PUBLIC VERSION

Business models for distributed energy resource development:

A case study with Tata Power Delhi Distribution Limited

Final report

May 27, 2015

Energy+Environmental Economics

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Abbreviations

CAPEX: capital expenditure

DER: distributed energy resource (e.g., energy efficiency or distributed solar)

DISCOM: state electricity distribution utility

FiT: Feed in tariff

FOR: Forum of Regulators

INR: Indian national rupee

IREDA: Indian Renewable Energy Development Agency

JNNSM or NSM: Jawaharlal Nehru National Solar Mission

kWh: kilowatt-hour

kWp: kilowatts peak

MNRE: Ministry of New and Renewable Energy

NEM: Net energy metering

O&M: operation and maintenance

OPEX: operating expenditure

PV: photovoltaic

RPO: Renewable Portfolio (or Purchase) Obligation

SERC: State Energy Regulatory Commission

USTDA: United States Trade and Development Agency

USD: United States dollar

Wp: Watts peak

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Abstract

We evaluate and develop the business models for distributed energy resources (DER) using the Tata Power Delhi Distribution Limited (TPDDL) as a case study. TPDDL is a distribution utility based on a public-private partnership that provides electricity to the northwest part of Delhi. TPDDL seeks to meet a portion of its future power needs using distributed energy resources (DER), which are power technologies located at the customer site and often behind the meter. DER include distributed solar (or other generation), demand response, energy efficiency, storage and load shifting technologies. In this study, we developed planning tools that will enable TPDDL to incorporate DER technologies into its planning process and develop the strategy to promote the adoption of DER technologies — especially solar — in a way that promotes economical, reliable and environmentally sustainable power.

A core aspect of our study was to develop the regulatory case for DER technologies, focusing on the benefits and costs of DER to all TPDDL's consumers. We are able to show that using reasonable and "mid-range" assumptions, solar technologies can lower TPDDL's costs, maintain reliability, and reduce its environmental footprint in approximately five years. Under more optimistic assumptions on future solar and conventional power prices, solar is immediately cost-effective to TPDDL's consumers. We find that the inclusion of complementary non-solar DER technologies can help lower TPDDL's capacity needs, lower the overall cost of TPDDL's energy supply, and facilitate the integration of solar into the grid. In the near term, we find that the adopted Net Energy Metering (NEM) policy results in an economically attractive proposition for solar to commercial and industrial customers. However, NEM can create a cross-subsidy. Over the long term, a shift to a NEM alternative, similar to a "feed-in-tariff" or "generation based tariff" as it has been applied in Germany provides the regulator with more flexibility to manage the cost shift and tune the payment to encourage adoption. We find that given TPDDL's excellent relationships with its customers, access to financing, experience with complementary DER (demand response and energy efficiency) it is in an excellent position to foster and grow the solar and DER market for New Delhi and be an example for other utilities, cities, and planning agencies to follow.

1 Executive summary

1.1 Introduction and context

US Trade and Development Agency Commissioned Study

Tata Power Delhi Distribution Limited (TPDDL) has received a grant from the US Trade and Development Agency (USTDA) to complete a feasibility study titled "Business Models for Distributed Energy Resource Deployment". Energy and Environmental Economics (E3) completed the study.

This broad goal of this project is to develop an implementable plan and integrated planning tools that will enable TPDDL to invest in distributed energy resource (DER) technologies. DER technologies are a class of resources that are typically installed behind the meter of a customer and/or at a customer site, rather than at a central generation station. The goal is to use DER technologies to improve the reliability of TPDDL's electricity system, reduce its environmental footprint, and reduce its overall costs to customers. We investigated the following types of DER technologies:

- Distributed solar
- Energy efficiency
- Demand response
- Grid storage (batteries)
- Thermal energy storage

Given the recent price declines of solar, TPDDL aims to manage a portion of its future power needs with solar using DR and other DER for balancing purposes. The intent of this study is to develop the analytical tools, business models and recommendations to promote the adoption of cost-effective DER technologies, especially rooftop solar. We pay particular focus towards how to develop the regulatory justification for investment in DER; because TPDDL is a regulated utility, investment decisions and policy choices that affect TPDDL and its consumers must be evaluated by its regulator, the Delhi Electricity Regulatory Commission (DERC). Although the project uses TPDDL as a case study, the methods and insights are applicable to utilities across India.

Regulatory context

Solar policy development in India is receiving high visibility and support at all levels. The landmark three phase Jawaharlal Nehru National Solar Mission includes ambitious targets, driving solar momentum. National goals are set at 20 GW by 2022, and recent announcements indicate that it may be increased to 100 GW. At the same time, NSM incentives for solar are likely to be decreased. The uncertainty around the incentives puts emphasis on the value proposition for solar and what can be achieved economically.

So far India has roughly 3000 solar MW installed, or 1.2% of the total Indian capacity. It has not yet been integrated into utility resource planning frameworks and development has happened largely through 3rd party suppliers. The favorable regulatory environment towards solar combined with low solar costs worldwide presents opportunities for solar development in India.

> **National Solar Mission**
> "Our vision is to make India's economic development energy-efficient. Over a period of time, we must pioneer a graduated shift from economic activity based on fossil fuel to one based on non-fossil fuels and from reliance on non-renewable and depleting sources of energy to renewable sources of energy. In this strategy, the sun occupies centre-stage, as it should, being literally the original source of all energy. We will pool our scientific, technical and managerial talents, with sufficient financial resources, to develop solar energy as a source of abundant energy to power our economy and to transform the lives of our people. Our success in this endeavor will change the face of India. It would also enable India to help change the destinies of people around the world."

Solar development to date has focused on grid scale installations that are remote of load centers. However locally sited distributed systems may offer unique benefits to both customers and utilities. These benefits extend to other types of distributed energy resource (DER) to a greater or lesser extent. Other DER technologies include energy efficiency (EE) (also called demand side management in India, or DSM), demand response (DR), grid storage, and thermal energy storage (TES).

The Delhi Electricity Regulatory Commission has adopted a net energy metering (NEM) policy that encourages local solar development and can help realize the benefits that it offers. Adding to that, TPDDL and other utilities have programs in place and in development that encourage adoption of DER such as EE and DR.

Challenges to solar market expansion

Despite the progress that India has made, the current policies may not be sufficient to grow the solar market in a significant way. Key challenges must be overcome to encourage solar deployment in Delhi. Where should the solar be sited and who will adopt solar? How will the solar system be financed and by whom? Access to financing — and to low-cost financing — is a challenge across India. Stakeholders noted uncertainty regarding the interconnection process. How can this process be simplified? How can customers be ensured that they are receiving quality installations at reasonable prices? Finally, what policies are necessary to ensure that solar is adopted in a way that benefits all consumers?

TPDDL is well positioned to address the barriers to solar deployment and is in a position to help advance solar deployment across Delhi.

- Trust: As a company with a trustworthy brand, it can help overcome the "trust" barrier.
- Targeting and outreach: TPDDL has invested in technologies, such as AMI and GIS, that can help identify viable solar installations
- Financing: TPDDL has access to low cost financing which will be useful in providing solar options to customers at competitive costs, in the even TPDDL owns and operates these systems.
- Interconnection: As a utility, TPDDL has the Ability to streamline the process

Other DER, such as energy efficiency and demand response, can provide complementary benefits to solar and should be incorporated into overall utility planning for DER. TPDDL has engaged in EE and DR programs; these resources in combination with solar can lower overall portfolio costs and can provide solar integration benefits over the long term.

Developing the regulatory case

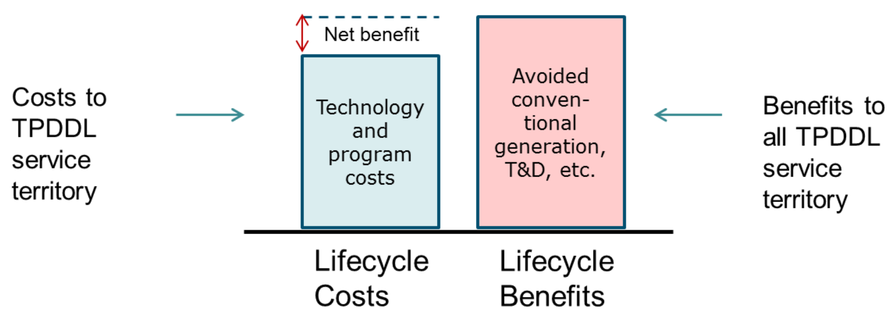
The goal of this project is to help TPDDL and other utilities take an active role in developing a local market for solar and other DER. We develop the business case of DER, with a focus on rooftop solar. The project included the following core components:

- Developed a planning tool to help TPDDL and other Indian utilities identify the value of solar and other DER for incorporation into energy resource plans;
- Exercised the planning tool to assesses the tradeoffs between different solar policies (NEM and alternatives) and the benefits of other non-solar DER
- Developed an implementation and regulatory strategy that will enable TPDDL and other utilities to leverage the solar opportunity and coordinate solar with complementary DER technologies.

The DER portfolio evaluation tool is designed to compare the value of DER against otherwise procuring equivalent amounts of energy and capacity from grid scale coal or gas resources. As a utility planning tool, it can inform decision makers about the relative value of DER portfolios when making integrated resource plans. It can also be used more broadly by regulators or program administrators to evaluate distributed energy resources against grid scale alternatives for program and tariff design decisions.

Whether DER resources are cost effective is a decision best made on a lifecycle basis that accounts for all costs and benefits over the lifetime of the resource being evaluated. The DER portfolio evaluation tool accounts for the lifetime costs of DER, including capital expenditures, operating and financing costs, taxes, and incentives. It also accounts for the lifetime benefits, including the avoided costs from not having to procure grid scale coal or gas PPAs for energy and capacity, and the associated lost energy.

Figure 1: Valuation framework for regulatory program development



Detailed net cost information from the tool informs the implementation and regulatory strategy to encourage solar. Decisions are based on how much the policy will cost or benefit ratepayers, the utility, and society at large.

1.2 Key findings

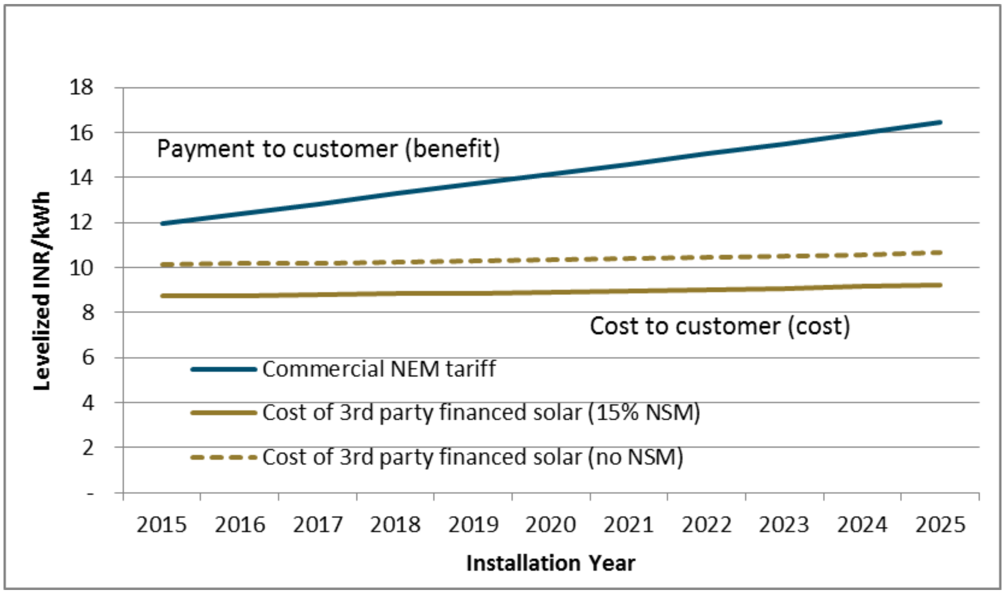
For a customer to install solar under a NEM policy, the benefits of the solar must exceed the costs. The benefits to the customer are the bill savings. These include the savings from not having to pay for energy the customer would otherwise have used, and the potential sales the customer makes of exported generation. The bill savings are referred to henceforth as the NEM tariff and is the levelized payment made to a customer per kWh of solar over the lifetime of the project.

As Figure 2 shows, both commercial and industrial customers receiving the NEM tariff for their solar output is compensated at a rate that exceeds the cost of the installed solar.[1] The customer saves money

[1] In this example, the industrial customer example has a higher connected load, and thus, higher tariff than the commercial customer.

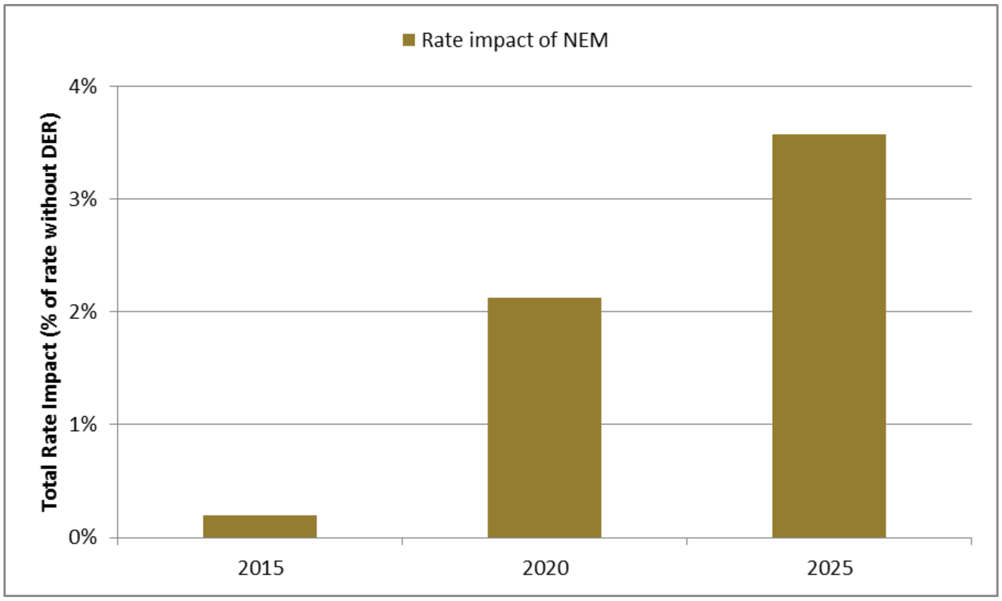
with the solar and is therefore incentivized to install a rooftop solar system. Based on economics, the main opportunity for solar is in the C&I sectors, because the residential tariffs are much lower.

Figure 2: Lifecycle NEM tariff versus cost of solar for commercial and industrial customers



The above analysis presents the perspective, only, from the customer that may adopt a rooftop solar system. While some customers may be motivated to install rooftop solar systems, not all customers will install solar. Therefore, not all customers will benefit from the solar installation. The benefits to all customers must be evaluated. When some customers install solar (or other DER), the utility might be able to avoid procuring energy and capacity from alternative resources such as coal and gas, and potentially building new transmission and distribution. Under a NEM policy, the utility will lose some revenue, or the bill savings ("NEM tariff") that the select group of customers installing solar will experience. If the total benefits of the solar are less than the revenue losses, the utility will have to recover the difference by raising tariffs. Intuitively, this is because the utility must continue to maintain the grid infrastructure. The resulting tariff impact is small, shown in Figure 3, amounting to only a 3.5% increase in rates in 2025, based on 440 MW of solar installed on the system by that time. The small rate increase is offset by the solar market transformation, job creation, and experience gained by TPDDL in interconnection and DER system management.

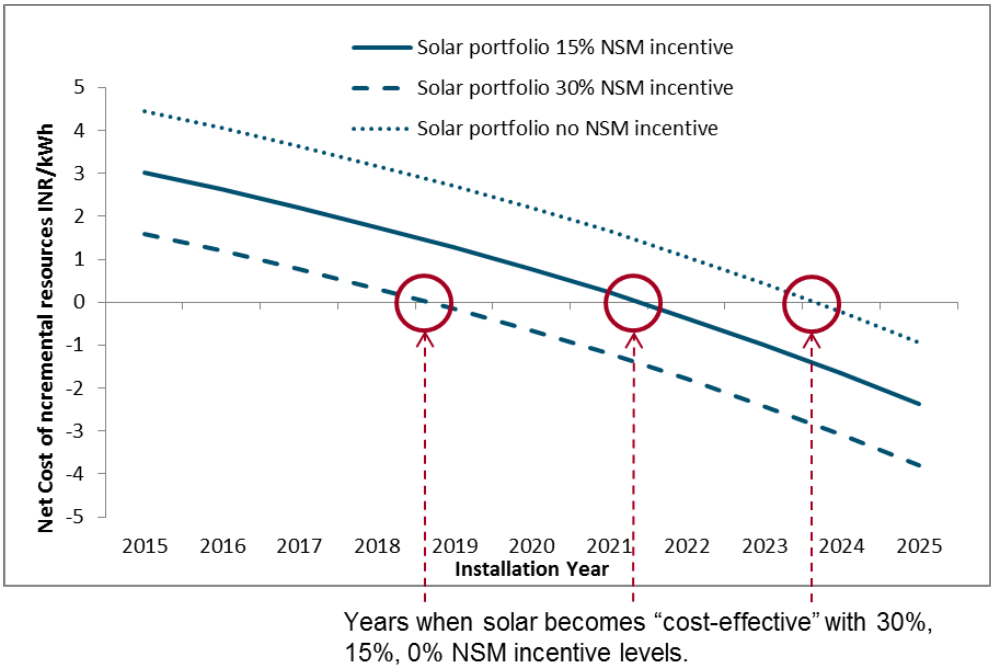
Figure 3: Tariff impact of NEM policy in 2015, 2020, and 2025



The third perspective, and arguably, most important question is whether solar is cost-effective and beneficial to all utility customers overall, based on the comparison of solar costs to the savings that occur by avoiding conventional power plant resources, such as coal and gas, transmission and distribution investments, and avoided T&D losses. The avoided costs come in the form of both energy and capacity. If the lifecycle solar costs are lower than the lifecycle benefits due to avoided conventional resources, solar is cost-effective to all customers or societal overall.

Figure 4 illustrates the net benefits of solar for different levels of NSM incentives and assuming solar avoids coal. Solar becomes cost-effective compared to coal (based on a 75% domestic/ 25% import blend) by 2019 if a 30% NSM incentive is available; 2022 if a 15% NSM incentive is available; and 2024 without an NSM incentive. The NSM incentive is valuable for achieving cost-effectiveness sooner, which has benefits to all TPDDL's customers and Delhiites.

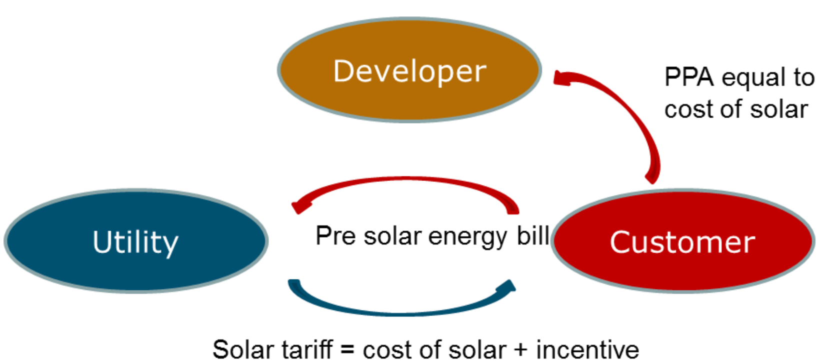
Figure 4: Net cost of solar installed in years 2015 through 2025



However, there will still be a distributional impact from NEM where customers not participating in the program will pay higher bills. As Figure 3 shows, these bill impacts are very low between now and 2025. As the solar program grows though, they will become more significant and an alternative policy to NEM could be considered in the future that has less of a distributional impact.

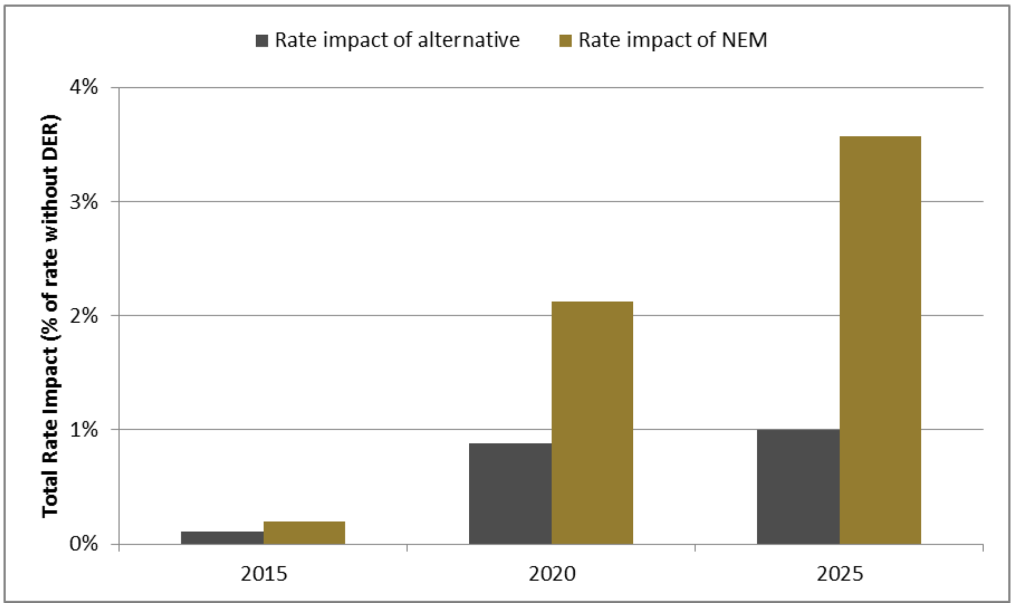
One such alternative policy is a fixed payment per kWh of solar generated that is equal to the cost of solar, plus an incentive to the installing customer to make it worthwhile. This is referred to as the 'NEM alternative' throughout the rest of the document. There are multiple business arrangements that can support this policy. The figure below illustrates one such arrangement.

Figure 5: Example business model of an alternative policy to NEM



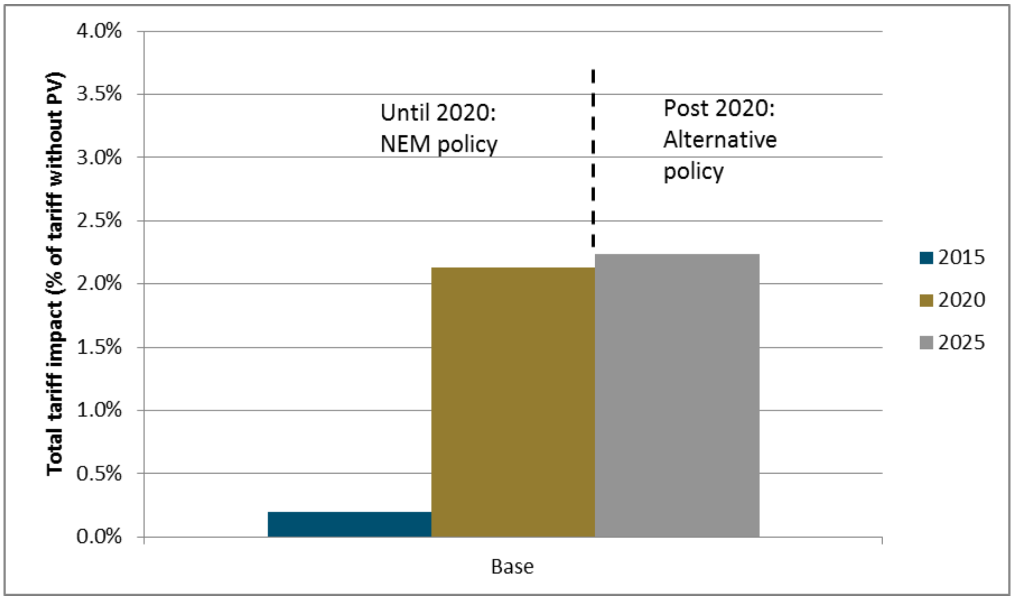
In this example, the utility provides the solar tariff to the customer, equivalent to the cost of solar and the incentive; the customer has a solar PPA with a developer; the customer experiences overall bill savings equivalent to the pre solar bill minus the solar tariff payment. Figure 6 below shows the impact of such a policy compared to NEM where the incentive paid to installing customers is 1 INR/kWh of solar. This approach to a solar incentive significantly reduces rate impacts. If solar prices drop further in future relative to alternative coal or gas resources, the net benefit of solar will increase. In that case, the alternative solar incentive policy may start decreasing rates.

Figure 6: Tariff impact of an alternative solar policy to NEM



Given that the NEM tariff has already been adopted by the DERC, a more realistic scenario is one in which the NEM policy is used to promote adoption in the early years with a transition to an alternative policy. Since the NEM policy will be revisited every five years, we analyzed the tariff impacts if the NEM policy is maintained through 2020, with a transition to the alternative policy in 2020. By transitioning away from the NEM policy, the tariff impact can be stabilized beyond 2020, as shown in Figure 7.

Figure 7: Tariff impact for NEM policy through 2020 with transition to alternative in 2020



Finally, we analyze the benefits of including other non-solar DER. We analyzed mixed portfolios that contained energy efficiency, demand response and storage. Each resource brings different types of benefits. Although solar has both energy and capacity benefits, the capacity value is limited by the coincidence of solar output with when peak load occurs. Air conditioning energy efficiency provides energy and capacity value over daytime and nighttime hours. Demand response and storage are useful resources to address peak loads and have capacity benefits.

