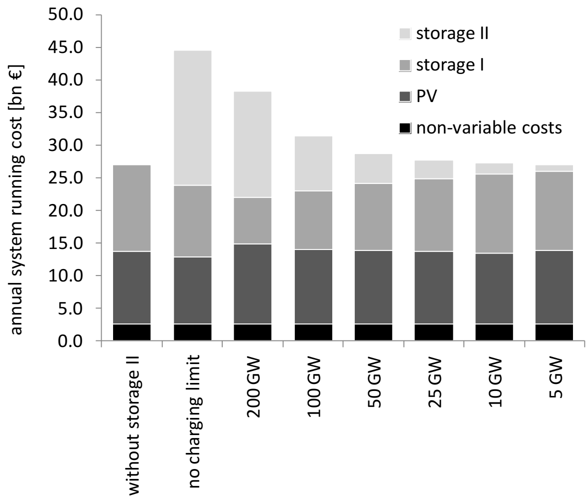

Fig. 4 Annual minimum system cost for the different system configurations

In terms of the generated electricity this renders 4.2 €ct per kWh (taking into account the assumed annual consumption of 640 TWh). At an assumed population of 170 million inhabitants in the grid area the generation cost is 160 € per person and year, or 13 € per person and month.

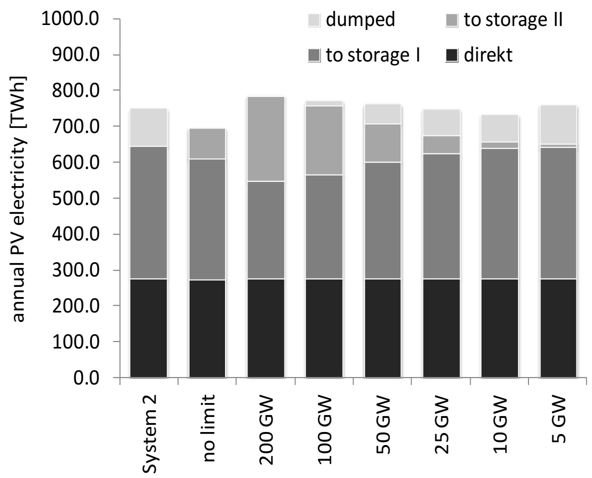

Fig. 5 Destination of the generated PV electricity in the respective optimum system configurations

PV and storage systems come along with by far the highest share of the total costs. This is not surprising taking into account that PV covers about 90% of the total power and that only a very limited share of the generated PV electricity is used directly while a large share is sent to the storage systems (Fig. 5).

An important result is that the integration of a long-term storage does not reduce the system running cost if a battery cost of 100 €/kWh is considered. This may be surprising as special long-term storages, like gas storages, are frequently considered as essential to make seasonal balancing economically viable (Agora Energiewende, 2014). But, under the given conditions, in particular in a grid in which the seasonal fluctuations of the electricity generation from renewable resources are quite limited, and under the mentioned optimistic battery cost assumptions there is no economical need for special long-term storage systems. However, if the battery cost is higher, the integration of a gas storage system makes economic sense. Fig. 6 shows the minimum annual system running costs for battery costs from 100 €/kWh to 300 €/kWh for a system with without methane storage and a system with such a storage.

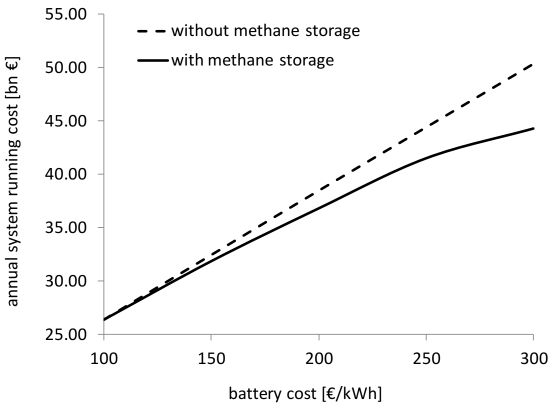

Fig. 6 Annual minimum system cost in dependency on the battery cost for the system with and without gas storage

The battery costs have an impact on the optimum electrolyzer capacity. The higher the battery cost is, the larger the electrolyzer capacity should be. Fig. 7 shows this dependency.

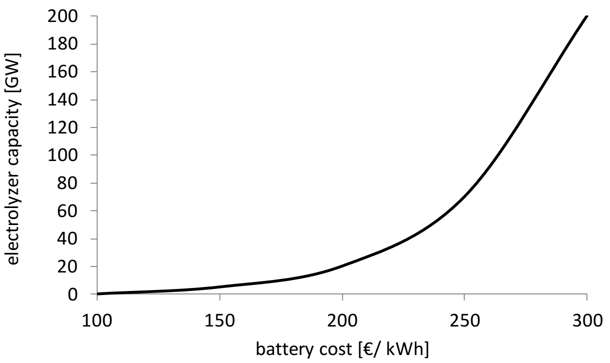

Fig. 7 Electrolyzer capacity at the economic optimum configuration

6. Total System Costs and Power Generation Costs

Until this point only the running costs (operational costs and component renovation costs) have been considered. The fact that the system binds capital and that the invested capital may require some return has not yet been taken into account.

The decision to consider exclusively the running costs allows the avoidance of assumptions about the financing conditions. The advantage of this approach is to reduce the speculative character of the economic evaluation. No assumptions have to be made about interest rates. The drawback of neglecting the capital costs is, however, that an error is accepted because the capital investment will come along with some return requirement, at least in a power supply system that is not completely financed with public money.

