11.7.10 RESPONSE TIME

The guaranteed response time of a maintenance contractor is an important component of the O&M contract. As soon as notification of a fault occurs, it is the responsibility of the contractor to go to the site within a set period of time. The faster the response time, the swifter the issues can be diagnosed and the system returned to full production. The distance between the PV plant and the contractor's premises has a direct correlation with the duration of the guaranteed response time.

The time of year coupled with the accessibility to the site can have a bearing on the actual response time for any unscheduled maintenance event. Restrictions to access roads at certain times of the year can delay response. Adverse conditions can also reduce the size of the payload that can be transported to the site, thus extending the duration of the maintenance work.

The presence of a strong PR guarantee also ensures that the contractor is motivated to undertake an efficient response and restore system performance when alerted to a fault. If such guarantees are sufficiently strong, the need for explicit response times within a contract may be reduced.

11.7.11 SELECTING A CONTRACTOR

When choosing an O&M contractor, the capability of the company should be thoroughly examined. In particular, the following aspects should be considered:

- Familiarity of the contractor with the site and technology.
- Location of the contractor's premises.
- Number and competency of staff.
- Experience and track record.
- Financial strength and ability to honour warranty obligations.

The intention should be to select a suitably experienced contractor able to meet the requirements of the contract for the duration of the project.

O&M Contracting Checklist

The checklist below sets out the basic requirements for the drafting of a strong solar PV power plant O&M contract.

- [ ] Legal and technical advisors engaged to advise on form of contract.
- [ ] The O&M contractor is suitably experienced on a similar scale plant and familiar with the technology.
- [ ] Performance guarantees included to allow owner to claim liquidated damages (LDs) in the event of low availability or PR.
- [ ] Payments are made to the contractor in arrears to allow for deduction of any LDs over the corresponding period.
- [ ] LDs sized to be a genuine pre-estimate of losses likely to be incurred.
- [ ] Rules for spare parts management are clearly defined. Contractor is responsible for replenishing stock and ensuring original level is maintained.
- [ ] Rules for subcontracting clearly defined to ensure principal contractor is fully responsible for all sub-contractor works.
- [ ] The O&M contract requires the contractor to maintain all equipment in line with manufacturer guidelines (to ensure that all equipment warranties remain valid).
- [ ] Preventative maintenance regime defined in contract is comprehensive, helping to minimize the need for corrective maintenance.

Policies and Support Mechanisms for Solar PV

12

Developers should consider how policy provisions are designed and what specific support mechanisms for solar PV projects are available to bridge the gap between the costs of conventional power sources and solar PV.

12.1 POLICIES AND SUPPORT MECHANISMS OVERVIEW

While the cost per kWh of solar PV power has come down dramatically and continues to fall, in most cases direct or indirect financial incentives are still required in order to increase the commercial attractiveness of solar PV projects so that there is sufficient investment in new projects to meet national goals for renewable energy production.

Price-based incentives such as FiTs remain among the most common instruments to boost the commercial case for solar. In place of price-based incentives, quantity-based mechanisms use binding policy provisions to establish quotas that require power utilities to purchase a specific percentage of their power from a renewable source. Quotas translate into investment opportunities for developers, who are able to supply utilities with the required electricity generated by renewable energy facilities. Complementing the arsenal of policy instruments available to governments are fiscal incentives—e.g., investment or production tax credits, and direct public support schemes, such as soft loans or an equity participation by a public entity. Policies that guarantee and facilitate connection and access of PV plants to the grid are also important for the viability of PV projects by removing common barriers.

Developers should consider how policy provisions are designed and what specific support mechanisms for solar PV projects are available to bridge the gap between the costs of conventional power sources and solar PV power.

It is important for developers to understand the conditions under which they may access support schemes and the requirements they must fulfil to do so within a given market. The process a developer must follow to meet the requirements for obtaining support differ from country to country, reflecting the priorities of the regulatory regime and the structure of the power market. Levels, types, and duration of support that developers can access will vary. Incentives are generally offered at the national level.

Sometimes state and provincial authorities offer additional incentives.

The critical mandate for any developer is to:

- Learn what support mechanisms are available.
- Determine whether the project will be able to meet the criteria for securing support and understand the historical reliability of the delivery of these supports.
- Factor all this information into the business plan and demonstrate to investors that the discounted cash flows are appealing.
- Follow through meeting the requirements to secure the support available.

Refer also to the checklist at the end of the chapter for key considerations in accessing support mechanisms in any market.

12.2 POLICIES AND SUPPORT MECHANISMS OVERVIEW

12.2.1 *TYPES OF SUPPORT MECHANISMS*

This sub-section provides an overview of the six common types of renewable energy support mechanisms used by governments, including both mechanisms that help developers to improve cash flow and those that offer opportunities to competitively enter the market:

- **Feed-in Tariffs (FiTs):** A FiT is a predetermined price for every unit of electricity generated by a solar PV power plant, paid through a long-term contract. Typically, projects must meet certain eligibility criteria and receive authorization from a government body to receive the FiT (and usually preferential grid access as well); smaller projects may automatically receive the FiT up to a certain maximum level of MWs (maximum capacity).
- **Reverse Auctions and Tenders:** Reverse auctions for independent power producers (IPPs) involve the competitive procurement of energy, whether at a specific site or without specifying where a new plant must be built. Renewable energy auctions can be technology-neutral where solar competes with other renewable energy sources, or technology-specific where different solar projects compete with each other. A tender of a specific site is a call for bids for the rights to develop a PV project on a site pre-selected by the government or utility.
- **Market-based Instruments:** These accompany quantity-based mechanisms, such as renewable portfolio standards or quota obligations. Certificates associated with renewable energy production are traded on a market and result in additional revenue for renewable energy producers. Examples include tradable renewable certificates or carbon certificates.
- **Tax Incentives:** Tax incentives can be used by a project owner to offset capital costs or profits, or to reduce specific taxes such as VAT or import duties. Accelerated depreciation is another option intended to attenuate the high capital costs of renewable energy projects.
- **Soft Loans:** Soft loans—i.e. those with a below-market interest rate or extended tenor—are sometimes made available, especially in the early stage of technology deployment by government-backed institutions.
- **Capital Grants:** Capital grants from public sources reduce the upfront financing burden and can stimulate interest in a new market. This option was used in the early stages of PV development. As the technology has matured, it is not necessary and now very rare.

The above provide direct and indirect financial supports designed to cover the incremental costs of solar PV power against conventional power supply options. The relative merits and conditions of different energy policy frameworks vary widely between countries and regions. Hence, it is crucial for developers to consider the effect on the commercial viability of their project, including the private investment risk of policies within a specific political and economic context.[53] The International

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53 For more on this topic, see IEA, IRENA, the US National Laboratories (including Lawrence Berkeley, Sandia, and the National Renewable Energy Laboratory) and the World Bank's Energy Management Assistance Program. See also, IRENA's "Evaluating Policies in Support of the Deployment of Renewable Power" (2012), and the World Bank's Renewable Energy Financial Instrument Tool (REFINe).

Renewable Energy Agency and the International Energy Agency host a joint database that provides relatively comprehensive and up-to-date information on the types of support mechanisms and corresponding incentives available for renewable energy projects in different countries.[54]

12.3 SOLAR PV SUPPORT MECHANISMS

This sub-section discusses in detail the six types of support mechanisms that may be available to solar PV power plant developers. It explains the nature of support provided by each mechanism, as well its advantages and disadvantages. Key concerns for the developer are also discussed for each mechanism.

12.3.1 FEED-IN TARIFFS (FiTs)

FiTs offer a fixed, typically long-term (10–25 years) electricity sales price, often combined with preferential grid access and other favourable off-take terms, such as priority dispatch. This fixed price, typically linked to inflation, is intended to cover the actual cost of renewable energy generation (typically higher than conventional power sources) and allow a sufficient margin to enable investors to make a return commensurate with the risk profile of the project. Box 8 provides an example of FiTs in Thailand for both rooftop and utility-scale solar PV projects.

FiTs played a critical role in stimulating the early growth of solar PV energy, especially in Europe and Japan, and remain a widespread tool to support PV projects in many markets. FiTs protect a PV project from competition with other sources of generation and from price fluctuations on the wholesale electricity market, stabilizing revenues.[55]

FiTs are generally attractive to lenders because they are secure and stable. The long-term revenues for a project with a FiT can be modelled with a high degree of certainty, making such projects easier to finance. However, in accepting a FiT, the developer takes on policy and credit risk, and must assess whether the off-taker is required, willing, and able to provide support at the contracted level over the project's life; this is especially critical if the FiT is substantially higher than prevailing power prices. The key issues and risks related to FiTs are summarized below.

12.3.1.1 The Level of FiT and Sustainability of Support

It is wise to assess the sustainability of the FiT—specifically, whether the mechanism is sustainable through which the incremental cost of a PV project is recovered. For example, if the regulatory framework specifies that the incremental costs will be covered through a specific component in the energy bill of the consumers, this may be viewed as sustainable and lower risk. However, if the incremental cost is covered by sources that are not certain, the sustainability of the FiT may be viewed with some caution. Countries that adopted FiTs early on, when the PV costs were still high, had to absorb substantial incremental costs, burdening either the end-user tariffs or the government's fiscal situation. As PV costs declined substantially (especially over the period 2010–2014), these countries were under pressure to revise the FiTs. Revision for future projects is rational, especially if PV costs decline, but retroactive revision (affecting PV plants already built) is not rational and has affected developers who have incurred high costs. For example, due to the fiscal strain under which governments found themselves after the financial crisis in 2008, Spain in 2010 retroactively altered their FiT, impacting contracted projects. Spain was followed by Bulgaria in 2012 and Greece in 2014.[56] In late 2013, several Australian state governments proposed retroactive cuts to FiT schemes, although these were withdrawn due to unpopular public reactions.

54 http://www.iea.org/policiesandmeasures/renewableenergy/

55 There are many publications analyzing feed-in tariffs. Among them, see "Feed-in Tariffs as a Policy Instrument for Promoting Renewable Energy and Green Economies in Developing Countries," United Nations Environment Programme (UNEP), 2012.

56 Legislation: Royal Decree 1565/2010 adopted on 19 November 2010 by the Council of Ministers. For more details, see the European Photovoltaic Industry Association's "Retrospective Measures at the National Level and their impact on the photovoltaic sector." 10 December 2013. Available at www.epia.org.

Even for technologies where costs haven't dropped as dramatically over the past decade, most governments will today put in place cost containment measures for FiT schemes to cap the overall fiscal costs. In particular, tariff levels may decrease on a sliding scale over years or the support for new sites will be capped in terms of the total fiscal cost they represent. Also, some FiTs are envisioned to be updated periodically (every 2–3 years); in this case, changes should affect future contracts and will not be retroactive. Retroactive changes to FiT schemes are rare, but they can be extremely detrimental to the projects affected. It is more common for policies to be abruptly

Box 8: Thailand's Feed-in Tariff (FiT) Policies

The solar market in Thailand is currently driven by two key Feed-in Tariff (FiT) policies designed to help the country meet its ambitious targets for solar development by 2021.[a]

1. Rooftop solar projects policy.[b]
2. Ground-mounted solar projects policy.

The rooftop FiT policy provides an incentive for developing rooftop and community ground-mounted solar systems, and is capped at an installed capacity of 200 MW. The FiT rate is scaled dependent on the project size. The FiT rates below are granted to projects that were fully commissioned before December 2013 and are valid for a 25-year operational period.

FiT Rates for Rooftop Solar Projects in Thailand

Project Size (kW)	FiT Rate (Baht/kWh)	FiT Rate (USD/kWh) (1 Thai Bhat = 0.0310 USD)
0–10	6.96	0.22
10–250	6.55	0.20
250–1000	6.16	0.19

The ground-mounted FiT policy provides an incentive for up to 800 MW of projects to be commissioned by the end of 2014. The FiT rate varies throughout the lifetime of a developed project and is presented below.

FiT Rates for Ground-mounted Solar Projects in Thailand

Year	FiT Rate (Baht/kWh)	FiT Rate (USD/kWh) (1 Thai Bhat = 0.0310 USD)
1–3	9.75	0.30
4–10	6.50	0.20
11–25	4.50	0.14

For both the rooftop and ground-mounted FiT policies, the FiT rate can be considered relatively generous and project IRRs should be attractive to investors. The Thai government has periodically revised the FiT rates and current information on incentives for projects developed beyond 2014 can be found online.[c]

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a http://thaisolarpvroadmap.org/wordpress/?p=940

b http://www.eppo.go.th/nepc/kpc/kpc-145.html

c http://www.iea.org/policiesandmeasures/renewableenergy/?country=Thailand cancelled or altered, impacting un-contracted projects under development more than those already in operation.

There are several types of existing insurances for project risks. The risk of retroactive changes in the regulatory support framework has surfaced in recent years and attempts have been made to provide insurance coevrage. For example, the World Bank Group may cover such risks through Partial Risk Guarantees. In many cases, a lender will require appointing an insurance advisor who can ensure the adequacy of insurance for a solar power project.

12.3.1.2 FiT Limitations

Commensurate with the determination of the tariff, the regulator or utility usually set a maximum level of capacity (MW) or energy (GWh) eligible for the FiT. For distributed generation, i.e., small-scale energy generated close to its point of use, the volume of power and number of projects eligible for the tariff may be open-ended (although, given the experience of several European countries overwhelmed by an unexpected response to such incentives, setting a cap in line with public budget priorities seems wise). For utility-scale projects (the focus of this guide), it is more common for the FiT to set limits, i.e., 200 MW of capacity in a given technology category, whereby the threshold is often a function of the national target a government intends to reach for its renewable energy production.

In addition to transparently-announced capacity limits, there may also be de-facto limits on securing the FiT. If particular permits are required prior to FiT application, bottlenecks may develop around key approval points, for example authorizations from local or national planning authorities, energy regulators or environmental authorities. Developers should also consider the available transmission capacity to carry power from their project site/the areas suited for solar PV project development to the areas that require power.[57] In Chile, for example, an extraordinarily rapid increase in solar development in the North may lead to strained grid capacity, while in Japan, utilities concerned about maintaining power reliability (and the price of solar PV power) have demonstrated reluctance to embrace high volumes of solar energy and have delayed grid connection.

12.3.1.3 Off-take Agreement

The tariff with its feed-in provisions is secured through a PPA between the solar producer and the off-taker, which can be the utility, the system operator, or the specially-created institution. As with any power sale agreement, the main risk factor to consider is the creditworthiness of the off-taker. For example, Kazakhstan has adopted relatively attractive FiTs for renewable technologies, but private projects cannot get commercial financing because the bankability of the PPA with the off-taker Cost Settlement Center (CSC) is a key concern. The CSC is a newly-created entity with no assets, credit history or established cash flows. More information on the PPA is provided in Section 13.

12.3.1.4 Currency Exchange Risk

Considering that in many countries a substantial percentage of the investment requirement is in hard currency while the revenue is in the local currency, there may be substantial risk associated with foreign exchange fluctuations. Some countries have recognized this and have indexed the FiT to a hard currency. This reduces the risk exposure of the developer. If such protection is not provided, the developer needs to assess the risk exposure and take appropriate precautions.

12.3.1.5 Sustainability of the Power Sector

It is always advisable for a developer to consider the financial sustainability of the tariff in the context of the local power market, including the forecasted demand for power, the current and projected levelized cost of energy from the existing power mix, the marginal cost of power supply (present and future), the ability of the utility to pass on the costs to consumers, and public willingness to pay for renewable energy. When the FiT is out of line with other trends in the market or significant price distortions

57 While solar is less site-specific than other renewables like hydro or wind, utility-scale ground-mounted projects require large plots of un-shaded land, ideally of relatively low value. These areas are more likely to be in remote areas than in large urban areas where demand for power is growing, particularly in rapidly urbanizing developing countries.

exist, extra caution is merited, and it is wise to consider the project economics in the event of policy changes.

12.3.2 REVERSE AUCTIONS AND TENDERS

The alternative to a policymaker or off-taker pre-determining the FiT to be offered for a solar PVproject is to conduct a reverse auction (or tender) for new capacity. Developers bidding for the opportunity to construct the project determine the level of the FiT. In this way, the price that the off-taker pays the developer that wins the bid is competitively determined. Sometimes reverse auctions allow for developers to propose project sites, while other times a tender will be announced with sites pre-selected by the off-taker. Conducting such a process requires specialized expertise and can incur higher transaction costs, but ultimately may be more cost-effective, as competition can drive the tariff to the lowest level necessary to support projects.

12.3.2.1 Procedure

A reverse auction starts with an announcement from a government or utility that has responsibility for this task. The government or utility then invites developers to bid the tariff they are willing to receive to provide solar energy. The tender will seek an announced number of MW and may be limited to (or sub-divided by) projects of a certain size (i.e., above or below 10MW), in certain regions (i.e., near an area with need for more capacity), and for certain technology (solar PV rather than CSP). In order to participate in a tender, a developer must qualify by fulfilling certain criteria to demonstrate the ability to finance and implement the project. As a rule, qualification requirements include providing financial information about the developer's business and relevant technical experience. Additional criteria aimed at maximizing the beneficial impact of the investment on the local economy can also play a role in the process, e.g., the nationality of key staff, employees, relationships with local suppliers/content providers, etc.[58]

58 For a good example of renewable energy tenders generally, and the inclusion of local content requirements more specifically, in the context of South Africa, see: Eberhard, A., 2013. *Feed-In Tariffs or Auctions, Procuring Renewable Energy Supply in South Africa*, Viewpoint, The World Bank, Washington, D.C.

Tender awards will be allocated to developers who have the lowest tariff bid, starting with the lowest electricity sales price bid. For example:

- Solar PV Project A: 25 MW @ $0.10/kWh
- Solar PV Project B: 15 MW @ $0.12/kWh
- Solar PV Project C: 10 MW @ $0.14/kWh

The developer with the lowest electricity production costs will be best positioned to bid the lowest tariff, and most likely to be awarded a contract. If the cap set in the tender was for 40 MWs, for example, only Projects A and B would be awarded a contract.

The details of tender award allocation will differ between countries and potentially even within rounds of the same country program. Awards may be made until the quota for that technology has been fully allocated, or sometimes only partially completed tenders take place.

When a tendered bid has been confirmed, the project developer and the off-taker will sign a PPA based on the proposed tariff over the predefined period of time.

12.3.2.2 Risks and Issues

The main risk for a developer under a tender scheme is that s/he will not win the bid. Preparing a bid for a large-scale PV installation can be costly. Developers must be willing to expend considerable time and resources in costing projects and potentially optioning land lease rights without any certainty that their bid will be successful. These costs are non-refundable if the project fails to win the tender. Developers must therefore balance their expenditure against the risk that their bid will be unsuccessful. Tender issuers can promote an efficient market by being transparent and sharing information on the number of qualified bidders, expectations of whether the tender will be oversubscribed, and information on future tenders. A second major risk is that competition becomes so great that margins are eroded to unsustainable levels, driving developers with lesser resources out of the market.

Box 9: South Africa'a REIPPP

South Africa has in place policies and initiatives that are aimed at accelerating growth in the solar PV power sector, including REIPPP and the Eskom Standard Offer.

REIPPP

South Africa's REIPPP is split into different bidding rounds. The allocated resources are shown below for Rounds 1 to 3. The decreasing trend in average PV bid price and the increase in local content is indicative of the policy's success in incentivizing solar development, although it remains to be seen whether developers can truly sustain operation at such low prices.[a]

Under Round 1 of the REIPPP, construction has commenced on 18 large-scale solar PV projects with a combined installed capacity of 630 MW. In Round 2, a total of nine projects with a combined capacity of 417 MW were awarded preferred bidder status and are currently under construction. An additional six projects with a capacity of 435 MW have achieved preferred bidder status in Round 3 and are approaching financial close. In 2013, nearly all of South Africa's solar PV power market consisted of large ground-mounted systems and it is expected that this market will remain strong.

However, historically there have been a number of delays with the bidding process. In September 2012, the Department of Energy announced delays to Round 3 of the REIPPP due mainly to difficulty in progressing the first round projects to financial close. The need to focus on financial closure for projects selected during the first two bidding rounds had a knock-on effect.[b]

In 2013, the government delayed an announcement on a final list of preferred bidders in the third round of its national renewable energy programme. This was finally completed in November 2013, more than 12 mosnths later than expected.

The Department of Energy is now in the process of finalising the financial close protocol for the Round 3 preferred bidders.

Allocated Resources for Rounds 1 to 3[c]			
Parameter	Bid Window 1	Bid Window 2	Bid Window 3[d]
Date	5 November 2012	9 May 2013	4 November 2013
MW allocated for Bid Window	632	417	435
Average Bid Price/kWh	$0.26	$0.15	$0.097
Local Content	28.5%	47.5%	53.8%

a http://www.esi-africa.com/sas-third-round-bidding-sees-prices-drop-dramatically/

b http://irp2.files.wordpress.com/2011/10/pvsouthafricamap-2013-04-17.pdf

c www.esi-africa.com/sas-third-round-bidding-sees-prices-drop-dramatically/

d www.ey.com/UK/en/Industries/Cleantech/Renewable-Energy-Country-Attractiveness-Index---country-focus---South-Africa

Competitive bidding processes have been successfully implemented recently in several emerging markets, including India and South Africa. In South Africa, the Renewable Energy Independent Power Producer Procurement (REIPPP) scheme (see Box 9) is a bidding process in which proponents bid to be awarded a power sale agreement until a certain MW quota (announced for each round) is reached. Similarly, India operated a reverse auction to award successful proponents a PPA as part of the Jawaharlal Nehru National Solar Mission (JNNSM).

While involving higher preparation costs for the entity running the tender, and higher risks for the parties bidding, the competitive bidding process does offer a greater level of assurance that projects are being incentivized at the minimum levels required ("revealed prices"). As such, it can be a good strategy for larger markets that have established interest and are looking to scale up installed capacity.

Box 10 summarises key elements of India's regulatory support framework, which has evolved over time and used multiple options, including FiTs, tenders and renewable

Box 10: India's Evolving Regulatory Support Mechanisms

India has implemented a number of different regulatory support schemes including FiTs, renewable obligations and reverse auctions.

The National Action Plan on Climate Change (NAPCC) of India sets Renewable Purchase Obligation (RPO) targets for each state in India. This provides a minimum level of the total power that electricity distribution companies need to purchase from renewable energy sources. Although this is not directly related to solar projects, it requires the states to incentivise the development of renewable energy projects. Among the states, Gujarat has offered the highest FiT, at 12 Rupees ($0.20), resulting in an installed capacity of 916.4 MW as of 31 March 2014. Below is a short summary of the FiT rates by state awarded by individual state-based solar energy policies.[a]

Feed-in Tariffs of Selected States

State	Feed-in Tariff (in Rupees)
Rajasthan	Flat rate of 6.45/kWh (USD 0.106) for 25 years.
Gujarat	Flat rate of 12/kWh (USD 0.198) for first 12years and 3/kWh (USD 0.049) from 13 to 25 years.[b]
Bihar	Flat rate of 9.85/kWh (USD 0.163) for 25 years.
Punjab	Minimum FiT awarded was 7.40/kWh (USD 0.122) and highest was 8.70/kWh (USD 0.144).
Karnataka	Minimum FiT awarded was 5.5/kWh (USD 0.091) and highest was 8.0/kWh (USD 0.132).
Tamil Nadu	6.48/kWh (USD 0.107) with an escalation of 5 percent every year.
Andhra Pradesh	Fixed 6.49/kWh (USD 0.107).
Madhya Pradesh	Minimum FiT awarded was 6.47/kWh (USD 0.107) and highest was 6.97/kWh (USD 0.115).