Figure 8: Comparison of total net costs across all DER portfolios

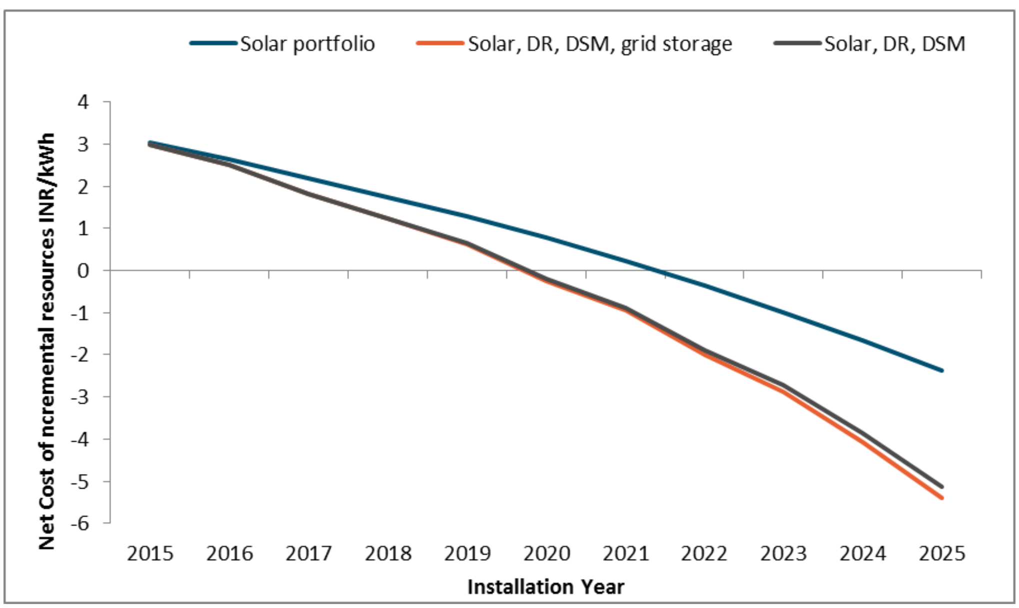


Figure 8 shows the net cost of portfolios that include energy efficiency (DSM), demand response (DR) and storage. The figure illustrates that mixed DER portfolios are more cost-effective than solar-only portfolios. Utilities can tune their programs to target not just solar but other DER so that the total portfolio costs, and hence, energy procurement costs, are lower. DER such as using DR and storage to provide load balancing and integrate high levels of solar.

1.3 Implementation

NEM, as a market transformational strategy, should encourage job growth and training in system installation, marketing, and maintenance. The increasing rate of system installations will also increase the experience on the utility side of interconnecting and integrating solar on the distribution system. Experience gained on both sides of the meter should lead to cost reductions, efficiency gains, and faster adoption. Improvements in these areas can be increased through looking at international best practices — learning from the mistakes of regions that have already installed significant amounts of DER. Regulators and standards agencies also have a role to play in facilitating these improvements through quality control mechanisms and codes and standards.

Interconnection standards and best practices include the following.

- Process: Streamlining the process is critical to expand the distributed solar market. Clear timelines, milestones, and communication between customer and utility reduce barriers to adoption.
- Targeting: Identify the easy to interconnect resources on a substation or ideally at the feeder level. Easy to interconnect resources do not require the utility to upgrade distribution facilities.
- Advanced inverters: These can improve interconnection by providing voltage support and islanding based on real time grid conditions.
- Setting limits: Early interconnection of distributed generation in the United States imposed strict limits on interconnection of local resources. The penetration thresholds have been relaxed as the effects of solar have become better understood and as more data has become available.
- Monitoring: Historically, most utilities have not collected real-time solar generation data and do not have visibility into the solar operation on a continuous basis. While third party developers monitor their installations, they have not necessarily shared this data with utilities. Solar planning and grid operations with solar can be enhanced if utilities and grid operators have visibility into the solar operation.

Ensuring quality control is important to achieve desired solar performance. Quality control mechanisms may include the following.

- Maintaining the high standard of reliability set by TPDDL.
- Develop a database of installed projects to track PV customers, installed MWs and performance
- Develop a database of installed distribution side upgrades to create a record of experience
- Explore potential by distribution planning area to focus solar where the grid is most resilient

Codes and standards, and green building initiatives can play a useful role in deploying solar and DER in the new construction segment. Given the new development occurring in India and in Delhi, this is an important opportunity to deploy more cost-effective DER technologies.

- "Solar-ready" mandates for new construction is one mechanism to ensure that rooftops have sufficient space and electrical connectivity for future solar installation.
- Partnership with green building initiatives (such as LEED) and developers can help with deployment of multiple DER simultaneously (efficiency, demand response, solar).
- Third party or utility financing can help overcome the first cost barriers to solar and enabling technologies for efficiency and demand response (energy management control system).

Non-solar DER can provide an important role in lowering the cost of DER portfolios and providing capacity value where solar falls short. Energy efficiency applied to air conditioning has high energy and capacity benefits, particularly due to the large nighttime loads that TPDDL faces. Grid storage and demand response are very valuable as capacity resources because they are dispatchable. Thermal energy storage can provide both energy and capacity benefits provided the customer tariffs are structured to encourage the desired operation.

Finally, utilities can utilize existing smart grid infrastructure — advanced metering infrastructure, GIS systems — to identify customers with suitable load shapes and potential for solar and other DER.

1.4 Recommendations

TPDDL is in a good position to encourage the rooftop solar market and transition to a solar future. First, there are complimentary programs that TPDDL can offer its customers to get more value out of solar and integrate the deployment of solar with the overall resource plan. These include demand response, energy efficiency (which TPDDL has begun) and managing the supply portfolio according to the solar.

Second, TPDDL is a trusted provider of energy for its customers, particular C&I customers. Third, TPDDL can ensure quality installations that help develop the market, provide consumers with confidence in solar for the long term, and set the standard business practice in the market. Our overall recommendations to TPDDL are as follows.

- Begin offering C&I customers quality, financially beneficial, rooftop solar systems
- Develop complimentary programs such as DR and EE to maximize utility value from the solar
- Develop codes and standards to ensure quality of solar installations and to encourage cost-effective solar, EE, DR in new construction
- Explore partnerships through existing initiatives such as the LEED green building initiatives as these can help identify willing customers.
- As the installed solar increases, manage the conventional supply portfolio in a complimentary manner, identifying resources that meet the utility's changing load demand needs.
- Track the impact on C&I tariffs as well as installed system costs. When the tariff impact begins to increase to a level of concern, transition from the NEM policy to a less generous compensation system that better reflects solar value in the utility portfolio.

Over the long term, TPDDL will gain practice with programs and can optimize these programs to incorporate solar along with other DER at more aggressive levels. The framework can be used to identify which types of DER become more valuable as load growth patterns change along with DER technology costs and performance, and fuel cost projections.

More broadly, this study developed a planning methodology can be useful across Delhi, for different regions, and for central policy decisions. A central level analysis can show overall benefits when fossil fuel subsidies are lowered. A multi-regional analysis can show overall benefits of solar when diesel and lost load would otherwise occur.

2 Background and regulatory context

2.1 Project introduction

Tata Power Delhi Distribution Limited (TPDDL) has received a grant from the US Trade and Development Agency (USTDA) to complete a feasibility study titled "Business Models for Distributed Energy Resource Deployment". Energy and Environmental Economics (E3) completed the study.

This broad goal of this project is to develop an implementable plan and integrated planning tools that will enable TPDDL to invest in U.S. based power system technologies that will improve the reliability of its electricity system, reduce its environmental footprint, and reduce its overall costs to customers. We explored a specific set of power system technologies known as distributed energy resource (DER) technologies. DER technologies are a class of resources that are typically installed behind the meter of a customer and/or at a customer site, rather than at a central generation station. We investigated the following types of DER technologies:

+ Distributed solar
+ Energy efficiency
+ Demand response
+ Grid storage (batteries)
+ Thermal energy storage

A main motivation for this study is, given solar prices have been declining, TPDDL would like to manage a portion of its future power needs with solar. Our study gave special emphasis to solar PV and demand response. We analyzed and developed business models that might help promote the adoption of DER technologies, especially rooftop solar under different scenarios. We investigated how non-solar DER (e.g., energy efficiency and demand response), can help play a complementary role towards DER programs and possibility help integrate solar into the TPDDL grid. We explored different business models, ranging from utility owned assets to third party owned assets, as well as different policies that can promote solar adoption. We pay particular focus towards how to develop the regulatory justification for investment in DER; because TPDDL is a regulated utility, investment decisions and policy choices that affect TPDDL and its consumers must be evaluated by its regulator, the Delhi Electricity Regulatory

Commission (DERC). Although the project uses TPDDL as a case study, the methods and insights are applicable to utilities across India.

2.2 Regulatory context

Solar is receiving high visibility and support at all levels of government. New policy development at all levels is being motivated by an interest in promoting environmental leadership and sustainability as India's economy and infrastructure evolves. Solar has benefited from significant investment in utility scale solar under the National Solar Mission (NSM), one of the eight missions under the National Action Plan for Climate Change. The NSM platform has stimulated interest in distributed solar applications. Simultaneously, interest in other distributed energy resources (DER), including demand response, energy efficiency, storage and combined heat and power has increased.

> **National Solar Mission**
> "Our vision is to make India's economic development energy-efficient. Over a period of time, we must pioneer a graduated shift from economic activity based on fossil fuel to one based on non-fossil fuels and from reliance on non-renewable and depleting sources of energy to renewable sources of energy. In this strategy, the sun occupies centre-stage, as it should, being literally the original source of all energy. We will pool our scientific, technical and managerial talents, with sufficient financial resources, to develop solar energy as a source of abundant energy to power our economy and to transform the lives of our people. Our success in this endeavor will change the face of India. It would also enable India to help change the destinies of people around the world."

India's energy needs are increasing and availability of low price and subsidized fossil fuel is decreasing. This can result in the power sector not being able to meet energy needs because generators cannot recover the cost of expensive imported fuel and may choose to idle their capacity. To maintain reliability, additional allocations of subsidized fuels or increased rates may be necessary to create the market incentives for the generation fleet to meet energy needs.

In addition to the issues associated with subsidized fuel allocation, the domestic supply of fossil fuel has not kept up with the increased demand which has led to increasing dependence on high cost imports. The share of imported energy is expected to increase over the next decade which will put increasing pressure on meeting energy needs. Policy makers and regulators are viewing solar and other DER programs as a way to reduce dependence on fossil fuel based power and provide a fixed price hedge against long term variable price volatility of fossil fuels.

The table below summarizes the key findings from the meetings with the external stakeholders.

Table 1: Insights from select stakeholder meetings

Agency	Summary insights
DERC	• DERC notes that the program must have a neutral tariff impact • DERC expressed interest in understanding trade-offs of different solar policies • The regulatory case must be based on real costs faced by TPDDL, including the effect of subsidies on TPDDL's cost of supply.
Local agencies (DDUC, DSIIDC, DDA, DDE)	• Each agency expressed strong interest in environmental leadership. • DDE expressed possibility for additional incentive support • Opportunity to inform building codes and standards for new construction to prepare buildings for solar readiness • These agencies have ongoing solar deployment (on captive generation basis) efforts and broad solar deployment goals, both for their own buildings and their developments.
MNRE	• There is support for national solar deployment through NSM & solar cities programs • Incentives are available for solar deployment • (Note, after the meetings with regulators in July 2014, MNRE made announcements that incentives would likely be reduced to 15%.)
CERC	• There is broad support for solar and a vision to create markets to integrate renewable energy. • FOR model NEM regulation closely resembles California policies and thus has potential for resulting in cross-subsidies. • CERC generation based tariffs cite solar costs of 7.72 INR/kWh for ground mounted 1 MW systems.
CEA	• CEA has grid connectivity standards for distributed generation on <33kV distribution system. • Standards are designed to preserve reliability of the system with interconnected distributed generation but are not solar specific • There are no current limits for solar penetration nor operational standards from a grid security perspective (This is under investigation by CEA task force)
SLDC and NRLDC	• Current level of penetration of renewables is small (SLDC noted 0.2% across Delhi). • In future, winter ramping problem may become worse with increased solar (NRLDC). (Grid scale storage, though not explicitly discussed by SLDC and NRLDC, is a potential solution for renewables integration, and can provide ramp services as well as frequency regulation). • Demand response may help integrate RE and is practical in the Indian context, noting the example of geysers (water heaters), but no price incentive exists for customers (per SLDC).
EESL & SECI	• These organizations represent successful models for DER deployment in Indian context, with slow to move actors (state DISCOMS, government offices) • They have seen that there is active interest among stakeholders for technical assistance and support

Agency	Summary insights
	• During meeting, SECI noted it is exploring the RESCO with the rooftop leasing model
Developers	• Developers have concerns regarding suitable roof space in Delhi and availability of the roof space from the owner of the rooftop and cost of the roof • Developers indicated they cannot compete with retail tariffs without the MNRE subsidy for rooftop solar systems (Note, cost competitiveness improves as solar system size increases) • Lack of NEM or NEM alternative policy is a barrier (hence mostly sized for captive generation) and not clear what the best business model is moving forward • Developers need clarity on the process for interconnection, but with recent NEM regulation and implementation guideline addressed both NEM and interconnection issues.
Key customers	• There is strong interest in solar and DER (incentive/ subsidy may be required to make financial case for customers) • Customers have concern if rooftop is used for commercial purposes, as it may violate subsidized land agreements

Our meetings with regulators and governmental officials at the local and central levels revealed that there is strong regulatory support for DER, particularly solar, at all governmental levels; thus, the objectives of this project are aligned with broader agency goals. However, making the regulator case for solar and other DER will hinge upon demonstrating that there value to solar and DER — namely, demonstrating that DER is cost-effective to the utility when compared to conventionally procured resources, and that the tariff increase must be negligible or small. A tariff neutral (or near neutral) solar policy has the advantage of avoiding cross-subsidies (among customer segments and between participants/non-participants of a program). Given the notification of the NEM policy in Delhi, identifying alternatives was an important aspect to address in subsequent tasks of this study.

2.3 Barriers

There area number of barriers that must be addressed to achieve a scalable market. The siting of solar projects presents an additional challenge. There is a lack of suitable roofs for solar PV installation in Delhi due to both competition for other rooftop uses (e.g., commercial uses such as base transceiver stations, water tanks, gardens, clothes drying, mechanical cooling equipment) and other structural issues (e.g., roof slope, shading, weight bearing limitations). Targeted deployment towards larger buildings and specific classes of customers (government office buildings, schools, hospitals, etc.) is likely needed in the near term. In the long term, new construction and developments could be prepared for solar with the introduction of requirements into building codes or land leases.

Customers and developers both face specific challenges. For some customers, there is an additional legal issue associated with rooftop solar as many customers have been given land at subsidized rates, from agencies like Delhi Development Agency, with preclusions to use the rooftop for commercial activity. Exemptions may be required to ensure solar can be developed on these rooftops. An additional implementation challenge noted by developers is that they are not clear on what is required for the interconnection process. While the interconnection standards are clear, the process of communication with the utility can be improved.

Finally, both customers and developers may encounter challenges in financing. Renewable projects must compete for access to limited financing as India's growth fuels numerous investment opportunities. Solar also presents unique investment challenge because lack of clarity on transfer of ownership.it is a long term fixed physical asset and changes in building ownership may limit customer owned systems. In order to avoid this barrier to large scale investment, it could be necessary to use a third party (RESCO) model or utility owned model to see significant adoption of rooftop solar PV.

3 Description of TPDDL

3.1 Overview and role

TPDDL is a leading utility in the world. It was formed under a private/public partnership model in 2002. Among its many achievements, TPDDL reduced losses from over 50% to roughly 10%. TPDDL is a leader in the smart grid world. With the support of prior UTSDA grants, TPDDL has invested in advanced technologies, such as Automated Meter Reading and grid substation automation systems. However, TPDDL faces a growing supply/demand deficit, growing peak to off-peak load differentials, and increasing costs. The declining cost of solar power, advanced inverters, battery storage, controls and communication systems provide a ripe platform for helping TPDDL to meets its challenges in a cost-effective and environmentally sustainable way. TPDDL is a well suited to demonstrate the solar opportunity based on the following attributes:

- Public-private partnership
- Well managed and access to financing
- Has good relationships with customers
- Delhi solar potential is large according to others' studies

TPDDL has already engaged in DSM activities that can play complementary roles to solar. Energy efficiency and demand response are valuable resources that can help integrate solar and lower overall costs of the DER portfolio.

The E3 team spent three weeks in country conducting interviews externally and internally within TPDDL. We summarize below the qualitative insights gained from review of TPDDL data and documents, interviews conducted through site visits, and many follow-up discussions and email exchanges. The table below describes key aspects of TPDDL's operation on a qualitative basis.

Table 2: Description of TPDDL

Driver	Description
Load	TPDDL has a bimodal peak in the summer months. Load factors can be as high as 81% in the summer months. Large peak load reductions are possible by targeting relatively few hours.
Cost of procurement, energy security and current supply	Supply is dominated by conventional power PPAs of which roughly 90% is with fossil generation, largely coal. The average net cost of power (inclusive of loss due to sale of surplus power losses) is ~5-6 INR/kWh. Future procurement cost will increase as fuel prices increase.
Financing	TPDDL has excellent financing and access to capital. Access to financing will further improve over time as TPDDL becomes an older company and as they are able to show persistent cost recovery.
Reliability	Several focused TPDDL initiatives have provided significant improvements in reliability metrics.
Environment	Carbon intensive traditional sources of power dominate current portfolio. DER has the potential to reduce carbon intensity over the long term.

TPDDL's dedication towards its obligation to serve, experience with DER programs (EE and DR), credit worthiness, and excellent customer relationships render it a perfect utility to demonstrate the solar business model at the distribution utility level. TPDDL can play a critical role in developing a scalable DER market. Critical elements of the utilities participation include: implementing quality control and standards for third party developers and developing a clear process on interconnection to facilitate deployment of DER. Most importantly, TPDDL will be able to promote the adoption of solar using its strong customer relationships and has the ability to communicate cost reductions through monthly electricity billing cycles. This will continually remind the customers of the benefits of their investment. If successful, this model can be replicated by other utilities across India.

3.2 System demand characterization

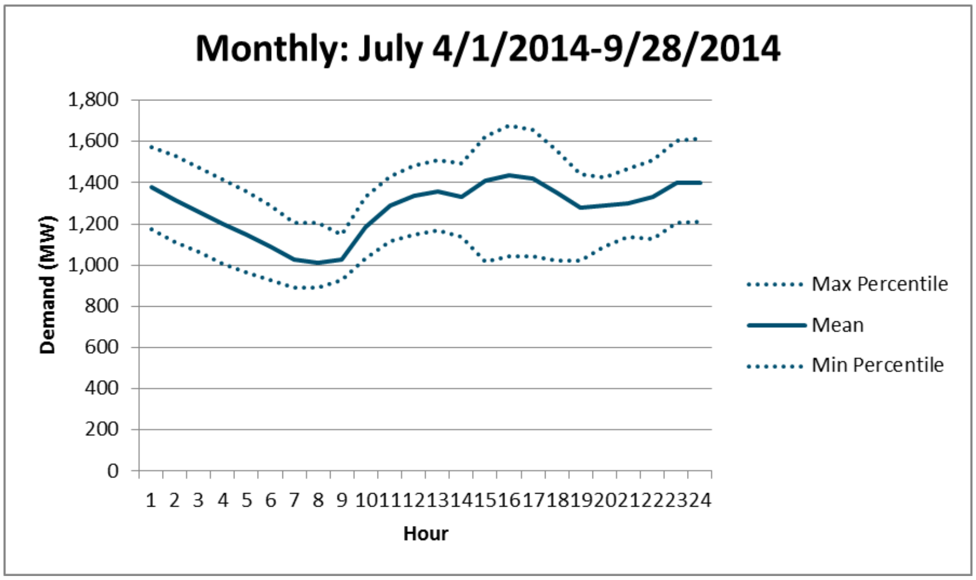
The system level demand characterization is essential to developing the regulatory case. It determines the energy and capacity requirements, and hence the cost of supply to TPDDL and it's customers. The rate at which load and energy growth occurs determines the rate at which the cost of supply increases. We summarize key points from our analysis of TPDDL's system demand.

+ From 2011-2014, system peak demand has grown at 5.9%; system energy consumption has grown at 4.9%; this suggests that DER providing both capacity and energy are necessary to meet long term needs. The 5.9% is consistent with TPDDL's forecast that uses an annual 6% growth in peak load and a 5% growth in energy going forward.

+ Analysis confirms summer bimodal peak with difference between these two peaks varying by year from ~30MW to ~100MW. The day time peak occurs at hour ending (HE) 4pm or HE 5pm, and the night time peak occurs at HE 11pm or HE 12am.
+ The relatively flat system load shape/ load factor suggests that the energy value of DER will be more important than the capacity value; this has implications for which DER are most valuable from a system avoided cost perspective

The figure below illustrates the historical hourly load for July through September in 2014. The purpose of this figure is to provide a visual example of the high load factor that characteristics TPDDL's load.

Figure 9: Average, minimum, and maximum loads over the month of June in the latest fiscal year



The frequency of high load hours and when these load hours occur is relevant for assessing which types of DER are appropriate for meeting TPDDL's future needs.

+ The load duration curve shows there is opportunity for capacity expansion deferral by reducing load growth in a small number of hours during the year. A 7% decrease in load in the 2013-2014 fiscal year is possible by lowering load in just 10 hours. Demand side measures such as EE, PLS, DR, storage, and PV have the potential to realize capacity avoided costs if their impact shapes correlate with these peak load hours.
+ Capacity benefits for DSM with daytime peaking shapes, such as PV, are limited by the nighttime peak. Capacity deferral can only be realized when the daytime peak is equal to or larger than the nighttime peak. The difference between these peaks in the 2011-2012 fiscal year was only 27 MW; 54 MW in 2012-2013; 106 MW in 2013-2014. The number of MWs of PV that would receive capacity benefits from reducing this daytime load is still high, however three years of data is not enough to ensure that the daytime peak is always higher than the nighttime peak.

The system analysis identifies that while solar may be valuable for meeting daytime loads, other DER will be useful for meeting early morning/nighttime/evening loads when solar is not available, as well as for meeting demand in the highest load hours.

3.3 Customer perspective

TPDDL and its customers have prior experience with DER technologies through its energy efficiency (which they call Demand Side Management, or DSM) initiatives and through a Demand Response pilot program. The DSM program has taken more of an educational approach, advising consumers on energy efficiency standards (e.g., Star labeling scheme). Prior EE initiatives at TPDDL have spanned LED lighting programs, appliance replacement programs, cool roofs, educational programs, and others. TPDDL's DSM group conducted a survey of its consumers and this study revealed that price and brand are the most critical factors affecting consumer adoption of energy efficiency.

TPDDL has implemented a demand response (DR) program, including an automated DR (ADR) pilot. The DR program has focused on high end consumers who volunteered to install the controls equipment. The DR program intent was to have peak reduction as well as a mechanism to allow peak load shifting. We describe the aspects of TPDDL's DR program that are most relevant to this project:

- The success of the DR pilot underscores the quality of TPDDL's relationship with its customers. This high quality relationship will facilitate any future DER program, particularly ones that involve TPDDL engagement.
- Given the success of the DR program in the absence of financial incentives to customers, a program that contains financial incentives may be even more successful.
- The level of sophistication of controls at customer sites must be taken into account when developing program goals and implementation on DR; many commercial customers lack automation systems (e.g., EMCS's or BMS's).
- TPDDL has noted that several customers have backup generation and UPS units that are infrequently used because of the quality of TPDDL service. These types of resources could potentially be utilized in a DR program.[2]

The team conducted interviews with a few key consumers — namely a private hospital and private school to assess their interest in solar and DER. We describe key insights from these interviews.

[2] The E3 Team interviewed Mr. Gireesh Pradhan, Chairperson of Central Electricity Regulatory Commission. Mr. Pradhan expressed that tampering may be a potential barrier to using the USP systems as utility controllable assets.

- Strong interest in solar and DER; both customers identified available rooftop space for solar
- Private hospital has sophisticated mechanical and electrical system, including a backup generator that is rarely used and could potentially be utilized in a DR program
- Concern that if rooftop is used for commercial purposes, land agreement may be violated

Overall, the prior experience that TPDDL and its customers have with DER will facilitate the implementation of a future solar program and expanded DER program.

4 Analytical approach

4.1 Valuation framework

The DER portfolio evaluation tool is designed to compare the value of DER against otherwise procuring equivalent amounts of energy and capacity from grid scale coal or gas resources. The comparison is therefore between two procurement scenarios: the scenario where DER is installed under DER focused utility incentive or procurement programs, and a scenarios where all system needs are met with traditional coal or gas resources — henceforth referred to as the business as usual scenario (BAU). The relative cost of a DER scenario may be cheaper or more expensive than the BAU scenario, and also may be compared against the relative cost of other DER scenarios to inform decision makers about the relative value of different DER solutions when making integrated resource plans.

Whether DER resources are cost effective is a decision best made on a lifecycle basis that accounts for all costs and benefits over the lifetime of the resource being evaluated. The DER portfolio evaluation tool accounts for the lifetime costs of DER, including capital expenditures, operating and financing costs, taxes, and incentives. It also accounts for the lifetime benefits, including the avoided costs from not having to procure grid scale coal or gas PPAs for energy and capacity, and the associated lost energy.

The valuation framework is designed to answer the following main questions:

+ Will the DER program save money for all of TPDDL’s customers?
+ What will be the tariff impact of the DER program?
+ Will TPDDL’s customers adopt DER technologies?

To make the regulatory case, the first two questions are important, and specifically, the first question which asks how DER technologies affect the utility’s overall cost of supply. Traditionally, TPDDL’s and most utilities’ cost of supply is dominated by conventional resources, and particularly coal in India. If solar or DER technologies are cost-effective, relative to conventional power, then they have the potential to save money on an overall basis to the TPDDL service territory.

