Before the Public Service Commission of Utah

In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program	**Docket No. 14-035-184** Vote Solar Exhibit 2.0 (DT)

DIRECT TESTIMONY OF DAVID W. DERAMUS, PH.D.

ON BEHALF OF

VOTE SOLAR

June 8, 2017

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I. <u>Qualifications</u>

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is David W. DeRamus. I am a Partner with Bates White, LLC. My business address is 1300 Eye Street N.W., Suite 600, Washington, DC 20005.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I am a Partner with the economic consulting firm of Bates White, LLC. I have been in this position since 1999. During this time period, I have performed economic analyses related to a range of litigation, arbitration, and regulatory matters, many of which pertain to competition issues and energy markets. I have previously served as an economic expert in various proceedings before the Federal Energy Regulatory Commission ("FERC"), various state regulatory authorities, federal and state courts, and arbitration associations. In many of these proceedings, I have analyzed issues of market power, market manipulation, monopolization, price-fixing, mergers and acquisitions, and various regulatory proposals related to electricity markets. I have also previously testified in regulatory proceedings related to residential distributed solar generation. I have worked on behalf of the U.S. Department of Justice, the Maryland Public Service Commission, public utilities, independent power producers, industrial and residential consumers of electricity, industry associations, and various other parties. Prior to joining Bates White, I was employed by the management consulting firm A.T. Kearney, the accounting firm KPMG Peat Marwick, and the Harvard Graduate School of Business Administration. I received a Ph.D. in Economics from the University of Massachusetts at Amherst.

Q. DO YOU APPEND ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes, I append Vote Solar Exhibit 2.1 to this testimony, which is my curriculum vitae.

II. Purpose and Summary of Testimony

Q. WHO IS SPONSORING YOUR TESTIMONY?

A. My testimony is sponsored by Vote Solar.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked to review and respond to the November 9, 2016 Compliance Filing by Rocky Mountain Power ("RMP"), including the testimony submitted by RMP witnesses Ms. Steward, Mr. Meredith, Mr. Marx, Mr. Wilding, and Mr. Hoogeveen. In particular, I have been asked to assess RMP's analysis of the costs and benefits of residential distributed solar generation ("DSG") resources in Utah; and to assess RMP's proposal to alter the rate structure for RMP's net energy metering ("NEM") customers in Utah. In addition, I have been asked to provide the Public Service Commission of Utah (the "Commission") with other suggested modifications, if any, to RMP's rate structure for residential DSG/NEM customers in Utah.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. Based on my analysis of the information provided by RMP, and my own research on these issues, I come to four primary conclusions. First, RMP is incorrect in concluding that the costs associated with Utah's residential NEM program costs are greater than its benefits. Second, RMP has no reasonable basis for proposing a separate residential NEM rate class. Third, RMP has no reasonable basis for imposing demand charges or increased monthly fixed charges on residential NEM customers. Fourth, if the Commission decides that the recent growth in residential DSG in Utah warrants changes to the current NEM program, the Commission should limit any changes to the amount of the credit provided for NEM customer exports, and only implement any such changes gradually. Over the long-term, the Commission should establish a process to reevaluate periodically the value of the export credit in light of changes in the development and deployment of complementary technologies, which have the potential to significantly reduce the costs and increase the benefits of DSG in the future.

Q. PLEASE SUMMARIZE THE BASIS FOR YOUR CONCLUSION REGARDING THE COSTS AND BENEFITS OF UTAH'S RESIDENTIAL NEM PROGRAM.

A. RMP's conclusions regarding the costs and benefits of the residential NEM program are based on insufficient data and a flawed analysis. At current levels of penetration, residential NEM customers do not impose additional costs on the system, other than the costs that they directly reimburse. While RMP asserts that NEM customers may cause additional costs associated with "reverse flows," it provides no evidence that reverse flows have actually caused such costs, or are likely to cause such costs in the near future. On the contrary, at current penetration levels, such reverse flows benefit the system by reducing the need for peak energy that is more expensive, reducing system peak demand, and reducing loading on distribution circuits and transformers. RMP also incorrectly asserts that all NEM customers' generation – including both their "behind-the-meter" generation and their excess energy exported to the system and consumed by neighboring customers – imposes a system cost, on the purported basis that customer energy generation represents foregone RMP sales revenue. A reduction in revenue is not the same as an increase in costs, and similar reductions in revenue from energy efficiency measures, for example, are never treated as a cost of service. RMP's proposed treatment of NEM customers' generation – and particularly their behind-the-meter generation – as a system cost would be unduly discriminatory. On the benefit side of the equation, RMP only considers its avoided cost of generation and purchases, plus avoided line losses, resulting from the energy produced by DSG systems. In so doing, RMP undervalues NEM customers' export generation, and it ignores a broad range of additional long-term benefits provided by residential DSG. RMP ignores the significant capacity benefits of residential DSG, as well as its environmental, reliability, local grid resiliency, and other benefits. Some of these benefits are longer-term in nature, but they are nonetheless critical to consider in assessing the appropriate rate design for residential DSG customers. Appropriately evaluated, DSG provides a net benefit, not a net cost, to Utah customers.

Q. PLEASE SUMMARIZE THE BASIS FOR YOUR CONCLUSION REGARDING RMP'S PROPOSED SEGREGATION OF RESIDENTIAL NEM CUSTOMERS IN A SEPARATE RATE CLASS.

A. The very limited load research study on which RMP bases its conclusions is an insufficient basis on which to justify such a major change in the rate structure for residential NEM customers, and in fact demonstrates that residential NEM customers are situated similarly to other residential customers in all relevant respects. While residential NEM customers' excess generation during certain hours does flow onto the local distribution system as exports, this physical phenomenon does not require creating a separate class of residential NEM customers. Moreover, this excess generation provides a benefit to the system by serving the load of neighboring customers, especially during peak hours when it is most valuable. Even RMP's limited sample of information shows that on average, the load factors for residential NEM customers are not significantly different than other residential customers, and that their monthly consumption is similar to or higher than other residential customers (depending on the month). RMP's conclusion that NEM customers fail to cover an adequate portion of their costs of service is similarly flawed, since residential NEM customers do not cause RMP to incur any significant incremental costs.

Q. PLEASE SUMMARIZE THE BASIS FOR YOUR CONCLUSION REGARDING RMP'S PROPOSED DEMAND CHARGE.

A. Because RMP has failed to provide valid evidence that residential NEM customers are underpaying for their net energy consumption relative to their cost of service, RMP's proposed demand charge is unjustified and unduly discriminatory. While RMP has styled its proposal as a means of preventing "cost shifting" from residential NEM to non-NEM customers, RMP has strong incentives to reduce the ability of residential customers to install DSG systems provided by competitive suppliers, since this may increase RMP's risks of cost under-recovery and may limit the growth in RMP's asset base on which it earns a return. Rather than incentivizing NEM customers to reduce their aggregate peak demand, demand charges will simply serve to stifle the continued development of residential DSG in Utah. Furthermore, the combination of large demand charges, increased fixed monthly charges, and low energy rates provides poor incentives for customers to reduce their overall consumption, to shift their consumption from high demand to low demand time periods, and to adopt additional energy efficiency measures. RMP's proposed demand charge would seriously undermine the continued development of residential DSG in Utah, preventing Utah from obtaining future benefits from the industry's continuing innovations, deployment of complementary technologies, and cost reductions.

Q. DO YOU HAVE ANY RECOMMENDATIONS FOR THE COMMISSION?

A. If the Commission were to make any changes to the current residential NEM compensation, such changes should be implemented gradually to avoid eliminating the many benefits of residential DSG, particularly given its low current penetration levels. Such changes to the NEM rate design, if any, should be limited to the export credit (or crediting mechanism), taking into consideration the potential for changes in both DSG costs and benefits over time, as penetration levels increase, complementary technologies are deployed further (including battery storage, smart inverters, demand management, and other smart-grid advances), and Utah's overall energy mix and grid management concerns change. Ultimately, it may be appropriate for RMP to adopt time-of-use ("TOU") rates for residential NEM customers (as well as other residential customers), as that will provide the right incentives for customers to reduce their coincident peak load, which in turn will provide additional significant benefits to all customers by reducing the need for system investments by RMP.

Q. PLEASE PROVIDE A GUIDE TO THE REMAINDER OF YOUR TESTIMONY.

A. I first describe the current penetration of residential DSG in Utah and RMP's incentives to limit its future growth. I then proceed to assess RMP's COS analysis. Next, I analyze the broader benefits of residential DSG in Utah. I then review RMP's proposed changes to the NEM rate structure, and I discuss why the Commission should reject RMP's proposal. Finally, I provide my own recommendations to the Commission.

III. <u>RMP's Incentives to Limit the Growth of Residential DSG in Utah</u>

Q. WHAT IS RMP'S FORECAST FOR NEM GROWTH IN UTAH?

A. As of the end of 2016, RMP's cumulative NEM capacity (both residential and non-residential) is 105 MW_{AC}. This represents 2.3% of 2007 non-coincident peak load in Utah (the measure used by the Commission to establish the cap for NEM capacity). RMP forecasts that cumulative NEM capacity will grow four-fold over the next 10 years, increasing to 461 MW_{AC} in 2026. Even at RMP's growth expectation, total NEM capacity in Utah still would only be 10% of Utah's 2007 peak load by 2026, or 8.5% of Utah's 2026 peak load.[1] RMP forecasts that cumulative NEM capacity in Utah (both residential and non-residential) would not reach the Commission's 20% cap until 2035, as shown in Figure 1 below.[2]

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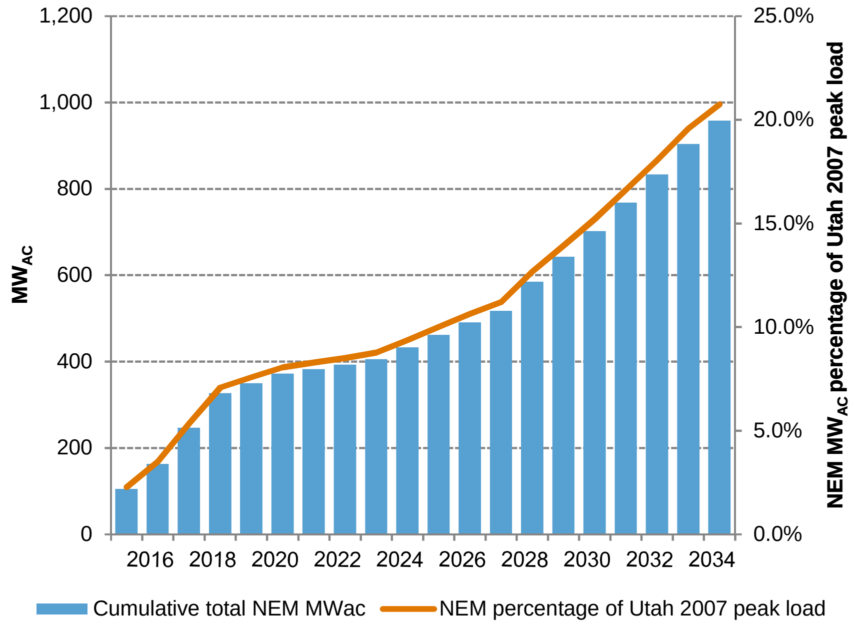
[1] Measured on a DC basis, RMP forecasts that cumulative NEM capacity will reach 10% of total capacity by 2023, since the DC capacity for solar PV is approximately 1.2 times higher than its corresponding AC capacity.

[2] Measured on a DC basis, RMP expects to reach the Commission's 20% NEM capacity cap in 2032.

Figure 1: Projected cumulative NEM growth in Utah



Q. PLEASE DESCRIBE THE RECENT GROWTH OF RESIDENTIAL DSG IN UTAH.

A. Residential DSG, which constitutes more than 70% of total NEM in Utah, has grown considerably in Utah in recent years. The number of residential NEM customers in Utah rose from 4,390 in 2015, to 15,992 in 2016, and to approximately 19,000 as of March 2017. By the end of 2016, NEM customers represented 2% of Utah residential customers; and their 77 MW_{AC} of residential solar photovoltaic ("PV") generation capacity represented 1.7% of RMP's 2007 peak load in Utah, or 1.6% of its 2016 coincident peak load in Utah. In 2015, the total amount of NEM production and excess energy was just 0.2% and 0.1% of RMP's retail sales in Utah, respectively. Thus, despite its rapid recent growth, residential DSG in Utah is still very small by all relevant metrics.

Q. ARE THERE OPPORTUNITIES FOR RESIDENTIAL DSG TO INCREASE FURTHER?

A. Yes, there is both a significant opportunity for and a public benefit to further growth in Utah's residential DSG portfolio. Overall, the vast majority of electricity in Utah continues to be generated by fossil fuels. In 2016, 73% was generated by coal-fired units; 21% by natural gas-fired units; and only 6% by solar and other renewable resources.[3] The Salt Lake City area also suffers from high levels of smog (particulate emissions and ozone),[4] which could be reduced by increasing the amount of renewable generation, particularly if paired with increased electrification of transportation. Utah has relatively high levels of insolation, and a favorable mix of housing and rooftops to allow for a considerable expansion of residential DSG. According to one recent study, Utah could generate approximately 25 – 34% of its electricity needs from rooftop PV (accounting for the specific rooftop profile in the state).[5] This provides a general indication of the current unexploited opportunities for further increases in residential DSG in Utah. Much of RMP's testimony is directed at potential costs to the system in a scenario in which residential DSG achieves a very high level of penetration (e.g., in discussing the potential cost impact of reverse flows from DSG on the distribution network), but it does not address the substantial benefits to Utah that would result in that scenario.

Q. SHOULD THE COMMISSION BE CONCERNED ABOUT THE RECENT GROWTH OF RESIDENTIAL DSG IN UTAH?

A. No. The recent rate of growth of residential DSG in Utah does not justify a major change in the NEM program. While residential DSG has grown rapidly in the past few years, that growth rate is measured relative to a very small base. Residential DSG comprises a very small portion of Utah's energy generation portfolio, and it will remain so for the foreseeable future. Some of the most recent increase may also be attributable to this very proceeding, and to customer

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3 SNL database.

4 *See* e.g., Emma Penrod, "American Lung Association ranks SLC in top 10 for worst air quality," Salt Lake Tribune, May 17, 2017 ("Salt Lake County received an F grade for both ozone and particles. Overall, Utah averaged an F for ozone and D for particulate pollution.") Available at: http://www.sltrib.com/home/3799747-155/slc-ranked-as-6th-worst-in-the. *See also*, David Montero, "Utah is the land of ski runs, pristine parks and a really bad smog problem," *Los Angeles Times*, February 2, 2017. Available at: http://www.latimes.com/nation/la-na-utah-smog-2017-story.html.

5 NREL, "Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment", January 2016, p. iv. The 25% lower bound only accounts for small rooftops, while the 34% upper bound includes medium and large rooftops (Table 3 and 5).

perceptions that they need to install DSG now, given RMP's proposal to radically reduce the financial value to customers of participating in the NEM program. The potential phase-out of Utah state income tax credits for new residential solar system installations, as proposed in HB 23 ("Utah Residential Solar Tax Credit Repeal"), is likely an additional factor stimulating the rapid recent growth in applications.[6] If the concern is the recent growth rate of DSG, rather than its current level, then an appropriate response would be to design a forward-looking program that is sufficiently flexible to moderate its growth rate in the future, while not stifling its further development, as RMP's proposal threatens to do.

Q. PLEASE DESCRIBE HOW THE COST OF RESIDENTIAL DSG HAS EVOLVED.

A. Rapid advances in technology and manufacturing efficiency have driven down the cost of PV modules dramatically in recent years. The resulting increase in sales, in turn, has led to economies of scale, which have further reduced costs. With increased scale and experience, competing firms have also been able to lower the costs of financing, marketing, customer acquisition, design, and installation. Figure 2 shows the substantial decline in the overall installed costs for residential PV.[7]

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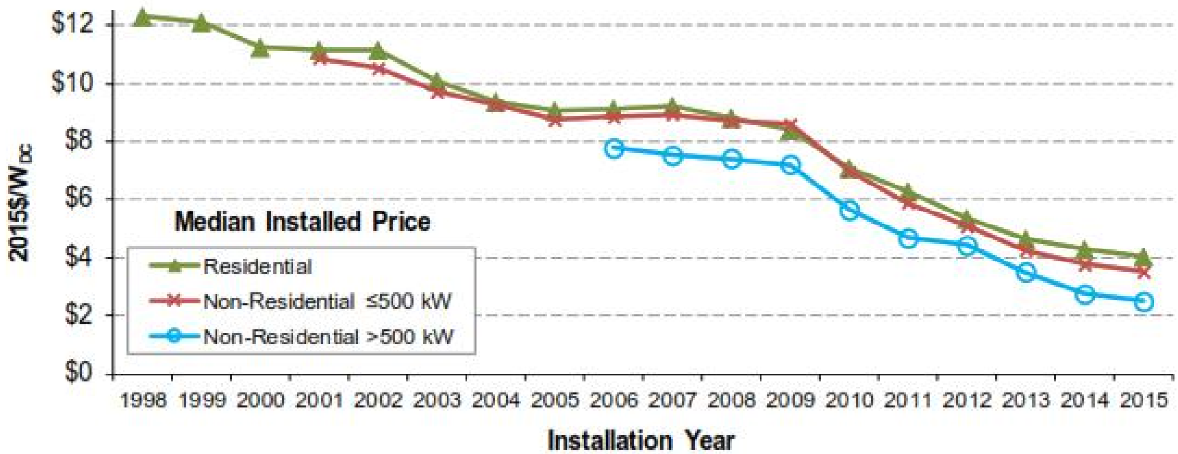
[6] *Utah Political Capitol*, "Flagged Bill: HB 23 – Utah Residential Solar Tax Credit Repeal – Rep. Jeremy Peterson," December 18, 2016. Available at: http://utahpoliticalcapitol.com/2016/12/18/flagged-bill-hb-23-utah-residential-solar-tax-credit-repeal-rep-jeremy-peterson/

[7] Lawrence Berkeley National Laboratory, "Tracking the Sun IX, The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States," (Aug 2016), page 14.

Figure 2: Residential PV Installed Price, Module Price Index, and Non-Module Costs[8]



Q. WHAT TYPES OF COMPANIES HAVE BEEN RESPONSIBLE FOR THE RECENT GROWTH IN RESIDENTIAL PV SOLAR?

A. Residential rooftop solar would not now exist as an option for Utah customers without the wide range of competitive businesses that have developed and advanced this market segment, including not just panel manufacturers, but also developers of complementary technologies, installers, financing companies, and a wide range of service companies. Lowering costs to enable increased customer adoption has required investments and innovation by many different types of firms, operating all along the supply and development chain. Many firms are continuing to invest in developing and deploying complementary technologies, such as "smart" inverters, batteries, and communications technologies, that will enable increased future benefits from DSG. As the Commission contemplates changes to the current NEM program, it should ensure that any changes do not limit the ability or incentives for consumers or competitive firms to deploy these technologies, which have the potential to further reduce costs and increase long-term future benefits.

[8] *Id.*, figure reproduced from Figure 9, page 14.

Q. CAN YOU DESCRIBE IN GENERAL TERMS HOW COMPETITIVE CHOICES FOR RESIDENTIAL DSG BENEFIT A UTILITY'S CUSTOMERS?

A. Competitive residential DSG provides a utility's residential customers with an important choice regarding their electricity consumption. For many residential DSG customers, the ability to reduce their reliance on their retail provider of electricity service is a significant factor in their decisions to invest in rooftop solar.[9] In addition to the expanded service choice and reduced cost that competitive solar providers offer customers, various residential DSG business models provide customers with access to non-utility sources of capital that can diversify risk away from captive ratepayers. Competition has also encouraged companies to provide more fully integrated services, from project financing to installation, while the larger scale of residential DSG service providers has allowed for further cost reductions.[10] The competitive residential solar industry has also demonstrated continued innovation in service offerings, such as the bundling of residential rooftop solar, battery storage, and energy management services.[11] This combination of different services and assets, provided by a range of companies using various innovative technologies, at times in cooperative endeavors with utilities, has the added benefit of reducing consumers' overall energy use and improving grid resiliency.[12]

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[9] *See e.g.*, Paul Balcombe, Dan Rigby, and Adisa Azapagic, "Investigating the importance of motivations and barriers related to microgeneration uptake in the UK," *Applied Energy*, Vol. 130, October 2014, pp. 403-418. Available at: http://ac.els-cdn.com/S030626191400542X/1-s2.0-S030626191400542X-main.pdf?_tid=e4872a70-e64e-11e5-820e-00000aacb360&acdnat=1457566402_faf2e050465cd86f1250ebbd48fa9d8b. *See also* Ria Langheim, Georgina Arreola, and Chad Reese, "Energy Efficiency Motivations and Actions of California Solar Homeowners," August 2014 (published in proceedings of ACEEE 2014 Summer Study on Enegy Efficiency in Buildings), p. 10. Available at: https://energycenter.org/sites/default/files/docs/nav/policy/research-and-reports/Energy%20Efficiency%20Motivations%20and%20Actions%20of%20California%20Solar%20Homeowners.pdf

[10] The Morningstar Equity Analyst Report of Mar 3, 2016 on SolarCity Corp reported that "the company has reduced per-watt customer costs 40% since 2012, and is targeting another 14% cost reduction by 2017."

