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Techno-economic analyis of battery storage for peak shaving and frequency containment reserve

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***Abstract*—When does large scale battery storage become economically feasible? To answer this question and put a value on the different services battery storage can provide, we performed techno-economic analyses on the use of large-scale battery storage in Norwegian electricity distribution systems. In the first use case we looked at the feasibility of batteries for peak load shaving and thereby network charge reduction under the power based tariff structure. In the second use case, battery storage was used to reduce both peak load and peak infeed in order to comply with the 100 kW max feed-in rule that is part of the Norwegian prosumer regulation, the "Plusskundeordning". Both of these applications are far from economical at current prices. The third use case was about battery storage used to provide balancing power. This seems to be the most feasible application at the moment. We performed sensitivity analyses under different balancing prices, grid charges, battery degradation levels, battery rest value and capital costs, to identify where battery storage becomes profitable in the Norwegian market. We reference the description of new regulations, tariffs structures, the battery degradation model, the methodology used for the economic evaluation and the controller models for all use cases. The study was performed in the project IntegER.**

***Index Terms*—Batteries, frequency containment reserve, solar energy, techno-economic analysis.**

I. Introduction

Batteries may be used for many different services, which can be divided into grid services and market services. The distribution system operator (DSO) must operate the grid in a way that stability and safety is assured, as well as having voltage quality and thermal limits within given ranges. A battery can provide grid services such as voltage regulation, balancing of phases, avoiding congestion, increasing short circuit current in weak grids, and local frequency control. A battery might also provide services which do not necessarily tackle grid issues, which are here defined as market services. These are for instance load shifting, energy arbitrage, primary frequency control or self-consumption of solar energy.

The cost of lithium-ion batteries has fallen drastically the last years, but battery costs today are in many cases still too high for the investment to be profitable, both for grid and market services [1]. What if the battery is used for a combination of services (also known as application stacking)? This will reduce the idle time of the battery, hence increasing the benefit, but might contribute to a faster degradation depending on how the battery is operated. A typical area where a battery is used for several services is in a microgrid, by managing local frequency control, voltage regulation (active and reactive) and balancing load and generation [2]. Not all services are possible to combine, and the combination of services should be considered when sizing the battery (energy and power). A combination of services will also require a controller deciding the operation strategy of the battery.

In Norway, because of deregulation, DSOs may not operate batteries unless they have a dispensation from the regulator. The EU Winter package also clearly states that DSOs should not own, develop, manage or operate energy storages [3]. In other words, if DSOs want to use batteries for grid services, the services could be provided by a third party operating the battery. A possible business model could be that the third party owns and operates the battery, using it for market services, but allocates a certain amount of time or power for the DSO. The DSO would then need to compensate the third party according to the time or power allocated. Such an agreement has the benefit of combining services and reducing idle time but would need to have a contract with strict penalties to for instance avoid the battery being fully discharged in a time when the DSO requires it for grid services.

The following is a description of the first four use cases for the application of battery storage in Norwegian distribution networks that were evaluated in the research project IntegER. The first use case is to use battery storage to reduce peak loads and therewith grid charges when the customer is charges with a power based tariff. In the second case we expand the first one to reduce both peak load and peak infeed to comply with the 100 kW max feed-in of the Plusskundeordning. The Plusskundeordning is a scheme for prosumers, where the prosumer gets the market price for the

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electricity sold and does not need to pay a fee for feed-in, if it is below 100 kW [4]. Both of these applications are far from economical at current prices. We include a third case about battery storage used to provide balancing power. This seems to be the most feasible application at the moment. The fourth use case is one where the battery storage is used to provide balancing power, while at times serving the DSO to relieve congestion in a medium voltage line.

The following is a result of work package 2 of the Norwegian research project IntegER. In work package 2 we made a first economic evaluation of four use cases of battery storage in Norwegian distribution systems. The upcoming work package 4 will redefine the battery storage applications and accuracy of the evaluations based on the demonstration activities and laboratory research in work package 3.

II. FOUR BATTERY USE CASES

A. *Case 1: Battery storage to reduce grid charges*

In the first case we consider an industrial load with a yearly peak of 150 kW. It is a historical generic industrial load profile taken from [5], scaled to fit the yearly peak of 150 kW. The customer pays a grid tariff consisting of a variable per kWh and a fixed per kW, plus a fixed monthly component of 2 245 EUR per month as shown in TABLE 1. The power tariff is paid based on the maximal monthly peak load value.

