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ROOFTOP PV VS. CENTRALISED PV

A COST-BENEFIT ANALYSIS

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About Ekistica

Ekistica is a professional advisory and technical consultancy firm based in Central Australia. We deliver innovative solutions to the complex challenges of remote area infrastructure development through a diverse team of more than twenty professional engineers, project managers, engagement specialists and data analysts. We provide high quality, independent advice, project development, engineering design and project delivery services for a wide range of infrastructure and related services, to clients that include state and national governments, intergovernmental agencies, power utilities, community service organisations, large commercial firms and private investment firms.

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Disclaimer

Executive Summary

This techno-economic cost benefit analysis explores the potential benefits to to Power and Water Corporation (PWC) from installing distributed rooftop PV as opposed to centralised ground-mounted PV, to support community loads in remote communities serviced by its not-for-profit subsidiary Indigenous Essential Services Pty Ltd (IES). For the purposes of this report, distributed rooftop PV refers to an aggregation of numerous household roof-mounted PV systems, integrated with the central power station in the community, generating power in conjunction with the existing diesel generator(s). These roof-mounted systems differ from conventional residential rooftop PV systems in the sense that they don't service individual loads of the residential sites they are installed at. Further, centralised ground-mounted PV referenced in this report implies a collection of co-located panels generating power at a single site, and also integrated with the central power station.

To avoid excessive analysis across all 72 IES communities, this study conducted technical and financial modelling at three communities: Kaltukatjara, Lajamanu and Maningrida. These communities were chosen to represent the range of climactic conditions, geographical regions and population sizes that typically exist in IES communities across the Northern Territory. These communities and their characteristics are in Table 0-1 below. Note that community latitude affects the optimal PV panel tilt, as well as the total solar energy that can be captured at that location.

Table 0-1: Characteristics of SETuP 1.0 Communities Chosen For This Study

Community	Latitude and Climate	Population [1]	Average Community Load (kW)	Installed Diesel (kW)	Installed Centralised PV (kW_{AC})
Kaltukatjara	-24.86°, Arid	463	182	980	100
Lajamanu	-18.48°, Arid	703	412	1,870	400
Maningrida	-12.05°, Humid	2,712	971	4,720	1,175

The study found that rooftop PV systems can deliver similar levels of technical outputs – generation, renewable energy fractions and fuel savings – as centralised PV systems. Therefore, the economic benefit of installing distributed rooftop PV as opposed to centralised PV can be reduced to a comparison of the capital and operational expenditures, while noting that social, environmental and regulatory issues may still impact on their business cases for each application site.

Rooftop PV systems have the advantage of lower capital costs as they do not require earthworks, site-preparation, high-strength array frames and extensive cabling that ground-mounted systems do, and benefit from lower operational costs and maintenance requirements. The assumed capital and operational expenditure for centralised and rooftop PV systems used in this analysis is in Table 0-2 below. Note that PV CAPEX per DC Watt is calculated to include the cost of the arrays, frames, footings (where applicable) and assembly. These price indices come after accounting for solar price rebates in the NT. The key financial metrics used to compare investments are provided in Table 0-3.

Table 0-2: Cost Indices for PV System Type

Category	Metric	Centralised PV	Rooftop PV
PV Capital Costs	PV CAPEX per PV DC Watt ($/W)	$ 1.41	$ 0.81
	Inverter CAPEX per PV AC Watt ($/W)	$ 0.25	$ 0.15
	Control Room, Equipment and Cabling ($/W)	$ 0.69	$ 0.15
PV Operating Costs	PV OPEX per PV DC Watt ($/W)	$ 0.030	$ 0.020
	Inverter Operational Life (Years)	15	10

Table 0-3: Financial Modelling Outputs

	Kaltukatjara		Lajamanu		Maningrida	
Scenario	**Centralised**	**Rooftop**	**Centralised**	**Rooftop**	**Centralised**	**Rooftop**
LCOE [$/MWh]	$394	$373	$392	$360	$365	$352
NPV ['000, $]	$911	$1,415	$2,115	$3,785	$8,485	$10,153
Initial Investment ['000 $]	$222	$85	$889	$339	$2,611	$996
IRR [%]	33%	110%	22%	77%	28%	72%
Payback Period [Years]	4	1	5	2	4	2

While the analysis demonstrates rooftop PV systems have financial benefits over centralised PV systems, it is important to acknowledge that the cost of deploying a control system that can reliably integrate all the distributed rooftop PV arrays to work in conjunction with an existing diesel power grid was not considered in the financial model. This cost would vary widely with the type of integration mechanism – 4G or physical cables – and with the number of roof-mounted arrays and until such systems are deployed to a meaningful extent in a remote community, this cost is difficult to quantify. However, as an example, such a system could add an additional $300,000 to the initial investment at Lajamanu, and still present an IRR of around 40% and a payback period of 3 years. This is illustrated in Table 0-4 below where varying initial control system investments are mapped out against the resulting project NPV, IRR and payback periods. Of note is the fact that if initial investment exceeds $500,000 then rooftop PV becomes non-competitive with centralised PV.

Table 0-4: Control System Investment Impact on NPV and IRR - Lajamanu

Initial Investment	Rooftop PV Project NPV 25-Year ($)	Rooftop PV Project IRR 25-Year ($)	Rooftop PV Project Payback Period
$0	$3,588,514.36	73.48%	2
$100,000.00	$3,485,172.50	56.56%	2

$200,000.00	$3,381,830.65	46.09%	3
$300,000.00	$3,278,488.79	38.96%	3
$400,000.00	$3,175,146.94	33.77%	4
$500,000.00	$3,071,805.08	29.83%	4
$600,000.00	$2,968,463.22	26.71%	4
$700,000.00	$2,865,121.37	24.18%	5
$800,000.00	$2,761,779.51	22.08%	5

This study is limited in scope to a techno-economic analysis. Deploying distributed rooftop PV would involve a concerted acquisition of regulatory approvals and social licenses from all households selected for installation, disruption of daily routines for the period of installation, and engagement with community members around the stewardship, operation and distribution of benefits of the system. Environmental impacts of the PV system would also now be distributed across the installation sites instead of being confined to a single geographical location. The variability in social, environmental and regulatory implications is also significantly impacted by site considerations and for this reason exploring them is intentionally excluded from the scope of this study. While acknowledging the limitations of this approach, it was concluded that there can be significant economic benefit from installing distributed rooftop PV as opposed to centralised ground-mounted PV in IES communities.

