

Congo Epela Project

SNEL and ISTA Building
Energy Modelling and
Rooftop PV Analysis

Pre-Feasibility Report

Gregory Ireland (M.Sc.)
Avia Linke (M.Sc.)
Catherina Cader (Ph.D.)

2024



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General introduction

Since 2019, Resource Matters has conducted extensive research to develop sustainable electrification solutions for the Democratic Republic of Congo (DRC). This in-depth analysis focused on the country's existing energy infrastructure, its energy potential, and electricity demand.

Building upon this research, we launched the Congo Epela platform in 2022. This platform offers a range of tailored electrification solutions for different regions, including grid extension, mini-grid development, and the deployment of individual solar kits. This initiative benefited from the technical expertise of renowned universities such as UCT, KTH, and RLI, as well as the collaborative efforts of our Mwangaza partner network.

Expanding on this work, we addressed a significant challenge in improving the DRC's energy supply: electricity consumption in public buildings. Rapid urban growth and increasing energy demand in major cities, particularly Kinshasa, are straining the national grid. Public buildings, often lacking cost constraints, contribute substantially to this consumption, resulting in considerable financial losses for grid operators.

To explore more sustainable and efficient alternatives, we initiated pilot energy modeling projects for several public buildings in Kinshasa. The objective was to evaluate the feasibility of solar self-consumption solutions to decrease these buildings' reliance on the main electricity grid.

Despite challenges in acquiring necessary data from relevant authorities, we ultimately concentrated our efforts on two pilot sites: the SNEL management concession and the ISTA site. The collected data enabled us to perform detailed simulations and assess the potential for energy self-sufficiency in these buildings.

The detailed results of these analyses are presented in the subsequent sections.

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1 Introduction

This pre-feasibility report explores the potential for optimizing building energy systems including solar photovoltaic rooftop installations at the SNEL and ISTA compounds in Kinshasa in the Democratic Republic of Congo. The study follows a methodology beginning with the collection of data and a review of relevant literature to gather key information, such as building layouts, rooftop suitability, energy demand, grid reliability and blackouts, and existing available thermal backup generators; These data sources and assumptions are combined into a computational optimization model to evaluate multiple different system configurations, scenarios, and sensitivities on input assumptions.

The study first involved analysing the rooftops at both building compounds to estimate their potential to generate solar energy. Using data obtained from on-site sources, combined with satellite imagery and the PVGIS¹ simulation software, the most viable rooftops were identified, and their solar generation capacity and performance were estimated. Different rooftop configurations were then combined to explore various system size installation scenarios. To understand energy needs, demand profiles were created for each compound, including simulations of grid blackouts needed to predict how often backup systems would be required (diesel, batteries, and PV), how to optimally size and dispatch them, and how they would interact and/or compliment the different system configurations. Importantly, a “Feed-in Tariff” was also included in the model to allow an economic benefit to be given to excess PV generation that could be fed back into the grid during periods where the PV generation of the system is greater than the demand. The collected data was fed into an energy system optimization tool offgridders² (based on the oemof framework) that simulated different configurations of solar PV installations, battery storage, diesel generation costs, and feed-in tariff prices to identify the most cost-effective solution for each configuration. The model ensures reliable energy supply, even during power outages, while minimizing overall lifetime system costs.

This work falls under the “Congo Epela Project” in which researchers are working with partner organisations to support electricity access planning in the Democratic Republic of Congo. Alongside this building energy system modelling, they are also improving the [Congo Epela](#), online visualisation platform, updating data and producing case studies on decentralised power supply options at local level. The project is the third phase of an [ongoing project](#) in which the RLI has already been involved since November 2020. The RLI is part of a project consortium that works with numerous local actors including national and local government, civil society representatives and the private sector. The project is funded by a grant from the American Jewish World Service “11th Hour Project” fund. The aim of this program is to raise awareness about climate change, fair resource management and use, and the promotion of modern, sustainable renewable energy sources.

1 https://joint-research-centre.ec.europa.eu/photovoltaic-geographical-information-system-pvgis_en

2 <https://offgridders.readthedocs.io/en/latest/Home.html> and <https://oemof.org/libraries/>

This report summarizes and explains the used methodology and the results of our work. It starts with an introduction, then the second section describes the study's approach and methodology, then results are presented in the third section, and finally the report ends with discussions and conclusions.

Model input and output files including technoeconomic assumptions, rooftop PV map data, hourly solar generation profiles, as well as full model output breakdowns and hourly timeseries files are attached separately to the report.

2 Building compound energy system modelling methodology

The energy system modelling methodology adopted in this pre-feasibility study is summarized in Figure 1 below and includes the four main sections of “Data Collection and Literature Review”, “Solar PV Rooftop Analysis”, “Demand Modelling”, and finally “Energy System Optimisation”. This process is carried out for both the SNEL compound and the ISTA compound in Kinshasa using data collected from both entities. Both buildings have different energy situations, and the differences may provide information on other potential installations that may be similar to these situations.

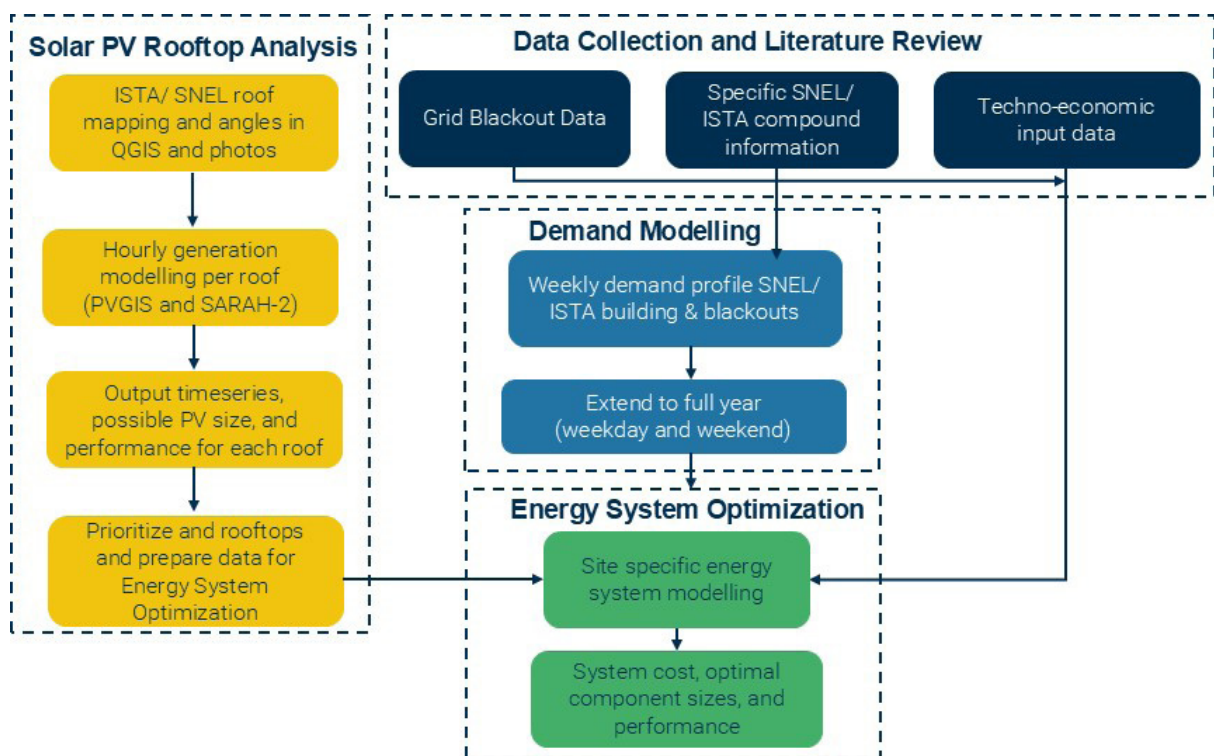


Figure 1. Methodology overview for building compound energy system modelling

2.1 Data Collection, Literature Review, and Feed-in Tariff

The first step involved data collection and literature review where numerous data inputs that are required to undertake an energy systems simulation of a building compound are obtained from various sources. Data on the building's suitable roofs, energy demand, and desired system configurations for the buildings was needed. Historical blackout data for the SNEL/ISTA buildings was used to assess grid reliability and identify potential for blackout mitigation. The size of any available backup thermal fuel generators (diesel or petrol) is also an important into the models as well as the assumed cost of fuel. Additionally, techno-economic data was sourced from existing studies to provide input on the costs and performance of solar PV systems, battery storage, and backup systems. Importantly, a "Feed-in Tariff" was also included in the model (at varying levels) to allow an economic benefit to be given to any excess PV generation that could be fed back into the grid during periods where the PV generation of the system is greater than the demand and if any storage (if included) is already fully charged. For the feed-in tariff to be modelled appropriately it needs to be less than the assumed price of the grid electricity (0.07 \$/kWh), so a feed-in tariffs of 0.05 \$/kWh was assumed for a "reasonable/good" scenario and also at 0.069 \$/kWh to simulate the most optimistic scenario of a "net metering" scheme where "full credit" is given for any PV fed back into the grid.

2.2 Solar PV Rooftop Analysis

An analysis of the rooftop potential for photovoltaic (PV) solar energy generation was conducted in several steps for each location. Using QGIS, site photos, and satellite imagery; all suitable rooftops were mapped and modelled individually to estimate installable PV system sizes and expected energy output potential per roof. Their suitability for solar installations and the likelihood of shading from trees or other nearby buildings was determined and their orientation and tilt angles were estimated to determine expected output potential. Solar generation timeseries are created for each rooftop combining all estimated input data values and using PVGIS³ (v5.2) with SARA-2 satellite data. The rooftops were then prioritized based on their potential energy generation (capacity factor – CF) and combined into scenarios with varying total installed PV capacities for analysis in the energy system modelling and optimization step. The mapping files (.gpkg) and timeseries outputs (.csv) for all modelled roofs for both buildings are provided along with this report.

2.3 Demand Modelling and Blackout Profiles

Hourly demand profiles were developed for an entire year for the SNEL and ISTA compounds separately using measured data provided to the modelling team that recorded the building electricity demand over a typical working day. These hourly daily profiles were extended to cover an entire year, for both weekdays and weekends, assuming a reduced demand over the weekend. Data on blackouts for both

3 https://joint-research-centre.ec.europa.eu/photovoltaic-geographical-information-system-pvgis_en

buildings were obtained and used to simulate the grid being unavailable – the duration and frequency of blackouts is modelled separately for each building based on data shared by SNEL and ISTA.

