



TECHNICAL REPORT

FROM SUN TO ROOF TO GRID

The Economics and Policy of Distributed PV

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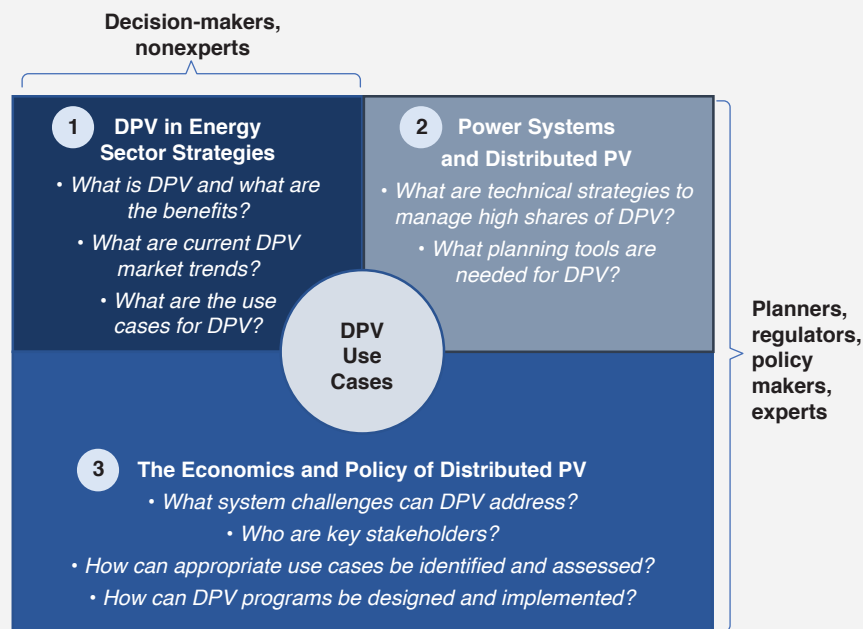
ABSTRACT

From Sun to Roof to Grid: The Economics and Policy of Distributed Photovoltaics explores the benefits, challenges, and risks of DPV, with special attention to the economics of its deployment and its uses for utilities. The challenges addressed include inadequate electricity supply, energy access for low-income groups, natural disasters, decarbonizing the grid, and supply diversification. The report also offers a new paradigm to design policy packages for systems with more decentralized generation. In the new paradigm, DPV facilities can be better promoted by aligning the incentives of various stakeholders and distributing costs and benefits in a fair and efficient manner. The report also discusses the risks of DPV technology, and the means of mitigating them. Finally, it offers a comprehensive analysis of the benefits and advantages of DPV technology.

ABOUT THIS SERIES: FROM SUN TO ROOF TO GRID

This report is the third in the series “From Sun to Roof to Grid” on distributed photovoltaics (DPV), the world’s fastest-growing local power generation technology. For the purpose of these series of reports, DPV is defined broadly as PV systems located close to the consumers of the electricity being generated, with a focus on grid-connected consumers.¹ The series, produced by the World Bank’s Energy Sector Management Assistance Program (ESMAP), is for the benefit of various stakeholders—from policy makers to regulators and utilities—and provides a comprehensive, structured approach for distribution utilities to plan the development of the DPV sector. It offers a menu of ideas, approaches, and examples for deploying DPV and bringing its benefits to a variety of stakeholders, distribution utilities in particular. The plan behind the series is depicted below.

RELATIONSHIP OF REPORTS AND INTENDED AUDIENCES OF THE SERIES



The series aims to show stakeholders how to fully leverage this low-cost, easy-to-install modular technology, whether in a large, stable power system or in small systems like those found on islands or in regions marked by fragility, conflict, and violence.

The first report of the series, “Distributed PV in Energy Sector Strategies” (ESMAP 2021), introduces nine distinct use cases, or applications, of DPV to address challenges in different low- and middle-income

¹ DPV systems may be connected to a distribution grid or connected to grid-connected consumers. In other words, they can be located on the grid side or the consumer side of a consumer’s grid connection point. The definition of DPV used in this series of reports does not imply a minimum or maximum capacity. Off-grid installations, that is, for consumers or facilities with no grid connection, are not the focus of this report, even though they are distributed. The report series does, however, consider grid-tied DPV installations that may be “islanded” to become temporarily independent of the main grid, as well as off-grid PV installations that may have the potential to become tied to the grid within their economic lifetimes.

country contexts; it is aimed at energy ministries and other decision-makers. Technical challenges and solutions for grid-friendly DPV from a power system perspective are covered in the second report of the series, “Power Systems and Distributed PV” (ESMAP 2023), which covers the technical regulations (grid codes, including connection standards).

This third report, “Distributed PV Economics and Policy,” completes the series, covering key considerations for developing a program or policy package with DPV. Building on the content of the other two reports, it focuses on the economics and regulation of DPV. Chapter 1 outlines three key steps for designing and implementing a program that includes DPV. Chapter 2 delves into the first step: how to identify suitable use cases for a given country context and DPV market status. Chapter 3 details key elements of designing a program that includes DPV, and chapter 4 outlines how to implement such a program.

Together, these reports (and their key messages for different stakeholders) aim to enable low- and middle-income countries, consumers, and utilities to harness power from the sun.

It is worth noting that life-cycle issues and agrivoltaics are out of the scope of the series.

For more information, visit www.worldbank.org/energy and www.esmap.org.

ACKNOWLEDGMENTS

This report is an activity of the World Bank’s Energy Sector Management Assistance Program (ESMAP). The main authors are Thomas Flochel, Leonardo Lupano, Vivek Mishra, and Mohua Mukherjee. The report series has been led by Alan David Lee, Zuzana Dobrotkova, and Thomas Flochel, with supervision support from Christophe de Gouvello. For this report, many individuals and partner organizations contributed content and/or review suggestions. These include: World Bank staff and consultants—Abhinav Goyal, Ashok Sarkar, Bill Gallery, Claire Nicolas, Daron Bedrosyan, Jeremy Levin, Luis Maurer, Monali Ranade, Oliver Knight, Pierre Audinet, Sandra Chavez, Silvia Martinez Romero, Simon Müller, Tarek Keskes, Tatyana Kramskaya, Torrey Beek, and Tu Chi Nguyen; Toby Couture (E3 Analytics); US National Renewable Energy Laboratory—Owen Zinaman, Nate Blair, Francisco Flores-Espino, Julieta Giraldez, Adarsh Nagarajan; Rocky Mountain Institute’s James Sherwood. Management guidance was provided by Demetrios Papathanasiou, Gabriela Elizondo Azuela, and Rohit Khanna. Steven Kennedy and Fayre Makeig provided copy-editing. All views expressed and any shortcomings are those of the authors.

KEY MESSAGES

When designed and implemented properly, DPV can yield substantial benefits for utilities, consumers, and the economy as a whole. As a rapidly deployable, modular source of clean electricity with low operating costs, it can lower consumers' electricity bills, make their power supply more reliable, and potentially also provide a backup for the grid in the event of outages. Managed well, DPV can help meet major power system challenges, starting with the high costs of production, supply, and network expansion. It can also compensate for shortages of system services. Finally, it can be a good way to cater to customers with low payment ability or discipline.

Successful DPV programs can take several forms. They may be scaled up from unplanned, consumer-initiated deployments (bottom-up), centrally planned (top-down), or likely a combination of both. But any program designed to include DPV must consider many aspects of power system planning and operation.

Policy packages and programs to promote DPV should also consider other distributed energy resources. These include demand-side energy efficiency, demand-response mechanisms, and storage modalities (including electric vehicle charging, smart metering, and digital technologies), as well as complementary schemes to ensure social inclusion and affordability for underserved and low-income consumers.

When paired with other distributed resources, DPV systems can help people in low- and middle-income countries by lowering electricity bills, by being a better backup power source than diesel generators, and by providing reliable power for productive uses.

DPV's benefits for utilities are many. Chief among them are the supply of least-cost generation to the grid, especially where land is scarce; the possibility to defer certain transmission and distribution upgrades; the ability of underperforming utilities to rapidly improve service (especially in order to retain high value customers) and increase bill collection; the provision of so-called ancillary services that enable the grid to better integrate electricity from distributed sources; and the fulfilment of urgent needs following a disaster using a preassembled kit of PV panels and batteries.

Energy sector decision-makers must determine which use cases make sense in their context. Respective use cases can be implemented with a variety of business models, whereby the beneficiaries (consumers and/or utilities) compensate investors (consumers, developers, or utilities) through appropriate financing terms. Successful schemes can be replicated to develop a self-sustaining market.

Three types of business models have emerged. They are based on which agent drives DPV promotion: customers, a third-party service provider, or the utility. Each has pros and cons and will suit some use cases better than others depending on the state of DPV deployment and market maturity. All three can co-occur in a given market.

The first two models are well established, whereas the utility-driven model is relatively new. Yet utilities have distinct advantages for achieving economies of scale, allocating project risks appropriately, raising funds at relatively low costs, and using DPV to resolve technical issues rather than creating them.

Coordination among consumers, developers, and utilities—in partnership with governments, planners, and financiers—can help identify and exploit synergies to multiply the benefits of DPV markets. Under the first two models, power system regulators and governments can help ensure that DPV deployment is attractive to consumers, grid friendly and does not erode utility revenues. Financiers must often be helped to understand the market opportunities for DPV, so as to ensure that affordable financing to leverage such opportunities is available in low- and middle-income countries. Policy stances—such as clear strategic objectives for the deployment of DPV (and other distributed energy resources), associated targets, and nimble program administration—are essential and depend on government leadership.

Policies for DPV should foster an effective market while retaining the flexibility to evolve. It is important for the government to raise awareness of its objectives and the policies designed to support them. Preparing a policy package to foster the development and expansion of DPV markets to achieve policy objectives requires identifying the right legal, regulatory, commercial, and informational tools; considering the package's links to power system planning and operation; engaging stakeholders; and implementing rigorous monitoring and evaluation procedures. A timeline of milestones for each stakeholder can be helpful in coordinating stakeholders as a group and keeping them advancing toward policy objectives.

Regulation, backed by system and project-level analysis, is key to guiding the growth of DPV markets. Besides setting technical standards for equipment and specifying requirements for connection with the distribution system, regulation must consider how to meter, price, and bill DPV schemes. Governments may supplement pricing schemes with incentives, subsidies (for lower-income consumers, for example), and fiscal measures.

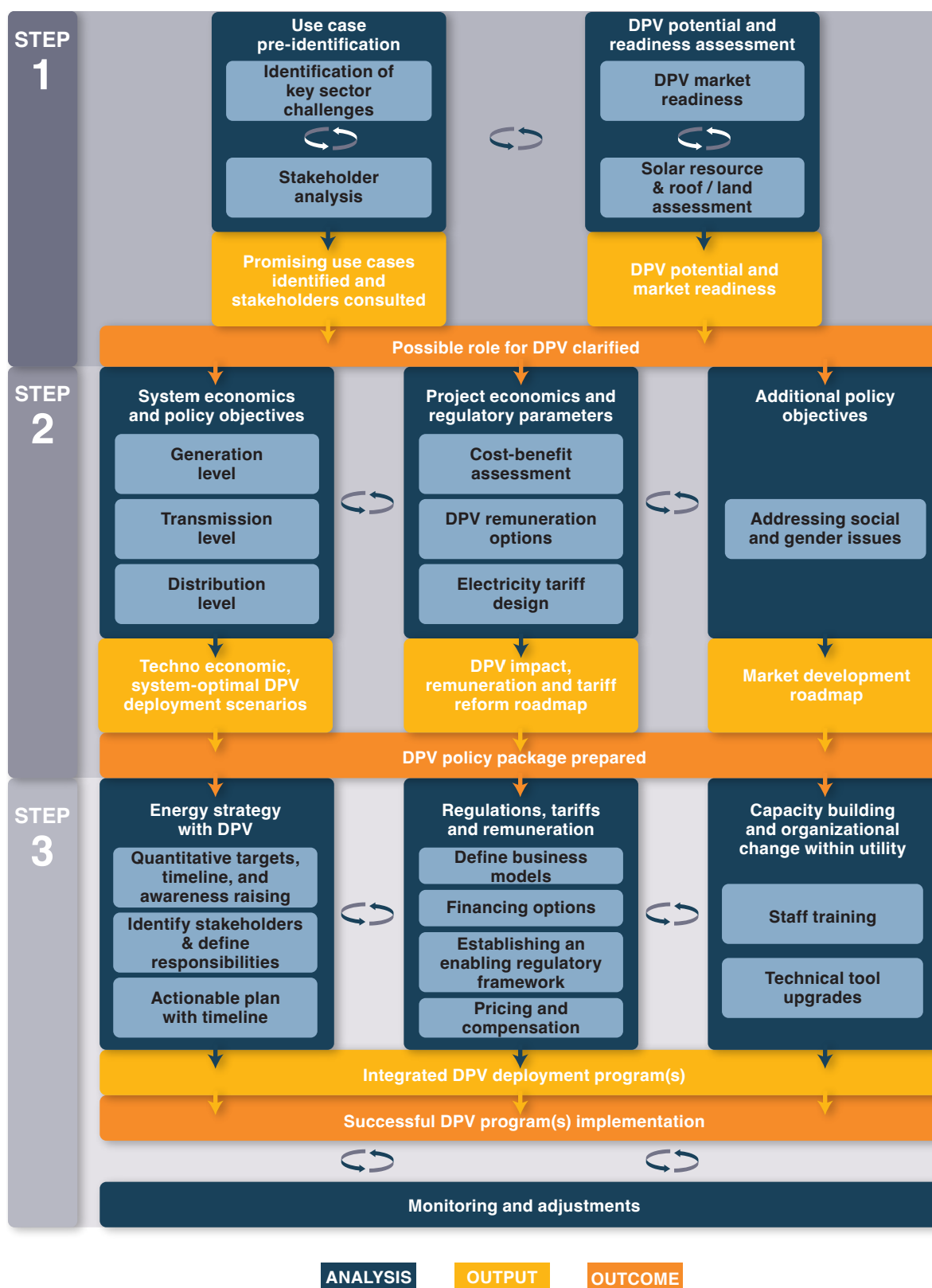
The choice of the grid feed arrangement applicable to DPV systems is a critical part of program design. DPV systems can be set to feed all, some, or none of their energy output to the grid. The choice has important technical, economic, and policy implications, especially for remuneration and pricing schemes. For example, “feed-all” DPV arrangements can make it possible to offer cost savings to consumers not directly connected to a DPV system—savings that would otherwise be available only to consumers with on-site DPV. For “feed-some” arrangements, early proponents of DPV used net metering to kick-start markets, counting on consumers’ desire to lower their electricity bills. However, there is now a trend toward gross metering (accompanied by net billing) owing to the flexibility it provides in setting compensation rates independently of retail consumption rates.

Irrespective of the feed arrangement that is used, investments must provide a clear, stable, and attractive return for project proponents, and consumers and utilities must share in the benefits. DPV power fed into the grid may be compensated in a variety of ways, either by the utility or by other consumers. In designing pricing and compensation schemes, consumers’, developers’, and utilities’ interests must be balanced to ensure a fair distribution of risk, benefits, and costs, in particular legacy network costs and future investments.

Because DPV markets can change quickly, implementation mechanisms must include adequate monitoring and evaluation, as well as the flexibility to change course if developments diverge from defined program objectives.

The entity responsible for integrating DPV within the national energy supply chain must be identified from the outset and given the expertise, as well as the legal and budgetary power to carry out its brief. The same entity should also be responsible for tracking stakeholders’ achievements, assessing their performance, and providing feedback for appropriate course correction.

Implementation includes other important aspects. Notable examples are (1) promotion of R&D; (2) education and training of energy planners, regulators, transmission system operators, and technical staff; (3) acquisition of equipment for billing and monitoring; (4) continuous tracking of markets and technology trends; (5) safe disposal of DPV systems after they have exceeded their useful life; and (6) opening markets for the services that small-scale resources such as DPV can provide. With respect to the last point, because transmission system operators generally operate with a small number of large-scale resources, it can be challenging to manage a large number of small and agile resources scattered over the grid. Encouraging small-scale providers of varied services will require fair market compensation for new entrants.



INTRODUCTION AND CONTEXT

Power systems around the world are being irrevocably changed by the generation technology known as distributed photovoltaics (DPV), thin and modular solar photovoltaic (PV) cells that can be installed in myriad ways on or near electricity consumption points. This distinguishes them from other power generation technologies that have large space requirements and transmit energy over long distances to consumers. DPV systems of up to several megawatts (MW) can be installed on rooftops, as canopies above irrigation canals or car parks, or in floating arrays on industrial ponds. Solar cells are even being integrated directly in construction materials such as window glass, roof tiles, and the surfaces of sidewalks and highways. In fragile and conflict-affected regions, DPV systems are growing as a power source more resilient to attacks and political instability than traditional central grid infrastructure. DPV (with battery storage) can offer a low-carbon alternative for system expansion to cover future demand growth (IFC 2019).²

These transformations imply new challenges such as massive penetration of intermittent renewables, bidirectional power flows, and a need for daily or seasonal storage. To add to that, the power sectors of emerging economies continue to grapple with well-known issues such as subsidized tariffs, high losses, and incorrect economic signals, among others. While these last aspects are not caused by DPV, they affect the possibility of this technology's development (i.e., subsidized tariffs are a hurdle for DPV development).

DPV poses technical, legal, regulatory, and commercial challenges—while offering opportunities as well. This document intends to answer the key questions that arise when deciding to implement DPV to maximize benefits and eliminate barriers that some stakeholders may perceive. This document provides insights on the following issues:

- Who makes decisions regarding DPV development and then its control (monitoring development and limiting it if necessary)?
- How can different business models for DPV deployment be characterized?
- What do the economics of DPV look like? What are the costs? What are the benefits?
- Who bears the costs and who appropriates the benefits? How can distributional impacts be managed?
- Will the distribution utility be remunerated for the entire infrastructure that is made available when DPV is implemented? How will they be remunerated?
- Will DPV users receive a fair price for the energy they inject? Will they pay for the real cost to the system?
- Distribution companies (discoms) and DPV users are the key actors; how can they be assigned roles that ensure a win-win situation?

² Three and a half billion people live without reasonably reliable access to energy, according to Ayaburi et al. (2020).

- What are the cases for subsidies, and what are the alternative financing models that exist?
- What are the key options for electricity pricing for consumers with DPV and for compensating for power fed to the grid?
- What are the training and capacity-building requirements for discoms operating DPV systems, for private firms seeking to participate in implementation, and for public institutions responsible for standard setting, quality control, and regulation?
- How does DPV concern jobs, social inclusion, and social protection, including from a gender perspective?
- What is (are) the legal, policy, and commercial framework(s) that need(s) to be implemented for the desired DPV development?

OVERALL PLAN OF THE REPORT

From Sun to Roof to Grid: The Economics and Policy of Distributed PV has been prepared for policy makers, regulatory authorities, utilities, and energy experts. The report provides guidance on cases where DPV can provide a full or partial solution to existing challenges, the economics and impacts of its use for utilities, and possible business models and their implications.

Policy makers will benefit from the report's examination of how DPV can address challenges such as inadequate electricity supply, energy access of low-income groups, natural disasters, and supply diversification. It also highlights a new paradigm for planning system expansion with more decentralized generation.

Regulatory authorities will find guidance on the challenges they need to address (and possible solutions) to maintain utilities' financial sustainability, while promoting DPV facilities by aligning the incentives of various stakeholders and distributing costs and benefits in a fair and efficient manner.

Utilities will benefit from the reports' explanation of the risks of DPV technology, and the means of mitigating them, as well as beneficial business models.

Finally, energy experts can find a comprehensive analysis of the advantages of this technology, the challenges it may address and the benefits it may bring, and ways to mitigate any negative impacts.



Photo description

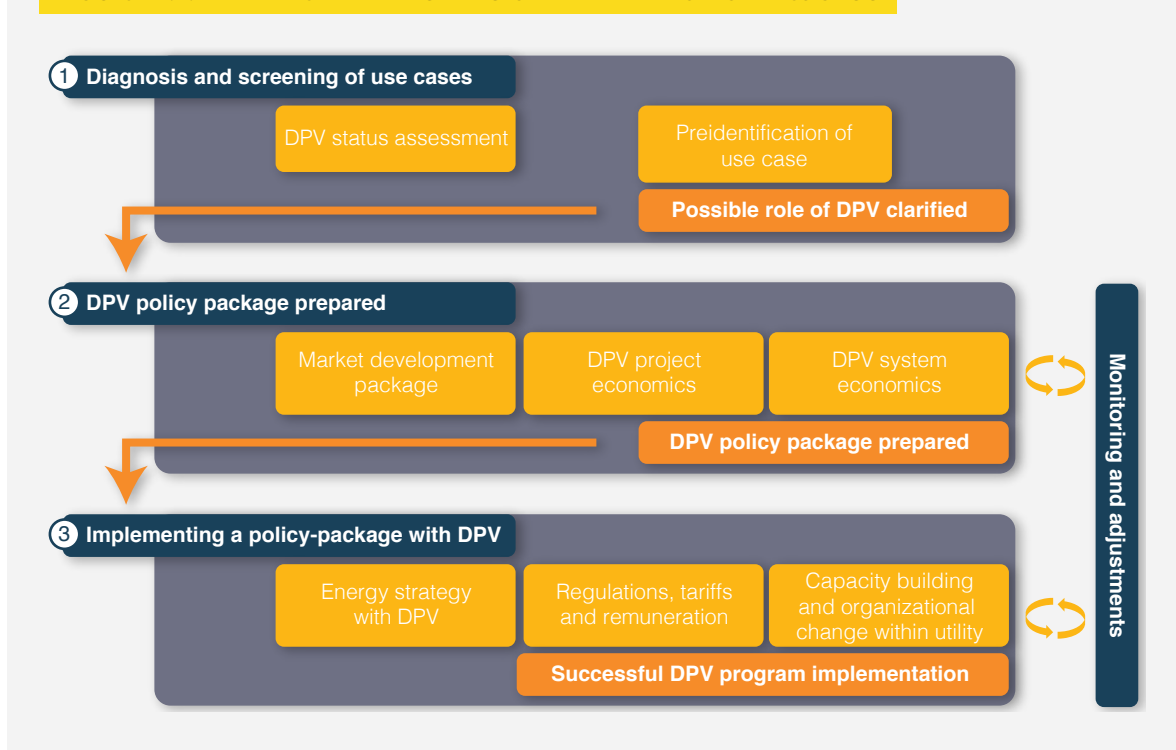
THE THREE MAIN STEPS OF THE DPV POLICY PROCESS

The three main steps outlined in this report are:

1. Diagnosis and use case screening (Step 1),
2. Preparing a policy package with distributed photovoltaics (DPV) (Step 2), and
3. Implementing a policy package with DPV (Step 3).

These steps build on one another but include distinct priorities in terms of analysis, process, and stakeholder involvement (Figure 2.1).

FIGURE 2.1: THE THREE MAIN STEPS OF THE DPV POLICY PROCESS



Source: Original compilation.

Note: DPV = distributed photovoltaics.

STEP 1: DIAGNOSIS AND USE CASE SCREENING

The first step outlined in this report is diagnosis and use case screening, whose objective is to determine DPV's possible role in meeting energy sector targets. For this, it is necessary to:

1. Preselect DPV use cases that are appropriate for meeting energy policy objectives, and
2. Obtain a systematic picture of DPV's potential and overall market readiness.

In the first report of this series (ESMAP 2021), nine use cases have been identified through which DPV can offer distinct solutions to specific issues. The use cases represent value propositions for DPV that may stand alone or be combined with other use cases and other distributed energy resources.

Output from Step 1 should consist of:

1. Identifying promising use cases and relevant stakeholders through a preidentification of use cases;
2. A clearer picture of the relevant stakeholders for the policy and program design process; and
3. An overview of the DPV market, along with an initial assessment of DPV's technical potential for evaluating market readiness and potential.

STEP 2: PREPARING A POLICY PACKAGE WITH DPV

Assessing DPV's potential and its market readiness can be useful when calibrating the level of ambition for DPV deployment. It also provides important information on the baseline against which additional market development policies need to be implemented. The assessment should be performed from two angles, elaborated on below.

System economics and policy objectives. Analysis of DPV systems' economics helps understand DPV's potential contribution to the energy system as a whole. The results of the analysis are usually summarized in a dedicated report that compares total system costs for different scenarios (with/without DPV and different levels of DPV penetration).

Project economics and regulatory parameters (microeconomics). The economic effects of DPV at the system level are quantified based on technoeconomic modeling. Project-level economics are best understood by considering retail tariffs, possible tariff changes, and remuneration of a DPV grid. The likely effects on various power system stakeholders—especially the utility and retail customers investing in DPV to lower their electricity bill (and possibly incurring debt-service costs on a commercial loan)—must be assessed as well. Once these assessments are complete, governments can set a specific DPV deployment path. The path should include an appropriate model for DPV remuneration and possible changes to end-user pricing, as well as technical and economic regulation. Other policy goals should also be included in the analysis—notably the protection of vulnerable populations, which will require addressing the issues of affordability, access to finance, and gender.

Output from Step 2 should consist of:

- A market development road map highlighting the steps for removing DPV deployment barriers;
- Concrete and actionable recommendations for utility incentives, reforming electricity tariffs, and remuneration for DPV; and
- DPV deployment pathways across different scenarios, backed by robust analysis.

STEP 3: IMPLEMENTING A POLICY PACKAGE WITH DPV

There are three broad implementation areas: strategic actions, core policies for DPV deployment, and skill and capacity building.

Concerning strategic action, there is a need to set clear, credible, and feasible targets, which will form a valuable foundation for the practical implementation of DPV policy packages.

Regarding DPV deployment policies, the different potential businesses and the available financing options must be analyzed. The enabling framework for achieving DPV implementation targets must be prepared and approved based on an assessment of business models and their financial viability. This includes investment to upgrade the last-mile distribution network, which was designed and built for one-way electricity flow. Hosting DPV, which will occasionally feed surplus generation back to the grid, requires certain technical upgrades and grid enhancement. Securing a utility's cooperation in promoting a DPV program will require determining how these upgrades and enhancements will be paid for. Reliance on tariff hikes for nonsolar users to pay for grid upgrades (needed by solar users) should be avoided.

It is essential to assess the skill and capacity building need of utility staff transitioning into two-way power flows resulting from hosting DPV on the last-mile network. It is especially crucial to evaluate the need for staff training and identify the technical and/or billing tools that may require upgrades.

The output of Step 3 is an integrated DPV deployment program based on the three broad implementation areas mentioned above. The main outcome is the successful implementation of DPV programs.



Photo description

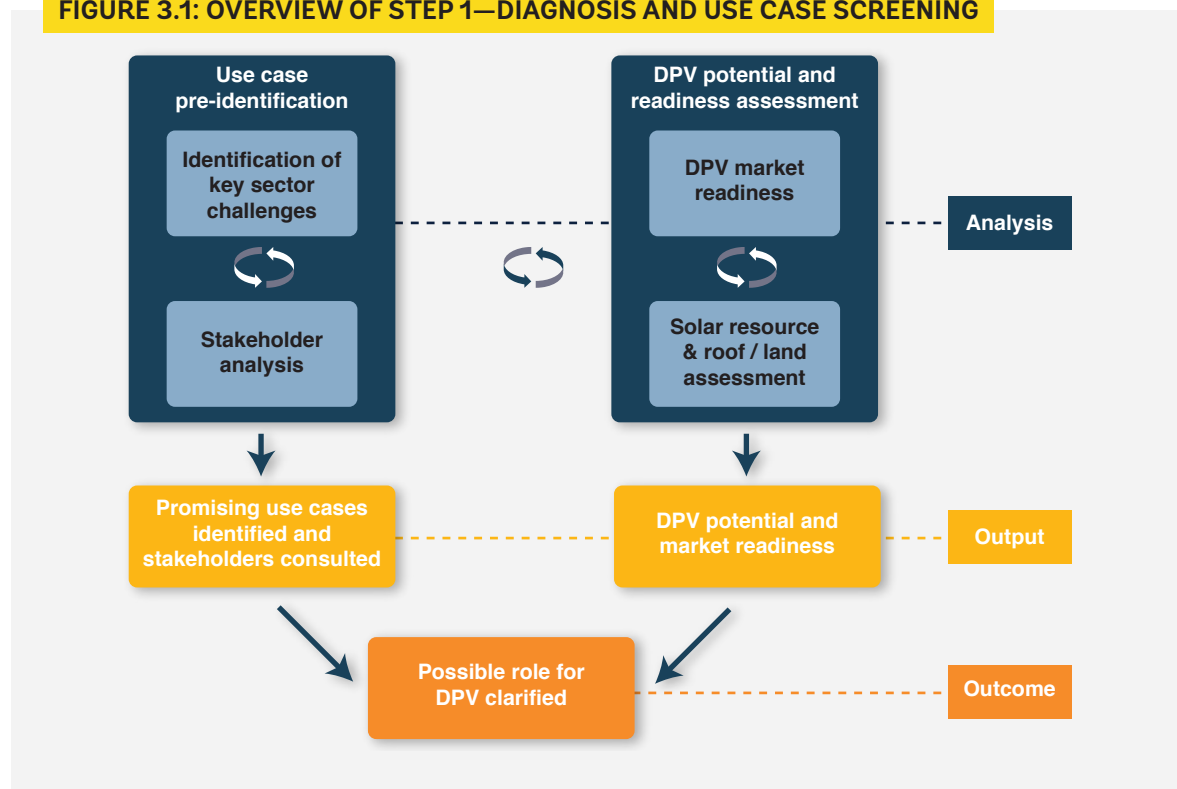
STEP 1: DIAGNOSIS AND USE CASE SCREENING

The objective of this step is to clarify distributed photovoltaics' (DPV's) possible role in meeting energy sector targets (Figure 3.1). In turn, this requires:

- Preselecting DPV use cases that are appropriate for meeting energy policy objectives, and
- Obtaining a systematic picture of DPV's potential and overall market readiness.