Future study should explore in more detail the social and environmental aspects of integrating rooftop solar PV in remote communities when compared to centralised solar PV, while considering the operational constraints imposed on hybrid power stations to ensure PWC can ensure the safe and reliable supply of electricity.

Abbreviations and shorthand

Abbreviation	Definition
ARENA	Australian Renewable Energy Agency
IES	Indigenous Essential Services
IRR	Internal Rate of Return
KALT	Kaltukatjara
LAJA	Lajamanu
LCOE	Levelised Cost of Electricity
LV	Low Voltage
MANI	Maningrida
NPV	Net Present Value
NT SETuP	Northern Territory Solar Energy Transformation Program
PV	Photovoltaic
PWC	Power and Water Corporation
REF	Renewable Energy Fraction

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1 Introduction

1.1 Background

Between 2017 to 2019, the Northern Territory Solar Energy Transformation Program (NT SETuP) successfully integrated approximately 10 MW of solar photovoltaic (PV) capacity into 25 diesel-powered remote grids in the Northern Territory (NT). Deployed by Power and Water Corporation (PWC) in communities being serviced by its subsidiary Indigenous Essential Services (IES), the project is estimated to save over 94 million litres of diesel across its 25-year lifetime. Building on the success of NT SETuP, PWC seeks to produce a suite of studies looking into ways to improve power system reliability throughout its IES portfolio of communities, while supporting higher levels of customer solar investment and further reductions in operating costs.

This new initiative – the NT Microgrid Futures Project – will result in a set of detailed business cases for investment for select communities, along with a set of broad-application microgrid technologies [2]. For the purposes of this study, the NT Microgrid Futures project will be referred to as SETuP 2.0. This presents an opportunity to explore whether integrating distributed rooftop PV in IES-serviced communities can capture additional social, financial, and/or environmental benefits when compared to installing centralised, ground-mounted PV systems.

1.2 Situated Context and Focus of Study

IES-serviced communities are mainly powered via diesel generation. Their power stations comprise 3-4 diesel generators of varying capacities, automatically dispatched to meet the daily variable community demand. SETuP 1.0 communities are serviced by a hybrid diesel-PV power system. All PV installations in SETuP 1.0 are centralised, comprising ground-mounted flat-plate arrays and inverters. Power generated by the PV system is integrated into the generation mix in a way that ensures the diesel generators can maintain supply as the PV varies over the course of the day. This control strategy is tailored to allow the diesel generators to run just above their minimum loading, while aiming to achieve approximately 15% Renewable Energy Fraction (REF) for the power system. For a full breakdown of the power mix over the entire range of SETuP communities, please refer to [3].

There are numerous variables which inform the decision to integrate a PV system within an existing power grid such as in IES-serviced communities. These can be grouped under the broad categories of: capital costs, stakeholder engagement, deployment, maintenance, and reliability of generation. They are outlined in Table 1-1, with contexts of centralised and rooftop solar reported alongside.

This study explores the economic aspect of the decision-making process around deployment of PV systems in remote isolated power grids. The different capital and operational expenditures associated with centralised and rooftop PV systems inform what their relative financial benefits will be – that is, avoided costs of fuel to power the community, versus the initial investment required. It is recommended that the social and environmental aspects of deployment also be carefully considered before making final investment decisions on the type of solar PV to install in remote communities. This report, however, will remain limited to the techno-economic analysis of integration of PV systems within isolated power grids, and restricted to the analysis of direct costs.

Table 1-1: Key Variables For Selection Of PV System Type

Perspective	Consideration	Centralised	Rooftop
Stakeholder Engagement	Community buy-in	Community engagement required and focused on access to land for construction of the PV site	Engagement required on an individual basis with each household site of installation, focused on "stewardship" of the rooftop system
Deployment/Delivery	Access to community land	Required	Not required
Deployment/Delivery	Fencing and security	Yes, will be required to surround the centralised PV system.	No, if community engagement is done properly
Deployment/Delivery	Plant Design	Fixed module types and arrangement; easy to model	Flexible arrangements; modelling is more complex if accounting for variations
Direct Cost	Cabling Required	Yes; cables of high power ratings to connect arrays to inverters and the PV site to the existing diesel power station	Yes; cables of lower power ratings, for both purposes.
Direct Cost	Module Footings	Footings required	Footings not required
Direct Cost	Trenching	Can be significant if located far away from existing diesel power station, and if using underground signal cables instead of overhead.	Usually none, unless rooftop systems are centrally controlled and integrated with the existing diesel power station using underground signal cables
Direct Cost	Monitoring and Control	Simple monitoring and control	Need to ensure individual arrays are reliably connected and can respond to control inputs
Reliability and Maintenance	Orientation	Modules can be oriented optimally	Module orientation depends on the rooftop they're being installed on
Reliability and Maintenance	Repairs and Expansion	Plant needs to be de-energised for repairs/replacement. Expansion may not	Individual strings can be taken offline to perform repairs and replace equipment. Expansion is

		be possible on the same installation site	simpler if there is available additional roof space and social license
Reliability and Maintenance	Transmission Losses	Low transmission losses	Transmission losses may get compounded with increasing system size and footprint

1.3 Analysis Methodology

This study was conducted on SETuP 1.0 communities, given the availability of their baseline power system data and the financial data made available by PWC. Diesel-only and Diesel-centralised PV systems therefore formed the base cases for comparison against a Diesel-distributed rooftop PV integration scenario. The following sub-sections detail the selection of communities to perform the analysis on, and the process flow for technical and financial modelling of the base cases and scenarios.

