Solar PV Technical Guidelines for Financiers

Techno-Commercial Risk Mitigation for grid-connected PV systems in Southeast Asia

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Executive Summary

Among the countries of the Association of Southeast Asian Nations (ASEAN), there is a significant potential for the use of Renewable Energy (RE), which draws an increasing interest among the ASEAN Member States (AMS).

In 2012 the Renewable Energy Support Programme for ASEAN (ASEAN-RESP), jointly implemented by the ASEAN Centre for Energy (ACE) and Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ), conducted a comprehensive survey on prevalent success factors and remaining barriers for “bankable” RE projects in chosen AMS.

ASEAN-RESP was tasked to identify examples of good practice of private investment in renewable energy projects and to develop “ASEAN RE Lending Guidelines” for banks/investors (henceforth called “the Lending Guidelines”). The need for such guidelines, especially for solar Photovoltaic (PV) investments, was confirmed by banks from the AMS at several occasions.

The Technical Guidelines in this report intend to give a summary of international good practice for solar PV projects developed under non-recourse project finance, oriented to include projects financed in ASEAN. Each project needs to be assessed individually and investors’ views on the risks they are prepared to take on vary. Also, as technology evolves and is demonstrated, good practice guidelines change on experience needed. Nevertheless, it is hoped that these technical guidelines will be a useful tool for the evaluation and development of projects – which may lead to increased activities in the region and increased use of green energy in ASEAN.

The Technical Guidelines highlight some key technical items through the project cycle and summarise common current views on bankability, taking regional specificities (climate, market size, etc.) into account. The Guidelines have been drafted with banks and similar investors in the ASEAN member states in mind.

Mott MacDonald has prepared the Technical Guidelines, drawing on its extensive PV project experience as the leading international consultancy for solar PV power in Southeast Asia, and incorporating Lender community feedback from a regional Banker’s focus group discussion held jointly with ASEAN-RESP in May 2014.

1 Introduction

1.1 Context and objectives

Renewable energy (RE) is an important element in a diversified and sustainable energy mix, which increases energy security and contributes to the mitigation of climate change by reducing the CO_2 emissions. Among the countries of the Association of Southeast Asian Nations (ASEAN), there is a significant potential for the use of RE, which draws an increasing interest among the ASEAN Member States (AMS).

Over the last decade, many member states introduced regulatory frameworks, including financial incentives, in order to stimulate the RE market and to tap the huge potential in the region. Despite those efforts, the large-scale deployment of RE technologies for power generation is still facing barriers. One of the reasons is the fact that private investments in the RE sector are relatively scarce and often made on a case-to-case basis.

Nevertheless, many success stories of private investment in RE projects in the ASEAN region exist and important lessons can be learnt in order to push the regional RE market from the inception to the take-off phase. In 2012 the Renewable Energy Support Programme for ASEAN (ASEAN-RESP), jointly implemented by the ASEAN Centre for Energy (ACE) and Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ), conducted a comprehensive survey on prevalent success factors and remaining barriers for “bankable” RE projects in chosen AMS. As an outcome the “ASEAN Guideline on Renewable Energy Support Mechanisms for Bankable Projects” (Policy Guidelines) presents effective policy approaches and support mechanisms to improve framework conditions for positive investment decisions in the RE sector.

Despite the Policy Guidelines, large-scale investments are still missing. For this reason, ASEAN-RESP was tasked by the ASEAN Specialized Bodies for Energy to identify good practices of private investment in renewable energy projects and to develop “ASEAN RE Lending Guidelines” for banks/investors (henceforth called “the Lending Guidelines”). The need for such guidelines, especially for solar Photovoltaic (PV) investments, was confirmed by banks from the AMS at several occasions. The Guidelines as presented here are intended to provide techno-commercial guidance of international good practice for solar PV projects developed under non-recourse project finance and to include lessons learnt from project examples financed in ASEAN. It is envisaged to become a practice-oriented tool which helps investors in their risk assessment of potential RE projects. In the long run, with effective dissemination, it is expected that the Lending Guidelines will cause increased investment activities in the region and in effect increased use of green energy in ASEAN.

The Lending Guidelines highlight common (technical) risks throughout the project cycle and offer advice on how to manage and/or mitigate them, taking regional specificities (climate, market size, etc.) into account. The target group of the guidelines are local banks and investors in the ASEAN member states, however, investors in other RE markets can also benefit from the guidelines.

Each project needs to be assessed individually to check the particular context, components and structure. Also, investors have different views on which risks are manageable. These Lending Guidelines do not replace the need for an independent technical advisor during the project finance process and it is recommended that Lenders use the services of an experienced technical consultant to assist them and, in particular, to identify the project specific risks and issues that need to be addressed.

1.2 Bankers workshop

In order to support the identification of good practices/needs assessment among the target group (bankers/investors) in the AMS, a regional focus group discussion for bankers was conducted jointly by Mott MacDonald and ASEAN-RESP in order to: (i) present the current practices and guidelines of banks with experience in solar PV and other Renewable Energy (RE) technologies (on-shore wind) investments (both international and regional) and (ii) identify key issues to be addressed by the Lending Guidelines.

The regional focus group discussion on “RE Lending Guidelines for Bankers in the ASEAN” was held in Bangkok, Thailand, on 22-23 May 2014. Targeted participants were bankers from ASEAN Member States, particularly countries with high potential of solar PV power and/or wind power such as Indonesia, Malaysia, Philippines, Thailand and Vietnam. Representatives from NGOs and consulting/advisory companies also joined the workshop.

The workshop served as a starting point for developing RE Lending Guidelines for bankers in the ASEAN region, with a particular focus on PV projects. The main topics discussed in the workshop included both technical and commercial aspects, focusing on the risk assessment of solar PV and wind power projects. The issues identified in the workshop are used as the basis for determining structure and content of the Lending Guidelines presented in this report which focus on techno-commercial risk mitigation in solar PV project financing.

1.3 Renewable Energy Support Programme for ASEAN (ASEAN-RESP)

The Renewable Energy Support Programme for ASEAN (ASEAN-RESP) is a jointly implemented project by the ASEAN Centre for Energy (ACE) and the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH. The programme supports the regional exchange to improve framework conditions for renewable energies in ASEAN. By implementing its activities and working towards the overall objective, the project supports the realization of the APAEC and encourages ACE and the ASEAN member states in working towards a greener region.

As a regional project ASEAN-RESP implements activities with relevance for all ASEAN member countries, following its guiding principle ‘learning from each other’. Through its close collaboration with ACE and other relevant regional institutions, the project supports the ASEAN member states in better making use of existing policies and experiences, transfering knowledge and exchanging regional expertise.

1.4 Mott MacDonald

Mott MacDonald is a global management, engineering and development consultancy and a top firm in power. As the leading international consultancy for solar power in Southeast Asia, we draw from a wide resource pool of in-house expertise covering all aspects of the engineering and technology sectors, with specialists in power markets, regulation, policy, electrical networks, civil design, PV module manufacturing, solar resource assessment and PV plant development.

The Mott MacDonald engineers contributing to the authorship of these Lending Guidelines have supported the majority of operating solar PV capacity within ASEAN to date, comprising more than 900 MWp across 140 projects, as well as a further 500 MWp of projects under development in the region. We have supported domestic Lenders with proposed project finance for PV projects in Thailand, the Philippines and Malaysia. The Mott MacDonald team has published a range of technical papers regarding layout design, technology selection and performance assessment for solar PV plants in the Asia Pacific region[1].

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[1] Including for example:

1.5 Guideline structure

This guideline document is structured into the following sections:

- *Section 2, Introduction to solar PV systems,* provides a brief overview of main components and technologies of a PV system, system performance and cost considerations serving as a general glossary and guidance to contextualize subsequent sections.
- *Section 3, Risk management and mitigation,* briefly explains risk management and risk mitigation under the context of non-recourse project finance.
- *Section 4, Due diligence checklist,* presents a **techno-commercial risk assessment** highlighting common technical risks throughout the project cycle and offers advice on how to manage and/or mitigate them. It should be noted that no environmental and permitting risks, which are mostly country-specific, are included in these Lending Guidelines.