[11] SolarCity has such a home energy system offered in Hawaii. http://www.greentechmedia.com/articles/read/SolarCitys-System-For-Self-Supply-in-Hawaii-Includes-PV-Storage-Water-He

[12] *Id*. See also, Nest Labs, "Energy Savings from the Nest Learning Thermostat: Energy Bill Analysis Results," Nest White Paper, February 2015, available at: https://nest.com/downloads/press/documents/energy-savings-white-paper.pdf.

Q. CAN YOU DESCRIBE THE POTENTIAL FOR ADDITIONAL INNOVATION IN RESIDENTIAL DSG?

A. A wide range of emerging technologies are currently being developed and deployed that will further serve to drive down its costs and increase its benefits to the grid and ratepayers. Smart inverters, for example, allow residential DSG to be "dispatched" by the grid operator to allow for increased reliability, or to be used as reactive power for local voltage support. Improved battery storage technologies, which are just beginning to be deployed in the U.S. residential customer segment, as well as in utility grid operations, also allow for increased "dispatchability" of solar resources, shifting supply to the peak period of demand. Electric vehicles (EVs) plugged into smart charging stations also have the ability to be treated as flexible load resources, especially with electricity price signals that influence when and how charging is done, thus potentially helping to alleviate some of the grid integration challenges associated with the rapid growth of solar (and wind) generation more generally.[13]

Q. HAVE ANALYSTS PREVIOUSLY STUDIED THE POTENTIAL IMPACT OF RESIDENTIAL DSG ON A UTILITY'S SYSTEM COSTS?

A. Yes. The primary cost-related concern for residential DSG is that at very high levels of penetration, it can result in "reverse flows" on system elements designed for unidirectional power flows, which may result in the need for additional infrastructure investments (or maintenance expenditures). The MIT Energy Initiative, for example, recently published an extensive study of DSG that evaluates potential system cost increases resulting from higher levels of DSG penetration (among other issues).[14] However, as shown in Figure 3 below (reproduced from the MIT study), system cost increases are negligible with DSG penetration

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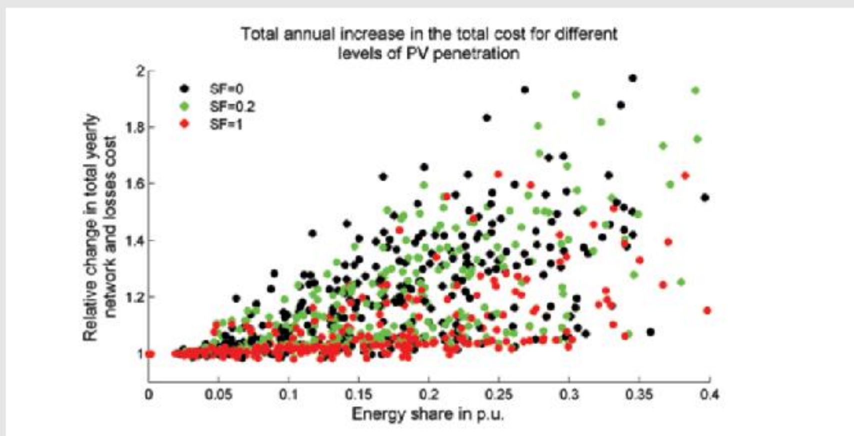
[13] For example, EVs can ease the pressure on the system by absorbing excess electricity in the middle of the day and reducing the amount of excess solar generation during peak periods.

[14] MIT Energy Initiative, "Utility of the Future," December 2016, p. 48. Available at: http://energy.mit.edu/wp-content/uploads/2016/12/Utility-of-the-Future-Full-Report.pdf

levels below 5%, as in Utah. At penetration levels above 5%, the impact of DSG on system costs depends on whether DSG is paired with other technologies, such as battery storage, or demand management policies and consumer incentives that mitigate reverse flows.[15] It is highly unlikely that DSG will cause RMP to incur any significant incremental system costs in the next several years. In the interim, as residential DSG continues to grow, improved technological options and increased data from net metering experiences across the country will provide the Commission with better and more reliable information with which to assess whether any costs that are incurred at higher penetration levels would justify a change in the NEM rate design at that time.

Figure 3: Impact of DSG on Network Costs with Different Levels of Storage[16]



Note: The chart shows the cost-mitigating effect of energy storage (represented by a storage factor, SF). Source: MIT (2015)

Q. ISN'T RESIDENTIAL DSG INHERENTLY MORE EXPENSIVE THAN OTHER TYPES OF SOLAR OR OTHER RENEWABLE POWER?

A. There are unavoidable tradeoffs between almost every generation technology, with advantages and disadvantages to each. This pertains not only to comparisons of residential and utility-scale solar, but also to comparisons of PV and concentrated solar power (CSP), or of solar and

[15] The different colored dots represent alternative assumptions regarding a system's "storage factor" (SF).

[16] MIT Energy Initiative, "Utility of the Future," December 2016, p. 49.

wind. Large-scale generation facilities have an installation and maintenance cost advantage over smaller scale facilities, such as residential systems. Larger-scale facilities may also be more efficient in generating output when equipped with tracking systems. On the other hand, residential systems generally do not raise environmental siting concerns, as may arise with utility-scale projects (for both the generation and the transmission investments). If a utility has residential DSG customers who are geographically dispersed across its service territory, their combined generating capacity may also be subject to less intermittency (in the aggregate) under certain weather conditions (i.e., in comparing 100 MW of DSG to a single 100 MW solar facility). Most importantly, however, DSG is located close to consumption, which obviates the need for large infrastructure investments to deliver that generation to load (in contrast to RMP's proposed major transmission upgrades to bring additional wind generation from Wyoming, for example). Furthermore, as a local demand-side resource, DSG can be integrated into a utility's overall demand management and dispatch protocols, particularly if paired with complementary technologies such as smart inverters or local battery storage, to provide additional benefits that distant utility-scale generating stations simply cannot provide. Finally, DSG provides an opportunity to bring in new sources of capital to fund investments in renewable generation: rather than relying on a large utility-financed project, with its allowed ROE and "socialized" cost risks spread across all ratepayers, DSG provides an opportunity for individual homeowners and other market participants to invest their capital in developing new renewable generating resources. Given these unique benefits, DSG can play an important role in a state's overall generation portfolio, despite its higher installed costs per kW compared to utility-scale PV generation. RMP fails to quantify these unique benefits of DSG in its cost-benefit analysis, thus understating the benefits of the NEM program.

Q. WHAT HAS BEEN THE ROLE OF UTILITIES SUCH AS RMP IN THE DEVELOPMENT OF DSG?

A. Utilities with a monopoly retail franchise, such as RMP, have neither the incentive, nor the expertise, nor the risk capital to develop or innovate in customer-sited solar offerings. Some utilities have recently proposed their own residential DSG programs, including customer-sited generation in their rate base (on which they are able to earn a return). Other utilities have provided residential customers with solar-based "green power" offerings, i.e., a contractual commitment to supply them with a certain amount of renewable energy from utility-scale solar or other renewable facilities (notwithstanding the fact that all electricity is commingled in the network). RMP, for example, recently began its "Subscriber Solar" program: it entered a PPA with a developer of a new utility-scale solar facility (far from load), and it offered residential customers monthly "subscriptions" to the output of that facility (in tranches of 200 kWh per month), in return for a 20-year PPA rate of approximately 12 cents/kWh.[17] Customers taking service under this program in effect are "virtual solar" customers of this single solar facility, up to their full monthly consumption requirements, even though they continue to be served by RMP's broader portfolio of generating, transmission, and distribution assets in all hours. Thus, many utilities often have been supportive of solar and other renewables, particularly when it involves an increase in their rate base; PacifiCorp's proposed expansion of its wind power generation and transmission investments in its most recent IRP provide one such example. In the past few years, however, some utilities have attempted to limit or even completely stop the expansion of residential DSG provided by competing solar companies – typically by proposing radical changes to their respective state NEM policies, including imposing prohibitively high demand charges and a dramatic reduction in the value of energy credits. With very limited exceptions, however, regulators have declined to adopt

[17] Of which, 7.7 cents/kWh of generation costs are fixed for 20 years, while 4 cents/kWh of T&D costs may vary.

utility proposals to adopt demand charges for residential NEM customers;[18] and the majority of state NEM programs continue to credit net excess generation at the full retail rate, particularly in states with low solar penetration (less than 5%).[19]

Q. IN YOUR VIEW, WHY ARE SOME UTILITIES PROPOSING TO RADICALLY ALTER NEM POLICIES?

A. Because erecting barriers to the adoption of residential DSG increases some utilities' profits and reduces their risks. Customer choice and DSG provide benefits to electricity consumers and Utah residents more broadly, and they help to advance the state's environmental policies. However, they also threaten the profits of a regulated retail monopoly franchise by reducing retail sales revenue between rate cases and reducing the need for infrastructure investments on which a regulated utility earns a rate of return. For many utilities in states with traditional cost-of-service rate regulation (such as Utah), DSG provides the only real competition that they face at the retail level. A utility subject to cost-of-service rate regulation generally maximizes its profits by maximizing the size of its allowed rate base, on which it earns an allowed rate of return. When residential customers choose to install solar panels on their roofs, they reduce their utility's retail sales, and – depending on the volume of such installations and several other factors – they may reduce the need for their utility to invest in additional generating, transmission, and distribution assets. Thus, over the long term (and for some utilities, even in the near term), the expansion of DSG threatens to reduce a utility's profits by potentially reducing the size of its rate base. Furthermore, to the extent that a utility is at risk of full cost recovery, e.g., between rate cases or in the event that its costs are not deemed

18 The few utilities that have imposed demand charges specifically for NEM customers include the Salt River Project (SRP) in Arizona and Santee Cooper in South Carolina. While We Energies in Wisconsin attempted to impose a demand charge on residential DSG customers, the courts struck down this provision. See Midwest Energy News, "Court Rejects Wisconsin's Fee on Solar Customers," October 30, 2015. Available at: http://midwestenergynews.com/2015/10/30/court-rejects-wisconsin-utilitys-fee-on-solar-customers/ (last accessed June 7, 2017).

19 Database of State Incentives for Renewables & Efficiency ("DSIRE"). DSIRE is a source of information on incentives and policies that support renewable energy and energy efficiency operated by the N.C. Clean Energy Technology Center. Data on solar penetration (as of October 2016) obtained from: https://www.ohmhomenow.com/2016-solar-penetration-state/

prudent, the loss of revenues from residential DSG customers also poses a risk to a utility's profitability.

Q. HOW IS THIS RELEVANT TO THE CURRENT PROCEEDING?

A. As an economist, in evaluating RMP's NEM rate proposal, I consider it important for the Commission to consider incentives – both for customers and RMP. RMP has asserted that it is advancing its proposal to avoid a "cost shift" from NEM to non-NEM residential customers. An alternative explanation for its proposal is that RMP is concerned that higher rates of DSG penetration from competing solar providers are reducing its electricity sales, increasing its risk of under-recovery of its costs, contributing to the deferral of its investments in additional generation and transmission infrastructure, and ultimately eroding the size of its rate base over the long term. I note, however, that the overall decline in load growth and increased participation in energy efficiency (EE) programs have caused a far greater reduction in RMP's electricity sales than DSG. Both NEM and EE programs reduce utilities' sales of electricity. EE programs, however, have had a much greater impact on retail electricity sales than DSG. According to one recent estimate, utility energy efficiency programs and federal appliance efficiency standards reduced total U.S. retail electricity sales by approximately 14% in 2015.[20] By comparison, all DSG installed through the end of 2015 reduced retail electricity sales by just 0.4%.[21] Growth in EE is expected to continue to outpace DSG in the foreseeable future.

Q. HOW DOES EE COMPARE TO DSG IN UTAH?

A. Since 2008, demand-side resources such as EE have provided alternatives to supply-side options in PacifiCorp's service territory. In 2015, incremental EE resources in Utah are

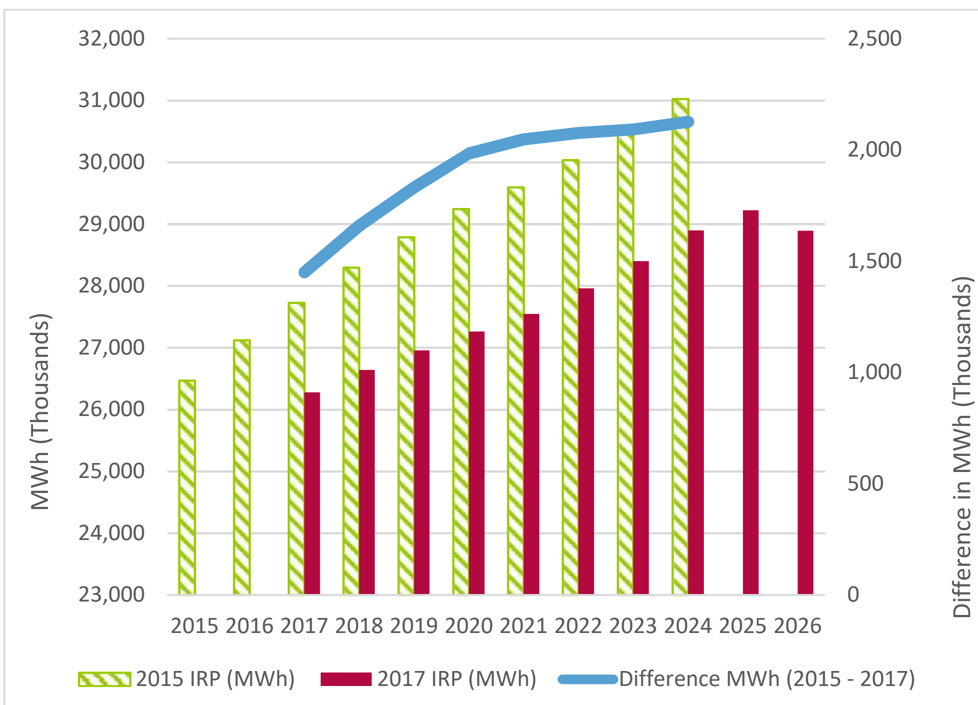
[20] Galen Barbose, "Putting the Potential Rate Impacts of Distributed Solar into Context," LBNL-1007060 (January 2017), p. 5.
[21] Id., p. 15.

expected to account for 264,360 MWh, which is five times larger than RMP's estimate of 52,877 MWh of residential DSG generation in 2015.[22]

Q. HOW DOES RMP'S DECLINE IN LOAD GROWTH COMPARE TO DSG IN UTAH?

A. Figure 4 below shows that RMP's load forecast in Utah decreased relative to projected loads used in the 2015 IRP. On average, forecasted annual load is down 1,909 GWh or 6.5% between 2017 and 2025 when compared to the 2015 IRP. Through the planning horizon, the average annual load growth rate is down from 1.8% to 1.1%, a 40% reduction in the annual load growth rate when compared to the 2015 IRP. This decline in annual load growth is far greater than the reduction in retail sales caused by DSG in Utah.[23]

Figure 4: Utah annual load growth forecast (MWh)



22 PacifiCorp 2015 IRP, Appendix D, p. 64.

23 PacifiCorp 2015 IRP, Appendix A, p. 3 and PacifiCorp 2017 IRP, Appendix A, p. 2.

Q. IF REVENUES FROM NEM CUSTOMERS DECLINE, DO REVENUES FROM OTHER RESIDENTIAL CUSTOMERS HAVE TO INCREASE TO ALLOW RMP TO RECOVER ITS COSTS?

A. Not necessarily. First, as I discuss below, DSG provides benefits to all customers, including non-residential customers, in the form of increased grid reliability and resilience (especially when coupled with advanced technologies), environmental benefits (reduced emissions), and (with enough penetration) reduced utility investments in transmission, distribution, and generation assets. Second, all residential customers are entitled to reduce their electricity consumption, whether from energy efficiency, DSG, or simply changes in their consumption patterns. Before adopting DSG systems, on average, DSG customers are higher-use customers than the average Utah ratepayer. Simply because high-use customers become average-use customers does not mean they have "shifted costs" onto other customers. If a 2,000 kWh/month customer becomes a 750 kWh/month customer (i.e., a "typical" RMP residential customer), RMP's revenue declines by the amount of the reduced sales. This does not mean, however, that the formerly high-use customer has necessarily "shifted costs" onto other customers. In between rate cases, the only real effect of such a reduction in consumption is a reduction in RMP's profits (after accounting for RMP's reduced costs of foregone utility generation, power purchases, and line-losses), just as greater-than-expected sales in between rate cases will increase RMP's profits.

Q. WHEN RMP FILES A RATE CASE, WON'T REDUCED REVENUES FROM NEM CUSTOMERS RESULT IN INCREASED RATES FOR OTHER CUSTOMERS?

A. Not necessarily, and RMP's submission fails to show that this scenario is more likely than not. Many considerations other than a reduction in consumption by some subset of customers come into play in a rate case. First, increased revenues from load growth (e.g., from population growth, electric vehicles, etc.) may be sufficient to offset the decline in revenues from certain customers. Second, the reduction in consumption by some customers may lower the need for additional future investments, the costs of which (plus a return for RMP) would otherwise be borne by all customers. Third, even assuming there were an increase in the rates paid by other customers as a result of a reduction in consumption, it does not mean that NEM customers are paying less than an appropriate share of system costs, or that this result is necessarily inconsistent with standard cost-causation principles and the Commission's broader objectives with its current rate design. Indeed, to some significant extent, high-usage customers often "subsidize" other customers (by paying more than their cost of service), and their installation of PV systems may actually be mitigating such (intra-class) "subsidies" and existing "cost shifts" between groups of residential customers.[24]

Q. WHAT COMMISSION OBJECTIVES ARE YOU REFERENCING WITH REGARD TO THE CURRENT RESIDENTIAL RATE DESIGN?

A. The increasing block rates used in RMP's current residential rates (Schedule 1), as approved by the Commission, are designed to discourage high levels of monthly consumption (particularly from May through September, but also in other months). Furthermore, residential rates have relatively low monthly fixed customer charges ($6 for single-phase customers), with the vast majority of revenues obtained from the variable energy charge. This energy-focused rate structure further incentivizes customers to reduce their energy consumption.[25] Indeed, customers who choose to install DSG are likely to be relatively high-use customers,[26] responding to the incentives in the approved residential rate structure designed to discourage high levels of monthly consumption, regardless of whether that reduction is achieved through

[24] The CPUC's 2013 NEM study found that NEM customers paid 133% of their full cost of service before installing solar PV systems, while residential NEM customers paid 154%. Thus, by installing solar systems, NEM customers were able to reduce the amount of subsidies they had traditionally been paying to support other customers. *See* "California Net Metering Ratepayer Impacts Evaluation," California Public Utilities Commission (CPUC), October 2013, at p. 10, Table 5.

[25] Utah's increasing block rate structure also helps to provide lower electricity bills for lower-income customers, although it also provides for lower bills for partial-year residents. RMP's Schedule No. 3 ("Low Income Lifeline Program") provides more explicit rate relief for qualified low-income customers.

[26] This may be changing over time, as the cost of DSG declines. RMP does not collect detailed data on NEM customers' pre- and post-installation consumption to be able to assess this systematically.

energy efficiency, DSG, or simply a change in behavior. Thus, it should be no surprise to RMP that some high-use customers have chosen to reduce their bills by installing DSG, as that is consistent with the Commission's objectives with the current residential rate structure.[27]

Q. WHAT ABOUT THE FACT THAT MANY COSTS ARE A FUNCTION OF PEAK LOAD, NOT AGGREGATE MONTHLY ENERGY CONSUMPTION?

A. That is a problem associated with the overall residential rate design approved by the Commission, not with NEM customers' rates *per se*. If RMP is concerned with reducing peak load, it should be proposing an expansion of time-of-use (TOU) rates.[28] If RMP is concerned that the current residential rate design relies too heavily on variable energy charges such that low-use customers (whether NEM or non-NEM customers) are not paying an appropriate share of system costs, it should propose a corresponding change in the rate design for all residential customers. I do not think such a fundamental change is warranted at this time, however, because RMP has not shown that the current residential rate design is unworkable, and a change towards increased monthly fixed costs and demand charges for all customers would conflict with the Commission's other objectives in its current rate design (e.g., incentives for energy efficiency and affordability). Applying increased monthly fixed charges and demand charges only to NEM customers, as RMP proposes, however, would be unduly discriminatory, since the asserted "problem" these changes are meant to address are by no means unique to NEM customers (nor would it even be accurate to characterize NEM customers as low-use customers, as discussed further below).