1.3.1 Community Selection

SETuP 1.0 communities were reviewed based on community population, location, amount of exploitable roof space, and the quality of available historical power system operational data. Community location and population are two major factors influencing their electricity consumption and trends thereof, and were important considerations in selecting which communities to include in this study. Maningrida, Lajamanu and Kaltukatjara span three different climatic regions of the NT and have significantly different populations, and therefore represent, to some extent, a broad range of IES communities across the NT. Their locations are shown in Figure 1-1. These three communities were identified as candidates for analysis for the purposes of this study.

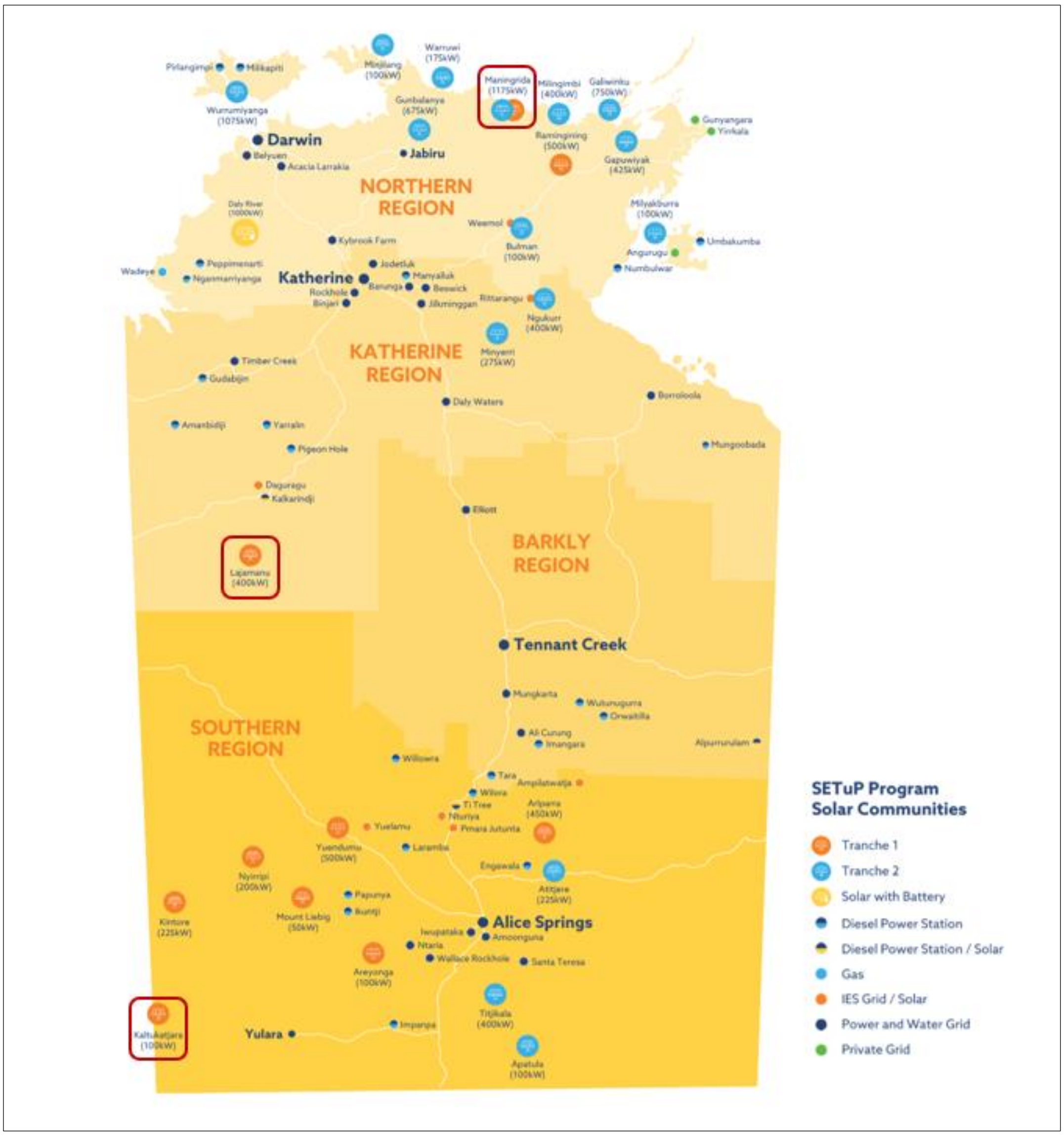

Figure 1-1: SETuP 1.0 Program Communities, with communities chosen for this analysis highlighted in red. Image from [4]

1.3.2 Modelling Process Flow

The flow diagram shown in Figure 1-2 demonstrates the modelling process undertaken in generating the results presented in this study.