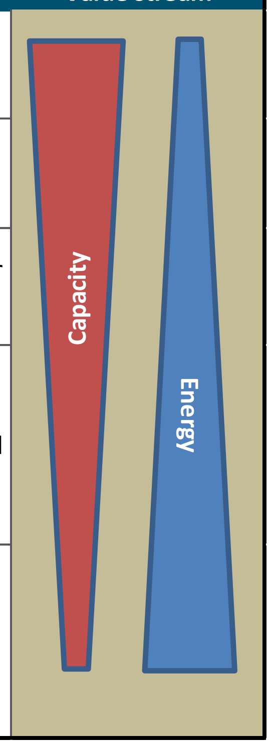
The valuation framework assesses what portion of conventional resources are avoided, for example:

+ Can current PPA charges (fixed or variable) be avoided?

- Can the building of a new power plant be avoided? In other words, avoiding investing in new coal or gas capacity to meet higher peak loads that result from load growth.
- How much conventional fuel is avoided and at what cost? In other words, what quantity of energy generated in the BAU scenario is displaced by energy generated from DER?

The ability to avoid each of these types of conventional resource categories depends on the performance of the respective DER technology. Broadly speaking, the two main categories of value streams are capacity/fixed or energy/variable. The valuation framework has the ability to compare the value of different types of DER, based on their performance characteristics. Each type of DER technology will vary in terms of the relative portions of energy vs. capacity value, as shown in Figure 10.

Figure 10: DER technologies; capacity vs. energy value

Category	Primary purpose	Timeframe	Value stream
Emergency demand response	Improve reliability	Seldom, during contingency	
Demand response	Reduce powerplant construction	<100 hours per year	
Permanent load shifting	Improve load factor	Daily, all year, or by season	
Renewable distributed generation	Reduce fuel consumption and emissions, avoid new powerplant construction	Year round with seasonal, diurnal trends	
Energy efficiency	Reduce fuel consumption and emissions, avoid new powerplant construction	During device operation (e.g., seasonal, or daily)	

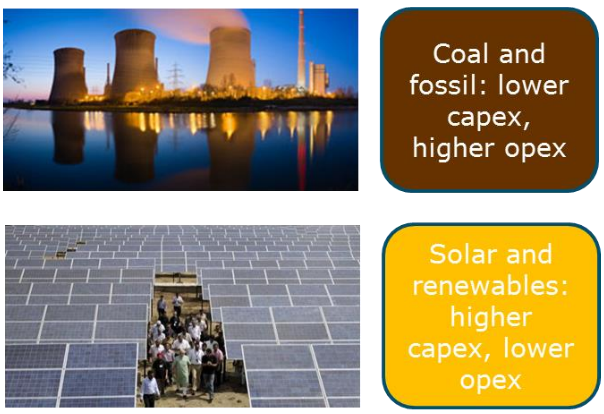
The four main classes of "clean energy" DER technologies are demand response (emergency or economic), permanent load shifting (which may include thermal energy storage, TES), renewable distributed generation and energy efficiency.

- DER technologies should be selected based on the value streams that offer the most value. For example, if the load duration curve shows there are only 1 or 2 hours in a year where the anticipated system load may exceed available power plant capacity, demand response may be a very attractive option for addressing this short term capacity need.

+ At the lower end of the figure lies energy efficiency. Energy efficiency is typically adopted for its energy value, rather than capacity value, although certain types of energy efficiency, such as air conditioning energy efficiency, will have higher capacity value compared to flat types of energy efficiency, such as lighting energy efficiency.
+ Solar energy and permanent load shifting provide a mix of energy and capacity value.

Conventional resources tend to have higher operating costs, primarily driven by fuel costs, while renewable and DER technologies tend to have higher upfront costs and lower operating costs.

Figure 11: Comparing conventional with renewable resources



The valuation framework compares these resources using a "lifecycle" approach. The lifecycle approach takes into account present and future cost streams and places these on a common metrics that facilitates comparison. Additional details on the methods are described below.

4.2 Cost effectiveness methods

Our analytical framework is based on utility cost-effectiveness practices in which the value of demand side technologies are compared against supply-side resources; the cost-effectiveness framework was originally developed to evaluate the benefits of energy efficiency by viewing energy efficiency as a utility resource. This framework can be used to engage multiple stakeholders, support the design of utility programs, standards and labels and other clean energy policies. The basic cost-effectiveness equations calculate the lifecycle net benefits of the proposed technology, compared to a 'baseline' scenario.

$$\text{Net Benefits (dollars)} = NPV \sum_{k=1}^{n} \text{benefits(dollars)} - NPV \sum_{k=1}^{n} \text{costs(dollars)}$$

$$\text{Benefit to Cost ratio} = \frac{NPV \sum_{k=1}^{n} \text{benefits(dollars)}}{NPV \sum_{k=1}^{n} \text{costs(dollars)}}$$

where “k” represents a specific year over the measure lifetime of “n” years. A Benefit to Cost ratio that exceeds one indicates that the net present value (NPV) of the benefits exceeds the NPV of the costs. A Net Benefits that exceeds zero also indicates the resource is cost-effective.

The table below, adapted from the National Action Plan for Energy Efficiency[3], describes the three primary cost effectiveness tests that can be used to develop the regulatory case for DER.

Table 3: Principal cost-effectiveness tests

Test	Acronym	Key question answered	Benefits	Costs
Total resource cost test	TRC	Will the total costs of energy in the utility service territory decrease?	Avoided cost benefits	DER technology costs
Participant cost test	PCT	Will the participants benefit over the measure life?	Bill savings, incentives and other payments	DER technology costs
Tariff impact or ratepayer Impact measure	TIM or RIM	Will utility rates increase?	Avoided cost benefits (energy, generation and T&D capacity, losses)	Bill savings

Each cost test takes a unique perspective in terms of assessing the value of the DER technology and is used for a specific purpose.

- The **total resource cost (TRC) test** evaluates whether the DER program is cost effective, overall, to all consumers within the utility service territory (rather than only to the customers installing the DER). The TRC test takes a ‘wholesale’ perspective. The benefits in the TRC test are the “avoided cost benefits”; these reflect the avoided capacity and energy procurement due to DER. The costs in the TRC test are the DER technology costs.[4] The societal cost test is a variation of the TRC test that includes non-monetized public benefits, such as health benefits from reduced

[3] National Action Plan for Energy Efficiency, 2008, *Understanding cost-effectiveness of energy efficiency programs: Best practices, technical methods, and emerging issues for policy-makers*. Prepared by Energy and Environmental Economics and Regulatory Assistance Project. Available at http://www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf

[4] As a simple example, consider the DER program avoids, on a lifecycle basis, $10,000 in avoided cost benefits with a lifecycle DER cost of $5000; the net benefits are $10,000 - $5000 or a benefit/cost ratio of 2.

pollution exposure. Based on discussion with the DERC, we will not utilize the societal cost test to develop the regulatory case.

- The **participant cost (PCT) test** evaluates whether DER is cost-effective to the consumer adopting the technology. The PCT test is important if the DER program expects consumers to play an active role in adopting DER technologies. For example, for a customer to install rooftop solar under a NEM scheme, the bill savings to the customer must be greater than the cost of the solar system to the customer.
- The **tariff impact or ratepayer impact (TIM or RIM) cost test** assesses if tariffs will increase. The implicit assumption is that any reduction in revenue (e.g., from reduced sales from NEM or energy efficiency) is made up by tariff increases. For utilities that have sufficient cost recovery through tariffs, energy efficiency programs typically fail the RIM test. To pass the tariff impact test, the lost revenue must be less than the avoided cost benefits. Note, the TIM/RIM test does not directly inform what tariff/rate design decisions the utility will take.[5]

The TRC test is often utilized as the 'primary' test to assess if the DER program is cost-effective overall to the utility service territory. The other tests are often treated as 'secondary' tests because they assess the distributional impacts of a DER program. Based on our interaction with DERC, both the TRC and TIM tests must be evaluated and shown to be cost effective (or minimal tariff impact).

The cost-effectiveness tests are usually used to evaluate the cost-effectiveness of customer owned or behind the meter systems. All three cost tests are relevant for evaluating the cost effectiveness of a NEM solar policy. An alternative policy to NEM, where the payment made to a customer per kWh of solar generated is equal to the cost of solar plus an incentive payment to the customer, the TRC cost test remains the most important cost test, as it allows the utility to compare the cost of procurement of DER technologies vs. conventional technologies. Under this policy, the PCT is always positive as the customer receives an incentive payment above the cost of solar; however, the TIM test remains a useful framework for assessing tariff impacts from the procurement strategy. It is worth noting that under this policy if the system is 3rd party or utility owned, the customer involvement is limited. The customer just receives an incentive payment with no initial investment made in the solar system. In this case, the PCT is positive, as the customer is not investing. The incentive payment has to be set higher than some threshold above

[5] The TIM/RIM test is defined to evaluate the net benefit or cost of the DER program based on a comparison of avoided cost benefits, which are treated as benefits in the RIM/TIM test, and bill savings, which are treated as costs in the RIM/TIM test. The net cost is often represented in two different ways: (1) The net cost of an individual DER installation is divided by DER output; (2) The net cost of the DER program (all DER installations) is divided across all units sold as a rough proxy of tariff impact. Actual tariff design is beyond the scope of cost-effectiveness calculations but is required to determine how the DER programs will exactly impact tariffs.

which it is worth the customer's while to use roof space and experience the inconvenience of the system installation.

4.3 Avoided conventional resources

The avoided conventional resources determine the "benefits" from the total resource cost (TRC) perspective which is the perspective that evaluates if the DER are beneficial to all customers in the utility service territory (this perspective is in contrast to the customer or participant perspective).

In this study, we evaluated three types of TRC benefits that DER technologies can bring — avoided energy value, avoided generation capacity value, and avoided losses. Such benefits are also known as "avoided cost benefits" and represent the benefits of both the TRC and TIM tests described earlier. Avoided cost benefits are calculated in the comparison between the DER scenario and the BAU scenario in the portfolio evaluation tool. How many megawatts (MW) of capacity and megawatt-hours (MWh) of energy from coal or gas resources does building DER avoid?

Avoided energy value

The avoided energy costs (or energy value of DER) relates to the fuel costs that TPDDL can avoid through deployment of DER[6]. In the context of TPDDL's operations, there are two broad factors that determine the avoided energy costs: is DER displacing existing power plant fuel costs ('short run' view), or is DER avoiding fuel costs for a new power plant ('long run' view)?

Based on TPDDL forecasted growth and current contracts, we build the regulatory case using a long term perspective. We do not use the short term perspective in our valuation analysis because TPDDL requires new resources beginning in 2015. The advantage of the long run view is that both the avoided capital costs of a new power plant and the fuel mix of a new contract can be considered as potential benefits of the solar and DER. We term the hypothetical new power plant as a **"Proxy plant"**. This proxy plant provides less energy in the DER scenario than the BAU scenario because DER displaces its output.

We assume new generation resources may be fueled by coal or gas, and with various domestic/imported blends. The most expensive case would be if the new power plant was fueled with

[6] Avoided energy costs also include other variable costs, such as variable O&M, however, per TPDDL's contracts and the CERC Tariffs, O&M costs are considered as fixed costs in coal and gas power plant tariffs, and thus, contribute towards capacity value, rather than energy value in the context of TPDDL's avoided energy costs.

100% imported gas or 100% imported coal. In the least expensive case, new power plants would be fueled 100% by domestic fuel. However, since TPDDL's generation is currently a mix of domestic and imported fuel in the rough proportion of 25% imported, 75% domestic for both coal and gas, a 100% domestic contract seems unlikely.

We describe our assumptions on our projected fuel costs below.

Domestic fuel cost assumptions

Domestic gas falls into two categories: subsidized or unsubsidized. Subsidized gas prices are determined by the Government of India (GoI) through the Administered Price Mechanism. Although a price of $7-8/MMBtu had been expected, the GoI recently announced a subsidized gas price of $5.6/MMBtu[7]. Unsubsidized gas is likely to follow international market pricing and will match the imported gas fuel. Given the demand for subsidized gas, it is unlikely that much domestic gas will be available for the spot market, after allocations have been met. For these reasons and because the proxy plant scenarios represent book end scenarios (or bounds), we assume the domestic gas proxy plant will have access to subsidized gas. We escalate the current subsidized gas price at 8% on a nominal basis (based on 2% real escalation and 6% inflation rate).

Domestic coal prices have been set by Coal India Limited (CIL) in the past. The coal market was deregulated in 2000; there is no regulated price analogous to the natural gas Administered Price Mechanism. The cost of domestic coal varies dramatically based on the grade of coal and on transportation costs. Although the costs by grade are listed by CIL, there is no visibility on CIL's website into the transportation costs, as these are direct pass through costs. We relied on public sources to inform the cost of domestic coal for the proxy plant case relying on domestic coal. Based on a survey of sources, we selected an average coal cost, inclusive of transportation costs, of $50/tonne.[8] This price is escalated at a rate of 8% per year on a nominal basis (2% real escalation and 6% inflation rate).

[7] The Hindu, Oct 19, 2014, "Diesel prices deregulated"; http://www.thehindu.com/business/Economy/diesel-prices-deregulated/article6514970.ece?utm_source=Bulletin20141023&utm_campaign=BizJournalOct2314&utm_medium=email

[8] The following resources support this assumption.
The Wall Street Journal, Aug 4, 2014, "India Runs Short on Coal, Despite Global Price Slump"; http://online.wsj.com/articles/india-runs-short-on-coal-despite-global-price-slump-1407139782, which cites a $50/tonne for domestic coal (inclusive of transportation).
World Institute of Sustainable Energy, 2013, "Future of coal electricity in India and sustainable alternatives"; http://wisein.org/WISE_Projects/final_coal_report.pdf, which cites a INR 2200/tonne or $37/tonne for domestic coal and INR 6000/tonne or $100/tonne for imported coal.
The Mauda Unit I tariff approved by CERC, 7th August, 2014; http://www.cercind.gov.in/2014/orders/SO69.pdf cites an all-in coal price of INR 2397/tonne or $40/tonne. The cited calorific content of 3250 kCal/kg suggests this is for domestic coal.

Imported fuel cost assumptions

India is expected to increase its share of imported fuel over the next two decades. Prime Minister Modi has focused on expanding electricity service to all households by 2022 and eliminating the supply side driven electricity shortages. Both efforts will drive a significant increase in the demand for both convention fossil fuels and renewable projects over the next decade. We utilize the World Energy Outlook (WEO) forecasted prices to inform the price of imported coal and gas using the "Current policies scenario". For coal, because the WEO coal prices do not reflect the most recent slump in worldwide coal prices, we assume a current price of $70/tonne with a transportation adder of $30/tonne[9]. We escalate the coal price at the trend forecasted by WEO — an average rate of 2% between 2014 and 2035. For gas, we use a current price of $14.5/MMBtu and escalated at a rate of 2% per year on a real basis, the average escalation rate per year between 2014 and 2035. The 2% per year on a real basis is equivalent to 8% on a nominal basis. (Note, 8% escalation is consistent with TPDDL's historical fuel escalation).

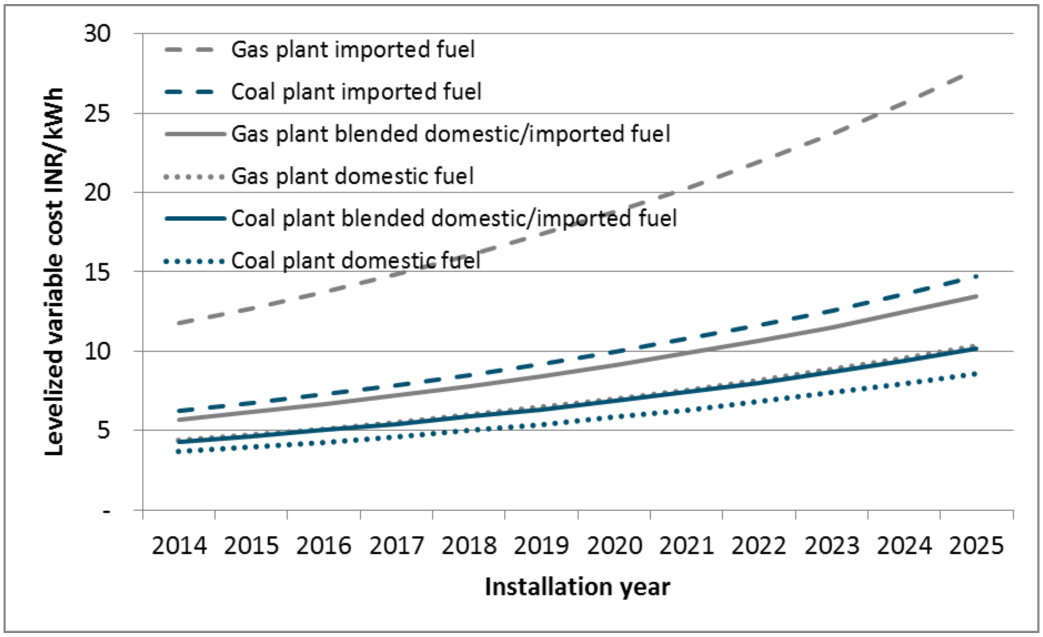
The figure below illustrates four choices of fuel combinations to meet load growth: coal or gas plants fueled with the current mix of domestic and imported fuels seen by TPDDL (25% imported, 75% domestic for coal and gas); and coal or gas plants fueled by imported fuel only. The fuel prices are converted into kWh units using heat rates and calorific value[10] and are levelized over the plant lifetime. In our study, we assume that the fuel cost makes up 100% of the variable cost. (Other costs, such as O&M, are considered fixed costs as per the CERC regulations and conventional resource tariffs.)

The Farakka Super Thermal Power Station Stage III tariff approved by CERC, 21 January, 2014; http://www.cercind.gov.in/2014/orders/SO204.pdf cites an all-in coal price of INR 3550/tonne or $60/tonne. The cited calorific content of 3240.7 kCal/kg suggests this is for domestic coal.

[9] The Central Electricity Authority, February 2004, "Report of the expert committee on fuels for power generation Executive Summary"; http://www.cea.nic.in/reports/articles/thermal/expert_committee_report_fuel.pdf cites a transportation cost of INR 895/tonne for a distance of 1200 km, which reflects the distance between Raipur, Chhattisgarh and New Delhi, a proxy for the distance between the coal mines in Eastern India and the NTPC power plants in Northern India serving Delhi. This transportation cost is equivalent to $30/tonne assuming an 8% inflation rate and conversion rate of 60 INR/USD.

[10] Assumptions: Coal calorific value is 3240.67 kCal/kg (CERC) for domestic and 3800 kCal/kg for imported coal; coal heat rate is 2250 kCal/kWh and 1853 kCal/kWh for natural gas.

Figure 12: Lifecycle variable cost for gas and coal power plants for new power plants



Using our tool, we evaluate the benefit of solar and other DER against different proxy plant fuel future, such as 100% imported fuel, and domestic/imported fuel blends.

Generation capacity value

The generation capacity value is the avoided cost of the investment in new capacity that would otherwise have been made if DER was not installed. The capacity value is related to the fixed costs of building a power plant. Some portion of these fixed costs may be avoided by DER, depending on the specific performance characteristics of the DER (e.g., when the solar panel generates electricity). (Our assumptions and calculations of conventional power plant fixed costs are described further below.)

The investment in new capacity is accounted for at the resource balance year, which represents the year when new capacity is required to meet new load growth. The avoided cost of installing DER is the deferral benefit of moving investments in new capacity from the original resource balance year to a year in the future. The capacity value of a DER resource is dependent on how much capacity a resource can reliably offer during peak load times. For example, consider air conditioning energy efficiency measures implemented across the TPDDL service area that, on aggregate, reduce load by 10 MW during peak load hours. Assuming that 10 MW reduction can be reliably counted on during peak load hours, the deferral will be 10 MW. However, resource planners have to be confident that the energy efficiency is providing a dependable reduction of 10 MW. We therefore only assess the dependable reduction in load when calculating generation capacity value.

Determining the dependable reduction in load and the capacity value is dependent on several factors:

- The coincidence of the DER measure caused reduction in load with the highest load hours. To evaluate this coincidence we use a Peak Capacity Allocation Factor (PCAF) methodology. The higher the coincidence, the greater the measure's contribution to peak load reductions, and the higher it's capacity value.
- The dependable output of the DER measure. This is the load reduction caused by a DER measure that a resource planner can trust to actually occur, and can therefore factor into decisions on what capacity to build. What the actual dependable load reduction is can vary depending on the risk profile of the system planner, and the set of resources installed. This can take the form of a derate on output for measures such as energy efficiency and storage to account for outages etc. However, determining the dependable load reduction is particularly important for PV because of the uncertainty in PV output.
- The cost of new capacity that would have otherwise been built if the DER measure were not installed. Options include new coal or gas plants with different types of financing. The portfolio evaluation tool uses a capacity **proxy plant**, i.e. the plant built in the BAU case, but deferred or avoided in the DER case because of the capacity offered by the DER technologies.

Determining DER measure coincidence with peak load hours: The PCAF method

The PCAF method determines the contribution of a DER measure towards peak load reductions. For example, consider an energy efficiency measure with variable output over the day but a maximum hourly load reduction of 1 MW. The coincidence of the energy efficiency measure's shape with peak load hours may show that of that 1 MW, only 0.8 MW contributes towards peak load reduction. The peak period is typically defined as the 150 hours with the highest loads (this is a model input that can be changed by the user). The load in the 151st highest hour is the threshold cutoff and is the highest load that is not considered to be part of the peak period. Reducing loads in the hours outside of the peak period is assumed not to have any capacity value for the system. The relative importance of each hour (within those 150 hours) in reducing load is then determined using weights assigned to each peak hour in proportion to their level above the threshold. These weights reflect that the peak hours in future years are unknown, yet may occur with higher likelihood in hours with higher loads in the current year.

The formula for calculating the PCAFs for the top 150 hours is shown below.

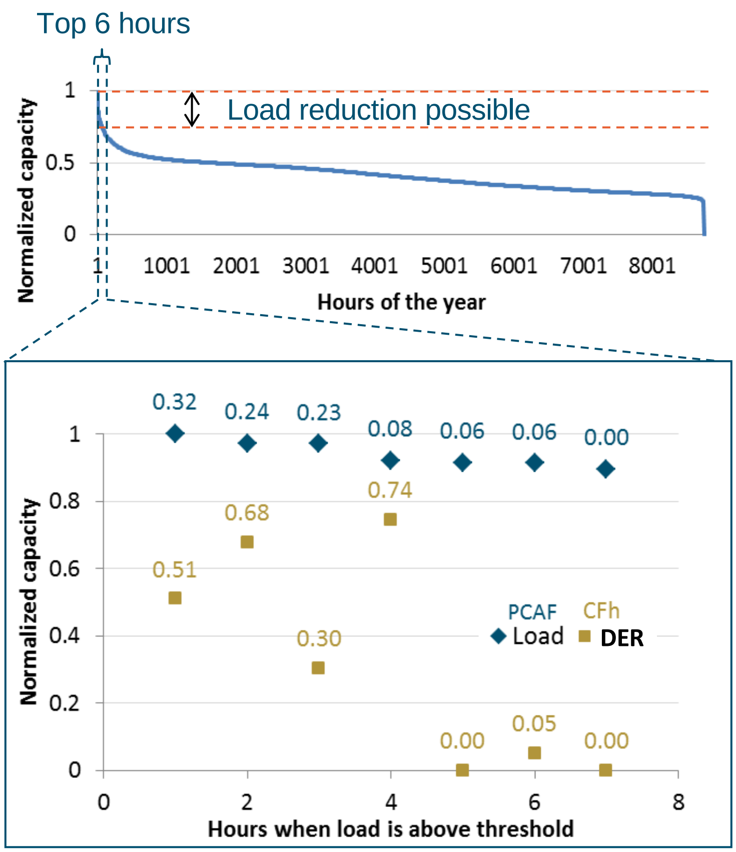
$$PCAF[hr] = \frac{Load[hr] - Thresh}{\sum_{hr=1}^{150} Load[hr] - Thresh}$$

where, *Load [hr]* is the load of that hour; *Thresh* is the load for the 151st highest network load.

As the load changes with load growth and DER implementation, the allocation factors will change. A clear example of this is when thermal energy storage is used to shift usage from the peak period to the off-peak period. As more thermal energy storage is installed, the highest load hours are reduced. In the following year, those hours with the highest allocation factors may be different from the previous year. Another example is the well-known effect of adding PV to a system with a daytime peak. Since PV is also daytime peaking, the system peak is shifted to later in the day as more PV is added to the system. The model updates the PCAFs in every year to account for these types of shift.

Once the PCAFs have been determined for each hour of the year, these are multiplied by the hourly dependable output of each DER shape (described in the following sub-section) to determine the dependable MW contribution to peak load reductions. The following figure shows an example of this process for a generic DER technology where the peak period is defined as the top 6 hours for simplicity.

Figure 13: Example of PCAF calculation



The top 6 hours from the load duration curve shown in the top chart above, as well as the hour defining the threshold, are plotted in the bottom chart (shown as blue diamonds). The PCAF value is calculated using the formula from earlier in this section for each of the hours and is shown above the load points. The DER output that corresponds to the same hour of the year as each one of the top load points is also plotted (shown as gold squares). The hourly dependable output (CFh), otherwise described as the percentage of AC nameplate produced by DER in each one of those hours, is shown above each of the plotted points. To calculate the dependable MW output of DER, the following formula is used:

$$DepMW = \sum_{h \in (H|L_h \geq threshold)} CF_h \times PCAF_h \times DER\ nameplate\ capacity\ (MW)$$

In the above simple example, assuming the DER output is 46% of the nameplate capacity qualifies towards load reductions. For a DER with nameplate capacity of 100 kW the dependable MW contribution is 46 kW. This number is then multiplied by the cost of capacity corresponding to that year calculated in the proforma module of the tool to get an avoided cost of capacity. In our example, if capacity costs of the proxy plant, as estimated by the proforma tool, are 10000 INR/kW-yr, the capacity value of the DER would be 4600 INR/kW-yr. Note, the portfolio evaluation tool allows the user to select which type of proxy plant is used to provide capacity value (e.g., gas vs. coal). The following section describes further the process of determining the dependable output of each DER shape.

