DISTRIBUTED SOLAR UTILITY TARIFF AND REVENUE IMPACT ANALYSIS

A Guidebook for International Practitioners

Owen Zinaman
National Renewable Energy Laboratory

Naim Darghouth
Lawrence Berkeley National Laboratory

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List of Acronyms

DG	distributed generation
DPV	distributed photovoltaics
EGU	electric generation utility
IPP	independent power producer
NEM	net energy metering
NREL	National Renewable Energy Laboratory
PPA	power purchase agreement
SAM	System Advisor Model
TOU	time-of-use
TRIA	tariff and revenue impact analysis
VIU	vertically integrated utility

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Foreword

Around the world, jurisdictions are contending with a range of opportunities and challenges associated with the increasing adoption of customer-sited distributed photovoltaics (DPV). Depending on a range of technical, economic, policy, regulatory, and market-related factors, the adoption of DPV may have a net positive or negative financial impact on utilities and ratepayers. As DPV policy and program-related decisions are considered, it is oftentimes useful to quantify this expected net financial impact, such that an acceptable balance can be struck between ratepayer protections, DPV market development, and other relevant public policy objectives.

This guidebook provides a methodological approach for quantifying the net financial impact of DPV on utilities (in the form of "net revenue losses") and ratepayers (in the form of "net tariff impacts"). The approach for calculating net revenue losses can be applied in nearly any utility jurisdiction, regardless of institutional arrangements, business models, or regulatory paradigms. The approach for calculating net tariff impacts works best in settings where some form of cost-based economic utility regulation is present (i.e., settings where there is an established policy or regulatory mechanism to pass through changes in utility costs to ratepayers).

The methodology and guidance set forth in this document is not, by any means, the only way to conduct this type of analysis. Rather, we present a variety of experientially-derived insights and approaches that might guide the reader toward creating a practically designed, impact-focused DPV analysis. Notably, these methods have been developed over time by the authors as they conducted these analyses in jurisdictions where key utility sector data was lacking, such as in developing and emerging economies. In that context, the authors chose to describe a simplified yet rigorous method for quantifying DPV financial impacts that could be applied in lower data environments.

This guidebook has been written for technical staff at utilities, regulatory bodies, energy ministries, research institutes, and civil society organizations who wish to better understand the financial impacts of DPV in their jurisdiction. It can be used to inform important decisions regarding DPV compensation, tariff design, and regulatory cost allocations, among other aspects. It is focused exclusively on customer-sited DPV systems and adopts a primarily cost-based (as opposed to an equally valid value-based) perspective to understanding DPV financial impacts.

The gap in the literature that this guidebook sets forth to fill is threefold. First, while there are many meta-studies (see e.g., ICF 2018; Orrell, Homer, Tang 2018) and jurisdiction-specific studies that analyze the costs and benefits of distributed solar to various stakeholders, few describe the inner workings of the employed quantitative methodologies sufficiently to be emulated in a separate jurisdiction. Second, while a limited number of reports are focused on the methodologies themselves, (see e.g., Rabago and Keyes 2013; Denholm et al. 2014), they are either limited in scope to jurisdictions with net energy metering (NEM), take a "system" perspective rather than directly summing measurable utility costs and benefits, and/or they do not provide practical and implementation-related insights that a research analyst may need to successfully conduct an analysis. Third, the current set of literature generally focuses on areas where detailed utility sector data is assumed to be available—this report offers a concrete methodology that can be employed in a lower data environment.

1 Introduction

1.1 Guidebook Context and Purpose

Around the world, there has been increasing interest in understanding the impacts of prospective and emerging distributed photovoltaic (DPV) programs on utilities and ratepayers. This guidebook has been assembled to provide clear direction to policymakers, regulators, utilities, and researchers in designing and executing a DPV utility tariff and revenue impact analysis (TRIA), with some special considerations offered for doing so in developing and emerging economy environments with lower availability of utility sector data.

In short, a TRIA aims to quantify the expected changes in revenue collection, operational costs, and expenditures that utilities might experience due to DPV adoption. Summing these various impacts together, TRIA then translates the total net financial impact on utilities into a tariff impact for ratepayers, in alignment with local ratemaking practices. Ultimately, the impacts of DPV on utilities and ratepayers may be positive, neutral, or negative—and the direction and scale of impact depends in large part on retail tariff design, solar compensation schemes, ratemaking practices, and other parameters that are typically within the control of policymaking and regulatory authorities. TRIA can provide actionable insights to inform decisions on how-best to allocate the costs and benefits of DPV, in alignment with public policy priorities. TRIA results can be used by regulators and policymakers to evaluate and inform DPV program design; however, it is outside the scope of this report to discuss the application of TRIA. Ultimately, it is regulators and policymakers who will determine the acceptable level of net benefit or net cost of DPV to utilities and ratepayers based on their own local conditions and priorities and, consequently, whether changes should be made to DPV program design.

The methodology and guidance set forth in this document is not, by any means, the only way to conduct this type of analysis. Rather, we present a variety of experientially derived insights and approaches that might guide the reader toward creating a practically designed, impact-focused DPV analysis.

Importantly, the methodology presented in this document attempts to balance several objectives, including to:

1. Provide sufficient analytical depth/detail to ensure both accuracy and credibility of results
2. Conduct a transparent analysis that avoids complicated or "black box" assumptions and methodologies that may ultimately degrade credibility of results among stakeholders
3. Offer useful and actionable analysis insights to policymakers, regulators, and utilities
4. Meet short-term needs of policymaking processes by providing analysis insights in a reasonably responsive timeframe.

Importantly, while some developing country settings are data poor and feature distinct power market conditions, this handbook has been designed to be applicable in a range of contexts. This specific method has been employed in Tongsopit et al. (2017), Tongsopit et al. (2019), and Darghouth et al. (2020). In these three cases, distributed solar impact analyses were conducted in Thailand, the Philippines, and Indonesia, with very different utility business models, regulatory frameworks, and levels of utility and energy market data availability. This methodology is intended to quantify the impact of customer-side (also referred to as "behind-the-meter") grid-connected DPV systems. It is not intended to calculate the impact of grid-side (also referred to as "front-of-the-meter") DPV systems,[1] or the impact of DPV on mini-grid or microgrid systems.

1.2 Guidebook Structure

Section 2 establishes terminology (Section 2.1) and provides a range of relevant background information (Section 2.2–2.4).

Section 3 describes the various types of analysis questions that might be addressed in a TRIA through the design of a suite of modeling scenarios.

Section 4 provides an overview of various DPV value drivers and discusses a range of practical considerations surrounding analytical complexity and data availability requirements.

Section 5 provides an overview of short-term utility revenue impacts associated with DPV deployment, with distinct considerations offered for different utility types and DPV metering and billing arrangements.

Section 6 details a six-step process for designing and conducting a TRIA.

Appendix A provides a list of stakeholder interview questions that may be useful at the beginning of a TRIA analysis process.

[1] The financial impact of grid-side DPV installations on utilities and ratepayers is typically similar to centrally planned conventional power system investments and require less complex analysis to characterize their impact. Thus, grid-side DPV is outside the scope of this guidebook.

2 Background Information

2.1 Terminology

Having a uniform set of well-defined terminology is critical for data requests and communicating DPV analysis results. Using specific and consistent terminology throughout the analysis process can help to avoid confusions and ambiguities during each step, from initial data collection to the sharing of results. This subsection will provide a review of key terminology for DPV utility revenue and tariff impact studies.[2]

This report uses definitions and language set forth in Zinaman et al. (2017), which describes a universal approach to defining various components of DPV compensation mechanisms. For a review of the myriad ways that utilities may charge retail customers for electricity, see Lazar and Gonzalez (2015) and Linvill, Shenot, and Lazar (2013).

2.1.1 Stakeholder Perspectives

This subsection defines the various types of stakeholder perspectives that may be relevant for conducting a TRIA.

Distribution Utility: Distribution utilities exclusively provide distribution services and retailing of electricity to retail customers (i.e., metering and administration services), including DPV customers. Primarily, they are tasked with maintaining the distribution network and associated customer-facing business infrastructure for electricity retailing, as well as the procurement of wholesale electricity that they ultimately distribute and resell.[3] These entities are subject to economic regulation, and, thus, their expenditures to procure wholesale electricity, maintain the distribution network, and function as a business is carefully monitored. They are customer-facing in nature and tend to exclusively offer regulator-approved retail electricity tariffs. They are sometimes also referred to as "distributors" or "wires-only utilities."

Electric Generation Utility (EGU): EGUs generate and sell wholesale electricity directly to distribution utilities and wholesale customers, typically from centralized (i.e., nondistributed) power plants and transmit that electricity over their transmission lines. EGUs are sometimes granted a monopoly over electricity sales to distribution utilities and wholesale customers in their jurisdiction; however, they do not always have a monopoly over the entire transmission or generation sector. Rather, they may own and operate much of a jurisdiction's generation fleet, but also rely on power purchase agreements (PPAs) with independent power producers[4] (IPPs) for at least a portion of their generation mix (e.g., for renewable energy), playing a "single buyer" role. While EGUs are by no means present in every market, EGUs as defined in this guidebook are subject to economic regulation, and thus their expenditures to procure new infrastructure and PPAs with IPPs are carefully monitored. They typically sell wholesale electricity to distribution utilities using regulated wholesale electricity tariffs.[5] Tariffs with higher demand wholesale customers (e.g., large industrial customers) are typically less regulated or unregulated, and are instead freely negotiated between two parties.

[2] The terminology and associated definitions offered henceforth are not intended to be seminal; rather, they are an attempt to provide readers with an internally consistent set of terminology to enhance reader understanding.
[3] Distributed generation is beginning to change this model to some extent, as distribution utilities are increasingly able to purchase electricity from DPV generators and/or facilitate peer-to-peer trading between DPV generators and consumers connected to the distribution grid.
[4] Defined later in this subsection.
[5] Defined in Section 2.1.2.

Vertically Integrated Utility (VIU): VIUs are companies that own assets across all segments of the electricity supply chain, providing retail, distribution, transmission, and generation services. Some are also "horizontally integrated," owning all sets in generation, transmission, or distribution in a given power sector, as is the case with single nationally owned electric utilities in some countries, whereas others plays a "single buyer" role. These are becoming increasingly rare as countries liberalize their electricity markets; where the generation sector is not subject to a monopoly, VIUs typically rely on or compete with IPPs for some portion of their power generation needs. Similarly, in power sectors where the distribution sector is not subject to a monopoly, VIUs may have a retail business selling directly to retail customers and a wholesale business selling to more local distributors and/or large wholesale customers. All VIUs are subject to economic regulation, offering regulator-approved retail (and/or wholesale) electricity tariffs to customers. When DPV is deployed in a setting with a VIU, the exact impact to revenue depends on whether or not the DPV is deployed in a distribution service territory that the VIU operates.

IPP: IPPs are companies that own utility-scale power plants. These companies typically operate under contract with utility entities or large consumers, or trade on a wholesale power market to create revenue.

DPV Customer: A retail electricity consumer that has a DPV system installed on or near their premises and is subject to a specific metering and billing arrangement[6] and retail electricity tariff.[7] The DPV customer does not always own the DPV system, as DPV systems can also be owned by third-party solar leasing companies and utilities.

Electricity Ratepayers: Electricity ratepayers is a broad term to describe the group of regulated retail customers who purchase electricity from distribution utilities or VIUs under terms specified in regulated retail electricity tariffs. Ratepayers purchase electricity for their own use and contribute to the recovery of utility revenue requirements.[8] The main impact of DPV deployment to ratepayers is a potential change in retail tariff levels, due to shifts in utility costs (e.g., operating costs and cost of capital[9]) and utility sales. Electricity ratepayers can further be divided into ratepayer classes, which can be impacted differently by DPV deployment depending on deployment patterns, tariff structures, ratemaking procedures, and changes in potential cross-subsidies.

Society: Society encompasses all groups, regardless of whether they participate in the electricity markets, and hence is impacted by factors not typically included in financial analyses for utilities (i.e., externalities). These include, for example, macro-economic impacts from DPV deployment, job creation, health benefits from generator emission reductions, and the social value of carbon abatement.

2.1.2 Utility Ratemaking and Cost Recovery Terminology

This subsection defines a range of terms related to utility regulation and ratemaking that are relevant for conducting a TRIA.

Retail Electricity Tariff: The structure under which a retail customer—purchasing electricity from a utility—is charged for the electricity they consume from a distribution utility.[10] The word "tariff" communicates a set structure of prices,[11] and, in this context, implies that the entity offering the tariff is

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[6] Defined in Section 2.1.3.
[7] Defined in Section 2.1.2.
[8] Defined in Section 2.1.2.
[9] If DPV deployment impacts a utility's financial health, the cost of equity and debt can change, resulting in changes in overall costs that must be recovered through retail rates.
[10] Defined in Section 2.1.3.
[11] Retail electricity tariffs typically also imply a set of other terms and conditions related to retail service provision.

subject to economic regulation (and thus the tariff itself can be considered "regulated"). The word "retail" implies the tariff is designed for the large majority of customers who do not directly purchase their electricity from electricity generators or the wholesale market but, rather, for retail electricity customers who purchase electricity from utilities. Retail electricity tariffs may contain multiple types of utility charges[12] to recover costs from customers (e.g., energy charges, fixed charges, demand charges). These charges may vary by time of consumption, level of consumption, and/or location. They are also customized for specific classes of retail customers (e.g., residential versus commercial versus industrial, sometimes further categorized by voltage level). In practice, this term is sometimes referred to as "retail tariff," "retail rate," or "retail electricity rate."

Wholesale Electricity Tariff: The price structure under which: (1) a distribution utility is charged for the electricity they purchase from an electricity generation utility or VIU before reselling to retail customers; or (2) a large direct buyer of electricity (e.g., an industrial customer) purchases electricity from an electricity generation utility or VIU. Again, the word "tariff" communicates a set structure, which in this context implies that the entity offering the tariff is under economic regulation. The world "wholesale" implies the tariff is designed only for larger customers who wish to acquire larger amounts of electricity. The term wholesale electricity tariff is commonly used when a distribution utility is purchasing electricity from a separate utility at regulated rate.[13] Wholesale electricity tariffs may contain multiple utility charges[14] to recover costs, most commonly volumetric energy charges (i.e., $/kilowatt-hour) and peak demand charges (i.e., $/kilowatt), and are commonly variant by time of consumption and/or voltage interconnection level. The term is sometimes referred to as "wholesale electricity rate," "wholesale rate," or "wholesale tariff."

Wholesale Electricity Price: The cost to a particular entity of purchasing larger (i.e., wholesale) quantities of energy. This is intended to be a broad term. This may be used to describe the volumetric energy charge rate (e.g., $0.09/kilowatt-hour) in a wholesale electricity tariff. It may also be used to describe a dynamic locational marginal price in a power system where the distribution utility can purchase electricity on a wholesale power market. It can also be used to describe the cost at which a single-buyer VIU (e.g., Eskom in South Africa) purchases electricity from an IPP. In a number of regions, the wholesale electricity price is determined on an hourly or subhourly basis through a wholesale electricity market, often managed by an independent system operator or similar entity. In the context of utility revenue and retail tariff impact analyses, this may be an important (and potentially dynamic) quantity to be aware of when tracking what kinds of costs are accrued or avoided to different stakeholders. This term is sometimes referred to as "wholesale electricity procurement price."

Average Energy Cost: The average cost of wholesale generation for a power system or a particular electricity generation utility over a particular period of time (oftentimes, this is an annual quantity).[15] If a DPV kilowatt-hour (kWh) is self-consumed or injected into a power system that does not have an energy shortage, this results in a commensurate reduction in bulk power generation. While the actual avoided energy cost nearly always deviates from any average estimate, the average energy cost is nevertheless an indicator of the average avoided cost of generation associated with a DPV kWh. The term is sometimes referred to as "blended cost of generation," "average pooled purchase price," or other variants.

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[12] Defined below in this subsection.
[13] For example, the VIU Eskom in South Africa sells wholesale electricity under a regulated tariff to municipal distributors.
[14] Defined later in this section.
[15] Average energy cost could also be invoked to describe the volumetric energy charge (e.g., $/kWh) component of a retail electricity tariff.

Utility Cost: Costs incurred by a utility to operate the power system. These are generally categorized into generation, transmission, distribution, retailing, administration, and policy/program costs. They can also be characterized as fixed and variable utility costs.[16] Such costs will sometimes be detailed on a retail customer's bill as separate components of a specific utility charge[17] (e.g., a volumetric energy charge). Other rates are bundled and do not provide such a breakout of utility costs.

Fixed Utility Cost: Costs associated with generation, transmission, distribution, or retail of electricity that do not vary based on short-term customer consumption of electricity. In the context of short-term DPV impact analyses, where DPV penetrations are not high enough to impact transmission and distribution planning, these costs do not reduce when DPV generation increases. Examples of fixed costs include costs of constructing and maintaining the electric network, power line repairs, and general metering expenses.