The national Jawaharlal Nehru National Solar Mission (JNNSM),[c] also referred to as the National Solar Mission, was launched in January 2010 to specifically incentivise the development of solar power as part of the broader national renewable energy targets. JNNSM set a target of 20GW of grid-connected solar power by 2022. It aims to reduce the cost of solar energy-to-grid parity by supporting large-scale deployment (through a reverse auction scheme in Phases 1 and 2), long-term policy, research and development and domestic production. The development road map of JNNSM is divided into three phases, presented below.

JNNSM Road Map and Solar PV Targets

Timeline	Grid connected, including Roof-Top Plan	Status as of March 2014
Phase 1 (2010–2013)	1,100MW	67% of the projects commissioned.
Phase 2 (2013–2017)	10,000MW	750 MW projects selected after bidding.
Phase 3 (2017–2022)	20,000MW	Details not yet announced.

In the first phase, selected developers were awarded a PPA with the Central Electricity Regulatory Commission (CERC) through a reverse auction scheme. The average tariff was approximately US$0.15/kWh, representing a 43 percent decrease on the benchmark tariff approved by the CERC. It is noted that only 67 percent of Phase 1 projects were commissioned as of March 2014. There are a variety of reasons for this, including delays to financial close, land acquisition and grid connection issues. Reverse auction was used in Phase 2[d] through which 10,000 MW are expected to be awarded.

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a http://mnre.gov.in/file-manager/UserFiles/guidelines_sbd_tariff_gridconnected_res/salient_features_for_State-wise_solar_policies.pdf

b http://geda.gujarat.gov.in/policy_files/Solar%20Power%20policy%202009.pdf

c Ministry of New and Renewable Energy, Towards Building SOLAR INDIA Available at: http://mnre.gov.in/pdf/mission-document-JNNSM.pdf

d http://seci.gov.in/content/innerpage/phase-ii--batch-i-log-of-documents-releasednotifications-issued.php purchase obligations. Also, it shows that in India (as in many other countries), the regulatory support framework of the federal/central government may be supplemented by initiatives of the state/local governments.

12.3.3 *MARKET BASED INSTRUMENTS*

Market-based instruments accompany quantity-based mechanisms such as renewable portfolio standards or **quota** obligations. They involve the creation of a credit/certificate, which can be traded in the open market. Renewable energy credits and carbon credits are the most common of such certificates.

Market-based mechanisms are appealing because they promise greater cost-efficiency in reaching a renewables target set by a government, by providing regulated entities with greater flexibility to achieve compliance with renewable energy obligations. However, as discussed in the two examples below of renewable energy credits and carbon credits, they can also be complex and demand a fairly high level of sophistication both from the regulator and covered entities. They are best suited for markets where the power sector is already highly competitive and there is sufficient capacity amongst market players to implement the system.

Quotas require electricity suppliers (typically utilities) to derive a specific percentage of the electricity they sell from renewable sources. Quotas are different from government targets/political goals because they have legal force and some form of penalty for non-compliance. For example, if an electricity supplier sells 100 GWh of electricity per year and 10 percent of that must be generated by renewable sources, the supplier would either need to generate or purchase 10 GWh from renewable facilities.

In some instances, a quota will require that the supplier purchase renewable power from within a certain jurisdiction, for example within regional or national borders. Other quotas require only that the supplier purchase a certain proportion of renewable electricity, which can be sourced from anywhere within reach of the transmission network. Yet another model for quotas is one that allows for the renewable energy to be “stripped” from the electricity itself and be traded in the form of renewable energy credits (RECs), also called green certificates. (More on RECs is provided in sub-section 12.3.3.1).

A quota system instructs electricity utility companies to comply with quota obligations, but may or may not specify how the quota is to be achieved. The utility may build renewable generation capacity itself or it may procure it through a tender process. The utility also may negotiate power prices with IPPs independent of government, or off-take renewable energy at a FiT determined by government.

By design, quotas only provide an incentive to produce renewable energy up to the level stipulated. For a developer, the major risk of operating in response to a renewable quota is that the project may not be approved before the quota cap is exceeded. This is especially an issue if there is limited transparency on future quotas or incentives. For this reason, markets with smaller quotas can struggle to attract interest from private sector developers and investors, as the business opportunity is not sufficiently large to justify the transaction costs of entering the market. In such instances, quotas may need to be combined with other incentive programs and reforms.

12.3.3.1 Renewable Energy Credits

Market-based instruments encourage investment in renewable energy by setting a specified quota of renewable energy to be developed by the market players, usually utilities or generators. These utilities or generators can meet their quota obligations either by developing renewable energy projects themselves or by purchasing from other market players the “proofs” for specific amounts of renewable energy electricity, which are commonly referred to as Renewable Energy Credits (RECs), Renewable Obligation Certificates (ROCs) and Tradable Green Certificates (TGCs). As with other mechanisms, the quota is typically split into technology types. If there is no technology type split, the market will seek the cheapest form of renewable energy first, which is the purpose of an efficient market, yet may not fulfil public policy goals to support a range of technologies.

Under a REC program, a government announces a quota, or series of quotas (annual or multi-annual), for renewable energy supply, which electricity suppliers are obligated to meet over a given time period. Unlike a traditional quota or renewable portfolio standard though, the renewable aspect of electricity can be "stripped" from the energy itself. In other words, a PV power plant will be awarded RECs based on its generated energy or installed capacity. These RECs can be traded in the market separately from the electricity that is generated by the same facility. Depending on the rules of each specific market, the covered entity does not necessarily have to deliver the energy generated by the renewable plant into the central market. Sometimes the electricity can be sold to a third-party (which may be physically closer or have better transmission networks) at prevailing power prices, while the renewable aspect embodied in the REC can be sold separately on a dedicated exchange. This allows for greater flexibility in developing solar PV power plants where the resource or transmission capacity may be best, rather than requiring them to be developed within the physical reach of the covered entities' transmission networks, which ultimately are expected to reduce overall compliance costs.

By setting a quota that increases over time, the demand for certificates should increase, stimulating the market to deliver more certificates through investment in renewable energy. If the market is "short" (i.e., demand is greater than supply), prices will go up, and if the market is "long" (i.e., there are more certificates than needed), prices will go down. In theory, the fluctuating price of RECs provides a "real-time" calibration of market needs and guides new investment prospects.

In order to enforce a REC scheme, penalties are required to ensure compliance by the off-taking utilities. Penalties need to be considerably higher than the expected value of certificates in order to motivate quota compliance. If penalties are set too low, they will become a price ceiling.

In practice, it has proven challenging in many situations to match a solar PV project developer's need for long-term revenue certainty with the short-term demand and price signal provided by RECs, which in many markets are only traded in significant volume a few years in advance. A developer seeking to hedge price risk by selling their RECs forward over the lifetime of the power project will often have to accept a price well below the current forward price, if they are able to find a buyer at all.

The REC model has been popular in the United States (with multiple state and voluntary schemes in existence) and the United Kingdom (with varying degrees of success). Several emerging markets, including India, Romania, and El Salvador have introduced REC trading schemes as well.

Market-based mechanisms represent significantly more risk for developers than other incentives. In small markets, if there is insufficient active trading (low liquidity), then REC markets are especially prone to experience boom and bust cycles. Banks are likely to highly (even entirely) discount the potential value of RECs unless they are sold forward to a highly credit-worthy off-taker, effectively making them pure "upside" for the developer, i.e. a potential benefit to a project that cannot be borrowed against in the same manner as power revenue. If REC markets evolve and deepen, they may become bankable, but it is wise for developers to approach RECs with some caution.

12.3.3.2 Carbon Credits

Unlike the other incentives described here, carbon credits are an indirect form of support for solar energy, primarily designed to reduce greenhouse gas (GHG) emissions. Electricity generated by renewable facilities replaces electricity generated by energy sources, which utilize fossil fuels and release CO_2 emissions. The renewable facility is awarded carbon credits for the avoided CO_2 emissions.

Carbon markets seek to price GHG emissions and incentivize their reduction. However, in the markets that have (or had) a robust carbon price, namely the EU-ETS and the state of California, that price has recently been insufficient to act as the main driver for solar energy projects because the price for carbon is driven by the lowest-cost technology (typically energy efficiency or fuel-switching).

The Kyoto Protocol's Clean Development Mechanism did briefly provide an incentive for renewable energy (although very little solar)[59] in developing countries, but for various reasons, this incentive effectively no longer exists, and it has not yet been replaced by national carbon markets. However, numerous countries, provinces, and cities are considering or beginning implementation of carbon pricing policies, including South Africa, Chile, and China (see the World Bank's Partnership for Market Readiness for examples).[60] In addition to carbon credit trading, carbon taxes or reductions in fossil fuel subsidies are also under consideration to incentivize energy efficiency and lower emissions.[61] Thus, while the price of carbon in most countries is absent or too low to be the main driver for solar energy at present, there is a possibility that carbon pricing will again become more relevant in the future.[62]

12.3.4 TAX INCENTIVES

Tax incentives are a common tool to promote solar and other renewable energy, including tax credits for capital expenditure, reduced Value-Added Tax (VAT), reduced corporate income tax, import/customs and excise tax holidays, accelerated depreciation, and (though not exactly a tax incentive) relaxed rules on foreign exchange borrowing and foreign investment.[63] Due to the differing tax bases and nature of taxes levied, the tax incentives, which have been successful in developed economies such as the United States, may or may not be relevant to emerging markets.

Developers should undertake a thorough review of the local tax laws with qualified professionals to ensure they take advantage of all potential tax efficiencies. Tax benefits are often difficult to find, and it can be challenging to determine the criteria for eligibility and to understand the related administrative procedures. Appropriate time to consider local tax issues should always be built into the project timeline.

The largest market with tax credit support for solar PV projects is the United States. The U.S. investment tax credit provides owners of a project with a 30 percent tax credit on the capital expenditure of a solar PV project to offset against their tax liabilities. The United States also offers wind developers a production tax credit based on the energy generated rather than the initial capital investment. In order to take advantage of either tax credit, the project owner must have a substantial or tradable tax burden. While this model has been quite successful at incentivizing solar power (both distributed and utility-scale) in the United States, it is generally recognized that the form of the incentive generates significant transaction costs and is attractive only to investors with a large tax burden. Further, it would be of limited relevance in economies where collection of corporate income tax remains low. A similar outcome could be achieved with a capital grant (see Section 12.3.5 below on soft loans).

Other tax policies that reduce the amount of tax paid on equipment or reduce the rate of tax on corporate profit have been utilized in emerging markets, including Thailand and India. An important consideration is import duties. Some countries have elected to eliminate them or reduce them to reduce the cost of renewables. Other countries may have very high import duties whereby the motivation for the latter can be the protection of local industries (or the promotion of their emergence).

As with all renewable energy policies, there is a risk of policy expiration, which can be mitigated by closely following policy discussions and considering project economics should the incentive be phased out.

59 As of February 2015, 369 out of 7,598 registered CDM projects were solar, less than 5%. See www.cdmpipeline.org.

60 The Partnership for Market Readiness (PMR), for which the World Banks acts as Secretariat, trustee and delivery partner "supports countries to prepare and implement climate change mitigation policies—including carbon pricing instruments— in order to scale up GHG mitigation. It also serves as a platform where countries share lessons learned and work together to shape the future of cost-effective GHG mitigation." See www.thepmr.org for more information.

61 For more analysis on this, see Moarif, S and Rastogi, N. "Market-Based Climate Mitigation Policies in Emerging Economies," Center for Climate and Energy Solutions (C2ES). December 2012.

62 See "2014 State and Trends of Carbon Pricing," The World Bank (Publication 88284). May 2014

63 For an overview of numerous countries tax incentives, see for example "Taxes and incentives for renewable energy," by KPMG (2014). Available at kpmg.com/energytax.

12.3.5 *SOFT LOANS*

Loans with low interest rates and other concessionary terms, such as extended tenors or risk sharing, have also been deployed by governments to support solar PV development. Such loans are typically available only to a small volume of projects and only through certain designated financial intermediaries, typically a national, regional or multilateral development bank. To obtain concessionary loans, certain criteria must be fulfilled, potentially constricting the type of technology employed, or the contractors to be employed in the development of a project. Soft loans are often part of a broader renewable energy policy platform that also includes other incentives, such as a guaranteed Feed-in Tariff (FiT).

National governments that play a strong role in the banking sector often take a more policy-driven perspective, seeing subsidized loans as a direct method of achieving renewable energy targets. For example, China has stimulated renewable energy development through state-mandated concessional loans.[64] Depending on how soft loans are implemented, they can be a relatively cost-efficient means of achieving a policy goal.[65]

Soft loans are generally offered only at early stages of a technology's introduction into a new market. Unlike a policy-based incentive, which is applied uniformly across all projects meeting certain criteria, soft loans require individual, project-specific due diligence to avoid financing projects that will not be well-implemented or operated as efficiently as possible. As such, soft loans have relatively high transaction costs. The use of soft loans to support broader market development is typically achieved through financial intermediaries at a large scale, as the use of a wide-reaching banking instrument is able to bring down transaction costs associated with individual loans. This approach becomes difficult in particular markets where loan provision is limited to a single or small set of financing entities and it is not possible to engage the broader commercial banking sector.[66] Soft loans can play a role in building interest in solar technology in new markets, and offer few risks to developers, other than constraints that are typically presented clearly in policy statements and loan documents.

12.3.6 *CAPITAL GRANT SCHEMES*

Capital grants awarded through a tender or application process have also helped support solar PV projects, especially in the early stages of PV power commercialization when its costs were very high, the awareness of its characteristics limited, and the perceived risks high. Grants can be awarded based on a fixed incentive amount per MW or as a percentage of capital cost. Capital grant schemes are often introduced by governments on a temporary basis or for limited capacity, with the intention of providing market traction for a specific technology that is unproven or considered high-risk.

Capital grants present few risks for developers or financers. However, as with other incentives offered on a short-term basis, grants can create a "boom and bust" cycle, with prices for services and equipment bid up in the period prior to the incentive expiration, only to crash when it is no longer available and the number of profitable project opportunities is reduced. To mitigate these business cycle risks, developers can consider longer-term contracts with equipment suppliers and service providers and seek out opportunities (perhaps in niche markets) where solar projects are viable with no support.

The "1603" federal cash grant program introduced in the United States in 2009 is one example of a large-scale capital grant program for solar PV projects, introduced in recognition that the tax-based incentives typically provided were ineffective during a recessionary period.[67]

64 For more, see B. Shen et al., "China's Approaches to Financing Sustainable Development: Policies, Practices, and Issues," Lawrence Berkeley National Lab paper LBNL-5579E. June 2012.

65 For one assessment of policies in India, see G. Shrimali, et al., "Solving India's Renewable Energy Financing Challenge: Which Federal Policies can be Most Effective?," *Climate Policy Initiative*. March 2014.

66 The Green Climate Fund's stated intention to work directly with the private sector raises the interesting possibility of combining multilateral donor funding with local implementation, but is still in early stages.

67 "1603 Treasury Program," section of the Solar Energy Industry Associations website, available online at http://www.seia.org/policy/finance-tax/1603-treasury-program

India has also provided capital grants at both the national and state level over many years.

12.4 FURTHER GUIDANCE TO DEVELOPERS ON REGULATORY SUPPORT FRAMEWORKS

Developers need to be aware of secondary regulations that may influence project transaction costs. For example, a lengthy waiting period for generation permits could significantly delay the start-up of the new plant, and thus create financial losses for the developer. Another example is power quality regulations, which may include frequency regulation (defined by a grid code) that applies to all electricity producers. While power quality requirements are not solar specific, they can make it more difficult for sources of intermittent power, such as solar, to meet criteria for grid integration.[68] Further examples of regulations that are secondary to solar, including important aspects of the grid connection process, are covered in Section 8 on Permits and Licenses.

Renewable energy policies need to be considered in the context of the broader power market in which the project is being developed. Is the market fully de-regulated with generation, transmission, and distribution each operated independently? Or is the project being developed for a vertically-integrated, state-owned utility through a Public Private Partnership?

In markets where a state-owned entity controls generation, the major opportunity for a developer is likely to be in response to a public tender or a Public Private Partnership, such as a Build-Operate-Transfer (BOT) or a Build-Own-Operate (BOO) with a PPA. The structure of the power market defines the types of project development opportunities available. However, while having this broader context on the structure of the relevant power market is critical, this topic will not be discussed further here, as the purpose of this guide is to focus on aspects of project development unique to solar PV power plants.[69]

Given how rapidly solar PV power costs have dropped in the last five years (2009–2014), it is especially important for solar energy developers to consider the possibility that solar energy incentives will evolve as well, either through anticipated policy expirations and adjustments or unexpected policy changes. By the end of 2014, most FiTs in Europe were reduced substantially from the peak levels observed in 2008, reflecting the reduction in capital cost of a solar PV power installation. Interestingly, thus far, it is governments in developed economies (such as Spain, Italy, and Greece) that have made retroactive changes to pre-existing support mechanisms in order to reduce levels of support provided to existing solar PV projects. While retroactive changes of this kind are not common (and, in the case of the countries cited above, were influenced by the strained financial situation of a number of European countries in the global recession after 2008), it is wise to consider the risk that policies may change.

If the share of renewable energy in a market coming from variable output power plants is high or expected to become high (over 5–10 percent), it is important to understand not only the support policies for solar power per se, but also the policies that have an impact on the overall power system, including the grid development, investment in storage and flexible power generation, and demand-side management. In other words, support mechanisms for solar PV power cannot be considered in isolation because integration of solar and other types of renewables into a given power system and electricity market creates additional challenges that may affect a developer, if the level of penetration of intermittent renewable power grows to high levels.

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68 In many emerging markets, where maintaining the power supply is the predominate concern and the penetration of intermittent renewables such as solar is low, power quality and variable energy integration may not be top concerns. However, as the share of renewables grows in global markets, power quality may become more of a priority.

69 While not the focus of this publication, electricity market structure and reform is a priority topic for the World Bank Group. World Bank's Energy Sector Management Assistance Program (ESMAP) and the World Bank Energy Practice Group have many publications and activities covering this important issue from the perspective of the government/regulator. Many have a specific country or regional focus.

Leveraging Financial Incentives Checklist

The checklist below identifies key considerations for developers seeking to access support mechanisms for solar PV projects in any market.

- [ ] Review structure of electricity market, dynamics of energy pricing, and potential for near-term changes in market prices.
- [ ] Review energy generation regulations, including specific policies for renewables and evidence of application in current market.
- [ ] Identify specific support mechanisms for utility-scale solar PV power projects, evidence of their utilization and government adherence to terms in the current market, as well as project qualification criteria, application cut-off dates, and other potential risks.
- [ ] Understand the grid regulatory regime, including integration of regulatory and approval processes for new generation projects using renewables, specifically solar PV power projects.
- [ ] Develop a PPA model based on best understanding of viable public incentives.
- [ ] Mitigate policy risks by considering project economics without incentives, which may include hedging on market-based instruments and/or political risk insurance.

Power Purchase Agreements 13

The PPA is the most important agreement for financing a solar PV project. All other related agreements—the loan agreement, grid connection agreement, and EPC contract—should be aligned with the PPA.

13.1 POWER PURCHASE AGREEMENT OVERVIEW

Solar PV power plant projects generate revenue by selling power. How power is sold to the end users or an intermediary depends mainly on the power sector structure (vertically integrated or deregulated) and the regulatory framework that governs PV projects. Power can be sold either through a long-term PPA or through participation in an open market ("merchant" plant).

At the writing of this guide (early 2015), there were only a few merchant solar projects in the world; the vast majority of PV power plants are developed using longer-term PPAs. Merchant PV power plants are rare because PV costs typically result in power that is more expensive than other energy sources and excessively risky to financiers. Also, regulations (support mechanisms) promoting PV technology and other renewables are usually based on some form of long-term PPA. However, as PV costs continue to decline, merchant PV plants may become more common. For example, in 2014, IFC and other partners financed the first merchant solar PV project in Chile, the La Huayca II project, with no subsidy and no PPA. Merchant plants, depending on how the power sector is structured, may be able to sell both energy and capacity (the latter in a day-ahead market). Including La Huayca, as of early 2015, IFC had financed four large-scale PV projects in Chile, of which three were merchant projects and only one had a PPA. These projects are described briefly in Table 19.

This section looks at the key elements of the typical PPA for large-scale PV projects, and describes how small solar power plants (distributed generation) can utilize similar contractual arrangements.

PPAs are legally binding agreements between a power seller and power purchaser (off-taker). The party that is selling the power is, in most cases, the owner of the solar PV plant. The purchaser of power could be a power company, power trading company, or individual consumer, depending on the structure

Table 19: IFC-financed, Utility-scale PV Plants in Chile	
Project Name	**Description**
Sun Edison Cap *PPA (2014)*	The Project consists of the construction and operation of an approximately 100 MW solar PV power plant in the municipality of Copiapo in Chile's Atacama Region. Energy produced from the project will be injected into the Chilean Central Interconnected System. The project has a 20-year Contract for Differences with Compania Minera Del Pacifico S.A., an iron ore mining company.
La Huayca II *Merchant (2014)*	The Project is to expand the existing 1.4 MW La Huayca I PV solar power plant, to a total capacity of 30.5 MW. The plant is being developed by Selray Energias Ltda. and would be the first large-scale merchant solar project in Chile's SING (Northern Interconnected Electricity) system.
Luz del Norte *Merchant (2014)*	The Project consists of the construction and operation of a 141 MW-ac solar photovoltaic power plant in the municipality of Copiapo in Chile's Atacama Region. Energy produced from the project will be injected into the Chilean Central Interconnected System at prevailing spot market prices.
Sun Edison MER *Merchant (2015)*	The Project consists of the construction and operation of an approximately 50 MW solar PV power plant in the municipality of Copiapo in Chile's Atacama Region. Energy produced from the project is to be injected into the Chilean Central Interconnected System at prevailing spot market prices.

of the power market. For renewables (including PV) that are supported by regulatory mechanisms (see Section 12), the most common option is to sell all electricity generated to a power company (vertically integrated, transmission or distribution), often wholly or partially government-owned. However, a solar PV plant may also sell electricity to a trading company or a consumer, provided that this is allowed by market rules. In the latter case, wheeling charges may have to be paid by one of the two parties of the PPA.

