Techno-Economic Aspects of Grid Forming Inverters in Small Power Systems

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***Abstract*— Power generation on small islands, especially in tropical areas, is typically provided solely by diesel generators. The cost of electricity in such systems is high due to the fuel cost and the high maintenance efforts required especially for small high-speed diesel generators. As economics of scale have led to a stark reduction of PV panel and inverter prices over the last two decades, PV became an economically feasible alternative to diesel generation. Tropical islands usually have moderately high solar potential, and PV can usually generate at a lower cost than diesel generators, especially in more remote areas, where fuel is even more expensive due to transportation cost. Grid-forming inverter technology has recently become commercially available, allowing for 100 % instantaneous penetration of PV and batteries in systems where it is deployed. As demonstrated by a number of pilot projects, the technology is mature, and in island systems with very high generation cost, it can already be economically competitive. This paper focuses on the economic results of studies in a number of islands in the Caribbean and South East Asia, the exact locations of the grids remaining undisclosed.**

Keywords*— *PV, island, hybrid system, diesel battery PV hybrid; grid forming inverter.

I. Background

PV integration in small island systems presents some unique challenges. If PV is to contribute significantly to energy supply to save diesel and reduce costs, installed capacities need to be high, leading to high instantaneous penetrations of load and generation during the mid-day peak. This may lead to the following issues:

- Diesel generators have an inherent minimum stable output power, below which they cannot operate, limiting PV penetration;
- PV fluctuations need to be balanced out by diesels; thus, the ramping speed of the diesels may limit PV penetration;

With very high instantaneous penetration levels of PV (non-synchronous generation), inertia in the grid is very low, possibly leading to stability issues.

Moreover, the load in small tropical islands with little industry and a possibly low state of development tends to be lower during the day and have its peak during early night time hours due to cooking, lightning and air conditioning. Load factors are low (large different between maximum and minimum yearly load) and load coincidence factors and subsequently load fluctuations are typically high, especially for very small islands. This further aggravates the inherent issues with PV integration.[1]

The introduction of battery systems with grid forming inverters can eliminate most of these issues, but the technology has not seen a large scale rollout due to the additional cost incurred. While the integration of PV capacities up to instantaneous non-synchronous penetration levels of 80 – 90 % has proven to be technically feasible with no or relatively small battery capacities in small power systems up to 5 MW peak load, grid forming systems capable of operating at comparable stability and security of supply require a battery large enough to take over the entire demand expected during diesel-off operation time windows. This power requirement induces the need for either relatively large battery capacities or batteries with a very high C rate (power output to energy content ratio), and a large grid-forming inverter, all of which add significant investment cost. Operational grid-forming systems do exist, but are mostly considered pilot projects in which cost likely played a minor role if at all, and is usually not disclosed to the public. [2]

With the ongoing decline in cost of battery cells and power electronics, such systems are however becoming economically competitive, especially in systems with very high generation cost, or unfavorable conventional generation structures. This paper describes observations on the conditions under which grid-forming systems have determined to be a viable alternative in 2019 and 2020 in studies of different systems conducted by the authors. These are anecdotal observations in particular systems, but may be the first step on the way to a more holistic description of the situation in future work.

II. Grid Forming Inverter Basics

Most inverters connected to power systems today are of the grid-following type. Grid-following inverters act as controlled current sources to the grid, of which the frequency and the angle of the voltage are measured via a phase-locked loop (PLL) in order for the controller to adjusts the inverter current so as to inject the desired active and reactive power. State of the art grid-following inverters include grid-supporting controls such as frequency or voltage droop. However, the grid-following inverters can only operate when connected to a grid in which there is already one or more voltage sources also called grid-forming sources.