Variable Utility Cost: Costs associated with generation, transmission, distribution, or retailing of electricity that vary based on short-term customer consumption of electricity. In the context of DPV analyses, these costs will usually decrease when DPV generation increases. A common example of a variable utility cost is the cost of fuel associated with a thermal power plant.

Utility Charge: Specific substructure of a retail electricity tariff or wholesale electricity tariff designed to collect revenue from customers. Specific types of utility charges include volumetric energy charges, demand charges, fixed charges, and minimum bills. Some utility charges, such as energy charges, may themselves have specific substructure associated with them (e.g., inclining block or time-of-use [TOU] charges). Also referred to as a "tariff component".

Fixed Charges: Utility charges contained within retail or wholesale electricity tariffs that do not increase or decrease with customer consumption of electricity. In the context of DPV, customers would not experience a reduction in fixed charges when DPV generation increases.

Variable Charges: Utility charges contained within retail or wholesale electricity tariffs that increase or decrease with customer consumption of electricity. Variable charges can either be a function of energy consumption (e.g., energy charge, priced per kWh) or maximum consumption within a specified time period (e.g., demand charge, priced per kW). In the context of DPV, customers would experience a reduction in variable energy charges when DPV generation displaces retail electricity purchases, and, in some cases, may experience a reduction in variable demand charges if DPV generation is coincident with a customer's and/or power system's peak usage.[18]

Tariff Cross-Subsidization: The practice of charging higher than cost-reflective prices to one class of retail electricity customers (the subsidiz*ing*) to reduce prices for another customer class (the subsidiz*ed*). In the context of a ratemaking process, this involves allocating a larger portion of the revenue requirement[19] to the subsidizing rate class while reducing the subsidized rate class's revenue requirement allocation.

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[16] Defined later in this subsection.
[17] Defined later in this subsection.
[18] In general, there are two categories of demand charges. Noncoincident demand charges are per-kW fees that are applied to a customer's peak demand at any time during a billing cycle. Coincident demand charges are per-kW fees that are applied to a customer's highest demand during a power system peak demand period, the timing of which is often specified in the tariff or otherwise communicated in advance to the customer.
[19] Defined later in this subsection.

Rate Period: The period of time over which a specific set of tariffs are implemented for a utility to collect a revenue requirement.

Revenue Requirement: Lazar (2016) defines the revenue requirement as the "total amount of revenue the utility would need to provide a reasonable opportunity to earn a fair rate of return on its investment, given specified assumptions about sales and costs." Alternatively, this can be understood as the total expected amount of revenue required by a utility over a rate period to cover approved expenditures and earn a regulated rate of return on its prudent investments. Using expectations of sales for each customer class, retail electricity tariffs are designed to (in aggregate) collect the revenue requirement over the rate period. Importantly, revenue requirements may or may not contain estimates of expected operating expenses, depending on the jurisdiction.

Rate Case: A periodic process where the revenue requirement is set and retail electricity tariffs (and, if applicable, wholesale electricity tariffs) are designed to collect the revenue requirement. The electric utility submits their rate case application to the regulator, who is responsible for reviewing and approving it. In countries or jurisdictions where electricity pricing is not subject to regulatory review, there may not be formal rate cases to set tariffs.

Revenue Decoupling: A regulatory construct that partially or fully breaks the link between how much energy a utility sells and the revenue it ultimately collects. This approach mitigates sales-related variability in revenue for utilities, essentially decoupling a utility's revenue from its energy sales. It is frequently employed to remove utility disincentives to energy efficiency and DPV deployment, as utilities under revenue decoupling are no longer motivated to increase sales to increase profits. Under revenue decoupling, prices could rise to recover the full revenue requirement if retail sales fall below expectations. Conversely, prices may fall if the revenue decoupling mechanism is "symmetric" and retail sales exceed expectations.

Fuel Adjustment Clause: A regulatory provision which permits changes in specific charges (e.g., energy charges) within retail electricity tariffs or wholesale electricity tariffs in between rate cases, because of short-term changes in the cost of fuel or purchased power expenses.

Lost Revenue Adjustment Mechanism: A regulatory provision that allows for regulated utilities to partially offset revenue losses associated with energy efficiency measures, energy conservation efforts, and DPV deployment. This includes lost fixed cost recovery mechanisms, which are specifically intended to help utilities recover a portion of their fixed utility costs, which tend to accrue regardless of customer consumption levels. The cost of lost revenue adjustment mechanisms (including lost fixed cost recovery mechanisms) can be recovered within the customer classes where customer consumption is reduced, or across all ratepayers. Lost revenue adjustment mechanisms are not necessary when revenue decoupling policies are adopted, since there are no revenue losses associated with energy efficiency or DPV deployment with decoupling.

2.1.3 DPV Compensation Mechanism Terminology

This subsection defines a range of terms related to how retail customers who host a DPV system on their premises might be compensated.

DPV Compensation Mechanism: Compensation mechanisms are the instruments designed to reward the DG system owner for electricity that is self-consumed and/or exported to the utility grid. A compensation mechanism is composed of three core components: Metering and billing arrangements, sell rate design, and retail electricity tariff design. Clean energy certificates, performance-based incentives, and other volumetric performance incentives can be considered financial/policy incentives and not part of the compensation mechanism.

Metering & Billing Arrangements: This element of a DPV compensation mechanism defines how consumption- and generation-related electricity flows are measured and billed. The three options for metering & billing arrangements are net energy metering (NEM), buy-all/sell-all, and net billing.[20] The selection of a metering & billing arrangement does not in itself imply an amount of compensation for the distributed generation (DG) system owner, except in the case of NEM where the customer is effectively credited at the full volumetric energy charge rate applicable to that customer for electricity exported to the grid within a given billing period.[21]

NEM: NEM is a type of metering & billing arrangement, where the customer's gross DPV generation within a predefined period (often the billing cycle) is subtracted from the customer's electricity consumption within that same predefined period, and any DPV generation in excess of consumption can either roll over to offset consumption in future periods or billing cycles or be compensated at a predefined rate, or a combination of both. See *Grid-Connected Distributed Generation: Compensation Mechanism Basics*, page 3, for more details.

Buy-All/Sell-All: Buy-all/sell-all is a type of metering & billing arrangement, where all DPV generation is compensated at a predefined sell rate and cannot displace any electricity consumption (i.e., self-consumption is not allowed). See *Grid-Connected Distributed Generation: Compensation Mechanism Basics*, page 5, for more details.

Net Billing: Net billing is a type of metering & billing arrangement where customers are able to consume their own DPV generation or export DPV generation to the grid. DPV generation that is exported to the grid is compensated at a predefined sell rate.[22] See *Grid-Connected Distributed Generation: Compensation Mechanism Basics*, page 7, for more details.

Sell Rate: This element of a DPV compensation mechanism defines the level of compensation a DG system owner receives for electricity exported from the DG system to the utility grid. The sell rate applies to distinct quantities, depending on the metering & billing arrangement selected (this will be described in more detail later). Sell rates can be static, remaining fixed over the length of an interconnection contract. They can also be more dynamic in nature, changing with time or by location with various degrees of granularity.

Retail Electricity Tariff: Defined in Section 2.1.2. In the context of a DPV compensation mechanism, this defines purchase rates the DPV system owner must pay the utility for electricity consumed from the grid, and, thus, which costs the DPV system owner can avoid if they self-consume the electricity produced by their DPV system. Some DPV customers are subject to the same retail electricity tariffs as other ratepayers (i.e., non-DPV owners), whereas others are subject to retail electricity tariffs designed specifically for DPV customers.

Feed-In Tariff: General term describing a predetermined sell rate for electricity that is fed back into the grid. As defined in this report, it is not a metering & billing arrangement in itself. In practice, the term

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[20] A fourth metering & billing arrangement is sometimes referred to as "feed-none" or "self-consumption only," where DPV exports to the utility grid are either physically restricted or not financially remunerated, but self-consumption of DPV electricity is allowed. For the purposes of a TRIA, such an arrangement can be treated as net billing with a sell rate of zero for DPV exports.
[21] There can be provisions to zero out any remaining credits after a specified time period (e.g., 1 year).
[22] From a financial standpoint, NEM and net billing would be equivalent if the net billing sell rate is equivalent to the total volumetric energy charge component of the retail electricity tariff.

feed-in tariff has been used to describe both buy-all/sell-all and net billing arrangements but is most often associated with a buy-all/sell-all scheme.

Crediting Terms: These terms define whether compensation is granted as a retail electricity bill credit (either in currency or kilowatt-hours) or as cash payments. Crediting terms determine whether the credit can be carried over between billing cycles and the circumstances under which credits might expire and/or cash payments are paid to the DG system owner.

Credit Reconciliation Period: A predetermined time at which a customer's banked kilowatt-hour credits (for NEM schemes) or banked currency credits (for net billing and buy-all/sell-all schemes) expire.

Netting Frequency: If the system owner consumes DPV electricity, netting frequency is the time period under which DPV production and customer electricity consumption are summed and measured for billing purposes.

2.2 Fundamentals of Utility Ratemaking for TRIAs

This section provides a concise overview of: (1) how utility rates are calculated; (2) how electricity tariffs are designed; and (3) how changes in utility revenue are addressed under cost-of-service regulation. Understanding how utilities create revenue, charge various customers for electricity, and respond to changes in revenue in the absence of DPV is important to understand before attempting to accurately quantify the revenue and tariff impacts associated with DPV deployment. Thus, this guidebook suggests that the first step of any TRIA analysis is to understand, through interviews and qualitative research as necessary, how exactly ratemaking processes unfold, how tariffs are designed, and how changes in revenue are addressed. Indeed, part of the data collection effort is requesting government documents that outline the ratemaking process and discussing the regulatory framework with energy regulators, the utilities, and/or other government agencies responsible for retail electricity regulation.[23]

This guidebook is written for jurisdictions featuring a regulatory paradigm in which tariffs can be adjusted to reflect changes in net utility costs, such as cost-of-service regulation. The core principle of cost-of-service regulation is that revenues that utilities aim to earn should be equivalent to reasonably incurred actual costs of electricity service provision (plus a rate of return for prudent investments, where applicable).[24,25]While the specifics differ by jurisdiction, at a high level, power sector regulators are tasked with determining an appropriate revenue requirement necessary to maintain utility revenue sufficiency for a given period, and also determine the total power sales for each customer class for that same period, based on a historical or future test year. The revenue requirement is then allocated across customer classes (with different corresponding estimates of expected sales) in alignment with cost-based and policy priorities, which determines the portion of the revenue requirement that is expected to be recovered from each customer class.[26] These revenue targets are used as the basis for designing retail electricity tariffs. Each customer class's retail electricity tariff will have specific utility charges (i.e., subcomponents of electricity tariffs), along with associated structures (e.g., inclining or declining quantity

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[23] In the event that a regulatory body does not exist, data collection from other government bodies that perform traditional power sector regulatory functions may be required.
[24] A discussion of what qualifies as a "reasonable" or "prudent" utility expenditure is outside the scope of this guidebook.
[25] While full cost recovery is not often achieved in many developing country settings, philosophies of ratemaking that use incurred costs as a basis for tariff design are common throughout the world, including in lower data environments.
[26] At this stage, subsidies may also be considered and included. Subsidies may originate directly from governments or other customer classes in the form of a cross-subsidy.

schedules) as merited. Utility charge levels are adjusted with the aim of meeting the revenue requirement for each customer class.[27]

Because this ratemaking process relies on a range of forecasts and often historical cost data, in some jurisdictions, utilities may over- or under-collect revenue if costs or sales deviate from what is assumed in the revenue requirement and rate-setting. There are policy mechanisms that allow utilities to adjust future retail electricity tariffs, often referred to as a "true-up." Utilities can recalculate tariffs through a rate case by waiting until the end of the rate period, or, in some cases, choosing to initiate it early. At this point, the revenue requirement is recalculated to take into account any changes in the utilities' fixed and operating costs, as well as the expected sales by tariff class, thus resetting tariffs and ensuring a better alignment between revenues and costs. In some cases, utilities do not need to wait until the next rate case to adjust rates to account for under- or over-collection. For example, there could be an interim regulatory proceeding designed to address true-up issues periodically, monthly, or several times over years. This true up mechanism, sometimes structured as a rate rider[28] or adder, can be explicitly designed by regulators to cover fuel costs only (e.g., a fuel adjustment clause) or cover costs associated with under- or over-estimating sales levels (e.g., a lost revenue adjustment mechanism). The timing of these true-ups has important implications for TRIA (see Section 2.3).

In the event that utility costs or sales fall outside of *ex ante* estimates established during the rate case, regulatory bodies often have established protocols to allocate additional costs and/or return excess revenue based on the circumstances causing the deviation. For example, if diesel costs rise beyond forecasted expectations and cause a price spike, regulators would decide exactly how ratepayers and the utility[29] would share this additional cost burden for electricity service, sometimes limiting the increase in the retail electricity tariff in a given period. In the case of DPV programs, if net revenue impacts are positive to the utility, regulators may allow for electricity tariffs to decrease to return some portion (or all) of the revenue surplus to ratepayers under a revenue decoupling scheme. One key task for analysts undertaking a TRIA is to understand how any additional net cost burdens or revenue surpluses associated with DPV deployment would be shared by ratepayers and utilities.

Finally, it is outside the scope of this guidebook to discuss common regulatory benefit-cost tests, such as those used commonly in the United States for utility programs (such as DPV programs), which help determine the cost-effectiveness of programs, including: Participant cost test; utility cost test; societal cost test; total resource cost; and program administrator cost. However, the utility tariff impact calculations proposed in this guidebook are related to the ratepayer impact measure test.

More details on the ratemaking process can be found in Lazar, Chernick, and Marcus (2020), NARUC (2016), Lazar (2016), and CPUC (2001).

2.3 Timeframe of Revenue and Tariff Impacts

DPV generation results in the *instantaneous* loss of utility sales for DPV output that is consumed on-site, as well as reductions of bulk power generation levels for all DPV generation; however, the timing-related details of the utility regulatory process determine when exactly those impacts are experienced. Thus, we propose a standard set of terminology to discuss the timing of revenue and tariff impacts.

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[27] A similar process might ensure for wholesale electricity tariffs, as well.
[28] A rate rider is defined as an explicit charge on a utility bill intended to recover a specific set of costs that are not otherwise covered in the approved set of tariffs. Rate riders can be adjusted during or between rate cases.
[29] In some cases, governments may also absorb additional cost burdens.

Short-term impacts: DPV revenue and tariff impacts that occur before the next rate case. Utilities are commonly asked to absorb net revenue losses from DPV in the short term, due to decreases in electricity sales and generation levels. As well, depending on the setting, it is also possible that energy charges may be adjusted in the short term through fuel adjustment clauses or other interim (i.e., non-rate case) regulatory proceedings.

Medium-term impacts: DPV revenue and tariff impacts that occur at/after the next rate case. Tariff adjustments to reconcile short-term net revenue losses and ensure cost recovery generally happen in the medium term (i.e., during rate cases).

Long-term impacts: DPV tariff impacts that might occur in future rate cases. Importantly, some benefits of DPV to utilities and ratepayers may not be realized for several years and may not always be tracked or noticed (e.g., deferral or avoidance of future generation investments due to DPV), whereas a decrease in electricity sales and revenue collection occurs immediately for any DPV that is self-consumed. Thus, situations may arise where short- or medium-term tariff increases due to DPV could be followed by long-term tariff decreases. In addition, electricity generation mixes can change significantly over time, resulting from higher renewable penetrations or other policies that impact the marginal cost of generation (e.g., environmental policies). Changes to the generation mix can potentially lead to different valuations for DPV generation over time and, thus, changes in impacts to utility revenues or retail electricity tariffs.

At a high level, it is important for analysts to distinguish DPV impacts to various stakeholder groups by the timeframe of their impact.

2.4 Understanding DPV Generation Behavior at the Source

To understand and conduct a TRIA, it is useful to understand the full progression of impacts resulting from a kilowatt-hour of DPV generation. In principle, this requires an understanding of *who* is impacted, *what* the level of the impact is, *how* the impact happens, and *when* they are impacted.