2.4 Energy System Optimization

All of the previous steps and data sources are then combined into an energy system optimisation tool named offgridders⁴ (based on the oemof framework – “open energy modelling framework”) that is used to simulate the various system configurations and scenarios developed. The model incorporates the potential solar PV generation from the rooftops, along with the energy demand and system blackout profiles, to create an optimized system that balances energy supply and demand over every hour of the year, and feeding excess PV generation back into the grid. The tool simulates each system configuration over a full year of 8760 hours, with the objective of achieving the minimum total system cost over the lifetime of the system. The goal was to find the most cost-effective solution that could reliably meet the energy needs of the SNEL/ISTA compounds during normal grid operation and blackout conditions for different sizes of rooftop PV installed, while including any financial benefits that could be obtained by feeding excess PV generation (if available) back into the grid under different feed-in tariff price scenarios.

2.5 Study limitations and changes made after stakeholder consultations

This report serves as a pre-feasibility study rather than a comprehensive system design ready for immediate implementation. It is important to understand that the analysis presented herein provides a preliminary assessment of potential energy solutions, not a detailed design for system deployment.

Several important limitations should be noted regarding the methodology employed in this study:

- 1 Simplified demand and blackout time series were used and simulated over a year. The same timeseries were also used for each simulation to allow them to be compared to each other, but then requires the exact same blackouts at the same times to occur.
- 2 Upfront costs presented in this report offer a general indication of cost ranges. These figures should not be taken as definitive or absolute values for budgeting purposes and actual installation costs and optimal system sizes could vary significantly.
- 3 The scenarios modelled in this study represent simplified versions of real-world conditions. Actual implementations may face many unforeseen challenges or opportunities not captured in this analysis.

Given these limitations, it is strongly recommended that stakeholders do not rely solely on the numbers presented in this report for system implementation and detailed implementation plan should be developed by engineers experienced with rooftop PV installations in the DRC, taking into account any necessary specific site conditions and local or national regulatory requirements.

4 <https://offgridders.readthedocs.io/en/latest/Home.html>

In response to stakeholder feedback and presentations, several changes were made to the initial analysis which are summarized as follows:

- 1 Expanded scenario modelling:
 - › System setups now include: Genset + grid, PV + genset + grid, PV + genset + storage + grid, PV + storage + grid, Genset + storage + grid.
 - › This allows for comparison of more potential system configurations and for the stakeholders to select from among many scenarios and system sizes.
 - › This also allows for specific systems that exclude or include any specific technologies such as specifically including or excluding battery storage, and or systems that eliminate diesel use even if they may be more expensive.
- 2 Sensitivity analyses were conducted on critical parameters:
 - › PV feed-in tariff: Scenarios at \$0.05/kWh and \$0.069/kWh were evaluated
 - › Fuel price: Analyses were performed at \$1.20/litre, \$1.80/litre and \$2.40/litre
- 3 Increased genset capacity was incorporated into SNEL model as requested after consultation.
 - › The genset at the SNEL compound was set to 635kW, an increase from the initial communication received for an assumption used of 250kW.
 - › This change has key impacts on the optimal system configurations as the diesel generator is now large enough to serve the total load during blackouts without additional battery storage backup and blackouts are not very common at the SNEL compound.

These additions provide a more comprehensive understanding of the potential energy solutions and their sensitivity to various economic and technological factors. Despite these improvements, it remains essential to conduct site-specific studies and consult with local experts before proceeding with any actual system implementation.

2.6 Summary of Key Input Data

2.6.1 Scenarios for Each Building

Table 1. Scenario summary of key variables used for energy system optimisations

Location	System configurations	Installed PV sizes	Demand	Blackouts	Sensitivities
SNEL compound Kinshasa (-4.3179, 15.2766)	genset + grid				
	PV + genset + grid	861.4 kWp: "All Suitable Roofs"	Peak: 599 kW	Duration: 1 hour	PV feed-in tariff: 0.05 & 0.069 \$/kWh
	PV + genset + storage + grid	526.3 kWp: "All Roofs — No Parking"	Total: 3.225 GWh per year	Frequency: 0.6/month	Fuel price: 1.2 & 2.4 \$/litre
	PV + storage + grid	451.2 kWp: "Best Roofs Only"			
	genset + storage + grid				
ISTA compound Kinshasa (-4.3233, 15.3319)	genset + grid				
	PV + genset + grid		Peak: 150 kW	Duration: 1 hour	PV feed-in tariff: 0.05 & 0.069\$/kWh
	PV + genset + storage + grid	512.4 kWp: "All Suitable Roofs"	Total: 0.737 GWh par an	Frequency: 45/month	Fuel price: 1.2, 1.8, 2.4\$/litre
	PV + storage + grid				
	genset + storage + grid				

2.6.2 Key techno-economic input assumptions for energy system optimization modelling

A summary of the most important techno-economic input parameters is included in the table below. Not every parameter is included to improve report clarity. The complete full list of all techno-economic input parameters is shared in the attached excel input sheets.

Table 2: Summary table of most significant input parameters. All parameters included in attached model files.

Parameter	Value	Unit	Link/Source
Solar PV – Investment Cost	441	\$/kW	https://www.esmap.org/mini_grids_for_half_a_billion_people_the_report
Solar PV – O&M Cost	10	\$/kWp/a	https://www.esmap.org/mini_grids_for_half_a_billion_people_the_report
Inverter and EMS	415	\$/kW	https://www.esmap.org/mini_grids_for_half_a_billion_people_the_report

Parameter	Value	Unit	Link/Source
Storage — Investment Cost	314	\$/kWh	https://www.esmap.org/mini_grids_for_half_a_billion_people_the_report
Storage — O&M Cost	10	\$/kWh/a	https://www.esmap.org/mini_grids_for_half_a_billion_people_the_report
Storage — Round-Trip Efficiency	92%	percentage	https://www.esmap.org/mini_grids_for_half_a_billion_people_the_report
Fuel Price — Thermal Generator	[1.2, 1.8, 2.4]	\$/l	https://de.globalpetrolprices.com/Democratic-Republic-of-the Congo (1.2 taken at date of model runs, others used as sensitivities)
Fuel — Energy Value	9.8	kWh/l	https://www.energie-lexikon.info/dieselmkraftstoff.html
Fuel — CO ₂ Emission Factor	2.68	kg CO ₂ eq/l	https://www.umweltbundesamt.de/sites/default/files/medien/1968/publikationen/co2_emission_factors_for_fossil_fuels_correction.pdf
Maingrid — CO ₂ Emission Factor	0.004159	kg CO ₂ eq/kWh	https://ecometrica.com/assets/Electricity-specific-emission-factors-for-grid-electricity.pdf
Maingrid — Electricity Price	0.07	\$/kWh	Assumption — direct communication with SNEL
PV — Feed-in Tariff	[0.05 & 0.699]	\$/kWh	Assumption — values used in scenarios. No official feed-in tariff for grid connected PV currently exists.
Discount Rate	9.6%	percentage	https://www.esmap.org/mini_grids_for_half_a_billion_people_the_report
Project Economic Lifetime	20	years	Assumption. Typical guarantee period and economic lifetime of PV systems. Used in most PV energy system optimisations.

3 Results and discussion

3.1 Site-specific PV generation potential

Following the PV rooftop estimation and modelling approach described in the methodology section 2.2 previously, the results for the two building compounds are presented below. In addition, several of the key input parameters used in the PVGISv5.2 model and rooftop capacity estimations are also included in Table 3. The results showing all individually modelled rooftop areas are shown for the SNEL compound in Figure 2, and for the ISTA compound in Figure 3. Tables summarizing the results for each rooftop are also included for SNEL and ISTA in Table 4 and Table 5 respectively.

The colour scales range from “green” being the “best” performing roofs, and “red” being the “worst” performing roofs, measured by their average annual capacity factors (CF – measured in %). The colours used in the images and tables to distinguish the rooftops are not exact scales and only for visualisation.

The total estimated installable capacity for the SNEL compound is 861.4kWp and for the ISTA compound was 512.4kWp, assuming all areas are filled and conservative assumptions for installable capacity are used (as listed in Table 3).

The mapping files (.gpkg) showing each of the rooftop surfaces and their assumptions and summary results, and the hourly timeseries outputs (.csv) for all modelled roofs for both buildings are shared separately with this report.

Table 3: Summary of Parameters used in the PV rooftop potential and performance calculations

Parameter	Value	Description
PVGIS Model version	5.2	Version of PVGIS used in the analysis. V5.2 was the latest available at the time of the study. Link: PVGIS user manual – European Commission (europa.eu)
Installable area per roof	90%	Factor representing what percentage of the calculated area is realistically possible to completely fill with PV panels.
Shading loss factor	10%	Factor representing shading losses. 10% additional losses assumed for roofs that are expected to have shading from surrounding buildings or trees.
PV capacity installable per usable area	0.1 kW/m ²	Conservative assumption used to assume that a minimum of 0.1 kWp of PV per m ² of rooftop area could be installed. The true amount may be more or less if for e.g. some of the area is not suitable or if more efficient panels are used.
Latitude	“per site”	Latitude of the location (in decimal degrees)
Longitude	“per site”	Longitude of the location (in decimal degrees)

Parameter	Value	Description
System loss factor	14%	Additional other system losses as a fraction, including cabling, inverters, aging, dirt/soiling — not thermal, shading or storage based losses. (PVGIS v5.2 default 14% losses — typical for PV systems of this type).
Roof orientation angle	“specific per roof”	The azimuth, or orientation of the roof, is the angle of the PV modules relative to the direction due South. -90° is East, 0° is South and 90° is West.
Roof tilt angle	“specific per roof”	The angle of the solar panels, specific to each roof. Flat roofs are put to optimal tilt (calculated to be 0 degrees (flat) at this site)
Mounting place	“building mounted”	The location where the PV panels are mounted (building or free field).
PV technology	“crystSi”	PV technology type (e.g., “crystSi” for crystalline silicon). Here only affects system performance and spectral characteristics, not cost.
Radiation database	“PVGIS-SARAH2”	The satellite database used for the calculations to obtain solar radiation components, cloud coverage, windspeed, and ambient temperature (PVGIS-SARAH2).
Historical data year	2014	Historical year of satellite solar irradiation and weather data used for the PV simulation.