(i) "Lessons Learned from Solar PV Project Development in Japan: Optimal Array Design for Complex Sites", Renewable Energy World Asia, Kuala Lumpur, September 2014. Smithtinand, P.; Cherdsanguan, N.

(ii) "In-field performance of a polycrystalline versus a thin-film solar PV plant in Southeast Asia", Photovoltaics International - 22nd Edition, 18 December 2013. Verojporn, S.; Napier-Moore, PA.

(iii) "Gaining confidence in PV module performance through laboratory testing, factory audit and analysis of in-field data", Renewable Energy World Asia, Bangkok, October 2012. Napier-Moore, PA; Verojporn, S.

(iv) "Concentrating solar power compared with flat-plate collectors: Why South-East Asia's largest solar plant uses thin film PV technology", Energy, Volume 164 May, Issue EN2, Proceedings of the Institution of Civil Engineers, May 2011, Napier-Moore, PA.

2 Introduction to solar PV systems

2.1 Solar PV systems

In a grid connected solar PV power plant, the most distinctive technology items are solar modules and inverters. The modules will harvest the solar energy (solar irradiance) and convert it into direct current (DC) power. The inverters will be designed to work under the variable power output of the modules, to convert the DC power into alternating current (AC) power, for which voltage will be then stepped-up through transformer(s) in order to deliver useful AC power to the grid.

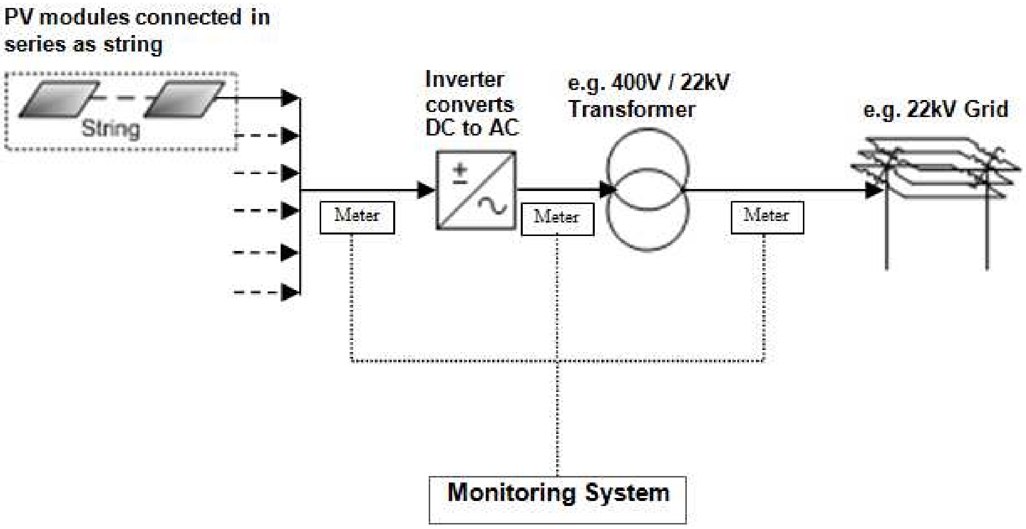
Solar PV systems can be small-scale building mounted systems that either supply power to building demands or inject power to the grid (rooftop solar PV systems), or large-scale ground mounted grid connected solar PV systems. Although the Lending Guidelines are based on Mott MacDonald's experience on large-scale ground mounted grid connected solar PV systems (as it is necessary to achieve a minimum of scale and investment for lenders to engage in non-recourse project finance); most of the points outlined in the Lending Guidelines are also applicable to rooftop solar PV systems, in case these comprise large commercial developments or can be bundled to meet the minimum size for non-recourse project finance.

Typically, the main components of a grid-connected PV system include:

- PV module;
- Inverter;
- Mounting structure (fixed or tracking);
- Transformer;
- Electrical cable;
- Protection systems (e.g. short current, over voltage and lightning protection);
- Transmission line; and
- Monitoring system and weather station.

Figure 2.1 provides a simplified diagrammatic representation of a solar PV system, including how selected main components typically connect to one another.

Figure 2.1: Typical Solar PV System



Source: Mott MacDonald

2.1.1 PV module

The PV module can be considered as the most critical component in a solar PV system. A PV module is a packaged product comprising an electrically connected assembly of solar cells. DC electricity is generated via the photo-electric effect using irradiance energy from the sun to create an electric current through the PV module.

A commercial PV module is typically rated by its DC output power at an approximate range of 100 – 320 watts (W) with a nominal efficiency under standard test conditions (STC) typically ranging from 8% – 20% depending on technology and quality. STC conditions are further described in Section 2.2.3.1 below.

Generally, solar PV module technologies can be classified as follows:

- Crystalline PV, including mono-crystalline and poly-crystalline; and
- Thin-film PV, including amorphous silicon (a-Si), copper indium gallium selenide (CIGS), and cadmium telluride (CdTe).

2.1.1.1 Crystalline and thin-film PV modules

Crystalline silicon solar technology (Figure 2.2) was the first type of PV technology to be widely commercialised. Based on the silicon crystal type and crystal size, crystalline cells are categorised as monocrystalline and poly-crystalline. Typically, a monocrystalline PV module has a higher nominal efficiency of up to 20% while a poly-crystalline PV module has a nominal efficiency ranging from approximately 14% to 18%.

Figure 2.2: Crystalline PV module

Figure 2.3: Thin-film PV module

Thin-film technology (Figure 2.3) comprises a thin semiconductor layer deposited on a low cost flexible substrate. The lower use of silicon or other semiconductor material can reduce the manufacturing costs of the module considerably but typically leads to lower efficiency (7 to 11%) compared to crystalline silicon technology.

Technology selection is driven by project and site features and associated techno-commercial aspects. Key variables for decision making are, for example, as follows:

Technical aspects
- Nominal efficiency (STC);
- Performance affected by site temperature conditions; and
- Performance affected by site irradiance condition.

Commercial aspects
- Choices of PV module manufacturers; and
- Costs of PV modules.

The pros and cons between crystalline and thin-film PV module technology, particularly for the Southeast Asia (SEA) region, are highlighted in Table 2.1.

Table 2.1: Crystalline and Thin-film PV module technology comparison

Item	Description	Crystalline	Thin-film
Technical aspects			
Nominal Efficiency (at STC)	Nominal efficiency (at STC) has a direct impact on required land area for solar PV development. Higher nominal efficiency of PV modules installed leads to lower land area requirements at a given plant output capacity.	Relatively more suitable for sites with limited land area due to its higher nominal efficiency (STC).	Suitable for projects with no significant land constraints (e.g. low cost to purchase land, or where peak output rather than available area is the main limiting factor). The cost to purchase additional land can offset the cost benefit of thin-film technology.
Temperature conditions	Ambient temperature within the SEA region is usually high, which critically impacts on the PV modules performance. Different PV module technologies perform differently at high temperature conditions.	Higher power loss compared to thin-film PV module technology under high temperature conditions.	In most cases, lower power loss compared to PV crystalline technology in high temperature conditions.
Irradiance condition	PV module efficiency varies with irradiance condition (e.g. efficiency is lower at 200 W/m^2 irradiance compared to STC irradiance condition at 1000 W/m^2).	Poorer capacity of converting low irradiance into useful energy output compared to thin-film PV due to light absorbing characteristics.	Typically uses low irradiance resource more effectively compared to crystalline PV modules, especially relevant in a tropical climate.
Commercial aspects			
Manufacturer options	The more manufacturer options, the more flexibility to select a solar PV technology that suits project needs. This again adds flexibility when module replacements or technology/manufacturer modifications.	More manufacturer options as the technology has higher track record and is more widely commercialised.	Lesser manufacturer options compared to crystalline PV module manufacturers.
Costs	Cost of the PV module significantly drives the cost of a solar PV system, typically accounting for 30 – 40% of capital expenditure (CAPEX).	Commercialised crystalline PV module cost in 2014 ranges approximately between 0.6 – 0.8 USD/Wp.	Commercialised thin-film PV module cost in 2014 ranges approximately between 0.4 – 0.5 USD/Wp.