We first begin our understanding of DPV impacts by exploring the two potential paths for DPV generation. There are two potential paths for DPV generation that are relevant for TRIAs, which can be experienced simultaneously, depending on the metering and billing arrangement for the customer.[30]

1. **Self-consumption of DPV generation**: Any DPV generation that is used to supply the customer directly with electricity for instantaneous consumption is said to be "self-consumed." Self-consumption allows DPV system owners to reduce or eliminate the variable utility charge portion of their electricity bills, as consumption from the grid is replaced by consumption from their DPV system. For a utility, self-consumption of DPV generation leads to reduced expenditures related to purchasing or generating wholesale electricity and, in some cases, may reduce some future fixed capital and associated operations and maintenance costs. In most cases, under pre-existing tariff designs, this may still lead to an under-recovery of distribution system fixed costs because utilities often recover a (sometimes substantial) portion of the fixed costs incurred for maintaining the network from the volumetric energy charge component of their retail tariff. This will be discussed in more detail, along with other costs, benefits, and stakeholder perspectives, in a

[30] If customers are under a buy-all/sell-all metering and billing arrangement, they must export 100% of their generated electricity to the distribution network, which has a distinct financial impact as the utility does not lose any sales from the customer—rather, they are party to a micro-PPA with a set cost structure. Because buy-all/sell-all schemes are not particularly common, this guidebook will not focus on the topic with significant detail.

subsequent section. Self-consumption only occurs under NEM, net billing, or "feed-none"[31] metering & billing arrangements.

2. **Grid injection of DPV generation**: If the DPV system generates more electricity than the customer self-consumes at any given moment, or if the DPV customer is subject to a buy-all/sell-all scheme, then the DPV generation (in excess of what is self-consumed, if any) is injected into the grid. The customer is typically granted a kWh- or cash-based bill credit for this injected electricity. From the distribution utility and VIU standpoint, these payments for DPV grid injections are additional expenditures, but there are also reduced expenditures as these grid injections offset purchasing or generating wholesale electricity. Thus, the difference between the sell rate for grid injections and the utility's avoided costs, driven in large part by the wholesale electricity price, is a key driver of distribution utility financial impacts.

These two behaviors may have distinct financial impacts on different utility stakeholders, depending on the details of the DPV customer's metering and billing arrangements, retail electricity tariff structure, sell rate level, and crediting terms.[32]

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[31] Under feed-none (also known as "self-consumption only") schemes, DPV grid injections are either physically restricted or not financially remunerated. For the purposes of TRIA, feed-none schemes can be treated as a net billing arrangement with a sell rate of zero.

[32] The exception to this statement is for electric generation utilities, which experience both DPV self-consumption and grid injections as a reduction of wholesale electricity sales and a commensurate reduction in generation-related costs.

3 Crafting an Appropriate TRIA Question Through Scenario Design

There are a range of important questions that a TRIA can help answer, and stakeholder input is quite important for designing a relevant analysis question. This section lists several categories of analysis questions that a TRIA might ask through scenario design. At a high level, these different analysis questions are asked through the creation of a suite of scenarios—certain input parameters and analysis assumptions are systematically varied (or "parameterized," in modeling-speak), while most others are kept the same.

3.1 Quantifying the Impact of Expected Deployment

Requests from stakeholders are oftentimes quite high-level: *What impact will DPV have on our utility?* Stakeholders may have a particular DPV deployment level and timeframe in mind (e.g., a long-term target from a national power sector plan) or may require assistance in developing scenarios. Oftentimes, stakeholders are interested in understanding the bounds of possible outcomes; this can be addressed through a set of scenarios that examine low and high DPV deployment levels, as well as other important assumptions (e.g., fuel price projections). Importantly, if a jurisdiction does not have a DPV program in place, it is imperative to interact with local stakeholders for the analysis to design the most relevant compensation mechanisms possible in advance of commencing analysis activities.

3.2 Informing Metering & Billing Arrangement Design

Understanding the impact of different DPV metering & billing arrangements on utilities is another commonly requested analysis question. What will happen if a utility begins granting credit for net excess generation under an NEM program? What if a utility shifts from an NEM program to net billing?[33] What if our self-consumption-only program begins to allow grid injections? As was mentioned previously, terminology around metering & billing arrangements is quite easily confused, so establishing terminology upfront is a useful exercise.[34]

Discussions surrounding metering & billing arrangements tend to go hand-in-hand with sell rate design.

3.3 Informing Sell Rate Design

Depending on the metering & billing arrangement, sell rates for DPV grid injections may be a key driver of DPV customer economics and utility financial impacts. Stakeholders may request insights on what is considered a "fair" payment for DPV grid injections (i.e., balancing customer interests and utility interests), and/or simply what impact different sell rates will have on utility finances.

In general, there are several aspects that can be explored in the realm of sell rate design. Analysts can vary the exact level of a static sell rate and quantify the corresponding impact across a range of scenarios. Such an exercise can inform the extent to which sell rate levels financially impact the utility and also identify desirable sell rate levels that may help the utility offset self-consumption-related revenue losses. If more dynamic sell rates are on the table, analysts can help stakeholders design and understand the impact of various time-variant sell rates.

[33] Discussions around shifts in metering & billing arrangements tend to go hand-in-hand with discussions of sell rates. See Section 6.3.
[34] The terminology offered in Section 2.1 of this report may serve as a useful starting point.

3.4 Informing Retail Tariff Design

It is growing increasingly common in many DPV markets for DPV customers to be placed on DPV-specific retail electricity tariffs. These tariffs are designed with the intention of ensuring utility fixed cost recovery, while also fairly rewarding DPV customers for the value they provide to the system. Thus, it may be useful for stakeholders to understand the extent to which potential changes to retail tariff structures may help to reduce utility revenue impacts or blunt expected tariff increases. How would the implementation of TOU rates, demand charges, or minimum bills for DPV customers impact utility finances? What about a shift from inclining block tariffs to declining block tariffs? It is important here to carefully design potential changes to retail tariffs in close collaboration with relevant stakeholders (e.g., regulators, utilities) to maximize the chance that analysis results might be utilized.

3.5 Informing Wholesale Tariff Design

Similar to retail tariff design, changes to wholesale electricity tariffs (i.e., how a regulated EGU charges distribution utilities for wholesale electricity) may help to blunt the revenue and tariff impacts of DPV. Generally speaking, moving toward more granular pricing schemes (e.g., offering additional time windows with distinct wholesale tariff levels to distributors) helps to more accurately reflect a utility's time-variant cost of generation. When a DPV system is producing electricity and wholesale electricity demand declines, the difference between: (1) the revenue loss associated with a reduced wholesale electricity sale; and (2) the utility's avoided cost of generation becomes smaller, resulting in lower net revenue losses for the electricity wholesaler (and in many cases, the distribution utility).

This type of exploration could be relevant for jurisdictions featuring an EGU or a VIU selling wholesale electricity to a distribution utility. Experimentation through modeling with more granular wholesale electricity tariffs (either time- or location-based), or alternative tariff structures such as demand-based charges, may be an instructive exercise in certain jurisdictions.

3.6 Informing Cost Allocation or Other Regulatory Strategies

In many contexts, policymakers and regulators have leeway to allocate utility revenue losses associated with DPV deployment in different proportions between utilities and ratepayers (and, when ratepayers absorb revenue losses, among various ratepayer classes). Thus, TRIA can be a useful exercise to understand impacts under different regulatory cost allocation rules. For instance, analysts can test a scenario in which 100% of net revenue impacts are passed through to customers, versus a scenario where impacts associated with self-consumed DPV are split 50-50, and utility profitability (and/or other relevant financial metrics besides revenue) slightly shifts.

Importantly, the creation of cost allocation strategy scenarios happens after net revenue impact calculations for a given deployment scenario. During the analysis step where utility net revenue impacts are converted to net tariff impacts (see Section 6.6), analysts can vary their assumptions about how exactly costs are passed through to utilities and ratepayers.

Other regulatory strategies that might be tested include the implementation of a lost fixed cost recovery mechanism, more frequent rate adjustments, and/or revenue decoupling strategies. These strategies tend to be quite politically sensitive, and are best explored only after strong stakeholder interest and buy-in.

3.7 Understanding the Impact of Geography

Some stakeholders may want to understand the extent to which DPV deployment in different regions impacts the utility. Solar insolation and customer mixes typically vary with geography, and some countries feature retail electricity tariffs that are distinct by region as well (e.g., due to distinct weather patterns). These geographic explorations may be useful for helping governments understand where best to deploy their resources to promote (or prudently limit) DPV deployment.

Linking TRIA Frameworks to Individual Project Techno-Economic Analysis

Making changes to the aspects mentioned in Sections 6.2, 6.3, 6.4, and 6.5 will not only impact utilities and ratepayers, but also individual customers. It is generally useful for decision makers to understand the attractiveness of the existing DPV market for customers and also how various policy choices may impact prospective DPV customers, and, thus, the DPV market at large.

At a high level, this can be accomplished by examining typical project financial metrics (e.g., simple payback period, net present value) for the prototypical DPV customers being modeled in a TRIA; these examinations can serve as a useful "sanity check" on the underlying assumptions being made. For instance, if prototypical DPV customers are experiencing a payback period of 25+ years under current policy and market conditions, the efforts of policymakers may be better focused on building the fundamentals of the DPV market, rather than protecting utility revenues. On the other hand, if a particular change in policy (e.g., boosting a DPV sell rate) is expected to shift DPV payback periods from 8–10 years to 2–4 years, then the opposite may be true.

Importantly, linking TRIA frameworks to analyses of individual customer economics is quite straightforward; the additional effort required is small. This is because TRIA exercises already rely foundationally on the modeling of individual prototypical DPV customers (see Section 8.3). The modeling of these DPV customers for TRIAs requires a range of input data and assumptions, but can be performed without making assumptions about DPV system costs or financing terms. This is because the outputs that are required for TRIAs surround changes in customer bills, but not necessarily the multiyear cumulative effect of those changes on the economics of the DPV project. However, by simply including a few extra assumptions into the modeling exercise (e.g., capital costs, operations and maintenance costs, debt/equity ratio, cost of debt and equity financing, and so on), customer economic metrics can be easily obtained.

4 Tracking DPV Value Drivers

As a matter of practicality for implementation, the methodologies and approaches set forth in the subsequent sections of this guidebook are predominantly focused on quantifying direct, noticeable, and easily trackable utility costs and benefits; these predominantly comprise changes in utility sales and direct short-term expenditures due to DPV. However, these utility-perspective cost-based "value drivers"[35] are part of a broader portfolio of DPV value drivers that can accrue to utilities and ratepayers over various periods of time. This chapter will provide a brief overview of various DPV value drivers and offer some practical considerations related to quantifying them.

4.1 Value Driver Dimensions and Practical Considerations

Before discussing the broader portfolio of DPV costs and benefits, it is important to note that the various value drivers being discussed here have multiple dimensions to them. When considering the addition of particular value drivers to a TRIA analysis, it is worthwhile to review the following considerations.

Value Magnitude: The value magnitude is the $/kWh or $/kW[36] figure associated with a particular DPV value driver. These magnitudes may change with time or location of the DPV, and almost certainly evolve over time.

Accrual Timeframe: What is the timeframe for when a value driver is first able to be incorporated into utility tariff design and/or planning decisions? The costs and benefits of DPV are not always realized immediately. In many circumstances, the short-term revenue decreases and medium-term tariff increases resulting from reduced electricity sales can be followed by long-term net revenue increases and tariff decreases resulting from (for example) deferred or avoided investments. In other words, the true long-term system value of DPV systems may outweigh immediate-term cost shifting impacts. Thus, it is important to obtain a good understanding of the timeframe of value accrual.

Value Recipient: To whom does a particular value aspect accrue? If the value aspect is noticeable/tracked, there is inevitably a stakeholder to whom this additional cost burden or benefit accrues (e.g., distribution utilities, electric generation utilities, ratepayers, and so on). It is worth noting that a cost experienced by a particular stakeholder may be a benefit for another stakeholder, and vice versa.

Accrual Mechanism: Assuming that a value aspect can be tracked and/or analyzed, is there an adequate mechanism in place to ensure that the net cost or benefit of DPV can be passed through to utilities, ratepayers, and/or DPV owners? For instance, most power systems will experience a capacity-related benefit from the presence of DPV (i.e., a reduced need for generation investment), and this benefit can either be passed through to ratepayers or the utility. However, if the utility does not consider DPV in its capacity planning exercises, it may build or procure unneeded generation capacity and the benefit of DPV will not in fact accrue.

Assessment Complexity: In some cases, value drivers may be easily noticeable and trackable by utilities and regulators. For instance, reduced electricity sales or increased utility purchases of DPV grid injections are easily noticeable and trackable quantities; they can thus be more easily addressed by utilities and in regulatory proceedings. However, this is not uniformly the case for all DPV value aspects. For instance, while utilities may experience reduced fuel costs due to DPV (a noticeable and potentially trackable quantity), it may be more difficult to notice (let alone track) the system benefit of reduced exposure to

[35] Value drivers are also sometimes referred to as "value streams."
[36] $/kW values are common for investment-related value drivers and can be levelized over the lifetime of the DPV system to become $/kWh values.

fuel price volatility. As well, the quantification of certain value drivers requires specialized and oftentimes detailed analyses, such as marginal cost of service studies required to quantify avoided distribution investment value.

Data Availability: Related to assessment complexity, is the requisite data available to adequately quantify specific DPV value drivers? To the extent possible, analysts will benefit from attempting to understand upfront what kind of input data (and analysis techniques) will be required to quantify various value aspects. These issues will be discussed in more detail in Sections 4.3 and 4.4.

4.2 Overview of DPV Value Drivers

The subsequent table summarizes common DPV value drivers, including the relative magnitude of the value driver, accrual timeframe, and the relative complexity of assessment.[37]

[37] Impacts of these various value drivers on utility returns on equity are not considered in this table or document. See Satchwell et al. (2015) for a deeper discussion into these issues.

Table 1. Common DPV Value Drivers From a Utility Perspective and Associated Dimensions

	Value Stream	Relative Magnitude*	Accrual Timeframe†	Assessment Complexity	Potential Utility Value Recipient‡	Description
Utility Sales and Purchases	Reduced Retail Electricity Sales	↓↓ to ↓↓↓	Short-term	Low	DU; VIU	Reduction in utility revenue due to lower retail electricity sales (i.e., fewer retail kWh and potentially lower collected kW demand charges)
	Reduced Wholesale Electricity Purchases	↑ to ↑↑	Short-term	Low	DU; EGU; VIU	Reduction in utility wholesale electricity purchases due to fewer wholesale kWh required to be purchased
	Reduced Wholesale Electricity Sales	↓ to ↓↓	Short-term	Low	EGU; VIU	Reduction in utility revenue due to fewer wholesale kWh sold
	Additional DPV Injection Purchase Obligation	↓ to ↓↓↓	Short-term	Low	DU; VIU	Additional cost of purchasing injected DPV electricity from customer
Generation Values	Avoided Energy Generation Cost	↑↑ to ↑↑↑	Short-term	Low or Moderate	EGU; VIU	Avoided cost of generating energy from centralized resources due to DPV
	Avoided Generation Capacity Investment ¶	↑ to ↑↑	Medium- or Long-term	Low or Moderate	EGU; VIU	Avoided or deferred cost of investment in centralized generation capacity due to DPV
	Avoided Power Plant O&M	↑	Short-term	Low or Moderate	EGU; VIU	Decreases in conventional power plant operations and maintenance costs associated with lower generation levels due to DPV
	Fuel Hedging	↑ to ↑↑	Medium- or Long-term	High	EGU; VIU	Avoided cost to utility due to reduced risk and exposure to fossil fuel price volatility due to DPV
	Ancillary Services	↓ to ↑	Medium- or Long-term	High	EGU; VIU	Net changes in cost associated with changes in ancillary service requirements due to DPV §
	Regulatory Compliance	↑	Short-term	Low	EGU; VIU	Avoided cost of complying with regulatory mandates, such as clean certificate programs or emission caps (e.g., for particulates, CO_2, NO_X, SO_X)
	Integration Costs	↓	Medium-term	Moderate or High	EGU; VIU	Additional power plant operational costs associated with more frequent power plant ramping, cycling, and startups due to DPV
Transmission Values	Avoided Transmission Investment	↑ to ↑↑	Medium- or Long-term	Moderate	EGU; VIU	Avoided costs due to reduced transmission constraints from DPV that result in deferred or avoided transmission infrastructure investments
	Avoided Transmission Line Losses	↑	Short-term	Low	EGU; VIU	Avoided cost of energy that would otherwise be lost in the transmissions system due to DPV
	Avoided Transmission O&M	↓ to ↑	Short-term	High	EGU; VIU	Increases or decreases in operations and maintenance costs associated with the transmission system due to DPV
Distribution Values	Changes in Distribution Investment Requirements	↓ to ↑↑↑	Medium- or Long-term	High	DU; VIU	Changes in distribution costs due to DPV that result in deferred or avoided distribution infrastructure investments and/or requires new distribution investment needs to accommodate higher levels of DPV
	Avoided Distribution Line Losses	↑ to ↑↑	Short-term	Low or Moderate	DU; VIU	Avoided cost of energy that would otherwise be lost in the distribution system due to DPV
	Avoided Distribution O&M	↓ to ↑	Short-term	High	DU; VIU	Increases or decreases in operations and maintenance costs associated with the distribution system due to DPV
Utility Earnings	Reduced Return on Investment/Equity	↓	Medium- or Long-term	Moderate or High	DU; EGU; VIU	Reduced return on assets resulting from reduced capital expenditures due to DPV
	Avoided Debt Service Costs	↑	Medium- or Long-term	Moderate or High	DU; EGU; VIU	Avoided debt service payments resulting from reduced capital expenditures and associated borrowing requirements due to DPV
Other	Program Administration Costs	↓	Short- or Medium-term	Moderate or High	DU; VIU	Additional costs incurred by utility to administer and staff a DPV program

* ***Relative Magnitude:*** *↑ = Zero to low magnitude benefit; ↑↑ = Moderate magnitude benefit; ↑↑↑ = Higher magnitude benefit; ↓ = Zero to low magnitude cost; ↓↓ = Moderate magnitude cost; ↓↓↓ = Higher magnitude cost*

† ***Accrual Timeframe:*** *Short-term = Before next rate case; Medium-term = After next rate case; Long-term = Multiple rate cases*

‡ ***Potential Utility Value Recipient:*** *DU = Distribution Utility; EGU = Electric Generation Utility; VIU = Vertically Integrated Utility*

¶ *A secondary impact of avoided capacity investment is the avoided operations and maintenance costs associated with the power plant investment that is deferred or avoided.*

§ *With the appropriate technical interconnection standards in place, DPV may itself be able to provide ancillary services.*

What About Lost Fixed Cost Recovery Issues?

