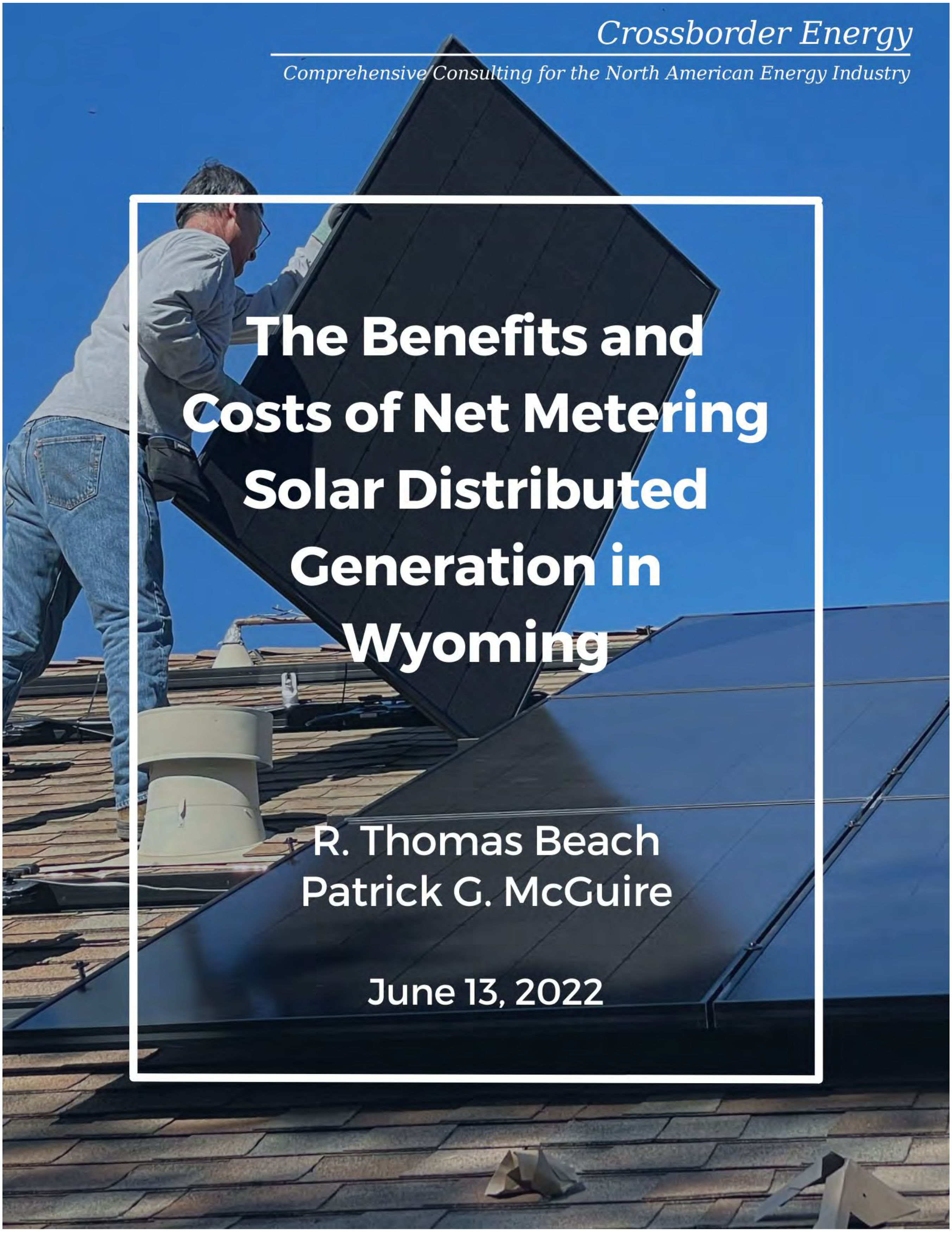

Crossborder Energy

Comprehensive Consulting for the North American Energy Industry

The Benefits and Costs of Net Metering Solar Distributed Generation in Wyoming

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Executive Summary

This report provides a review of net energy metering (NEM) in Wyoming. The current penetration of renewable distributed generation (DG) in Wyoming is relatively low – there are about 10 MW of solar DG on-line today, and this customer-sited resource is growing by about 3 MW per year.

This report includes a benefit-cost analysis of the impacts on ratepayers of the net metering of solar DG in the service territories of several utilities in Wyoming. The utilities covered in this report include PacifiCorp (dba Rocky Mountain Power [RMP]), the largest investor-owned utility (IOU) in the state and two rural electric cooperatives (RECs) – High Plains Power (HPP) and Carbon Power & Light (CP&L). This analysis has the following key attributes:

1. **Examines multiple perspectives.** We examine the benefits and costs of solar DG from the perspectives of all of the key stakeholders – DG customers, other ratepayers, and the utility system and society as a whole. Together, these stakeholders constitute the public interest implicated by DG development. To capture all of these perspectives, we examine the benefits and costs of solar DG using the full set of cost-effectiveness tests for demand-side resources that commonly are used in the utility industry.

2. **Considers a comprehensive list of benefits and costs.** The benefits include not just the benefits of avoided generation, transmission, and distribution costs for the utilities, but also the avoided costs for environmental compliance and the impacts on the energy markets that serve Wyoming. The costs we consider include the costs of integrating small-scale, distributed renewable generation into the electric grid.

3. **Uses a long-term, life-cycle analysis** that covers the useful life of a solar DG system, which is at least 25 years. This treats solar DG on the same basis as other utility resources, both demand- and supply-side.

To calculate the benefits of net-metered solar DG, this report begins with the same avoided costs that U.S. utilities typically employ to evaluate the benefits of their other demand-side programs. We have supplemented these avoided costs with data from RMP's FERC Form 1 and with market data from the regional gas and electric markets in which Wyoming utilities operate. Our approach to valuing solar DG draws upon relevant analyses that have been conducted in other states, including the "public tools" for evaluating net-metered DG that have been developed in Nevada and California[1] and the cost-effectiveness methodology used in Arkansas.[2]

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1 See the Public Utilities Commission of Nevada's (PUCN) 2014 net metering study at http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study. The California Public Utilities Commission's Public Tool is described and is available at http://www.cpuc.ca.gov/General.aspx?id=3934.

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

We also evaluated costs of solar DG, including system costs, lost revenues, and integration costs, as appropriate under each of the standard cost-effectiveness tests. The cost of solar DG as a resource for the utility system and for participating ratepayers is the levelized cost of energy (LCOE) from solar DG installations. We calculate the LCOE for residential solar using a current installed cost of $2.75 per watt-DC, plus typical operating and financing assumptions for such systems. 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, i.e. running the meter backward using net metering. To determine these costs, we calculate the 25-year levelized lost revenues from residential customers who install solar DG under net metering. In this calculation we assume that RMP's retail rates escalate at 2% per year in the long run. Finally, as the cost of integration, we include an estimate of $1 per MWh as the cost of additional ancillary services that may be needed to integrate solar DG into the grid.

Our work concludes that the benefits of residential DG on the systems of RMP and the two RECs 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 net metering in Wyoming. The following **Figure ES-1** and **Table ES-1** summarize the results of our application of the primary cost-effectiveness tests to residential solar DG on the RMP system.

Figure ES-1: *Cost-effectiveness Results – Net Metered Residential Solar for RMP*

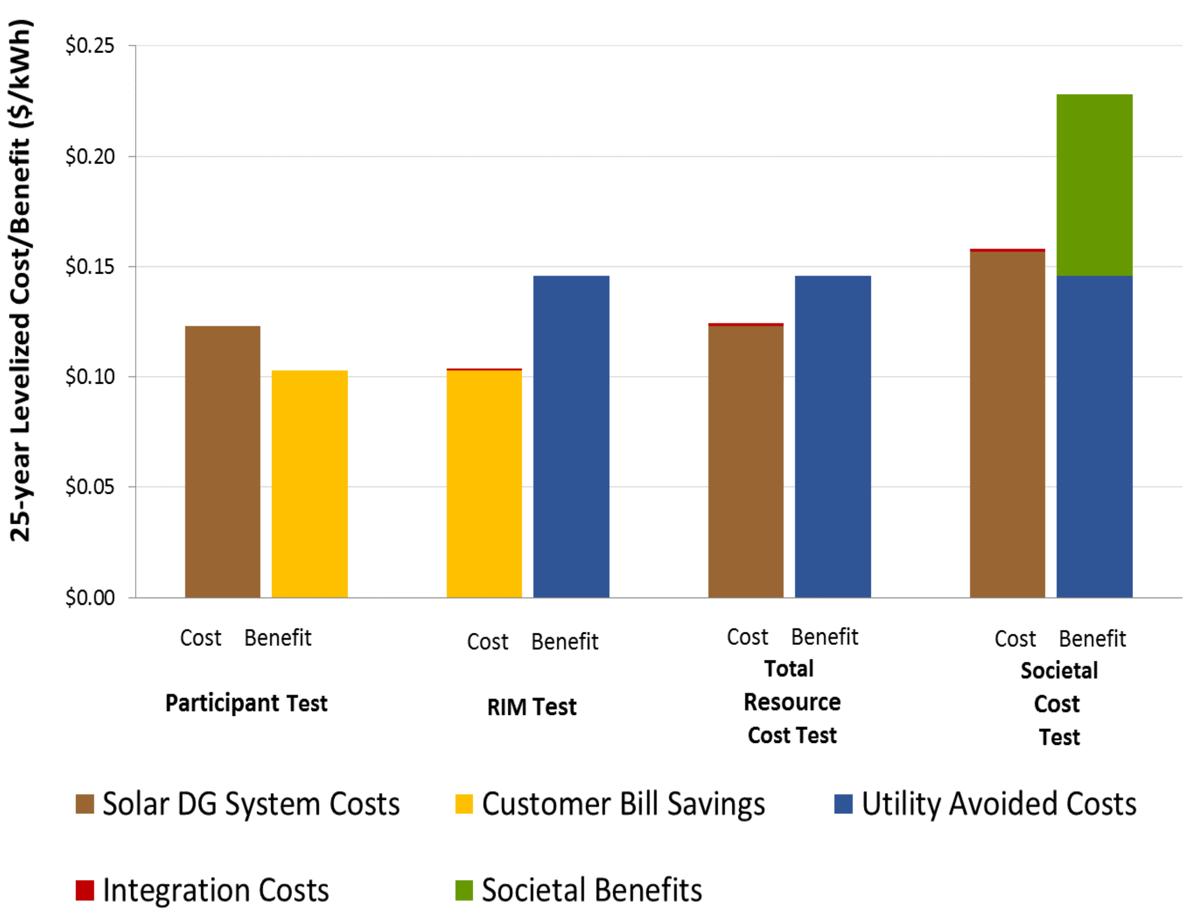

Table ES-1: *Benefits and Costs of Residential Solar for RMP (25-yr levelized cents/kWh)*

Benefit-Cost Test	**Participant**		**RIM / PAC**		**TRC**		**Societal**	
Category	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Avoided Utility Costs – Energy, Capacity, T & D, CO2, Hedging				14.6		14.6		14.6
Lost Revenues / Bill Savings (RIM / PCT)		10.3 (8.6 – 11.9)	10.3 (8.6 – 11.9)					
Integration (RIM/TRC/SCT)			0.1		0.1		0.1	
Solar DG LCOE	12.3				12.3		15.7	
Societal Benefits								8.2
Totals	12.3	10.3	10.4	14.6	12.4	14.6	15.8	22.8
Benefit-Cost Ratios	**0.84**		**1.40 (RIM) >> 1 (PAC)**		**1.18**		**1.44**	

The principal conclusions of our analysis are as follows:

1. **Net metering does not cause a cost shift to non-participating ratepayers**, as shown by the result above 1.0 for 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 or cost of service. On average, utility bills will decline, as shown by the high score on the Program Administrator Cost test.

2. **Modifications to net metering are not needed** to recover the utility's full cost of service over time from net metering customers. Major rate design changes for residential DG customers, such as increased fixed charges, the use of demand charges, or two-channel billing to set different compensation rates for imported and exported power, are not needed to recover the utility's full cost of service over time from net metering customers.

3. **The economics of solar DG are not favorable for residential customers in Wyoming**, as shown by the Participant test results below 1.0. This accounts for the modest amount of solar adoption to date in the state. This means that any reduction in the compensation provided to solar DG customers is likely to be detrimental to the growth of this resource, although these economics may improve as solar costs continue to fall.

4. 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 utilities in Wyoming, as shown by the scope above 1.0 on the Total Resource Cost test.

5. There are **significant, quantifiable societal benefits from solar DG**, including public health improvements from reduced air pollution. When these additional societal benefits are considered, solar DG passes the Societal test by a significant margin.