In the following, the total generation system costs, including capital costs, are estimated in an exemplary way. We assume a unique interest rate of 4% that is applied to the capital that is bound in the different system components (in reality, interest rates may be different for different system components).

Under these conditions, the minimum annual generation system cost amounts to 42 bn €. This equals a power generation cost of 6.5 €ct/kWh and a per-capita cost of 20 € per month. This power generation cost is competitive with the current average power generation costs in many countries (Intitute for Energy Research, 2017; Kost, 2018), and it is only slightly higher than the current average power generation cost in the Java-Bali grid (5.3 €ct/kWh, MEMR, 2017), which is quite low due to the high share of currently relatively cheap coal power.

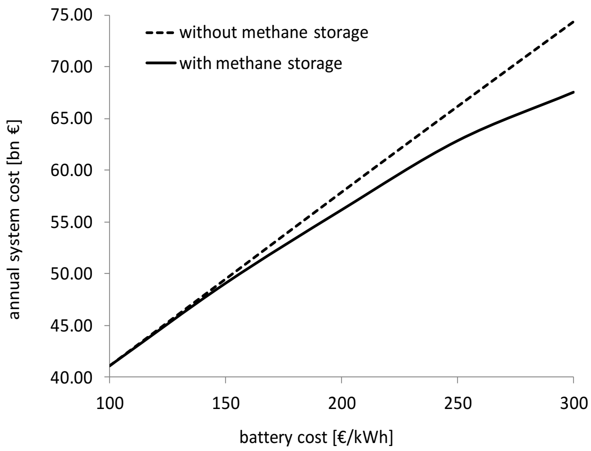

Fig. 8 Annual minimum total generation system cost in dependency on the battery cost for the system with and without gas storage

The power generation cost can be derived from the annual system cost by dividing them by the power generated per year. Fig. 9 shows the result.

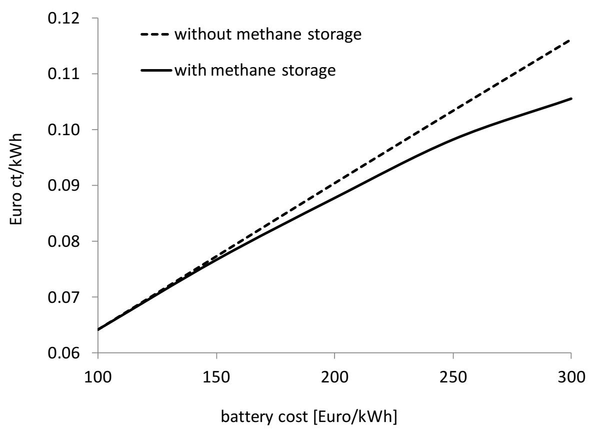

Fig. 9 Power generation cost in dependency on the battery cost

It should be observed that this comparison considers only the costs that have to be borne by the consumers directly, and that it does not take into account external costs of the power generation. If external costs, for instance due to carbon dioxide emissions and air pollution, are internalized then the cost of the mainly coal-based power in the Java-Bali grid would be considerably higher. And it would certainly be higher than the calculated RE power cost. A thorough discussion of external costs exceeds the focus of the present paper. In (Sanchez, 2017) external costs of more than 5 €ct/kWh are estimated for coal power in Central Java, the internalization of which would lead to a total cost of more than 10 €ct/kWh.

Assuming the mentioned financing conditions, the total cost calculation shows again, and even more clearly than the running cost comparison, that the inclusion of a long-term storage is economically unnecessary at a battery cost of 100 €/kWh. Quite a high amount of capital is bound in the gas infrastructure, which adds respective financing costs. Only at battery costs clearly above 200 €/kWh a long-term gas storage shows a noticeable economic benefit.

Analogous to Fig. 6, Fig. 8 shows the minimum annual system costs in dependency on the battery cost for systems with and without gas storage.

7. Conclusion

Two main conclusions should be highlighted: First, the cost of electricity for the Java-Bali grid from a future generation system that is based completely on renewable resources is in the range of the current generation cost in many countries. This holds although a complete renewable-energy based supply in the Java-Bali grid faces quite serious challenges, in particular the high dependency on solar energy and the related high demand for storage capacities. However, as seasonal fluctuations, and not daily fluctuations, are generally the main reason for high storage demands, and as the seasonal fluctuations are quite small due to the tropical location of the two islands, the high dependency on solar energy is easier to handle in this grid than in many other grids. The storage can be smaller than it would be for many other, non-tropical grids with a similar load and consumption profile and a similar dependency on solar energy.

Second, the inclusion of a long-term gas storage is economically not favourable if battery costs continue to decrease as it is predicted by battery manufacturers and market observers. At current battery costs, a special long-term gas storage does make sense for seasonal balancing. However, at lower costs these storages are not necessary, at least in a grid like the Java-Bali grid with its relatively low seasonal fluctuations.

The latter does not mean that the inclusion of a power-to-gas infrastructure would be completely pointless. It still can serve as link between the power sector and other energy sectors like transportation and process heat generation where chemical energy carriers may have a high importance also in an energy system that is widely based on electricity generated from renewable resources. But this is a topic that deserves an own study and should not be discussed here.

The results of this study hold only for the selected grid with its particular load conditions, its particular meteorological conditions, and its assumed power mix. They cannot be transferred to other grids. In particular the dependency on given natural conditions makes power supply grids more individual and specific when based on renewable energy resources than when they still were based on easily transportable chemical and nuclear energy carriers.

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