The PPA is the most important agreement for financing a solar PV project. All other related agreements—the loan agreement, grid connection agreement, and EPC contract—should be aligned with the PPA. The PPA should define all of the commercial terms affecting the sale of electricity between the two parties, including the date the project will begin commercial operation, the schedule for delivery of electricity, the tariff, the volume of energy expected to be delivered, payment terms, penalties for underperformance on either side, and provisions for termination.

As such, the PPA is the principal agreement that defines the revenue stream, and thus the credit quality of an electricity-generating project, and is therefore a key instrument of project financing. A robust PPA helps de-risk projects by clearly specifying rights and responsibilities, and creating greater certainty around the revenue stream. Off-taker credit-worthiness is a factor whose importance cannot be overemphasized. It is one of the most critical elements considered when developing a PPA and the focus of thorough due diligence.

PPAs may be standardized and non-negotiable (except possibly for the tariff); standardized to provide an initial framework for negotiations; or open to bilateral negotiations. PPAs for solar PV projects have historically been shaped by the supporting regulatory framework, as described in Section 12. For example, it has been common for the tariff, off-take terms (take or pay), and contract duration to be pre-defined by a national or regional policy (see sub-section 12.3).

While the classic PPA model of a utility off-taker paying a fixed price to the producer is likely to remain common in the coming years, developers and financers should stay abreast of market developments, and consider both the risks and opportunities introduced by changes in pricing and business models. Box 11, at the end of this section, considers the recent rise in opportunities for distributed generation projects, sometimes referred to as "Commercial PPAs."

Refer also to the checklist at the end of this section for basic requirements specific to PPAs for solar PV projects.

The remainder of this section describes the key elements of a typical PPA. There are numerous sources that readers can consult for more in-depth coverage,[70] as well as several brief overviews on the topic.[71]

13.2 MAIN POWER PURCHASE AGREEMENT TERMS

The PPA sets out the terms of the power purchase, including the tariff, the volume of power to be sold, and the duration of the agreement. Some of the key commercial, legal, and technical terms to be considered while reviewing a PPA are described below. Where appropriate, these descriptions include comments on the potential risks associated with the key terms.

13.2.1 TARIFF OF ENERGY SOLD

The methodology for calculating the electricity price will depend on the market within which the project is operating and the prevailing regulatory regime. Under a FiT regime, a flat-fixed rate price could be offered for the life of the project. Alternatively, the tariff may be set through a reverse auction, negotiated or based on power market parameters (e.g., marginal cost of power supply).

The tariff may be adjusted based on an index that reflects annual inflation and foreign exchange fluctuations. If indexation is not included, the developer should assess the risks associated with inflation and changes in foreign exchange rates. Long-term operating costs for solar projects are very low, making inflation less of a concern than for other technologies, but should still be considered. In markets where it is difficult to obtain long-term financing in local currency, foreign exchange rates reflect substantial risk exposure. Foreign exchange is also a substantial risk linked to repatriation of profits.

Tariffs for solar power projects may continue to be determined through regulations, but as the cost of electricity from PV power approaches that of conventional power tariffs (often referred to as "grid parity"), tariff setting may change. For example, in South Africa, the average solar PV tariff fell 68 percent, from over US$0.34/kWh to $0.10/kWh between Round I auctions conducted over 2011–2012 and Round 3 auctions in 2013.[72] Tariffs around $0.10/kWh were also reached in other locations around the world, such as India and Brazil, and fell still lower to $0.06/kWh in an auction in Dubai.[73]

Also, as the solar PV market evolves, PPAs are likely to introduce increasing levels of exposure to market risk. For example, in 2013, IFC financed the Aura Solar Project in Mexico, a 38.6 MWp greenfield PV project with a 20-year PPA in which the off-taker pays a tariff determined by marginal cost of power supply, with no subsidy. Aura is the largest PV solar power plant to be built to date in Mexico.

The PPA also specifies the expected installed capacity of the solar PV project (in MW) and the predicted annual electricity production in MWh. The installed capacity of a solar PV plant is simply the maximum power of the PV plant, as specified and warranted by the PV plant supplier.

The predicted annual energy production is estimated based on the project's installed capacity, solar irradiation, and the resulting capacity factor or performance ratio, as described in detail in Section 5 on Energy Yield. The predicted annual production should take into account seasonal variations in solar irradiation and system losses to the point of metering. Also, panel degradation loss should be taken into account reflecting how efficiency and annual energy production may be reduced year-on-year over the life of the plant.

An accurate annual production prediction gives the off-taker comfort in knowing how much energy it will receive and the seller comfort knowing how much it can sell. The

70 The World Bank Group has publicly available PPA resources at http://ppp.worldbank.org/public-private-partnership/solar-power-energy

71 For example, see "Understanding Power Purchase Agreements," funded by the U.S. government's Power Africa initiative, available at no cost online at http://go.usa.gov/FBzH

72 Ebehard, A., Kolker, J. and Leigland, J. "South Africa's Renewable Energy IPP Procurement Program: Success Factors and Lessons." Public-Private Infrastructure Advisory Facility (PPIAF) of the World Bank. May 2014.

73 Upadhyay, A. "Dubai Shatters Solar Price Records Worldwide — Lowest Ever!" Cleantechnica Website, November 29th, 2014.

level of accuracy required of this prediction is dependent on the market in which the project operates. For small distributed solar PV installations operating under a FiT regime, it may be acceptable to use software tools made available by the regulator. However, utility-scale projects should include a professional independent energy yield assessment, produced and/or verified by an experienced consultant with a track record of producing "bank grade" data, and a confidence interval of at least P75, if not P90.

The project's actual energy generated will be based on meter readings. However, the energy yield prediction gives both parties a reference against which any anomalies in production can be checked and is sometimes used as a back-up to meter readings in the event of meter failure or discrepancies. Thus, energy yield prediction is important both during project planning and during operation.

Most solar and other renewable energy, as non-dispatchable forms of power, are sold on an "obligation to take" or "take or pay" basis, whereby all power they generate must be accepted by the grid. If this is not the case, then the volume of power being transacted should also be specified, with clarity on any penalties due should that volume of power not be delivered.

13.2.2 PPA DURATION

The PPA specifies the expected start and termination dates of the agreement. The duration of the PPA should be equal to and ideally longer than the period of time required to repay the project's lenders and to meet expected equity returns. In some cases, the duration will be determined by the regulatory support mechanism under which the solar PV project is developed; in other cases, the PPA duration can be negotiated. PPAs covering a 15- to 25-year period are desirable for PV plants and are relatively common. The longer the term of the PPA, the less exposure the project has to future changes in power prices, and the more secure its revenue stream. A sufficiently long PPA duration is especially critical for solar PV plants because the vast majority of costs are incurred up front and must be repaid over the project's life. PV power plants are expected to operate with fairly predictable degradation rates for 20 years or more, which is also suited to PPAs with long duration.

13.2.3 RIGHTS TO ENVIRONMENTAL CREDITS

Some regulatory frameworks may offer environmental credits (i.e., RECs) as part of an incentives package for new solar PV projects. The developer should determine the eligibility of the PV project for receiving environmental credits and ensure the assignment of rights to any credits linked to the project is clearly specified in the PPA. This should include the term for which these rights will be assigned (usually the project lifetime or duration of project eligibility), as well as provisions for the assignment of environmental credits that may potentially become available in the future.

13.2.4 CONDITIONS TO COMMENCEMENT

"Conditions to commencement" or "conditions precedent" define conditions that must be satisfied by the developer prior to commencement of the PPA term.

These conditions generally include securing the required project permits/approvals, the execution of an O&M agreement (covering civil works for land maintenance, module and balance of system routine inspections), a secure grid connection, and issuance of a takeover certificate.

The conditions to commencement set out a common understanding of the requirements of the project before commissioning. If the project developer does not satisfy all conditions, the off-taker may have the right to terminate the PPA. However, conditions to commencement often define requirements for the developer that, if not met, might leave the project legally exposed. Therefore, it is in all parties' interest for the conditions to commencement to be met.

13.2.5 GRID CONNECTION AGREEMENT

The PPA will typically reference and summarise the terms of the Grid Connection Agreement, often in an annex. It is very common for grid connection to be delayed, and where the off-taker or grid company is responsible, the seller will want to clearly specify the method for calculating liquidated damages related to such delays.

13.2.6 GRID CODE COMPLIANCE

The grid code, controlled by the grid operator, specifies how a generating plant must connect to and interface with the electricity distribution network. The PPA should reference the grid code and clearly specify how compliance with that code is determined as a condition for commercial operation. There may be room to negotiate relaxation of grid code requirements for solar projects if specific code for renewables has not yet been adopted. If the grid code has not been updated to cover intermittent energy sources, such as solar, certain provisions may need to be included in the PPA.

13.2.7 USE OF NETWORK CHARGES

The owners of the electricity distribution and/or transmission networks normally charge a fee for facilitating the evacuation of electricity from the generating plant and delivering it to the consumer. Renewable facilities may be exempt by the regulatory support framework. In some cases, the owner of the local distribution network may be different than the owner of the transmission network and different fees may be payable to each owner. The size of the solar PV plant can dictate whether fees are payable to one or both owners. For example, a fee may be payable only to the distribution network owner if the installed capacity is below a specified level. If the rated capacity is above the specified level, then a fee will be payable to both the transmission and distribution owners, recognising that the electricity generated will not necessarily be consumed locally. The associated costs will be specified in the grid connection agreement and referenced in the PPA.

13.2.8 METERING ARRANGEMENTS IN COMPLIANCE WITH GRID OPERATOR

Metering arrangements are critical to ensure the project owner is fully compensated for electricity generated. However, metering arrangements are often poorly defined in PPAs, with weaknesses only brought to light when there is a dispute.

Metering arrangements are usually defined in the country's grid code or metering code and ownership of the meter will normally reside with the grid operator or the off-taker. The PPA should define how electricity generation will be measured or calculated in the event that the meter is damaged or found to be inaccurate or there is a dispute over the reading. Even if the PPA or grid code does not require a back-up meter, it is good practice to install one, in the event of failure of the main meter or inaccurate operation. Generally, in the event of a faulty or damaged meter, output will be based on historic data or on predicted energy yield values.

It is usually the project developer's responsibility to install meters, but it is not uncommon for the off-taker to be responsible for metering arrangements and for ownership of the meter to pass to the grid operator or off-taker.

13.2.9 PRODUCTION FORECASTING

The PPA may define additional responsibilities of the seller and the buyer beyond delivering and paying for power, such as production forecasting. Production forecasting is a future prediction of energy production from a generating plant. Forecasting time horizons can vary from hours to days depending on the requirements specified in the grid code. The grid operator uses regular updates of production forecasts from across its distribution and transmission network to balance the flow of electricity across the network, which will require other electricity generators (typically thermal plants) to reduce or increase production to accommodate the varying output from renewable sources, such as solar.

Production forecasting becomes more necessary as the size of the renewable energy generator increases and the proportion of intermittent generation on the distribution and transmission networks increases. Consequently, it may not be necessary for smaller solar PV plants to implement production forecasting for a solar PV facility, and this requirement may therefore be a negotiable part of the PPA.

13.2.10 SCHEDULED & UNSCHEDULED OUTAGES

Just as the PPA addresses periods when the off-taker may be unable to accept delivery (curtailment), it should also address periods when the project will be unable to deliver energy. A scheduled outage is one that is planned and is reasonably under the control of the solar PV facility's owner. An example is periodic inspection of electrical infrastructure. Unscheduled outages are unpredictable and random events, for example an electrical fault within the solar PV facility that forces it to shutdown suddenly.

As an outage will disconnect all or part of a solar PV facility, the grid operator will normally require advance notification so it can plan accordingly. The notification requirements should be specified in the PPA. In turn, these notification requirements should be reflected in the project's O&M contract, as the O&M contractor will likely be responsible for notifying the grid operator.

The PPA may also specify the number and timing of scheduled outages and this can often be negotiated. For example, it would best suit a solar PV facility to plan scheduled outages at night or in the least sunny season in order to minimise the impact on electricity production.

Depending on the size of a solar PV facility, repeated unscheduled outages could cause problems with regard to the stability of the electrical distribution and transmission network. Consequently, the PPA may detail punitive measures that will be enforced on the solar PV facility should its production be unstable, and it is recommended that the criteria that might trigger any punitive measures are negotiated with the off-taker.

Finally, the PPA should include a methodology to determine the amount of energy that could have been delivered by the generator and that could not be accepted by the off-taker, often referred to as deemed generation. The energy yield prediction, updated based on actual operational performance, may be used as the basis for determining deemed generation. This is discussed further in sub-section 13.2.11, Curtailment, Grid Downtime & Network Maintenance.

13.2.11 CURTAILMENT, GRID DOWNTIME & NETWORK MAINTENANCE

As discussed earlier in this section, power delivery can be reduced both by project outages (by the seller), as well as by the grid operator (who may or may not be the same party as the buyer). The grid operator provides access to the distribution and transmission network to allow for electricity export from the solar PV plant. This network requires maintenance (scheduled or unscheduled); also, unexpected operating conditions may happen requiring curtailment of power in-flows locally or to the grid in general. In such cases, the grid operator may require that the solar PV plant be disconnected from the grid temporarily.

The grid operator should be obligated in the PPA to advise the solar PV plant operator of scheduled grid downtime, with sufficient notice to allow the operator to plan accordingly. The duration and frequency of downtime events must be clearly specified in the PPA.

Unscheduled grid downtime, also referred to as curtailment, is even more critical to address. The PPA should specify the level of availability that the grid operator expects to provide. The PPA should either identify how to determine deemed generation or another form of compensation/penalty if the grid operator fails to maintain the agreed level of grid availability, with a clear methodology for calculating the compensation due to lost production caused by grid downtime.

The PPA should outline clearly how curtailment will be addressed. In markets with very high penetration rates of renewable energy (e.g., Germany and some remote regional or island grids), curtailment may be due specifically to the volume of intermittent energy. However, some amount of curtailment is to be expected as part of routine operations due to grid constraints and load balancing needs. The amount of curtailment can generally be expected to be higher in many emerging economies where transmission networks are more constrained. Also, in emerging markets, it is more common for the power off-taker to also be the grid system operator, making them the responsible party for grid availability. If the roles of power off-taker and grid operator are separate, then curtailment might instead be dealt with under the grid connection contract. It is common for PPAs to allow up to a certain level of curtailment for which the solar PV plant owner is not compensated; however, the PPA states the terms of payment above this level. In some cases, the solar PV plant owner is getting paid for all the curtailed generation.

13.2.12 CHANGE OF LAW AND QUALIFIED CHANGE IN LAW

The change in law clause protects the developer against changes to applicable laws and regulations or new laws introduced after the PPA is executed and that have a financial impact on the project. "Law" refers broadly to legislation—for example, commitments and incentives for renewable energy—as well as regulations and technical guidance, such as the grid code or interconnection procedure. The PPA should also address how any appropriate compensation should be determined in response to a change of law.

13.2.13 ASSIGNMENT AND STEP-IN RIGHTS

It is important for the PPA to contain assignment rights empowering the project owner to assign the present/future rights, bank receivables, and interest from the project to the financing institutions (both equity and debt) to serve as security. In the event the developer runs into serious problems, step-in rights facilitate a smoother transfer of control over a project to its creditors. The lenders will seek to resolve the issue and if possible, also "step-out" of the developer's role. Including assignment rights in the PPA improves bankability by improving the worst-case scenario, and can improve financial terms for the developer.

13.2.14 ARBITRATION

While a good PPA will help identify potential areas of disagreement and provide clarity on how defaults can be remedied, disputes are always possible. After informal steps like closed-door negotiation or the appointment of an independent engineer for technical disputes, arbitration is the next step towards dispute resolution. The venue and rules of arbitration should be specified in the PPA.

Arbitration is generally considered to be preferable to going to court as it is faster, offers privacy and is typically less expensive. Further, for projects in emerging markets, it can be the only realistic approach to dispute resolution in light of overly-burdened local courts. From a lender's perspective, it is preferable for arbitration to be conducted internationally for large projects to ensure that the arbitration panel is neutral. For small projects, international arbitration is unrealistic due to the potentially high costs of dispute resolution. Different arbitral rules may be selected, such as the World Banks' International Centre for Settlement of Investment Disputes (ICSID), the United Nations' Commission on International Trade Law (UNCITRAL) model provisions or International Chamber of Commerce (ICC) rules. National/state-owned off takers are often reluctant to accept foreign jurisdiction.

13.2.15 FORCE MAJEURE

Force majeure events are those events that are completely beyond the control of either party and have a material impact on a project, such as wars, natural disasters, and extreme weather events. Events of force majeure should be listed in all PPAs to exclude situations over which either party has reasonable control.

The duration for which a force majeure event can continue prior to a party seeking termination of the PPA should also be defined. This is termed *Prolonged Force Majeure,* which may have its own definition in a PPA. Termination due to force majeure can generally occur if the event continues for a continuous six- to 12-month period, or an aggregate period of 12 to 18 months.

It is important that neither party be defined in the PPA as being liable to the other party in the case of a force majeure event. At the same time, the recognition of force majeure does not mean that parties should not seek out appropriate insurance to cover such risks.

13.2.16 LIMIT OF LIABILITY

The overall limit of liability of either party to the other party will be defined in a PPA. There is no industry standard for limits of liability and these vary widely. Limits may be an aggregate value over the full PPA term, limited on an annual basis or limited per event. Although it is beneficial for liability not to be limited on an annual basis but instead as an aggregate limit, it is more common for an annual limit to be in place. The key risk associated with the limit of liability is that the limit is too low and does not cover potential lost revenue or costs incurred due to an act or omission of the other party. The suitability of a limit of liability can be determined by comparing the liability limit with the revenue assumptions in the financial model.

13.2.17 TERMINATION

The contract will specify an end date, which is its natural termination. In addition to this, the PPA should list early termination events, along with a clear methodology for determining termination payments. Termination events generally include:

- Insolvency events or similar.
- Default in performance of obligations under the PPA when not cured or remedied within the specified period including:
  - *Failure to meet conditions precedent.*
  - *Failure to meet licensing or permitting requirements.*
  - *Failure to make payments due.*
  - *Reaching the limit of liability.*

This section focused on aspects of a typical PPA for grid-connected utility-scale solar PV power projects. PPAs for distributed generation PV installations have many similarities with utility-scale PV plants, and some important differences too. Box 11 provides information on PPAs for distributed PV systems, even though this report does not cover such installations in a comprehensive manner.

Box 11: Distributed Generation and Commercial PPAs

As a modular technology, solar power can easily be scaled up to meet a range of power needs. While this publication focuses on financing and business models suited to utility-scale solar power projects, informally defined as 5 MW or larger, much of the technical guidance it contains also applies to smaller projects (see Annex 4 on Rooftop PV Systems). As the price of solar power has fallen, there are increasingly interesting opportunities for distributed generation of solar power in emerging economies. This is especially true in economies where the price of power is high and/or reliability of the grid is low, and solar power can effectively compete with diesel generators and other forms of back-up power generation.

Distributed generation refers to power generation that occurs close to the load or end user, and involves plants with typically small generating capacity located on the off-taker's land or nearby. In a traditional utility model, power generation takes place at a large central plant and is transmitted through the grid and sold by a distribution company to end-users. In contrast, distributed generation projects sell power directly to the end user and can exist independent of the grid, although sometimes power is delivered to the end user (e.g., off-taker) over the grid, in a process known as "wheeling." Depending on local regulations, wheeling may or may not require paying a fee to the grid company.

Distributed generation projects still require purchasing agreements, sometimes called "Commercial PPAs," which obligate the customer to purchase power for a period of time suitable to pay off project debt and earn a suitable return. There are a variety of business models, the potential of which depends on the particular power market and its regulations. Commercial PPAs may govern the sale of electricity to a range of customers, from individual residences[a] to large-scale industrial facilities. However, a very large project selling to a single buyer is more commonly referred to as "captive power".[b] In many emerging economies, the credit worthiness of individual commercial or industrial customers may be superior to that of the utility, and customers may be willing to pay a tariff higher than that offered by the utility to ensure they have an adequate and high-quality supply of power.

An opportunity sometimes exists to sell excess power from distributed generation to the grid. This model of distributed generation represents over half the recent growth of solar energy in Germany[c] and between a quarter and half of recent solar PV growth in the United States.[d] In Germany, this growth was driven by a national feed-in tariff (FiT) for distributed solar. In the U.S., distributed solar has been largely driven by regulations that allow net-metering.[e] Also referred to as "behind the meter" pricing, net metering allows the customer to sell electricity back to the grid, typically at the same rate as a utility tariff, and pay only for the net amount of grid power consumed.

Several distributed generation sites may collectively function similarly to a utility-scale project if they have significant exposure to the utility alongside private buyers as a key off-taker. The terms of sale to the grid from distributed PV projects are often standardized, with a predetermined price and a requirement for the utility to purchase all electricity from projects under a certain installed capacity.

The amount of distributed solar power in emerging markets at present is very small, but there is significant potential for growth. While the models that proved successful in the United States and Europe may be taken as starting points, new business models are likely to develop in response to unique local conditions. In many emerging markets, insulation levels for solar power are high (increasing capacity factors), and utility efficiency and reliability are low—factors that improve the competitive position for distributed solar power. Improvements in energy storage will drive further innovation. While still in its infancy, the potential for distributed solar power (and other distributed renewable energy) presents interesting opportunities. Thailand, the Philippines, and Pakistan have recently introduced legislation permitting distributed generation.

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a Although this publication does not address business models for off-grid or mini-grid solar PV, this topic is addressed in IFC's publication From Gap to Opportunity: Business Models for Scaling Up Energy Access.

b Whether an opportunity exists to serve different customer types in a specific market depends on many factors, including whether it is permitted under local regulation.

c Trabish, Herman K. "Why Germany's Solar is Distributed." Greentech Media, May 29, 2013.

d Solar Energy Industries Association (SEIA), "Solar Market Insight Report 2014 Q4."

e The Investment Tax Credit (ITC), representing a 30% tax credit on allowed capital investment, also plays a key role in promoting both utility-scale and distributed solar within the United States, but the focus here is on the specific incentive for distributed (as opposed to utility-scale) solar.

Solar-Specific Power Purchase Agreement (PPA) Checklist

The checklist below sets out some of the basic requirements that are specific to solar PV for drafting of a PPA.

- [ ] PPA terms specify the expected installed capacity of the solar PV project (in MW) and the predicted annual electricity production in MWh.
- [ ] PPA includes "take-or-pay" provision, or otherwise specifies volume of power to be transacted and penalties for failure to deliver.
- [ ] PPA term meets or exceeds the term of debt repayment.
- [ ] Conditions to commencement agreed with off-taker.
- [ ] Metering arrangements in place that align with national code, including for installation and ownership.
- [ ] Terms of loan agreement, grid connection agreement, EPC contract, and O&M contract are aligned with the terms of PPA.
- [ ] Obligations for grid code compliance included in PPA.
- [ ] PPA outlines clearly how curtailment will be addressed, including how liquidated damages will be calculated.
- [ ] Assignment and step-in rights established.
- [ ] PPA defines limits of liabilities, early termination events, and methods to calculate termination payments.

