EMPOWERING SOLAR ENERGY

IN SOUTH DAKOTA

ECONOMIC IMPACT STUDY

PREPARED BY

CROSSBORDER ENERGY

AUGUST 2023

DAKOTA RURAL ACTION
GRASSROOTS ORGANIZING FOR THE FUTURE

Thank you!

Dakota Rural Action is proud to present this study of distributed solar energy in the Black Hills Power service area prepared by Crossborder Energy.

We want to thank the SD Chapter of the Sierra Club and 32 other donors who helped make this project possible. Many people gave through a GoFundMe campaign.

We believe the results of this study apply across South Dakota. Many utilities in South Dakota have claimed that distributed generation solar installations cost the utility and non-participating customers money. The only benefit goes to the customer with the solar installation.

This study flips those assertions on their head. It shows higher costs for the customers with solar installations and significant benefits for the utility and non-participating customers.

We hope this study will reignite discussions about needed policies at the state and utility levels to promote the installation of distributed solar generation by more people in South Dakota.

Join in on the conversation at **www.dakotarural.org** or follow us on Facebook or Instagram.

The Direct Benefits and Costs of Distributed Renewable Generation in the South Dakota Service Territory of Black Hills Power

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The Direct Benefits and Costs of Distributed Renewable Generation in the South Dakota Service Territory of Black Hills Power

Executive Summary

This report provides a review of the direct benefits and costs of behind-the-meter, renewable distributed generation (DG) in the South Dakota service territory of Black Hills Power (BHP or Black Hills), a subsidiary of Black Hills Energy (BHE). Dakota Rural Action (DRA) and the South Dakota Chapter of the Sierra Club asked Crossborder Energy (Crossborder) to prepare this study in order to evaluate the reasonableness of a new "Buy All / Sell All" tariff (BA/SA Tariff) proposed by BHP in 2021.[1] The BA/SA Tariff proposal has been resolved temporarily by a Stipulation Agreement signed by intervenors in 2021 in which they agreed to work with BHP to come up with an alternative tariff by the end of 2023. The underlying issue is whether DG, mostly solar, is actually causing a "cost-shift" from DG owners to the rest of BHP's customers. The alleged need to mitigate this cost shift was the reason that BHP proposed the new BA/SA Tariff. This study addresses this question.

This report presents a benefit-cost analysis of the direct impacts on ratepayers of customer-owned installations of solar DG in BHP's service territory in western South Dakota. Crossborder's analysis has the following key attributes:

1. **Examines multiple perspectives.** The benefits and costs of solar DG are examined from the different perspectives of the key stakeholders – the customers who install DG, other ratepayers, and the utility system as a whole. Together, these stakeholders constitute the public interest concerned with DG development. To capture all of these perspectives, we analyze the benefits and costs of solar DG using the full set of cost-effectiveness tests for demand-side resources commonly used in the U.S. utility industry.
2. **Considers a comprehensive list of benefits and costs.** When customers install their own DG on their premises, using their own private capital, the resulting power production allows the utility to avoid incurring future costs for generation, transmission, and distribution. The utility also may avoid costs for environmental compliance, and the new renewable generation will reduce ratepayers' exposure to volatile fossil fuel prices in the energy markets that serve western South Dakota. Two of the principal benefit-cost tests – the Total Resource Cost (TRC) and Ratepayer Impact Measure (RIM) tests – use these avoided costs as the benefits of renewable DG. To obtain a complete picture of the cost-effectiveness of renewable DG, it is important to consider a comprehensive list of these benefits.

   On the cost side, in addition to the capital and operating costs of solar DG (in the TRC test) and the lost revenues for the utility (in the RIM test), solar DG also may cause the utility to incur new costs to integrate DG solar resources into its system. Our analysis includes these integration costs in both the TRC and RIM tests.

[1] For BHP's original BA/SA Tariff proposal, see https://puc.sd.gov/Dockets/Electric/2021/EL21-011.aspx.

3. **Uses a long-term, life-cycle analysis.** The Crossborder analysis covers the useful life of a solar DG system, which is at least 25 years. This long-term perspective is important if solar DG is to be treated fairly in comparison to other long-term utility resources.

To calculate the benefits of solar DG, this report uses the same analyses of avoided costs that U.S. utilities typically employ to evaluate the benefits of their demand-side programs. Much of the data for these analyses comes from BHE's most recent (2021) *Integrated Resource Plan* (*2021 IRP*).[2] We also use data from BHP's FERC Form 1 and market data from the regional electric markets which serve South Dakota. This approach to valuing solar DG draws upon similar analyses that have been conducted in other states, including the "public tool" for evaluating net-metered DG that has been developed in California[3] and the cost-effectiveness methodology used in Arkansas.[4]

On the cost side, this study evaluates system costs for solar DG, lost revenues when customers install DG, and the utility's integration costs, as appropriate under each of the standard cost-effectiveness tests:

- **System costs.** The levelized cost of energy (LCOE) from solar DG installations is the cost of solar DG as a resource for the utility system and for the participating ratepayers who install DG systems. The LCOE for residential solar was calculated using a current average cost of $2.75 per watt-DC (before any tax credits), plus typical operating and financing assumptions for such systems.[5]
- **Lost revenues.** The costs of solar DG for non-participating ratepayers are principally the revenues that the utility loses from solar DG customers who use their on-site solar generation to serve their own loads and who export excess output back into the grid. To determine these costs, we calculated the 25-year levelized lost revenues from residential customers who install solar DG, with an assumption that BHP's retail rates will escalate at 2% per year.
- **Integration costs.** BHE's *2021 IRP* provided an estimate of $1 per MWh as the cost of additional ancillary services that may be needed to integrate solar DG into the grid.

This study concludes that the benefits of residential DG on BHP's system exceed the costs, such that residential DG customers do not impose a burden on other ratepayers. In other words, there is no "cost shift" from solar DG in BHP's service territory. The following **Figure ES-1** and **Table ES-1** summarize the results of this application of the primary cost-effectiveness tests to residential solar DG on BHP's system.

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2 See *2021 Integrated Resource Plan of Cheyenne Light, Fuel, and Power Company and Black Hills Power, Inc.* Note that Black Hills Power, Inc. [d/b/a Black Hills Energy, a direct, wholly-owned subsidiary of Black Hills Corporation] provides electric service to customers in western South Dakota, northern Wyoming and southeast Montana; the company is referred to as 'Black Hills Power' throughout the IRP.

3 The California Public Utilities Commission's Public Tool is described and is available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/idsm.

4 See Arkansas PSC Docket No. 16-027-R, especially Order No. 28 (issued June 1, 2020).

5 See https://www.solarreviews.com/solar-panel-cost.

Figure ES-1: *Cost-effectiveness Results of Residential Solar DG to BHP*

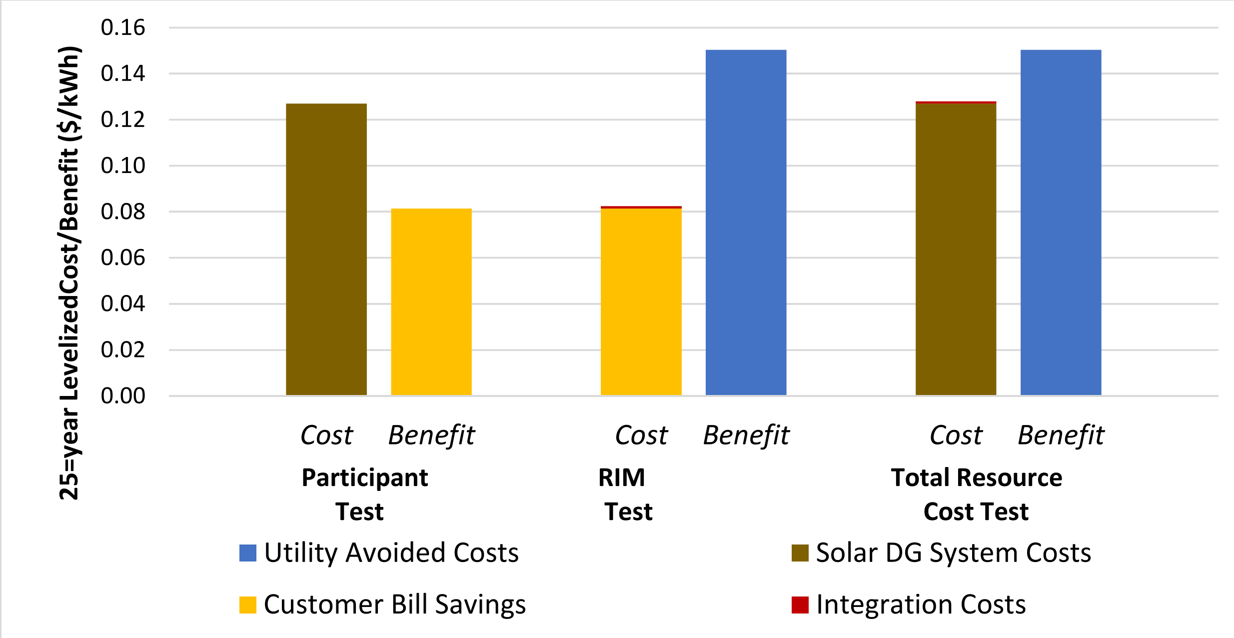

Table ES-1: *Benefits and Costs of Residential Solar for BHP (25-year levelized $/kWh)*

Benefit-Cost Test	**Participant**		**RIM / PAC**		**TRC**	
Perspective	**Solar customers**		**Non-participants**		**As a resource for BHP**	
Category	**Cost**	**Benefit**	**Cost**	**Benefit**	**Cost**	**Benefit**
Avoided Utility Costs – Energy, Capacity, T & D, and Hedging				0.149		0.149
Lost Revenues / Bill Savings		0.081	0.081			
Integration			0.001		0.001	
Solar DG LCOE	0.127				0.127	
Totals	0.127	0.081	0.082	0.149	0.128	0.149
Benefit-Cost Ratios	**0.64**		**1.82**		**1.16**	

The principal conclusions of this analysis are as follows:

1. **Distributed Generation (DG) does not cause a cost shift to non-participating ratepayers**, as shown by the score greater than 1.0 on the stringent Ratepayer Impact Measure test. As a result, in the long-run, deployment of solar DG will not have an adverse impact on the utility's rates, on its cost of service, or, most important, on other ratepayers who do not install DG. In the long-run, customer adoption of distributed solar generation will reduce rates for all of BHP's ratepayers.

