Value of Solar+Storage in Guam

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Executive Summary

A valuation of distributed solar was performed for the island of Guam using solar PV performance data from nine representative PV systems provided by Micronesia Renewable Energy (MRE) and using load, cost, and planning data from Guam Power Authority (GPA). Solar production, represented by the composite output of the nine systems, scaled as a 1 kW-AC resource, was shown to be generally uncorrelated with the GPA system peak. This indicated that grid capacity benefits would require the use of dispatchable energy storage.

Dispersed energy storage was therefore included in the study. A simple energy storage dispatch algorithm was developed as illustrated in Figure ES-1. Storage was employed daily during peak hours, three months of the year. It is charged using only solar energy (not grid energy) as a priority for morning solar generation. It is then discharged to meet the evening peaks between 7 pm and 10 pm. While stored energy incurs some losses, it provides dispatchable renewable energy with the goal of capturing potential capacity-related grid benefits.

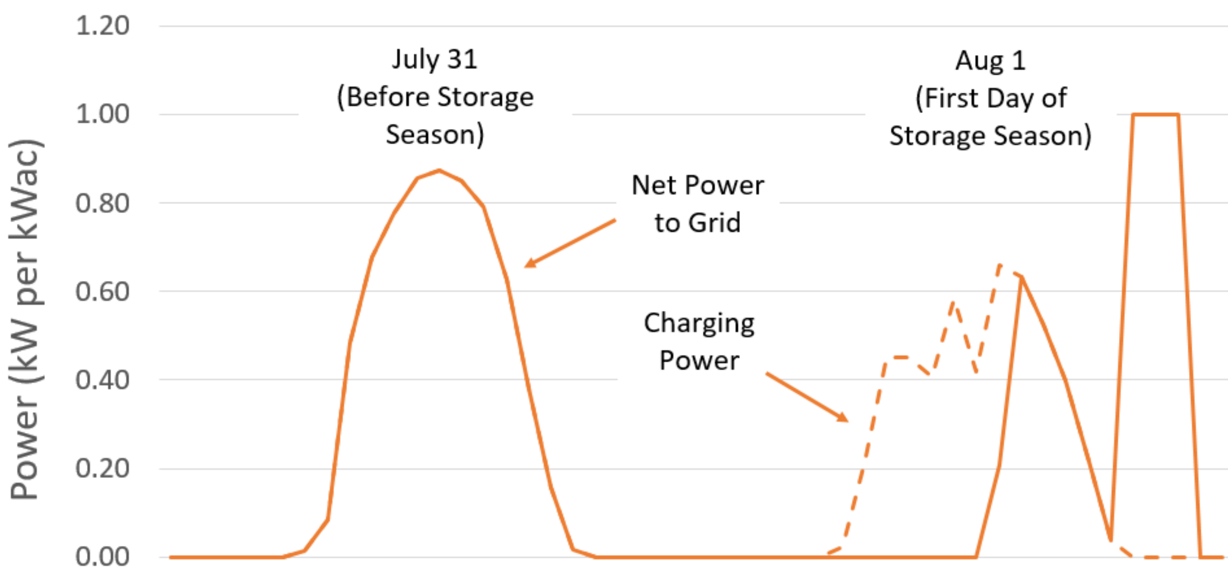

Figure ES-1. Illustration of solar+storage charge-discharge profile.

Effective capacity of the DER resource was defined as the average output over the top 100 load hours during the year 2015. Solar-only generation provided no capacity benefit, while solar+storage provided 72.7 percent of its rated capacity. This result would vary depending on the capacity metric selected and the dispatch algorithm used, and may be worthy of additional study.

The four study scenarios are based on two types of utility generation fuels—LNG and ULSD—and two storage options: storage was either included as a complement to the solar generation or excluded in the solar-only case. The utility generation is assumed to be displaced on the margin by the distributed resource.

An example calculation of first year valuation results is shown in Table ES-1 for one study scenario (LNG with solar+storage). The first column shows the gross value for a fully dispatchable, centrally-located resource. The generation capacity value is then adjusted by the 72.7% load match factor. Next, a loss savings factor adjusts for avoided losses in the transmission and distribution system. Finally, the distributed value is calculated and summed.

Table ES-1. First year VOS results, Scenario 2.

First Year Value	Gross Starting Value	×	Load Match Factor	×	(1 + Loss Savings Factor)	=	Distributed PV Value
	A	×	B	×	(1+C)	=	D
	($/kWh)		(%)		(%)		($/kWh)
Avoided Fuel Cost	$0.120				4.8%		$0.126
Avoided Gen Capacity Cost	$0.064		72.7%		4.8%		$0.049
Avoided RPS Costs	$0.031						$0.031
Avoided Fuel Uncertainty	$0.056				4.8%		$0.059
							$0.264

Final results for all four scenarios are shown in Table ES-2. Values range from $0.210 per kWh for solar-only displacing LNG generation up to $0.284 per kWh for the hybrid solar+storage option with ULSD. Levelized results are shown in Table ES-3.

Table ES-2. First year VOS results, all scenarios ($ per kWh).

	1 LNG | Solar	2 LNG | Solar+Storage	3 ULSD | Solar	4 ULSD | Solar+Storage
Avoided Fuel Cost	0.126	0.126	0.157	0.157
Avoided Gen Capacity Cost	0.000	0.049	0.000	0.049
Avoided RPS Costs	0.025	0.031	(0.005)	0.000
Avoided Fuel Uncertainty	0.059	0.059	0.078	0.078
	0.210	0.264	0.230	0.284

Table ES-3. Levelized VOS results, all scenarios ($ per kWh).

	1 LNG | Solar	2 LNG | Solar+Storage	3 ULSD | Solar	4 ULSD | Solar+Storage
Avoided Fuel Cost	0.162	0.162	0.203	0.203
Avoided Gen Capacity Cost	0.000	0.064	0.000	0.063
Avoided RPS Costs	0.033	0.039	(0.006)	0.001
Avoided Fuel Uncertainty	0.076	0.076	0.100	0.100
	0.272	0.342	0.298	0.368

Technical Analysis

Composite System Resource

The valuation was based on the hourly output of a “composite” resource made up of nine distributed PV sample systems in Guam as described here. Micronesia Renewable Energy (MRE) provided hourly production data for 2015 for the nine systems, and the output of these are shown in *Figure 1* on the peak system load day of the year, August 31, 2015. Hourly output was cleaned as described in the appendix.

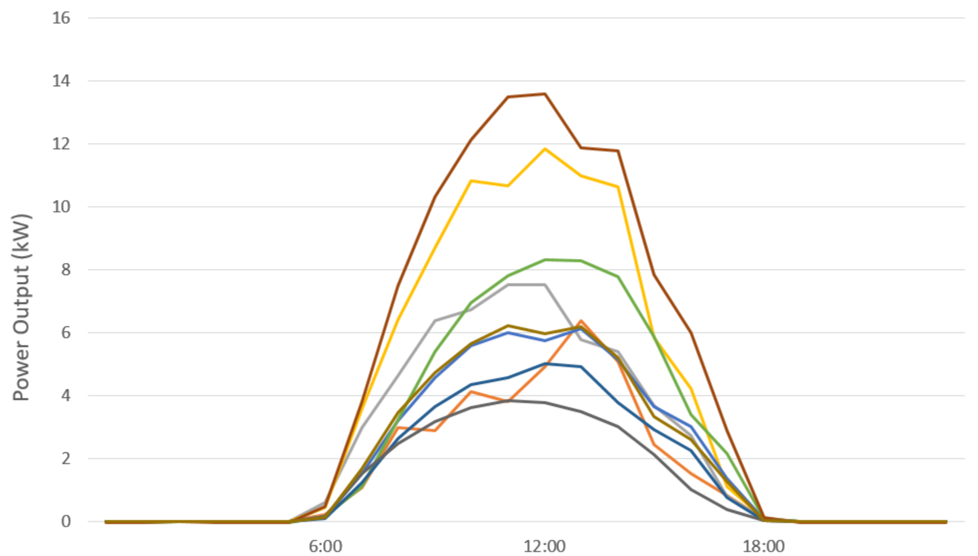

Figure 1. Nine sample systems on peak load day (August 31, 2015)

Three observations are relevant about these energy production data series. First, the outputs reflect different system ratings. The system with the highest output (brown curve) has a rated output of 18.36 kW-DC, while the system with the lowest (black curve) is a 4.75 kW-DC system. To account for these variations, the composite system must be normalized to a unit rating.

