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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. 14-035-114

DIRECT TESTIMONY OF JEREMY I. FISHER REGARDING NET METERING

[Redacted Public Version]

HEAL Utah ("HEAL") hereby submits the redacted public version of the prefiled Direct Testimony of Jeremy I. Fisher in this docket regarding PacifiCorp's benefit/cost assessment of distributed generation net metering in Utah.

DATED this 8th day of June 2017.

Respectfully submitted

By: /s/ *Phillip J. Russell*
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Certificate of Service
Docket No. 14-035-114

I hereby certify that a true and correct copy of the foregoing redacted public version of the prefiled Direct Testimony of Jeremy I. Fisher was served by email this 8th day of June 2017, on the following:

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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. 14-035-114

Direct Testimony of Jeremy I. Fisher, PhD

On Behalf of HEAL Utah

REDACTED PUBLIC VERSION

June 8, 2017

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name, business address, and position.

A My name is Jeremy I. Fisher. I am a Principal Associate with Synapse Energy Economics, Inc. ("Synapse"), which is located at 485 Massachusetts Avenue, Suite 2, in Cambridge, Massachusetts.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues and policies for electricity sector issues. These include: fossil generation, efficiency, renewable energy, ratemaking and rate design, restructuring and market power issues, and environmental regulations.

Q Please summarize your work experience and educational background.

A I've worked in electricity system energy planning for a decade, evaluating and helping to shape resource plans, performing planning on behalf of states and municipalities, helping regulators navigate environmental rules, and assisting states craft or revise resource planning rules. I lead the resource planning group at Synapse, which engages in the assessment of planning processes across a wide cohort of states and regions.

I have provided consulting services for a wide variety of public sector and public interest clients, including the U.S. Environmental Protection Agency ("EPA"), the National Association of Regulatory Utility Commissioners ("NARUC"), the National Association of State Utility Consumer Advocates ("NASUCA"), National Rural Electric Cooperative Association ("NRECA"), the energy offices and public utility commissions of Alaska, Arkansas, Michigan, and Utah, the Commonwealth of Puerto Rico, Tennessee Valley Authority Office of Inspector General ("TVA OIG"), the California Division of Ratepayer Advocates ("CADRA"), the California Energy Commission ("CEC"), the Regulatory

Assistance Project ("RAP"), the Western Grid Group, the Union of Concerned Scientists ("UCS"), Sierra Club, Earthjustice, Natural Resources Defense Council ("NRDC"), and other organizations. I have provided training to federal regulators on resource planning practice and issues. I recently led an intensive statewide planning process on behalf of the Michigan Public Service Commission ("MPSC") and worked on behalf of the Puerto Rico Energy Commission ("CEPR") towards the development of state-of-the-art integrated resource plan ("IRP") rules.

I have provided testimony in electricity planning and general rate case dockets in California, Georgia, Idaho, Indiana, Kansas, Kentucky, Louisiana, Nevada, New Mexico, Oklahoma, Oregon, Puerto Rico, Utah, Washington, Wisconsin, and Wyoming.

I hold a doctorate in Geological Sciences from Brown University, and I received my bachelor degrees from University of Maryland in Geology and Geography.

My full curriculum vitae is attached as Exhibit HEAL___(JIF-1).

Q On whose behalf are you providing testimony in this case?

A I am providing testimony on behalf of HEAL Utah.

Q Have you previously provided comments to or testified before the Public Service Commission of Utah previously?

A Yes. I have submitted testimony in three Utah dockets filed by PacifiCorp ("Company," d.b.a. "Rocky Mountain Power"), two rate case dockets (10-035-124 and 13-035-184) and the Company's voluntary application to install emissions controls at Jim Bridger power plant (12-035-92). I've also prepared Utah comments on behalf of Sierra Club in the last two IRP proceedings.

Q Are you familiar with PacifiCorp's system?

A Yes. Since 2010, I've reviewed PacifiCorp's long-term resource planning and short-term modeling in dockets across the Company's service territory. This includes expert testimony in rate cases (WY 20000-384-ER-10, WY 20000-446-ER-14, OR UE 246, WA UE-152253), certificates of public convenience and necessity ("CPCN") (WY 20000-418-EA-12), and assessments of fuel contracts (OR UM 1712, CA 15-09-007).

In 2015, I led a team which re-assessed the Company's IRP using PacifiCorp's System Optimizer model.

Q What is the purpose of your comments?

A My testimony evaluates the PacifiCorp's ("Company," d.b.a. "Rocky Mountain Power") benefit / cost assessment of distributed generation net metering in Utah. In particular, I assess the Company's Net Power Cost ("NPC")-based Cost of Service Study ("COSS"), evaluate the avoidable energy elements excluded from this analysis, and provide an assessment of the cost shifting attributed by the Company to residential distributed generation customers. I examine and seek to quantify other system benefits of distributed generation over both the short-term and long-term that are not captured by the Company's assessment.

Q Please provide a brief background on the purpose of your testimony.

A In November 2015, this Commission approved a framework to assess the costs and benefits of solar photovoltaic distributed generation. In that order, the Commission cites to Utah Code 54-15-105.1(1) which seeks to assess "whether the costs that the electrical corporation or other customers will incur from a net metering program will exceed the benefits of the net metering program." In interpreting this statute, the Commission determined that the benefits and costs of distributed generation were best illustrated through a Cost of Service Study ("COSS"). To assess the benefits of distributed generation, the Commission required that PacifiCorp determine the differential between an "actual cost of service study" ("ACOS") performed with a known amount of distributed generation, and a counterfactual COSS ("CFCOS") with that distributed generation removed from the system. The difference between the two studies would then be used to establish the benefit of existing distributed generation as the reduced cost of serving customers.

PacifiCorp's resulting filing presents two results from its study: a short-term avoided energy benefit study based on the Commission's framework, and a cost-shifting analysis.

By focusing on only a test-year analysis in the COSS framework, and by virtue of the Company's modeling structure, PacifiCorp allocates distributed generation its lowest possible value—the value of avoided energy only. As I'll discuss, PacifiCorp's largely thermal boiler system incurs very high fixed costs and relatively low variable costs: by focusing on a study where only the short-term energy costs are avoidable by incremental distributed generation, PacifiCorp steers away from assessing the capacity, transmission, or emissions benefits associated with distributed generation.

In its filing, PacifiCorp went one additional step, interpreting a Commission concern with impacts on "other *current* customers" to imply that the cost impact of distributed generation was best demonstrated through a cost-shifting assessment. The Company believes that "it is imperative that the Commission consider [a new ratemaking structure] immediately to prevent significant cost shifts from net metering customers to all other customers,"[1] touting a cost-shift risk of nearly $667 million (undiscounted) by 2035.

My testimony is designed to illustrate the benefits of distributed generation that go above and beyond the short-term energy benefits found in the COSS analysis,

[1] Direct Testimony of Gary Hoogeveen, page 7 at 146-150.

and contextualize the "other" ratepayer impacts envisioned by PacifiCorp with respect to other elements of the Company's fleet.

Q What are your findings with respect to the Company's net energy metering analysis?

A My findings are as follows:

1. **COSS analysis only illustrates short-term energy benefits**. The analysis provided by the Company can only account for short-term displaced energy benefits, a fraction of the overall system benefits provided by customer-sited distributed generation.

2. **COSS analysis uses an outdated renewable integration charge.** The Company assumes an integration charge for renewable energy from a vintage 2012 study, a value that has been updated twice and fallen by nearly 80 percent since 2012.

3. **COSS analysis does not to account for all short-term avoidable costs.** The Company's assessment of avoided costs—i.e. the system benefits attributable to distributed generation—does not take into account avoided variable operations and maintenance ("O&M") costs at existing coal plants, or the full variable cost of coal.

4. **COSS analysis does not account for avoided capacity benefits as determined in 2017 IRP.** PacifiCorp's 2017 IRP shows that incremental distributed generation would likely defer and avoid capacity acquisitions, resulting in substantial system cost savings that are not accounted for in the short-term COSS analysis.

5. **COSS analysis does not account for incremental low-cost procurement as determined in 2017 IRP.** The Company's 2017 IRP shows a large increase in near-term cost-effective utility renewable procurement when more customers

build distributed generation systems. This results in system cost saving that is not accounted for in the short-term COSS analysis.

6. **Long-run cost-shift assessment is flawed.** The Company's assessment of a long-run $667 million cost shift from net metering customers to other residential customers fails to take into account any of the long-run anticipated system benefits of distributed generation, assumes an effectively unchanged electricity system, and is undiscounted, dramatically overstating the impacts.

7. **If assessed similarly to distributed generation resources, PacifiCorp's least-economic coal units would require above retail rates to be economic**. Based on information from the 2017 IRP, I estimate that three units [redacted] would require rates at or above residential retail levels to break even if assessed on an equal footing with distributed generation.

8. **PacifiCorp's non-economic coal units impose present-day ratepayer impacts far in excess of the cost shift attributed by the Company to distributed generation**. Based on information in the 2017 IRP, I estimate that 11 coal units incurred net losses in 2016 relative to the market, amounting to [redacted] million in total losses (in comparison to the $6.5 million 2016 cost shift estimated by the Company).

9. **PacifiCorp's non-economic coal units result in long-term losses on par or above the Company's estimated long-run cost-shift estimate.** Constructing an assessment from the 2017 IRP, I estimate that the Company's coal units will incur [redacted] million in present value losses, above the Company's flawed estimate of a long-run cost shift, discounted at $417 million. This analysis assumes that PacifiCorp does not need to construct additional environmental equipment for compliance with the Regional Haze rule.

10. **Distributed generation avoids harmful air emissions**. PacifiCorp's short-term COSS analysis does not account for the near-term societal benefits of

reducing harmful air emissions. On a monetized basis, I estimate short-term (2015 only) health benefits of about $530,000.

11. **Distributed generation can contribute to avoided environmental compliance obligations**. Seven units in the Company's coal fleet currently require selective catalytic reduction ("SCR") by 2021/2022. The Company's high-penetration estimate of distributed generation contributes to the ability to retire, without replacement, one or more non-economic coal units, resulting in system cost savings.

Q How should your findings be considered by the Commission in this docket?

A My findings demonstrate that the benefits of distributed generation resources reach well beyond the short-term benefits illustrated in the Company's COSS analysis. At this time, I am not making a specific recommendation to adjust the value as I believe that there are far broader benefits than can be captured in either PacifiCorp's short-term COSS analysis or even through the current 2017 IRP. The Company has not provided sufficient information through a reasonable mechanism to assess the short- or long-term benefits of distributed generation, and its estimates of long-run costs are clearly flawed.

In the November 2015 order, the Commission asks that "to the extent any party believes a cost impact of net metering should be included in one of the studies or used to supplement the result of a study, the party bears the burden to demonstrate the existence of the impact and that it will be (or has been) realized in the test period." Many of the benefits associated with distributed generation will not be realized in the test period, and cannot be recognized by PacifiCorp's COSS analysis. Yet, they are recognized by other studies, including those conducted by PacifiCorp.

Overall, my analysis supports the current net metering construct, or a similar construct, as just and reasonable. The continued growth of solar distributed generation, stimulated in part by the current net metering tariff, will provide near-term emissions and health benefits, allow for greater cost-effective utility-scale renewable energy penetration, and may ultimately help displace some of the Company's least cost-effective thermal boilers.

2. PACIFICORP NET POWER COST ANALYSIS NEGLECTS SHORT- AND LONG-TERM SYSTEM BENEFITS

Q Describe the benefits of distributed generation found by the Company in the COSS analysis.

A The COSS analysis provided by the Company relies on a 2015 Net Power Cost ("NPC") filing. In the NPC, the Company ran the GRID production cost model in two forms: one with then-present Utah net metering customers, and one without the 57,784 MWh of distributed generation provided by those customers.[2] Mr. Wilding reports that, based on the NPC study, there is a system benefit of "approximately $1.3 million if the Company were required to supply the energy that was otherwise generated by net metering customers."[3]

Q Please describe the elements of the $1.3 million benefit reported by Mr. Wilding.

A The benefit reported by Mr. Wilding can be broken into four components: avoided fuel costs from PacifiCorp generators, avoided off-system purchases, increased off-system sales, and a solar integration cost. Holding aside the solar integration cost, the Company finds an avoided energy benefit of $1.45 million.[4]

Of the $1.45 million in benefits, $635,000 are generated by increased off-system sales (particularly in July and August),[5] $453,000 are an outcome of reduced off-

[2] Direct Testimony of Robert Meredith, line 272.

[3] Direct Testimony of Michael Wilding, lines 73-75.

[4] Value differs between workbooks. MGW-1, line 40 without integration cost (line 38) results in $1.451 million in NPC benefits; Wilding workbook "UT Net Metering - GRID AC Study CONF _Base_NoNEM" shows [redacted] million in NPV benefits (tab "Delta", cell E262).

[5] Sum product of MGW-1 line 10 (UT Net Metering Solar Generation) and line 34 (Unit Value of Solar - Purchases/Sales [mislabeled, should read "Sales" only]).

system purchases (June to August),[6] and the remaining $363,000 are savings from reduced system generation (primarily in the spring and autumn).[7] Over 90 percent of the estimated savings from reduced system generation are from coal,[8] and [redacted]

All of the elements of the NPC study are avoided energy only.

Q What are your concerns with the Company's COSS analysis?

A Focusing only on the COSS analysis, and not the benefits excluded from the COSS analysis, I have two high level concerns. First, the assumed integration cost for solar is not reasonable at this time. Second, the avoided energy cost does not capture all of the short-term avoidable costs experienced by PacifiCorp.

Q Why is the $2.83/MWh integration cost for solar not reasonable?

A This value is outdated and does not represent PacifiCorp's estimated integration costs. For this figure, the Company cites to a mid-2013 order in docket 12-035-100. In that Order, the Commission acknowledges the absence of a solar integration study and offered, in its stead, a Division proposal to apply a fraction of the estimated 2012 Wind Integration Study (WIS) costs, resulting in $2.83 per MWh cost.

There are a few notable components of this cost:

[6] Sum product of MGW-1 line 10 (UT Net Metering Solar Generation) and line 35 (Integration Cost - Fixed Solar [mislabeled, should read "Purchases"]).

[7] Sum product of MGW-1 line 10 (UT Net Metering Solar Generation) and lines 36-37 (Unit Value of Solar – Coal / Gas [respectively]).

[8] Id.

[9] Author's calculations based on Wilding workbook "UT Net Metering - GRID AC Study CONF _Base_NoNEM" tab "Delta", cells E203 and E262.

- First, the basis for the cost is now more than five years old, having originated in a 2012 Q2 Schedule 38 compliance filing.[10]
- Second, the $2.83/MWh represented a proxy cost, estimated by the Division in the absence of better information.[11]
- Third, unlike other NPC costs, the integration charge is based on a projected long-run cost, levelized over a 20-year period (2013–2033).[12]

Since 2012, the Company has conducted two additional integration studies in support of the 2015 and 2017 IRPs, respectively. In that time, the costs of integration have dropped substantially. Table F.22 of the 2017 IRP shows a 2014 Wind Integration cost of $3.06/MWh, dropping in 2017 to $0.57/MWh for wind and $0.60/MWh for solar.

Substituting in the contemporaneous solar integration costs results in an upward adjustment of the distributed generation benefits from $1.29 to $1.41 million.

Q Does the Net Power Cost study capture all of the reasonable avoided costs of solar?

A No. The NPC study misses substantial real benefits over both the short and long run. The NPC study cannot account for any form of capacity benefit, reduced capital expenditures for generation, transmission, distribution, or social benefits.

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[10] Direct Testimony of Greg Duvall 12-035-100 at lines 436-439, January 31, 2013.

[11] Phase II Order in 12-035-100 (August 2013), page 33. "The Division therefore proposes that Fixed Solar resources be charged an integration cost of 65 percent of the current $4.35 per megawatt hour wind integration cost, or approximately $2.83 per megawatt hour and 50 percent of the $4.35 per megawatt hour or $2.18 per megawatt hour for Tracking Solar. **The Division recommends these proposed solar integration costs as interim measures until such time as PacifiCorp provides a definitive solar integration cost study or until another party provides better estimates**."

[12] Phase II Order in 12-035-100 (August 2013), page 31. "To account for wind integration costs, PacifiCorp proposes using its 2012 Wind Integration Study ("WIS"), as included in the 2013 IRP. In the WIS, PacifiCorp calculates wind integration cost to be $4.35 per megawatt hour, on a levelized basis over a 20 year period beginning in 2013."

Q Are these elements common to distributed solar valuation studies?

A Yes. Typical "value of solar" studies start from a structure of avoided long-term costs, and build from there. In addition to avoided energy costs, valuation studies include avoided capacity, avoided transmission and distribution losses, avoided transmission and distribution investments, avoided emissions compliance payments, avoided ancillary services, and avoided renewable energy credit (REC) purchases if applicable. In addition, some jurisdictions assess avoided health and environmental impacts associated with reduced central station generation and emissions.[13]

Q What should the Company's NPC framework represent?

A The Company's Net Power Cost analysis is supposed to capture all of the variable costs of production at PacifiCorp over a year, based on the output of the GRID model. By extension, the difference between two NPC studies was supposed to have represented the total *avoidable energy only* cost of distributed solar generation.

Q Even within this narrow scope, does the NPC framework successfully capture all of the elements of avoidable energy cost on the operational margin?

A No. The NPC framework fails to capture the variable cost of operations and maintenance ("O&M") at PacifiCorp's coal-fired power plants, or the full cost of fuel at multiple facilities. By casting some fuel costs as fixed contract costs and others as capital costs, the Company excludes substantial costs from consideration in the NPC. Using Jim Bridger as a key example, avoided generation at Bridger is

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[13] See, for example, Denholm, P.; Margolis, R.; Palmintier, B.; Barrows, C.; Ibanez, E.; Bird, L.; Zuboy, J. 2014. *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System*. 86 pp.; NREL Report No. TP-6A20-62447.

priced at the avoided cost of fuel only, neglecting both variable (and avoidable) O&M and fuel costs incurred at Bridger mine.[14]

In the 2017 IRP, the Company estimates $[redacted] in variable O&M at Jim Bridger plant in 2016,[15] a fraction of which should be rendered avoidable in the NPC,[16] but was not (adding [redacted] percent to the NPC study).

Fuel costs are another example in which the Company's avoided NPC calculations are out of step with actual costs. The avoided cost of coal in the NPC study is based on the Company's assessed "cash cost" of coal, which is sometimes critically different than the actual procurement cost of that fuel. For example, at the Jim Bridger plant, [redacted],[17] the Company assesses a dispatch coal cost of [redacted]/MMBtu[18] and an "actual" cost of [redacted]/MMBtu in 2015.[19] In contrast, PacifiCorp reports to the Energy Information Administration (EIA) that the all-in cost of fuel at Bridger was $2.71/MMBtu in 2015.[20] The difference between these values are capital costs and depreciation expenses incurred at the Bridger Mine, which the Company considers for EIA reporting, but not for cost purposes in the NPC. This is an

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[14] Mr. Wilding notes that 29 percent of the energy avoided by distributed generation is from displaced coal generation. Direct Testimony of Michael Wilding, Table 1. Mr. Wilding's workpapers demonstrate that [redacted]

[15] Workpapers from Utah docket 17-035-16 (2017 IRP Review) provided in response to HEAL DR 2.1(a). Workpapers\CONF\Data Disk 2_CONF\Assumptions + Inputs Conf.zip\Assumptions + Inputs\Master Assumptions, CONF\Vol III RH5\2017 IRP Alt. Case RH-5 20161212.xlsx, tab "2 - NonCAI O&M (Nom$)."

[16] Estimated at [redacted] in 2015. Author's calculation from difference in Bridger generation from Wilding workbook "UT Net Metering - GRID AC Study CONF _Base_NoNEM."

[17] Refer to Michael Walding CONF workpaper UT Net Metering - GRID AC Study CONF _Base, line 203 ("Coal Fuel Burn Expense") divided by line 465 ("Coal Generation").

[18] Refer to Michael Walding CONF workpaper UT Net Metering - GRID AC Study CONF _Base, line 616 ("Average Fuel Cost").

[19] Wilding Exhibit MGW-4, line 288 ("Coal Fuel Burn Expense") divided by line 288 ("Coal Generation") to yield $/MWh; divide by heat rate in Michael Walding CONF workpaper UT Net Metering - GRID AC Study CONF _Base line 586 ("Burn Rate (MMBtu/MWh)").

[20] EIA Form 923.

inappropriate decoupling that obfuscates the real cost of fuel procurement at Bridger, and therefore the real opportunity to avoid fuel procurement costs. Recent history at the Bridger Coal Mine has decisively demonstrated that the Company regularly assesses tradeoffs between high capital and high variable cost coal at Bridger. In other words, the Company is able to reduce fixed capital costs by increasing high variable cost fuel. Since these substitutions can be made on an ongoing basis, it implies that far more—if not all—of the costs incurred at Bridger mine should be considered avoidable.

Accounting for the full 2015 cost of fuel procured for Bridger, or the potential to avoid an incremental fuel requirement, increases the NPC benefit of distributed generation by an incremental [redacted] percent. Actual fuel costs at Bridger in 2016 were yet higher, at $3.00/MMBtu, resulting in an NPC benefit adjustment [redacted] percent higher than provided by the Company. While these values, and that of the O&M costs, appear relatively small, they are indicative of the uncertainties and short-term view incumbent in the NPC study.

These neglected costs from the NPC only begin to scratch the surface of the system costs avoided by distributed generation. In the next section, I discuss the evidence—from PacifiCorp studies—that demonstrates distributed generation avoids new capacity and enables additional non-distributed generation cost-effective renewable energy.

3. Distributed Generation Avoids New Capacity, Allows New Renewable Energy

Q Does the Company demonstrate that it believes distributed generation will continue to grow substantially and contribute as a system resource?

A Yes. PacifiCorp witness Joelle Steward estimates an ongoing rapid growth of distributed generation with reference to the cost-shift potential over time. Ms.

Steward estimates a cost shift of $27 million per year in 2020.[21] In doing so, she assumes 316 MW of installed distributed generation in Utah over the next three years, or approximately seven (7) times today's installed capacity. In fact, Ms. Steward's long-run cost shift of $667 million through 2035[22] relies on an estimated 16 percent cumulative average growth rate projected in an independent Navigant Study, topping out at 731 MW of installed capacity by the end of the analysis period.[23]

The Navigant study used by Ms. Steward features prominently in the 2017 IRP, filed April 4, 2017.[24] The base case findings from this study are incorporated into the IRP as a reduction to load, while the low- and high-penetration cases are examined as sensitivities (called PG-1 and PG-2, respectively). Comparing the results of high- and low-penetration cases demonstrates the system resource value of solar assumed and modeled by PacifiCorp. Table 1, below, shows the total present value of revenue requirements (PVRR) for sensitivities with low and high distributed generation penetration (Low DG and High DG, respectively) and the resulting cost differential between the cases.

[21] Direct Testimony of Joelle Steward, lines 200-201.

[22] Direct Testimony of Joelle Steward, lines 204-205.

[23] Workpapers of Joelle Steward, 290065WrkpaperStewardTestCopyPotFutCostShiftResNEM11-9-2016. Tab "Navigant Forecast."

[24] 2017 IRP, Volume II, Appendix O. Private Generation Long-Term Resource Assessment (2017-2036). Prepared by Navigant Consulting for PacifiCorp. Final December 22, 2016.

Table 1. System resource benefit of distributed generation from 2017 IRP (million $)

	Low DG Penetration (PG-1)	High DG Penetration (PG-2)	Difference (Resource Benefit)
System Optimizer[25]	$23,304	$22,899	$405
PaR[26] (90th percentile)	$23,417	$22,985	$432
Risk Adjusted PVRR[27]	$24,794	$24,330	$464
PaR expected w/ CO_2[28]	[redacted]	[redacted]	[redacted]

Both of the models used by the Company in the 2017 IRP, System Optimizer and Planning and Risk (PaR), assessed over $400 million (NPV 2017–2036) in system benefits from faster distributed generation penetration. PacifiCorp's model estimates that in out-years, customers will save $142 million (2016$) per year[29] with higher distributed generation penetration, amounting to $100/MWh of savings (2016$) from 2028–2036.

Of the 20 sensitivity cases examined by PacifiCorp in the 2017 IRP, the case in which customers provided substantial self-generation (PG-2) consistently produced the lowest overall system costs.[30]

What accounts for the substantial system savings with increased distributed generation penetration? PacifiCorp's model assesses that increasing customer-sited penetration has the ability to displace the need for large central-station generators, and allows lower cost energy into the system.

[25] 2017 IRP, Volume 2, Table K.3.

[26] 2017 IRP, Volume 2, Table L.21.

[27] 2017 IRP, Volume 2, Table L.31.

[28] 2017 IRP workpapers, \CONF\Data Disk 3_CONF\PaR Summary Reports\PaR Summary Report Sensivities.zip\PaR Summary Report\PaR Stochastic Summary PG-1_MB and PaR Stochastic Summary PG-2_MB, tab NPV, cell D3.

[29] Derived from PaR outputs, average outcomes with PAC fixed cost adjustment. Assumed 2.22 percent inflation to adjust to 2016$. Includes CO_2 pricing as derived by PacifiCorp and included in PaR runs.

[30] Exception is "low load" sensitivity which envisions a nearly 1,000 MW peak load reduction from base case conditions by 2036.

Q What is your evidence that incremental distributed generation avoids new thermal capacity requirements?

A The Company's 2017 IRP definitively shows a reduction in central station generating capacity with increased distributed generation resources. The System Optimizer model, used for capacity expansion modeling in the IRP, generally starts selecting new thermal resources in out-years after PacifiCorp allows existing coal units to retire. In the low distributed generation sensitivity (PG-1), five new gas-fired generators (1,568 MW) are built between 2029 and 2035, while in the high distributed generation sensitivity (PG-2), only three new generators (1,113) are built. Specifically, the model makes three markedly different choices: first, it downsizes a west-side combined cycle gas turbine (CCGT) from 509 MW to 436 MW, and defers its construction date back by a year; second, it defers a new 447 CCGT in Wyoming from 2030 to 2033; finally, it simply avoids two simple-cycle turbines in Utah and Wyoming in 2033 and 2035 (200 and 182 MW, respectively). Overall, the increased distributed generation scenario avoids 455 MW of new thermal capacity requirements.

Q If the avoidable thermal capacity resources all appear in modeling after 2028, why do they matter for the Commission's decision today with respect to the benefits of distributed generation?

A First, the avoidable central-station thermal resources are a demonstration that sufficient distributed generation can have a substantial impact on resource decisions at the utility. Second, the distributed generation installed today will likely still be in operation in a decade and contribute to decisions in 2028.

The amount of distributed generation installed today, while growing quickly, is still relatively small. PacifiCorp's long-term modeling is designed to dampen the impact of small capacity changes, but this does not diminish the intrinsic capacity contribution of distributed generation, as demonstrated through the Company's modeling.

In early years, distributed generation avoids short-term market capacity purchases, called "front office transactions" (FOT) by the Company. PacifiCorp asserts that it has the opportunity to acquire up to 1,575 MW of these market capacity resources from off-system purchases.[31] FOTs are used heavily in interim years during periods of capacity shortage. Taking these FOTs into account as capacity resources, PacifiCorp's model assesses that 119 MW of summer FOT resources are avoidable by 2027 through the use of increased customer-sided distributed generation resources.[32] In the Company's modeling, every installed MW of distributed generation capacity contribution avoids about 0.5 MW of FOT acquisition through 2027,[33] more than the capacity value of the distributed generation resource.[34]

Q What is your evidence that incremental distributed generation allows for incremental cost-effective renewable energy acquisitions?

A The Company's 2017 IRP shows a substantial increase in cost-effective 2021 wind procurement for deeper penetrations of distributed generation. Overall, the IRP indicates that large amounts of cost-effective wind are available in Wyoming, but for transmission constraints. Increased distributed generation may free up otherwise constrained transmission, which allows incremental wind resources to come online. In 2021, the low distributed generation case (PG-1) acquires 211 MW of Wyoming wind, the reference case acquires 229 MW, and the high distributed generation case (PG-2) acquires 300 MW of wind.[35] Figure 1, below, shows that there is nearly a one-to-one procurement of low-cost wind in 2021 for

[31] 2017 IRP, Table 6.16

[32] 2017 IRP, Appendix K (PG-1 and PG-2), difference between sum of non-winter FOTs.

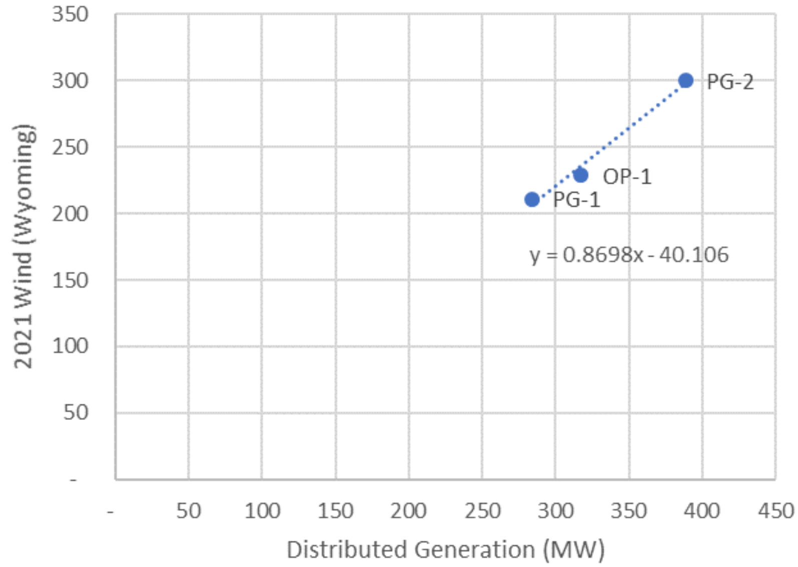
[33] PG-1 assumes 440 MW of DG by 2027, while PG-2 assumes 770 MW by 2027, a differential of 330 MW (Navigant study, Figure 9). PG-1 requires 939 MW of summer FOTs in 2027, while PG-2 requires 820 MW, a differential of 119 MW.

[34] PacifiCorp assumes [redacted] MW peak capacity per MW installed, as derived from peak loads in the 2017 IRP PG-1 and PG-2.

[35] 2017 IRP, Appendix K (PG-1 and PG-2).

every MW of distributed generation in PacifiCorp's system. Coupled with the distributed generation, this incremental wind procurement provides lower long-term system costs and cannot be captured in the short-term NPC study.

Figure 1. Wind procurement in 2021 against distributed generation penetration in the 2017 IRP.



Q What are your findings with respect to the system benefits of distributed generation?

A I find that the Company's NPC modeling only captures a fraction of the energy benefits of distributed generation and, in turn, those energy benefits are only a small component of the longer-run benefits of distributed generation as demonstrated through the Company's own modeling framework. The Company intrinsically assesses distributed generation as a system resource, and accounts for it in modeling as well as in long-term decision-making. The Company's IRP demonstrates that distributed generation provides a substantial near- and long-run capacity benefit and allows for incremental cost-effective renewable energy.

4. PACIFICORP'S COAL-FIRED UNITS WOULD FAIL UNDER DISTRIBUTED GENERATION TEST FRAMEWORK

Q Why is it appropriate to discuss the Company's coal-fired units in the context of this net metering case?

A There are two reasons that its appropriate to discuss the Company's existing fleet in this docket, both of which are contextual in nature.

First, the Company has evaluated the complete value of distributed generation on the basis of a single year net power cost—i.e. the avoided cost of energy only. It's important to demonstrate that some of the Company's most substantial assets would fail to show a benefit under the same test circumstances. Imagining for a moment that these massive plants were required to compete side-by-side with customer-owned solar, the three worst performing units ([redacted]) would require retail rates to simply break even.

Second, the economic performance of PacifiCorp's coal plants provides a reasonable check against the purported cost shifts of the distributed generation program. The Company calculates a short-term cost shift from residential distributed generation customers to other residential customers of $1.7 million in 2015,[36] and "at least $6.5 million" in 2016.[37] As a point of comparison, however, PacifiCorp customers (system-wide) were subject to losses of about [redacted] million in 2016 at 11 coal-fired power plants,[38] or about [redacted] million on a Utah residential jurisdictional basis.[39]

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[36] Direct Testimony of Mr. Michael Wilding, line 129.

[37] Direct Testimony of Joelle R. Steward, lines 40-41.

[38] Relative to Mid-Columbia energy prices, based on data from PacifiCorp 2017 IRP workpapers.

[39] Assumes 44 percent allocation to Utah (EIA 861, 2015), and 38 percent allocation to residential customers in Utah (workpapers for RMM-1).

In addition, the Company assesses a long-run cost shift of $667 million[40] through 2035, a value that relies on erroneous assumptions and lacks context.

In this section, I'll discuss my analysis of the Company's coal fleet based on recently released information from the 2017 IRP. I'll also compare the Company's assessment of distributed generation against my assessment of the coal fleet on as equal terms as feasible.

Q How is Ms. Steward's long-run cost-shift value calculated?

A Ms. Steward simply takes the 2015 cost shift and increases it linearly with Navigant's expected residential distributed generation penetration in Utah through 2035. She then takes the sum across all years, without discounting.

Leaving aside the validity of the 2015 cost-shift assessment itself, this long-term cost-shift calculation is fundamentally flawed. The cost shift represents excess costs not recovered through net metering customers and thus potentially imposed on other customers. But as distributed generation penetration rises, PacifiCorp's portfolio will change as well and in reaction, by shedding some resources and by avoiding new capital costs and other energy costs. The value of the cost shift will change year to year, and it could reasonably be expected to fall on a per-customer basis as overall system costs (not just net power costs) are offset. From the perspective of a long-run cost-shift assessment, there are at least two critical elements that can be expected to change over time with increasing distributed generation: (a) distributed generation avoids and defers new future capacity resources, reducing the balance of fixed revenues that the Company must recover from the "cost" side of the ledger; (b) distributed generation may allow the Company to more readily retire (without replacement) high fixed cost existing plants; and (c) increasing distributed generation can allow larger plants to de-

[40] Direct Testimony of Joelle Steward, lines 204-205.

commit, avoiding substantial off-peak energy cost losses from the highest cost units.

The 2017 IRP indicates that distributed generation can be expected to have a substantial impact on the overall shape and structure of the PacifiCorp system. The difference between the Low DG and High DG penetration scenarios in the 2017 IRP, and the resulting $400+ million in savings (net present value) are indicative that the cost shift should be dampened over time.

Ms. Stewards' simplified assessment implicitly assumes that PacifiCorp is only able to avoid operational energy costs, that marginal energy costs do not change, and that the portfolio of resources contributing to PacifiCorp's system remain static. Overall, I would expect a correctly calculated cost shift, if occurring at all, to be substantially lower than that proposed by Ms. Steward.

Finally, there are few circumstances in utility long-term planning where discussing a potential cost incurred today (or comparable to today) is appropriate without discounting. To ensure that Ms. Steward's total cost-shift estimate is on par with other resource planning costs, we can discount the inflation-adjusted series using PacifiCorp's 2017 IRP discount rate of 6.57 percent, resulting in a total long-term cost shift of $417 million, rather than $667 million.

Aside from the fact that the cost shift should be mitigated substantially over time, we can compare this total cost shift against the valuation of other resources to determine if ratepayers are treated unreasonably.

Q You state that some of the Company's most substantial assets would fail to show a benefit under the distributed generation cost test performed in this docket. Please explain.

A The COSS analysis provided by PacifiCorp in this docket assess the benefit of distributed generation as its avoided cost of energy in 2015 only. If this same criteria were used to assess the economic value of the Company's thermal generation portfolio , almost every coal-fired unit would fail to show a benefit.

Holding aside the Company's integration cost reduction of $2.83/MWh, Mr. Wilding shows an avoided NPC of $22.32/MWh.[41] Eight PacifiCorp coal-fired units, representing 2,200 MW of capacity, have average production costs above that avoided NPC value.[42] All, save two, of PacifiCorp's coal units have an average all-in cost (including capital and fixed O&M) above that cost. The average all-in cost of energy for [redacted] representing [redacted] MW of capacity, are above $88.50/MWh –PacifiCorp's first Schedule 1 residential block rate. At the moment, all customers are paying for the full cost of those units.

Q How did you determine the "average production cost" for PacifiCorp's coal units?

A I pulled production costs directly from the Company's input and output files for the System Optimizer model as used in the 2017 IRP. In this case, "average production cost" represents the average of the unit's production cost across every year through the end PacifiCorp's end of life, adjusted to 2016$.[43]

Q How did you determine the "average all-in cost of energy" for PacifiCorp's coal units?

A In addition to the annual production cost, I pulled annual fixed, variable, labor, and overhaul O&M values from PacifiCorp's System Optimizer input files.[44] In

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41 Direct Testimony of Mr. Michael Wilding, page 8, Table 3.

42 [redacted]

43 Preferred Portfolio. Source: PacifiCorp 2017 IRP workpapers, CONF\Data Disk 2_CONF\System Optimizer Output\Preferred Portfolio\Preferred Portfolio-Model Input+Output_CONF.zip\Model Input + Output\FS-GW4\StaMoPerf-I17_S_OP_GW4b0000.csv, column "Ave Var Cost."

44 Preferred Portfolio. Source: PacifiCorp 2017 IRP workpapers, CONF\Data Disk 2_CONF\Assumptions + Inputs Conf.zip\Assumptions + Inputs\Master Assumptions, CONF\Vol III RH5\2017 IRP Alt. Case

addition, I pulled annual Preferred Portfolio (FS-GW4) capital, including ongoing, mine, and environmental capital.[45] I created a simplified capitalization schedule, allowing capital costs to depreciate to PacifiCorp's end-of-life date, and incurring a return on investment (ROI) for remaining new capital balance. Like PacifiCorp, I excluded any consideration of current remaining plant balance in this equation, only taking into account new and expected fixed and capital costs.

For each unit, I divided the fixed cost by PacifiCorp's modeled annual generation for the unit to derive an estimated all-in cost of generation. Finally, I adjusted each year to 2016$ and took the average through PacifiCorp's end-of-life.

CONFIDENTIAL Figure 2, below, shows the average production and all-in cost of generation for each of PacifiCorp's coal units against Wilding's avoided NPC and the first block of Schedule 1 residential rates (8.8498c/kWh). As shown here, the all-in-cost of every one of PacifiCorp's coal units is above the avoided NPC value. This is, of course, expected—the average avoided cost of energy would generally be expected to be lower than the all-in cost of most types of generation, particularly in circumstances where capacity is not valued as part of the cost of energy (ERCOT being the exception). However, the degree to which PacifiCorp's coal units are above avoided NPC—being twice as high—is notable.

RH-5 20161212.xlsx. Tabs 2 - NonCAI O&M (Nom$), 1b - Clean Air CapEx, 7 - Runrate Plant CapEx, 11 - Mine Capital.

[45] Note that because this is the Preferred Portfolio, it does not include the incremental additional costs of Selective Catalytic Reduction (SCR) at Hunter 1, Hunter 2, Huntington 1, Huntington 2, Jim Bridger 1, Jim Bridger 2, or Wyodak, as required under promulgated Federal Implementation Plans. The addition of these environmental capital costs would render the all-in cost of these units substantially higher.

CONFIDENTIAL Figure 2. Average production cost and all-in cost of PacifiCorp coal units (2016$) relative to 2015 NPC and current retail rates (first block).

[redacted]

Overall, this assessment demonstrates that even PacifiCorp's most established generation units would fail an avoided NPC benefit test, and as I'll show below, they also fail a cost-shift test.

Q Do you find a negative value for any of PacifiCorp's coal units today?

A Yes. I find a negative net value for [redacted] representing just under 2,000 MW of capacity. In addition, I would consider [redacted] "on the bubble" in that they are marginal with no clear benefit. This assessment is extremely conservative in that it assumes [redacted] do not require SCRs and can instead be retired in [redacted] as per PacifiCorp's alternative regional haze plan in the 2017 IRP. Indeed, SCR capital costs could readily tip [redacted] and [redacted] into a negative value range.

I estimate [redacted] million (2016$ NPV) in current fleet liability, excluding new SCR requirements (or as per Ms. Steward's non-discounted sum methodology, $[redacted] million in losses).

Q How can the distributed generation cost shift and the coal liability be compared?

A Directly. PacifiCorp has oriented towards stopping the losses incurred by a failure to collect revenue from distributed solar customers, asserting that these are costs imposed on other ratepayers. Ms. Steward attributes a potential long-term cost shift of $667 million, or $417 million on a net present value basis. I estimate a similar scale of loss at [redacted] million over a shorter timeframe that will be incurred by all ratepayers, and that only serves to prop up increasingly non-viable generating sources. Unlike distributed generation, these liability coal units are not paid for out-of-pocket by customers, do not reduce net system costs, do not avoid transmission losses, do not reduce harmful emissions, and prevent existing transmission from being used for cost-effective clean energy resources.

Q How did you calculate the value of individual coal units?

A I constructed a cash flow analysis from the same 2017 IRP data sources used to determine the "all-in" cost of each coal unit. As a "replacement" portfolio, I tested the retirement of each unit in 2018 (having incurred and paid for all capital in 2017 & 2018), then replaced each with market-based energy from the Mid-Columbia hub for 2019 through the unit's end-of-life date. The difference between these two cost streams is the value of the coal unit.

CONFIDENTIAL Figure 3, below shows a graphical example for Naughton 1.

CONFIDENTIAL Figure 3. Valuation analysis for Naughton 1. Annual cost against

[redacted]

This example shows the total fuel, O&M, and amortized capital costs through 2029, as per the modeled output of Naughton 1 in the 2017 IRP (System Optimizer, Preferred Portfolio). Overlaid is a line representing the annual cost of Naughton 1 in 2017 and 2018 (higher in those two years to accept the accelerated depreciation of capital in 2017 and 2018), transitioning to market-based energy from Mid-Columbia 2019–2029. This graph shows that the all-in cost of Naughton 1 is [redacted] the replacement cost in [redacted] resulting in a net [redacted] value.

Q Why is it reasonable to assess the coal plants against market-based energy?

A The Company's 2017 IRP shows that PacifiCorp believes 1,575 MW of market energy-based FOTs are available (at least). These products, priced at the cost of market energy, but available for capacity purposes, effectively set a capacity price near zero. In PacifiCorp's estimation, there is effectively no incremental cost to acquire an FOT over spot energy market purchases, but the FOT provides capacity value as well. This implies that sellers are not charging a capacity premium for these products, and PacifiCorp expects that this trend will continue through 2036 at least. Therefore, following PacifiCorp's logic, it is reasonable to assess the existing coal fleet against market energy prices.

Q What is your valuation for PacifiCorp's coal fleet with 2018 assumed alternative retirements?

A Overall, I assess $681 million in losses at 10 units that are well below a classification of "marginal," as per CONFIDENTIAL Table 2, below.

CONFIDENTIAL Table 2. Valuation for PacifiCorp coal units, as derived from 2017 IRP Preferred Portfolio. PacifiCorp share.

Unit	End of Life	Total Value (M 2016$)	Value (2016$/kW)
[redacted]			

Again, these costs do not include the SCRs currently required by EPA's Regional Haze Federal Implementation Plans for Utah or Wyoming, which could render some of these units substantially deeper liabilities than as indicated above.

Q Are PacifiCorp's coal plants long-term liabilities only, or are there also losses being incurred today?

A PacifiCorp's coal fleet incurs substantial losses today. Relative to potential market revenues, [redacted] incur losses today, amounting to an estimated [redacted] million in 2017 (2016$). This is the difference between the total production cost of each unit plus its O&M expenses (no capital) and the market price at Mid-Columbia for the same amount of energy. Again, I believe this to be a valid assessment as (a) the Company is flush on capacity through non-capacity market transactions, and (b) the Mid-Columbia hub is the [redacted].

These units would not show up in the NPC assessment as specifically out of merit because most of their losses are incurred from O&M expenses, which are not considered avoidable in the NPC assessment. If O&M expenses were considered avoidable, I would predict that these units would be displaced by distributed generation, and not market energy, as reported by Mr. Wilding.

Q If elements of the Company's coal fleet are such a substantial liability and are incurring current day losses, why hasn't the Company found economic retirements in the IRP process, or even outside of it?

A This raises a particular question about the validity and veracity of the Company's IRP process overall, but I'm quite certain that the simple answer is that the process is substantially simpler for PacifiCorp if the Company can simply make decisions about its coal units outside of the IRP process. Thus far, PacifiCorp (uniquely amongst U.S. utilities) has decided that its coal fleet is almost all cost effective—with very few exceptions—but generally has shown no sense of obligation to demonstrate that assertion. PacifiCorp's IRP process, by design, is unable to assess cost-effective coal plant retirements and does not provide a mechanism to regularly assess the value of the existing fleet. PacifiCorp's preferred mechanism seems to be to wait for specific triggering events (such as environmental compliance proceedings), pushing them off if possible. This leaves the Company in a position of having current liabilities on the books with current day losses, but providing no mechanism of regulatory review.

Q Please summarize your findings with respect to the validity of the net power cost assessment and cost-shift analysis.

A As a point of illustration, I compared the current production and "all-in" costs of the Company's current coal fleet against the avoided NPC costs, and determined that most of the fleet would not pass this screening assessment as a "system benefit." Further, three units have total costs of generation that rival residential retail rates.

The Company's focus on the magnitude of the overall cost shift through 2035 and its potential impacts on ratepayers is belied by the Company's inattention or misdirection with respect to its current coal fleet, which is both incurring current day losses an order of magnitude larger than the calculated 2015 cost shift, and long-term losses far in excess of the calculated total cost shift so touted by the Company in this filing. Overall, I believe Steward's long-term distributed generation cost-shift assessment lacks validity, is incorrectly structured, and pales in comparison to the losses being incurred by the existing coal fleet.

5. DISTRIBUTED GENERATION AVOIDS HARMFUL AIR EMISSIONS

Q Are there benefits to distributed generation that cannot be captured through PacifiCorp's NPC model?

A Yes. One notable short-term *and* long-term benefit is the reduction in harmful air pollution from thermal boilers. Along with carbon dioxide (CO_2), fossil fuel combustion releases harmful air pollutants such as oxides of nitrogen (NO_X), sulfur dioxide (SO_2), and coarse and fine particulate matter (PM_{10} and $PM_{2.5}$). Increasing distributed generation and other clean energy resources displaces marginal generation, which, on an operational basis is usually fossil fuel-based.

Over the long run, distributed generation displaces the need for new thermal capacity (as described above) and can ultimately contribute to the ability to retire existing generation (as I'll describe later). In reducing both short- and long-term fossil generation, distributed generation avoids emissions from fossil generation, resulting in statistically improved health outcomes with monetizable benefits.

Q Do the externalized benefits of distributed generation impact today's rates?

A In the construct currently considered by the Commission, no. However, damages to health and wellbeing do drive state and federal policies, which can be considered internalizations of these otherwise external costs. Even without these policies, emissions still directly impact Utah and non-Utah populations; the opportunity to avoid these emissions poses a direct benefit to both distributed generation participants, other ratepayers, and regional populations as a whole.

Q How does one ascribe a value to avoided damages from emissions due to programs like distributed generation?

A For the purposes of distributed generation valuation, health benefits can be monetized by taking into account the value of a statistical life (VSL), a notional value society imparts on health and wellbeing. The relationship between new clean energy and monetized health impacts is well established and extensively studied. [46] The literature on this topic includes an early groundbreaking study commissioned by multiple Utah state agencies.

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[46] For a methodology applied to distributed generation, see Denholm, P.; Margolis, R.; Palmintier, B.; Barrows, C.; Ibanez, E.; Bird, L.; Zuboy, J. 2014. *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System*. 86 pp.; NREL Report No. TP-6A20-62447.

The monetary valuation of short- and long-run health benefits imparted by distributed generation requires three steps: (a) the evaluation of emissions avoided or displaced by distributed generation, (b) the health impacts of those reduced emissions, and (c) the valuation of the health impacts.

Distributed generation displaces emissions both within a utility's system, and because of the well-connected electrical system, beyond its boundaries. For example, PacifiCorp calculates that more than two-thirds of displaced generation occurs outside of its service territory in the NPC study.[47] Calculating emissions displaced in the wider region from distributed generation or other clean energy requires either a regional dispatch model (like PacifiCorp's Aurora production-cost model used in the IRP[48]) or a purpose-built tool such as EPA's Avoided Emissions and Generation Tool (AVERT).[49]

Q Does the Company claim an avoided emissions benefit from renewable energy in its application?

A Yes. Dr. Gary Hoogeveen testifies that the Company's "Blue Sky customers supported 159 million kilowatt-hours of western region wind energy providing benefits equivalent to planting 2.2 million trees."[50] In describing his methodology, he describes that "the Company utilizes EPA guidelines to calculate environmental benefits,"[51] and shows the Company's reliance on an older avoided

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[47] See Direct Testimony of Michael Wilding, Table 1 (page 3). Change in System Balancing Sales (22 GWh) and Purchases (17 GWh) account for 67 percent of avoided total generation (58 GWh). Only 18 GWh are displaced from coal and gas in PacifiCorp's system over the short run.

[48] 2017 IRP, page 151. "Aurora [is] the production cost dispatch model used by PacifiCorp to generate a long-term wholesale power price forecast for each natural gas price scenario."

[49] Previously at https://www3.epa.gov/avert/index.html. EPA's site, including AVERT, is currently under reconsideration. Archived version of tool is available from various academic institutions and Synapse Energy Economics.

[50] Direct Testimony of Gary Hoogeveen, lines 340-342.

[51] EFCA DR 1.24(b).

emissions calculation provided by EPA.[52] EPA's calculation is regional in nature, accounting for power plant emissions throughout the northwest. Clearly, the Company recognizes the regional avoided emissions benefits provided through increasing renewable energy.

Q How do health benefits result from avoided emissions?

A A series of studies evaluate the impacts of emissions on health, such as a seminal study of emissions in the Wasatch Front by Dr. C. Arden Pope,[53] and subsequent detailed emissions and damages studies.[54] The process of monetizing health damages for the purposes of pricing emissions is not new. In 2009, public health researchers published a detailed study of damages on a per-ton basis from coal-fired power plants,[55] and in 2010 the National Research Council published a detailed monograph detailing estimated damages per ton from most large U.S. fossil-fired generating stations.[56]

Several studies have put all of the pieces together, estimating highly detailed displaced emissions, exposure to those emissions via atmospheric transport models, health damages from that exposure, and the monetized value of those damages. A recent study in the east coast calculated between $54 and $120/MWh of health and climate benefits from offshore wind[57]—about half of which are attributable to health impacts alone. The EASIUR model, designed by researchers

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[52] EPA's eGRID-based "non-baseload" emissions factor.

[53] Pope C.A., III, Schwartz J., Ransom M.R.. "Daily mortality and PM_{10} pollution in the Utah Valley." *Arch Environ Health*. 1992;47:211–217. https://www.ncbi.nlm.nih.gov/pubmed/1596104.

[54] Levy, J. I.; Hammitt, J. K.; Yanagisawa, Y.; Spengler, J. D., "Development of a new damage function model for power plants: Methodology and applications." *Environmental Science & Technology* 1999, 33, 4364-4372.

[55] Levy J.I., Baxter L.K., Schwartz J. "Uncertainty and variability in health-related damages from coal-fired power plants in the United States." *Risk Analysis*. 2009 Jul; 29(7):1000-14.

[56] *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use* (2010).

[57] Buonocore, J.J., Luckow P., Fisher J, Kempton W., Levy J. 2016. "Health and climate benefits of offshore wind facilities in the Mid-Atlantic United States." *Environmental Research Letters*. 11(7).

at Carnegie Mellon University (CMU), is designed to allow users to rapidly assess the quantified and monetized health impacts on a per-ton basis of emissions from electrical generating units around the United States.[58]

Overall, there is a substantial suite of research and models that have been designed, tested, and rigorously peer-reviewed to assess the monetized health benefits of distributed generation.

Q Do other jurisdictions account for the value of avoided health impacts in assessing the value of solar?

A Yes. The Commissions of both Maine and Minnesota have published value of solar (VOS) studies that specifically assess the ability of distributed generation resources to avoid emissions of criteria air pollutants. The 2014 Minnesota study assessed an avoided cost per MMBtu of CO_2, PM_{10}, carbon monoxide (CO), NO_X, and lead (Pb).[59] The 2015 Maine study evaluated avoided damages per ton of CO_2, NO_X, and SO_2 using externality values for criteria pollutants published by the U.S. EPA in a Regulatory Impact Analysis (RIA).[60]

A study performed on behalf of the Public Service Commission of Mississippi evaluated the ability of distributed generation to avoid environmental compliance obligations, using the social cost of carbon as a proxy for the value of environmental compliance.[61]

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58 EASIUR: Marginal Social Costs of Emissions in the United States. http://barney.ce.cmu.edu/~jinhyok/easiur/. Based on Jinhyok Heo, Peter J. Adams, H. Oliver Gao, "Reduced-form modeling of public health impacts of inorganic PM2.5 and precursor emissions", *Atmospheric Environment*, 137, 80–89, 2016.

59 Minnesota Department of Commerce, Division of Energy Resources. Minnesota Value of Solar: Methodology. April 1, 2014. http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf. Attached as Exhibit HEAL___(JIF-3).

60 Maine Public Utilities Commission. Maine Distributed Solar Valuation Study. April 14, 2015. Executive Summary. http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-FullRevisedReport_4_15_15.pdf .Attached as Exhibit HEAL___(JIF-4).

61 Mississippi Public Service Commission. Net Metering in Mississippi: Costs, Benefits, and Policy Considerations. September 19, 2014. http://www.synapse-

Q Has Utah assessed the value of avoided health impacts for new renewable energy?

A Yes. In 2009, my firm, Synapse Energy Economics was contracted by Utah State agencies, including the State Energy Program, the Division of Public Utilities, the Division of Air Quality, the Committee of Consumer Services, and the Governor's Energy Advisor to develop and apply methods of calculating water and health co-benefits of displacing electricity generation technologies in Utah with new energy efficiency or renewable energy. The resulting study, attached as Exhibit HEAL___(JIF-2). estimated, for solar, a health-based displaced emissions benefit of about $19/MWh (2008$) and up to an additional $5.5/MWh of avoided water consumption.[62] This early model used emissions data from 2007, prior to extensive emissions retrofits at multiple coal units in Wyoming and Utah. We would expect a contemporary model to show more modest benefits as the overall emissions profile of the fleet has shrunk.

Q Have you constructed an estimate of the avoided health impacts associated with incremental distributed generation?

A Yes. I used EPA's AVERT model[63] and CMU's model[64] to assess the avoided health damages associated with 45 MW of residential solar, Ms. Steward's estimate of Utah residential penetration in mid-2016 at 45 MW. AVERT estimates that this level of DG would displace 24.9 tons of SO_2 and 44.68 tons of NOx in a single year alone. Using CMU's model for each power plant location, I estimate short-term avoided health-based damages of about $532,000 or $6.92/MWh.

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energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf. Attached as Exhibit HEAL___(JIF-5).

[62] See Table 1-2.

[63] 2015 EPA Data, Northwest Regional Data File as provided by US EPA; solar profile constructed

[64] 2015 population estimate.

Notably, AVERT does not yet estimate avoided particulate emissions, and thus a substantial component of health risk is missing from this estimate.

Q Could you use PacifCorp's NPC model results to assess the avoided health impacts associated with distributed generation?

A No. The NPC model only returns avoided generation in PacifiCorp's system, but as illustrated by the NPC model results, much of the displaced generation (and thus emissions) occur beyond the boundaries of PacifiCorp's plants.

Q Is it appropriate to consider avoided damages from distributed generation not imparted by PacifiCorp's plants?

A Yes. PacifiCorp's customers are impacted by emissions from plants not owned by the Company, and emissions from PacifiCorp's plants impact a population base far larger than those served by the Company. Avoided health damages are societal in nature, and should be assessed for the entire impacted population.

Q Does the AVERT study capture long-term avoided emissions impacts?

A No. Over the long run, if distributed generation (and other clean resources) are able to displace large emissions sources, the health contribution of distributed generation on a per MWh basis can be substantially larger. For example, the 2009 Utah State agencies study found that if clean energy programs and lower emissions generation were used to replace coal directly, the programs would result in health benefits of $67–$69/MWh. Again, since PacifiCorp's fleet achieves lower emissions than in 2007, the per MWh health impacts of replacement are not as dramatic, but still notable.

Q Please summarize your findings with respect to avoided health impacts.

A I find that PacifiCorp's NPC model, used by the Company to evaluate the benefits of distributed generation, fails to represent either a short- or long-run distributed generation health benefit. The avoided heath impacts imparted by customer-sited solar are substantial and they should be considered in setting just and reasonable rates for net metering.

6. Distributed Generation Could Avoid Emissions Compliance Costs

Q You state that distributed generation has the opportunity to avoid emissions compliance costs at existing coal-fired facilities. How so?

A PacifiCorp's coal-fired fleet has substantial impending environmental compliance requirements for the Regional Haze Rule. Finalized Federal Implementation Plans ("FIP") in Utah and Wyoming require selective catalytic reduction ("SCR") at Hunter 1 & 2, Huntington 1 & 2, Jim Bridger 1 & 2, and Wyodak by 2021 (2022 for Bridger 2). PacifiCorp estimates that, collectively, these retrofits will cost nearly [redacted],[65] and increase operational costs by over [redacted] per year (2016$ in 2023).[66] As I showed earlier, even without the retrofit requirements, much of the coal fleet is already non-economic. While, in my opinion, the Company should absolutely assess and seek to retire non-economic coal units even without an immediate impending capital requirement, the imposition of a capital requirement provides the opportunity to both retire non-viable coal plants and avoid compliance obligations.

Distributed generation will avoid some of the SCR catalyst replacement costs, a benefit not accounted for in the Company's NPC study, but more impactfully it can displace both the generation and a substantial fraction of the capacity from one or more of PacifiCorp's existing coal fleet; offering the opportunity to avoid substantial capital investments at an otherwise non-economic coal unit.

[65] Workpapers provided in response to HEAL DR 2.1(a). Workpapers\CONF\Data Disk 2_CONF\Assumptions + Inputs Conf.zip\Assumptions + Inputs\Master Assumptions, CONF\Vol III RH5\2017 IRP Ref Case 20161021.xlsx, tab "1g – Clean Air CapEx."

[66] Workpapers provided in response to HEAL DR 2.1(a). Workpapers\CONF\Data Disk 2_CONF\Assumptions + Inputs Conf.zip\Assumptions + Inputs\Master Assumptions, CONF\Vol III RH5\2017 IRP Ref Case 20161021.xlsx, tab "5 - NOX O&M."

The Company assesses that under a rapid distributed generation penetration scenario (titled PG-2 in the 2017 IRP), distributed generation could provide around 400 MW of nameplate capacity by 2021/2022,[67] or a peak contribution of about [redacted] MW.[68] While this is not sufficient capacity to displace Hunter, Huntington, Jim Bridger, or Wyodak, it does provide a substantial capacity benefit. In the high distributed generation penetration case (PG-2), the Company also assesses that there are over 940 MW of peak FOTs still available in 2021 and 830 MW of peak FOTs in 2022 after the retirement of Cholla 4. Taken together, the customer-sited distributed generation and PacifiCorp's asserted market-available FOTs leave room for a substantial cost-effective coal retirement without immediate replacement.

Q If customer-sited solar distributed generation continues to increase, which coal units could be retired cost effectively to avoid environmental compliance obligations?

A The obvious candidates are [redacted] My analysis of the coal units as derived from the 2017 IRP indicates that [redacted] are relatively clearly aligned for retirement, with 2021 SCR obligations and negative valuations relative to market-based energy.

CONFIDENTIAL Figure 4 (below) shows the relative valuation of each coal-fired unit (in $/kWh) in the PacifiCorp fleet including the SCR obligations. Coal plants with SCR requirements in 2021/2022 are highlighted in yellow. The figure shows that [redacted] are non-economic over the period 2017–2036.

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[67] *Private Generation Long-Term Resource Assessment (2017-2036)*, Navigant Consulting, Inc., July 29, 2016. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_IRP_DG_Resource_Assessment_Final.pdf. See footnote 1 to Direct Testimony of Joelle Steward.

[68] Capacity contribution derived from peak load differential between PacifiCorp 2017 IRP scenarios PG-1 and PG-2, and comparing these reductions against the absolute installed capacity assumed by Navigant in the basis projection. The comparison indicated an approximately [redacted] percent assumed system capacity contribution for distributed generation resources.

CONFIDENTIAL Figure 4. Coal fleet valuation (2016 $/kW) with Regional Haze Compliance Obligations (2018 retirement, PacifiCorp share)

[redacted]

More specifically, the analysis indicates that these units have fixed costs well in excess of their net energy margins through most of the analysis period, and are unable to recoup losses. CONFIDENTIAL Figure 5, below, shows the annual cost of fuel, O&M, and capital recovery through the end of the unit's life in [redacted] (in millions $). The black line shows the total all-in cost of replacement energy, which includes the unit's fuel, O&M, and capital costs in 2017–2018, and then market energy replacement through the end of the analysis period. The figure shows that this unit's non-capital costs are approximately on par with the cost of replacement generation through the mid-2020s. With incremental capital (including the environmental projects), the all-in cost of the unit exceeds the market energy prices to nearly the end of the analysis period.

CONFIDENTIAL Figure 5. Cash flow for Jim Bridger 1 through 2036, with SCR, [redacted]

Q **Can distributed generation resources really provide enough energy to displace a central station coal unit?**

A According to PacifiCorp's assessment, yes. Comparing PacifiCorp's projected distributed generation growth from the 2017 IRP against the modeled generation of Jim Bridger 4 from the Company's Preferred Portfolio shows that PacifiCorp—in the same analysis—assumes more generation from customer-sited resources than this 350 MW boiler through 2027. The analysis shows that a high penetration of distributed generation could easily surpass the full output of the unit in out-years.

CONFIDENTIAL Figure 6. 2017 IRP distributed generation scenarios (PacifiCorp system) and 2017 IRP generation from Jim Bridger 4

[redacted]

Q Why should the potential displacement of one or two coal units with environmental compliance obligations be considered in this docket?

A This analysis is a demonstration that distributed generation can play a role in providing long-term system benefits to customers throughout PacifiCorp's system. The capacity and generation from distributed generation resources can provide a substantial offset to existing generators, as evidenced through the Company's own analyses. My assessment shows that ratepayers will be benefited through the retirement of a number of existing non-economic units, and that customer-provided generation can reduce the burden of resource replacement. PacifiCorp can and should consider distributed generation as one of the resources at its disposal to plan for fleet transition. Ultimately, a tariff structure that encourages the growth of this resource will make it easier for PacifiCorp to achieve cost-effective unit retirements.

Q What is your conclusion with respect to the valuation of distributed generation in this case?

A Overall, I have demonstrated that distributed generation resources have substantial short- and long-run benefits that are not captured by the Company's avoided energy analysis embedded in the Cost of Service Study. These benefits are real, demonstrable, and quantifiable, and they cannot be illustrated through an avoided energy analysis only. The Company's analysis does not demonstrate that Utah needs a new net metering tariff to tamper the growth of distributed generation. Instead, evidence from the Company's resource planning shows that distributed generation will result in both short- and long-run system benefits not captured here. Additionally, avoided fixed costs at existing thermal generators, avoided environmental compliance costs, and societal benefits are not illustrated through the Company's IRP process, and they should be evaluated in a reasonable cost/benefit assessment.

Q Does this conclude your testimony?

A It does.

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 14-035-114

Exhibit HEAL___(JIF-1)
Curriculum Vitae

June 8, 2017

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Cambridge MA. *Principal Associate*, 2013 – present, *Scientist*, 2007 – 2013.

Consulting on economic analysis of climate change and energy, carbon, and emissions policies. Quantitative evaluations of regional climate change impact, energy efficiency programs, long- and short-term electric industry planning, carbon reduction planning, and emissions compliance programs.

Tulane University, New Orleans, LA. *Ecology and Evolutionary Biology Postdoctoral Research Scientist*, 2006 –2007.

Determining Hurricane Katrina's impact on Gulf Coast ecosystems using satellite and field data.

University of New Hampshire, Durham, NH. *Earth, Oceans, and Space Postdoctoral Research Scientist*, 2006 –2007.

Organizing team synthesis review of causes and rates of natural rainforest loss in the Amazon basin.

Brown University Watson Institute for International Studies, Providence, RI. *Visiting Fellow*, 2007 – 2008.

Designing study to examine migratory bird response to climate variability in the Middle East.

Brown University Department of Geological Sciences, Providence, RI. *Research Assistant*, 2001 –2006.

Tracking impact of climate change on New England forests from satellites. Working with West African communities to determine impact of climate change and practice on landscape. Modeling coastal power plant effluent from satellite data.

EDUCATION

Brown University, Providence, RI
Doctor of Philosophy in Geological Sciences, 2006

Brown University, Providence, RI
Master of Science in Geological Sciences, 2003

University of Maryland, College Park, MD
Bachelor of Science in Geography and Geology, 2001

FELLOWSHIPS & AWARDS

- *Visiting Fellow*, Watson Institute for International Studies, Brown University, 2007
- *Finalist*, Congressional Fellowship, American Institute of Physics and Geological Society of America, 2007
- *Fellow*, National Science Foundation East Asia Summer Institute (EASI), 2003
- *Fellow*, Henry Luce Foundation at the Watson Institute for International Studies, Brown University, 2003

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Washington Utilities and Transportation Commission (Docket UE-152253): Response, cross-answer, and supplementary cross-answer testimony regarding the general rate case on behalf of Pacific Power & Light Company. On behalf of Sierra Club. June 1, 2016.

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Kentucky Public Service Commission (Docket 2011-00401): Direct testimony regarding the application of Kentucky Power Company for approval of its 2011 environmental compliance plan, for approval of its amended environmental cost recovery surcharge tariff, and for the granting of a certificate of public convenience and necessity for the construction and acquisition of related facilities. On behalf of Sierra Club. March 12, 2012.

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Wyoming Public Service Commission (Docket 20000-384-ER-10): Direct testimony in the matter of the application of Rocky Mountain Power for authority to increase its retail electric utility rates in Wyoming approximately $97.9 million per year or an average overall increase of 17.3 percent. On behalf of Powder River Basin Resource Council. April 11, 2011.

Resume dated May 2017

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 14-035-114

Exhibit HEAL___(JIF-2)

Fisher, J., J. Levy, Y. Nishioka, et al. 2010. Co-Benefits of Energy Efficiency and Renewable Energy in Utah: Air Quality, Health and Water Benefits. Synapse Energy Economics for State of Utah Energy Office.

June 8, 2017

Synapse
Energy Economics, Inc.

Co-Benefits of Energy Efficiency and Renewable Energy in Utah

AIR QUALITY, HEALTH, and WATER BENEFITS

May 19, 2010

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Utah Disclaimer

The following report was prepared as part of a study to quantify and monetize the co-benefits of energy conservation, energy efficiency, and renewable energy deployment in Utah. The principle funding source was a $150,000 U.S. Department of Energy grant (DF-FG26-07NT43340) awarded in September 2007 to the Utah State Energy Program. Matching funds were provided by the Governor's Energy Advisor and by the Division of Public Utilities. The Office of Consumer Services, State Energy Program, and Division of Air Quality, also provided in-kind support for the project. Collectively, the participating agencies issued a nationwide Request for Proposals seeking a firm to undertake the study. This report is the result of that study.

The participating agencies have monitored and reviewed the project at multiple stages and have provided input and comments about this report. However, this report represents primarily the findings of Synapse Energy Economics, Inc. Its findings and recommendations do not necessarily reflect the positions or policies of any or all of the participating state agencies.

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1. Executive Summary

Synapse Energy Economics, Inc. (Synapse) was contracted by Utah State agencies, including the State Energy Program, the Division of Public Utilities, the Division of Air Quality, the Office of Consumer Services, and the Governor's Energy Advisor (collectively, "Utah Agencies") to develop and apply methods of calculating water and health co-benefits of displacing electricity generation technologies in Utah with new energy efficiency (EE) or renewable energy (RE).

Co-benefits are defined herein as the monetary value of avoided externalities, or the indirect social costs, of energy production. The externalities of power production include both socialized benefits, such as employment opportunities and an increased tax base, as well as significant social and environmental costs, such as health problems, regional haze, and acid rain caused by emissions, as well as the consumption of limited natural resources, including water. Co-benefits are the social and environmental externalities that can be avoided through the implementation of new policies that either displace or replace existing generation. Regulatory mechanisms, such as compelling emissions and/or water controls on existing and new generators, are one method of mitigating external social costs.

According to this and other research, the monetary value of co-benefits and externalities is on the same order of magnitude as the direct costs of energy production (such as capital, fuel, and operational costs) and benefits (such as reliability and availability). These monetizations provide a more comprehensive economic evaluation of existing generation, and of technologies that avoid harmful externalities. Toward this end, Synapse' research establishes and applies a methodology to quantify and monetize two co-benefits of energy efficiency and renewable energy: avoided human health costs and depletion of water resources.

Currently, electricity generation in Utah is almost entirely fired by fossil combustion, and of that, about 82% is fired by coal. This resource mix is relatively inexpensive in direct costs to both Utah and out-of-state consumers, but results in significant emissions of air pollutants and consumes a large share of Utah's increasingly valuable water resources. The authors estimate that fossil generation in Utah today:

- consumes about 73,800 acre feet, or 24 billion gallons, of fresh water per year;
- results in 202 premature deaths per year;
- contributes to 154 hospital visits per year for respiratory injuries, and 175 asthma-related emergency room visits each year.

We estimate that the health and water impacts from Utah fossil generation have a monetary value of between $1.7 and $2.0 billion dollars per year (2008$), or between

$36 and $43 per megawatt-hour (MWh) of fossil generation in Utah, a value similar to the direct costs of conventional electricity generation.[1]

The purpose of this study is to put forth methodologies estimating the co-benefits that can be achieved from renewable energy and energy efficiency. The quantification of these co-benefits, and of the externalities from which they derive, is by no means straightforward, and there are significant assumptions and uncertainties that underlie this study. Some of these uncertainties are:

- The statistical dispatch model relies on limited, public historic generation data to estimate how fossil resources will respond to efficiency and renewable energy (Section 3);
- Emissions of fine primary particulate matter ($PM_{2.5}$) are estimated where reported data are not available, primarily for gas-fired generators (Section 4.2.1);
- Population exposure to $PM_{2.5}$ emissions are based on previous modeling exercises, which carry an intrinsic degree of uncertainty (Section 4.2.2);
- For most gas-fired power plants in Utah, no direct chemistry-transport modeling has been conducted, and therefore this study relies on extrapolations from previously modeled power plants (Section 4.3);
- Ozone exposure modeling is based on a single paper in which relationships were derived for a single summertime month in 1996, and therefore the uncertainties on ozone impacts (morbidity) are likely large and potentially highly biased (Section 4.3);
- Morbidity estimates are based largely on recent peer-reviewed meta-analyses, rather than Utah-specific studies (Section 4.2.3);
- The relationship between population emissions exposure and premature mortality (the concentration-response function) is approximated as linear (Section 4.2.3);
- While this study uses the federally recommended value of $8 million per statistical life. This, economic estimates of the value of a statistical life (VSL) is based on the previously EPA-designated value of $5.5 million (1999$) adjusted to $8 million (2008$). The range of economic estimates of the VSL in EPA's determination ranged widely between $1 and $10 million dollars (1999$) (Section 4.2.5);
- Water use at power plants is inconsistently reported and sparsely available, and therefore this study has estimated water consumption for some power plants based on values from the literature (Section 5.2);

[1] The ranges on the co-benefit and externality values reflect only uncertainties in the externality cost of water consumption, a previously undefined metric which was derived for the purposes of this study. The range indicates neither the uncertainty associated with the impacts of emissions on health, nor does it incorporate the range of published value of statistical life (VSL) measures.

- The externality cost of water is undefined and likely highly variable by region, even within Utah (Section 5.3)

To give a sense of the magnitude of the uncertainties for just some of these estimates, a paper co-authored by one of this study's authors quantified and propagated uncertainties in all aspects of uncertainty modeling.[2] For the coal-fired power plants in Utah, health damages per kWh ranged between 20% of the central estimate (at the 5th percentile) to 250% of the central estimate (at the 95th percentile) represented in this paper.

Most of the externality costs estimated in this study are sourced at coal-fired generators. Reducing the level of in-state coal-fired generation would result in significant benefits for residents of Utah and downwind states. This reduction could occur, in small part, from a reduction in load in Utah, or the integration of new renewable energy onto the grid in Utah and surrounding states. However, Utah is a net electricity exporter in an extensive and highly integrated Western electric grid that extends from the Rocky Mountain States to the Northwest, and from the Northwest down to California. Because of the dynamics of this system, it is unlikely that modest amounts of EE or RE in Utah alone would effectively displace coal-fired generation in Utah. Therefore, the co-benefits from the "passive" integration of EE and RE are modest relative to the externality costs of generation. We estimate that total co-benefits for EE and RE range from a high of $27 per MWh of fossil generation avoided, when wind or solar photovoltaics are employed, to a low of a *cost* of $4 per MWh, when high water-use concentrating solar thermal systems are employed.

By way of contrast, an active replacement of the least efficient power plants in Utah with energy efficiency and either gas generation or renewable energy results in very high co-benefits to the state. We find that for each MWh of coal generation avoided, Utah avoids $69 - $79 of externality cost, a benefit that exceeds the cost of most electrical generation.

This analysis examines the marginal health and water benefits from modest amounts of energy efficiency and renewable energy in Utah. It does not examine the benefits that could be realized from a market transformation in the West, with significant penetrations of new renewable energy, dramatic load reductions, or a price on greenhouse gas emissions.

1.1. Approach

In this study, calculating co-benefits entails four processes. First, we must determine which conventional resources are likely to be displaced, replaced, or avoided by EE and RE. Second, we must establish the health and water impacts that are avoided by displacing conventional generation. Third, a monetary value must be ascribed to these physical externalities. Finally, we present the co-benefit cost-effectiveness of EE and RE

[2] Levy, J.I.; Baxter, L.K.; Schwartz, J. Uncertainty and variability in health-related damages from coal-fired power plants in the United States. *Risk Analysis*. **2009**, 29(7) 1000-1014.

as the value saved for every unit of conventional energy avoided. Applied in this research, co-benefits are estimated as the difference in externality costs between a baseline (business-as-usual) future versus alternative scenarios with new investments in energy efficiency, renewable energy, or a proactive replacement of existing generators.

Synapse analyzed a range of feasible energy efficiency and renewable energy options to assess their potential in realizing health and water co-benefits. These scenarios are organized into four over-arching categories, including:

1. **Baseline**, in which load growth continues unabated and new in-state demand is met with gas generators; [3]
2. **Energy efficiency and demand response**, ranging from modest reductions of 1% per year relative to baseline load growth, to more aggressive targets of 3% per year by 2020;
3. **Renewable energy**, including wind at any of three locations (Porcupine Ridge, TAD North, and Medicine Bow, Wyoming), two photovoltaic options (flat plate and tracking), two concentrating solar thermal projects (parabolic trough and a solar tower), and geothermal operations; and
4. **Replacement** of selected inefficient and aging coal generators with either energy efficiency and new combined cycle gas, or energy efficiency and a combination of renewable energy projects

We compare the projected 2020-21 generation and emissions from each of the alternative scenarios to the projected baseline generation and emissions using a load-based probabilistic emissions model, described in Chapter 3. This model, which is based on statistical analysis of 2007-2008 generation and emissions data from the US EPA's continuous emissions monitoring (CEM) program, was developed by Synapse to determine the emissions benefits of replacing conventional generation with emissions-free resources. Once the generation and emissions for each scenario have been determined, we estimate water and health impacts for each scenario, including water use, mortality, and morbidity, relative to the baseline. We also estimate some aspects of lost productivity, including restricted activity days and lost school days. The externality costs are calculated based on the physical impacts (mortality, morbidity, and water use).

In addition to producing carbon dioxide (CO_2) that has been linked to climate change, the combustion of fossil fuels results in the emission of pollutants such as nitrous oxides (NO_X), sulfur dioxide (SO_2), and fine particulates, and in some cases mercury, all of which are harmful to human health. We use an independent modeling framework to estimate the downwind chemical and particulate impacts, as well as resulting premature deaths (mortality), hospitalizations for respiratory and cardiac illnesses and asthma (morbidity), and lost productivity.

[3] Load growth is estimated from data provided in 2008 by PacifiCorp, a western utility serving over 88% of Utah generation.

A value of statistical life (VSL) is used to assign monetary values to health outcomes, reflecting a societal willingness-to-pay to avoid adverse health effects. The VSL used in this study is not an explicit recommendation. Numerous studies have attempted to derive a VSL, with estimates ranging from under $1 million to over $10 million per statistical life, as noted above. Based on an EPA's recommended value of $5.5 million (in 1999$), this study used a time-adjusted VSL of approximately $8 million. The method used here has been widely applied, and is endorsed by the EPA Science Advisory Board, the US Office of Management and Budget, and the National Academy of Sciences, amongst others.

The water-related externality cost is derived from the consumption of water by thermal generators (both fossil and renewable), and the estimated marginal cost of water in Utah. Thermal generators use water for boilers, cooling, and emissions controls. In this study, we track consumptive (non-recycled) water use for cooling purposes, based on the historical rate of water consumption for individual fossil generators in the state. We estimate a range of social values for water in Utah based on recent water-rights transactions. We estimate that, in general, Utahns are willing to pay between $520 and $5,182 per acre-foot, or 0.16 to 1.59 cents per gallon for water rights (2008$). Fresh water consumed by power plants that could otherwise be used for other purposes costs the state $38-$383 million per year today.

1.2. Summary of Results

1.2.1. Externalities

In a business-as-usual baseline scenario, we project 279 premature deaths per year by 2020 associated with electric generation impacts, compared to 202 premature deaths in the the reference year, an increase primarily due to population growth.[4] We further project nearly a 25%-45% increase over the baseline year in hospital admissions and ER visits per per year associated with electric generation impacts. However, we estimate that water consumption for generation will grow only moderately, to 77,400 acre feet per year (a 5% 5% increase) due to increasing gas use and only moderate increases in existing coal-fired fired generation (see

Table 1-1).

The energy efficiency and renewable energy scenarios reduce externalities only moderately relative to the baseline. Clean energy programs in Utah would tend to primarily displace gas generation, and do not result in significant externality savings. According to our analysis, significant co-benefits would accrue only when older, inefficient coal units are retired and replaced with energy efficiency programs, renewable enegy and gas-fired generating units.

[4] Approximately 86% of these deaths occur in downwind states from particulates and pollution emitted from generators in Utah. Breakdowns between Utah and out-of state externalities are given in Table 7-2.