Conversely to grid-following inverters, grid-forming inverters act as voltage source to the grid. Grid-forming control schemes are typically designed to emulate the behavior of traditional voltage sources connected to power systems, i.e. synchronous generators [1]. Similar to those, grid-forming inverters try to keep the voltage and frequency at the inverter terminals according to the setpoints provided by its controllers. Different control strategies can be used to set such setpoints, such as for instance in order for the inverter to specific active or reactive power setpoints or for by a droop control with the purpose of adjusting frequency and voltage setpoints to signal information to other grid users. Several different control schemes for grid forming inverters in islanded microgrids are reviewed in detail in [2]. Different control concepts are classified there as follows:

- Communication-based concepts
- Droop-characteristic-based concepts
- Virtual-structure-based concepts
- Signal-injection-based concepts
- Hybrid concepts

III. Study Case 1: Small Island, 200 kW

A. *Study Case Description*

Study Case 1 [3][4] is a small island in the greater Caribbean region with an annual electricity demand of ca. 530 MWh, a peak load of 200 kW and a resulting load factor of 30 %. The load characteristic is typical for very small systems, as shown in Figure 1. The load factor as a ratio between annual peak and average load is very low, but can be traced back to infrequently occurring extreme load peaks which are a result of a low number of customers connected and a subsequently high load coincidence factor. On an average day with no extreme peak, the daily load factor is closer to 50 %. Peak load usually occurs in the early evening hours, as do the extreme peaks, the lowest load situation is in the early morning just before sunrise. Demand is not expected to increase significantly in the years to come. The island has only 60-70 permanent inhabitants, tourism is well developed and shows no clear seasonal pattern.

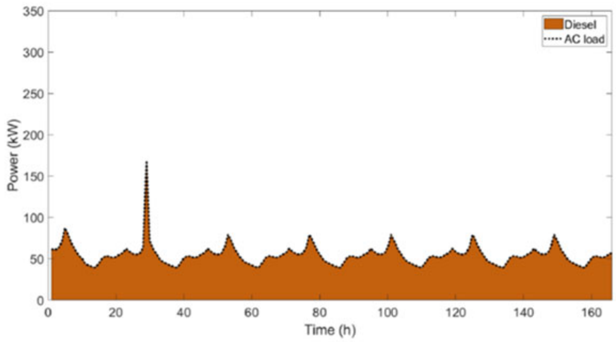

Figure 1: Demand curve and generation (100 % diesel) for a typical week.

The extreme load peaks are relatively unpredictable, they occur only during the evening hours, but very infrequently. This has a significant impact on the supply and dispatch situation. At least during the evening hours, enough generation capacity has to always be online to cover the annual maximum of 200 kW. The local utility has solved this by operating a 250 kW high speed diesel genset around the clock, which is running in partial load between 20 and 50 % of its output most of the time. This leads to significant efficiency losses, as obvious from the genset's efficiency curve shown in Figure 2. It does however facilitate control of the system, as a single generator running in isochronous load sharing mode (fixed speed) can cover all the demand all of the time, and the power plant is not even necessarily manned at all times. A second 250 kW genset of the same type is available, and both units are alternated regularly. An older 180 kW genset is available as a backup source.

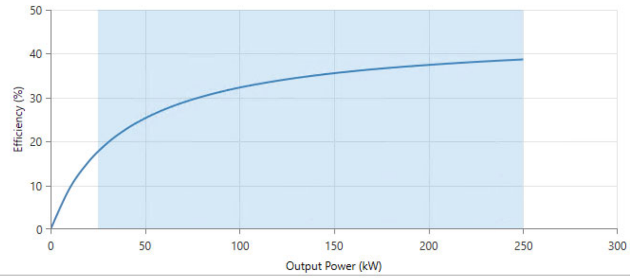

Figure 2: 250 kW diesel genset efficiency curve.

Electricity cost can reasonably expected to be high, but the actual cost structure is somewhat opaque at the utility, as available cost data is averaged over multiple island systems of different sources. Total electricity cost, including losses as well as transmission and distribution expenses, is reported to exceed USD 0.50 per kWh. With the fuel price, generator and load characteristics input into the optimization tool HOMER Energy, generation cost alone was determined to be USD 0.438, with the cost structure given in Figure 3.