Financing Solar PV Power Projects

14

This section focuses on forms of financing, key considerations of project financing, and the due diligence process that are unique to solar PV power projects.

14.1 FINANCING SOLAR PV POWER PROJECTS OVERVIEW

In order to obtain financing, the developer must prepare comprehensive documentation of the project details so that potential financiers are able to assess the risk of the investment. This is particularly true of project financing, as the lender depends entirely on the cash flow of the project for repayment rather than on the balance sheet of the sponsor.

A range of financing structures can be used for solar PV development, however project finance is the most common. The appropriate structure will be influenced by the commercial and financial needs of investors, as well as the market and incentives available for solar PV power projects in a particular geography. At early stages, equity financing is used to explore and develop a project opportunity, and later, debt is typically brought in for project construction. In general, most financing structures will involve two key components:

- Equity from one or more investors, injected directly or via the project developer into a special purpose vehicle (SPV or "project company").
- Non- or limited-recourse debt from one or more lenders, secured against the assets owned by the SPV.

This section provides an overview of the financing process, focusing on aspects that are unique to solar PV projects.[74] This includes forms of financing (debt versus equity), key considerations of project finance (requirements, timing, and structure), and the due diligence process (risks and ways to mitigate them). Issues related to project costs and revenues, as well as solar PV-specific aspects of the project's financial model are discussed in Section 15.

74 Two well-known textbooks on this subject: E.R. Yescombe, *Principles of Project Finance,* 2nd Edition, 2002, Elsevier Academic Press; Scott Hoffman, *The Law and Business of International Project Finance*, 3rd Edition, 2008. Cambridge University Press.

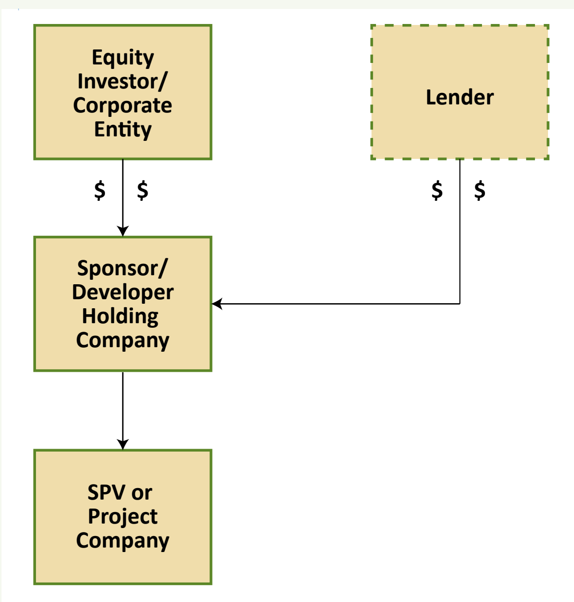
Refer to the checklist at the end of this section for the basic steps in seeking project financing for solar PV projects.

14.2 FORMS OF FINANCING

14.2.1 CORPORATE FINANCING

Large companies may fund solar plants "on balance sheet," providing equity themselves and obtaining debt as part of their broader operations and corporate financing. This model would be typical for self-generation (i.e., for a single user's own power needs), rather than the larger utility-scale projects that this guide focuses on. This type of financing can also be an appropriate model when the project developer is a large entity that has access to very low-cost financing, which might be the case for a highly-rated utility or conglomerate. It is also utilized, even for large projects, in economies that do not have a strong tradition of off-balance-sheet financing, such as Japan. Figure 27 illustrates corporate financing.

Figure 27: Corporate Financing



Corporate Financing

- Single ownership structure.
- May be suitable for developers that can finance an entire project to completion and then re-finance the development to free up equity.
- A project sponsor has full ownership of the project but is also exposed fully to the risks.
- May be applicable for companies with a large balance sheet or for smaller projects.

14.2.2 100 PERCENT EQUITY FINANCING

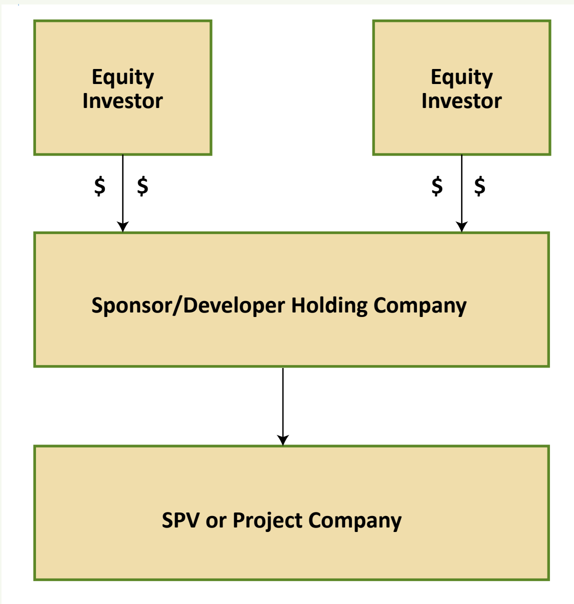
In general, debt is cheaper than equity, and thus it is more attractive to finance projects using debt financing. However, in certain circumstances, solar PV power projects may be financed entirely with equity. If debt is not available at attractive pricing or tenors, all-equity financing may be pursued, especially for smaller projects.

For example, in Europe following the global financial crisis, many banks previously active in the project financing space were no longer lending, or were only lending for shorter tenors than in earlier years. However, due to strong policy incentives, renewable energy projects still offered sufficiently high returns in comparison with other investment opportunities available at the time to make all-equity investment in solar projects attractive, and all-equity deals took place.

Today, in many developing countries, the local market for long-term financing is still not very deep, and developers may be obliged to finance a larger portion of the project with their own equity. Whether this is attractive ultimately comes down to a project's expected return and the developer's other options to deploy capital.

Equity financing may also be opportunistic; equity can often be deployed more rapidly than debt, so if there is a high-return opportunity and strict timelines to secure incentives such as feed-in tariffs (FiTs) by a certain date, a developer may be willing to finance the entire project out of pocket or in partnership with a co-sponsor such as an infrastructure fund. Once the project is built and operational and the risk profile is reduced, the equity holders can then seek to refinance it using cheaper debt financing. Figure 28 illustrates equity financing options.

Figure 28: Equity Financing



100% Equity Financing

- Development funds secured internally or from a third party equity partner.
- Often can be deployed rapidly.
- Independent developers can use their local or solar technology experience to attract equity from new equity providers who have the capital but not necessarily the solar experience.

14.3 PROJECT FINANCING

Project financing is the most common approach to long-term financing of utility-scale solar projects. The main distinguishing feature of project financing is that loans are made based on the strength of ring-fenced project revenue, with no or limited recourse to the project sponsor. This approach separates an individual project from other activities of the sponsor. Project financing is attractive for developers as it can allow for higher rates of leverage (thereby maximising return on equity) and move liabilities to a project company rather than keeping them with the developer. It also allows developers to free up equity in order to develop more projects. With a project financing structure, projects are normally held in a project company or a special purpose vehicle (SPV) that holds all project assets and liabilities.

Given the limited recourse to the parent company, lenders require that there is a secure revenue stream from the project, and will undertake in-depth due diligence of the project to gain confidence on the project's ability to service debt repayments. This will include a thorough technical and legal review of the project and all associated contracts, especially the PPA, so that confidence can be placed in project revenues. Due diligence is described in sub-section 14.4. PPAs are described in Section 13.

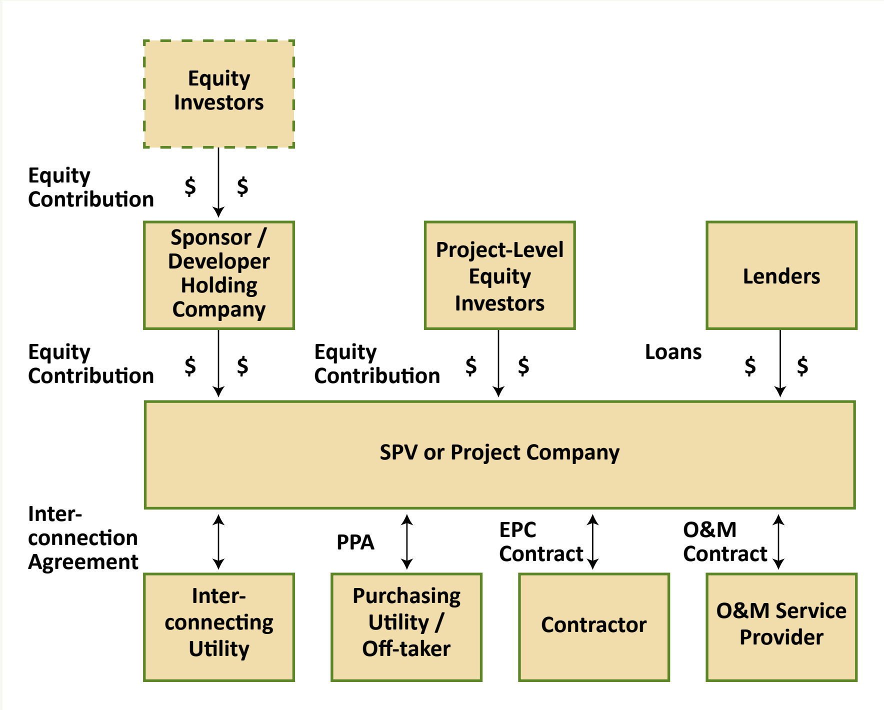
Project financing can be particularly useful in emerging markets where perceived and actual risks may be higher and guarantees from the host country government or another party may be required. Bilateral and multilateral lending agencies (such as the IFC) are also able to provide credit enhancement and other support, and in some instances (typically in less developed countries) may also be able to mobilize some concessional financing to mitigate certain risks.

Solar PV projects have historically been well suited to project financing because many sell power at a fixed tariff (as opposed to a fluctuating price on a merchant market) and often on a "take-or-pay" basis whereby the off-taker purchases whatever volume of power is produced, thus mitigating both price and volume risk. Further, as there is no fuel, there is no price uncertainty to be hedged on any feedstock. While project financing can be obtained even in the absence of these conditions with appropriate risk mitigation, these favourable off-take conditions have helped smooth the introduction of solar technology into new markets. If recent price declines of solar technology continue, it can be expected that solar will be increasingly competitive even with contractual conditions that today are typical for fossil-fuel power plants. Figure 29 illustrates project financing options.

14.3.1 THE ROLE OF THE SPV

Developers and equity partners typically begin the development process by forming a project company or SPV, which is assigned all the rights and obligations of the project. The SPV owns the project and plant when

Figure 29: Project Financing



Project Financing

- Lenders loan money for the development of the project based on projected cash flows of the project.
- Enables developers and equity partners to leverage their funds by securing debt against the revenues of a solar PV project.
- In the event of default, recourse is against the SPV.
- Pricing and structuring of the debt based on the forecasted cash flows.
- Lenders require extensive due diligence to gain confidence in the projected cash flows

constructed, signs the EPC contract, O&M contract, the PPA, and is paid project revenues.

Such project structures offer businesses the opportunity to isolate the solar PV project from the rest of the developer's business activities. The working capital requirements and debt servicing are taken from project cash flows as well (although the sponsor may be required to inject capital in the event that required debt coverage ratios are in danger of being breached). A debt service reserve account is typically required (usually six months of debt service), which functions as the support mechanism on the debt coverage. Covenants are also typically required by the lenders to prevent equity holders from receiving dividends when debt service ratios fall below a specified point. Only when other financial obligations have been met (typically laid out in a highly-specified cash "waterfall") will the equity partners realize their return, often in the form of dividends. SPVs can be governed by local law or may refer to appropriate international law, depending on the requirements of the country in which the project is being developed and the preferences of the shareholders.

14.3.2 EQUITY AND DEBT POINT OF ENTRY

The terms of financing for a solar power project will evolve over the course of its development. Initially, the project is not well defined: there are risks and uncertainties with regards to many aspects of the project, including solar resource, expected yield, grid connection, and land lease and development rights with the landowner. As a project progresses, it becomes better defined: the solar

Box 12: Equity Investment and Joint Development Support from IFC InfraVentures

IFC InfraVentures—the IFC Global Infrastructure Project Development Fund—helps develop public-private partnerships and private projects for infrastructure in developing countries. It provides early-stage risk capital and actively participates in the project development phase to create private infrastructure projects that are commercially viable and able to more rapidly achieve financial close.

Through IFC InfraVentures, the World Bank Group has set aside a $150 million fund, from which IFC can draw to initiate project development in the infrastructure sector. IFC serves as a co-developer and provides expertise in critical areas, while partially funding the project's development.

IFC InfraVentures is an additional resource for addressing the limited availability of funds and for providing experienced professionals dedicated to infrastructure project development, both of which are key constraints to private participation in infrastructure projects in frontier markets.

http://www.ifc.org/wps/wcm/connect/Industry_EXT_Content/IFC_External_Corporate_Site/Industries/Infrastructure/IFC_InfraVentures/

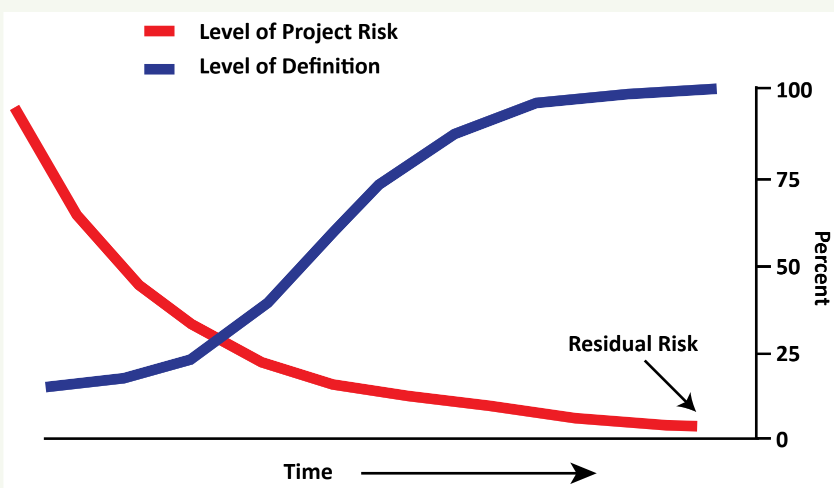
resource assessment is carried out and the outline design allows an energy yield prediction to be performed.

A solar PV project developer entering a new geography may assess the feasibility of numerous potential solar PV project sites, but many will not be selected. As the project progresses and is defined in more detail, the risks are reduced and the project becomes more valuable and attractive to potential investors.

The balance of risk and definition as the development progresses is illustrated in Figure 30. At the start, there is little project definition and high associated risk. As time progresses and development activities are performed, the project becomes better defined, and the associated risk falls.

If an early-stage developer does not have sufficient capital to bring a project to completion, the developer must consider when in the project cycle to seek additional financing from other equity investors. The earlier equity investors are involved in the project, the higher the risk they take, and the higher the return they will demand, commensurate with that risk. A debt provider will not loan to a project until there is a high degree of certainty that the project can proceed and it has been sufficiently de-risked.

Figure 30: Project Risk versus Project Definition



Source: Holland and Holland Enterprise Ltd, "Project Risk versus Project Definition," 2011, http://www.successful-project-management.com/images/risk-vs-definition.jpg (accessed June 2014).

14.3.3 THE PROJECT DEVELOPMENT CYCLE & PROJECT VALUATION

Different developers play different roles in the project development cycle. Some developers focus solely on the early stages of project development and the local knowledge required to secure land, permits, and a grid connection. Especially if they do not have access to their own capital, their business model may be selling their project for a success fee to another (typically larger) developer, who then takes on construction of the "shovel-ready" project.

In another example, smaller developers might initiate project development and desire to carry the project through to commercial operation, but lack sufficient financing of their own prior to the stage where it would be possible to seek project debt. The developer might then seek additional equity from a second project sponsor, either from a "passive" financial investor looking for a return, or a specialized fund providing both financing and implementation expertise. As a condition of external equity investment, the first developer is often expected to remain partially invested so that all parties have an incentive to ensure that the project reaches completion.

When a project or equity stake in a project is sold, the two parties must agree on a project valuation. The earlier a project is in its development, the less certain it is to be successfully realized, the less certain its revenue stream, and the more discussion there is likely to be between the buyer and seller on the value of the project. The challenge of agreeing on a project price is certainly not unique to solar PV power projects, but it can be more difficult in new markets, where "industry standards" have not yet developed and there is a lack of clear information on different steps in the development process and the value each step adds. Solar PV is also unique in that the technology has experienced dramatic drops in cost, leaving developers who purchased panels only 18 months earlier than other developers with a comparatively expensive and un-competitive project.

14.3.4 PROJECT FINANCING STRUCTURE

As shown in Figure 32, in a typical project financing structure, there will be one or more equity investors injecting funds directly or via the project developer into the project company (SPV). Lenders, typically a consortium of banks, provide debt, which is secured against the assets contained within the SPV.

When considering project financing, developers should consider the following:

- The usual term of a project financing loan ranges from 10 to 15 years or longer. For solar PV projects, the term may be limited to the period of the PPA or FiT,

Box 13: IFC Financing of Solar Energy

IFC is the largest global development institution focused on the private sector, bringing its AAA credit rating to 108 offices around the globe. As of May 2015 IFC has made over 350 investments in power in more than 65 countries, and is often at the forefront of markets opening to private participation.

The majority of IFC's current portfolio in power generation is in renewable energy (76 percent in fiscal year 2014, and renewable energy consistently makes up two-thirds of IFCs portfolio), including more than $500 million in solar power projects. IFC has invested in more than 55 solar projects that generate more than 1,397 MW, with key transactions in Thailand, the Philippines, India, China, Jordan, Mexico, South Africa, Honduras, and Chile.

IFC provides a range of financing solutions, including debt and equity at the project or corporate level. IFC can offer long maturities tailored to meet project needs, flexible amortization schedules, fixed or floating interest rates, and lending in many local currencies. IFC also helps to mobilize additional sources of financing through syndications as well as third-party capital managed by the IFC Asset Management Corporation (AMC).

IFC works with experienced and best-in-class new developers who demonstrate commitment to project success through their equity contribution to the project.

potentially introducing re-financing risks should the project require debt financing beyond that period.

- Lenders may have requirements or conditions related to the term (duration) and form of the PPA structure, making it ideal to finalize contracts after discussions of key terms with the lender have taken place. However, the PPA is essential to bankability and some lenders may not sign mandates or proceed with appraisal without a PPA in place, in which case it is necessary to sign a direct agreement that will allow the PPA to later be amended with lender requirements.
- Long-term financing for solar PV projects is increasingly available for projects meeting certain criteria, but in many emerging markets, may take longer to obtain.
- Individual projects from smaller developers may receive financing with a loan-to-value ratio of 75 percent (e.g., leverage ratio of 75 percent), whereas portfolios of solar PV projects from experienced developers may be financed with leverage up to 80 percent.
- Depending on the sponsor, the market, and the project financing fees, project financing may not be attractive for projects less than approximately 10 MW. Developers can consider consolidating several solar PV plants in a portfolio to obtain financing on a larger portfolio. For example, a developer may aggregate ten 5 MWp solar PV projects and seek financing on a 50 MWp portfolio.
- Lenders will conduct due diligence on the project prior to achieving financial close, and will include particular covenants that mitigate debt service risk throughout the life of the loan. Lenders will also include conditions precedent (requirements to be achieved prior to the disbursement of funds), such as a permit being obtained or a PPA being executed.
- Equity investors may rely on the lender's due diligence or conduct their own.

Developers should be aware that due to the global financial crisis and introduction of Basel III reforms[75] there are tighter restrictions on bank reserve requirements. Banks may have a reduced risk appetite and may be less willing to provide loans of long duration.

In new solar PV markets, local banks may not be familiar with solar PV projects and may be less willing to lend. Global development finance institutions (such as IFC) and regional development finance institutions (such as the Asian Development Bank and African Development Bank) can play a role in helping to build a local bank's confidence in new technologies and business models by investing in projects themselves, by offering risk-sharing products, and, under certain circumstances, by offering concessional financing.

14.4 DUE DILIGENCE

As with all investments, investors and lenders in a solar PV project need to understand the risks. This is especially important for lenders providing project financing, as loan repayments depend upon the cash flow of the project, with no or limited recourse to the balance sheet of the sponsor. Lenders require that due diligence is carried out on projects before they are willing to close the financing and fund the loan.

The process of due diligence can require considerable effort from the developer to satisfy the requirements of commercial lenders. Developers should plan to commence the financing process several months prior to the expected date that financing is required (frequently six months, in the case of IFC).

The due diligence process will identify risks and help develop solutions to mitigate the risks identified, typically including the following disciplines:

75 Bank for International Settlements, "International Regulatory Framework for Banks (Basel III)," 2011 & 2013, http://www.bis.org/bcbs/basel3.htm (accessed June 2014).

- **Legal due diligence** to assess the permits and project contracts (EPC and O&M), including assignability and step-in rights.
- **Environmental and social due diligence** to assess environmental and social impacts and risk mitigation, including relevant stakeholder consultations. This is discussed briefly in Box 10, and in greater detail in Section 8.
- **Technical due diligence** to assess the technology, energy production profile, design, construction risks, integration, and technical aspects of the permits and contracts (EPC and O&M). Technical due diligence will cover technical concepts discussed throughout this guidebook and summarised in sub-section 14.4.1. The technical due diligence process may identify risks that are unacceptable to the lender, in which case changes in the design, components or contracts may be required in order to make the project "bankable" for the lenders.
- **Financial/commercial due diligence** to assess the financial health of the project company. This will include an assessment of the quality and commercial viability of the PPA. Section 14 discusses the financial analysis process and analysis required to secure external financing. It is important that the developers have realistic financial models with contingencies clearly shown.

The due diligence conducted at the equity stage may be based on preliminary technical information that is provided by the developer. As the due diligence for lenders of project financing is conducted at a later stage in the development process, it will often be supported with more detailed technical information and designs, and a higher level of certainty.

As banks in new markets may not be familiar with solar PV technology, developers should be prepared for a rigorous due diligence process and incorporate sufficient time to discuss and address the lender's requirements. While risk is inherent in every project, the developer should reduce and mitigate these risks where possible. Those projects deemed to be low risk are capable of attracting debt at a lower cost.

Lenders and equity partners may often want to influence the choice of the equipment technology, design, and terms of contracts based on what they perceive to be "bankable." They may require consent on key decisions, such as the panel manufacturer or selection of inverter. It is therefore advisable to have discussions with the potential project financing partners early in the design phase to help satisfy the requirements of all partners and to avoid revisions. However, engaging fully with the due diligence process too early can result in excessive and unnecessary expenditure if changes in project technology, design, or even choice of lender is required. This cost will ultimately be borne by the developer.

Box 14: Environmental, Social, and Governance Issues in Financing

While solar PV projects are often considered to be inherently socially beneficial based on their potential to reduce greenhouse gas (GHG) emissions and local pollution, it is still important to consider the full scope of environmental, social, and governance impacts of any project. In addition, lenders often require compliance with social and environmental standards, such as the Equator Principles (EPs)[a] before agreeing to finance a project (see Section 8 for further details on EP requirements).

