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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power to Establish Export Credits for Customer Generated Electricity	**Docket No. 17-035-61 Phase 2**

REVISED AFFIRMATIVE TESTIMONY OF MICHAEL MILLIGAN, PH.D.

ON BEHALF OF

VOTE SOLAR

May 8, 2020

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I.   INTRODUCTION

Q.   Please state your name and business address.

A.   My name is Michael Milligan. My business address is 9584 W 89th Avenue, Westminster, Colorado 80021.

Q.   On whose behalf are you submitting this revised direct testimony?

A.   I am submitting this revised testimony on behalf of Vote Solar.

Q.   By whom are you employed and in what capacity?

A.   I am principle consultant with Milligan Grid Solutions, Inc., an independent power system consulting firm.

Q.   Please summarize your education and professional experience.

A.   I have a Ph.D. in Economics from the University of Colorado and a B.A. from Albion College in Mathematics. My experience includes working in the power system industry for about seven years. I then was Principal Researcher at the National Renewable Energy Laboratory ("NREL") for 25 years, where I authored/co-authored more than 225 technical reports, journal articles, and book chapters. I served on multiple technical committees at the Western Electricity Coordinating Council ("WECC") and the North American Electric Reliability Corporation ("NERC"), which is the official reliability regulator in the U.S., and I was a charter member of the IEEE Wind and Solar Coordinating Committee. For many years, I served on the International Energy Agency Task 25 – Large-scale Wind Integration – research team where I led multiple international research papers

21   on integrating wind into the power system. As an independent consultant, my clients have

22   included NERC, the Electric Power Research Institute, the Southwest Power Pool,

23   GridLab, and multiple trade and educational/research organizations. Exhibit 1-MM

24   provides a statement of my qualifications and experience.

25   **Q.   Have you previously testified before the Utah Public Service Commission**

26   **("PSC" or "Commission")?**

27   A.   No.

28   **II.   PURPOSE OF TESTIMONY**

29   **Q.   What is the purpose of your testimony in this proceeding?**

30   A.   The purpose of my testimony is to quantify several aspects of the value of exported

31   customer generation ("CG") on the Rocky Mountain Power ("RMP") system to support

32   the overall valuation provided in the testimony of Vote Solar witness, Dr. Carolyn Berry.

33   Specifically, I will address three categories of value: (i) Avoided Energy Costs;

34   (ii) Avoided Generation Capacity Costs; and (iii) Avoided Emissions volume.

35   Currently, over 99% of customers with CG in RMP's Utah service territory have

36   distributed generation ("DG") solar.[1] As a result, I focus my analysis of the value of CG

37   exports on the characteristics of DG solar. It is my understanding that the compensation

38   mechanism for exported CG that will be approved in this case will take effect in 2021.

39   Accordingly, all of my results are provided in 2021 dollars and cover the 20-year period

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[1] Vote Solar, *Revised Affirmative Testimony of Sachu Constantine*, lines 175–77.

40   2021-2040. I focus on this time period because it provides an accurate representation of

41   the value of CG commensurate with the minimum expected lifetime of DG solar.

42   The *first* value that I quantify in my testimony is the value of avoided energy costs

43   associated with CG exports. When solar energy is generated at the customer's location and

44   exported to the grid, that energy flows to the nearest load sink and offsets the amount of

45   energy that needs to be provided by RMP. The reduction in electricity demand is matched

46   by either a reduction in electricity produced by RMP or in an additional unit of energy that

47   RMP can sell to a neighboring utility. My analysis examines the specific attributes of

48   exported CG in RMP's Utah service territory to derive a value for avoided energy costs

49   inclusive of avoided line losses.

50   The *second* value that I quantify is the avoided generation capacity cost. To the extent that

51   CG exports are produced during times of system peak, the required capacity that RMP

52   needs to acquire to serve its demand will decrease. In my testimony, I calculate the value

53   of this avoided capacity need that results from CG exports.

54   *Finally*, I calculate avoided carbon dioxide emissions ("CO_2") that result from CG exports

55   by examining the emissions profile of RMP's fossil-fuel powered fleet and how those

56   resources may change over time.

57   The results of each of my analyses were provided to Dr. Berry who then provided the total

58   assessment of the value of CG.

59   **III.   SUMMARY OF RECOMMENDATIONS**

60   **Q.   Please provide a brief summary of your recommendations.**

61 A.   I recommend that the avoided cost results from my testimony be adopted in the

62 valuation of CG exports to inform just and reasonable compensation that captures the value

63 of this resource. I find that CG exports provide benefits to RMP in the form of avoided

64 energy costs, avoided line losses, avoided generation capacity costs, and avoided carbon

65 emissions.

66 As described in full detail in my testimony, I recommend the following values be

67 incorporated into the value of CG analysis:

68   1. An avoided energy value of 3.55 c/kWh;

69   2. An avoided line loss value of 0.31 c/kWh;

70   3. An avoided generation capacity value of 1.48 c/kWh; and

71   4. Avoided carbon emissions based on my annual projections that average to 232

72   tons/year.

73 My lack of comments on RMP's affirmative testimony filed on February 3, 2020 should

74 not be interpreted as acquiescence or agreement with RMP. I reserve the right to express

75 additional opinions, to amend or supplement the opinions in this testimony, or to provide

76 additional rationale for these opinions as additional documents are produced, and new facts

77 are introduced during discovery and trial. I also reserve the right to express additional

78 opinions in response to any opinions or testimony offered by other parties to this

79 proceeding.

IV.   AVOIDED ENERGY COSTS

Q.   What drives energy costs for a utility such as RMP?

A.   The cost of energy is driven primarily by fuel costs and maintenance costs. These costs are variable costs – they depend directly on the volume of electricity produced. Demand for electricity varies significantly from hour to hour, day to day, and even year to year. To ensure demand is met at all times, utilities, including RMP, utilize complex software and telecommunications systems so that the electric energy can be supplied reliably and at minimum cost. The computer software evaluates the suite of available resources – including their energy cost, physical characteristics, and capabilities – and develops a generation schedule for each resource that takes all of these items into account. This is generally referred to as a "least-cost dispatch" (also called "economic dispatch" because the solution is economic—the lowest-cost solution to meet demand) and is standard operating practice in the power system industry.

Figure 1 shows how demand generally varies throughout the day, with a representation of weekly demand on the lower side of the diagram.[2] At low levels of demand, the cost-minimization algorithm chooses the resource with the lowest marginal cost,[3] followed by the resource with the next-lowest marginal cost if needed. The process generally occurs at intervals of 5-minutes up to one hour throughout the day; PacifiCorp is a member of the Western Energy Imbalance Market, which carries out this dispatch process every five

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[2] *See* Michael Milligan, Erik Ela, Jeff Hein, Thomas Schneider, Gregory Brinkman, and Paul Denholm, *Renewable Electricity Futures Study Volume 4: Exploration Bulk Electric Power Systems: Operations and Transmission Planning,* National Renewable Energy Laboratory, v. 4, p. 25-1, June 2012, https://www.nrel.gov/docs/fy12osti/52409-4.pdf.
[3] The resource with the lowest marginal cost is the cost of producing one additional MWh or GWh.

99   minutes.[4] At the time of peak demand, if all low-marginal-cost resources are already being

100   dispatched, relatively expensive resources will need to be deployed. The economic dispatch

101   model will, however, minimize total production cost by avoiding the use of these expensive

102   resources whenever possible.[5] Minimizing production cost is also a general requirement

103   imposed on utilities by state regulatory commissions.

104   The "least-cost" nature of the dispatch process guarantees that resources with zero or near-

105   zero marginal cost are chosen before a more expensive resource is chosen. Examples of

106   these low-cost resources include hydro power, wind power, and solar power. Although

107   there are exceptional times when these resources may be curtailed, they are utilized

108   whenever system balance and reliability can be maintained. Viewing Figure 1 in the

109   context of economic dispatch, if a new inexpensive resource becomes available, it will

110   displace the resource at the "top" of the stack as the displaced resource is the highest cost

111   resource.[6]

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[4] Western Energy Imbalance Market, *About*, 2020, https://www.westerneim.com/Pages/About/default.aspx.
[5] For a short description of common power system models, see Erin Boyd, *Power Sector Modeling 101*, U.S. Department of Energy – Office of Energy Policy and Systems Analysis, https://www.energy.gov/sites/prod/files/2016/02/f30/EPSA_Power_Sector_Modeling_FINAL_021816_0.pdf.
[6] Michael Milligan, Erik Ela, Bri-Mathias Hodge, Brendan Kirby, Debra Lew, Charlton Clark, Jennifer DeCesaro, and Kevin Lynn, *Cost-Causation and Integration Cost Analysis for Variable Generation*, National Renewable Energy Laboratory, June 2011, https://www.nrel.gov/docs/fy11osti/51860.pdf; *see also, e.g.*, U.S. Energy Information Administration, *Electric generator dispatch depends on system demand and the relative cost of operation* (Aug. 17, 2012), https://www.eia.gov/todayinenergy/detail.php?id=7590.
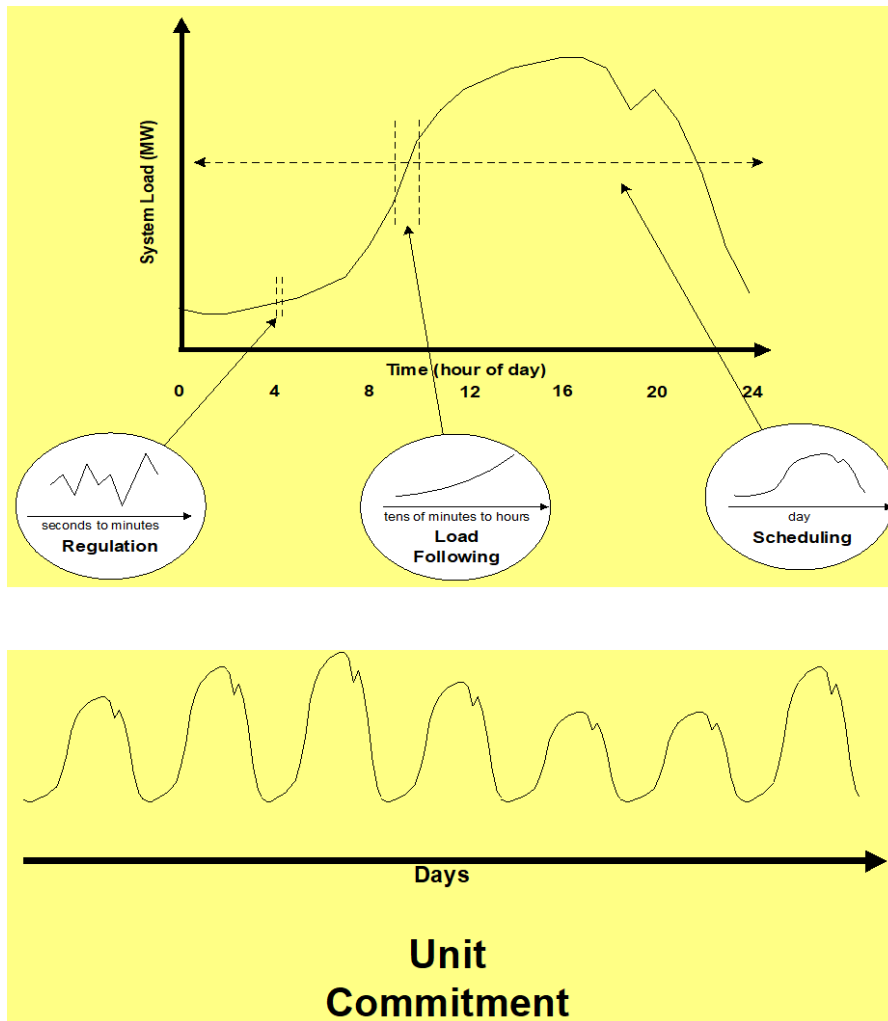
Figure 1. Sample daily and weekly electricity demand