Although thin-film PV modules generally perform better for the SEA climate conditions, nonetheless because of their higher land requirements and recent diminished cost differential compared to PV crystalline technologies, their popularity in this region has reduced in the last few years. Technology choice should however be considered on a project by project basis, based on evaluation of the specific aforementioned techno-commercial aspects.

2.1.1.2 PV module testing and certification

Table 2.2 presents typical PV module testing and certifications to international standards, including both:

- Obligatory certifications, which are usually considered a minimum requirement for use of a PV module under project financing; and
- Optional certifications and PV module tests that may also apply depending on the specific project location or design.

Table 2.2: Typical PV Module Certifications and Tests

Subject of Certifications	Standards
Obligatory Certifications	
Design qualification and type approval	
- Crystalline silicon terrestrial photovoltaic modules **or**	IEC 61215:2005
- Thin-film terrestrial photovoltaic modules	IEC 61646:2008
Photovoltaic (PV) module safety qualification; Part 1: Requirements for constructions Part 2: Requirements for testing	IEC 61730 Part 1 and Part 2
Safety qualification of PV module	Safety class II
Optional Certifications / Tests	
Compliance with EU legislation	CE
Standard for flat-plate photovoltaic modules and panels	UL 1703
Environmental certification	PV Cycle
Ammonia testing	IEC 62716
Salt mist corrosion test (usually to severity level 1 or 6)	IEC 61701
Potential-induced degradation (PID) test	IEC 62804 'System voltage durability test for crystalline silicon modules'
Damp heat test (extended)	Test under IEC 61215 standard
Certifications of Module Manufacturer's Facilities	
Quality management systems	ISO 9001:2008
General requirements for the competence of testing and calibration laboratories	ISO 17025:2005
Environmental management systems	ISO 14001:2004
Design and manufacturing of solar modules	BS OHSAS 18001:2007
Manufacturing of solar power devices for the automotive industry - with product design and development -	ISO 16949:2009

2.1.2 Inverter

As the grid network usually carries AC electricity, the DC power generated by the solar PV modules must be converted for delivery to the grid network in the form of AC power. The inverter is designed to work under variable power output conditions of PV modules in order to convert DC power to AC power.

2.1.2.1 String and central inverters

The global market for grid-tied PV inverter supply is more concentrated than for PV modules. Typically, grid connected PV inverters can be broadly classified into two categories (see Figure 2.4 and Figure 2.5 below):

- String-inverter (typically < 50kW AC power output); and
- Central-inverter (in the usual range of 100 kW to 1,200 kW AC power output).

Figure 2.4: Central inverter

Figure 2.5: String inverter

Key parameters for technology comparison are defined as follows and further explained below:

- Inverter efficiency;
- Installation area requirements; and
- Maintenance requirements.

In addition to technological differences, string and central inverters usually have a different cost profile, with a different inverter installed cost and requiring differing lengths of DC and AC cables to be installed.

Inverter Efficiency

The inverter efficiency is mainly dependent on associated losses related to:

- DC to AC conversion;
- Maximum Power Point Tracking; and
- Auxiliary power consumption.

Maximum Power Point Tracking (MPPT) is essential in any PV system as the power output changes under changing environmental conditions. In order to maximize the power output, the MPP tracker adjusts the module voltage to reach maximum power output under given conditions.

Typically, central inverter technology is more efficient to convert DC-AC compared to string inverter. Conversely, string inverters are more efficient for Maximum Power Point Tracking, in case of variable and dynamic irradiation conditions across the PV arrays. Central inverters will generally also have higher auxiliary power demands in the SEA region, in particular for cooling of the inverter enclosure. Considering all factors central inverter technology is generally more efficient compared to string inverters as losses in DC to AC conversion is the major factor driving the overall inverter efficiency. Generally central inverter technology is found to be more economical when compared to string inverters, especially for larger PV systems. However, the choice of technology should be justified on a project by project basis through a project cost-benefit analysis, also bearing in mind the additional factors discussed below.

Installation area requirement

Central inverters are typically installed in a concrete building or to a lesser extent in container boxes which require a certain amount of site space. String inverters can be installed underneath PV modules and therefore may not require any additional area, which is beneficial under land/area constrained scenarios, including for some rooftop solar PV plants.

Maintenance requirement

For the same amount of AC power output capacity, the number of string inverters required is higher to central inverter. For equivalent unit failure rates, lower maintenance requirements are therefore required for central inverters compared to string inverters. Conversely, a single string inverter outage has a much less significant impact on the overall plant output, and outages due to string inverter failures can be quickly rectified, by simply replacing a failed unit with an on-site spare while awaiting repair.

String inverters are therefore often favored for smaller projects up to several megawatts capacity and remote locations where maintenance response time from the inverter supplier is expected to be slow.

2.1.2.2 Inverter testing and certification

Table 2.3 presents typical inverter certifications to international standards, including German VDE standards that are widely referenced internationally. Inverters manufactured for international markets will often possess such certification, which provides reassurance that the inverter technical characteristics can meet typical quality, safety and grid code requirements. Nonetheless, we note that compliance with national grid code requirements for the project site location is the key requirement for inverter testing, rather than international code compliance. This contrasts with PV module certifications, where international codes are usually the primary reference.

Table 2.3: Typical Inverter Certifications

Subject of Certifications	Certifications
Low voltage Directive (Electronic equipment designed for use within certain voltage limits)	2006/95/EC EN 50178:1997
Electromagnetic compatibility (EMC)	2004/108/EC EN 61000-6-2:2005 EN 61000-6-4:2007 EN 61000-3-12:2004
Compliance to EU legislation	CE
Photovoltaic (PV) systems. Characteristics of the utility interface	IEC 61727:2004
Safety of power converters for use in photovoltaic power systems	EN 62109-1:2010
Grid Management	VDE-AR-N 4105/08.11 DIN VDE V 0124-100/07.12

2.1.3 Foundation and mounting structures

Foundation and mounting structures should be designed to support the solar PV module positioning for the entire project life (e.g. typically 20 – 25 years).

Mounting structures can be either fixed or tracking systems, with the latter changing the module orientation to track the positioning of the sun (either through a one or two axis rotation). Fixed systems are lower cost, so the energy production gains resulting from tracking systems should be considered in a cost-benefit analysis on a project by project basis. In general, tracking systems will result in a more significant benefit at extreme latitudes, so are less relevant for application in SEA than in temperate regions of the world, though may still be cost-effective.

In terms of foundations, piled foundations (Figure 2.6) for mounting structures are most common, although depending on site soil conditions and local material supply costs, use of concrete spread footings (Figure 2.7) may also be applicable.

Figure 2.6: Piled foundation

Figure 2.7: Spread footing

For piled foundations, piled beams, screw piles, or cast concrete,pile foundations are commonly used in solar PV systems depending on the soil conditions of the site, established through preliminary geotechnical surveys.

With the exception of concrete foundation elements, all other foundations and mounting structures typically use galvanized steel, for adequate corrosion resistance. Galvanization thickness will depend on the specific site climate condition. Aluminum mounting structures are also used for some plants, usually with stainless steel fittings.

Mounting structure and foundation suppliers are often specialized international firms, however domestic steel fabricators have also sometimes been successfully used for projects within SEA.

2.1.4 Transformer

The solar PV system will generate electrical power at a low voltage level (LV), similar to that used for domestic power supply. In order to step-up this low level voltage to adequate grid voltage level, transformers are used. A transformer is an electrical device that transforms electrical energy (stepping up or stepping down the voltage) between two or more circuits through the principle of electromagnetic induction.

2.1.4.1 Transformer losses

Transformer losses can be expected during day and night time, and the two major loss types are generally categorized as follows:

- Load loss (“copper” loss); and
- No-load loss (“iron” loss).

