TECHNO-ECONOMIC EVALUATION OF STRING INVERTER

Techno-economic evaluation of String Inverter

Huawei Tech (UAE) FZ-LLC

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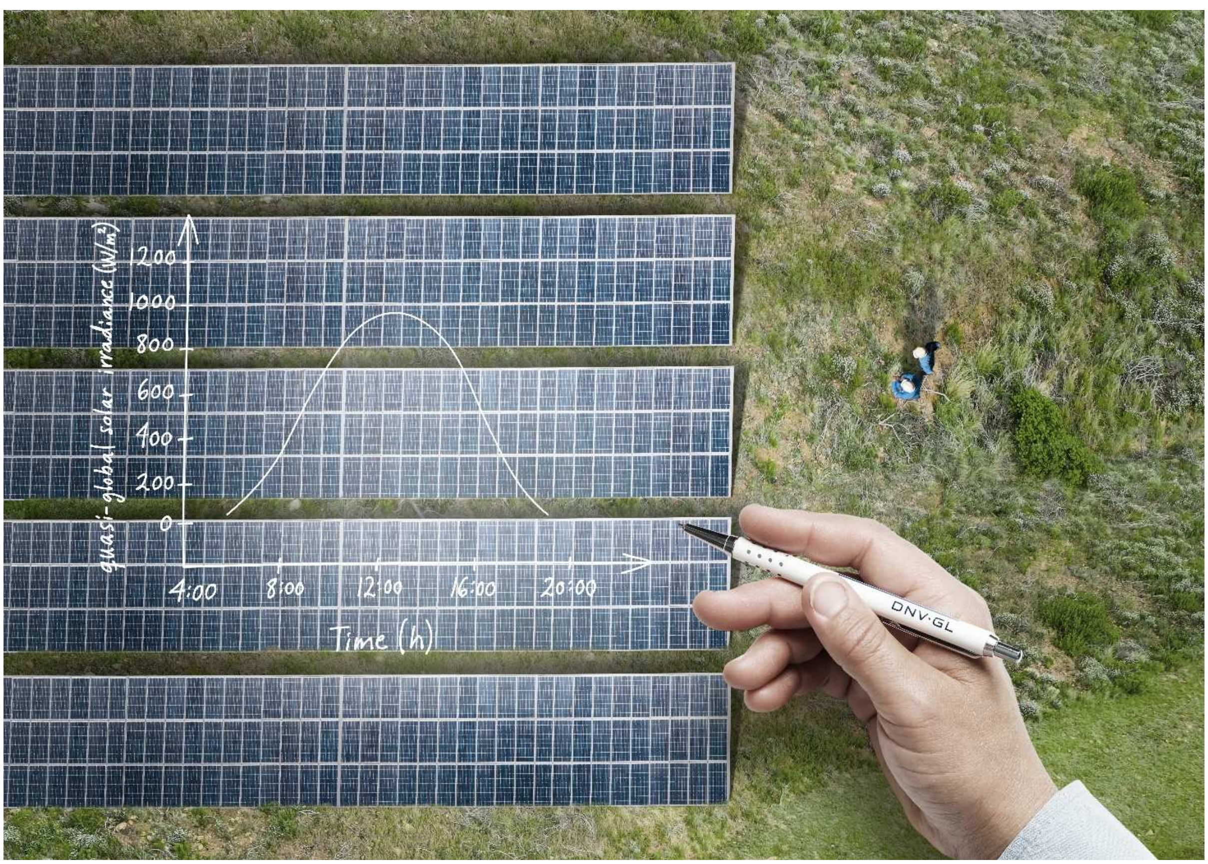

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List of Abbreviations

Abbreviation	Definition
AC	Alternating Current
AR	Anti-Reflective Coating
BOQ	Bill of Quantities
BOS	Balance of System
CAD	Clipping-Adjusted Degradation
CAPEX	Capital Expenditure
CEC	California Energy Commission
DC	Direct Current
DCDB	Direct Current Distribution Box
DHI	Diffuse Horizontal Irradiance
DNI	Direct Normal Irradiance
DTM	Digital Terrain Model
EPC	Engineering, Procurement, and Construction
EYA / EPA	Energy Yield Analysis / Energy Production Assessment
GCR	Ground Coverage Ratio
GHI	Global Horizontal Irradiance
GW	Gigawatt
HPDC	High Performance and Hybrid Passivated Dual-Junction Cell
HV	High-Voltage
IAM	Incidence Angle Modifier
IBC	Interdigitated-Back Contact
IEC	International Electrotechnical Commission
IGBT	Insulated Gate Bipolar Transistors
Inv	Inverter
IP	Ingress Protection
IRENA	International Renewable Energy Agency
Isc	Short Circuit Current
KPI	Key Performance Indicator
LCOE	Levelized Cost of Energy
LID	Light Induced Degradation
LTDB	Low Tension (Voltage) Distribution Board
LTSA	Long Term Service Agreement
MEA	Middle East & Africa
MMS	Module mounting Structure
MPPT	Maximum Power Point Tracking
MQF	Module Quality Factor
MTBF	Mean Time between Failure
MTTD	Mean Time to Detect
MTTR	Mean Time to Resolve
MV	Medium Voltage
MW	Megawatt
NA	Not Applicable
NOCT	Nominal Operating Cell Temperature
NREL	National Renewable Energy Laboratory
OEM	Original Equipment Manufacturers
OPEX	Operational Expenditure
PPA	Power Purchase Agreement

Abbreviation	Definition
PV	Photovoltaic
PVGIS	Photovoltaic Geographical Information System
RCA	Root Cause Analysis
SCADA	Supervisory Control and Data Acquisition
SLD	Single Line Diagram
SRTM	Shuttle Radar Topography Mission
STC	Standard Test Conditions
TMY	Time Month Year
USD	United States Doller
Voc	Open Circuit Voltage
WACC	weighted average cost of Capital

1 EXECUTIVE SUMMARY

This report presents a comprehensive techno-economic assessment aimed at identifying the optimal inverter configuration for a utility-scale solar photovoltaic (PV) project in Saudi Arabia, focusing particularly on Levelized Cost of Energy (LCOE). The study incorporates basic block design, energy yield assessment, and financial assumptions to evaluate various project scenarios, with special emphasis on comparing string and central inverter technologies.

This study presents a comparative techno-economic assessment of string and central inverter configurations for a utility-scale PV project. The analysis began with the definition of project-specific design assumptions, including module selection, string sizing, temperature, and mounting structure, to reflect realistic site conditions. A preliminary optimization exercise determined that the most effective configurations included a 7.0 m pitch and DC:AC ratios of 1.23 for string inverters and 1.25 for central inverters, which were subsequently shortlisted for detailed analysis.

In the second stage, detailed system layouts were prepared for the shortlisted configurations, enabling accurate loss modelling, design specific BOQ, and design specific LCOE calculation. The final LCOE results indicate that string inverters achieve a lower LCOE of USD 18.51/MWh, compared to USD 18.80/MWh for central inverters—a 1.6% relative improvement, which increases to 2.1% when availability differences are considered using a sensitivity case.

In the current study, string inverters appear to offer a cost-effective and operationally robust solution, based on the specific system design and assumptions considered. However, for other projects, this conclusion should be validated through project-specific modelling and analysis aligned with the respective design and context.

2 INTRODUCTION

Huawei Tech (UAE) FZ-LLC ("the Customer") has contracted DNV to undertake technical advisory services for comparing solar energy yield and Levelized Cost of Electricity Analysis (LCOE analysis) between a string inverter model and a central inverter model for a site in Saudi Arabia.

The aim of this study is to evaluate the differences between solar plant designs corresponding to both inverters and assess their impact on energy yield and LCOE. The two inverter types that are considered for the analysis are string inverter with capacity of 330 kW (max capacity @ 30°C) and central inverter with capacity of 1320 kW (max capacity @ 23°C).

The site location is provided by the Customer. The site is located in the State of Makkah, in the Rabigh region of Saudi Arabia, as shown in Figure 2-1. The coordinates representing the location of the site are as follows:

Coordinates	Site
Latitude	22.59867°
Longitude	39.17881°
Altitude	23m

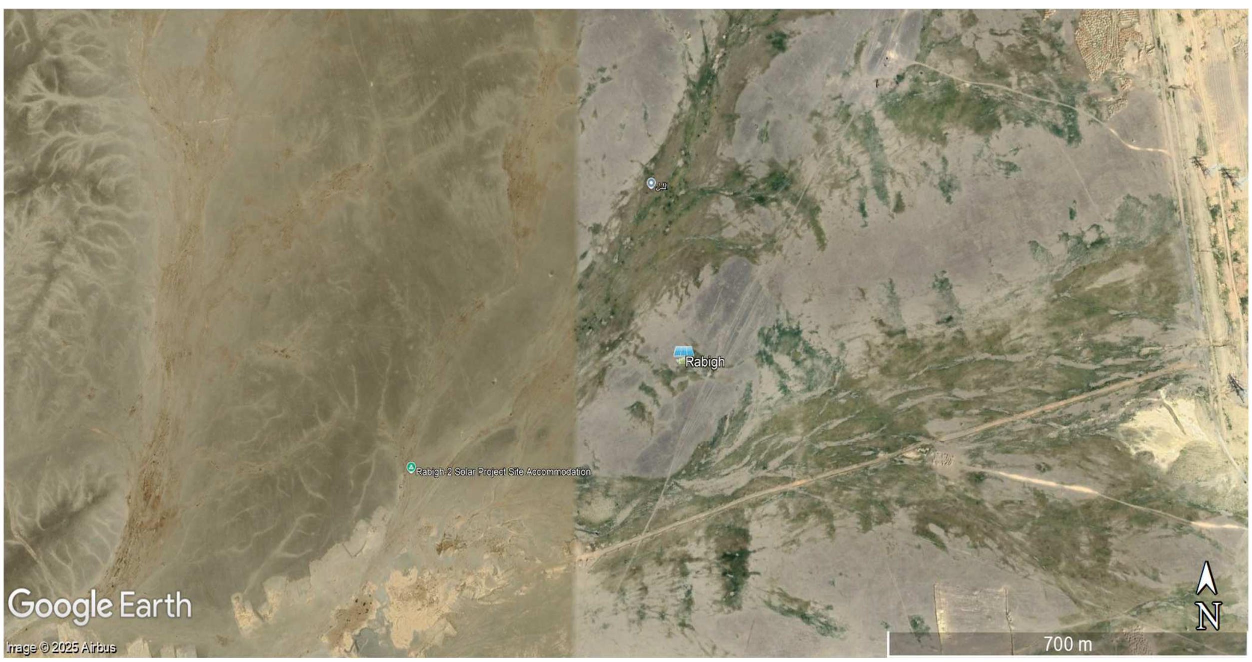

Figure 2-1 Location of the Project

3 GENERAL ASSUMPTIONS FOR THE ANALYSIS

The Figure 3-1 outlines the structured process followed to evaluate the LCOE for a solar PV project by comparing string and central inverter configurations.

The overall process is conducted in two main stages: initial-level optimization and detailed LCOE calculation.

- Initial-level optimization:

  In the initial optimization stage, the objective is to identify the optimal configuration of key variable components—specifically, the pitch (6.5m vs. 7m) and DC:AC ratio (1.1 to 1.25 at 45°C)—while keeping certain components fixed, such as the PV module, inverter type, mounting structure (MMS), and AC capacity.

  The pitch of 6.5m to 7.0m has been considered based on engineering experience in the Middle East region, particularly with tracker designs when there is space availability. Multiple feasibility studies conducted in the region have indicated that this range offers optimal balance between land utilization, shading losses, and energy yield resulting in best LCOE. However, in areas with land constraints, higher Ground Coverage Ratio (GCR) values are also observed as a trade-off to accommodate capacity within limited space.

  At elevated temperatures, inverter output capacity may decrease due to thermal derating, a built-in protective mechanism to prevent overheating. Operating inverters with high DC:AC ratios under such conditions can lead to more frequent and prolonged inverter power clipping, especially during peak irradiance hours, which may reduce the efficiency of energy capture. Over time, sustained high loading combined with thermal cycling can contribute to accelerated wear on internal components, potentially impacting the operational life of the equipment. DNV has assessed both high and low temperature conditions at the site and has considered a maximum temperature of 45°C, based on the historical peak values observed in the time series meteorological data, as detailed in Section 4.5.

  In projects with grid export limitations, surplus energy generated under high DC:AC ratios may be curtailed, further contributing to energy loss. Considering these factors—along with the region's temperate-to-hot climate—a DC:AC ratio in the range of 1.10 to 1.25 is generally considered optimal to balance energy capture, inverter longevity, and curtailment risk.

  Using default loss assumptions and high-level Capital Expenditure (CAPEX) / Operational Expenditure (OPEX) estimates, a batch of simulation scenarios is run. These scenarios are evaluated using a high-level energy yield analysis (EYA) to rank configurations based on LCOE performance, ultimately resulting in the selection of final configurations for both string and central inverter setups.

- Detailed LCOE calculation:

  In the second stage, detailed layouts are developed for the shortlisted configurations, allowing for accurate calculation of site-specific losses and generation of a design specific bill of quantities (BOQ). These inputs are then used to refine the EYA, CAPEX, and OPEX assessments, leading to a detailed and differentiated LCOE calculation that reflects the unique characteristics of each system configuration. This two-step approach ensures that the selected system design is both technically optimized and economically viable for the specific site conditions.

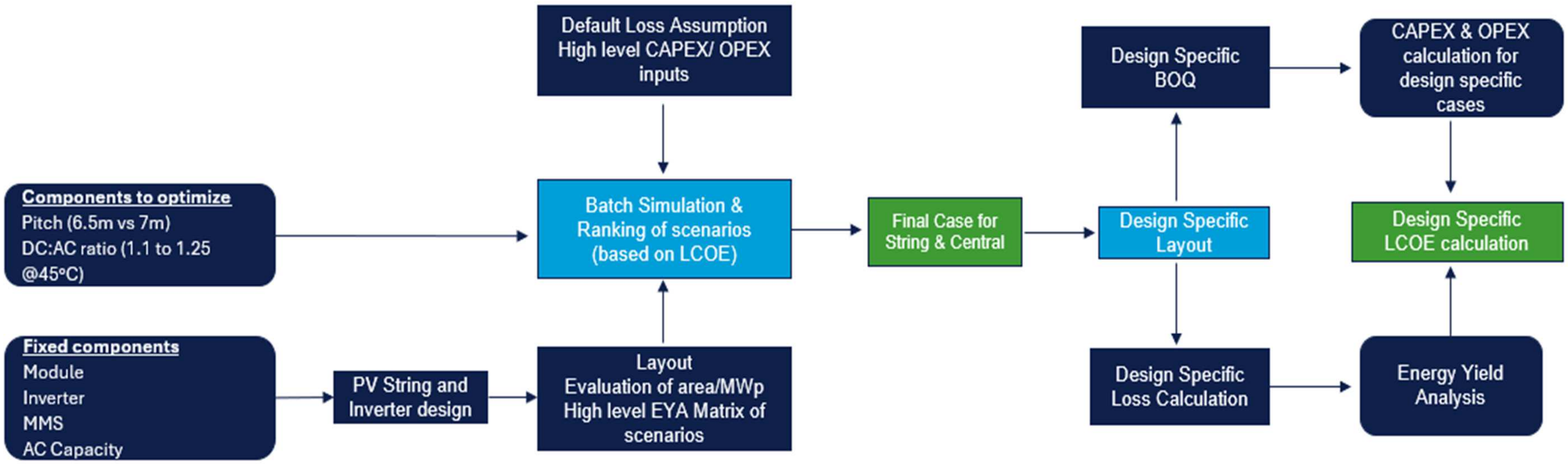

Figure 3-1: Process Flow Diagram for LCOE Analysis

4 DESIGN BASIS FOR ANALYSIS

4.1 Module Characteristics

In recent years significant technologies have emerged such as TOPCon, Interdigitated Back Contact (IBC), and Perovskite solar cells contributing to notable improvements in efficiency and overall performance. HPDC (High Performance and Hybrid Passivated Dual-Junction Cell) represents an advanced bifacial solar cell architecture developed through hybrid passivation technology. This innovative design utilizes different passivation techniques on the front and rear surfaces of the cell, effectively minimizing carrier recombination and significantly improving energy yield. On the rear side, the integration of high and low junctions enables full-surface passivation, further reducing surface recombination losses. As a result, HPDC cells exhibit key performance advantages, including higher open-circuit voltage (Voc), improved conversion efficiency, and a favourable power temperature coefficient, making them well-suited for high-performance PV applications.

The site's has good ground albedo (0.25) favouring bifacial modules, which are expected to provide a gain of approximately 5-6%, making them ideal for the location. The price gap between monofacial and bifacial modules has decreased, making bifacial technology more appealing from an LCOE perspective. Given the site conditions, a bifacial system is considered for optimal performance.

DNV has considered Bifacial Half Cut HPDC 620Wp Tier 1 module for the analysis based on inputs received from Customer. Some of the important parameters of the same are highlighted below.

Table 4-1: PV Module Characteristics

Model		Half Cut Bifacial HPDC 620 Wp
Nominal Power	W	620
Tolerance	[%]	+3.0%
Technology		Si-mono HPDC
Isc	A	16.1
Voc	V	48.5
Impp	A	15.4
Vmpp	V	40.2
Vmax	V	1500
Temperature Coefficient of Power µPmax	(%/°C)	-0.28
Temperature Coefficient of Voltage µVoc	(%/°C)	-0.23
Temperature Coefficient of Current µIsc	(%/°C)	0.045
NOCT	(°C)	45
Bifaciality	[%]	80

4.2 Inverter Characteristics

Both high-voltage (1,500V) string inverters and central inverters are viable options in the current utility-scale PV market. Given the diversity of environmental conditions and operational priorities, a site-specific assessment is essential to determine the optimal inverter design. To identify the most suitable solution for the site, DNV has conducted a LCOE analysis comparing string and central inverter technologies. A summary of the key characteristics of both inverter types is presented below in Table 4-2, with a more detailed comparison provided in Appendix C

Table 4-2: Inverter Specifications

Type		String	Central
Model		SUN2000-330XXX-XX	Typical 1100 KW Central Inverter
Vmpp min	V	500	938
Vmpp max	V	1500	1500
Vmax	V	1500	1500
Maximum PV current	A	390 (65 x 6)	1435
MPPT	Nos	6	1
Nb inputs DC	Nos	28	5
Isc max per MPPT	A	115	3528
Max AC Power	kW	330	1320
Inverter Capacity@50°C	kW	275	1109
Inverter Capacity@Design Temperature (45°C)	kW	287	1158
Nominal Output Voltage	V	800	660
Nominal Output Current	A	198.5	962
Max. Output Current	A	240.3	1155
Adjustable Power Factor Range		0.8 lagging - 0.8 leading	0.8 lagging - 0.8 leading
Total Harmonic Distortion	%	＜1	<3
Max. Efficiency*	%	99.0%	99.0%
European Efficiency*	%	98.8%	98.7%

Efficiency defined for 3 voltages*				
	SUN2000-330XXX-XX			Reference [15]
	Input	**CEC**	**Euro**	
	V	**%**	**%**	
Low Voltage	930	98.3	98.2	Third Party Test Report
Medium Voltage	1080	98.4	98.3	Third Party Test Report
High Voltage	1300	98.7	98.6	Third Party Test Report

* Based on data sheet values / **Based on test report

4.3 Module Mounting Structure design

For large-scale solar PV installations, single-axis trackers are generally recommended over fixed-tilt structures due to their ability to follow the sun's path, thereby maximizing solar irradiance capture throughout the day. This leads to significantly higher energy yields, improved shading performance, and enhanced system efficiency.

While the upfront capital cost for tracker systems is typically higher, the long-term benefits—particularly the increased energy generation and lower LCOE—make them a favourable option for utility-scale projects with strong return-on-investment potential. In scenarios where land availability is not a limiting factor, optimizing the system layout to maximize energy output becomes significantly more feasible. As a result, single-axis tracker systems tend to perform better in such cases, offering enhanced energy yield and improved project economics. DNV has considered 1P single axis tracker configuration considering the benefit over fixed tilt system and assuming availability of sufficient land area. Additionally, the site's climatic conditions in the region characterized by a high Direct Normal Irradiation (DNI) / Global Horizontal Irradiation (GHI) ratio further enhances the energy gain potential for tracker configuration.

4.4 String Sizing

From a technical standpoint, the design of a photovoltaic (PV) plant is organized around the concept of strings—each formed by connecting multiple PV modules in series. These strings are then connected to the DC side of inverters, typically directly in case of string inverter and via string combiner boxes in case of central inverter. A sound and efficient electrical design must account for two primary constraints determined by inverter specifications:

1. **Series Connection (Voltage Constraint):**

The number of PV modules connected in series (i.e., string length) is primarily limited by the inverter's DC input voltage capabilities.

Two critical parameters must be considered:

a. Maximum DC input voltage – This must not be exceeded under the coldest expected site conditions, as it directly relates to the open-circuit voltage (Voc) of the PV modules.

b. MPPT voltage range – The operating voltage of the string should lie within the inverter's Maximum Power Point Tracking (MPPT) range for optimal energy yield, which must align with the PV module's typical operating voltage.

2. **Parallel Connection (Current Constraint):**

The number of strings connected in parallel to a single inverter is limited by the maximum allowable DC input current of the inverter. Exceeding this can lead to overcurrent conditions and reduced inverter efficiency or even damage.

As a result, there is a maximum allowable number of PV modules of a given type that can be connected to one inverter. This is determined by the product of the maximum number of strings (defined by the current limit) and the maximum string size (defined by voltage limits).

Considering the selected PV modules and inverter models, the electrical configuration has been carefully designed to ensure an optimal balance between string size and the number of strings per inverter. This ensures both performance and compliance with equipment limitations. The tables below present the outcome of the design analysis conducted for bifacial n-type mono PV modules using string and central inverters, evaluated under Standard Test Conditions (STC).

Table 4-3: String & Inverter Design Calculation for String Inverter

<table>
<tr><td colspan="3"></td><td colspan="6">STRING INVERTER</td></tr>
<tr><td colspan="3"></td><td colspan="4">Voltage Features</td><td colspan="2">Current Features</td></tr>
<tr><td colspan="3"></td><td colspan="2">DC V_{max} (V) =</td><td colspan="2">DC V_{mpp} range (V) =</td><td>DC I_{max} (A) =</td><td>Physical connections</td></tr>
<tr><td colspan="3"></td><td colspan="2">1500</td><td>500</td><td>1500</td><td>65.0</td><td>6 MPPT (28 strings)</td></tr>
<tr><td rowspan="3">Module</td><td>V_{oc} (V)</td><td>48.5</td><td>Max string</td><td>30</td><td colspan="2">-</td><td colspan="2">-</td></tr>
<tr><td>V_{mpp} (V)</td><td>40.17</td><td colspan="2">-</td><td>13</td><td>37</td><td colspan="2">-</td></tr>
<tr><td>Impp (A)</td><td>15.44</td><td colspan="2">-</td><td colspan="2">-</td><td>Max string (p/Inv)</td><td>25</td></tr>
<tr><td colspan="3"></td><td colspan="6">String size: [13-30] mod/string;</td></tr>
<tr><td colspan="3"></td><td colspan="6">Maximum inverter load: 25 strings</td></tr>
</table>

Temperature Behavior	Temperature Coefficient	Operating Temperature Range for Cell (°C)		Inverter range		Check	Comments
	%/°C	85.9	14.9	Max	Min		
V_{OC} (V)	-0.230	1251	1489	1500	-	P	O.K.
Vmpp (V)	-0.230	1036	1233	1500	500	P	O.K.
Isc (A)	0.045	315	292	390	-	P	O.K.