The discussion above has particular relevance for the energy value of DG solar. Solar power, generated at a customer location on the distribution network, will reduce demand, which then reduces the need for electricity from the most expensive generator on the system. Thus, the value of the solar-generated energy is the cost of the energy from the most expensive resource. This concept is illustrated by a hypothetical supply curve from the U.S. Energy Information Administration in Figure 2. The supply curve shows that resources with low or zero marginal cost, such as solar energy, are dispatched first. As

121   demand increases, higher-cost resources are deployed. Conversely, as demand falls, the

122   operating cost falls as expensive units are taken off dispatch. Solar energy, whether

123   connected to the transmission system or to the distribution system, will displace relatively

124   high-cost resources on the supply curve.
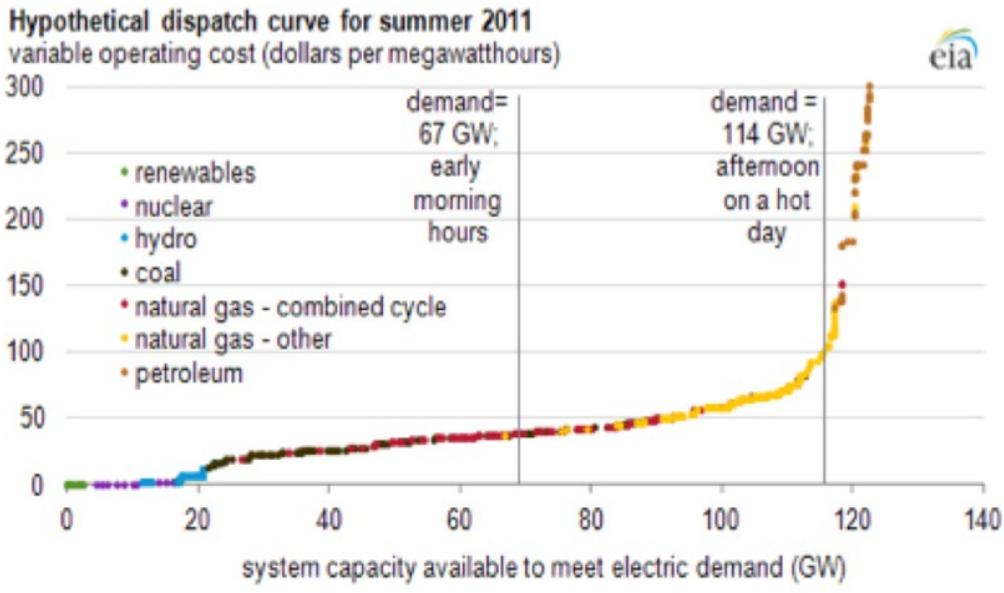
125

126   **Figure 2. Example demand curve shows that renewables are dispatched first because of**
127   **their low marginal cost[7]**

128   The economic dispatch as described above does not consider constraints that may occur on

129   the grid that prevent the least-cost dispatch from being realized. For example, the least-cost

130   resource might be unavailable because it is behind a network constraint, which means there

131   is insufficient transmission or distribution capacity to deliver the energy to the load center.

132   In such situations, an alternative, more expensive resource may be needed to avoid the

133   congested path, which can increase the cost of energy.

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[7] U.S. Energy Information Administration, *Electric generator dispatch depends on system demand and the relative cost of operation* (Aug. 17, 2012), https://www.eia.gov/todayinenergy/detail.php?id=7590.

134   During extreme peak periods, the utility may need to deploy its most expensive resource

135   (highest marginal cost resource) to meet demand. In some cases, it may be necessary to

136   import electricity from a neighboring system during such a peak period. The value of

137   energy in such a transaction is determined by a combination of the marginal cost of each

138   of the two neighboring systems, along with potential network constraints. When a

139   transaction is carried out, the price paid is a direct indicator of the value to both the buyer

140   and seller.

141   In the U.S. Western Interconnection,[8] there are several large substations that are often used

142   as electricity delivery points for market transactions between utilities. Utilities have well-

143   developed trading frameworks in place at these market hubs that facilitate common market

144   products.[9] Many utilities that trade in these hubs have a desire to forecast future market

145   fundamentals—including detailed price forecasts for each trading hub covering time

146   periods from the present to the future—so that they can plan how best to invest in new

147   facilities to meet future demand. The trading price at any hub at a given time will depend

148   upon the utilities' positions on their supply curve for the hour in question, the internal

149   resources that are available and at what price, and what bids from other resource-owners

150   are available, along with other information such as projected transmission congestion.

151   RMP participates in some of these markets, and it has developed a comprehensive price

152   forecast for its key trading hubs, hourly by hub, through 2040. This price forecast is useful

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[8] The Western Interconnection is described on the web site of the Western Electricity Coordinating Council ("WECC"). *The Western Interconnection,* Western Electricity Coordinating Council, https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/The-Western-Interconnection.aspx.
[9] *See, e.g.*, S&P Global, *Methodology and specifications guide, North American Electricity*, p. 8, Feb. 2020, https://www.spglobal.com/platts/plattscontent/_assets/_files/en/our-methodology/methodology-specifications/na_power_method.pdf.

153   for evaluating avoided energy costs associated with exported CG in RMP's Utah service

154   territory.

155   **Q.   How can CG result in avoided energy costs?**

156   A.   For every MWh of CG energy that is produced, the utility reduces its energy

157   delivery requirement to its end-use customers by one MWh. Because power plants are

158   operated according to cost-minimization principles, a low-cost or no-cost resource, such as

159   CG, will cause a reduction in power and energy production for the utility. Since the power

160   system must be in balance at all times according to rules set out by the NERC,[10] if the

161   aggregate increase in CG is 100 MW over an hour, that energy will appear as a reduction

162   in demand on the distribution system and a commensurate amount of generation will be

163   turned down for the hour. Therefore, a power system operator for a utility like RMP must

164   decide which unit(s) to reduce so that there is no excess generation on the grid. In practice,

165   these decisions will be made by sophisticated software tools that are well equipped to

166   handle fluctuations in demand (whether resulting from CG exports or other customer

167   activities).

168   Alternatively, if there is an offer from another utility to purchase the excess energy made

169   available by CG exports, then another resource in a different utility control area must

170   reduce its power for the hour so that it can import the extra power and energy. In this

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[10] NERC balancing standards are described in *Standard BAL-001-2 – Real Power Balancing Control Performance*, North American Electric Reliability Corporation, https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf. NERC's "Balancing and Frequency Control" technical document describes other aspects of the balancing standard including the equation for Area Control Error ("ACE") that shows the relationship between the level of generation, demand, frequency, imports, and exports. NERC Resources Subcommittee, *Balancing and Frequency Control*, North American Electric Reliability Corporation, Jan. 26, 2011, https://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf.

171   scenario, RMP must therefore reduce its dispatch stack or find a buyer for the excess

172   energy. In the first case, the value of displaced energy depends on which unit(s) are reduced

173   and their marginal cost. If 100 MWh is displaced from a combined cycle gas unit with cost

174   of $50/MWh, then the energy value of the CG is 100 MWh x $50/MWh = $5,000. In the

175   second case, the avoided energy value of CG is determined in the market when the power

176   is sold.

177   **Q.   How did you determine the appropriate value of avoided energy costs**

178   **associated with exported CG?**

179   A.   I based avoided energy costs associated with exported CG on the market price for

180   energy in RMP's Utah service territory. I based assumptions regarding market pricing on

181   PacifiCorp's Official Forward Price Curve ("OFPC").[11] The OFPC is updated quarterly

182   and represents PacifiCorp's "official quarterly outlook."[12] It is developed based on market

183   forwards and fundamentals derived from a WECC-wide market model.[13] At the time of

184   writing, the most recently available OFPC was developed September 30, 2019 and

185   provided to Vote Solar under the confidentiality agreement in this Proceeding.[14,15]

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[11] PacifiCorp is the parent company of RMP.
[12] *2019 Integrated Resources Plan*, PacifiCorp, Volume 1, p. 180, October 18, 2019,
https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf.
[13] *Id.*
[14] Exhibit 2-MM, 1909 OFPC (CY2018_2041)_2019 10 10 (min 0.01)###_GLOBAL_csv, RMP's Responses to Vote Solar 9th Set Data Requests – Attach 9.2-1 (Feb. 6, 2020).
[15] The OFPC does not include any assumptions for CO_2 pricing. *See supra* n.12 at 180. As described in more detail in Section VI, I developed a separate analysis of avoided emissions volume to support the avoided carbon costs discussed in the testimony of Dr. Berry.