Second, these systems are distributed across the island on various circuits, and are not concentrated as in the case of a single utility-scale resource. This means that each individual system responds to a slightly different solar resource. The brown curve reflects a relatively clear day, with some minor presence of early afternoon clouds. The orange curve, on the other hand, shows a system responding to significant morning clouds. The evaluation is intended to reflect the combined output of these samples, rather than resting on the output of a single system.

It is understood that the combined output is less subject to short-term (e.g., 1-minute or 10-minute) variability than a single, concentrated resource. On the other hand, the maximum output is not delivered by all systems at the same time, and the combined resource rating would be less than the sum of its individual component systems.

Finally, the systems are not uniformly installed with the same tilt-azimuth design angles. The high output system (brown), for example, appears to be a south facing system because its output is fairly symmetric over the course of the day. The third-highest output system (green), however, appears to employ west-facing panels because the afternoon output is higher than the morning output. The composite system should also account for this variation.

The composite resource is shown in *Figure 2*. It is composed by summing the hourly output of the nine sample systems and dividing each hour by the maximum 2015 aggregate hourly output of 73 kW. This method results in a profile with the same shape as the aggregate output, reflecting the diversity of location on the island and the diversity of system designs.

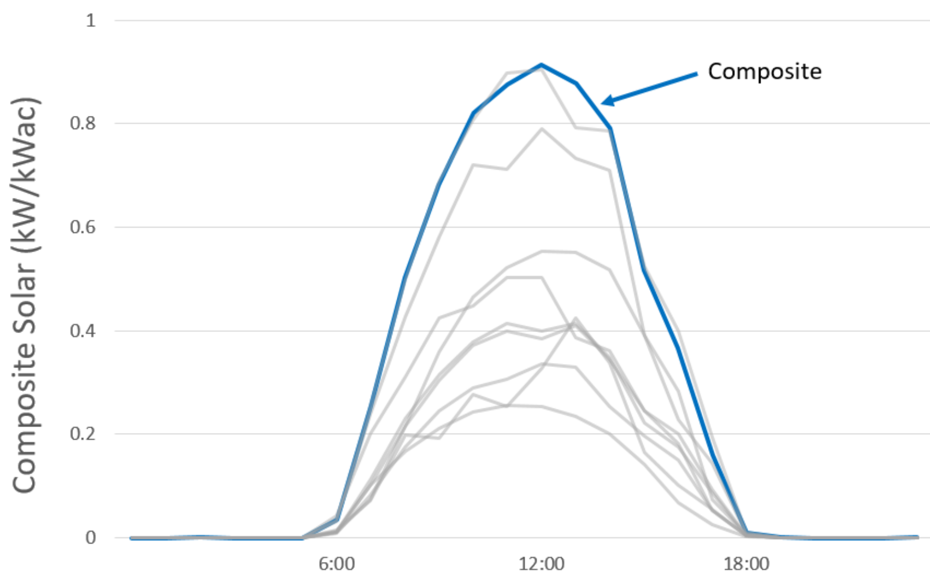

Figure 2. Composite solar power output on peak load day (August 31, 2015)

The performance of individual systems, their aggregation, and the resulting composite system is shown in *Figure 3*. Note that in this study we approximate the "AC Rating" as the maximum output over the year. The composite system has an AC rated output of 1.000 kW, and this corresponds to a DC rating of 1.21 kW based on the same ratio of DC to AC ratings as the aggregate. The composite resource delivers a maximum of 1 kW of electricity to the grid at its peak hour, and 1869 kWh of electricity per kW_{ac} during the year.[1]

[1] This amount corresponds to the aggregate of all systems. Annual output from each system is obtained by summing the output for all included hours of the year and multiplying by the ratio of 8760 actual hours to 8592 sampled hours after data cleaning.

System ID	006WJK	006YEK	0071UY	006VL2	0079SL	007G9W	00735E	007V5J	009GS1	Aggregate	Composite
System Size kWdc	**8.1**	**9.99**	**14.58**	**7.83**	**10.53**	**6.25**	**18.36**	**4.75**	**8.25**	**88.64**	**1.21**
Max = System Size kWac	7.142	8.471	13.406	6.789	8.747	5.293	14.777	4.15	7.049	73.056	1.0000
Min	-0.005	-0.004	-0.006	-0.006	-0.007	-0.004	-0.012	-0.004	-0.009	-0.042	-0.001
Ann. Energy kWh	12309	14969	23130	12535	16036	9854	27118	7835	12740	136525	1869
Ann. Energy kWh/kWac	1723	1767	1725	1846	1833	1862	1835	1888	1807	1869	1869
Capacity Factor (DC)	18%	17%	18%	19%	18%	18%	17%	19%	18%	18%	18%
Capacity Factor (AC)	20%	21%	20%	21%	21%	22%	21%	22%	21%	22%	22%
kWac/kWdc	88.2%	84.8%	91.9%	86.7%	83.1%	84.7%	80.5%	87.4%	85.4%	82.4%	82.4%

Figure 3. System performance summary.

Effective Capacity

<u>Solar Only</u>

The Guam Power Authority (GPA) provided hourly island system loads for 2015, and this was cleaned using methods described in the appendix. *Figure 2* shows the hourly GPA system load overlaid with the output of the composite resource. Note that the peak load hours are not in good alignment with the solar hours, in agreement with a previous study.[2]

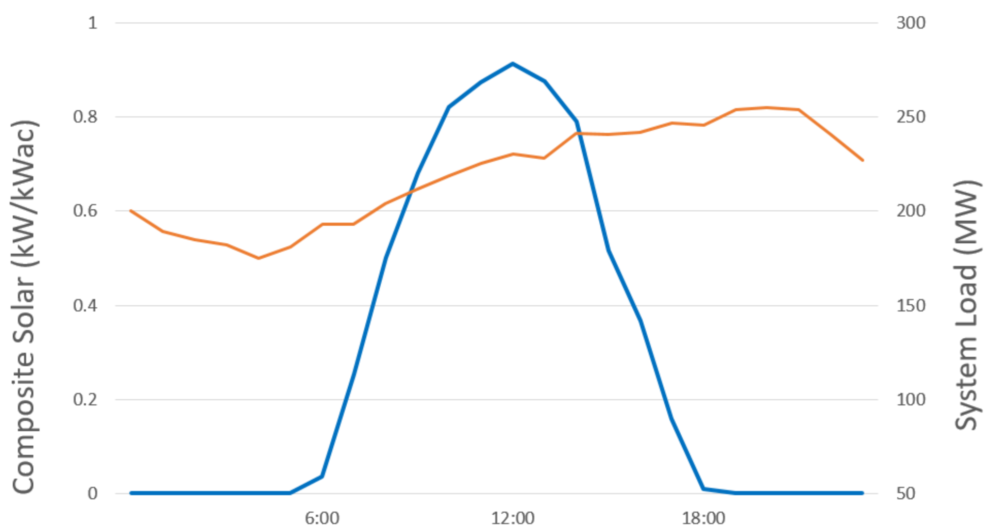

Figure 4. GPA system load and composite system output on peak load day (August 31, 2015).

This analysis uses the average composite resource output during the top 100 load hours as a simple metric for effective capacity. Using this metric, the composite resource delivers an average of only 0.014 kW per kW_{ac} (i.e., 14 W per kWac), effectively zero. *Table 1* further indicates that all of the top 20 hours occur in the evening hours after sundown when there is no PV output to support the system peak and provide peaking capacity.[3] We conclude that there is no capacity-related benefit to distributed PV when it is not coupled with load shifting, storage, or some other means to support the peak.