Determining the dependable output of a DER measure

As described above, the dependable output of a DER measure varies by the risk profile of a system planner. For example, a planning rule could be to accept a level of DER output that the DER measure is at or greater than for 97% of the time during peak load hours, similar to the outage rate of a large generator. DER measure output can be derated to meet the defined planning criteria. The derate is determined by several factors:

+ Whether the DER technology can be reliably called or controlled during peak load hours
+ The outage rate of the DER technology
+ In the case of renewable generation, the uncertainty around the output
+ Diversity effect due to geographic diversity and the number of installed measures

These factors influence the derate to a greater or lesser extent. For example, energy efficiency is not 'dispatched', but is built into the infrastructure of the building or building appliances. In addition, energy efficiency measures tend to be installed in large numbers, increasing the certainty of good performance of the aggregate set of energy efficiency measures; this converges to a relatively low derate. DR, on the other hand, must be controlled in the absence of a strong price signal. The derate factor is multiplied by the output of the DER to determine the dependable output. The CFh, the hourly dependable output described in the previous sub-section, incorporates on an hourly basis the derate factor. Estimating the derate factors comes from experience over time with installed measures. However, for all DER measures except PV, the derate will be relatively low, and this is reflected in the estimated derates we include in the model. For most DER, other than PV, the derate factors can be treated as simple constants.

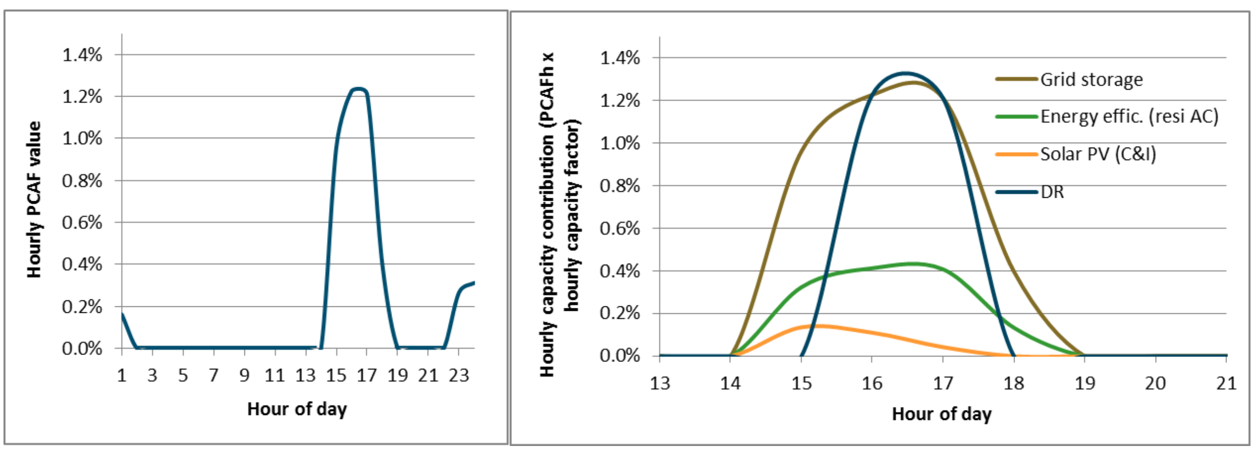
For PV, the derate factor will vary by hour. Therefore, for PV, the dependable output shape (CFh) incorporates implicitly the effect of time-varying derate factors. For PV, first we determine the distribution of PV output in each hour and season. From these distributions we take the percentile corresponding to the planning rule determined by the model user. <u>For example, if 95% reliability is chosen, the model will take the 5th percentile of the PV output for each hourly and seasonal</u>

distribution. The result is a level of output from PV that in each hour of the year, PV would be expected to produce at or higher than for 95% of the time.

Illustrative example of capacity contribution of DER technologies for an example summer day

The tool estimates the capacity value of all DER resources that are part of the portfolio being analyzed. From a planning perspective, a key output is understanding the yearly MW contribution of DER resources towards avoided capacity procurement, along with the required new capacity requirements. However, this output is built up from an hourly assessment of how each resource contributes towards meeting capacity needs. Using an illustrative example, we show the capacity contribution of each DER resource for an example summer day. The hourly PCAF values are shown in the left frame. These are a measure of the weighted likelihood of experiencing a peak load event based on the historical load, and sum to 100% over the year. In the figure below, some of the historical top load hours reside in this example day resulting in non-zero PCAF values. The hourly capacity contribution of DR, grid storage, energy efficiency and solar are shown in the right frame.

Figure 14: Illustration of capacity contribution of individual DER technologies for a summer day



The right frame illustrates how DR and grid storage provide the highest relative contributions towards meeting this capacity need. The contribution is the capacity factor multiplied by the PCAF value; because DR and storage peak at about 100% of their capacity, the capacity contribution is 100% of the hourly PCAF value. This is because DR and grid storage are dispatched to meet these high load hours. Storage and DR therefore have very high capacity contributions, amounting to close to their full capacity over all of the PCAF hours. We limited the maximum duration of DR calls to two hours, while storage is able to operate over 4 hours. Energy efficiency provides the next highest contribution towards meeting capacity needs, followed by solar. The lower coincidence between the hourly solar output and PCAF values are responsible for the lower contribution from solar.

Cost of new capacity

The fixed costs of a new conventional power plant resource or "proxy plant" determines the capacity value of solar and DER resources. The fixed costs are generally made up of capex, fixed O&M, and financing costs. Fixed costs exclude variable costs that are dependent on how much the power plant operates — namely fuel costs and any variable O&M. We calculated levelized fixed costs for both gas and coal power plants for each installation year from 2014 and onwards. The costs are based on the following capital cost, performance, fixed operating and financing assumptions. Unless otherwise stated, these assumptions follow the CERC tariff and Indian income tax laws:

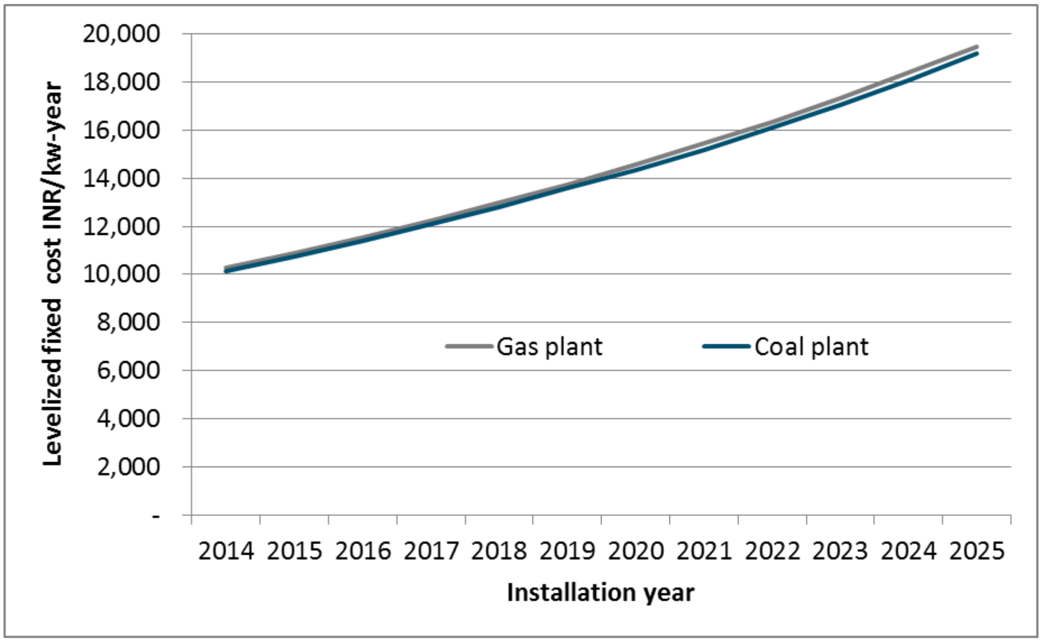
Table 4: Proxy plant assumptions (a)

Assumption	Coal	Gas
Capital cost	INR Lak 520/MW for coal	INR Lak 540/MW for gas
Capital cost escalation	6% per year	
Availability factor (CERC)	85%	85%
Auxiliary consumption (CERC)	7.5%	2.5%
Fixed O&M (CERC)	1600 INR/kW-year	1500 INR/kW-year
Fixed O&M escalation	6% per year	
After tax return on equity (CERC)	15.5%	
Debt/equity structure (CERC)	70/30%	
Cost of debt	12.5% (e)	
Debt term	10 years	
Financing lifetime	25 years	
Minimum Alternative Tax (Indian tax laws)	20.96%	
Corporate income tax (Indian tax laws)	33.99% (30% plus cess)	
Corporate income tax holiday (Indian tax laws)	10 years	
Depreciation (CERC)	Straight line depreciation method	

(a) Rupee to USD conversion rate of 62 INR/USD.
(b) Based on a survey of capital plant costs observed in CERC tariffs:
The CERC tariff orders for Mauda Unit 1, Unit 2, Bahr, and Farakka coal power plants cite capital costs of INR Lak 366/MW, 455/MW, 594/MW and 522/MW for commercial operation dates of 2013, 2013, 2013 and 2012, respectively. Average cost was escalated at 8% inflation for 1 year.
This is line with The World Institute of Sustainable Energy, 2013, "Future of coal electricity in India and sustainable alternatives"; http://wisein.org/WISE_Projects/final_coal_report.pdf, which cites a INR Lak 507/MW for a new coal power plant.
(c) Based on a survey of capital plant costs observed in CERC tariffs:
The CERC tariff order for Unosugen cites capital costs for Unosugen and ONGC Tripura of INR Lak 486/MW, 513/MW, respectively. See http://www.cercind.gov.in/2013/orders/SO175.pdf Average cost was escalated at 8% inflation for 1 year.
(d) The imported coal calorific value is based on Indonesian coal heat content.
(e) Based on a survey of the following sources: (1) Per discussion with Renew Power quoting 13%; WISE report (footnote b of this table) uses 12%; Tata Power Solar, "Beehives or elephants? How should India drive its solar transformation", 2014, assumes 12% for utility scale plants.

The proforma estimates for each installation year a levelized or lifecycle fixed cost payment for a new coal or gas power plant. If solar and DER can avoid the need for a new coal or gas power plant, then it will receive some capacity value, which will represent some portion of the levelized fixed costs of the new power plant. The figure below shows the levelized fixed costs for gas and coal power plants.

Figure 15: Lifecycle variable cost for gas and coal power plants for new power plants



Avoided losses and T&D avoided investments

We considered two additional classes of benefits: avoided losses and T&D avoided investments.

Avoided losses: DER technologies provide benefits in terms of avoided energy requirements due to reduction in distribution losses within the TPDDL network. DER that is located at the customer can avoid technical losses within the TPDDL network and are included in our analysis.

T&D avoided investments: DER technologies can, in some cases, avoid the need for new transmission and distribution investments. A methodology similar to the avoided generation capacity methodology can be used. T&D benefits can be included if T&D investments are required due to load growth. The assessment should take into account the specific location of the DER investment. Given the uncertainty on the location of the DER technologies that will be adopted in the future, it was not appropriate to include avoided T&D investment benefits in this analysis.

4.4 DER customer perspective and tariff impact

While Section 4.3 described the benefits to all customers, taking the ”Total resource cost” perspective, this section describes how the DER technology is evaluated from the DER customer perspective (“participant perspective”) and the tariff impact that may result due to the DER program (“tariff impact perspective”). As noted in the Section 4.2 each perspective estimates the lifecycle costs and the lifecycle benefits. The lifecycle benefits for the customer installing the DER is equivalent to the bill savings or bill credits. The calculation of cost effectiveness of energy efficiency is relatively intuitive: for example, what are the lifetime bill savings of a LED light vs. the cost of a LED light?

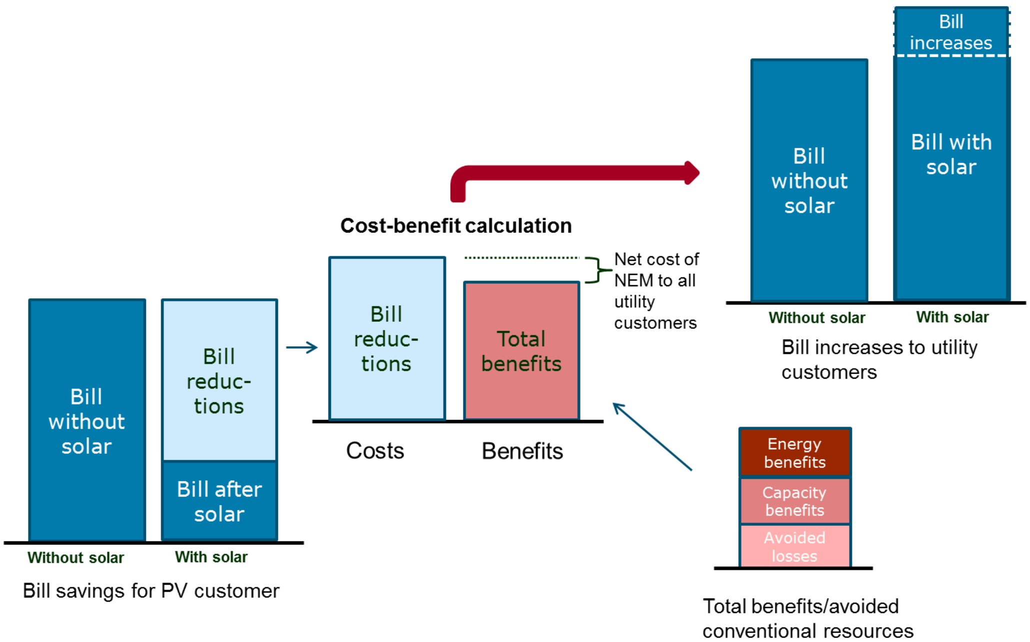
Because the Net Energy Metering (NEM) solar policy is relatively new, we describe briefly the customer savings and tariff impact calculations associated with NEM. In the case of a Net Energy Metering (NEM) policy, the customer receives a bill credit at the retail tariff for their solar generation. The bill savings are calculated as follows:

+ For each month, if solar is consumed on site, the customer’s consumption is reduced by the amount of solar generation.
+ If there is excess generation, then the excess generation is treated as credit and rolled into the next month as credit.
+ At the end of the year remaining “credit” is paid at the “average power purchase cost” (or “export” price).

If the utility has a slab tariff, customers that have greater consumption before they install a DER technology (solar, energy efficiency) are able to receive higher bill credit than customers with lower consumption.

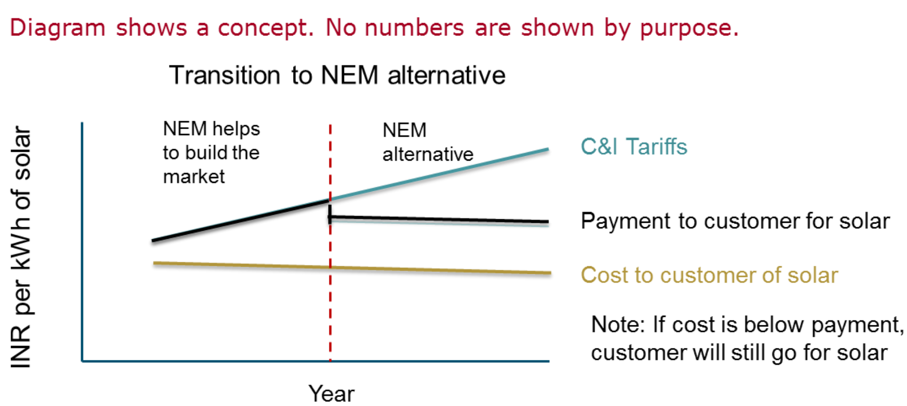
The tariff impact from DER technology or program is calculated from the revenue loss (which is the bill savings to the customers that install DER) minus the benefits from the DER program (avoided conventional resource costs). This net loss or savings is applied as an adjustment towards the tariff of all customers. The figure below describes the tariff impact estimation for a NEM Solar policy. This methodology is also applied towards estimating the tariff impact of all DER.

Figure 16: NEM policy tariff impact cost benefit methodology



Aside from the NEM policy, we evaluate an alternative policy to NEM with the intent of identifying a policy that will have a lower tariff impact. The basic concept is that rather than paying the customer at the retail tariff via a NEM policy, a lower payment can potentially still promote the adoption of solar but with a lower tariff impact, as shown in the figure. The "payment to the customer for solar" is lower than the "C&I tariff" but larger than the "cost to customer of solar". If the cost of the solar is below the payment to the customer by the utility for the solar, the customer may still adopt solar.[11]

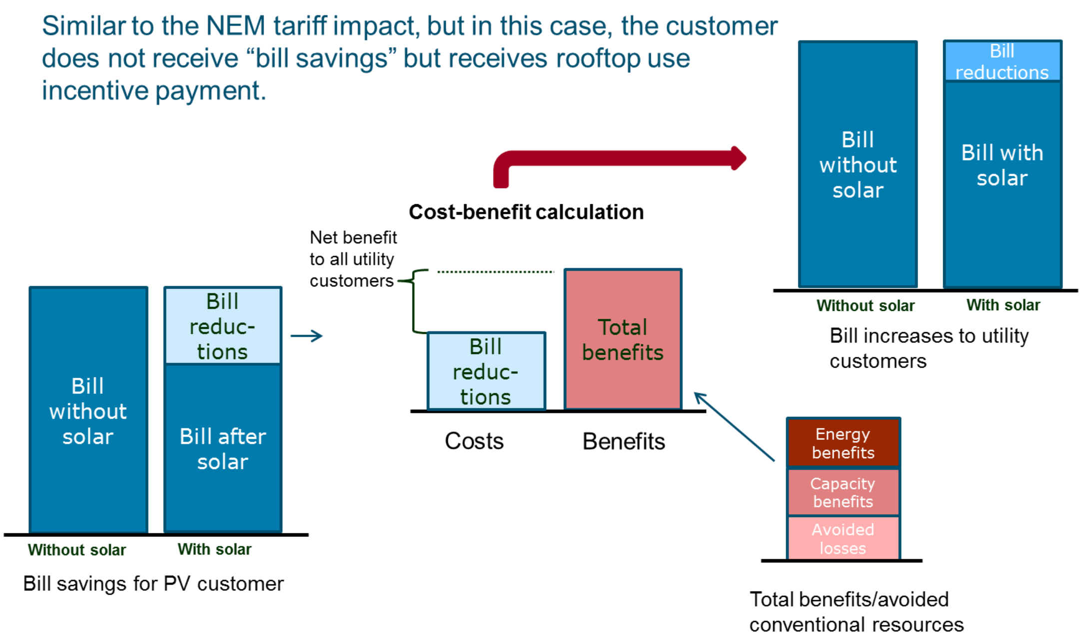
Figure 17: NEM Policy vs. NEM Alternative policy



[11] This type of policy is referred to as a "Feed in tariff" in Germany and the United States (not to be confused with Feed in tariff in the Indian context, which refers to the export price under a NEM policy).

The tariff impact calculation for the NEM Alternative policy follows the same approach as with the NEM policy but with some important distinctions.

Figure 18: NEM Alternative policy tariff impact cost benefit methodology



If the solar payment to the customer installing solar under the NEM Alternative policy is lower than the retail tariff, the NEM Alternative policy may result in a lower tariff increase as compared to the NEM policy. This is shown in Figure 18; the "Bill reductions" are lower than the "Total benefits" which results in a net benefit to all utility customers. In this scenario, the tariff for all customers may actually get lowered due to the solar program.

5 Results

5.1 Portfolio descriptions

We developed three portfolios to answer the key questions that are necessary to build the regulatory case for DER and simultaneously meet the USTDA grant requirements.

+ The portfolios reflect a mix of solar and other DER and are based on TPDDL's stated goals
+ Particular focus is given to understanding the benefits of solar and informing solar policy

The four portfolios we developed are described in the table below.

Table 5: DER Portfolio descriptions

Portfolio	DER technologies	Key question being answered	Installation targets (2025)
1a	Solar via NEM policy	What are the impacts of the NEM solar policy if TPDDL reaches its longterm rooftop solar goal?	440 MW solar
1b	Solar via NEM policy alternative	How does the NEM policy compare against a NEM policy alternative?	440 MW solar
2	Solar, EE, DR	What are the benefits from including other DER that offer capacity value in the portfolio?	440 MW solar 48 MW EE 42 MW DR
3	Solar, EE, DR, Grid Storage	What is the incremental benefit of including storage over portfolio 2?	440 MW solar 48 MW EE 42 MW DR 15 MW grid storage
3b (storage sensitivity)	Solar, EE, DR, TES	What benefits does TES offer over portfolio 2?	440 MW solar 48 MW EE 42 MW DR 15 MW TES

By designing the portfolios with this specific mix of DER technologies, we can understand the feasibility of solar programs and programs that combine solar with other DER technologies. Portfolios 1a and 1b are solar focused, but differ in terms of the solar policy that motivates adoption (NEM policy vs. NEM alternative policy).

Portfolios 2 and 3 differ in terms of the additional types of DER. Portfolio 2 brings in EE and DR programs that offer both energy and capacity benefits. Portfolio 3 extends portfolio 2 by adding grid storage.

5.2 Installed cost of solar

An important aspect of our DER portfolio assessment is our assumption on cost of solar. The world has witnessed steep declines in the cost of solar over the last few decades. At one time, the cost of PV cells was more than $76 per Watt; currently, PV cells are less than a dollar.

Many stakeholders in India expect the installed cost of rooftop solar systems to continue to decline. However, there are multiple factors that must be considered in assessing how solar costs will evolve in India. The following key drivers will influence how installed solar costs will vary in the future.

+ World demand for panels
+ Technological innovation
+ Learning
+ Inflation
+ Exchange rate risk

Each of these drivers will have different directional impacts on the installed cost of solar. For example, as technological innovation continues, panel costs will decline. As inflation continues in India, the installation costs, due to labor, will increase. At the same time, learning effects can reduce the time required to perform solar installations, driving down the installed costs. Finally, to the extent India utilizes foreign panels and components, exchange rate risk can increase the prices experienced by India.

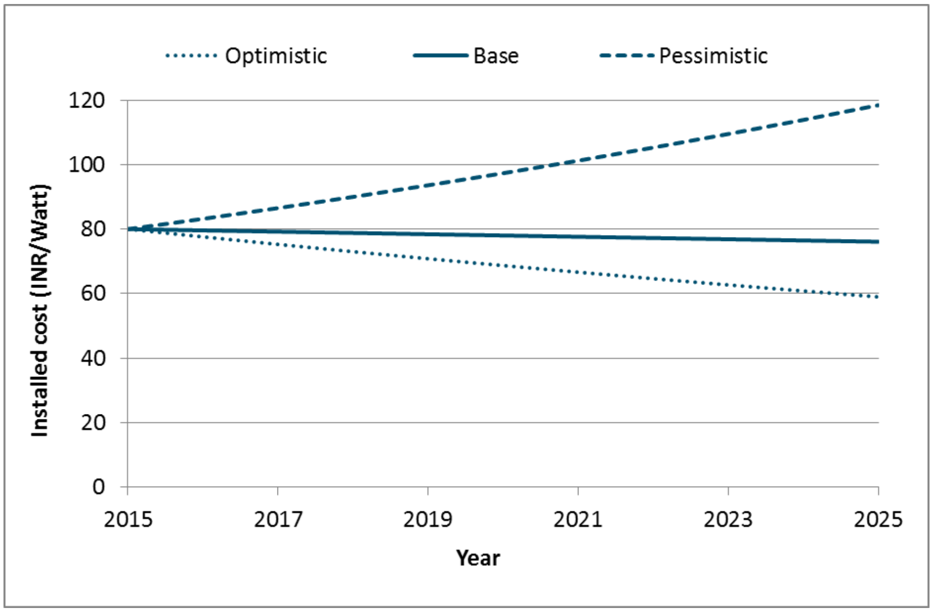
These drivers can be thought of affecting either the panel and equipment costs, or the installation and other soft costs (e.g., commissioning, testing). We developed three cases of future installed solar costs to reflect different future scenarios. The base, optimistic and pessimistic solar cost cases reflect different assumptions on each of the key drivers as described in the table below.

Table 6: Key drivers influencing solar costs

<table>
<tr><th></th><th>Driver</th><th>Optimistic</th><th>Base</th><th>Pessimistic</th></tr>
<tr><td rowspan="3">Drivers affect panel and equipment costs</td><td>World demand for panels</td><td>Medium</td><td>Medium</td><td>High</td></tr>
<tr><td>Technological innovation</td><td>High</td><td>Medium</td><td>Low</td></tr>
<tr><td>Exchange rate risk</td><td>Low</td><td>Medium</td><td>High</td></tr>
<tr><td rowspan="2">Drivers affect installation and other costs</td><td>Learning</td><td>High</td><td>High</td><td>Low</td></tr>
<tr><td>Inflation</td><td>Low</td><td>Medium</td><td>High</td></tr>
</table>

After synthesizing the effects of these different drivers, we arrive at the following installed cost projections for the three cases.

Figure 19: Installed cost of solar trends assumed in the study



We describe the key trends of each of these cases.

+ Optimistic solar cost projection: Equipment cost continue to drop dramatically due to technological innovation; learning effects reduce balance of system costs eliminating any inflationary price increases for the balance of system. In the optimistic solar cost projection, installed solar costs decline at 3% per year.
+ Base solar cost projection: Equipment cost declines are moderate with balance of system learning effects counteracting most of inflationary effect. In base solar cost projection, installed solar costs decline at 0.5% per year.
+ Pessimistic solar cost projection: Equipment costs are subject to low technological innovation and exchange rate pressure; balance of system costs track with inflation. In the pessimistic solar cost projection, installed solar costs increase at 4% per year.