186   **Q.   Why is the market price a reasonable basis for the determination of avoided**

187   **energy costs?**

188   A.   Market prices provide a measure of value, and the OFPC prices represent

189   PacifiCorp's official assessment of the state of the power system—and the value of

190   energy—at each hour and location from 2020-2040. At electricity trading hubs, any

191   participating utility can offer electricity for sale or bid to purchase electricity, and as its

192   needs change throughout the day, month, and year, a given utility may participate as a

193   buyer during some periods, and a seller at other periods. There may be times at which the

194   utility chooses not to participate.[16]

195   The decision of whether to buy or sell at the trading hub is primarily driven by economics

196   and public service commission oversight that requires cost-effective operation of the power

197   system, subject to reliability constraints. For example, in RMP's case, it may find that there

198   are times during which there is electricity for sale at a price that is lower than what it could

199   generate itself with its incumbent fleet of resources. At other times, RMP might find that

200   it has excess generation (energy) that it could sell in the market, obtaining a higher price

201   than the cost of generating that level of energy.

202   The other utilities that trade at these hubs face the same economic decision. Transactions

203   are therefore characterized when a buyer, who has determined that its cost to purchase is

204   less than its cost to generate (or purchase) from internal resources, finds it economical to

205   buy power. At the same time, the seller has determined that it can generate energy and sell

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[16] For an in-depth discussion of electricity markets, see Daniel S. Kirschen and Goran Strbac, *Fundamentals on Power System Economics* (2d ed. 2018).

206   that energy at a cost that exceeds its marginal cost. The decisions of both buyers and sellers

207   are driven by the relationship between their internal marginal cost and market prices.

208   Specifically, sellers find that their marginal cost is less than the market price, and buyers

209   find that their marginal cost exceeds the market price. Prices at electricity trading hubs

210   represent the characteristics of operational cost for electricity that intersect when a

211   transaction is executed. If RMP were to find that it must commit an additional generating

212   unit to meet demand, but instead realizes that it can buy energy at a lower cost, the value

213   of these additional MWhs is determined by the combined marginal cost curves of the buyer

214   and seller.

215   The market prices that comprise the OFPC represent RMP's best effort to value electricity

216   in the trading region. As described below, the OFPC accurately reflects relative scarcity

217   accompanying high levels of demand. During these periods, the value of electricity is high

218   because relatively high-cost resources must be dispatched to help meet demand.

219   Neighboring systems may themselves be in similar situation, which is captured in the price

220   forecasts. During off-peak times, the OFPC prices are lower, reflecting the relative lack of

221   value of energy during those times. An economically rational utility will always compare

222   its own internal cost of energy against the price it could pay in the market. If its own internal

223   cost is high at the same time that a neighboring system is selling at a low price, then the

224   economically rational utility will enter into a transaction that allows it to purchase energy

225   at a price less than its own internal cost. In practice, utilities may not always be able to act

226   in an economically rational way as operational or system constraints may impact their

227   ability to trade in the market. Thus, market prices provide a conservative estimate of the

228   value of CG exports.

229   **Q.   Please describe the market hub data included in the OFPC as it relates to**

230   **RMP's service territory.**

231   A.   The OFPC data that PacifiCorp developed represents hourly electricity prices at

232   several relevant trading hubs, from 2020-2040. Because RMP is in the PacifiCorp East

233   Balancing Area ("PACE"), several of these trading hubs that are connected to the

234   PacifiCorp West Balancing Area ("PACW") may not be directly accessible to RMP. This

235   can be seen on a map that was taken from the 2019 Integrated Resource Plan ("IRP") of

236   PacifiCorp, shown below in Figure 3.

237
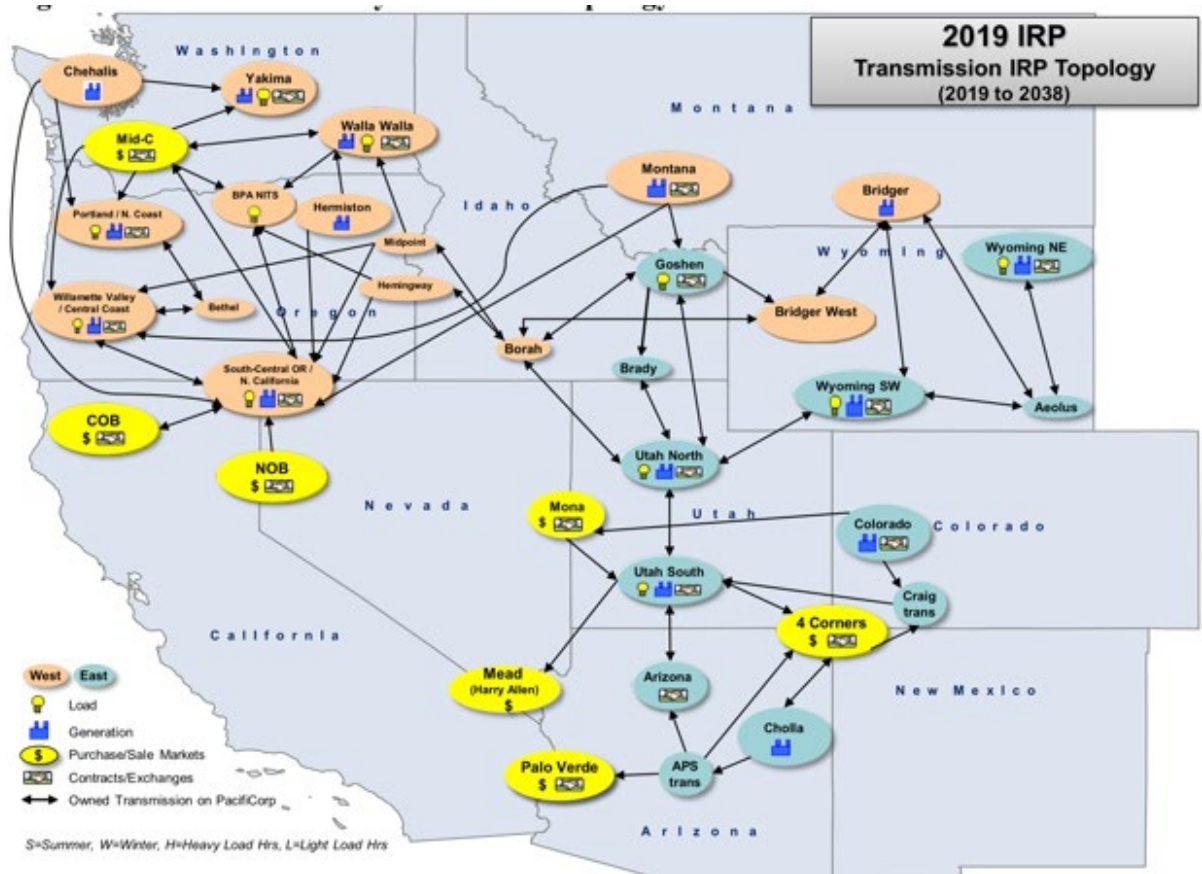
Figure 3. Transmission Map with Trading Hubs from the 2019 PacifiCorp IRP[17]

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239   The map shows the bifurcation of the PacifiCorp system into two control areas (PACW

240   and PACE)–otherwise known as balancing areas ("BA"). This bifurcation makes it

241   difficult to move energy between the two BAs when there is insufficient transmission

242   through the path at Borah. For the purposes of my analysis, I assumed that it is never

243   possible to move energy from PACW to PACE, or conversely from PACE to PACW. This

244   represents a conservative assumption because PacifiCorp can often move energy between

245   control areas.

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[17] *2019 Integrated Resources Plan*, PacifiCorp, Volume II, p. 279, Oct. 18, 2019,
https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-
plan/2019_IRP_Volume_I.pdf.

246   Focusing on PACE, the map shows that Utah South has direct connections to trading hubs

247   at Mead, Mona, and Four Corners. Depending on transmission loading and economics,

248   Utah South may also have access to Palo Verde, and Utah North may, at times, have access

249   to transmission through Borah, which could then allow access to other trading hubs.

250   However, I assume that Utah South will primarily connect with its direct market hubs and

251   flows between Utah North and South are generally unimpeded.

252   **A. ANALYSIS OF OFPC**

253   **Q.   How did you analyze the OFPC data?**

254   A.   For my analysis I used the OFPC data for the Mead, Mona, and Four Corners

255   trading hubs. My analysis is divided into several sections:

256   1.   Analysis of the OFPC data from the three trading hubs;

257   2.   Combining the prices from all three hubs into a representative single market

258   price assessment;

259   3.   Calculating the value of solar, using the Vote Solar Load Research Study

260   ("Vote Solar LRS") data; and

261   4.   Further analysis of the pricing and solar-value results as described below.

262   **Q.   What do market prices look like at the three trading hubs based on the OFPC?**

263   A.   In order to get a general sense of pricing at the three hubs that are directly connected

264   to RMP, I examined the OFPC data from 2021. This year was chosen because it is not far

265   out in the future, and as such, is more likely representative of relative prices than periods

266   that are far in the future, where forecasting errors are likely higher. The first step I took

267   was to compare prices from the three hubs by first calculating the average, maximum, and

268   standard deviation for each trading hub. The results appear in Figure 4. The graph indicates

269   that the maximum price, average prices, and standard deviations from Four Corners and

270   Mona are similar. Therefore, the two prices have similar variability properties and overall

271   range. Mead has a lower maximum price, a higher average, and lower standard deviation.