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[2] Black and Veatch, *Report and Recommendations to Net Metering*, Draft Report prepared for GPA, 15 July 2016.

[3] The small negative numbers presumably reflect the draw from minor control power.

Table 1. Top 20 load hours of 2015.

	Date	Hour	System Load (MW)	Composite Output (kW/kWac)
1	31-Aug-15	20:00	255.0	-0.000372
2	31-Aug-15	19:00	254.0	-0.000327
3	31-Aug-15	21:00	254.0	-0.000372
4	17-Sep-15	20:00	254.0	-0.000372
5	17-Sep-15	19:00	253.0	-0.000372
6	17-Sep-15	21:00	253.0	-0.000384
7	24-Sep-15	19:00	252.5	-0.000372
8	24-Sep-15	20:00	252.5	-0.000372
9	10-Aug-15	20:00	252.0	-0.000327
10	12-Aug-15	20:00	252.0	-0.000372
11	12-Aug-15	21:00	252.0	-0.000372
12	12-Aug-15	19:00	251.0	-0.000350
13	24-Aug-15	20:00	251.0	-0.000361
14	05-Oct-15	19:00	251.0	-0.000372
15	05-Oct-15	20:00	251.0	-0.000372
16	10-Aug-15	21:00	250.0	-0.000384
17	19-Aug-15	21:00	250.0	-0.000384
18	01-Sep-15	19:00	250.0	-0.000361
19	05-Oct-15	21:00	250.0	-0.000361
20	07-Oct-15	20:00	250.0	-0.000350

Solar+Storage

While the solar-only case is unable to support the peak loads in Guam, we consider here the combination of solar with storage in a hybrid resource that could, in effect, be dispatched to meet the peaks. Such a method would incur additional capital costs on the part of the owner, but would also provide additional benefits to the grid. It would require that the storage resource be operated in accordance with the peak loads of the grid. This could be accomplished by establishing rates or other control mechanisms to result in the desired charge/discharge patterns.

The dispatch of the combined solar+storage resource is critical, and must be consistent with the expected cycle life of the storage technology. The storage would probably not be cycled every day, for example, because this would lead to degraded storage performance and premature end of life. A breakdown of the 2015 system loads in Guam however (see *Table 2*), indicates that most of the top 100 hours occur during the three months of August, September and October and during the contiguous hours of 7 pm through 10 pm (i.e., the hour beginning at 9 pm).

Table 2. Top 100 load hours (a) by hour of day, (b) by month of year.

	Count
3 PM	1
4 PM	2
5 PM	3
6 PM	2
7 PM	33
8 PM	40
9 PM	19
Total	**100**

(a)

	Count
May	8
Jun	8
Jul	0
Aug	30
Sep	24
Oct	25
Nov	5
Total	**100**

(b)

This suggests that an effective method of dispatching the storage would be to discharge it daily only during these three months and only during the three-hour period. Such as strategy would ensure that most of the peak 100 hours are supported, and all of the top 20 hours shown in *Table 1* would be supported. The storage battery would be designed for three kWh of storage per kW of discharge capacity.

This strategy would require charging and discharging the storage 92 days per year. A technology with a cycle life of 2000 charge-discharge cycles would last over 21 years before requiring replacement.

This analysis assumes that this simple strategy is used to dispatch stored energy. It is certainly possible to consider more advanced strategies, for example, to dispatch stored energy at power levels that vary within the hour using real-time load feedback, rather than dispatching in 1-hour constant output blocks. The dispatch could be further refined by incorporating load and solar forecasts.

This analysis makes the following design and dispatch assumptions:

- 3 hours of installed storage capcity (3 kWh per kW_{ac} of PV capacity)
- 80% solar-to-storage-to-AC efficiency
- 1 kW per kW_{ac} maximum charge/discharge rate
- Simple Dispatch Algorithm
    - Only in August, September, and October (to preserve life)
    - 3-hour constant output discharge, 7 pm until 10 pm daily
    - Charge from solar energy only (not from grid power)
    - All solar is used to charge storage until full, spilled to grid thereafter
- Start at 0% state of charge, and track hourly

Figure 5 illustrates the combined solar+storage hybrid production profile. On July 31 (the last day before the three-month storage dispatch season), all of the solar generation is delivered to the grid. Thus, the output of solar+storage is the same as the composite solar-only output. On August 1, the initial solar production is used to charge the storage from 0% state-of-charge (SOC). Once the system reaches 100% SOC in the afternoon hours, the remaining excess solar is "spilled" onto the grid. At 7 pm the storage is discharged at 1 kW for three hours. Note that the SOC calculation (and consequently the discharged energy) includes the effect of storage losses, so the energy represented by the solar+storage case is less than the solar-only case.

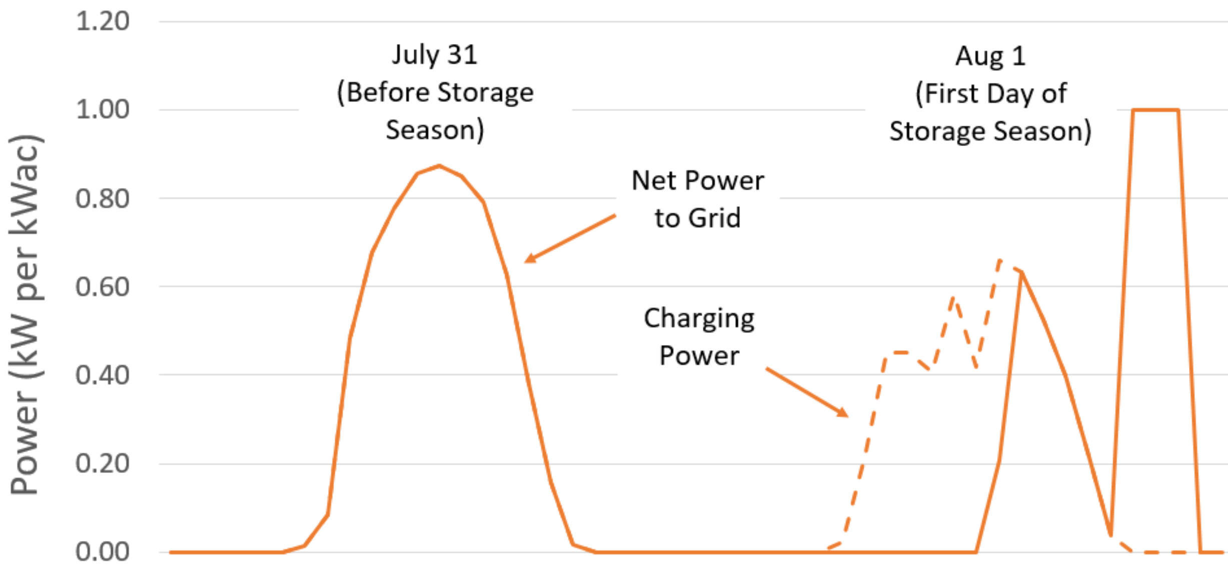

Figure 5. Illustration of storage dispatch.

Using the same metric as before, the average output of the solar+storage resource over the top 100 load hours is 0.727 kW per kW_{ac} of capacity, so the solar+storage thus designed and dispatched has an effective capacity of 72.7% of its rating. The annual energy delivered is 1806 kWh per kW_{ac} as compared to 1869 kWh for the solar-only case.

As noted above, this could be further improved with more sophisticated algorithms and feedback. Also, if the metric was changed to the average output over the top 20 load hours, then the solar+storage system would have an effective capacity of 100% since it would be dispatched at full output during all the hours in *Table 1*. This study retains the more conservative metric of 100 hours as described above.