TABLE 1: GRID TARIFF

	Fixed tariff [EUR/month]	Energy tariff [c/kWh]	Power tariff [EUR/kW]
Summer	2 245	0.37	5.94
Winter		0.43	6.91

We wish to see how much we can reduce the monthly peak load with the use of a battery. For this we use a 30 kWh capacity and 18 kW output battery (TABLE 2).

TABLE 2: BATTERY PARAMETERS

Battery capacity	30 kWh
Battery output	+18kW/-18kW
Roundtrip efficiency	83%

To maximize the effect of the battery we use a heuristic procedure. Given the day-ahead prices and the load, we optimize the battery use during the day with a linear program, so that the battery charges when prices are low and discharges when prices are high. In addition, we introduce a peak constraint on the combined load and battery output. We run the optimization and gradually reduce the peak load constraint. That is if the monthly peak is 150 kW we try if we can with the help of the battery keep it below 149 kW, then 148 kW and so on until we reach the limit of the battery contribution to peak reduction.

The monthly peaks and grid costs associated with the peak load are listed in TABLE 3. The table also shows the monthly peaks and costs achieved with the use of the battery, which are 5-7% lower, resulting in a cost reduction of 589.4 EUR per year. There is a slight increase in the energy tariff costs of 12.3 EUR (TABLE 4). This is due to the battery losses as these cause a small increase in energy consumption. The savings from price arbitrage on the spot market are 34.1 EUR per year.

TABLE 3: MONTHLY PEAKS AND GRID COSTS

	Peak load [kW]		**Power tariff cost [EUR]**	
Month	**No battery**	**With battery**	**No battery**	**With battery**
January	150.0	141.0	1036.2	974.1
February	147.5	137.2	1018.8	947.5
March	141.3	132.8	976.1	917.7
April	122.6	117.7	728.0	698.8
May	122.7	117.2	728.7	695.9
June	114.5	108.8	680.2	646.4
July	108.3	101.8	643.2	604.3
August	111.3	105.2	661.0	624.6
September	114.5	108.2	680.2	642.8
October	128.5	117.5	887.4	812.0
November	139.6	130.4	964.1	901.1
December	146.1	138.8	1009.3	958.7
Total			10 013.2	9 423.9

TABLE 4: PARAMETERS FOR ECONOMIC ANALYSIS IN CASE 1

Savings on power tariff	589.4 EUR
Increase in energy tariff	12.3 EUR
Savings from spot market + losses	34.1 EUR
Investment cost	100 – 700 EUR/kWh
Discount rate	5%
Loan	70% of investment
Interest rate	2.24%
Project lifetime	10 years
O&M cost	1% of investment cost
Rest value of battery after 10 years	20% of investment

Given these values and the other parameters in TABLE 4 we calculate the internal rate of return (IRR) for different levels of investment costs between 100 and 700 EUR/kWh as shown in Figure 1. We assume a 10 year project lifetime, with 20% battery rest value at the end. Figure 1 shows how the IRR varies with the investment cost. The horizontal dotted black line is the discount rate (we chose 5%). The returns above this line result in a positive net present value (NPV) shown as shaded green, the returns below result in a negative net present value shown as shaded red. The blue line represents the IRR for grid costs as they are today. The battery becomes feasible at around 200 EUR/kWh. The green line represents to the return with grid costs at double today's price and the yellow line at triple today's price. We can see that even with such dramatic increases in grid costs the battery only becomes feasible at very low costs of 400 EUR/kWh at double and 600 EUR/kWh at triple the 2019 grid cost. These battery costs can be reasonably expected in

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the next years, but such increases in grid prices are hardly plausible. These numbers serve to show how far from feasibility this battery storage application actually is.

