Interim Report
on Work Packages 1 to 12
Final Version

Economic Analysis to Facilitate the Establishment of a Stable Price for Electricity from Renewable Sources

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EXECUTIVE SUMMARY

This interim report summaries the results of the work on WP1 to WP11, which were scheduled to be completed by the time of the interim report. It incorporates a number of changes based on the draft interim report supplied to the Energy Division in March 2017.

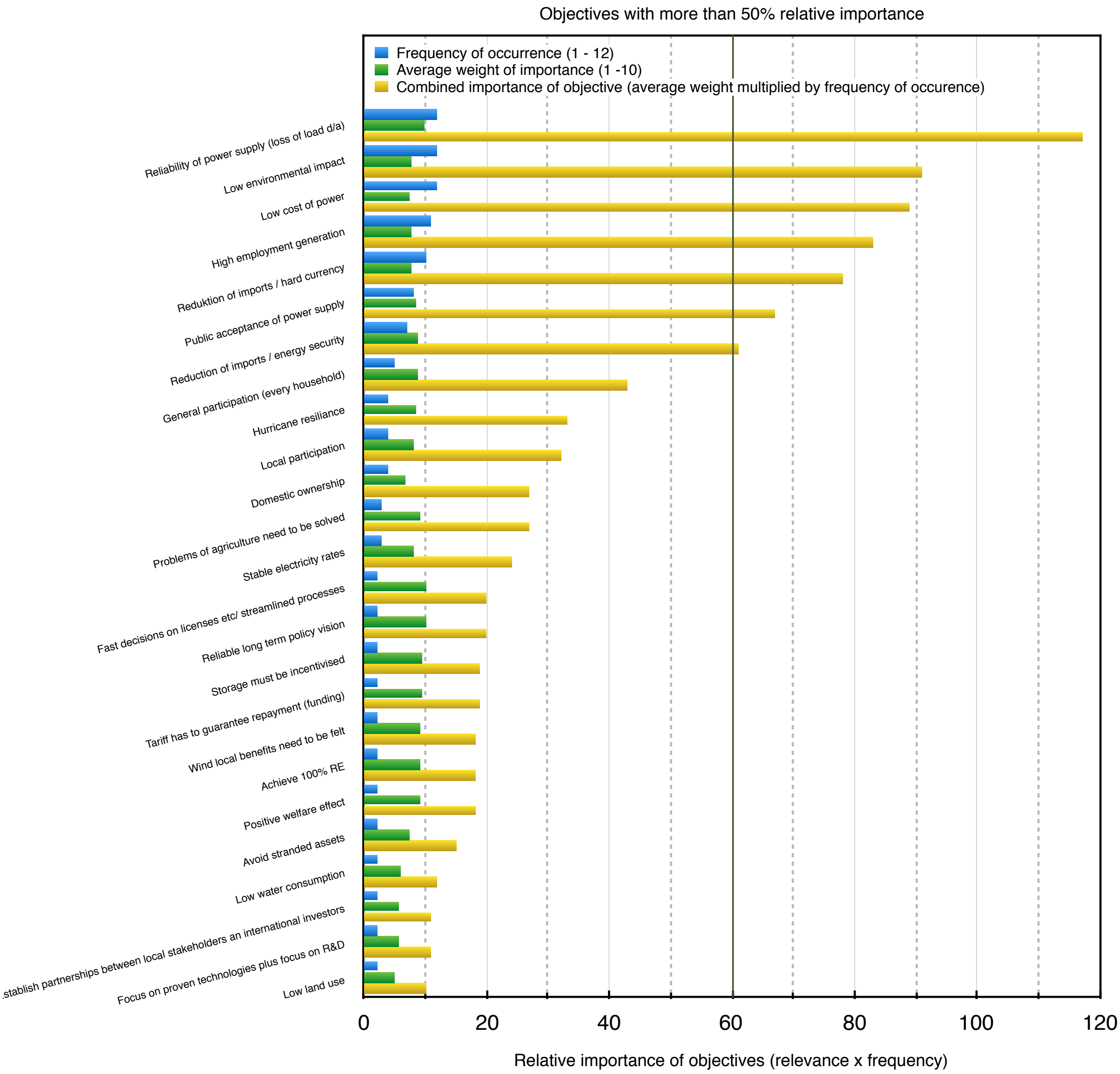
WORK PACKAGE 1: STAKEHOLDER CONSULTATIONS

As the report has to recommend the most appropriate market structure, support mechanisms and policy measures for a sustainable development and stable prices of renewable electricity in Barbados it was necessary to find out the most important objectives of the introduction of renewable energy held by important stakeholders in the energy sector in Barbados. Interviews with twelve key stakeholders in power generation and renewable energy were conducted asking for the important objectives seen and their relative importance. The interviews produced 56 different objectives, out of which 30 objectives were only mentioned by one stakeholder. Combining the results of all interviews (average weight times the frequency at which an objective was mentioned) lead to an ordered set of objectives by relative importance. The results are shown in Figure IR1 below. Besides the *reliability of the power supply* a *low environmental impact, low cost of power, high employment generation,* and *reduction of imports* to reduce *to outflow of hard currency* and to *increase energy security* are objectives of high importance to the interviewed stakeholders. *Local participation* and *domestic ownership were* mentioned as other important objectives. The *public acceptance of the power supply* was an other important objective relating to public involvement. One group of stakeholders with an agricultural background stressed the objective p*roblems of agriculture need to be solved.*
These important objectives can give orientation beyond the often used *low cost of power* and *reliability of power supply* for the design of energy policies and support mechanisms as well as for the discussion on the most appropriate market structure.

WORK PACKAGE 2: UPDATED ESTIMATES ON RENEWABLE ENERGY POTENTIALS AND COSTS

In work package 2 the available information on international cost developments for wind and solar PV were brought together with information on local cost and potentials. As a result it can be concluded that especially in the case of solar PV Barbados has made substantial progress in reducing the cost differences of systems installed in Barbados and in the world market. By early 2017 PV systems were installed at cost as low as 2.13 BBD/Wp. Nevertheless, very expensive systems are being installed at up to 20 BBD/kWp, which strongly influence average investment cost to between 5.9 and 11.4 BBD/Wp depending on system size. At the same time international PV prices are in the range of 2.8 to 5.8 BBD/Wp depending on system size.

Figure ES1: Frequency of occurrence, average weight of importance and relative importance of the twenty five objectives mentioned by at least to key stakeholders



For wind no reliable data exist for Barbados, but experts involved in the first two larger wind development projects suggest that the cost are about 20-25% higher in Barbados as compared to the world market due to market size and transport cost. At the end of 2016 world market prices for wind turbines including all investment and financing cost are in the range of 3,400 BBD/kW, with very similar costs in Europe (Germany as European lead market) and in the US.

Cost for biomass are highly project specific and no cost figures can be quoted from international markets, which could be directly compared to the two major biomass activities in Barbados for which cost estimates are
available. The investment costs for the bagasse combustion plant are quoted at 18,400 BBD/kW (230 million USD for 25 MW capacity), while the first estimates for the gasification and power production from King Grass are at 10,000 BBD/kW.

Concerning the potential of of renewable energy resources in Barbados specifically wind seems to be critical. A new assessment by Rogers (2015) shows a good potential of about 450 MW as a result of a detailed study of the local wind resource. The potential of bioenergy depends highly on the agricultural land available and the type of use (energy crops only or energy like King Grass as a byproduct of an other crop utilisation like bagasse). In the case of King Grass 20,000 acres could produce about 400 GWh of electricity per year, while the use of bagasse from 18,000 acres of sugar cane plus river tamarind from additional 5,000 acres could produce about 169 GWh/a (net) in the biomass combustion planned by the cane industry.

WORK PACKAGE 3: UPDATED DISCUSSION OF THE APPLICABILITY OF PUMP STORAGE HYDRO SYSTEMS AND THEIR COSTS IN BARBADOS

Latest studies have shown that pump storage installations in the range of 1 to 5 GWh of storage are feasible in Barbados (Stantec 2016) and that the costs will most likely be in the range of about 3,000 BBD/kW. Pump storage experts visiting the island in late 2016 came to the conclusion that the cost should be close to the average of present pump storage facilities build around the world. As the system will play a central role in controlling the frequency and voltage of the power system the specific technology used will allow a very fast and continuous operation shifting from 100% pumping to 100% generation within less than 180 seconds.

Battery storage, although becoming cheaper in the last years is still far away from being competitive with pump storage at the necessary scale for Barbados. The concentration on battery storage mislead the authors of the IRENA road map for Barbados to ignoring the potential of their own scenario. As shown in new model simulations including in this report the inclusion of a sizeable pump storage plant (3 GWh storage) instead of the assumed battery storage of 150 MWh would have lead to 94% of renewable energy production with the same installed renewable energy capacity instead of the 84% reached by the battery based scenario. Nevertheless, battery storage will play an important role in the short term stabilisation of local distribution grids with high renewable energy penetration.

WORK PACKAGE 4: EXTENSION AND UPDATE OF HOURLY POWER SYSTEM SIMULATION MODEL FOR BARBADOS

The analysis of the most appropriate market structure, support mechanisms and policies for a sustainable development of renewable electricity generation in Barbados needs to be tested against the target to be reached and the transition pathway to the renewable energy based target system. To analyse different possible target systems for a 100% renewable electricity supply for Barbados the existing hourly simulation model developed by the author and applied to 100% renewable energy solutions was extended to accommodate the use of flexible bioenergy from King Grass gasification. This extension allows to model seasonal harvesting and flexible hour of day production based on a day ahead prognosis of the production from wind and solar energy. At the same time the model was extended to handle power production from waste gasification on the same basis.

In addition the model was extended by a discounted cash flow subprogram, which allows to account for the hourly income from residual load dependent feed-in tariffs for example for electricity from King Grass or solid waste gasification. This can be used to assess the impact of load dependent tariffs on flexible production units as a precondition to the setting of such tariffs.

WORK PACKAGE 5: SIMULATION OF ALTERNATIVE 100% RE TARGET SYSTEMS AND ANALYSIS OF THEIR PROSPECTIVE COSTS

A set of 18 different target systems were simulated to analyse all relevant combinations of the renewable power technologies available to Barbados. These technologies are wind turbines, solar PV systems, solid biomass combustion, biomass gasification, solid waste combustion and waste gasification. The comparison of the power costs of all alternative target systems showed that a combination of wind, PV and solid waste combustion can produce 100% renewable power at the lowest cost (0.39 BBD/kWh in a year of low winds).

Table ES1: Electricity cost per kWh of simulated target systems for 100% RE power for Barbados

Scenario		LCOE
No.	Name	BBD/ kWh
11	100% RE / Wind / PV / Solid waste combustion	0.3883
7	100% RE Wind and PV plus storage	0.3999
13	100% RE / Wind / PV / King Grass / WTE combustion	0.4004
6	100% RE Wind and storage alone	0.4013
17	100% RE / Wind / PV / King Grass / Bagasse / WTE combustion	0.4128
14	100% RE / Wind / PV / Bagasse / WTE combustion	0.4143
12	100% RE / Wind / PV / King Grass / WTE gas	0.4209
8	100% RE / Wind / PV / King Grass	0.4212
9	100% RE / Wind / PV / Bagasse	0.4233
10	100% RE / Wind / PV / WTE gas	0.4356
18	100% RE / Wind / PV / King Grass / Bagasse / WTE gasification /WTE combustion	0.4361
13a	100% RE / Wind / PV / King Grass / WTE combustion	0.4386
1	New diesel only (base line)	0.4495
16	100% RE / Wind / PV / King Grass / Bagasse / WTE gasification	0.4584
15	100% RE / Wind / PV / Bagasse / WTE gas	0.4614
2	Bagasse and river tamarind only	0.4810
3	King grass gasification only	0.4886
5	100% RE PV and storage alone	0.5100
4	Waste to energy gasification only	0.5126

The target system addressing the agricultural problem still having relatively low costs is the combination of wind, PV, solid waste combustion and the gasification of King Grass from about 6,000 acres leading to costs of 0.4 BBD/kWh. Table IR1 shows the costs of each simulated scenario in the sequence of the cost per kWh.

WORK PACKAGE 6: DISCUSSION OF THE ALTERNATIVE 100% RE TARGET SYSTEMS WITH THE RELEVANT STAKEHOLDERS AND THE ENERGY DIVISION

As all reasonable alternatives have been covered by the scenarios calculated and as it has become clear that only one option can be dismissed right away, while all other decisions will need to be made by policymakers, it was decided that a stakeholder workshop could not decide on the final technology choices. Only if a decision on the solution of the agricultural problem is taken by policymakers, the decision on the final target system can be made.

Policymakers will need to decide how to complement the basic mixture of wind, PV and solid waste combustion with a biomass technology for securing the future of intercropping agriculture in Barbados. As the King Grass gasification is right know entering the demonstration phase, it might be wise to postpone this decision until the results of the first demonstration project on Barbados will be available about 2020. In the meantime the expansion of wind and solar PV can be pursued without the need for such a decision for the energy system before 2025.

Instead of holding the planned stakeholder workshop on the modelling results there will be a broader workshop at the end of the project for the discussion of all results of phase one and phase two of the project. From recent discussions it has become clear that, while most stakeholders see the advantages of a differentiated dynamic feed-in tariff system, the first price points to be suggested in the report and the assumptions going into their calculation will meet far greater interest as some details of the final target scenario.

WORK PACKAGE 7: ANALYSIS OF THE PRESENT POWER SUPPLY SYSTEM AS THE STARTING POINT OF THE NECESSARY TRANSITION TO A 100% RE TARGET SYSTEM

The analysis of the present power supply system shows that this is dominated still by oil based power production (96%), although the installation of solar PV has increased significantly during the last years. With respect to the necessary back-up of future renewable power systems the present generating equipment with the exemption of the steam turbines (2 x 20 MW out of 239 MW total generating capacity) can be used as flexible back-up capacity, if the necessary maintenance is done and the generators are kept operating. The target system simulations show a back-up capacity between 160 and 200 MW will be need. Therefore, the flexible part of the present generators of BL&P will be a sufficient back up capacity for the target systems. As the equipment will be fully written off by the time when it will go into back-up operation, these generators will be the cheapest back-up capacity available to the system.

Form the IRP (integrated resource plan) of Barbados Light and Power (2012), filed in 2012 the power demand for 2035 is estimated to be around 1,350 GWh/a in the base case. In a low case it is estimated at about 950 and in a high demand case at about 2,000 GWh/a. For the simulations of the 100% RE target system a demand of 1,350 GWh/a has been assumed based on the numbers of the IRP.

WORK PACKAGE 8: DESIGN OF AN APPROPRIATE TRANSITION PATHWAY FROM THE PRESENT ELECTRICITY SYSTEM TO THE 100% RE TARGET SYSTEM

As a result of the eighteen 100% RE target systems simulated in WP5 four different target scenarios have been selected for the design of four alternative transition pathways. These systems are the combination of wind, PV and solid waste combustion (scenario 11) as the lowest cost alternative. The combination of these three technologies with a modest use of King Grass gasification (scenario 13), or with an extensive use of King Grass (scenario 13a) and with the combustion of solid biomass (scenario 14). All scenarios employ between 200 and 260 MW of wind and PV and 11 MW of solid waste combustion. They only differ in the extent of biomass utilisation and the technology used for the biomass utilisation.

All scenarios start faster on PV, because the ramping up of wind energy requires more preconditions to be set appropriately, while the power cost will benefit substantially from the use of wind energy. A substantial share of renewable energy will decrease cost as compared to the starting system, while power cost will increase again as the full 100% are finally approached. By 2020 the share of RE electricity is between 22% and 41%, where the main difference is due to the assumed commissioning of the solid biomass combustion plant (25 MW) before 2020 in scenario 14 bringing the share of RE in this scenario to 41% in 2020 already. The other scenarios show shares close to 25% (see Table IR3 below). By 2030 the RE share increases to between 59% and 75%, with the lowest share in scenario 13a including a massive use of King Grass gasification, while the scenario 14 still has the highest share of RE due to the operation of the solid biomass combustion. By 2030 all scenarios have shares of RE between 86% and 91% with the shares of RE moving closer together. In 2035 all scenarios reach 96.3% of RE based on the selected renewable technologies. The rest of 4.7% is based on bio fuels used in the back-up units. Tables IR2 and IR3 show the development of the four transition pathways.

Table ES2: Four target scenarios for 100% RE power supply in 2035 and transition pathways to these target scenarios

Scenario / Wind year 2011		Year	Annual power demand	LCOE	Installed capacities and annual generation									
					Wind		PV		King Grass		Bagasse and river tamarind combustion		Solid wate combustion	
No.	Name			BBD/ kWh	MW	GWh/ a	MW	GWh/ a	MW	GWh/ a	MW	GWh/ a	MW	GWh/a
11	100% RE / Wind / PV / WTE combustion	2015	950		0		10	19					0	
		2020	1050	0.3664	25	114	55	113					5	34
		2025	1150	0.3002	105	481	125	258					11	74
		2030	1250	0.3123	185	847	195	403					11	74
		2035	1350	0.3883	265	1213	265	547					11	74
13	100% RE / Wind / PV / King Grass / WTE combustion	2015	950		0	0	10	19	0	0			0	0
		2020	1050	0.3696	20	92	65	134	2	5			5	34
		2025	1150	0.3253	90	412	120	248	10	30			11	74
		2030	1250	0.3161	160	733	175	361	18	75			11	74
		2035	1350	0.4004	232	1062	232	479	26	120			11	74
13 a	100% RE / Wind / PV / King Grass / WTE combustion	2015	950		0		10	19	0	0			0	
		2020	1050	0.3749	20	92	50	103	2	5			5	34
		2025	1150	0.3354	80	366	100	206	14	45			11	74
		2030	1250	0.3451	140	641	150	310	27	150			11	74
		2035	1350	0.4331	200	916	200	413	40	300			11	74
14	100% RE / Wind / PV / Bagasse / WTE combustion	2015	950		0	0	10	19			0	0	0	0
		2020	1050	0.3807	20	92	65	134			25	169	5	34
		2025	1150	0.3452	85	389	120	248			25	169	11	74
		2030	1250	0.3609	170	778	175	361			25	169	11	74
		2035	1350	0.4143	219	1003	219	452			25	169	11	74

Table ES3: Four target scenarios for 100% RE power supply in 2035 and transition pathways to these target scenarios. The development of the need for storage during the transition period.

Scenario / Wind year 2011		Year	Annual power demand	LCOE	Installed capacities and annual generation							Share of RE	Total overproduction
					Diesel/ Biodiesel		Storage volume	Storage generation		Storage pumping			
No.	Name			BBD/ kWh	MW	GWh/ a	MWh	MW	GWh/ a	MW	GWh/ a	%	GWh/a
11	100% RE / Wind / PV / WTE combustion	2015	950		239	950							
		2020	1050	0.3664	140.9	789						24.9 %	0
		2025	1150	0.3002	148.8	354	3000	150.5	60	90	80	69.2 %	17
		2030	1250	0.3123	162.2	118	5000	186.3	176	220.7	202	90.6 %	192
		2035	1350	0.3883	166.7	50	5000	196.8	205	307	238	96.3 %	400
13	100% RE / Wind / PV / King Grass / WTE combustion	2015	950		239	950	0	0	0	0	0	0.0 %	0
		2020	1050	0.3696	140.2	785						25.2 %	0
		2025	1150	0.3253	148	422						63.3 %	36
		2030	1250	0.3161	155.6	164.4	5000	178	142	162.8	163	86.8 %	157.4
		2035	1350	0.4004	144.8	50	5000	172.9	163	253.4	190	96.3 %	435
13 a	100% RE / Wind / PV / King Grass / WTE combustion	2015	950		239	950						0.0 %	
		2020	1050	0.3749	140.2	816						22.3 %	0
		2025	1150	0.3354	140.5	469						59.2 %	10
		2030	1250	0.3451	135.3	168	5000	156	97	131.5	110	86.6 %	93
		2035	1350	0.4331	131.6	50	5000	156.8	129	199.8	151	96.3 %	403
14	100% RE / Wind / PV / Bagasse / WTE combustion	2015	950		239	950	0	0	0	0	0	0.0 %	0
		2020	1050	0.3807	121.7	621						40.9 %	0
		2025	1150	0.3452	129.9	286	5000	138.4	56	85.3	75	75.1 %	16
		2030	1250	0.3609	139.4	133	5000	165	157	181.4	181	89.4 %	265
		2035	1350	0.4143	151.9	50	5000	180.6	176	248.3	205	96.3 %	398

WORK PACKAGE 9: DISCUSSION OF POSSIBLE MARKET MECHANISMS AND POLICIES FOR THE SUCCESSFUL INTRODUCTION OF RENEWABLES IN BARBADOS

Basically four main market or support mechanisms for the introduction of renewable energy sources into electricity production are used world wide. These are net metering, feed-in tariffs (FIT), renewable portfolio standards (RPS) and auctioning. All are used widely throughout the world, while net metering is seen only as an early mechanism of limited applicability, as it shifts the other power system costs to the customers not producing renewable electricity, which can become overwhelming, if large shares of RE are produced based on net metering. Like net metering FITs approach the target of inducing higher RE shares from the side of the pricing of energy and the quantity installed is determined by the market players, while RPS and auctioning set quantity targets and the final price for the quantity of RE installed is set by market processes.

While pay-as-bid auctions allow to approximate the cost curve for the supply of renewable power RPS combined with the trading of green certificates price according to the last unit of RE supplied. Thus, all other producers with lower costs can benefit from a substantial producer surplus. Therefore, by tendency the cost of renewable electricity supplied under RPS will be higher than under an auctioning system. Both approaches have the serious disadvantage that they require sophisticated well informed market players in sufficient numbers for a competitive market. Thus, most likely they are either not applicable to small island states or may require a substantial number of international investors to reach the necessary level of competition.

FITs rely heavily on an informed administration and well informed policy makers setting differentiated tariffs according to the cost structure of the different RE technologies. If FITs are differentiated for different system sizes and different conditions under which the RE are deployed (e.g. the quality of a wind site) it is possible to approximate the cost curve of a technology similar to the auction process. If FITs are applied in a dynamic way, reducing the rates for new installations every year according to the cost digression of a technology seen in the market, they can result in lower RE cost than auctioning and RPS, as historic experience shows in the comparison between the cost development of RE in Germany (FIT), the UK (auctioning and RPS) and the USA (RPS). At the same time FITs don't need competitive markets to find the tariff to be paid. As RE technologies are traded internationally national FITs can be informed by the international cost structures and developments as long as the local specifics are taken into account.

Empirical evidence has shown that specifically a wide participation of all citizens in RE investments is best accommodated by FITs and that these can induce a very rapid market diffusion of RE.

A review of experiences with different support mechanisms for the market diffusion of renewable energy sources in five island systems with high RE penetration and the experiences of the Dominican Republic, which is the only CARICOM country with a FIT system legislated showed that FITs and net metering systems had very effectively promoted RE market diffusion. RPS and auctioning or tendering have been used only in rare cases (Hawaii uses RPS and Crete and Reunion are forced to move to tendering by EU law) with limited success. In the case of Hawaii non dynamic FITs had to be capped for maximum capacity and lead to speculative project queuing. In Crete and Reunion dynamic FIT tariffs were able to calm down very fast developments of PV in the years after 2008. Nevertheless, FIT systems have to be very well tailored to the circumstances of an island country and have to follow the cost trends of renewable energy technologies for new investments.

WORK PACKAGE 10: ANALYSIS OF THE PRESENT MARKET SITUATION OF RENEWABLES IN BARBADOS

Presently only solar PV has been installed in sizeable numbers as RE electricity technology in Barbados. As Table IR4 shows the installation of PV capacity has started in significant numbers in 2012 with 910 kW of capacity installed and annual installation has been increasing ever since. The main driver of the installation of PV has been the renewable energy rider (RER) first introduced in 2010 for a trial period of two years and allowed as a permanent support mechanism in August 2013. The RER was directly linked to the fuel cost adjustment clause and thereby to the world market price of oil. In 2016 the variable rates of the RER based on the Fuel Clause Adjustment was temporarily converted to a fixed feed in tariff of 0.416 BBD/kWh for PV and 0.315 BBD/kWh for wind energy. This change was due to the fact that the world market crude oil price had gone down to below 40 USD/bbl while it was at more than 100 USD/

bbl in the years when the RER was originally designed. This massive drop in oil prices led to many solar installations becoming economically endangered. As the 2016 RER ruling, is only temporary investors are waiting for the further development of the Barbados support mechanism.

As the RER initially only applied to installations up to 150 kW, a limit that was later raised to 250 and then to 500 kW, larger installations are not seen in Barbados except the 10 MW PV plant built by BL&P, which does not come under the support mechanisms applied to all other investors

Besides the unclear future of the renewable energy support mechanism the development of RE is slowed down by relatively unclear and lengthy licensing and permitting processes. The new requirement of an ELPA license and the financial burdens posed by it on investors is seen by many as one of the main obstacles to a faster development of RE. The situation that every project over 500 kW is treated as an independent power producer (IPP) under the Electric Light and Power Act (ELPA) puts investors into a very difficult negotiating position with the vertically integrated monopoly of BL&P, as this is a totally asymmetrical negotiating position.

Table IR4: Development of PV capacity in Barbados since 2010 (sources: UNDP no year, p.19, IDB 2016, p.12 and application data for ELPA licenses)

Year	No. of PV Systems	Annually Installed Capacity (kW)	Cumulative Installed Capacity (kW)
2010	4	7	7
2011	8	7	14
2012	63	896	910
2013	350	1990	2900
2014	710	2600	5500
2015		4900	10400
2016	850	12455	22855

In addition the frequent demand for additional information from investors in unclear licensing and permitting processes are a main obstacle to substantial RE investments in Barbados. Some wind energy projects have been in the licensing and permitting process for more than five years with the end of the process still pending. As compared to international standards this is absolutely not acceptable.

One special problem of the permitting of wind power installations are the distance rulings applied by Town and Country Planning. As different from the international standard rules Town and Country Planning requires minimum distances from the perimeter of the property on which a wind turbine is placed, while the international standard is based on the distance to an object to be protected from the direct impact of wind energy. As the Barbados ruling does not allow to locate wind turbines in the middle of uninhabited agricultural land owned by a several land owners it only allows a small fraction of the wind energy capacity which could be placed on such land as compared to the international standards. If Barbados wants to benefit of its superb wind energy resource and the low cost of wind energy this rule has to be brought up to international standards.

WORK PACKAGE 11: COMPARISON OF PRESENT MARKET SITUATION AND INSTRUMENTS TO POSSIBLE ALTERNATIVE CHOICES

In WP11 the present support situation and the alternative support mechanisms discussed in WP9 are analysed with respect to the important objectives that they should fulfil according to the interviews with key stakeholders (see WP1). In addition to the 13 most important objectives two additional criteria were introduced into the discussion, the *applicability of* such *a support mechanism* and the *necessary administrative effort* to handle a support mechanism. Table ES5 shows the results of the comparison of the support mechanisms with the objectives. Green colour showing that a support mechanism can fulfil an objective and red colour showing that it does not fulfil the objective.

As pointed out before, net metering should not be applied at a large scale, as it drives up the cost for the poorest customers and benefits richer investors. The same applies to the original renewable energy riders system, which in times of high oil prices prohibits that power prices are stabilised by the extensive use of cheaper renewables. Thus, both systems have to be ruled out for a large scale application in Barbados.

Renewable portfolio standards (RPS) require functioning markets for green certificates based on the production of renewable electricity. In addition they require spot and futures markets for electricity to fully function. Both types of large anonymous markets can not be established with the small number of market participants in Barbados and with the monopoly generator of conventional electricity. Thus, RPS are not applicable for Barbados and are therefore dismissed.

The final discussion boils down to a comparison of auctioning and feed-in tariffs (FITs) with respect to the important objectives. As measured against all thirteen objectives and the two additional criteria FITs do well on all of them. ***There is not a single objective which could not be met by a well set differentiated dynamic FIT system***.

While auctioning does best on *low cost of electricity* and by tendency even better than an FIT system, if there is enough competition in the auctions, it does badly on *high employment generation, reduction of imports/hard currency, public acceptance of power supply, general participation, local participation* and *domestic ownership*, while it necessitates a large *administrative effort* for the regular auctions and the setting of multiple quantity targets at short intervals. It can do well on *reduction of imports/energy security* and *solving agricultural problems*.

The detailed discussion of all different aspects in WP11 has shown that ***a differentiated dynamic FIT system tailored to the needs of Barbados is by far the most adequate support mechanism for the sustainable long term diffusion and stable prices of renewable energy in Barbados***.

Table IR5: Summary of the scores of all support mechanisms on thirteen objectives for the renewable energy policy of Barbados and two additional criteria

Priority objectives	Relative importance of objective (Score, max. 120)	Support mechanisms						
		Barbados today			Options for the future			
		RER	FTC fixed tariffs	Single PPAs	Net metering	FIT	RPS	Auctioning
Applicable to Barbados								
Administrative effort necessary								
Reliability of power supply (loss of load d/a)	117.0							
Low environmental impact	91.0							
Low cost of power	89.0							
High employment generation	83.0							
Reduktion of imports / hard currency	78.0							
Public acceptance of power supply	67.0							
Reduction of imports / energy security	61.0							
General participation (every household)	43.0							
Hurricane resiliance	33.0							
Local participation	32.0							
Domestic ownership	27.0							
Problems of agriculture need to be solved	27.0							

WP 1: STAKEHOLDER CONSULTATIONS

As Barbados is embarking on a process to convert its entire energy system from the basis of fossil fuels, namely mineral oil products, to a green energy supply based on domestic renewable energy sources, it is embarking on a transition process of the economy which will have very substantial impacts on many walks of life. Besides a massive reduction of Barbados' green house gas emissions this transition can have positive impacts on environmental pollution and human health in Barbados through the reduction of sulphur dioxide, nitrous oxide, VOC (volatile organic compounds) and particulate emissions from power generation, transportation including the energy consumption of cruise liners berthed at Barbados' harbour and other energy uses like cooking. These emissions can virtually be reduced to zero. At the same time the switch to domestic renewable energy sources can reduce Barbados' exposure to the risk of fast changing oil prices as well as it reduces the high burden of fossil fuel imports on Barbados' balance of payments by eventually reducing the imports of mineral oil products for energy to zero.

Although, some equipment for the generation of green energy will need to be imported, a first analysis shows that the transition to a domestic 100% renewable energy supply can reduce net energy related imports by about 80% (based on fuel costs of 2013) (see Hohmeyer 2015, p.27). By the virtue of import reductions GDP (gross domestic product) will rise accordingly leaving hundreds of millions of dollars in the hands of Barbadians, which are presently spend on energy imports. This will result in a substantial creation of additional employment. By the same mechanism the tax income of Barbados' government will rise due to the fact that much more taxable income stays in Barbados' economy. Nevertheless, it has to be pointed out that most of the possible positive economic effects for Barbados' economy will only occur to the extend that the new energy system will be owned and operated by Barbadian nationals or by international investors leaving the money earned with renewable energy production in Barbados' economy.

At the same time it will be essential that the reliability of Barbados' energy supply, especially the supply of electricity, will remain at its present high level and that the energy costs to the consumer will be substantially below the extremely high levels of some of the past years and that they will be stabilised at such a level for the future.

It follows from these different possible impacts of Barbados' transition to a green energy supply that the energy policy enabling this transition has to take into account a number of different objectives. Depending on the emphasis on different objectives eg. lowest costs (which may require large foreign investors to come into play) versus greatest positive impact on the domestic economy (which may preclude higher levels of foreign investment), the market structure and policy measures designed to facilitate and guide the transition process need to take into account how these different objectives are weighed by the major players in the field of power generation, especially those stakeholders concerned about the introduction of renewable energy.

Although the new draft energy policy for Barbados spells out over a hundred different objectives it is not possible to use this large array of objectives to guide the shaping of the market structure for renewable energy sources and policy measures to guide the transition process, as there is no clear ranking of the importance of all the different objectives mentioned in the draft energy policy (see Ince 2016). Therefore, the consultant conducted a short survey amongst key stakeholders in Barbados' electricity sector to find out which of the different possible objectives are seen as relevant for the electricity sector (which is the focus of this report) and how these are weighed with respect to each other. This survey was conducted in coordination with the Division of Energy and Telecommunications (Mr. Bryan Haynes) in as much as the selection of stakeholders to be interviewed was done as a joint exercise. Fifteen key stakeholders have been interviewed during the time available. The interviews were conducted as structured interviews with open questions. Thus, the interviewees were not given a list of objectives to choose from, but they voiced their own choices without much external influence. The only exemption from this rule was that the reliability of the power system mentioned by the interviewer, which is unquestionably a central objective of each power supply system in the world. Reliability was used in the second part of the interviews, when the interviewees were asked to rank the mentioned objectives on a scale from 1 to 10 (least important to most important). To allow the interviewed persons to calibrate their answers, they were asked, how important the reliability of the electricity supply was to them. Then all other objectives were ranked by the interviewees.

As four of the persons were interviewed in one meeting at Barbados Light and Power and as these persons were representing BL&P as well as EMERA Caribbean their answers, which were given collectively, were weighed by factor two. This was done as they were representing the Barbados power company entrusted with all of the public fossil fuel based power generation, the transmission and distribution of electricity in Barbados as well as the control of the system, and EMERA Caribbean, the Canadian owned holding company of BL&P. Thus, the interviewees can rightfully be considered the key players of the electricity sector most heavily affected by the envisaged transition away from fossil fuel based power generation.

In total the interviewees mentioned 56 different objectives. Three objectives (*Reliability of power supply*, *Low environmental impact* and *Low cost of power*) were mentioned by all interviewees. Four further objectives were mentioned by eleven (*Employment generation*), ten (*Reduction of imports/outflow of hard currency*), eight (*Public acceptance of source of power supply*) and seven stakeholders (*Reduction of imports to increase energy security*).

All other objectives were mentioned by clearly less than 50% of the interviewees, although the three objectives mentioned either by five (*General participation in the new energy system/all households*) or by four stakeholders (*Local participation*) (*Domestic ownership*) are all pointing into the direction of a necessary increase of public participation in and domestic ownership of the new energy supply system. A trend often discussed as ‚democratisation of power production‘.

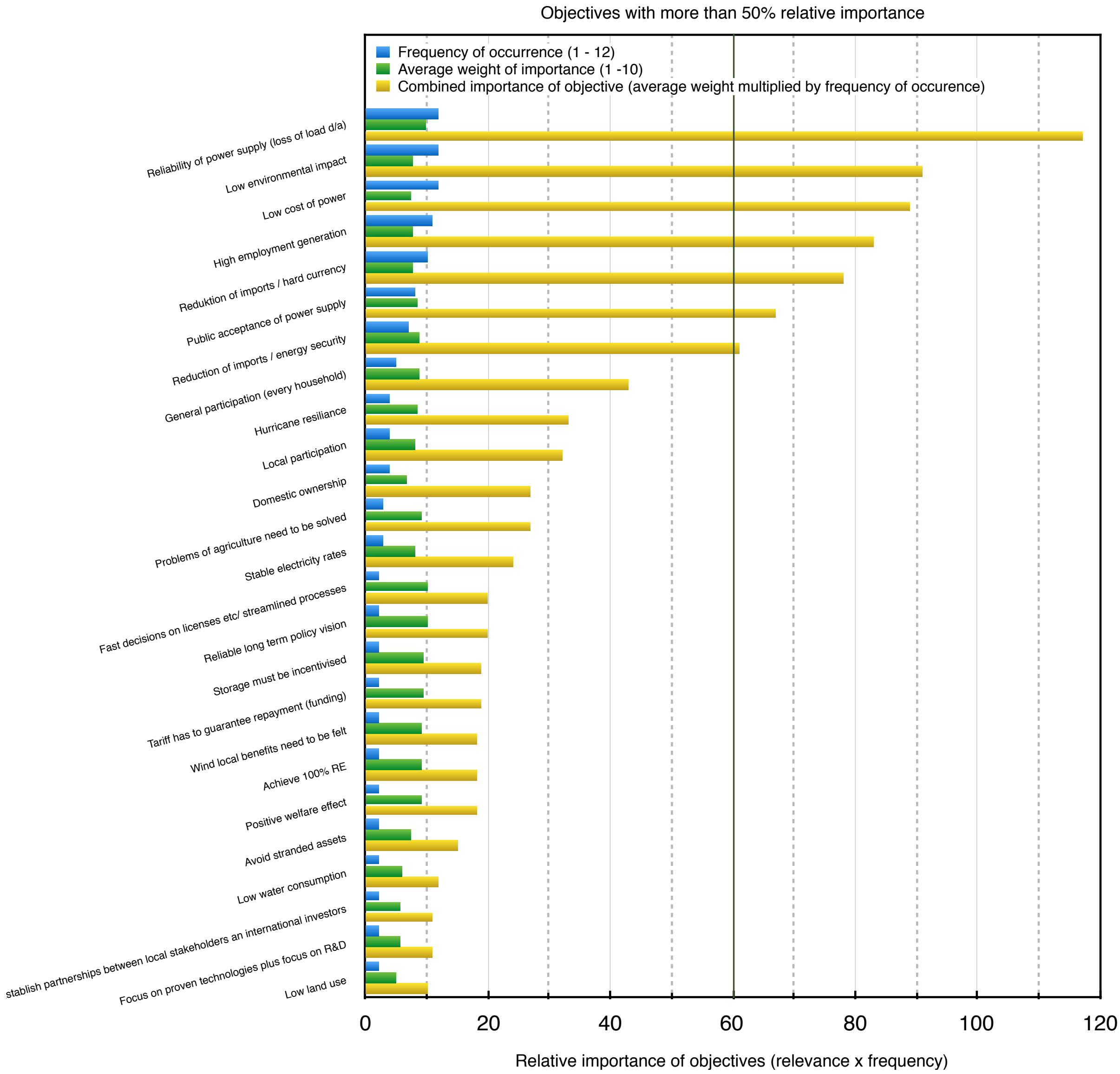
Four stakeholders mentioned the necessary *resilience* of the new energy system *against* the risks of *hurricanes*, while three stakeholders mentioned *Stable electricity rates,* and the necessity that the new energy system needs to *contribute to the solution of the agricultural problems of Barbados.*

Twelve objectives were mentioned by two stakeholders, while another thirty objectives were just mentioned by one interviewee. It can certainly be assumed that objectives mentioned only by one or two stakeholders would be relatively low on the priority scale if many more stakeholders would be interviewed.

In a review of the *Visionary goals,* the *Core Values,* the *Overall objectives,* the *Objectives for renewable energy sources,* the *Objectives for Electricity* as well as the suggested *Policy Measures for the renewable energy sector* and the *Objectives for the Electricity Sector* of the draft new energy policy for Barbados (Ince 2016), about 140 different *Values*, *Objectives* and *Measures* were counted. The review showed that there is strong overlap between the objectives raised by the stakeholders in the interviews and the objectives given in the Draft National Energy Policy. While all three objectives raised by all stakeholders are put forward in the Draft Energy Policy, three objectives mentioned by the majority of the stakeholders (*High employment generation*, *Reduction of outflow of hard currency*, *Public acceptance of sources of power supply*) were not found in the draft available to the consultant, although due to the sheer number of objectives and the short time available for the review, it may have escaped the attention that these objectives are mentioned in the Draft Energy Policy in different locations of the document not reviewed.

For all objectives, which were at least mentioned by two different stakeholders, the number of stakeholders, who had mentioned a given objective (frequency) was multiplied by the average weight (importance) attached to an objective by all stakeholders, who had mentioned it. The resulting value is called the relative importance (RI) of an objective in the following text. The objectives were than ordered in the sequence of the resulting relative importance value on a scale between 0 and 120. Across the twenty five ranked objectives, which were mentioned by at least two stakeholders, relative importance values from 10 (Low land use) to 117 (Reliability of power supply) were reached. Figure 1 shows the graphed values for the the *Frequency* at which an objective was mentioned (blue), the *Average importance* attached to an objective (green) and the *Relative importance* (yellow) of an objective.

Figure 1: Frequency of occurrence, average weight of importance and relative importance of the twenty five objectives mentioned by at least to key stakeholders (Table with data in Annex 1)



The graphing of the relative importance (RI) values shows that there is a group of four objectives, which follows the outstanding criterion of *Reliability of power supply* (RI=117) at a high level of importance with RI values between 78 and 91 (*Low environmental impact (91), Low cost of power (89), High employment (83)* and *Reduction of imports (78))*. Within the group the distance between every pair of neighbouring objectives is less than 7 points. Thus, this can be seen as a group of objectives with similar high importance. The next group of objectives is constituted by just two objectives, which have a distance of more than ten points to the lowest ranking objective of the top group and a distance of almost twenty points to the next objective. At the same time both objectives (*Public acceptance of sources of power supply (67)* and *Reduction of imports for energy security (61)*) are the only remaining objectives achieving at least 50% of the maximum RI score. Of the remaining objectives only three reach at least 25% of the maximum possible IR score (*General participation (41)*, *Hurricane resilience (33)* and *Local participation (32)*) forming the next group of objectives by importance. Three further objectives reach at least 20% of the maximum possible score (*Domestic ownership (27)*, *Solving the problems of the agricultural sector (27)* and *Stable electricity rates (24)*), while the other ten objectives, which were mentioned by at least two stakeholders reached RI scores between 11 and 20.

While the results of the survey clearly point to the fact that energy policy has to address substantially more objectives than just the of short term low cost energy for the ratepayers, the number of important objectives seems to be quite manageable. Although a *low cost of electricity* is among the most important objectives *low environmental impacts* or *high employment generation* and the net *reduction of energy imports* for balance of payment and energy security reasons were seen to be of similar or even higher importance by the interviewees.

Besides these core objectives public participation in the new energy system in its different forms all the way from domestic to local ownership seems to be a strong concern of the key stakeholders interviewed.

If a new energy policy will be able to make a substantial contribution to the solution of Barbados' agricultural problem connected to the decline of the sugar industry and if it can deliver a very high reliability of the future electricity supply including a substantial hurricane resilience, it will be able to address the prime concerns voiced by the interviewees.

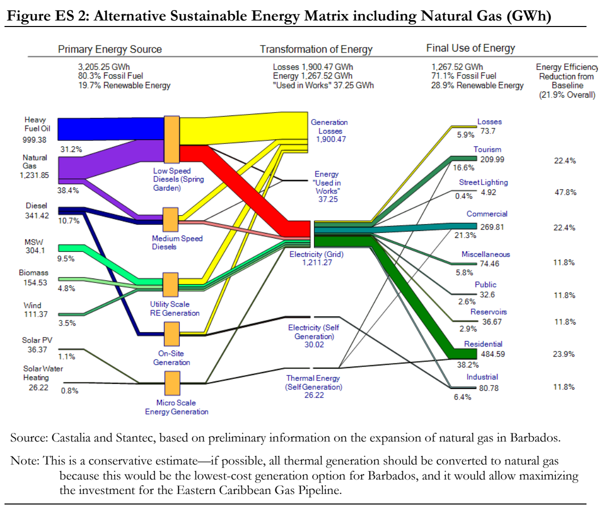
WP 2: UPDATED ESTIMATES ON RENEWABLE ENERGY POTENTIALS AND COSTS

2.1 Analyses on the cost or potential of renewable in Barbados presented so far

2.1.1 CASTALIA AND STANTEC (2010)

In the past there have been a number of discussions on the possible contributions of renewable energy sources to the electricity production of Barbados and to the overall energy supply. The first extensive treatment was in the Sustainable Energy Framework for Barbados developed by Castalia and Stantec in 2010. In this study an *alternative sustainable energy matrix* was developed, which included 10.2% of renewable energy

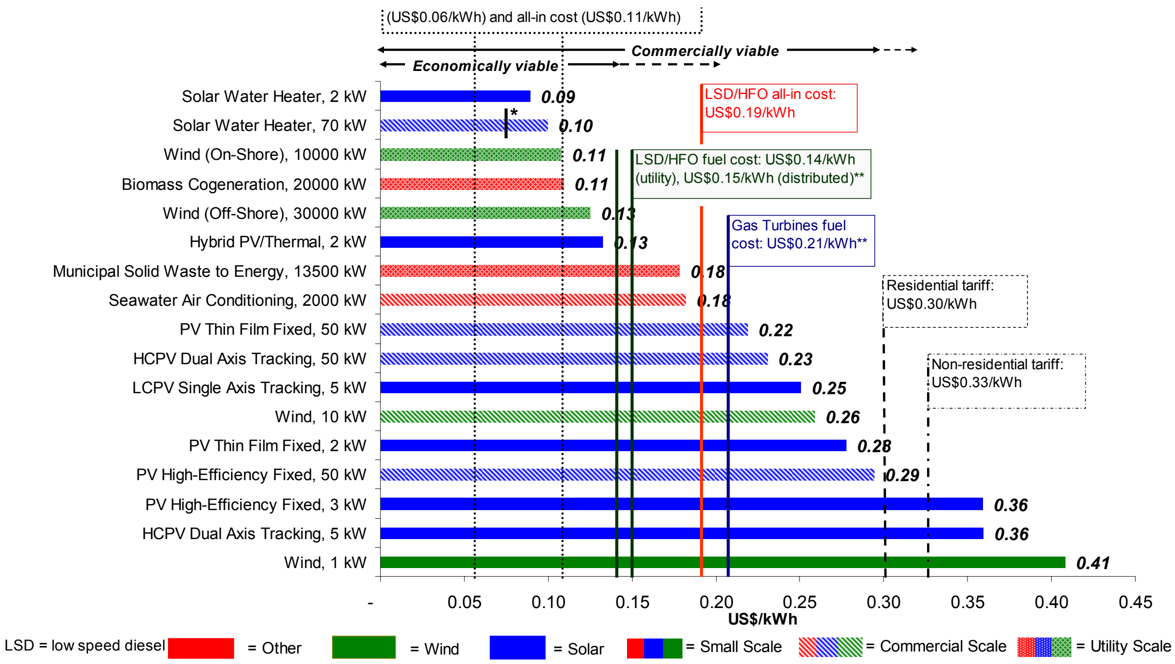
Figure 2: Alternative Sustainable Energy Matrix by Castalia and Stantec (2010, p. iii)



sources (4.8% of biomass, 3.5% wind, 1.1% solar PV and 0.8% solar hot water). A share of 9.5% energy input from municipal solid waste (waste-to-energy) was included in the matrix as well, which ended up with a share of more than 80% of fossil fuels in the ‚sustainable‘ energy mix.

The study of Castalia and Stantec formed the basis for the decision of the Barbados government to set its indicative renewable energy target for electricity production to 29% to be reached by 2029 (Government of Barbados, National Sustainable Energy Policy (no year), p. 8), which explicitly contains the *Sustainable Energy Matrix* developed by Castalia on page 10 of the policy. Furthermore, the study gave a cost comparison of the different energy technologies in 2009/10 showing generation costs of 0.11 USD/kWh for large on-shore wind (10 MW), 0.11 USD/kWh for biomass cogeneration, 0.13 USD/kWh for off-shore wind, 0.18 USD/kWh for municipal solid waste, 22 USD/kWh for larger PV installations (50 kW) and 0.36 USD/kWh for small solar PV systems (2 kW) (see Figure 3 below).

Figure 3: Cost of renewable energy generation according to Castalia and Stantec (2010, p. 6)



Source: Castalia and Stantec estimates

Note: * For "Solar water heater, 70kW" the comparator is fuel oil boiler heating (US$0.08 per kWh). ** 'Fuel costs' also include variable O&M costs; and are grossed up for losses (6.6%) for distributed technologies, but *not* for utility scale technologies. Generation costs and tariffs estimated based on oil prices of US$100 per barrel, and natural gas prices of US$7 per MMBTU. All-in cost of LSD with natural gas contingent on availability from the planned Eastern Caribbean Gas Pipeline.

2.1.2 HOHMEYER (2015)

In fall 2014 a first analysis of the possibility to convert Barbados entire electricity supply to 100% renewable energy was introduce to key Barbados stakeholders and later published by Hohmeyer (2015). This study assumed that Barbados has a sufficient potential to install 452 MW of wind turbines, 376 MW of solar PV, to produce 25 GWh of liquid biofuels and that it had the potential to install a pump storage hydro power scheme with a storage capacity of 3 GWh (see Figure 4 below). For the calculations it was assumed that all passenger cars would be converted to green electricity, which would be supplied by the simulated power system on top of the basic electricity demand for all other purposes.

Based on an hourly system simulation the study could show that a 100% renewable energy supply for Barbados is possible, could supply all power needs in every hour of the year and would lead to substantially lower costs than the costs of the substituted fossil fuels of the conventional power production of 2013. Figure 5 shows the cost of the electricity produced from the 100% renewable power system in comparison to the cost of the conventional electricity produced in 2013. Furthermore, the graph shows production costs of wind energy, solar PV and the pump storage costs per average kilo watt hour sold.

These results were based upon assumed investment costs of 1,500 Euro/kWp for PV systems and 1,050 Euro/kW for wind turbines (for all assumptions see Hohmeyer 2105, p.25). The prices assumed were 2014 prices and converted into BBD by the factor of 2.53. Thus, the cost were equal to 3,795 BBD/kWp for PV and 2,657 BBD/kW for large wind turbines. Based on 6% interest rate for financing, a solar radiation (GHI/Global Horizontal Irradiation) of 2025 kWh/m^2/a, an average wind speed of 4.97 m/sec at 10 meter measuring hight, which translates to an average wind speed of 8.44 at an assumed hub hight of 66m with an assumed roughness at the measuring site of 0.28. Assuming annual operating costs of 5% of the initial investment costs the calculations resulted in production costs of 0.07 BBD/kWh for wind energy and 0.252/kWh for PV.

The study was based on international system prices of 2014 and on the assumption that Barbados would have sufficient space available for the deployment of the wind and solar capacities assumed. While this assumption is not critical for solar PV, as it requires rather limited space per MW installed, this assumption is critical for wind energy, as the possible area for the deployment for wind turbines is largely restricted by the minimum distances of wind turbines from dwellings and protected areas and by the minimum distance of wind turbines in a wind park. At the time of the study the necessary information of a detailed assessment of the wind potential of Barbados was not available.

A second shortcoming of the study was the assumption of prevailing world market prices for wind, PV and pump storage installations, as the market size for these technologies is limited in Barbados, which could lead to substantially higher costs than the costs realised in the world lead markets like Germany or the United States.

A third shortcoming was that the wind data used in the first calculations were data from the Caribbean region (Dominica), but not from Barbados. What is more, the assumed surface roughness of 0.28 was most likely to high, producing to high calculated wind speeds at hub hight.

Figure 4: Basic configuration of Barbados' electricity system supplying the regular electricity demand plus the demand for electrical mobility 100% by renewable energy sources (Source: Hohmeyer 2015, p. 32)

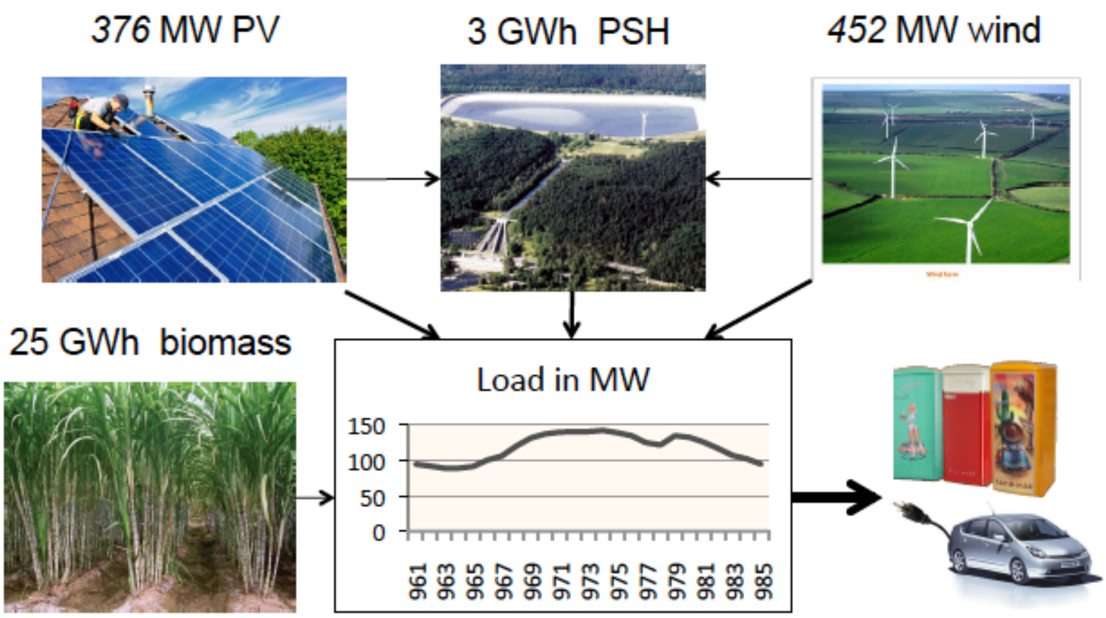
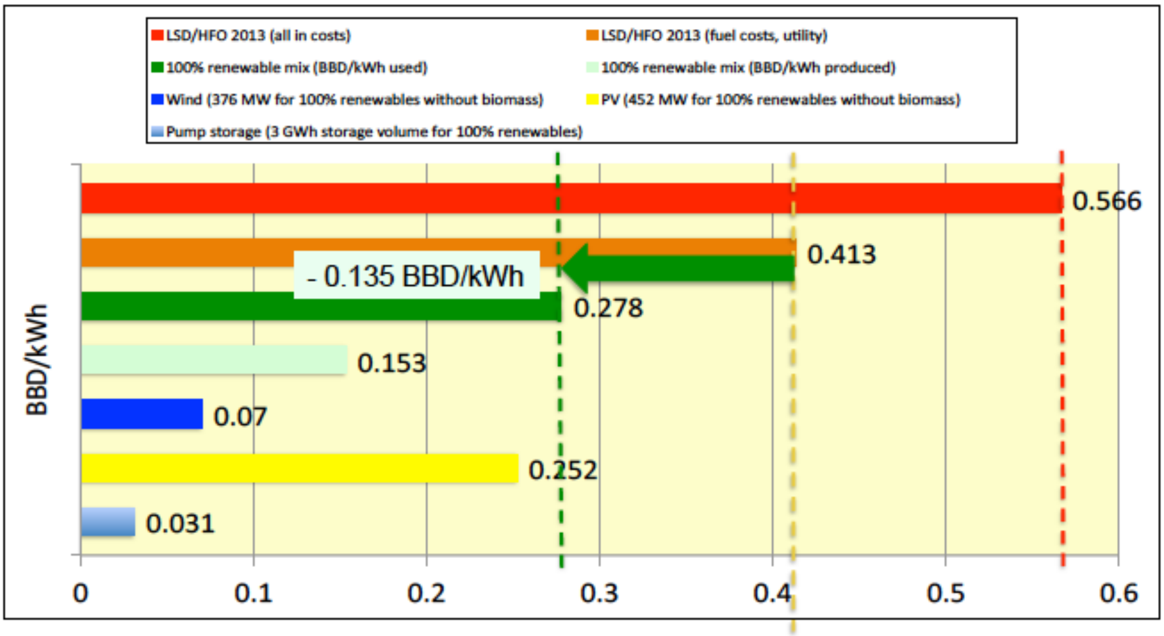


Figure 5: Costs of a 100% renewable power supply for Barbados including electrical mobility compared to present generation costs (2013) based on present prices for renewable energy technologies (Source: Hohmeyer 2015, p.33)



GE GRID INTEGRATION STUDY (2015)

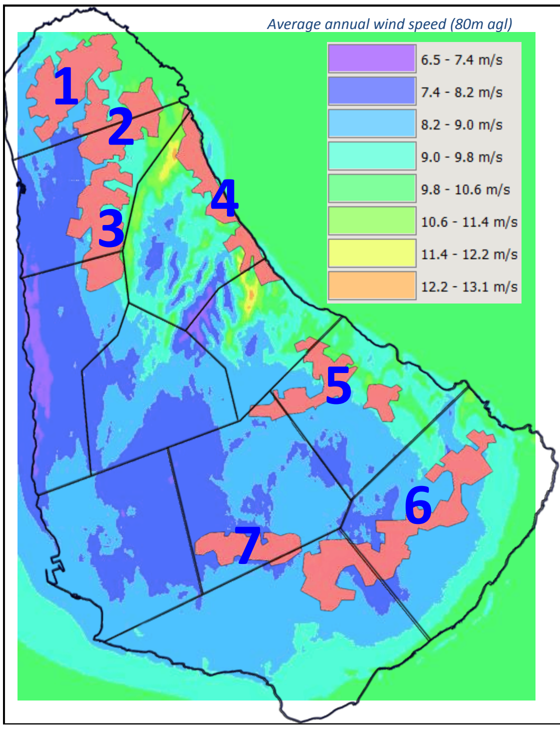
In March 2015 a grid integration study commissioned by Barbados Light and Power suggested that 55 MW of solar and wind energy can be taken up by the existing system without any mitigation measure and 80 MW could be integrated with modest mitigation measures (GE 2015, p. 127). The report does not give information on higher renewables penetration, as no such scenarios were commissioned for the analysis. Presently a follow up study is underway, which is supposed to look at up to 150 MW of renewable generation capacity in a power system with a peak load of a little more than 150 MW.

The GE study did not look at the potential for the different renewable energy sources, as the capacities considered for inclusion were seen as easily available in Barbados and it did not look at investment and operation costs of renewable energy sources, as the focus was on the impact of the inclusion of wind and PV on the operation of the conventional units and on the system reliability.

2.1.3 ROGERS (2015)

In November 2015 Rogers (2015) introduced the first more detailed wind energy assessment of Barbados at a workshop of the Barbados Renewable Energy Association held at the Central Bank of Barbados on November 7th 2015. He identified seven zones with good wind speeds and enough distance to dwellings with a total area of about 64 km^2 available to locate a substantial number of wind turbines. Figure 6 below shows the distribution of wind speed in Barbados and the location of the seven wind siting areas.

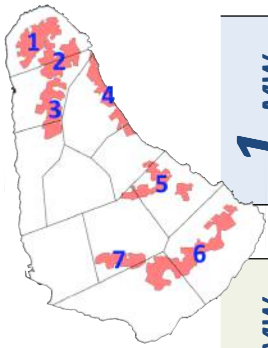
Figure 6: Average annual wind speeds at 80m and possible zones for locating wind turbines on Barbados (Rogers 2015)



Zone	Area (km^2)
1	9.4
2	9.2
3	9.4
4	7.0
5	7.9
6	16.2
7	5.2
	64.2

Rogers showed that 317 to 456 MW of wind capacity can be located in these zones depending on the use of 1 or 3 MW wind turbines reaching capacity factors between 30.9 and 51.8%. In an average wind year the capacities could translate into a total production of 1,144 GWh/a (1 MW turbines) or 1,594 GWh/a (3 MW turbines). The detailed results are shown in Figure 7 below.

Figure 7: Possible wind energy production on Barbados in seven wind zones with preferential conditions (Rogers 2015)



	Zone	Area (km²)	No. turbines	Installed capacity (MW)	Capacity density (MW/km²)	Energy yield (GWh/year)	Capacity factor	Yield per turbine (GWh)
1 MW	1	9.4	48	48	5.1	174.3	41.5%	3,632
	2	9.2	42	42	4.6	166.0	45.1%	3,953
	3	9.4	35	35	3.7	135.3	44.1%	3,864
	4	7.0	51	51	7.3	231.4	51.8%	4,537
	5	7.9	38	38	4.8	138.7	41.7%	3,651
	6	16.2	76	76	4.7	224.7	33.7%	2,956
	7	5.2	27	27	5.2	73.2	30.9%	2,710
		64.2	**317**	**317**	**5.1**	**1,143.6**	**41.2%**	**3,607**
3 MW	1	9.4	19	57	6.1	226.0	45.3%	11,895
	2	9.2	24	72	7.9	270.4	42.9%	11,267
	3	9.4	24	72	7.7	262.3	41.6%	10,930
	4	7.0	16	48	6.9	196.3	46.7%	12,267
	5	7.9	16	48	6.1	170.2	40.5%	10,634
	6	16.2	40	120	7.4	361.0	34.3%	9,026
	7	5.2	13	39	7.5	107.5	31.5%	8,268
		64.2	**152**	**456**	**7.1**	**1,593.7**	**39.9%**	**10,485**

One interesting result of a stakeholder discussion at the workshop was a unanimous agreement on the choice of the larger turbine size based on realistic foto images of the turbines put in their actual locations on some selected sites in the wind zones. The images showed that an increase in turbine size from 1 to 3 MW can substantially reduce the clutter of the landscape as Pictures 1 and 2 show for locations in St. Lucy and a location on the east coast of Barbados.

Picture 1: Realistic foto image of the location of 1 and 3 MW wind turbines at St. Lucy (Rogers 2015)

Picture 2: Realistic foto image of the location of 1 and 3 MW wind turbines on the east coast of Barbados (Rogers 2015)

Rogers' assessment showed that the assumptions made by Hohmeyer (2015) that Barbados could actually install about 450 MW of wind had not been far from the real potential, although, it would stretch the potential analysed by Rogers to the full.

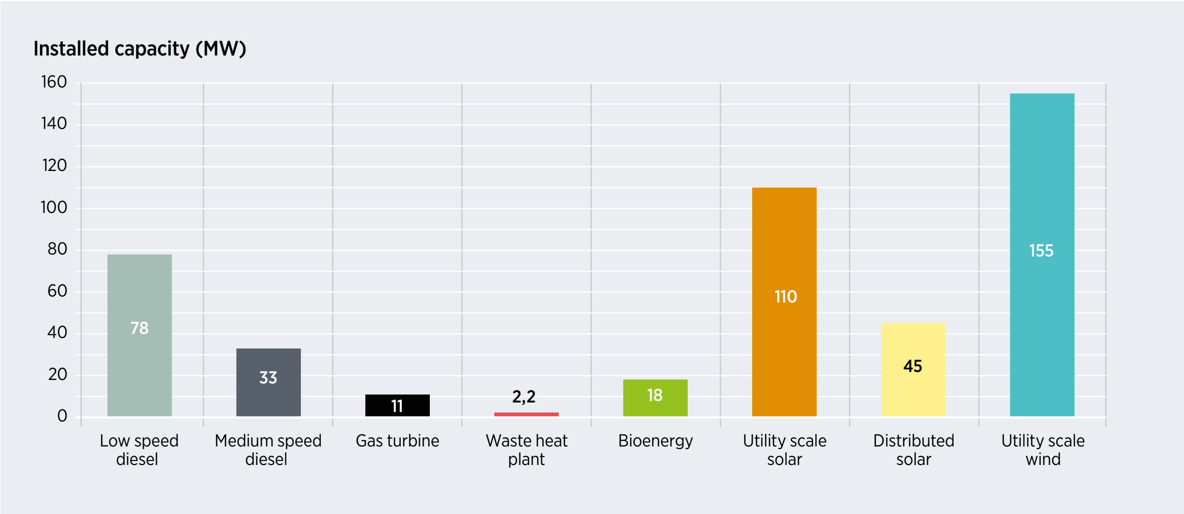
2.1.4 IRENA (2016)

In 2016 the International Renewable Energy Agency (IRENA) introduced the draft of a Barbados Energy Roadmap, which looked at a least cost scenario of electricity production plus a change of up to 50% of the individual cars to green electricity. As the road map did not include the possibility of pump storage hydro installations as system back-up (IRENA 2016, p.37), the scenarios produced for 2030 and the path from the present to the 2030 power system resulted in a share of 76% of the total electricity production in 2030 (IRENA 2016, p.42). Table 1 shows the power production in the minimal cost reference scenario for 2030. These production shares are a result of about 330 MW of renewable capacity installed, which is shown in Figure 8 below.

Table 1: 2030 generation by power plant type: IRENA Reference Scenario (Source: IRENA 2016, p.42)

Generator type	Generation (GWh)
Low-speed diesel	221.12
Medium-speed diesel	8.03
Gas turbine	0.72
Waste heat plant	10.57
Bioenergy	120.08
Utility-scale PV	205.83
Distributed PV	70.45
Utility-scale wind	365.8
Total	**1 002.6**
Renewable energy total	762.17
Renewable energy share	76%
Variable renewable energy total	642.08
Variable renewable energy share	64%

Figure 8: 2030 installed capacities per generation technology in the IRENA Reference Scenario



The IRENA calculations are based on a few central cost assumptions, like the 2030 oil price, which is assume to reach 113 USD/bbl in the ‚new policies oil price scenario' (see Figure 9 below), PV investment cost of 3,800 to 5,200 BBD/kWp and wind energy investment costs of 3,450 BBD/kW in 2014. Table 2 below gives the central assumptions of the Road Map for wind and PV and Figure 10 below shows how these are assumed to decline until 2030. Table 3 gives the investment cost assumptions used in the Road Map for new diesel generators, bioenergy and battery storage.

