Comments to “Community Reinvestment Act: Interagency Questions and Answers Regarding Community Reinvestment”

Agency Name: OCC

Docket ID OCC-2014-0021

Date Submitted: November 7, 2014

To whom it may concern,

Please accept the below and attached comments in the matter of Docket ID OCC-2014-0021.

My comments here pertain to proposed Q & A changes, specifically those that concern renewable energy and energy efficiency, affordable housing and renewable energy and energy efficiency, and community facilities Docket ID OCC-2014-0021.

Other non-energy matters covered in Docket ID OCC-2014-0021 I do not comment on.

Please note that these comments are colored by my more than 11 years of practicing as both an attorney and accountant while serving primarily the affordable housing and renewable energy sectors. To date, I have advised on the tax treatment and financing of more the $10 Billion in renewable energy projects located in the United States. I have also worked with hundreds of clients who were either affordable housing project developers or their financial institutional lenders and investors who were receiving CRA credit for their participation. Many of the affordable housing projects that I've advised on also included renewable energy or energy efficiency measures as part the affordable housing project in states all across the U.S.

Should further clarification of my comments be desired, or more information be required with respect to any of the comments below, I am available to provide such clarifications in a timely and thorough manner.

Respectfully submitted,

[redacted]

Lee J. Peterson, Esq.

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EXPLANATION – of Comments

Introduction

By their very nature, affordable housing projects are economically challenged – revenue constrained--precisely because they expressly serve low and moderate income individuals across the nation.

Therefore, any federal policy or program which aids in cost savings or cost stabilization for residents in affordable housing dramatically improves that affordable housing project and its residents' lives. Because of this, I hereby submit comments in full support of the proposed guidance on renewable energy and energy efficiency for affordable housing and community facilities.

I also respectfully submit comments requesting that the Agencies should additionally broaden the scope and clarity of the proposed Q and A to expand the number, type and geographic locations of renewable energy and energy efficiency projects that are eligible for CRA.

Executive Summary of Comments

The proposed Q&A clearly support the important, forward looking policy goals of stabilizing or reducing the cost of providing affordable housing and related services to low and moderate income individuals as it pertains to their energy costs.

I therefore unequivocally support the proposed Q&A as presently proposed.

However, I respectfully view the proposed guidance as being the *bare minimum* that the agencies should approve regarding both renewable energy and energy efficiency.

Therefore, in addition to supporting the changes as proposed by the Agencies, I also strongly encourage the Agencies and their personnel to expand the policy and regulatory support of the Agencies to do even more, specifically as it pertains to renewable energy and energy efficiency.

I also understand that when adopted, the proposed Q&A would become effective approximately 12 months or more from the closing of the official comment period. I am therefore concerned that this normal regulatory due process delay could materially impair those low and moderate income areas in their ability to meet their current and ongoing renewable energy and energy efficiency demands during the regulatory process, both within the affordable housing industry as well as the broader low and moderate income community that these proposed regulations are intended to serve.

In addition, given existing federal income tax provisions which specifically pertain to the renewable energy technologies most beneficial to the affordable housing sector (specifically, the energy credit under IRC §48), is scheduled under current law to reduce from 30% to 10% on January 1, 2017, time is further of the essence in order for the policy objectives of these proposed questions to be implemented in a way that coincides with federal income tax law, and in a way that will actually benefit low and moderate income community.

Therefore, given the requirements of due process, public notice, and comment, I respectfully suggest that the Agencies, effective as of the date of the closing of this comment period, a policy to expand the proposed rule and execute such additional policy implementation as can be done prior to the finalization of these Q & A so that these additional efforts by the Agencies may be complete and published in the federal register by the final effective date of such regulations.

Background

Both renewable energy and energy efficiency meet basic human needs and meets those important needs typically without using any of the community's valuable water resources, without requiring the expense of fossil fuel and without the pollution from combustion of fossil fuels (which always gives rise to toxic and non-toxic air and water pollution), pollution that often disproportionately harm low and moderate income areas and individuals.[1] Yet these economic damages experienced by low and moderate income area residents can be mitigated and avoided with today's renewable energy and energy efficiency technology.

In fact, since the inception of the CRA, both technology and economic efficiency have advanced remarkably to the point where relatively small investments in today's energy generation and energy efficiency technology yield dramatic, decades-long lasting positive community-wide benefits on a commercially viable and commercially reasonable basis.