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[27] RMP has other electric service schedules that are also explicitly intended to reduce residential energy consumption, e.g., Schedule No. 111 (Residential Energy Efficiency), which provides various incentives for lighting, appliances, etc., regardless of when the energy efficiency benefits from these appliances are expected to materialize (e.g., night time electricity savings from energy efficient lighting).

[28] RMP currently has an experimental residential "time-of-day" rider (Schedule No. 2), limited to 1,000 customers. The time of day rates are in effect from May through September, with peak times defined as between 1 and 8 p.m. weekdays (excluding holidays). Peak rates are 4.356 cents above standard residential rates, while off-peak rates are 1.6334 cents less.

Q. IS RMP'S PROPOSAL JUSTIFIED BASED ON THE COST CAUSATION PRINCIPLES IT INVOKES IN ITS FILING?

A. No. First, as I discuss in more detail below, RMP has not identified any incremental system costs that are attributable to the NEM program and that are not borne directly by NEM customers. While RMP points to *hypothetical* costs associated with "reverse flows," it has provided no evidence – either in its filing or in its responses to various parties' data requests – that the limited amount of excess generation by NEM customers currently flows beyond local circuits, that it has had to invest in additional distribution network upgrades (other than those that have been funded by NEM customers directly), or that it has even been required to manage its system differently to accommodate these reverse flows. More broadly, however, it is important to note that the Commission, like state regulatory commissions everywhere, is appropriately concerned with multiple objectives in designing rates for Utah customers. Aligning rate structures with principles of cost causation is one very important factor, as it encourages consumers to make economically efficient energy consumption decisions. Other longer-term objectives, however, are also important for the Commission to consider, such as the impact of a given rate structure on reducing emissions, encouraging energy efficiency, promoting the development of renewable resources, ensuring affordability, and providing some degree of customer choice. Even if RMP were under-recovering a certain amount of costs from NEM customers, as RMP asserts (incorrectly), the overall rate structure should still be evaluated relative to all of the Commission's objectives. Even accepting at face value RMP's (incorrect) contention that some of its costs have been "shifted" onto other residential customers, the Commission can and should continue with the current NEM rate structure, as it is consistent with its broader objectives, and it is not unduly discriminatory. This conclusion is further supported by the fact that the purported cost shift accounts for a very small fraction of RMP's total costs, given the very low current penetration rate of residential DSG in Utah. To the extent that the Commission wants to develop a forward-looking framework for compensating residential DSG, given the relatively rapid recent growth in installations and applications, there are steps that the Commission can take in that direction, as I discuss further below, but it should do so without stifling the development of this emerging segment and its attendant technologies.

Q. WHAT IMPACT WILL RMP'S PROPOSED NEM RATE DESIGN HAVE ON THE RISKS TO RMP ASSOCIATED WITH THE GROWTH OF DSG?

A. In effect, RMP's proposal will insulate RMP from the risks it faces associated with lower residential sales from the continued growth of DSG in Utah – i.e., risks of cost under-recovery either in-between and during future rate cases, and risks associated with the potential erosion of its rate base. RMP currently enjoys an allowed ROE of 9.8% (as approved by the Commission in its last rate case).[29] This approved ROE is predicated on the assumption that RMP bears some significant level of commercial risks (for comparison, the current risk-free interest rate is approximately 1.1%, using 1-year U.S Treasury bills as a benchmark). I consider the risk to RMP of lower sales due to the growth of residential DSG adoption in Utah to be a risk that RMP should be able to manage, commensurate with its 9.8% ROE, particularly given the very low cumulative penetration of residential DSG in Utah. RMP's proposal to further "de-risk" its business with its proposed rate design for residential NEM customers would be inconsistent with its current approved ROE. Indeed, this demonstrates why it is inappropriate for RMP to propose such major changes in the residential NEM customer rate structure outside of a full rate proceeding, since such changes must be evaluated in conjunction with a reevaluation of RMP's allowed ROE. However, I disagree with RMP's proposed changes, regardless of the regulatory proceeding in which they are proposed.

[29] Docket No. 13-035-184, Settlement Stipulation, June 25, 2014.

IV. <u>Review and Critique of RMP's Cost of Service Study</u>

Q. WHAT IS THE PURPOSE OF A NEM COST-BENEFIT STUDY IN THIS PROCEEDING?

A. The purpose of this proceeding is to determine whether the benefits of NEM exceed its costs, or vice versa. To achieve this goal, the Commission has provided a general analytical framework for performing a NEM cost-benefit study.

Q. PLEASE DESCRIBE THE GENERAL COST-BENEFIT FRAMEWORK SET FORTH BY THE COMMISSION.

A. On November 10, 2015, the Commission ordered RMP to perform two cost of service ("COS") studies – the actual COS ("ACOS") and a counterfactual COS ("CFCOS") – to gauge the benefits NEM customers bring to Utah customers through a reduction in costs, using a one-year period of analysis commensurate with the 2015 test year in RMP's filing.[30] According to the Commission, the ACOS should reflect RMP's actual cost of service inclusive of NEM customers, while the CFCOS should reflect RMP's hypothetical cost of service if NEM customers were to produce no electricity and instead draw their entire load from RMP. The Commission thus expects that that – if performed correctly – the costs in the CFCOS that are not present in the ACOS will reflect the benefits of net metering.[31]

Q. WHAT ARE RMP'S CONCLUSIONS FROM ITS COST OF SERVICE STUDIES IN THIS PROCEEDING?

A. RMP prepared the two ACOS and CFCOS studies, as well as a cost of service study with net metering segregated into its own class ("NEM Breakout COS"). The studies use 2015 actual data, including data collected from RMP's load research study for residential NEM customers. RMP concludes that the costs of the NEM program exceed its benefits based on the results of

[30] November 2015 Order, at p. 16.

[31] Id., at p. 12.

its comparison of the ACOS to the CFCOS, and that residential NEM customers have unique load and cost characteristics that require changes in the current rate structure to avoid cost-shifting to other customers. Based on the results of its COS and load research studies, RMP asks the Commission to find that: (i.) the CFCOS, the ACOS, and the NEM Breakout COS are compliant with and fulfill the November 2015 Order; (ii.) the costs of the NEM program under the current structure exceed its benefits; (iii.) the unique usage characteristics of residential net metering customers justify segregating them into a distinct class for ratemaking; and (iv.) the current rate structure for residential net metering customers is unjust and unreasonable because it does not reflect the costs imposed on and the benefits contributed to the system and unfairly shifts costs of net metering customers to other customers.[32]

Q. WHAT ARE YOUR RESPONSES TO RMP'S CONCLUSIONS?

A. First, I disagree with the conclusion that RMP's costs of serving NEM customers in Utah are in excess of the benefits they provide to the system as a whole, whether those benefits are defined narrowly as in RMP's studies, or if they are defined more broadly, as I analyze in the following section. Second, I disagree with RMP's conclusion that the revenue received from NEM customers is insufficient to cover their cost of service. The testimony submitted by RMP witnesses and RMP's responses to other parties' discovery requests show that Utah NEM customers have not caused RMP to incur any significant incremental system costs in excess of costs that NEM customers have directly reimbursed, e.g., the costs associated with new bidirectional meters and local distribution network upgrades; nor have Utah NEM customers reduced the reliability of the Utah electricity transmission and distribution grid, or otherwise increased the costs and risks borne by non-NEM customers. Third, I disagree with RMP's conclusion that NEM customers have "shifted costs" onto non-NEM customers in Utah. As

[32] RMP Compliance Filing, at p. 2.

discussed above, the "shifted costs" asserted by RMP are not "new" costs created by the NEM program, but they are simply a result of the need for RMP to recover existing costs from fewer sales. In that sense, there are always "shifted costs" when customers reduce load through various actions or reasons – e.g., demand-side management ("DSM") and EE – that RMP and the Commission encourage through various financial incentives (just as there are "shifted costs" in the other direction when customers increase load, e.g., via an electric vehicle purchase). The reduction in load resulting from a customer's decision to install rooftop PV should not be treated any differently than other actions that customers take to manage and reduce their utility bills. Fourth, RMP's cost of service studies lack sufficient details, the input data and modeling assumptions are flawed, and the results are unreliable, as I explain more fully below. Therefore, the Commission should not grant RMP's requests.

Q. PLEASE DESCRIBE HOW RMP PERFORMED THE ACOS AND CFCOS STUDIES.

A. Mr. Meredith performed the ACOS study using the 2015 study year. He then performed the CFCOS study assuming that the NEM program does not exist. In performing the CFCOS, (i) he includes higher net power costs to supply energy (accounting for system losses) to replace energy generated by NEM customers; (ii) he removes NEM customers' bill credits, both for behind-the-meter generation and exported energy; (iii) he removes costs associated with serving NEM customers, e.g., the avoided metering, billing, engineering, and administration costs associated with the NEM program; and (iv) he allocates increased system costs to Utah to reflect the higher demand that would have resulted in the absence of NEM. Next, Mr. Meredith compared the results of the CFCOS and ACOS, showing that the NEM program resulted in \$2 million and \$1.7 million in net costs for Utah and residential customers, respectively. In order to calculate the inputs for his CFCOS study, Mr. Meredith estimated what the energy consumption would have been for NEM customers, using their actual billing data and estimating their generation production profile based on the sample from RMP's load research data. His estimate of total NEM production is 52,877 MWh. Assuming this DSG output would have been supplied by central generating stations using the transmission system instead, Mr. Meredith added line losses to increase the counterfactual total generation to 57,784 MWh. Based on this, Mr. Wilding estimated the change in net power cost between the ACOS and CFCOS.

Mr. Meredith estimated the impact of removing NEM bill credits by taking the revenue difference between the actual billed revenue and the counterfactual full requirements revenue from NEM customers, including RMP's "hypothetical" revenue associated with removing NEM customers' behind-the-meter energy consumption. He estimated the value of the overall bill credits associated with the NEM program to be $4.2 million, of which he allocated $3 million (71%) to residential customers. Next, Mr. Meredith estimated the increased costs associated with NEM customers, including increased metering, billing, engineering, and administration costs, based on RMP's operations data. His estimate of overall increased costs associated with the net metering program is approximately $772,000, of which he allocated $553,000 (72%) to residential customers. Combining these elements, he concluded that the total cost to serve NEM customers is approximately $5 million ($4.2 million of bill credits, plus $772,000 of increased costs), of which he allocated $3.5 million (71%) to residential customers.

Q. PLEASE DESCRIBE HOW RMP PERFORMED THE NEM BREAKOUT COS STUDY.

A. Mr. Meredith also conducted the ACOS study by segregating NEM customers into a separate class ("NEM Breakout COS"). To do so, he began with the ACOS study and created separate NEM classes for the residential and other customer classes (Schedules 23, 6, 8, and 10). For these different NEM classes, he identified their characteristics, removed them from their original classes, and assigned them to separate NEM classes. The characteristics he considered include energy and demand values, system coincident peak, distribution coincident peak, non-coincident peak, and other costs. Energy values were based on delivered energy; demand values were based on the load research study; system coincident peak and distribution coincident peak were based on energy deliveries to the customer; non-coincident peak was based on the maximum of either energy delivery or energy export; and other costs identified in the CFCOS study were directly assigned to the different NEM classes. Lastly, Mr. Meredith directly assigned excess energy credits to each NEM class based on the net power costs estimated in the CFCOS study, and he allocated the offsetting cost for the excess credits to all classes. Mr. Meredith then concluded that the cost of serving residential NEM customers is significantly different than the cost of serving other residential customers, and that the revenue collected from residential NEM customers is insufficient to cover the costs of serving them, i.e., 61% as compared to 90 to 109% for other customer classes.

Q. DO YOU AGREE WITH RMP'S ASSERTION THAT NEM CUSTOMERS SHIFT COSTS TO NON-NEM CUSTOMERS?

A. No. As I discuss in more detail below, RMP's own data shows that NEM customers have provided significant benefits to non-NEM customers, and RMP has not incurred any significant incremental costs in excess of costs that NEM customers have directly reimbursed (e.g., the costs associated with new bidirectional meters and local distribution network upgrades borne by NEM customers). In addition, it is also important to recognize that some amount of "cost shifting" or subsidization both within and among customer classes is inevitable under cost-of-service regulation; at issue is whether those are unduly discriminatory. For example, when a utility builds new power plant or invests in grid infrastructure to meet increasing electricity demands due to the interconnection of new customers, or due to an increase in certain customers' use, all customers pay for such investments, even though some customers – especially those who have invested in reducing their consumption – do not directly benefit from such investment.[33] Similarly, the cost of electricity is much greater during times of peak demand, but utilities' residential rates – including RMP's rates – do not typically reflect this difference in cost. As a result, customers who use more power during peak times are effectively "subsidized" by other customers who use relatively less power during those times. By investing in rooftop PV systems, NEM customers not only reduce their use of energy during peak time periods, but they also supply power to other customers at those times.

Q. HOW DO YOU DEFINE PEAK TIME PERIODS?

A. Utilities often refer to many different time periods when they use the term "peak" period, both in their rate schedules, market transactions, and regulatory filings. In some contexts, RMP defines the peak period as 3 p.m. – 8 p.m.; in others, it defines it as 1 p.m. – 8 p.m. (e.g., in its time-of-day rider); in yet others it includes 8 a.m. – 10 a.m. (e.g., in its proposed demand charges for residential NEM customers in the winter months); and for some non-residential customers (under Schedule 6A), it includes 7 a.m. – 11 p.m. (in summer). Wholesale market contracts generally divide the day into 16 on-peak hours (6 a.m. – 10 p.m.) and 8 off-peak hours (10 p.m. – 6 a.m.) (Monday through Friday, excluding holidays). The system peak hour refers to a single hour (in a month, year, or season) corresponding to maximum system load, which will vary (by month, year, and season). In my analysis below, I specify whether I am referring to a single hour or a range of hours in referring to the "peak." It is important to note, however, that on average, RMP's annual average load profile shows relatively elevated load throughout the period from 9 a.m. to 9 p.m. – which is precisely the period when DSG generates energy – with load dropping off relatively sharply before and after that time. Even

[33] There are also various policy-driven subsidies. For example, urban customers often subsidize rural customers, while high-income customers often subsidize low-income customers, etc.

during RMP's summer system peak (June 30, 2015), load is close to its peak level throughout the 2 p.m. - 6 p.m. period (a period with significant solar output), dropping off sharply before and after that time.[34]

Q. ACCORDING TO RMP, WHAT ARE THE TOTAL COSTS TO SERVE NEM CUSTOMERS?

A. RMP estimates the total costs to serve NEM customers to be $5 million. RMP estimates that bill credits comprise 85% of these costs ($4.2 million), followed by engineering and administration costs ($528,000), metering costs ($161,000) and customer service and billing costs ($83,000). RMP estimates the costs to serve residential NEM customers to be $3 million, or 60% of total NEM costs.

Q. WHAT ARE RMP'S COSTS ASSOCIATED WITH BILL CREDITS?

A. It is important to keep in mind that RMP only provides bill credits for power exported to the grid. In its analysis, however, RMP considers both NEM customers' behind-the-meter consumption and their excess energy exports to be costs associated with bill credits. On average, RMP estimates that residential NEM customers' behind-the-meter consumption accounts for 44% of the energy they generate, with the remaining 56% exported to the grid.[35]

Q. DO YOU AGREE WITH RMP'S TREATMENT OF DG SOLAR'S BEHIND-THE-METER CONSUMPTION AS COSTS TO SERVE NEM CUSTOMERS?

A. No. Since RMP does not compensate behind-the-meter consumption of DSG through bill credits, RMP should not have included such consumption as a "cost" in its cost of service study. RMP does not consider it a "cost" when customers reduce their load for any other reason, and it should not do so here, either; to do otherwise is to conflate costs and revenues, and to treat NEM customers in an unduly discriminatory manner. In its CFCOS study, RMP

[34] On that day, system load increased by only 3% between 2 p.m. and the 5 p.m. needle peak, and by less than 1% after 3 p.m.

[35] RMP's response to Vivint Solar data request 2.17(a).

allocates about $3 million as bill credit "costs" associated with residential NEM customers. Since residential NEM customers consume about 44% of solar production on site, RMP should not have included about $1.3 million out of RMP's $3 million in total estimated bill credit. This single change would reduce RMP's asserted total residential NEM costs from $3.5 million to $2.2 million, and it would reduce RMP's asserted revenue shortfall (net cost) of residential NEM customers from $1.7 million to just $357,000.

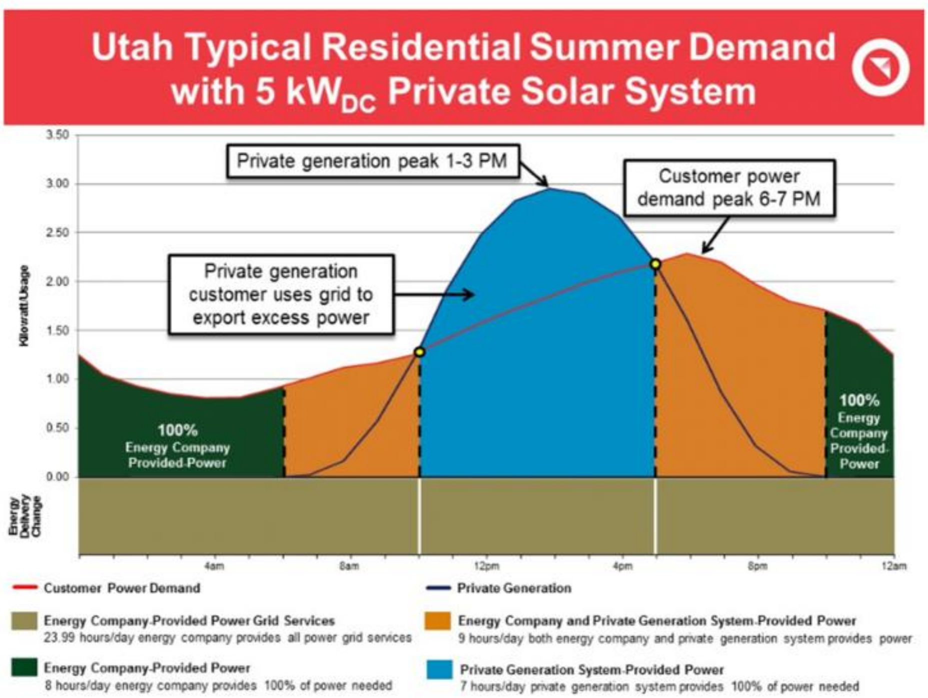
Q. WHAT IS YOUR BASIS FOR EXCLUDING BEHIND-THE-METER CONSUMPTION OF DSG FROM COSTS?

A. Behind-the-meter consumption of a NEM customer is no different than a non-NEM customer who reduces day-time electricity consumption by installing a more efficient air conditioner, installing better insulation materials, or adjusting their thermostat to reduce power use during the day. RMP does not attempt to recover "lost revenue" from such customers, and behind-the-meter consumption by NEM customers should not be treated any differently.

Q. ISN'T THERE A DIFFERENCE BETWEEN DSG AND ENERGY EFFICIENCY, SINCE DSG AT TIMES SUPPLIES POWER TO THE GRID?

A. Yes, but this difference does not justify treating behind-the-meter generation differently from other energy efficiency measures. NEM customers both reduce consumption and export power to the local grid, and appreciating these multiple roles of NEM customers, which change over the course of a day, is important in properly performing the cost of service studies and evaluating the results. Figure 5 below reproduces Mr. Marx's stylized example of the power flows between the RMP system and a residential DSG customer over the course of a summer day (although this can vary considerably from customer to customer). From 10 p.m. to 6 a.m. (the side bands in dark green), a DSG customer is a regular residential customer, receiving their electricity from the grid and paying the full retail rate for this service. From 7 a.m. to 10 a.m. and again from 5 p.m. to 10 p.m. (the side bands in light brown), a DSG customer reduces consumption with behind-the-meter generation in the same fashion as a regular residential customer reduces consumption with energy efficiency measures, and a DSG customer pays the full retail rate for their reduced usage during these hours. However, from 11 a.m. to 5 p.m. (the middle band in light blue), PV production exceeds on-site consumption and a DSG customer exports power to the grid and receives bill credits from RMP (currently credited at the full retail rate). In these hours, a DSG customer acts like a small generator supplying 100% renewable energy to neighboring loads, and obviates the need for RMP to generate its own power (or purchase third-party power), which it would otherwise have to deliver over its transmission and distribution lines.