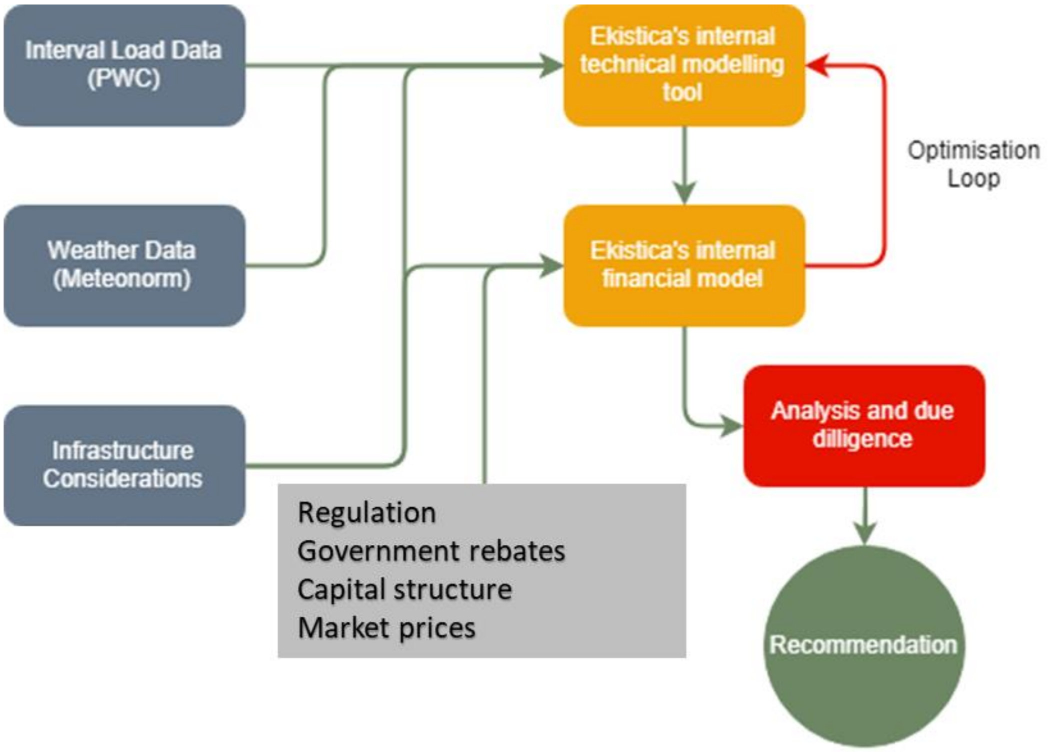

Figure 1-2: Modelling Process Flow-chart

A typical meteorological year of hourly solar irradiance data was sourced from Meteonorm and was provided as input to Python's PVlib software package to simulate an annual solar PV generation profile in each community. Historical load data was downloaded at each community. The hourly dispatch of solar PV and diesel generation required to meet the load over one year, while maintaining diesel minimum loading requirements, was simulated using a custom modelling tool in Python. Energy outputs from the technical model act as inputs to the financial model, where project returns are calculated with respect to a business as usual scenario. A list of all technical and financial modelling inputs and assumptions are outlined in Section 2.1 and Section 2.2. Key financial metrics, such as Net Present Value (NPV), Internal Rate of Return (IRR), payback period, initial investment and Levelized Cost of Electricity (LCOE) are reported on and compared.

2 Analysis

2.1 Technical Modelling

For ease of comparison, the distributed rooftop solar PV capacity modelled in each community was set to equal the centralised solar PV capacity installed in SETuP 1.0 in each community; and this study does not suggest that these generation capacities are optimal from either a technical or financial point of view.

Upon close inspection of satellite imagery at each community, it is evident that there exists enough north-facing roof space to house the required solar PV capacity. Table 2-1 below summarises the centralised PV, rooftop PV, and diesel generation capacities in each community, as well as providing estimates on community populations. Note that the modelled rooftop PV comprises of contributions from arrays facing North-West (between 0 to -45 degrees azimuth) and arrays facing North-East (between 0 to +45 degrees azimuth). The proportionality between these two array contributions is derived from measuring the azimuthal orientations of a sample of 30 households in Maningrida. This proportion has also been carried forward to Kaltukatjara and Lajamanu .

Table 2-1: Community Characteristics

Community	Population [1]	Installed Diesel (kW)	Installed Centralised PV (kW_{AC})	Modelled Rooftop PV (kW_{AC})
Kaltukatjara	463	980	100	71 NW 29 NE
Lajamanu	703	1,870	400	284 NW 116 NE
Maningrida	2,712	4,720	1,175	835 NW 340 NE

For exemplary purposes, Figure 2-1 shows Maningrida's median summer and winter community load profile and the median daily profile of the modelled rooftop PV. Maningrida's population is one of the largest out of the SETuP 1.0 communities and has the most centralised solar PV installed. In summer there is a near-constant load between 10 AM and 8 PM, which is likely a result of air-conditioning load. Winter's daytime load is lower than that in summer, varying between 0.8 to 1.2 MW. Winter heating loads are minimal given Maningrida's proximity to the equator and relatively tropical climate. Lajamanu and Kaltukatjara on the other hand, which are located further south in the NT, experience lower winter temperatures and have proportionally higher winter loads with respect to summer. Note that the solid lines indicate median hourly values of load and PV generation, while the shaded region indicates the day-to-day variability (25^{th} to 75^{th} percentile) in the same.

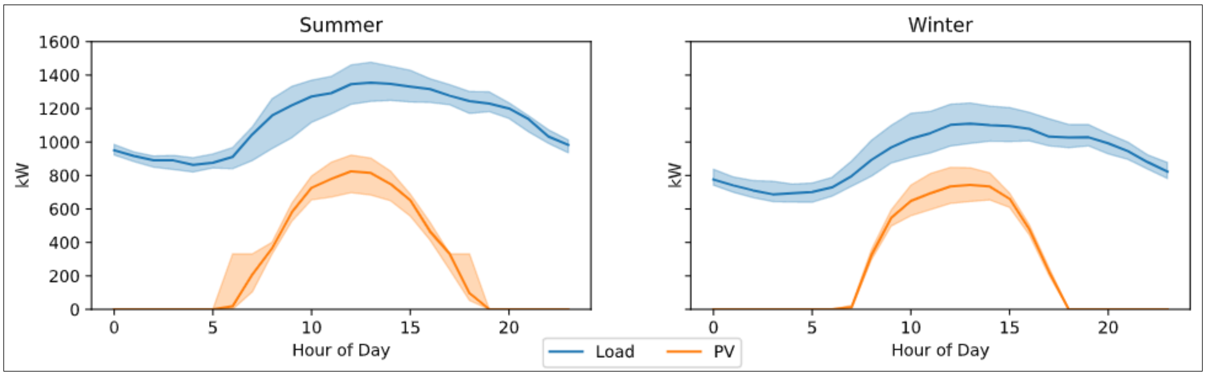

Figure 2-1: Maningrida daily load and rooftop PV generation profile

Figure 2-2 shows the amount of energy serving the load from diesel and solar PV under the scenarios of business as usual (BAU), centralised PV with diesel, and rooftop PV with diesel within each community. BAU refers to diesel-only generation, where diesel serves 100% of the load.