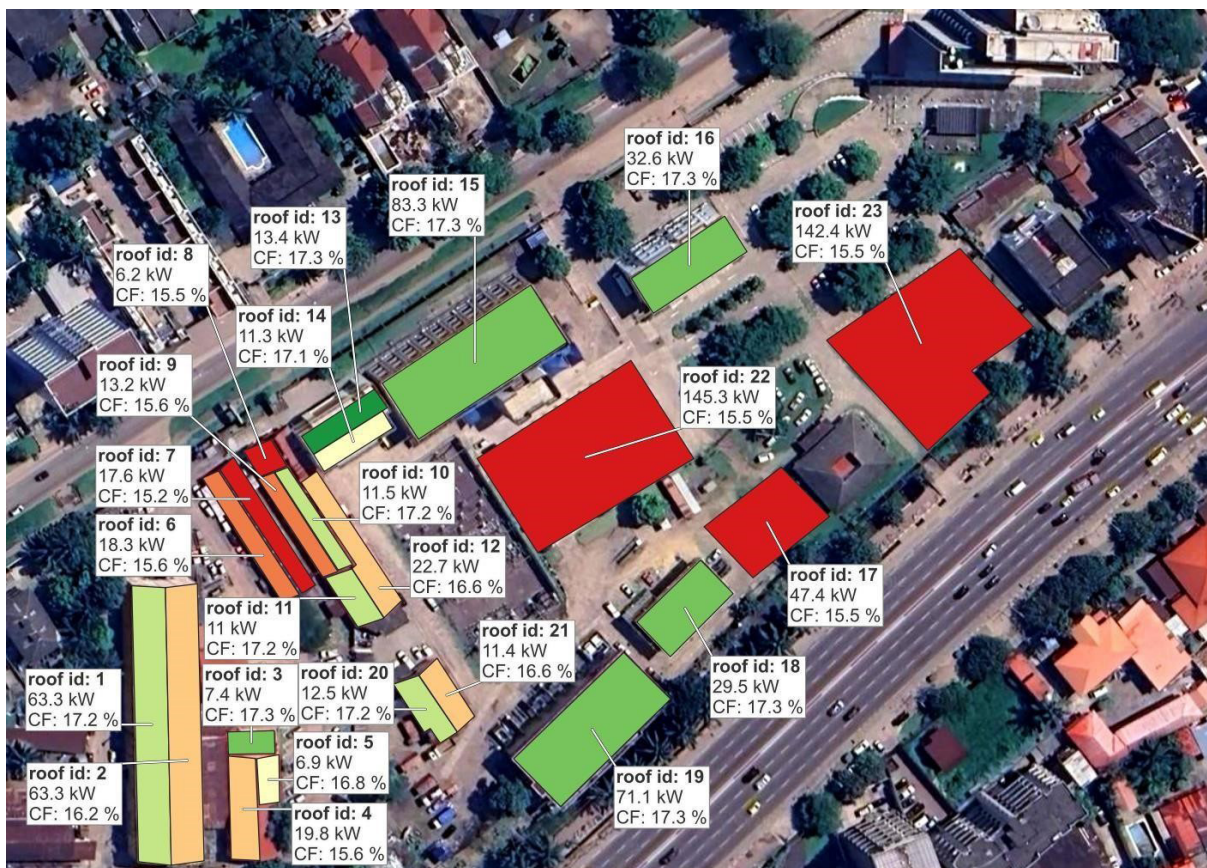


Figure 2: SNEL rooftop PV assessment results including all modelled roofs, estimated installable capacities (kWp), and estimated average annual performance (capacity factor – “CF”). 23 separate PV areas were modelled including 3 parking areas. Maximum total installable capacity is estimated to be 861.4kWp

For the SNEL compound 23 separate PV areas were modelled including 3 parking areas. The best performing rooftop areas achieved an average estimated annual capacity factor of roughly 17.3%. For both building compounds shading had the largest impact on system performance (typically dropping their capacity factors by 1.7% corresponding to the assume 10% shading loss). Panels facing in non-optimal directions (because of rooftops facing in those directions) also have less expected performance, losing up to roughly 1% of their annual capacity factors.

For the SNEL building compound the following PV installation scenarios were created:

- **861.4 kWp – “All Suitable Roofs”**
 - The maximum scenario where all rooftop areas and parking areas are used regardless of their shading losses or if they are not facing optimal directions.
- **526.3 kWp – “All Roofs—No Parking**
 - This scenario uses all rooftop areas regardless of performance but excludes the parking areas since parking area PV is not always possible in the specific situation and the parking areas being surrounded by buildings are expected to have shading losses.

- **451.2 kWp —“Best Roofs Only”**

- › In this scenario only the best roofs that are not expected to have any shading and are facing the optimal directions are used (with a typical capacity factor of ~17.3%).

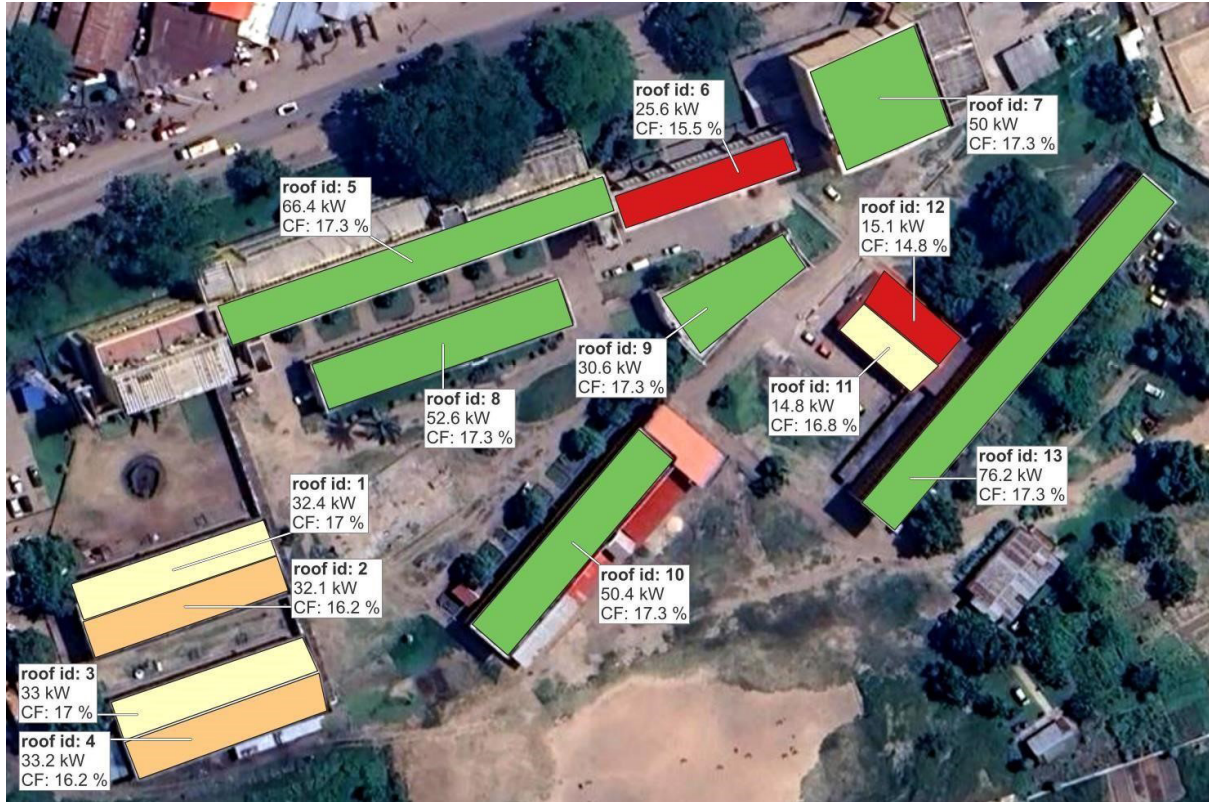


Figure 3: ISTA rooftop PV assessment results including all modelled roofs, estimated installable capacities (kWp), and estimated average annual performance (capacity factor — “CF”). Thirteen separate PV areas were modelled, no suitable parking areas were identified for PV installation. Maximum total installable capacity is estimated to be 512.4kWp.

For the ISTA building 13 separate PV areas were modelled on rooftops in the compound that were considered suitable for PV installation. Only a single scenario was modelled that combines all possible rooftop PV installation capacities into a 512.4kWp PV system. Removing the worst performing roofs and creating new scenarios for this did not change the total capacity significantly and therefore did not change the final energy system results meaningfully. Only actual “rooftops” were modelled for PV installation at the ISTA compound, and therefore no parking areas were modelled and the open areas used for a basketball court and football pitch were not assumed to be available or repurposed for PV installations.

Table 4: SNEL — Individual rooftop results data in summary table

Roof id	Area (m ²)	Orientation of roof (deg)	Roof tilt angle (deg)	Shading likely	Capacity factor (%)	installable PV (kWp)
13	149	150	5	No	17.3%	13.4
3	82	-180	0	No	17.3%	7.4

Roof id	Area (m ²)	Orientation of roof (deg)	Roof tilt angle (deg)	Shading likely	Capacity factor (%)	installable PV (kWp)
15	926	150	0	No	17.3%	83.3
16	362	150	0	No	17.3%	32.6
18	328	135	0	No	17.3%	29.5
19	790	135	0	No	17.3%	71.1
10	128	70	15	No	17.2%	11.5
11	122	70	15	No	17.2%	11
20	138	70	15	No	17.2%	12.5
1	703	90	20	No	17.2%	63.3
14	126	-30	5	No	17.1%	11.3
5	77	-90	10	No	16.8%	6.9
12	252	-110	15	No	16.6%	22.7
21	126	-110	15	No	16.6%	11.4
2	703	-90	20	No	16.2%	63.3
4	220	90	10	Yes	15.6%	19.8
9	146	70	5	Yes	15.6%	13.2
6	203	70	10	Yes	15.6%	18.3
17	527	140	0	Yes	15.5%	47.4
22	1615	150	0	Yes	15.5%	145.3
23	1582	150	0	Yes	15.5%	142.4
8	69	70	15	Yes	15.5%	6.2
7	195	-110	10	Yes	15.2%	17.6
					Total (kWp)	861.4

Table 5: ISTA – Individual rooftop results data in summary table

Roof id	Area (m ²)	Orientation of roof (deg)	Roof tilt angle (deg)	Shading likely	Capacity factor (%)	installable PV (kWp)
5	738	160	0	No	17.3%	66.4
7	556	160	0	No	17.3%	50
8	584	160	0	No	17.3%	52.6
9	34	150	0	No	17.3%	30.6
10	560	130	0	No	17.3%	50.4
13	846	130	0	No	17.3%	76.2
1	360	160	20	No	17.0%	32.4
3	367	160	20	No	17.0%	33
11	165	40	20	No	16.8%	14.8
2	357	-20	20	No	16.2%	32.1
4	369	-20	20	No	16.2%	33.2
6	285	160	0	Yes	15.5%	25.6
12	168	-130	20	Yes	14.8%	15.1
					Total (kWp)	512.4

3.2 Demand profiles for SNEL and ISTA

The hourly electricity demand profiles are a key input into the energy system modelling and are shown for SNEL and ISTA below in Figure 4. The demand profiles show one-week typical week, with weekend and weekday days shown, this profile is repeated for a full year of 8760 hours.