A perfect example of this is renewable energy and energy efficiency.

Wind and solar energy construction projects either enable a community to save energy or help generate the essential commodity of electricity or heat energy which meets residential, commercial and industrial heating and cooling needs, thereby making residential real estate habitable by low and moderate income individuals, and creating, retaining or improving jobs in low and moderate income areas.

I therefore strongly encourage and support the Agencies' interpretation of CRA and PWI rules and definitions in a manner consistent with current market trends in renewable energy development across the nation.

Because the number of financial institutions that are regulated by the Agencies find themselves in the midst of financing this nation's overall conversion to a cleaner energy economy, which includes renewable energy and energy efficiency as part of that conversion, a failure by the Agencies to clearly encourage and thereby support regulated institutions to participate more actively and broadly in renewable energy finance through CRA and PWI authority, not only within the affordable housing industry but within the broader community, will directly cause increased harm to low and moderate income communities because it will limit and restrict the amount of investment made in those low and moderate income areas and thus directly and indirectly harm low and moderate income individuals both economically, and as a matter of public health are concerned that a defacto, if not de jure redlining effect

[1] See, Environmental Inequality in Exposures to Airborne Particulate Matter Components in the United States, NIH, Michelle L. Bell and Keita Ebisu, Yale University at, http://ehp.niehs.nih.gov/wp-content/uploads/2012/10/ehp.1205201.pdf

might occur. Something that CRA was and expressly intended to prevent, and which I feel is preventable through clear guidance that expands the financing of renewable energy and energy efficiency nationwide in low and moderate income areas.

General Information

Renewable energy project development typically takes one of two forms.

One form is distributed generation.

This is typically “small” energy systems, such as a few solar panels typically attached to the roof of a single family home, or multi-family building or small business, and which serves the electrical energy needs of a single individual, family, or the common area of a real estate development, community facility or small business either non-profit or for-profit.

Graphic Showing Single Family Residential Distributed Roof Top Solar - Solar Hot Water Application

Graphic Showing Multi Family Residential Distributed Roof Top Solar - Solar PV – Oakland, CA

This form also involves commercial or industrial energy systems, which are similar in function to and are still commonly classified as “distributed generation.”

Commercial systems are simply larger versions of the smaller distributed generation systems that an individual might use. However, industrial and commercial systems generate considerably more electricity and serve larger building spaces or industrial and commercial operations.

Graphic Showing Commercial Scale – 1.5 Megawatt Solar PV – Rooftop

The second form is utility scale, which most often are designed and intended to serve the energy needs of the public by supplying public utilities with the electricity those utilities distribute to their energy users. As such, the only energy user is the public utility which then in turn distributes and transmits the energy to the customers of the utility. However, I am seeing a move by some public utilities to enter into the “distributed generation” arena as well.

Graphic Showing Utility Scale, Multi-Acre Solar PV Facility

Expanded Scope Necessary for CRA

America is in the midst of an energy renaissance, and therefore, it is essential that the Agencies, through the CRA and PWI authorities keep pace with the 21st century energy economy in the U.S. by broadening the express language in the guidance to clearly state such approval.

To the extent that the Agencies’ CRA and PWI rules do not clearly and expressly state the support of regulated institutions in serving all forms of renewable energy project development, low and moderate income individuals are delayed, if not prevented from renewable energy being able to improve their standard of living and personal health effective immediately if the larger commercial, industrial or utility scale projects are deemed to be ineligible for CRA credit.[2]

Therefore, while the Q & A as proposed will certainly benefit residents of IRC §42 affordable housing or residents of other “affordable housing” projects within the definition of “affordable housing” as previously adopted by the Agencies, this very limited subset of low and moderate income individuals is far too narrow and thus, the Q & A as proposed, do not sufficiently serve the broader low and moderate income community as they primarily, if not only, focus on real estate financing as a means to achieve CRA policy goals rather than renewable energy of energy efficiency alone.

[2] See note 1 supra.

Lastly, time is of the essence.

Change in the economy is happening quickly and the Agencies must keep pace.