6. Solar DG also provides other important benefits that are difficult to quantify. These include 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, and results in **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 Wyoming's clean energy infrastructure and allows Wyoming to take advantage of federal tax incentives for solar that may drop to zero in 2024 for residential customers**.

1. Background: Distributed Renewable Generation and Net Metering in Wyoming

Wyoming has significant resources of renewable energy. The state's substantial wind resources are being developed at utility-scale wind farms. The state has good solar resources, comparable to other nearby Rocky Mountain states, but these have seen far less development. Solar can be deployed at a broad range of scales, and small-scale, behind-the-meter distributed solar generation (solar DG) can allow customers to save money, provide greater freedom of choice in their energy supply, improve the local and global environment, and – when combined with on-site battery storage – provide more resilient electric service.

The following **Table 1** compares the deployment of small-scale solar DG in Wyoming to other nearby states, based on Energy Information Administration (EIA) data as of April 2021.[3]

Table 1: *Metrics of Small-scale Solar Deployment in Rocky Mountain States*

State	Solar DG		Solar Resource[4]	Residential Electric Rate	Solar Value
	MW	*Watt/customer*	*Annual kWh/kW*	*$/kWh*	*$/kW-year*
Wyoming	10	30	1,533	$0.111	$170
Utah	353	273	1,440	$0.101	$145
Idaho	66	70	1,425	$0.097	$138
Montana	27	41	1,316	$0.111	$146
Colorado	495	178	1,580	$0.125	$198

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 April 2021 EIA data) times the annual output of a typical solar system (in annual kWh per kW-DC) in each state's largest city. The solar value for Wyoming is the second highest among these Rocky Mountain states, trailing only Colorado, but Wyoming has the lowest penetration of solar DG among these states. The solar value metric implicitly assumes that most states have made available some form of net energy metering (NEM), such

3 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 2021 with data through April 2021. Available at https://www.eia.gov/electricity/monthly/. The solar Watt per customer divides the total small-scale solar MW by the total number of electric customers.

4 The solar resource is the annual kWh per kW-DC produced by a typical fixed array solar system in the largest city in each state (e.g, Cheyenne for Wyoming, Salt Lake City for Utah, Boise for Idaho, Billings for Montana, and Denver for Colorado), per the National Renewable Energy Lab's (NREL) PVWATTS calculator, available at https://pvwatts.nrel.gov/.

that customers can receive value roughly equal to the state's average retail electric rate if they produce on-site solar electricity.

Net metering is the billing arrangement used in most states in the U.S. to compensate customers who install renewable DG on their premises, including solar photovoltaic (PV) systems. Today, 47 states offer some type of net metering.[5] 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, where the utility uses that generation to serve neighboring loads. Under net metering, 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. In the accounting used to calculate the DG customer's bill, the customer can 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 is a major factor in its widespread use and popularity.

Thus, DG located behind the meter 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, 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 supplier providing a service (generation) to the utility.

As generators, renewable DG customers typically have legal status as qualifying facilities (QFs) under the Public Utilities Regulatory Policies Act of 1978 (PURPA). 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.[6]

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 exports to the grid.[7]

Wyoming's current net energy metering statute embodies the basic "netting" concept of NEM.[8] NEM customers use a bi-directional meter to measure their net consumption in each billing period, and pay for net usage in each period. If a customer has net production (exports) in a billing period, the net exports can be carried over to the next billing period, with any net

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5 See http://programs.dsireusa.org/system/program/maps. This includes Arizona, California, Nevada, New Hampshire, South Carolina, and Hawaii, states which have large numbers of existing DG customers on traditional net metering, but which have adopted revised compensation rules for new DG customers that reduce the compensation for excess generation exported to the grid.

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

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

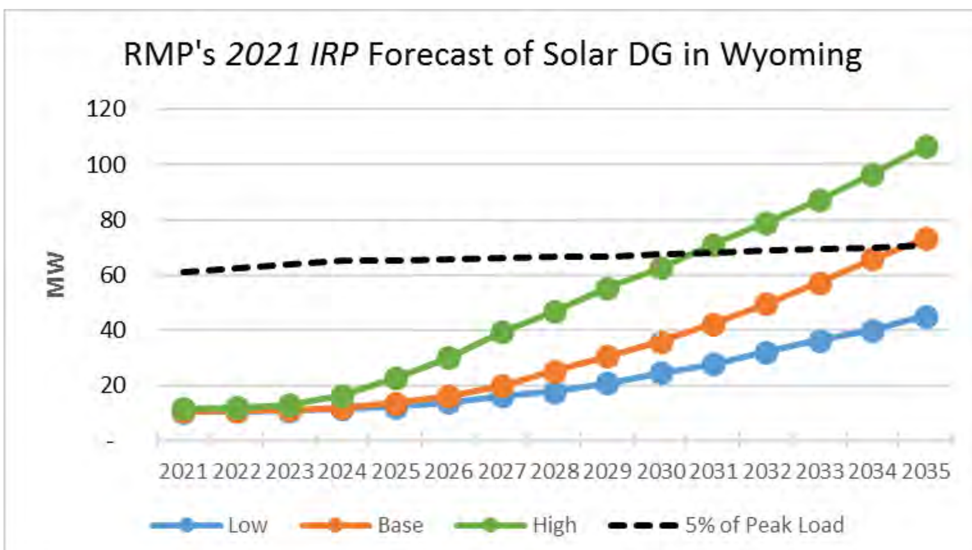
8 Wyoming Statutes Title 37. Public Utilities § 37-16-101 to 104.

production at the end of each year sold to the utility at its filed QF avoided costs.[9]

State regulators periodically evaluate the economics of NEM – particularly in states with high levels of solar DG penetration. These reviews often consider the impacts of NEM compensation on other, non-participating ratepayers, to gauge whether there are any unreasonable "cost shifts" associated with NEM. Although this analysis is important, 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 (1) the solar customer who makes a long-term investment in solar, (2) all ratepayers collectively, and (3) the citizens of Wyoming as a whole. Finding a balance of interests among of all of these stakeholders should constitute the public interest in assessing net metering policy in Wyoming.

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 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 example, by reducing the export rate to a level less than the retail rate. For example, in California and Hawaii, this initial 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 at 5% of peak demand is a first indicator of when a state may want to evaluate whether a change to NEM is appropriate. RMP's *2021 Integrated Resource Plan* (*2021 IRP*) includes a detailed forecast of solar DG growth in its Wyoming service territory (see Figure 1).[10] This forecast assumes continuation of the current NEM rules, and shows that solar DG penetration will not reach 5% of peak demand in RMP's service area until 2035 in the Base forecast, and 2031 in the High forecast.

Figure 1



The next section discusses our approach to evaluating the costs and benefits of NEM in Wyoming.

9 *Ibid*., Public Utilities § 37-16-103(a) and (b).

10 See Appendix L of the *2021 IRP*, available on PacifiCorp's website, at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/2021-irp-support-and-studies/PacifiCorp_2021_IRP_PG_Resource_Assessment.pdf. The detailed assumptions used in the study can be found starting on page 19.

2. Methodology

Solar DG is a long-term generation resource for Wyoming. New solar DG systems will provide benefits for at least the next 25 years. Thus, our analysis develops 25-year levelized benefits and costs for solar DG on several representative utility systems in Wyoming.

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 analyses of 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.

Accordingly, we have evaluated the long-term benefits and costs of net-metered solar DG from multiple perspectives, using each of the major cost-effectiveness tests widely used in the utility industry.[11] 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).

[11] See the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (October 2001), available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF. We understand that these tests are used in Wyoming, with the Total Resource Cost test being the primary test for assessing the cost-effectiveness of energy efficiency portfolios.

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

Category	Total Resource Cost (TRC) and Societal	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 AR) -- Societal (Societal Test only)	+	+	+	
Federal Tax Benefits (excluded from Societal Test)	+			+

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, full retail net metering is the program under evaluation. First, the program should provide a resource that is a net benefit to the utility system or to society – thus, the Total Resource Cost (TRC) and Societal Tests compare the costs of solar DG systems to their benefits to the utility system and society as a whole. 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 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 and Societal tests).

Data. We have developed data on avoided energy costs from current electric market prices in Wyoming and the expected long-term trajectory of these prices. For avoided capacity-related costs for generation, we have used data from RMP's *2021 IRP*, released on September 1, 2021. Data on the line losses that distributed resources can avoid is available from RMP's current general rate case. We also use data on RMP's loads and its transmission and distribution (T&D) costs from FERC Forms 1 and 714 to calculate the utility's long-run avoided T&D costs. Finally, we use EPA emission data to determine the avoided costs for environmental compliance and the broader societal benefits of an improved environment. Our analysis is based entirely on public data sources without the use of confidential data.

Benefits. The largest quantifiable direct benefits of DG are avoided energy, avoided generation capacity, avoided transmission and distribution 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 RMP's *2021 IRP* combine with EE and DR to help to defer the need for larger-scale resources in the long-run. The *2021 IRP* finds that RMP will have a continuing need for new clean energy resources over the next decade, and shows that RMP is depending on the continued growth of demand-side resources to meet its future energy and capacity needs.

New renewable generation 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 RMP and other Wyoming utilities operate.

In addition, solar DG also provides quantifiable societal benefits to the citizens of Wyoming. These include important environmental benefits, such as reduced emissions of greenhouse gases and criteria air pollutants, and lower use of water resources. We have assembled the data needed to quantify the reduced emissions of these pollutants as well as the water savings, drawing upon recent quantifications of these societal benefits. We also quantify and comment on the impacts on the local economy of developing local businesses that install net-metered renewable energy systems. Finally, we discuss but do not quantify the benefits of enabling customers to enhance the reliability and resiliency of their electric service and of expanding competition and customer choice.

Costs. The relevant costs of solar DG vary across the benefit-cost tests.

The Total Resource Cost, Societal, 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. The cost of DG systems per kilowatt-hour of output can vary based on size, installation costs, financing terms, and output. For those tests in which the utility's costs are relevant, we add an estimate of the solar integration costs which the utility will incur to incorporate these resources into its system, based on solar integration studies performed by other utilities with growing amounts of solar generation on their systems.

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 RMP and the two rural co-ops. 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, and we express the results as 25-year levelized costs using the same 6.88% per year discount rate that RMP uses in its *2021 IRP*.[12]

3. Direct Benefits of Solar DG

a. Energy

Solar DG on the utility systems in Wyoming will avoid the energy costs of the marginal source of electric generation. The most direct source for these energy costs are wholesale electric market prices.

There is now an Energy Imbalance Market (EIM) that covers most of the WECC footprint and that provides granular, 5-minute data on electricity market prices.[13] **Figure 2** below shows the still-expanding EIM footprint in the western U.S. Hourly EIM price data is available for the PacifiCorp East ("PACE") trade hub.[14] This is an aggregated price covering PacifiCorp's eastern control area, which includes RMP's service territory in Wyoming. RMP has proposed to use this price for a real-time pricing pilot program in Wyoming,[15] and the utility has characterized this price as "a rough representation of the general magnitude of hourly marginal energy cost on PacifiCorp's PACE balancing authority area."[16]

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[12] This discount rate is RMP's after-tax weighted average cost of capital. See RMP's *2021 IRP*, at p. 226.

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

[14] These EIM prices are available on the California Independent System Operator (CAISO) OASIS website at the "ELAP_PACE15_APND" node (the "PACE node").

[15] See Direct Testimony of Robert M. Meredith in RMP's general rate case (Docket No. 20000-587-ER-20), at p. 42.

[16] *Ibid*.

Figure 2: *Energy Imbalance Market Participants in the WECC*

Table 3 shows an hourly solar output profile by month and daylight hour for Rock Springs, Wyoming, from the National Renewable Energy Laboratory's (NREL) PVWATTS calculator. The table shows average hourly solar output as a percentage of the solar nameplate capacity, in alternating-current (AC) kW.