International development finance institutions, such as the IFC, have their own social and environmental standards (IFC Performance Standards directly inform the Equator Principles). Government bodies may aim to mitigate the adverse impact of developments through permitting requirements. Developers should strive to follow best practices to mitigate environmental and social risks even when this is not required or enforced by national law.

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a The Equator Principles (EPs) are a set of 10 environmental and social principles adopted by the Equator Principle Financing Institutions (EPFIs). These principles are criteria that must be met by projects seeking financing from these institutions. EPs ensure that the projects that receive finance are developed in a manner that is socially responsible and reflect sound environmental management practices. The full set of principles can be accessed through the following link: http://www.equator-principles.com

Dedicating sufficient time at the negotiation stage of PPA and EPC agreements to achieve favourable terms will save time and money at the financing stage by avoiding extensive re-negotiation.

14.4.1 TECHNICAL DUE DILIGENCE

Investors and project financing lenders, in particular, will require technical due diligence to be carried out on the solar PV project in order to understand the risk to investment. The technical due diligence process can take several weeks and as a minimum will involve technical experts carrying out the following tasks:

- Site visit to assess the suitability of the site for the installation of a solar PV power plant.
- Solar resource assessment and energy yield prediction with uncertainty analysis.
- Review of system design to confirm viability.
- Technology review of modules, inverters, transformers, and mounting or trackers, including warranties and design life.
- Contracts review (EPC, O&M and PPA), including acceptance testing procedures and liabilities within the EPC contract.
- Assessing the warranty and guarantee positions within the contracts.
- Review of grid connection agreement and timelines.
- Review of permitting status to confirm compliance with all necessary permits and approvals, and absence of serious environmental issues.
- Review of financial model inputs to help ensure financial projections are realistic.
- Review of acceptance testing procedures.

The process of technical due diligence typically requires the sponsor to place project documentation in an online "data room" and culminates in the delivery of a technical due diligence report.

14.4.2 RISK MITIGATION STRATEGIES

Developers and investors should make every effort to understand, and where possible, mitigate the project risks. Advice from independent experts will in some instances be required. Table 20 summarises the key risks and corresponding strategies for risk mitigation that a developer should consider when seeking financing for a solar PV project.

14.4.3 RISK MITIGATION PRODUCTS

Demand for solar PV project insurance is increasing. However, in most countries, the insurance industry has not standardised insurance products for PV projects or components. A number of insurers provide solar PV project insurance policies, but underwriters' risk models have not yet been standardised. The data required for the development of fair and comprehensive insurance policies are lacking as insurance companies often have little or no experience with solar PV projects. As a consequence, developers should seek insurance offers from a number of parties in order to drive competitive terms and expose potentially punitive conditions.

In general, large solar PV systems require liability and property insurance, and many developers may also opt to have coverage for environmental risks too. Various types of insurance available to developers are:

- **General Liability Insurance** covers policyholders for death or injury to persons or damage to property owned by third parties. General liability coverage is especially important for solar system installers, as the risk to personnel or property is at its greatest during installation.
- **Property Risk Insurance** protects against risks not covered by the warranty or to extend the coverage period. The property risk insurance often includes theft and catastrophic risks, and typically covers PV system components beyond the terms of the manufacturer's warranty. For example, if a PV module fails due to factors covered by the warranty, the manufacturer is responsible for replacing it, not the insurer. However, if the module fails for a reason not accounted for in the warranty, or if the failure occurs after the

Table 20: Solar PV Project Risk Matrix		
Risk	**Description**	**Mitigation**
Interest rate risk	If debt is provided on a variable rather than a fixed rate, the interest payable may increase if rates rise.	• Finance projects on long-term fixed interest rate loans, as opposed to variable rate loans. • Obtain an interest rate swap; development finance institutions, such as the IFC, provide swaps even in markets where a strong commercial swap market does not yet exist.
Foreign exchange risk	Debt may be denominated in a different currency from the cash flows generated by the solar PV project. This can create gains or losses for the developer and project owners.	• Use hedging to reduce exposure (however, this does entail a cost). • Transfer the risk through bonds, contracts, and insurance. • Obtain local currency financing when possible if the PPA or project revenues will be in local currency. • See Box 15.
Debt structure	Should the project not proceed as expected, the project may be unable to repay debt.	• Structure debt payment to maintain adequate liquidity. • Create a contingency account in case of short-term cash flow issues. • Limit leverage (ratio of debt to equity). • Seek financing of the appropriate tenor to avoid re-financing risks.
Quality of off-take agreement	The reliability of revenue payment is dependent on the terms of the power off-take agreement.	• Use PPA with a term in excess of the debt term. • Reduce exposure to power market risk. • For cross-border transactions, ensure both local and international counsel have reviewed the contract for enforceability.
Counterparty Credit Risk	In many emerging markets, there is only one or a small number of power off-takers, and this entity may not have a strong balance sheet or credit history.	• Carry out thorough evaluation of the off-taker creditworthiness. • Consider options to sell power to alternative off-takers in the event of default. • Seek a guarantee from the government or a multilateral institution; see Box 15 "World Bank Group Risk Mitigation Products." • Reserve account may need to be set up.
Technology	Risk that the system (especially modules, inverters, and transformers) do not function as expected, or performance degrades more rapidly than projected.	• Carefully select technology and pursue technical due diligence (see Box 7 on "Construction Lessons Learned"). • Ensure proper contracting, maintenance, warranties, and third party insurance, as described in Box 1, "Module Risk".
Solar resource	Variation of the solar resource from that predicted in the pre-construction financial models.	• Use services of a technical consultant to ensure high quality resource data is used and covers a sufficient time period. • Carry out an uncertainty analysis (P90 resource estimate) as discussed in Section 5.
Reduced energy yield	Failure to deliver the projected energy yield (and therefore cash flow) to service the debt requirements.	• Ensure pre-construction technical due diligence, including analysis of confidence in the energy yield. • Choose technology with reliable and known performance. • Include maintenance, performance penalties, and warranties within O&M contracts. • Reduce exposure to revenue losses due to grid curtailment by addressing this issue pro-actively in the PPA.
Cost escalation	Exposure to changes in the prices of components.	• Use fixed-price EPC contracts. • Include a contingency fund for construction and operation.
Delay	Contractors or third-party suppliers delay commercial operation, including delays with the grid connection. Delay will impact project cash flows and could impact project eligibility for tariff incentives.	• Use a "fully wrapped" EPC contract. • Contractually define liquidated damages. • Reduced price paid to the contractor if delays miss subsidy support cut-off dates. • Use experienced contractors. • Schedule allowance for delays. • Thoroughly research grid connection procedures, import/duty procedures for equipment and other local regulations in each market to ensure appropriate timelines are built into the EPC's schedule.

Continued

Table 20: Solar PV Project Risk Matrix *(Continued)*		
Risk	**Description**	**Mitigation**
Construction Permitting	Risk that construction has not been carried out in compliance with permits.	• Engage early with the relevant agency responsible for granting permits. • Thoroughly complete the technical due diligence.
Grid connection	Risk that the connection to the distribution or transmission network has not been completed or is not approved by the relevant authority before the expected date of commercial operation.	• Become familiar and follow required design specifications and procedures. • Submit grid connection applications early in development phase. • Define grid connection deadlines in contracts. • Thoroughly research grid connection procedures to ensure appropriate timelines are built into the EPC's schedule.
Incentive eligibility	Special tariffs, tax credits/holidays, and other incentives for renewable energy development may have strict cut-off dates and eligibility criteria.	• Ensure familiarity with the regulatory environment. • Insert clauses in EPC contracts to ensure eligibility based on timeline.
Policy change	Change in government policy towards solar energy, including retroactive subsidy cuts or new taxes that have a material impact upon project revenues.	• Choose politically stable countries with strong regulatory frameworks and evidence of long-standing support to solar PV projects. • Be wary of excessive dependence on the incentive system.
Operation and Maintenance	Poor operation and maintenance (O&M) can give rise to poorly performing plants with a material impact on project revenues.	• Include performance tests within the O&M contract, with associated liquidated damages. This is described further in Section 11 and Annex 3. • Use experienced contractors. • Seek advice from technical advisors when negotiating contract scope. • Consider performance incentives within the O&M contract. • Ensure plant performance is monitored. • Ensure spare parts are readily available. • Include maintenance reserve accounts and/or extended component warranties.

warranty period has expired, the insurer must provide compensation for the replacement of the PV module.

- **Environmental Risk Insurance** provides environmental damage coverage, and indemnifies solar PV system owners against the risk of either environmental damage inflicted by their development or pre-existing damage on the development site.
- **Business Interruption Insurance** provides coverage for the risk of business interruption, and is often required to protect the cash flow of the solar PV project. This insurance policy can often be a requirement of the financing process.

Though solar PV project insurance costs can be quite high, it is likely that rates will drop as insurers become familiar with solar PV projects and as installed capacity increases. A 2010 study by the United States National Renewable Energy Laboratory (NREL), referring to solar PV systems installed in the USA, stated:

> *"Insurance premiums make up approximately 25% of a PV system's annual operating expense. Annual insurance premiums typically range from 0.25% to 0.5% of the total installed cost of a project, depending on the geographic location of the installation. PV developers report that insurance costs comprise 5% to 10% of the total cost of energy from their installations, a significant sum for a capital-intensive technology with no moving parts."*

The benefits of insurance need to be weighed against the price; for small projects, some developers may feel

Box 15: World Bank Group Risk Mitigation Products

IFC Risk Management Tools

The International Finance Corporation (IFC) provides **financing in nearly 60 local currencies**, at both fixed and variable rates, which allows a company with local currency revenues (such as tariff payments under a PPA) to obtain long-term financing denominated in that currency, reducing foreign exchange risks. IFC also provides **interest rate and currency swaps** and **credit enhancement structures** that enable clients to borrow in local currency from other sources. IFC is one of the few multilateral development banks prepared to extend long-maturity risk management products to clients in emerging markets. More information can be found at http://www.ifc.org/wps/wcm/connect/Topics_Ext_Content/IFC_External_Corporate_Site/Structured+Finance.

World Bank Guarantees

World Bank Guarantees are risk mitigation instruments intended to diversify the financing options of the governments and government-owned entities through credit enhancement. They protect the beneficiaries against the risk of default by sovereign or sub-sovereign governments with respect to their obligations arising from contracts, law, or regulations. There is a wide range of risks that could be covered by World Bank Guarantees, such as off-take/payment risk, regulatory risk, change in law, political force majeure (including war, revolution, and expropriation), transferability & convertibility of foreign exchange, etc. The World Bank Guarantee can be issued in foreign or local currency.

World Bank Guarantees are only given for projects that are strongly supported by the government, which is embodied in a counter-guarantee from the government to the World Bank. They are anchored on the strong day-to-day relationship of the World Bank with the government, through policy dialogue, loans, grants, technical assistance, etc., which enables the World Bank to pre-empt an event that could result in the materialization of a risk. In the event that a claim is made under a guarantee, the World Bank does not require an arbitral award or any other formal decision from a court of law as a condition to pay. Guarantees are paid promptly upon recognition by the parties that amounts are owed and are undisputed. More information on the World Bank's Private Risk Guarantee group can be found at http://web.worldbank.org/external/default/main?menuPK=64143540&pagePK=64143532&piPK=64143559&theSitePK=3985219.

Political Risk Insurance with MIGA

The Multilateral Investment Guarantee Agency (MIGA) provides political risk insurance to private sector investors on a commercial basis through insurance products, with the exception of the Non Honoring of Sovereign Financial Obligations (NHSFO), which operates as a guarantee. These risks include **currency inconvertibility and transfer restriction, expropriation, war, terrorism, civil disturbance, breach of contract, and non-honoring of financial obligations**. MIGA's objective is to compensate investors in the event of a loss. The baseline relationship is between MIGA and the private investor, with no government involvement. The government is required to provide a no-objection clause for MIGA participation but does not provide specific support to MIGA or the project. Claims under MIGA insurance, including NHSFO, are paid once the claimant has obtained the respective award from a judicial court or an arbitration tribunal, which usually takes several months or years depending on the jurisdiction. More information on MIGA can be found at http://www.miga.org/investmentguarantees/index.cfm.

comfortable bearing certain risks. For larger projects, lenders may require insurance as a means of reducing the risk they bear by transferring it to the insurance provider. Some types of insurance may also be required as part of the national permitting process. However, insurance is never a substitute for quality design, equipment or contracts. Risk mitigation products may be needed to increase lender confidence, however the appropriate product or mix of products will depend entirely on details of the specific project and context. Box 15 describes risk mitigation products offered by three institutions of the World Bank Group.

14.5 RE-FINANCING

Once a project is operational, particularly after one or two years, the project risks, including construction, technology, energy yield, and performance risk are significantly reduced and there is an opportunity to refinance a project by seeking debt at a lower interest rate.

Less risk means that banks will often accept less return from their loan, so it may be possible to negotiate better debt terms, either from the original lender or another lender. A rather new development in the area of solar PV projects is the use of securitization, a process that enables a developer to exit the investment, which is described in Box 16.

Box 16: Refinancing, Solar Securitization and the Rise of the Yieldco

Since 2013 there has been rapid development in securitisation of solar and other power generation assets. Securitisation is the process of pooling multiple projects and packaging the portfolio as a tradable asset (a security). This can either be in the form of a project-backed bond or a "yieldco." A yieldco is an exchange-listed entity designed to hold cash-generating assets, generally with stable expected dividends. While securitisation is common for other assets, such as mortgages and automobile financing, and for infrastructure in countries like Australia and Canada, it is a relatively new tool for solar energy projects.

Solar projects are well suited for securitisation because they typically have predictable long-term revenues secured through a PPA and have mitigated many project uncertainties and risks through their project finance structure. These stable, low-risk cash flows are desirable for institutional investors, such as pension fund managers.

Once a project is operational, developers often want to exit the project so that they can focus on deploying their capital and creating value with new projects. Securitization allows developers to create their own vehicle to hold projects so that they can sell the project to the securitized vehicle and exit their investment. While this can also be achieved through sale to another buyer, by creating their own securitized pool of assets, developers are able to retain more value. Securitisation is also attractive for large pools of smaller projects, as it can reduce the transaction costs of selling these projects individually.

While these relatively sophisticated vehicles are still in nascent stages in developed markets, they may also become relevant in emerging markets. For example, SunEdison's Terraform announced they will launch a second emerging markets-focused yieldco in mid-2015.

Steps to Securing Project Finance Checklist

The checklist below sets out basic steps that developers and owners must complete if they are seeking project finance for solar PV projects.

- [ ] Seek equity funding (if required).
- [ ] Develop project to the point where it is ready for debt finance.
- [ ] Prepare due diligence documentation.
- [ ] Mitigate risks to reduce debt interest rates.
- [ ] Work with investors and lenders to achieve financial close.

Financial Analysis – Project Costs and Revenue

15

The commercial viability of a solar PV project is determined through a financial analysis that takes into account the expected costs, including investment requirements and O&M costs, as well as revenues.

15.1 PROJECT COSTS AND REVENUES OVERVIEW

Project financing is only possible when a solar PV plant is capable of generating enough revenue to pay for debt obligations and the overall costs of O&M, and to yield a reasonable return for the equity invested. The decision to proceed with the development of a solar PV project rests upon the commercial viability of the project, as determined through a financial analysis. This analysis takes into account the expected costs, including investment requirements and O&M costs, as well as revenues. The key inputs are investment requirements and assumptions about the future performance of the solar PV power plant. As such, they should be based upon verifiable and objectively collected data, and backed up by real-world experience and local knowledge.

The checklist at the end of this section sets out the basic financial modelling requirements for developers of solar PV projects.

The following sub-sections provide information on the key inputs to and outputs from the financial analysis that are specific to solar PV, including a breakdown of typical project costs and revenues.

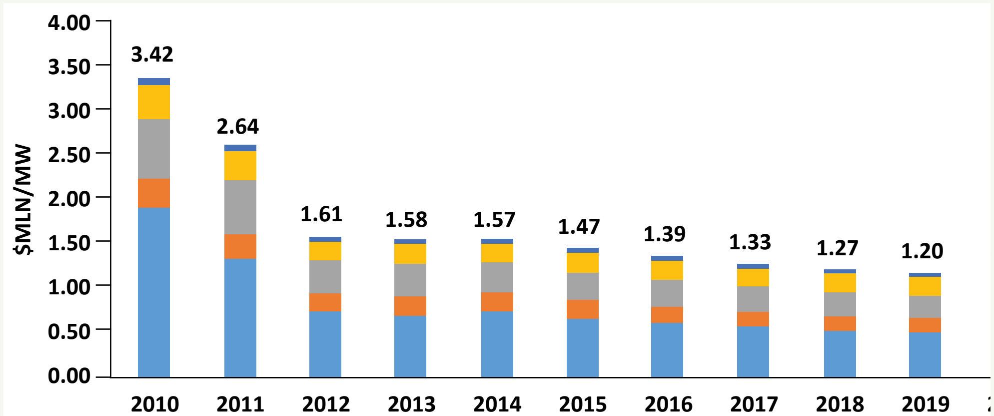
15.2 SOLAR PV PROJECT CAPITAL AND OPERATIONAL COSTS

Capital expenditure (capex) and O&M costs are site-specific and should be assessed as part of the prefeasibility and feasibility studies. Initially, these costs are established as evidence-based assumptions, and they will only be finalized with the signing of the EPC contract. Nevertheless, they are essential inputs for the financial model. For illustrative purposes, some indicative estimates for solar PV project costs (both capex and operating expenditures, or opex) are provided in this section.

15.2.1 CAPITAL EXPENDITURE (CAPEX)

Figure 34 shows the historical and forecasted values for solar PV project capital costs (excluding fees and taxes) for a ten-year

Figure 31: Forecasted average Capex Costs for Multi-MW Solar PV Park, 2010–2020 (based on data from 2014)



Source: BNEF, SgurrEnergy, collected from project developer and installers. Not including developer fees, taxes, legal costs, corporate finance fees.

period starting in 2010. Note that significant module price declines were achieved from 2010 to 2012. As Figure 31 illustrates, further price reductions can be expected going forward. However, the developer should equally consider that the rate of cost decline is impossible to predict with complete accuracy.

The historical data referenced in Figure 31 comes from larger, more developed solar PV power markets (principally Europe, North America, and Asia). Hence, the forecasts for capex pricing are useful in other markets primarily for benchmarking purposes.

Table 21 illustrates the variability of capex and opex based on actual project costs observed during 2013 and 2014. The spread in capex costs is explained on the low end by the inclusion of data from projects using low-cost, domestically-installed, Chinese solar PV installations. Values on the high end reflect the highest installed costs in the U.S. solar PV market. Variations in capex costs are also a result of differences in labour costs, local taxes, local content rules, and the level of subsidy or other pre-operating incentives provided to project developers within a specific policy/regulatory context.

In countries where solar PV technology has been only recently introduced, prices may vary widely as a result of the early process of supply chain development in a given market. However, greater pricing transparency and competition across the global supply chain, from raw materials like polysilicon to inverters and balance of systems, has allowed developers to make more informed assumptions about capital costs before hiring an EPC contractor. This is advantageous to the developer, as more accurate cost-input assumptions will be reflected in the perceived accuracy of the financial model outputs from an investor's viewpoint.

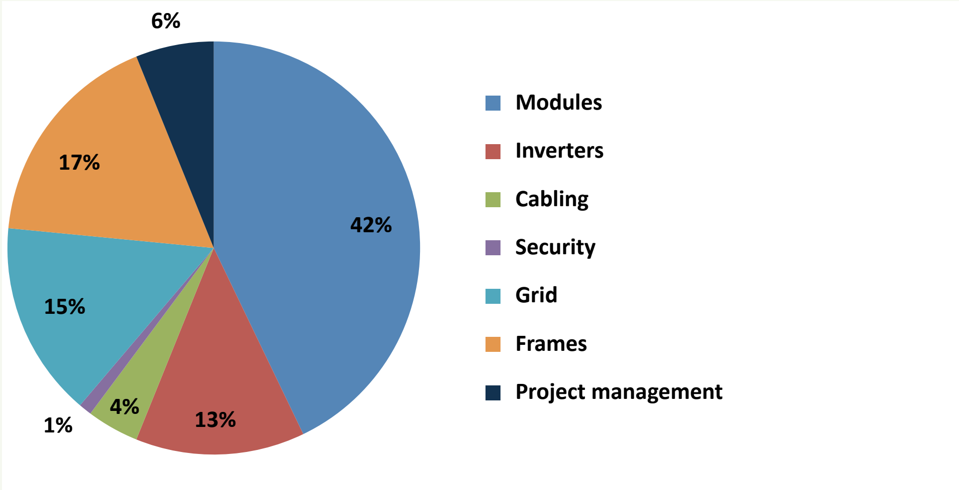
A breakdown of costs for a typical solar PV project is presented in Figure 32, which is based on a standard

Table 21: 2013/14 Solar PV Capex and Opex Cost Variations

Value $/MW	Min	Average	Max	Percent Variation
Capex	$1.5 million	$1.6 million:	$2.2 million	47 percent
Opex	$2,200	$4,200	$7,500	241 percent

Source: SgurrEnergy 2014

Figure 32: Average Breakdown Costs for a Ground-Mounted Solar PV Project



Source: The dataset is extracted mainly from the mature markets of Europe and North America, 2014.

multi-megawatt, ground-mounted installation (excluding trackers). Average installed costs in emerging markets are broadly similar, particularly the costs of PV modules, inverters, and cables. Deviations from the average may occur due to local taxes, local content rules, and variable labour rates for construction and project management.

In the example above, 55 percent of solar PV project capital costs arise from modules and inverters, and excluding local tax and content rules, these capex costs appear the most consistent over time for the majority of projects.

It is widely recognized that economies of scale are delivering lower pricing for modules, inverters, and balance of systems such as framing and support structures. There has also been a less dramatic, but still significant reduction in "soft costs," such as construction and financing costs for new project development, as more local service providers have developed their offerings. These cost reductions were first seen in more developed markets, but it is possible that they are representative of near-term trends in emerging markets.

As opportunities for solar PV project development have increased, the number of qualified installers has commensurately expanded. Compared to the EPC process used for other forms of power generation, solar is relatively straightforward and local construction companies have been able to build capacity quickly. This has resulted in competitive pricing for EPC activities and shorter construction and commissioning periods. As solar PV project developers grow in size and number, their processes are also becoming more efficient and they are able to reduce transaction costs, including costs related to business development.

The cost of financing has also fallen in more established solar PV markets as they have grown and proven to be reliable sources of cash flow. A developer's cost of financing has become a critical distinguishing factor for success as the solar PV market becomes increasingly competitive.

Total capital costs also include the cost of land and support infrastructure, such as roads and drainage, as well as the project company's start-up costs. The extent of cost variation largely depends on the project location (reflecting host country costs), the project design (such as the type of power cables), and the technology utilised (i.e., use of a tracking system, or selection of monoverses multi-crystalline modules). Solar PV technology in particular is a source of significant variation in system component costs. A project with crystalline solar PV technology requires less surface area per kWp installed capacity compared to thin-film modules. As a result, the mounting structure and DC cabling costs are lower (other cost components should not change significantly). Grid connection costs are another element of capex and can be highly variable; these costs should be investigated early during the feasibility stage.