2. **Modifications to BHP's current net billing policy are not needed** to recover the utility's full cost of service over time from net metering customers. In fact, full retail net energy metering (NEM) – with exports compensated at the full retail rate – would be cost-effective in BHP's service territory. Other rate design changes for residential DG customers, such as increased fixed charges or the use of demand charges, are not needed to recover the utility's full cost of service over time from net metering customers.

3. Solar DG is installed based on individual customer decisions, and customers have the right under federal law (PURPA), to interconnect these systems to the grid and to sell their excess generation to the utility at a state-regulated rate based on avoided costs. Although such installations are not planned or controlled directly by utilities, from a resource planning perspective, **solar DG is a cost-effective resource for BHP's South Dakota service territory**, as shown by the score above 1.0 on the Total Resource Cost test.

4. **The economics of solar DG are not favorable for residential customers in South Dakota**, as shown by the Participant test results well below 1.0. This accounts for the small amount of solar adoption to date in South Dakota. BHP currently compensates solar customers for their exports at a low rate that significantly understates the utility's avoided costs for energy and for generation, transmission, and distribution capacity. Any further reduction in the compensation provided to solar DG customers – such as the proposed BA/SA Tariff – is likely to be further detrimental to today's slow growth of this resource.

Renewable generation has additional environmental and societal benefits for the citizens of South Dakota. These include public health improvements from lower emissions of criteria air pollutants, and reduced damages from the carbon emissions that drive climate change. These benefits can be quantified, but are beyond the scope of this study.[6]

Finally, solar DG provides other important benefits that are difficult to quantify, including:

- the **enhanced reliability and resiliency** of customers' electric service, because solar DG is a foundational element for backup power systems and micro-grids that can provide uninterrupted power when the utility grid is down.
- Distributed generation also **enhances customers' freedom**, allowing them to choose the source of their electricity.
- Customer involvement in producing a portion of their own power produces **customers who are more engaged and better informed** about how their electricity is supplied.
- The choice of using private capital to install solar DG on a customer's private premises **leverages a new source of capital to expand South Dakota's clean energy infrastructure** and allows customers to take advantage of **significant tax incentives**.

[6] For a quantification of the societal benefits of solar DG in Wyoming, a neighboring state in which BHE also operates, see https://www.powderriverbasin.org/2022/06/13/the-benefits-costs-of-net-metering-solar-distributed-generation-in-wyoming/.

The Direct Benefits and Costs of Distributed Renewable Generation in the South Dakota Service Territory of Black Hills Power

1. Background: Distributed Renewable Generation in South Dakota

South Dakota has significant resources of renewable energy. The state's substantial wind resources are being developed, primarily at utility-scale wind farms. South Dakota also has good solar resources, comparable to other nearby states, but to date the state has seen far less development of its solar resources. The current penetration of DG solar in South Dakota is low compared to most of the rest of the U.S.

The following **Table 1** compares the deployment of small-scale solar DG in South Dakota and other nearby states, based on Energy Information Administration (EIA) data as of April 2022.[7]

Table 1: *Metrics of Small-scale Solar Deployment in South Dakota and Nearby States*

State	Solar DG		Solar Resource	Residential Electric Rate	Solar Value
	MW	*W/Customer*	*Annual kWh/kW*	*$/ kWh*	*$/kW-yr*
IA	192	114	1,392	$0.121	$168
MN	154	54	1,343	$0.138	$186
MT	32	49	1,331	$0.110	$146
ND	1	2	1,290	$0.105	$135
NE	20	18	1,410	$0.111	$156
SD	1	3	1,452	$0.120	$175
WY	13	36	1,533	$0.111	$170

The final column shows the annual "solar value" that could be earned by a residential customer who installs a kW of solar DG capacity. For each state, this is calculated as the average residential electric rate (from the April 2022 EIA data) times the annual output of a typical solar system (in annual kWh per kW-DC) in each state's largest city (except using Rapid City for South Dakota).[8] The solar value for South Dakota is the second highest among neighboring states, trailing only Minnesota. It is an important metric that solar customers can use to judge the benefit of producing their own on-site energy. However, South Dakota also has the lowest penetration of solar DG among these states, tied with North Dakota at only 1 MW. This

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[7] The EIA data on MWs of small-scale solar deployment (systems under 1 MW), numbers of electric customers, and average residential electric rates is from EIA's Electric Power Monthly, Tables 5.8, 6.2.B, and 5.6.A, sampled in May 2022 with data through April 2022. Available at https://www.eia.gov/electricity/monthly/. The solar Watt per customer is based on dividing the total small-scale solar MW by the total number of electric customers.

[8] The solar resource is the annual kWh per kW-DC produced by a typical fixed array solar system per the National Renewable Energy Lab's (NREL) PVWATTS calculator, available at https://pvwatts.nrel.gov/.

customer-sited resource is growing very slowly, primarily due to the poor economics from the lack of net energy metering (NEM) and the low avoided costs paid by utility companies in South Dakota for the exports of excess solar DG production.

NEM is the billing arrangement that most states use to compensate customers who install renewable DG on their premises, including solar photovoltaic (PV) systems. The output of a PV array first serves the DG customer's onsite load, reducing the amount of power which the customer purchases from the serving utility. When the DG output exceeds the onsite load, the excess generation is exported to the utility grid and the utility uses that generation to serve neighboring loads. Under NEM, the DG customer receives a credit for these exports at the same volumetric rate that the customer pays when it imports power from the utility. Thus, the essence of net metering is the ability of a customer with a solar PV system to "run the meter backwards" when the customer exports power and serves as a generation source for the utility. The accounting used to calculate the DG customer's bill allows the customer to use the credits (when the meter runs backward) to offset the cost of usage from the grid (when the meter runs forward). The customer simply pays the net bill each month. The simplicity of net metering for the DG customer has been a major factor in its widespread use and popularity. A total of 47 states currently offer – or have offered in the past – some type of NEM, but NEM has never been available in South Dakota.[9]

Solar can be deployed at a broad range of scales, but small-scale, behind-the-meter distributed solar generation allows customers to save money, provides greater freedom of choice in their energy supply, improves the local and global environment, and provides more resilient electric service, especially when combined with on-site battery storage. Behind-the-meter DG both reduces the DG customer's use of power from the utility, and, at times, allows the DG customer to provide a service to the utility – exports of excess renewable generation – thus becoming a producer (i.e., a generator). Some have applied a new label – "prosumers" – to DG customers in recognition of this dual role as both a customer of the utility and as a power producer who supplies a service (generation) to the utility.

As generators, renewable DG customers have legal status as qualifying facilities (QFs) under the Public Utilities Regulatory Policies Act of 1978 (PURPA).[10] Under this federal law, a utility in whose territory a QF is located is required to do the following:

- interconnect with a customer's renewable DG system,
- allow a DG customer to use the output of his system to offset his on-site load, and
- purchase excess power exported from such systems at a state-regulated price.

9 See http://programs.dsireusa.org/system/program/maps. States that reached a significant penetration of solar DG customers under traditional net metering (including Arizona, California, Nevada, New Hampshire, South Carolina, and Hawaii) typically have adopted revised compensation rules for new DG customers that reduce the compensation for excess generation exported to the grid. South Dakota's net billing structure already does this, with exports compensated at lower rates based on avoided energy costs.

10 The PURPA requirements can be found in 18 C.F.R. §292.303.

These provisions of federal law are independent of whether a state has adopted net metering. Thus, the adoption of net metering only impacts the accounting credits which the customer-generator receives for the power that it exports to the grid.[11]

Instead of NEM, South Dakota's current electricity metering statute embodies the basic concept of "net billing." Under net billing, customers with behind-the-meter DG systems have a bi-directional meter installed to measure their consumption (imports) from the utility as well as their export of power to the grid, in each billing period.[12] Customers are compensated for the power they export to the grid at the "avoided cost rate" which is currently just $0.0248/kWh in BHP's territory.[13]

BHP has now proposed to change from this "net billing" construct to a new "Buy All / Sell All" tariff (BA/SA Tariff) under which a solar customer would be required to sell all of its output to BHP at the low avoided cost rate. This proposal appears on its face to be contrary to the Federal Energy Regulatory Commission's rules implementing PURPA, which obligate a utility to purchase, at an avoided cost-based price, "any energy and capacity which is made available from a qualifying facility."[14] QFs have the option to make available either their entire output or just their excess production after serving their own load; we are not aware that the utility can dictate that a QF must sell their entire output to the utility.

State regulators periodically re-evaluate the economics of solar DG, particularly in states with high levels of solar DG penetration. These reviews often consider the impacts of DG compensation on other, non-participating ratepayers, to gauge whether there are any unreasonable "cost shifts" associated with NEM or net billing. These periodic analyses are important, and it is critical to recognize that non-participating ratepayers are not the only stakeholders in DG deployment. As discussed below, policymakers also should weigh the interests of: a) the customer who makes a long-term investment in solar; b) all ratepayers collectively; and c) the citizens of the state as a whole. Finding a balance of interests among of all of these stakeholders should constitute the public interest in assessing the DG metering policy in South Dakota.

Some states with high penetrations of solar have moved away from net metering at the full retail rate. On electric systems where the penetration of solar resources is high, the hours of greatest concern for reliability shift into the evening, at or just after sunset. This reduces the value of solar, and can prompt an evaluation of the merits of full retail NEM and a change to reduce NEM compensation, for instance, by using a net billing structure that reduces the export rate to a level less than the retail rate. In California and Hawaii, for example, this re-evaluation of NEM did not occur until solar DG penetration reached about 5% and 15%, respectively, of peak demand. This experience indicates that solar DG penetration of at least 5% of peak demand is a

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11 Although behind-the-meter DG systems meet the requirements for a qualifying facility, FERC has held that a state requirement that utilities must credit customers for exports at the retail rate (i.e. full retail NEM) does not run afoul of PURPA's avoided cost requirement. See MidAmerican Energy Co., 94 FERC ¶ 61,340 (2001).

12 South Dakota Statutes 49-34A-4. See https://sdlegislature.gov/Statutes/Codified_Laws/2070675.

13 See https://puc.sd.gov/Dockets/Electric/2019/EL19-022.aspx. Note that BHP's avoided cost calculation is confidential.

14 See 18 C.F.R. §292.303(a).

first indicator of when a state may want to evaluate whether an approach different than NEM is appropriate. South Dakota's overall solar penetration is far lower than 5% of the state's peak demand, and South Dakota has never had full retail NEM.