Table 3: *PV-Watts Output Profile for Solar PV in Rock Springs, Wyoming*

Hour	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Average
7	0%	0%	0%	0%	3%	5%	3%	0%	0%	0%	0%	0%	**1%**
8	0%	1%	3%	7%	17%	18%	16%	10%	3%	0%	1%	0%	**7%**
9	6%	13%	16%	24%	36%	36%	35%	28%	18%	10%	10%	6%	**20%**
10	18%	29%	35%	41%	53%	52%	51%	45%	35%	25%	23%	16%	**35%**
11	30%	44%	50%	57%	66%	65%	63%	60%	49%	41%	34%	27%	**49%**
12	36%	52%	60%	69%	70%	71%	71%	70%	61%	50%	40%	34%	**57%**
13	39%	57%	63%	72%	67%	75%	78%	75%	64%	56%	40%	34%	**60%**
14	37%	49%	65%	72%	74%	74%	76%	72%	69%	55%	37%	29%	**59%**
15	28%	36%	57%	67%	68%	74%	67%	66%	61%	49%	27%	20%	**52%**
16	17%	28%	48%	53%	68%	70%	55%	48%	50%	39%	15%	10%	**42%**
17	5%	13%	33%	41%	55%	54%	52%	43%	35%	25%	5%	1%	**30%**
18	0%	2%	17%	32%	35%	38%	40%	28%	22%	10%	1%	0%	**19%**
19	0%	0%	6%	16%	19%	25%	25%	15%	7%	1%	0%	0%	**10%**
20	0%	0%	0%	3%	6%	11%	12%	4%	0%	0%	0%	0%	**3%**
Average	**9%**	**13%**	**19%**	**23%**	**27%**	**28%**	**27%**	**24%**	**20%**	**15%**	**10%**	**7%**	**18.5%**

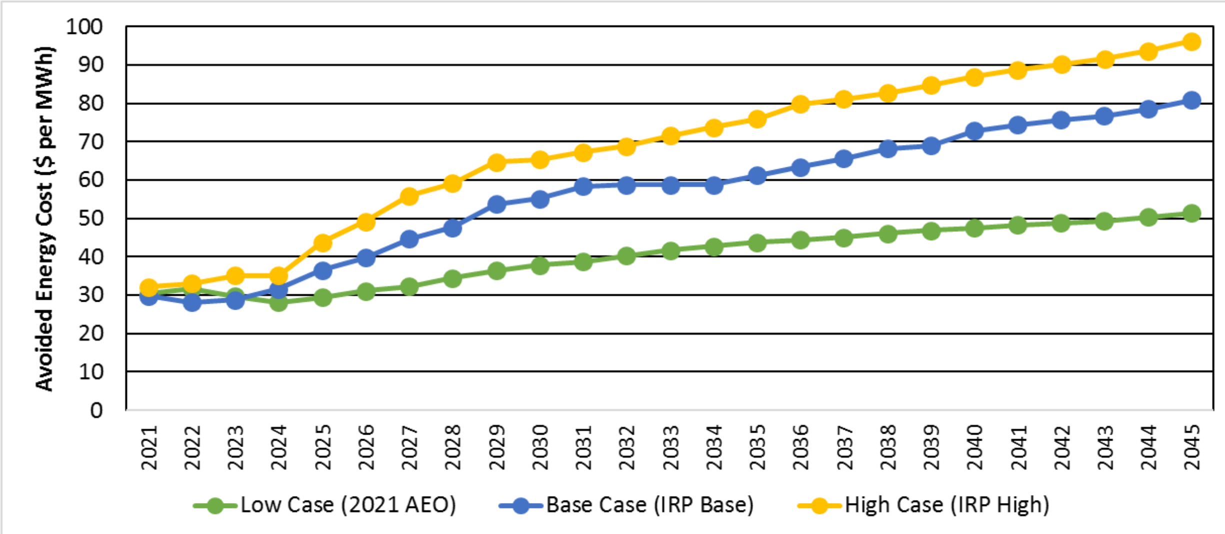
Table 4 indicates the level of June 2020 to May 2021 EIM prices at PACE in these hours. The solar-weighted average price for this period was $21.00 per MWh; this is about 82% of the baseload price over this period of $25.70 per MWh.

Table 4: *2020 PACE EIM Hub Prices ($/MWh)*

Hour	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	**Average**
7	22.8	48.2	29.0	24.9	22.9	18.2	17.3	18.0	19.4	25.3	24.3	25.3	19.4
8	25.9	59.0	31.4	27.5	21.2	17.9	17.3	18.0	19.0	19.6	26.3	31.3	20.8
9	26.1	44.3	25.3	45.2	14.6	10.7	13.7	17.0	22.6	31.3	22.8	30.9	21.8
10	27.5	27.3	22.9	17.7	14.3	8.4	12.4	17.0	19.4	24.0	17.8	23.9	17.6
11	19.0	20.6	18.3	16.8	14.9	10.3	15.2	17.3	17.5	19.7	17.5	23.9	16.9
12	16.6	17.2	17.6	16.5	14.3	10.9	17.6	19.8	19.1	20.2	17.7	20.7	17.1
13	15.7	15.6	13.9	28.4	13.7	14.8	21.2	24.6	21.5	21.1	17.9	20.0	19.3
14	15.3	12.1	12.0	15.9	15.0	14.4	19.5	29.8	22.0	41.0	16.7	19.5	19.6
15	14.9	12.6	11.3	16.9	22.4	14.4	22.7	32.5	30.6	23.2	16.9	18.4	20.6
16	16.1	12.9	10.7	17.4	18.9	23.8	34.6	59.4	42.1	22.1	18.1	17.8	26.4
17	19.2	19.8	11.3	17.4	18.3	30.8	26.9	42.2	29.1	34.0	23.6	22.2	25.8
18	28.7	45.8	10.6	18.4	17.5	20.4	20.8	68.3	32.2	22.6	24.0	28.7	26.3
19	25.3	87.7	27.5	23.9	33.4	41.6	23.0	51.3	36.6	30.6	25.3	29.3	33.9
20	24.7	72.4	37.5	34.8	99.8	28.0	62.8	77.7	31.7	27.3	24.6	28.9	58.4
Average	17.5	18.2	15.0	20.1	17.8	17.1	21.5	31.3	25.4	25.7	17.9	21.1	**21.0**

After determining the solar-weighted average price for the PACE node, we escalate that value, based on the long-term electric market price forecast in RMP's *2021 IRP*, to produce a base long-term forecast of avoided energy costs. As a low sensitivity, we assume that natural gas-fired generation will remain the marginal source of electricity, and escalate the PACE market price by the most recent EIA *2021 Annual Energy Outlook* long-term forecast for natural gas costs. For a high case, we use the high-price sensitivity for electric market prices from the RMP *2021 IRP*. The following **Figure 3** shows the resulting low, base, and high projections of long-run solar-weighted avoided energy costs.

Figure 3: *Solar-weighted Avoided Energy Costs*



We have levelized these prices over the 25-year period from 2021 to 2045 using RMP's 6.88% discount rate. 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** shows our base, low, and high forecasts of RMP's avoided energy costs for solar DG. The base case forecast is a 25-year levelized value of $51.20 per MWh, or 5.1 cents per kWh, in 2021 dollars.

Table 5: *RMP Avoided Energy Costs (25-year levelized 2021 $/MWh)*

Scenario	**Base Case**	**Sensitivities**	
		Low	**High Case**
Forecast	RMP *2021 IRP* Electric Market Base Case	RMP *2021 IRP* EIA 2021 AEO Natural Gas	RMP *2021 IRP* High Case
Avoided Energy ($/MWh)	51.2	36.0	61.5

b. Generation capacity

The *2021 IRP* finds that RMP has a continuing need for new generating capacity. Storage is the predominant capacity resource that RMP is adding. This includes both standalone storage capacity and storage included with solar resources as "hybrid" solar-plus-storage units. For the avoided cost of capacity, we have calculated the capacity-related cost of a new utility-scale storage unit, using the *2021 IRP*'s cost assumptions for a 200 MWh, 50 MW 4-hour utility-scale storage unit.

The capacity value of solar resources is only 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 more solar resources will shift the need for capacity later in the afternoon, diminishing the need for capacity over time. RMP's 2021 IRP contains a discussion of the capacity contribution of solar resources, and calculates that solar's capacity contribution in Wyoming will be 14% of nameplate in 2030.[17]

[17] See *2021 IRP*, at Appendix N; see Table N.1.

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. RMP's current planning reserve margin is 13%.[18] Accordingly, we increase avoided capacity costs by 13% to reflect the benefit of the lower required reserves.

Assembling all of these considerations, **Table 6** presents the complete calculation of RMP's avoided generation capacity costs of $21.85 per MWh for solar resources in Wyoming.

Table 6:

Calculation of Avoided Generation Capacity Costs based on Battery Storage Costs					
Storage Capital Cost	*a*	$	1,820	*$/kW*	*PAC 2021 IRP, at Table 7.1 for utility-scale storage, 2020$ in 2023*
Real Economic Carrying Charge	*b*		12.2%		*Assumes 80% equity at 12% and 20% debt at 8%*
Storage O&M	*c*	$	28	*$/kW-year*	*PAC 2021 IRP, at Table 7.1 for utility-scale storage, 2020$ in 2023*
Annual Cost	*d*	$	255		*d = a x b + c, converted to 2021$ assuming 2% inflation*
Energy Rents	*e*	$	(31)		*PAC 2021 IRP, at Table N.1 for 2024-2040*
Planning Reserve Margin	*f*		13%		*PAC 2021 IRP, at p. 149*
Net Capacity Cost	*g*	**$**	**252**		*g = (d + e) * (1 + f)*
Solar Capacity Contribution	*h*		14%		*PAC 2021 IRP, at Table K.1, solar ELCC for Rock Springs*
Solar Capacity Value	*i*	$	35	*$/kW-year*	*i = g x h*
Annual solar output	*j*		1,617	*kWh per kW*	*PVWATTS solar output for Rock Springs WY*
Avoided Generation Capacity	*k*	$	21.85	*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. RMP's latest line loss study, included in its GRC testimony, shows line losses of 10.34% for capacity and 10.27% for energy.[19] The line loses included in this study represent average losses over all hours. We have increased these losses by 50% 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.[20] 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 7** shows our calculations of avoided line losses for both energy and capacity.

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[18] See *2021 IRP*, at pp. 135 and 153.

[19] *See Exhibit Accompanying Rebuttal Testimony of Robert M. Meredith: Updated Line loss Study* in RMP's general rate case (September 2020, Docket No. 20000-578-ER-20), at p. 1 (Table 2).

[20] 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.

Table 7: *Avoided Line Losses ($ per MWh in 2018$)*

Avoided Cost	Value *($ per MWh)*	Loss Factor	Convert to Marginal Losses	Avoided Losses *($ per MWh)*
Energy	51.20	10.27%	1.5	7.90
Capacity	21.85	10.34%	1.5	3.40
Total				11.30

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 system by the solar customer's neighbors, unloading the upstream portions of the distribution system and the transmission system. Thus, much like 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.

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.

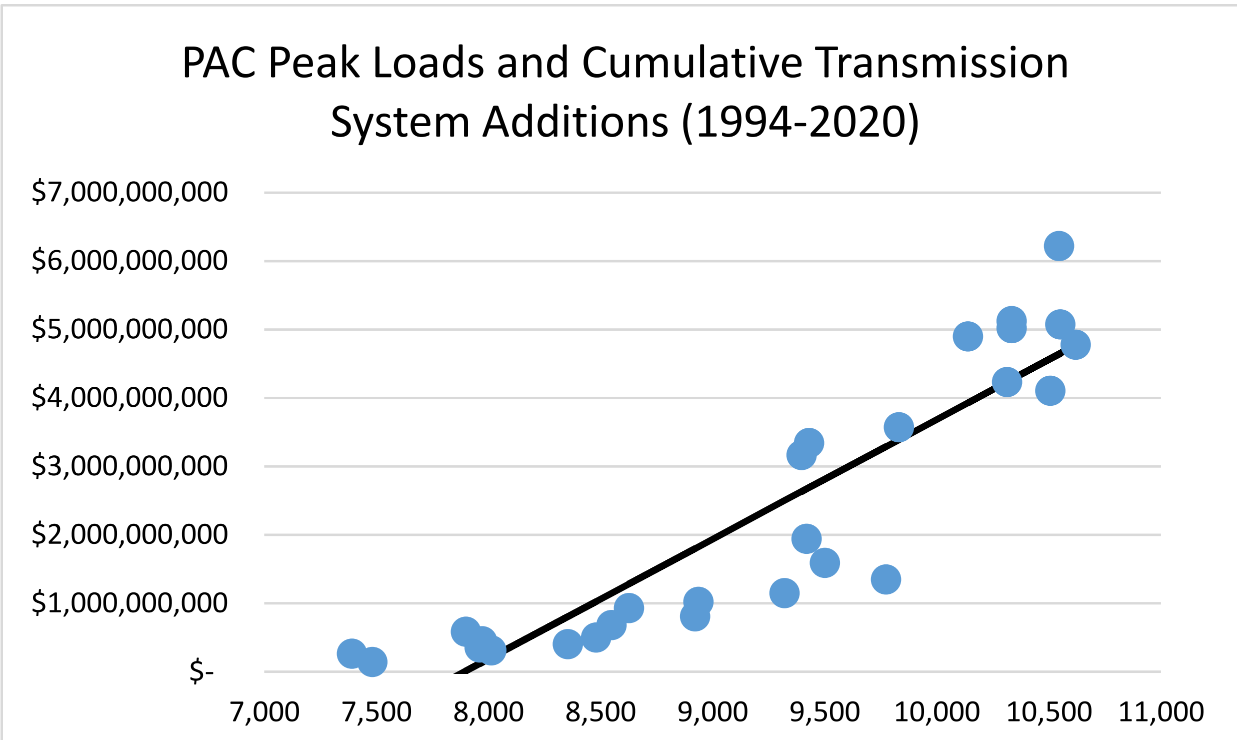
As DG penetration grows, and a deeper understanding is gained of the impacts of DG on the T&D system, utility T&D planners will integrate existing and expected DG capacity into their planning. A comparable evolution has occurred over the last several decades, as the long-term impacts of EE and DR programs 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.