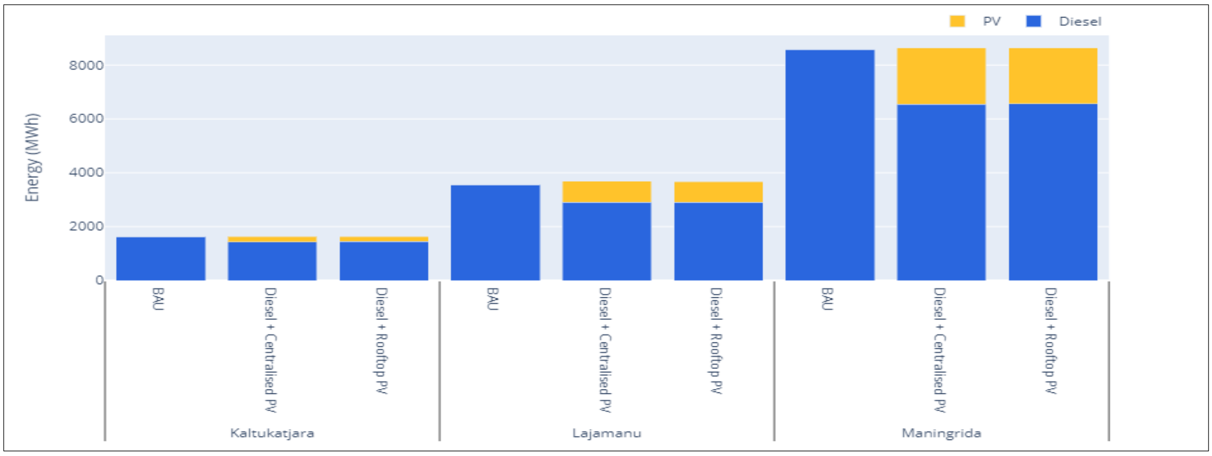

Figure 2-2: Generator Contributions to Annual Load - All Communities

Centralised solar PV serves 12%, 18% and 24% of the load in Kaltukatjara , Lajamanu and Maningrida, respectively, as does rooftop solar. Figure 2-3 shows the fuel consumption over the life of the project for BAU, centralised PV and rooftop PV scenarios in each community. Both centralised PV and rooftop PV reduced diesel consumption by 11%, 18% and 23% in Kaltukatjara, Lajamanu, and Maningrida, respectively. Figure 2-3 shows lifetime fuel savings for Maningrida to be approximately 3 and 11 times higher than Lajamanu and Kaltukatjara, respectively. Solar PV generation in Maningrida over the lifetime of the project is also 3 to 11 times higher than in Lajamanu and Kaltukatjara, respectively. This highlights the approximate 1:1 correlation between energy offset and fuel savings.

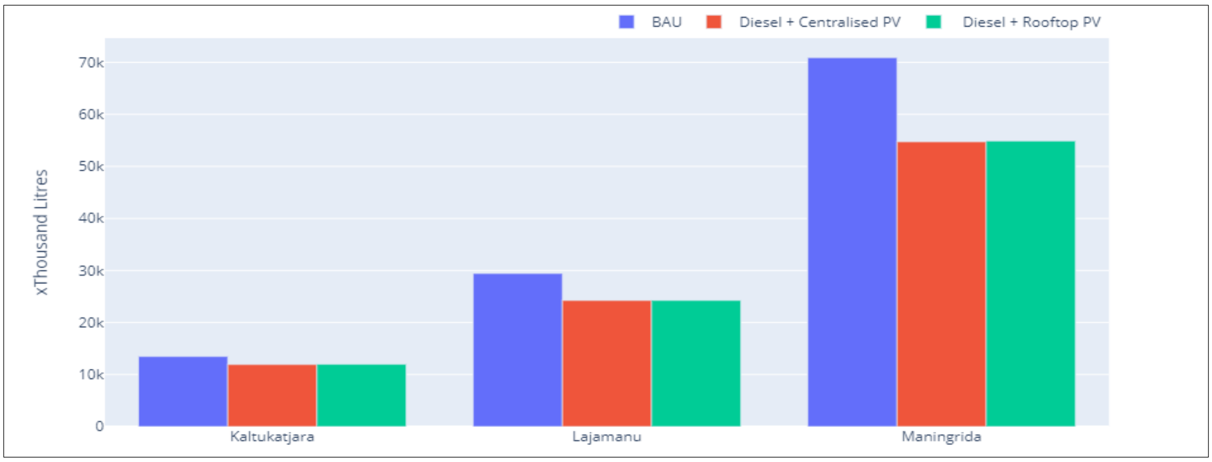

Figure 2-3: Cumulative Fuel Consumption For Each Scenario - All Communities

As the modelled distributed rooftop PV capacities are the same as installed centralised PV capacity, there are no significant differences in generation between the two PV system types for the purpose of the analysis conducted. Distributed rooftop PV can achieve similar, if not higher levels of fuel savings as centralised PV microgrids can, accomplishing the goal for NT SETuP 1.0. The following section of this study focusses on exploring the difference in cost between rooftop and centralised solar PV systems.

2.2 Financial Modelling

The analysis of two different technology options for a hybrid microgrid, subject to the same capacity and generation constraints, requires a deeper understanding of the costs involved. CAPEX for ground-mounted centralised PV systems include those associated with geotechnical assessment, site clearing and preparation, foundation and earthworks, construction and installation of frames, construction of enclosed, weather-proof spaces for housing inverters, control equipment, switchboards etc., and fencing. Most of these costs are not part of line-item costs for rooftop PV. Therefore, for smaller overall system capacities, rooftop PV has lower installed costs than ground-mounted systems of the same capacity. However, for larger overall system capacities, ground-mounted systems can take advantage of economies of scale and come out to be cheaper than rooftop systems [4]. Figure 2-4 illustrates this.