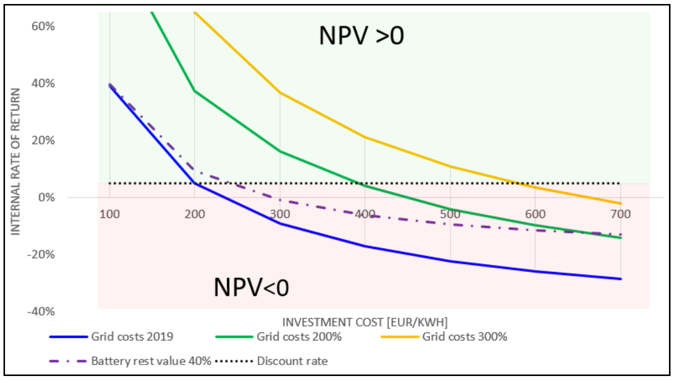

Figure 1. Internal rate of return vs. investment cost Case 1

B. *Case 2: Battery for grid and peak PV infeed reduction*

We have the same industrial consumer as in A – Case 1 with a 150 kW peak load, yet this time the customer also has 287 kWp photovoltaic (PV) installation. The PV production profile is a yearly profile measured in Oslo with an hourly resolution obtained from [6]. A prosumer in Norway receives the spot market price for the feed-in up to 100 kW. Above the 100 kW threshold the prosumer has to pay 0.13 c/kWh [7]. If it makes economic sense the battery will absorb energy when prices are relatively low and release it when prices are high, and perhaps absorb the power over the 100 kW limit to avoid paying 0.13 c/kWh and later, when production falls below 100 kW, discharge it into the grid to receive the spot market price.

We use the same heuristic procedure as in A – Case 1 to evaluate the battery's cost saving potential. The battery generates savings on the power tariff of 788.9 EUR per year, 14.8 EUR on the energy tariff and 144.6 EUR on the spot market (TABLE 5). With the PV installation the battery generates greater savings in terms of grid costs than in Case 1 (TABLE 4). The greater savings occur during the summer months. Daily load peaks are somewhat flatter during these months which makes it more difficult for the battery to reduce them. The PV infeed, however, cuts into the load peaks and shortens their duration allowing the battery to reduce them more effectively.

TABLE 5: PARAMETERS FOR ECONOMIC ANALYSIS IN CASE 2

Savings on power tariff	788.9 EUR
Savings on energy tariff	14.8 EUR
Savings from spot market + losses	144.6 EUR

Let us look at the profitability of the battery investment for the industrial load. The project parameters are the same as in Case 1, that is project lifetime 10 years, 20% battery rest value, 1% O&M and 2.24% interest. We again vary the investment cost of the battery between 100 EUR/kWh and 700 EUR/kWh. This gives us the blue line in Figure 2. The battery reaches a 5% IRR at around 300 EUR/kWh.

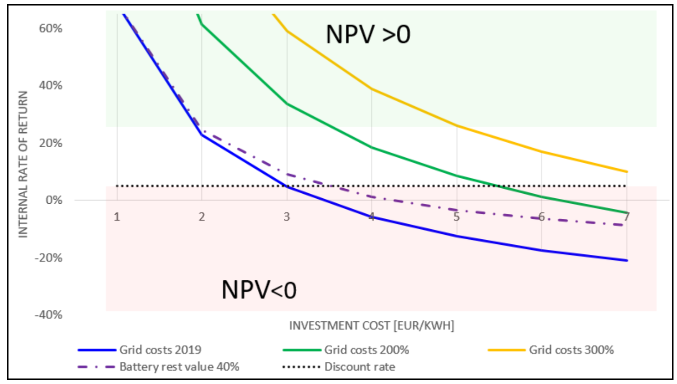

Figure 2: Internal rate of return vs. investment cost Case 2

The green and yellow lines correspond to the IRR with double and triple the power tariff, respectively. Last, the purple dashed line represents the IRR for the case where the rest value of the battery after 10 years is 40% instead of 20%, which improves somewhat the feasibility of the battery particularly at higher battery prices.

C. *Case 3: Battery for frequency containment reserve*

The third case we examine is the use of battery storage for Frequency Containment Reserve (FCR). The technical specifications for FCR can be found in [8]. We simulated participation in both the FCR for normal operation (FCR-N) and FCR for disturbances (FCR-D), but the FCR-D activation was so rare in the simulation that we just leave it out of consideration. We used the data for 2017 from the French transmission system operator (TSO) RTE to simulate the battery response to the frequency signal as we could not get hold of the Norwegian system frequency data. The original frequency data resolution is 1 second but we scaled it up to 10 seconds. We implemented a simple but effective battery controller strategy taken from [9] to estimate the potential revenues from the FCR-N provision.