Loss Savings

GPA provided *Table 3* showing their calculation of average losses for two years, each at 4.6%. While other studies[4] performed by CPR have calculated losses for each hour so that the loss in each hour is

[4] See, for example, *Maine Distributed Valuation Study: Volume 1, Methodology*, prepared for the Maine Public Utilities Commission, April 2015.

dependent upon the hourly system load, this study assumes that all hours have the same 4.6% losses. The simplification is required because GPA is not able to provide losses at the peak hour or some other data to facilitate this calculation. However, the correlation between load and solar production is not strong in Guam, and solar is most often producing at middle levels of load, so the simplification is justified here.

Table 3. Calculation of losses.

	Moving 12 Months Ending Dec 2015	Moving 12 Months Ending Dec 2016
Total-Generation Reports (Production)	**1,698,902,240**	**1,731,386,296**
Station Service/Auxiliary	79,649,447	64,212,913
Sales to Navy (@34.5Kv)	315,469,265	317,055,000
Sales to customers	1,221,457,935	1,267,630,175
GPA use-KWH	3,819,920	3,285,921
Total Accounted For Energy	**1,620,396,567**	**1,652,184,009**
Unaccounted For Energy (Losses)	**78,505,673**	**79,202,287**
Loss %	**4.6%**	**4.6%**

The analysis incorporates a "loss savings factor" (LSF) which, by definition is the effective fractional increase in energy produced over that of the DER that would have to be produced by the utility to overcome losses and serve the equivalent load. So, the conversion between LSF and the "loss fraction" above is as follows:

$$Generation = DEREnergy(1 + LSF)$$

$$Generation(1 - LossFraction) = DEREnergy$$

$$LSF = \left(\frac{1}{1 - LossFraction}\right) - 1$$

So, a LossFraction of 4.6% is the same as an LSF of 4.8%. In other words, to match every 1 kWh of energy produced by a DER at the point of the load, the utility would have to produce 1.048 kWh to overcome the 4.6% loss and deliver the same 1 kWh to the customer.

Value Analysis

Input Assumptions

Four study scenarios were developed as follows. GPA provided a set of planning assumptions from their 2016 IRP, the primary options of which are presented in *Table 4*. Of these, two mid-cost options were selected (highlighted in blue) for this study. They include two fuel options including ultra-low-sulfur diesel (ULSD) and liquified natural gas (LNG). The cost of developing the LNG infrastructure is not included in the costs shown.

Table 4. 2016 selected IRP planning options.

Plant Description		Recip	Recip	CC CT	CC CT	CC CT	CC CT
Technology		FM/Man 18V DF Med Speed w/ HRSG (2x17.5 MW) ULSD	FM/Man 18V DF Med Speed w/ HRSG (2x17.5 MW) LNG	GE LM2500 1x1 ULSD	GE LM2500 1x1 LNG	GE 6F 1x1 ULSD	GE 6F 1x1 LNG
Nominal Capacity	MW	39	39	48	48	73	76
Capital Cost	$/kW	3,307	3,307	2,158	2,163	1,971	1,893
Max Net Capacity	MW	38.3	38.3	46.1	46.0	70.4	73.3
Min Net Capacity	MW	6.9	6.9	16.1	16.1	37.3	38.9
HR @ Max	Btu/kWh (HHV)	7,393	7,399	7,137	7,319	7,038	7,179
HR @ 75%	Btu/kWh (HHV)	7,573	7,613	7,565	7,758	7,568	7,719
HR @ 50%	Btu/kWh (HHV)	9,520	9,239	8,921	9,148	8,280	8,446
HR @ Min	Btu/kWh (HHV)	10,130	11,320	9,635	9,880	8,280	8,446
Primary Fuel		ULSD	LNG	ULSD	LNG	ULSD	LNG
Secondary Fuel		LNG	ULSD	LNG	ULSD	LNG	ULSD

The four scenarios are shown in *Table 5*. These vary by effective capacity, either 0 or 72.7%, depending on whether the scenario is solar-only or solar+storage. The loss savings factor is 4.80 for all scenarios. The first-year annual energy amounts are described previously for the solar-only composite system and the solar+storage system, including charge/discharge losses. The power generation cost and heat rate assumptions are taken from the GPA data (DER generation is assumed to displace the stated utility generation resource at 75% load). The generation life is assumed to be 35 years and the degradation of heat rate is assumed to be 0.10% per year.

Table 5. Study scenarios.

SCENARIO		(1) LNG, Solar	(2) LNG, Solar+Storage	(3) ULSD, Solar	(4) ULSD, Solar+Storage
Load Match Analysis					
Effective Capacity	% of rating	0%	72.7%	0%	72.7%
Loss Savings Factor	% of PV output	4.80%	4.80%	4.80%	4.80%
DER Delivered Energy					
First year annual energy	kWh per kW-AC	1869	1806	1869	1806
Power Generation					
Fuel		LNG	LNG	ULSD	ULSD
Installed Cost	$/kW	2163	2163	2158	2158
Average Heat Rate	BTU/kWh	7758	7758	7565	7565
Generation life	years	35	35	35	35
Heat rate degradation	per year	0.10%	0.10%	0.10%	0.10%

Other assumptions, applying to all scenarios, are shown in *Table 6*. Solar PV is assumed to have a life of 25 years and a degradation of 0.5% per year. Utility battery assumptions (for limiting ramp rates of central solar projects) are shown, where the cost is assumed based on an assessment of Tesla Energy in Australia,[5] and the others provided by GPA. GPA also provided the discount rate, the cost of meeting RPS goals, and fuel price forecasts. US Treasury Yields are taken from the US Treasury Department.[6]

[5] https://www.forbes.com/sites/rodadams/2017/07/07/megahype-over-tesla-battery-capable-of-providing-nameplate-power-for-less-than-80-minutes/#39a41e8e4919

[6] https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

Table 6. Fixed study assumptions.

PV Assumptions				Fuel Price Forecasts ($/MMBTU)		
PV degradation rate	0.50%	per year			ULSD	LNG
PV life	25	years		2018	12.50	12.15
				2019	15.10	13.52
Utility Battery Storage				2020	17.11	14.63
ESS Capital Cost	600	$/kWh		2021	18.43	15.38
ESS Storage Capacity	1	hour		2022	19.45	16.04
ESS Ramping Requirement	0.62	MW ESS per MW PV		2023	20.47	16.69
				2024	21.52	17.35
Economic Assumptions				2025	22.64	18.01
Start Year	2018			2026	23.81	18.69
Discount rate (WACC)	6.0%	per year		2027	25.07	19.41
General escalation rate	2.75%	per year		2028	26.16	20.13
RPS Cost	$6.50	per W		2029	27.33	20.89
				2030	28.51	21.67
Treasury Yields				2031	29.83	22.51
1 Year	1.83%			2032	31.18	23.39
2 Year	1.92%			2033	32.63	24.33
3 Year	2.01%			2034	34.15	25.32
5 Year	2.25%			2035	35.81	26.36
7 Year	2.38%			2036	37.49	27.41
10 Year	2.46%			2037	39.14	28.44
20 Year	2.64%			2038	40.94	29.51
30 Year	2.81%			2039	42.88	30.63
				2040	44.90	31.78

Economic Factors and Example Calculations

The following sections describe the calculation methodology in the study, using study scenario 2 (“LNG, Solar+Storage”) for illustrative purposes.

Economic factors are calculated for each year in the 25-year study period in *Table 7*. The utility discount factor and escalation factors are calculated by applying the respective rate for each year. The risk-free discount rate is interpolated from the US Treasury yields. The DER production is shown where the starting annual energy is taken from the load analysis described previously, and subsequent years are adjusted for the degradation rate. Similarly, DER capacity is assumed to decline at the same rate. The generation capacity also declines by its assumed rate.

Table 7. Economic factors.