The profile for the SNEL building has a 598.8 kW peak demand, with a total annual demand of 3.225 GWh per year. Saturdays and Sundays are assumed to be “weekend” and are assumed to have a flat demand profile equivalent to that of the nighttime load. The key input data shared by SNEL is also shown in Figure 5 for reference.

At the ISTA building compound a 150kW peak demand is assumed, with a total annual demand of 0.737 GWh per year. Here only Sundays are assumed to be “weekend” as assumed in the shared on-site measured data report, and again the minimum nighttime load is assumed for the weekend day. The hourly profile used in this modelling (overlaid in red) is compared to the 1-minute resolution data plot (blue) from the report shared by ISTA in Figure 6.

Electricity Demand Profiles - SNEL & ISTA Compounds

1 Week shown with 'Weekdays' and 'Weekend' - Full Year Modelled

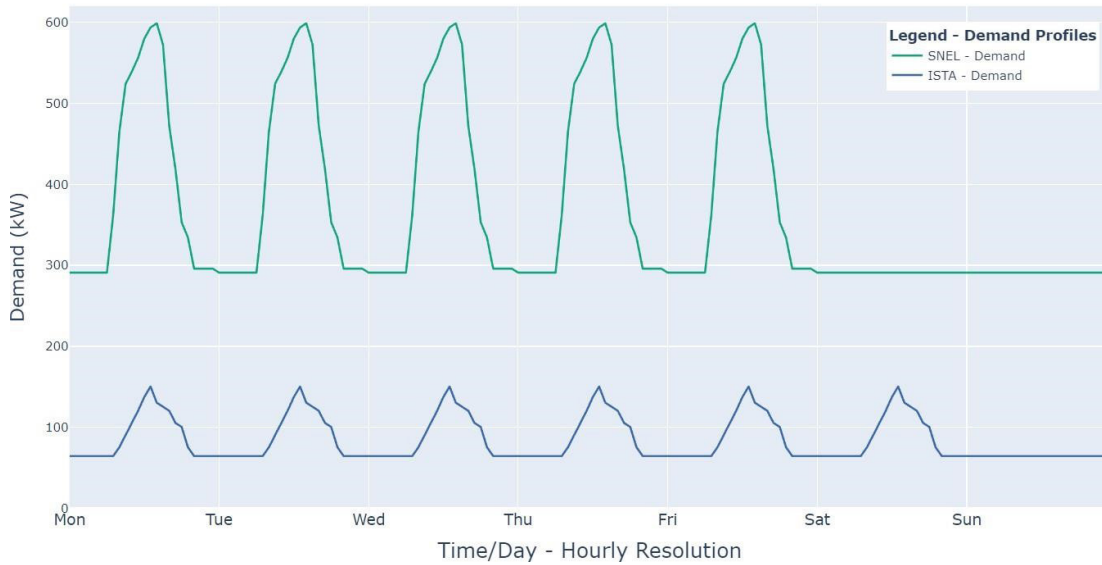
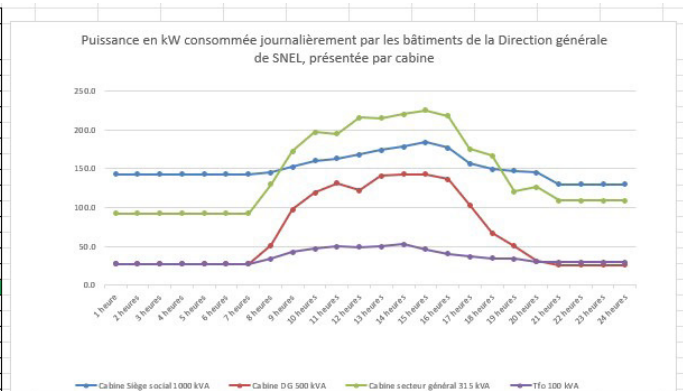


Figure 4. Modelled demand profile for SNEL and ISTA, showing 1 week, with weekend and weekday typical days shown (full year modelled). SNEL - 598.8 kW peak demand is assumed with a total annual demand of 3.225 GWh per year. ISTA - 150kW peak demand is assumed with a total annual demand of 0.737 GWh per year.

Courant (A)					
heure	Cabine SIEGE SOCIAL 1000 kVA	Cabine DG 500 kVA	Cabine SECTEUR GENERAL	Cabine SERV. AUX 100 kVA	Total courant Siège DG
heure	256.33	49	165	49.33	519.66
1 heures	256.33	49	165	49.33	519.66
2 heures	256.33	49	165	49.33	519.66
3 heures	256.33	49	165	49.33	519.66
4 heures	256.33	49	165	49.33	519.66
5 heures	256.33	49	165	49.33	519.66
6 heures	256.33	49	165	49.33	519.66
7 heures	256.33	49	165	49.33	519.66
8 heures	256.33	49	165	49.33	519.66
9 heures	256.33	49	165	49.33	519.66
10 heures	259.66	92	233	61	645.66
11 heures	272	174.66	308	76.33	830.99
12 heures	287.33	213.33	352.33	83.66	936.65
13 heures	292	234.66	348	89	963.66
14 heures	301	218.66	386	88.33	993.99
15 heures	310.66	251.33	385	89.33	1036.32
16 heures	318.33	255.33	393.33	94	1060.99
17 heures	328.66	255.33	403	83.33	1070.32
18 heures	316.33	244.33	390	72.66	1023.32
19 heures	279.66	184.33	314	66	843.99
20 heures	267.33	120.33	298.33	62	747.99
21 heures	263	90.33	216.33	61	630.66
22 heures	259.66	56	226.66	55	597.32
23 heures	232.66	47	195.33	53.33	528.32
24 heures	232.66	47	195.33	53.33	528.32



Puissance en kW					
heure	Cabine SIEGE SOCIAL 1000 kVA	Cabine DG 500 kVA	Cabine SECTEUR GENERAL	Cabine SERV. AUX 100 kVA	Total Puissance siège SNEL
heure	143.4	27.4	92.3	27.6	290.7
1 heures	143.4	27.4	92.3	27.6	290.7
2 heures	143.4	27.4	92.3	27.6	290.7
3 heures	143.4	27.4	92.3	27.6	290.7
4 heures	143.4	27.4	92.3	27.6	290.7
5 heures	143.4	27.4	92.3	27.6	290.7
6 heures	145.3	51.5	130.3	34.1	361.2
7 heures	152.2	97.7	172.3	42.7	464.9
8 heures	160.7	119.3	197.1	46.8	524.0
9 heures	163.4	131.3	194.7	49.8	539.1
10 heures	168.4	122.3	215.9	49.4	556.1
11 heures	173.8	140.6	215.4	50.0	579.8
12 heures	178.1	142.8	220.0	52.6	593.6
13 heures	183.9	142.8	225.5	46.6	598.8
14 heures	177.0	136.7	216.2	40.6	572.5
15 heures	156.5	103.1	175.7	36.9	472.2
16 heures	149.6	67.3	166.9	34.7	418.5
17 heures	147.1	50.5	121.0	34.1	352.8
18 heures	145.3	31.3	126.8	30.8	334.2
19 heures	130.2	26.3	109.3	29.8	295.6

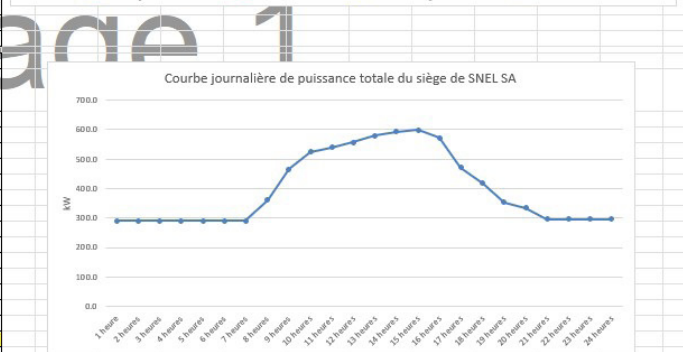


Figure 5. Screenshot from shared measured SNEL demand data for 1 day used to create annual demand profile.