During the day time, when the transformer is in-operation, the ohmic loss in the copper windings of the transformer is the predominant loss.

No-load losses, which relate to energisation of the iron transformer core, can be also expected during day-time and night-time. Such no-load losses predominate at night-time or when a plant is not in operation but remains connected to the grid and consumes power from the grid. Such losses could be avoided by opening the MV/HV breaker every evening, if permitted by the grid operator and plant electrical configuration.

2.1.4.2 Transformation stages

As mentioned, transformers are used to step-up the voltage level of the plant to the grid voltage level. However, some projects may require several transformer stages (e.g. two stages) in order to achieve grid voltage level.

Typically, if the plant will be connected to the grid with medium voltage (MV) (e.g. 22 kV or 33 kV) a single transformation stage is used for the project. However, when connecting to the grid at high voltage (HV) (e.g. 69 kV or 115 kV), use of two transformation stages is common. Multiple transformation stages will lead to higher transformer losses for the projects, but may nonetheless be useful to optimize the overall cost and cabling losses of the project.

2.1.4.3 Transformer types

Transformers can be broadly classified into two types which are ‘dry’ and ‘liquid’ type transformers, describing the transformer cooling and insulation mechanism. The ‘liquid’ type generally uses mineral oil to insulate and cool the transformer windings. Generally, the pros and cons for these two types of transformer are:

Dry type

- Higher cost
- Lower maintenance
- Indoor/Outdoor use

Liquid type

- Lower cost
- Higher maintenance
- Outdoor use

One of the most common types of low capacity transformer which are being used for solar PV plants within the region is the hermitical sealed oil transformer. This type of transformer requires lower maintenance than a standard oil-type transformer (which is open to moisture ingress with oil heating/cooling). For oil-type main HV transformers used in large solar PV plants, forced circulation of the air using fans to cool the internal oil may also be used in some cases, and increases transformer capacity.

It is common to source domestically manufactured transformers for solar PV projects. However, it is expected that the transformer will be made to IEC 60076 standard, are designed suitably for site conditions (e.g. tropical conditions for SEA) with a two to three year defect warranty period. Transformer supplier facilities should preferably be certified to ISO 9001 (design and development and manufacture of distribution transformers and power transformers) and ISO 14001 (manufacture of distribution transformers and power transformers). Transformer track-record from the supplier should preferably include reference projects within the same region, and use within PV projects.

2.1.5 Electrical cables

Electrical power generated in a solar PV system is transmitted between each series component via electrical cables. Selection of cable size, type and installation method depends on the design and configuration of the plant. Undersized DC or AC cables in any one of the multiple series connections between the PV module and grid connection point can significantly affect overall plant losses, and, in the worst case, cause cable fire.

Copper cable is used for LV conductors in order to minimize cable losses. Copper or aluminum cable is used for medium voltage (MV) cables.

One of the specific types of cable which are commonly used in solar PV projects is ‘solar cable’. In brief, solar cables are used for cabling of the solar PV modules through inverters, and are designed to tolerate a wide range of temperature, various environmental conditions, and provide resistance to UV radiation in order to be suitable for typical outdoor solar PV plants conditions.

One key design issue throughout the PV plant is that cable insulation must be appropriately selected and be able to withstand thermal and mechanical loads. Cable insulation materials must be appropriately resistant to weathering, UV radiation, and abrasion. Poor cable insulation may lead to current leakage, usually resulting in a ground fault, which in turn lowers the available operating hours of the plant. Although cables may be selected properly, poor construction quality could also result in cable insulation damage impacting on plant availability.

2.1.6 Transmission line

Solar PV systems can be located in remote areas without access to existing transmission lines. In this case new transmission lines must be constructed in order to transmit electrical power from the plant to the grid. Responsibility of construction typically rests with the grid owner, although cost for new transmission will be subject to agreement between the project company and the grid owner, and will often be borne by the project.

2.1.7 Monitoring system

The monitoring system is a fundamental part of the solar PV plant as it allows the owners and operators to monitor the real performance of the plant against the expected performance. The real performance of the plant is monitored based on the output power from the inverters. The expected performance of the plant for the same period is calculated based on the actual weather conditions at the site location including irradiation, temperature of the solar cells and ambient temperature.

2.2 Resource potential and revenue calculation

Calculation of expected energy production and related revenue from electricity sales is key for any power generation project investment. The energy yield assessment performed for any solar PV plant is intended to provide a best-estimate of the expected energy output of the plant, which in turn can be used in the project financial model to assess financial performance.

The key parameters for energy yield assessment are:

- Solar irradiance as a critical and sensitive modelling input;
- Ambient temperature as a modelling input; and
- Performance Ratio (PR) calculation.

2.2.1 Solar irradiance

The energy production of a solar PV plant depends on the incident amount of irradiance available on its solar PV modules. Irradiance, or sunlight, is a measure of the electromagnetic radiation hitting a surface of the solar PV modules. Irradiance varies throughout the course of a day as well as seasonally. The irradiance is usually averaged over a day, month or year to then predict the Performance Ratio (PR) and energy yield of the plant.

The SEA region has relatively scarce measurements of solar irradiation levels, compared with more established solar PV markets in Europe and the US; techniques to reliably estimate irradiation given such data scarcity are also not yet commonplace in the global solar PV industry.

In our experience, it is currently not uncommon for estimates of irradiation resource in SEA to be inaccurate and insufficiently rigorous, and for significant overestimates of energy yield to result.

For a Project Lender, robust selection of solar irradiance data is therefore a critical and sensitive input to the financial model, which drives the ability of the project to meet debt service obligations.

2.2.1.1 Solar irradiance data considerations

Typically, more than one source of irradiation is used for comparison prior to evaluation of energy production in solar systems. Irradiance at a given proposed site location can be estimated based on:

- Ground-based measurements or irradiance at nearby weather stations, made using a pyranometer; or
- Satellite-derived estimates of irradiance, either from public sources or specialised private data providers.

Irradiance data is usually recorded as Global Horizontal Irradiance (GHI), which is defined as the amount of sunlight that falls on a 1 m^2 horizontal area measured in kWh/m^2. Irradiance at the inclined plane can also be measured, or else calculated from the horizontal values.

When assessing irradiation data for a specific location, it is recommended to have long-term data (10 to 20 years) to be able to establish a reliable average value with a clear assessment of its variation (maximum and standard) over the Project life.

Available public irradiance sources in the region (e.g. MeteoNorm, National Meteorological Agencies, NASA SSE) and data from solar irradiance data providers are commonly used for energy yield assessment for solar PV systems. The annual average GHI in SEA approximately ranges between 1,600 – 1,800 kWh/m^2/year.

Ground-measured irradiance data

Use of ground-based irradiance measurements weather stations to estimate irradiance data at a given site is generally preferable, providing that the data quality can be established and that the reference weather station is located in close proximity to the solar PV plant site (e.g. within 25 km radius), as at this proximity the risk of variability in local conditions is largely mitigated. To ensure that irradiance data from ground weather stations is reliable, it is important to understand the methodology applied to obtain the data including:

- Type of instrumentation and associated data logging equipment used;
- Operation and maintenance scheme of such instrumentation, including sensor cleaning and instrument recalibration;
- Resolution of data logging;
- Methodology applied when there are data gaps;
- Surrounding condition of the weather station (e.g. shading on pyranometer may lead to negative-bias of data obtained); and
- Quality control approach used for the data generated.

In some cases, ground meteorological stations are developed at the project site to obtain irradiance data and other environmental data at the specific site location, usually as short-term data (e.g. 1 – 2 years).

If the methodology applied to obtain irradiance data is considered satisfactory, the data can be correlated against a representative long-term data source to reduce the risk of local variability.

Satellite-derived irradiance data

In general, satellite-derived irradiation data sets comprise extrapolations from satellite photography combined with supporting satellite- or ground-based measurements and assumptions regarding the composition of the atmosphere and geographical inputs.