This step will likely be performed by a public body such as an energy agency or via a consultancy firm commissioned by the government or an international donor. Its aim is to establish a baseline against which policy makers can then design and implement a DPV policy package in the subsequent steps. As such, the analyses conducted at Step 1 should provide a comprehensive overview rather than exploring specific issues in detail.

FIGURE 3.1: OVERVIEW OF STEP 1—DIAGNOSIS AND USE CASE SCREENING



Source: Original compilation.

Note: DPV = distributed photovoltaics

Depending on available data and the amount of existing analysis, this step may involve summarizing available material in the simplest case or require substantial research. For example, data collection and analysis are required when there is little systematic information on the financial health of the electricity sector and its main challenges.

For preselecting use cases, this chapter provides guidance on the energy sector challenges and opportunities that DPV can address and the stakeholders that are likely relevant in the DPV policy process.

USE CASE PREIDENTIFICATION

DPV can be deployed in different technoeconomic setups (or use cases). The first report of this series (ESMAP 2021) contains a more detailed introduction of the various use cases, while Table 3.1 briefly summarizes them. The analysis in this step is to identify use cases that merit further analysis and policy

TABLE 3.1: USE CASES FOR DPV

<i>Use case</i>
1. Bill reduction (common) Distributed photovoltaics (DPV) can help consumers keep electricity bills affordable by displacing electricity that would otherwise be purchased from the grid.
2. Least-cost backup (common) Consumers facing grid electricity outages have DPV systems, typically with batteries, to provide improved service while forgoing the costs of and the dependence on fuel for backup generators.
3. Least-cost generation (emerging) DPV may be consistent with least-cost generation planning, especially in places with land constraints, given the short timeline for installation and low levelized cost of electricity.
4. Transmission and distribution alternative (emerging) DPV helps avoid or defer more costly power-line expansion or installation of new power lines (nonwire alternative).
5. Utility bootstrap (opportunity) A utility installs DPV with batteries and/or backup generators to improve service for a targeted set of consumers as part of a strategy to build trust and increase bill collection.
6. Ancillary services (opportunity) DPV, especially in combination with inverters and batteries, can provide a range of services to the grid such as frequency regulation and voltage support.
7. Community social support (emerging) Medium-to-large DPV systems are installed at suitable sites for the benefit of low-income communities.
8. Financial loss reduction (emerging) DPV can be used to reduce the load of customers with chronic arrears.
9. Box solution (common) A preassembled DPV system, typically with a battery or other backup, can be installed quickly and easily and address urgent power needs, for example, when the grid becomes unavailable following a disaster.

Note: Common = use case has been deployed in several countries at scale; emerging = several countries have recently implemented or are considering implementing the use case; opportunity = cost-effectiveness has been established in initial countries and implementation is underway; medium-term opportunity = can provide net benefits in principle, but there are only demonstration projects currently.

attention in the subsequent steps. Most likely, multiple use cases will be identified. Which use case can help meet energy sector targets, critically depends on the challenges faced by the sector.

Identification of Sector Challenges

Many attributes of developing countries' power sectors present opportunities to increase the appeal of DPV, both as a box solution and to supplement insufficient grid supply (Foster and Rana 2020). In many developing countries, utilities serve only a fraction of the potential market, with electrification rates occasionally as low as 10–20 percent, and more typically in the 40–60 percent range. Grid extension tends to require a distinct regulatory mandate and/or public financing to be viable for a utility. Even when service is available, it is often highly unreliable, with frequent interruptions, leaving consumers to rely on their own backup generation alternatives, which have traditionally been diesel based. Most national power utilities in developing countries are in weak financial situations due to operational inefficiency, including significant technical and nontechnical losses.³

While there exist differences among power systems, it is possible to identify certain basic sector challenges that apply across a wide set of developing country contexts. This simplified categorization can be useful to guide more detailed analysis. Consequently, this report distinguishes seven sector challenges (see Figure 3.2).

For the purposes of this chapter, the terms *distribution company*, *electric generation company*, and *vertically integrated utility* (or “utility”) will be used (see the glossary for the differences between them).

Table 3.2 presents an overview of the type of data⁴ and analytical requirements for different system challenges and opportunities and proposes which use case is most applicable for addressing a challenge or opportunity.

Stakeholder Analysis

Stakeholder engagement is integral to all stages of policy and program processes. For DPV, inclusive processes are especially important given the distinct set of stakeholders involved with the technology (Figure 3.3). Political economy analysis may help identify potential points of resistance and hidden concerns and opportunities to effectively address them in program design.

Several stakeholders play important roles in creating the DPV ecosystem. They include the government, as mentioned, which provides the requisite political support (including policy and subsidy support, if needed); regulators, which facilitate the evolution of business models through an appropriate regulatory framework and remuneration; the distribution utility, which facilitates the seamless connection of DPV systems with its distribution systems; the community of qualified rooftop installers; the industry, which develops the value chain; and, finally, financial institutions, which aid in arranging the required funds and design appropriate financial instruments. More on the typical roles and responsibilities of different stakeholders, guidance on defining a time-bound actionable plan and communicating it can be found under Step 3.

3 Of the 31 Sub-Saharan African countries that publicly reported annual transmission and distribution losses between 2010 and 2015, more than half had losses greater than 20 percent of annual generation (Power for All 2019).

4 Data quality and availability determine this step's time and resource requirements. Where data on tariffs, system costs, and the balance sheets of utilities are accurate, up to date, and accessible, a summary of available material will be sufficient to select the most promising use cases. Where this is not the case, data collection and analysis will require dedicated studies with the associated resource and time requirements.

FIGURE 3.2: SEVEN SECTOR CHALLENGES



Note: DPV = distributed photovoltaics.

Utilities, of course, are a crucial group of stakeholders. Throughout this report, utilities have received special focus as grid operators, producers, and retailers that can be impacted (positively or negatively depending on the case) by DPV generation. A section dedicated to “Impacts of DPV on the utility” can be found under Step 2.

DPV users are an equally important group of stakeholders.⁵ Ultimately, they must perceive a benefit and have the instruments to allow DPV deployment. For this reason, the report also focuses on the business models, incentives for, and the roles of this group.

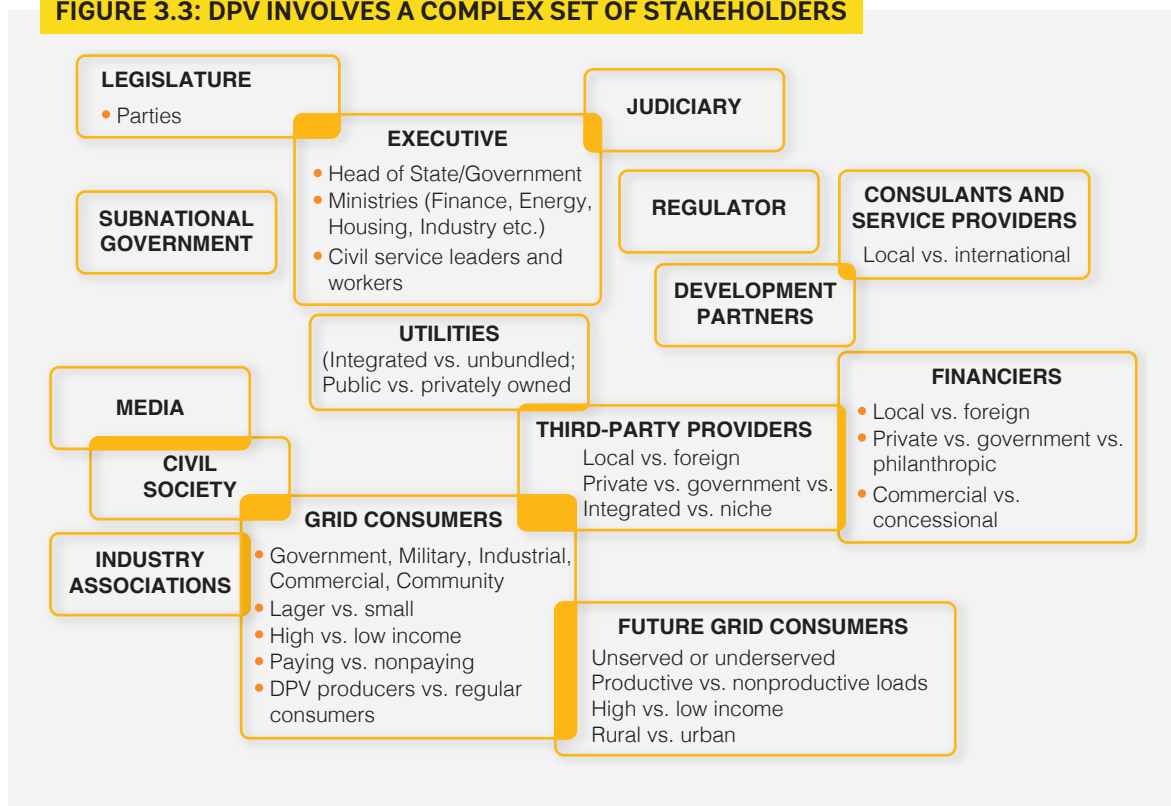
⁵ In this report, the term “DPV user” means a client of a DPV facility, or a consumer.

TABLE 3.2: LINKS BETWEEN SYSTEM CHALLENGES, ANALYTICAL REQUIREMENTS, AND USE CASES

CHALLENGE: QUICK CHECK	DATA AND ANALYTICAL REQUIREMENTS FOR BASELINE ANALYSIS	USE CASE
Revenue loss: Financial viability issues since revenues do not recover the costs of supply	System focused: Cost of service study including the financial health of sector stakeholders (utilities); assessment of technical and nontechnical losses; tariff structures for customer groups, including exemptions and regional differences; generation costs (CAPEX, O&M, fuel); benchmarking with similar countries; affordability of tariffs and subsidies.	5) Utility bootstrap 7) Community social support 8) Financial loss reduction
High cost of production: Grid electricity expensive to produce centrally compared with peer countries	System focused: Assessment of short-term generation costs—fixed and variable O&M costs, fuel costs, costs due to technical and commercial losses, and financing costs. Assessment of long-term costs—CAPEX (LRMC) for new generation and transmission, O&M costs, fuel costs, and costs due to losses.	3) Least-cost generation 5) Utility bootstrap
Transmission and distribution cost: for example, land constraints, long project development times, high technical losses	Infrastructure focused: Review of existing and planned T&D projects and costs.	4) Transmission and distribution (T&D) alternative
Power supply quality: Grid electricity unreliable or unavailable; diesel backup expensive or insecure	Customer focused: Multitier framework for energy access assessment, where applicable—system analyses, SAIDI/SAIFI statistics, customer surveys, market data for backup generators, fuel price and consumption statistics (as available), “willingness to pay” studies	2) Least-cost backup 5) Utility bootstrap 6) Ancillary services 9) Box solution
High grid supply cost: Grid electricity expensive relative to self-generation or peer benchmark	Customer focused: Tariff structures by customer groups, including cross-subsidies, subsidies, exemptions, and regional differences.	1) Bill reduction 7) Community social support
System services: Systemwide frequency and voltage quality	Analysis of historic performance, power system, and stability.	6) Ancillary services

Note: System adequacy issues such as future potential network-adequacy-related issues are treated in the second report (ESMAP 2023). CAPEX = capital expenditure; LRMC = long run marginal cost; O&M = operation and maintenance; SAIDI = System Average Interruption Duration Index; SAIFI = System Average Interruption Frequency Index; T&D = transmission and distribution.

FIGURE 3.3: DPV INVOLVES A COMPLEX SET OF STAKEHOLDERS



Source: Original compilation.

Note: Many actors share links that are not shown in this arrangement. DPV = distributed photovoltaics.

Output: Promising Use Cases and Relevant Stakeholders Identified

The output of this step is a preidentification of promising use cases—based on the identified system challenges and opportunities—and a clearer picture of the relevant stakeholders for the policy and program design process. The results are ideally summarized in a dedicated report or slide deck that identifies the system challenges that DPV is well suited to address and the actors that should be involved in a subsequent step.

DPV'S POTENTIAL AND MARKET READINESS

DPV's possible role in meeting energy sector targets also depends on the country-specific solar resource potential and the DPV market's maturity.

DPV Market Readiness

Several indicators can be used to assess market readiness for DPV deployment. These can be, for example, the ease with which consumers can apply for and install a system, the credit rating of the distribution company,

the quality of the consumer experience, and the time from application to installation. Given below is a list of additional indicators for obtaining a picture of DPV market maturity:

- **Deployment levels.** Historic and current deployment levels can provide a quick, high-level overview of where DPV currently stands and how its market has been developing. The applicability of this indicator critically depends on the quality and segmentation of deployment statistics.
- **System costs.** The cost of installed DPV systems can provide an aggregate assessment of the maturity of the DPV supply chain, from equipment sourcing and financing to installation. Elevated system costs—compared with international benchmarks—can indicate deployment barriers that need to be clearly identified and addressed as part of policy and program design.
- **DPV developer survey.** Interviews with DPV developers can provide further insights into the ease of project development. A particularly important aspect in this area is the ease of obtaining permits and a grid connection for DPV projects.
- **Assessment of related industries.** Where the DPV market is entirely undeveloped, an assessment of related industries—notably, large-scale PV or installers of backup power supply systems—can provide valuable insights on relevant barriers.
- **Capable technical staff.** A relevant number of technical staff capable of not only installing but also maintaining DPV systems, eventually with registers of authorized technical staff, provides an indication of market readiness.

A good example can be found in India. The State Rooftop Solar Attractiveness Index (“SARAL,” which means simple)—convened by the national government (MNRE 2019)—combines 34 indicators across policy and market parameters (Figure 3.4). Each indicator is assigned a different weight based on extensive nationwide stakeholder consultation. The government has used the index to assess 31 states, which are assigned scores in the range of 14–79 out of 100.⁶ The single most influential indicator for SARAL is the ease with which consumers can apply for and install a system.

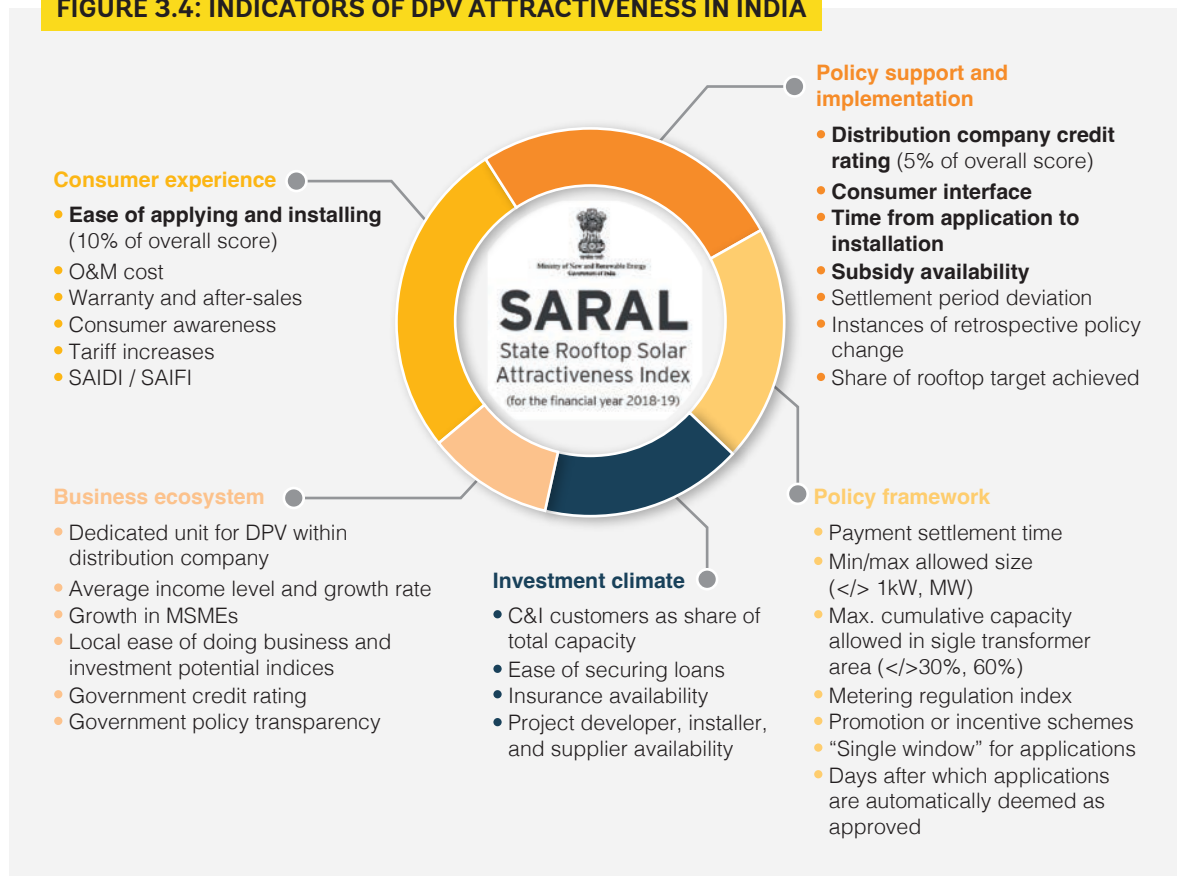
Solar Resource and Rooftop Potential

DPV resource potential depends on two principal factors: the quality of the solar resource and the suitable roof surface area available. The first factor is becoming less relevant with a decline in PV module costs and an increase in their efficiency. The second factor could be more complex since it may involve different variables. DPV deployment constraints may differ between developing and developed nations, notably because of the quality of building stock. Existing buildings may not be capable of supporting the weight of larger rooftop installations. Ground-mounted installations could be an alternative. More in-depth analysis of building stock, useful rooftop space, and available land space is thus needed when preparing plans. Geospatial analysis could help estimate these variables through a set of useful tools for policy makers and other stakeholders, as presented in Box 3.1.

While rooftops are an excellent surface for installing DPV systems, the technology is not limited to rooftop systems. For example, the community solar use case typically relies on a larger system, which can also be ground mounted, preferably with a nearby distribution transformer for low-cost connection to the grid (urban

⁶ Top performers in 2019 included Karnataka, Telangana, Gujarat, and Andhra Pradesh.

FIGURE 3.4: INDICATORS OF DPV ATTRACTIVENESS IN INDIA



Source: Adapted from MNRE (2019).

Note: C&I = commercial and industrial; DPV = distributed photovoltaics; kW = kilowatt; MSME = micro, small, and medium enterprise; MW = megawatt; O&M = operation and maintenance; SAIDI = System Average Interruption Duration Index; SAIFI = System Average Interruption Frequency Index.

ground-mounted DPV is suitable provided adequate security is available for the DPV systems and other uses of the identified vacant urban land, for example, recreation, play areas, outdoor meetings/classes, and weekly markets, are not displaced). Agrivoltaics (deploying solar panels next to crops) have not been included in the scope of this report.

Output: DPV Potential and Market Readiness

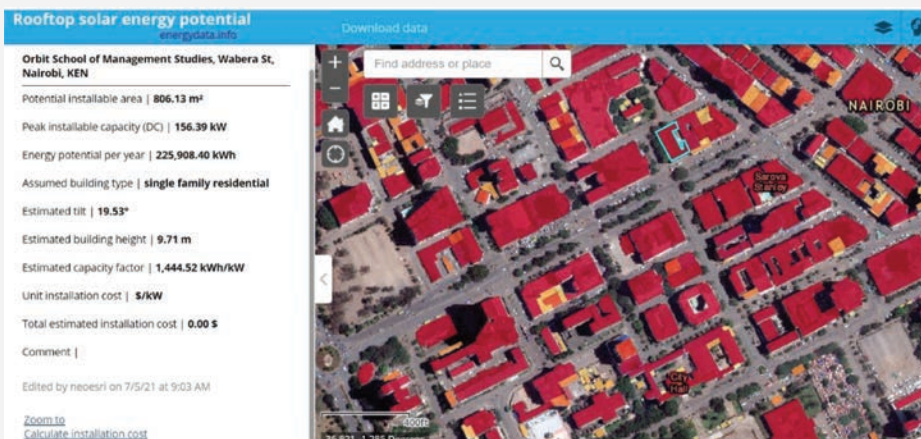
The output of this step is a general overview of the DPV market, along with an initial assessment of DPV's technical potential, which strives to include—as far as possible—aspects such as the structural quality of roofs in the building stock. The results are summarized in a dedicated report or slide deck that presents the basic market data, the most important barriers and challenges, and data on DPV's technical potential. It is worth mentioning that the Energy Sector Management Assistance Program's solar rooftop potential mapping tool (World Bank, ESMAP, and Solargis n.d.), launched in 2017, provides a free web-based solution to help investors and policy makers identify potential sites for solar power generation virtually anywhere in the world. The tool is thus key for evaluating DPV's potential and market readiness.

BOX 3.1

ESMAP's Rooftop Solar PV Mapping Tool

The Energy Sector Management Assistance Program's (ESMAP's) Rooftop Solar PV Mapping Tool is a user-friendly map viewer that shows potential electricity generation from PV installations on individual buildings. The tool helps energy system planners, building owners and occupants, and solar installers/developers to estimate potential rooftop PV system size, angles, configurations, and cost. It yields electricity generation estimates based on analysis of building footprints using high-resolution stereo satellite imagery along with solar irradiation data from ESMAP's Global Solar Atlas. Overhead three-dimensional maps are displayed with a color-coded legend to show each building's potential solar PV generation. Users can search addresses or points of interest to zoom in on specific buildings. The tool has helped derive metrics such as installable rooftop area, installable capacity, and electricity potential for individual buildings. All data points are also summed up to obtain the total potential for each city displayed by the tool. City-level data can be downloaded on the World Bank's Energydata.info portal. The results can also be further aggregated for different building sectors (commercial, industrial, public, and residential). The tool also allows users the flexibility to enter a custom installation cost per kilowatt based on their own local estimates to estimate the cost for a PV installation on any individual building.

FIGURE B3.1.1: ROOFTOP SOLAR PV MAPPING TOOL - EXAMPLE FROM KENYA



Source: Based on World Bank (ESMAP).

Note: DC = direct current; kWh = kilowatt-hour; m = meter; m² = square meter.

OUTCOME OF STEP 1: CLARIFICATION OF THE POSSIBLE ROLES OF DPV

Combining the two outputs of Step 1, DPV's possible role in meeting energy sector targets and policy priorities can be clarified. It clarifies the system challenges and opportunities that DPV can address, who the most important stakeholders are, and which use cases are the most promising in each country or region.

This provides a basis for different stakeholder groups to obtain a common understanding of DPV's possible role. It also informs the next step, where concrete policy packages are prepared.

STEP 2: PREPARING A POLICY PACKAGE WITH DPV

The objective of this step is to assess the potential benefits of distributed photovoltaics (DPV) taking into account the perspective of the sector/economy as a whole and the impacts on the key stakeholders, namely, DPV users and distribution companies (discoms). It also addresses other aspects such as the relationship with low-income consumers and gender issues. For these ends, the activities under this step are organized as follows:

- DPV system economics—assessment of impacts on the sector,
- DPV project economics—assessment of impacts on the key stakeholders, and
- Additional policy objectives—relationship with low-income consumers and gender issues.

Step 2 will likely be performed by a public body such as an energy agency or via a consultancy firm commissioned by the government or an international donor. This step aims at establishing—in the specific case—whether DPV is socially feasible, what the impacts are on each key stakeholder, how the electricity injected to the grid can be remunerated, the issues with the tariff system, how DPV can be beneficial for low-income consumers, and what the gender issues are surrounding DPV. Figure 4.1 provides an overview of Step 2.

This chapter describes the main analyses and policy design steps required to catalyze DPV deployment.

The discussion comprises three sections:

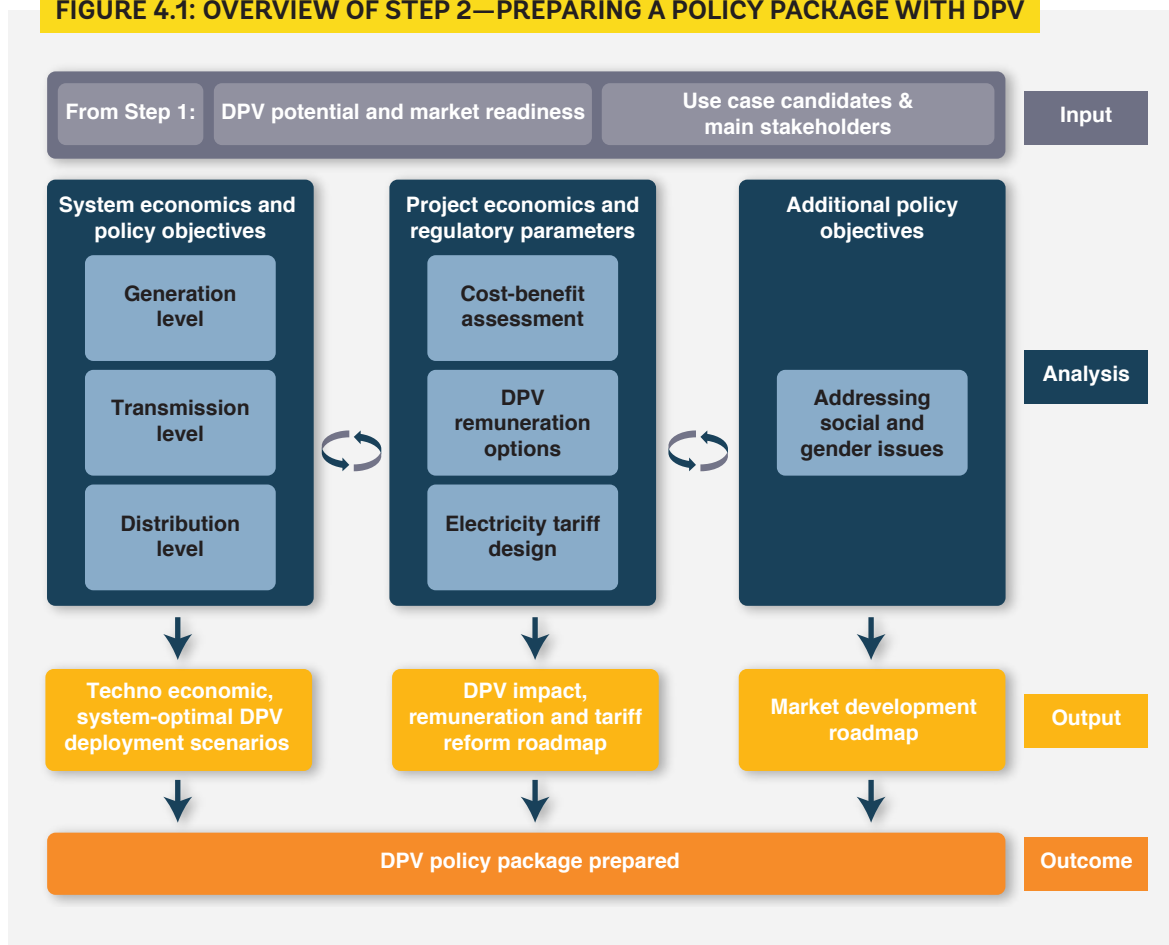
- The first section describes how DPV's contribution to the power system can be quantified.
- The second section provides an in-depth account of how DPV-related costs and the technology's benefits can be assessed for different stakeholders (cost and benefit sharing) and how economic incentives at the project level can be well crafted.
- The third and final section considers additional instruments for developing the DPV market.