Therefore, given the unavoidable lag between the effective date of these proposed Q & A and the ongoing affordable housing construction and rehabilitation activities, I strongly request:

1. the Agencies to not only approve the renewable energy and energy efficiency related Q & A as drafted, but I additionally request,

2. the Agencies expand the energy specific scope of the Q & A so that when finalized, the questions as proposed are both approved as proposed, but expanded with additional text, so that it is clear that the Q & A not only supports the renewable energy requirements of the IRC §42 affordable housing project and not only “community facilities” as defined for purposes of this Q & A, but the separate and broader community as well.

Why the Agencies Need to Broaden the Scope of “Community Development Component”

The CRA regulations at 12 CFR 25.12(h) define a “community development loan” to mean a loan that has community development as its primary purpose.

I agree with the Agencies’ current proposal to add an example to clarify how examiners may consider loans related to renewable energy or energy-efficient technologies that also have a community development component.

However, the Q & A as currently being proposed are too limited and somewhat self-defeating to their full purpose.

Therefore, it is both appropriate and consistent with the existing regulations for the Agencies to add additional detail in the examples with the Q & A in order to further clarify how examiners may consider loans related to renewable energy or energy efficient technologies that also have a “community development component.“

To be clear, I strongly believe that the “component” referred to in this regulatory context is the key. Because in many instances what the Agencies may be viewing as a “component” may in fact be the primary purpose and driver of the community development if the definition of “community development” is properly defined to include consideration of the indirect individual and community benefits of renewable energy or energy efficiency but not just in the extremely limited cases of either affordable housing or community facilities as presently defined by the Agencies.

I therefore respectfully submit that limiting the scope of this Q & A to just these two narrow types of Community Development Loans, i.e., “affordable housing” and “community facility” is insufficient for the detailed reasons I set forth below.

Please see attached supporting materials and data incorporated as part of these comments to this end.

Comments to Specific Questions Posed by The Agencies: Questions # 10 - 18

Q10. Does the proposed revised guidance clarify what economic development activities are considered under CRA?

(a) **No. The reference to “affordable housing or community facility” is ultimately unclear and in the case of “affordable housing” also a circular reference. Given that affordable housing is already defined as “community development” and because in many cases including renewable energy or energy efficiency in an affordable housing project actually entails treating much, if not all, of the renewable energy and energy efficiency equipment or materials as part of either the physical structure of that housing and/or the federal income tax credit basis of the affordable housing tax credit, in a number of such cases this new guidance actually says and does nothing new.**

However, where this new guidance can be useful, and can help clarify which economic development activities are considered eligible under CRA, is in cases where the affordable housing project or buildings are being served by a renewable energy or energy efficiency improvement that is ***not*** physically part of the building or community facility per se, but nonetheless serves the energy needs of the building’s tenants, or the common areas of the affordable housing project or community facility and/or the broader low and moderate income area. For example, a ground-mount solar Photo Voltaic (*hereinafter PV*) array located on adjacent land, or on the roof of an adjacent structure or building.

Graphic Showing Solar PV Facility On Adjacent Land, Serving Nearby Building Energy Needs.

Accordingly, the guidance should ultimately make it clear that regardless of whether the renewable energy or energy efficiency equipment or materials are physically part of, or separately apart from, the affordable housing building or community facility, lending to a renewable energy company that provides renewable energy generating equipment under a lease, power-purchase agreement, energy services contract or otherwise, and whereby such affordable housing or community facility may obtain part or all of its energy needs and/or the needs of its residents or customers in the community from that separate energy resource, such lending to said "stand alone" renewable energy or energy efficiency provider should, on a stand alone basis, be in and of itself eligible for CRA.

(b) **Consistent with this express and necessary clarification as to stand alone renewable energy or energy efficiency projects or their providers, the providers of community renewables, e.g., "community solar" or "community wind" and/or "micro-grid" projects or providers should also be listed as an express example of the kind of project and borrowings that this guidance authorizes and supports for CRA eligibility.**

NOTE: See definition and detailed comments below on both community renewables and micro-grids.

As long as community renewables and/or micro-grid projects are either physically located in, or serve the energy needs of low or moderate income individuals or areas, both community renewables and micro-grids should also be eligible for CRA on a stand-alone, independent basis.

I respectfully submit that such projects have sufficient favorable economic community impact to warrant such consideration within the allowed parameters of the CRA as well as the PWI authority.