Figure 9: Oil price developments assumed in the IRENA Road Map (source: IRENA 2016, p.31

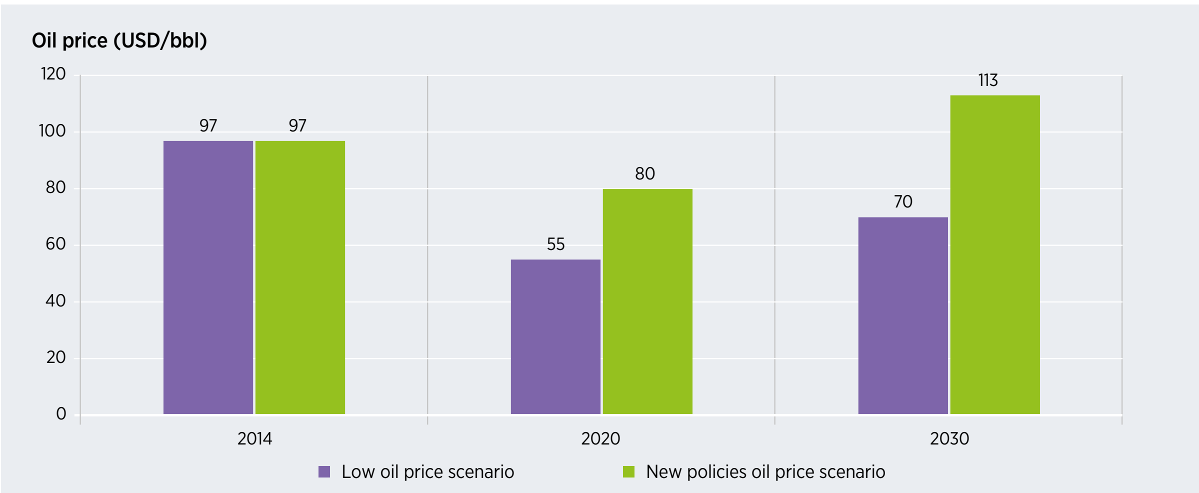


Table 2: IRENA assumptions made for PV and wind (source: IRENA 2016, p.30)

Assumption	Units	Technology		
		Residential and commercial PV	Utility-scale PV	Utility-scale wind
CAPEX	BBD/MW_{AC}	5 200 000	3 800 000	3 450 000
OPEX	BBD/MW/year	52 000	38 000	138 000
cost of capital	%	10	10	10
lifetime	years	30	30	30

Figure 10: In the IRENA Road Map assumed cost digression of wind and PV over time (source: IRENA 2016, p.31)

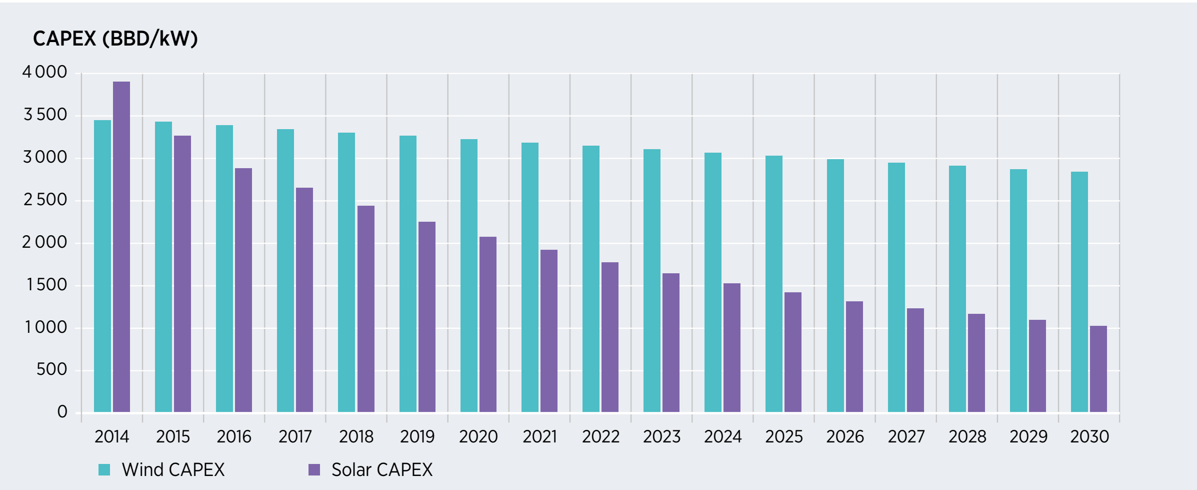


Table 3: Investment costs for new diesel generators, biomass and battery storage used in the IRENA Road Map (source: IRENA 2016, p.30)

Generation expansion candidate	CAPEX (BBD/kW)
Medium-speed diesel	2 344
Low-speed diesel	2 853
Bioenergy	7 000
Battery energy storage system*	1 400

** Assumes lithium-ion batteries with 1 MWh of energy storage capacity per MW of AC power and price in 2020.*

For biomass IRENA is assuming that the planned 18 MW bagasse combustion will go into operation in 2017. It looks like this is assumed as a given, although it is pointed out in the Road Map that solid fuel combustion will not fit into the future power system with a very high share of wind and solar power. It actually urges to convert to either biogas or liquid biofuels *‚Given the large shares of solar and wind in the system, it will be essential that this (biomass) plant is as flexible and as efficient as possible, considering a feedstock conversion process from solid biomass to liquid or gas. Direct combustion of solid bioenergy feedstock to feed a steam turbine is not advisable, as these plants lack the necessary flexibility.‘ (IRENA 2016, p.29).*

The Road Map briefly discusses the possibility of a 100% renewable energy supply (IRNEA 2016, p.37), which is introduced by an outright rejection of the option of pump storage for Barbados ‚*One of the solutions* (for a 100% renewable energy scenario) *discussed was to built a large pump hydropower storage facility; however, this option has been considered as non realistic for Barbados.‘* Unfortunately, not a single reason or argument is given for this outright dismissal of pump storage. This is even more astounding, as the authors of the Road Map acknowledge in the same box (p.37) that a 100% renewable power supply ‚*would require a major increase in battery storage capacity, with a substantial increase in system cost‘.* Instead of seriously discussing the extension of low cost storage (pump storage) the Road Map reverts to the suggestion of expanding the biomass combustion from 18 to 54 MW. At the same time the authors realise that this would require about 20,000 hectares of sugar cane production, while the present production is done on approximately 5,000 hectares. At the end the Road Map does not offer any solution for going to higher shares of renewables than the 76% realised in the reference scenario.

Considering the available evidence on the possible implementation of pump storage in Barbados (see WP 3 below), it is quite striking that the International Renewable Energy Agency does give this kind of advice. It may just be that the models available to the authors did not include the pump storage option and by that virtue limited the scope of the study or that the authors simply assumed Barbados not to have the necessary elevation differences, which they could easily have checked by looking at google maps.

The Road Map is not explicitly considering any resource constraints on the availability of wind or solar energy. Looking at the analysis by Rogers (2015) the installed capacities of wind energy (155 MW in the Reference Scenario) will most likely not meet with space constraints in Barbados, if the areas identified by Rogers will be earmarked for wind energy in the new Physical Development Plan for Barbados to be amended in 2017, which is in the drafting stages at the time of writing of this document.

2.2 International cost assessment for solar PV

2.2.1 IPCC SRREN (2012)

In 2012 the Intergovernmental Panel on Climate Change (IPCC) published a special report on ‚Renewable Energy Sources and Climate Change Mitigation‘, which gave a very thorough state of the art review of the possible use of renewable energy sources to reduce green house gas emissions, mainly carbon dioxide from the use of fossil fuels to supply energy. Among other questions the report gave an in depth treatment of the costs of different renewable energy sources as of 2010.

For PV the report documents the vast cost reduction of PV systems between 1990 and 2010, starting out at about 24 USD_{2005}/W_p in 1990 reducing to less than 5 USD_{2005}/Wp in 2010 as can be seen in Figure 11 below. The same figure shows that PV system costs have constantly been higher in the US than in Europe. This points to the fact that the European market, specifically the German market, which was the largest PV market until 2015 (see Figure 12), has been more competitive than the US market.

Figure 11: Installed system costs for smaller PV systems up to 100 kW (source: IPCC 2012, p.382)

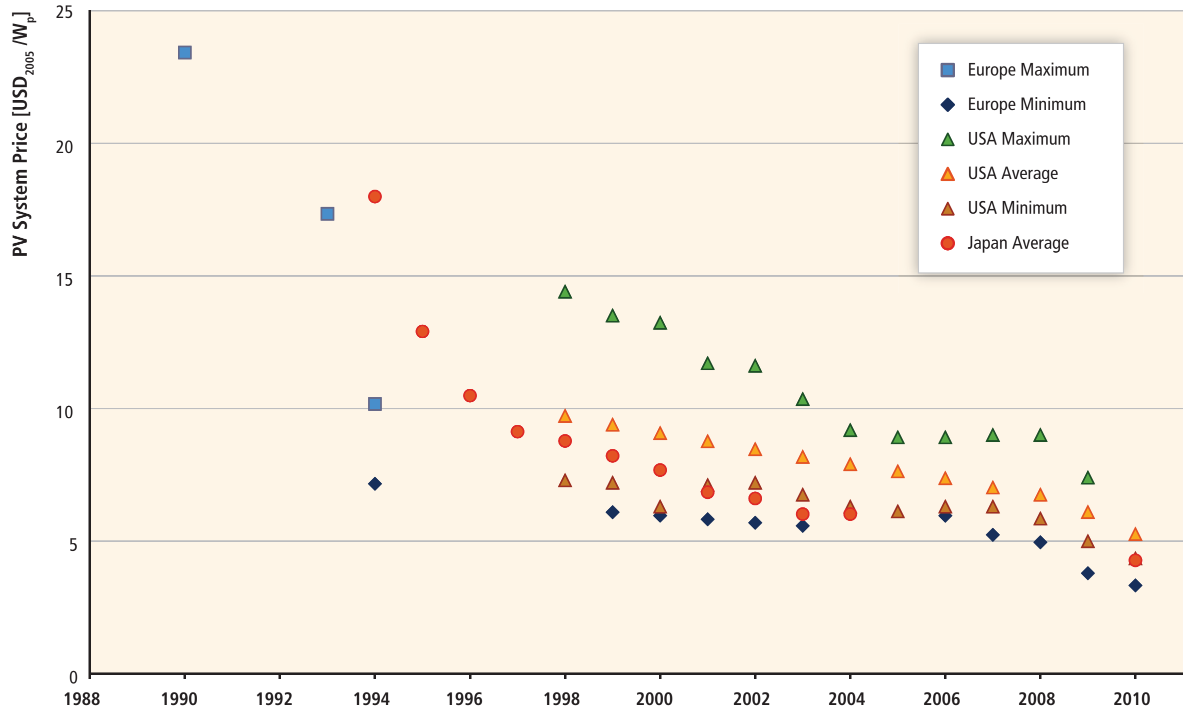
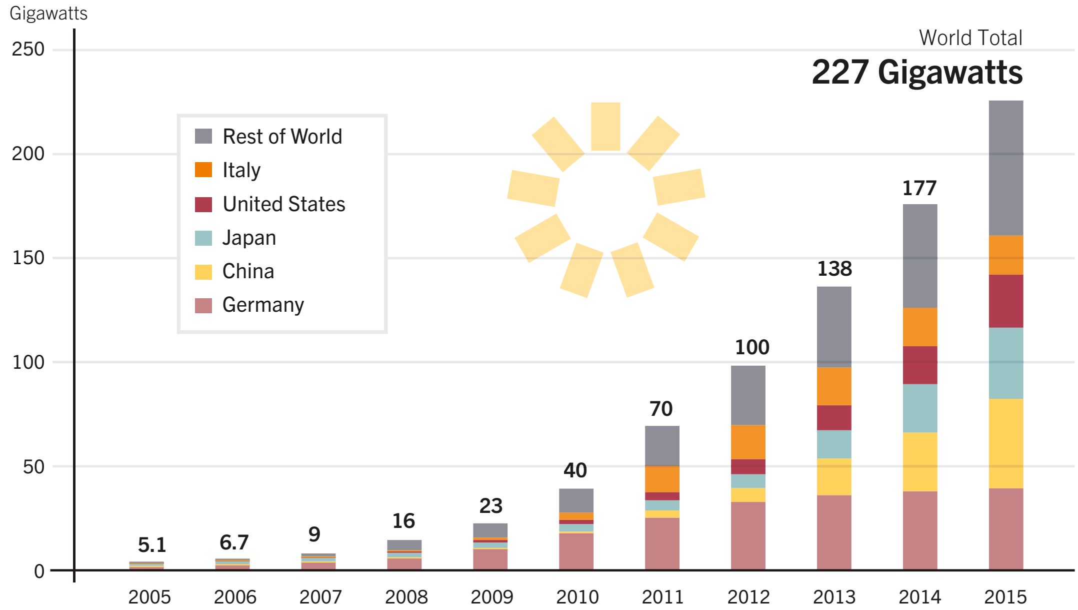


Figure 3.18 | Installed cost of PV systems smaller than 100 kW_p in Europe, Japan and the USA. Data sources: Urbschat et al. (2002); Jäger-Waldau (2005); Wiser et al. (2009); Bundesverband Solarwirtschaft e.V. (2010); SEIA (2010a,b).

Figure 12: Installed solar PV capacity by country/region 2005-2015 (source: REN 21 2016, p.62)



Much of the system cost reduction has been driven by the learning curve for the production of PV modules, which is shown for silicon modules in Figure 13. The graph shows that with increasing installed capacity there has been a cost reduction by 20% for each doubling of the global PV capacity starting at 65 USD/W_p in 1976 the module cost had been reduced to 1.4 USD/W_p in 2010.

Figure 13: Solar price experience or learning curve for silicon PV modules (source: IPCC 2012, p. 393)

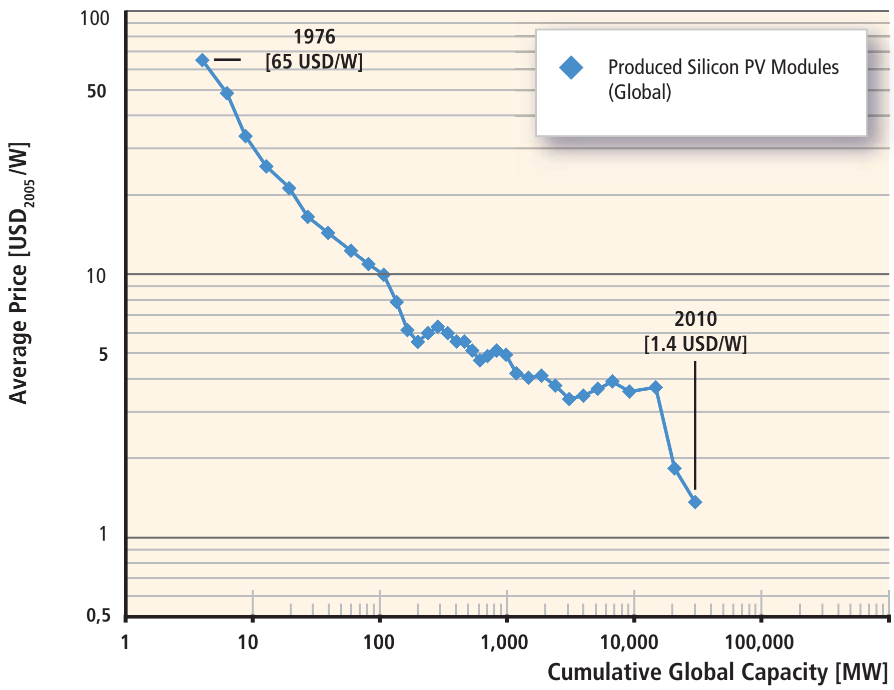


Figure 3.17 | Solar price experience or learning curve for silicon PV modules. Data displayed follow the supply and demand fluctuations. Data source: Maycock (1976-2003); Bloomberg (2010).

At the same time the cost reduction for the so called Balance of Systems (BOS) costs showed learning rates in the range of 19 to 22% (IPCC 2011, p.380).

Depending on the solar radiation at the installation site the Levelized Costs of Electricity (LCOE) generation with PV systems in 2009 were anywhere between 0.1 and 0.78 USD/kWh. The differences in the levelized costs are due to different solar radiation (reflected in the capacity factor), the investment cost of the system, the size of the system and the interest rate applied in the calculations. Thus, the lowest costs were seen with large utility scale systems (larger than 2 MW) with low system prices (2700 USD/kWp) and low interest rates (3%). Fixed systems were seen with maximum capacity factors of 21% in very good locations (similar to or better than the radiation in Barbados), whereas systems tracking the sun over two axes, which can always point the solar array directly towards the sun, were seen with maximum capacity factors of 27%. The impact of the different factors on LCOEs are shown in Figure 14 below. The capacity factor used can be translated into a system output equivalent to a certain number of operation hours at full load. A capacity factor of 10% for example translates into a full load operation of 876 hours. Thus, a system with a rated power of 1 kW will produce 876 kWh/a. At a different location with higher solar radiation the system may reach a capacity factor of 20% producing 1752 kWh/a.

Figure 14: Levelized costs of PV electricity generation in 2009 as a function of different parameters (source: IPCC 2012, p383)

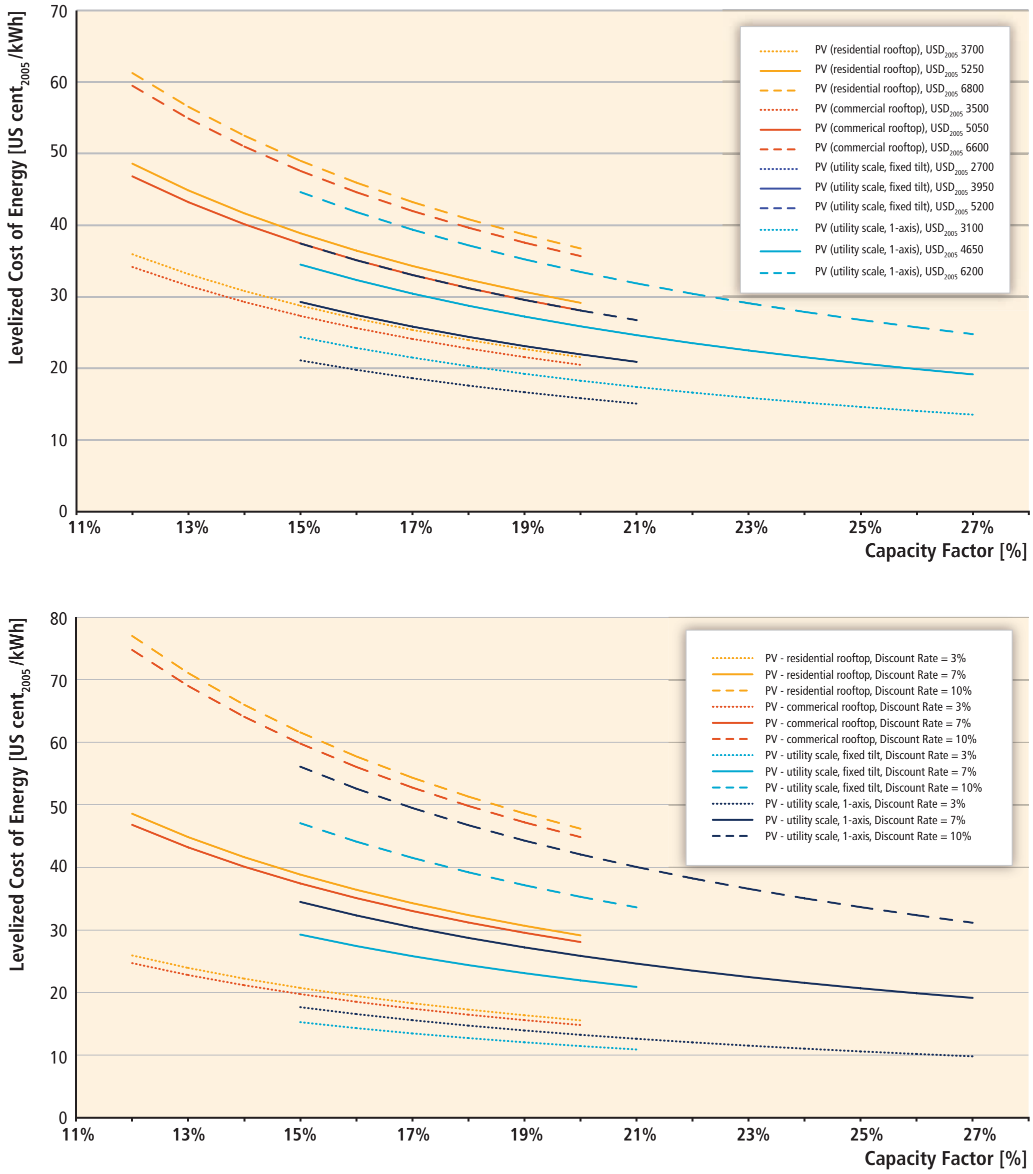


Figure 3.19 | Levelized cost of PV electricity generation, 2009. Upper panel: Cost of PV electricity generation as a function of capacity factor and investment cost[1,3]. Lower panel: Cost of PV electricity generation as a function of capacity factor and discount rate[2,3]. Source: (Annex III).

Notes: 1. Discount rate assumed to equal 7%. 2. Investment cost for residential rooftop systems assumed at USD$_{2005}$ 5,250/kW, for commercial rooftop systems at USD$_{2005}$ 5,050/kW, for utility-scale fixed tilt projects at USD$_{2005}$ 3,950/kW and for utility-scale one-axis projects at USD$_{2005}$ 4,650/kW. 3. Annual O&M cost assumed at USD$_{2005}$ 41 to 64/kW, lifetime at 25 years.

Different studies showed LCOEs of 0.145 to 0.363 USD$_{2005}$/kWh for 2009 (IPCC 2012, p.381), which are well in line with the cost functions shown in Figure 14. At the time the US DOE targeted 8 to 10 US cents$_{2005}$/kWh for residential, 6 to 8 US cents$_{2005}$/kWh for commercial and 5 to 7 cents UD $_{2005}$/kWh for utility scale installations (US DOE, 2008 according to IPCC 2012, p.381f).

2.2.2 FHG-ISE (2017)

In January 2017 the German Fraunhofer-Institute for Solar Energy (FhG-ISE) published updated facts on the quarterly investment cost development of roof top PV installations of 10-100 kW capacity for the time of 2006 to 2015. These investment costs developed from 5,000 Euro/kW_p in the first quarter of 2006 to 1,270 in the last quarter of 2015 as shown in Figure 15. These costs are equivalent to a decrease from 6,278 USD/kW_p in 2006 to 1,409 USD/kW_p in 2015 for readily installed roof top PV systems or a drop from about 3,500 USD in 2010 (see Figure 11) to 1409 USD/kWp, a further investment cost reduction by 60% in five years following the period documented in the IPCC report cited above.

Figure 15: Average consumer system price (net VAT) for installed roof top PV systems with a capacity of 10-100 kWp (FhG-ISE 2017, p.8)

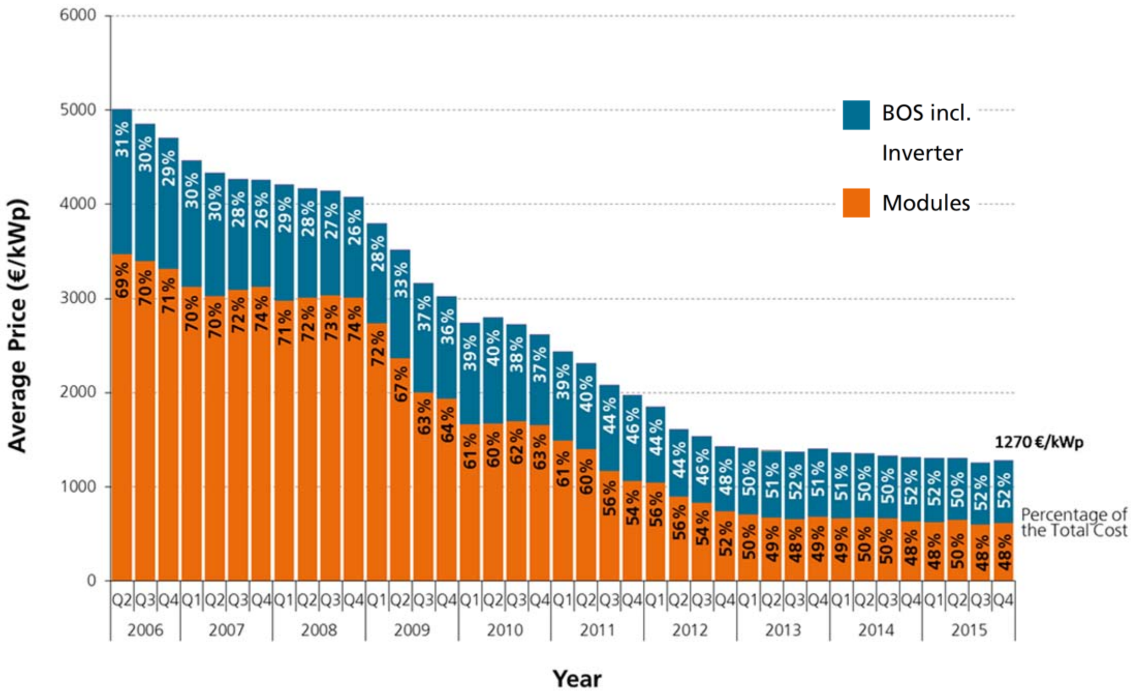


Abbildung 3: Durchschnittlicher Endkundenpreis (Systempreis, netto) für fertig installierte Aufdachanlagen von 10-100 kW_p, Daten von BSW, Darstellung PSE AG

The same publication takes the learning or experience curve for PV modules five years further (see Figure 16 below) as compared to the IPCC reports (see Figure 13). It actually shows how the module prices fluctuate around the trend line of the learning curve (the straight line in the double logarithmic system) reaching about 0.6 $Euro_{2015}$/kWp or about 0.67 USD_{2015}/kWp in 2015.

Figure 16: Price development of PV-modules between 1980 and 2015 (source: FhG-ISE 2017, p.9)

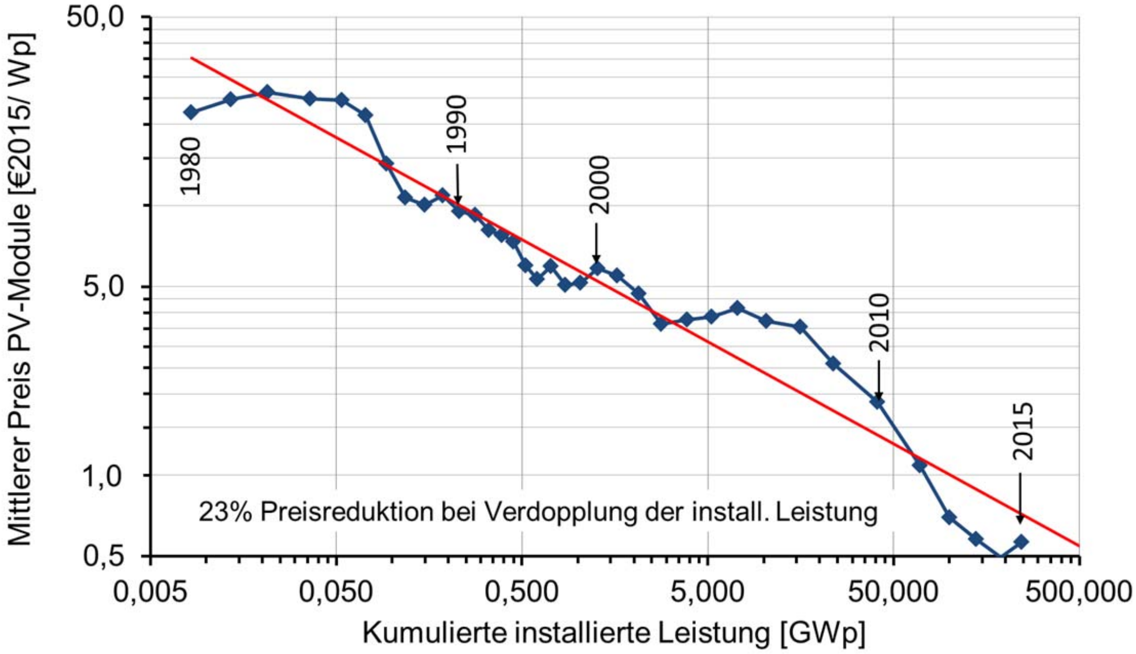


Abbildung 4: Historische Entwicklung der Preise für PV-Module (PSE AG/Fraunhofer ISE, Datenquelle: Strategies Unlimited/Navigant Consulting/EuPD). Die Gerade zeigt den Trend der Preisentwicklung.

2.2.3 NREL 2016

In September 2016 NREL, the US National Renewable Energy Laboratory, published US benchmark figures for PV systems (NREL 2016). These are detailed model calculations on the benchmark costs for PV systems in the United States. The report shows the development for an average installed residential PV system of 5.6 kW_p, a commercial system of 200 kW_p and a utility scale system of 100 MW_p from the fourth quarter of 2009 until the first quarter 2016 (NREL 2016, p. V). By that time the costs for residential roof top systems came down from 7.06 USD_{2016}/kW_p in Q4 2009 to 2.93 USD_{2016}/kW_p in Q1 2016. At the same time commercial scale installations went down from 5.23 USD2016/kWp to 2.13 USD2016/kWp and very large utility scale systems came down from 4.46 to 1.42 USD2016/kWp. These cost developments and the cost structures of the different systems are shown in Figure 17 below. The report shows by comparison to the reported costs of three relevant solar system integrators that the modelled benchmark results are quite realistic (NREL 2016, p.17). This comparison is reproduced in Figure 18 below.

The same report shows quite nicely how the model can be used for the calculation of cost reduction effects reached trough economies of scale and how the different components of such cost reduction can be analysed (see NREL 2016, p.28). The results of such decomposition and the distribution of the scale effects across different system costs are shown in Figure 19 below.

Figure 17: NREL PV system cost benchmark results Q4 2009 until Q1 2016 (source: NREL 2016, p. V)

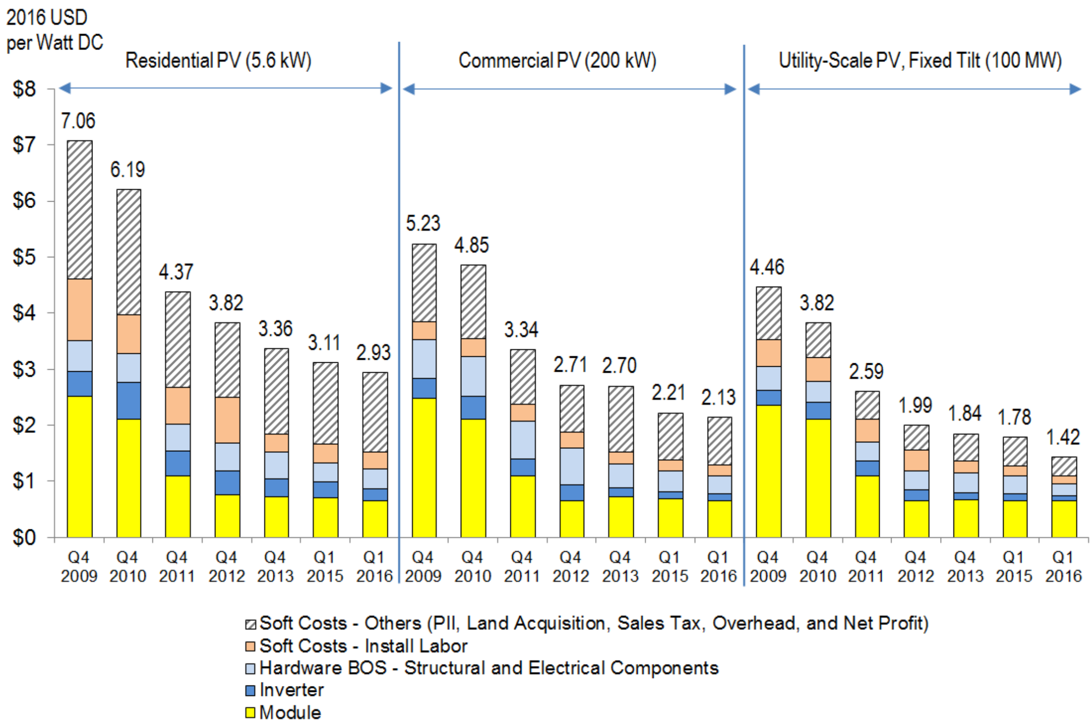


Figure ES-1. NREL PV system cost benchmark summary (inflation adjusted), Q4 2009–Q1 2016

Figure 18: Comparison of NREL benchmark results vs. company reported costs (source: NREL 2016, p. 17)

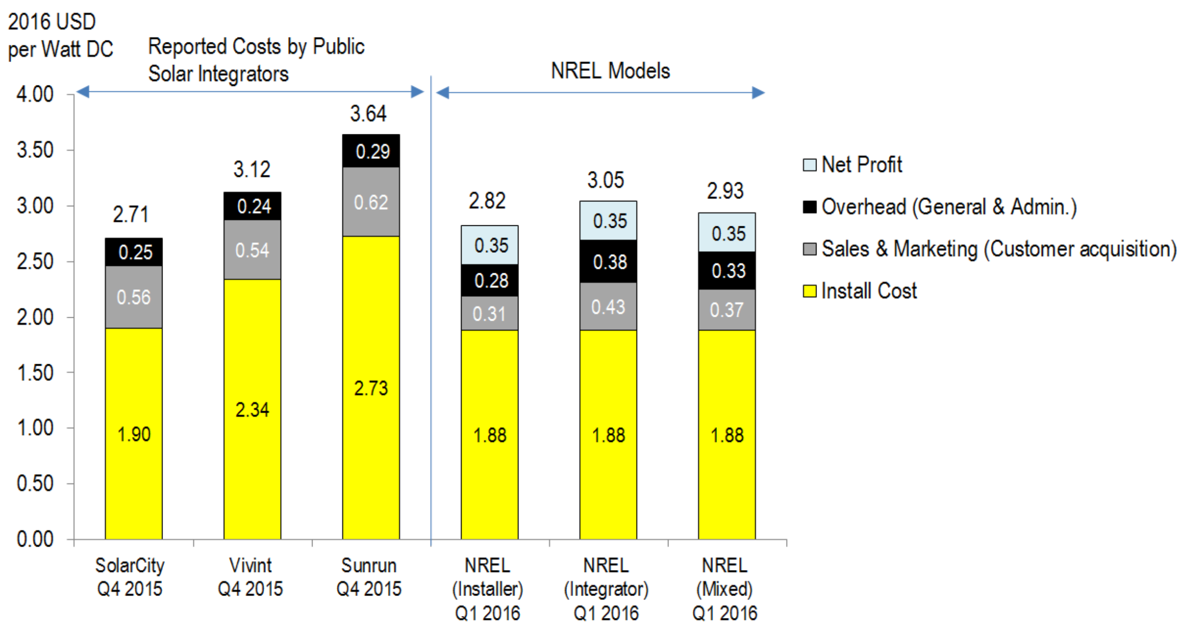


Figure 14. Q1 2016 NREL modeled cost benchmark (2016 USD/Wdc) vs. Q4 2015 company-reported costs

Figure 19: NREL results on economies of scale for increasing system size from 10 to 100 MW_p (source: NREL 2016, p.28)

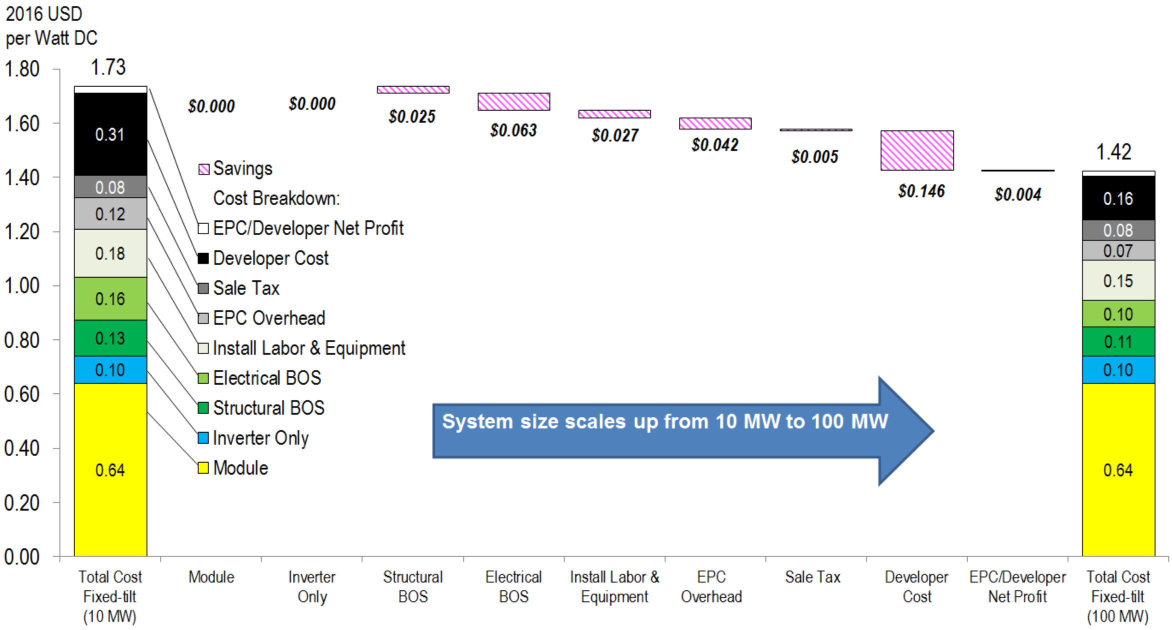
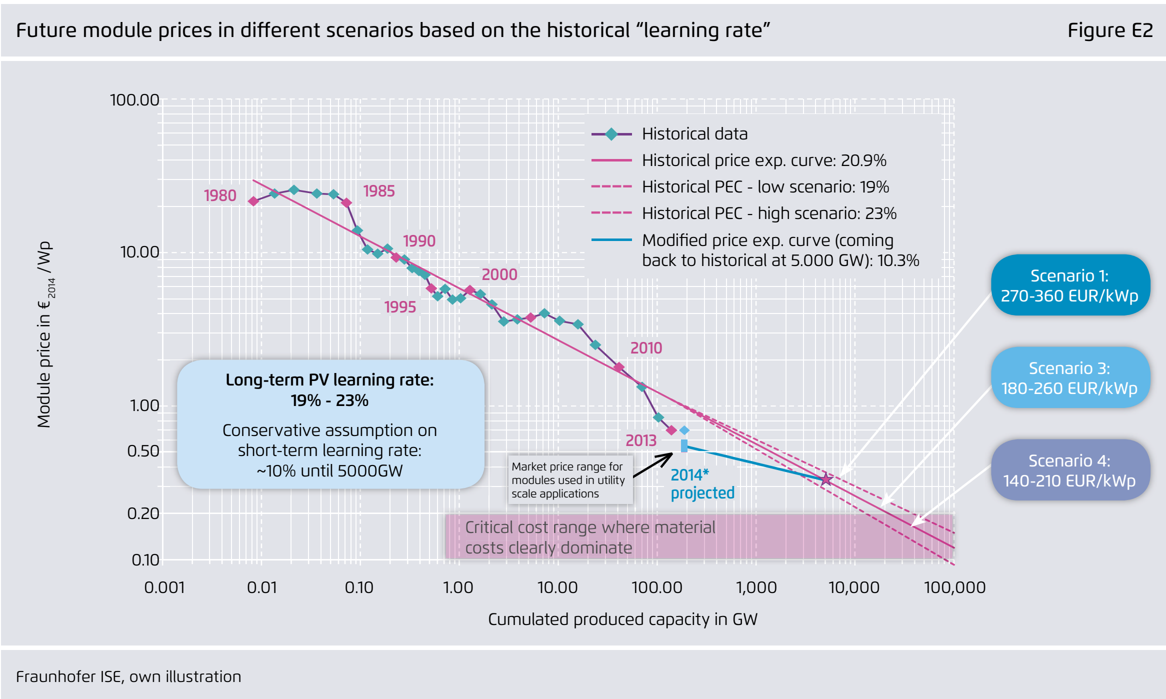


Figure 22. Model application: U.S. utility-scale fixed-tilt PV system cost reduction from economies of scale (2016 USD/Wdc)

2.2.4 AGORA (2015)

An other German study published in 2015 takes a look at the current and future costs of PV systems until 2050 (AGORA 2015). It is based on a detailed expert assessment of the learning/experience curves of PV modules and inverters and it discusses in detail the cost reduction potentials of other important parts of the BOS (Balance of System Costs). Depending on the future installation volume of PV the study derives module costs between 0.14 and 0.36 $Euro_{2015}$/Wp, which translates into 0.155 to 0,399 USD_{2015}/Wp (AGORA 2015, p.6). Figure 20 below shows the future costs and the learning curve approach used.

Figure 20: Future module prices based on installed quantities by 2050 and historical ‚learning rate' (source: AGORA 2015, p.6)

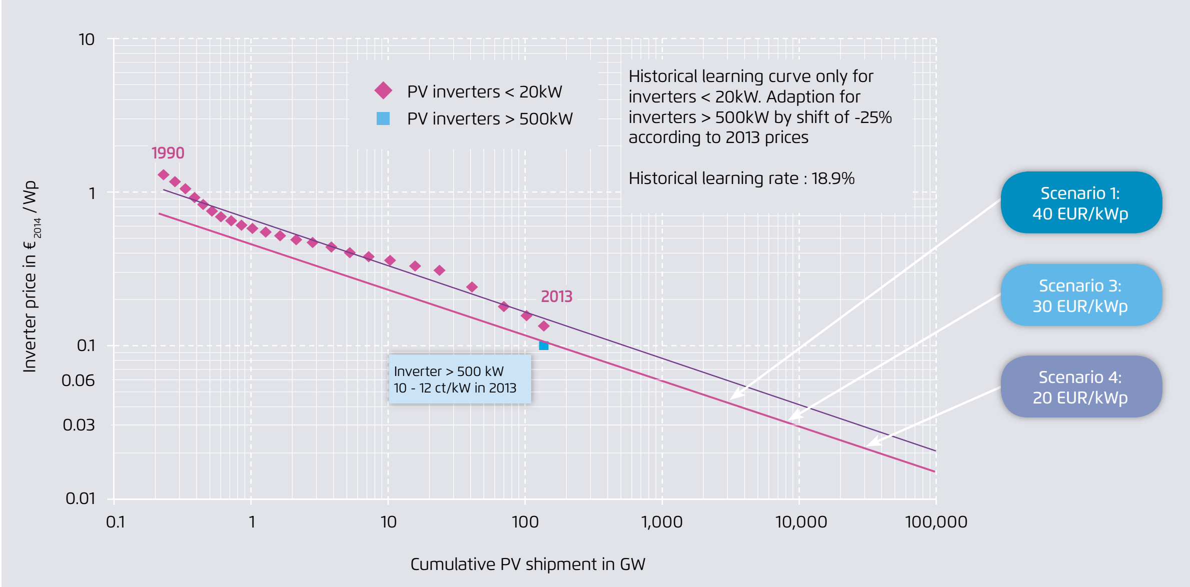


The same type of analysis is done for the inverter of the solar PV system. Based on the ‚learning curve' approach and the estimated installed volumes a cost reduction from 1 - 1.2 $Euro_{2015}/W_p$ down to 0.2 to 0.4 $Euro_{2015}/kW_p$ is estimated for the inverters (AGORA 2015, p.35). This is equal to a price decrease from 1.11 - 1.33 USD_{2015}/Wp to 0.22 - 0.44 USD2015/Wp. Figure 21 below shows the development of the inverter costs over time.

Starting from the cost composition (system integrator costs) of an installed ground mounted PV system of about 1000 $Euro_{2015}$/kWp, which are made up of about 550 Euro for the module, 110 Euro for the inverter and about 340 Euro for all other (BOS) costs (see Figure 22), the study further details the BOS costs into seven major components of which the five most important components are then analysed separately for their cost depression potential (compare Figures 23 and 24 below).

Figure 21: Future price scenarios for PV inverters by 2050 (source: AGORA 2015, p. 35)

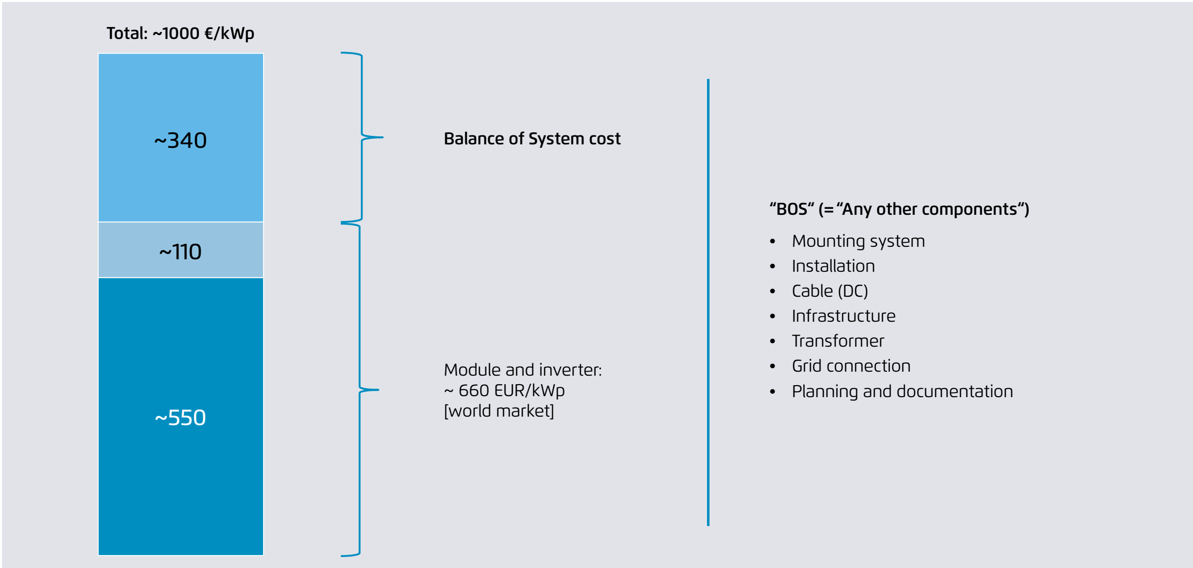
Extrapolation of the price experience curve of PV inverters Figure 25



Own illustration

Figure 22: Present structure of PV system costs for Germany (source: AGORA 2015, p. 40)

Overview of today's total system cost for ground-mounted PV systems (example from Germany) Figure 29

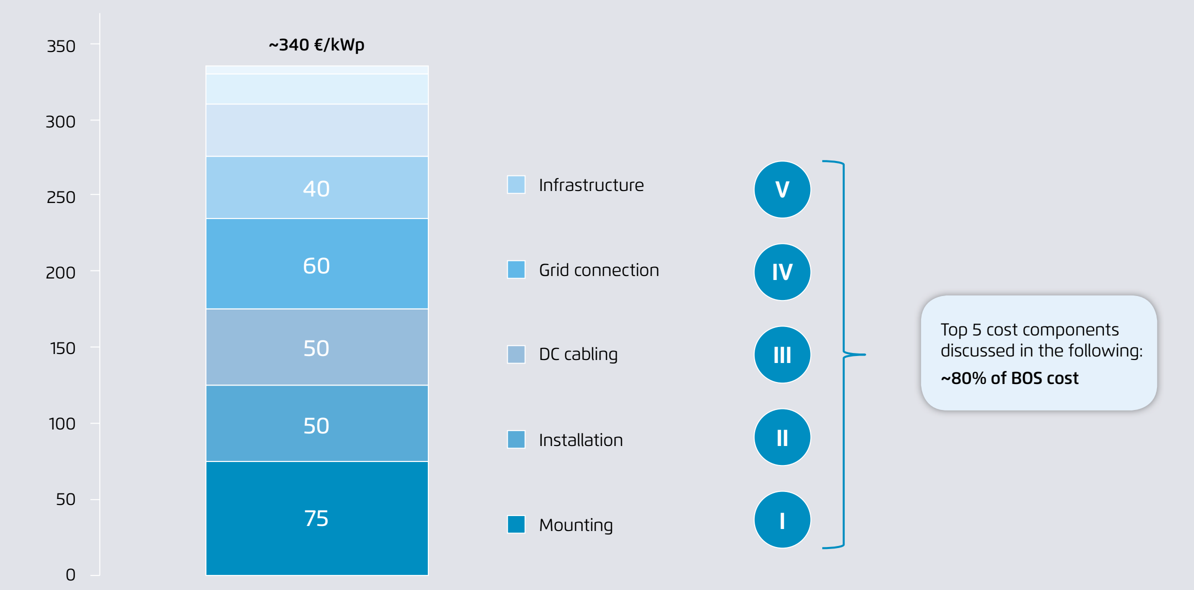


Own illustration

* "Cost" here: Prices paid by system integrator; price paid by investors may be higher; cost in countries with less competitive markets for PV may be higher

Figure 23: Split of present BOS costs (without inverter) of PV systems in Germany (source: AGORA 2015, p.40)

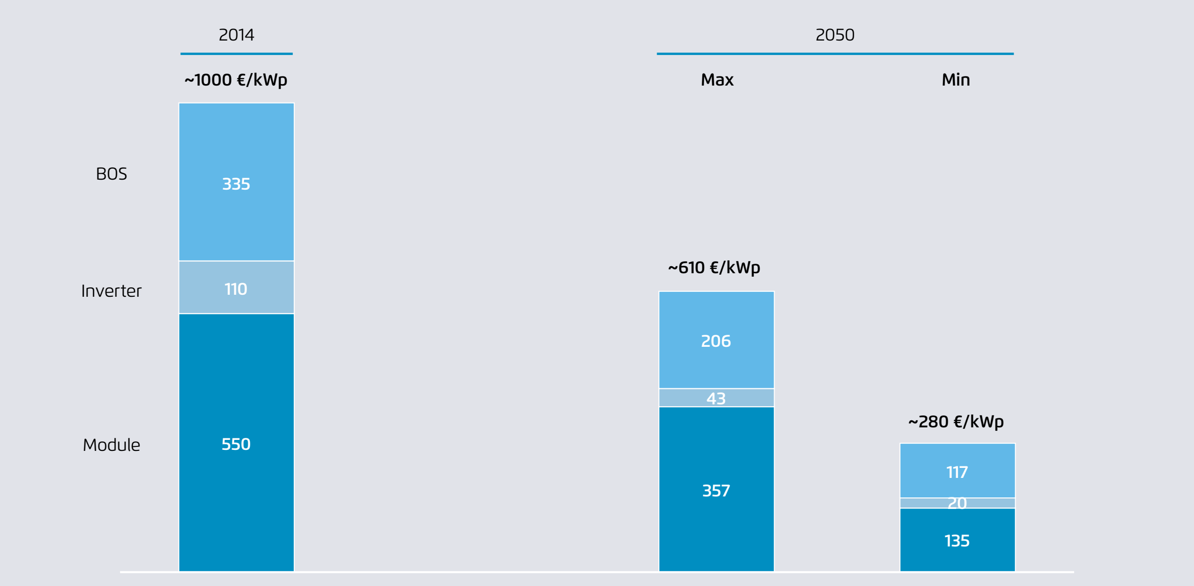
Overview of Balance of System cost for ground-mounted PV systems (example from Germany) Figure 30



Own illustration

Figure 24: Cost reduction for PV systems by 2050 divided by major cost component (source: AGORA 2015, p. 50)

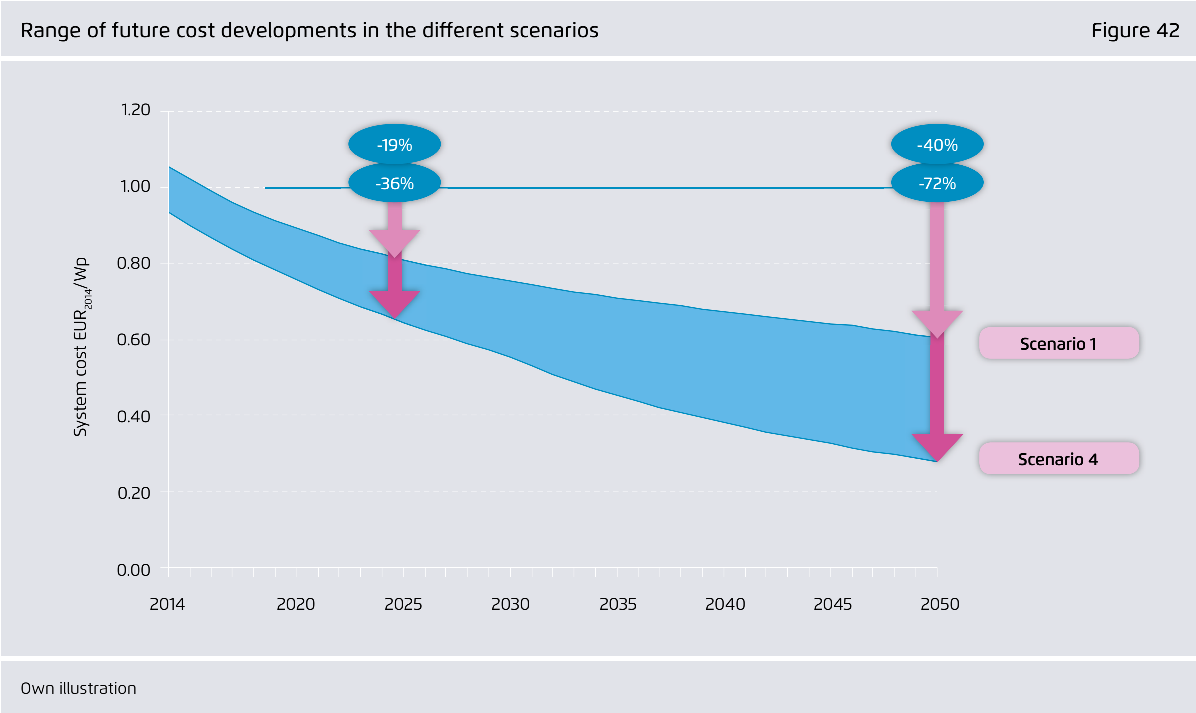
A range of PV system costs in 2050 is derived by combining minimum and maximum assumptions Figure 40



Own illustration

The study concludes that PV costs can be reduced by 19-36% by 2025 (as compared to 2015) and by 40 to 72% by 2050 (AGORA 2015, p.52). The extent of the cost reduction depends mainly on the volumes installed and the system efficiencies reached, as higher efficiencies lower many of the BOS cost components, as the systems become smaller producing the same output. Figure 25 shows the derived cost reduction corridor.

Figure 25: Range of future PV system cost developments (AGORA 2015, p.52)



2.3 Present PV costs in Barbados

In Barbados some first information on the costs of installed PV systems has become available since the operator of the system has to apply for a licence under the Barbados Electric Light and Power Act (ELPA). About 500 PV systems have applied for a licence under the ELPA by January 2017 representing a total installed capacity 9.9 MWp and system sizes from 0.5 to 350 kW. As the applications for seven larger systems with capacities between 180 and 350 kWp had not been finalised at the time of writing, the maximum size of systems included in the cost overview given in Table 4 is about 200 kW.

A first overview of the average, minimum and maximum costs of PV systems installed in Barbados shows that these reflect approximately world market prices in the case of the minimum cost systems installed, but that a fair share of outrageously overpriced systems is sold in almost every system size segment. This observation speaks to a asymmetrical market, where a substantial number of customers are not well informed about the prevailing market prices. A situation which seems to be capitalised upon by some PV system installers in Barbados. On average systems are installed at about 6 BBD/Wp, while low cost systems are installed for prices between 2 and 3 BBD/Wp. On the high end systems in the range of up to 10 kW have been installed at up to 20 BBD/Wp, which is eight to nine times the price (800 - 900%) paid for the lowest cost systems in the same size range. The bolded size ranges (0.5-3

kW_p, 3-10 kW_p and 10kW_p - 2 MW_p) have been introduced to increase direct comparability with international PV prices used for example in the NREL cost assessments.

Table 4: PV system costs in Barbados 2015 and 2016 according to ELPA license applications

PV system costs in Barbados 2015 and 2016

System size range	Average cost in BBD/W_p	Minimum cost in BBD/W_p	Maximum cost in BBD/Wp
0.5 kW_p	11.42	9.20	12.00
1 kW_p	9.73	5.10	19.20
1,5 - 2,99 kW_p	7.54	3.10	20.00
0,5 - 3 KW_p	***8.13***	***3.10***	***20.00***
3 - 4,9 kW_p	7.16	2.50	20.00
5 - 9,9 kW_p	6.16	2.13	11.80
3-10 kW_p	**6.47**	**2.13**	**20.00**
10 - 19,9 kW_p	6.65	4.11	16.72
20 - 49 kW_p	5.87	2.50	10.21
50 - 99 kW_p	6.17	4.00	16.58
99 - 200 kW_p	6.05	3.02	9.15
10 kW_p - 2 MW_p	**6.25**	**2.50**	**9.15**

2.4 International cost assessment for wind energy

2.4.1 NREL 2012

The cost development for wind energy looks back on a considerably longer period of commercial applications as compared to solar PV. The commercial basis for the predominating three bladed horizontal axis wind turbines, which are installed at an average size of 2 to 3 MW per machine today, was laid in the late 1970ties in Denmark with the first series production of such types of wind turbines in the size range of about 20 kW per machine. With the help of different wind turbine markets developing internationally (in the US in the early 1980ties, in Germany in the 1990ties, in Spain in the late 1990ties) over time it was possible to scale up the turbines through numerous size steps to a maximum of about 8 MW per turbine build for offshore applications today. Thus, most of the historic cost digression took place between 1980 and 2005 bringing down the levelized costs of wind energy from 0.25 USD/kWh in 1980 to 0.05 USD/kWh in 2005, as can be seen in Figure 26 below. Due to increased steel prices and due to a very substantial increase in international demand for wind turbines the levelized costs increased substantially till 2009 to a level of 0.075 USD/kWh (see NREL 2012, p. iv). It can be observed that the historic LCOEs have been considerably lower in Europe (mainly Denmark, Germany and Spain) as compared to the United States.

Figure 26: Estimated levelized costs of energy (LCOE) for wind energy between 1980 and 2009 for the United States and Europe (excluding incentives) (Source: NREL 2012, p. iv)

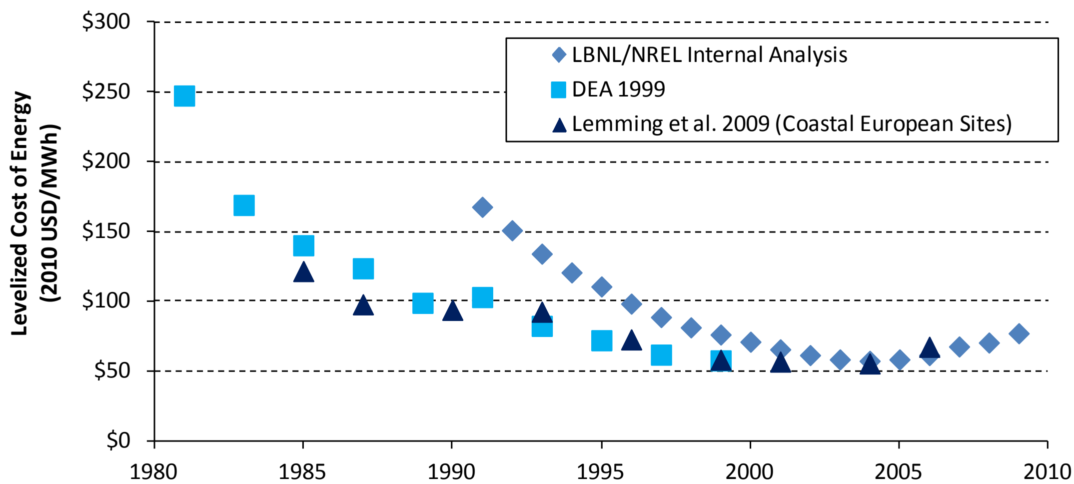


Figure ES-1. Estimated LCOE for wind energy between 1980 and 2009 for the United States and Europe (excluding incentives)

Sources: LBNL/NREL (internal analysis), Lemming et al. 2009, and DEA 1999

2.4.2 IPCC SRREN (2012)

The IPCC Special Report on ‚Renewable Energy Sources and Climate Change Mitigation' shows a very similar development of the investment costs of wind energy projects as the results given by NREL 2012 for the levelized costs of electricity shown above. According to the IPCC the US investment costs decreased from about 4,000 USD_{2005}/kW in 1982 to about 1,300 USD_{2005}/kW in the year 2000. Subsequently the investment costs increased to about 1,950 USD_{2005}/kW in 2009 (see Figure 27 lower part). At the same time a similar but less pronounced development can be seen for Denmark (see upper part of Figure 27) where investment costs of wind projects declined from about 2,600 USD_{2005}/kW in 1983 to about 1,000 USD_{2005}/kW in 2003. In the following years investment costs increased to slightly less than 1,500 USD_{2005}/kW in 2007 and 2008 and started to decline again in 2009 (see IPCC 2012 p. 585). The results allow the conclusion that the European wind turbine market has been substantially more competitive than the US market with cost levels 10 to 25% under the costs experienced in the United States. This is quite surprising from a theoretical perspective, as the policy instruments used in the United States (renewable portfolio standards) are putting high emphasis on competitive pricing and the better cost information available to market participants as compared to policymakers. At the same time the leading European wind energy countries (Denmark, Germany and Spain) were heavily relying on policy controlled price setting through Feed-in tariffs (FITs), which rely exclusively on the cost information available to policy makers (mostly compiled by wind energy research institutes).

Figure 27: Wind energy investment cost development in Denmark and the United States between 1982 and 2009 (source: IPCC 2012, p.585)

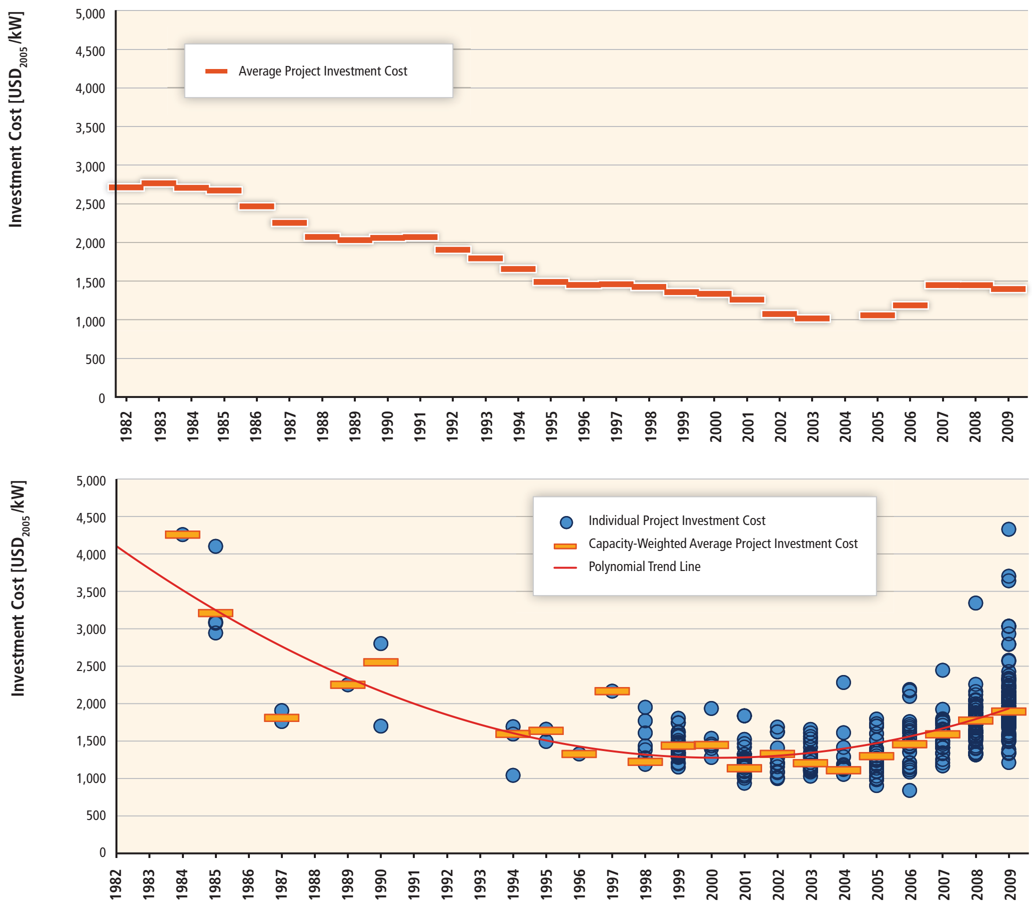


Figure 7.20. Investment cost of onshore wind power plants in (upper panel) Denmark (Data source: Nielson et al., 2010) and (lower panel) the USA (Wiser and Bolinger, 2010).

The IPCC report shows the very strong influence of the available wind speeds (expressed as capacity factor) on the levelized costs of wind energy. Depending on the capacity factor (varied between 50 and 15%) and other circumstances (investment costs, interest rate) held constant, the same wind turbine can produce levelized costs of electricity between 5.5 and 14 US $cent_{2005}$/kWh depending on the wind regime. A capacity factor of 15% represents a very marginal location allowing just about 1300 hours of full load operation per year, while a capacity factor of 50% represents an exceptionally good offshore wind site with more than 4300 full load hours of operation. Wind sites at the German of Danish coast have capacity factors in the range of 20 to 30%, which are considered favourable onshore wind energy locations in the two countries, which have been leading the technical wind energy development over the last 35 years. Figure 28 shows the impacts of three central parameters on the costs of wind energy, which are the achieved capacity factor, the investment costs per kW and the interest rate available for financing the investment.

Figure 28: Estimated levelized cost of on- and offshore wind energy in 2009 as function of capacity factor and investment cost (left) and as function of capacity factor and discount rate (source: IPCC 2012, p.588)

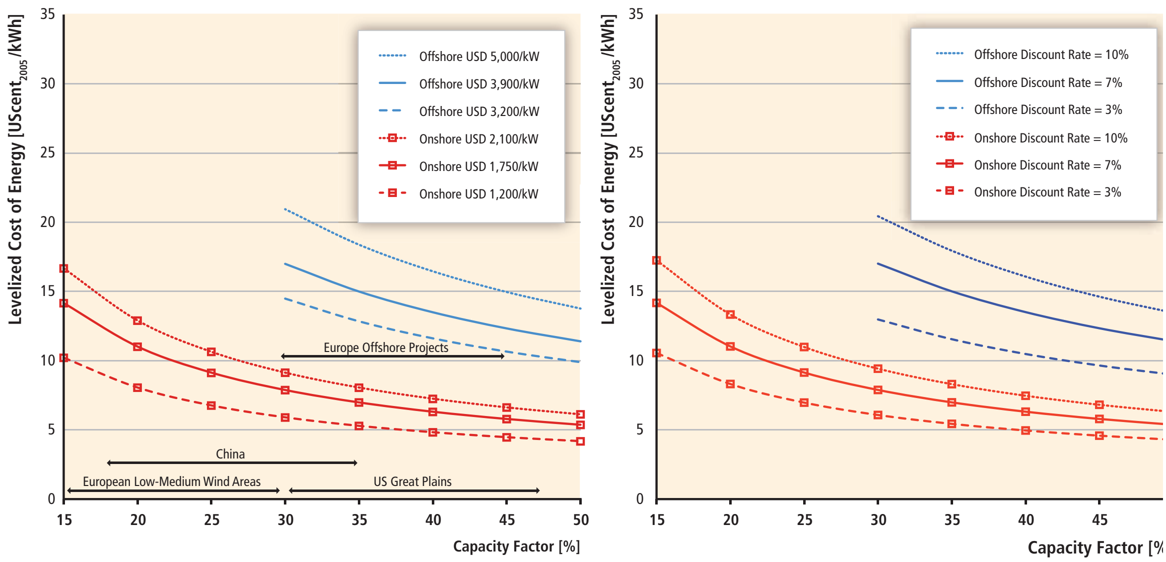


Figure 7.23 | Estimated levelized cost of on- and offshore wind energy, 2009: (left) as a function of capacity factor and investment cost* and (right) as a function of capacity fact and discount rate**.