Collectively, these three installed solar cost projections capture the different cost trends that India may experience in the rooftop solar market in the future.

5.3 Solar portfolio base case results

We analyze the solar portfolio to answer the multiple key questions that will determine how successful solar adoption is. We describe these questions.

- Solar portfolio customer value analysis under NEM policy
  Key question answered: Will customers adopt solar given the NEM policy?
- Solar portfolio total resource cost evaluation.
  Key question answered: Does solar make sense overall for TPDDL?
- Comparison of conventional resources procured between the BAU and solar portfolio
  Key question answered: Does solar help us lower our conventional generation procurement?
- NEM policy vs. NEM alternative policy evaluation.
  Key question answered: What is the best policy to promote solar in a sustainable fashion that minimizes tariff increases to TPDDL's customers?

Each key question is answered in its own respective subsection below.

Customer value proposition under NEM policy

The customer value proposition seeks to answer the question of whether solar is cost effective given the NEM policy. The analysis includes the following aspects:

- Comparison of cost of solar to bill savings that result from the NEM policy
- Lifecycle analysis is conducted
- TPDDL is assumed to escalate at 5% per year
- Exports are priced at 5.7 INR/kWh (average power purchase cost)

The solar cost is calculated with different levels of the NSM solar incentive. The levelized costs are evaluated using a proforma model with the assumptions as per the table below.

Table 7: 'Base case' solar cost assumptions

Assumption	Value
Capital cost for 2014 installation	80 INR/Watt DC basis
Capacity factor	17.36% DC basis (20.4% AC basis)
Capital cost escalation by installation year	Declines 0.5% per year (c)
NSM incentive	Three levels of NSM incentive are calculated: 0%, 15% and 30% of the benchmark price (benchmark price is 100 INR/Watt) (a)
Fixed O&M	1.5% of current capital cost

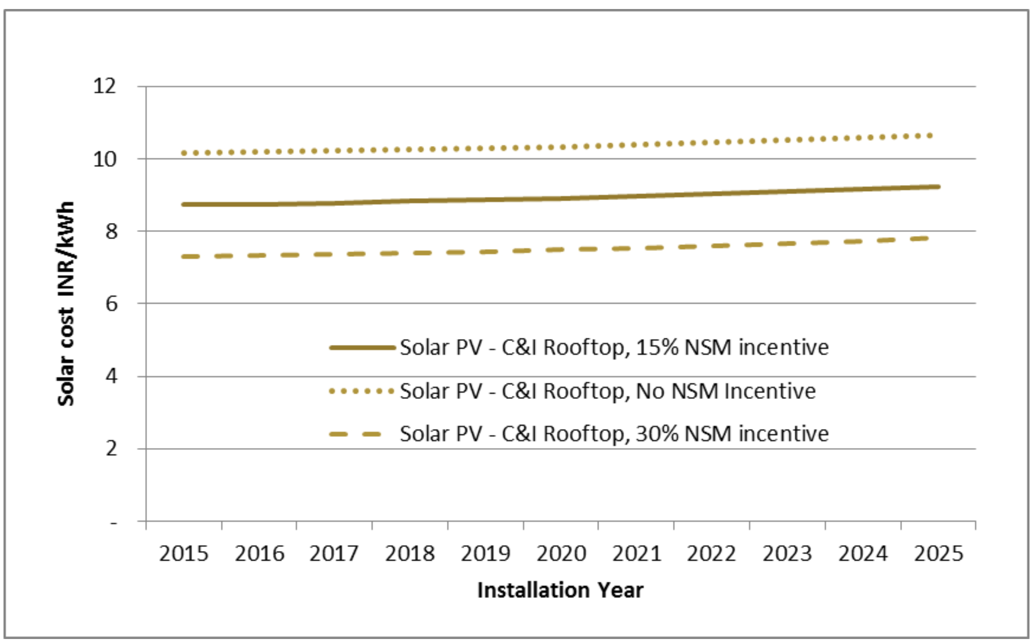
Assumption	Value
Fixed O&M escalation	2% per year on real basis, equivalent to 8% on a nominal basis (b)
After tax return on equity	15.5%
Debt/equity structure	70/30%
Cost of debt	12.5%
Debt term	10 years
Inflation	6%
Financing lifetime	25 years
Minimum Alternative Tax	20.96%
Corporate income tax	33.99% (30% plus cess)
Corporate income tax holiday	10 years
Depreciation	Straight line depreciation method

(a) Given the uncertainty on the future of the available NSM incentive, we assumed three levels: 0%, 15% and 30% for the NSM incentive. Recent announcements by MNRE suggest that they might reduce the incentive to as low as 15%.
(b) Note, this is consistent with the fixed O&M escalation on the conventional.
(c))) Additional solar cost projections are considered in the next section.

The lifecycle (or levelized) cost of energy (LCOE) accounts for capital cost, operating costs, taxes and incentives, and financing costs. The LCOE is the same as the PPA price if the PPA is structured to be flat over the life of the asset.

The figure below shows the levelized cost of solar, based on the assumptions listed above.

Figure 20: Cost of solar portfolio



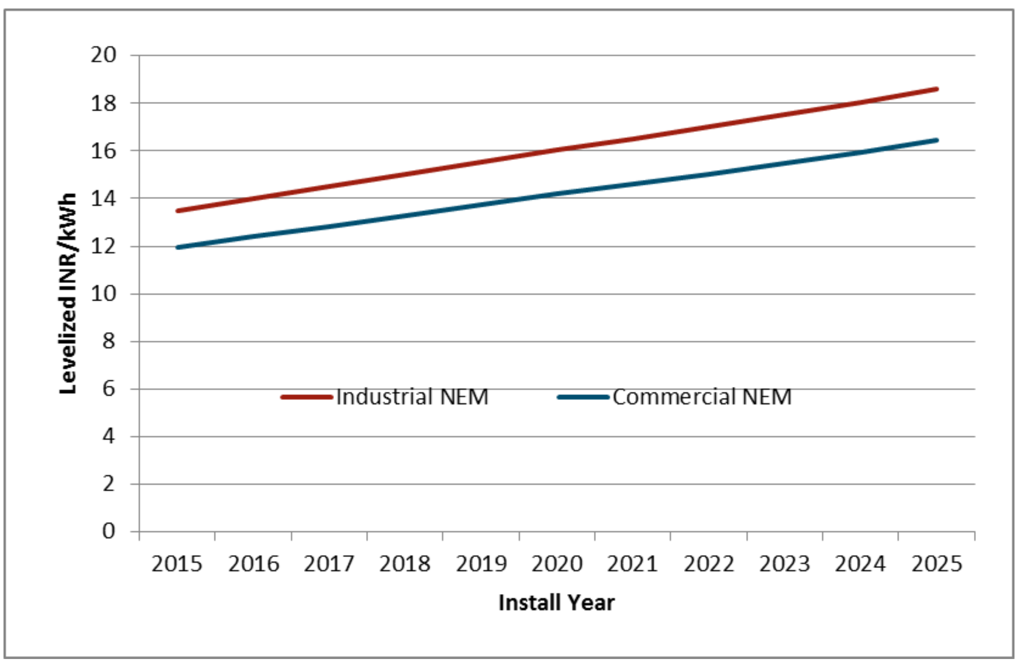
Note, even though the installed solar cost is declining at 0.5% per year in the base solar case, the O&M is assumed to be 1.5% of the 2015 installed solar cost and increasing at the rate of inflation. This is why the levelized cost does not decline at the same rate at which the installed solar cost declines.[12]

The bill savings to the customer are estimated as per the guideline of the NEM policy. Essentially, the NEM policy provides a bill credit for the solar generated over the peak and off-peak TOU periods.

+ Within each TOU period of the month, if solar is consumed on site, customer is paid for their solar generation at the TOU period tariff.
+ Within each TOU period of month, if solar is consumed on site and there is remaining generation exported, then this excess generation is treated as a credit and is carried forward to the next month. At the year end, the customer is paid for the excess generation at the "export" price.

The lifecycle bill savings or the "Lifecycle NEM Tariff" is calculated for each solar installation year. By representing the bill savings in a lifecycle form, we can compare the bill savings with the solar cost. We show the result for industrial and commercial tariffs for two example customers.[13]

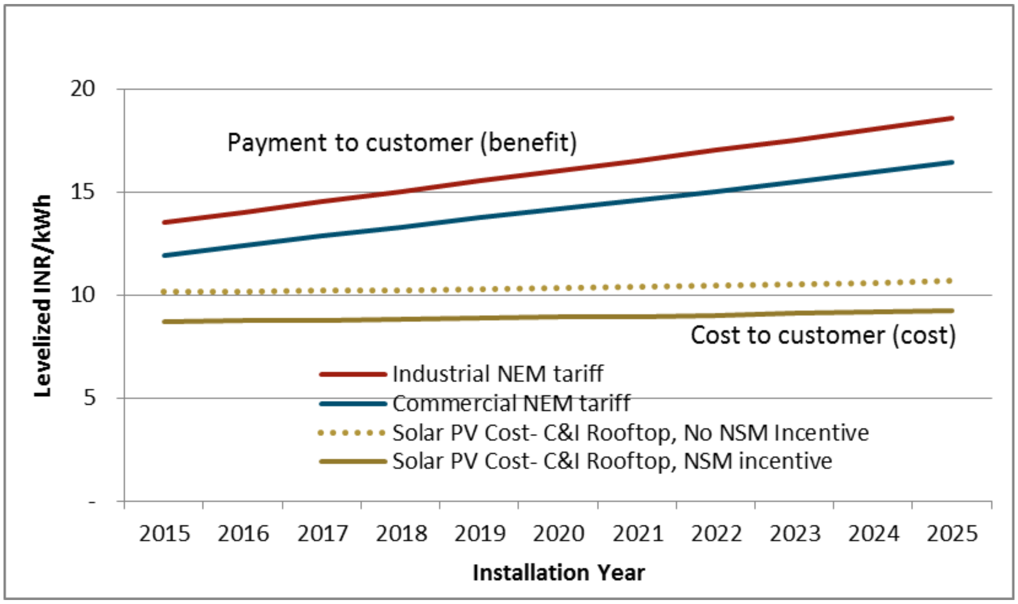
Figure 21: Lifecycle bill savings or "NEM tariff"



[12] Although O&M is a small fraction of the yearly cost, it must still be considered. Arguably, the key drivers that may lower the installed cost of solar over time will not apply to the O&M cost.
[13] Note, the example industrial customer (daal mill) has a higher connected load than the example commercial customer (commercial complex), and therefore, falls into a higher tariff slab.

Finally, we compare the solar cost, with and without the 15% NSM incentive, with the NEM tariffs.

Figure 22: Comparing commercial and industrial NEM tariffs with solar costs



The figure above illustrates the NEM tariff (payment to customer) for two cases: commercial and industrial tariffs. It illustrates the solar cost for two cases: with and without the NSM incentive. Under both the commercial and industrial tariffs and for both solar cost scenarios (with and without the NSM incentive), solar is cost-effective on a lifecycle basis for 100% onsite consumption[14].

Key insight: Customers have an economic incentive to adopt solar under the NEM policy at today's solar costs. Over time, solar will become even more attractive to the customer under a NEM policy in the event solar costs decline and tariffs continue to increase.

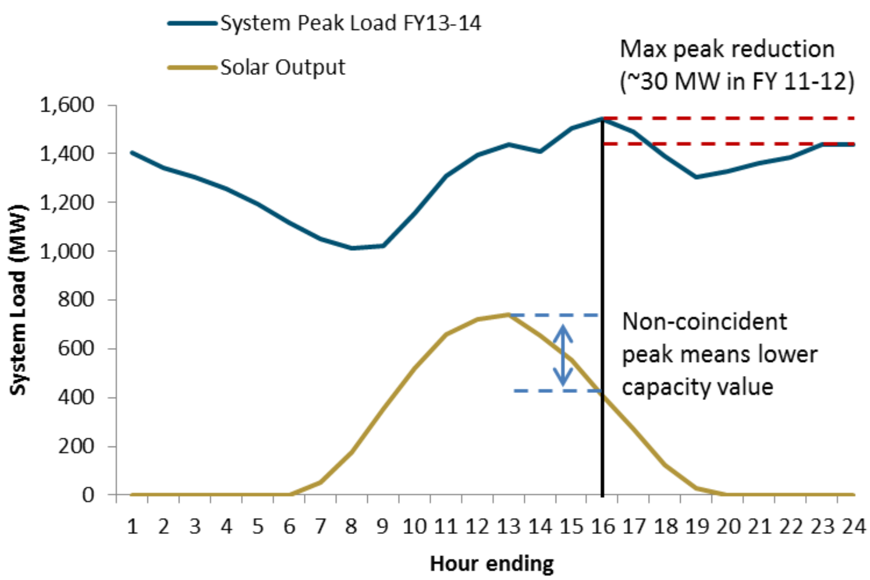
Total resource cost perspective

The total resource cost perspective compares the overall benefits to all customers in the TPDDL district from the solar program with the costs of the solar program. It answers the question, "Does solar make sense overall for all of TPDDL's customers?"?

[14] We conducted a sensitivity analysis to assess a 75% onsite consumption vs. 25% export case. Even in this condition, solar remained cost effective, although the bill savings decrease. Customers are likely to optimally size their system under a NEM policy to minimize the export and maximize the onsite consumption since that increases the bill savings.

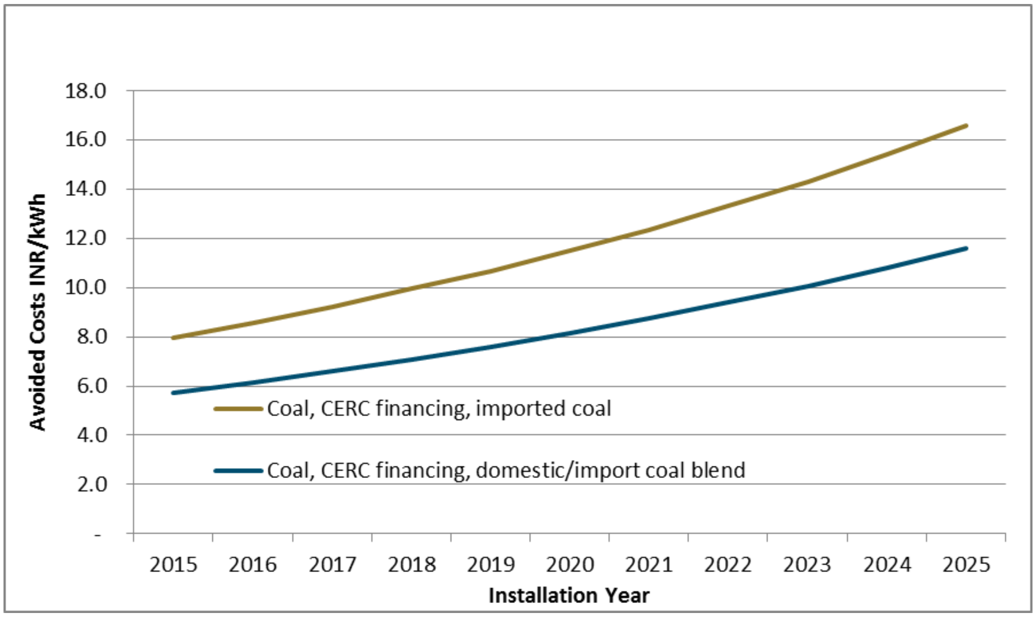
Step 1: Load and solar shape. The figure below compares system load with solar output and illustrates the importance of load and solar shape. Solar coincidence with system load is important for capacity value. Greater coincidence results in higher capacity value. There is a ceiling on capacity value of PV: Effectiveness declines with more MWs of PV (peak becomes shifted). However, despite a reduction in capacity value, solar provides energy value over time, lowered only by the degradation of the panels.

Figure 23: Illustrative example of peak coincidence



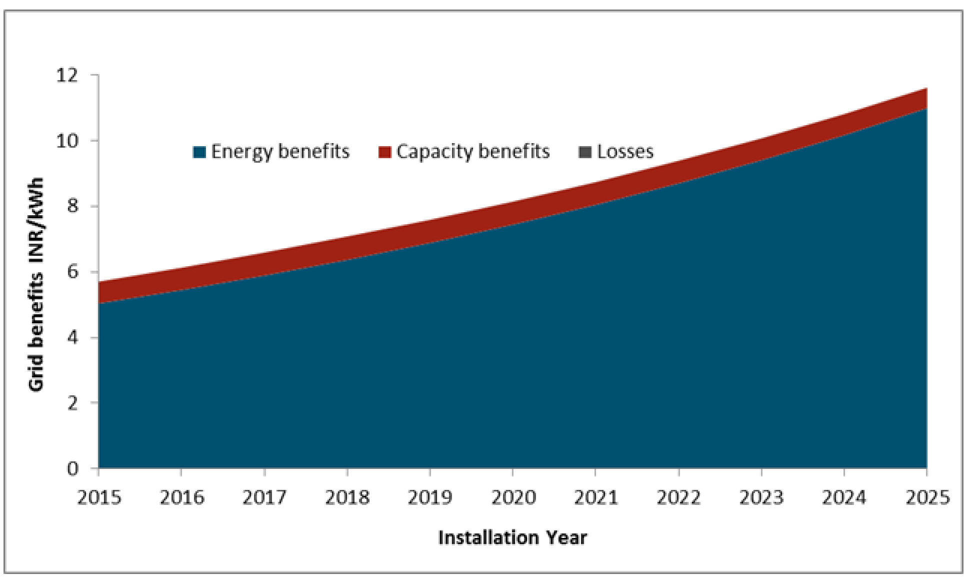
Step 2: Avoided cost benefits by energy / capacity. The benefits of solar are realized quickly because resource balance year occurs in 2014, given the recent contract retirements. As shown in **Figure 24**, the choice of the proxy plant greatly affects value: benefits on average are 50% higher for the imported coal proxy plant vs. the blended coal proxy plant (75% domestic/25% imported). The benefits would be larger if some natural gas is displaced in the BAU portfolio. This last point is explored further down in the next section where additional sensitivities are conducted.

Figure 24: Grid benefits of solar portfolio



The grid benefits are composed of capacity and energy value (Figure 25). However, a majority of benefit is from energy value, and specifically avoided fuel. The capacity value is small and decreases with time; this is because solar serves to move out the time at which the system peak occurs. A small contribution from avoided losses is present, though this quantity is sufficiently small that it is not visible in the figure.

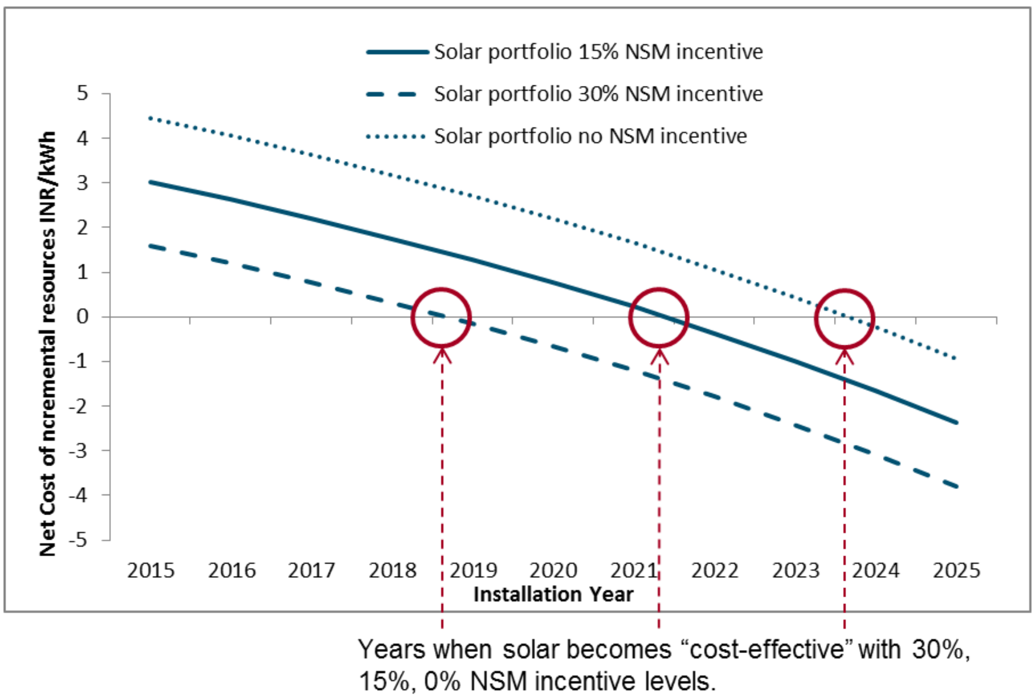
Figure 25: Grid benefits of solar portfolio: benefits from avoided energy, capacity and losses



Step 3: Solar portfolio costs. The solar costs are calculated with and without the NSM solar incentive. The assumptions for the 'base case' solar is consistent with what was shown under the "Customer value proposition" section above (as shown in Figure 20).

Step 4: Net costs of solar (TRC). By subtracting the avoided cost benefits (Step 2) from the solar costs (Step 3) generates the net cost of solar. The figure below illustrates the benefits and costs for Portfolio 1, the solar portfolio, from the total resource cost perspective when considering 3 levels of NSM incentive and when solar is avoiding an imported coal/domestic coal blend (25% imported coal; 75% domestic coal).

Figure 26: Total net costs of the solar portfolio for base solar avoiding domestic/import coal blend



Solar becomes cost effective under the base case proxy plant resource assumption in 2019 with 30% NSM incentive; 2022 with 15% NSM incentive; 2024 with 0% NSM incentive.

The choice of the proxy plant fuel is important. The figures below show the total net cost for the solar portfolio for 100% imported coal and a domestic/imported coal blend when a 15% NSM incentive is included (Figure 27) and is excluded (Figure 28).

Figure 27: Total net costs of the solar portfolio including NSM incentive; coal proxy plant

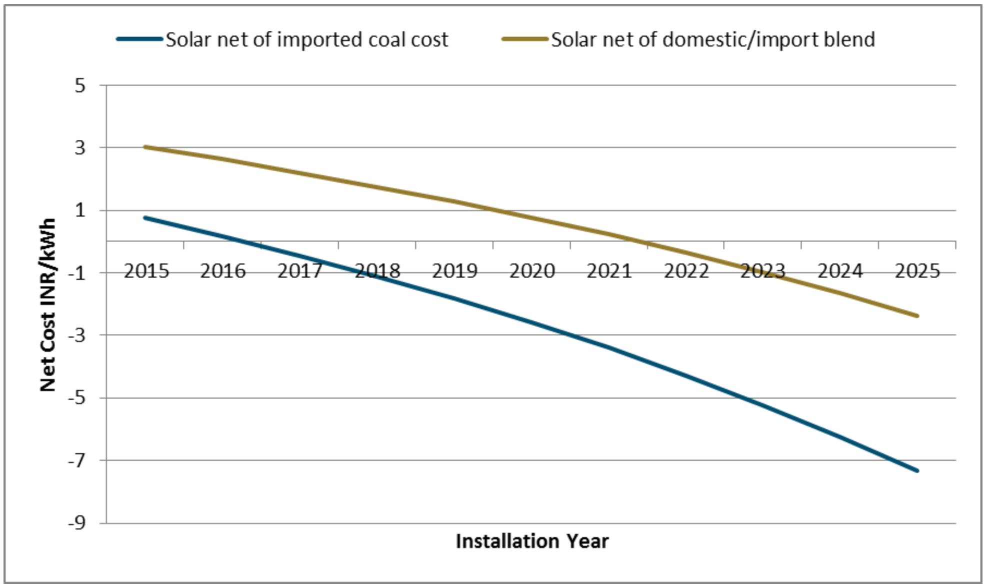
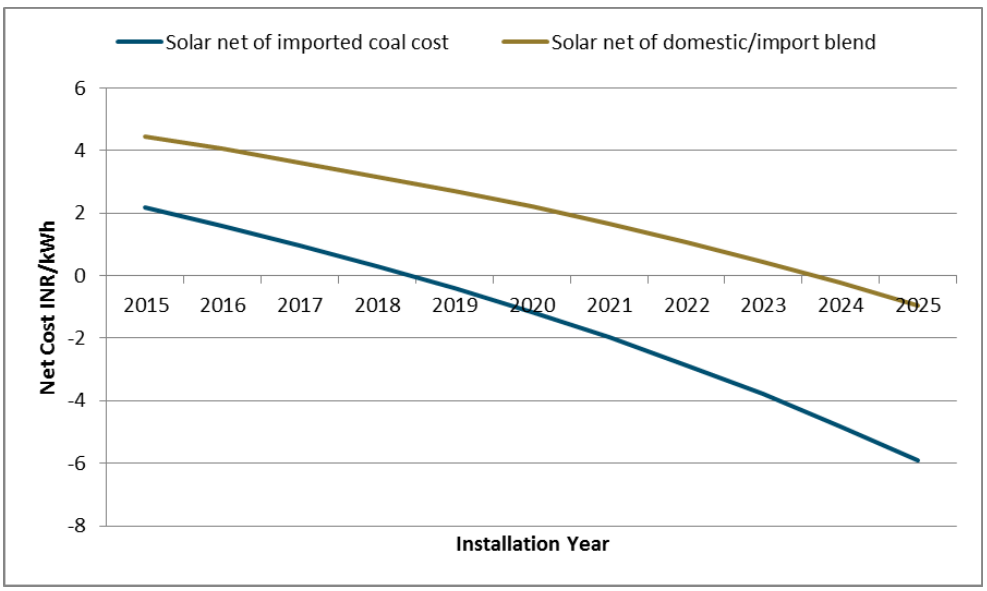


Figure 28: Total net costs of the solar portfolio excluding NSM incentive; coal proxy plant



When including the 15% NSM incentive, we note the following key messages.