272   On balance, Mead has somewhat lower volatility, is higher on average, but has less range

273   than the other two hubs.
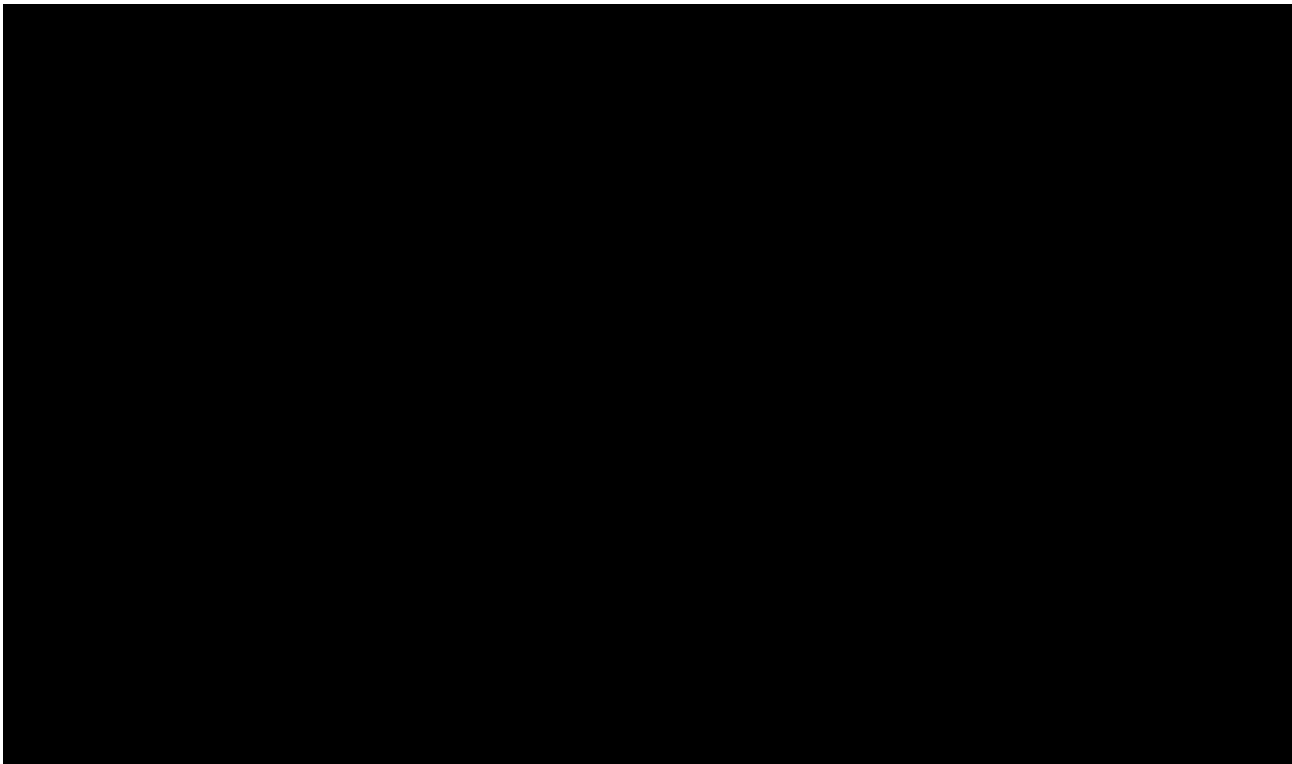
274

275   **Figure 4. Statistics for Three Trading Hubs, 2021**[18]

276   Next, I examined average price on a monthly basis for each of the trading hubs. A graphical

277   comparison as shown in Figure 5 demonstrates that there are two key patterns. The first is

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[18] *See supra* n.14.

278   illustrated by the common movement of Four Corners' prices and Mona prices, which

279   follow a very similar pattern for the 12-month period. Mead's prices are different;

280   significantly higher in winter months and somewhat lower in the peak months of July-

281   September.
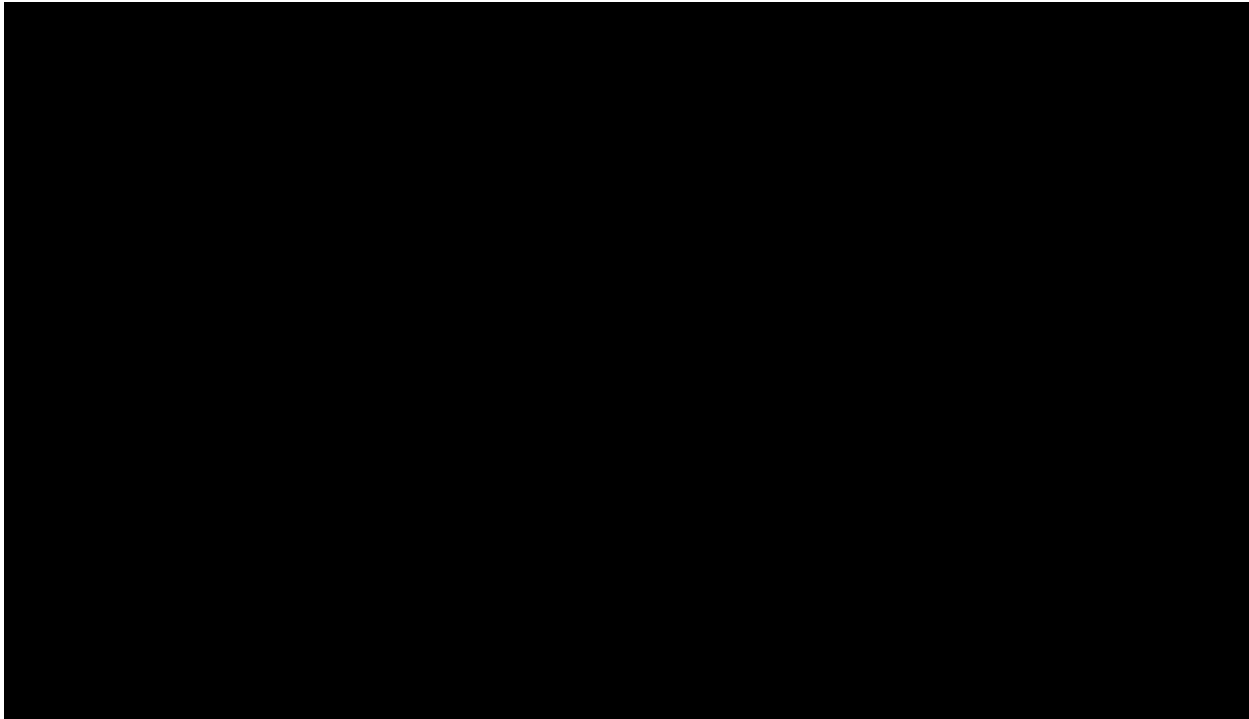
283   **Figure 5. Average Monthly Prices[19]**

284   I additionally calculated the average price for each hour of each month. This results in a

285   block of 12x24 price averages and shows the average price by hour and month for each

286   hub. The graphs appear in Appendix Fig. 1.[20] Each panel of the chart shows one of the

287   trading hubs, and each cell of the table shows the average price at the relevant location for

288   the month and hour that are indicated by the row label and the column header, respectively.

289   To help visualize the relatively large quantity of data in each of the three tables, a "heat

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[19] *Id.*
[20] *Id.*

290   map" colorization was applied so that the highest prices are shown with a red background,

291   moderate prices with a yellow background, and low prices with a blue background. Price

292   levels that lie between these ranges are given appropriate color mixes.

293   Although the absolute prices levels differ—especially those of Mead—from each other,

294   the overall price patterns are similar. Prices tend to peak in the late afternoon/early evening

295   of July, August, and September. In time periods surrounding these periods, prices are

296   moderate-to-high and are colored in some combination of orange and yellow. Moderately

297   low prices appear in early morning hours, especially in July, August, and September, with

298   more moderate prices appearing in the early morning hours of February, March, and

299   occasionally January.

300   **Q.   How did you use this information?**

301   A.   Because these three trading hubs are directly accessible to RMP without wheeling

302   energy across other systems, I averaged prices across the three hubs. The average price

303   table appears in Appendix Fig. 2. I then calculated the 12x24 price block to facilitate

304   comparison with Appendix Fig. 1.[21] The combined prices exhibit similar properties

305   throughout the year, as can be seen by comparing Appendix Fig. 1 with Appendix Fig. 2.

306   Although the characteristics of Mead prices are somewhat different than the other two, the

307   overall shape of the 12x24 average prices are similar, and the average of the three hubs

308   does not show significant changes from the individual hubs.

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[21] *Id.*

309   To illustrate the wide range of prices, I developed a price duration curve as shown in Figure

310   6. Although it is difficult to ascertain precise point-values from the graph, it indicates that

311   the price exceeded ███ MWh approximately ██ times in the 8,760 hours in the year. The

312   price of ██ /MWh was exceeded ████ times. From this information, I determined that the

313   overall price level is low—below about ███ /MWh about half of the time, and higher than

314   ███ /MWh about ██ % of the time. Very high prices—those above ███ /MWh—occurred

315   just over █ % of the time.

316

317   **Figure 6. Price Duration Curve for 3-hub Average Price[22]**

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[22] *Id.*

318   **B. CALCULATING THE ENERGY VALUE OF CG EXPORTS**

319   **Q.   How did you use the OFPC to calculate the avoided energy costs associated**

320   **with CG exports?**

321   A.   To evaluate the avoided energy costs associated with CG exports, I applied the 3-

322   hub average hourly OFPC price for 2021-2040 to the shape of CG exports. I obtained the

323   CG export shape from the Vote Solar LRS, as shown in Exhibit 1-AJL-REVISED. Figure

324   7 below provides the resulting average avoided energy costs in nominal dollars for the

325   duration of the study period.

326
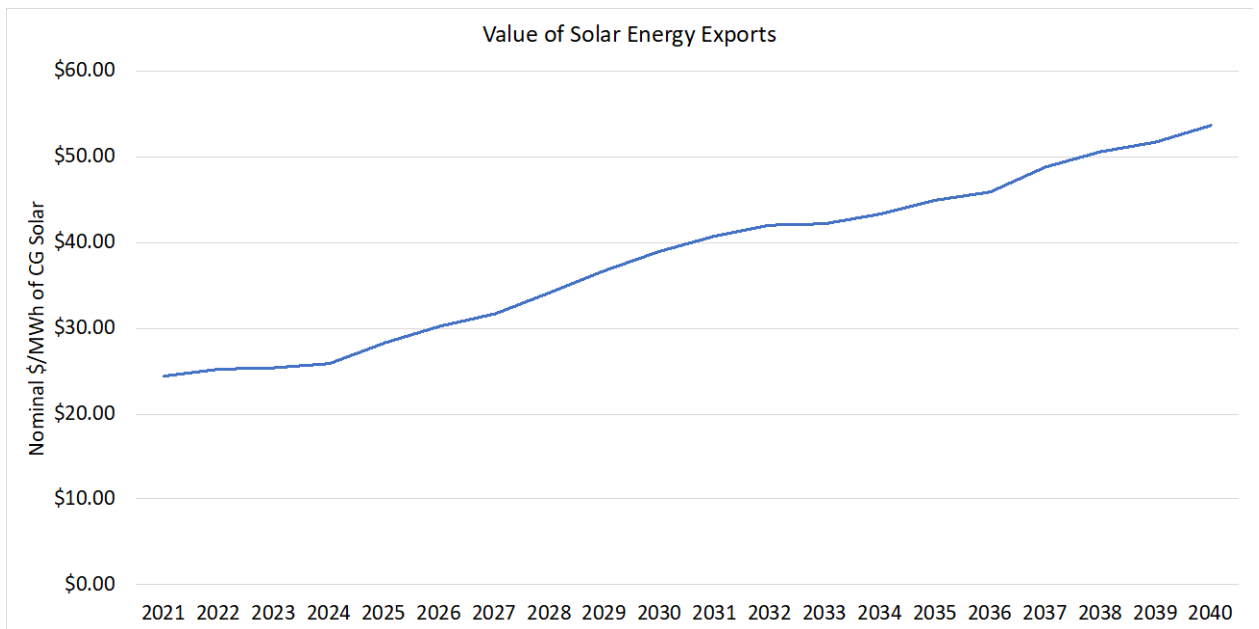
327   **Figure 7. Value of Solar Energy**

328   The avoided energy costs are a direct function of the price levels at the time that CG is

329   exporting power. There is some overlap of CG exports with high prices, but that overlap is

330   offset somewhat because, even though solar generation is high during peak periods of the

331   summer, it produces power at a lower rate later in the day during the highest-price periods.