How many of BHP's customers currently have solar DG? The *2021 IRP* only provides national renewable generation trends and does not include any data about how many BHP customers have behind-the-meter DG.[15] In recent discussions, BHP has stated to the intervenors in the BA/SA Tariff proceeding that BHP currently has less than 200 DG customers out of a total of about 72,000 in South Dakota.[16] This is equivalent to a penetration of less than 0.3%. Thus, solar DG penetration will not reach 5% of peak demand in BHP's service area for a long time, probably more than a decade at the current rate of customer adoption.

2. Methodology

Solar DG should be considered a long-term generation resource for South Dakota. New solar DG systems will provide benefits to the electric utilities for at least the next 25 years. Thus, this analysis develops 25-year levelized benefits and costs for solar DG on BHP's system.

It should be noted that the issues raised by the growth of behind-the-meter DG are not new. The same issues of impacts on the utilities, on non-participating ratepayers, and on society as a whole also arose when state regulators and utilities began to manage demand growth through energy efficiency (EE) and demand response (DR) programs. To provide a framework to analyze these issues in a comprehensive fashion, the utility industry developed a set of standard cost-effectiveness tests for demand-side programs. These tests examine the cost-effectiveness of demand-side programs from a variety of perspectives, including from the viewpoints of the program participant, other ratepayers, the utility, and society as a whole.

This framework for evaluating demand-side resources is widely accepted, and state regulators have years of experience overseeing this type of cost-effectiveness analysis, with each state customizing how each test is applied and the weight which policymakers place on the various test results. This suite of cost-effectiveness tests is now being adapted to analyze net metering and behind-the-meter DG, as state commissions recognize that evaluating the costs and benefits of all demand-side resources – EE, DR, and DG – using the same cost-effectiveness framework will help to ensure that all of these resource options are evaluated in a fair and consistent manner. It should also be noted that BHP currently does not have any demand-side management (DSM) plans. As stated in the *2021 IRP*: "On September 1, 2020, the utility discontinued its South Dakota DSM program because of the inability to establish a portfolio of energy efficient offerings that are and that will remain cost-effective."[17]

The long-term benefits and costs of net-metered solar DG will be evaluated from multiple perspectives in this analysis, using each of the major cost-effectiveness tests widely used in the

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15 See *2021 IRP*, at pp. 3-10 to 3-11 and 3-15.

16 Per Marc Eyre, Vice President of Operations at BHP, in a meeting with BA/SA Tariff intervenors on November 15, 2022.

17 See *2021 IRP*, at p. 3-17.

utility industry.[18] Each of the principal demand-side cost-effectiveness tests uses a set of costs and benefits appropriate to the perspective under consideration. These are summarized in **Table 2** below ("+" denotes a benefit; "-" a cost).

Table 2: *Demand-side Benefit (+) and Cost (-) Tests*

Category	Total Resource Cost (TRC)	Ratepayer Impact Measure (RIM)	Program Administrator - Utility (PAC)	Participant (PCT)
Capital and O&M Costs of the DG Resource	–			–
Utility Lost Revenues (same as Customer Bill Savings)		–		+
Costs for Incentives (if available)	–	–	–	+
Integration and Program Administration Costs	–	–	–	
Avoided Costs -- Energy -- Generation Capacity -- T&D, including losses -- Risk / Hedging / Market -- Environmental Compliance -- RPS (not applicable in SD)	+	+	+	
Federal Tax Benefits	+			+

The key goal for regulators is to implement demand-side programs that produce balanced, reasonable results when the programs are tested from each of these perspectives. In this case, the current net billing approach used by BHP is the program under evaluation. First, the program should provide a resource that is a net benefit to the utility system and to society – thus, the Total Resource Cost (TRC) Test compares the costs of solar DG systems to their benefits to the BHP system. Second, the DG program will need to pass the Participant test if it is to attract customers to make long-term investments in DG systems. Finally, the Ratepayer Impact Measure (RIM) test gauges the impact on other, non-participating ratepayers. The RIM

[18] See the California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects (October 2001), available at https://www.raponline.org/wp-content/uploads/2016/05/cpuc-standardpractice-manual-2001-10.pdf. We assume that these tests are also used in South Dakota, with the Total Resource Cost test being the primary test for assessing the cost-effectiveness of energy efficiency portfolios.

test sometimes is called the "no regrets" test because, if a program passes the RIM test, then all ratepayers are likely to benefit from the program. However, it is important to keep in mind that the RIM test measures equity among ratepayers, not whether the program provides an overall net benefit as a resource (which is measured by the TRC test).

Data. Crossborder has obtained data on avoided energy costs from current electric market prices in South Dakota and the expected long-term trajectory of these prices. Data on the line losses that distributed resources can avoid are available from BHE's most recent IRP. Data on BHP's loads and its transmission and distribution (T&D) costs from FERC Form 1 is used to calculate the utility's long-run avoided T&D costs. Finally, EPA air emissions data are used to determine the avoided costs for environmental compliance. This analysis is based entirely on public data sources without the use of confidential data.

Benefits. The quantifiable direct benefits of DG include:

- avoided energy,
- avoided generation capacity,
- avoided transmission and distribution (T&D) capacity,
- avoided environmental compliance costs, and
- avoided line losses.

Our methodologies for quantifying these benefits are discussed in detail below. Several of the most important (and beneficial) characteristics of DG are the shorter lead times and smaller, scalable increments in which DG is deployed, compared to large-scale generation resources. In this respect, DG should be treated like energy efficiency and demand response, which also are small-scale, short-lead-time resources. For example, the modest amounts of DG included in BHP's service territory combine with on-going EE and DR to defer the need for larger-scale resources in the long-run. Based on BHE's *2021 IRP*, the utility appears to have a continuing need for new clean energy resources over the next decade.

New renewable generation from wind and solar has essentially zero variable costs, and will displace marginal fossil generation at natural gas and coal plants. This will have market impacts that also will reduce long-term ratepayer costs, including:

- **Fuel hedging benefits.** Renewable generation, including solar DG, reduces a utility's exposure to volatility in fossil fuel prices – in particular, natural gas.
- **Price mitigation benefits.** Solar generation, at any scale, reduces market demand both for electricity and for the natural gas used to produce the marginal kWh of power. These reductions have the broad benefit of lowering prices across the gas and electric markets in which BHP and other South Dakota utilities operate.

Solar DG also provides a number of societal benefits to the citizens of South Dakota. Customer-sited generation allows customers to enhance the reliability and resiliency of their electric service, expands competition to provide electric service, and increases customers' freedom to choose the sources of their energy supplies. Renewable DG also provides important environmental benefits, such as reduced emissions of greenhouse gases and criteria air pollutants, and lower use of water resources. Finally, the installation of DG systems provides new local businesses that have a positive impact on the local economies where the systems are installed. Although all of these societal benefits of DG can be quantified, and are substantial, that work is beyond the scope of this study.

Costs. The benefit-cost tests summarized in Table 2 use different metrics on the cost side, depending on the perspective that each test examines.

The Total Resource Cost and Participant Tests use the capital, financing, and operating costs for solar DG systems, as incurred by the participating customers who install solar. These include the installation costs for the systems (offset by the federal investment tax credit), plus the costs for financing, maintenance, and periodic inverter replacement. For those tests in which the utility's costs are relevant, we add an estimate of the solar integration costs which BHP will incur to incorporate these resources into its system, based on a study of such integration costs that is included in the *2021 IRP*.

In the RIM Test, the costs of solar DG for non-participating ratepayers are principally the revenues which the utility loses from customers serving their own load with DG. To these lost revenues we add the estimate of solar integration costs.

The following sections discuss each of the benefits and costs of solar DG for BHP. Solar DG is a long-term resource with an expected useful life of at least 25 years. Accordingly, we calculate the benefits and costs of DG over a 25-year period in order to capture the value of these long-term resources. We express the results as 25-year levelized costs using BHP's weighted average cost of capital (WACC) of 7.76% as the discount rate.[19]

3. Direct Benefits of Solar DG

a. Energy

Solar DG systems avoid the energy costs of the marginal source of electric generation. The most direct source for determining these avoided energy costs are wholesale electric market prices in the region where BHP operates. There is now an Energy Imbalance Market (EIM) that covers most of the WECC footprint and that provides granular, 5-minute real-time data on electricity market prices.[20] **Figure 1** below shows the still-expanding EIM footprint in the western U.S. Hourly EIM price data is available for the Wyodak power plant in eastern Wyoming, which is 20% owned by BHE and 80% owned by PacifiCorp (an EIM participant). Generation from Wyodak serves BHP's South Dakota service territory.[21] We believe this to be a reasonable price to use for BHP's avoided energy costs. We note that PacifiCorp, BHE's partner in Wyodak and a major investor-owned utility serving six western states, has characterized EIM prices in its Wyoming service territory as "a rough representation of the general magnitude of hourly marginal energy cost on PacifiCorp's PACE balancing authority area."[22]

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[19] This 7.76% discount rate is BHP's pre-tax weighted average cost of capital. See *2021 IRP*, at p. 7-27.

[20] See https://www.westerneim.com/Pages/About/default.aspx.

[21] These EIM prices are available on the California Independent System Operator (CAISO) OASIS website at the "WYODAKBH_LNODELD" node (the "WYODAK" node).

[22] See Direct Testimony of Robert M. Meredith in Rocky Mountain Power's general rate case in before the Wyoming Public Service Commission (Docket No. 20000-587-ER-20), at p. 42.

Figure 1: *The EIM Participants in the WECC*

The energy market costs that solar generation can avoid are the EIM prices in the region of BHP's South Dakota service territory, weighted by the hourly output of a typical solar system. We used the National Renewable Energy Laboratory's (NREL) PVWATTS calculator to estimate the average hourly solar capacity factor by month and hour for a typical rooftop solar system in Rapid City, South Dakota, as shown in **Table 3** below. The table shows the solar capacity factor in each daylight hour.