Table 4-4: String & Inverter Design Calculation for Central Inverter

			CENTRAL INVERTER					
			Voltage Features				Current Features	
			DC V_{max} (V) =		DC V_{mpp} range (V) =		DC I_{max} (A) =	Physical connections
			1500		938	1500	1435.0	1 MPPT
Module	V_{oc} (V)	*48.5*	*Max string*	30	-		-	
	V_{mpp} (V)	*40.17*	-		24	37	-	
	Impp (A)	*15.44*	-		-		*Max string (p/Inv)*	92
			String size: [24-30] mod/string;					
			Maximum inverter load: 92 strings					

Temperature Behavior	Temperature Coefficient	Operating Temperature Range for Cell (°C)		Inverter range		Check	Comments
	%/°C	85.9	14.9	Max	Min		
V_{OC} (V)	-0.230	1251	1489	1500	-	P	O.K.
Vmpp (V)	-0.230	1036	1233	1500	938	P	O.K.
Isc (A)	0.045	1294	1199	1435	-	P	O.K.

The current vs. voltage characteristic of a PV module, measured at STC (Standard Test Conditions, i.e., irradiance 1,000 W/m2, cell temperature 25ºC and air mass AM1.5), may vary significantly in normal outdoor operation, mainly due to temperature. This variation is provided by the manufacturers, in the shape of temperature coefficients for the relevant electrical characteristics (Pmax, Isc, Voc).

DNV reviewed the open-circuit voltage, short-circuit current, and maximum power point characteristics of the system design across a range of temperatures, using the selected PV module datasheet, the expected minimum ambient temperature at the project site, and in accordance with IEC 62738 guidelines. The temperature range considered has been selected based on the historical hourly ambient temperature data provided by Solcast for the Project location. The obtained extreme cell temperature values have been estimated as of ~14.9ºC and ~85.9ºC. However, it is important to note that these extremes occur very rarely in the time series data (<0.01%). Therefore, the module's operational temperature range of -40°C to +85°C is considered adequate for the site’s environmental conditions.

Considering the climatic conditions of the Project and the technical characteristics of the equipment, the maximum design values do not exceed the voltage and current levels recommended by the manufacturer in extreme temperature conditions are shown in Table 4-5.

Table 4-5: Maximum DC design for the Project according to extreme temperature behaviour

Temperature Behaviour			
Inverter		String	Central
Inputs	Temp. Coefficient Pmax (%/ºC)	-0.28	-0.28
	Temp. Coefficient V_{OC} (%/ºC)	-0.23	-0.23
	Temp. Coefficient I_{SC} (%/ºC)	0.045	0.045
	Minimum Cell temperature (ºC)	14.9	14.9
	Maximum Cell temperature (°C)	85.9	85.9
V_{mpp}	Maximum number of modules per string	**30**	**30**
	Maximum inverter MPP voltage (V)	1,500	1500
I_{sc}	Maximum number of strings per inverter	**25**	**92**
	Maximum inverter current (A)	390 (65A/MPPT)	1435

4.5 Temperature Considerations

To verify the temperature conditions at the site, DNV analysed meteo time series data sourced from Solcast for the period 2007–2025. The temperature frequency distribution reveals that approximately 99.9% of the data points fall within the range of 14°C to 45°C. Based on this analysis, DNV considers design temperature of 45°C as a suitable design temperature for the project site. The Figure 4-1 below shows distribution of Temperature bins from minimum to maximum temperatures.

	Timeseries	
	Frequency	Frequency (GHI >800 W/m^2)
14	0.0%	0.0%
16	0.1%	0.0%
18	0.8%	0.0%
20	2.4%	0.0%
22	4.9%	0.0%
24	8.1%	0.0%
26	10.3%	0.1%
28	12.0%	0.3%
30	14.0%	0.5%
32	14.0%	0.6%
34	11.6%	0.8%
36	8.4%	1.5%
38	7.0%	2.5%
40	4.5%	2.1%
41	1.0%	0.5%
42	0.4%	0.2%
43	0.2%	0.1%
44	0.1%	0.1%
45	0.1%	0.1%
46	0.0%	0.0%
47	0.0%	0.0%
48	0.0%	0.0%
49	0.0%	0.0%
50	0.0%	0.0%

Figure 4-1: Frequency distribution of timestamps (2007-2025)

The design temperature plays a critical role in the engineering and performance evaluation of solar PV systems—particularly in the thermal performance and reliability of key components like inverters. Selecting 45°C as the design temperature ensures that the system is engineered to operate effectively under the elevated temperatures expected at site.

In addition to assessing the maximum expected ambient temperatures, DNV also reviewed lower temperature conditions to ensure that component performance remain within acceptable operational limits during cooler periods. At lower temperatures PV Module and inverter efficiency is typically at highest level of efficiency and hence the same is considered as well for design calculations like string calculations, cable calculation etc.

The inverter's thermal derating behaviour is directly influenced by ambient temperature—at higher temperatures, inverter starts derating (reduce power output) to prevent overheating. Section 9.3 covers inverter deration characteristics of the string and central inverter in detail. DNV has reviewed the temperature deration curve profiles of the inverters selected and confirmed that they are capable of operating reliably at 45°C.

5 INITIAL LEVEL OPTIMIZATION

The aim of this section is to provide a preliminary technical design optimization of the PV Plant for both configurations. DNV has performed design optimization for the solar PV plant by performing multiple simulation scenarios using typical system losses.

Objective and Methodology

The primary objective of this analysis is to determine optimal configurations in terms of key design variables—specifically, DC:AC ratio and row pitch—for each inverter type. These parameters significantly influence both energy yield and the overall economics of the project, as measured by Levelized Cost of Electricity (LCOE).

For consistency across the analysis all the system components and design assumptions were considered as per Section 4.

- **Module:** Half Cut Bifacial HPDC 620 Wp modules
- **Mounting Structure:** Single-axis tracker (1P configuration)
- **Inverter Configurations:** Configurations of string inverter and central inverter
- **Temperature:** AC Capacity for design temperature of 45°C

DNV selected a target AC capacity of 500 MWac as the baseline for comparison. A scenario matrix was developed by varying two design parameters, overall ending with total 28 scenarios as mentioned in the Appendix D:

- DC:AC ratios: ranging from 1.10 to 1.25
- Pitch values: 6.5 meters and 7.0 meters
- Inverter: String and Central

Table 5-1: Simulation Scenarios for Initial Optimization

Sr. No.	DC:AC Ratio@45ºC	DC Capacity (MWp)	AC Capacity (MW@45ºC)	Pitch (m)	Inverter
1	1.1	549.9	500.0	6.5	String
2	1.13	565.0	500.0	6.5	String
3	1.15	574.9	500.0	6.5	String
4	1.17	585.0	500.0	6.5	String

Sr. No.	DC:AC Ratio@45ºC	DC Capacity (MWp)	AC Capacity (MW@45ºC)	Pitch (m)	Inverter
5	1.2	599.9	500.0	6.5	String
6	1.23	615.0	500.0	6.5	String
7	1.25	624.9	500.0	6.5	String
8	1.1	549.9	500.0	7	String
9	1.13	565.0	500.0	7	String
10	1.15	574.9	500.0	7	String
11	1.17	585.0	500.0	7	String
12	1.2	599.9	500.0	7	String
13	1.23	615.0	500.0	7	String
14	1.25	624.9	500.0	7	String
15	1.1	549.9	500.4	6.5	Central
16	1.13	565.0	500.4	6.5	Central
17	1.15	574.9	500.4	6.5	Central
18	1.17	585.0	500.4	6.5	Central
19	1.2	599.9	500.4	6.5	Central
20	1.23	615.0	500.4	6.5	Central
21	1.25	624.9	500.4	6.5	Central
22	1.1	549.9	500.4	7	Central
23	1.13	565.0	500.4	7	Central
24	1.15	574.9	500.4	7	Central
25	1.17	585.0	500.4	7	Central
26	1.2	599.9	500.4	7	Central
27	1.23	615.0	500.4	7	Central
28	1.25	624.9	500.4	7	Central

Based on the scenarios listed above DNV performed energy yield analysis in the PVsyst using batch simulation under predefined loss assumptions. The energy yield simulation approach is mentioned below:

1. All simulations were performed using PVsyst, 2D shading tool within PVsyst with backtracking activated.
2. Default identical losses were considered for both type of inverter as per DNVs default assumptions mentioned in the Section Appendix B.2.3
3. The DC & AC Ohmic losses considered for the initial optimization are outlined below in Table 5-2

Table 5-2: DC & AC Ohmic Losses for Initial Optimization

Loss	String	Central
DC Ohmic	0.7%	1.5%
AC Ohmic	1.0%	0.5%

4. To better reflect system performance under realistic conditions, grid limitation losses were included—without which the results would disproportionately favour higher DC:AC ratios. The grid limit was applied for 500 MW capacity at the point of injection.

After the simulation of all the scenarios, high-level, LCOE calculation was done. Total 28 scenarios were considered each for both inverter configurations. The scenarios were ranked according to the LCOE. Table 5-3 below provides the input assumptions on CAPEX and OPEX for the high-level LCOE calculation that was performed for initial optimization.

Table 5-3: Input assumptions for high-level average cost of energy

Item	Unit	Value
CAPEX DC Components	USD /kWp	310.25
CAPEX AC Components	USD / kW	68.65
CAPEX Common Components	Price USD / (kWp+kVA) (65% DC +35% AC)**	167.42
OPEX	USD / kWp / Year	5.412
Annual escalation for O&M	%	2.40
Discount rate	%	6.60
PPA Term	Year	30

** The expression USD / (65% × kWp + 35% × kWac) is used to normalize CAPEX by accounting for both DC and AC system sizing, reflecting the typical cost distribution in utility-scale PV projects—where ~65% of costs are driven by DC components (modules, structures, DC side BoS) and ~35% by AC components (transformers, interconnection, AC side BoS).

- Figure 5-1 & Figure 5-2 below are the results of the optimization exercise for both inverter configurations, showing a comparison of the relative LCOE and lifetime energy considering 30-year period. Appendix D represents the result of all 28 scenarios considered for the optimization.

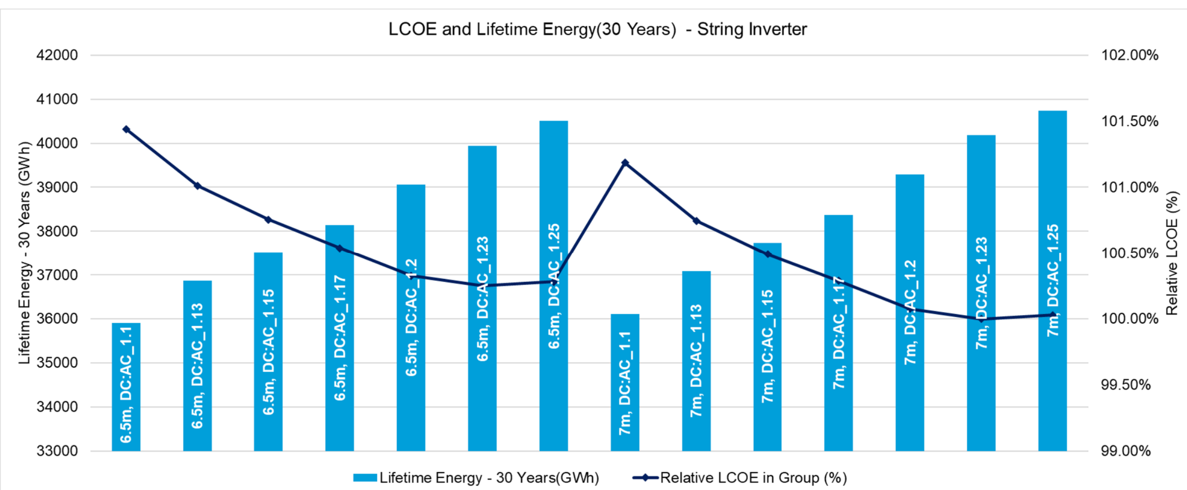

Figure 5-1: Optimization Result for String Inverter

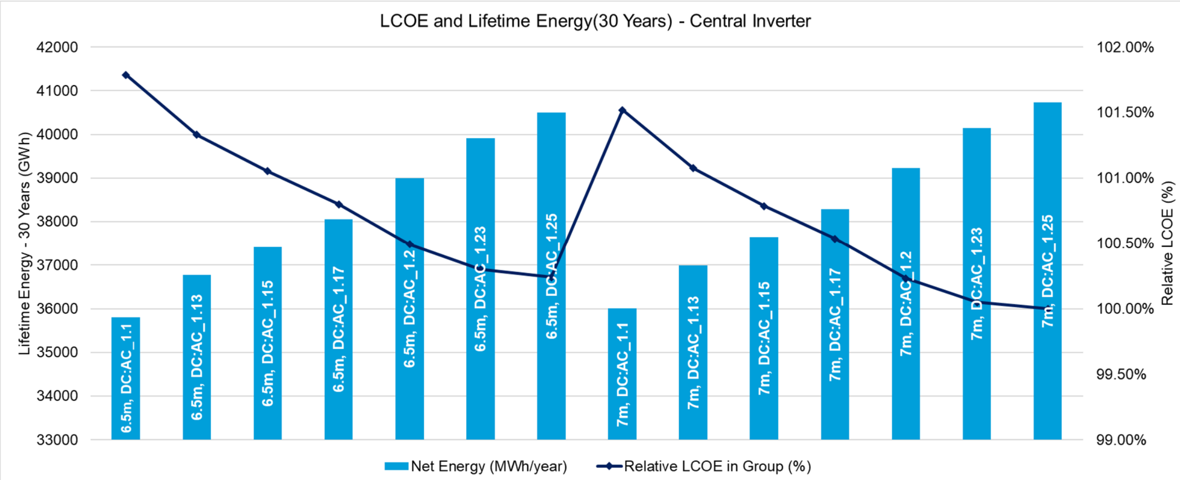

Figure 5-2: Optimization Result for Central Inverter

Results

Table 5-4 shows an extract of the results obtained. This table displays two best scenarios in each configuration if sorted according to relative LCOE.

Table 5-4: Optimization Summary and Result

DC:AC Ratio@45ºC	DC Capacity (MWp)	AC Capacity (MW@45ºC)	Pitch (m)	Overall Relative LCOE (%)	Yield (MWh/MWp/Year 1)	Lifetime Energy - 30 Years (MWh)	LCOE Rank in Group	Overall LCOE Ranking	Configuration
1.25	624.9	500.4	7	**100.00%**	2385	40739569	1	1	Central
1.23	615.0	500.0	7	**100.02%**	2390	40178028	1	2	String

The lowest relative LCOE is achieved at lower GCR values, corresponding to a 7-meter pitch. Based on the CAPEX assumptions, the cost associated with additional land requirements is relatively low for this site and is outweighed by the energy gains achieved at lower GCR. Regarding the DC:AC ratio, the optimal value is 1.23 for string inverters and 1.25 for central inverters. The difference in relative LCOE between the best-case scenarios for each configuration is marginal. It is important to note that the objective of this analysis was to identify the optimal combination of DC:AC ratio and pitch within the scenarios of both the String and Central inverter groups. Therefore, the analysis does not aim to determine whether string or central inverters are categorically superior. Apart from DC and AC cable ohmic losses, all other components—such as CAPEX and OPEX—have been assumed to be identical for both string and central inverter configurations.

Overall, the configurations mentioned above for both groups are considered the most optimal within their respective categories and will be analysed in detail for LCOE in the following section.

6 SCENARIO COMPARISON

6.1 Block Design

The total capacity of the plant is 500 MWac. Given the site's environmental conditions and ambient temperatures, the system is designed to operate reliably at a design temperature of 45°C, ensuring that the full 500 MWac capacity is deliverable under such high-temperature conditions.

In utility-scale solar PV projects, such large capacities are typically modular in nature—comprising repeated units or blocks of a fixed capacity, which together constitute the overall plant capacity. Hence, In this case, the 500 MWac system can be viewed as an aggregation of multiple identical blocks, each sized at ~9 MWac.

This modular block-level analysis is technically sufficient and representative because:

- Both inverter configurations (string and central) are designed at the same AC output per block.
- The electrical behaviour, system efficiency, and performance ratios at the block level remain consistent across the plant due to the repetitive nature of the layout.
- Key system elements on the DC side—up to the transformer—can vary significantly depending on the inverter configuration, i.e., string vs. central. This includes differences in string sizing, combiner box requirements, cabling layouts, and inverter station architecture. However, on the AC side, particularly beyond the medium-voltage (MV) station, the infrastructure—such as switchgear, power transformers, protection systems, and grid interconnection equipment—scales proportionally and remains largely consistent across both configurations. A minor variation in MV AC ohmic losses may occur between the MV station and the grid interconnection point, primarily due to small differences in block capacity. As a result, design-specific MV AC ohmic losses have been explicitly calculated and incorporated into the analysis to ensure technical accuracy and fairness in comparing the configurations.

For LCOE analysis and design optimization, evaluating a representative inverter station block (e.g., 9 MWac) is technically sufficient, as utility-scale PV plants are typically composed of modular, repeatable units. Insights from this block-level study can be confidently extended to the full 500 MWac plant, ensuring a fair, scalable, and technically sound comparison between string and central inverter configurations.

To support the assessment, DNV has developed configuration-specific system layouts (Appendix A) based on this standardized ~9 MWac inverter station block for both string and central inverter configurations. These layouts form the basis for calculating design specific components and losses. This variable component forms basis for difference in CAPEX (Section 6.4) and variable losses form basis for difference in EYA (Section 6.3).

In addition to block-level losses, plant-wide losses—such as AC Ohmic loss up to interconnection point, HV transformer losses, auxiliary loads, and unavailability losses—have also been incorporated into the EYA model. These can be scaled appropriately to reflect the entire 500 MWac plant, not just a representative block. Below is summary of block configurations considered for LCOE analysis.

Table 6-1: Block Design for String & Central

	String	Central
Pitch	7m	7m
PV Module	Half Cut Bifacial HPDC 620 Wp	Half Cut Bifacial HPDC 620 Wp
Qty of Module	18240	18720
String Length	30	30
Strings	608	624
DC Capacity (kWp)	11308.8	11606.4
Inverter Capacity @45° (kW)	287	1158
Total Inverter Capacity/Block @45° (kW)	9184	9264
DC/AC Ratio@45° (kW)	1.23	1.25
Inverter Qty	32	8
Strings per Inverter	19	78
String Combiner Box	-	16 in 1 out – 39 Nos
Strings per Combiner Box	-	16
LV AC Panel	16 in 1 Out - 2 Nos	-
Transformer Capacity @45°C(kW)	9350	9264
No Of Blocks required for 500 MWac @45°C	54.5*	54

* 54 full blocks with 32 string inverters and 1 half block with 16 string inverters.

6.2 Design specific Losses

6.2.1 Inverter Loss

The inverter losses considered in the energy yield assessment include several components: inverter efficiency losses, power and voltage threshold losses, and inverter auxiliary consumption losses. Each of these loss categories is influenced by the specific characteristics defined within the .OND (inverter data) file used in PVsyst. All these losses are evaluated through hourly simulations in PVsyst, using detailed input data including third-party test reports and manufacturer-supplied technical specifications for individual inverter type.

- Inverter Efficiency Loss: This refers to the intrinsic conversion efficiency of the inverter when converting DC power from the PV modules into AC power. The efficiency varies with input voltage, and temperature, and is typically represented by an efficiency curve provided by the manufacturer. These curves, validated by third-party test reports, have been incorporated into the inverter OND files to ensure realistic performance estimates.
- Power Threshold Losses: Losses occur when the DC power from the array is outside window of the inverter's minimum and maximum threshold preventing it from operating.
- Voltage Threshold Losses: These arise when the array's MPP voltage falls outside the inverter's MPPT voltage range.
- Inverter Auxiliary Consumption: This accounts for the inverter's internal consumption for its control electronics, communications, cooling systems, and other functions.
- Night Consumption: This loss represents the inverter standby loss incurred when the inverter is energized but not operational, mainly at night

6.2.2 Cable Loss Calculations

6.2.2.1 DC Ohmic Loss

DC ohmic losses occur when connecting the modules to the input of the inverter(s). As current passes through a wire, the wire resistance induces a voltage drop and dissipates some power as waste heat. This loss is dependent upon the conductor material (i.e. aluminium or copper), gauge (i.e. diameter), and resistive properties; the length of the wire; and the current at the input of the wire.

DNV has estimated the DC ohmic losses for both the string inverter and central inverter configurations based on the proposed system design and layout. The calculation methodology accounts for typical industry-standard cable sizing and routing practices. Cable lengths have been estimated in accordance with standard utility-scale PV plant designs.

For the string inverter configuration, DC ohmic losses are primarily attributed to the string cables that connect the PV modules directly to the string inverters. For the central inverter configuration, the losses are more complex and comprise two segments: (i) string cable losses between the modules and the string combiner boxes, and (ii) main DC cable losses between the combiner boxes and the central inverters.

Based on calculations presented in Appendix E, the estimated DC ohmic loss is mentioned in Table 6-2.

6.2.2.2 AC Ohmic Loss

AC ohmic losses occur when connecting the inverter cabinet(s) to the production meter on the customer side of the grid interconnection point. As current passes through a wire, the wire resistance induces a voltage drop and reduction in power. This loss is dependent upon the conductor material (i.e. aluminium or copper), gauge (i.e. diameter), and resistive properties; the length of the wire; and the current at the input of the wire.

DNV has estimated the AC ohmic losses for both the string inverter and central inverter configurations, based on the proposed system design, layout, and industry-standard practices for cable sizing and routing. The analysis distinguishes losses up to the interconnection point. losses are calculated based on estimated cable lengths, conductor properties, and current flow, in alignment with the plant’s design.

- Losses Beyond the MV Station: DNV has the loss for string and central configurations on account for combined MV and high-voltage (HV) AC losses.
- Losses on the Low-Voltage (LV) Side: For the string inverter configuration, LV AC ohmic losses are associated with the AC cables connecting the string inverters to the MV station. In contrast, for the central inverter configuration, LV AC cable losses are anticipated for busbar between inverter and transformer. This direct integration eliminates the need for additional LV cable loss.