The perspective of lost fixed utility costs is often raised in dialogues about DPV financial impacts and utility cost recovery. This refers to the portion of utility fixed costs that is not recovered through variable charges in electricity tariffs when sales are lost due to DPV. How does this perspective sync up with the value drivers and analytical lens described in this guidebook?

At a high level, analyses that examine which specific fixed and variable utility costs are: (1) unrecovered, (2) avoided, and (3) recovered following the deployment of DPV requires a much more detailed and granular understanding of utility ratemaking processes than TRIA. While it is relatively straightforward to provide an estimate of gross and net revenue impacts due to DPV deployment, to provide an analytically robust comment about lost fixed cost recovery, it is important to understand the composition of the utility revenue requirement and other variable costs that might be reduced due to DPV. At a high level, an understanding of what share of the utility revenue requirement can be considered (a) fixed utility costs versus (b) variable utility costs (see definitions of these terms in Section 2.1.2) is required. As well, knowledge of how exactly the revenue requirement and expected utility sales are allocated to each customer class is required, as well as an understanding of how each customer class's retail electricity tariffs were designed.

Ultimately, this type of detailed data is often difficult to obtain in regulatory settings, and, thus, analysis of this nature is outside the scope of this guidebook. While we know that under DPV self-consumption, fixed cost recovery issues are likely happening at least to some extent, it is also quite likely that these costs are being passed through to ratepayers, which may make it a short-term question for utility stakeholders.

5 Considerations for Lower Data Environments

In an ideal world, TRIA can be conducted using a robust series of data sets; however, the full range of data desired are not always available or accessible due to a variety of reasons. This presents a challenge for analysts conducting TRIA. The subsequent subsections discuss why data may be incomplete, unavailable, or inaccessible, and present strategies for how to conduct TRIA in data constrained environments.

5.1 Limitations to Data Availability

Readily available energy data can be limited due to:

(a) Real or perceived sensitivities in sharing customer or utility data with researchers. Customer data—especially when containing personally identifiable information—can be difficult to obtain due to utilities' interests in protecting customer privacy. These concerns can be appeased if it is made clear that any personally identifiable information can be removed from the shared data, the data will not be shared or revealed when presenting analysis results, proper care will be taken to keep the data on secure servers, and the data provider will ultimately benefit from the analysis results. Other than customer data, any utility financial and operations-related data can also be seen as sensitive, particularly data which is not required to be shared in annual reports. In some cases, signing nondisclosure agreements to obtain data may be necessary.

(b) Difficulty in locating, collecting, or aggregating the data that may not be readily accessible or located amongst disparate files and formats, and potentially spread across various utility departments. In some cases, the requested data may not have been collected or aggregated before (e.g., customer-level hourly load data, granular distribution network infrastructure cost data), and coordinating amongst the various staff from the utility or regulatory agency to find the appropriate data can be challenging. In these cases, it is important to be very clear on the data needs, eliminating any ambiguities, and to work with partners inside the appropriate company or agency that know who is the correct person that has access to this data.

(c) Time and financial resource limitations. In some cases, it may be possible to extract or aggregate the required data, but either the organization being requested to share the data does not have the time (due to staffing limitations) or the resources (to pay the appropriate staff) to execute on the data request. In other cases, it may take time before the correct staff is located and before they can begin to work on aggregating and sharing the requested data, which may delay the TRIA analysis beyond a reasonable time of completion.

Even when working closely with the various organizations that may have access to the data, in some cases it is not possible to locate and receive all the requested data. However, there may still be value in conducting the analysis, using reasonable assumptions based on expert estimates or data from similar contexts. For example, if it is not possible to obtain residential customer load data, as smart meters may not have been installed for residential customers before, one could use data obtained from neighboring countries with similar climate and home characteristics in its place. In all cases, working with various stakeholders to develop any assumptions will be particularly valuable, to ensure that the assumptions made are most appropriate.

5.2 Practical Considerations for Data Acquisition Efforts

Determining which data are necessary versus desirable is challenging, but the following guidelines will help determine how to proceed on a case-by-case basis.

1. Focus on impacts from DPV that are largest in magnitude. Some of the benefits from DPV are much larger in magnitude than others, so focusing efforts on obtaining and refining data from those categories is most valuable to improve the analysis results. For example, the energy value from DPV (i.e., the avoided costs resulting from offset energy generation) is in most cases the largest value component, so working to refine inputs to the energy value analysis will be most important. Other benefits may be much smaller in magnitude in comparison (e.g., administrative costs related to DPV programs), so simplifying assumptions is appropriate. Reviewing value of solar analyses can indicate which value components are most important to focus on (e.g., see ICF 2018 for a review of recent value of solar studies).
2. Work with stakeholders to understand which cost or benefit streams are most relevant to the local context. Determining the priorities for DPV programs and what is of greatest interest to various stakeholders can help shape which data and scenarios could be considered. For example, if there may be particular interest in residential DPV, due to targeted policies or subsidies, then it may be valuable to consider various types of residential customer loads, whereas in other cases, the priority may be larger industrial DPV customers, in which case considering one or two residential customer load profiles—but a larger number of industrial load profiles—would be sufficient.
3. If reliable data are not available, one common strategy is to use a range of input assumptions to bound the results can be an effective strategy. Particularly for DPV deployment scenarios, where there are large uncertainties in the amount of total DPV adoption and the distribution among different customer types, creating bounding scenarios (e.g., complementing the central estimate with a low rate/revenue impact and a high rate/revenue impact) can be useful and instructive. Again, working with the DPV stakeholders to determine the appropriate range of assumptions to be used in the TRIA ensures the relevance of the selected assumptions is appropriate to the local context.
4. If reliable data are not available, another common strategy is to utilize proxy data. Proxy data is often required when input data such as customer electricity demand or solar insolation profiles are not available but may also be used for key input assumptions such as avoided energy generation cost. At a high level, there are two types of proxy data that may be useful for TRIA. First, there may be proxy data that originates from outside the analysis jurisdiction but is assumed to be relatively representative of what is missing, for example, 30-minute residential demand data from a neighboring country with a similar climate and level of socio-economic development. Second, there may be data that originates from within the analysis jurisdiction that is not a perfect fit but can nevertheless be used/adapted to serve as an acceptable proxy, even if it is not the exact type of data that is required. For instance, it is common for utilities to not collect hourly or subhourly demand data from individual residential customers; however, feeder-level data is commonly collected. In this case, it may be possible to identify a feeder that predominantly hosts residential customers and adapt its hourly load shape to match the known average annual consumption of a residential customer.

6 Understanding Short-Term Revenue Impacts

This section discusses the key sources of short-term revenue losses and avoided expenditures associated with DPV deployment. We discuss the short-term revenue impacts for each combination of stakeholder perspective and DPV metering & billing arrangement. All revenue impacts discussed are assumed to happen in the short term,[38] and not all categories introduced in Table 1 are included, as some of the structural changes to the electricity grid happen on a longer time scale. Many DPV TRIAs will require analysts to assume multiple stakeholder perspectives.

The short-term revenue impacts for distribution utilities, generation utilities, and VIUs are summarized in Table 2. The following sections focus on the differences among the three types of utilities.

[38] Inherent to this analysis methodology is also an implicit assumption that DPV generation is not used to offset unserved energy. DPV has distinct impacts if the affected utilities are not currently serving all customer energy needs. In particular, there may not be reduced retail sales or avoided energy generation or wholesale purchase costs if 1 kWh of DPV results in 1 less kWh of unserved energy.

Table 2. Select Short-Term Financial Impacts by Utility Type and Compensation Mechanism

	Distribution Utilities			VIUs			EGUs
DPV Compensation Mechanism	NEM	Net Billing	Buy-All/Sell-All	NEM	Net Billing	Buy-All/ Sell-All	All
Reduced Retail Electricity Sales	✓	✓	X	✓	✓	X	X
Reduced Wholesale Electricity Sales	X	X	X	✓ B	✓ B	✓ B	✓
Additional DPV Injection Purchase Obligation	✓ C	✓	✓	✓ C	✓	✓	X
Reduced Wholesale Electricity Purchases	✓	✓	✓	✓ D	✓ D	✓ D	✓ D
Avoided Energy Generation Cost	X	X	X	✓ E	✓ E	✓ E	✓ E
Avoided Distribution Line Losses	✓	✓	✓	✓	✓	✓	X
Avoided Transmission Line Losses	X	X	X	✓	✓	✓	✓

✓ ***= Value driver is relevant for tracking*** X ***= Value driver is not applicable***

[A] *Does not apply for "feed-none" or "self-consumption only" variants, where DPV exports to the utility grid are either physically restricted or not financially remunerated.*
[B] *Only applies if DPV is located within the retail service territory of a VIU wholesale customer (i.e., a separate distribution utility)*
[C] *Only applies if kWh NEM credits are converted into financial credit upon expiration*
[D] *Only applies if DPV displaces energy purchases from wholesale market or IPP.*
[E] *Only applies if DPV displaces energy generation from power plants owned by utility.*

6.1 Distribution Utilities

The exact nature of short-term DPV revenue impacts for distribution utilities depends on the DPV generation behavior and the DPV compensation mechanism. Table 3 explains a selection of short-term revenue impacts for various DPV metering and billing arrangements.

Table 3. Select Short-Term Financial Impacts of DPV on Distribution Utilities

	NEM	Net Billing	Buy-All/Sell-All
Reduced Retail Electricity Sales	Self-consumed electricity and injected DPV generation result in reduced retail electricity sales (due to injections being credited at the volumetric energy rate).	Self-consumed electricity results in reduced retail electricity sales.	Not applicable. Because DPV self-consumption does not occur under this scheme, there are no reduced retail electricity sales.
Reduced Wholesale Electricity Sales	Not applicable. Distribution utilities do not typically sell wholesale electricity and thus cannot experience reduced wholesale electricity sales.		
Additional DPV Injection Purchase Obligation	Only accrues if expired kWh credits are purchased from customer.	All DPV generation injected into the grid results in an additional purchase obligation.[A]	All DPV generation results in an additional purchase obligation.
Reduced Wholesale Electricity Purchases	All DPV generation (both self-consumed and injected) results in avoided energy purchase obligations for distribution utilities.		
Avoided Energy Generation Cost	Not applicable. Distribution utilities do not typically own generation assets and thus cannot avoid energy generation costs.		
Avoided Distribution Line Losses	All DPV generation (both self-consumed and injected[B]) results in avoiding incremental amounts of wholesale electricity that would need to be purchased to offset distribution network technical losses.		
Avoided Transmission Line Losses	Wholesale electricity purchases are typically delivered and metered at an interconnection point with the distribution network; hence there are no transmission losses to be avoided by DPV generation.		

[A] Does not apply for "feed-none" or "self-consumption only" variants, where DPV exports to the utility grid are either physically restricted or not financially remunerated and the sell rate for grid injections is effectively zero.
[B] Assumes that all injected electricity is immediately consumed by geographically adjacent customers without additional technical losses in the distribution system

Additional Considerations: Reduced retail electricity sales are likely to be greater for NEM than for net billing, as kWh credits for injected DPV generation also reduce sales under NEM, whereas DPV generation injected into the grid under net billing does not. Additional DPV purchase obligations only accrue under NEM when excess kWh credits are present and due to expire at the end of the predefined credit expiration period (often monthly or annually); under some NEM regulations, kWh credits may never expire, or expired kWh credits are forfeited without remuneration; thus, there may be circumstances in which NEM does not result in any additional utility purchase obligations.

6.2 Electric Generation Utilities

Electric generation utilities are not distinctly impacted by DPV self-consumption versus grid injections distinctly, nor by the choice in compensation mechanisms offered by their wholesale customers (e.g., distribution utilities) to retail customers.

For a DPV system producing electricity, the following short-term revenue impacts are experienced by the EGU:

Table 4. Select Short-Term Financial Impacts of DPV on Electric Generation Utilities

<table>
<tr><th></th><th>NEM</th><th>Net Billing</th><th>Buy-All/Sell-All</th></tr>
<tr><td>Reduced Retail Electricity Sales</td><td colspan="3">EGUs do not sell electricity to retail customers and, thus, do not experience reduced retail electricity sales</td></tr>
<tr><td>Reduced Wholesale Electricity Sales</td><td colspan="3">All DPV generation (both self-consumed and injected) results in reduced wholesale electricity sales for EGUs. Assuming the point-of-sale for wholesale electricity is at a transmission-distribution infrastructure interface (e.g., a substation), reduced wholesale electricity sales will include avoided losses in the offtaker’s distribution network.</td></tr>
<tr><td>Additional DPV Injection Purchase Obligation</td><td colspan="3">Not applicable. EGUs do not operate distribution networks or sell electricity directly to retail customers, and, thus, would not experience additional purchase obligations for DPV injections into the distribution network.</td></tr>
<tr><td>Reduced Wholesale Electricity Purchases</td><td colspan="3" rowspan="2">All DPV generation (both self-consumed and injected) results in either avoided energy purchase obligations or avoided energy generation costs, depending on whether the need for energy purchases or energy generation (or some combination thereof) is offset during times of DPV production for the EGU.</td></tr>
<tr><td>Avoided Energy Generation Cost</td></tr>
<tr><td>Avoided Distribution Line Losses</td><td colspan="3">Not applicable. EGUs do not operate distribution networks or sell electricity directly to retail customers, and, thus, cannot experience avoided distribution line losses.</td></tr>
<tr><td>Avoided Transmission Line Losses</td><td colspan="3">All DPV generation results in avoiding incremental amounts of electricity that would need to be purchased or generated by the EGU to offset transmission network technical losses.</td></tr>
</table>

6.3 VIUs

If DPV is deployed in the distribution service territory of a wholesale customer that retails electricity (i.e., a distribution utility), then the VIU is effectively serving as an EGU. Thus, from the standpoint of revenue impacts, the gains and losses experienced are identical to that of an EGU (see Section 6.2).

However, if DPV is deployed in a location where the VIU sells retail electricity, then the VIU acts as both the EGU and the distribution utility, and the exact short-term revenue impacts are distinct, depending on the DPV compensation mechanism and the DPV generation path (i.e., self-consumption versus grid injection). These impacts are summarized in Table 5. The revenue impacts for the VIU are similar to that of the distribution utility for the three DPV compensation mechanisms considered, but in addition to those of the distribution utility, they also include avoided energy VIU generation costs and reduced transmission network losses, as the VIU also owns the transmission lines and benefits from reduced losses accrue to the VIU.

Table 5. Select Short-Term Financial Impacts of DPV on VIUs When DPV is Deployed in a Location Where Retail Electricity Is Sold by the VIU

	NEM	Net Billing	Buy-All/Sell-All
Reduced Retail Electricity Sales	Self-consumed electricity and injected DPV generation result in reduced retail electricity sales (due to injections being credited at the volumetric energy rate).	Self-consumed electricity results in reduced retail electricity sales.	Not applicable. Because DPV self-consumption does not occur under this scheme, there are no reduced retail electricity sales.
Reduced Wholesale Electricity Sales	If the DPV is located within the VIU's retail service territory, then the VIU does not experience reduced wholesale electricity sales. If the DPV is located within the retail service territory of a VIU wholesale customer (e.g., a separate Distribution Utility), then they are acting in this case as an EGU (see Table 4).		
Additional DPV Injection Purchase Obligation	Only accrues if expired kWh credits are purchased from the customer.	All DPV generation injected into the grid results in an additional purchase obligation.[A]	All DPV generation results in an additional purchase obligation.
Reduced Wholesale Electricity Purchases	All DPV generation (both self-consumed and injected) results in either avoided energy purchase obligations or avoided energy generation costs, depending on whether the need for energy purchases or energy generation (or some combination thereof) is offset during times of DPV production.		
Avoided Energy Generation Cost			
Avoided Distribution Line Losses	All DPV generation (both self-consumed and injected[B]) results in avoiding incremental amounts of electricity that would need to be purchased or generated by the VIU to offset distribution network technical losses.		
Avoided Transmission Line Losses	Similar to avoided distribution losses, all DPV generation results in avoiding incremental amounts of electricity that would need to be purchased or generated by the VIU to offset transmission network technical losses.		