Step 2 builds and elaborates on the inputs from Step 1. Assessment of DPV's potential and market readiness is beneficial for calibrating the ambition level for DPV deployment in the analysis of DPV systems' economics. It also provides important information on the baseline against which additional market development policies need to be implemented. Most importantly, Step 1 yields a better understanding of which use cases are best suited for the system. This in turn helps prioritize further analyses and ensure that relevant stakeholders are involved continuously.

THE SYSTEM-LEVEL ECONOMICS OF DPV

Like all power generation technologies, DPV implies costs and benefits for the overall power system. Policy makers need information on the mix of generation technologies that will minimize overall power system costs, which ultimately influence consumers' bills. Also, because electricity storage and transportation are

FIGURE 4.1: OVERVIEW OF STEP 2—PREPARING A POLICY PACKAGE WITH DPV



Source: Original compilation.

Note: DPV = distributed photovoltaics.

important parts of the overall system's economics, analytical tools should capture temporal and spatial effects with sufficient accuracy.

Variable-renewable-energy technologies require more sophisticated modeling than that typically used for fossil-fuel-dominated systems. This difference in approach stems from the variability of the output of intermittent solar resources and the presence of a two-way power flow, both of which impose system flexibility requirements. In addition, distribution grids that include DPV need to be modeled more accurately to capture local effects on the grid.

Analyzing the systemwide economics of DPV is critical when making strategic decisions on deployment that integrate costs and benefits optimally for society and the private sector. Among the key questions to be answered in such an analysis are the following: Will deploying DPV reduce overall electricity costs? Do costs and benefits differ based on the extent and location of DPV deployment? Will the power system be sufficiently flexible to integrate DPV reliably and how might other power plants be affected?

All or most of these questions should be answered through a sound system expansion plan. Most such plans provide the least-cost solution for system expansion and enable a reliable supply of energy of adequate quality to customers. This optimal system expansion is guided by policy objectives or policy considerations (including environmental, security of supply, and other aspects).

DPV's Impact on the Planning Process

The introduction of DPV into the equation makes planning more complex in some contexts; as a few traditional large power plants with one-way power flow to distribution transformers and from there to consumers is no longer the solution. Nonetheless the main principles still apply: the need to find the least-cost solution that helps achieve policy objectives.

In traditional planning, the “least cost” concept was easily understood. A vertically integrated company was generally involved, and cost referred to the cost that company had to bear. The basic concept does not change with the introduction of DPV—the least-cost solution is the one the entire economy must support to provide reliable service and meet policy objectives. Arriving at the chosen solution is a matter of incentives, deterrents, and regulations.

In early stages and until penetration is high, impacts are minor and predominantly at the distribution level. At this stage, intermittency of system operation has a very limited or negligible impact since intermittency can be treated like any fluctuation in load. Normal reserve levels and frequency control means are sufficient to manage DPV. However, at the distribution level, even a small DPV unit (depending on its use case) may exert a hyperlocalized, relevant impact on the feeder to which it is connected. This can also affect other non-DPV users connected to the same feeder. Thus, there is a need for detailed planning at the distribution level.

When DPV participation grows, impacts on generation and transmission planning become visible: Demand is affected by DPV's impact, and the system load curve shifts. These effects, together with intermittency, lead to starkly different generation and transmission needs (reserve, more capacity for frequency control, different requirements in terms of transmission, etc.).

At the distribution level, the impacts already mentioned above become more pronounced.

To cope with these problems, new hardware and software are needed to operate and manage the system. State-of-the-art software to tackle such issues is commercially available, but there are associated costs for the utility, including staff training and retention of trained staff.

These problems are compounded for small systems, potentially necessitating reconfiguration of the entire system—generation, transmission, and distribution—to find a reasonable solution. This is the case for small islands or small isolated grids, for example.

For distribution, granularity in analysis becomes indispensable, and analysis per individual feeder or a small group of feeders may be necessary.

Batteries are an important resource to solve many of these problems, although their use on customers' premises or at a grid scale (with important cost-benefit implications for payers in either case) requires the optimization of existing generation, generation expansion alternatives, peak demand management, capital expenditure deferral, and policy objectives for renewable penetration. For example, the island of São Tomé (which has 20 MW of peak and important suppressed demand) is developing an expansion plan with policy objectives supporting high renewables penetration—more specifically, grid-connected utility-scale solar. This means high inclusion of grid-scale batteries to mitigate intermittency during the day and cover the peak during the night.

Typically, governments propose a certain penetration of renewables in the generation mix. These objectives can be achieved most of the time, if not always. However, the associated cost may be too high. Penetration rates (proposed by policy) should be compared to a baseline scenario where policy objectives do not restrict generation expansion. The cost of any decision or predefined objective must be assessed for an informed final decision on the specific issue.

The second report in this series (ESMAP 2023) provides detailed insights into how planning for an optimal distribution grid evolves with a growing DPV share. In a nutshell, it is no longer sufficient to adopt the classical fit-and-forget one-way power flow approach, where grids are designed based on the expected, long-term peak demand of (a specific portion of) the distribution grid.

Box 4.1 illustrates the transformation that DPV is driving.

The Imperative of Considering Various Operational Scenarios

The presence of DPV affects the load curve, which can be very different from the traditional load curves when DPV participation grows due to injections/consumptions. This variation will have a certain degree of uncertainty due to the differences in consumers' consumption patterns and in the types of equipment installed (two similar consumers may represent different requirements from the system because the DPV systems they have installed are different).

Different operational scenarios must be considered, for example, differentiating high DPV generation/low load and low DPV generation/high load. Further, DPV can aid in grid management and limiting build-out requirements. Such technical capabilities should thus be considered in planning models, and their implications on costs and benefits should reflect in the associated economic modeling.

It is important to consider opening markets for the services that small-scale resources can provide. This can be challenging, however, since transmission system operators generally operate with relatively few and large-scale resources. It can, thus, be challenging to manage an important number of small and agile resources scattered over the grid. Achieving this (small-scale resources providing other services) would require fair market compensation for new service providers.

Toward the Goal of System-Optimal DPV Deployment Scenarios

Analysis of system economics yields an understanding of DPV's potential overall contribution at the energy system level. The results of this analysis are typically summarized in a dedicated report that compares total system costs for different scenarios, alongside other relevant indicators such as air pollution and greenhouse gas emissions. It also provides insights on potential best locations for DPV installation, potential distribution areas where an installation cap is required in the short term, the need for storage at the utility level, the need to request for hybrid systems, the maximum size of installations, the requirement of ancillary services, among others. From a policy perspective, it is the main analytical basis for deciding on the target level of DPV deployment (including locational aspects) as well as systemwide measures to facilitate its cost-effective and reliable grid integration.

THE ECONOMICS OF DPV AT THE PROJECT LEVEL

The analysis in the previous step assesses DPV's cost-effectiveness from the perspective of total system costs. However, for deployment to commence, DPV must be economically feasible at the project level—that is, for specific DPV users. Project-level economics is heavily affected by specific business models and the remuneration implied in their variants.

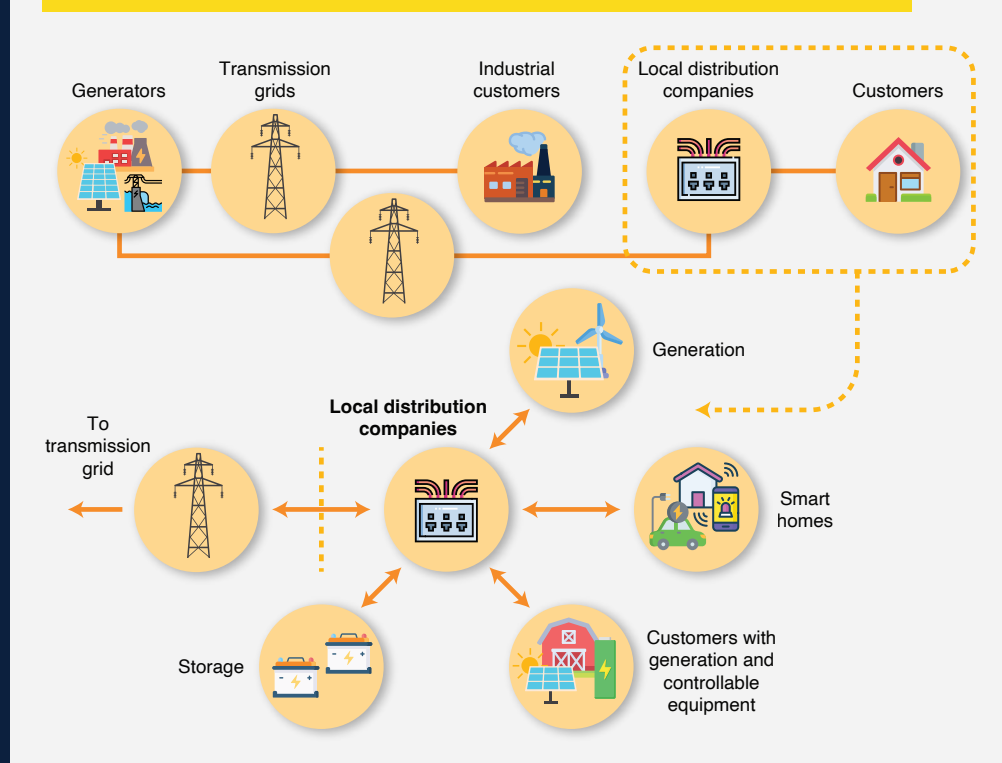
A project-level analysis of DPV's economics requires distinguishing the three possible feed-in arrangements for the technology.

BOX 4.1

Unlocking the Potential of Distributed Energy Resources— Opportunities and Challenges

Small-scale, clean installations behind consumers' meters, such as photovoltaic panels, are increasingly being adopted and already transforming energy systems.

FIGURE B4.1.1: THE POWER SYSTEM OF THE PAST AND THE FUTURE



Distributed energy resources (DERs) offer multiple benefits to consumers, support decarbonization, and improve resilience. However, their rapid uptake can challenge electricity grids that are unprepared. In most cases, today's grids were designed based on concepts of the twentieth century, when the DER share was small. Now, with a growing share of variable-renewable-generated electricity, greater system flexibility is needed to consistently balance supply and demand and ensure adequate quality.

Digitalization can transform DERs into manageable and valuable grid assets, but that will require technological developments and the right incentives. The following
(continues)

BOX 4.1

Unlocking the Potential of Distributed Energy Resources— Opportunities and Challenges (Continued)

technologies and solutions are considered as promising and can make a positive contribution even if none of them can provide the full solution on their own:

- Battery storage systems can provide a range of services to the grid.
- Electric vehicles used as mobile battery systems can be versatile and aid in the provision of similar battery-related services.
- Electric water storage and space heaters equipped with low-cost control devices can provide system flexibility.
- Grid-interactive efficient buildings.
- Virtual power plants.

Meanwhile, unlocking DERs' full potential requires changes in regulation and electricity markets since the introduction of DERs and new technologies have led to changes in how the power sector is organized. Intervention in the following key areas would accelerate DERs' deployment, integration, and scope for capturing their benefits:

- **Better visibility on the distribution system and consumer dynamics.** DERs' integration into power systems is hindered by a key obstacle: lack of sufficient visibility into low-voltage grids and behind-the-meter resources.
- **Reliable and flexible grid connections for behind-the-meter resources.** This will help tackle the challenges to DERs' grid integration while scaling up their deployment (update of codes and filling gaps potentially created by new technologies).
- **Markets for aggregated small-scale resources.** In general, increased competition and improved system efficiency can lower costs. So long as system reliability is assured, opening markets to aggregated small-scale resources can have a positive impact.
- **Fair market compensation for the multiple flexibility benefits of agile technologies at the grid's edge.** DERs are readily adaptable energy resources located near electricity consumption points. This makes them suitable for providing flexibility along the supply chain for transmission system operators, distribution system operators, retailers, and consumers. New service providers should be adequately compensated for helping ensure this flexibility.

Source: Based on IEA (2022).

Feed-in Arrangements and Metering Options for DPV

There are three feed-in arrangements for DPV: Feed all, feed none, and feed some.

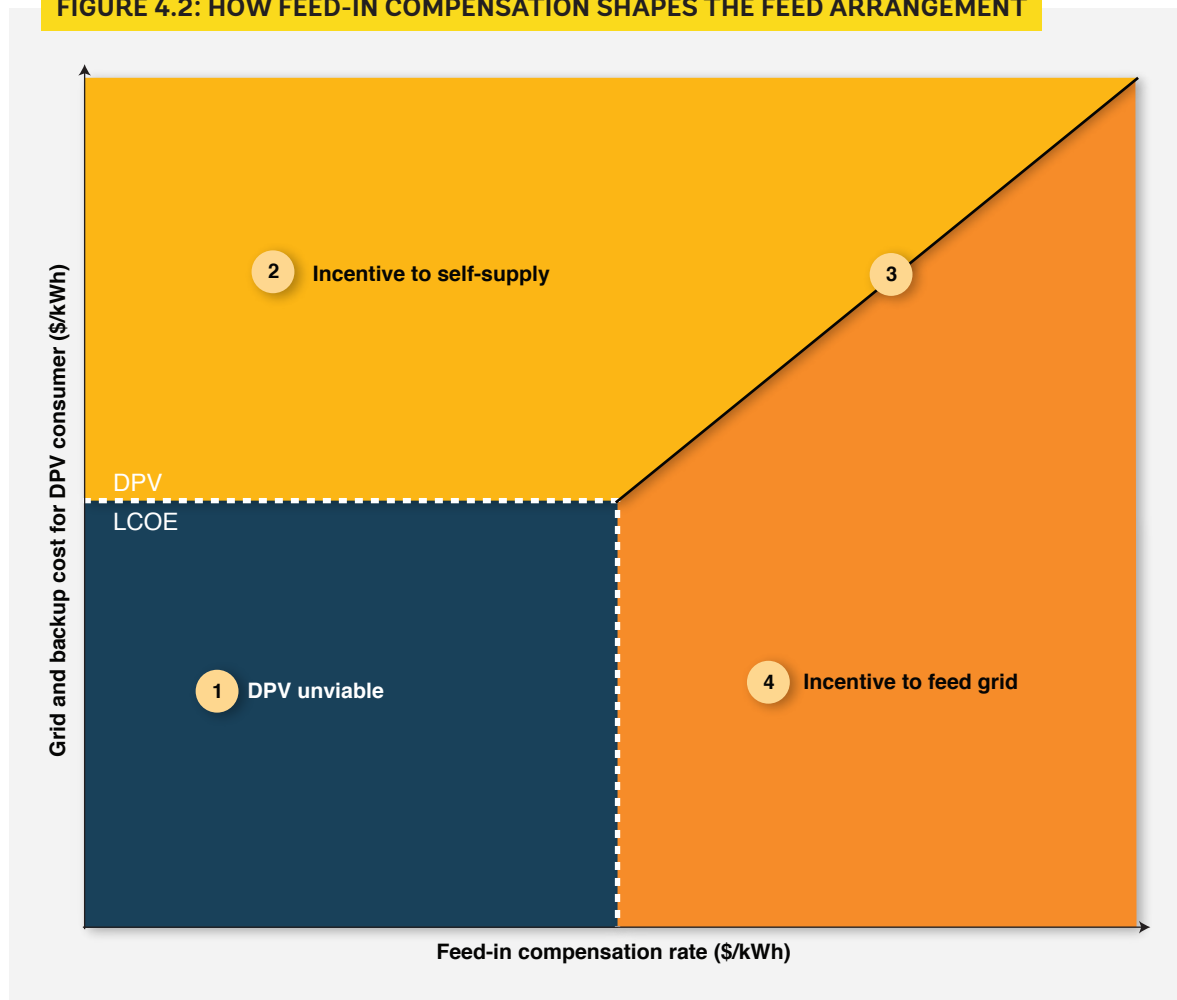
1. **Feed all.** All DPV output is fed into the grid. This arrangement can be further categorized based on whether DPV is on the grid side or the consumer side, in other words if there is a consumer on site.
 - a. Feed-all arrangements may have no grid consumer on site (buy none, feed all). Such arrangements are like a standard power plant serving a distribution grid.
 - b. A feed-all DPV arrangement with an on-site consumer can be called buy all, feed all because the consumer buys all its power from the grid. It might be technically possible to wire such a system to enable self-supply, although the feed-in arrangement implies that there is no economic incentive to do so or that it would be prohibited by regulation (notwithstanding the risk of illicit self-supply).
 - c. One remuneration model most commonly associated with feed-all schemes is the subscription model (also known in some places as “virtual net metering”), whose workings are similar to that of net metering (see below and glossary) when either a group of customers install a solar photovoltaics facility off site (not directly connected to the customers’ premises) and the energy fed to the network is credited against each participants’ bill, or the facility is for a single customer but is not located where the utility supplies electricity.
2. **Feed some.** Some of the power from the distributed generation source may be consumed on site (or stored for later use) as a substitute for consuming power from the grid. The remainder of the electricity from the distributed generation source is fed to the grid. There are many remuneration options for feed-some arrangements. The most common ones are as follows:
 - a. Net metering: Customers can offset—on a one-to-one basis—the energy fed to the grid against their own consumption of grid-connected energy. In most cases, the surplus can be banked over a period of time (generally one year), facilitating the offset. Any unused credit at the end of that period is either paid for by the utility at a predefined buyout rate or is lost. Specific cases of net metering and the lessons learned are summarized in annex 2 (Roux and Shanker 2018).
 - b. Net billing: The price received for the net energy injected to the grid is paid at a predefined rate, which may vary based on the time of day or the value of the energy provided to the utility.
3. **Feed none.** All output is for the consumer’s self-supply. However, the consumer remains connected to the grid, because they purchase grid power from the utility whenever the DPV system is malfunctioning, for example, at night or during the rainy season. These DPV systems may not require a meter, or a meter may simply inform the user and/or the utility of the output for load forecasting purposes. The key point is that the consumer receives no cash flow from the utility. This affects the microeconomics in terms of the consumer’s payback period when deciding to invest in DPV.

Metering requirements vary by type of arrangement. Depending on the type of billing arrangement—net or gross—meters may require functionalities for the time of use and/or hourly recording and charging. Costs for upgrading metering, if any, should be covered by the DPV installation. Metering cost is not a constraint at current market prices, unless the facilities are rather small.

Feed in Arrangements and DPV Remuneration

With bill reduction, the most widespread use case, DPV benefits consumers only if their levelized cost of energy (LCOE) is below the retail price,⁷ the feed-in remuneration, or both (Figure 4.2). DPV is not viable when the LCOE exceeds the grid tariff, the backup costs, or the feed-in rate. As the grid tariff or backup cost rises and feed-in compensation is absent or insufficient, consumers have an incentive to self-supply, which can affect project viability since projects are rarely economical for self-supply only. In the hypothetical cases where feed-in compensation exceeds the grid tariff or backup costs, consumers will have an incentive to maximize feed-in to the grid, minimizing self-supply.

FIGURE 4.2: HOW FEED-IN COMPENSATION SHAPES THE FEED ARRANGEMENT



Source: Original compilation.

DPV = distributed photovoltaics; kWh = kilowatt-hour; LCOE = levelized cost of energy.

⁷ Retail prices here are taken to include all fixed and variable charges and any tax that is avoided through self-consuming DPV systems.

If the retail tariff is below DPV's LCOE, there must be remuneration for the exported energy, as in the case of the feed-all mechanism. However, when the retail tariff exceeds the LCOE, the scheme will require feed-in compensation to work successfully under a feed none arrangement.

Feed-all arrangements for large DPV systems or an aggregated set of small systems may be priced like a mini independent power producer (IPP). In this case, feed-in remuneration must equal or exceed DPV systems' LCOE to succeed.

Some utilities are given a cross-subsidized tariff structure. This requires them to charge certain customer categories heavily to subsidize others. These subsidized customers, as explained above, will not prefer DPV because their cheapest source of electricity is from the grid. However, the grid makes a loss for every unit of electricity it supplies to this group. Therefore, even though these customers will not be incentivized to invest in DPV, it may be financially beneficial for the utility itself to invest in DPV as the source of supply for these loss-making customers. While the utility cannot change the tariff it is allowed to charge these customers, it can at least help lower its cost of supply, in turn reducing the loss it incurs due to this group. This is where utility-owned DPV is highly relevant.

The question of utilities' operational efficiency is also important for the analysis of nonsubsidized customer groups. In one scenario, the tariffs for a particular group may look high "on paper" but the utility's billing and collection efficiency may be very low. This results in tariffs not actually being collected from consumers. Such consumers will not invest in DPV—despite having nominally high tariffs and a DPV investment potentially yielding positive returns—because their high nominal tariff is not reflected in reality. The grid thus remains the cheapest source also for this group—due to operational inefficiency at the utility.

The local context is always important for the optimal application of these guidelines.

Setting a Compensation Level for Feeding DPV Energy to a Grid: Options

The theoretically optimal economic price for distributed generation will vary by location and time of day. This variation will depend on grid conditions, demand, and variation in marginal costs besides other avoided costs, for example, due to loss reduction, ancillary services provision, decongestion gains, grid investment deferral, and so on. However, analyzing—let alone applying—time- and location-specific pricing systems at very high granularity requires substantial computational sophistication, which is difficult even for high-income countries—not to mention that it can be politically unfeasible. Any practical pricing system is thus an extremely simplified compromise, likely to involve suboptimal investment and consumption decisions. Box 4.2 summarizes various approaches to valuing energy fed to the grid.

Net metering has proven able to kick-start markets since it visibly lowers DPV customers' bills and shortens the payback period for recovering the initial investment cost through savings in bills. However, while retail-parity compensation incentivizes deployment by consumers who face high retail rates, on many occasions, this comes at the expense of other customers. Additionally, net meters distort revenue recovery for non-energy volumetric payments, financially stressing utilities. These are the disadvantages of net metering for utilities and non-DPV customers.

Many countries are moving away from net metering. Feed-all arrangements (with gross metering and billing) and net billing (i.e., feed-some at rates above or below retail rates) are the emerging trend. Gross metering utilizes two separate meters, whereas net billing utilizes just one bidirectional meter to measure electricity that is generated and exported to the grid. The glossary contains the definitions of "gross

Approaches to Valuing DPV Energy Fed to the Grid

Null value. Some countries may not compensate distributed photovoltaics (DPV) consumers at all for injections to the electricity network. This suits feed-in schemes, although some countries allow feed-in without compensation. The utility benefits by effectively not having to bear the marginal cost for energy that is on-sold to other users at the prevailing retail volumetric tariff. However, the incentive for consumers is to maximize DPV's on-site use.

Energy component of the electricity retail price (net metering). The cost of the energy used to produce electricity is incorporated into the final retail price consumers pay. Compensation at this level defines the concept of “net metering” (as used in this report), whether with a net meter or other metering devices. It provides an ambiguous signal on whether to self-supply or feed to the grid.

Options requiring “gross metering” or “net billing”

- **Retail electricity price.** This is the volumetric price, which includes the energy component, grid costs, taxes, and levies.
- **Avoided costs method.** This sets the value of excess energy equal to the incremental costs borne by power companies to generate and distribute comparable electricity. This method compensates for energy fed to the grid, encompassing all avoided costs due to lower consumption and demand that the power system no longer has to incur. Avoided generation costs are driven by the variable costs of the marginal resource that DPV replaces. These variable costs depend on the resource's fuel prices, and variable operation and maintenance costs. Avoided network costs include the avoided capacity costs (if any) as well as avoided network losses. This method may not be as easy to implement as other methods given the complexity of the parameters to be considered.
- **Value of solar tariff.** This includes the avoided costs of grid electricity along with wider environmental, social, and financial benefits of solar PV installation. This may theoretically be above or below retail levels.
- **Levelized cost of energy produced by solar PV.** This corresponds to the levelized cost of the energy produced by the facility over its useful life.
- **Wholesale electricity price.^a** This is the varying reference price obtained from a wholesale electricity market, typically for a period of a week, month, or year. This might also include compensating suppliers for their energy transaction costs in the market.

BOX 4.2

Approaches to Valuing DPV Energy Fed to the Grid (Continued)

- **Spot market electricity price.** This is the hourly value of wholesale electricity in the power exchange in the day-ahead market.
- **Spot market photovoltaics electricity price.** This is a special form of the previous method. It is established to make a true market assessment of photovoltaics electricity on the power exchange.
- **Avoided emissions.** Decarbonization objectives require meeting demand (generation mix) with other sources of energy. Renewables, together with storage systems, provide an alternative to achieve these objectives.

Source: Adapted from Energy Community Secretariat (2018).

Note: See glossary for definitions of key terms.

a. In competitive electricity markets, the wholesale electricity price and the energy component of retail electricity prices should theoretically converge. However, this may not be the case even in countries with advanced competition since wholesale electricity prices may be more volatile compared with the energy component of retail electricity prices, which may be more stable and predictable.

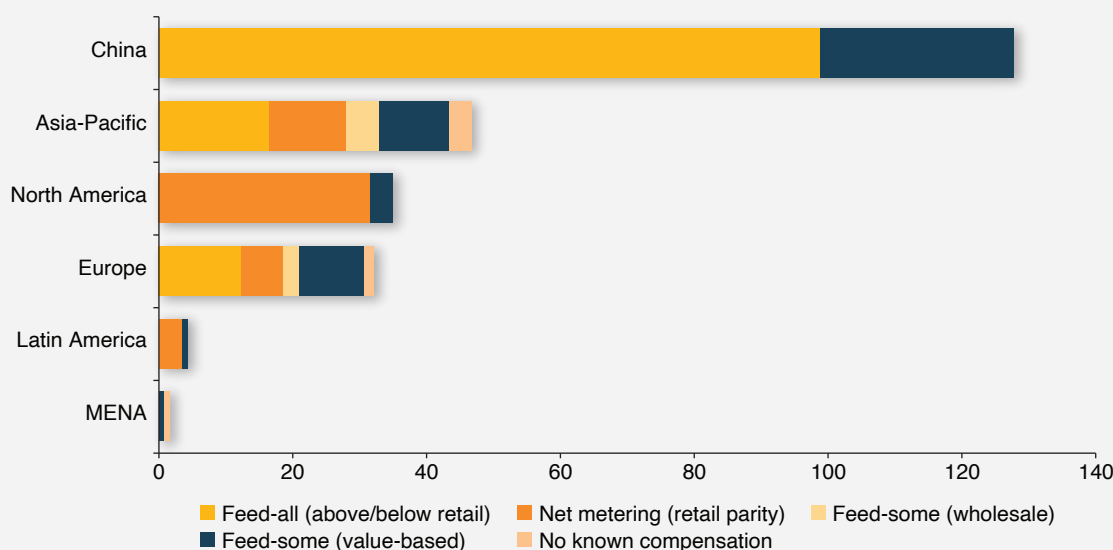
metering” and “net billing.” Figure 4.3 shows the variation of compensation rates globally in terms of expected capacity growth up to 2023. In North America, growth is predicted to continue predominantly in net metering markets (i.e., retail-parity feed-some arrangements). In comparison, growth globally and in China is dominated by feed-all and value-based feed-some schemes.⁸

Cost-Benefit Analysis

Grid-tied DPV, like any other technology in the energy sector, should be assessed on its economic costs and benefits and compared against alternative solutions (Meier, Vagliasindi, and Imran 2015). Cost-benefit analysis for DPV has historically lacked systematic analysis of costs and benefits for utilities. This gap can be explained by three factors. First, at low DPV penetration, sector-level impacts tend to be disregarded. Second, prevailing use cases to date have largely been driven by private financial benefits for DPV consumers (i.e., first- and second-generation business models, see Step 3) and emissions reductions as a social benefit. Third, the majority of DPV deployment at scale has so far occurred in developed countries (Germany, the United States, Australia, etc.), where utilities do not face the same operational challenges as in developing countries.

⁸ For other regions, a variety of approaches are expected. For details on the status of DPV compensation policies by country, see REN21 (2020). REN21 (2020) uses terms differently than this report. Its term “net metering” includes any feed-some arrangement, not just retail parity. The term “feed-in tariff” in REN21 (2020) refers specifically to a feed-all arrangement.

FIGURE 4.3: DPV COMPENSATION SCHEMES BY REGION AND FORECASTED CAPACITY GROWTH (GW), 2018–23



Source: Adapted from IEA (2019a).

Note: DPV = distributed photovoltaics; GW = gigawatt; MENA = Middle East and North Africa.

Consumer tariffs in developed countries are not as distorted as in developing countries, and service reliability, as well as efficiency, is considered a “given.” This means that in developed countries, published tariffs are actually the same as the tariffs paid by consumers, and cost trade-offs can be made at face value. Service is also reliable. In developing countries, consumers may weigh the cost of backup generation against that of DPV-based generation, rather than comparing it with the cost of the grid tariff. Service reliability is purchased via DPV systems or diesel gensets since the utility is often unable to ensure it.