Overall the summary of both DC & AC Ohmic losses is mentioned in Table 6-2 below

Table 6-2: Design Specific Cable Loss Summary

Loss	String	Central
String Cable Loss [%]	0.60	0.59
DC Cable Loss [%]	0.00	0.79
Total DC Ohmic [%]	**0.60**	**1.38**
LV AC Cable Loss [%]	0.90	0.03
MV AC Cable Loss [%]	0.33	0.3

Loss	String	Central
Total AC Ohmic [%]	**1.23**	**0.35**
Total plant ohmic loss [%]	**1.83**	**1.73**

The values in the table reflect DNV's engineering judgment using standard assumptions and typical design practices commonly applied in large-scale PV installations.

Overall, DNV's approach incorporates standard design assumptions and best practices to ensure that the estimated AC ohmic losses accurately reflect real-world system behaviour.

It is observed that cable losses are higher in the case of string inverters, primarily because DNV restricts the use of cable sizes beyond 400 sq.mm. for LV cable. This limitation is not only due to economic considerations but also aligns with practical design constraints. On the other hand, DC cabling in central inverter system is also capped at 400 sq.mm due to several factors—such as optimization of string combiner box design, permissible cable spacing in the trench, underground installation parameters, grouping of conductors, burial depth, and soil thermal resistivity. While using 300 sq.mm cables is technically feasible, it would require two runs per phase instead of one per combiner box, significantly impacting cost-effectiveness.

Despite the slightly higher cable losses associated with string inverter setups, they remain a highly cost-effective and practical solution.

6.2.3 Mismatch Loss

Electrical mismatch in a PV system arises from two main causes:

Voltage mismatch – Voltage mismatch occurs when multiple conductors, operating in parallel, are forced to operate at a common "compromise" voltage at the inverter bus. Usually is minor unless strings differ in module count/type or are affected by bypass diodes.

Current mismatch – Occurs when dissimilar modules are connected in series. Weaker modules limit current, causing a greater power loss than voltage mismatch.

DNV accounts for three main factors that affect the calculation of the overall mismatch:

- Module mismatch (differences in each module's voltage and current): Module mismatch happens when modules with varying characteristics are connected, even if they are of the same type. Differences in power, current, and voltage cause this mismatch. DNV uses flash test data to check the deviations between voltage and current levels of all the modules. In the absence of flash test data, DNV uses standard deviations of voltage and current derived from the PV module's power tolerance to estimate mismatch.
- Wire run mismatch (voltage mismatch from different length wire runs): Voltage mismatch arises from varying DC wire run lengths, with greater mismatch occurring when there's a wide range between the shortest and longest runs. For string inverters, this mismatch is minimal due to low number of strings connected to a MPPT and hence marginal difference is expected which is not accounted for so DNV considers this as per the standard deviation in module datasheet. However, for central inverters, the effect of minimum and maximum wire losses between 0.1% and 1.7% is considered over and above standard deviation from data sheet based on estimated string cable loss.
- Soiling mismatch (mismatch due to non-uniform dust accumulation): Varying levels of dust or snow on each module will cause more total mismatch for dusty location than a rainy location where modules are more

uniformly cleaned. In the project DNV has considered uniform dust or effect of rainy location considering regular automatic robotic cleaning system.

Overall, with all considerations, DNV ended up with 0.5% mismatch loss for string inverter and 0.6% mismatch loss for central Inverter.

As evidenced in the mismatch loss analysis report by kiloWattsol (Report No. 90735, Version 1.2) [11], shared by Customer both numerical simulations and empirical data confirm that inter-string mismatch losses increase with the number of strings per connected to MPPT i.e. higher mismatch loss is expected for central inverter due to multiple strings connected to single MPPT. However, the increase remains marginal in well-designed utility-scale systems. For example, the study shows that mismatch loss rises from 1.27% to 2.85% over 15 years when moving from a 2 strings/MPPT to 100 strings/MPPT configuration—a difference of just 1.58 percentage over 15 years of lifetime. These results validate DNV's approach, considering the current project is a utility-scale plant with uniform terrain, minimal shading, and standardized racking, where mismatch sources are limited. That said, in more complex or non-uniform designs—such as those with varying pitch, string design, undulated terrain, or shading—the use of string inverters becomes more favourable in terms of mismatch loss. Their distributed MPPT architecture allows for better handling of voltage dispersion and localized mismatch, offering a clear advantage in such scenarios.

6.2.4 Availability

In large-scale photovoltaic (PV) systems, inverter topology plays a critical role in determining system availability, operational resilience, and fault management. String inverters, owing to their modular design and distributed architecture, present a range of technical advantages over centralized inverters with respect to minimizing downtime and enhancing maintainability.

- **Monitoring Granularity and Diagnostic Responsiveness**

String inverter systems are inherently equipped with string-level monitoring, enabling precise localization of underperformance or electrical faults. This facilitates real-time diagnostics and targeted intervention, substantially reducing mean time to detect (MTTD) and mean time to repair (MTTR). In contrast, central inverters offer aggregate-level monitoring, often necessitating manual inspection across multiple strings to isolate anomalies, which increases detection latency and extends system under performance.

- **DC Combiner Box Requirement**

Central inverter configurations typically integrate DC combiner boxes to aggregate input from multiple PV strings. These units introduce additional interconnections, fusing elements, and circuit breakers—all of which constitute potential single points of failure. Each added component in the DC collection system raises the risk of electrical faults and adds to repair complexity. String inverter architectures, by contrast, perform direct MPPT and DC-to-AC conversion at the string level, obviating the need for DC combiners and simplifying the system topology.

- **System Isolation During Faults via Distributed Units**

The higher individual capacity of central inverters (ranging from 500 kW to multi-MW) implies that any inverter-level failure results in the loss of a substantial fraction of plant capacity. This centralized risk concentration leads to increased exposure to downtime. In string inverter systems, each inverter handles a limited number of modules (typically <300 kW per inverter) and this capacity is further divided into available MPPTs of the inverter thereby localizing the operational impact of a fault to a small subsection of the array and ensuring continuity of power delivery from unaffected zones.

Electrical anomalies originating on the DC side, such as insulation faults or ground faults, often translate directly to inverter trips in central configurations, potentially causing complete inverter shutdown. With string inverters, such faults are confined to the affected string only, significantly enhancing system fault containment and enabling continued operation across the majority of the PV array.

- **Streamlined Inverter Replacement and Reduced Downtime**

The plug-and-play modularity of string inverters allows for rapid physical replacement without the need for significant disassembly, heavy equipment, or site reconfiguration. Conversely, central inverters require extensive disconnection, mechanical lifting infrastructure, and labour-intensive processes for replacement or component-level repair—resulting in extended periods of downtime and higher OPEX.

- **Simplified O&M Workflow and Resource Allocation**

Operational maintenance workflows for string inverters are generally limited to unit replacement and re-commissioning, which can be executed by standard O&M personnel with minimal technical specialization. For central inverters, troubleshooting often entails component-level diagnostics, such as inspection of IGBTs, control boards, capacitors, and other internal electronics—requiring specialized teams, OEM coordination, and extended lead times for part procurement. These factors not only increase maintenance complexity but also contribute to longer system unavailability.

Availability Statics based on Market data

According to a collaborative study between DNV and NREL analysing operational data from 1,128 plants in the NREL database for U.S.[12], string or small inverters (<250 kW) demonstrated a cluster median availability of 99%, while larger or central inverters showed a slightly lower median availability of 98%. A separate study conducted by VDE Americas on 182 projects [13], reported that systems using string inverters achieved an average availability of 99.2%, compared to 98.3% for systems employing central inverters.

DNV considers that due to size and nature of the project, it will be supported by local operational staff and will implement a centralized monitoring system. Based on these assumptions, a plant unavailability rate of 0.8% has been applied for tracker systems. Furthermore, DNV has not differentiated availability between string and central inverter configurations, as availability guarantees are typically governed by contractual warranties that apply uniformly across inverter types. In most cases, these contractual warranties do not reflect inverter-specific availability differences and are instead structured to cover the overall system performance.

Loss	Portfolio Size	String	Central
NREL	1128 sites (10 kW – 400 MW size)	99%	98%
VDE Americas	182 (60 kW – 11 MW size)	99.2%	98.3%
DNV Consideration	-	99.2%	99.2%

6.3 Energy Yield Analysis

DNV has performed an independent energy yield analysis of the two final cases that were identified in the Section 5. Section 4 describes Project's main characteristic. Table 6-3 summarizes the main characteristics for both the cases for string and central inverter.

Table 6-3 Main Characteristics of the Project

		String Inverter	Central Inverter
Structure	Azimuth (0º=South)	0º	0º
	Mounting system	Tracker	Tracker
	Tilt angle [°]	-60 / 60	-60 / 60
	Row spacing [m]	7.0	7.0
	Backtracking	Yes	Yes
	Number of modules per structure	90 | 30 x 3	90 | 30 x 3
Modules	PV modules	620 Wp	620 Wp
	PV module type	Bifacial Si-monocrystalline HPDC	Bifacial Si-monocrystalline HPDC
	PV module capacity [Wp]	620	620
	Number of PV modules	18,240	18,720
Inverters	Inverters	330 kW	1320 kW
	Inverter type	String	Central
	Inverter capacity [kWac] *	287	1158
	Number of inverters	32	8
Layout	Modules per string	30	30
	Number of strings per inverter	19	80 (7 Inv) | 64 (1 Inv)
	Total number of strings	608	624
Total Power	Total rated power P_{DC} [kWp]	11,309	11,606
	Total inverter power P_{AC} [kW] *	9,184	9,264
	Maximum power at connection point [kW]**	9,174	9,259
	Rate P_{DC}/P_{AC} *	1.23	1.25
	Rate P_{DC}/P_{AC} at connection point **	1.23	1.25

*Considering inverter power at 45°C. The Power x Temperature curve of the equipment was considered according to the equipment data sheet, as shown in Appendix B.

**Considering 500 MWac grid limitation at the connection point for the project, the capacity for the block is derived by dividing 500 MWac into total number of blocks

6.3.1 Meteorological data used

In the absence of good-quality ground measured data for the Project site, DNV has considered employing specific satellite-derived data – Solcast as a solar resource for site. The Typical Meteorological Year (TMY) composed by GHI, DHI and ambient temperature representative dataset of the Project is shown in Table 6-4. This table shows data from Solcast provider. [1]

Table 6-4: Monthly values of the TMY for GHI, DHI and temperature for the Project

Source	GHI [kWh/m²] Solcast derived TMY [1]	DHI [kWh/m²] Solcast derived TMY [1]	T [°C] Solcast derived TMY [1]
Period	**Jan 2007 – Dec 2024**	**Jan 2007 – Dec 2024**	**Jan 2007 – Dec 2024**
Jan	133	45	22.3
Feb	145	43	24.9
Mar	190	62	25.0
Apr	204	70	29.9
May	220	75	32.2
Jun	216	77	32.5
Jul	217	81	34.7
Aug	201	77	34.3
Sep	182	77	34.0
Oct	172	58	32.2
Nov	139	46	29.0
Dec	129	43	26.0
Annual	**2,146**	**753**	**29.8**

Figure 6-1 shows the sun path for the whole year at the site location, as well as the horizon considered.

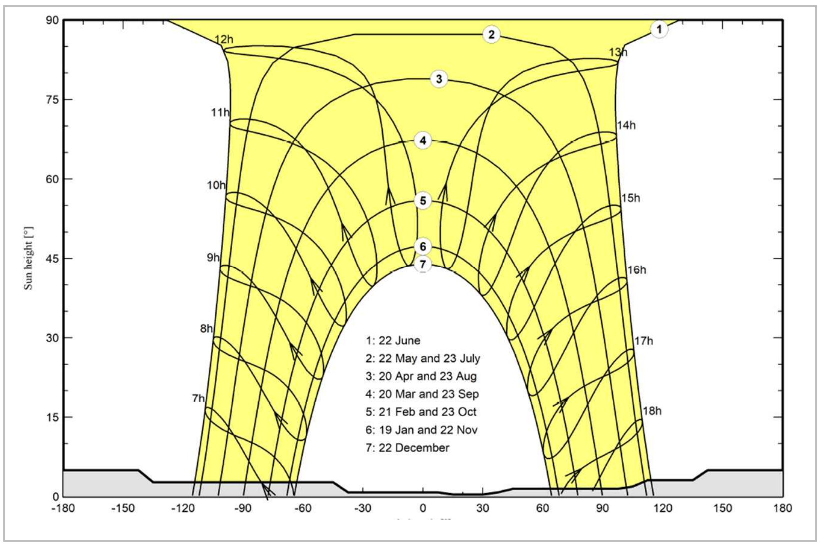

Figure 6-1 Solar path diagram for the Project

The Horizon was calculated using a digital terrain model (DTM) with a resolution of 3 arc-seconds (around 90 m x 90 m) based on the SRTM topographic model from PVGIS.

6.3.2 Loss factors and energy production

DNV simulated the solar PV project based on the layout, configuration and components presented on Appendix A, 0, C, & E, using PVsyst simulation tool. DNV currently utilizes version 7.4.8 and always perform quality checks on new versions prior to implementation on energy assessments.

DNV assumes that a minimum distance will be kept between existing trees and the Project to reduce potential external shading by vegetation. The terrain inclination at the site was remotely assessed and found not significant impact in the energy production for the site. DNV has assumed a low complexity terrain for the PV simulations, therefore, it was considered that current unlevelled areas can be levelled during the construction of the plant.

The simulation is based on hourly basis, using the "one-diode" model [3], which has become industry practice. The "one-diode" model is non-linear and implicit, and the required hourly calculations at the site are performed with the support of computational software. This procedure consists in an energy production assessment correspondent to the long-term weather conditions.

DNV has calculated, estimated, or assumed losses for the energy simulation, and the results are shown in Table 6-6. Losses occurring after the inverter (i.e., inverter derate, AC ohmic, transformer, station loads, and availability) are calculated in a post-processing tool. The description of the loss mentioned in Table 6-5 factors present aspects where the Project characteristics deviated from the DNV standard assumptions detailed in Appendix B.

Table 6-5: Loss and Other Factors Considered for Energy Yield Analysis

No.	Parameters	Unit	String	Central	Notes
1	Albedo	%	As per SolarGIS prospect	As per SolarGIS prospect	-
2	Bifaciality Factor	-	0.8	0.8	Typical value observed for N type bifacial PV module technology
3	Rear structural shade	%	10	10	Default assumption for typical tracker system in the absence of tracker drawings
4	Rear Mismatch	%	2	2	Default assumption for typical tracker system in the absence of tracker drawings
5	Module transparency	%	5	5	Default
6	Shadings	-	As per the layout design for the string inverter	As per the layout design for the central inverter	No undulations or ground data considered.
7	Light-Induced Degradation	%	1	1	DNV has applied a default LID loss of 1% based on type of PV module
8	IAM	-	Fresnel AR	Fresnel AR	For the IAM loss, Fresnel AR coating profile is considered as per module glass type.
9	Soiling (Robotic)	%	1	1	Considering daily robotic cleaning operation
10	Module Quality Gain	-	-0.20	-0.20	This includes -0.8% Quality gain, 0.5% MPPT non ideal behavior, 0.1% modelling error
11	Mismatch loss	%	0.50	0.60	DNV accounts module mismatch, wire run mismatch and soiling mismatch for mismatch loss calculation
12	DC Ohmic Losses	%	0.60	1.38	As per cable calculation in Section 6.2.2.1
13	AC Ohmic Losses (LV side)	%	0.90	0.03	As per cable calculation in Section 6.2.2.2
14	AC Ohmic Losses (MV side)	%	0.33	0.32	As per cable calculation in Section 6.2.2.2
15	Inverter losses	%	Based on Inverter OND	Based on Inverter OND	-
16	LV / MV Transformer losses	%	fixed-load loss of 0.2%, variable-load loss of 0.9%	fixed-load loss of 0.2%, variable-load loss of 0.9%	For the medium voltage (MV) transformers, DNV assumed a fixed-load loss of 0.2% and a variable-load loss of 0.9% at STC.
17	MV / HV Transformer losses	%	fixed-load loss of 0.1% and a variable-load loss of 0.4%	fixed-load loss of 0.1% and a variable-load loss of 0.4%	For the high voltage (HV) transformers, DNV assumed a fixed-load loss of 0.1% and a variable-load loss of 0.4% at STC
18	Auxiliary Losses	%	Equal station load to be considered for both the cases to get loss in range of ~0.3%	Equal station load to be considered for both the cases to get loss in range of ~0.3%	DNV estimated the auxiliary loads for the Project based on typical numbers. The same will be considered for the project. The inverter Auxiliary loss is part of Inverter loss.

No.	Parameters	Unit	String	Central	Notes
19	Unavailability	%	0.8	0.8	DNV assumed that the project will be assisted by local staff and will adopt a monitoring system. With these assumptions the plant unavailability was set to 0.8%. If the above considerations are not valid the availability value should be updated. This value should also be amended in conjunction with guaranteed availability from the O&M contract once this becomes available. The same will be considered for the project.
20	Grid Limitation	%	500 MWac	500 MWac	A grid export limitation of 500 MWac has been considered for the project. As per DNV's methodology, losses occurring after the inverter output—such as grid limitation—are calculated separately outside of PVSyst. Therefore, the grid limitation loss is not modeled within PVSyst but is instead applied during the post-processing stage.
21	PV degradation	linear %/year	0.64	0.64	The degradation will be considered with clipping adjustment due to overloading loss if any.

Table 6-6 presents the predicted long-term annual energy production for the design specific blocks, excluding the effects of PV system degradation. Table 6-7 shows the monthly estimate. Loss factors are indicated for the whole system in the block, on an annual basis. The net energy forecast below represents the estimate for the annual energy output of the photovoltaic system (P50). This value is the best estimate of the annual value, from the proposed project. There is therefore a 50% chance that, even taken over very long periods, the mean energy production will be less than the value given.

The following "net energy" forecast represents the energy estimate in year 1, including the electrical and availability losses of the photovoltaic system and grid until connection point. This value is the best estimate of the annual value for the Project.

Table 6-6: Energy estimate for the block – 9 MW (no degradation applied)

		Unit	String Inverter	Central Inverter
Input data	Global Horizontal Irradiation	[kWh/m2/year]	2,146	2,146
	Global irradiation on the inclined plane	[kWh/m2/year]	2,725	2,725
	Ambient Temperature	[ºC]	29.8	29.8
	Azimuth	[deg]	0	0
	Tilt angle	[deg]	-60 / 60	-60 / 60
	Peak power	[kWp]	11,309	11,606
Loss factors and Energy Results	Loss factors			
	Global Incident below threshold	[%]	0.0	0.0
	Horizon	[%]	0.6	0.6
	Shadings	[%]	0.7	0.7
	IAM	[%]	0.7	0.7
	Soiling	[%]	1.0	1.0
	Ground reflection on front side	[%]	-0.6	-0.6
	Back side influence	[%]	-5.8	-5.8
	Low-irradiance efficiency fall-off	[%]	-0.3	-0.3
	Temperature	[%]	7.6	7.6
	Module quality	[%]	-0.7	-0.7
	MPPT non-ideality	[%]	0.5	0.5
	Light induced degradation (LID)	[%]	1.0	1.0
	Mismatch	[%]	0.5	0.6
	Mismatch for back irradiance	[%]	0.1	0.1
	Ohmic (DC)	[%]	0.6	1.2
	Inverter	[%]	1.8	2.8
	Transformers LV-MV	[%]	1.3	1.3
	Transformers MV - HV	[%]	0.6	0.6
	Auxiliary loads	[%]	0.3	0.3
	Ohmic AC (AC cabling until connection point)	[%]	0.9	0.2
	Plant Controller	[%]	1.0	0.6
	Sub hourly correction	[%]	0.4	0.5
	System unavailability	[%]	0.8	0.8
	Grid unavailability	[%]	0.0	0.0
	Net Energy (P50 Year 1)	**[MWh/year]**	**26,918**	**27,434**
	Yield Factor Net Energy	**[kWh/kWp]**	**2,380**	**2,364**
	Performance Ratio Net Energy	**[%]**	**87.4%**	**86.7%**

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Table 6-7: Monthly Energy Estimates for block

	String Inv		Central Inv	
Month	**Energy [MWh]**	**PR**	**Energy [MWh]**	**PR**
Jan	1,800	90.9%	1,841	90.6%
Feb	1,940	89.3%	1,981	88.9%
Mar	2,400	86.5%	2,441	85.7%
Apr	2,480	85.4%	2,521	84.6%
May	2,650	85.2%	2,691	84.3%
Jun	2,580	85.6%	2,621	84.7%
Jul	2,600	86.2%	2,641	85.4%
Aug	2,420	86.7%	2,461	85.9%
Sept	2,220	87.9%	2,271	87.6%
Oct	2,220	88.3%	2,271	88.0%
Nov	1,860	89.6%	1,901	89.2%
Dec	1,750	90.3%	1,791	90.1%
Total	**26,918**	**87.4%**	**27,434**	**86.7%**

6.3.3 Long Term Energy Production Tables

The energy figures in previous sections do not include the power degradation ratio. DNV notes that the power degradation considered covers all module components (cells, EVA, glass), as well as other components of the whole PV system. DNV has performed an extensive review of available industry literature and data regarding historical long-term system-level degradation of PV systems ([5][6][7]). Most of the literature refers only to modules degradation results, but system-level effects add up to the total degradation rate, although the exact mechanisms are not well characterized. Based on these results, the median system-level degradation rate is reported to be 0.64%, and the interquartile range (P25-P75) is 0.2%-1.2% per annum. DNV considered the median value of 0.64% for the annual degradation of PV systems.

DNV has performed a clipping-adjusted degradation (CAD) rate calculation for the Project. Project degradation will be partially masked by the impact of inverter-level and plant-level clipping. The mechanisms of this effect are well-understood, and DNV considers it reasonable to adjust base degradation rate assumptions within financial models accordingly. When project dc-to-ac loading ratios are sufficiently high, generated dc energy exceeds the inverter rating during certain periods and excess energy is “clipped” down to inverter-rated outputs; this energy does not contribute to net energy forecasts and is not realized at the revenue meter. Since the system generates more dc energy than reaches the inverter output, metered production decreases at a lower effective annual degradation rate than that experienced by modules and the dc system. DNV refers to this rate as the “clipping-adjusted” degradation rate.

DNV has estimated annual clipping-adjusted degradation rates for the system obtaining an average clipping-adjusted degradation rate modelling the system with DNV’s standard degradation rate of 0.64% from Year 2 through year 30. DNV opines that there is additional uncertainty associated with useful life after 25 years, which is unknown.

The resulting production figures with corresponding Performance Ratios, are presented in Table 6-8 for both the cases.