Economic Factors

Year	Analysis Year	Utility Discount	Risk-Free Discount	Escalation	DER Production (kWh)	DER Capacity (kW)	Gen. Capacity (p.u.)
2018	0	1.000	1.000	1.000	1,806	1.000	1.000
2019	1	0.943	0.982	1.028	1,797	0.995	0.999
2020	2	0.890	0.963	1.056	1,788	0.990	0.998
2021	3	0.840	0.942	1.085	1,779	0.985	0.997
2022	4	0.792	0.919	1.115	1,770	0.980	0.996
2023	5	0.747	0.895	1.145	1,761	0.975	0.995
2024	6	0.705	0.872	1.177	1,752	0.970	0.994
2025	7	0.665	0.848	1.209	1,744	0.966	0.993
2026	8	0.627	0.827	1.242	1,735	0.961	0.992
2027	9	0.592	0.805	1.277	1,726	0.956	0.991
2028	10	0.558	0.784	1.312	1,718	0.951	0.990
2029	11	0.527	0.764	1.348	1,709	0.946	0.989
2030	12	0.497	0.744	1.385	1,701	0.942	0.988
2031	13	0.469	0.724	1.423	1,692	0.937	0.987
2032	14	0.442	0.705	1.462	1,684	0.932	0.986
2033	15	0.417	0.685	1.502	1,675	0.928	0.985
2034	16	0.394	0.667	1.544	1,667	0.923	0.984
2035	17	0.371	0.648	1.586	1,658	0.918	0.983
2036	18	0.350	0.630	1.630	1,650	0.914	0.982
2037	19	0.331	0.612	1.674	1,642	0.909	0.981
2038	20	0.312	0.594	1.720	1,634	0.905	0.980
2039	21	0.294	0.577	1.768	1,626	0.900	0.979
2040	22	0.278	0.560	1.816	1,617	0.896	0.978
2041	23	0.262	0.543	1.866	1,609	0.891	0.977
2042	24	0.247	0.527	1.918	1,601	0.887	0.976

Avoided Fuel Cost

Avoided fuel costs are shown in *Table 8*, where the DER energy injected into the grid is assumed to displace the resource described in *Table 5*. These calculations are performed without avoided losses considered (these will be handled later).

Burnertip fuel prices were provided by GPA,[7] and the heat rate is the first year assumed rate, with degradation applied annually. From this, the utility costs per kWh and total cost of delivering the DER

[7] The last two years were extrapolated.

production energy for each year are calculated and discounted. The "VOS" is the levelized rate that leads to the same discounted total cost as the utility fuel cost, i.e., $3,625 to deliver the same amount of energy over the life of the DER system.

Table 8. Avoided fuel cost, Scenario 2.

Avoided Fuel Cost

			Cost per kWh			Costs			Disc. Costs	
Year	Burnertip Fuel Price ($/MMBtu)	Heat Rate (Btu/kWh)	Utility ($/kWh)	VOS ($/kWh)	p.u. DER Production (kWh)	Utility ($)	VOS ($)	Discount Factor	Utility ($)	VOS ($)
2018	$12.15	7758	$0.094	$0.155	1,806	$170	$280	1.000	$170	$280
2019	$13.52	7766	$0.105	$0.155	1,797	$189	$278	0.943	$178	$263
2020	$14.63	7774	$0.114	$0.155	1,788	$203	$277	0.890	$181	$247
2021	$15.38	7781	$0.120	$0.155	1,779	$213	$276	0.840	$179	$231
2022	$16.04	7789	$0.125	$0.155	1,770	$221	$274	0.792	$175	$217
2023	$16.69	7797	$0.130	$0.155	1,761	$229	$273	0.747	$171	$204
2024	$17.35	7805	$0.135	$0.155	1,752	$237	$272	0.705	$167	$191
2025	$18.01	7812	$0.141	$0.155	1,744	$245	$270	0.665	$163	$180
2026	$18.69	7820	$0.146	$0.155	1,735	$254	$269	0.627	$159	$169
2027	$19.41	7828	$0.152	$0.155	1,726	$262	$267	0.592	$155	$158
2028	$20.13	7836	$0.158	$0.155	1,718	$271	$266	0.558	$151	$149
2029	$20.89	7844	$0.164	$0.155	1,709	$280	$265	0.527	$147	$140
2030	$21.67	7852	$0.170	$0.155	1,701	$289	$264	0.497	$144	$131
2031	$22.51	7859	$0.177	$0.155	1,692	$299	$262	0.469	$140	$123
2032	$23.39	7867	$0.184	$0.155	1,684	$310	$261	0.442	$137	$115
2033	$24.33	7875	$0.192	$0.155	1,675	$321	$260	0.417	$134	$108
2034	$25.32	7883	$0.200	$0.155	1,667	$333	$258	0.394	$131	$102
2035	$26.36	7891	$0.208	$0.155	1,658	$345	$257	0.371	$128	$95
2036	$27.41	7899	$0.216	$0.155	1,650	$357	$256	0.350	$125	$90
2037	$28.44	7907	$0.225	$0.155	1,642	$369	$254	0.331	$122	$84
2038	$29.51	7915	$0.234	$0.155	1,634	$382	$253	0.312	$119	$79
2039	$30.63	7923	$0.243	$0.155	1,626	$395	$252	0.294	$116	$74
2040	$31.78	7930	$0.252	$0.155	1,617	$408	$251	0.278	$113	$70
2041	$32.97	7938	$0.262	$0.155	1,609	$421	$249	0.262	$110	$65
2042	$34.21	7946	$0.272	$0.155	1,601	$435	$248	0.247	$107	$61
						Validation: Present Value			**$3,625**	**$3,625**

Generation Capacity Cost

Table 9 shows the valuation for generation capacity. The installed cost of the displaced resource ($2,163 per kW) is amortized over its 35 year life, so the cost of capacity is $149 per kW-year. This is adjusted to account for annual degradation in both the utility capacity and the DER capacity, and discounted using the discount factor. The VOS is the levelized rate that results in the same discounted costs, assuming that the DER provides firm capacity (i.e., as if the effective capacity were 100% of rating). Effective capacity is adjusted in a later step.

Table 9. Generation capacity cost, Scenario 2.

Avoided Gen Capacity Cost

Year	Capacity Cost ($/kW-yr)	Utility Capacity (p.u.)	DER Capacity (kW)	p.u. DER Production (kWh)	Costs: Utility ($)	Costs: VOS ($)	Discount Factor	Disc. Costs: Utility ($)	Disc. Costs: VOS ($)	Prices: Utility ($/kWh)	Prices: VOS ($/kWh)
2018	$149	1.000	1.000	1806	$149	$151	1.000	$149	$151	$0.083	$0.083
2019	$149	0.999	0.995	1797	$149	$150	0.943	$140	$141	$0.083	$0.083
2020	$149	0.998	0.990	1788	$148	$149	0.890	$132	$133	$0.083	$0.083
2021	$149	0.997	0.985	1779	$147	$148	0.840	$124	$124	$0.083	$0.083
2022	$149	0.996	0.980	1770	$147	$148	0.792	$116	$117	$0.083	$0.083
2023	$149	0.995	0.975	1761	$146	$147	0.747	$109	$110	$0.083	$0.083
2024	$149	0.994	0.970	1752	$146	$146	0.705	$103	$103	$0.083	$0.083
2025	$149	0.993	0.966	1744	$145	$145	0.665	$96	$97	$0.083	$0.083
2026	$149	0.992	0.961	1735	$144	$145	0.627	$91	$91	$0.083	$0.083
2027	$149	0.991	0.956	1726	$144	$144	0.592	$85	$85	$0.083	$0.083
2028	$149	0.990	0.951	1718	$143	$143	0.558	$80	$80	$0.083	$0.083
2029	$149	0.989	0.946	1709	$143	$142	0.527	$75	$75	$0.084	$0.083
2030	$149	0.988	0.942	1701	$142	$142	0.497	$71	$70	$0.084	$0.083
2031	$149	0.987	0.937	1692	$142	$141	0.469	$66	$66	$0.084	$0.083
2032	$149	0.986	0.932	1684	$141	$140	0.442	$62	$62	$0.084	$0.083
2033	$149	0.985	0.928	1675	$140	$140	0.417	$59	$58	$0.084	$0.083
2034	$149	0.984	0.923	1667	$140	$139	0.394	$55	$55	$0.084	$0.083
2035	$149	0.983	0.918	1658	$139	$138	0.371	$52	$51	$0.084	$0.083
2036	$149	0.982	0.914	1650	$139	$138	0.350	$49	$48	$0.084	$0.083
2037	$149	0.981	0.909	1642	$138	$137	0.331	$46	$45	$0.084	$0.083
2038	$149	0.980	0.905	1634	$138	$136	0.312	$43	$42	$0.084	$0.083
2039	$149	0.979	0.900	1626	$137	$135	0.294	$40	$40	$0.084	$0.083
2040	$149	0.978	0.896	1617	$137	$135	0.278	$38	$37	$0.084	$0.083
2041	$149	0.977	0.891	1609	$136	$134	0.262	$36	$35	$0.085	$0.083
2042	$149	0.976	0.887	1601	$135	$133	0.247	$33	$33	$0.085	$0.083
					Validation: Present Value			$1,950	$1,950		

Avoided RPS Cost

The calculation of avoided RPS costs are based on the cost to GPA of procuring renewable resources that contribute toward its goal. It is assumed here that each kW of distributed solar provides the same environmental benefit as a kW of utility-owned generation.