332   This is shown in Appendix Fig. 3,[23] where the two temperature maps are stacked for ease

333   of comparison. The value of solar is highest just after the high-price periods during the

334   middle of the summer days.

335   **Q.   What did you conclude regarding avoided energy costs associated with CG**

336   **exports?**

337   A.   To produce an estimate of avoided energy costs, I applied an inflation rate of 2.28%

338   and a discount rate of 6.92% consistent with PacifiCorp's assumptions in its 2019 IRP.[24]

339   The levelized value for the years 2021-2040 is 3.55 cents/kWh in 2021 dollars.

340   **Q.   Does your value of 3.55 cents/kWh include avoided line loss costs?**

341   A.   No. My value of 3.55 cents/kWh represents the avoided energy costs associated

342   with CG exports at the location of the CG solar. For this amount of energy to be delivered

343   to the distribution system, an additional amount of energy would be required to be

344   generated and delivered to the customer's location. To capture the full avoided costs of

345   energy, it is necessary to include avoided lines losses as well. Using data provided Mr. Curt

346   Volkmann, I applied an energy loss percentage of 8.62% to calculate the additional avoided

347   energy loss value of 0.31 cents/kWh.

---

[23] *Id.*
[24] *Supra* n.12 at 179.

V.   AVOIDED GENERATION CAPACITY COSTS

348

349   **Q.   What drives generation capacity costs for a utility?**

350   A.   Utility capacity costs are driven by the need to meet peak demand and satisfy

351   reserve requirements. Utilities need to have sufficient capacity to meet peak demand with

352   a planning reserve margin that protects against unforeseen operational problems or

353   inaccurate peak demand forecasts. Capacity is measured by the expected availability of the

354   resources on the system, after considering power plant performance characteristics that

355   include capacity ratings and availability, which can be impacted by unexpected (forced)

356   outages. In resource planning processes like that of PacifiCorp the utility identifies future

357   expected capacity needs and plans for additional resources as necessary.

358   **Q.   How can CG exports allow a utility to avoid generation capacity costs?**

359   A.   CG exports can allow a utility to avoid generation capacity costs if the exports

360   provide capacity support for the utility. Generally, this means that the exports are available

361   during peak periods. The extent to which CG can reduce capacity cost must be analyzed

362   with appropriate calculations, as discussed in detail below.

363   **Q.   What information is required to evaluate the avoided generation capacity costs**

364   **associated with CG?**

365   A.   There are two primary components required to evaluate the avoided capacity costs:

366   (1) an estimate of the capacity value of the CG resource, measured in MW and (2) a cost

367   of capacity on a $/kW or $/MW basis. I will address each in turn.

368   **A. RESOURCE CAPACITY VALUE**

369   **Q.   What is a resource capacity value?**

370   A.   The resource capacity value is a measure of the contribution of a resource to

371   planning reserves. The basic algorithms to estimate resource capacity value have existed

372   for many years, pre-dating the adoption of renewable resources. Every thermal plant has a

373   rated capacity expressed in MW and also has a non-zero forced outage rate ("FOR"). This

374   rate is a function of plant size and type, and generally older plants have higher FORs. The

375   capacity value of any resource measures how it contributes to the overall planning reserve

376   requirement, which is often expressed as a "loss-of-load" probability or mathematical

377   expectation ("LOLP" or "LOLE," respectively). The most robust calculation of capacity

378   value is based upon these LOLP models, and it is common to have a resource adequacy

379   target of expected loss of load 1 day in every 10 years. The capacity contribution metric

380   recommended by the North American Electric Reliability Corporation ("NERC") is the

381   effective load carrying capability ("ELCC") metric or a similar variant that is based on

382   loss-of-load probability or related metric.[25]   The ELCC metric calculates the additional

383   demand that can be served by the resource in question, returning long-term reliability to its

384   level prior to adding the new resource.

385   Depending on the system characteristics, a thermal plant with nameplate capacity of 100

386   MW and FOR of 0.10 will generally have an ELCC of 90-92% of its rated capacity. Older

---

[25] North American Electric Reliability Corporation, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*, Mar. 2011, https://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%20IVGT/Sub%20Teams/Probabilistic%20Techniques/IVGTF1-2.pdf.

387   plants may have FORs ranging up to 0.15 or even 0.20, with corresponding ELCCs of

388   approximately 80-85% of rated capacity. Variable generation such as wind and solar have

389   lower capacity contributions because of the variable nature of the wind or solar fuel.

390   **Q.   Please describe the ELCC Method.**

391   A.   The ELCC method determines how much additional demand can be served by a

392   new resource, holding reliability constant. Reliability is defined as a metric such as LOLP,

393   LOLE, or expected unserved energy ("EUE," where "expected" refers to a probabilistic

394   expected value), or similar metric. Much of the fundamental work on this was done by Roy

395   Billinton and Ronald Allen.[26]

396   To use the ELCC method, a reliability target is chosen—a loss of load expectation of 0.1

397   day/year is common—and the base system is evaluated and adjusted so that it achieves the

398   target. The new resource, such as solar generation, is added to the resource mix and the

399   LOLE is recalculated. The new LOLE will have fallen because of the new resource. Then,

400   demand is incremented until the LOLE increases to its original target. The amount of

401   increased load that can be served while holding reliability constant is the ELCC of the new

402   resource. Figure 8 is an adaptation of a graphic from the NERC 2011 report that illustrates

403   the concept.[27] At point one, the system target of 0.1 day/year is achieved. A new resource

404   is added, which shifts the reliability curve down and to the right. The new reliability level

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[26] Roy Billinton and Ronald N. Allen, *Reliability Evaluation of Power Systems* (2d. ed. 1996).
[27] North American Electric Reliability Corporation, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*, Mar. 2011, https://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%20IVGT/Sub%20Teams/Probabilistic%20Techniques/IVGTF1-2.pdf.

405   is depicted by point 2, and it is approximately 0.09 days/year. This is more reliable than

406   the target, and because reliability is expensive, we gradually increase demand until the

407   target reliability level is reached again, traveling through point 3 and arriving at point 4.

408
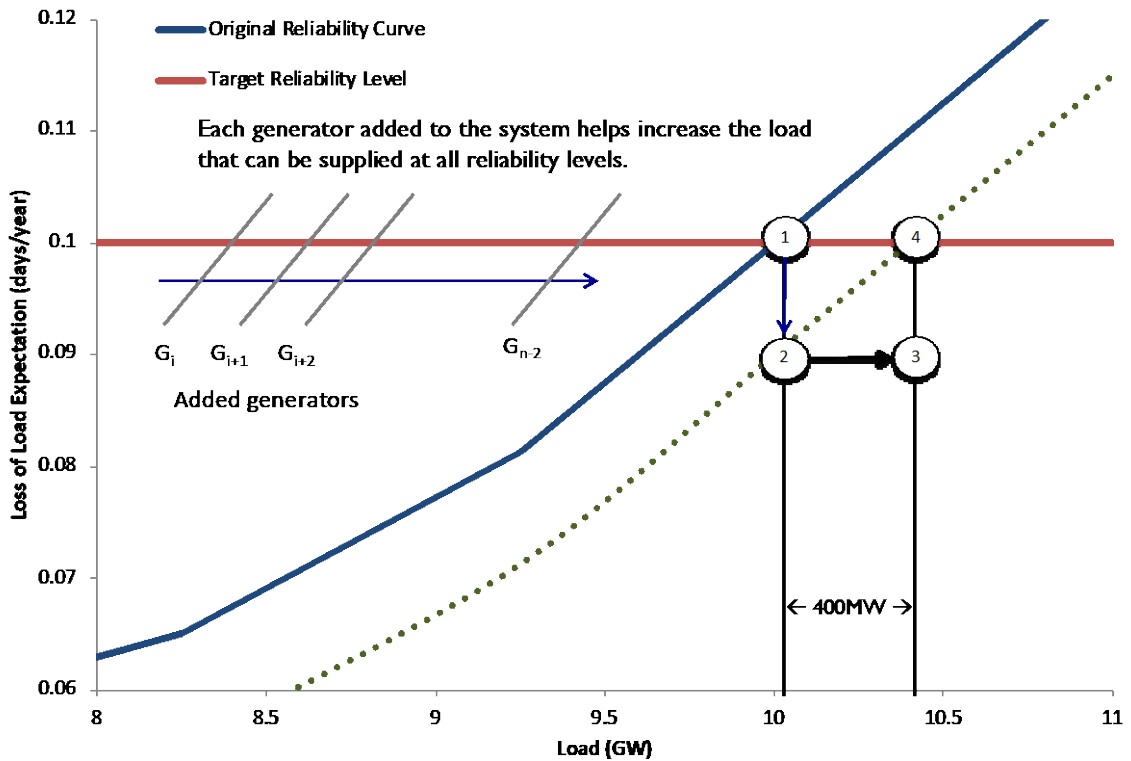
Milligan and Ibanez presentation to WECC, June 2015

409   **Figure 8. Graphical depiction of ELCC**

410   **Q.   Is ELCC Method always the best approach?**

411   A.   Even though the ELCC is the preferred method, it is a relatively complex

412   calculation, not particularly transparent, and requires significant data and computing

413   capability. Because of these factors, there are several methods that simplify or approximate

414   ELCC. Some of these simplified methods have been benchmarked against ELCC so their

415   ability to approximate ELCC is well understood.

416   **Q.   What information did you review to determine the best method to employ in**

417   **this case?**

418   A.   In its 2019 IRP, PacifiCorp included a discussion and analysis of resource capacity

419   value. In preparation for my testimony, I reviewed the method employed by PacifiCorp as

420   well as the underlying data and analyses, which were provided in discovery.