Notes: * Discount rate assumed to equal 7%. ** Onshore investment cost assumed at USD_{2005} 1,750/kW, and offshore at USD_{2005} 3,900/kW.

2.4.3 NREL 2015

In a more recent study the US National Renewable Energy Laboratory (NREL) has published rather detailed cost estimates for a typical wind energy project based on a standard 2 MW turbine design. In prices of 2014 the investment costs are 1,710 USD_{2014}/kW (NREL 2015, p. vi), which is equivalent to 1,410 USD_{2005}/kW, if the inflation of 17.5% (for the entire period) is considered. Thus, the cost of wind turbines has come down again from the high levels in 2009, but it has not quite reached the lowest point on the cost curve given by IPCC 2012 for the year 2000 (see Figure 27 above).
On the basis of a net capacity factor of 39.6% NREL arrives at 6.5 US $cent_{2014}$/kWh for a very good on shore site (see Table 5 below). What is more, the study gives a very good break down of the cost structure for a wind energy development (see Figure 30 below) as well as a sensitivity analysis of the levelized cost of electricity (LCOE) with respect to the most important parameters (see Figure 29 below).

As Table 5 shows, there are substantial additional costs beyond the costs of the turbine, these are the so called balance of system costs (e.g. development, electrical infrastructure, assembly and installation) as well as the financial cost (e.g. insurance and construction financing). On average the other costs constitute roughly 30% of the onshore wind energy costs (NREL 2015, p. vii). Operation and maintenance cost constitute between 20 and 25% of the overall LCOE.

Table 5: Cost structure of land based wind energy reference projects in 2014 (source: NREL 2015, p. VI)

Table ES1. Summary of the Land-Based Reference Project Using 1.94-MW Turbines

Data Source[a]		1.94-MW Land-Based Turbine ($/kilowatt [kW])	1.94-MW Land-Based Turbine ($/MWh)
Model	Turbine capital cost	1,221	35
Model	Balance of system	345	10
Model	Financial costs	154	3
Market	Market price adjustment[b]	–10	0
Market	Capital expenditures (CapEx)	1,710	49
Market	Operational expenditures (OpEx; $/kW/yr)	51	15
Market	Fixed charge rate (%)	10.3	
Model	Net annual energy production (MWh/MW/yr)	3,466	
Model	Net capacity factor (%)	39.6	
Calculated	**TOTAL LCOE ($/MWh)**	**65**	

[a] Sources are listed in the relevant sections of this report related to the specific cost components.
[b] The market price adjustment is the difference between the modeled cost and the average market price paid for the typical project in 2014.

A sensitivity analysis (see Figure 29 below) shows that the LCOE of wind are extremely sensitive to the prevailing wind speeds of a site. An net capacity factor of 51% brings down the LCOE from 6.5 to approximately 5 US $cent_{2014}$/kWh while a reduction of the capacity factor to 18% can increase the same LCOE to more than 14 US $cent_{2014}$/kWh. At the same time a variation in investment costs can increase or decrease LCOE considerably as well, while a variation of operating costs (OPEX) has a substantially lower impact. Although the variation of the discount rate (interest rate for financing) seems to have a low impact, it has to be taken into account that the NREL calculations vary the discount rate only over a small range (8.0 to 9.4%), while German experience shows financing at far lower interest rates (as low as 2-3%). Such strong variation would reduce LCOE as much as the variations in capacity factor (wind speed).

Figure 29: Sensitivity analysis for on shore wind energy LCOE with respect to key parameters (source: NREL 2015, p. IX)

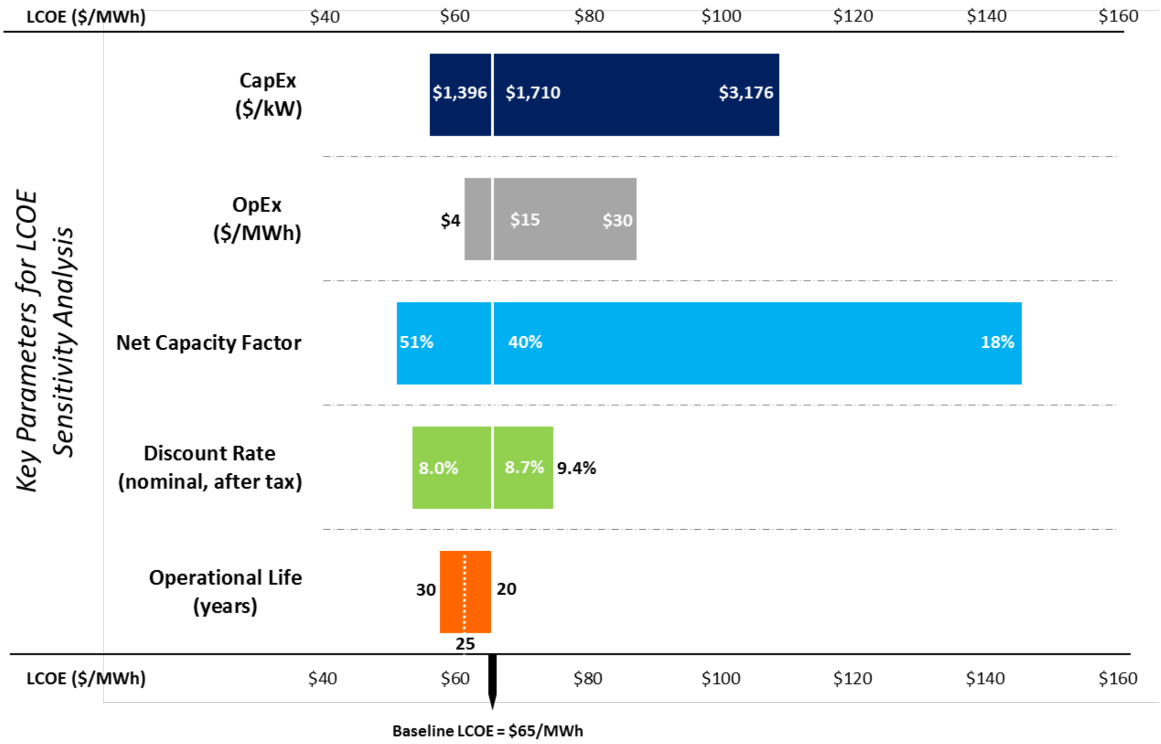


Figure ES3. Land-based wind plant assumptions and ranges for key LCOE input parameters

Source: NREL

NREL (2015) shows a very clear cost breakdown of the capital expenditure cost (CAPEX) for onshore wind energy in the case of the standard 2 MW wind turbine (see Figure 30 below). While the turbine constitutes 71% of CAPEX, the nacelle, containing the generator and the drive train, makes up over 40% of the entire CAPEX followed by the cost of the rotor (17%) and the cost of the tower (13%). The electrical infrastructure (9%) makes up almost 50% of the balance of system cost (20%). The detailed cost figures for the CAPEX break down are given in Table 6 below, while Table 7 gives a breakdown of the operating cost (OPEX).

Figure 30: Structure of capital expenditure (CAPEX) for a typical 2 MW on shore wind turbine in the United States in 2014 (source: NREL 2015, p.11)

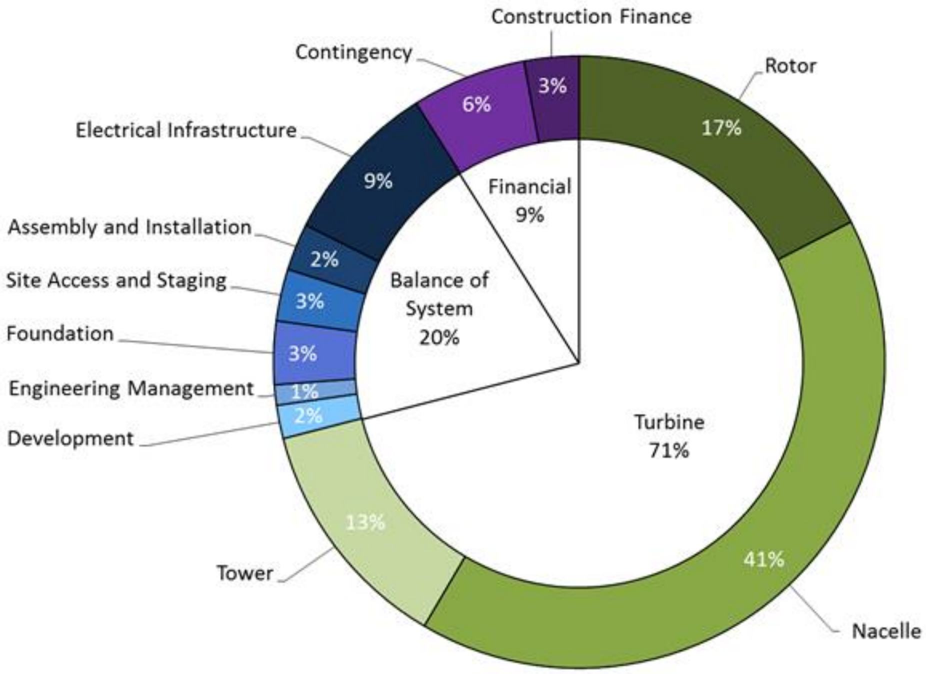


Figure 5. Capital expenditures for the land-based wind reference project

Source: NREL

Table 6: CAPEX cost break down of on shore wind energy in the United States in 2014 based on a standard 2 MW wind turbine (source: NREL 2015. p.12)

Table 2. Land-Based LCOE and CapEx Breakdown

	1.94-MW Land-Based Turbine ($/kW)	1.94-MW Land-Based Turbine ($/MWh)
Rotor Module	**300**	**9**
Blades	182	5
Pitch assembly	68	2
Hub assembly	50	1
Nacelle Module	**706**	**20**
Nacelle structural assembly	153	4
Drivetrain assembly	240	7
Nacelle electrical assembly	282	8
Yaw assembly	40	1
Tower Module	**215**	**6**
TURBINE CAPITAL COST	**1,221**	**35**
Development Cost	30	1
Engineering Management	19	1
Foundation	58	2
Site Access and Staging	47	1
Assembly and Installation	43	1
Electrical Infrastructure	149	4
BALANCE OF SYSTEM	**345**	**10**
Market Price Adjustment	-10	0
Construction Financing Cost	50	1
Contingency Fund	104	3
FINANCIAL COSTS	**144**	**4**
TOTAL CAPITAL EXPENDITURES	**1,710**	**49**

Table 7: OPEX cost break down of on shore wind energy in the United States in 2014 based on a standard 2 MW wind turbine (source: NREL 2015. p.12)

Table 3. Land-Based Wind Reference Project OpEx

	1.94-MW Land-Based Turbine	1.94-MW Land-Based Turbine
Operations (OPER)	$15/kW/yr	$5/MWh
Land lease cost	$8/kW/yr	$2/MWh
Maintenance (MAIN)	$28/kW/yr	$8/MWh
OpEx	**$51/kW/yr**	**$15/MWh**

2.4.4 DEUTSCHE WIND GARD 2015

A study on the cost structure of wind power in Germany has been published by Deutsche Wind Guard in 2015. This study is based on industry surveys among six wind turbine manufacturers holding a joint market share of 97% in the German market, which constituted about 50% of the entire European wind energy market in 2015 (REN 21 2016, p.76) with newly installed wind energy capacities of about 6 000 MW bringing the total installed German wind energy capacity to 45 GW. Deutsche Wind Gard has been one of the consultants helping the German government to find appropriate Feed-in tariffs (FITs) for wind energy in the past.

For onshore wind park developments planned for 2016/17 Wind Guard derived main investment costs (consisting of turbine cost, transportation cost and installation cost) of 980 - 1,380 $€_{2015}$/kW and other investment costs (consisting of all on site cost like foundations, connection to the power grid and site preparation plus planing and financing cost) of 387 $€_{2015}$/kW. Taking the average annual exchange rate of 1.0672 USD/Euro in 2015 and an inflation rate of 0.1% from 2014 to 2015 into account gives a range of 1,045-1,471 USD_{2014}/kW for the main investment costs and 413 USD_{2014}/kW for the other investment cost. The total CAPEX resulting are 1457 to 1884 USD_{2014}/kW or an average CAPEX value of 1671 USD_{2014}/kW. As Wind Guard and NREL have reached their results totally independently of each other the results show that wind energy costs seem to be converging substantially in the leading international markets. What is more, it looks like the capital cost of wind energy are not decreasing any more as compared to the market prices paid between 2000 and 2005 in Europe.
As onshore wind energy is a mature technology by now which is mainly based on electrical and mechanical components it seems highly unlikely that very substantial cost reductions will be reached in the future. Nevertheless, wind energy is one of the cheapest options to generate renewable power in locations with good average wind speeds and it will remain to be that for the decades to come. For policy makers an regulators like the FTC this fact will make it easier to stay on top of future wind energy cost developments for the design of appropriate pricing policies.

At the same time offshore wind energy is just approaching the status of mature technology with numerous lessons still to be learned. At present the costs for offshore wind energy in shallow waters (up to 50m water depth) are well established and estimated for the United States at about 19.3 US $cent_{2014}$/kWh roughly three times as expensive as the cost of onshore wind (6.5 US cent2014/kWh) (NREL 2015, p. vi), but major cost reductions are still possible. For Barbados offshore wind turbines would need to be deployed at very large water depth of several hundred or more meters. The necessary deep water offshore wind technology is in a first full scale testing phase. Figures quoted by Norwegian developers in 2016 on the first offshore wind park off the coast of Great Britain are in the range of 8,000 Euro/kW. Nevertheless, these figures have only been quoted during a discussion at a wind energy conference in Norway and have not surfaced in the literature thus far.

2.5 Cost assessment for biomass to power

2.5.1 GENERAL USE OF BIOMASS FOR ENERGY

The assessment of the cost of power production from biomass is substantially more complex than for the cost of PV or wind energy. As shown in Figure 31 below there are many possible combinations of biomass feedstocks with numerous conversion technologies to produce different kinds of energy outputs. In the case of this study we concentrate on power as the energy output and possibly heat as a by-product of the process. Feedstocks can be oil crops, sugar crops, lignocellulosic biomass and biodegradable waste. Depending on the form of feedstock the biomass can be combusted, hydrogenated, fermented, gasified, pyrolysed or digested. Due to the multitude of possible permutations the cost of the energy produced can vary across a very large range. Thus, it is not possible to give similar cost figures from the international literature relevant for Barbados as for wind and solar PV. Therefore, the following text will concentrate on the developments seen in Barbados and try to give cost figures for these developments as far as possible.

Figure 31: Different routes of converting biomass feedstocks to different forms of energy (source: IPCC SRREN 2012, p.235)

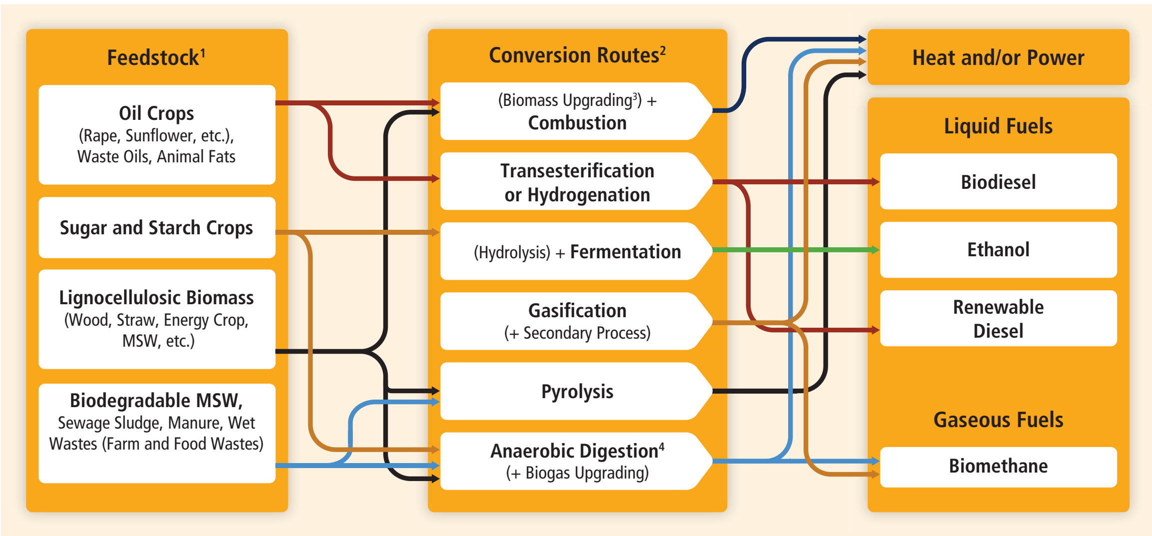


Figure 2.6 | Schematic view of commercial bioenergy routes (modified from IEA, Bioenergy, 2009).

Notes: 1. Parts of each feedstock, for example, crop residues, could also be used in other routes. 2. Each route also gives co-products. 3. Biomass upgrading includes any one of the densification processes (pelletization, pyrolysis, etc.). 4. Anaerobic digestion processes release methane and CO_2 and removal of CO_2 provides essentially methane, the main component of natural gas; the upgraded gas is called biomethane.

2.5.2 TWO PROPOSED BIOMASS TO ENERGY PROJECTS FOR BARBADOS

In Barbados two possible routes for the conversion of biomass to power seem to be of interest. The combustion of bagasse from sugar production has long been favoured by the sugar cane industry and the government of Barbados. A project for the combustion of bagasse plus some additional biomass from river tamarind is in the planning stages a number of years now. Recently, an alternative biomass utilisation route has been researched. This approach is trying to use King Grass grown on former sugar cane land, to produce synthetic gas through pyrolysis and to use this gas in combustion engines to produce electricity.

Both projects address a major problem of Barbados' agriculture, the necessity to keep up some form of agricultural grass cultivation in order to preserve the rather thin top soil of Barbados. Due to its very young age of just about 100,000 years, there has been a very limited formation of fertile topsoil on the limestone basis of the island. For agriculture in the tropics with its frequent heavy rain falls such thin topsoil is very prone to water erosion in every major rainfall event. Only in the case that the topsoil is either fully covered by a plant cover or it is held together with a tight mesh of roots, the topsoil will withstand erosion from heavy rainfall and fast run off. For Barbados this has lead to a rotation agriculture intercropping non grass plants (e.g. beans or sweat potatoes) with sugar cane, which belongs to the family of grasses and supplies the tight mesh of roots holding together the topsoil during the intercropping period.
Since the sugar industry has lost its international competitiveness and its preferential status for sugar sales into the European Union, Barbados' sugar industry is in decline. Besides the negative impacts on the industry itself and the extent of sugar cane farming, the reduction of acreage used for the production of sugar cane means a reduction of intercropping possibilities for other vegetables on the island, as the intercropping partner (sugar cane) is loosing ground.

The two approaches pursued to produce biomass for energy in Barbados, the use of bagasse and the use of King Grass both aim at retaining sugar cane or (King) grass cultivation to enable intercropping of other vegetables. Without any such approach it is foreseen by many farmers that Barbados will not just loose its sugar cane production, but that it will loose virtually all of its normal agricultural production except green house based agriculture.

COMBUSTION OF BAGASSE AND RIVER TAMARIND

In the case of the bagasse utilisation a project has been designed, which would use the bagasse and trimmings from 18,000 acres (7,285 ha or 72.8 km^2) (personal communication with Mr. Charles Simpson, January 2017) during the sugar campaign and 2,900 ha (29 km^2) of river tamarind production (assuming a yield of 28 tons of dry solids per ha and year) to fill in the rest of the year (see Barbados Draft NAMA 2013, p. 139). The project has been in planning stages since at least 2007. It is planned by the Barbados Cane Industry Association and is supported by the Barbados government.

Considering a base load operation of a steam turbine process the planned volume of biomass would suffice to operate a 22 to 24 MW_{el} generator. During the cane season this plant could produce about 18.5 MW of electricity due to the process use of some of the steam produce and 22.3 MW during the rest of the season assuming a 90% load factor (equivalent to 7,884 hours of full load operation per year) (see Barbados Draft NAMA 2013, p. 40). The investment costs are estimated between 240 Million USD (see Barbados Draft NAMA 2013, p. 39) and 230 Million USD (personal communication with Mr. Charles Simpson, January 2017). The estimated output is 169 GWh/a. Fuel costs are estimated at 40 BBD/t of (dry) bagasse or 5 - 5.6 BBD/GJ and 7.49 BBD/GJ of leucina (river tamarind). With 71% of the input energy from river tamarind and 29% from bagasse the levelized cost of electricity are estimated at 0.28 BBD/kWh (personal communication with Mr. Charles Simpson, January 2017).

Although the project compares favourably with the avoided average fuel costs of the last ten years, it may run into problems in a changing future energy system due to two reasons. First, the economics of the project are built on the assumption that the plant will run approximately 8,000 hours per year at full load, which is a fair assumption, if it would be running against the present diesel fired power production. With power production costs of 0.28 BBD/kWh it could outcompete diesel generation on the basis of marginal costs virtually every hour of the year. Unfortunately, the project, once completed, will have to compete with a power production based more and more on wind and solar energy, both of which have virtually no marginal costs for power production, as they are not depending on any kind of fuel. Thus, whenever the new solid biomass combustion has to compete against wind and solar energy, it will not be chosen, as it has substantially positive marginal (fuel) costs.

Such development has been experienced by thermal power plants all around the world in countries with increasing shares of wind and solar energy in power production like in Germany. The new situation will result in gradually declining operation hours per year eventually leaving the plant with a few thousand hours of full load operation per year. As the hours of operation decrease the cost of power production will increase. Thus, a plant operating only 4,000 full load hours a year will need an average price of 0.56 BBD/kWh to recover its cost at the pace originally planed. Whenever the hours of full load operation drop further, the average price has to go up even further to fully recover costs.

The second problem a solid biomass combustion will face in the future is the fact that it can not be operated continuously at a constant load factor, but that it has to be ramped up and down quite frequently and to operate in partial load to adjust to the new market situation with growing shares of wind and solar power production. Such partial load operation will lead to seriously reduced generation efficiencies, while frequent ramping and cold starts of the plant will increase fuel and maintenance costs. Thus, the necessary changed mode of operation will increase generation costs more than proportionately.

Both problems point to the fact that the planned solid biomass combustion will encounter serious economic problems during its expected 25 years of operation. Thus, it might not be the best choice to stabilise the production of sugar cane in Barbados. What is more, the present calculations are assuming that the sugar from 18,000 acres of cane production can still be sold in the world market with the additional income from the solid biomass combustion plant (5 - 5.6 BBD/GJ of bagasse), which may not be sufficient across the lifetime of the plant.

GASIFICATION OF KING GRASS

The second project is far more recent. It assumes that the production of sugar will not be economically viable in Barbados in the long run. Therefore, the farmers initiating the project have been looking for a grass type which can be used in crop rotation like sugar cane in order to stabilise the top soil in crop rotation, which yields a relatively high biomass output per acre and which can be planted and harvested more continuously around the year.

After a first pre selection successful field trials have been conducted with King Grass. The biomass yield has been 19 t of biomass at 10% moisture per acre and year with an energy content of 18 GJ/t of biomass at 10% moisture. To allow a flexible production of electricity from this biomass source, a gasification process is chosen which produces 1,897.4 Nm^3 of syngas per ton of biomass at 10% moisture with an assumed gasifier conversion efficiency of 70% (see Fichtner 2016, p.10). The produced syngas has an energy content of 5.5 MJ/Nm^3(see Fichtner 2016, p.10). A gasifier with a feed throughput of 575 kg biomass/hr will produce 1,091 Nm^3 of syngas per hour, which would be sufficient to operate a 600 kW_{el} gas engine for power production (see Fichtner 2016, p.10). Assuming a load factor of 80% and a biomass yield of 60 green t/acre equivalent to 19 t/acre at 10% moisture) about 216 acres of King Grass are needed to operate a 600 kW gas engine 7,008 hours per year producing 4.204 GWh of electricity per year. Gasifiers in the required size range come at about 6 Million USD (see Fichtner 2016, p.17). Gas engines combined with generators will most likely cost between 2 and 3 Million USD/MW. So far the exact costs of growing and harvesting King Grass as well as the operation and maintenance costs of the gasifier and the power production unit have not been analysed in detail, as a first pilot plant will be built in 2017. But the farmers involved in the project calculate that 3 t of wet King Grass needed to produce 1 t of dry King Grass (at 10% moisture) will cost about 120 BBD/t.

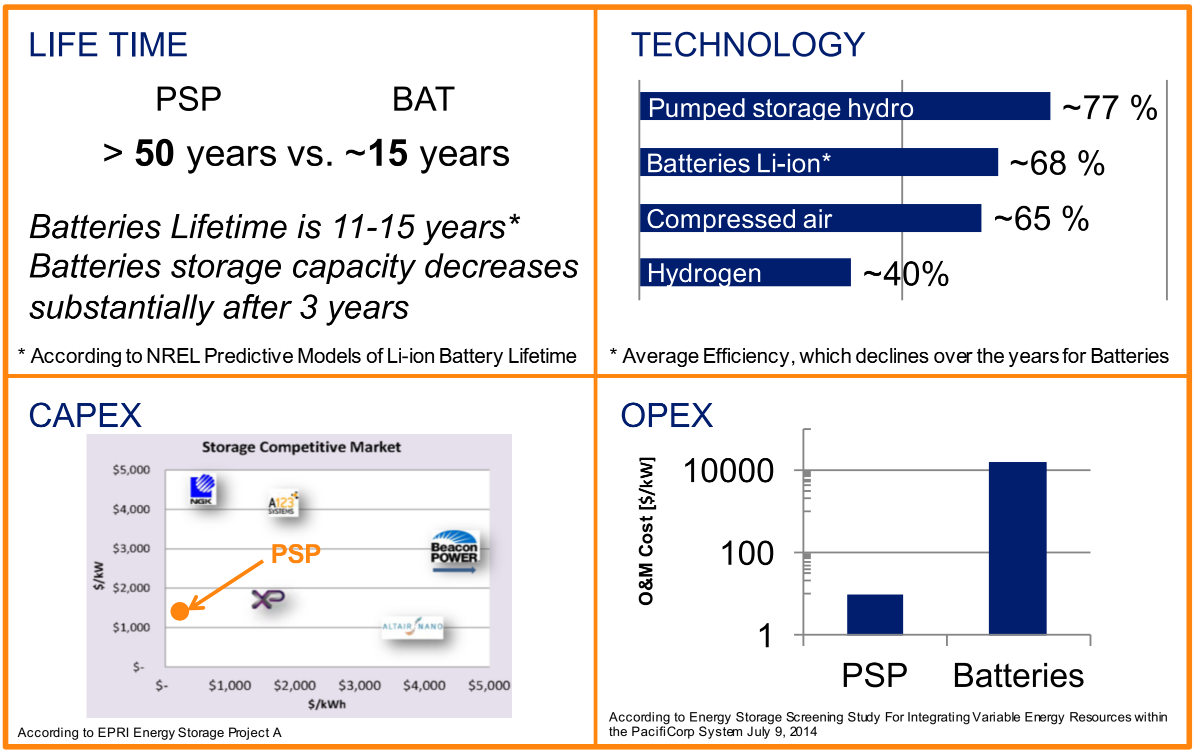
The King Grass approach has a number of systemic advantages over solid biomass combustion in the future energy system build mainly on the variable renewable energy sources wind and solar energy. The combustion engine allows a ramping of the system from no operation to full operation within less than 15 minutes, which allows to follow the residual load of the power system (the load remaining after wind and solar power production have been deducted from the total load or power demand of any given hour). Thus, the system can supply the flexibility needed in the future power system to complement wind and solar energy. What is more, the flexible planting and cropping of King Grass across the year allows to adjust the harvest of the biomass to the expected seasonal output from wind and solar energy. Additionally, the produced syngas can be stored for a number of hours or days allowing a high flexibility in the operation of the gas engine for power production, while the gasifier can be in constant operation. The relatively small size of single systems (about 0.6 MW_{el}) allows the adjustment of the operated production capacity to the residual load in every hour of the year. Thus, from a systems perspective the more flexible second option for the energetic use of biomass in Barbados seems to fit Barbados' future power production better than the large scale solid biomass combustions based on bagasse and river tamarind.

WP 3: UPDATED DISCUSSION OF THE APPLICABILITY OF PUMP STORAGE HYDRO SYSTEMS AND THEIR COSTS IN BARBADOS

Substantial storage will only be needed whenever the production from variable renewable energy sources like wind and solar energy are installed at capacities large enough to cause substantial overproduction. As both energy sources have virtually no variable costs the overproduction of electricity comes at no additional cost for the system. Thus, the cost of utilising this overproduction is equal to the cost of storage to make it available in times when wind and solar energy can not cover the full system load and the energy saved can substitute other forms of power production with substantial variable cost.

As discussed in detail in Annex 2, pump storage hydro facilities seem to offer the lowest cost solution for the necessary large scale storage of the future electricity supply of Barbados mostly supplied by wind and solar energy. Although, batteries will play an important role in local grid stabilisation they are far more expensive than pump storage given the positive preconditions found on Barbados for pump storage with achievable altitude drops of up to 300m. Figure 32 summarises the major aspects pertaining to the costs of different storage systems.

Figure 32: Comparison of pump storage and battery storage systems (source: Stoebich 2016)



Details on the assessment of a promising pump storage location can be found in Annex 2. It is worth mentioning that the water collection facilities for the pump storage can be used to collect far more water from the water shed for drinking water and irrigation purposes. The outflow of the watershed is about 12 million cubic meters per year, which are presently flowing out into the Atlantic without any use for

Barbados. The pump storage facility will need 4 million cubic meters of cleaned water from this watershed once and about 30,000 m^2/a once the system is filled. All other water collected could be feed into the public water system.

WORK PACKAGE 5: SIMULATION OF ALTERNATIVE 100% RE TARGET SYSTEMS AND ANALYSIS OF THEIR PROSPECTIVE COSTS

Based on an extended version of the energy system simulation model used in the former 100% scenario calculations for Barbados (see Annex 4 for the extensions implemented) and the updated results on the costs and potentials of different renewable energy sources and storage options for Barbados and interviews with investors in wind and bio energy 18 different possible 100% RE target systems were simulated for a target year take as 2035. From international experience it is quite clear that based on available renewable energy technologies and available international know how, a transition to a 100% renewable power supply can be achieved by 2035 without any major problem, as soon as the policy and the administrative framework are set to facilitate such transition. For 2035 the annual power demand projected by Barbados Light and Power in their IRP of 2012 for 2035 was taken from the graph on page 9 of the IRP (Barbados Light and Power 2012, p.9). This is approximately 1350 GWh/a.

As a basic reference case a power supply exclusively based on new large diesel engines was calculated in scenario 1. The other scenarios look at the possibilities to supply 100% RE power from four different sources (wind, solar PV, biomass and municipal solid waste) using six different technologies. In the case of biomass the combustion of solid biomass (bagasse and river tamarind) and the gasification of King Grass were analysed. Both are relevant options to solve part of the agricultural problem created by the international competitive situation of sugar produced from sugar cane in Barbados. For municipal solid waste the widely used technology of solid waste combustion was used as one option and the proposed plasma gasification as a second option. Thus, in total six different technologies can be combined to produce a 100% renewable power supply for Barbados. As in earlier simulations (Hohmeyer 2015) a small residual power production is done by the existing diesel generators and gas turbines to allow to limit storage to an economic and manageable size for Barbados. This back-up production is limited to 50 GWh/a, which is less than 4% of the total power demand.

In a first set of scenarios (scenario 2 to 6, see Table 8 below) each technology was used on its own. If the potential allowed (e.g. in the case of PV) it was attempted to supply the 100% RE power just based on this source and storage. In the case of biomass and municipal waste this in not possible, therefore, in these cases the production was limited to the resource potential. As municipal solid waste is far from such a potential only an extreme case of a 13 MW for plasma gasification was taken into account assuming high system efficiencies. For solid waste combustion the contribution would be limited to a 11 MW plant due to lower system efficiencies, which is even smaller. Therefore, solid waste combustion was not calculated as a separate scenario. In the case of bagasse and river tamarind the limit was set by the constant full load operation of the planned 25 MW plant. In the case of King Grass a limit of 300 GWh/a which is equivalent to 15 000 acres of land used for King Grass production was used as a limit.

With the exemption of a pure wind scenario (which requires about 10% more area than the 456 MW production possible on the sites proposed by Rogers (2015), which has a cost of just about 0.4 BBD/kWh all single resource scenarios have cost close to 0.5 BBD/kWh.

In scenario 7 wind and PV, the technologies with the largest potential were combined to see, whether the combination of the two can bring down cost and solve the capacity problem of wind (only 450 MW of good sites). The combination of wind and PV actually turns out to have slightly lower cost than wind energy alone, again very close to 0.4 BBD/kWh.

In scenario 8 to 11 wind and PV are combined with each of the other options, one at a time to see the best fit. Only the combination with municipal solid waste (MSW) combustion leads to lower cost than the combination of wind and PV alone. It actually can bring down cost for the 100% RE power supply to slightly less than 0.39 BBD/kWh. The assumed MSW capacity appropriate for Barbados is taken to be 11 MW for constant firing. All other combinations increase costs. The use of biomass leads to costs of about 0.42 BBD/kWh for both bagasse and river tamarind combustion as well as for King Grass gasification. The most expensive combination results from the use of waste plasma gasification.

In scenario 12 and 13 wind, PV and King Grass gasification were combined with the two waste to power technologies one at a time. The combination with King Grass results in a slight cost increase from 0.39 to 0.4 BBD/kWh, while again the combination with waste plasma gasification results in a more significant increase to 0.42 BBD/kWh.

In scenario 14 and 15 wind, PV and solid biomass combustion (bagasse and river tamarind) were combined with the two waste to energy technologies. In the case of solid waste combustion this increases the cost as compared to the use of King Grass from 0.4 to about 0.42 BBD/kWh, while in the case of waste plasma gasification the costs increase from 0.42 to 0.46 BBD/kWh. Thus, it seems that a combination with King Grass gasification is the more attractive solution for the agricultural problem of Barbados.

As the lowest cost solution with a substantial use of King Grass is only 120 GWh/a from King Grass, which is equivalent to about 6000 acres of land planted with King Grass, an additional scenario (13a) has been calculated to show the impact of extensive use of King Grass equivalent to 15 000 acres, which translates into an annual electricity production of 300 GWh from King Grass gasification. This scenario leads to cost of about 0.44 BBD/kWh. Thus, if a very large acreage is supposed to be kept in agricultural production and if sugar production will be viable at that scale the solid biomass combustion based on bagasse and river tamarind may have a cost advantage over a very large scale use of King Grass. On the other side it will be highly risky to follow such strategy as the world market for sugar does not show any signs that such a strategy can be sustained on the side of the sugar production, which is the very basis for the bagasse concept. River tamarind alone will not solve the agricultural problem of loosing the sugar cane crop for intercropping as explained above.

Scenario 16 and 17 combine wind, PV, King Grass and solid biomass combustion with either municipal waste combustion or waste plasma gasification. Again the combination with the simple waste combustion leads to substantially lower cost at about 0.41 BBD/kWh, while the inclusion of waste plasma gasification brings up the cost to about 0.46 BBD/kWh.

In the last scenario (18) all technologies were combined for a 100% RE power supply. In this case the capacities for waste combustion and waste gasification were cut in half, as they are limited by the available municipal and commercial waste in Barbados. As could be expected this combination of all available technologies leads to relatively high costs of about 0.44 BBD/kWh.

To complete the overview of the nineteen basic scenarios calculated Table 9 gives the additional information on the use of back-up power and storage as well as the overproduction in the 100% scenarios, which is necessary to meet the 100% goal. This excess production will actually be down regulated in reality.

To give a clear impression of the relative costs of the different scenarios they are ordered by cost per kWh in Table 10 below. It becomes quite clear that a combination of wind, PV and the standard combustion of waste has the lowest cost. Second is the simple combination of wind and PV like it was used by Hohmeyer (2015) in his first calculations on a 100% RE scenario for Barbados. Third is the first combination with King Grass gasification at the level of 120 GWh/a or 6000 acres. The most expensive option is waste to energy gasification.

Table 8: Composition and electricity costs of 18 basic scenarios analysed (pleas note that in this table the comma is used as decimal point (German notation, comma as decimal point)

Scenario		LCOE	Installed capacities and annual generation											
			Wind		PV		King Grass		Bagasse and river tamarind combustion		Wast gasification		Solid wate combustion	
No.	Name	BBD/ kWh	MW	GW h/a	MW	GW h/a	MW	GW h/a	MW	GW h/a	MW	GW h/a	MW	GW h/a
1	New diesel only (base line)	0.4495												
2	Bagasse and river tamarind only	0.4810							25	169				
3	King grass gasification only	0.4886					40	300						
4	Waste to energy gasification only	0.5126									25	200		
5	100% RE PV and storage alone	0.5100			755	1559								
6	100% RE Wind and storage alone	0.4013	505	2312										
7	100% RE Wind and PV plus storage	0.3999	286	1309	286	589								
8	100% RE / Wind / PV / King Grass	0.4212	224	1026	224	463	26	200						
9	100% RE / Wind / PV / Bagasse	0.4233	240	1099	237	485			25	169				
10	100% RE / Wind / PV / WTE gas	0.4356	265	1213	265	547					13	100		
11	100% RE / Wind / PV / Solid waste combustion	0.3883	265	1213	265	547							11	74
12	100% RE / Wind / PV / King Grass / WTE gas	0.4209	234	1071	234	483	25	110	10	67.6				
13	100% RE / Wind / PV / King Grass / WTE combustion	0.4004	232	1062	232	479	26	120					11	74
13a	100% RE / Wind / PV / King Grass / WTE combustion	0.4386	200	916	200	413	40	300					11	74
14	100% RE / Wind / PV / Bagasse / WTE combustion	0.4143	219	1002	219	425			25	169			11	74
15	100% RE / Wind / PV / Bagasse / WTE gas	0.4614	219	1002	219	425			25	169	13	100		
16	100% RE / Wind / PV / King Grass / Bagasse / WTE gasification	0.4584	212	971	212	438	25	120	10	68	13	100		
17	100% RE / Wind / PV / King Grass / Bagasse / WTE combustion	0.4128	213	975	213	440	25	120	10	68			11	74
18	100% RE / Wind / PV / King Grass / Bagasse / WTE gasification /WTE combustion	0.4361	213	975	213	440	25	120	10	68	6.5	50	5.5	37

Table 9: Cost, conventional power production, storage and overproduction in 18 basic scenarios analysed

Scenario		LCOE	Installed capacities and annual generation							Total overproduction
			Diesel/Biodiesel		Storage volume	Storage generation		Storage pumping		
No.	Name	BBD/ kWh	MW	GWh/a	MWh	MW	GWh/a	MW	GWh/a	GWh/a
1	New diesel only (base line)	0.4495	196.8	1350						0
2	Bagasse and river tamarind only	0.4810	177.5	1181						0
3	King grass gasification only	0.4886	156.8	1050						0
4	Waste to energy gasification only	0.5126	171.8	1154						0
5	100% RE PV and storage alone	0.5100	177.9	50	10000	196.8	661	558.8	758	259
6	100% RE Wind and storage alone	0.4013	177.3	50	10000	196.8	197	320.1	197	1012
7	100% RE Wind and PV plus storage	0.3999	175.1	50	5000	196.8	218	335.6	252	598
8	100% RE / Wind / PV / King Grass	0.4212	152.4	50	5000	182.7	184	232.7	217	389
9	100% RE / Wind / PV / Bagasse	0.4233	159.8	50	5000	190.4	188	272.2	218	453
10	100% RE / Wind / PV / WTE gas	0.4356	165.5	50	5000	196.8	193	299.7	225	560
11	100% RE / Wind / PV / Solid waste combustion	0.3883	166.7	50	5000	196.8	205	307	238	400
12	100% RE / Wind / PV / King Grass / WTE gas	0.4209	146.6	50	5000	174.9	165	256.1	192	431.6
13	100% RE / Wind / PV / King Grass / WTE combustion	0.4004	144.8	50	5000	172.9	163	253.4	190	435
13a	100% RE / Wind / PV / King Grass / WTE combustion	0.4386	131.6	50	5000	156.8	129	199.8	151	403
14	100% RE / Wind / PV / Bagasse / WTE combustion	0.4143	151.9	50	5000	180.6	176	248.3	205	370
15	100% RE / Wind / PV / Bagasse / WTE gas	0.4614	147.3	50	5000	175.4	164	241.0	191	396
16	100% RE / Wind / PV / King Grass / Bagasse / WTE gasification	0.4584	134.1	50	5000	160.0	139	219.3	162	397
17	100% RE / Wind / PV / King Grass / Bagasse / WTE combustion	0.4128	138.6	50	5000	165.2	151	228.3	176	377
18	100% RE / Wind / PV / King Grass / Bagasse / WTE gasification / WTE combustion	0.4361	136.3	50	5000	162.6	145	224.6	169	390

Table 10: Scenarios ordered by cost per kilowatt-hour

Scenario		LCOE
No.	**Name**	**BBD/ kWh**
11	100% RE / Wind / PV / Solid waste combustion	0.3883
7	100% RE Wind and PV plus storage	0.3999
13	100% RE / Wind / PV / King Grass / WTE combustion	0.4004
6	100% RE Wind and storage alone	0.4013
17	100% RE / Wind / PV / King Grass / Bagasse / WTE combustion	0.4128
14	100% RE / Wind / PV / Bagasse / WTE combustion	0.4143
12	100% RE / Wind / PV / King Grass / WTE gas	0.4209
8	100% RE / Wind / PV / King Grass	0.4212
9	100% RE / Wind / PV / Bagasse	0.4233
10	100% RE / Wind / PV / WTE gas	0.4356
18	100% RE / Wind / PV / King Grass / Bagasse / WTE gasification / WTE combustion	0.4361
13a	100% RE / Wind / PV / King Grass / WTE combustion	0.4386
1	New diesel only (base line)	0.4495
16	100% RE / Wind / PV / King Grass / Bagasse / WTE gasification	0.4584
15	100% RE / Wind / PV / Bagasse / WTE gas	0.4614
2	Bagasse and river tamarind only	0.4810
3	King grass gasification only	0.4886
5	100% RE PV and storage alone	0.5100
4	Waste to energy gasification only	0.5126

Finally the scenario assumptions of the IRENA reference scenario for 2030 were put into the model to see how this scenario performs in comparison to the 100% scenarios analysed. There are two main differences between the scenario assumptions used by IRENA and the ones used in this analysis. First, IRENA denies the possibility of pump storage for Barbados (without any evidence) and second IRENA has a far lower electricity demand, namely 1,002.6 GWh/a in 2030. Using the assumed capacities of 155 MW wind, 155 MW PV and 18 MW of solid biomass combustion the scenario was run with all other assumptions as set for the 19 scenarios above.

The first result of the calculation is that the IRENA scenario has lower costs than all the other scenarios, but this is mostly due to the fact that only 1,002 and not 1,350 GWh/a need to be produced.

The most interesting result is that the inclusion of realistic data on pump storage, easily allowing 3,000 MWh of storage, 20 times as much as the 150 MWh battery capacity used in the IRENA road map, allows a far better utilisation of the renewable energy produced. This leads to an increase of the RE power share from 84 to 94% without any additional generating capacity. If the back-up is covered by bio diesel this scenario can easily qualify as a 100% RE scenario for Barbados. As the use of large storage capacities in the form of pump storage reduces the conventional generation by 100 GWh/a it allows to reduce the cost per kWh from 0.31 to 0.29 BBD/kWh using the assumptions applied to all other scenarios and using, as in all other calculations the low wind speeds of 2011. The results point to the fact that a substantial increase in energy efficiency could help reduce specific electricity cost. At the same time the results produced with the specific wind energy data for 2011 point to the fact that IRENA may have been using rather low wind speeds for Barbados as suspected by Dr. Rogers in a personal communication before.

Table 11: Scenarios based on IRENA road map for Barbados

Scenario			**Installed capacities and annual generation**											
		LCOE	**Wind**		**PV**		**Bagasse and river tamarind combustion**		**Diesel/ Biodiesel**		**Storage volume**	**Storage generation**		**RE**
No.	**Name**	**BBD/ kWh**	**MW**	**GWh/ a**	**MW**	**GWh/ a**	**MW**	**GWh/ a**	**MW**	**GWh/ a**	**MWh**	**MW**	**GWh/ a**	**%**
IRENA 2030	85% RE / Wind / PV / Solid biomass / 150 MWh battery storage	0.3057	155	710	155	320	18	122	123.0	156	150	126.4	51	84.4 %
IRENA 2030 mit 3 GWh PSH	95% RE / Wind / PV / Solid biomass / 3 GWh PSH	0.2884	155	710	155	320	18	122	119.7	56	3000	142	143	94.4 %

WORK PACKAGE 6: DISCUSSION OF THE ALTERNATIVE 100% RE TARGET SYSTEMS WITH THE RELEVANT STAKEHOLDERS AND THE ENERGY DIVISION

As all reasonable alternatives have been covered by the scenarios calculated and as it has become clear from the simulations that only one option can be dismissed right away, which is the plasma gasification of waste. Plasma gasification is the most expensive option and at the same time not a proven technology. Besides taking plasma gasification out of the target scenarios all other decisions will need to be made by policymakers based on their perspective on the solution of the agricultural sector and the future of the Barbados sugar industry. Therefore, it was decided that a stakeholder workshop could not decide on the final technology choices.

Policymakers will need to decide how to complement the basic mixture of wind, PV and solid waste combustion with a biomass technology for securing the future of intercropping agriculture in Barbados. As the King Grass gasification is right know entering the demonstration phase, it might be wise to postpone this decision until the results of the first demonstration project on Barbados will be available in 2020. In the meantime the expansion of wind and solar PV can be pursued without the need for such a decision before 2025. The combustion of solid waste can be pursued whenever this is advisable for the municipal waste handling in Barbados.

Instead of the stakeholder workshop on the modelling results there will be a broader workshop at the end of the project for the discussion of all results of phase one and phase two of the project. From recent discussions it has become clear that, while most stakeholders see the advantages of a differentiated dynamic feed-in tariff system, the first price points to be suggested in the report and the assumptions going into their calculation will meet far greater interest as some details of the final target scenario.

As the lowest cost scenario including a solution of the agricultural intercropping problem was the combination of wind, PV and solid waste combustion with a modest volume of King Grass gasification (120 GWh/a) and as the gasification of biomass can be far better integrated with the other renewables than solid biomass combustion, scenario 13 was selected as the first target scenario for 2035. In addition three further target scenarios were selected for the transition pathway analysis, which are scenario 13a (300 GWh/a from King Grass gasification), as this covers a far larger share (15 000 acres) of the land under sugar cane cultivation compared to scenario 13. Scenario 14 (wind, PV, solid waste combustion and solid biomass combustion) was selected as well, as this scenario covers 18 000 acres of sugar cane and has lower costs than scenario 13a. Scenario 11 (wind, PV and solid waste combustion) was selected as well, having the lowest cost of all 2035 scenarios analysed.

WORK PACKAGE 7: ANALYSIS OF THE PRESENT POWER SUPPLY SYSTEM AS THE STARTING POINT OF THE NECESSARY TRANSITION TO THE 100% RE TARGET SYSTEM

The present power demand and supply in Barbados and the development of power demand until 2036

Power is publicly supplied by Barbados Light and Power to about 126 000 customers, which had a power consumption of about 900 GWh/a in 2014 (see EMERA Caribbean 2015, p. 7) and 915 GWh/a in 2015 (IDB 2016, p. 14) and a maximum load of about 155.2 MW in 2015 (IDB 2016, p. 10). The installed conventional generation capacity is about 239 MW (see IDB 2016, p. 10). The Barbados power supply is characterised by comparatively low system losses between 5 and 7.5% (IDB 2016, p.33).

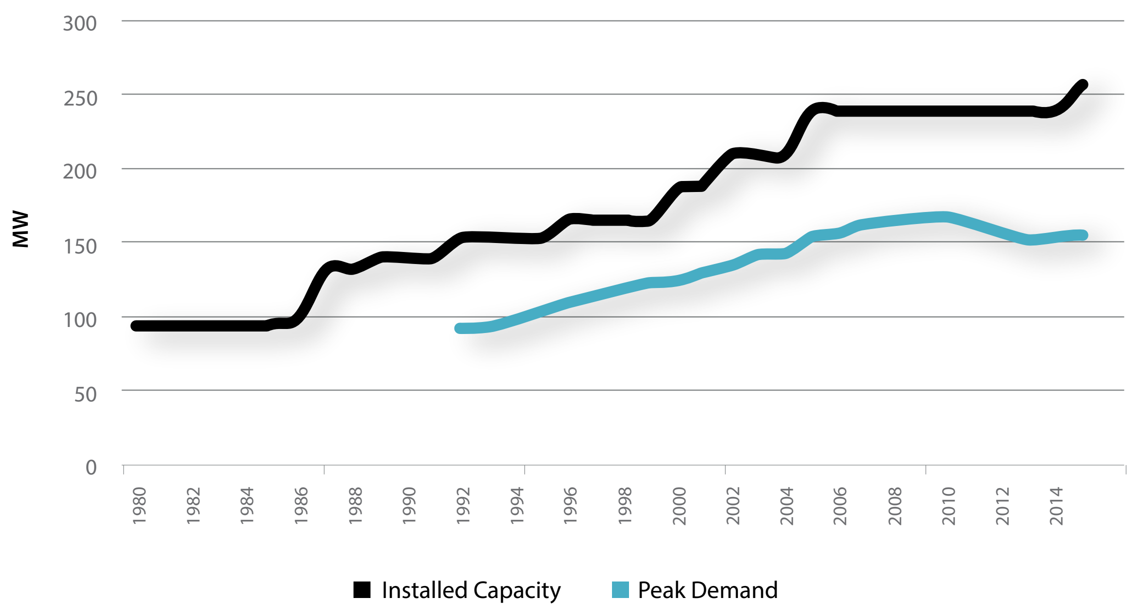
Table 12: Barbados Power and Light generating capacities as of 2014 (source: IDB 2016, p.10)

Power Stations	Fuel	Capacity	Details	Heat Rate kJ/kWh	Year of PPA
BL&P		256.6MW			
Spring Garden		153.1MW	Opened 1967		
S1	HFO	20MW	Steam Turbine Generator	14,377	2017/01
S2	HFO	20MW	Steam Turbine Generator	14,377	2017/01
S10	HFO	12.5MW	Low Speed Diesel Generator	8,063	2019/01
S11	HFO	12.5MW	Low Speed Diesel Generator	8,063	2019/01
S12	HFO	12.5MW	Low Speed Diesel Generator	8,063	2019/01
S13	HFO	12.5MW	Low Speed Diesel Generator	8,063	2019/01
CG01		1.5MW	Co-generating unit connected to D10-13		2019/01
CG02		2.2MW	Co-generating unit connected to D10-13		2036/01
DA14	HFO	29.7MW	2005, Low Speed Diesel Generator	7,456	2036/01
DA15	HFO	29.7MW	2005, Low Speed Diesel Generator	7,456	2036/01
GT01			Retired		
Seawell		73MW			
GT03	Diesel	13MW	1996, Gas Turbine Generator	13,276	2022/01
GT04	Diesel	20MW	1999, Gas Turbine Generator	11,134	2025/01
GT05	Av-Jet	20MW	2001, Gas Turbine Generator	11,134	2027/01
GT06	Diesel	20MW	2002, Gas Turbine Generator	11,134	2028/01
Garrison Hill		13MW			
GT02	Diesel	13MW	1990, Gas Turbine Generator	13,276	2017/01

Since 2009 the installed capacity of solar PV installations connected to the public grid has increased to about 10.4 MW by the end of 2015 and an additional 10 MW PV plant has been installed by BL&P in 2016 (see IDB 2016 p. 12f). BL&P reported payments for 18.7 GWh for the renewable energy capacity installed in 2015 (see IDB 2016, p. 17), which would be equal to about 2% of the annual gross power production by BL&P, which amounted to 969.4 GWh/a in 2015 (see IDB 2016, p. 14). Even if this renewable power production can be doubled by the new capacities installed in 2016, Barbados is still supplied to more than 95% by electricity generated from mineral oil products.

While the power production capacity has increased from about 100 MW in 1980 to about 260 MW in 2016 (including about 19 MW of solar PV capacity) the peak demand has risen from just a little below 100 MW in 1980 to about 160 MW in 2010 and has declined afterwards due to high power prices. At the moment the peak demand is about 150 MW (see Figure 33 below).

Figure 33: Development of peak demand and installed capacity in Barbados (source: IDB 2016, p. 11)



The hourly load curve for Barbados is not publicly available, but it has been reconstructed by Hohmeyer (2015, p.11) and by IRENA (2016, p.18). The annual hourly load curve derived by IRENA is virtually identical with the curve derived by Hohmeyer. The load curve derived by IRENA is given in Figure 34 below.

In its Integrated Resource Plan of 2012, which shows the possible future development of the electricity demand for Barbados until 2036 Barbados Power and Light has developed three scenarios, a low, a base and a high scenario, which are based on detailed analyses of the power demand of the different sectors. As Figure 35 shows, the peak demand may increase to about 300 MW in the high scenario, to about 210 MW in the Base scenario and may even decline to about 140 MW in the low scenario. BL&P foresees a total power demand of about 2,000 GWh/a in the high scenario, about 1,360 GWh/a in the base scenario and a decline to about 900 GWh/a in the low scenario (see BL&P 2012 Table 1, p.9). This development will mostly depend on the overall economic development of Barbados, but it will certainly depend upon the future price of electricity and the efficiency measures, which will be taken to reduce the power demand of different uses.

Figure 34: Reconstructed annual load curve of Barbados for 2014 (source: IRENA 2016, p.18)

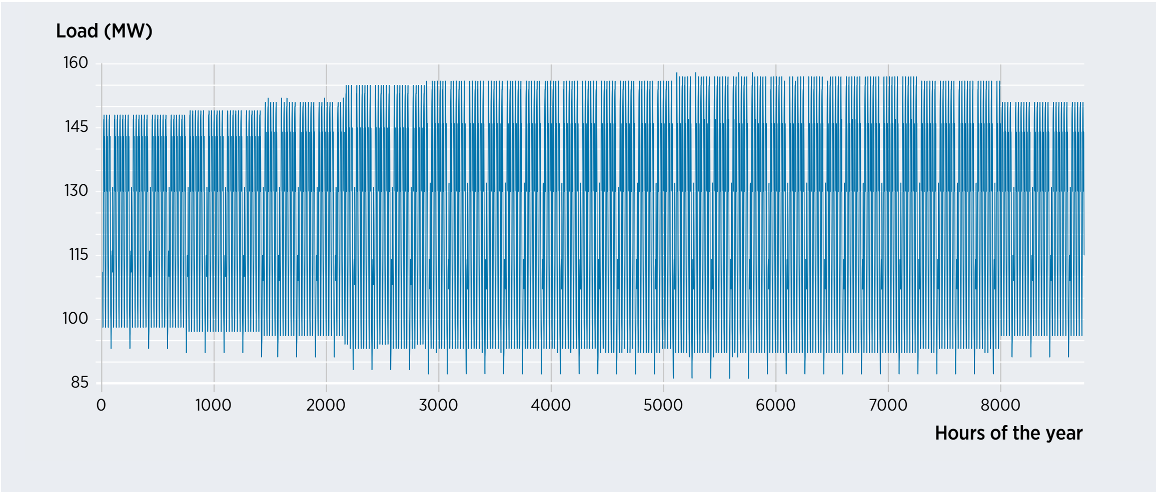


Figure 35: Three possible scenarios for the development of Barbados' future maximum electrical load (source: BL&P 2012, p.26)

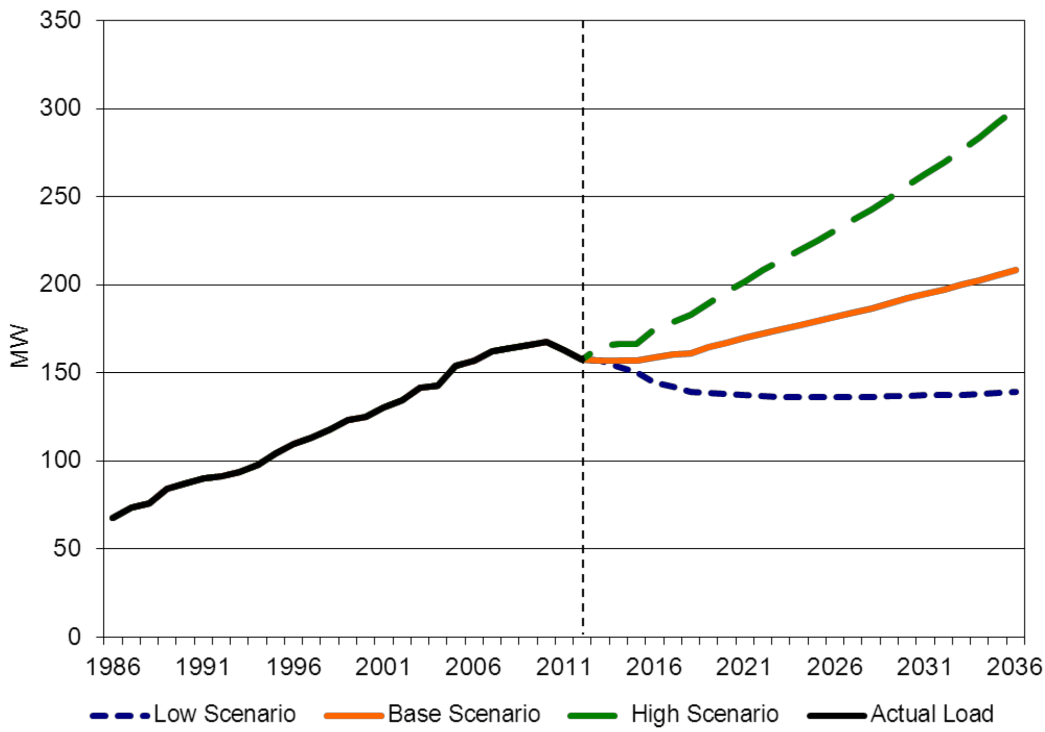
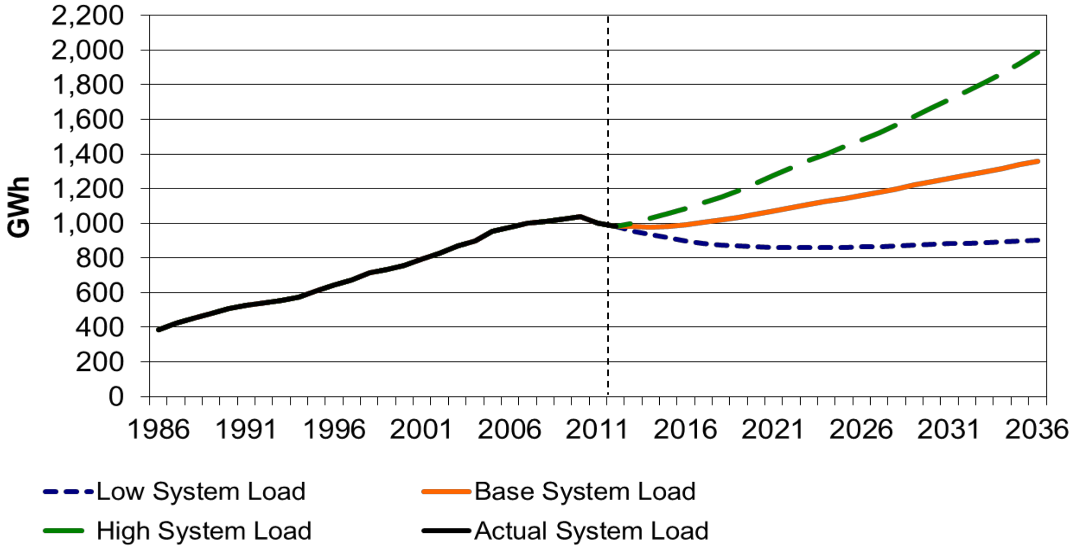


Figure 36: Three possible scenarios for the development of Barbados' future annual electricity demand (source: BL&P 2012, p.9)



From the Integrated Resource Plan of BL&P it becomes quite clear that the build up of the future power supply of Barbados needs to be quite flexible in order not to risk too low capacities and an unstable power supply and not to risk stranded investment into additional supply capacities which will sit idle due to a lack of power demand in the case of the lower scenarios. As the present installed firm capacity in conventional equipment is at about 240 MW and most of this equipment is already written off, one of the cheapest strategies to keep enough firm capacity would be to maintain the existing generators as long as possible.

Barbados' present power market structure and regulatory regime

The electricity market of Barbados is characterised by the dominant position of the BL&P, which is a vertically integrated utility company responsible for the generation, supply, and distribution of electricity (see IDB 2016, p. 28). Since 2014 BL&P is owned by EMERA Caribbean, which in turn is owned by EMERA, a Canadian-based company (80%), the National Insurance Board and approximately 1700 other shareholders (see IDB 2016, p. 29).

The power market is regulated by the Barbados Fair Trading Commission (FTC), which was established in 2001 under the Fair Trading Commission Act (see IDB 2016, p.31). With the passing of the Electric Light and Power Act (ELPA) in 2013 the power sector was opened to independent power producers (IPPs). As of 2016 no IPP has entered the market for either conventional generation, transmission or distribution (see IDB 2016, p. 28). Despite the market opening to IPPs BL&P still holds an official mandate for the generation, transmission and distribution of electricity under its current license, which runs until 2028 (see IDB 2016, p. 29). Thus, the present electricity market of Barbados is dominated by a vertically integrated privately owned utility producing about 96% of the traded electricity acting as a single buyer for all other power producers.

According to the nomenclature of the World Bank developed for the full liberalisation of power markets (see Gratwick and Eberhard 2008, p. 3952) Barbados has adopted seven of nine reform steps (corporisation, commercialisation, passage of requisite energy legislation, establishment of an independent regulator, introduction of IPPs, divestiture of generation assets, divestiture of distribution assets). Only the two steps of restructuring (unbundling the vertically integrated utility) and the introduction of competition through the introduction of wholesale and retail markets have not been taken (compare Gratwick and Eberhard 2008, p. 3952). According to Gratwick and Eberhard (2008, p. 3954) the Barbados situation resembles the single buyer model, which can be seen as one of the standard hybrid forms of power market liberalisation, which have evolved during the last two decades in the power market liberalisation of developing countries. It can well be argued that the power market in Barbados is too small to allow retail or wholesale competition or unbundling (see e.g. Bacon 1995, p.4 or Weiser 2004, p. 108f). Bohun, Terway and Chander (2001) ‚*have emphasised that developing countries with capacities below approximately 1000 MW would not attract sufficient numbers of participants in generation and distribution to introduce sustained competition*‘ (Wiser 2004, p. 109). Only five out of 54 SIDS have installed capacities over 1000 MW (Cuba, Dominican Republic, Jamaica, Trinidad and Tobago and Singapore) (see Wiser 2004, p. 110). The minimum market size of 1000 MW compares to just about 150 MW of peak load in Barbados. Thus, taking into account this limited market size the liberalisation of the Barbados power sector has already reached a comparatively high level, where unbundling could be discussed but may well have to high transaction and coordination costs and little positive effect, while it seems to be extremely unlikely that wholesale and retail competition could generate any positive returns.

Barbados’ past and present renewable energy policy

Presently the use of renewable energy sources to increase the share of domestic power production and to reduce the drainage of foreign exchange earnings for imported fossil fuels for power production remains at the very low level of less than 4% in 2016, while other islands and SIDS have already reached very substantial shares of renewable power production e.g. Fiji with 59.3% Reunion with 31.2%, Crete with 26%, and Cape Verde with 21% (see Kuang et al. 2016, p. 506) to name a few prominent examples.

In 2015 the goals for the renewable energy policy of Barbados have been (nominally) increased from the 2012 target of 29% for renewable power by 2029 (AOSIS 2012, p.6 and Revised National Sustainable Energy Policy, 3.3, first bullet) to 65% of the maximum electrical load in 2030 (Barbados Intended Nationally Determined Contribution 2015, p.5). Depending on the composition of the renewable energy sources used in 2030 to reach this share of 65%, this might just be the same target as the 29% for 2029, which referred to the total electricity produced by renewables per year. In the likely case that the renewable power production of 2030 will be mostly based upon wind and photovoltaic solar energy (PV) the share of 65% of the maximum electrical load of 192 MW in 2030 (derived from the IRP of Barbados Light and Power 2014, p.10) would equal 125 MW of installed wind and PV capacity. This would produce just about 350 GWh/a (assuming 50% PV and 50% wind), which would be equal to 28.2% of the annual system load of 2030 projected by BL&P (interpolated figure based on BL&P 2014, p.9). Thus, the nominal change of the target from 29% of annual electricity produced to 65% of the maximum capacity might hardly result in an increase of renewable electricity being produced.

Recently the Barbados declared a 100% renewable power target to be reached by 2066 (declared by the Prime Minister of Barbados at the BREA Sustainable Energy Conference on November 10th, 2016). The proclaimed target of 100% renewable power by *2066* can hardly be seen to be in line with the claim to reach 100% renewable domestic energy supply ‚*as rapidly as possible*‘ as made by the CVF at COP 22.