- The solar portfolio becomes cost effective by 2016 when compared against a 100% imported coal proxy plant
- Solar becomes cost cost-effective by 2022 when compared against a blended (75% domestic/25% imported) coal proxy plant

When excluding the NSM incentive, we note the following points.

- Solar becomes cost effective by 2019 when compared to imported coal.
- Solar becomes cost effective by 2024 when compared to the domestic/import blend.

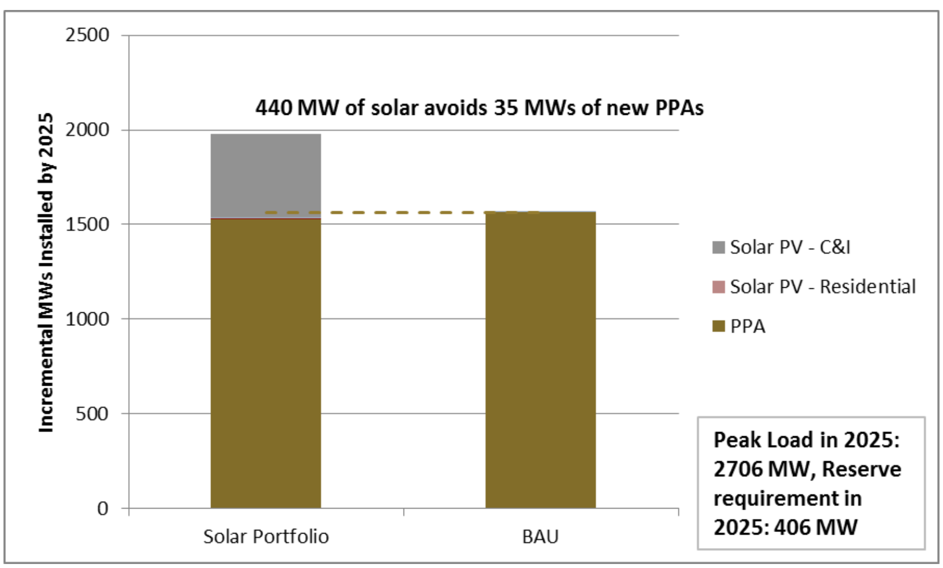
The analysis emphasize the importance of the NSM incentive towards reducing solar costs. Without the incentive, solar becomes cost effective much later.

Comparison of conventional resources procured between the BAU and solar portfolio

By comparing the resource procurement under the solar portfolio scenario with the resources needed under the BAU scenario, we answer the following question: **"Does solar help us lower our conventional generation procurement?"**

We compare the capacity resources between the solar portfolio against the BAU portfolio (Figure 29). The figure illustrates that the solar portfolio does not avoid the need for investment in additional conventional resources. This is true because solar has limited reliable production during peak load hours during the year. For a discussion of how reliable production is determined, see how a dependable MW contribution for solar is calculated in the task 4 report.

Figure 29: Comparison of resource mix between solar and BAU portfolios



We explore the use of other DER resources in Portfolios 2 and 3, which is reported in a latter section.

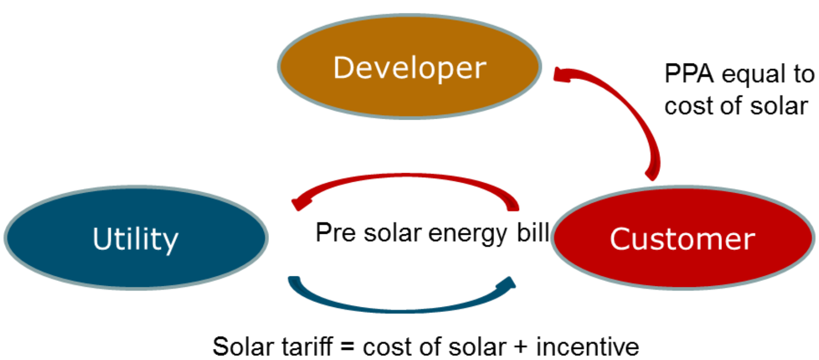
NEM policy vs. NEM Alternative policy

In this section, we compare the NEM policy with an alternative policy, which we call "NEM Alternative policy". We compare both of these policies in terms of their potential to encourage solar adoption and on their tariff impacts. This analysis helps us to answer the following question: "What is the best policy to promote solar in a sustainable fashion that benefits all utility customers?"

Our NEM Alternative policy is designed as follows: a customer is paid the cost of their solar system, plus an incentive payment. The incentive payment is designed to be large enough that customers will choose to give up their roof space and experience the inconvenience of installation for the returns. Under this policy, the customer does not need to own the system; there are multiple business arrangements that can support this policy. TPDDL or a 3rd party may own the system, receive the cost of the solar portion of the NEM Alternative tariff, leaving the customer the incentive payment.

The figure below illustrates one such arrangement. In this illustrative example, the utility provides the solar tariff to the customer, equivalent to the cost of solar and the incentive; the customer has a solar PPA with a developer; the customer experiences overall bill savings equivalent to the pre solar bill minus the solar tariff payment.

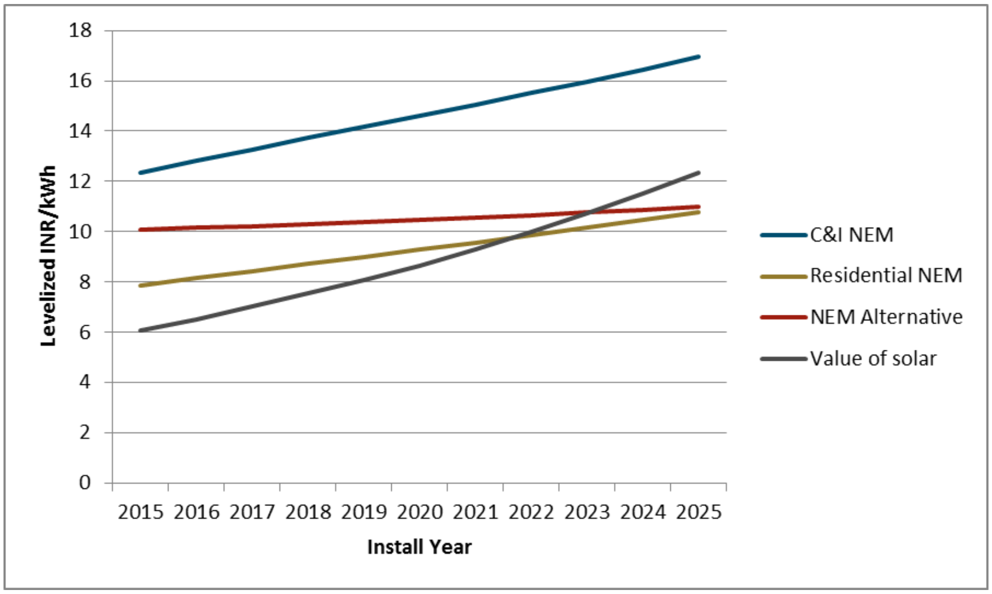
Figure 30: Example business model of an alternative policy to NEM



The NEM Alternative presented in this section includes a 1 INR/kWh of solar incentive payment.

The figure below can be used to understand whether solar adoption might occur under NEM or NEM alternative policies. The NEM tariff shows for a given solar installation year, the levelized payment that is made to the customer. Note, this scenario considers that the proxy plant is fueled by 75% domestic coal/ 25% imported coal.

Figure 31: Comparing customer adoption between NEM and NEM alternative policies; blended proxy plant comparison



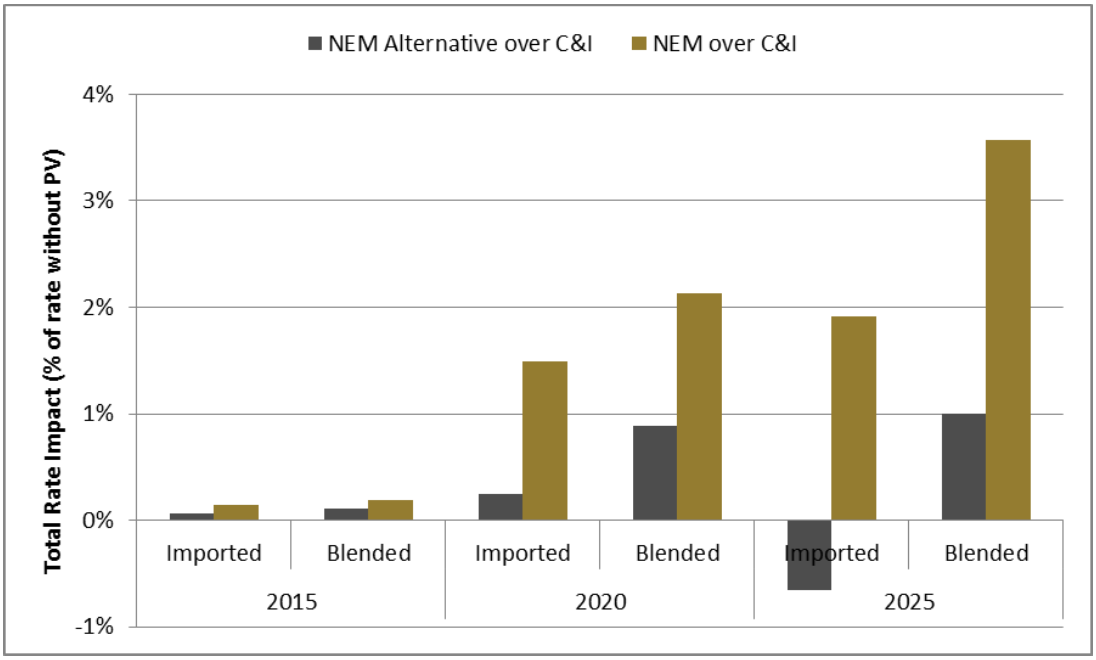
The figure shows the levelized values (INR/kWh) for solar that is installed in that respective year. By comparing the relative costs between the different levelized tariffs, we can understand whether solar adoption might occur under either a NEM or NEM alternative policy. The key insights from the figure are described.

+ The NEM policy is likely to be sufficient for motivating C&I customers' solar adoption under any business model because the C&I NEM tariff is always greater than the cost of solar (the NEM alternative tariff is set to the cost of solar plus an incentive of 1 INR/kWh escalated at 5% - the same rate as the tariffs).
+ A NEM alternative that makes a customer payment equal to the value of solar is unlikely to promote adoption before 2023 because it is less than the cost of solar; this means that the investor cannot recover their costs. After 2023 a value of solar based NEM alternative would promote investment.
+ A NEM alternative that makes a customer payment equal to the cost of solar plus the incentive can promote adoption as the investor can recover costs, however, it will increase rates prior to 2023 because the value of solar is less than the cost of solar.

We evaluated the tariff impacts over time for a solar portfolio that reaches 440 MW by 2025. This result also assumes that the proxy plant is fueled by 75% domestic coal/ 25% imported coal. The result for the

C&I class in the example below was found using an example commercial case. However, the results are very similar, and the same conclusions are drawn, if an example industrial shape were used.

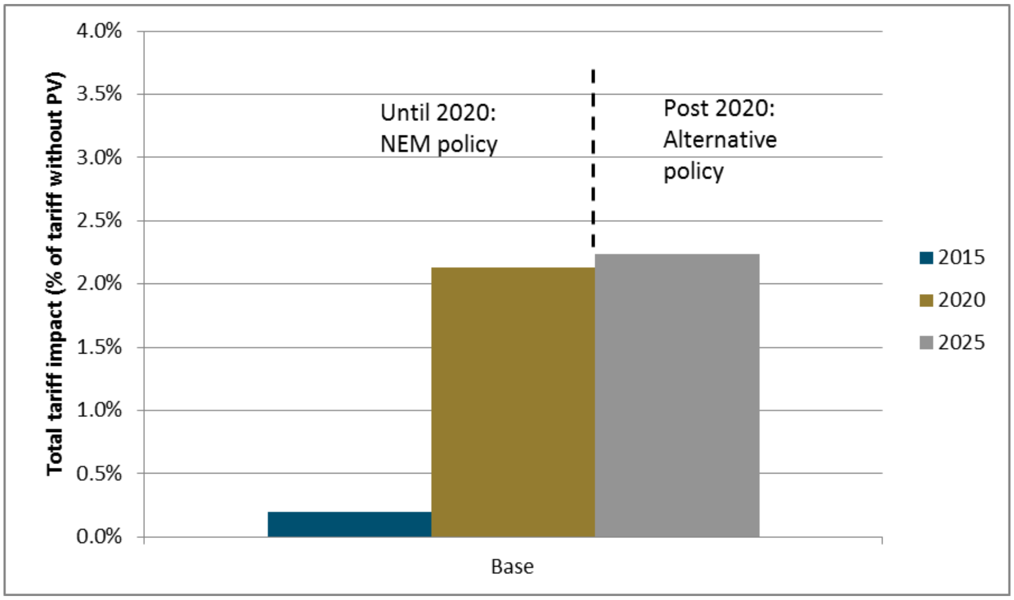
Figure 32: Comparison of tariff impacts between NEM and NEM Alternative policies; imported and blended coal proxy plant comparison



Both the NEM and the NEM Alternative policies always serve to increase the tariffs of C&I customers, with the exception of the impact of the NEM Alternative policy in 2025 when comparing to an imported proxy plant. However, the NEM Alternative policy has much less of an impact because it is much closer to the value of solar than the NEM rate. The total tariff impact is large under the NEM policy, reaching 3.6% of the C&I customer tariff by 2025.

Given that the NEM tariff has already been adopted by the DERC, a more realistic scenario is one in which the NEM policy is used to promote adoption in the early years with a transition to an alternative policy. Since the NEM policy will be revisited every five years, we analyzed the tariff impacts if the NEM policy is maintained through 2020, with a transition to the alternative policy in 2020. By transitioning away from the NEM policy, the tariff impact can be stabilized beyond 2020, as shown in Figure 33.

Figure 33: Tariff impact for NEM policy through 2020 with transition to alternative in 2020



5.4 Solar portfolio additional scenario analysis

As observed in the previous section, the range of cost-effectiveness depends on many factors that drive the avoided costs and the solar costs. Given that the following key variables may change simultaneously — financing, fuel blend of the proxy plant, solar incentives — we developed optimistic, mid and pessimistic scenarios to better understand the range of solar cost effectiveness, from a TRC perspective. The table below describes the assumptions that were altered between the scenarios.

Table 8: Development of optimistic, base/mid and pessimistic scenarios

Key driver	Optimistic	Base/Mid	Pessimistic
Solar cost	Low	Base	High
Avoided cost	High	Base	Low
NSM incentive	Included (15%)	Included (15%)	Excluded
Solar capex	Declines 3% per year	Declining 0.5% per year	Increases 4% (sub-inflation)
Financing cost of debt	TPDDL financing (10.5%)	Third party (12.5%)	Third party (12.5%)
Displaced fuel of proxy plant	95% coal (50% imported/50% domestic); 5% imported gas	75% domestic; 25% imported coal	100% domestic coal

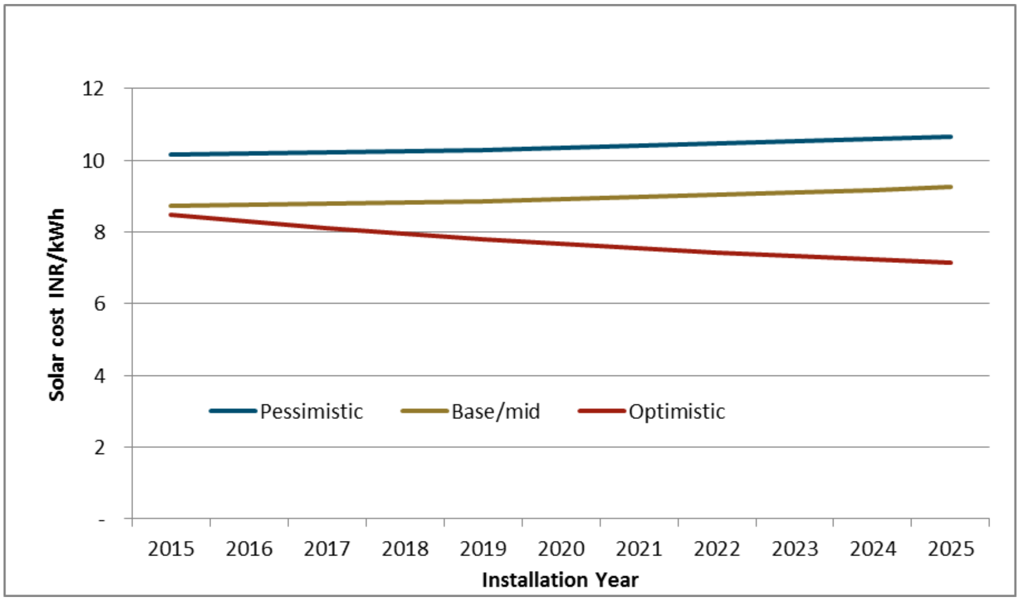
We show the following figures for each of the scenarios:

+ Cost of solar portfolio
+ Total net cost of solar portfolio (solar costs minus the avoided cost benefits)

+ Comparison of solar adoption under NEM vs. NEM Alternative policies
+ Tariff impacts of NEM and NEM Alternative policies

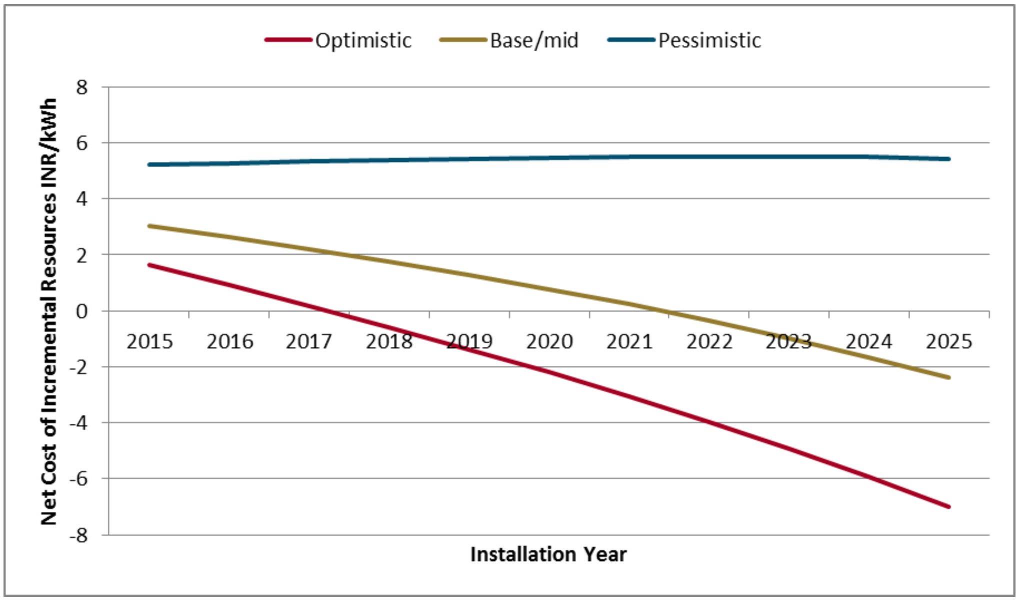
The figure below illustrates the cost of solar for the three cases. The difference in levelized cost between the optimistic and pessimistic scenarios vary from 2 INR/kWh for an installation year of 2015 to 4 INR/kWh for an installation year of 2025.

Figure 34: Cost of solar portfolio for optimistic, base/mid and pessimistic cases



We show the net costs of the three cases, taking the solar portfolio cost and subtracting the avoided cost benefits for each respective case (Figure 35).

Figure 35: Total net costs of the solar portfolio for optimistic, base/mid and pessimistic cases



This figure illustrates the following key insights.

- Under the most optimistic scenario, solar is a cost-effective solution beginning in 2018.
- Under the base/mid scenario, solar becomes cost-effective by 2022.
- Under the most pessimistic scenario, solar is not cost-effective.

The range of cost-effectiveness provides insights to TPDDL, solar developers and policy makers on the circumstances in which solar is and is not cost-effective. The combined effect equates to ~ 12 INR/kWh of difference between the optimistic and pessimistic scenarios in 2025.

The figure below illustrates the value proposition for solar adoption for the customer, utility and developer under the optimistic, mid and pessimistic cases.

Figure 36: NEM and NEM Alternative policy tariffs in the optimistic scenario (C&I tariff is reflective of commercial tariff)

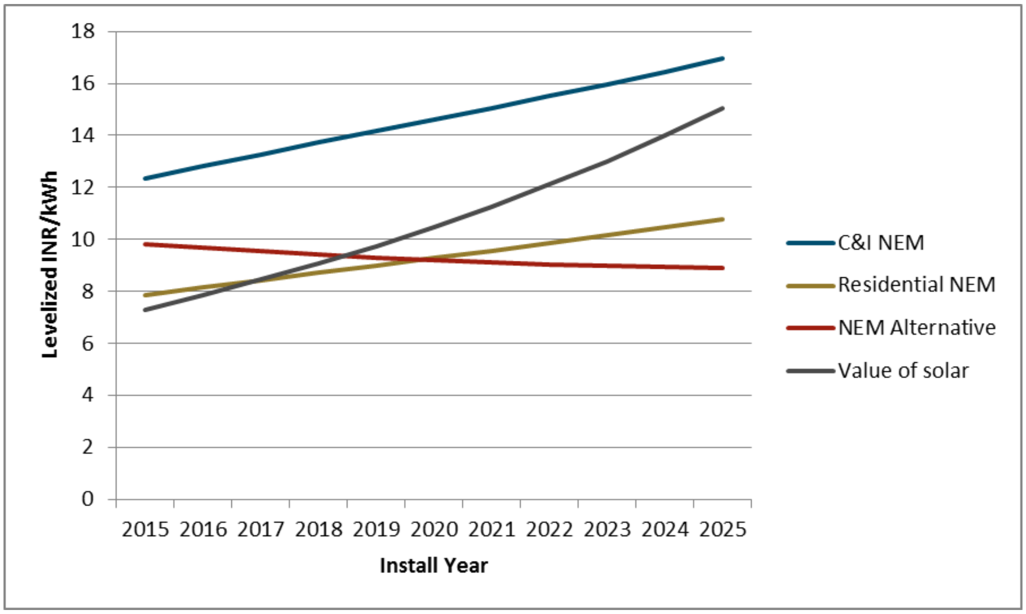


Figure 37: NEM and NEM Alternative policy tariffs in the mid scenario (C&I tariff is reflective of commercial tariff)

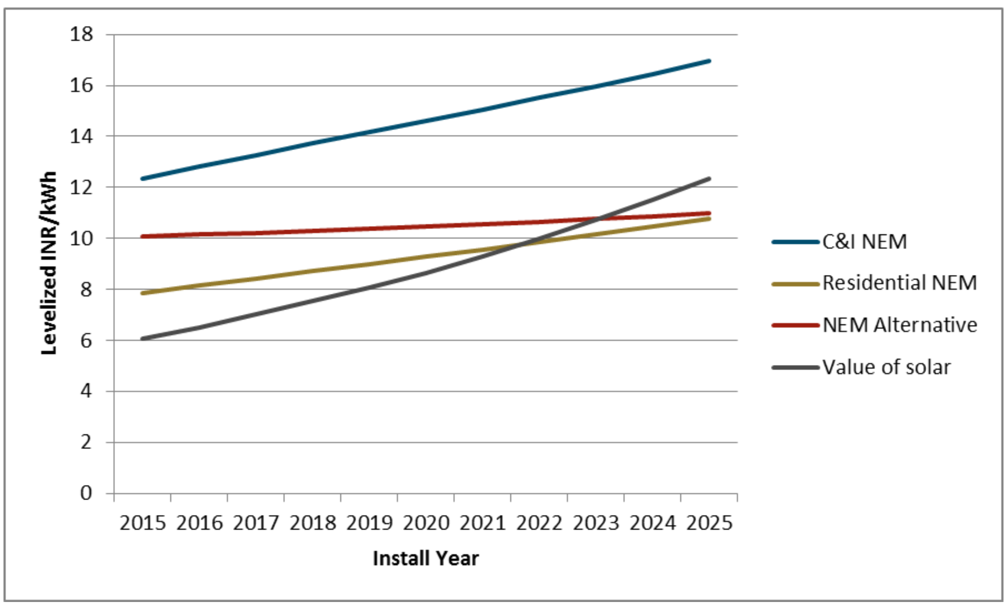
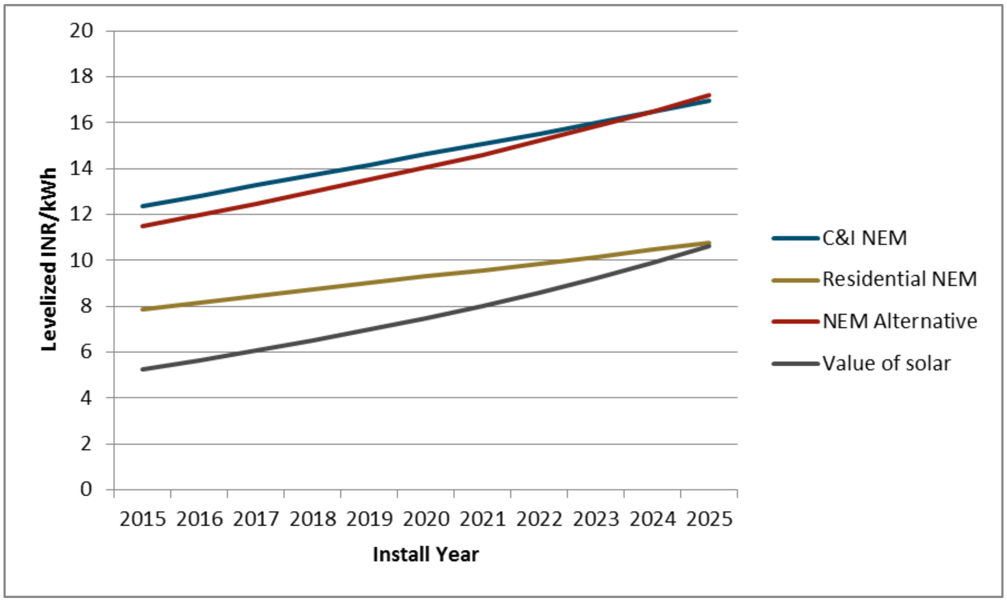


Figure 38: NEM and NEM Alternative policy tariffs in the pessimistic scenario (C&I tariff is reflective of commercial tariff)

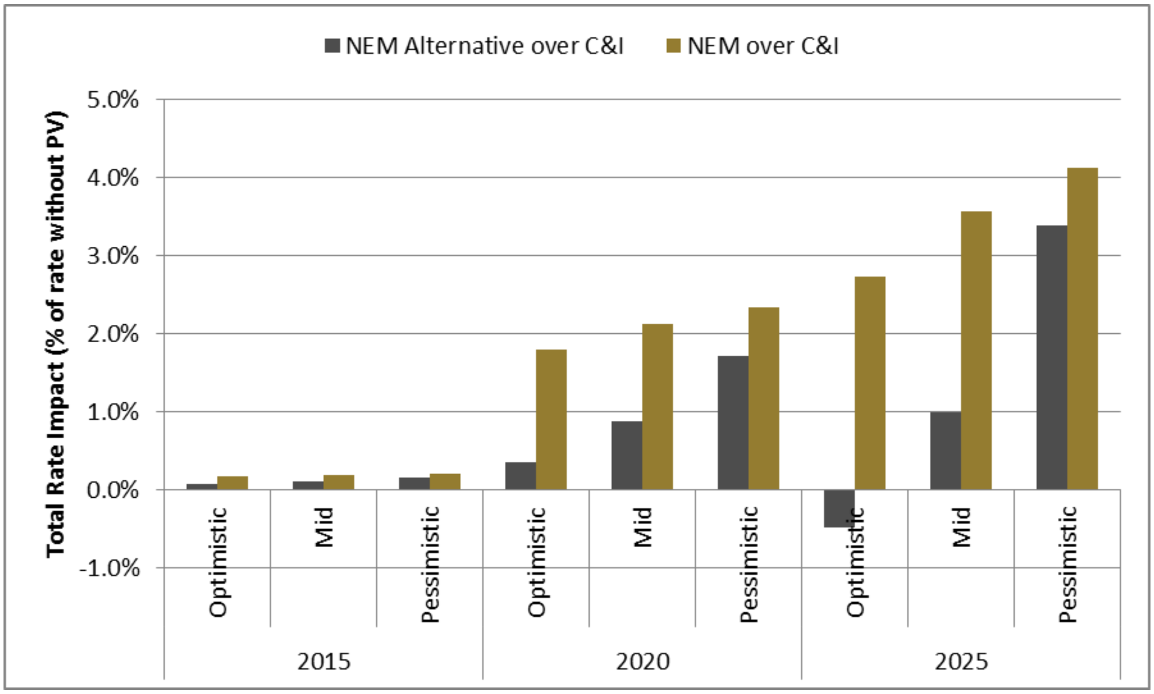


The key insights from these figures are as follows.