ST (1 min) VA

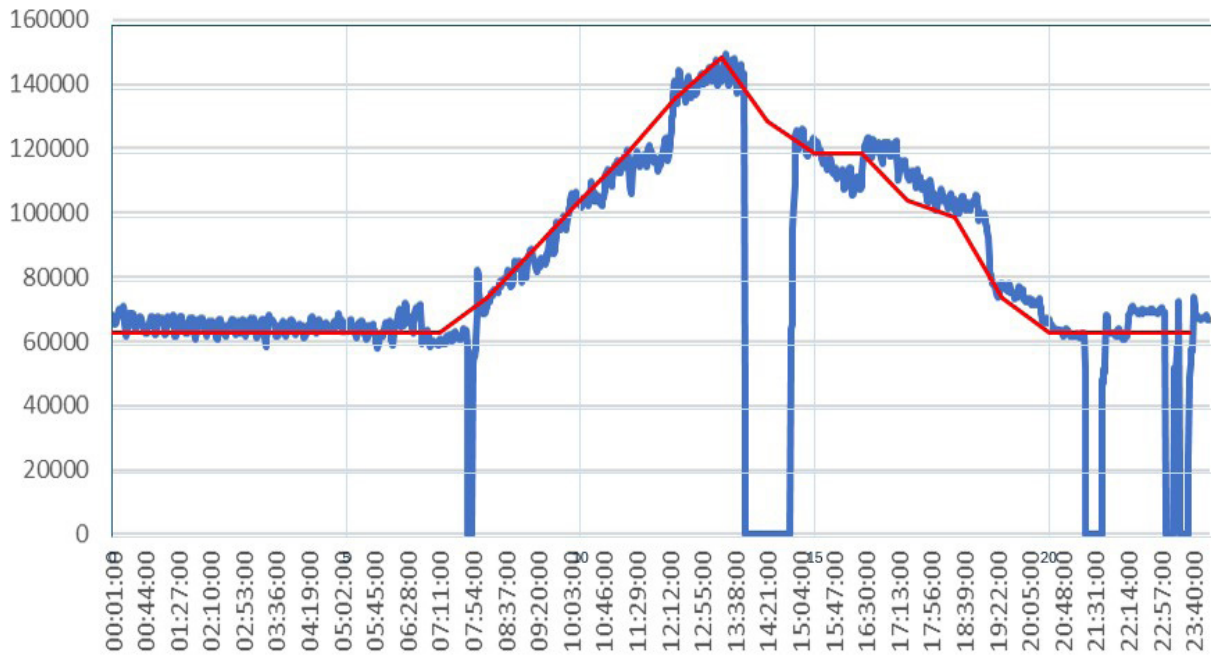


Figure 6. Estimated hourly profile for weekday overlaid onto 1-minute measured data from ISTA compound. 150kW peak demand is assumed with a total annual demand of 0.737 GWh.

3.3 Blackout assumptions for SNEL and ISTA

The electricity blackout assumptions used in the modelling for SNEL and ISTA are shown in Figure 7 and Figure 8 below. At the SNEL compound blackout timeseries were created with a duration of 1 hour and an average frequency of 0.6/month. At the ISTA building the duration was also assumed to be 1 hour but are much more common with a frequency of 45/month. The data used for these blackout assumptions was taken from data shared by SNEL and ISTA respectively. Blackout durations in the model need to be a multiple of 1 hour and cannot be a fraction of an hour as the maximum resolution of the model is 1 hour.

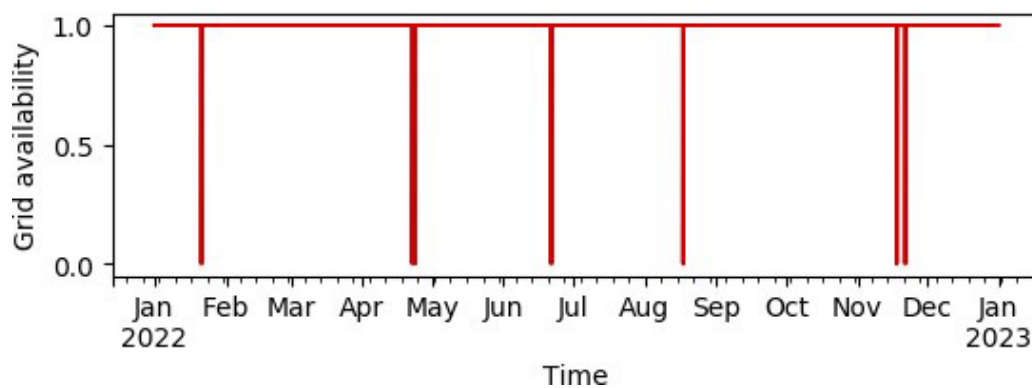


Figure 7. Annual grid availability profile for SNEL compound

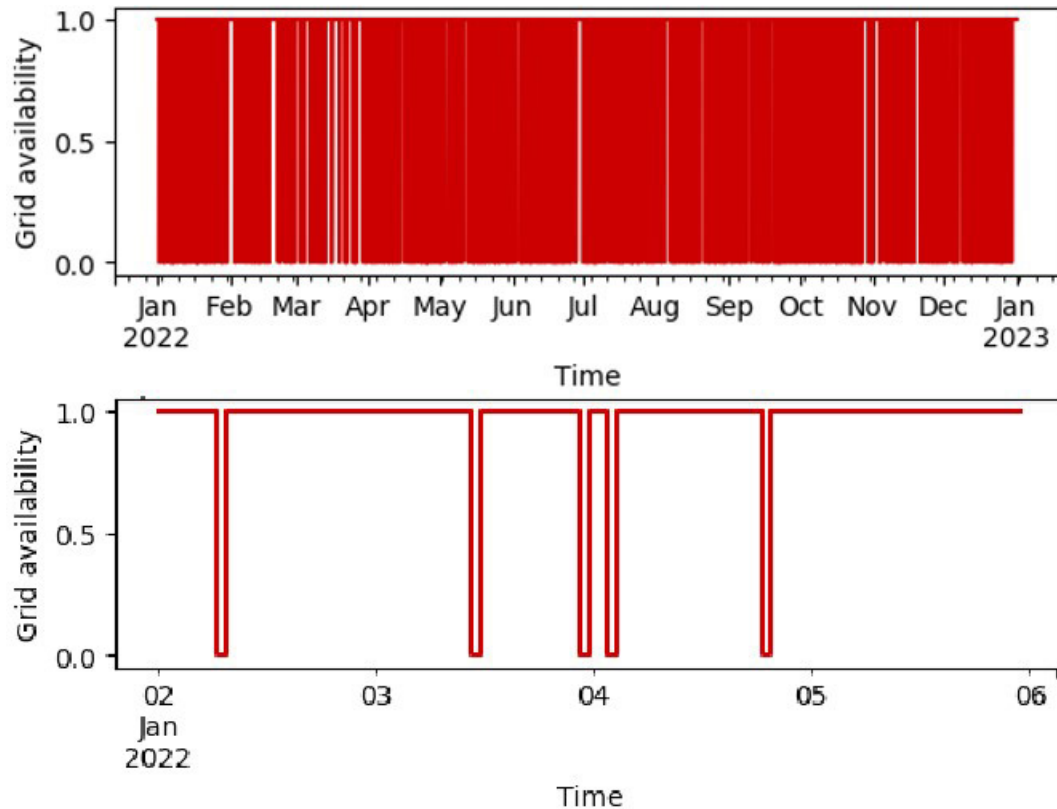


Figure 8. Annual (top) and weekly (bottom) grid availability profile for ISTA compound

3.4 Energy Modelling Optimization Results

The energy system modelling results presented in this section explore the interactions involved in incorporating photovoltaic (PV) systems and storage solutions for a building, with a particular focus on the implications for optimal system component sizes (PV size, battery size etc), initial investment costs, and operational aspects such as fuel use, energy autonomy, and sales of excess energy back to the grid with a feed-in tariff. Many different system configurations were tested combining different technology options, and several sensitivities on input variables were included to see if and how much those variables impacted the results.

Not every single configuration or sensitivity will be discussed in detail and where possible the results of “redundant” systems/configurations/sensitivities that had no impact on the configurations were specifically not included in the SNEL results table (Table 7) to reduce data clutter. The ISTA results table (Table 9) includes all of them for completeness, however both compounds were tested for all system configurations and sensitivities listed. The scenario table presented in Table 1 is also repeated (with the same information) at the start of each of the building compounds results section with only the scenarios and inputs for that specific compound for ease of reference with the results. The various model input and output files including technoeconomic assumptions, rooftop PV map data, hourly solar generation profiles, as well as full model output breakdowns and hourly timeseries files are made available and attached separately to the report. Many more inputs and outputs than are realistic to discuss in full detail in the report are available in these files and if the reader wishes

to find more specific details about system configurations, performance metrics, cost breakdowns etc, they are available.

The hourly timeseries outputs that are a result from the system optimisation and dispatch are shown in Figure 9 and Figure 10 below for demonstration and many summary statistic results that are tabulated later like fuel use, autonomy factor are calculated from these timeseries over the whole year.

Four days of system operation from the PV + Genset + Grid configuration (no storage) for both the maximum (top figure) and minimum PV scenarios (bottom figure) at the SNEL site are demonstrated in Figure 9 below. The demand (in green) can be seen over the days starting from a Sunday with a flat demand and moving into the week, the daily daytime PV generation (in yellow) in the maximum scenario reaches a similar output to the total demand during the daytime peak but naturally does not supply power during the night and is not enough to achieve full energy autonomy even in the maximum PV case. PV is used first for own consumption and otherwise if the grid is available the main grid is used to supply the remaining demand (dark purple) During the day on the weekend and for some hours in the week there is some excess PV that is fed back into the main grid with a feed-in tariff benefit (in pink). In the bottom figure the smallest PV scenario where only the best roofs are used shows that typically only for a few hours around midday on weekends is there just enough excess PV to feed back into the grid otherwise during the week there is never excess available, and all PV is used for own consumption.

In Figure 10 a full year is shown and for the same maximum PV scenario, but for a scenario that specifically includes battery storage as a replacement for the diesel generator with enough capacity to provide the demand during the modelled random blackouts (red) – the diesel generator is now allowed to be used in this specific scenario. The storage state of charge (blue) is tracked for every hour of the year and cycles up and down based on if there is excess PV above the demand to charge the battery, if the battery is full (which happens many times over the year) then the excess PV is fed back into the main grid for a feed-in tariff.