In this study, we have developed estimates of long-run avoided T&D costs for PacifiCorp/RMP. These estimates are based on long-term data on how PacifiCorp'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 dropping.

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.

Transmission. We have utilized a NERA regression based on RMP's historical peak load growth and transmission expenditures, over an 26-year period from 1994 to 2020. Our analysis of marginal transmission costs uses RMP's FERC Form 1 data for this period. **Figure 4** shows the regression fit of cumulative transmission capital additions as a function of incremental demand growth on the RMP system.

Figure 4: *Regression of Cumulative RMP Transmission Costs vs. Peak Demand*



The regression slope resulting from this analysis is $1,749 per kW. We add 4.5% to this amount as a general plant loader, convert the total to an annualized marginal transmission cost using a real economic carrying charge (RECC) of 5.78%,[21] and include $20 per kW-year for transmission O&M costs.[22] The resulting avoided cost for transmission capacity for RMP is $125.60 per kW-year.

[21] Based on RMP's currently-authorized capital structure and cost of capital.

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

Table 8: *RMP Marginal Transmission Cost*

Parameter	Value
Slope ($/kW)	1,749
General Plant Loader (%)	4.5%
General Plant Loader ($/kW)	79
Total Marginal Transmission ($/kW)	1,828
RECC Factor	5.78%
Annualized Transmission ($/kW-yr)	105.6
Transmission O&M ($/kW-yr)	20.0
Total Annual Marginal Cost ($/kW-yr)	**125.60**

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 RMP transmission system. We determined that the capacity contribution of solar PV to reducing peak transmission loads is 18.6% of the solar nameplate capacity. This is based on our analysis of solar output in Rock Springs and Casper at the time of RMP's monthly peak loads in each month of 2020. The peak load data is from PacifiCorp's FERC Form 714. This 12 CP method is consistent with how RMP allocates transmission costs in its cost-of-service in Wyoming.

Table 9 shows our calculations of this avoided cost of transmission capacity for RMP. We escalate the levelized cost of T&D capacity by 2% per year over a 25-year period, then calculate a levelized price of $29.80 per kW-year for 2022-2046, including standard degradation of 0.5% per year in solar output and RMP's 6.88% discount rate. We then multiply this 25-year marginal transmission cost times the 18.6% solar capacity contribution based on the 12 CP method. 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 1,617 kWh per kW-AC. The result is that solar DG avoids transmission capacity costs of $16.50 per MWh of solar output.

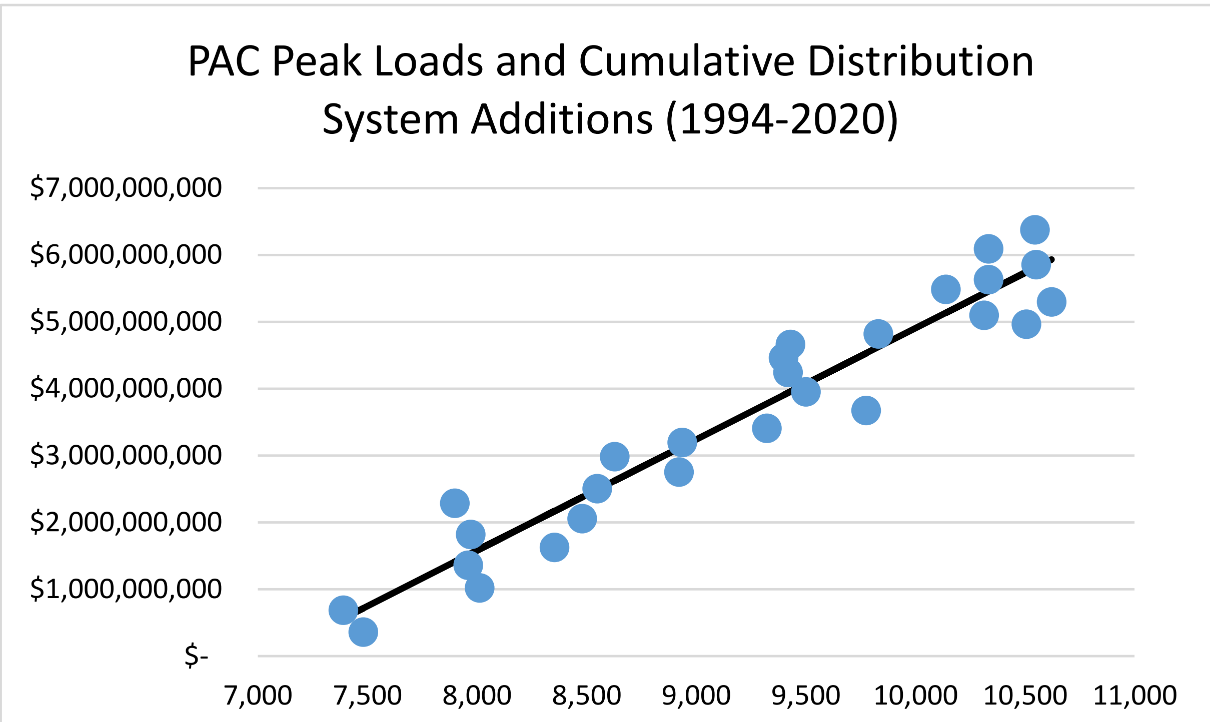
Table 9: *25-year Levelized Avoided Transmission Marginal Capacity Cost for Solar DG*

Parameter	Value	Notes
Avoided Transmission Capacity Cost	125.60	*From Table 8*
Annual Escalation Rate	2.0%	*General inflation*
Annual Degradation Rate	0.5%	*Industry standard*
25-year Levelized Cost (2021 $)	$143.50 per kW-year	*Assumes a 6.88% discount rate*
Solar Contribution to PacifiCorp System Peak Load	18.6%	*12 CP calculation*
Solar Output – Annual kWh per kW-AC	1,617 kWh/kW-AC	*NREL PVWATTS for Rock Springs, Wyoming*
Solar Avoided Transmission Capacity Cost	**$16.50 per MWh**	*$143.5 x 0.186 / 1617*

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 RMP'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 2020. **Figure 5** shows the regression fit of cumulative distribution capital additions as a function of incremental demand growth on the RMP system.

Figure 5: *Linear Regression of Cumulative Distribution Costs vs. Peak Demand*



Converting the regression slope of $1,662 per kW to an annual cost using a RECC of 5.78%, plus loaders for general plant and O&M from FERC Form 1 data, results in an annualized marginal distribution cost of $120.70 per kW-year.

Table 10: *RMP Marginal Distribution Cost*

Parameter	Value
Slope ($/kW)	1,662
General Plant Loader (%)	4.5%
General Plant Loader ($/kW)	75
Total Marginal Transmission ($/kW)	1,737
RECC Factor	5.78%
Annualized Transmission ($/kW-yr)	100.3
Transmission O&M ($/kW-yr)	20.4
Total Annual Marginal Cost ($/kW-yr)	**120.70**

For the solar capacity contribution to reducing distribution costs, we used the hourly profile of RMP's loads to determine an hourly allocation of RMP's system demands that exceed 90% of the annual system peak. This is commonly called the Peak Capacity Allocation Factor (PCAF) approach to allocating capacity costs to peak hours. We then applied this PCAF allocation to the typical meteorological year profile of hourly solar output in Rock Springs and Casper. The result is a capacity contribution of 21.4% of solar nameplate to reducing the highest loads. **Table 11** shows the resulting calculation of avoided distribution costs on a $ per MWh basis.

The loads used in this analysis are for the eastern control area of PacifiCorp's system (PACE), which of course includes more than just Wyoming. The PACE control area is summer-peaking, whereas we are aware that portions of RMP's system in Wyoming have winter peaks that are similar to, and may slightly exceed, the summer peak.[23] The winter peak hours can fall in the evening or early morning, outside of hours of significant solar output. This raises the question of whether solar can avoid distribution projects must serve both summer and winter peak loads. In the future, distributed solar can address both the summer and winter peaks – and make a capacity contribution greater than the 21.4% indicated in our PCAF analysis – if it is paired with storage and critical-peak or time-of-use pricing that can time-shift a significant portion of solar output to the hours of the local distribution peak demands. To reflect the complication of winter-peaking loads and the time that may be required before there is significant penetration of solar-paired-storage systems, we have discounted our avoided distribution capacity costs by 50%.

Table 11: *25-year Levelized Avoided Distribution Costs for RMP*

Parameter	Value	Notes
Avoided Distribution Capacity Cost	120.7	*From Table 10*
Annual Escalation Rate	2.0%	*General inflation*
Annual Degradation Rate	0.5%	*Industry standard*
25-year Levelized Cost (2021 $)	$138.00 per kW-year	*6.88% discount rate*
Solar Contribution to PACE Distribution Load	21.4%	*PCAF calculation*
Discount for Winter-peaking Wyoming Distribution Systems	50%	
Solar Output – Annual kWh per kW-AC	1,617 kWh/kW-AC	*NREL PVWATTS for Rock Springs, Wyoming*
Solar Avoided Distribution Capacity Cost	**$9.10 per MWh**	*$138 x 0.214 x 0.5 / 1617*

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.

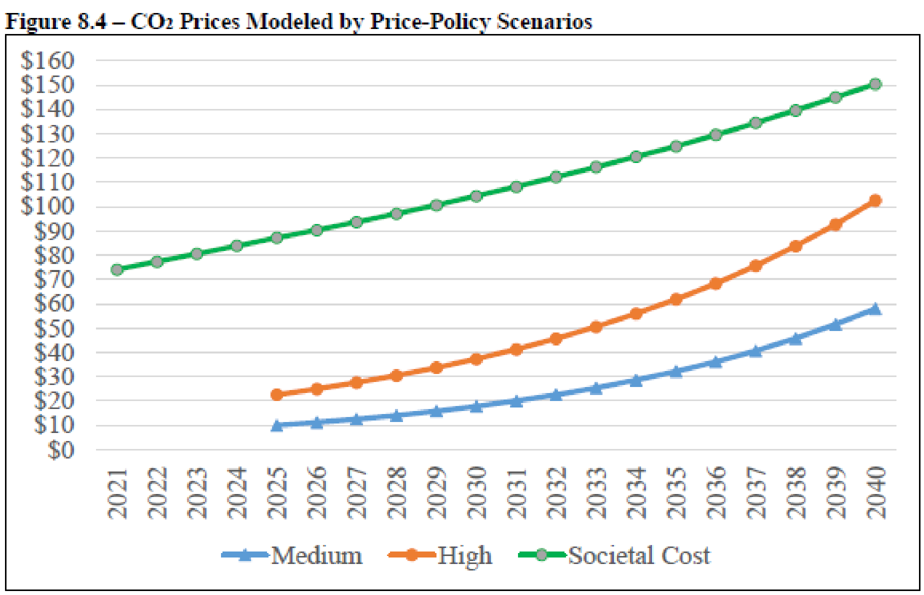
[23] See, for example, RMP's 2017 briefing on five-year planning studies on local transmission needs http://www.oatioasis.com/PPW/PPWdocs/2017_Q8_Park_Ct-Big_Horn-WY_West.pdf.

e. Avoided carbon emission compliance costs

Solar PV will avoid carbon emissions from traditional fossil-fueled power plants, and thus avoid the anticipated 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 Wyoming. AVERT calculates hourly avoided emissions based on a given hourly profile for energy efficiency savings or renewable energy production. Our model assumes 3 MW of DG solar in the state, uses a PV profile for Rock Springs, and the Rocky Mountain AVERT regional data file to calculate the avoided carbon emissions in Wyoming. The avoided carbon emissions are 1.71 lbs per kWh of DG output.