What is more, the new ‚ambitious' 100% target is nothing else than the 29% target for 2029. Assuming a linear distribution of the market diffusion of renewable energy over the 50 year period from 2017 to 2066 the new policy target implies a growth of 25.48% from 2017 to 2029. If this is added to a renewables share of roughly 4% by the end of 2016 the set policy target for 2029 remains virtually unchanged as compared to the target set in 2012. It seems that some policy makers try to leave the impression with the public in Barbados and the world that Barbados is speeding up its pace in the introduction of renewable electricity, while they are still just pursuing the old target of 2012.

WORK PACKAGE 8: DESIGN OF AN APPROPRIATE TRANSITION PATHWAY FROM THE PRESENT ELECTRICITY SYSTEM TO THE 100% RE TARGET SYSTEM

Different from the original idea to select one target scenario in a stakeholder workshop by consensus, it was decided based on the results of a complete set of scenarios to go ahead with four different target scenarios and to develop transition pathways for all of them. These four target scenarios were selected on the basis of their power costs and their possible contribution to the solution of the agricultural problem of Barbados connected to the decline of the sugar industry and sugar cane farming.

As the lowest cost scenario including a solution of the agricultural intercropping problem was the combination of wind, PV and solid waste combustion with a modest volume of King Grass gasification (120 GWh/a) and as the gasification of biomass can be far better integrated with the other renewables than solid biomass combustion, scenario13 combining wind, PV, solid waste combustion and King Grass gasification (120 GWh/a) was selected as the first target scenario for 2035. In addition three further target scenarios were selected for the transition pathway analysis, which are scenario 13a (300 GWh/a from King Grass gasification), as this covers a far larger share of the land (15 000 acres) under sugar cane cultivation as scenario 13. Scenario 14 (wind, PV, solid waste combustion and solid biomass combustion) was selected as well, as this scenario covers bagasse from 18 000 acres of sugar cane and has lower costs than scenario 13a. Scenario 11 (wind, PV and solid waste combustion) was selected as well, having the lowest cost of all 2035 scenarios analysed.

The different target scenarios diverge, based on the renewable energy sources utilised, on the following criteria:

- low cost of power
- employment generation
- public acceptance of power supply
- general participation (every household)
- solving the problems of agriculture.

On the other criteria of significant importance to the stakeholders interviewed the different target scenarios don't differ. With respect to the *cost of power*, the target scenario without any biomass performs best, but at the same time it does not contribute to the *solution of the agricultural problem*, while the two target scenarios performing best on the solution of the agriculture problem (lack of grass crop to continue intercropping agriculture), scenario 13a and 14, are the most expensive scenarios (see Table 13 and 14 below). The cost differences of 0.02 to 0.04 BBD/kWh (as compared to a cost level of about 0.4 BBD/kWh) are in the range of 5 - 10% of the total generation cost. With a total electricity demand of 1 350 GWh/a this difference translates into additional costs of 27 to 54 million BBD/a. This figure needs to be compared to the subsidies necessary to keep the sugar cane based agriculture going without any help from the future power generation.

On the objective of *employment generation* the target scenarios including the substantial use of biomass will have the greatest positive impact, as the employment in agriculture will have the largest domestic employment effect of all renewable energy technologies. This employment will either be secured through the continuous farming of sugar cane with the help of bagasse utilisation (if successful) or through the farming of King Grass for gasification on the same agricultural land, if the sugar production does not survive. Nevertheless, all 100% renewable energy scenarios will have far higher employment effects than the use of imported fossil fuels for power generation, as a far larger share of the cost of electricity will stay in Barbados' economy.

Public acceptance is critical for all four target scenarios as there are only gradual differences in the use of wind energy (at least 200 MW and 260 MW in the maximum case). As compared to solar PV wind energy is highly visible. This has lead to situations of low public acceptance in cases where the local population was not seriously involved in the development as well as in the investment. As shown by Mitchell (2004, p.1937) a badly planned introduction of wind energy combined with a lack of local involvement can lead to very strong and lasting public opposition to wind energy, while at the same time wind energy can reach very high diffusion rates (up to 5% of the total land area used for wind parks in parts of Schleswig-Holstein, Germany), when the investment is done in the form of citizen wind parks, with local farmers driving the process allowing for very broad local participation in the investment. As all scenarios without wind energy are substantially more expensive in Barbados, all target scenarios include a substantial share of wind energy. To achieve such a penetration of wind energy in Barbados a high degree of local ownership and participation in the development of wind energy will be necessary.

With respect to the objective of *general participation*, more or less a chance for every household to participate, solar PV performs well, as the smallest systems of a kilowatt or less can be installed by many households on their roofs. In the case of wind energy the threshold for participation as a single investor is far higher and starts in the range of about 1 million BBD. Nevertheless, as the international examples of citizen wind parks show, it is quite well possible to join in such an investment, if it is done by a large group of citizen investors. An other possibility is the investment by credit unions in wind parks, which allows a very widespread participation. Both approaches are applicable to larger solar PV installations as well. In the case of a waste combustion plant it is highly unlikely that this will be done in such form. Here it is more likely that a large investor either from the waste handling industry or a utility company will invest in a plant of 5 to 15 MW capacity. In the case of the 25 MW solid biomass combustion based on bagasse it is clear that this is an investment project of the cane industry. Thus, this is not a project for broad citizen participation. In the case of King Grass gasification a substantial number of farmers, eventually more than 50, can participate in this investment due to the modular size of the single installations of about 500 to 1000 kW each. So solar and wind can do very well on this objective, while the large single projects (waste and biomass combustion) are not performing well on this objective.

Concerning the four target scenarios it boils down to the weighing cost on one side and employment and solving the agricultural problem on the other. Target scenario with a modest share of biomass and still very low cost can be seen as a compromise with respect to meeting all criteria.

During the first years of the transition up to 2020 the main difference between the different transition pathways is the decisions whether or not to pursue the planned bagasse combustion. As this carries a substantial risk of ending up as stranded investment if the sugar production does not survive, it may not be the best choice to take this decision based on the present knowledge about the future development of the sugar industry in Barbados. At the same time the gasification of King Grass may provide an interesting alternative, which is independent of the production of sugar in Barbados and can solve the intercropping problem just as well as the farming of sugar cane. What is more, a gradual shift to the farming of King Grass for energy production can be done gradually, depending on the development of the international sugar markets and Barbados' sugar industry. At the same time it can be tailored to the need for agricultural land for intercropping other crops.

Based on the decision concerning the use of biomass for power production the market diffusion of wind and solar energy is somewhat different over time. Nevertheless, as the maximum difference between the scenarios is just 30% of the lowest market diffusion (200 MW wind and PV each in 2035), the diffusion paths don't differ much. A late decision for a low share of biomass in the energy mix can always be compensated by a somewhat faster diffusion of wind and PV in the later years of the transition period.

In the following work packages all four target scenarios will be used in the discussion of policies and support instruments.

With respect to storage it can be seen in Table 14 below that the scenarios including King Grass gasification don't need storage in 2025, while the other two scenarios, scenario 11 without biomass and scenario 14 with the solid biomass combustion, benefit of substantial storage as early as 2025. Thus, a decision for the 25 MW bagasse combustion plant implies a relatively early construction of a substantial pump storage facility just as a development not using biomass at all, based exclusively on wind and solar PV with some additional waste combustion, will need substantial storage by 2025 due to the faster growth of wind and solar PV. As large pump storage plants have a lead time from the beginning of a pre feasibility study to commercial operation of five to eight years, it may be necessary to seriously advance such plans within the next years in order to have sufficient storage available at the time needed during the transition.

Table 14 shows as well that target scenarios for 2035 with a demand of 1,350 GWh/a will have the lowest electricity costs if the storage is as large as 5 GWh. This is substantially larger than the storage volumes discussed so far (see Hohmeyer 2015), where 3 GWh were seen as sufficient for a target system of about 1,050 GWh/a.

The four pathways developed will be used in later work packages for the evaluation of different market mechanisms and policies to introduce and steadily diffuse the different renewal energy technologies into the power generation of Barbados

Table 13: Four target scenarios for 100% RE power supply in 2035 and transition pathways to these target scenarios

Scenario / Wind year 2011		Year	Annual power demand	LCOE	Installed capacities and annual generation									
					Wind		PV		King Grass		Bagasse and river tamarind combustion		Solid wate combustion	
No.	Name			BBD/ kWh	MW	GWh/ a	MW	GWh/ a	MW	GWh/ a	MW	GWh/ a	MW	GWh/a
11	100% RE / Wind / PV / WTE combustion	2015	950		0		10	19					0	
		2020	1050	0.3664	25	114	55	113					5	34
		2025	1150	0.3002	105	481	125	258					11	74
		2030	1250	0.3123	185	847	195	403					11	74
		2035	1350	0.3883	265	1213	265	547					11	74
13	100% RE / Wind / PV / King Grass / WTE combustion	2015	950		0	0	10	19	0	0			0	0
		2020	1050	0.3696	20	92	65	134	2	5			5	34
		2025	1150	0.3253	90	412	120	248	10	30			11	74
		2030	1250	0.3161	160	733	175	361	18	75			11	74
		2035	1350	0.4004	232	1062	232	479	26	120			11	74
13 a	100% RE / Wind / PV / King Grass / WTE combustion	2015	950		0		10	19	0	0			0	
		2020	1050	0.3749	20	92	50	103	2	5			5	34
		2025	1150	0.3354	80	366	100	206	14	45			11	74
		2030	1250	0.3451	140	641	150	310	27	150			11	74
		2035	1350	0.4331	200	916	200	413	40	300			11	74
14	100% RE / Wind / PV / Bagasse / WTE combustion	2015	950		0	0	10	19			0	0	0	0
		2020	1050	0.3807	20	92	65	134			25	169	5	34
		2025	1150	0.3452	85	389	120	248			25	169	11	74
		2030	1250	0.3609	170	778	175	361			25	169	11	74
		2035	1350	0.4143	219	1003	219	452			25	169	11	74

Table 14: Four target scenarios for 100% RE power supply in 2035 and transition pathways to these target scenarios. The development of the need for storage during the transition period.

Scenario / Wind year 2011		Year	Annual power demand	LCOE	Installed capacities and annual generation							Total overproduction
					Diesel/ Biodiesel		Storage volume	Storage generation		Storage pumping		
No.	Name			BBD/ kWh	MW	GWh/ a	MWh	MW	GWh/ a	MW	GWh/ a	GWh/a
11	100% RE / Wind / PV / WTE combustion	2015	950		239	950						
		2020	1050	0.3664	140.9	789						0
		2025	1150	0.3002	148.8	354	3000	150.5	60	90	80	17
		2030	1250	0.3123	162.2	118	5000	186.3	176	220.7	202	192
		2035	1350	0.3883	166.7	50	5000	196.8	205	307	238	400
13	100% RE / Wind / PV / King Grass / WTE combustion	2015	950		239	950	0	0	0	0	0	0
		2020	1050	0.3696	140.2	785						0
		2025	1150	0.3253	148	422						36
		2030	1250	0.3161	155.6	164.4	5000	178	142	162.8	163	157.4
		2035	1350	0.4004	144.8	50	5000	172.9	163	253.4	190	435
13 a	100% RE / Wind / PV / King Grass / WTE combustion	2015	950		239	950						
		2020	1050	0.3749	140.2	816						0
		2025	1150	0.3354	140.5	469						10
		2030	1250	0.3451	135.3	168	5000	156	97	131.5	110	93
		2035	1350	0.4331	131.6	50	5000	156.8	129	199.8	151	403
14	100% RE / Wind / PV / Bagasse / WTE combustion	2015	950		239	950	0	0	0	0	0	0
		2020	1050	0.3807	121.7	621						0
		2025	1150	0.3452	129.9	286	5000	138.4	56	85.3	75	16
		2030	1250	0.3609	139.4	133	5000	165	157	181.4	181	265
		2035	1350	0.4143	151.9	50	5000	180.6	176	248.3	205	398

WORK PACKAGE 9: DISCUSSION OF POSSIBLE MARKET MECHANISMS AND POLICIES FOR THE SUCCESSFUL INTRODUCTION OF RENEWABLES IN BARBADOS

Due to the fact that most of the environmental and health benefits of renewable energy technologies as well as economic benefits like the reduction of necessary fuel imports for power production are external to the market process the cost savings to society don't show up in market prices (see e.g. Hohmeyer 1988, Ottinger et al. 1990). Thus, although the use of renewable energy sources may be highly beneficial to a country like Barbados, market prices alone will not bring about the implementation of renewable energy technologies for power production. This fact has lead many countries of the world to enact policies to support the market introduction of technologies utilising renewable energy sources. As early as 1990 Germany introduced the first so called Feed-in tariff (FIT), while the United Kingdom introduced an auctioning system for all non fossil fuels (NFFO) in 1989/90, which was succeeded by renewables obligations in 2002 after the auctioning under NFFO had failed to reach the set targets. Many federal states of the US introduced so called renewable portfolio standards (RPS) mostly between 1997 and 2010. In the early stages of renewable energy policies many countries have introduced net metering for limited volumes of renewable energy capacity as a simple first measure for the promotion of renewable energy sources.

Before such preferential policies were established some utility companies offered to pay the variable costs of power production replaced by the renewable electricity for each kilowatt-hour feed into the grid, but many times utilities, possessing regional monopoly status, even refused to buy any electricity from independent power producers, which was produced with renewable energy technologies. Most of the time there were no laws to mandate the buying of such electricity by utility companies. Such was the situation in Germany until the first FIT was established in 1990.

All of these policies for the promotion of renewable energy production have in common that they establish separate markets or market conditions for renewable energy sources, but they approach the problem in different ways. Net metering pays the full consumer price for the renewable electricity produced. Net billing pays a lower fixed price for produced by consumers while it charges the full consumer tariff for the electricity consumed. FITs (feed-in tariffs) establish separate tariffs for renewables, at which these can be sold to the grid. By doing so they set a price, which is considered a fair and appropriate price for electricity produced from renewable energy sources taking into account differences between the external costs of conventional and renewable power production. As the quantification of external costs is difficult and sometimes depending on value judgements (see Hohmeyer 2002), FITs are seen as incorporating external costs in a very rough manner (see Lipp 2007, p.5488). Under an FIT regime the tariffs are set by a public authority, most of the time based on a scientific assessment of the cost of the technologies in question. In auctioning the policy sets a certain quantity target for the market share of renewable energy sources to be met at a certain point in time. This longer term quantity target is then broken down into single rounds of auctioning/tendering, where the price is either set by the final bid necessary to achieve the volume auctioned (marginal bid price) or each successful bidder is paid the price he has bid for in the auction (pay as bid). In a renewable portfolio standard (RPS) longer term targets for the share of renewables are set (e.g. 15% by year 2020) and all companies selling electricity to final consumers have to prove that their power production portfolio contains the necessary share of renewable energy. Thus, auctioning as well as renewable portfolio standards are quantity policies while net-metering and FITs are price policies. If there is full information on the marginal cost curve of a given renewable energy technology quantity and price policies targeting a certain quantity of renewable energy to be produced will theoretically lead to the same result (see e.g. Lamy et al. no year, p.5). Nevertheless, such situation of full information is hardly ever given.

By 2016 net metering was used in 52 countries (see REN 21 2016, p.114), FITs were established in 75 countries plus 35 federal states (see REN 21 2016, p. 109), while auctioning, referred to as competitive bidding or tendering as well, has been established in 65 countries (see REN 21 2016, p.111). Renewable portfolio standards (RPS) were in place in 26 countries and in 74 federal states or provinces (see REN 21 2016, p.114). In total 114 countries throughout all parts of the world had one or the other policy for the support of renewable energy technologies in place by the end of 2015 (see REN 21 2016, p.112).

To understand the advantages and disadvantages of the different policies one has to go into some details of each policy.

Net metering and net billing

Net metering and net billing are policies normally offered to electricity consumers, who operate a renewable energy plant mostly to cover their own consumption. Net metering is a very simple policy as the electricity produced by e.g. a solar PV installation on the roof of a private household substitutes the electricity which would normally by bought by that household from the grid. As this principle is applied to the annual sum of all electricity produced, even if at times when the PV installation produces more electricity than the household consumes in a given hour, the household is only charged with the price for the net number of kilowatt-hours supplied from the grid (number of total kilowatt-hours supplied from the grid minus number of kilowatt-hours fed into the grid from the solar installation). For small installations and small shares of renewable power in the system this is a very simple and straight forward policy, as it does not need any additional price or quantity setting by policy makers or public authorities. As Hughes and Bell (2006, p.1536) have pointed out, there are about eight different ways to set up a net metering system depending on the way excess production is treated (not paid for, banked or bought at a certain buy-back rate). The renewable energy rider (RER) established in Barbados in July 2010 on a two year trial basis (see Fair Trade Commission 2010, p.7) was a mixture of net metering and a bonus payment for the excess electricity feed into the grid, which was originally set at 1.8 times the fuel adjustment clause, which is basically representing the avoided fuel costs of BL&P, or at a minimum of 31.5 cents/kWh (see Fair Trade Commission 2010, p.22). Such premium payments are rare cases, but there were good arguments concerning the value of the energy, which led to the premium payment.

The main disadvantage of net metering is the fact that the producer of renewable electricity is relieved from the payment of all power system costs for each kilowatt-hour he is producing for his own consumption, although, he is still fully relying on all grid services to supply his electricity whenever his own production is not sufficient to meet his power consumption. These system costs are e.g. the cost for the grid, the cost for the full back-up capacity and the cost for all grid services like frequency and voltage stabilisation. As more and more renewable energy installations are connected to the grid, these system costs are concentrated more and more on the bills of customers not operating any form of renewable power production (see Hunter 2015). Eventually, the poorest households will have to shoulder most of these costs while the richer households enjoy the benefits of the system. It is obvious that net metering can not be used for any substantial share of a countries power production.

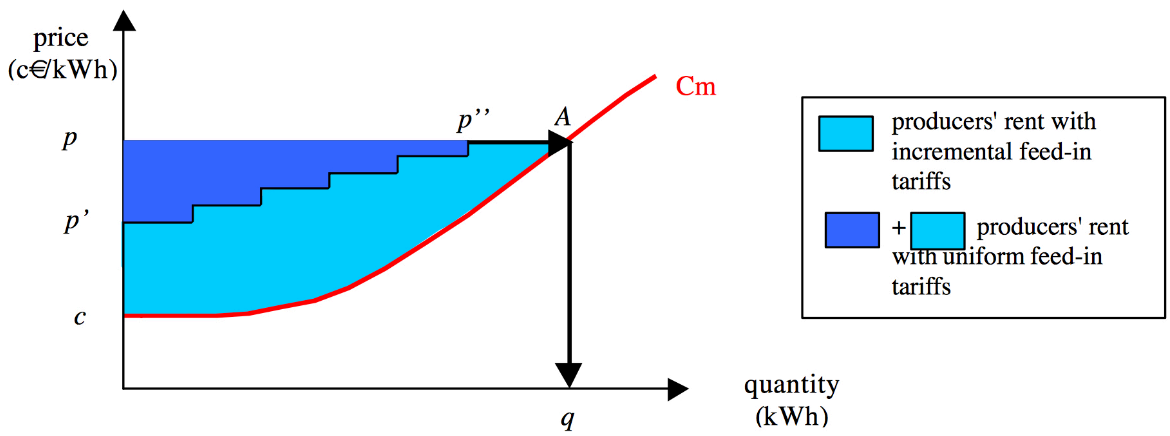
Net billing is avoiding this disadvantage of net metering as it separates the payments for the electricity produced by the renewable energy installation, which is bought at a fixed buy-back rate, while the energy consumed is charged the full consumer rate (see Hughes and Bell 2006, p. 1535). Depending on the compensation arrangement eight sub-types are described by Hughes and Bell (2006, p. 1536), which differ in the buy-back policy, the banking policy and the buy-back rate. Blechinger et al. (2012, p. 1) describe net billing as a feed-in tariff below retail price. Like net metering net billing aims at smaller installations, which are predominantly operated to supply the own consumption of a private or small commercial electricity consumer (customer generators), which are distinct from independent power producers (IPPs), who are primarily in the business of electricity generation (see Hughes and Bell, 2006, p. 1533).

Feed-in Tariffs

Feed-In Tariffs have started as an attempt to increase the payment for electricity produced from renewable energy sources to a level at which they can enter into the power market at a reasonable return to the operator of any such technology. FITs are always combined with a mandate for the utility company to buy all renewable electricity produced from any renewable energy source delivered to the grid and sometimes they are combined with the obligation to extend and improve power lines to enable the uptake of all electricity produced from renewable energy sources in the area of a grid operator.

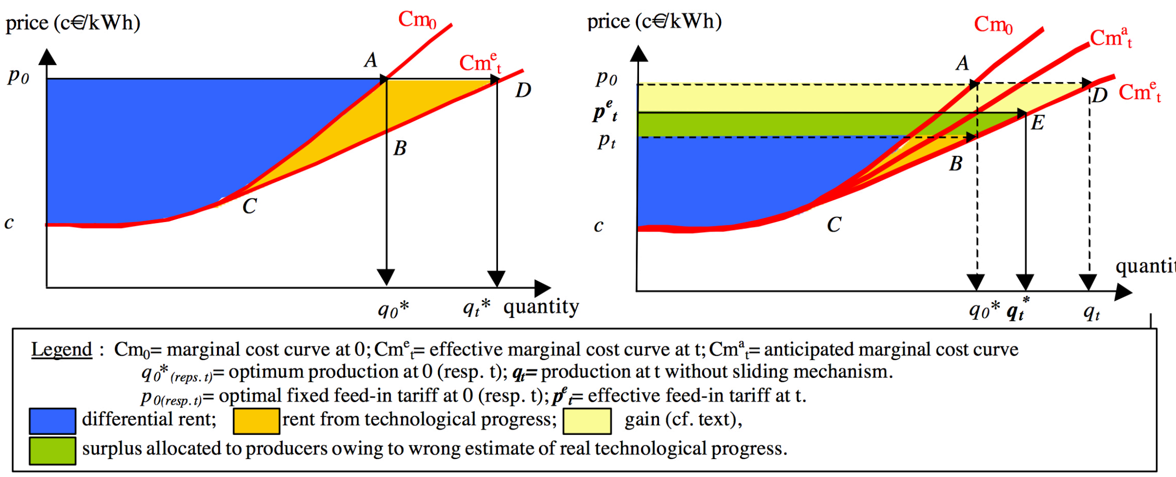
Feed-in tariffs are normally differentiated by the renewable energy source used, by the size of the system and by the conditions at a given site (incremental feed in tariff). The later is important for wind energy, as the output from a given turbine can vary extremely with the prevailing wind speeds, as the output from the system increases with the third power of the wind speed (v^3). Even in a relatively small country like Barbados the output of a wind turbine can easily differ by factor 2 to 3 depending on the very location of the turbine. Even considering just the best areas for wind energy in Barbados the output from the same turbine can be about 70% higher in the best location as compared to the least favourable of the good locations (see Rogers 2015). Figure 37 shows how a fixed and an incremental Feed-in tariff works and how an incremental Feed-in tariff can limit excessive producers rents on very good sites. The differentiation between different sites or different installation sizes allows the incremental FIT to follow the shape of the marginal cost curve and the producer and surplus can be limited to a reasonable amount.

Figure 37: Producers' rents under uniform and incremental FITs (source: Lamy, no year, Graph 1)



Feed-in tariffs are normally guaranteed for fifteen or twenty years from the day of the first production in order to secure high bankability of the investment leading to low financing cost. In order to assure that the tariffs capitalise on the reduction of technology cost over time (see e.g. Chapter 2 for the development of PV cost over time), the tariff is reduced every year by a given percentage and is reviewed in a given interval (two to four years). Figure 38 shows how a sliding FIT can capture at least some part of the future cost reductions due to technological progress.

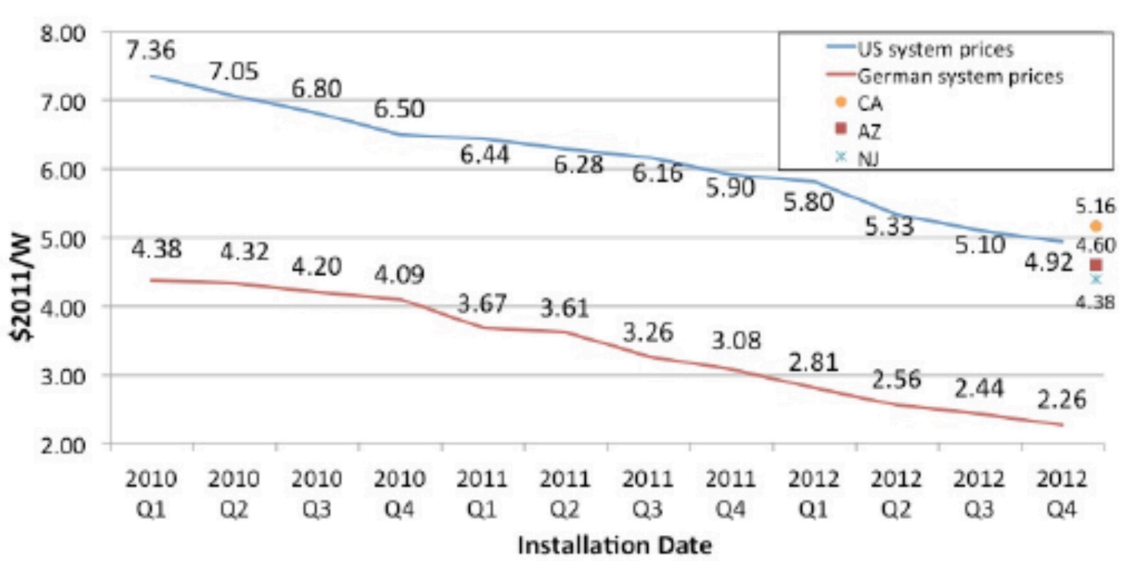
Figure 38: Technological progress and fixed (left) versus sliding (right) FIT to capture technological progress (source: Lamy, no year, Graph 7)



The payments for the FIT are made by the grid operator, who collects the money as part from every customer as FIT levy. If there is a power exchange the grid operator sells the renewable electricity at the prevailing hourly prices at the power exchange and collects the remaining difference through an FIT levy charged to each customer. Thus, no public funding or taxpayers money is involved in the financing of FITs. With increasing shares of renewables the FIT levy may become a major part of the consumer electricity rate. Simultaneously the cost for conventional generation will constitute a decreasing share of the consumer rate.

It has been argued that FITs will by tendency be set too high, as the public authority setting the tariff does not have the full information of all market participants. Thus, an incentive system utilising the full market information (like auctioning or renewable portfolio standards) should be able to produce lower cost. So far this advantage has not materialised in reality, as can be seen in the market prices for PV installations in Germany (FIT system) as compared to the United States (RPS system). Both countries are large PV markets, but historically the prices for PV systems and the payments for PV electricity have been considerably lower in Germany than in the US (see Figure 39 below and Chapter 2.2 above).

Figure 39: Median installed price of customer owned PV systems <= 10 kW (source: Seel, Barbos and Wyser 2013, p.3470)



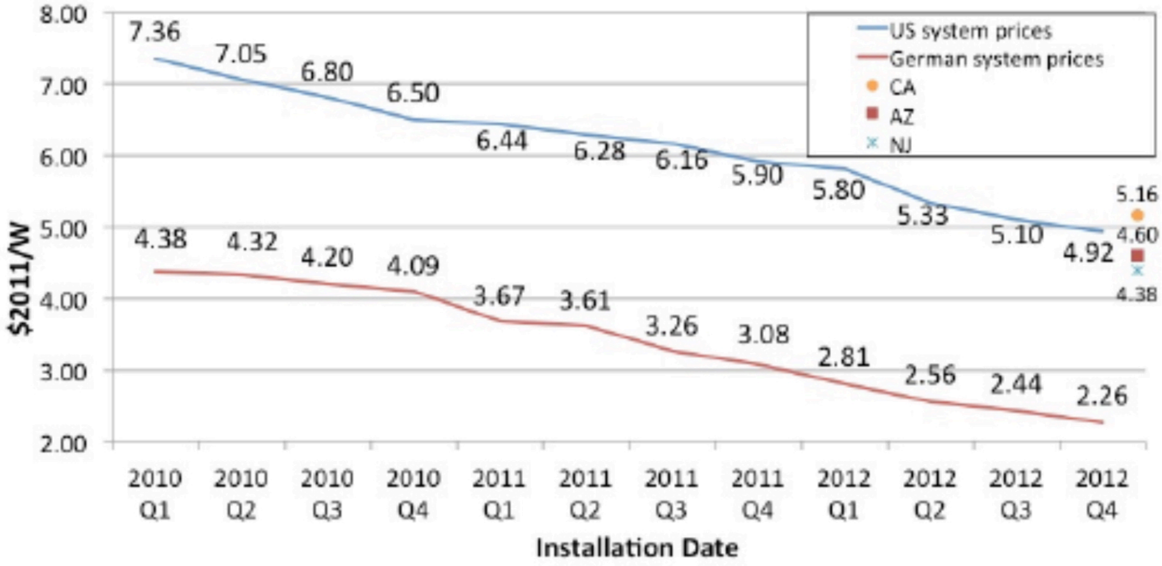
Seel, Barbos and Wyser (2013, p.3473) show that the lower system costs in Germany have a multitude of reasons. Experience shows that lower financing costs due to the very good bankability under a FIT system enable the investment even further by better bankability and lower interest rates for loans. Thus, the claimed advantage of strongly market based policies have not materialised during the last 25 years.

A disadvantage of FIT systems can be the reaction time to fast market developments. This can be seen in the past development in Germany, where the FIT rates for PV were evaluated by parliament every two years after 2004. Due to a scarcity of solar grade silicon production capacities in the market between 2003 and 2006 module prices actually did not decrease according to the cost digression reached (see Figure 20 in Chapter 2), but they slightly increased during these years leading to a constantly high FIT for PV. In the years 2007 and 2008 module prices decreased only a little. After substantial additional production capacity entered the market in 2009 module prices dropped sharply for five years making up more than the expected cost decrease. As prices dropped substantially every month and as this development was not foreseen in the FIT digression structure, the possible margins to be earned with PV investments increased tremendously. This led to an increase of the annual installation from less than 2 GW in 2008 to about 4.5 GW in 2009 and more than 7 GW in 2010, 2011 and 2012. The installed capacity increased from 6.1 GW in 2008 to more than 33 GW PV in 2012 (see Quaschning 2017). During these years many institutional investors discovered PV as a very safe investment with exceptionally high returns. Investment fonds rating different types of investments for their customers rated PV investments as save as German government bonds, while they rated their return as high as very risky investments in shipping or airplanes, yielding a return in the range of 10%, while German government bonds where yielding negative returns of about -0.15%. This return structure explains, why the investment in PV boomed during the years 2009 to 2012. Finally the government switched to lowering the FIT for PV on a quarterly and even monthly basis to follow the fast drop in PV prices and to lower the margin of investors to a reasonable rate again. The FIT rate for rooftop-mounted PV installations up to 30 kW decreased from 0.574 Euro/kWh in 2004 to 0.4675 Euro/kWh in 2008 and 0.3914 Euro cent by the first half of 2010. Due to the sharp drop in PV system prices the adjustment cycle of the tariff was shortened to three month by mid 2010. Thus, the rate was dropped to 0.3405 Euro/kWh by July 2010 and to 0.3303 Euro/kWh by October 2010. It was further dropped to 0.2874 Euro/kWh in 2011 and 0.2443 Euro/kWh by January 2012. From May 2012 to October 2012 a monthly reduction by 1% was introduced. This monthly reduction was kept until 2014, but the percentage of reduction was actually varied. Details can be seen in Table 15a and 15b below. Seel, Barbos and Wyser (2013, p.3474) show how well the adjustment of the FIT worked reducing the gap between the FIT and the system cost drastically between January 2010 and July 2012 (see Figure 40 below). Although, this adjustment process did not go very smoothly and left rather substantial returns to be earned until 2012, a tremendous reduction in solar PV cost was induced allowing a reduction from 0.54 to 0.13 Euro/kWh or to less than 25% within ten years.

This extreme situation shows the main disadvantage of FITs, if there is a very fast and continuous drop in investment costs in the market, which policy can only follow with substantial delay. Nevertheless, once the trend becomes clear it is quite possible to adjust the mechanism to such development. Until policy is on top of the development the payment for the renewable electricity fed into the grid will be too high.

In export intensive economies, like in Germany, policy makers may decide to exempt energy intensive businesses from the payment of the FIT levy. As long as the total sum of the FIT payments is low, this does not cause a problem, but with increasing shares of renewables in the energy mix this can lead to relatively high FIT levies for the rest of the electricity customers. If such situation is combined with an open power market, at which the grid operator sells the renewable electricity bought from the producers of renewable electricity, this may lead to a situation where average power prices drop whenever there is

Figure 40: German residential PV system prices and value of FIT payments in high and low solar regions in Germany (source: Seel, Barbos and Wyser 2013, p.3474)



much PV or wind energy production. This has lead to substantially decreasing power prices at the German power exchange during the last years. So energy intensive businesses, not paying the FIT levy actually are enjoying substantially lower power prices than in a situation without renewable energy production, while all other customers, paying the FIT levy are confronted with significantly higher power prices, subsidising the reduced power prices for the energy intensive industries. This development and the early installation of large volumes of very expensive PV systems have lead to a rather significant FIT levy in Germany, which is subsidising vastly increased power exports, as these are exempted from the FIT levy as well. Such developments could easily be counteracted if policymakers would decide to act on the problem (see Hohmeyer 2014). Considering the necessary FIT levy for countries switching to renewable power today the necessary FIT levy will in most cases be lower than the possible reductions of the conventional power production cost achieved by the introduction of a growing share of renewable energy sources, as Hohmeyer has shown for Barbados (Hohmeyer 2015) and the Seychelles (Hohmeyer 2016, 2016a).

Table 15: Development of the German FITs for solar PV 2004 to 2014 (source: Wikipedia 2017, Feed-in tariffs in Germany)

Table 15a: 2004 to 2012

Type		2004	2005	2006	2007	2008	2009	2010	July 2010	October 2010	2011	January 2012
Rooftop-mounted	up to 30 kW$_p$	57.40	54.53	51.80	49.21	46.75	43.01	39.14	34.05	33.03	28.74	24.43
	above 30 kW$_p$	54.60	51.87	49.28	46.82	44.48	40.91	37.23	32.39	31.42	27.33	23.23
	above 100 kW$_p$	54.00	51.30	48.74	46.30	43.99	39.58	35.23	30.65	29.73	25.86	21.98
	above 1000 kW$_p$	54.00	51.30	48.74	46.30	43.99	33.00	29.37	25.55	24.79	21.56	18.33
Ground-mounted	conversion areas	45.70	43.40	40.60	37.96	35.49	31.94	28.43	26.16	25.37	22.07	18.76
	agricultural fields	45.70	43.40	40.60	37.96	35.49	31.94	28.43	—	—	—	—
	other	45.70	43.40	40.60	37.96	35.49	31.94	28.43	25.02	24.26	21.11	17.94

Installations on agricultural fields were removed under the PV Act (2010).

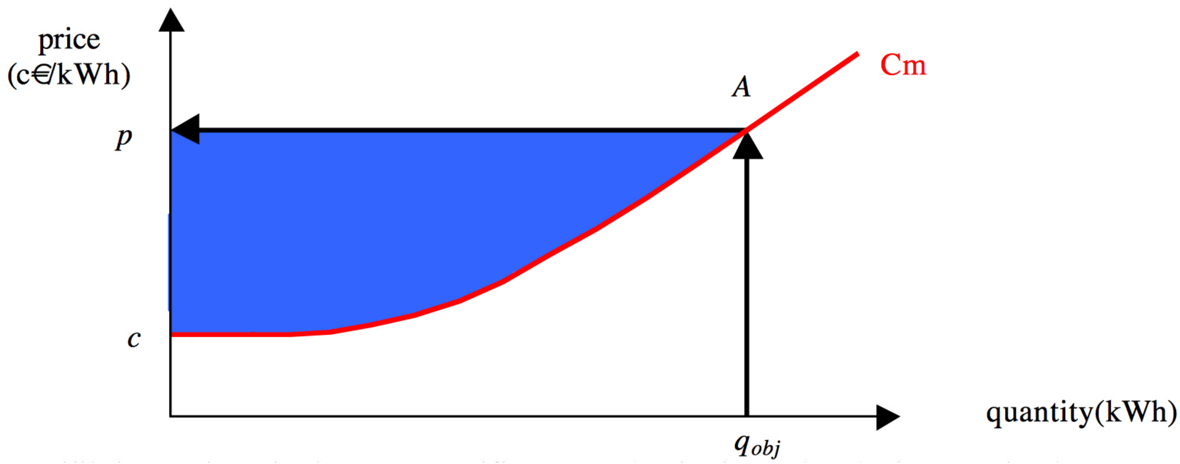
Table 15b: 2012 to 2014

Year	Month	Degression	Rooftop mounted				Ground mounted
			up to 10 kW$_p$	up to 40 kW$_p$	up to 1 MW$_p$	up to 10 MW$_p$	up to 10 MW$_p$
2012	April	—	19.50	18.50	16.50	13.50	13.50
	May	1.0%	19.31	18.32	16.34	13.37	13.37
	June		19.11	18.13	16.17	13.23	13.23
	July		18.92	17.95	16.01	13.10	13.10
	August		18.73	17.77	15.85	12.97	12.97
	September		18.54	17.59	15.69	12.84	12.84
	October		18.36	17.42	15.53	12.71	12.71
	November	2.5%	17.90	16.98	15.15	12.39	12.39
	December		17.45	16.56	14.77	12.08	12.08
2013	January		17.02	16.14	14.40	11.78	11.78
	February	2.2%	16.64	15.79	14.08	11.52	11.52
	March		16.28	15.44	13.77	11.27	11.27
	April		15.92	15.10	13.47	11.02	11.02
	May	1.8%	15.63	14.83	13.23	10.82	10.82
	June		15.35	14.56	12.99	10.63	10.63
	July		15.07	14.30	12.75	10.44	10.44
	August	1.8%	14.80	14.04	12.52	10.25	10.25
	September		14.54	13.79	12.30	10.06	10.06
	October		14.27	13.54	12.08	9.88	9.88
	November	1.4%	14.07	13.35	11.91	9.74	9.74
	December		13.88	13.17	11.74	9.61	9.61
2014	January		13.68	12.98	11.58	9.47	9.47
	February	1.0%	13.55	12.85	11.46	9.38	9.38
	March		13.41	12.72	11.35	9.28	9.28
	April		13.28	12.60	11.23	9.19	9.19
	May		13.14	12.47	11.12	9.10	9.10
	June		13.01	12.34	11.01	9.01	9.01

Renewable Portfolio Standards

Renewable Portfolio Standards try to avoid the pitfalls of FITs as they simply set a quantity target to be fulfilled by every company selling electricity to final customers. To enable the lowest cost to be realised in the market the tradable certificates for every kilowatt-hour of renewable electricity produced are given to the producers of renewable electricity. Sometimes differentiated for large and small installations like in the case of Australia, where Large-scale Generation Certificates (LGC) and Small-scale Generation Certificates (SGC) are traded as different commodities. As the certificates are standardised they can be traded freely in the market. Thus, the company selling electricity to final consumers can buy or produce any kind of electricity, it just needs to buy enough renewable energy certificates (or produce renewable electricity) to meet the set standard. On the other hand the producers of renewable electricity sell their electricity in the normal power market at the prevailing price of each hour. Theoretically, these mechanisms should lead to a situation in which the producers with the lowest costs will produce renewable electricity and the set quantity target will be reached at minimum cost. Nevertheless, RPS allocate the total producer surplus to the producers as they can not differentiate between good and not so good sites or between large and small installations. Figure 41 shows the basic principle of the function of an RPS and its impact on producer rents.

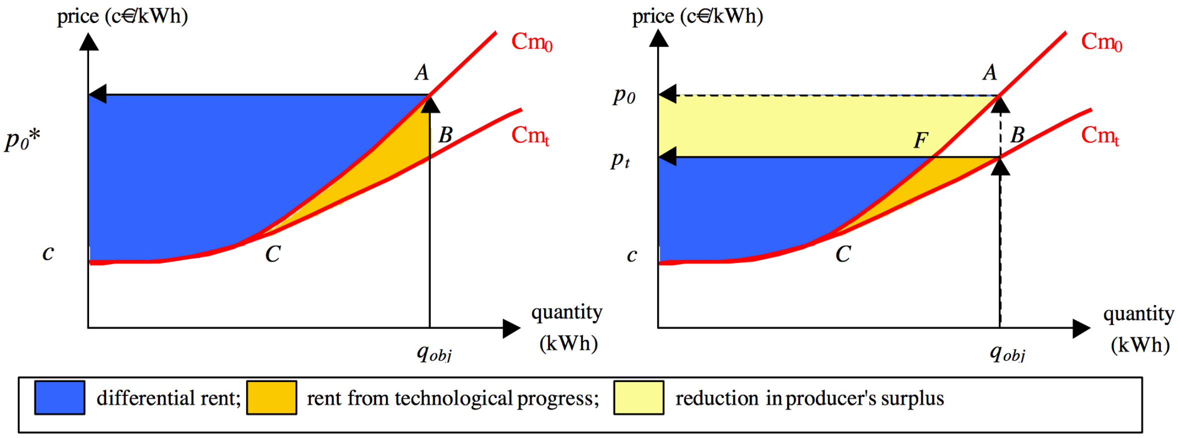
Figure 41: Operation of renewable portfolio standards and green certificates and the allocation of the producers rent (source: Lamy, no year, Graph 3)



In the case of technical progress cost reductions are easily captured by RPS as the certificate prices is set by the market progress which has the information on eventual cost reductions due to technological progress. Figure 42 shows how the price adjustment follows the cost reduction and how the producer surplus in reduced.

Unfortunately, the theoretical consideration, asserting that RPS should produce lower cost solutions than FITs, misses out on the high risk that investors in technologies for power production from renewable energy sources are subject to. Different from the payments under an FIT system, which guarantee a discounted cash flow for twenty years, if a reliable technical system is installed, the investor does not know his future income neither from the sale of electricity in the power market nor from the sale of renewable energy certificates. As Figure 43 shows the price for renewable certificates (in this case LGCs

Figure 42: RPS/green certificates markets and the impact of technological progress on prices and producers rent (source: Lamy, no year, Graph 5)



in Australia) can fluctuate vastly. In the case of LGCs the monthly average price starting at about 31 AUSD fluctuated anywhere between 11 and 54 AUSD over the period of fifteen years. If the sales of certificates are combined with the electricity sales in power markets a similar picture remains as Figure 44 shows. Between 2003 and 2012 the average annual return in Australian dollars per Megwatt hour fluctuated between 60 and 120 AUSD/MWh. Even elections can have very significant impacts on the total revenues earned by a given renewable energy installation.

Figure 43: Price fluctuations of spot price for Large-scale Generation Certificates for renewable electricity in Australia between June 2001 and June 2015 (source: Parkinson, 2015)

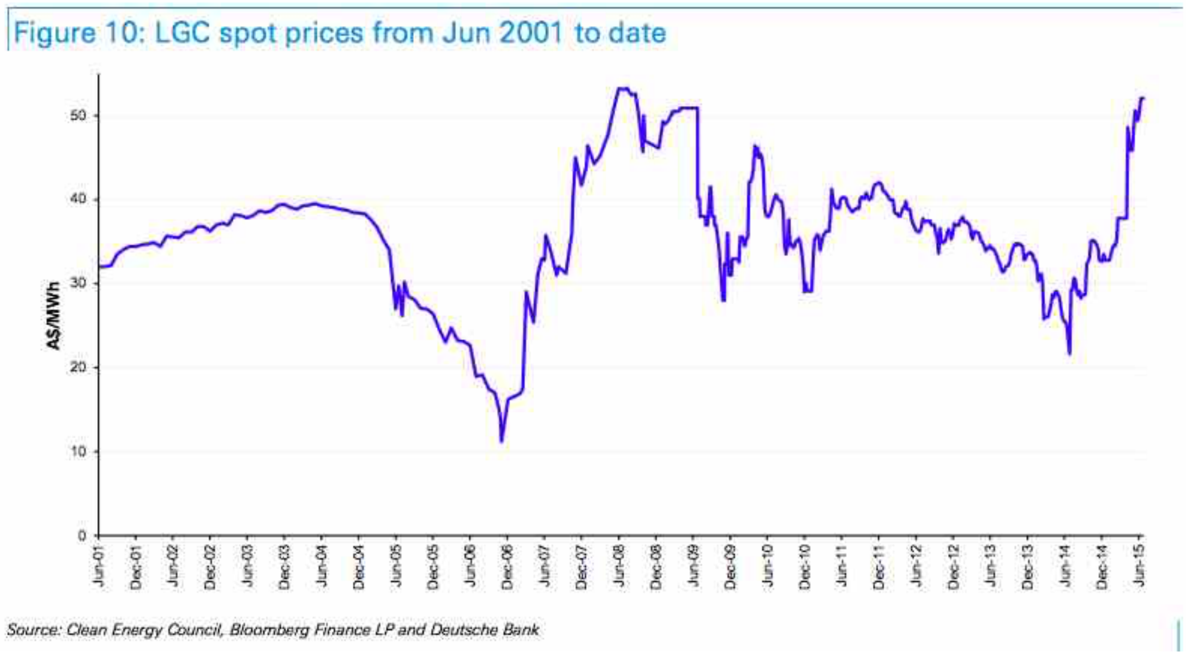
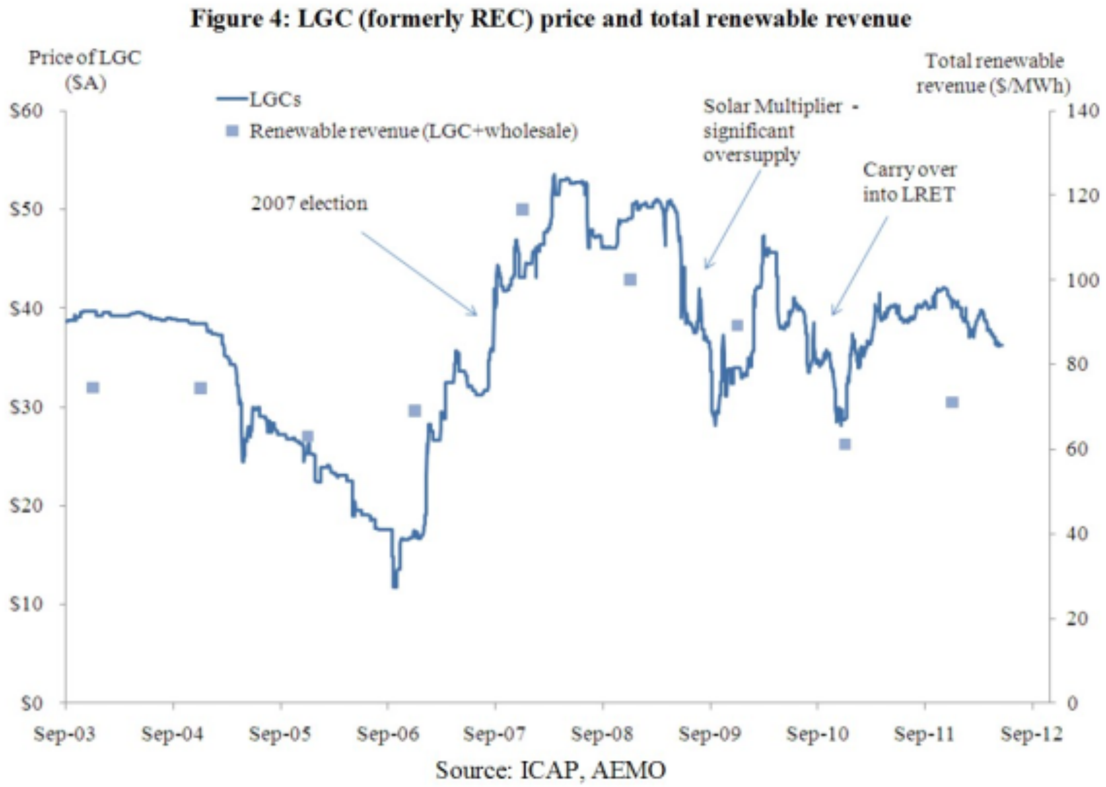


Figure 44: Price fluctuations of spot price for Large-scale Generation Certificates (LGC) and total revenue for renewable electricity including revenues from electricity sold a the spot market for renewable electricity in Australia from September 2003 to September 2012 (source: Morton 2017, Figure 4)



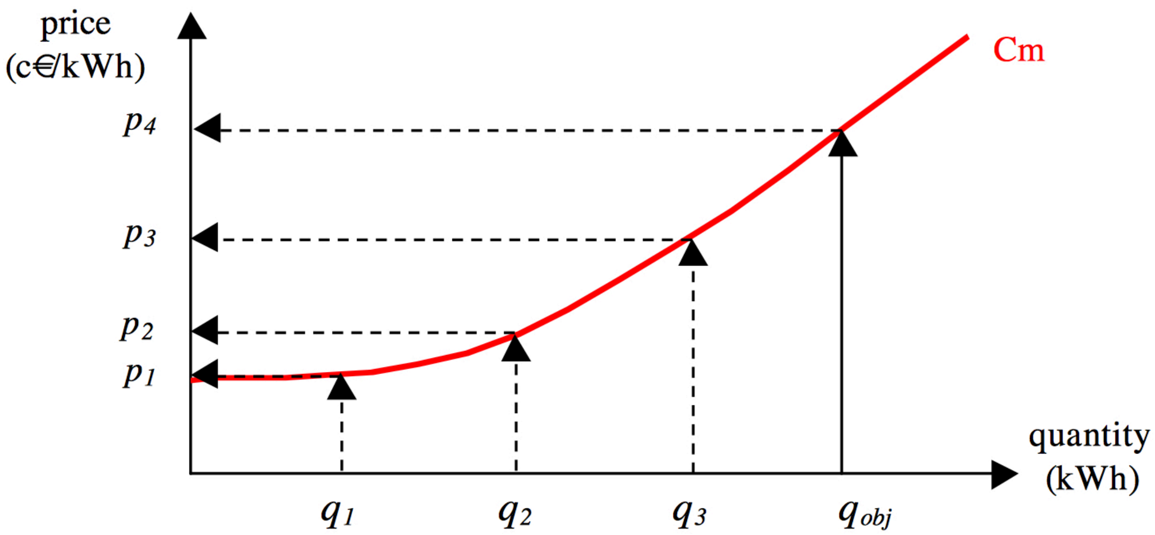
It is obvious that the income flow for a renewable energy investment can not be predicted with any sufficient degree of reliability. Thus, banks financing renewable energy investments under such regime will need to ask for a high risk margin in order to secure their loans. For the investor a renewable energy investment becomes highly speculative, thus, every investor will ask for a very high return to compensate him for the possible risk of bankruptcy. He is actually faced with the opposite situation of the investment under a guaranteed FIT regime. Reuter et al. (2012) show that risk perception can increase the levelized cost of electricity (LCOE) for the same wind site from 79 to 102 Euro/MWh if uncertainty about future payments increase (Reuter et al. 2012, p.253). Although, the calculation is carried out for the risk perception of a set FIT to be changed in the future, this can be seen as a good indication for the impact of the uncertainty in the returns on green certificates. As Langniß (2003) has shown this structural property of RPS systems leads to a concentration of the renewable investments in the hands of large investors with a substantial capacity to absorb the risk of single investments and a strong enough capitalisation to reap the benefits of speculation gains. In a small island state like Barbados an RPS system would either lead to the concentration of all renewable energy investments in the hands of a few very large domestic investors or it would need to invite international investors to create a sufficiently wide investor basis. In any case an RPS system would lead to very high renewable power production costs, as these would need to absorb all necessary risk premiums. What is more, the market for renewable electricity certificates would certainly lack the necessary level of volatility with only a few sales being made and only one power company being obliged to adhere to the quantity targets set by the RPS policy.

It is fair to conclude that RPS systems are not suitable for any small isolated power market like in the case of most SIDS and especially in the case of Barbados.

Auctioning

Auctioning (called tendering or bidding as well) of renewable production capacities is trying to combine a lower risk about future payments for renewable electricity produced, similar to FITs, with a market mechanism to find the lowest possible rate necessary to be paid for a kilowatt-hour of renewable electricity. If there are enough bidders to create a highly competitive bidding process in the auction, auctioning should lead to lower renewable energy costs than FITs, as the bidders know their production cost structures better than any state agency could ever estimate such costs. There two main types of actions, strike price auctions and pay-as bid auctions. In a strike price auction every successful bidder gets the price of the marginal bid reaching the actioned quantity. In this case the producer rents is allocated like in the case of RPS with green certificates (see Figure 54 above). In a pay-as-bid auction every bidder receives the price for which he has been bidding. In this way the auction can actually pay exactly according to the underlying cost curve, if perfect competition can be realised. Figure 45 shows the prices payed as a result of a pay-as-bid auction.

Figure 45: Prices according to a pay-as-bid auction (source: Lamy, no year, Graph 2)

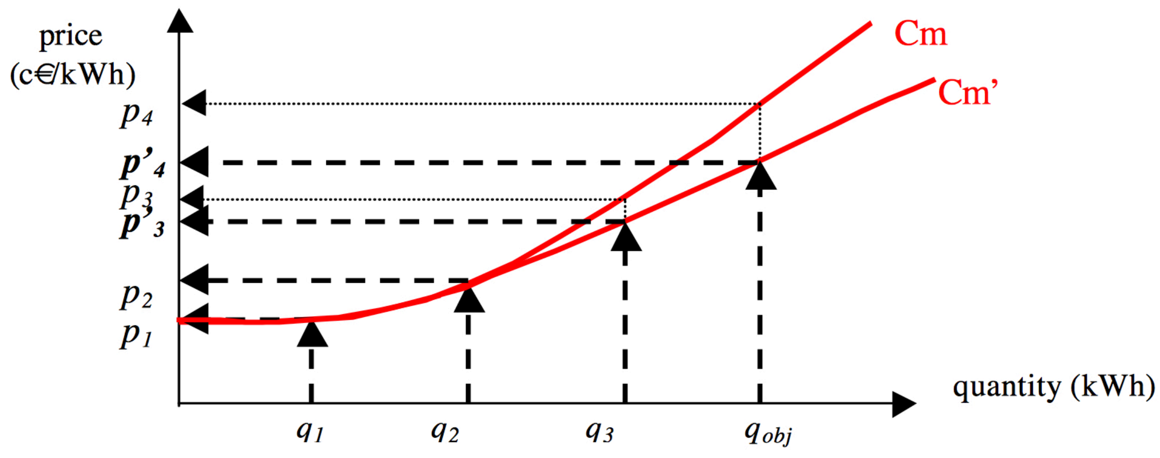


Auctioning can accommodate cost reductions due to technological learning as easily as RPS with green certificates, as the information on technological progress can be incorporated into the bids directly, as Figure 46 shows. Nevertheless, NFFO 4 and 5 have shown that this may turn out to be a trap for optimistic bidders under the circumstances of a substantial grace period until the capacity has to be installed (see below).

Furthermore, both forms of auctioning can lead to lower costs as compared to renewable portfolio standards (RPS), as auctioning can avoid the high risk premiums necessary for the economic survival of renewable energy projects under RPS (see above). In an auctioning system the rates, once granted after the auction, are fixed for a given time frame just like in an FIT system.

The first auctioning framework for renewables was created in 1989 in the United Kingdom as part of the NFFO (Non Fossil Fuel Obligation) system and it made up the core of the UK renewable energy policy for

Figure 46: Auctioning and the accommodation of cost reductions due to technological progress (source: Lamy, no year, Graph 6)



about ten years (see Agnolucci 2005, p.1). It was created as a side aspects of the attempt of the British government to privatise nuclear power plants, which proved not to be competitive to coal based power production in the liberalised UK power market (see Mitchell 2004, p.1936). Therefore, NFFO was designed to create an additional payment for new nuclear capacity, which in the times of power market liberalisation would not have been built. As Mitchell (2004, p.1936) reports there was actually no policy target for the implementation on renewable energy sources at the time of the first round (NFFO 1), although this was set at 600 MW, when the NFFO contracts were announced. What is more, two thirds of the contracts was with renewable power plants already generating and the payments per kWh were agreed between the civil servants and the operators before these entered their bids (see Mitchell 2004, p.1936). Thus, NFFO 1 was not a real auction process. This changed with NFFO 2. The auction was geared towards new capacity and competition occurred to a limited degree (see Mitchell 2004, p.1936). But there was a major pitfall in the NFFO process, as this was originally designed to support nuclear energy. Due to this fact the whole scheme had to be sanctioned by the EU Commission, which allowed the support only to last until 1998. Thus, in the early rounds NFFO 1 and NFFO 2 the bidders were confronted with a very short time frame for the recovery of their investments. As Mitchell points out (Mitchell 2004, p.1936f) investors were rushing to the best sites in similar locations. This lead to a well organise campaign against wind farms. The ‚*creation of anxiety about the ‚wind rush‘ was wholly unnecessary and a direct result of NFFO contracts ending in 1998.. The anti-wind feelings engendered in 1990 and 1991 are still felt in some parts of the UK and is an important reason why onshore wind developments have been so slow*.‘ (Mitchell 2004, p.1937).

As the history of NFFO shows there are numerous pitfalls which can be encountered in the design and execution of an auctioning system. At first it was unclear to the potential bidders for how long a period the payment would be guaranteed (see Mitchell 1995, p.1079), making it very difficult to calculate bids allowing to recover cost. Then, the payment period in NFFO 1 and 2 was extremely short, leading to an unnecessary rush for the best sites (see above). Furthermore, it was not clear when and how further rounds of auctioning would be performed after the first round was completed. Additionally, the differentiation of auctioned capacities between different renewable energy technologies only developed between the first and second round of auctioning (see Mitchell 1995, p.1082). The pitfalls of NFFO and the inherent structure of auction processes lead to the crowding out of smaller developers. Mitchell (1995, p. 1082) finds that ‚*Small-scale projects and independent generators (whether individuals or* *communities) found it particularly hard to obtain contracts; the smaller scale projects because they were on the whole more expensive than the larger-scale projects and independent generators found it hard to obtain finance. .. In fact, not one project within NFFO2 was developed by an independent developer who did not have their own equity. All such projects initially developed by independent companies were forced to accept equity from companies (either the RECs (Regional Electricity Companies), generators or water companies or venture capitalists) at very high capital cost, ..'.* An other pitfall was the imposition of a total cost cap for the total enumerations payed under a NFFO bidding round combined with the lack of a penalty for companies which did not take up their contract (see Mitchell 2004, p.1937). As NFFO 3 to 5 allowed a 5 year grace period and the fact that planning permission did not have to be granted at the time of bidding, bidders speculated on the best sites and future cost reductions of the technology (see Mitchell 2005, p.1937). This structure lead to the situation that extremely low bids were entered, which later proved t be uneconomic and resulted in lower and lower completion rates of the contracts as Figure 47 shows. Only the use of land-fill-gas did not decline to a completion rate of 10% or lower in NFFO 5 pulling up the average completion rate of all NFFO projects substantially. The completion rate of wind energy dropped drastically from over 50% in NFFO 3 to below 5% in NFFO 4 and 5.

Figure 47: Project completion rates under NFFO in the UK (source: Mitchell 2004, p. 1938) (LFG: land-fill-gas, MIW: municipal and industrial waste combustion)

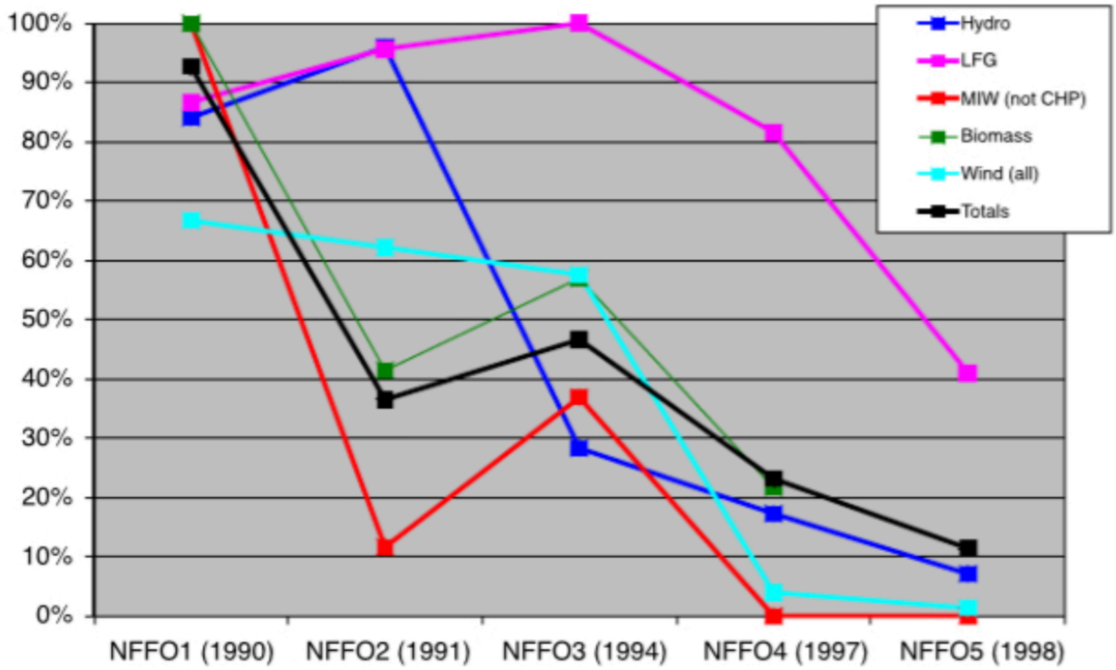


Fig. 1. Overall completion rates for NFFO contracts in 2003. Hartnell (2003).

As can be seen in the example of wind energy, the NFFO auctioning process lead to very low costs on paper with 4.43 p/kWh in NFFO 3, 3.56 p/kWh in NFFO 4 and 2.88 p/kWh in NFFO 5. Unfortunately, these extremely low costs did virtually not support any real project, as can be seen in the completion rates for wind in NFFO 4 and 5 (see Figure 60).

Table 16 summaries the most important information on the different NFFO rounds. It shows quite clearly how badly the auctioned quantities were missed. Even in NFFO 2 only 36% of the auctioned capacity was finally built, with the share of build capacity dropping to just 5% in NFFO 5. At the same time the preoccupation with the lowest possible cost for renewable energy sources led to a situation, where the UK fell far behind the developments in other European countries employing FIT systems as Table 17 below shows. While the installed German wind capacity rose from 68 MW in 1990 to 13,184 MW in 2003, the installed wind capacity in the UK rose from 10 MW in 1990 to just 588 MW in 2003. Lamy et al. (no year, p.9) point out that the three leading countries in Europe using FITs had installed 20 times the capacity of wind energy in 2000 as the European countries using competitive bidding schemes.

Table 16: Average price results (listed in GBP) for NFFO rounds (1 to 5) in UK (source: Wiser, 2002)

	NFFO-1	NFFO-2	NFFO-3	NFFO-4	NFFO-5
Period of guaranteed contract	1990-1998	1991-1998	1994-2009	1997-2012	1998-2013
Capacity of winning bids (MW, DNC)	152	472	627	843	1 177
Installed capacity (MW, DNC)	145	172	293	156	55
Average price (GBP/kWh)	0.065	0.066	0.044	0.035	0.027
Average price (USD2011/kWh)	0.093	0.092	0.055	0.045	0.034

Table 17: The deployment of wind energy in Europe between 1990 and 2003 (source: Mitchell 2004, p. 1936)

Table 1
The deployment of wind energy in Europe (MW)

	1990	End 1995	End 1999	End 2001	End 2002	Late 2003
Germany	68	1136	4445	8753	12001	13184
Spain	7.2	145	1530	3335	4830	5198
Denmark	343	619	1742	2556	2880	2927
Italy	2.9	25	211	697	785	800
Netherlands	49	236	410	483	688	829
UK	9.9	200	356	485	552	588
Sweden	8	67	220	280	325	364
Greece	1.8	28	87	272	276	354
Portugal	0.5	13	60	127	194	217
France	0.3	7	23	85	145	219

Source: WPM (1999, 2001, 2003).

As Lamy et al. stress the point that competitive bidding schemes have left to little producers surplus to the manufacturers of renewable energy technologies to invest in sufficient research and development necessary for the technology development. Although the UK government wanted to incentives the formation of a national renewable energy industry, the bidding scheme did not facilitate such national industry formation. Virtually all contracts for wind energy were taken by projects based on Danish wind turbines (see Lamy et al. no year, p.6) and in the year 2000 eight of the ten biggest wind manufacturers in the world were located in Germany, Denmark and Spain, all three countries relying on FITs granting relatively high shares of producer surplus to the manufacturers Lamy et al. (see Lamy et al. no year, p.6).

As Mitchell (2004, p.1937) has pointed out competitive bidding can lead to substantial problems with project acceptance. This point is underscored by Lamy et al. (see Lamy et al. no year, p.6) as well, who stress that FITs have an undeniable advantage to the criteria ‚Stimulation of renewables', ‚Positive industrial impact' and ‚Project acceptability' (see Lamy et al. no year, p.6). Nevertheless, in the early years of renewable energy technology development this came at a substantial cost to electricity consumers, as the high uptake rates of renewable energy technologies, which were still considerably more expensive than conventional power generation had to be paid for, even when intelligent FIT systems were able to push down these costs and to limit the extent of producer surplus, as can be seen in the comparison of the US RPS and the German FIT systems (see Barbos and Wyser 2013).

It is fair to summarise that all systems have their advantages and disadvantages which make it necessary to consider the specific policy goals and market structures of any given country to be able to design the best market structure and renewable energy policy framework to achieve the given goals as far as possible.