Table 6-8: Annual Net Energy [MWh/year] and related Performance Ratio for the Block – 9 MW

	String Inverter		Central Inverter	
Year	**PR**	**P50**	**PR**	**P50**
1	87.4%	26,918	86.7%	27,434
2	86.9%	26,775	86.3%	27,293
3	86.4%	26,630	85.9%	27,151
4	86.0%	26,485	85.4%	27,008

	String Inverter		Central Inverter	
Year	**PR**	**P50**	**PR**	**P50**
5	85.5%	26,338	84.9%	26,864
6	85.0%	26,191	84.5%	26,719
7	84.5%	26,042	84.0%	26,573
8	84.0%	25,891	83.6%	26,426
9	83.5%	25,739	83.1%	26,278
10	83.0%	25,584	82.6%	26,129
11	82.5%	25,428	82.1%	25,977
12	82.0%	25,270	81.7%	25,824
13	81.5%	25,110	81.2%	25,669
14	81.0%	24,950	80.7%	25,512
15	80.4%	24,788	80.2%	25,353
16	79.9%	24,624	79.7%	25,192
17	79.4%	24,460	79.1%	25,030
18	78.8%	24,294	78.6%	24,865
19	78.3%	24,128	78.1%	24,699
20	77.8%	23,961	77.6%	24,532
21	77.2%	23,793	77.0%	24,364
22	76.7%	23,624	76.5%	24,194
23	76.1%	23,455	76.0%	24,024
24	75.6%	23,285	75.4%	23,853
25	75.0%	23,114	74.9%	23,681
26	74.5%	22,943	74.3%	23,508
27	73.9%	22,772	73.8%	23,335
28	73.3%	22,600	73.2%	23,161
29	72.8%	22,428	72.7%	22,987
30	72.2%	22,256	72.1%	22,812
Lifetime Energy	-	**739,876**	**-**	**756,448**

6.3.4 Energy Yield for 500 MWac

As outlined in the Section 6.1, the total plant capacity of 500 MWac is structured as an aggregation of multiple standardized ~9 MWac blocks. Since all design differences—from the DC side up to the AC interconnection point—have been fully accounted for in the block-level EYA for both inverter configurations, the total plant-level energy yield can be accurately derived by scaling the block-level results. This is achieved by simply multiplying the energy yield per block by the number of blocks required to reach the full 500 MWac capacity for each case. The results of total project capacity of 500 MWac capacity are outlined in Table 6-9.

Table 6-9: Energy estimate for the Project (no degradation applied)

		String	Central
DC Capacity of the Block	MWp	11.308	11.606
AC Capacity of the Block @45°C	MW	9.184	9.264
System Multiplier	Nos	54.5*	54
DC Capacity of the Project	MWp	616.3	626.7
AC Capacity of the Project @45°C	MW	500	500
Yield Factor Net Energy	[kWh/MWp]	**2,380**	**2,364**
Net Energy (P50 Year 1)	[GWh/year]	**1,467.0**	**1,481.4**
Performance Ratio Net Energy	[%]	**87.4%**	**86.7%**

* 54 full blocks with 32 string inverters and 1 half block with 16 string inverters.

The Table 6-10 below shows the Monthly energy estimate for the entire project capacity

Table 6-10: Monthly Energy Estimates for the Project

	String Inv		Central Inv	
Month	Energy [MWh]	PR	Energy [MWh]	PR
Jan	98.1	90.9%	99.4	90.6%
Feb	105.7	89.3%	107.0	88.9%
Mar	130.8	86.5%	131.8	85.7%
Apr	135.1	85.4%	136.1	84.6%
May	144.4	85.2%	145.3	84.3%
Jun	140.6	85.6%	141.6	84.7%
Jul	141.7	86.2%	142.6	85.4%
Aug	131.9	86.7%	132.9	85.9%
Sept	121.0	87.9%	122.6	87.6%
Oct	121.0	88.3%	122.6	88.0%
Nov	101.4	89.6%	102.7	89.2%
Dec	95.4	90.3%	96.7	90.1%
Total	**1,467.0**	**87.4%**	**1,481.4**	**86.7%**

6.4 CAPEX & OPEX Comparison

This section covers the approach followed for estimating the CAPEX and OPEX of the project for corresponding string and central configurations.

6.4.1 CAPEX

The Capital Expenditure (CAPEX) estimation used in this analysis is derived from robust sources, ensuring that the financial assumptions underpinning the LCOE modelling reflect realistic, region-specific, and market-validated benchmarks. The first source of CAPEX data comprises cost inputs from 34 utility-scale solar PV projects across Saudi Arabia, with capacities ranging from ~25 MWp to 3 GWp. These 34 plants have cumulative approximately capacity of 30 GWp. These projects span different development stages, including financial close, construction, operational, and pre-construction phases. The cost dataset used is filtered to exclude outliers—projects with atypical geographical or regulatory complexities—to ensure the uniformity and accuracy of comparison. The design specific CAPEX estimation is provided below in Table 6-11 for one block of size ~9 MW.

Table 6-11: CAPEX considered for the Block – 9 MW

Components	String Inverter CAPEX (KUSD)	Central Inverter CAPEX (KUSD)	Remark
Additional BOS	635.4	743.9	The design specific cost considered based on actual BoM of the two cases. The differentiation will be applicable to items - Combiner boxes, LV AC Panels, Trenches up to MV transformer.
Area Acquisition	310.1	317.6	Cost of area acquisition based on required area
Array Cable	326.5	318.2	The design specific cost to be considered based design specific cable system cost - DC & AC side up to MV Station
Array Cable Installation	33.2	33.9	The design specific cost to be considered based design specific cable system cost - DC & AC side up to MV Station
Connection application	10.9	10.9	Identical cost for both the system
Development application	87.6	87.6	Identical cost for both the system
Engineering	316.1	322.8	Difference due to difference in DC capacity
Export Cable	9.5	9.5	Identical cost for both the system
Export Cable Installation	4.5	4.5	Identical cost for both the system
Inverter	0.0	0.0	The inverter cost is excluded from the analysis.
Logistics	72.9	74.4	Difference due to difference in DC capacity
Mounting structure	1552.3	1593.2	Difference due to difference in DC capacity
Onshore Substation	57.5	57.5	Identical cost for both the system
Other Development and Project Management	4.5	4.5	Identical cost for both the system
Preliminary studies	5.0	5.0	Identical cost for both the system
Site Preparation	704.5	723.1	Difference due to difference in DC capacity
Solar Installation	395.4	405.8	Difference due to difference in DC capacity
Solar PV module	904.7	928.5	Module prices are considered for latest module price from open source for the same technology with modules imported from China.
Total	**5430.4**	**5640.6**	**Total CAPEX of the project**
DC Component	**314.5**	**314.5**	**USD/KWp**
AC Component	**-**	**-**	**USD/KW**
DC+AC (65/35)	**131.0**	**138.4**	**USD/(65%*kWp+35%*kW)****
Fixed Cost	**179.4**	**179.4**	**Common components**
Area based on Layout	**1.92**	**1.92**	**USD/Sq.m**

** The expression USD / (65% × kWp + 35% × kWac) is used to normalize CAPEX by accounting for both DC and AC system sizing, reflecting the typical cost distribution in utility-scale PV projects—where ~65% of costs are driven by DC components (modules, structures, DC side BoS) and ~35% by AC components (transformers, interconnection, AC side BoS).

6.4.2 OPEX

The Operational Expenditure considered reflect the lifetime average—essentially, the equivalent annual cost of operating a project in year one. The estimates apply to single-axis tracker systems and account for factors such as supply chain tariffs on spare parts, age-related equipment failures, and operational efficiency improvements. The cost also considers real labour wage growth in each market and supply chain and commodities costs. However, the modelling excludes Inverter corrective maintenance & replacements, site-specific variables like project location (in terms of advantages from logistics), technological differences between equipment manufacturers (OEM specific advantages due to technological differences between components/subcomponents for e.g. the string inverter considered in this study includes an integrated digital IV curve diagnosis feature, which can significantly reduce the overall cost associated with PV module IV curve testing. However, this benefit has not been accounted for in the current analysis and is expected to provide an additional OPEX advantage in favour of the string inverter case), and pricing impacts from different contract structures.

The cost considers macroeconomic trends, including real labour wage growth and fluctuations in supply chain and commodity costs.

Table 6-12: OPEX cost for the Block - 9MW

Components	String (USD/MWp/1st Year)	Central (USD/MWp/ 1st Year)
Operational Oversight and Administrative Support - Project management, reporting, remote monitoring, administrative overhead	64	64
Solar Panel Cleaning Services – this cost is for manual water cleaning of modules considering 3 cleaning cycles in a year. Robotic cleaning expense is included in routine preventive maintenance and repair cost.	619	619
Vegetation Control - Routine mowing considering 1 mowings per year	275	275
Routine Preventive Maintenance – this includes preventive maintenance cost for all plant inspections and preventive maintenance activities such as visual inspections, thermal inspections, tests, calibrations, routine periodic inspections of PV module, inverter, BoS & substation.	792	799
Repairs and Issue Resolution - Minor part replacements, basic diagnostics, field-level troubleshooting excluding inverter related items	601	601
Inverter Maintenance & Replacement – Not included	-	-
Tracking Systems Maintenance - Preventive servicing of motors, actuators, alignment corrections	1,051	1,051
Total OPEX (USD – Year 1)	**38,476**	**39,573**
Total OPEX / MWp (Year 1)	**3,402**	**3,410**

6.4.3 Discount Rate (WACC)

A Weighted Average Cost of Capital (WACC) of 6.6% has been used in the LCOE calculation, representing the blended cost of financing through debt and equity. This rate reflects typical market conditions for utility-scale solar PV projects in stable investment environments, where perceived project risk is moderate, and financing is competitively sourced. This rate reflects a balanced mix of debt and equity financing and accounts for project risk, investor expectations, and macroeconomic conditions.

The WACC incorporates:

- Cost of Debt – adjusted for interest rates, loan tenors, and debt servicing conditions, often supported by international or local financial institutions.
- Cost of Equity – reflecting investor return expectations, market risks, and long-term policy stability.
- Capital Structure – assuming a balanced ratio of debt to equity commonly observed in the region.

The 6.6% discount rate aligns with historical benchmarks seen across Middle East solar tenders and independent financial models, where renewable energy investments have gained maturity and competitive pricing.

6.4.4 Inflation Rate or Escalation

An average annual inflation rate of 2.4% has been observed in Saudi Arabia between 2001 and 2023. This relatively low and stable inflation reflects consistent macroeconomic management, supported by strong fiscal reserves and energy sector revenues. In the context of long-term project modelling, this rate is used to adjust nominal values to real terms, helping assess cost trends and maintain consistency in LCOE and financial forecasts.

6.4.5 Project Life

In the LCOE calculation, the project life defines the duration over which capital and operating costs are spread and energy generation is accumulated. For this LCOE study, a 30-year project life has been assumed. This is supported by current industry trends, where PV modules are commonly offered with 30-year performance warranties, reflecting advances in technology and long-term reliability. While actual project lifespans may vary based on site-specific and contractual factors, this assumption provides a realistic basis for long-term economic evaluation in the context of this analysis.

7 LCOE CALCULATION

LCOE is a common measure that is used to compare different projects and technologies based on the combination of CAPEX, OPEX, energy yield and fuel cost. In renewable technologies usually fuel cost tends to zero compared to conventional technologies. LCOE is usually used because includes all the costs over lifetime of a project including cost of capital. It is also important to highlight that using the discounted cash flow method the time value of money is considered. This is based on the use of the Weighted Average Cost of Capital (WACC) or also called the discount rate. The analysis utilizes a standard, industry-accepted LCOE formula, consistent with methodologies endorsed by institutions such as the National Renewable Energy Laboratory (NREL) and the International Renewable Energy Agency (IRENA).

$$\mathrm{LCOE} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where:

LCOE	=	the average lifetime levelised cost of electricity generation
I_t	=	investment expenditures in the year ***t***
M_t	=	operations and maintenance expenditures in the year ***t***
F_t	=	fuel expenditures in the year ***t***
E_t	=	electricity generation in the year ***t***
r	=	discount rate
n	=	economic life of the system.

$$\mathrm{LCOE} = \frac{\text{sum (NPV) of costs over lifetime}}{\text{sum (NPV) of electrical energy produced over lifetime}}$$

Figure 7-1: RENEWABLE POWER GENERATION COSTS, IRENA

DNV has conducted an LCOE analysis for both the string inverter and central inverter configurations.

Key input parameters for the analysis include:

- Energy yield (based on design specific simulations)
- Capital expenditures (CAPEX) excluding inverter cost
- Operational expenditures (OPEX) excluding inverter replacement cost

- weighted average cost of capital (WACC)
- Escalation/Inflation rate

As detailed in previous sections, DNV has considered the design specific components between the two configurations—particularly in energy yield and cost structure—ensuring a transparent and comparative evaluation of LCOE for informed decision-making.

Table 7-1: LCOE Results for block – 9 MW

Type	Unit	String	Central
DC Power	***MWp***	11.309	11.606
Relative DC Power	***%***	100.0%	102.6%
AC Capacity@45°C	***MW***	9.184	9.264
Total Area Including road and other infrastructure	***km2***	0.162	0.166
Results (Including Availability)			
Yield Factor	***MWh/MWp***	**2,380.3**	**2,363.7**
Net Energy	***MWh/year***	26,918	27,434
Performance ratio	***%***	87.4%	86.7%
Degradation (CAD)	***%***	0.64%	0.64%
Lifetime Energy	***MWh***	739,876	756,448
Relative Lifetime Energy	***%***	**100%**	**102.2%**
Total CAPEX	***USD***	5,430,433	5,640,647
Overall Unit CAPEX	***USD/Wp***	0.480	0.486
Relative Unit CAPEX	***%***	**100.0%**	**101.2%**
Discount Rate	***%***	6.60%	6.60%
Escalation/Inflation	***%***	2.40%	2.40%
OPEX	***USD / Wp / Year***	0.00340	0.00341
Relative OPEX	***%***	**100%**	**100.2%**
LCOE	***USD / MWh***	**18.51**	**18.80**
Relative LCOE	***%***	**100.0%**	**101.6%**

7.1.1 LCOE Calculation for 500 MWac

As explained in Section 6.1 the entire 500 MWac plant is designed as a repetition of standardized ~9 MWac inverter station blocks, all relevant technical and financial parameters—CAPEX, OPEX, energy yield, and system losses—scale proportionally with the number of blocks. As a result, the LCOE derived at the block level remains representative and consistent when extended to the full project scale. This is because:

- CAPEX & OPEX costs are distributed evenly per block and scale linearly.
- Energy yield differences, based on inverter configuration, are embedded in the block-level EYA and remain consistent across all blocks due to uniform design.
- System architecture beyond the MV station (e.g., HV transformer, grid interface) contributes proportionally and is factored into both design specific block-level cost modelling.

Therefore, multiplying the block-level results by the number of blocks required to achieve 500 MWac produces an accurate reflection of full-plant performance and economics, validating the extrapolation of LCOE outcomes to the entire project. Table 7-2 shows design specific project level LCOE study.

Table 7-2: LCOE Results for the Project

Type	Unit	String	Central
DC Power	***MWp***	616.3	626.7
Relative DC Power	***%***	100.0%	101.7%
AC Capacity@45°C	***MW***	500.5	500.3
Total Area Including road and other infrastructure	***km2***	8.83	8.96
Results (Including Availability)			
Yield Factor	***MWh/MWp***	**2,380.3**	**2,363.7**
Net Energy	***GWh/year***	1,467.0	1,481.4
Performance ratio	***%***	87.4%	86.7%
Degradation (CAD)	***%***	0.64%	0.64%
Lifetime Energy	***GWh***	40,323.2	40,848.2
Total CAPEX	***KUSD***	295,958.6	304,594.9
LCOE	***USD / MWh***	**18.51**	**18.80**
Relative LCOE	***%***	**100.0%**	**101.6%**

Based on the analysis, the string inverter configuration demonstrates a better LCOE of USD 18.51/MWh compared to USD 18.80/MWh for the central inverter. This results in a relative LCOE improvement of 1.6%, primarily driven by slightly higher energy yield and lower CAPEX associated with the string inverter setup. While the difference is modest, it suggests that string inverters may offer better value under the given assumptions. However, this conclusion is site- and design-specific. Therefore, a detailed techno-economic assessment, tailored to the specific project conditions—including equipment specifications, layout, and long-term operational requirements—is recommended before finalizing the inverter configuration.

8 SENSITIVITY ANALYSIS

A sensitivity analysis was conducted to evaluate the potential impact of availability differences on overall energy yield and LCOE for the central inverter configuration. As outlined in Section 6.2.4, industry data suggests that string inverters tend to exhibit higher median availability compared to central inverters, primarily due to their distributed architecture and enhanced redundancy.

To explore this aspect, DNV performed a sensitivity case assuming a 0.5% lower availability for the central inverter configuration relative to the string inverter system. DNV has considered this based on regional experience with utility scale projects of similar size where inverter availability is often governed by contractual guarantees and service provisions. This adjustment reflects a more conservative operational outlook for central inverters, which may experience some of the constraints like longer downtimes or limited redundancy in specific scenarios as explained in Section 6.2.4.

It is important to note that this assumption is not absolute and cannot be generalized across all projects, as inverter availability is influenced by a combination of factors like O&M strategy and response time, contractual performance guarantees, system design and redundancy, environmental and site-specific conditions and technology maturity and supplier support.

Overall, the resulting annual EYA and corresponding LCOE due to the adjusted availability is mentioned in the Table 8-1

Table 8-1: Energy estimate & LCOE for the Project (availability impact)

Type	Unit	String	Central
DC Capacity of the Project	**MWp**	616.3	626.7
AC Capacity of the Project @45°C	**MW**	500	500
Availability Consideration	**%**	99.2%	98.7%
Yield Factor Net Energy	**[kWh/MWp]**	**2,380**	**2,352**
Net Energy (P50 Year 1)	**[GWh/year]**	**1,467.0**	**1,473.9**
Performance Ratio Net Energy	**[%]**	**87.4%**	**86.3%**
Lifetime Energy	**GWh**	**40,323.2**	**40,640.9**
LCOE	USD / MWh	**18.51**	**18.90**
Relative LCOE	%	**100%**	**102.1%**

The sensitivity analysis shows that the LCOE for the string inverter configuration is USD 18.51/MWh, while the central inverter configuration results in a slightly higher LCOE of USD 18.90/MWh. This reflects a relative increase of 2.1%, indicating a modest economic advantage for the string inverter under the given assumptions.

This exercise is intended solely to assess the relative impact of availability assumptions on project economics. It reinforces the need for project-specific evaluation of operational reliability parameters when comparing inverter configurations in utility-scale solar PV systems.

9 TECHNOLOGY REVIEW OF SOLAR PV INVERTERS

Inverters are the power electronic devices that are directly connected to the PV array (on the DC side) and to the electrical grid (on the AC side). They essentially convert the DC energy produced by the array into the AC energy that is to be injected into the grid. This section will provide a high-level technical review of PV inverter technologies and current market trends.

9.1 String vs Central

Two main types of inverter arrangements are available in the market for utility scale solar PV plants, namely central and string inverters. Central inverters are more commonly deployed on utility scale solar PV plants, but string inverters have also been deployed on utility scale solar PV plants and are increasingly being deployed on utility scale solar PV plants due to the decreasing cost difference between the two technology types. The advantages and disadvantages of each main type of inverter are shown in Figure 9-1 below:

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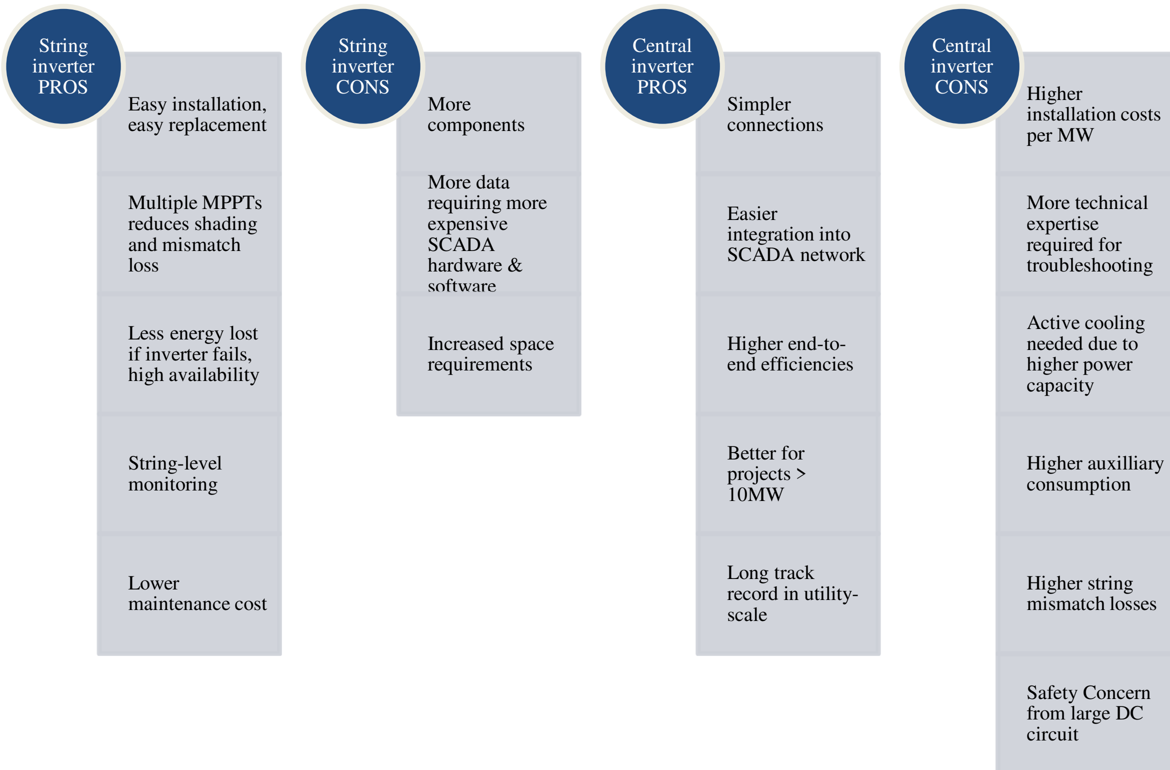

Figure 9-1: Advantages and disadvantages of each main inverter type

Three-phase string inverter shares (Utility and Resi/C&I) in 2023 in the utility solar sector witnessed an increase of 71% year-over-year in the global solar inverter market. Some of the main reasons behind the increase are presented under Figure 9-2.