[A] Does not apply for "feed-none" or "self-consumption only" variants, where DPV exports to the utility grid are either physically restricted or not financially remunerated."
[B] Assumes that all injected electricity is immediately consumed by geographically adjacent customers without additional technical losses in the distribution system

6.4 Electricity Ratepayers

As opposed to the electricity companies noted above who experience more direct short-term net revenue impacts from DPV deployment, electricity ratepayers do not experience "revenue impacts" in a similar way. Rather, they are affected by DPV through changes to retail electricity tariffs. When ratemaking regulations allow for revenue impacts to utilities to be recovered through changes to retail electricity tariffs, retail rate levels can change as a result of DPV deployment. In some cases, this is added to the rate explicitly as a rate rider or another form of interim rate adjustment mechanisms (e.g., a fuel adjustment charge), which impacts rate levels in the short term, and in other cases, retail rates are adjusted at the rate case to allow utilities to recover their costs over a reduced sales base in the medium to long term.

6.5 Less Common TRIA Stakeholder Perspectives

6.5.1 Central or State Governments

As a matter of social policy in developing countries, retail electricity tariffs are sometimes underpriced relative to the true cost of retail service. This is accomplished through the provision of cross-subsidies (from one tariff class to another) or explicit subsidies to utilities (e.g., from the central government). If customers on a tariff subsidized by the government deploy DPV, this can sometimes lead to a cost savings from the perspective of a central government.[39] As well, depending on the details of each

[39] For instance, in 2017, the Government of Mexico performed an analysis to understand the potential to reduce central government subsidy payments through the accelerated deployment of DPV (Spanish):

individual context, if cross-subsidizing customers who pay higher tariffs deploy DPV and no longer support subsidized customers, a central government may need to make up the revenue difference, leading to an additional cost.[40] Central governments in many countries also subsidize fuels used for large-scale power generation and diesel backup generators. Use of DPV to displace both or either fuel would also reduce the financial burden of those subsidies while maintaining the same level of energy services to customers.

6.5.2 IPPs

When DPV is deployed and wholesale electricity generation levels reduce, IPPs may experience a reduction in generation levels and commensurate reduction in revenue in certain contexts. This depends on the contractual arrangements (if any) that they have with their counterparty utility, fuel contracts that are currently in place, market dispatch rules, and/or the construct of the wholesale power market they participate in (e.g., an hourly spot market). It is important to understand if IPPs are impacted by DPV deployment, as governments may find it more socially/politically acceptable to allocate revenue reduction costs/risks to private companies, at least up until the point that it effects sector investability.

https://www.gob.mx/sener/documentos/beneficios-de-la-generacion-limpia-distribuida-y-la-eficiencia-energetica-en-mexico.

[40] Retail electricity tariff increases are perhaps the most common strategy for addressing the loss of cross-subsidization revenue.

7 Analysis Process

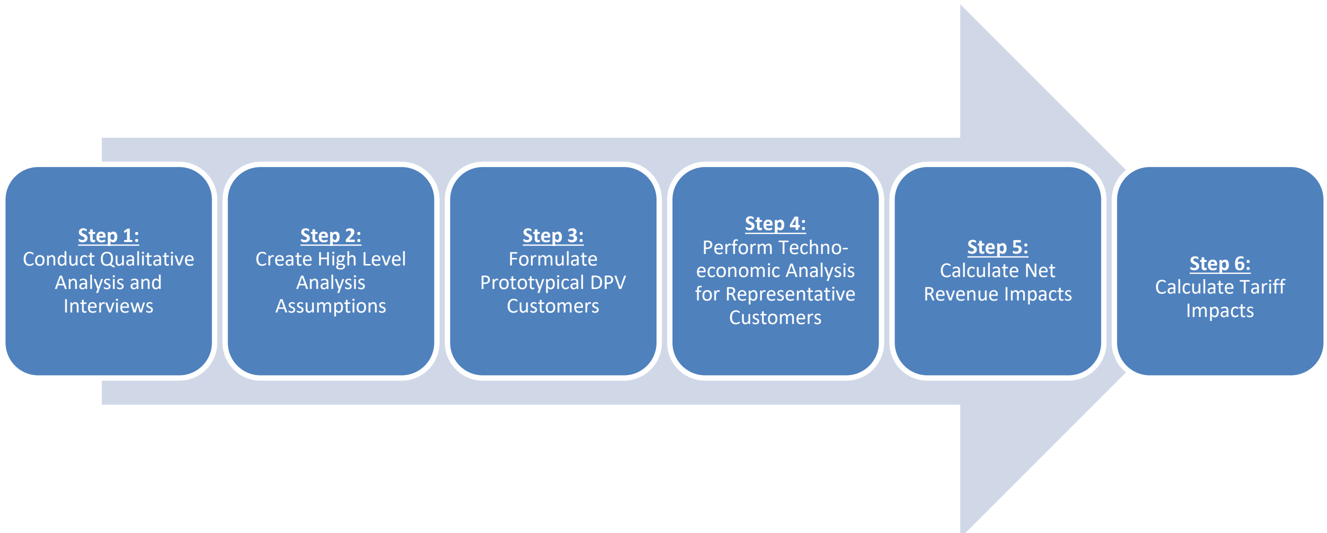

Figure 1. TRIA Analysis Process

In this section, we outline each of the steps in the TRIA process, beginning with data collection through desk research and interviews in Step 1, development of assumptions in Step 2, development of customer characteristics in Step 3, bill calculations in Step 4, and finally, revenue and tariff impact analysis in Steps 5 and 6.

7.1 Step 1: Qualitative Analysis and Interviews

In this initial analysis step, information is collected related to:

1. The power sector regulatory structure and detailed ratemaking procedures and considerations in the context in question
2. Whether and how the deployment of DPV would be accounted for in this ratemaking process in practice
3. How the deployment of DPV would financially impact the stakeholders in question under the existing regulatory structure.

The purpose of this step is to understand how a conceptual kWh of behind-the-meter DPV generation—distinguishing between self-consumed and injected generation—impacts utility revenues and tariffs through the existing ratemaking process.

This process is also useful to help characterize the current environment of retail rates, compensation mechanisms, and other DPV policy levers. It is also helpful for understanding the state of data that may ultimately be used to conduct the analysis, and to assess if there is any ambiguity/confusion among stakeholders about the theoretical impacts of DPV.

While desk research may prove useful as an initial step, the primary feature of this analysis step is a series of in-depth stakeholder interviews. While certain resources (e.g., regulatory dockets) may be available online, they may not necessarily reflect the most up-to-date rules and regulations that are used in practice by utilities and regulators. Confirming findings from desk research via stakeholder interviews is thus essential to ensure correct understanding of the most recent regulatory rules and structures. The most critical stakeholders to interview typically include the utility, the regulatory body (or other relevant government authority overseeing proceedings of economic regulation), and energy ministries or other government departments responsible for setting policy related to DPV compensation.

An extensive list of potential research and interview questions is detailed in Appendix A. These questions are designed to assist analysts in uncovering relevant details of local ratemaking processes and potential DPV impacts.

7.1.1 Desired Outputs

Below is a list of desired outputs from Step 1: Qualitative Analysis and Interviews.[41]

Utility Net Revenue Impact Equations: For each utility stakeholder under examination, a high-level theoretical equation that describes how revenues are impacted by DPV (using the existing revenue requirement as a baseline) should be formulated. This equation should include impacts associated with self-consumed DPV versus grid injections of DPV.[42]

Average Utility Tariff Impact Equations: For each utility under examination, a high-level theoretical equation that describes how average (retail and/or wholesale) tariffs are calculated under the status quo (i.e., in the absence of DPV) can be formulated—this will reflect the best understanding of the ratemaking process in the country. Thereafter, an equation can be formulated that shows how average tariffs might be calculated while considering DPV deployment. Again, distinctions may need to be made for self-consumed DPV versus grid injections. Furthermore, all established practices on how revenue impacts are passed through to ratepayers can be included. Given the importance of these equations for the TRIA framework, these equations can be developed collaboratively with stakeholders from multiple utility departments, the regulator, and other relevant stakeholders, and thereafter broadly corroborated. Sections 2.1–2.2 of *Understanding the Impact of Distributed Photovoltaic Adoption on Utility Revenues and Retail Electricity Tariffs in Thailand* offer examples of these important equations.

Understanding of Wholesale Electricity Generation/Procurement: The analyst can gain an understanding of how the utility in whose service territory DPV is deployed generates and/or procures wholesale electricity.

Understanding of Generation and/or Electricity Purchase Offsets: The analyst can gain a high-level understanding of: (1) what kind of generation and/or electricity purchases may be offset by DPV deployment; (2) who owns the generation that is being offset (e.g., EGU, VIU, or IPP); (3) how the generation owner would be financially impacted by reduced generation levels; and (4) the extent to which financial impacts are shouldered by utility entities and/or ratepayers.

Understanding of Relevant Retail Tariff Structures: The analyst can gain a robust understanding of the retail tariffs being offered to relevant customer classes that might deploy DPV and the extent to which retail tariff structures may change for customers that choose to deploy DPV. Knowledge of the volumes of customers in each rate class, as well as an understanding of stakeholder interest, can help identify "relevant" customer classes for analysis purposes.

Understanding of DPV Compensation Mechanism: The analyst can gain a robust understanding of how DPV customers are (or might be) metered and billed under various circumstances. This includes

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[41] Because these outputs are resulting from a qualitative analysis, the below list may appear higher level and/or more subject to interpretation than the outputs listed in 'Desired Outputs' in subsequent sections.
[42] As an example, see *Understanding the Impact of Distributed Photovoltaic Adoption on Utility Revenues and Retail Electricity Tariffs in Thailand.*

understanding what quantities would be tracked by the utility for billing purposes (e.g., gross DPV generation, net electricity consumption, grid injections, and so on) and how exactly grid injections are valued.

Allocations of Revenue Requirement and Expected Sales by Customer Class: While not required, an understanding of revenue requirement allocations across customer classes can help aid in a more detailed treatment of tariff and cross-subsidization impacts.

Understanding of Policy and Regulatory Decisions Informed by Analysis: A robust understanding of the ongoing decision processes that the analysis is intended to inform can help focus efforts and lead to a better understanding of which specific details and assumptions may matter more than others.

7.2 Step 2: Creating High-Level Analysis Assumptions

Following initial research activities, it becomes feasible to begin formulating high-level governing assumptions for conducting the TRIA.

7.2.1 Cost and Benefit Tracking

The analyst can formulate a list of DPV value drivers whose short-term revenue impacts can feasibly be tracked within the TRIA framework. At a minimum, the avoided energy cost for utilities is a short-term revenue impact that can be included. Other costs and benefits discussed can also be considered (see Table 1), provided they are short-term or can be translated from medium or long-term impacts into short-term impacts. Decisions to include or exclude particular costs or benefits can be based on the availability of relevant data sets needed to analyze them and the complexity of the methods required to analyze them. As discussed in Section 4, it is important to determine whether each value driver is noticeable to the utility/regulator and whether it can be tracked, as well as the feasibility of acquiring the requisite data to quantify the value driver.

The focus of this guidebook is on revenue impacts that occur in the short-term and medium-term timeframes—notably, this excludes most longer-term investment-related impacts from DPV, which in some contexts with low solar deployment levels are neither tracked, quantified explicitly, or included in planning exercises by utilities/regulators.[43] If it is decided to include these investment-related impacts (e.g., value of generation investment avoidance/deferral), great care must be taken to ensure that long-term benefits are translated into annuitized benefits, that stakeholders are comfortable with the level of accuracy of avoided long-term investment costs, and that there is currently (or likely will be in the future) a relevant planning process that actually accounts for DPV and allows investment-related benefits to accrue.

7.2.2 Analysis Period

The analysis period is the specified period of time over which financial impacts are examined in the TRIA.[44] Having a clear and well-defined analysis period is critical to any DPV analysis. The appropriate analysis period tends to be best informed directly by stakeholders to ensure analysis results are both used

[43] The notable exception to this recommendation is generation capacity value. DPV capacity value calculations can be methodologically straightforward to conduct, and without requiring too complex or difficult-to-acquire data sets; furthermore, DPV deployment (in MW) can be easily noticed and tracked by utilities, and generally is included in generation planning exercises.
[44] Note that even for a shorter analysis periods (e.g., the expected tariff impact in a specific year), TRIA can potentially include annuitized long-run marginal costs and benefits such as avoided or additional investment costs.

and useful. For the purposes of a TRIA, the analysis period is defined as the timeframe under which revenue and rate impacts are being tracked and analyzed.

The analysis period can be a single-year period (e.g., expected DPV impacts in 2032), the length of a single multiyear rate period (e.g., between 2020–2022), or tracking cumulative impacts spanning multiple rate periods (e.g., between 2020–2040). While most analyses tend to be forward-looking, analysis periods can also feasibly be in the past, if stakeholders are requesting an *ex-post* evaluation of an existing DPV program (e.g., how were revenues and rates impacted by the NEM program between 2015–2017*?).* To understand how future revenues and rates are impacted by DPV, a number of assumptions need to be made, including:

- Annual retail electricity tariff change
- Annual projected customer demand increase/decrease
- Annual power system demand increase/decrease
- Annual macroeconomic inflation rates
- Changes to bulk electricity generation patterns
- Annual wholesale electricity tariff change (if applicable)
- Changes to electricity generation and/or electricity procurement costs (if applicable).

It is important to distinguish whether the analysis is expected to quantify single-year DPV impacts or cumulative multiyear impacts. For simplicity, syncing up the analysis period with rate periods (or other relevant regulatory timeframes as desired by stakeholders, such as interim rate adjustment hearings) ensures that the analysis results are relevant and useful to stakeholders.

7.2.3 Cost Pass-Through Assumptions

A central output of the qualitative analysis is a detailed understanding of the rules for passing additional utility costs through to ratepayers, if any. While there tend to always be well-established rules and procedures for addressing deviations from expected utility sales or revenue collection, there may be ambiguity as to whether and how those rules might apply to forgone revenue from DPV self-consumption, additional purchases of DPV electricity, and/or avoided energy generation/procurement costs. In this case, important assumptions may need to be made, and, in some cases, varied to explore the efficacy of different pass-through methods/approaches (see Section 6.6). In other cases, ratemaking is more of a political process without established rules and regulations; this is more likely to be the case for state-owned utilities. In these cases, there are no cost pass-through rules to follow. This makes analyses of rate impacts difficult to conduct, and so one might assume that all financial impacts fall on the utility net revenues (see e.g., Darghouth et al. 2020).

7.2.4 Scenario Suite

A suite of scenarios can be proposed to respond to stakeholder needs and answer relevant questions. When balancing various stakeholder needs and requests, a common approach is to grow the scenario suite to answer all desired analysis questions. While a more complex scenario suite can answer a broader range of questions, it requires greater effort and may also lead to a less precise or straightforward core message for analysis stakeholders. The appropriate scenario suite will depend on the intended purpose of the TRIA (see Section 6).

7.2.4.1 DPV Deployment Assumptions

The level of DPV deployment (in MW) is one of the core analysis inputs. Importantly, TRIAs do not endogenously formulate their own deployment projections; rather, they depend on exogenously defined assumptions. Developing DPV deployment projections from customer adoption models, for example, is beyond the scope of TRIAs.