Figure 6 shows the range of carbon emission compliance costs (in $ per short ton) from the *2021 IRP*.[24] The figure also shows the U.S. Environmental Protection Agency's (EPA) social cost of carbon (SCC), which is a measure of carbon costs based on the societal damages from unmitigated climate change. We use the SCC later in this report to value the societal benefits from reduced carbon emissions.

Figure 6: *Carbon Cost Forecasts from 2021 IRP*



Based on the carbon compliance costs in Figure 6 and the modeled avoided carbon emissions of 1.71 lbs per kWh, we calculate 25-year levelized avoided costs for carbon compliance, assuming a 6.88% discount rate and 0.5% annual solar output degradation. This calculation results in the following avoided costs.

[24] *2021 IRP*, at p. 227 (Figure 8.4).

Table 12: *RMP Marginal Carbon Costs*

Scenario:	Base	Low Case	High Cases	
Carbon cost forecast	*2021 IRP* Reference Case	*2015 IRP* High Case	*2015 IRP* High Case	IRP SCC*
Avoided Carbon ($/MWh)	**10.5**	**0**	**20.2**	**63.6**

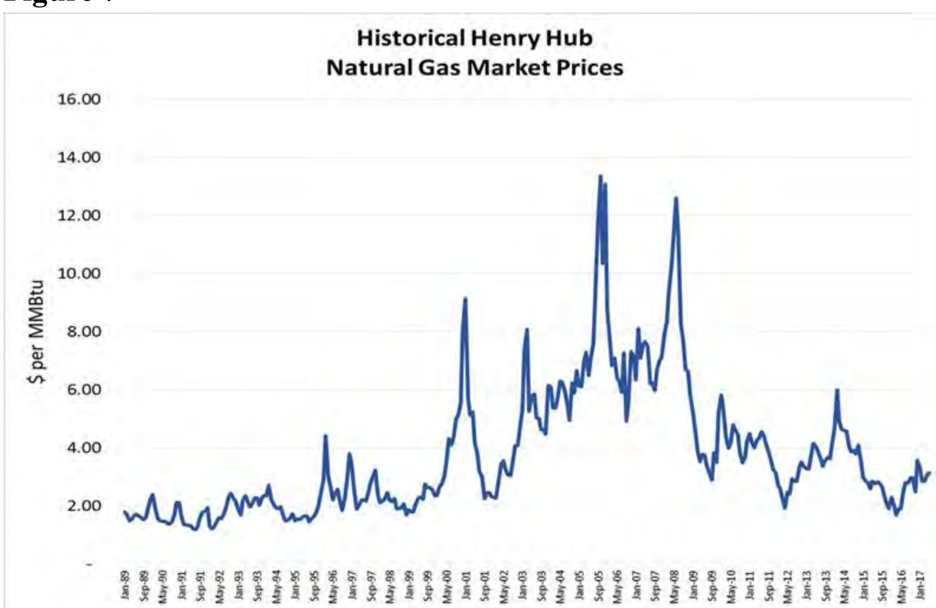
* The SCC forecast is <u>not</u> used to calculate carbon compliance costs. It is only used to calculate societal benefits.

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 7** below.[25]

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.[26]

Figure 7



To calculate this benefit, we follow the methodology used in the *Maine Distributed Solar Valuation Study (Maine Study)*, a 2015 study commissioned by the Maine Public Utilities

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[25] Source for Figure 3: Chicago Mercantile Exchange data.

[26] 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.

Commission and authored by Clean Power Research.[27] 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. This would eliminate 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 of reducing the uncertainty in the costs for the fuel that solar DG displaces.

We have performed this calculation for RMP, assuming our base gas cost forecast (the EIA *AEO 2017* forecast), U.S. Treasuries (at current yields) as the risk-free investments, and a marginal heat rate of 7,500 Btu per kWh. The result is a value of **$23.10 per MWh** as the 25-year levelized benefit of reducing fuel price uncertainty.

g. Market price mitigation

The increasing penetration of new renewable generation in Wyoming will place downward pressure on the region's energy market prices. New renewable generation, including solar DG, will reduce demand in the MISO South market. Because this generation is must-take (and has zero variable costs), it will displace the most expensive power that utilities such as RMP would otherwise have generated or purchased, which typically is natural gas-fired generation. Thus, the addition of this local generation in RMP's service territory will reduce the demand which RMP places on the regional markets for both electricity and natural gas. With this reduction in demand, there is a corresponding reduction in the prices in these markets, which benefits RMP across the full volumes of its purchases in these markets. This "market price mitigation" benefit of renewable generation is widely acknowledged, and has become highly visible in markets that now have high penetrations of wind and solar resources.[28] The benefit is illustrated schematically in the yellow-shaded section of **Figure 8**.

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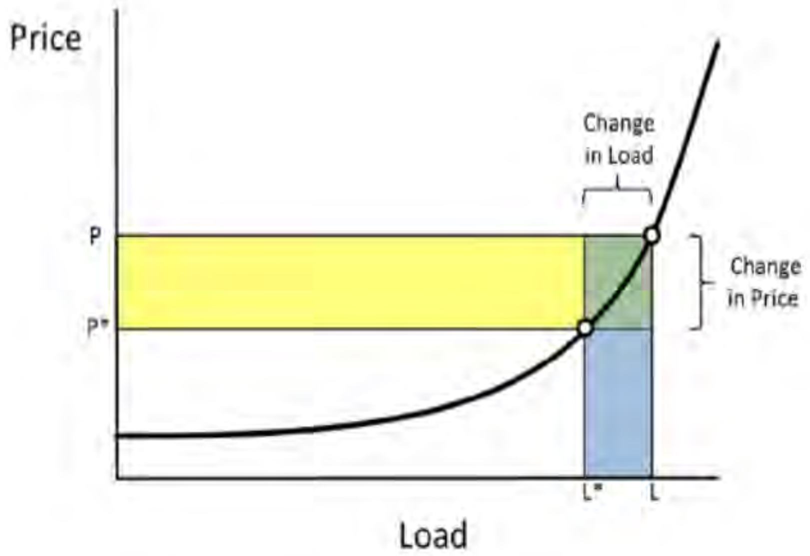
[27] See Maine Public Utilities Commission, *Maine Distributed Solar Valuation Study* (March 1, 2015). Available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.

[28] The market price mitigation benefit is not the same as the fuel hedging benefit discussed above. Both benefits involve energy market prices for electricity and natural gas. However, the fuel hedging benefit for consumers results from a reduction in the volatility of these market prices – in other words, in a reduced risk of periodic price spikes in these commodity markets, whereas the market price mitigation benefit is from an overall reduction in the levels of these market prices. Thus, these benefits are related but do not overlap and are not duplicative.

Figure 8: *Reduced Demand in the Energy Market Lowers the Price*



The magnitude of this benefit will depend on the overall amount of renewables on the grid. From 2010-2014, the National Renewable Energy Laboratory (NREL) and GE Consulting released the multi-phase Western Wind and Solar Integration Study (WWSIS), a major modeling effort to analyze much higher penetrations of wind and solar resources in the western U.S.[29] This work focused on the West Connect area (basically, Arizona, Colorado, New Mexico, Nevada, and Wyoming), but also modeled the entire WECC grid in the U.S. This modeling included analysis of the impact of increasing solar penetration on market prices in the West; the results for spot prices in Arizona are shown in the figure below.[30] Generally, the high penetration solar cases (15% to 25% penetration) result in 10% to 20% reductions in spot market prices. Note that the largest reductions in market prices occur from the initial 5% penetration of solar, which Wyoming is still well within.

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[29] All reports from the WWSIS, are available on the NREL website at http://www.nrel.gov/electricity/transmission/western_wind.html.

[30] The results from the WWSIS for high penetrations of solar are reported in *Impact of High Solar Penetration in the Western Interconnection* (NREL and GE Consulting, December 2010), with the impact on spot market prices in Arizona reported at p. 8 and Figure 19.

Figure 9:

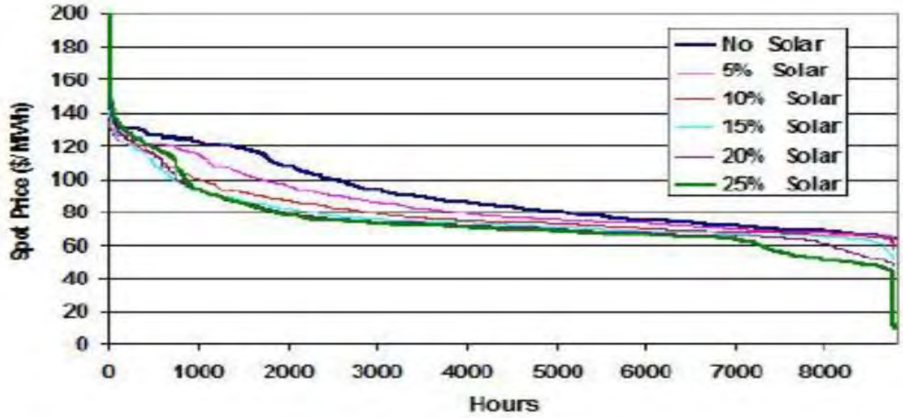

Figure 19 – Arizona Spot Price Duration Curves.

The same market mitigation benefit exists on the natural gas side. Renewable generation reduces marginal gas-fired generation, thus lowering the demand for natural gas. A study by Lawrence Berkeley National Lab (LBNL) has estimated that the gas-related market mitigation benefits of renewable energy range from $7.50 to $20 per MWh of renewable output.[31]

The New England states have done the most extensive work to calculate this market benefit, which they have labelled the Demand Reduction Induced Price Effect (DRIPE). DRIPE is included in the region's biennial forecast of avoided costs used for demand-side programs, *Avoided Energy Supply Costs in New England (AESC)*.[32] We have reviewed the DRIPE calculations in the *2013 and 2015 AESC* reports. There is a significant difference in the DRIPE impacts between the *2013* and *2015 AESC* reports, as a result of changes in the methodology for the DRIPE calculations in the *2015 AESC.*[33] For example, the *2015 AESC* assumes (1) a much shorter duration for energy DRIPE impacts (three years) and (2) zero capacity DRIPE as a result of an assumed near-term need for new capacity in New England. We have not attempted to resolve these differences, but for the purposes of this study have used the average of the energy DRIPE impacts between the two studies – a 4% reduction in avoided energy costs. We do not assume any capacity DRIPE, given the near-term need for new capacity in Wyoming. **Thus, the energy market price mitigation benefit is 4% of our avoided energy costs, plus associated losses, or $2.40 per MWh**.

h. Total Direct Benefits

The following **Table 13** summarizes the direct benefits of solar DG for RMP's ratepayers. **The direct benefits total 14.6 cents per kWh.**

[31] See Wiser, Ryan; Bolinger, Mark; and St. Clair, Matt, "Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency" (LBNL, January 2005), at p. ix, available at http://eetd.lbl.gov/EA/EMP.

[32] See *2015 AESC*, at Appendix B., Tables One and Two. This report is available at https://www9.nationalgridus.com/non_html/eer/ne/AESC2015%20merged%20report.pdf.

[33] See *2015 AESC*, at pages 1-5 and 1-16 to 1-17.

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

Benefit	Avoided Costs ($ per MWh)
Energy	51.20
Generation Capacity	21.85
T&D Losses	11.30
Carbon Emissions	10.50
Transmission Capacity	16.50
Distribution Capacity	9.10
Fuel Price Uncertainty	23.10
Market Price Mitigation	2.40
Total Benefits	145.95
	14.6 cents per kWh

4. Societal Benefits of Solar DG

Renewable DG has benefits to society that do not directly impact utility rates. When renewable generation takes the place of conventional fossil fuel generation, all members of society benefit from reductions in air pollutants that harm human health and exacerbate climate change. Demands on existing water supplies are reduced, avoiding the potential need to acquire new sources of supply. Distributed generation uses already-built sites, preserving land for other uses or as natural habitat. Distributed generation makes the power system more reliable and resilient, and stimulates the local economy. Many of these benefits can be quantified, as discussed below. We use a lower, societal discount rate of 5% (3% real) in calculating these benefits, rather than the 6.88% RMP discount rate used for the direct benefits.

a. Carbon

The **social cost of carbon** (SCC) is "a measure of the seriousness of climate change."[34] It is a way of quantifying the value of actions to reduce greenhouse gas emissions, by estimating the potential damages if carbon emissions are not reduced. The carbon costs which we have included in the direct benefits of solar DG above are limited to the anticipated costs to comply with future regulation of carbon emissions. These compliance costs are assumed to be lower than the true costs that carbon pollution imposes on society, which are the damages estimated by the SCC. As a result, the additional costs in the SCC, above the compliance costs of mitigating carbon emissions, represent the societal benefits of avoided carbon emissions.