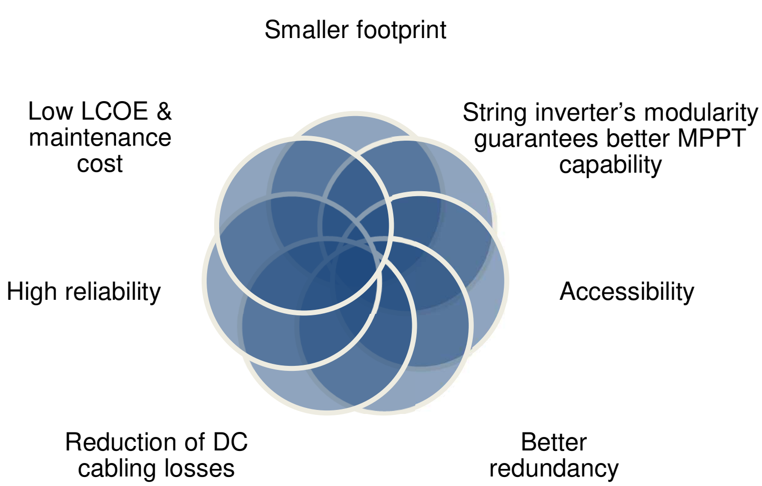

Figure 9-2: Reasons behind increase in three-phase string inverters shares in 2023

9.2 Price Trend

China's rapid expansion of the photovoltaic (PV) market in recent years has led inverter manufacturers to significantly scale up production capacity, while simultaneously making substantial investments in research and development (R&D) and automation technologies. Driven by continuous design optimization and intense market competition, the prices of residential, commercial, and utility-scale inverters have plummeted to unprecedented lows. This trend is expected to persist, with further price reductions projected over the next decade.

9.2.1 String Inverter

Leading companies have significantly ramped up the production of 1,500 V string inverters, now offering models with power ratings of up to 350 kW. The increased power density of these inverters is driving down costs on a USD/W basis.

In China, prices have fallen below USD 0.02/WT, while similar products are priced between USD 0.03 and USD 0.04/W in Europe, remaining competitively priced against EU-manufactured central inverters. Global prices are expected to continue a gradual decline driven by ongoing improvements in design efficiency. The price forecast trend for utility string inverters is shown in the Figure 9-3.

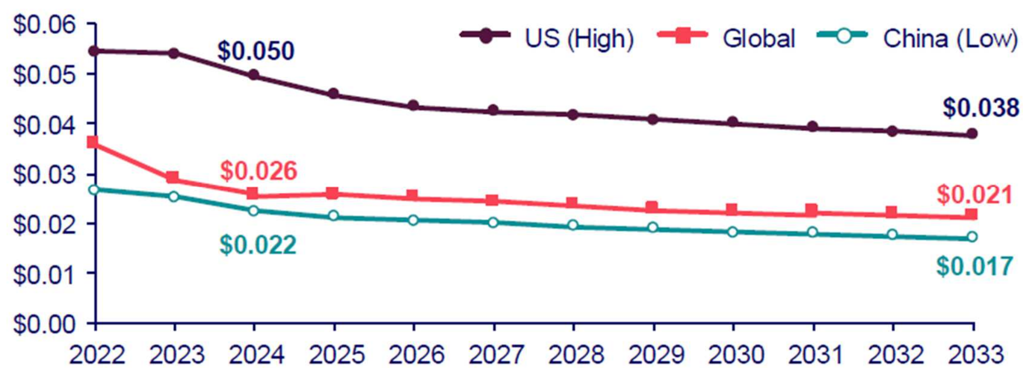

Figure 9-3: Utility-scale string inverter average selling price 2022-2033 (USD/Wac) [10]

9.2.2 Central Inverter

Central standalone inverters remain the most cost-effective option for large-scale solar projects, with prices well below USD 0.02/Wac in regions like China and India, and factory gate prices approaching USD 0.01/Wac. The larger electronic components used in central inverters have driven manufacturers to adopt higher levels of automation in their production processes, contributing to further cost reductions.

Central MV station solution follow similar pricing trends to central standalone inverters but carry a premium of USD 0.003/Wac to USD 0.01/Wac due to the inclusion of integrated transformers and switchgear. An overall downward trend is expected, with a 22% cost reduction over the next decade. [10]

The price forecast trend for central standalone inverters is shown in Figure 9-4 & central inverter solution is shown in Figure 9-5.

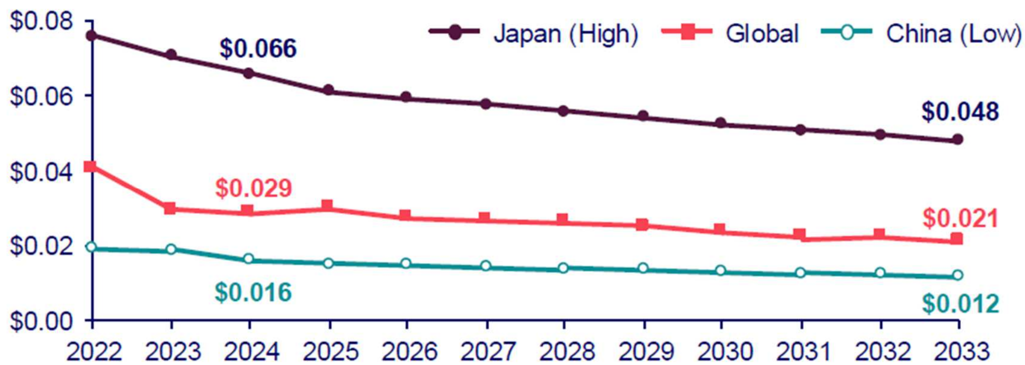

Figure 9-4: Central standalone inverter average selling price 2022-2033 (US$/Wac) [10]

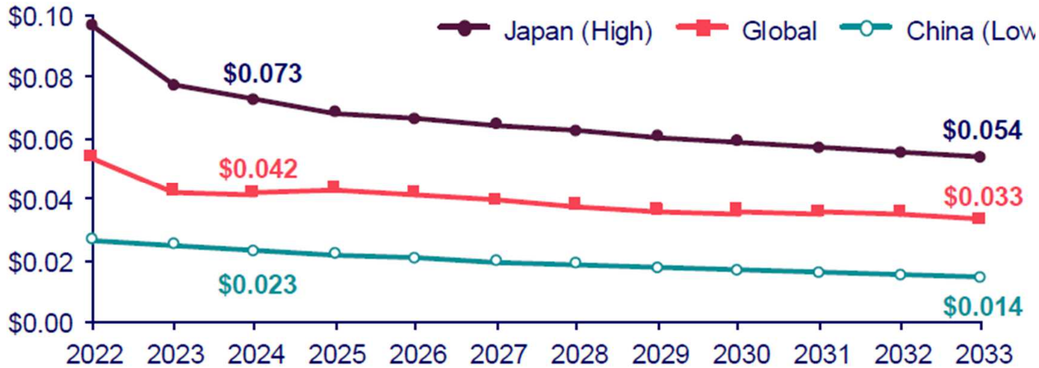

Figure 9-5: Central solution inverter average selling price 2022-2033 (US$/Wac) [10]

9.3 Other Technical Characteristics

The techno-economic performance of an inverter is influenced by a range of technical and operational characteristics that directly impact energy yield, reliability, and cost-efficiency over the system's lifetime. Among these, several key attributes play a particularly critical role in determining overall project performance and financial viability. Evaluating these parameters in detail is essential to selecting an inverter that aligns with the site-specific conditions and long-term performance expectations of the project. Below are some of these parameters highlighted in detail.

- **Long term Service Agreement (LTSA):** The LTSA provides extended warranty coverage, routine maintenance, and performance optimization for solar inverters in utility-scale plants. It ensures predictable O&M costs, minimizes unplanned downtime, and enhances inverter reliability through proactive monitoring and firmware updates. LTSAs also mitigate performance degradation risks by committing to timely repairs and replacements, ensuring sustained system efficiency. This technical support ensures maximum uptime and energy yield, while protecting against inverter-related operational risks. From a techno-commercial perspective, the decision to adopt an LTSA should consider project-specific factors such as equipment selection, site conditions, O&M strategy, and risk tolerance. Evaluating the cost-benefit implications of LTSA adoption is therefore essential in aligning long-term operational goals with financial performance expectations.

- **Expected Equipment Lifetime:** The expected lifetime of the inverter is a critical factor in evaluating its long-term performance and economic viability. Most modern inverters are designed with a typical operational life of 15 to 20 years, although this can vary based on design quality, environmental conditions, and maintenance practices. Thermal management plays a key role in longevity, as inverters operating in high ambient temperatures without proper cooling systems may degrade faster and experience reduced performance.

Additionally, the durability of internal components such as capacitors, fans, and power electronics significantly influence reliability.

In regions like the Middle East, environmental stress factors—such as dust, humidity, salinity, and UV radiation—can further affect the inverter's life expectancy, making it crucial to ensure the equipment is suitably rated for such conditions. A favourable degradation profile, characterized by a low annual failure rate and consistent efficiency retention, contributes to predictable operational expenditures and strengthens the project's financial modelling. Manufacturer warranties, typically ranging from 5 to 10 years and often extendable to 15 or 20 years, are important indicators of confidence in the product's longevity and should be backed by strong after-sales support to mitigate operational risks.

- **Uptime Warranty:** Most inverter manufacturers offer contractual uptime warranties of up to 99.5%-99.7%, typically including provisions for liquidated damages. To support such warranties, inverter OEMs maintain a sufficient inventory of spare parts on-site and ensure regular inverter maintenance. In cases of significant operational disruptions, the OEM may also be liable for compensation, helping to reduce the financial impact on the developer or plant operator. However, it is common for such liability to be capped at the cost of the inverter itself and may not fully cover the broader financial losses incurred due to downtime or lost generation.
- **Response time:** A defined response time ensures that inverter failures are addressed promptly, reducing the risk of extended operational disruptions. By setting clear expectations for repair and replacement timelines, plant operators can mitigate financial losses caused by power generation shortfalls. Additionally, a fast response time helps maintain system reliability and performance, improving the long-term operational efficiency of the solar plant while minimizing the impact of inverter failures on overall energy output.
- **String level monitoring:** String-level monitoring in solar systems is essential for optimizing performance, enhancing system reliability, and improving maintenance efficiency. By tracking each string's voltage, current, and power output in real time, it enables early detection of underperformance, faults, or shading issues at the individual string level. Since high number of inverter-related issues stem from frequent DC-side faults like short circuits, ground faults, and over/under voltage, string monitoring allows for the early identification and early mitigation of these problems, preventing permanent damage to the inverter and minimizing downtime.
- **Performance at elevated temperatures:** Inverter temperature derating curves are crucial for understanding how inverters perform in higher ambient temperatures. Typically, the data provided by inverter manufacturers is based on a limited number of samples tested during the product design phase. Furthermore, these inverters are often tested for temperature derating over short durations, which may not accurately represent real-world conditions in arid regions where high temperatures persist over extended periods. DNV recommends for conducting prolonged testing to better validate inverter performance in sustained high-temperature environments, ensuring that the system performs reliably under real-world conditions. As explained in Section 4.5 the site-specific temperature condition is studied in detail. Also, the temperature deration curves are sensitive to the altitude of the project. The figure below shows temperature and altitude derating curves of central inverter units at unity power factor. These derating curves are for the inverter units without the medium voltage transformer. In case of String Inverter in the study, output power starts derating beyond 30ºC and reaches 55% at 60ºC (@altitude 2000m). In case of Central Inverter, output power starts derating beyond 23ºC and reaches 10% at 60ºC (@altitude 2000m). When designing systems at higher altitudes and/or higher ambient temperatures, the inverter power rating at the worst-case temperature should be considered.

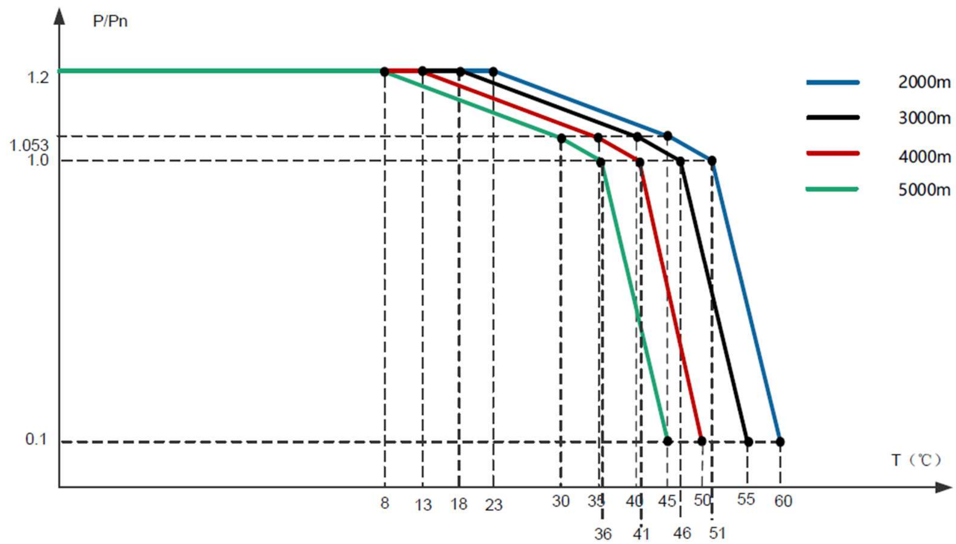

Figure 9-6: Deration Curve with respect to temperature (Central Inverter)

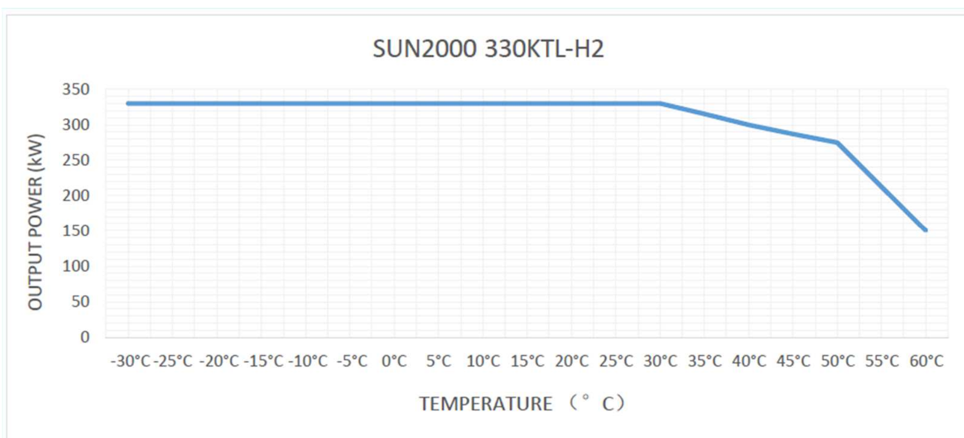

Figure 9-7: Deration Curve with respect to temperature (String Inverter)

- **Design for suitable input DC voltage:** One often overlooked aspect in inverter design is its performance in relation to the input DC power. The figure below illustrates the performance of the string inverter with respect to DC input power. This curve is representative of the characteristics seen across all inverters. As shown in the image, once the DC input voltage exceeds 1,300V, the inverter not only limits the power but also begins to derate it. This highlights the importance of designing within the proper DC input voltage range to avoid potential power derating. It's important to note that this DC input voltage is measured at the inverter, after accounting for losses on the DC side, such as cable losses, mismatch, LID losses, temperature-related losses, and others.

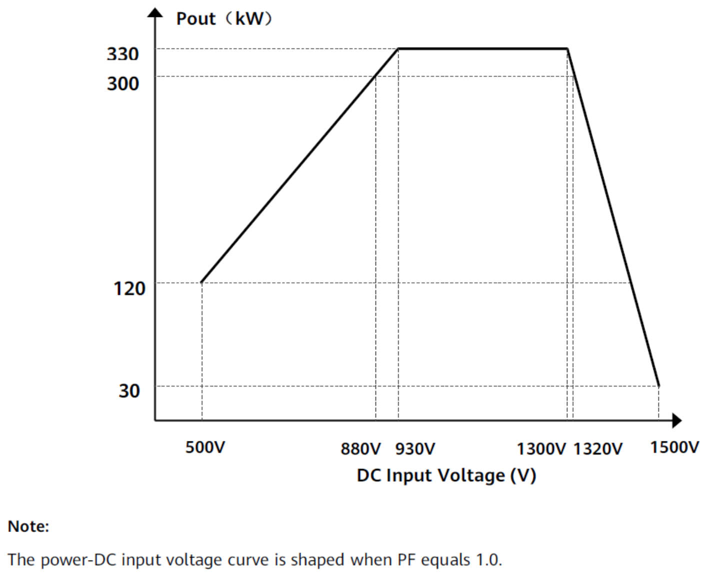

Figure 9-8: Power-DC input voltage curve

- **Mean Time Between Failures (MTBF):** MTBF is a critical reliability metric used to estimate the average operational time between failures of a system or component. A higher MTBF value indicates superior reliability and reduced likelihood of system downtime. DNV recommends selecting inverters with a higher, proven MTBF to enhance plant reliability and minimize potential operational disruptions. It is equally important to assess the methodology employed in evaluating MTBF, as many inverters lack bankable data or standardized testing protocols, which can impact the accuracy and confidence in the reported MTBF values.

10 CONCLUSIONS

High-voltage (1,500V) string inverters have gained substantial market traction across regions such as Asia-Pacific, the Middle East, Europe, and Latin America—driven by their modularity, ease of maintenance, and declining price trends. Their adoption in utility-scale applications continues to rise, particularly in the Middle East, where they now rival central inverters in market share, reflecting increasing industry confidence in their long-term viability.

This comparative analysis followed a two-stage optimization approach. In the first stage, a batch of simulation scenarios was developed to evaluate key design variables—including pitch (6.5–7.0 m) and DC:AC ratio (1.10 to 1.25 at 45°C). Each configuration was assessed using a high-level EYA and CAPEX/OPEX assumptions to identify the best-performing options based on LCOE. The results showed that the lowest LCOE values were achieved at a 7.0 m pitch, where land cost impact was outweighed by energy gains, and that optimal DC:AC ratios were 1.23 for string inverters and 1.25 for central inverters. The objective of this step was not to compare inverter types directly, but to determine the most favourable configuration within each inverter category for further detailed analysis.

In the second stage, detailed system layouts were prepared for the shortlisted configurations, enabling accurate loss modelling, design specific BOQ, and design specific LCOE calculation.

From a techno-economic standpoint, the analysis indicates that string inverters deliver a lower LCOE of USD 18.51/MWh, compared to USD 18.80/MWh for central inverters—a 1.6% relative improvement. This advantage is attributed to slightly higher energy yield and lower CAPEX under the assumed design and cost parameters.

Additionally, a sensitivity analysis incorporating availability differences further underscores this benefit: with central inverter availability assumed to be 0.5% lower, the resulting LCOE increases to USD 18.90/MWh, pushing the relative

LCOE gap to 2.1%. While this reinforces the string inverter's advantage under the current assumptions, the difference remains modest.

Ultimately, the choice between string and central inverters should not be based solely on LCOE, but rather guided by a comprehensive, project-specific techno-commercial assessment. Factors such as site conditions (e.g., irradiation, temperature, soiling, humidity), inverter protection ratings, service offering, equipment quality, and long-term O&M strategy must all be considered to determine the optimal configuration.

Under the current assumptions and system design, string inverters appear to offer a cost-effective and operationally robust solution. However, for other projects, this conclusion should be validated through project-specific modelling and analysis aligned with the respective design and context.

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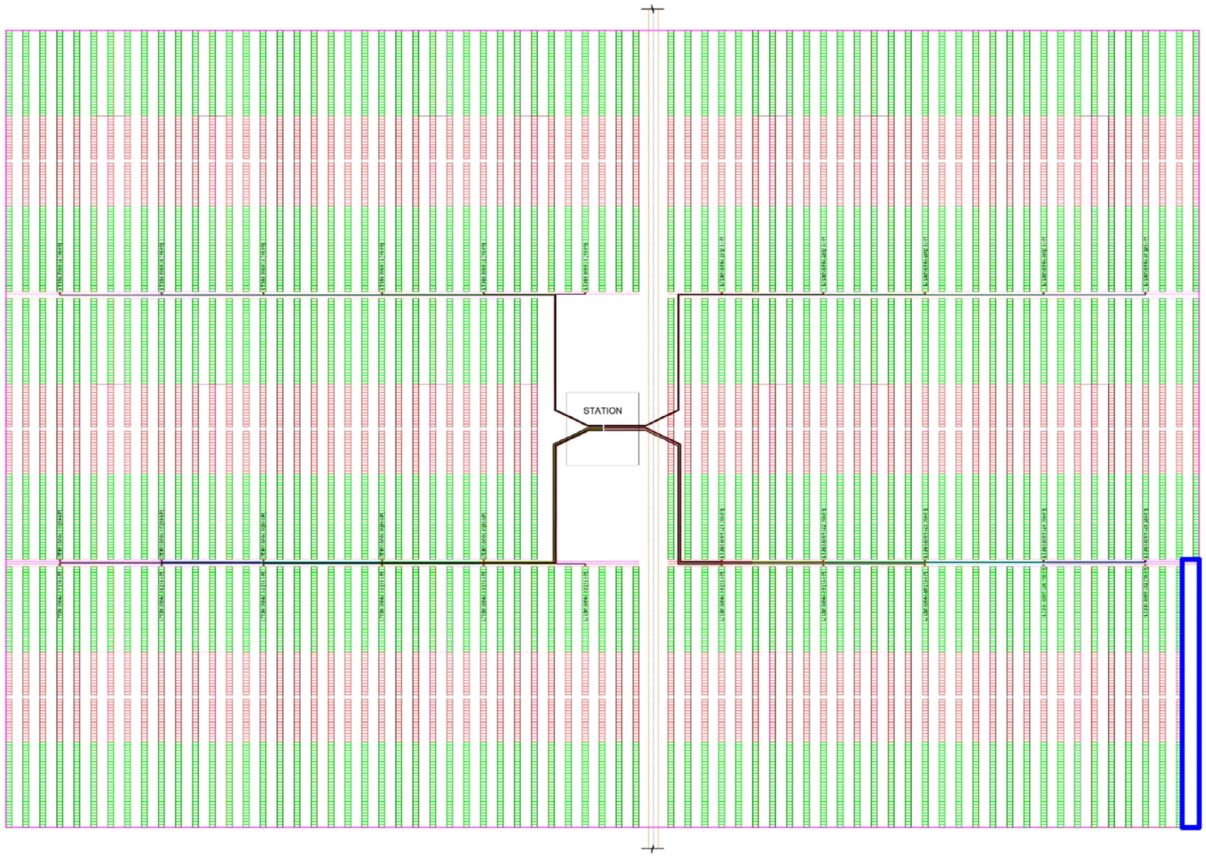

Figure 11-1: Layout Design for String Inverter Design

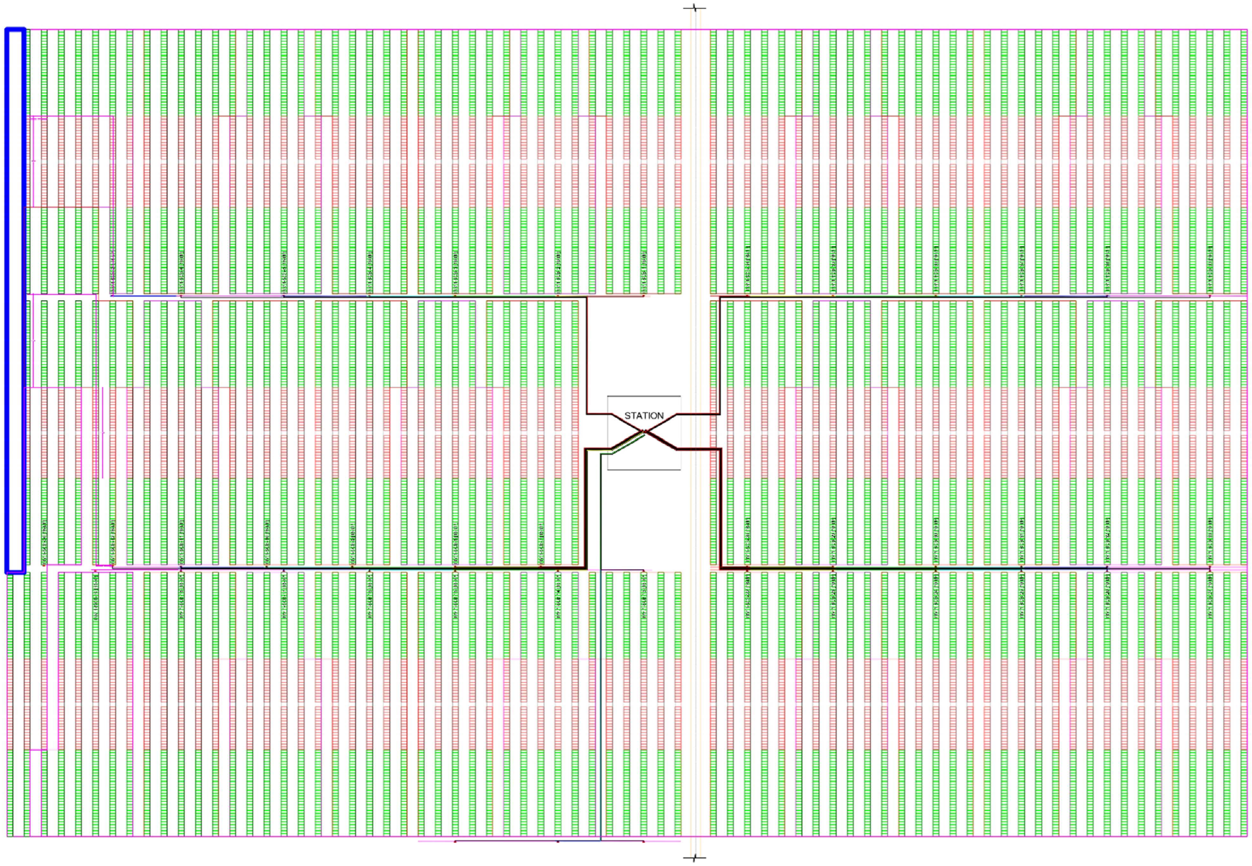

Figure 11-2: Layout Design for Central Inverter Design

APPENDIX B – ENERGY PRODUCTION ASSESSMENT METHODOLOGY

B.1 Analysis of solar radiation and temperature data

Solar irradiance and temperature data measured on site (when available) are first subjected to a quality control procedure. The data recorded by the main pyranometers mounted at the station are then reconstructed from data recorded at the station itself by redundant equipment or at reference stations (if applicable), in order to improve the coverage of data for the measurement period.