Table 1-1: Physical externalities from baseline and scenarios in 2020-2021

	Health Externalities				Water Use, Acre Feet per Year
2007-2008	Statistical Deaths per Year	Cardiovascular Hospital Admissions per Year	Respiratory Hospital Admissions per Year	Emergency Room Visits per Year	
Reference Case	202	21	154	175	73,800
2020-2021					
	Baseline Scenario				
Baseline Load Growth	279	32	194	225	77,400
	Energy Efficiency Scenarios				
EE (SWEEP)	277	31	193	224	75,900
EE (2% per yr)	274	31	192	223	75,800
EE (3% per year)	267	30	186	216	72,400
	Renewable Scenarios				
Wind (Porcupine)	273	31	189	220	74,400
Wind (TAD North)	271	31	187	218	74,000
Wind (Medicine Bow)	271	31	187	218	73,900
Solar (Flat Plate PV)	276	31	191	222	75,900
Solar (One-Axis Track)	275	31	190	221	75,500
Solar (CSP Trough, Wet Cooled)	277	31	192	224	82,700
Solar (CSP Trough, Dry Cooled)	277	31	192	224	76,500
Geothermal	269	31	186	217	89,600
	Replacement Scenarios				
Replace Coal w/ EE and Gas	182	20	137	157	57,300
Replace Coal w/ EE and RE	178	20	136	155	56,200

In this research, mortality, morbidity, and water consumption are monetized to obtain an externality cost for the reference case (2007-2008), a business-as-usual baseline scenario, and the EE and RE scenarios. We find that fossil-fired generators in Utah result in $1.6 billion (2008$) of health-based damages, and consume between $38-383 million of water. On a per unit energy basis, externalities cost between $36 and $43 per MWh today.

Synapse was not contracted to estimate damages or externalities associated with the emissions of greenhouse gasses, such as carbon dioxide (CO_2). However, other research has evaluated the extent of potential damages occurring from climate change and estimated a range of costs attributable to climate change associated with each ton of CO_2 emissions. If the externality cost of CO_2 were included at a cost of $80 per ton of CO_2, the externality cost of greenhouse gas emissions from power generation in Utah today would be approximately $3.4 billion (2008$), or $72 per MWh of conventional generation.

1.2.2. Co-Benefits

To monetize the estimated co-benefits of avoided fossil generation in Utah, we have calculated expected externality savings, relative to the baseline scenario, in dollars per unit energy of avoided generation. The most significant cost savings from a co-benefit perspective are in avoided mortality, followed by avoided water and morbidity (Table 1-2).

Table 1-2: Monetary co-benefits in dollars per avoided MWh of generation in 2020-2021.

2020-2021	Health Co-Benefits 2008$ / MWh **All** (in Utah) Mortality		Morbidity		Avoided Cost of Water 2008$ / MWh (Low - High)	Total Co-Benefit 2008$ / MWh (Low - High)
			Efficiency Scenarios			
EE (SWEEP)	**$5.6**	($1.5)	**$0.1**	$0.0	**$0.2 - $2.1**	**$5.9 - $7.8**
EE (2% per yr)	**$7.8**	($1.7)	**$0.1**	$0.0	**$0.1 - $1.4**	**$8.0 - $9.3**
EE (3% per year)	**$12.3**	($2.8)	**$0.2**	$0.1	**$0.3 - $3.1**	**$12.8 - $15.6**
			Renewable Scenarios			
Wind (Porcupine)	**$18.6**	($4.5)	**$0.4**	$0.2	**$0.5 - $5.5**	**$19.5 - $24.4**
Wind (TAD North)	**$20.4**	($4.5)	**$0.5**	$0.2	**$0.6 - $5.5**	**$21.4 - $26.3**
Wind (Medicine Bow)	**$18.9**	($4.4)	**$0.4**	$0.2	**$0.5 - $5.2**	**$19.8 - $24.5**
Solar (Flat Plate PV)	**$19.0**	($4.9)	**$0.4**	$0.2	**$0.6 - $5.5**	**$20.0 - $25.0**
Solar (One-Axis Track)	**$20.7**	($5.0)	**$0.4**	$0.2	**$0.5 - $5.5**	**$21.7 - $26.6**
Solar (CSP Trough, Wet Cooled)	**$7.7**	($2.6)	**$0.1**	$0.1	**-$12.0 - -$1.2**	**-$4.2 - $6.6**
Solar (CSP Trough, Dry Cooled)	**$7.7**	($2.6)	**$0.1**	$0.1	**$0.2 - $2.0**	**$8.0 - $9.8**
Geothermal	**$19.8**	($4.6)	**$0.4**	$0.2	**-$15.6 - -$1.6**	**$4.6 - $18.7**
			Replacement Scenarios*			
Replace Coal w/ EE and Gas	**$67.26**	($7.39)	**$1.00**	($0.48)	**$0.9 - $8.7**	**$69.1 - $76.9**
Replace Coal w/ EE and RE	**$68.94**	($7.79)	**$1.00**	($0.48)	**$0.9 - $9.0**	**$70.8 - $78.9**

*The replacement scenarios estimate co-benefits against is avoided *coal* generation. These values are not directly comparable to the other scenarios

We find that reducing energy consumption through energy efficiency measures results in savings of between $6 to $16 per MWh of conventional generation displaced. In the renewable energy scenarios, we find total co-benefits range from a *cost* of $4 per MWh to a savings of $27 per MWh.

To achieve even more dramatic co-benefits, if approximately one-third of Utah's most inefficient and polluting coal generators are replaced with a rigorous energy efficiency program and either gas or renewable energy, externalities amounting to $70 - $79 could be realized for each MWh of coal retired or displaced.[5]

1.3. Policy Implications

Externalities are costs that have an impact on society but that are not included (internalized) in the direct cost to the producer of a good or service. In the case of electric power generation, the externalities explored here are the costs of mortality, morbidity, and depletion of water resources as experienced in Utah and downwind – costs that are imposed upon society but are borne incompletely or not at all by the

[5] These last two scenarios cannot be considered on the same scale as the other EE and RE scenarios because the denominator (MWh of generation avoided) is different. Because externalities from coal-fired generation are far higher than those from gas-fired generation, simply replacing coal generation with gas reduces the externality cost significantly, but does not avoid fossil generation. Estimated as a co-benefit, this calculation would result in unreasonably high co-benefits per MWh avoided.

owners or operators of the generating plants. Avoiding these "indirect" costs represents a co-benefit to the state, as well as for neighboring states. This co-benefit is additional to the direct benefits of avoided fuel consumption, operating costs, and the need for new generation and transmission.

In this research, we find that the externality cost of fossil fuel combustion for electricity is expensive, comparable in magnitude to the total direct cost of conventional generation. However, we conclude that newn energy efficiency and renewable energy programs in Utah can achieve relatively modest externality savings. This is because efficiency and renewable energy in Utah primarily displaces natural gas-fired energy and imported hydroelectric capacity, rather than coal. As a theoretical bookend, we find that replacing older, inefficient generators with efficiency and low-emissions units results in a dramatic reduction in externality costs.

Another approach that is likely to achieve significant societal benefits in Utah, not quantified in this research, is to reduce energy consumption requirements throughout the Western United States. Utah is an electricity exporting state in a tightly interconnected regional grid; reducing regional power requirements or introducing a high penetration of renewables throughout the region could result in avoided generation in the region and significant water and health benefits in Utah. Coalitions such as the Western Regional Air Partnership (WRAP) or the Western Climate Initiative (WCI) provide opportunities to influence regional demand that affects Utah. Without integrated regional approaches, EE and RE are unlikely to produce significant co-benefits in Utah.

Modeling emissions avoidance, externalities, and co-benefits can be useful for planning and licensing purposes. The results of this study may be used in state processes for considering the full costs and benefits of new generators in utility integrated resource plans (IRPs), determining effective strategies to comply with federal or regional air quality plans and state implementation plans (SIPs), estimating pathways to meet emissions targets for regional and federal regulations, calculating benefits of state, regional, or federal renewable portfolio standards, and examining indirect costs and benefits of transmission expansion plans. This approach can help lead to resource planning and policy decisions that better reflect the interests of Utah and its residents.

2. Introduction and Scope

Energy efficiency (EE) and renewable energy (RE) both decrease dependences on fossil fuels and reduce harmful emissions and environmental impacts from energy production. Meeting energy requirements by improving end-use efficiency has the joint benefit of moderating energy costs, while also trimming "criteria" and greenhouse gas emissions and reducing water consumption at fossil power plants. New renewable energy projects can serve to displace existing fossil generation, also lessening emissions and water consumption. These reductions improve public health, increase water availability for other uses and ecosystems, and reduce the risk of climate change. The monetary values of these benefits, known as co-benefits, are not often considered in energy resource plans, but could have significant impacts if the social costs of damaged human health or water consumption were considered.

This study focuses on the health and water co-benefits of efficiency and renewable energy to more thoroughly examine the costs and benefits of alternative energy supply. Turning to EE and RE is rapidly becoming a mainstream mechanism to achieve emissions reductions and other environmental benefits. For example, the US Environmental Protection Agency (EPA) allows states to reward select EE and RE projects with emissions allowances as an option to meet air quality goals.[6] A number of states have implemented EE and RE "set-asides" for EPA mandated emissions reductions. In these states, a portion of emissions reductions may be met through efficiency and renewable energy programs. Such states include Connecticut,[7] the District of Columbia, Delaware, Illinois,[8] Indiana,[9] Massachusetts,[10] Maryland, Michigan, Missouri,[11] New Jersey,[12] New York,[13] Ohio, Pennsylvania, Virginia, Wisconsin, and Texas.[14] Increasingly, state and proposed federal renewable portfolio standards[15] are designed to reduce emissions.

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14 Reducing Emissions Using Energy Efficiency and Renewable Energy. Texas Comission on Environmental Quality. 2008. http://www.tceq.state.tx.us/implementation/air/sip/eere.html
15 H.R. 2454--111th Congress: American Clean Energy and Security Act of 2009. (2009). In GovTrack.us (database of federal legislation). Retrieved Nov 18, 2009, from http://www.govtrack.us/congress/bill.xpd?bill=h111-2454

The Utah Agencies requested a report that develops methods of quantifying and valuing health and water co-benefits of EE and RE implemented within the state.[16] This report is designed to help State agencies establish quantitative metrics to inform state policy. Specifically, State agencies are interested in understanding the costs of uncontrolled and/or fugitive emissions from traditional sources within the state that could lead to undervaluing renewable energy, energy efficiency, and/or energy conservation programs meant to supplement, displace, or replace traditional generation.

2.1. Co-Benefits and Externalities, Direct and Indirect Costs

Externalities are defined by the National Academy of Sciences as "activit[ies] of one agent (i.e., an individual or an organization like a company) that affect the wellbeing of another agent and occur outside the market mechanism."[17] External costs and benefits are imposed upon society and are external to the costs experienced by generation owners or utility ratepayers.[18] In this research, externalities are specifically negative impacts. The co-benefits of alternative energy programs are defined here as the benefits accrued to society by avoiding negative externalities associated with energy production. These benefits are distinct from the direct, internalized costs and benefits of energy production: direct, internalized costs are met by ratepayers, while external, indirect costs and benefits are faced by society at large.

[16] "Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analysis. The IRP analysis should include a range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options." Utah Docket 90-2035-01 (1992).

[17] National Academy of Sciences. Hidden Costs of Energy: *Unpriced Consequences of Energy Production and Use.* Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption; National Research Council. National Academies Press, 2009.

[18] In this research, we define "costs" as expenditures or losses, and "benefits" as improvements in wellbeing (monetary or otherwise) and costs avoided.

Certain costs are traditionally estimated for the purposes of planning and rate-making, while other costs are not usually considered. In most cases, only the direct costs and benefits are internalized as costs to ratepayers. Examples of direct and indirect costs and benefits are characterized in Table 2-1.

Table 2-1: Examples of direct and indirect costs and benefits of power generation

	Direct Costs and Benefits	Indirect Costs and Benefits
Typically considered in planning [19]	- Capital and infrastructure - Fuel - Operations and maintenance (O&M) - Transmission requirements - Capacity and reliability - Environmental regulation compliance	- Employment - Tax basis - Future environmental regulation compliance [a]
Typically not considered in planning	- Downstream economic impacts - Economic multiplier effects - Demand response impact price effect	- Health impacts - Water consumption - Environmental degradation (land use, haze and visibility, ecosystem impacts) - Waste storage / disposal - Upstream environmental impacts (extraction, processing, and transportation)

[a] Future environmental regulations include the risk or probability that regulations will restrict future activities or increase the cost of operations.

In this analysis, co-benefits are estimated as the monetized value of the social externality costs of generation that are avoided by renewable energy or efficiency, on an energy unit basis (i.e. $/MWh). Each unit of fossil generation avoided reduces a social cost (health, premature deaths, and water consumption), yet not all displaced MWh of fossil generation are equally harmful. Co-benefits measure the value of the harm of each MWh avoided by using EE or RE.

By monetizing these impacts, externalities can be considered on a similar scale with direct costs and benefits. In Utah, the direct application of this exercise is in the valuation of least cost resources for utility integrated resource plans (IRP), resource acquisition approval processes, and demand-side management program approval and review.

2.2. Report Approach and Organization

Establishing the monetary value of the co-benefits of efficiency and renewable energy programs requires several distinct steps. First, we must determine which conventional resources are likely to be displaced, replaced, or avoided by EE and RE. Second, we must establish the impacts that are avoided by displacing conventional generation.

[19] "Considered in planning" is the typical case; some states and utilities consider other costs and benefits as well.

Third, a monetary value must be ascribed to these physical externality impacts. Finally, we present the co-benefit cost-effectiveness of EE and RE as the value saved for every unit of conventional energy avoided. The merit of this presentation is that different EE and RE pathways may be evaluated on a similar basis to standard costs and benefits, given here in constant dollars per megawatt-hour.

In this paper, we estimate the physical and monetary externalities of a baseline scenario, as well as thirteen alternative scenarios, including moderate penetrations of wind, solar, geothermal, and efficiency technologies on the existing electrical grid. The physical and monetary co-benefits are calculated as the difference between the baseline scenario and each of the alternative scenarios.

We do not estimate the direct costs (capital, fuel, or O&M) of new generation or transmission, nor do we estimate the direct costs of energy efficiency programs, or avoided costs of saved fuel, operations, or new infrastructure. Both EE and RE programs are assumed achieve moderate penetrations in Utah, and do not account for large-scale market or technological transformations or new environmental control technologies on existing conventional facilities. The scope of this report is to quantify the physical and monetary co-benefit value of EE and RE programs relative to the existing, or foreseeable future, grid.

The baseline scenario assumes that state energy demands grow according to utility forecasts, and new demands for energy and capacity are met through new gas-fired generators, a relatively conservative approach that assumes a state or federal interest in a low emissions future. To calculate the conventional generation and emissions avoided by EE and RE programs, we create a series of scenarios, organized into four over-arching categories: a baseline (described above), energy efficiency at three levels of penetration, eight renewable energy scenarios, and two auxiliary scenarios exploring the impact of replacing one-third of the most inefficient generation in Utah with energy efficiency and new gas generators or a mixed portfolio of renewable energy.

In each of the scenarios, we run a statistical model designed to estimate the expected hourly generation and emissions from each of Utah's fossil generators both now and in the future, given load growth over time. We create hourly load profiles for potential near term efficiency and renewable options, and impose these profiles on hourly demand, assuming the new resources are non-dispatchable.[20] The statistical model, described in Chapter 3 and Appendix D returns estimated generation and emissions from each of Utah's fossil generators, which are then used to calculate health and water impacts. The model is calibrated with data from a reference year (2007-2008) and run to 2020-2021.

This study estimates health impacts, including mortality, morbidity, and reduced productivity, using an EPA-standard model. We use a source-receptor matrix method to estimate how emissions of oxides of nitrogen (NO_X), sulfur dioxide (SO_2), and

[20] Solar and wind resources do not generate on demand, and therefore either run and displace fossil or hydroelectric resources, or must be curtailed. Therefore, the demand profile that must be met by conventional resources is demand less the energy produced by renewables or reduced by energy efficiency.

particulates (PM) from Utah generators impacts air quality in Utah and downwind regions. These air quality impacts are, in turn, used to estimate the number of premature deaths, hospitalizations, and lost work days. Different EE and RE scenarios produce a range of emissions from fossil units in Utah, resulting in varying levels of health impacts. Ascribing a dollar value to life, health, and wellbeing is difficult and controversial, but is a required component of monetizing externalities and co-benefits. Our externality cost for each scenario in 2020 is derived from standard (federal) monetary values associated with statistical mortality and morbidity. This analysis is described in Chapter 4.

We estimate water consumption from historical records of cooling water requirements for fossil generating units in Utah. Assuming that no dramatic changes are made to the way cooling water is used at fossil generators, we can estimate future water consumption requirements based on generation. We estimate twp monetary externality prices for fresh water consumed based on, at the high end, the marginal “willingness to pay” for water rights in Utah and at the low end, the median water transaction price in Utah. The monetary cost of water used by power generation (including water intensive renewable energy projects) is the estimated social externality cost in Utah. Chapter 5 details these methodologies.

The baseline, energy efficiency, renewable energy, and replacement scenarios are all built from hourly load profiles, based on the model described in Chapter 3. To estimate the impact of these resources on hourly generation and emissions, we build load profiles from existing data sources detailing efficiency targets, wind availability, and solar patterns. The methods used to build the scenarios and their resulting externalities and co-benefits are described in Chapter 6.

The externalities estimated from this exercise are significant; we find that society is paying roughly as much for damages imparted by fossil generation in Utah as are ratepayers, on a unit-energy basis. However, despite these high costs, the co-benefit value of Utah-based EE and RE is relatively modest, unless a proactive approach to reducing damages is taken in concert with new resources. Chapter 7 presents key findings and discusses assumptions and policy implications.

This report is scoped with addressing secondary benefits and co-benefits of new EE and RE as well, particularly potential impacts on natural gas prices in Utah and possible reductions of regional haze. We postulate that there would be a negligible and fleeting (or non-existent) impact on natural gas prices form changes in generation in Utah, and find that there is insufficient data on haze constituents in Utah to characterize feasible reductions. We discuss these ancillary environmental and economic costs in accompanying appendices.

3. Avoided Generation and Emissions

In this research, we estimate the externalities avoided by implementing modest levels of new energy efficiency (EE) and renewable energy (RE) in Utah. This analysis seeks to quantify co-benefits from *marginal* changes in EE and RE, rather than systemic operational or structural changes to the electricity grid or market. The following chapter describes a method for estimating displaced or avoided generation and emissions, given an electrical grid largely similar to the one in operation today. An equally valid, but distinctly different approach might estimate displaced or avoided generation and emissions given a structurally different electricity market, such as one with a very high penetration of renewable energy, carbon constraints, or a modified transmission grid. The purpose of this study is to provide an estimate of the co-benefits of EE and RE in the near future.

To estimate marginal avoided generation and emissions, we construct a model simulating fossil dispatch dynamics based on historical generator behavior. One significant factor in this analysis is Utah's position as a net exporter of fossil generation for most months of the year. In this chapter, we (a) review the structure of the electricity sector in Utah and the US West, (b) describe our statistical dispatch model, and (c) review how the model is modified to incorporate seasonal changes imposed by hydroelectric output in the Northwest. The statistical dispatch model relies on limited, public historic generation data to estimate how fossil resources will respond to efficiency and renewable energy.

3.1. Electricity Generation and Demand in Utah and the West

Utah is a net exporter of electric power to the US West, generating over 45,372 GWh of energy in 2007, yet consuming only about 61% of the energy produced in the state (see Figure 3-1). Over 98% of Utah's generation in 2007 was derived from fossil resources (coal, petroleum, and gas), and of this, coal accounted for about 83% of all energy produced. Many of Utah's coal generators sit relatively close to coal mines; between rich local resources and inexpensive transportation costs, coal generation in Utah is a relatively inexpensive proposition. The amount of gas generation used in Utah has risen sharply since 2005, as several new combined cycle plants were brought into operation.

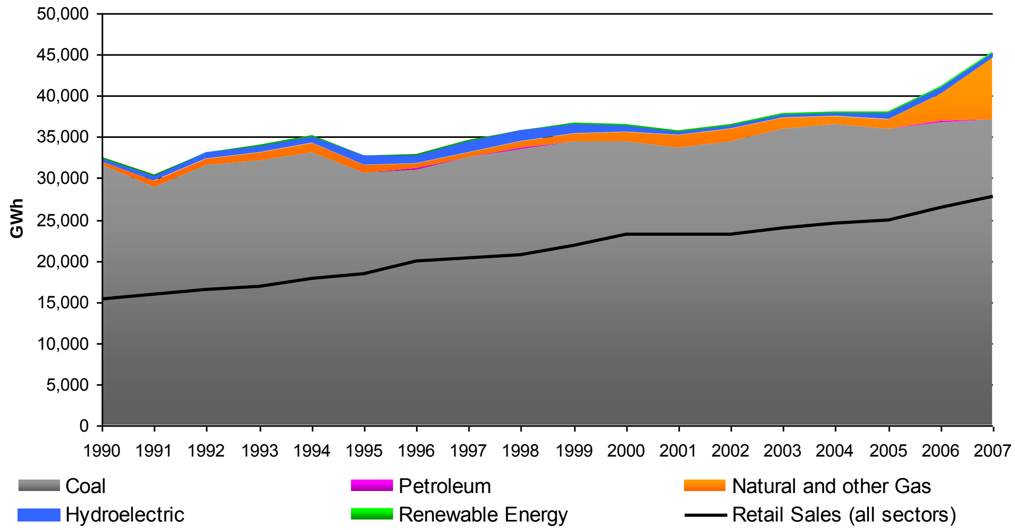

Figure 3-1: Electricity generation and consumption in Utah, 1990 through 2007. Fuel types labeled by color; the dark line represents demand in Utah over the same time period, on the same scale. Source: EIA[21,22]

Utah is part of a highly interconnected grid in the west, comprised of high capacity transmission running from the Rocky Mountain West (MT, WY, UT, and CO) to the Northwest (WA, OR and ID), and from the Southwest (NV, AZ, and NM) into California. There is significant transfer capacity from the Northwest down to California as well, and a direct connection between a coal power station in Utah (the Intermountain Power Project, or IPP) and southern California. Of the major sources of electricity throughout the West, coal generation in Utah, Wyoming, and Montana are amongst the least expensive (at least in terms of direct costs of generation).

The relationship between generation in the Rocky Mountain West (RMW) and electricity use in the Northwest and California is complex and important to this analysis, both in estimating power plant dynamics and in understanding the magnitude of co-benefits that can be expected from modest renewable or energy efficiency programs in Utah. In 2008, RMW and the Southwest produced ~230% and ~140% more energy, respectively than these regions required. In the same year, California imported ~20% of its electricity from other states in the West (see Figure 3-2), while the Northwest remained approximately energy balanced, on net.[23]

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[21] US DOE Energy Information Administration, 2009. Utah Electricity Profile: Generation by Primary Energy Source, 1990 Through 2007. Available online at: http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept05ut.xls

[22] US DOE Energy Information Administration, 2009. Utah Electricity Profile: Retail Sales, Revenue, and Average Retail Price by Sector, 1990 Through 2007. Available online at: http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept08ut.xls

[23] Author's calculations. Source data EIA Form 861 (Demand) and EIA Form 923 (Generation), 2008.

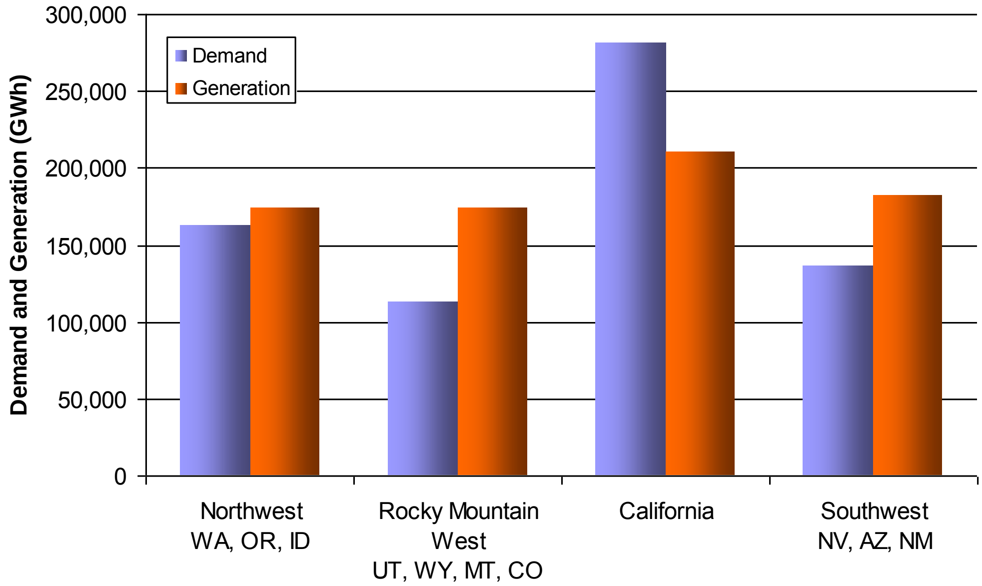


Figure 3-2: Electrical demand and gross generation in Western states, 2008. Source: EIA Forms 923 and 861.

Much of the electricity in the Northwest is produced from hydroelectric sources (70% in 2008), many of which are seasonally dependent on spring runoff, continuing through the summer. When hydroelectric energy is abundant, the Northwest supplies energy to California, and capacity to some parts of the RMW. When rivers run low in the autumn and winter, the Northwest imports significantly more energy from the RMW and supplies much less to California.[24] Therefore, generation in the RMW is highly dependent on hydroelectric conditions in the Northwest. The net effect is that the RMW region is able to supply relatively inexpensive coal generation to the Northwest, which in turn can "bank" the energy as water and supply premium hydroelectric energy to California during periods of high energy demand.

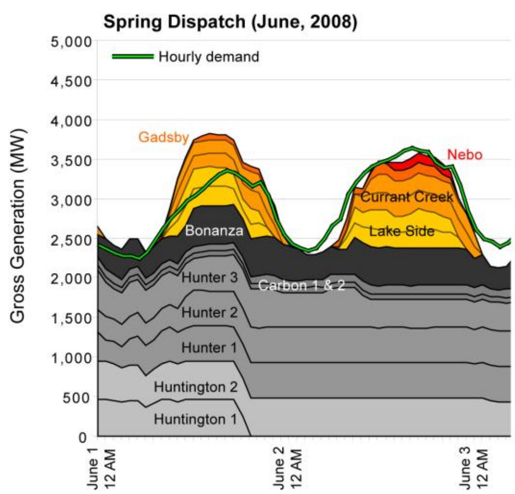
Utah is a net exporter to the Western grid, both via a direct current (DC) line from the coal-fired Intermountain Power Project (IPP) to southern California, and through connections to Idaho and the Northwest. IPP operates largely independently of demand in Utah: more than 80% of generation from the power station is sold and transferred directly to California. Other coal-fired stations operate nearly continuously, providing power to Utah during spring runoff (which coincides with peak demand in Utah), and energy for export during the autumn and winter (see Box 1, below). Gas fired power stations in Utah, however, respond both to daily fluctuations in demand, as well as seasonal changes in demand and interstate supply.

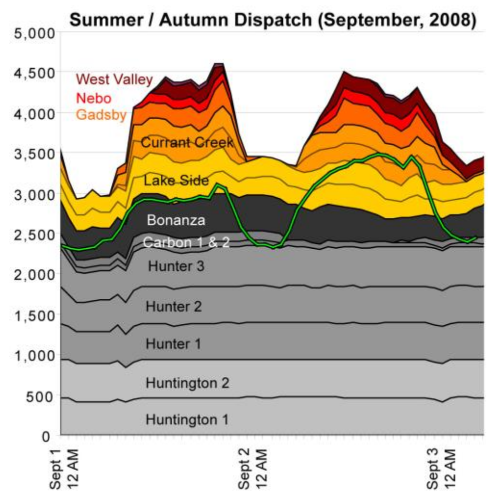
[24] Western Electric Coordinating Council. Historical Analysis Work Group. (April, 2009) *2008 Annual Report of the Western Electricity Coordinating Council'sTransmission Expansion Planning Policy Committee: Part 3 Western Interconnection Transmission Path Utilization Study.*

Box 1: Electric Generation Dispatch in Utah

Electric systems are typically dispatched in "economic merit" order to optimize resource use and provide electricity at the lowest possible direct cost. In economic dispatch, generators with the lowest operating and fuel costs operate often, while generators with higher costs operate less frequently. Electric dispatch can be visualized as a "stack" of generators, with the most often operating generators (baseload) at the bottom and least frequent (peakers) at the top. The diagrams below shows such stacks for Utah's fossil generators (excluding the Intermountain Power Project [IPP]) in spring (June) and summer (September), respectively. Coal generators appear in shades of gray, and gas generators appear in shades of orange. The total height of all of the stacked plots indicates the total gross generation of fossil generators in the state during any given hour. The green line indicates load requirements in Utah during these time periods.

The diagrams show that Utah is a net exporter of electric power during almost all times of the year. During spring runoff (left diagram), hydroelectric power is available in the Northwest, and Utah power plants are dispatched to primarily meet load requirements in Utah. In the autumn, hydroelectric power in the Northwest decreases, and fossil-fired generation increases. Utah generators run near maximum capacity, in this case delivering to out of state customers over 1,500 MW during peak hours and 1,000 MW during off-peak hours.





The primary difference between the spring and summer dispatch order is that both combustion and combined-cycle gas generators run at far higher capacity factors when hydroelectric energy is unavailable; some coal generators may undergo maintenance during these periods. Otherwise, coal generators in Utah run at very high capacity factors (>85%) in almost all circumstances.

Due to the complex regional interactions, and because Utah is a net exporter of generation, it is likely that demand reduction programs (EE or RE) will reduce more expensive gas generation in Utah, or provide the opportunity for Utah to export unused capacity to out-of-state markets. Coal generation in Utah is imperceptibly impacted by changes in demand in Utah today, and thus we can predict that it is unlikely that coal-fired generation will be displaced on the margin in Utah with moderate in-state EE or RE.

It is feasible, however, that more significant penetrations of RE, or regional moves to reduce energy consumption could impact coal-fired generators. Such regional transformations are not modeled in this analysis. Ultimately, as this analysis will show, as in other studies,[25,26] that the most significant health and water externalities from electrical generation are associated with coal generation. Therefore, we expect relatively small co-benefits from EE and RE unless coal generation is replaced by other energy sources.

To quantify the extent to which EE and RE in Utah could provide monetary co-benefits, we construct a dispatch dynamics model. The following section describes the model basis.

3.2. Displaced Emissions

In this paper, we define “displaced” emissions as those emissions that would otherwise be emitted from generators within our defined system in the absence of new energy projects. The question at hand can be defined simply: assuming that new EE reduces demand and new RE are must-take resources, which generators back down to balance load and generation? In a highly integrated electrical grid, the answer is not obvious.

A number of methods have been used to estimate emissions displaced on the margin when renewable energy or energy efficiency are brought online.[27] The question of how to calculate displaced emissions is, at its core, an economic question. In the absence of transmission or environmental constraints, resources are dispatched in economic merit order (see Box 1). In this research, rather than defining the costs and operational constraints of each resource to approximate the loading order, we use historical behavior to statistically represent each unit’s behavior relative to demand, a behavior which, we assume, has been guided by economics, as well as operational and transmission constraints.

The basis of this model is that, within a conceptual box, generation is dispatched to meet load requirements. When load increases, generation must increase somewhere in the system to meet the load requirement; conversely, when load decreases, some electricity generation units will decrease generation accordingly. The model examines historical behavior in load and generation and predicts how each generator will respond if load increases or decreases. Therefore, as load increases or decreases, the model will estimate the amount of generation that would have historically been required to meet the load requirement, and the quantity of pollutants that would have been emitted if the generator had operated as predicted. In this model framework, adding small to moderate

[25] National Research Council of the National Academy of Sciences. 2009. Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use. National Academies Press.
[26] Lockwood, A.H., K. Welker-Hood, M. Rauch, B. Gottlieb. November, 2009. Coal’s Assault on Human Health. Physicians for Social Responsibility.
[27] Several other approaches are described in Appendix C: Displaced Emissions, Background.

amounts of renewable energy or energy efficiency to the system is similar to decreasing hourly load requirements. As existing fossil generators see lower loads, they decrease generation (and emissions) and are thus displaced.

Synapse Energy Economics developed the following analytical technique for the State of Connecticut and the US Environmental Protection Agency to estimate emissions reductions from energy efficiency and scrubber technologies.[28] The model estimates generation and subsequent emissions from the relationship between historic hourly load (demand) and fossil generation. In the model, statistics are defined for the frequency of unit operation (on or off) and unit generation (MW output) for any given demand, and the probability distribution of emissions of NO_x, SO_2, and CO_2 for unit generation. Once these statistics are defined, a Monte Carlo simulation is used to estimate expected mean and distribution of generation and emissions at each load level.

Our model construct is backwards looking, building a statistical database that portrays the system behavior at a period of time. Manipulating some of the assumptions of this statistical model, we can predict how simple, short-term changes will impact dispatch operations.

3.3. Data sources: Demand, Generation, and Emissions

The model requires inputs of hourly load for an appropriate time-period (in this case, a full leap year, or 8,784 hours) and hourly fossil generation from units which comprise some defined region of the grid (preferentially a full power control area). The model structure developed here is unique in that it estimates generation dynamics from historical and generally non-proprietary data. The detailed hourly generation and emissions data are freely available from the EPA. Hourly demand was obtained from utility sources.

3.3.1. Hourly Load Data

The reference year for the Utah analysis begins in the fourth quarter of 2007 (October 1, 2007) and runs through the end of the third quarter in 2008 (September 30, 2008). At the time of this analysis, complete year 2008 data were unavailable for either load or generation. In addition, the Lake Side combined cycle plant was brought online in 2007, and was not fully operational until the third quarter of the year. Because the use of either calendar year would result in an incomplete dataset, the reference year comprises parts of both.

PacifiCorp provided hourly load profiles for 2007 and 2008 in each service region, including Utah. Over the time period of interest, PacifiCorp provided over 80% of

[28] James, C., J. Fisher. June 10, 2008. Reducing Emissions in Connecticut on High Electric Demand Days (HEDD): A report for the CT Department of Enviromental Protection and the US Environmental Protection Agency. Available online at http://www.ct.gov/dep/lib/dep/air/energy/ct_hedd_report_06-12-08_12noon.pdf

electricity in Utah (see Table 3-1).[29] Hourly load data were unavailable from other electricity providers in Utah; therefore contemporary PacifiCorp loads were scaled up to represent total monthly demand in Utah.[30] It is assumed that the historical and future hourly load profiles of other load-serving entities in Utah are proportional to that of PacifiCorp.

Table 3-1: Largest 10 load-serving entities in Utah in 2007. *Source: EIA Form 861*

Electric Utility	Sales (MWh)	Fraction of State Sales
PacifiCorp (Utah)	22,352,159	80.4%
Provo City Corporation	793,540	2.9%
City of St. George	620,654	2.2%
City of Logan	429,124	1.5%
City of Murray	371,964	1.3%
Moon Lake Electric Assn. Inc.	367,492	1.3%
Dixie Escalante R E A, Inc.	320,820	1.2%
City of Bountiful	307,068	1.1%
City of Springville	237,306	0.9%
Spanish Fork City Corporation	203,050	0.7%

3.3.2. Hourly Fossil Generation and Emissions Data

Generation and emissions are derived from the EPA Clean Air Markets Division (CAMD) dataset of hourly reported gross generation, heat input, and emissions of NO_x, SO_2, and CO_2.[31] The data are collected by the EPA Continuous Emissions Monitoring (CEM) program to inform compliance with the Acid Rain Program, Title IV of the Clean Air Act.[32] The program covers all fossil power units over 25 MW. The CAMD dataset is made available to the public and updated on a quarterly basis.

Table 3-2 shows statistics for the units in this analysis, including the unique DOE code for each plant (ORISPL), the first year the generator was in operation, the operating capacity of the plant during the study period (in MW), the total gross generation over the study period, hours in operation (out of a total of 8,784),[33] capacity factor, and average emissions rates over the study period.

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[29] US Department of Energy, Energy Information Administration (2009). Form 826, Monthly Electric Utility Sales and Revenue Data. Available online at http://www.eia.doe.gov/cneaf/electricity/page/eia826.html

[30] Monthly demand by major utilities, cooperatives, and municipal utilities in Utah from EIA Form 826

[31] Available at http://camddataandmaps.epa.gov/gdm/

[32] US EPA (2009). Acid Rain Program: Emissions Monitoring and Reporting. http://www.epa.gov/airmarkets/progsregs/arp/basic.html

[33] Year 2008 included a leap year, increasing total hours in the analysis period by 24 hours to 8,784.

Table 3-2: Basic information on fossil units in Utah that report to the CAMD database.

Plant Name	Unit ID	Fuel Type	ORISPL [a]	Generator Year Online [b]	Gross Operating Capacity (MW)[c]	Gross Generation (MWh)	Hours in Operation [d]	Capacity Factor	Emissions Rate NO_x lbs/MWh	Emissions Rate SO_2 lbs/MWh	Emissions Rate CO_2 tons/MWh
Bonanza	1-1	Coal	7790	1986	507	3,965,905	8,607	89.1%	3.60	0.52	1.07
Carbon	1	Coal	3644	1954	79	560,449	8,171	80.8%	5.29	8.06	1.03
Carbon	2	Coal	3644	1957	113	753,150	7,190	75.9%	5.16	8.58	1.11
Currant Creek	CTG1A	Gas	56102	2005	289	1,607,484	7,660	63.3%	0.06	0.00	0.39
Currant Creek	CTG1B	Gas	56102	2005	295	1,609,129	7,645	62.1%	0.06	0.00	0.38
Gadsby	1	Gas	3648	1951	60	48,037	1,664	9.1%	1.44	-	0.79
Gadsby	2	Gas	3648	1952	72	71,451	2,091	11.3%	1.44	0.00	0.80
Gadsby	3	Gas	3648	1955	107	135,590	2,635	14.4%	0.85	0.00	0.67
Gadsby	4	Gas	3648	2002	42	93,016	4,209	25.2%	0.18	-	0.63
Gadsby	5	Gas	3648	2002	42	90,939	4,075	24.6%	0.17	-	0.61
Gadsby	6	Gas	3648	2002	44	88,264	3,980	22.8%	0.17	-	0.61
Hunter	1	Coal	6165	1978	464	3,487,376	8,201	85.6%	3.92	1.59	1.07
Hunter	2	Coal	6165	1980	465	3,631,600	8,602	88.9%	3.85	1.32	1.04
Hunter	3	Coal	6165	1983	506	3,869,964	8,439	87.1%	3.44	0.56	0.96
Huntington	1	Coal	8069	1977	485	3,611,204	8,192	84.8%	3.34	1.33	0.94
Huntington	2	Coal	8069	1974	491	3,942,857	8,574	91.4%	2.10	0.52	0.98
Nebo	U1	Gas	56177	2004	151	572,325	4,928	43.1%	0.17	0.00	0.44
West Valley	U1	Gas	55622	2002	60	107,093	4,186	20.3%	0.21	-	0.61
West Valley	U2	Gas	55622	2002	60	108,051	4,261	20.5%	0.18	-	0.61
West Valley	U3	Gas	55622	2002	60	89,225	3,754	16.9%	0.17	-	0.62
West Valley	U4	Gas	55622	2002	40	97,684	3,899	27.8%	0.19	-	0.61
West Valley	U5	Gas	55622	2002	41	96,163	3,726	26.7%	0.15	-	0.60
Lake Side	CT01	Gas	56237	2007	307	1,636,421	7,072	60.7%	0.04	0.00	0.38
Lake Side	CT02	Gas	56237	2007	308	1,691,057	7,235	62.5%	0.04	0.00	0.38
Millcreek	MC-1	Gas	56253	2006	40	35,067	928	10.0%	0.56	-	0.52
Intermountain	1SGA	Coal	6481	1986	956	7,785,281	8,376	92.7%	3.72	0.76	0.96
Intermountain	2SGA	Coal	6481	1987	965	7,365,781	7,912	86.9%	3.54	0.74	0.97

[a] ORISPL = DOE plant identification number. Multiple units comprise single plants; combined cycle units are identified by combustion turbine components.
[b] Generator year online from EPA eGRID dataset
[c] Capacity in this table represents maximum gross generation (before busbar) reported during study period, as reported to CAMD. This value may differ from reported nameplate net capacity.
[d] Hours online represents the number of hours during the study period where gross generation is greater than zero. Study year has 8784 hours.

3.4. Representation of exports and seasonal dynamics

The analysis estimates total required generation on an hourly basis by comparing trends of historic gross generation and demand. In most regions of the country, these are correlated, but not necessarily the same, depending on imports and exports. The basis of the analysis relies on an implicit relationship between total system load and individual unit operations.

Due to the significant differences between demand and generation during periods of high imports and exports, the analysis required a manual characterization of period of high export or moderate imports due to hydroelectric operations in the Northwest.

Figure 3-3 shows the relationship between Utah hourly demand during the study period and Utah hourly fossil generation over the same period, plotting 8,784 data points of demand and generation on a scatterplot.[34] If every unit of generation produced in Utah was consumed in Utah, this graph would show only a 1:1 line, with as much being consumed as being produced. Instead, this figure shows that demand in Utah is not strongly correlated with generation in Utah. Often, generation exceeds demand by as much as 2000 MW, and is sometimes lower than demand by a few hundred MW.

During periods of either high hydroelectric availability in the Northwest or high local demand, Utah's generators ramp with local load requirements (the lower, nearly 1:1 bound on the scatter plot of load versus generation in Figure 3-3) and exports are small. However, during the autumn and early spring, when hydroelectric availability is low, baseload coal generators increase operations.

[34] The figure excludes generation from the Intermountain Power Project (IPP), 80% of which is sold to California through a high capacity direct current transmission line.

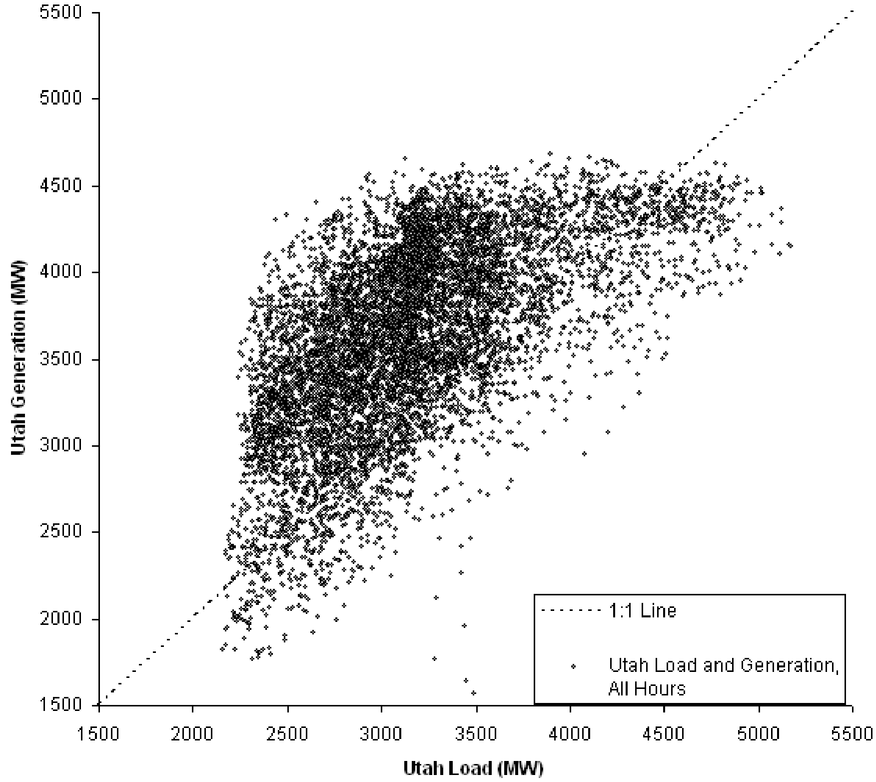

Figure 3-3: Hourly generation and load in Utah, excluding the IPP facility. Each point represents one hour during the study period (8784 points total). Points near the 1:1 line are periods of few net exports. Exports are above the 1:1 line; the top of the triangle is saturated generation, where all Utah generators are operating near full capacity.

Because of these significant discrepancies in behavior relative to an exogenous variable, hydroelectric capacity, we divide the year into two categories:

Category A: High hydroelectric availability in the northern Western Electric Coordination Council (WECC-N) Region *and/or* high demand in Utah (minimal exports from Utah)

Category B: Low hydroelectric availability (high level of exports from Utah)

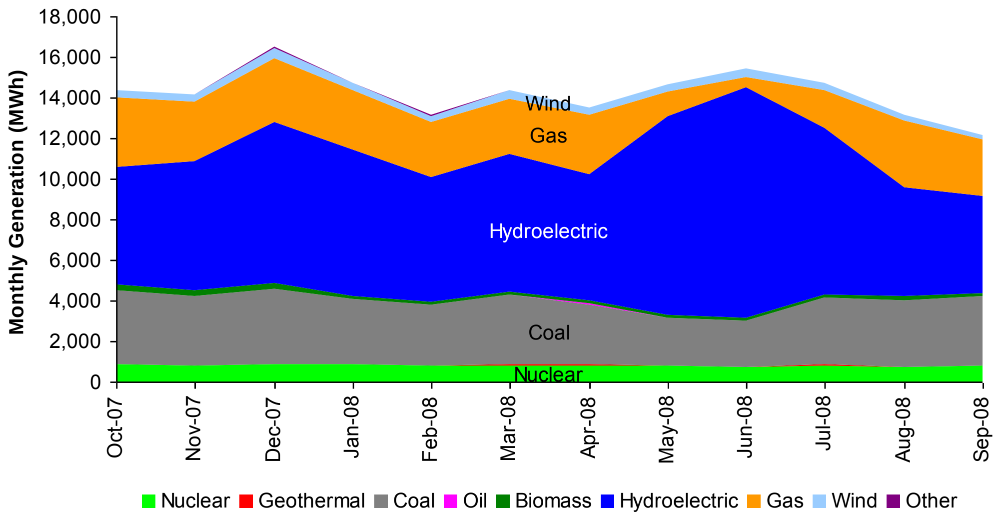

Figure 3-4: Monthly generation in the Western Electric Coordination Council (WECC-N) Region (includes OR, WA, ID, MT, UT, and parts of CA, WY, and CO). Hydroelectricity output peaks May through July, displacing gas and coal. A smaller peak occurs in the winter.

Examining patterns of load and generation throughout the region, and monthly hydroelectric generation in WECC (see Figure 3-4 and Figure 3-5), we chose the period from May 4th through August 31st and November 28th through March 3rd (with the exception of December 18 to January 1st) in Period A, and the remainder of the year in Period B. These categorizations roughly separate the year into periods when plants in Utah are exporting, and when Utah load is served by local generation (see Box 1, page 21).

A timeline of average daily load and generation (excluding the Intermountain Power Plant) during the study period is shown in Figure 3-5. On top of the time series, shaded regions indicate the dates covered by load periods A and B. Dispatch dynamics are fundamentally different during these two load periods (see Box 1, above), and so we analyze fossil displacement within each period independently.

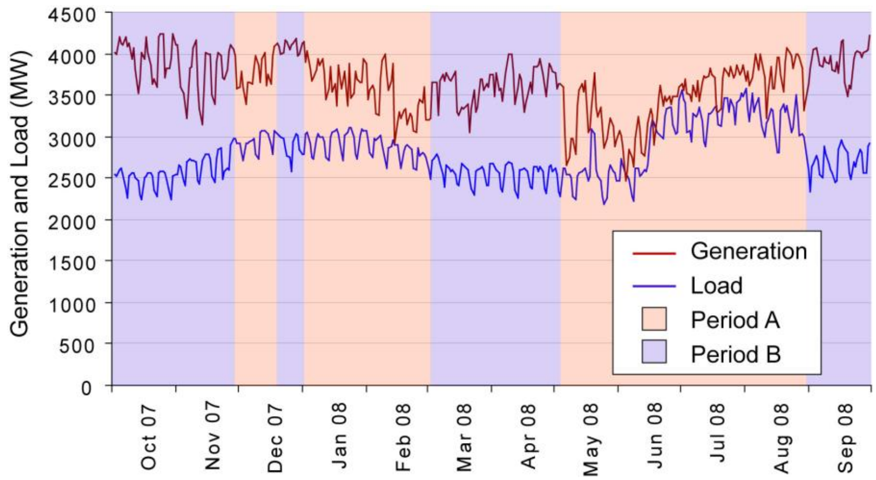

Figure 3-5: Time series of average daily generation (red) and load (blue) in Utah. Shaded regions represent load periods, differing by level of demand and hydroelectric operations.

3.4.1. Generation Statistics from Load

Statistics are gathered from the generation dataset by examining discrete "load bins", the hours when load fell between an upper and lower bounding demand. There are 40 such load bins, distributed such that each load bin represents the same number of hours. These bins can be envisioned as evenly spaced slices of a load duration curve. In this study, there are 8784 hours divided into two "categories" due to fluctuating hydroelectric conditions in the Northwest (see section above); bins in the first period (A) represent 123 hours each, and bins in the second period (B) represent 101 hours each.

In each load bin, two statistics are gathered:

- The probability that each unit is operational, defined by the number of hours in which a unit generates more than zero gross MW, divided by the number of hours in the bin.
- The probability distribution function of the unit's generation within the load bin, in linearly spaced categories.

Operational Probability

The fraction of time that an electricity generating unit (EGU) is operational is a function of the type of generator, relative to the generation mix. For example, a baseload unit, or a unit which is maintained for the purposes of exporting energy, will be operational even when very little load is demanded (off-peak hours), and thus generate in most of the load bins. A peaking unit, however, is unlikely to ever operate at low load levels, but might occasionally operate at high loads. For forecasting purposes, this analysis assumes that the historical fraction of time that a unit operated at any given load is also the probability that it will operate in the future at that same load, given similar conditions.

The analysis algorithm references each hour of the year into a load bin. In each load bin (i.e. each "slice" of the load duration curve), we count the number of hours in which each generator was operational. The operational probability for each generator in each load bin is simply the number of hours the unit was operational divided by the total hours in the bin.

Generation Probability Distribution

When units do run, the amount generated is often also a function of demand. The program collects statistics for each generator on how much energy the unit produces in each load bin. The information is translated into a discrete probability distribution function with twenty different generation options. This process creates a histogram of potential power outputs for a generator when a particular load is demanded.

The analysis algorithm parses each EGU's generation into twenty bins, from one MW output to the maximum output of the EGU. Within each load bin, for each hour that the generator is operational, the level of its output is used to score one of the twenty load bins. For example, combustion turbine #1 on the Currant Creek Power Project is able to generate up to 270 MW, so twenty bins of approximately 13.5 MW each are created in each load bin. In almost all hours where Utah load is above 3,500 MW, the unit has a gross generation of 210 MW. When Utah load drops below 3,500 MW, the unit reduces generation to about 160 MW. This behavior is captured in the statistics represented by the generation probability distribution. The distribution is used to then estimate future output under new load conditions.

3.4.2. Emissions statistics from generation (probabilistic emissions rate)

Unit emissions statistics relative to unit generation are gathered from the database similarly to the way in which generation statistics were gathered relative to load. For many types of units, emissions are a reasonably straightforward function of generation (higher emissions when more power is generated). In other datasets,[35] emissions are calculated as a rate relative to generation (lbs NO_x / MWh, or tons CO_2 / MWh), assuming a linear increase with generation. However, emissions (particularly NO_x and SO_x) are not always tightly correlated with generation (see Figure 3-6), and can vary depending on running conditions, operating temperatures, and whether emissions controls are in operation.

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[35] For example, see the US Environmental Protection Agency's eGRID dataset (http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html), one of the most comprehensive resources for plant-level, state and regional emissions reporting data, based on the CAMD dataset.

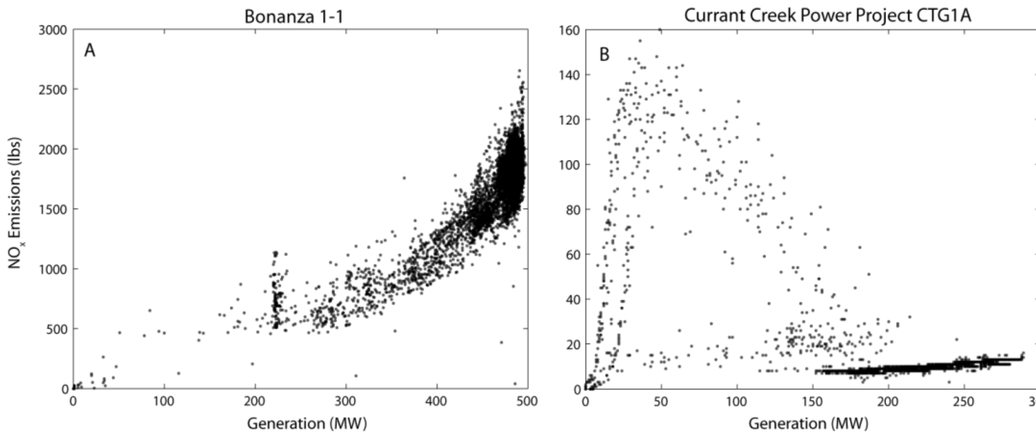

Figure 3-6: NOx emissions versus generation for two Utah EGUs. Dots represent hours of the year; there are 8784 dots per scatter plot. (A) Emissions from Bonanza 1-1 rise with generation output along a non-linear curve. (B) Currant Creek 1 emissions are high as the plant warms from cold start; emissions rise slowly past 150 MW of output. *Please note that the graph scales are different and not proportional.*

The model uses 20 generation bins, or categories, for each unit, bounded by zero and the highest recorded generation output the unit. Emissions are recorded in all hours where the unit generated the amount in each bin. Within each generation bin, a probability distribution function (PDF) of emissions is created. For some units, this is a very tightly bounded constraint (where emissions are fixed for a particular level of generation), while for other units, this distribution can be quite wide.

3.4.3. Monte Carlo Simulation

We use a Monte Carlo simulation to estimate generation and emissions under certain load conditions. A Monte Carlo simulation is a method of obtaining both likely average system behavior and error bounds when there are a large number of uncertain variables. This analytical technique runs a model numerous times (in this case, one hundred), each time drawing the value for uncertain variables randomly according to a probability distribution function. The median result of all of the runs is the expected value, and the variance of the results defines the error term. In this analysis, there is uncertainty on:

1. the number of units operating when a particular demand is required,
2. the generation level of those units which are operating when a particular demand is required, and
3. the emissions level of those units at a particular generation.

The analysis solves for expected generation and load by running 100 manifestations of the model in the Monte Carlo simulation. This process is divided into three distinct steps:

1. choosing which units operate,
2. choosing the generation of each of these units, and
3. choosing the emissions level of each of these units.

Each manifestation of the Monte Carlo approach runs as follows. The model determines the correct load bin for a given hourly load. Within this load bin, each plant has a certain probability of operating. A random variable is used to determine if a unit will operate or not, given its probability. For each unit determined to be in operation, a second random variable determines the level of operation, based on the probability distribution function of generation.[36] Finally, given the level of operation (in MW), a final random variable determines the emissions in that hour, given the probability distribution function of emissions. Results are reported as total annual generation and annual emissions of NO_X, SO_2, and CO_2 for all iterations of the Monte Carlo run. In post processing, the median is obtained from the series of runs. The results are used to estimate mortality and morbidity from air emissions, and water use from generation, as described in the next two chapters.

[36] This is accomplished by transforming the PDF into a cumulative distribution function (CDF), with values from zero to one. When the random variable is drawn, it is compared to the CDF and chooses the generation with a cumulative probability less than or equal to the random variable. If we repeat this operation multiple times, the histogram of all chosen generation values converges on the shape of the PDF.

4. Emissions and Health

4.1. Introduction

The public health implications of emissions from power plants are generally estimated using a damage function approach, in which emissions of key pollutants are estimated, population exposures resulting from those emissions are modeled, and the health impacts of those exposure changes are quantified given epidemiological evidence for a variety of health outcomes. In many circumstances, it is also desirable to assign monetary values to health outcomes, reflecting either direct health care costs or societal willingness to pay to avoid adverse health effects. These values allow for a comparison with control costs as well as a mechanism to aggregate across disparate health outcomes. This methodology has been widely applied, including by the EPA when estimating the public health benefits of air pollution regulations,[37,38,39,40] and within the academic literature.[41,42,43,44,45] The approach has also been endorsed by the EPA Science Advisory Board [46], the U.S. Office of Management and Budget [47], and the National Academy of Sciences [48], among others.

Generally, fairly complex chemistry-transport models are used to simulate the effects of emission changes on ambient concentrations across a large geographic area. However, such models are computationally and resource intensive and are impractical for applications such as this. To allow the results from previous detailed modeling

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[37] US Environmental Protection Agency, *The Benefits and Costs of the Clean Air Act: 1990 to 2010*. Office of Air and Radiation: Washington, DC, 1999.
[38] US Environmental Protection Agency, *Regulatory Impact Analysis - Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements*. Office of Air and Radiation: Washington, DC, 1999.
[39] US Environmental Protection Agency *Final Regulatory Analysis: Control of Emissions from Nonroad Diesel Engines*; EPA420-R-04-007; Assessment and Standards Division, Office of Transportation and Air Quality: Washington, DC, 2004.
[40] US Environmental Protection Agency *Regulatory Impact Analysis for the Final Clean Air Interstate Rule*; EPA-452/R-05-002; Office of Air and Radiation: Washington, DC, 2005.
[41] Levy, J. I.; Greco, S. L.; Spengler, J. D., The importance of population susceptibility for air pollution risk assessment: A case study of power plants near Washington, DC. *Environmental Health Perspectives* **2002,** 110, 1253-1260.
[42] Levy, J. I.; Hammitt, J. K.; Yanagisawa, Y.; Spengler, J. D., Development of a new damage function model for power plants: Methodology and applications. *Environmental Science & Technology* **1999,** 33, 4364-4372.
[43] Levy, J. I.; Spengler, J. D., Modeling the benefits of power plant emission controls in Massachusetts. *J Air Waste Manage Assoc* **2002,** 52, 5-18.
[44] Muller, N. Z.; Mendelsohn, R., Measuring the damages of air pollution in the United States. *Journal of Environmental Economics and Management* **2007,** 54, (1), 1-14.
[45] Lopez, M. T.; Zuk, M.; Garibay, V.; Tzintzun, G.; Iniestra, R.; Fernandez, A., Health impacts from power plant emissions in Mexico. *Atmospheric Environment* **2005,** 39, (7), 1199-1209.
[46] US Environmental Protection Agency, *Air Quality Criteria for Particulate Matter*. Office of Research and Development: Research Triangle Park, NC, 2004.
[47] US Environmental Protection Agency, *Regulatory Impact Analyses for the Particulate Matter and Ozone National Ambient Air Quality Standards and Proposed Regional Haze Rule*. Office of Air Quality Planning and Standards: Research Triangle Park, NC, 1997.
[48] Committee on Estimating the Health-Risk-Reduction Benefits of Proposed Air Pollution Regulations, *Estimating the Public Health Benefits of Proposed Air Pollution Regulations.* National Research Council: Washington, DC, 2002

applications to be extrapolated to unstudied sources and settings, researchers have developed a concept known as the intake fraction.[49] This simply reflects the fraction of an emitted pollutant or its precursor that is inhaled by some member of the population. For primary pollutants,[50] the emitted pollutant is identical to the exposed pollutant, and the intake fraction represents atmospheric dispersion, deposition, and population density downwind of the source. For secondary pollutants (such as ozone, sulfate, or nitrate), the intake fraction characterizes the concentrations associated with emissions of the precursors (such as NO_x or SO_2), and represents the above elements for primary pollutants as well as chemical transformation in the atmosphere. Intake fractions will clearly vary by source and location, so it is necessary to either apply estimates from closely analogous sources or from regression models that explain variability in intake fractions as a function of available covariates.[51,52] Other researchers have used complex chemistry-transport models to develop relatively simple source-receptor models that can allow for rapid assessments of the impact of changes in emissions at a given source on concentrations at a number of receptor locations. [38,53,54]

Given an exposure model, the applicability of the damage function approach ultimately hinges on the assumption that the modeled pollutants have public health impacts at current and projected future ambient concentrations (i.e., that background concentrations are above any potential population threshold). Two air pollutants for which this assumption appears to hold at present are fine particulate matter ($PM_{2.5}$) and ozone. $PM_{2.5}$ has been associated with a number of health outcomes, including mortality from long-term exposure,[55,56,57,58] mortality from short-term exposure,[59,60,61] and various

[49] Bennett, D. H.; McKone, T. E.; Evans, J. S.; Nazaroff, W. W.; Margni, M. D.; Jolliet, O.; Smith, K. R., Defining intake fraction. *Environ Sci Technol* **2002,** 36, (9), 207A-211A.

[50] Primary pollutants include: carbon monoxide (CO), oxides of nitrogen (NO_X), sulfur dioxide (SO_2), volatile organic compounds (VOCs), and particulates ($PM_{2.5}$).

[51] Levy, J. I.; Wolff, S. K.; Evans, J. S., A regression-based approach for estimating primary and secondary particulate matter intake fractions. *Risk Analysis* **2002,** 22, 895-904.

[52] Zhou, Y.; Levy, J. I.; Evans, J. S.; Hammitt, J. K., The influence of geographic location on population exposure to emissions from power plants throughout China. *Environ Int* **2006,** 32, (3), 365-73.

[53] Tong, D. Q.; Mauzerall, D. L., Summertime state-level source-receptor relationships between nitrogen oxides emissions and surface ozone concentrations over the continental United States. *Environ Sci Technol* 2008**,** 42, (21), 7976-84.

[54] Abt Associates *User's Manual for the National Co-Benefits Risk Assessment Model, Beta Version 2.0.*; US EPA State and Local Capacity Building Branch: Bethesda, MD, 2004.

[55] Dockery, D. W.; Pope, C. A.; Xu, X.; Spengler, J. D.; Ware, J. H.; Fay, M. E.; Ferris, B. G. J.; Speizer, F. E., An association between air pollution and mortality in six U.S. cities. *New England Journal of Medicine* **1993,** 329, (24), 1753-1759.

[56] Laden, F.; Schwartz, J.; Speizer, F. E.; Dockery, D. W., Reduction in fine particulate air pollution and mortality: Extended follow-up of the Harvard Six Cities study. *Am J Respir Crit Care Med* **2006,** 173, (6), 667-72.

[57] Pope, C. A., 3rd; Thun, M. J.; Namboodiri, M. M.; Dockery, D. W.; Evans, J. S.; Speizer, F. E.; Heath, C. W., Jr., Particulate air pollution as a predictor of mortality in a prospective study of U.S. adults. *American Journal of Respiratory & Critical Care Medicine* **1995,** 151, (3 Pt 1), 669-74.

[58] Pope, C. A.; Burnett, R. T.; Thun, M. J.; Calle, E. E.; Krewski, D.; Ito, K.; Thurston, G. D., Lung cancer, cardiopulmonary mortality, and long-term exposure to fine particulate air pollution. *JAMA* **2002,** 287, (9), 1132-41.

[59] Daniels, M. J.; Dominici, F.; Samet, J. M.; Zeger, S. L., Estimating particulate matter-mortality dose-response curves and threshold levels: an analysis of daily time-series for the 20 largest US cities. *American Journal of Epidemiology* **2000,** 152, (5), 397-406.

non-fatal outcomes ranging in severity.[62, 63] Importantly, these studies have not shown a threshold below which health effects are not observed. A generally linear concentration-response function is present throughout the range of ambient concentrations. Similarly, ozone has been associated with mortality due to short-term exposure at current ambient concentrations,[64,65,66,67] and with various non-fatal outcomes. [68] Prior regulatory impact analyses demonstrate that the vast majority of the public health benefits of air pollution control strategies are due to reduced exposure to $PM_{2.5}$ and ozone.[37,38,39,40] Thus, we focus on these two pollutants in our analysis.

As a general point, while this damage function approach is well-supported in the academic and regulatory literature, it clearly contains some significant uncertainties, especially given limitations in available emissions data, uncertainties in chemistry-transport modeling, and the assumptions regarding health effects at current ambient concentrations and the economic values assigned to those health effects. Uncertainties are discussed at length later in this chapter, but it should be recognized that the values presented in this report are meant to be plausible central estimates, with the objective that it is equally likely that the impacts are above or below the reported values.

Below, we describe the methodology we apply to estimate the public health impacts associated with various emissions and generation scenarios in Utah. We first describe the source of emissions data utilized, which is directly available for SO_2 and NO_x but requires estimation for primary $PM_{2.5}$. We describe the methodology used to estimate population exposure, including both a subset of power plants where prior modeling efforts defined chemistry-transport outputs, as well as a subset for which exposures needed to be estimated indirectly using intake fraction concepts. We summarize the studies used to develop concentration-response functions for $PM_{2.5}$ and ozone, focusing herein on premature mortality and selected morbidity outcomes. We describe the methods used to characterize population patterns, baseline disease rates, and economic

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[60] Dominici, F.; Daniels, M.; McDermott, A.; Zeger, S. L.; Samet, J. M., Shape of the exposure-response relation and mortality displacement in the NMMAPS database. In *Health Efffects Institute Special Report: Revised Analyses of Time-Series Studies of Air Pollution and Health*, Charlestown, MA, 2003; pp 91-96.

[61] Schwartz, J. *Airborne particles and daily deaths in 10 US cities*; Health Effects Institute: Boston, MA, 2003, 2003; pp 211-218.

[62] Zanobetti, A.; Schwartz, J., The effect of particulate air pollution on emergency admissions for myocardial infarction: a multicity case-crossover analysis. *Environ Health Perspect* **2005,** 113, (8), 978-82.

[63] Bateson, T. F.; Schwartz, J., Who is sensitive to the effects of particulate air pollution on mortality? A case-crossover analysis of effect modifiers. *Epidemiology* **2004,** 15, (2), 143-9.

[64] Bell, M. L.; Peng, R. D.; Dominici, F., The exposure-response curve for ozone and risk of mortality and the adequacy of current ozone regulations. *Environ Health Perspect* **2006,** 114, (4), 532-6.

[65] Levy, J. I.; Chemerynski, S. M.; Sarnat, J. A., Ozone exposure and mortality: an empiric bayes metaregression analysis. *Epidemiology* **2005,** 16, (4), 458-68

[66] Ito, K.; De Leon, S. F.; Lippmann, M., Associations between ozone and daily mortality: analysis and meta-analysis. *Epidemiology* **2005,** 16, (4), 446-57.

[67] Bell, M. L.; Dominici, F.; Samet, J. M., A meta-analysis of time-series studies of ozone and mortality with comparison to the national morbidity, mortality, and air pollution study. *Epidemiology* **2005,** 16, (4), 436-45.

[68] Ostro, B. D.; Tran, H.; Levy, J. I., The health benefits of reduced tropospheric ozone in California. *J Air Waste Manag Assoc* **2006,** 56, (7), 1007-21.

values for premature mortality and morbidity, and we conclude by listing the key assumptions and uncertainties in our modeling framework.

4.2. Methodology

As a general point, we note that the methods below are described in extensive detail in two publications by this section's author, Dr. Jonathan Levy. Methods for estimating $PM_{2.5}$ externalities are described in Levy, Baxter and Schwartz (2009),[69] while concentration-response functions for ozone morbidity and mortality are detailed in Ostro, Tran and Levy (2006).[68] Below, we briefly summarize these methods and provide detail about aspects of our analysis not included in these publications, but refer the reader to the original publications for more methodological detail.

4.2.1. Emissions

For each of the scenarios developed, SO_2 emissions, NOx emissions, and MWh generated were simulated for each power plant for each simulated year (see Chapter 3). We used these emissions estimates directly for each power plant, focusing on the average estimates across Monte Carlo simulations, and considering 2007, 2010, 2015, and 2020 for health risk estimation. Primary $PM_{2.5}$ emissions were not simulated, so these emissions needed to be approximated external to the simulations. For many power plants, primary $PM_{2.5}$ emissions are estimated in the EPA National Emissions Inventory (NEI) database. The most recent data available at the time of our assessment was for 2002. We used that data combined with MWh generated for these plants to determine the emissions per MWh generated for each plant. Lacking any data to the contrary, we assumed that emissions would remain proportional to electricity generation in future years, and scaled emissions accordingly across all scenarios.

Primary $PM_{2.5}$ emissions data were not available from the NEI or the Utah DEQ for four power plants (Nebo, Currant Creek, Lake Side, and Millcreek). Primary $PM_{2.5}$ emissions therefore needed to be approximated for these plants. Lacking detailed data on plant configuration and combustion technology, we simply calculated the average primary $PM_{2.5}$ emission rate per MWh for gas-fueled power plants within this study (West Valley and Gadsby), and we applied this rate to all four power plants lacking any emissions data. This clearly represents a fairly significant uncertainty from the perspective of primary $PM_{2.5}$ emissions (especially given that some of the plants lacking data are combined-cycle plants, whereas the plants with data are thermal or gas turbines), and the implication of this assumption is considered within our analysis.

4.2.2. Exposure Characterization

Chemistry-transport modeling had been previously conducted for primary and secondary $PM_{2.5}$, using a source-receptor (S-R) matrix, for all of the coal-fired power plants in Utah considered within this study (Bonanza, Carbon, Hunter, Huntington, and Intermountain Power Project).[69] The results of this modeling could therefore be used directly, providing

[69] Levy, J. I.; Baxter, L. K.; Schwartz, J., Uncertainty and variability in health-related damages from coal-fired power plants in the United States. *Risk Anal* **2009,** 29, (7), 1000-14.

estimates not only of total population exposure, but also of population exposure within Utah and within each county across the United States. Population exposure to $PM_{2.5}$ emissions are based on previous modeling exercises, which carry an intrinsic degree of uncertainty. In addition, the same S-R matrix used in this recent publication had sufficient data to directly model the exposures associated with emissions from Gadsby. For the remaining gas-fired power plants (Nebo, Currant Creek, Lake Side, Millcreek, and West Valley Generation Project), no such models were available, so we needed to utilize the intake fraction concept described above to approximate population exposures. We applied a regression equation derived in a prior publication and detailed in Levy, Baxter and Schwartz (2009), which characterized primary and secondary particulate matter intake fractions for a number of power plants across the United States as a function of population within various distances of the plants. Thus, greater uncertainty would be anticipated for the exposure and health impact estimates for these gas-fired power plants.

For ozone, directly-modeled estimates are not available for any of the individual power plants. Instead, we use a source-receptor matrix developed by Tong and Mauzerall [53] to estimate the intake fractions of ozone for every ton of NO_x emitted in Utah. Tong and Mauzerall analyzed the effect of interstate transport on surface ozone in each continental US state in July 1996 using the Community Multiscale Air Quality (CMAQ) model. The S-R matrices show the effect NO_x emissions from one state (source state) have on surface O_3 concentrations over the source state and other states (receptor states) for July 1996 mean daily peak 8-h as well as 24-hour O_3 concentration changes. Based on their model results, we derive the relationship between NO_x emissions from Utah in July 1996 (8-hr max) and the ozone mass inhaled by the population residing in the six states in which ozone impacts were found to be non-zero in their S-R matrix (Idaho, New Mexico, Arizona, Wyoming, Colorado, and Utah). Clearly, there are significant uncertainties associated with using state-level estimates averaged across all NO_x sources, and there is a positive bias associated with using a summertime relationship to reflect exposures across the year. However, modeling ozone formation in more detail was beyond the scope of our assessment.

4.2.3. Concentration-response functions

For $PM_{2.5}$, the concentration-response function for premature mortality was derived from a recent cohort study,[70] as documented in Levy, Baxter and Schwartz (2009).[69] Of note, this recent study specifically evaluated the likelihood of thresholds or other non-linearities in the concentration-response function, and found that a linear model throughout the range of ambient concentrations was by far the most likely model structure given the observed data. For morbidity, while a large number of outcomes have been characterized previously, we focus on a subset that are interpretable, span a range of severity, and may contribute significantly to monetized health damages. This includes hospital admissions for cardiovascular and respiratory causes, asthma-related

[70] Schwartz, J.; Coull, B.; Laden, F.; Ryan, L., The effect of dose and timing of dose on the association between airborne particles and survival. *Environ Health Perspect* **2008,** 116, (1), 64-69.

emergency room visits, and minor restricted activity days (MRADs, days in which people had to reduce their activities due to symptoms but could still work). This should not be considered an exhaustive list of health endpoints and could potentially result in an underestimate of damages; however, monetarily, the impact of such underestimation would likely be small. Morbidity estimates are based largely on recent peer-reviewed meta-analyses, rather than Utah-specific studies.

For hospital admissions for cardiovascular causes, we rely on a recent meta-analysis [71] which combined 51 published studies to determine that cardiovascular hospital admissions increase by an estimated 0.9% per 10 $\mu g/m^3$ increase of PM_{10}. However, given that differences in health care systems among countries may influence an outcome like hospital admissions, utilizing a large number of non-U.S. studies to determine a concentration-response function for this outcome may not be appropriate. We therefore re-ran the meta-analysis restricted to the 33 estimates from U.S. studies, and determined a central estimate nearly identical to that above (a 0.97% increase in cardiovascular hospital admissions per 10 $\mu g/m^3$ of PM_{10}, slightly higher than the all-study value). We use a standard conversion between $PM_{2.5}$ and PM_{10} (a typical ratio of 0.6 based on evidence in the Particulate Matter Criteria Document) to derive a best estimate of a 0.16% increase in cardiovascular hospital admissions per $\mu g/m^3$ increase of $PM_{2.5}$, among individuals age 65 and older.

To derive an estimate for respiratory hospital admissions, we conducted a meta-analysis of the published literature, given a large number of studies and no recently published meta-analyses. The studies considered were taken from Levy et al. [72], from the EPA's BenMAP program, and from the Air Quality Criteria Document for Particulate Matter [73]. From the large number of studies available, we eliminated a subset of studies that could not be statistically pooled with other studies for a variety of reasons. These reasons included the application of statistical methods that were not comparable with other studies, use of a pollutant measure other than $PM_{2.5}$ (i.e., only considering acid aerosols or black smoke), consideration of specific respiratory diseases rather than all-cause respiratory hospital admissions, or evaluation of effects on children only. This does not imply that these studies did not represent good scientific evidence, but simply that they were not the best studies to combine to develop concentration-response functions using statistical meta-analysis techniques. If we pool all remaining studies [74,75,76,77,78,79,80,81,82,83,84] using inverse-variance weighting with statistical methods to

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[71] Committee on the Medical Effects of Air Pollutants *Cardiovascular Disease and Air Pollution*; Department of Health, United Kingdom: 2006.

[72] Levy, J. I.; Hammitt, J. K.; Yanagisawa, Y.; Spengler, J. D., Development of a new damage function model for power plants: Methodology and applications. *Environmental Science & Technology* **1999,** 33, 4364-4372.

[73] EPA *Air Quality Criteria for Particulate Matter*; EPA/600/P-99/002aF; National Center for Environmental Assessment, Office of Research and Development: Research Triangle Park, NC, October 2004, 2004.

[74] Anderson, H. R.; Bremner, S. A.; Atkinson, R. W.; Harrison, R. M.; Walters, S., Particulate matter and daily mortality and hospital admissions in the west midlands conurbation of the United Kingdom: associations with fine and coarse particles, black smoke and sulphate. Occupational & Environmental Medicine 2001, 58, (8), 504-10.

account for the possibility of true between-site heterogeneity, as done previously [65,85], the central estimate is a 0.2% increase in respiratory hospital admissions per 1 $\mu g/m^3$ increase of $PM_{2.5}$, applicable to all ages.

Another morbidity outcome of concern for $PM_{2.5}$ is ER visits among asthmatic individuals. As we did for respiratory hospital admissions, we gathered studies from Levy et al. [86] and the Air Quality Criteria Document for Particulate Matter [87]**,** and supplemented this database with an independent literature search. We were able to restrict our focus to U.S. studies for the formal statistical meta-analysis. In total, we found five studies that were suitable for meta-analysis [88,89,90,91,92]. As there is broad

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[75] Atkinson, R. W.; Bremner, S. A.; Anderson, H. R.; Strachan, D. P.; Bland, J. M.; de Leon, A. P., Short-term associations between emergency hospital admissions for respiratory and cardiovascular disease and outdoor air pollution in London. *Archives of Environmental Health* **1999,** 54, (6), 398-411.

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[82] Schwartz, J.; Spix, C.; Touloumi, G.; Bacharova, L.; Barumamdzadeh, T.; le Tertre, A.; Piekarksi, T.; Ponce de Leon, A.; Ponka, A.; Rossi, G.; Saez, M.; Schouten, J. P., Methodological issues in studies of air pollution and daily counts of deaths or hospital admissions. *J Epidemiol Community Health* **1996,** 50 Suppl 1, S3-11.

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consistency across studies in the magnitude and significance of the effect, it makes sense to consider this an all-age effect. We consider a best estimate to be a 0.8% increase in asthma-related ER visits per $\mu g/m^3$ increase of $PM_{2.5}$.

Finally, we consider MRADs. There are a variety of respiratory symptom outcomes available in the literature, but we use MRADs given the fact that they capture a number of types of symptoms, have contributed significantly to monetized damages in the past, and to avoid possible double-counting. Only one published study considered MRADs [93], but this was a large nationally-representative sample of adult workers. Using inverse-variance weighting on six individual year estimates, we determine a 0.7% increase per $\mu g/m^3$ increase of $PM_{2.5}$.

For ozone, the concentration-response functions for mortality and morbidity are described in Ostro, Tran and Levy (2006) and are not replicated herein, but include time-series mortality (associated with short-term exposure rather than long-term exposure), respiratory hospital admissions, asthma emergency room visits, MRADs, and school loss days.

4.2.4. Baseline population data

As described in Levy, Baxter and Schwartz (2009), the core population data used in our prior externality modeling was based on the 2000 Census, with county-level baseline mortality rates taken from the CDC Wonder database. Characterizing externalities in future years and with consideration of morbidity outcomes requires application of additional information. Population growth was determined using data from Woods and Poole used in prior regulatory impact analyses, [94] which provides county-level population projections from 2000 to 2030 in five-year increments, for different age ranges and for the population as a whole. Thus, we can determine the at-risk population for each of the forecast years of interest, assuming linear interpolation between the five-year intervals characterized by Woods and Poole.

Population growth varies across counties and states, complicating our analysis, and we only have spatial characterization of exposure for a subset of power plants and pollutants. We apply population growth estimates at the county level for the particulate matter S-R matrix, at the state level for the ozone S-R matrix, and we use the relative differences between years for primary and secondary particulate matter health risks for directly modeled plants to scale up (or down) health impact estimates for indirectly modeled plants.

We also need to characterize the baseline incidence and prevalence of key health outcomes over time. For all outcomes, we assume that the age-specific rates will not change over time. However, as the age distribution of the population shifts over time,

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and pediatric emergency room visits for asthma in Atlanta, Georgia, USA. *Am J Epidemiol* **2000,** 151, (8), 798-810.

[93] Ostro, B. D.; Rothschild, S., Air pollution and acute respiratory morbidity: an observational study of multiple pollutants. *Environ Res* **1989,** 50, (2), 238-47.