Table 3: *PVWATTS Output Profile for Solar PV in Rapid City, South Dakota*

Hour	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Average
7	0%	7%	7%	12%	19%	18%	17%	12%	9%	2%	6%	0%	1%
8	17%	26%	24%	31%	36%	36%	35%	33%	29%	17%	22%	15%	9%
9	29%	41%	40%	46%	50%	50%	51%	51%	44%	35%	37%	33%	27%
10	43%	57%	54%	59%	62%	61%	61%	61%	57%	49%	46%	46%	42%
11	55%	63%	60%	71%	69%	66%	70%	71%	67%	59%	53%	54%	55%
12	53%	65%	72%	72%	76%	73%	77%	75%	74%	66%	57%	50%	63%
13	49%	61%	73%	73%	74%	74%	76%	75%	68%	57%	44%	41%	67%
14	43%	49%	63%	65%	67%	70%	62%	71%	60%	57%	35%	27%	64%
15	24%	33%	50%	55%	58%	60%	54%	63%	52%	43%	18%	12%	56%
16	2%	13%	33%	43%	47%	48%	44%	49%	40%	27%	2%	0%	44%
17	0%	0%	15%	24%	29%	34%	35%	31%	20%	7%	0%	0%	29%
18	0%	0%	3%	8%	12%	16%	17%	11%	3%	0%	0%	0%	16%
19	0%	0%	0%	0%	2%	3%	3%	1%	0%	0%	0%	0%	6%
Average	13%	17%	21%	23%	25%	26%	25%	25%	22%	17%	13%	12%	**20.0%**

Table 4 below indicates that the level of calendar year 2022 EIM prices at WYODAK in the daylight hours. In the final column, we weight the hourly EIM prices by the hourly solar capacity factors from Table 3. The solar-weighted EIM price at WYODAK in 2022 was $43.90 per MWh. This is a measure of the avoided energy costs for a rooftop solar installation in 2022 in BHP's service territory. Note that this market price for energy was substantially higher than the export rate of $24.80 per MWh that BHP paid to its solar customers in 2022.

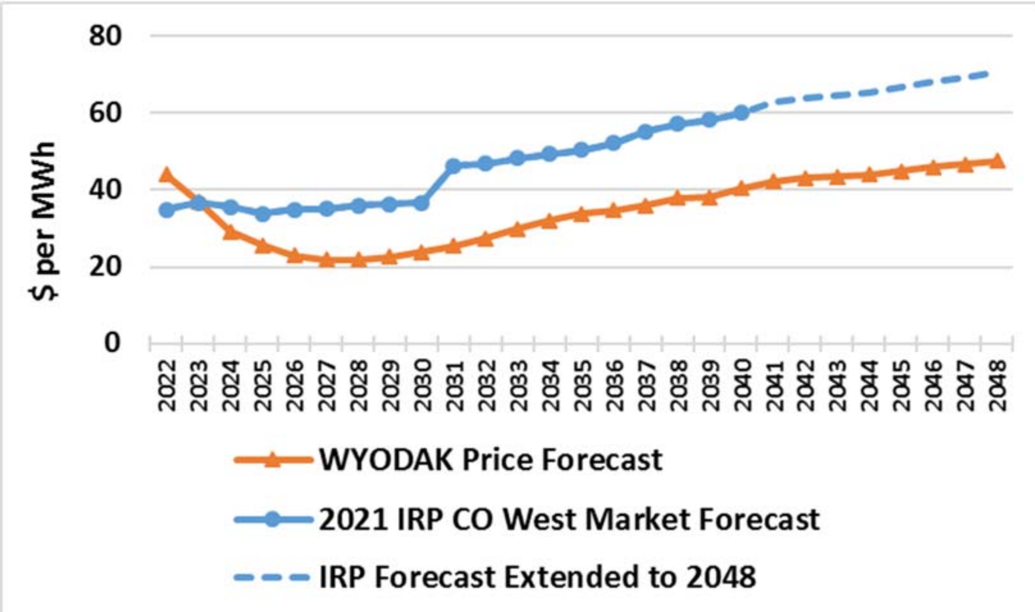
Table 4: *2022 WYODAK EIM Hub Prices ($/MWh)*

12x24	1	2	3	4	5	6	7	8	9	10	11	12	Solar Average
1	31.2	30.9	32.0	52.4	44.0	19.3	53.2	57.9	57.3	54.6	68.6	174.5	-
2	29.5	30.4	31.4	47.9	41.1	15.0	43.0	57.8	53.8	56.2	68.7	172.5	-
3	29.7	29.6	27.0	44.4	39.1	10.6	40.6	55.9	54.7	52.5	67.7	173.9	-
4	28.9	29.6	26.6	42.9	38.2	9.1	37.5	54.5	50.8	51.5	66.8	172.0	-
5	31.0	31.2	26.6	44.6	37.8	9.3	36.7	54.2	51.2	52.1	68.3	171.3	**17.3**
6	31.9	34.2	28.6	47.5	41.3	12.3	38.3	53.5	54.5	56.5	72.9	184.4	**32.6**
7	32.1	39.2	31.6	50.1	44.7	17.9	41.7	59.4	61.0	61.5	78.4	196.8	**44.8**
8	35.0	42.0	32.7	51.1	44.4	15.4	39.7	57.8	62.5	67.2	92.9	218.3	**55.5**
9	28.7	31.3	30.5	37.8	27.5	9.4	35.2	53.6	55.9	69.7	98.0	237.0	**54.6**
10	23.6	22.0	24.3	32.6	20.7	15.3	37.1	46.7	48.6	46.5	67.5	195.0	**45.7**
11	29.6	20.5	23.0	26.1	20.3	17.5	38.8	46.5	47.7	44.5	58.3	185.1	**44.3**
12	23.4	19.4	18.1	21.0	20.2	19.9	44.3	51.2	48.6	41.9	53.7	179.8	**41.9**
13	21.9	16.3	14.6	21.2	20.5	24.7	44.6	56.8	50.5	42.5	50.7	168.2	**40.1**
14	20.4	14.9	13.3	20.0	22.1	30.7	48.5	60.8	55.1	42.7	47.7	156.0	**39.4**
15	19.0	13.8	12.0	18.3	22.7	38.8	57.7	70.3	58.4	43.0	48.0	152.2	**40.8**
16	18.1	10.5	10.4	19.3	25.4	27.0	58.9	73.4	60.7	45.7	49.7	158.9	**39.6**
17	24.8	13.4	11.5	22.2	28.3	22.1	64.8	79.8	87.3	47.2	69.2	187.3	**46.5**
18	37.0	30.0	15.2	20.6	26.8	20.9	66.0	67.0	84.7	53.2	78.9	207.8	**42.4**
19	29.9	37.4	32.9	29.2	30.0	20.2	64.5	71.4	113.6	67.8	77.4	198.9	**42.5**
20	31.0	34.2	45.2	54.1	45.8	21.6	62.7	116.1	179.9	62.2	73.5	195.6	**46.4**
21	32.1	33.4	30.1	53.1	53.0	35.7	73.5	106.3	133.7	58.1	72.9	204.8	-
22	32.4	34.3	30.2	51.0	49.8	25.7	60.6	72.8	56.2	58.9	75.6	206.5	-
23	31.2	35.4	28.6	50.8	45.9	21.1	50.4	66.7	50.5	59.4	75.1	199.2	-
24	33.2	32.5	30.1	54.2	50.7	24.2	67.0	62.3	61.1	60.0	73.1	190.8	-
Average													**43.9**

To derive a long-term forecast of avoided energy costs, we escalate the solar-weighted average price for the WYODAK node, $43.90 per MWh as shown in Table 4, using the EIA's long-term forecast for natural gas commodity prices in EIA's 2023 *Annual Energy Outlook*. The following **Figure 2** shows the resulting projection of long-run solar-weighted avoided energy costs for BHP (the orange line in the figure). The starting point for the forecast is the $43.90 per

MWh solar-weighted EIM price in 2022. The figure also shows the long-term projection of solar-weighted energy prices in the CO West Market Area that BHE modeled in its *2021 IRP*.[23] This forecast of energy market prices from the *2021 IRP* (the blue line in Figure 2) is higher than our forecast of solar-weighted prices.

Figure 2: *Long-run Solar-weighted Avoided Energy Costs for BHP*



We have levelized our forecast of avoided energy costs over the 25-year period from 2023 to 2048 using a discount rate equal to the utility's WACC from the 2021 IRP (7.76%).[24] The levelized avoided cost also assumes that solar output declines by 0.5% per year, based on the industry-standard assumption for the degradation over time in solar panel output.

With these inputs, **Table 5** below shows the 25-year levelized forecast of BHP's avoided energy costs for solar DG.

Table 5: *Avoided Energy Costs (25-year levelized 2023 $/MWh)*

Scenario	**Base Case**	**High Case**
Source	WYODAK EIM Prices in 2022	BHE *2021 IRP* CO West Prices
2022 Starting Price (solar-weighted)	$43.90	$34.80
Escalation	EIA *2023 AEO* Natural Gas	See Figure 2
Avoided Energy ($/MWh)	**$30.10**	**$45.50**

23 See Appendix N, 2021 IRP Modeling Summary, Table 3, page N-19.

24 See *2021 IRP*, at Appendix D, p. 2-2. The WACC from the settlement in BHP's last South Dakota rate case apparently is not public information. See *2021* IRP, at p. 4-10.

b. Generation capacity

Distributed solar generation will provide generation capacity to a utility based on its output during the peak demand periods that drive the need for that capacity. The capacity contribution of a solar resource is a fraction of its nameplate capacity, because solar will not be producing at full nameplate during the afternoon hours when demand peaks. Further, the addition of significant solar resources can shift the need for capacity to later in the afternoon or into the evening, diminishing solar's capacity contribution over time as solar penetration grows.

BHP's peak demands occur in mid-afternoon hours in the summer months. During a meeting with the BA/SA Tariff intervenors, BHP stated that their peak loads occur between the hours of 3:00 pm to 5:00 pm (i.e. 15:00 -17:00).[25] In October 2022 comments in a demand response docket before the South Dakota Public Utilities Commission (SDPUC), BHP stated that "[m]onthly system peak loads tend to occur between the hours of 3:00 pm and 7:00 pm during the months of May through September and varies between the hours of 8:00 am and 6:00 pm during the other months."[26] We reviewed BHP's FERC Form 1 reports to determine when peak demand times have occurred over the last 4 years, with the data summarized in **Table 6** below.[27]

Table 6: *BHP's Peak Demand Times by Month in 2019-2022*

Month	2019	2020	2021	2022	Average
January	1900	1800	1500	1800	1750
February	2000	0900	1100	0700	1175
March	2000	1100	1900	0700	1425
April	0900	0900	0900	0800	0875
May	1800	1700	1600	1600	1675
June	1700	1600	1700	1500	1625
July	1600	1600	1600	1500	1575
August	1600	1900	1700	1600	1700
September	1700	1700	1700	1600	1675
October	0800	1900	1600	0900	1300
November	1800	1800	1800	1700	1775
December	0800	1700	1800	1800	1525

This data show that peak demand occurs at various times during the year, with the critical summer months of May - September highlighted. The data confirm BHP's statements that their peak demand in the summer months of the past several years does indeed occur between the hours of 3:00 p.m. to 5:00 p.m. Looking at the data in Table 3 on solar capacity factors by month and hour, a solar system on BHP's system will have an average capacity factor of 38% of nameplate in the hours between 3 p.m. and 5 p.m. from May to September. This is one metric of solar's capacity contribution.