421   **Q.   What method did PacifiCorp employ to determine the resource capacity value**

422   **in its IRP?**

423   A.   According to the IRP, PacifiCorp utilized a LOLP model to calculate hourly LOLP

424   value for its system by constructing a sample year with energy-not-served data (an output

425   from an LOLP model), from June-September of 2030, and October-May from 2036. RMP

426   then used these hourly LOLP values as weights, applied to the solar generation, to calculate

427   the capacity value.[28]

428   **Q.   Is PacifiCorp's IRP method reasonable for adoption in this case?**

429   A.   No. The method used in the PacifiCorp IRP suffers from two related deficiencies:

430   (1) it is based upon a method that has been shown to be less accurate than other simplified

431   approximations to ELCC and (2) it is based solely on hourly LOLP values from two half-

432   years that are unlikely to represent periods of long-term risk, which is what LOLP methods

433   are intended to do.

---

[28] *See supra* n.12 at 397-405. Although wind and solar energy differ in some of their qualities, they both have variable and uncertain output, therefore it is reasonable to apply the results of the 1997 study to solar.

434   **Q.   Please describe how the PacifiCorp method compares to other approximation**

435   **methods.**

436   A.   The method used by PacifiCorp has not been sufficiently analyzed, nor has it been

437   validated as an accurate way to estimate ELCC. Interestingly, PacifiCorp's analysis refers

438   to a paper that I co-authored in 1997. In the 1997 paper, my co-author and I compared 3

439   simplified ELCC approximation methods to the rigorous ELCC calculation itself: (1) top

440   load hours; (2) LOLP indicators; and (3) LOLP-weighted (the same method as used by

441   PacifiCorp). Figure 9 is reproduced from that paper. [29] The three methods were compared

442   to a full ELCC calculation for wind energy in two ways.[30] The *first* was a simple counting

443   metric: how many years, out of the 13 years studied did each method out-perform the other

444   methods in replicating ELCC? This comparison is shown in the red bars in Figure 8. A

445   higher score indicates better performance. The *second* comparison was based on the root

446   mean square error ("RMSE") statistic,[31] which was calculated for the 13-year period. This

447   comparison is shown in the green bars in Figure 8. For RMSE, a higher score is associated

448   with poorer performance.

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[29] Michael Milligan and Brian Parsons, *A Comparison and Case Study of Capacity Credit Algorithms for Intermittent Generators*, https://www.nrel.gov/docs/legosti/fy97/22591.pdf.
[30] *Id*.
[31] RMSE is a common metric that is used to calculate statistical errors. The calculation involves calculating the sum of the squares of the errors, and then taking the mean value of that sum.

Overall Method Comparison
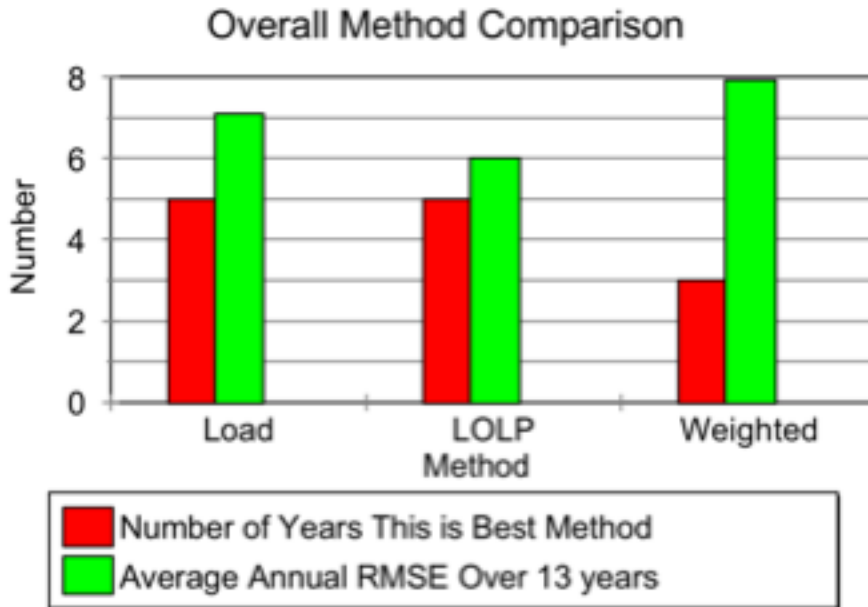
449

450   **Figure 9. Comparison of capacity value methods, Milligan and Parsons, 1997**

451   The "weighted" method that PacifiCorp used to evaluate the capacity contribution of

452   renewables is shown to be the worst-performing metric among the ones studied in my 1997

453   paper. It outperformed the other methods in only 3 of the 13 years studied, and it had the

454   highest RMSE of all the methods.

455   **Q.   What additional elements should be considered in the selection of a method to**

456   **approximate ELCC?**

457   A.   There are other considerations beyond the accuracy of a method to match ELCC in

458   a long-term planning study related to data availability. Because both demand and solar

459   generation are clearly influenced by the weather, a single year of data will not represent

460   the long-term performance of the resource. As described by NERC,[32] multiple years of

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[32] North American Electric Reliability Corporation, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*, Mar. 2011,

461 demand and renewables data should be used to ascertain the long-term level of resource

462 adequacy that wind and solar energy can provide. Section 2.3 of the NERC report focuses

463 on inter-annual variability and shows how the capacity value is sensitive to annual

464 variations.

465 With a limited data set such as that used in the PacifiCorp IRP, a false sense of security

466 may be found in a precise calculation that is based on hourly LOLP values that are likely

467 to be quite different in other years. Generally, utilities are well aware of periods of time

468 when there are risks of insufficient resources, and methods such as the "Load" method in

469 my 1997 paper are the preferred approach for capturing long-term capacity value when

470 data is limited, as it is in this case. It is extremely unlikely that RMP's hourly LOLP results

471 will ever be replicated in a different year. In the absence of multiple years of renewable

472 data, a more robust estimate of capacity value is necessary for long-term planning

473 documents, such as an IRP.

474 **Q. Do you recommend that RMP's IRP method be used in the determination of**

475 **the resource capacity value associated with CG in this case?**

476 A. No. I don't recommend the RMP method for any long-term planning use because

477 of the concerns described above: (1) it has not been carefully and successfully compared

478 to ELCC and long-term capacity value and (2) there are better methods.

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https://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%20IVGT/Sub%20Teams/Probabilistic%20Techniques/IVGTF1-2.pdf.

479   **Q.   What method do you recommend be adopted for determination of the resource**

480   **capacity value?**

481   A.   Ideally, a full ELCC analysis would be conducted, taking into account multiple

482   years of time-coincident demand, because solar, wind, and hydro data are each driven by

483   weather, which rarely if ever repeats itself. I discussed this issue in a recent presentation,[33]

484   and it is discussed in the NERC document.[34] Because PacifiCorp's data does not allow for

485   the ideal calculation, the next-best approach must be adopted.

486   I recommend that resource capacity value be developed based on the "Load" method from

487   my 1997 paper.[35] This method is often called the "capacity factor" method and is similar

488   to a method utilized for many years by the PJM Regional Transmission Organization.[36]

489   The capacity factor method utilizes a range of hours based upon the annual peak demand

490   to determine the performance of algorithms that use the top 1%, 2%, through to the top

491   30% of load hours. In my judgment, based upon decades of researching and publishing on

492   the subject, a capacity factor method that examines 10% of the top load hours will provide

493   an adequate approximation of ELCC. In situations where multiple years of demand and

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[33] Michael Milligan, *Building the Power Grid of the Future: Resource Adequacy Issues*, Presentation to Minnesota Clean Energy Advocates, Oct. 25, 2019, http://www.milligangridsolutions.com/MCEA%20Symposium%202019.pdf.

[34] North American Electric Reliability Corporation, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning,* Mar. 2011, https://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%20IVGT/Sub%20Teams/Probabilistic%20Techniques/IVGTF1-2.pdf.

[35] Michael Milligan and Brian Parsons*, A Comparison and Case Study of Capacity Credit Algorithms for Intermittent Generators,* National Renewable Energy Laboratory, Mar. 1997, https://www.nrel.gov/docs/legosti/fy97/22591.pdf.

[36] M. Milligan and K. Porter, *Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation*, National Renewable Energy Laboratory, p. 12–14, June 2008, https://www.nrel.gov/docs/fy08osti/43433.pdf.

494   production data are not available, such as this, the capacity factor method will provide a

495   more robust analysis for resource capacity value than PacifiCorp's LOLP-based method.

496   **Q.   Can you elaborate why PacifiCorp's LOLP-based method is less robust?**

497   A.   LOLP-based methods are dependent upon finding periods of relatively high risk.

498   The focus is the risk of having insufficient generation. Over a multiple-year period, weather

499   can vary substantially. Because weather is an important driver for demand patterns along

500   with renewable energy generation patterns, a period of LOLP risk in one year does not

501   necessarily translate to LOLP risk at the same time(s) in another year. Therefore,

502   employing a precise set of equations to a specific year of data may not capture the long-

503   term risk patterns. The risk of LOLP has generally been shown to occur during high-

504   demand periods, although other factors can contribute, such as maintenance schedules and

505   off-system imports and exports.[37]

506   To illustrate, I used a 10-year subset of the load data provided by RMP in discovery[38] to

507   show periods of potential LOLP risk throughout the 10-year period starting with 2021. I

508   then calculated the MW demand of the top 10% of load-hours, or 876 hours of the year. I

509   tabulated the periods of time that demand is in the top 10% of load hours. This captures

510   potential time periods during which RMP could potentially be at LOLP risk. A graphical

511   depiction of the monthly results appears in Figure 10.

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[37] North American Electric Reliability Corporation, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*, Mar. 2011, https://www.nerc.com/comm/PC/Integration%20of%20Variable%20Generation%20Task%20Force%20IVGT/Sub%20Teams/Probabilistic%20Techniques/IVGTF1-2.pdf.

[38] Exhibit 3-MM, 20190916 data disks/Confidential Attachments 6.10-1/Data Disk 2/Data Disk 2_CONF/Assumptions + Inputs/ Load,CONF/Base Loads (Net of PG).csv, RMP's Responses to Vote Solar 6th Set Data Requests – Attach 6.10-1 (Aug. 26, 2019).