As satellite-based irradiance data is derived through modelling and assumptions, uncertainties of irradiance data from satellite-based data are generally higher compared to ground-measured data, although the relative accuracy varies with each location and region, depending on both the quality of ground measurements and accuracy of the satellite-based models.

When using satellite-based irradiance data, it is strongly recommended that the data provider shows evidence that the irradiance data has been validated with irradiance derived from ground meteorological stations located nearby the specific site location. Because uncertainties of satellite-based data inherently vary by location, due for example to relatively low spatial resolution of the atmospheric inputs used in the modelling, data validation is important quantify uncertainties. Accurate ground measurements may also be used as the basis for tuning of the satellite-based models, to improve overall accuracy in a given region

2.2.2 Ambient Temperature

Ambient temperature is another important input for energy yield assessment, as PV module performance is highly dependent on this parameter.

Similar to solar irradiance, ambient temperature data can be obtained from ground-measurement or satellite-based sources depending on availability and quality of such data. It is typically recommended to have 10 – 20 years length of data to reduce inter-annual variability.

Ground based measurements of ambient temperature are much more commonplace than for ground based measurements of irradiation, and it is usually possible to obtain several different data sources of acceptable relevant, which can be used for cross-validation.

2.2.3 Performance Ratio

The losses experienced in a system are cumulatively combined to give a Performance Ratio (PR) of the plant which is a measure of both the performance and the efficiency of the 'on the ground' equipment and systems, and is defined below as:

$$PR = \frac{real\_energy}{theoretical\_energy}$$

The PR compares the system Coefficient of Performance (COP) with benchmark module performance at STC condition, $\eta_{STC,}$ which can be defined as:

$$PR = \frac{COP}{\eta_{STC}}$$

where,

- COP = Ratio of the electric energy, E_{AC} ,from the system divided by the estimated irradiance to the system's inclined surface, G_k; and
- η_{STC} = Ratio of nominal PV power, P_{nom} (kWp), divided by the irradiance at STC condition, G_{STC} (1 kW/m^2).

Thus,

$$PR = \frac{\left(\frac{E_{AC}}{G_k}\right)}{\left(\frac{P_{nom}}{G_{STC}}\right)}$$

The higher the quality of the modules and the system, the higher the PR. Before a plant becomes operational the PR can be predicted based on the proposed equipment and design. Typically, PR is calculated using commercially available software PVsyst and complemented where necessary with additional modelling.

The PR metric is widely used contractually in order for the construction contractor to guarantee the plant performance during an agreed period of time from plant commercial operation.

A step-by-step annual energy output calculation derived from PR and incident irradiance, for the Lender's practical use, is attached in Appendix A.

2.2.3.1 Standard Test Conditions (STC)

Performance data given by the PV module manufacturer is only valid for certain test conditions which are given in Table 2.4. The power output at STC is known as the nameplate power or installed Watt-peak (Wp). STC is an international standard to measure module performance.

Table 2.4: Standard Test Conditions (STC), for PV module output rating

Criteria	Condition
Irradiance	1000 W/m^2
Spectrum	Air Mass (AM) 1.5
Cell Temperature	25°C

Spectrum at STC is represented by the air mass coefficient, which approximates the change in spectrum of solar radiation given scattering and absorption as light waves travel through the atmosphere. The STC condition of AM 1.5 represents 1.5 times the optical path length through the Earth's atmosphere compared to when the sun is at the zenith (i.e. directly overhead the site location), and is approximately representative of idealised spectral conditions in the upper latitudes of Southeast Asia.

The actual site conditions at the module surface will differ from the laboratory conditions (and will also differ continuously throughout the day and depending on the specific region) and can affect the performance of the module. It is important to use a consistent performance indicator benchmarked to STC throughout the industry in order to make meaningful comparisons.

2.2.3.2 Key losses and Performance Ratio Calculation

The key losses in solar PV project can be broadly categorized into two types of losses which are:

- Capture losses; and
- System losses;

In brief, capture losses are mainly dependent on the quality of equipment and its properties performing under the site conditions together with the design of the plant. While the system losses will mainly depend on plant design.

Key losses considered for PR calculation are shown in Table 2.5 below.

Table 2.5: Key losses for PR calculation

Type of Losses (Annual)	Typical Annual Average Losses in Percentage Terms (in SEA)
Capture losses	
Spectral	1% loss to 1% gain
Shading	1 – 5% loss
Soiling (e.g. dust)	1 – 2% loss
Angular	1 – 3.5% loss
Low irradiance performance	3.5% loss to 2% gain
Temperature losses	4 – 12% loss
Power Tolerance	3% loss to 2% gain
Light-induced degradation (LID)	1 – 2% loss
Mismatch	0 – 3% loss
System losses	
DC and AC cabling	1 – 4% loss
Inverter curtailment	0 – 4% loss
AC/DC performance of Inverter	1 – 4% loss
Transformers	1 – 2% loss
Availability	0 – 2% loss

From Table 2.5 it can be seen that the PR is highly dependent on module temperature. The efficiency of PV cells decreases at a rate of approximately 0.2 – 0.5 % per °C above STC module temperature of 25°C. Modules can heat up to 70°C, with a higher module temperature resulting in lower power output. The magnitude of the effect mainly depends on the local environment, the insulation of the back of the cell and the specific cell in question. Due to high ambient temperatures across the majority of SEA, projects located in the region would typically experience high temperature losses compared to other losses.

An example of PR calculation for solar PV project using crystalline PV modules is shown in Table 2.6.

Table 2.6: Example PR Calculation for a solar PV plant

Type of Losses (Annual)	Losses	Performance
Spectral	0.5%	99.5%
Shading	1.7%	97.8%
Angular	1.0%	96.8%
Low irradiance performance	2.5%	94.4%
Temperature losses	9.2%	85.7%
Mismatch	0.5%	85.3%
Power tolerance	0.0%	85.3%
Light-induced degradation (LID)	1.5%	84.0%
DC wiring losses	0.3%	83.8%
MPPT performance	0.5%	83.3%
AC/DC performance of Inverter	2.4%	81.3%
AC wiring losses	0.5%	80.9%
AC transformers	1.2%	80.0%
Availability	1.0%	79.2%
Soiling	1.0%	78.4%
Example Initial Annualised PR		**78.4%**

Generally the initial operating PR for a solar PV system in SEA with good design and equipment quality would be in the approximate range of 75 – 85%.

2.2.3.3 Energy yield and revenue calculation

Revenue of a solar PV project can be calculated based on the energy production from the solar PV system.

The energy production is estimated from:

- Project installed capacity;
- Solar irradiance; and
- Project PR in each operating year.

Specific yield

For a solar PV plant, specific yield is generally used to determine the plant's energy production capability per unit installed capacity (kWh/kWp). The specific yield is simply the product of the irradiance and the initial annualised PR of the project. The specific yield is usually calculated based on monthly data and summed to give an estimated annual specific yield. For the annual energy prediction over a project's life, the PR in each respective operating year is used.

The specific yield is a useful parameter to compare solar PV system performance.

For instance, if the plant annual plant PR and annual irradiance are:

Project A

- Annual Plant PR: 75.0%
- Annual Irradiance: 1,700 kWh/m^2

Project B

- Annual Plant PR: 80.0%
- Annual Irradiance: 1,500 kWh/m^2

The annual specific yield of Project A and Project B are therefore:

- Project A: 1,275 kWh/kWp/year
- Project B: 1,200 kWh/kWp/year

It can be seen that although the PR of Project A is lower the specific yield is still higher compared to Project B due to high irradiance conditions manifested for Project A. Both annual PR and annual irradiance parameters are therefore necessary for determining energy production of a given project.

Energy yield calculation

An energy yield calculation is finally derived based on the product of specific yield and total plant installed capacity.

PV module performance degradation over time also needs to be considered when calculating annual energy production of a solar PV project. Typically, a PV module manufacturer will provide a degradation warranty to ensure that PV module performance will not degrade beyond certain magnitude.

Assuming the inputs below for Project A:

- Initial Installed capacity: 5,000 kWp
- Annual degradation rate: 0.6% per year
- Project life: 5 years

Project A’s energy production for an illustrative 5 years of operation is calculated and shown in Table 2.7.