[94] US Environmental Protection Agency *2006 National Ambient Air Quality Standards for Particle Pollution*; US Environmental Protection Agency: Washington, DC, 2006.

this will result in changes to the total population rates (often increasing the rates given an aging population). For cardiovascular and respiratory hospital admissions, rates are available by region (Northeast, Midwest, South, West) from the National Hospital Discharge Survey. For asthma emergency room visits, rates are similarly available by region from the National Ambulatory Medical Care Survey. Baseline incidence rates of both school loss days and MRADs are taken from articles in the peer-reviewed literature and are listed in Ostro, Tran and Levy (2006).

4.2.5. Valuation of health outcomes

For premature deaths, we use a value of statistical life (VSL) approach. This should not be taken as the value assigned to a life, but rather, as the aggregation of what a number of people are willing to pay for small risk reductions. In other words, if someone is willing to pay $50 for an intervention that would reduce their risk of dying by 1/100,000, their VSL would be $5 million ($50 divided by 1/100,000). Stated another way, if 100,000 people were all willing to pay $50 for this intervention, one life would be expected to be saved at a cost of $5 million.

As described in Levy, Baxter and Schwartz (2009), we calculate the VSL for premature deaths using EPA's recommended value, which was derived from multiple meta-analyses of the literature. EPA determined a central estimate of $5.5 million in 1999 dollars based on 1990 income distributions, with an uncertainty range from $1 million to $10 million. To determine appropriate values for future years, we need to take account of inflation as well as per capita real GDP growth, which influences how much people are willing to pay. As done by EPA, for all future years, we scale up using an elasticity value of 0.40 to account for per capita real GDP growth. We estimate the economic value in 2008 dollars in all future years, accounting for inflation from 1999 to 2008. In 2008, the estimated VSL for this study is approximately $8 million. Historical data for GDP growth per capita were taken from the U.S. Bureau of Economic Analysis, and we used the general consumer price index (CPI-U) to put VSL prices into 2008 dollars. We assumed 1.5% GDP growth per capita between 2009 and 2020, reflecting historical trends and lacking more detailed economic projections.

For morbidity outcomes, some values are based on what people are willing to pay to reduce the risk, while others reflect direct health care costs. For MRADs, we use EPA's willingness to pay values as described in Ostro, Tran and Levy (2006), accounting for real GDP growth per capita using an elasticity value of 0.14 as recommended by EPA for minor health outcomes. For the remaining morbidity outcomes, economic values are either based on the direct health care costs (cardiovascular or respiratory hospital admissions, asthma emergency room visits) or on the value of time for caregivers (school loss days). For economic values based on direct health care costs, we use the medical care CPI (CPI-MED-U) to scale from 1999 to 2008 dollars, and use these values for all model years. For the value of time for caregivers, we use the general CPI to scale from 1999 to 2008. More detail regarding the economic values used for morbidity and the nature of the evidence base is available in Ostro, Tran and Levy (2006).

4.3. Assumptions, caveats, & uncertainty

There are clearly numerous assumptions associated with our externality calculations, and the results should therefore be interpreted with caution. In general, externality estimates for particulate matter from the coal-fired power plants in Utah are based on peer-reviewed and published methods in which detailed plant-specific modeling was conducted. To give a sense of the magnitude of the uncertainties for these estimates, the paper by Levy, Baxter, and Schwartz (2009) quantified and propagated uncertainties in all aspects of the externality modeling. For the coal-fired power plants in Utah, the 5th percentile estimates of monetized health damages per kWh of electricity generation were about a factor of 5 lower than the central estimates, while the 95th percentile estimates were about a factor of 2.5 higher than the central estimates. Thus, even the well-characterized estimates have appreciable uncertainties, though with an equal likelihood that the values are overestimated as underestimated.

For most gas-fired power plants in Utah, no direct chemistry-transport modeling has been conducted, so we rely on extrapolations from previously modeled power plants. This generally yields population exposures per unit emissions on a par with coal-fired power plants, which is likely reasonable at first order given general similarities in plant locations, stack heights, and other basic characteristics affecting pollutant fate and transport. However, the one directly-modeled gas-fired power plant (Gadsby) did have significantly greater exposures per unit emissions than all coal-fired power plants, likely due to its location near population centers. The intake fraction regression models predicted somewhat lower values for the other gas-fired power plants, even in reasonably close proximity to Gadsby. To the extent that the intake fraction regression models may have missed local nuances associated with populations and topography near the gas-fired power plants, there may be biases in those estimates (which appear more likely to be downward biases based on available information). However, to place the significance of this issue in context, gas-fired power plants contribute minimally to the total health risks, although they do make appreciable contributions to the effects of selected scenarios. In addition, we were lacking primary PM emissions from multiple gas-fired power plants, and in general, primary PM emissions are more poorly characterized than NO_x or SO_2 emissions and should be considered more uncertain.

As described previously, ozone exposure modeling is based on a single paper in which relationships were derived for a single summertime month more than 10 years ago, so the uncertainties for ozone impacts are likely large and potentially highly biased. That said, there is some evidence that the annual ozone health effect is due to a high effect in the ozone season and minimal effect in other seasons, so there may be offsetting errors. Also, Tong uses NO_x emissions from both emission inventories and natural sources, but we use only the anthropogenic source emissions. Although we exclude the NO_x emissions from the natural sources in Utah, such additional information will further decrease the ozone intake fractions and therefore the contribution of ozone-related mortality to the total NO_x-related mortality.

While there are significant uncertainties associated with the concentration-response functions for mortality and morbidity outcomes, as well as for the economic valuation of health outcomes, the studies and methods we applied are comparable to those used by US EPA and in the peer-reviewed literature. Thus, while these elements have relatively large uncertainties, they represent standard practice for health impact assessment (as opposed to chemistry-transport modeling, in which more simplified assumptions were used given available resources).

A final category of uncertainty is related to the relatively small contribution that individual power plants make to ambient concentrations, especially for lower-emitting gas-fueled plants and receptors located at significant distances from the source. While it has been well established that particulate matter and ozone can have regional-scale impacts, the quantitative contributions are clearly more uncertain at long range. That said, the underlying atmospheric model did involve calibration with ambient monitoring data, which should help to limit model biases. More generally, even a small contribution to ambient concentrations would be expected to have an incremental health risk, given the basic logic behind a population concentration-response function. In other words, presuming that ambient concentrations are above any population threshold (as epidemiological evidence indicates for particulate matter and ozone), any change in ambient concentrations would change health risks in the population, as there is no theoretical basis for a “stepwise” concentration-response function in which only changes of certain magnitudes would influence population risk.

5. Water Use

5.1. Introduction

Water must be divided between multiple users, including agriculture, industry, and the public. Historically, a large majority of Utah's water has gone toward irrigation for agricultural users;[95] however, a growing population has caused some of the water use in the state to shift from agriculture to urban uses.[96] Utah has experienced continuous population growth for the last 150 years, and from 1990 to 2000, the state grew at the fourth fastest rate in the nation.[97] Projections from the Governor's Office of Planning and Budget predict that Utah's population will more than double in the next 50 years – growing from 2.3 million in 2000 to just under 6 million in 2050.[98] Historical population growth has already created a strain on the state's water supply, and projected growth over the next several decades "presents a major challenge to meet water demands."[99]

Much of Utah is classified as desert, receiving less than 13 inches of rainfall annually, and water in the state is a limited resource during all years.[100] Water becomes increasingly limited during periods of drought, which can last for a decade or more, and often have economic, social and environmental consequences that take years to be realized. The duration and severity of droughts have been measured in Utah since 1895. When taken in aggregate, the state of Utah has been in a period of major drought for 55 of the last 111 years.[101] Currently, the Division of Water Resources recommends that water suppliers increase their rate of investment in equipment and distribution systems in order to boost future supplies, and encourages Utah's water districts to focus on conservation of existing water supplies.

Table 5-1 shows the amounts of water withdrawn by various users in the state in 2005. As was mentioned above, the majority of water is withdrawn by agricultural users. Public supply and aquaculture are the second and third greatest users of water, respectively. Thermoelectric power generation is fourth, but still withdraws large volumes of water, estimated to be more than 58 million gallons per day, amounting to 65,000 acre-feet per year.[102]

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[95] US Geological Survey. *Estimated Use of Water in the United States in 2000*. USGS Circular 1268. Released March 2004, revised April 2004, May 2004, February 2005. Available at: http://water.usgs.gov/watuse/data/2000/index.html
[96] See discussion of water transactions in the following sections.
[97] Utah Division of Water Resources. *Conjunctive Management of Surface and Ground Water in Utah*. Utah State Water Plan. July 2005. Page xi, 27.
[98] Governor's Office of Planning and Budget. Demographic and Economic Projections. 2008 Baseline Projections. Available at: http://governor.utah.gov/dea/projections.html
[99] Utah Division of Water Resources. *Conjunctive Management of Surface and Ground Water in Utah*. Utah State Water Plan. July 2005. Page 2.
[100] Utah Division of Water Resources. *Long-term Water Supply Outlook.* Available at: http://www.water.utah.gov/waterconditions/WaterSupplyOutlook/default.asp
[101] *Ibid*. Page 28.
[102] US Geological Survey. *Estimated Use of Water in the United States in 2005*. USGS Circular 1344. Released October 27, 2009. Available at: http://pubs.usgs.gov/circ/1344/

Table 5-1: Water Withdrawals in Utah by Sector.[103]

Sector	Freshwater withdrawals (million gallons per day)
Public Supply	607
Domestic	14
Irrigation	4,000
Livestock	18
Aquaculture	88
Industrial	35
Mining	5
Thermoelectric Power	58

Fossil-fired electric generators use large quantities of water for power plant cooling, and smaller amounts to increase efficiency of turbines and for pollution control. As a state's population grows, so does the demand for energy, increasing the demands on thermal generators and potentially requiring greater volumes of water for use in power plants. Conversely, declining demand for thermal generation, as achieved through energy efficiency or non-water intensive renewable energy programs, can lead to decreases in the rate of water use by thermal generators for power production. The displacement of thermal generators in favor of renewable sources of energy production such as wind or solar power may have a similar effect on water use.

This analysis examines the water co-benefit of EE and RE; since water consumption by thermal generating units is an externality of generation, avoided water use is the co-benefit of reduced generation. The monetary value of reduced water consumption is estimated as the marginal cost of water in Utah. These calculations are described below.

5.2. Estimating Water Use of Thermal Generating Units

To obtain a total quantity of water saved, the water consumption rate of the generating units in this analysis had to first be determined. The use of water at power plants is inconsistently reported and sparsely available, and therefore this study has estimated water consumption for some power plants based on values from the literature. Self-reported rates of water consumption in cubic feet per second were available from the Energy Information Administration (EIA) Form 767 for coal- and gas-fired units using steam turbines as a prime mover. The EIA discontinued the use of Form 767 in 2006, thus water consumption data are from 2005, the last year they were available. Form 767 also contained data on unit generation, and these numbers were combined with consumption rates to yield water consumption by unit in gallons per megawatt-hour (gal/MWh).

Water consumption data for gas turbines and combined-cycle units were not publicly available, and were estimated using information on unit cooling systems, combined with average water consumption rates found in a number of studies that examined the link

[103] US Geological Survey. *Estimated Use of Water in the United States in 2005*. USGS Circular 1344. Released October 27, 2009. Available at: http://pubs.usgs.gov/circ/1344/

between power generation and water use.[104] Information on the cooling systems for the three combined-cycle units was available from Title V Operating Permits issued by the Utah Division of Air Quality. Total water consumption was determined by estimating prime-mover consumption and adding this to the cooling water requirements. Combined-cycle units with evaporative cooling were assumed to require 100 gal/MWh,[105] while combined-cycle units with dry-cooling were assumed to use 10 gal/MWh.[106]

The remaining conventional units in the analysis used gas turbines as a prime mover, which use little to no cooling water. However, the Title V Operating Permits for these units also give information on installed technologies that use water either as a means for pollution control or to increase unit efficiency. For example, the Gadsby units 4-6 are equipped with water injection for NO_x control, while some of the West Valley units are equipped with water injection for NO_x control as well as evaporative spray mist inlet air cooling, which is intended to increase unit efficiency under increased ambient temperatures.[107]

Water consumption rates for the displaced generating units are shown in Table 5-2. Note that while this table shows the Currant Creek units as being combustion turbines, the units are in fact components of a single combined-cycle plant. The Currant Creek Power Plant was constructed in two phases. Phase 1 focused on installing and putting into service two simple-cycle gas-fired units, which began operation in 2005. Phase II added a steam cycle to Currant Creek, turning it into a combined-cycle power plant, which began commercial operation in March 2006. Water consumption for the Currant Creek units was estimated at 10 gal/MWh per unit, due to the fact that "Currant Creek's design incorporates an air-cooled condenser that uses only 10% of the amount of water that a similarly sized plant with wet cooling towers would require."[108]

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[104] See, for example: Myhre, R. *Water & Sustainability (Volume 3): US Water Consumption for Power Production – The Next Half Century*. Electric Power Research Institute, Palo Alto, CA. 2002. Page viii. Clean Air Task Force. *The Last Straw: Water Use by Power Plants in the Arid West*. Prepared for the Energy Foundation and the Hewlett Foundation. April 2003. Page 3.; US Department of Energy. *Concentrating Solar Power Commercial Application Study: Reducing Water Consumption of Concentrating Solar Power Electricity Generation*. Report to Congress. Pages 4-5 and 11-13.; US Department of Energy. *Energy Demands on Water Resources*. Report to Congress on the Interdependency of Energy and Water. December 2006.

[105] Myhre, R. *Water & Sustainability (Volume 3): US Water Consumption for Power Production – The Next Half Century*. Electric Power Research Institute, Palo Alto, CA. 2002. Page viii.

[106] Dry cooling systems use considerable less water than wet cooling systems, and most estimates of water use from fossil plants with dry cooling found in the literature show water consumption to be zero. However, these estimates are given in gallons per kilowatt-hour. Indeed, a fossil unit utilizing dry cooling consumes a volume of water equivalent to "less than 10% of the consumption of an evaporative cooled plant," and thus consumption was calculated at 10% of 100 gal/MWh for a combined-cycle unit, or 10 gal/MWh. See: US Department of Energy. *Concentrating Solar Power Commercial Application Study: Reducing Water Consumption of Concentrating Solar Power Electricity Generation*. Report to Congress. Pages 4-5 and 11-13. While this is a paper largely about water consumption in concentrating solar power units, it provided information on thermal generating units for comparison purposes.

[107] Utah Title V Operating Permits. Utah Division of Air Quality. Available at: http://www.airquality.utah.gov/Permits/Report_OPS_Permits_Issued.htm

[108] Odis F. Hill and Robert Van Engelhoven. *Currant Creek Power Plant, Mona, Utah*. POWER Magazine. August 15, 2006. *Available* at: http://www.powermag.com/print/gas/Currant-Creek-Power-Plant-Mona-Utah_460.html

Finally, we estimate consumption at Mill Creek as 0 gal/MWh, as it uses a gas combustion turbine with dry NO_x controls, per the unit's Title V permit.

Table 5-2: Water Consumption Rate for Displaced Generating Units.

Plant Name	Unit	Prime Mover	Primary Fuel	Water Consumption Rate (gal/MWh)
Bonanza	1	ST	Coal	673
Carbon	1	ST	Coal	762
Carbon	2	ST	Coal	745
Currant Creek	CT1A	CT	Gas	10*
Currant Creek	CT1B	CT	Gas	10*
Gadsby	1	ST	Gas	6,761
Gadsby	2	ST	Gas	3,147
Gadsby	3	ST	Gas	1,092
Gadsby	4	GT	Gas	10*
Gadsby	5	GT	Gas	10*
Gadsby	6	GT	Gas	10*
Hunter	1	ST	Coal	642
Hunter	2	ST	Coal	620
Hunter	3	ST	Coal	621
Huntington	1	ST	Coal	630
Huntington	2	ST	Coal	634
Intermountain Power Project	1	ST	Coal	505
Intermountain Power Project	2	ST	Coal	460
Lake Side Power Plant	CT01	CC	Gas	100*
Lake Side Power Plant	CT02	CC	Gas	100*
Mill Creek		GT	Gas	0
Nebo Power Station	U1	CC	Gas	100*
West Valley Generation Project	U1	GT	Gas	10*
West Valley Generation Project	U2	GT	Gas	10*
West Valley Generation Project	U3	GT	Gas	10*
West Valley Generation Project	U4	GT	Gas	10*
West Valley Generation Project	U5	GT	Gas	10*

* Values are estimated.

Certain renewable energy generating technologies require the use of water, as shown in Table 5-3, below. Wind turbines require no water to generate electricity and are not included in this table. Solar photovoltaic systems require water to rinse away dust that may accumulate on the panels, while concentrating solar power (CSP) systems use solar-generated heat to power a steam-cycle electric generator, much like traditional fossil-fired units. In CSP units, some water is used for steam make-up and mirror washing, but much like fossil plants, the largest use of water in CSP units goes toward wet-cooling systems used to condense steam and complete the cycle.

Freshwater consumption in geothermal plants can vary significantly; from very little in high temperature dry steam or flash-steam plants, to fairly high consumption in low-temperature binary geothermal plants. In a binary system, geothermal fluids transfer heat to a closed-loop steam cycle with a low-boiling point hydrocarbon-based fluid. If the generating plant is wet-cooled, water is used to condense the steam. It is anticipated that much of the future geothermal fleet will be comprised of lower temperature binary systems, and thus we model a high water consumption rate for future geothermal facilities.

Table 5-3: Water Consumption Rate for Renewable Generating Technologies.

Renewable Technology	Water Consumption Rate (gal/MWh)
Solar Photovoltaic (PV)[109]	25
Wet cooled CSP Trough[110]	840
Dry cooled CSP Trough[111]	80
Wet cooled Binary Geothermal[112]	1,400

Rates of water consumption in gal/MWh were multiplied by the electric generation (MWh) of each of the units within the scenarios to determine total water consumption by both fossil and renewable energy technologies. The difference between consumption in the EE and RE scenarios determined the avoided water use. Finally, a range of prices for water in Utah was determined based on a review of the literature. These values were multiplied by avoided water usage to determine the total economic value of the co-benefits to water from EE and RE programs. Section 5.3 describes the marginal cost methodology used in this analysis.

5.3. Cost of Water in the West and in the State of Utah

Once avoided water consumption was determined, a water price had to be chosen in order to calculate the total economic value of water saved through efficiency and renewable strategies. The externality cost of water is undefined and likely highly variable by region, even within Utah. The economic value of a good is determined by a consumer's "willingness to pay," or to give up other goods or services (in this case, money) in order to obtain or retain that good. A marginal cost methodology was used to determine this willingness to pay for water in Utah, and therefore value the co-benefit of water savings from avoided generation in Utah. The marginal value of a good is simply the value of the next unit. When a good is abundant, the marginal value of each additional unit declines, because a buyer has a lower willingness to pay for those units. In an area experiencing water scarcity, however, each additional unit of water is more difficult to obtain and the cost to acquire the next unit of water is increasingly higher. This value of the next unit of water is the marginal price.

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[109] Estimates of water consumption are based on similar estimates of water used to wash mirrors and panels in applications of concentrated solar power applications. See for example: US Department of Energy. *Concentrating Solar Power Commercial Application Study: Reducing Water Consumption of Concentrating Solar Power Electricity Generation*. Report to Congress.

[110] US Department of Energy. December, 2006. Energy Demands on Water Resources: Report to Congress on the Interdependency of Energy and Water.Table B-1

[111] University of Texas at Austin. April 2009. Energy-Water Nexus in Texas. Page12.

[112] US Department of Energy. December, 2006. Energy Demands on Water Resources: Report to Congress on the Interdependency of Energy and Water.Table B-1

Observing prices for water in a market would be the easiest way to determine willingness to pay for that water. However, because water is a public good there has not historically been a robust and competitive marketplace in which water rights may be bought and sold. The nature of water as a public good usually demands that responsibility must be taken at some level of government to make sure that an adequate supply of water is received by those that need it. Because access to clean water is usually seen as an essential government function, water is often made available for basic consumptive purposes through subsidized prices, or even for free. The rate at which customers are charged by municipal water providers is therefore not an appropriate choice for the marginal value of water.

A system of “prior appropriation” for water rights has traditionally been used in western states, whereby the first person to use a quantity of water for a beneficial purpose has the right to use that same quantity of water in perpetuity without payment. Water rights in Utah are completely allocated, and in some regions over-allocated, meaning that any party wishing to acquire new or additional water rights must find another party that is willing to sell them. This has begun to occur with greater frequency over the past two decades, and this increase in market activity leads to a more useful estimate of the value of water.

An estimate of the marginal cost in Utah was achieved through a survey of a database of water transactions in the twelve western states[113] maintained by the Bren School at the University of California, Santa Barbara. The source for these transactions is the monthly trade publication *Water Strategist*, and its predecessor *Water Intelligence Monthly*, published by Stratecon, Inc. in Claremont, California. The issues used in this study summarize water transactions from 1987 to 2008 and provide information about the buyer, seller, purpose for which water was purchased (agriculture, urban, or environmental), type of transaction (purchase or lease), and the source of the water. Together, they form “the most comprehensive set of information available about water market trades in the western United States.”[114] Figure 5-1gives a frequency distribution of the water transactions in Utah according to their value per acre-foot.

[113] “Western states” include Arizona, California, Colorado, Idaho, Montana, New Mexico, Nevada, Oregon, Texas, Washington, Utah, and Wyoming.

[114] Brown, Thomas. *The Marginal Economic Value of Streamflow from National Forests: Evidence from Western Water Markets*. US Forest Service, Rock Mountain Research Station. Fort Collins, Colorado. October 2004.

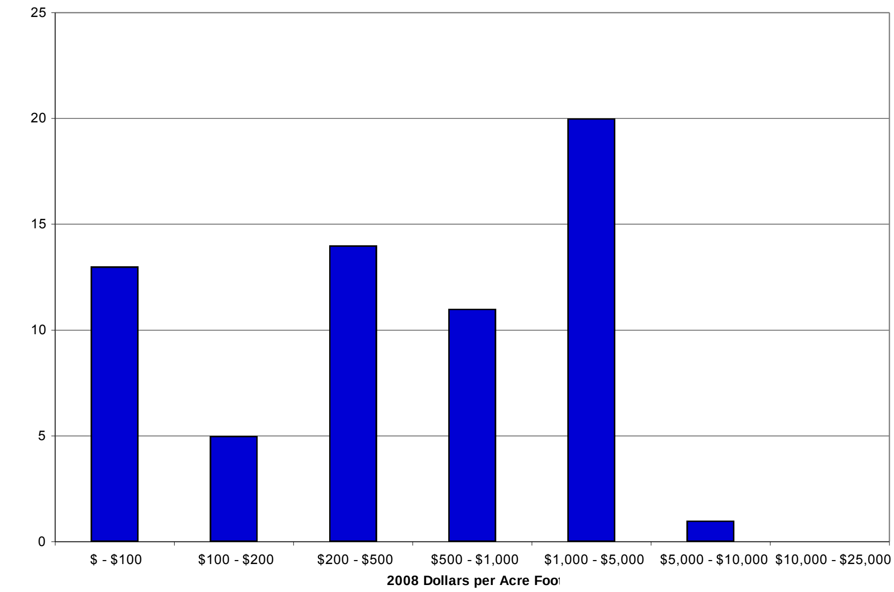

Figure 5-1: Frequency Distribution of Utah Water Transactions.

As mentioned above, as population increases and demand for water increases, water rights begin to move to their highest valued use. Figure 5-2 shows the number of transactions by value and purpose for which the water was purchased. "Ag-to-Urban" indicates, for example, that water rights shifted from an agricultural user to an urban user.

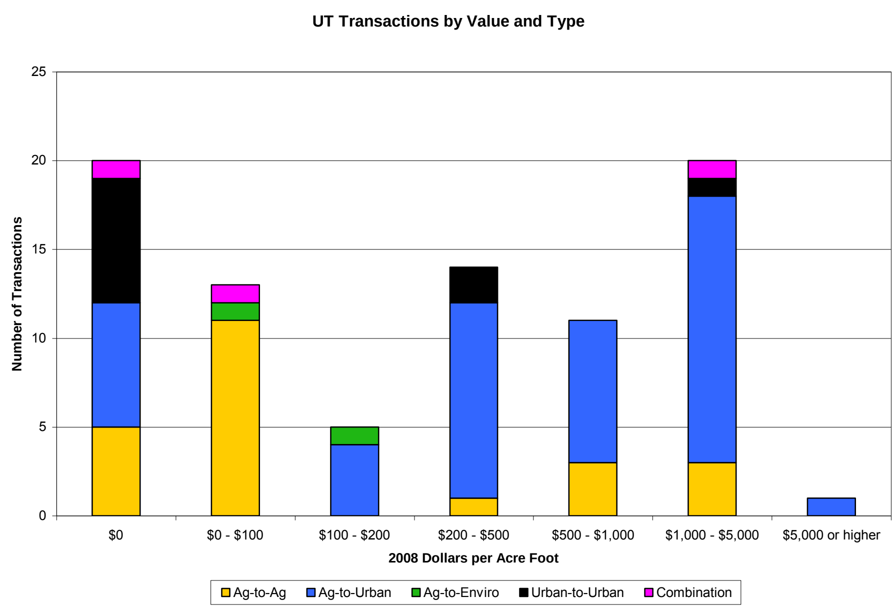

Figure 5-2: Utah Water Transactions by Value and Type.

Several different variables affect the price of water in these documented transactions, including, but not limited to, geography, volume of water transacted, time period, and the use for which the purchased water is intended. Variability of water prices suggests that it may be more appropriate to consider a range of values of the marginal price for water, rather than select a single value. In this research, we select the lower bound of water as the market rate of water, or what one would pay on the open market for a water right. At the upper bound, we select the marginal price of water from historic transactions.

- The lower bound of this range is set at $520 per acre-foot, the median value of historic Utah water transactions. This value is representative of a price that might likely be paid to obtain the rights to existing water in Utah in the market today.
- The marginal price of water is estimated at $5,182 per acre-foot, which represents a known historical willingness-to-pay. In this transaction, the water rights to the Beaver Creek were purchased in 1999 from an irrigator (an agricultural user) by a developer (an urban user) to provide services to a 60-condominium development, with the rest being held for future residential development.

The upper bound of a range of water values might then be the price that is paid to obtain additional water in a region of the state that is water-scarce. This project did not distinguish between geographical regions of the state or water scarcity status. An online water rights exchange suggests that the marginal price of water estimated above ($5,182) is not an unreasonable value for current water values in Utah.

At the time of this writing, sellers throughout Utah were offering to sell units of water at prices ranging from $1,000 to $10,000 per AF, with a majority of the asking offers ranging between $5,000 and $7,000 per AF.[115] The closest seller to an existing plant was offering 100 AF at $7,000 / AF in the same water district as the new Currant Creek combined cycle plant.

[115] Water Rights Exchange. Accessed March 19, 2010. Available online at http://waterrightexchange.com/

6. Scenario Design and Results

In this research, we developed four over-arching scenario categories (with sub-scenarios) to explore the influence of reduced demand, new renewable resources, or replacing inefficient generators. The scenario categories are:

1. **Baseline**, or business-as-usual (BAU) scenario, in which demand grows at a rate estimated by PacifiCorp in 2008, a major Utah utility. In this scenario, increasing peak demand is met by new in-state combined-cycle gas units.
2. **Energy efficiency and demand response** scenarios, that reduce both total energy demand over time, and shave peak load requirements through demand response. Three energy efficiency scenarios are explored, from relatively modest to aggressive reductions.
3. **Renewable energy** scenarios, that reduce requirements for new and existing fossil generation by harnessing renewable resources. In this study, we explore three wind build-out options, two aggressive solar photovoltaic options, two central station concentrating solar power (CSP) options, and one geothermal scenario. In the solar and wind cases, the amount of renewable energy is arbitrarily fixed at a moderate penetration of 880 MW by 2020, and the geothermal scenario is fixed at 440 MW by 2020.
4. **Replacement** scenarios, where approximately one-third of the most harmful generators are replaced. We build two scenarios: one in which select coal units are replaced by moderate demand-side management and efficient gas-fired units, and one in which the efficiency is complimented by two wind farms and a concentrating solar plant.

A realistic alternative energy future for Utah would probably comprise elements of each of these scenarios, reducing demand through cost-effective energy efficiency and demand response strategies, diversifying energy supply with several different renewable energy options, and replacing older, inefficient generators with a combination of resources. Such a scenario was not deemed in the scope of this research. This research does not propose an energy plan, but is built to support planning exercises by estimating the impact of a moderate increase in alternative energy resources. The replacement scenarios do not reflect an optimized solution or specific recommendation; rather, they are illustrative of the social and environmental costs of operating the current fleet and the benefits that could be realized through replacement.

6.1. Baseline Scenario

The baseline scenario analyzes what would occur between 2008 and 2020 if load requirements and demand were to continue to grow according to BAU assumptions. Because this scenario represents the baseline against which all other scenarios are measured, the scenario does not assume emissions reductions, additional efficiency beyond that predicted by PacifiCorp in 2008, or new renewable energy in-state.

In this scenario, load growth follows estimates from PacifiCorp, made available by request in 2008.[116] PacifiCorp provided estimated monthly non-coincident peak load requirements for all states in their service territory for 2009 through 2023. To translate peak load requirements into estimated hourly load profiles, we determine the linear relationship between each year's monthly peaks and the following year's peaks, a slope and offset through twelve points. Each year's slope and offset are used to scale the reference year (2007-2008) hourly load profile, discussed in Section 3.3.1, through 2020.

In the baseline scenario, new growth is met with additional combined cycle and combustion gas turbines (detailed in section 6.5). The addition of gas-fired generators in the base case is a conservative estimate for the purposes of this analysis, and in line with current trends. If the analysis met future demand with coal-fired generation, baseline externalities would rise dramatically (coal plants are disproportionately high impact). Displacing potential future coal with EE and RE would then result in universally high co-benefits. This analysis attempts to illustrate the impact of EE and RE in a future in which externalities are valued or internalized. In such a future, new conventional generation would likely be gas-fired.

Results from the generation analysis are shown in Table 6-1 and Figure 6-1. Generation during the study period is projected to total approximately 47,230 GWh, with coal generation amounting to 83% of all energy supplied. At the end of the study period, in 2020, coal generation has not decreased significantly, and gas generation has nearly doubled, eventually supplying 27% of all fossil power production in Utah.

Table 6-1: Fossil generation (GWh) in Utah during the reference period (2007-2008) and at the end of the study period (2020-2021)

	Fossil Generation in Utah, GWh		
2007-2008	**Coal**	**Gas**	**Total**
Reference	38,988	8,240	47,228
2020-2021			
Baseline Load Growth	39,486	14,778	54,264

[116] It should be noted that the load growth estimates obtained from PacifiCorp are dated from 2008, and may pre-date long-term changes in demand brought about by the economic downturn starting in 2008.

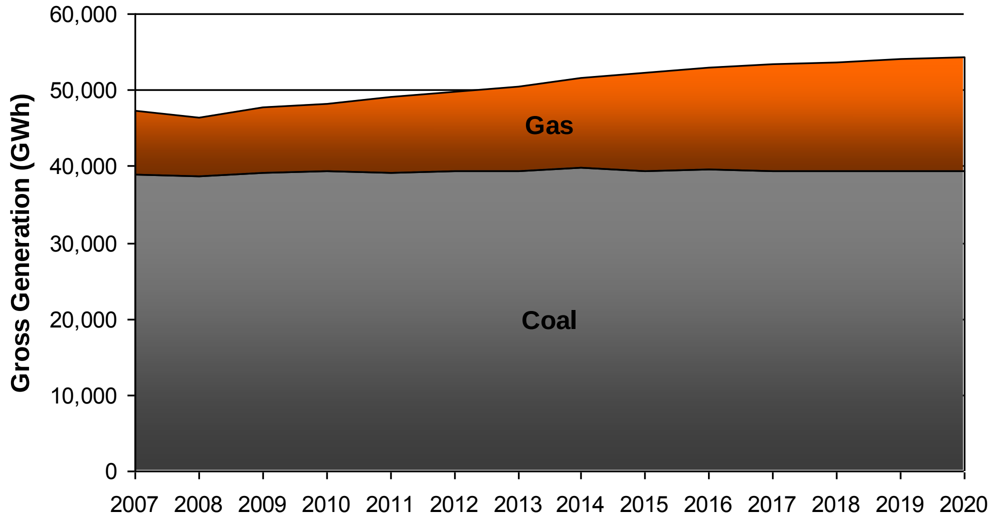

Figure 6-1: Annual gas and coal generation in the baseline scenario, in GWh.

There are no co-benefits calculated for the baseline scenario; however, we calculate externalities to compare against EE and RE scenarios. The externality cost of the system today is divided into mortality and morbidity, and the cost of water. Health impacts are experienced both in Utah and in downwind states; therefore we show first total health impacts and then impacts experienced only in Utah.

Table 6-2 shows the value of the baseline externalities. Premature deaths from fossil generation in Utah today are valued at $1,612 million of which $222 million are experienced within Utah's borders. Healthcare costs for metrics explored here amount to $32 million, with about half of the costs experienced within Utah's borders. We value water consumed by Utah electric power producers at between $38 and $469 million, based on the range for the value of water derived in Chapter 5. In total, we estimate a total externality cost between $1.68 and $2.03 billion dollars from generation in Utah today.[117]

As population increases and generation rises to meet demand, more residents in and out of Utah are exposed to criteria pollutants. In 2020, at the end of the study period, Mortality is valued at $2,337 million. Water use does not increase substantially, because new gas-fired generators have low water consumption rates. Total externality costs rise to between $2.4 and $2.8 billion by 2020.

[117] All generation, emissions, and externality values reported in this chapter are the median value of all Monte Carlo runs (see Section 3.4.3)

Table 6-2: Annual externality costs for baseline scenario relative to reference (2007-2008) and at end of study period (2020-2021). Externality cost of mortality, morbidity, and water, in millions of 2008 dollars per year. In health valuation, bold values are totals, values in parentheses are Utah only.

	Health Costs and Valuation, Million 2008$ per year All (in Utah)		Externality Cost of Water (Low - High)	Total Externality Cost (Low - High)
2007-2008	**Mortality**	**Morbidity**		
Reference Case	**$1,612** ($222)	**$32** ($16)	**$38 - $383**	**$1,683 - $2,027**
2020-2021				
Baseline	**$2,337** ($339)	**$41** ($21)	**$40 - $401**	**$2,418 - $2,779**

6.2. Energy Efficiency and Demand Response Scenarios

Historically, Utah has had one of the fastest growing energy demands in the nation. In the baseline scenario, load grows between 1-4% per year from 2009 to 2020—nearly 26% in twelve years. While this baseline assumption may have changed due to the recent economic downturn, it does not change that Utah's rapid growth in electrical consumption has significant room for efficiency programs across all sectors. A number of recent reports have found a significant potential for significant cost-effective energy efficiency in the state of Utah.

A 2006 Western Governors Association (WGA) report consolidates efficiency and demand-side management reports from several western states, and estimates that cost-effective efficiency measures could reduce demand by 0.5 to 2% per year, and finds feasible 20% reductions from projected 2020 levels throughout the west. Using the 2008 load growth estimates, this 1.4% energy efficiency per year rate would still entail growth in Utah's energy requirements. A report specific to the state of Utah in 2002 identified an economic potential of nearly 2,309 GWh per year of efficiency by 2006,[118] an ambitious goal which was not realized.

On April 26, 2006, Governor Huntsman released a comprehensive energy efficiency savings plan for the State of Utah, with a target of meeting a 20% reduction from baseline energy use by 2015. An executive order, signed one month later, codifies this objective for state facilities and sets the target for the state as a whole.[119]

Finally, a 2008 report by the Southwest Energy Efficiency Project (SWEEP) recommends a detailed series of policy options to capture energy efficiency potential. The report finds a technical potential of 6,200 GWh of savings by 2015 (an 18% reduction from baseline) and 10,319 GWh by 2020 (a nearly 26% reduction from the

[118] Nichols, D. and D. Von Hippel. 2001. An Economic Analysis of Achievable New Demand-Side Management Opportunities in Utah. Report prepared for the Systems Benefit Charge Stakeholder Advisory Group to the Utah Public Service Commission. Boston, MA: Tellus Institute.

[119] Utah State Executive Order 2006/004. Improving Energy Efficiency. Governor Jon Huntsman, May 30, 2006. Available online at: http://www.energy.utah.gov/energy/docs/energy_executive_order.pdf

projected baseline). The report projects achievable energy savings rising from 0.5% in 2006 through 1% in 2011, and maintaining that level of reductions thereafter.[120]

In considering demand-side management techniques, utilities often find significant benefit in demand response (DR) programs, that reduce requirements for capacity, rather than energy. DR often entails reducing peak load requirements for industrial and commercial, and occasionally residential, locations using combinations of peak pricing mechanisms and direct load controls. DR programs target the most costly peak hours of production and benefit ratepayers by reducing requirements for expensive new generation or wider reserve margins. SWEEP suggests that, historically, utilities have maintained a ratio of approximately 0.3 to 0.4 MW of DR for every GWh/year of reduction. We use these assumptions in constructing a combined EE / DR set of scenarios.

The scenarios considered here are:

- **EE, SWEEP:** Reductions in total energy requirements begin at 0.5% per year statewide, increasing to 1% per year by 2011, and maintaining 1% per year through 2020. Ratio of DR to EE is 0.33 MW peak reductions per GWh EE reduction.
- **EE, 2% per year:** Reductions begin at 0.5% per year statewide, increasing to 2% per year by 2015, and maintaining 2% per year through 2020. Ratio of DR to EE is 0.40 MW peak reductions per GWh EE reduction.
- **EE, 3% per year:** Reductions begin at 0.5% per year statewide, increasing to 3% per year by 2016, and maintaining 3% per year through 2020. Ratio of DR to EE is 0.40 MW peak reductions per GWh EE reduction.

Energy efficiency is modeled as a flat percentage reduction from each hour based on the annual expected percent savings. Typically, EE measures have a limited lifespan, between 8 to 20 years. An average measure life of 12 years is considered a standard approximation; therefore, during this analysis period, the efficiency measures modeled by the reduction do not expire and continue to accumulate. DR is modeled as a MW reduction off the highest peak hour. For example, after applying the SWEEP energy efficiency assumptions, the maximum peak in 2015 is 5,778 MW. We model DR as reducing this peak to 5663 MW (a reduction of 115 MW) and assume that no hour in 2015 may exceed this peak. The same reasoning is applied to the other scenarios accordingly. Table 6-3 below, shows the annual assumed reduction for each scenario in three key years, the cumulative reduction from baseline by 2020, the annual and cumulative energy reduction required to meet the target, and the associated peak reductions associated with each scenario.

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[120] Geller, H., S. Baldwin, P. Case, K. Emerson, T. Langer, and S. Wright. October, 2008. Utah Energy Efficiency Strategy: Policy Options. Available online at: http://www.aceee.org/transportation/UT%20EE%20Strategy%20Final%20Report%20-%2010-01-07.pdf

Table 6-3: Assumptions for energy efficiency scenarios, annual and cumulative reductions from baseline, and demand response characteristics.

Annual Reduction (%)	2010	2015	2020
SWEEP	0.90%	1.00%	1.00%
2% EE	1.00%	2.00%	2.00%
3% EE	1.30%	2.80%	3.00%
Cumulative Reduction (%)	**2010**	**2015**	**2020**
SWEEP	2.35%	7.00%	11.50%
2% EE	2.54%	9.89%	18.43%
3% EE	2.93%	12.88%	25.02%
Annual Reduction (GWh)	**2010**	**2015**	**2020**
SWEEP	256	349	361
2% EE	284	655	659
3% EE	367	889	915
Cumulative Reduction (GWh)	**2010**	**2015**	**2020**
SWEEP	673	2317	4093
2% EE	728	3272	6561
3% EE	838	4260	8907
Demand Response (MW)	**2010**	**2015**	**2020**
SWEEP	84	115	119
2% EE	113	262	264
3% EE	147	356	366

Table 6-4 shows expected generation today and at the end of the study period. Efficiency primarily drives down natural gas-fired generation, and coal generation does not change significantly in the less aggressive energy efficiency scenarios. The displacement of natural gas, rather than coal, is because (a) even as Utah decreases its own consumption, it remains a net exporter of low-cost energy (coal-fired generation), and (b) gas is the marginal fuel in Utah in nearly every hour, and will therefore be displaced preferentially to coal when available.

As EE is ramped to 3% energy efficiency per year, coal generation begins to decline moderately, dropping to 38,414 GWh (over 1,000 GWh below the baseline in 2020). At higher levels of EE and demand response, in-state demand is sometimes reduced to a point where, historically, some amount of coal generation is not required. Therefore, it is estimated that higher penetrations of EE will reduce very modest amounts of Utah coal generation, while lower penetrations will primarily impact exclusively gas-fired generators.

Table 6-4: Fossil generation (GWh) in Utah at the end of the study period (2020-2021)

	Fossil Generation in Utah, GWh*		
2020-2021	**Coal**	**Gas**	**Total**
Baseline	39,500	14,800	54,300
EE (SWEEP)	39,600	11,200	50,800
EE (2% per yr)	39,400	9,000	48,500
EE (3% per year)	38,400	7,500	46,000

**Values rounded to nearest hundred GWh*

The externality cost of the energy efficiency scenarios is not significantly lower than the baseline scenario. Table 6-5 shows externality values for the baseline and scenarios in 2020-2021.

Table 6-5: Externality costs for baseline and energy efficiency scenarios at end of study period (2020-2021). Externality cost of mortality, morbidity, and water, in millions of 2008 dollars per year. In health valuation, bold values are totals, values in parentheses are Utah only.

2020-2021	Health Costs and Valuation, Million 2008$ per year All (in Utah)				Externality Cost of Water (Low - High)	Total Externality Cost (Low - High)
	Mortality		Morbidity			
Baseline	**$2,337**	($339)	**$41**	($21)	**$40 - $401**	**$2,418 - $2,779**
EE (SWEEP)	**$2,317**	($334)	**$41**	($21)	**$39 - $393**	**$2,397 - $2,751**
EE (2% per yr)	**$2,291**	($329)	**$41**	($21)	**$39 - $393**	**$2,372 - $2,725**
EE (3% per year)	**$2,234**	($316)	**$40**	($20)	**$38 - $375**	**$2,312 - $2,649**

The co-benefits are estimated as the difference between the externality cost of each scenario and the baseline, per unit energy (in this case, MWh). Table 6-6 shows the co-benefits of the energy efficiency scenarios. The SWEEP energy efficiency scenario saves approximately $5.9-8.3 per MWh by 2020, while a more aggressive efficiency scenario can offset $12.8-16.3 for each MWh of avoided generation. As noted previously, increasingly aggressive efficiency may displace some amount of coal generation, resulting in larger co-benefits on a per-MWh basis.

Table 6-6: Value of co-benefit for efficiency scenario at end of study period (2020-2021). Co-benefits in avoided dollars per MWh of avoided generation. In health valuation, bold values are totals, values in parentheses are Utah only.

2020-2021	Health Co-Benefits, 2008$ per MWh All (in Utah)				Avoided Cost of Water (Low - High)	Total Co-Benefit (Low - High)
	Mortality		Morbidity			
EE (SWEEP)	**$5.63**	($1.50)	**$0.05**	($0.03)	**$0.2 - $2.1**	**$5.9 - $7.8**
EE (2% per yr)	**$7.77**	($1.66)	**$0.07**	($0.03)	**$0.1 - $1.4**	**$8.0 - $9.3**
EE (3% per year)	**$12.32**	($2.81)	**$0.20**	($0.10)	**$0.3 - $3.1**	**$12.8 - $15.6**

6.3. Renewable Energy Scenarios

6.3.1. Wind Energy

Utah has moderate wind energy potential and select areas in the state are considered highly favorable for wind development. A 2006 study for the DOE estimated an achievable capacity of 700-2000 MW in the state,[121] and in 2008, Edison Mission brought 18.9 MW (nine 2.1 MW turbines) of wind online in at the mouth of the Spanish Fork Canyon, east of Utah Lake. In the fall of 2003, First Wind's Milford Phase 1 wind farm came on line in Beaver County with 203 MW of capacity.

[121] Mongha, N., ER Stafford, CL Hartman. May, 2006. US Department of Energy, Energy Efficiency and Renewable Energy. An Analysis of the Economic Impact on Utah County, Utah from the Development of Wind Power Plants. http://www.windpoweringamerica.gov/pdfs/wpa/econ_dev_jedi.pdf

In 2001, the Utah Geological Survey began collecting data from a state-sponsored anemometer loan program. Data from 20 and 50 meter (65 and 164 feet) towers are available for sites throughout the state, including ridge tops, plains, and canyon mouths. Filtering by average annual wind speed, we collected data for three potential sites. Two of these sites are in Utah, and were chosen because they have reported average annual wind velocities exceeding 12 mph at the measured hub heights.[122] The last site in Wyoming is near existing Pacificorp wind development sites. The sites included:

- **TAD North:** Tooele Army Depot in eastern Tooele County (north-central Utah), 30 miles SW of Salt Lake City, UT. Anemometer data from 2007 were obtained from 20 meter towers.
- **Porcupine Ridge:** Northern Summit County, 45 miles NE of Salt Lake City, UT. Anemometer data from 2007 were obtained from 20 meter towers.
- **Medicine Bow, WY:** 2008 data was obtained from anemometers located near Medicine Bow / Kroenke, Wyoming, a proxy site near existing PacifiCorp wind farms. This site represents the patterns of wind generation that could be expected from expanded wind operations in Wyoming.[123]

The data from each site were scaled to 80 meter equivalent wind speeds by the Utah State Energy Program, and resampled to one hour average wind speeds by Synapse.

The power output from a wind turbine is proportional to the cube of the wind speed. Turbines are designed for different wind applications, optimized to harness sporadic high wind speeds, consistent lower wind speeds, or a variety of conditions. In modern turbines, power output saturates at a specific wind speed, and the turbine will maintain this output until wind speeds exceed safe velocities, at which point turbines stall or apply breaks to prevent damage. The shape of this behavior is the power curve for a turbine, describing the expected output at any given wind speed. For the purposes of this project, we used the output characteristics of a GE 2.5xl turbine, a 2.5 MW capacity turbine with a 100 meter (328 ft) diameter, sweeping 7854 square meters (84,500 square feet).[124] The turbine would normally be mounted at heights from 50 to 75 meters (246 to 328 feet, respectively). The approximate power curve of the turbine is found in Figure 6-2.

The expected power output from each site was determined by running the wind speeds through a look-up table representing the shape of the power curve. This transformation yields an estimated gross power output as if a 2.5 MW turbine were mounted at an 80 meter hub-height. The median hourly output (as well as 33rd and 66th percentiles) from each site are shown in Figure 6-3; median monthly output is shown in Figure 6-4.

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[122] Wind turbine sites are classified by average annual wind speeds, with classes ranging from Class 1 (Poor) to Class 7 (Superb). Speeds exceeding 12 mph on average are considered at least marginal sites. Wind speeds (and thus suitability for wind capture) are often greater at higher hub-heights.
[123] The Medicine Bow wind proxy in this research represents a realistic near-term wind expansion site, but unlike the other projects in this study is not located in Utah, and may be subject to a different set of transmission constraints than the projects in Utah. It is feasible that, because of transmission dynamics in the WECC region, Wyoming wind is primarily delivered to the Northwest, rather than to Utah.
[124] http://www.gepower.com/prod_serv/products/wind_turbines/en/downloads/ge_25mw_brochure.pdf

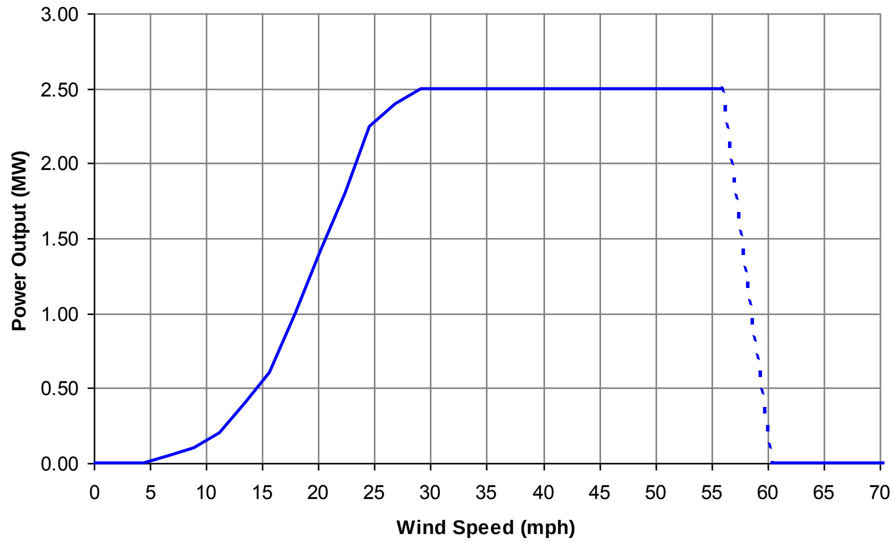

Figure 6-2: Power curve for GE 2.5xl turbine. Replicated from public specifications, see text for reference.

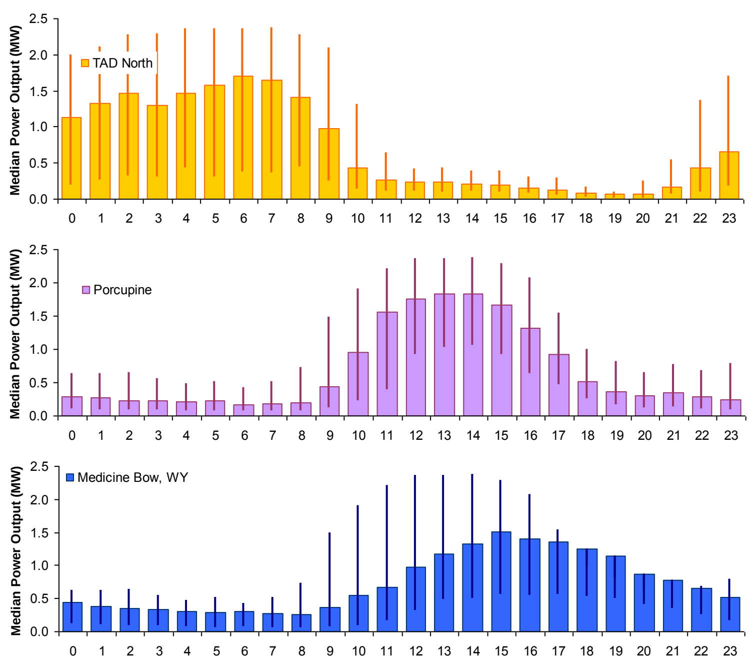

Figure 6-3: Hourly median power output by site. Error bars represent 33rd and 66th percentile around the median.

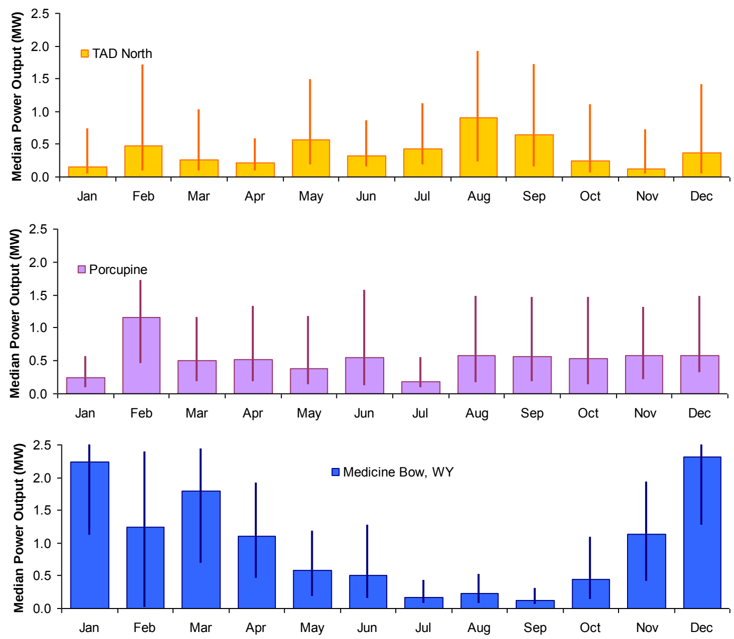

Figure 6-4: Monthly median power output by site, as if turbines were mounted at simulated 80-meter hub heights. Error bars represent 33rd and 66th percentile around the median.

It should be noted that the wind time series have very different characteristics. The TAD North and Porcupine locations both maintain high wind speeds throughout the year (with winter storms driving a February peak), but the TAD North site peaks overnight, reaching maximum output in early morning hours (between midnight and noon) while the Porcupine site produces during the day, peaking in the early afternoon. The Medicine Bow location is highly seasonal, with the fastest wind speeds through the winter, and peaking through afternoon hours.

A future balanced portfolio of wind might choose to erect turbines at different types of sites, reducing opportunities to have all the sites non-operational at the same time. An illustrative mixed portfolio with wind and concentrating solar power was modeled as one of the coal replacement scenarios, discussed later in this chapter.

In this study, we assumed a moderate penetration of wind power built on behalf of Utah, a total of 880 MW by 2020 (or a linear increase of 80 MW per year after 2011). This value is chosen to represent a non-transformative amount of wind power, altering dispatch but not large enough to require significant new resources for integration. To represent the 880 MW of capacity, we scale the transformed output from 2.5 MW (a single turbine equivalent) to 880 MW linearly. Each hour of output is similarly transformed. To estimate the impact of this new renewable energy on conventional generation in Utah, we subtract the expected hourly output of the wind turbines from the hourly demand of Utah. This simulates the wind as a must-take resource, dispatched directly into Utah's grid before all other conventional generation.

We assume that there are no emissions from wind power sites, and that wind energy uses no water for operational purposes.

The equivalent gross capacity factors and power output from each of the wind sites are given in Table 6-7.

Table 6-7: Potential gross capacity factor at 80 meter hub heights, and expected gross power output in simulation by year.

	Gross Capacity Factor (at hub height)	Gross Power output in 2010 (GWh)	Gross Power output in 2015 (GWh)	Gross Power output in 2020 (GWh)
TAD North	35.9%	253	1,516	2,779
Porcupine	37.6%	264	1,584	2,905
Medicine Bow	42.6%	297	1,784	3,271

6.3.2. Solar Photovoltaic and Concentrating Solar Power

Southern Utah has high solar energy potential. In this study, we explore the impacts of photovoltaic (PV) arrays and large, central station concentrating solar power (CSP) plants.

PV arrays are typically comprised of arrays of solid cells that convert sunlight into electricity. Such arrays could be the equivalent of the large 14 MW array erected at Nellis AFB (Nevada) in 2007,[125] or a state or utility sponsored program to increase residential and commercial rooftop PV availability, such as the California Solar Initiative with a target of 1,800 MW of PV.[126]

CSP has three commercial configurations: (a) parabolic troughs, where rotating, curved mirrors reflect sunlight onto long fluid-filled tubes, which in turn drive steam turbines; (b) so-called “power towers” where fields of mirrors orient to reflect sunlight onto a fluid-filled tank on a tower, which in turn drives a steam turbine; or (c) stirling solar, in which concentrated light is focused onto one end of a stirling engine, which turns a shaft based on the heat differential between cool and warm compartments. The 64 MW Nevada Solar One project[127] is an example of an operating solar trough plant, while the experimental (and now discontinued) Solar Two project in California[128] and the 10 MW commercial Planta Solar 10 project in Spain are early examples of the solar tower concept. In the US, two large-scale stirling solar projects will potentially break ground in California in 2010 (the Imperial Valley [Solar 2] and SES Solar One projects).

From a displaced emissions and generation analysis, the primary difference between these solar projects are on the hours of the day in which they are most active, and hence the generation which they would be expected to displace. All solar projects operate in sunlight, but differ significantly based on how light is received and if they have

[125] Nellis Air Force Base. Nellis activates Nations largest PV Array. December 18, 2007. http://www.nellis.af.mil/news/story.asp?id=123079933

[126] California Public Utilities Commission. California Solar Initiative. http://www.gosolarcalifornia.org/csi/index.html

[127] Nevada Solar One. Acciona Power. http://www.acciona-na.com/About-Us/Our-Projects/U-S-/Nevada-Solar-One.aspx

[128] Solar Two Project. http://ucdcms.ucdavis.edu/solar2/history.php

energy storage available. PV systems have no intrinsic storage capacity, but will produce energy under overcast conditions with indirect sunlight. PV systems that are able to track the sun can harness more energy during dawn and dusk hours than fixed-plate systems.[129] Concentrating troughs and towers track the sun but require exposure to direct sunlight. The systems warm a fluid, which can have anywhere from a few to 15 theoretical hours of energy storage capacity, depending on design. Stirling systems also require direct sunlight, and are highly efficient, but have no storage capacity. For this analysis, we choose two PV scenarios and one CSP option in a wet-cooled and dry-cooled configuration. We did not choose a stirling system because the output would be expected to closely match the output from a tracking PV system, assuming low cloud cover. The four solar scenarios are:

- **Flat plate PV:** A flat plate photovoltaic collector lying in a horizontal orientation, consistent with a simple, low-cost commercial or industrial rooftop application, such as on warehouses and retail locations;
- **Single-axis track PV:** A PV array oriented 15 degrees south (from the horizontal), tracking solar position, approximating the output from a single or series of utility-scale PV systems;
- **Parabolic trough CSP with wet cooling:** a solar farm configuration similar to that seen in the Nevada Solar One project, in Boulder NV, built to provide six hours of storage;
- **Parabolic trough CSP with dry cooling:** a solar farm configuration similar to the wet tower-cooled scenario above, but with the ability to cool boiler steam without extensive water consumption.

Solar potential for PV systems was obtained using the National Renewable Energy Laboratory (NREL) PV Watts calculator for Cedar City, Utah.[130] The PV Watts system draws on meteorological station data from the National Solar Radiation Data Base. Data in this system are based on the second derived typical meteorological year (TMY2),[131] which chooses the best representative month for a typical year between 1961 and 1990. The PV Watts calculator derives hourly electrical output from a PV array of a defined size in a particular orientation. The results are not affected by scale (size of the defined PV array). In this study, a one-watt array was chosen as a proxy system, and scaled linearly to the equivalent size anticipated in each year of the study (880 MW by 2020).

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[129] Single-axis tracking solar farms are comprised of hundreds to thousands of PV arrays. Each array is mounted on a rotating axis which tilts from east to west, tracking the movement of the sun. The additional tracking allows higher direct exposure during the morning and afternoon, extending the effective time in which a PV array can produce power. The largest solar PV array erected to date is a single-axis track system at Nellis Air Force Base in southern Nevada; 72,000 panels, each 200 watts, produce 14 MW at peak.

[130] National Renewable Energy Laboratory. 2008. PV Watts Version 1 Calculator. http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/

[131] National Renewable Energy Laboratory. National Solar Radiation Data Base. http://rredc.nrel.gov/solar/old_data/nsrdb/tmy2/

Output for a simulated CSP was estimated using the NREL Solar Advisor Model (SAM), with output modeled for Cedar City, Utah.[132] We used default settings for a 100 MW parabolic trough system with six hours of storage. The model returns expected hourly output in MW. Strictly speaking, CSP operations with storage are dispatchable to limited extent, however there is little information to suggest exactly how these resources would be dispatched, if at all, and which price signals they would use to alter or optimize performance. In this case, we assume that the SAM output represents typical operations in this environment.

CSP systems have the potential to be significant water consumers. Photovoltaic systems do not generally require water to operate, but must be washed regularly to maintain efficiency. In our analysis, we assume a consumption rate of 25 gallons per MWh to wash solar PV arrays (see Section 5.2). The modeled CSP systems run by heating a transfer fluid, which in turn heats water to steam. Steam boiler operations require water for both powering the boiler and for cooling. It is estimated that wet cooled CSP operations will use approximately 840 gallons per MWh, while dry cooled systems require approximately 80 gallons per MWh (see Section 5.2). This water consumption would presumably target the same water supplies used by conventional generation, and is therefore factored into the externality cost of the scenario.

Expected hourly output was derived for all four solar systems, and scaled up to a moderate penetration of the technology in Utah. Similarly to the wind scenario, each was assumed to reach 880 MW by 2020, or 80 MW per year from 2011 to 2020.

The equivalent capacity factors and power output from the two solar PV scenarios are given in Table 6-8.

Table 6-8: Potential capacity factor of for solar PV and CSP scenarios and expected power output in simulation by year.

	Capacity Factor	Power output in 2010 (GWh)	Power output in 2015 (GWh)	Power output in 2020 (GWh)
Flat Plate PV	17.8%	166	999	1,374
Single Axis Track PV	23.8%	178	1,071	1,831
Parabolic Trough CSP, wet and dry cooled[133]	34.5%	243	1,455	2,668

6.3.3. Geothermal

The Basin and Range formation of central and western Utah is considered a rich geothermal resource. Utah has two geothermal power plants, the Blundell Power Station and Thermo Hot Springs, both in Beaver County. Combined, the state had 50 MW of nameplate geothermal capacity online in 2008.[134]

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[132] Solar Advisor Model. https://www.nrel.gov/analysis/sam/

[133] Dry cooled systems do not have exactly the same power output characteristics as wet cooled systems. Dry cooled plants are de-rated in warmer weather because there is smaller temperature gradient between the steam and ambient air temperatures. These dynamics and differences are not captured in this analysis.

[134] Geothermal Power Plants in Utah, Table 5.5. Utah Geological Survey. Available online at http://geology.utah.gov/emp/energydata/statistics/electricity5.0/pdf/T5.5.pdf

In this study, there is a single geothermal scenario. The scenario assumes that a geothermal plant has a constant output of its full capacity. Geothermal plants are typically not used to meet peaking loads and are taken offline only for maintenance purposes. Therefore, to estimate the impact of geothermal energy on displaced generation and emissions, the proxy plant runs at capacity at all hours. The geothermal scenario models 440 MW of capacity by 2020.

Binary geothermal operations can consume significant amounts of water. In a binary system, relatively low-temperature (100-300°F) geothermal fluids are used to evaporate low-boiling point fluids through a steam power cycle. Cooling water is used to condense the steam and complete the cycle. We estimate 1,400 gallons per MWh of fresh water are required in wet- cooled binary plants. [135] While there are several different models of geothermal facility currently in use and proposed for Utah today, it is expected that over the next decades, the most economic geothermal plants may be wet cooled binary. For internal consistency, we assume a single plant type in this analysis.

6.3.4. Renewable Energy Results

The generation expected in the renewable energy scenarios is shown in Table 6-9. Coal generation is displaced moderately in some of the scenarios, but gas generation decreases far more substantially. The largest reductions of coal fired generation, excluding the replacement scenarios, are in the geothermal scenario.

Table 6-9: Fossil generation (GWh) in Utah at the end of the study period (2020-2021)

	Fossil Generation in Utah, GWh		
2007-2008	**Coal**	**Gas**	**Total**
Reference Case	38,966	8,202	47,169
2020-2021			
Baseline	39,494	14,854	54,347
EE (SWEEP)	39,565	11,225	50,790
EE (2% per yr)	39,511	8,998	48,509
EE (3% per year)	38,459	7,562	46,021
Wind (Porcupine)	38,745	12,816	51,561
Wind (TAD North)	38,283	12,840	51,123
Wind (Medicine Bow)	38,425	12,412	50,837
Solar (Flat Plate PV)	39,115	13,825	52,940
Solar (One-Axis Track)	38,960	13,584	52,544
Solar (CSP Trough, Wet Cooled)	39,320	12,718	52,039
Solar (CSP Trough, Dry Cooled)	39,320	12,718	52,039
Geothermal	38,170	12,112	50,283
Replace Coal w/ EE and Gas	27,456	20,796	48,252
Replace Coal w/ EE and RE	27,273	15,522	42,796

Table 6-10 lists the externality costs of the various scenarios, as well as the baseline.

[135] US Department of Energy. December, 2006. Energy Demands on Water Resources: Report to Congress on the Interdependency of Energy and Water.Table B-1

Table 6-10: Externality costs for renewable energy scenarios at end of study period (2020-2021). Externality cost of mortality, morbidity, and water, in millions of 2008 dollars per year. In health valuation, bold values are totals, values in parentheses are Utah only.

2020-2021	Health Costs and Valuation, Million 2008$ per year All (in Utah) Mortality		Morbidity		Externality Cost of Water (Low - High)	Total Externality Cost (Low - High)
Baseline	**$2,337**	($339)	**$41**	($21)	**$40 - $401**	**$2,418 - $2,779**
Wind (Porcupine)	**$2,285**	($327)	**$40**	($20)	**$39 - $386**	**$2,364 - $2,711**
Wind (TAD North)	**$2,271**	($325)	**$40**	($20)	**$38 - $383**	**$2,349 - $2,694**
Wind (Medicine Bow)	**$2,270**	($324)	**$40**	($20)	**$38 - $383**	**$2,349 - $2,693**
Solar (Flat Plate PV)	**$2,310**	($332)	**$41**	($20)	**$39 - $393**	**$2,390 - $2,744**
Solar (One-Axis Track)	**$2,299**	($330)	**$41**	($20)	**$39 - $391**	**$2,379 - $2,731**
Solar (CSP Trough, Wet Cooled)	**$2,319**	($333)	**$41**	($21)	**$43 - $429**	**$2,403 - $2,789**
Solar (CSP Trough, Dry Cooled)	**$2,319**	($333)	**$41**	($21)	**$40 - $396**	**$2,400 - $2,757**
Geothermal	**$2,256**	($320)	**$40**	($20)	**$47 - $464**	**$2,343 - $2,760**

The efficacy of the renewable energy cases in health and water co-benefits is given in Table 6-11. Co-benefit efficacy is estimated as the avoided externality cost relative to the amount of conventional generation displaced by the technology. By this analysis, the wind built at the TAD North site, and a single-axis tracking PV system produce the most significant co-benefit on a per MWh basis. It should be noted that the geothermal scenario effectively reduces health impacts but these benefits are offset by relatively high water consumption. The wet cooled CSP and geothermal scenarios are disadvantaged in this analysis by their water requirements, which exceed the water savings achieved by displacing mostly natural gas-fired generation.[136]

Table 6-11: Value of co-benefit for renewable energy scenarios at end of study period (2020-2021). Co-benefits in avoided dollars per MWh of avoided generation. In health valuation, bold values are totals, values in parentheses are Utah only.

2020-2021	Health Co-Benefits, 2008$ per MWh All (in Utah) Mortality		Morbidity		Avoided Cost of Water (Low - High)	Total Co-Benefit (Low - High)
Wind (Porcupine)	**$18.6**	($4.5)	**$0.4**	$0.2	**$0.5 - $5.5**	**$19.5 - $24.4**
Wind (TAD North)	**$20.4**	($4.5)	**$0.5**	$0.2	**$0.6 - $5.5**	**$21.4 - $26.3**
Wind (Medicine Bow)	**$18.9**	($4.4)	**$0.4**	$0.2	**$0.5 - $5.2**	**$19.8 - $24.5**
Solar (Flat Plate PV)	**$19.0**	($4.9)	**$0.4**	$0.2	**$0.6 - $5.5**	**$20.0 - $25.0**
Solar (One-Axis Track)	**$20.7**	($5.0)	**$0.4**	$0.2	**$0.5 - $5.5**	**$21.7 - $26.6**
Solar (CSP Trough, Wet Cooled)	**$7.7**	($2.6)	**$0.1**	$0.1	**-$12.0 - -$1.2**	**-$4.2 - $6.6**
Solar (CSP Trough, Dry Cooled)	**$7.7**	($2.6)	**$0.1**	$0.1	**$0.2 - $2.0**	**$8.0 - $9.8**
Geothermal	**$19.8**	($4.6)	**$0.4**	$0.2	**-$15.6 - -$1.6**	**$4.6 - $18.7**

[136] It should be recalled that the geothermal scenario represents a build-out of wet cooled binary geothermal facilities. Lower water-use geothermal facilities would result in a smaller water externality, and therefore a higher co-benefit.

6.4. Coupled Energy Efficiency and Plant Replacement

In the face of tightening air quality standards, impending federal carbon regulations, falling gas prices, and as interest in developing new renewable energy and energy efficiency resources grows, utilities may face increasing pressure to replace or retire inefficient or high emissions fossil generators. Two scenarios were designed to explore the externality benefit of replacing selected coal generators with renewable energy and energy efficiency. In the scenarios, approximately one third of generation is replaced by a combination of efficiency, renewable energy, and combined cycle gas generation.

The co-benefit values of the two replacement scenarios are measured differently than other scenarios in this analysis. Rather than estimate the efficacy of the scenarios against the total amount of fossil generation displaced by efficiency or renewable energy, these two scenarios are measured against the amount of coal generation replaced by efficiency, gas, and renewable energy. The reasoning behind this fundamentally different analysis mechanism is that simply replacing coal generation with gas on a one-for-one basis would inevitably result in reduced health and water externalities, but no fossil reduction. Therefore, the benefit of this replacement would appear artificially inflated.[137] Because the scenarios have a fundamentally different design, their final co-benefit is measured relative to the total amount of coal generation displaced or replaced.

In these scenarios, generators built prior to 1980 were taken offline in order of their first year in operation. The unit order coincided, largely with the NO_x and SO_2 emissions rate of the unit, where older units have higher emissions rates. Table 6-15 at the end of this section shows the unit ages, emissions rates, and scenario-year offline. The plant replacement scenario retires the Carbon units in 2012 and 2013, the Huntington units in 2014 and 2016, and the Hunter 1 unit in 2018. Load growth follows the 2% Energy Efficiency Scenario, reducing the requirement for new generation over time.

In both of the scenarios, the 2% efficiency per year primarily offsets requirements for new gas generation. In the gas-based replacement version, gas generation rises by 41% as coal plants are replaced or retired. In the renewable-based scenario, a plausible mix of new renewable generation is brought online to eventually meet 20% of Utah's demand by 2020.[138] This resource mix includes:

- 60 MW per year of wind from Medicine Bow, WY (660 MW by 2020)
- 35 MW per year of wind from the TAD North site (385 MW by 2020)
- 30 MW per year of dry cooled solar parabolic trough CSP from Cedar City (330 MW by 2020)

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[137] Co-benefits are measured as the avoided externality per MWh of avoided generation. If there are few or no MWh of fossil generation avoided, the denominator becomes small, and the apparent co-benefit becomes very large.

[138] This ramp rate is moderately faster than the renewable energy goal called for under Utah's Energy Resource and Carbon Emission Reduction Initiative (S.B. 202), March 2008. Note that this RE goal is relative to Utah's demand, not generation. As a state, Utah generates nearly twice as much as it demands, and so this target results in less than 10% of generation served by RE.

A significant amount of coal generation is reduced by replacing a select number of inefficient coal generators with a combination of moderately aggressive energy efficiency (2% per year) and either gas-fired generators or renewable energy (see Table 6-12 and Figure 6-5 and Figure 6-6). Overall, coal generation drops by 30% relative to today.

Table 6-12: Fossil generation (GWh) in Utah at the end of the study period (2020-2021)

	Fossil Generation in Utah, GWh		
2007-2008	**Coal**	**Gas**	**Total**
Reference Case	38,966	8,202	47,169
2020-2021			
Baseline	39,494	14,854	54,347
Replace Coal w/ EE and Gas	27,456	20,796	48,252
Replace Coal w/ EE and RE	27,273	15,522	42,796

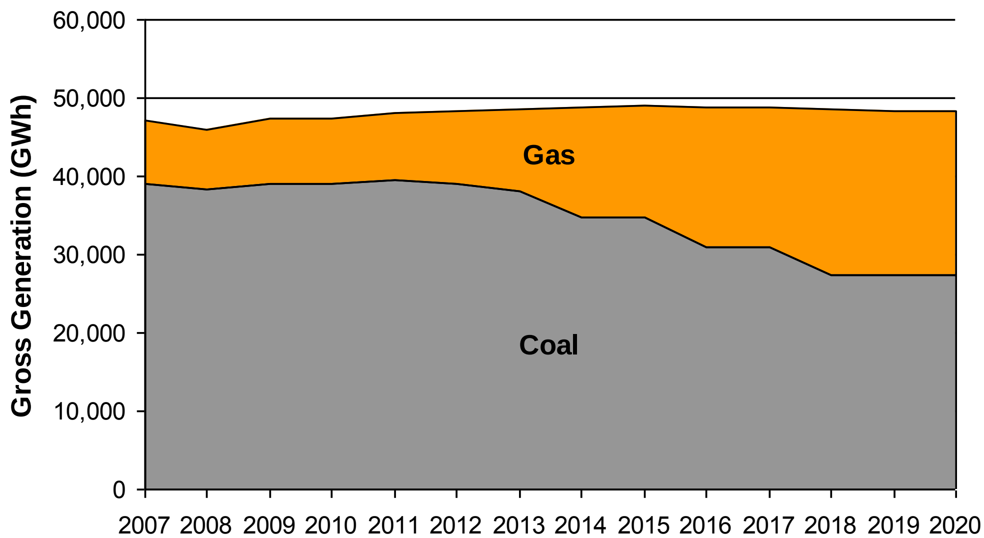

Figure 6-5: Annual gas and coal generation in the "Replace coal with EE and gas" scenario, in GWh.

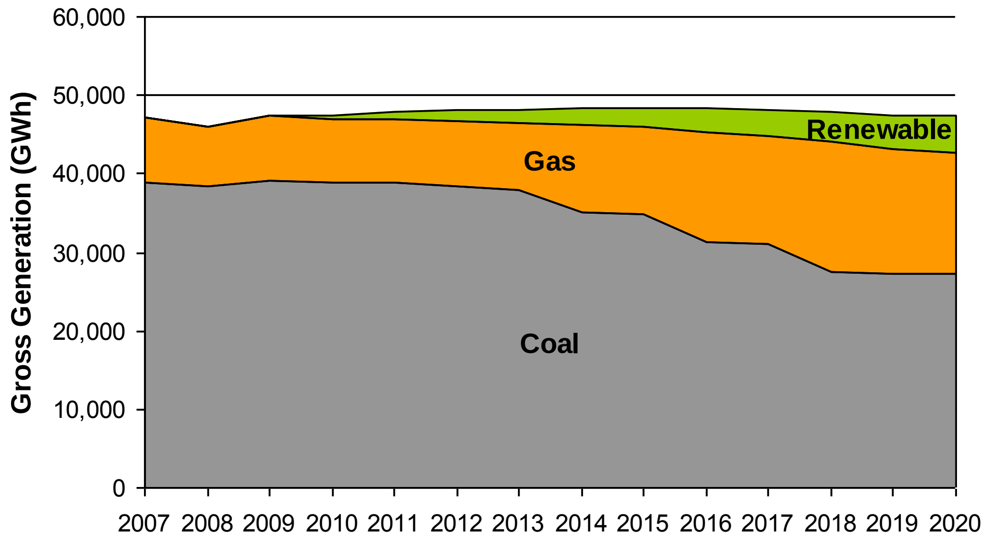

Figure 6-6: Annual gas, coal, and renewable generation in the "Replace coal with EE and RE" scenario, in GWh.

The externality costs of mortality, morbidity, and water drop significantly by replacing inefficient coal generators (see Table 6-13, below). The total externality cost drops from $2,418-2,779 million down to $1,553-1,853 million per year, an avoided cost between.$865 and $926 million each year.

Table 6-13: Externality costs for baseline and replacement scenario at end of study period (2020-2021). Externality cost of mortality, morbidity, and water, in millions of 2008 dollars per year. In health valuation, bold values are totals, values in parentheses are Utah only.

2020-2021	Health Costs and Valuation, Million 2008$ per year All (in Utah)				Externality Cost of Water (Low - High)	Total Externality Cost (Low - High)
	Mortality		Morbidity			
Baseline	**$2,337**	($339)	**$41**	($21)	**$40 - $401**	**$2,418 - $2,779**
Replace Coal w/ EE and Gas	**$1,527**	($250)	**$29**	($15)	**$30 - $297**	**$1,586 - $1,853**
Replace Coal w/ EE and RE	**$1,494**	($244)	**$29**	($15)	**$29 - $291**	**$1,553 - $1,815**

Co-benefits in the replacement scenarios cannot be judged against the same criteria as the other efficiency or renewable energy scenarios. In the other scenarios, EE or RE *passively* displaced existing generation, and therefore a proper metric was estimated as an avoided externality cost relative to avoided conventional generation. In the replacement scenarios, there would be significant benefits even if there was no net reduction in conventional generation. In this case, the benefits are realized because of active displacement of coal. Therefore, we estimate co-benefits relative to avoided MWh of coal generation.

The co-benefits of these scenarios range from $69 to $79 per MWh, depending on the estimated externality cost of water (see Table 6-14). Replacing coal with renewable energy reduces the amount of gas which needs to be brought online to support energy requirements (again, presuming no significant changes in dispatch), and therefore results in a slight improvement in health co-benefits. The water co-benefit of avoiding new gas is largely erased by the use of a water-intensive CSP operation in this scenario, yielding approximately the same water co-benefit for both scenarios.

Table 6-14: Value of co-benefit for replacement scenario at end of study period (2020-2021). Co-benefits in avoided dollars per MWh of avoided generation. In health valuation, bold values are totals, values in parentheses are Utah only.

	Health Co-Benefits, 2008$ per MWh All (in Utah)				Avoided Cost of Water (Low - High)	Total Co-Benefit (Low - High)
2020-2021	Mortality		Morbidity			
Replace Coal w/ EE and Gas	**$67.26**	($7.39)	**$1.00**	($0.48)	**$0.9 - $8.7**	**$69.1 - $76.9**
Replace Coal w/ EE and RE	**$68.94**	($7.79)	**$1.00**	($0.48)	**$0.9 - $9.0**	**$70.8 - $78.9**

Clearly, there are significant co-benefits to be realized from the replacement of existing coal generators alone. If we consider these co-benefits relative to the amount of fossil generation displaced by EE and RE, the values multiply into more than one hundred dollars saved per MWh of conventional generation avoided.

Table 6-15 below shows the characteristics of the coal units currently in operation in Utah.

Table 6-15: Capacity, year online, emissions rates, and heat rate of coal units in Utah. Emissions and heat rates for 2008 (January through December). Source: Derived from Clean Air Markets Division Dataset, EPA.