Small island experiences with different support mechanisms for the integration of renewable energy sources

Due to their system size and insularity small island power systems like in Barbados may have special circumstances impacting on the applicability of different support mechanisms for renewable energy sources just as they may have special circumstances for power market reform and liberalisation. As there are a number of island countries or isolated larger islands, which seem to have been quite successful in the adaptation of renewable energy sources for power generation, it is interesting to see whether there are any lessons to be learnt from these successful examples applicable to Barbados. Islands with major grid connections to a mainland don't qualify as useful examples, as they can use the grid of the mainland as back-up making it much easier to reach high shares of renewables. This condition, grid connection to the mainland, applies for example in the much discussed case of the Danish island Samsoe, which has virtually reached a 100% renewable power supply measured as the sum of all RE power produced throughout the year, but which is still heavily relying on imports and exports of electricity from the Danish mainland.

As mentioned above Kuang et al. (2016, p. 506) have identified a number of such examples of SIDS or large islands with high RE penetration. The island countries or isolated islands with the highest shares of RE power production according to Kuang et al. are Fiji with 59.3%, Reunion with 31.2%, Crete with 26%, and Cape Verde with 21% of renewable power production. A thorough literature review has revealed that Hawaii should be added to the list due to its relatively high share of renewable power production (25.8%) and due to the multitude of support mechanisms used. These five SIDS or isolated islands will be looked at in the following in some detail to find out whether there are lessons to be learnt for Barbados. In addition the Dominican Republic will be looked at as it is the only CARICOM country with feed-in tariffs legislated.

The case of Fiji

As compared to Barbados Fiji is relatively large in land mass with 18,274 km^2 divided into 322 islands. Nevertheless, the majority of its 909,000 inhabitants (about 600,000) live on the main island Viti Levu, which has more than half of Fiji's land mass (10,388km2). In a number of publications Fiji, reaching about 60% of renewable power has been mentioned as a prime example for the successful introduction of high shares of renewable electricity production (e.g. Kuang et al. 2016). Fiji has set very ambitious renewable power targets of 81% for 2020 and 99% for 2030 (see Table 18 below). Thus, it should be expected that such a high penetration of renewable power reached already and such extremely ambitious policy goals are backed up by effective support mechanisms for the further market diffusion of renewable energy.

While Fiji has achieved 59.3% of renewable power production (see Kuang et al. 2016, p. 506), this is mostly due to a very high share of large hydropower, with hydropower producing about 55% of Fiji's electricity (see Table 19 below). As large hydropower has historically been pursued by incumbent utility companies, a high share of large hydropower production does not require a special renewable energy support policy. Prime examples for large hydropower development by large public utility companies can be found in Norway or Switzerland, where hydropower has developed over the last 100 years without any special renewable energy policy support mechanism. In the case of Norway almost 100% of the countries electricity is supplied by large hydropower installations (Norwegian Ministry of Petroleum and Energy 2016).

In Fiji the state owned Fiji Electrical Authority (FEA) has build up Fiji's power supply around large hydropower with the completion of the Monasavu hydropower scheme on the main island. In 1982 this single dam with a capacity of 83 MW was able to supply the entire electricity demand of the main island (Dorman and Jotzo 2011, no page number). This hydropower scheme was build with the help of the World Bank and other international donors (see Dorman and Jotzo 2011). With the expanding electricity demand the share of fossil fuel generation has grown again leading to attempts of the FEA to build more hydropower schemes resulting in a total installed hydropower capacity of 134 MW (see Table 20 below).

Table 18: Fiji's renewable energy targets 2015 to 2030 (Source: IRENA 2015, p. 20)

Indicator	Baseline	Targets		
		2015	2020	2030
Access to modern energy services				
Percentage of population with electricity access	89%[a] (2007)	90%	100%	100%
Percentage of population with primary reliance on wood fuels for cooking	20%[b] (2004)	18%	12%	<1%
Improving energy efficiency[c]				
Energy intensity (consumption of imported fuel per unit of GDP in megajoules (MJ)/FJD)	28.9[d] (2011)	2.89 (-0%)	2.86 (-1%)	2.73 (-5.5%)
Energy intensity (power consumption per unit of GDP in kWh/FJD)	0.23[d] (2011)	0.219 (-4.7%)	0.215 (-6.5%)	0.209 (-9.1%)
Share of renewable energy				
Renewable energy share in electricity generation	56%[e] (2011)	67%	81%	99%
Renewable energy share in total energy consumption	13%[f] (2011)	15%	18%	25%[g]

[a] Preliminary data from 2007 Census, Fiji Islands Bureau of Statistics 2012b
[b] 2002-2003 Household Income and Expenditure Survey, Fiji Islands Bureau of Statistics,(2004). Reliance on wood fuels alone for cooking.
[c] Based on 15% fuel substitution to local fuels and a 3% annual efficiency improvement.
[d] Fiji Islands Bureau of Statistics based on average 36 MJ per litre of fuel.
[e] Annual report 2011, FEA
[f] Based on total energy consumption of 16,500 terajoules (TJ) (Fiji Islands Bureau of Statistics, 2011) and 55% power generation from renewables (FEA).
[g] Based on 99% renewable power and 25,000 kL of biofuel.

Source: SE4ALL Rapid Assessment and Gap Analysis Report, 2014

Table 19: Installed capacities and electricity generation from renewable energy sources in Fiji in 2012 (Source: IRENA 2014, p. 16)

Electricity Access in 2012	92 percent
Installed Capacity in 2012	263 megawatts
Renewable Capacity in 2012 • Hydro • Wind • Biomass	164 megawatts (62% of all capacity) • 129 megawatts (49%) • 10 megawatts (4%) • 25 megawatts (9%)
Electricity Generation in 2012	823 gigawatt-hours
Renewable Generation in 2012 • Hydro • Wind • Biomass	493 gigawatt-hours (60% of generation) • 452 gigawatt-hours (55%) • 33 gigawatt-hours (4%) • 8 gigawatt-hours (1%)
Electricity Tariff (residential) in 2012	Subsidised: 8 U.S. cents per kilowatt-hour Unsubsidised: 17 U.S. cents per kWh

Table 20: Detailed installed generation capacity in Fiji by plant (Source: Source: IRENA 2015, p. 20)

Location/site	Installed Capacity (MW)	Energy Source	Nameplate Output	Year of Commission
		Viti Levu Island		
Monasavu Wailoa	83	Hydro	60% of the electricity in Viti Levu	1983
Nadarivatu	42		101 GWh[19]	2012
Wainikasou	6.6		18 GWh	2004
Nagado/Vaturu	2.3		10 GWh	2006
Buton	10	Wind	-	2007
Multi-locations	72 (total)	Industrial Diesel Oil	-	
Kinoya	20.6	Heavy Fuel Oil	-	2007
		Vanua Levu Island		
Labasa	13.5	Industrial Diesel Oil	-	-
Savusavu	5.2		-	-
Wainiqeu	0.8	Micro-hydro	-	-
		Ovalau Island		
Levuka	2.9	Industrial Diesel Oil	Distribution network 11 kV and below	-
		Total Installed Generation Capacity		
		258.9 MW		

Source: FEA Power Development Plan, FEA Presentation Energy Forum 2013

Figure 61 shows the expansion of Fiji's renewable energy capacities. Mainly hydropower and solid biomass combustion have grown, while wind has had a single expansion in 2007, when 10.2 MW of wind capacity were installed. PV has expanded from 0.2 MW in 2010 to 3.9 MW in 2016 contributing just about 1.1 GWh form 2.2 MW of PV in 2014 (no data on the PV production is available from the IRENA database for 2015 and 2016 at the moment). As Table 21 shows, the share of Fiji's renewable power production has varied widely over the years between 92% in 2002 and 56% in 2014 and the trend is a decline not an increase of the share of renewables in Fiji's power production due to increasing consumption and very limited additions of new renewable power capacities since 2012 when the last big hydropower plant was commissioned.

Figure 61: Installed RE capacities in Fiji in MW from 2000 to 2016 (Source: IRENA 2017) (Large hydro: dark blue, medium sized hydro: lighter blue, wind energy: light blue, PV: orange and solid biomass: dark green)

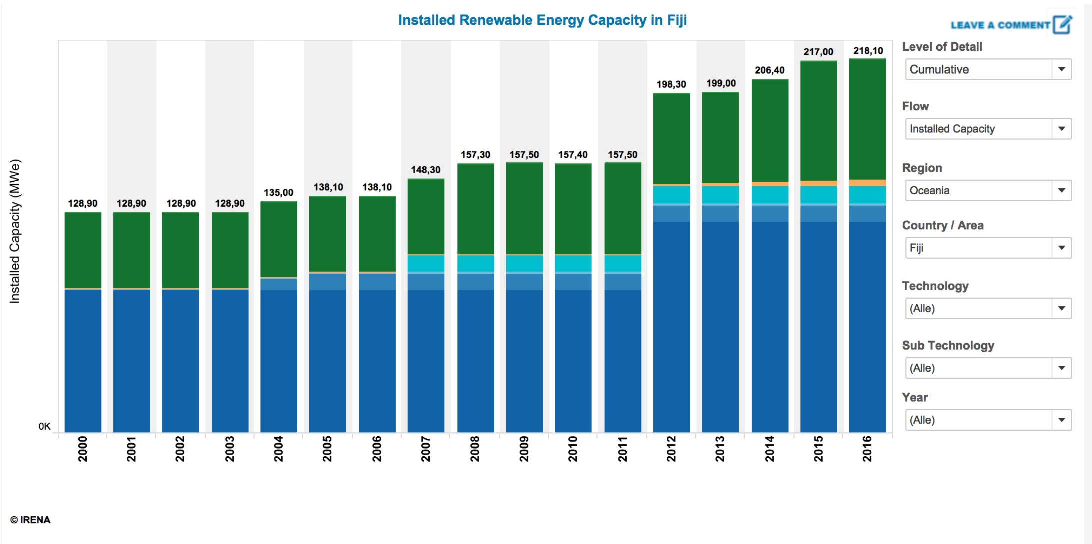


Figure 62: Installed wind (light blue) and PV (orange) capacities in Fiji in MW from 2000 to 2016 (Source: IRENA 2017)

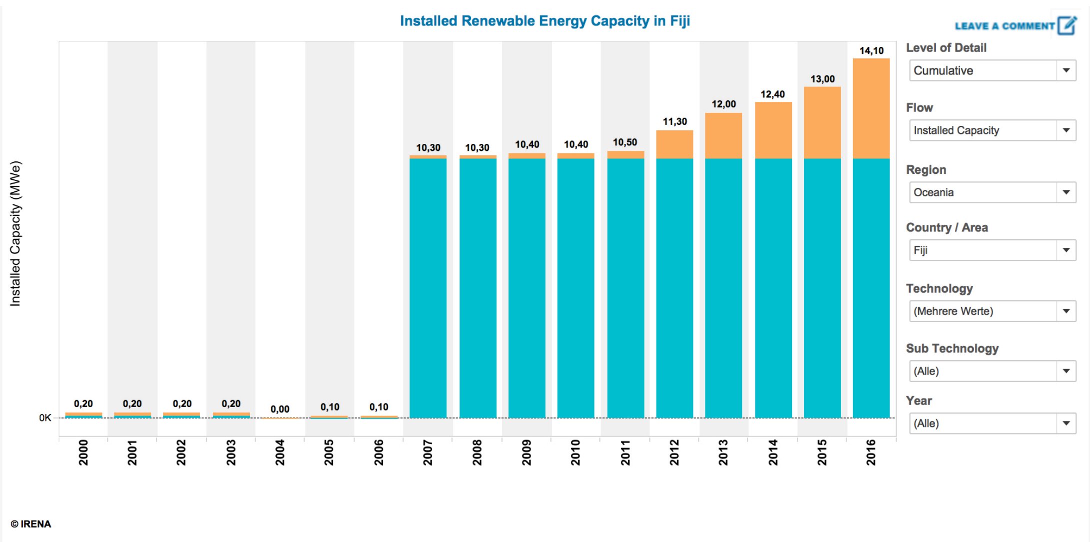


Table 21: Development of electricity production and capacities in Fiji from 2000 to 2016 (data sources: IRENA 2017 and US EIA 2017)

Fiji	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total generation capacity in MW	200	200	200	200	200	260	260	280	291	291	291	291	305	306	321		
Total RE capacity in MW	83.26	83.06	83.06	83.06	84.06	140	140	160	171	171	171	171	185	186	201		
Wind	0.1	0.1	0.1	0.1	0	0	0	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
PV	0.06	0.06	0.06	0.06	0.06	0	0.1	0.1	0.1	0.1	0.2	0.3	1.1	1.8	2.2	2.8	3.9
Solid Biomass	44.5	44.5	44.5	44.5	44.3	44.3	44.3	44.3	53.3	53.3	53.3	53.3	53.3	53.3	60.3	70.3	70.3
Hydropower, large	83.2	83.2	83.2	83.2	83.2	83.2	83.2	83.2	83.2	83.2	83.2	83.2	123.2	123.2	123.2	123.2	123.2
Hydropower, medium size	6.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Hydropower, small size	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Total electricity production in GWh/a	600	600	600	600	700	705.1	756.1	794.1	785.1	790.1	835.1	801.1	803	857	859		
Share of RE	84.7 %	90.6 %	92.9 %	73.0 %	67.4 %	62.6 %	60.0 %	75.2 %	75.0 %	68.2 %	58.3 %	66.8 %	74.0 %	69.0 %	56.0 %		
Share of non hydro RE	15.6 %	13.4 %	17.9 %	15.7 %	14.9 %	14.5 %	14.9 %	11.1 %	11.9 %	10.0 %	8.8 %	9.9 %	8.5 %	7.5 %	9.4 %		
Share of non hydro and non large biomass RE	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.5 %	0.6 %	0.9 %	0.8 %	0.7 %	0.9 %	0.7 %	0.6 %		
Total RE electricity production in GWh/a	508	543.5	557.3	438.1	471.7	441.1	453.6	596.8	588.5	539.1	487.2	535.5	593.9	591.7	481.4		
Non hydro RE production in GWh/a	93.6	80.6	107.1	94.3	104.3	102.3	112.3	88.3	93.4	78.9	73.5	79	68.6	64.3	80.4		
Non hydro and non large biomass RE	0.2	0.2	0.2	0.2	0	0.1	0.1	3.6	4.8	7.5	6.7	5.5	7.5	6.2	5.4		
Wind	0.1	0.1	0.1	0.1	0	0	0	3.4	4.6	7.2	6.4	5	6.8	5.3	4.3		
PV	0.1	0.1	0.1	0.1	0	0.1	0.1	0.2	0.2	0.3	0.3	0.5	0.7	0.9	1.1		
Solid Biomass	93.4	80.4	106.9	94.1	104.3	102.2	112.2	84.7	88.6	71.4	66.8	73.5	61.1	58.1	75		
Hydropower, large	412.1	460.6	448.3	343.7	357.3	322.5	315.6	481.1	463	436.1	383	424.8	496.7	518.8	381.9		
Hydropower, medium size	0	0	0	0	8.9	15.2	24.4	26	31.4	24	29.8	29.7	27.6	6.5	18.1		
Hydropower, small size	2.3	2.3	1.9	0.1	1.2	1.1	1.3	1.4	0.7	0.1	0.9	2	1	2.1	1		

In spite of its ambitious policy targets Fiji has virtually no support mechanisms like net metering, feed-in tariffs, auctions or renewable portfolio standards. The only exemption from this is a minimum feed-in tariff for independent power producers, which was established by the Fiji Commerce Commission in 2010 (see Dornan 2014, p. 707) but this was generally deemed to be too low to attract private investment. In 2014 this minimum tariff was increased from 0.2565 FJD/kWh to 0.3308 FJD/kWh (IRENA 2015, p.26). As the future development of this minimum tariff is not clear, it is considered to be a major obstacle to IPP investment in renewable energy sources in Fiji (IRENA 2015, p. 33).

In general the shaping of Fiji's energy policy since 1996 has been subject to numerous changes in government with a first government (SVT) trying to commercialise FEA in 1998. This was stopped by the following government (FLP) in 1999 reversing the process. The FLP government was overthrown by a coup in 2000. A newly appointed government (SDL) won the next elections and pursued some moderate reforms of the FEA, but did not go back to privatisation. This government was overthrown again in 2006 by the military, which remained in power until 2014 not pursuing major reforms of the energy sector (see Dorman 2011, p.706). In this general political situation the main influence on the actual development seemed to have remained with the Fiji Electricity Authority (FEA) operating as an integrated monopoly in the electricity market.

Thus, although Fiji has set very ambitious goals for the share of renewable electricity there seems to be only one lesson to be learned from this example, which is that a continued lack of support mechanisms for private investment in renewable energy technologies will most likely lead Fiji not to achieve the set targets unless all of the development will be done by FEA.

The case of Reunion

Although Reunion is an island in the southern hemisphere, it actually belongs to France and comes under French legislation and energy policy. Being part of the European Union EU rules apply, which has a strong impact on the present transition from a feed-in tariff system to a tendering mechanism.

Reunion presently has a population of 830,000 with a projected growth to about 1 million by 2030 (see Go 100% renewable energy, 2017). In 2008 electricity consumption was about 2,500 GWh (see Go 100% renewable energy, 2017). Thus, the electricity system has roughly three times the size of Barbados with a very similar per capita electricity consumption. In 2000 the share of renewable power production was about 43.2% (see Table 22), while all other power production was based on imported fossil fuels. The bulk of the renewable power production came from large hydropower plants producing 512 GWh in 2000, while medium sized hydropower plants produced 48.3 GWh and two bagasse power plants produced 261 GWh (see Table 22). In 2000 there was no electricity production from wind or solar energy, small hydropower plants or biogas (source: IRENA 2017 and US Energy Information Administration 2017).

As Figure 64 shows the electricity production from renewable energy sources has exclusively been based on hydropower (dark blue) and solid biomass combustion (dark green) until 2004. Even in 2014 hydropower and solid biomass supplied more than two thirds of Reunion's renewable power. The installation of first wind turbines started in 2004 and PV was first installed in 2005. Wind energy was built up to its present level of 14.8 MW in the years 2005 to 2007. PV expanded very fast after a slow introductory phase until 2008. The installed PV capacity increased from 10 MW in 2008 to 180.4 MW in 2015 reaching about 18.5% of the total installed generation capacity of 980 MW. It looks like the fast expansion came to a halt in 2016, when only 0.6 MW were added (all data excerpted from IRENA 2017). Despite the fast expansion of PV until 2016 the share of renewable electricity in Reunion has decreased from 43.2% in the year 2000 to just 35.5% in 2014 due to the strong growth in electricity demand from 1,900 to 2,650 GWh/a in 2014. At the same time the share of non hydro and non solid biomass based renewable power production has increased from 0 to 10% of the total electricity production of Reunion.

Figure 64: Electricity generated from renewable energy sources in Reunion in GWh/a in the years 2000 to 2014 (Source: IRENA 2017)

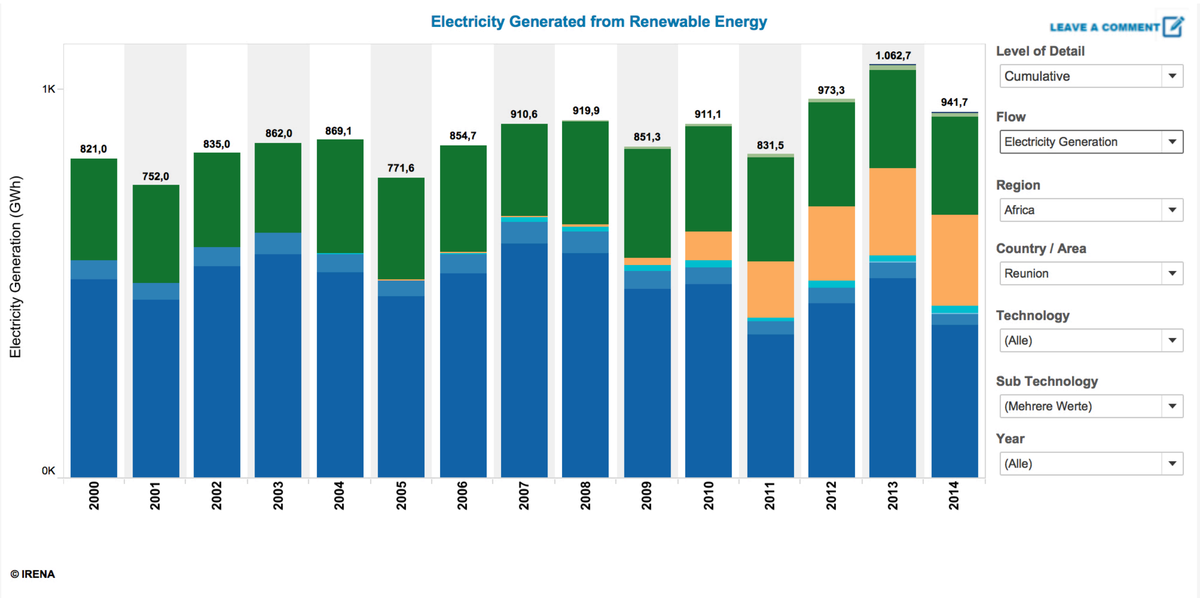


Figure 65: Installe RE capacities in MW in Reunion since 2000 (Source: IRENA 2017)

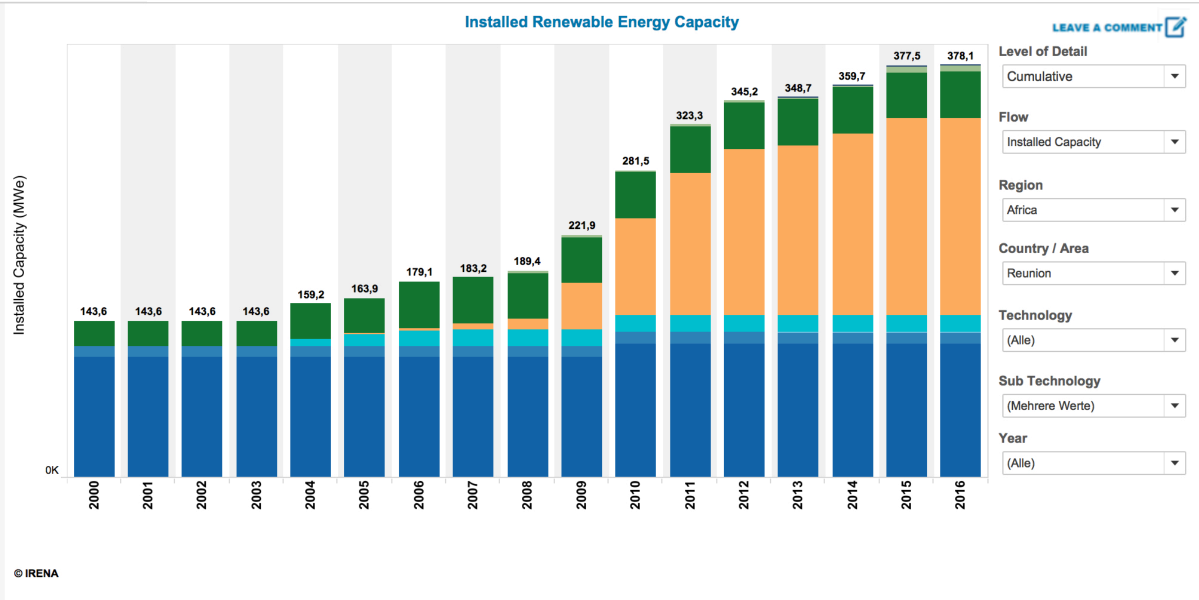


Table 22: Development of electricity production and capacities in Reunion from 2000 to 2016 (data sources: IRENA 2017 and US EIA 2017)

Reunion	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total generation capacity in MW	500	500	500	500	500	578	608	660	665	734	780	828	949	969	980		
Total RE capacity in MW	143.6	143.6	143.6	143.6	159.2	163.9	179.1	183.2	189.4	221.9	281.5	323.3	345.2	348.7	359.7	377.5	378.1
Wind	0	0	0	0	6.6	10.5	13.5	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8
PV						0.8	3.0	5.8	10	42.5	89.3	131.1	153.0	156.0	167.0	180.4	181.0
Solid Biomass	23.0	23.0	23.0	23.0	32.0	32.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
Biogas	0	0	0	0	0	0	0	0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	6.4	6.4
Hydropower, large	110.2	110.2	110.2	110.2	110.2	110.2	110.2	110.2	110.2	110.2	123.0	123.0	123.0	123.0	123.0	123.0	123.0
Hydropower, medium size	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Hydropower, small size	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2	0.2	0.2	0.2
Total electricity production in GWh/a	1900	2000	2000	2100	2300	2438	2461	2548	2425	2484	2507	2649	2620	2535	2650		
Share of RE	43.2 %	37.6 %	41.8 %	41.0 %	37.8 %	31.6 %	34.7 %	35.7 %	37.9 %	34.3 %	36.3 %	31.4 %	37.1 %	41.9 %	35.5 %		
Share of non hydro RE	13.7 %	12.6 %	12.1 %	11.0 %	12.7 %	10.7 %	11.3 %	9.9 %	11.9 %	12.9 %	14.7 %	16.2 %	18.5 %	19.9 %	19.5 %		
Share of non hydro and non large biomass RE	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.0 %	0.2 %	0.6 %	1.0 %	1.7 %	4.0 %	6.0 %	8.3 %	10.0 %	10.0 %		
Total RE electricity production in GWh/a	821.0	752.0	835.0	862.0	869.1	771.6	854.7	910.6	919.9	851.3	911.1	831.5	973.3	1062.7	941.7		
Non hydro RE production in GWh/a	261.0	252.0	241.0	232.0	292.1	261.6	278.7	252.6	287.9	320.3	369.6	429.8	485.3	505.6	515.9		
Non hydro and non large biomass RE	0	0	0	0	0.1	0.6	5.7	14.6	24.9	42.8	100.6	159.9	218.2	254.2	264.7		
Wind	0	0	0	0	0.1	0.3	4.3	11.8	15.0	15.5	16.9	11.7	18.2	15.1	15.7		
PV	0	0	0	0	0	0.3	1.4	2.8	4.8	20.5	76.1	141.8	190.4	224.2	235.9		
Solid Biomass	261.0	252.0	241.0	232.0	292.0	261.0	273.0	238.0	263.0	277.5	269.0	269.9	267.1	251.4	251.2		
Biogas	0	0	0	0	0	0	0	0	5.1	6.8	7.6	6.4	9.6	14.9	13.1		
Hydropower, large	511.7	456.9	542.8	575.7	527.2	466.0	526.3	601.3	577.5	485.2	499.3	370.4	450.0	512.8	392.0		
Hydropower, medium size	48.3	43.1	51.2	54.3	49.8	44.0	49.7	56.7	54.0	45.8	42.2	31.3	38.0	43.4	33.1		
Hydropower, small size														0.8	0.6		

France has experimented with feed-in tariffs since 2001, when a first set of FITs was set, which were deemed not appropriate to induce much new renewable energy investment (see Lesieur, no year). In 2005 an new law introducing improved FITs was introduced and the FITs were reviewed on a two year basis. In 2006 FITs have been set according to the new law. In March 2011 the feed-in tariff system was adjusted for PV. For installations up to 100 kWp the feed in tariff was adjusted every trimester on the basis of a defined quarterly cap (50MW/quarter for residential and 200 MW/quarter for non-residential installations (for France). Tariffs were dropped by 2.6%/quarter when the cap was reached. If the cap was not reached the reduction was lower. For installations larger than 100 kWp and for all ground mounted installations a tendering procedure was introduced. By July 2016 building-integrated PV installations no larger than 9 kWp were entitled to an FIT rate of 0.246 EUR/kWh, systems no larger than 36 kWp received 0.133 EUR/kWp and plants between 36 and 100 kWp received 0.126 EUR/kWh (source IEA 2016). The tariffs guaranteed up to 2016 are given in Table 15d below.

Table 15d: French feed-in tariffs applicable in Reunion until 2015 (source: AGORA 2015, p.28)

Feed-in Tariff Levels for Selected Renewable Technologies Table 6

Technology	Orders governing the purchase of electricity	Duration of contracts	Sample tariffs for installations commissioned on the date that FiT order was issued
Hydro	1 March 2007	20 years	**6.07 c€/kWh** + bonus **between 0.5 and 2.5** for small installations + premium between **0 and 1.68 c€/kWh** in winter depending on level of production **15 c€/kWh** for offshore hydropower (wave, tidal, and hydrokinetic)
Geothermal	23 July 2010	15 years	**Mainland France: 20 c€/kWh** + premium for energy efficiency of between **0 and 8 c€/kWh** **Overseas France (DOM): 13 c€/kWh** + premium for energy efficiency between **0 and 3 c€/kWh**
Wind	17 June 2014	15 years (onshore) 20 years (offshore)	**Onshore: 8.2 c€/kWh** for 10 years, then between **2.8 and 8.2 c€/kWh** for 5 years depending on site **Offshore: 13 c€/kWh** for 10 years, then between **3 and 13 c€/kWh** for 10 years depending on site
Solar	4 March 2011, amended 7 Jan. 2013	20 years	Tariff rates for solar power are set quarterly, based on the number of projects submitted over the previous quarter and compared to annual targets*. Tariffs are set for facilities under 100 kW, and tenders issued for facilities above 100 kW**. The FiT for the last quarter of 2014 are the following : - Rooftop PV, 0-9kW: **26.96 c€/kWh** - Simplified rooftop PV, 0-36 kW: **13.75 c€/kWh** - Simplified rooftop PV, 36-100 kW: between **13.05 c€/kWh** - All types of ground-mounted installations (from 0 to 12 MW): **6,80 c€/kWh**

Ministère de l'Écologie, du Développement durable et de l'Énergie, 2013.; * As of the 7 January 2013, amendments to the FiT, the total annual target for solar power is 1000 MW for the next several years. This doubles the previous target. It is divided into targets for various sizes of rooftop and ground-based solar PV [Ministère de l'Écologie, du Développement durable et de l'Énergie, 2013a.].,
** Ministère de l'Écologie, du Développement durable et de l'Énergie, 2013b.

Due to the general shift of the EU renewable energy policy towards mandated tendering feed-in tariffs have only survived for smaller installations and technologies in their early stages of development. As the latest changes in the support mechanism have had no direct impact on the past installations of renewable energy technologies in Reunion they will not be treated in detail here.

Figure 65 above shows that the feed-in tariffs granted in France have lead to a substantial expansion of solar PV installations in Reunion between 2006 and 2016. In 2009 a critical threshold seems to be have reached by the FIT rates granted spurring a fast development of PV installations in Reunion. The installation numbers of 2016 seem to reflect a situation were the automatic tariff reduction has dried out further market penetration. In the case of wind energy two wind farms of 8.4 and 6.3 MW have been built from 2004 to 2006. The exposition of Reunion to frequent cyclones with wind speeds of more than 200 km/h have lead to a rather slow development of wind energy based on smaller turbines (275 kW each), which can be taken down in a cyclone. Nevertheless, some of the machines have been damage in cyclones while on the ground (see Praene et al. 2012, p. 431). Praene et al. (2012, p. 431) argue that the best possible use of the remaining limited wind energy potential will require the use of larger turbines build for cyclone conditions to make better use of the rather limited potential.

Praene et al. (2012, p. 439) point out that in the island context transport cost and local taxes can increase investment costs for renewables by up to 30%, which presents a major disadvantage when the national FIT rates for France are applied to Reunion. Thus, although the French renewable energy policy has helped to boost the expansion of PV on Reunion it simultaneously has put investors in Reunion, faced with higher investment costs, at a systematic disadvantage as compared to investors in the mainland of France with the same FIT rates being applied. It has to be mentioned though, that the solar irradiance in Reunion is most likely substantially higher than in most parts of France, offsetting this disadvantage at least partially.

In 2012 Praene et al. (p. 439) were already foreseeing difficulties for a sustained market penetration of PV due to the drastic reductions in FIT rates and market size limitations introduced by the French government in 2011. Nevertheless, it took until 2016 that the reductions in FIT rates outpaced the cost reductions for PV systems to bring the market diffusion of PV in Reunion to a halt.

The lesson, which can be learnt from Reunion is that a well administered and reliable FIT system with long term guaranteed FIT rates for PV systems, once installed, can induce a very strong market diffusion of PV systems and that a reduction of the tariff level below the threshold of economic viability can reduce market diffusion almost instantaneously. As no net metering was applied in France the FIT tariffs for small solar installations have the same effect as net billing with full buy-back at the guaranteed FIT rate. As there are no statistics available on the different size ranges of PV systems installed in Reunion it can not be judged how successful this part of the policy has been.

A general policy lesson which was derived by Praene et al. (2012, p. 440) was that the lack of high quality information on support measures hampered the development of renewable energy sources in Reunion, just as a lack of coordination between authorities has lead to long administrative procedures. Furthermore the lack of competent technical and administrative support for projects has lead to delays in processing projects (see Praene et al. 2012, p. 440).

The case of Crete

Crete is the largest non grid connected island of Greece. It has a size of 8336 km^2 and is inhabited by approximately 650,000 inhabitants (Executive Agency for Competitiveness and Innovation, no year, p.23). The total electricity demand is 3,000 GWh/a, which is supplied by about 600 MW of conventional power plants mostly based on diesel, about 200 MW of wind energy, about 78 MW of PV and some 5 MW of biomass and small hydropower systems with about 1.25 MW (see Antoniakis 2005, p. 24 and Greek TSO 2017). Unfortunately, energy data specific to Crete are very rare, as most information on the Greek electricity system is reported at the national level. Although, there are special reports on the non grid connected Greek islands by the new Greek transmission system operator, these reports have only been published since August 2012. The circumstance that these reports are in Greek language makes the bulk of the information rather inaccessible to non native speakers, as it is the case with many recent publications on the Greek regulatory system and its details.

As Crete is part of Greece, which again is part of the European Union, the regulations of the power sector in Crete are controlled by the Greek legislation pertaining to the power sector. In some respects, like the transition from feed-in tariffs to tendering, the Greek legislation has to follow the EU policy framework, just like we have seen this in the case of Reunion, following the French legislation, which in turn has to apply the EU rules.

Different from Reunion there are no separate data sets on Crete in the IRENA renewable energy database. All available information is aggregated on the national level of Greece. As the national renewable energy legislation applies, the trends in the market diffusion of renewable energy sources relying on support mechanisms like wind and PV, should be similar for Crete as for Greece as a whole. Thus, a first look is taken at the development of renewable energy sources in Greece since the year 2000, while the scant available information for Crete is used in a second step to see in how far the market diffusion of renewable energy sources has differed in Crete from the Greek mainland. As only wind energy and PV play a significant role in Crete, the other renewable energy sources playing a role in Greece, like large hydropower, are not treated explicitly.

Greece has a very old tradition in using wind energy. Based on a generally positive attitude of the population towards the usefulness of wind energy, modern wind energy started to develop as early as 1991, but it only took off in 1999 when the installed capacity more than doubled from 40 to more than 100 MW in just one year (Figure 66). Since 2000 wind energy has grown almost continuously until 2016 (see Figure 67) from about 200 MW to almost 2,400 MW in an electricity system with about 19,000 MW total installed capacity (see Table 22). By 2014 renewable energy sources contributed about 25% to the Greek electricity production. Non hydropower renewables contributed about 16%, while wind energy as well as PV contributed 8% each to the Greek electricity production. Thus, the renewable energy contribution to the Greek power production was about equally shared between wind, PV and hydropower in 2014.

Compared to wind energy PV developed very late in Greece experiencing a very fast development between 2009 and 2013 (see Table 22 and Figure 68). The years of fast PV expansion coincide with the international cost trends. As shown above (see Figure 15) the costs of PV systems decreased from more than 4000 EUR/kWp in the fourth quarter of 2008 to below 1500 EUR/kWp in the lead market Germany. As in the case of Germany the existing feed-in tariffs opened up highly profitable investment opportunities for PV in these years, as the FIT adjustments could not quite keep pace with the fast decline in prices. In 2014 the FIT level was obviously reduced so much that only minor investments were realised (19 MW in 2014, 8 MW in 2015 and 7 MW in 2016 after 1,043 MW in 2013).

Figure 66: Early development of wind energy in Greece between 1990 and 2004 (source: Antoniakis 2005, p. 17)

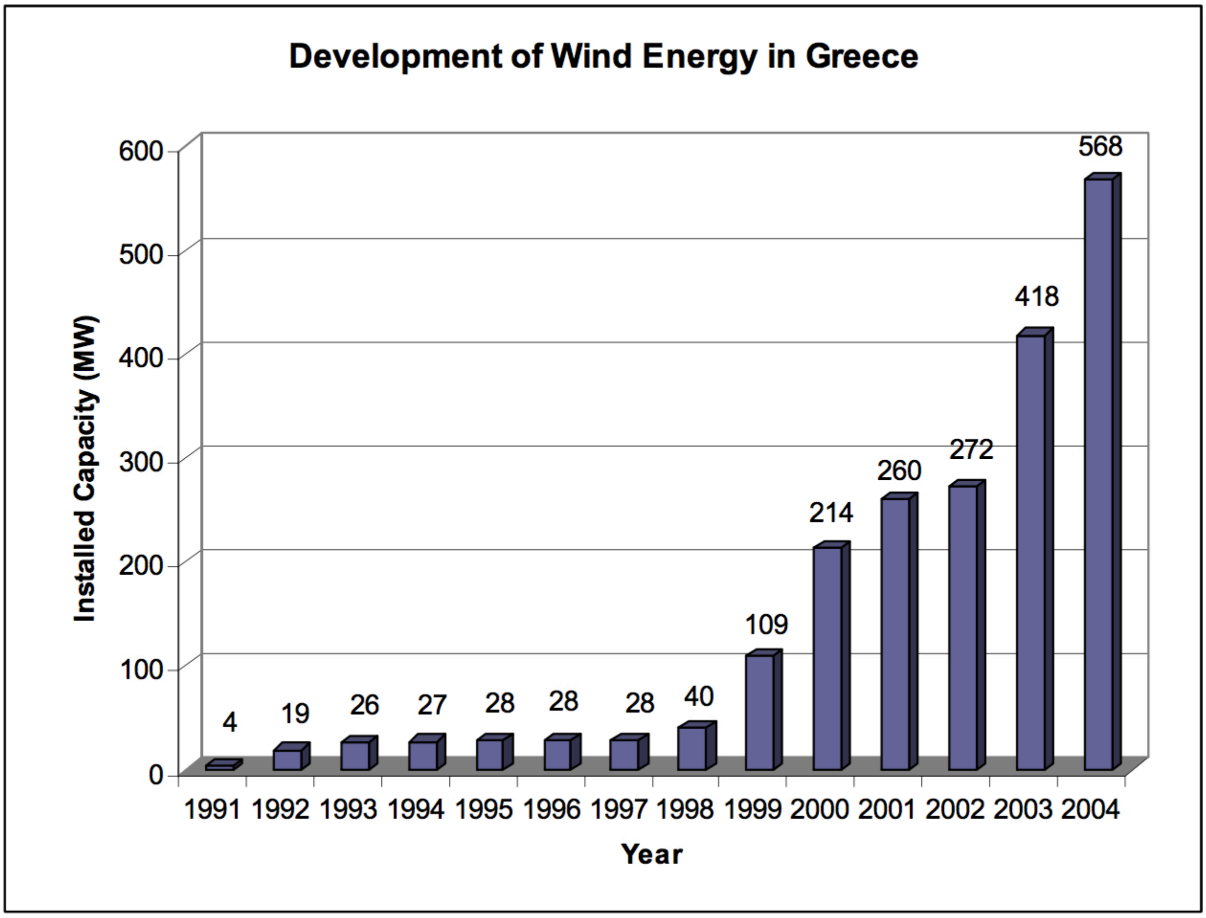


Figure 67: Development of installed wind energy capacity in Greece from 2000 to 2016 (data source: IRENA 2017)

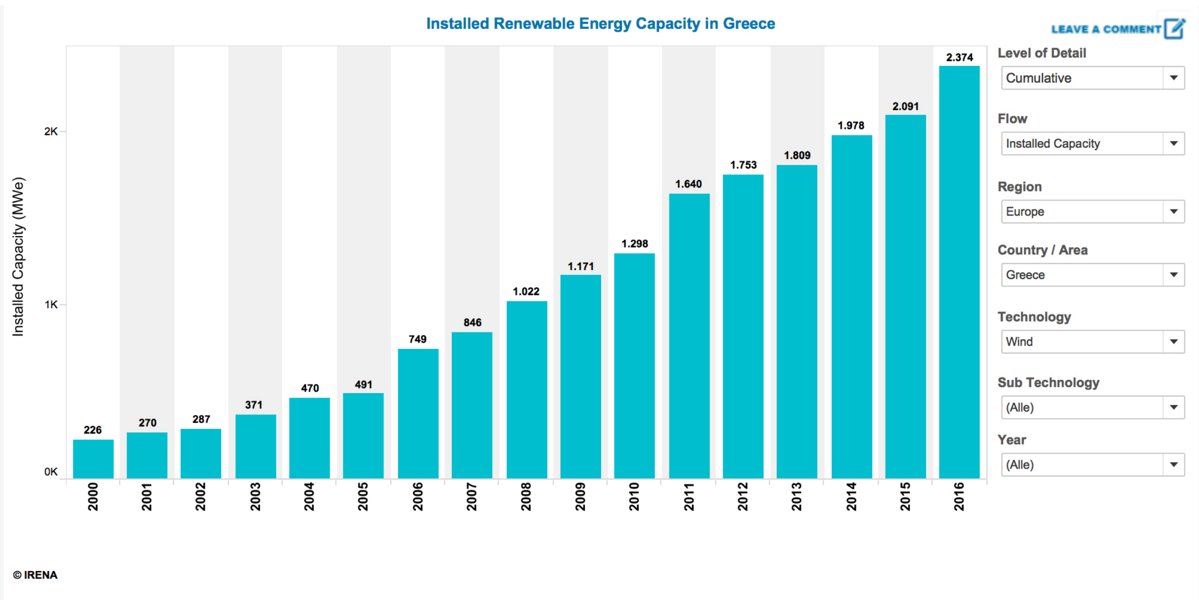
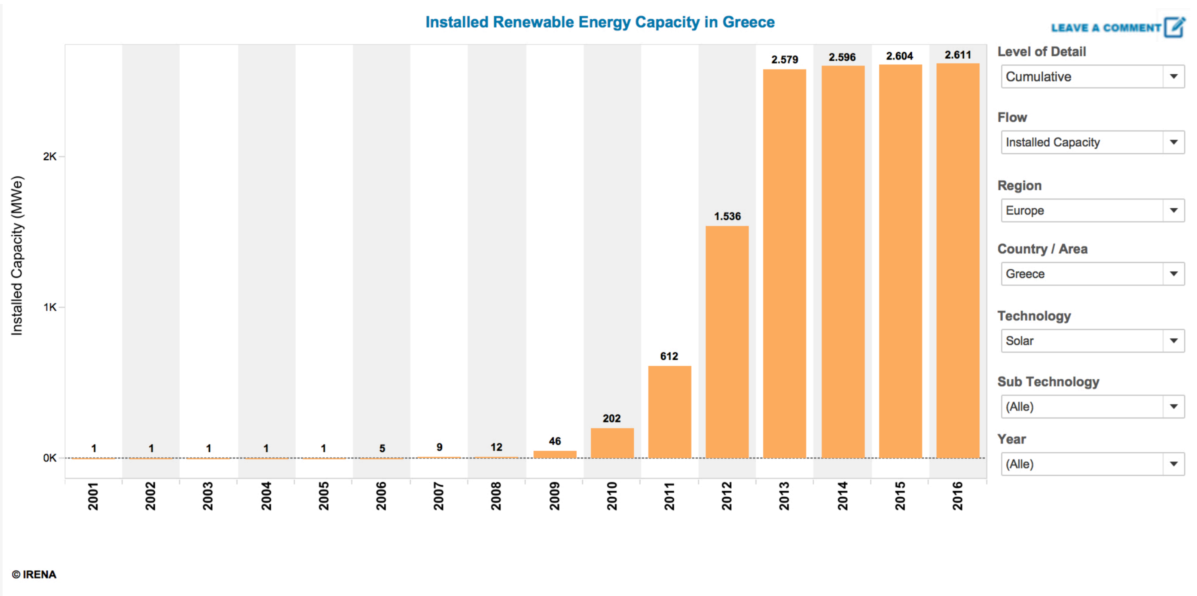


Table 22: Development of electricity production and capacities in Greece from 2000 to 2016 (data sources: IRENA 2017 and US EIA 2017)

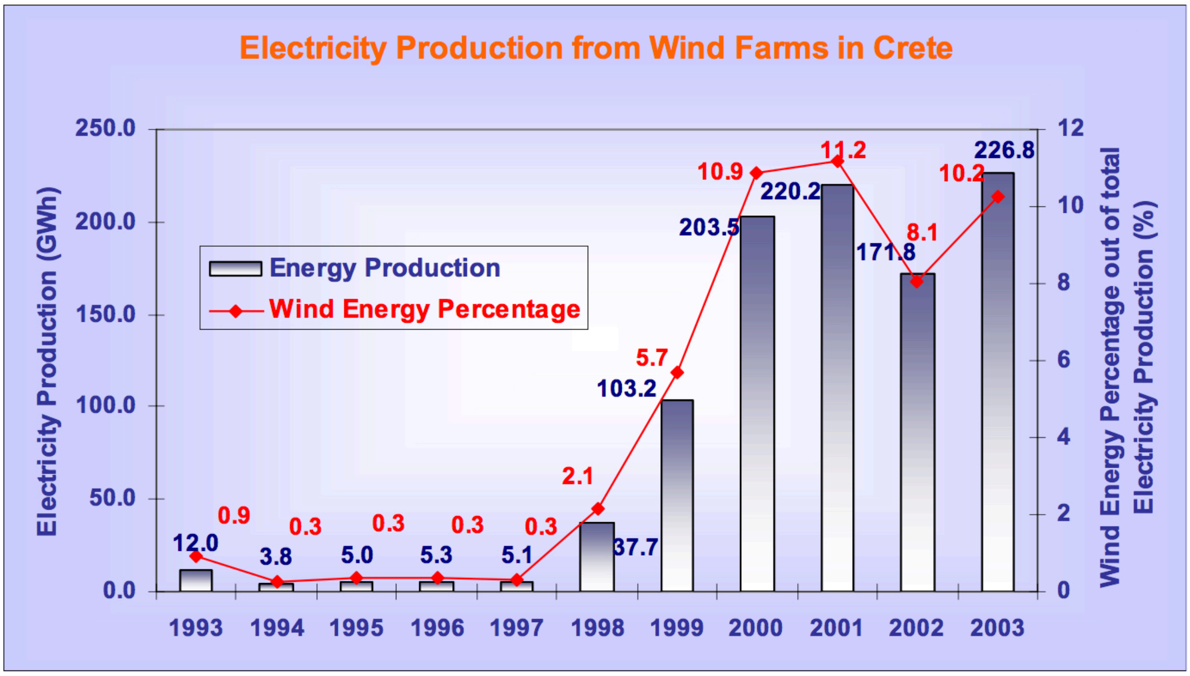
Greece	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total generation capacity in MW	11,000	11,000	12,000	12,000	12,000	13,306	13,570	13,686	14,253	14,499	15,184	16,524	17,751	18,855	18,895		
Total RE capacity in MW	2601	2670	2689	2780	2894	2922	3211	3343	3549	3757	4055	4820	5869	6971	7311	7437	7728
Wind	226	270	287	371	470	491	749	846	1022	1171	1298	1640	1753	1809	1978	2091	2374
PV	1	1	1	1	1	1	5	9	12	46	202	612	1536	2579	2596	2604	2611
Biogas	1	22	22	22	24	24	24	39	40	40	41	45	45	46	47	49	50
Hydropower, large	2317	2317	2317	2317	2317	2317	2317	2317	2317	2317	2317	2317	2317	2317	2470	2470	2470
Hydropower, medium	42	45	45	50	59	63	95	95	114	151	163	172	184	187	185	188	188
Hydropower, small	14	15	17	19	23	26	21	37	44	32	34	34	34	33	35	35	35
Total electricity production in GWh/a	50,000	50,000	51,000	55,000	55,000	55,966	56,673	58,835	59,049	57,708	54,478	55,961	57,612	54,475	47,957		
Share of RE	8.3 %	5.9 %	7.0 %	10.7 %	10.8 %	11.4 %	13.5 %	7.8 %	9.7 %	14.2 %	19.3 %	14.6 %	17.6 %	26.3 %	25.4 %		
Share of non hydro RE	0.9 %	1.7 %	1.5 %	2.0 %	2.3 %	2.5 %	3.2 %	3.4 %	4.1 %	4.9 %	5.6 %	7.4 %	10.0 %	14.7 %	16.1 %		
Total RE electricity production in GWh/a	4,144	2,932	3,577	5,893	5,918	6,406	7,679	4,595	5,749	8,186	10,522	8,143	10,150	14,350	12,177		
Non hydro RE production in GWh/a	451.0	835.0	777.0	1127.0	1246.0	1389.0	1814.0	2003.0	2438.0	2811.0	3062.0	4132.0	5748.0	8003.0	7701.0		
Wind	451	756	651	1021	1121	1266	1699	1818	2242	2543	2714	3315	3850	4139	3689		
PV	0	0	0	1	1	1	1	1	5	50	158	610	1694	3648	3792		
Biogas	0	79	126	105	124	122	114	184	191	218	190	207	204	216	220		
Hydropower, large	3,527	1,962	2,650	4,521	4,369	4,693	5,477	2,297	2,987	4,808	6,703	3,430	3,733	5,575	3,775		
Hydropower, medium	140	95	92	169	212	218	299	177	207	446	613	485	549	650	572		
Hydropower, small	26	40	58	76	91	106	89	118	117	121	144	96	120	122	129		

Figure 68: Development of installed solar PV capacity in Greece from 2000 to 2016 (data source: IRENA 2017)



In Crete wind energy had reached a capacity of 117 MW in 2003. At this time the total installed wind energy capacity in Greece was at 371 MW. Thus, Crete, although having just 5.5% of the overall power demand of Greece had 31.5% of the installed wind energy capacity. As no direct figures on the installed wind energy capacities on Crete are available figures on the electricity production from wind farms in Crete are used to give a rough impression of the installed capacities (see Figure 69). Taking into account the variable wind speeds in the different years, it can be assumed that much of the wind energy diffusion in Crete happened between 1998 and 2001, when almost the capacity installed in 2003 must have been reached.

Figure 69: Electricity production from wind energy in Crete 1993 to 2003 (source: Antonakis 2005, p. 20)



From the available data it is not clear, how the wind energy capacities developed in Crete between 2003 and 2012, the next year for which data could be found. According to the Greek distribution system operator HENDO (Hellenic Electricity Distribution Network Operator S.A) the wind energy capacity in Crete was173.94 MW in August 2012. This capacity increased to 186 MW by December 2013, 194.36 MW by December 2014, stayed constant in 2015 and increased to 200.31 MW by December 2016 (see HENDO homepage).

The development of PV seems to have followed a very similar path as in Greece at large. The Executive Agency for Competitiveness and Innovation states a PV capacity of 1.5 MW in Crete in 2008 (no year, p. 24). According to HENDO PV had reached an installed capacity of 70.37 MW by December 2012, which increased to 78.3 MW by December 2013 and remained constant ever since. Thus, PV in Create seems to have followed the same massive expansion pattern between 2009 and 2013 as in Greece.

In 2008 feed-in tariffs for wind and PV in Greece (see Table 23) were well above the level in Germany, with 0.507 EUR/kWh (as compared to 0.4675 EUR/kWh in Germany) for PV and 0.09945 EUR/kWh for wind energy in non grid connected islands (German FIT at about 0.079 EUR/kWh).

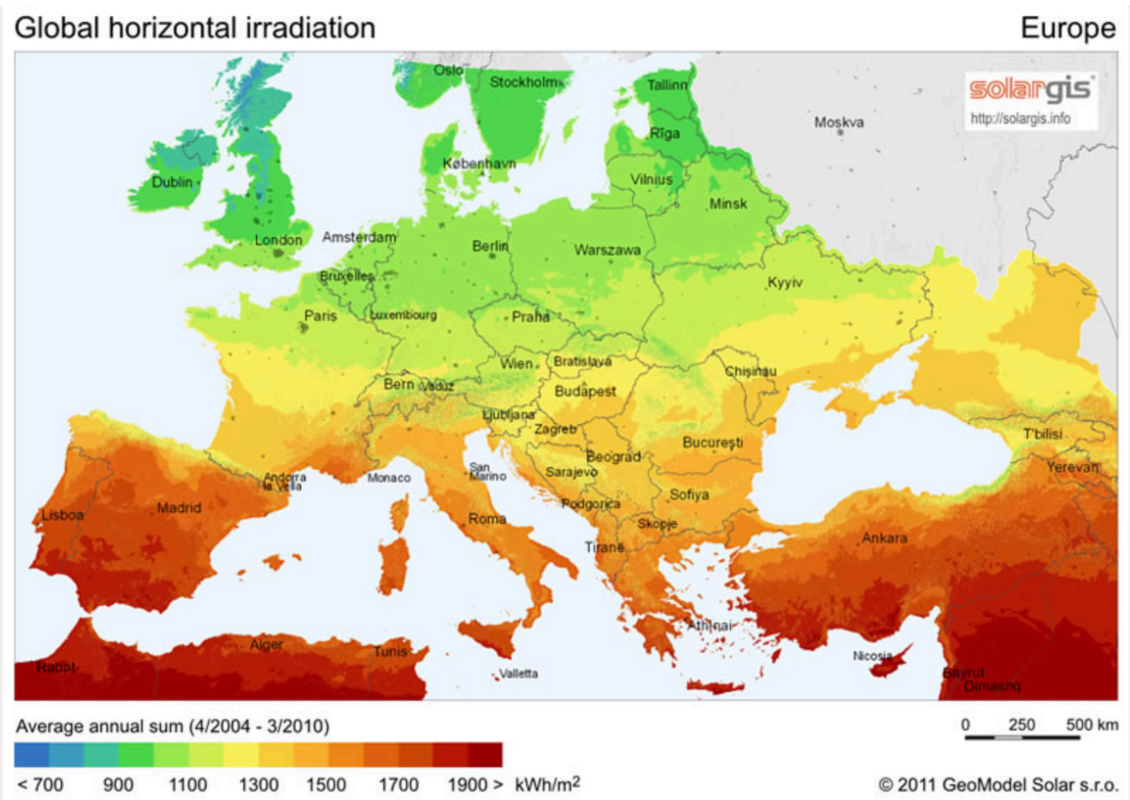
Table 15/2: Early feed in tariffs in Greece in 2008 (source: Executive Agency for Competitiveness and Innovation, no year, p.23)

Electricity production from	Mainland	Non-interconnected islands
Wind	87,85	99,45
Off-shore wind	104,85	
Small hydro <15MW	87,85	99,45
Photovoltaics< 100kWp	457,14	507,14
Photovoltaics > 100kWp	407,14	457,14
Solar thermal < 5MW	264,85	284,85
Solar Thermal> 5MW	244,85	264,85
Other RES	87,85	99,45
Cogeneration	87,85	99,45

Table 2. Feed-in tariffs for RES energy (€/MWh)

Considering the fact that the solar radiation in Crete is about 1.5 to 2 times as high as in Germany (see Figure 70) it becomes obvious that these feed-in tariffs induced the explosion of PV capacity in Greece and on the island of Crete, which we have seen in the market diffusion numbers.

Figure 60/5: Global horizontal solar radiation in Europe (source: solargis.info)



As of 2017 Greece has substantially modified its feed-in tariff system due to EU legislation forcing tendering procedures for any larger installations. Up to the end of 2015 the feed in tariff for wind energy on non-interconnected systems (islands) was 0.11 EUR/kWh, while the FIT for PV was 0.095 EUR/kWh (EU Renewable energy policy database, accessed April 2017). These FITs still apply for wind energy plants up to 3 MW and PV plants up to 500 kWp. Larger systems have to participate in the power market and are awarded a feed-in premium based on a tendering procedure. Renewable energy systems on non-interconnected islands are awarded fixed prices contracts still, as they can not participate in the Greek power market.

The lessons to be learnt from the example of Crete are that FITs can induce a continuous (example wind) and explosive (PV) market diffusion of renewable energy sources depending on the ability of the regulator or policy makers setting the FIT rates to approximate the production costs of electricity for a given technology at a given time. As it was extremely difficult for a country with high scientific and administrative capacities like Germany to anticipate the full extend of the PV price reductions seen between 2009 and 2013 it was even more difficult for Greece to adjust its FIT rates fast enough. Nevertheless, it seems that the original FIT rates for PV set for 2008 were already comparatively high as compared to Germany, a country with far lower solar radiation and higher costs per kilowatt hour in the case of similar investment costs. This mistake in the setting of the Greek FIT rates could have been avoided by taking the FIT rates in other countries into account.

The other lesson to be learnt is that comparatively high FIT rates can induce an extremely fast market diffusion of renewable energy technologies, which may drive the absorption capacity of electricity systems in small island very fast to their technical limits, far faster than in large interconnected power systems like in Germany, where it was possible to absorb 40,000 MW of PV within a few years without any major system disruption (into a system with a peak load around 90,000 MW). In Greece this problem has been taken care of by the early legal provision that no more than 30% of the power production can be supplied by non controlled systems like wind and PV.

In small island states like in Barbados feed-in tariffs need to be accompanied by quantity restrictions based on the absorption capacity of the grid and subsections of the grid ensuring that the expansion of renewable electricity production from wind and solar energy only grows with the reinforcement of the grid and eventually with the construction of storage facilities.

A third lesson to be learnt from Crete is that it is necessary to combine the high level penetration of wind and solar energy in island systems with the building of storage. In Crete only hybrid plants (wind plus storage or large solar plus storage) will be allowed into the grid in the case of major renewable energy capacity extensions due to the high penetration of wind and PV reached already. As the direct coupling of isolated renewable energy installations with storage will lead to suboptimal use of the storage, the development of centralised or dispatchable decentralised storage will be necessary to achieve higher penetration rates of wind and PV at the lowest possible cost. It is interesting to note that there are many considerations of the introduction of pump storage facilities in combination with additional wind parks in Crete ranging from sophisticated theoretical calculations (e.g. Karapidakis 2015) to actual projects in advanced planning stages (e.g. Terna Energy 2017).

An other lesson that can be learnt from Crete is that its electricity system is officially considered to be of a sufficient size (3,000 GWh/a of demand) to allow unbundling and competition at the generation level ((Executive Agency for Competitiveness and Innovation, no year, p.25).

The case of Cape Verde

The Republic of Cape Verde consists of 10 islands and 13 islets approximately 400 km off the coast of Senegal. The total land area is 4033 km2. The population stands at 542,000 inhabitants (see ECREE Secretariat no year, p.3). The total electricity production was 325.5 GWh in 2014 (see Table 24 below) resulting in a per capita electricity consumption on about 600 kWh/cap/a, which is just about one fifth of the per capita electricity consumption in Barbados. By 2012 99% of the population had electricity access, but as in most other island nations the residential electricity tariff was at 38 US cents/KWh (IRENA 2014, p. 6) even higher than the tariffs in Barbados at the time. The water and electricity supply of Cape Verde is in the hands of ELECTRA, which is owned to 85% by the Cape Verde government and 15% by different municipalities. The conventional energy generation is heavily depending on petroleum products like HFO and diesel. (see ECREEE Secretariat no year, p. 4) Out of 140.5 MW of total installed capacity 33.9 MW of wind (26.4 MW) and PV (7.5 MW) were installed by 2012 as Table 24 below shows. In 2012 this installed renewable energy capacity resulted in 21% of the total production.

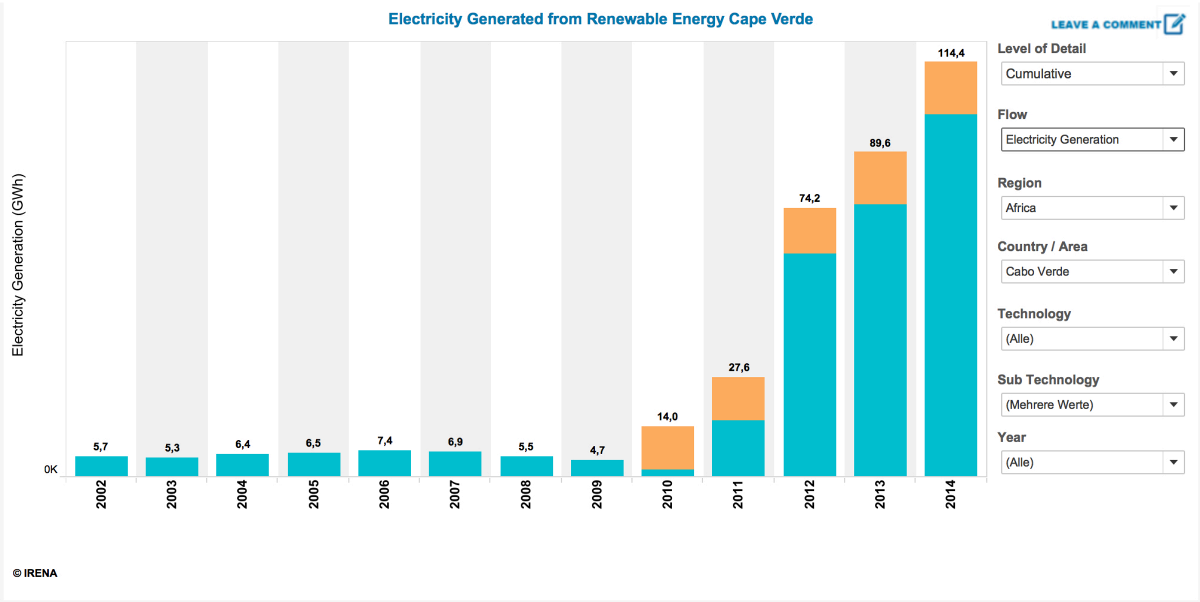
Table 24: Installed electricity generation capacities in MW, resulting production in GWh/a, electricity access and residential electricity rate in Cape Verde in 2012 (source: IRENA 2014, p. 6)

Electricity Access in 2012	99 percent
Installed Capacity in 2012	140.5 megawatts
Renewable Capacity in 2012 • Wind • Solar	33.9 megawatts (24% of all capacity) • 26.4 megawatts (19%) • 7.5 megawatts (5%)
Electricity Generation in 2012	330 gigawatt-hours
Renewable Generation in 2012 • Wind • Solar	68.7 gigawatt-hours (21% of generation) • 61.3 gigawatt-hours (19%) • 7.4 gigawatt-hours (2%)
Electricity Tariff (residential) in 2012	38 US cents per kilowatt-hour

As Table 25 below shows the share of electricity produced from renewable energy sources has increase in the Cape Verdes from 1.8% in 2009 to 35.1% in 2014. Different from Reunion and Fiji the Cape Verde islands did not have any major contribution from hydropower or large scale solid biomass combustion. Thus, the achieved high penetration of renewable electricity is exclusively driven by recent government policies. Figure 71 below shows the fast rising production from wind and PV since 2010.

A first national energy plan was published in 2003 for the time 2003 to 2010 to consolidate the energy sector and to guarantee national energy security. Unfortunately, the national utility went bankrupt, which increased the pressure to move to a commercially viable electricity supply based on rapid investment in renewable energy (see IRENA 2014, p 8). The government then developed a new Renewable Energy Plan for 2010 to 2020 to achieve a renewable energy share of 50% of the countries electricity supply by 2020. This included 94 MW wind energy, 24 MW solar and 7 MW biomass plus a new 20 MW pump storage power plant (see IRENA 2014, p.8).

Figure 71: Electricity generation from renewable energy sources in the Cape Verdes from 2000 to 2014 in GWh/a (data source: IRENA 2017)



The central policy mechanism to achieve these high penetration rates of renewables is a framework for IPPs (Independent Power Producers) and the law n1/2011 with guaranteed PPAs (Power Purchase Agreements) for 15 years. Within a very short time this framework lead to a 25.5 MW wind energy project developed by the IPP Cabeólica S.A. under a PPP (public private partnership) with IfraCo, a donor funded infrastructure company, Electra, the national utility company and the government of Cape Verde (see IRENA 2014, p. 8). The government of Cape Verde explicitly did not use any type of feed-in tariff (see IRENA 2014, p.8), but allowed negotiated guaranteed rates under single power purchase agreements. Nevertheless, the direct involvement of the government in the first large PPA shows some similarities to government administered feed-in tariffs.

Due to the strong involvement of the government the European Investment Bank and the African Development Bank agreed to finance the large IPP project with an investment cost of about USD 83 million (see IRENA 2014, p. 8). The PPP actually administers all aspects of the project consisting of 4 wind parks (IRENA 2014, p. 8). The project has signed a 20 year PPA with the national power company. As can be seen from Table 25 below, the project constitutes practically all of the new wind energy capacity that has been added under the new energy plan until 2016. At the same time it actually contributed 87% of the renewable electricity produced in 2014 or 30% of the total electricity supply of Cape Verde of that year.