Some costs and benefits are common to all or most DPV use cases (Table 4.1). Stakeholders typically benefitting from DPV include on-site consumers with DPV systems; project financiers, developers, and suppliers; and society at large—when DPV reduces local pollution and greenhouse gas emissions by displacing high-carbon fuels. Women in particular have much to gain from DPV as household energy managers, business owners, and employees.

Less clear is DPV’s impact on other stakeholders, namely, discoms, consumers without DPV systems, wholesale generation and transmission companies, suppliers of fuel-based generation alternatives, and governments’ finance ministry (and specifically, the impact on tax revenues and subsidy costs). For these stakeholders, the total net impact may be neutral, positive, or negative depending on the specific circumstances.

Table 4.1 lists the key potential benefits that drive each of the nine use cases introduced under section “Use case preidentification” of chapter 3. The *bill reduction* use case involves a distinct trade-off between consumers and discoms in terms of avoided grid electricity consumption.

In summary, the results of use cases reflect each country’s reality. What is convenient for one country may not be convenient for another. And what is convenient for one country at a certain moment may not be so at another moment/situation.

TABLE 4.1: KEY POTENTIAL BENEFITS AND TRADE-OFF COSTS FOR NINE DPV USE CASES

USE CASE	KEY BENEFIT AND ASSOCIATED AGENT	TRADE-OFF COST FOR OTHER STAKEHOLDERS
1. Bill reduction	Consumers avoid grid electricity purchase, reduce some demand charges, and/or earn revenue from feed-in. Distribution companies also avoid wholesale purchase.	Distribution companies forgo revenue from grid electricity sales and demand charges. The effect of compensation depends on the compensation level and tariff design.
2. Least-cost backup	Consumers avoid backup diesel consumption and the associated pollution.	Fuel suppliers forgo sales.
3. Least-cost generation	Distribution companies avoid the purchase of more expensive wholesale power. Consumers avoid more expensive tariffs.	Generation companies forgo sales of more expensive wholesale thermal power. If there is a wholesale market, market price can be reduced, with corresponding impact on all generators' revenues (marginal price reduced). Transmission companies forgo wheeling charges.
4. Transmission and distribution (T&D) alternative	Utilities defer grid investments to transmit and/or distribute energy. Consumers defer tariff increases.	There is no distinct trade-off. T&D contractors would forgo business.
5. Utility bootstrap	Utilities avoid grid defection and acquire new users. Consumers enjoy better-quality service.	There is no distinct trade-off.
6. Ancillary services	Distribution companies receive ancillary services. Consumers may be compensated.	There is no distinct trade-off if compensation reflects value to the distribution company. More expensive ancillary service providers may lose.
7. Community social support	Distribution companies reduce sales to loss-making consumers (and reliance on government subsidies). Other consumer classes avoid cross-subsidies or the government reduces the cost of subsidies.	There is no distinct trade-off.
8. Financial loss reduction	Distribution companies avoid sales to loss-making consumers, especially if they have high tariffs on paper, which, however, remain uncollected due to various reasons (i.e., government customers in many countries). It is better for the utility if such consumers shift to self-supply, ⁹ in case the utility's billing and collection efficiency cannot be improved. Governments avoid the need for subsidies to the utility to cover its losses.	There is no distinct trade-off.
9. Box solution	Communities benefit from greater energy security. Consumers avoid unmet demand.	There is no distinct trade-off.

Source: Original compilation.

⁹ "Loss making" customers are heavily subsidized because they require support in some form to develop DPV facilities. These typically include low-income and agricultural customers.

Cost-benefit analysis must be implemented if it yields a positive result for the sector. Analysis of this type commonly includes an evaluation of use cases from the perspective of the economy as a whole and often from the perspective of groups of stakeholders. Costs and benefits are compared against the base case with the economy considered as a whole, independently of who bears costs and receives benefits.

There are winners and losers when implementing a use case. This is found through an evaluation of the use case from the point of view of each stakeholder. It is typically necessary to design instruments that allow fair distribution of costs and benefits among stakeholders, if only to prevent those losing from a broadly beneficial use case from raising barriers to its implementation.

IMPACTS OF DPV ON THE UTILITY

Each of the nine DPV deployment use cases carries distinctive implications for the utility (Table 4.2). In seven of these use cases, DPV deployment is likely to be driven by utilities since it has a positive effect on them (or a neutral effect, in one case).

Utility-Led Use Cases

Some use cases are typically utility led and favorable to utilities under all circumstances. *Financial loss reduction* and *utility bootstrap* are clear examples. Electricity regulators often present utilities with a cross-subsidized tariff structure that requires them to charge some customer categories more so as to subsidize others. Subsidized customers tend not to seek out DPV because their cheapest source of electricity is from the grid. But because the utility loses money on every unit of electricity supplied to this group it may have an incentive to invest in DPV to supply these customers. While the utility cannot change the tariff it is allowed to charge these customers, it can at least reduce the amount of grid power it supplies them, thus reducing its losses. This is where utility-owned DPV is highly relevant. In the utility bootstrap case, a utility that is unable to satisfy its customers with adequate quality and quantity of grid power, may decide to offer the possibility of installing DPV to improve their service, while remaining a utility customer.

Under *least-cost generation*, discoms benefit from lower costs of power. Generation companies may lose out in unbundled sectors, or if DPV deployment is led by a third party, where the third-party provider sells directly to discoms/consumers, as this reduces the demand for their power. Certain country-context-specific elements however need to be accounted for. For example, many generation companies in developing countries enter into long-term “take-or-pay” contracts with their offtakers, the distribution utilities, which safeguard them against revenue loss even if the discoms wish to reduce the contracted volumes. “Two-term formulas” in power purchase agreements, which ensures the generator is recovering its investment regardless of the volume generated, have a similar effect. However, in cases where there is a power supply shortage, DPV may contribute to fulfilling unmet demand, rather than competing with generation companies. This is applicable in much of the developing world, where a energy demand is growing and installed power generation capacity is insufficient. In such cases, DPV has the added advantage of being easier and faster to build than a large new power plant. The time factor may also be considered when estimating the effects on the economy to energy shortages, since the most economically costly power is power not supplied, which hinders economic activity and job creation.

Other use cases, such as the *box solution* and *least-cost backup*, have positive implications for utilities since they do not affect the grid load. Yet, driving their deployment can aid utilities in capturing consumers or load shares that were previously unconnected or relied on backup solutions. In developing countries,

**TABLE 4.2: USE CASES AND THEIR COMMERCIAL IMPLICATIONS FOR UTILITIES
(DISCRIMINATING GENERATION FROM NETWORK)**

USE CASE	POSITIVE EFFECT ON UTILITY	NEGATIVE EFFECT ON UTILITY
1. Bill reduction	Distribution: Reduction of energy purchases and losses	Generation: Forgoes sales Distribution: May incur losses if feed-in compensation exceeds the retail tariff, or simply because of sales reduction (depends on the tariff structure). This revenue loss impacts the capacity to cover operation and maintenance costs
2. Least-cost backup	Distribution: No impact; consumers solve the problem themselves	Distribution: May lose customers (and income) if DPV proves to be a feasible solution. As in the previous use case, this may represent difficulties to cover costs Generation: Forgoes sales
3. Least-cost generation	Distribution: Avoids having to purchase more expensive energy	Generation: Forgoes sales; market prices (marginal prices) may be reduced and affect all generators if generation prices are set based on marginal prices
4. Transmission and distribution alternative	Transmission and distribution: Improved service quality, reduced technical losses, deferred investments	Generation: Forgoes sales
5. Utility bootstrap	Distribution: Improved service quality, acquisition of new customers, improved revenues	
6. Ancillary services	Distribution: Improved service quality (frequency control, voltage control) Generation: Lower requirements to provide ancillary services	
7. Community social support	Distribution: Benefits by decreasing sales to loss-making consumers	
8. Financial loss reduction	Distribution: Reduces sales to loss-making consumers, or sales at tariffs below operating costs	Generation: Forgoes sales
9. Box solution	Distribution: Covers social needs at a lower cost than other alternatives; can gain customers and/or generation assets if grid extends to the box areas	

Source: Original compilation.

where many people still do not have access to electricity, these newly connected people are a potential source of future customers for the utility.

The *bill reduction* use case is probably the most likely to occur without the utility's involvement—and potentially at the utility's expense, at least financially, as explained below.¹⁰ These negative impacts are true if the tariff system is not adequate and if the generated energy is supplied under inflexible or inadequate short-term contracts.

Some DPV use cases are well established whereas others are nascent. For example, *bill reduction* and *least-cost backup* have instances of investments going back many years. These use cases were traditionally justified based simply on private net benefits. By contrast, *utility bootstrap* and *ancillary services*, as cases driven by benefits to the utility, are still mostly at the pilot stage. Even for well-established use cases, systematic analyses of DPV's costs and benefits for utilities are often lacking.

Box 4.3 provides a review of selected analyses from the literature on DPV impacts on utilities.

The benefits of DPV penetration are evident primarily to those utilities that have digitalized their systems. Utilization of smart meters enables them to obtain granular cost and revenue information at a customer level. The prevalence of bill reduction as the most common case, coupled with shortcomings in revenue and pricing regulation, has caused revenue losses to numerous utilities. This has fueled the misconception that DPV poses a universal issue for these utilities. Increased digitalization and smart meter deployment will help utilities obtain specific, granular information by disaggregating their own financial information. This will also help combat such generalizations as the mistaken belief that DPV always creates losses.

Key Challenges for Utilities in Emerging and Developed Countries

In practice, challenges for utilities in emerging and developed countries are generally related to existing pricing arrangements for surplus electricity generation, where three key issues are typically present.

- The use of net metering and net billing arrangements does not compensate the utility for the difference in value between the energy injected to the network by customers (at off-peak hours) and the energy withdrawn from the network (at peak hours).
- The application of tariff structures with one-part energy-based charges¹¹ may imply that the utility does not recover the costs it incurs in providing network services to DPV customers. In many cases, one-part tariffs, combined with net metering arrangements, suggests that customers with DPV are either not paying at all for the network costs incurred by the utility or are paying very little.
- Tariff charges applied to higher user categories of domestic, commercial, and industrial customers¹² are set well above the cost of supply (to subsidize other customers). This artificially expands the benefits to these customers from installing DPV systems, and thus the associated revenue loss for discoms.

¹⁰ Note that if the utility is the one deploying DPV, then it can capture the revenue from that deployment. This is a strategy that some private utilities have already implemented worldwide.

¹¹ One-part charging refers to cases where electrical energy consumption is charged solely on the units of electricity consumed (kWh).

¹² Most countries enforce tariff structures that benefit residential and agricultural consumption at the expense of commercial and industrial consumers. Residential tariffs are typically about half of industrial and commercial tariffs, whereas agricultural consumers tend to pay only about a fifth of what other consumer categories are charged. Further, for commercial and industrial consumers, time-of-use factors complemented by load-related fixed charges are increasingly common, especially in middle- and high-income countries (Foster and Witte 2020).

BOX 4.3

Analyses of DPV's Impacts on Utilities

The most comprehensive analyses of DPV's impacts on utilities are for the United States. ICF's (2018) meta-analysis reviewed 15 studies from different US states chosen to be representative of the nation as a whole. The studies converged on three common value categories, all of which represented benefits at the wholesale or bulk power level: (1) avoided energy generation; (2) avoided generation capacity; and (3) avoided transmission capacity. Despite their differences, the studies imply that more significant benefits stem from avoided energy generation and avoided generation capacity (20–50 percent of the net impact), as well as avoided environmental costs (25–40 percent). Other value categories, such as ancillary services, are discussed but not explicitly quantified. Lost utility revenues are itemized only in one case, where they accounted for negative 45 percent of the net impacts.

A recent study of the costs and benefits to a modernized and privatized discom in New Delhi, India, found that the total inherent benefits of a rooftop solar system outweigh the revenue loss, with a net value of \$0.0027 per kilowatt-hour (kWh) (Kuldeep and others 2019). Savings on power procurement and fulfillment of renewable portfolio obligations constituted about 77 percent of the overall benefits to the discom. Rooftop solar systems contributed to reducing peak demand by about 13 percent of the systems' rated capacity. The discom under study has a highly subsidized residential customer base. Another study in India (Shakti and Deloitte 2017) analyzed the prospective impact on 17 selected utilities of multiple DPV deployment scenarios. It found positive impacts from lower power purchase costs traceable to reductions in the technical losses that had been sapping utility revenues. It also found that with an increase in DPV capacity, utility sales would fall and cross-subsidy collections would be altered. At the same time, however, the utility might benefit from deemed compliance with renewable portfolio obligations and reductions in technical losses, causing the overall impact on cross-subsidies to become positive. Annex 3 presents the results of a case study analyzing the impacts of rooftop solar systems on a discom (BSES Rajdhani Power Limited, BRPL), highlighting that the benefits of DPV installation exceed the discom's revenue loss.

Note: a. Equivalent to Re 0.22/kWh. Exchange rate is at \$1 = Rs 82.

Since these issues result in unrecovered costs and revenue loss from typically higher-income (and well-paying) customers, the medium-term impact on the utility is magnified. This may create a potential vicious cycle of cost underrecovery, higher prices, and increased incentives for other customers to install DPV systems.

The revenue and cost risks to the utility are higher under net metering than net billing or mini IPPs. This is because under net metering, the value of the withdrawn energy (at peak hours) is considered equivalent to the value of the energy injected to the network at off-peak hours. Therefore, customers with DPV have no incentive to alter consumption during the peak-demand period, whereas the costs incurred by the utility to manage the system are higher.

A key risk factor, especially for net metering and net billing, is the ability to recover network costs, which are demand related. Since self-generation reduces the amounts of energy sold by the utility to customers with DPV, revenue may reduce significantly if network costs are entirely or mostly recovered through volumetric charges, and network costs may not be recovered. This is likely because the fixed charges (supposedly for network maintenance) have traditionally been loosely estimated and were set at a time when periodic network upgrade was minimal and infrequent. This is no longer the case in a two-way power flow era, when DPV penetration is expected to increase. Therefore, a part of the network maintenance cost is undoubtedly covered also through volumetric (metered consumption) charges since the old, fixed charge alone is inadequate. The loss of these volumetric revenues due to a shift to DPV, therefore, hurts the utility's finances. Meanwhile, non-DPV consumers will be hurt if regulators respond by increasing the fixed charge across the board, and the consumers will be made to pay for something they did not cause. One possible response is to increase the fixed charges for DPV consumers only, to reflect the increased marginal costs they are imposing on the network.

A related risk for the utility is the adoption of DPV by higher-consumption residential customers where tariff are based on an increasing block tariff structure. These customers typically pay tariff rates above cost-reflective values and have higher purchasing power. This situation has two potential adverse effects: (1) a reduction in utility revenues and (2) a need to further increase tariffs for the remaining high-use residential customers to subsidize those with lower consumption—in turn increasing the incentive to shift to DPV. This is sometimes referred to as the utility “death spiral.” An important mitigation strategy is to ensure all customers with DPV systems pay the full network costs, and that cross-subsidies are targeted effectively, without creating unanticipated effects.

Table 4.3 illustrates certain key challenges in greater detail and potential means to address them.

An additional country-context-specific consideration is whether a utility is operating under a multiyear tariff regime that employs a revenue or price cap to ascertain its annual remuneration:

- Under a revenue cap, the utility can respond to a reduction in energy revenue from customers who have invested in DPV installation by raising tariffs for other customers. However, the utility's ability to raise tariffs may be influenced by the risk of higher prices encouraging further DPV adoption. This would compound the cost under-recovery mentioned earlier, in turn being unsustainable.¹³
- Where the utility operates under a price cap and net metering is implemented, a key issue for setting sustainable prices is the ability to accurately predict DPV's penetration in the demand forecast. Where the energy supplied by DPV exceeds that assumed in the demand forecast, the utility's revenue falls in proportion to the divergence in the energy supplied by DPV, everything else being equal.

¹³ An assessment in the Philippines confirmed that privately owned discoms' net revenues are largely not impacted by DPV generation in the short term since the regulatory framework allows for full cost recovery regardless of total sales. Any potential cost underrecovery due to DPV would lead to future rate increases to recover those costs in future years (Tongsopit and others 2019). A similar study in Thailand came to the same conclusion (Tongsopit and others 2017).

TABLE 4.3: CHALLENGES DUE TO THE CONNECTION OF DPV SYSTEMS AND POTENTIAL MITIGATION MEASURES

CHALLENGES	POTENTIAL MITIGATION MEASURES
Reduction of the utility's revenue stream if the tariff structure is primarily based on volumetric charges (based on per kWh consumed), which would otherwise help recover costs.	<ul style="list-style-type: none"> • Ensure two-part (demand and energy) pricing for utility services for all customers, allowing the utility to leverage the demand charge to recover the fixed (demand related) costs of providing a network connection to customers with distributed photovoltaics (DPV) systems. • Charge a fixed network usage fee or a minimum value to DPV customers to recover (at least partially) network costs.
High DPV adoption by high-consumption residential users under increasing block tariff structures.	<ul style="list-style-type: none"> • Incorporate two-part (demand and energy) pricing, or the application of a network usage fee as a precondition for adopting DPV. • Introduce two-part pricing for all residential users. • Minimize cross-subsidization between and within tariff categories to essential cases. • Design DPV programs to target consumers whose volumetric rate is structurally below cost-recovery levels and customers in chronic arrears who cannot be disconnected (e.g., government).
Customers consume energy from the network at peak hours while feeding energy to the grid at off-peak hours.	<ul style="list-style-type: none"> • Prefer gross metering (or net billing) arrangements to traditional net metering, ensuring that the tariff structure reflects the values of the energy supplied to the grid and the energy withdrawn from the grid to the utility. • Prefer gross metering (or net billing) arrangements based on time-of-use tariffs. • Design regulations to help match supply and demand by implementing actions such as inverter clipping, demand-response and/or battery installation.
Utility's potential inability to recover a portion of generation/energy purchase costs—for example, if it has to cover costs for high capacity or costs under “take or pay” contracts during the periods when DPV is generating energy.	<ul style="list-style-type: none"> • Effectively plan energy generation and power purchase agreements, ensuring customers are installing DPV only in cases supported by least-cost planning. • Allow any short-term “stranded” costs of this nature to be recovered from DPV customers. • Add fixed (capacity) generation costs to fixed network charges under two-part pricing. • Structure power purchase agreements with two-part formulas and with no “take or pay” energy clauses.
Utility's costs increase due to DPV, and this increase is recovered through a general increase in volumetric rates, in turn shifting costs to those (usually less affluent) customers who do not have DPV systems, storage systems, or photovoltaic systems installed behind the meter.	<ul style="list-style-type: none"> • Ensure customers with DPV pay for the network costs faced by the utility (see two-part pricing above). • Ensure the price paid for the energy injected to the grid reflects avoided costs and nothing beyond that.
Self-generating customers are voluntarily choosing to disconnect from the grid.	<ul style="list-style-type: none"> • Review the existing tariff system, including for cross-subsidies and any stranded costs borne by the concerned customer category. • Seek enhancements in service quality by the utility. • Develop options for sale to the grid to encourage business opportunities for customers considering disconnection.

(continues)

TABLE 4.3: CHALLENGES DUE TO THE CONNECTION OF DPV SYSTEMS AND POTENTIAL MITIGATION MEASURES (Continued)

CHALLENGES	POTENTIAL MITIGATION MEASURES
Higher cost of utility operations due to issues with voltage control and higher network losses, especially during peak periods, when two-way energy flows will be highest.	<ul style="list-style-type: none"> • Provide tariff incentives to customers to make their consumption more flexible (e.g., storage solutions), and/or ensure time-of-use pricing that reflects the increased costs faced by the utility. • Plan DPV programs to assist in voltage control through inverter functions and to target DPV systems' locations. • Adequately represent DPV's impact on the system at the planning stage. This may represent a need for more detailed/sophisticated studies at a planning level.
Self-generating consumers who oversize their production capacity to export electricity via the distribution network create network congestion and contribute to network losses.	<ul style="list-style-type: none"> • Plan DPV programs to target locations and system designs that can ease congestion and reduce network losses. • Restrict the capacity of the DPV systems permitted to reflect expected consumption.

THE REGULATORY AND TARIFF CHALLENGES IMPOSED ON UTILITIES BY DPV

The key challenges posed by DPVs to utilities are largely related to pricing. Addressing them might require tariff reform ensuring that:

- Customers with DPV pay for the network usage costs and generation capacity costs incurred by the utility to provide them with the electricity services they use. A recommendation is to use two-part tariffs, with the capacity component recovering sufficient fixed (demand-related) costs. It will be more accurate if the utility is digitalized and can identify granular costs and revenues specific to each customer (utilities in many developing countries today struggle to even identify feederwise costs and revenues due to a lack of sensors and other monitoring equipment across the network).
- The rates of the tariff's variable (energy) component—whose application on customers could lead them to adopt DPV—are not set unduly above cost-reflective levels. This is to ensure DPV is only adopted efficiently: that is, customers adopt DPV only when doing so adds to efficiency for them as well as the electricity system.
- The implicit and/or explicit costs of DPV feeding energy to the network and withdrawing energy from it reflect the utility's marginal costs of purchasing energy in the respective periods.
- Application of time-of-use tariffs, which are especially useful when the costs of service delivery differ significantly between peak and off-peak periods. This requires sophisticated software, advanced metering, and a digitalized network, which may not yet be a reality for the utilities of many developing countries.

The regulatory framework can support the above measures in several areas, depending on the digitalization and capacity for regulatory sophistication.

First, in systems applying multiyear tariff regimes, the use of revenue caps for distribution services can provide the utility with greater assurance of recovering network costs where customers install DPV. Revenue caps provide additional certainty to the utility in recovering its revenue requirement when customers with DPV disconnect completely from the network.

Second, net metering systems should be phased out and replaced with forms of net billing and/or mini IPPs that compensate customers for the value of the energy fed to the grid. In countries where renewable purchase obligations are in place, this can also allow the utility to fulfill these, or renewable portfolio standards, rather than entering formal and inflexible power purchase agreements with large external renewable generators. Such a regulatory compliance benefit to the utility also assures DPV customers that their sales to the utility will continue for a prolonged period, preferably at least until the initial investment has been paid back. The use of time-of-use pricing is recommended, where the price of the energy supplied may be set close to zero during off-peak periods and at the marginal cost of alternative supplies during peak hours. Time-of-use pricing has the additional advantage of encouraging customers with DPV systems to install storage solutions.

Third, the regulatory framework can provide a means of socializing additional costs incurred through DPV, including the additional cost of ramping up generation at peak hours and any take-or-pay obligations incurred by the utility through the large-scale production of energy during off-peak hours. Where possible, these costs should be allocated to customers with DPV, potentially as a form of backup charge. Where this is not possible, these costs should be socialized among other customers trying to minimize pricing distortions.

Fourth, transmission and distribution planning should better accommodate DPV's requirements, including through greater sophistication in the software used to model and address the technology's variable nature, demand forecasting techniques, and the ability to better match the changing needs and costs of non-DPV generation.

A long-term objective of the regulatory and tariff arrangements is to move to a system where dynamic tariffs are possible. Dynamic tariffs adapt the cost of the energy to the grid to its value to the utility and incentivize customers with DPV systems to incorporate storage solutions to shift supply periods and modify the value of the peak demand. With greater pricing flexibility and market maturity, utilities can potentially get involved in the provision of DPV, for example, through the utility ownership of customer-sited PV and the maintenance of PV facilities.

Output: DPV's Impact, Road Map Tariff Reform, and Remuneration

The discussion in this section presented different options for the remuneration of DPV and key considerations for designing electricity tariffs consistent with DPV's deployment, besides shedding light on the methods to assess DPV's cost-benefits for different stakeholders as well as the sector as a whole. Policy package preparation must consider the analysis of project-level economics for setting remuneration levels, adjusting electricity tariffs, and ensuring costs and benefits are shared equally among stakeholders, as far as possible.

ADDITIONAL POLICY OBJECTIVES

Subsequent sections focus on the inclusion of low-income customers and the considerations related to gender equality and women's empowerment as consumers. Energy interventions, which fail to recognize the differences between men and women, could lead to reduced program reach and inequitable uptake. There is scope for further research regarding evidence on how DPV projects and policies can specifically address gender gaps or make special efforts to target female consumers.

DPV for Low-Income Customers

Low-income households could be supported in accessing DPV's benefits through dedicated long-term funding for community education and engagement, integration with existing energy assistance programs, and job training and placement opportunities. Programs targeting low-income consumers could consider certain key questions and options—namely (1) accessibility and affordability, (2) community engagement, (3) consumer protection, (4) sustainability and flexibility, and (5) compatibility and integration—as described in the first report of this series (ESMAP 2021).

Key questions to be considered in this section are as follows:

- How should low-income consumers best be reached? The options include a “carve-out” (a targeted program), an “anchor tenant” (a high-volume consumer colocated with low-volume consumers), or special incentives.
- Where are projects best sited? The options include being close to users or at locations with the most utility grid benefits.
- Are up-front costs best covered by grants or loans through utilities or other government agencies?
- Who should acquire, retain, and bill or credit consumers? Is it discoms, or is it a third-party provider, for example, an affordable housing facility with “virtual metering”?
- How is eligibility for program benefits best defined and verified?
- How are customers best retained (e.g., through managed subscriptions, flexible subscriptions, short contracts)?

Policies or programs that do not include such considerations are less likely to be successful. For example, community programs that include a carve-out for low-income customers but do not include additional incentives may not result in the desired participation. Programs that offer meager savings to consumers are also unlikely to succeed. The most effective programs targeting low-income customers include long-term, dedicated funding; cover up-front costs; integrate with energy efficiency offerings; mesh seamlessly with existing energy assistance programs; include direction and funding for community education and engagement; and include job training and placement opportunities (Figel and others 2016).

Women DPV Users

DPV developers and operators could benefit from targeting women as prospective customers. When acting as household energy managers, women can especially benefit from the improved energy services of DPV and the energy savings that it generates. Reduction of electricity supply costs and greater supply reliability may lead women to use DPV instead of polluting fuels for household activities. Depending on the country, one-fifth to over one-third (or close to half) of households are women headed. As electricity and appliances become more affordable, women, as energy-consuming entrepreneurs, are also more likely to benefit from productive uses of energy. Women entrepreneurs contribute significantly to economies. Small and medium enterprises with full or partial female ownership represent 31–38 percent (8–10 million) of formal small and medium enterprises in emerging markets (IFC 2011). Shared community facilities (e.g., mills and other agro-processing facilities), where women perform a disproportionate amount of the labor, could be brought under community solar schemes. This is a particularly suitable match for facilities that are predominantly used during the daytime. Such facilities would benefit from the more reliable and affordable DPV-based electricity, which would support the productivity of their income-generating activities.

For all these reasons, access to DPV should be facilitated for women. Yet, as prospective buyers of residential DPV systems, women face greater challenges than men in many countries. Globally, women's incomes are on average lower than men's, and women are overrepresented among those living in poverty. Thus, they are less likely to be able to afford DPV. Lower income levels, along with cultural norms and a lack of collateral, also hinder finance access for women. They also have less access to property and, thus, less likely to own an eligible rooftop.

Adverse gender norms pose a barrier to women's decision-making power. Men are often the decision-makers in the purchase of household assets. Women may therefore be less likely to consider DPV, unless targeted measures are implemented. Yet, there is also evidence that women can play the role of "hidden influencers" (Calvert Impact Capital 2018). A renewable energy operator reported, while collecting market intelligence data, that although men often made the purchase decision and signed the contract, women were influencing that decision. The operator modified its sales strategy and approached households when both men and women were likely to be available. This resulted in a faster sales process, more timely repayments, and more solar system upgrades.

Women's Participation in the DPV Industry

The solar PV industry is a large employer in the energy sector. Women can be included in, for example, (1) the initiation phase, (2) the development phase, (3) the construction phase, and (4) the operation phase of DPV deployment (Edun and others 2022).