An early source for estimates of the social cost of carbon was the federal government's Interagency Working Group on the Social Cost of Carbon.[35] These values were vetted by numerous government agencies, research institutes, and other stakeholders. The cost values were derived by combining results from the three most prominent integrated assessment models, each run under five different reference scenarios.[36] However, the Interagency working group forecast

[34] Anthoff, D. and Toll, R.S.J. 2013. The uncertainty about the social cost of carbon: a decomposition analysis using FUND. *Climactic Change* 117: 515-530.

[35] Interagency Working Group on Social Cost of Carbon, *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (May 2013, Revised July 2015). Available at: https://www3.epa.gov/climatechange/Downloads/EPAactivities/social-cost-carbon.pdf.

[36] *Id.* The three models are the Dynamic Integrated Climate-Economy (DICE) model, the Climate Framework for Uncertainty, Negotiation and Distribution (FUND) model, and the Policy Analysis of the Greenhouse Effect

is more than 10 years old, and is in the process of being updated. A recent academic estimate of the SCC for the U.S. is the median estimate of $417 per metric tonne from a review of the range of SCC values published in October 2018 in *Nature Climate Change*.[37] This more recent SCC is far higher than the Interagency SCC values. RMP's *2021 IRP* uses an SCC forecast that starts at $74 per metric tonne, as shown in Figure 6 above. This appears to be an effort to escalate the older Interagency SCC values to today. We have used the RMP SCC values recognizing that they are likely to be a conservatively low value.

We calculate the societal benefits of reducing carbon emissions in the years 2022 – 2046 as (1) the SCC values used in the RMP IRP less (2) the base case for the compliance carbon costs used in our direct benefits, discussed above. The 25-year levelized difference is $53.20 per MWh.

Reduced methane leakage. In addition, we also determine the total greenhouse gas emissions that will result from methane leakage in the natural gas infrastructure that serves marginal gas-fired power plants. We attach to this report as **Attachment 1** a white paper calculating the additional greenhouse gas emissions associated with methane leaked in providing the fuel to gas-fired power plants. This issue has received significant attention as a result of the major methane leak in 2015 from the Aliso Canyon gas storage field in southern California and new technologies for the remote sensing of methane leakage. The bottom line is that the CO_2 emission factors of gas-fired power plants should be increased by more than 60% to account for these directly-related methane emissions from the production and pipeline infrastructure that serves gas-fired electric generation. This additional societal benefit amounts to $5.00 per MWh.

b. Health benefits of reducing criteria air pollutants

Reductions in criteria pollutant emissions improve human health. Exposure to particulate matter (PM) causes asthma and other respiratory illnesses, cancer, and premature death.[38] Nitrous oxides (NO_X) react with volatile organic compounds in the atmosphere to form ozone, which causes similar health problems.[39]

We use AVERT to calculate the avoided emissions of SO_2, NO_x, and fine particulate matter ($PM_{2.5}$), assuming 3 MW of solar DG development. The avoided emissions of these criteria pollutants are shown in **Table 14**.

(PAGE) model.

37 See Ricke et al., "Country-level social cost of carbon," *Nature Climate Change* (October 2018). Available at: https://www.nature.com/articles/s41558-018-0282-y.epdf.

38 EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014), p. 4-17 ("CPP Technical Analysis"). Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

39 *Ibid.*

Table 14: *Avoided Emissions of Criteria Pollutants*

Pollutant	Avoided Emissions lbs/MWh
SO_2	0.52
NOx	0.93
$PM_{2.5}$	0.033

The value of these avoided emissions is calculated as follows:

1. Determine the amount of avoided emissions using AVERT as described above.
2. Calculate the social cost of the avoided emissions and subtract the compliance cost or emissions market value of those emissions.

For quantifying the health benefits, we recommend using the health co-benefits from reductions in criteria pollutants that EPA developed in conjunction with the Clean Power Plan. These benefit estimates were developed in 2014 as part of the technical analysis for the proposed rule.

SO_2. The total social cost of SO_2 emissions is taken from the EPA's *Regulatory Impact Analysis for the Final Clean Power Plan (CPP Impact Analysis)*.[40] The EPA calculated social cost values for 2020, 2025, and 2030. This analysis uses the values given for these three years assuming a 3% discount rate. Values for intermediate years are interpolated between the five-year values. The market value of SO_2 is taken from the EPA's 2016 SO_2 allowance auctions. However, the final clearing price of the latest spot auction was just \$0.06 per ton.[41] This is low enough compared to the social cost that it is negligible for our calculations. The societal benefit of avoided SO_2 emissions is \$19.70 per MWh.

NOx. Heath damages from exposure to nitrous oxides come from the compound's role in creating secondary pollutants: nitrous oxides react with volatile organic compounds to form ozone, and are also precursors to the formation of particulate matter.[42] The social cost of NOx is taken from the EPA's CPP Impact Analysis.[43] We use a 2017 NO_x market price of \$750 per ton for compliance with the Cross State Pollution Rule as the compliance cost for NOx.[44] The benefit of avoiding NOx emissions is \$2.20 per MWh.

Fine Particulates ($PM_{2.5}$). We use the emissions factor and damage costs for $PM_{2.5}$, because $PM_{2.5}$ are the small particulates with the most adverse impacts on health. The EPA health co-benefit figures distinguish between types of PM, and calculate two separate benefit-per-ton estimates for PM: for PM emitted as elemental and organic carbon, and for PM emitted as crustal particulate matter.[45] The EPA estimates that approximately 70% of primary $PM_{2.5}$ emitted in Wyoming is crustal material, with the bulk of the remainder being elemental or

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40 *Regulatory Impact Analysis for the Final Clean Power Plan*. Found at: https://www.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule-ria.pdf.

41 EPA 2016 SO2 Allowance Auction. Found at: https://www.epa.gov/airmarkets/2016-so2-allowance-auction.

42 CPP Technical Analysis, p. 4-14.

43 *CPP Impact Analysis*, at Table 4-7.

44 See the EPA Cross State Air Pollution Rule. Found at: https://www.epa.gov/csapr. NOx emission allowance prices can be found at http://www.evomarkets.com/content/news/reports_23_report_file.pdf.

45 CPP Technical Analysis, p. 4-26, Table 4-7.

organic carbon.[46] The emissions factor of 0.0077 lbs per MMBtu for total primary $PM_{2.5}$ does not differentiate among particle types.[47] As a result, we weigh the mid-point of each of the two benefit-per-ton estimates according to EPA's assumptions for Wyoming emissions. The health benefits of reducing $PM_{2.5}$ emissions are $1.10 per MWh on a 25-year levelized basis.

c. Water

Thermal generation consumes water, principally for cooling. Reducing water use in the electric sector through the use of renewable generation lowers the vulnerability of the electricity supply to the availability of water, and reduces the possibility that new water supplies will have to be developed to meet growing demand. However, water consumption by efficient gas-fired generation is relatively low, and the cost of incremental water supplies varies widely depending on the local abundance of water resources. As a result, the value of avoided water use is relatively modest. We have used $1.20 per MWh for the value of avoided water use, based on several sources.[48]

d. Land use

Distributed generation makes use of the built environment in the load center – typically roofs and parking lots – without disturbing the existing use for the property. In contrast, central station fossil or renewable plants require large single parcels of land, and tend to be more remotely located where the land has agricultural or habitat uses. Unless the site is already being used for power generation, the land must be removed from its prior use when it becomes a solar farm or a fossil power plant. Although fossil natural gas plants have small footprints per MWh produced, one must also consider that upstream natural gas wells, processing plants, and pipelines have substantial land use impacts in the basins where gas is produced. Central-station solar photovoltaic plants with fixed arrays or single-axis tracking typically require 7.5 to 9.0 acres per MW-AC, or 3.3 to 4.4 acres per GWh per year. The lost value of the land can vary over a wide range, depending on the alternative use to which it could be put. As an example of the magnitude of land use impacts, we calculate that, based on the 2020 U.S. Department of Agricultural rental value for irrigated croplands in Wyoming ($89 per acre),[49] and the alternative of a utility-scale solar plant (4 acres per GWh), the land use value avoided by DG is about $0.4 per MWh. This value will be lower if the land has an alternative use of lower value than irrigated land for farming.

e. Local economic benefits

The development of solar DG will benefit the economy of the community in which it is installed. A portion of the costs of installing a DG system – principally for installation labor,

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46 *Ibid*., p. 4A-8, Figure 4A-5.

47 AP 42, Table 1.4-2, Footnote (c).

48 This figure is based on the American Wind Energy Association's estimate that, in 2016, operating wind projects produced 226 million MWh and avoided the consumption of 87 billion gallons of water, with a cost of new water resources of about $1,000 per acre-foot. This is similar to the mid-point of cost estimates for the cost of water savings at gas-fired power plants by implementing dry cooling technologies. See Maulbetsch, J.S.; DiFilippo, M.N. *Cost and Value of Water Use at Combined-Cycle Power Plants*. CEC-500-2006-034. Sacramento: California Energy Commission, PIER Energy-Related Environmental Research, 2006, available at http://www.energy.ca.gov/2006publications/CEC-500-2006-034/.

49 See USDA, National Agricultural Statistics Service, Survey of 2017 Cash Rents, available at https://quickstats.nass.usda.gov/results/58B27A06-F574-315B-A854-9BF568F17652#7878272B-A9F3-3BC2-960D-5F03B7DF4826.

permitting, permit fees, and customer acquisition (marketing) – are spent in the local economy, and thus provide a local economic benefit in close proximity to where the DG is located. These local costs are an appreciable portion of the "soft" costs of DG.

There have been a number of recent studies of the soft costs of solar DG, as the industry has focused on reducing these costs, which are significantly higher in the U.S. than in other major international markets for solar PV. The following **Table 15** presents data on the soft costs for residential PV systems that are likely to be spent in the local area where the DG customer resides, from detailed surveys of solar installers that were conducted by two national labs (LBNL and NREL) in 2013.

Table 15: *Residential Local Soft Costs*

Local Costs	**LBNL – J. Seel** *et al.*[50]		**NREL – B. Friedman** *et al.*[51]	
	$/watt	**%**	**$/watt**	**%**
Total System Cost	6.19	100%	5.22	100%
Local Soft Costs				
Customer acquisition	0.58	9%	0.48	9%
Installation labor	0.59	10%	0.55	11%
Permitting & interconnection	0.15	2%	0.10	2%
Permit fees	0.09	1%	0.09	2%
Total local soft costs	**1.41**	**22%**	**1.22**	**23%**

Based on these studies, we assume that 22% of residential solar PV costs are spent in the local economy where the systems are located. These economic benefits occur in the year when the DG capacity is initially built, which for the purpose of this study is 2021. We have converted these benefits into a $ per kWh benefit over the expected DG lifetime that has the same net present value in 2021 dollars. We also use more current (and thus lower) DG capital costs than the system costs used in the LBNL and NREL studies. The result is a societal benefit of $30.70 per MWh of DG output for residential systems.

Importantly, the magnitude of this local economic benefit is comparable to the fuel cost for the fossil generation from coal or natural gas that may be displaced by the renewable DG output – fossil generation that is likely to have been fueled by coal or gas produced in Wyoming. This comparison shows that the growth of renewable DG in Wyoming communities will generate economic activity that offsets the loss to the state's economy of fossil fuel production.

f. Reliability and resiliency

Renewable distributed generation resources are installed as thousands of small, widely distributed systems and thus are highly unlikely to experience unexpected, forced outages at the same time. Furthermore, the impact of any individual outage at a DG unit will be far less consequential than an outage at a major central station power plant. In addition, the DG customer, not the ratepayers, will pay for the repairs.

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50 J. Seel, G. Barbose, and R. Wiser, *Why Are Residential PV Prices So Much Lower in Germany than in the U.S.: A Scoping Analysis* (Lawrenece Berkeley National Lab, February 2013), at pp. 26 and 37.

51 B. Friedman et al., *Benchmarking Non-Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey – Second Edition* (National Renewable Energy Lab, October 13, 2013), at Table 2.

Most electric system interruptions do not result from high demand on the system, but from weather-related transmission and distribution system outages. In these more frequent events, renewable DG paired with on-site storage can provide customers with an assured back-up supply of electricity for critical applications should the grid suffer an outage of any kind. This benefit of enhanced reliability and resiliency has broad societal benefits as a result of the increased ability to maintain government, institutional, and economic functions related to safety and human welfare during grid outages.