Table 22 shows a typical breakdown of costs for a multi-mega-watt (MW) European ground-mounted solar PV power plant at the time of writing in late 2014. Total costs for a European solar PV plant average around US $1.7 million per MW. However, European costs are only a partial proxy for costs in other markets, and project costs must be adjusted for local duties and taxes and logistics/transport costs.[76]

It is advisable for developers to seek pricing for modules and inverters from multiple vendors and to balance the security of fixed prices and delivery dates against the opportunity for future price reductions and technology improvements. Also, during the past few years, module oversupply and industry reorganization led to some inconsistency in module quality and concerns about the value of manufacturer warranties. While the industry has now stabilized, seeking modules from a reputable manufacturer with a proven track record is still critical.

Further price reductions in solar PV technology are expected in the future, yet project developers are advised to be cautious about making predictions. These price

76 Bloomberg New Energy Finance is a source of data on costs in emerging markets: http://www.newenergyfinance.com.

Table 22: Average Benchmark Costs for Ground-mounted Solar PV Development

Cost Item	Cost ($/MWp)	Details
Land	8,300	It is assumed that 2 acres/MWp is required. This estimate will vary according to the technology chosen and land costs.
PV Modules	720,000	Crystalline-based solar PV modules have an average global factory gate price of $550-930k/MW[a] and this can vary depending upon the perceived quality of the supplier. An average module price of $720k/MWp has been assumed based upon collected third-party data. Thin-film modules such as Cadmium Telluride are available at an 8 percent to 10 percent discount to this price. However, this economic benefit is often lost due to increased land and balance of system cost requirements.
Mounting structure	306,000	This is the cost assumed for the mounting structure irrespective of the type of technology.
Power conditioning unit/ inverters	220,000	This is for the power conditioning unit/inverters, including the required controls and instrumentation.
Grid connection	255,000	This cost includes supply, erection, and commissioning of all cabling, transformers, and evacuation infrastructure up to the grid connection point. This is a highly variable cost depending on the distance to the point of connection.
Preliminary and operating expenses	11,000	This cost includes services related to design, project management, insurance, and interest during construction, among others. Though it is expected to vary with project size, the cost assumed is for a generic multi-megawatt site.
Civil and general work	120,000	This includes general infrastructure development, application for permits and approvals, and prepara-tion of project reports per MW.
Developer fee[b]	100,000	This is an average figure for the EU and dependent on market conditions.
TOTAL	**1,740,300**	

a PVinsights, 2014, www.pvinsights.com (accessed June 2014).

b SgurrEnergy compiled data sources in the EU around 2013.

Source: Source Data : SgurrEnergy, collected from project developers and installers in addition to PV Insights and Photon Consulting.

declines are being driven by improved manufacturing techniques, cell efficiency innovation, and cost reductions in the balance of systems. However, short-term volatility in pricing is likely to occur.

By following current and expected costs for major components, developers will be better informed when developing their financial model. The model should include a capex sensitivity analysis to account particularly for the forward cost curve on solar PV equipment. This will help the developer assess the potential impact of project delays against the possibility of changing equipment costs. However, it is important to remember that it is impossible to accurately predict the magnitude or timing of price changes.

15.2.2 OPERATIONS AND MAINTENANCE COST (OPEX)

Operation and maintenance (O&M) costs for solar PV projects are significantly lower than other renewable energy and conventional technologies due to the simple engineering and relatively minor maintenance required. The average O&M costs in the developed European market are currently around $4,200/MW per annum.[77] This figure will vary according to local labour costs, but is much lower as both an absolute number and a relative number than for other types of power projects.

O&M costs also depend on other factors, including the project location and the surrounding environment. For example, a site located in a dusty environment is likely to suffer higher soiling and require more frequent module cleaning. Given that wages are generally lower in most emerging markets, O&M costs can be expected to be consistent with or less than the European norm. However, early stage developing markets may not initially possess the industry structure/supply chain and economies of scale to fully exploit lower costs. For example, generally lower country cost may be offset by the need to bring technical experts from another country in the event of a major issue and if no local experts are available. It may be necessary to reserve funds for this contingency.

In addition to labour, operational expenditure includes comprehensive insurance, administration costs, professional fees, and land rental. Insurance costs vary considerably in new markets, and in some cases will not be available as a standard product.

The wide variation in opex costs between markets (shown in Table 21) reflects differing levels of market penetration (and therefore pricing competition), costs driven by lack of infrastructure, site transportation costs, subsidies, land rental costs, and labour costs.

15.3 SOLAR PV PROJECT REVENUES

Electricity from a solar PV project is converted to revenue by selling it to an off-taker. The amount of revenue will depend on the amount of energy generated and delivered and the price per unit of energy. Having a strong forecast of both these inputs is therefore central to the strength of financial model outputs and to obtaining outside financing.

15.3.1 ANNUAL ENERGY YIELD

There are a number of factors that affect the annual energy yield of a solar PV project, as discussed in detail in Section 5 (Energy Yield Prediction).

Annual energy yield directly drives the revenue line in the cash flow model and income statement. As such, accurate energy yield predictions are critical. Annual energy yield must be calculated by an experienced, independent, and suitably-qualified solar energy consultant who is able to provide "bank grade" energy yield analysis.

The confidence level of the yield forecast (or uncertainty) is also important, as the annual energy yield directly affects the annual revenue and therefore project viability. A P90 assessment is typically required. However, utility-scale projects that include a professional independent energy yield assessment, produced and/or verified by an experienced consultant with a track record of producing

77 SgurrEnergy compiled developer data and market provider quotations around 2013.

"bank grade" data, are sometimes bankable with a confidence interval of P75. As mentioned previously, additional sensitivity analysis may be advisable in markets with less data and project history.

15.3.2 *ELECTRICITY TARIFFS*

The key revenue stream for most solar power plants is the fee (tariff) paid for each kWh of electricity generated. As discussed in Section 12, sometimes there are other sources of revenue, such as renewable energy credits, tax credits, and other financial incentives available to developers. The stability and durability of such incentives should be assessed carefully.

At present, most utility-scale solar power plants sell electricity to an off-taker (in most cases a power company) through long-term PPAs. In many emerging economies, the power company is a state-owned enterprise. Increasingly, there are also opportunities to sell power to large private off-takers, such as industrial groups. The creditworthiness of the off-taker should be assessed carefully, particularly when the price of power in the PPA is higher than the average retail tariff in the respective power market. Off-taker credit risk and potential mitigation of those risks are covered in Table 20 and Section 12.

15.4 FINANCIAL MODELLING

A financial model is needed to assess the viability of the project. Such a model is requested by financial institutions and it is an essential piece in the preparation of the project for financing.

Table 23 lists key inputs for the financial model of a solar PV project relying on both equity and debt. Each input described below should be supported by robust and independently-verified evidence.

The financial model estimates the key parameters that are needed to decide whether or not to proceed with the project. Such parameters include (but are not limited to): economic and financial rate of return, return on equity (equity IRR), payback period, etc. Also, the model should prove that the project is able to service the debt.

15.4.1 *SOLAR PV PROJECT FINANCIAL ANALYSIS-LENDER'S MODEL*

Lenders are primarily concerned with the ability of the project to meet debt service requirements. The financial model that a developer or their agent prepares for lenders must address this concern and should include the following metrics:

- Cash Flow Available for Debt Service (CFADS) is calculated by subtracting operating expenditure

Table 23: Key Inputs to the Financial Model

Inputs	Comments
Project size (MW)	Based upon feasibility/technical study reflecting the constraints of grid capacity and land, in addition to energy yield prediction reference project capacity (e.g., MW's).
Energy yield/capacity factor	Calculated to reflect module efficiency, lifetime degradation, inverter losses, module soiling, and the potential for shading losses.
Tariff and other revenue streams	The price for power in the PPA along with other incentives is needed to determine project revenues.
Capex costs	One-off costs for the construction and commissioning of the project, generally based on an EPC contract.
Opex costs	Normally a 25-year view of costs, which are based upon initial contract agreements (e.g., O&M, land rent/lease, and corporate overheads) that will be subject to adjustments for inflation and other variables.
Debt service and repayment costs	This involves the repayment of debt interest and capital over a defined pre-agreed period with the lender (debt length is normally equal to contractual period of the PPA).
Grid tolling costs	Potential grid access fee, if applicable.
Taxes	Payment of central and local government taxes.

(opex), working capital adjustment, interest, and tax from revenue. It does not include non-cash items such as depreciation or cash that is already committed elsewhere. CFADS is used as an indicator of how much cash the project will produce, and thus how much debt can comfortably be serviced.

- Debt Service Coverage Ratio (DSCR) is a simple measure of the ability of a project to meet interest and capital repayments over the term of the debt. It is calculated as CFADS divided by the amount of expected debt service over a certain period.
- Loan Life Coverage Ratio (LLCR) provides another measure of the credit quality of the project, looking at the project's ability to pay over the total project life. It is calculated by dividing the net present value (NPV) of the CFADS over the project life by the remaining amount of debt owed.
- Maintenance Reserve Account (MRA) is an amount to cover operational contingencies, such as inverter replacements.
- Debt Service Reserve Account (DSRA) is a fund, often equivalent to 6 months of debt service, designed to cover any shortfalls in debt. If drawn on, it is then replenished on an on-going basis.

The most important measure to analyse is the DSCR. The average DSCR represents the average debt serviceability of the project over the debt term. A high DSCR indicates a higher capacity of the project to service the debt, while the minimum DSCR represents the minimum repayment ability of the project over the debt term. The lender's model should contain analysis on the minimum and average DSCR over a range of scenarios, including over discrete periods of time in the project's development. A minimum DSCR value of less than 1.0 indicates the project is unable to service the debt in at least one year.

15.4.2 *SENSITIVITY ANALYSIS*

Sensitivity analysis involves changing the inputs in the financial model (such as power tariff, capital cost and energy yield) to analyse how the cash flow of the project is impacted. Lenders will conduct sensitivity analyses around these key variables in order to determine whether the project will be able to service the debt in a bad year, for example if the energy yield is lower than expected, or if operational expenditure is higher than expected. Sensitivity analysis gives lenders and investors a greater understanding of the effects of changes in inputs, such as power tariffs, on the project's profitability and bankability. It helps lenders and investors understand the key risks associated with the project.

Typical variables investigated during sensitivity analysis include:

- Capital costs, especially on the panels and inverters.
- Operational costs (less critical for solar PV projects).
- Annual energy production.
- Interest rate.

15.4.3 *FINANCIAL BENCHMARKS AND HURDLE RATES FOR INVESTMENT*

The project financing structure generally comprises both debt and equity, as described in Section 14 (Financing Solar PV Projects).

Solar PV projects typically have a debt-equity mix with the following broad terms:

- Financing structure—equity 30 percent (or higher) with a corresponding debt element of 70 percent or less.
- Equity levered IRR's in excess of 10 percent, and significantly so in higher-risk markets.
- Debt repayment period of between 8 and 18 years.
- Debt service cover ratio (DSCR) of at least 1.3, or 1.5 for merchant solar PV projects.

15.4.4 CARRYING OUT A FINANCIAL ANALYSIS

A financial model's output determines not only the structure of the project's financing, but also the project company's maximum supportable level of debt. Performing financial modelling requires a highly specialized skillset. In order to build a financial model, a developer will require the services of a financial analyst with advanced knowledge of Excel spread sheets, or alternatively, someone with experience building models in one of the several other sophisticated software tools designed for this purpose.

Yet the ability to construct the mechanical aspects (e.g., the functions/calculations) of the financial model is itself not the only or necessarily even the most important key requirement.

It is critical that the developer understand the importance of reliable inputs to the financial model, as well as the significance of the model's key outputs from an investor's perspective. The developer should have a clear understanding of the probable degree of variation for different inputs, as well as the cause(s) of variation. Furthermore, a firm grasp of the terms used by investors to describe key outputs from the financial model will be necessary for the developer to enter into informed negotiations on project financing.

Financial Modelling Requirements/Procedures Checklist

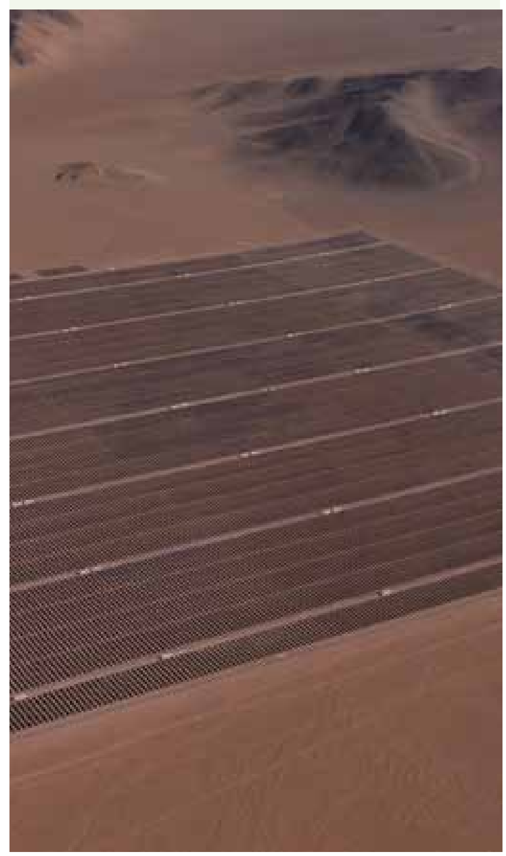
The checklist below is for developers, and sets out basic financial modelling requirements and procedures that investors in solar PV projects typically expect.

- [ ] Independently verify key assumptions in the financial model, including EPC and O&M costs, energy yield, off-take pricing, and terms of financing.
- [ ] Prepare financial model covering full lifecycle of the project.
- [ ] Include stress tested results and scenario analysis for debt service for potential lenders and equity investors.
- [ ] Clearly present cash flow analysis and relevant indicators, such as IRR, DSCR, CFADS, LLCR, MRA calculations, etc.
- [ ] Provide a sensitivity analysis for key inputs on capex, opex, and financing costs.

ANNEX 1

Common Construction Mistakes

The following images have been taken from megawatt-scale, ground-mounted solar PV power plants constructed in the U.K., India and South Africa. The images show a variety of common construction mistakes and issues that may arise under a variety of environmental conditions during operation. They are intended to illustrate topics that have been discussed throughout the guidebook and inform readers so that the mistakes may be avoided.



Photographs of common construction mistakes		
ID	Picture	Comment
1		Soiled pyranometers give conservative solar irradiation measurements, which can lead to over-estimated performance ratio measurements. Pyranometers must be well-maintained, kept calibrated and placed in locations where they will not be shaded by nearby obstacles.
2		Soiled modules will result in lower performance and can cause unexpected growth of vegetation, with associated shading loss.
3		Heavy rainfall, including monsoons, can restrict vehicular access and delay construction. Effective planning will avoid construction during heavy rain or incorporate mitigating measures such as sealing access routes before construction begins.
4		Poor waste management can lead to environmental damage and represents a risk to health and safety.

(continued)

Photographs of common construction mistakes (continued)		
ID	Picture	Comment
5		Inadequate pre-construction design and due diligence can result in sagging support structures with misaligned modules.
6		Inadequate pre-construction design and due diligence can lead to the need for costly post-construction remedial design alterations, such as on the pictured support structures.
7		Inadequate temporary security fencing can let livestock enter a site with associated risk of damage.
8		Poorly designed foundations and improper anchor bolts can result in mounting structures that are not properly bolted/secured and therefore unstable under heavy load conditions.
9		Heavy rains can erode the construction site when the risk of flood has been poorly assessed/mitigated.

(continued)

Photographs of common construction mistakes (continued)		
ID	Picture	Comment
10		Heavy soiling in desert conditions needs to be considered as part of the O&M strategy. Shading of modules by adjacent rows can be avoided at the design stage.
11		Poor DC cable management. DC cables should be kept neat and secured with cable ties, respecting cable-bending radii.
12		All plastic glands entering primary combiner boxes should be properly affixed to prevent slippage.
13		All plastic conduits should be filled with a suitable material, for example expanding foam, to reduce the risk of water ingress and rodents.
14		Cables should be protected from sharp metallic edges using appropriate padding.

(continued)

Photographs of common construction mistakes		
ID	Picture	Comment
15		Glands should be used for all cables entering combiner boxes, to prevent cable movement and damage to cable insulation.
16		Drainage issues should be solved early in the construction phase. Water is seen here jetting through the foam sealant in the flooded inspection chamber.
17		Landscaping, re-seeding and vegetation control is required to remove the risk of vegetation shading modules and reducing performance.

ANNEX

2

EPC Contract Heads of Terms

This Annex provides a summary of the key technical terms to be discussed between a potential EPC contractor (the "Contractor") and the potential owner ("Owner") of a megawatt-scale, ground-mounted solar photovoltaic (PV) power plant. It is expected that the term sheet that follows will be used to guide discussions between the Owner and the Contractor. Throughout the term sheet, [x] is used to indicate a value that needs to be determined through an agreement between the Contractor and the Owner, and in some cases an indicative value [such as 10 percent] is provided in place of [x]. Once all the details have been agreed upon, lawyers will typically use the term sheet to draft the full contract.

It is assumed that all plant equipment will be sourced by the EPC contractor and that the EPC contract has separately been provided with "Employer's Requirements" documentation, which specifies minimum technical requirements for the plant construction, including technical specifications for modules, inverters, transformers, cables, civil works, and procedures for safety, quality control, monitoring, and security.

EPC Contract Heads of Terms	
Topic	**Nature of Agreement**
Project Name	
Capacity	
Owner	
Contractor	
Type of Contract	Turnkey Engineer, Procure and Construct contract for implementation of a solar photovoltaic (PV) power plant with a design life of [25] years.
Contract Price	The Contract price is [XX].
Scope of Work	• The provision of all plant materials (including, support structures and PV modules). • Site preparation, ground and civil works including drainage. • Assembly and installation. • Grid connection infrastructure. • Equipment (including construction equipment). • Labour and the performance of all works and services. • Design, engineering, construction, commissioning, start-up, and testing according to industry standards. • Procurement and construction of fencing, security arrangements, and monitoring system. • Construction of all balance of plant. • Removal of debris. • Remedying defects.
Owner Responsibilities	Owner shall be responsible for: • Ensuring that the Contractor has right of access to the site. • Obtaining all permits and consents required for the operation of the plant (including planning permission and grid connection permits). Owner shall provide Contractor with all existing site information for review. Contractor shall be responsible for interpreting this data and for additional site investigations required. Owner shall pay the Contract Price to Contractor according to the Payment Schedule.
Contractor's Responsibilities	Contractor will review all relevant permits and authorisations obtained by the Owner and declare that they are acceptable. Works shall comply with requirements of the technical specifications as described in the Owners Requirements document. Works shall comply with all applicable laws, consents, and permits (including regional and local laws). All materials, equipment, and plant components shall be new. The Works will be performed so as to ensure the safety and health of the workers. The works/facility shall achieve the performance requirements and Guaranteed Performance levels. Contractor will be responsible for: • All activities necessary for the completion of the PV plant. • Compliance with all applicable laws. • Technical design and specifications. • Quality control of PV modules, and ensuring they are installed in accordance with the module installation manual. • Safeguarding all equipment and materials, including transport and storage. • Engineering, technical design, drawings, and manuals. The Contractor is responsible for obtaining and maintaining: • Consents and permits required to perform the works. • Export/import licences for materials, plant, equipment, and similar consents. • Consents and permits for transporting materials, plant and equipment to site, and unloading. • Labour necessary for the assembly and installation of all of the equipment, accessories, and materials provided.

(continued)

EPC Contract Heads of Terms (continued)	
Topic	**Nature of Agreement**
Quality Standards	Contractor shall provide a comprehensive Quality Standards document describing plant acceptance criteria. This shall be reviewed and approved by the Owner and will include a description of factory acceptance test procedures and site acceptance test procedures for major plant components, including transformers and inverters.
Project Schedule	Contractor shall provide a Gantt chart construction schedule. Contractor shall provide progress report updates on a weekly basis during construction.
Subcontracting	The Contractor remains fully responsible for all works completed by subcontractors. The Contractor additionally confirms that the work of its subcontractors meets the specifications set forth in the EPC Contract and complies with the law.
Implementation	• Contractor warrants ability to complete the plant, the electrical infrastructure and connection infrastructure in accordance with the project schedule. • Liquidated damages will apply if scheduled completion dates are not achieved. • Contractor shall supply manuals, documents and records as per industry norms. • Contractor to be responsible for storage and disposal of hazardous materials and rectification of any contamination caused by performance of the plant. • Contractor to provide spare parts and consumables. • Contractor to provide tools necessary for commissioning and testing and to make provision for commissioning and testing to be witnessed by the Owner's representative.
Site Conditions	• Owner is to provide Contractor with all available site information describing the physical characteristics of the site. • Contractor to carry out further site investigations as required. • Contractor takes full responsibility and risk for further site investigations and ensures that it has studied and inspected to its full satisfaction the geotechnical, geo-morphological, and hydrogeological studies and accessed conditions and environmental characteristics of the site. • Contractor shall declare in the EPC contract that the site is suitable for the execution of the works but will not be responsible for costs arising from the discovery of: a) pre–existing toxic waste; b) artistic, historical or archaeological findings; c) underground pipelines; or d) munitions, where these were not detected in the information provided by Owner.
Completion Date	The Completion Date (date of signing the Provisional Acceptance Certificate) will be achieved within [x] months from the date of the EPC contract Notice To Proceed.