Initiation Phase

- *Encourage women-led developers to bid by directly advertising procurement to female-focused energy groups.*
- *Include the percentage of women staff as a metric when assessing developers' bids.*
- *Require developers to have a dedicated officer to handle instances of gender equality/gender-based violence.*
- *Require capacity building as the bid criteria for skills and jobs for women and other marginalized groups.*

Development Phase

- *Collect data prioritizing diverse groups to ensure all perspectives are considered, including those of women; youth; and other groups marginalized by disability, occupation, religion, or ethnicity. Consult with community leaders and women's organizations.*
- *Conduct an environmental and social impact assessment during site selection to determine the generation plant's effects on women and children in the area and explore opportunities for equity and inclusion measures.*

Construction Phase

- *Collect data related to skill development, employment opportunity, and customer-related aspects to ensure customer-centric energy services delivery.*

- *Provide skill training for women and youth to benefit from and to equip themselves to participate in the construction and operation of renewable-embedded generation.*
- *Maintain constant community engagement throughout project lifetime.*
- *Provide hands-on learning opportunities for women engineers. An on-site training program could be designed to enhance women's exposure to the construction and operation of energy systems and aid their professional growth. This will help create an entry point for women in the communities and beyond to gain valuable exposure to career pathways in the energy sector.*
- *Combat sexual exploitation and abuse at worksites and in communities by integrating measures to ensure women's and girls' safety at construction sites, including transport, codes of conduct, and sharing details on age-of-consent agreements with employees on site.*

Operations Phase

- *Train women and vulnerable groups in operational processes such as maintenance, security, and customer care.*
- *When hiring operational staff, focus on women's employment and other social inclusion measures. Use language encouraging women candidates, set targets for female employment, and approach women's professional associations to identify talent.*
- *Design customer care and payment methods that align with processes familiar to communities and have a consumer-centric focus, prioritizing affordability, usability and accessibility, transparency, customer care, and safety. Design these processes including consultation with community leaders, women's groups, and members of such groups.*
- *Explore roles for community members in service delivery and bill payment, for example, energy theft reduction through community mobilization.*
- *Document various gender, equality, and social inclusion outcomes and impacts, such as time poverty reduced, income for women-led enterprises enhanced, and jobs created.*

Box 4.4 depicts the situation of employment and gender in this subsector of the energy industry.

Output: Market Development Road Map

The previous sections highlighted the consideration of additional policy objectives that DPV deployment is expected to achieve, along with concrete measures for how these objectives can be incorporated as part of DPV deployment programs.

OUTCOME OF STEP 2: PREPARATION OF THE DPV POLICY PACKAGE

The outcome of Step 2 should be a DPV policy package prepared with sufficient detail. DPV's system-level economic effects are quantified based on robust technoeconomic modeling and after assessing different expansion paths. Project-level economics are well understood by considering existing retail tariffs, possible tariff changes, and remuneration for the DPV grid. The likely effects for different power system stakeholders have been assessed.

BOX 4.4

Women's Participation in the PV Industry and Training for Utility Staff

Solar photovoltaics (PV) is the largest employer in the renewable energy sector with about 4.3 million jobs in 2021 (one-third of all renewable energy jobs). Further, the solar PV sector will remain the largest source of employment in an energy transition pathway consistent with the Paris Climate Agreement. It will account for an estimated 40 million jobs in 2030 (37 percent of all renewable energy jobs).

Women represent 40 percent of the PV industry. This is almost twice as high as in the oil and gas sector (22 percent) and the wind industry. Women in the solar PV sector predominantly hold administrative positions, where they represent 58 percent of the workforce. However, they are not as well represented in science, technology, engineering, and mathematics (STEM) positions, where they represent only a 32 percent share, or in other non-STEM technical positions, such as lawyers or contracting experts, where they represent a 38 percent share. As for managerial positions, women represent a 30 percent share and only a 13 percent share of senior management positions in the PV subsector.

Women's entry, retention, and advancement in the solar PV workforce face several barriers, of which the most significant are the perception of gender roles, a lack of fairness and transparency in internal policies, and cultural and social norms. Measures to remove these barriers are critical and will require reviving gender awareness, improving national policies, and removing restrictive laws; establishing better workplace practices, policies, and regulations; and forming networks and support systems for training and mentoring.

Organizations must devise measures to attract, retain, and promote women in the distributed photovoltaics sector. To attract women, they must be provided access to training at all levels and restrictive laws impeding their access to finance and markets must be removed. Women's training and recruitment can also expand the talent pool and help minimize potential skill shortages within utilities. To retain female talent, organizations must ensure management support, especially in the childbearing years. Women can be tomorrow's leaders provided they have access to professional networks and are provided mentoring for development. Moreover, profitability could be boosted through gender quotas to ensure greater gender diversity on corporate boards (Harvard Business Review 2016).

With the World Bank's support, the Ethiopian Electric Utility (EEU) is pioneering a new model to promote equality between men and women as it works toward universal electricity access. The EEU aims to have women represent 30 percent of its employees within five years, up from 20 percent in 2018, and it has a long-term vision of achieving
(continues)

BOX 4.4

Women's Participation in the PV Industry and Training for Utility Staff (Continued)

institution-wide gender equality. With an aim to develop a future workers' pipeline, the EEU signed a unique partnership with the Ministry of Science and Higher Education and 12 Ethiopian universities to launch STEM courses essential for boosting the existing female share in staff so that women can advance their careers in the energy sector and the education gap with male employees can be closed. The EEU is also offering full scholarships for female staff to go back to university to obtain a master's degree, or gain the required technical training. Also, 40 female STEM graduates have an opportunity to complete internships at EEU offices across the country for a few weeks to get tangible work experience. Upon completing their internships, the female students will be offered employment opportunities within the EEU, provided they meet the onboarding requirements. The utility has also developed leadership training for its female employees to ensure they advance beyond junior roles. Work is also underway to investigate some of the barriers faced by women during the school-to-work transition, such as hostile study environments for women and limited professional networks. The EEU is establishing childcare facilities in one-fifth of its offices after it identified childcare as an impediment to female workforce participation.

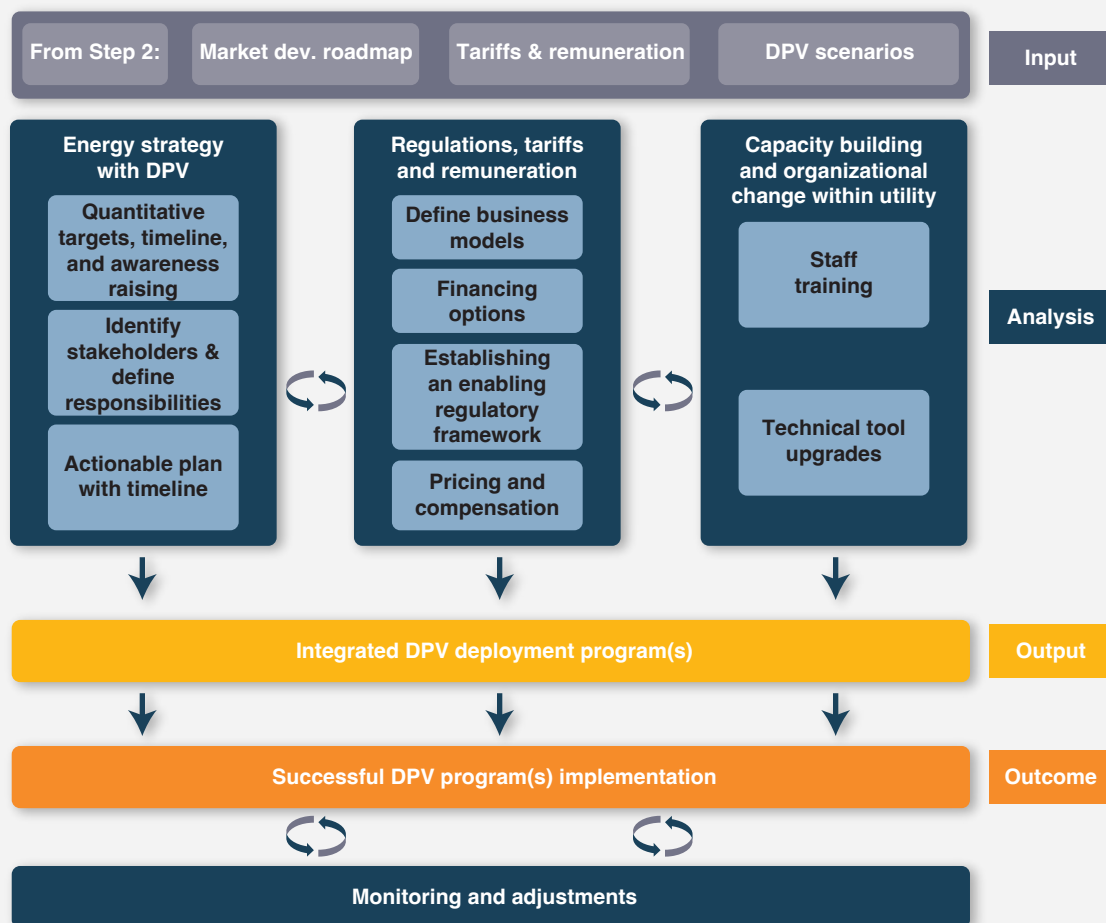
Source: IRENA 2022; ESMAP; World Bank 2017a, 2019, 2020a (cases presented here have no connect with the DPV program).

Building on this analysis, the government decides on a specific DPV deployment path, combined with the model for DPV remuneration, as well as possible changes to retail tariffs. Also, training and capacity building requirements have been identified. In short, it has become evident what actions must be taken. The next step is to proceed with implementation.

STEP 3: IMPLEMENTING A POLICY PACKAGE WITH DPV

Step 3 aims to implement the DPV policy package developed in Step 2. A policy package must have distinct components clearly indicating what is to be achieved, how to achieve it (supporting business models with the required regulatory and pricing prerequisites in place), the role and responsibilities of different stakeholders, and the identification of a nodal organization (with structure and skills) for implementation support for achieving these targets. Figure 5.1 provides an overview of Step 3.

FIGURE 5.1: OVERVIEW OF STEP 3—IMPLEMENTING A POLICY PACKAGE WITH DPV



Source: Original compilation.

Note: DPV = distributed photovoltaics.

A DPV program combines a suite of integrated implementation measures with appropriate mechanisms to monitor the impact of different strategic components on DPV's deployment at a desired scale, with a desired market, and with a geographic spread over a defined period. The program has a strong feedback mechanism for course correction of the strategic components in the event of a divergence between actual achievement and targets.

INPUTS FROM STEP 2

Based on several technoeconomic analyses, Step 2 yielded a set of targets and policy measures for a desirable level of DPV adoption. In short, it provided the guidelines to answer the following questions: What should be the desired DPV deployment level? Where should DPV be deployed? What are the right policy, regulatory, and market instruments to achieve the desired level of adoption? Who is responsible for achieving the targets?

Step 3 builds on this input and considers the practical aspects of implementation. It includes an in-depth discussion on the implementation framework with all relevant stakeholders, such as consumers, distribution utilities, the DPV industry, financial institutions, and regulators, to seek their perspectives on strategic goals, collaboration, and partnerships for strategic action and communication. The discussion seeks the stakeholders' strategic support and their buy-in of the proposed implementation framework, motivates them to avail business opportunities, seeks their support in overcoming the policy implementation challenges, and seeks their feedback for appropriate changes to the implementation framework.

Inputs from Step 2 should ideally consist of:

- DPV deployment pathways backed by robust analysis of the economic, commercial, and social impacts of DPV deployment on the system as a whole and on various stakeholders under different market design scenarios;
- A market development road map highlighting the required steps for removing DPV deployment barriers; and
- Concrete and actionable recommendations for the regulatory framework, reforming electricity tariffs, and remunerating DPV.

DPV ENTRY STRATEGY

DPV must be placed in a wider context of policy measures to help the energy sector fulfil its priorities and achieve its goals. As explained in Step 2, this calls for an integrated approach to establish possible roles of DPV and strategic instruments to manage the technology's deployment.

The two most relevant aspects in this regard are DPV deployment targets and identification of the roles and responsibilities of different stakeholders—the latter supported by a time-bound action plan to help the stakeholders achieve these targets.

Set Quantitative Targets with Timelines, and Raise Awareness

The practical implementation of DPV policy packages requires clear, credible, and feasible targets along with a deployment pathway, which together provide a valuable implementation foundation. This strategy-level instrument helps increase the predictability of demand for the supply chain, in turn supporting

investment decisions for building manufacturing, installation, and operational capacities. Fixing targets helps stakeholders coordinate implementation activities, and it also aids in the evolution of an appropriate regulatory framework, business models, and remuneration level.

The regulatory framework, business models, and remuneration level would depend on the market subsegment that is being targeted for DPV deployment. This could differ for residential, commercial, and industrial consumers, and public institutions. The implementation strategy must evolve with the evolution of the DPV market.

Business models would emerge spontaneously depending on the customer segment, the risk that an investor is willing to assume, and, of course the profits to be made. Business models cannot be dictated top-down. However, the regulations governing the sector should be sufficiently flexible to allow the market itself to identify opportunities and create new models (and new risk allocation). For example, if electricity regulations were to allow DPV system's ownership only by the entity in whose name electricity meters are registered, then an entire class of third-party business models would be eliminated (see next section for a more detailed description of business models).

At the implementation stage, a clear and conspicuous communication of the quantitative target—reinforced by strong political commitment and supportive regulations—helps to capture the required stakeholder attention. Confidence in the sector's medium- and long-term viability can then be bolstered through periodic review of targets, options for adjusting them upward, and announcing additional measures in case market dynamics fall short of the target corridor. The possibility of having to adjust targets downward may also have to be considered.

From an industry perspective, the desired annual capacity additions convey information that makes it possible to calibrate supply chain capabilities and helps lenders estimate a DPV project pipeline. Targets (and the road maps to achieve them) are an important part of the picture, because too rapid a ramp-up risks overstretching industry capabilities, which could increase costs (in some cases substantially) in certain parts of the supply chain. Conversely, if targets do not convey the full policy ambition, then their desired effect on industry expansion will not materialize. Targets must be in harmony with the strategic intent and policy framework. For example, in some countries, as noted earlier, the retail tariff for domestic customers is less than the cost of supplying those customers, whereas tariffs for C&I customers are higher than the cost of supplying them. In such circumstances, C&I customers, which the distribution utility needs for its financial viability, may be expected to adopt DPV more aggressively than domestic consumers. Thus, the targets for C&I customers can also be higher. The opposite situation prevails for domestic consumers: As long as their grid tariffs remain highly subsidized, the electricity grid will be more attractive to them than DPV, which they will not be interested in adopting, regardless of the government's targets. The decision variable would change only when tariffs are brought closer to the cost of service. A rising retail tariff, coupled with the observation of electricity bill savings accruing to early DPV adopters, may favor faster DPV adoption. An illustration is provided in Table 5.1.

Target setting, which is fundamental to trust building, requires sound planning for targets to be credible and acceptable to stakeholders. Targets should be set with stakeholders' participation during planning and should provide information for the final decision to factor in aspects such as industry capacity, trained workforce, availability of commercial credit for DPV, among others.

Identify Stakeholders and Define Their Roles and Responsibilities with a Time-Bound Actionable Plan

It is desirable that all major stakeholders, including governments, regulators, distribution utilities, the DPV industry, and financial institutions, have access to the same information regarding installation targets.

TABLE 5.1: TIMELINE FOR DPV TARGETS BY CONSUMER CATEGORY AND REGION

SL. NO.	ADMINISTRATIVE UNIT	CONSUMER CATEGORY	YEAR 1 (MW)	YEAR 2 (MW)	YEAR 3 (MW)	YEAR 4 (MW)	YEAR 5 (MW)
1	Region 1	Domestic	1	2	4	6	8
		Commercial	2	4	8	12	16
		Industry	5	10	15	20	25
		Public institutions	2	3	4	5	6
2	Region 2	(As above)					

Note: DPV = distributed photovoltaics; MW = megawatt.

They should be aware of especially the annual subtargets and the market subsegments for which they apply, the geographic spread, and the period within which the targets must be achieved.

Governments have another fundamental responsibility: to explain what DPV is to customers, and communicate with them about this technology, the government objectives (regarding DPV), DPV's benefits, and how consumers can access this solution. It must be remembered that DPV adoption will stem from, to a great extent, consumers' decentralized decision. Therefore, for DPV to be successful, consumers must be well informed and must have access to information free from biases potentially introduced by companies. Lenders should also be prepared to make DPV affordable for consumers since very few would be able to pay up front for the full cost of a 100 percent equity purchase upfront. Financing for DPV is crucial to increase its adoption. And last, governments (through one of their agencies) must closely follow up on DPV's development progress. This is so that they can adjust the supporting measures if needed and/or have access to precise data to assess the impacts on the distribution system (namely, from an operational point of view).

Synchronized action of all relevant stakeholders is important to achieve targets. The responsibility matrix for all relevant stakeholders must be identified, and a time-bound actionable plan must be created to help them achieve their respective milestones—to eventually contribute to achieving policy objectives. An illustration is provided in Table 5.2.

BUSINESS MODELS, FINANCING OPTIONS, REGULATIONS, AND PRICING

One of the core aspects of implementing DPV policy packages is to support the spontaneous emergence of viable business models. Such support includes incentivizing lenders to provide adequate financing access. There should also be policy support for adjusting electricity tariffs, ensuring sufficient DPV remuneration, and facilitating a stable regulatory framework. All of these add certainty in providing an operating environment that, among others, helps customers gain eligibility; creates the conditions for energy exchange with distribution utilities; improves energy accounting, metering, and billing; expedites connections and grid code update. All of these form part of the core implementation priorities for establishing viable business models that would spontaneously emerge from the market players, which include consumers and third-party investors, if these are permitted.

TABLE 5.2: AN ILLUSTRATION OF STAKEHOLDERS' ROLES AND RESPONSIBILITIES

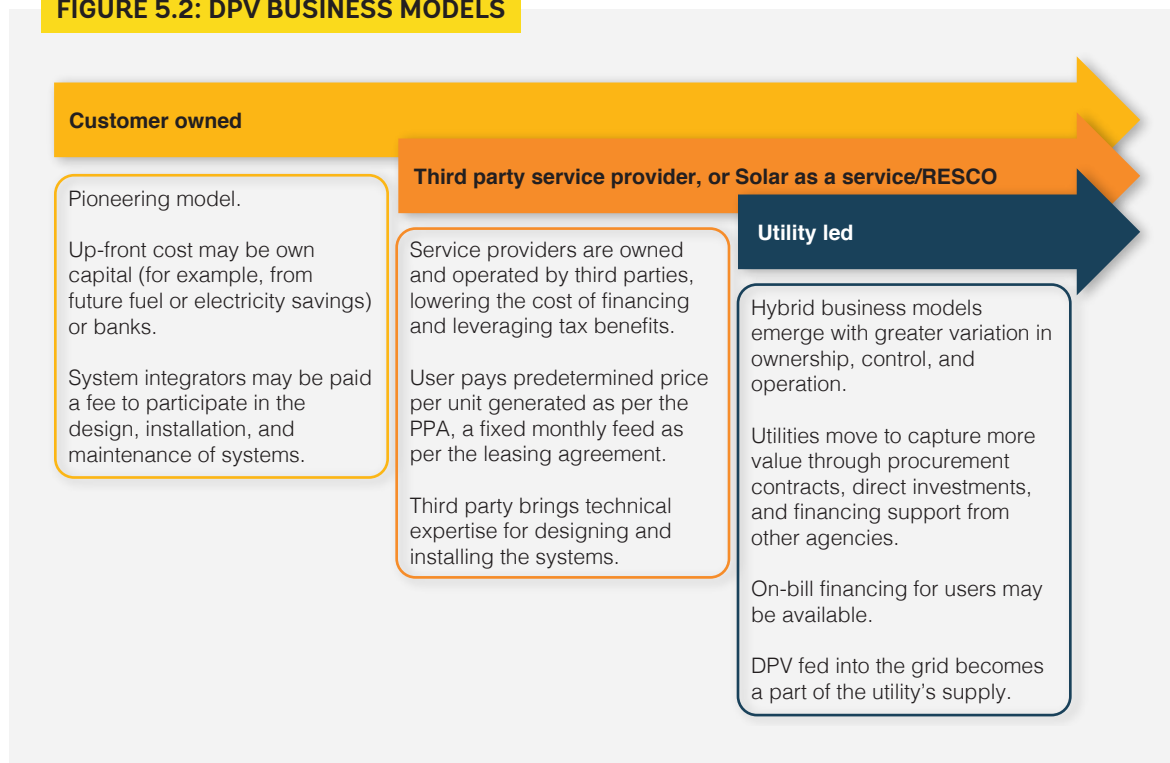
STAKEHOLDER	ROLES AND RESPONSIBILITIES	TIMING OF ACTION
1. Government	Promote and establish a market for DPV. Governments should lead policy and strategy formulation, identify the nodal agency and the institutional arrangement (define role and responsibilities) for synchronized action of stakeholders, provide subsidy and incentive mechanisms for establishing the DPV market, educate consumers, ensure access to finance, and perform monitoring and evaluation for course correction.	Governments should take the lead in establishing the market and overseeing its development. It may undertake strategic interventions for course correction.
2. Regulator	Establish the regulatory framework. Establish a compensation mechanism for owners/providers, create applicable technical standards, and make appropriate changes to licensing conditions for the active participation of distribution utilities so that the DPV market can evolve and mature through the evolution of business models. It should also advise governments for appropriate policy changes considering the changes in the business environment for DPV.	It should facilitate the implementation of government policies and advise (share its views) on the policy interventions required for course correction of the DPV market's evolution of ensuring all stakeholders' interests are considered.
3. Distribution utility	Facilitate the realization of the DPV market by implementing the required interconnection, metering, and billing process and guidelines updates. Consider this as a business opportunity, and actively participate in the DPV market to avail DPV's benefits under various use cases and achieve policy targets.	Implement policies and regulations in letter and spirit and share feedback with the regulator to protect the interest of non-DPV customers.
4. Industry/developers	Contribute to the evolution of business models and industry best practices and implement them, educate and pursue eligible customers, develop the value chain, and raise the required funds.	Innovate and implement business models and contribute to the development of a DPV market once the requisite policy, regulatory, and implementation framework has been laid, and share feedback for appropriate changes to the policy, regulatory, and implementation framework so that the DPV market can be aligned with international developments.

Note: DPV = distributed photovoltaics.

Business Models

DPV business models are typically developed to suit the circumstances of specific markets and their regulatory frameworks, as well as their consumers' needs and preferences. These business models range from those that are customer led and involve direct systems ownership, to those where third-party providers aggregate projects and facilitate DPV design, installation, and financing (typically for highly creditworthy customers, since the third party directly assumes their payment risk), to the more recently emerging one, where distribution utilities take the lead, as shown in Figure 5.2. There is no direct continuum in terms of these models; no model is better than another in absolute terms, and their prevalence will

FIGURE 5.2: DPV BUSINESS MODELS



Source: Adapted from IFC (2014); Singh, Sethi, and Mazumdar (2019); and CPI (2018).

Note: DPV = distributed photovoltaics; PPA = power purchase agreement; RESCO = renewable energy service company.

depend on market regulations, customers, and investors' preferences. Different countries would utilize different categories of models in combination based on the DPV market's maturity and the policy and regulatory environment, and they can all coexist in the same market, as has been seen in India (see Box 5.1). Hybrid business models are also possible, combining the elements of different models for a given project. All business models are available to public and private stakeholders. For example, a government can purchase DPV systems for its buildings (under the absolute up-front ownership model, or capital expenditure [CAPEX] model). It can lease systems or buy electricity via a power purchase agreement from a third-party investor in rooftop hardware, under the "solar as a service" model, or it can allow a utility to implement on-bill financing for DPV systems for low-income users who do not have a formal credit history and whose payment performance is best known to the utility from their electricity bill payment behavior.

Table 5.3 summarizes the three prevalent business models (including their variants), the related financing options, relevant use cases, and the associated issues/barriers that should be addressed for their implementation success for achieving DPV targets.

Customer-Owned (Full Payment Up Front, or CAPEX) Business Model

The up-front payment and instant full ownership business model is attractive for customers who face high retail tariffs (higher than the cost of generation of DPV). Once they get full ownership of the rooftop DPV system, they need not make any further payment for the portion of grid electricity bills that are now avoided

BOX 5.1

Indian Rooftop Solar Business Model Innovations in the C&I Segment

An important feature of the Indian distributed solar market is the “solar as a service” or third-party ownership business model. The third party is typically known as a renewable energy service company (RESCO). The RESCO looks for clients that are typically creditworthy commercial and industrial (C&I) rooftop owners. These clients are sold solar energy generated by the RESCO’s mini solar power plant, which will be installed on the clients’ rooftop or premises. The RESCO must offer a discounted price compared with the grid price to attract customers.

These creditworthy clients could directly qualify for a commercial loan to buy their own rooftop systems under the capital expenditure (CAPEX) model. However, for business strategy reasons they do not want ownership of the distributed solar systems. They prefer to keep their credit lines open to meet the needs of their core business—either in terms of working capital requirements or through term loans. Instead they enter into a contract with a RESCO that owns hardware and invite the RESCO to install their system on their rooftop. This allows the C&I client/rooftop owner to simply buy the solar energy “as a service” from a system installed on their own rooftop or premises. When they buy only the metered energy units without any ownership of hardware, the cost they bear for the solar energy becomes an operating expenditure on their income statement. The third-party ownership model is thus known as the operational expenditure (OPEX) model. The PV system’s purchase cost is not entered into the C&I company’s balance sheet since ownership is with the RESCO. The C&I company is effectively able to use solar energy with zero up-front payment.

The third-party ownership model, or the OPEX model, has four variations: (1) build-own-operate-maintain (BOOM), (2) build-own-operate-transfer (BOOT), (3) lease, and (4) rooftop rental.

Under the BOOM model, C&I customers want to permanently continue buying solar kilowatt-hours from the RESCO and never take ownership. The RESCO remains responsible for ensuring that the distributed solar system is always in working condition and generates maximum energy for the customers with whom the system is co-located. The RESCO installs, owns, operates, and maintains the hardware over its lifetime. If technology evolves—so that the same area can accommodate panels that generate twice as much energy as before—the RESCO needs to consider replacing the original panels and selling twice as much solar energy to the customers—if they are willing to buy. This could boost the RESCO’s revenues. BOOM is a pure OPEX model since the solar energy always remains an operating expenditure.

Under the BOOT model, C&I customer/rooftop owners estimate that in 10 or 12 years, their balance sheet would be sufficiently sound to accommodate solar panel ownership. They thus want a “deferred ownership,” under which they enter into
(continues)

BOX 5.1

Indian Rooftop Solar Business Model Innovations in the C&I Segment (Continued)

a 10- or 12-year power purchase contract with the RESCO. During this time, the RESCO earns enough money from selling solar energy to the customers to pay off the loan it availed to purchase the hardware. It also earns the desired rate of return on the 20 percent equity, which it had to contribute to qualify for the hardware loan. Once the loan is repaid and the return on equity is earned, the RESCO transfers hardware ownership to the customers for a symbolic \$1. The asset has life of at least 13–15 years remaining. It is fully owned by the C&I customers, who/which do not make any further payments but enjoy free solar energy kilowatt-hours and are responsible only for maintaining the system. BOOT is a hybrid of first OPEX and then CAPEX.

Under the lease model, C&I customers pay the RESCO at a flat monthly rate and energy is not metered. The RESCO does not bear the generation risk. Rooftop owners pay the RESCO the same amount, regardless of substantial generation due to a full month of sunny days or a small generation due to many rainy days. In case generation is high, the imputed per unit cost is low, and vice versa (in fact, in the event of insufficient generation, consumption must be supplemented with additional purchase from the grid). Under the lease model, customers bear all of the generation risk—unlike the BOOM and BOOT models, where the RESCO was the one losing, with reduced revenue in the event of insufficient solar generation due to bad weather or poorly maintained panels. The cost of solar energy is predictable for customers as an operating expenditure due to the flat rate they pay as a lease. This is a simplified business model with predictable payment. There is no ownership transfer at the end of the lease unless this is included in the contract (in which case it is a variation of BOOT).

Under the rooftop rental model, rooftop owners do not consume any part of the solar energy generated by the systems installed on their roofs. Instead, roofs are selected for their favorable location and solar generation potential. If the rooftop area is large and south facing, shade free, and connected to a noncongested grid, then this is ideal for any RESCO that wants to sell its entire generation directly to the electricity distribution company (discom). Occasionally, the discom itself rents the roof. In certain regulatory environments, the discom owns the distributed solar systems and only needs to install them on suitable rooftops near load centers to avoid transmission losses. Some discoms invest in solar to reduce their cost of service to subsidized clients, whereas others do so to meet their renewable purchase obligations. RESCOs or discoms wishing to feed the entire energy from distributed generation directly into the grid view suitable roofs as prime real estate. They work out a negotiated rate per unit area with rooftop owners, who receive the rental amount monthly as a deduction from their electricity bill or as a stand-alone payment. Rooftop rental is the only business model where rooftop owners consume no solar energy but receive a payment.

Source: Mukherjee 2022.