Table 2.7: Example for energy yield calculation of solar PV project

Operational Year	Initial Specific Yield (kWh/kWp/year)	Initial Installed Capacity (kWp)	Effective Installed Capacity after Degradation (kWp)	Energy Estimate (MWh/year)
1	1,275	5,000	4,985	6,356
2	1,275	5,000	4,955	6,318
3	1,275	5,000	4,925	6,280
4	1,275	5,000	4,896	6,242
5	1,275	5,000	4,866	6,205

It can be seen that the energy production will decrease each year due to the annual degradation performance of PV module.

As already noted, a step-by-step annual energy output calculation derived from PR and incident irradiance, for the Lender's practical use, is attached in Appendix A.

Recommended energy yield results for Lenders

Energy yield estimation inherits uncertainties from various parameters such as irradiance data, modelling, and variations of irradiance over a project's life.

The probability of achieving a given energy yield is represented by a P number. The probabilities are reached by considering project specific uncertainties and the whole range of exceedance probabilities of the solar PV plant's annual energy production. P75 is the annual energy production which is reached with a probability of exceedance of 75%. In other words, the risk that an annual energy production of P75 is not reached is 25%.

Choice of the P75, P90 or other P value for the base case scenario in the financial model depends on the risk appetite of the Lenders, although use of the P90 value is more typically seen in international project finance transactions.

Assuming the total uncertainty for energy yield estimation is 5% (over the return period of interest), the total plant energy production for every year of operation with P50, P75, P90, and P99 for Project A is outlined in Table 2.8. These results would usually be presented for several different return periods (e.g. 1 year, 10 years etc), with uncertainty reducing for longer return periods. For example, P90 yield over a 10 year return period might be used to assess project viability for debt financing, and P90 yield over a 1 year return period for structuring planned yearly loan repayments.

The P50 and P99 are usually recommended as upside and downside sensitivity cases, respectively.

Table 2.8: Example for P50, P75, P90, and P99 energy yield calculation of a solar PV project

Operational Year	P50	P75	P90	P99
1	6,356	6,160	5,967	5,633
2	6,318	6,123	5,931	5,600
3	6,280	6,086	5,895	5,566
4	6,242	6,050	5,860	5,533
5	6,205	6,013	5,825	5,499

Revenue calculation

Project revenue can be calculated based on the agreed value stated in the Power Purchase Agreement (PPA).

Revenue of Project A for P50, P75, P90, P99 are outlined in Table 2.9, assuming the example of the PPA states that the relevant party will purchase the energy from Project A based on an illustrative 5 year Feed-in-Tariff scheme with the fixed-rate of 0.20 USD/kWh. The Lenders would use these generated revenues as inputs into the financial model, based on the actual project lifetime or loan term duration.

Table 2.9: Example of P50, P75, P90, and P99 revenue calculation of solar PV project

Operational Year	P50	P75	P90	P99
1	1,271,200	1,232,000	1,193,400	1,126,600
2	1,263,600	1,224,600	1,186,200	1,120,000
3	1,256,000	1,217,200	1,179,000	1,113,200
4	1,248,400	1,210,000	1,172,000	1,106,600
5	1,241,000	1,202,600	1,165,000	1,099,800

2.3 Cost structure of a solar PV project in the region

It is important for Lenders to understand whether the solar PV project to be financed can be considered expensive for the given technology and design proposed. In order to support the understanding of key cost drivers of a solar PV project, an approximate cost breakdown for solar PV plants, based on international and regional experience, is provided in Table 2.10. It should be noted that the cost of solar PV panels and equipment has changed significantly during recent years and there may be project specific issues which also need to be considered to confirm the reasonableness of the project costs for any given project.

Table 2.10: Typical cost breakdown for a solar PV project, SEA, 2014

Items	USD/Wp	% Portion with respect to CAPEX
CAPEX	1.70 – 2.40	
EPC	1.50 – 2.00	80 – 90
PV modules	0.60 – 0.80	25 – 40
Inverters	0.15 – 0.35	5 – 15
Foundation and Mounting structures	0.15 – 0.35	5 – 15
Balance of Plant (BoP) including civil and electrical equipment and installation works	0.30 – 0.60	15 – 35
Non-EPC (Development, financial, contingencies, etc. but excluding land costs)	0.20 – 0.40	10 – 20
OPEX per year (O&M fee, land lease, insurance, etc.)	0.03 – 0.06	

3 Risk management and mitigation under project finance

Having provided an introductory background to solar PV project technology, yield assessment and typical costs, the subsequent focus of these Lending Guidelines is on techno-commercial risk mitigation under non-recourse project finance solar PV projects.

Project finance can be defined as the financing of infrastructure projects with an upfront spend element in a way that removes recourse by the Lenders to the Sponsors (non-recourse financing), or limits such recourse (limited recourse financing). In such projects the sole security of the Lenders is the revenue stream and assets of the project.

Project finance projects are highly structured deals that move liabilities off Sponsor's balance sheet and bound and contain the risk in the project vehicle company. In project finance deals banks negotiate at the micro level and well defined are placed liabilities on contracting parties to ensure delivery of revenue stream. Project risks need to be clearly allocated, understood and bounded. Project risks are therefore assessed and managed and/or mitigated (when possible) by the project stakeholders that are best placed to do so.

The following section provides a set of due diligence checklists highlighting common key techno-commercial risks throughout the project lifecycle, emphasizing benchmarks and factors to consider, risk management and mitigation actions, and project stakeholders that should ordinarily be best placed to manage and mitigate such risks. The due diligence checklist is provided for the following project risk areas typical of both power projects in general, and solar PV power projects in particular:

- Technology risks (e.g. underperformance, warranty coverage);
- Design and construction risks (e.g. delay, cost overrun, underperformance);
- Performance projection risks (e.g. underperformance);
- Operation risks (e.g. plant unavailability, lack of cost control); and
- Contractual risks (e.g. delay, cost overrun).

4 Due diligence checklists

4.1 Overview

This section highlights common technical risks throughout the project cycle and offers advice on how to manage and/or mitigate them. The list of risks given in the following sections should not be considered exhaustive. Each project will have some unique risks that need to be identified and mitigated.

It should also be noted that no environmental and permitting risks, which are mostly country-specific, are included in these Lending Guidelines.

4.2 Key technology risks

Table 4.1: Key technology risks and risk management/mitigation actions

Due Diligence Item	Factors to consider/check	Benchmark	Risk management/mitigation actions	Party involvement
Proven Technology	PV module bankability	Model track-record of at least of 100 MW in operation, preferably within non-recourse project financed utility-scale plants	Assess PV module technology bankability including: PV module specifications IEC certifications held by module model proposed ISO certifications held by manufacturing facility Laboratory based performance testing Request Original Equipment Manufacturer (OEM) support Request for OEM insurance If insufficient track record, commission a PV module bankability report undertaken by an independent third party focusing on module manufacturing quality, testing and operating performance	PV module manufacturer/supplier Insurance company Independent technical advisor
	Inverter bankability	Inverter model track-record of 100 MW at operational availability of minimum 98% and rated efficiency of more than 95% Appropriate “ingress protection” (IPxx) rating for installation environment	International certifications held Check against approved inverter list from the grid owner if applicable Request laboratory test reports to support compliance with the most recent national grid-tied inverter requirements If insufficient track record, commission a third party review of manufacturing quality, testing and operating performance	Inverter manufacturer/supplier Insurance company Independent technical advisor