Plant (Replacement Date)	**Capacity (MW)**	**Year Online**	**NO_X** (lbs/MWh)	**SO_2** (lbs/MWh)	**CO_2** (t/MWh)	**Heat Rate** (btu/kWh)
Carbon 1 (2012)	75.0	1954	5.32	7.75	1.05	10,270
Carbon 2 (2013)	113.6	1957	5.11	7.94	1.10	10,725
Huntington 1 (2014)	498.0	1974	3.34	1.26	0.95	9,209
Huntington 2 (2016)	498.0	1977	2.08	0.54	0.97	9,451
Hunter 1 (2018)	488.3	1978	3.93	1.57	1.07	10,411
Hunter 2	488.3	1980	3.84	1.21	1.05	10,185
Hunter 3	495.6	1983	3.35	0.54	0.96	9,372
Bonanza 1	499.5	1986	3.60	0.50	1.08	10,506
Intermountain 1	820.0	1986	3.68	0.75	0.95	9,232
Intermountain 2	820.0	1987	3.47	0.74	0.94	9,184

6.5. Supplemental Fossil Additions

In all scenarios, excepting the 3% energy efficiency scenario, it was determined that additional fossil units may be needed to meet anticipated load growth. In each scenario, gas combined cycle (CC) and combustion turbine (CT) units were added as required with the simple criteria that the maximum open position each year could not exceed 300 MW. The fossil units are added simply to meet peak requirements in the dispatch model, and chosen as proxies of the types of plants that could be built in the future to meet new demand. Existing units are used to approximate statistical behavior of new units. The following scenario additions, shown in Table 6-16 are used to balance the model only, and do not represent a plan, optimized portfolio, or least cost solution. In most of the circumstances, the same cohort of units are added over time as in the baseline scenario to allow comparisons between emissions under BAU conditions and moderate penetrations of renewable energy.

Table 6-16: Additional units added to meet capacity requirements in each scenario. Values represent maximum reported gross generation for single or combined existing gas combined cycle (CC) or combustion turbine (CT) units in Utah.

	Baseline	EE (SWEEP)	EE (2% per yr)	EE (3% per year)	Wind (Cricket II)	Wind (Porcupine)	Wind (TAD North)	Wind (Medicine Bow)	Solar (Flat Plate PV)	Solar (One-Axis Track)	Solar (CSP Trough)	Solar (CSP Tower)	Geothermal	Replace Coal w/ EE and Gas	Replace Coal w/ EE and RE
2009															
2010															
2011	307 CC				307 CC	307 CC	307 CC	307 CC	307 CC	307 CC	307 CC	307 CC	307 CC		
2012															
2013	120 CT	120 CT	60 CT		120 CT	120 CT	120 CT	120 CT	120 CT	120 CT	120 CT	120 CT	120 CT		307 CC
2014	160 CT				160 CT	160 CT	160 CT	160 CT	160 CT	160 CT	160 CT	160 CT	160 CT	60 CT	308 CC
2015	289 CC	307 CC			289 CC	289 CC	289 CC	289 CC	289 CC	289 CC		289 CC	289 CC	60 CT	
2016														307 CC	584 CC
2017	295 CC				295 CC	295 CC	295 CC	295 CC	295 CC	295 CC	289 CC	295 CC	295 CC		
2018														308 CC	307 CC 60 CT
2019	120 CT	60 CT			120 CT	120 CT	120 CT	120 CT	120 CT	120 CT	120 CT	120 CT	120 CT		
2020	60 CT				60 CT	60 CT	60 CT	60 CT	60 CT	60 CT	60 CT	60 CT	60 CT		

7. Findings and Discussion

Utah is part of a highly interconnected Western grid, and is a net exporter of relatively inexpensive coal-based electricity. The externality costs of generation in Utah today and in the future are high: health and water externalities from Utah generators cost between $1.7 and $2.0 billion dollars today,[139] and could rise to between $2.4 and $2.8 billion per year by 2020. On a unit-energy basis, this externality cost ranges from $36 to $43 per MWh hour today, rising to $45 to $51 per MWh by 2020. These costs are comparable to the direct costs of generation (i.e. fuel, O&M, and capital recovery).

In general, we predict that reducing demand in Utah without the participation of neighboring states does not substantially benefit air quality or water availability in Utah. There are undoubtedly substantial financial and environmental benefits to both energy efficiency (EE) and renewable energy (RE), including reduced requirements for fossil fuels, reduced emissions of criteria and greenhouse gasses, and financial benefits to ratepayers. However, our results indicate that, because of Utah’s position as a net exporter of coal-fired energy, reducing demand in the state will not substantially lower health risks or water consumption in Utah. Indeed, it is possible that reduced energy consumption in the state will instead result in larger exports of baseload coal-fired energy: a scenario that would likely result in a benefit for inexpensive power out-of-state, yet a high social cost of externalities in Utah and downwind states. This dilemma can be resolved by:

1. internalizing externality costs into resource and transmission planning exercises, or even dispatch decisions;
2. proactively reducing electric sector emissions and water consumption in Utah;
3. working with neighboring states to cut regional energy consumption, thus reducing export requirements from Utah.

These strategies can help Utah effectively realize high co-benefits from EE and RE in the state.

The following sections discuss results from this research, including avoided generation and emissions from implementing EE and RE in Utah, the externality costs of the system today and in the future, and the co-benefit cost effectiveness of EE and RE on health and water. Two appendices discuss non-quantified co-benefits on natural gas prices and regional haze in Utah.

7.1.1. Avoided Generation

This study finds that when energy efficiency or renewable energy impinges on load, gas generators are displaced preferentially, almost to the exclusion of coal generators. This is a fairly realistic portrayal of an expected response to moderate penetrations of efficiency or new renewable energy: gas generators are more expensive and more

[139] The range of costs is due to the uncertainty in the externality cost of water used in this study.

flexible then coal-fired generators and thus are more likely to respond to intermittent renewable generation. In a dispatch modeling exercise focused on the Western grid, researchers at the National Renewable Energy Laboratories (NREL) found that solar photovoltaic technologies would have to supply more than 15% of energy before coal in the west would be displaced.[140] It is feasible that at higher penetrations, renewable resources such as wind would actually require greater amounts of gas to balance intermittency, and therefore displace coal. However, in this exercise, we find that reducing generation requirements targets in Utah reduces gas generation, a finding with important implications for emissions, externalities, and eventually, the co-benefits of energy efficiency and renewable energy.

A second notable feature of this work is that our modeled penetrations of renewable energy and energy efficiency primarily displace new resources, rather than existing resources. According to estimates provided by PacifiCorp in 2008, load is expected to grow by an average of 2.15% per year between 2010 and 2018.[141] At this rate of growth and if Utah expects to continue exporting baseload coal-fired power, new resources would be required over the study period. This study assumes, from an emissions conservative standpoint, that new conventional resources would be fired by natural gas. Thus, new renewable energy would displace primarily new gas power. Even if load growth is significantly attenuated, EE and RE still primarily reduce gas-fired generation.

Table 7-1: Generation and avoided generation (GWh), by scenario.

	Generation (GWh)			Avoided Generation (GWh)		
2007-2008	**Coal**	**Gas**	**Total**	**Coal**	**Gas**	**Total**
Reference Case	38,966	8,202	47,169			
2020-2021						
Baseline	39,494	14,854	54,347			
			Energy Efficiency Scenarios			
EE (SWEEP)	39,565	11,225	50,790	-71	3,628	3,557
EE (2% per yr)	39,511	8,998	48,509	-17	5,855	5,838
EE (3% per year)	38,459	7,562	46,021	1,035	7,292	8,327
			Renewable Scenarios			
Wind (Porcupine)	38,745	12,816	51,561	749	2,038	2,786
Wind (TAD North)	38,283	12,840	51,123	1,211	2,014	3,225
Wind (Medicine Bow)	38,425	12,412	50,837	1,068	2,442	3,510
Solar (Flat Plate PV)	39,115	13,825	52,940	379	1,028	1,407
Solar (One-Axis Track)	38,960	13,584	52,544	533	1,270	1,803
Solar (CSP Trough, Wet Cooled)	39,320	12,718	52,039	173	2,135	2,309
Solar (CSP Trough, Dry Cooled)	39,320	12,718	52,039	173	2,135	2,309
Geothermal	38,170	12,112	50,283	1,323	2,741	4,065
			Replacement Scenarios			
Replace Coal w/ EE and Gas	27,456	20,796	48,252	12,038	-5,942	6,096
Replace Coal w/ EE and RE	27,273	15,522	42,796	12,220	-669	11,552

[140] Denholm, P. R.M. Margolis, J.M. Milford. 2009. Quantifiying Avoided Fuel Use and Emissions from Solar Photovoltaic Generation in the Western United States. *Environmental Science and Technology*. **43**(1):226-231

[141] Estimates provided by PacifiCorp may not reflect the subsequent economic downturn.

Table 7-1 shows changes in coal generation and gas generation from the reference period (2007-2008) through the end of the analysis period (2020-2021) for both the baseline and EE and RE cases. It can be seen that, with the exception of the two replacement scenarios, coal generation remains essentially unchanged and gas generation increases. The second set of columns in Table 7-1 and the diagram in Figure 7-1 show the avoided generation of gas and coal, or the difference between the given scenario and the baseline case.

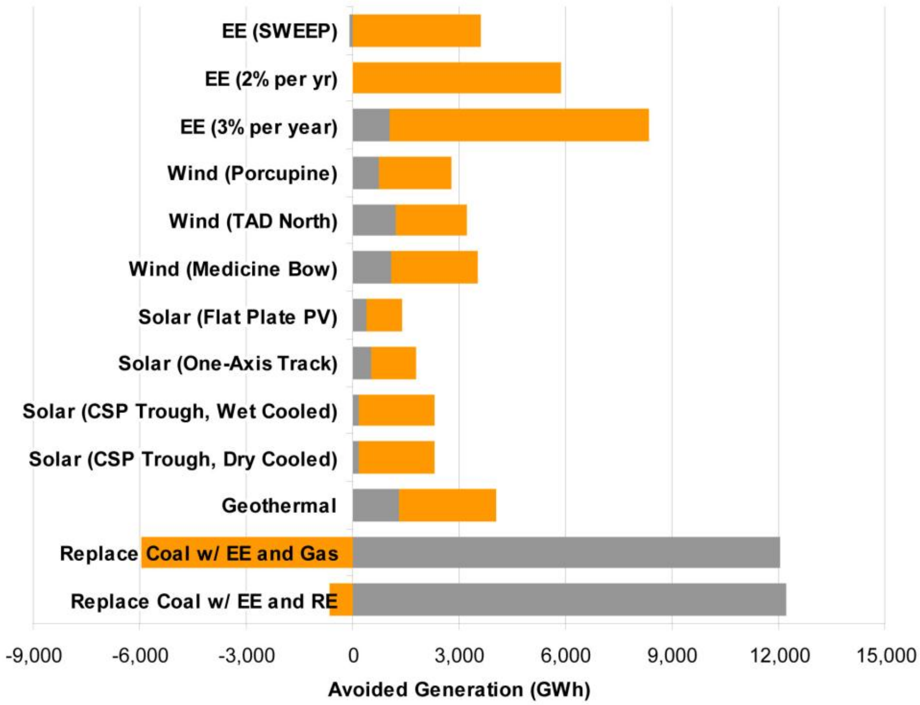

Figure 7-1: Avoided annual fossil generation (GWh) in each scenario by 2020. Gray bars are generation from coal, orange bars represent generation from gas. Negative avoided generation indicates increased utilization of gas in replacement scenario.

In all of the cases, new EE and RE primarily displace natural gas-fired generation. The impact of displacing only new and relatively efficient gas units is that modest penetrations of alternative energy resources yield onlymodest co-benefits in Utah. Gas-fired generators have relatively low emissions profiles and low water use relative to coal-fired generators; therefore, these programs only avoid a small fraction of the overall externalities imposed on society by Utah's generation fleet. In this study, only the replacement scenarios significantly reduce coal generation.

7.1.2. Physical Externalities and Avoided Externalities

In the reference case, fossil generation in Utah today results in an estimated 202 premature deaths per year. Damages from generators in Utah are experienced both in Utah and in downwind states. In this analysis, we find that over 86% of premature deaths occur in downwind states. In Table 7-2, below, we show morbidity and mortality across all impacted areas, followed by the number of deaths or sicknesses experienced by Utah's residents (in parentheses).

Table 7-2: Physical externalities from conventional generation

	Health Externalities, All (in Utah)								**Water Use** Acre Feet per Year
2007-2008	Statistical Deaths per Year		Cardiovascular Hospital Admissions per Year		Respiratory Hospital Admissions per Year		Emergency Room Visits per Year		
Reference Case	**202**	(28)	**21**	(2)	**154**	(70)	**175**	(72)	**73,800**
2020-2021									
	Baseline Scenario								
Baseline Load Growth	**279**	(41)	**32**	(3)	**194**	(90)	**225**	(93)	**77,400**
	Energy Efficiency Scenarios								
EE (SWEEP)	**277**	(40)	**31**	(3)	**193**	(90)	**224**	(92)	**75,900**
EE (2% per yr)	**274**	(39)	**31**	(3)	**192**	(89)	**223**	(92)	**75,800**
EE (3% per year)	**267**	(38)	**30**	(3)	**186**	(86)	**216**	(89)	**72,400**
	Renewable Scenarios								
Wind (Porcupine)	**273**	(39)	**31**	(3)	**189**	(88)	**220**	(90)	**74,400**
Wind (TAD North)	**271**	(39)	**31**	(3)	**187**	(87)	**218**	(89)	**74,000**
Wind (Medicine Bow)	**271**	(39)	**31**	(3)	**187**	(87)	**218**	(89)	**73,900**
Solar (Flat Plate PV)	**276**	(40)	**31**	(3)	**191**	(89)	**222**	(91)	**75,900**
Solar (One-Axis Track)	**275**	(39)	**31**	(3)	**190**	(88)	**221**	(91)	**75,500**
Solar (CSP Trough, Wet Cooled)	**277**	(40)	**31**	(3)	**192**	(89)	**224**	(92)	**82,700**
Solar (CSP Trough, Dry Cooled)	**277**	(40)	**31**	(3)	**192**	(89)	**224**	(92)	**76,500**
Geothermal	**269**	(38)	**31**	(3)	**186**	(86)	**217**	(89)	**89,600**
	Replacement Scenarios								
Replace Coal w/ EE and Gas	**182**	(30)	**20**	(2)	**137**	(65)	**157**	(67)	**57,300**
Replace Coal w/ EE and RE	**178**	(29)	**20**	(2)	**136**	(65)	**155**	(67)	**56,200**

Table 7-2 shows major categories of physical externalities, including health (mortality and morbidity) and water consumption. In the health externalities, columns are paired, with the first sets of values indicating total externalities, and the second sets of columns (in parenthesis) indicating the externalities estimated to occur within Utah's borders. On a business-as-usual trajectory, even if all new resources are relatively low-emissions gas fired generators, the model predicts nearly 280 premature deaths per year by 2020 (with 41 of these deaths, or 15% occurring in-state). In all of the non-replacement scenarios, the mortality rate increases with rising population. By replacing the most inefficient coal generators with energy efficiency and gas, the total mortality rate drops by 2020 to 182 premature deaths per year. All of the energy efficiency and renewable energy scenarios result in slightly decreased mortality rates relative to the baseline.

Morbidity statistics track similarly to mortality in the baseline scenario: respiratory disease hospitalizations rise by 25%, while cardiovascular hospital admissions rise by 50% from 2007 to 2020. Similar to mortality, only the replacement scenario results in significantly lower morbidity by 2020 relative to 2008.

Finally, we estimate that fossil generators in Utah consume approximately 73,800 acre feet of water for boilers and cooling purposes today; a majority of this consumption is by coal generators (93%). With increasing load growth and additional gas capacity, consumption rises to 77,400 acre feet per year by 2020 (91% coal). For the most part, renewable energy and energy efficiency projects displace low-water use gas generation. In most of the EE and RE scenarios, water consumption does not fall significantly from the baseline, and in the wet-cooled concentrating solar project (CSP) and the geothermal scenario, water consumption rises relative to the baseline scenario. When select coal generators are retired, consumption drops 25% to 56,200 - 57,300 acre feet, a savings of over 20,000 acre feet.

We consider co-benefits on a cost-efficacy basis, i.e. avoided externalities relative to the fossil energy avoided by new EE and RE programs. The scenarios in this research do not all displace the same amount of generation; thus to judge the efficacy of a particular technology on reducing externalities, we estimate reductions relative to displaced energy. It is useful to examine the avoided physical externalities (mortality, morbidity, and water use) by how much fossil generation (both gas and coal) is avoided.

Table 7-3: Avoided physical externalities per unit of energy for scenarios at end of study period (2020-2021). Health impacts in avoided externalities per avoided TWh of generation and avoided water use per avoided MWh of generation. In health valuation, bold values are totals, values in parentheses are Utah only.

2020-2021	**Health Co-Benefits, All** (in Utah) Deaths, Hospital Admissions, & ER Visits per Avoided TWh: Avoided Statistical Deaths per Year		Avoided Cardiovascular Hospital Adm / Year		Avoided Respiratory Hospital Adm / Year		Avoided ER Visits / Year		**Avoided Water Use** Gallons per Avoided MWh
	Energy Efficiency Scenarios								
EE (SWEEP)	**0.7**	(0.2)	**0.1**	(0.0)	**0.3**	(0.1)	**0.3**	(0.1)	**135**
EE (2% per yr)	**0.9**	(0.2)	**0.1**	(0.0)	**0.3**	(0.1)	**0.5**	(0.2)	**90**
EE (3% per year)	**1.5**	(0.3)	**0.2**	(0.0)	**0.9**	(0.4)	**1.1**	(0.5)	**195**
	Renewable Scenarios								
Wind (Porcupine)	**2.2**	(0.5)	**0.2**	(0.0)	**1.7**	(0.9)	**2.0**	(0.9)	**343**
Wind (TAD North)	**2.4**	(0.5)	**0.3**	(0.0)	**2.1**	(1.1)	**2.4**	(1.1)	**346**
Wind (Medicine Bow)	**2.3**	(0.5)	**0.2**	(0.0)	**1.8**	(0.9)	**2.1**	(0.9)	**325**
Solar (Flat Plate PV)	**2.3**	(0.6)	**0.2**	(0.0)	**1.9**	(0.9)	**2.1**	(1.0)	**349**
Solar (One-Axis Track)	**2.5**	(0.6)	**0.3**	(0.1)	**2.0**	(1.0)	**2.2**	(1.0)	**344**
Solar (CSP Trough, Wet Cooled)	**0.9**	(0.3)	**0.1**	(0.0)	**0.6**	(0.3)	**0.7**	(0.4)	**-755**
Solar (CSP Trough, Dry Cooled)	**0.9**	(0.3)	**0.1**	(0.0)	**0.6**	(0.3)	**0.7**	(0.4)	**124**
Geothermal	**2.4**	(0.6)	**0.3**	(0.0)	**1.9**	(1.0)	**2.2**	(1.0)	**-981**
	Replacement Scenarios*								
Replace Coal w/ EE and Gas	**8.0**	(0.9)	**0.9**	(0.1)	**4.7**	(2.1)	**5.7**	(2.1)	**545**
Replace Coal w/ EE and RE	**8.2**	(0.9)	**1.0**	(0.1)	**4.8**	(2.1)	**5.7**	(2.1)	**565**

*The replacement scenarios estimate co-benefits against is avoided coal generation. These values are not directly comparable to the other scenarios

Physical co-benefits are shown in Table 7-3. Health co-benefits are shown relative to avoided TWh (one million MWh) of fossil energy.[142] Water co-benefits are displayed relative to each avoided MWh of energy. The energy efficiency scenarios save on the order of one to 1.5 statistical lives per TWh of avoided generation, while the renewable energy scenarios avoid from one to two and half statistical lives per TWh of avoided generation. The energy efficiency scenarios primarily reduce the need for gas generation, and so there is very little water avoided on a per MWh basis. Only the most aggressive efficiency scenario impacts coal generation, thus saving more water per year on a MWh basis.

The replacement scenarios are specifically designed to understand the net impact of replacing coal-fired generation, and are not strictly “displacement” scenarios. Therefore, the estimate of co-benefits is gauged relative to the total amount of coal generation removed or displaced in the study year, rather than the total amount of conventional generation displaced. Nonetheless, these two scenarios have significant social benefits in Utah and in downwind states. By 2020, the replacement scenarios are estimated to avoid approximately 100 statistical deaths each year, 30% of which are in Utah. For each TWh of coal generation avoided, these scenarios avert approximately 8 deaths. These scenarios also reduce the total amount of water that is required for electrical generation, saving between 545 and 565 gallons per MWh of coal generation avoided.

7.1.3. Externality Costs and Co-Benefits

Mortality from fossil generation in Utah today is valued at more than $1.6 billion, of which $222 million (13%) is realized in Utah (see Table 7-4). Adding additional gas generators, increasing the utilization of existing coal units, and increasing the population results in a cost over $2.3 billion from premature deaths, of which a slightly higher fraction (14.5%) is in Utah. The increased fraction in Utah is due to particulates from gas closer to existing population centers. Mortality costs are moderately lower for the energy efficiency and renewable energy scenarios, with aggressive energy efficiency (3%) resulting in the lowest cost without removing existing generators. As seen above, replacing inefficient coal units results in the greatest reduction in health externality costs, 5.5% below today’s costs.

[142] For comparative purposes, a 400 MW power plant operating at an 85% capacity factor would produce about three TWh per year.

Table 7-4: Externality costs for scenarios relative to reference (2007-2008) and at end of study period (2020-2021). Externality cost of mortality, morbidity, and water, in millions of 2008 dollars per year. In health valuation, bold values are totals, values in parentheses are Utah only.

	Health Costs and Valuation, Million 2008$ per year **All** (in Utah)				Externality Cost of Water (Low - High)	Total Externality Cost (Low - High)
2007-2008	**Mortality**		**Morbidity**			
Reference Case	**$1,612**	($222)	**$32**	($16)	**$38 - $383**	**$1,683 - $2,027**
2020-2021						
	Baseline Scenario					
Baseline	**$2,337**	($339)	**$41**	($21)	**$40 - $401**	**$2,418 - $2,779**
	Efficiency Scenarios					
EE (SWEEP)	**$2,317**	($334)	**$41**	($21)	**$39 - $393**	**$2,397 - $2,751**
EE (2% per yr)	**$2,291**	($329)	**$41**	($21)	**$39 - $393**	**$2,372 - $2,725**
EE (3% per year)	**$2,234**	($316)	**$40**	($20)	**$38 - $375**	**$2,312 - $2,649**
	Renewable Scenarios					
Wind (Porcupine)	**$2,285**	($327)	**$40**	($20)	**$39 - $386**	**$2,364 - $2,711**
Wind (TAD North)	**$2,271**	($325)	**$40**	($20)	**$38 - $383**	**$2,349 - $2,694**
Wind (Medicine Bow)	**$2,270**	($324)	**$40**	($20)	**$38 - $383**	**$2,349 - $2,693**
Solar (Flat Plate PV)	**$2,310**	($332)	**$41**	($20)	**$39 - $393**	**$2,390 - $2,744**
Solar (One-Axis Track)	**$2,299**	($330)	**$41**	($20)	**$39 - $391**	**$2,379 - $2,731**
Solar (CSP Trough, Wet Cooled)	**$2,319**	($333)	**$41**	($21)	**$43 - $429**	**$2,403 - $2,789**
Solar (CSP Trough, Dry Cooled)	**$2,319**	($333)	**$41**	($21)	**$40 - $396**	**$2,400 - $2,757**
Geothermal	**$2,256**	($320)	**$40**	($20)	**$47 - $464**	**$2,343 - $2,760**
	Replacement Scenarios					
Replace Coal w/ EE and Gas	**$1,527**	($250)	**$29**	($15)	**$30 - $297**	**$1,586 - $1,853**
Replace Coal w/ EE and RE	**$1,494**	($244)	**$29**	($15)	**$29 - $291**	**$1,553 - $1,815**

On a relative scale, morbidity costs are significantly lower, but this is primarily a function of how lost lives are valued versus a range of sicknesses, including cardiovascular and respiratory illnesses. Today's cost is about $32 million, with half of the cost experienced in Utah's borders ($16 million). These morbidity costs reflect healthcare costs for the fraction of health problems attributed to particulates, ozone, and other power plant pollutants.

The externality cost of water is predominated by water use from coal generators; increasing demand by 2020 does entail a higher water cost, but because this new load is primarily met with gas-fired generation, the additional water cost only rises by 5% in the baseline case. The range of externality costs of water extends from $38 million at the low end to $383 million at the upper end, depending on how water is valued (as described in Section 5.3). These costs could rise by five percent in the baseline case, or anywhere from a tenth of a percent (in the Medicine Bow wind case) to twelve percent (the water intensive concentrating solar trough case) above today's costs, according to the scenarios constructed for this study. Conversely, retiring water intensive coal-fired power plants and replacing them with either gas-fired generation or renewable energy reduces the social cost of water by 22-24% from today's costs.

Combined, health and water externalities from Utah generators cost between $1.7 and $2.0 billion today, and could rise to $2.4 to $2.8 billion by 2020. On a per unit energy basis, externalities cost society $36-$43/MWh generated today, expenses on par with the cost of conventional generation, a conclusion shared by a recent report of the National Academy of Sciences. [143] Electricity generated in Utah to serve both Utah and Pacific states results in damages to both Utahns and downwind populations, primarily to the east of Utah.

Without mitigation, in the future Utah and the West's expanding population will put more people at risk for exposure to fine particulates and ozone from conventional generation. In the baseline scenario, externality costs rise to $44-$51/MWh. These costs, internalized into the cost of generation, would have deep implications as to how new resources are selected or dispatched.

While externalities from electric fired generation are very high, the co-benefits that can be realized by passively displacing existing generation with new energy efficiency programs or renewable energy programs are fairly modest.[144] In this study, the most effective technologies for reducing health and water impacts will yield a higher cost savings per MWh. In Table 7-5, co-benefits are estimated for mortality and morbidity (both in total, and in Utah alone), and water consumption by power plants. Figure 7-2 portrays this information graphically,

[143] National Academy of Sciences. Hidden Costs of Energy: *Unpriced Consequences of Energy Production and Use.* Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption; National Research Council. National Academies Press, 2009.

[144] It should be noted that co-benefits are defined in this paper as the monetized social externalities of generation avoided for every MWh of avoided generation.

Table 7-5: Value of co-benefit for scenarios at end of study period (2020-2021) per MWh. Co-benefits in avoided dollars per MWh of avoided generation. In health valuation, bold values are totals, values in parentheses are Utah only.

2020-2021	Health Co-Benefits, 2008$ per MWh **All** (in Utah) Mortality		Morbidity		Avoided Cost of Water (Low - High)	Total Co-Benefit (Low - High)
			Efficiency Scenarios			
EE (SWEEP)	**$5.6**	($1.5)	**$0.1**	$0.0	**$0.2 - $2.1**	**$5.9 - $7.8**
EE (2% per yr)	**$7.8**	($1.7)	**$0.1**	$0.0	**$0.1 - $1.4**	**$8.0 - $9.3**
EE (3% per year)	**$12.3**	($2.8)	**$0.2**	$0.1	**$0.3 - $3.1**	**$12.8 - $15.6**
			Renewable Scenarios			
Wind (Porcupine)	**$18.6**	($4.5)	**$0.4**	$0.2	**$0.5 - $5.5**	**$19.5 - $24.4**
Wind (TAD North)	**$20.4**	($4.5)	**$0.5**	$0.2	**$0.6 - $5.5**	**$21.4 - $26.3**
Wind (Medicine Bow)	**$18.9**	($4.4)	**$0.4**	$0.2	**$0.5 - $5.2**	**$19.8 - $24.5**
Solar (Flat Plate PV)	**$19.0**	($4.9)	**$0.4**	$0.2	**$0.6 - $5.5**	**$20.0 - $25.0**
Solar (One-Axis Track)	**$20.7**	($5.0)	**$0.4**	$0.2	**$0.5 - $5.5**	**$21.7 - $26.6**
Solar (CSP Trough, Wet Cooled)	**$7.7**	($2.6)	**$0.1**	$0.1	**-$12.0 - -$1.2**	**-$4.2 - $6.6**
Solar (CSP Trough, Dry Cooled)	**$7.7**	($2.6)	**$0.1**	$0.1	**$0.2 - $2.0**	**$8.0 - $9.8**
Geothermal	**$19.8**	($4.6)	**$0.4**	$0.2	**-$15.6 - -$1.6**	**$4.6 - $18.7**
			Replacement Scenarios*			
Replace Coal w/ EE and Gas	**$67.26**	($7.39)	**$1.00**	($0.48)	**$0.9 - $8.7**	**$69.1 - $76.9**
Replace Coal w/ EE and RE	**$68.94**	($7.79)	**$1.00**	($0.48)	**$0.9 - $9.0**	**$70.8 - $78.9**

*The replacement scenarios estimate co-benefits against is avoided *coal* generation. These values are not directly comparable to the other scenarios

Moderate savings from energy efficiency (primarily reduced gas usage) save from $6-$16 per MWh in externality costs by 2020, with more aggressive EE displacing more coal generation and therefore yielding greater benefit. Amongst the renewable energy technologies, wind at the TAD north site and tracking solar PV in Cedar City offer the best opportunities to reduce the externality costs quantified in this analysis. The concentrating solar thermal projects show a lower net co-benefit (even a negative co-benefit, or a net cost) because of the high water demand from these units. Since the renewable energy projects primarily displace gas at moderate penetrations, any significant use of water (such as in solar boilers) is a net cost to society, unless these costs are internalized by renewable energy projects.

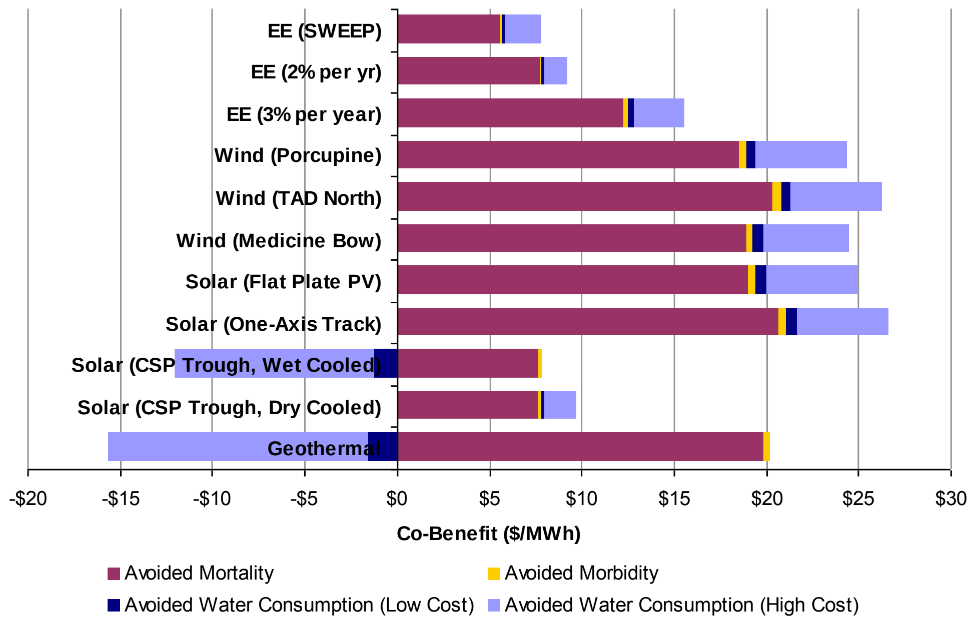

Figure 7-2: Value of co-benefits for energy efficiency and renewable energy scenarios in 2020, relative to baseline. Light blue bar represents savings (or cost) of avoided water use at a high externality cost of water. Dark blue bar represents the differential if the externality cost of water is low. Negative values of water co-benefits indicate that the energy alternative (i.e. concentrating solar power) is more water intensive than conventional generation.

As seen in Figure 7-2, the highest co-benefits are derived from avoiding premature deaths due to fine particulates and other air pollution. Avoided water use can result in large co-benefits as well, if the social value of water is priced at the margin (as discussed in Section 5.3) and if replacement technologies do not use more water than would otherwise be saved. In both the wet cooled CSP trough and geothermal scenarios, more water is consumed by the replacement energy than is saved by passive displacement. Using dry cooled technologies can mitigate this problem.

The societal benefits from replacing coal with natural gas or a mix of renewable energy are significant, but not directly comparable to the passive displacement by EE and RE alone. Again, the final two scenarios are measured against the amount of coal generation replaced or displaced. For each MWh of coal displaced by a combination of energy efficiency and gas or renewable energy in 2020, externalities are reduced by $69-$81. This large co-benefit exceeds the all-in cost of coal-fired generation in almost all circumstances.

7.2. Study Assumptions and Exclusions

It should be noted that these analyses have several key assumptions, and that changes from them may affect the results. The assumptions and the way results could change are described below.

7.2.1. Existing Transmission Constraints are Maintained

Dispatch decisions today are guided by variable resource costs, availability, reliability, and physical constraints. One significant constraint that determines which resources will be dispatched to meet load are transmission constraints.

Utah is a net exporter of energy, producing more electricity than it consumes. However, the amount of energy that can be transmitted out-of-state is limited by the capacity of the transmission lines to areas of demand (load centers). Currently, when demand out-of-state is high and there is little hydroelectric capacity available, coal generators in Utah operate nearly continuously. The exception to this is during off-peak hours in Utah. In these hours, Utah enters a unique position where it has more capacity than can be carried by transmission systems into the Northwest or California, and even some large coal generators are forced to back down slightly. An example of this dynamic can be seen in the time series in Figure 7-3.

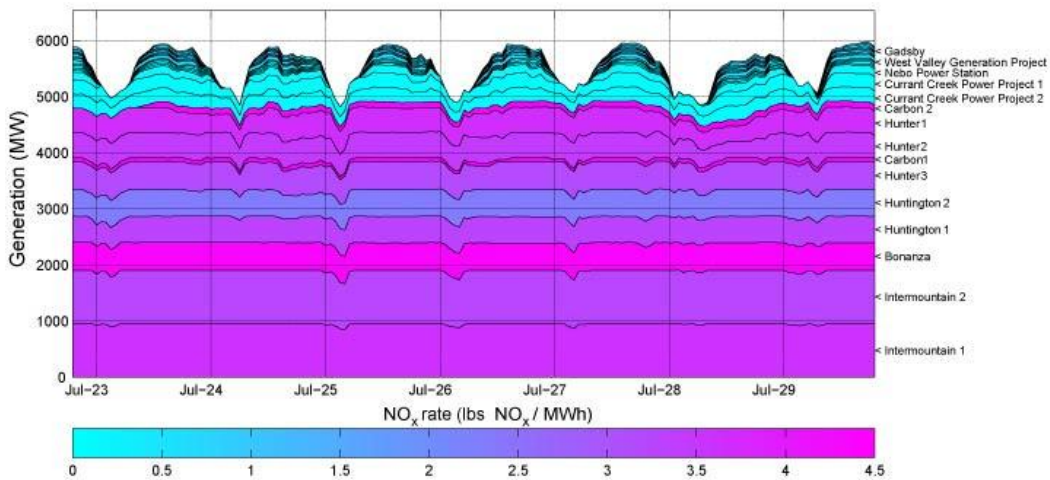

Figure 7-3: Generation in Utah from July 23, 2007 through July 29, 2007, showing few hours in which coal units (shades of pink and purple) back down during summer trough hours. Colors indicate NO_X emissions rate in lbs per MWh. Generators are ordered by capacity factor during week.

The model used here recognizes the hours in which generators change behavior due to the dispatch decisions described above, but the analysis does not model these decisions, it simply replicates choices made in the past. If transmission constraints were lifted or modified, dispatch decisions could change markedly throughout the West, and historical behavior might provide a poor analog for future decisions. If these constraints were lifted by building more transmission from or through Utah, there would be fewer hours where coal generators could not operate continuously. Barring changes in environmental regulations or other constraints, additional transmission would likely result most immediately in even higher capacity factors for baseload generators. The expected impact on the results of this analysis would be an increase in the externality cost, and fewer opportunities to displace the large externalities of coal except through direct replacement.

7.2.2. Social Cost of Greenhouse Gas Emissions are Not Evaluated

At the time that the Utah agencies developed this project, it was determined that potential or future carbon costs should not be addressed pending resolution of ongoing policy debates and/or actual federal legislation. As a result, this study was not scoped to estimate the externality cost of greenhouse gas (GHG) emissions. GHG, such as CO_2, accumulate in the atmosphere and trap solar radiation, leading to a warming of the atmosphere. A large body of research suggests that GHG emissions that are released today will lead to significant changes in the earth's climate, including warming at the poles, changes in precipitation patterns, sea level rise, and expansion of disease vectors.[145] Models and field experiments have shown that the changes that could result from global climate change would permanently alter or destroy ecosystems and economies, and displace numerous individuals.[146] These impacts have been shown to have a large economic impact on society.[147, 148] Since these costs are not currently internalized into the cost of emitting GHG, these costs can be considered an externality cost. In the United States, most anthropogenic (human-caused) emissions of GHG are from the combustion of fossil fuels,[149] and are in the form of CO_2. The externality cost of CO_2 emissions from power plants may, in the future, be partially internalized by climate legislation.[150] However, the un-internalized cost today and in the future could quickly exceed other costs estimated in this study.

Following findings in other studies, including the Integrated Panel on Climate Change,[145] the Stern Report,[147] a recent National Academy of Sciences report,[151] and recommendations on the avoided cost of energy sponsored by New England utilities, [152] we estimate a *social* cost of CO_2 at \$80 per ton of CO_2 (2008\$).[153] If this long-run marginal abatement cost were included formally in this study, the externality cost of

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[145] Contribution of Working Groups I, II and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. Core Writing Team, Pachauri, R.K. and Reisinger, A. (Eds.) IPCC, Geneva, Switzerland. pp 104

[146] Climate Change and Displacement. Forced Migration Review. Issue 31, October 2008. Refugee Studies Center. Available online: http://www.fmreview.org/FMRpdfs/FMR31/FMR31.pdf

[147] Stern Review: The Economics of Climate Change. 2006. Cambridge University Press. Available online: http://www.hm-treasury.gov.uk/stern_review_report.htm

[148] Ackerman, F. and E.A. Stanton. 2008. The Cost of Climate Change: What We'll Pay if Global Warming Continues Unchecked. Available online: http://www.nrdc.org/globalwarming/cost/cost.pdf

[149] US. EPA. 2009 US Greenhouse Gas Inventory Report. April 2009. Available online: http://www.epa.gov/climatechange/emissions/usinventoryreport.html

[150] If legislation puts a price on greenhouse gas emissions, the externality price would be the net difference between the social cost of greenhouse gas emissions and the market price of these emissions.

[151] National Academy of Sciences. Hidden Costs of Energy: *Unpriced Consequences of Energy Production and Use.* Committee on Health, Environmental, and Other External Costs and Benefits of Energy Production and Consumption; National Research Council. National Academies Press, 2009.

[152] Hornby, R., P. Chernick, C. Swanson, et al. 2009. Avoided Energy Supply Costs in New England. Prepared for the Avoided-Energy-Supply-Component (AESC) Study Group [New England Utilities]

[153] These externality costs are *not* the expected costs of compliance, but rather the damage costs of emissions. We anticipate that as carbon dioxide emissions are regulated in coming decades that an increasing portion of this \$80 social cost will be "internalized" by regulation, with potentially far lower compliance or abatement costs. This internalization is not reflected in the long-run externality cost estimated here.

generation from Utah today would be nearly $3.4 billion, or $72 per MWh of conventional generation. Table 7-6 shows emissions from gas and coal in Utah today (in million short tons per year) and in each of the scenarios at the end of the analysis period. The fifth column shows the externality cost with a social cost of carbon at $80/t$CO_2$. Finally, the last two columns show the avoided CO_2 emissions (in million short tons per year) and the CO_2 co-benefit which would be realized on a per MWh basis for each of the scenarios.

Table 7-6: Emissions of carbon dioxide (million tons CO_2), externality cost (in millions), avoided emissions, and the CO_2 co-benefit for each scenario. The co-benefits for the replacement scenarios are relative to avoided coal generation.

	CO_2 (M Tons)			CO_2 Externality, Million $	Avoided CO_2	CO_2 Co-Benefit ($/MWh)
2007-2008	**Gas**	**Coal**	**Total**			
Reference Case	38.85	3.41	42.26	$3,381		
2020-2021						
Baseline	39.39	6.13	45.52	$3,642		
	Energy Efficiency Scenarios					
EE (SWEEP)	39.49	4.69	44.18	$3,535	1.34	$30.09
EE (2% per yr)	39.40	3.79	43.19	$3,455	2.33	$32.00
EE (3% per year)	38.36	3.12	41.48	$3,319	4.04	$38.79
	Renewable Scenarios					
Wind (Porcupine)	38.63	5.25	43.88	$3,510	1.64	$47.17
Wind (TAD North)	38.19	5.28	43.48	$3,478	2.04	$50.73
Wind (Medicine Bow)	38.38	5.09	43.47	$3,478	2.05	$46.74
Solar (Flat Plate PV)	39.00	5.68	44.68	$3,574	0.84	$47.96
Solar (One-Axis Track)	38.91	5.57	44.48	$3,559	1.04	$46.10
Solar (CSP Trough, Wet Cooled)	39.26	5.27	44.53	$3,563	0.99	$34.23
Solar (CSP Trough, Dry Cooled)	39.26	5.27	44.53	$3,563	0.99	$34.23
Geothermal	38.12	4.94	43.06	$3,445	2.46	$48.51
	Replacement Scenarios*					
Replace Coal w/ EE and Gas	27.34	8.43	35.76	$2,861	9.76	$64.84
Replace Coal w/ EE and RE	27.16	6.54	33.70	$2,696	11.82	$77.36

If a greenhouse gas externality cost is adopted, the price of CO_2 emissions quickly exceeds the cost of most conventional generation. Conversely, large co-benefits of $30-$51/MWh are realized for new energy efficiency and renewable energy programs from CO_2 avoidance alone. Not unexpectedly, replacing coal with energy efficiency and either gas generation or a mix of renewable energy and gas would yield significant co-benefits for each MWh of coal replaced. These costs and co-benefits are not estimated in the analysis of health and water co-benefits.

7.2.3. Additional Environmental Costs

In this study, internalized environmental costs are not estimated. New federal emissions rules, including the Clean Air Interstate Rule (CAIR) and regional haze reduction regulations (known as the Best Available Retrofit Technology ruling, or BART), may impose additional costs on fossil-fired generators, effectively internalizing a portion of the external costs of generation. In addition, mercury and other toxic reduction rulings (such as CAMR, the Clean Air Mercury Rule) could impart an additional environmental cost representing the internalization of a social externality. If new environmental costs are internalized into the variable cost of operation, the dispatch decisions in the region could change dramatically (including making coal units more expensive to run), thus changing the results of this analysis.

7.2.4. Utah Acts Alone

One of the most significant assumptions in this analysis is that Utah acts alone in implementing new renewable energy or energy efficiency programs. This study is scoped to determine the impact of implementing new EE and RE in Utah, or delivered to Utah. If other states participate in similar programs, the demand for conventional generation exported from Utah could fall, yielding social benefits to Utah and downwind states in excess of those estimated in this study. For example, changes in demand from neighboring states, and particularly in electricity importing states such as California, could have broad impacts on Utah's generators.

California is currently scoping a plan to reduce the state's carbon footprint.[154] In a recent study, the state determined that California demand is met in part by coal-fired plants in the Rocky Mountain West, and that two of Utah's plants are within the top five emitters contributing to California's energy.[155] Demand for energy from coal-fired plants that both serve California entities directly, such as the Intermountain Power Project, and indirectly by sales through the Western Interconnect may be reduced as California works to decrease demand, increase renewable energy, and decrease dependencies on high emissions plants in the west.

7.3. Policy Implications

The research presented in this project has a number of potential applications in informing Utah policy and planning processes. Externalities reflect social costs that are not accounted for in the market cost of a commodity. As such, the consideration of externalities in planning marks an opportunity to more fully account for the public good. Generation and the delivery of energy is commonly considered a pubic service, provided for the benefit of society. However, the current cost of energy to consumers masks an additional social cost of lost lives from air pollution, lost productivity and quality of life from medical conditions caused or exacerbated by emissions, and the opportunity cost of using scarce water resources for power generation rather than development, agriculture, or environmental needs.

The future of energy planning will require rigorous accounting of emissions and water consumption. Rules recently promulgated by and expected from the US EPA cover air emissions and water use, and the stringency and enforcement of these rules is only expected to become tighter. Locally, studies conducted for the California greenhouse

[154] Climate Change Scoping Plan: a Framework for Change. December, 2008. California Air Resources Board. Available online at: http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf
[155] Mandatory Greenhouse Gas Reporting: 2008 Reported Emissions. November, 2009. California Air Resources Board. Available online at: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-reports.htm

gas reduction plan, A.B. 32, identify power plants in Utah as sources of imported emissions. As Utah prepares for a new energy paradigm, the social costs of generation and the benefits accrued from EE and RE should be an intrinsic part of the planning process. The following are several mechanisms in which externalities and co-benefits may be directly considered.

- **Integrated Resource Plan (IRP):** PacifiCorp's 2008 IRP was submitted to Utah and five other states in May 2009. Utah PSC Docket 90-2034-01 prescribes the standards required for IRPs, including the identification of current and future financial risks. The docket specifically requires externalities and environmental costs to be considered, and the IRP process in Utah allows externality costs to be recognized in the definition of "least cost" resources. New renewable energy and energy efficiency programs may be more effectively characterized not only through the avoided cost of energy, but through externalities avoided. A full accounting of the cost of power in resource plans might include downstream social costs, such as health impacts, water consumption and pollution, and risk of damages from greenhouse gas emissions, as well as upstream costs and benefits associated with the procurement of fuel and land use impacts.
- **State Implementation Plan (SIP):** Four metropolitan areas along the Wasatch Front were recommended by Utah for non-attainment designation under the EPA eight-hour ozone standard. EPA's final decision is due by March 2010. The Utah air quality agency must then develop requirements, for approval by EPA, that reduce emissions that cause or contribute to ozone non-attainment. Several of the scenarios analyzed for this report could be further evaluated (to improve precision to the level required for EPA approval) and included as revisions to Utah's SIP; this process, using similar tools, is moving forward in other states in cooperation with the EPA.
- **Evaluation of Utility DSM Programs:** As PacifiCorp develops new or revises existing demand side management (DSM) programs, regulators may choose to calculate the value of displaced externalities and factor that value into cost/benefit evaluations. This would tend to support the implementation of programs that would appear to be less effective on a strict direct cost basis.
- **Resource Acquisition Approvals:** At present, PacifiCorp is required to seek approval from the Public Service Commission for the building or purchase of "significant energy resources" over 100 MW capacity (300 MW for renewables). (UT Code 54-17). An understanding of the externality value (or costs) of different types of resources may be used as part of the evaluation of competing generation resource types.
- **Regional air quality, water quality and greenhouse gas planning processes:** Utah actively participates and/or observes several concurrent environmental planning processes. These include the Western Regional Air Partnership (WRAP), the Western Climate Initiative (WCI), the Western States Air Resources Council (WESTAR), and various water quality planning efforts. Reducing environmental impacts from the generation of electricity will require

cooperation from several states to ensure that similar policy measures are consistently implemented. This report suggests that if California or other net consuming states in the WECC region reduce electricity imports, the quantity of Utah's fossil-fuel generation could be markedly decreased, with a positive impact on health and water in the state and downwind regions.

- **Internalizing social costs:** Regulatory rules designed to reduce emissions or water consumption effectively compel the internalization of currently external costs. The EPA's Clean Air Visibility Rule (CAVR) and recently adopted Best Available Retrofit Technologies (BART) guidelines set a social cost for reduced visibility and other externalities. [156] The rules, which require a reduction in emissions at older, large facilities, are an explicit mechanism designed to internalize social externalities by mitigating visibility and health impacts.
- **Costs and benefits of renewable and/or energy efficiency standards:** In March of 2008, Utah enacted The Energy Resource and Carbon Emission Reduction Initiative (S.B. 202), which sets a goal of 20% renewable energy provided to Utah customers by 2025.[157] States that have enacted specific renewable energy or energy efficiency standards (RPS or EES) have adopted the practice of estimating air emissions reductions from RPS (i.e. Massachusetts[158]). In Utah, there is an opportunity to include externalities and co-benefits in the consideration of cost effectiveness in meeting Utah's 20% goal.
- **Social costs of generation:** The co-benefits from energy efficiency and renewable energy investments can be applied broadly to topics beyond the IRP and SIP processes. Improvements in public health and air quality benefit the state's budget, saving healthcare costs, increasing visibility in cities and at natural monuments, and ultimately providing important climate benefits for future generations. This document can assist the state in avoiding significant economic impacts by recognizing externality costs and adopting policies to benefit Utahns, both in the near and long-term.

While this report details several opportunities for Utah to pursue that could improve energy and environmental planning, we emphasize that this report is not a plan per se, nor does it reflect currently internalized costs or a range of additional externalities. Prior to the adoption of specific policies, the state should engage in additional research and evaluation. This report serves to point out opportunities for significant benefits in Utah.

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[156] U.S. EPA. June 2005. Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations. Office of Air and Radiation. EPA-452/R-05-004. Available online at: http://www.epa.gov/visibility/pdfs/bart_ria_2005_6_15.pdf

[157] Energy Resource and Carbon Emission Reduction Initiative (March, 2008). State of Utah, S.B. 202. Available online http://le.utah.gov/~2008/bills/sbillenr/sb0202.pdf

[158] Massachusetts Renewable Portfolio Standard: Cost Analysis Report. December, 2000. Available online: http://www.mass.gov/Eoeea/docs/doer/rps/fca.pdf

8. Appendix A: Wholesale Natural Gas Prices

8.1. Introduction and Purpose

Synapse was requested to discuss and/or quantify the second-order economic benefits of preventing summertime generation using natural gas peaking units. The focus of this section was subsequently defined as a qualitative and/or quantitative analysis of the impact of new energy efficiency and renewable energy programs on natural gas prices.[159] These impacts are referred to as demand-reduction-induced price effects, or DRIPE. DRIPE is defined as the change in wholesale prices experienced by all consumers due to reductions in procurement of a commodity (either electricity or natural gas) by some consumers. DRIPE describes the elasticity of a supply price, given a change in demand.

In general, we postulate that reduced demand for natural gas in Utah from energy efficiency or renewable energy programs will have little impact on Utah or regional natural gas prices. This section presents a qualitative discussion of the drivers of the impacts of demand reductions on natural gas prices and why these drivers may not be directly relevant to Utah or the gas-serving region to which it is connected (known as the Central Region[160]). Context is provided on Utah's natural gas production, consumption, transport, and delivery systems, in order to substantiate this argument. We did not produce an accompanying quantitative analysis due to the fact that we have projected little impact in natural gas prices due to demand reductions.

8.2. Background

Studies that quantify the DRIPE effect for natural gas have generally been conducted at a national level or for deregulated states. In general, these studies have focused on non-gas producing states and/or states that have relatively high natural gas consumption, both of which are highly prone to market price impacts and thus have potentially high DRIPE effects. One of the most comprehensive and recent analyses, a 2005 analysis by Ryan Wiser et al. of the Lawrence Berkeley National Laboratory,[161] stated that the twelve studies evaluated all analyzed renewable portfolio standard (RPS) and energy efficiency proposals at a national level.[162] In addition, there are five known state and regional level energy efficiency analyses, but all were conducted for large gas

[159] These second-order economic benefits are indirect, but tangible costs which are recognized in normal economic analyses and ratemaking. Shifts in the price of natural gas due to changes in supply or demand are not considered externalities, and therefore savings due to EE or RE programs would not strictly be considered co-benefits in the context of this study.

[160] The Central Region gas market includes CO, IA, KS, MO, MT, NE, ND, SD, UT, and WY. See http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/central.html

[161] Ryan Wiser, Mark Bolinger, and Matt St. Clair. Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency. Lawrence Berkeley National Laboratory. LBNL-56756. January 2005.

[162] This includes five studies by the EIA, six studies by the Union of Concerned Scientists (UCS) and one study by ACEEE.

consuming states.[163] A study by the American Council for an Energy Efficient Economy (ACEEE), conducted in 2003 and updated in 2005 modeled three scenarios including (a) the impact of a national energy efficiency and renewable energy policy on the lower 48 states, (b) the impact of a national energy efficiency policy on the lower 48 states and (c) the impact of a Midwest policy on Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, Ohio and Wisconsin. [164,165] For all the studies conducted, none were conducted in the previously defined Central Region, or for a gas producing region with low consumption and high exports. Most other studies of natural gas price elasticity have mainly been conducted on the impact of supply shocks on demand, rather than the impact of demand shocks on supply. Although each of these studies did find a DRIPE effect, none of these studies is directly applicable to Utah or to the Central Region.

8.3. Natural Gas DRIPE Drivers and Variables

The price of natural gas is driven by a number of factors: the scarcity of supply relative to demand, the ability of this supply to reach market, and the demand for the supply. DRIPE describes only the process that occurs when demand slackens. Significant DRIPE will occur only if the reduction in demand is proportionally large relative to supply, or if the demand reduction occurs in a constrained system. The following section describes five factors that can drive changes in the price of gas relative to a baseline, and details why these factors are unlikely to apply in Utah. These factors include:

- Scale and connectivity of the regional and national natural gas markets
- Proportion of supply subject to market prices,
- Scarcity of supply,
- Transport constraints, and
- High demand

8.3.1. Scale and connectivity of the regional and national natural gas markets

One of the most important drivers of DRIPE is the size of the market that establishes the natural gas prices. Local changes in demand more effectively influence regional markets as compared to national markets, where the demand reductions can appear comparably small and can be easily offset by other market changes. In natural gas markets, the

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[163] This includes 1 study by the Tellus Institute for Rhode Island and 5 scenarios in the American Council for an Energy Efficient Economy (ACEEE) study including one for California, Oregon, and Washington; another for the northeast and mid-Atlantic regions; a third for New York; and a fourth for Texas.

[164] R. Neal Elliott, Ph.d., P.E. and Anna Monis Shipley. Impacts of Energy Efficiency and Renewable Energy on Natural Gas Markets: Updated and Expanded Analysis. Report Number E052. American Council for an Enegy Efficient Economy (ACEEE). April 2005.

[165] R. Neal Elliott, Ph.d., P.E., Anna Monis Shipley, Steven Nadel, and Elizabeth Brown. National Gas Price Effects of Energy Efficiency and Renewable Energy Practices and Policies. Report Number E032. American Council for an Enegy Efficient Economy (ACEEE). December 2003.

impact of DRIPE can be ambiguous because natural gas is traded on regional, national, and some international markets.

Much of the research to date suggests that the natural gas market is a national market, rather than a regional market. This is demonstrated by the fact that annual average regional wellhead price trends and annual average Henry Hub price trends are relatively well correlated. As a result, changes in regional demand caused by localized energy efficiency and renewable efforts do not have a large impact on natural gas prices for that region. To confirm whether or not this is true for Utah, we compared trends of annual average Utah wellhead prices and annual average Henry Hub prices (Figure 8-1).

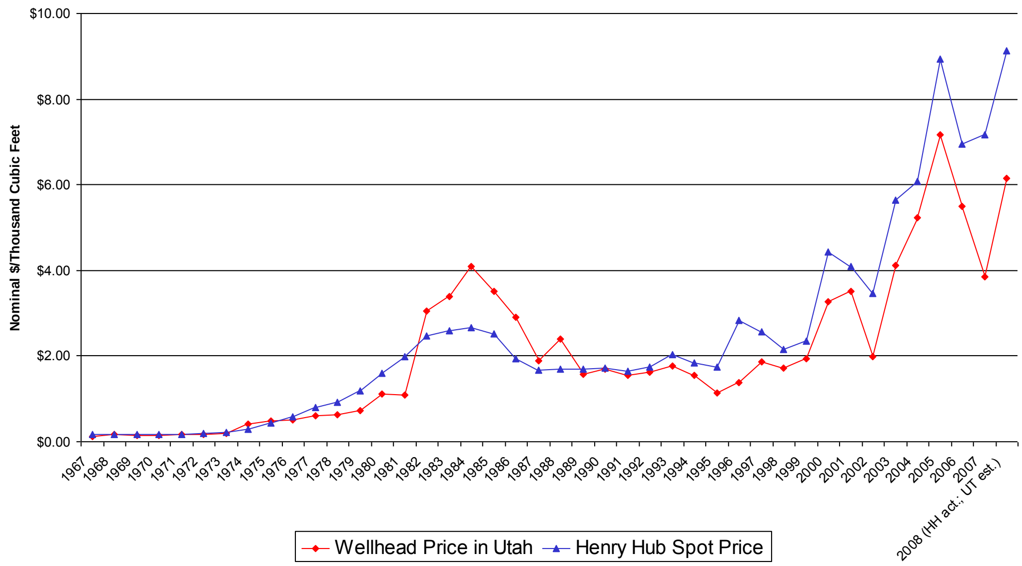

Figure 8-1: Comparison of Annual Average Utah Wellhead Prices and Annual Average Henry Hub Prices

Prior to the late 1990s, annual average Utah wellhead prices do not track annual average Henry Hub prices. This is due to the fact that Utah went from being a net importer of natural gas to a net exporter around this time. [166] However, since then, annual average Utah wellhead prices have tracked annual average Henry Hub prices. This indicates that regional fluctuations in usage would not be reflected in prices.

8.3.2. Proportion of Supply Subject to Market Prices

Another driver of DRIPE is the extent to which supply is subject to changes in market prices. If most of the supply is subject to changes in market prices (such as procured in a spot market), the price impacts will be larger. If most of the supply is procured at regulated prices or by long term contracts, the price impacts will be smaller.

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[166] Isaacson, Alan E. The Structure of Utah's Natural Gas Industry. Utah Economic and Business Review. University of Utah. Available at: http://www.bebr.utah.edu/Documents/uebr/UEBR2003/Nov-Dec%202003.pdf

There are some unique characteristics driving the price of Utah's natural gas supplies. The state's largest natural gas utility, Questar Gas, provides natural gas distribution services to almost 900,000 customers in Utah, southwestern Wyoming and southeastern Idaho. However, Questar Gas is unique in that it is one of the only utilities in the United States that also owns significant reserves of natural gas. "Historically, about half of the natural gas sold to Questar Gas retail customers comes from Questar-owned supplies that are typically more-stably priced than gas purchased from other suppliers." [167] As a result, Utah is more isolated from price shifts as compared to other states and regions.

8.3.3. Scarcity of Supply

A third important driver of DRIPE is the extent to which supplies are limited by inadequate supply that cannot meet demand. In cases where supply is limited, demand reductions are more effective at alleviating pricing pressures and the impact will be greater. In general, natural gas producing states do not have the supply limitations experienced by states that are not natural gas suppliers. For example, as demand increased in Utah in 2007 and 2008 due to the installation of natural gas electric generating plants, production increased as well, such that deliveries to other states were slightly increased (see Table 8-1).

Date	Utah Natural Gas Marketed Production (MMcf)	Utah Natural Gas Total Consumption (MMcf)	Utah Natural Gas Deliveries to Electric Power Consumers (MMcf)	% In-State Consumption by Electric Power Consumers
1997	257,139	165,253	4,079	2.5%
1998	277,340	169,776	5,945	3.5%
1999	262,614	159,889	6,478	4.1%
2000	269,285	164,557	10,544	6.4%
2001	283,913	159,299	15,141	9.5%
2002	274,739	163,379	15,439	9.4%
2003	268,058	154,125	14,484	9.4%
2004	277,969	155,891	9,423	6.0%
2005	301,223	160,275	12,239	7.6%
2006	348,320	187,399	28,953	15.5%
2007	376,409	219,687	56,438	25.7%

Table 8-1: Percent of In-State Consumption by Electric Power Consumers[168],[169]

These data indicate that, with some advance notice, Utah producers can adjust to meet changing demand conditions. If demand were reduced due to energy efficiency and renewables, Utah could simply deliver a greater proportion of its production out-of-state. If out-of-state requirements were steady or decreasing, Utah producers could simply produce less in order to maintain prices. A reduction in prices would not be observed for either of these scenarios.

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[167] Questar Gas website. Available at: http://www.questargas.com/AboutQGC.php (8/5/09)
[168] Utah Natural Gas Marketed Production by End Use. Available at: http://tonto.eia.doe.gov/dnav/pet/hist/n9050ut2a.htm
[169] Utah Natural Gas Consumption by End Use. Available at: http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_sut_a.htm

8.3.4. Transport Constraints

A fourth driver of DRIPE is the extent to which limitations exist in transporting excess supply to areas of higher demand. If excess supply cannot be transported to areas of higher demand, supply shortages relative to demand will drive prices up. Demand reductions will be more effective at reducing prices if this pressure exists.

Utah is part of the Central Region natural gas production and distribution network that also includes Colorado, Iowa, Kansas, Missouri, Montana, Nebraska, North Dakota, South Dakota, and Wyoming. The states in this region are interconnected with twelve interstate natural gas pipeline systems that enter the region from the south and east and four that enter the region from the north carrying Canadian supplies. Interstate pipeline systems that are interconnected in Utah include: the Kern River Pipeline originating in Wyoming and traveling through Utah to Nevada; the Northwest Pipeline running between Utah and Idaho; the Questar Pipeline running from Utah to Wyoming; and the Colorado Interstate Gas Pipeline running from Utah to Colorado. In addition, more pipelines have been added in the Rocky Mountain region to allow natural gas to be transported to the Midwest and West Coast, forging a more integrated system between the Rockies and the rest of the country.

Historically, Utah delivery of production out-of-state has been constrained. However, the capacity of pipelines that were operating with constraints throughout the 1990s and early 2000s has been expanded over time. More than 14 billion cubic feet per day of interstate natural gas pipeline capacity was added in the Central Region between 1998 and 2008 (see Figure 8-2). Additionally, new pipelines have been constructed to connect new sources of supply to existing pipelines and facilitate interstate transport. Approximately 6 bcf per day of new intrastate pipeline was built in the Central Region between 1998 and 2008 to transport gas to the Midwest and West. While these expansions and additions have not alleviated all of the constraints, and further expansion will be required in the future, the expansions and additions have been increasing the region’s ability to transport supply throughout the region as well as out of this region to other markets.

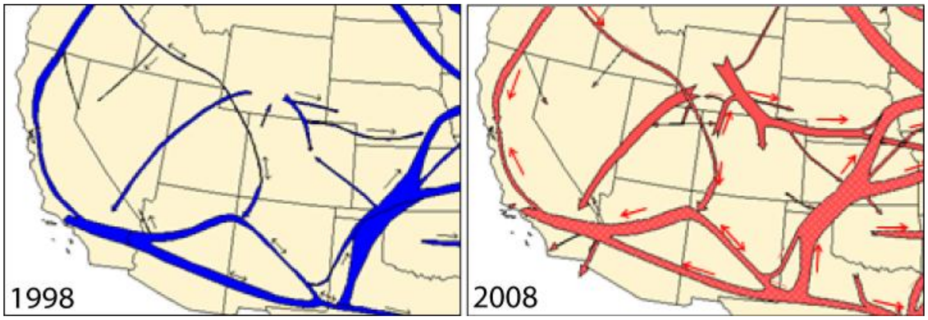

Figure 8-2: Comparison of Natural Gas Pipeline Systems in 1998 and 2008 [170]

In summary, as natural gas demand has increased, pipeline capacity has been expanded or constructed to accommodate the need to transport gas from producing areas to markets. As a result, it is unlikely that a significant price reduction would be observed in Utah due to reductions in natural gas consumption in the state. Any additional supply would be delivered out of state to expanding Midwest or West markets. Since pipeline constraints can be alleviated, it is unlikely there would be much of a gap between the reduction and the associated increase in pipeline capacity to accommodate increased out-of-state deliveries.

8.3.5. High Demand

A fifth driver of DRIPE is the extent to which demand is high. If demand is high, it is less likely that the supply will be able to meet the demand, thus driving prices up. Demand reductions in areas of particularly high demand can help bring demand more in line with supply and reduce prices. However, the Central Region does not have particularly high demand as compared to other parts of the country. The region currently consumes less natural gas than it produces and is a net exporter of natural gas.[171]

It is noteworthy that consumption by natural gas electric generating plants in Utah did double between 2005 and 2006 and further increased by approximately 65% between 2006 and 2007. The increases were due to the following:

- The addition of the Current Creek combined cycle plant that became operational in two stages in 2005 and 2006,
- the addition of the Mill Creek Generating Station unit for the City of St. George in 2006; and,

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[170] Major Changes in Natural Gas Transportation Capacity, 1998-2008. Prepared by James Tobin, Office of Oil and Gas. EIA. November 2008. Available at: http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/comparemapm.pps

[171] EIA. About U.S. Natural Gas Pipelines - Transporting Natural Gas. Natural Gas Pipelines in the Central Region. Available at: http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/central.html (8/5/09).

- the addition the Lake Side Generation Station which came online in 2007.[172]

As a result, consumption increased from 2.5% in 1997 to 25.7% in 2007. However, the proportion of in-state consumption relative to production remained relatively stable due to increases in production.

Other states in the region are experiencing this trend as well. However, since production is able to adjust with demand, no significant changes in the price due to reductions in demand due to energy efficiency and renewable efforts would be expected. In fact, continued expansions in natural gas generation may offset any reductions due to energy efficiency and renewables and result in stable use over the next decade. Utilities are very likely to build additional gas generating stations in this region in the near future.

8.4. Conclusions

Natural gas price impacts due to demand reductions from energy efficiency and renewables in Utah will not be substantial at this time. Natural gas is priced on a national market. With low consumption relative to other regions of the country, demand reductions in the Central Region will not be significant enough to impact the national market. Marginal changes in gas consumption due to displacement by renewable energy or energy efficiency will not substantially change medium to long-term price signals in Utah or its interconnected region.

Although it was not the focus of this analysis, we would be remiss if we did not mention that natural gas price impacts due to demand reductions from national energy efficiency and renewables efforts, or potentially carbon mitigation policies, could be substantial. It is not clear what impact a national reduction in the consumption of natural gas would be on natural gas prices in Utah.

[172] Utah Geological Survey. Table 5.16.a: Natural Gas-Fired Electricity Generation in Utah by Utility Plant, 1990-2007. Available at:
http://geology.utah.gov/emp/energydata/statistics/electricity5.0/pdf/T5.16a.pdf

9. Appendix B: Regional Haze Impacts and Research

9.1. Introduction and Purpose

The dramatic and iconic vistas present in Utah's urban and wilderness areas provide significant economic benefits to the state. The degree to which this benefit is realized is highly dependent on the visual experience of visitors and residents of the state; therefore maintaining good visibility is of economic importance to Utah.

Regional haze, caused by both natural and human-caused (anthropogenic) sources located both in-state and upwind, can and does episodically impair visibility for residents and visitors in Utah. Natural sources include rain, wildfires, volcanic activity, sea mists, and wind blown dust from undisturbed desert areas. Anthropogenic sources of air pollution may include industrial processes, (electric power generation, smelters, refineries, etc.), mobile sources (cars, trucks, trains, etc.) and area sources (residential wood burning, prescribed burning, wind blown dust from disturbed soils). The economic and environmental impacts from regional haze that can be attributed to Utah power-sector emissions is an externality of electric generation, and any amount that these haze impacts may be mitigated by new energy efficiency or renewable energy programs would be a co-benefit of those programs.

For the purposes of this analysis, the externality cost of regional haze attributable to power generation is not characterized. While there is a base of literature examining the economic implications of good visibility in natural areas, such as Utah's extensive public lands and National Forests and Parks, the degree to which regional haze and poor visibility in Utah can be attributed to Utah power generation is as of yet unclear. In addition, new rules promulgated by the US EPA strive to reduce regional haze formation at National Parks and other high-value public lands through emissions controls. If electric power generators in Utah are required to apply emissions controls to reduce haze, and visibility is improved as a result, this particular external cost may be successfully internalized.

This section reviews the economic impact of poor visibility in general, the impact of haze in areas such as Utah's parks and urban areas, the components and complexities of haze, and the current rules promulgated by the EPA to internalize the social costs of haze through emissions controls.

9.2. The Social Cost of Regional Haze and Reduced Visibility

Several researchers and the US EPA have attempted to evaluate the economic impact of poor visibility in urban areas and in natural areas. In the West, there is particular interest in achieving improved air quality in parklands where visitation often depends on good visibility. Reduced visibility has an economic impact in recreation where visitation numbers may drop if expansive views are unavailable. Low visibility also implies poor air quality (and associated health consequences), and may, to some extent, drive housing prices or interest in living in areas with better air quality. Economists have developed two methods of evaluating the social cost of visibility:

- *Hedonic price analyses* in residential areas examine how housing prices vary statistically with air quality, amongst a range of other variables. Studies are typically conducted over a locality where there is a clear gradient of air quality or visibility, as well as other housing price drivers. These studies are not able to necessarily distinguish the price differential due to a preference for better visibility from a preference for healthier air quality.
- *Contingent valuation* surveys individuals with a hypothetical trade-off between fixed price commodities and less tangible values, such as visibility. Individual willingness-to-pay is determined directly from survey results.

A meta-analysis in 2002 estimated the social valuation of air quality health and visibility from a hedonistic price analysis of housing prices.[173] The study used compiled results from 37 studies, and, based on 1990 air quality and housing prices, estimated that the poor health and visibility cost between $46-$77 billion (1991$). Citing other researchers, the study estimated that $7-$27 billion (1991$), or 15-35% of this cost could be attributed to visibility concerns or aesthetics, while the remainder was due to concerns of health, soiling, or other impacts.

The social cost of regional haze has resulted in dramatic regulation aimed at internalizing the cost of haze by controlling pollution. In 1991, Congress created the Grand Canyon Visibility Transport Commission to find mechanisms to improve air quality at the Grand Canyon and other locations on the Colorado Plateau, which includes all of Utah's National Parks. Amongst other recommendations in the resulting 1996 report, the commission suggested preventing air pollution by monitoring and potentially regulating stationary sources, as well as promoting renewable energy and increased energy efficiency.[174] In 1999, those regulations were promulgated by the EPA in the Regional Haze Rule and the Guidelines for Best Available Retrofit Technology (BART), recognizing that the burden of retrofitting high emissions sources was outweighed by the social benefit of controlling air pollution. In 2005, the EPA estimates that the rule will provide about $240 million (1999$) in improved visibility benefits each year, while preventing $8.4-$9.8 billion of heath impacts, including premature deaths. The rule is estimated to cost approximately $1.4-$1.5 billion annually (1999$).[175]

When the financial implications of the BART rule were analyzed in 2005, the EPA chose to use a contingent valuation method to estimate the recreational cost of haze.[176] The

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[173] Delucchi, M.A., J.J. Murphy, D.R. McCubbin. 2002. The health and visibility cost of air pollution: a comparison of estimation methods. *Journal of Environmental Management.* 64:139-152.
[174] Report of the Grand Canyon Visibility Transport Commission to the United States Environmental Protection Agency. June 1996. Available online at http://www.wrapair.org/WRAP/reports/GCVTCFinal.PDF
[175] Fact Sheet – Final Amendments to the Regional Haze Rule and Guidelines for Best Available Retrofit Technology (BART) Determinations. Available online at http://www.epa.gov/visibility/fs_2005_6_15.html
[176] Chestnut, L.G., and R.D. Rowe. 1990a. Preservation Values for Visibility Protection at the National Parks: Draft Final Report. Prepared for Office of Air Quality Planning and Standards, U.S. Environmental

study estimated the demand for visibility in National Parks in California, the Southwest, and the Southeast through a survey of individuals in five states. There are a number of caveats and assumptions in this type of study related to (a) how individuals choose to characterize their own preferences versus the preferences of others, (b) the distinction (or lack thereof) between aesthetic valuation and concern for associated health impacts of poor air quality, and (c) the visibility value of the particular areas featured in the survey. Extrapolating the results of this survey to all Class 1 areas (National Parks and other high value public lands), the EPA determined that the implementation of the Clean Air Visibility Rule (CAVR) would result in benefits of $84-$240 million (1999$), annually.[177] The map in Figure 9-1 shows the distribution of some of these benefits in the Class 1 areas examined by the valuation study.

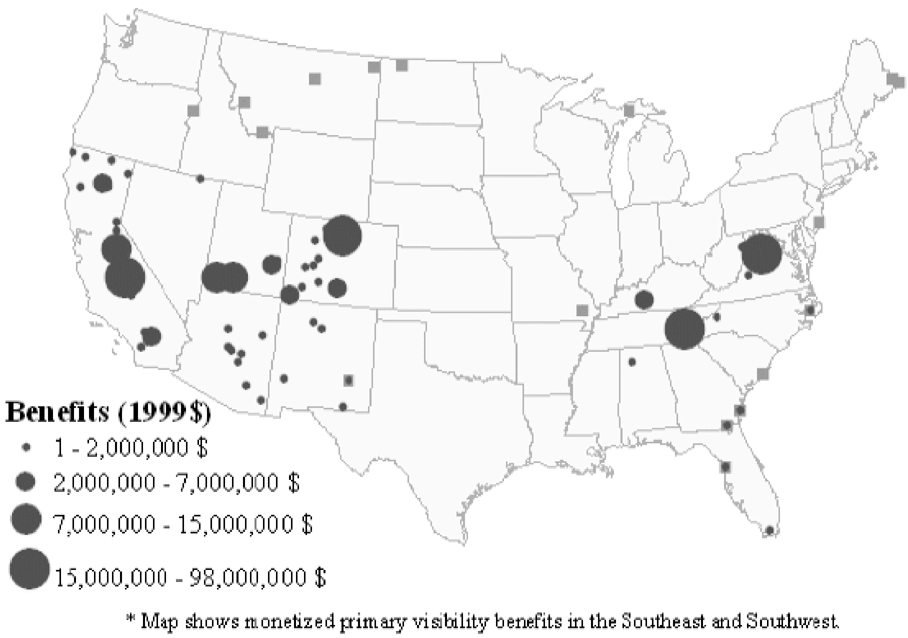

Figure 9-1: EPA estimated benefits of the Clean Air Visibility Rule in Class 1 areas in five states. Benefits are in 1999$.[177]

While the valuation of visibility is feasible, linking poor visibility and regional haze to specific emissions sources requires complex models, unavailable for this preliminary study. Delucchi *et al.* (2002, referenced above) estimates that visibility concerns are 21%-50% as valuable as health (from a social cost standpoint). In the context of this study, we do not attempt to value visibility impacts in Utah.

Protection Agency, Research Triangle Park, NC and Air Quality Management Division, National Park Service, Denver, CO.

177 U.S. EPA. June 2005. Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations. Office of Air and Radiation. EPA-452/R-05-004. Available online at: http://www.epa.gov/visibility/pdfs/bart_ria_2005_6_15.pdf

9.3. Regional Haze in Utah

Haze in Utah impacts both local areas and wide regions encompassing national parks and other wilderness areas in the state. The following section details haze impacts in Class 1 (public lands) regions and along the Wasatch front.

9.3.1. Class I Regions

The Clean Air Act defines mandatory Class I Federal areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence as of August 1977.[178] Regional haze regulations have the goal of improving visibility in the 156 "Class I" areas across the US.

In Utah, there are a total of five national parks that meet the Class I criteria. These parks are:

- Arches National Park (65,098 acres)
- Bryce Canyon National Park (35,832)
- Canyonlands National Park (337,570)
- Capitol Reef National Park (221,896)
- Zion National Park (142,462)

These parks in 2008 saw approximately 5.2 million visitors.[179] In 2005, Utah and the National Park Service signed a memorandum of understanding that recognized the importance of regional solutions to improve visibility in Class I areas.[180] Predicting the timing and magnitude of regional haze affecting Class I regions would require atmospheric transport models that go beyond the scope of the current project. However, Federal regional haze regulations allow states to develop coordinated strategies and implement programs to make reasonable progress toward the goal of "no manmade impairment" in national parks and wilderness areas by reducing emissions that contribute to haze.[181]

Figure 9-2 below shows two photos taken from the same location on days which are clear (left) and hazy (right).

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[178] http://www.law.cornell.edu/uscode/html/uscode42/usc_sec_42_00007472----000-.html
[179] http://travel.utah.gov/research_and_planning/visitor_statistics/2008yearendind.htm
[180] http://home.nps.gov/applications/release/Detail.cfm?ID=564

181 http://www.epa.gov/oar/vis/facts.pdf

Figure 9-2: Visibility in Bryce Canyon National Park on a clear day and a hazy day. Source: EPA

9.3.2. Wasatch Range

The Wasatch Front region is bounded to the North by the city of Ogden, and to the South by the City of Provo.[182] This 80 mile long region is located in a valley that is bounded by Wasatch Range to the east and the Oquirrh mountains to the southwest of Salt Lake City.

With population of 1.7 million in the region, the Wasatch Front region contains approximately 75% of the state's population.[183] Haze in the Wasatch Front region affects residents and vsisitors to the most populous region of the state. Meteorology, geography, and pollution form the basis for visibility impairment in the Wasatch Front region. Haze affecting the natural vistas within the state impact the enjoyment of scenic beauty of the Utah landscape by visitors. Because this reduction can significantly reduce the enjoyment of vistas, and it may influence the decision to return that can have a significant local economic impact. With 20 million visitors to the state and a $6 billion industry, tourism is a significant component to the Utah economy.[184] Local and regional pollution from stationary sources and regional transport form the basis of visibility impairment of the landscape.

In the absence of pollution, the natural visual range is approximately 140 miles in the West and 90 miles in the East. However, pollution has significantly reduced the natural visual range. In the West, the current range is 33-90 miles, and in the East, the current range is only 14-24 miles.[185]

9.4. Components of Regional Haze

Haze is made up of numerous small particles suspended in the air, known as aerosols. Small particles, less than 0.05 microns, interfere with visibility by scattering light in random directions. The physics of Rayleigh scattering preferentially interferes with blue light. [186] For example, smoke, which is made up of numerous fine particles as well as

[182] http://www.saltlakecityutah.org/salt_lake_demographics.htm
[183] http://www.edcutah.org/files/Section3_Demographics_09.pdf (p.3.2)
[184] Utah Office of Tourism- Annual Report. May 14, 2008.
[185] US EPA. 2009. Visbility: Basic Information. http://www.epa.gov/visibility/what.html
[186] Hinds, W., "Aerosol Technology Properties, Behavior, and Measurement of Airborne Particles." John Wiley & Sons, New York. 1999 (p.349)

larger ash particulates, appears bluish in direct light as the particles reflect blue light back to the viewer. However, if backlit, the same smoke takes on an orange tone because the blue components of light are scattered away from the viewer.

Larger particles, up to 2.5 microns ($PM_{2.5}$) scatter and refract light in many wavelengths. Smaller particles (0.1 to 1 micron), however, are closer in size to the wavelengths of visible light. Blue light bends and scatters around these small particles, giving a bluish and hazy look to front-lit landscapes (i.e. the sun behind the observer), and orange sunrises and sunsets. The light scattering ability of different particle sizes results in the different visual appearance of haze seen by an observer.

Small particles stay suspended in the atmosphere, and thus persist for longer time periods and over longer distances than larger particles. Haze is defined on a regional basis, rather than as a state or local issue, because small particles can be transported over extremely long distances and impact visibility in remote locations, while coarser particles tend to be deposited closer to their source and are more likely to impact local conditions. Haze may be realized in at least three different forms: intrusive plumes from local smokestacks, low-lying inversion layers that are often found around urban areas, and regional haze that obscures the view in all directions. Each of these forms of visibility impairment is a function of the nature and source of emissions and the prevailing meteorological conditions.