As reported by GPA, the cost of procuring utility-scale solar is about $6.5 per W, including the cost of an energy storage system (ESS) used for ramping support.[8] GPA specified an ESS with a rating of 16 MW / 16 MWh to support a centralized 26 MW solar installation at Talofofo Substation. Thus, the ESS requirement is about 16/26 = 0.62 MW of one-hour ESS per MW of central solar. The assumed cost of utility scale storage is $600 per kWh, so the cost for ramping support is about $600 per kWh x 0.62 x 1

[8] Additional ESS capacity will be procured by GPA with 15 minutes of storage for frequency control and contingency support. These functions are not considered in this analysis.

hour = $369 per kW of installed central station solar, and the net solar-only cost is $6,500 - $369 = $6,131 per kW. This cost is amortized (assuming the same 25 year of solar) to $480 per kW-year.

Annual calculations are shown in *Table 10*, showing the amortized costs. Adjustments are made using the same method as the avoided generation cost table, but since this is a solar resource, the adjustments are moot. Next, adjustments must be made for the benefits provided by the utility scale solar resource in fuel cost and generation capacity, and these are taken from *Table 8* and *Table 9* (benefits are assumed to be the same as distributed solar). Subtracting these benefits, the “net cost” represents the cost of providing only the “renewable attribute” of the RPS resource. Note that the net cost is negative in future years due to the escalating cost of fuel. The net cost is discounted, and the VOS rate is calculated such that the total discounted costs are the same.

Table 10. Avoided RPS cost, Scenario 2.

Avoided RPS Costs

Year	Capacity Cost ($/kW-yr)	Utility Capacity (p.u.)	DER Capacity (kW)	p.u. DER Production (kWh)	Costs: Utility ($)	Costs: Fuel Cost Adj. ($)	Costs: Gen Cap Adj. ($)	Costs: Net Cost ($)	Costs: VOS ($)	Discount Factor	Disc. Costs: Utility ($)	Disc. Costs: VOS ($)	Prices: Utility ($/kWh)	Prices: VOS ($/kWh)
2018	$480	1.000	1.000	1806	$480	($170)	($149)	$160	$71	1.000	$160	$71	$0.089	$0.039
2019	$480	0.995	0.995	1797	$480	($189)	($149)	$142	$71	0.943	$134	$67	$0.079	$0.039
2020	$480	0.990	0.990	1788	$480	($203)	($148)	$128	$71	0.890	$114	$63	$0.072	$0.039
2021	$480	0.985	0.985	1779	$480	($213)	($147)	$119	$70	0.840	$100	$59	$0.067	$0.039
2022	$480	0.980	0.980	1770	$480	($221)	($147)	$112	$70	0.792	$88	$55	$0.063	$0.039
2023	$480	0.975	0.975	1761	$480	($229)	($146)	$104	$69	0.747	$78	$52	$0.059	$0.039
2024	$480	0.970	0.970	1752	$480	($237)	($146)	$97	$69	0.705	$68	$49	$0.055	$0.039
2025	$480	0.966	0.966	1744	$480	($245)	($145)	$89	$69	0.665	$59	$46	$0.051	$0.039
2026	$480	0.961	0.961	1735	$480	($254)	($144)	$82	$68	0.627	$51	$43	$0.047	$0.039
2027	$480	0.956	0.956	1726	$480	($262)	($144)	$73	$68	0.592	$43	$40	$0.042	$0.039
2028	$480	0.951	0.951	1718	$480	($271)	($143)	$65	$68	0.558	$36	$38	$0.038	$0.039
2029	$480	0.946	0.946	1709	$480	($280)	($143)	$57	$67	0.527	$30	$36	$0.033	$0.039
2030	$480	0.942	0.942	1701	$480	($289)	($142)	$48	$67	0.497	$24	$33	$0.028	$0.039
2031	$480	0.937	0.937	1692	$480	($299)	($142)	$39	$67	0.469	$18	$31	$0.023	$0.039
2032	$480	0.932	0.932	1684	$480	($310)	($141)	$29	$66	0.442	$13	$29	$0.017	$0.039
2033	$480	0.928	0.928	1675	$480	($321)	($140)	$18	$66	0.417	$8	$28	$0.011	$0.039
2034	$480	0.923	0.923	1667	$480	($333)	($140)	$7	$66	0.394	$3	$26	$0.004	$0.039
2035	$480	0.918	0.918	1658	$480	($345)	($139)	($5)	$65	0.371	($2)	$24	-$0.003	$0.039
2036	$480	0.914	0.914	1650	$480	($357)	($139)	($16)	$65	0.350	($6)	$23	-$0.010	$0.039
2037	$480	0.909	0.909	1642	$480	($369)	($138)	($28)	$65	0.331	($9)	$21	-$0.017	$0.039
2038	$480	0.905	0.905	1634	$480	($382)	($138)	($40)	$64	0.312	($12)	$20	-$0.024	$0.039
2039	$480	0.900	0.900	1626	$480	($395)	($137)	($52)	$64	0.294	($15)	$19	-$0.032	$0.039
2040	$480	0.896	0.896	1617	$480	($408)	($137)	($65)	$64	0.278	($18)	$18	-$0.040	$0.039
2041	$480	0.891	0.891	1609	$480	($421)	($136)	($78)	$63	0.262	($20)	$17	-$0.048	$0.039
2042	$480	0.887	0.887	1601	$480	($435)	($135)	($91)	$63	0.247	($23)	$16	-$0.057	$0.039

Validation: Present Value	Utility	VOS
	$923	$923

Avoided Fuel Price Uncertainty

Through the use of fossil fuels, Guam is exposed to the risk of fluctuating and uncertain fuel prices. Solar generated electricity, on the other hand is not subject to this risk. So, this benefit category places the two generating options on equal footing with respect to risk exposure.

The GPA forecasted fuel cost in *Table 11* is taken directly from *Table 8*. This represents the expected future cost of fuel necessary for future electricity deliveries. Using the "non-risk free" discount, i.e., the standard utility discount rate, we can calculate the discounted fuel cost. However, if we instead use the "risk free" discount rate, we calculate the discounted fuel cost that would be necessary to "lock in" the prices of future fuel delivery[9] and eliminate the price uncertainty. The difference between the discounted costs using the standard discount rate and the risk-free discount rate is the hedge value.

Table 11. Avoided fuel price uncertainty, Scenario 2.