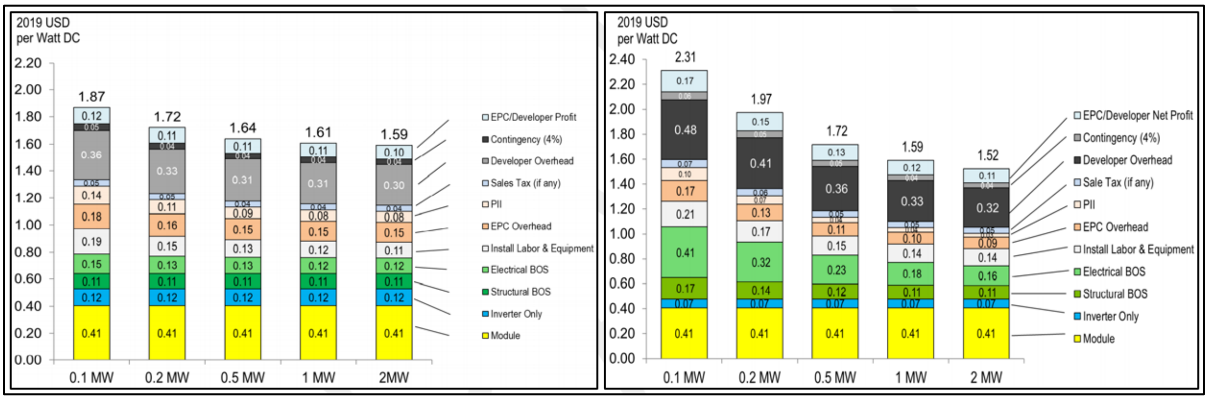

Figure 2-4: Cost Breakdown for Different Capacities of Rooftop PV system (Left) and Centralised PV system (right). Image from [4]

In the figure it can be seen that, for PV systems of capacities up to 500kW, the total installed cost per watt is lower for rooftop systems (between 1.87 to 1.64 USD per Watt) than for centralised systems (2.31 to 1.72 USD per Watt). For capacities beyond 500kW, the installed costs are lower for centralised systems (1.59 to 1.52 USD per Watt) as compared to rooftop systems (1.61 to 1.59 USD per Watt). It also appears that installed costs for centralised PV systems decrease with increasing system capacity at a higher rate than they do for rooftop PV systems.

Some of the OPEX items for a ground-mounted PV system located in an isolated microgrid include Operations and Maintenance (O&M), vegetation control, land lease, insurance, asset management, defect rectifications, travel, materials, equipment, community engagement, site works, and environmental regulation. Rooftop PV systems can experience lower operating costs compared to ground-mounted because some of the major OPEX items like vegetation control and environmental regulation are not a factor

In a sensitivity analysis performed by NREL into the cost of a 200kW rooftop PV, it was shown that inverter type and labour were the parameters that affected CAPEX the most. The same study reported that for a ground-mounted system, material location, equipment location and construction labour were the dominant factors affecting CAPEX [4]. Transporting materials and equipment over long distances to remote locations can impose significant costs to a project. As reported in the NT SETuP 1.0 knowledge sharing report on challenges of remoteness [5], mobilisation costs hinder site inspections and defect rectification. Shipping containers carrying materials and equipment are expensive to transport to remote communities. Further, in the case that they need to be returned to base, costs of transportation are higher than the value of their contents. For many communities in the NT, delivery of materials in bulk is only possible via barge, which is a significantly more expensive means of transport than on-road. The wet season also poses risks to scheduling as roads may often not be constructed for all-weather access. Therefore projects involving ground-mounted PV systems, being sensitive to material and equipment costs, are likely to be turn out to be more expensive than those involving rooftop PV systems.

Table 2-2 outlines the financing and project-related assumptions feeding the financial model, while Table 2-3 outlines the CAPEX and OPEX assumptions for each technology. These costs come from Ekistica's experience delivering similar projects and PWC's pricing and tariffs. They are also reflective of the major findings from established projects and literature detailed above. Note that PV CAPEX per DC Watt is calculated to include the cost of the arrays, frames, footings (where applicable) and assembly. These price indices come after accounting for solar price rebates in the NT

Table 2-2: Project and financial assumptions

Category	Metric	Value
Financing	Cost of Debt (%)	4.0%
	Cost of Equity (%)	10.0%
	WACC (%)	4.96%
	Loan Tenure (years)	10
	CPI (%)	2.5%
	Tax Rate (%)	30.0%
Project	Construction Start Year	2021

	Year of First Generation	2022
	Project Lifetime	25
	PV Degradation Rate	-0.5%

Table 2-3 – Technical CAPEX and OPEX assumptions

Category	Metric	Centralised PV	Rooftop PV
PV Capital Costs	PV CAPEX per PV DC Watt ($/W)	$ 1.41	$ 0.81
	Inverter CAPEX per PV AC Watt ($/W)	$ 0.25	$ 0.15
	Control Room, Equipment and Cabling ($/W)	$ 0.69	$ 0.15
PV Operating Costs	PV OPEX per PV DC Watt ($/W)	$ 0.030	$ 0.020
	Inverter Operational Life (Years)	15	10
Diesel Operating Costs	Starting Diesel Price ($/L)	$ 1.20	
	Diesel Generator Maintenance ($/kW/hour)	$ 0.03	
	Fuel Efficiency (L/kWh)	0.33	

The financial modelling yielded the following outputs, tabulated in Table 2-4 below.