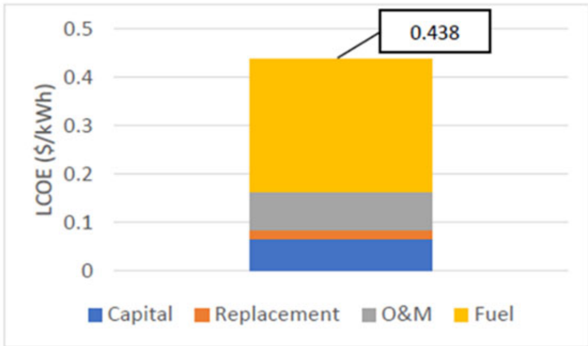

Figure 3: Generation cost structure.

With the LCOE of PV between USD 0.05 and 0.10 per kWh in 2020, depending on location and size, and most of the generation cost attributed to fuel cost, there is potential for significant cost savings in this island. PV potential is very good, at 20 % annual capacity factor (1750 full load hours) achievable. Integration is however complicated by the fact that the utility seeks to retain the existing, relatively new gensets. As the genset operating runs between 20 and 30 % output during daytime and should not be run below 10 %, there is little room for large PV capacities. The best strategy in this regard would be the installation of a battery with grid-forming inverter along with the PV, to allow for the diesels to be "moved out of the way" and run without any synchronous generators at least during daylight hours. This strategy was also favored by the system operator in several Indonesian islands where the authors conducted renewable energy integration studies in 2018 and 2019 [5][6], but was shown there to be economically less favorable to other strategies with less battery and hybrid operation. Fuel prices and overall generation cost were however significantly lower in these cases.

Customers on the island are supplied through a radial 13.8 kV distribution grid. Detailed grid simulations were conducted, but are not presented in this paper.

B. *Fuel Price Sensitivity*

There is a direct relationship between the fuel price in an island system and the economic feasibility of PV integration. With low fuel prices, PV integration may still lead to cost savings, but at the point where battery systems are needed, cost may rise again. The more expensive the fuel, the more a case is to be made for PV with battery systems, and with very high fuel prices, a large battery with grid-forming inverter becomes economically advantageous. With reductions in PV and battery prices over the years, the threshold at which fuel price either partial or full hybridization becomes feasible has become lower and lower. It is of course subject to other constraints, such as the flexibility of generators, generator efficiency and the cost of the required control systems, but fuel price as the major cost component is by far the most important indicator.

A simplified sensitivity analysis was conducted to determine from which point on the switch to grid forming inverters with a larger battery for the system in question was conducted in HOMER Energy. Simplifications were the following:

- Battery inverters were assumed to be grid forming in all cases, as HOMER Pro does not accept binary parameters in this regard;
- 100 % of PV output would be required in spinning reserve or usable battery output;
- The system is assumed to be entirely new and operate for at least 20 years.

With this, the load curve, hourly PV data for the location from the HOMER database and the cost assumptions given in Table 1,[1] PV, battery and battery inverter capacities were optimized.

Table 1: Cost inputs.

	Diesel	PV	Li-Ion battery	Battery inverter
CAPEX	700 USD/kW	1000 USD/kWp	364 USD/kWh	336 USD/kW
O&M	0.011 USD/kW/h	14.8 USD/kWp/a	6.65 USD/kWh/a	0.43 USD/kW/a

The raw optimization results are shown in Table 2 (installed capacities) and Table 3 (generation cost and renewable contribution).

While the results for fuel prices below USD 0.60 per liter are somewhat unrealistic in that they allow diesel-off operation with too little battery capacity, there is a paradigm change starting around that fuel price, clearly visible in Figure 4. From this point on, the optimal PV capacity quickly rises from 200 to 400 kW, battery capacity from ca. 100 kWh to 1000 kWh, and inverter capacity from 70 to 140 kW, which enables the battery to take over the entire day time load. This indicates the economic feasibility of a grid-forming system, as generation cost is reduced by 25 – 50 % despite the high (and hence costly) PV, battery and battery inverter capacities.

Table 2: Optimization results with fuel price as sensitivity variable, installed capacities.