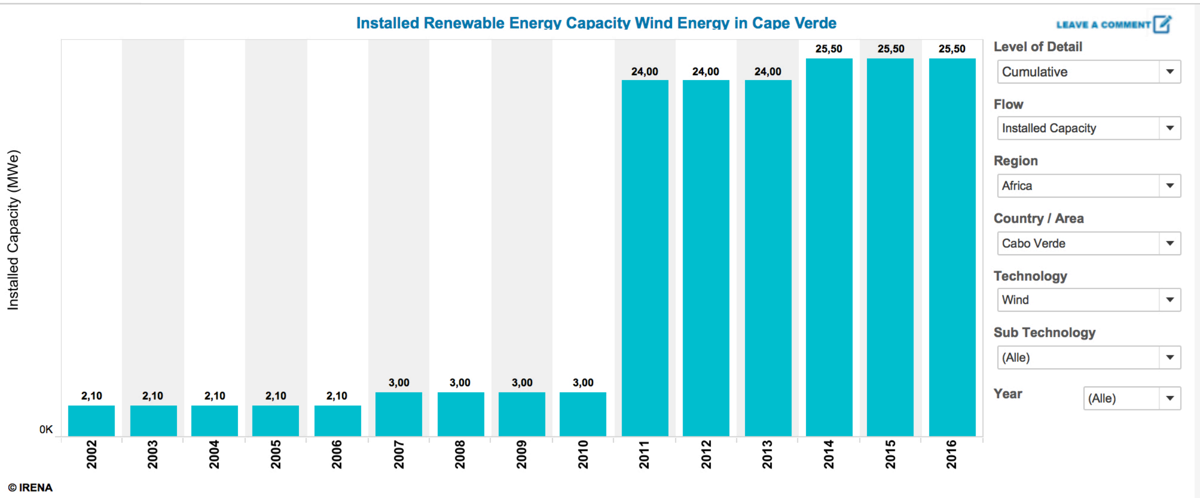
Besides the framework for independent power producers and power purchase agreements the law of 2011 provided a regime for micro generation, it sets out conditions for self producers and tax exemptions for imported equipment. The national utility Electra has provisions for bundling owners to install small scale roof PV under a net metering scheme. Only a minority of the households of Cape Verde can afford the investment, although the investments have very short pay-back times (see IRENA 2014, p. 9). Of the 11 MW of installed PV capacity at least 7.5 MW are due to single large projects (Santiago with 5 MW and Sal with 2.5 MW) (see ECREEE Secretariat no year, p. 4)

Table 25: Installed generation capacities and electricity production in the Cape Verdes from 2000 to 2014 (data sources: IRENA 2017 and US EIA 2017)

Cape Verde	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total generation capacity in MW	45	51	79	77	77	79.8	71.8	74.8	89.8	89.8	103.8	133.5	156.5	142.5	147		
Total RE capacity in MW	0	0	0	2.1	2.1	2.1	2.1	3	3	3	10.5	31.5	32	33	35.5	36.2	36.5
Wind capacity in MW	0	0	0	2.1	2.1	2.1	2.1	3.0	3.0	3.0	3.0	24	24	24	25.5	25.5	25.5
PV capacity in MW	0	0	0	0	0	0	0	0	0	0	7.5	7.5	8.0	9.0	10.0	10.7	11.0
Total electricity production in GWh/a	100.0	100.0	200.0	200.0	200.0	206.5	219.5	235.3	251.1	261.3	300.4	309.7	319.9	307.8	325.5		
Share of RE	0.0 %	0.0 %	0.0 %	2.7 %	3.2 %	3.1 %	3.4 %	2.9 %	2.2 %	1.8 %	4.7 %	8.9 %	23.2 %	29.1 %	35.1 %		
Total RE electricity production in GWh/a	0	0	0	5.3	6.4	6.5	7.4	6.9	5.5	4.7	14	27.6	74.2	89.6	114.4		
Wind production in GWh/a	0	0	0	5.3	6.4	6.5	7.4	6.9	5.5	4.7	2.0	15.6	61.4	75.2	100		
PV production in GWh/a	0	0	0	0	0	0	0	0	0	0	12	12	12.8	14.4	14.4		

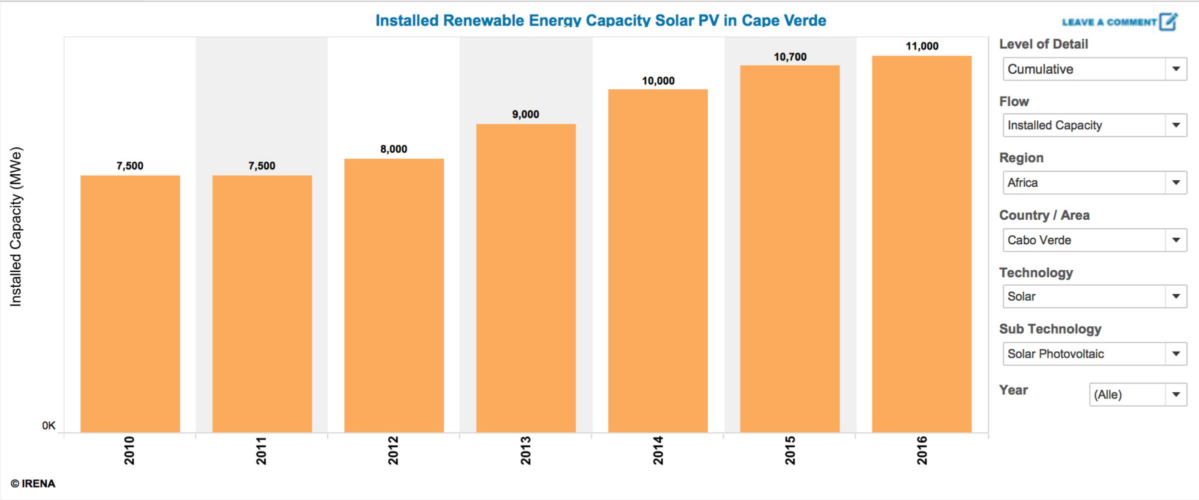
Figure 72 below shows the great impact of single wind energy projects on the installed wind energy capacity. It is interesting to see that the capacity expansion shown in Figure 72 is not immediately matched by an increase in wind energy production as shown in Figure 71 above. It seems that the capacity figures have been reported to the IRENA database before the wind parks were in full operation.

Figure 72: Installed wind energy capacity in Cape Verde from 2000 to 2016 in MW (data source: IRENA 2017)



In the case of PV development in Cape Verde about 500 kWp of PV capacity have been added per year after the two large developments (7.5 MW) had been completed in 2011 as can be seen in Figure 73 below.

Figure 73: Installed solar PV capacity in Cape Verde from 2000 to 2016 in MW (data source: IRENA 2017)



A lesson to be learnt from Cape Verde is that a very determined government of a small island state can achieve a very fast penetration of renewable energy sources with the help of appropriate market conditions and the help of international funding agencies and donors. As pointed out in a number of studies and plans such development has to be accompanied with a strengthening of the grid infrastructure and, as foreseen in the Cape Verde renewable energy plan, it has to be matched by adequate storage as soon as a share of 50% intermittent renewable electricity is reached. In the case of Cape Verde a pump storage hydro plant of 20 MW is foreseen as part of the first 50% renewable power supplied planned by 2020.

An other lesson, which can be learnt from Cape Verde, is that the participation of low income households in renewable energy investment is very difficult, even if the pay-back times are very short under favourable net metering programs.

The case of Hawaii

Hawaii is an archipelago consisting of eight main islands and a land area of 28,311 km^2. The population of about 1.4 million is mainly living on the island of Oahu (about 950,000) (Wikipedia 2017). As Table 26 shows only four islands have more than 10,000 inhabitants.

Table 26: Basic information on the main islands of the Hawaiian archipelago (source: Wikipedia 2017)

Island	Nickname	Area	Population (as of 2010)	Density	Highest point	Elevation	Age (Ma)[24]	Location
O'ahu[27]	The Gathering Place	596.7 sq mi (1,545.4 km^2)	953,207	1,597.46/sq mi (616.78/km^2)	Mount Ka'ala	4,003 ft (1,220 m)	3.7–2.6	21°28′N 157°59′W
Hawai'i[25]	The Big Island	4,028.0 sq mi (10,432.5 km^2)	185,079	45.948/sq mi (17.7407/km^2)	Mauna Kea	13,796 ft (4,205 m)	0.4	19°34′N 155°30′W
Maui[26]	The Valley Isle	727.2 sq mi (1,883.4 km^2)	144,444	198.630/sq mi (76.692/km^2)	Haleakalā	10,023 ft (3,055 m)	1.3–0.8	20°48′N 156°20′W
Kaua'i[28]	The Garden Isle	552.3 sq mi (1,430.5 km^2)	66,921	121.168/sq mi (46.783/km^2)	Kawaikini	5,243 ft (1,598 m)	5.1	22°05′N 159°30′W
Moloka'i[29]	The Friendly Isle	260.0 sq mi (673.4 km^2)	7,345	28.250/sq mi (10.9074/km^2)	Kamakou	4,961 ft (1,512 m)	1.9–1.8	21°08′N 157°02′W
Lāna'i[30]	The Pineapple Isle	140.5 sq mi (363.9 km^2)	3,135	22.313/sq mi (8.615/km^2)	Lāna'ihale	3,366 ft (1,026 m)	1.3	20°50′N 156°56′W
Ni'ihau[31]	The Forbidden Isle	69.5 sq mi (180.0 km^2)	170	2.45/sq mi (0.944/km^2)	Mount Pānī'au	1,250 ft (381 m)	4.9	21°54′N 160°10′W
Kaho'olawe[32]	The Target Isle	44.6 sq mi (115.5 km^2)	0	0	Pu'u Moaulanui	1,483 ft (452 m)	1.0	20°33′N 156°36′W

The total electricity production in Hawaii was about 10,200 GWh/a supplied by a total installed capacity of 2,670 MW (see Table 27). Thus, the electricity system has about ten times the size of Barbados, while the population is about five times as large.

Although Hawaii sees itself as a pioneer in renewable energy the market penetration of renewable electricity has reached only 12.7% in 2014 according to EIA statistics (see Table 15g). At the same time three leading power companies Hawaiian Electric, Maui Electric and Hawai'i Electric Light give a joint penetration rate of 25.8% by 2016 (see Table 28). Historically geothermal energy, biomass and large hydropower have contributed substantially to Hawaii's electricity supply. In the year 2000 the three sources contributed about 920 GWh/a to Hawaii's electricity consumption of about 10,500 GWh. Due to a massive reduction in biomass combustion in 2001 the electricity production from renewable energy sources dropped to just under 600 GWh in 2001. Wind energy did not play a significant role until the year 2006, when the installed capacity increased from 11 to 43 MW and jumped to 64 MW in 2007. A second larger expansion happened in 2011 with an increase in capacity from 62 to 91 MW. In 2012 the capacity increased to about 200 MW (see Table 27). In contrast to Crete wind energy developed relatively late in Hawaii and compared to the 200 MW of wind energy reached in Crete, with a system of less one third of the size of Hawaii, Hawaii still has installed a rather limited capacity.

The same seems to apply for the market penetration of PV in Hawaii, which did not really start until 2012, when the installed capacities increased from 2 to 7 MW doubling in 2013 (15 MW) and 2014 (32 MW) (see Table 27). Compared to the European islands Crete (78 MW) and Reunion (183 MW) the installed capacity seems to be rather modest and the development has occurred rather late.

Table 27: Installed generation capacities and electricity production in the Hawaii from 2000 to 2014 (data source: US EIA 2017a and 2017b)

Hawaii	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		3 major utilities 2016
Total generation capacity in MW	2,389	2,292	2,267	2,268	2,311	2,358	2,414	2,436	2,437	2,565	2,536	2,562	2,730	2,757	2,672		
Total RE capacity in MW	217	213	173	175	173	175	207	228	229	342	341	371	503	539	553		
Wind	12	11	11	11	11	11	43	64	64	64	62	92	206	206	206		202
PV	0	0	0	0	0	0	0	0	1	1	2	2	7	15	32		665.7
Biomass	145	144	106	109	109	109	109	109	109	222	222	222	222	250	247		
Hydropower, large	27	25	23	22	22	24	24	24	24	24	24	24	25	25	25		
Geothermal	33	33	33	33	31	31	31	31	31	31	31	31	43	43	43		
Total electricity production in GWh/a	10,593	10,633	11,663	10,976	11,410	11,523	11,559	11,533	11,376	11,011	10,836	10,723	10,469	10,267	10,204		
Share of RE	8.7 %	5.6 %	4.0 %	5.6 %	5.6 %	5.5 %	6.4 %	7.3 %	7.6 %	7.4 %	7.5 %	9.1 %	9.9 %	11.7 %	12.7 %		
Share of non hydro RE	7.7 %	4.7 %	3.2 %	4.8 %	4.8 %	4.7 %	5.3 %	6.5 %	6.8 %	6.4 %	6.9 %	8.2 %	8.8 %	11.0 %	11.8 %		
Share of non hydro and non geothermal RE	5.2 %	2.7 %	2.6 %	3.2 %	2.9 %	2.8 %	3.5 %	4.5 %	4.8 %	4.9 %	5.0 %	6.1 %	6.3 %	8.3 %	9.3 %		
Total RE electricity production in GWh/a	920	598	467	618	643	635	738	845	860	817	817	975	1040	1204	1300		
Non hydro RE production in GWh/a	817.0	497.0	372.0	527.0	549.0	539.0	618.0	753.0	776.0	704.0	747.0	882.0	925.0	1126.0	1206.0		
Non hydro and non geothermal RE	555.0	290.0	299.0	349.0	336.0	317.0	406.0	523.0	542.0	536.0	546.0	658.0	664.0	851.0	952.0		
Wind	17	2	2	2	7	7	80	238	240	251	261	341	378	503	579		
PV	0	0	0	0	0	0	0	0	0	1	2	4	5	19	39		
Biomass	538	288	297	347	329	310	326	285	302	284	283	313	281	329	334		
Hydropower, large	103	101	95	91	94	96	120	92	84	113	70	93	115	78	94		
Geothermal	262	207	73	178	213	222	212	230	234	168	201	224	261	275	254		

Considering the more recent information from the three major Hawaiian utilities given for installed capacities in their territories shows a strong increase in installed PV capacity to 666 MW by the end of 2016 (see Table 28). Which marks an explosive market diffusion of PV in 2015 and 2016. At the same time the wind energy capacity by the three utilities amounts to 202 MW by the end of 2016, a figure slightly below the value given for all of Hawaii by the US EIA statistics for the end of 2014. Thus, it seems that wind energy has only experienced a modest increase in 2015 and 2016 for all of Hawaii, although this can not firmly be concluded, as the three utility companies don't entirely cover Hawaii.

With respect to the use of different supportive instruments for the introduction of renewable energy sources Hawaii is a very interesting case. As a US federal state has established renewable portfolio standards in 2004 for all companies selling electricity in Hawaii. These standards have successively been increased with a standard of 100% to be reached by 2045. As of July 1st 2015 the following standards apply:

- 10% of its net electricity sales by December 31, 2010;
- 15% of its net electricity sales by December 31, 2015;
- 30% of its net electricity sales by December 31, 2020;
- 40% of its net electricity sales by December 31, 2030;
- 70% of its net electricity sales by December 31, 2040;
- 100% of its net electricity sales by December 31, 2045.

Existing renewables may be counted in the total. In addition, an electric utility company and its electric utility affiliates may aggregate their renewable portfolios in order to achieve the renewable portfolio standard. Hawaii actually became the only state with a legislative goal of 100% renewable energy by 2045 with enacting these standards (see NC Clean Energy Technology Center 2017a). All other instruments have to bee seen in the context of this RPS framework, which sets the binding quantity targets for the introduction of renewable electricity in Hawaii. Comparing the 2010 value reported in the

US EIA statistics (see Table 27 above) to the RPS standard of 10% Hawaii was short by 25%, reaching only a contribution of 7.5% in 2010. Looking at the figures for 2014, the last reported in the US EIA database, Hawaii seemed to fall short again reaching 12.7% one year before the 15% standard had to be met.

Table 28: Installed power generating capacities in the supply areas of Hawaii's three major utilities (source: Hawaiian Electric 2017)

Power facts

The Hawaiian Electric Companies – Hawaiian Electric, Maui Electric and Hawaiʻi Electric Light - provide electricity for 95% of residents of the State of Hawaiʻi on the islands of Oʻahu, Maui, Molokaʻi, Lānaʻi and Hawaiʻi Island.

Tri-company 2016 renewable energy percentage* is 25.8%
Total customers: 460,000 (Residential: 403,000)
Total employees: 2,662

HAWAIIAN ELECTRIC

Customers: 304,261

Firm generation:

Hawaiian Electric plants

- Waiau (oil) .... 500 MW
- Kahe (oil) .... 650 MW
- Campbell Industrial Park (biofuel) .... 120 MW

Independent power producers

- HPOWER (waste-to-energy) .... 68.5 MW
- Kalaeloa Partners (oil) .... 208 MW
- AES-Hawaiʻi (coal) .... 180 MW

Total firm capacity .... 1,726.5 MW

Deactivated units:

- Honolulu Power Plant (oil) (113 MW) .... 0 MW

Variable (as-available) generation:

Independent power producers

- Kahuku Wind .... 30 MW
- Kawailoa Wind .... 69 MW
- Waiʻanae Solar .... 27.6 MW
- Par Hawaii .... 18.5 MW
- Chevron .... 9.6 MW
- Waihonu Solar .... 6.5 MW
- Aloha Solar Fund 1 .... 5 MW
- Kalaeloa Solar Two .... 5 MW
- Kalaeloa Renewable Energy Park .... 5 MW
- Kapolei Sustainable Energy Park .... 1 MW
- Customer-sited solar .... 411 MW

Approximate non-firm capacity: .... 588.2 MW

Renewable energy percentage* 19.4%

MAUI ELECTRIC

Serving Maui Island, Molokaʻi & Lānaʻi
Customers 70,872

Firm generation:

Maui Electric plants (oil)

- Māʻalaea .... 212.1 MW
- Kahului .... 37.6 MW
- Lānaʻi .... 10.4 MW
- Molokaʻi .... 12.0 MW
- Hāna (dispersed generation): .... 2.0 MW

Total firm capacity .... 274.1 MW

Variable (as-available) generation:

Independent power producers

- Kaheawa Wind Farm I .... 30 MW
- Kaheawa Wind Farm II .... 21 MW
- Auwahi Wind Farm .... 21 MW
- Mākila Hydro .... 0.5 MW
- Lānaʻi Sustainability Research (PV) .... 1.2 MW
- Customer-sited solar .... 93.7 MW

Approximate non-firm capacity: .... 167.4 MW

Renewable energy percentage* 36.9%

HAWAIʻI ELECTRIC LIGHT

Customers 85,029

Firm generation:

Hawaiʻi Electric Light plants (oil)

- Hill .... 35.5 MW
- Puna .... 38 MW
- Keāhole .... 79.8 MW
- Kanoelehua .... 21 MW
- Waimea: .... 7.5 MW
- Dispersed generation: .... 5 MW

Independent power producers

- Puna Geothermal Venture .... 34.6 MW
- Hāmākua Energy Partners (oil) .... 60 MW

Total firm capacity: .... 281.4 MW

Retired units:

- Shipman (oil) (15.2 MW) .... 0 MW

Variable (as-available) generation:

Hawaiʻi Electric Light plants

- Waiau Hydro .... 1.1 MW
- Puʻuʻeo Hydro .... 3.25 MW

Independent Power Producers

- Wailuku River Hydro 12.1MW
- Pakini Wind (Tawhiri) .... 20.5 MW
- Hawi Renewable Development (wind) .... 10.56 MW
- Customer-sited generation .... 81.5 MW

Approximate non-firm capacity .... 129.01 MW

Renewable energy percentage* 54.2%

* Renewable energy percentages as of 12/31/16 as defined by Hawaiʻi Revised Statutes 269-91
Generation projects as of 3/15/2017. Generation capacity figures in gross megawatts.

Hawaiian Electric
Maui Electric
Hawaiʻi Electric Light

For more information visit: www.hawaiianelectric.com 3/2017

In September 2009, the Hawaii Public Utilities Commission (PUC) issued a decision that established a feed-in tariff in Hawaii. The rates for the feed-in tariff, schedule, and standard interconnection agreements were approved on October 13, 2010. This program was reviewed by the PUC two years after the start of the program and every three years thereafter. The FIT for Tiers 1 and 2 opened November, 2010. Rates for Tier 3 were approved November 22, 2011 and revised tariffs were filed by December 30, 2011. Tier 3 projects are capped at 33% of the aggregate feed-in tariff cap for each of the HECO companies (see NC Clean Energy Technology Center 2017b). The FIT system was discontinued as of April 1, 2017. The FIT program on all islands and all Tiers have been closed to new applications (Hawaiian Electric 2017).

To apply for the feed-in tariff, applicants had to register and apply online at an Independent Observer FIT web site. After January 3, 2012, systems must file a building permit application on the same day, or before applying for the feed-in tariff, unless no building permit is required by the county.
Under this program, qualified projects received a fixed rate over a 20-year contract. There were three tiers for rates, with the tiers and rates differentiated by technology and system size. The maximum caps on system size varied by island and by technology. Tier 1 included all islands and technologies where the project is less than or equal to 20 kilowatts-AC (kW-AC) in capacity. Tier 2 included systems sized greater than 20 kW-AC and less than or equal to 100 kW-AC for on-shore wind and in-line hydropower on all islands; 100 kW-AC for PV and CSP on Lanai and Molokai; 250 kW-AC for PV on Maui and Hawaii; 500 kW-AC for CSP on Maui and Hawaii; and 500 kW-AC for PV and CSP on Oahu. Tier 3 covered all systems larger than the Tier 2 caps, up to 5 megawatts-AC (MW-AC) on Oahu and 2.72 MW-AC on Maui and Hawaii. Wind projects on Maui and Hawaii were subject to the Tier 2 caps. (see NC Clean Energy Technology Center 2017b)

Table 29: Rates under the Hawaiian FIT program (source: NC Clean Energy Technology Center 2017b):

Feed-in Tariff Rates*

Tier	Technology	Eligible System Size	Rate
Tier 1	Photovoltaics	Less than or equal to 20 kW	$0.218/kWh
Tier 1	Concentrating Solar Power	Less than or equal to 20 kW	$0.269/kWh
Tier 1	On-Shore Wind	Less than or equal to 20 kW	$0.161/kWh
Tier 1	In-line Hydro	Less than or equal to 20 kW	$0.213/kWh
Tier 2	Photovoltaics	Greater than 20 kW, less than or equal to 500 kW	$0.189/kWh
Tier 2	Concentrating Solar Power	Greater than 20 kW, less than or equal to 500 kW	$0.254/kWh
Tier 2	On-Shore Wind	Greater than 20 kW, less than or equal to 100 kW	$0.138/kWh
Tier 2	In-line Hydro	Greater than 20 kW, less than or equal to 100 kW	$0.189/kWh
Tier 3	Photovoltaics	Greater than 500 kW, less than or equal to 5 MW	$0.197/kWh
Tier 3	Concentrating Solar Power	Greater than 500 kW, less than or equal to 5 MW	$0.315/kWh
Tier 3	On-Shore Wind	Greater than 100 kW, less than or equal to 5 MW	$0.120/kWh
Baseline FIT	Other RPS-Eligible Renewable Energy Technologies**	Maximum size limits for facilities	$0.120/kWh

The tariffs given in Table 29 take into account that income generated from renewable energy sources enjoys a 35% tax credit. The rate for applicants without such tax credit are approximately 30% higher (see Table 30).

Table 30: FIT rates under Tier 1 and 2 for applicants without 35% tax credit (source: Hawaiian Electric 2010, sheet 78D)

Renewable Generator Type and Size	FIT Energy Payment Rate (¢/kWh)
Tier 1 PV ≤ 20 kW	27.4
Tier 1 CSP ≤ 20 kW	33.1
Tier 2 PV > 20 kW and ≤ 500 kW	23.8
Tier 2 CSP > 20 kW and ≤ 500 kW	27.5

Due to the substantial caps on the volume of projects allowed under the FIT system projects were allowed into a project queue. As a result Hawaii experienced speculative queuing of projects not ready for implementation. This problem was dealt with by an independent review of the project applications. If projects were considered not ready for implementation they were taken out of the queues (see Hawaii Clean Energy Initiative 2014).

Overall the FIT programme induced many renewable energy projects and easily reached the given quantity targets. The actual problem was an oversubscription of the program and the resulting speculative queuing of developers.

If the program would have been continued a frequent adjustment of the FIT rates would have been more than necessary.

> Hawaii's original net-metering law was enacted in 2001 and expanded in 2004 by HB 2048, which increased the eligible capacity limit of net-metered systems from 10 kilowatts (kW) to 50 kW. In 2005, the law was further amended by SB 1003, which authorized the Hawaii Public Utilities Commission (PUC) to increase certain limits outlined in the law and provided for the carryover of net excess generation (NEG) to the customer's next bill. In March 2008, the PUC issued an order to implement SB 1003. This order generally raised both the individual system capacity limit and the aggregate capacity limit for net-metered systems. In October 2008, Hawaii's governor; the Hawaii Department of Business, Economic Development and Tourism; the Hawaii consumer advocate, and the HECO companies entered into an energy agreement, a product of the Hawaii Clean Energy Initiative. This agreement provides that there should be no system-wide caps on net metering, and that net metering should transition towards a feed-in-tariff. In December 2008, the PUC issued an order to raise the aggregate capacity limit for net-metered systems in the service territories of HELCO and MECO. In January 2011, the PUC issued an order approving changes to Kauai's program, which was full, and the aggregate capacity limits for HECO companies were lifted and are now based on per-circuit caps rather than a percentage of peak demand. (NC Clean Energy Technology Center 2017c)

The original net metering program was stopped in October 2015 by the Hawaiian public utility commission (PUC) (see Rocky Mountain Institute 2015) in favour of two new options, the ‚grid-supply‘ and the ‚self-supply‘ option. The ‚grid-supply‘ option is similar to the former net metering, but the excess electricity sold to the grid is bought at a reduced rate (between 0.15 and 0.28 USD/kWh), while the average residential rate, at which net metering worked before was about 0.38 USD/kWh. Under the ‚self-supply‘ option no exports into the grid are allowed except for very limited amounts for very short periods. Any exported solar electricity is not paid for by the utility (see Rocky Mountain Institute 2015). Specifically the ‚grid-supply‘ option seems to be in line with the agreement of October 2008, stipulating that net metering should transition towards a feed-in tariff.

In the case of Hawaii there are a number of lessons, which can be learnt. The first is that net metering with banking and substantial volumes of solar power being bought back by the utility has reached a limit, which should drive a substitution of a generous net metering system by net billing or a fair feed-in tariff, as agreed by the different stakeholders in Hawaii in 2008. By now solar PV costs have declined so much that a substitution by net billing seems to be more than justified. In Hawaii the electricity production cost from small systems are in the range of half the average consumer price, while the cost in Germany has gone to less than a third of the Hawaiian consumer rate for electricity.

A second lesson seems to be that a proper feed-in tariff needs to have a clear tariff reduction perspective. With the very dynamic development of PV system costs a fixed FIT tariff with a volume cap but without a dynamic tariff reduction for future investments will induce oversubscription of the envisaged volumes and will lead to speculative queuing as in the case of Hawaii.

The third lesson seems to be that a quantity oriented support mechanism like RPS (renewable portfolio standards) does not necessarily lead to the achievement of the set quantity targets, especially when these targets are quite ambitious like in the case of Hawaii.

It remains to be seen how the Hawaiian support mechanisms will evolve in the future and whether these will actually achieve the set targets. So far the performance has been lower than in the case of the European islands Reunion or Crete, which are more comparable to Hawaii than Fiji or Cape Verde.

The case of the Dominican Republic

The Dominican Republic is of special interest, because it is the only country in the Caribbean with a feed-in tariff for renewable energy sources. It is a comparatively large island county. With 48,442 km^2 it has more than one hundred times the size and with about 10 million inhabitants it has more than thirty times the population of Barbados (see Wikipedia 2017a).

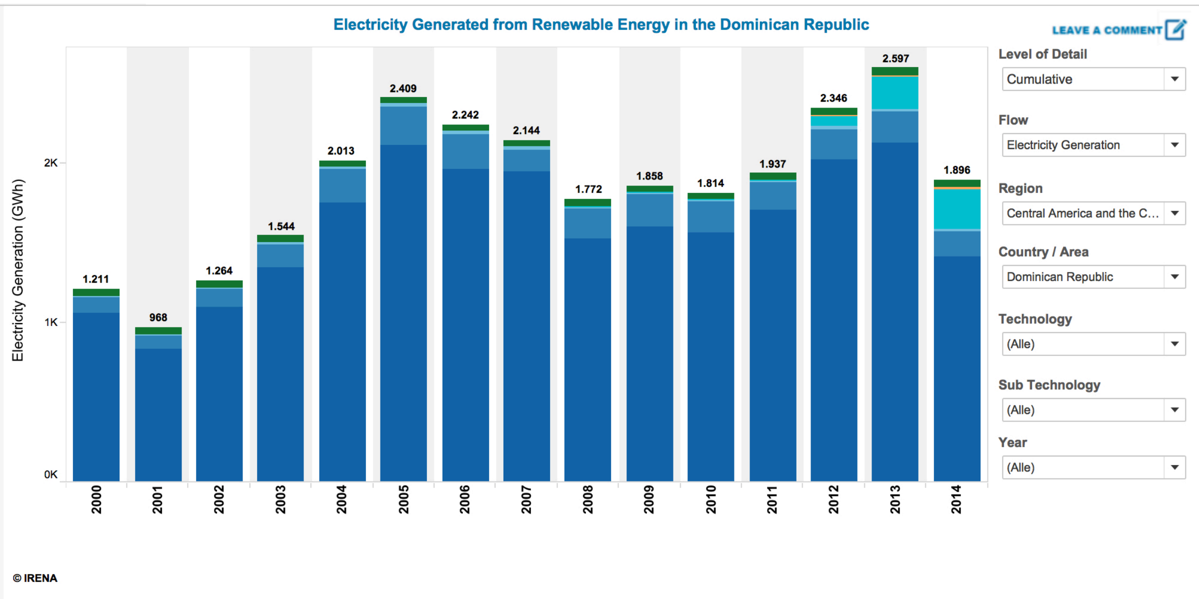
The electricity system of the Dominican Republic had an installed capacity of 3,778 MW in 2014, the last year reported in the US EIA statistics and produced about 14,350 GWh/a in the same year (US EIA 2017), which is almost fifteen times the power production of Barbados. The peak demand was about 1,800 MW in 2012 (Energy Transition Initiative 2015, p.2) The generation of electricity has been liberalised and up to 2012 13 private companies were generating power in the Dominican Republic (Energy Transition Initiative 2015, p.1). The largest generator in the country is AES Andre, which produced 15.64% of the total electricity generated in 2012 (Energy Transition Initiative 2015, p.1).

The Dominican Republic has a legislated feed-in tariff and uses net-metering (Energy Transition Initiative 2015, p.2). It has set a renewable electricity target of 25% for 2025 (Energy Transition Initiative 2015, p. 1), of which it had reached 14% in 2012 (Energy Transition Initiative 2015, p.2). The share of renewable electricity production is heavily dependent on hydropower and the rainfall of any given year, as Table 31 shows. In 2013 this has lead to a renewable share of 15.1%, which dropped to 11.3% in 2014 with little change in the overall production level. The dominant influence of hydropower on the renewable electricity generation in the Dominican Republic can be seen clearly from Figure 74 (the dark blue representing large hydropower and the slightly lighter blue representing medium sized and small hydropower). The figure shows as well that only wind energy has started to supply a significant amount of renewable power other than hydropower since 2012.

Table 31: Installed generation capacities and electricity production in the Dominican Republic from 2000 to 2014 (data source: US EIA 2017a and 2017b)

Dominican Republic	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Total generation capacity in MW	2,500	2,900	3,000	3,400	3,300	3,177	3,206	3,206	2,958	2,981	3,008	3,040	3,169	3,716	3,778		
Total RE capacity in MW	400	400	500	500	500	480.61	479	479	482.2	504.2	533.2	566.6	588.6	685	695		
Wind									0.2	0.2	0.2	0.2	33.3	81.1	85.0	85.5	135
PV													1.6	7.4	12.3	15.5	45.5
Solid Biomass	10.6	11	11	11	11	11	11	11	11	11	14	14	14	14	14	14.6	31.6
Hydropower, large	400	400	500	500	500	470.61	469	469	472	494	523	523	543	583	588		
Total electricity production in GWh/a	8,100	9,700	12,000	13,000	11,000	11,980	13,060	13,650	11,676	11,558	12,304	13,093	13,963	14,082	14,367		
Share of RE	10.3 %	7.6 %	7.8 %	9.6 %	15.2 %	16.0 %	13.6 %	12.7 %	12.1 %	12.9 %	11.9 %	11.9 %	13.5 %	15.1 %	11.3 %		
Share of non hydro RE	0.5 %	0.4 %	0.3 %	0.3 %	0.6 %	0.0 %	0.2 %	0.3 %	0.3 %	0.2 %	0.3 %	0.2 %	0.7 %	1.7 %	2.1 %		
Total RE electricity production in GWh/a	838	738	939	1,245	1,670	1,913	1,779	1,739	1,414	1,493	1,467	1,563	1,888	2,126	1,622		
Non hydro RE production in GWh/a	38.0	38.0	39.0	45.0	70.0	5.0	29.0	38.0	29.5	28.5	31.5	31.5	103.5	242.9	298.9		
Wind									0.5	0.5	0.5	0.5	67.9	197.0	246.9		
PV													2.6	11.9	20		
Solid Biomass	38	38	39	45	70	5	29	38	29	28	31	31	33	34	32		
Hydropower, large	800	700	900	1,200	1,600	1,908	1,750	1,701	1,384	1,464	1,435	1,531	1,784	1,883	1,323		

Figure 74: Annual power production from renewable energy sources in the Dominican Republic (dark blue: large hydro, slightly lighter blue: small and medium sized hydro, light blue: wind, dark green: biomass, orange: PV) (data source: IRENA 2017)



Before 2012 the renewable electricity capacity has been almost exclusively constituted by hydropower as Figure 75 shows. Wind energy has develop since 2012 in three major steps. In 2012 about 33 MW of wind capacity was taken into operation, in 2013 another 48 MW were added. In 2014 an additional capacity of just 4 MW were connected, while the capacity stayed virtually constant in 2015. Most of the capacity installed by 2014 consisted of the two wind parks Los Cosos I (25.2 MW) and Los Cosos II (52 MW). In 2016 an other 50 MW were added at the site El Guanillo (see Energy Transition Initiative 2015, p. 3) bringing the present capacity to 135 MW of wind energy (see Figure 76).

Figure 75: Development of the installed renewable electricity capacity in the Dominican Republic since 2000 (dark blue: large hydro, slightly lighter blue: small and medium sized hydro, light blue: wind, dark green: biomass, orange: PV) (data source: IRENA 2017)

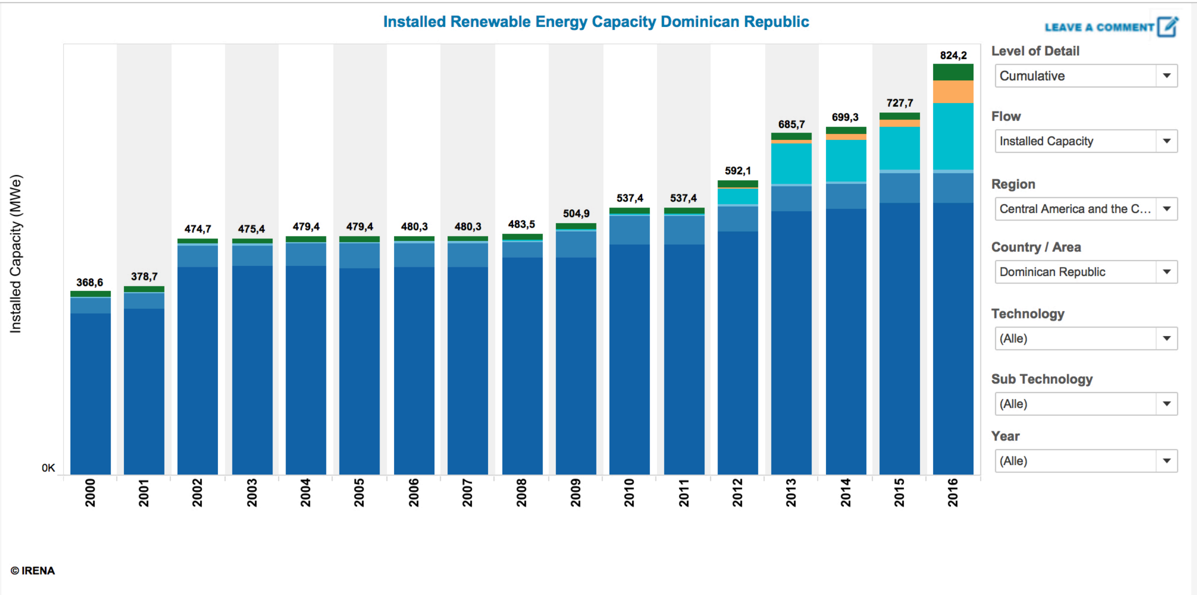
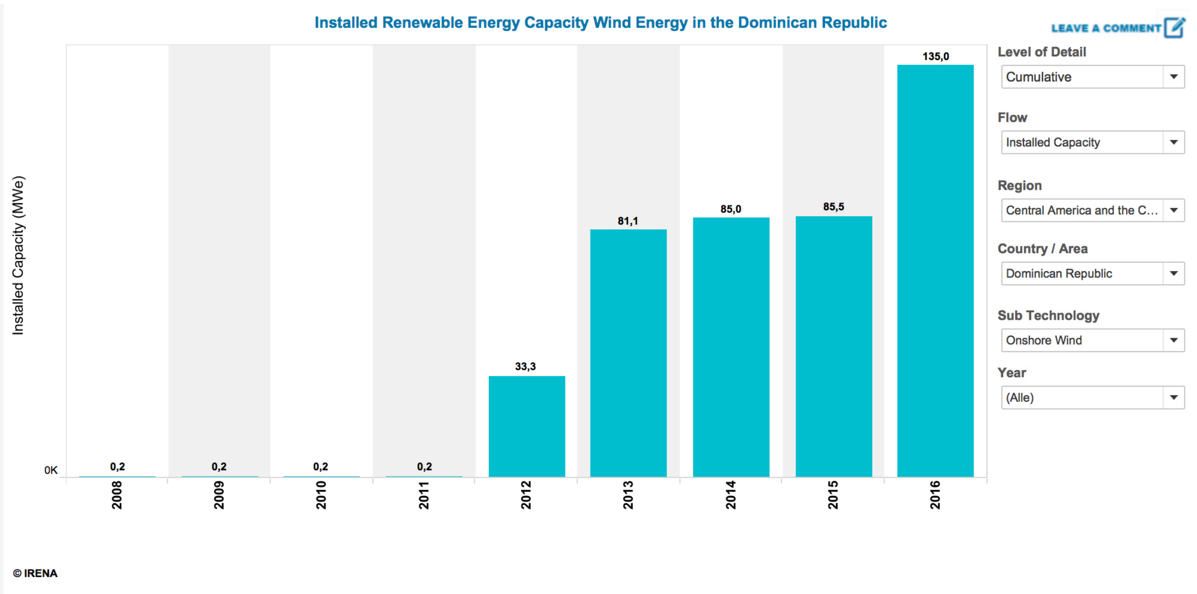
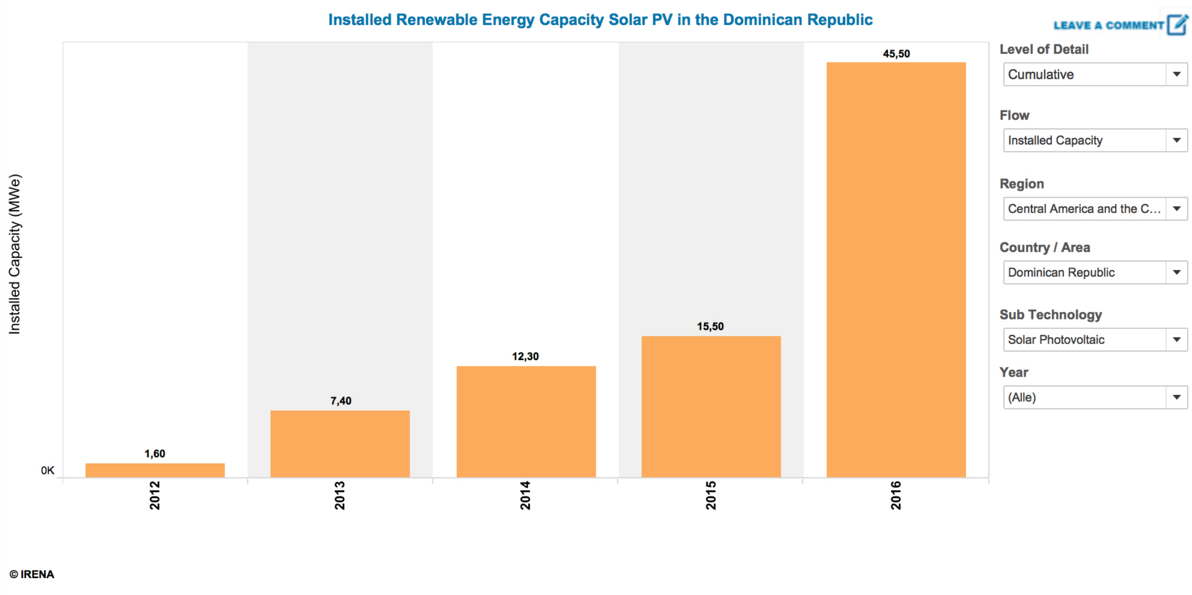


Figure 76: Development of the installed wind energy capacity in the Dominican Republic since 2000 (data source: IRENA 2017)



Like wind energy PV started to take off in the Dominican Republic in 2012, when the first 1.6 MW of PV were installed. In 2013 the new installations increased to 6.6 MW, while 4.9 MW were added in 2014. In 2015 further 3.2 MW were installed, while 2016 witnessed the addition of 30 MW of PV brining the total installed PV capacity to 45.5 MW by the end of 2016 (see Figure 77). This capacity is far below the expectations of 2015, when a 54 MW solar plant was under construction in Monte Plata, and additional contracts were awarded in 2012 for a 50 MW plant in the Santo Domingo province and a 58 MW plant in the the Monte Cristi province. An additional 130 MW of projects were to be developed by Grupo Empresas Dominicanas de Energy Renovable (see Energy Transition Initiative 2015, p.3).

Figure 77: Development of the installed solar PV capacity in the Dominican Republic since 2000 (data source: IRENA 2017)



The actual development of renewable energy sources other than large and medium sized hydropower seems to be in sharp contrast to the political ambitions of the Dominican Republic put forward in 2007 in Law 57-07 on *Renewable Sources of Energy Incentives and Its Special Regimes,* which set a target of a 25% share for renewable energy in the country's final energy consumption for 2025 (see Worldwatch 2015, p. 160). Besides setting up diverse tax incentives the law introduced the framework for feed-in tariffs for renewable energy sources. Beside setting out the framework the law actually contained feed-in tariffs in the form of a premium payment to the wholesale electricity price for both utilities and self-generators (see Worldwatch 2015, p. 163). The tariffs given in Table 32 below did not include an adjustment mechanism over time (like in the German FIT) and where extremely high as compared to international standards. The rate for PV was 0.54 USD/kWh at a time when the FIT in Hawaii was at 0.22, in Germany at 0.18 and in France at 0.14 USD/kWh as the comparison in Table 33 shows.
The very high feed-in tariffs were considered to be to high to sustain by CDEEE, the national utility company holding of all transmission and distribution companies, and the government followed this view (see Worldwatch 2015, p. 163). As a consequence the feed-in tariffs were never applied. Instead power

Table 32: Feed-in tariffs stipulated in law 57-07 (see Worldwatch 2015, p. 163)

Table 8.4 Renewable Energy Feed-In Tariff Rates Under Law 57-07, Proposed But Not Enacted

Energy Source	Feed-in Tariff Rate
	U.S. cents per kWh
Wind (connected to SENI)	12.5
Wind (self-generation for sales to SENI)	4.9
Biomass (connected to SENI)	11.6
Biomass (self-generation for sales to SENI)	4.8
Municipal Solid Waste (for sales to SENI)	8.5
Solar PV (self-generation greater than 25 kW, for sale to SENI)	10.0
Solar PV (greater than 25 kW, connected to grid)	53.5
Solar PV (less than or equal to 25 kW, connected to grid)	60.0
Small hydro (connected to SENI)	10.0
Small hydro (self-generation for sales to SENI)	4.8

Source: See Endnote 55 for this section. ©Worldwatch Institute

Table 32: Comparison of the feed-in tariff for PV of law 57-07 with international feed-in tariffs (see Worldwatch 2015, p. 163)

Table 8.5 Select International Examples of Large-Scale Solar PV Feed-In Tariff Rates

Country	Feed-in Tariff Rate
	U.S. cents per kWh
Dominican Republic	**0.54**
Japan	0.53
Switzerland	0.47
Czech Republic	0.40
Israel	0.39
Malaysia	0.38
Slovenia	0.38
Uganda	0.36
Ontario, Canada	0.33
Malaysia	0.26
United Kingdom	0.24
Hawaii, USA	0.22
Germany	0.18
France	0.14

Source: See Endnote 56 for this section.

purchase agreements (PPAs) were made with large solar installations like the 30 MW Monte Plata solar plant, which receives a price of 0.175 USD/kWh, less than 1/3 of the official feed-in tariff for PV (see Worldwatch 2015, p. 163).

In 2011 the national energy commission (CNE) launched a net metering program. This net metering program allows consumers to balance their renewable energy overproduction with power consumption from the grid. Surplus energy can be sold to the grid operator at a given price (see Worldwatch 2015, p. 164). The program has been reasonably successful by the end of 2014 with 519 net metering customers (see Worldwatch 2015, p. 164). About two thirds of these customers had installations smaller than 10 kWp and 68% of the clients were residential (see Worldwatch 2015, p. 165). However, the size of the average installed system grew from 10.2 kWp in July 2012 to 23.7 kWp in 2014 (see Worldwatch 2015, p. 165). The total generation capacity under the net metering program was 13.3 MW by the end of 2014 with largely varying degrees of participation (42% with EDE Norte to 0.19% with CEB) (see Worldwatch 2015, p. 165). Although the program does not have a size cap only 76 out of 519 installations were larger than 25 kW (see Worldwatch 2015, p. 165).

One of the major problems for the program is a low level of public awareness and some customers showing distrust in the program (see Worldwatch 2015, p. 166). The Worldwatch report recommends: ‚To build public trust, it is also crucial that energy distributors dutifully remunerate net metering participants if they still have an accumulated credit in December of every year. So an emphasis must be placed on adequately and promptly paying clients, as this will build public trust and credibility‘ (Worldwatch 2015, p. 166).

A second concern is that the absence of a cap for potential capacity could prove problematic due to the limited technical and financial capacity of the countries power system (Worldwatch 2015, p. 166). The Worldwatch report (2015, p.166) recommends: ‚..that CNE and other government agencies develop a maximum net metering installed capacity that allows for significant growth but ensures stability for the grid‘.

Lessons to be learned from the renewable energy policy in the Dominican Republic are that the net metering program has been less successful than the RER in Barbados and that the feed-in tariffs established by the judiciary were just so unrealistic and ill informed that they met with strong resistance by the national transmission system operator and the government, which lead to the fact that they were never actually applied. At the same time the expansion of large scale wind and solar installations has progressed based on power purchase agreements (PPAs) with independent power producers (IPPs). Nevertheless, many projects seem to be far behind schedule and it is unclear whether this is due to cumbersome administrative procedures or difficulties in project financing. As the Worldwatch report (2015, p.167) mentions ‚Private local and international banks remain reluctant to offer loans to renewable energy projects due in large part to the perceived risks of these investments. The Dominican Republic’s poor credit rating and the lack of established sustainable energy markets create a high-risk lending environment.‘

Conclusions for support mechanisms from the island examples

All islands looked at in this short review have different support mechanisms for renewable energy in place. Some of them are so successful that they have to be limited or substantially modified, others have not had such success.

Net metering is and has been applied in the Dominican Republic, Cape Verde, Crete and Hawaii. In the case of Hawaii the scheme has been so successful that it has been modified in 2017 to resemble a net billing system. After agreement between the different stakeholders reached in 2008 on the development of net metering in Hawaii towards a feed-in tariff system, this step takes into account that the costs of solar systems have fallen so far and the success of the net metering system has been so great that a continuation at the customer retail price rate would cause to high a burden on the average rate payer. In the case of Reunion and Crete the feed-in tariff for small systems actually establishes a similar system of net billing, but the rates for small PV installations seem to be substantially lower than in the proposed net billing case in Hawaii. Thus, for the future of net metering or net billing in Barbados it seems to be appropriate to move into the direction of net billing.

Feed-in tariffs, which are and have been used in Crete, Reunion, Hawaii and the Dominican Republic have been very successful in inducing a fast diffusion of wind and solar energy. In the case of Crete and Reunion short term explosive expansions of installed PV capacity could not be avoided between 2009 and 2014 due to the very fast decline in PV system costs and due to the fact that no cap was applied to the installed capacities. Eventually, the tariff rates were adjusted downwards fast enough to eventually stop the explosive diffusion of PV in these island systems. In Hawaii no similar development occurred as the installed quantities were heavily capped, but a removal of most caps seemed to have driven a very fast expansion of PV in 2015 and 2016.

In the case of wind energy feed-in tariffs performed quite well in Crete allowing an early fast but gradual development of the wind capacity up to the set limit of 30% of the system generation. In the Dominican Republic unrealistically high feed-in tariffs set by law lead to a strong resistance by the national grid operator and the government (who owns and controls the national grid operator) and a situation where the feed-in tariff system has not been applied since 2007.

For Barbados the international experiences with feed-in tariffs show that they can be a very strong support mechanism, but that they hinge on realistic tariffs set for the different technologies, a dynamic reduction over time following the decrease in technology costs and on caps for the capacities of renewables installed to avoid technical problems for the island grid.

The case of Fiji shows that political target setting without much systematic support will not lead to a substantial expansion of renewable energy production, a fact which is masked by the large share of hydropower in Fiji's power production. Although, Fiji is often mentioned as a forerunner for the development of renewable energy use the share of renewable energy based power production has decreased from over 92% in 2002 to 56% in 2014. Although some of this difference is due to different amounts of rainfall in the respective years, the trend of the share of renewable power in Fiji is clearly downward.

Although the the Cape Verde islands have been very successful in increasing their share of renewable power from 0% in 2002 to over 35% in 2014 the lack of a clear support mechanism leads to the need for high government involvement in settling the conditions for large wind and solar installations. This has lead to a concentration on large projects with significant international ownership. For every country looking for a broad citizen participation and a high share of local ownership such a model is certainly not advisable.

Barbados market size and market structure as background for the integration of renewable energy sources and the applicability of different mechanisms for the promotion or RE diffusion

The size of Barbados' electricity market poses substantial restrictions on the applicability of the different support mechanisms for renewable energy sources. In the past Barbados' electricity market has been converted from a publicly owned vertically integrated monopoly supplier to a regulated privatised vertically integrated monopoly supplier.

As Bacon (1995) has shown, the deintegration of a vertically integrated monopoly supplier may cause substantially higher costs in small countries than the possible cost savings achievable by the deintegration. Bacon shows that in small countries the vertical deintegration will cause substantial coordination costs specifically in the dispatch of production capacity while it is doubtful that any cost savings can be achieved by splitting up power generation into three to five competing companies with comparable assets enabling effective competition (Bacon 1995, p.21f). If vertical deintegration is meeting a situation with little competition in generation, its benefits will be minimal while costs will be high (Bacon 1995, p.15). Effective competition in generation requires that non of the competing firms dominates the market and that the competing companies own generating capacities, which directly compete against each other, which is to say that a cost reduction of a specific plant of one competitor enables him to substitute capacities of his competitors in the merit order (see Bacon 1995, p.23). If such competitive capacity does not exist, there will be no effective competition.

Bacon and Beasant-Jones (2001) emphasise that developing countries with less than 1000 MW installed generation capacity will not attract sufficient numbers of participants in generation and distribution to induce substantial competition. Besides the problem of attracting a sufficient number of investors for an unbundled power sector in Barbados it would be impossible to split up the generating capacities of Barbados Light and Power in such a way as to produce three or more competing companies with such generating equipment even if the investors could be found.

A look at Table 9 (above) shows that the Spring Garden plant combines most of the essential generation capacity, while the Seawell plant only runs on peak capacities with high marginal cost and the Garission Hill plant consists only of one diesel engine with just about 5% of the total generation capacity. As it is totally unreasonable to split up the Spring Garden plant among different owners it is impossible to split up the existing generation capacity in such way as to create sufficient competition in generation. In such situation the advantages of keeping a vertically integrated power company clearly outweigh the advantages of deintegration (see Bacon 2005, p. 14f). In this much Barbados shows the typical structure of small economies and has achieved the maximum feasible degree of market liberalisation. As Bacon (1995, p.2) has put it: ,.. *in small or very poor economies, where the existing power system is small scale, it is becoming apparent that the balances of advantages and disadvantages of a particular pattern of reform and restructuring may be quite different from those in a larger system.'*

At the same time Barbados has empowered the Fair Trade Commission to control the privatised vertically integrated monopoly to reduce the danger of an inefficient uncontrolled monopoly. As compared to many developing countries Barbados has gone beyond the stage of hybrid models for power sector reform, where state owned and privately owned utilities coexist, like Gratwick and Eberhard (2008, p.3958) point out. Considering the stage of market liberalisation reached it is very likely and highly recommendable that this overall market structure should and will remain largely unchanged.

There may certainly be chances for improvement by the introduction of performance based regulation (as suggested by Woo et al. 2003, p.1103) and by strengthening the capacities of the FTC to effectively regulate the privatised vertically integrated monopoly (BL&P). In the situation where renewable energy technologies can contribute substantially to the reduction of electricity costs and massive spending of hard currency for fossil fuel imports for most SIDS Weisser (2004, p.108) concludes that ‚*it is important that power sector reform allows these technologies to play an integral - and in the long-run perhaps dominant - part of providing electricity in SIDS.*‘

Weisser (2004, p.120) suggests that independent power producers (IPPs) producing electricity from renewable sources can play an important role in the diffusion of renewables into the market and that this will require certain precondition to be successful, namely the creation of a regulatory framework that allows fair competition or tender for power production from IPPs as well as ensuring PPAs and a transparent and stable electricity tariff regime (see Weisser, 2004, p.120). He ascertains that the introduction of IPPs can lead to the proliferation of renewable energy technologies ‚*especially where feed-in tariffs exist*‘ (Weisser 2004, p.120), but he points out that under some circumstances ‚*the provision of long-term stable feed-in tariffs in economies with weak currencies can constitute a considerable risk to both foreign investors and the power utility in the presence of significant variations in both the utilities own fuel prices and the country's currency value.*‘ (Weisser 2004, p.124). Thus, appropriate precautions need to be taken against such risk in case long-term stable FITs should be established.

Due to the limited size of the electricity system capacities of renewable energy technologies which can be installed in the short- and midterm are in the range of a few ten mega-watts for wind and solar PV as well as for the possible use of solid biomass, biogas or waste to energy. Even when the power system will be supplied 100% by renewable energy sources the installed capacities are in the range of about 200 MW for wind and PV each and in the range of a few ten mega-watts or even smaller for all other technologies. This will limit the number of utility scale installations. In wind energy utility scale wind parks are normally larger than 10 MW and easily in the range of 30 and more MW each. In the case of solar PV a utility scale installation will be most likely in the range of 10 MW to realise full economies of scale, while in solid biomass combustion single plants will be most likely in the range of 10 to 30 MW each. Only in the case of biomass gasification a tendency towards farm size installations in the range between 0.5 and 5 MW will be considerably smaller than 10 MW each.

Considering the scope of the present system integration studies we are looking at a total of up to 60 MW of combined additional wind and solar capacity to be installed within the next years, out of which 35 MW are supposed to be distributed (smaller) PV, 10 MW central PV and 15 MW wind (see GE Energy Consulting 2015, p.9). The draft NAMA strategy foresees a 22.5 MW bagasse cogeneration plant (solid biomass combustion) and a 13.5 MW waste to energy (plasma gasification) plant (Barbados Government 2013, p.42). The bagasse plant would be substantially more expensive, if the plant would be scaled down and the waste to energy plant even banks on imported waste to be able to scale to an economical size plant. Thus, it is quite clear that there will only be a few possible utility scale investors for each type of renewable technology applicable in Barbados. This has serious implications for the choice of the most appropriate policy for the promotion of the use of renewable energy sources in Barbados.

Considering the introduction of differentiated FITs the number of possible utility scale investors does not matter, thus, this policy is fully applicable in Barbados.

For the establishment of renewable portfolio standards and a green certificate market, where only BL&P would be required to fulfil the RPS standards, a monopsony would exist with the power to push down the rents of the competing producers of renewable electricity. A market for green certificates could not successfully be established, as the number of buyers in such a market would not be sufficient. Thus, due to the size and structure of the electricity system in Barbados no RPS system can be established.

In the case of an auctioning system the limited number and volume of auctions would make it very difficult to attract a sufficient number of bidders. It is highly doubtful that there will be a sufficient number of truly competing bidders for auctions in the range of 10 to 20 MW of wind or solar capacity per year, even if international participation would be invited. In the later case it is highly likely that the international bidders would be able to undercut Barbadian bidders due to their ability to access the necessary capital to favourable conditions and to contract larger volumes of renewable capacity. A similar trend towards international domination has been documented in power sector liberalisation in many developing countries (see Wamukonya 2003, p. 1276). Wamukonya shows that ten international companies dominated the investment into private electricity projects in developing countries. In the period of 1990 to 1997 156 out of 534 projects were controlled by the ten largest international companies representing roughly half of the entire investment volume of about 130 billion USD (see Wamukonya 2003, p. 1276). Among them four US companies and the French quasi monopoly EDF. Thus, though not impossible, auctions will be an instrument that may need to invite international bidders and end up with a situation were most renewable energy capacity is controlled be large international investors reducing the possible benefits to Barbados' economy as the income derived from the operation of renewable energy technologies will most likely be transferred out of Barbados' economy leaving Barbados with a similar money drain as the diesel imports for conventional power production.

While FITs do not have any problems with a limited number of possible investors and while they don't require a minimum economic size of an investor, they pose two other challenges for small economies like Barbados, which are the general asymmetry of information between the regulator and the investor and the regulator's inexperience in determining RE tariffs under an FIT system as Atherley-Ikechi (2015, p.35) suggests. Both problems are solved well by the auctioning process as shown above.

Concerning the first problem, the asymmetry of information, the German case shows that this problem can be handled in a way as to result in lower installation costs than quantity based instruments (see Barbos and Wyser 2013, p.3474). The German case shows that the setting of sliding FIT rates and their calibration was usually done with the help of experienced independent consultants and research institutes, an approach which is open to any government in the world. What is more, as most renewable energy technologies have matured considerably during the last 25 years, it is much easier to determine appropriate FIT rates today than in the early years of FITs. Cost data are usually well documented internationally and have to be adapted to the specific local condition, but they will not be fundamentally different around the world, as all technologies are traded internationally.

Concerning the second challenge, the inexperience of a regulator in determining appropriate FIT rates can be approached in the same way, by acquiring international experience and know-how through the help of experienced independent international consultants and research institutes.

Thus, although FITs face their own challenges in small countries, they may be a better fit than RPS or auctions, as they do not experience the same problems with a lack of possible market participants.

Work package 13 will apply the general considerations of this chapter to Barbados to derive the best possible market and policy framework for the successful market diffusion of renewable energy sources.

WORK PACKAGE 10: ANALYSIS OF THE PRESENT MARKET SITUATION OF RENEWABLES IN BARBADOS

The present market structure (and regulator)

The electricity market of Barbados is characterised by the dominant position of the BL&P, which is a vertically integrated utility company responsible for the generation, supply, and distribution of electricity (see IDB 2016, p. 28). Since 2014 BL&P is owned by EMERA Caribbean, which in turn is owned by EMERA, a Canadian-based company (80%), the National Insurance Board and approximately 1700 other shareholders (see IDB 2016, p. 29). With the passing of the Electric Light and Power Act (ELPA) in 2013 the power sector was opened to independent power producers (IPPs). As of 2016 no IPP has entered the market for either generation, transmission or distribution (see IDB 2016, p. 28). Despite the market opening to IPPs BL&P still holds an official mandate for the generation, transmission and distribution of electricity under its current license, which runs until 2028 (see IDB 2016, p. 29). Thus, the present electricity market of Barbados is dominated by a vertically integrated privately owned utility producing about 96% of the traded electricity acting as a single buyer for all other power producers.

According to the nomenclature of the World Bank developed for the full liberalisation of power markets (see Gratwick and Eberhard 2008, p. 3952) Barbados has adopted seven of nine reform steps (corporisation, commercialisation, passage of requisite energy legislation, establishment of an independent regulator, introduction of IPPs, divestiture of generation assets, divestiture of distribution assets). Only the two steps of restructuring (unbundling the vertically integrated utility) and the introduction of competition through the introduction of wholesale and retail markets have not been taken (compare Gratwick and Eberhard 2008, p. 3952).

According to Gratwick and Eberhard (2008, p. 3954) the Barbados situation resembles the single buyer model, which can be seen as one of the standard hybrid forms of power market liberalisation, which have evolved during the last two decades in the power market liberalisation of developing countries. It can well be argued that the power market in Barbados is too small to allow retail or wholesale competition or unbundling (see e.g. Bacon 1995, p.4 or Weiser 2004, p. 108f).

Looked at it in a functional way the present theoretical structure of Barbados' energy system is including the possibility of IPPs operating conventional and renewable generation capacity and consumers producing solar energy and feeding it back into the grid. It can be pictured as in Figure 78. It mainly consists of the privatised former monopoly (BL&P), which is responsible for the transmission and distribution of the electricity as well as for the functional control of the system. BL&P presently holds all significant conventional generation units and it is operating a substantial PV capacity. At the same time consumers are producing solar energy, which is partially fed back into the grid and is payed for under the fixed RER rate regime. According to the given legal framework it is possible that independent power producers own and operate renewable energy plants as well as conventional generation units.

In real life no IPP has successfully started its own production of electricity. This present system structure is depicted in Figure 79. In the case of wind energy an IPP has been formed (RePower Barbados), but so far the negotiations, licensing and permitting procedures have not been completed (see the discussion above). Nevertheless, there is a realistic option to start a successful IPP operation in the field of wind energy or PV, once a long term contract can be signed guaranteeing a fixed price for the electricity produced.

In the case of conventional power generation it is very unlikely that an IPP can successfully operate an additional conventional power plant in Barbados. As shown in Figure 80 to 83 it will not be possible to

Figure 78: Present theoretical structure of Barbados power supply system (own graphical representation)

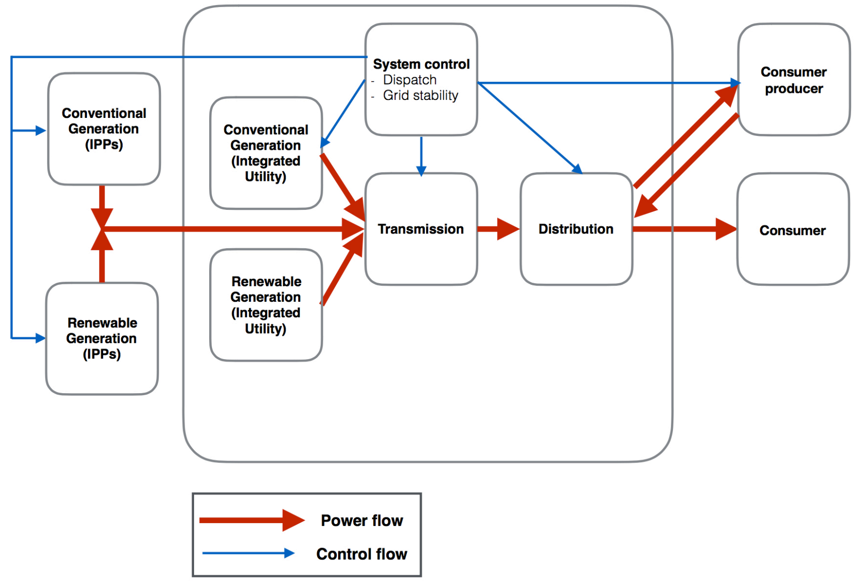
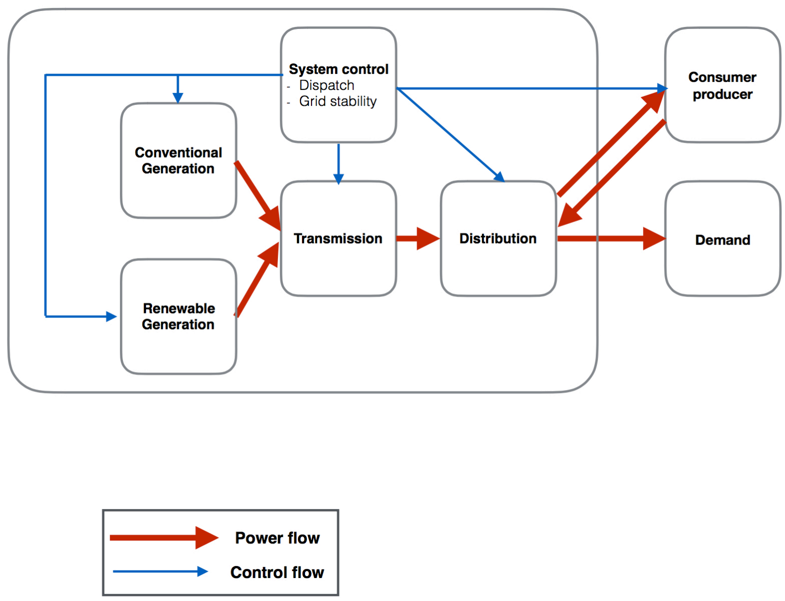


Figure 79: Present factual structure of Barbados power supply system (own graphical representation)



actually generate sufficient returns for such new conventional system due to the limited number of competitive generators in a power system of the relatively small size of Barbados.

Bohun, Terway and Chander (2001), have emphasised that developing countries with capacities below approximately 1000 MW would not attract sufficient numbers of participants in generation and distribution to introduce sustained competition‘ (Wiser 2004, p. 109). By 2004 only five out of 54 SIDS had installed capacities over 1000 MW (Cuba, Dominican Republic, Jamaica, Trinidad and Tobago and Singapore) (see Wiser 2004, p. 110). The minimum market size of 1000 MW compares to just about 150 MW of peak load in Barbados.