(c) Further consistent with this guidance needing to more clearly indicate its support of "community" and "micro-grid" related borrowing, the Agencies, in order to be fully consistent with this commentator's proposed changes to the guidance, should further expressly mention in the final guidance, language that would also expressly allow "brownfield" development of renewable energy projects in low and moderate income areas or that serve low or moderated income individuals, as well as "greenfield" development of renewable energy projects.

Many low and moderate income areas, precisely because they are low and moderate income areas are the sites of environmentally challenged land, e.g., sites of former landfills, super-fund sites, etc. Each distressed site amounts to a blight, often a permanent blight, on the low and moderate income community and represents a waste of a community asset, a non-productive property and net liability for the community. Fortunately, renewable energy technology, such as solar PV, when installed on such otherwise burdened and otherwise useless or too expensive to clean brownfield sites can actually be used[3]. in order to make a positive economic impact in low and moderate income areas, create jobs, increase the local tax base.

[3] See, http://www.epa.gov/oswercpa/docs/best_practices_siting_solar_photovoltaic_final.pdf

Graphic Showing Solar and Landfill Gas Recovery Project on Retired – Hickory Ridge Landfill – Atlanta, GA

Moreover, because such renewable energy projects have the potential for a significant quantity of energy production and because the economy of scale necessary to make the cost per kWh of energy produced compatible with, (or lower in cost than) public electric utility provided electricity, some “excess” energy, i.e., an amount of energy that exceeds the need of the low and moderate income individuals resident in the area, may need to be transmitted into the electrical “grid” and put in the hands of the public utility.

However, this reality, should ***not*** be viewed by the agencies as a disallowed activity for CRA eligibility because, as is shown in the attached appendix, in the example of solar energy, there is a community Value of Solar (VOS) which cannot be separated from a solar project which benefits low and moderate income persons disproportionately given the percentage of their income that goes toward their energy purchases.

Thus, to the extent that renewable energy is being produced in, or transmitted from off-site to a low and moderate income area, the renewable energy project generating or transmitting such energy, may by definition, be viewed as having for CRA purposes as its primary purpose, the purpose of community development, of promoting economic development, of attracting new, or retain existing businesses or residents, of supporting permanent job creation, retention and/or improvement and/or being an activity that revitalizes or stabilizes low or moderate income geographies; all due to the value of solar (VOS).

***NOTE**: the VOS by definition contains a material component of public health, often referred to as a "social cost" representing a further additional economic benefit to low and moderate income individuals in the community. More detail on this aspect of VOS is provided below and in the appendices*

***NOTE**: the VOS generally represents electric ratepayer savings. Therefore, the more solar power put onto the utility power-grid, the greater the ratepayer savings. Such savings are generally to be "refunded" to all electric ratepayers, including low and moderate income ratepayers, either through an overall reduced power cost as part of ongoing ratemaking regulation or, simply by enabling public utilities to avoid additional costs, thereby avoiding increase rates in the normal course. This reduced power cost will, in general, lower the cost of electricity to low and moderate income individuals in areas where solar is supplying the grid regardless of whether the reduction is explicit or implicit.*

***NOTE**: Because the VOS is trending much higher than the cost of producing that same solar power,[4] the savings from solar power appears to be, specifically for low and moderate income individuals, a material, economic improvement realized not less than monthly. An economic improvement essentially similar in impact to a permanent wage-raise increase, or akin to a federal, state or local tax reduction. As solar costs of construction continue to decline, the positive economic impact is expected to increase on a per kWh basis going forward as it costs less to obtain the same or greater savings, particularly in markets where the cost of energy from the public utility keeps increasing and is never expected to decrease in real terms.*

(d) **Finally, as a general matter as it regards the "clarity" of the proposed guidance, the term "permanent" in the context of job creation is not sufficiently well defined, and in addition, the term appears to lack relevance, given macroeconomic trends in the overall U.S. economy that note a marked systemic shift away from full-time "permanent" jobs.**

I am therefore concerned that reliance on "permanent" jobs as a metric for assessing CRA policy attainment may be unduly suppressing otherwise acceptable CRA eligible investment and as such, suggest a more flexible and adaptable economic impact analysis that considers the indirect economic benefits of renewable energy and energy efficiency (including but not limited to the full

[4] Compare VOS studies in appendices with the cost of generating such power. See., e.g., **Georgia Power seeks certification for 515MW of solar under 6.5c/kwh** http://www.platts.com/latest-news/electric-power/boston/georgia-power-solar-rfp-yields-515-mw-in-power-21392015[platts.com] vs. the VOS of solar shown in appendices, e.g., 15 cents per kW, a 8.5 cent ratepayer savings.