Those data series are compared with available long-term sources, in this case, satellite data, in order to create a long-term representative adjusted estimate of solar resource and temperature averages at the project location.

Solar radiation distribution histogram and the long-term typical year estimates are determined from the measured, reconstructed and adjusted long-term data for the weather station compared with reference satellite data.

Finally, an analysis of the uncertainty of the solar irradiation for the whole measurement campaign period, long-term reference data period and for the correlation between them is carried out.

B.1.1 Processing and validation of data from measurement stations

Meteorological data measured at the project location shall be provided in raw format, preferably encrypted. Sufficient documentation shall be provided to ensure the integrity and traceability of the measured data.

Meteorological data is subjected to a quality control procedure to identify records that have been lost or affected by equipment malfunction and other anomalies that may have occurred during the measurement campaign. These records are considered invalid and excluded from the analysis.

DNV uses proprietary data processing software, taking an overview of consistency and thoroughly evaluating the quality of measurements.

The data provided must include pyranometer calibration certificates, so DNV can check the calibration parameters of these certificates was correctly used for the conversion of raw data into actual measurement data. Station installation and maintenance reports are also decisive when validating the data and evaluating the uncertainties involved in the measurements

B.1.2 Reference satellite derived data

The methodologies used in computational models for the interpretation of satellite images that are developed and verified in one region may not produce reasonable results in others. The possible problems related to this are as follows:

- Predominant cloud types may be different;
- Atmospheric aerosols may be more or less absorbent;
- Surfaces may have large albedo differences; and,
- Seasonal wind patterns can carry significant pollutants into or out of the region.

Ignoring regional differences can produce deviations and generate uncertainties. For this reason, the comparison between long-term data from satellites and data measured at local stations is generally the best industry practice for this type of assessment and a method for reducing uncertainties.

Satellite derived data used by DNV relies on Global Horizontal Irradiation (GHI), Diffuse Horizontal Irrigation (DHI) and temperature data. The data referred to have a coverage greater than 99%. Data on low declivity angles of the sun are obtained by extrapolating the open sky index. The data provided has all gaps filled using different algorithms by data provider (Solargis).

The primary parameters for solar irradiance calculations are derived from advanced and scientifically validated models using Meteosat and GOES (Geostationary Operational Environmental Satellite) data with a resolution of about 250 m and frequency of hourly calculations.

The solar irradiation is calculated through numerical models that are parameterized by a set of inputs characterizing the cloud transmittance, the state of atmosphere and conditions of the terrain.

The open sky irradiance is calculated by the simplified SOLIS model. This model allows the fast calculation of open-sky irradiance of the set of input parameters. The position of sun is a determining parameter and is described by numerical models with satisfactory accuracy. The stochastic variability of open sky atmospheric conditions is determined by changing concentrations of atmospheric constituents such as aerosols, water vapor and ozone layer. The data provider counts several validation stations of the models around the world and the precision is presented in a satisfactory way.

Attested quality temperature data from stations close to the project can be also analyzed in order to achieve greater confidence for calculations of calculated averages.

B.1.3 Correlation of measured data with long-term reference data

When measurement data is available at the project area, DNV correlates ground measurements with long-term satellite-derived data.

In order to derive the long-term irradiation data for a given location it is desirable to use a series of data with the longest possible duration. For the sake of recovering the missing records and extending the data period for irradiation and temperature, correlation methods are used as detailed below.

The data measured at the station itself by redundant sensors for the same variable (by simple average or adjusted, in case of observation of trend in the sensor) are first used, followed by data measured at reference stations within a radius of 10 km, if exists, and evaluating their applicability and if sensor maintenance and installation records are available.

B.1.3.1 Verification of correlation

The quality of the correlation between the long-term satellite data and the target (measured data) can be verified by comparing it to a concurrent period between the two series. If the irradiance values predicted by the reconstructed series are sufficiently similar to the values actually measured for the same period, the quality of the correlation is considered adequate. If the values are outside the range considered acceptable by DNV, the use of correlation is re-evaluated.

B.1.3.2 Time Series Correlation Method

In this correlation method, it is performed on an hourly, daily or monthly basis, where integrations of the 10-minute measurements are made in hourly, daily or monthly series, so that it can be related to the long-term reference data (satellite derivatives) in the same time frequency.

For the correlation, the data measured in the weather station should have a minimum concurrent period of 12 months with satellite data, the last one used as long term data. This establishes a correlation between locally measured data and long-term satellite data. This correlation is then used to calibrate satellite data, to reconstruct data at the weather station and extend the period of irradiation and temperature data for a long-term period.

The result of the described analysis is an equation describing the relationship between the target and long-term series, performed for both GHI and temperature data. These relationships are used to scale the long-term data on the location of the weather station, thus obtaining reconstructed time-tables for a period of more than 11 years of data, forming the long term adjusted series.

The long-term series are then derived from the measured and reconstructed hourly data.

B.1.4 Typical meteorological year

If local measurements are not available, DNV will evaluate available satellite sources at the location of the Project. The uncertainties of the source, spatial representativity, temporal representativity and the monthly daily profiles of the data are evaluated in order to select the most representative typical meteorological year to be used as input to PVsyst software in order to perform the energy simulations for the Project.

When local measurement are available the typical meteorological year selected in the previous phase of the Solar Resource Assessment is reconstructed accounting for the bias obtained by the correlation presented in section B.1.3.

B.2 Energy assessment process

B.2.1 PVsyst software

The most commonly used model used to depict a DC photovoltaic equivalent circuit is often referred to as a "one-diode" model, with multiple variations of the model in place. The one-diode model, when fitted with finite values for series and shunt resistance, requires an implicit solution. The hourly calculations required are best performed with the aid of software packages. There are several software packages available which use the "one-diode" model. DNV has used the PVsyst software package, along with internally developed worksheets and statistical tools, to calculate energy loss factors for the PV plants.

PVsyst is the most commonly used modeling software for forecasting the expected energy production of utility-scale solar PV systems. In PVsyst, system components are defined within .PAN (module) and .OND (inverter) files, respectively. DNV verifies all models of modules and inverters used in energy simulations using manufacturer datasheets and applicable third-party test data. When creating .OND files, DNV will use test data from the California Energy Commission (CEC), when available, to supplement the datasheet.

B.2.2 Simulation of the PV plant

Based on the long-term solar resource evaluated for the project site, the simulation is performed to estimate the energy production considering the proposed arrangement and the estimated loss factors. This process typically involves the following steps::

1. Determination of climatic conditions, primarily the global and diffuse irradiation on the horizontal plane, in addition to the long term temperature for the project site.
2. Calculation of irradiation on the tilted plane using the known global and diffuse horizontal irradiation. Transposition is the calculation of incident irradiance on a tilted plane from horizontal irradiance data. This is calculated separately for each irradiance component: diffuse, beam, and reflective. The transposition of the diffuse component is typically calculated using the Perez model or the Hay model; DNV most frequently uses the Perez transposition model. The beam component of transposition involves a geometrical transformation that accounts for the module and sun angles. The reflective or albedo component is evaluated as a given fraction (i.e. the "albedo coefficient") of the global irradiance, weighted by the angle between the horizontal and the PV plane. The albedo coefficient depends on the soil cover, DNV generally assumes a generic albedo coefficient of 0.2 for projects in locations outside of desert areas.
3. Assessment of the irradiation losses due to optical effects and near shading, using the known layout of the PV plant and a model of the plant surroundings. This enables calculation of the usable irradiation.
4. Calculation of the final energy delivered at the output of the inverters. The electrical simulation takes into account the properties of the PV modules (output power, irradiation performance, partial shading effects, temperature behavior, etc.), the inverters (conversion efficiency, partial load, etc.) and losses in the electrical wiring.
5. Final energy yield is obtained by computing power losses on the AC network (cables, transformer, etc.) and the expected long-term plant unavailability due to either internal maintenance operations or grid unavailability.

B.2.3 Derate factors

Meteorological data of temperature and irradiation are introduced in the simulation in order to obtain the net energy produced by the photovoltaic system (kWh per year). Several loss factors are calculated, applied or estimated during the calculated simulation based on hourly data. The loss factors considered are:

B.2.3.1 Far shading (horizon line) losses

The far shading calculation uses the definition of the horizon line to model the incident irradiance lost due to the presence of horizon obstacles. DNV usually imports the PVGIS-generated horizon profile for each project into PVsyst using its “Horizon” tool, and the horizon profile is checked for accuracy using Google Earth, with Google Earth itself sometimes used to generate such profiles.

PVsyst also allows for the importation of horizon profiles using other tools such as the Solmetric SunEye and Carnaval software. DNV will assess the accuracy of horizon profiles generated from these other tools through a review of provided documentation, calculations and other relevant details, and will use these horizon profiles in the PVsyst simulation as appropriate.

B.2.3.2 Near shading losses

DNV uses the PVsyst “Near Shadings” tool to model tracker systems and projects experiencing near field shading (e.g., trees, buildings, etc.). This tool uses a detailed 3D description of the PV system that considers the distance between consecutive rows of PV modules, near shading objects, and their relationship to the source circuit (i.e., string) layout in its calculation. DNV utilizes satellite imagery and detailed design drawings when constructing a system in PVsyst.

DNV typically enables the “backtracking” feature when modeling tracker systems in PVsyst. Backtracking prevents row-to-row shading of direct beam irradiation by continuously adjusting the tilt angle of adjacent rows or arrays of modules. While the implementation of backtracking prevents row-to-row shading of direct beam irradiation, systems will still experience near shading losses due to the shading of diffuse and ground-reflected irradiation.

DNV models how a module will respond to the partial shading of strings using the PVsyst “electrical effect” option. Depending on module characteristics, DNV will choose either “Linear shadings” (area-based) or “According to module strings” to model this effect. When implementing the latter, DNV defines the “fraction for electrical effect”, or the percentage of module production that is lost when a string is partially shaded.

In specific cases, the influence of wind power ventures in the proximity of the project may still cause intermittent shading effects of wind turbine blades in the area of photovoltaic modules. The impact of intermittent shading is calculated by reducing the direct irradiance, considering only the incidence of diffuse irradiation factors in the hours impacted by the shade, as well as considering the estimated duration of the shading in the modules. This impact is assessed on a case-by-case basis, according to each project.

B.2.3.3 Angular losses

The irradiation reaching the PV cell surface varies as the angle of the sun changes relative to the surface of the module. The Incidence Angle Modifier (IAM) loss is calculated in PVsyst based on user inputs of the reflection properties of the module. If independent, third-party IAM test results are provided, DNV will evaluate the validity of the findings and may use the resultant IAM curve in the energy simulation. If third-party test data is not provided, DNV typically uses the Fresnel profiles provided in PVsyst: “normal glass” for modules without indication of anti-reflective coating and “AR coating” for modules with anti-reflective coating.

B.2.3.4 Irradiance level losses

The performance characteristics detailed in a module datasheet represent the expected module performance under standard test conditions. Because a project will not continuously experience STC irradiation levels (1,000 W/m_2), the actual module efficiency will diverge from nameplate-rated efficiency as the solar irradiation deviates from this level. The irradiance level loss represents the difference in the module efficiency at STC and the module efficiency at the modelled solar irradiance within each hour. DNV considers a relative efficiency of 96.5% from an irradiance of 1000W/m2 to 200W/m2 in the absence of information from manufacturer.

B.2.3.5 Temperature losses

DNV recommends different thermal loss factors (Uc and Uv factors in PVsyst software) for different system orientations. Guidelines that allow greater free air circulation between the modules (higher thermal loss factors) will dissipate more heat and will have lower temperature losses.

The temperature coefficient of power for a given PV module defines how the module output power will respond to changes in module temperature. Thermal loss factors indicate how changes in temperature and wind speed will affect cell temperatures. Temperature loss is calculated in PVsyst using the technical specifications of the module and the thermal loss factor inputs.

Module datasheets detail the temperature coefficient of power for a class of modules. While projects normally experience temperature losses, the local meteorological conditions may result in a slight production gain if the ambient temperature remains low throughout the year. This is most commonly seen in areas of high elevation that also receive abundant solar irradiation.

DNV recommends different thermal loss factors (UC and UV in PVsyst) for different system orientations. Orientations that allow for more free-flowing air to circulate around the modules (higher thermal loss factors) will dissipate more heat and experience lower temperature losses.

B.2.3.6 Module quality factor

The module quality factor (MQF) is a user-defined generic loss factor in PVsyst used by DNV to account for miscellaneous losses, and it may be either positive (loss) or negative (gain). DNV includes the following three adjustments in the MQF calculation: nameplate bias (loss/gain), maximum power point tracking loss, and modeling bias (loss/gain).

Module datasheets quote a power tolerance window in which the actual power rating of a given module is expect to reside. Often, the quoted power tolerance window is “positive”, indicating that the actual power rating of the module will at least equal, but may exceed, the nameplate rating. These power tolerance windows are expressed both in terms of percentages (e.g. 0 to +3%) and wattages (e.g. 0 to +5 W). In the absence of flash test data, it is unknown where the lot average of a group of modules will be centered within a quoted power tolerance window. DNV assumes that the distribution is centered at the lower quartile of this window, or 0.8% above nameplate (gain) for a +3% tolerance window (e.g. 0.25 x 3% ~ 0.8%). To ensure that the most accurate inputs are used in the MQF and production simulation, DNV requests manufacturer flash test data in order to determine the actual nameplate bias for delivered modules.

Maximum power point (or “peak power”) tracking (MPPT) is the process by which inverters continuously monitor and adjust the dc input voltage to the voltage that maximizes power generation and system efficiency. DNV applies a 0.5% loss to account for this imperfect inverter behavior.

To eliminate potential bias in a manufacturer PAN file, DNV creates PAN files using manufacturer datasheets and independent, third-party test data. Often, the nameplate power of the module defined within the PAN file differs from the nameplate power stated on the datasheet. DNV corrects this deviation so that the modeled nameplate power matches the actual nameplate power of the module.

These loss factors are then combined to determine the overall MQF loss or gain.

B.2.3.7 Light-induced degradation losses

Light-induced degradation (LID) corresponds to an attenuation of the power of the module (with crystalline silicon technology) once it is exposed to the actual operating conditions. This factor is typically verified through an independent measurement performed for the proposed module model for the project. When available, independently measured data provided by a manufacturer or testing agency is used to determine the LID for a crystalline module. DNV applies LID loss in the first-year simulation.

In the absence of such data, DNV assumes a 2% loss for polycrystalline silicon modules, a 2.5% loss for boron-doped monocrystalline silicon modules, 1% for gallium and TOPCon monocrystalline silicon modules and 0% for Heterojunction modules.

In Cd-Te technology First PV modules, the initial LID loss is considered to be zero, but other degradation factors affect this technology, which is analyzed differently in several respects.

B.2.3.8 Soiling losses

Losses due to accumulated dirt on the modules (soiling) depend on the historical levels of precipitation, the system configuration, the washing frequency of the modules and the accumulation rate of dust and debris. The rate of particle accumulation is site specific and can be influenced by factors such as soil type, moisture content, proximity to highways or farmland, and prevalence of bird droppings. DNV typically uses a pragmatic loss factor according to the type of land, considering that appropriate O&M plans will be put in place when plant operation

When documents related to the planning of the cleaning of the modules are available, they can be analysed in order to consider specific premises for a particular project. Monthly soiling profiles can be developed using site-specific details such as historical levels of precipitation, system orientation, module wash schedule and past experience. If a customer does not detail the month (s) in which the modules will be washed, DNV assumes that the modules will be washed in the month (s) that produce the least annual loss of dirt. DNV will provide the details of the cleaning month to customers.

B.2.3.9 Bifacial effects

DNV uses PVsyst to model systems employing bifacial modules. The bifacial model is characterized by the module bifaciality coefficient, layout and mounting configuration, diffuse fraction, and albedo values at the Project site. For each Project, DNV analyses the dimensions and configuration of the specific mounting structure, then applies a structure shading factor in PVsyst to account for shading from structural objects onto the backside of the modules. A mismatch loss factor for the backside of the modules is also applied as a result of design specific shading and backside interference. DNV notes that the accuracy of bifacial modelling could be improved with on-site albedo measurements or an in-depth review of the proposed mounting system to determine backside shading and mismatch. The bifacial inputs into PVsyst are discussed below.

Bifaciality factor: The module bifaciality factor specifies the power efficiency of the module backside relative to the front side. The value is typically specified in the module datasheet and entered in PVsyst as part of the module .PAN file.

Rear structural shading: The structural shade factor is a relative loss of the absolute backside structural shade loss divided by the bifacial boost. DNV considers two types of backside structural shading. First is the shade caused by the direct area blockage of sunlight by structural objects (mostly torque tube or mounting purlins, and sometimes wires, boxes) that run parallel to the plane of the module. Second is the sun blockage caused by structural members that project out in a direction perpendicular to the module plane, or the perpendicular shade (or “fin”) area. The structural members act like fins in reducing the field of view from the back side of the module. DNV calculated the structural shading based on the view factor of the rear side, taking into account the Project’s bifacial parameters as well as the dimensions of the structural members for the mounting system. DNV has calculated similar structural shading loss to other industry findings of test bifacial arrays.

Rear mismatch: The relative mismatch loss is calculated by dividing an absolute backside-only mismatch loss by the bifacial boost. The resulting value also depends on most of the other bifacial input terms, especially the rear shading loss. Backside variation in irradiation can readily be as much as 50%, but isolating the two factors of mismatch and structural shading loss leads to a less severe mismatch loss factor than the structural shade effect. DNV has used backside mismatch calculation methods from industry findings of test bifacial arrays. The front side mismatch value is not affected by the rear side value in PVsyst, which models the combined effect of adding a second source of current on the rear side of the module.

The simulation results result in a gain related to the reflection on the front of the modules, in addition to an effective irradiation on the back of the modules resulting from the aforementioned parameters.

The gains in terms of the final energy of the system translate into greater energy from the photovoltaic arrangement in general, which influence the other parameters of subsequent losses.

B.2.3.10 Module mismatch losses

Mismatch losses occur when the actual modules in an array do not have exactly the same current-voltage characteristics. The mismatch loss is dependent upon the standard deviations of the short-circuit current (ISC) and open-circuit voltage (VOC), the distribution type (i.e. normal or square), and precipitation levels.

Because the lowest current in a string will drive the current for the entire string in a series connection, the array mismatch loss can be minimized by using only modules of the same type and with very similar currents. DNV typically completes a series of mismatch tests using PVsyst's "Detailed computation" mismatch tool. DNV can update this loss if module Flash test results are provided.

Bifacial systems also include a portion of mismatch related to the rear part of the modules, inserted into the simulation software from a premise calculated based on the system parameters.

B.2.3.11 DC ohmic losses

DC ohmic losses occur when connecting the modules to the input of the inverter(s). As current passes through a wire, the wire resistance induces a voltage drop and dissipates some power as waste heat. This loss is dependent upon the conductor material (i.e. aluminum or copper), gauge (i.e. diameter), and resistive properties; the length of the wire; and the current at the input of the wire. If detailed wiring schedules are not provided, DNV assumes a dc ohmic loss of 1.5% at STC for central inverters and 0.7% at STC for string inverters. Because the project will not continuously operate at STC, usually at levels well below STC, the actual dc ohmic loss will tend to be notably less than the assumed loss at STC.

B.2.3.12 Transformer losses

There are two losses associated with medium voltage (MV) and high voltage (HV) transformers: iron (i.e. fixed or core) losses and ohmic (i.e. winding, or variable) losses. Fixed-load losses continue to draw a load irrespective of whether the array is producing power (e.g. at night), while the severity of the variable, ohmic loss is dependent upon the resistive properties of the primary and secondary transformer windings and the current entering the transformer. When provided, DNV calculates the fixed and variable load losses from transformer datasheets. If datasheets cannot be provided, DNV assumes the losses detailed below.