Both DG and storage are essential in order to provide the reliability enhancements that are needed to eliminate or substantially reduce weather-related interruptions in electric service. The DG unit ensures that the storage is full or can be re-filled promptly in the absence of grid power, and the storage provides the alternative source of power when the grid goes down. DG also can supply some or all of the on-site generation necessary to develop a micro-grid that can operate independently of the broader electric system. Solar DG is a foundational element necessary to realize this benefit – in much the same way that smart meters are necessary infrastructure to realize the benefits of time-of-use rates, dynamic pricing, and demand response programs that will be developed in the future – and thus the reliability and resiliency benefits of wider solar DG deployment should be recognized as a broad societal benefit.

g. Customer choice

There are important public policy reasons to ensure that the customers who invest in DG are treated equitably in assessments of the merits of net metering and renewable DG, so that consumers continue to have the freedom to exercise a competitive choice, to become more engaged and self-reliant in providing for their energy needs, and to encourage others to invest private capital in Wyoming's energy infrastructure.

There are many dimensions to the customer choice benefits of DG technologies, including:

- **New Capital.** Customer-owned or customer-sited generation brings new sources of capital for clean energy infrastructure. Given the magnitude and urgency of the task of moving to clean sources of energy, expanding the pool of capital devoted to this task is essential.

- **New Competition.** Rooftop solar provides a competitive alternative to the utility's delivered retail power. This competition can spur the utility to cut costs and to innovate in its product offerings. With the widespread availability of rooftop solar, energy efficient appliances, and load management technologies, plus – in the near future – customer-sited storage, this competition will only intensify. In the now-foreseeable future, the combination of solar, storage, and load management may offer an electric supply whose quality and reliability is comparable to utility service.

- **High-tech Synergies.** Rooftop solar appeals to those who embrace the latest in technology. Solar has been described as the "gateway drug" to a host of other energy-saving and clean energy technologies. Studies have shown that solar customers adopt more energy efficiency measures than other utility customers, which is logical given that it makes the most economic sense to add solar only after making other lower-cost energy efficiency improvements to your premises.[52] Further, with net metering, customers retain the same incentives to save energy that they had before installing solar. These synergies will only grow as the need to make deep cuts in carbon pollution drives the increasing electrification of other sectors of the economy, such as transportation.

- **Customer Engagement.** Customers who have gone through the process to make the long-term investment to install solar learn much about their energy use, about utility rate structures, and about producing their own energy. Given their long-term investment, they will remain engaged going forward. There is a long-term benefit to the utility and to society from a more informed and engaged customer base, but only if these customers remain connected to the grid. As we saw in Nevada in 2015-2016, when the Nevada commission unexpectedly slashed the compensation for existing net-metered solar customers, this positive customer engagement can turn to customer "enragement" if the utility and regulators do not accord the same respect and equitable treatment to customers' long-term investments in clean energy infrastructure that is provided to the utility's investments and contracts. Emerging storage and energy management technologies may allow customers in the future to "cut the cord" with their electric utility in the same way that consumers have moved away from the use of traditional infrastructure for landline telephones and cable TV. Given the important long-term benefits that renewable DG can provide to the grid if customer-generators remain connected and engaged, it is critical for regulators and utilities to avoid alienating their most engaged customers.

- **Self-reliance.** The idea of becoming independent and self-reliant in the production of an essential commodity such as electricity, on your own property using your own capital, has deep appeal to Americans, with roots in the Jeffersonian ideal of the citizen (solar) farmer.

These benefits of customer choice are difficult to express in dollar terms; however, all are strong policy reasons for ensuring that the development of clean energy infrastructure includes policies which sustain a robust market for rooftop solar.

h. Summary of societal benefits

Many of the societal benefits discussed above can be quantified, and indeed they do have significant value. **Table 16** below summarizes the societal benefits of solar DG that we have quantified and discussed above. **The societal benefits total 8.2 cents per kWh.** Accordingly, these benefits cannot and should not be ignored by policymakers, because ignoring them implicitly values them at zero.

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52 See the *2009 Impact Evaluation Final Report on the California Solar Initiative*, prepared by Itron and KEMA and submitted in June 2010 to Southern California Edison and the Energy Division of the California Public Utilities Commission. See pages ES-22 to ES-32 and Chapter 10. Also available at the following link: http://www.cpuc.ca.gov/workarea/downloadasset.aspx?id=7677. Also see Center for Sustainable Energy, *Energy Efficiency Motivations and Actions of California Solar Homeowners* (August 2014), at p. 6, finding that more than 87% of solar customers responding to a survey had installed or upgraded one or more energy efficiency technologies in their homes. Available at https://energycenter.org/sites/default/files/docs/nav/policy/research-and-reports/Energy%20Efficiency%20Motivations%20and%20Actions%20of%20California%20Solar%20Homeowners.pdf.

Table 16: *Societal Benefits*

Benefit	Value ($ per MWh)	Method Used
Carbon: avoid societal damages from climate change	53.20	Use the difference between RMP's *2021 IRP* social cost of carbon estimate and the assumed carbon compliance costs.
Carbon: reduce methane leaks from natural gas infrastructure	5.00	Assumes 2% leakage, per 2015 National Academy of Sciences report
Reduce SO_2 emissions	19.70	EPA AVERT model for avoided SO2 emissions. EPA estimates of health benefits.
Reduce NO_x emissions	2.20	EPA AVERT model for avoided NOx emissions. EPA estimates of health benefits.
Reduce $PM_{2.5}$ emissions	1.10	EPA Clean Power Plan technical appendices and EPA AP 42 for emissions factors.
Avoid consumptive water use	1.20	Several estimates of avoided water use from renewable generation.
Local economic benefit	Neutral	The portion of DG system costs spent in the local economy offsets any loss to the Wyoming economy from displaced fossil fuel production.
Land use	Small and positive, but varies	Highly variable based on alternative uses of land at which large power plants are sited.
Reliability	Significant and positive	Significant reliability and resiliency benefits from the pairing of solar DG and on-site storage.
Customer choice	Significant and positive	Increased customer choice, engagement, and self-reliance. New capital for the energy sector.
Total	**82.40**	Use in the Societal Test

5. Costs of Solar DG for Participants

We use a pro forma cash flow analysis to project the lifecycle levelized cost of energy (LCOE) from a solar DG system. based on 2021 solar system costs of $2.75 per watt-DC that RMP uses in its *2021 IRP*.[53] The other major assumptions we use are summarized in **Table 17**. The calculated **LCOE of residential solar is 12.3 cents per kWh.**

Table 17: *Key Assumptions for the Residential Participant Cost of Solar*

Assumption	Value
Median Cost	$2.75 per watt DC (in 2021)
Federal ITC	26%
Financing Cost	5%
Participant discount rate	5%
Financing Term	20 years
Inverter Replacement	$500/kW in Year 15
Maintenance Cost	$10 per kW-year

53 See *2021 IRP*, Appendix L, p. 16 (Table 5).

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

There are two other 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 are the retail bill savings provided to solar customers through net metering. These bill savings are the revenues that the utility loses as a result of DG customers serving their own load; these revenues may be shifted to other ratepayers after rates are readjusted in a subsequent rate case.

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 80% of the customer's annual load prior to any degradation. Thus, the customer's solar PV system produces 8,000 kWh per year in the first year of operation. We assume this output degrades by 0.5% per year thereafter. Thus, by year 25, the PV system is assumed to produce 7,093 kWh per year, or about 71% of the customer's annual load. Over a 25-year period, the PV system produces 75% of the customer's annual pre-solar load.

We model hourly customer load based on NREL data for a typical load profile for a residential customer in Rock Springs, Wyoming.[54] An hourly solar PV generation profile for a rooftop PV system in Rock Springs is taken from the NREL PVWATTS model.[55] We scale the customer load to 10,000 kWh per year, and scale the PV output to 8,000 kWh per year (the estimated output for a 4.9 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 net usage amounts that determine the customer's bills under net metering.

Bill calculations assume RMP's July 25, 2021, Residential Service (Schedule 2) rates, as approved in Docket No. 20000-578-ER-20.[56] We estimate that the modeled customer's bill would decrease in the first year (i.e. prior to any degradation) from $84 per month without solar to $31 per month with solar PV. The $53 per month bill savings associated with our modeled 4.9 kW-AC solar PV system indicate that the customer is able to save 8.0 cents per kWh of solar PV generation in the first year (i.e. $53 per month bill savings / 348 kWh per month solar output = $0.080 per kWh). Assuming 2% annual rate escalation, 0.5% solar PV degradation, and a 6.88% discount rate the same as RMPs weighted average cost of capital, **the 25-year levelized value of the customer's bill savings, equivalent to the utility's lost revenue, is 8.6 cents per kWh**.

For the Wyoming municipal co-ops, we performed a significantly simpler analysis, given that these entities tend to have a single flat rate for electricity. Carbon Power and Light (CP&L) has a Schedule A, General Service rate of approximately $0.120 per kWh.[57] While excess annual energy is priced out at avoided cost rate of approximately $0.042 per kWh, we expect that a net metering customer with solar equal to 80% of total load would receive the $0.12 per kWh in bill savings. Assuming similar solar integration costs as for PAC, the combination of reduced customer bills and solar integration costs is **11.9 cents per kWh for CP&L**. For High Plains

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54 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 Rock Springs, Wyoming.

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

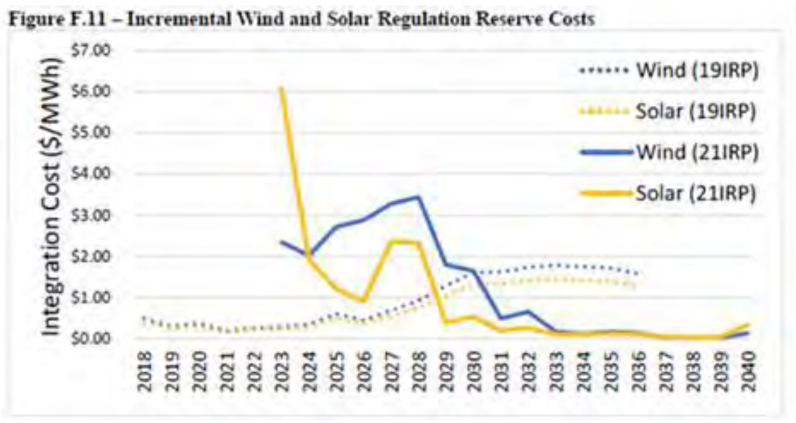
56 See https://www.rockymountainpower.net/about/rates-regulation/wyoming-rates-tariffs.html

57 See https://carbonpower.com/rates-0

Power, the energy charge for cooperative members (single phase, secondary voltage level) is $0.10845 per kWh; in addition, High Plains has a $30 per month facilities charge. Thus, after integration costs, we assume combined cost of **10.7 cents per kWh for High Plains Power**. We note these costs are in the range of 23% (for High Plains) to 37% (for CP&L) higher than for an RMP customer.

Next, we add an estimate of solar integration costs derived from solar integration studies of other utilities with much higher solar penetrations.[58] 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 RMP 2021 IRP includes a figure illustrating its estimate of regulation reserve costs for wind and solar (see the solid yellow line below). Based on these costs, we estimate a levelized solar integration cost of $1.08 per MWh over a 25-year period. We assume that **$1 per MWh represents a reasonable assumption for a 25-year levelized solar integration cost in Wyoming**.

Figure 10



Thus, for RMP, the utility costs associated with **reduced customer bills and solar integration combine to equal 8.7 cents per kWh** (i.e. 8.6 cents per kWh in lost retail revenues plus 0.1 cents per kWh in solar integration costs).