Fuel price [USD/l]	PV capacity [kWp]	Battery [kWh]	Battery [kW]
0.3	165	90	64
0.4	191	96	68
0.5	199	105	69
0.6	348	849	105
0.7	391	1030	120
0.8	397	1031	125
0.9	405	1057	125
1	427	1211	143
1.1	435	1199	142
1.2	439	1203	147
1.3	456	1204	141

Table 3: Optimization results with fuel price as sensitivity variable, generation cost and PV share.

Fuel price [USD/l]	COE [USD/kWh]	COE Base Case [USD/kWH]	Annual PV contribution to demand
0.3	0.23	0.25	39 %
0.4	0.26	0.28	41 %
0.5	0.28	0.32	42 %
0.6	0.3	0.36	80 %
0.7	0.3	0.39	89 %
0.8	0.31	0.43	89 %
0.9	0.31	0.47	90 %
1	0.32	0.51	94 %
1.1	0.32	0.54	94 %
1.2	0.32	0.58	94 %
1.3	0.32	0.62	95 %

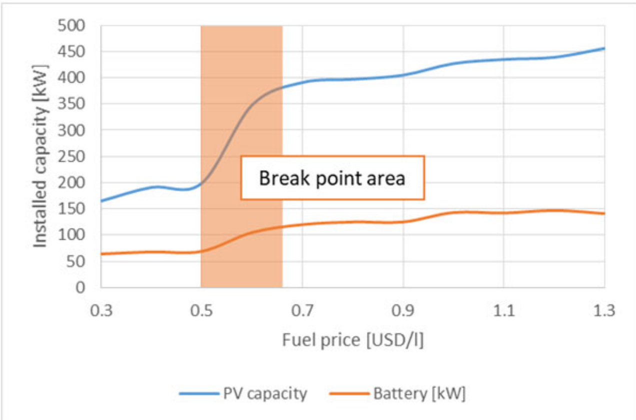

Figure 4: Installed PV and battery inverter capacity versus fuel cost.

With PV and battery covering 80 – 95 % of the load, it is clear that the diesels are reduced to a status as backup

[1] Detailed information on cost assumptions can be found in [3], [4]

generators at this point, which are none the less necessary, as 100 % renewable systems would require yet larger PV and battery capacities, increasing cost again, or tolerate higher levels of unsupplied load.

C. *Realistic Simulation Results*

The real fuel cost of the study case system is approximately USD 0.70 per liter of diesel. The previously presented sensitivity analysis clearly indicates that the installation of a grid-forming system and a switch to a majority annual share of PV generation would be economically feasible. However, there are a number of additional constraints in the system, which require a more thorough modelling to develop a realistic plan. Moreover, the project client requested to first analyze how much PV capacity could be absorbed by the system without battery energy storage before moving to a more significant system transformation. Analysis was hence conducted in two steps which will be presented briefly in the following.

1) *PV Integration Without Batteries*

The system's absorption capacity for PV without any battery systems in place is largely limited by the minimum load of the diesel generators. Stable minimum output, sustainable for four hours at a time, is low, at 10 % of rated output, but as the diesels are oversized to meet exceptional load peaks at night, this is still 40 – 50 % of daytime load. [7] The diesel gensets, only one of which is operating at each point in time, can however balance out all PV fluctuations and the diurnal pattern with ease, running in isochronous load sharing mode, without any additional control systems. PV must be equipped with a frequency sensitivity characteristic so output will automatically curtailed once the diesels reach their minimum output power.

With these provisions, a PV capacity of 64.5 kWp, leading to an annual PV contribution of 15 % and some curtailment was found to be economically optimal, with a typical dispatch week shown in Figure 5.

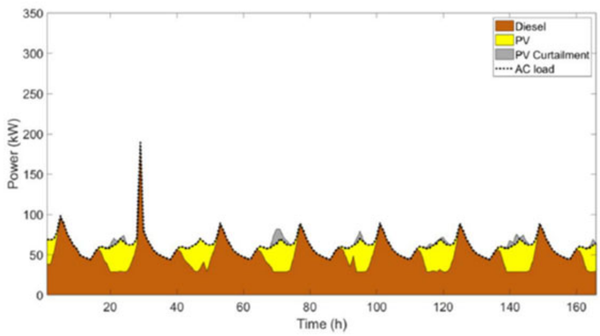

Figure 5: Typical week dispatch with PV without batteries.