Fine particles may contain a variety of chemical species including organic and elemental carbon, ammonium nitrate, sulfates, and soil. Each of these components can be naturally occurring or the result of human activity. The natural levels of pollutant species will result in some level of visibility impairment that, in the absence of any human influences, will vary with season, meteorology, and geography. A significant difficulty with valuing individual contributions to regional haze is that natural levels of haze vary significantly over time, and even the formation of fine aerosols from anthropogenic sources can depend on natural phenomena, such as sunlight, temperature, and volatile organic compounds (VOC) from plants.

Pollutants commonly associated with haze formation include the following:

- **Carbon** in the form of particulates or volatile organic compounds may be emitted from both stationary and mobile sources, and organic compounds in soil. Elemental, or black, carbon contributes to visibility impairment because it readily absorbs light. The contribution of absorption by elemental carbon is generally less than 10 percent of the loss in transmission radiance. [187]
- **Sulfur Dioxide** is especially important because it contributes to the formation of sulfates, that often dominate other causes of visibility impairment, particularly in eastern states.[188] Anthropogenic sources of sulfur dioxide are predominantly

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[187] Malm, W. Introduction to Visibility. Cooperative Institute for Research in the Atmosphere (CIRA), NPS Visibility Program, Colorado State University. May 1999.
[188] Abt Associates. Out of Sight: The Science and Economics of Visibility Impairment. Prepared for the Clean Air Task Force, August 2000.

from electricity generation, fossil fuel combustion, and industrial processes.[189] Once in the atmosphere, sulfur dioxide forms sulfates, which can also lead to acidic rain.

- **Nitrogen dioxides** are found in emissions from cars, trucks and buses, power plants, and off-road equipment.[190] NO_2 gas impairs visibility, and the gas reacts with VOCs to create ground-level ozone and fine particulates.

The federal government tracks haze constituents and visibility in 156 Class I areas across the country. The Interagency Monitoring of Protected Visual Environments (IMPROVE) dataset, available from 1985 through 2003 contains detailed information on multiple constituent properties, as well as visibility metrics. [191] Although the IMPROVE data solely focuses on Class I regions, the information available illustrates the level of detail to adequately monitor constituent pollutants that contribute to haze observed in Class I areas that are generally not near local sources of pollutants.

The IMPROVE data do not contain information to determine source apportionment. However, the Western Regional Air Partnership (WRAP) has conducted an analysis using the IMPROVE dataset to apportion sources in broad categories through its Tagged Species Source Apportionment and Trajectory Regression Analysis models.[192] Figure 9-3 and Figure 9-4 detail the source apportionment of emission and source categories for Utah emissions in 2002.[193] Figure 9-3 and Figure 9-4 show apportionment of major constituents in Utah as of 2002, as determined by WRAP. Left-hand columns show human-caused (anthropogenic) sources, while the right-hand columns show natural sources.

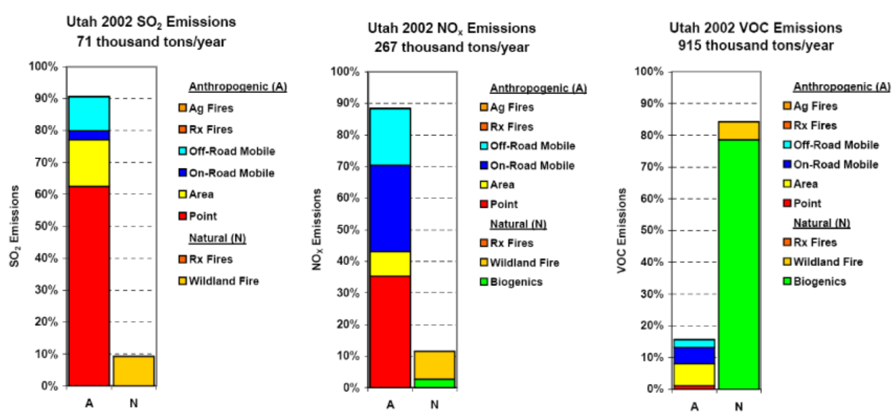

Figure 9-3: Apportionment of criteria air pollutants in Utah, 2002. Western Regional Air Partnership Data [194]

[189] http://www.epa.gov/air/emissions/so2.htm
[190] http://www.epa.gov/air/emissions/nox.htm
[191] http://vista.cira.colostate.edu/improve/
[192] http://www.wrapair.org/forums/aoh/index.html
[193] Data available at http://www.wrapair.org/forums/aoh/ars1/state_reports.html
[194] Source Western Regional Air Partnership (2002 Inventory)

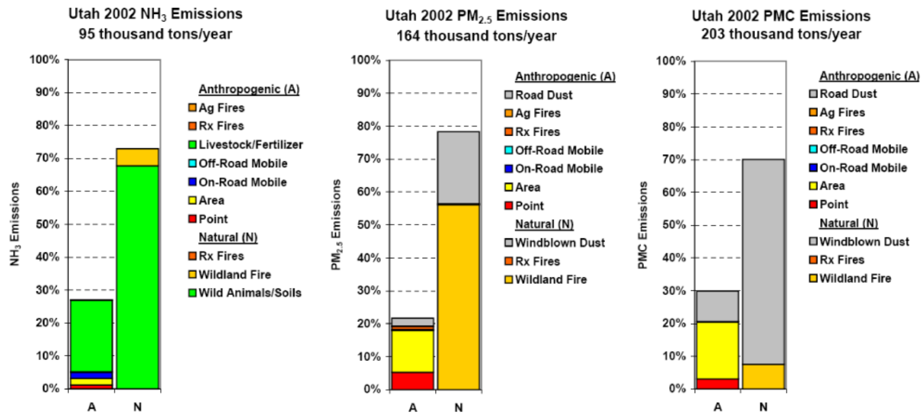

Figure 9-4: Apportionment of criteria air pollutants in Utah, 2002. Western Regional Air Partnership Data [195]

While the figures show clear differences between anthropogenic and natural contribution, the major sources of pollutants are not always anthropogenic sources. For instance, sulfur dioxide and nitrogen dioxide show clear anthropogenic contributions. In Utah, of the approximately 71,000 tons of SO_2 release in state, approximately 90% were from anthropogenic sources in 2002. Data from this study's analysis, shown in Figure 9-3 indicates that in the reference case, approximately 24,000 tons of sulfur dioxide are released annually by electric generation plants burning coal.[196] Although the data sets are different from the WRAP analysis and the probabilistic electric model, it is clear that a significant reduction in pollutant emissions from the electric generating sector will result in the reduction of pollutant levels associated with haze. On the other hand, the approximately 203,000 tons of elemental carbon released in 2002 was about 70% from natural sources. Meteorological and pollutant transport issues will still influence the formation of haze within the state.

9.5. Internalizing the Cost of Haze

Apportioning the specific point sources of haze in Utah is a complex task, requiring models of transport, as well as estimates of natural and anthropogenic causes of haze. Utah would require a comprehensive model of the formation of haze in Utah, and a determination of which population exposures are to be evaluated as an externality.

Attaching a value to haze in Utah requires estimating the social cost of visibility and other components (excluding health, which is estimated separately as a damage function). This value may be significantly different for residents of Utah and for visitors to Utah. Local residents are concentrated at the foot of the Wasatch Range and are

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[195] Source Western Regional Air Partnership (2002 Inventory)
[196] For NO_x, the Synapse reference case estimates annual emissions of approximately 68,800 tons from coal-fired generation. The WRAP Utah emission inventory for NO_x is 267,000 tons, of which point sources represent approximately 93,400 tons of emission. While not a perfect comparison, the data suggests that controlling NO_x emissions from coal-fired generation will have a beneficial impact to the amount of NO_x released within the state.

exposed to both locally generated smog as well as regional haze, and experience a cost as a preference for clear air and a perceived health benefit. Visitors to Utah prefer high visibility in natural areas, and may choose to exercise leisure dollars elsewhere if visibility remains low. Ultimately, Utah may have to determine if the preference of visitors to Utah has an economic impact on the state, and if so, how to estimate the ripple effects of those preferences through the Utah economy.

If these two steps were executed, Utah could estimate the externality associated with poor visibility and a reduced aesthetic from power generation in the state. An avoided energy analysis, similar to that conducted in the remainder of this study, could be used to determine how much haze, and therefore what value could be attached to a reduction in conventional generation.

However, these steps may be supplanted to some degree by EPA rules governing haze and the emissions associated with haze. As noted earlier in this section, in 1999 the EPA promulgated rules designed to reduce haze through emissions controls on older, large stationary sources. The EPA rules were followed up with a more recent analysis of the costs and benefits of these emissions reductions, which found that the preference for healthy air and high visibility exceeded the cost of retrofitting existing generators. A series of amendments in 2005 finalized the 1999 regional haze rule. A series of power generators will be required under this regulation to install best available technologies to control emissions which cause haze. By promulgating and enforcing this rule, the EPA will force the internalization of the cost of visibility. According to the EPA analysis of this rule, the cost of reducing emissions is significantly less expensive than the social cost of haze.

10. Appendix C: Displaced Emissions, Background

There have been a number of methodologies proposed to calculate near-term indirect emissions displacement, from simple estimates based on average emissions rates to full dispatch modeling efforts. This appendix details other methods used to estimate displaced emissions, a critical element for estimating the health externalities and co-benefits of energy efficiency and renewable energy.

10.1.1. EPA Power Profiler and Green Power Equivalency Calculator

At the national scale, the EPA publishes two calculators, one to estimate an emissions footprint for consumed electricity and the other to estimate avoided emissions for renewable energy purposes. The footprint calculator, Power Profiler,[197] estimates the consumption mix for local distribution companies (LDCs) and the equivalent emissions from that generation. The footprint is not a displaced emissions estimator, but is often used for the purpose by third parties.

The avoided emissions calculator, the Green Power Equivalency Calculator,[198] is meant to calculate emissions avoided by the purchase of green power on a regional scale. It operates by estimating the “non-baseload emissions rate”. This emissions rate is based on the resource type and capacity factor of each electrical generating unit (EGU). It ignores all non-emitting generation (as it is usually very inexpensive to generate) and all baseload generation, or EGU which have capacity factors greater than 80%. The non-baseload emissions rate is calculated as the emissions rate of each included EGU, weighted by the capacity factor, with smaller capacity factors receiving greater weight.[199]

An average regional emissions rate (er_{avg}) would be calculated as follows:

$$er_{avg} = \sum_{i=1}^{n} E_i \Big/ \sum_{i=1}^{n} G_i$$

Where the emissions rate (er_{avg}) is equal to the sum of the emissions (*E*) of all generators (*i*) divided by the sum of the generation (*G*) of all generators.

The EPA non-baseload emissions rate (er_{nbl}) is calculated similarly, but counting only fossil generators with capacity factors (*c*) below 0.8. Note that generators with capacity factors below 0.2 receive a weight (*w*) of one.

$$er_{nbl} = \sum_{i=1}^{n} (w_i E_i) \Big/ \sum_{i=1}^{n} (w_i G_i)$$

$$w_i = 1 - \frac{(c_i - 0.2)}{1 - 0.8}$$

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197 US Environmental Protection Agency. February 19, 2009. Power Profiler. http://www.epa.gov/cleanenergy/energy-and-you/how-clean.html

198 US Environmental Protection Agency. February 17, 2009. Green Power Equivalency Calculator. http://epa.gov/grnpower/pubs/calculator.htm

199 US Environmental Protection Agency. April 27, 2009. eGRID Users Manual. http://www.epa.gov/cleanenergy/documents/egridzips/eGRIDwebV1_0_UsersManual.pdf

The non-baseload emissions rate assumes that capacity factor is a reasonable proxy for loading order, and that larger units near the margin will contribute more to the marginal emissions rate.[200] This method of estimating a displaced emissions rate can be applied only as an annual estimation.

10.1.2. MIT Hourly Marginal Emissions Rate

In 2004, the Laboratory for Energy and the Environment at the Massachusetts Institute of Technology (MIT) published a research paper estimating emissions reductions from solar photovoltaic (PV) systems.[201] The researchers postulated that rather than using the fraction of generation that an EGU contributes to electrical generation, units which ramp up or down with increasing or decreasing system load could be defined as units which are marginal. Using historical hourly data collected by the US EPA's Clean Air Markets Division dataset (CAMD, discussed in depth in section 3.3.1), the researchers devised a complex methodology of determining which units were operating on the margin. The hourly average emissions rate from these units were taken as the hourly marginal emissions rate, or the displaced emissions rate for new RE or EE. This paper was amongst the first to suggest that the marginal emissions rate can change dramatically over time depending on the season and other exogenous variables.

10.1.3. Synapse/EPA Hourly and Annual Marginal Emissions Rate

In 2008, Synapse Energy Economics was contracted by the EPA to explore and validate options for estimating the marginal emissions rate, including using hourly methods, using only publically accessible data; a report was published in 2008.[202] The researchers explored several methods of estimating the marginal emissions rate from the CAMD dataset, and concluded that two were equally appropriate for different circumstances.

The first methodology is the regional annual average marginal emissions rate, termed the "emissions slope factor", which is simply the slope of the line fit to hourly gross generation and emissions (see Figure 10-1). The slope reflects the change in emissions per unit change in generation, on average, but does not capture hourly behavior or non-linear relationships. This method is a reasonable estimator for medium-term displaced emissions, or for estimating displacement from non-stochastic measures (such as geothermal sources or energy efficiency).

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[200] In the non-baseload emissions rate estimation, if there are two units with equal capacity factors but different capacities, the larger unit will contribute more to the displaced emissions rate than the smaller unit. If the larger unit is twice the capacity, its emissions rate will count for twice that of the smaller unit.

[201] Connors, S., K. Martin, M. Adams, E. Kern, and B Asiamah-Adjei. 2005. "Emissions Reductions from Solar Photovoltaic (PV) Systems" Publication MIT LFEE 2004-003 Report.

[202] Hausman, E., J. Fisher, B. Biewald. 2008. Analysis of Indirect Emissions Benefits of Wind, Landfill Gas, and Municipal Solid Waste Generation. US EPA, National Risk Management Research Laboratory, Air Pollution Prevention and Control Division. http://www.epa.gov/nrmrl/pubs/600r08087/600r08087.pdf

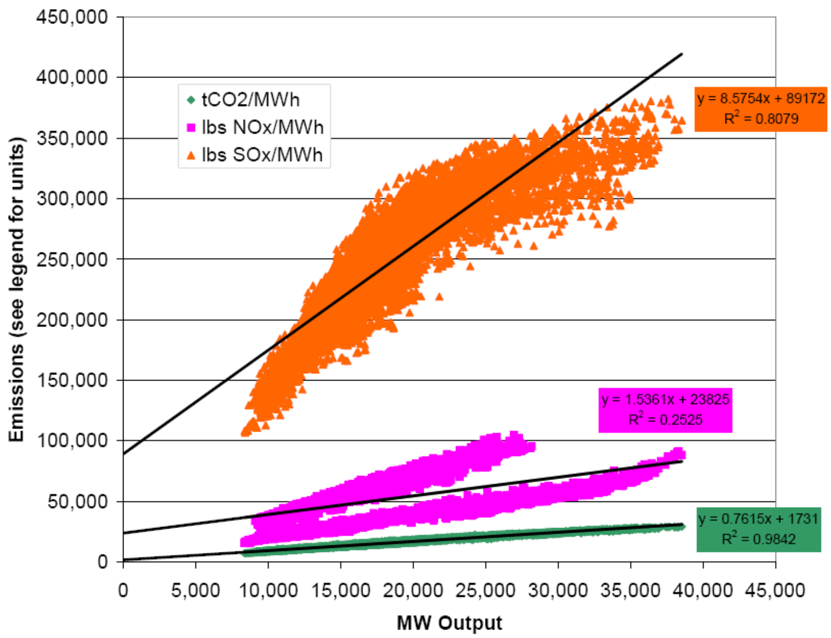

Figure 10-1: The regional Emissions Slope Factor in the RFCE (Reliability First/Central) region. Total emissions of CO2, NOx and SO2 vs. MW output for each hour of 2005 are shown. A linear line of best fit is calculated for each pollutant, and the slope of this fit determines the annual slope factor for the region. The bifurcation of the NOx data reflects the differential operations of pollution control equipment during the ozone (summer) vs. non-ozone seasons. Source: Hausman et al., 2008 (Synapse/EPA).

The second methodology strives to capture instantaneous changes in the system based on historical behavior for a reference year, following precepts introduced by the MIT research (see above). The "flexibility-weighted hourly average emissions rate" is built on the premise that each unit has an intrinsic flexibility, determined by its ramp rate and economics relative to all other generators in its region. EGU which frequently respond to changes in load by ramping up or down have a higher flexibility, while baseload EGU rarely change output. At each hour (t), the marginal emissions rate ($er_{flex,t}$) is the average emissions rate of all units (i) online in that hour, weighted by the flexibility index (F_i).

$$er_{flex,t} = \sum_{i=1}^{n}(F_i er_i) \Big/ \sum_{i=1}^{n} F_i$$

The flexibility index is calculated as the number of hours (N) that a unit is ramping divided by the number of hours in operation. Ramping (up or down) is defined as a unit changing its gross generation by at least 2.5% of its maximum generation in one hour.

$$F_i = N_{ramping,i} / N_{operating\,i}$$

The flexibility-weighted hourly average emissions rate is taken as a reasonable proxy for the displaced emissions rate for new, stochastic renewable energy or demand response programs, where it is highly likely that only marginal units will respond to changes in load. This method has also been used to estimate the marginal emissions rate of wholesale markets.[203]

10.1.4. Connecticut DEP/EPA

The Connecticut DEP and US EPA contracted with Synapse to examine the impact of energy efficiency programs on emissions reductions in Connecticut from 2009 to 2020. Researchers developed a displaced generation and emissions model based on the CAMD dataset and tested several energy efficiency scenarios, as well as the implementation of rigorous emissions control technologies, to determine the combination of EE and emissions controls required to meet increasingly rigorous state air quality standards. Unlike historical-only estimations, the model needed to estimate future changes in demand and generation, including possible new generators and generator retirement. Synapse developed the Load-Based Probabilistic Emissions Model (LBPEM), which is the basis of the current research.

10.1.5. Dispatch Models

The most comprehensive method of estimating displaced emissions is by using a transmission-constrained dispatch model, explicitly calculating the most economic mix of generation (and associated emissions) based on constraints of transmission, ramp rates, and other operating parameters. These models are generally proprietary, complex, and expensive to run. Nonetheless, there are examples of dispatch models used for the purposes of estimating displaced emissions.

In 2002, Synapse compiled a displaced emissions calculator based on dispatch model runs for the Ozone Transport Commission (OTC).[204] Outputs from the runs were used to determine the marginal units, and thus the marginal emissions rate. The calculator allows users to estimate emissions saved from load control and new renewable energy.

In 2008, the National Renewable Energy Laboratory (NREL) ran a series of dispatch models for the US West designed to estimate the impact of high penetration PV on all resource generation and fossil emissions.[205] The research found that new PV primarily displaced gas throughout the West, only impacting coal generation at high penetrations. Hydroelectric generation remained unchanged on net, but shifted temporally to accommodate large amounts of peaking solar generation.

Using dispatch models can be a highly effective mechanism for determining displaced generation and emissions from energy efficiency and renewable energy, but these models are often prohibitively expensive for non-commercial entities.

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[203] Hausman, E. J Fisher, L Mancinelli, B Biewald. 2009. Productive and Unproductive Costs of CO_2 Cap-and-Trade: Impacts on Electricity Consumers and Producers. Synapse Energy Economics. Prepared for NARUC, APPA, NASUCA, and NRECA. http://www.synapse-energy.com/downloads/cap-and-trade.pdf

[204] Keith, G., D White, B Biewald. 2002. The OTC Emission Reduction Workbook 2.1: Description and User's Manual. Prepared for the Ozone Transport Commission.

[205] Denholm, P., R. Margolis, J. Milford. 2009. Quantifying Avoided Fuel Use and Emissions from Solar Photovoltaic Generation in the Western United States. Environmental Science and Technology, 43(1):226-232

11. Appendix D: Displaced generation model details: extrapolation to future loads, adding new units and retiring units

The core of the analysis, described in the main text of this document (see Chapter 3), is able to generate an assessment of emissions in a reference year. However, in future years, under different conditions, demand may increase or decrease above or below values seen today. The model needs to be able to extrapolate out to higher and lower energy requirements. In addition, the model needs to accept statistics for potential new units to accommodate growing demand and retire units according to user interest.

Because of the nature of the structure, the model is able to dynamically adapt to changes in the base case by adopting to changing loads through load growth, energy efficiency, or must-take renewables, or adding and removing generators. The extension of the model allows this functionality.

The basic concept in the following sections is that expected generation and statistics remain constant within load bins, and load bins and statistics are created for levels of demand which have not previously been experienced (i.e. loads above reference year peak, or loads reduced below the lowest troughs). [206] In addition, it is assumed that instead of units responding to demand, they are responding to a perceived demand; if another generator is retired, all other generators in the topology must fill the gap left by the retired generator.

The statistics which are gathered for the core version of this analysis have a critical shortfall, in that they are only able to portray a world in which the load falls in the dynamic range of the reference year. If projected loads extend above or below the reference year dynamic range then the non-extended version of the model is unable to identify a load bin and is unable to use the available statistics. The first expansion module extrapolates available statistics out to load categories that did not exist in the base year to estimate how existing generators would operate in these unknown conditions.

New load categories are defined for loads up to 50% above and 50% below the existing dynamic range. For each generator, the system extrapolates the probability that the unit is in operation using the first third and last third of the probability at a load period as a basis for the extrapolation. If a unit always operates at the historical peak load, then it will also always operate at any higher loads (see Figure 11-1). If a unit never operates at minimum loads, then at any loads below it will also never operate. If an extrapolated line would otherwise extend above a probability of one (or below zero), the probability is fixed at one (or zero, respectively).

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[206] The constancy of the generation vs. load relationship is critical to this statistical approach. We assume that the amount of energy generated by fossil units is a relatively constant ratio, and other types of generators and transmission remain relatively constant as well.

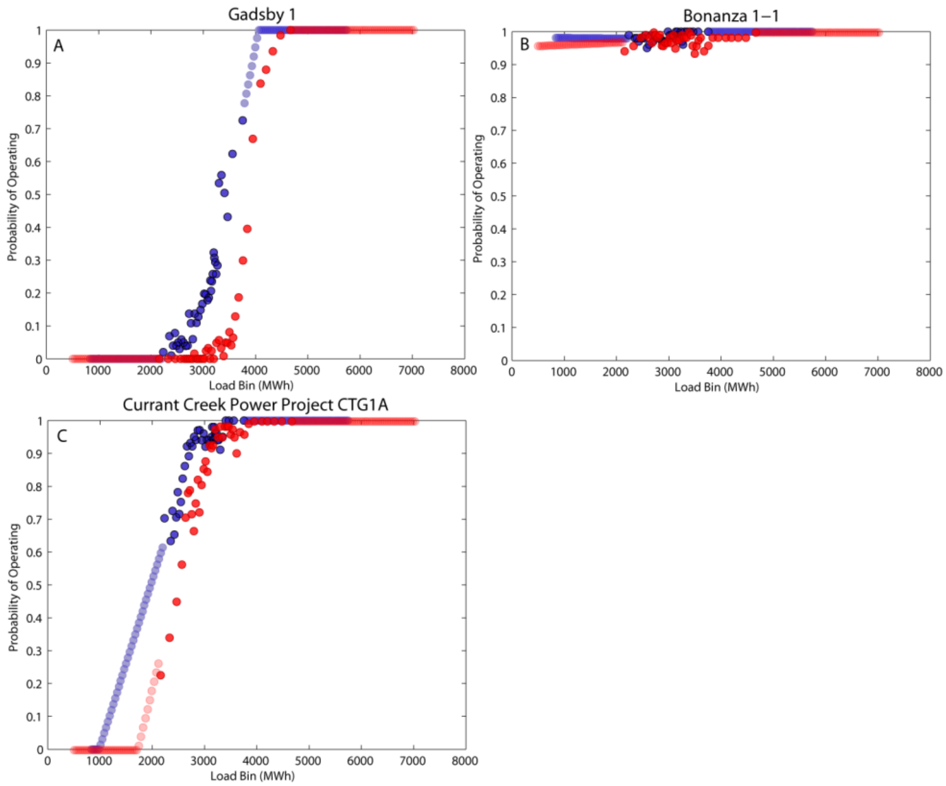

Figure 11-1: Extrapolating probability of operation in three representative units (A: Gadsby 1. B: Bonanza 1, C: Currant Creek Power Project 1). Blue dots represent historical and extrapolated fraction of hours online during Period A time periods (high hydro, low export), while red dots represent Period B time periods. Dark dots (blue and red) are probabilities derived from historical behavior, while lighter colored dots are extrapolated up and down to accommodate new peaks and troughs.

The expected level of generation is also extrapolated out for high and low load bins. The PDF of unit generation in each load bin is extrapolated up and down similarly to the probability of operation. Once these statistics are gathered, the Monte Carlo approach can be run at higher and lower loads than are otherwise available in the reference year.

In the assumption basis of the model, retiring a unit is akin to increasing load requiremnts for all other generators. When a unit is retired, the model first runs its statistics to determine what it would have generated if it were still in the system; this value is added to the generation required by all other EGU still in operation.

Adding a unit is the inverse of a retirement in the model. Since statistics for fundamentally new units are unavailable, the user selects an existing unit which will serve as a proxy new unit, externally to the model run. New units are not chosen as an optimal resource, instead they are simply feasible options from the standpoint of the model user. When a new unit is designated to begin operation, the statistics (probability of operation and PDFs of generation and emissions) from an existing unit are copied. The model runs a simulation of the new units, and then subtracts the resulting generation from the demand required of all other EGU in the system.

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 14-035-114

Exhibit HEAL___(JIF-3)

Minnesota Department of Commerce, Division of Energy Resources. Minnesota Value of Solar: Methodology. April 1, 2014.

June 8, 2017

Public Service Commission of Utah
Docket 14-035-114
Exhibit HEAL___(JIF-3)

Minnesota Value of Solar: Methodology

Prepared for

Minnesota Department of Commerce,

Division of Energy Resources

January 30, 2014

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Legal Notice from Clean Power Research

Executive Summary

Minnesota passed legislation[1] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The Department of Commerce (Commerce) was assigned the responsibility of developing and submitting a methodology for calculating the VOS tariff to the PUC by January 31, 2014. Utilities adopting the VOS will be required to follow this methodology when calculating the VOS tariff. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology, and additionally held four public workshops to develop, present, and receive feedback.

The 2013 legislation specifically mandated that the VOS legislation take into account the following values of distributed PV: energy and its delivery; generation capacity; transmission capacity; transmission and distribution line losses; and environmental value. The legislation also mandated a method of implementation, whereby solar customers will be billed for their gross electricity consumption under their applicable tariff, and will receive a VOS credit for their gross solar electricity production.

The present document provides the methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input, and guidance from Commerce. It includes a detailed example calculation for each step of the calculation.

Key aspects of the methodology include:

- A standard PV rating convention
- Methods for creating an hourly PV production time-series, representing the aggregate output of all PV systems in the service territory per unit capacity corresponding to the output of a PV resource on the margin
- Requirements for calculating the electricity losses of the transmission and distribution systems
- Methods for performing technical calculations for avoided energy, effective generation capacity and effective distribution capacity
- Economic methods for calculating each value component (e.g., avoided fuel cost, capacity cost, etc.)
- Requirements for summarizing input data and final calculations in order to facilitate PUC and stakeholder review

Application of the methodology results in the creation of two tables: the VOS Data Table (a table of utility-specific input assumptions) and the VOS Calculation Table (a table of utility-specific total value of

[1] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

solar). Together these two tables ensure stakeholder transparency and facilitate stakeholder understanding.

The VOS Calculation Table is illustrated in Figure ES-1. The table shows each value component and how the gross value of each component is converted into a distributed solar value. The process uses a component-specific load match factor (where applicable) and a component-specific Loss Savings Factor. The values are then summed to yield the 25-year levelized value.

Figure ES-1. VOS Calculation Table: economic value, load match, loss savings and distributed PV value.

25 Year Levelized Value	Gross Value ($/kWh)	×	Load Match Factor (%)	× (1 +	Loss Savings Factor (%)	) =	Distributed PV Value ($/kWh)
Avoided Fuel Cost	GV1				LSF-Energy		V1
Avoided Plant O&M - Fixed	GV2				LSF-Energy		V2
Avoided Plant O&M - Variable	GV3				LSF-Energy		V3
Avoided Gen Capacity Cost	GV4		ELCC		LSF-ELCC		V4
Avoided Reserve Capacity Cost	GV5		ELCC		LSF-ELCC		V5
Avoided Trans. Capacity Cost	GV6		ELCC		LSF-ELCC		V6
Avoided Dist. Capacity Cost	GV7		PLR		LSF-PLR		V7
Avoided Environmental Cost	GV8				LSF-Energy		V8
Avoided Voltage Control Cost							
Solar Integration Cost							
							Value of Solar

As a final step, the methodology calls for the conversion of the 25-year levelized value to an equivalent inflation-adjusted credit. The utility would then use the first year value as the credit for solar customers, and would adjust each year using the latest Consumer Price Index (CPI) data.

Contents

Introduction

Background

Minnesota passed legislation[2] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The Department of Commerce (Commerce) was assigned the responsibility of developing and submitting a methodology for calculating the VOS tariff to the PUC by January 31, 2014. Utilities adopting the VOS will be required to follow this methodology when calculating the VOS rate. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology, and additionally held four public workshops to develop, present, and receive feedback.

The present document provides the VOS methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input and guidance from Commerce.

Purpose

The State of Minnesota has identified a VOS tariff as a potential replacement for the existing Net Energy Metering (NEM) policy that currently regulates the compensation of home and business owners for electricity production from PV systems. As such, the adopted VOS legislation is not an incentive for distributed PV, nor is it intended to eliminate or prevent current or future incentive programs.

While NEM effectively values PV-generated electricity at the customer retail rate, a VOS tariff seeks to quantify the value of distributed PV electricity. If the VOS is set correctly, it will account for the real value of the PV-generated electricity, and the utility and its ratepayers would be indifferent to whether the electricity is supplied from customer-owned PV or from comparable conventional means. Thus, a VOS tariff eliminates the NEM cross-subsidization concerns. Furthermore, a well-constructed VOS tariff could provide market signals for the adoption of technologies that significantly enhance the value of electricity from PV, such as advanced inverters that can assist the grid with voltage regulation.

VOS Calculation Table Overview

The VOS is the sum of several distinct value components, each calculated separately using procedures defined in this methodology. As illustrated in Figure 1, the calculation includes a gross component value, a component-dependent load-match factor (as applicable for capacity related values) and a component-dependent Loss Savings Factor.

[2] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

For example, the avoided fuel cost does not have a load match factor because it is not dependent upon performance at the highest hours (fuel costs are avoided during all PV operating hours). Avoided fuel cost does have a Loss Savings Factor, however, accounting for loss savings in both transmission and distribution systems. On the other hand, the Avoided Distribution Capacity Cost has an important Load Match Factor (shown as Peak Load Reduction, or 'PLR') and a Loss Savings Factor that only accounts for distribution (not transmission) loss savings.

Gross Values, Distributed PV Values, and the summed VOS shown in Figure 1 are all 25-year levelized values denominated in dollars per kWh.

Figure 1. Illustration of the VOS Calculation Table

25 Year Levelized Value	Gross Value ($/kWh)	×	Load Match Factor (%)	× (1 +	Loss Savings Factor (%)	) =	Distributed PV Value ($/kWh)
Avoided Fuel Cost	GV1				LSF-Energy		V1
Avoided Plant O&M - Fixed	GV2				LSF-Energy		V2
Avoided Plant O&M - Variable	GV3				LSF-Energy		V3
Avoided Gen Capacity Cost	GV4		ELCC		LSF-ELCC		V4
Avoided Reserve Capacity Cost	GV5		ELCC		LSF-ELCC		V5
Avoided Trans. Capacity Cost	GV6		ELCC		LSF-ELCC		V6
Avoided Dist. Capacity Cost	GV7		PLR		LSF-PLR		V7
Avoided Environmental Cost	GV8				LSF-Energy		V8
Avoided Voltage Control Cost							
Solar Integration Cost							
							Value of Solar

VOS Rate Implementation

Separation of Usage and Production

Minnesota's VOS legislation mandates that, if a VOS tariff is approved, solar customers will be billed for all usage under their existing applicable tariff, and will receive a VOS credit for their gross solar energy production. Separating usage (charges) from production (credits) simplifies the rate process for several reasons:

- Customers will be billed for all usage. Energy derived from the PV systems will not be used to offset ("net") usage prior to calculating charges. This will ensure that utility infrastructure costs will be recovered by the utilities as designed in the applicable retail tariff.
- The utility will provide all energy consumed by the customer. Standby charges for customers with on-site PV systems are not permitted under a VOS rate.
- The rates for usage can be adjusted in future ratemaking.

VOS Components

The definition and selection of VOS components were based on the following considerations:

- Components corresponding to minimum statutory requirements are included. These account for the "value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value."
- Non-required components were selected only if they were based on known and measurable evidence of the cost or benefit of solar operation to the utility.
- Environmental costs are included as a required component, and are based on existing Minnesota and EPA externality costs.
- Avoided fuel costs are based on long-term risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel, as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments.
- Credit for systems installed at high value locations (identified in the legislation as an option) is included as an option for the utility. It is not a separate VOS component but rather is implemented using a location-specific distribution capacity value (the component most affected by location). This is addressed in the Distribution Capacity Cost section.
- Voltage control and solar integration (a cost) are kept as "placeholder" components for future years. Methodologies are not provided, but these components may be developed for the future. Voltage control benefits are anticipated but will first require implementation of recent changes to national interconnection standards. Solar integration costs are expected to be small, but possibly measureable. Further research will be required on this topic.

Table 1 presents the VOS components selected by Commerce and the cost basis for each component. Table 2 presents the VOS components that were considered but not selected by Commerce. Selections were made based on requirements and guidance in the enabling statute, and were informed by stakeholder comments (including those from Minnesota utilities; local and national solar and environmental organizations; local solar manufacturers and installers; and private parties) and workshop discussions. Stakeholders participated in four public workshops and provided comments through workshop panels, workshop Q&A sessions and written comments.

Table 1. VOS components included in methodology.

Value Component	Basis	Legislative Guidance	Notes
Avoided Fuel Cost	Energy market costs (portion attributed to fuel)	Required (energy)	Includes cost of long-term price risk
Avoided Plant O&M Cost	Energy market costs (portion attributed to O&M)	Required (energy)	
Avoided Generation Capacity Cost	Capital cost of generation to meet peak load	Required (capacity)	
Avoided Reserve Capacity Cost	Capital cost of generation to meet planning margins and ensure reliability	Required (capacity)	
Avoided Transmission Capacity Cost	Capital cost of transmission	Required (transmission capacity)	
Avoided Distribution Capacity Cost	Capital cost of distribution	Required (delivery)	
Avoided Environmental Cost	Externality costs	Required (environmental)	
Voltage Control	Cost to regulate distribution (future inverter designs)		Future (TBD)
Integration Cost[3]	Added cost to regulate system frequency with variable solar		Future (TBD)

[3] This is not a value, but a cost. It would reduce the VOS rate if included.

Table 2. VOS components not included in methodology.

Value Component	Basis	Legislative Guidance	Notes
Credit for Local Manufacturing/ Assembly	Local tax revenue tied to net solar jobs	Optional (identified in legislation)	
Market Price Reduction	Cost of wholesale power reduced in response to reduction in demand		
Disaster Recovery	Cost to restore local economy (requires energy storage and islanding inverters)		

Solar Penetration

Solar penetration refers to the total installed capacity of PV on the grid, generally expressed as a percentage of the grid's total load. The level of solar penetration on the grid is important because it affects the calculation of the Effective Load Carrying Capability (ELCC) and Peak Load Reduction (PLR) load-match factors (described later).

In the methodology, the near-term level of PV penetration is used. This is done so that the capacity-related value components will reflect the near-term level of PV penetration on the grid. However, the change in PV penetration level will be accounted for in the annual adjustment to the VOS. To the extent that PV penetration increases, future VOS rates will reflect higher PV penetration levels.

Marginal Fuel

This methodology assumes that PV displaces natural gas during PV operating hours. This is consistent with current and projected MISO market experience. During some hours of the year, other fuels (such as coal) may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption that is not expected to materially impact the calculated VOS tariff. However, if future analysis indicates that the assumption is not warranted, then the methodology may be modified accordingly. For example, by changing the methodology to include displacement of coal production, avoided fuel costs may decrease and avoided environmental costs may increase.

Economic Analysis Period

In evaluating the value of a distributed PV resource, the economic analysis period is set at 25 years, the assumed useful service life of the PV system[4]. The methodology includes PV degradation effects as described later.

Annual VOS Tariff Update

Each year, a new VOS tariff would be calculated using current data, and the new resulting VOS rate would be applicable to all customers entering the tariff during the year. Changes such as increased or decreased fuel prices and modified hourly utility load profiles due to higher solar penetration will be incorporated into each new annual calculation.

Customers who have already entered into the tariff in a previous year will not be affected by this annual adjustment. However, customers who have entered into a tariff in prior years will see their Value of Solar rates adjusted for the previous year's inflation rate as described later.

Commerce may also update the methodology to use the best available practices, as necessary.

Transparency Elements

The methodology incorporates two tables that are to be included in a utility's application to the Minnesota PUC for the use of a VOS tariff. These tables are designed to improve transparency and facilitate understanding among stakeholders and regulators.

- **VOS Data Table.** This table provides a utility-specific defined list of the key input assumptions that go into the VOS tariff calculation. This table is described in more detail later.
- **VOS Calculation Table.** This table includes the list of value components and their gross values, their load-match factors, their Loss Savings Factors, and the computation of the total levelized value.

Glossary

A glossary is provided at the end of this document defining some of the key terms used throughout this document.

[4] [4] NREL: Solar Resource Analysis and High-Penetration PV Potential (April 2010). http://www.nrel.gov/docs/fy10osti/47956.pdf

Methodology: Assumptions

Fixed Assumptions

Table 3 and Table 4 present fixed assumptions, common to all utilities and incorporated into this methodology, that are to be applied to the calculation of 2014 VOS tariffs. These may be updated by Commerce in future years as necessary when performing the annual VOS update. Table 4 is described in more detail in the Avoided Environmental Cost subsection. Table terms can be found in the Glossary.

Published values from the Bureau of Labor and Statistics for the Urban Consumer Price Index (CPI) (ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt) were used to calculate an average annual inflation rate of 2.53% over the last 25 years (see equations below). This was taken as the expected general escalation rate.

$$25yrAvgAnnualInflation = \left(\frac{Nov2013\ UCPI}{Nov1988\ UCPI}\right)^{1/(2013-1988)} - 1 \tag{1}$$

$$25yrAvgAnnualInflation = \left[\left(\frac{224.939}{120.300}\right)^{1/_{25}} - 1\right] = 2.53\% \tag{2}$$

The “Guaranteed NG Fuel Price Escalation” value of 4.77%, used as described later to calculate the Avoided Fuel Costs, is calculated from a best fit to the listed NYMEX futures prices (also shown in Table 3). This fit can be seen below in Figure 2.

Figure 2. Fit to NYMEX natural gas futures prices.

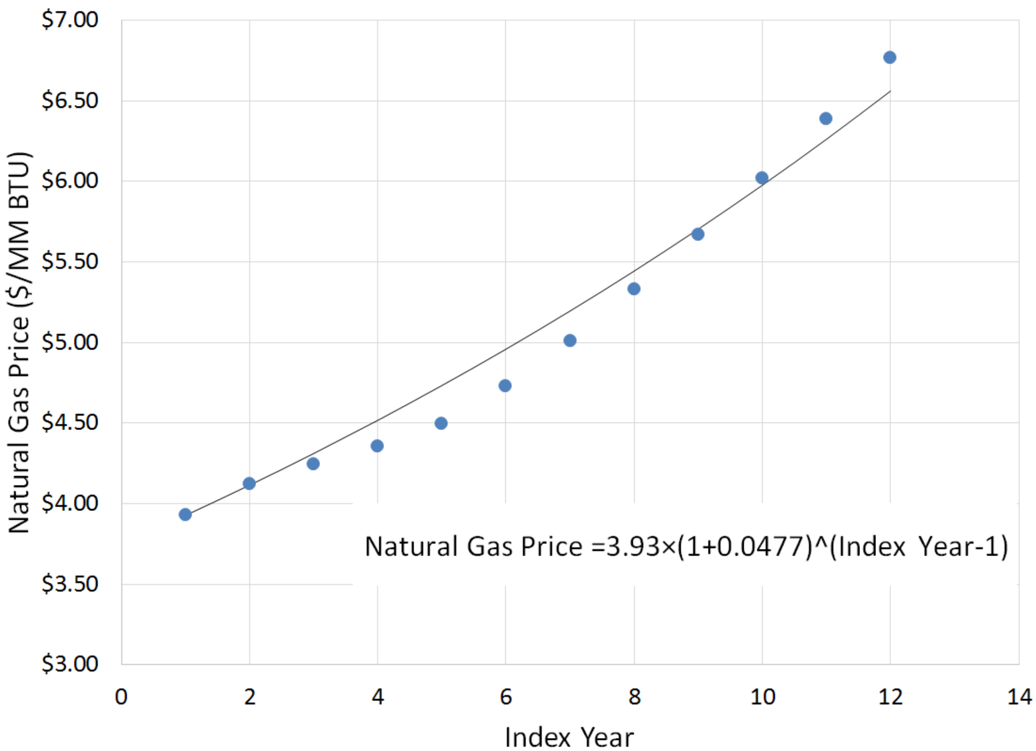


Table 3. Fixed assumptions to be used for 2014 VOS calculations – common to all utilities.

Guaranteed NG Fuel Prices						
Year				**Environmental Externalities**		
2014	$3.93	$ per MMBtu		Environmental discount rate (nominal)	5.61%	per year
2015	$4.12	$ per MMBtu		Environmental costs	(shown in separate table)	
2016	$4.25	$ per MMBtu				
2017	$4.36	$ per MMBtu		**Economic Assumptions**		
2018	$4.50	$ per MMBtu		General escalation rate	2.53%	per year
2019	$4.73	$ per MMBtu				
2020	$5.01	$ per MMBtu				
2021	$5.33	$ per MMBtu		**Treasury Yields**		
2022	$5.67	$ per MMBtu		1 Year	0.13%	
2023	$6.02	$ per MMBtu		2 Year	0.29%	
2024	$6.39	$ per MMBtu		3 Year	0.48%	
2025	$6.77	$ per MMBtu		5 Year	1.01%	
				7 Year	1.53%	
NG fuel price escalation	4.77%			10 Year	2.14%	
				20 Year	2.92%	
PV Assumptions				30 Year	3.27%	
PV degradation rate	0.50%	per year				
PV life	25	years				

Table 4. Fixed environmental externality costs by year.

Year	Analysis Year	CO_2 Cost ($/MMBtu)	PM10 Cost ($/MMBtu)	CO Cost ($/MMBtu)	NO_x Cost ($/MMBtu)	Pb Cost ($/MMBtu)	Total Cost ($/MMBtu)
2014	0	2.140	0.027	0.000	0.044	0.000	2.210
2015	1	2.255	0.028	0.000	0.045	0.000	2.327
2016	2	2.375	0.028	0.000	0.046	0.000	2.449
2017	3	2.499	0.029	0.000	0.047	0.000	2.575
2018	4	2.628	0.030	0.000	0.048	0.000	2.706
2019	5	2.829	0.030	0.000	0.050	0.000	2.909
2020	6	2.970	0.031	0.000	0.051	0.000	3.052
2021	7	3.045	0.032	0.000	0.052	0.000	3.130
2022	8	3.195	0.033	0.000	0.053	0.000	3.282
2023	9	3.351	0.034	0.000	0.055	0.000	3.439
2024	10	3.512	0.034	0.000	0.056	0.000	3.603
2025	11	3.679	0.035	0.000	0.058	0.000	3.772
2026	12	3.853	0.036	0.000	0.059	0.000	3.948
2027	13	4.033	0.037	0.000	0.061	0.000	4.131
2028	14	4.219	0.038	0.000	0.062	0.000	4.320
2029	15	4.413	0.039	0.000	0.064	0.000	4.516
2030	16	4.613	0.040	0.000	0.065	0.000	4.719
2031	17	4.730	0.041	0.000	0.067	0.000	4.839
2032	18	4.944	0.042	0.000	0.069	0.000	5.054
2033	19	5.165	0.043	0.000	0.070	0.000	5.278
2034	20	5.394	0.044	0.000	0.072	0.000	5.510
2035	21	5.631	0.045	0.000	0.074	0.000	5.750
2036	22	5.877	0.047	0.000	0.076	0.000	5.999
2037	23	6.131	0.048	0.000	0.078	0.000	6.257
2038	24	6.395	0.049	0.000	0.080	0.000	6.524

See explanation in the Avoided Environmental Cost section.

Utility-Specific Assumptions and Calculations

Some assumptions and calculations are unique to each utility. These include economic assumptions (such as discount rate) and technical calculations (such as ELCC). Utility-specific assumptions and calculations are determined by the utility, and are included in the VOS Data Table, a required transparency element.

The utility-specific calculations (such as capacity-related transmission capital cost) are determined using the methods described in this methodology.

An example VOS Data Table, showing the parameters to be included in the utility filing for the VOS tariff, is shown in Table 5. This table includes values that are given for example only. These example values carry forward in the example calculations.

Table 5. VOS Data Table (EXAMPLE DATA) — required format showing example parameters used in the example calculations.

	Input Data	Units
Economic Factors		
Start Year for VOS applicability	2014	
Discount rate (WACC)	8.00%	per year
Load Match Analysis (see calculation method)		
ELCC (no loss)	40%	% of rating
PLR (no loss)	30%	% of rating
Loss Savings - Energy	8%	% of PV output
Loss Savings - PLR	5%	% of PV output
Loss Savings - ELCC	9%	% of PV output
PV Energy (see calculation method)		
First year annual energy	1800	kWh per kW-AC
Transmission (see calculation method)		
Capacity-related transmission capital cost	$33	$ per kW-yr

	Input Data	Units
Power Generation		
Peaking CT, simple cycle		
Installed cost	900	$/kW
Heat rate	9,500	BTU/kWh
Intermediate peaking CCGT		
Installed cost	1,200	$/kW
Heat rate	6,500	BTU/kWh
Other		
Solar-weighted heat rate (see calc. method)	8000	BTU per kWh
Fuel Price Overhead	$0.50	$ per MMBtu
Generation life	50	years
Heat rate degradation	0.100%	per year
O&M cost (first Year) - Fixed	$5.00	per kW-yr
O&M cost (first Year) - Variable	$0.0010	$ per kWh
O&M cost escalation rate	2.00%	per year
Reserve planning margin	15%	
Distribution		
Capacity-related distribution capital cost	$200	$ per kW
Distribution capital cost escalation	2.00%	per year
Peak load	5000	MW
Peak load growth rate	1.00%	per year

Methodology: Technical Analysis

Load Analysis Period

The VOS methodology requires that a number of technical parameters (PV energy production, effective load carrying capability (ELCC) and peak load reduction (PLR) load-match factors, and electricity-loss factors) be calculated over a fixed period of time in order to account for day-to-day variations and seasonal effects, such as changes in solar radiation. For this reason, the load analysis period must cover a period of at least one year.

The data may start on any day of the year, and multiple years may be included, as long as all included years are contiguous and each included year is a complete one-year period. For example, valid load analysis periods may be 1/1/2012 0:00 to 12/31/2012 23:00 or 11/1/2010 0:00 to 10/31/2013 23:00.

Three types of time series data are required to perform the technical analysis:

- **Hourly Generation Load:** the hourly utility load over the Load Analysis Period. This is the sum of utility generation and import power needed to meet all customer load.
- **Hourly Distribution Load:** the hourly distribution load over the Load Analysis Period. The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses).
- **Hourly PV Fleet Production:** the hourly PV Fleet production over the Load Analysis Period. The PV fleet production is the aggregate generation of all of the PV systems in the PV fleet.

All three types of data must be provided as synchronized, time-stamped hourly values of average power over the same period, and corresponding to the same hourly intervals. Data must be available for every hour of the Load Analysis Period.

PV data using Typical Meteorological Year data is not time synchronized with time series production data, so it should not be used as the basis for PV production.

Data that is not in one-hour intervals must be converted to hourly data (for example, 15-minute meter data would have to be combined to obtain 1-hour data). Also, data values that represent energy must be converted to average power.

If data is missing or deemed erroneous for any time period less than or equal to 24 hours, the values corresponding to that period may be replaced with an equal number of values from the same time interval on the previous or next day if it contains valid data. This data replacement method may be used provided that it does not materially affect the results.

PV Energy Production

PV System Rating Convention

The methodology uses a rating convention for PV capacity based on AC delivered energy (not DC), taking into account losses internal to the PV system. A PV system rated output is calculated by multiplying the number of modules by the module PTC rating[5] [as listed by the California Energy Commission (CEC)[6]] to account for module de-rate effects. The result is then multiplied by the CEC-listed inverter efficiency rating[7] to account for inverter efficiency, and the result is multiplied by a loss factor to account for internal PV array losses (wiring losses, module mismatch and other losses).

If no CEC module PTC rating is available, the module PTC rating should be calculated as 0.90 times the module STC rating[8]. If no CEC inverter efficiency rating is available, an inverter efficiency of 0.95 should be used. If no measured or design loss factor is available, 0.85 should be used.

To summarize: [9]

Rating (kW-AC) = [Module Quantity] x [Module PTC rating (kW)] x [Inverter Efficiency Rating] x [Loss Factor]

Hourly PV Fleet Production

Hourly PV Fleet Production can be obtained using any one of the following three options:

1. <u>Utility Fleet - Metered Production</u>. Fleet production data can be created by combining actual metered production data for every PV system in the utility service territory, provided that there are a sufficient number of systems[10] installed to accurately derive a correct representation of aggregate PV production. Such metered data is to be gross PV output on the AC side of the

[5] PTC refers to PVUSA Test Conditions, which were developed to test and compare PV systems as part of the PVUSA (Photovoltaics for Utility Scale Applications) project. PTC are 1,000 Watts per square meter solar irradiance, 20 degrees C air temperature, and wind speed of 1 meter per second at 10 meters above ground level. PV manufacturers use Standard Test Conditions, or STC, to rate their PV products.
[6] CEC module PTC ratings for most modules can be found at: http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php
[7] CEC inverter efficiency ratings for most inverters can be found at: http://www.gosolarcalifornia.ca.gov/equipment/inverters.php
[8] PV manufacturers use Standard Test Conditions, or STC, to rate their PV products. STC are 1,000 Watts per square meter solar irradiance, 25 degrees C cell temperature, air mass equal to 1.5, and ASTM G173-03 standard spectrum.
[9] In some cases, this equation will have to be adapted to account for multiple module types and/or inverters. In such cases, the rating of each subsystem can be calculated independently and then added.
[10] A sufficient number of systems has been achieved when adding a single system of random orientation, tilt, tracking characteristics, and capacity (within reason) does not materially change the observed hourly PV Fleet Shape (see next subsection of PV Fleet Shape definition).

system, but before local customer loads are subtracted (i.e., PV must be separately metered from load). Metered data from individual systems is then aggregated by summing the measured output for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

2. Utility Fleet, Simulated Production. If metered data is not available, the aggregate output of all distributed PV systems in the utility service territory can be modeled using PV system technical specifications and hourly irradiance and temperature data. These systems must be deployed in sufficient numbers to accurately derive a correct representation of aggregate PV production. Modeling must take into account the system's location and each array's tracking capability (fixed, single-axis or dual-axis tracking), orientation (tilt and azimuth), module PTC ratings, inverter efficiency and power ratings, other loss factors and the effect of temperature on module output. Technical specifications for each system must be available to enable such modeling. Modeling must also make use of location-specific, time-correlated, measured or satellite-derived plane of array irradiance data. Ideally, the software will also support modeling of solar obstructions.
   - To make use of this option, detailed system specifications for every PV system in the utility's service territory must be obtained. At a minimum, system specifications must include:
     - Location (latitude and longitude)
     - System component ratings (e.g., module ratings an inverter ratings)
     - Tilt and azimuth angles
     - Tracking type (if applicable)
   - After simulating the power production for each system for each hour in the Load Analysis Period, power production must be aggregated by summing the power values for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

3. Expected Fleet, Simulated Production. If neither metered production data nor detailed PV system specifications are available, a diverse set of PV resources can be estimated by simulating groups of systems at major load centers in the utility's service territory with some assumed fleet configuration. To use this method, one or more of the largest load centers in the utility service territory may be used. If a single load center accounts for a high percentage of the utility's total load, a single location will suffice. If there are several large load centers in the territory, groups of systems can be created at each location with capacities proportional to the load in that area.
   - For each location, simulate multiple systems, each rated in proportion to the expected capacity, with azimuth and tilt angles such as the list of systems presented in Table 6. Note

that the list of system configurations should represent the expected fleet composition. No method is explicitly provided to determine the expected fleet composition; however, a utility could analyze the fleet composition of PV fleets outside of its territory.

Table 6. (EXAMPLE) Azimuth and tilt angles

System	Azimuth	Tilt	% Capacity
1	90	20	3.5
2	135	15	3.0
3	135	30	6.5
4	180	0	6.0
5	180	15	16.0
6	180	25	22.5
7	180	35	18.0
8	235	15	8.5
9	235	30	9.0
10	270	20	7.0

- Simulate each of the PV systems for each hour in the Load Analysis Period. Aggregate power production for the systems is obtained by summing the power values for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.
- If the utility elects to perform a location-specific analysis for the Avoided Distribution Capacity Costs, then it should also take into account what the geographical distribution of the expected PV fleet would be. Again, this could be done by analyzing a PV fleet composition outside of the utility's territory. An alternative method that would be acceptable is to distribute the expected PV fleet across major load centers. Thereby assuming that PV capacity is likely to be added where significant load (and customer density) already exists.
- Regardless of location count and location weighting, the total fleet rating is taken as the sum of the individual system ratings.

PV Fleet Shape

Regardless of which of the three methods is selected for obtaining the Hourly PV Fleet production, the next step is divide each hour's value by the PV Fleet's aggregate AC rating to obtain the PV Fleet Shape. The units of the PV Fleet Shape are kWh per hour per kW-AC (or, equivalently, average kW per kW-AC).

Marginal PV Resource

The PV Fleet Shape is hourly production of a Marginal PV Resource having a rating of 1 kW-AC.

Annual Avoided Energy

Annual Avoided Energy (kWh per kW-AC per year) is the sum of the hourly PV Fleet Shape across all hours of the Load Analysis Period, divided by the numbers of years in the Load Analysis Period. The result is the annual output of the Marginal PV Resource.

$$Annual\ Avoided\ Energy\ (kWh) = \frac{\sum Hourly\ PV\ Fleet\ Production_h}{NumberOfYearsInLoadAnalysisPeriod} \quad (3)$$

- Defined in this way, the Annual Avoided Energy does not include the effects of loss savings. As described in the Loss Analysis subsection, however, it will have to be calculated for the two loss cases (with losses and without losses).

Load-Match Factors

Capacity-related benefits are time dependent, so it is necessary to evaluate the effectiveness of PV in supporting loads during the critical peak hours. Two different measures of effective capacity are used:

- Effective Load Carrying Capability (ELCC)
- Peak Load Reduction (PLR)

Near term PV penetration levels are used in the calculation of the ELCC and PLR values so that the capacity-related value components will reflect the near term level of PV penetration on the grid. However, the ELCC and PLR will be re-calculated during the annual VOS adjustment and thus reflect any increase in future PV Penetration Levels.

Effective Load Carrying Capability (ELCC)

The Effective Load Carrying Capability (ELCC) is the measure of the effective capacity for distributed PV that can be applied to the avoided generation capacity costs, the avoided reserve capacity costs, the avoided generation fixed O&M costs, and the avoided transmission capacity costs (see Figure 1).

Using current MISO rules for non-wind variable generation (MISO BPM-011, Section 4.2.2.4, page 35)[11]: the ELCC will be calculated from the PV Fleet Shape for hours ending 2pm, 3pm, and 4pm Central Standard Time during June, July, and August over the most recent three years. If three years of data are unavailable, MISO requires "a minimum of 30 consecutive days of historical data during June, July, or August" for the hours ending 2pm, 3pm and 4pm Central Standard Time.

The ELCC is calculated by averaging the PV Fleet Shape over the specified hours, and then dividing by the rating of the Marginal PV Resource (1 kW-AC), which results in a percentage value. Additionally, the ELCC must be calculated for the two loss cases (with and without T&D losses, as described in the Loss Analysis subsection).

Peak Load Reduction (PLR)

The PLR is defined as the maximum distribution load over the Load Analysis Period (without the Marginal PV Resource) minus the maximum distribution load over the Load Analysis Period (with the Marginal PV Resource). The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses). In calculating the PLR, it is not sufficient to limit modeling to the peak hour. All hours over the Load Analysis Period must be included in the calculation. This is because the reduced peak load may not occur in the same hour as the original peak load.

The PLR is calculated as follows. First, determine the maximum Hourly Distribution Load (D1) over the Load Analysis Period. Next, create a second hourly distribution load time series by subtracting the effect of the Marginal PV Resource, i.e., by evaluating what the new distribution load would be each hour given the PV Fleet Shape. Next, determine the maximum load in the second time series (D2). Finally, calculate the PLR by subtracting D2 from D1.

In other words, the PLR represents the capability of the Marginal PV Resource to reduce the peak distribution load over the Load Analysis Period. PLR is expressed in kW per kW-AC.

Additionally, the PLR must be calculated for the two loss cases (with distribution losses and without distribution losses, as described in the Loss Analysis subsection).

[11] https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

Loss Savings Analysis

In order to calculate the required Loss Savings Factors on a marginal basis as described below, it will be necessary to calculate ELCC, PLR and Annual Avoided Energy each twice. They should be calculated first by *including* the effects of avoided marginal losses, and second by *excluding* them. For example, the ELCC would first be calculated by including avoided transmission and distribution losses, and then re-calculated assuming no losses, i.e., as if the Marginal PV Resource was a central (not distributed) resource.

The calculations should observe the following

Table 7. Losses to be considered.

Technical Parameter	Loss Savings Considered
Avoided Annual Energy	Avoided transmission and distribution losses for every hour of the load analysis period.
ELCC	Avoided transmission and distribution losses during the MISO defined hours.
PLR	Avoided distribution losses (not transmission) at peak.

When calculating avoided marginal losses, the analysis must satisfy the following requirements:

1. Avoided losses are to be calculated on an hourly basis over the Load Analysis Period. The avoided losses are to be calculated based on the generation (and import) power during the hour and the expected output of the Marginal PV Resource during the hour.

2. Avoided losses in the transmission system and distribution systems are to be evaluated separately using distinct loss factors based on the most recent study data available.

3. Avoided losses should be calculated on a marginal basis. The marginal avoided losses are the difference in hourly losses between the case without the Marginal PV Resource, and the case with the Marginal PV Resource. Avoided average hourly losses are not calculated. For example, if the Marginal PV Resource were to produce 1 kW of power for an hour in which total customer load is 1000 kW, then the avoided losses would be the calculated losses at 1000 kW of customer load minus the calculated losses at 999 kW of load.

4. Distribution losses should be based on the power entering the distribution system, after transmission losses.

5. Avoided transmission losses should take into account not only the marginal PV generation, but also the avoided marginal distribution losses.

6. Calculations of avoided losses should not include no-load losses (e.g., corona, leakage current). Only load-related losses should be included.

7. Calculations of avoided losses in any hour should take into account the non-linear relationship between losses and load (load-related losses are proportional to the square of the load, assuming constant voltage). For example, the total load-related losses during an hour with a load of 2X would be approximately 4 times the total load-related losses during an hour with a load of only X.

Loss Savings Factors

The Energy Loss Savings Factor (as a percentage) is defined for use within the VOS Calculation Table:

$$Annual\ Avoided\ Energy_{WithLosses} = Annual\ Avoided\ Energy_{WithoutLosses}\left(1 + Loss\ Savings_{Energy}\right) \tag{4}$$

Equation 3 is then rearranged to solve for the Energy Loss Savings Factor:

$$Loss\ Savings_{Energy} = \frac{Annual\ Avoided\ Energy_{WithLosses}}{Annual\ Avoided\ Energy_{WithoutLosses}} - 1 \tag{5}$$

Similarly, the PLR Loss Savings Factor is defined as:

$$Loss\ Savings_{PLR} = \frac{PLR_{WithLosses}}{PLR_{WithoutLosses}} - 1 \tag{6}$$

and the ELCC Loss Savings Factor is defined as:

$$Loss\ Savings_{ELCC} = \frac{ELCC_{WithLosses}}{ELCC_{WithoutLosses}} - 1 \tag{7}$$

Methodology: Economic Analysis

The following subsections provide a methodology for performing the economic calculations to derive gross values in $/kWh for each of the VOS components. These gross component values will then be entered into the VOS Calculation Table, which is the second of the two key transparency elements.

Important Note: The economic analysis is initially performed as if PV was centrally-located (without loss-saving benefits of distributed location) and with output perfectly correlated to load. Real-world adjustments are made later in the final VOS summation by including the results of the loss savings and load match analyses.

Discount Factors

By convention, the analysis year 0 corresponds to the year in which the VOS tariff will begin. As an example, if a VOS was done in 2013 for customers entering a VOS tariff between January 1, 2014 and December 31, 2014, then year 0 would be 2014, year 1 would be 2015, and so on.

For each year *i*, a discount factor is given by

$$DiscountFactor_i = \frac{1}{(1 + DiscountRate)^i} \qquad (8)$$

The *DiscountRate* is the utility Weighted Average Cost of Capital.

Similarly, a risk-free discount factor is given by:

$$RiskFreeDiscountFactor_i = \frac{1}{(1 + RiskFreeDiscountRate)^i} \qquad (9)$$

The *RiskFreeDiscountRate* is based on the yields of current Treasury securities[12] of 1, 2, 3, 5, 7, 10, 20, and 30 year maturation dates. The *RiskFreeDiscountRate* is used once in the calculation of the Avoided Fuel Costs.

Finally, an environmental discount factor is given by:

$$EnvironmentalDiscountFactor_i = \frac{1}{(1 + EnvironmentalDiscountRate)^i} \qquad (10)$$

[12] See http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

The *EnvironmentalDiscountRate* is based on the 3% *real* discount rate that has been determined to be an appropriate societal discount rate for future environmental benefits.[13] As the methodology requires a nominal discount rate, this 3% *real* discount rate is converted into its equivalent 5.61% nominal discount rate as follows:[14]

$$NominalDiscountRate = (1 + RealDiscountRate) \times (1 + GeneralEscalationRate) - 1 \qquad (11)$$

The *EnvironmentalDiscountRate* is used once in the calculation of the Avoided Environmental Costs.

PV degradation is accounted for in the economic calculations by reductions of the annual PV production in future years. As such, the PV production in kWh per kW-AC for the marginal PV resource in year I is given by:

$$PVProduction_i = PVProduction_0 \times (1 - \mathrm{PVDegradationRate})^i \qquad (12)$$

where PVDegradationRate is the annual rate of PV degradation, assumed to be 0.5% per year – the standard PV module warranty guarantees a maximum of 0.5% power degradation per annum. $PVProduction_0$ is the Annual Avoided Energy for the Marginal PV Resource.

PV capacity in year *i* for the Marginal PV Resource, taking into account degradation, equals:

$$PVCapacity_i = (1 - \mathrm{PVDegradationRate})^i \qquad (13)$$

Avoided Fuel Cost

Avoided fuel costs are based on long-term, risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments.

PV displaces energy generated from the marginal unit, so it avoids the cost of fuel associated with this generation. Furthermore, the PV system is assumed to have a service life of 25 years, so the uncertainty in fuel price fluctuations is also eliminated over this period. For this reason, the avoided fuel cost must take into account the fuel as if it were purchased under a guaranteed, long term contract.

[13] http://www.epa.gov/oms/climate/regulations/scc-tsd.pdf
[14] http://en.wikipedia.org/wiki/Nominal_interest_rate

The methodology provides for three options to accomplish this:

- **Futures Market.** This option is described in detail below, and is based on the NYMEX NG futures with a fixed escalation for years beyond the 12-year trading period.
- **Long Term Price Quotation.** This option is identical to the above option, except the input pricing data is based on an actual price quotation from an AA-rated NG supplier to lock in prices for the 25-year guaranteed period.
- **Utility-guaranteed Price.** This is the 25-year fuel price that is guaranteed by the utilities. Tariffs using the utility guaranteed price will include a mechanism for removing the usage fuel adjustment charges and provide fixed prices over the term.

Table 8 presents the calculation of the economic value of avoided fuel costs.

For the Futures Market option, Guaranteed NG prices are calculated as follows. Prices for the first 12 years are based on NYMEX futures, with each monthly price averaged to give a 12-month average in $ per MMBtu. Prices for years beyond this NYMEX limit are calculated by applying the assumed annual NYMEX price escalation. An assumed fuel price overhead amount, escalated by year using the assumed NYMEX price escalation, is added to the fuel price to give the burnertip fuel price.

The first-year solar-weighted heat rate is calculated as follows:

$$SolarWeighedHeatRate_0 = \frac{\sum HeatRate_j \times FleetProduction_j}{\sum FleetProduction_j} \qquad (14)$$

where the summation is over all hours *j* of the load analysis period, *HeatRate* is the actual heat rate of the plant on the margin, and *FleetProduction* is the Fleet Production Shape time series.

The solar-weighted heat rate for future years is calculated as:

$$SolarWeighedHeatRate_i = SolarWeighedHeatRate_0 \times (1 - \mathrm{HeatRateDegradationRate})^i \qquad (15)$$

The utility price in year *i* is:

$$UtilityPrice_i = \frac{BurnertipFuelPrice_i \times SolarWeighedHeatRate_i}{10^6} \qquad (16)$$

where the burnertip price is in $ per MMBtu and the heat rate is in Btu per kWh.

Utility cost is the product of the utility price and the per unit PV production. These costs are then discounted using the risk free discount rate and summed for all years. A risk-free discount rate (fitted to the US Treasury yields shown in Table 3) has been selected to account for the fact that there is no risk in the avoided fuel cost.

The VOS price (shown in red in Table 8) is the levelized amount that results in the same discounted amount as the utility price for the Avoided Fuel Cost component.

Avoided Plant O&M – Fixed

Economic value calculations for fixed plant O&M are presented in Table 9. The first year fixed value is escalated at the O&M escalation rate for future years.

Similarly, PV capacity has an initial value of one during the first year because it is applicable to PV systems installed in the first year. Note that effective capacity (load matching) is handled separately, and this table represents the “ideal” resource, as if PV were able to receive the same capacity credit as a fully dispatchable technology.

Fixed O&M is avoided only when the resource requiring fixed O&M is avoided. For example, if new generation is not needed for two years, then the associated fixed O&M is also not needed for two years. In the example calculation, generation is assumed to be needed for all years, so the avoided cost is calculated for all years.

The utility cost is the fixed O&M cost times the PV capacity divided by the utility capacity. Utility prices are the cost divided by the PV production. Costs are discounted using the utility discount factor and are summed for all years.

The VOS component value is calculated as before such that the discounted total is equal to the discounted utility cost.

Table 8. (EXAMPLE) Economic Value of Avoided Fuel Costs.

Year	Guaranteed NG Price	Burnertip NG Price	Heat Rate	Prices Utility	Prices VOS	p.u. PV Production	Costs Utility	Costs VOS	Discount Factor	Disc. Costs Utility	Disc. Costs VOS
	($/MMBtu)	($/MMBtu)	(Btu/kWh)	($/kWh)	($/kWh)	(kWh)	($)	($)	(risk free)	($)	($)
2014	$3.93	$4.43	8000	$0.035	$0.061	1,800	$64	$110	1.000	$64	$110
2015	$4.12	$4.65	8008	$0.037	$0.061	1,791	$67	$110	0.999	$67	$110
2016	$4.25	$4.79	8016	$0.038	$0.061	1,782	$68	$109	0.994	$68	$109
2017	$4.36	$4.93	8024	$0.040	$0.061	1,773	$70	$109	0.986	$69	$107
2018	$4.50	$5.10	8032	$0.041	$0.061	1,764	$72	$108	0.971	$70	$105
2019	$4.73	$5.36	8040	$0.043	$0.061	1,755	$76	$108	0.951	$72	$102
2020	$5.01	$5.67	8048	$0.046	$0.061	1,747	$80	$107	0.927	$74	$99
2021	$5.33	$6.03	8056	$0.049	$0.061	1,738	$84	$107	0.899	$76	$96
2022	$5.67	$6.40	8064	$0.052	$0.061	1,729	$89	$106	0.872	$78	$93
2023	$6.02	$6.78	8072	$0.055	$0.061	1,721	$94	$106	0.842	$79	$89
2024	$6.39	$7.18	8080	$0.058	$0.061	1,712	$99	$105	0.809	$80	$85
2025	$6.77	$7.60	8088	$0.061	$0.061	1,703	$105	$105	0.786	$82	$82
2026	$7.09	$7.96	8097	$0.064	$0.061	1,695	$109	$104	0.762	$83	$79
2027	$7.43	$8.34	8105	$0.068	$0.061	1,686	$114	$104	0.737	$84	$76
2028	$7.78	$8.74	8113	$0.071	$0.061	1,678	$119	$103	0.713	$85	$73
2029	$8.15	$9.16	8121	$0.074	$0.061	1,670	$124	$102	0.688	$85	$70
2030	$8.54	$9.60	8129	$0.078	$0.061	1,661	$130	$102	0.663	$86	$68
2031	$8.95	$10.06	8137	$0.082	$0.061	1,653	$135	$101	0.637	$86	$65
2032	$9.38	$10.54	8145	$0.086	$0.061	1,645	$141	$101	0.612	$86	$62
2033	$9.83	$11.04	8153	$0.090	$0.061	1,636	$147	$100	0.587	$87	$59
2034	$10.29	$11.57	8162	$0.094	$0.061	1,628	$154	$100	0.563	$86	$56
2035	$10.79	$12.12	8170	$0.099	$0.061	1,620	$160	$99	0.543	$87	$54
2036	$11.30	$12.70	8178	$0.104	$0.061	1,612	$167	$99	0.523	$88	$52
2037	$11.84	$13.30	8186	$0.109	$0.061	1,604	$175	$98	0.504	$88	$50
2038	$12.41	$13.94	8194	$0.114	$0.061	1,596	$182	$98	0.485	$88	$48

Validation: Present Value	$1,999	$1,999

Table 9. (EXAMPLE) Economic value of avoided plant O&M – fixed

Year	O&M Fixed ($/kW)	Utility Capacity (p.u.)	PV Capacity (kW)	p.u. PV Production (kWh)	Costs Utility ($)	Costs VOS ($)	Discount Factor	Disc. Costs Utility ($)	Disc. Costs VOS ($)	Prices Utility ($/kWh)	Prices VOS ($/kWh)
2014	$5.00	1.000	1.000	1800	$5	$6	1.000	$5	$6	$0.003	$0.003
2015	$5.10	0.999	0.995	1791	$5	$6	0.926	$5	$5	$0.003	$0.003
2016	$5.20	0.998	0.990	1782	$5	$6	0.857	$4	$5	$0.003	$0.003
2017	$5.31	0.997	0.985	1773	$5	$6	0.794	$4	$5	$0.003	$0.003
2018	$5.41	0.996	0.980	1764	$5	$6	0.735	$4	$4	$0.003	$0.003
2019	$5.52	0.995	0.975	1755	$5	$6	0.681	$4	$4	$0.003	$0.003
2020	$5.63	0.994	0.970	1747	$5	$6	0.630	$3	$4	$0.003	$0.003
2021	$5.74	0.993	0.966	1738	$6	$6	0.583	$3	$3	$0.003	$0.003
2022	$5.86	0.992	0.961	1729	$6	$6	0.540	$3	$3	$0.003	$0.003
2023	$5.98	0.991	0.956	1721	$6	$6	0.500	$3	$3	$0.003	$0.003
2024	$6.09	0.990	0.951	1712	$6	$6	0.463	$3	$3	$0.003	$0.003
2025	$6.22	0.989	0.946	1703	$6	$6	0.429	$3	$2	$0.003	$0.003
2026	$6.34	0.988	0.942	1695	$6	$6	0.397	$2	$2	$0.004	$0.003
2027	$6.47	0.987	0.937	1686	$6	$6	0.368	$2	$2	$0.004	$0.003
2028	$6.60	0.986	0.932	1678	$6	$6	0.340	$2	$2	$0.004	$0.003
2029	$6.73	0.985	0.928	1670	$6	$6	0.315	$2	$2	$0.004	$0.003
2030	$6.86	0.984	0.923	1661	$6	$6	0.292	$2	$2	$0.004	$0.003
2031	$7.00	0.983	0.918	1653	$7	$5	0.270	$2	$1	$0.004	$0.003
2032	$7.14	0.982	0.914	1645	$7	$5	0.250	$2	$1	$0.004	$0.003
2033	$7.28	0.981	0.909	1636	$7	$5	0.232	$2	$1	$0.004	$0.003
2034	$7.43	0.980	0.905	1628	$7	$5	0.215	$1	$1	$0.004	$0.003
2035	$7.58	0.979	0.900	1620	$7	$5	0.199	$1	$1	$0.004	$0.003
2036	$7.73	0.978	0.896	1612	$7	$5	0.184	$1	$1	$0.004	$0.003
2037	$7.88	0.977	0.891	1604	$7	$5	0.170	$1	$1	$0.004	$0.003
2038	$8.04	0.976	0.887	1596	$7	$5	0.158	$1	$1	$0.005	$0.003

Validation: Present Value	Utility	VOS
	$66	$66

Avoided Plant O&M – Variable

An example calculation of avoided plant O&M is displayed in Table 10. Utility prices are given in the VOS Data Table, escalated each year by the O&M escalation rate. As before, the per unit PV production is shown with annual degradation taken into account. The utility cost is the product of the utility price and the per unit production, and these costs are discounted. The VOS price of variable O&M is the levelized value resulting in the same total discounted cost.

Table 10. (EXAMPLE) Economic value of avoided plant O&M – variable.

	Prices			Costs			Disc. Costs	
Year	**Utility**	**VOS**	**p.u. PV Production**	**Utility**	**VOS**	**Discount Factor**	**Utility**	**VOS**
	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	$0.0010	$0.0012	1,800	$2	$2	1.000	$2	$2
2015	$0.0010	$0.0012	1,791	$2	$2	0.926	$2	$2
2016	$0.0010	$0.0012	1,782	$2	$2	0.857	$2	$2
2017	$0.0011	$0.0012	1,773	$2	$2	0.794	$1	$2
2018	$0.0011	$0.0012	1,764	$2	$2	0.735	$1	$2
2019	$0.0011	$0.0012	1,755	$2	$2	0.681	$1	$1
2020	$0.0011	$0.0012	1,747	$2	$2	0.630	$1	$1
2021	$0.0011	$0.0012	1,738	$2	$2	0.583	$1	$1
2022	$0.0012	$0.0012	1,729	$2	$2	0.540	$1	$1
2023	$0.0012	$0.0012	1,721	$2	$2	0.500	$1	$1
2024	$0.0012	$0.0012	1,712	$2	$2	0.463	$1	$1
2025	$0.0012	$0.0012	1,703	$2	$2	0.429	$1	$1
2026	$0.0013	$0.0012	1,695	$2	$2	0.397	$1	$1
2027	$0.0013	$0.0012	1,686	$2	$2	0.368	$1	$1
2028	$0.0013	$0.0012	1,678	$2	$2	0.340	$1	$1
2029	$0.0013	$0.0012	1,670	$2	$2	0.315	$1	$1
2030	$0.0014	$0.0012	1,661	$2	$2	0.292	$1	$1
2031	$0.0014	$0.0012	1,653	$2	$2	0.270	$1	$1
2032	$0.0014	$0.0012	1,645	$2	$2	0.250	$1	$0
2033	$0.0015	$0.0012	1,636	$2	$2	0.232	$1	$0
2034	$0.0015	$0.0012	1,628	$2	$2	0.215	$1	$0
2035	$0.0015	$0.0012	1,620	$2	$2	0.199	$0	$0
2036	$0.0015	$0.0012	1,612	$2	$2	0.184	$0	$0
2037	$0.0016	$0.0012	1,604	$3	$2	0.170	$0	$0
2038	$0.0016	$0.0012	1,596	$3	$2	0.158	$0	$0

Validation: Present Value	**$24**	**$24**

Avoided Generation Capacity Cost

The solar-weighted capacity cost is based on the installed capital cost of a peaking combustion turbine and the installed capital cost of a combined cycle gas turbine, interpolated based on heat rate:

$$Cost = Cost_{CCGT} + (HeatRate_{PV} - HeatRate_{CCGT}) \times \frac{Cost_{CT} - Cost_{CCGT}}{HeatRate_{CT} - HeatRate_{CCGT}} \qquad (17)$$

Where $HeatRate_{PV}$ is the solar-weighted heat rate calculated in equation (14).

Using equation (17) with the CT/CCGT heat rates and costs from the example VOS Data Table, we calculated a solar-weighted capacity cost of $1,050 per kW. In the example, the amortized cost is $86 per kW-yr.

Table 11 illustrates how utility costs are calculated by taking into account the degrading heat rate of the marginal unit and PV. For example, in year 2015, the utility cost is $86 per kW-yr x 0.999 / 0.995 to give $85 for each unit of effective PV capacity. Utility prices are back-calculated for reference from the per unit PV production. Again, the VOS price is selected to give the same total discounted cost as the utility costs for the Generation Capacity Cost component.

Table 11. (EXAMPLE) Economic value of avoided generation capacity cost.