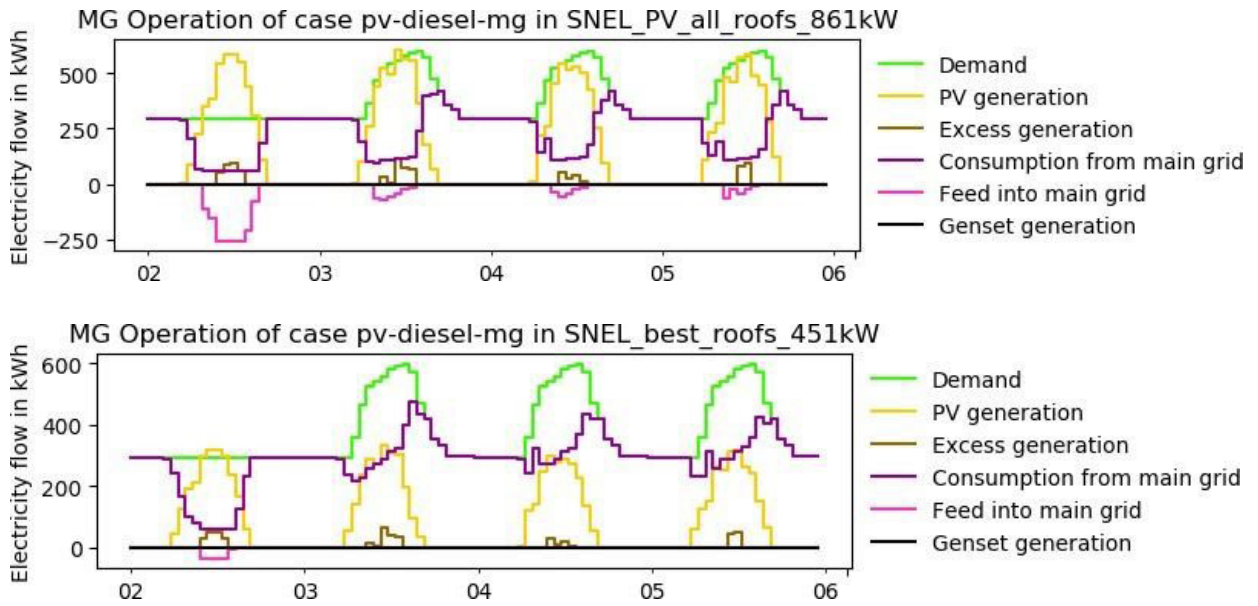


Figure 9: SNEL Hourly modelling outputs for three different scenarios demonstrating the hourly operation dynamics for 4 days (of full year). Top: All roofs PV, no storage scenario. Bottom: “Best PV” roofs only, no storage.

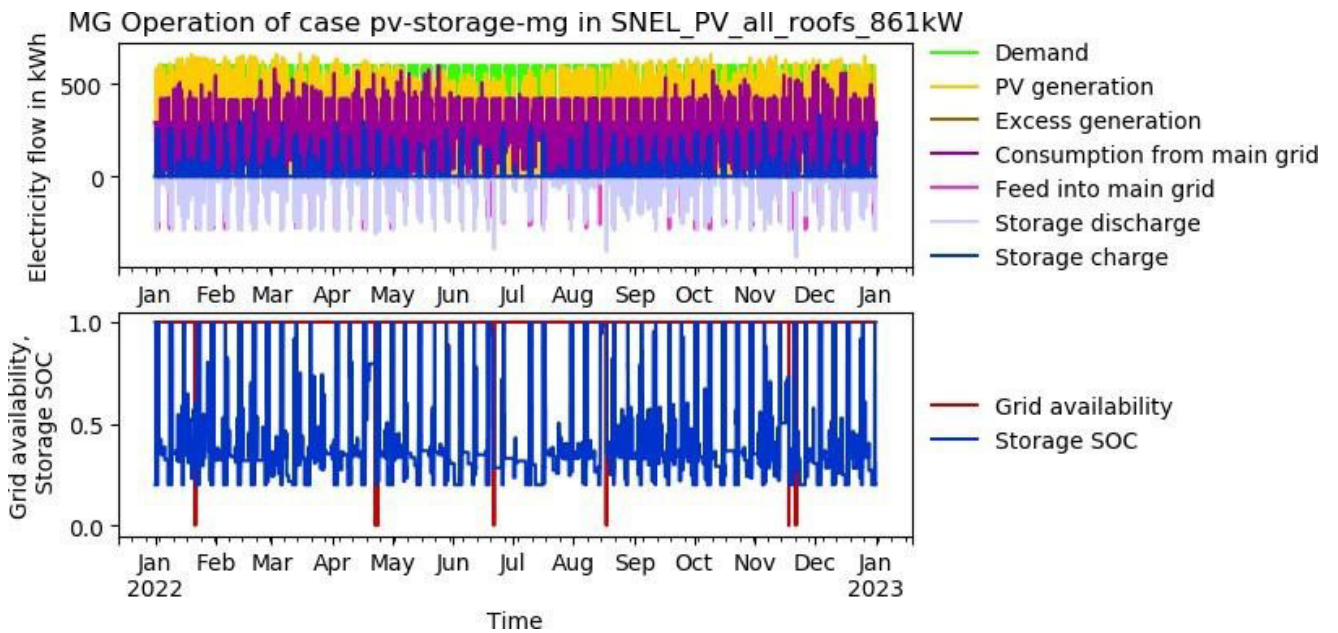


Figure 10: SNEL Hourly modelling outputs for full year of the scenario with “All Roofs PV” (861kW), with battery storage (695.2kWh), and no diesel scenario. Full 365 days hourly profile and storage and blackout timeseries shown.

3.4.1 Results: SNEL compound Kinshasa

The key results from the energy system optimization modelling analysis for the SNEL compound are presented in this section and the key output variables are summarized in Table 7 below, which shows the most significant system configuration results, combining the existing grid connection, the

three different solar PV capacity installation size scenarios, battery storage options, and the existing backup genset system of 635kW.

Table 6 lists again all of the scenarios, configurations, sensitivities and other key input variables for the SNEL compound for ease of reference. All system configurations are required to meet all the demand in all hours of the day of the assumed demand timeseries, even during grid blackouts. All system configurations were tested with PV feed-in tariff levels of 0.05 \$/kWh and 0.069 \$/kWh and fuel prices of 1.2 & 2.4 \$/litre. The “Grid + Genset” scenario is also included in the results which estimates the current building energy system and serves as a “baseline” to compare the other scenarios against.

The results summary in Table 7 only shows the most relevant results and configurations, and specifically excludes the configurations and sensitivities that had no impact on the key output variables listed. E.g. no configurations with storage that also have the genset available and the table only shows the results for the fuel price of 1.2 \$/kWh as the optimal system configurations do not change compared to the configurations and sensitivities that are already listed in the table.

Several of the same results as those listed in the table are also shown graphically and for visual comparison in chart format for the various scenarios in Figure 11, Figure 12, and Figure 13.

Table 6. (SNEL only) – Scenario summary of key variables used for energy system optimisations

Location	System configurations	Installed PV sizes	Demand	Blackouts	Sensitivities
SNEL compound Kinshasa (-4.3179, 15.2766)	genset + grid (“baseline”)				
	PV + genset + grid	861.4 kWp: “All Suitable Roofs”	Peak: 599 kW	Duration: 1 hour	PV feed-in tariff: 0.05 & 0.069 \$/kWh
	PV + genset + storage + grid	526.3 kWp: “All Roofs – No Parking”	Total: 3.225 GWh per year	Frequency: 0.6/month	Fuel price: 1.2 & 2.4 \$/litre
	PV + storage + grid	451.2 kWp: “Best Roofs Only”			
	genset + storage + grid				

Location	System configurations	Installed PV sizes	Demand	Blackouts	Sensitivities
ISTA compound Kinshasa (-4.3233, 15.3319)	genset + grid	512.4 kWp: "All Suitable Roofs"	Peak: 150 kW Total: 0.737 GWh par an	Duration: 1 hour Frequency: 45/month	PV feed-in tariff 0.05 & 0.069 \$/kWh Fuel price: 1.2, 1.8, 2.4 \$/litre
	PV + genset + grid				
	PV + genset + storage + grid				
	PV + storage + grid				
	genset + storage + grid				

Table 7. Building energy system modelling results for SNEL compound for the most significant system configurations with a diesel price of 1.2 \$/litre.

System configurations	PV system size (kWp)	PV feed-in tariff	Battery storage sapacity (kWh)	System autonomy factor (%)	Fuel use per year (l)	PV upfront cost (USD)	Battery upfront cost (USD)	Inverter upfront cost (USD)	Total upfront cost (USD)	
grid + genset ("baseline")	0	0	0	0.1 %	1019 l	N/A	N/A	N/A	N/A	
PV + storage + grid	861.4	0.069 \$/kWh	695.2	35.0 %	0 l	443,114	337,227	291,247	1,071,588	
	526.3		763.3	23.7 %	0 l	270,734	370,247	291,247	932,228	
	451.2		782.4	20.8 %	0 l	232,102	379,496	291,247	902,845	
PV + genset + grid	861.4		0	31.6 %	688 l	443,114	0	249,287	692,401	
	526.3		0	22.2 %	811 l	270,734	0	157,136	427,87	
	451.2		0	19.7 %	839 l	232,102	0	136,702	368,804	
PV + storage + grid	861.4		0.05 \$/kWh	695.2	36.5 %	0 l	443,114	337,227	291,247	1,071,588
	526.3			763.3	24.0 %	0 l	270,734	370,247	291,247	932,228
	451.2			782.4	20.8 %	0 l	232,102	379,496	291,247	902,845
PV + genset + grid	861.4	0		31.6 %	688 l	443,114	0	234,296	677,41	
	526.3	0		22.2 %	811 l	270,734	0	154,454	425,188	
	451.2	0		19.7 %	839 l	232,102	0	134,031	366,133	

The existing "Grid + Genset" configuration represents the "baseline scenario" of the current building energy system with a grid connection and the 635kW backup genset, which with the assumed blackout data is expected to consume roughly 1019 litres of fuel annually, and achieves an "autonomy factor" of 0.1% due to the roughly 0.1% of annual electricity demand delivered with on-site generation from the backup genset during blackouts. This system receives 99.9% of its electricity from the grid.

Importantly, for the SNEL compound, the model does not select battery storage as an economic alternative to using the diesel genset, if it is available. This is a key difference to earlier results presented in this study that assumed that only a 250kW genset was available. Since this was updated to a 635kW genset, the model prefers to use the genset to cover the demand during blackouts, which for the SNEL building are not very common and do not last for very long durations. The additional benefit of storing excess PV in the battery, and using it during blackouts, does not fully make up for the costs of investment and low utilization, as excess PV can also be sent back to the grid with the feed-in tariff for an attractive price and there is not a large amount of excess PV available even in the largest PV system.

However, since it is an interesting option to consider replacing the genset with a battery backup system configurations were included (PV + storage + grid) that remove the genset, to see how much battery storage would be needed, what it would cost, and how the system results would change.

When adding storage to the systems with PV, fuel consumption drops to zero. For the PV capacities tested ranging from 451.2 kWp to 861.4 kWp, the resulting optimal storage capacities change slightly from 782.4kWh to 695.2 kWh. As the PV capacity decreases, battery sizes are required to increase slightly to be able to store enough energy from the PV system and grid charging to be able to meet the demand during the simulated blackouts.

System autonomy factors also improve with larger PV and battery systems, reaching a maximum of 36.5%. Importantly, this shows that even when installing PV to the maximum capacity on every available rooftop and parking area, and including storage backup systems to maximize own use, there is not enough generation potential to achieve complete energy autonomy using PV systems alone.