Even this relatively small amount of PV leads to a reduction in generation cost from USD 0.438 to USD 0.391, as shown in Figure 6, a reduction of 9 %.

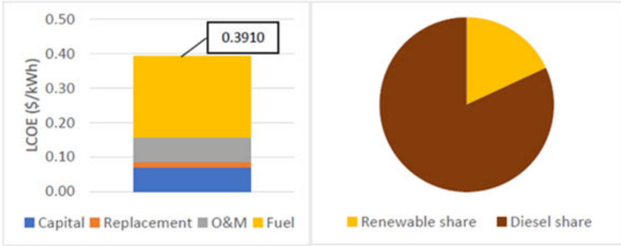

Figure 6: Cost structure and generation mix with PV without batteries.

2) *Battery with Grid-Forming Inverter*

As indicated by the sensitivity analysis results, the optimization would very likely yield results with high PV capacities and a large amount of storage if given the option to include battery storage. With realistic constraints, the results included 360 kWp of PV, 1000 kWh of lithium ion batteries and a 127 kW grid forming inverter. A typical dispatch week and the state of charge of the battery is given in Figure 7. Quite notably, the battery is charged with PV power during the day, but also charged from the diesel generator during the evening peak.

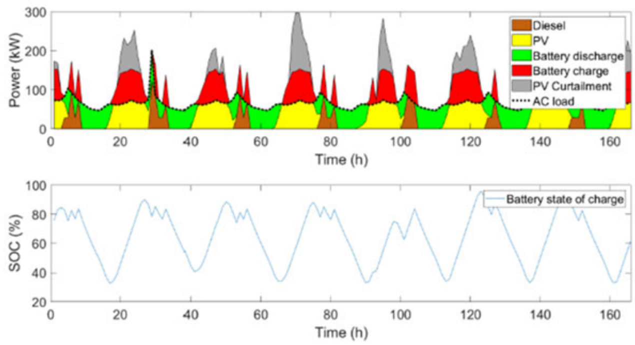

Figure 7: Typical week dispatch and battery state of charge with PV, batteries and grid forming inverter.

This behavior was explicitly enabled in the control strategy in HOMER, as it allows the oversized generator to operate at it optimum power output and hence leads to an efficiency gain. A relatively large amount of curtailment (24 % annually) is accepted on days with high PV output to have enough PV power available on cloudy days. The system, as optimized, comes out at a significantly lower generation cost than the base case and the scenario with PV without batteries, as shown in Figure 8. Generation cost is reduced by 25 % from the base case, at an annual PV contribution of approximately 75 %.

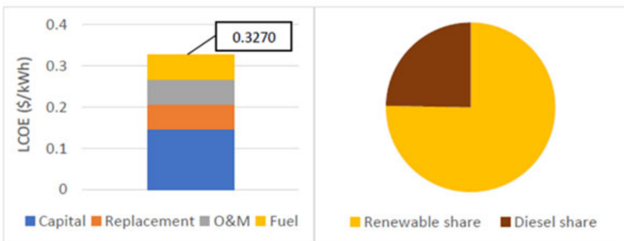

Figure 8: Cost structure and generation mix with PV PV, batteries and grid forming inverter.

IV. Study Case 2: Larger Island 5 – 15 MW

A. *Study Case Description*

The second study case is an island in South East Asia, with conditions radically different from the Caribbean study case previously presented. The island is considerably larger, more densely settled with ca. 100,000 inhabitants, and electricity consumption is mostly residential, but includes small scale industry and commercial enterprises, agricultural and customers. Tourism is not well developed. The typical daily load curve is given in Figure 9 and is representative for most small scale power systems in the region. Daytime load is almost even, with a pronounced load peak only appearing in the evening, driven by people returning home, switching on lights, stoves and air conditioning.