Due Diligence Item	Factors to consider/check	Benchmark	Risk management/mitigation actions	Party involvement
	Warranty terms	PV Module: 10 year product warranty and 25 year performance warranty Inverter : 5-10 years product warranty	Ensure robustness of warranty terms: particular attention should be given to definition of a defect; scope of cost coverage; and testing basis for a performance warranty claim	Equipment manufacturer/supplier
Technology Sustainability	Suitability for conditions in SEA (high humidity and temperature)	Model track-record of 100 MW in similar weather conditions Damp heat tests 1,000 hrs as a minimum, or 2,000 hrs for high humidity conditions Testing against “potential induced degradation” (PID)	Check track record, operational data, specifications, and certifications for high humidity and temperature conditions. Request for OEM support Request for OEM insurance	Equipment manufacturer/supplier Insurance company Independent technical advisor
Capacity of local O&M service delivery	Review: manufacturer track record team /company structure and service in the region	Track record of 100 MW in the region Active service presence in the country	Ensure equipment suppliers have good track record and after sales service in region Inverter supplier provide maintenance teams capable of carrying out the full usual range of on-site repairs in region The inverter supplier contractually commits to twenty-four hour response time	Equipment manufacturer/supplier

4.3 Design and construction risks

Table 4.2: Key design and construction risks and risk management/mitigation actions

Due Diligence Item	Factors to consider/check	Benchmark	Risk Management/Mitigation Actions	Party Involvement
Site suitability	Ground conditions	Ground conditions to support 25 years of design life	Ensure that a geo-technical assessment (clay, rock, porosity, stability) is undertaken to confirm ground stability and ability to support the solar PV installation Ensure slope stabilization and good drainage if applicable	Independent geotechnical advisor Independent technical advisor
	Flooding risk	50 cm above the maximum historical flood level	For sites with risk of flooding: Flood mitigation design in place referenced to robust maximum historical flood level, with adequate return period (e.g. 50 years) Take flood insurance	Hydrologist Project developer/ owner Independent technical advisor
	Earthquake risk	n/a	Foundation design is sufficiently robust	Geologist

Due Diligence Item	Factors to consider/check	Benchmark	Risk Management/Mitigation Actions	Party Involvement
			under earthquake conditions Take earthquake insurance	Project developer/ owner Independent technical advisor
	Logistics	n/a	Undertake site visit to ensure site access, ingress/egress, and that transportation routes (roads, ports, etc.) are suitable for transportation of heavy equipment (excavators, modules, etc.)	Project developer/owner Design and construction contractor
	Infrastructure required to make power plant operational	n/a	Ensure that all supporting infrastructure to be built by the project developer is scoped, interfaces between works contracts clearly defined and costs included in the project budget (especially transmission lines, transformers, etc.), with appropriate contingency reserves for overruns	Project developer/owner Independent technical advisor Design and construction contractor
Construction Contractor capability	Construction contractor company & team track record and capability Sponsor capability to supervise	n/a	Contracting an experienced Construction contractor providing experienced design and team In particular for the case where multiple construction contractors will be involved, with works interfaces to be managed, then a capable Sponsor site team is also important	Construction Contractor Project Sponsor
Adequate foundations and mounting structure	Foundations and mounting structure design, geo-technical conditions	Design for 25 years of design life	Adequate foundations and mounting structure design for site geo-technical conditions and loading conditions	Design and construction contractor Independent technical advisor
Adequate design and selection of electrical components	Size and compatibility of electrical components	1:1.10 – 1:1.25 (DC:AC ratio)	Ensure that inverter size matches with module capacity (Wp) Transformer and cable sizing do not lead to unusual loss levels (refer to Table 2.5)	Designer and construction contractor Independent technical advisor
	Equipment specification	n/a	Ensure specifications comply with international and local standards and requirements (see section 2 for illustrative international standards on key equipment)	Designer and construction contractor Independent technical advisor
Grid code compliance	Confirm ability of the project to meet relevant grid code	n/a	Ensure that the design meets the grid code, that the contractor has experience meeting grid operator commissioning requirements, and that commissioning in line with grid code is a contractor obligation	Designer and construction contractor Independent technical advisor Grid utility
Prevent load shedding and curtailment (when possible)	Grid connection conditions Plant dispatchability Plant design	n/a	Commission dispatch studies by the utility to confirm plant ability to deliver power (and dispatchability) at the connection point Independent verification by a third party of plant ability to deliver power (and dispatchability) at the connection point	Designer and construction contractor Independent technical advisor Grid utility
Procurement constraints	Procurement of long lead-time	n/a	Confirm schedule for procurement of long-lead items/equipment such as High Voltage	Equipment Supplier Project Owner

Due Diligence Item	Factors to consider/check	Benchmark	Risk Management/Mitigation Actions	Party Involvement
and project delays	items		(HV) transformer as early as possible, which might for example be 12 months	

4.4 Performance projection risks

Table 4.3: Key performance risks and risk management/mitigation actions

Due Diligence Item	Factors to consider/check	Benchmark	Risk Management/Mitigation Actions	Party Involvement
Predict solar irradiation with low uncertainty when possible	Availability and quality of solar irradiation data	n/a	Check historical data If using satellite data, then ensure that the data source has been successfully validated under similar conditions to the site in the region Account appropriately for data source uncertainty Ideally, set up a site meteorological station to validate satellite data Optimized utilization and correlation of terrestrial and satellite information	Independent energy yield assessor Independent technical advisor Project developer/owner
Adequate energy yield modelling and prediction	Modelling methodologies	Use standard internationally accepted software (e.g. PVSyst)	Undertake an independent energy yield assessment using internationally accepted modelling standards	Independent energy yield assessor Independent technical advisor Project developer/owner
	PR and de-rating factor	PR: 75% – 85% 1st year de-rating factor: 0.6%-2.0% Subsequent year de-rating factor: 0.5%-0.8%	Improve PR performance through optimal project design and technology selection Use data on degradation from manufacturer lab and operational data	Independent energy yield assessor Independent technical advisor Project developer/owner Module supplier/manufacturer
	Input data for modelling/calculating plant performance	n/a	Use of optimal data sources Develop and derive critical data before modelling and undertake checking against laboratory and operating data	Independent energy yield assessor Independent technical advisor Project developer/owner
	Soiling	n/a	Undertake site visit to assess potential current and future sources of dust from nearby construction, industry, traffic (e.g. on gravel	Independent energy yield assessor Independent technical advisor

Due Diligence Item	Factors to consider/check	Benchmark	Risk Management/Mitigation Actions	Party Involvement
			roads), or agriculture (e.g. harvesting, crop burning) Include sufficient project budget for PV module cleaning if required Ensure performance warranties clearly define soiling risk ownership	Project developer/owner
	Grid availability	Availability 98.5-100%	Understand potential risks of grid outage and load shedding by the utility (reducing project power sales) in advance by undertaking a dispatch studies and load analysis	Independent energy yield assessor Independent technical advisor Off-taker Utility
Shading	Buildings, structures and trees with potential to cast shadows on modules during operation	1 – 5% shading losses	Undertake site visit to check the real condition Assess the possibility of buildings/structures/trees to be erected in vicinity of the PV plant Ensure that shading is considered in performance calculation (if applicable)	Independent energy yield assessor Independent technical advisor

4.5 Operation risks

Table 4.4: Key operation risks and risk management/mitigation actions

Due Diligence Item	Factors to consider/check	Benchmark	Risk Management/Mitigation Actions	Party Involvement
O&M contractor capability	O&M contractor and operations team track record and capability	n/a	Contracting an experienced O&M contractor with experienced O&M team	O&M Contractor Project developer/owner
Adequate plant performance monitoring	Existence and quality of performance monitoring system How the plant performance will be monitored, and by which party	n/a	Set up an intelligent system for plant monitoring of performance to monitor variables including accurate irradiance, DC and AC power output & voltage control Plant performance optimization with skilled O&M teams with the aim to maintain PR between 75 – 80%, before degradation Optimal cleaning regime	O&M Contractor Project developer Independent technical advisor
Adequate plant availability	Effective operational hours of the solar PV plant	Availability between 98.0% - 100.0%	Effective service availability (e.g. module, inverter) Proactive and responsive maintenance	O&M Contractor Project developer/owner
O&M cost control	Probability of O&M cost overrun	Common annual O&M costs: 20-30 USD/kWp	Effective O&M planning and cost control Budget for maintenance reserve accounts	O&M Contractor Project developer/owner
Robust O&M	Preventive and	n/a	Adequate preventive and	O&M Contractor