For LV/MV transformers, DNV assumes a fixed load loss of 0.2% and a variable load loss 0.9% at STC. For MV/HV transformers, DNV assumes a fixed load loss of 0.1% and a variable load loss of 0.4% at STC. The HV transformer loss is lower than the MV transformer loss because, in accordance with Ohm's Law, resistive power losses are proportional to the square of the current. For example, a 50% reduction in current will result in 25% of the resistive losses.

B.2.3.13 AC ohmic losses

AC ohmic losses occur when connecting the inverter cabinet(s) to the production meter on the customer side of the grid interconnection point. As current passes through a wire, the wire resistance induces a voltage drop and reduction in power. This loss is dependent upon the conductor material (i.e. aluminium or copper), gauge (i.e. diameter), and resistive properties; the length of the wire; and the current at the input of the wire. If detailed wiring schedules are not provided, DNV assumes an ohmic AC loss of 0.5% at STC for central inverters and 1% at STC for string inverters. Because the project will not continuously operate at STC, the actual ac ohmic loss will always be somewhat less than the assumed 0.5% STC loss.

B.2.3.14 Inverter losses

DNV considers both PVsyst-computed inverter losses and losses calculated in a post-processing tool for an energy assessment. The PVsyst "loss tree" found on the final page of a PVsyst report details the percent loss for a variety of different inverter losses. DNV typically verifies all models of inverters used in an energy simulation through the use of manufacturer datasheets and third-party efficiency curve test data from the California Energy Commission (CEC). If CEC test data is not available for an inverter, DNV relies on manufacturer efficiency curve data to model an inverter in PVsyst.

The "Inverter Loss during operation (efficiency)" is a function of the efficiency curve data points entered into the .OND file(s) for a project. The CEC typically provides independent, third-party efficiency curve test results at three different voltage levels (VMIN, VNOM, and VMAX).

The "Inverter Loss over nominal inv. power", also known as inverter "clipping", is most often observed during times of peak solar irradiation and clear skies, or in projects with high DC:AC loading ratios. These conditions may cause the power produced by an array to exceed the nominal power level of the inverter. Limiting production to the nominal inverter power "clips" the additional potential energy production of the array. Clipping losses are most prevalent early in a project's lifecycle before years of system-wide degradation have impacted the system.

The "Inverter Loss due to power threshold" occurs when an array cannot produce enough power to exceed the power threshold of the inverter. The power threshold is computed based on information provided in the datasheet and CEC test results, and it is entered into the .OND file for the inverter. This threshold represents the power necessary for an inverter to operate.

The "Inverter Loss over nominal inv. voltage" results when the inverter input voltage exceeds the maximum MPP voltage (VMPP) defined in the OND file. This loss represents the difference between the MPP power (PMPP) at this higher system voltage and the power the system generates at the maximum VMPP defined within the OND file.

The "inverter Loss due to voltage threshold" occurs when the dc input voltage drops below the minimum MPP voltage (VMPP) defined in the OND file. This loss is most frequently seen in systems with near shading objects present or backtracking disabled. As strings become partially or fully shaded, the string voltage observed by the inverter drops below the minimum MPP voltage and results in production losses.

The "Night Consumption" loss represents the inverter standby loss incurred when the inverter is energized but not operational, mainly at night. This loss is often listed on a manufacturer's datasheet or in the CEC efficiency curve test results. The night loss is inputted into the .OND file used in the PVsyst simulation.

For some projects, DNV will also apply temperature, voltage, or power derates (i.e. limitations) to a system. These additional inverter losses are captured in post-processing tools developed by DNV or provided by an inverter manufacturer.

B.2.3.15 Unavailability losses

Energy losses associated with equipment failures, unplanned outages, or scheduled maintenance are applied to the PVsyst production estimate using a post-processing tool. Because this loss is energy-weighted, system downtime occurring at night does not affect the overall unavailability loss. DNV assumes a higher unavailability loss for single-axis tracker systems as the added complexity, controls, and moving parts associated with a tracker open up additional potential modes of failure.

The table below details DNV's standard unavailability assumptions.

Table E-1: DNV availability loss assumptions

System type	Staffed	Unstaffed
Fixed-tilt	0.3%	1.0%
Single-axis tracker	0.8%	1.5%

The default assumption of grid unavailability varies according to the country and is explained in Section 6.3.2. Grid curtailment is not considered in DNV assessment and should be evaluated separately.

B.2.3.16 Auxiliary losses

DNV also considers the auxiliary loads for a project that are not separately metered and billed. Examples include losses on the customer side of the meter associated with monitoring equipment, grounding transformers, inverter stations, and substations. The extent of this loss is dependent on the climate, system capacity, and other project characteristics.

B.2.3.17 Hourly Modelling Correction

Irradiance measurements are typically hourly averages, and PVsyst modeling is conducted at an hourly resolution. As a result, traditional hourly modeling underestimates inverter clipping. This is especially pronounced in regions where frequency of clouds vs. clear sky is high and for plants with a high DC/AC ratio.

DNV's refined approach employs a machine learning model developed at NREL [8][8] to estimate the annual Hourly Modelling Correction without requiring site-specific sub-hourly data (which is commonly not available). The feature variables include hourly GHI, POA, Clearsky GHI, Clearsky POA, module temperature, rate of change of POA, difference of Clearsky POA and hourly POA and the hourly averaged clipping percentage. The target variable will result in an annual Hourly Modelling Correction (%). This annual impact does not consider the use of batteries or differences/changes resulting due to spatial variability.

B.2.4 Performance Ratio and Energy Production

The Performance Ratio (PR) is an international measure to describe the level of use of a photovoltaic system. This factor represents the fraction of useful energy in relation to the total nominal energy produced. The nominal energy is defined by the surface area of the module, the efficiency of the module (according to specifications) and the radiation incident on this surface. PR is dimensionless and it is a parameter that allows the comparison between photovoltaic systems in different locations and orientations.

The PR is calculated during the simulation process, by multiplying the different factors described. Given the overall PR factor, the total energy delivered is calculated as follows:

$$E_{AC} = \frac{PR(\%) G_{INC} P_{STC}}{100 I_{STC}}$$

The yield factor Y_F is defined as the total energy produced in kWh per kW peak of installed capacity, i.e.

$$Y_F = \frac{E_{AC}}{P_{STC}} = \frac{PR(\%) G_{INC}}{100 I_{STC}}$$

In the formulae:

- E_{AC} (kWh / year) is the system yield;
- P_{STC} (kW) is the peak installed power (at STC);
- G_{INC} (kWh/m^2) is the irradiation on the collector plane; and
- I_{STC} (1 kW/m^2) is the irradiance (at STC).

B.2.5 Uncertainties of the Energy Production Assessment

The uncertainty factors are defined and quantified according to the overall experience of DNV in the pre-construction evaluation of PV plants under development and performance study of the generation of PV plants in operation.

The uncertainty of the final result is determined by inaccuracies in the simulation procedure (i.e. model selection) and also by "external" influences (i.e. shading, dirt, deviation of components from specification, inverter losses, cabling, etc.), and the uncertainty of solar radiation (here, the global horizontal radiation that is defined in the Report). In addition to experience, DNV uses statistical and stochastic internal tools to determine uncertainties.

An additional description of the uncertainties considered in the project is presented below and the values assigned for each parameter are presented in the Certification Report:

Uncertainty of irradiation – resulting from uncertainties of satellite dataset or measurements and correlation with satellite data, if available. The quality of the measurements, the quality of the instruments used and the measurement period compared to the long-term period considered are considered in these factors. For projects with local measurements, these values can range from **2.0 to 5.0%.**

Uncertainty of the correction for the plane of array – uncertainty associated with the model used for the correction for the inclined plane (Perez or Hay). These values can range from **3.0 to 4.0%**.

Uncertainty of interannual variability of solar resource – uncertainty associated with the standard deviation of the measurement resource period under study, taking into consideration the number of years used for the study. Based on DNV experience, these values vary up to **2.0%** for a 20-year evaluation period.

Uncertainty of solar plant losses calculation – uncertainties regarding the calculations made for the study of energy, such as shading, IAM, mismatch and losses in inverters. In every calculation there is an associated uncertainty, and in this element we define the uncertainty for each loss calculation. These values, from the experience of DNV, vary from **2.0 to 7.0%**.

Uncertainty of representativity of the monitored period – uncertainty considering the standard deviation of the data, in the long term perspective (20 years).

Uncertainty of spatial variability – uncertainty associated with the distance between the measurements and the proposed solar plant location. This value varies up to **3.0%.**

Uncertainty of the energy simulation model – uncertainty regarding the deviation of the real conditions of the STC conditions and the impact on the modeling of the radiation and temperature curves. These values may range from **3.0 to 5.0%**.

Resulting Default Uncertainty – Sum of the square roots of the factors described above. For current projects, the uncertainties of solar photovoltaic projects are varying from **5.0 to 10.0%.**

APPENDIX C – INVERTER CHARACTERISTICS

Below is the information about both the inverter utilized in the project

Table 11-1: Inverter Characteristics

	String Inverter [14] [15] [16] [17]	Central Inverter	Reference
MAIN PARAMETER			DNV Source /Remarks
Model	SUN2000-330XXX-XX	Typical 1100 KW Central Inverter	DNV Creates OND file based on Datasheet, technology writeups, Third Party Test Reports & information available on CEC
Input side (DC PV field)			
Minimum MPP Voltage [V]	500	938	Datasheet
Min Voltage for Pnom [V]	N/A	N/A	Datasheet
Nominal MPP Voltage [V]	1080	1100	Datasheet
Max MPP Voltage [V]	1500	1500	Datasheet
Absolute Max Voltage [V]	1500	1500	Datasheet
Power threshold [W]	1361	5445	PVsyst
Nominal PV Power [kW]	N/A	N/A	Datasheet
Maximum PV Power [kW]	N/A	N/A	Datasheet
Maximum PV Current [A]	390	1435	Datasheet
Output side (AC grid)			
Type - Phase	Tri	Tri	Datasheet
Frequency - 50 Hz	TRUE	TRUE	Datasheet
Frequency - 60 Hz	TRUE	TRUE	Datasheet
Grid Voltage [V]	800	660	Datasheet
Nominal AC Power [kW]	275	1100	Datasheet
Maximum AC Power [kW]	330	1320	Datasheet
Nominal AC Current [A]	199	962	Datasheet
Maximum AC Current [A]	240	1155	Datasheet

ADDITIONAL PARAMETER			
Multi-MPPT			
Multi-MPPT Capability	TRUE	FALSE	Datasheet
Number of MPPT Inputs	6	1	Datasheet
Transformer			
Transformer	NA	NA	Datasheet
Auxiliary consumptions			

Fans and auxiliary (W)	0	0	Manufacturer OND
… from output power (W)	0	0	Manufacturer OND
Night consumption (W)	4.8	152	Manufacturer OND
"String" inverter			
String inverter	With Securities on Input	NA	Datasheet /Manufacturer OND
Master/ Slave			
Master/ Slave	No M/S capability	No M/S capability	Datasheet /Manufacturer OND
Other specifications			
Number of DC inputs	28	1	Datasheet /Manufacturer OND
Isolation Monitoring	Yes	Yes	Datasheet /Manufacturer OND
DC Switch	Yes	Yes	Datasheet /Manufacturer OND
AC Switch	No	Yes	Datasheet /Manufacturer OND
AC Disconnect Adj	Yes	Yes	Datasheet /Manufacturer OND
ENS	Yes	N/A	Datasheet /Manufacturer OND
Sizes			
Width (mm)	1048	700	Datasheet
Depth (mm)	395	1525	Datasheet
Height (mm)	732	2290	Datasheet
Weight (kg)	112.0	800.0	Datasheet

Efficiency defined for 3 voltages**				
	SUN2000-330XXX-XX			Reference [15]
	Input	**CEC**	**Euro**	
	V	**%**	**%**	
Low Voltage	930	98.3	98.2	Third Party Test Report
Medium Voltage	1080	98.4	98.3	Third Party Test Report
High Voltage	1300	98.7	98.6	Third Party Test Report

Max AC Power (Temperature)							
Nom. ac Power	275	kWac	upto 50° C	1100	kWac	up to 51° C	Temperature Deration Curve Declared by Manufacturer [16]
Max ac Power	330	kWac	up to 30 °C	1320	kWac	up to 23° C	Temperature Deration Curve Declared by Manufacturer [16]
High temperature limitation							
Power limit 1	212	at	55° C	660	at	55° C	Temperature Deration Curve Declared by Manufacturer [16]
Power limit abs.	150	at	60° C	110	at	60° C	Temperature Deration Curve Declared by Manufacturer [16]

APPENDIX D – INITIAL OPTIMIZATION RESULT

Below is a summary of Initial level optimization for both String and Central Inverter Configuration

Table 11-2: Optimization Result for String Inverter Configuaration

String Inverter											
S.No.	DC:AC Ratio@45ºC	DC Capacity (MWp)	AC Capacity (MW@45ºC)	Pitch (m)	Overall Relative LCOE (%)	Yield (MWh/MWp/Y)	Performance Ratio (%)	Net Energy (MWh/year)	Lifetime Energy - 30 Years (MWh)	LCOE Rank in Group	Overall LCOE Ranking
1	1.1	549.9	500.0	6.5	101.46%	2398	88.404	1318992	35900201	14	26
2	1.13	565.0	500.0	6.5	101.03%	2397	88.365	1354387	36870925	12	21
3	1.15	574.9	500.0	6.5	100.77%	2396	88.315	1377561	37512706	11	18
4	1.17	585.0	500.0	6.5	100.56%	2394	88.226	1400125	38146045	9	16
5	1.2	599.9	500.0	6.5	100.34%	2387	87.979	1431986	39063712	7	12
6	1.23	615.0	500.0	6.5	100.27%	2376	87.584	1461216	39942606	4	8
7	1.25	624.9	500.0	6.5	100.30%	2367	87.238	1479084	40502503	5	9
8	1.1	549.9	500.0	7	101.20%	2412	88.592	1326666	36109482	13	24
9	1.13	565.0	500.0	7	100.76%	2412	88.562	1362420	37090027	10	17
10	1.15	574.9	500.0	7	100.51%	2410	88.513	1385733	37735916	8	14
11	1.17	585.0	500.0	7	100.31%	2408	88.414	1408277	38368950	6	11
12	1.2	599.9	500.0	7	100.09%	2401	88.167	1440333	39292719	3	5
13	1.23	615.0	500.0	7	100.02%	2390	87.771	1469748	40178028	1	2
14	1.25	624.9	500.0	7	100.05%	2381	87.425	1487732	40741867	2	3

Table 11-3: Optimization Result for Central Inverter Configuration

Central Inverter											
S.No.	DC:AC Ratio@45ºC	DC Capacity (MWp)	AC Capacity (MW@45ºC)	Pitch (m)	Overall Relative LCOE (%)	Yield (MWh/MWp/Y)	Performance Ratio (%)	Net Energy (MWh/year)	Lifetime Energy - 30 Years (MWh)	LCOE Rank in Group	Overall LCOE Ranking
15	1.1	549.9	500.4	6.5	101.79%	2390	88.098	1314420	35796900	14	28
16	1.13	565.0	500.4	6.5	101.33%	2390	88.088	1350144	36773210	12	25
17	1.15	574.9	500.4	6.5	101.05%	2389	88.068	1373706	37418430	10	22
18	1.17	585.0	500.4	6.5	100.80%	2388	88.028	1396987	38059658	9	20
19	1.2	599.9	500.4	6.5	100.49%	2385	87.900	1430699	39003409	6	13
20	1.23	615.0	500.4	6.5	100.30%	2378	87.653	1462371	39918075	5	10
21	1.25	624.9	500.4	6.5	100.24%	2372	87.416	1482101	40505893	4	7
22	1.1	549.9	500.4	7	101.52%	2404	88.295	1322226	36009897	13	27
23	1.13	565.0	500.4	7	101.08%	2404	88.276	1358010	36987847	11	23
24	1.15	574.9	500.4	7	100.79%	2403	88.266	1381864	37641037	8	19
25	1.17	585.0	500.4	7	100.54%	2402	88.226	1405286	38286259	7	15
26	1.2	599.9	500.4	7	100.23%	2399	88.098	1439202	39236020	3	6
27	1.23	615.0	500.4	7	100.05%	2392	87.841	1470906	40152238	2	4
28	1.25	624.9	500.4	7	100.00%	2385	87.593	1490592	40739569	1	1

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APPENDIX E – CABLE LOSS CALCULATION

E.1 Cable Sizing & Loss Calculation – String Inverter

- **DC Cable Loss – String Cable**

Derating Factors considered:	Value
Ambient Air Temperature (45°C) (G1)	0.87
Reduction Factor for Conductor temperature (120°C) (G2)	1
Grouping Factor (G3)	0.38
Overall derating factor = (G1 x G2 x G3)	0.33
Cable Size	1C x 6 Sq.mm Cu
Current Carrying Capacity of the cable with group of positive negative (A)	57
Derated Current Carrying capacity of the cable (A)	19
Number of Solar panels in series	30 Nos
Conductor temperature (°C)	90
Solar panel Vmp @ STC (V)	40.17
Solar panel Imp @ STC (A)	15.44

Sr. No	Inverter	String	Positive Cable length (Mtr)	Negative Cable length (Mtr)	Cable Derating Factor	Total resistance of cable (Ohms)	Voltage drop (V)	Voltage drop (%)	DC cable loss (kWp)	Power loss (%)
1 to 21	Inverter Type 1	S1	7	8	0.33	0.06	0.99	0.08%	0.0154	**0.00%**
		S2	42	43	0.33	0.37	5.72	0.47%	0.0883	**0.02%**
		S3	79	81	0.33	0.69	10.67	0.89%	0.1648	**0.05%**
		S4	14	15	0.33	0.12	1.93	0.16%	0.0298	**0.01%**
		S5	49	50	0.33	0.43	6.65	0.55%	0.1027	**0.03%**
		S6	86	88	0.33	0.75	11.61	0.96%	0.1792	**0.05%**
		S7	21	22	0.33	0.19	2.86	0.24%	0.0442	**0.01%**
		S8	56	57	0.33	0.49	7.59	0.63%	0.1172	**0.03%**
		S9	93	95	0.33	0.81	12.54	1.04%	0.1936	**0.05%**
		S10	28	29	0.33	0.25	3.80	0.32%	0.0586	**0.02%**

Sr. No	Inverter	String	Positive Cable length (Mtr)	Negative Cable length (Mtr)	Cable Derating Factor	Total resistance of cable (Ohms)	Voltage drop (V)	Voltage drop (%)	DC cable loss (kWp)	Power loss (%)
		S11	63	64	0.33	0.55	8.52	0.71%	0.1316	**0.04%**
		S12	100	102	0.33	0.87	13.47	1.12%	0.2081	**0.06%**
		S13	14	15	0.33	0.12	1.93	0.16%	0.0298	**0.01%**
		S14	49	50	0.33	0.43	6.65	0.55%	0.1027	**0.03%**
		S15	86	88	0.33	0.75	11.61	0.96%	0.1792	**0.05%**
		S16	21	22	0.33	0.19	2.86	0.24%	0.0442	**0.01%**
		S17	56	57	0.33	0.49	7.59	0.63%	0.1172	**0.03%**
		S18	93	95	0.33	0.81	12.54	1.04%	0.1936	**0.05%**
		S19	100	102	0.33	0.87	13.47	1.12%	0.2081	**0.06%**
								Total Loss		**0.62%**

Sr. No	Inverter	String	Positive Cable length (Mtr)	Negative Cable length (Mtr)	Cable Derating Factor	Total resistance of cable (Ohms)	Voltage drop (V)	Voltage drop (%)	DC cable loss (kWp)	Power loss (%)
22 to 32	Inverter Type 2	S1	7	8	0.33	0.06	0.99	0.08%	0.0154	**0.00%**
		S2	42	43	0.33	0.37	5.72	0.47%	0.0883	**0.02%**
		S3	79	81	0.33	0.69	10.67	0.89%	0.1648	**0.05%**
		S4	14	15	0.33	0.12	1.93	0.16%	0.0298	**0.01%**
		S5	49	50	0.33	0.43	6.65	0.55%	0.1027	**0.03%**
		S6	86	88	0.33	0.75	11.61	0.96%	0.1792	**0.05%**
		S7	21	22	0.33	0.19	2.86	0.24%	0.0442	**0.01%**
		S8	56	57	0.33	0.49	7.59	0.63%	0.1172	**0.03%**
		S9	93	95	0.33	0.81	12.54	1.04%	0.1936	**0.05%**
		S10	28	29	0.33	0.25	3.80	0.32%	0.0586	**0.02%**
		S11	63	64	0.33	0.55	8.52	0.71%	0.1316	**0.04%**
		S12	14	15	0.33	0.12	1.93	0.16%	0.0298	**0.01%**

Sr. No	Inverter	String	Positive Cable length (Mtr)	Negative Cable length (Mtr)	Cable Derating Factor	Total resistance of cable (Ohms)	Voltage drop (V)	Voltage drop (%)	DC cable loss (kWp)	Power loss (%)
		S13	49	50	0.33	0.43	6.65	0.55%	0.1027	**0.03%**
		S14	86	88	0.33	0.75	11.61	0.96%	0.1792	**0.05%**
		S15	21	22	0.33	0.19	2.86	0.24%	0.0442	**0.01%**
		S16	56	57	0.33	0.49	7.59	0.63%	0.1172	**0.03%**
		S17	93	95	0.33	0.81	12.54	1.04%	0.1936	**0.05%**
		S18	28	29	0.33	0.25	3.80	0.32%	0.0586	**0.02%**
		S19	63	64	0.33	0.55	8.52	0.71%	0.1316	**0.04%**
								Total Loss		**0.56%**
							Average String Cable Loss			**0.60%**

- **AC Cable Loss – LV Cable**

Table 11-4: : AC Cable Sizing – AC cable between String Inverter and MV station

Max Inverter O/P Current	240	Amps
Deration Factor (IEC 60364-5-52:2009)		
Considering ground temp @35ºC	0.89	
Grouping Factor (0.4m distance between two cables)	0.71	
Thermal Resistivity (2.5m.k/W)	1	
Depth of laying (0.8m)	1	
Ampacity 400 Sq.mm AC Cable, 3C Al Ar. XLPE Insulated, 1.8/3.3 kV (E)	386	Amps
Derated Rating	244	Amps
No Runs Required	**1**	