Why is it impossible to have sufficient competition in conventional power generation in a system of 150 MW maximum load? This question can be answered by looking at the technically determined cost structure of the present conventional power supply for Barbados (see Figure 80). In a competitive market the use of power generation units is determined by their variable costs. Ordering the capacities of all units available to the market according to their variable costs results in the so called merit order. At any given point in time the electricity demand on the system determines the capacity necessary for the electricity generation. The units are operated in their order of merit (variable costs). The last unit necessary to cover the market demand, the marginal unit, determines the market price. All units which want to economically survive have to operate a substantial part of the year at market prices well above their marginal costs in order to recover their investment costs. For the overall system a reserve capacity is needed for all those periods when some of the low cost units are not in operation due to regular maintenance or downtime for unscheduled repair. Thus, all larger power suppliers need to run reserve units as well, which are mostly paid for from the earnings from the most cost effective units.

Figure 80: Merit order and system load of Barbados’ power supply in 2016 (based on heat rates of generators, used fuels and international fuel prices in April 2017)

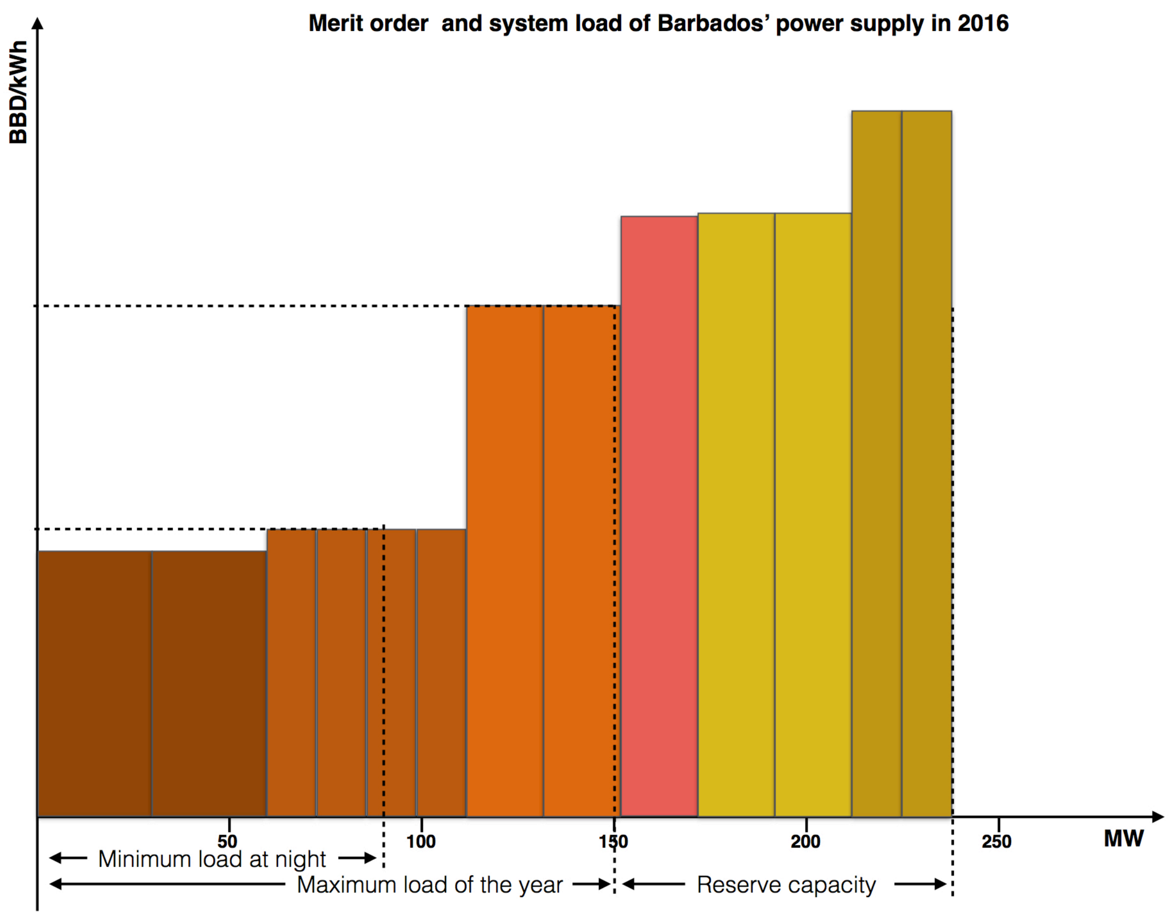
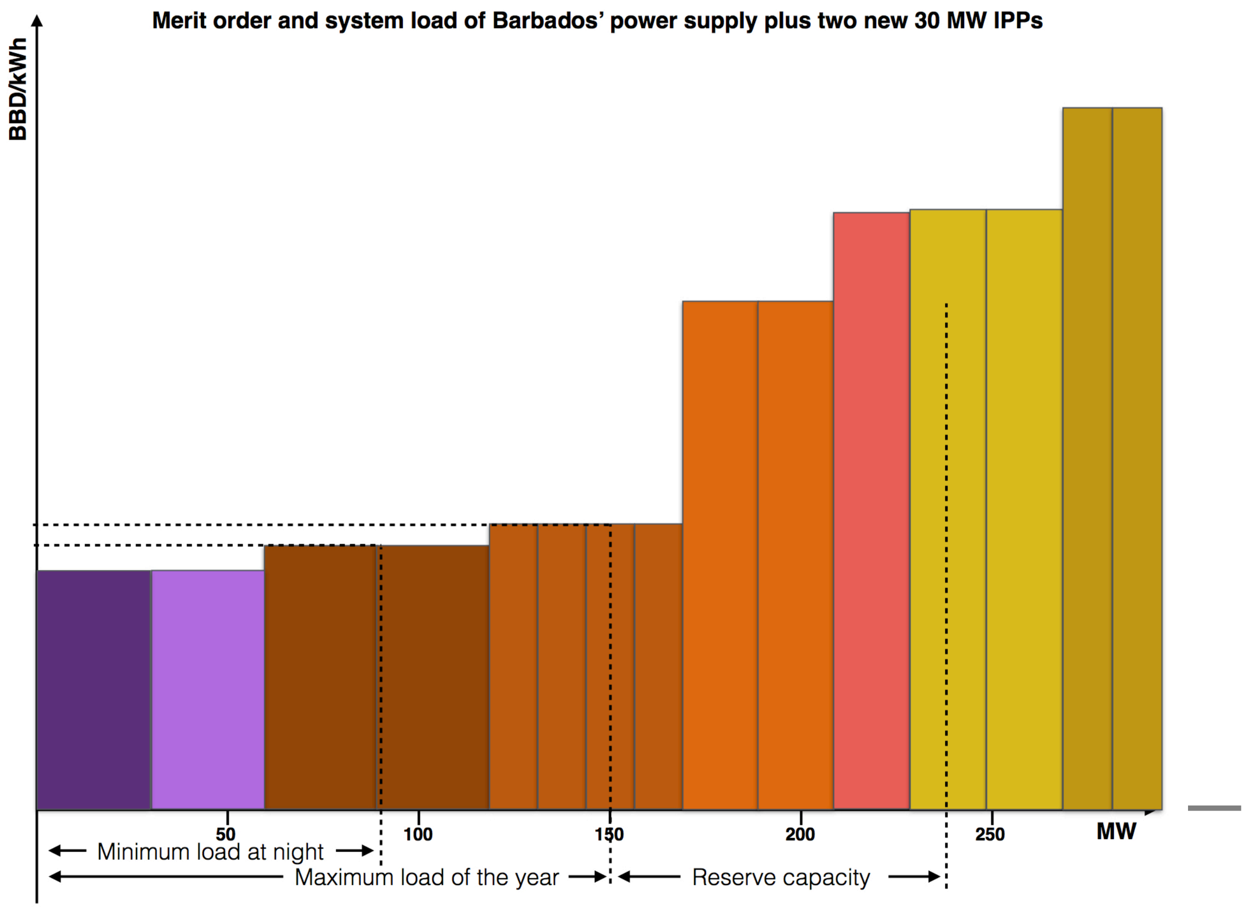


Figure 80 shows that only eight out of thirteen generators are necessary to supply the maximum load of 150 MW in the grid. The five other units are necessary as back up, but it can not be expected that they will earn more than their variable costs in operation. At night time and minimum system load of around 80 MW only the five most efficient units with the lowest variable costs are necessary to service the load. For any further considerations on introducing competition at the generation level it has to be taken into account that the nine most efficient units are all located in the Spring Garden plant of Barbados Light and Power. Thus, it is not feasible to split the relevant existing production capacity into different companies each operating competitive units. Competition on the generation level can only be introduced by building independent new capacity. As will be shown below, this is not attractive to independent investors due to inherent restrictions of the relatively small power system of Barbados.

It can be seen from Figure 80 that the six lowest cost units can make substantial earnings during peak load hours, when the price is set by the next group of generators with substantially higher costs, while only the two most efficient units can make some small earnings during low load times (up to 110 MW). In case one or two of the most efficient units with 30 MW each are not in operation prices will increase substantially during higher load hours and may increase (if both units are not working) during the low load hours.

If we imagine that at least two additional competitors with competitive equipment are necessary to start liberalising the power market in Barbados (it actually takes more than that, but for the sake of a simple argument, we assume this), then two new 30 MW low speed diesel generators using HFO (heavy fuel oil is by far the cheapest fuel) will need to be added to the merit order. Lets assume they are slightly more efficient than the two best units of BL&P and they enter into the merit order all the way to the left hand side. This situation is pictured in Figure 81 below.

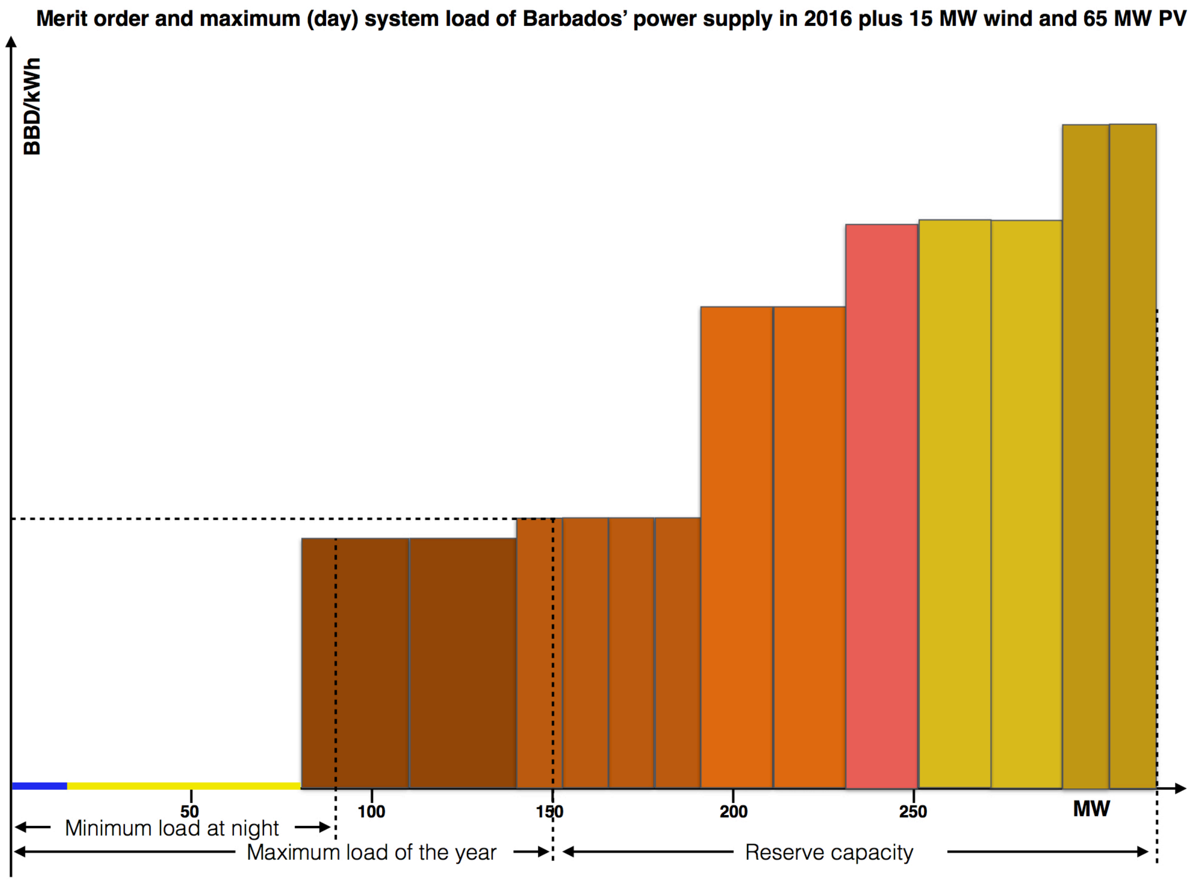
Figure 81: Barbados' merit order with two additional IPP generators of 30 MW each



In this case the new units would run all year, but the price during low load phases and even during high load phases will be reduced so far that these new generation units will never be able to recover their investment costs. What is more, Barbados Light and Power will not be able to generate sufficient returns to keep all the necessary reserve units in working order although the three least efficient units could be retired. Overall the new system will run into economic problems unless it will operate with substantial capacity payments to BL&P and even to the new IPPs.

What makes the situation even more hopeless for the conventional generators is the fact that the system is in transition to substantial shares of renewable energy production. As wind and solar energy have virtually no variable costs their production enters into the merit order to the left, as Figure 82 shows for 15 MW of wind and 65 MW of PV production (according to one of the scenarios of the BL&P grid integration study).

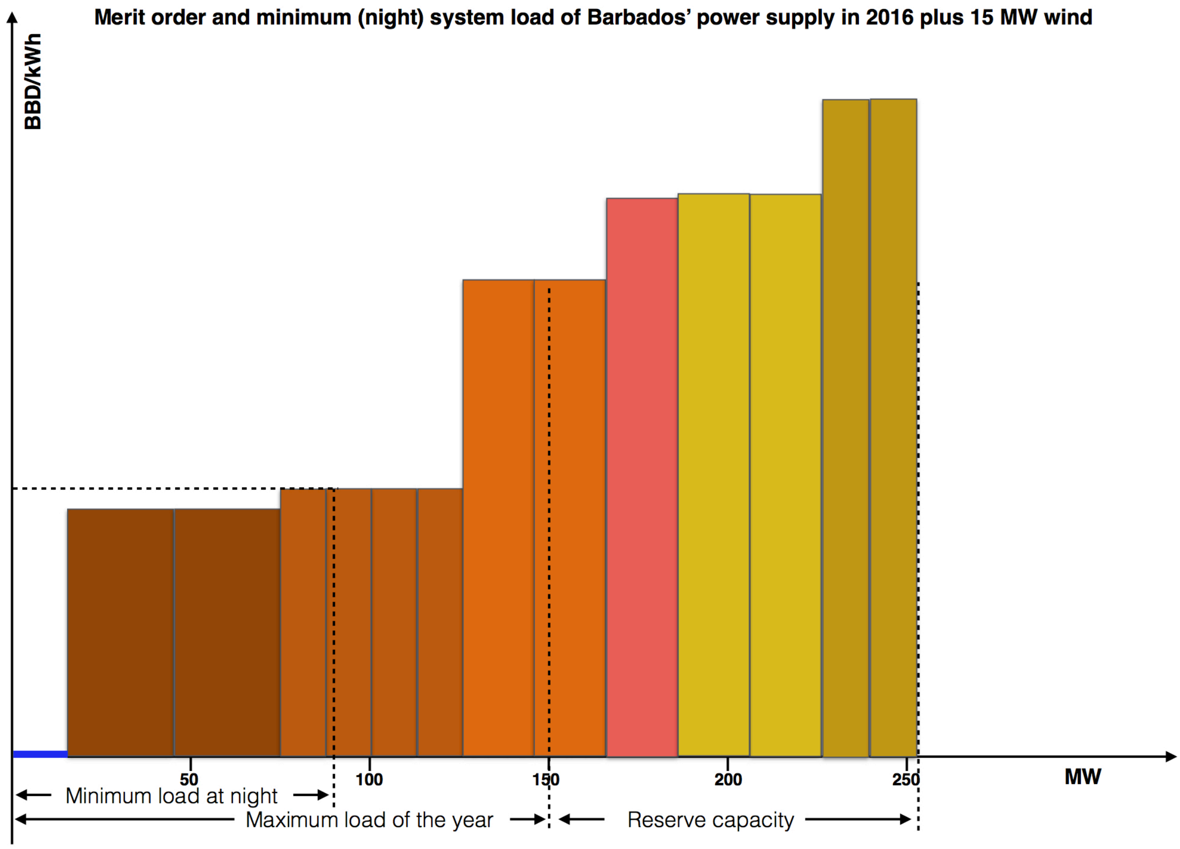
Figure 82: Barbados' merit order with the existing conventional capacity plus 15 MW of wind and 65 MW of PV production (situation at noon time, maximum load case)



Compared to the situation without wind and PV now the marginal power plant is not in the third most efficient category but in the second. Accordingly the market price for electricity is substantially lower. Again for a new market entrant this would leave even less room to earn enough money to recover his investment. During the night time, when load is low, but PV will not produce any electricity, the situation with production from 15 MW of wind is similar as Figure 83 shows. Again, only small margins can be earned by the most efficient generators.

These considerations show that the present power market and even more so Barbados' future power market with substantial shares of renewable energy sources don't make it attractive for independent power producers to start a business based on new conventional generation capacity.

Figure 83: Barbados' merit order with the existing conventional capacity plus 15 MW of wind production (situation at night time, minimum load case)



Even if the electricity demand will increase in the coming years as foreseen in the integrated resource plan of BL&P to about 210 MW in 2035 this will be accompanied by a strong growth in power generation from renewable energy sources. As the present conventional generators can back up a total system demand up to 235 MW it is questionable that the increased demand will create a business case for independent power producers. Even if Barbados switches to full e-mobility, which only makes sense if power is not generated from HFO or Diesel but from renewable energy sources, intelligent charging strategies (centrally dispatched charging between 10 a.m. and 3 p.m.) will not add any additional load to the system, which would need to be covered by conventional generation. Thus, even e-mobility will not create a business case for an IPP to invest into new conventional generation capacity.

Thus, taking into account the limited market size the liberalisation of the Barbados power sector has already reached a comparatively high level, where unbundling (splitting up the vertically integrated structure of conventional generation, transmission, distribution and system control) could be discussed but may well have to high transaction costs and little positive effect, while it seems to be extremely unlikely that wholesale and retail competition could generate any positive returns (see discussion above).

As Bacon (1995, p.15) points out unbundling (vertical deintegration of generation, transmission and distribution) may come at a very substantial price in small economies and will not have substantial advantages if there is no effective competition at the generation level. Thus, unbundling would most likely come at high costs and low befits in Barbados.

In this situation, where the vertically integrated private conventional producer of fossil fuel based electricity is the main feature of the electricity market it is central that an independent regulator with the necessary regulating powers controls the pricing of the monopoly. Such control requires sufficient numbers of well trained staff. In Barbados this regulator is the Barbados Fair Trading Commission (FTC), which was established in 2001 under the Fair Trading Commission Act (see IDB 2016, p.31). Judging by the documented decisions of the FTC and by its legal powers, Barbados has a very competent regulator with the necessary powers. Nevertheless, it is doubtful that the FTC has a sufficient number of well trained staff to handle all the necessary tasks in connection to the control of the vertically integrated monopoly on the one hand and to oversee the necessary expansion process of renewable power production in Barbados on the other. Fortunately, the necessary structures exist, but it will take a substantial increase in the FTC budget for additional highly qualified staff to meet the future challenges of the necessary power market transition.

Renewable energy policy targets

Barbados is one of the signatories of the ‚Vision of the Climate Vulnerable Countries‘, which was published at COP 22 in Marrakech on November 18, 2016, which pledged that the signatory countries ‚strive to meet 100% domestic renewable energy production as rapidly as possible‘ (Climate Vulnerable Forum 2016).

In 2015 the goals for the renewable energy policy of Barbados have been (nominally) increased from the 2012 target of 29% for renewable power by 2029 (AOSIS 2012, p.6 and Revised National Sustainable Energy Policy, 3.3, first bullet) to 65% of the maximum electrical load in 2030 (Barbados Intended Nationally Determined Contribution 2015, p.5). Depending on the composition of the renewable energy sources used in 2030 to reach this share of 65%, this might just be the same target to the 29% for 2029, which referred to the total electricity produced by renewables per year. In the likely case that the renewable power production of 2030 will be mostly based upon wind and photovoltaic solar energy (PV) the share of 65% of the maximum electrical load of 192 MW in 2030 (derived from the IRP of Barbados Light and Power 2014, p.10) would equal 125 MW of installed wind and PV capacity. This would produce just about 350 GWh/a (assuming 50% PV and 50% wind), which would be equal to 28.2% of the annual system load of 2030 projected by BL&P (interpolated figure based on BL&P 2014, p.9). Thus, the nominal change of the target from 29% of annual electricity produced to 65% of the maximum capacity might hardly result in an increase of renewable electricity being produced.

Recently the Barbados declared a 100% renewable power target to be reached by 2066 (declared by the Prime Minister of Barbados at the BREA Sustainable Energy Conference on November 10th, 2016). The proclaimed target of 100% renewable power by 2066 can hardly be seen to be in line with the claim to reach 100% renewable domestic energy supply ‚as rapidly as possible‘ as made by the CVF at COP 22. What is more, the new ‚ambitious' 100% target is nothing else than the 29% target for 2019. Assuming a linear distribution of the market diffusion of renewable energy over the 50 year period from 2017 to 2066 the new policy target implies a growth of 25.48% from 2017 to 2029. If this is added to a renewables share of roughly 4% by the end of 2016 the set policy target for 2029 remains virtually unchanged as compared to the target set in 2012. It seems that some policy makers try to leave the impression with the public in Barbados and the world that Barbados is speeding up its pace in the introduction of renewable electricity, while they are still just pursuing the old target of 2012. Thus, it has to be concluded that the renewable energy target measured in the share of power produced is still just about 30% of the total power production by 2030.

A recent study has shown that a 100% renewable electricity supply for Barbados is possible, if a sizeable pump storage hydro plant is integrated into the system (Hohmeyer 2015, p.24). From the evidence available so far it can be concluded that ‚to meet 100% domestic renewable energy production as rapidly as possible‘ for Barbados would mean about ten to twenty, but not 50 years from now. Such fast transition to a 100% renewable electricity supply will result in substantially lower electricity costs than the average conventional power generation cost of the last ten years and its expected future cost. Furthermore, it will result in vastly lower net outflows of hard currency for imports and substantial economic growth for Barbados.

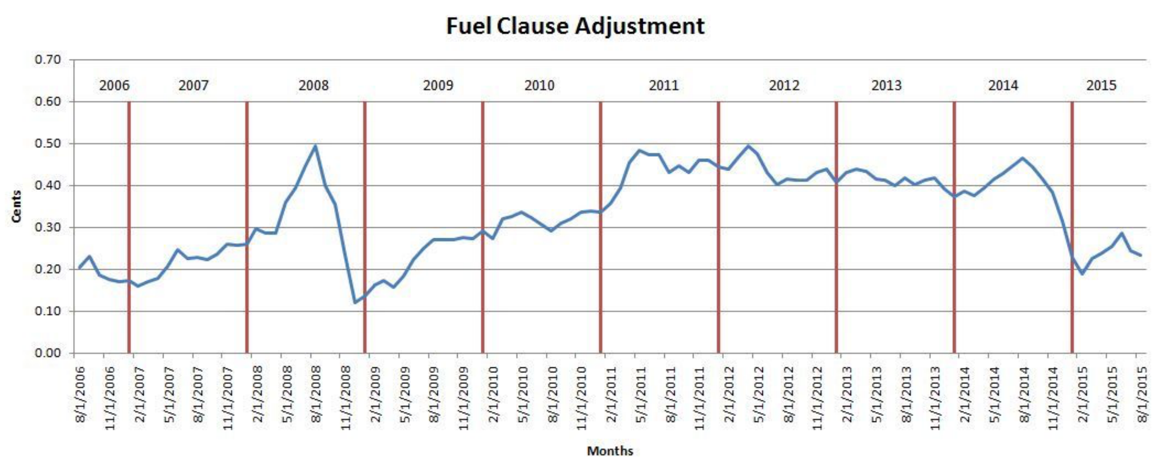
Renewable energy policy instruments

The present regulatory framework for the use of renewable energy sources in electricity production is characterised by high uncertainty for the average investor and very high license fees for the permission to operate a renewable energy installation like a solar PV system.

The first instrument to promote the market diffusion of renewable power production was the instrument of the Renewable Energy Rider (RER), which linked the payments for the electricity produced by a solar or wind energy facility to the avoided fuel costs of the conventional electricity. The RER was suggested by Barbados Light and Power and accepted by the Fair Trade Commission (FTC) in 2010 for a two year pilot programme. The RER was combined with a floor of 0.315 BBD/kWh. During this time 1.6 MW of solar PV systems were installed. In 2013 the FTC granted the permission to make the RER permanent, but it removed the provision of a floor. By the middle of 2015 9 MW of solar PW were installed (see IDB 2016, p. 12). As the RER was developed from the perspective of the monopoly utility company operating all conventional generation assets it was straight forward to base the payment for renewable electricity on the avoided fuel cost of the conventional production. In this way the RER did not have any major impact on the cost structure of BL&P, but it left the investors in renewable power production in a gambling situation as their income was directly linked to the development of the international oil prices.

After years of high oil prices and high fuel costs for the conventional power generation by BL&P and high payments under the RER based on the so called Fuel Clause Adjustment investors realised in 2015 with slumping oil prices that they were confronted with extremely high uncertainty about the future cash flows of their renewable energy investments, which in wind and solar energy are characterised by high up front investment costs and low operating costs. Figure 84 shows the development of the Fuel Clause Adjustment, the basis for the RER calculation. Many investors, who had invested in times of high oil prices and high RER, were running into a substantial chance of bankruptcy.

Figure 84: Development of the Barbados Fuel Clause Adjustment (source: Solar Barbados)



Due to massive complaints the FTC decided on July 13th, 2016, to established two fixed rates for wind (0,315 BBD/kWh) and solar PV installations (0,416 BBD/kWh) of a capacity up to 500 kW (FTC 2016, p. 23), trying to avoid the most severe consequences of the fallen oil prices and the vast drop in the RER rates (FTC 2016, p. 4f).

Nevertheless, these new rates have been qualified by the FTC as temporary RER credits (FTC 2016, p. 5) and the decision does not fix these credits for a specified time for any new installation. Thus, although the decision of the FTC was intended to do so, it did not give the necessary certainty about the future cash flow produced from a given RE investment, as the rates can always be substituted by altered new rates for any existing installation. As a consequence investor confidence does not seem to be restored.

The present policy framework for the introduction and market diffusion of renewable energy sources seems to be insufficient to reach even the very modest targets of 29% by 2029 or 100% by 2066. The present situation of the renewable energy policy and the regulatory and planning framework seem to be major obstacles for a rapid market diffusion of renewable energy sources. Thus, Barbados is looking for a new policy framework and mechanisms to enable a faster transition to a renewable energy based power supply.

Renewable energy permitting and licensing

At the moment three different licenses, permits or approvals have to be granted for a renewable power production facility larger than 5 kW (private households) or 20 kW (commercial operators). This is an approval granted by the Chief Electrical Engineer, a planning permit from Town and Country Planning and a license under the Electric Light and Power Act. In addition the installation has to comply with the requirements laid out by BL&P for grid connection.

The Electric Light and Power Act (ELPA) enacted in 2013 and amended in 2015 was aiming at a further market liberalisation and at increasing the share or renewable energy sources in Barbados by introducing independent power producers (IPPs). But instead of speeding up the market diffusion of renewable energy sources the ELPA ended up introducing new financial and organisational obstacles. Due to the critical budget situation of the Barbados government (induced mainly by the sugar crisis and the high import spending on extremely expensive fuels for power generation) it introduced a new annual license fee system for power generators, which according to well informed critics have taken up to 40% of the earnings of the operators of renewable power plants and diminished the economics of the systems further in an investment situation already stressed by the high uncertainty about the income generated under the RER.

Besides the financial burden the execution of the ELPA resulted in a substantial delay of the permitting and licensing process for renewable energy installations. The ElPA set up the Electric Power Advisory Committee, which is made up of nine experts, to advise the minister responsible for energy on the award of electricity supplier licenses. Such licenses are required for any commercial operator with a capacity of more than 20 kW and any domestic operator with a capacity of more than 5 kW. Instead of using the expert advice to streamline the process and to discuss very difficult cases like the licensing of large IPPs and new issues to be resolved, the ELPA is used to practically review every single license application. Thus, after being formally cleared by the Energy Division, every application is put in front of the ELPA for approval. Thus, every application is delayed at least to the next ELPA meeting, which should normally be called in an one month cycle, but recently has met at longer intervals, a process which could be done for the bulk of the applications by a streamlined process executed by the Energy Division without every license application going to the ELPA committee..

For wind energy the overall licensing and permitting process are extremely lengthy and unclear. The first independent power producer (IPP) to apply for the necessary permits and licenses for a wind energy project reports that so far this has been an almost never ending process of trying to find out, which licenses and permits need and which information has to be supplied to be acquired to finally get permission to operate the wind turbine. So far the company in question has spend over ten years in the process of trying to get all necessary permits and the license to operate. It can be stated that there are neither clearly specified requirements nor does a streamlined permitting process exist, which would allow to estimate the necessary time and effort to get a project from the first planning stages to realisation.

Due to the fact that standard wind turbines have capacity of well over 1 MW (internationally 2-3 MW per turbine are the present standard for onshore installations) the FTC rulings on rates paid to wind energy producers, which have an upper limit of 500 kW, don't apply. Thus, virtually each wind energy investor has to go through a lengthy negotiation process with BL&P to get an idea on the payment he will receive for the electricity produced by his wind turbine. As discussed above, this is a totally asymmetric bargaining situation, as a small IPP has to negotiate the terms of his IPP contract with the vertically integrated monopoly. Although the outcome of the negotiations is subject to FTC approval, but the FTC does not have any experience to judge the fairness of such an agreement. Thus, every wind energy investor (trying to install turbines of a capacity over 500 kW) will be confronted with an extremely lengthy licensing and permitting process and an unclear situation about the possible economic returns on his investment. This has led to the situation that only one IPP has tried to undergo this procedure and that there is no wind energy capacity installed in Barbados so far.

One other factor seriously limiting the possible development of wind energy in Barbados are the distance rules applied by Town and Country Planning to the permitting of wind turbines in Barbados. Different from international procedures Town and Country Planning applies distance rules for a wind turbine to the boundaries of the property on which the wind turbine is located. Internationally the distance rules always consider the distance from objects or areas which need to be protected from certain impacts of wind energy like noise or impacts on birds and bats. If for example a distance of 500m or three rotor diameters of the wind turbine from the next house is set as a limit, this can include a number of different properties between the turbine and the dwelling. In Barbados the rule applies to the distance of the turbine to the boundaries of the property on which the turbine is located. Thus, only very large pieces of property will qualify for the location of wind turbines with the effect that most of the possible good wind sites on the island are blocked due to the ownership structure of farmland around the country. Considering the need to move to 100% renewable energy supply in the long term and the fact that wind energy will most likely be the cheapest source of renewable electricity this very unfortunate distance rule applied by Town and Country Planning may induce high cost to Barbados rate payers and the country.

At the same time there is a lack of earmarked land for wind energy development in the present physical development plan and in the planned amendment (see Cameron et al. 2016). Only very few single locations (like the Lamberts site, for which BL&P has been planning a wind park for many years) are identified in the physical development plan and the planned amendment so far. Considering the widespread sprawl of residential property around Barbados, this lack of planning for the future location of wind energy in the best sites with the least negative impacts on all other land uses will lead to an unplanned reduction of the possible wind capacity of about 450 MW to most likely only a few ten megawatt within the next few years. Again this lack of foresight will cost Barbados ratepayers and the country dearly as a large share of the possible capacity of the most cost effective form of renewable power production will be lost due to uncoordinated planning procedures. In this respect much will depend on the inclusion of the present knowledge on the best areas for wind energy production (see Rogers 2015) in the amendment of the physical development plan for Barbados.

At the same time that a serious development of wind energy is massively discouraged by the circumstances there is a danger that uneconomical small wind turbines will block the best available sites due to the existing incentive structure. As the latest ruling of the FTC on fixed rates under the RER guarantees a tariff of 0.315 BBD/kWh (FTC 2016, p.23) has created an extremely strong signal for small wind energy turbines in the range between 100 and 500 kW to be installed. Compared to the international cost of wind energy of about 1,700 USD/kW or 3,400 BBD/kW the assumed 7,500 BBD/kW seems to be extremely high leading to a very high tariff per kilowatt-hour. The first application for smaller wind turbines is a project of three turbines with 275 kW each with investment costs in the range of 6,000 BBD/kW (concluded from information submitted for the ELPA license). If this is build under a 0.315 BBD/kWh tariff, it will result in unreasonably high profit margins on the one hand and in the blocking of sites most likely suitable for larger turbines, which could make a higher contribution to Barbados' renewable energy supply at substantially lower cost.

At the same time that wind energy will get a relatively high tariff as compared to international cost data (more than factor 2) solar energy is given a similarly strong incentive. At first sight the 5,500 BBD/kWp used by the FTC as a basis for its calculation of the fixed tariff (0.416 BBD/kWh) seem to measure well against the average investment cost of 6,250 BBD/kWp of the approximately 500 applications for an ELPA license, but a second look reveals that these average figures are heavily influenced by seriously overpriced systems. Considering the lowest cost systems in the different size categories reveals that it is possible to construct PV systems in the size range of 0.5-3 kWp in Barbados at investment costs as low as 3,100 BBD/kWp, while PV systems in the size range from 3-10 kWp have been realised at investment costs as low as 2,130 BBD/kWp. Interestingly enough larger systems in the range of 10-200 kWp have been realised at minimum cost of 2,500 BBD/kWh. These empirical figures from Barbados show that the tariff set by the FTC can be lowered substantially and still leave substantial profit margins for the investors.

Status of renewable energy market diffusion

Since 2009 the installed capacity of solar PV installations connected to the public grid has increased to about 10.4 MW by the end of 2015 and to about 23 MW by the end of 2016 as Table 34 below shows. Part of the capacity reached in 2016 is the 10 MW PV plant installed by BL&P in 2016 (see IDB 2016 p. 12f). BL&P reported payments for 18.7 GWh for the renewable energy capacity installed in 2015 (see IDB 2016, p. 17), which would be equal to about 2% of the annual gross power production by BL&P, which amounted to 969.4 GWh/a in 2015 (see IDB 2016, p. 14). Although the capacity doubled in 2016 the solar power produced will most likely not have doubled as the 10 MW PV plant of BL&P came online only in the second half of 2016. The project costs are quoted to be 43 million BBD for 10 MW (Greaves and Gill, no year, slide 12). Picture 1 gives an arial view of the solar farm.

Table 34: Development of PV capacity in Barbados since 2010 (sources: UNDP no year, p.19, IDB 2016, p.12 and application data for ELPA licenses)

Year	No. of PV Systems	Cumulative Installed Capacity (kW)
2010	4	7
2011	8	14
2012	63	910
2013	350	2900
2014	710	5500
2015		10400
2016	850	22855

Picture 1: Ariel view of the 10 MW PV solar farm of BL&P (source: Greaves and Gill, no year, slide 10)

By the end of 2016 there was no operating wind turbine installed in Barbados feeding electricity into the public grid. As early as 1986 a 250 kW Howden wind turbine was built at Lamberts. Obviously, the system failed after few years of operation. Nevertheless, it is reported that the broken down turbine was up for many more years.

Besides the 825 kW wind project, which applied for an ELPA license in 2016, there is one larger IPP wind energy project that has been pursued by RePower Barbados since 2009. In 2011 RePower announced the plan to build a 5.6 MW wind park in Barbados (RePower Barbados 2011, p.1). At the moment the last hurdle for the project is the modernisation of the airport radar system of Grantley Adams International

Airport, which was announced for 2017 (personal communication with Mr. Barry Reid Creamer on November 23rd, 2016). In addition there are plans by BL&P to built a wind farm at Lamberts. The size of the wind farm is planned to be 10 MW composed of 11 wind turbines with a capacity of 850 kW each. It is foreseen that the Lamberts wind farm will be operational by 2018.

A grid integration study commissioned by Barbados Light and Power, which was published in March 2015, suggests that 55 MW of solar and wind energy can be taken up by the existing system without any mitigation measure and 80 MW could be integrated with modest mitigation measures (GE 2015, p. 127). The report does not give information on higher renewables penetration, as no such scenarios were commissioned for the analysis. Presently a follow up study is underway, which is supposed to look at up to 150 MW of renewable generation capacity in a power system with a peak load of a little more than 150 MW.

In the field of power production from biomass there are mainly two projects in planning stages at the moment. One is the bagasse co-generation plant planned by the Barbados Cane Industry Corporation. It is a solid biomass combustion fired with bagasse during the sugar cane harvest season and with river tamarind during the rest of the year. The planed capacity is 22.5 MW electric, which will require large volumes of bagasse and large land areas for river tamarind production (29 km2) according to the Barbados Draft NAMA document (p. 42). More details on the project are given in Work Package 2 (WP2) above.

The second project is far more recent. It assumes that the production of sugar will not be economically viable in Barbados in the long run. Therefore, the farmers initiating the project have been looking for a grass type which can be used in crop rotation like sugar cane in order to stabilise the top soil in crop rotation, which yields a relatively high biomass output per acre and which can be harvested continuously all around the year. After a first pre selection successful field trials have been conducted with King Grass. The biomass yield has been 19 t of biomass at 10% moisture per acre an year with an energy content of 18 GJ/t of biomass at 10% moisture. To allow a flexible production of electricity from this biomass source, a gasification process is chosen which produces 1897,4 Nm^3 of syngas per ton of biomass at 10% moisture with an assumed gasifier conversion efficiency of 70% (see Fichtner 2016, p.10). The produced syngas has an energy content of 5.5 MJ/Nm^3(see Fichtner 2016, p.10). A gasifier with a feed throughput of 575 kg biomass/hr will produce 1,091 Nm^3 of syngas per hour, which would be sufficient to operate a 600 kW_{el} gas engine for power production (see Fichtner 2016, p.10). (For more details see WP2 above).

Thus, besides the substantial development of solar PV since 2012 all other renewable energy developments for electricity production are still on paper and lag far behind the political ambitions of Barbados.

Main deficits of the present situation of renewable electricity in Barbados

In summary the main deficits of the enabling policy and regulatory framework leading to a very slow uptake of renewable energy sources for power production are:

- an insufficient incentive structure, which still leaves investors at a substantial risk
- no incentives for renewable energy investments in installations larger than 500 kW
- an asymmetrical bargaining situation between IPPs trying to invest in larger renewable energy installations and the vertically integrated monopoly BL&P

- an unclear and drawn out permitting and licensing process for installations larger than 5 kW (domestic) and 20 kW (commercial)
- a totally insufficient physical development plan not setting aside the appropriate areas for wind energy development in Barbados
- a distance ruling for wind turbines, which requires extremely large pieces of property to be able to install any sizeable turbine

WORK PACKAGE 11: COMPARISON OF PRESENT MARKET SITUATION AND INSTRUMENTS TO POSSIBLE ALTERNATIVE CHOICES

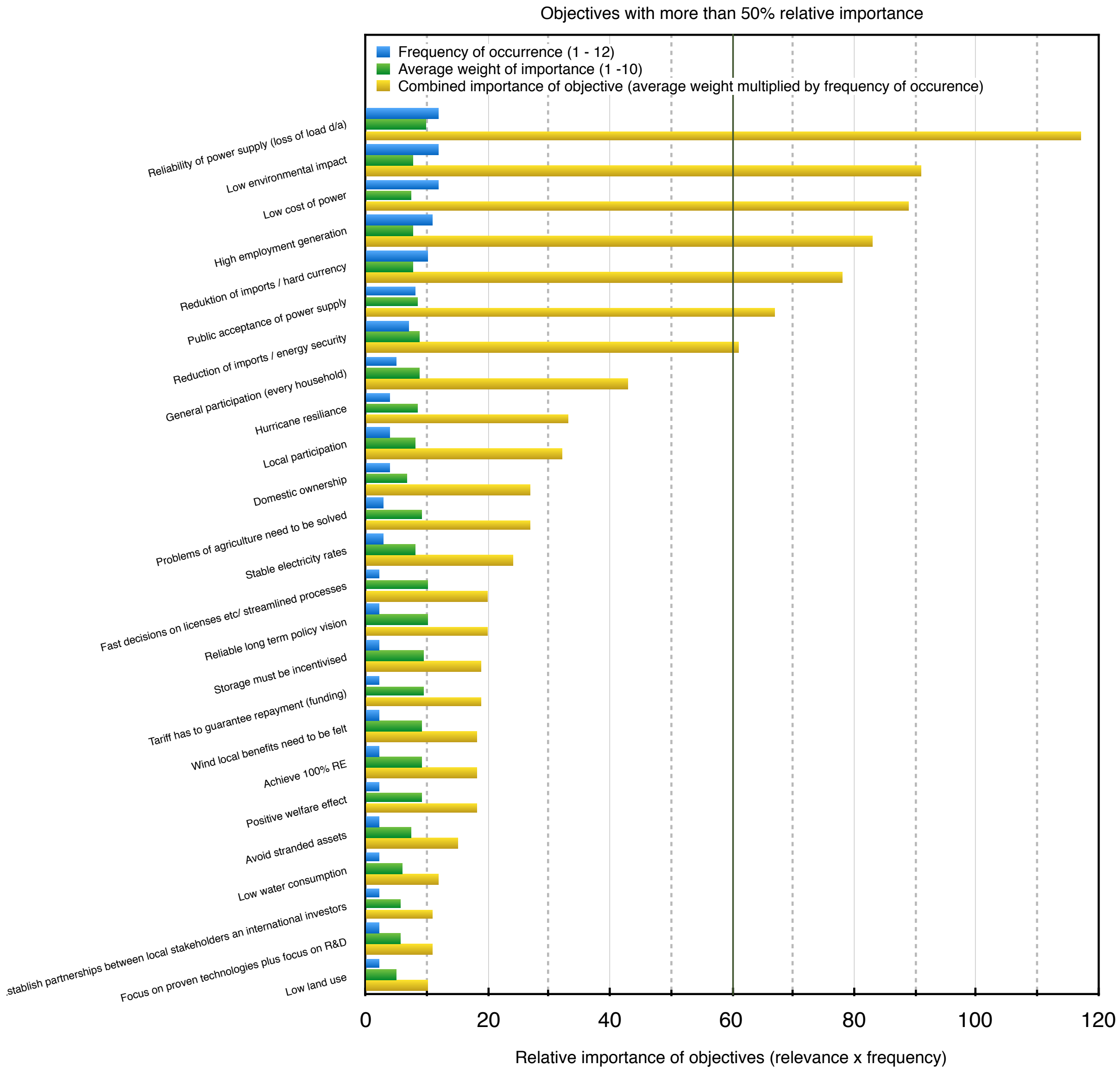
As WP10 has shown there are substantial deficits in the present market situation and the instruments used to promote an adequate market diffusion to meet the goals of the energy policy of Barbados. This Work Package will systematically compare the present instruments and the theoretically available instruments (WP9) for the promotion of renewable energy technologies with the most important objectives for an energy policy derived from the stakeholder interviews in WP1. The following six instruments will be discussed:

- Renewable Energy Rider (RER)
- Fixed rates for wind and PV under the RER
- Net metering
- Feed-in Tariffs (FITs)
- Renewable Portfolio Standards (RPS) with green certificate trading and
- Auctioning.

To recap the outcome of the stakeholder interviews Figure 1 from WP1 is reproduced below as Figure 85. The results of the interviews were condensed in a score in relative importance of a policy objective, which was defined as the product of the average weight attached to an objective multiplied by the frequency that this was mentioned by the interviewed stakeholders (maximum possible score120). The text summing up the results on the relative importance of different goals is reproduced in the following to recap the main results from WP1:

‚The graphing of the relative importance (RI) values shows that there is a group of four objectives, which follows the outstanding criterion of Reliability of power supply (RI=117) at a high level of importance with RI values between 78 and 91 (Low environmental impact (91), Low cost of power (89), High employment (83) and Reduction of imports (78)). Within the group the distance between every pair of neighbouring objectives is less than 7 points. Thus, this can be seen as a group objectives of similar high importance. The next group of objectives is constituted by just two objectives, which have a distance of more than ten points to the lowest ranking objective of the top group and a distance of almost twenty points to the next objective. At the same time both objectives (Public acceptance of sources of power supply (67) and Reduction of imports for energy security (61)) are the only remaining objectives achieving at least 50% of the maximum RI score. Of the remaining objectives only three reach at least 25% of the maximum possible IR score (General participation (41), Hurricane resilience (33) and Local participation (32)) forming the next group of objectives by importance. Three further objectives reach at least 20% of the maximum possible score (Domestic ownership (27), Solving the problems of the agricultural sector (27)

Figure 85: Frequency of occurrence, average weight of importance and relative importance of the twenty five objectives mentioned by at least to key stakeholders (Table with data in annex 1)



and Stable electricity rates (24)), while the other ten objectives, which were mentioned by at least two stakeholders reached RI scores between 11 and 20.

While the results of the survey clearly point to the fact that energy policy has to address substantially more objectives than just the of short term low cost energy for the ratepayers, the number of important objectives seems to be quite manageable. Although a low cost of electricity is among the most important objectives low environmental impacts or high employment generation and the net reduction of energy imports for balance of payment and energy security reasons were seen to be of similar or even higher importance by the interviewees.

Besides these core objectives public participation in the new energy system in its different forms all the way to domestic and local ownership seems to be a strong concern of the key stakeholders interviewed. If a new energy policy will be able to make a substantial contribution to the solution of Barbados' agricultural problem connected to the decline of the sugar industry and if it can deliver a very high reliability of the future electricity supply including a substantial hurricane resilience, it will be able to address the prime concerns voiced by the interviewees.'(text taken from WP1 above)

In the following the thirteen objectives with scores above 20 in relative importance will be used to assess the performance of six instruments to be discussed. In addition two further criteria are included in the discussion, which may have a substantial impact on the choice of the most appropriate instrument. One is the applicability of an instrument to a small island economy like Barbados, as an instrument may theoretically be able to meet all criteria, but it may still be possible that its application needs a far larger energy system and economy to be successfully applied. As we have seen in WP9 this may be the case for RPS with green certificate trading. The second additional criterion is the administrative effort, needed for the execution of an instrument. Again, this is not a policy objective in itself, but it may have strong implications for the successful implementation of an instrument. Different from the first criterion, which may be a killer criterion, if not met, the second criterion is more of a gradual nature, as it will not make it impossible to implement a certain instrument, but it may burden the administration heavily. Thus, it should be taken into account in the choice of instruments. In total a set of 13 objectives and two criteria will be used to check the six instruments under discussion. These are (in the sequence of their scores on relative importance:

- Reliability of supply
- Low environmental impact
- Low cost of power
- High employment generation
- Reduction of imports / hard currency
- Reduction of imports / energy security
- General participation (every household)
- Hurricane resilience
- Local participation
- Domestic ownership
- Solution for Barbados' agricultural problems
- Stable electricity rates
- Applicable to Barbados.
- Administrative effort necessary.

Each instrument will be discussed to whether it has a positive or negative impact on each of the objectives and criteria. The results are represented in a simple matrix showing either a green field for a positive impact or a read field for a negative impact. This matrix will give an overview on the match between the objectives for Barbados' policy for the promotion of renewable energy and the available instruments.

Reliability of power supply

The highest scoring policy objective from the stakeholder interviews is the reliability of Barbados' power supply. It is quite obvious that any policy risking this would not be supported by any stakeholder. The instruments that might eventually risk some stability would be the original RER and net metering without controlling the capacity for which net metering or the RER are used. To the old RER this did not apply, as it was restricted to rather low volumes of PV. Net metering and an uncontrolled RER may give a very strong incentive to install roof top PV systems inducing a very fast transition to large shares of uncontrolled PV production capacity. Such fast growth can potentially destabilise certain grid regions. Thus, net metering and (uncontrolled RER) get a negative rating on this objective (red) (see Table 35).

Table 35: Scores of the different instruments for *Reliability of Power Supply*

Priority objectives	Relative importance of objective (Score, max. 120)	Support mechanisms						
		Barbados today			Options for the future			
		RER	FTC fixed tariffs	Single PPAs	Net metering	FIT	RPS	Auctioning
Reliability of power supply (loss of load d/a)	117.0							

As Feed-in Tariffs and single Power Purchase Agreements (PPAs) are primarily price instruments they can have a tendency towards a high speed of renewable energy implementation, if they are not well linked to the prevailing cost of a technology in the market (as the German example of very fast PV expansion after a sudden price drop in 2009 has shown, see WP9). Nevertheless, a well tailored FIT will induce a reasonable growth rate, which can normally be accommodated without grid stability problems. In small electricity systems like in Barbados it should be coupled with quantity caps linked to the results of technical grid integration studies. It might even be advisable to cap quantities for a certain period of time for every feeder area, as to insure the stability of every section of the grid. Thus, FITs get are rated positive (green) as their impact on grid stability can be well controlled. For the existing fixed tariff under the RER (fixed by the FTC) a quantity cap applies already. Therefore, this fixed tariff is rated positive as well. PPAs are controlled by the utility and the FTC, thus it is extremely unlikely that the capacity installed under single PPAs will interfere with grid stability. Therefore individual PPAs get a positive rating. The quantity policies (RPS and Auctioning) control the quantity of installed renewable capacity directly either via the setting of quantity targets (standards) or via the auctioned volumes, thus, if the quantities are set in agreement with the grid capacities, these instruments should never cause any reliability problems of the power supply. Therefore, both get a positive rating.

Low environmental impact

As all support mechanisms will allow an increased market diffusion of renewable energy technologies, they all score positive on this account.

Table 36: Scores of the different instruments for *Low environmental impact*

Priority objectives	Relative importance of objective (Score, max. 120)	Support mechanisms						
		Barbados today			Options for the future			
		RER	FTC fixed tariffs	Single PPAs	Net metering	FIT	RPS	Auctioning
Low environmental impact	91.0							

Low cost of power

Although, the low cost of electricity does not have quite the score of low environmental impacts, it is virtually just as important to the stakeholders as the reduction of negative environmental impacts by increasing the use of renewable energy sources. This is to say that it would be best, if the introduction of renewable energy sources would not lead to an increase in power cost, but that it has such a high score that some increase in power cost can be traded against a high score on solving the environmental problem, but the massive market diffusion of renewable energy sources should certainly not lead to a massive increase in power cost.

The different support mechanisms include very different possibilities to curtail the cost of the market diffusion of renewable energy technologies. The renewable energy rider (RER) was designed to be cost neutral to BL&P, nevertheless, as it paid out factor 1.6 times the fuel adjustment clause, this would not hold if the RER would have been used on very substantial renewable energy capacities. The lower the cost of renewable energy sources will be compared to the fuel costs of conventional power generation it will turn more and more into an instrument unnecessarily increasing the cost of a renewable energy diffusion. Therefore, the RER gets a negative rating. Net metering and the presently fixed tariffs (fixed by the FTC) are by tendency granting to high payments for renewable energy sources and don't have any mechanism for adjustment to renewable energy cost reductions over time. Therefore, net metering and the presently fixed tariffs under the RER get a negative rating like the RER. As shown in WP9 renewable portfolio standards (RPS) allocate the full producer surplus to the producer, but they achieve cost reductions according to decreased equipment costs, while differentiated FITs can redistribute some of the producer surplus to the consumer and lower prices and auctioning can discover the marginal cost curve and minimise producer surplus and cost to the consumer. RPS, FITs and auctions get a positive rating on low cost (see Table 37).

Table 37: Scores of the different instruments for *Low cost of power*

Priority objectives	Relative importance of objective (Score, max. 120)	Support mechanisms						
		Barbados today			Options for the future			
		RER	FTC fixed tariffs	Single PPAs	Net metering	FIT	RPS	Auctioning
Low cost of power	89.0							

High employment generation

Employment generation is strongly related to the ability of a support mechanism to foster national ownership of renewable energy technologies. All mechanisms requiring a substantial number of large investors, like auctioning and to a certain extent RPS will need to draw on international investors to stimulate the markets necessary for their functioning. Therefore, auctioning and RPS get a negative on the objective of employment generation. The original RER, the present fixed tariffs under the RER, FITs in general and net metering don't need any international investors to facilitate the full scale diffusion of renewable energy sources in Barbados. Therefore, they all are rated positive on domestic employment generation. As individual PPAs will require somewhat stronger investors to negotiate with the integrated monopoly, there is some tendency to favour experienced international investors, although, this is not an absolutely necessary feature as in the case of auctioning. Therefore, PPAs are still rated positive on this objective as can be seen in Table 38.

Table 38: Scores of the different instruments for *High (domestic) employment generation*

Priority objectives	Relative importance of objective (Score, max. 120)	Support mechanisms						
		Barbados today			Options for the future			
		RER	FTC fixed tariffs	Single PPAs	Net metering	FIT	RPS	Auctioning
High employment generation	83.0							

Reduction of imports / hard currency

The reduction of the necessary use of hard currency for imports or of the drain of hard currency is one of the key objectives for the country as a whole, as every dollar not leaving the country actually causes a growth of GDP. As in the employment question RPS and auctioning will lead to high involvement of international investors in renewable energy sources. International ownership will lead to the fact that the profits made will eventually be transferred out of the country to the account of the investor. This has a similar effect as the import of fossil fuels for hard currency. Therefore, while reducing the import bill for fossil fuels through the use of renewable energy sources the money will leave the country through a different route. As RPS will result in very high profits for these investors and as auctioning will most likely crowd out most domestic investors both are rated negative on import reductions. As individual PPAs will induce more international investment as the price oriented mechanisms PPAs are rated positive on this objective, as the pressure for international investment is considerably lower as in the case of auctioning and RPS. The RER, net metering and the present fixed tariffs under the RER don't induce international investment avoiding the problems of RPS and auctioning they are rated positive. As dynamic and differentiated FITs can lead to low investment costs and can as well induce 100% domestic investment, they are rated positive on import reductions and the reduction of outflow of hard currency (see Table 39).

Table 39: Scores of the different instruments for *Reduction of imports / hard currency*

Priority objectives	Relative importance of objective (Score, max. 120)	Support mechanisms						
		Barbados today			Options for the future			
		RER	FTC fixed tariffs	Single PPAs	Net metering	FIT	RPS	Auctioning
Reduktion of imports / hard currency	78.0							

Public acceptance of power supply

For renewable energy a main problem in public acceptance is related to the local acceptance of wind energy. Most of the other technologies don't experience major acceptance problems, with the exception of biomass creating serious smell problems (biogas from manure) or very large energy crop monoculture, as in some cases of maize growing as an energy crop. Sometimes the use of potential food biomass for energy production can lead to strong public resentment (see a willingness to pay analysis conducted by Hohmeyer et al. in Schleswig-Holstein in 2014). The most relevant acceptance problem to avoid for Barbados will be related to the local acceptance of wind energy, if this is to be deployed with large capacities. It is well know that the local perception of wind energy is significantly different depending on the ownership structure. Citizens wind parks have lead to very high local acceptance of wind energy in coastal areas of northern Germany, while outside investment combined with a rush for the best locations has created a long lasting resistance against wind energy in Wales (see Mitchel 2004, p.1937). As discussed in WP9 auctioning and RPS have lead to very low local involvement leaving the investment to large outside investors. Therefore, auctions as the most extreme form are ranked negative, while RPS are ranked negative as well as they do create a rush for the best sites. The RER and the present fixed tariffs under the RER don't induce such a strong race for the best sites and allow a high share of local investment, but they don't allow a differentiation of the rates for different wind sites to spread the installation of wind energy more evenly, as it can be done with differentiated FITs. Well tailored FITs can even include provisions for the ownership by proximity. So people living directly around a wind site could get their own small share in a wind park for their exposition (without having to pay money into the investment). Such feature, generating a regular income to these persons or families, could increase the local acceptance of wind developments very substantially. At the same time FITs could induce the investment of local credit unions, due to the fact that a guaranteed FIT will allow an extremely save investment. Through such vehicle the local acceptance of wind energy can be increased further. FITs, RER and the present fixed tariffs under the RER are ranked positive. As individual PPAs will require strong investors it is highly unlikely that citizens wind parks will be induced by PPAs. As local involvement is not very likely with PPAs they will not have a similar positive impact on local acceptance. But as PPAs don't create a rush for the best sites they are still rated positive on this objective (see Table 40).

Table 40: Scores of the different instruments for *Public acceptance of power supply*

Priority objectives	Relative importance of objective (Score, max. 120)	Support mechanisms						
		Barbados today			Options for the future			
		RER	FTC fixed tariffs	Single PPAs	Net metering	FIT	RPS	Auctioning
Public acceptance of power supply	67.0							

Reductions of imports / energy security

A second reason for reducing imports is to increase the energy security of Barbados. The mechanisms all induce an increased market diffusion of domestic renewable energy sources and by this virtue reduce the import of fossil fuels for power production and eventually for transportation, if the green power is used to convert Barbados' transport sector to green electricity from domestic renewable energy sources. Therefore, all support mechanisms score positive on this objective (see Table 41).

Table 41: Scores of the different instruments for *Reduction of imports / energy security*

Priority objectives	Relative importance of objective (Score, max. 120)	Support mechanisms						
		Barbados today			Options for the future			
		RER	FTC fixed tariffs	Single PPAs	Net metering	FIT	RPS	Auctioning
Reduction of imports / energy security	61.0							

General participation (every household)

A wide participation in the development of renewable energy source is a much discussed objective in Barbados and it is voiced in different forms (democratisation, local participation, general participation, local ownership). But in its most general form it can be interpreted as the request that every household should have a chance to become part of the development. Auctioning, RPS and PPAs all are addressing large investors leaving no room for a broad participation. Therefore, they are all ranked negative on this objective. The RER as well as net metering and the fixed tariffs under the RER address property owners, who own a property and have enough income to invest into their own renewable energy installation. By this virtue non owners are excluded from participating actively in the development of renewable energy sources. Nevertheless, RER, the present fixed tariffs and net metering perform substantially better than RPS or auctioning and are rated positive on this objective. As FITs have shown their potential for broad citizens involvement and offer even the possibility to involve non owners in the development of renewable energy technologies (e.g. through credit unions, pension funds or local shares based on exposition to wind parks), FITs are rated positive on this objective (see Table 42).

Table 42: Scores of the different instruments for *General participation (every household)*

Priority objectives	Relative importance of objective (Score, max. 120)	Support mechanisms						
		Barbados today			Options for the future			
		RER	FTC fixed tariffs	Single PPAs	Net metering	FIT	RPS	Auctioning
General participation (every household)	43.0							

Hurricane resilience

Hurricane resilience is another objective that has been stressed by some interviewed stakeholders. It relates very much to the objective of a stable power supply, but it addresses a very specific aspect of this. Hurricane resilience matters with wind turbines and solar PV installations just as much as with overhead grid lines. Nevertheless, if wind turbines are not built to stand a very strong hurricane, this may have a longer lasting impact on the power system as a certain share of power lines being brought down, as a failure of a large number of turbines can cause severe problems to the power supply needing to fall back on the old fossil fuel generators for a substantial period of time, as not all the spare parts necessary to repair a large scale failure of many turbines can be stocked on the island (different from the cables necessary to repair overhead lines. The same applies if large shares of PV panels would be blown away and seriously damaged. Nevertheless, all support mechanisms are neutral with respect to this objective and are rated to be neutral (yellow) (see Table 43). It can be discussed in how far an FIT system could be modified to include a provision to encourage hurricane resilience.

Table 24: Scores of the different instruments for *Hurricane resilience*

Priority objectives	Relative importance of objective (Score, max. 120)	Support mechanisms						
		Barbados today			Options for the future			
		RER	FTC fixed tariffs	Single PPAs	Net metering	FIT	RPS	Auctioning
Hurricane resiliance	33.0							

Local participation

The objective of local participation relates strongly to the objective of democratisation of the energy system on the one hand and to the objective of public acceptance on the other. As it does not require every household to have a chance to be involved, it is not as strict a requirement as the general participation discussed above, but it is mixed with local acceptance. As FITs are rated positive on both objectives, they can address the issue of local participation in both respects and are rated positive on local participation as well. RER, the present fixed tariffs under the RER and net metering can involve many local home owners and score higher on public acceptance, while they are not doing quite as well as tailor made FITs, but they still are rated positive. As PPAs require large investors it is very unlikely that these will be local investors (with some exemptions). Therefore, they are rated negative on local participation. RPS and auctioning will drive the development into the opposite direction with a dominance of large international investors. Therefore, RPS and auctioning are rated negative (see Table 44).

Table 44: Scores of the different instruments for *Local participation*

Priority objectives	Relative importance of objective (Score, max. 120)	Support mechanisms						
		Barbados today			Options for the future			
		RER	FTC fixed tariffs	Single PPAs	Net metering	FIT	RPS	Auctioning
Local participation	32.0							

Domestic ownership

Domestic ownership is an other aspect of the objective of general participation, although this objective would be satisfied, if only a few large local investors would own all of the renewable energy investments. Thus, it is only a minor part of the objective, but it relates strongly back to the objective of import reductions for the reduction of the outflow of hard currency, as domestic ownership (by many or few) would keep the profits made in Barbados' economy. RER, the present fixed tariffs under the RER, net metering and FITs all encourage domestic ownership and don't need international investors. Therefore, they all are rated positive. As individual PPAs require strong investors there is a certain incentive for international ownership. As this is only a week incentive PPAs still are rated positive on this objective. As RPS and auctioning will require strong international market participation to function, they both are rated negative on this objective (see Table 45).

Table 45: Scores of the different instruments for *Domestic Ownership*

Priority objectives	Relative importance of objective (Score, max. 120)	Support mechanisms						
		Barbados today			Options for the future			
		RER	FTC fixed tariffs	Single PPAs	Net metering	FIT	RPS	Auctioning
Domestic ownership	27.0							

Problems of agriculture need to be solved

At least by a number of stakeholders the objective was put forward that the introduction of a large share of renewable energy in power production needs to help solve the problem of the sugar industry crisis. Even if it would not solve the problem of the sugar industry it still would need to help to establish an alternative grass crop for rotation agriculture, as the thin topsoil needs the rotation cropping with a form of grass to stabilise the soil for the cropping of other crops like vegetables, which can not stabilise the soil against water erosion in heavy tropical rain fall. Due to the fact that most stakeholders interviewed do not know this background it is a special objective. Accordingly, it was only voiced by the experts in the agricultural field, but for them this objective was extremely important.

As the RER and the present fixed tariffs under the RER don't address biomass for power production at all, they are rated negative on this objective. Due to the fact that renewable portfolio standards (RPS) address all kinds of renewables with the same green certificates and due to the fact that the use of biomass will most likely have higher cost for renewable power production as wind, biomass will be crowded out under RPS in Barbados. Therefore, RPS are rated negative on this objective. Individual PPAs can be done for power from biomass. Therefore, individual PPAs are rated positive. Net metering could be used on larger farms producing power from biomass in smaller installations (e.g. 500 kW). Therefore, net metering is rated positive. Feed-in tariffs and auctioning of quantities for single renewable technologies could induce the full biomass potential by either differentiated FITs or by technology specific auctions. Therefore, FITs and auctions are rated positive on the possible contribution to solving the central agricultural problem of Barbados (see Table 46).

Table 46: Scores of the different instruments for *Problems of Agriculture need to be solved*

Priority objectives	Relative importance of objective (Score, max. 120)	Support mechanisms						
		Barbados today			Options for the future			
		RER	FTC fixed tariffs	Single PPAs	Net metering	FIT	RPS	Auctioning
Problems of agriculture need to be solved	27.0							

Two additional criteria: applicability to Barbados and administrative effort

As pointed out above it is necessary to evaluate for the different support mechanisms whether they are applicable to such a small island economy like Barbados and whether the administrative effort involved in a certain support mechanism can be handled successfully by the Barbados authorities. This evaluation and the resulting scores are discussed in this subchapter.

The criterion that a support mechanism is applicable in Barbados is a necessary condition. That is to say, if this criterion is not fulfilled all other scores are irrelevant as the support mechanism can not be used in Barbados. For RER, the present fixed tariffs under the RER, PPAs and net metering the criterion is easily fulfilled, thus Table 47 shows a positive rating (green) for these support mechanisms. For differentiated dynamic FITs the answer is not as easy, as this support mechanism requires substantial knowledge about the cost of the different renewable energy options for Barbados and a good understanding of the local solar and wind resource. At the moment this knowledge is not directly available at the Energy Division and the FTC, the two agencies, which would have to administer such FITs. Nevertheless, even the German government is regularly using contractors and research institutes to acquire the necessary cost and resource information to base its FIT decisions. Specifically with the help of the EU and other international donors putting great emphasis on the development and diffusion of renewable energy technologies it will not be difficult to built up the necessary in house capacities at the Energy Division and at the FTC and to pay for the necessary independent consultant work to assess the actual cost of the different renewable energy options for Barbados on a regular basis. The EU Delegation seems to be quite positive on the financing of a full fledged wind measuring program to allow even community wind parks to acquire bankable wind data for the relevant sites in Barbados. Thus, even differentiated dynamic FITs can be applied in Barbados and FITs are rated positive. In the case of renewable portfolio standards (RPS) the discussion in WP9 has shown that Barbados can not implement a system of traded green certificates and a spot market for the trade of electricity. For the full implementation of RPS these markets would both need futures trading in addition to spot market trading. Therefore, RPS can not be applied to Barbados and Table 47 shows a negative rating (red). The case of auctions can not easily be answered. On the one hand, although it will be difficult for the FTC to administer frequent auctions for different renewable energy technologies it might be possible, but on the other hand it is doubtful that the auctioned quantities will draw enough competitors to fully explore the marginal cost curves of different renewable energy technologies in each auction by a sufficient number of bids. Therefore, although it is possible to implement auctions for renewable energy they may not be very successful. As a result the criterion of applicability to Barbados is barely fulfilled, but they are still qualified as applicable. Therefore, Table 28 notes a positive rating for auctioning.