512

Figure 10. Periods of high demand that could put system at LOLP risk

513

514   As shown in the figure, periods of high demand occur primarily during the peak months of

515   July and August, but lesser peak periods can also occur in May, June, and September.

516   PacifiCorp relied on a single-year assessment of LOLP, but as demonstrated in Figure 10,

517   LOLP-risk periods can vary year-to-year. When inter-annual variations are considered

518   more fully, the periods of LOLP risk will change from year to year.[39] Therefore,

519   PacifiCorp's method utilizing a precise calculation, but based upon limited data, is likely

520   to miss periods of LOLP risk in a long-term planning study.

521   **Q.   What method do you recommend be adopted for determination of the resource**

522   **capacity value?**

523   A.   For my assessment of the capacity value of solar for RMP, I used the capacity factor

524   method including the top 10% of load hours as an input. I then used the solar energy

---

[39] Other analyses have found a much larger impact when multiple years of actual data are considered. Consider this quote: "Analysis that was undertaken for the California Energy Commission found that during an unusually late, hot summer period when many units were taken out of service for scheduled maintenance, the hourly LOLP in late September was nearly as high as during the peak summer period. Situations like this can result in a lack of recognition of the exposure of the power supply to potentially high levels of risk…." *Supra* n.36 at 8–9.

525   production in those hours to calculate the capacity factor—the ratio of the mean to the

526   maximum. This method is preferred in instances, such as this, where data is limited and

527   has been shown to reliably approximate ELCC.[40]

528   Using this method, I found the capacity value of CG exports averages 27.65% of the rated

529   installed capacity. This was calculated for each of the years 2021-2030, and varied slightly

530   from year to year, from 26.91% to 28.53%. For 2038-2040, when demand data was

531   unavailable, I used the average of 2021-2037, which is 27.65% of rated capacity.

532   **B. COST OF CAPACITY**

533   **Q.   What is the cost of capacity in the context of avoided generation costs?**

534   **A.**   The cost of capacity is typically evaluated based upon the cost of a peaking

535   resource, which could be a combustion turbine, aeroderivative generator, or reciprocating

536   engines. Regardless of the specific technology used, the capacity resource selection

537   attempts to isolate the contribution of capacity from the contribution of energy or other

538   ancillary services. Peaking plants typically have a low cost in terms of $/kW, but often

539   have high energy costs. Due to these characteristics, peaking plants are commonly used in

540   the power system industry as proxy resources in the evaluation of capacity.

541   **Q.   What information did you review to determine the appropriate cost of**

542   **capacity to employ in your analysis?**

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[40] Michael Milligan and Brian Parsons*, A Comparison and Case Study of Capacity Credit Algorithms for Intermittent Generators,* National Renewable Energy Laboratory, Mar. 1997, https://www.nrel.gov/docs/legosti/fy97/22591.pdf.

543   A.   I consulted the 2019 IRP, Table 6.1, which showed costs of options for RMP's

544   preferred portfolio of resources.[41] Because my method calls for a capacity resource, I

545   selected a low-cost capacity resource based on its combined base capital cost and fixed

546   O&M cost.

547   **Q.   Which resource do you recommend be considered in the analysis of avoided**

548   **generation capacity costs of CG?**

549   **A.**   I selected the CCCT Dry "J/HA.01", DF, 2x1, ISO resource because it is a low-cost

550   capacity resource, consistent with a least-cost planning process and consistent with the

551   objective of calculating an avoided capacity cost for CG. The net capacity of this resource

552   is listed at 126 MW, with base capital cost of $316/kW, fixed O&M of $4.05/kW-yr, with

553   a 40-year design life.

554   **C. CALCULATION OF AVOIDED GENERATION CAPACITY COST**

555   **Q.   How did you calculate the avoided generation capacity cost associated with**

556   **CG exports in RMP's Utah service territory?**

557   A.   I employed several assumptions to derive a levelized c/kWh rate for avoided

558   generation capacity costs associated with CG exports based on the above-described

559   findings for resource capacity value and generation capacity cost. To conduct the

560   calculation, I adopted a 9.39% carrying charge to convert the capital cost to an annual

561      $/kW-year.[42] I applied my findings that solar exports have an average 27.65% resource

---

[41] *Supra* n.12 at Table 6.1.
[42] I selected the 9.39% carrying charge based on PacifiCorp's 20-year Generation Annual Economic Carrying
Charge from a 2018 Marginal Cost Study filed in California. PacifiCorp, *Exhibit Accompanying Direct Testimony of*

562   capacity value to the resulting annualized costs to derive the avoidable capacity value. In

563   order to incorporate the effect of avoided line losses, I adopted a line loss factor of 1.09080

564   as recommended by Mr. Volkmann. Finally, I adopted PacifiCorp's inflation rate of 2.28%

565   and discount rate of 6.92% and find that the levelized value of the CG solar is $14.80/MWh

566   of the solar resource, or 1.48 cents/kWh.

VI.   AVOIDED CARBON EMISSIONS

568   **Q.   How does CG allow the utility to avoid carbon emissions?**

569   A.   Because solar energy has a marginal cost of $0/MWh, it is always preferred in the

570   dispatch stack, as discussed previously in this testimony in Section IV. The process of

571   determining the dispatch stack—the combination of resources' deployed capacity to meet

572   demand—is a complex economic optimization that chooses the resource mix based upon a

573   least-cost dispatch, subject to a variety of physical and reliability constraints. Because the

574   marginal cost of solar is lower than any thermal resource, it will always be fully deployed

575   unless some constraint on the power system requires an uneconomic dispatch, which raises

576   operational costs of the power system. Distributed solar is not subject to the usual economic

577   dispatch performed by power system operators, but it has the same impact on the dispatch

578   stack. For every MW of solar power at a given time, one less MW of thermal generation is

579   needed, and therefore less fuel burn is required to meet demand; thereby, reducing

---

Robert M. Meredith Marginal Cost of Service Study, Public Utilities Commission of the State of California, Docket No. 18-04-002, p. 42, Apr. 2018.

580   emissions. The specific emission reduction is a complex calculation, and the level of

581   emission reduction per MWh of solar generation can vary based upon system conditions.

582   **Q.   What source of information did you use to evaluate the avoided carbon**

583   **emissions associated with CG exports in RMP's Utah service territory?**

584   A.   To evaluate the avoided carbon emissions associated with CG exports, I developed

585   a blended emissions rate based on actual emissions data from the U.S. Environmental

586   Protection Agency ("EPA") and the U.S. Energy Information Administration.[43] This data

587   includes the annual energy generation from each thermal power plant in PACE, measured

588   both in electrical energy (kWh) and fuel (BTU – British Thermal Units, a measure of the

589   energy content in fuels). The data set also contains emission information for several

590   pollutants, including carbon dioxide (CO_2). Data on power plant emissions is specific to

591   each power plant, and I utilized data from 2017 and 2018 to construct average emission

592   rates for RMP.[44] Before calculating the emissions associated with RMP, I pro-rated RMP's

593   ownership rate for all jointly-owned plants so that my calculations would apply only to

594   RMP. Because the 2019 IRP contains many coal plant retirements, this average emission

595   rate will change as plants retire and can either result in the increase or the decrease of

596   average emissions per unit of energy, depending on the relationship of the retired plants'

597   emission rates compared to the average. To account for this, I relied upon the Preferred

---

[43] *Power Plant Data Highlights*, U.S. Environmental Protection Agency, https://www.epa.gov/airmarkets/power-plant-data-highlights; *2017 National Emissions Inventory (NEI Data)*, U.S. Environmental Protection Agency (Feb. 2020), https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data.
[44] Emissions and production data from Naughton were not used because it appeared incorrect or incomplete in the EPA/EIA data.

598 Portfolio P-45CNW as described in the 2019 IRP.[45] Each year in which there was a thermal

599 plant retirement (or multiple retirements), I recalculated the emissions rate accordingly.

600 This analysis takes into account that CG exports will displace thermal generation and

601 incorporates coal retirements based on expectations set forth in the IRP. The only cases in

602 which CG exports would replace another renewable is if the system is not planned for

603 flexibility. Renewable curtailment generally occurs because thermal units are not flexible

604 enough to respond to changing net demand. PacifiCorp has demonstrated a keen interest,

605 backed by significant analysis, to ensure their system will have the needed flexibility.[46]

606 **Q.** **How did you calculate avoided carbon emissions reductions?**

607 A. Using the average carbon emission rate for each year, I calculated carbon emission

608 reductions based the CG export profile provided by Dr. Lee in Exhibit 1-AJL-REVISED.

609 Because of losses, one MWh of energy that is generated on the distribution system requires

610 more than one MWh of energy generated at a central power plant, I utilized the same energy

611 loss factor of 8.86% to calculate avoided carbon as used to calculate the avoided energy in

612 my earlier testimony based on the recommendation of Mr. Volkmann. The annual results

613 for the CG-related reductions in CO_2, are shown in Figure 11 where one can discern a

614 downward trend in the annual emissions reduction, caused by the relatively early

615 retirements of high-emission units. This causes the remaining operating thermal fleet to

616 have lower emissions than before, reducing the emission benefits from solar energy.