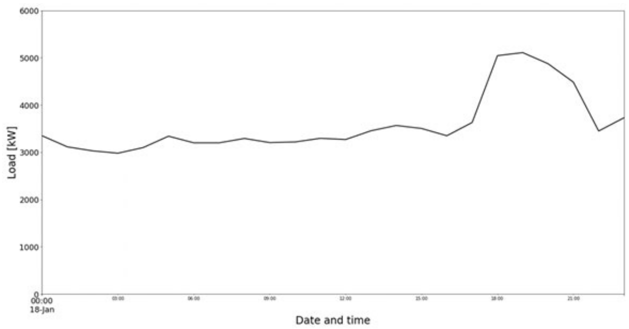

Figure 9: Typical daily load curve Study Case 2.

Electricity is supplied by a single power plant with 10 diesel generators with 1 MW each of different manufacturers and vintages. PV integration is somewhat more challenging here due to the fact that multiple diesel generators are always dispatched in parallel and need to be controlled accordingly. Primary frequency control is implemented with a speed droop on all generators, secondary frequency control is manual.

Both PV and wind potential are significant on the island. PV can achieve capacity factors of up to 17 % (1500 full load hours). Potential is lower than in Study Case 1 though, and short-term PV output fluctuations can be expected to be quite high due to frequently changing overcast. Wind potential is in the range of 25 – 35 % capacity factor in the best locations.

Moreover, demand and peak load are expected to grow quickly as shown in Table 4. Energy intensity is currently low on the island, but economic development is picking up quickly, and annual demand increases between 8 and 12 % are expected in the coming years.

Table 4: Load and demand projection Study Case 2.

Year	**Peak load [MW]**	**Annual demand [GWh]**
2018	6.0	32.9
2020	7.5	41.2
2024	11.9	65.2
2028	18.1	98.7

Customers on the island are supplied through a radial 20 kV distribution grid. Detailed grid simulations (steady state and dynamic) were conducted, but are not presented in this paper.

B. *Optimization and Capacity Expansion*

A detailed capacity expansion plan, based on a strict least cost approach as required by the applicable legislation, was developed using HOMER Energy in combination with the grid analysis and simulation tool DIgSILENT PowerFactory. Detailed results and cost assumptions are confidential and have been presented to the utility, the results are therefore briefly summarized in this section.

Coast assumptions are based on data provided by the utility and several cost surveys and studies by DANIDA and IRENA. [8][9]

Current generation cost in the island is USD 0.22 per kWh, owing to the larger and more efficient generators, better generator utilization, and a significantly lower fuel price than in Study Case 1. Liquefied natural gas (LNG) and multi-fuel engines of 3.5 MW each will be available on the island starting in 2022 according to the plans of the utility, further decreasing generation cost to USD 0.16 – 0.17 per kWh.

With the current cost development of PV and batteries in the region, the applicable constraints for spinning reserves and the introduction of SCADA and an automated energy management system (EMS), the achievable cost savings from hybridization are significantly lower than in Study Case 1. The integration of PV is nevertheless advantageous, while wind power may be feasible only from 2028 onwards, when system demand has grown enough to allow for the installation of turbines of the 500 kW class.

The system was found to be incapable of tolerating the output fluctuations of single PV sites larger than 1.3 MWp at an acceptable frequency quality, but more than one such unit could be integrated considering spatial smoothing effects obtainable from the relatively large size of the island. Smoothing batteries on each PV unit could allow for larger installations, but it was found that there was no economic advantage to be gained from this. Moreover, larger installations could lead to an unacceptably large single contingency, especially as the outage risk on distribution feeders was found to be considerably higher than inside the conventional power station, which is to include the larger 3.5 MW gas engines.

Both diesel and gas engines were found capable of keeping the system stable at PV penetration levels up to 70 % during the day, given an adequate automated secondary control system. Smoothing batteries on the multiple 1.3 MWp PV units were found to be a feasible option, reducing strain on the gensets, improving frequency quality and slightly reducing PV curtailment. These batteries however produce no further cost savings, overall generation cost results with and without batteries came out at very similar levels. Results were similar for all future years simulated, leading to an overall 11 -16 % annual PV contribution and cost reductions in the range of approximately 5 % across the board.