Concerning the second criterion the RER, the present fixed tariffs under the RER, individual PPAs and net metering require a minimum administrative effort by the FTC and the Energy Division. This is actually considering the ELPA license process as an administrative procedure which is not necessary to the present extent for these support mechanisms. Most of the present effort relates to the desire to collect additional government income but is not necessary for the administration of these mechanisms. Therefore these four mechanisms are all rated positive. As pointed out above the administrative effort for setting and frequently reevaluating differentiated dynamic Feed-in tariffs is substantial and will require frequent consultant support. Nevertheless, once the tariff structure is set, relatively little administrative effort is necessary for the application of the FITs. Therefore, FITs are rated positive on administrative effort. Renewable portfolio standards can be set by a legislative act, nevertheless, green certificates have to be granted for every kilowatt-hour of green electricity produced. Once the certificates are traded there has to be a register that follows each certificate sale and to check that all obliged entities hold the necessary green certificates at the end of a year. In case of a violation penalties have to be applied and the late compliance has to be checked. The certificate register requires a substantial effort on the side of the public administration in addition to the markets for certificates, which can be operated by private entities. Therefore, RPS are rated negative on administrative effort. Frequent auctions of quantities for different renewable energy technologies will require a very substantial effort by the public administration (in Barbados this would most likely be done by the FTC). At the moment the FTC is certainly not equipped to handle the necessary effort, nevertheless, with a substantial addition of highly qualified personnel this might be possible. Therefore, auctioning is rated positive.

Table 47: Scores of the additional criteria *Applicability to Barbados* and *Administrative effort*

Priority objectives	**Relative importance of objective (Score, max. 120)**	**Support mechanisms**						
		Barbados today			**Options for the future**			
		RER	**FTC fixed tariffs**	**Single PPAs**	**Net metering**	**FIT**	**RPS**	**Auctioning**
Applicable to Barbados								
Administrative effort necessary								

Summarized assessment of the different support mechanisms

Table 48, summarising the assessment, shows that there is only one support mechanism that has the potential to successfully address all objectives and to fulfil the additional criteria for Barbados. This is a well tailored Feed-in tariff system. It does well on the low cost of power and very well on most other objectives. If it is not connected to clear limits of capacity to be installed, it can lead to problems in grid stability, which have to and can be avoided by capacity caps. The main disadvantages in the RER and the present fixed tariffs is that they lead to high costs for renewable electricity and that they can not address the problems of Barbados agriculture. Nevertheless, combined with PPAs for biomass the present system can even be used to address this area, but at comparatively high electricity cost for the final consumer. The introduction of a differentiated dynamic FIT system can certainly substantially reduce electricity cost as compared to the present support mechanisms, while it could address most other objectives better than the present system.

Renewable portfolio standards (RPS) are not applicable to Barbados, as the economy is far to small for the establishment of such system. Even if it would be applicable it would not be able to address most other objectives due to the need to bring in international investors to make the system work.

Auctioning can be implemented in Barbados with a very high administrative effort, but due to the limited market size and the number of bidders, which could be attracted to frequent auctions of rather limited capacities, it is very unlikely that it will result in low electricity cost. What is more, similar to RPS auctioning, it will not be able to address most other objectives due to the need to involve a sizeable number of international investors in the bidding to make the process work at all.

Thus, it is strongly recommended to establish a differentiated dynamic FIT system for Barbados in order to achieve its goals at low cost to the consumers and at a maximum benefit for the people of Barbados. It can be argued that for very small consumer producers a simple net metering may be used together with the dynamic FIT system for all larger producers. It seems to be reasonable to limit net metering to roof top PV installations of 1 kWp. This will allow to benefit lower income households with a rather high tariff, while it will not overburden the bill of the average utility customer.

Table 29: Summary of the scores of all support mechanisms on thirteen objectives for the renewable energy policy of Barbados and two additional criteria

Priority objectives	Relative importance of objective (Score, max. 120)	Support mechanisms						
		Barbados today			Options for the future			
		RER	FTC fixed tariffs	Single PPAs	Net metering	FIT	RPS	Auctioning
Applicable to Barbados								
Administrative effort necessary								
Reliability of power supply (loss of load d/a)	117.0							
Low environmental impact	91.0							
Low cost of power	89.0							
High employment generation	83.0							
Reduktion of imports / hard currency	78.0							
Public acceptance of power supply	67.0							
Reduction of imports / energy security	61.0							
General participation (every household)	43.0							
Hurricane resiliance	33.0							
Local participation	32.0							
Domestic ownership	27.0							
Problems of agriculture need to be solved	27.0							

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ANNEX 1: DATA

Table A1: Numerical values for Figure 1

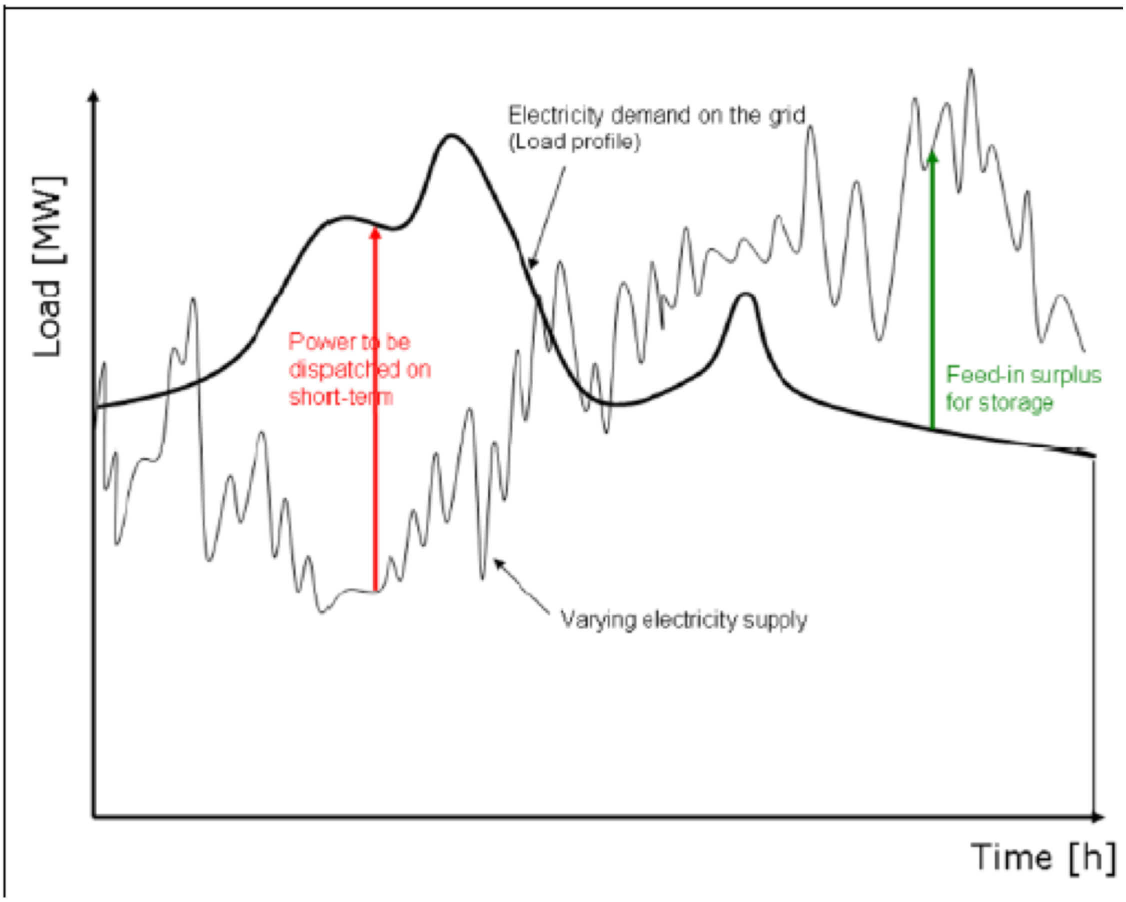
	Objectives	Frequency at which the objective was mentioned	Average weight attached to objective	Relative importance of objective (Frequency x average weight)
1	**Reliability of power supply (loss of load d/a)**	12	9.8	117.0
2	**Low environmental impact**	12	7.6	91.0
3	**Low cost of power**	12	7.4	89.0
4	**High employment generation**	11	7.5	83.0
5	**Reduktion of imports / hard currency**	10	7.8	78.0
6	**Public acceptance of power supply**	8	8.4	67.0
7	**Reduction of imports / energy security**	7	8.7	61.0
8	**General participation (every household)**	5	8.6	43.0
9	**Hurricane resiliance**	4	8.3	33.0
10	**Local participation**	4	8.0	32.0
11	**Domestic ownership**	4	6.8	27.0
12	**Problems of agriculture need to be solved**	3	9.0	27.0
13	**Stable electricity rates**	3	8.0	24.0
14	**Fast decisions on licenses etc/ streamlined processes**	2	10.0	20.0
15	**Reliable long term policy vision**	2	10.0	20.0
16	**Storage must be incentivised**	2	9.5	19.0
17	**Tariff has to guarantee repayment (funding)**	2	9.5	19.0
18	**Wind local benefits need to be felt**	2	9.0	18.0
19	**Achieve 100% RE**	2	9.0	18.0
20	**Positive welfare effect**	2	9.0	18.0
21	**Avoid stranded assets**	2	7.5	15.0
22	**Low water consumption**	2	6.0	12.0
23	**Establish partnership between local stakeholders and international investors**	2	5.5	11.0
24	**Focus on proven technologies plus focus on R&D**	2	5.5	11.0
25	**Low land use**	2	5.0	10.0

ANNEX 2: A DETAILED DISCUSSION OF STORAGE

A2.1 THE CONCEPT OF RESIDUAL LOAD

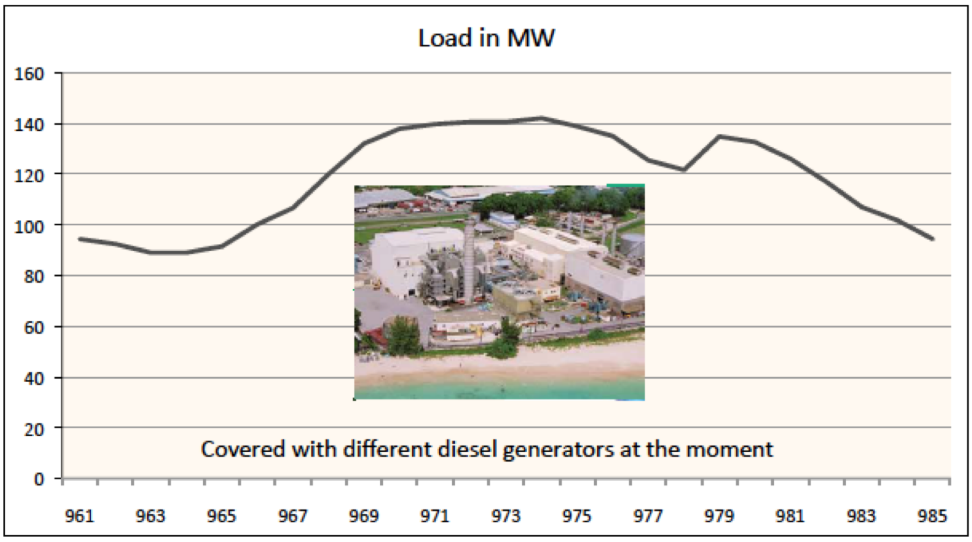
To understand how the energy demand can be met by using very large shares of wind and solar energy a new concept needs to be introduced, the concept of **residual load**. While in conventional electricity systems the hourly demand, which we call electrical load, had to be met by different controllable production units like base load or peak load power plants, in the new electricity systems the controllable units don't have to follow the load but they have to match the difference between the load (demand) and the uncontrolled production of wind and solar energy, which produce as much electricity as possible as soon as they are installed, because they don't have variable costs which could be saved by stopping their operation at times of low demand. No money can be saved by turning these power plants down or running them at partial load. The difference between the hourly load and the hourly production from wind and solar energy, which can be positive or negative, is called residual load. Thus, it is the task of all controllable units to meet the residual load of the system. As Figure A1 shows the residual load changes far faster than the load. This requires that all controllable production units can change their production much faster than in a conventional electricity system. As pointed out before, this can lead to substantial problems for the operation of solid biomass combustion based on bagasse and river tamarind in Barbados.

Figure A1: Hourly load, hourly production from wind and solar energy and the resulting residual load of a system with high shares of wind and solar energy (Source: Hohmeyer 2014, slide 9)



As an example, Figure A2 shows the load and the residual load for Barbados employing wind and solar PV in a system with 200 MW installed wind and 195 MW PV capacity on a day February (see Hohmeyer 2014, slide 10). The system was set up to cover almost 100% of Barbados' power demand by wind and PV across the year. We can see that the *residual load* can change by more than 100 MW (50% of the maximum system load) within an hour up or down. This is more than the change in the *load* during the entire day. Furthermore, the structure of the solar energy output leads to a negative residual load from the morning to the afternoon. Although, the sum of wind and solar energy production of the day seems to be sufficient to meet the total electricity demand of the day, it is quite clear that we will need substantial storage capacity to meet the residual load every hour of the day.

Figure A2: Load curve and residual load for Barbados on February 9th with 200 MW wind and 195 MW of PV installed (Source: Hohmeyer 2014, slides 5 and 10)



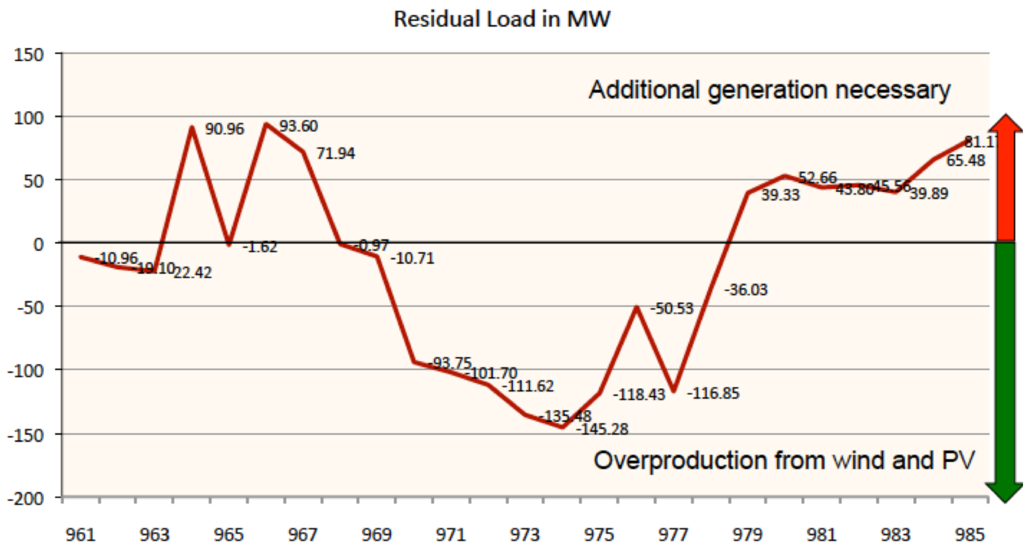
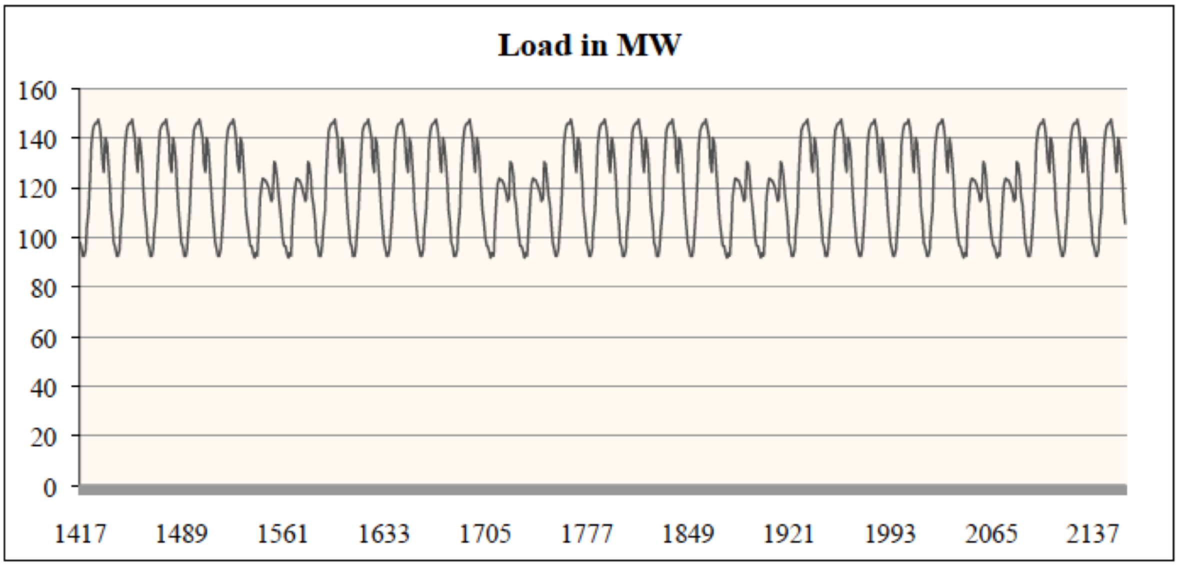


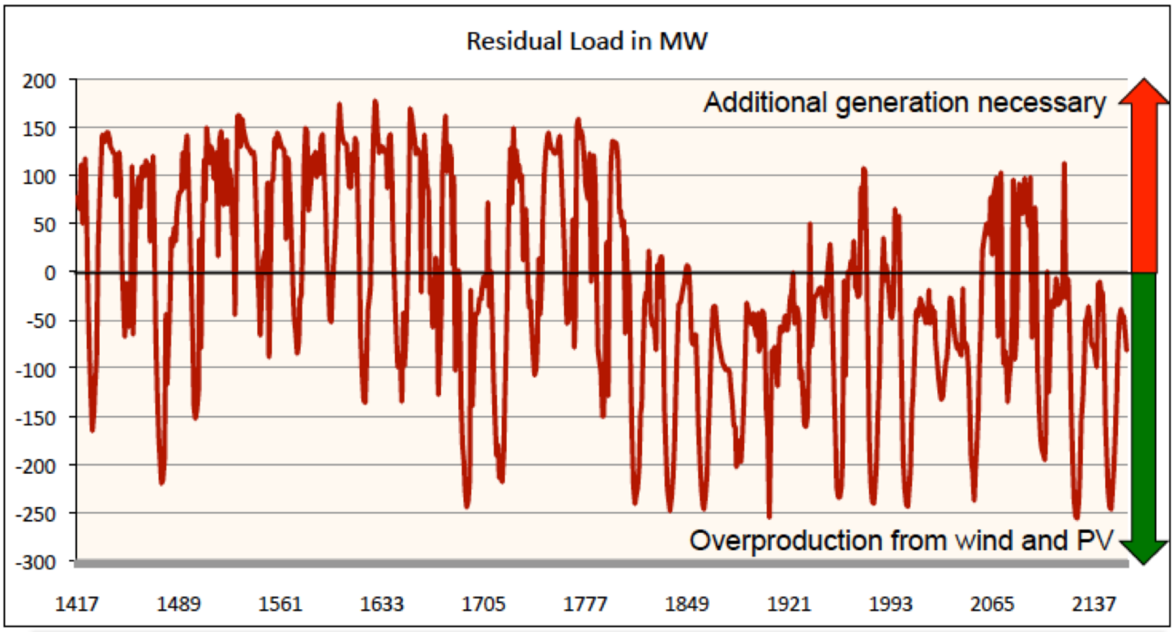
Figure A3a shows the daily and weekly pattern of the electrical load for the month of March, which needs to be met every hour of the month. Subtracting the wind and solar energy production of an installed capacity of 200 MW wind and 195 MW of solar energy leads to the fast fluctuating residual load shown in Figure 34b, which has to be covered by the controllable units of the system. In the first half of the month we have too little production from wind and solar energy to meet the full demand, while in the second half we produce more electricity than needed. The structure of the residual load suggests that Barbados will need substantial storage to balance the residual load in the case of a 100% renewable energy supply, if the availability of biomass is limited.

Figure A3: Load curve for the month of March (6.a) and resulting residual load with 200 MW wind energy and 195 MW PV installed (6.b) covering an increased electricity demand and load

A3.a Simulated hourly load curve (Source: Hohmeyer 2014, slide 15)



A3.b Hourly residual load curve (Source: Hohmeyer 2014, slide 18)



A2.2 STORAGE IN POWER SYSTEMS WITH HIGH WIND AND PV PENETRATION

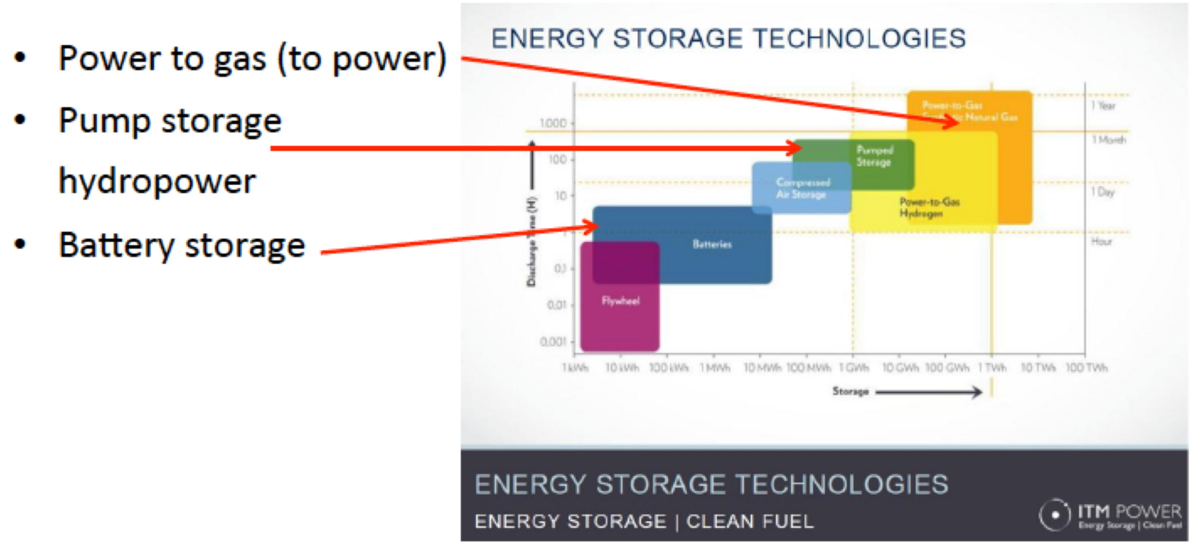
As a high share of solar and wind energy will lead to an electricity production which will at some hours be higher and at other hours considerably lower than the electricity demand, a power supply based predominantly on renewable energy sources will require substantial volumes of storage. The electricity produced by the storage should be available within a few minutes due to the fast changes in the residual load (see above). The capacity of the power production from the storage needs to be equivalent to the maximum load of the electricity system and the storage volume should be in the order of at least twelve hours of demand. If affordable it might be in the order of the power demand of a number of days or weeks, depending on the load characteristics of the country being served and the specific cost of storage. Considering a 100% renewable power supply for Barbados, based predominantly on wind and solar energy, the storage needs to have a generation capacity of 150 to 200 MW and a storage volume of 100 MWh to 10 GWh. These properties need to be taken into account in the selection of the most appropriate storage options.

If very flexible power production from biomass is available in large capacities this can substitute some storage for electricity, as the biofuels or biogases can be stored prior to combustion. Nevertheless, such use of biomass can only cover some remaining load, but it can not absorb any overproduction from wind and biomass, as real storage can. Unfortunately, solid biomass combustion is not flexible enough to similarly substitute fast reacting storage like power generation from biofuels, biogas or syngas.

As electricity demand from many households combined is far smoother than the demand of every single household and as the production from many solar installations and many wind turbines combined is far more regular than the production from each single operation, the storage demand for a connected electricity system is considerably less than the storage necessary to level the renewable energy production from a single solar installation and the demand from a single household. Thus, even if decentralised storage is used, it has to be operated on the basis of the storage needs of the entire system not on the basis of the demand of single households. For this reason every storage installation needs to be centrally controlled ('dispatched' in the terms of power systems).

As Figure A4 shows, there are at least six different storage technologies that might be considered for use in Barbados' power system. Two of these options don't apply for technical reasons. First, flywheels, large rotating masses, which store kinetic energy have a capacity of 1 - 100 kWh. Therefore, they are not able to supply storage volumes in the necessary range of 100 MWh to 10 GWh.

Figure A4: Different storage technologies for electricity with range of storage volumes and discharge times (double logarithmic scale) (Source: Hohmeyer 2014, slide 14)



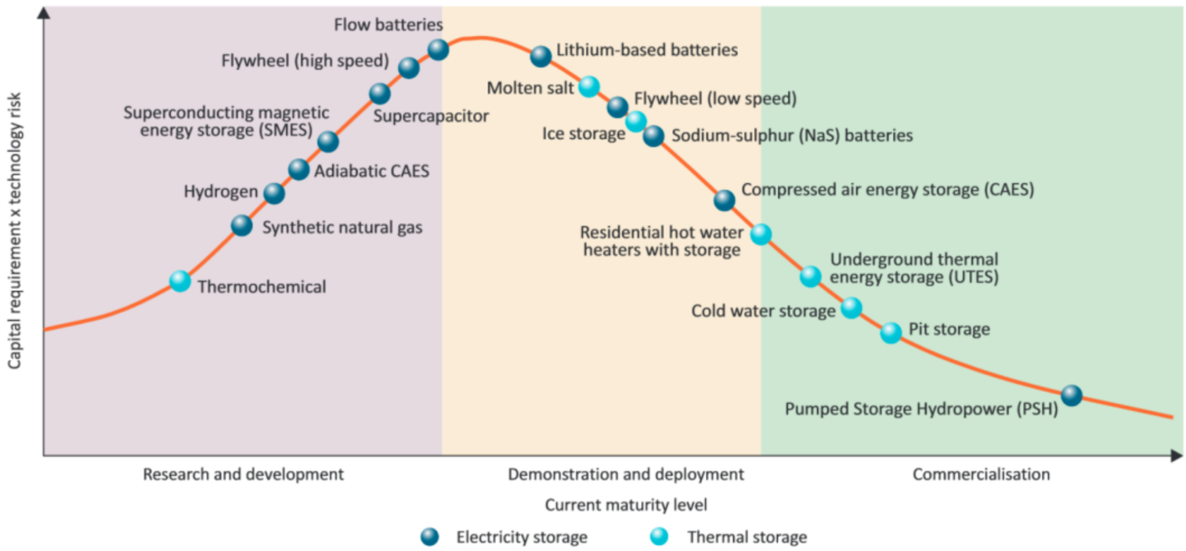
The second technology that does not apply in Barbados is compressed air storage (CAES). Compressed air storage needs very large underground salt formations to form caverns of a volume between 100,000 and 500,000 m³. These are used to press air under high pressure into the caverns at times of overproduction of power. The maximum pressure in the cavern is brought up to about 150 bar. Whenever additional power is needed from the storage the compressed air is released through an air turbine to produce electricity. For this purpose the pressure is dropped to about 100 bar. Thus, the active storage is made up by the pressure difference between 100 and 150 bar in the salt cavern. As the air is heated up in compression to temperatures in the range of 500 to 600°C and the salt in the cavern would melt at such temperatures, the air has to be cooled down to ambient temperature. On the return the air has to be heated up to temperatures between 400 and 500°C before it can drive an air turbine. Thus, it is strongly desirable to store the heat energy as well. Such combined air pressure and heat storage systems are called adiabatic air storage (adiabatic CAES). There are no large salt formations under Barbados. Therefore, CAES is not an applicable storage option for Barbados, although, if applicable, it could supply storage in volumes of up to 1 GWh.

Thus, four storage technologies remain for a possible application in the case of Barbados, which can not be disqualified right from the beginning. These technologies are:

- Battery storage
- Pump storage hydropower
- Power-to-gas storage in the form of hydrogen
- Power-to-gas storage in the form of methane.

Nevertheless, it has to be taken into account that the different storage technologies are at very different levels of technical and economic maturity as Figure A5 shows.

Figure A5: Technical and economic maturity levels reached by different storage technologies



Source: Decourt, B. and R. Debarre (2013), "Electricity storage", *Factbook*, Schlumberger Business Consulting Energy Institute, Paris, France and Paksoy, H. (2013), "Thermal Energy Storage Today" presented at the IEA Energy Storage Technology Roadmap Stakeholder Engagement Workshop, Paris, France, 14 February.

Battery storage is a rather mature technology and available in very different sizes ranging from batteries for single devices like calculators to large containerised battery storage applications for the stabilisation of weak electrical grids. The storage capacity goes up to volumes in the range of 50 MWh (50,000 kWh). As Barbados will need storage volumes between 100 and 10,000 MWh (10,000,000 kWh), battery storage appears to be falling short in the necessary storage volume. Nevertheless, it is far closer to the target range than the flywheel technology discussed above. What is more, battery storage could be used in smaller units for certain grid services independent of the overall storage volume used to balance a power system mainly relying on wind and solar energy.

Figure A6: Pros and cons of battery storage (Source: Hohmeyer 2014, slide 13)

As battery storage can be bought ‘off the shelf’ in containers ready to be connected to a grid, it is very easy to install. It just takes the cabling and some foundations for the containers to set up this storage option. Figure A6 shows a picture of containerised battery storage and sums up the main pros and cons for battery storage.

Battery storage has a relatively high efficiency for the storage of electricity. In short term storage more than 90% of the energy stored may be retrieved from a battery, if it is used shortly after the energy has been stored. If a battery is used for energy storage over weeks it may loose a substantial share of the stored energy even without being used.

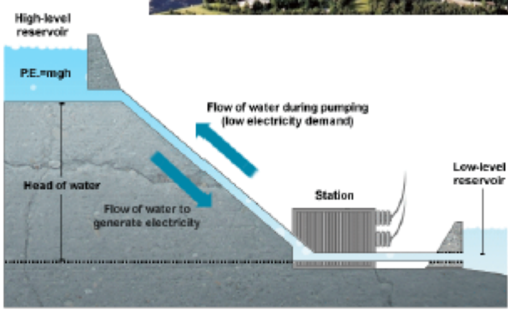
One of the major disadvantages of battery storage is its relatively high costs, which are in the range of 500 to 600 US$/kWh of storage volume. Thus, a storage volume of 1 GWh would cost about 500 to 600 million US$. The IRENA road map for Barbados assumes 700 USD/kWh (2016, p.30). During recent years there have been announcements of battery storage systems with costs as low as 250 USD/kWh, but so far these systems have not been made available in the market. At the same time batteries have a relatively short lifetime of 5 to 10 years compared to e.g. pump hydro storage (50 to 100 years) even if they are very well maintained.

Another relevant option is pump storage hydropower. This technology has been used for more than a hundred years all over the world to back up and stabilise larger electricity systems. It uses the gravitational potential energy held by water at high elevations. A normal pump storage system consists of an upper and a lower storage lake, which exchange freshwater. If energy needs to be stored, water is pumped with the help of an electric motor (driving a pump) from the lower lake into the higher lake. Once the energy is needed for the electricity supply the water runs from the upper lake to the lower lake driving a turbine, which is connected to an electric generator producing the electricity needed. Figure A8 shows a picture of the upper lake and the power plant of a pump storage hydro system and a cross section of such an installation showing the basic principle. The altitude difference between the two lakes should be greater than 100 m, as the stored energy is directly related to the height difference (head) and the volume of the water stored.

Figure A8: Pump storage hydro systems and their main advantages and disadvantages (Source: Hohmeyer 2014, slide 14)

Pump storage hydropower:

- Appropriate size GWh
- Low cost per MWh storage (<100 US/ kWh storage)
- Major construction needed
- Only special locations with large altitude difference possible
- Technology chosen for the modelling (3 GWh)



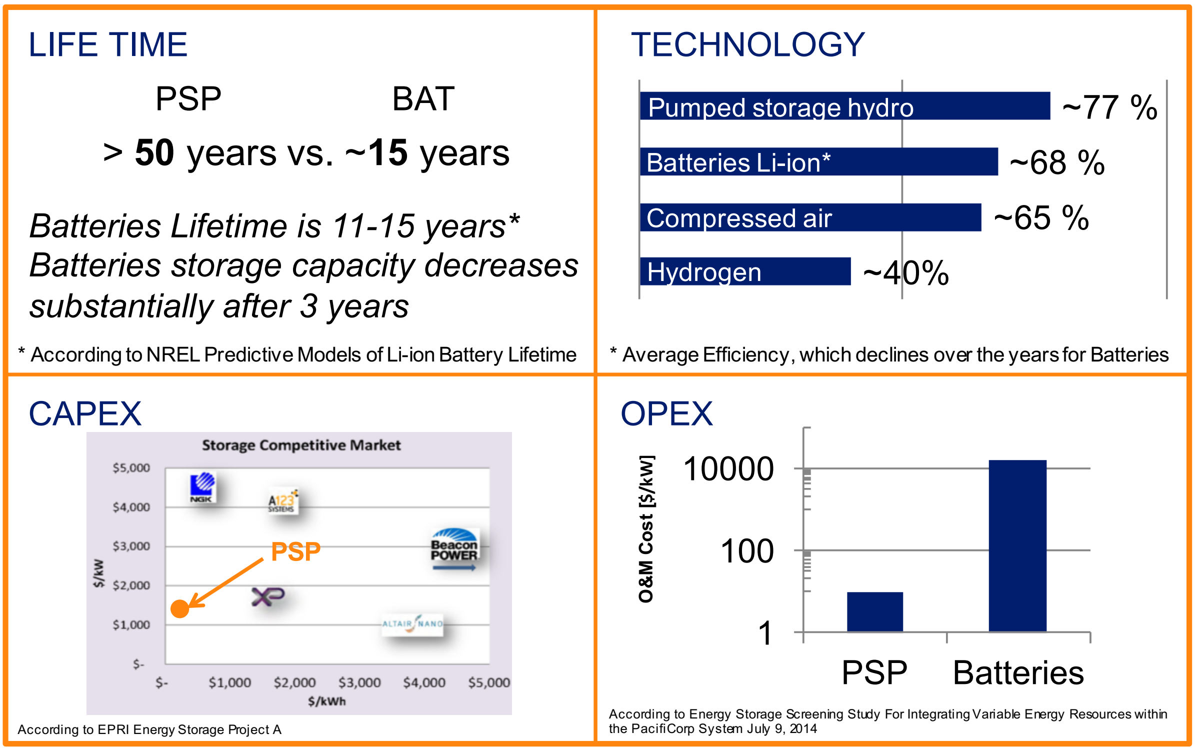
As the energy stored in the upper reservoir is directly proportionate to the hight above the lower reservoir, the volume of the reservoirs increase with a shrinking altitude difference. Assuming an altitude difference of 300 m the necessary storage volume of each lake to store 1 GWh (1,000,000 kWh) is about 1,250,000 m^3. As Barbados has substantial areas with an elevation around 300 m above sea level, the necessary storage volume can easily be estimated by multiplying each kWh of necessary energy storage by 1.25 m^3. If it should turn out that the location of the reservoirs will result in an altitude difference of 250 m this can be easily recalculated by 300 m / 250 m * 1.25 million m^3 = 1.5 million m^3.

In the overall storage operation about 20 to 30% of the original electricity is lost. Thus, the efficiency of the storage is not as high as in battery storage, but it is far better than in the power-to-gas storage discussed below. As Figure 35 above shows, pump storage hydro is applied in a range of 50 MWh to 50 GWh (50,000 to 50,000,000 kWh), which covers the most likely size range of the necessary storage for a power system predominantly based on wind in solar energy in Barbados. Although the cost of a pump storage hydro system will vary considerably with the construction costs of the storage lakes and the pipeline or tunnel connections (the so called penstock) between them, the costs for such systems are most likely below 100 USD/kWh of storage volume. Which is about one fifth of the cost of battery storage in the market or 40% of the costs quoted for the lowest cost battery storage devices announced so far.

One of the historic reasons for including pump storage hydro systems in almost all major electricity supply systems is the ability to ramp such a system from no operation to full load operation in about 90 seconds. Thus, a pump storage system can change from full load operation for storage to full load operation for electricity production within three minutes, with the most recent systems claiming just about 120 seconds for a complete turn around. This capacity has rendered pump storage hydro systems ideal for dealing with all short term fluctuations in power supply systems. Under normal circumstances the relation between the storage volume, measured in MWh, and the electricity production capacity, measured in MW, allows for a full load operation of 4 to 6 hours. In conventional power systems pump storage hydro systems are used for short term peak power production. The storage is normally filled by cheap electricity produced during low load hours during the night and electricity is produced during peak load hours of the day or to smoothen the production to exactly meet demand at every minute of the day.

A comparison of pump storage and battery storage shows the substantial advantages of pump storage for all systems with sufficient altitude drop and of a sufficient minimum size (see Figure A9 below).

Figure A9: Comparison of pump storage and battery storage systems (source: Stoebich 2016)



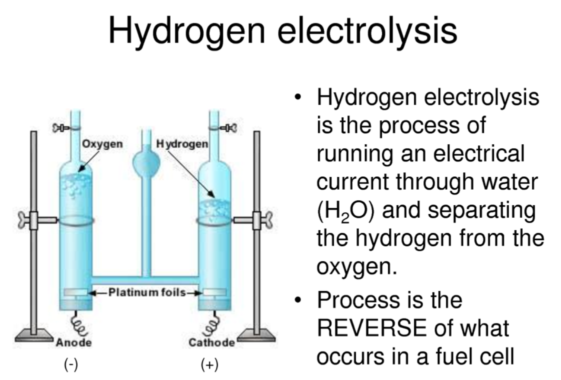
Although it will be necessary to do a very detailed site assessment for the location of a pump storage hydro plant on Barbados including detailed geological assessments of the underground between the two storage lakes, this technology seems to offer the right size and technical properties for the storage needed for an electricity supply for Barbados relying predominantly on wind and solar energy. Pump storage comes at substantially lower life-cycle cost as compared to battery storage.

Before a final decision on the storage system to be used in Barbados is made, the other options have to be looked at. These are the two so called power-to-gas technologies. In the first case the electricity to be stored is used to split water (H_2O) with electricity into its two components hydrogen (H) and oxygen (O) in a process called electrolysis. Figure A10 shows the basic principle of the electrolysis process.

In the electrolysis process the two produced gases (oxygen and hydrogen) have to be separated, because a mixture of the two gases is highly explosive (detonating gas). The energy is stored in the hydrogen produced. As soon this is recombined with oxygen from the surrounding air, the stored energy is set free. This recombination can be done in a combustion engine or in a fuel cell, which is just a controlled electrolysis process in reverse. In this recombination process of hydrogen and oxygen the stored energy is set free in the form of electricity (and waste heat). Although there are a number of different fuel cell technologies, most of the technologies are still in demonstration stage and are hardly available as robust commercial technologies.

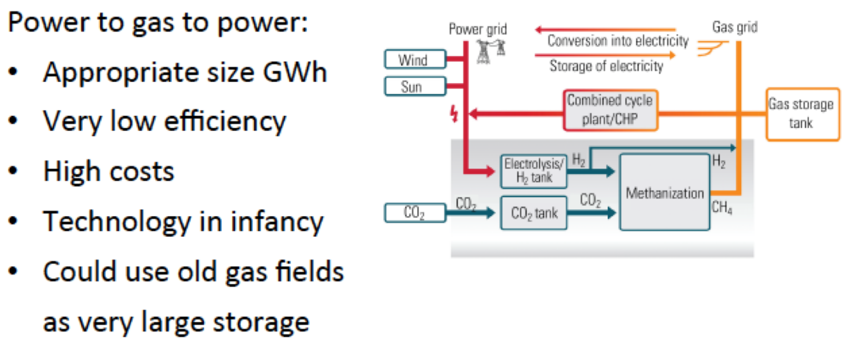
As hydrogen is relatively difficult and expensive to store the suggestion has been made to take this technology one step further to make storage much easier. This is achieved by using the hydrogen generated to produce methane (CH_4), which is a major part of natural gas. The idea is that methane can be stored and distributed using the natural gas infrastructure, pipelines and storage, existing in many countries.

Figure A10: Electrolysis: splitting water with electricity (Source: imagekid.com 2015)



This would reduce storage costs drastically. For the production of methane from hydrogen we need carbon dioxide (CO_2) to supply the carbon (C) necessary. This so called methanisation process is a standard synthesis process in the chemical industry. Once the electricity is needed the methane can be used in combustion engines or turbines to drive generators to produce electricity. Figure A11 shows the principle of power-to-gas storage of electricity.

Figure A11: The principle of power-to-gas storage and its major advantages and disadvantages (Source: Hohmeyer 2014, slide 12)



Due to the different conversion steps, 60% of the originally produced electricity will be lost in hydrogen storage. In the case of methane storage 70 to 80% is lost. Thus, from these types of storage 2.5 to 5 kWh of electricity need to be produced and fed into such storage system for every 1 kWh to be finally used after storage. The numerous conversion steps and the high losses lead to relatively high storage costs. As the technology is still in its early stages of development, actual cost figures for mature systems are not available.

Although power-to-gas storage covers the right size range of storage for Barbados and old gas fields could be used for methane storage, it will not be looked into further in this report, as it is not clear how expensive such a system would be as the technology is still in its infancy.

As a result of this preliminary analysis of the different possible storage options, pump storage hydro systems seem to have the greatest potential and the lowest costs for the necessary storage needed in the future power system of Barbados relying predominantly of wind and solar energy eventually achieving a 100% renewable power supply. During the last year first pre feasibility considerations for possible pump storage hydro systems have been carried out. The next sub chapter reports on the findings of these considerations.

A2.3 FIRST ANALYSIS OF POSSIBLE PUMP STORAGE LOCATIONS FOR BARBADOS

After a first discussion of the possibility to use pump storage hydro systems to supply the necessary storage for a 100% renewable energy system for Barbados (Hohmeyer 2015), the idea was picked up by interested investors, who commissioned a first prefeasibility report on the assessment of the potential for the development of a pump storage system in Barbados, which was carried out by Stantec Consulting Caribbean Ltd (Stantec 2016). The study was targeted to find possible locations with sufficient altitude differences for the upper and lower reservoir and to identify possible sources of water to supply the water necessary to fill the system and to replace evaporation losses during the operation of the system.

In principle Stantec identified different locations on the plateau above the Scotland district as possible locations for an upper reservoir and some locations at the lower end of the Scotland district. The achievable altitude drop between the upper and lower reservoirs are 270 and 240 meters (see Stantec 2016, p.3.1f). The available land areas for the upper reservoirs are in the range of 0.15 to 0.2 km^2 (see Stantec 2016, p.3.1ff). Depending on the depth to the reservoirs such lakes could hold between 1.5 to 4.0 Million m^3 of storage water if 10 or 20 meters deep. As the possible locations at the lower elevation are of a similar size, a pump storage system with an energy storage capacity of up to 2 900 MWh can be constructed if just one of the identified sites were to be used. This storage volume compares well with a first analysis of the necessary storage volume for a 100% renewable electricity system for Barbados based on 200 MW of wind and 195 MW of solar PV (see Hohmeyer 2015, p.19).

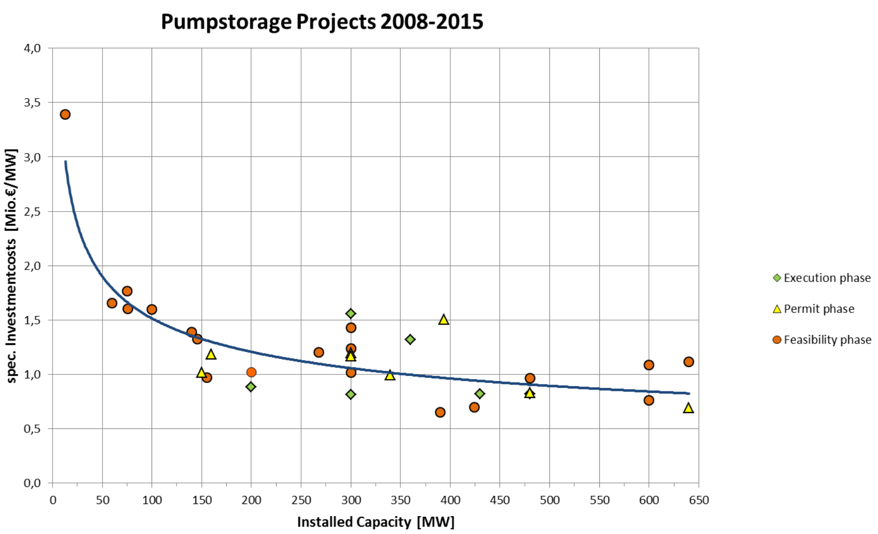
The Stantec study looked at the availability of runoff water from the watersheds from which the lower reservoir could collect water to fill the system. Even with a very conservative estimate for the annual precipitation in the area of 1,143 mm/a and a 50% runoff factor the two most relevant watersheds (Bruce Vale and St. Simons) will produce a runoff of more than 8 million m^3/a (see Stantec 2016, p.3.2), which is more than double of the required maximum volume to fill the system. At present this runoff is not used and dewaters directly into the Atlantic Ocean. What is more the two adjacent watersheds directly to the north of Bruce Vale and St. Simons, Bawdens North and Bawdens South add another 4.6 million m^3 of runoff per year (see Stantec 2016, p.3.5) dewatering into the Atlantic at almost the same location. Thus, the overall water availability in the area of the lower reservoir is about three times the maximum volume required to fill the system. After the system has been filled the annual evaporation losses are estimated at 30,000 m^3 for 20 hectares (0.2km^2) (see Stantec 2016, p.3.2) or the maximum reservoir size or 60,000 m^3/a for both reservoirs (upper and lower) together. Thus, for compensating the evaporation losses from the system less than 1% of the collectible runoff will be needed.

As the collection and purification facility for the runoff will have to be separate from the lower reservoir and as it will be scaled for the original filling needs of the pump storage system (1.5 - 4 million m^3) there will be a high excess water collection capacity once the pump storage system will be filled, although the collection and purification facility will need to continue operation for the substitution of evaporation losses. It has been discussed that an additional reservoir for irrigation and drinking water collection could easily be supplied with large volumes of runoff from the collection and purification facility once the pump storage system is filled initially. In a situation where Barbados considers itself to be a water scarce country and some areas of Barbados experience frequent shut off periods for the freshwater supply, this additional sweet water supply may add substantial value to the pump storage development. The collected water, once purified and stored in a separate fresh water reservoir could be pumped up to a large water pressure vessel of the Barbados Water Authority located on the upper rim of the Scotland District, from which it could be easily distributed to all parts of the Barbados freshwater supply system.

As land of the appropriate size and altitude as well as freshwater availability don't seem to be major obstacles for a pump storage development on Barbados the remaining challenge is the geology of the proposed sites. It is quite clear that the underground beneath the upper reservoir locations is coral rock, which is comparatively soft, but a stable limestone formation. The main lower reservoir location is located in an area of river alluvium and terrace deposits overlaying the Mount All Member (MA) formation consisting of grained sandstone (see Stantec 2016, p.3.3). At the moment it is not clear whether the underground between the upper and lower lake consist of stable formations or whether there are some moving formations in between, which could cause problems for the construction of the penstocks connecting the reservoirs.

In addition to the Stantec prefeasibility study a site visit was conducted by Christian Stoebich (in November 2016) an international expert for pump storage plants from Andriz Hydro, one of the leading pump storage producers in the world. According to the assessment of this expert a pump storage installation seems to be quite possible at the locations identified in the Stantec study. In order to avoid unstable underground formations for the penstocks a detailed geological analysis of the area under consideration is necessary. The most likely design will use vertical shafts underneath the upper reservoir down to the level of the lower reservoir to utilise as much of the coral rock environment as possible and then use horizontal tunnels to reach the lower reservoir. If the formations towards the lower reservoir prove to be less stable than the limestone, the power house could be located at the bottom of the vertical shafts. According to the expert opinion of Mr. Stoebich a pump storage installation for Barbados should cost in the range of 1,500 USD/kW installed, which is in the mid range of present worldwide pump storage investment costs for systems in the range between 50 and 200 MW installed capacity as Figure A12 shows.

Figure A12: Pump storage investment costs over installed capacity (source: Zeller(Poeyry) 2016, slide 12)



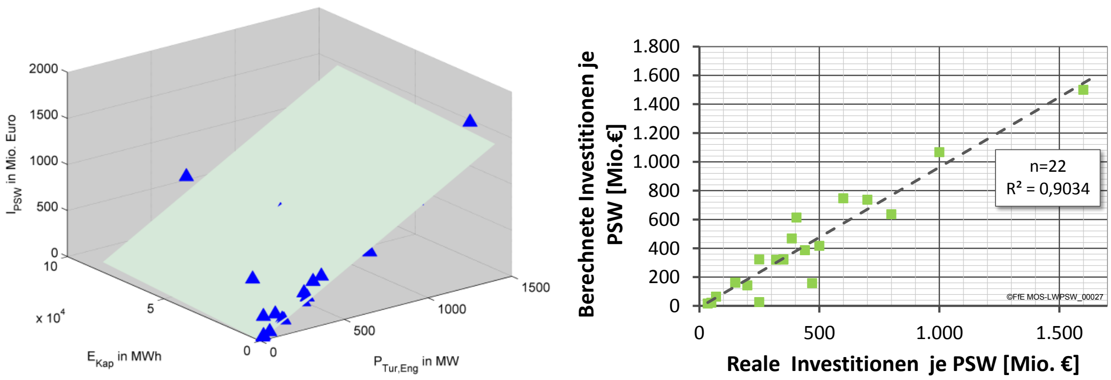
A2.4 THE CALCULATION OF PUMP STORAGE INVESTMENT AND OPERATION COST

Drawing upon the empirical evidence of German and Austrian pump storage hydro projects Conrad et al. (2014) have developed a model to calculate the investment and operation cost of pump storage installations. The investment is mainly dependent on the capacity installed (measured in MW) and on the storage volume connected to the system (measured in MWh). As the analysis was done in Europe the Euro is used as the monetary unit. Conrad et al. show that the investment cost can be calculated by multiplying the installed capacity by roughly 1 Euro/kW and adding to this the installed storage volume multiplied by 1.3 EURO/kWh. This calculation and the empirical data, which the function is based upon are shown in Figure A13.

Figure A13: Estimated function for the investment cost of pump storage plants (source: Conrad et al. 2014, p. 12)

$$I_{PSW} = 1.059{,}24\,\frac{€}{kW}\cdot P_{Tur,Eng} + 1{,}3\,\frac{€}{kWh}\cdot E_{Kap} \qquad (4\text{-}2)$$

I_{PSW}:	Investition für PSW
$P_{Tur,Eng}\ [kW]$:	Engpassleistung der Turbine
$E_{Kap}\ [kWh]$:	Nutzbarer Energieinhalt des PSW (Speicherkapazität)



The operation of pump storage plants induces fixed and a small share of variable costs. The fixed share can be calculated based on the installed capacity in MW. Conrad et al. estimate this term at 2.86 Euro/kW. Assuming a technical availability of 90% they estimate three types of variable operating costs. The first kind is directly proportionate to the number of system starts. This term is estimated to be 3.34 Euro/MW for each start of the turbine. The second kind is directly proportionate to the number of starts of the pump. This term is estimated to be 8.95 Euro/MW for each start of the pumps. The last term is proportionate to the electricity produced. This term is estimated to be 0.56 Euro/MWh of electricity produced. The different terms for the estimation of pump storage operating costs are given in Table A3 below.

Table A3: Fixed and variable operating costs of pump storage systems (source: Conrad et al. 2014, p.13) (German notation: comma used as decimal point)

Fixe Betriebs-kosten	Anteil bezogen auf die installierten Leistung		$\left[\frac{€}{kW \cdot a}\right]$	2,86
Variable Betriebskosten	Anteil bezogen auf die Startvorgänge pro Jahr	Anteil Turbine	$\left[\frac{€}{MW \cdot Start_{Tur}}\right]$	3,34
	Anteil bezogen auf die Startvorgänge pro Jahr	Anteil Pumpe	$\left[\frac{€}{MW \cdot Start_{Pump}}\right]$	8,95
	Anteil bezogen auf die erzeugte Strommenge		$\left[\frac{€}{MWh}\right]$	0,56
	Technische Verfügbarkeit			0,90

It seems to be appropriate to use the cost calculations for pump storage installations developed by Conrad et al. in the case of a preliminary analysis for Barbados, but due to the fact that Conrad et al. base their estimates on average costs of 1000 Euro/kW installed capacity, it seems to be more appropriate to multiply their coefficients with the factor 1.5 to translate the estimates to the cost range of about 1,500 Euro/kW in the case of Barbados.

ANNEX 3: WORK PACKAGE 4: EXTENSION AND UPDATE OF HOURLY POWER SYSTEM SIMULATION MODEL FOR BARBADOS

The model used by Hohmeyer in past analyses on 100% RE Barbados

In 2014 a first model for the hourly simulation of the Barbados power system with high shares of variable renewable energy sources was developed by Hohmeyer (Hohmeyer 2015) and used for a first analysis of possible 100% RE energy supply options for Barbados. The model included the existing generators and assumed the future use of the diesel generators as backup units for a future power supply largely based on wind and solar energy. The model included wind and photovoltaic solar energy production based upon hourly time series of wind speeds and solar radiation available from international data sources. The hourly electricity demand was reconstructed from a typical 24 hour load profile available for Barbados and from monthly power sales of Barbados Light and Power. Storage was modelled as a pump storage hydro system storing excess power production in times of high solar radiation and high wind speeds producing electricity from the storage in times of a lack of renewable energy production.

Ultimately, when there was a continuous underproduction of power from wind and solar and the pump storage was used up (all water in the lower reservoir) the existing diesel generators and gas turbines were used to cover the remaining power demand. Depending upon the installed wind and solar capacities and the volume of the storage the demand to be covered by the diesel generators could be kept as low as 2.5% of the annual power production. It was assumed that the diesel would be substituted by bio-diesel. Thus, it could be shown that a 100% renewable energy production for Barbados was feasible. In the publication of 2015 Hohmeyer showed that such a 100% renewable energy based system could save up to 30% of Barbados power cost as compared to 2013 assuming international cost figures for renewable energy technologies (see Hohmeyer 2015, p. 27). The model did not include any technology for the use of solid biomass or biogas, neither did it include any technology for the conversion of waste to energy.

In fall 2015 an new version of the model was extended through the inclusion of technologies for the combustion of solid biomass (based on the plans of the Barbados Cane Industry Corporation) and the plasma gasification of waste (as mentioned in the draft final report on a Barbados NAMA). Furthermore, the model was extended to include run-of-river hydropower and long term gas storage for the syngas produced from the plasma gasification.

This extended model was used in the stakeholder workshop ‚Renewable Energy and Energy Efficiency - Towards A Clean Energy Sector In Barbados' conducted by the Barbados Renewable Energy Association (BREA) and the Barbados Central Bank on November 2nd, 2015. Based on the discussion with about 25 stakeholders from all parts of society roughly 15 new scenarios on possible 100% renewable energy scenarios were run. During the discussion of the scenario results it became quite clear that a solid biomass combustion of the size planned by the Barbados Cane Industry Association would run into serious economic problems or that it would increase the overall cost of a 100% renewable power supply. While scaling down the size of the plant from 23.5 MW to 10 MW would increase the need for back-up diesel by about 50% and reduce the cost increase, it would still not be economically attractive. The production of syngas from the plasma gasification of waste would increase the total system cost even further especially if the syngas would need to be stored in larger volumes from a continuous plasma gasification process.

Necessary extensions of the model for the present consulting work

The extended model used in the workshop does not include the production of electricity from biogas produced from King Grass or sugar cane as presently planned at ARMAG Farms in cooperation with BL&P. As this is a serious proposition for a very flexible energy production from biomass, which could fit into the future electricity system with large shares of wind and solar energy substantially better than the solid biomass production from bagasse and river tamarind, it needs to be included in the model to give a realistic representation of the renewable energy options available to Barbados.

In addition some modifications in the operating schedule of the solid biomass production need to be tested on the possibility of cost reductions.

For the waste-to-energy plasma gasification plant a switch to short term storage needs to be analysed, as the very large volumes necessary for long term storage of syngas made this option extremely expensive. In the following the basic model logic and the new extensions of the model are described.

The basic model logic

The starting point for the hourly modelling is the hourly load curve (demand) for electricity in Barbados for an entire year. Based on hourly wind and solar radiation data for Barbados and on typical wind turbines and solar PV installations the remaining load to be covered by other sources is calculated for a given hour (residual load 1). This residual load can be positive, which indicates a need for additional supply from other sources or it can be negative, indicating that wind and solar production actually exceed the demand in this hour. A negative residual load indicates how much energy could be stored, if enough storage is available.

In the next step all the production from other facilities, which have to run in this hour independent of the residual demand (must run) are subtracted from residual load 1 resulting in residual load 2, which again can be positive or negative like residual load 1. In the next step it is checked whether the remaining residual load 2 can be matched by the storage available. In the case of a positive residual load 2 the remaining demand will be covered by the power production from storage, as long as there is some storage production potential available (e.g. water in the upper reservoir of a pump storage system). If residual load is negative the energy will be stored as long as there is any partially empty storage available. Whenever total storage is entirely full, the excess energy has to be spilled or possible production has to be turned down. The remaining demand or the excess energy production after storage has been used is residual load 3, which is zero whenever residual load 2 is positive but there is enough stored energy to satisfy residual load 2 entirely.

In case residual load 3 is still positive, which is to say that wind, solar, all other must run technologies and storage did not suffice to meet the demand of a given hour, this demand is satisfied by operating the existing generators of BL&P, which are assumed to have enough fast starting capacity (gas turbines and diesel engines) to cover any remaining demand. This calculation is executed consecutively for every hour of the year.

Based on the available investment, operation, maintenance and fuel (as far as applicable) cost the total cost of the annual electricity production are calculated. This total cost is divided by the number of kilowatt-hours sold to arrive at the levelized cost per average kilowatt-hour sold.

In the model many technical and economic parameters can be varied to allow for the exploration of different scenarios as well as the analysis of sensitivities of the calculated results towards the variation of central parameters.

The model extension for the inclusion of King Grass gasification

The gasification of King Grass offers a number of systematic advantages over the combustion of bagasse and river tamarind combustion and one advantage over sugar cane gasification. King Grass can be harvested continuously all throughout the year. Thus, if there is a clear seasonality in wind and solar energy production, King Grass can be harvested almost with the opposite seasonality as the combined wind and solar production. This is not possible for sugar cane, which has to be planted at very specific times of the year and to be harvested in a fairly fixed cane season (personal communication with sugar cane farmers from Barbados). Thus, the production of sugar cane for an all year round operation of a gasification process is not possible and would need to be complemented by a second crop.

As compared to solid biomass combustion like bagasse and river tamarind, the gasification of King Grass is far more flexible, as it can be harvested according to seasonal demand (residual load 3) and the gas produced in a gasifier operating at a constant rate once fired up, can be stored in short term storage to adjust the hourly production during a day according to the prognosis of the hourly residual load 3. As the syngas can be used in combustion engines for electricity production the King Grass power production process can react to short term variations of the actual residual load very well. Typical combustion would be in gas engines with a capacity between 500 kW and 5 MW, which can be ramped from zero production to full load in less than 10 minutes. With this high degree of flexibility electricity production based on King Grass gasification can complement wind and solar energy quite well based on short term forecasts of wind speeds and solar radiation and the filling level of the pump storage.

In the model the power production from King Grass is integrated after storage is used. Based on the given seasonality of wind and solar energy production of a base year a complementary harvesting of King Grass (or a dry biomass storage fulfilling the same task) is assumed on a monthly basis. This determines the total gas volume to be converted to electricity in a given month. During each month a gasifier capacity is operated that converts the given volume of King Grass by constant operation entirely to syngas. The storage volume for syngas is calibrated to the constant gas production of 24 hours to allow a time shift of the power production during an entire day. According to the short term prognosis of residual load 3 (the residual load after storage operation) the power production is shifted to the hours with the highest positive residual load during a day (as a proxy for a future prognosis the data from a given past year are used as input to this calculation). After the power production from King Grass a new residual load results, which is then matched with back-up capacity (bio diesel or ordinary diesel). Thus, the introduction of power production from King Grass adds a new step to the model logic.

The changed operation of the solid biomass combustion

In the case of Barbados solid biomass combustion will most likely be done by the long planned bagasse combustion plant described in chapter 2. This plant will have a capacity of roughly 25 MW and operate a steam turbine driven by the solid biomass (bagasse and river tamarind) combustion in a steam boiler.

As the process has to be heated up to relatively high steam temperatures (about 400°C) for the turbine operation, it does take hours until the operation can start at all, as first the water boiler has to heat up the water and steam to about 400°C to begin the cold start of the turbine. The start up of a cold boiler can take anywhere between 2 and 6.5 hours (see Taler et al. 2015, p.159). Then the cold start of the turbine will take about 90 minutes to start with part load operation of 15-20% and it will take seven to eight hours to reach full load in order not to damage the turbine (see Figure 44). Thus, the full process from firing up the cold boiler to full load power production will take in the range of ten to 12 hours.

Figure 44: Typical cold start up operation of a steam turbine rotor (source: research gate / https://www.researchgate.net/figure/284930570_fig9_Fig-9-The-typical-cold-start-up-operation-curve-of-the-steam-turbine-rotor)

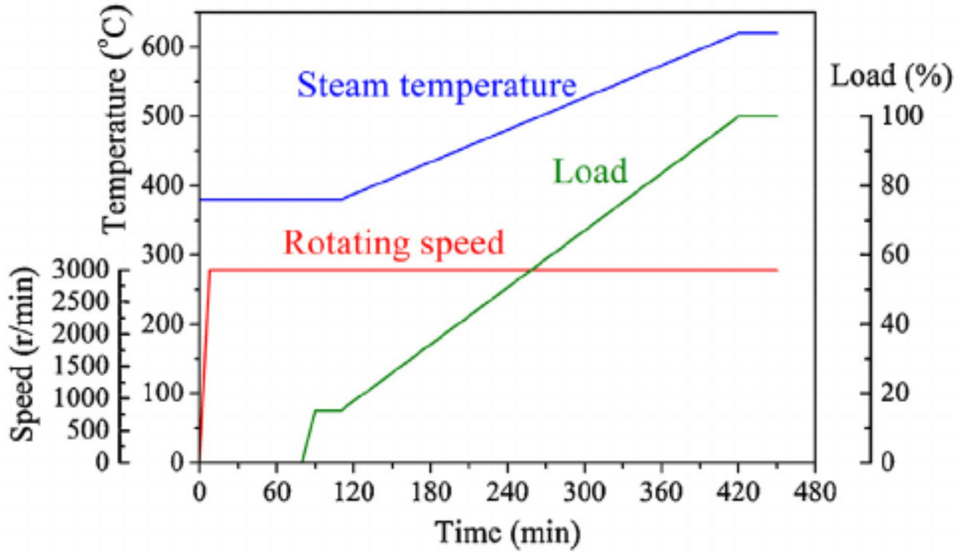
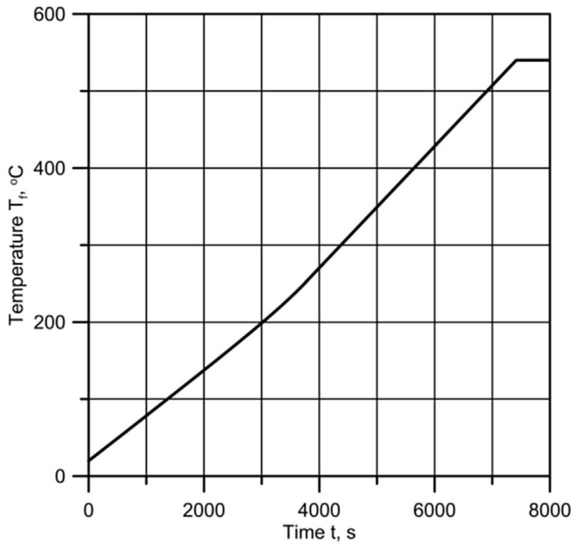


Figure 45: Steam temperature at the outlet of a power plant boiler after a cold start (source: Taler et al. 2015, p.157)



A power plant which takes more than 10 hours for a cold start will not be able to react to short term variations in residual load. Once it is fully operational (warm) it can be put into partial load operation. This will normally not be less than 25% and is often considerably higher. Thus, the solid biomass combustion could be entirely shut down for certain parts of the season, when residual load is expected to be low or negative. During the rest of the season it could be tried to vary the the operation between low partial load during times of high sunshine (around noon) and full load operation during the night hours. The exact operating cycle will depend on the technical specifications of the boiler and the turbine used.

The model has been modified to allow different operating schedules to accommodate as much of the foreseeable impact of wind and solar energy on residual load 1.

The introduction of short term syngas storage for the WTE plant

As the trials with large scale storage for the waste to energy plasma gasification plant, assuming a constant operation of the gasifier and the storage of all excess gas not used directly in combustion during the hour of gasification have shown that this would require extreme storage volumes inducing very high electricity cost, a new alternative has been included in the model, which uses all syngas produced within a day, but with a storage and generation capacity that allows to store up to 24 hours of syngas production and to use it in just a few hours, when wind and solar are low. As the actual power production during a day can be based on wind and solar energy forecasts the operation will be similar to the operation of the power generation from King Grass. It will be based on the 24 hour forecast of residual load 3.

The calculation of discounted cash flows for the different investments based on hourly model calculations

In order to allow an assessment of modified rate payments to the different investments necessary for the future energy system a new discounted cash flow module has been integrated into the model. It actually calculates the payments to each technology on the basis of the hourly operation calculated by the model. These payments will be made at the end of each month based on the sum of the monthly production. Assuming similar operation years over the lifetime of a technology the discounted cash flow can be calculated for the life time of an investment and it can be checked which payment per kilowatt-hour is necessary to result in a desired internal rate of return. The results of these calculations will be used for the estimation of first price points in WP14. They can be used in the discussion with stakeholders on appropriate tariffs for renewable energy sources. In addition these calculations can be used to show the impact of reduced operational hours on the economic feasibility of biomass or waste to energy plants.