Figure 5: Hypothetical power consumption by residential DSG customer[36]



36 Direct testimony of Douglas L. Marx, at p. 6.

Q. WHAT DO YOU CONCLUDE FROM THIS DIFFERENCE?

A. From this difference, I conclude that: (i) when NEM customers do not export power to the grid, they should not be treated differently than other DSM or EE customers; (ii) RMP's "bill credits" (as estimated by RMP in this proceeding) associated with behind-the-meter consumption should be excluded from the cost of service study; and (iii) the value of exported energy should be determined separately outside of the cost of service framework, just as the value of DSM and EE programs is determined through a separate process. Indeed, the Commission has ordered that, in preparing the actual cost of service study, RMP "should not assign a price or value to the net metering customers' excess energy other than as recognized in the net power cost analysis."[37]

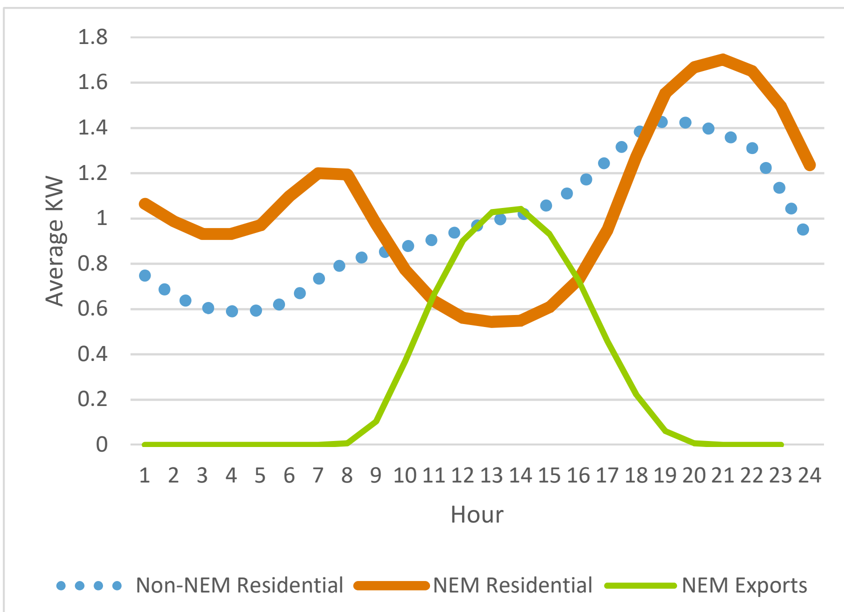
Q. MR. MARX LABELED THE ABOVE FIGURE AS BEING "TYPICAL" FOR UTAH. IS THE PRODUCTION AND LOAD SHAPE REPRESENTATIVE OF UTAH RESIDENTAIL NEM CUSTOMERS?

A. No, the above figure significantly overstates the amount of exports by a typical Utah residential NEM customer during the summer (or any other season). By overstating the amount of a residential NEM customer's net exports, RMP greatly mischaracterizes the extent to which reverse flows from such customers are likely to require RMP to make investments on the local distribution system to handle such reverse flows. Figure 6 below compares the actual load profile of RMP's NEM vs. non-NEM residential customers. On average, NEM customers still consume significant amounts of energy across all months. While on average, they do have significantly lower consumption than non-NEM customers during most of the system peak hours (3 p.m. to 8 p.m.), due to the output of their DSG systems, this reduction in consumption by NEM customers when it is of the greatest value should be considered a system benefit, not a system cost. During RMP's peak hours (3 p.m. to 8 p.m.) in 2015, a

[37] November 2015 Order, at p. 9.

typical residential NEM customer consumed about 12% less energy than a typical non-NEM residential customer, and they exported to the grid about 31% of a non-NEM residential customer's consumption during peak hours, which was consumed by neighboring non-NEM customers. If the peak period is defined as between 1 p.m. and 8 p.m., which RMP uses as the peak period for its current experimental time-of-day rider, residential NEM customers consumed 19% less energy than non-NEM customers, and they exported 46% of a non-NEM customer's consumption.

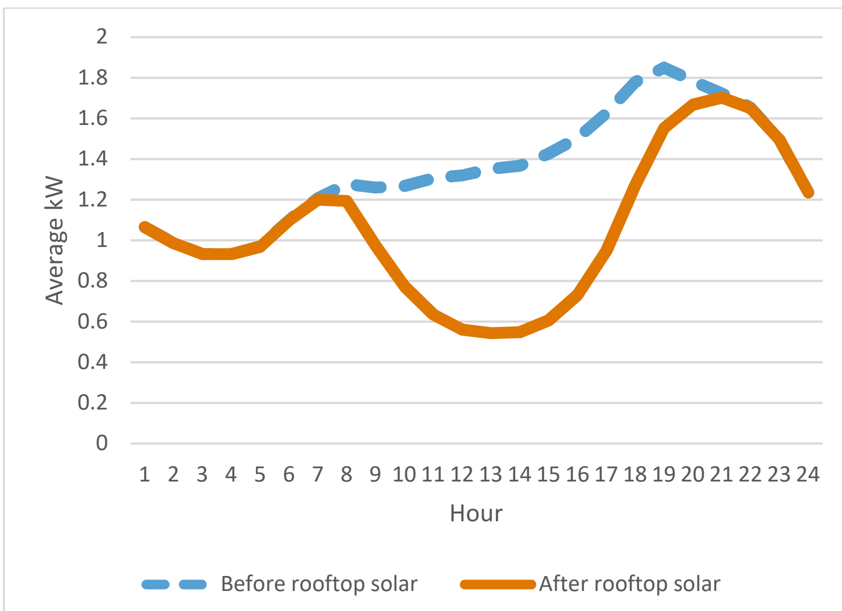
Figure 6: Average load profile of NEM vs. non-NEM residential customers



Q. HAVE YOU COMPARED THE USAGE OF RESIDENTIAL CUSTOMERS BEFORE AND AFTER THEY INSTALL ROOFTOP SOLAR?

A. Yes, at least to the extent possible with the limited information collected by RMP. Figure 7 below compares the load profile of a typical RMP residential NEM customer before and after installing a rooftop PV system. Using RMP's load research data, I estimated the complete profile of the average NEM customer's usage characteristics, including production, on-site consumption, energy exported to the grid, and energy delivered from the grid. On average, the load for an average residential NEM customer would have been approximately 11,832 kWh annually in the absence of a rooftop PV system. With such a system, their load declines to approximately 9,226 kWh annually, a decline of 22% on an overall annual basis. Most of this reduction in residential NEM customers' load occurs during peak hours, thereby significantly reducing their burden on the system. For example, between 3 p.m. and 8 p.m., RMP residential customers are able to reduce their load by 32% by installing DSG systems. Expanding the peak time period to between 1 p.m. and 8 p.m. shows a 38% reduction in load. At the system peak hour of 5 p.m., residential NEM customers are able to reduce their load by nearly 40%, and by nearly 60% at 2 p.m. as the system approaches its peak hour.

Figure 7: Estimated residential customer load profile before and after DSG installation



Q. WHAT ARE THE IMPLICATIONS OF YOUR CONCLUSIONS ABOVE FOR THIS PROCEEDING?

A. There are several. First, since they both reduce consumption, NEM customers should not be segregated from other DSM/EE customers in a separate rate class, nor should they be effectively penalized for alleged "cost shifting" resulting from their reduction in consumption.

The Commission discourages high consumption through tiered rates and financial incentives to reduce consumption. NEM customers have helped the Commission meet its objectives by reducing their consumption, particularly during peak hours when both PV production and air-conditioning demand – the dominant source of residential consumption – is high. Second, RMP's alleged revenue shortfall (net costs) to serve NEM customers become insignificant if the asserted "costs" associated with the behind-the-meter consumption are removed from the cost of service study. Third, RMP's cost parity ratio for residential NEM customers increases significantly if their exported energy is valued at the retail rate, consistent with how it is consumed and paid for by neighboring residential customers on the same circuit.

Q. WHAT IS YOUR RESPONSE TO RMP'S ESTIMATE OF INCREASED COSTS TO SERVE NEM CUSTOMERS?

A. RMP estimates that it costs $772,000 to serve NEM customers, of which $161,000 is attributable to increased metering costs, $528,000 to increased engineering/administration costs, and $83,000 to increased customer service costs for NEM customers.[38] As a general matter, RMP should include only actual *incremental* costs in excess of those it would otherwise incur, and it should remove any costs either paid or reimbursed by NEM customers.

Q. HAS RMP IDENTIFIED ANY SUCH INCREMENTAL COSTS?

A. No, RMP has not provided any data demonstrating that the above cost figures represent the actual incremental costs to serve NEM customers, rather than simply an allocation of the same amount of costs that RMP would have otherwise incurred. Many of these activities involve the same types of activities or analyses that RMP's staff perform for all its customers. For example, RMP must perform distribution planning to interconnect new customers, whether they are a NEM or non-NEM customer. For example, when a new load submits an

[38] For residential NEM customers, the amount is $553,000, of which $112,000 is attributable to increased metering costs, $369,000 to increased engineering/administration costs, and $72,000 to increased customer service costs.

interconnection application, RMP studies any reliability issues associated with an application and develops a solution, if needed (such as increasing the wire size or installing equipment to regulate voltages).

Q. IS IT LIKELY THAT IT TAKES MORE TIME TO PROCESS APPLICATIONS FOR RESIDENTIAL NEM CUSTOMERS THAN NON-NEM CUSTOMERS?

A. Yes. Since residential DSG customers both consume power from the grid and export power to the grid, this can increase the complexity of processing NEM applications and can conceivably cause incremental administration, engineering, and metering-related costs, particularly as the number of applications increase. If there are such incremental costs, however, they can be recovered in the Application fee.

Q. WHO PAYS FOR ANY INCREMENTAL INTERCONNECTION COSTS ASSOCIATED WITH RESIDENTIAL DSG SYSTEMS?

A. Any customer who seeks a NEM interconnection must pay for any necessary costs resulting from that interconnection. As RMP stated, "Any modification required to the distribution system to accommodate a solar interconnection will be paid for by the customer, in accordance with Commission interconnection rules and regulations."[39] To date, NEM customers have paid more than $240,000,[40] while RMP has not paid any additional costs associated with the asserted increase in NEM customers' use of the system.[41] Of the $240,000 in upgrades paid by NEM customers, $228,000 was spent on upgrading 26 transformers, and $14,000 was spent on upgrades to 10 secondary lines – all fully borne by NEM customers.[42]

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[39] RMP response to Vivint Solar data request 2.11.

[40] RMP's original estimate of $251,166 (RMP response to DPU data request 6.5(b)) was revised to $240,092 in RMP's response to Vote Solar data request 3.7.

[41] RMP response to DPU data request 6.5(b).

[42] RMP responses to Vivint Solar data requests 2.9 and 2.10.

Q. DO OTHER CUSTOMERS BENEFIT FROM THESE UPGRADES?

A. Yes, in the long run. These upgrades help to reinforce the local distribution network and avoid the need for at least some upgrades in the future, the costs of which would have been borne by all customers. RMP did not consider this benefit to non-NEM customers in its analysis.

Q. HAS RMP INCURRED ANY INCREMENTAL MAINTANANCE (EMERGENCY OR ROUTINE) COSTS ASSOCIATED WITH THE NEM SYSTEMS?

A. No. RMP stated that "[t]o date, there has been no increase in maintenance activities on the distribution system related to distributed net energy metering (NEM) generation due to the low number of installations."[43]

Q. HOW MANY NEW EMPLOYEES DID RMP HIRE IN UTAH IN 2015 AS A RESULT OF THE NEM PROGRAM?

A. RMP stated that one employee was hired in Utah in 2015 as a result of the growth of the NEM program. However, that employee began work in early 2016.[44]

Q. HAS RMP PROVIDED ANY DATA TO SUPPORT ITS CLAIM THAT RMP REALLOCATED COSTS AND RESOURCES TO ADMINISTER THE NEM PROGRAM IN UTAH IN 2015?

A. No. Without such data, it is not feasible to quantify RMP's actual incremental costs associated with the NEM program.[45]

Q. HAS RMP PROVIDED DATA SHOWING WHAT FRACTION OF DISTRIBUTION UPGRADE COSTS ARE INCREMENTAL TO SERVE NEM CUSTOMERS?

A. No. In 2015, RMP authorized about 2,400 new distribution upgrade projects to serve new customers in Utah. However, RMP stated that it does not know if any of these are related to NEM customers, since RMP cannot determine whether a given project is a new line

43 RMP response to DPU data request 6.6(d). Emphasis added.

44 RMP response to Vivint Solar data request 2.26.

45 RMP response to Vivint Solar data request 2.26(e).

construction only or whether it included an upgrade of existing facilities, nor does RMP review whether any given project is at all related to NEM vs. non-NEM customer use or needs.[46]

Q. WHAT IS YOUR ESTIMATE OF THE NET COST OR BENEFIT OF THE RESIDENTIAL NEM PROGRAM?

A. I estimate that the NEM program provides a net benefit to RMP and its residential customers of $200,000. This estimate results from correcting the errors in RMP's analysis that I identified above. First, as explained above, RMP should remove bill credits associated with behind-the-meter consumption. This adjustment reduces RMP's estimate of the total cost to serve residential NEM customers from $3.5 million to $2.2 million. Second, since there is no evidence that RMP actually incurred significant incremental costs to serve NEM customers, such uncertain costs should be excluded from the study, which reduces the total cost to approximately $1.7 million. RMP claims that the total benefit provided by residential NEM customers is approximately $1.9 million. This would then show that the NEM program provides a net benefit in Utah of about $200,000, rather than a net cost of $1.7 million, as asserted by RMP. The amount of this net benefit would significantly increase if all of the benefits were included in the analysis, as I explain in the following section.

Q. HOW DOES THE $1.7 MILLION NET COST CLAIMED BY RMP DUE TO RESIDENTIAL ROOFTOP SOLAR CUSTOMERS IMPACT A TYPICAL RESIDENTIAL CUSTOMER'S MONTHLY BILL?

A. RMP's actual revenue shortfall amount is negligible to non-existent, as shown above. Even if RMP's revenue shortfall estimate were correct, however, it would account for a very small fraction of RMP's residential revenue requirement. For example, in 2015, RMP's asserted

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46 RMP response to Vote Solar data request 4.5.

$1.659 million revenue shortfall due to residential NEM customers is just 0.23% of total residential revenue.

Q. HOW DOES RMP'S ALLEGED REVENUE SHORTFALL DUE TO RESIDENTIAL NEM CUSTOMERS COMPARE TO REVENUES FROM OTHER CLASSES?

A. Depending on the customer class, RMP has either under-recovered or over-recovered from other customer classes. These amounts, however, are much greater than the $1.659 million in claimed under-recovered costs from NEM customers in RMP's current filing. For example, in 2015, RMP under-recovered over $30 million from residential customers,[47] while RMP over-recovered about $38 million from the Schedule 6 (large general service) customers.[48]

Q. MR. MEREDITH CONCLUDES FROM HIS NEM BREAKOUT COS STUDY THAT RMP RECOVERS ONLY 61% OF COSTS TO SERVE RESIDENTIAL NEM CUSTOMERS. DO YOU AGREE?

A. No. This conclusion is incorrect because RMP has underestimated the value of exported energy in the NEM Breakout COS study. In 2015, residential NEM customers exported about 16 million kWh of excess energy to the grid. Figure 8 shows the amount of exported energy by each block on a monthly basis.[49] I calculate the annual value of the exported energy by multiplying the kWh amount of each energy block to the corresponding rate and summing them over the year. This results in about $1.74 million for the Schedule 1 residential NEM customers. RMP, however, has assigned just $363,170 for the total value of excess NEM credits, inclusive of offsetting costs in the NEM Breakout COS study. Applying the full value of exported bill credits, the resulting cost recovery increases to about 91%, meaning that RMP is adequately recovering the costs to serve residential NEM customers.

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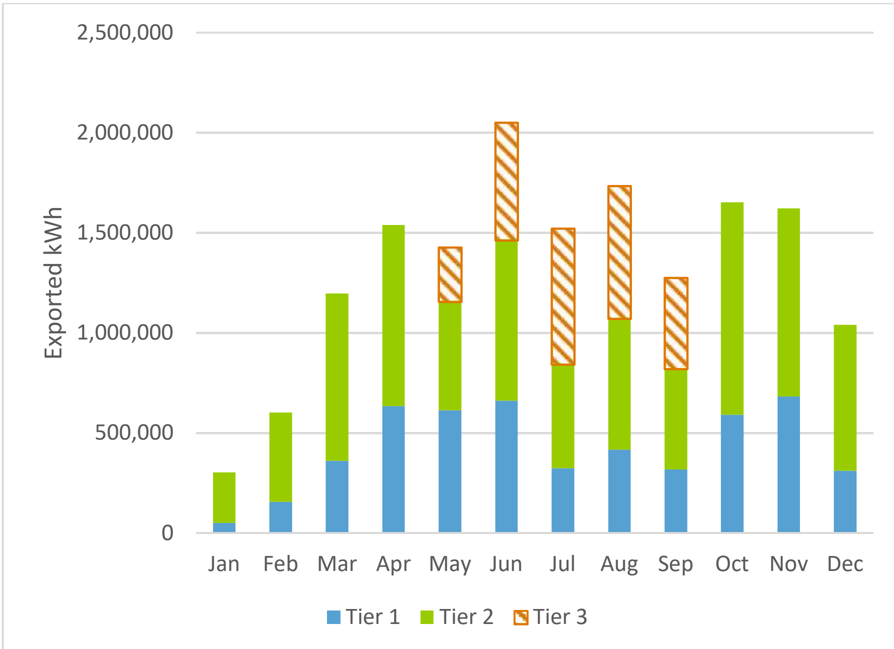
47 Meredith work paper, "2016.11.09 - 51 - Rocky Mtn Pwr - Exhibit B - Exhibit RMP (RMM-2) Summary of Results for ACOS and CFCOS," "Page 1" tab.

48 Id.

49 RMP's residential rates are based on three blocks: Tier 1 (less than 400 KWh); Tier 2 (more than 400 kWh); and Tier 3 (more than 1,000 KWh). Rates vary by Tier: 8.85 cents/kWh for Tier 1; 10.7 cents for Tier 2; and 14.5 cents for Tier 3.

Figure 8: Amount of exported energy by each tier level on a monthly basis (kWh).



Q. PLEASE DESCRIBE HOW RMP PERFORMED ITS NET POWER COST ANALYSIS.

A. Mr. Wilding conducted RMP's net power cost (NPC) analysis to quantify the avoided energy and line losses provided by NEM customers. Using RMP's production cost model (the GRID), he calculated the NPC benefits of the NEM program by comparing the output of two GRID studies with and without NEM generation. His results show that about 58,000 MWh of NEM generation is replaced by a mix of market purchases (69%), coal (29%), and gas generation (2%). After accounting for $2.83/MWh of solar integration cost, Mr. Wilding concludes that 58,000 MWh of NEM generation provides $1.3 million (or $22.28/MWh) of NPC benefits in 2015.

Q. DO YOU AGREE WITH THE RESULTS OF MR. WILDING'S NET POWER COST ANALYSIS?

A. No. Overall, RMP's estimate of $22.28/MWh is incomplete, as it only includes NPC benefits associated with avoided energy and line losses, and it ignores other benefits such as avoided capacity benefits. RMP's estimate of $22.28/MWh is even lower than RMP's QF avoided cost of $50/MWh in 2015.[50] In addition, Mr. Wilding's NPC analysis contains several errors that bias his results downward.

Q. PLEASE DESCRIBE THE ERRORS YOU HAVE IDENTIFIED.

A. There are at least two errors with Mr. Wilding's analysis. First, Mr. Wilding assumes that only 2% of NEM production is replaced with natural gas generation, while the remaining 98% of the output is replaced with either cheaper baseload coal or market purchases. It is more reasonable to expect that the output from DSG reduces the marginal (highest cost) output at the top of the dispatch stack. In addition, Mr. Wilding does not include variable O&M costs, and he applies average rather than marginal heat rates. Both of these errors underestimate the avoided energy costs. Second, Mr. Wilding's solar integration cost estimate is outdated. In fact, RMP has updated the solar PV integration costs from $2.83/MWh, as is being used, to $0.60/MWh.[51] Since Mr. Wilding subtracts solar integration costs from the NEM benefits associated with avoided energy and line losses, RMP's NPC estimate is understated.

Q. WHAT IS RMP'S BASIS FOR ITS PROPOSAL TO SEGREGATE RESIDENTIAL NEM CUSTOMERS INTO A DISTINCT RATE CLASS?

A. RMP provides three reasons for segregating residential NEM customers into a separate class: (i) the usage characteristics of NEM customers differ from other residential customers; (2) NEM customers use the grid more than other customers; and (3) peak generation of NEM customers does not coincide in time with RMP's peak load, and thus NEM customers have a modest ability to reduce peak load.[52]

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[50] Direct testimony of Paul Clements on behalf of RMP, at p. 4:72-74. Docket No. 14-035-114 (Submitted July 30, 2015). "My testimony shows that the value or benefit of distributed solar generation using an avoided cost method such as Schedule 37 (the "benefit" in our cost-benefit analysis) is currently equal to approximately five cents per kilowatt-hour…"

[51] PacifiCorp 2017 IRP Table 6.2, at p. 111.