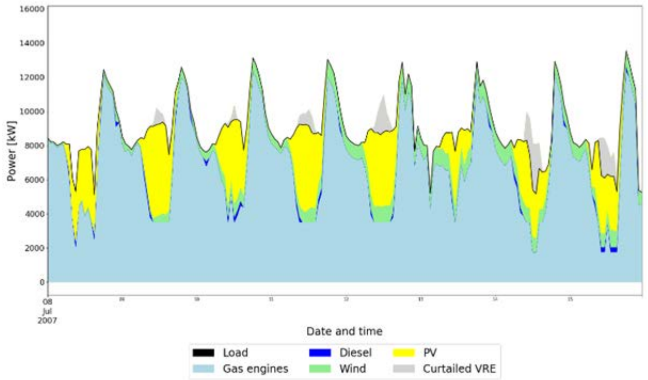

Figure 10: Typical dispatch week 2028, scenario without batteries.

PV contribution is limited by the flexibility of the conventional generation and by the low generation cost, which, following a strict least-cost approach, prohibits the installation of large batteries to increase contribution, even considering battery cost reductions in the coming 5-10 years.

C. *PV Integration Sensitivities*

Raw simulation results, as mentioned, yielded results without any battery storage for all scenario years, and with the 1.3 MWp site size limit and an EMS system, these results were found to be technically feasible. As there are other advantages to higher shares of renewable energy such as reduced emissions and a reduced dependence on fuel imports and fossil fuel prices, sensitivity scenarios with relaxed cost optimization constraints were optimized, resulting in a comparison of three cases for each year:

- The optimized base case with several 1.3 MWp PV sites and no batteries;
- A case with a battery at each PV size (lithium ion and lead carbon types considered), capable of eliminating 50 % of the expected output fluctuations;
- A case with a grid forming battery, single site, capable of covering the entire daytime load for at least one hour, and PV capacity optimized on top of it.

The results indicated that the cases with and without smoothing batteries would yield very similar PV contributions (Table 5) and overall generation cost (Figure 11). The scenario with batteries showed higher investment, but lower operation cost as reserve margins on the conventional generators could be reduced and fewer generators could operate at more favorable power setpoints.

As expected, the grid forming case almost tripled annual PV contribution (Table 5, but proved to be significantly more expensive up until at least 2026. With cost projections for PV, batteries and inverters taken from IRENA data [8] and adapted to local conditions such as interest rates and transport cost, the grid forming case however became feasible from 2028 onwards (Figure 11).

Table 5: Sensitivity analysis results, installed capacities and PV contribution.

	Installed capacity [MW]		**Optimal annual PV contribution**		
	Diesel	***LNG***	***PV only***	***PV + Smoothing battery***	***PV + Grid forming***
2020	10	0	11 %	11 %	35 %
2022	2	10	12 %	13 %	33 %
2024	2	10	12 %	14 %	32 %
2026	2	14	14 %	16 %	31 %
2028	2	17	16 %	17 %	30 %

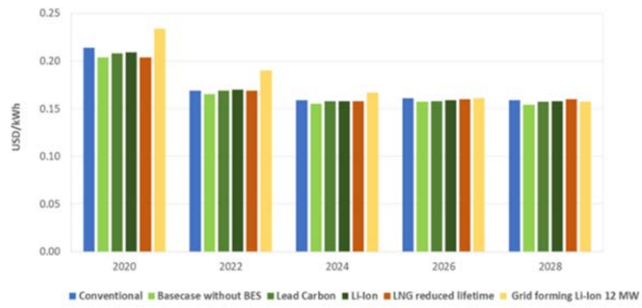

Figure 11: Cost comparison between sensitivity scenarios.

As visible in Figure 12, the grid forming battery is used only to achieve 100 % PV penetration during the day, while the amount of energy that is stored during the day and released later is small. Simulations with higher battery capacities would always result in higher generation cost – there is an economic case for "moving the gensets out of the way" during the day in 2028, but still no case for large scale energy arbitrage due to the low generation cost of the planned gas engines. If the new engines continue to be operated on diesel, as LNG supply fails to materialize, the situation changes slightly, with the grid-forming case reaching economic competitiveness already in 2025-26 and approximately 50 % more storage capacity. However, even in this case, the scenario with smoothing batteries and no grid-forming capability is still somewhat cheaper, but the cost difference is within the margin of error.