The appropriate deployment assumptions will depend on the intended purpose of the TRIA (see Section 6) and the interests/needs of the stakeholders. Key aspects of DPV deployment assumptions include:

- What: DPV Deployment Level: Assumption for amount of DPV deployed. The DPV deployment can be expressed as total DPV nameplate capacity (e.g., 1 GW) or energy penetration level (e.g., DPV deployment capable of generating 1% of expected 2022 power system annual demand). These could be legislated mandates or goals defined in renewable energy laws or government target deployment levels.
- When: DPV Deployment Timing
    - Assumption for when DPV is being deployed. Is it deploying incrementally over time (i.e., on a trajectory), or is all DPV deployment assumed to take place in a single out-year for analysis purposes?
    - This consideration is tied to the analysis period (see Section 6.2.2).
- Who: DPV Customer Types
    - What types of customers are assumed to be deploying the DPV? What demand profiles should be used? To what retail electricity tariffs are they subject?
    - This assumption tends to be practically limited by available data, in particular customer demand data (see Section 6.2.4.2 for more detailed explanation of this aspect).
- Where: Geographic Distribution
    - Where is the assumed DPV deployment distributed geographically?
    - One potential approach is to select highly populous urban centers for DPV deployment. In general, this assumption can be particularly limited by data if available solar insolation data has been collected from individual weather stations.
- How: Compensation Mechanism
    - How is the assumed DPV deployment metered and billed? To what DPV compensation mechanism is the assumed DPV deployment subject?
    - Is the compensation mechanism the same for all DPV assumed to be deployed, or is this differentiated based on customer classes, system sizes, or other dimensions?

At a high level, each of these assumptions have important implications for the type of data that is required to perform the analysis. TRIAs are often limited in some capacity by data availability, and data availability will likely influence the degrees of freedom analysts have to formulate DPV deployment assumptions.

7.2.4.2 Mix of Retail Customers

Different classes of retail electricity customers are, by definition, placed under different retail electricity tariff structures. Thus, when different customer classes deploy DPV, they have a distinct financial impact on utilities and ratepayers. Because of this, the assumed mix of retail customers deploying DPV is a critical input assumption to any TRIA framework.

Again, the ability of analysts to examine the impact of DPV deployment on certain customer classes may be limited by data availability, in particular high time-resolution customer demand data. For instance, if a particular customer class is subject to TOU rates, demand charges, and/or net billing schemes, then higher time-resolution demand and solar insolation data are necessary to meaningfully understand differences in utility revenue collection under these structures. Without this higher resolution data, the number of customer classes where meaningful and accurate insights can be quantified may be limited.

Potential approaches for selecting a customer mix include:

1. Design a customer mix that reflects the most likely customer classes to deploy DPV (e.g., those with the highest retail electricity tariffs, better access to capital, suitable roofs, availability of government subsidies, and so on).
    A. Example: 50% of DPV is assumed to be deployed by high-use residential customers in the three most populous cities in each province, with the remaining deployment split equally between high-use commercial customers and industrial customers with the same geographic distribution.
2. Design a customer mix that somewhat or entirely reflects the proportions of retail customers present on the power system, using number of sales or customers/meters, as appropriate.
    B. Example: 88% of customers in Thailand are placed on Residential (50%), Small General Service (20%), Medium General Service (10%), or Large General Service (8%) retail electricity tariffs. Of the 1,000 MW of DPV assumed to be deployed, the following DPV customer mix is assumed:
        i. Residential: 1,000 MW x 50/88 = 568 MW
        ii. Small General Service: 1,000 MW x 20/88 = 227 MW
        iii. Medium General Service: 1,000 MW x 10/88 = 114 MW
        iv. Large General Service: 1,000 MW x 8/88 = 91 MW.

7.2.4.3 Policy and Regulatory Changes

The nature of the scenario suite will strongly depend on the intended purpose of the analysis, particularly in the realm of specific policy and regulatory changes that are of interest to stakeholders. See Section 3 for a more detailed explanation of options.

Scenario suites will commonly be designed to test the impact of different metering & billing arrangements (e.g., impacts of NEM versus net billing) and/or the extent of the financial impact of different DPV sell rates. Explorations of new retail rates may be a more sensitive topic in some jurisdictions, as retail rate design is usually considered a matter of social policy, and government/utility stakeholders may be sensitive even to the appearance of exploring options in this realm.

7.2.5 Avoided Energy Generation Cost or Reduced Wholesale Electricity Purchase Cost Calculations

The principle energy-related benefit of DPV is the generation that is displaced and/or wholesale electricity purchases that are avoided when DPV electricity is supplied to the grid, and the financial value associated with that reduction. The key analysis assumptions then become:

- What kind of generation is assumed to be offset by DPV production? Does this assumption change based on the time of DPV production?
- What is the financial impact of this generation offset, and to whom does that impact accrue?

Table 6 details the accrual of avoided energy costs (and benefits), organized by ownership of the power plant whose generation is offset by DPV production.

Table 6. Impact of Generation Offset Categorized by Ownership

Owner of Offset Power Plant	Additional Description	Financial Impact for Offset Power Plant	Financial Impact for Offtaker Utility
EGU	N/A	**Benefit:** Avoided generation costs (e.g., fuel costs) at power plant **Cost:** Reduced wholesale kWh sales	Utility owns offset power plant; therefore, utility impacts are that of offset power plant
VIU	DPV is deployed in distribution service territory*	**Benefit:** Avoided generation costs at power plant (e.g., fuel costs)) and/or purchase costs from IPPs or the wholesale market **Cost:** Reduced wholesale kWh sales	Utility owns offset power plant; therefore, utility impacts are that of offset power plant
IPP	Selling kWh under flexible PPA	**Benefit:** Avoided generation costs (e.g., fuel costs) at power plant **Cost:** Reduced wholesale sales	**Benefit:** Reduced IPP purchase expenditures **Cost:** Reduced wholesale or retail kWh sales[†]
	Selling kWh under take-or-pay PPA	**Benefit:** Generation cost savings at power plant **Benefit:** Revenue from wholesale sale (despite no physical delivery or energy)	**Cost:** Reduced wholesale or retail kWh sales[†]
	Selling kWh in wholesale power market	**Benefit**: Generation cost savings at power plant **Cost**: Reduced wholesale sales at relevant day-ahead or spot market marginal price	**Benefit:** Reduced wholesale market purchase at relevant marginal price **Cost:** Reduced wholesale or retail kWh sales[†]

***** *If DPV is deployed in the service territory of a distributor that purchases wholesale electricity from the VIU, see 'Electric Generation Utility row.***
[†] ***Whether this results in a reduction of wholesale or retail sales depends on the type of utility. A VIU with DPV deployed in its distribution service territory will result in a reduced retail sale. An electric generation utility with DPV deployed in the service territory of one of its wholesale customers will result in a reduced wholesale sale.***

Note: We assume that a Distribution Utility cannot own the offset generation (though this may be possible in some settings). We also do not include/discuss the possibility that Distribution Utility demand charge reductions may occur due to DPV.

The cost savings associated with the reduced cost of generation is a key assumption that must be formulated for the TRIA. First and foremost, a common assumption employed is that electricity generators are dispatched in the power system in order of variable cost (from lowest to highest) to meet load at the lowest possible cost, and, thus, DPV will typically displace the highest variable cost generator at the time of production, except in cases where unit commitment and/or transmission system constraints impede this.

Next, the analyst can make an assumption that energy-related cost savings (i.e., benefits) are associated with either: (1) directly reduced generation costs from power plants owned by the impacted stakeholder; (2) reduced PPA purchases; (3) reduced regulated wholesale electricity purchases; or (4) reduced wholesale electricity market purchases.

7.2.5.1 Power Plant Fuel Cost Saving Calculation Methodologies

In most cases, DPV generation leads to reduced fossil fuel consumption. The type and quantity of fuel saved depends on which generator is on the margin.[45]

The publication *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System* offers several approaches for identifying the appropriate offset generator and assigning an appropriate benefit value to that generation offset from a higher-level power system perspective. These have been summarized in Table 7, describing methods to quantify the avoided energy generation cost (i.e., the fuel cost saving benefit) associated with DPV production from the perspective of a utility that owns the offset power plant.

Table 7. Description of DPV Avoided Energy Generation Cost Calculation Methodologies

Method	Description
Simple Avoided Generator	Assumes DPV displaces a typical "marginal" generator with a fixed heat rate and fixed input fuel cost.
Weighted Avoided Generator	Assumes DPV displaces a blended mix of typical "marginal" generators with fixed heat rates and fixed input fuel costs. The mix can be weighted based on established annual generation mixes, or other more precise proportions (e.g., generation mixes during typical DPV production hours) based on data availability.
Historical Dispatch Data Analysis	Identify the technology of the marginal generator at every hour of assumed DPV production for a recent year, creating a higher time-resolution (e.g., hourly) schedule of assumed fuel cost savings. If marginal generators report heat rates (which are in reality dynamic quantities), employ dynamic heat rates in calculations. Otherwise, assume static heat rates.
Production Simulation Analysis	Utilize a detailed production cost model to characterize expectations of dispatch behavior in future years when DPV deployment is assumed. Using this tool as a basis, the analyst can create a schedule of assumed fuel cost savings for each hour of the day that DPV is producing electricity, including consideration of power plant-specific generator heat rate curves and fuel procurement costs, if relevant data sets are available.

7.2.5.2 Reduced PPA Electricity Purchase Savings Calculation Methodologies

If the analyst identifies that the offset generator is party to a PPA with an EGU or VIU, the first step is to understand the terms of the PPA. Is there sufficient flexibility in the PPA terms such that the offtaker utility can avoid a purchase? Or are there inflexible "take-or-pay" stipulations in the contract? It is possible that PPA stipulations and energy purchase rates may be difficult data to obtain, as they are often considered politically or business sensitive. Nevertheless, public websites and stakeholder interactions may be useful sources to accurately determine the relevant energy purchase rate(s).

7.2.5.3 Reduced Regulated Wholesale Electricity Purchase Methodologies

If considering a distribution utility which purchases wholesale electricity at a regulated rate, the energy-related benefit of DPV is simply an avoided regulated wholesale electricity purchase for an EGU or VIU. If this is the case, a calculation of the reduced wholesale electricity purchase benefit requires an

[45] In rare occurrences, the assumed offset generator may be a hydropower unit. In this case, the analyst can then examine to what extent reservoir storage is available. If storage is available, the analyst can then assess if a theoretical stored hydropower kWh would be used to offset fossil fuel generation at a later time. This adds slightly more analytical complexity, but may nevertheless best reflect the reality of DPV's financial impact to utilities and ratepayers.

understanding of the wholesale electricity tariff structure that the distribution utility is subject to—this tends to be publicly available information and straightforward to obtain.

7.2.5.4 Reduced Wholesale Electricity Market Purchase Calculation Methodologies

If the energy-related utility benefit of DPV is due to an avoided wholesale electricity market purchase, there are several methodologies that can be employed to quantify this benefit to the relevant utility entity. These methods are summarized in Table 8.

Table 8. Description of Avoided Wholesale Electricity Market Purchase Calculation Methodologies

Method	Description
Average Market Cost	Assumes DPV productions helps to avoid the purchase of electricity priced at an annual or monthly average market price. Average prices may be available for each zone or node in the market, or only on a system-wide basis, depending on the market.
Daytime Average Market Cost	Using slightly more granular market data, the analyst can calculate the average cost of electricity during times of day when DPV is producing electricity. In terms of time resolution, this may be possible to calculate on a daily, weekly, monthly, or annual basis. With respect to geographic resolution, appropriate data may be available by zone or node, or only on a system-wide basis, depending on the market.
Historical Market Data Analysis	Using more complete sets of historical market data, identify the locational marginal price for each hour of the day and create a schedule of assumed avoided electricity purchase costs by market zone or node.
Market Simulation Analysis	Utilize a detailed production cost model to characterize expectations of locational marginal prices or system marginal energy prices in future years when DPV deployment is assumed, creating a schedule of assumed avoided electricity purchase costs.

7.2.6 Avoided Distribution and Transmission Line Loss Calculations

As has been discussed previously, energy-related benefits can be adjusted upward to reflect avoided distribution (and in some cases, transmission) losses. In general, DPV customers connected to low voltage lines (e.g., residential and small commercial) avoid distribution and transmission losses, whereas customers connected to higher voltage lines only avoid transmission losses. The avoided losses accrue because locally generated energy does not need to be delivered through network infrastructure, hence avoiding technical network losses.[46]

7.2.6.1 Avoided Distribution Line Loss Calculations

Information about technical distribution system losses is commonly tracked and available. If the analysis period looks far into the future and technical losses are currently high, the analysis can make transparent assumptions about whether those losses reduce over time. A loss reduction trajectory, if appropriate, can be designed with utility stakeholders. Avoided distribution losses are linearly related to avoided energy benefit of DPV, described with the equation:

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[46] DPV can also boost voltage on distribution networks through the use of smart inverters. In doing so, it can help to reduce technical losses in the distribution network. This can be considered a separate form of avoided distribution network losses from the avoided line losses due to localized delivery discussed in this section. Due to the extremely localized nature of this benefit, its high analytical complexity to assess, and its relatively low magnitude of benefit level, this is not a commonly assessed value driver of DPV and is neither considered nor discussed in this report.

$$Avoided\ Distribution\ Losses = (DL_t) * Avoided\ Energy\ Benefit$$

Where:

$$Avoided\ Energy\ Benefit = Applicable\ generation\ or\ wholesale\ purchase\ offset\ value$$

$$DL_t = Annual\ technical\ distribution\ losses\ [\%\ of\ retail\ sales]$$

7.2.6.2 Avoided Transmission Line Loss Calculations

Information about technical transmission system losses is commonly tracked and available. If the analysis period looks far into the future and technical transmission losses are currently higher than most international standards, the analysis can make transparent assumptions about whether those losses reduce over time. A loss reduction trajectory, if appropriate, can be designed with utility stakeholders. Avoided transmission losses are linearly related to avoided energy benefit of DPV, described with the equation:

$$Avoided\ Transmission\ Losses\ = (TL_t) * Avoided\ Energy\ Benefit$$

where:

$$Avoided\ Energy\ Benefit = Applicable\ generation\ or\ wholesale\ purchase\ offset\ value$$

$$DL_t = Annual\ technical\ distribution\ losses\ [\%\ of\ wholesale\ sales]$$

7.3 Step 3: Formulating Prototypical DPV Customers

DPV markets comprise a multitude of individual customers who have invested in a solar system for their home or business. Each customer is unique with respect to how much electricity they consume, where they are located, the size and performance of their DPV system, the retail rates and DPV compensation mechanism they are subject to, and various other important characteristics that have implications for understanding utility revenue and tariff impacts.

To conduct a robust system-level impact analysis of DPV, the analyst can take steps to represent the heterogeneity of the DPV market by considering a number of representative DPV customer types to include in the analysis. Specifically, the analyst can design DPV customers who exhibit statistically representative or “average” characteristics for the larger pool of customers under consideration in the TRIA. In doing so, more broadly applicable insights can be identified about the potential impact of DPV. While creating prototypical customers is not a perfect approach, it is nevertheless a practical necessity and a useful construct to gain insights into broader system-level impacts. Thus, the approach of creating a “family” of statistically representative prototypical customers is recommended. Ideally, this family can include both average-looking customers, and also customers with characteristics that might make them more likely to install DPV, such as wealthier residential customers who pay higher retail electricity tariffs and have higher consumption levels relative to others in their customer class. The latter set of customers represents the “tail” of the statistical distribution of customers that might install DPV and is important to consider.

In low data environments that lack robust consumer load data, analysts can rely on stakeholder consultations to make the most relevant and robust assumptions possible. It may be necessary to rely on feeder- or circuit-level data, and/or consumer load data from other jurisdictions with similar climates and customer types. Key design elements of prototypical customers are discussed in the subsections below.

7.3.1 Electricity Consumption Levels and Patterns

Robust assumptions about prototypical customer electricity consumption are central to conducting TRIAs accurately. Depending on the nature of available consumption data, the analyst may have to exhibit some expert judgement in terms of formulating assumptions. It is generally good practice to ensure prototypical customers represent those customers who are most likely to adopt solar, which may mean customers with higher electricity demand[47] relative to an average customer in their rate class. In the event that data is limited and it is not possible to isolate demand characteristics of those more likely to adopt solar, prototypical customers can also be designed to represent statistically average customers within their rate class (e.g., those which represent the mean of the distribution with respect to electricity consumption and other characteristics rather than the tails).

For analyses where DPV customers are under net billing and/or wholesale or retail tariffs include TOU or demand-based charges, higher time-resolution electricity consumption data (e.g., 1 year of hourly data) is necessary to meaningfully understand differences in utility revenue collection. Otherwise, for NEM with customers with a time-invariant tariff, average monthly consumption data for each customer class suffices. In the complete absence of customer consumption data, the analyst can work with utility stakeholders to create reasonable but simple load shapes and monthly consumption levels that reflect commonly held knowledge on customer behavior (e.g., higher electric heating demands in winter, midafternoon air conditioning load, and so on).

All utilities that sell retail electricity and have established billing procedures have customer consumption data, at least at the resolution of the billing cycle (e.g., on a monthly basis). It is nevertheless a question as to whether and how this data is stored, and whether it can be shared outside the utility. Records may be physical (i.e., paper) and/or confidential in nature. Aggregated retail sales statistics (i.e., total retail sales per customer class per billing cycle [or annually]), are typically tracked by utilities and regulators. This data may be helpful to inform monthly consumption assumptions.