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

The following **Table 18** and **Figure 11** incorporate the results of the above analyses into each of the primary cost-effectiveness tests for residential solar DG on the RMP 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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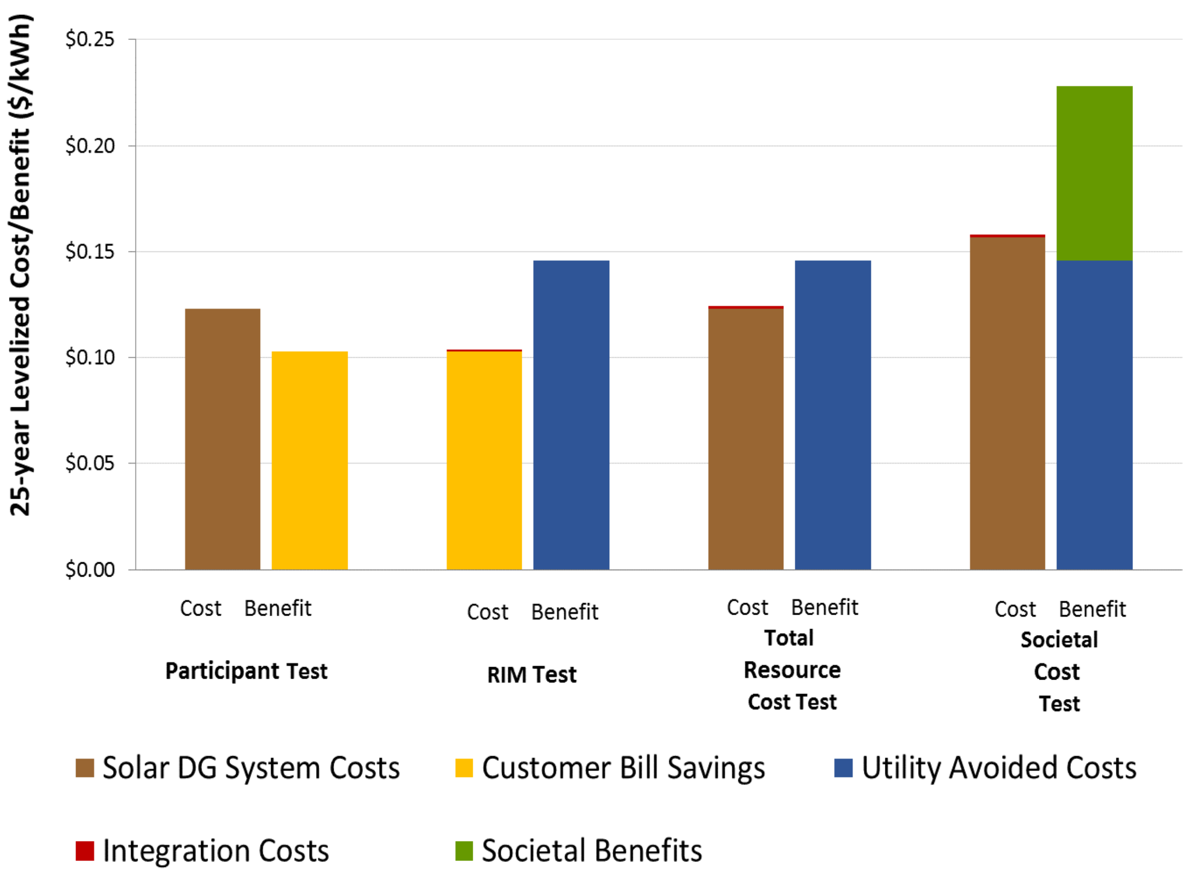
58 It is also possible that the utility may incur costs to administer the net metering program. It is speculative to estimate these costs without specific information from the utility. However, we expect that such costs are minimal at the current penetration of net metered systems in Wyoming.

Table 18: *Benefits and Costs of Residential Solar for RMP (25-yr levelized cents/kWh)*

Benefit-Cost Test	**Participant**		**RIM / PAC**		**TRC**		**Societal**	
Category	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Avoided Utility Costs – Energy, Capacity, T & D, CO2, Hedging				14.6		14.6		14.6
Lost Revenues / Bill Savings (RIM / PCT)		10.3 (8.6 – 11.9)	10.3 (8.6 – 11.9)					
Integration (RIM/TRC/SCT)			0.1		0.1		0.1	
Solar DG LCOE	12.3				12.3		15.7	
Societal Benefits								8.2
Totals	12.3	10.3	10.4	14.6	12.4	14.6	15.8	22.8
Benefit-Cost Ratios	**0.84**		**1.40 (RIM) >> 1 (PAC)**		**1.18**		**1.44**	

Figure 11: *Cost-effectiveness Results for Residential Solar in Wyoming*



The principal conclusions of our analysis are as follows:

1. **Net metering does not cause a cost shift to non-participating ratepayers**, as shown by the result above 1.0 for 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 or cost of service. On average, utility bills will decline, as shown by the high score on the Program Administrator Cost test.

2. **Modifications to net metering are not needed** to recover the utility's full cost of service over time from net metering customers. Major rate design changes for residential DG customers, such as increased fixed charges, the use of demand charges, or two-channel billing to set different compensation rates for imported and exported power, are not needed to recover the utility's full cost of service over time from net metering customers.

3. **The economics of solar DG are not favorable** for residential customers in Wyoming, as shown by the Participant test results below 1.0. This accounts for the modest amount of solar adoption to date in the state. This means that any reduction in the compensation provided to solar DG customers is likely to be detrimental to the growth of this resource, although these economics may improve as solar costs continue to fall.

4. 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 utilities in Wyoming, as shown by the score above 1.0 on the Total Resource Cost test.

5. There are **significant, quantifiable societal benefits from solar DG**, including local economic benefits and public health improvements from reduced air pollution. When these additional societal benefits are considered, solar DG passes the Societal Test by a significant margin.

6. Solar DG also provides other important benefits that are difficult to quantify. These include 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, and results in **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 Wyoming's clean energy infrastructure and allows Wyoming to take advantage of federal tax incentives for solar that may drop to zero in 2024 for residential customers.**

Methane Leaks from Natural Gas Infrastructure Serving Gas-fired Power Plants

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1. Summary

Natural gas has been commonly depicted as a “bridge” fuel between coal and renewable energy for the generation of electricity. Natural gas is considered more environmentally friendly because burning natural gas produces less CO_2 than coal on a per unit of energy basis. Most analyses of the greenhouse gas (GHG) emissions associated with burning natural gas to produce electricity use an emission factor of 117 lbs of CO_2 per MMBtu of natural gas burned. However, this number does not include methane leaked to the atmosphere during the production, processing, and transmission of natural gas from the wellhead to the power plant. Methane is both the primary constituent of natural gas and a potent greenhouse gas (GHG), so quantifying the methane leakage is important in assessing the impact of natural gas systems on global warming.

Methane is emitted to the atmosphere from natural gas systems in both normal operating conditions and in low frequency, high emitting incidents. The Environmental Protection Agency’s (EPA) “Inventory of U.S. Greenhouse Gas Emissions and Sinks” attempts to calculate methane emissions from natural gas systems using a “Bottom Up” accounting method, which essentially adds up methane emissions from production, processing, transmission, storage, and distribution. This method sets a reasonable baseline for methane emissions during normal operating conditions, but does not account for low frequency high emitting situations.

Low frequency high emitting situations happen when some part of the production, processing, or transmission systems fail, leaking large amounts of methane into the atmosphere. The recent Aliso Canyon leak from a major Southern California Gas storage field in Parker Ranch, California is probably the best-known example of a low frequency high emitting event. The Aliso Canyon leak has emitted 2.4 MMT CO2-eq., or roughly 1.5% of total yearly methane emissions from all U.S. natural gas Infrastructure, in a single event. Several studies have shown that low frequency high emitting events like Aliso Canyon contribute significantly to methane emissions from natural gas systems.

The following analysis and discussion lays out an argument for increasing the carbon emission factor for burning natural gas in power plants to include the carbon equivalent of the methane emitted in the production, processing, transmission, and storage of natural gas, leaving out the losses in local distribution that are downstream from power plants on the gas system. A conservative starting point for the leakage from wellhead to power plant is that 2% of natural gas produced is lost to leakage in the form of methane. This estimate is based the IPCC Fifth Assessment Report, the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks," adjusted based on several studies quantifying how the EPA's method underestimates actual emissions.

Using the conservative estimates of 2% of total production emitted, and a global warming potential (GWP) of 25 (the low end of methane's GWP) increases the CO_2 emitted by burning methane to 175.5 lbs of CO_2-eq. per MMBtu of natural gas burned (a factor of 1.5). Using a GWP of 34 (high end) yields 196.6 lbs of CO_2 per MMBtu of natural gas burned (a factor of 1.68).

2. Measuring Natural Gas Leakage (Methods)

Determining methane leaks from natural gas systems is relatively new field of study. Until 2011 methane leaks were calculated almost exclusively using a Bottom Up accounting method based on data published in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks". Several issues with this method, including outdated Emission Factors and low frequency high emitting events, have led researchers to use "Top Down" aerial measurements of methane leakage.

Bottom Up. Bottom Up (BU) methods attempt to identify all sources of methane emissions in a typical production chain and assign an Emission Factor (EF) to each source. The total emissions are determined by adding up all of the EFs through the life cycle of natural gas. BU measurements are useful because they avoid measuring methane from biogenic sources (landfills, swamps, etc), anthropogenic sources in geographic proximity to natural gas systems (coal plants, oil wells, etc), and only require an engineering inventory of equipment and activity. However, BU measurements often rely on decades-old EFs. The EFs used in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks" are based on a report published in 1996, which in turn is based on data collected in 1992. The EPA has developed a series of correction factors based on technological improvements and new regulations.

BU studies have been shown to underestimate methane emissions from natural gas systems.[1]–[5] While outdated EFs can cause both under and overestimation of emissions, low frequency high emission events are responsible for consistent underestimation of emissions by BU calculations.[1], [5]–[7] A recent study in the Barnett Shale region of Texas found that 2% of facilities were responsible for 50% of the emissions and 10% were responsible for 90% of the emissions.[5] BU measurements do not accurately take into account these low frequency high emitters. First, most BU measurements either sample only a few facilities or rely on facility and equipment inventories rather than local measurements. Secondly, most BU data is self-reported. Finally, several studies have found that the low frequency high emitters were both spatially and temporally dynamic, with the high emission rates resulting from equipment breakdowns and failures, and not from design flaws in a few facilities.

Top Down. Top Down (TD) methane measurements have used aerial flyovers to measure the atmospheric methane content, then use mass balance and atmospheric transport models to determine methane emissions from a geographical region. A signature compound such as ethane is used to distinguish fossil methane from biogenic methane. Unlike BU measurements, TD measurements account for low frequency high emitter situations. TD studies consistently measure higher levels of methane emissions than do BU studies. Only recently have measurements TB and BU studies converged, and this convergence was only after additional low frequency high emission situations were characterized in BU studies.[5]

3. Methane Leak Calculations

The EPA divides methane emissions from natural gas systems into four categories: Field Production, Processing, Transmission and Storage, and Distribution. This analysis focuses on only the first three categories, leaving out local distribution networks. Detailed descriptions of these categories can be found in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks."

US Natural Gas Production 2005 - 2013

Expressed as BCF Natural Gas

Source	2005	2009	2010	2011	2012	2013
Withdrawals from Gas Wells	16,247	14,414	13,247	12,291	12,504	10,760
from Shale Shale Wells	0	3,958	5,817	8,501	10,533	11,933
Total Withdrawals from Natural Gas Systems	16,247	18,373	19,065	20,792	23,037	22,692

Emissions from US Natural Gas Systems 2005 - 2013

Expressed as % of Total Production

Stage	2005	2009	2010	2011	2012	2013
Field Production	0.91	0.66	0.58	0.48	0.42	0.41
Processing	0.20	0.20	0.18	0.20	0.19	0.20
Transmission and Storage	0.59	0.56	0.53	0.51	0.44	0.47
Total	1.70	1.43	1.30	1.19	1.05	1.07

Using the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks," methane emissions from natural gas infrastructure from the wellhead to a gas-fired power plant (excluding local distribution) are currently estimated to be 1.1% of production.[8] Given that EPA uses a BU method for calculating emissions, it is reasonable to assume that 1.1% is an underestimation. A 2015 study that combined seven different datasets from both TD and BU and included the most aerial measurements to date concluded that methane emissions were 1.9

(1.5 – 2.4) times the number reported in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks."[5] If the EPA's estimate is multiplied by 1.9 the result is 2.09%.

The IPCC Fifth Annual Report agrees, stating that: "Central emission estimates of recent analyses are 2% - 3% (+/– 1%) of the gas produced, where the emissions from conventional and unconventional gas are comparable." [9]

4. Global Warming Potential of Natural Gas

Global warming potentials (GWP) provide a method of comparing different GHGs. A GWP is: "a relative measure of how much heat a greenhouse gas traps in the atmosphere. It compares the amount of heat trapped by a certain mass of the gas in question to the amount of heat trapped by a similar mass of carbon dioxide." The Intergovernmental Panel on Climate Change (IPCC) regularly publishes updated GWPs based on the most current scientific knowledge. The most current value for methane (based on the 2013 IPCC AR5) is 34 for the 100-year GWP of methane.[9] The previous value (based on the 2007 IPCC AR4) is 25. Because methane's heat-trapping impacts are greatest in the first years after it enters the atmosphere, methane's 20-year GWP is about 85.[10]

5. Conclusion

This report recommends the use of a 2% emissions rate for methane leakage from natural gas systems when calculating the GHG emissions associated with natural gas-fired electric generation. Current analyses use 117 lbs of CO2 per MMBtu as the emissions factor from burning natural gas, which essentially assumes zero leakage. Adopting a 2% emission rate would increase this number to 190 lbs of CO2 per MMBtu of natural gas burned, assuming a 20-year GWP of 85.

6. Citations

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