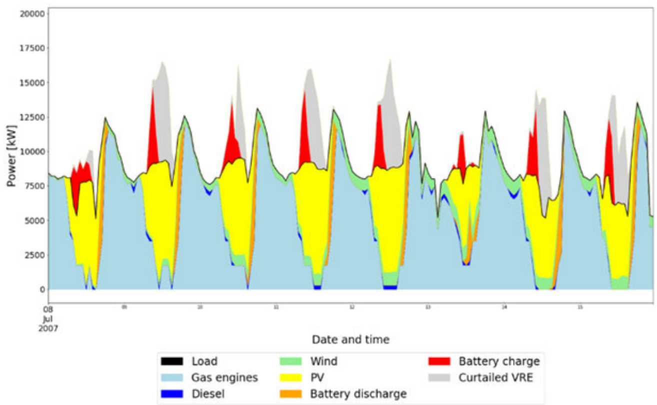

Figure 12: Typical dispatch week, grid forming scenario.

D. *Recommendations to the Utility*

The recommendations presented to the utility in this case, briefly summarized, were the following:

- Go ahead with the single 1 MW PV site with smoothing battery already planned;
- Add more such installations as demand grows;
- Investigate wind power and grid-forming batteries from 2025 onwards

The investment into a communication system connecting PV units to an EMS system inside the conventional power plant was found to be unavoidable, but could be deferred by a few years if the PV units had smoothing batteries, reducing frequency impact at fluctuations.

V. Conclusions and Outlook

As shown in two exemplary cases through optimization and sensitivity analysis, the economic feasibility of hybrid systems utilizing PV, grid-forming inverters and sufficient battery capacity for small power systems depends heavily on the characteristics of the system in question. If diesel generator flexibility can be adequately controlled, PV shares between 15 and 20 % can often be achieved without the need for grid-forming capability and large battery capacities. Significant cost savings can be achieved even at moderately low fossil fuel prices.

Grid-forming systems, by today's state of the art reliant on significant battery capacities that make up the majority of the investment required, are currently economically interesting especially in very small systems with high fuel prices and low overall efficiency. Low load factors, which are in most cases unfavorable for PV integration without battery support, and the oversizing of generators often found in such systems contribute to the need for diesel-off operation arising quite early on. Annual PV contribution in excess of 70 %, achieved with grid-forming inverters and large storage capacities, was found to become cheaper than diesel based generation in the respective study case already at fuel prices around USD 0.60 per liter diesel. Owing to recent cost reductions in PV, batteries and power electronic equipment, this is a drastic difference from the (outdated) numbers that are still being circulated in public discussion where PV integration is considered to be feasible at a fuel price of USD 1.00 per liter.[2]

The picture is still somewhat different for larger systems and/or lower fuel prices. Larger systems tend to be operated more efficiently as generator operation can be optimized much easier. Larger generators are also usually more efficient, albeit somewhat less flexible, and larger system often see more favorable fuel prices as they buy larger quantities. Additional integration challenges are imposed by having to dispatch and control multiple generators and balance PV fluctuations with them. These exact challenges however contribute to battery systems becoming feasible at some point, as the cost of spinning reserves may be higher than the cost of batteries. The study case analyzed, from an island with relatively low generation cost in the range of USD 0.20 per kWh, shows that even grid-forming systems with large batteries could become feasible in just a few years.

As an outlook, the authors will continue to work on hybridization projects in island systems in the Caribbean and South East Asia and plan to map out the constraints and characteristics of the systems more thoroughly. The intended outcome is a framework, in the form of an Excel or Python tool, that allows for a quick high-level analysis of island power systems concerning PV, battery and grid-forming inverter strategies based on key system characteristics.

[2] Some of the graphics from SMA publication [10] have proven to be quite prolific online, even though they were first published in 2013 and have been updated by SMA themselves in the meanwhile.

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