Configurations that include the PV system combined with the grid and the backup genset maintain fuel consumption (ranging from 688 to 839 liters annually) and have lower autonomy compared to storage systems. This setup eliminates battery costs, reducing total upfront investment, but requires fuel expenditure for the genset.

Changing the feed-in tariff (e.g., \$0.069/kWh and \$0.05/kWh) does not affect the storage sizes (in the scenarios that include batteries) and also do not change the fuel consumption, but slightly reduces the system autonomy factor as slightly more PV is sold back to the grid, and a slightly larger inverter is also needed to be able to send the full excess amount onto the grid.

CO₂ emissions were not the focus of the study, but their results were included in the charts in Figure 13 for reference. This could potentially be worth looking into in more detail for the potential to receive “carbon credits” for the PV installations (and even more for the systems with batteries eliminating diesel completely). This might improve the economics of the system slightly, however the diesel generator is only used quite rarely so it may also not have a highly significant impact on the overall system cost.

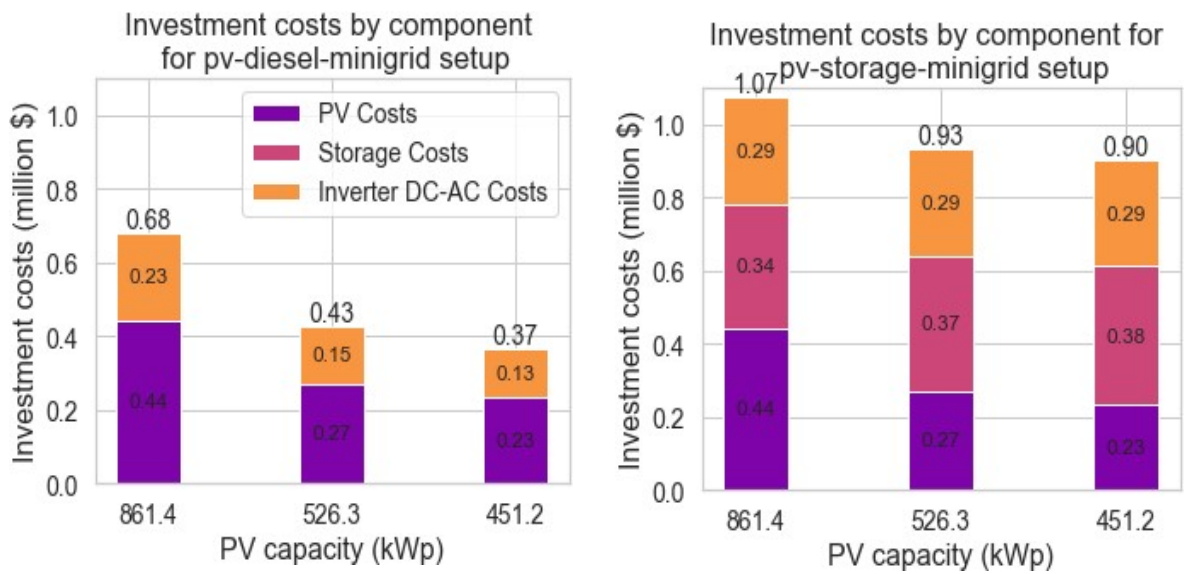


Figure 11. System component investment costs by PV capacity for a PV-diesel-minigrad system (left) and a PV-storage-minigrad system (right)

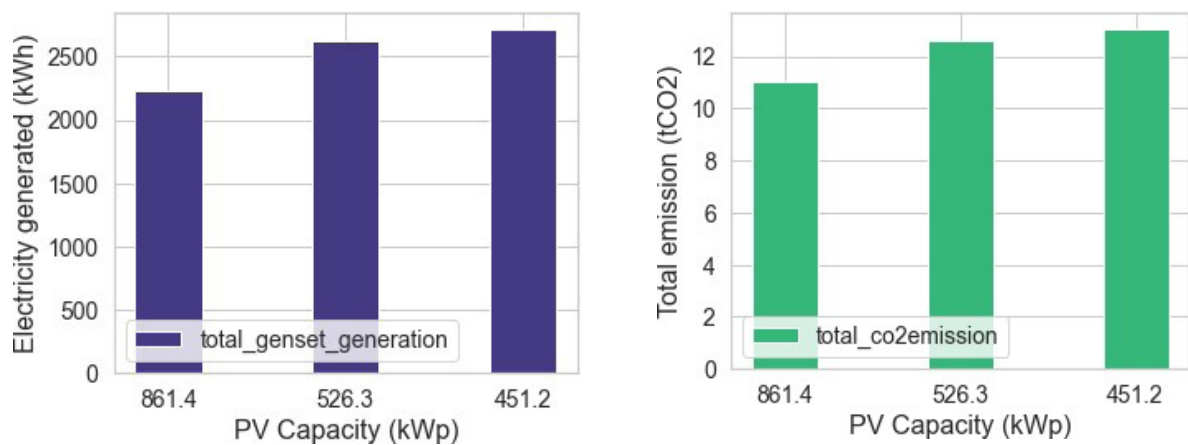


Figure 12. Annual generated/used electricity amount by PV capacity for a PV-diesel-minigrad system (left) and a PV-storage-minigrad system (right)

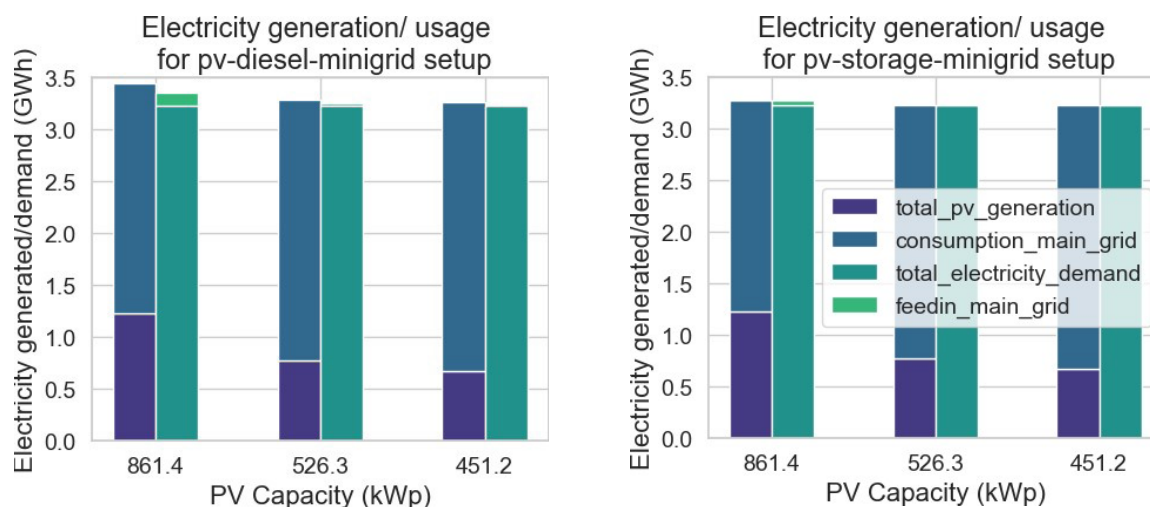


Figure 13. Annual generated electricity from diesel (left) and total CO2 emissions (right) by PV capacity for a pv-diesel-minigrid setup

3.4.2 Results: ISTA university compound Kinshasa

Similarly to the SNEL compound results section above for the ISTA compound the scenario variables are repeated for reference in Table 8 and the key results summary variables are included in Table 9. For the ISTA compound the full list of summary results for all system configurations and all sensitivities is included even if the results between certain combinations are exactly the same. This demonstrates that there is no impact when that is the case, but creates a much bigger and cluttered table with redundant information. Including the full table here also demonstrates which kind of redundant results were excluded from the SNEL table in the previous section. Alternative chart formats for the storage and fuel consumption results for each system configuration are included in Figure 14.

Table 8: Scenario summary of key variables used for energy system optimisations

Location	System configurations	Installed PV sizes	Demand	Blackouts	Sensitivities
ISTA compound Kinshasa (-4.3233, 15.3319)	genset + grid ("baseline")	512.4 kWp: "All Suitable Roofs"	Peak: 150 kW Total: 0.737 GWh par an	Duration: 1 hour Frequency: 45/month	PV feed-In tariff 0.05 & 0.069\$/kWh Fuel price: 1.2, 1.8, 2.4\$/litre
	PV + genset + grid				
	PV + genset + storage + grid				
	PV + storage + grid				
	genset + storage + grid				

Table 9: Building energy system modelling results for ISTA compound for all system configurations and sensitivities.

System configurations	PV system size (kWp)	PV feed-in tariff	Fuel price (USD/l)	Battery storage capacity (kWh)	System autonomy factor (%)	Fuel use per year (l)	PV upfront cost (USD)	Battery upfront cost (USD)	Inverter upfront cost (USD)	Total upfront cost (USD)
PV + storage + grid	512.4	0.069 \$/kWh	1.2	388.2	57.7	0	263,584	188,278	129,236	581,098
	512.4		1.8	388.2	57.7	0	263,584	188,278	129,236	581,098
	512.4		2.4	388.2	57.7	0	263,584	188,278	129,236	581,098
PV + genset + grid	512.4		1.2	0	43.5	8,282	263,584	0	151,707	415,291
	512.4		1.8	0	43.5	8,282	263,584	0	151,707	415,291
	512.4		2.4	0	43.5	8,282	263,584	0	151,707	415,291
PV + storage + genset + grid	512.4		1.2	67.4	49.9	2,171	263,584	32,677	149,002	445,263
	512.4		1.8	101.0	50.6	738	263,584	49,016	146,797	459,397
	512.4		2.4	101.0	50.6	738	263,584	49,016	146,797	459,397
storage + genset + grid	0	1.2	0	5.9	13,531	0	0	0	0	
	0	1.8	67.4	2.1	5,615	0	32,677	26,048	58,725	
	0	2.4	101.0	0.7	2,868	0	49,016	39,072	88,088	
grid + genset ("baseline")	0	1.2	0	5.9	13,531	0	0	0	0	
	0	1.8	0	5.9	13,531	0	0	0	0	
	0	2.4	0	5.9	13,531	0	0	0	0	