[52] Direct testimony of Gary W. Hoogeveen, at lines 186 – 199.

Q. WHY DOES RMP BELIEVE THAT THE USAGE CHARACTERISTICS OF NEM CUSTOMERS DIFFER FROM OTHER RESIDENTIAL CUSTOMERS?

A. RMP alleges that its load research study for residential NEM customers shows that: (i) they have a different load profile than other residential customers, but not necessarily a different peak requirement; (ii) their reduced usage results in lower load factors compared to other residential customers; and (iii) they use the system differently than low-usage residential customers, since they use the grid not only to import energy, but also to export excess energy.

Q. PLEASE DESCRIBE RMP'S LOAD RESEARCH STUDY.

A. RMP installed 52 load research profile meters on a small sample of residential NEM customers to measure the delivered and exported energy from their solar systems. Of those 52 customers, RMP received permission to install 36 production profile meters to measure the solar generation from their systems. RMP asserts that the data from the 52 load research profile meters show that the profile of residential solar customers have distinctly different usage characteristics than other residential customers, and while those NEM customers take less energy (kWh) from the grid after they install their solar systems, their overall demand (kW) requirements are not reduced proportionally.[53]

Q. PLEASE COMMENT ON RMP'S LOAD RESEARCH STUDY.

A. RMP's very limited load research study is a statistically insufficient and unreliable basis for the Commission to use in implementing a radical change in the NEM rate design, as RMP proposes. RMP is unable to collect adequate information on its residential customers due to the very limited capabilities of its metering infrastructure. RMP tried to overcome this deficiency with its very limited load research study for a very small sample of customers, which was selected based on 2014 data, when the number of residential NEM customers was

[53] Direct testimony of Joelle R. Steward, at lines 56 – 59.

a much smaller number than it is today. Even for this small sample of customers, RMP has not collected detailed data on NEM customers' usage before and after installing solar systems – which is particularly important in assessing how these systems have caused their use to change, e.g., in reducing their peak load.[54] Most importantly, the variance of the available data from both the NEM and non-NEM sample of customers is so large that observed differences in usage characteristics of these two samples are not statistically meaningful.

Q. PLEASE EXPLAIN.

A. The sample size used by RMP was comprised of only 52 NEM customers for the load profile study and only 36 customers for the production profile study. RMP selected this small sample in December 2014, based on a population of only 1,578 residential DSG customers in Utah. As of March 2017, there were approximately 19,000 residential DSG customers in Utah, a number that is expected to grow significantly in the future. Residential customers who have adopted DSG more recently may well have different usage or production characteristics than earlier adopters of DSG technologies, given the continued decline in solar panel costs, changes in panel technology, etc. By comparison, in support of its recent rate case filing, APS analyzed the hourly data of over 37,000 residential DSG customers in Arizona (about 67% of the 55,000 residential DSG customers to date).[55] Given the rapid changes in residential DSG adoption in Utah, a more up-to-date study based on a larger sample size is essential to assess accurately how residential NEM customers differ from non-NEM customers in their usage patterns, and to assess if these differences are significant in any meaningful sense as it relates to cost-causation. A sound factual basis is the *sine qua non* for reasoned decision-making

[54] UCE data request 6.2 requested hourly, monthly, and annual consumption; peak loads; and annual load factors for each residential customer with DSG, for the twelve months before and after the installation of their DSG system. RMP responded that it only collected information for 2015.

[55] Direct testimony of James A. Heidell before the Arizona Corporation Commission, Docket No. E-01345A-16-0036 (February 3, 2017), at p. 5.

regarding whether to segregate residential NEM customers into a separate rate class. RMP's limited load research study is inadequate for this task.

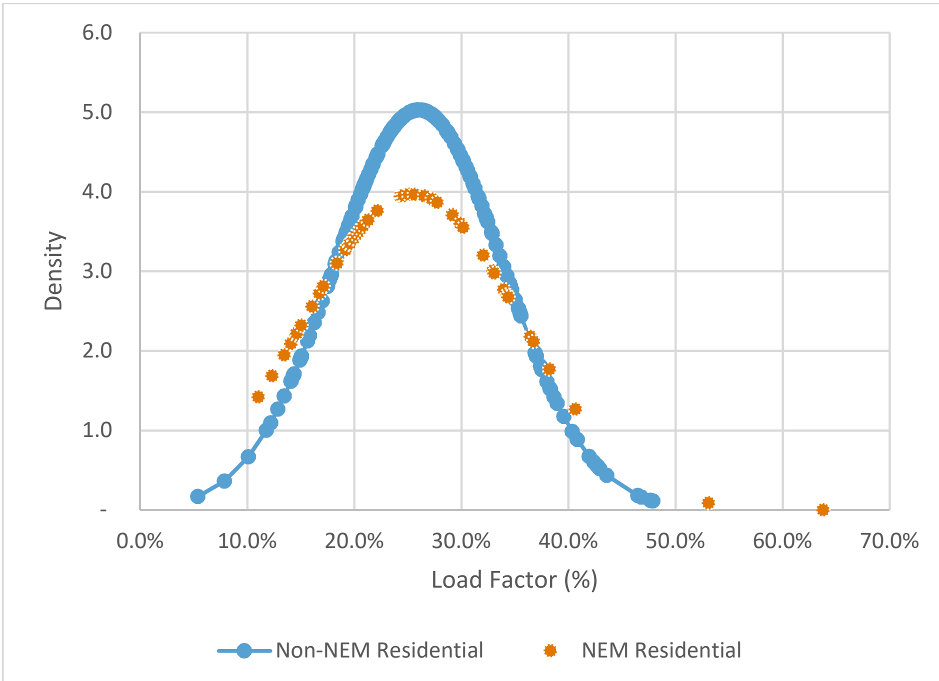
Q. DO YOU AGREE WITH RMP THAT NEM CUSTOMERS' LOAD FACTORS ARE FUNDAMENTALLY DIFFERENT THAN THOSE OF OTHER CUSTOMERS?

A. No. Even accepting at face value the limited samples selected by RMP and the limited data collected, RMP's own analysis of customer load factors shows that the load factors for residential NEM and non-NEM customers are not meaningfully different, as shown in Figure 9 below.[56] The mean and standard deviation of the load factors for the 52 residential NEM customers are 25% and 10%, compared to 26% and 8% (respectively) for the 195 residential non-NEM customers. In terms of the "tails" of the distribution, the 20th and 80th percentile load factors for the NEM customers are 17% and 33%, compared to 19% and 32% (respectively) for non-NEM customers. Thus, the load factors for RMP's selected sample of residential NEM solar customers are not significantly different from those for other residential customers. I performed a formal statistical test to verify this conclusion.[57]

[56] RMP's response to DPU DR 4.3.

[57] I applied the Kolmogorov–Smirnov test (KS test) to test if the distribution of load factors between the NEM and non-NEM customers are significantly different in the samples provided by RMP. The KS test is similar to other statistical tests that compare the difference in means between two samples (e.g., a t-test), but it has a more general applicability. In general, if the resulting p-value is larger than 0.1, the two samples are considered to be drawn from the same distribution. Applying the KS test to the two customer samples results in a p-value of approximately 0.3, meaning that that there are no statistically significant differences between the distribution of observations in the two samples. For a description of the KS test, see: E. Noether, "A brief survey of nonparametric statistics," in R.V. Hogg (ed.), Studies in Statistics, Math. Assoc. Amer. (1978); or M. Hollander and D.A. Wolfe, Nonparametric Statistical Methods, Wiley (1973).

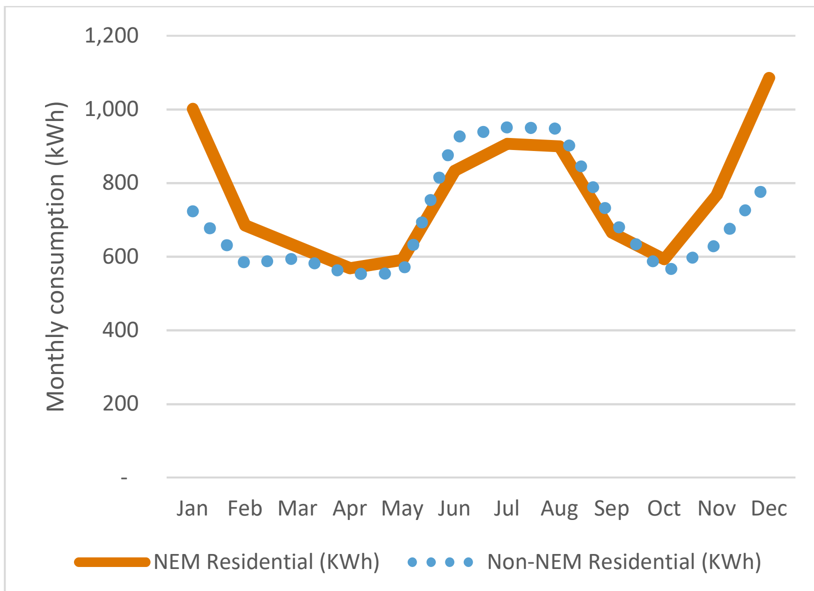
Figure 9: Load factor distribution for NEM and non-NEM customers.



Q. HAVE YOU ANALYZED OTHER USAGE CHARACTERISTICS OF RESIDENTIAL NEM VS. NON-NEM CUSTOMERS?

A. Yes. In addition to the load factors, I also analyzed the energy consumption (delivered load) for residential NEM and non-NEM customers on a monthly basis, as shown in Figure 10 below. On average, NEM customers consume more energy than non-NEM customers (769 kWh vs. 710 kWh, respectively), although this varies somewhat by season. Residential NEM customers purchase more energy from RMP than non-NEM customers in the winter months (November – February); their monthly consumption declines to a level that is effectively the same as for non-NEM residential customers during the shoulder months (March – May and September – October); and their consumption is slightly lower than for non-NEM residential customers in the summer (June – August). This indicates that on average, NEM customers must have been high-usage customers before installing their solar systems; that even after installing solar systems, they continue to consume energy purchased from RMP consistent with or higher than the average consumption of other residential customers (across all months); and that their consumption is lower than that of other customers during the summer (when their solar output is highest) – precisely when it is of the greatest value to the system for NEM customers to reduce their consumption. The monthly on-peak consumption data for residential NEM and non-NEM customers generally show a similar pattern.[58]

Figure 10: Residential NEM vs. non-NEM average monthly energy consumption



Q. DO YOU AGREE WITH RMP'S ASSERTION THAT NEM CUSTOMERS PLACE A GREATER BURDEN ON THE SYSTEM THAN NON-NEM CUSTOMERS?

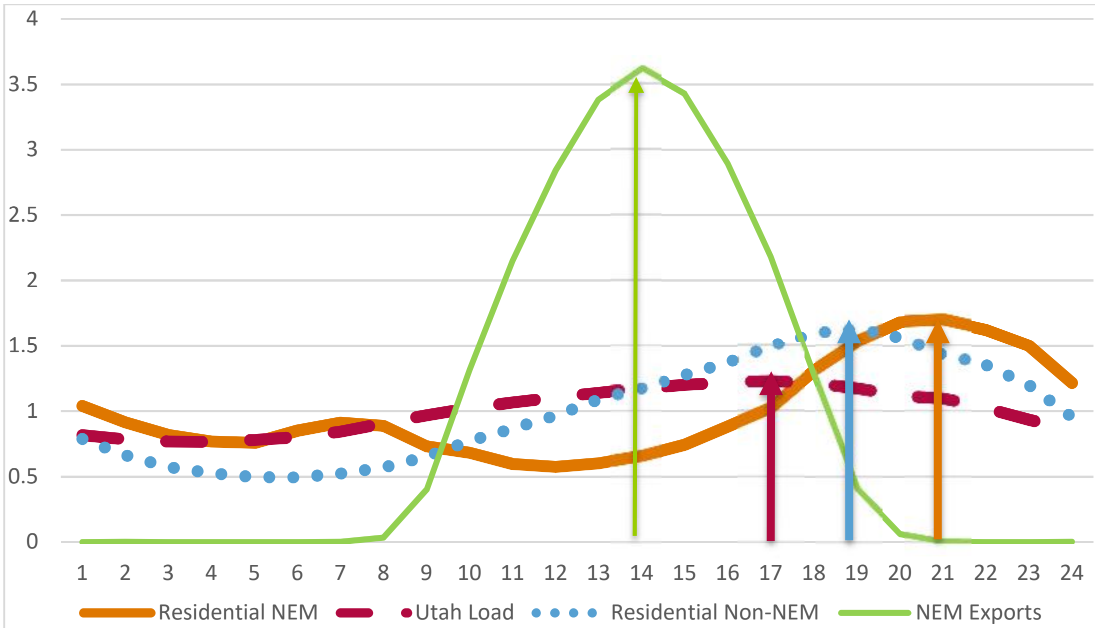
A. No. First, the amount of excess power exported to the grid by NEM customers is far too small to have any meaningful impact on the RMP system. In July 2015, the average rooftop solar customer exported less than 0.3 kWh of solar generation, which is a minute quantity as compared to the corresponding average Utah load of more than 3,300 MWh. Second, Figure 11 below compares the average hourly load profile of the entire Utah system, non-NEM residential customers, NEM customers, and NEM excess energy exports during July 2015. I

[58] On-peak hours during October – April are 8:00 a.m. to 10:00 a.m. and 3:00 p.m. to 8:00 p.m., Monday – Friday, except holidays. During May – September, on-peak hours are 3:00 p.m. to 8:00 p.m., Monday – Friday, except holidays.

have normalized the hourly profile values relative to the corresponding mean of each distribution to enable a comparison, since the average hourly load of Utah is vastly greater than both average hourly NEM and non-NEM customer loads and excess energy exports. Values greater than 1 in Figure 11 are larger than the average of the corresponding distribution, and vice-versa.[59] (Following the procedure used by RMP's witnesses, all hours are measured in Pacific Prevailing Time, at the hour-ending time.) Several observations are in order. First, the Utah system load peaks at 5 p.m., as compared to 7 p.m. for residential non-NEM customers' load peak, 9 p.m. for residential NEM customers' load peak, and 2 p.m. for residential NEM customers' excess energy production peak. Second, at the system peak, the load from non-NEM customers is 50% greater than their daily average, but the load from NEM customers is slightly less than their daily average load. Third, even at the 5 p.m. system peak, NEM customers' solar systems still provide more than 60% of their maximum excess output to the grid, which helps to lower the system peak. Fourth, on average, NEM customers consume the most at 9 p.m., i.e., 4 hours after the system peak and 2 hours past the residential peak, which means that the timing of their peak consumption puts *less* of a burden on the system peak than residential non-NEM customers.

[59] For example, a value of 1.5 for the Utah hourly load profile corresponds to 4,973 MW, while a value of 1.5 for the NEM export profile corresponds to less than 0.5 kW.

Figure 11: Comparison of standardized hourly load profiles (July 2015)



Q. MR. MARX ASSERTS THAT RMP MUST HANDLE REVERSE POWER FLOWS CAUSED BY NEM CUSTOMERS. DO YOU AGREE?

A. No. RMP cannot "handle" something it does not measure, attempt to control, or otherwise respond to. In response to a discovery request for reverse power flow data on the upstream distribution system, RMP testified that such data is not available because "metering systems are not capable of differentiating sources of energy generation."[60] In fact, RMP does not need to measure or manage reverse power flows at current levels of residential DSG penetration, because NEM customers' exported power is consumed by neighboring loads before it reaches the upstream distribution system. Mr. Marx's assertion that RMP "handles" reverse power flows is therefore entirely speculative and unsupported by any evidence that such reverse flows exist.

[60] RMP Response to Vote Solar Data Request 4.2.

Q. HAS RMP PROVIDED ANY DATA SHOWING CHANGES IN THE USE OF DISTRIBUTION CIRCUITS AS A RESULT OF RESIDENTIAL DSG SYSTEMS?

A. No. RMP stated that "[t]he limited data available does not provide enough historical data to provide for any meaningful analysis at this time."[61]

Q. HAS RMP PROVIDED ANY EVIDENCE OF ANY ACTUAL REVERSE POWER FLOWS PAST THE SECONDARY TRANSFORMER DUE TO NEM CUSTOMERS?

A. No. RMP stated that it does not meter electric energy at the secondary transformer.[62]

Q. HAS RMP PROVIDED DATA TO DETERMINE WHAT FRACTION OF REVERSE POWER FLOWS IS CONSUMED WITHIN THE SECONDARY DISTRIBUTION SYSTEM?

A. No. RMP stated that existing metering systems are not capable of differentiating sources of energy generation.[63] As a matter of physics, however, most of the excess energy from the NEM systems will flow to serve the nearest load within the secondary distribution system.

Q. HAS RMP INCREASED THE SIZE OF THE LOCAL DISTRIBUTION SYSTEM TO ACCOMMODATE REVERSE POWER FLOWS FROM NEM CUSTOMERS?

A. No.[64]

Q. WHY IS THAT?

A. First, at current levels of DSG penetration, all excess energy is used by neighboring customers. Second, residential non-NEM customers' peak demand in summer is generally higher than NEM customers' peak exports in spring. Mr. Marx asserts that peak exports for rooftop solar in Utah typically occur during spring, when temperatures are mild and residential loads are relatively low. Excess energy then decreases in summer, as temperatures rise and residential

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[61] RMP response to DPU data request 6.8.

[62] RMP response to Vote Solar data request 1.13.

[63] RMP response to Vote Solar data request 4.3.

[64] RMP response to DPU data request 6.6.

loads reach their annual peak. He then concludes that the local distribution system must be sized to accommodate the greater of the two, and to handle the greater reverse power flows in the spring months, which means the local distribution system must be sized to accommodate 30 to 50% more than normal. These hypothetical concerns, however, are not supported by the data. For example, Figure 12 and Figure 13 show the generation profile for NEM power exports as compared to load profiles for residential NEM and non-NEM customers in April and July 2015, respectively. Average peak power exports in April are about 50% more than those in July, but the average April peak exports from rooftop solar systems (1.4 kW) is still lower in magnitude than the July peak demand for residential non-NEM customers (over 2 kW). It is also important to bear in mind that these are average statistics on a per customer basis; the fact that there are many more residential non-NEM customers than NEM customers, whether in the aggregate or on a given circuit, means that Utah is far from needing any additional distribution investments to accommodate reverse power flows by NEM customers.

Figure 12: Generation profile for power exports as compared to load profiles for residential NEM and non-NEM customers in April 2015.