From	To	No. Of Run	Cable Size (Sq.mm)	Total Length (Mtr.)	Power (kW)	Current (A)	Ac Resistance @90°C (Ohm/Km)	Reactance @60hz (Ohm/Km)	Voltage Drop (V)	Voltage Drop (%)	Power Loss (kW)	Power Loss (%)
INV.-1	LTDB 1	1	400	83	10	93	287	207.13	0.105	0.085	3.49	0.44%
INV.-2	LTDB 1	1	400	101	10	111	287	207.13	0.105	0.085	4.17	0.52%
INV.-3	LTDB 1	1	400	142	10	152	287	207.13	0.105	0.085	5.71	0.71%
INV.-4	LTDB 1	1	400	191	10	201	287	207.13	0.105	0.085	7.55	0.94%
INV.-5	LTDB 1	1	400	234	10	244	287	207.13	0.105	0.085	9.16	1.15%
INV.-6	LTDB 1	1	400	276	10	286	287	207.13	0.105	0.085	10.74	1.34%
INV.-7	LTDB 1	1	400	101	10	111	287	207.13	0.105	0.085	4.17	0.52%
INV.-8	LTDB 1	1	400	142	10	152	287	207.13	0.105	0.085	5.71	0.71%
INV.-9	LTDB 1	1	400	191	10	201	287	207.13	0.105	0.085	7.55	0.94%
INV.-10	LTDB 1	1	400	234	10	244	287	207.13	0.105	0.085	9.16	1.15%
INV.-11	LTDB 1	1	400	276	10	286	287	207.13	0.105	0.085	10.74	1.34%
INV.-12	LTDB 1	1	400	83	10	93	287	207.13	0.105	0.085	3.49	0.44%
INV.-13	LTDB 1	1	400	101	10	111	287	207.13	0.105	0.085	4.17	0.52%
INV.-14	LTDB 1	1	400	142	10	152	287	207.13	0.105	0.085	5.71	0.71%
INV.-15	LTDB 1	1	400	191	10	201	287	207.13	0.105	0.085	7.55	0.94%
INV.-16	LTDB 1	1	400	234	10	244	287	207.13	0.105	0.085	9.16	1.15%
INV.-17	LTDB 2	1	400	276	10	286	287	207.13	0.105	0.085	10.74	1.34%
INV.-18	LTDB 2	1	400	101	10	111	287	207.13	0.105	0.085	4.17	0.52%
INV.-19	LTDB 2	1	400	142	10	152	287	207.13	0.105	0.085	5.71	0.71%
INV.-20	LTDB 2	1	400	184	10	194	287	207.13	0.105	0.085	7.29	0.91%
INV.-21	LTDB 2	1	400	100	10	110	287	207.13	0.105	0.085	4.13	0.52%
INV.-22	LTDB 2	1	400	142	10	152	287	207.13	0.105	0.085	5.71	0.71%
INV.-23	LTDB 2	1	400	184	10	194	287	207.13	0.105	0.085	7.29	0.91%
INV.-24	LTDB 2	1	400	234	10	244	287	207.13	0.105	0.085	9.16	1.15%
INV.-25	LTDB 2	1	400	276	10	286	287	207.13	0.105	0.085	10.74	1.34%

From	To	No. Of Run	Cable Size (Sq.mm)	Total Length (Mtr.)	Power (kW)	Current (A)	Ac Resistance @90°C (Ohm/Km)	Reactance @60hz (Ohm/Km)	Voltage Drop (V)	Voltage Drop (%)	Power Loss (kW)	Power Loss (%)
INV.-26	LTDB 2	1	400	318	10	244	287	207.13	0.105	0.085	9.16	1.15%
INV.-27	LTDB 2	1	400	100	10	110	287	207.13	0.105	0.085	4.13	0.52%
INV.-28	LTDB 2	1	400	142	10	152	287	207.13	0.105	0.085	5.71	0.71%
INV.-29	LTDB 2	1	400	183	10	193	287	207.13	0.105	0.085	7.25	0.91%
INV.-30	LTDB 2	1	400	233	10	243	287	207.13	0.105	0.085	9.13	1.14%
INV.-31	LTDB 2	1	400	275	10	285	287	207.13	0.105	0.085	10.70	1.34%
INV.-32	LTDB 2	1	400	318	10	286	287	207.13	0.105	0.085	10.74	1.34%
								Average Drop & Loss				**0.90%**
								Maximum Drop & Loss				**1.34%**

E.2 Cable Sizing & Loss Calculation – Central Inverter

- DC Cable Loss – String Cable Loss

Derating Factors considered:	Value
Ambient Air Temperature (45°C) (G1)	0.87
Reduction Factor for Conductor temperature (120°C) (G2)	1
Grouping Factor (G3)	0.41
Overall derating factor = (G1 x G2 x G3)	0.36
Cable Size	1C x 6 Sq.mm Cu
Current Carrying Capacity of the cable with group of positive negative (A)	57
Derated Current Carrying capacity of the cable (A)	20
Number of Solar panels in series	30 Nos
Conductor temperature (°C)	90
Solar panel Vmp @ STC (V)	40.17
Solar panel Imp @ STC (A)	15.44

Sr. No	Combiner Box	String	Positive Cable length (Mtr)	Negative Cable length (Mtr)	Cable Derating Factor	Total resistance of cable (Ohms)	Voltage drop (V)	Voltage drop (%)	DC cable loss (kWp)	Power loss (%)
1 to 11	DCDB Type 1	S1	7	8	0.36	0.06	0.99	0.08%	0.02	0.01%
		S2	42	43	0.36	0.37	5.72	0.47%	0.09	0.03%
		S3	79	81	0.36	0.69	10.67	0.89%	0.16	0.06%
		S4	14	15	0.36	0.12	1.93	0.16%	0.03	0.01%
		S5	49	50	0.36	0.43	6.65	0.55%	0.10	0.03%
		S6	86	88	0.36	0.75	11.61	0.96%	0.18	0.06%
		S7	21	22	0.36	0.19	2.86	0.24%	0.04	0.01%
		S8	56	57	0.36	0.49	7.59	0.63%	0.12	0.04%
		S9	93	95	0.36	0.81	12.54	1.04%	0.19	0.07%
		S10	21	22	0.36	0.19	2.86	0.24%	0.04	0.01%
		S11	56	57	0.36	0.49	7.59	0.63%	0.12	0.04%
		S12	14	15	0.36	0.12	1.93	0.16%	0.03	0.01%
		S13	49	50	0.36	0.43	6.65	0.55%	0.10	0.03%
		S14	86	88	0.36	0.75	11.61	0.96%	0.18	0.06%
		S15	21	22	0.36	0.19	2.86	0.24%	0.04	0.01%
		S16	56	57	0.36	0.49	7.59	0.63%	0.12	0.04%
Total							**0.53%**			

Sr. No	Combiner Box	String	Positive Cable length (Mtr)	Negative Cable length (Mtr)	Cable Derating Factor	Total resistance of cable (Ohms)	Voltage drop (V)	Voltage drop (%)	DC cable loss (kWp)	Power loss (%)
12 to 36	DCDB Type 2	S1	7	8	0.36	0.06	0.99	0.08%	0.0154	0.01%
		S2	42	43	0.36	0.37	5.72	0.47%	0.0883	0.03%
		S3	79	81	0.36	0.69	10.67	0.89%	0.1648	0.06%
		S4	14	15	0.36	0.12	1.93	0.16%	0.0298	0.01%
		S5	49	50	0.36	0.43	6.65	0.55%	0.1027	0.03%

DNV

Sr. No	Combiner Box	String	Positive Cable length (Mtr)	Negative Cable length (Mtr)	Cable Derating Factor	Total resistance of cable (Ohms)	Voltage drop (V)	Voltage drop (%)	DC cable loss (kWp)	Power loss (%)
		S6	86	88	0.36	0.75	11.61	0.96%	0.1792	0.06%
		S7	21	22	0.36	0.19	2.86	0.24%	0.0442	0.01%
		S8	56	57	0.36	0.49	7.59	0.63%	0.1172	0.04%
		S9	93	95	0.36	0.81	12.54	1.04%	0.1936	0.07%
		S10	14	15	0.36	0.12	1.93	0.16%	0.0298	0.01%
		S11	49	50	0.36	0.43	6.65	0.55%	0.1027	0.03%
		S12	86	88	0.36	0.75	11.61	0.96%	0.1792	0.06%
		S13	21	22	0.36	0.19	2.86	0.24%	0.0442	0.01%
		S14	56	57	0.36	0.49	7.59	0.63%	0.1172	0.04%
		S15	93	95	0.36	0.81	12.54	1.04%	0.1936	0.07%
		S16	100	101	0.36	0.87	13.46	1.12%	0.2078	0.07%
Total										**0.61%**

Sr. No	Combiner Box	String	Positive Cable length (Mtr)	Negative Cable length (Mtr)	Cable Derating Factor	Total resistance of cable (Ohms)	Voltage drop (V)	Voltage drop (%)	DC cable loss (kWp)	Power loss (%)
12 to 36	DCDB Type 2	S1	7	8	0.36	0.06	0.99	0.08%	0.0154	0.01%
		S2	42	43	0.36	0.37	5.72	0.47%	0.0883	0.03%
		S3	79	81	0.36	0.69	10.67	0.89%	0.1648	0.06%
		S4	14	15	0.36	0.12	1.93	0.16%	0.0298	0.01%
		S5	49	50	0.36	0.43	6.65	0.55%	0.1027	0.03%
		S6	86	88	0.36	0.75	11.61	0.96%	0.1792	0.06%
		S7	21	22	0.36	0.19	2.86	0.24%	0.0442	0.01%
		S8	56	57	0.36	0.49	7.59	0.63%	0.1172	0.04%
		S9	93	95	0.36	0.81	12.54	1.04%	0.1936	0.07%
		S10	14	15	0.36	0.12	1.93	0.16%	0.0298	0.01%

Sr. No	Combiner Box	String	Positive Cable length (Mtr)	Negative Cable length (Mtr)	Cable Derating Factor	Total resistance of cable (Ohms)	Voltage drop (V)	Voltage drop (%)	DC cable loss (kWp)	Power loss (%)
		S11	49	50	0.36	0.43	6.65	0.55%	0.1027	0.03%
		S12	86	88	0.36	0.75	11.61	0.96%	0.1792	0.06%
		S13	21	22	0.36	0.19	2.86	0.24%	0.0442	0.01%
		S14	56	57	0.36	0.49	7.59	0.63%	0.1172	0.04%
		S15	93	95	0.36	0.81	12.54	1.04%	0.1936	0.07%
		S16	100	101	0.36	0.87	13.46	1.12%	0.2078	0.07%
Total										**0.61%**

Sr. No	Combiner Box	String	Positive Cable length (Mtr)	Negative Cable length (Mtr)	Cable Derating Factor	Total resistance of cable (Ohms)	Voltage drop (V)	Voltage drop (%)	DC cable loss (kWp)	Power loss (%)
37	DCDB Type 3	S1	114	115	0.36	0.99	15.25	1.27%	0.2355	0.08%
		S2	107	43	0.36	0.65	10.02	0.83%	0.1547	0.05%
		S3	100	81	0.36	0.78	12.03	1.00%	0.1857	0.06%
		S4	93	122	0.36	0.93	14.32	1.19%	0.2210	0.07%
		S5	86	50	0.36	0.59	9.08	0.75%	0.1402	0.05%
		S6	79	88	0.36	0.72	11.09	0.92%	0.1713	0.06%
		S7	86	129	0.36	0.93	14.32	1.19%	0.2210	0.07%
		S8	77	57	0.36	0.58	8.94	0.74%	0.1381	0.05%
		S9	70	95	0.36	0.71	10.95	0.91%	0.1691	0.06%
		S10	63	22	0.36	0.37	5.65	0.47%	0.0872	0.03%
		S11	56	57	0.36	0.49	7.54	0.63%	0.1164	0.04%
		S12	49	15	0.36	0.27	4.24	0.35%	0.0655	0.02%
		S13	42	50	0.36	0.40	6.14	0.51%	0.0948	0.03%
		S14	49	88	0.36	0.59	9.08	0.75%	0.1402	0.05%
		S15	7	22	0.36	0.12	1.93	0.16%	0.0298	0.01%

Sr. No	Combiner Box	String	Positive Cable length (Mtr)	Negative Cable length (Mtr)	Cable Derating Factor	Total resistance of cable (Ohms)	Voltage drop (V)	Voltage drop (%)	DC cable loss (kWp)	Power loss (%)
		S16	12	57	0.36	0.30	4.60	0.38%	0.0710	0.02%
					Total					**0.75%**

Sr. No	Combiner Box	String	Positive Cable length (Mtr)	Negative Cable length (Mtr)	Cable Derating Factor	Total resistance of cable (Ohms)	Voltage drop (V)	Voltage drop (%)	DC cable loss (kWp)	Power loss (%)
38	DCDB Type 4	S1	150	151	0.36	1.30	20.14	1.67%	0.3109	0.10%
		S2	143	43	0.36	0.81	12.46	1.03%	0.1924	0.06%
		S3	136	81	0.36	0.94	14.47	1.20%	0.2234	0.08%
		S4	129	158	0.36	1.24	19.20	1.59%	0.2965	0.10%
		S5	122	50	0.36	0.75	11.53	0.96%	0.1780	0.06%
		S6	112	88	0.36	0.86	13.32	1.11%	0.2056	0.07%
		S7	105	165	0.36	1.17	18.05	1.50%	0.2787	0.09%
		S8	98	57	0.36	0.67	10.37	0.86%	0.1602	0.05%
		S9	91	95	0.36	0.80	12.38	1.03%	0.1912	0.06%
		S10	84	22	0.36	0.46	7.08	0.59%	0.1093	0.04%
		S11	85	57	0.36	0.61	9.47	0.79%	0.1463	0.05%
		S12	92	15	0.36	0.46	7.11	0.59%	0.1098	0.04%
		S13	47	50	0.36	0.42	6.50	0.54%	0.1003	0.03%
		S14	47	88	0.36	0.58	9.01	0.75%	0.1391	0.05%
		S15	14	22	0.36	0.16	2.40	0.20%	0.0370	0.01%
		S16	7	57	0.36	0.28	4.29	0.36%	0.0663	0.02%
					Total					**0.92%**

Sr. No	Combiner Box	String	Positive Cable length (Mtr)	Negative Cable length (Mtr)	Cable Derating Factor	Total resistance of cable (Ohms)	Voltage drop (V)	Voltage drop (%)	DC cable loss (kWp)	Power loss (%)
39	DCDB Type 5	S1	7	8	0.36	0.06	0.99	0.08%	0.0154	0.01%
		S2	42	43	0.36	0.37	5.72	0.47%	0.0883	0.03%
		S3	14	15	0.36	0.12	1.93	0.16%	0.0298	0.01%
		S4	49	50	0.36	0.43	6.65	0.55%	0.1027	0.03%
		S5	14	15	0.36	0.12	1.93	0.16%	0.0298	0.01%
		S6	49	50	0.36	0.43	6.65	0.55%	0.1027	0.03%
		S7	21	22	0.36	0.19	2.86	0.24%	0.0442	0.01%
		S8	56	57	0.36	0.49	7.59	0.63%	0.1172	0.04%
		S9	10	11	0.36	0.09	1.39	0.12%	0.0215	0.01%
		S10	42	43	0.36	0.37	5.72	0.47%	0.0883	0.03%
		S11	17	18	0.36	0.15	2.33	0.19%	0.0360	0.01%
		S12	49	50	0.36	0.43	6.65	0.55%	0.1027	0.03%
		S13	24	25	0.36	0.21	3.26	0.27%	0.0504	0.02%
		S14	56	57	0.36	0.49	7.59	0.63%	0.1172	0.04%
		S15	87	88	0.36	0.75	11.63	0.97%	0.1796	0.06%
		S16	94	95	0.36	0.81	12.57	1.04%	0.1940	0.07%
Total										**0.44%**
Total String Cable Loss										**0.59%**

- DC Cable Loss – DC Cable

Table 11-5: DC Cable Sizing : DC Cable between DC Combiner Box and Central Inverter

Breaker Size for DCDB	400	Amps
Breaker Size for DCDB with Safety	320	Amps
PV Module Isc	16.15	Amps
PV Module Isc with Bifacial Gain of 10%	17.55	Amps
No of Strings	16	Nos
Current Requirement for DC	280.8	Amps
Is Breaker Rating Sufficient	Yes	
Deration Factor (IEC 60364-5-52:2009)		
Considering ground temp@35º for ambient temp	0.89	
Grouping Factor (0.4m distance between pair)	0.71	
Thermal Resistivity (2.5m.k/W)	1	
Depth of laying (0.8m), Cable >185 mm^2	1	
Ampacity 400 Sqmm DC Cable, 1 C, Al Ar. XLPE Insulated, 1.8/3.3 kV (E) (IEC 60502-2 - Table B.3)	448	Amps
Derated Rating for Cable	283	Amps
No Runs Required	**1**	

From	To	Strings	No of Run	Cable Size (Sq.mm)	Total Length (Mtr)	Power (kW)	Current (A)	DC Resistance @20°C (Ohm/Km)	DC Resistance @90°C (Ohm/Km)	Voltage Drop (V)	Voltage Drop (%)	Power Loss (kW)	Power Loss (%)
DCDB -1	INV	16	2	400	216	297.7	247.0	0.078	0.100	5.32	0.44%	1.31	**0.44%**
DCDB -2	INV	16	2	400	194	297.7	247.0	0.078	0.100	4.78	0.40%	1.18	**0.40%**
DCDB -3	INV	16	2	400	278	297.7	247.0	0.078	0.100	6.85	0.57%	1.69	**0.57%**
DCDB -4	INV	16	2	400	348	297.7	247.0	0.078	0.100	8.58	0.71%	2.12	**0.71%**
DCDB -5	INV	16	2	400	418	297.7	247.0	0.078	0.100	10.30	0.85%	2.54	**0.85%**
DCDB -6	INV	16	2	400	502	297.7	247.0	0.078	0.100	12.37	1.03%	3.06	**1.03%**
DCDB -7	INV	16	2	400	208	297.7	247.0	0.078	0.100	5.13	0.43%	1.27	**0.43%**
DCDB -8	INV	16	2	400	276	297.7	247.0	0.078	0.100	6.80	0.56%	1.68	**0.56%**
DCDB -9	INV	16	2	400	360	297.7	247.0	0.078	0.100	8.87	0.74%	2.19	**0.74%**
DCDB -10	INV	16	2	400	432	297.7	247.0	0.078	0.100	10.65	0.88%	2.63	**0.88%**
DCDB -11	INV	16	2	400	504	297.7	247.0	0.078	0.100	12.42	1.03%	3.07	**1.03%**
DCDB -12	INV	16	2	400	557.2	297.7	247.0	0.078	0.100	13.73	1.14%	3.39	**1.14%**
DCDB -13	INV	16	2	400	192	297.7	247.0	0.078	0.100	4.73	0.39%	1.17	**0.39%**
DCDB -14	INV	16	2	400	504	297.7	247.0	0.078	0.100	12.42	1.03%	3.07	**1.03%**
DCDB -15	INV	16	2	400	420	297.7	247.0	0.078	0.100	10.35	0.86%	2.56	**0.86%**
DCDB -16	INV	16	2	400	350	297.7	247.0	0.078	0.100	8.62	0.72%	2.13	**0.72%**
DCDB -17	INV	16	2	400	280	297.7	247.0	0.078	0.100	6.90	0.57%	1.70	**0.57%**
DCDB -18	INV	16	2	400	196	297.7	247.0	0.078	0.100	4.83	0.40%	1.19	**0.40%**

From	To	Strings	No of Run	Cable Size (Sq.mm)	Total Length (Mtr)	Power (kW)	Current (A)	DC Resistance @20°C (Ohm/Km)	DC Resistanc e @90°C (Ohm/Km)	Voltage Drop (V)	Voltag e Drop (%)	Power Loss (kW)	Power Loss (%)
DCDB -19	INV	16	2	400	571.3	297.7	247.0	0.078	0.100	14.08	1.17%	3.48	**1.17%**
DCDB -20	INV	16	2	400	613.2	297.7	247.0	0.078	0.100	15.11	1.25%	3.73	**1.25%**
DCDB -21	INV	16	2	400	558	297.7	247.0	0.078	0.100	13.75	1.14%	3.40	**1.14%**
DCDB -22	INV	16	2	400	210	297.7	247.0	0.078	0.100	5.17	0.43%	1.28	**0.43%**
DCDB -23	INV	16	2	400	280	297.7	247.0	0.078	0.100	6.90	0.57%	1.70	**0.57%**
DCDB -24	INV	16	2	400	364	297.7	247.0	0.078	0.100	8.97	0.74%	2.22	**0.74%**
DCDB -25	INV	16	2	400	434	297.7	247.0	0.078	0.100	10.69	0.89%	2.64	**0.89%**
DCDB -26	INV	16	2	400	504	297.7	247.0	0.078	0.100	12.42	1.03%	3.07	**1.03%**
DCDB -27	INV	16	2	400	588	297.7	247.0	0.078	0.100	14.49	1.20%	3.58	**1.20%**
DCDB -28	INV	16	2	400	208	297.7	247.0	0.078	0.100	5.13	0.43%	1.27	**0.43%**
DCDB -29	INV	16	2	400	278	297.7	247.0	0.078	0.100	6.85	0.57%	1.69	**0.57%**
DCDB -30	INV	16	2	400	360	297.7	247.0	0.078	0.100	8.87	0.74%	2.19	**0.74%**
DCDB -31	INV	16	2	400	432	297.7	247.0	0.078	0.100	10.65	0.88%	2.63	**0.88%**
DCDB -32	INV	16	2	400	504	297.7	247.0	0.078	0.100	12.42	1.03%	3.07	**1.03%**
DCDB -33	INV	16	2	400	588	297.7	247.0	0.078	0.100	14.49	1.20%	3.58	**1.20%**
DCDB -34	INV	16	2	400	208	297.7	247.0	0.078	0.100	5.13	0.43%	1.27	**0.43%**
DCDB -35	INV	16	2	400	278	297.7	247.0	0.078	0.100	6.85	0.57%	1.69	**0.57%**
DCDB -36	INV	16	2	400	362	297.7	247.0	0.078	0.100	8.92	0.74%	2.20	**0.74%**

From	To	Strings	No of Run	Cable Size (Sq.mm)	Total Length (Mtr)	Power (kW)	Current (A)	DC Resistance @20°C (Ohm/Km)	DC Resistanc e @90°C (Ohm/Km)	Voltage Drop (V)	Voltag e Drop (%)	Power Loss (kW)	Power Loss (%)
DCDB -37	INV	16	2	400	432	297.7	247.0	0.078	0.100	10.65	0.88%	2.63	**0.88%**
DCDB -38	INV	16	2	400	502	297.7	247.0	0.078	0.100	12.37	1.03%	3.06	**1.03%**
DCDB -39	INV	16	2	400	586	297.7	247.0	0.078	0.100	14.44	1.20%	3.57	**1.20%**
										Average Drop & Loss			**0.79%**
										Maximum Drop & Loss			**1.25%**

About DNV

DNV is the independent expert in risk management and assurance, operating in more than 100 countries. Through its broad experience and deep expertise DNV advances safety and sustainable performance, sets industry benchmarks, and inspires and invents solutions.

Whether assessing a new ship design, optimizing the performance of a wind farm, analyzing sensor data from a gas pipeline or certifying a food company's supply chain, DNV enables its customers and their stakeholders to make critical decisions with confidence.

Driven by its purpose, to safeguard life, property, and the environment, DNV helps tackle the challenges and global transformations facing its customers and the world today and is a trusted voice for many of the world's most successful and forward-thinking companies.