- The NEM policy is likely to be sufficient to motivate customer adoption under all cases.
- The NEM Alternative Policy that makes customers payments based on the value of the solar will not promote adoption under the pessimistic case, but could promote adoption under the optimistic and mid cases because it exceeds the cost of solar.
- The NEM Alternative Policy that makes customers payments based on the cost of the solar and the rooftop rental incentive can promote adoption under any case, but under the optimistic case, the cost-based NEM Alternative Policy will not increase tariffs for most years (since the cost-based NEM Alternative Policy payment is less than the value of solar payment) but will act to increase tariffs under the pessimistic case (since, in this case, the cost-based NEM Alternative Policy is greater than the value of solar).

Figure 39 illustrates the tariff impacts of the NEM and NEM Alternative policies in snapshot years based on the cumulative solar that has been installed by the respective year.

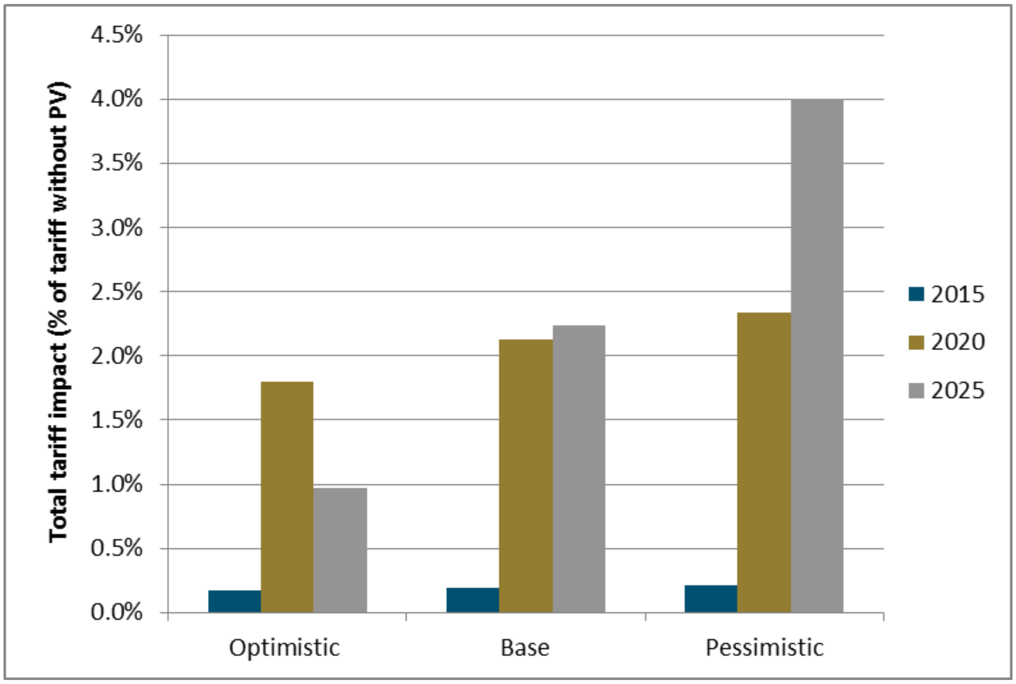
Figure 39: Comparison of tariff impacts between NEM and NEM Alternative policies; blended proxy plant comparison (C&I tariff is reflective of commercial tariff)



As expected, based on the previous figure, the NEM policy serves to increase the tariff under all cases. The NEM Alternative Policy payment (defined as the cost of solar plus the rooftop leasing payment to the customer) will not increase tariffs under the optimistic scenario but will under the mid and pessimistic scenario. The figure illustrates that the tariff impact from a NEM Alternative Policy will be less than with a NEM policy.

As in the Section 5.3, we acknowledge that the NEM tariff has already been adopted by the DERC and analyze a more realistic scenario in which the NEM policy is used to promote adoption in the early years with a transition to an alternative policy in 2020.

Figure 40: Tariff impact for optimistic, base and pessimistic cases assuming NEM policy through 2020 with transition to NEM alternative in 2020



The results illustrate how the a transition away from the NEM policy can not only stabilize tariff increases under the base case but can reduce the tariff as shown in the optimistic case. This is because the cost of solar is low and grid benefits of solar are high. In the pessimistic case, because the cost of solar remains relatively high, and grid benefits of solar are low, there is only a small benefit to switching away from the NEM policy in terms of tariff impact.

5.5 Solar portfolio cost effectiveness tests

The cost effective implementation of a program, and therefore the subsequent adoption of DER, is dependent on the value proposition to the different stakeholders. If a customer does not save money by buying and installing DER over the lifetime of the technology, they will not invest. Likewise, if a DER program impacts non-participant customer rates too severely, the utility may choose not to incentivize it. These types of assessment can be made through cost tests focused on different questions. For convenience, we reiterate the cost test types described earlier below.

1. Total Resource Cost (TRC) – This is the system wide benefits of installing DER net of its costs. A TRC cost test ratio is the benefits divided by the costs. Benefits include the avoided costs of the thermal resources that would have otherwise been built or utilized without DER. A ratio of

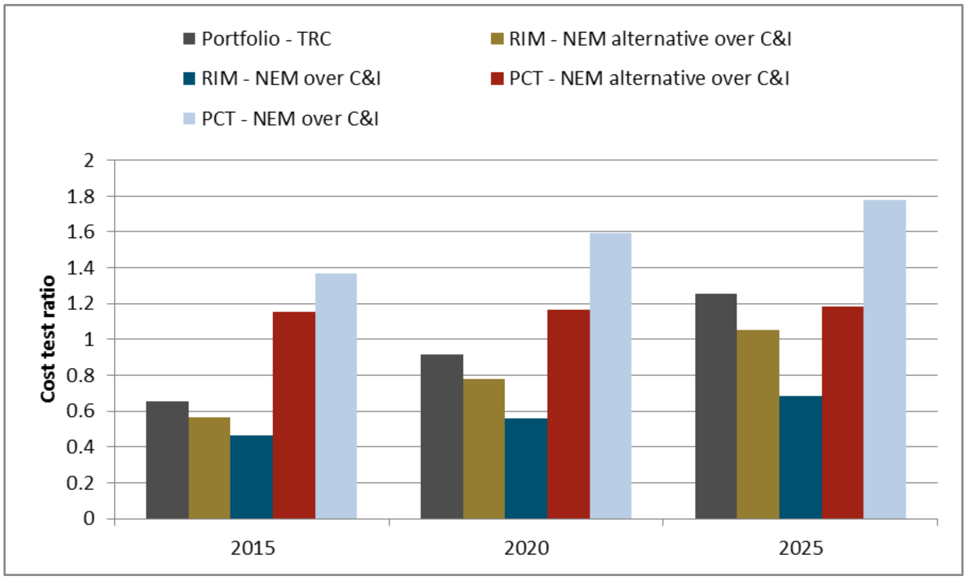
greater than 1 therefore means that installing DER reduces overall system costs relative to the thermal resource alternative.

2. Ratepayer Impact Measure (RIM) – This is the impact of installing DER on rates. RIM is often used to gauge the impact of a DER program on non-participant customers. It is equal to the system wide benefits of the DER net of the bill savings of customers installing the DER. If the ratio of benefits divided by costs is greater than 1 then savings to the system are greater than the costs in lost revenue from participating customers. If the ratio is less than 1 then the savings are less than the costs, and revenue will have to be recovered from other sources, such as raising the rates.

3. Participant Cost Test (PCT) – The PCT measures the net cost to the customer, namely the bill savings from installing DER net of its costs. If the ratio of savings to costs is greater than 1 then the customer will save money over the lifetime of the measure, and customers are more likely to adopt it. If the ratio is less than 1 then customers will lose money over lifetime, and adoption is unlikely.

The effectiveness of a DER program can be studied through looking at the cost tests. Ratios of less than 1 are unfavorable to the stakeholder perspective being studied. Comparing the cost tests across different DER program designs and business cases is a useful evaluation tool. Below the cost test are shown for the Solar Portfolio.

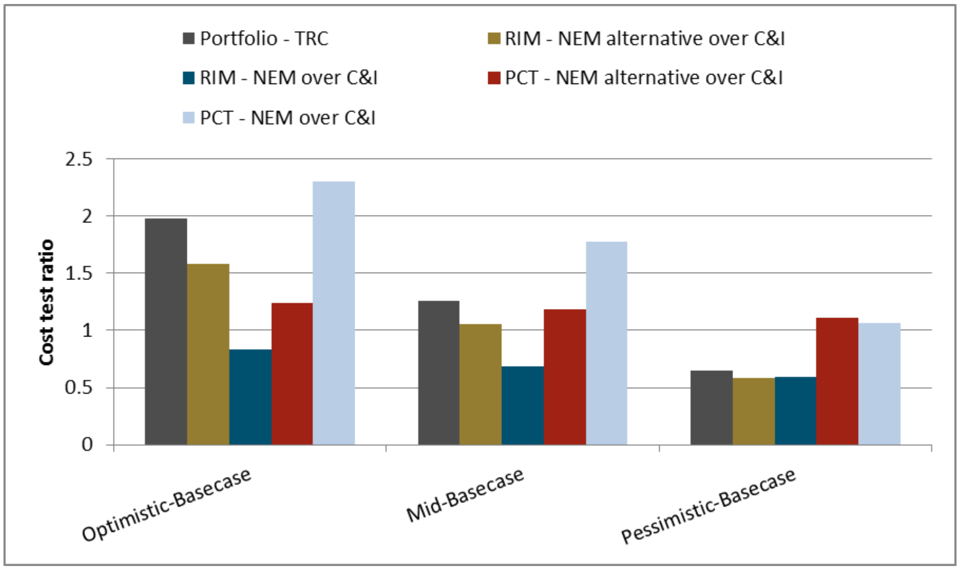
Figure 41: Cost test ratios for solar portfolio (C&I tariff is reflective of commercial tariff)



The figure shows snapshots for solar installed in 2015, 2020, and 2025. The TRC remains below 1 in the near term, but increases slightly each year and is greater than 1 by 2025. The RIM test follows the same trend for the NEM alternative policy, showing that the rate impact of systems installed in 2025 could be favorable. The RIM test also increases under NEM but remains less than 1 in all years. The PCT is greater than 1 in both the NEM and NEM Alternative policy cases. In the NEM Alternative policy, the 1 INR/kWh (in 2015) incentive above the cost of solar guarantees that the savings to the customer are always higher than the costs. In the NEM case the ratio is substantially above 1, and increase over time as solar costs increase at a slower rate relative to the tariff.

These cost test results for the optimistic, mid and pessimistic cases are shown below.

Figure 42: Comparison of cost test ratios between Optimistic, Mid, and Pessimistic cases in 2025 (C&I tariff is reflective of commercial tariff)



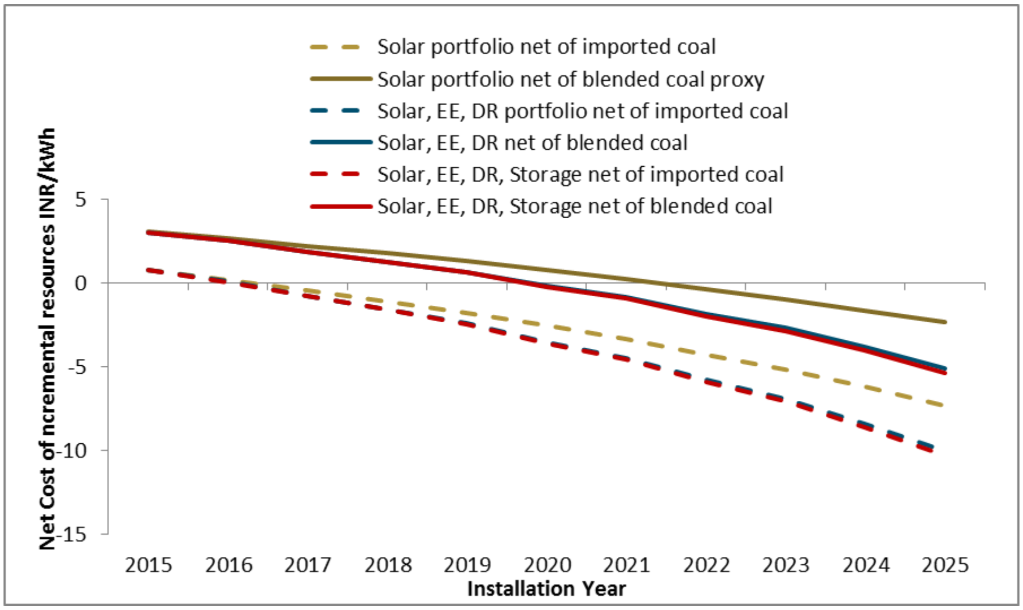
The RIM is above 1 for the NEM Alternative Policy in 2025 for the optimistic case, explaining the reduction in rates. The benefits of solar are high enough that they exceed the bill savings under NEM Alternative Policy, reducing the revenue to be recovered through rates.

As in the Solar Portfolio, the PCT for both the NEM Alternative Policy and NEM remains above 1 in all cases. The TRC is greater than 1 in the mid and optimistic cases. The overall system benefits in the Pessimistic case is less than the overall costs.

5.6 Mixed DER portfolio results

Portfolios 2 and 3 include a mix of solar and other DER technologies. The figure below shows a summary of the cost effectiveness across all the DER portfolios.

Figure 43: Comparison of total net costs across all DER portfolios

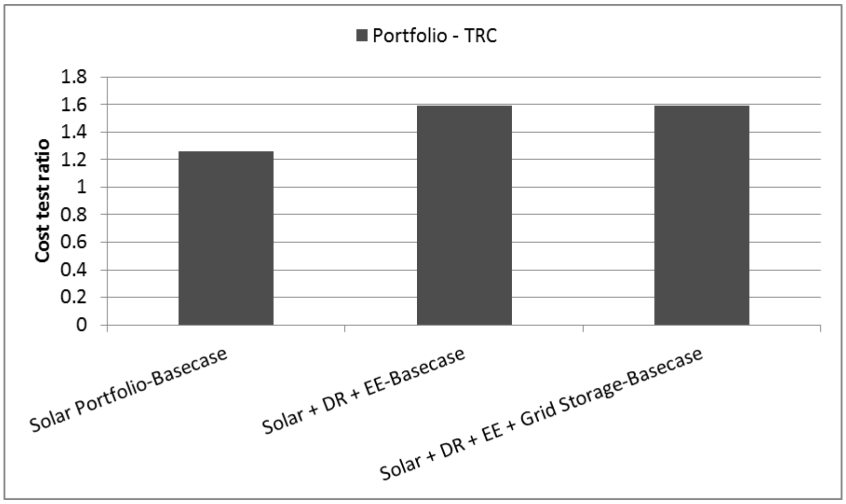


The figure illustrates that the mixed DER portfolios are more cost effective than the solar only portfolio under all scenarios.

+ Portfolio 2, containing solar, energy efficiency, and demand response is ~ 3 INR/kWh lower in 2025 than the solar only portfolio. This is because the other DER technologies are more cost effective (using TPDDL's costs) than solar or conventional resources for providing capacity value.
+ Portfolio 3, which adds storage to the portfolio 2 resource mix, is also ~ 3 INR/kWh lower in 2025 than the solar only portfolio. The storage reduces the cost of portfolio 2 even further.

The blended portfolios illustrate how different DER can be used to tune portfolios to be more cost-effective, given the need for capacity vs. energy resources. The net cost information presented in the above chart is a more detailed look at the TRC. If the net cost is greater than zero, the TRC ratio is less than 1, and the program is not cost effective overall. If the net cost is less than zero, then the TRC ratio is greater than 1. The ratio comparison across portfolios and cost tests in the year 2025 is shown below for the base case (blended fuel proxy plants).

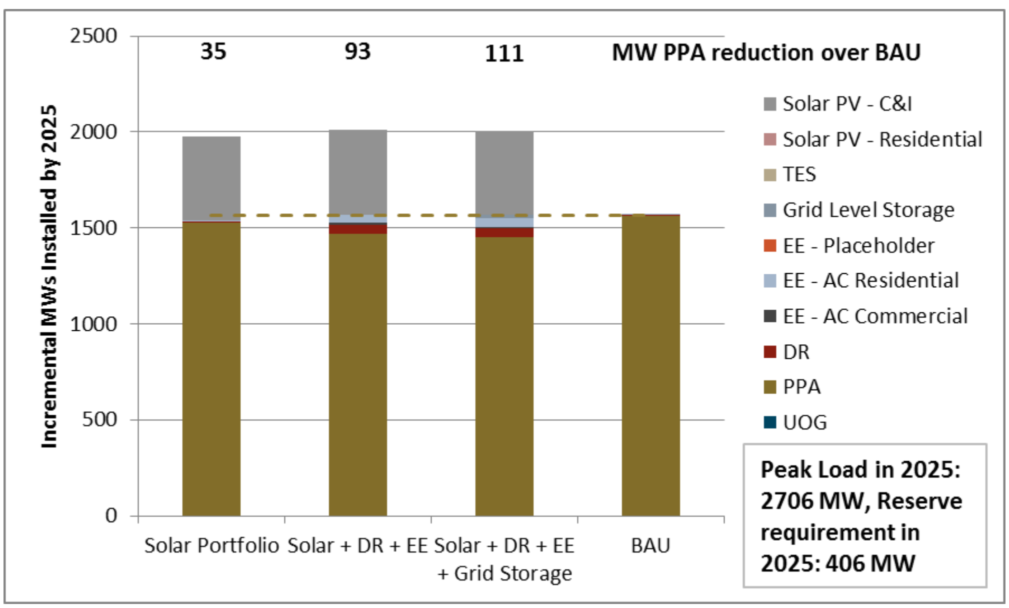
Figure 44: Comparison of TRC cost test ratios across mixed DER portfolios in 2025 to Solar Portfolio



Going left to right in the above chart shows the addition of incremental DER technologies to the Solar Portfolio. Adding DR and EE to the portfolio significantly increases the cost effectiveness, pushing the TRC further above 1. The addition of 15 MW of storage adds further value to the portfolio in 2025.

The figure below compares the resource procurement across the portfolios in the long term.

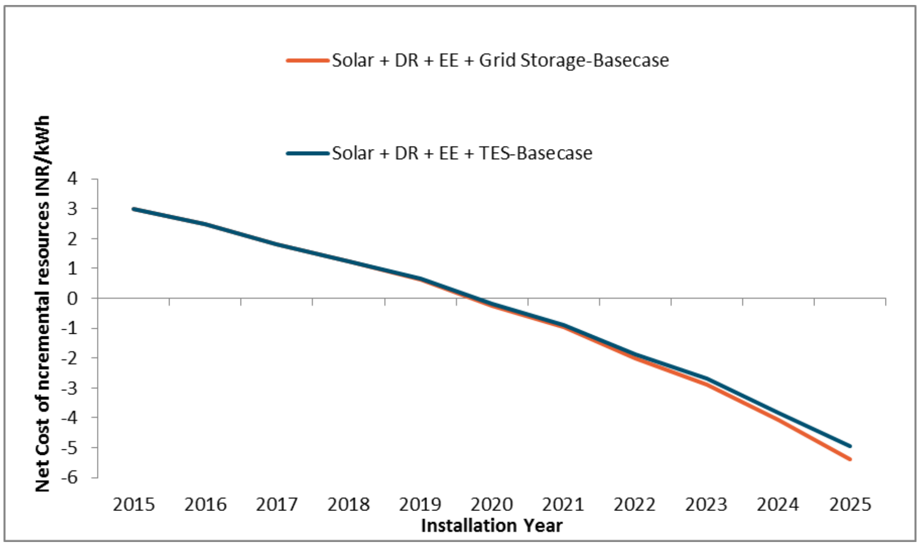
Figure 45: Comparison of resource procurement across the DER portfolios in the long term



The figure illustrates that TPDDL will require some conventional generation under all scenarios. The DER solar portfolio requires a significant amount of conventional gas or coal to meet future capacity requirements and more conventional generation than the mixed portfolios. While the Portfolio 2 that includes some storage reduces the requirement for conventional generation, it does not entirely. Additional DER resources with capacity value will be required if TPDDL is to meet all future capacity needs through solar. Further, because solar energy acts to shift the peak further out in the day over time, the capacity resources will need to be flexible.

In addition, we investigated substituting grid storage for TES in the portfolio 3 resource mix to create portfolio 3b. The resulting comparison between net cost trajectories is shown in the figure below.

Figure 46: Comparison of grid storage and TES in the resource mix (blended proxy plant comparison)



Grid storage is very valuable as a capacity resource, given its dispatchability. It remains a high value resource targeting peak load hours. TES is less valuable than grid-storage given the fixed dispatch of the resource and that TES is dispatched[15] against the time of use periods in the commercial and industrial tariffs to minimize cost for the customer. Despite grid storage being much more expensive than TES (by 3x), the net cost of grid storage is lower than TES. Grid storage is higher valued because of being dispatched according to the system needs. As solar penetration increases over time, the current time of use periods will become less aligned with the times of day with the highest peak loads. TES may well be a valuable resource on the TPDDL system, however changes to the tariff definitions to reflect the changing load patterns over time will be needed to maximize this value.

[15] The TES tank is charged at night when air conditioning loads for C&I customers are low and discharged during the late afternoon and early evening periods consistent with the TOU peak periods and when air conditioning loads are present.

5.7 Summary of results

Solar portfolio customer perspective

Under the NEM policy, both commercial and industrial customers are incentivized to adopt solar at today's tariff and solar costs. Over the lifetime of the solar, the bill savings exceed the cost of the solar, even when the NSM incentive is excluded.

+ When excluding the NSM incentive, the lifecycle NEM payment to the customer exceeds the lifecycle solar cost by 2.2 INR/kWh
+ When including the NSM incentive, the lifecycle NEM payment to the customer exceeds the lifecycle solar cost by 3.6 INR/kWh
+ A solar installation today will save the customer money over the lifecycle under the NEM policy

Our analysis shows that the value proposition to the customer will only improve over time given future solar costs decline and future tariffs.

Solar portfolio societal perspective and tariff impacts

Overall, the solar portfolio is cost effective to the whole TPDDL service territory over the long term, when including a 15% NSM incentive, and even without the NSM incentive if compared against imported coal. The solar portfolio is not cost effective when compared against a blended domestic/imported (75% domestic/25% imported) and when the NSM incentive is excluded. To understand the effect of uncertainty, we developed three additional scenarios labeled as pessimistic, optimistic and mid. These scenarios reveal very useful insights. Under the optimistic case solar is always cost effective; under the mid case, solar becomes cost effective in a few years. Under the pessimistic case, solar is never cost-effective.