[25] Per Jason Keil, BHP Manager - Regulatory & Finance, in a meeting with EL-21-011 Intervenors on May 17, 2022.

[26] See page 2 of BHP's October 28, 2022 filing in SDPUC Docket No. AA22-003, available at https://puc.sd.gov/Dockets/Admin/2022/AA22-003.aspx.

[27] Data is from FERC Form 1 for Black Hills Power (see https://elibrary.ferc.gov/eLibrary/search).

Another similar metric of solar's capacity contribution is to look at solar output in all hours when BHP's demand was within 10% of its peak hourly demand for the year. We have used BHP's load data reported in FERC Form 1 to identify such hours in 2022. We then weighted the solar output in each of these high-demand hours by how much the demand in each hour exceeds the threshold of 90% of the highest hourly demand in that year. This placed the greatest weight on the annual peak hour. This "peak capacity allocation factor" (PCAF) method resulted in a solar capacity contribution of 41% of nameplate.

These two metrics support a solar capacity contribution of 40% of nameplate on BHP's system.

The next step is to determine BHP's avoided cost for generation capacity. The utility's *2021 IRP* finds that BHP has a continuing need for new generating capacity to meet a current shortfall in capacity. BHP plans to meet its load growth with 100 MW of new renewable generation, with the preferred scenario including a mix of solar and battery storage. The battery storage represents a pure capacity addition, and we have used the costs for new battery storage as BHP's avoided cost of capacity.

Battery storage costs have changed significantly since the 2021 IRP, as a result of the 2022 Inflation Reduction Act (IRA). The IRA provides for a 30% investment tax credit for new standalone battery storage. We have used a recent estimate of battery storage costs in the western U.S. that uses utility-scale battery cost data from NREL's *2022 Annual Technology Bulletin* (NREL 2022 ATB) and a pro forma model of levelized battery costs developed by Energy and Environmental Economics (E3), including the cost reductions due to the IRA.[28] We also reduce the capacity costs of the battery by an estimate from PacifiCorp's current IRP of the energy rents that utility-scale batteries can earn in western energy markets.

The capacity value of distributed solar PV is based on its ability to reduce the peak demand for power on the grid. This reduced peak demand also lowers the reserve capacity that the utility must maintain to serve that peak. BHP's current planning reserve margin is 15%.[29] Accordingly, we increase avoided capacity costs by 15% to reflect the benefit of the lower required reserves.

Assembling all of these considerations, **Table 7** presents the complete calculation of BHP's avoided generation capacity costs of $51.80 per MWh for solar resources in its South Dakota territory.

[28] See the utility-scale Li-ion battery storage costs for 2022-2025, based on data from the NREL 2022 ATB, reported in California Public Utilities Commission, *Inputs & Assumptions: 2022-2023 Integrated Resource Planning* (June 2023), at Table 51 and Figure 9. Available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/draft_2023_i_and_a.pdf.

[29] See *2021 IRP*, at p. 1-4.

Table 7: *Calculation of Avoided Generation Capacity Costs*

Calculation of Avoided Generation Capacity Costs based on Battery Storage Costs					
Storage Capital Cost	*a*	$	1,550	*$/kW*	*NREL 2022 ATB, 2022$*
Levelized Annual Fixed Costs	*b*		181	*$/kW-year*	*2022$, from E3 pro forma model. Includes IRA ITC.*
Storage O&M	*c*	$	39		*2.5% of capital cost, from NREL 2022 ATB, 2022$*
Annual Cost	*d*	$	229		*d = b + c, converted to 2023$ assuming 4% inflation*
Energy Rents	*e*	$	(31)		*PAC 2021 IRP, at Appendix N, Table N.1 for 2024-2040*
Planning Reserve Margin	*f*		15%		*BHE 2021 IRP, at p. 1-4*
Net Capacity Cost	*g*	**$**	**227**		*g = (d + e) * (1 + f)*
Solar Capacity Contribution	*h*		40%		*from solar capacity factor at time of BHP summer peak demands*
Solar Capacity Value	*i*	$	91	*$/kW-year*	*i = g x h*
Annual solar output	*j*		1,750	*kWh per kW*	*PVWATTS solar output for Rapid City SD*
Avoided Generation Capacity	*k*	$	51.84	*per MWh*	*k = 1000 * (i / j)*

c. Line losses

The avoided energy and capacity costs calculated above are at the generation level, and need to be increased to reflect the marginal line losses on both the transmission and distribution systems that are avoided by customer-sited solar DG, which is located behind the customer's meter at the point of end use. BHE's *2021 IRP* references its system average line losses as 7.6%.[30] These line losses represent average losses over all hours. We have increased these losses by 50%, to 11.4%, to capture the higher marginal losses avoided by new DG resources, based on a study from the Regulatory Assistance Project on the relationship between average and marginal line losses.[31] The resulting loss factors are still conservative, in that they may not reflect the higher losses experienced during the peak demand hours in summer afternoons when solar output is high. **Table 8** shows our calculations of avoided line losses for both energy and capacity.

Table 8: *Avoided Line Losses ($ per MWh in 2023$)*

Avoided Cost	Value *($ per MWh)*	Average Loss Factor	Convert to Marginal Losses	Marginal Loss Factor	Avoided Losses *($ per MWh)*
Energy	30.10	7.6%	1.5	11.4%	3.40
Capacity	51.80	7.6%	1.5	11.4%	5.90
Total					9.30

d. Avoided transmission and distribution capacity

A significant share of the output of solar DG serves on-site loads. This share typically ranges from 40% to 60%, and depends on the size of the solar system and the load profile of the customer. The DG output used onsite never touches the grid, and thus clearly reduces loads on the utility's T&D system. The remaining excess generation from a solar DG unit is exported to the local distribution system. These exports are likely to be entirely consumed on the distribution

30 *Id.*, at p. 7-11.

31 Regulatory Assistance Project, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements* (August 2011), at p. 5. See http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

system by the solar customer's neighbors, unloading the upstream portions of the distribution system and the transmission system. Thus, like other demand-side energy-efficiency and demand response resources, solar DG displaces traditional generation sources which must use the utility T&D system to be delivered to customers. This makes more T&D capacity available for the utility to use to serve load growth.

Solar DG avoids transmission and distribution capacity costs to the extent that solar production occurs at times of peak demand on the T&D system. Solar DG helps the utility to manage and to reduce current loads and load growth, thus avoiding and deferring the need for load-related T&D investments. Solar DG also can defer the need for new transmission to access utility-scale renewables, if DG provides an alternative to larger-scale renewable projects to supply needed capacity or to meet renewable energy goals. These T&D benefits can be quantified by calculating the utility's marginal cost of load-related transmission and distribution capacity.

As DG penetration grows, and a deeper understanding is gained of the impacts of DG on the T&D system, utility T&D planners will integrate existing and expected DG capacity into their planning. A comparable evolution has occurred over the last several decades, as the long-term impacts of EE and DR programs are now incorporated into utilities' capacity expansion plans for generation, transmission, and distribution. It is generally recognized that these demand-side programs can help to manage demand growth and to avoid capacity-related costs for T&D as well as generation. Many U.S. utilities now include avoided T&D capacity costs among the benefits of their EE and DR programs.

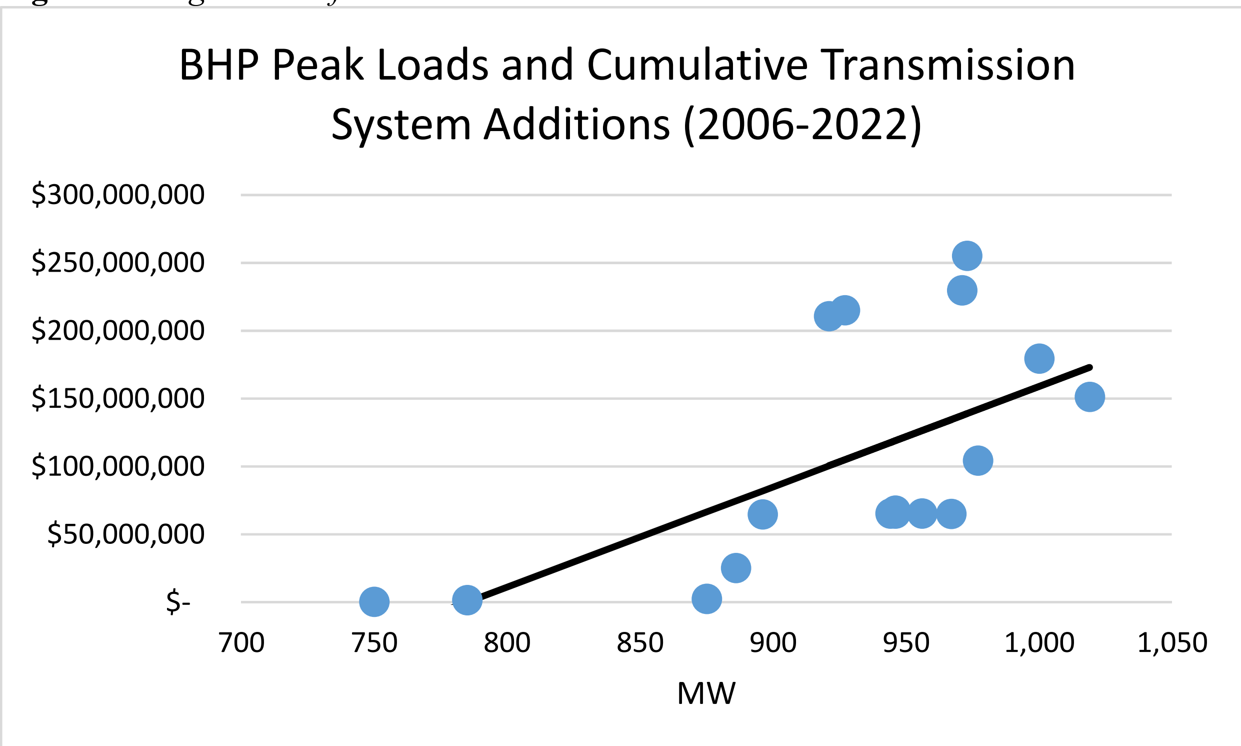
In this study, we have developed estimates of long-run avoided T&D costs for Black Hills. These estimates are based on long-term data on how BHP's investments in transmission and distribution have increased as a function of load growth. This long-term, "top-down" calculation captures the fact that peak loads impact T&D additions in many ways. Most directly, T&D infrastructure must be expanded as load grows, to serve peak demands. Load growth can also be an indirect factor in other types of T&D expansions and upgrades. For example, an upgrade may be required for reliability reasons to address contingencies that arise under high-load conditions, or to access new generation resources needed to serve growing customer demands. Although peak demand may not be the primary driver of these projects, it has a significant influence on the need to invest in T&D infrastructure. Even replacement projects are demand-related in that they are necessary to keep the grid's capacity from decreasing.