Due Diligence Item	Factors to consider/check	Benchmark	Risk Management/Mitigation Actions	Party Involvement
Scheme	corrective maintenance scheme		corrective maintenance scheme in place clearly illustrated in the O&M manual	Project developer/owner
Sufficient spare parts availability	Availability of the spare parts at the site, or at a depot in the region	PV module spares: 0.1%-0.2% of total installed Inverter spares per supplier standard	Maintain strategic spare parts on site, or at an in-region depot	O&M Contractor Project developer/owner

4.6 Contractual risks

Table 4.5: Key contractual risks and risk management/mitigation actions

Due Diligence Item	Factors to consider/check	Benchmark	Risk Management/Mitigation Actions	Party Involvement
PPA technical risks	Clauses in PPA for RE generators (esp. Solar PV): - Is there any compensation in the event of grid outage? : Force Majeure for “interruptions in the distribution system…” Any performance requirements (energy production, construction completion, commissioning requirements, etc)	n/a	Given standardised forms of PPA, no project level risk mitigation actions are usually possible At national level; improve strength of “priority dispatch” terms for renewable generators Improve information from off-taker regarding grid reinforcement and load flow scenarios	Government Industry associations Off taker Project developer/owner
Multi-contract versus EPC versus risk	Contract structure and risk allocation Uncovered risks	n/a	Ensure EPC wrap-up when possible, and if not, ensure well-structured multi-contract approach with experienced management of works interfaces Consider owner’s engineer	Construction contractor Project developer/owner Owner’s engineer
Contractor capability (EPC, O&M, others)	Contractor track record	n/a	Ensure contractor track record and team capability	EPC contractor Project Owner
Cost overrun	Cost overrun (EPC and Operations) by multiple factors	Contingencies : more than 3% of EPC cost depending on project factors	Allocate reasonable contingencies following robust project development, design , construction and procurement Follow EPC wrap contract approach when possible, with major risks including geotechnical risk allocated to the EPC contractor Establish maintenance reserve	EPC contractor O&M contractor Project developer/owner Lender

Due Diligence Item	Factors to consider/check	Benchmark	Risk Management/Mitigation Actions	Party Involvement
			accounts depending on inverter warranties Run financial model sensitivities	
Robust EPC contract terms	Scope of work is a lump sum turnkey scope	n/a	Identify EPC scope and ensure that it is inclusive and wrapped under lump sump	EPC contractor Project developer/owner Owner's engineer
	Owner's obligation to the Project	n/a	Clearly identify any responsibilities that might require consents or actions from the owner in order to allow the contractor to perform the work adequately	EPC contractor Project developer/owner Owner's engineer
	Key project milestones	n/a	Key project milestones, in particular for completion, shall clearly be implemented in the EPC contract	EPC contractor Project developer/owner Owner's engineer
	Defect warranty for material and workmanship	Minimum of 2 years	Warranty scope and terms clearly defined in the EPC contract Warranty obligations backed by financial security (e.g. performance bond) if appropriate	EPC contractor Project developer/owner Owner's engineer
	Performance Guarantee	PR guarantee prior to plant take over PR guarantee for the first 2-5 operation years	Guarantee terms clearly defined in the employer requirements and EPC contract PR test methodology to follow good industry practice	EPC contractor Project developer/owner Owner's engineer
	Liquidated Damages	n/a	Clearly defined rates and caps for liquidated damages for both delay and performance shortfalls stated within the EPC contract. In line with good industry practice	EPC contractor Project developer/owner Owner's engineer
	Testing and Commissioning	In accordance with IEC 62446	Clearly defined in the employer requirements and EPC contract In line with PPA and grid code requirements	EPC contractor Project developer/owner Owner's engineer
Robust O&M terms	Scope of work	n/a	Ensure inclusive O&M scope (e.g. site staff; preventative, routine, and reactive maintenance; spare parts supply/storage; site security etc)	O&M contractor Project developer/owner
	Contract Duration	5 years as a minimum	Clearly defined in the O&M contract	O&M contractor Project developer/owner
	Plant Availability Guarantee	A minimum of 98% plant availability guarantee	Compensation equivalent to foregone revenue for a shortfall in plant availability guarantee, capped at 100% of annual O&M fee	O&M contractor Project developer/owner

Appendices

Appendix A. Detailed Annual Energy Output Calculation Derivation

$$PR = \frac{\mathit{Estimated\ Annual\ Actual\ Energy\ Output}}{\mathit{Theoretical\ Energy\ Output\ (at\ STC\ Condition)}}$$

$$\mathit{Estimated\ Annual\ Actual\ Energy\ Output} = PR \times \mathit{Theoretical\ Annual\ Energy\ Output\ (at\ STC\ Condition)}$$

Whereas,

Theoretical Energy Output (at STC Condition) is calculated by ratio method below.

At STC Condition, the power output is Pnom W (the power output stated in the module specification multiplied by the total number of installed module in the plant). So in order to find the theoretical energy (at STC condition) given the irradiance condition at the site, the following ratio method is used:

1 kW/m^2 (STC Condition) $\longrightarrow$ Pnom kW

Annual Incident Irradiance kWh/m^2 $\longrightarrow$ $\frac{\text{Annual Incident Irradiance } (\text{kWh}/\text{m}^2)\times \text{Pnom}(\text{kW})}{1\ (kW/m^2)}$

(irradiance condition at the site)

Therefore,

$$\mathit{Theoretical\ Annual\ Energy\ Output\ (at\ STC\ Condition)} = \frac{\text{Annual Incident Irradiance } (\text{kWh}/\cancel{\text{m}^2}) \times \text{Pnom}(\cancel{\text{kW}})}{1\ (\cancel{kW/m^2})}$$

$$= \text{Annual Incident Irradiance } \times \text{Pnom } (\text{kWh})$$

Hence,

$$\mathit{Estimated\ Annual\ Actual\ Energy\ Output} = PR \times \text{Annual Incident Irradiance } \times \text{Pnom } (\text{kWh})$$

Please note that the linear degradation has not included in the PR (except for light-induced degradation), however it should be included in the estimated annual actual energy output calculation, therefore.

$$\mathit{Estimated\ Annual\ Actual\ Energy\ Output}$$
$$= PR \times \text{Annual Incident Irradiance } \times \text{Pnom } \times \text{Annual Linear Degradation } (\text{kWh})$$

Glossary

AC	Alternating Current
ACE	ASEAN Centre for Energy
AMS	ASEAN Member States
ASEAN	Association of Southeast Asian Nations
ASEAN-RESP	Renewable Energy Support Programme for ASEAN
a-Si	Amorphous Silicon
CAPEX	Capital Expenditure
CdTe	Cadmium Telluride
CIGS	Copper Indium Gallium Selenide
COD	Commercial Operation Date
DC	Direct Current
EPC	Engineering, Procurement and Construction
GIZ	Deutsche Gesellschaft für Internationale Zusammenarbeit
HV	High Voltage
Hz	Hertz
Km	Kilometre
kV	Kilovolt
kVA	Kilovolt-Ampere
kW	Kilowatt
kWh	Unit of electrical energy in kilowatt hour
LV	Low Voltage
LTA	Lender’s Technical Advisor
m MSL	Meters above mean sea level
MM	Mott MacDonald
MPPT	Maximum Power Point Tracking
MW	Megawatt
MWp	Megawatt Peak (Rated DC capacity at STC), see Wp below
MV	Medium Voltage
OEM	Original Equipment Manufacturer

O&M	Operation and Maintenance
OPEX	Operation Expenditure
P50	The expected net energy production at probability of 50%
P75	The expected net energy production at probability of 75%
P90	The expected net energy production at probability of 90%
PID	Potential Induced Degradation
PPA	Power Purchase Agreement
PR	Performance Ratio
PV	Photovoltaic
RE	Renewable Energy
SEA	Southeast Asia
STC	Standard Test Conditions, for testing Solar PV modules
W	Watts