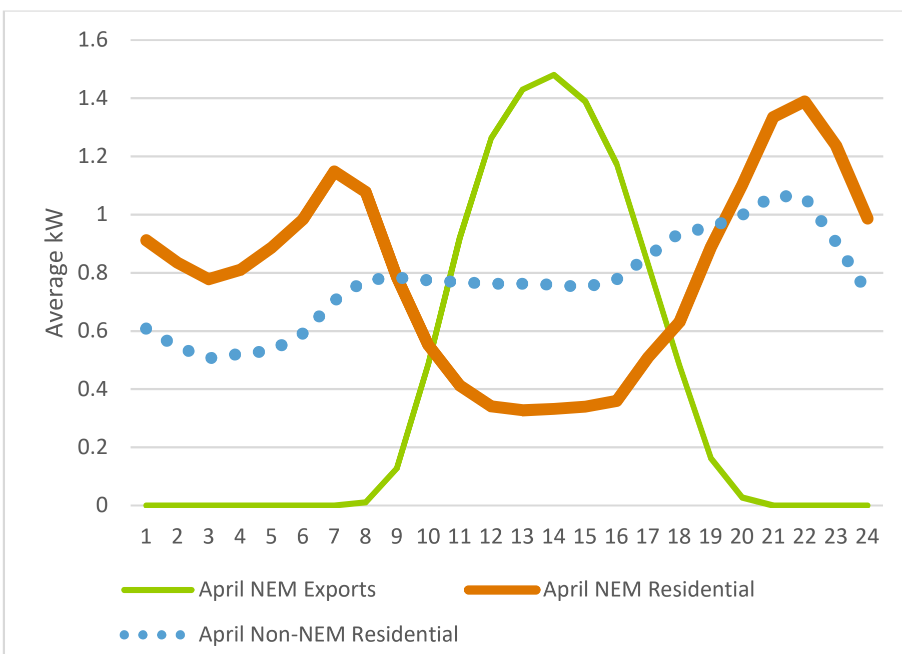
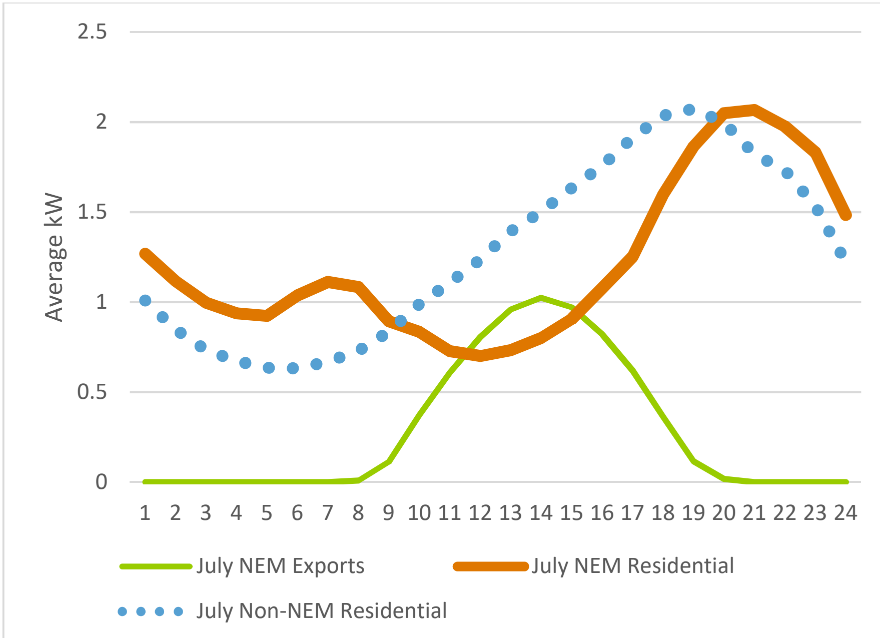


Figure 13: Generation profile for power exports as compared to load profiles for residential NEM and non-NEM customers in July 2015



Q. HAS RMP ACCOUNTED FOR AVOIDED DISTRIBUTION INVESTMENTS PROVIDED BY NEM CUSTOMERS?

A. No. Mr. Marx alleges in his testimony that DSG does not reduce peak demand on the distribution system sufficiently to warrant a reduction in infrastructure. To support his claim, Mr. Marx presented the results of the neighborhood rooftop solar study for the area served by the Northeast #16 circuit, showing that DSG offsets at most 7% of the peak demand on the circuit. He also presented another study, showing that DSG reduces the peak circuit loading by only 3.6% at the Bingham #11 circuit. Since the data show that NEM customers do reduce system peak load, RMP should have reflected this as a benefit of the NEM program in its analysis.

Q. HOW DO YOU RESPOND TO MR. MARX'S STUDIES?

A. First, my review of the Bingham #11 circuit study shows a 6.8% circuit peak reduction, rather than a 3.6% reduction, as reported by Mr. Marx. Second, and more importantly, since every distribution planning area and feeder will have a different amount of load reduction capability due to various local characteristics, it is premature to reach a meaningful conclusion based on the two circuit level studies. Rather, aggregate DSG coincidence at the system peak level should be calculated to estimate avoided distribution capacity costs. If such system data is used as a whole, DSG may provide a sufficient reduction in peak load to reduce the need for certain distribution infrastructure investments.

Q. MR. MARX ASSERTS THAT NEM CUSTOMERS USE THE GRID MORE THAN NON-NEM CUSTOMERS.[65] DO YOU AGREE?

A. No, and it is my view that the methodology Mr. Marx uses in concluding otherwise is flawed. A NEM customer either imports power from the grid or exports excess energy to the grid, and not both at the same time. Therefore, it is incorrect to measure a NEM customer's grid use by summing up the absolute value of a NEM customer's energy flows, as Mr. Marx did in his testimony.[66] When NEM customers import power from the grid, they use the grid *less* than they would otherwise, because they consume a significant fraction of their energy on site through behind-the-meter generation. When NEM customers export power to the grid, they also use the grid less than they would otherwise, because their exported power is consumed by neighboring loads, and thus RMP does not have to use its transmission and distribution grid to deliver power to the same load from distant power sources. Lastly, since NEM customers' exported energy is consumed locally, it does not use RMP's upstream substations and long-distance transmission network. In its cost of service study, RMP ignores the fact that net exports from NEM customers do not use RMP's substations and long-distance transmission network. Since NEM customers do export excess generation back on the grid in certain hours, they do use the grid differently (at times) than other residential customers; but

[65] Direct testimony of Douglas L. Marx, at pp. 5:92 – 7:116.

[66] Id.

other residential customers benefit from that "different use," and RMP has submitted no evidence to support the conclusion that this "different use" has caused RMP to incur additional costs. On the contrary, the "different use" associated with NEM customers' exports reduces line-loadings on the local distribution network during time periods when that reduction is of value to the system. Furthermore, the recipients of that exported power (neighboring customers) obtain that excess energy as if it had come from RMP's resources – and they pay RMP for that power at the full retail rate, i.e., inclusive of embedded transmission and distribution costs, generation capacity and fuel costs, line losses, etc.

Q. IN ITS COS STUDIES, HAS RMP CONSIDERED THE FACT THAT REDUCED LOAD FROM NEM CUSTOMERS LOWERS UTAH'S REGIONAL COST ALLOCATIONS FROM PACIFICORP?

A. Yes, but only to a limited extent. First, NEM customers' reduced load benefits all Utah ratepayers by reducing RMP's regional capacity cost allocation to Utah. In addition, a reduction in peak load in Utah – whether it results from DSG, energy efficiency, or simply a change in customer behavior – will also reduce the total amount of PacifiCorp's fixed (capacity) costs, as many of PacifiCorp's assets are used to serve customers across its multi-state footprint. RMP did not consider these system-level benefits that DSG customers provide in reducing PacifiCorp's aggregate system investment needs, as reflected in its integrated resource plan ("IRP"). I consider this as part of the long-term benefits of DSG, which I analyze in the following section.

V. <u>Additional Benefits of Residential DSG in Utah</u>

Q. WILL A COST OF SERVICE FRAMEWORK CAPTURE ALL OF THE BENEFITS OF DSG, AS IN A COST-BENEFIT ANALYSIS?

A. No. Generally, a COS study is a relatively well-defined tool to determine a utility's costs to serve customers, and to assign those costs to different customer classes. By focusing on a single test-year, a COS study by definition cannot capture either the long-term costs or long-term benefits of the policy or program under consideration – nor does it typically need to in a rate case, in which the purpose is to ensure that costs are reasonably allocated among different customer classes. By contrast, a cost-benefit study is typically broader in scope, as the process of quantifying all the relevant costs and benefits of a given policy or program (such as NEM) often requires a very different analytical framework and a longer timeframe. While future costs and benefits are often difficult to quantify, they should still be considered in evaluating policies and programs.

Q. HAS THE COMMISSION ADOPTED A LONG-TERM COST-BENEFIT APPROACH IN EVALUATING OTHER PROGRAMS?

A. Yes. Pursuant to the Commission's guidance, RMP has been using a long-term cost-benefit approach in evaluating the benefits and costs of demand-side resource ("DSR"), small-scale renewable resources, and EE programs.[67] There is no meaningful difference between NEM and other demand-reduction programs (e.g., DSM and EE) that would prevent a similar approach from being used to evaluate the long-term costs and benefits of the NEM program.[68] Supply-side resources are also evaluated over the lifetime of the specific resource.

Q. IS IT CUSTOMARY TO USE A ONE-YEAR TIME PERIOD TO ESTIMATE THE BENEFITS OF NEM?

A. No, I have reviewed numerous NEM cost-benefit studies, and I have not previously encountered one that relies on a single-year, COS framework. There is relatively broad consensus that the benefits of NEM will accrue over the entire lifetime of the deployed technology, e.g., 25 years or longer for DSG, and thus most cost-benefit studies adopt a longer-

[67] See, e.g., Public Service Commission of Utah, "In the Matter of the Proposed Revisions to the Utah Demand Side Resource Program Performance Standards," Docket No. 09-035-27. Order issued October 7, 2009; Utah Demand Side Management and Other Resources Benefits and Costs Analysis Guidelines and Recommendations," (April 2009).

[68] See, e.g., RMP response to Vote Solar data request 4.13 and references therein.

time horizon to assess accurately its actual benefits. NEM systems provide long-term benefits to both NEM and non-NEM customers in terms of reduced energy, reduced system losses, reduced generation, transmission and distribution capacity costs, and reduced emissions.

Q. CAN YOU PROVIDE EXAMPLES OF THE LONG-TERM VALUE OF DSG?

A. Yes. Two recent examples demonstrate how NEM customers have reduced costs for all ratepayers. While these examples are not specific to Utah, due its currently very low level of DSG penetration, they are indicative of the magnitude of financial benefits achievable with DSG, if it is appropriately integrated into RMP's planning process. First, in New York City, rather than investing in transmission facilities, Consolidated Edison has been able to deploy a mix of DSG and energy efficiency measures to address a sharp increase in New York City's demand for power. The conventional transmission solution (i.e., adding a substation) would have cost more than $1.2 billion, but the demand-side solution will cost only about $200 million.[69] These savings of $1 billion in reduced transmission investments is a direct financial benefit to all customers in New York. Second, in March 2016, CAISO announced it was canceling 13 transmission projects that previously had been planned for the PG&E service territory, due to the effect of DSG and energy efficiency programs in reducing load forecasts in that area. The canceled projects include planned line improvements, transformer replacements, and bus upgrades, which resulted in $192 million in transmission cost savings for all customers.[70]

[69] Utility Dive, "The non-wire alternative: ConEd's Brooklyn-Queens pilot rejects traditional grid upgrades," (August 3, 2016). Available at http://www.utilitydive.com/news/the-non-wire-alternative-coneds-brooklyn-queens-pilot-rejects-traditional/423525/ (last accessed on May 18, 2017).

[70] Greentech Media, "Californians Just Saved $192 Million Thanks to Efficiency and Rooftop Solar," (May 31, 2016). Available at https://www.greentechmedia.com/articles/read/Californians-Just-Saved-192-Million-Thanks-to-Efficiency-and-Rooftop-Solar (last accessed on May 18, 2017).

Q. DO YOU HAVE ANY OTHER COMMENTS ON THE COMMISSION'S ANALYTICAL APPROACH USED IN THIS PROCEEDING?

A. Yes. I agree with the Commission's recognition that the general framework does not fully specify some important details that need to be resolved, including specifics of how the studies should be conducted and what costs and benefits should be included.[71] I also agree with the Commission's recognition that some costs and benefits that exist may not be fully captured in RMP's cost of service framework.[72] As a result, the Commission allows any party to supplement the result of the COS studies with more comprehensive categories of costs and benefits of NEM, to the extent that the party can demonstrate the existence of such costs and benefits.[73]

Q. WHAT TYPES OF BENEFITS AND COSTS HAVE BEEN INCLUDED IN OTHER STATE COST-BENEFIT ANALYSES OF DSG?

A. At least 18 states, including Utah, have commissioned cost-benefit studies of DSG, and a variety of benefits and costs of DSG have been considered or acknowledged in these studies.[74] Broadly, these categories are associated with energy, capacity and ancillary services, financial, reliability, environmental and social benefits, as shown in Figure 14 below.

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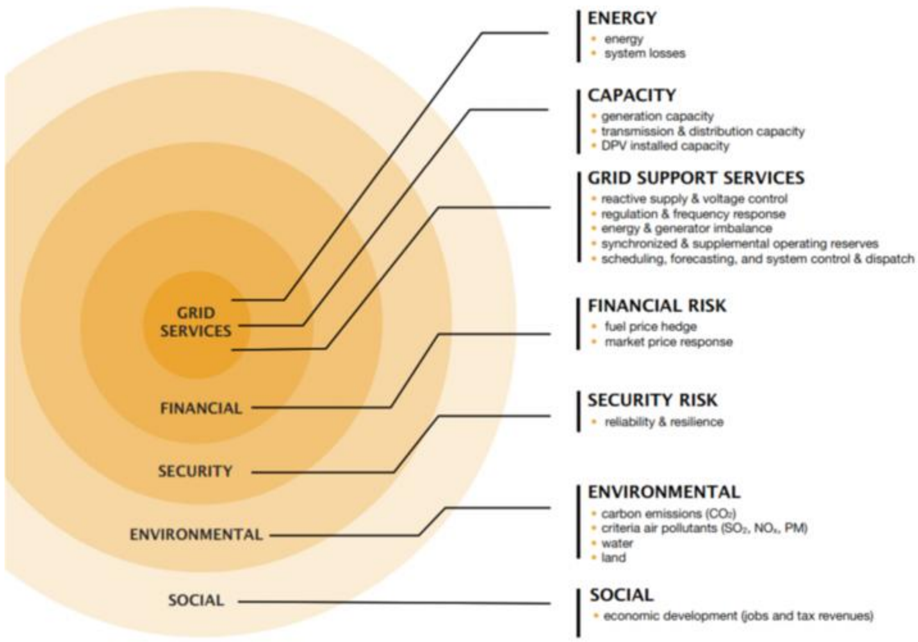
71 November 2015 Order, at p. 4.

72 Id., at p. 12.

73 Id., at p. 13.

74 These include Arizona, California, Colorado, Florida, Georgia, Hawaii, Massachusetts, Maine, Minnesota, Mississippi, North Carolina, Nevada, New Jersey, New York, Pennsylvania, Texas, Utah, and Vermont. See SEIA, "Solar Cost-Benefit Studies," available at http://www.seia.org/policy/distributed-solar/solar-cost-benefit-studies (accessed May 17, 2017).

Figure 14: Benefits and costs categories of DSG.[75]



Q. CAN THESE BENEFIT AND COST CATEGORIES BE VERIFIED AND QUANTIFIED?

A. Yes. While there are differences in the degree of certainty with which certain benefit categories have been quantified, all of these benefit and cost categories have been verified and quantified in a variety of cost-benefit studies, using well-accepted methodologies. While some of these benefits are more uncertain or longer-term in nature, they are nonetheless important to consider in quantifying the costs and benefits of DSG.

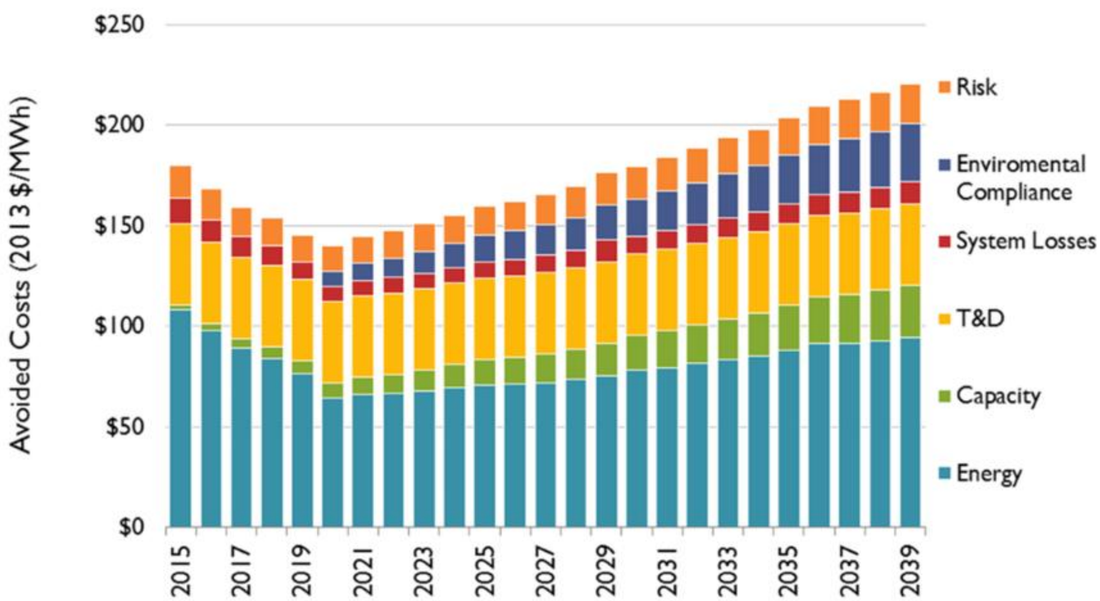
Q. CAN YOU PROVIDE EXAMPLES OF COST-BENEFIT STUDIES COMMISSIONED BY STATE REGULATORS THAT FOUND LONG-TERM NET BENEFITS OF DSG?

A. Yes. In 2014, a study commissioned by the Public Utility Commission of Nevada ("PUCN") concluded that net metering provided $36 million in net benefits to non-NEM customers of

75 Hansen, L., V. Lacy, and D. Glick, "A Review of Solar PV Benefit & Cost Studies," Rocky Mountain Institute, at p. 13 (September 2013).

NV Energy over the lifetime of DSG installed through 2016.[76] The net benefits increase to $166 million to non-NEM customers if avoided distribution upgrade costs are included.[77] Similarly, in 2014, a study commissioned by the Public Service Commission of Mississippi found that DSG in Mississippi would displace peaking resources, avoid costs associated with energy generation and line losses, reduce the need for future investments in the generation, transmission, and distribution system, and reduce environmental compliance costs and other risk-related costs.[78] As a result, the study concluded that the benefits of implementing net metering for DSG in Mississippi outweigh the costs in all but one scenario.[79] Figure 15 below shows that benefits increase over the lifetime of DSG.[80]

Figure 15: Annual benefits (avoided costs) of DSG in Mississippi.[81]



76 Energy and Environmental Economics (E3), "Nevada Net Energy Metering Impacts Evaluation," at pp. 7-8 (July 2014).

77 Id., at p. 14-15.

78 Synapse Energy Economics, "Net Metering in Mississippi," at p. 1 (September 2014).

79 Id., at p. 2.

80 Note that avoided energy costs decline over the first few years because the displaced marginal unit changes from a mix of oil and gas units to gas units alone.

81 Synapse Energy Economics, "Net Metering in Mississippi," at p. 37 (September 2014).

In March 2014, Minnesota adopted a "value of solar" policy.[82] Initial estimates found that the value of DSG is worth more than its retail rate (i.e., net metering undervalues DSG), with the value of solar estimated to be 14.5 cents per kWh, or 3 - 3.5 cents more than Xcel's retail rates. As in the Nevada and Mississippi NEM studies, the Minnesota value of solar study factored in a broad range of long-term benefits, including avoided energy, capacity, and grid infrastructure costs, as well as avoided environmental cost over a 25-year time horizon.[83]

Q. HAVE ANY STATES USED A SHORT-TERM ASSESSMENT OF DSG BENEFITS?

A. Arizona and Nevada have recently used a short-term approach to estimate the benefits of DSG. For example, in 2015, the PUCN moved away from a long-term approach to analyze the costs and benefits of its NEM program. By limiting the study to the short-term cost of service for NEM customers, the PUCN found that costs of the NEM program exceed short-term benefits. As a result, the PUCN effectively ended the NEM program in Nevada by significantly increasing the charges for NEM customers and reducing the credits for excess energy from 11 cents/kWh to less than 3 cents/kWh.

Q. WHAT HAS BEEN THE RESULT OF USING A SHORT-TERM APPROACH IN CALCULATING BENEFITS OF DG SOLAR?

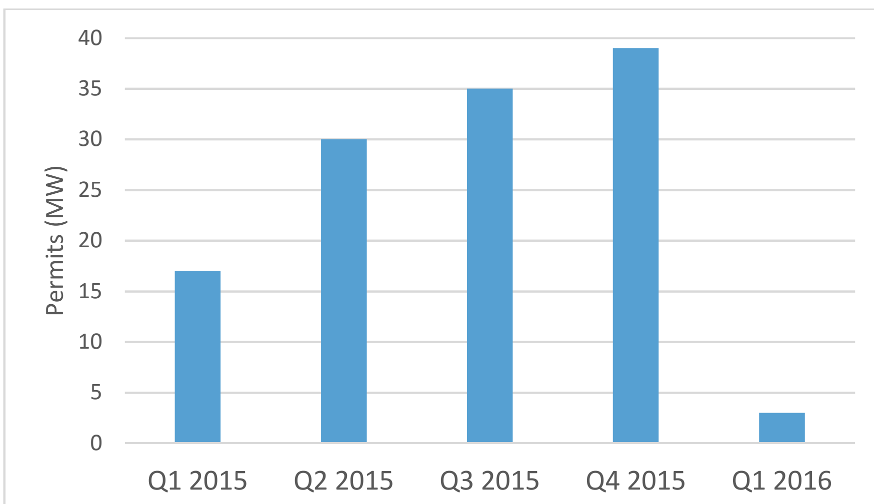
A. Since many benefits accrue over the lifetime of DSG, a short-term valuation approach is more likely to show net costs, even if DSG actually provides large net benefits to customers when evaluated over a longer time horizon. For example, the Nevada study results changed from large net benefits to net costs when the PUCN moved away from a long-term cost-benefit approach to analyze NEM in that state. The PUCN's December 2015 decision halted the previously fast-growing DSG market in Nevada and forced the state's three largest providers

[82] Under the value of solar framework, customers net the dollars paid for energy at the retail rate with the dollars earned selling solar energy to the utility at the value of solar rate.