To calculate long-term avoided T&D investment costs, we have used the well-accepted National Economic Research Associates (NERA) regression method. This approach is used by many utilities to determine their marginal transmission and distribution capacity costs that vary with changes in load. The NERA regression model fits incremental T&D investment costs to peak load growth. The slope of the resulting regression line provides an estimate of the marginal cost of T&D investments associated with changes in peak demand. The NERA methodology typically uses 10-15 years of historical expenditures on T&D investments and peak transmission system loads, as reported in FERC Form 1, and, if available, a five-year forecast of future expenditures and expected load growth.

i. Transmission.

We have utilized a NERA regression based on BHP's historical peak load growth and transmission expenditures, over a 17-year period from 2006 to 2022. Our analysis of marginal transmission costs uses BHP's FERC Form 1 data for this period. **Figure 3** shows the regression fit of cumulative transmission capital additions as a function of incremental demand growth on the BHP system.

Figure 3: *Regression of Cumulative Transmission Costs vs. Peak Transmission Demand*



The regression slope resulting from this analysis is $739 per kW. We convert to an annualized marginal transmission cost using a real economic carrying charge (RECC) of 6.5%,[32] add 6.9% to this amount as a general plant loader, and include $24.33 per kW-year for transmission O&M costs.[33] The resulting avoided cost for transmission capacity for BHP is $75.65 per kW-year.

[32] Based on BHP's currently-authorized capital structure and cost of capital, at a 7.76% WACC.

[33] Our estimates of general plant and transmission O&M costs are also based on data from BHP's FERC Form 1.

Table 9: *BHP Marginal Transmission Cost*

Parameter	Value
Slope ($/kW)	739
RECC Factor	6.5%
Annualized Transmission ($/kW-year)	48.02
General Plant Loader (%)	6.9%
General Plant Loader ($/kW-year)	3.29
Transmission O&M ($/kW-year)	24.33
Total Annual Marginal Cost ($/kW-yr)	**75.65**

The next step is to convert a portion of this marginal transmission capacity value into an equivalent price per kilowatt-hour that considers the extent to which solar DG avoids investments in marginal T&D capacity. Distributed generation can avoid transmission investments by reducing peak loads on the BHP transmission system. We determined that the capacity contribution of solar PV to reducing peak transmission loads is 25.9% of the solar nameplate capacity. This is based on our analysis of solar output in Rapid City at the time of BHP's annual peak loads in each year from 2006 to 2022, using transmission system peak load data from BHP's FERC Form 1.

Table 10 shows our calculations of the avoided cost of transmission capacity for BHP. We escalate the levelized cost of T&D capacity by 2% per year over a 25-year period, then calculate a levelized price of $89.60 per kW-year for 2023-2047, including standard degradation of 0.5% per year in solar output and using BHP's 7.76% discount rate. We then multiply this 25-year marginal transmission cost times the 25.9% solar capacity contribution at the time of historical peak transmission loads. We convert the marginal transmission costs avoided by solar in $ per kW-year into a $ per MWh value by dividing by the annual solar output of 1,750 kWh per kW-AC. The result is that solar DG avoids transmission capacity costs of $13.26 per MWh of solar output

Table 10: *25-year Levelized Avoided Transmission Capacity Cost for Solar DG*

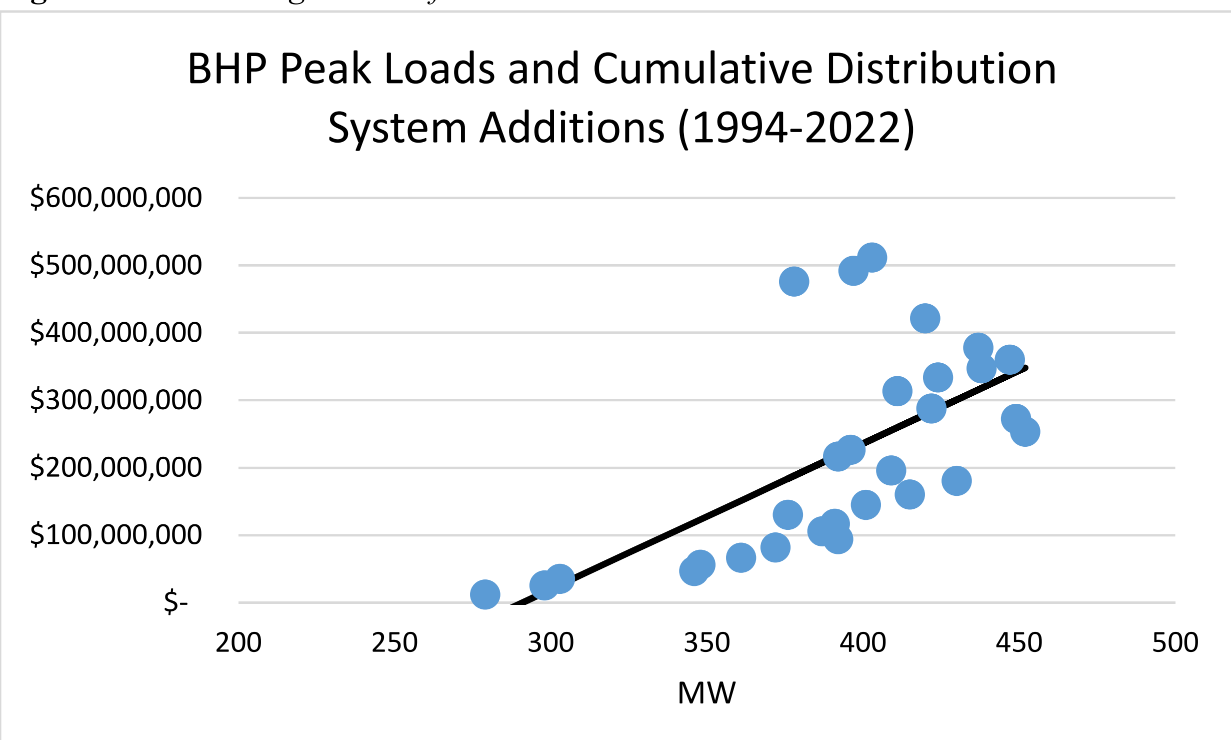
Parameter	Value	Notes
Avoided Transmission Capacity Cost	75.65	*From Table 9*
Annual Escalation Rate	2.0%	*General inflation*
Annual Degradation Rate	0.5%	*Industry standard*
25-year Levelized Cost (2023 $)	$89.60 per kW-year	*Assumes a 7.76% discount rate*
Solar Contribution to BHP System Peak Load	25.9%	*Annual Peak calculation*
Solar Output – Annual kWh per kW-AC	1,750 kWh/kW-AC	*NREL PVWATTS for Rapid City, South Dakota*
Solar Avoided Transmission Capacity Cost	**$13.26 per MWh**	*$89.60 x 0.259 / 1750*

ii. Distribution.

The extent to which solar generation avoids distribution capacity costs is a more complex question than for transmission, for various reasons. Distribution substations and circuits can peak at different times than the system as a whole, which complicates the calculation of the avoided distribution costs that result from solar DG reducing distribution system loads. It is clear, however, that the significant share of solar DG output which serves on-site loads will reduce demand on the distribution system, because that power is consumed behind the meter, never touches the grid, and will reduce the loads that must be served from the grid. Further, the remaining DG output that is exported to the distribution system will serve nearby loads, and thus will unload upstream portions of the local distribution system. As a result, solar DG will reduce distribution system loads, avoiding the cost of distribution system expansions or upgrades, and extending the life of existing equipment.

To calculate BHP's marginal distribution costs, we use the same NERA regression method discussed above, using historical peak load growth and distribution expenditures, from FERC Form 1, over the years 1994 to 2022.[34] **Figure 4** shows the regression fit of cumulative distribution capital additions as a function of incremental demand growth on the BHP system.

Figure 4: *Linear Regression of Cumulative Distribution Costs vs. Peak Demand*



Converting the regression slope of $2,162 per kW to an annual cost using a RECC of 6.5%, and adding loaders for general plant and O&M from FERC Form 1 data, results in an annualized marginal distribution cost of $168.52 per kW-year.

[34] Form 1 system peaks are available starting in 1994; whereas transmission-system peaks begin in 2006.

Table 11: *BHP Marginal Distribution Cost*

Parameter	Value
Slope ($/kW)	2,162
RECC Factor	6.5%
Annualized Distribution ($/kW-year)	140.55
General Plant Loader (%)	6.9%
General Plant Loader ($/kW-year)	9.64
Distribution O&M ($/kW-year)	18.33
Total Annual Marginal Cost ($/kW-yr)	**168.52**

For the solar capacity contribution to reducing distribution costs, we used an average of solar capacity factors at the time of BHP's annual peak system loads in 1994 to 2022. Using, modeled PV output at Rapid City, the result is a capacity contribution of 43.5% of solar nameplate to reducing the highest distribution loads. **Table 12** shows the resulting calculation of avoided distribution costs on a $ per MWh basis.

We recognize that BHP's winter peak loads are not significantly less than its summer peak loads, although it does not appear that BHP has peaked in the winter months in recent years. We acknowledge that winter peak hours are likely to fall in the evening or early morning, outside of hours of significant solar output. As a result, there is a question of whether solar can avoid distribution projects designed to serve increases winter peak loads. Thus, we assign a solar capacity contribution of zero to avoiding winter peak loads, and therefore reduce the overall solar capacity contribution by 50%. In the future, distributed solar can address both the summer and winter peaks – and make a non-zero capacity contribution in winter months – if it is paired with storage and time-of-use pricing that signals customers to time-shift a significant portion of their solar output to the hours of the local distribution peak demands. Our 50% discount to distribution capacity costs reflects the complication of winter-peaking loads and the time that may be required before there is significant penetration of solar-paired-storage systems.