Generally, individual customer load data can be difficult to acquire; it is often considered business-sensitive and is not publicly available. This type of data in particular may require a formal request from a regulator or ministry to obtain from the utility. Importantly, even if the utility is able to make a group of customers' hourly consumption data available for multiple years, these customers' consumption characteristics are most likely not average or statistically representative. Nevertheless, they can be useful for informing load shapes and can be scaled to desired monthly or annual consumption levels.

One possible method for informing assumptions about customer consumption is using "average" load shapes for each customer class when the utility has already studied and formulated their own. This is a common practice for utilities with more complex distribution planning processes, as distribution network models must make assumptions about customer consumption for planning purposes. Often, these average load shape analyses take place within distribution network engineering departments and may not be well known or utilized in other departments.

7.3.2 DPV System Sizing

DPV system sizing (i.e., the size of the DPV system that each prototypical customer class chooses to build) can drive results significantly for TRIAs. In reality, the size of the system that DPV customers choose to deploy depends to some extent on the economic signal they receive via the DPV compensation mechanism (i.e., their applicable retail electricity tariff structure, the metering & billing arrangement, the

[47] Electricity consumption levels in developing countries are often indicative of key socioeconomic and demographic indicators that can influence a willingness to adopt DPV.

DPV sell rate, crediting terms, and other elements), and also their understanding of their own consumption levels.

When the analyst is considering each customer class, they can attempt to consider the economic signal that each receives. For instance, if DPV sell rates are quite low under a net billing scheme for small commercial customers, there may be more of an incentive to undersize systems. On the contrary, if residential customers are under an NEM scheme with a high net excess generation credit, designing a system to reduce a large portion of their annual bills may be a more reasonable approach. Beyond the economic signal, the analyst can also consider whether adequate roof space would likely be available. For instance, would large commercial or industrial customers have sufficient roof space for large enough DPV systems to cover their annual consumption under an NEM scheme? In the absence of high-quality geographic information system data, the issue of roof space can be discussed with stakeholders to arrive at a reasonable assumption.

Common approaches to sizing include[48]:

- Picking a single number with stakeholders:
  - Example: All low-use residential customers deploy 1.5-kW systems.
- Design DPV systems dynamically to meet a fixed percentage of annual consumption:
  - Example: Residential customers deploy systems that will meet approximately 80% of their annual consumption under an NEM scheme.
- Design DPV systems dynamically to meet X% of customer maximum peak demand:
  - Example: Residential customers deploy systems that will meet approximately 80% of their annual maximum peak demand under a net billing scheme.
- Design DPV system to maximize DPV system net present value:
  - Requires more sophisticated modeling software.

7.3.3 Customer Location

DPV systems must have a specific geographic location for modeling purposes. Customer location impacts solar irradiance levels and DPV system outputs. It may also influence the tariffs that are offered—for instance, certain regions of a country may offer customized tariffs (e.g., a rural low-use tariff) or not contain any customers under certain rate classes (e.g., agricultural customers in urban zones). The analyst can ensure modeled customer tariffs reflect geographic location to the extent possible; it is good practice to ensure that modeled customers exist in a particular area being modeled.

If the only available data in the country is time-series solar insolation data from individual weather stations, then the customers can be assumed to deploy at or near those stations. When a broader set of time-series satellite solar insolation data is available, a common approach is to model DPV customers in highly populous urban centers. The "A Multi-Perspective Quantification of Benefits of Rooftop Solar" analysis described in *Informing Mexico's Distributed Generation Policy with System Advisor Model (SAM) Analysis* models DPV customers in the city center of the three most populous cities in each of the 16 tariff geographic divisions in Mexico. *Understanding the Impact of Distributed Photovoltaic Adoption on Utility Revenue and Retail Electricity Tariffs in Thailand* models customers in Thailand's 56 most populous cities, assuming Bangkok accounts for ~30% of deployment and spreading the remaining 70%

[48] In general, the analyst can consider rounding the customer DPV system capacity to the nearest panel size increment.

equally across the other 55 cities modeled. Though this approach is more work-intensive, it is also more analytically complete.

7.3.4 DPV System Technical Characteristics

While different classes of modeled prototypical customers will have different system sizes, there are a variety of other DPV system technical characteristics that must be assumed. Analysts can formulate a single, uniform set of DPV technical characteristics and apply them across all customer classes or use a more precise approach that treats different customer classes distinctly. These characteristics include:

- **Array Type**: DPV systems may be mounted on rooftops or on an open rack. Analysts can determine which type of array is more likely for various customer classes or pick a single array type for all customers.
- **Tilt**: This is the DPV system's tilt angle in degrees from horizontal, where 0° represents a DPV system on a flat roof, and 90° represents a DPV standing vertically. Speaking to stakeholders about commonly known characteristics of roofs may be a useful exercise to formulate credible assumptions.
- **Azimuth**: The array's east-west orientation in degrees. An azimuth value of zero is facing north, 90° = east, 180° = south, and 270° = west, regardless of whether the array is in the northern or southern hemisphere. For systems north of the equator, the optimal azimuth value from an energy production standpoint would be 180°. For systems south of the equator, the optimal value from an energy production standpoint would be 0°.
- **Shading**: Percentage reduction in the incident solar radiation from shadows caused by objects near the array such as buildings or trees. A default value for consideration—derived from NREL's System Advisor Model (SAM)—is 3%.
- **Annual Degradation Rate**: Assumed year-to-year decline in the DPV system's output due to, for example, aging of equipment over time. A default value for consideration—again derived from NREL's SAM—is 0.5%/year.
- **Module Type**: Module technology selection, which has implications for a variety of more detailed technical characteristics of the DPV system.

7.4 Step 4: Perform Techno-Economic Analysis for Prototypical Customers

Once many of the assumptions about prototypical customers are formulated, a project-level techno-economic performance analysis tool—such as the NREL SAM[49]—can be used to perform the DPV production and electricity bill modeling for prototypical customers. Techno-economic performance analysis is conducted in this step to generate differentiated estimates of gross short-term utility revenue losses for each customer class.

To generate the required outputs (see Section 6.4.2), each prototypical customer type is modeled with and without a DPV system; the difference in electricity bills between a customer with and without DPV is a key analysis output. This will be discussed in more detail in Section 7.4.2.

[49] SAM is a free model that offers a user-friendly, detailed treatment of DPV, including rooftop solar systems. The model takes into account customer consumption patterns, retail electricity rates, DPV compensation schemes, and a variety of other technical and economic inputs. For more information, see: https://sam.nrel.gov/.

7.4.1 Key Inputs for Analysis Step

Beyond the input assumptions discussed in Section 6.3, the following key inputs are required for this analysis step:

Solar Insolation Data: A measure of the solar resource, often using historical or typical meteorological year data; can be used to formulate DPV production estimates. In simpler analyses, annual or monthly capacity factors can be assumed.

Photovoltaic Panel Performance: A quantitative description of how photovoltaic panels are expected to perform over time. This can include annual performance degradation rates and panel or inverter failure rates, which may be a significant factor in settings with low-quality equipment and/or inadequate maintenance practices.

Metering and Billing Arrangement: A description of how consumption- and DPV generation-related electricity flows are measured and billed. Options include NEM, buy-all/sell-all, and net billing.

Retail Electricity Tariff: For NEM and net billing arrangements, retail electricity purchases can be avoided via self-consumption of DPV. In such cases, the retail electricity tariff for each prototypical customer type must be accurately characterized to estimate reduced utility revenues and additional utility power purchasing expenditures.

DPV Sell Rate: The level of compensation a DPV customer receives for injected electricity into the grid; can take the form of a bill credit (in units of kWh or cash) with specific limitations of use (e.g., expiration dates), or simply a cash payment each billing cycle or year. Sell rates can stay the same over time, change based on time of production, or increase/decrease over multiyear periods.

7.4.2 Required Outputs From Analysis Step

Techno-economic simulation tools for DPV projects are used in DPV analyses to simulate monthly and annual bill savings for customers—for TRIAs, these bill savings are equivalent to the short-term utility gross revenue loss resulting from the modelled prototypical DPV customer. This gross revenue loss can then be broken down into more detailed subcomponents.

First, the gross utility revenue loss can be differentiated by its primary driver, DPV generation behavior:

1. **Self-consumption of DPV**: Leads to gross short-term utility revenue loss resulting from reduced utility sales
2. **Grid injection of DPV**: Leads to either gross short-term utility revenue loss when an energy credit is provided for grid injections (e.g., for NEM) or an additional energy purchase cost for the utility.

Next, the gross short-term revenue loss must be broken down further by the relevant TOU retail tariff periods and/or other relevant time periods identified as necessary for accurately calculating the value of reduced retail sales, additional DPV purchases, and avoided energy costs (see Section 6.2.5) in net revenue calculations in Step 5. If TOU tariff structures are not present in the power system and will not be investigated in the TRIA, then this step can be ignored. Otherwise, reduced utility sales and additional energy purchase obligations are differentiated by TOU periods at the retail (and, if relevant, wholesale[50])

[50] If regulated wholesale and retail TOU tariffs exist simultaneously, they likely will not be synced up in their exact time periods. The analyst will then have to break down self-consumption and grid injections by retail TOU period and wholesale TOU period separately.

level. If different customer classes have different TOU periods, then reduced utility sales and additional utility purchase obligations will need to be time-differentiated separately for each customer class.

Thus, the required outputs from this analysis step are:

- Reduced utility sales by TOU period by customer class[kWh]
- Reduced utility sales by TOU period by customer class [$]
- Additional utility purchase obligation by TOU period by customer class [kWh]
- Additional utility purchase obligation by TOU period by customer class [$].

Finally, if the analysis will explore the impact of changes to any key inputs (Section 6.4.1) or assumptions (Chapter 6.3) for prototypical customers, it is necessary to create separate iterations of the previously mentioned outputs for each scenario.

Quantifying the Impact of Solar + Storage Systems

As battery costs continue to decline, the potential financial impact of customer-sited DPV paired with battery energy storage systems is an increasingly popular topic among policymakers, regulators, and utilities. In the context of TRIAs, how might the deployment of storage be included? Principally, the addition of a battery energy storage system would change the mix and/or timing of DPV self-consumption and DPV grid injections. Beyond making technical assumptions about the characteristics of the battery for prototypical customers (e.g., system size, maximum power rating, storage capacity, efficiency, leakage rates, and so on), the analyst would need to make assumptions how the battery *operates*. Is it optimized to reduce DPV grid injections and maximize self-consumption? Or to maximize bill reduction in response to TOU rates, demand charges and/or dynamic DPV sell rates? Once these operational assumptions are made, modeling can ensue, and a similar set of outputs would be generated as for DPV systems without linked battery energy storage systems. The resulting DPV-plus-storage system operation also has implications for avoided utility costs, which will impact TRIA results.

Both the NREL SAM model and the NREL REopt Lite™ models can help users assess battery energy storage systems in conjunction with DPV, as well as independent systems. See https://sam.nrel.gov and https://reopt.nrel.gov/tool for more information.

7.5 Step 5: Calculating Net Revenue Impacts

While Step 4 focuses on the calculation of gross short-term utility revenue impacts associated with a prototypical single customer in each customer class, Step 5 focuses on calculating the net short-term revenue impacts associated with a diverse fleet of DPV deployment. Importantly, Analysis Steps 5 and 6 require the construction of a spreadsheet tool, which is best assembled in a single effort; nevertheless, this guidebook chooses to explain Step 5 and Step 6 separately to enhance reader understanding.

It should be noted that inherent to calculating net revenue impacts as precursor to tariff impacts is an assumption that tariffs will not be adjusted to reflect net revenue impacts until the following rate case. This is not the case when tariffs are based on future test years that take into account expected DPV deployment during ratemaking processes, or if there are true-up mechanisms that allow a utility to adjust tariffs as a result of DPV before the next rate case. In these cases, assuming tariffs are calculated accurately to collect expected utility net losses from DPV, there would be no net revenue impact.

As a first step, the analyst can begin by calculating the overall short-term revenue impact over all customers and then focus on calculating the net short-term revenue impact for each individual prototypical customer for each utility stakeholder being examined, if sufficient data is available for customer class differentiated analysis. These net revenue impacts can then be scaled to different levels of deployment and/or different customer mixes at a later time. Net revenue calculations can be customized for each utility stakeholder group and prototypical customer type, and include the revenue impacts detailed in Section 5. This includes the gross revenue losses calculated in Step 4, but also avoided distribution, transmission, and/or energy-related benefits. Calculations can consider the impact of DPV self-consumption and grid injection at different relevant time periods, with relevance being determined by wholesale or retail TOU periods and/or the time resolution of the generation or wholesale purchase offset value calculations (see Section 6.2.5).

7.5.1 Accounting for Short-Term Tariff Impacts

In the event that tariff impacts would occur in the short term due to the presence of an interim tariff adjustment mechanisms (i.e., tariff adjustments that happen before the next rate case), this would ultimately impact annual net revenue impact calculations with a compounding effect. In other words, if retail tariffs are adjusted upward every 3 months to account for certain DPV impacts (e.g., compensating a distribution utility for additional DPV energy purchases, but not reduced sales or avoided energy costs),[51] then it is possible that net revenue losses would increase every 3 months as well, all else being held equal.

In this event, the analyst can make adjustments to ensure that medium-term tariff calculations (see Step 6) accurately include short-term tariff adjustments that have already been calculated in Step 5 without double-counting and will likely need to ensure that revenue impacts are calculated at the same frequency as the interim tariff adjustment mechanism. Separately, it is important to note that the exact equation for interim tariff adjustment mechanisms depends on the specifics of the power market under analysis, and what kinds of revenue impacts are allowed to be passed through to ratepayers.

7.5.2 Iterative Approaches for Analyses Spanning Multiple Rate Periods

Importantly, when considering an analysis period that spans multiple rate periods, the analysis will move forward iteratively between Step 4, Step 5, and Step 6 to compound the cumulative revenue and rate impacts of DPV. As medium-term retail tariff impacts occur, the short-term net revenue impacts of the subsequent rate period will also shift—this compounding effect can be captured in the TRIA framework. This is graphically depicted in Figure 2.

[51] It is also possible that all DPV net revenue impacts could be passed through to ratepayers in the short term and not as a part of rate cases.

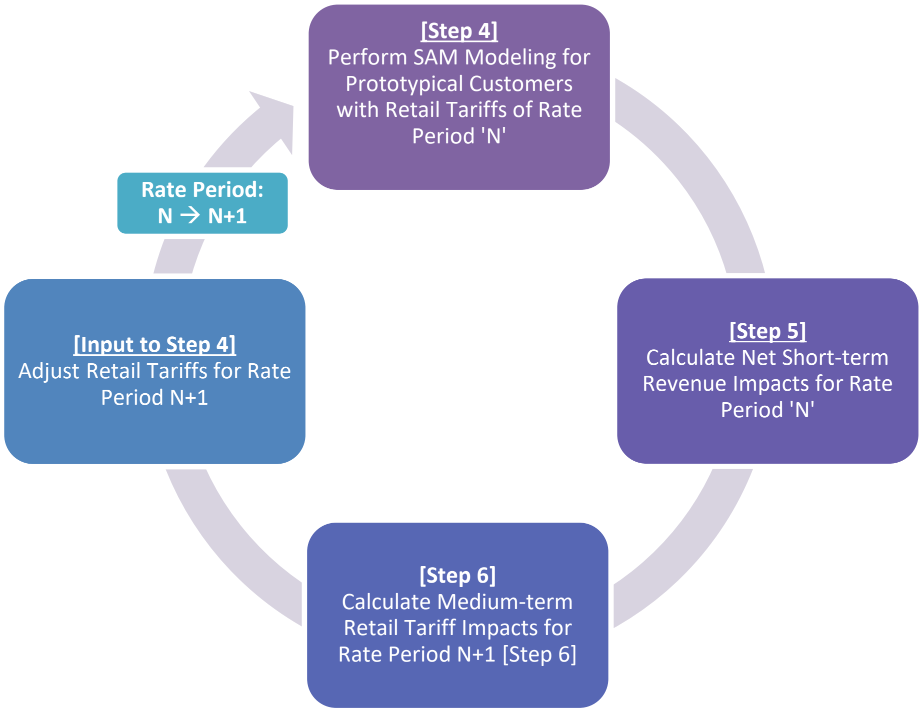

Figure 2. TRIA Framework for Iterative Retail Tariff Adjustments Between Rate Periods

If an interim tariff adjustment mechanism exists to help recover certain utility revenue losses or additional expenditures within the rate period, the analyst will need to determine how frequently this process of iteration is reasonable and appropriate. For instance, if the rate period spans 3 years, and tariffs are adjusted quarterly to cover additional utility DPV energy purchases, the analyst can consider calculating rate adjustments at the end of Year 1 and Year 2 to reflect the interim tariff adjustment mechanism and then calculate the impact of the remaining revenue losses (due to DPV self-consumption) at the end of Year 3.