[83] Quantified benefits consist of eight separate categories, but the following four account for most of the value: avoided natural gas purchases, avoided new power plant purchases, avoided transmission capacity, and avoided environmental costs.

of rooftop solar to leave the Nevada market.[84] As a result, new residential solar installation permits in Nevada plunged 92 percent in the first quarter of 2016, as shown in Figure 16 below.[85] Some of the rapid increase in permits issued in 2015 was likely motivated by a "rush to file" ahead of the expected change in the NEM program. Notably, however, after this change in policy caused several solar companies to close their businesses in the state, the PUCN accepted a settlement under which then-existing NEM customers were grandfathered so that they continued to participate in the NEM program under its prior rules. Most recently, the Nevada legislature passed a bill (AB 405) that would reinstate the NEM program, with excess generation compensated at 95% of the retail rate.[86]

Figure 16: Permits issued for Nevada residential PV, Q1 2015 – Q1 2016 (MW)



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[84] Greentech Media (GTM), "Nevada's Solar Job Exodus Continues, Driven by Retroactive Net Metering Cuts," (January 08, 2016). Available at https://www.greentechmedia.com/articles/read/nevadas-solar-exodus-continues-driven-by-retroactive-net-metering-cuts (last accessed at May 17, 2017).

[85] Brookings, "Rooftop solar: Net metering is a net benefit," (May 23, 2016). Available at https://www.brookings.edu/research/rooftop-solar-net-metering-is-a-net-benefit/# (last accessed at May 17, 2017).

[86] Greentech Media (GTM), "Nevada Legislature Passes Bill to Restore Net Metering to Rooftop Solar," (June 05, 2017). Available at https://www.greentechmedia.com/articles/read/nevada-bill-to-restore-net-metering-for-rooftop-solar-passes-in-the-senate (last accessed June 7, 2017). AB 405 also provides for future reductions in the value of the export credit, depending on the state achieving specified penetration targets, to a floor of 75% of the retail rate.

Q. HOW DOES THIS INFORM THE CURRENT PROCEEDING?

A. Similar to Nevada, the Utah Commission has specified a one-year analytical framework for this proceeding.[87] While many issues remain to be resolved, the Commission's short-term approach to quantifying the benefits of DSG is more likely to result in net costs to non-NEM customers, as it fails to capture the longer-term benefits run benefits of DSG, and it also adds difficulties and uncertainties in quantifying otherwise verifiable benefits categories. For example, despite the PUCN's finding that there are 11 components to the value of DSG, only two components of DSG value (i.e., avoided energy costs and line losses) were quantified and accepted under the PUCN's short-term approach.[88] The approach taken by RMP is particularly problematic, as RMP uses the hypothetical future costs associated with "reverse flows" to further support its conclusion regarding net costs, without also considering corresponding future benefits (I note also that RMP has not even accounted for the benefits from local distribution upgrades that NEM customers are already funding).

Q. IN YOUR ANALYSIS, HAVE YOU CONSIDERED OTHER NEM BENEFIT CATEGORIES THAT RMP HAS IGNORED?

A. Yes. In terms of NEM benefits included in the COS analysis, as discussed above, RMP considers only the reduced energy costs and reduced line losses. In evaluating the benefits of DSG, it is also important to consider its environmental benefits, capacity benefits, reliability benefits, and the benefits of the foregone need for future transmission and distribution investments. Whether many of these long-term benefits of DSG are actually realized depends on the actions the Commission takes today regarding the NEM rate structure. Nevertheless,

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[87] November 2015 Order, at pp. 8-9.

[88] These 11 components are: avoided energy costs; line losses; avoided capacity; ancillary services; transmission and distribution capacity; avoided criteria pollutants; avoid CO_2 emission costs; fuel hedging; utility integration and interconnection costs; utility administration costs; and environmental costs. See PUCN December 23, 2015 Order in Dockets Nos. 15-07-041 and 15-07-042, at pp. 66-67 and 95-96.

the available information combined with the results from previous studies provides a reasonable lower bound for these additional benefit values in Utah.

Q. HAS RMP PREVIOUSLY INCLUDED SUCH ADDITIONAL BENEFITS IN ANALYZING THE NEM PROGRAM?

A. Yes. In analyzing the costs and benefits of NEM, RMP previously included the avoided costs of capacity, transmission, distribution, and environmental compliance.[89]

Q. IN ITS CURRENT FILING, HOW DID RMP CALCULATE THE NEM PROGRAM BENEFITS RESULTING FROM AVOIDED ENERGY AND LINE LOSSES?

A. RMP used the GRID production cost model to calculate avoided energy costs and line losses associated with the NEM program. By comparing the results of two GRID studies – a "Base Study" and a "No NEM Study" – RMP estimates the total benefit of NEM to be $22.28/MWh, after deducting $2.83/MWh of solar integration costs.

Q. DO YOU AGREE WITH RMP'S ESTIMATE?

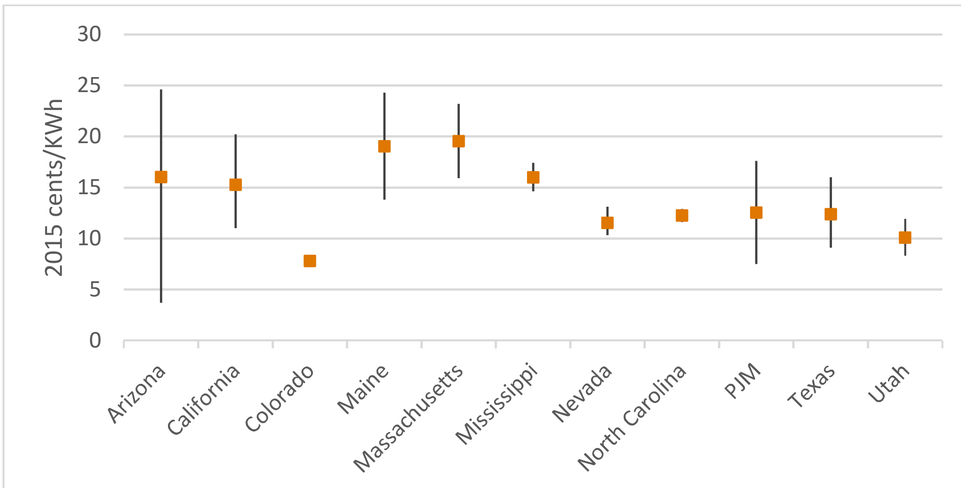
A. No. As I discussed above, RMP underestimates the value of avoided energy costs and line losses, and it overestimates solar integration costs. RMP's estimate of total NEM benefits ($22.28/MWh) is also significantly lower than other estimates of NEM benefits commissioned by numerous state regulators across the country. Figure 17 below shows the range of NEM benefits estimated in recent cost-benefit studies.[90] Estimates of DSG benefits vary considerably, ranging from $37/MWh to $246/MWh, due to differences in scope, methodology, input assumptions, and the local characteristics of the regions under study. However, none of the other cost-benefit studies value DSG at less than $23/MWh, as RMP

[89] Docket No. 14-035-114. Surrebuttal testimony of Paul H. Clements on behalf of RMP, Exhibit RMP_(PHC-25R). Submitted on September 29, 2015.

[90] LBNL, "Putting the Potential Rate Impacts of Distributed Solar into Context," at p. 12 (January 2017).

does. This demonstrates that the short-term (1-year) approach to estimating NEM benefits fails to capture most of its actual benefits.

Figure 17: Estimates of DG solar benefits from recent cost-benefit studies



Q. IS THERE A LOWER BOUND ESTIMATE FOR NEM BENEFITS IN UTAH?

A. Yes. NEM benefits in Utah must be larger than QF avoided costs, which in 2015, RMP stated were approximately $50/MWh.[91]

Q. WHY IS THAT A LOWER BOUND?

A. Residential DSG will almost certainly provide more benefits than QF generation purchased through power purchase agreements (PPAs), since DSG generates power at the point of consumption. When RMP purchases excess energy from a QF, some of the purchased energy is lost in transmission and distribution facilities (e.g., lines, substations and transformers). DSG avoids such losses. Such avoided losses also have a "multiplier effect," since they further reduce the required amount of capacity, operating reserves, and emissions needed to enable a given kWh of energy consumption by a customer.

[91] Direct testimony of Paul Clements on behalf of RMP, at p. 4:72-74. Docket No. 14-035-114 (Submitted July 30, 2015). "My testimony shows that the value or benefit of distributed solar generation using an avoided cost method such as Schedule 37 (the "benefit" in our cost-benefit analysis) is currently equal to approximately five cents per kilowatt-hour…"

Q. DO RESIDENTIAL NEM CUSTOMERS PROVIDE CAPACITY-RELATED BENEFITS?

A. Yes. Residential DSG systems can help RMP to defer or avoid additional investments in generation, transmission, and distribution assets by reducing both system and distribution peak demands. The two key determinants of generation capacity benefits are: (i) DSG's effective capacity; and (ii) RMP's generation capacity needs. The two key determinants of transmission and distribution (T&D) capacity benefits are: (i) DSG's ability to meet rising distribution demands and relieve transmission constraints upstream;[92] and (ii) RMP's T&D investment needs, as developed in its IRP. As discussed in the context of the energy benefits of DSG, avoided system losses also should be included in analyzing the capacity benefits of DSG, since (for example) RMP would need about 111 MW of central capacity to meet 100MW of local capacity, if RMP's effective system loss is 10%.

Q. WHAT IS THE VALUE OF THIS GENERATION CAPACITY BENEFIT IN UTAH?

A. The generation capacity benefit depends on the Effective Load Carrying Capacity (ELCC) of the residential DSG systems.[93] ELCC measures the percentage of resource capacity that can be reliably deployed to meet peak demand. All else equal, the value is generally higher if DSG output is more aligned with RMP's peak demand. RMP has been considering the capacity value of solar resources in its IRP. The DSG systems in Utah also provide such benefits, regardless of who owns these resources. For example, in the 2015 IRP, PacifiCorp estimated the peak capacity contribution value to be 34.1% for fixed-tilt solar PV in Utah.[94] This value

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92 Upstream transmission constraints also affect generation capacity value. For example, at the January 26-27, 2017 public input meeting, PacifiCorp identified the potential for transmission constraints to impact the effective capacity contribution from resources in Utah South. See, 2017 IRP: Public Input Meeting 7. January 26-27, 2017. Presentation available at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_2017_IRP_PIM07_1-26-17_Presentation.pdf (last accessed on June 6, 2017).

93 Madaeni, S. H.; Sioshansi, R.; and Denholm, P. "Comparison of Capacity Value Methods for Photovoltaics in the Western United States." NREL/TP-6A20-54704, Denver, CO: National Renewable Energy Laboratory, July 2012 (NREL Report), available at http://www.nrel.gov/docs/fy12osti/54704.pdf (last accessed on June 6, 2017).

94 PacifiCorp 2015 IRP Volume II, Appendix N, Table N.1 (page 405), available at http://pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP

was increased to 37.9% in the current 2017 IRP.[95] RMP omitted this benefit from DSG in its cost-benefit study. In its recent study, Clean Power Research ("CPR") estimated that NEM customers in Utah provide a generation capacity value of $14/MWh.[96]

Q. WHAT IS THE VALUE OF T&D CAPACITY BENEFITS OF RESIDENTIAL DSG?

A. Residential NEM customers also provide T&D capacity benefits by providing power close to demand. In its recent study, CPR estimated that NEM customers in Utah provide a T&D capacity value of $11/MWh.[97]

Q. DO RMP'S NEM CUSTOMERS PROVIDE A FUEL PRICE HEDGING BENEFIT?

A. Yes. Solar generation does not need fuel to produce power. Therefore, DSG effectively provides a "hedge" against a utility's generation fuel price volatility, reducing customers' risk exposure. Several cost-benefit studies have quantified such hedging benefits, using NYMEX futures market prices as an indicator of fuel price volatility.[98] The resulting benefit estimates range from less than $5/MWh to more than $40/MWh, depending on methodology, input assumptions, and local market characteristics (e.g., the marginal resource and the affected utilities' exposure to fuel price volatility). In its recent value of solar study in Utah, CPR has estimated a value of $26/MWh as a fuel hedging price benefit from NEM customers in Utah.[99]

Q. WHAT IS THE VALUE OF RELIABILITY-RELATED NEM BENEFITS?

A. Distributed generation located near end users can reduce outages by reducing congestion on the transmission and distribution network. Power outages are more likely to occur when

-Vol2-Appendices.pdf (last accessed on June 6, 2017).

95 PacifiCorp 2017 IRP Volume II, Appendix N, Table N.1 (page 316), available at http://pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeII_2017_IRP_Final.pdf (last accessed on June 6, 2017).

96 Clean Power Research, "Value of Solar in Utah," at p. 11. (January 2014).

97 Id.

98 See, e.g., Mark Bolinger and Ryan Wiser, "The Value of Renewable Energy as a Hedge Against Fuel Price Risk," (December 2008).

99 Clean Power Research, "Value of Solar in Utah," at p. 11. (January 2014).

demand is high and the grid is congested. DSG also has the potential to reduce large-scale outages by providing a more geographically dispersed generation portfolio. Furthermore, DSG equipped with smart inverters and storage can provide further customer benefits in the form of reactive power or back-up power during power outages. While there is general agreement that DSG either can or does provide reliability and resiliency benefits, most studies do not calculate this benefit due to the difficulty of quantification. CPR estimated that the value of avoided outages exceed $20/MWh, based on the total cost of power outages to the U.S. each year, and based on the ability of DSG to decrease the incidence of outages at a capacity penetration of 15%.[100] Given the current low level of DSG penetration in Utah, it is difficult to quantify with any degree of certainty the reliability benefits currently provided by DSG, but this is nonetheless a benefit that the Commission should consider from a longer-term perspective.

Q. WHAT IS THE VALUE OF AVOIDED ENVIRONMENTAL COMPLIANCE COSTS?

A. DSG systems reduce a utility's environmental emissions, including not only CO_2 but also other criteria pollutants. One way to value this reduction in emissions is to assess its impact on a utility's environmental compliance costs. In its 2015 IRP, RMP estimated a CO_2 compliance cost of $22/ton in 2020 to $76/ton by 2034, escalating at 1.9% per year.[101] In its 2017 IRP, RMP used a lower compliance cost of between $5 and $28/ton starting in 2025.[102] In its own value of solar study in Utah, CPR separately estimates $9/MWh as the avoided environmental cost.[103] This provides a reasonable lower-bound proxy for the overall environmental value of reduced emissions from DSG.

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[100] Perez, R., Norris, B., Hoff, T., "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania." Clean Power Research, 2012.

[101] PacifiCorp 2015 Integrated Resource Plan, p. 146.

[102] PacifiCorp 2017 Integrated Resource Plan, p. 192.

[103] Clean Power Research, "Value of Solar in Utah," at p. 11. (January 2014).

Q. WHAT DO YOU CONCLUDE FROM THESE ESTIMATES OF OTHER BENEFITS FROM DSG?

A. Based on the available information from an extensive number of studies, taking into account any of these other benefits from DSG will significantly increase RMP's estimate of benefits, and further confirm that the benefits of the Utah residential NEM program exceed its costs. These estimates of other benefits also strongly support the conclusion that the value of export energy provided by residential NEM customers is well in excess of the avoided cost of wholesale purchases and line losses, as RMP incorrectly suggests.

VI. <u>Problems Associated with RMP's Proposed Rate Design</u>

Q. SHOULD THE COMMISSION ESTABLISH A SEPARATE RATE CLASS FOR NEM CUSTOMERS?

A. No. As explained above, while there are differences between residential NEM and non-NEM due to the fact that NEM customers periodically generate excess electricity, that fact does not *ipso facto* make them sufficiently distinct to justify treatment in a distinct rate class. As noted above, the load factors and monthly consumption of NEM customers is within the range of that observed for non-NEM customers (based on the small sample of customer information collected by RMP). Furthermore, RMP has provided no evidence that residential NEM customers have caused it to incur significant incremental costs as a result of their installation and use of DSG systems.

Q. HAS RMP CONDUCTED ANY STUDIES OF THE IMPACT OF ITS PROPOSED NEM RATE CHANGES ON THE ROOFTOP SOLAR INDUSTRY IN UTAH?

A. No.[104]

[104] RMP response to EFCA data request 1.16.

Q. HAS RMP ANALYZED THE IMPACT OF ITS PROPOSED NEM RATE CHANGES ON FUTURE ENERGY CONSUMPTION BY RESIDENTIAL NEM CUSTOMERS?

A. No.[105]

Q. SHOULD THE COMMISSION CHARGE RESIDENTIAL NEM CUSTOMERS A DEMAND CHARGE?

A. No. As a threshold matter, it would be unduly discriminatory for RMP to impose a demand charge only on residential NEM customers, while not imposing such a charge on other residential customers. If RMP has concluded that it is under-recovering costs due to its current volumetric energy residential rate design, that is an issue associated with all of its residential customers, not just its NEM customers; and that is an issue that is best addressed in a full rate proceeding, which RMP has not yet filed. Second, demand charges have long been almost exclusively used for commercial and industrial customers, who tend to be more sophisticated than residential customers in managing their demand, and who have much larger peak usage to manage. There is no evidence that demand charges are effective at reducing residential customers' peak energy consumption,[106] nor have any studies adequately evaluated customer acceptance of demand charges.[107] Given the lack of empirical evidence, the Commission should not approve RMP's proposed demand charge. Third, RMP's proposed demand charges would be ineffective in reducing system peak load, as they are intended to reduce an individual customer's peak use of the utility's generation, transmission, and distribution network, and not to reduce aggregate system peak load, which is what drives most system infrastructure investment needs. In contrast, experience with TOU rates shows that, if they are well designed, they can reduce system peak demand and total energy consumption while also being accepted

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[105] RMP response to EFCA data request 1.17.

[106] James Sherwood, et al., "A Review of Alternative Rate Designs," (Rocky Mountain Institute, May 2016), at p. 56.

[107] Id., at p. 56.

by customers.[108] Lastly, imposing a demand charge on NEM customers would seriously impede the further growth of residential DSG in Utah, and it would fail to send appropriate price signals to customers.

Q. HAS RMP CONDUCTED ANY RESEARCH REGARDNG HOW THE PUBLIC IS LIKELY TO REACT TO THE PROPOSED RESIDENTIAL DEMAND CHARGE?

A. No.[109]

Q. CAN RESIDENTIAL NEM CUSTOMERS VIEW THEIR PEAK DEMAND?

A. No.[110]

Q. IF NOT, HOW DOES RMP EXPECT RESIDENTIAL CUSTOMERS TO ASSESS THEIR DEMAND IN REAL-TIME TO MANAGE THEIR DEMAND CHARGES?

A. RMP suggests that residential NEM customers will be able to review their demand as follows: "[m]uch like a residential customer can now go and read its meter to calculate the total quantity of energy that has been consumed so far during the monthly billing period by subtracting the prior read from the present, a residential customer who is on a tariff under which it is subject to demand charges may read what its highest on-peak kilowatt (kW) is so far for the monthly billing period."[111] RMP's suggestion in no way allows for residential NEM customers to actually manage their demand charges during the hours in which they will be determined; or to identify in which specific hour they are likely to be set; or even to know when they have been set and in what amount (until they are billed by RMP after the fact).

[108] James Sherwood, et al., "A Review of Alternative Rate Designs," (Rocky Mountain Institute, May 2016), at p 45.

[109] RMP response to EFCA data request 1.18.

[110] RMP response to EFCA data request 1.21.

[111] RMP response to EFCA data request 1.22.

Q. WHY WOULD A DEMAND CHARGE FOCUSING ON A RESIDENTIAL CUSTOMER'S PEAK CONSUMPTION BE INEFFECTIVE IN REDUCING SYSTEM PEAK DEMAND?

A. A single household's peak usage is too small to be a significant driver of system-wide costs, and it can vary significantly among customers. Aggregate system peak usage is what drives a utility's fixed costs. This aggregate system peak corresponds closely to particular times in each season, but it corresponds poorly to the demand peaks of many individual residential customers, which often occur outside of the system peak. Therefore, even if a demand charge were to cause an individual's peak usage to decrease, the aggregate system demand could actually increase during peak times. Moreover, RMP's proposed demand charges fail to send the right customer incentives regarding energy consumption.