System configurations	PV system size (kWp)	PV feed-in tariff	Fuel price (USD/l)	Battery storage capacity (kWh)	System autonomy factor (%)	Fuel use per year (l)	PV upfront cost (USD)	Battery upfront cost (USD)	Inverter upfront cost (USD)	Total upfront cost (USD)
PV + storage + grid	512.4	0.05 \$/kWh	1.2	388.2	62.1	0	263,584	188,278	116,334	568,196
	512.4		1.8	388.2	62.1	0	263,584	188,278	116,334	568,196
	512.4		2.4	388.2	62.1	0	263,584	188,278	116,334	568,196
PV + genset + grid	512.4		1.2	0	43.5	8,282	263,584	0	134,279	397,863
	512.4		1.8	0	43.5	8,282	263,584	0	134,279	397,863
	512.4		2.4	0	43.5	8,282	263,584	0	134,279	397,863
PV + storage + genset + grid	512.4		1.2	67.4	51.1	2,171	263,584	32,677	132,045	428,306
	512.4		1.8	101.0	51.8	738	263,584	49,016	130,723	443,323
	512.4		2.4	101.0	51.8	738	263,584	49,016	130,723	443,323
storage + genset + grid	0		1.2	0	5.9	13,531	0	0	0	0
	0		1.8	67.4	2.1	5,615	0	32,677	26,048	58,725
	0		2.4	101.0	0.7	2,868	0	49,016	39,072	88,088
grid + genset ("baseline")	0	1.2	0	5.9	13,531	0	0	0	0	
	0	1.8	0	5.9	13,531	0	0	0	0	
	0	2.4	0	5.9	13,531	0	0	0	0	

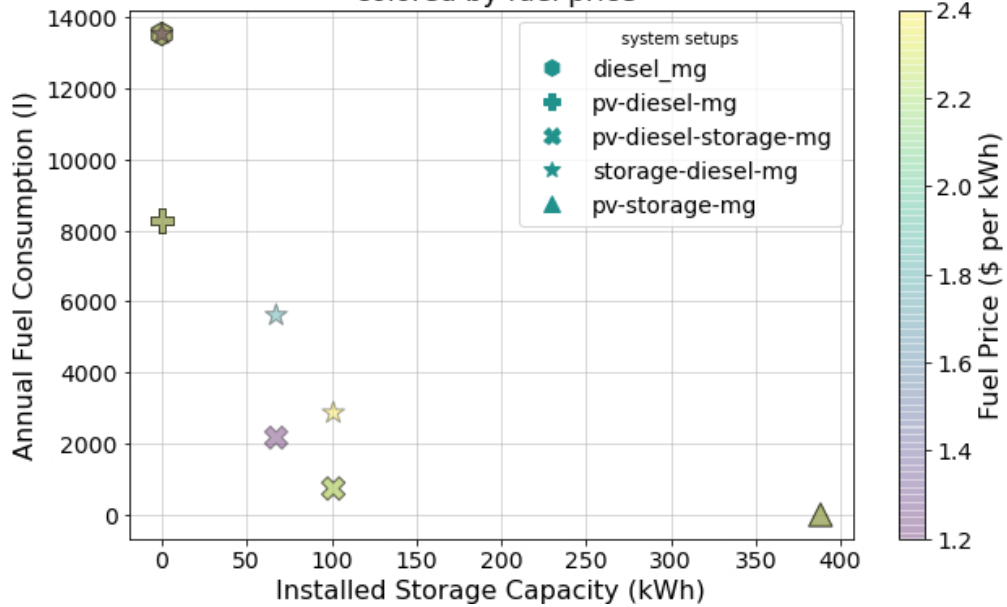
The results for the ISTA compound are somewhat different to the SNEL compound, which seems to come mostly from the assumptions of more frequent blackouts, and therefore more expected diesel use in the “baseline scenario”. The maximum installable PV scenario in the ISTA case also provides a larger amount of excess PV as the ISTA estimated demand is much lower than the SNEL case. This then impacts the system configurations and overall system economics more as there is more genset fuel use to be reduced and there is also more potential excess PV generation available to be stored in batteries, both of which increase the economic attractiveness of PV+Storage backup systems compared to at the SNEL compound. The scenarios tested here also assume that all demand during blackouts is supplied in each case, which is needed to be able to have all scenarios be comparable to each other. This demand during grid blackouts is supplied either by the genset, or by any of the combinations of genset+PV+storage, which for the baseline scenario assumes 13,531 litres of fuel which is likely higher than in reality, as it is likely that some of that demand is instead “lost” during grid blackout scenarios by only supplying priority loads.

The PV system size tested for ISTA is smaller than the SNEL compound, but since the demand is much lower than the SNEL compound the system is able to achieve much higher system autonomy factors which reach 62.1% in the highest case that excludes the diesel generator and uses more PV for own consumption through storage. The combination of allowing the system to select from all available options (PV + storage + genset + grid) does still achieve a roughly 50% to 52% autonomy factor. These results suggest that a large amount of the demand could be supplied if the entire PV rooftop system is installed with storage systems, however it is still very far from being fully autonomous and would require a large investment to achieve this autonomy factor.

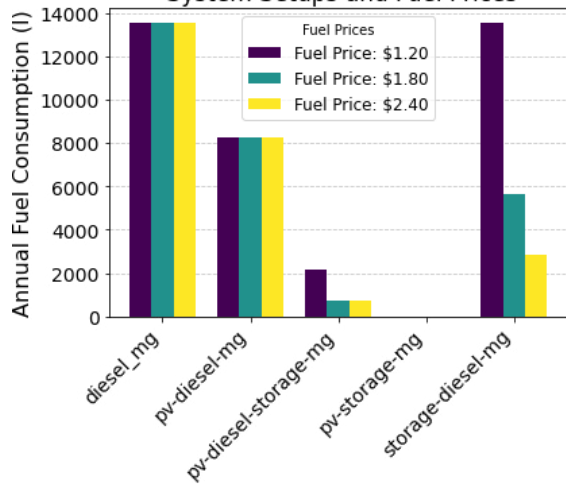
Contrasting to the SNEL salutation the cost sensitivities of genset fuel does influence the optimal system setups at ISTA. This demonstrates that if the cost of fuel increases it will become increasingly attractive to install storage to complement and increase own PV usage and reduce fuel expenditure over the 20 year lifetime of the PV+storage system, but would require a large upfront investment compared to the incremental but expensive expected future diesel use.

Similarly to the SNEL case the feed-in tariff prices tested have a minimal impact on the sizes of the different components installed with just a small increase in the inverter size, but otherwise affects the system autonomy factor by a small amount as slightly more PV is instead fed back into the grid rather than stored for own consumption when the feed-in tariff is set to the highest value representing a “net metering” scenario.

Annual fuel consumption for installed storage capacities for all system setups colored by fuel price



Annual Fuel Consumption across Different System Setups and Fuel Prices



Optimised Storage Capacities across Different System Setups and Fuel Prices

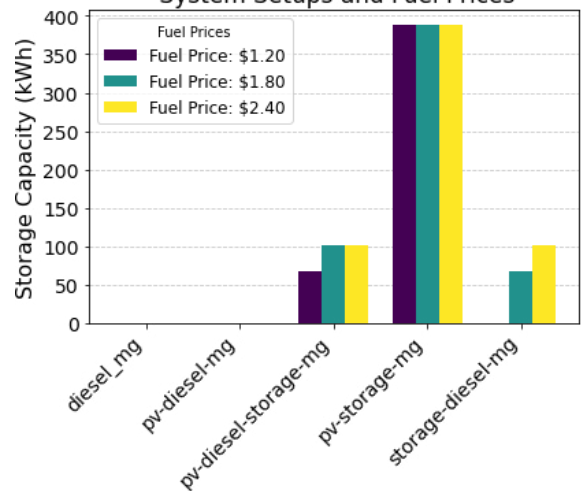


Figure 14: Storage capacities and annual fuel consumption results for the ISTA building for each system configuration and fuel price sensitivity in scatter chart format (top) and bar chart format (bottom right and bottom left)

4 Conclusions

A pre-feasibility analysis for the SNEL and ISTA compounds in Kinshasa was done to investigate various scenarios of installing solar PV systems on the rooftops of the buildings in the compounds. System configurations including all possible combinations of components including: solar PV systems, the existing grid connection, battery storage, and thermal backup gensets were evaluated. The study provides initial estimates for the total installable capacities of PV on the rooftops which resulted in a total of 861.4kWp for SNEL compound and 512.4kWp for the ISTA compound with the best capacity factors for the rooftop PV areas reaching roughly 17.3%, and with suboptimal but still suitable rooftops achieving lower capacity factors of roughly 15% - areas with expected significantly worse performance were not included in the totals and considered unviable. The various system configurations, and estimates for each compounds energy demand, were evaluated in an energy system optimisation model to determine how different system setups might perform over a year and what they might be expected to cost.

Many scenarios were run to test different system configurations and input assumptions to investigate the range of options available beyond only a single “optimal” system and presenting the trade-offs between initial investment costs, system autonomy, and genset fuel use. In some situations, certain sensitivities or different system configurations also did not impact the optimal system configuration and component sizes or only had a minimal impact (mainly for the SNEL compound), however for the ISTA compound it was found that the fuel price assumption could change system configurations and economics more significantly if the cost of fuel were to increase.

An important finding is that in all scenarios tested there is not enough rooftop PV potential capacity estimated to be installable to provide all building energy needs at either compound with the maximum energy autonomy factor reaching 36.5% in the SNEL case and 62.1% in the ISTA case. This is typical for larger buildings in cities that usually do not have extra space to build large PV plants.

This report serves as a pre-feasibility study rather than a comprehensive system design ready for immediate implementation and the analysis presented herein provides a preliminary assessment of potential energy solutions, not a detailed design for system deployment. Given these limitations, it is strongly recommended that stakeholders do not rely solely on the numbers presented in this report for system implementation and detailed implementation plan should be developed by engineers experienced with rooftop PV installations in the DRC, taking into account any necessary specific site conditions and local or national regulatory requirements.

The various model input and output files including technoeconomic assumptions, rooftop PV map data, hourly solar generation profiles, as well as full model output breakdowns and hourly timeseries files are made available and attached separately to the report. Many more inputs and outputs than are realistic to discuss in full detail in the report are available in these files and if the reader wishes to find more specific details about system configurations, performance metrics, cost breakdowns etc, they are available. The rooftop PV mapping files (.gpkg) and timeseries outputs (.csv) for all modelled roofs for both buildings are also provided.