TABLE 5.3: DPV BUSINESS MODELS, FINANCING OPTIONS, APPLICABLE USE CASES, AND ISSUES/BARRIERS TO BE ADDRESSED

BUSINESS MODEL (INCLUDING VARIANTS)	DESCRIPTION	FINANCING ARRANGEMENT	USE CASES FOR WHICH IT IS RELEVANT	BARRIERS/ISSUES
Customer owned	<ul style="list-style-type: none"> The DPV system is installed by customers on their premises to primarily meet their self-consumption under a feed-none or feed-some arrangement with net metering or net billing. Note feed-all is also possible under gross metering but is less preferred. The system installer provides EPC and other installation support for a fee. The entire project (including performance) risk due to DPV is borne by the customer, who owns the asset. 	<ol style="list-style-type: none"> Self-financing with full up-front payment Loan financing from banks against collateral from customers Leasing arrangement Distribution utility can provide financing services through PPA securitization and facilitate loan recovery through on-bill financing Government direct subsidy Indirect subsidy by government through the provision of accelerated depreciation (higher than the standard permissible depreciation) 	<p>From the customer's perspective:</p> <ol style="list-style-type: none"> Bill reduction Least-cost backup <p>From the distribution utility's perspective:</p> <ol style="list-style-type: none"> Least-cost generation Transmission and distribution alternative 	<p>From the customer's perspective:</p> <ol style="list-style-type: none"> Up-front cash commitment Ability to evaluate the utility; design, procure, and install the DPV system; and ensure quality Operate and maintain the DPV system <p>From the distribution utility's perspective:</p> <ol style="list-style-type: none"> Loss of better-paying customers—adverse impact on cash flow Loss of revenue and ability to cross-subsidize lifeline customers; increased tariff may increase bill payment defaults Reduced ability to recover fixed costs Bidirectional flows result in operational issues <p>General</p> <ol style="list-style-type: none"> Limited ability to scale up DPV
Third-party service provider or solar as a service/ RESCO	<ul style="list-style-type: none"> The third party undertakes all activities from design to operation, and finances the DPV. The third party enters into a rental agreement with a customer for accessing the roof under a feed-none arrangement and into a PPA with the distribution utility (like an IPP). 	<ol style="list-style-type: none"> Financing is arranged by the third party through financial institutions (debt) and equity investors for a portfolio of projects Leasing arrangement with an equipment supplier for onward lease arrangement with the customer 	<p>From the customer's perspective:</p> <ol style="list-style-type: none"> Bill reduction Least-cost backup <p>From the distribution utility's perspective:</p> <ol style="list-style-type: none"> Least-cost generation Transmission and distribution alternative Utility bootstrap 	<p>From the third party's perspective:</p> <ol style="list-style-type: none"> Customer payment default risk Customer may like to exit the roof-related agreement/ PPA; in that case, alternative customers (sites) for the DPV system, which has been customized for the roof of the customer who has exited the agreement, may not be found

(continues)

TABLE 5.3: DPV BUSINESS MODELS, FINANCING OPTIONS, APPLICABLE USE CASES, AND ISSUES/BARRIERS TO BE ADDRESSED (*Continued*)

BUSINESS MODEL (INCLUDING VARIANTS)	DESCRIPTION	FINANCING ARRANGEMENT	USE CASES FOR WHICH IT IS RELEVANT	BARRIERS/ISSUES
	<ul style="list-style-type: none"> The third party enters into an agreement with a customer for supply of power under a feed-all arrangement at rates that can be lower than the retail tariff. An agreement is made with the customer and the distribution utility under a feed-some arrangement. 	3. Concessional loans by the government	4. Ancillary services 5. Community social support 6. Financial loss reduction 7. Box solution	3. Project performance risk since roof owner may block access to the roof where the DPV is installed 4. Payment default risk by the distribution utility
Utility led	<ul style="list-style-type: none"> The distribution utility undertakes system design, financing, operation, and maintenance, which it either does itself or gets done via a third party under all the three feed-in arrangements possible. DPV ownership and the activities that can be undertaken by the distribution utility are as per the regulatory provisions for license and its terms and conditions. 	1. Debt from a financial institution 2. Third-party funding, with repayment as a rental fee or a tariff for the energy supplied 3. Public financing/grants for capital investment 4. Customer may agree to finance a part of the DPV systems in exchange for lower payments against electricity tariffs 5. Recovery of investment through an aggregate revenue requirement if permitted by the regulator	From the customer's perspective: 1. Additional income leading to bill reduction 2. Least-cost backup From the distribution utility's perspective: 1. Least-cost generation 2. Transmission and distribution alternative 3. Utility bootstrap 4. Ancillary services 5. Community social support 6. Financial loss reduction 7. Box solution	From the distribution utility's perspective: 1. Capacity to plan, finance, build, operate, and maintain DPV systems over their useful life 2. Third-party operators may demand payment security

Note: DPV = distributed photovoltaics; EPC = engineering, procurement, and construction; IPP = independent power producer; PPA = power purchase agreement; RESCO = renewable energy service company.

due the system's ownership. Depending on the percentage of their electricity consumption that the DPV can supply, they may be able to enjoy substantial savings in the daytime and reduce their grid purchases primarily to meet the nighttime demand. If business is closed at night, the DPV system can help them become largely self-sufficient and significantly reduce consumption at high retail tariffs paid to the utility. In developing countries, C&I customers generally cross-subsidize other customers. The average retail tariffs for them are thus significantly higher than the average cost of supply for the distribution utility. Further, such customers have also been found to face electricity quality and reliability issues. For such customers, the main motivators for DPV installation are electricity bill reduction and low-cost power backup. Meanwhile, the customer-owned business model cannot contribute significantly to DPV market development due to its limited outreach, since this model will likely be attractive only to customers who can pay up front in full or have access to a loan to finance the DPV system's cost. Project financing (lending) support is available only if customers can provide a collateral to the financial institutions. Governments may choose to promote such business models through a number of policies, including lowering lending rates (interest cost reduced) through renewable energy funding (including DPV) from financial institutions under preferential low-cost lending (provision for low-cost funding) and allowing accelerated depreciation (higher than the normal depreciation rate) of the capital cost of DPV for its early recovery. Besides their ability to finance DPV adoption and absorb the allowed depreciation, customers must also be able to meet the cost of hiring a project-implementing partner to install the system on their premises.

As noted, this business model will be preferred by customers who are well-off and can pay high tariffs. Distribution utilities are not keen on supporting such business models since they lose electricity sales to customers paying the highest tariffs, which adversely affects their cash flow and cost recovery. To compensate for this revenue loss, the tariffs of other customers (who have not installed DPV) will have to be raised, further aggravating the situation. Although the limited outreach of the up-front payment and instant full ownership business model hinders it from contributing significantly to DPV market development, the demonstrative effect of such business a model on other customers is an important step toward the market's development and of its ecosystem. Even in a mature market, DPV systems could see investment from some C&I customers that do not wish to avail of debt but wish to reduce their electricity bills, or are keen to take advantage of the benefits of accelerated depreciation accounting. Such customers could opt for this model even when there is a range of other models available to them (see Box 5.2). Distribution utilities must realize that such developments are inevitable and must take measures to realize the benefits that can possibly accrue to them from DPV installation. Distribution utilities can take the following measures:

- Promote DPV in operational areas where it will help them avoid/delay CAPEX outlays in transmission and distribution schemes (Use case 4).
- Promote such models with behind-the-meter energy storage as a part of demand-side management so that the utilities can avoid their own purchase of costly power during peak hours of the day. (This means utilities want as little solar energy coming into their grid during the midday hours, when solar energy production is the highest but demand is the lowest—it is better for utilities if customers also invest in storage and keep this midday power on their own premises, instead of feeding it to the grid.)
- Promote time-of-use tariffs, that is, it is a source of low-cost power (Use case 3). This means the price paid by the prosumer and the utility will vary at different times of the day, reflecting peak times—when the demand for power is the highest but power is the most scarce, and, therefore, at a high price—and trough times—when power is abundant, at midday, but demand is lowest, resulting in lower payment for the solar electricity units supplied to the utility at midday compared with the units supplied in the evening.

BOX 5.2

RESCO Business Model: An Example from China

The Beijing Distributed Solar PV Scale-Up Project (World Bank 2013) is an example of the *bill reduction* use case, which demonstrates the viability of the third-party service company business model to scale up DPV deployment in China, including for public consumers, contingent on the right policy support. During project inception, the service company model was relatively new for DPV in China. The project was implemented by Yuanshen Energy Saving Technology Company, a subsidiary of the government-owned Beijing Energy Investment Holding Company Limited, which was originally established to provide demand-side energy efficiency services. For this project, the company established a complementary new business line that involved energy management contracts signed with different consumers. The company provides finance, engineering, procurement, and construction services; retains DPV ownership; and splits with consumers the financial savings from reduced electricity bills to pay back the government loan availed to cover up-front costs. To kick-start the market, Yuanshen relied on initial central and local government incentive schemes in the form of subsidies.

The performance of the service company business model varied significantly for public sector and private consumers. The project originally aimed to install 100 megawatts (MW) on rooftops of schools, with systems ranging from 50 to 200 kW. Thirty megawatts were installed during the first four years of implementation. Scale-up in schools was hindered, however, due to misaligned interests of key public sector parties. First, public schools did not directly benefit from electricity cost savings since the municipal government pays electricity expenses centrally. Schools had little incentive to sign up for the program. Second, schools in Beijing pay the lowest electricity tariffs. This resulted in the energy service company having to share a relatively small margin of bill reduction savings. The government also began phasing out subsidies as the prices of photovoltaics modules fell. In response, the project expanded its focus to cover private consumers, whose electricity bills, at higher rates, constituted a significant operational expense. The project achieved 70 MW during the last two-year period, including several large installations, such as on industrial rooftops and car park canopies. The total 100 MW installed was equivalent to 20 percent of the total solar photovoltaics capacity in Beijing as of December 2019, when the project closed. Over the project period, the company used the same business model to install 207 MW in other parts of China. The company expects some financial setbacks once subsidies are completely phased out, although continuous cost reduction and economies of scale should allow it to prosper in the commercial and industrial sector. The varying success between public and private consumers highlights the need for deep market research and consultation covering multiple sample sites to test a new business model. Subsequent projects elsewhere have explored government-led business models for public consumers.

Source: Adapted from World Bank (2020b).

- Treat this as a new business opportunity for additional income by providing all services that an implementation partner is likely to provide to a customer within the framework of the regulatory provisions for a license. This means the distribution utility tries to mimic the range of services offered by the third-party service provider and creates a similar value proposition for its customers so as to not lose them to the third-party investor.

The following regulatory interventions may be required to balance the interest of customers and the distribution utility (overcome its reluctance to grant approval for connecting DPV assets to the distribution network) for the successful implementation of this business model and the growth of the DPV market:

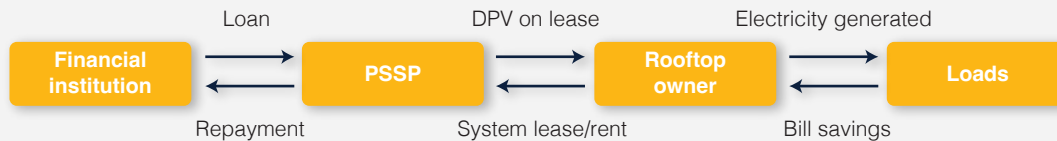
- Rebalancing the fixed tariffs and energy tariffs of the customer categories that are most likely to implement DPV so that fixed charges better reflect the fixed costs of the distribution utility, which must be borne by all its network users.
- The fixed cost that a customer must pay to the distribution utility must be recovered from that customer even if DPV generation meets the entire self-consumption. As long as the customer remains connected to the grid, they must pay their share of the grid maintenance cost via a suitable cost-reflective fixed charge (which does not depend on grid electricity consumption, which may be near zero).
- The distribution utility must notify a time-bound procedure for the connection of DPV systems to its distribution system. This will prevent procedural issues from hindering DPV's growth.
- The technical standards applicable to DPV should be transparent, clearly laid down, and strictly enforced so that customers have faith in DPV fulfilling the purposes for which it is installed.
- Clear commissioning and testing standards for the connection of DPV systems to the distribution system must be established. This is ensure the security and reliability of the distribution system.
- Agreements to be concluded between customers and the distribution utility must be standardized for consistency in the interpretation of terms and conditions, and for clarity of roles and responsibilities of the parties toward DPV systems' installation and operation.

Third-Party Service Provider (Solar as a Service) Model

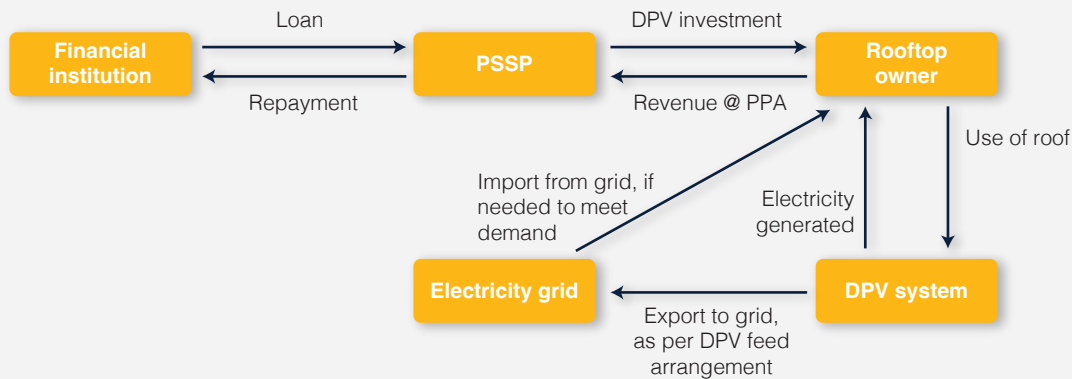
Under this business model, DPV systems are installed on customers' premises but are owned by a third party, such as a renewable energy service company (RESCO). The third-party service provider may also act as an aggregator (provided the regulatory framework permits or encourages aggregation for greater efficiency). The RESCO identifies willing and financially capable DPV users, on whose rooftops it is prepared to install its own DPV equipment and with whom it is prepared to enter into a solar energy sales contract. The customer and the third-party service provider may sign a lease (Figure 5.3a) or a power purchase agreement (PPA) at a predetermined price per kWh generated. This price is to be paid over a prespecified period—typically coinciding with the billing cycle (Figure 5.3b)—and the agreement's duration is typically related to the term of the loan that the RESCO has taken to finance its DPV equipment. The fundamental premise of this business model is that the RESCO finds and possibly also aggregates creditworthy customers and then obtains bulk purchasing discounts on the large volume of DPV hardware needed for this group. Once the discounts are secured, the RESCO then calculates the amount that it can borrow to finance this discounted purchase. The monthly solar energy sales contracts will generate revenues from the RESCO's customers' roofs. The RESCO will use the revenues to repay the loan that it had taken to buy the hardware. What this means in effect is that the fortunate customers—who were “chosen” by the RESCO—will not have to take a loan, nor pay any up-front costs for hardware. They can

FIGURE 5.3: VARIATIONS OF THE THIRD-PARTY BUSINESS MODEL FOR DPV DEPLOYMENT

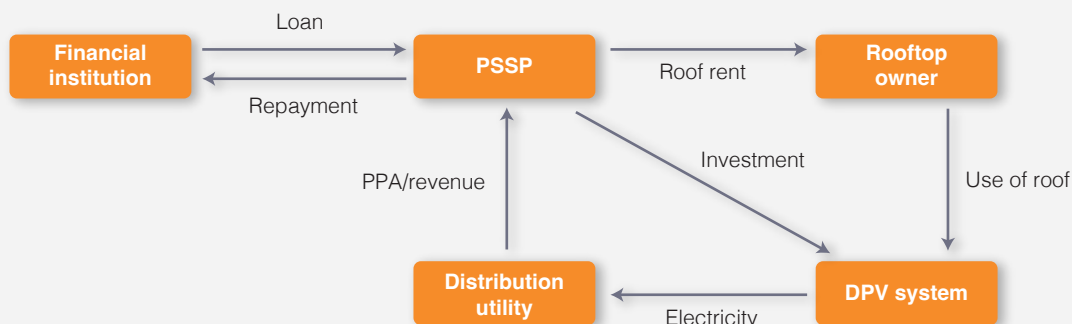
a) Third-party-owned leased solar rooftop system



b) Third-party-owned DPV system (PPA)



c) Third-party-owned DPV system and supplying power to the distribution system



Source: Adapted from Singh, Sethi, and Mazumdar (2019).

Note: DPV = distributed photovoltaics; PPA = power purchase agreement; PSSP = private sector (third-party) service provider.

only pay the agreed price per kWh of the solar electricity generated on their rooftops, which is metered, and produced by the RESCO's equipment. This is a zero up-front cost model, where solar energy is literally available for consumption and payment only on an "as used" basis. The RESCO bears all equipment risk. Under such scenarios, the third party supplies electricity to the customer under a feed-none or feed-some arrangement. Under the feed-all arrangement, the third party signs a roof rental agreement with the customer (a roof owner) and signs a tripartite PPA with the customer and the distribution utility. All of the electricity generated by the DPV system is fed into the distribution system, and the distribution utility pays the third party for this electricity directly at the pre-agreed rate (as per the PPA) (Figure 5.3c). Figure 5.3 outlines different configurations of third-party-owned business models for DPV deployment.

Certain customers find the third-party business model more attractive than the CAPEX business model for DPV market development because the former model helps manage project risk better. The third-party owner, instead of the customer, assumes the DPV system's operational risk. If the system malfunctions,

due to, for example, damaged panels, generation will be lower, and the customer will have to pay for fewer units. The owner, which is the RESCO, will bear the revenue loss and will be driven to repair the equipment damage as quickly as possible to maximize its sales revenues. Under the CAPEX model—where the customer/owner bears all the operational risk from the outset—there is a possibility that an inexperienced rooftop owner remains unaware of the system’s below-capacity operation for a while. The third party develops the skills to address DPV’s design-, installation-, operation-, and maintenance-related risks. As the third party undertakes a portfolio of projects, achieves lower project and operating costs due to economies of scale of project implementation and operation, and obtains hardware purchase discounts due to aggregation, it may require a smaller loan and have lower financing costs, as well as less debt service burden. The third party can use innovative nonrecourse project financing models to raise a larger volume of funds at a lower cost and absorb government incentives such as accelerated depreciation more efficiently in its business. The third-party business model has enabled quick scale-up of the DPV market in developing countries like India. This is because third parties actively scout and convince creditworthy customers to install DPV, fund the technology at lower costs (to achieve grid parity tariffs), and assume project implementation and operational risks. This model therefore addresses the barriers faced by the CAPEX business model in DPV deployment (see Box 5.2 for an example from China) (Obi and others 2022; World Bank 2020b; SEG Ingeniería; WB, 2022).

Although the third-party business model addresses the major concerns of creditworthy customers, issues of concern to the utility persist. These include the more critical issues of the distribution utility losing revenue from high-tariff-paying consumers and the nonrecovery of its fixed costs. Distribution utilities are inherently reluctant to this business model’s implementation. However, they must be encouraged to deploy “solar as a service” business models for use cases such as least-cost generation, transmission and distribution alternative, ancillary services, community social support, financial loss reduction, and well-tested solutions to improve operational and financial business efficiency. Distribution utilities can also avail the benefits offered by the business model [e.g., lower project risk for customers, lower cost of finance for third-party investors, the ability to raise large volumes of funds, and lower-cost electricity production by DPV—improving supply reliability and quality (i.e., better operational performance)] in fulfilling its universal service obligations.

Apart from the suggested measures to facilitate the CAPEX business model’s implementation, distribution utilities can also take the following measures to facilitate the deployment of a third-party business model:

- Identification of business opportunities such as sharing consumers’ electricity consumption data and bill payment history with financial institutions and project developers, assistance in customer credit rating, and facilitating payment from DPV customers to the third-party service provider for the electricity consumed from the service provider’s DPV—by acting as an “on-bill collection agent” for a lender at a minimal additional transaction cost.
- Analysis of the costs and benefits of different use cases and incorporation of beneficial use cases in their business.
- Aiding in the implementation of different use cases that are beneficial to the market and contribute to its evolution (business opportunities).

The following regulatory interventions may contribute to the implementation success of the “solar as a service” business model by helping to balance the competing business interests of the third-party investor and the distribution utility:

- Implementation of supportive regulatory measures (identified earlier) that facilitate the CAPEX business model’s deployment.

- A provision for the third-party service provider to sell electricity to customers without requiring an electricity generation and distribution license, and develop abridged (simplified) licenses for the case.
- Standardize different agreements to be concluded between the third-party service provider, customers, and the distribution utility.
- Ensure unhindered access to the distribution system for sale by the third-party service provider to customers where DPV is not colocated (group metering and virtual metering).
- A framework for cost-benefit analysis of DPV under various use cases and guidelines for the distribution utility to consider use cases for its business and system planning.

Utility-Led Business Model

This model is still nascent and currently has limited global spread in terms of implementation. However, it is expected to attract more interest from the distribution utilities of developing countries, especially those that are not in financial distress. Utilities are battling numerous priorities simultaneously and are therefore likely to require policy and capacity building support to be able to implement this business model as a priority.

This business initiative is distribution utility led. The distribution utility offers the customers in its operation area who are willing to deploy DPV on their premises DPV design-, finance-, installation-, operation-, and maintenance-related services itself or via a third party (an external agency or a team of in-house consultants). The provision of these services depends on the regulatory framework. The form and extent of the distribution utility's business initiative will depend on the regulatory provisions for an electricity distribution license and its terms and conditions. The three regulatory possibilities are as follows:

- Electricity distribution and supply are licensed activities, and as per the license's terms and conditions, the distribution utility cannot generate electricity or own generating assets. Thus, the distribution utility cannot act as a third-party service provider since generation is typically considered a separate licensed activity.
- Electricity distribution and supply are licensed activities, and as per the license's terms and conditions, the distribution utility is not barred from generating electricity or owning generating assets for self-use or for sale in the power market (the legal and regulatory framework in India allows distribution utilities this power supply option). The distribution utility can thus act as a third-party service provider.
- Electricity distribution and supply are two different business activities. Electricity distribution is a licensed activity, whereas electricity supply does not require a license. The electricity supplier is free to choose any power supply option for its customers and can thus act as a third-party service provider.

The distribution-utility-led DPV deployment business model hinges on the regulatory possibilities as indicated above. Distribution utilities can offer a range of services. These could be a combination of the following services, which could be offered based on the distribution and supply license's terms and conditions.

1. Regulatory restriction on the ownership of generation assets by a distribution utility

Distribution utilities under such regulatory restrictions may act as facilitators, or as aggregators and engineering, procurement, and construction services providers. They may provide services such as demand aggregation for DPV. The utilities may identify modalities of the business model, for example, the rent to be paid by a third party for a roof under a feed-none arrangement, fixing the tariff to be paid by the customer for the energy consumed, or the project cost to be paid by the customer to the third party under a feed-all or feed-some arrangement through a competitive or any other acceptable process.

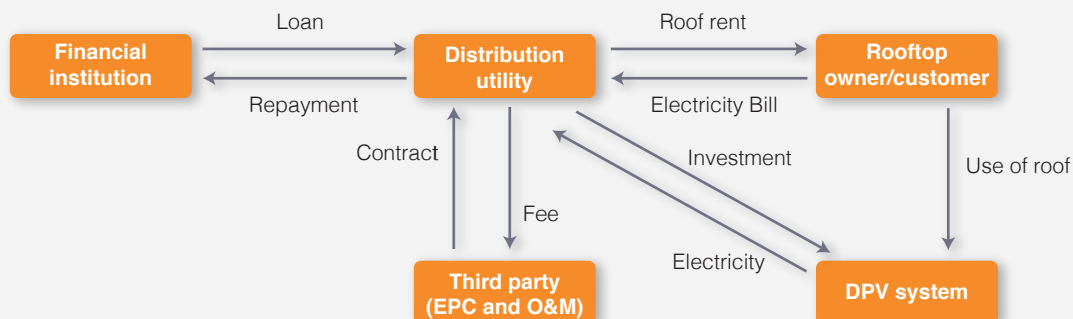
Distribution utilities may select project developers or engineering, procurement, and construction (EPC) services providers for customer-owned models (through a competitive selection process) for addressing customers' project risk. They may also provide project management services to customers; for example, they may help specify equipment standards, develop and vet project design, standardize contracts to be signed between customers and project developers, and ensure customers receive the agreed services from project developers. Distribution utilities may also facilitate the payment of energy consumption charges from customers to developers, besides facilitating the assessment of customers' credit ratings by sharing information related to their bill payment history with financial institutions and project developers, and servicing loans to customers through electricity bills. Distribution utilities can also facilitate access to low-cost finance by participating via a tripartite agreement between themselves, the customer, and a financial institution, and assuming the responsibility of collecting equated monthly installments through on-bill financing. This financing support entails some financial risk, which may, however, not be significant because of distribution utilities' unique relationship with customers and the right to disconnect supply in case equated monthly installments are not paid. However, the assumption of such a financial risk may require evaluating regulatory provisions and the regulator's approval. Distribution utilities have thus adopted variants of this business model by choosing combinations of listed services depending on their technical capabilities, human resources' availability, and perceived business risk. Distribution utilities provide these services as part of their regulated business and share the fee earned from the services provided to customers or third party as Other Income considered as part of the aggregate revenue requirement. This business model can address the business risks for customers, developers, and financiers better than the second-generation model since it leads to reduced technology risk, transaction cost, and customer acquisition cost. Economies of scale, lower project cost, higher payment security, and greater contract compliance reduce the financing cost, which leads to lower LCOE compared with the first- and second-generation models. The business risk increases for the distribution utility, however, although this model can address this risk better, due to customer connect, the business's monopolistic nature, technical competence, the scale of business, and the greater faith of financial institutions in the model to address the loan default risk.

2. No regulatory restriction on the ownership of generation assets by a distribution utility (or exceptions for some types of distributed generation)

The distribution utility can aggregate the demand for DPV and invest in DPV projects. It acts as a third party (super RESCO), wherein it owns, operates, and maintains (although these services can be outsourced) DPV systems under a preferred feed-some or feed-all arrangement. The distribution utility enters into a lease agreement with the customer for its roof for the DPV systems' useful life and pays under the agreement by offering a certain percentage of the DPV-generated power for free or paying a fixed amount (per kW) and adjusting it in the customer's bill. This super RESCO arrangement has another variant, where the distribution utility does not own the assets but enters into a PPA with a RESCO (which owns, operates, and maintains the DPV system)—at a price determined through a competitive selection process—and a lease (or rental) agreement with the customer (which is subleased to the RESCO), like the one described earlier. The distribution utility thus acts as a trader. The distribution-utility-owned business model is better placed than the earlier version of the distribution-utility-led DPV business model, described in the previous paragraph, since it reduces the transaction cost further, lowers the financing cost, boosts economies of scale for greater reduction of operational and maintenance costs, and facilitates larger quantum of DPV financing—further lowering the LCOE, and, in turn, facilitating more rapid DPV deployment. The business risks for customers, the RESCO, and financial institutions are further reduced, whereas they increase for the distribution utility—offset by increased income generation from the trading margin on power sales, reduced power purchase costs (LCOE of solar is now less than the generation cost of a conventional plant), compliance with renewable energy purchase obligations, and preventing the migration of high-paying customers to self-generation. The distribution utility continues to avail itself of the benefits that accrue under the use cases described earlier in Table 5.3 for the third-generation business model.



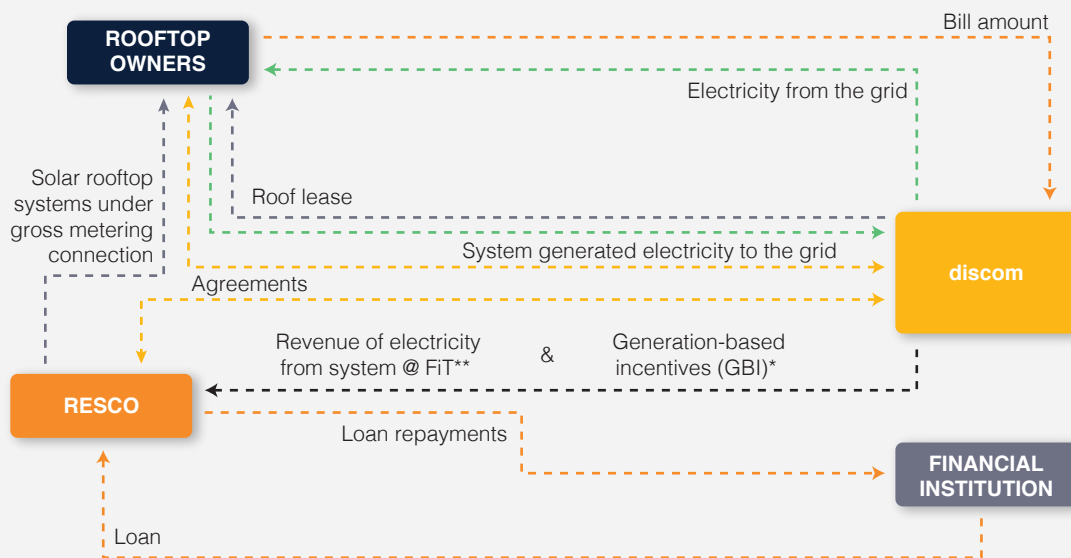
FIGURE 5.4: UTILITY-BASED BUSINESS MODEL BASED ON A FEED-ALL ARRANGEMENT, WITH THE UTILITY ACTING AS A SUPER RESCO



Note: Rent for roof can be paid as free energy or a discount on the customer's (rooftop owner's) electricity bill. DPV = distributed photovoltaics; EPC = engineering, procurement, and construction; O&M = operation and maintenance.