Year	Capacity Cost	Utility Capacity	PV Capacity	p.u. PV Production	Costs Utility	Costs VOS	Discount Factor	Disc. Costs Utility	Disc. Costs VOS	Prices Utility	Prices VOS
	($/kW-yr)	(p.u.)	(kW)	(kWh)	($)	($)		($)	($)	($/kWh)	($/kWh)
2014	$86	1.000	1.000	1800	$86	$87	1.000	$86	$87	$0.048	$0.048
2015	$86	0.999	0.995	1791	$85	$86	0.926	$79	$80	$0.048	$0.048
2016	$86	0.998	0.990	1782	$85	$86	0.857	$73	$73	$0.048	$0.048
2017	$86	0.997	0.985	1773	$85	$85	0.794	$67	$68	$0.048	$0.048
2018	$86	0.996	0.980	1764	$84	$85	0.735	$62	$62	$0.048	$0.048
2019	$86	0.995	0.975	1755	$84	$84	0.681	$57	$57	$0.048	$0.048
2020	$86	0.994	0.970	1747	$84	$84	0.630	$53	$53	$0.048	$0.048
2021	$86	0.993	0.966	1738	$83	$84	0.583	$49	$49	$0.048	$0.048
2022	$86	0.992	0.961	1729	$83	$83	0.540	$45	$45	$0.048	$0.048
2023	$86	0.991	0.956	1721	$83	$83	0.500	$41	$41	$0.048	$0.048
2024	$86	0.990	0.951	1712	$82	$82	0.463	$38	$38	$0.048	$0.048
2025	$86	0.989	0.946	1703	$82	$82	0.429	$35	$35	$0.048	$0.048
2026	$86	0.988	0.942	1695	$82	$81	0.397	$32	$32	$0.048	$0.048
2027	$86	0.987	0.937	1686	$81	$81	0.368	$30	$30	$0.048	$0.048
2028	$86	0.986	0.932	1678	$81	$81	0.340	$28	$27	$0.048	$0.048
2029	$86	0.985	0.928	1670	$81	$80	0.315	$25	$25	$0.048	$0.048
2030	$86	0.984	0.923	1661	$80	$80	0.292	$23	$23	$0.048	$0.048
2031	$86	0.983	0.918	1653	$80	$79	0.270	$22	$21	$0.049	$0.048
2032	$86	0.982	0.914	1645	$80	$79	0.250	$20	$20	$0.049	$0.048
2033	$86	0.981	0.909	1636	$80	$79	0.232	$18	$18	$0.049	$0.048
2034	$86	0.980	0.905	1628	$79	$78	0.215	$17	$17	$0.049	$0.048
2035	$86	0.979	0.900	1620	$79	$78	0.199	$16	$15	$0.049	$0.048
2036	$86	0.978	0.896	1612	$79	$77	0.184	$14	$14	$0.049	$0.048
2037	$86	0.977	0.891	1604	$78	$77	0.170	$13	$13	$0.049	$0.048
2038	$86	0.976	0.887	1596	$78	$77	0.158	$12	$12	$0.049	$0.048

Validation: Present Value	$958	$958

Avoided Reserve Capacity Cost

An example of the calculation of avoided reserve capacity cost is shown in Table 12. This is identical to the generation capacity cost calculation, except utility costs are multiplied by the reserve capacity margin. In the example, the reserve capacity margin is 15%, so the utility cost for 2014 is calculated as $86 per unit effective capacity x 15% = $13. The rest of the calculation is identical to the capacity cost calculation.

Avoided Transmission Capacity Cost

Avoided transmission costs are calculated the same way as avoided generation costs except in two ways. First, transmission capacity is assumed not to degrade over time (PV degradation is still accounted for). Second, avoided transmission capacity costs are calculated based on the utility's 5-year average MISO OATT Schedule 9 charge in Start Year USD, e.g., in 2014 USD if year one of the VOS tariff was 2014. Table 13 shows the example calculation.

Table 12. (EXAMPLE) Economic value of avoided reserve capacity cost.

Year	Capacity Cost	Gen. Capacity	PV Capacity	p.u. PV Production	Costs		Discount Factor	Disc. Costs		Prices	
					Utility	VOS		Utility	VOS	Utility	VOS
	($/kW-yr)	(p.u.)	(kW)	(kWh)	($)	($)		($)	($)	($/kWh)	($/kWh)
2014	$86	1.000	1.000	1800	$13	$13	1.000	$13	$13	$0.007	$0.007
2015	$86	0.999	0.995	1791	$13	$13	0.926	$12	$12	$0.007	$0.007
2016	$86	0.998	0.990	1782	$13	$13	0.857	$11	$11	$0.007	$0.007
2017	$86	0.997	0.985	1773	$13	$13	0.794	$10	$10	$0.007	$0.007
2018	$86	0.996	0.980	1764	$13	$13	0.735	$9	$9	$0.007	$0.007
2019	$86	0.995	0.975	1755	$13	$13	0.681	$9	$9	$0.007	$0.007
2020	$86	0.994	0.970	1747	$13	$13	0.630	$8	$8	$0.007	$0.007
2021	$86	0.993	0.966	1738	$13	$13	0.583	$7	$7	$0.007	$0.007
2022	$86	0.992	0.961	1729	$12	$12	0.540	$7	$7	$0.007	$0.007
2023	$86	0.991	0.956	1721	$12	$12	0.500	$6	$6	$0.007	$0.007
2024	$86	0.990	0.951	1712	$12	$12	0.463	$6	$6	$0.007	$0.007
2025	$86	0.989	0.946	1703	$12	$12	0.429	$5	$5	$0.007	$0.007
2026	$86	0.988	0.942	1695	$12	$12	0.397	$5	$5	$0.007	$0.007
2027	$86	0.987	0.937	1686	$12	$12	0.368	$4	$4	$0.007	$0.007
2028	$86	0.986	0.932	1678	$12	$12	0.340	$4	$4	$0.007	$0.007
2029	$86	0.985	0.928	1670	$12	$12	0.315	$4	$4	$0.007	$0.007
2030	$86	0.984	0.923	1661	$12	$12	0.292	$4	$3	$0.007	$0.007
2031	$86	0.983	0.918	1653	$12	$12	0.270	$3	$3	$0.007	$0.007
2032	$86	0.982	0.914	1645	$12	$12	0.250	$3	$3	$0.007	$0.007
2033	$86	0.981	0.909	1636	$12	$12	0.232	$3	$3	$0.007	$0.007
2034	$86	0.980	0.905	1628	$12	$12	0.215	$3	$3	$0.007	$0.007
2035	$86	0.979	0.900	1620	$12	$12	0.199	$2	$2	$0.007	$0.007
2036	$86	0.978	0.896	1612	$12	$12	0.184	$2	$2	$0.007	$0.007
2037	$86	0.977	0.891	1604	$12	$12	0.170	$2	$2	$0.007	$0.007
2038	$86	0.976	0.887	1596	$12	$12	0.158	$2	$2	$0.007	$0.007

Validation: Present Value	$144	$144

Table 13. (EXAMPLE) Economic value of avoided transmission capacity cost.

Year	Capacity Cost	Trans. Capacity	PV Capacity	p.u. PV Production	Costs		Discount Factor	Disc. Costs		Prices	
					Utility	VOS		Utility	VOS	Utility	VOS
	($/kW-yr)	(p.u.)	(kW)	(kWh)	($)	($)		($)	($)	($/kWh)	($/kWh)
2014	$33	1.000	1.000	1800	$33	$33	1.000	$33	$33	$0.018	$0.018
2015	$33	1.000	0.995	1791	$33	$33	0.926	$30	$30	$0.018	$0.018
2016	$33	1.000	0.990	1782	$33	$33	0.857	$28	$28	$0.018	$0.018
2017	$33	1.000	0.985	1773	$33	$33	0.794	$26	$26	$0.018	$0.018
2018	$33	1.000	0.980	1764	$32	$32	0.735	$24	$24	$0.018	$0.018
2019	$33	1.000	0.975	1755	$32	$32	0.681	$22	$22	$0.018	$0.018
2020	$33	1.000	0.970	1747	$32	$32	0.630	$20	$20	$0.018	$0.018
2021	$33	1.000	0.966	1738	$32	$32	0.583	$19	$19	$0.018	$0.018
2022	$33	1.000	0.961	1729	$32	$32	0.540	$17	$17	$0.018	$0.018
2023	$33	1.000	0.956	1721	$32	$32	0.500	$16	$16	$0.018	$0.018
2024	$33	1.000	0.951	1712	$31	$31	0.463	$15	$15	$0.018	$0.018
2025	$33	1.000	0.946	1703	$31	$31	0.429	$13	$13	$0.018	$0.018
2026	$33	1.000	0.942	1695	$31	$31	0.397	$12	$12	$0.018	$0.018
2027	$33	1.000	0.937	1686	$31	$31	0.368	$11	$11	$0.018	$0.018
2028	$33	1.000	0.932	1678	$31	$31	0.340	$10	$10	$0.018	$0.018
2029	$33	1.000	0.928	1670	$31	$31	0.315	$10	$10	$0.018	$0.018
2030	$33	1.000	0.923	1661	$30	$30	0.292	$9	$9	$0.018	$0.018
2031	$33	1.000	0.918	1653	$30	$30	0.270	$8	$8	$0.018	$0.018
2032	$33	1.000	0.914	1645	$30	$30	0.250	$8	$8	$0.018	$0.018
2033	$33	1.000	0.909	1636	$30	$30	0.232	$7	$7	$0.018	$0.018
2034	$33	1.000	0.905	1628	$30	$30	0.215	$6	$6	$0.018	$0.018
2035	$33	1.000	0.900	1620	$30	$30	0.199	$6	$6	$0.018	$0.018
2036	$33	1.000	0.896	1612	$30	$30	0.184	$5	$5	$0.018	$0.018
2037	$33	1.000	0.891	1604	$29	$29	0.170	$5	$5	$0.018	$0.018
2038	$33	1.000	0.887	1596	$29	$29	0.158	$5	$5	$0.018	$0.018

Validation: Present Value	$365	$365

Avoided Distribution Capacity Cost

Avoided distribution capacity costs may be calculated in either of two ways:

- **System-wide Avoided Costs**. These are calculated using utility-wide costs and lead to a VOS rate that is “averaged” and applicable to all solar customers. This method is described below in the methodology.

- **Location-specific Avoided Costs**. These are calculated using location-specific costs, growth rates, etc., and lead to location-specific VOS rates. This method provides the utility with a means for offering a higher-value VOS rate in areas where capacity is most needed (areas of highest value). The details of this method are site specific and not included in the methodology, however they are to be implemented in accordance with the requirements set for the below.

System-wide Avoided Costs

System wide costs and peak growth rates are determined using actual data from each of the last 10 years. The costs and growth rate must be taken over the same time period because the historical investments must be tied to the growth associated with those investments.

All costs for each year for FERC accounts 360, 361, 362, 365, 366, and 367 should be included. These costs, however, should be adjusted to consider only capacity-related amounts. As such, the capacity-related percentages shown in Table 14 will be utility specific.

Table 14. (EXAMPLE) Determination of deferrable costs.

Account	Account Name	Additions ($) [A]	Retirements ($) [R]	Net Additions ($) = [A] - [R]	Capacity Related?	Deferrable ($)
	DISTRIBUTION PLANT					
360	Land and Land Rights	13,931,928	233,588	13,698,340	100%	13,698,340
361	Structures and Improvements	35,910,551	279,744	35,630,807	100%	35,630,807
362	Station Equipment	478,389,052	20,808,913	457,580,139	100%	457,580,139
363	Storage Battery Equipment					
364	Poles, Towers, and Fixtures	310,476,864	9,489,470	300,987,394		
365	Overhead Conductors and Devices	349,818,997	22,090,380	327,728,617	25%	81,932,154
366	Underground Conduit	210,115,953	10,512,018	199,603,935	25%	49,900,984
367	Underground Conductors and Devices	902,527,963	32,232,966	870,294,997	25%	217,573,749
368	Line Transformers	389,984,149	19,941,075	370,043,074		
369	Services	267,451,206	5,014,559	262,436,647		
370	Meters	118,461,196	4,371,827	114,089,369		
371	Installations on Customer Premises	22,705,193		22,705,193		
372	Leased Property on Customer Premises					
373	Street Lighting and Signal Systems	53,413,993	3,022,447	50,391,546		
374	Asset Retirement Costs for Distribution Plant	15,474,098	2,432,400	13,041,698		
TOTAL		3,168,661,143	130,429,387	3,038,231,756		$856,316,173

Cost per unit growth ($ per kW) is calculated by taking all of the total deferrable cost for each year, adjusting for inflation, and dividing by the kW increase in peak annual load over the 10 years.

Future growth in peak load is assumed to be at the same rate as the last 10 years. It is calculated using the ratio of peak loads of the most recent year (year 10) and the peak load from the earlier year (year 1):

$$GrowthRate = \left(\frac{P_{10}}{P_1}\right)^{1/10} - 1 \qquad (18)$$

A sample economic value calculation is presented in Table 15. The distribution cost for the first year ($200 per kW in the example) is taken from the analysis of historical cost and growth as described above. This cost is escalated each year using the rate in the VOS Data Table.

For each future year, the amount of new distribution capacity is calculated based on the growth rate, and this is multiplied by the cost per kW to get the cost for the year. The total discounted cost is calculated ($149M) and amortized over the 25 years.

PV is assumed to be installed in sufficient capacity to allow this investment stream to be deferred for one year. The total discounted cost of the deferred time series is calculated ($140M) and amortized.

Utility costs are calculated using the difference between the amortized costs of the conventional plan and the amortized cost of the deferred plan. For example, the utility cost for 2022 is ($14M - $13M)/54MW x 1000 W/kW = $14 per effective kW of PV. As before, utility prices are back-calculated using PV production, and the VOS component rate is calculated such that the total discounted amount equals the discounted utility cost.

Location-specific Avoided Costs

As an alternative to system-wide costs for distribution, location-specific costs may be used. When calculating location-specific costs, the calculation should follow the same method of the system-wide avoided cost method, but use local technical and cost data. The calculation should satisfy the following requirements:

- The distribution cost VOS should be calculated for each distribution planning area, defined as the minimum area in which capacity needs cannot be met by transferring loads internally from one circuit to another.
- Distribution loads (the sum of all relevant feeders), peak load growth rates and capital costs should be based on the distribution planning area.
- Local Fleet Production Shapes may be used, if desired. Alternatively, the system-level Fleet Production Shape may be used.

- Anticipated capital costs should be evaluated based on capacity related investments only (as above) using budgetary engineering cost estimates. All anticipated capital investments in the planning area should be included. Planned capital investments should be assumed to meet capacity requirements for the number of years defined by the amount of new capacity added (in MW) divided by the local growth rate (MW per year). Beyond this time period, which is beyond the planning horizon, new capacity investments should be assumed each year using the system-wide method.
- Planning areas for which engineering cost estimates are not available may be combined, and the VOS calculated using the system-wide method.

Table 15. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

		Conventional Distribution Planning				Deferred Distribution Planning			
Year	Distribution Cost	New Dist. Capacity	Capital Cost	Disc. Capital Cost	Amortized	Def. Dist. Capacity	Def. Capital Cost	Disc. Capital Cost	Amortized
	($/kW)	(MW)	($M)	($M)	$M/yr	(MW)	($M)	($M)	$M/yr
2014	$200	50	$10	$10	$14				$13
2015	$204	50	$10	$9	$14	50	$10	$9	$13
2016	$208	51	$11	$9	$14	50	$10	$9	$13
2017	$212	51	$11	$9	$14	51	$11	$9	$13
2018	$216	52	$11	$8	$14	51	$11	$8	$13
2019	$221	52	$11	$8	$14	52	$11	$8	$13
2020	$225	53	$12	$7	$14	52	$12	$7	$13
2021	$230	53	$12	$7	$14	53	$12	$7	$13
2022	$234	54	$13	$7	$14	53	$12	$7	$13
2023	$239	54	$13	$6	$14	54	$13	$6	$13
2024	$244	55	$13	$6	$14	54	$13	$6	$13
2025	$249	55	$14	$6	$14	55	$14	$6	$13
2026	$254	56	$14	$6	$14	55	$14	$6	$13
2027	$259	56	$15	$5	$14	56	$14	$5	$13
2028	$264	57	$15	$5	$14	56	$15	$5	$13
2029	$269	57	$15	$5	$14	57	$15	$5	$13
2030	$275	58	$16	$5	$14	57	$16	$5	$13
2031	$280	59	$16	$4	$14	58	$16	$4	$13
2032	$286	59	$17	$4	$14	59	$17	$4	$13
2033	$291	60	$17	$4	$14	59	$17	$4	$13
2034	$297	60	$18	$4	$14	60	$18	$4	$13
2035	$303	61	$18	$4	$14	60	$18	$4	$13
2036	$309	62	$19	$4	$14	61	$19	$3	$13
2037	$315	62	$20	$3	$14	62	$19	$3	$13
2038	$322	63	$20	$3	$14	62	$20	$3	$13
2039	$328					63	$21	$3	
				$149				$140	

CONTINUED Table 15. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

Year	p.u. PV Production	Costs Utility	Costs VOS	Discount Factor	Disc. Costs Utility	Disc. Costs VOS	Prices Utility	Prices VOS
	(kWh)	($)	($)		($)	($)	($/kWh)	($/kWh)
2014	1800	$16	$15	1.000	$16	$15	$0.009	$0.008
2015	1791	$15	$15	0.926	$14	$14	$0.009	$0.008
2016	1782	$15	$15	0.857	$13	$13	$0.009	$0.008
2017	1773	$15	$15	0.794	$12	$12	$0.009	$0.008
2018	1764	$15	$15	0.735	$11	$11	$0.009	$0.008
2019	1755	$15	$15	0.681	$10	$10	$0.008	$0.008
2020	1747	$15	$15	0.630	$9	$9	$0.008	$0.008
2021	1738	$15	$15	0.583	$9	$8	$0.008	$0.008
2022	1729	$14	$14	0.540	$8	$8	$0.008	$0.008
2023	1721	$14	$14	0.500	$7	$7	$0.008	$0.008
2024	1712	$14	$14	0.463	$7	$7	$0.008	$0.008
2025	1703	$14	$14	0.429	$6	$6	$0.008	$0.008
2026	1695	$14	$14	0.397	$6	$6	$0.008	$0.008
2027	1686	$14	$14	0.368	$5	$5	$0.008	$0.008
2028	1678	$14	$14	0.340	$5	$5	$0.008	$0.008
2029	1670	$13	$14	0.315	$4	$4	$0.008	$0.008
2030	1661	$13	$14	0.292	$4	$4	$0.008	$0.008
2031	1653	$13	$14	0.270	$4	$4	$0.008	$0.008
2032	1645	$13	$14	0.250	$3	$3	$0.008	$0.008
2033	1636	$13	$14	0.232	$3	$3	$0.008	$0.008
2034	1628	$13	$14	0.215	$3	$3	$0.008	$0.008
2035	1620	$13	$14	0.199	$3	$3	$0.008	$0.008
2036	1612	$13	$13	0.184	$2	$2	$0.008	$0.008
2037	1604	$12	$13	0.170	$2	$2	$0.008	$0.008
2038	1596	$12	$13	0.158	$2	$2	$0.008	$0.008
2039								

Validation: Present Value	$166	$166

Avoided Environmental Cost

Environmental costs are included as a required component and are based on existing Minnesota and EPA externality costs. CO_2 and non-CO_2 natural gas emissions factors (lb per MM BTU of natural gas) are taken from the EPA[15] and NaturalGas.org,[16] both of which have nearly identical numbers for the emissions factors. Avoided environmental costs are based on the federal social cost of CO_2 emissions[17] plus the Minnesota PUC-established externality costs for non-CO_2 emissions[18].

The externality cost of CO_2 emissions shown in Table 4 are calculated as follows. The EPA Social Cost of Carbon (CO_2) estimated for a given year is published in 2007 dollars per metric ton. These costs are adjusted for inflation (converted to current dollars), converted to dollars per short ton, and then converted to cost per unit fuel consumption using the assumed values in Table 16.

For example, the EPA externality cost for 2020 (3.0% discount rate, average) is $43 per metric ton of CO_2 emissions in 2007 dollars. This is converted to current dollars by multiplying by a CPI adjustment factor; for 2014, the CPI adjustment factor is of 1.12. The resulting CO_2 costs per metric ton in current dollars are then converted to dollars per short ton by dividing by 1.102. Finally, the costs are escalated using the general escalation rate of 2.53% per year to give $50.77 per ton. Which equates to $51.22 per ton of CO_2, divided by 2000 pounds per ton, and multiplied by 117.0 pounds of CO_2 per MMBtu = $2.970 per MMBtu in 2020 dollars.

Table 16. Natural Gas Emissions.

	NG Emissions (lb/MMBtu)
PM10	0.007
CO	0.04
NOX	0.092
Pb	0.00
CO2	117.0

[15] http://www.epa.gov/climatechange/ghgemissions/ind-assumptions.html and http://www.epa.gov/ttnchie1/ap42/
[16] http://www.naturalgas.org/environment/naturalgas.asp
[17] See http://www.epa.gov/climatechange/EPAactivities/economics/scc.html, EPA technical document appendix, May 2013.
[18] "Notice of Updated Environmental Externality Values," issued June 5, 2013, PUC docket numbers E-999/CI-93-583 and E-999/CI-00-1636.

All pollutants other than CO_2 are calculated using the Minnesota externality costs using the following method. Externality costs are taken as the midpoint of the low and high values for the urban scenario, adjusted to current dollars, and converted to a fuel-based value using Table 16.

For example, MN's published costs for PM10 are $6,291 per ton (low case) and $9,056 per ton (high case). These are averaged to be ($6291+$9056)/2 = $7674 per ton of PM10 emissions. For 2020, these are escalated using the general escalation rate of 2.53% per year to $8,917 per ton. Which equates to $8,917 per ton of PM10, divided by 2000 pounds per ton, multiplied by 0.007 pounds of PM10 per MMBtu = $0.031 per MMBtu. Similar calculations are done for the other pollutants.

In the example shown in Table 17, the environmental cost is the sum of the costs of all pollutants. For example, in 2020, the total cost of $3.052 per MMBtu corresponds to the 2020 total cost in Table 4. This cost is multiplied by the heat rate for the year (see Avoided Fuel Cost calculation) and divided by 10^6 (to convert Btus to MMBtus), which results in the environmental cost in dollars per kWh for each year. The remainder of the calculation follows the same method as the avoided variable O&M costs but using the environmental discount factor (see Discount Factors for a description of the environmental discount factor and its calculation).

Avoided Voltage Control Cost

This is reserved for future updates to the methodology.

Solar Integration Cost

This is reserved for future updates to the methodology.

Table 17. (EXAMPLE) Economic value of avoided environmental cost.

Year	Env. Cost	Heat Rate	Prices		p.u. PV Production	Costs		Discount Factor	Disc. Costs	
			Utility	VOS		Utility	VOS		Utility	VOS
	($/MMBtu)	(Btu/kWh)	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	2.210	8000	$0.018	$0.029	1,800	$32	$52	1.000	$32	$52
2015	2.327	8008	$0.019	$0.029	1,791	$33	$52	0.947	$32	$49
2016	2.449	8016	$0.020	$0.029	1,782	$35	$52	0.897	$31	$46
2017	2.575	8024	$0.021	$0.029	1,773	$37	$51	0.849	$31	$44
2018	2.706	8032	$0.022	$0.029	1,764	$38	$51	0.804	$31	$41
2019	2.909	8040	$0.023	$0.029	1,755	$41	$51	0.761	$31	$39
2020	3.052	8048	$0.025	$0.029	1,747	$43	$51	0.721	$31	$36
2021	3.130	8056	$0.025	$0.029	1,738	$44	$50	0.682	$30	$34
2022	3.282	8064	$0.026	$0.029	1,729	$46	$50	0.646	$30	$32
2023	3.439	8072	$0.028	$0.029	1,721	$48	$50	0.612	$29	$30
2024	3.603	8080	$0.029	$0.029	1,712	$50	$50	0.579	$29	$29
2025	3.772	8088	$0.031	$0.029	1,703	$52	$49	0.549	$29	$27
2026	3.948	8097	$0.032	$0.029	1,695	$54	$49	0.519	$28	$25
2027	4.131	8105	$0.033	$0.029	1,686	$56	$49	0.492	$28	$24
2028	4.320	8113	$0.035	$0.029	1,678	$59	$49	0.466	$27	$23
2029	4.516	8121	$0.037	$0.029	1,670	$61	$48	0.441	$27	$21
2030	4.719	8129	$0.038	$0.029	1,661	$64	$48	0.417	$27	$20
2031	4.839	8137	$0.039	$0.029	1,653	$65	$48	0.395	$26	$19
2032	5.054	8145	$0.041	$0.029	1,645	$68	$48	0.374	$25	$18
2033	5.278	8153	$0.043	$0.029	1,636	$70	$47	0.354	$25	$17
2034	5.510	8162	$0.045	$0.029	1,628	$73	$47	0.336	$25	$16
2035	5.750	8170	$0.047	$0.029	1,620	$76	$47	0.318	$24	$15
2036	5.999	8178	$0.049	$0.029	1,612	$79	$47	0.301	$24	$14
2037	6.257	8186	$0.051	$0.029	1,604	$82	$46	0.285	$23	$13
2038	6.524	8194	$0.053	$0.029	1,596	$85	$46	0.270	$23	$12

Validation: Present Value	**$697**	**$697**

VOS Example Calculation

The economic value, load match, distributed loss savings, and distributed PV value are combined in the required VOS Levelized Calculation Chart. An example is presented in Figure 3 using the assumptions made for the example calculation. Actual VOS results will differ from those shown in the example, but utilities will include in their application a VOS Levelized Calculation Chart in the same format. For completeness, Figure 4 (not required of the utilities) is presented showing graphically the relative importance of the components in the example.

Figure 3. (EXAMPLE) VOS Levelized Calculation Chart (Required).

25 Year Levelized Value	Gross Starting Value ($/kWh)	×	Load Match Factor (%)	× (1 +	Loss Savings Factor (%)	) =	Distributed PV Value ($/kWh)
Avoided Fuel Cost	$0.061				8%		$0.066
Avoided Plant O&M - Fixed	$0.003		40%		9%		$0.001
Avoided Plant O&M - Variable	$0.001				8%		$0.001
Avoided Gen Capacity Cost	$0.048		40%		9%		$0.021
Avoided Reserve Capacity Cost	$0.007		40%		9%		$0.003
Avoided Trans. Capacity Cost	$0.018		40%		9%		$0.008
Avoided Dist. Capacity Cost	$0.008		30%		5%		$0.003
Avoided Environmental Cost	$0.029				8%		$0.031
Avoided Voltage Control Cost							
Solar Integration Cost							
							$0.135

Having calculated the levelized VOS credit, an inflation-adjusted VOS can then be found. An EXAMPLE inflation-adjusted VOS is provided in Figure 5 by using the general escalation rate as the annual inflation rate for all years of the analysis period. Both the inflation-adjusted VOS and the levelized VOS in Figure 5 represent the same long-term value. The methodology requires that the inflation-adjusted (nominal) VOS be used and updated annually to account for the current year's inflation rate.

To calculate the inflation-adjusted VOS for the first year, the products of the levelized VOS, PV production and the discount factor are summed for each year of the analysis period and then divided by the sum of the products of the escalation factor, PV production, and the discount factor for each year of the analysis period, as shown below in Equation (19).

Figure 4. (EXAMPLE) Levelized value components.

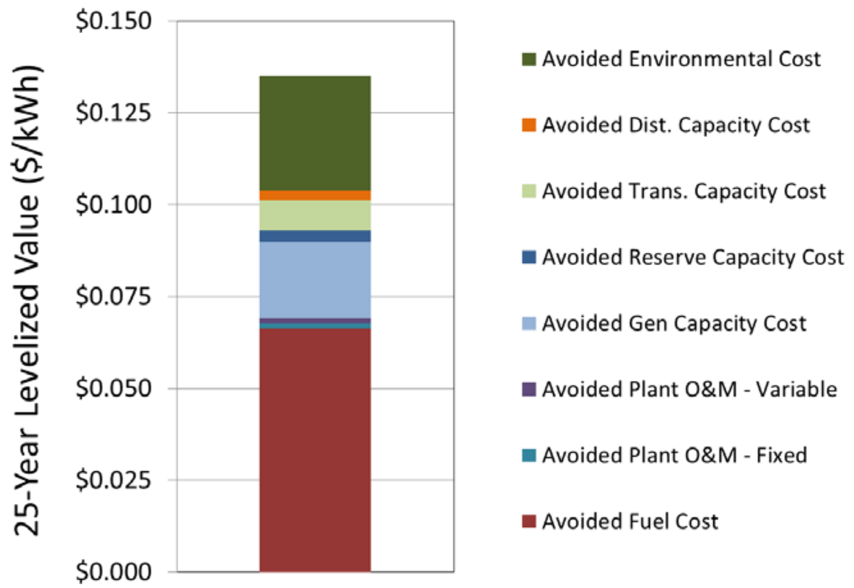
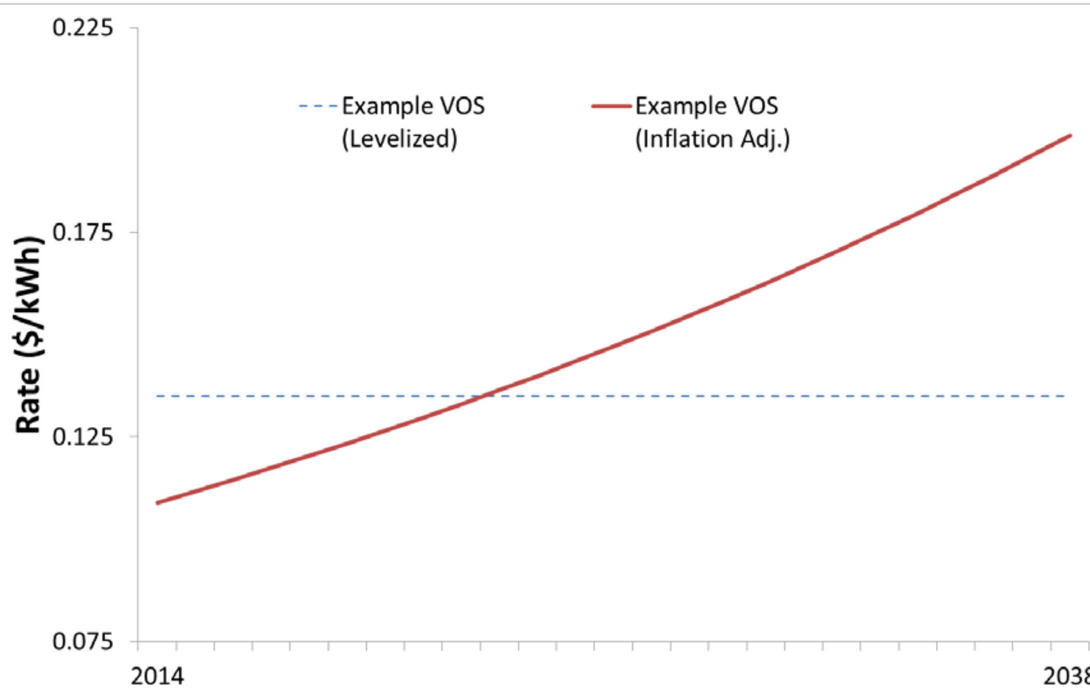


Figure 5. (EXAMPLE) Inflation-Adjusted VOS.



$$InflationAdjustedVOS_{Year0}\left(\frac{\$}{kWh}\right) \tag{19}$$

$$= \frac{\sum_i LevelizedVOS \times PVProduction_i \times DiscountFactor_i}{\sum_i EscalationFactor_i \times PVProduction_i \times DiscountFactor_i}$$

Once the first-year inflation-adjusted VOS is calculated, the value will then be updated on an annual basis in accordance with the observed inflation-rate. Table 18 provides the calculation of the EXAMPLE inflation-adjusted VOS shown in Figure 5. In this EXAMPLE, the inflation rate in future years is set equal to the general escalation rate of 2.53%.

Table 18. (EXAMPLE) Calculation of inflation-adjusted VOS.

Year	Discount Factor	PV Production (kWh)	Escalation Factor	Example VOS (Levelized)	Disc. Cost ($)	Example VOS (Inflation Adj.)	Disc. Cost ($)
2014	1.000	1800	1.000	0.135	243	0.109	196
2015	0.926	1791	1.025	0.135	224	0.112	185
2016	0.857	1782	1.051	0.135	206	0.115	175
2017	0.794	1773	1.078	0.135	190	0.117	165
2018	0.735	1764	1.105	0.135	175	0.120	156
2019	0.681	1755	1.133	0.135	161	0.123	147
2020	0.630	1747	1.162	0.135	149	0.127	139
2021	0.583	1738	1.192	0.135	137	0.130	132
2022	0.540	1729	1.222	0.135	126	0.133	124
2023	0.500	1721	1.253	0.135	116	0.136	117
2024	0.463	1712	1.284	0.135	107	0.140	111
2025	0.429	1703	1.317	0.135	99	0.143	105
2026	0.397	1695	1.350	0.135	91	0.147	99
2027	0.368	1686	1.385	0.135	84	0.151	94
2028	0.340	1678	1.420	0.135	77	0.155	88
2029	0.315	1670	1.456	0.135	71	0.159	83
2030	0.292	1661	1.493	0.135	65	0.163	79
2031	0.270	1653	1.530	0.135	60	0.167	74
2032	0.250	1645	1.569	0.135	56	0.171	70
2033	0.232	1636	1.609	0.135	51	0.175	66
2034	0.215	1628	1.650	0.135	47	0.180	63
2035	0.199	1620	1.692	0.135	43	0.184	59
2036	0.184	1612	1.735	0.135	40	0.189	56
2037	0.170	1604	1.779	0.135	37	0.194	53
2038	0.158	1596	1.824	0.135	34	0.199	50
					2689		2689

Glossary

Table 19. Input data definitions

Input Data	Used in Methodology Section	Definition
Annual Energy	PV Energy Production	The annual PV production (kWh per year) per Marginal PV Resource (initially 1 kW-AC) in the first year (before any PV degradation) of the marginal PV resource. This is calculated in the Annual Energy section of PV Energy Production and used in the Equipment Degradation section.
Capacity-related distribution capital cost	Avoided Distribution Capacity Cost	This is described more fully in the Avoided Distribution Capacity Cost section.
Capacity-related transmission capital cost	Avoided Transmission Capacity Cost	The cost per kW of new construction of transmission, including lines, towers, insulators, transmission substations, etc. Only capacity-related costs should be included.
Discount rate (WACC)	Multiple	The utility's weighted average cost of capital, including interest on bonds and shareholder return.
Distribution capital cost escalation	Avoided Distribution Capacity Cost	Used to calculate future distribution costs.
ELCC (no loss), PLR (no loss)	Load Match Factors	The "Effective Load Carrying Capability" and the "Peak Load Reduction" of a PV resource expressed as percentages of rated capacity (kW-AC). These are described more fully in the Load Match section.
Environmental Costs	Avoided Environmental Cost	The costs required to calculate environmental impacts of conventional generation. These are described more fully in the Avoided Environmental Cost section

Input Data	Used in Methodology Section	Definition
Environmental Discount Rate	Avoided Environmental Cost	The societal discount rate corresponding to the EPA future year cost data, used to calculate the present value of future environmental costs.
Fuel Price Overhead	Avoided Fuel Cost	The difference in cost of fuel as delivered to the plant and the cost of fuel as available in market prices. This cost reflects transmission, delivery, and taxes.
General escalation rate	Avoided Environmental Cost, Example Results	The annual escalation rate corresponding to the most recent 25 years of CPI index data[19], used to convert constant dollar environmental costs into current dollars and to translate levelized VOS into inflation-adjusted VOS.
Generation Capacity Degradation	Avoided Generation Capacity Cost	The percentage decrease in the generation capacity per year
Generation Life	Avoided Generation Capacity Cost	The assumed service life of new generation assets.
Guaranteed NG Fuel Price Escalation	Avoided Fuel Cost	The escalation value to be applied for years in which futures prices are not available.
Guaranteed NG Fuel Prices	Avoided Fuel Cost	The annual average prices to be used when the utility elects to use the Futures Market option. These are not applicable when the utility elects to use options other than the Futures Market option. They are calculated as the annual average of monthly NYMEX NG futures[20], updated 8/27/2013.

[19] www.bls.gov

[20] See for example http://futures.tradingcharts.com/marketquotes/NG.html.

Input Data	Used in Methodology Section	Definition
Heat rate degradation	Avoided Generation Capacity Cost	The percentage increase in the heat rate (BTU per kWh) per year
Installed cost and heat rate for CT and CCGT	Avoided Generation Capacity Cost	The capital costs for these units (including all construction costs, land, ad valorem taxes, etc.) and their heat rates.
Loss Savings (Energy, PLR, and ELCC)	Loss Savings Analysis	The additional savings associated with Energy, PRL and ELCC, expressed as a percentage. These are described more fully in the Loss Savings section.
O&M cost escalation rate	Avoided Plant O&M – Fixed, Avoided Plant O&M – Variable	Used to calculate future O&M costs.
O&M fixed costs	Avoided Plant O&M – Fixed	The costs to operate and maintain the plant that are not dependent on the amount of energy generated.
O&M variable costs	Avoided Plant O&M – Variable	The costs to operate and maintain the plant (excluding fuel costs) that are dependent on the amount of energy generated.
Peak Load	Avoided Distribution Capacity Cost	The utility peak load as expected in the year prior to the VOS start year.
Peak load growth rate	Avoided Distribution Capacity Cost	This is described more fully in the Avoided Distribution Capacity Cost section.
PV Degradation	Equipment Degradation Factors	The reduction in percent per year of PV capacity and PV energy due to degradation of the modules. The value of 0.5 percent is the median value of 2000 observed degradation rates.[21]

[21] D. Jordan and S. Kurtz, "Photovoltaic Degradation Rates – An Analytical Review," NREL, June 2012.

Input Data	Used in Methodology Section	Definition
PV Life	Multiple	The assumed service life of PV. This value is also used to define the study period for which avoided costs are determined and the period over which the VOS rate would apply.
Reserve planning margin	Avoided Reserve Capacity Cost	The planning margin required to ensure reliability.
Solar-weighted heat rate	Avoided Fuel Costs	This is described in the described in the Avoided Fuel Costs section.
Start Year for VOS applicability	Multiple	This is the first year in which the VOS would apply and the first year for which avoided costs are calculated.
Transmission capital cost escalation	Avoided Transmission Capacity Cost	Used to adjust costs for future capital investments.
Transmission life	Avoided Transmission Capacity Cost	The assumed service life of new transmission assets.
Treasury Yields	Escalation and Discount Rates	Yields for U.S. Treasuries, used as the basis of the risk-free discount rate calculation.[22]
Years until new transmission capacity is needed	Avoided Transmission Capacity Cost	This is used to test whether avoided costs for a given analysis year should be calculated and included.

[22] See http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

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 14-035-114

Exhibit HEAL___(JIF-4)

Maine Public Utilities Commission. Maine Distributed Solar Valuation Study. Executive Summary. April 14, 2015.

June 8, 2017

Public Service Commission of Utah
Docket 14-035-114
Exhibit HEAL___(JIF-4)

Maine Public Utilities Commission

Maine Distributed Solar Valuation Study

Revised April 14, 2015

Maine Public Utilities Commission

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Note on Edition

This edition is an updated and revised version of the March 1, 2015 report delivered to the Maine Legislature and incorporates changes and clarifications further described in the March 25, 2015 addendum.

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Table of Contents

Maine Distributed Solar Valuation Study

Executive Summary

Background

During its 2014 session, the Maine Legislature enacted an Act to Support Solar Energy Development in Maine. P.L Chapter 562 (April 24, 2014) (codified at 35-A M.R.S. §§ 3471-3473) ("Act"). Section 1 of the Act contains the Legislative finding that it is in the public interest is to develop renewable energy resources, including solar energy, in a manner that protects and improves the health and well-being of the citizens and natural environment of the State while also providing economic benefits to communities, ratepayers and the overall economy of the State.

Section 2 of the Act requires the Public Utilities Commission (Commission) to determine the value of distributed solar energy generation in the State, evaluate implementation options, and to deliver a report to the Legislature. To support this work, the Commission engaged a project team comprising Clean Power Research (Napa, California), Sustainable Energy Advantage (Framingham, Massachusetts), Pace Energy and Climate Center at the Pace Law School (White Plains, New York), and Dr. Richard Perez (Albany, New York).

Under the project, the team developed the methodology under a Commission-run stakeholder review process, conducted a valuation on distributed solar for three utility territories, and developed a summary of implementation options for increasing deployment of distributed solar generation in the State.

The report includes three volumes which accompany this Executive Summary:

Volume I	Methodology
Volume II	Valuation Results
Volume III	Implementation Options

Volume I – Methodology

The methodology developed in Volume I was designed to quantify the benefits and costs of the gross energy produced by a photovoltaic (PV) system, as if it were delivered to the grid through its own meter, i.e., prior to serving any local load. Variants of this methodology could be used to determine the value of energy exported to the grid after netting local load (or even generation technologies other than solar), but these would require the development of generation/load profiles that are not included in this methodology.

Guided by the Act and a stakeholder-driven process, the methodology provides for the calculation of the costs and benefits of distributed solar generation for each of the selected components shown in Table ES- 1. The basis for the cost calculations is also shown.

Table ES- 1. Benefit/Cost Bases

Component	Benefit/Cost Basis
Avoided Energy Cost	Hourly avoided wholesale market procurements, based on ISO New England day ahead locational marginal prices for the Maine Load Zone.
Avoided Generation Capacity and Reserve Capacity Costs	ISO New England Forward Capacity Market (FCM) auction clearing prices, followed by forecasted capacity prices by the ISO's consultant. For reserves, the ISO's reserve planning margin is applied.
Avoided NG Pipeline Costs	Not included, but left as a future placeholder if the cost of building future pipeline capacity is built into electricity prices.
Solar Integration Costs	Operating reserves required to handle fluctuations in solar output, based on the New England Wind Integration Study (NEWIS) results.
Avoided Transmission Capacity Cost	ISO New England Regional Network Service (RNS) cost reductions caused by coincident solar peak load reduction.
Avoided Distribution Capacity Cost	Not included, but left as a future placeholder if the peak distribution loads begin to grow (requiring new capacity).
Voltage Regulation	Not included, but left as a future placeholder if

	new interconnections standards come into existence allowing inverters to control voltage and provide voltage ride-through to support the grid.
Net Social Cost of Carbon, SO2, and NOx	EPA estimates of social costs, reduced by compliance costs embedded in wholesale electricity prices.
Market Price Response	The temporary reduction in electricity and capacity prices resulting from reduced demand, based on the Avoided Energy Supply Costs in New England (AESC) study.
Avoided Fuel Price Uncertainty	The cost to eliminate long term price uncertainty in natural gas fuel displaced by solar.

Volume II - Valuation Results

First Year Value

Figure ES- 1 presents the overall value results from Volume II for the Central Maine Power (CMP) Base Case in the first year using the stakeholder reviewed methodology of Volume I. Avoided market costs—including Energy Supply, Transmission Delivery, and Distribution Delivery—are $0.09 per kWh. Additional societal benefits are estimated to be $0.092 per kWh. Avoided NG Pipeline Cost, Avoided Distribution Capacity Cost, and Voltage Regulation are included as placeholders for future evaluations should conditions change that would warrant inclusion.

Avoided market costs represent the benefits and costs associated with capital and operating expenses normally recovered from ratepayers, such as wholesale energy purchases and capacity. Societal benefits are those which accrue to society but are not typically included in setting rates. For example, the social cost of carbon is based on an estimate of costs that will be incurred to mitigate future impacts of carbon emissions, but those costs are not collected from Maine electric customers.

Figure ES- 1. CMP Distributed Value – First Year ($ per kWh)

First Year		Distributed Value ($/kWh)	
Energy Supply	Avoided Energy Cost	$0.061	Avoided Market Costs $0.090
	Avoided Gen. Capacity Cost	$0.015	
	Avoided Res. Gen. Capacity Cost	$0.002	
	Avoided NG Pipeline Cost		
	Solar Integration Cost	-$0.002	
Transmission Delivery	Avoided Trans. Capacity Cost	$0.014	
Distribution Delivery	Avoided Dist. Capacity Cost		
	Voltage Regulation		
Environmental	Net Social Cost of Carbon	$0.021	Societal Benefits $0.092
	Net Social Cost of SO_2	$0.051	
	Net Social Cost of NO_x	$0.011	
Other	Market Price Response	$0.009	
	Avoided Fuel Price Uncertainty	$0.000	
		$0.182	

Environmental Results

The above results indicate a very high environmental value relative to other solar valuation studies. In particular, the Net Social Cost of SO2 is 28% of the total value (market plus societal benefits). The study methodology was based on a three year historical calculation of marginal emissions rates. However, emissions of SO2 and NOx rates are expected to decline in the coming years. If the fuel type were assumed to be only oil and natural gas (FTA marginal emissions rates as described in the Displaced Pollutants section), the displaced emissions and the net social costs shown above would be reduced to 8% and 20% of the values calculated here for SO2 and NOx, respectively.

Long Term Value

Figure ES- 2 provides additional details in the benefit and cost calculations, including load match factors and loss savings factors, and the costs and benefits are shown as 25 year levelized values. The selection 25 years is based on the assumed useful service life of a typical solar PV system.

It is important to note that Figure ES-2 does not identify who the benefits and costs accrue to. For example, avoided energy cost is calculated based on avoided wholesale energy purchases, but this value may involve a series of transactions between the solar customer, the distribution utility, and the energy market participants.

The value shown in Table ES-2 represents a longer term projection of the levelized value of a solar PV system over a 25 year horizon. It is meant to be illustrative and not as a standalone value apart from First Year Value descriptions.

The societal benefits, such as the net Social Cost of SO_2, are external to what present market mechanics monetize; as such they do not monetarily accrue to any market participants (distribution utility, transmission provider, third party generators, etc.). It is left as a policy decision to determine whether these values are relevant and whether to include them in tariff design, incentives, and other structures.

Figure ES- 2. CMP Distributed Value – 25 Year Levelized ($ per kWh)

25 Year Levelized		Gross Value A ($/kWh)	×	Load Match Factor B (%)	×	Loss Savings Factor (1+C) (%)	=	Distr. PV Value D ($/kWh)	
Energy Supply	Avoided Energy Cost	$0.076				6.2%		$0.081	Avoided Market Costs $0.138
	Avoided Gen. Capacity Cost	$0.068		54.4%		9.3%		$0.040	
	Avoided Res. Gen. Capacity Cost	$0.009		54.4%		9.3%		$0.005	
	Avoided NG Pipeline Cost								
	Solar Integration Cost	($0.005)				6.2%		($0.005)	
Transmission Delivery Service	Avoided Trans. Capacity Cost	$0.063		23.9%		9.3%		$0.016	
Distribution Delivery Service	Avoided Dist. Capacity Cost								
	Voltage Regulation								
Environmental	Net Social Cost of Carbon	$0.020				6.2%		$0.021	Societal Benefits $0.199
	Net Social Cost of SO_2	$0.058				6.2%		$0.062	
	Net Social Cost of NO_x	$0.012				6.2%		$0.013	
Other	Market Price Response	$0.062				6.2%		$0.066	
	Avoided Fuel Price Uncertainty	$0.035				6.2%		$0.037	
								$0.337	

Gross Values represent the value of perfectly dispatchable, centralized resources. These are adjusted using

- Load Match Factors to account for the non-dispatchability of solar; and
- Loss Savings Factors to account for the benefit of avoiding energy losses in the transmission and distribution systems.

The load match factor for generation capacity (54%) is based on the output of solar during the top 100 load hours per year. The load match factor for Avoided Transmission Capacity Cost (23.9%) is derived from average monthly reductions in peak transmission demand.

The Distributed PV value is calculated for each benefit and cost category, and these are summed. The result is the 25-year levelized value, meaning the equivalent constant value that could be applied over

25 years that would be equivalent to the combined benefits of avoided market costs and societal benefits.

First Year results for all three utility service territories, including Emera Maine's Bangor Hydro District (BHD) and Maine Public District (MPD), are shown in Figure ES- 3. The results are the same for the first year results except for the avoided transmission cost component which reflects hourly load profiles. RNS rates do not apply to MPD so there is no avoided transmission cost included. Avoided energy is the same because the solar profile was assumed to be the same state-wide, and the LMPs are taken for the Maine zone. Avoided generation capacity costs are based on the same solar profiles and the same ISO-NE loads, so there are no differences in this category. There are differences in long term value due to differences in utility discount rate (not shown).

Figure ES- 3. Base Case Results for CMP, BHD, and MPD – First Year

First Year		CMP $/kWh	BHD $/kWh	MPD $/kWh
Energy Supply	Avoided Energy Cost	0.061	0.061	0.061
	Avoided Gen. Capacity Cost	0.015	0.015	0.015
	Avoided Res. Gen. Capacity Cost	0.002	0.002	0.002
	Avoided NG Pipeline Cost			
	Solar Integration Cost	(0.002)	(0.002)	(0.002)
Transmission Delivery Service	Avoided Trans. Capacity Cost	0.014	0.017	0.000
Distribution Delivery	Avoided Dist. Capacity Cost			
	Voltage Regulation			
Environmental	Net Social Cost of Carbon	0.021	0.021	0.021
	Net Social Cost of SO_2	0.051	0.051	0.051
	Net Social Cost of NO_x	0.011	0.011	0.011
Other	Market Price Response	0.009	0.009	0.009
	Avoided Fuel Price Uncertainty	0.000	0.000	0.000
		0.182	0.184	0.168

Volume III - Implementation Options

Objective

The Act sought information on options for distributed solar energy implementation. Volume III of this report provides an analysis of options for increasing investment in or deployment of distributed solar generation, with an emphasis on those options used in ten states with similarities to Maine in market structure (deregulated) and economic opportunity (driven by insolation, land use, electricity prices, etc.). It also provides general guidance to help the Legislature consider which options, approaches or models may be appropriate for Maine, considering the State's utility market structures.

Solar Implementation Options

Volume III includes a thorough list of solar implementation options in widespread use. The range of implementation options are organized into four major categories:

- **Instruments Used to Incentivize Solar -** Incentives commonly used as vehicles to incentivize distributed solar PV include a suite of implementation options aimed at changing market or economic decision making by (i) creating market demand, (ii) removing financing barriers, and/or (iii) lowering installation costs for solar PV.

- **Financing Enabling Policies -** Financing enabling policies enhance the accessibility of financing, lower financing transactions costs, open up access to lower-cost forms of financing, and otherwise lower the entry barrier to solar investment and enable a broader range of players to participate in the solar market.

- **Rules, Regulations and Rate Design –** Rules, regulations and rate design at all levels of government ensure legal access to the solar market, regulate the economics of solar PV and provide technical support to solar PV deployment.

- **Industry Support -** Industry support approaches are often paired with other implementation strategies to accelerate solar deployment. By incentivizing in-state solar investment, many industry support approaches are also designed to stimulate local job creation and foster state economic growth.

Table ES- 2Table ES- 5 provide an overview of implementation options. Options in shaded rows are commonly-used implementation options but of less potential interest for legislative consideration, and are only discussed briefly in Section 0 of Volume III. The other implementation options are more fully characterized and evaluated. Where applicable, Volume III highlights implementation examples in the five New England States (Connecticut, Massachusetts New Hampshire, Rhode Island and Vermont), New York, and four states (Delaware, Maryland, New Jersey, and Pennsylvania) within the PJM territory. The authors underscore important observations from implementation experiences in these states, as well as notable variations. Volume III also includes a summary of the identified solar implementation options that have been adopted in each state.

Table ES- 2. Summary of Solar Implementation Option: “Instruments Used to Incentivize Solar”

Subcategory	Implementation Examples	Description
Direct Financial, Up-front Incentives	Grants, Rebates, or Buy-Downs	Capacity-denominated (i.e., $/kW) incentives designed to reduce up-front cost of PV installations; typically targeted to small- and medium-scale customers
Direct Financial, Performance-Based Incentives (PBIs)	Feed-In-Tariffs, Standard Offer PBI Contracts or Tariffs, or PBIs	Pre-determined, fixed energy-denominated (i.e., $/kWh) incentives for solar energy production designed to provide predictable revenue stream; typically targeted to small- and medium-scale customers
	Competitive Long-Term PPAs	Long-term (10 – 25 years) PPAs for RECs, energy and/or capacity solicited through a competitive process; typically targeted to larger, more sophisticated players
	Long-Term Value of Solar Tariffs	Mechanism crediting solar generation at a rate determined by a value of solar analysis
	Technology-Specific “Avoided Costs”	Incentive rates set at the avoided-costs of a technology
Indirect Financial Incentives	Emissions Markets	Market-based emission cap-and-trade programs; usually regional scale
Expenditure-Based Tax Incentives	Investment Tax Credits	Capacity-denominated tax incentives (i.e., $/kW); Federal ITC is the most common form
Production Tax Incentives	Production Tax Credits	Electricity-production-based tax incentives (i.e., $/kWh)
Demand-Pull/Solar Minimum Purchase Mandates	Renewable Portfolio Standards (RPS)	Mandate requiring certain % of electric utilities’ annual retail sales be met with renewable generation
	Solar Set-Asides in RPS (SREC Market)	Mandate creating a separate tier or requiring certain portion of RPS to be met with solar
Net Metering	Net Metering Crediting Mechanism	Mechanism used for utilities to credit customers for excess on-site generation
	Virtual NM Crediting Mechanism	Subset of net metering that enables the aggregation of net metering accounts/facilities
	Community-Shared Solar	Subset of virtual net metering allowing multiple customers to share ownership interest in a single remote net metered facility

Table ES- 3. Summary of Solar Implementation Option: “Finance Enabling Policies”

Implementation Examples	Description
Solar Loan Programs	A broad spectrum of loan products supported by private sector financing or utilities
On-Bill Financing	Long-term, low interest loans where repayments are made through utility bills
PACE Financing	Long-term, low interest loans where payments are made through property taxes and are tied to hosting sites instead of system owners
Green Bank – Institutions and Suite of Other Programs	State-chartered institution offering a suite of programs and financing products; leverages and recycles public funding to stimulate growth of private financing markets for solar
Utility Ownership	Policies enabling T&D utilities to own generation assets in deregulated markets
Solar Lease and/or Third-Party Ownership Enabling Policies or Eligibility in Other Policies	Policies allowing a private developer to (i) install and own a PV system hosted by a property owner, then selling the power to the property owner through PPA; or (ii) lease PV panels to customers

Table ES- 4. Summary of Solar Implementation Option: “Rules, Regulations and Rate Design”

Subcategory	Implementation Examples	Description
Removing Institutional Barriers	Interconnection Standards	Regulations standardizing the requirements of integrating solar PV to the grid
	Solar Access Laws	Rules protecting customers’ access to sunlight and solar development rights
	Business Formation/Financing Laws	Policies authorizing certain types of business models or market structures designed to lower the entry barrier and expand access to the solar market
	Permitting Simplification, Other “Soft-Cost Reduction” Strategies	A suite of strategies designed to reduce the non-equipment costs associated with various stages of solar PV development
Building Codes	Solar-Ready Building Standards, Zero-	Various building standards that (i) regulate orientation, shading, and other siting- and

	Energy Capable Home Standards	construction-related criteria; or (ii) support "plug-and-play" PV system configurations
Tax	Property Tax Exemption or Special Rate	Property tax relief to property owners installing solar PV
	Sales Tax Exemption	Tax relief exempting system owners from paying sales taxes for PV system equipment
	Property Tax/Payment in lieu of taxes (PILOT) Standardization or Simplification	State policies designed to limit community-by-community variations in property tax and PILOT rules; designed primarily to remove uncertainty
Grid Modernization	Policies Enabling Microgrids, Smart-Grid and Other DG-Friendly Grid Architecture	Policies designed to promote installations of DG-friendly technologies and grid architecture; aim to ease interconnection and advance implementation of solar PV
Rate Design	Time-Varying Rates, Rate Design, Fixed Charges and Minimum Bills	Cost-based utility rate design or rate structures designed to provide a correct or supportive price signal for the installation and operation of solar generation facilities

Table ES- 5. Summary of Solar Implementation Option: "Industry Support"

Implementation Examples	Description
Incentives for Companies, Technology Development, or Economic Development	Funding mechanisms designed to provide incentives for in-state solar businesses; allocated from the state budget, RPS alternative compliance payments, RGGI proceeds and/or public good funds
Local Content Bonus Or Mandate	Incentives or requirements that give preference to projects supporting in-state investment
Customer Acquisition Cost Reduction	Strategies leveraging scale economies or other measures to increase solar participation at a lower cost
Outreach/Education/Public Information/Voluntary Market Encouragement	Strategies designed to increase customer awareness of solar technology, voluntary and compliance solar markets, and solar funding and financing options
Public Sector Leadership and Demonstration	State or local initiatives, such as demo projects on public properties or statewide PV goals
Creation of Public Good Funds to Support Solar Programs/Policies	Policies establishing funds collected from ratepayers through utility bill surcharges; designed to provide long-term funding for solar incentive programs
Installer/Inspector Training and Certification	Training and certification programs designed to build a qualified local solar workforce

Solar Implementation in Maine

Section 2 of Volume III summarizes the current suite of implementation mechanisms applicable to solar PV in Maine. Maine's solar implementation mechanisms include a range of approaches that are broadly applicable to various renewable resources and not specific to solar. Implementation mechanisms currently used to support renewable energy implementation in Maine include net metering, shared ownership net metering, Renewable Portfolio Standard, community-based renewable incentives, long-term contracts, time-of-use rates, and interconnection standards.

Solar Implementation in Other States: Key Themes and Lessons Learned

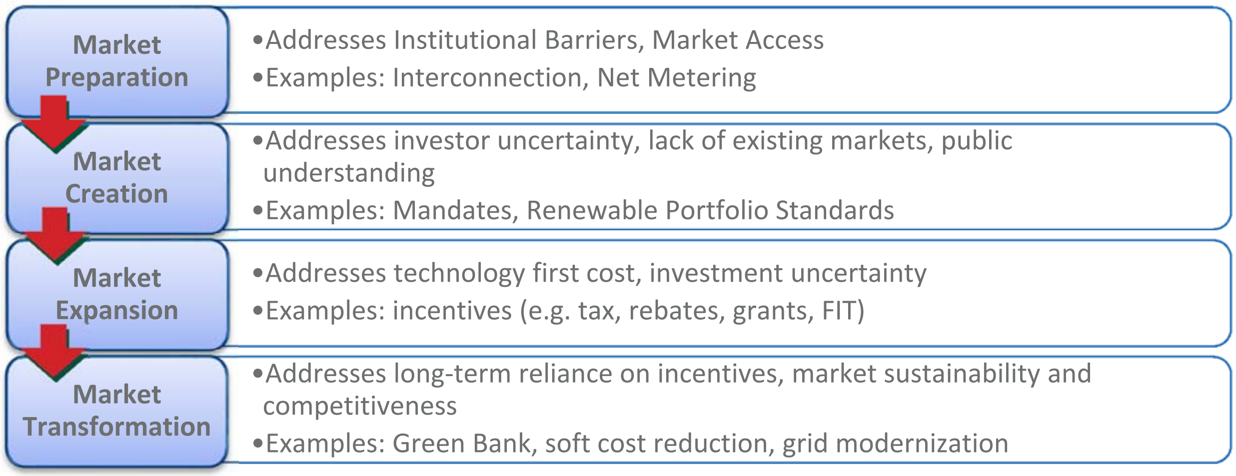
Section 3 of Volume III identifies and describes solar implementation options used in other states, with particular emphasis on the ten northeastern states identified above. The other states studied in Volume III have established a variety ofsolar-specific implementation options specifically targeted to grow solar penetration. Based on our analysis and evaluation of solar implementation experiences in these states, we identify four key themes or lessons learned from these other states that may be considered appropriate within Maine's context.

- A comprehensive strategy to support solar PV has proven effective at increasing solar PV penetration. In all ten states studied here, state policymakers implemented a combination of implementation options simultaneously to maximize the support available for, and reduce barriers to, diverse solar deployment. The Legislature may wish to consider combining various policies, programs, rules, regulations, incentives and industry support strategies to achieve multiple implementation objectives (e.g., develop scale economies, reduce costs, reduce risk and create an attractive investment climate, etc.).

- Low- or no-cost implementation options - options to enhance distributed solar adoption with minimal financial outlay relative to direct incentive programs - are available, and may be considered either alongside direct incentives, prior to adoption of incentives, or when there is limited appetite for costlier measures. Certain financing enabling policies and changes to rules and regulations such as revising building codes and implementing targeted tax measures; along with other industry support initiatives can be implemented in various market stages with minimal cost. Specific options are discussed in more detail in Section 4.3.2 in Volume III.

- Sequencing implementation options in a particular order enhances the cost-effectiveness of solar deployment. Figure 1 shows a path of implementation ordering commonly adopted by other states.

Figure 1 – Sequencing Solar Implementation



- Adopting synergetic implementation options can advance support for increased solar penetration, while over-stimulation and duplicative implementation objectives may impede or disrupt healthy market growth.

Other Considerations for Solar PV Implementation

In addition to the key themes and lessons learned, the authors identify a list of considerations that the Legislature may wish to take into account when developing a comprehensive implementation approach:

- Implementation options selected (if any) should align as best possible with the Legislature's definition of priorities and objectives. Table 7 in Volume III identifies a list of objectives organized under 6 implementation priorities: market growth, equity, feasibility, compatibility with Maine's energy market, economic and environmental goals that the Legislature may wish to consider. Because policy objectives like those delineated in Table 7 can conflict - specific implementation options can maximize one objective while working counter to another - it is important that the legislature understand the tradeoffs among these options.

- The Legislature may wish to create leverage with polices and initiatives already in place in other states in the region to finance local projects and support solar PV deployment in Maine. For example, the Maine Legislature may choose to adopt implementation options that leverage net metering benefits with RPS demand in other New England states.

- Implementation objectives and options are subject to constraints. Examples of implementation constraints include federal preemption via the supremacy clause of the US constitution, siting feasibility, and grid interconnection constraints.

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 14-035-114

Exhibit HEAL___(JIF-5)

Mississippi Public Service Commission. Net Metering in Mississippi: Costs, Benefits, and Policy Considerations. September 19, 2014.

June 8, 2017

Net Metering in Mississippi

Costs, Benefits, and Policy Considerations

Prepared for the Public Service Commission of Mississippi

September 19, 2014

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CONTENTS

1. EXECUTIVE SUMMARY

At its December 7, 2010 Open Meeting, the Mississippi Public Service Commission voted to open docket 2011-AD-2 in order to investigate establishing and implementing net metering and interconnection standards for Mississippi. Mississippi is one of only a few states that do not have some sort of net metering policy for their distribution companies.[1] In this report we describe a potential net metering policy for Mississippi and the issues surrounding it, focusing on residential and commercial rooftop solar.

Two vertically integrated investor-owned utilities serve customers in Mississippi: Entergy Mississippi and Mississippi Power. The Tennessee Valley Authority, a not-for-profit corporation owned by the United States government, owns generation and transmission assets within the state. Many Mississippi customers are served by electric power associations, including South Mississippi Electric Power Association, a generation and transmission cooperative, and the 25 distribution co-ops. These entities rely primarily on three resources for electric generation: natural gas, coal, and nuclear power. About 3 percent of generation is attributable to wood and wood-derived fuels. Less than 0.01 percent of Mississippians participated in distributed generation in 2013. We modeled and analyzed the impacts of installing rooftop solar in Mississippi equivalent to 0.5 percent of the state's peak historical demand with the goal of estimating the potential benefits and potential costs of a hypothetical net metering program.

Highlights of analysis and findings:

- Generation from rooftop solar panels in Mississippi will most likely displace generation from the state's peaking resources—oil and natural gas combustion turbines.
- Distributed solar is expected to avoid costs associated with energy generation costs, future capacity investments, line losses over the transmission and distribution system, future investments in the transmission and distribution system, environmental compliance costs, and costs associated with risk.
- Distributed solar will also impose new costs, including the costs associated with buying and installing rooftop solar (borne by the host of the solar panels) and the costs associated with managing and administering a net metering program.
- Of the three cost-effectiveness tests used for energy efficiency in Mississippi—the Total Resource Cost (TRC) test, the Rate Impact Measure, and the Utility Cost Test—the TRC test best reflects and accounts for the benefits associated with distributed generation.
- Net metering provides net benefits (benefit-cost ratio above 1.0) under almost all of the scenarios and sensitivities analyzed, as shown in ES Table 1.

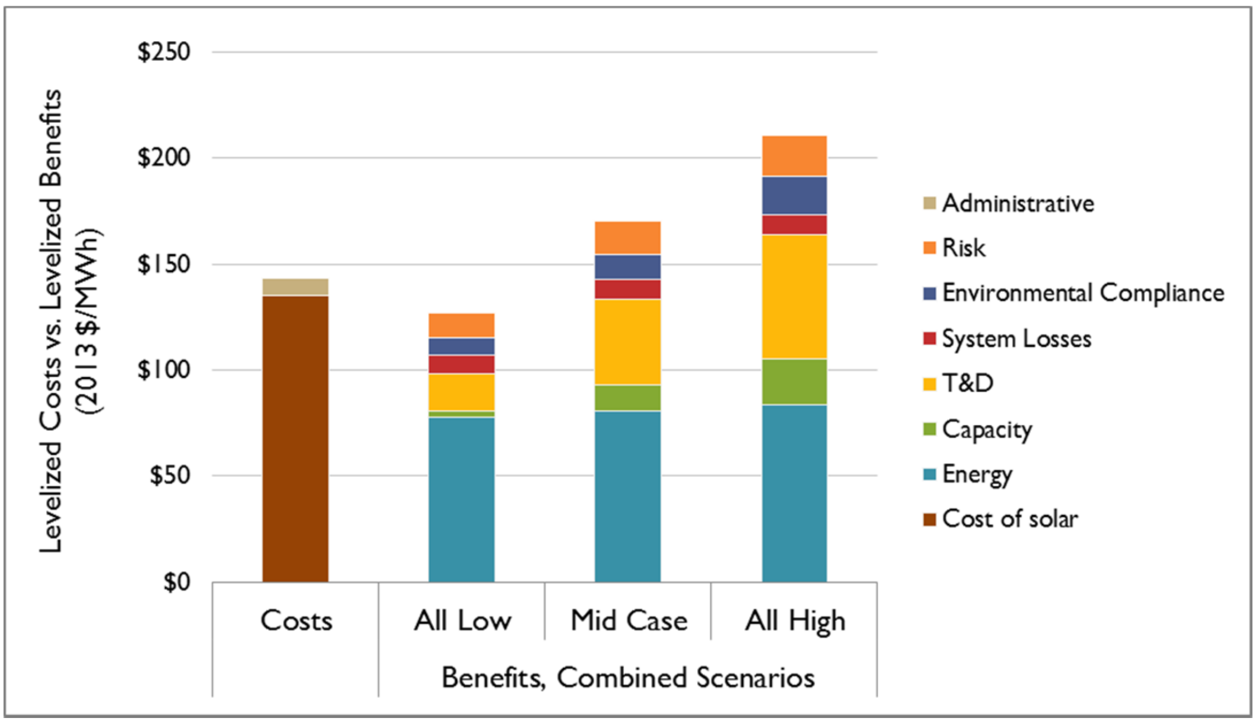
[1] Other states that do not have a net metering policy: Idaho, South Dakota, Texas, Alabama, and Tennessee.

ES Table 1. Summation of TRC Test benefit/cost ratios under various sensitivities

	Low	Mid	High
Fuel Price Scenario	1.17	1.19	1.21
Capacity Value Sensitivities	1.11	1.19	1.26
Avoided T&D Sensitivities	1.01	1.19	1.32
CO_2 Price Sensitivities	1.16	1.19	1.24
Combined Scenarios	0.89	1.19	1.47

- To determine the widest range of possible benefits, our analysis included combined scenarios in which all of the inputs were selected to yield the highest possible benefits (in the All High scenario) and the lowest possible benefits (All Low); the All Low scenario was the only scenario or sensitivity that did not pass the TRC test (see ES Figure 1).

ES Figure 1. Results of scenario testing under combined scenarios



- Distributed solar has the potential to result in a downward pressure on rates.
- Distributed solar provides benefits to hosts in the form of reduced energy bills; however, the host pays for the panels and if the reduced energy bills do not offset these costs, it is unlikely that distributed solar will achieve significant adoption within the state.
- If net metered customers are compensated at the variable retail rate in Mississippi, it is unlikely they will be able to finance rooftop solar installations.

2. BACKGROUND CONTEXT

2.1. What is Net Metering?

Net metering is a financial incentive to owners or leasers of distributed energy resources. Customers develop their own energy generation resources and receive a payment or an energy credit from their distribution company for doing so. Mississippi is one of only a few states that do not have some sort of net metering policy for their distribution companies (voluntary or otherwise).[2] In addition to presenting results of a cost-benefit analysis of net metering in Mississippi, this report describes some of the key issues that may be contested in the development of a net metering policy for Mississippi.

In our description of net metering and the issues surrounding it, we focus on residential and commercial rooftop solar.

Why Net Metering?

Net metering provides customers with a payment for electricity generation from their distributed generation resources. Distributed generation provides benefits to its host and to all ratepayers. Valuation of these benefits, however, has proven contentious. This section discusses issues in calculating costs avoided by distributed generation, as well as some additional difficult-to-monetize benefits: freedom of energy choice, grid resiliency, risk mitigation, and fuel diversity.

Avoided Costs

The term "avoided costs" refers to costs that would be borne by the distribution company and passed on to ratepayers were it not for distributed generation or energy efficiency (or other alternative resources). Avoiding these costs is a benefit to both ratepayers and distribution companies. Under the Public Utility Regulatory Policy Act (PURPA), utilities and commissions already go through the process of calculating avoided costs associated with generation from qualified facilities. As a result, the incremental costs associated with calculating avoided costs for net metering facilities is small. We provide a review of the avoided cost and screening tests already used in Mississippi below.

A variety of methods have been used to calculate avoided costs. Estimation of system benefits can be difficult and costly, and small changes in assumptions can sometimes dominate benefit-cost results. Avoided cost estimation methods range from:

- Adoption of the simple assumptions that (a) a single type of power plant is on the margin in all hours of the day and (b) distributed generation has no potential for offsetting or postponing capital expenses; to

[2] Other states that do not have a net metering policy: Idaho, South Dakota, Texas, Alabama, and Tennessee.

- The rigorous modeling of production costs using hourly dispatch of all units in a region and capacity expansion over long time horizons. This method requires development of distributive generation load shapes (patterns of generation over the day and year) for present and future years, energy and capacity demands for the region, expected environmental regulations and their respective compliance costs, and projections for commodity prices such as natural gas and coal.

Table 1 provides a list of avoided costs from distributed generation facilities that have been analyzed in other studies. The appropriate avoided costs to include in a benefit-cost analysis depend on state- and distribution-company-specific factors.

Table 1. List of potential costs avoided by distributed generation

Avoided Costs	Description
Avoided Energy	All fuel, variable operation and maintenance emission allowance costs and any wheeling charges associated with the marginal unit
Avoided Capacity	Contribution of distributed generation to deferring the addition of capacity resources, including those resources needed to maintain capacity reserve requirements
Avoided Transmission and Distribution Capacity	Contribution to deferring the addition of transmission and distribution resources needs to serve load pockets, far reaching resources, or elsewhere
Avoided System Losses	Preventing energy lost over the transmission and distribution lines to get from centralized generation resources to load
Avoided RPS Compliance	Reduced payments to comply with state renewable energy portfolio standards
Avoided Environmental Compliance Costs	Avoided costs associated with marginal unit complying with various existing and commonly expected environmental regulations, including pending CO_2 regulations
Market Price Suppression Effects	Price effect caused by the introduction of new supply on energy and capacity markets
Avoided Risk (e.g., reduced price volatility)	Reduction in risk associated with price volatility and/or project development risk
Avoided Grid Support Services	Contribution to reduced or deferred costs associated with grid support (aka ancillary) services including voltage control and reactive supply
Avoided Outages Costs	Estimated cost of power interruptions that may be avoided by distributed generation systems that are still able to operate during outages
Non-Energy Benefits	Includes a wide range of benefits not associated with energy delivery, may include increased customer satisfaction and fewer service complaints

Distributed energy avoids costs related to energy generation and future capital additions, as well as transmission and distribution load losses and future capital expenditures, especially in pockets of concentrated load. Net metering may also result in some additional transmission and distribution expenses where the excess generation is significant enough to require upgrades. Because distributed generation occurs at the load source, a share of transmission and distribution line losses also may be avoided. In states with Renewable Portfolio Standard (RPS) goals set as a percent of retail sales, distributed generation reduces the RPS requirement and associated costs.

Generation from distributed energy resources also results in price suppression effects in the energy and capacity markets (where applicable). As a recent addition to MISO, Entergy will participate in future MISO capacity and energy markets and may therefore experience a price suppression effect from net metering.

In 2013, Mississippi's electricity generation was 60 percent natural gas, 21 percent nuclear, 16 percent coal, and 3 percent biomass and others.[3] Maintaining a diverse mix of generation resources protects ratepayers against a variety of risks including fuel price volatility, change in average fuel prices over time, uncertainties in resource construction costs, and the costs of complying with new environmental regulations. In Mississippi, increased electric generation from solar, wind, or waste-to-energy projects would represent an improvement in resource diversity, thereby lowering these potentially costly risks.

Other costs that may be avoided by integrating distributed generation onto the grid have not been as rigorously studied or quantified. For example, distributed generation may contribute to reduced or deferred costs associated with ancillary services, including voltage control and reactive supply. It may also reduce lost load hours during power interruptions and costs associated with restoring power after outages, including the administrative costs of handling complaints. Allowing for and assisting in the adoption of distributed generation may increase customer satisfaction and result in fewer service complaints, both of which are in energy providers' best interest.

Additional Benefits

<u>Grid resiliency</u>

Grid resiliency reduces the amount of time customers go without power due to unplanned outages. Resiliency may be achieved with: major generation, transmission, and distribution upgrades; load reductions from distributed generation and energy efficiency; and new technologies, such as smart meters that allow for real-time data to be relayed back to grid operators. Distributed generation may also improve grid resiliency to the extent that it is installed in conjunction with "micro-grids" that have the capacity to "island."[4] Valuing grid resiliency as a benefit is sometimes done using a "value of lost

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[3] U.S. Energy Information Administration (EIA). 2013. *Form 923*.

[4] A micro-grid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that act as a single controllable entity with respect to the grid. A micro-grid can connect and disconnect from the grid to enable it to operate fully connected to the grid or to separate a portion of load and generation from the rest of the grid system. To learn more about the micro-grid, Synapse recommends these documents as primers:
http://energy.gov/sites/prod/files/2012%20Microgrid%20Workshop%20Report%2009102012.pdf
http://energy.pace.edu/sites/default/files/publications/Community%20Microgrids%20Report%20(2).pdf
http://nyssmartgrid.com/wp-content/uploads/Microgrid_Primer_v18-09-06-2013.pdf

load" to determine how much customers would be willing to pay to avoid disruption to their electric service (discussed later in this report).

Freedom of energy choice

The "right to self-generate" or the freedom to reduce energy use, choose energy sources, and connect to the grid is sometimes cited as a benefit of distributed generation. Some supporters of freedom of energy choice assert that any barrier to self-generation is an infringement of rights. Others take the position that customers have no right to self-generate unless they are disconnected from the grid.

Implementing a Net Metering Policy

States have made a variety of choices regarding several technical net metering issues that may have important impacts on costs to ratepayers. The technical issues discussed in this section are metering, treatment of "behind-the-meter" generation, treatment of net excess generation, third-party ownership, limits to installation sizes, caps to net metering penetration, "neighborhood" or "community" net metering, virtual net metering, distribution company revenue recovery, and the value of solar tariff.

Metering

Distributed generation resources are metered in one of three ways, depending on state requirements:

1. For customers with an electric meter that can "roll" forwards or backwards (measuring both electricity taken from the grid and electricity exported to the grid), distribution companies track only net consumption or generation of energy in a given billing cycle. Excess generation in some hours offsets consumption in other hours. If generation exceeds consumption within a billing cycle, the customer is a net energy producer. Because generation from some net metered facilities (particularly renewables) is subject to variability on hourly, monthly, and annual time scales, generation may exceed consumption in some months but be less than consumption in others. Distribution companies' data on net consumption or production are limited by the frequency at which meters are monitored.

2. More advanced "smart" meters log moment-by-moment net consumption or generation at each customer site. With this type of meter, distribution companies may pay customers for excess generation using different rates for different hours.

3. Net metering facilities may also be installed with two separate meters: one for total electricity generation and one for total electricity consumption. Metered generation may be bought at a pre-determined tariff rate while consumption is billed at the retail rate. It is also common to have a second meter installed for tracking solar generation for Solar Renewable Energy Credit (REC) tracking.

Treatment of "Behind-the-Meter" Generation

Net metered systems are typically attached to a host site, which has a load (and meter) associated with it. During daylight hours on a net metered solar system:

1. The host site's load may exceed or be exactly equal to generation. In these hours, solar generation is entirely "behind the meter." From the distribution company's perspective, the effect of this generation is a reduction in retail sales (see Figure 1).

2. Generation may exceed the host site's load. In these hours, solar generation is exported onto the grid. From the distribution company's perspective, the effect of this generation is both a reduction in retail sales and an addition to generation resources (see Figure 2).

Figure 1. Illustrative example of net metered facility with demand greater than generation

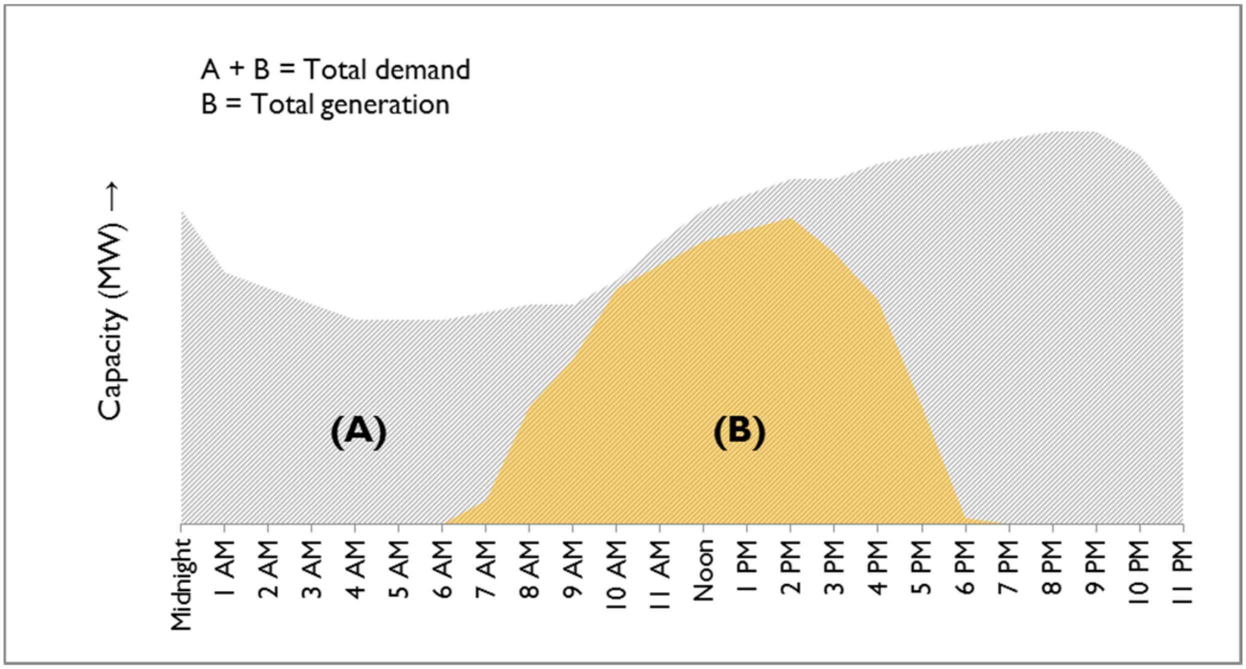
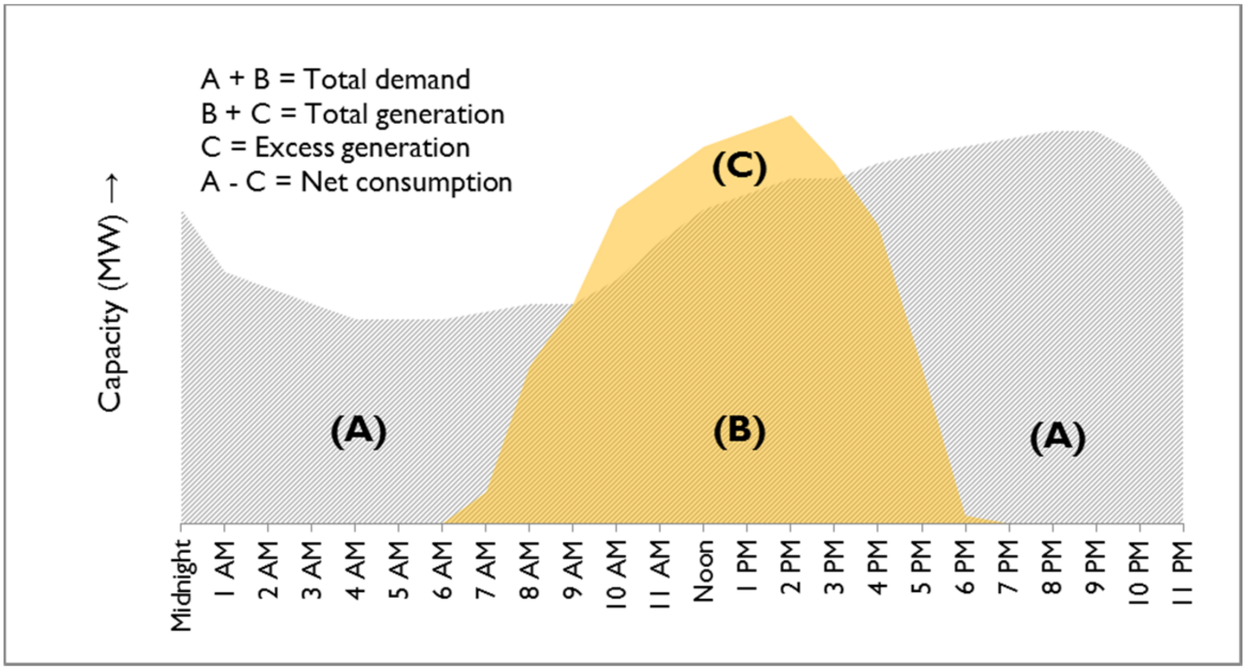


Figure 2. Illustrative example of net metered facility with excess generation



Typically, generation is considered behind the meter up to the point where a host load is exactly equal to generation when summed over a typical billing period. Systems that are designed to accomplish this are called Zero Net Energy Systems. While these systems, summed over the billing cycle, do not produce any net excess generation, they do produce excess generation during some hours of the day and do, therefore, utilize the grid.