The NEM policy will have a tariff impact and the level of this tariff impact will depend on quantity of solar adopted and when the solar is adopted. In our analysis, the near term impact on tariff is small. By 2020, with an adoption of 160 MW, the impact on C&I customers will result in a tariff increase of 1.5-2% to the C&I customer classes.

Benefits of multiple DER

The analysis of Portfolio 1 reveals that the solar portfolio provides minimal capacity value and under this portfolio design, TPDDL would still require procurement of conventional resources to meet its capacity needs. However, Portfolio 2 combining 440 MW of solar with 48 MW of energy efficiency and 42 MW of demand response is able to lower the procurement of conventional resources by 93 MW over the BAU (or 6%). Portfolio 3, which adds an additional 15 MW of grid storage to portfolio 2 lowers the procurement of conventional resources by 111 MW or 7%. The analysis shows that both Portfolios 2 and 3 are more cost-effective than Portfolio 1.

TPDDL can develop DER programs to support the deployment of non-solar DER technologies in addition to solar DER. These DER technologies can be proposed to the regulator as individual stand-alone programs, or as a combined program in which the total DER program level cost-effectiveness is presented to the regulator.

6 Implementation

6.1 Regulatory case for DER programs

There are many program design and business model insights that can be gleaned from the analysis presented in this report. They help to answer the following key questions.

- Can the regulatory case be made for solar, based on the total resource cost argument?
- What solar policy can minimize tariff increases to TPDDL's customers?
- What is needed to stimulate solar adoption?

We tackle each of these questions in the table below.

Table 9: Key questions informing program design and business models

Key question	Insights
Can the regulatory case be made for solar, based on the total resource cost argument?	Not in the near term without additional incentives beyond the NSM incentive. Becomes cost-effective over the long term, especially with inclusion NSM incentive (15%); without NSM incentive, solar is still cost-effective over the long term if it displaces imported coal Regulatory case is easier when combining solar with other DER
What solar policy can minimize tariff increases to TPDDL's customers?	NEM policy will have significant tariff increases in the long term; The NEM Alternative policy will have some tariff increases but the tariff increase can be less than with NEM policy; utility/regulator can manage the tariff cost risk.
What is needed to stimulate solar adoption?	NEM policy is likely to stimulate adoption in the C&I sector The NEM Alternative policy may stimulate adoption under the third party or utility owned model if the rooftop leasing payment to the customer is adequate to overcome the "hassle" factor (Gujarat is using 2 INR/kWh; we assume 1 INR/kWh). Under a NEM alternative, customers may also choose to finance their own systems, but this model is far less attractive to the customer than NEM. TPDDL can leverage customer relationships to promote solar awareness and adoption.

TPDDL can take an active role in the development and implementation of a solar and solar/DER program directly through utility owned and financed systems. First, there are complimentary programs that TPDDL can offer its customers to get more value out of solar and integrate the deployment of solar with the overall resource plan. These include demand response, energy efficiency (which TPDDL has begun) and managing the supply portfolio according to the solar. Second, TPDDL is a trusted provider of energy for its customers, particular C&I customers. Third, TPDDL can ensure quality installations that help develop the market, provide consumers confidence in solar for the long term, and set the standard business practice in the market.

6.2 Lessons from abroad

Solar and DER programs have a long history in California, other states in the United States and in Europe. TPDDL can draw from the best (and worst) practices based on these experiences. We summarize the key lessons from world-wide rooftop solar programs.

Table 10: Summary of lessons from abroad

Issue	Key lessons
Solar policy and rate design	• NEM policies: NEM for rooftop solar programs has been a popular incentive program in the United States. Customers on NEM receive a typically high incentive – effectively being paid the delivered energy cost specified in a customer's tariff for solar production. It is easy for customers to understand and has allowed various market installers; SunRun, SolarCity, Sungevity to build innovative installation and financing models. However, NEM programs often result in a transfer (cross-subsidy) as the rates include other utility investments including the cost of building out and maintaining the grid. The full grid costs are not avoided when customers put solar on their rooftops. NEM policies are currently under review in many states in order to shift the policy to a more sustainable long term market for rooftop solar. The policy changes are very contentious due to the high stakes for the publicly traded solar companies. • NEM Alternative policies: What the United States and Germany call "feed in tariff programs", where the customer is paid a price for each unit produced, provide more flexibility to the utility and regulatory agency, as the tariff can be set separately from rates and changed over time. However, a NEM alternative can also provide generous incentives; Germany's FIT is set at \$0.40/kWh, which far exceeds the "value" of solar or a NEM tariff. A NEM alternative program gives more control over the incentive offered to customers and can therefore be tailored to increase solar adoption while limiting the cost of the program. However, changing the design of a program after years of operation will also be contentious based upon the strong incentives of the winners and losers.
Solar performance and cost	• Maintenance has a huge impact on performance. Incentives can be set to promote good performance (e.g., unit based incentive); standards should be set to regulate the quality of solar systems being installed, particularly by third party developers who may not be invested in long term performance of solar systems. • Rooftop installation costs have dropped considerably in regions with high solar adoption, either through NEM or alternative policies. The experience gained through early installations in a solar program will increase the efficiency of installation by reducing labor hours and construction costs and improving permitting and interconnection costs and timing. • From a broader planning perspective, rooftop solar is often considerably more expensive than centralized solar, even when transmission costs are considered. The motivation for rooftop solar should be carefully considered; if the goal is overall least-cost generation procurement, rooftop solar is unlikely to be the cheapest resource. However, if solar is part of a portfolio of clean distributed resources that reduce the use of conventional generation (e.g. diesel), there are much more substantial local pollution reduction benefits.

Issue	Key lessons
Interconnection procedures	• Historically, most utilities have not collected real-time solar generation data and do not have visibility into the solar (utility meters run "backwards") – Third party developers like Solar City monitor their solar installations but have not necessarily shared this with utilities or grid operators – Grid operators, also, have not had visibility into distributed solar which is creating operational challenges – Distributed solar has created challenges for forecasting load – Planning with large amounts of behind the meter solar impacts the ability to interconnect utility scale and "front of the meter" solar • Streamlining interconnection is critical for the expansion of a robust distributed solar market. Best practices include identifying the available amount of "easy to interconnect" resources on a substation or ideally feeder level. The easy interconnections are those which do not require additional upgrades on the distribution system. • Improved interconnection can also be supported by advanced inverters which can provide voltage support and islanding based upon real time grid conditions. • Interconnection procedures and customer interaction are important to foster a productive market place. Clear timelines, steps required, and communication between customer and utility reduce barriers to adoption. • Early interconnection of distributed solar in the United States was under strict regulation of the local penetration of solar, avoiding distribution system issues and integration costs. Solar interconnecting above a threshold local penetration was studied to assess the impacts on the distribution system, and the potential upgrades required to maintain reliability. Over time that threshold has been relaxed as the effects of solar have become better understood and more data is available about its effects.

TPDDL and India, more broadly, has an opportunity to develop solar and DER markets by learning from the best and worst practices lessons from abroad.

6.3 Role of non-solar DER and solar integration

A key finding of the study is that solar has relatively low capacity value because of the non-coincident relationship between TPDDL's system load and the solar output. Due to the high air conditioning demand in the evening hours; the difference between the afternoon peak and evening peak is limited. Over time, as more and more solar is deployed, the capacity benefit of solar diminishes further as the system peak load becomes later with increasing solar deployment. However, due to their more targeted nature, non-solar DER technologies, such as demand response (DR) and storage, can be useful resources for meeting utility capacity needs. Energy efficiency resources can also provide capacity value.

DR and storage are dispatchable resources. If these can be contracted to respond with a high level of certainty to TPDDL high load events, or operated through direct load control, they can significantly reduce peak load requirements on the system. These high capacity value resources can displace investment in new thermal generation such as coal and gas at lower cost.

Energy efficiency can also be a cost-effective resource compared to gas or coal generation. In particular, energy efficiency that targets air conditioning loads can be used to mitigate evening and night-time loads — where solar is ineffective — and help with system load shaping.

The tool results demonstrate how planning for future capacity needs should consider the capacity contributions of non-solar DER along with solar, and in fact, 440 MW of solar does not equate to 440 MW of displaced conventional resource requirements. Figure 45 showed the capacity contribution of each DER resource among different portfolios along with the necessary conventional resource procurement. This type of analysis can be incorporated into forward looking utility planning processes, and as programs are refined over time, the inputs to the tool (e.g., dependable MW and installation goals) can be refined and incorporated into the tool to obtain more accurate information on how DER programs can interplay with long term utility planning.

Clean DER portfolios can also improve reliability system wide and/or a local grid (microgrid) level. An expanded use of clean DER could therefore have a substantial impact on local air pollution by reducing the need for and operation of diesel backup generation. This could provide an even greater policy imperative than some of the broader longer term climate and fuel independence goals.

6.4 Codes, standards, quality control

As the number of installed MWs increases, both solar developers and the utility will gain experience in how the process may be streamlined. The effects on the distribution system may require distribution upgrades to maintain reliability at higher solar penetration levels. Standardizing the process of interconnection and evaluating the reliability upgrades related to specific projects or distribution planning areas could have the following benefits:

+ Maintain the high standard of reliability set by TPDDL
+ Allow customers to interconnect quickly at the same time as minimizing the burden to TPDDL of evaluating grid impacts
+ Develop a database of installed projects to track customers with PV, installed MWs, and system performance
    - Providing grid side reliability benefits through tracking greater system information and, therefore, more informed distribution planning

   - Quality control — allows tracking of system performance over time, and the basis for corrective actions for underperforming systems

+ Develop a database of installed distribution side upgrades such that the future response to interconnection upgrades can build on earlier experience
+ Understand potential by distribution planning area to focus market development efforts on areas where the grid is the most resilient

The above set of benefits expands the CERC defined interconnection standards for DER into procedural best practices. These can be developed by TPDDL based on their own experience and planning processes. In California, the rules for interconnecting DER have been set by the California Public Utilities Commission. These are described as Rule 21, and are a collection of interconnection and procedural standards. Some of the key components for efficient interconnection are as follows:

+ Interconnection screens — if a project passes several different screening tests on how it will affect the distribution system then it may be subject to minimal study, and allowed to interconnect to the system very quickly.
   - For example, rooftop solar systems who's addition will not cause generation from solar on a particular part of the system to exceed some safe fraction of peak load on that same part of the system are normally allowed to interconnect without further study.
   - Screens will trigger additional interconnection study if not met, therefore targeting distribution engineering time to the projects that actually require it.
+ Clear study timeline, including making customers aware of all of the requirements to interconnect to the system, the expected time it will take to complete the study, any interconnection or study costs, and all steps required by the customer or developer to interconnect.
+ Clear point of contact between customer and TPDDL, ensuring that a line of communication is always open.

Beyond TPDDL's internal procedures, there are regulatory changes that could help develop the solar market. An additional regulatory tool that can increase adoption of DER at the same time as lowering costs over equivalent retrofits is through building codes for new construction. Building codes that require new construction to directly incorporate DER or facilitate the future installation of DER (for example pre-wiring) can dramatically reduce the costs of installing a system. One example is the "solar ready" criteria in the California Building Energy Efficiency Standards (known as "Title 24"). Solar readiness criteria have been developed for both residential and non-residential buildings. We describe key pieces of the non-residential solar-ready standards[16].

+ The intent of the solar ready building requirements is to integrate design considerations that impact the feasibility of installing solar energy systems into the original building design.
+ The standards require buildings to have an allocated solar zone that is free of obstructions and is not shaded. The solar zone would be a suitable location to install PV or SWH collection panels.
+ The standards require that the construction documents depict a plan for connecting a PV and SWH system to the building's electrical or plumbing system. For areas of the roof designated as solar zone, the plans must also clearly indicate the structural design loads for roof dead load and roof live load.
+ There are no infrastructure requirements; equipment such as solar modules, inverters, metering, conduit, piping, or pre-installed mounting hardware do not need to be installed.

Beyond codes and standards, voluntary programs such as the LEED (Leadership in Energy and Environmental Design) can encourage DER in buildings. The LEED labeling system, developed in the US, has gained traction in India and can be leveraged to encourage sustainable buildings that utilize a combination of energy efficiency, solar and demand response. In fact, India currently has 1,675 registered and certified LEED projects and has 621 LEED professionals[17].

6.5 Leveraging smart grid investments for DER

The prior USTDA grants resulted in TPDDL investment in smart grid infrastructure, including AMI, AMR, distribution automation and controls, and OMS. This infrastructure, combined with knowledge from pilot DR and EE programs, and customer surveys can help design effective future DER programs. We describe a few examples.

+ Utilize customer interval data available via AMI to identify suitable customers for different DER applications. Examples include:
    - Commercial customers with large evening loads, driven by air conditioning, would be good candidates for air conditioning EE.
    - Commercial and industrial customers that exhibit very high contribution to system peak for a few hours could be targeted for DR.

[16] http://www.energy.ca.gov/2013publications/CEC-400-2013-002/chapters/09_solar_ready.pdf
[17] http://www.usgbc.org/articles/leed-online-now-available-leed-india-projects

  - Thermal energy storage can help shift usage from peak load hours, such as for Commercial customers with late afternoon/early evening cooling loads.

- Utilize AMI to automate and facilitate implementation of demand response ("Auto DR") (additional controls and communication infrastructure may still be required)
- Implement new time-based tariffs that generate grid benefits using AMI. Examples include:
  - These could promote flexible DR and TES operation in ways that generate grid level benefits when they are most needed.
  - Conservation of demand or energy based on operational or behavioral change; these may not require any additional technology purchase by the customer or utility.
- Utilize GIS system to enhance DER program design and customer targeting. Examples include:
  - Generate solar potential estimates using GIS information and make this information available to customers through a web portal[18]
  - Identify types of customers and the energy efficiency technologies that might be suitable for these types of customers; this information could be made available to customers and certified ESCOs to promote adoption of EE

TPDDL's existing knowledge and experience and previously installed infrastructure can be leveraged to develop leading DER programs that can serve as examples for other Indian utilities.

[18] For example, the US solar developer, Sungevity, estimates solar potential for each house in CA using GIS and makes this information available to customers through a portal.

7 US sources of supply

One task of this study involved identifying potential US suppliers and US export potential for the projects described. This is a task that is generally required in all USTDA funded projects.

7.1 Potential US suppliers

Several US companies may have opportunities to provide DER technologies that support the development of the broad DER portfolios and the pilot installations. The table below lists the various US companies, including contact information, equipment that could be supplied and US content. The companies listed below have operations in the US and are potential candidates for the United States Export-Import bank financing.

Table 11: Potential US suppliers

US company	DER technologies	Contact info (Name, phone, email)
Solaria	Solar panels	Suvi Sharma, CFO. Email: ssharma@solaria.com Phone: 1-510 270 2500; Fax: 1 510-793-8388 Address: 6200 Paseo Padre Parkway, Fremont, CA 94555, USA
PV Power	Supplier, Solar World panels	General Sales. CustomerService@PVPower.com Phone 1 866 274-0642; Fax: Not available Address: 4256 N. Ravenswood Ave. Suite 201 Chicago, IL 60613 USA
Outback	PV inverters	Gord Petroski Email: GPetroski@alpha.com Phone: 1-360 220-8123; Fax: 1 360 435 6019 India office: Phone: +91 8861640001 Address: (Sales office in India) # 255, Block -25, LIC Jeevan sathi,10th Cross, J.P. Nagar Phase I, Bangalore - 560087 Karnataka (India)
Trojan	Batteries	Erich Heidemeyer Phone: 1-415 – 648- 7650; Fax 1-415-648 0333 Address: 10 Loomis St, San Francisco, CA 94124 USA India supplier: Manak Engineering Services Subodh Raheja Phone: +91-9810411336/ Fax: +91-9871381011 Address: B- 46, Flatted Factory Complex, Phase- 3, Okhla, New Delhi 110020, India
Imergy	Batteries	Joshua Turner; A. Sethuraman, Managing Director, India and Senior Vice President, Global Operations Email: joshua.turner@imergy.com

US company	DER technologies	Contact info (Name, phone, email)
		US Phone: +1 510-668-1485 US Address: 48611 Warm Springs Blvd. Fremont, CA 94539 India Phone: +91 124 3998555 India Address: Plot No. 732, Pace City-II, Sector-37, Gurgaon-122001, Haryana, India
Calmac	Thermal energy storage	Mark MacCracken, CEO. Email: MMacCracken@calmac.com Phone: 1 201 797 1511 Address: 3-00 Banta Place, Fair Lawn, NJ 07410 USA
Honeywell	Demand response controls	Various contacts in the India offices: Emails: Sham R Pathak, Sham.Pathak@Honeywell.com; Vishal Agarwal Vishal.Agarwal@Honeywell.com; Rohan Chopra, Rohan.Chopra@Honeywell.com
General Electric	Demand response controls	Ravi Segal, Managing Director. Email: ravi.segal@ge.com Phone: +91 (80) 4048 2440; mobile: +91 9611988922 Address: 6th Floor, Tower B, RMZ Infinity, Old Madras Road, Bangalore - 560 016. Karnataka. India
Cisco	Networking to support demand response	US contact: C. Prasanna Venkatesan, Sr. Mgr. Market Development & Strategic Planning Email - prasanve@cisco.com Phone. - +1 (408) 894-3362 (W) | +1 (773) 330-2338 (M) India contact: Ankush Charagi, Territory Business Manager, Cisco Systems (I) Pvt Ltd Email - acharagi@cisco.com Phone: +91-9873319777 Address: 7th Floor,Birla Tower, 25 Barakhamba Road, New Delhi 110 001 India

As illustrated in the table, several US companies are qualified to provide DER technologies that could support TPDDL with the pilot system development and broader DER market development in Delhi.

7.2 Estimate of US export potential for TPDDL

This study may result in significant US export potential. We estimated the US export potential for both the pilot and broad DER installations. These US export potential numbers assuming the following technology cost assumptions.

Table 12: Cost estimate sources for estimation of US export potential

Component	Unit type	Unit cost USD	Source of estimate
Solar panels	Per Watt DC	$0.84 (d)	Solar World
PV Inverter	Per Watt AC	$0.65	Outback
Demand response controls	Per kW	$26	TPDDL procurement (a)

Thermal energy storage	Per kW	$525	Calmac (b)
Grid-storage batteries	Per kWh	$300	Imergy (c)

(a) Based on the prior USTDA smart grid studies, TPDDL procured US based controls equipment to support the pilot demand response. These included companies such as Honeywell. Their actual procurement cost is used here. Conversion rate: INR 62 to 1 USD
(b) Based on average $/ton-hour cost of $87.5/ton-hour. To convert into $/kW, discharge duration of 6 hours and avoided chilled water system consumption of 1 kW/ton is assumed.
(c) Assumes $300/kWh capital cost (nominal dollars) which is converted into $/kW by assuming 4 hour discharge duration; this discharge duration is consistent with the maximum battery storage dispatch assumed in the Task 5 analysis.
(d) Equates to $0.97/Watt$_{AC}$ assuming DC to AC ratio of 1.15.

The 3 DER portfolios developed in Task 5 have varying levels of DER penetration in 2025; these are shown in the table below.

Table 13: Long term DER portfolio composition

DER Technology	DER portfolio 1	DER portfolio 2	DER portfolio 3	DER portfolio 3b
Solar panels	440 MW	440 MW	440 MW	440 MW
PV Inverter	440 MW	440 MW	440 MW	440 MW
Demand response controls		42 MW	42 MW	42 MW
Thermal energy storage				15 MW
Grid-storage batteries			15 MW	

Using these pricing estimates and the DER portfolio specifications, we estimate the following longterm US export potential in USD Millions.

Table 14: Long term US export potential for DER portfolio implementation in TPDDL service territory

DER Technology	DER portfolio 1	DER portfolio 2	DER portfolio 3	DER portfolio 3b
Solar panels	$425 Millions	$425 Millions	$425 Millions	$425 Millions
PV Inverter	$286 Millions	$286 Millions	$286 Millions	$286 Millions
Demand response controls	$0 Millions	$1 Millions	$1 Millions	$1 Millions
Thermal energy storage	$0 Millions	$0 Millions	$0 Millions	$8 Millions
Grid-storage batteries	$0 Millions	$0 Millions	$18 Millions	$0 Millions
Totals	$711 Millions	$712 Millions	$730 Millions	$720 Millions

Note, the above estimates are in $2015 and do not account for inflation; export potential in nominal units would be larger.

We developed estimates for 35 kW and 50 kW solar installations at TPDDL grid-stations that could be procured directly by TPDDL as part of a pilot project. These systems could be directly procured by TPDDL. The table below shows the US export potential for the pilot installation. Additional US export potential may result if additional DER are deployed with the solar. For purposes of this estimate, we assume that TPDDL might install additional DER in the form of 50 kW of grid-interactive storage.

Table 15: US export potential for the pilot installations

DER Technology	Deployment quantity	Export potential, $ 35 kW system	50 kW system
Solar panels	35 kW and 50 kW	$30,100	$43,000
PV Inverter	35 kW and 50 kW	$22,750	$32,500
Grid-interactive storage (a)	50 kW	$35,000	$35,000
Totals	--	$89,300	$111,950

(a)The grid-interactive storage is based on a smaller scale US battery – the Trojan battery estimated at $175 per kWh, or, on a 4 hour discharge duration basis, $700/kW.

As expected, the potential US export potential is approximately 6000 times larger for the DER portfolios as compared to the individual pilot installations. This scaling factor underscores the importance and benefit of developing the broader market for DER technologies over the long term towards motivating US exports.

7.3 Estimate of US export potential across private utilities

This study may result in an even larger US export potential when considering the possibilities of deployment beyond TPDDL. If we consider equivalent deployment across additional private utilities in India —Tata Power Mumbai, Reliance Infrastructure, and Torrent, in addition to TPDDL, the US export potential is significantly larger. The total deployment potential, including all these utilities, is *conservatively* estimated at 10 times what was estimated for a TPDDL deployment alone[19].

Table 16: Long term US export potential for DER portfolio implementation across private Indian utilities

DER Technology	DER portfolio 1	DER portfolio 2	DER portfolio 3	DER portfolio 3b
Solar panels	$4.3 Billions	$4.3 Billions	$4.3 Billions	$4.3 Billions
PV Inverter	$2.9 Billions	$2.9 Billions	$2.9 Billions	$2.9 Billions
Demand response controls	$0 Millions	$11 Millions	$11 Millions	$11 Millions
Thermal energy storage	$0 Millions	$0 Millions	$0 Millions	$81 Millions
Grid-storage batteries	$0 Millions	$0 Millions	$180 Millions	$0 Millions
Totals	$7.1 Billions	$7.1 Billions	$7.3 Billions	$7.2 Billions

The US export potential for the non-solar DER resources alone ranges from $11 Million to $190 Million. When including solar, the US export potential ranges from ~ $7.1 Billion to $7.3 Billion.

[19] TPDDL has roughly 460,000 customers that consume more than 400 units per month; Tata power Mumbai has roughly 500,000 customers (Source: http://www.business-standard.com/article/pti-stories/merc-grants-25-yr-power-distribution-licence-to-tata-power-114081500220_1.html); Torrent Power serves roughly 3 million customers (Source: http://www.torrentpower.com/about_us/ab_ataglance.php); Reliance Infrastructure serves roughly 5 million customers (Source: http://www.rinfra.com/kar_energy_distribution.html)

8 Summary recommendations

Our analysis suggests that the opportunity for rooftop solar is significant. TPDDL is in a good position to encourage the rooftop solar market and transition to a solar future. First, there are complementary programs that TPDDL can offer its customers to get more value out of solar and integrate the deployment of solar with the overall resource plan. These include demand response, energy efficiency (which TPDDL has begun) and managing the supply portfolio according to the solar. Second, TPDDL is a trusted provider of energy for its customers, particular C&I customers. Third, TPDDL can ensure quality installations that help develop the market, provide consumers with confidence in solar for the long term, and set the standard business practice in the market. Our overall recommendations to TPDDL are:

- Begin offering C&I customers quality, financially beneficial, rooftop solar systems
- Develop complementary programs such as DR and EE to maximize utility value from the solar
- Develop codes and standards to ensure quality of solar installations and to encourage cost-effective solar, EE, DR in new construction
- Explore partnerships through existing initiatives such as the LEED green building initiatives as these can help identify willing customers.
- As the installed solar increases, manage the conventional supply portfolio in a complimentary manner, identifying resources that meet the utility's changing load demand needs.
- Track the impact on C&I tariffs as well as installed system costs. When the tariff impact begins to increase to a level of concern, transition from the NEM policy to a less generous compensation system that better reflects solar value in the utility portfolio.

Over the long term, TPDDL will gain practice with programs and can optimize these programs to incorporate solar along with other DER at more aggressive levels. The framework can be used by TPDDL to identify which types of DER become more valuable as load growth patterns change along with DER technology costs and performance, and fuel cost projections.

Our analysis has broader implications that go beyond TPDDL.

- While the NEM policy can help grow the solar market in the near term in some utility service territories, it has the potential to create unintended consequences in the form of a cross-subsidy. This is true in utility service territories where utilities are able to recover their costs through retail tariffs. (In the event where the retail tariff is far lower than the marginal cost of electricity to the utility, a NEM policy is unlikely to motivate adoption.)

- To contain the cross-subsidy, a transition away from NEM is needed to mitigate the cross-subsidy; this transition can be in the form of a solar tariff in which the customer is paid for the solar generation based on the cost of the solar with an additional incentive.
- Complementary DER technologies can help integrate solar and lower overall portfolio costs. Particularly with growing nighttime loads due to air conditioning, the capacity value of solar will be limited and may not be able to meet future capacity needs due to load growth. Energy efficiency and demand response can be useful additions to a utility portfolio.

This study developed a planning methodology can be useful across Delhi, for different regions, and for central policy decisions. A central level analysis can show overall benefits when fossil fuel subsidies are lowered. A multi-regional analysis can show overall benefits of solar when diesel and lost load would otherwise occur.