FIGURE 5.5: UTILITY-BASED BUSINESS MODEL BASED ON A FEED-ALL ARRANGEMENT, WITH A PPA WITH A RESCO



Note: APPC = avoided power purchase cost; discom = distribution company; FIT = feed-in tariff; PPA = power purchase agreement; RESCO = renewable energy service company.

Box 5.3 describes examples of hybrid business models for mutual benefits that are being explored in Nigeria.

DPV deployment is gradually growing, although not linearly, from a customer-led model focused on the direct ownership of systems most often installed on rooftop owners' premises, to models that separate DPV system ownership from the ownership of rooftops. This enables distribution utilities to drive DPV deployment. This model also tries to align distribution utilities' incentives with greater DPV deployment, in turn directly addressing the utilities' inherent reluctance toward DPV, which they see as a revenue loss for themselves. This new and evolving business model has the potential to provide distribution utilities with significant financial and technical benefits under the following use cases:

1. Least-cost generation
2. Transmission and distribution alternative
3. Utility bootstrap
4. Ancillary services
5. Community social support
6. Financial loss reduction
7. Box solution

BOX 5.3

Exploring Business Models to Improve Utility Finances in Nigeria with Undergrid Microgrids

Nigeria is exploring the viability of microgrids or mini grids for undergrid businesses or communities (i.e., communities underserved by discoms) akin to the *utility bootstrap* use case. Defined as having up to 1 MW capacity, microgrids can improve service reliability while helping reduce system cost compared with isolated mini grids by leveraging the existing distribution infrastructure (see the glossary for the differentiation between mini grids and microgrids). Four business models have been identified, each led by a different actor, namely:

- **A private operator**, which would engage the discom and community;
- **A special purpose vehicle (SPV)**, formed by the discom investors, for example, with certain functions subcontracted to an operator;
- **A cooperative**, formed by the community; or
- **A collaborative SPV**, where the operator, the community cooperative, and the discom's investors share asset ownership and operation.

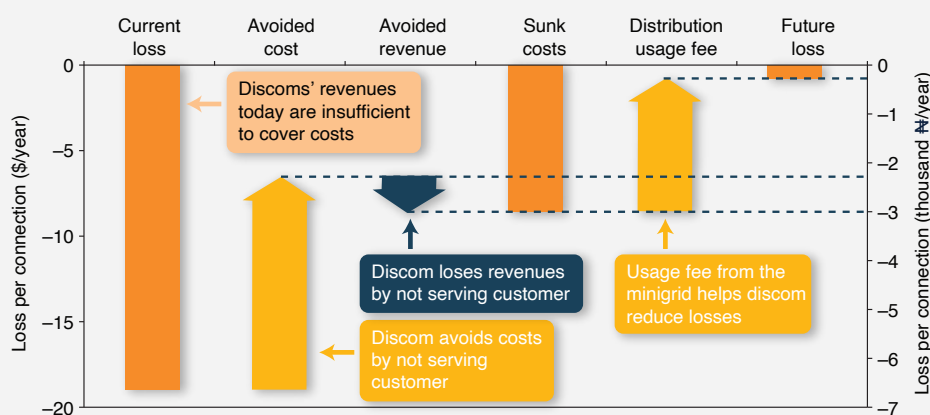
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BOX 5.3

Exploring Business Models to Improve Utility Finances in Nigeria with Undergrid Microgrids (Continued)

Figure B5.3.1 illustrates a typical case where the discom can avoid 50 percent of the current financial losses by cooperating with a mini-grid developer to serve a community, thereby eliminating the costs of bulk power purchase and distribution, and variable operating expenses. While the discom retains some sunk costs (e.g., overhead, debt, asset depreciation), it will, nevertheless, save a minimum of US\$12 per connection on average. Finances are further improved with additional revenues through a usage fee (the value shown is representative). Whereas distribution utilities are not currently covering their costs, and struggle to invest the required capital in metering all customers, the independent operator can charge a cost-reflective tariff and install metering solutions to minimize collection losses.

FIGURE B5.3.1: AN ILLUSTRATIVE MODEL TO IMPROVE PROFITABILITY WITH AN UNDERGRID MINI GRID IN NIGERIA



Source: Graber, Mong, and Sherwood 2018.

Note: Discom = distribution company.

As noted earlier, this model enables distribution utilities to reach out to a larger number of customers who may benefit from DPV deployment. The key feature of the utility-led model is that the distribution utility can enable customers to qualify for loans at a lower cost when DPV deployment is the objective and purpose. Its existing business relationship with customers allows it to more accurately assess customers' creditworthiness and ability to pay. Even if customers lack a formal credit history, the utility has a rich data set of all customers' payment history and electricity consumption patterns. Accordingly, it can become a valued partner in tailoring loan repayment options for customers who represent lower rates of default. In the event of a default, the distribution utility can remove the defaulting customers' DPV systems and reinstall them on other customers' premises, thus providing a measure of support for the lender. The possibility of existing DPV systems becoming stranded is thus low. The distribution utility can aggregate the demand for DPV, achieve economies of scale in the business, and rapidly scale DPV deployment. This business model offers economies of scope to the distribution utility, enabling it to offer various services (identified earlier) at a lower cost (because it can optimize the use of manpower and other resources) and raise a larger amount of funds. The distribution utility is thus in an advantageous position to lower DPV's project and operation costs, aiding in faster DPV scale-up. The resulting economies of scale will enable the distribution utility to reduce these costs even further.

This business model offers the distribution utility another major advantage: the utility can plan and influence the geographical dispersion of DPV and its deployment timing through an appropriate tariff and other financial incentives for customers. It can integrate DPV in its power procurement and distribution system planning to avoid/defer the purchase of costly power and CAPEX on distribution schemes. The latest technological developments in DPV systems enable the technology to provide ancillary services, which in the emerging scenario of increased penetration of renewable energy, are being sought through mandatory provisions and levy of costs for these services on distribution utilities. Distribution utilities can reduce their financial loss by incentivizing customers (especially those paying low tariffs and with poor payment track record) to deploy DPV for self-consumption and export surplus generation to their network for additional income (e.g., the Government of India's KUSUM scheme for agricultural customers). Governments and distribution utilities can provide these customers with financing support (through subsidies designed to maintain a low tariff, by helping cover the funding cost for meeting financial losses, by helping cover higher commercial distribution losses, and by helping cover cash losses due to lower collections) for DPV system procurement and installation.

The ways in which utility-led business model allows distribution utilities to preserve revenue and improve their finances have already been described. Since DPV deployment is inevitable, this business model converts DPV development into a business opportunity. However, the legal/regulatory provisions for the model may be country specific and may have to be evaluated. The terms and conditions of the distribution license should allow distribution utilities to undertake these activities. Regulations are not difficult to modify in case there is a regulatory barrier, although the modification of a law may prove much more difficult in case of a legal system barrier. Table 5.4 shows some examples of distribution-utility-owned business models that have been successfully implemented by Indian distribution utilities to avail the business opportunities emerging from the deployment of the DPV market.

Distribution utilities can encourage DPV installation in areas with high technical distribution losses and low voltage. DPV installation significantly reduces the distribution's system technical losses due to reduced power flows, which are proportional to the square of current flows. The reduced current flows also reduce the voltage drop in the distribution system, improving its voltage profile. Utility-led business models may be particularly relevant in countries affected by fragility, conflict, and violence. For instance, as part of their strategy to boost revenue recovery and establish a sound commercial relationship with consumers, distribution utilities may install DPV systems to provide a better-quality service to some consumers and, in exchange, also install meters at their residences to increase billing and bill collection. Increased supply reliability and quality, which cannot be guaranteed for other grid customers, are likely to motivate consumers to pay for the power. This could be a business option for distribution utilities in deep financial and operational difficulty. DPV's modular nature allows

TABLE 5.4: THE UTILITY-OWNED BUSINESS MODEL AND DEMAND AGGREGATION MODEL FOR RESIDENTIAL CUSTOMERS IN THE STATE OF KERALA, INDIA

MODEL 1	MODEL 2 (120/150/200 KWH/MONTH)				MODEL 3
<ul style="list-style-type: none"> The distribution utility aggregates willing consumers. Customers lease their roofs and receive 10 percent solar power free of cost. The distribution utility/RESCO invests in DPV; designs and operates the systems; and generates/sells power. The RESCO sells power to the distribution utility at a competitively determined tariff. 	<ul style="list-style-type: none"> Consumers pay only part of the capital cost; the remaining is contributed by the distribution utility. The distribution utility (can be subcontracted) is responsible for designing, installing, and operating DPV systems. Consumers get an energy rebate as part of solar generation. Options are available based on monthly consumption. 				<ul style="list-style-type: none"> RESCO is responsible for supply, installation, metering, testing, and commissioning. RESCO is responsible for the supply of power for 25 years. O&M for 25 years is mandatory. RESCO paid two-thirds of the capital cost upon the plant's commissioning and the remaining one-third of the capital cost is paid on a levelized tariff basis throughout the project life. Customers are to be paid a roof rent.
	OPTION	AVERAGE MONTHLY CONSUMPTION (KWH)	CONSUMER'S CONTRIBUTION % IN PROJECT COST	REBATE % OF GENERATION	
	1A	Up to 120	12%, maximum of \$77/kWp	25%	
	1B	Up to 150	20%, maximum of \$136/kWp	40%	
	1C	Up to 200	25%, maximum of \$173/kWp	50%	

Source: https://solarrooftop.gov.in/grid_others/knowledge.

Note: DPV = distributed photovoltaics; kWh = kilowatt-hour; kWp = kilowatt-peak; O&M = operation and maintenance; RESCO = renewable energy service company.

it to be deployed initially in one region—isolating a microgrid of consumers to guarantee them service even during grid malfunction—at a reasonable cost and expanding services rapidly.

Distribution utilities may take the following measures to avail business opportunities emerging from the third-generation business model:

- Identify use cases that will be beneficial to it;
- Consider the impact of DPV installation on power procurement requirements and distribution system planning;
- Develop business plans and implementation strategies for the identified use cases;
- Identify DPV's geographical dispersion and deployment timing;
- Identify and tie up with third parties for DPV implementation, financiers, DPV equipment suppliers; and
- To comply with regulatory requirements, maybe form a separate and distinct business entity to carry out this business.

The following regulatory support may be required to promote the third-generation business model:

- Clarity on whether the distribution utility can avail business opportunities emerging from the third-generation model—especially whether investment in and ownership of DPV assets is a part of its regulated distribution business or whether it will be a separate unregulated business;

BOX 5.4**Nigeria's Distribution-Utility-Owned Business Model**

Despite its potential, the growth of embedded generation in Nigeria has been limited, mostly due to the concern about the ability of the Nigerian distribution companies (discoms) to pay for the electricity purchased. The renewable-embedded generation (REG) business model improves supply for customers by combining solar photovoltaics (PV), battery storage, and thermal generation. Through the inclusion of solar PV, an REG plant increases supply for all customers in a given REG cluster, while the inclusion of battery storage and thermal generation enables reliable 24/7 power supply to a subset of customers called premium customers. The model addresses the discoms' payment concern by directing REG customers' payment into an independent collections account (ICA). The ICA uses customers' meter numbers to identify them on REG feeders and directs their payments into a separate account, which is not directly managed by the discoms.

Providing additional generation to the discoms increases their electricity sales and, thus, their revenues. This provides the discoms with the capital to improve their distribution network and serve their customers, in turn reducing their losses. The REG model also helps discoms boost profitability by charging customers cost-reflective tariffs. Finally, the REG model also helps discoms prevent premium customers, for example, companies with large facilities, from leaving the network.

The REG business model reduces electricity costs for customers compared with their current mix of grid supply and self-generated electricity. Costs for premium customers can be reduced by up to 50 percent, whereas costs for nonpremium customers are reduced by 20–30 percent. On the other hand, the REG business model allows developers to access to a larger number of customers, provides them with a risk-free structure to collaborate with discoms, and enables their access to finance from dedicated climate financiers.

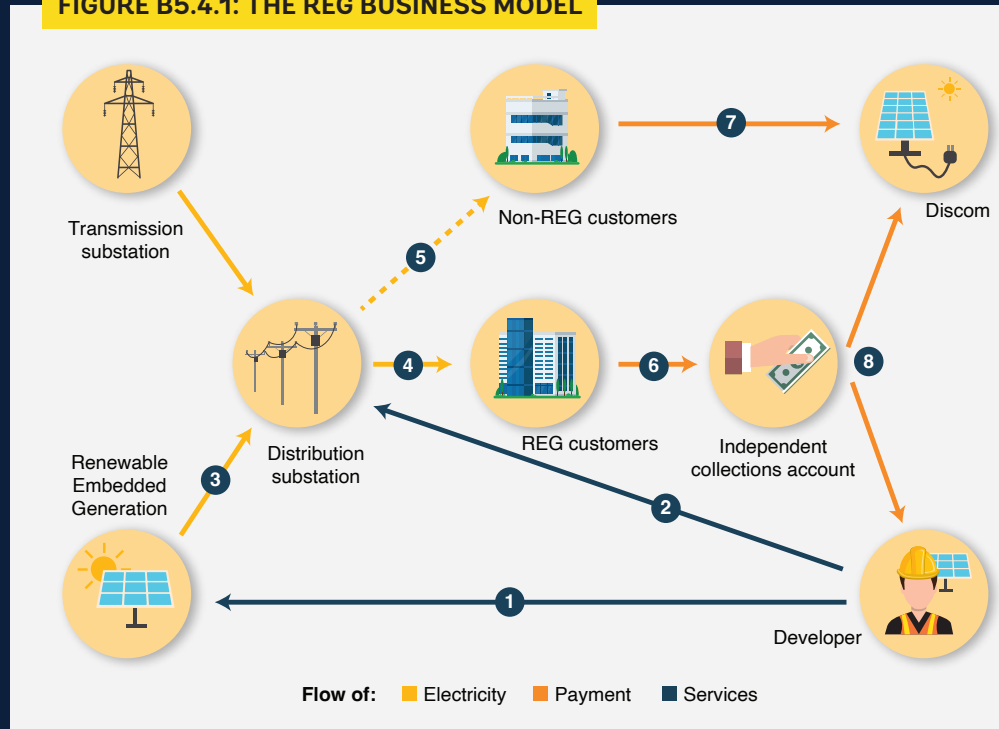
The model is explained in Figure B5.4.1, with the corresponding steps described below the figure.

1. A developer builds a solar-PV-embedded generation plant to increase supply to the feeder, along with sufficient battery storage and fossil fuel backup to guarantee 24/7 reliability to premium customers.
2. The developer funds the metering and the necessary distribution network upgrades.
3. The REG interconnects at the distribution substation.
4. Premium customers of REG are sold a mix of REG electricity and electricity from the main grid at premium tariffs, whereas nonpremium customers are charged service-based tariffs.

(continues)

Nigeria's Distribution-Utility-Owned Business Mode (Continued)

FIGURE B5.4.1: THE REG BUSINESS MODEL



Note: Discom = distribution company; REG = renewable-embedded generation.

5. Excess electricity is sold to customers on non-REG feeders at service-based tariffs.
6. Customers' payment from REG-served feeders goes into an independent collections account (ICA).
7. Customers' payment from non-REG feeders goes into the discom's existing accounts.
8. Disbursements are made from the ICA to the discoms and developers.

Finally, discoms will need to identify and analyze potential REG clusters to select a suitable location, prepare projects for developer contracting through data collection and customer engagement, and select a qualified developer to execute a project. Once a developer is selected, both parties will negotiate contracts, conduct project development activities, design the REG solution and procure land, construct and test the REG solution, and operate the generation and distribution assets as needed to ensure improved supply to customers.

Source: Edun and others 2022.

- DPV deployment may be considered a part of demand-side management activity, and investments may be considered a part of the regulated asset base for returns. The power purchase cost may be considered the operating cost.
- Methodology for considering the income earned and costs incurred by this business and its impact on the regulated distribution business;
- Ring fencing of the financial accounts of the distribution utility's regulated and unregulated businesses; and
- Regulatory provision for charging differential tariffs in the licensed area and for providing supply of varying quality and reliability, and permission to vary tariff rates accordingly.

Finally, an emerging model of decentralized energy trade between customers, though still in its early stages of development in the European and United States markets (see Box 5.5), may offer promising results for developing countries in the future.

Financing Options for DPV Scale-Up

Private financing by customers and third-party service providers may not be sufficient to provide the required impetus for rapid DPV adoption. As mentioned, DPV adoption is hindered either by an explicit restriction or a lack of provision for distribution utilities to invest in the technology. In most cases, distribution utilities are under financial stress and are in no position to invest in DPV. The DPV market is still evolving; market risk and the required mitigation strategies have not yet been internalized and appropriately allocated by stakeholders. Under such an evolving scenario, securing the required fund cost-effectively from commercial financial institutions for rapid DPV scale-up is proving to be a challenge. It would be appropriate to provide public financing support to customers, third-party service providers, and distribution utilities in some test cases (not for asset ownership, but for onward funding of customers) (see Box 5.4) (Edun and others 2022; Timilsina 2022; NESP 2020, 2022; World Bank 2022). The support may be in the form of:

1. Direct or indirect subsidy and finance (low cost and without collaterals)—for customers;
2. Direct and indirect subsidy, and government guarantees for loans raised from commercial banks—for third-party service providers, and
3. Direct or indirect subsidy for revenue loss, and line of credit for routing to customers and for a third party operating on its behalf—for distribution utilities.

The financing support could be in the form of a public-private partnership arrangement with a public institution customer, where the third party is provided payment guarantees on behalf of these institutions for any payment default during the term of the contract with the third party. The public-private partnership arrangement can also be promoted with the distribution utility. Here, the third party installs DPV systems as per the distribution licensee's mandate, but the investment recovery is counter-guaranteed.

ESTABLISHING A POLICY AND REGULATORY FRAMEWORK

Successful implementation of DPV requires seamless interplay of market dynamics and the regulatory framework, which shape each other. Market dynamics drive and influence the technology, project and operating costs, financing instruments, and possible use cases (affect DPV's supply as well as demand side), while the related project risks and their mitigation strategies (including the compensation) are driven and influenced by the business options provided by the prevailing regulatory framework to the distribution licensee.

Recent Development of a Decentralized Market for Trading Surplus Energy from DPV Plants

Customer-owned, third-party-owned, and distribution-utility-led distributed photovoltaics (DPV) business models enable exchanging regulated quanta of surplus energy at regulated prices with the incumbent utility. Distribution utilities in many regions are not financially sound and are not the preferred counterparty for the injection of surplus energy. Recent digital innovations such as blockchain have given prosumers options to engage in trading mutually acceptable quanta of decentralized energy at mutually acceptable prices with other customers (peer-to-peer [P2P] transactions) of distribution utilities. The application of blockchain is likely to enrich and expand the market for surplus energy through an increase in the number of participants and the transparent discovery of market-reflective prices for the traded energy. Numerous pilot projects are underway in Europe and North America to establish this technology, trading platforms, and market rules for the trade.

Blockchain is a distributed and digital transaction technology that allows secured data storage and the execution of smart contracts in P2P networks. “Smart contracts” are integrating mechanisms of blockchain, which make it possible for actual transactions to be effected on a decentralized basis. These mechanisms operate based on individually defined rules (specifications of quantity, quality, price), which enable autonomous matching of distributed energy providers and their prospective customers.

This digital technology facilitates trade in surplus energy among participants through the establishment of contracts and the validation of transactions of surplus DPV-generated energy via a blockchain-based electronic P2P platform. The participant could be a prosumer or a customer of a distribution utility that is willing to sell or buy surplus DPV-generated energy via a P2P platform. Participants are registered with a service provider chosen by the distribution utility. The service provider is responsible for operating the P2P platform, energy accounting, and transaction services for energy trade. The participants are required to install smart meters to be able to trade energy on the P2P platform. The regulator has multiple tasks in this trade: to establish the terms and conditions for interday and intraday energy transactions on the P2P platform; to specify the quanta of power that participants can transact; to specify the energy charges applicable for under- and overdrawal, and under- and overinjection of power; to identify the billing cycle; to specify the consequences of defaults by participants; to ensure RPO benefits are accounted for (when relevant); and to specify the rights and responsibilities of the participants, service providers, and distribution utility.

Participants mutually agree upon the price of energy and the quanta to be traded on the P2P platform. Similarly, the transaction charges to be paid to the service provider and other charges payable to the distribution utility are also known up front.

BOX 5.5

Recent Development of a Decentralized Market for Trading

Surplus Energy from DPV Plants (Continued)

Since the prosumer bears the risk of energy sale and price, the DPV size limitation can be removed. Larger DPV size and the availability of numerous financially viable (validated on the platform) counterparties may reduce project and financing costs, in turn lowering the levelized cost of energy. Since the energy price may vary based on market requirements, this will encourage behind-the-meter storage and demand management. P2P trading arrangement supports environmentally conscious customers (who do not intend or are unable to install DPV) in buying “green power” from DPV at attractive rates to lower their carbon footprint. Distribution utilities may also benefit from this trading arrangement since they are not compelled to buy renewable-based power. However, customers with lower retail tariffs (lower than the levelized cost of energy) can also install DPV systems since surplus power can be traded at a price higher than the retail tariff under a net metering arrangement. Such market possibilities can be expected to support faster DPV adoption.

The form of DPV ownership does not restrict the utility in this decentralized trade business model. Besides providing secured energy trade options to participants, this model also enables distribution utilities to earn a revenue from multiple sources such as (1) wheeling charges, (2) billing and metering fees, and (3) transaction fees, besides the usual benefits due to reduced energy losses and the deferment of network upgrade.

Pilots for this model are being actively deployed in the European Union, with utilities besides those in the decentralized energy trade (which accounts for 40 percent of the use of blockchain) being involved in projects related to electricity vehicle charging, connected homes, wholesale settlement, among others. Following are examples of P2P trading using blockchain:

- LO3 Energy—Brooklyn Microgrid in 2017;
- Power Ledger—more than 22 projects across eight countries, including Australia, the United States, Italy, and Thailand, by Texas-based Grid+;
- Solar contract in Slovenia in 2018;
- Eemnes Energie—large-scale P2P energy trading platform in Europe.

This decentralized business model holds immense potential, although the market might take time to evolve. It may take the market two to five years to realize the business model’s full potential. This, however, will depend on the evolution of a supporting legal and regulatory framework for permitting the distribution and retail sale of electricity by prosumers to customers without a license.

The relevance of the above business models relies on the stage of market maturity and regulatory provisions. Policies should help synchronize DPV market development with appropriate regulatory changes, and vice versa, to aid in the evolution of business models according to stakeholders' requirements in different use cases. Policies should impart dynamism to the evolution of the DPV market and regulatory framework and should also evolve with shifting stakeholder needs.

Here is what policies should provide for and do:

1. They should clearly define how DPV fits into the larger objectives and goals of the country's energy policy.
2. They should provide for a mechanism to set and allocate targets to distribution licensees and also prescribe a mechanism for review of target achievement and revision of targets.
3. They should define the roles and responsibilities of the stakeholders and agencies involved in providing implementation support for the achievement of DPV targets and should provide for a time-bound action plan for these stakeholders.
4. They should identify an agency that will be responsible for considering and integrating DPV in the country's energy supply chain.
5. They should identify an agency that will be responsible for tracking stakeholders' achievements, assessing their performance, and sharing with them feedback for appropriate course correction.
6. They should assess financing needs and permissible financing options.
7. They should specify broad consideration for regulators to develop permissible business models and technical standards and a compensation mechanism for the energy exported to the grid.
8. They should promote research and development and skill development for the DPV market's growth and greater nationwide DPV deployment.
9. They should provide for the safe disposal of DPV systems at the end of their useful life.

The success of the above business models requires the following regulatory interventions to facilitate the seamless integration of the regulatory framework and the DPV market:

1. Rebalancing the tariff structure for consumers who are likely to install DPV systems.
2. A framework for cost-benefit analysis for various use cases and their consideration in distribution business planning and operation by distribution licensees.
3. Clarity on the licensing requirements for installing DPV systems for self-consumption and third-party sale, operating the systems, and distributing the electricity generated by them.
4. Specify technical standards for DPV systems for compliance by the industry and stakeholders.
5. Facilitate the development of feasible business models, including the first-, second-, and third-generation business models.
6. Identify feasible metering and billing arrangements.
7. Provide principles to determine buyout rates under various business models and metering and billing arrangements.
8. Establish technical standards for connection with distribution licensees' distribution systems.

9. Metering and billing infrastructure to be developed by the distribution licensees.
10. Testing and commissioning procedures to be followed for small, medium, and large DPV systems.
11. General guidelines for distribution licensees to frame their procedures for providing connections to DPV systems.
12. Appropriate grid code changes to accommodate embedded DPV generators in the distribution system.
13. Consideration of DPV in the integrated energy plans of the country and of distribution licensees in particular.
14. Provision for regular studies to evaluate the impact of DPV-based generation on-grid operation and its security and the measures required to address the impact.
15. Appropriate changes to health and safety regulations to account for bidirectional flows.

Pricing and Compensation

Step 2 provides a detailed account of the different options for DPV compensation (for the injected energy) and the role of electricity tariffs in determining the economic incentives for different feed-in arrangements for DPV. Therefore, this subsection only briefly highlights some key issues for the implementation phase.

In the rollout phase, regular review of market dynamics (also see Monitoring feedback Mechanism for strategy adjustments) is especially important for adjusting DPV compensation levels. As the supply chain matures and DPV costs decrease, too generous remuneration, for example, via value-based pricing, could lead to structural inefficiencies in the market, for instance, due to suppliers inflating the prices of installed DPV systems to capture some of the associated value. Remuneration should thus always include a dynamic component that automatically reduces economic incentives over time, contingent on the market remaining on a target trajectory (see point above on targets). Not adjusting incentives (according to price evolution) could lead to artificially inflated prices in the market, making remuneration appear appropriate despite it being higher than required.

Compensation levels under long-term agreements (such as feed-in rates under a feed-all arrangement) should remain valid for (the majority of) the project lifetime, that is, 10–20 years. Most importantly, *ad hoc* adjustments to compensation levels should be made only for new installations that are yet to become operational. Retroactive changes to compensation could have a lasting impact on investors' risk perceptions, driving up the price of DPV projects and hampering deployment.

The tariff structure should allow distribution utilities to recover their network-related costs and other elements of their fixed costs and provide incentives to export power to the network when it is needed the most.

When reforming electricity tariffs, a clear communication strategy for consumers is fundamental. Electricity prices are often politically sensitive, and changes—based on transparent criteria and objectives—should be announced well in advance.

SKILL AND CAPACITY BUILDING

Staff Training

Utilities do not require much capacity to manage DPV deployment when it is low. In fact, contracting a private operator to deploy and manage DPV resources is a good approach for utilities to get introduced to the sector.

Large-scale DPV deployment is likely to challenge existing institutional setups and require dedicated training and capacity building. As explained in more detail in ESMAP (2023), this includes planning and operation of the power system.

On the planning side, the most fundamental difference is a shift away from planning individual, large-scale projects and assessing their impact on the grid. Rather, for ensuring effective DPV adoption, planning processes at the distribution level must strike a balance between accuracy and simplicity. Automation of distribution grid planning—for example, for assessing the impact of larger DPV facilities on a given feeder—can be an important part of achieving this objective. Skilled personnel and tools must therefore be available to implement such new approaches. On the operations side, staff must be familiar with handling DPV systems and their behavior, especially during contingencies. Again, staff training is indispensable in this area. Skilled staff is also critical for installing DPV systems. This provides an opportunity to also (re-)train staff at generation and distribution grid companies, as well as utilities.

Relevant training elements and target staff could be identified as part of policy package development.