Table 12: *25-year Levelized Avoided Distribution Costs for BHP*

Parameter	Value	Notes
Avoided Distribution Capacity Cost	168.52	*From Table 11*
Annual Escalation Rate	2.0%	*General inflation*
Annual Degradation Rate	0.5%	*Industry standard*
25-year Levelized Cost (2023 $)	$200 per kW-year	*7.76% discount rate*
Solar Contribution to BHP Distribution Load	43.5%	*Annual peak calculation*
Discount for Winter-peaking Distribution Systems	50%	
Solar Output – Annual kWh per kW-AC	1,750 kWh/kW-AC	*NREL PVWATTS for Rapid City, South Dakota*
Solar Avoided Distribution Capacity Cost	**$24.80 per MWh**	*$200 x 0.435 x 0.5 / 1750*

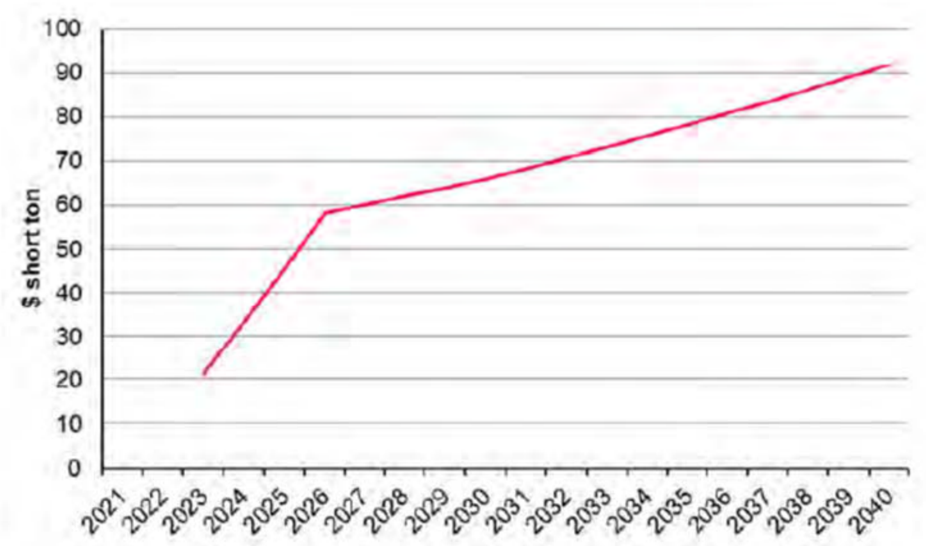
We note that this regression analysis considers only the historical relationship between distribution capital additions and load growth. Moving forward, with the advent of smart inverters and other technologies, PV systems will be able to provide additional services and avoid new categories of costs in addition to those attributable to capacity expansion alone. Such services include voltage regulation, power quality, and conservation voltage reduction. For these reasons, this estimate of avoided distribution costs should be considered conservative.

e. Avoided carbon emission compliance costs

Solar PV will avoid carbon emissions from traditional fossil-fueled power plants, and thus avoid the possible compliance costs associated with those emissions. Our analysis uses the Environmental Protection Agency's (EPA) "AVoided Emissions and geneRation Tool" (AVERT) to calculate the avoided carbon emissions due to solar DG installations in South Dakota. AVERT calculates hourly avoided emissions based on a given hourly profile for energy efficiency savings or renewable energy production. Our model assumes 1 MW of DG solar in the state, uses a PV profile for Rapid City, and the Rocky Mountain AVERT regional data file to calculate the avoided carbon emissions in South Dakota. The avoided carbon emissions are 1.71 lbs per kWh of DG output.

Figure 5 shows the carbon emission compliance costs (in $ per short ton) used in certain "environmental" scenarios in the *2021 IRP*.[35] These carbon costs are based, after 2026, on the U.S. Environmental Protection Agency's (EPA) social cost of carbon (SCC) developed during the 2010s as a measure of the societal damages from unmitigated climate change.

Figure 5: *Carbon Cost Forecast Used in BHE's 2021 IRP*



(Source: Energy Market Advisors)

[35] See 2021 IRP, at Appendix N, p. N-23.

Based on the carbon compliance costs in Figure 5 and the modeled avoided carbon emissions of 1.71 lbs per kWh, we calculate that the 25-year levelized avoided costs for carbon compliance are **$45.80 per MWh**, assuming a 7.76% discount rate and 0.5% annual solar output degradation.

South Dakota does not have a direct compliance regime for carbon emissions, nor is there a federal carbon tax or regulatory requirement to reduce carbon emissions. Nonetheless, U.S. utilities generally are planning to phase out their carbon emissions over time. Consistent with that trend, BHP has a corporate goal to reduce the carbon intensity of its utilities by 70% by 2040.[36] Like most U.S. utilities, BHE includes a scenario in its *2021 IRP* that include the carbon cost forecast in Figure 5 in the underlying economic assumptions.[37] The BHE *2021 IRP* states: "Cheyenne Light and Black Hills Power proactively seek solutions to reduce carbon emissions from fossil fuel generation."[38] Whether there is a non-zero carbon cost implicit in BHE's future resource plans is difficult to untangle.[39] We have not used the avoided carbon cost calculated above in our direct avoided costs for solar DG, but report the quantified value as an indicator of the value to the ratepayers and citizens in BHP's service territory of the reductions in carbon emissions that the utility is including in its planning efforts.

f. Reducing fuel price uncertainty

Renewable generation, including solar DG, reduces a utility's use of natural gas, and thus decreases the exposure of ratepayers to the volatility in natural gas prices, as exemplified by the periodic spikes in natural gas prices. Such spikes have occurred regularly over the last several decades, as shown in the plot of historical benchmark Henry Hub gas prices in **Figure 6** below.[40] The most recent example of such volatility in the western U.S. occurred in December 2022 and January 2023, when pipeline constraints in the West caused spikes in the delivered price of natural gas. The high electric market prices at WYODAK prices in December 2022 shown in Table 4 above reflect this recent example of fossil fuel price volatility.

Renewable generation also hedges against market dislocations or generation scarcity such as was experienced throughout the West during the California energy crisis of 2000-2001 or as has occurred periodically during drought conditions in the U.S. that reduce hydroelectric output and curtail generation due to the lack of water for cooling. For example, in 2014, the rapidly increasing output of solar projects in California made up for 83% of the reduction in hydroelectric output due to the multi-year drought in that state.[41]

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[36] BHE *2021 IRP*, at p. 2-6.

[37] See the Environmental Scenario 2 in the BHE *2021 IRP*.

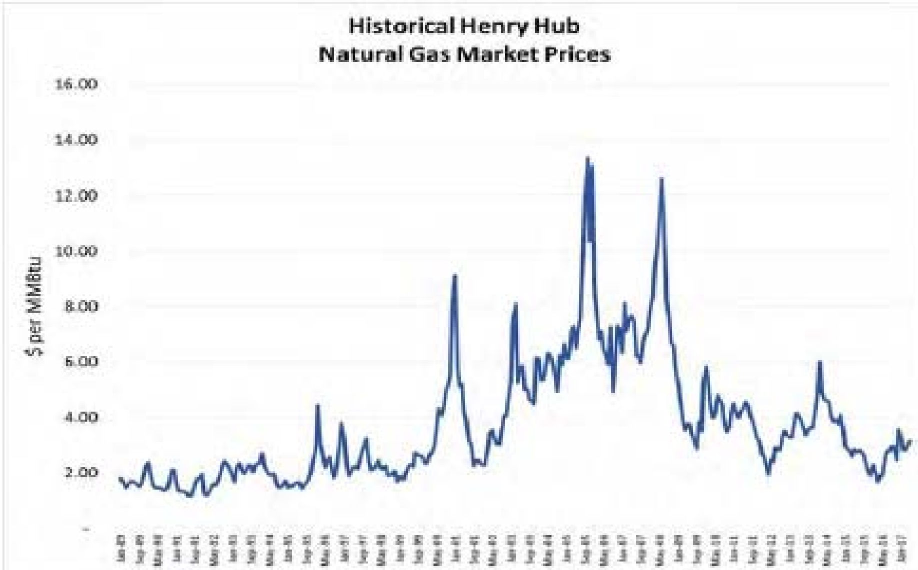
[38] See BHE *2021 IRP*, at p. 3-7.

[39] For example, BHP is planning to convert a coal unit to natural gas "as a hedge against potential environmental emission-reduction regulations and legislation" (2021 IRP, at p. 8-27). The value of this hedge – which also applies to the new renewables in the BHP resource plan – is unstated.

[40] Source for Figure 6: Chicago Mercantile Exchange data.

[41] Based on Energy Information Administration data for 2014, as reported in Stephen Lacey, As California Loses Hydro Resources to Drought, Large-Scale Solar Fills in the Gap: New solar generation made up for four-fifths of California's lost hydro production in 2014 (Greentech Media, March 31, 2015). Available at http://www.greentechmedia.com/articles/read/solar-becomes-the-second-biggest-renewable-energy-provider-in-california.

Figure 6



What is it worth to ratepayers to reduce their exposure to fossil fuel price volatility? It is worth what it would cost to fix the price of natural gas for 25 years, which is the economic life of the solar resource that displaces the gas. To calculate this benefit, we used the methodology developed by Clean Power Research for the *Maine Distributed Solar Valuation Study (Maine Study)*, a 2015 study commissioned by the Maine Public Utilities Commission.[42] This approach recognizes that one could contract for future natural gas supplies today, and then set aside in risk-free investments the money needed to buy that gas in the future, thus eliminating the uncertainty in future gas costs. The additional cost of this approach compared to purchasing gas on an "as you go" basis (and using the money saved for alternative investments) is the benefit to ratepayers from solar DG displacing fossil fuels that are subject to uncertain and volatile future prices. It is important to recognize that this value is significant – approaching the cost of the fuel itself – and thus it is almost never observed in practice. Because it is so expensive to fix the price of natural gas for a 20- or 25-year period, U.S. utilities typically purchase natural gas on a "pay-as-you-go" basis, with price hedging programs limited to a few years into the future and to just a fraction of the utility's gas supply.