Table 2-4 Financial Modelling Results

	Kaltukatjara		Lajamanu		Maningrida	
Scenario	**Centralised**	**Rooftop**	**Centralised**	**Rooftop**	**Centralised**	**Rooftop**
LCOE [$/MWh]	$394	$373	$392	$360	$365	$352
NPV ['000, $]	$911	$1,415	$2,115	$3,785	$8,485	$10,153
Initial Investment ['000 $]	$222	$85	$889	$339	$2,611	$996
IRR [%]	33%	110%	22%	77%	28%	72%
Payback Period [Years]	4	1	5	2	4	2

On average across the three sites, the BAU LCOE is 17.71% and 25% higher than the centralised and distributed rooftop PV LCOE, respectively. This is mainly due to the higher fuel expenses in BAU. Distributed rooftop PV capital costs and operational expenditure are lower than those for centralised PV systems, resulting in approximately 38% lower initial investment and 3% lower operating expenses on average. Distributed rooftop PV project NPV is consistently higher than centralised systems. Because of lower initial investment and operating costs, payback periods are quicker for distributed rooftop PV, and the internal rate of return (IRR) is 2.5-3.5 times higher than centralised PV systems.

Figure 2-5 presents the cumulative cashflows and cumulative IRR experienced over the life of centralised PV and distributed rooftop PV scenarios in Kaltukatjara. Due to lower capital costs, rooftop PV's smaller initial investment is recouped quicker than centralised PV. The payback period for distributed rooftop PV is one year as opposed to four years for centralised solar PV.

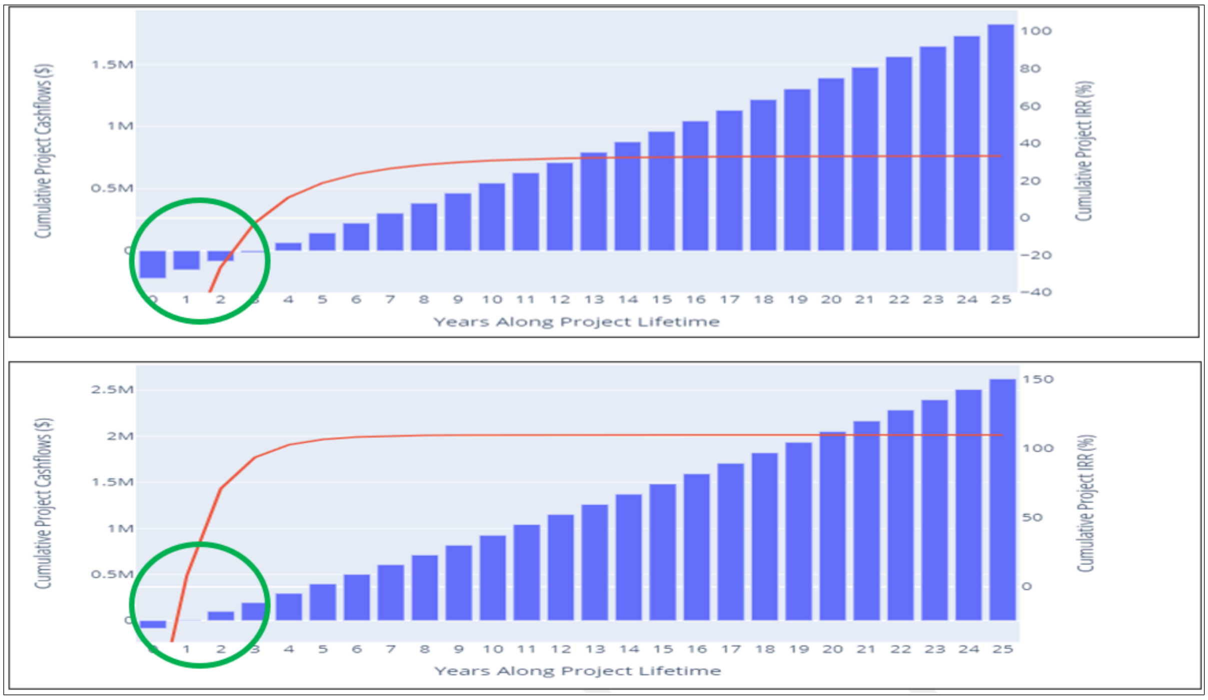

Figure 2-5: Cumulative Cashflows and IRR over the Project Lifetime for Centralised (top) and Rooftop PV (bottom) at Kaltukatjara

One cost that is not being accounted for in the calculations presented is the cost of integrating control system architecture across all distributed rooftop PV installations in a community. Centralised PV systems have a control mechanism via which they can be monitored, dispatched and curtailed. This mechanism is installed in the LV switchboards for each array, and is co-located with the arrays at the PV installation site [6]. For distributed rooftop PV systems however, this will need to be integrated either with the switchboards at each PV installation site (for example, a house in the community), or the LV feeder switchboards pertaining to each street or supply region within the community. Further, links to these control mechanisms will have to be run from each installation point, to converge at the central microgrid control station. The associated costs would vary widely with the type of integration and the linking mechanism employed – 4G wireless or physical cabling – as well as the installation costs. Until such a system is integrated in a remote community at a scale of operation similar to NT SETuP, it is difficult to quantify the associated expenses, or even provide an order-of-magnitude estimate.

However, to analyse the impact of such an investment on a rooftop PV system's financial model, an initial investment cost for a control system was added to Lajamanu's financial model. The resulting impact on NPV, IRR and payback period was analysed. This is presented in Table 2-5. This cost is not based on any known on-site control system costs, and exists rather to facilitate an indicative assessment of cost-competitiveness of rooftop PV over centralised PV. From the table, even at an initial control system investment of $300,000 a rooftop PV system returns an IRR of around 40% and a payback period of 3 years. However, beyond an initial control system cost of $500,000 the cost-benefit curve shifts back in favour of centralised PV system.