The responsibility for capacity building should be assigned to a specific agency or agencies, backed by accessible financial resources (Odarno, Martin, and Angel 2015). Key questions to consider include the following:

- How have specific capacity needs been identified for system operation and network management in a context where DPV is not marginal in the generation mix?
- How have specific capacity needs been identified for planning, developing, operating, and maintaining the DPV projects under consideration?
- Who is responsible for capacity building and how effective have they been in fulfilling their role?
- What are the existing initiatives for awareness building among consumers and communities and equipping them to participate?
- How accessible are financial resources for capacity development efforts?

A successful DPV rollout requires all key stakeholders to understand the program approach and be capable of meeting the related requirements. A program's rollout pace "should not exceed the existing capabilities of these stakeholders and where deficiencies in capability are identified (i.e., policy, regulation, standards, — not relevant), efforts should be made to address these issues directly" (ADB 2015).

A good practice is that contractors to the utility in the initial project development stages train the utility staff to facilitate the progressive handover of management to the utility. Training on new technologies can also be crucial in improving gender equality (Box 4.3).

Capacity-building efforts for a future of widespread DPV adoption extend beyond institutions. Energy researchers and analysts, project developers, investors, and members of the public (DPV and non-DPV consumers alike) would benefit from engagements aligned with DPV growth trajectories. Electricity system regulations often lag technological innovation. Regulators are likely to face a breadth of challenges, which will necessitate new entities for certification, oversight, and coordination on issues like access to and ownership of system and DPV resource data, access to communication and data networks, and public input into utility planning practices interfacing with DPV. Regulators and decision-makers may require external entities' help in locating the right capacity-building resources considering their specific goals, priorities, and available DPV capacity (IEA and NREL 2019).

Upgrading of Technical Tools

Automation is key to efficiently manage the distributed nature of DPV and its impact on electricity systems. As explained in Step 2, this includes the technical tools for electricity system planning and operations. Further, tools for the automated processing of DPV applications and analyses of grid integration effects can help save time, reduce costs, and accelerate DPV market development. While budgeting government DPV expenditure, consideration must be given to fund allocation for upgrading software and computer equipment at utilities and relevant authorities. The utility's buy-in is also needed. Many staff are apprehensive of automation, fearing an adverse impact on their employment prospects.

Monitoring the Feedback Mechanism for Strategy Adjustments

DPV is currently the most dynamically evolving power generation technology. Costs continue to fall, and combinations with other DPV systems, such as electric vehicles and batteries, are rapidly gaining traction in global markets. Thus, even a well-crafted and effectively implemented DPV policy package and DPV programs need to be updated in response to market dynamics. This could include achieving stated deployment levels at lower costs or raising DPV deployment ambitions for improved economics. Moreover, certain challenges may only emerge once DPV deployment has reached a sufficiently large scale, requiring policy, market, and regulatory framework to be updated.

This means that the design of DPV policy packages and programs must incorporate constant monitoring, feedback, and strategy adjustments. Distribution licensees should be mandated to collect relevant deployment data monthly. They should also be mandated to report to the regulator cases where they did not permit connections on technical grounds, along with the actions taken to address such issues, and share this information in the public domain. Pricing information for all relevant parts of the value chain should also be collected and published regularly. Benchmarking data to international reference countries could help separate global market dynamics—largely beyond the reach of national government policies—and identify market-specific effects that call for an update.

ABBREVIATIONS

BOOM	build-own-operate-maintain
BOOT	build-own-operate-transfer
C&I	commercial and industrial
CAPEX	capital expenditure
DER	distributed energy resource
discom	distribution company
DPV	distributed photovoltaics
EEU	Ethiopian Electric Utility
ESMAP	Energy Sector Management Assistance Program
ICA	independent collections account
IEA	International Energy Agency
IFC	International Finance Corporation
IPP	independent power producer
kW	kilowatt
kWh	kilowatt-hour
LCOE	levelized cost of energy
MW	megawatt
O&M	operation and maintenance
OPEX	operational expenditure
P2P	peer to peer
PPA	power purchase agreement
PV	photovoltaics
REG	renewable embedded generation
RESCO	renewable energy service company
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SARAL	State Rooftop Solar Attractiveness Index
STEM	science, technology, engineering, and mathematics
T&D	transmission and distribution

GLOSSARY

Bidirectional meter A meter that separately measures energy fed to the grid and the energy consumed (i.e., two gross volumes). It can be used for net metering or net billing.

Distributed photovoltaics (DPV) Any PV system that is connected to a distribution grid, or is installed on a person's premises or at a facility that consumes grid electricity. The term may also refer to PV used in off-grid settings.

Distribution company It exclusively provides electricity distribution and retailing services (i.e., metering and administration services) for retail consumers, including DPV consumers. It is responsible for maintaining the distribution grid and the related consumer-facing infrastructure for electricity retail, and for procuring the wholesale electricity that it distributes and resells. DPV is changing this model since distribution companies may now purchase from DPV generators or facilitate peer-to-peer trade between DPV generators and consumers within the distribution grid.

Electricity services Electricity services, in the context of a power system, are activities that add economic value by enabling electrical energy consumption or lowering the costs associated with this consumption, or both. The services' value is created by meeting different constraints related to electricity supply and delivery (physical, policy related, etc.) (Jenkins 2018).

Energy as a service See pay-as-you-go.

Feed-in arrangement Denotes whether a DPV system feeds some, none, or all of its generation to the grid.

Generation company Generation companies may be public utilities or independent power producers (IPPs). They generate and sell wholesale electricity directly to distribution companies and wholesale consumers. Utilities may own all their generation assets or rely on power purchase agreements with IPPs for a portion of their generation. They typically sell wholesale electricity to distribution companies at regulated tariffs, whereas tariffs for direct sale to wholesale consumers (e.g., large industrial customers) are typically negotiated. Although generation companies are central power stations, when generation is decentralized, the decentralized generation units can also be aggregated to act as a virtual power plant, including to participate in wholesale markets (as is allowed for up to 20 megawatts in the case of the New York Independent System Operator, for example).

Gross metering Separate measurement of the energy consumed from the grid and the energy fed to the grid, typically under a feed-all arrangement (i.e., gross production and gross consumption). This is also known as dual metering.

Microgrid A small grid system to serve one or more consumer facilities. It can have an interconnection to a main grid but is capable of operating independently.

Mini grid A small grid system to serve one or more consumer facilities, typically in an off-grid setting. It can have an interconnection to a main grid but is capable of operating independently.

Net energy The vector sum of the grid energy consumed by a customer and the energy fed by them to the grid over a given period (e.g., hour, day, or billing cycle). The sum for the given period may be a net feed-in ("credits" from the consumer's perspective, occasionally called "excess" energy), net consumption, or zero (if the feed-in and grid consumption happen to be the same).

Net billing Separate measurement and pricing of the energy consumed from the grid and the energy fed to the grid under a feed-some arrangement (i.e., energy fed to the grid, and energy consumed from the grid, each net of self-supply). This is typically through a bidirectional meter.

Net meter A meter for measuring net energy, for example, a meter that can spin forward or backward.

Net metering The process of accounting for DPV generation fed to the grid using a net meter or an equivalent, such that this energy is compensated for at the same rate as the energy component of the retail electricity tariff for the given time period (retail parity compensation). In practice, there are many forms of net metering, and different jurisdictions apply the term in different ways.

Pay-as-you-go Also known as “energy as a service,” this is a service payment model where consumers make small monthly payments under a contract with a provider for the specified services. It can be used to recover capital costs from consumers. Contracts may vary in their duration and commitment fees.

Value of solar An estimate of the value of the avoided costs of grid electricity—plus wider environmental, social, and financial benefits—due to DPV installation in a given context. The assessed value of DPV systems in a given power sector may be used as a benchmark or approach to determine the level of compensation for DPV generation fed to the grid.

Vertically integrated utilities (VIUs) These are companies that own assets in all parts of the electricity supply chain, providing retail, distribution, transmission, and generation services within a given service area. Some of them are also “horizontally integrated,” owning all generation, transformation, or distribution assets in a given power system service area. In power sectors with horizontally unbundled generation, VIUs typically rely on or compete with IPPs for some portion of the power generation needs. In such power sectors, some VIUs may have a retail business selling directly to consumers and a wholesale business selling to local distributors and/or large wholesale customers. All types of VIUs are subject to economic regulation, and they offer consumers regulator-approved retail (and/or wholesale) electricity tariffs. When DPV is deployed in a setting with a VIU, the precise impact on revenue depends on whether it is deployed in a distribution service territory that the VIU operates.

Virtual power plant A virtual power plant is a network of decentralized generation units, consumers of flexible power, and storage systems. They are all interconnected, and power is dispatched via central control, as though they were one power plant, yet independent in operation and ownership.

Note: See also the US Energy Information Administration glossary: <https://www.eia.gov/tools/glossary/>.

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ANNEX 1: RECENT DPV INVESTMENTS FINANCED BY WORLD BANK

REGION	COUNTRY: PROJECT OR PROGRAM NAME (ID NUMBER)	YEAR APPROVED– CLOSING	PROJECT DEVELOPMENT OBJECTIVE	EQUIVALENT USE CASES (PER CHAPTER 3)
Africa	Cabo Verde: Distributed Solar Energy Systems (P151979)	2016–18	Increase the generation of solar renewable energy.	1. Bill reduction
	Nigeria: Nigeria Electrification Project (P161885)	2018–23	Increase access to electricity services for households; public educational institutions; and underserved micro, small, and medium enterprises.	2. Least-cost backup
East Asia	China: Beijing Rooftop Solar Photovoltaic Scale-Up (P125022)	2013–19	Increase the share of clean energy in electricity consumption and demonstrate the viability of the renewable energy service company model for scaling up the deployment of rooftop solar photovoltaic (PV) systems in schools and other educational institutions in Beijing Municipality.	1. Bill reduction
	China: Renewable Energy and Battery Storage Promotion (P162299)	2019–25	Promote the integration and use of renewable energy through the deployment of battery storage systems and innovative applications of renewable energy.	4. Transmission and distribution alternative 6. Ancillary services
Pacific	Micronesia: Energy Sector Development (P148560)	2014–19	Increase the available generation capacity and efficiency of electricity supply in the state power utilities and strengthen the planning and technical capacities of the national and state power utilities in the energy sector.	3. Least-cost generation
	Micronesia: Sustainable Energy Development and Access (P165183)	2018–23	Improve the reliability of electricity supply, expand access to electricity, and scale up renewable energy generation.	3. Least-cost generation
	Solomon Islands: Electricity Access and Renewable Energy Expansion (P162902)	2018–23	Increase access to grid-supplied electricity and increase renewable energy generation in the Solomon Islands.	3. Least-cost generation

(continues)

REGION	COUNTRY: PROJECT OR PROGRAM NAME (ID NUMBER)	YEAR APPROVED– CLOSING	PROJECT DEVELOPMENT OBJECTIVE	EQUIVALENT USE CASES (PER CHAPTER 3)
Caribbean	Organisation of Eastern Caribbean States (OECS): Solar PV Demonstration & Scale Up (P153404)	2016–19	Demonstrate the use of commercial-scale PV systems in the Caribbean through pilot projects and disseminate the results throughout the region.	1. Bill reduction
	Haiti: Renewable Energy for All (P156719)	2018–24	Scale up renewable energy investments in Haiti to expand and improve access to electricity for households, businesses, and community services.	5. Utility bootstrap
Middle East	Yemen: Emergency Electricity Access (P163777)	2018–21	Improve access to electricity in rural and peri-urban areas within the Republic of Yemen.	9. Box solution
	West Bank and Gaza: West Bank and Gaza Electricity Sector Performance Improvement (P148600)	2018–23	Enhance the energy sector's institutional capacity, improve the efficiency of the distribution system in the targeted areas, and pilot a new business model for solar energy service delivery in Gaza.	2. Least-cost backup
	West Bank and Gaza: Advancing Sustainability in Performance, Infrastructure, and Reliability of the Energy Sector (ASPIRE) (P170928)	2020–28	Improve the operational and financial performance of electricity sector institutions and diversify energy sources.	2. Least-cost backup 7. Community social support
South Asia	Maldives: Accelerating Sustainable Private Investments in Renewable Energy (ASPIRE) (P145482)	2014–19	Increase PV generation in Maldives through private sector investment.	3. Least-cost generation
	Maldives: Accelerating Renewable Energy Integration and Sustainable Energy (ARISE) (P172788)	2020–25	Increase generation capacity from renewable energy sources and facilitate the integration of variable renewable energy into the country's grid infrastructure.	3. Least-cost generation
	Nepal: Grid Solar and Energy Efficiency (P146344)	2015–20	Increase the solar-PV-based electricity supplied to the Nepal Electricity Authority's grid and reduce the Authority's distribution losses in selected distribution centers.	3. Least-cost generation
	India: Grid-Connected Rooftop Solar Program (P155007) with Additional Financing (P160018)	2016–21	Increase the installed capacity of grid-connected rooftop solar PV and strengthen the capacity of institutions relevant for it.	1. Bill reduction
	Pakistan: Sindh Solar Energy (P159712)	2018–23	Increase solar power generation and electricity access in Sindh Province.	8. Financial loss reduction

Note: Information on the above projects can be found at www.worldbank.org/projects. Advisory services and analytics have also recently been undertaken or are being undertaken in the following countries: Bangladesh, Costa Rica, Ethiopia, Ghana, Kazakhstan, Kenya, Kiribati, Lebanon, Mexico, the Philippines, Sri Lanka, Tanzania, Türkiye, Uzbekistan, and Vietnam.

ANNEX 2: CASE STUDIES

This annex summarizes key findings of the study “Net Metering and PV Self-Consumption in Emerging Countries” by Andréanne Roux and Anjali Shanker (2018).

In this study, “net metering” is defined in a broad sense and encompasses different incentive mechanisms, given below:

- **Feed-in tariffs**, where consumers pay for electricity purchases (the regulated price) and are paid for injected energy (the “feed-in tariff”).
- **Green certificate**, where consumers pay for electricity purchases (the regulated price) and are awarded a certificate for the injected energy that they can sell.
- **Net metering/net billing**, where consumers can deduct the value of the injected kilowatt-hour in the n-1 month from their bill for month n.

The study was conducted for eight countries, of which Burkina Faso and Benin do not have a regulatory framework that allows net metering and Kenya does not have applications (at the moment of the report).

	CABO VERDE	GHANA	SOUTH AFRICA	INDIA	PHILIPPINES
System size limits	100 kW	200 kW	100 kW	0.25–1 MW	100 kW
Uptake	No achievement yet	No achievement yet	Net metering in 34 of 164 municipalities	3% of the 2022 solar rooftop target achieved	1,329 customers are under net metering contracts
Regulation	Each injected kWh gives rise to compensation for 1 kWh	Each injected kWh gives rise to compensation for 1 kWh	Varies per municipality	Varies per federal state	Exported kWh are compensated based on the average generation cost (the utility's average cost of supply and its pool of power suppliers)
Payback time	n/a	n/a	7–12 years (2015)	8.3–10.5 years	6–7 years (2013)
Distribution company point of view	The national company, ELECTRA, appears to fear an unfavorable compensation scheme.	There is no impact currently since no accredited system is in place.	Distribution companies (municipalities) negotiate the compensation scheme (with annual revisions) with the regulator.	n/a	Although utilities' compensation for prosumers does not exceed the utilities' own generation cost, progress is slow and renewable portfolio standards had to be introduced (enforce 1% of renewable energy).

Note: kW = kilowatt; kWh = kilowatt-hour; MW = megawatt; n/a = not available.

ANNEX 3: COSTS AND BENEFITS OF DPV FOR A DISCOM (CASE STUDY—BSES RAJDHANI POWER LIMITED)

As rooftop solar deployment grows, concerns about revenue loss heighten among distribution companies (discoms). Higher electricity tariffs make rooftop solar systems more attractive to high-paying commercial and industrial consumers, which currently cross-subsidize low-paying residential and agricultural consumers. Discoms will lose their best-paying consumers, who contribute to the cross-subsidy, if more of these high-consumption categories reduce their reliance on grid-supplied electricity. Further, greater penetration of rooftop solar technology at the distribution transformer level may require network upgradation on a case-to-case basis to support power flow adjustments due to distributed solar generators, grid balancing, scheduling and forecast, and anti-islanding protection.

However, rooftop solar also offers discoms multiple inherent benefits, which are often overlooked. Installation of rooftop solar systems in the distribution grid aids in, for example, balancing demand during peak and off-peak hours, decongesting the distribution network, avoiding energy procurement from expensive generators, the fulfilment of renewable purchase obligations by discoms, and reducing transmission and distribution losses. Discoms realize these benefits through savings on capital expenditure and by postponing the investment required to cater to growing energy demands.

Table A3.1 shows six benefits for discoms and the cost (revenue loss) that rooftop represents for 10 selected distribution transformer types, which represent different blends of consumers. All values are expressed in Rs/kWh (\$1 = Rs 82).

TABLE A3.1: COSTS AND BENEFITS FOR DISCOMS IN INDIA

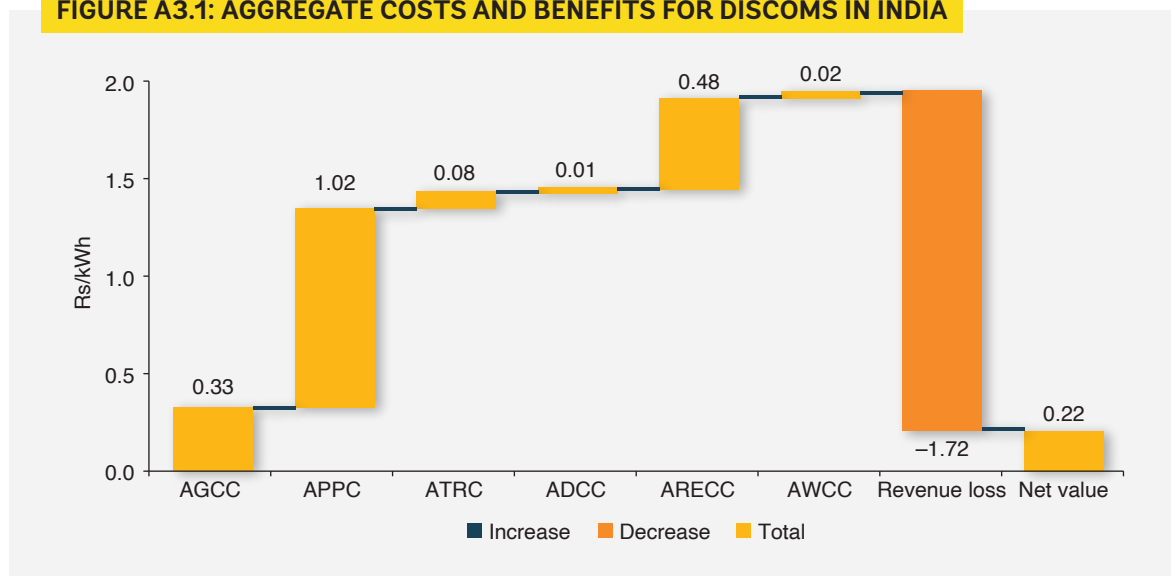
	DT1	DT2	DT3	DT4	DT5	DT6	DT7	DT8	DT9	DT10
AGCC	0.38	0.36	0.33	0.35	0.35	0.35	0.35	0.31	0.32	0.26
APPC	1.01	1.02	1.02	1.02	1.02	1.02	10.2	1.01	1.02	1.02
ATRC	0.09	0.09	0.08	0.09	0.09	0.09	0.09	0.08	0.08	0.07
ADCC	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—
ARECC	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48
AWCC	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.00
Revenue lose	1.74	1.92	1.92	1.86	1.92	1.74	1.92	1.92	1.40	1.08
Net benefit	0.48	0.06	0.02	0.09	0.04	0.21	0.04	-0.02	0.51	0.75

Source: Kuldeep and others 2019.

Note: ADCC = avoided distribution capacity cost; AGCC = avoided generation capacity cost; APPC = avoided power purchase cost; ARECC = avoided renewable energy certificate cost; ATRC = avoided transmission remuneration charges; AWCC = avoided working capital requirement; DT = distribution transformer.

The same information, averaged for the transformers shown in the above table, is presented in Figure A3.1.

FIGURE A3.1: AGGREGATE COSTS AND BENEFITS FOR DISCOMS IN INDIA



Source: Kuldeep and others 2019.

Note: ADCC = avoided distribution capacity cost; AGCC = avoided generation capacity cost; APPC = avoided power purchase cost; ARECC = avoided renewable energy certificate cost; ATRC = avoided transmission remuneration charges; AWCC = avoided working capital requirement; kWh = kilowatt-hour.

ANNEX 4: DETAILED ECONOMIC ASSESSMENT OF DPV USE CASES

Economic assessment can be relatively straightforward for some schemes and use cases. One such example is a *least-cost generation* use case with a *buy-none feed-all* arrangement, for example, a solar installation next to a village. This could be assessed in a manner similar to traditional generation projects—that is, by weighing the investment’s economic capital and operating costs and the benefits due to it for the power system against those of its alternatives and considering the project’s financial viability for the developer. Similarly, feed-none schemes, for example, a *least-cost backup* or a *box solution* use case, may predominantly involve private benefits and costs as an alternative to grid electricity, in addition to potential social and private benefits due to carbon dioxide and local emission reduction. In the *least-cost backup* use case, the consumer’s decision to invest in distributed photovoltaics (DPV) is more sensitive to the price and quantity of diesel consumed than the levelized cost of the energy generated by DPV. It is also worth noting that use cases can be combined synergistically. For example, a commercial and industrial consumer may install an islandable feed-none DPV system for *bill reduction* and *least-cost backup* at the same time as it provides a utility with *ancillary services* and a *transmission and distribution alternative*.

Schemes with two-way power flows between consumers and grids can be more complex. In these cases, it becomes especially important to consider how different potential costs and benefits are distributed among consumers, utilities, and other stakeholders.

Whether a given DPV scenario provides stakeholders with net economic benefits in aggregate, depends on the specific use case and context. A use case that is currently economically nonviable in a country may become viable in the future in the same country or may already be viable in another country that has different input costs or tariff schemes. Carbon benefits are worth mentioning here; that is, in cases where a country has set specific goals for carbon intensity reduction for the grid generation mix, avoided emissions will generate multifaceted benefits for the sector and society as a whole (i.e., less pollutants in the air, carbon credits, fulfilment of international commitments the country may have made, and so on), even though challenging economic choices to achieve carbon targets may have to be made. These choices are intimately linked to specific country policy contexts. As such, it is important to assess the costs and benefits of DPV use cases based on local conditions and policy objectives.

For *bill reduction* and *least-cost backup*, DPV systems can be deemed financially viable simply by proving that their levelized cost of energy is below the counterfactual of average retail electricity tariffs and/or backup energy costs as explained above.

Schemes justified by private cost savings and unmonetized emission reductions include most corporate sourcing of renewables (IRENA 2018a and many public DPV programs supported with development financing (see annex 1). For public DPV programs supported with development financing, pollution externalities can be assessed based on traditional approaches to estimate the social cost of carbon and shadow pricing (World Bank 2019e). In markets that include a cost of compliance for carbon or other

environmental factors, for example, a renewables portfolio standard, typically utilities bear the financial cost of emission reductions, so that the compliance costs would factor into a *least-cost generation* use case.¹⁴

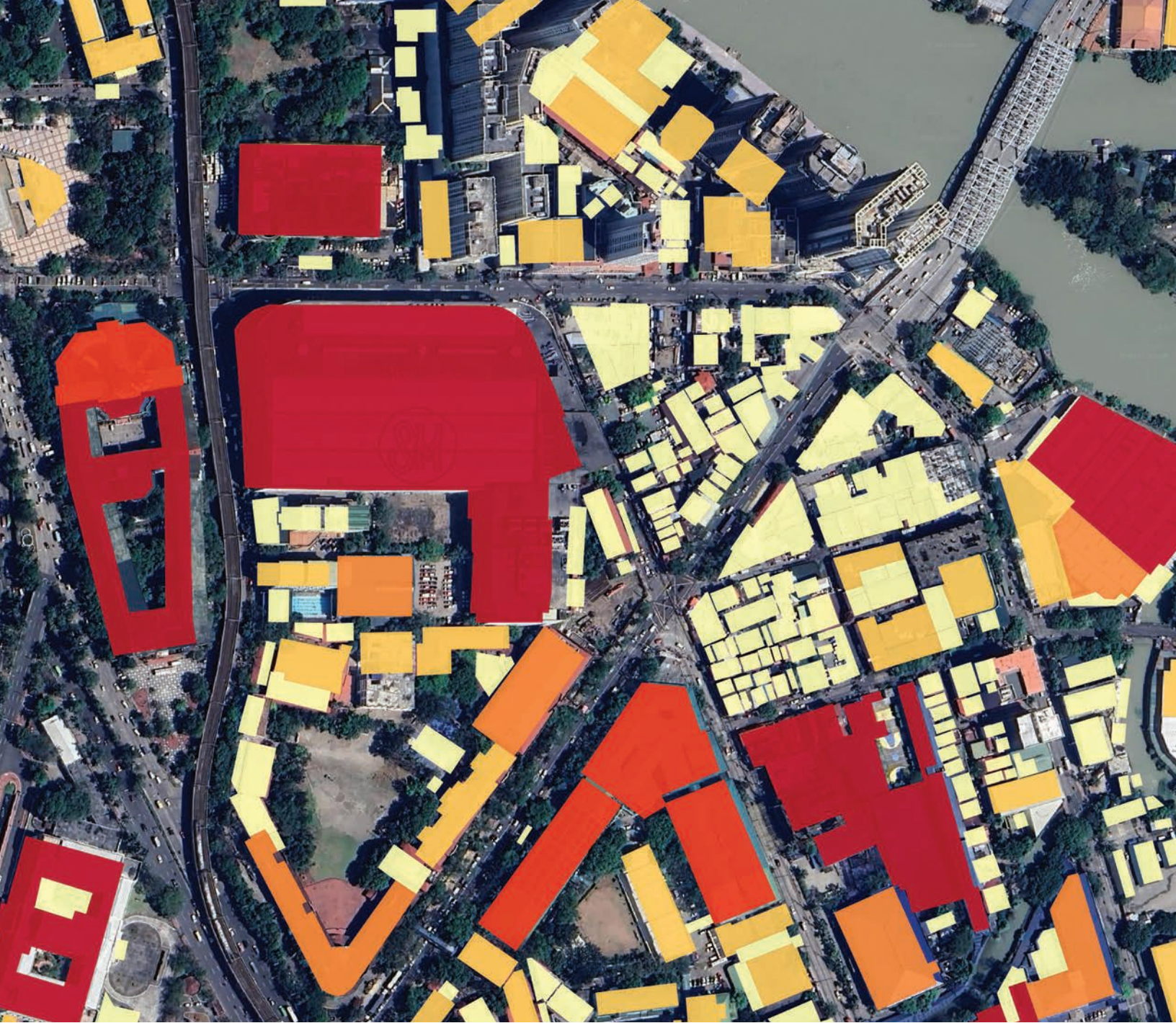
Added value from other use cases may not need to be quantified to contribute to an economic or financial justification. For example, a driving motivation for the Republic of Yemen's World-Bank-financed *box solution* DPV is to restore critical electricity services for example for hospitals previously connected to the grid. The project's cost-benefit analysis, however, was based primarily on reduced expenditure on alternative energy sources, noting simply that the restoration of critical services would "further increase estimated internal rates of return," without attempting to quantify this benefit (World Bank 2018a).

Externalities may be a decisive factor in a government's justification to support or roll out a DPV program, as part of an economic least-cost solution to achieve the country's sector development objectives. For example, DPV can boost energy security by increasing the energy independence of people or systems otherwise reliant on fuels such as diesel, whose costs are high or volatile and availability is uncertain. Energy security carries an implicit premium that is hard to define but is a useful element to discuss in the context of crises.

¹⁴ In some markets, consumers and third parties can have an opportunity to participate through the creation of solar renewable energy certificates (RECs). When DPV producers sell RECs to utilities or corporate consumers, they may generate an income for a private benefit akin to bill reduction.

ESMAP MISSION

The Energy Sector Management Assistance Program (ESMAP) is a partnership between the World Bank and over 20 partners to help low- and middle-income countries reduce poverty and boost growth through sustainable energy solutions. ESMAP's analytical and advisory services are fully integrated within the World Bank's country financing and policy dialogue in the energy sector. Through the World Bank Group, ESMAP works to accelerate the energy transition required to achieve Sustainable Development Goal 7 (SDG7), which ensures access to affordable, reliable, sustainable, and modern energy for all. It helps shape WBG strategies and programs to achieve the WBG Climate Change Action Plan targets. Learn more at: <https://www.esmap.org>.



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