This calculation for BHP has been performed assuming our base gas cost forecast (the EIA *AEO 2022* forecast), U.S. Treasuries (at current yields) as the risk-free investments, and a marginal heat rate of 8,000 Btu per kWh. The result is a value of **$19.80 per MWh** as the 25-year levelized benefit of reducing fuel price uncertainty.

g. Total Direct Benefits

The following **Table 13** summarizes the direct benefits of solar DG for BHP's ratepayers. **The direct benefits total 14.9 cents per kWh.**

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42 See Maine Public Utilities Commission, *Maine Distributed Solar Valuation Study* (March 1, 2015). Available at https://www.maine.gov/tools/whatsnew/attach.php?id=639056&an=1. See the "Avoided Fuel Price Uncertainty" section on pp. 39-40 of this study.

Table 13: *Summary of Direct Benefits (25-year levelized $ per MWh)*

Benefit	Avoided Costs ($ per MWh)
Energy	30.10
Generation Capacity	51.80
T&D Losses	9.30
Transmission Capacity	13.30
Distribution Capacity	24.80
Fuel Price Uncertainty	19.80
Total Benefits	149.10
	14.9 cents per kWh
Avoided Carbon Emissions (not included)	*45.80*

4. Costs of Solar DG for Participants

A pro forma cash flow analysis is used to project the lifecycle levelized cost of energy (LCOE) from a solar DG system based on 2022 solar system costs of $2.75 per watt-DC. The major assumptions we use in this analysis are summarized in **Table 14**. The calculated **LCOE of residential solar is 12.7 cents per kW.**

Table 14: *Key Assumptions for the Residential Participant Cost of Solar*

Assumption	Value
Median Cost	$2.75 per watt DC (in 2021)
Federal ITC	30%
Financing Cost	7%
Participant discount rate	5%
Financing Term	20 years
Inverter Replacement	$500/kW in Year 15
Maintenance Cost	$10 per kW-year

5. Costs of Solar DG for the Utility and Non-Participating Ratepayers

There are two other significant metrics used in the cost-effectiveness tests: solar customer bill savings (lost revenues) and solar integration costs. The primary costs of solar DG for non-participating ratepayers (in the RIM Test) are the revenues that the utility loses as a result of DG customers serving their own load. Without the DG systems, the utility might have served these loads, gaining incremental revenues that might reduce rates for other ratepayers when rates are readjusted in a subsequent rate case. The lost revenues from solar DG are just the retail bill savings that solar customers realize by installing solar on their homes; thus, these are also the primary benefit of DG for participating solar customers (in the Participant Test).

We calculate typical solar bill savings assuming that a residential customer using 10,000 kWh per year installs a solar PV system with annual generation equal to 75% of the customer's annual load prior to any degradation. Thus, the customer's solar PV system produces 7,500 kWh per year in the first year of operation. We assume this output degrades by 0.5% per year thereafter.

We model hourly customer load based on NREL Open EI data for a typical residential load profile in South Dakota.[43] An hourly solar PV generation profile for a rooftop PV system in Rapid City is taken from the NREL PVWATTS model.[44] We scale the customer load to 10,000 kWh per year, and scale the PV output to 7,500 kWh per year (the estimated output for a 4.3 kW-AC system). The hourly differences between these quantities are, when positive, the customer's net demand for power delivered from the utility, and, when negative, the customer's exports to the utility grid. We add up these hourly quantities in order to compute the monthly imports and exports that determine the customer's bills under BHP's net billing structure.

Bill calculations price imports at BHP's 2022 residential volumetric rate of 13.1 cents per kWh. We estimate that the modeled customer's bill would decrease in the first year (i.e. prior to any degradation) from $121 per month without solar to $76 per month with solar PV. The $45 per month bill savings associated with our modeled 4.3 kW-AC solar PV system indicate that the customer is able to save 7.2 cents per kWh of solar PV generation in the first year (i.e. $45 per month bill savings / 625 kWh per month solar output = $0.072 per kWh). Assuming 2% annual rate escalation, 0.5% solar PV degradation, and a 7.76% discount rate (the same as BHP's WACC), **the 25-year levelized value of the customer's bill savings, equivalent to the utility's lost revenue, is 8.1 cents per kWh**.

Next, we add an estimate of solar integration costs derived from the *2021 IRP*.[45] These integration costs are the cost of the additional ancillary services needed to accommodate the increased variability that intermittent solar output adds to the utility system. The BHE *2021 IRP* includes a study estimating the increased ancillary service costs for integrating wind and solar resources – **the solar integration cost is about $1 per MWh.**

6. Results and Key Conclusions of this Benefit / Cost Analysis

The following **Table 15** and **Figure 7** incorporate the results of the above analyses into each of the primary cost-effectiveness tests for residential solar DG on the BHP system. These tests of the cost-effectiveness of solar DG consider benefits and costs from multiple perspectives. Other demand-side programs typically are evaluated from these multiple perspectives, and policymakers should take a similarly broad view in assessing solar DG.

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43 See the data file at https://openei.org/datasets/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states for Rapid City, South Dakota.

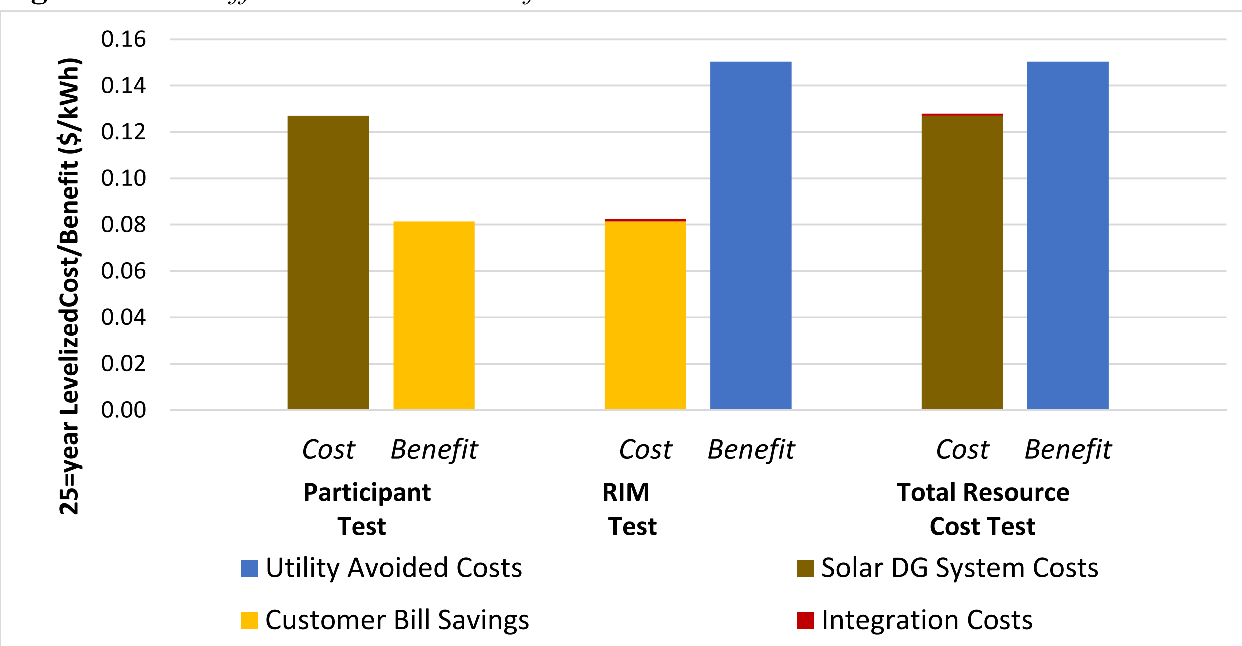
44 At https://pvwatts.nrel.gov/.

45 See *2021 IRP*, at Appendix N, Table 4 (pages N-23 and N-24). It is also possible that the utility may incur costs to administer the net metering program. It is speculative to estimate these costs without specific information from the utility. However, we expect that such costs are minimal at the current penetration of net metered systems in South Dakota.

Table 15: *Benefits and Costs of Residential Solar for BHP (25-yr levelized cents/kWh)*

Benefit-Cost Test	**Participant**		**RIM / PAC**		**TRC**	
Perspective	**Solar customers**		**Non-participants**		**As a resource for BHP**	
Category	**Cost**	**Benefit**	**Cost**	**Benefit**	**Cost**	**Benefit**
Avoided Utility Costs – Energy, Capacity, T & D, and Hedging				0.149		0.149
Lost Revenues / Bill Savings		0.081	0.081			
Integration			0.001		0.001	
Solar DG LCOE	0.127				0.127	
Totals	0.127	0.081	0.082	0.149	0.128	0.149
Benefit-Cost Ratios	**0.64**		**1.82**		**1.16**	

Figure 7: *Cost-effectiveness Results of Residential Solar DG to BHP*



The principal analytic conclusions of these cost-effectiveness results for distributed solar in BHP's service territory are as follows:

1. **Solar DG does not cause a cost shift to non-participating ratepayers**, as shown by the score greater than 1.0 (1.82) on the stringent RIM Test. As a result, in the long-run, deployment of solar DG will not have an adverse impact on the utility's rates, on its cost of service, or, most important, on other ratepayers who do not install DG. In the long-

run, customer adoption of distributed solar generation will reduce rates for all of BHP's ratepayers.

2. **Modifications to BHP's current net billing policy are not needed** to recover the utility's full cost of service over time from net metering customers. Other rate design changes for residential DG customers, such as increased fixed charges or the use of demand charges, are not needed to recover the utility's full cost of service over time from net metering customers.

3. Solar DG is installed based on individual customer decisions, and customers have the right under federal law (PURPA) to interconnect these systems to the grid and to sell their excess generation to the utility at a state-regulated rate based on avoided costs. Although such installations are not planned or controlled directly by utilities, from a resource planning perspective, **solar DG is a cost-effective resource for BHP**, as shown by the score above 1.0 on the TRC Test (1.16).

4. **The economics of solar DG are not favorable for residential customers in South Dakota**, as shown by the Participant Test results (0.64) well below 1.0. This accounts for the small amount of solar adoption to date in South Dakota. BHP currently compensates solar customers for their exports at a low rate that significantly understates the utility's avoided costs for energy and for generation, transmission, and distribution capacity. Any additional reduction in the compensation provided to solar DG customers – such as the BA/SA Tariff – is likely to be further detrimental to today's slow growth of this resource.

5. **In fact, full retail net energy metering (NEM) – with exports compensated at the full retail rate – would be cost-effective in BHP's service territory.**

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