VOS value as well as the relevant health care savings associated with the replacement of fossil fuel based energy with renewable energy or energy efficiency). See below for EPA 111(d), MATS and CSAPR healthcare data.

Q11. What information should examiners use to demonstrate that an activity meets the size and purpose tests described in the proposed revised guidance?

Examiners should include indirect economic impact in their metric, not merely jobs. Given the fact that energy is directly or indirectly essential to nearly every aspect of one’s daily life and personal economy, lowering of one’s monthly energy bill, the mitigation of public utility rate increases, the general public health impacts associated with lowering air and water pollution through the use of energy efficiency and renewable energy and/or the indirect acdess to either, plus the positive job creation impact, as well as the economic impact in terms of lifetime energy savings, in addition to the lifetime health savings per capita per megawatt of electrical or heat energy cumulated over the projected actual physical lifetime of the energy efficiency or renewable energy project.

Financial projections at the project level, available to the lender, can estimate the former, existing VOS and EPA data can be used to determine if not reasonably approximate the latter. See attached appendices for examples of VOS and EPA data sets.

Q12. Does the proposed revised guidance help to clarify what is meant by job creation for low- or moderate-income individuals?

No. The proposed revised guidance unduly relies on job creation as it’s metric in too narrow a fashion. This reliance is out of sync with the overall economy and is a less and less reliable indicator of economic impact. The modern economy is not merely the measure of jobs. The modern economy does not create the same kind, or the same value jobs it once did.

In addition, there appears to be too little clarity on how, over what periods, and what job retention requirement’s meet the qualification, and it’s further unclear how part time jobs, or persons with more than one part time job at any time would fairly factor into the equation.

Q13. Are the proposed examples demonstrating that an activity promotes economic development for CRA purposes appropriate? Are there other examples the Agencies should include that would demonstrate that an activity promotes economic development for CRA purposes?

No. The proposed examples demonstrating that an activity promotes economic development for CRA purposes are not appropriate because they are not sufficiently comprehensive. While the proposed examples demonstrating that an activity promotes economic development for CRA purposes were, in the past, appropriate before the advent of commercially available and cost effective renewable energy or energy efficiency technology, the examples are now at least partially outdated, per the comments above.

Yes, there other examples the Agencies should include that would demonstrate that an activity promotes economic development for CRA purposes.

Specifically, the Agencies should include examples of renewable energy and energy efficiency finance activity, i.e., the lending to or the making of permitted tax or non-tax equity financings in renewable energy projects that are not required to be “twinned” with IRC section 42 affordable housing, general affordable housing as otherwise defined, or “community facilities.”

As proposed, the scope of the current and proposed guidance is too narrow, and largely outdated and thus not truly meaningful given the present state of both the affordable housing and renewable energy and energy efficiency industries.

Therefore, additional, or expanded examples which expressly state that not only renewable energy projects twinned to affordable housing or community facilities but also those that are built and operate in, or simply provide renewable energy or energy efficiency savings to, low and moderate income areas should be expressly set forth in the final regulations.

Q14. What information should examiners review when determining the performance context of an institution seeking CRA consideration for its economic development activities?

Examiners should ensure that institutions seeking CRA consideration for its economic development activities are not being under-evaluated by virtue of examiners that place too much weight on job creation as viewed in its historical context within CRA regulation, specifically when examining an institutions’ efforts in renewable energy or energy efficiency finance.

If examiners must consider jobs, they also must be required to consider modern technology and the 21st century workforce and labor realities.

Specifically, solar energy technology.

Most solar PV panels that generate the energy from the sun are made and assembled by robot in sterilized clean rooms. The solar system itself, once constructed on site, is modular, often “plug and play” and even acres of solar panels can be constructed and made operational in months, rarely years.

Examiners must therefore not be forced by their own regulation or practice to insist that in order for renewable energy to be eligible for CRA that 19th and 20th century manual labor be a pre-requisite for CRA eligibility.

Attached in the appendix are two jobs studies that represent the typical jobs make up of a large utility scale and smaller commercial scale solar project construction. While the capital costs of such projects are declining due to favorable markets, the amount and type of labor generally does not vary in proportion to equipment or finance costs.