7.5.3 Outputs From Analysis Step

For each utility stakeholder and customer class under consideration, the following net revenue calculation subcomponents can be quantified:

- Distribution utilities:
    - Annual revenue reduction due to reduced retail sales [$]
    - Annual additional utility purchase obligation for injected DPV electricity [$]
    - Annual reduced wholesale electricity purchase costs or avoided energy generation costs [$]
    - Annual avoided distribution line loss benefit [$]
    - Annual total net revenue loss [$].
- EGUs:
    - Annual revenue reduction due to reduced wholesale electricity sales [$]
        - Note: EGUs are indifferent to whether DPV energy is self-consumed or injected; in either case a DPV kWh results in a reduced wholesale sale by the EGU.

- Annual reduced wholesale electricity purchases or avoided energy generation costs [$]
- Annual avoided transmission line loss benefit [$]
- Annual total net revenue loss [$].

- VIUs[52]:
  - Annual revenue reduction due to reduced retail electricity sales [$]
  - Annual additional utility purchase obligation for injected DPV electricity [$]
  - Annual reduced wholesale electricity purchase costs or avoided energy generation costs [$]
  - Annual avoided distribution line loss benefit [$]
  - Annual avoided transmission line loss benefit [$]
  - Annual total net revenue loss [$].

For each DPV deployment scenario and utility stakeholder being analyzed, total net revenue impacts for each customer class is scaled and aggregated together. For the purposes of passing through outputs to Analysis Step 6, the following output can be generated:

- Annual aggregated net short-term utility revenue impact for all DPV customers for relevant years within rate period under consideration [$].

7.6 Step 6: Calculate Tariff Impacts

Upon calculating short-term net revenue impacts, the next step is to translate these impacts into impacts to wholesale and/or retail electricity tariffs. The key to performing these calculations correctly is an accurate understanding of:

1. Which revenue impacts may be passed through to ratepayers versus absorbed by the utility (e.g., utility DPV purchases, reduced retail sales, avoided generation costs)?
2. To what extent may various revenue impacts passed through to ratepayers versus absorbed by the utility (i.e., how is the burden/benefit of a net revenue loss/gain split)?
3. Through what mechanism are various revenue impacts passed through and when (e.g., interim tariff adjustment mechanisms every 3 months, formal rate cases every 2 years)?

The primary focus of this step is calculating the medium-term (i.e., after the next rate case) tariff impacts associated with DPV deployment; however, the presence of interim tariff adjustment mechanisms may require the calculation of both short-term (i.e., before the next rate case) and medium-term tariff impacts. As mentioned previously, the analyst will need to determine how frequently interim tariff impact calculation require examination—generally speaking, annual calculations should meet the needs of most stakeholders.

Given the difficulty associated with acquiring detailed ratemaking information, particularly data and assumptions for how revenue requirements and sales expectations are allocated across customer classes to design retail tariffs, it may be more feasible in a lower data environment to perform an average tariff impact calculation. The complexity associated with an average tariff impact calculation lies in the

[52] Net revenue impact calculation subcomponents are offered for VIUs with DPV deployed in their retail service territory. If DPV is not deployed in their retail service territory, but a net revenue calculation is desired, the analyst should use the methods for EGUs.

underlying assumptions and data, while the mechanics of the equation itself are perhaps simpler. An average tariff impact can be calculated as:

$$\Delta T_{avg}[\%] = \frac{T_{DPV} - T_0}{T_0} \qquad \text{(Equation 1)}$$

where

$$T_0 = \frac{RR}{ES} \qquad \text{(Equation 2)}$$

and

$$T_{DPV} = \frac{RR + (C_{LS} * P_{LS}) + (C_P * P_P) - (B_{AE} * P_{AE})}{ES - E_{LS}} \qquad \text{(Equation 3)}$$

ΔT_{avg} [%] = average change in tariff
T_{DPV} [$/kWh] = average tariff for DPV deployment scenario for rate period under consideration
T_0 [$/kWh] = average business-as-usual tariff for rate period under consideration
RR [$] = utility revenue requirement for rate period
ES [kWh] = expected total sales during rate period
E_{LS} [kWh] = expected lost sales during rate period due to DPV self-consumption

C_{LS} [kWh] = volume of reduced utility sales due to DPV
C_{LS} [$] = cost, reduced revenue associated with reduced utility sales due to DPV
P_{LS} [%] = allowable pass-through of C_{LS} to ratepayers (0-100%)
C_P [$] = cost, additional DPV energy purchase obligation
P_P [%] = allowable pass-through of C_P to ratepayers (0-100%)
B_{AE} [$] = benefit, avoided expenditure associated with generation cost or energy procurement, including applicable transmission or distribution losses
P_{AE} [%] = allowable pass-through of B_{AE} to ratepayers (0-100%)

This equation can be further broken down for each utility stakeholder type (distribution utility, EGU, and VIU) to include volumes and timing of DPV self-consumption versus grid injections and associated costs and benefits.

It is possible that information on the revenue requirement for the relevant rate period(s) in question may not be available. If so, the revenue requirement may need to be estimated. For instance, an annual revenue requirement can potentially be implied by using recent, publicly available information on utility revenue collection; while revenue collection is not equivalent to utility revenue requirement, it is in the right order of magnitude for informing calculations when revenue requirement data are not available. As well, if retail or wholesale sales volumes are known, and information is available on customer tariffs and the number of customer meters, this information can be used to create an order of magnitude estimate of annual utility revenue.

One important step here, particularly for TRIAs looking farther out into the future, is formulating assumptions about future revenue requirements. While utility revenue requirements may be available for the current rate period, it is unlikely that they will be for future rate periods. Thus, the analyst will likely need to develop assumptions about how this revenue requirement will change with time. When possible, this assumption can be formulated in collaboration with the utility and regulatory stakeholders. A key consideration, however, is whether the impact of DPV itself would be included in future revenue requirements. In other words, is the revenue requirement assumed to grow in the next rate period due to DPV deployed in the previous? If not, how is it accounted for?

Finally, it is appropriate to conduct scenario analyses for various utility cost allocation strategies in Step 6 (as mentioned in Section 6.6).

Utility Impacts to Return on Equity and Profitability

Changes in net short-term costs (or benefits) to utilities are spread across ratepayers and utility profits, as specified by the regulatory framework. Where regulators allow the full short-term net costs of DPV to be passed through to ratepayers, the medium-term utility revenue impact is ultimately zero. When there are reduced short-term utility revenues that cannot be recovered by tariff increases (e.g., not all costs are allowed to be passed through, and/or rates are set based on historical sales levels that do not account for increase,d DPV deployment), then some net revenue losses may be passed through to the utility.

In this event, this may lead to reduced utility return on equity/earnings, as utility capital investments remain the same, yet revenues are lower as DPV deployment increases. While the return on equity may recover at the next rate case, without changes to the ratemaking process, return on equity may reduce again as more DPV is installed. DPV could also lead to reduced investments as capital costs are deferred, and this would also lead to reduced future earning opportunities since less equity investments would lead to lower profits, even if return on equity is constant. While these relationships and impacts can be important in some settings, it is beyond the scope of this type of analysis to quantify how capital investments may be impacted by DPV. See Satchwell et al. (2015) for a more detailed investigation of impacts from net-metered DPV on utility return on equity and profitability in the United States.

7.6.1 Required Outputs From Analysis Step

The retail electricity tariff with DPV (T_{DPV}) and the changes in Tariffs (ΔT_{avg}) are the primary required outputs from this step. It may also be instructive to stakeholders to disaggregate ΔT_{avg} into its key drivers. Are reduced utility sales due to DPV self-consumption the largest driver of ΔT_{avg}? What about additional utility purchases of DPV energy? This breakdown can be highly informative for policy decisions.

8 Concluding Remarks: Presenting TRIA Results

Utility tariff and revenue impact analyses can yield powerful insights into both current conditions and future scenarios of solar deployment, tariff reforms, solar compensation schemes, and ratemaking practices, among other important parameters. They are a key tool to help bound expectations of impacts and inform policy and regulatory decisions intended to begin, maintain, or adjust DPV programs. Notably, the impacts of DPV on utilities and ratepayers may be positive, neutral, or negative—and the direction and scale of impact will depend largely on policy decisions and/or analysis assumptions regarding the above-mentioned parameters, most of which are within the control of policymaking and regulatory authorities. Ultimately, it is these authorities who will determine the acceptable level of net benefit or net cost of a DPV program to utilities and ratepayers based on their own local conditions and priorities.

The effective presentation of TRIA is a key step in ensuring results are fully understood by decision makers and interpreted for application appropriately. To begin, to promote clarity among decision makers as to the scope and nature of the analysis, it may be useful to present which specific DPV value drivers (i.e., costs and benefits) are chosen to be included in the TRIA. It may also be useful to present the process for how analysis assumptions were formulated, with a specific emphasis on DPV deployment assumptions and key policies that are explored in the analysis.

With respect to presentation of results, it can be extremely useful for analysts to contextualize impacts to better inform decision makers. For instance, a figure of annual utility net revenue losses may be more informative if it is reported alongside data on annual utility revenue collection levels, and/or a discussion of which specific value drivers are typically passed through to ratepayers versus absorbed on the utility's balance sheet. Similarly, expected tariff impact estimates might be presented alongside tariff impacts for other programs (e.g., the tariff rider for an energy efficiency program) or generation resources (e.g., the required tariff increase to fund a utility-scale solar PPA). It may also be useful to place tariff impacts in the context of periodic tariff fluctuations which may occur due to changes in fuel costs, weather, macroeconomic conditions, or other factors. This can help to demonstrate to decision makers if expected tariff impacts due to DPV will be "in the noise" of regular utility operations, or if they will be a more noticeable and significant quantity.

As well, it may be constructive for analysts to visualize DPV financial impacts in an itemized manner based on their key drivers (e.g., reduced retail electricity sales, avoided energy generation cost, and so on). Doing so can help illustrate how DPV utility costs and benefits offset one another. It may also help decision makers glean insights into the relative impact of policy decisions currently under consideration. For instance, if the primary driver of utility costs is demonstrated to be reduced retail electricity sales due to DPV self-consumption, this might suggest that a more generous DPV sell rate currently under consideration might have a relatively smaller impact on utilities and ratepayers than retail tariff reforms for DPV customers.

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Appendix A

This appendix provides a nonexhaustive list of potential research/interview questions to help uncover relevant details of the local ratemaking process and potential DPV impacts.

[*Note:* S*upplemental comments may be listed in bracketed and italicized text*].

Ratemaking and Regulatory Framework

How long are rate periods typically in your jurisdiction? Are all utility stakeholders on the same cycle of ratemaking, or are they staggered?

Is ratemaking forward-looking? As in, are retail tariffs being designed based on future expectations of sales and required expenditures over the rate period? Or is ratemaking backward-looking, with tariffs being designed based on recent data around sales and expenditures? Is this data available? Are nondisclosure agreements required to move forward?

Is there an interim rate adjustment mechanism to help utilities "true-up" revenue shortages/surpluses? If so, how does it work? How frequently is it employed? What kinds of costs are included versus ineligible? Would additional electricity purchases and/or forgone revenue from DPV be included in this mechanism, or within rate case proceedings at the end of a rate period?

What are the rules for passing additional utility costs through to ratepayers? What types of costs are eligible for pass-through, and to whom, and under what circumstances? What costs are commonly passed through to ratepayers if there are deviations from expected sales or revenue? Are these the same rules that would apply to forgone revenue from DPV self-consumption, and/or additional purchases of DPV electricity (if stakeholder distributes electricity)?

How does your utility make money? Are they incentivized to increase revenue or profitability? If so, how? How do you expect DPV will impact this, and why? [*This information may or may not be directly useful for your quantitative analysis, but it may help inform specific analysis questions that are relevant for the utility.*]

Can you provide access to the most recently available utility revenue requirement figures? What period do these numbers apply to? What costs are included or not included in the revenue requirement? Are fuel costs and other variable costs included? If not, how are those incorporated into the ratemaking process? How many kWh of sales are assumed for the rate period as a basis for tariff design?

What DPV costs and benefits would be tracked and accounted for in today's ratemaking processes, if any? What would/could be tracked and accounted for in future ratemaking processes? [*There may or may not be established rules and procedures for this. Rather, outputs from a TRIA study may help to inform this question.]*

Is there any precedent for tariff design and/or compensation to customers for DPV systems? If so, what principles were used in the associated ratemaking process?

How is the revenue requirement allocated across customer classes? How are the assumptions of kWh of sales allocated across customer classes to design tariffs? [*Without an answer to these questions, it is only possible to quantify average tariff impacts.*]

If DPV is accounted for in ratemaking processes, would the impact of existing DPV systems be taken into account in the next rate case? Or would they be accounted for with interim rate adjustment mechanisms?

To what extent are ratemaking procedures governed by established legislation or direct requirements from energy ministries? Are there any important social policy considerations of current ratemaking practices to be aware of?

DPV Compensation Mechanism

Are customers allowed to interconnect DPV systems to the distribution network? Are they allowed to inject electricity into the distribution network?

Are customers granted a kWh credit for any DPV electricity that is injected into the distribution network? If so, how long can it be used for until it expires? If not, are they granted a cash payment or bill credit for their injected electricity?

How much DPV is currently deployed in your system? Are all of those systems being compensated in the same way, or were some interconnected under previous schemes?

Offsetting Generation or Energy Purchases

How does the stakeholder generate and/or procure wholesale electricity?

At a high level, what kind of wholesale electricity purchases and/or power plant generation behavior might reduce as a result of DPV generation?

Is there information available on bulk electricity generation patterns throughout the day? What generators would be expected to be offset by DPV? Who owns these generators? What portion of these generator costs are variable (e.g., fuel-related) relative to fixed?

Are any of the key utility generators that might be reducing their output due to DPV subject to inflexible take-or-pay fuel procurement contracts, or party to inflexible take-or-pay PPAs? If so, does this influence DPV's financial impact at all?

Wholesale Electricity Market

To what extent do distribution utilities procure their electricity through: (1) regulated wholesale electricity tariffs from electric generation utilities or vertically integrated utilities; (2) independently negotiated PPAs with IPPs; (3) independently negotiated wholesale pricing arrangements with electric generation utilities; (4) deregulated wholesale electricity market purchases on spot (or other energy product) market; (5) self-generation; or (6) other means.

If regulated wholesale electricity tariffs are used to some extent, how are wholesale tariffs structured? To what extent are they energy- versus demand-based? How frequently do they change?

If wholesale electricity procurement does not occur through regulated tariffs, what recent information exists on the quantities, sources, and prices of procured wholesale electricity?

Retail Electricity Market

How many retail customer classes do you have? Do retail rates change at all with geography or season? What are the largest groups of customers? Do you have recent data on your customer classes and gross monthly and annual sales per customer classes?

Do specific segments of customers (e.g., residential) ever move to different tariffs if their consumption changes? Is there any possibility of a DPV customer being moved onto a different tariff due to a reduction in grid consumption? [*Note: This is not asking about inclining or declining block tariffs. Rather, in some jurisdictions, if a customer's consumption drops/surpasses a specific monthly consumption for a specified period of time (e.g., 12 months), the utility places them on an entirely different tariff.*]

If a customer deploys DPV, do they stay in the same customer class and with the same tariff structure? Or are DPV customers placed into a special tariff class? Is a DPV retail tariff under consideration by any of the relevant stakeholders? Are there rules prohibiting/allowing/mandating that DPV customers need to be in their own customer class? If DPV customers are subject to the same retail electricity tariff as they were before they installed the DPV system, are there rules that allow for specialized modifications of tariffs (e.g., through rate riders) that would only apply to DPV customers?

What customer classes are you most concerned about deploying DPV? Why? Which customers classes would you most like to see deploy DPV, if any? Why?

Is information about retail tariff structures publicly available? How often do these change? What are the key features of retail rates? Are there seasonal or location-based differences in tariffs? Are there inclining or declining block structures? Are there demand charges? How much do retail electricity rates tend to escalate each year relative to inflation?

DPV Impacts

If a customer generates a kWh of DPV electricity and immediately self-consumes it, how would the relevant utility entity (or entities) be impacted from the standpoint of sales and revenue? Beyond losing a sale, would they save any money?

If a customer generates a kWh of DPV electricity and injects it into the distribution grid, how would the relevant utility entity (or entities) be impacted from the standpoint of sales and revenue? Beyond losing a sale, would they save any money?

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Jeremy Foster
U.S. Agency for International Development
Email: jfoster@usaid.gov

Sarah Lawson
U.S. Agency for International Development
Email: slawson@usaid.gov

Ilya Chernyakhovskiy
National Renewable Energy Laboratory
Email: ilya.chernyakhovskiy@nrel.gov

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