(continued)

EPC Contract Heads of Terms (continued)	
Topic	**Nature of Agreement**
Acceptance	**Acceptance Tests** The Contractor will perform: a) tests required under the applicable law; b) commissioning tests according to IEC 62446; c) performance tests. Performance tests will be carried out to determine whether the plant: a) has achieved the requirements for completion; b) is compliant with quality standards; c) is compliant with technical specifications; and d) to ascertain whether the guaranteed performance has been attained. The testing process shall be clearly described. A test sample of modules shall be taken from the plant and sent to an independent testing institute for flash testing. **Provisional Acceptance** The Owner shall provide a Provisional Acceptance Certificate when all of the requirements for completion have been achieved and testing has been completed. A punch list of outstanding items will be prepared. To pass provisional acceptance, the value of outstanding items must be less than 1% of the Contract Price. Items on the punch list will be remedied within [x] months from signing of the Provisional Acceptance Certificate. Signing of the Provisional Acceptance Certificate shall trigger the start of the Performance Warranty Period. **Intermediate Acceptance** The parties shall agree to requirements for Intermediate Acceptance. These will include: • A performance ratio test, averaged over one year of operation since provisional acceptance, taking into account an agreed rate of degradation. **Final Acceptance** The parties shall agree to requirements for final acceptance. These will include: • A performance ratio test, averaged over the two years of operation since provisional acceptance, taking into account an agreed rate of annual degradation. The Owner shall provide a Final Acceptance Certificate when all of the requirements for completion have been achieved.
Transfer of Title	The ownership of the plant, materials, equipment and warranties will transfer from the Contractor to the Owner at provisional acceptance. The Contractor shall be responsible for any materials or other items delivered by the Owner or by third parties up to provisional acceptance.
Warranty Periods	The **Performance Warranty Period** will be 2 years, starting from the signing of the Provisional Acceptance Certificate. The Contractor shall transfer all the guarantees and warranties directly from suppliers and sub-suppliers in favour of the Owner. This shall include: **Module Power Performance Warranty**: [25] years [90% until year 10, 80% until year 25, or linear power warranty according to the manufacturer's specifications]. **Inverter Warranty:** [5] years. **Support Structure Warranty:** [10] years. The **Defect Warranty Period** will have a duration of [2] years from issue of Provisional Acceptance Certificate. During this period the Contractor will remedy defects and omissions at its own cost. The period will be extended by a further period of [1] year for any defect that is remedied during the initial period.
Guaranteed Performance	A minimum Guaranteed Performance Ratio of [81]% will be achieved at provisional acceptance. The Performance Ratio (PR) shall be measured at the export meter over a period of [15] days prior to issue of the Provisional Acceptance Certificate. The PR measurement shall be temperature compensated and irradiation measured using secondary standard thermal pyranometers. A minimum of [x]% of test time shall be at a measured irradiance above [x]W/m^2. A minimum Guaranteed Performance Ratio of [80]% will be achieved during the Performance Warranty Period. Liquidated damages for PR shortfalls will be provided by the Contractor, according to agreed formulae.

(continued)

EPC Contract Heads of Terms (continued)	
Topic	**Nature of Agreement**
Payment Schedule	A schedule of milestones will be defined in the contract. The Owner will transfer a percentage of the Contract Price to the Contractor when milestones are achieved: Advance [10]% Civil Works completed [10]% Mounting System installed [10]% Modules and inverters delivered [40]% Inverters and modules Installed [10]% Grid connection achieved [5]% Mechanical Acceptance [5]% Provisional Acceptance [10]%
Performance Bond	At the signing of the contract, the Contractor will procure a performance bond (bank guarantee) of value [10]% of the contract price. The purpose of this is to guarantee funds for the Owner in case: a) delay liquidated damages are payable; b) Guaranteed Performance Ratio is not achieved at provisional acceptance; c) the Contractor has defaulted in its obligations under the contract. The performance bond will be returned to the Contractor at the signing of the Provisional Acceptance Certificate
Warranty Bond	Upon signing of the Provisional Acceptance Certificate, the Contractor will provide a warranty bond (bank guarantee) with a value of [5]% of the contract price. The warranty bond will guarantee the Owner funds in case liquidated damages that are payable or the Contractor do not meet obligations during the Defect Warranty Period. The warranty bond will be returned to the Contractor at the signing of the Final Acceptance Certificate.
Liquidated Damages	**Delay Liquidated Damages**: Delay liquidated damages of [0.25]% of the EPC contract price will be provided per week of delay beyond the agreed completion date, up to a maximum cap of [10]%. **Performance Liquidated Damages:** A price adjustment will apply if the Contractor fails to meet the Guaranteed Performance Ratio during acceptance tests and does not rectify such under-performance. The liquidated damages will be agreed as [1.5]% of the contract price for each [1]% shortfall in the PR below the Guaranteed Performance Ratio. The cap on the performance liquidated damages will be [10]% of the contract price.
Maximum Penalty Cap	The maximum aggregate liability of the Contractor for delay liquidated damages and performance liquidated damages will be [20]% of Contract Price.
Insurance	The Contractor shall procure insurance policies as follows: a) Construction All Risk Insurance; b) Marine Transit Insurance; c) Third Party Liability Insurance; d) all other compulsory insurances according to the applicable law.
Termination	The Owner shall be entitled to terminate the contract if: • The performance liquidated damages owed by the Contractor exceeds the agreed maximum cap. • The delay liquidated damages owed by the Contractor for late delivery of the plant exceeds the agreed maximum cap. • In case of justified refusal of issuance of the Provisional or Final Acceptance Certificates.

ANNEX
3

O&M Contract Heads of Terms

This document summarises the key terms to be discussed between the potential Operations and Maintenance (O&M) contractor (the "Contractor") and the potential owner ("Owner") of a megawatt-scale, ground-mounted solar photovoltaic (PV) power plant. When all the details have been agreed upon, lawyers will typically use the term sheet to draft the full contract.

O&M Contract Heads of Terms	
Topic	**Nature of Agreement**
Project Name	
Capacity	
Owner	
Contractor	
Remuneration	The Owner shall pay the Contractor a fixed remuneration of [x] per MWp installed capacity for each year of operation. This will be escalated at an annual rate to be agreed upon by both parties. Remuneration shall be paid monthly/quarterly in arrears.
Commencement Date	The Contractor shall perform the services commencing on the date of issuing of the Plant Taking-Over Certificate in accordance with the terms of the EPC contract.
Scope of Services	The performance of all preventative and corrective maintenance required to ensure the plant achieves the guaranteed availability level and/or Guaranteed Performance Ratio during each and every operational year of the Contract term. The Contractor shall monitor plant performance on an ongoing basis throughout the Contract term to detect abnormal operation and implement appropriate maintenance actions. Preventative maintenance: • The examination of solar PV plant components for operational and performance capability on an ongoing basis during the contract term, and the performance of tasks that are aimed at preventing the possible occurrence of future errors, disruptions or reduction in performance, in particular through the replacement of consumable parts, or the maintenance of individual components of the solar PV plant. • Without exception, maintain the plant and its components in line with manufacturer guidelines (such that third party warranty terms remain valid), the O&M manual and grid operator requirements. These shall be communicated to the Owner by the Contractor within a preventative maintenance schedule held as an appendix within the plant O&M Manual. • Preventive maintenance to be coordinated and scheduled in order to minimise the impact on the operation and performance of the plant. Corrective maintenance: • Shall be performed to ensure achievement of the Guaranteed Availability Level and/or Guaranteed Performance Ratio. • When a failure or malfunction is detected that impacts plant operations, Contractor shall promptly commence the required corrective maintenance actions in order to return the plant to operation under normal conditions of service in accordance with agreed response times.
Monitoring	The Contractor shall monitor the operation of the plant between the hours of [xx]am and [xx]pm every day, checking its operational readiness and generation capacity. Monitoring will be performed using on-site monitoring software and systems provided under the EPC Contract. The Contractor will ensure that any disruption messages generated by the plant are received and analysed every day. In particular the Contractor will carry out monitoring to at least the [DC combiner box] level. Measures for correction of fault messages in the case of those which cannot be rectified remotely will be undertaken in accordance with the severity of the fault and agreed upon response times.
Reporting	The Contractor shall provide the Owner with the following reports, the contents of which will be detailed within the O&M contract: • Monthly report to be delivered to Owner by the seventh calendar day of each month. • Annual report to be delivered to Owner not later than 21 calendar days following the end of an operational year. • Reports on Significant Disruptions—If during monitoring or testing the Contractor determines serious disruptions, damage or defects, the Contractor shall inform the Owner immediately and at the latest within 24 hours of the defect becoming known to the Contractor, detailing the type of the damage, and the anticipated time and duration for repair. Reports on any major maintenance to be delivered to the Owner within 7 days of completion. Report on the rectification of defects or interruptions to the operation of the plant issued within 7 days.

(continued)

O&M Contract Heads of Terms	
Topic	**Nature of Agreement**
Ground keeping	The Contractor shall perform ground keeping and vegetation control at the plant such that plant performance is not impeded through shading. Ground keeping shall be conducted in a manner and frequency that adheres to permit and lease obligations and component manufacturer's recommendations.
Security	The Contractor will be responsible for plant security and surveillance provision during the contract term. This will be provided on a 24 hours/day, 365 days/year basis.
Spare Parts Management	The Owner will make available to the Contractor an inventory of spare parts for use in performing the Services (The spare parts will have been previously provided by the EPC Contractor.) The Contractor is responsible for providing all other material, equipment, tools and consumables necessary to perform the Services. The Contractor shall ensure that all Spare Parts are labelled and maintained in a log when received into or withdrawn from the inventory. Contractor shall, at its own cost, replace any Spare Parts that it uses with new parts of equal or better quality and warranty levels. All Spare Parts remain the sole property of the Owner and shall be returned to Owner at the end of the Contract term. All Spare Parts shall be kept by the Contractor on the Site or within an acceptable distance for prompt transportation to the Site. The Contractor warrants to Owner that each installation or repair performed shall be free of defects in material or workmanship for a period of 12 months following the date of its installation or repair
Availability Guarantee	The Contractor guarantees that the Availability Level of the Plant shall be at least [99] % (Guaranteed Availability Level) during each operational year of the Contract Term starting at the Commencement date. Plant availability shall be calculated at the [inverter] level in accordance with the methodology contained within the O&M Contract. Measured Plant Availability shall be compared with the Guaranteed Availability Level. If Measured Plant Availability falls below the Guaranteed Availability Level, liquidated damages shall be payable to the Owner in accordance with the O&M Contract.
Performance Ratio Guarantee	The Contractor guarantees that the Performance Ratio (PR) of the Plant shall be at least [x]% (Guaranteed Performance Ratio) during each operational year of the Contract Term starting at the Commencement date, taking into account an agreed upon rate of annual degradation. For the purposes of calculating PR, plant energy output will be measured at the utility meter and plane-of-array irradiation will be measured by at least two secondary standard pyranometers, both in accordance with the methodology contained in the O&M Contract. Measured Plant PR shall be compared with the Guaranteed PR value. If Measured Plant PR falls below the Guaranteed Performance Ratio, liquidated damages shall be payable to the Owner in accordance with the O&M Contract.
Liquidated Damages	If it is established that the plant is performing in deficit of the Guaranteed Availability Level and/or Guaranteed Performance Ratio during the Contract terms, the Contractor shall pay to Owner liquidated damages by way of compensation. Both parties agree that liquidated damages will be sized at a level that represents a genuine pre-estimate of losses that may be anticipated from failure to achieve the Guaranteed Availability Level and/or Guaranteed Performance Ratio.
Limit of Liability	The Contractor's liability under the Contract is limited to the Contract price.
Health and Safety	The Contractor shall be responsible for the safety of all Contractor and Subcontractor personnel at the Site. The Contractor shall be responsible for ensuring the safety of all maintenance activities performed at the Site.

Rooftop Solar PV Systems

ANNEX 4

Rooftop solar applications are a substantial part of the deployment of PV technology and are expected to grow substantially in the future.

A4.1 ROOFTOP SOLAR PV SYSTEMS OVERVIEW

A4.1.1 INTRODUCTION

Rooftop solar PV systems can significantly vary in size from kW-scale systems on domestic properties to multi-megawatt-scale installations on non-domestic buildings such as commercial warehouses, factories or office parks. The modular nature of solar PV modules makes them highly adaptable for use on roof spaces. Benefits of roof-mounted solar PV system for a developer can include reduced land cost, the opportunity to offset electricity consumed on site and reduced connection cost due to close proximity to a connection point.

From a public benefit perspective, rooftop solar PV technology is a source of distributed generation that is by its nature close to the source of load demand. It also reduces stress on use of scarce ground surface, especially in urban settings. With the benefits come additional challenges in the design, construction and operation. These additional complexities are explored in the following sections.

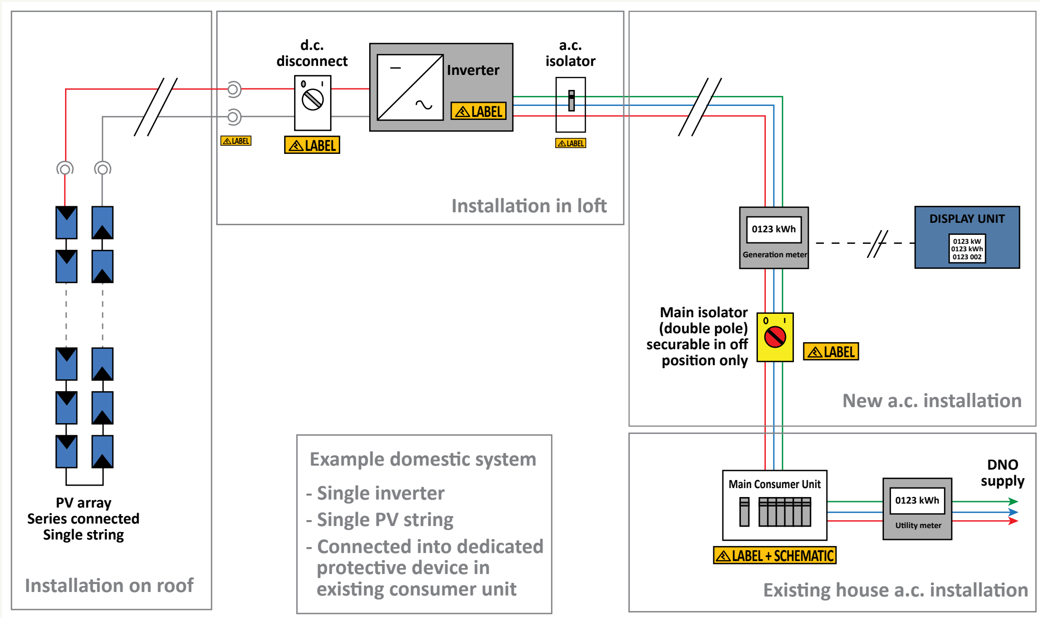
While this guidebook makes mention of aspects relating to small-scale residential systems, the main focus is on larger-scale systems for non-domestic rooftops. The guide focus is on the grid-connected sector and therefore does not address the additional challenges of off-grid systems, for which battery or other energy storage systems are required.

A4.1.2 SYSTEM SIZES

A4.1.2.1 Small-scale Residential Systems

A typical small (kW scale) residential system might consist of a single string of PV modules connected to a single string inverter as illustrated in Figure 33. The grid connection for a residential system can often make use of existing infrastructure (for example the existing power box) at the building.

Figure 33: Small-scale PV System Schematic



A number of design considerations are common across all rooftop solar PV applications. However, some aspects are simplified for small rooftop systems. For example, the electrical design for small systems is less complex than for large systems because small systems can often be connected to a single phase at low voltage (LV). This means the need for complexity in transformer and switch gear design is reduced or avoided.

The project structure can be simple, as small-scale residential systems are often funded by building owners who wish to offset their electricity use or export energy to the grid to benefit from incentives such as a FiT scheme. In some markets "third party leases" or loan structures offered by solar system supply companies or banks help residential owners overcome the high upfront cost of a system.

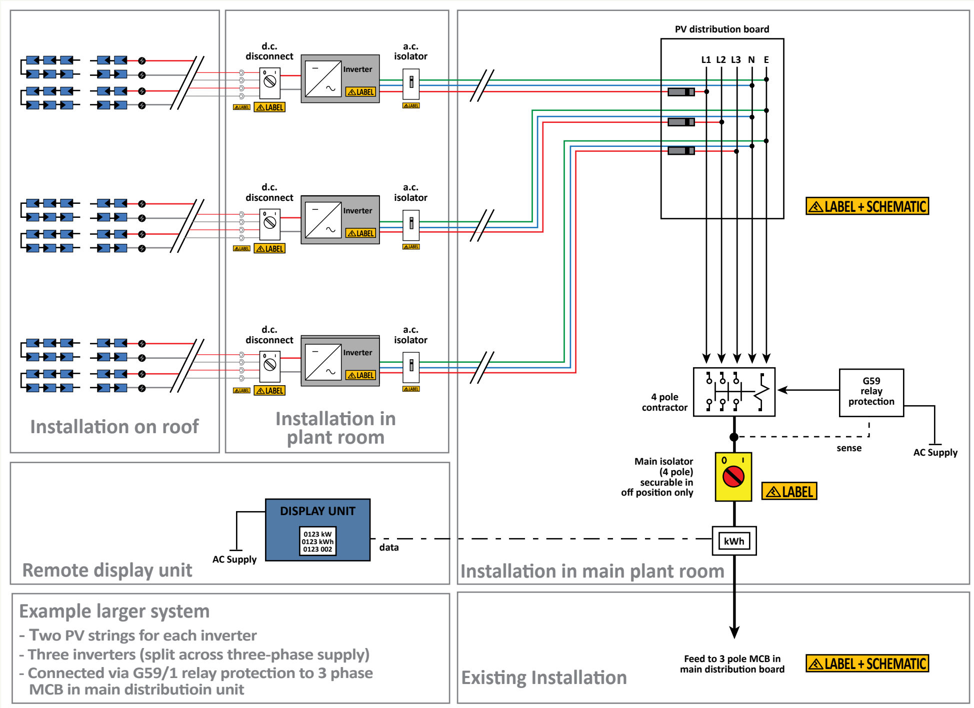
In a number of global markets, the design and installation of residential systems can unfortunately attract inexperienced contractors and therefore there have been cases of poorly designed, ineffective or unsafe installations. It is important that residential systems are designed to local and international standards (e.g., IEC 62548: 2013—Design Requirements for Photovoltaic (PV) Arrays, or local equivalents) and installed by experienced professionals. In a number of markets, incentives require a contractor to be certified and this helps to promote the quality and safety of PV design and installation.

A4.1.2.2 Medium to Large Scale Non-domestic Systems

Non-domestic solar PV rooftop systems can vary in scale, and may range from tens of kW to multi-megawatt scale. A medium to large non-domestic system would typically incorporate several strings of PV modules, combined into numerous string inverters, as illustrated in Figure 34.

While large-scale, ground-mounted PV systems can utilise central inverter systems, this is not common on rooftop arrays. Instead, string inverters are favoured in the interest of minimising DC cable runs from the roof space to the inverter, and thus minimising DC cable losses. When compared with a small residential system, the grid connection for a non-domestic system is likely to involve additional infrastructure, including marshalling boxes,

Figure 34: Non-domestic PV Rooftop Schematic



transformer(s), and more substantial electrical protection. The grid connection process is likely to be more lengthy and detailed. Recent advances in inverter technology have introduced the possibility of using micro-inverter technology, transforming DC current to AC at the module level, and thereby avoiding the need for central inverters. Other benefits include module-level controls that allow for instant adjustments to a string should any module be affected by debris or other performance reduction factors.

A4.1.3 SYSTEM TYPES

Rooftop solar PV systems generally fit into two categories: Building Applied PV (BAPV) and Building Integrated PV (BIPV). Figure 35 illustrates the difference between a BAPV and BIPV system.

BAPV is applicable for an existing building, while BIPV can be utilised for new buildings incorporating a solar PV system as part of the design.

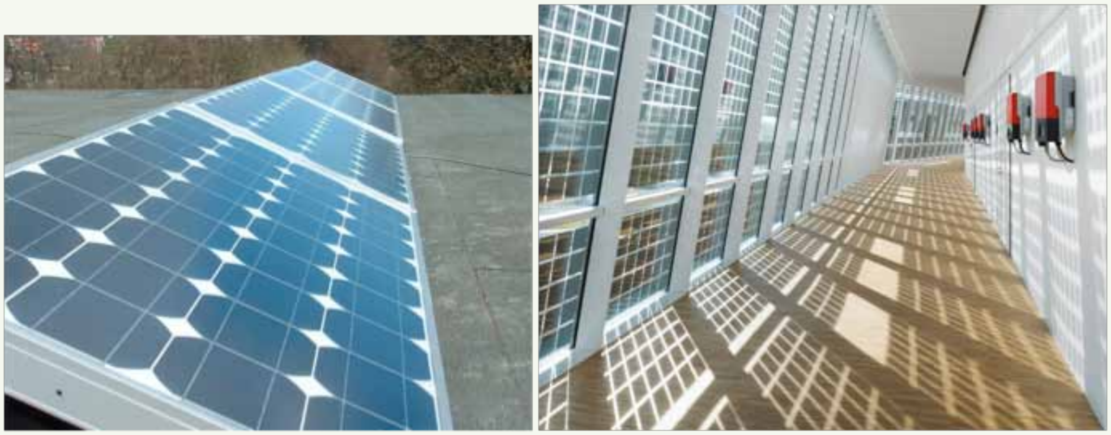
BIPV systems can make use of a number of versatile PV module types and mounting options including:

- Flexible PV roofing.
- PV used to create the facade of a building.
- PV used to create awnings for buildings (therefore also benefitting the passive solar design).
- Integrated glass/glass PV sky lights.
- PV tiles or slates, which can be used as substitute roofing materials.

PV panel-covered parking spaces/car ports are a popular way of integrating PV panels into a functional structure and while not covered here in detail, can be used in combination with electric car charging stations.

BIPV can be a good way to achieve desired aesthetic outcomes on building facades. Some commercially-available PV modules even allow custom PV cell colours (such as purple, yellow or green). BIPV applications

Figure 35: BAPV (Left) and BIPV (Right) Systems



Source: SMA Solar Technology AG

however, are more expensive than applied PV and result in sacrificed energy yield due to a reduced module efficiency or compromised tilt/orientation. BAPV is simpler and easier to install than BIPV. A greater number of building spaces are available with the potential for BAPV because BIPV is predominantly applicable to new buildings. For these reasons, the majority of systems installed globally are BAPV.

A4.2 ENERGY YIELD

There are a number of considerations for rooftop solar PV system energy yields. These include:

- Non-optimal tilts and orientation (azimuth).[80]
- Potential for increased module temperature losses.
- More complexity near shading elements.
- Potential for snow cover/bird droppings/dust build up.

The potential for a rooftop installation to be more difficult to access than a ground-mounted plant should be considered in the energy yield prediction with respect to cleaning (soiling losses) and plant availability (maintenance time to repair). The safety of personnel in gaining rooftop access should also be considered.

A4.2.1 SYSTEM TILT AND AZIMUTH

Wind loading and rooftop dimension constraints may limit the tilt angle that can be used. Tilt angles are therefore often lower for rooftop systems. While some system designs may aim for higher tilt angles to increase the yield, greater utilisation of the available roof space is possible with lower tilt angles. This is because it is possible to reduce the inter-row spacing of modules for a lower tilt angle without adversely affecting shading from row to row.

For countries near the equator, such as Indonesia, a low-tilt angle coincides with the optimal for annual energy yield.[81] However, with increasing distance from the equator, low-tilt angles can reduce the overall specific yield for the system.

Rooftops themselves are also often oriented with non-optimal azimuth and tilt angles. The reduction in total annual irradiation can be calculated on a site-by-site basis

80 The azimuth is the location of the sun in terms of north, south, east and west. Definitions may vary but 0° represents true south, -90° represents east, 180° represents north, and 90° represents west.

81 Tilt angles below 10° are not recommended as natural rainwater run-off has a less effective cleaning effect leading to increased soiling losses.

using knowledge of the diffuse and direct components of irradiation and the albedo of the ground. In general the reduction in annual energy yield is usually within acceptable limits if the azimuth remains within 45 degrees of the optimum orientation.