The battery receives the down regulation price for each MWh of absorbed energy and up regulation price for each MWh of delivered energy. The regulation prices are obtained from the Statnett website for the year 2017. Our model does not account for interruptions in operation that would be necessary to occasionally recharge or discharge the battery or the penalties incurred. The battery controller appears to be quite effective at maintaining an operational state of charge not running into capacity limits too often, which renders our estimates more realistic. At 400 kWh storage capacity and 1000 kW maximum output the operation would need to be interrupted less than once every three days. Increasing the size of the battery to 500 kWh would eliminate almost completely the need to interrupt operation. The optimal battery size will probably be somewhere in between with some penalties still incurred where the cost of an additional 1 kWh equals the decrease in expected penalty costs. We ran

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the simulations with a 400 kWh battery and 1000 kW maximum output.

We evaluated the capacity fade that would result from the battery use for FCR-N with a model developed in [6]. At the rate the battery is used for FCR-N, the capacity fade reaches 16.37% in 10 years. The model, however, does not include calendar aging so the actual degradation would probably be considerably higher after 10 years.

We vary the investment cost between 800 EUR/kWh and 1600 EUR/kWh (TABLE 6). The interest rate at 2.24% is very low and is rather in the range of what Norwegian DSOs pay on their loans [9]. A smaller company would probably pay a higher interest rate somewhere between 2.5% and 6%. However, assuming there is a form of partnership between the DSO and the battery operator, the interest rate could be brought down rendering the investment more attractive. Balancing services are much closer to profitability than the previous two applications. We vary the investment cost between 800 EUR/kWh and 1600 EUR/kWh.

TABLE 6: PARAMETERS FOR ECONOMIC ANALYSIS FCR-N

Category	Value
Investment cost	800 – 1600 EUR/kWh
Maintenance cost	1% of investment/year
Operating cost	5 019 EUR
Revenues	65 699 EUR
Loan	70% of investment
Interest rate	2.24 %
Discount rate	5 %
Project lifetime	10 years

In Figure 3 we can see how the internal rate of the project varies with the investment cost. The blue line shows the IRR with the default values from TABLE 6. What is immediately noticeable is that the NPV is positive in the range of today's battery costs at 1400 EUR/kWh. The green line represents the IRR curve with an increase in balancing prices by 10%. This scenario could correspond to an increased need for balancing due to a rise in intermittent generation. However, this is an unlikely scenario in the Norwegian market. More probable is a drop in balancing prices if batteries do in fact become commonplace. The 30% drop in FCR-N prices scenario is represented by the yellow curve. Even with 30% lower FCR-N prices the batteries break even around 960 EUR/kWh, which sounds realistic for the near future.

Next, we look at the scenario that's equal to default, but with double the battery rest value after the project end at 40%. This is represented by the dashed purple line. For higher battery costs this scenario renders the batteries even more feasible than a 10% rise in balancing prices. For lower battery cost levels, the effect on the returns is smaller.

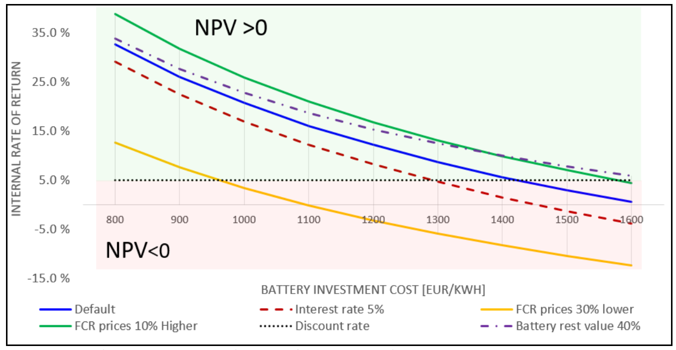

Figure 3: Internal rate of return vs. investment cost Case 3

Finally, we look at the effect of a higher interest rate on the project feasibility. The dashed red line represents the IRR curve at 5% interest. At this interest rate the batteries become profitable at 1300 EUR/kWh.

TABLE 7: OPPORTUNITY COST OF POWER FROM A FCR-N BATTERY FOR GRID SUPPORT

Hours for grid support	Reserved battery power [kW]	Effective apparent power [kVA]	Cost per year [EUR]
100	22	20	17
100	33	30	25
200	22	20	33
200	33	30	50
400	22	20	67
400	33	30	100

D. *Case 4: Battery for grid support*

The last case deals with a shared use of the battery between a balancing power provider and a distribution system operator. The DSO uses the battery for a small number of hours per year to relieve the grid and stay within the voltage and thermal limits of the lines and transformers. Instead of owning the battery and paying the full investment cost of it, the DSO pays for its use on an hourly basis to the owner that is bidding at the FCR-N market as in Case 3.