Avoided Fuel Uncertainty

		Risk Free		Non Risk Free					Costs		Disc. Costs		Prices	
Year	Forecasted Fuel Cost ($/kWh)	Discount Factor	Disc. Fuel Cost ($/kWh)	Discount Factor	Disc. Fuel Cost ($/kWh)	Disc. Hedge ($/kWh)	F.V. Hedge ($/kWh)	p.u. DER Production (kWh)	Utility ($)	VOS ($)	Utility ($)	VOS $	Utility ($)	VOS ($)
2018	0.094	1.000	0.094	1.000	0.094	0.000	0.000	1,806	$0	$131	$0	$131	$0.000	$0.073
2019	0.105	0.982	0.103	0.943	0.099	0.004	0.004	1,797	$8	$131	$7	$123	$0.004	$0.073
2020	0.114	0.963	0.109	0.890	0.101	0.008	0.009	1,788	$17	$130	$15	$116	$0.009	$0.073
2021	0.120	0.942	0.113	0.840	0.100	0.012	0.015	1,779	$26	$130	$22	$109	$0.015	$0.073
2022	0.125	0.919	0.115	0.792	0.099	0.016	0.020	1,770	$35	$129	$28	$102	$0.020	$0.073
2023	0.130	0.895	0.116	0.747	0.097	0.019	0.026	1,761	$45	$128	$34	$96	$0.026	$0.073
2024	0.135	0.872	0.118	0.705	0.095	0.023	0.032	1,752	$56	$128	$40	$90	$0.032	$0.073
2025	0.141	0.848	0.119	0.665	0.094	0.026	0.039	1,744	$68	$127	$45	$84	$0.039	$0.073
2026	0.146	0.827	0.121	0.627	0.092	0.029	0.046	1,735	$81	$126	$51	$79	$0.046	$0.073
2027	0.152	0.805	0.122	0.592	0.090	0.032	0.055	1,726	$95	$126	$56	$74	$0.055	$0.073
2028	0.158	0.784	0.124	0.558	0.088	0.036	0.064	1,718	$110	$125	$61	$70	$0.064	$0.073
2029	0.164	0.764	0.125	0.527	0.086	0.039	0.074	1,709	$126	$124	$66	$66	$0.074	$0.073
2030	0.170	0.744	0.127	0.497	0.085	0.042	0.085	1,701	$144	$124	$71	$62	$0.085	$0.073
2031	0.177	0.724	0.128	0.469	0.083	0.045	0.096	1,692	$163	$123	$76	$58	$0.096	$0.073
2032	0.184	0.705	0.130	0.442	0.081	0.048	0.109	1,684	$184	$123	$81	$54	$0.109	$0.073
2033	0.192	0.685	0.131	0.417	0.080	0.051	0.123	1,675	$206	$122	$86	$51	$0.123	$0.073
2034	0.200	0.667	0.133	0.394	0.079	0.054	0.138	1,667	$231	$121	$91	$48	$0.138	$0.073
2035	0.208	0.648	0.135	0.371	0.077	0.058	0.155	1,658	$257	$121	$95	$45	$0.155	$0.073
2036	0.216	0.630	0.136	0.350	0.076	0.060	0.173	1,650	$285	$120	$100	$42	$0.173	$0.073
2037	0.225	0.612	0.138	0.331	0.074	0.063	0.191	1,642	$314	$120	$104	$40	$0.191	$0.073
2038	0.234	0.594	0.139	0.312	0.073	0.066	0.211	1,634	$345	$119	$108	$37	$0.211	$0.073
2039	0.243	0.577	0.140	0.294	0.071	0.069	0.233	1,626	$379	$118	$111	$35	$0.233	$0.073
2040	0.252	0.560	0.141	0.278	0.070	0.071	0.256	1,617	$414	$118	$115	$33	$0.256	$0.073
2041	0.262	0.543	0.142	0.262	0.069	0.074	0.281	1,609	$452	$117	$118	$31	$0.281	$0.073
2042	0.272	0.527	0.143	0.247	0.067	0.076	0.308	1,601	$493	$117	$122	$29	$0.308	$0.073
									Validation: Present Value		**$1,704**	**$1,704**		

First Year Value

The VOS values calculated in the above tables are levelized, constant values over the life of the DER. Equivalent first-year values are calculated in *Table 12*. First year values are the values which, if applied and escalated at the assumed escalation rate, result in the same present value.

[9] Technically, the GPA would have to enter into a long-term (25-year) futures contract to lock these rates in.

Table 12. Calculation of first-year value, Scenario 2.

First Year VOS

Avoided Fuel Cost $/kWh	Avoided Gen Capacity Cost $/kWh	Avoided RPS Costs $/kWh	Avoided Fuel Uncertainty $/kWh	Total $/kWh	p.u. DER Production (kWh)	Annual ($)	Disc. ($)
0.120	0.064	0.031	0.056	0.271	1,806	489	489
0.123	0.066	0.031	0.058	0.278	1,797	500	472
0.126	0.068	0.032	0.059	0.286	1,788	512	455
0.130	0.070	0.033	0.061	0.294	1,779	523	439
0.134	0.072	0.034	0.063	0.302	1,770	535	424
0.137	0.074	0.035	0.064	0.310	1,761	547	409
0.141	0.076	0.036	0.066	0.319	1,752	559	394
0.145	0.078	0.037	0.068	0.328	1,744	571	380
0.149	0.080	0.038	0.070	0.337	1,735	584	367
0.153	0.082	0.039	0.072	0.346	1,726	597	354
0.157	0.085	0.040	0.074	0.355	1,718	611	341
0.161	0.087	0.041	0.076	0.365	1,709	624	329
0.166	0.089	0.042	0.078	0.375	1,701	638	317
0.170	0.092	0.043	0.080	0.386	1,692	653	306
0.175	0.094	0.045	0.082	0.396	1,684	667	295
0.180	0.097	0.046	0.085	0.407	1,675	682	285
0.185	0.099	0.047	0.087	0.418	1,667	697	274
0.190	0.102	0.048	0.089	0.430	1,658	713	265
0.195	0.105	0.050	0.092	0.442	1,650	729	255
0.201	0.108	0.051	0.094	0.454	1,642	745	246
0.206	0.111	0.052	0.097	0.466	1,634	762	238
0.212	0.114	0.054	0.100	0.479	1,626	779	229
0.218	0.117	0.055	0.102	0.492	1,617	796	221
0.224	0.120	0.057	0.105	0.506	1,609	814	213
0.230	0.124	0.058	0.108	0.520	1,601	832	206
					Present Value		**$8,202**

Avoided Fuel Cost $/kWh	Avoided Gen Capacity Cost $/kWh	Avoided RPS Costs $/kWh	Avoided Fuel Uncertainty $/kWh	Total $/kWh	p.u. DER Production (kWh)	Annual ($)	Disc. ($)
0.155	0.083	0.039	0.073	0.351	1,806	633	633
0.155	0.083	0.039	0.073	0.351	1,797	630	594
0.155	0.083	0.039	0.073	0.351	1,788	627	558
0.155	0.083	0.039	0.073	0.351	1,779	624	524
0.155	0.083	0.039	0.073	0.351	1,770	621	492
0.155	0.083	0.039	0.073	0.351	1,761	617	461
0.155	0.083	0.039	0.073	0.351	1,752	614	433
0.155	0.083	0.039	0.073	0.351	1,744	611	407
0.155	0.083	0.039	0.073	0.351	1,735	608	382
0.155	0.083	0.039	0.073	0.351	1,726	605	358
0.155	0.083	0.039	0.073	0.351	1,718	602	336
0.155	0.083	0.039	0.073	0.351	1,709	599	316
0.155	0.083	0.039	0.073	0.351	1,701	596	296
0.155	0.083	0.039	0.073	0.351	1,692	593	278
0.155	0.083	0.039	0.073	0.351	1,684	590	261
0.155	0.083	0.039	0.073	0.351	1,675	587	245
0.155	0.083	0.039	0.073	0.351	1,667	584	230
0.155	0.083	0.039	0.073	0.351	1,658	581	216
0.155	0.083	0.039	0.073	0.351	1,650	578	203
0.155	0.083	0.039	0.073	0.351	1,642	576	190
0.155	0.083	0.039	0.073	0.351	1,634	573	179
0.155	0.083	0.039	0.073	0.351	1,626	570	168
0.155	0.083	0.039	0.073	0.351	1,617	567	157
0.155	0.083	0.039	0.073	0.351	1,609	564	148
0.155	0.083	0.039	0.073	0.351	1,601	561	139
					Present Value		**$8,202**

Results

First year valuation results are shown in *Table 13*. The first column shows the gross value calculated above. In the case of the generation capacity value, the result must be applied by the load match factor of 72.7% to account for the fact that the distributed solar+storage resource has an effective capacity of 72.7 kW of effective capacity per kW of rated capacity. Next, the loss savings factor provides for an adjustment for three of the four categories. Finally, the distributed value is calculated and summed.