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[45] *Supra* n.12 at 279.
[46] For example, Appendix F of the 2019 IRP is a study of flexibility. *See supra* n.12 at 77.
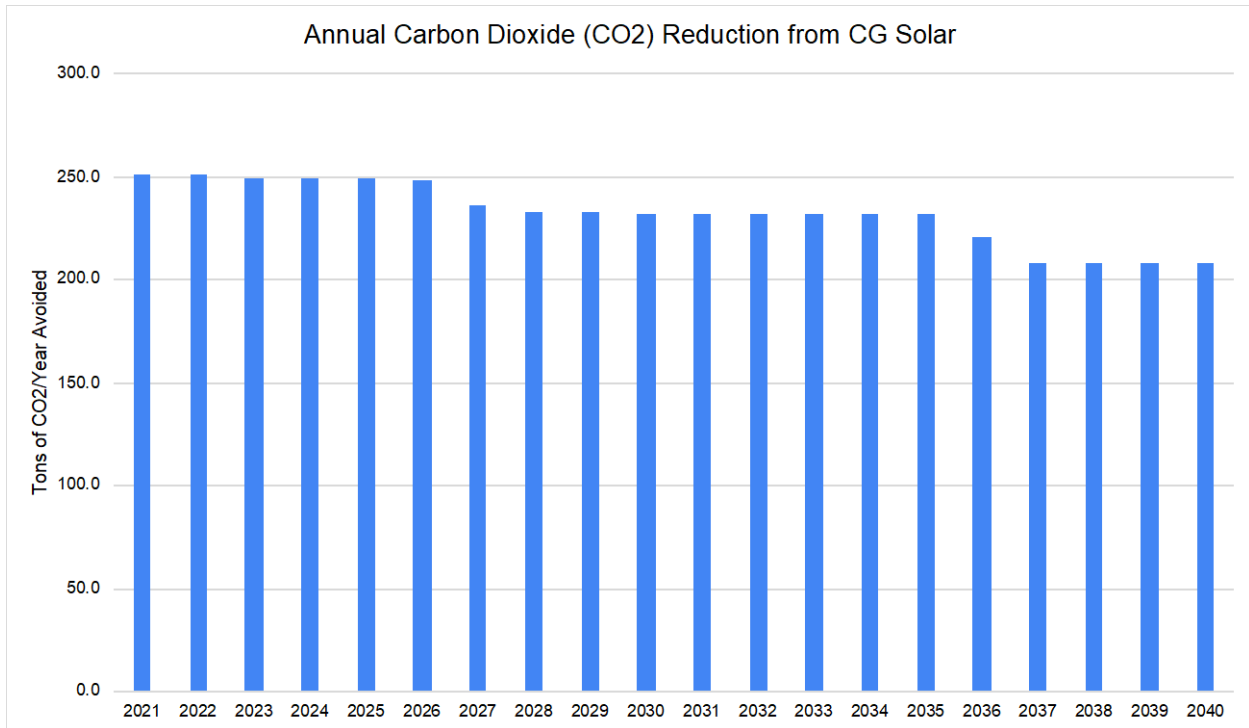
Figure 11. Emission reductions

617

618

619   **Q.   How was this information used in Vote Solar's Value of CG analysis?**

620   **A.**   I provided Dr. Berry with data on the annual carbon emissions avoided by CG over

621   the study period 2021-2040. It is my understanding that Dr. Berry has used this information

622   to derive values associated with avoided carbon emissions.

623 **VII.   SUMMARY OF RECOMMENDATIONS**

624   **Q.   Please summarize your recommendations.**

625   **A.**   Based upon my findings, I recommend that the following levelized avoided costs

626   be adopted in this proceeding:

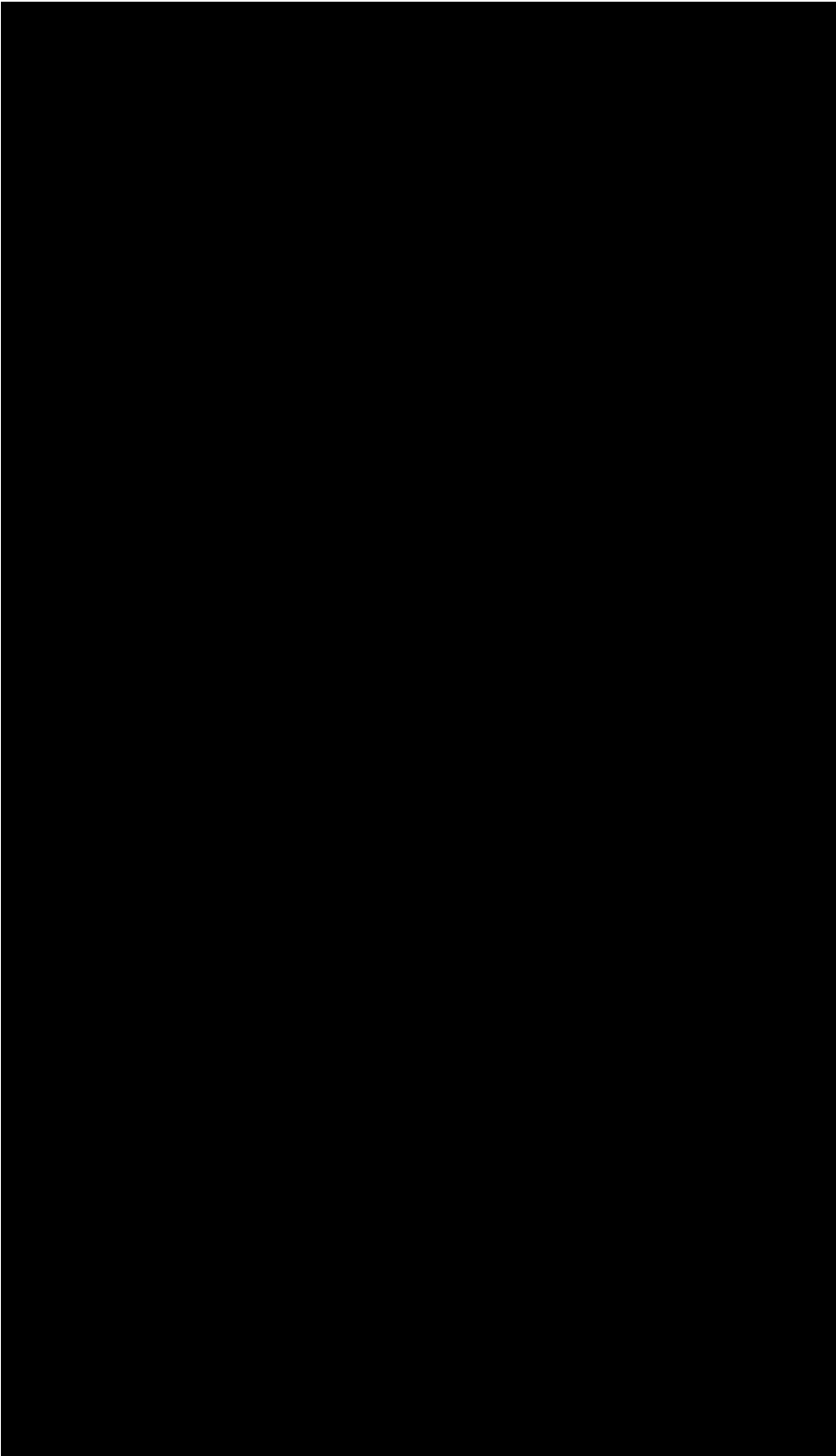627   1. An avoided energy value of 3.55 c/kWh;

628   2. An avoided line loss value of 0.31 c/kWh;

629   3. An avoided generation capacity value of 1.48 c/kWh; and

630   4. Avoided carbon emissions based on my annual projections that average to

631   232 tons/year.

632   **Q.**   **Does this conclude your revised testimony?**

633   A.   Yes.

634 **VIII.   APPENDICES**

635   Appendices to follow on next page.
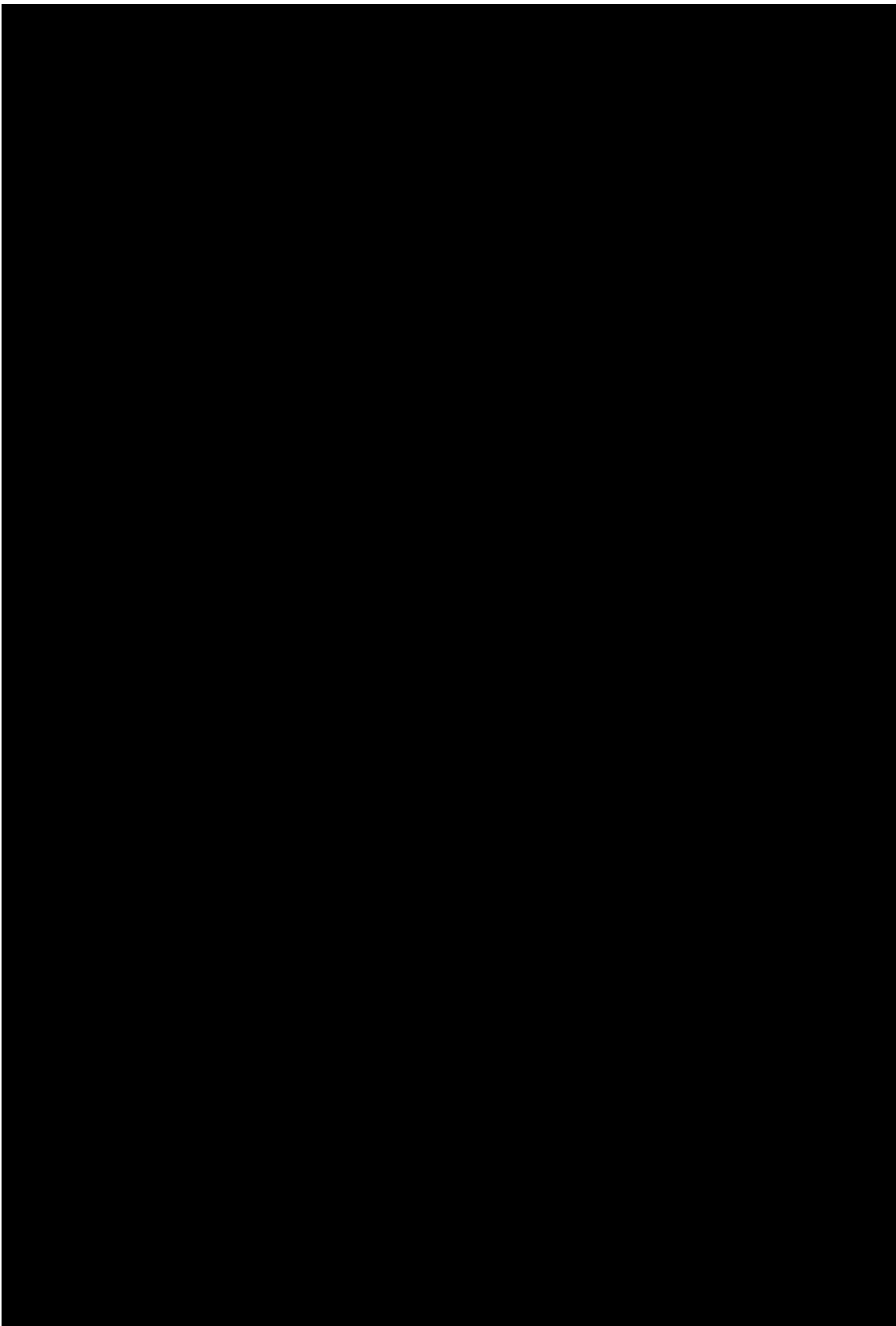
Appendix Fig. 1. Comparison of 12x24 price blocks

Appendix Fig. 2. 12x24 Average Prices Across Three Hubs

641

642 *Appendix Fig. 3. 12x24 Value of Solar Energy and Average 3-hub Prices*

<center>**CERTIFICATE OF SERVICE**</center>

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