Treatment of Net Excess Generation

Net excess generation is the portion of generation that exceeds the host's load in a given billing period. Some distributed resources (such as solar panels) will have net excess generation in some billing periods but require net electricity sales from the distribution company in other periods. Host sites receive payment for their net excess generation, but the value placed on this generation differs from state to state. Participants are compensated for net excess generation in various ways. Examples of ways in which participants are compensated include:

- receiving the full retail rate as a credit on their monthly bill; these credits can roll over to future bills indefinitely
- receiving the full retail rate as a credit on their monthly bill; these credits can roll over to future bills but for some finite period (typically one year) at which point they expire
- receiving the full retail rate as a credit on their monthly bill; these credits can roll over to future bills indefinitely or the customer can choose to be paid out at the avoided cost rate

- receiving a pre-determined rate (typically the avoided cost rate) as a credit on their monthly bill; these credits can roll over to future bills for a finite period (typically one year) at which point they expire
- receiving a pre-determined rate as a credit on their monthly bill, but with no set guarantee for how long they can roll over
- receiving no payment at all

Third-Party Ownership

Third-party financing is the practice by which the host of the distributed energy system does not pay the upfront costs to install the system and instead enters into a contract with a third party who owns the system.[5] Often structured through a power purchase agreement (PPA) or lease, third-party financing may increase access to distributed generation for households without access to other financing, or to public entities that want to offset their electric bills with solar but cannot benefit from state or federal tax incentives. With a PPA, the distributed generation is installed on the customer's property by the developer at no cost to the customer. The customer and the developer enter into an agreement in which the customer purchases the energy generated by the solar panels at a fixed rate, typically below the local retail rate. The distribution company experiences a reduction in retail sales but is not otherwise involved. (Note that some municipal owned generators ("munis") and electric co-ops do not allow net metering to be structured under a PPA with a third party.) With a solar lease, the customer enters into a long-term contract to lease the solar panels themselves, offsetting energy purchases and receiving payment from the distribution company for excess net generation.

Contract language to address issues such as responsibility for maintenance, ownership of renewable energy credits (RECs), and the risk for legislative or utility commission disallowance has been an area of concern in some states. In the PPA structure, the developer takes on some of the responsibilities of a provider and may need to be regulated by a public commission.

Limits to Installation Sizes

Most states have imposed limits on the size of installations eligible for net metering, often with different limits for different customer classes, or for private versus public installations. Limits may be set in absolute terms (a specific kW capacity limit) or as a percentage of historical peak load of the host site. In some states, the *de facto* limit is actually smaller than the official limit because the size of the installation is determined by policies other than net metering. For example, in Louisiana the legal limit to

[5] The National Renewable Energy Laboratory put together an extensive report outlining third-party PPAs and leasing: http://www.nrel.gov/docs/fy10osti/46723.pdf.

installations is 25 kW, but most installations are smaller than 6 kW due to a 50 percent tax rebate on solar installations 6 kW or smaller.[6]

Caps to Net Metering Penetration

In most states, there are limits to how much net metered generation is allowed on the grid. Net metering caps are commonly calculated as a share of each distribution company's peak capacity. Munis and co-ops may or may not be subject to the same caps as utilities. To the extent that new investments in transmission and distribution may be necessary with large-scale penetration of distributed generation, net metering caps keep the actual installation of distributed resources in line with the planned roll out.

"Neighborhood" or "Community" Net Metering

Where neighborhood or community net metering is permitted, groups of residential customers pool their resources to invest in a distributed generation system and jointly receive benefits from the system. The system may be installed in a nearby parcel of land or on private property within the neighborhood development. Multiple customers each invest a portion of the costs of installing the net metered facility and each receive a proportional amount of the energy credits based on their respective investment. Neighborhood net metering may make it possible for lower-income communities or renters to invest in renewable technologies that would otherwise be cost prohibitive.

Virtual Net Metering

Virtual net metering allows development of a net metered facility that is not on a piece of land contiguous to the host's historical load. The legal definition of virtual net metering differs from state to state. The energy generated at the remote site is then "netted" against the customers' monthly bill. Virtual net metering may permit customers to take advantage of economies of scale, but there is disagreement regarding how to differentiate a virtual net metering arrangement from a PURPA-regulated generator.

Distribution Company Revenue Recovery

Only one state, Hawaii, currently has solar capacity in excess of 5 percent of total capacity. In Hawaii, solar represents 6.7 percent of total capacity; in New Jersey, 4.7 percent; in California, 2.7 percent; and in Massachusetts, 2.3 percent. All other states have significantly less solar capacity as a share of total capacity.[7] Nonetheless, stakeholders in a number of states have begun drafting proposed legislation for special monthly fixed charges, rate classes, and/or tariffs for solar net metered projects. Supporters of

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[6] Owens, D. 2014. "One Regulated Utility's Perspective on Distributed Generation." Presented at the 2014 Southeast Power Summit, March 18, 2014.

[7] National Renewable Energy Laboratory. "The Open PV Project." Accessed June 3, 2014. Available at: openpv.nrel.gov. Supplemented with Synapse research (see Table 4 of this report).

the solar-specific fixed charges and rate classes argue that these policies help prevent shifting costs from those participating in net metering to those not participating. Special charges and rates may have the effect of discouraging solar net metered development by increasing the cost and complexity of net metering arrangements.

Value of Solar Tariff

A feed-in tariff or a value-of-solar tariff is subtly different from net metering. Feed-in tariffs are fixed rate payments made to solar generators. The tariff amount is predetermined in dollars per kilowatt-hour and is typically valid for a fixed length of time. In states that have a solar feed-in tariff (such as Minnesota and Tennessee), solar generation is metered separately from the host's demand. The host gets paid for all electricity generated by the solar panels at the tariff rate and pays for all the electricity consumed at the retail rate. Concerns raised regarding feed-in tariffs for distributed generation include the host's tax liability and the need for periodic changes to the value of solar. Tariffs have the potential to create stability in the financial forecasts for resource technologies, thereby lowering costs.

Rate Design Issues

Net metering raises several rate design issues related to cost sharing. In this section, we discuss cross-subsidization and fairness to distribution companies.

Cross-Subsidization

Situations in which one group of people pays more for a good or service while a different group of people pays less (or gets paid) for some related good or service are referred to as "cross-subsidization." In situations of regressive cross-subsidization, a lower income group pays more per unit of service and a higher income group pays less per unit of service. Utility rate design and implementation are fraught with opportunities for cross-subsidization. There are three main ways that net metering can potentially act as a cross-subsidy: credit for compliance with renewable energy goals; federal tax subsidies; and cost shifting in rate making.

<u>Compliance with renewable energy goals</u>

Most U.S. states have renewable energy goals or incentives. To meet their renewable energy goals, energy providers pay renewable credits or certificates in addition to the wholesale price of energy. Where net metered renewable facilities are eligible for these payments, there is a possibility of cross-subsidization. Since Mississippi does not have an RPS, tariff payments for renewables, or state tax incentives for renewable energy, renewable energy incentives are not a likely pathway for cross-subsidization in the state.

<u>Federal tax subsidies</u>

The federal government currently offers investment tax credits (ITC) for wind, solar, and other renewable energy resources. A small share of Mississippians' federal income taxes, therefore, subsidizes renewable energy generation. Given the relative lack of renewable energy development within the state, it is unlikely that the state is receiving its full share of federal funds for renewable energy development, and possible that Mississippians are cross-subsidizing renewable energy generation (at a very small scale) in California, New Jersey, Massachusetts, and other states with relatively more renewable energy development.

Cost shifting in rate making

Distributed generation reduces distribution companies' total energy sales. With lower sales, distribution companies' fixed costs are spread across fewer kilowatt-hours. The effect is a higher price charged for each kilowatt-hour sold. These costs are offset—at least in part—by the benefits that distributed generation provides to the grid and to other ratepayers (as discussed above in the Avoided Costs section of this memo). If all avoided costs are accurately and appropriately accounted for and the consumers are paid an avoided cost rate, then there is no cost shifting because the costs to non-participants (those customers without distributed generation) are equal to the benefits to non-participants. From a social equity standpoint, this is important because net metering customers may have higher than average incomes.[8] Net metering customers should be paid for the value of their distributed generation, but non-participants should not bear an undue burden as a consequence of net metering. One strategy to help mitigate the impact of cost shifting is to create opportunities for all income classes to participate in net metering; this is sometimes achieved through community solar projects.

Fairness to Distribution Companies

Mississippi's distribution companies reliably provide electricity to customers and are entitled to recover a return on their investments. Policies that undermine their financial solvency have the potential to put reliable electric generation and distribution at risk.

Reducing distribution company revenues

Distributed generation resources are sometimes viewed as being in competition with providers because they reduce retail sales and, therefore, reduce distribution companies' revenues. Reduced sales will eventually cause providers to apply for rate increases so that they can recoup their expenses over the new (lower) projected sales forecast. Higher electric rates make distributed energy and energy efficiency a better investment, and may lead to deeper penetration of these resources, further reducing retail sales. This feedback scenario has become known as the "utility death spiral." Arguments are made both that net metering (together with energy efficiency) may put providers out of business, and that the effect of net metering on providers' revenues is actually negligible. Distributed generation's share of

[8] Langheim, R., et. al. 2014. "Energy Efficiency Motivations and Actions of California Solar Homeowners." Presented at the ACEE 2014 Sumer Study on Energy Efficiency in Buildings. August 17-22, 2014. Available at: http://energycenter.org/sites/default/files/docs/nav/policy/research-and-reports/Energy%20Efficiency%20Motivations%20and%20Actions%20of%20California%20Solar%20Homeowners.pdf. See also: Hernandez, M. 2013. "Solar Power to the People: The Rise of Rooftop Solar Among the Middle Class." Center for American Progress. October 21, 2013. Available at: http://www.americanprogress.org/issues/green/report/2013/10/21/76013/solar-power-to-the-people-the-rise-of-rooftop-solar-among-the-middle-class/

total generation is a key factor in understanding these impacts. Mississippi had less than 0.01 percent of its customers participate in distributed generation in 2013.[9]

Increasing distribution company costs

Distributed generation also has the potential to reduce distribution companies' revenues by increasing costs. The argument that net metered facilities impose costs when providers are forced to plan for and manage excess generation, again, depends on the share of distributed generation resources out of total generation or the concentration of distributed resources in small, local areas. The share of distributed generation necessary to impose additional costs on a provider likely depends on a number of factors including (but not limited to) transmission and distribution infrastructure, the aggregate and individual capacity of solar installations, local energy demand, and the demand load shape over the day and the year.

Another potential cost issue for providers is the safety risk that rooftop solar panels may pose to utility line workers. This is primarily a design and permitting issue: in the absence of the proper controls, a utility worker could get electrocuted by excess generated from the solar panels.

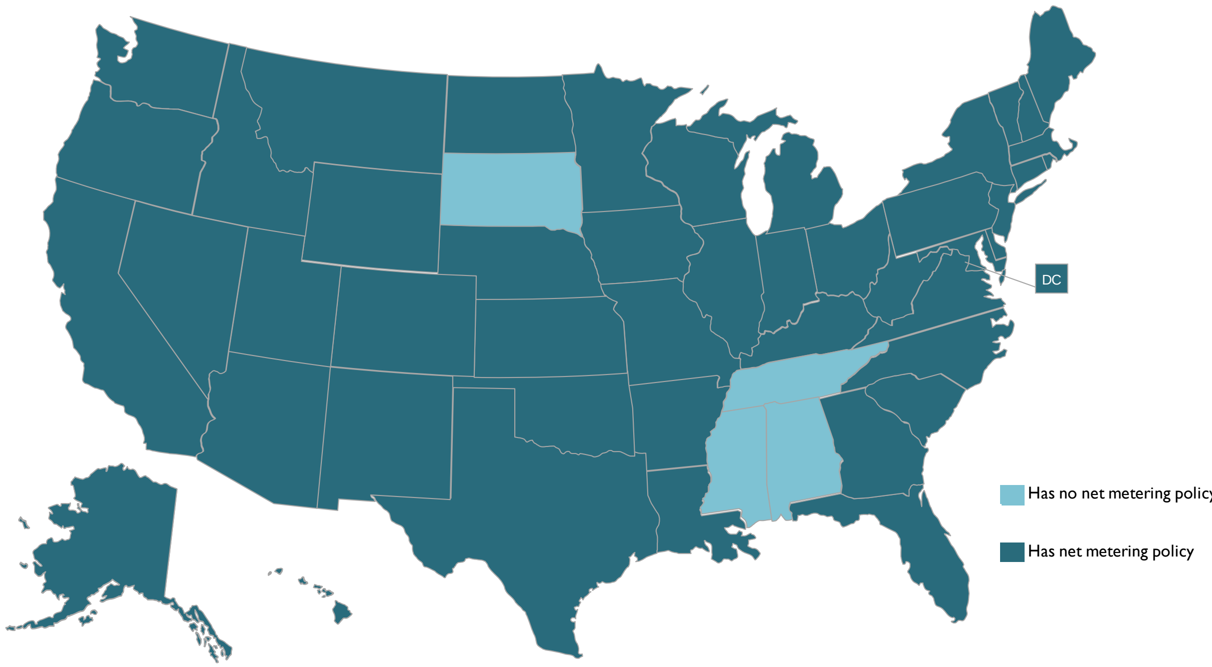
2.2. Regional Context

Net Metering in the Region

As shown in Figure 3, as of July 2013 net metering policies had been implemented in 46 states and the District of Columbia. Mississippi is one of four states that does not currently have any net metering policies in place. The active docket to investigate establishing and implementing net metering and interconnection standards for Mississippi is discussed below. Of those states immediately bordering Mississippi, Louisiana and Arkansas have net metering policies, while Tennessee and Alabama do not.

[9] Wesoff, E. 2014. "How Much Solar Can HECO and Oahu's Grid Really Handle?" *Greentech Media*. Available at: http://www.greentechmedia.com/articles/read/How-Much-Solar-Can-HECO-and-Oahus-Grid-Really-Handle

Figure 3. Net metering policy by state



Source: IREC and Vote Solar "Freeing the Grid" (2013, www.freeingthegrid.com)

The net metering policies of Louisiana and Arkansas are very similar: both states feature a 300 kW maximum capacity for non-residential customers and a 25 kW maximum for residential customers. There is a 0.5 percent aggregate capacity limit in Louisiana,[10] and net metered generators are compensated at the retail rate with excess carried over indefinitely. There is no policy in Louisiana regarding ownership of RECs sold to other states. Arkansas' net metering customers face no aggregate capacity limit, and while excess generation can be carried over indefinitely, only a limited quantity of carry-over is allowed. Arkansas' net metering payments are at the retail rate, and the customer retains ownership of any RECs generated by the net metered facility.

Mississippi Docket 2011-AD-2

At its December 7, 2010 Open Meeting, the Mississippi Public Service Commission voted to open docket 2011-AD-2 in order to investigate establishing and implementing net metering and interconnection standards for Mississippi. The Commission has called for a three-phase proceeding:

1. Identify specific issues that should be addressed in the rule and what procedures should be used to solicit input from interested parties;
2. If the Commission chooses to proceed, develop a Proposed Rule; and finally,
3. Use traditional rulemaking procedures to establish net metering process, eligibility, and rates.

[10] Entergy New Orleans has no aggregate capacity limit.

All three phases allow for interveners.

Renewable Energy Policies in the Region

States pursue a variety of channels to encourage increased renewable energy generation. Perhaps the most commonly discussed state-level renewable energy policy is the RPS, a policy that requires distribution companies within the state to procure an increasing number of RECs, inducing a demand for renewably generated energy. While 29 states, 2 territories, and the District of Columbia have binding RPS policies in place and an additional 7 states have formal, non-binding RPS goals, neither Mississippi nor any of its 4 surrounding states have such a policy. Louisiana has implemented a Renewable Energy Pilot Program to study whether a RPS is suitable for Louisiana.

The Tennessee Valley Authority (TVA), operating in nearly all of Tennessee and smaller portions of Mississippi, Alabama, Georgia, North Carolina, and Kentucky, does not have an RPS policy but does have a number of policies to encourage the procurement of renewably generated electricity, including TVA Green Power Providers, a feed-in tariff 20-year contract that pays generators an above-market price for energy. TVA's Green Power Providers program offers customers of TVA and participating munis and co-ops within the TVA corporation's territory the opportunity to enter into a 20-year purchase agreement for distributed, small-scale renewably generated electricity. Eligible residential and non-residential customers can install solar, wind, biomass, or hydro generators sized between 0.5 kW and 50 kW, subject to the additional size constraint that the expected annual generation does not exceed the expected demand of the customer at that site. TVA will pay the customer's retail rate for the generated electricity, plus an additional 3-4 cents per kWh for the first 10 years of the contract.[11] There are 18 distributor participants in Alabama, 14 in Georgia, 18 in Mississippi, 3 in North Carolina, 78 in Tennessee, and 1 in Virginia.[12]

There are a number of tax benefits available for renewable generation installations in the region, including both corporate and personal tax credits and property tax incentives in Louisiana for solar installations; property and sales tax incentives for installing wind, solar, biomass, and geothermal generators in Tennessee; and tax subsidies for switching from gas or electric to wood-fueled space heating in Alabama. Large tax incentives and government loans exist for the siting of substantial renewable generator manufacturing facilities in Mississippi, Arkansas, and Tennessee.

Subsidized loans are another common renewable policy mechanism, allowing for favorable lending conditions for the purchase and installation of renewable generation. Louisiana lends money to residential customers, and Alabama and Mississippi lend to commercial, industrial, and institutional customers. Alabama also lends to local municipalities, and Arkansas lends to a variety of customers.

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11 Tennessee Valley Authority. 2014. "2014 Green Power Providers (GPP) Update." Available at: http://www.tva.com/greenpowerswitch/providers/.

12 Tennessee Valley Authority. 2014. "Green Power Providers Participating Power Companies." Available at: http://www.tva.com/greenpowerswitch/providers/distributors.htm.

Table 2 summarizes the region's renewable energy policies.

Table 2. Renewable policies by state

Policy	LA	AR	TN	AL	MS
Renewable Portfolio Standard					
Feed-in Tariff			✓	✓ TVA	✓ TVA
Tax Incentives	✓		✓		✓
Incentives for Manufacturing		✓	✓		✓
Subsidized Loans	✓	✓		✓	✓

Solar Installations by State

Tracking all solar photovoltaic installations by state is not a simple exercise, though a variety of sources attempt to measure capacity installed. This report relies on *U.S. Solar Market Trends 2012*,[13] with the results detailed in Table 3. According to this source, in 2012, Mississippi installed 0.1 MW of solar photovoltaic capacity, which brought total capacity installed to 0.7 MW.

Table 3. Installed solar photovoltaic capacity by state

	Incremental Installed Capacity, 2012 (MW)	Cumulative Capacity Installed through 2012 (MW)
Louisiana	11.9	18.2
Arkansas	0.6	1.5
Tennessee	23.0	45.0
Alabama	0.6	1.1
Mississippi	0.1	0.7

2.3. Avoided Cost and Screening Tests Used in Mississippi

There is a precedent in Mississippi for using particular avoided cost and screening tests that may be relevant to the quantification of the state's avoided costs of net metering. The July 2013 Final Order from Mississippi Docket No. 2010-AD-2 added Rule 29 to the Public Utility Rules of Practice and Procedure related to Conservation and Energy Efficiency Programs, the purpose of which "is to promote the *efficient* use of electricity and natural gas by implementing energy efficiency programs and

[13] Sherwood, L. 2013. *U.S. Solar Market Trends 2012*. Interstate Renewable Energy Council. Appendix C.

standards in Mississippi."[14] Section 105 of Rule 29 specifies the cost-benefit tests to be used when assessing all energy efficiency programs. There are four tests used within the context of Rule 29.[15]

- The Total Resource Cost (TRC) test determines if the total costs of energy in the utility service territory will decrease. In addition to including all the costs and benefits of the Program Administrator Cost (PAC) test (described below), it also includes the benefits and costs to the participant. One advantage of the TRC test is that the full incremental cost of the efficiency measure is included, because both the portion paid by the utility and the portion paid by the consumer is included.

- The Program Administrator Cost (PAC) test, also known as the Utility Cost Test (UCT), determines if the cost to the utility administrator will increase. This test includes all the energy efficiency program implementation costs incurred by the utility as well as all the benefits associated with avoided generation, transmission, and distribution costs. Because the test is limited to costs and benefits incurred by the utility, the impacts measures are limited to those that would eventually be charged to all customers through the revenue requirements. These impacts include the costs to implement the efficiency programs borne by ratepayers and the benefits of avoided supply-side costs, both included in retail rates. This test provides an indication of the direct impact of energy efficiency programs on average customer rates.

- The Rate Impact Measure (RIM) determines if utility rates will increase. All tests express results using net present value, and each provides analysis from a different viewpoint. The RIM includes all costs and benefits associated with the PAC test, but also includes lost revenue as a cost. The lost revenue, equal to displaced sales times average retail rate, is typically significant.

- The Participant Cost Test (PCT) measures the benefits to the participants over the measure life. This test measures a program's economic attractiveness by comparing bill savings against the incremental cost of the efficiency equipment, and can be used to set rebate levels and forecast participation.

2.4. Mississippi Electricity Utilities and Fuel Mix

Just over 1.2 million Mississippi residents are served by Entergy in the west or Mississippi Power in the southeast. The electricity delivered to northeastern Mississippians is almost entirely generated by the Tennessee Valley Authority (TVA) and delivered by one of the 14 municipal entities or 14 cooperatives in the region.[16] Throughout the state are 26 not-for-profit cooperatives that collectively serve 1.8 million

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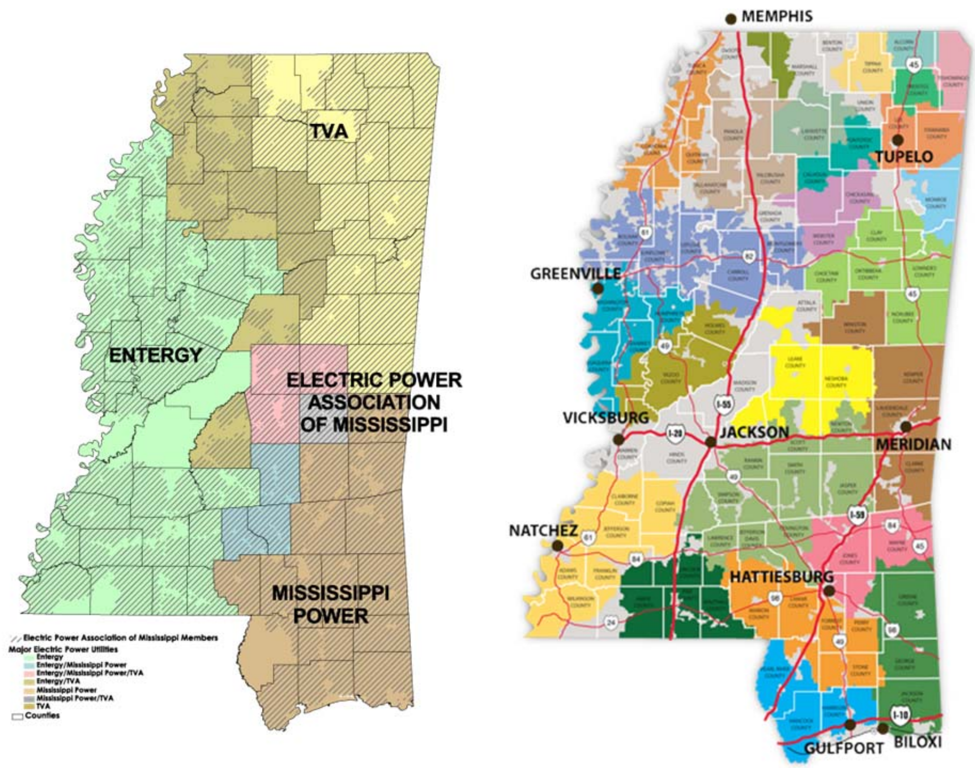
[14] Mississippi Public Service Commission, Final Order Adopting Rule, Docket No. 2010-AD-2. July 11, 2013. Original emphasis.

[15] Descriptions of the four tests come from Malone et al. 2013. "Energy Efficiency Cost-Effectiveness Tests (Appendix D)." *Readying Michigan to Make Good Energy Decisions: Energy Efficiency.* Available at: http://michigan.gov/documents/energy/ee_report_441094_7.pdf.

[16] TVA has seven directly served customers to which 4.5 billion kWh were sold in 2013. Available at: http://www.tva.com/news/state/mississippi.htm.

Mississippians. The service territories of Entergy, Mississippi Power, and the munis supplied by TVA are shown on the map on the left in Figure 4; the service territories of all 26 cooperatives are shown on the map on the right.

Figure 4. Mississippi electric utility maps



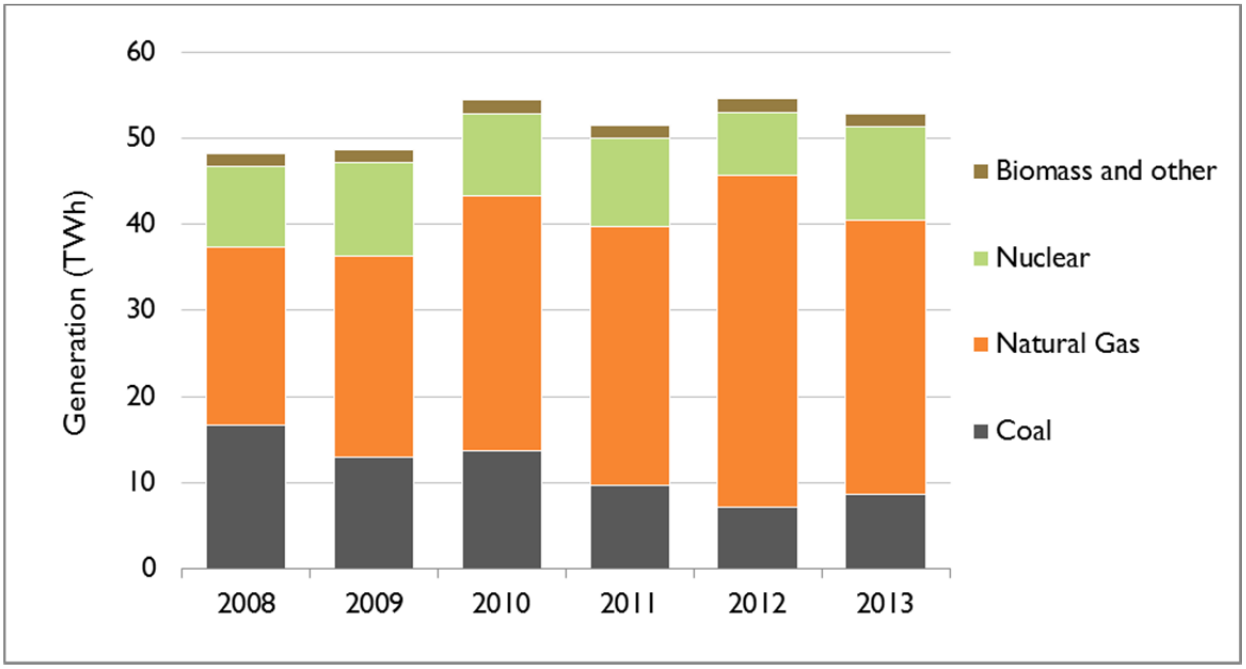
Source: Mississippi Development Authority, Electric Power Associations of Mississippi

Entergy and Mississippi Power are vertically integrated investor-owned utilities. TVA is a generation and transmission not-for-profit corporation owned by the United States government. While South Mississippi Electric Power Association is a generation and transmission co-op, the remaining 25 cooperatives are distribution electric power associations.

The primary fuel used for generating electricity in Mississippi is natural gas, accounting for approximately half of electricity generated (see Figure 5). Coal and nuclear power make up the vast majority of remaining generation, with about 3 percent attributable to wood and wood-derived fuels. In

2013, Mississippi withdrew 1.5 percent of the natural gas extracted in the United States[17] and mined 0.4 percent of the short tons of coal extracted from U.S. soil.[18]

Figure 5. Mississippi electric generation fuel sources



Source: EIA Form 923 2008-2012.
Note: "Other" includes generation from oil, municipal solid waste, and other miscellaneous sources.

2.5. Growth of Solar in the United States

Though not the case in Mississippi, solar resources have gained prevalence in other parts of the United States in recent years. U.S. solar installations have been growing rapidly over the past five years (see Figure 6). State data on solar and net metered generation is scattered and often under-reported. The National Renewable Energy Laboratory (NREL) runs the OpenPV project, which attempts to track solar projects of all sizes in all states. California, Hawaii, New Jersey, and Massachusetts have some of the most developed net metering programs and some of the most aggressive state goals for distributed solar. Based on NREL's OpenPV project, these states have installed solar capacity equivalent to between 0.9 and 4.7 percent of their state's generation capacity. Recognizing the lag in reporting, Synapse has conducted additional research in Hawaii and in Massachusetts. Based on this research, solar penetration in these states ranges from 2.3 and 6.7 percent (see Table 4).

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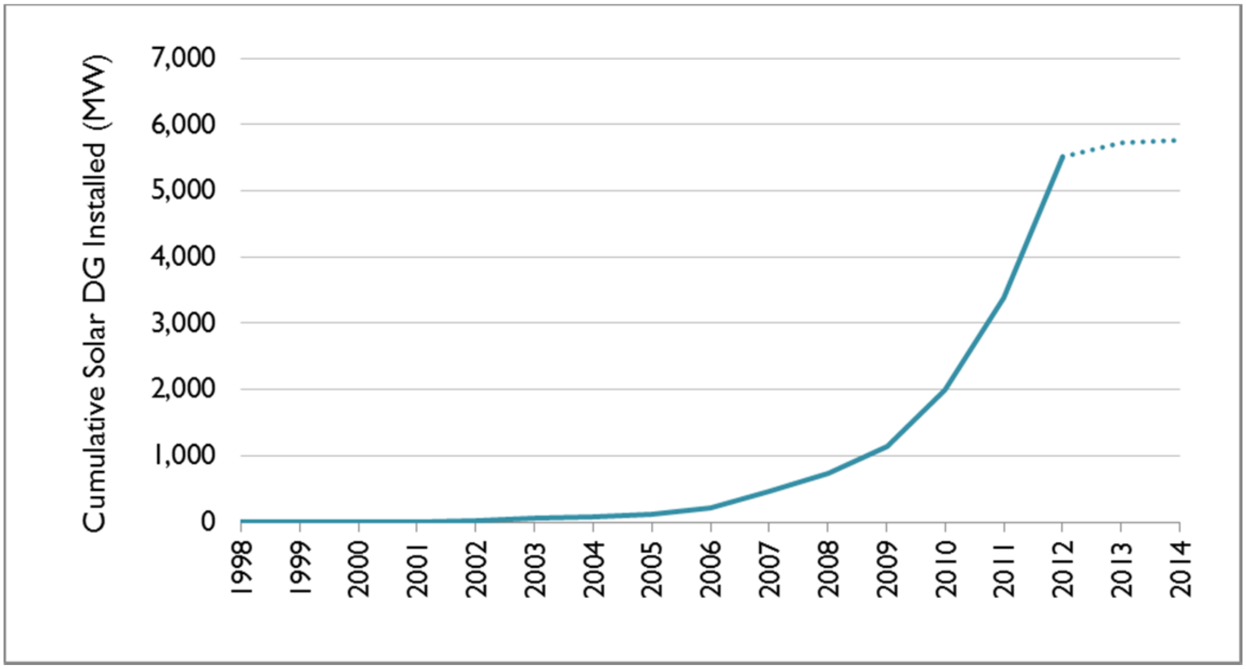
[17] Energy Information Administration. 2014. "Natural Gas Gross Withdrawals and Production." Available at: http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm.

[18] Energy Information Administration. June 30, 2014. *Quarterly Coal Report*. Table 2: Coal Production by State. Available at: http://www.eia.gov/coal/production/quarterly/pdf/t2p01p1.pdf.

Figure 6. U.S. cumulative solar distributed generation (MW)



Source: NREL's OpenPV project (openpv.nrel.gov); 2013 and 2014 reporting is as yet incomplete

Table 4. NREL solar capacity for selected states, with and without Synapse corrections

	Capacity (MW)		% of State Capacity	
	Per NREL OpenPV Project 2014	*With Synapse Supplemental Research*	*Per NREL OpenPV Project 2014*	*With Synapse Supplemental Research*
MS	1	1	0.0%	0.0%
CA	2,055	2,055	2.7%	2.7%
HI	27	200	0.9%	6.7%
NJ	979	979	4.7%	4.7%
MA	244	350	1.6%	2.3%

Source: NREL's OpenPV project (openpv.nrel.gov) and Synapse research

3. MODELING

Net metered generating facilities result in both benefits (primarily avoided costs) and costs, including lost revenues to distribution companies and the expense of distributed generation equipment. Our quantitative analysis of a net metering policy for Mississippi provides benefit and cost estimates at the state level to provide policy guidance for Mississippi decision-makers and to help establish a protocol for measuring the benefits and costs of net metering for use in distribution company compliance. The costs and benefits outlined in this report provide a framework for that discussion.

In the event that a net metering policy is adopted, distribution companies will likely be required to use their detailed, often proprietary data along with the long-term production cost models that they have at their disposal to measure benefits and costs specific to each company. Such modeling requires detailed forecasts of energy fuel prices, capacity, transmission, and distribution needs, as well as the expected costs of compliance with environmental regulations.

3.1. Modeling Assumptions

Our benefit and cost analysis is limited along the following dimensions:

- **Modeling years:** One-year time steps from 2015 to 2039, with results provided both on an annual and a 25-year levelized basis. A 25-year analysis was chosen to reflect typical effective lifespans of solar panels.
- **Technology used for net metering:** Solar rooftop only.
- **Geographic resolution of analysis:** The state of Mississippi on an aggregate basis; we do not address specific costs and benefits for Tennessee Valley Authority, Entergy Mississippi, Mississippi Power, SMEPA, or the co-ops.
- **Source of generation:** Energy demand within the state is assumed to be met by resources within the state with energy balancing at the state level.[19]
- **Rate of net metering penetration:** Net metering installations equivalent to 0.5 percent of historical peak load in 2015, which holds constant over the entire study period.
- **Data sources:** We supplement Mississippi average and utility-specific data with regional and national information regarding load growth, commodity prices, performance characteristics of existing power plants in Mississippi, and costs of generation equipment.
- **Marginal unit:** Mississippi's 2013 generation capacity includes 508 MW of natural gas- and petroleum oil-based combustion turbines (CT).[20] While these oil units do not contribute a significant portion of Mississippi's total energy generation, they do contribute to the state's peaking capabilities. On aggregate, these peaking resources operated 335 days in 2013—most frequently during daylight hours—and had a similar aggregate load shape to potential solar resources (see Figure 7). Our benefit and cost analysis follows the assumption that gas and oil CT peaking resources will be on the margin when solar resources are available and, therefore, that solar net metered facilities will displace the use of these peaking resources. At the level of solar penetration explored in our analysis (0.5 percent), it is unlikely that solar resources will

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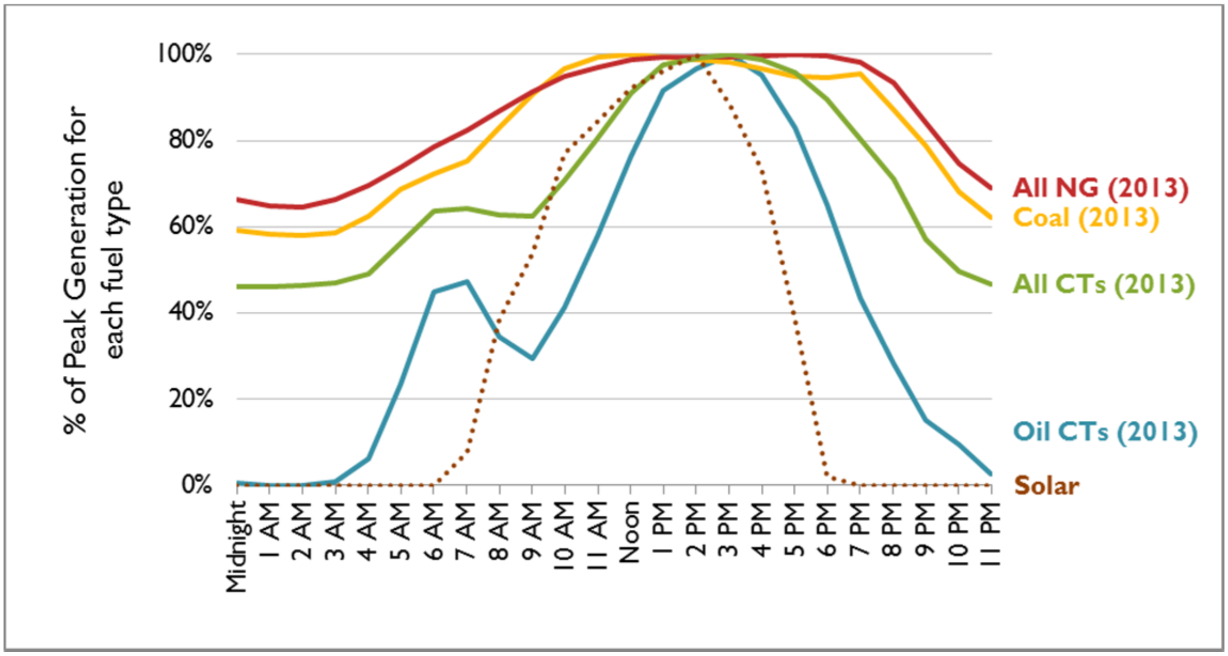
[19] It should be noted that this is a simplifying assumption, and that in reality each of the generation companies in Mississippi is free to buy or sell electricity and capacity to other states. The three largest owners of generation capacity in the state—Entergy Mississippi, TVA, and MPC—are all part of entities that operate in other states.

[20] EPA. 2012. Air Markets Program (AMP) Dataset.

displace base load units. Our analysis includes an estimate of how much net metered solar generation is necessary to displace base load units.

Figure 7: Normalized average load shapes by fuel type, including estimated shape of solar



Source: (1) EPA. 2012. Air Markets Program (AMP) Dataset. (2) NREL. 2014. PVWatts® Calculator.

- **Size of installations:** We assume that all solar net metered facilities will be designed to generate no excess generation in the course of a year. Because we are modeling on a state-level basis for each year, annual solar generation from net metered facilities is equivalent to the behind-the-meter load reduction.

- **Solar capacity contribution:** The amount solar panels will contribute to reducing peak load was determined by using a state-specific effective load carrying capacity (ELCC). In 2006, NREL updated its study on the effective load carrying capability of photovoltaics in the United States. The analysis was done by using load data from various U.S. utilities and "time-coincident output of photovoltaic installations simulated from high resolution, time/site-specific satellite data."[21] The report provides the ELCC for several types of solar panels and at varying degrees of solar penetration. Synapse used the values corresponding to 2 percent solar penetration (the lowest value provided in the report) and the average of three types of panels (horizontal, south-facing, and southwest-facing). The resulting assumed solar capacity contribution is 58 percent.

- **Solar hourly data and capacity factor:** NREL's Renewable Resource Data Center developed the PVWatts® Calculator as a way to estimate electricity generation and

[21] Perez, R., R. Margolis, M. Kmiecik, M. Schwab, M. Perez. 2006. *Update: Effective Load-Carrying Capability of Photovoltaics in the United States*. Prepared for the National Renewable Energy Laboratory. Available at: http://www.nrel.gov/docs/fy06osti/40068.pdf.

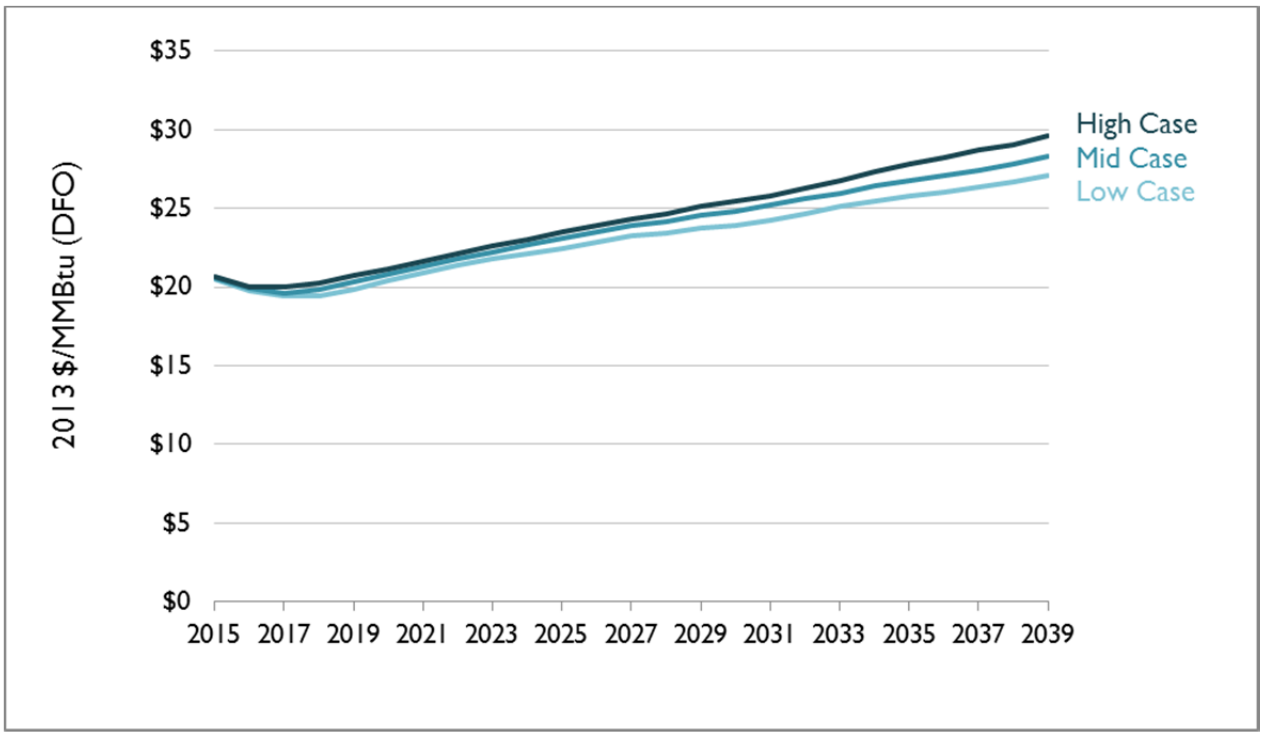
performance of roof- or ground-mounted solar facilities. The calculator, which uses geographically specific data, provides hour-by-hour data including irradiance, DC output, and AC output. PVWatts® only had one location in Mississippi—Meridian—and this was used as a sample for our hourly data and to calculate a capacity factor. The calculated capacity factor, used in all of the calculations in this analysis, is 14.5 percent.

3.2. Model Inputs: General

Fuel Price Forecast

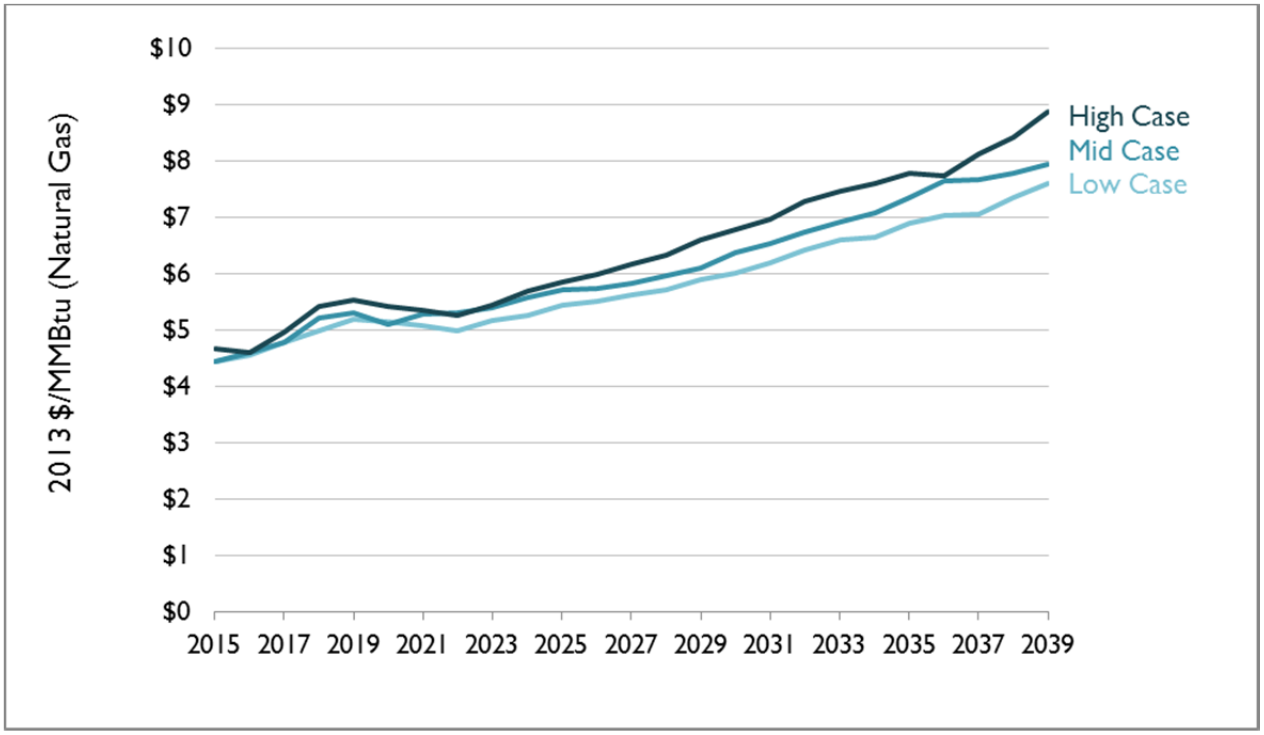
Our model assumes that net metered solar rooftop generation displaces oil- and natural gas-fired units. Consequently, fuel cost forecasts are a critical driver of avoided energy costs. The model uses fuel data price forecasts from AEO 2014 specific to the East South Central region (see Figure 8 and Figure 9). Our Mid case is the AEO Reference case, and our Low and High case values are the AEO 2014 High Economic Growth and Low Economic Growth cases, respectively.

Figure 8. East South Central diesel fuel oil price forecasts



Source: AEO 2014 Table 3.6. Energy Prices by Sector and Source - East South Central; Reference Case, High Economic Growth Case, and Low Economic Growth Case

Figure 9. East South Central natural gas price forecasts



Source: AEO 2014 Table 3.6. Energy Prices by Sector and Source - East South Central; Reference Case, High Economic Growth Case, and Low Economic Growth Case

Capacity Value Forecast

Mississippi's in-state energy resources comprised 17,542 MW of capacity in 2012,[22] serving an in-state peak demand of 9,400 MW along with significant out-of-state demand.[23] Even with the 582 MW Kemper IGCC plant scheduled to come online in 2015, additional capacity may still have a positive value in the future as Mississippi and its neighbors respond to expected environmental regulations. For example, in its 2012 planning document, Entergy identified a system-wide need for up to 3.3 GW of capacity in its reference load forecast.[24] Incremental capacity has the potential to serve other states in the service territories of distribution companies operating in Mississippi

The value of capacity is the opportunity cost of selling it to another entity that needs additional capacity for reliability purposes. For companies participating in capacity markets (such as MISO, PJM, and ISO New England), the value of capacity is determined by the clearing price. The most recent MISO South Reliability Pricing Model (RPM) Base Residual Auction (BRA) capacity market cleared at $16 per MW-day.

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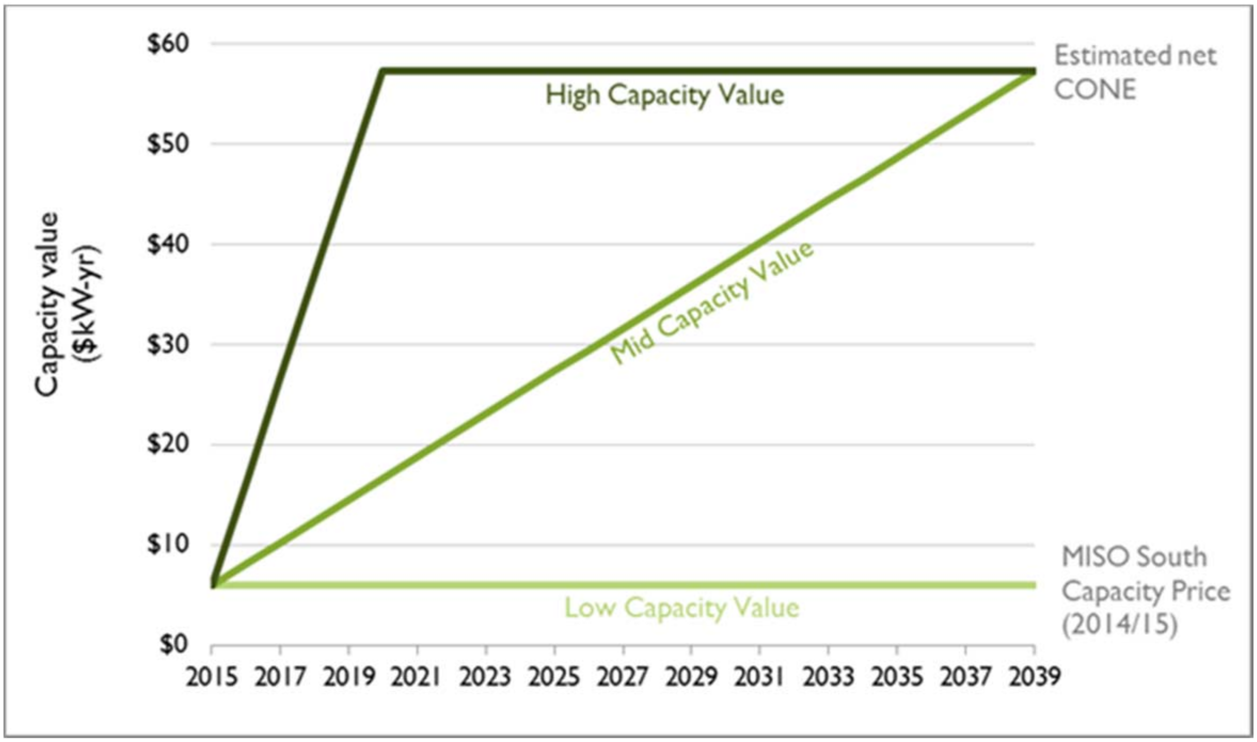
[22] EIA. 2012. EIA 860 2012. Available at: http://www.eia.gov/electricity/data/eia860/xls/eia8602012.zip.

[23] EIA. 2013. Air Markets Program Dataset, hourly 2013 for Mississippi. Available at: http://ampd.epa.gov/ampd.

[24] Entergy. 2012. *2012 Integrated Resource Plan: Entergy System*. Available at: https://spofossil.entergy.com/ENTRFP/SEND/2012Rfp/Documents/2012%20System%20IRP%20Report%20-%20Final%2002Oct2012.pdf.

To approximate the value of capacity in Mississippi, Synapse formulated three capacity value projections (see Figure 10). In these projections, gross cost of new entry (CONE) was calculated as the 25-year levelized cost of a new NGCC, and net CONE was calculated based on the ratio of net CONE to gross CONE observed in PJM reliability calculations (0.84).[25] In the Low case, the capacity value stays at the 2014/2015 MISO South BRA clearing price of $6 per kW-year. For the Mid case, the capacity value escalates linearly to a net CONE of $57 per kW-year by 2030. In the High case, the capacity value rises to the estimated net CONE value of $57 per kW-year by 2020, where it remains for the rest of the study period. These projections do not represent Synapse estimates of future MISO South BRA clearing prices[26]; rather, they approximate values suitable for estimating benefits and performing sensitivity analyses.

Figure 10. Inputs for avoided capacity cost sensitivities



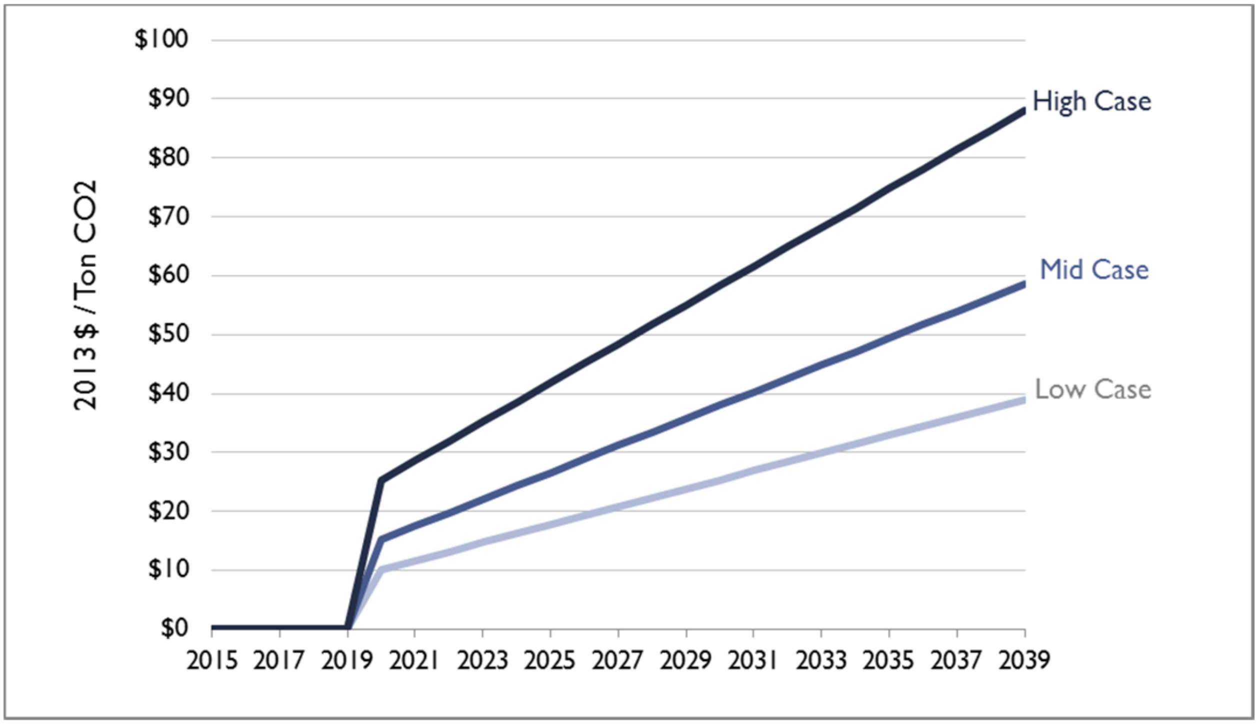
[25] PJM Planning Period Parameters 2017-2018. Available at: http://pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-planning-period-parameters.ashx. MISO calculates gross CONE but not net CONE.

[26] "MISO Clears 136,912 MW in Annual Capacity Auction" Electric Light & Power, April 15, 2014. http://www.elp.com/articles/2014/04/miso-clears-136-912-mw-in-annual-capacity-auction.html

CO_2 Price Forecast

Synapse has developed a carbon dioxide (CO_2) price forecast specifically for use in utility planning.[27] The Synapse CO_2 forecast is developed through analysis and consideration of the latest information on federal and state policymaking and the cost of pollution abatement.[28] Because there is inherent uncertainty in those regulations, the Synapse forecast is provided as High, Mid and Low cases, as illustrated in Figure 11. In this analysis, the Synapse Mid case was used for the policy reference case while the High and Low cases were used in sensitivity analyses.

Figure 11. Synapse high, mid, and low CO_2 price forecasts.



3.3. Model Inputs: Benefits of Net Metering

Generation from rooftop solar panels in Mississippi will displace generation from the state's CT peaking resources, thereby avoiding: these resources' future operating costs, the cost of compliance with certain environmental regulations, and the need for additional capacity resources.

[27] Luckow, P., E. A Stanton, B. Biewald, J. Fisher, F. Ackerman, E. Hausman. 2013. *2013 Synapse Carbon Dioxide Price Forecast*. Synapse Energy Economics. Available at: http://synapse-energy.com/project/synapse-carbon-dioxide-price-forecast.

[28] Luckow, P., J. Daniel, S. Fields, E. A. Stanton, B. Biewald. 2014. "CO2 Price Forecast." *EM Magazine*. Available at: http://www.synapse-energy.com/Downloads/SynapsePaper.2014-06.0.EM-Price-Forecast.A0040.pdf.

Avoided Energy Costs

The avoided energy costs include all fuel, variable operation and maintenance, emission allowances, and wheeling charges associated with the marginal unit (in our analysis, a blend of oil and gas combustion turbines).

Because fuel is a driving factor in the value of avoided energy costs, we made distinct short- and long-run assumptions regarding the fuel mix of peaking resources. We assumed the 2013 mix in year 2015 (approximately 25 percent oil and 75 percent natural gas), and a linear transition to 100 percent natural gas use in peaking units by 2020.

Avoided energy costs are estimated by multiplying the per MWh variable operating and fuel costs of the marginal resource by the projected MWh of solar generation in each modeled year.[29] AEO's 2014 Electric Market Module reports that the variable operation and maintenance for an oil CT is $15.67 per MWh, and for a NGCT it is $10.52 per MWh.[30] For fuel costs, we used the AEO 2014 data to project costs on an MMBtu basis and unit heat rates to convert to fuel costs on a dollars per MWh basis. Our analysis calculated the heat rates of fossil fuel units in Mississippi using data available from EPA's Air Markets Program. From this dataset, we calculated that the average in-state oil-fired unit (both steam and combustion turbines) had an 11.89 MMBtu per MWh heat rate and that the average natural gas-fired combustion turbine was 10.41 MMBtu per MWh.

Capacity Value Benefits

In this analysis, capacity value benefits were calculated as the contribution of solar net metering projects to increasing capacity availability within the state. For each year of the study period, we calculated the total amount of installed solar capacity (in this analysis, 88 MW) and then calculated the number of megawatts that contribute to peak load reduction by using the calculated Effective Load-Carrying Capability (ELCC) of 58 percent (88 MW × 58% = 51 MW of capacity contribution).[31] We then multiplied the capacity contribution by the capacity value in each year, and divided the total by the solar generation of that year to yield a dollar per MWh value.

Avoided Transmission and Distribution Capital Costs

The avoided capital costs associated with transmission and distribution (T&D) are the contribution of a distributed generation resource to deferring the addition of T&D resources. T&D investments are based on load growth and general maintenance. Growth of both the system's peak demand and energy

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[29] U.S. Energy Information Administration. 2014. *Annual Energy Outlook 2014 (AEO 2014).* Available at: www.eia.gov/forecasts/aeo.

[30] U.S. Energy Information Administration. 2014. *AEO 2014 Electric Market Module*. Table 8.2. Available at: http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf. Converted to 2013 dollars.

[31] Because distributed solar resources are a demand-side resource, they reduce the load and energy requirements that the distribution companies have to serve. The ELCC is used to translate how much the companies can expect peak load to be reduced as a result of distributed solar resources.

requirements are reduced by the customer-side generating resources (as it would be for other demand-side resources such as energy efficiency), and these costs can be avoided if the growth is counteracted by the solar resources. General maintenance costs are not entirely avoidable but can be reduced by distributed generation measures. For example, an aging 100-MW cable might be replaced with a slightly less expensive 85-MW cable. The same holds for distribution system costs. For example, costs associated with maintaining or building new transformers and distribution buses at substations will be lower if the peak demand at that substation is reduced.

In the absence of utility-specific values for avoidable T&D costs, we use our in-house database of avoided T&D costs calculated for distributed generation and energy efficiency programs to provide a reasonable estimate. The average avoided transmission value from this database is $33 per kW-year and the average avoided distribution value was $55 per kw-year, for a combined avoided T&D value of $88 per kW-year. This value is multiplied by the capacity contribution and divided by generation—the same way the capacity benefit was—to yield an avoided T&D cost in dollars per MWh.

Synapse is aware of no long-term avoided transmission and distribution (T&D) cost study that has been conducted for those entities that operate in Mississippi for use in this analysis. Synapse has assembled a clearinghouse of publicly available reports on avoided T&D costs. Our current database includes detailed studies on avoided costs of T&D for over 20 utilities and distribution companies that serve California, Connecticut, Oregon, Idaho, Massachusetts, New Hampshire, Maine, Rhode Island, Utah, Vermont, Washington, Wyoming, and Manitoba.[32] For our analysis, we developed a low, mid, and high estimate of avoided T&D costs by first separating transmission and distribution costs and then converting all costs to 2013$ values. The low value for each category (transmission and distribution) was calculated by taking the 25th percentile of reported values; the high value used the 75th percentile. The mid value was calculated as an average of the reported values for each category. The values for each category were then combined to develop an estimated avoided T&D cost.

[32] The values in this database are consistent with a 2013 review of avoided T&D costs of distributed solar in New York, New Jersey, Pennsylvania, Texas, Colorado, Arizona, and California. See: Hansen, L., V. Lacy, D. Glick. 2013. *A Review of Solar PV Benefit and Cost Studies, 2nd Edition*. Rocky Mountain Institute. Available at: www.rmi.org/elab_emPower.

Figure 12. Avoided transmission and distribution costs

Avoided System Losses

Avoided system losses are the reduction or elimination of costs associated with line losses that occur as energy from centralized generation resources is transmitted to load. Usually presented as a percent of kWh generated, these losses vary by section of the T&D system and by time of day. The greatest losses tend to occur on secondary distribution lines during peak hours, coincident with solar distribution generation.

To account for variation in line losses, our analysis estimates avoided system losses using a weighted average of line losses during daylight hours. This value was calculated by weighing daylight line losses of each Mississippi T&D system (Entergy Mississippi, Mississippi Power, and the rest of the state) in proportion to the load each system serves. Our analysis incorporates Entergy- and Mississippi Power-specific data for their T&D systems. For the remainder of the state, including SMEPA, our analysis uses national average T&D system losses adjusted to reflect losses during the hours when solar panels generate energy.[33]

Avoided system losses were calculated as the product of the weighted average system losses and the projected generation from solar panels in each year in kWh multiplied by the avoided dollars per kWh energy cost in that same year.

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[33] U.S. Energy Information Administration. 2014. "How much electricity is lost in transmission and distribution in the United States?" *EIA Website: Frequently Asked Questions.* Available at: http://www.eia.gov/tools/faqs/faq.cfm?id=105&t=3. Updated May 7, 2014.

Avoided Environmental Compliance Costs

Avoided environmental compliance costs are the reduction or elimination of costs that the marginal unit would incur from various existing and reasonably expected environmental regulations. For oil and gas CTs, these avoided environmental compliance costs are primarily associated with avoided CO_2 emissions.[34]

Mississippi's distribution companies have used a price for CO_2 emissions in their planning for many years. For the Kemper IGCC project, analysts included the impacts of "existing, moderate, and significant" future carbon regulations in their economic justification for the project.[35] Entergy developed a system-wide Integrated Resource Plan (IRP) for all six Entergy operating companies, including Entergy Mississippi, which modeled a CO_2 price in its reference case.[36] Tennessee Valley Authority's most recent finalized IRP also incorporates a CO_2 price in seven of its eight scenarios developed for that IRP.[37] Our benefit and cost analysis uses the Synapse Mid case in our avoided environmental compliance estimation. The Synapse Mid case forecasts a carbon price that begins in 2020 at $15 per ton, and increases to $60 per ton in 2040.[38]

Avoided Risk

There are a number of risk reduction benefits of renewable generation (and energy efficiency) from both central stations and distributed sources. The difficulties in assigning a value to these benefits lie in (1) quantifying the risks, (2) identifying the risk reduction effects of the resources, and (3) quantifying those risk reduction benefits. Increased electric generation from distributed solar resources will reduce Mississippi ratepayers' overall risk exposure by reducing or eliminating risks associated with transmission costs, T&D losses, fuel prices, and other costs. Increasing distributed solar electricity's contribution to the state's energy portfolio also helps shift project cost risks away from the utility (and subsequently the ratepayers) and onto private-sector solar project developers.

The most common practical approach to risk-reduction-benefit estimation has been to apply some adder (adjustment factor) to avoided costs rather than to attempt a detailed technical analysis. There is, however, little consensus in the field as to what the value of that adder should be. Current heuristic practice would support a 10 percent adder to the avoided costs of renewables such as solar. There are

[34] For more information on this topic see: Wilson, R., Biewald, B. June 2013. *Best Practices in Electric Utility Integrated Resource Planning*. Synapse Energy Economics for the Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6608.

[35] URS Corporation. March 7, 2014. IM Prudence Report, Mississippi Public Service Commission Kemper IGCC Project.

[36] Entergy. 2012. *2012 Integrated Resource Plan, Entergy System*. Available at: https://spofossil.entergy.com/ENTRFP/SEND/2012Rfp/Documents/2012%20System%20IRP%20Report%20-%20Final%2002Oct2012.pdf.

[37] Tennessee Valley Authority. 2011. *Integrated Resource Plan: TVA's Energy and Environmental Future.* Available at: http://www.tva.com/environment/reports/irp/archive/pdf/Final_IRP_Ch6.pdf.

[38] Luckow, P., E.A. Stanton, B. Biewald, J. Fisher, F. Ackerman, E. Hausman. 2013. *2013 Carbon Dioxide Price Forecast*. Synapse Energy Economics. Available at: http://synapse-energy.com/project/synapse-carbon-dioxide-price-forecast.

both more avoided costs and risk reduction benefits associated with distribution generation; thus, one would expect greater absolute risk reduction benefits with distributed generation. Based on this, we applied a 10 percent avoided risk adder when calculating avoided costs in this analysis. For more information on the value of avoided risk and the literature review of current practices, see Appendix A of this report.

3.4. Model Inputs: Costs

Net metered solar facilities will also result in some costs: reduced revenue to distribution companies and administrative costs. We assume that net metered resources in Mississippi will both reduce retail sales with their behind-the-meter generation and be compensated for their net energy generation.

Customer Perspective Modeling

CREST Model

In order to model costs and benefits, our analysis required the assumption that some solar net metered projects would be developed. However, it is entirely possible that, depending on the net metering policy, net metering would not experience widespread adoption in Mississippi. In order to determine the likelihood of customers in Mississippi adopting rooftop solar, we estimated the financial impacts of installing rooftop solar in Mississippi using the Cost of Renewable Energy Spreadsheet Tool (CREST) model to estimate the cost of rooftop photovoltaic projects in Mississippi and estimate the subsidies required to allow them to earn a competitive rate of return.[39] Developed for the National Renewable Energy Laboratory, CREST is a cash-flow model designed to evaluate project-based economics and design cost-based incentives for renewable energy.

Model Assumptions and Inputs

Using the CREST model, we analyzed residential-scale photovoltaic projects (assumed to be 5 kW in size) and commercial projects (500 kW). We assumed that all projects are developed and owned by the building owner. Projects are assumed to be developed in 2015; therefore, the effects of the 30 percent federal Investment Tax Credit (ITC) are included. Table 5 reports the inputs used in our CREST analysis.

The installed cost of photovoltaic projects continues to fall rapidly across the country, and it is difficult to discern current average project costs. Carefully reviewed datasets tend to appear a year or two after the fact, and information in the press or released by project developers often focuses on selected data points that are not representative of industry averages. Our assumed project costs, shown in Table 5, are based on ongoing review of data from government agencies and energy labs, solar industry trade

[39] National Renewable Energy Laboratory. 2011. "CREST Cost of Energy Models." Retrieved August 1, 2014. Available at: https://financere.nrel.gov/finance/content/crest-cost-energy-models.

groups, our work in proceedings before utility commissions, and discussions with photovoltaic project developers.

Table 5. Inputs for photovoltaic costs analysis

	Residential Projects	Commercial Projects
Capital Costs ($/$W_{DC}$)	$4.00	$3.65
O&M ($/kW-yr)	$21.00	$20.00
Federal Tax Rate (%)	28%	34%
State Tax Rate (%)	5%	5%
Inflation rate	2%	2%
Insurance (% of capital costs)	0.3%	0.3%
Federal ITC (% of capital costs)	30%	30%
Debt (% of capital costs)	40%	40%
Debt Term (years)	15	15
Interest Rate (%)	4%	4%
After-Tax Equity IRR (%)	0%	0%

We use a 0 percent return on equity to represent a project that exactly breaks even. Therefore, the revenue requirement the model produces represents the lowest expected revenue that would cause a rational building owner to proceed with the project. The revenue would cover all costs, including debt service, by the end of the project's 25-year life. (The payback period would be 25 years.) We have modeled projects in this way for ease of comparison with retail electricity rates. That is, where levelized, forecasted rates are higher than the levelized costs, projects would expect to earn a return on equity and have a shorter payback period. Where forecasted retail rates are lower, projects would be expected to lose money. Table 6 shows the levelized cost of energy for each of the project types and the average of the two values.

Table 6. The estimated levelized cost of energy from rooftop photovoltaic panels in Mississippi

Project type	Levelized Cost ($/MWh)
Residential	142
Commercial	129
Average	135

Finally, note that the federal ITC is scheduled to fall to 10 percent in 2016. If this occurs, it is likely to cause an elevation in levelized costs lasting several years, even as cost reductions continue on their recent trajectory during this period.

As shown in Table 6, our analysis indicates that the expected cost of net metered rooftop solar in Mississippi is $129 per MWh for commercial customers and $142 per MWh for residential customers (see Table 6). From this we can reasonably expect that more capacity of solar will be installed by commercial customers than residential; however, without additional information it is difficult to predict the rate of adoption and the relative share of installations between these two sectors. As a simplifying assumption in the modeling presented in this report, we refer to the average of the commercial and residential levelized cost of solar: $135 per MWh.

Administrative Costs

Because Mississippi currently has no net metering program, it was necessary to assume costs for administering the program. We conducted research sampling data from other states with net metering programs. The incremental costs associated with managing a net metering program in most states are difficult to separate from other normal, everyday administrative costs. However, cost data is widely available for many states' energy efficiency programs. We estimate that the average utility spends between 6 percent and 9 percent of energy efficiency program costs on administrative tasks, with the average administrator spending 7.5 percent.[40] This value includes program administration, marketing, advertising, evaluation, and market research. Based on a limited dataset on estimated costs to manage the net metering programs in California and Vermont and a comparison of those state's respective energy efficiency programs, we find that administering net metering programs tends to be less costly than administering energy efficiency programs.

In 2012, Mississippi spent approximately $12 million on energy efficiency, of which approximately $0.9 million was spent on various administration costs like the ones discussed above. For our analysis, we assumed a value of $0.9 million per year for administrative costs associated with net metering. These costs would include front office administrative costs, handling permitting issues, and keeping track of net metering installations. While these costs may not prove to perfectly reflect the experience Mississippi may have, it represents a reasonable, first order approximation of those costs.

Reduced Revenue to Distribution Companies

Distribution companies' kilowatt-hour sales will be reduced by net metered generation. These reduced revenues were calculated as the amount of energy generated by net metered facilities multiplied by the weighted average retail rate. The analysis also reflects retail rate escalation that matches the anticipated growth rate of natural gas and also includes a discussion of the impact of reduced revenues on rates and on the financial solvency of distribution companies.[41]

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[40] Synapse reviewed 2012 energy efficiency annual reports in 22 states in order to gather program participant cost data from states recognized by ACEEE as leaders in energy efficiency programs. For the purpose of this research, we have defined leading or high impact states as the top 15 states in the 2013 ACEEE State Energy Efficiency Scorecard in terms of annual savings as a percentage of retail sales or absolute annual energy savings in terms of total annual MWh savings. The 22 states that are leaders in one or both of these criteria are: Arizona, California, Connecticut, Florida, Hawaii, Illinois, Indiana, Iowa, Maine, Massachusetts, Michigan, Minnesota, New Jersey, New York, North Carolina, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, Vermont, and Washington.

[41] Utility lost revenues are not a new cost created by the net metered systems. Lost revenues are simply a result of the need to recover existing costs spread out over fewer sales. The existing costs that might be recovered through rate increases as a result of lost revenues are (a) not caused by the efficiency program themselves, and (b) are not a new, incremental cost. In economic terms, these existing costs are called "sunk" costs. Sunk costs should not be used to assess future resource investments because they are incurred regardless of whether the future project is undertaken. Consequently, the application

3.5. Literature Review of Costs and Benefits Not Monetized

Avoided Externality Costs

Externality costs are typically environmental damages incurred by society (over and above the amounts "internalized" in allowance prices). Some states choose to consider the externality costs associated with electricity generation in their policymaking and planning. Avoided externality costs from displaced air emissions are a benefit to the state and can be considered in benefit and cost analysis without necessarily including these non-market costs in an avoided cost rate. For example, the Societal Cost Test used by some states to screen energy efficiency measures includes avoided externality costs. In regions and states where utility commissions consider externality costs in their determination of total societal benefits, Synapse has used a value of $100 per metric ton of CO_2 as an externality cost.[42] We have not, however, monetized avoided externality costs for Mississippi.

Avoided Grid Support Services Costs

Distributed generation may contribute to reduced or deferred costs associated with grid support, including voltage control, reduced operating reserve requirements and reactive supply. Because most of the studies to date have focused on operating reserve requirement, and those benefits are embedded in our capacity benefits, our analysis does not include any additional avoided grid support services.

Avoided Outage Costs

Distributed generation facilities have the potential to help customers avoid outages if the facility is allowed to island itself off of the grid and self-generate during an outage event. For a cost-benefit analysis, the value of avoiding outages is typically represented by estimating a value of lost load (VOLL) as the amount customers would be willing to pay to avoid interruption of their electric service. A study conducted by London Economics International on behalf of ERCOT concluded that the VOLL for residential customers was approximately $110 per MWh and was between $125 per MWh and $6,468 per MWh for commercial and industrial customers.[43] An earlier literature review conducted for ISO New

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of the RIM test is not valid for analyzing the efficacy of net metered or distributed resources as it is a violation of this important economic principle.

[42] For example, see: Hornby, R. et al. 2013. *Avoided Energy Supply Costs in New England: 2013 Report*. Synapse Energy Economics. Available at: http://synapse-energy.com/project/avoided-energy-supply-costs-new-england.

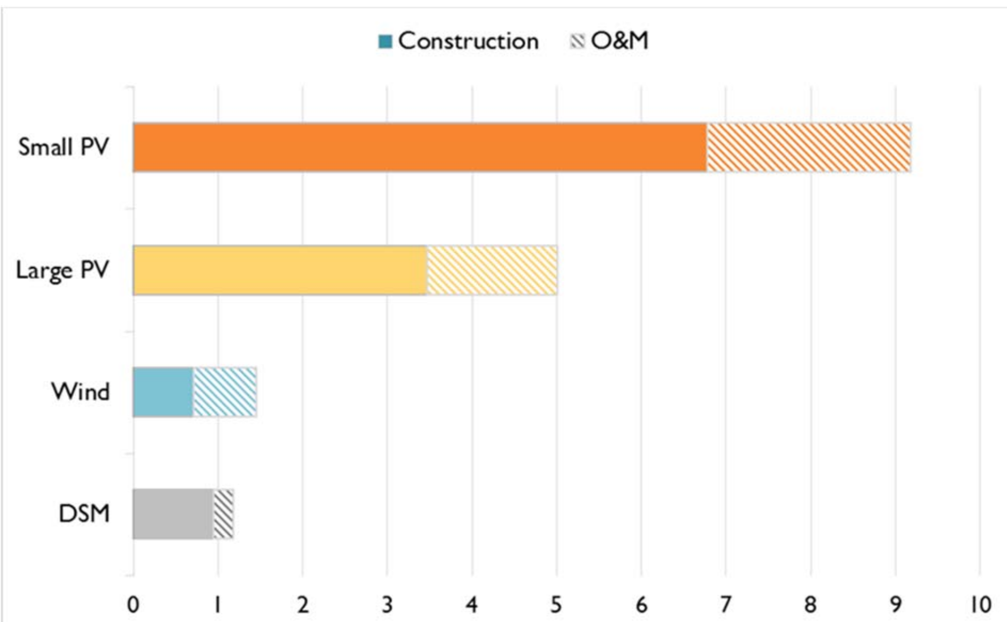
[43] Frayer, J., S. Keane, J. Ng. 2013. *Estimating the Value of Lost Load.* Prepared by London Economics on behalf of the Electric Reliability Council of Texas, Inc. Available at: http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf.