A4.2.1.1 Module Temperature Losses

Compared to a ground mount system, integrating a solar PV system on a roof space can increase the temperature of the PV modules, due to a reduction in wind cooling and absorption of heat emitted by the rooftop surface and other building surfaces. The range of temperature loss corrections on solar PV plants could range from a 14 percent loss to a 2 percent gain, depending on the climate, and therefore this consideration is significant. PV module efficiency decreases as the temperature increases. This effect is more pronounced with crystalline silicon as compared to thin-film technologies. A typical temperature co-efficient for silicon modules is in the order of -0.43 percent power loss per degree Celsius above a 25°C module temperature. Figure 36 shows the relationship between module efficiency at Standard Test Conditions (STC)[82] and temperature for a standard multi-crystalline silicon module.

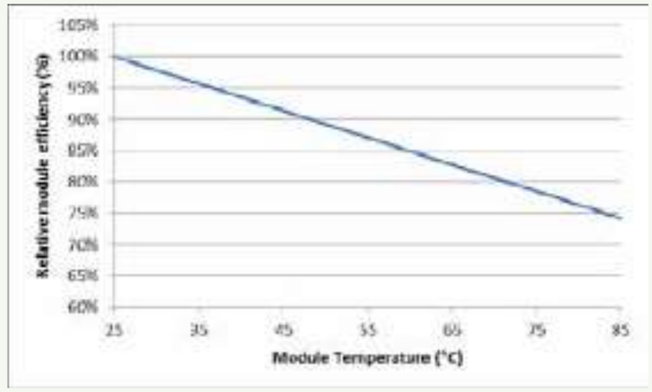
To ensure that rooftop systems do not reach excessive temperatures, suitable spacing between the roof and PV modules must be considered in the design specifications to allow ventilation.

A4.2.1.2 Near Shading Losses

Near shading losses can be significant for rooftop PV systems due to the location of nearby buildings, chimneys, air vents, trees, adjoining roof spaces, overhead lines and other potential shading objects. Such shading should be avoided. If shading is unavoidable, the use of string inverters rather than central inverters is one way to minimise the impact of shading loss on the overall system performance.

82 Standard Test Conditions: 1,000 W/m², Air Mass 1.5, Module Temperature 25°C

Figure 36: Reduction in Module Efficiency with Average Temperature Coefficient



It is important to model shading accurately prior to construction, incorporating all shading objects so that the expected energy yield and financial return may be accurately assessed. Developers should conduct site inspections of the rooftop to determine current obstructions and gather feedback on potential nearby high-rise buildings to be constructed. In case of negative feedback, such sites should be given a low priority for development.

A4.2.1.3 Snow Loss

For solar PV energy yield predictions in regions that experience snow fall, it is important to consider the effect of snow on system performance. For a rooftop solar PV system, roof objects such as gutters, vents or adjoining roof spaces can act as traps where snow accumulates. Due to the internal wiring of typical solar PV modules, it may be advantageous to mount modules in a landscape profile in situations where snow may build up along the bottom edge of the array. This allows by-pass diodes to be effective and therefore reduces losses.

A4.3 PLANT DESIGN

Some design risks are elevated for rooftop PV systems because of their potential to impact rooftop integrity, personnel or contents within a building. The plant design should adhere to local and international standards (such as IEC 62548: 2013, and the International Building

Code). The following sections explore plant design aspects that are particularly relevant to roof-mounted systems. Electrical designs must consider appropriate cabling layouts, lightning protection, and inverter selection. The civil designs must safely and effectively secure the system to the roof, while considering maintenance requirements for the PV array and the roof. Waterproofing is an important installation consideration. It is important to avoid negative impacts on roof longevity, which can in turn have negative impacts on roofing warranties and insurance. This is discussed further in sub-section 3.2 of this Annex.

A4.3.1 ELECTRICAL DESIGN

Many of the electrical design ratings required for ground-mounted systems, such as voltage and current sizing and isolation protection levels, are applicable for rooftop systems. However there are some additional issues that should be considered in the electrical design phase.

Minimising cable runs is more difficult for large-scale rooftop systems and this may lead to slightly higher cable losses due to longer cable lengths or increased costs from thicker cables. Cable placement needs to be carefully considered with appropriate cable ties holding cables in place. Loose cables are a hazard and may suffer from damage during windy conditions. Cables may also reach higher temperatures for rooftop systems due to less ventilation, increasing the resistance and, hence, cable losses. It is recommended cables meet or exceed the following requirements defined in IEC 61730-1:

- Size: minimum 4.0 mm^2 (12 AWG) for modules connected in series.
- Temperature rating from -40°C to +90°C.
- Type PV-wire, USE-2 or equivalent.

The correct fuse specification is also very important for rooftop systems, as failure to appropriately size a fuse can lead to a significant fire risk.

Lightning protection may be required for locations with a high risk of thunderstorms; standard IEC 62305 and UL2703 form the basis of grounding requirements. Buildings may already be fitted with a lightning protection system (LPS), in which case the PV installation will need to be integrated into this system. This may require bonding, provision of earth tape, and surge arrestors, subject to the arrangement of the installation.

As with ground-mounted systems, an earthing or grounding system should be applied to a roof-mounted solar PV system for safety and to allow proper functioning of the system. As there is no direct connection to earth via ground piles, a bonding system to earth the mounting structures should be considered. All earthing requirements of the PV installation will need to be integrated into the building earth requirements. The design of earthing systems should avoid breaching the building envelope and damaging either the waterproofing system or building electrical systems.

For system designs incorporating multiple tilts and orientations, it is important to ensure that, in the inverter design, only identically oriented sub-arrays are allocated to a single maximum power point tracker[83] (which usually implies the use of a single string inverter). Each PV array tilt and orientation will have its own unique output characteristics and therefore needs to be “tracked” separately to maximise yield.

Reactive power control may be required by a grid operator, with power factors lagging to leading at levels below unity. Most PV inverters have the capability to supply reactive power support. If reactive power is incorporated into the system design then it is important that electrical component and inverter sizings are conducted appropriately (generally higher ratings required for all electrical balance of plant and inverters).

Consideration should be given to other works on the building that could interface with the PV system installation. Cable runs inside buildings may need to be

83 A maximum power point tracker is a component of a PV inverter (some larger inverters have more than one) that varies the current and voltage of the PV array to achieve the maximum power output.

installed in heavy duty conduits for mechanical protection and marked as "solar" to avoid confusion with other wiring.

A grid connection application is typically required for the system even if all of the energy generated by the plant is consumed in the building itself. In particular, grid operators often use a grid connection application to verify that anti-islanding and other safety mechanisms are appropriate. Grid connection applications should be made well in advance of the installation date and ensure that the maximum export capacity is greater than or equal to the proposed plant installed capacity.

A4.3.2 CIVIL DESIGN

The civil design of a roof-mounted system must carefully consider an appropriate mounting concept that secures the PV array, minimises adverse effects on the water proofing of the roof, and resists uplift. In addition, a careful assessment of the added roof load must be made.

There have been a number of systems globally which have failed due to the incorrect design and sizing of the support structure on rooftop systems. These failures tend to be high profile as there is a significant risk of endangerment to humans compared to ground-mounted systems.

There are three main foundation options in securing a PV system to a roof:

- Structural fixing.
- Ballasted.
- Hybrid of ballast and structural attachment.

A4.3.2.1 Fixed Foundations

A foundation with structural fixing normally consists of penetrations in the roof surface and connections to the module framing.

Fixed foundations are beneficial as they reduce the dead loading to the structure and are often more flexible than other solutions. The main disadvantage of a fixed system is that penetrations into a roof surface can interfere with waterproofing materials and cause leaks. This is less of an issue for slopped roofs but the design of fixed systems on flat roofs, which are particularly attractive for utility-scale solar PV use, will need particular care. Existing warranties relating to the roof should also be checked because making any penetrations risks invalidating the warranty. Water damage from a punctured rooftop can lead to rot in buildings with wood foundations and loss of structural integrity.

A number of different fixing approaches are available depending on the roof type. Examples include standoffs welded or screwed in place, curbs integrated into the roofing or steel grids suspended above the roof surface. In the case of ceramic or slate tiles it is not considered appropriate to drill through the tile from a water-proofing perspective, and therefore custom-made clips or hooks can offer a solution. It should be ensured that fixings are made to structural components that are designed to accommodate extra weight.

A4.3.2.2 Ballasted Foundations

A ballasted foundation holds down solar PV systems with heavy materials such as concrete slabs. This is a relatively simple approach; however the roof load capacity needs to be considered due to the additional weight of the ballast. As a result, the tilt angle of the system is normally limited to 20° because a higher title angle increases the wind loading and therefore increases the ballast weight required.

Wind pressure distributions vary with location on the PV array structure. Corner and perimeter arrays tend to be loaded the highest and so require much more ballast than interior arrays. One method of reducing the effect of this is to interconnect the support structures so that the ballast weight can be better distributed across the roof. The foundation system must be adequately designed so that it is rigid enough to spread any such forces.

The ballasted system relies on the friction between the roof surface and the array in order to prevent it from sliding. The level of friction can have a significant impact on the amount of ballast required. It is possible to test the potential friction of a roof using specially designed tools in order to optimise the ballast design.

A4.3.2.3 Loading Assessment

A qualified engineer should conduct structural load calculations; this should be done for every rooftop solar PV system. The structural integrity of the existing roof space should be assessed by means of design drawing review and visual inspection. Visual inspection can reveal damage or degradation of existing structural members.

Load assessment calculations should consider:

- Assessment of the loads acting on the PV array and roof, including wind, snow, and seismic loads. The existence of the array will cause additional vertical wind loads onto the roof.
- Assessment of the roof structure to determine its spare load capacity.
- Comparison of the roof structure capacity with the new and existing applied loads.

Load assessments may reveal that the roof structure cannot accommodate the added weight of the solar PV system. In this case, structural reinforcements should be incorporated into the system design.

The solar PV system should not allow water to collect at certain areas of the roof because this will cause additional loading. Water should be rapidly distributed to the overall building drainage system.

The wind loading can cause sliding, uplift, and downward loads on the PV array and roof structure. The load magnitude tends to be dependent on a number of site-specific factors, such as distance to sea, character of the surrounding terrain and location of the array on the roof. A rooftop solar PV system may be split into three areas for wind loading considerations:

1. Interior zone.
2. Perimeter zone.
3. Corner zone.

Corner zones experience the highest wind loads, while interior zones have the lowest wind loads.

Generally, there are national or international standards, such as the International Building Code, which can be used as a basis for structural calculations for loading on buildings. Examples include the Eurocodes in Europe and the ASCE codes in the United States.

Existing design guides and codes can be used to estimate these forces, but as the wind load acting on the array is specific to the particular array and mounting system used, the loads derived by these codes tend to be very simplified. If optimisation is required, as is often the case for ballasted systems where ballast weight must be kept to a minimum, then wind tunnel testing tends to be undertaken and used alongside the relevant country design codes. A number of solar PV foundation providers have already undertaken wind tunnel tests on their products. A qualified structural engineer can apply these to site-specific conditions.

A4.3.2.4 Monitoring and Security

As is the case with large ground-mounted systems, a comprehensive monitoring system is required on roof-mounted systems. Because building systems are located close to end users, there is the opportunity for education and marketing. Real time displays inside the building, which inform building users of the amount of electricity generated and other environmental attributes, can be a good way to promote an organisation’s green credentials. Faults and downtime can also be monitored without having to inspect the rooftop system. There are also remote tracking systems, which allow a developer with many rooftop installations to monitor generation from multiple locations.

Generally, system security against module and inverter theft is increased due to roof spaces being generally inaccessible to the public. Where rooftops are accessible from other rooftops, additional security measures can be considered, such as security bolts.

A4.4 PERMITS, LICENSING AND AGREEMENTS

Planning requirements for large-scale rooftop solar PV systems differ from those for ground-mounted systems. For small systems, there is often very little permitting required, other than perhaps residential construction. Aspects of the approval process are generally less onerous due to the PV array having zero land impact, and therefore less effect on fauna or flora. A BAPV system may have minimal or no visual impact. Construction activities and site access impacts still need to be assessed, however, and some environmental assessments may be required depending on the location and the requirements of the consenting authority. There may be restrictions to development within historic districts to preserve aesthetic harmony, which should be investigated prior to any project development. Similarly, installers should note the impact of glare from PV modules on neighbouring businesses or residences.

Building permits are likely to assess structural designs and potentially the roof upgrade design if structural reinforcement is required to accommodate the additional weight of the PV system.

The ease with which any consents can be obtained will vary from country to country and depend on the complexity of the planned installation. Central government renewable energy targets can feed down to the local level and impact the approval process positively.

A4.5 CONSTRUCTION

PV modules are live as soon as they are exposed to daylight, and as such, pose a hazard to installers. Due to the location of installation, particular consideration should be given to ensuring that personnel accessing roofs for maintenance and other activities are not exposed to electrocution hazard. The design of the system should limit open circuit voltages and ensure that live parts are suitably insulated from contact.

There is additional complexity due to the awkward size and weight of modules while working at height. Therefore, extra care needs to be taken during installation and maintenance of a rooftop solar PV system as workers may not be experienced in dealing with working at height.

When assessing the risks associated with working at height and developing control measures, the following hierarchy should be followed:

1. **Avoid:** working at height unless it is essential.
2. **Use existing platforms:** if there is an existing purpose-built platform, then it must be used.
3. **Prevent:** falls by using work equipment that protects all those at risk (e.g., access equipment with guard rails, use mobile elevated working platforms, use scaffolding).
4. **Prevent:** falls by using equipment that protects the individual (e.g., harness with a fall restraint lanyard).
5. **Mitigate:** minimise the distance or consequence of a fall by employing personal protective equipment, fall arrest systems, nets or soft landing systems.

Training, instruction and supervision should be provided to the workforce at each stage of the hierarchy.

A4.6 COMMISSIONING

The commissioning requirements for rooftop PV systems are similar to ground-mount systems. Standards such as IEC 62446: "Grid connection photovoltaic systems—Minimum requirements for system documentation, commissioning tests and inspection" should be used for guidance. Further specific national requirements vary between countries and grid operators.

A4.7 OPERATION AND MAINTENANCE

Fixed solar PV rooftop systems, such as fixed, ground-mounted PV systems, are low maintenance in nature; they have no moving parts and PV modules have a design life of in excess of 25 years. All solar PV systems require some maintenance, which includes regular checks of wiring and components, replacement of faulty modules and inverters and in some cases, module cleaning.

A detailed O&M manual for a rooftop PV system should outline the procedure for carrying out maintenance activities safely at height. There are operational considerations pertaining to the roof space. A problem such as a leak in the roof can be exacerbated due to the difficulty of maintaining the roof integrity with a solar PV system in place. Therefore, the operation and maintenance plan, in combination with the lease, should define responsibilities and procedures for maintenance for the roof space and PV system.

A4.8 ECONOMICS AND PROJECT STRUCTURE

Installing PV systems on rooftops allows a direct feed into a nearby load (often the building on which the system itself is mounted) or fed into the grid. Both have the potential to reduce transmission and distribution losses, thus utilising the rooftop PV generated power efficiently. Because of the ability to offset electricity purchased to supply the building, the system has the opportunity to compete with residential and commercial electricity rates.

A4.8.1 METERING

The electricity generated by a solar PV rooftop system can be exported according to a number of metering configurations, depending on the specific project requirements and power purchase or FiT arrangements. Two common and distinctly different metering arrangements are:

1. **Net metering:** The PV system supplies the building load and exports any excess energy to the grid. When there is insufficient sunlight to generate power (e.g., at night) the building load needs are met by energy imports from the grid. A bi-directional meter is installed to measure and record the net result. If there is a PPA in place for the solar power, a second dedicated meter might be used to record the energy generated and exported by the solar array. "Smart Meters" or time-of-use meters are more commonly being used by retailers and utilities, and determine the value of the energy based on the time of day. If peak demand occurs at the same time as solar generation, smart metering could add value to solar power generated during peak demand times, and this can support the business case for projects.

   Net metering has been controversial in the United States because, though it provides a successful incentive for distributed generation, it ignores the ancillary benefits the transmission and distribution system provide. In countries where the grid operator does not have the option of charging for the benefits of transmission, a net metering scheme may not be wise from a public policy perspective.

2. **Gross metering:** All of the PV generation is exported to the grid. This is common where governments offer a FiT to PV system owners. The building energy requirement is drawn from the grid, and metered separately on regular (non-FiT) rates.

FA4.8.2 FEED-IN TARIFFS (FiTs)

In some markets, governments offer FiT schemes that provide a premium price for solar generation. Often FiT schemes offer a higher premium for rooftop systems over ground-mounted systems, which recognises the additional complexity as well as operational costs of rooftop design and installation. The FiT is usually regulated by government and executed by a government electricity retailer or utility.

A4.8.3 POWER PURCHASE AGREEMENTS

There is the opportunity to sign a PPA with the building user, in which case the system would typically be designed to supply an amount less than or equal to the building load. Alternatively the building owner may also be the system owner and a PPA could be made with an electricity retailer or utility, which would not limit the design system size to the building load.

A4.8.4 LEASE AGREEMENTS

If a third party owns the solar PV system, leasehold with the rooftop owner is required for the project term. The project term is dictated by the project financial business case and is commonly defined in a power purchase

Box 17: Lessons Learned from a 1 MWp Rooftop PV Array, India

As the market penetration of larger rooftop solar PV installations increases, the issues and differences between rooftop PV systems and ground-mount systems become more apparent. The siting, physical integration, interconnection and installation of rooftop PV systems all typically require more detailed field work, analysis, and planning compared to ground-mount systems. Several of the issues may be categorised as follows:

- Siting to maximise generation.
- Roof loading and method of attachment.
- Interconnection.
- Construction requirements.
- Access and safety.

Experience with rooftop arrays in India has yielded solutions to many of these issues.

Siting to Maximize Generation

- Location is often a trade-off as the roofs are not oriented optimally to the solar resource and adjacent structures can shade the array for significant periods of the day. A detailed site visit and measurement of dimensions are required for input into a shading model for the yield analysis. Large periods of shading can significantly alter the economics by reducing yield. Shading models require effort and expertise, but can prevent underperforming installations. Beyond failing to meet profit goals, contractual obligations can come forth where the building owner may not be receiving the output that was warranted in the PPA. An instance was highlighted in a project where shading from a building structure shaded half the array for several months each year. While there was not an easy solution, the energy yield prediction could have identified this.

Roof Loading and Method of Attachment

- The building structure design must be reviewed to ascertain its ability to accept the additional dead weight loads and potential lifting loads of PV arrays during high winds. While there is typically a margin in the roof load capacity, one must consider the individual frames and various sheathing and membrane on which the array will rest. The choice to use a ballasted array versus a mechanically secured frame utilising penetrations avoided concerns of leakage and the need to seek approval for the attachment method from the architect and the roof membrane provider, thereby saving on cost and reducing risk.

Interconnection

- Building power and facility areas are often built with minimal future expansion in mind, and require codes for access and open space. When a PV system must run power conductors via conduit and establish correct disconnects, metering and entrance into the main power panel, the job is often more difficult and requires preplanning and design. While one project had wall space for the correct PV system disconnects, there was no available space on the main panel and a larger panel had to be incorporated.

Construction Requirements

- Rooftop installations require clear and practiced planning for items such as:
  - Any required roof penetrations as the underlying substrate must be known.
  - Conduit runs to the power room and potential to interrupt fire blocks by the conduit installation, and assessing the run to not damage other conduits/services.
  - An outage may be required in the building, and interrupt services.
  - Precautions to protect the roof membrane and related structures.
  - Access for cranes or material lift equipment, including a material storage plan during installation.
- Roof space was tight on one project and this made construction in a small area more difficult. Because the crane was only available for a short period of time, all of the modules were delivered onto the roof space at once. This became problematic as it left very limited room for assembly activities. While there may not have been an alternative, further planning would have been beneficial.

Safety

- Safety is paramount because working at height, working with live modules, and working with high voltages present multiple hazards.
- As with the installation planning, safety is an integral part of any job and the various hazards must be inventoried, reviewed, and discussed with all personal.
- With multiple workers on the roof, various staff were working concurrently on the DC array string wiring. This led to uncontrolled voltage and current rises. Working practices had to be changed to reduce the electric shock risk.

agreement (typically 15–25 years). It is important that the lease terms are well defined and that they ensure:

- All construction activities can be undertaken.
- Solar access is maintained i.e., activities that shade the array are not permitted for the duration of the project.
- Access is granted to the array, inverters, monitoring equipment and electrical balance of plant.
- A clear definition is established for responsibilities and roof membrane impacts and roof maintenance requirements.
- A clear definition is made for what happens at the end of the lease term. The system might be de-commissioned or offered for sale to the building owner.

Legal and technical advisers may be required to ensure the system design is compliant with the terms of the lease. Rooftop solar PV systems are generally designed for a 25–30 year lifetime. The lease should therefore consider the building requirements during this period including re-roofing and maintenance. It should be noted that some module warranties are voided if a PV system is moved, and therefore any plans to move modules should be discussed with the manufacturer to ensure warranty requirements are met.

A4.8.5 THIRD-PARTY LEASES AND LOANS

For smaller residential systems, FiTs, capital grants or simply lower electricity bills might provide economic justification for a system. In global markets, in particular the United States, innovative loan or third-party lease schemes are becoming more common. These schemes can be offered by solar PV system providers, financial institutions or utilities as a means to address the capital cost barrier to homeowners installing PV systems.

In the United States, third-party lease structures are very common. The host does not pay for the electricity produced by the solar PV system, but instead pays a lease payment to a PV system provider. This may be a regular payment, which increases annually, although typically below the rate increase of grid-supplied electricity. The system owner is responsible for capital and maintenance costs and benefits from the lease payments and any tax incentives to achieve an overall savings compared to not having a solar PV system.

The uptake of third-party leases is most successful where the host saves money as compared to paying their normal electricity bill, i.e., in situations where PV generation is at grid parity or has been brought to grid parity[84] via government renewable energy incentives. The system depends on hosts being creditworthy off-takers, and therefore, credit checks are a prudent pre-requisite for the owner when selecting appropriate hosts.

A4.9 CONCLUSIONS

Rooftop solar PV systems offer an attractive option for future development. While using a roof space introduces some degree of complexity to a project, there are also technical and commercial benefits. Commercial benefits for developers include avoidance of land costs, offsetting electricity consumed on site at a higher value than exporting, and the opportunity for an onsite grid connection point.

Consenting timeframes and costs for the project may be reduced due to avoidance of land impact. There are also educational, marketing, and entrepreneurial opportunities introduced by implementing renewable energy at the point of use as well as local job demand.

It is paramount that qualified professionals carry out design work, particularly with regard to structural assessments and energy yield. Waterproofing is an important design and installation consideration for rooftop systems. It is important to avoid negative impacts on roof longevity and existing warranties and insurance. A number of project financing structures and metering arrangements are available which can help to support the business case for rooftop solar PV installation.

84 Grid parity occurs when the levelized cost of electricity is less than or equal to the price of purchasing power from the electricity grid.

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