Q. WHY DOES RMP'S PROPOSAL FOR DEMAND CHARGES FAIL TO SEND THE RIGHT CUSTOMER INCENTIVES REGARDING CONSUMPTION?

A. A demand charge does not provide an easily "actionable" price signal to consumers. RMP's customers do not have real-time metering, and even if they did, it would be impossible for them to sufficiently monitor their real-time usage to try to determine when their peak demand is likely to occur, and to reduce their consumption during that unknown peak hour. Once their peak demand has been calculated for a given time period, they face very little incentives to further reduce their consumption (other than the retail rate itself). Indeed, since RMP proposes to combine a new demand charge and increased monthly customer charge with a decrease in volumetric energy rates for NEM customers (i.e., increasing the fixed component of a NEM customer's monthly bill, while reducing the variable component), this rate design will encourage *increased* energy consumption by NEM customers, while reducing incentives for energy efficiency. If RMP wants to send customers actionable price signals to reduce peak consumption and encourage energy efficiency, it should have proposed TOU rates instead.

Q. WHY ARE TOU RATES PREFERABLE TO DEMAND CHARGES AS A WAY OF PROVIDING PRICE SIGNALS TO REDUCE PEAK CONSUMPTION?

A. Unless RMP provides extensive outreach to educate customers about demand charges, it will be difficult for customers even to differentiate between energy (kWh) and demand (kW), much less to actually respond to price signals. Also, there is generally no way for customers to even know when their demand charges are being set; such knowledge would require near-constant monitoring of real-time consumption data, which RMP does not collect (much less disseminate to customers). As a result, even relatively innocuous household activities at a particular time can result in a significantly higher customer bill (and large variations in customer bills), even though such actions have a *de minimis* impact on the system peak. TOU rates, in contrast, are much easier to understand: electricity consumption during peak hours (known in advance) is more expensive than during non-peak hours. Conceptually, TOU rates are also easily understandable, since customers are accustomed to paying higher prices when goods or services are scarce, such as airfares at peak travel times.

Q. WOULD IMPOSING A DEMAND CHARGE ON RESIDENTIAL NEM CUSTOMERS BE CONSISTENT WITH COST CAUSATION PRINCIPLES?

A. No. A residential NEM customer's energy consumption and production characteristics do not "cause" costs that have been already incurred in the past. Most of RMP's demand-related fixed costs are sunk, and thus a demand charge would not reflect the actual incremental costs caused by residential NEM customers. At current low levels of DSG penetration in Utah, NEM customers *at most* could only cause some amount of incremental costs associated with secondary lines and transformers; it important to emphasize, however, that RMP has not provided any evidence that NEM customers have actually caused such incremental costs (other than costs for which NEM customers already reimburse RMP). Nevertheless, even if NEM customers were to cause such costs, they would be a very small fraction of the existing fixed costs incurred by RMP to serve all customers. Thus, the only rationale for RMP to impose a demand charge on residential NEM customers would be to reduce the incentives for residential customers to adopt DSG, by making the value proposition for customers more expensive, more difficult to understand, and more uncertain, thereby reducing RMP's risks of an under-recovery of costs due to lower future sales. RMP, however, has not provided any evidence that it is under-recovering costs, and if so, that residential NEM customers are the primary reason for that under-recovery.

Q. SHOULD THE COMMISSION ADOPT RMP'S PROPOSAL TO INCREASE FIXED MONTHLY CHARGES FOR RESIDENTIAL NEM CUSTOMERS?

A. No. The Commission should also reject RMP's proposal to increase residential NEM customers' fixed monthly charges to $15/month. If RMP believes that it is under-recovering its costs from residential customers and that it is necessary to move to a higher fixed vs. variable rate structure as a result, it should advance that proposal in the context of a full rate case, where it can be fully vetted. Moving towards a higher fixed vs. variable rate structure can have significant negative consequences, i.e., by reducing customer incentives to reduce energy consumption and adopt energy efficiency measures. In any event, the Commission should reject RMP's proposal to charge higher monthly fixed costs only to residential NEM customers as unduly discriminatory, and as intended only to reduce the financial incentives of residential customers to invest in DSG systems.[112]

[112] RMP also asserts that the monthly customer charge of $15 is designed to recover certain components of the distribution system, such as costs related to line transformers (see Steward testimony, lines 402-411). However, these costs should be removed from the monthly customer charge for residential NEM customers, since many distribution facilities such as line transformers are also shared with other residential non-NEM customers.

Q. SHOULD THE COMMISSION ADOPT RMP'S PROPOSED ENERGY RATE FOR RESIDENTIAL NEM CUSTOMERS?

A. No. The Commission should also reject RMP's proposal to combine a demand charge and an increased fixed monthly charge with an energy charge of 3.8143 cents/kWh for all the reasons I discussed above: if there is an argument to be made to move the residential rate structure to a higher fixed vs. variable component, RMP should make that case in a full rate proceeding, and it should make any such changes to all residential rates. In addition, by combining demand charges and increased fixed charges with a lower variable energy component for NEM customers, RMP is proposing to dramatically lower the value of the energy credit provided to residential DSG customers for the excess energy they produce and export to the local distribution system. In effect, the value of the excess energy produced by NEM customers would drop from the current retail rate (valued at up to 14.5 cents/kWh) to 3.8143 cents/kWh. RMP's proposal significantly underestimates the benefits of DSG, and thus its proposed compensation is inconsistent with its value.

Q. DO YOU THINK RMP'S PROPOSED ENERGY RATE IS SUFFICIENT TO COMPENSATE NEM CUSTOMERS FOR THEIR EXCESS ENERGY?

A. No. RMP's proposal to compensate NEM customers for their excess energy at 3.8143 cents/kWh would not compensate residential DSG customers for the environmental, capacity, reliability, and peak load reduction benefits that they provide to the system. Second, providing such a low credit value would be unduly discriminatory towards NEM customers. A neighboring non-NEM customer who is consuming the excess energy generated by a NEM customer in the middle of a hot summer day will be paying RMP up to 14.5 cents/kWh, while RMP is compensating the NEM customer at an effective rate of only 3.8143 cents/kWh. RMP has provided no evidence demonstrating that it is appropriate to allocate in effect 10.7 cents/kWh in costs for the use of the local distribution circuit to enable that transfer of energy from one residential customer to another neighboring customer. For purposes of comparison, under RMP's "Subscriber Solar" program, participating residential customers pay RMP 3.9783 cents/kWh to account for their use of the transmission and distribution grid (plus 7.7250 cents/kWh to account for RMP's generation costs) – for all power purchased under the program, regardless of whether that power is consumed by subscribing customers in the middle of the day or in the middle of the night. Thus, it would be unreasonably discriminatory for RMP to compensate NEM customers at only 3.8143 cents/kWh, rather than at a rate that reflects the fact that they only make use of the local distribution network (the local feeder lines) to deliver their exported generation to neighboring residential customers. Third, and perhaps most importantly, RMP's proposed excess energy credit rate would also seriously impede the further growth of residential DSG in Utah, and it would fail to send appropriate price signals to customers.

Q. DOES RMP'S PROPOSED ENERGY RATE SEND THE RIGHT PRICE SIGNALS TO RESIDENTIAL NEM CUSTOMERS REGARDING CONSUMPTION?

A. No. A very low energy rate, as RMP proposes, does not incentivize NEM customers to reduce their overall energy consumption, either in the aggregate or in peak time periods, when such a reduction in demand is most valuable. Furthermore, the fact that RMP's proposed low energy rate also substantially lowers the value of residential NEM customers' export credits – undercompensating them for the value of their exported energy – reflects RMP's erroneous portrayal of such excess generation as a "burden" on the system, rather than as a benefit that provides significant value in reducing peak consumption.

Q. ARE THERE OTHER PERVERSE INCENTIVES CREATED BY RMP'S PROPOSED RATE STRUCTURE FOR RESIDENTIAL NEM CUSTOMERS?

A. Yes. RMP's proposal for high demand charges and low energy credits, exacerbated by the uncertainty associated with being placed in a distinct rate class, would incentivize customers who want to obtain the environmental benefits of DSG to pursue an "autarky" (or self-sufficiency) objective, i.e., to manage their electricity investments and consumption to entirely disconnect from RFP's transmission and distribution grid. From both a cost-recovery and efficiency perspective, autarky (or grid independence) is an inefficient outcome. It encourages DSG customers to install relatively expensive batteries in order to be able to effectively replicate the features of the current NEM program; even though relying on the interconnected grid as a "virtual battery" would be more cost-effective (from a societal perspective) and would at least make some positive contribution to RMP's recovery of its fixed costs. I am not in any way suggesting that the Commission should discourage the integration of residential battery storage systems with DSG. Quite the contrary, if such systems are integrated into a utility's grid management and dispatch protocols, there are considerable reliability, resiliency, and efficiency benefits that can be obtained. Battery storage (whether utility-scale or residential) also can provide important system efficiency benefits at high levels of renewable penetration. However, to the extent that such investments only become economical for customers as a result of radical changes in NEM programs, such as those proposed by RMP, and encourage DSG customers to isolate themselves from the grid, such a result would deprive all customers – NEM and non-NEM – of the efficiency and reliability benefits associated with making optimal use of the electrical grid.

VII. <u>Recommendations</u>

Q. DO YOU RECOMMEND THAT THE COMMISSION ADOPT ANY CHANGES TO ITS CURRENT NET METERING PROGRAM?

A. No, I do not consider changes to the current NEM program to be necessary at this time.

Q. IF THE COMMISSION IS CONCERNED ABOUT THE LONG-TERM IMPACTS OF HIGHER DSG PENETRATION RATES IN THE FUTURE, HOW SHOULD IT ADDRESS THOSE CONCERNS?

A. I understand that the Commission may be concerned about the rate of recent growth in residential DSG, and thus it may want to make gradual changes to the NEM program (or a successor to this program) in order to account for potentially higher levels of penetration, and changing costs and benefits, over time. Regulators often apply the principle of gradualism in making changes to rates or rate designs in order to prevent "rate shock," to prevent potential unintended consequences, and to allow new information to be incorporated into decision-making as it becomes available. These considerations are particularly important when, as is the case here, a policy change is implemented based on sparse or incomplete information.

Q. IF THE COMMISSION WERE TO IMPLEMENT GRADUAL CHANGES TO THE NEM PROGRAM, WHAT TYPES OF CHANGES WOULD YOU SUGGEST?

A. If the Commission determines that it is important for residential NEM customers to further reduce their load during peak hours, I recommend that RMP gradually implement a TOU rate structure for residential NEM customers (and eventually for all residential customers). Economists have long advocated TOU rates as sending better price signals than a time-invariant rate structure. TOU rates come closer to reflecting the time-varying value of the energy consumed, including both time-varying generating costs and transmission congestion costs. TOU rates also provide clear, easily understandable incentives for customers to shift consumption from high-cost to low-cost time periods. By providing incentives to reduce consumption in peak periods, TOU rates contribute to reductions in peak load, which in turn helps to reduce the need for future infrastructure investments. Indeed, in this proceeding, RMP has defined the reduction in coincident peak load as an important measure of system benefits from DSG, since RMP's investment needs are mostly driven by peak demands on the system.[113] Thus, the best way to obtain additional benefits from NEM customers would be to move them gradually to TOU rates to enable further reductions in their peak loads.

Q. WHY DO YOU SUGGEST IMPLEMENTING TOU RATES GRADUALLY?

A. In this instance, a gradual implementation of TOU rates is appropriate, since RMP residential customers do not currently have meters compatible with TOU rates. Such meters also presumably cost more than either RMP's standard meters or the current bidirectional meters for NEM customers (for which NEM customers reimburse RMP). It also may take some time for RMP to integrate a TOU rate system for NEM customers into its billing systems, although RMP's current experimental "time-of-day" rider (Schedule 2) should facilitate this.

Q. WOULD IT BE CONSISTENT WITH PRINCIPLES OF GRADUALISM AND COST CAUSATION TO GRANDFATHER EXISTING NEM CUSTOMERS, IF ANY CHANGES TO THE NEM PROGRAM ARE ADOPTED?

A. Yes. As I discuss above, RMP has provided no evidence that current residential NEM customers have caused RMP to incur additional incremental costs to date (other than the costs that NEM customers have reimbursed). Residential NEM customers also invested in solar PV systems based on the economics of the current NEM program. In addition to issues of equity, the failure to grandfather existing residential NEM customers would increase the uncertainty faced by future residential customers as they consider installing DSG systems, and this uncertainty will tend to reduce the level of future customer investments, all else equal.

Q. ARE THERE CHANGES TO THE EXPORT CREDITING MECHANISM THAT THE COMMISSION MIGHT ADOPT TO ADDRESS CONCERNS ABOUT

[113] RMP response to Vote Solar data request 4.4.

SHOULDER SEASON EXPORTS IN A FUTURE HIGH-PENETRATION SCENARIO?

A. Yes. One of RMP's concerns about the current NEM program appears to be that NEM customers may have significant net exports during shoulder months when their electricity demand is low, which are credited against consumption in summer months when their demand is high.[114] This can be a concern if the value of the net exports is significantly lower in the shoulder months, as compared to the NEM customers' consumption in summer months (against which the shoulder period net exports are credited). One way to address this concern would be to implement a monthly netting process, rather than crediting exports to future months on a kWh-for-kWh basis over an entire year. Based on the data RMP has produced, I do not consider this to be a particularly serious concern, given that residential NEM customers on average still have significant net consumption (i.e., load in excess of their exports) even in shoulder months. Nevertheless, it may be an alternative for the Commission to consider, if the situation were to change with greater residential DSG penetration in the future.

Q. DO YOU THINK IT IS APPROPRIATE TO REDUCE THE EXPORT CREDIT BELOW THE FULL RETAIL RATE?

A. No. As discussed, the retail rate reflects the amount that RMP receives from other residential customers when a residential NEM customer exports energy that then flows to support a neighboring customer's consumption. Because RMP has not shown that it incurs any significant incremental costs as a result of this process, the Commission should retain the current retail rate for NEM exports, at least until residential DSG penetration rates reach significantly higher levels. Since the costs and benefits of residential DSG are likely to change as levels of penetration increase, it may be reasonable for the Commission to re-evaluate the appropriate export credit amount once Utah reaches significantly higher levels of penetration.

[114] Direct Testimony of Gary W. Hoogeveen, at lines 196 – 198.

Indeed, over time, as complementary technologies are developed and further deployed, it is likely that the costs of DSG will decrease and the benefits will increase, such that future reductions in the export credit may not be warranted, even at significantly higher penetration levels. If the Commission disagrees with my conclusion and determines to reduce the value of the export credit in the near future, however, any such change should be adopted only gradually. If such a reduction were implemented gradually, it would ensure against both a sudden halt to DSG installations, and a sudden surge of customers seeking to "lock in" the financial benefits from DSG before the program becomes less attractive. The principle of gradualism also would allow the Commission to periodically revisit the appropriate amount of the excess generation credit, as residential DSG achieves higher penetration, as the development and deployment of complementary technologies continue, and as the corresponding system costs and benefits change over time.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE COMPLEXITY OF REDUCING THE EXPORT CREDIT BELOW THE FULL RETAIL RATE FROM A CUSTOMER PERSPECTIVE?

A. Yes, and that is an additional reason why any such changes should be implemented gradually. The current "kWh-for-kWh" crediting is easily understandable to residential customers considering installing DSG systems. The full "kWh-for-kWh" crediting is also more consistent with the economic position of a consumer who is considering installing solar panels. Consumers who install solar panels are interested in reducing their total electricity expenditures and in reducing their environmental footprint; they do not install solar panels in order to sell their generation output to RMP. From a consumer's perspective, a simple kWh-for-kWh crediting mechanism is consistent with the economic purpose of their investment decision. The increased complexity of lower export credits relative to higher energy charges also makes it more likely that some customers will defer or decline to make the investment –

simply because increased complexity leads to increased uncertainty, and increased uncertainty tends to reduce the amount of investment. And the greater the reduction in the value of the export credit, the more likely it is that the growth of residential DSG in Utah will come to a halt, preventing Utah from obtaining the benefits that DSG can provide over the long-term.

Q. COULD REDUCING THE EXPORT RATE BELOW THE FULL RETAIL RATE CREATE ANY ADVERSE INCENTIVES FOR CUSTOMER ENERGY USE?

A. Yes. If the Commission were to adopt an export credit that is substantially below the retail rate, it will incentivize NEM customers to shift their energy consumption from off-peak to peak time periods, when their DSG systems are generating. Consider a scenario in which the (marginal) retail energy rate that NEM customers face is 14.5 cents/kWh, and a (hypothetical) export credit were only valued at 5 cents/kWh, for example. Any NEM customer with a "moveable" load, e.g., an electric vehicle or a programmable thermostat, would have a strong incentive under such a rate structure to shift as much of their load as possible from the night to the middle of the day – since the 5-cent export credit they would otherwise earn from over-generating in the middle of the day would be far less than the 14.5-cent retail rate that the NEM customer would pay when consuming the corresponding amount of energy at night.

Q. FROM A SYSTEM PERSPECTIVE, IS IT DESIRABLE FOR NEM CUSTOMERS TO SHIFT THEIR CONSUMPTION SO THAT THEY INCREASE THEIR PEAK CONSUMPTION SIMPLY TO REDUCE THEIR VOLUME OF EXPORTS?

A. No, not at current penetration levels and in the absence of significant reverse flows caused by NEM exports. RMP's costs to generate or purchase electricity in the middle of the day are almost always higher than in the middle of the night. High loading during the day (particularly on hot days) is also when both congestion and line losses are greatest, even when system load is less than its "needle peak." From a system perspective, RMP reduces costs by having all customers – NEM and non-NEM customers alike – shift their consumption from peak hours to off-peak hours, not the reverse.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS FOR THE COMMISSION REGARDING RESIDENTIAL DSG?

A. Yes. Rather than simply considering NEM customers as a "cost" to other customers, the Commission (and RMP) should consider residential DSG as an opportunity for testing and deploying new technologies, as well as for collecting important information regarding customer behavior. RMP does not currently have advanced metering infrastructure ("AMI"). Since new NEM customers need new bidirectional meters, this may provide RMP an opportunity to include additional functionality in these meters that would enable broader system benefits. This additional functionality could include the ability to: capture hourly consumption data that would enable RMP to implement TOU rates, as discussed above; provide real-time information to enable RMP to identify local service outages or other system problems more rapidly; or integrate with "smart inverters" to enable RMP to use DSG to provide reactive power when needed. RMP could also help residential customers or local solar providers to optimize the placement of DSG on constrained locations of the local distribution network, where it would be of greatest value to all customers – a collaborative approach that some utilities in other parts of the country appear to be advancing (e.g., Hawaii and Minnesota).[115] Similarly, if increased installations of westward-facing DSG systems can provide additional system benefits by further reducing the system peak load, the Commission should consider establishing financial incentives to accomplish this result, commensurate with

[115] For Minnesota, see Xcel Energy, Distribution System Study, Distribution Grid Modernization Report, Docket No. E002/M-15-962, December 1, 2016. For Hawaii, see https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/locational-value-maps. Further support for collaborative approaches can be found in a 2014 study by the Solar Electric Power Association and EPRI, "Utility Strategies for Influencing Locational Deployment of Distributed Solar."

the incremental benefits and accounting for the reduced output of such systems, as some other utilities and states have done.[116]

Q. SHOULD THE COMMISSION CONSIDER OTHER TARIFF CHANGES TO ENABLE BROADER RESIDENTIAL CUSTOMER PARTICIPATION IN DSG, EVEN IF THEY ARE NOT HOMEOWNERS WITH SUITABLE ROOFTOP LOCATIONS?

A. Yes, the Commission should also consider expanding the residential DSG program to allow for "community solar" programs, which have attracted increasing interest in a number of states (including in other states with traditional cost-of-service rate regulation, as in Utah). Community solar programs allow somewhat larger-sized DSG systems (but generally less than 1 or 2 MW) to be connected directly to the local distribution network. Community solar programs can range from commercial-sized rooftop systems installed on a community structure (e.g., a 22-kW system installed on a church, as in Maryland) to somewhat larger "solar gardens." These projects allow for lower installed costs relative to typical residential systems and potentially higher output, while still providing the "distributed" benefits of DSG (with additional locational benefits possible if located on constrained portions of the distribution network). Like residential DSG, community solar programs provide a way for individuals (or solar companies) to use their own capital (rather than the utility's capital) to increase the amount of solar generation in a given service territory, while also providing non-homeowners an opportunity to participate in DSG programs. Since crediting mechanisms can be more complex with community solar programs than typical NEM programs, enabling community solar would likely require a tariff change. I am not suggesting that the Commission

[116] In 2014, the California Energy Commission approved guidelines providing incentives for west-facing solar systems. *See*: Renewable Energy World, "9% of Solar Homes are Doing Something Utilities Love. Will Others Follow?" December 2, 2014. Available at: http://www.renewableenergyworld.com/ugc/articles/2014/12/9-of-solar-homes-are-doing-something-utilities-love-will-others-follow.html (last accessed June 7, 2017). The article also reports some utilities offering higher TOU-based compensation for late afternoon vs. mid-day exports of excess customer generation.

should necessarily require such a tariff change as part of this proceeding, but this should be one of the longer-term goals for the Commission.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.