England found values between $2,400 per MWh and $20,000 per MWh.[44] Even if these values could be adapted to Mississippi customers, there is not sufficient evidence to indicate the extent to which solar net metering would improve reliability, and therefore these estimates cannot be translated into monetizable benefits of net metering at this time.

Economic Development Benefits

In states with growing net metering programs, the siting, installation, and maintenance of solar panels is an emergent industry. A recent Synapse study estimated the employment effects of investing in solar projects in another rural state: Montana. The study found that, compared to other clean energy technologies, small-scale photovoltaic provides the most job-years per average megawatt, as illustrated in Figure 13.[45] This level of detailed analysis was not conducted for Mississippi.

Figure 13. Average annual job impacts by resource per megawatt (20-year period)



Source: Synapse and NREL JEDI Model (industry spending patterns), IMPLAN (industry multipliers).

Solar Integration Costs

Solar integration costs are the investments distribution companies make in order to incorporate distributed resources into the grid. Typically, Synapse sees these costs escalate alongside increasing

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44 Cramton, P., J. Lien. 2000. *Value of Lost Load.* Available at: http://isone.org/committees/comm_wkgrps/inactive/rsvsrmoc_wkgrp/Literature_Survey_Value_of_Lost_Load.rtf.

45 Comings, T., et al. 2014. *Employment Effects of Clean Energy Investments in Montana*. Synapse Energy Economics for Montana Environmental Information Center and Sierra Club. Available at: http://www.synapse-energy.com/Downloads/SynapseReport.2014-06.MEIC.Montana-Clean-Jobs.14-041.pdf.

penetration levels. Our literature review found very little substantiated evidence that there are significant costs incurred by grid operators or distribution companies as a result of low levels of solar distributed resources. In a 2013 net metering proceeding in Colorado, Xcel Energy released its analysis for integrating distributed solar resources at a 2 percent penetration level. At that level, which is four times the level of penetration estimated for our analysis in Mississippi, Xcel Energy concluded that solar distributed generation would add a $2 per MWh cost to the system.[46] A 2012 study performed by Clean Power Research analyzing 15 percent penetration concluded that integration costs were about $23 per MWh.[47]

4. MISSISSIPPI NET METERING POLICY CASE RESULTS

Our Mississippi net metering policy case is based on the “mid” or reference inputs discussed above.

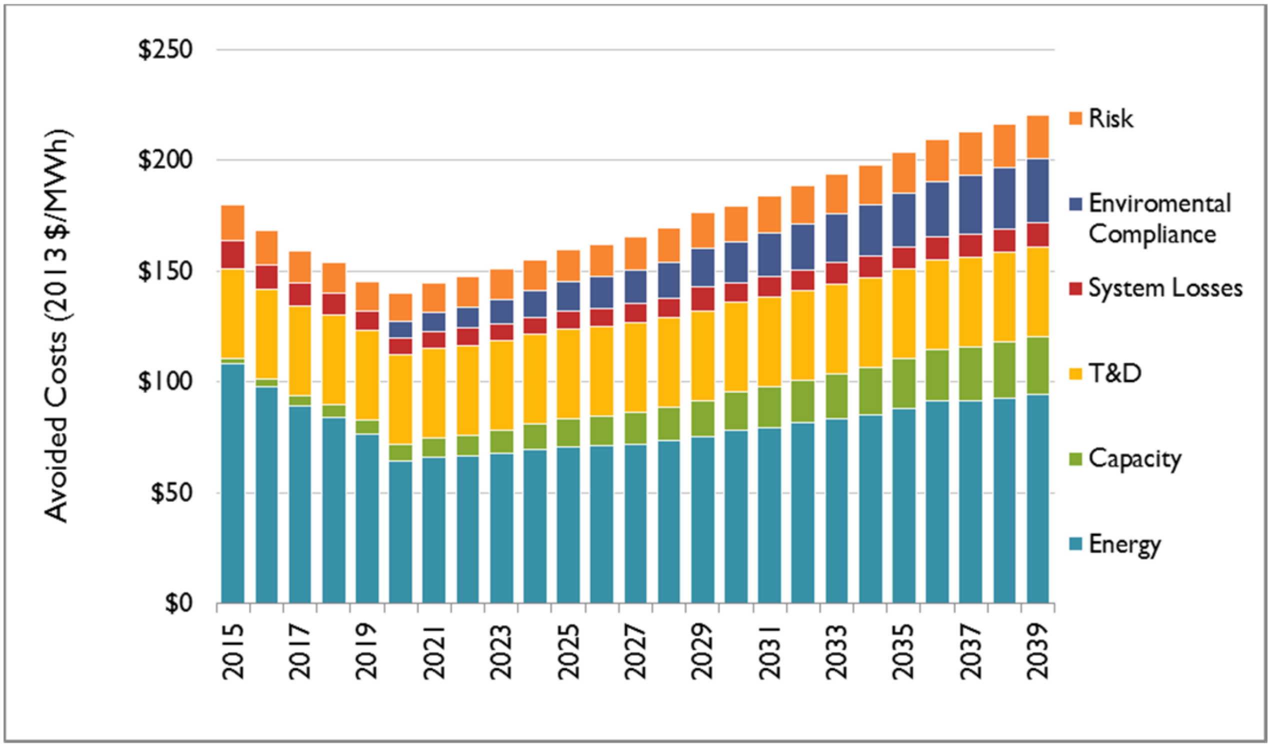
4.1. Policy Case Benefits

We estimated the annual potential avoided costs associated with a representative solar net metering program in Mississippi. Figure 14 demonstrates that the short-run benefits of net metering are dominated by avoided energy costs.

[46] Xcel Energy Services, Inc. 2013. *Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System*. Prepared in response to CPUC Decision No. C09-1223. Page 41. Available at: http://votesolar.org/wp-content/uploads/2013/12/11M-426E_PSCo_DSG_StudyReport_052313.pdf.

[47] Perez, R. et al. 2012. *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania*. Clean Power Research for Mid-Atlantic Solar Energy Industries Association and Pennsylvania Solar Energy Industries Association. Available at: http://mseia.net/site/wp-content/uploads/2012/05/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf.

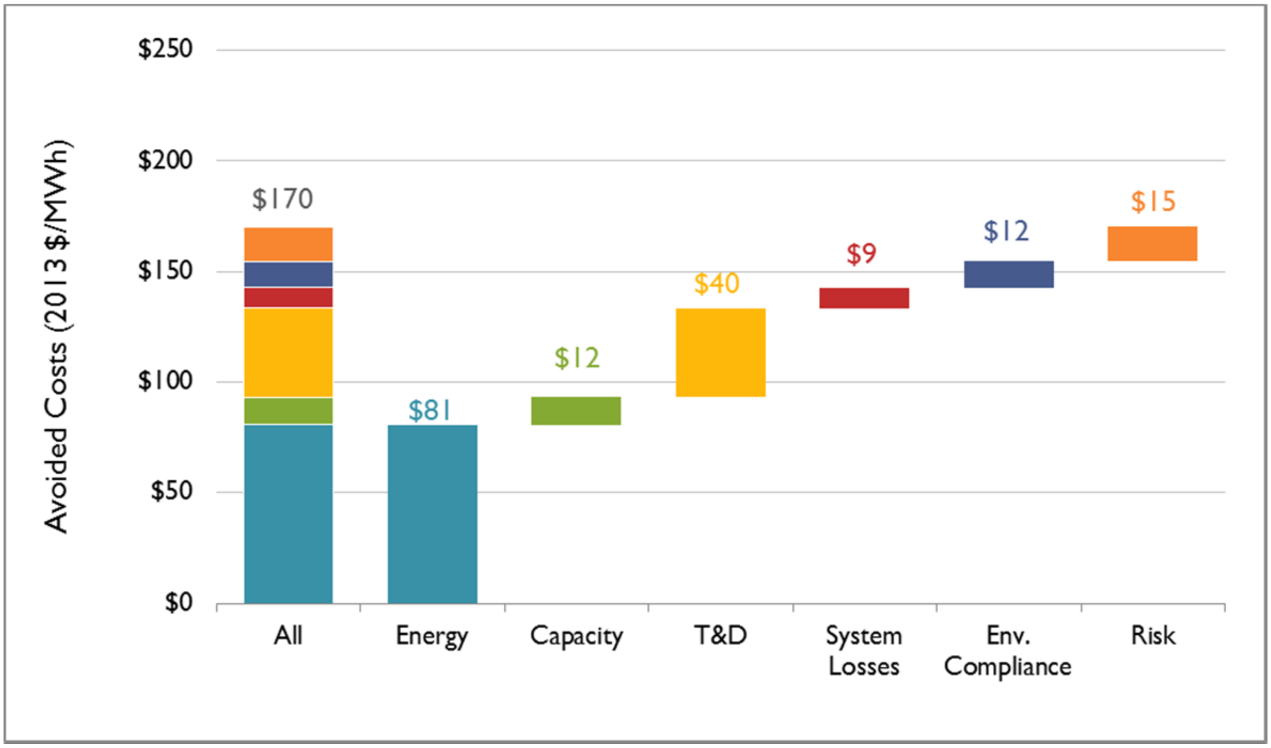
Figure 14. Annual potential benefits (avoided costs) of solar net metering in Mississippi



Avoided energy costs start at over $100 per MWh and decline over the first five years due to a gradual transition in the displaced marginal unit from a mix of oil and gas units to gas units alone. Because oil units are the most expensive units to operate, the benefits of net metering decline as less energy from oil units is displaced over time. Avoided capacity costs increase over the study period, rising from $3 per MWh in 2015 up to $26 per MWh at the end of the study period, due to the assumed increase over time in the value of capacity to Mississippi's distribution companies. Avoided environmental costs begin in 2020, the first year for which the Synapse CO_2 price forecast projects a non-zero value.

Figure 15 illustrates avoided costs of a net metering program in Mississippi on a 25-year levelized basis: $170 per MWh. Avoided energy costs account for the largest share of levelized benefits ($81 per MWh), followed by avoided T&D costs ($40 per MWh). The value associated with reduced risk is the third largest benefit ($15 per MWh).

Figure 15. 25-year levelized potential benefits (avoided costs) of solar net metering using risk-adjusted discount rate

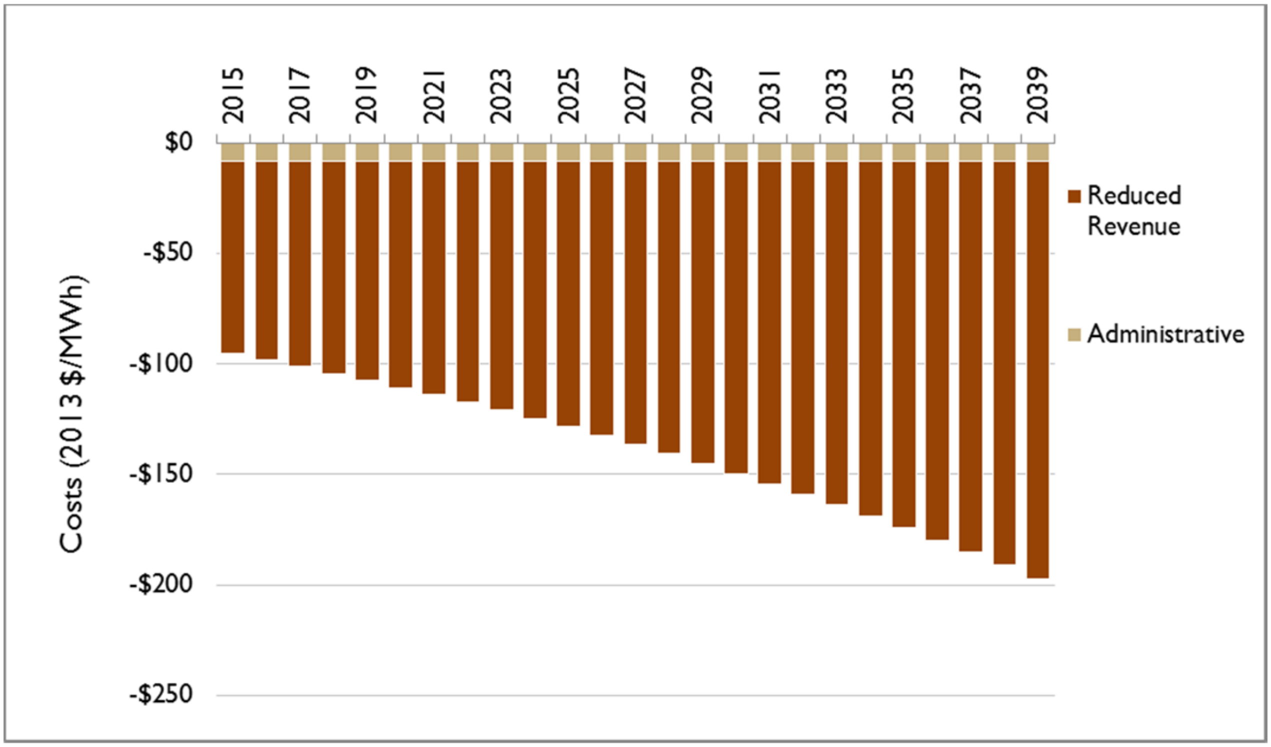


4.2. Policy Case Costs

Figure 16 reports annual potential utility costs of a representative solar net metering program in Mississippi. Reduced revenues to the utilities are projected to increase over the study period to reflect rate escalation. For this analysis, we assumed that rates in Mississippi would increase in proportion to natural gas prices.[48]

[48] This assumption is based on the fact that the volumetric portion of rates in Mississippi is primarily comprised of the variable costs of energy generation, the majority of which are fuel costs. Based on, among other things, the current portfolio of energy resources in the state, our calculations indicate that electric rates will correlate with natural gas prices.

Figure 16. Annual potential utility cost of solar net metering



4.3. Cost-Effectiveness Analysis

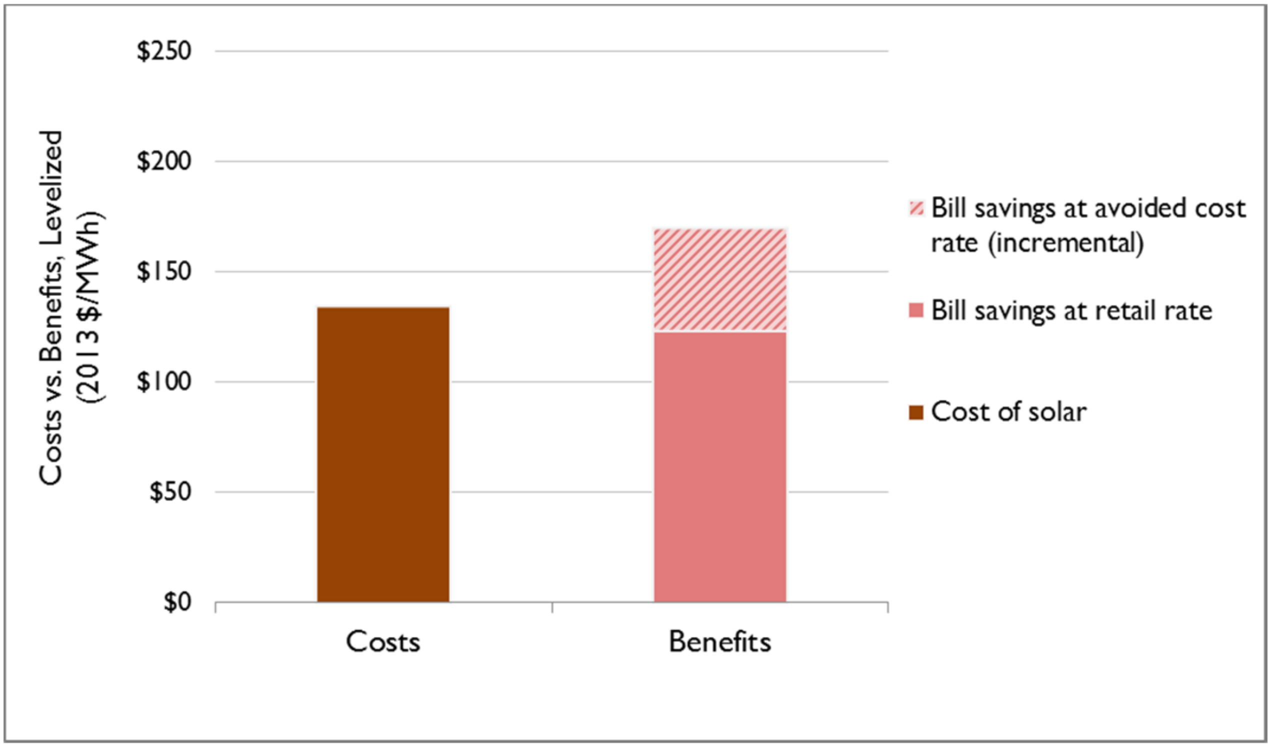
We performed cost-effectiveness analyses on a representative net metering program in Mississippi using several methods (refer to Section 2.3 above). Here we discuss:

- Participant perspective analysis using the Participant Cost Test (PCT)
- Utility perspective analysis using the revenue requirement savings-to-cost ratio
- Total resource perspective using the Total Resource Cost (TRC) test
- Societal perspective using the Societal Cost Test

Participant Perspective Analysis

To analyze the potential costs and benefits to participants of net metering, our analysis used the Participant Cost Test. Results of the Participant Cost Test depend on the way in which net metering customers are compensated. As shown in Figure 17, under net metering rules in which customers are only compensated at the variable retail rate, the levelized benefits ($124 per MWh) would be lower than levelized costs ($135 per MWh) resulting in a benefit-to-cost ratio below 1.0—suggesting that net metering would not be attractive to develop for economic reasons. If, instead, customers were compensated at the avoided cost rate ($170 per MWh) for every MWh of generated energy, projects would realize a return on investment. The minimum amount of return on investment that is needed to pursue a project is specific to the developer. A benefit-cost ratio of 1.0 means that the developer breaks even, which is unlikely to provide sufficient incentive to stimulate widespread adoption of net metering.

Figure 17. Levelized potential benefit/cost comparison under Participant Cost Test



As shown in Table 7, using the Participant Cost Test, under a net metering policy in which participants are only compensated at the retail rate, solar net metering would have a benefit-to-cost ratio of 0.92. If participants were paid the avoided costs, solar net metering would have a benefit-to-cost ratio of 1.26.

Table 7. Benefit-cost ratio under the participant cost test

	Compensated at retail rate	Compensated at avoided cost rate
B/C ratio	0.92	1.26

In order to determine what the 1.26 benefit-to-cost ratio would represent to a Mississippi ratepayer looking to develop rooftop solar, we ran an additional CREST model run assuming the customer would be compensated at the avoided cost rate for each unit of energy generated. If a solar net metered project were compensated at $170 per MWh (which we estimated to be the avoided cost rate) for every megawatt-hour and not just excess generation, then that project might expect an approximate 3.5 percent return on equity.

The Participant Cost Test evaluates cost effectiveness from the net metering participant’s perspective. As discussed above, our modeling for costs of solar include a 0-percent return on investment such that a benefit-to-cost ratio of 1.0 reflects “break even” conditions. The greater the benefit-to-cost ratio, the more likely that solar net metering projects will be developed. A benefit-to-cost ratio less than 1.0 represents a situation in which costs to the participant exceed benefits. It is possible that some ratepayers in Mississippi might be willing to purchase solar net metering panels for reasons that are not purely driven by a desire to make a return on investment; for example, they may value a lower emission source of energy. One important caveat of the Participant Cost Test results shown in Table 7 is that no benefits or cost related to change in property value as a result of installing solar panels are assumed. A 2011 Lawrence Berkeley National Laboratory analysis concluded that:

> The research finds strong evidence that homes with PV systems in California have sold for a premium over comparable homes without PV systems. More specifically, estimates for average PV premiums range from approximately $3.9 to $6.4 per installed watt (DC) among a large number of different model specifications, with most models coalescing near $5.5/watt.[49]

A recent report conducted in Colorado by the Appraisal Institute, the nation's largest professional association of real estate appraisers, made a similar conclusion, stating, "solar photovoltaic systems typically increase market value and almost always decrease marketing time of single-family homes in the Denver metropolitan area."[50] The extent to which the real estate market would reflect the trends observed in California and Colorado is unclear. Moreover, according to a 2014 Sandia National Laboratories report, real estate value impacts are affected by the photovoltaic ownership structure (if it is leased or owned out right by the property owner).[51] Consequently, this analysis omitted this potential benefit of increased home value in the calculation of the benefit-cost ratios.

Utility Perspective Analysis

Two tests, the Rate Impact Measure and the Utility Cost Test, are sometimes used to determine the cost effectiveness of energy efficiency programs from the utility's perspective. The only difference between the RIM test and the UTC is the "lost revenues" (i.e., the reduction in the revenues as a result of reduced consumption). If the utility is to be made financially neutral to the impacts of the energy efficiency programs, then the utility would need to collect the lost revenues associated with the fixed cost portion of current rates. If the utility were to recover these lost revenues over time, then we would expect to observe an upward trend in future electricity rates.

One of the problems with the RIM test in the context of this study is that the lost revenues are not a *new* cost created by the net metering programs. Lost revenues are simply a result of the need to recover *existing* costs spread out over fewer sales. The existing costs that might be recovered through rate

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[49] Hoen, B. et. al. 2011. *An Analysis of the Effects of Residential Photovoltaic Energy Systems on Home Sales Prices in California.* Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/sites/all/files/lbnl-4476e.pdf.

[50] Appraisal Institute. 2013. "Solar Electric Systems Positively Impact Home Values: Appraisal Institute." Press release. Available at: http://www.appraisalinstitute.org/solar-electric-systems-positively-impact-home-values-appraisal-institute-/.

[51] Klise G.T., J.L. Johnson. 2014. *How PV System Ownership Can Impact the Market Value of Residential Homes.* Sandia National Laboratories. Available at: http://energy.sandia.gov/wp/wp-content/gallery/uploads/SAND2014-0239.pdf.

increases as a result of lost revenues are (a) not caused by the efficiency program themselves, and (b) are not a new, incremental cost. In economic terms, these existing costs are called “sunk” costs. Sunk costs should not be used to assess future resource investments because they are incurred regardless of whether the future project is undertaken. Application of the RIM test is a violation of this important economic principle.

Another problem with the RIM test is that it frequently will not result in the lowest cost to customers. Instead, it may lead to the lowest rates (all else being equal, and if the test is applied properly). However, achieving the lowest rates is not the primary or sole goal of utility planning and regulation; there are many goals that utilities and regulators must balance in planning the electricity system. Maintaining low utility system costs, and therefore low customer bills on average, is often given priority over minimizing rates. For most customers, the size of the electricity bills that they must pay is more important than the rates underlying those bills.

Most importantly, the RIM test does not provide the specific information that utilities and regulators need to assess the actual rate and equity impacts of energy efficiency or distributed generation. Such information includes the impacts on long-term average rates, the impacts on average customer bills, and the extent to which customers participate in efficiency programs or install distributed generation and thereby experience lower bills.

The Utility Cost Test provides some very useful information regarding the costs and benefits of energy efficiency resources. In theory, the UCT should include all the costs and benefits to the utility system over the long term, and therefore can provide a good indication of the extent to which average customer bills are likely to be reduced as a result of distributed energy resources. However, when applied to net metering, the results of the UTC are less indicative of how distributed generation will impact customers, primarily due to the wide variety in market participants and financing methods associated with distributed generation.

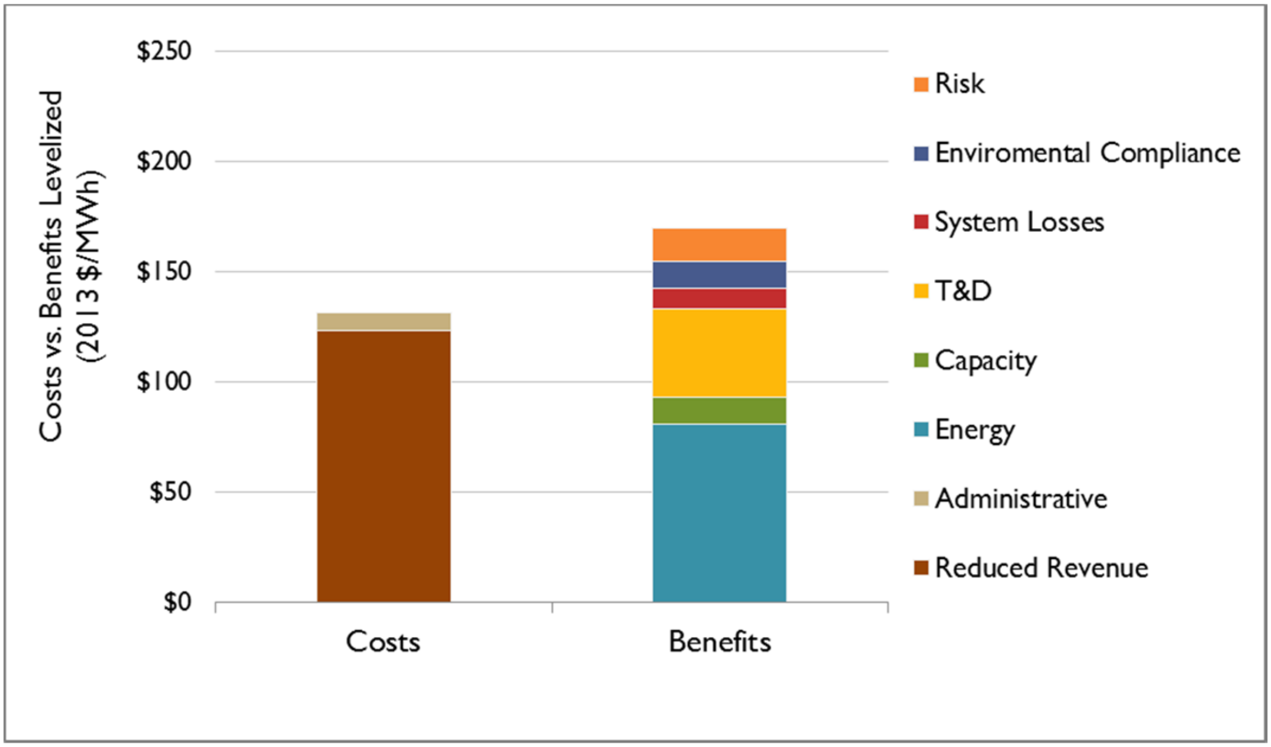
For these reasons, in this analysis we have chosen to use neither of these screening tests to investigate the impacts of net metering from the utility perspective.

Instead, we use a revenue requirement savings-to-cost ratio as an indicator of whether or not a net metering program will create upward or downward pressure on rates. Under a net metering policy where generation is compensated at the retail rate, utilities “pay” for the energy at the retail rate and receive a savings equivalent to the avoided cost rate. When the ratio, calculated by performing a 25-year levelization of avoided costs and dividing it by the 25-year levelized variable rate, is above 1.0, this indicates that there will be downward pressure on rates. When the ratio is below 1.0, it indicates that there will be upward pressure on rates. The results of this analysis cannot be directly translated into a rate or bill impact without additional analysis. Utility cost recovery and benefit sharing is dependent on future rate cases, program design, commission rulings, market changes, and other factors. Had the results of this test indicated that there would be upward pressure on rates, it would be necessary to perform additional analysis on rate and bill impacts on participants and non-participants in order to determine what, if any, regressive cross-subsidization was occurring.

For the revenue requirement savings-to-cost ratio, our analysis used a discount rate that reflects the utilities' cost of capital; for this analysis, we assumed this to be a 6-percent real discount rate. Use of this higher discount rate does not materially change the value of the avoided costs on a levelized basis.

Under our policy reference case assumptions, over the 25-year span of our analysis, the levelized savings (avoided costs) outweigh the levelized costs (retail variable rate plus administrative costs), as illustrated in Figure 18. This suggests that generation from net metering customers would put downward pressure on rates.

Figure 18. Levelized potential benefit/cost comparison under revenue requirement cost benefit analysis

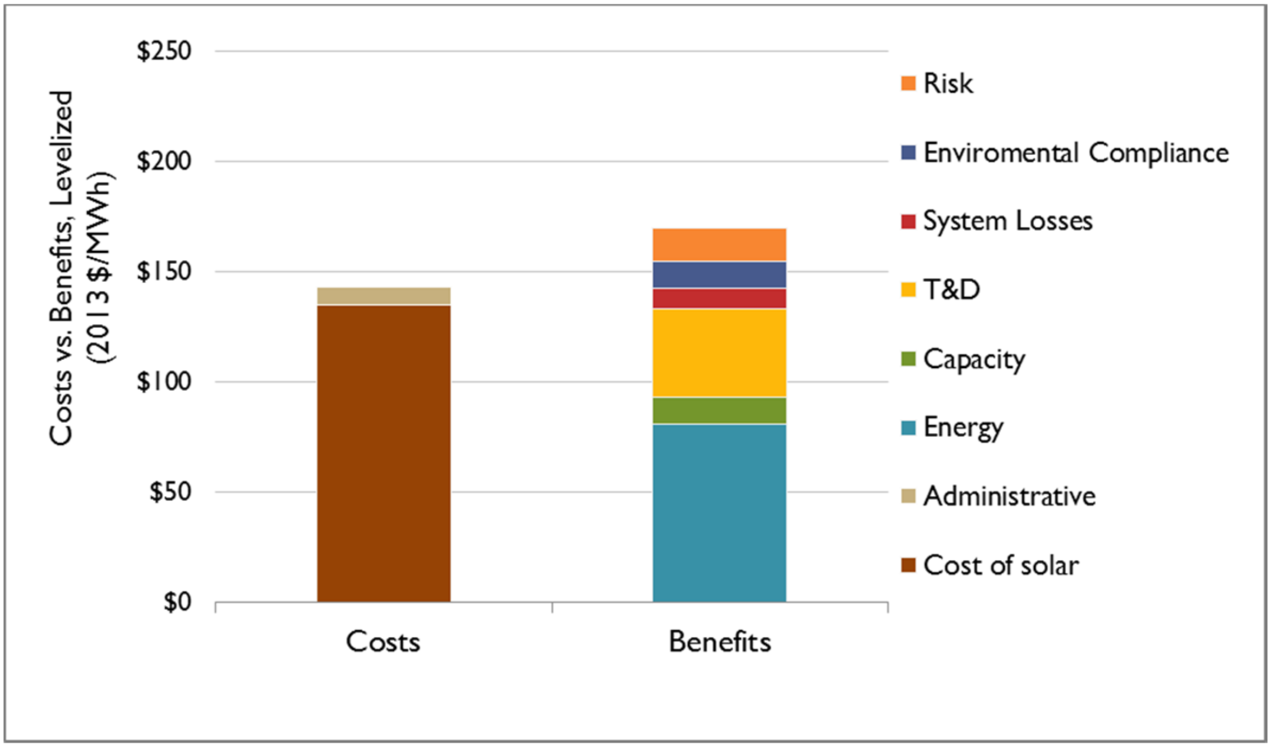


Total Resource Perspective

To determine the overall cost and benefits of a resource, this analysis employed the Total Resource Cost test, which compares net economic costs and benefits for the state as a whole but excludes avoided externality costs and economic development benefits. The test includes all of the avoided costs to the utility as benefits. It would also include any non-energy benefits as benefits if those could appropriately be accounted for. For our analysis, the cost associated with installing the solar panels and the administrative costs are the only costs reflected in our cost-benefit analysis using the TRC test. The analysis omits the potential for solar integration costs, as these are typically negligible at lower solar penetration.

As illustrated in Figure 19, under the assumptions of our policy reference case, solar net metering would provide net benefit to the state of Mississippi. With estimated benefits of $170 per MWh and estimated costs of $143 per MWh, net metered solar rooftop would result in $27 per MWh of net benefits to the state and passes the TRC with a benefit-to-cost ratio of 1.19.

Figure 19. Levelized potential benefit/cost comparison under Total Resource Cost Test



Societal Perspective

As stated above, the Societal Cost Test would include all the benefits and costs of the TRC test, plus any avoided externality costs and economic development benefits—including job creation and the potential for increased home value—if those could appropriately be accounted for. Since this analysis did not monetize these benefits (as explained in section 3.5), a Societal Cost Test benefit-cost analysis was not performed. Were these benefits included, the benefit-to-cost ratio would be higher than 1.19.

5. Sensitivity Analyses

We conducted sensitivity analyses—observing the impact of changing key modeling assumptions on our results—for the following inputs: oil and gas prices, projected capacity value, avoided T&D costs, and projected CO_2 emissions costs. All are compared to our policy case scenario, in which all variables are held at the Mid case.

5.1. Fuel Prices

Adjusting for high or low fuel prices has only a minor impact on the potential benefits of solar net metering, as illustrated in Figure 20. This figure also shows the levelized costs of solar for comparison. Changing fuel costs assumptions impacts the avoided energy, the avoided system losses, and the avoided risk benefits, with high fuel price assumptions resulting in increased benefits and low fuel price assumptions resulting in lower benefits. All three cases—High, Mid, and Low—result in a TRC benefit-to-cost ratio above 1.0, as shown in Table 8.

Figure 20. Results of fuel price sensitivities

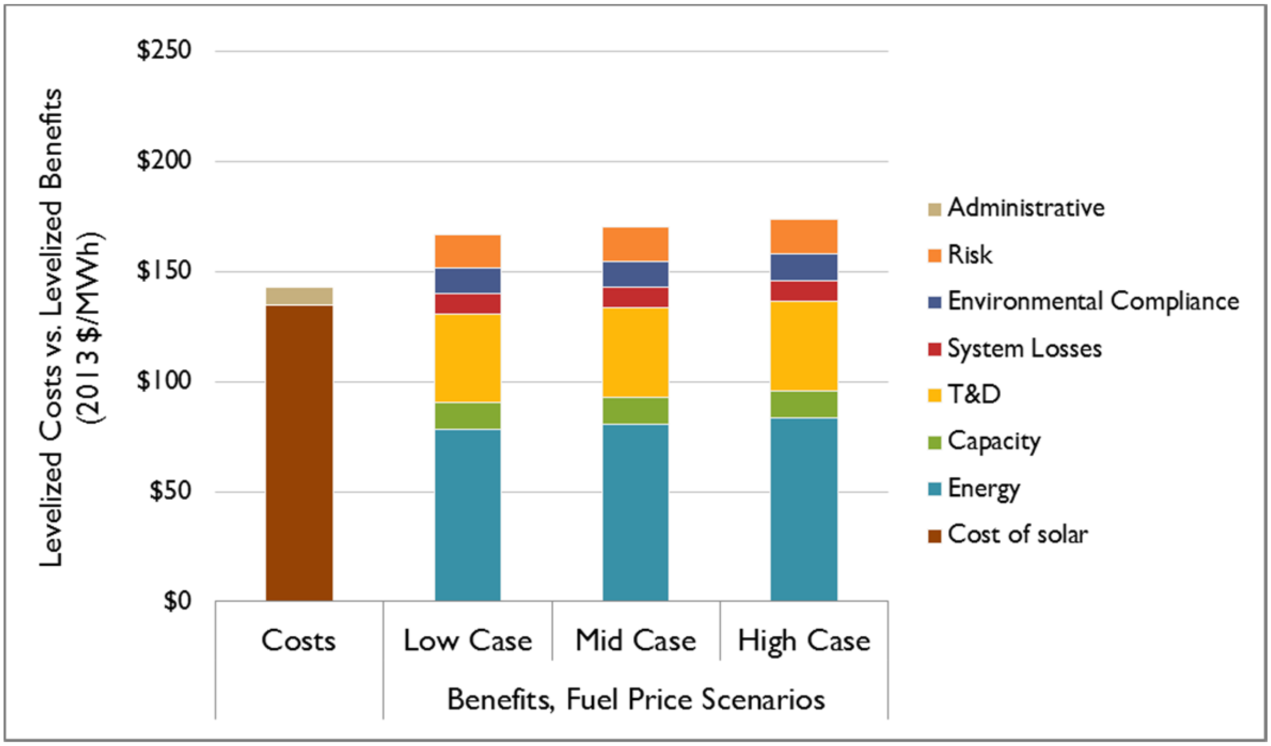


Table 8. Avoided energy benefits and TRC test benefit/cost ratios under fuel price sensitivities

	Low	Mid	High
Avoided Energy Benefit	$78/MWh	$81/MWh	$83/MWh
Fuel Price Sensitivities	1.17	1.19	1.21

5.2. Capacity Values

Adjusting for a high or low forecast of capacity value has some impact on the potential benefits of solar net metering, as illustrated in Figure 21. This figure also shows the levelized costs of solar for comparison. Changing capacity value projections impacts the avoided capacity cost and avoided risk benefits, with high capacity value projections resulting in increased benefits and low capacity value projections resulting in lower benefits. All three cases—High, Mid, and Low—result in a TRC benefit to cost ratio above 1.0, as shown in Table 9.

Figure 21. Results of capacity value projection sensitivities

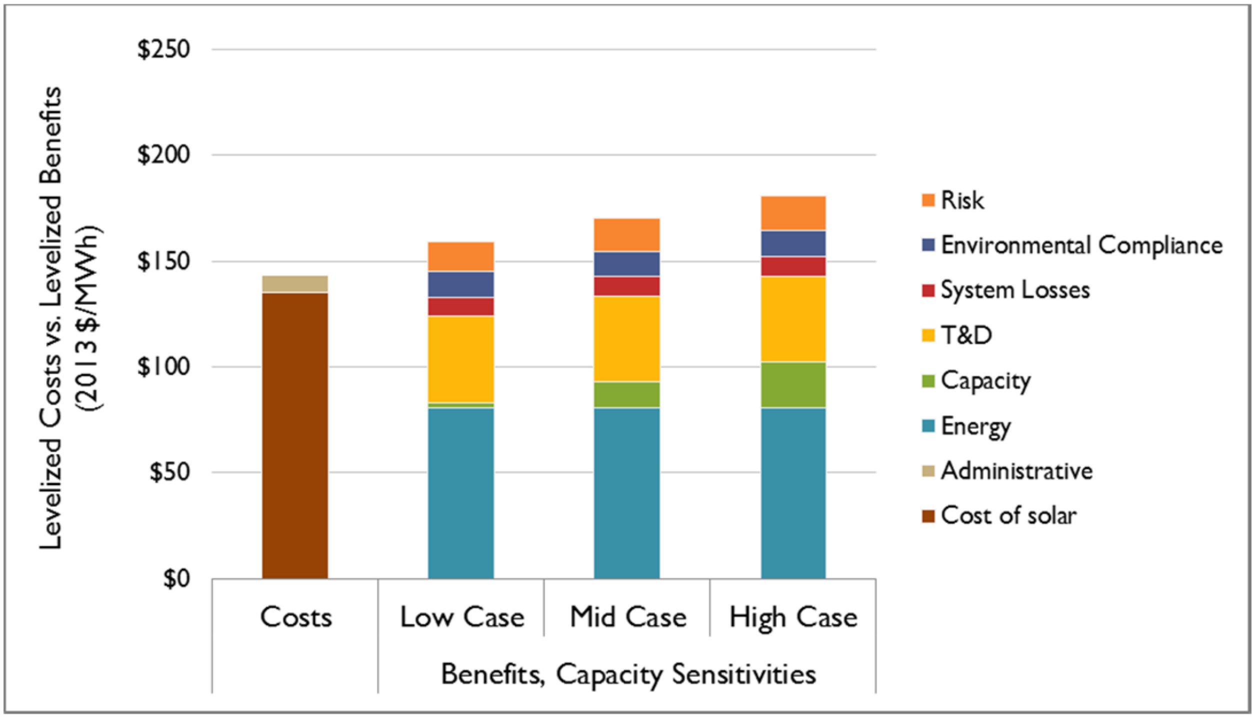


Table 9. Avoided capacity benefits and TRC test benefit/cost ratios under capacity value sensitivities

Capacity Value Sensitivities	Low	Mid	High
Avoided Capacity Benefit	$3/MWh	$12/MWh	$22/MWh
B/C Ratio under a TRC Test	1.11	1.19	1.26

5.3. Avoided T&D

Adjusting for high or low avoided T&D costs, which reflect the 25th and 75th percentile of our database of avoided T&D costs, had the most noticeable impacts on the potential benefits of solar net metering, as illustrated in Figure 22. Again, the figure shows the levelized costs of solar for comparison. Changing the costs of T&D impacts the avoided T&D costs and the avoided risk benefits, with high capacity value projections resulting in increased benefits and low capacity value projections resulting in lower benefits. All three cases—High, Mid, and Low—result in a TRC benefit to cost ratio above 1.0, as shown in Table 10.

Figure 22. Results of avoided T&D value sensitivities

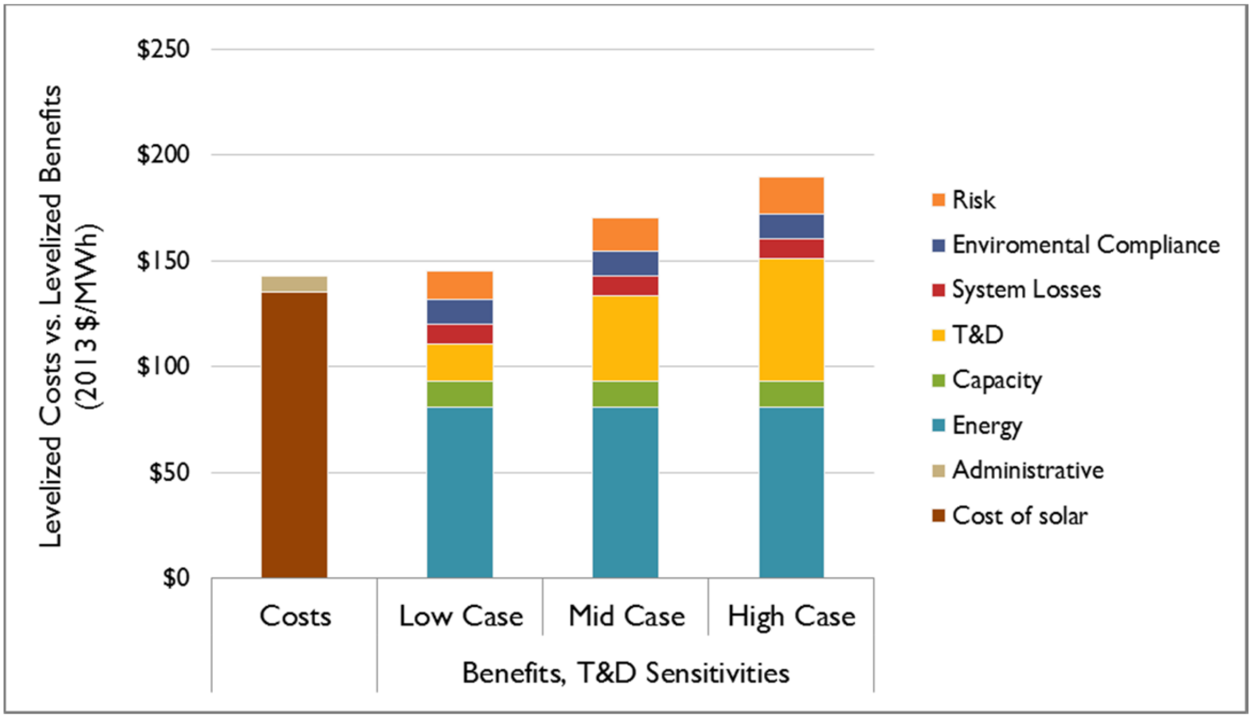


Table 10. Avoided T&D benefits and TRC test benefit/cost ratios under avoided T&D cost sensitivities

Avoided T&D Sensitivities	Low	Mid	High
Avoided T&D Benefits	$18/MWh	$40MWh	$58/MWh
B/C Ratio under a TRC Test	1.01	1.19	1.32

5.4. CO_2 Price Sensitivities

Adjusting for a high or low trajectory of CO_2 emissions costs has some impact on the potential benefits of solar net metering, as illustrated in Figure 23. This figure shows the levelized costs of solar for comparison. Changing CO_2 price forecasts impacts the avoided environmental compliance cost and avoided risk benefits, with the high projection resulting in increased benefits and low projection resulting in lower benefits. All three cases—High, Mid, and Low—result in a TRC benefit to cost ratio above 1.0, as shown in Table 11.

Figure 23. Results of CO_2 forecast sensitivities

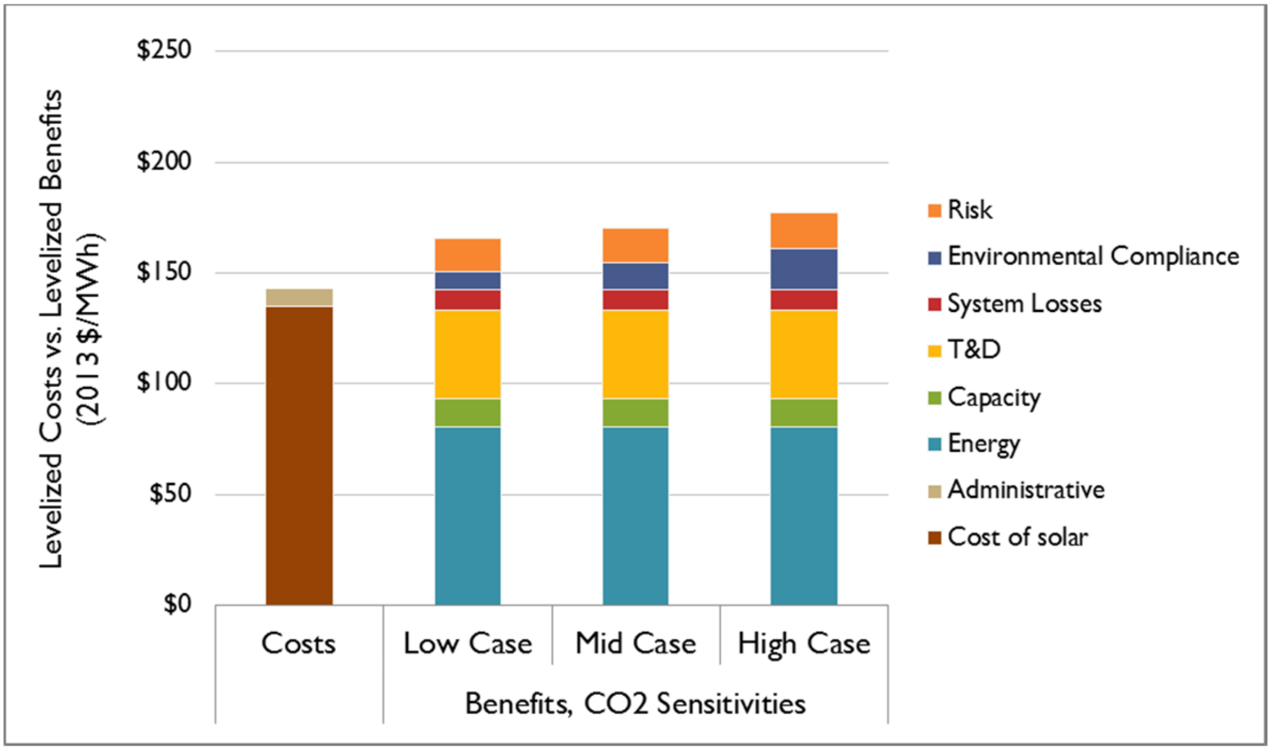


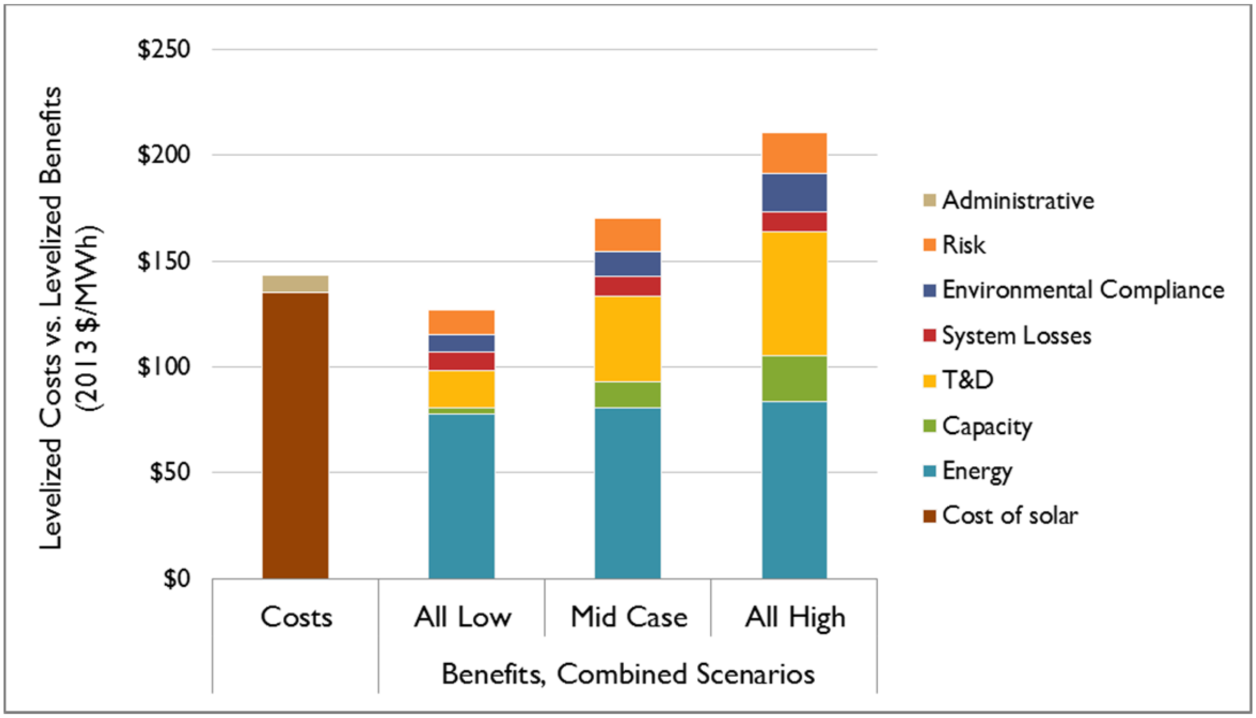
Table 11. Avoided environmental compliance costs and TRC benefit/cost ratios under CO_2 cost sensitivities

CO2 Price Sensitivities	Low	Mid	High
Avoided Environmental Compliance Costs	$8/MWh	$12/MWh	$18/MWh
B/C Ratio under a TRC Test	1.16	1.19	1.24

5.5. Combined Sensitivities

We modeled two combined sensitivities scenarios: (1) each variable was set to the assumption that would yield the lowest benefits for solar net metering; (2) each variable was set to the assumption that would yield the highest benefits for solar net metering. The levelized results of this analysis are shown in Figure 24.

Figure 24. Results of scenario testing under combined sensitivities



As shown in Table 12, solar net metering passes the Total Resource Cost test in all but one of the sensitivities described above.

Table 12. Summation of TRC Test benefit/cost ratios under various sensitivities

	Low	Mid	High
Fuel Price Sensitivity	1.17	1.19	1.21
Capacity Value Sensitivities	1.11	1.19	1.26
Avoided T&D Sensitivities	1.01	1.19	1.32
CO_2 Price Sensitivities	1.16	1.19	1.24
Combined Sensitivities	0.89	1.19	1.47

6. CONCLUSIONS

The analysis conducted and the results shown in this report reflect the potential costs and potential benefits that an illustrative net metering program could provide to Mississippians. From a Total Resource Cost perspective, solar net metered projects have the potential to provide a net benefit to Mississippi in nearly every scenario and sensitivity analyzed. These benefits will only be realized if customers invest in distributed generation resources. This may never happen if net metering participants are not expected to receive a reasonable rate of return on investment. Based on the results of the participant cost analysis, net metering participants in Mississippi would need to receive a rate beyond the average retail (variable) rate in order to pursue net metering. This suggests that Mississippi may want to consider an alternative structure to any net metering program they choose to adopt. One alternative structure would be to compensate distributed solar through a solar tariff structure similar to the ones used in Minnesota and by TVA, and under consideration in Maine.[52]

By appropriately using a solar tariff structure, it would be possible to structure Mississippi's proposed net metering rules to allow net benefits for participants and prevent cost shifting to non-participants. If all avoided costs are accurately and appropriately accounted for and the consumers are paid an avoided cost rate, then there is no cost shifting because the costs to non-participants (those customers without distributed generation) are equal to the benefits to non-participants. Net metering customers should be paid for the value of their distributed generation, but non-participants should not bear an undue burden as a consequence of net metering. This could be accomplished by compensating net metering customers at the avoided cost rate through a tariff structure. If participants will be compensated at the avoided cost rate, this value must be carefully calculated and updated periodically. The valuation process would include a rigorous quantification and monetization of all of the benefits and costs we identified and provided as preliminary estimates in this report.

[52] The Maine Solar Energy Act, Sec. 1. 35-A MRSA c. 34-B Available here: http://www.mainelegislature.org/legis/bills/bills_126th/billtexts/SP064401.asp

APPENDIX A: VALUE OF AVOIDED RISK

The objective of this appendix is to review the current practices regarding the risk value used in avoided cost analyses, primarily for distributed generation, and to recommend a reasonable value for a risk adjustment factor to apply to the cost-benefit analysis of distributed solar generation in Mississippi.

There are a number of risk reduction benefits of renewable generation (and energy efficiency), whether those resources come from central stations or distributed sources. The difficulties in assigning a value to these benefits lie in (1) quantifying the risks, (2) identifying the risk reduction effects of the resources, and (3) quantifying those risk reduction benefits.

The most common practical approach has been to apply some adder (adjustment factor) to the avoided costs rather than to attempt a more thorough technical analysis. However, there is little consensus in the field as to what the value of that adder should be. Based on expert judgment and experience, Synapse suggests a 10 percent adder be applied when calculating avoided costs for renewables such as solar and wind. The literature review below demonstrates that there is wide variance in the range of values used in practice.

Theoretical Framework

First, we will look at the types of avoided costs that might be associated with distributed generation. The full range of possible benefits as identified in recent testimony by Rick Hornby in North Carolina is quite extensive, as indicated by Table 13. Typically, distributed generation avoided costs are based on direct costs that can be easily quantified, as indicated by "Yes" in the DG column below. In some situations, attempts are made to assign values to hard-to-quantify categories, such as environmental, health, and economic benefits. The table also indicates categories where there might be possible risk benefits associated with these avoided costs. For example, renewable generation reduces the probability and effects of energy price spikes, reducing risk in that category.

Table 13. Avoided cost and possible risk reduction benefit categories

	Avoided Cost Category	PURPA	DG	Risk Benefits
1	Energy costs (electricity generation costs)	Yes	Yes	Yes
2	Capacity cost for generation	Yes	Yes	Yes
3	Transmission costs	?	Yes	Maybe
4	Distribution costs	No	Yes	Maybe
5	T&D Losses	?	Yes	No
6	Environmental costs (direct)	Yes	Yes	Yes
7	Ancillary services and grid support	?	?	Maybe
8	Security and resiliency of grid	No	?	Yes
9	Avoided renewable costs	Yes	Yes	Maybe
10	Energy market impacts	No	?	Maybe
11	Fuel price hedge	No	?	Yes
12	Health benefits	No	?	Yes
13	Environmental and safety benefits (indirect)	No	?	Yes
14	Visibility benefits	No	?	Maybe
15	Economic activity and employment	No	?	Maybe

How does a risk factor fit into this context? First, one needs to identify what categories of avoided costs are being used, and then where risk benefits might occur. For example, with avoided energy costs there is the possibility that those costs might be extremely high in some hours. Distributed generation resources reduce that possibility. Distributed generation resources may even reduce the chance of a system outage.

There is also a major conceptual problem in applying a risk factor to basic avoided costs. While there are likely risk values associated with distributed generation, it is overly simplistic to assume that the risk value can be represented as a simple factor applied to the avoided costs. As shown in Table 13, there are many kinds of avoided costs that may or not be considered in a particular analysis, and only some of those categories might also have risk reduction benefits.

Options and Hedging

The Black-Scholes (B-S) model is a mathematical formulation for evaluating the value of an option, which is the right to buy or sell a resource at a given future time at a given price. This is most commonly used in financial markets for the purchase or sales of stock. Consider the following example of a stock whose future price is uncertain but is currently $50 per share, which the buyer thinks is too high. The buyer could purchase an option to buy the stock in six months at $45 per share (assuming such an option is available). Then in six months, if the actual price is more than $45 per share, the buyer might exercise his option and purchase the stock at that price. If the market price is lower, the buyer can let his option expire and buy the stock on the market. The B-S model is based on historical price data and determines how much such an option should cost. There are of course a large number of assumptions and complications in such calculations, but supposedly in a liquid and competitive market (where participants know how to apply the B-S model), the option price would have the B-S value. Another issue to consider is that the B-S model tends to fail under unusual market situations, such as in the economic recession of 2008.

In theory, one could apply this approach to the value of reducing energy price risk. Consider that the expected future price of electricity is $100 per MWh, but the buyer wants to protect him- or herself against it going above $110. The buyer could then purchase an option to buy at $110 per MWh 12 months from now. The cost of that option represents the cost of protection against all prices $110 and greater at that point in time. However, option markets for electricity prices are uncommon and trading is very thin.[53] Options for natural gas products are much more active and can be used as an electricity price hedge.[54]

One methodology that has been used in some analyses reviewed here is to calculate the hedge value of a renewable or energy efficiency resource based on an imputed option value. This of course depends strongly on the assumptions used, which have generally not been very transparent.

Let's consider an example of how this might be implemented. Say that the avoided energy cost is determined to be $50 per MWh, which represents the average of a range of possible values. Say furthermore that one doesn't care about modest price swings but is concerned about prices greater than $75 per MWh. Then one could think of purchasing a call option with a strike price of $75, which limits the price exposure to that price.[55] The cost of that option represents the hedge value of a resource that also eliminates that risk.

Futures Markets

Futures markets provide a way of hedging against changes in prices but lack the optional aspect. In a futures market, one has an obligation to buy or sell at a certain price at a given future date. Supposedly the futures price represents a balance between sellers who want to avoid a decline in prices and buyers who want to avoid an increase in prices. Thus the risks are in balance and the price is at a neutral point. Now if a buyer locks in a price there is the risk that the actual price is lower, but they are committed at a higher price and thus experience a loss. But the expectation is that gains and losses balance out, at least in the long term.

[53] CME Group maintains an options market that includes PJM electricity products but only for about two years out, and trading levels are zero for many product months. See: http://www.cmegroup.com/market-data/settlements.

[54] EIA uses short-term natural gas energy options (which is a fairly robust market) to determine the confidence intervals for its short term natural gas price forecast. See: http://www.eia.gov/forecasts/steo/report/natgas.cfm.

[55] The closer to the expected price, the more expensive would such an option be. For example, a call option at the expected price of $50 could easily be $5 or more based on risk associated with all the prices above that level.

Distributed Generation and Energy Efficiency

In many ways, the benefits of distributed renewable generation are very similar to those of energy efficiency. Both affect loads at the user level and have variable costs that are very low or zero. However, there is a key difference in timing. Energy efficiency reduces usage for specific end uses, resulting in savings proportional to that load. For example, improved lighting reduces the load when lights are being used. Different energy efficiency measures will have different load saving shapes, but they will be load-related. In contrast, distributed solar generation produces energy based on the amount of sunlight that is available and the configuration of the devices. This means that the energy from distributed solar generation is only roughly correlated with load, and thus may have a greater or lesser benefit than energy efficiency energy savings. Still, the methods for calculating the value of avoided risk associated with energy efficiency measures and distributed generation are comparable, which is why the literature review summarized below considers studies in energy efficiency as well as distributed generation.

Current Practices

In this section, we review materials related to the question of risk value. Taken as a whole, these studies and documents demonstrate the wide variance in the range of values used to calculate the value of avoided risk. These values are summarized in Table 14, below.

Table 14. Value of risk factors used in various scenarios

Source	Description	Risk Factor
State Regulatory Examples		
Vermont	Adder to the cost of supply alternatives when compared to demand-side management	10%
Oregon	Cost adjustment factor to cost of avoided electricity supply in efficiency screening; represents risk mitigation but also environmental benefits and job creation	10%
Avoided Energy Supply Cost Studies		
2009	Wholesale risk premium applied to wholesale energy and capacity prices	8-10%
2013 (non-Vermont)	Wholesale risk premium applied to wholesale energy and capacity prices	9%
2013 (Vermont)	Wholesale risk premium applied to wholesale energy and capacity prices	11.1%
Maryland OPC Risk Analysis		
DWN portfolio	Insurance premium for Demand-Side-Management-Wind-Natural Gas portfolio	3.5%
DWC portfolio	Insurance premium for Demand-Side-Management-Wind-Coal portfolio	2.5%
Northwest Power and Conservation Council		
Sixth Power Plan	Risk measured using the TailVaR_{90} metric	-
Ceres Risk-Aware Electricity Regulation		
Ceres report	No distinct value, risk index relative to other resources	-
PacifiCorp 2013 IRP		
2013 IRP	Stochastic risk reduction credit as percentage of avoided costs	~10%
Rocky Mountain Institute Review of Solar PV Benefit and Cost Studies		
CPR NJ/PA	Fuel price hedge values as percentage of value of solar	~10%
NREL	Natural gas hedge value as percentage of avoided costs	0-12%

State Regulatory Examples

In the report *Best Practices in Energy Efficiency Program Screening*, Synapse authors identified two states that account for the risk benefit of energy efficiency directly in the criteria used to screen efficiency programs.[56] Vermont applies a 10 percent adder to the cost of supply alternatives when compared to demand-side management investments to account for the comparatively lesser risks of demand-side management. Oregon adds a 10 percent cost adjustment factor to the cost of avoided electricity supply when screening efficiency programs to represent the various benefits of energy efficiency that are not reflected in the market; these benefits include risk mitigation but also environmental benefits and job creation.

Avoided Energy Supply Cost (AESC) Studies

Since 2007, Synapse and a team of subcontractors have developed biannual projections of marginal energy supply costs that would be avoided due to reductions in electricity, natural gas, and other fuels resulting from energy efficiency programs offered to customers in New England.[57] In these studies, a risk factor identified as a "wholesale risk premium" is applied. This premium represents the difference in the price of electricity supply from full-requirement fixed price contracts and the sum of the wholesale market prices for energy, capacity, and ancillary-service in effect during that supply period. This premium accounts for the various costs that retail electricity suppliers incur on top of wholesale market prices, including costs to mitigate cost risks such as costs of hourly energy balancing transitional capacity, ancillary services, uplift, and the difference between projected and actual energy requirements due to unpredictable variations in weather, economic activity, and/or customer migration.

The wholesale risk premium is applied to both the wholesale energy and capacity prices. Estimates of this adder based on analysis of confidential supplier bids range from 8 to 10 percent. For the AESC 2013 study,[58] a value of 9 percent was used, except for Vermont where a mandated rate of 11.1 percent was used.[59]

Maryland OPC Risk Analysis Study

In 2008, Synapse conducted a project in conjunction with Resource Insight on behalf of the Maryland Office of the People's Counsel to identify the costs and risk benefits to residential customers of

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[56] Woolf, T., E. Malone, K. Takahashi, W. Steinhurst. 2012. *Best Practices in Energy Efficiency Program Screening*. Synapse Energy Economics for the National Home Performance Council.

[57] Hornby, R. et al. 2009. *Avoided Energy Supply Costs in New England: 2009 Report*. Synapse Energy Economics for the AESC Study Group, page 2-42.

[58] Hornby, R. et al. 2013. *Avoided Energy Supply Costs in New England: 2013 Report.* Synapse Energy Economics for the AESC Study Group, page 5-23, 24.

[59] The approved 10 percent Vermont risk value is applied to the cost of the energy efficiency measures and thus translates following state practice into a 11.1 percent adder to the avoided cost (i.e. 11.1% = 1.0/0.9).

alternative strategies for meeting their electricity requirements over a long-term planning period.[60] Synapse used a Monte Carlo analysis to examine the expected costs and risks of different procurement strategies for Standard Offer Service. A variety of strategies were considered, including contracts of varying duration as well as energy efficiency investments and longer-term contracts for new resources. The risk potential was determined by calculating the TailVaR$_{90}$ values (the average of the net present values for the costliest 10 percent of outcomes) for each portfolio. Although the risk and average costs were strongly correlated, there were some cases that were exceptions to this rule. For example, the DWN (Demand-Side-Management-Wind-Natural Gas) portfolio had a lower cost than the DWC portfolio (Demand-Side-Management-Wind-Coal), but a higher TailVaR$_{90}$ value. The results of course depend hugely on the assumptions used for the random variables, such as natural gas and carbon prices. Greater uncertainty in the carbon price would likely have changed that relationship. Although the risk was calculated, no explicit cost value was assigned to it since that depends on the value (or cost) of avoiding that risk.

Using the DWN and DWC portfolios from this report displayed in Table 15, we can infer a risk factor. For DWN, the expected cost was $12,023 million and the TailVaR$_{90}$ was $16,223 million, representing a possible increase of $4,200 million with a 10 percent probability. One could think then of hedging that with a 10 percent premium of $420 million, which corresponds to a risk factor of 3.5 percent. For the DWC case, that risk factor/insurance premium would be 2.5 percent. These risk factors only insure against part of the risk, and are specific to this particular analysis.

Table 15. Long-term NPV cost and TailVaR$_{90}$ risk by portfolio in Maryland procurement strategies study

		Difference from BAU			Spread Between TVaR$_{90}$ and Expected Cost	
Portfolio	**Expected Cost ($M)**	*Million Dollars*	*Percent*	**TVaR$_{90}$ ($M)**	*Million Dollars*	*Percent*
BAU	14,657			20,664	6,007	41%
Spot	13,723	(934)	−6%	19,333	5,609	41%
Clean BAU	13,082	(1,576)	−11%	17,849	4,767	36%
DWN	12,023	(2,634)	−18%	16,223	4,200	35%
DWC	12,263	(2,395)	−16%	15,259	2,997	24%
DWNC	12,095	(2,562)	−17%	15,643	3,548	29%

Source: "Risk Analysis of Procurement Strategies for Residential Standard Offer Service," p. 43

Northwest Power and Conservation Council (NWPCC)

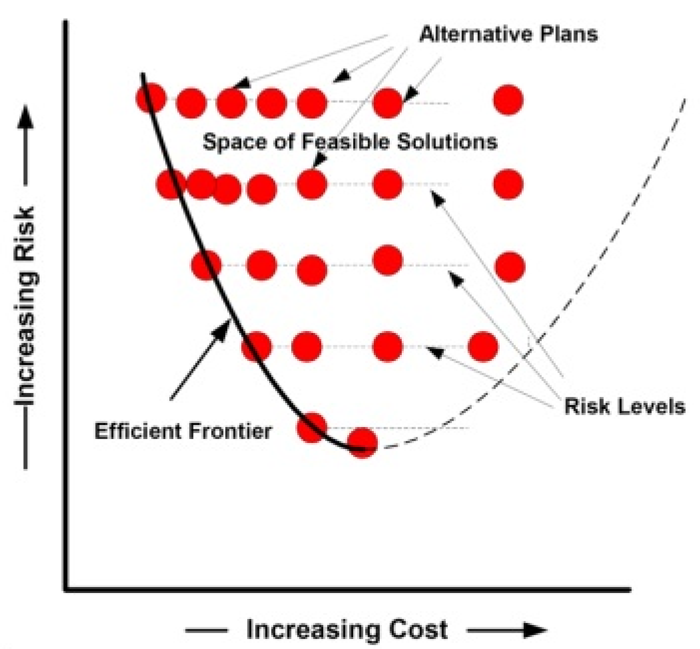
The Northwest Power and Conservation Council (NWPCC) has been assessing and developing plans for the future of energy resources in the Northwest region every five years since the organization was

[60] Wallach, J., P. Chernick, D. White, R. Hornby. 2008. *Risk Analysis of Procurement Strategies for Residential Standard Offer Service*. Resource Insight and Synapse Energy Economics for the Maryland Office of the People's Counsel.

created in 1980.[61] An important element of these plans is risk assessment and management. Since the first Power Plan, NWPCC has analyzed the value of shorter lead times and rapid implementation of energy efficiency and renewable resources. Starting in the Fifth Power Plan in 2005, NWPCC extended its risk assessment to incorporate risks such as electricity risk uncertainty, aluminum price uncertainty, emission control cost uncertainty, and climate change.[62]

The NWPCC addressed risk by evaluating numerous energy resource portfolios against 750 futures. It compares the risk of one portfolio (measured using the $TailVaR_{90}$ metric) and the average value of a portfolio (the most likely cost outcome for the portfolio). Figure 25 provides an illustrative example of this analysis. The set of points corresponding to all portfolios is called a feasibility space, and the left-most portfolio in the feasibility space is the least-cost portfolio for a given level of risk. The line connecting the least-cost portfolios is called the efficient frontier, which allows the NWPCC to narrow their focus, typically to a fraction of 1 percent of these portfolios. NWPCC calls this entire approach to resource planning "risk-constrained, least-cost planning" (NWPCC 2010, pp. 9-5 to 9-6).

Figure 25. Efficient frontier of feasibility space



Source: NWPCC 2005, p.6-13.

Using this approach, the NWPCC has found "the most cost-effective and least risky resource for the region is improved efficiency of electricity use" (NWPCC 2010, page 3).

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[61] Woolf, T., E. Malone, K. Takahashi, W. Steinhurst. 2012. *Best Practices in Energy Efficiency Program Screening*. Synapse Energy Economics for the National Home Performance Council.

[62] Northwest Power and Conservation Council. 2010. *The Sixth Northwest Conservation and Electric Power Plan*. Available at: https://www.nwcouncil.org/energy/powerplan/6/plan.

Ceres Risk-Aware Electricity Regulation

A 2012 study by the non-profit organization Ceres evaluated the costs and risks of various energy resources, and, like NWPCC, found energy efficiency to be the least cost and least risky electricity resource.[63] Ceres used the following categories to evaluate risk: fuel price risk, construction cost risk, planning risk, reliability risk, new regulation risk, water constraint risk.

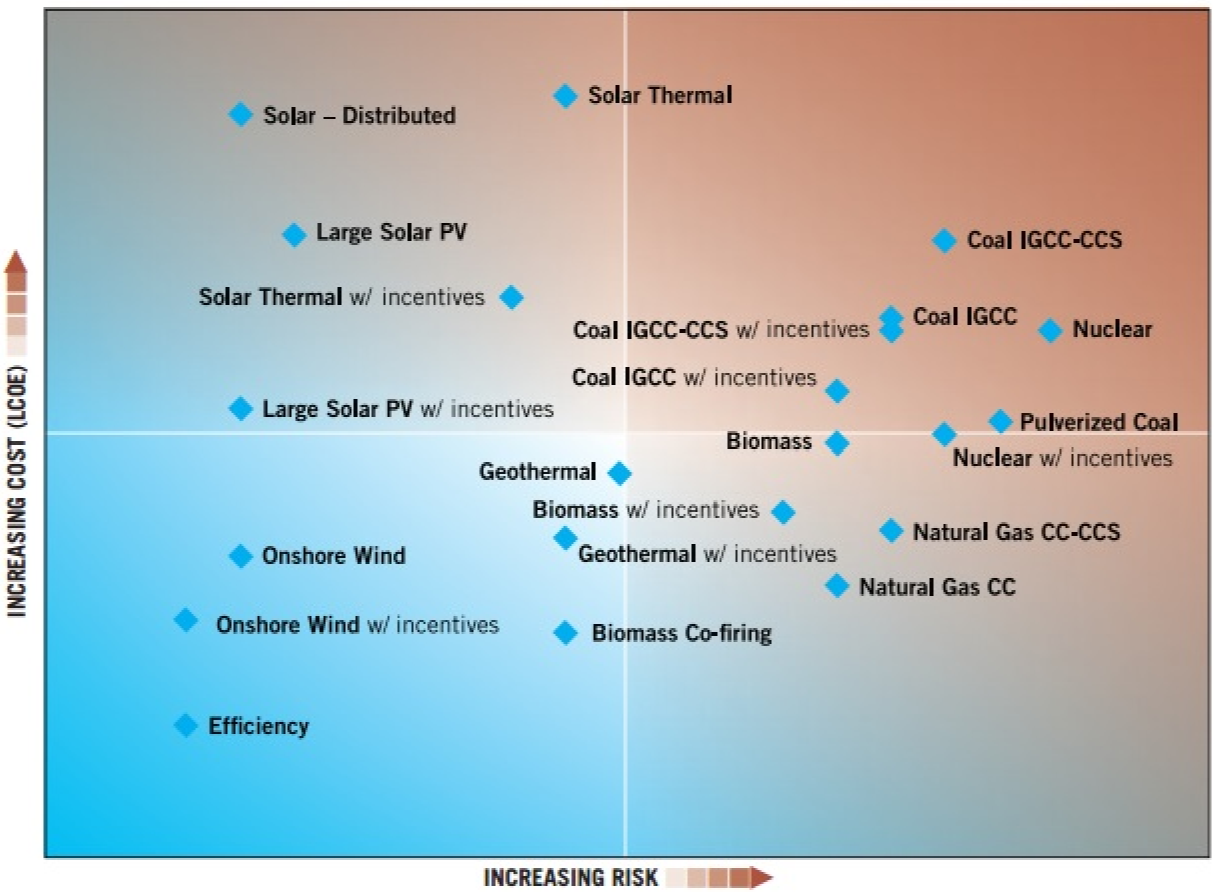
Fuel price risk stems from the volatility of prices, which historically have been driven by varying demand for and supply of natural gas. *Construction cost risk* is lower for energy efficiency as compared to other resources because conventional generation requires longer development timelines, which expose these resources to longer-term increases in the cost of labor and materials. For example, the construction cost schedule of the proposed Levy nuclear power plant in Florida has been delayed five years due to financial and design problems and its cost estimates has increased from $5 billion to $22.5 billion.[64] *Planning risk* is introduced when electric demand growth is lower than expected, since there is a risk that a portion of the capacity of new power plants may be unused for a long time. Ceres reported that in January 2012, lower-than-expected electricity demand along with unexpectedly low natural gas prices mothballed a brand-new coal-fired power plant in Minnesota. The utility (Great River Energy) was expected to pay an estimated $30 million in 2013 just for maintenance and debt service for the plant—energy efficiency resources that reduce load incrementally would never face this problem. *Reliability risk* is also mitigated by energy efficiency resources, which substantially reduce peak demand during times when reliability is most at risk and which slow the rate of growth of electricity peak and energy demands, providing utilities and generation companies more time and flexibility to respond to changing market conditions. *New regulation risk* is associated with the cost of complying with safety or environmental regulations, such as EPA's recently proposed Section 111(d) of the Clean Air Act, which will increase the cost of fossil fuel plants. Energy efficiency is not subject to these regulations and would in fact reduce the level of risk to the extent that efficiency displaces regulated resources. *Water constraint risk* includes the availability and cost of cooling and process water; energy efficiency is not subject to this risk, and again can mitigate the risk to the extent that efficiency resources displace conventional resources.

The Ceres report does not assign one value to avoided risk; however, it does rank resources based on relative levels of risk, and finds that distributed solar has one of the lowest composite risk scores of new generation sources. Ceres charts risk against increasing cost for these resources as shown in Figure 26.

[63] Binz, R., R. Sedano, D. Furey, D. Mullen. 2012. *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know.* Ceres. Available at: http://www.ceres.org/resources/reports/practicing-risk-aware-electricity-regulation/view.

[64] Kaczor, B. 2010. "Florida PSC hearing testimony on nuclear rates." *Bloomberg Businessweek.* Available at: http://www.businessweek.com/ap/financialnews/D9HQ2TN80.htm.

Figure 26. Relative cost and risk of utility generation resources



Source: Ceres 2012, figure 17, p. 37

PacifiCorp 2013 Integrated Resource Plan

In its 2013 integrated resource plan, PacifiCorp applied a stochastic risk reduction credit of $7.05 per MWh for demand-side management resources. This figure was estimated by taking the difference between a comparison of deterministic PaR runs for the 2011 IRP preferred portfolio with and without demand-side management and a comparison of stochastic PaR runs for the 2011 IRP preferred portfolio with and without demand-side management and then dividing that difference by the MWh of demand-side management in the 2011 IRP preferred portfolio. Table N.1 of the IRP (on page 357) indicates total avoided costs of $75.75 per MWh; therefore, $7.05 is a little less than 10 percent of the avoided cost before the risk factor is applied.

Rocky Mountain Institute Review of Solar PV Benefit and Cost Studies

Rocky Mountain Institute (RMI) conducted a review of solar photovoltaic benefit and cost studies.[65] In that study, RMI considers financial and security risks; a number of other types of risk, such as environmental ones, are not considered. While RMI notes that there is little agreement on an approach to estimating the unmonetized values of financial and security risk, it does report the risk-related benefits for fuel price hedge as reported by studies performed by Clean Power Research in Texas and New Jersey/Pennsylvania, as well as studies by NREL and by a team of researchers led by Richard Duke (RMI 2013, 35). There is a wide range in these values and they are fairly substantial, ranging from about 0.5 cents per kWh to over 3.0 cents per kWh ($5 per MWh to $30 per MWh).

The Clean Power Research (CPR) hedge benefits are based on an analysis of the volatility of natural gas prices, which are then reflected in electricity prices. The cited Texas reports are short on numbers, but the New Jersey/Pennsylvania report has more specifics. In the latter report, CPR calculates the levelized value of solar in Pennsylvania and New Jersey from $256 to $318 per megawatt hour. The fuel price hedge values range from $24 to $47 per MWh, thus roughly in the order of 10 percent.

The cited NREL study[66] gives a natural gas hedge value for photovoltaics a range from 0.0 to 0.9 cents per kWh. Overall, the total photovoltaic benefits in that study range from about 7 to 35 cents per kWh ($70 to $350 per MWh). So the hedge value fraction ranges from roughly 0 to 12 percent of the total avoided costs.

Note also that the hedge values cited in the RMI study appear to depend largely on the volatility of natural gas prices, which is likely to be lower in the future due to increased supply and lower prices in the U.S.

Conclusions and Recommendations

There are certainly a variety of risk reduction benefits of renewable generation (and energy efficiency), whether those resources come from central stations or distributed sources. The difficulties in assigning a value to these benefits lie in:

1. Quantifying the risks,
2. Identifying the risk reduction effects of renewables, and
3. Quantifying those risk reduction benefits.

To do all three steps properly would be both difficult and contentious. None of the research and case studies reviewed above has attempted it. The nearest example is the NWPCC Power Plans.

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[65] Hansen, L., L. Virginia. 2013. *A Review of Solar PV Benefit and Cost Studies*. Rocky Mountain Institute. Available at: http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue.

[66] Contreras, J.L., Frantzis, L., Blazewicz, S., Pinault, D., Sawyer, H. 2008. *Photovoltaics Value Analysis*. Navigant Consulting.

Current heuristic practice would support a 10 percent adder to the avoided costs for renewables such as solar and wind. There are both more avoided cost and risk reduction benefits associated with distributed generation (see Table 13). Thus, one would expect greater absolute risk reduction benefits with distributed generation, but there is insufficient information to determine how that might differ on a percentage basis.