Table 13. First year VOS results, Scenario 2.

First Year Value	Gross Starting Value	×	Load Match Factor	×	(1 + Loss Savings Factor)	=	Distributed PV Value
	A	×	B	×	(1+C)	=	D
	($/kWh)		(%)		(%)		($/kWh)
Avoided Fuel Cost	$0.120				4.8%		$0.126
Avoided Gen Capacity Cost	$0.064		72.7%		4.8%		$0.049
Avoided RPS Costs	$0.031						$0.031
Avoided Fuel Uncertainty	$0.056				4.8%		$0.059
							$0.264

Final results for all scenarios are shown in *Table 14*. Values range from $0.210 per kWh for solar-only displacing LNG generation up to $0.284 per kWh for the hybrid solar+storage option with ULSD. Levelized results are shown in Table 15.

Table 14. First year VOS results, all scenarios ($ per kWh).

	1 LNG | Solar	2 LNG | Solar+Storage	3 ULSD | Solar	4 ULSD | Solar+Storage
Avoided Fuel Cost	0.126	0.126	0.157	0.157
Avoided Gen Capacity Cost	0.000	0.049	0.000	0.049
Avoided RPS Costs	0.025	0.031	(0.005)	0.000
Avoided Fuel Uncertainty	0.059	0.059	0.078	0.078
	0.210	0.264	0.230	0.284

Table 15. Levelized *VOS results, all scenarios* ($ per kWh).

	1 LNG | Solar	2 LNG | Solar+Storage	3 ULSD | Solar	4 ULSD | Solar+Storage
Avoided Fuel Cost	0.162	0.162	0.203	0.203
Avoided Gen Capacity Cost	0.000	0.064	0.000	0.063
Avoided RPS Costs	0.033	0.039	(0.006)	0.001
Avoided Fuel Uncertainty	0.076	0.076	0.100	0.100
	0.272	0.342	0.298	0.368

Appendix: Data Cleaning

PV Data Cleaning

MRE provided 2015 hourly production data provided for 29 distributed PV systems across the island of Guam. This data included several systems with inconsistent reporting, so data was cleaned as follows. First. Systems with lower than 99% data availability were eliminated (i.e., more than 87 hours out of 8760 during the year). This left a sample of 13 systems.

Upon inspection, these systems were generally missing significant amounts of data during the period of May 15-18, 2015. However, an analysis of the GPA-provided system load data, shown as the highlighted period in *Figure 6*, indicated island power outages during this period. The analysis did not consider what parts of the island were affected or the location of individual PV resources. However, it does appear that many of the systems were unable to measure and/or log performance data for reasons related to power outages. For this reason, the suspect period was removed from the analysis.

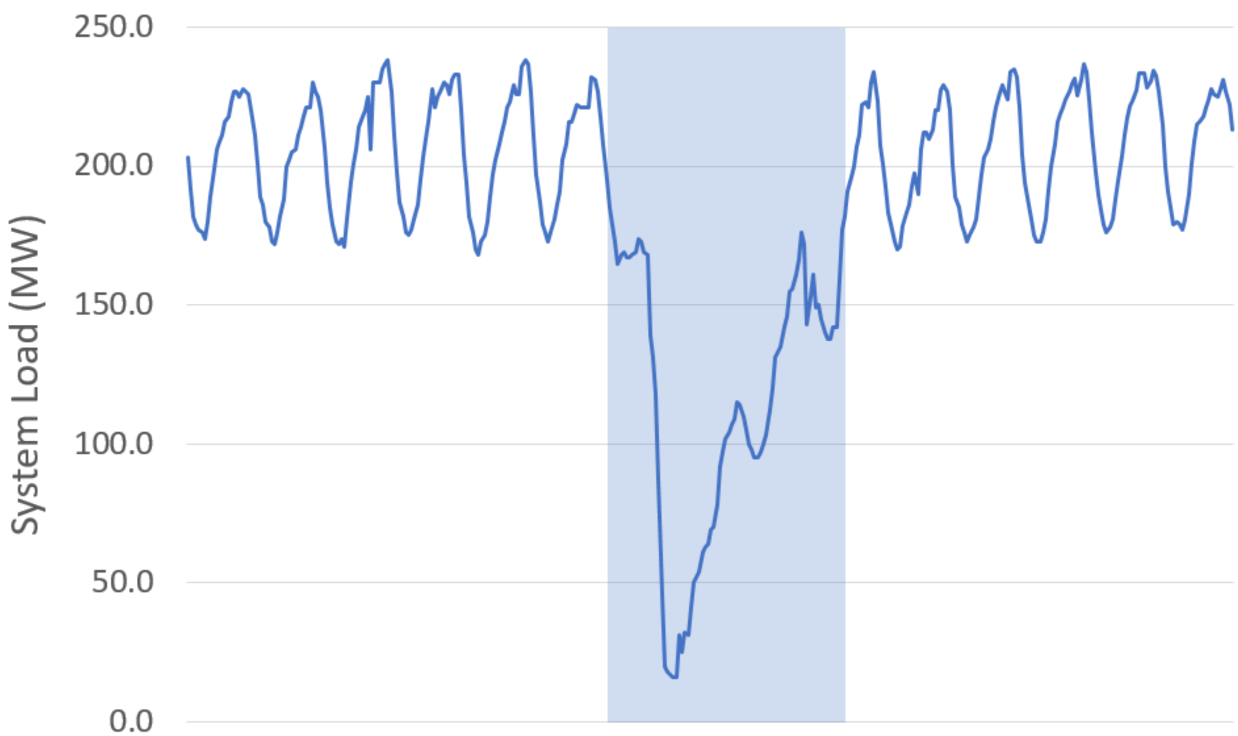

Figure 6. GPA System Load, May 9-23, 2015 (May 15-17 is highlighted).

Other inconsistent data reporting was observed for Systems 007R03, 007ZK3, 008I7U, 008Q5H, and so these were also removed from the analysis.

Load Data Cleaning

Several additional events of note were observed in the system load data. Three of these were ignored because either load was dropped during non-solar hours or because of unusual load shapes outside of the peak periods. In either case, these events were not believed to impact the analysis:

- 27 Feb 4 am. 20% drop in load, restored the next hour. Ignore because pre-dawn.
- 15 Mar. Unusual daily load shape with mid-day drop. Ignore because not peak day.
- 22 Apr 3 am. 45% drop in load, restored the next hour. Ignore because pre-dawn.

The above issues appeared to be valid data recording unusual load events. In addition, there were four hours of missing data, and for simplicity the full 24-hour days were removed from both the load and the solar production data during these periods. The data also included an extra reading that was removed from the load data. The following summaries the load data anomalies:

- Day 2 (Jan 2), 2:00 hour is missing. Removed day.
- Day 174 (Jun 23), included hour 7:01, same load (188 MW) as 7:00. Removed 7:01 hour only.
- Day 282 (Oct 9), 9:00 hour is missing. Removed day.
- Day 282 (Oct 9), 14:00 hour is missing. Removed day.
- Day 293 (Oct 20), 12:00 hour is missing. Removed day.

Data Filling

After removing selected PV systems and load days, there were nine systems remaining and 8592 hours of the year in full 24-hour contiguous days. Among the systems there still were a total of 31 missing data points (a data “point” is one hourly reading for one system), averaging 3.4 missing points per system. The worst case was one system with 13 missing points, with nine contiguous missing points, but these all occurred during non-solar hours. All missing data were filled by adding the corresponding output of the remaining systems and multiplying by the ratio of the target system rating to the combined rating of the remaining systems.

Adjustments were made to each system’s annual energy production to account for the reduced 358-day year.