Table 2-5: Investment Impact of Rooftop PV Control System on NPV, IRR and Financial Metrics - Lajamanu

Initial Investment	Rooftop PV Project NPV 25-Year ($)	Rooftop PV Project IRR 25-Year ($)	Rooftop PV Project Payback Period
$ 0	$3,588,514.36	73.48%	2
$100,000.00	$3,485,172.50	56.56%	2
$200,000.00	$3,381,830.65	46.09%	3
$300,000.00	$3,278,488.79	38.96%	3
$400,000.00	$3,175,146.94	33.77%	4
$500,000.00	$3,071,805.08	29.83%	4
$600,000.00	$2,968,463.22	26.71%	4
$700,000.00	$2,865,121.37	24.18%	5
$800,000.00	$2,761,779.51	22.08%	5

3 Conclusion

3.1 Remarks

The NT Microgrid Futures Project, referred elsewhere in this paper as SETuP 2.0, is investigating avenues to improve power system reliability and drive operating cost reductions in remote, isolated power systems serviced by PWC IES. It builds upon the learnings from NT SETuP 1.0, where ground-mounted PV systems were rolled out across 25 communities, integrating them with existing diesel-powered grids. This study explored the additional economic benefits that could be captured by installing distributed rooftop PV systems in these communities, as opposed to ground-mounted systems as used in SETuP 1.0.

Table 3-1: CAPEX and OPEX for Rooftop and Centralised PV systems.

Category	Metric	Centralised PV	Rooftop PV
PV Capital Costs	PV CAPEX per PV DC Watt ($/W)	$ 1.41	$ 0.81
	Inverter CAPEX per PV AC Watt ($/W)	$ 0.25	$ 0.15
	Control Room, Equipment and Cabling ($/W)	$ 0.69	$ 0.15
PV Operating Costs	PV OPEX per PV DC Watt ($/W)	$ 0.030	$ 0.020
	Inverter Operational Life (Years)	15	10

Distributed rooftop PV systems have the advantage of having lower installed capital costs, not requiring major construction or trenching works, relatively simpler maintenance, and no land development costs. Given these benefits, the hypothesis tested in this study is that integrating distributed rooftop PV systems within isolated power grids in remote communities has higher economic benefits than integrating ground-mounted PV systems, while achieving similar levels of technical performance.

Three SETuP 1.0 communities were analysed in this work: Kaltukatjara, Lajamanu and Maningrida. They were selected based on their size, location, and feasibility of generating community-scale power from distributed rooftop photovoltaic systems for being representative of communities across the NT. A techno-economic analysis of business-as-usual (diesel power only), diesel-centralised PV and diesel- distributed rooftop PV system scenarios was performed, yielding the following results.

Table 3-2: Financial Modelling Outputs: All Three Communities

	Kaltukatjara		Lajamanu		Maningrida	
Scenario	**Centralised**	**Rooftop**	**Centralised**	**Rooftop**	**Centralised**	**Rooftop**
LCOE [$/MWh]	$394	$373	$392	$360	$365	$352
NPV ['000, $]	$911	$1,415	$2,115	$3,785	$8,485	$10,153
Initial Investment ['000 $]	$222	$85	$889	$339	$2,611	$996
IRR [%]	33%	110%	22%	77%	28%	72%

Payback Period [Years]	4	1	5	2	4	2

The technical modelling of PV systems in these three communities yielded the observation that – given the same array size and operational constraints – distributed rooftop and centralised PV produced the same amount of fuel savings, because of their ability to generate the same levels of power. In our modelling, two out of three communities realised marginally better REFs with distributed rooftop PV than ground-mounted PV. Realising that distributed rooftop PV could fulfil the technical aims of SETuP 1.0, the study then completed a comparative financial analysis of the two PV technologies.

As can be seen in Table 3-2, distributed rooftop PV has lower LCOE, initial investment and payback periods than ground-mounted PV, while also having higher NPV and IRR. One cost that wasn't accounted for in our study was the cost of a control system architecture required to integrate all distributed rooftop PV installations in a community, and connect either physically or wirelessly to the existing power system's automated generator control. In the context of remote communities in the NT, the costs associated with such a system are currently unknown, and will likely prove to be a major cost item in the project finances for a distributed rooftop PV system. This unknown cost may end up tipping the scales back in favour of a ground-mounted PV system.

This techno-economic comparative analysis shows that distributed rooftop PV systems have the potential to produce the same technical outcomes, and better financial returns on investment than diesel-centralised PV systems. Yet, deployment of distributed rooftop PV systems in remote communities would present operational and project management challenges not seen before with centralised PV systems – not the least of which would be community consultation and obtaining social license, as well as schemes for reliable control and integration into the existing power system. There is clearly a lot of research and work to be done on that front.

3.2 Further questions and scope for analysis

For PWC to guarantee the safe and reliable supply of electricity to remote communities via distributed rooftop solar PV, some form of central control from the utility would likely be required. Integrating a mechanism that allows for central control would add significant CAPEX to rooftop solar PV installations. This unknown additional cost was not considered for in the modelling within this study and represents an area of potential future study. It's inclusion to the modelling may change the outcomes presented within this study.

This study compared the economics of installing distributed rooftop PV vs. centralised solar PV in remote communities. Another potential area for future study is to consider the social and environmental aspects of installing distributed rooftop vs. centralised solar PV. This study should include how these measures of success are impacted should the local utility retain operational control of each rooftop solar PV system.

Further study is required to better understand how the social, environmental, and economical benefits change for distributed rooftop vs. centralised solar PV as the population of the community changes. For instance, it is likely that for extremely small communities, that distributed rooftop solar PV systems are overall beneficial when compared to centralised solar PV systems. However, this may change once the size of a community increases above a certain point where the benefits of economies of scale are realised. It would be useful to better understand how the decision to install distributed rooftop vs. centralised solar PV changes with increasing community size.

Further reporting on line-item costs for distributed rooftop and centralised solar PV systems in remote and rural areas is needed to better inform modelling within this area. Accurate costings would enable useful sensitivity analyses to take place, allowing for risk profiles to be established.

4 References

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