The Norwegian TSO, Statnett, has relaxed the conditions for participation in FCR-N and as of April 2019 the minimum bidding quantity allowed is 1 MW [11]. We assume here that this 1 MW can be made up of a virtual power plant consisting of smaller batteries such as the 18 kW / 30 kWh batteries in Case 1 and Case 2 located in different parts of the grid.

Now let us assume that the DSO is facing a problem of overvoltages or undervoltages in the grid and could use the battery to either provide some power during load peaks or absorb some PV infeed. The DSO needs to reduce the apparent power, not real power, so how much battery capacity does it need to get from the battery owner to change the apparent power by 1 kVA? Assuming a grid power factor of 0.95 it will need about 1.11 kW of real power from the battery for a 1 kVA change in apparent power. The battery owner, participating in the FCR-N market has to reserve this

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power for the DSO and not bid with it on the market. So how much is the opportunity cost of this 1.11 kW that will not be bid in the FCR-N market?

TABLE 8: PARAMETERS FOR ASSESSMENT OF THE BATTERY VALUE FOR THE DSO

Yearly revenue from FCR-N for a 1 MW battery	65 699 EUR
Value of FCR-N per kW	65.7 EUR
Value of FCR-N per kW per hour (8760 hours in a year)	0.75 cent
Power factor	0.95
Battery output change for a 1 kVA change in apparent power	1.11 kW
Value of 1.11 kW of battery output for 1 kVA change	0.83 cent

We calculated in Case 3 that a 1 MW battery generates 65 699 EUR in revenues from FCR-N over the 8760 hours of the year (TABLE 8). That is 0.75 cent per hour for every 1 kW of battery output. We need 1.11 kW of battery power for 1 kVA, resulting in a cost of 0.83 cent per kVA per hour.

We list exemplary costs of reserved power for different numbers of hours per year in TABLE 7. For example, to use 30 kVA for 200 hours per year the DSO would have to pay the battery owner 50 EUR per year which is in the range of the cost of 1 kWh of battery capacity over 10 years.

The opportunity cost of the battery doesn't include penalties for at times not delivering the power to the FCR-N market, when contracted. Also, if the battery is available to the DSO for 200 hours, the battery owner has to bring the battery to the right state of charge before and after the scheduled times which presupposes additional cost. The DSO would need to pay a premium to the battery owner over the FCR-N market revenues to stimulate the owner to enable the service in the first place. The values do indicate that the opportunity costs per hour are very low compared to what it would cost the DSO to own the battery. The values in TABLE 7 also compare very favourably to the cost of replacing a distribution line. A 315 kVA line's cost can range from 30 600 EUR/km in rural areas up to 68 400 EUR/km in urban areas.

III. CONCLUSION

This article summarizes a first assessment of battery use cases in the Norwegian research project IntegER. We conclude that even with new power based grid tariffs and under the new prosumer regulation, the use of batteries for peak load reduction with or without solar PV remains far from profitable. Our assessment of battery use for frequency containment reserve is rather positive. Actual final large battery system prices are hard to come by at this time. Our simulations show that FCR-N provision can become profitable already at a cost around 1500 EUR per kWh of battery capacity.

One often discussed way of improving battery economics is to provide a number of services with the same unit. These services have to be limited in time and compatible in schedule. We looked at the provision of balancing power with the addition of congestion management for the DSO. The opportunity cost of providing battery capacity to a DSO is the profit lost on the balancing power market, which we estimate at below 1 cent per kVA per hour. In order for the battery owner to set the battery at the DSO's disposal the DSO would have to pay a premium over the opportunity cost that to make it viable for the storage owner. We expect that in some cases the battery cost could compare quite favourably to the cost of grid investments, or owning a battery for only grid support.

As is the case with renewable energy sources, batteries are very capital intensive, which makes their costs very susceptible to interest rates. The combination of different services and actors affects the project risk and with it the interest rate. A successful business model will therefore have to manage well the risks involved to make sure that banks charge an interest rate as low as possible.

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