Also, by way of comparison, you will note that just as an affordable housing project has many up-front construction jobs which are then eliminated upon project completion (leaving far fewer residual permanent jobs), so too is the case with renewable energy projects. The ratio of construction to permanent jobs may differ, but the dynamic is the same, and in either case, the benefit to the community is real.

In fact, given the additional cost of providing community services to new residents and workers it may be the case that on a net cost basis, the economic “cost” of a new job from a renewable energy or energy efficiency project may be better than a construction project of another kind.

Therefore, in order for the CRA to remain relevant to the times and persons it serves, less emphasis should be given to jobs and more emphasis put on the direct and indirect, individual and public benefits of solar, wind, waste to energy and other renewable energy technologies currently listed as eligible technologies under Internal Revenue Code sections 45 and 48.

Finally, a review of the other comments in this document, the sources cited in the footnotes herein and the appendices should help make this clear.

Q15. What information is available that could be used to evaluate the local business environment and economic development needs in a low- or moderate-income geography or among low- or moderate-income individuals within the institution’s assessment area(s)?

See all resources, data, and information cited, noted, or attached in these comments.

Q16. Are there particular measurements of impact that examiners should consider when evaluating the quality of jobs created, retained, or improved?

Yes.

First, examiners should compare the economic impact from energy costs savings attributed to energy efficiency or renewable energy technology on the low or moderate income per individual and weight those savings as if the economic value of that savings were in fact due to the low or moderate income person obtaining a new job, retaining an existing job, or improving their job.

Second, the per capita health care costs attributable each U.S person under the EPA MATS, CSAPR and Rule 111(d), in addition to any other such relevant studies available from EPA and other sources, should be evaluated in terms of increased productive economic activity due to, or akin to, the creation of new jobs.

EXAMPLE:

See, e.g., the EPA MATS data at page 13 at this website:

http://www.epa.gov/mats/pdfs/presentation.pdf?_sm_au_=iVV64F4DRrk2rJHP

> ***NOTE***: This data is showing only part, and less than half, of the total economic and health care cost damage associated with non-renewable energy generation. The data discussed here, and the numbers shown here, are ONLY the damages associated with one toxin from coal power combustion, i.e., Mercury. For additional and greater economic and health care cost damage associated with non-renewable energy generation see CSAPR data separately cited and referenced in these comments.

How To Measure Economic Impact and Jobs Impacts Using MATS and Other EPA Data

The proper way to understand this data for CRA purposes is to translate the EPA healthcare cost data, (i.e., negative economic impact of non-renewable energy) into the positive corollary of positive economic impact or growth you’d get from using either renewable energy, energy efficiency or both to replace thermoelectric coal power generation with renewable energy power generation.

Specifically, because we can project from the EPA data what the negative economic impact per megawatt or kWh of coal powered electricity is, using that data we can now calculate the cost avoidance resulting, per megawatt or kWh, of renewable powered electricity and/or energy efficiency.

Simply put, for each megawatt or kWh of renewable powered electricity and/or energy efficiency savings obtained by replacing the electricity generated by coal with electricity generated by renewable energy or electricity that is not needed to be generated because energy efficiency reduced the demand for that coal generated power, we can now calculate the public health cost savings and the increase in economic productivity due to fewer worker sick days and general health impacts simply by knowing the amount of renewable energy generated or the amount of energy use avoided through energy efficiency.

Similar data may be available for natural gas power plants as well.

According to existing EPA data, the ***ANNUAL*** lost workdays attributed to the health costs traceable directly to existing coal fired electric power generation is 850,000 missed work or “sick” days.

Moreover, if the amount of toxic mercury being generated by coal powered power plants were to be reduced, either by increased pollution control, or use of renewable energy or energy efficiency, per the EPA MATS data sets, the value of the improvements to public health alone total $59 billion to $140 billion ***EACH YEAR:***

• This means that for every dollar spent to reduce this pollution, society would get $5-$13 in
health benefits

• Each year, the proposed MATS rule would prevent serious health effects including:

• 6,800-17,000 premature deaths

• 11,000 heart attacks

• 120,000 asthma attacks

• 850,000 missed work or “sick” days

• Avoiding “sick days” saves companies and families money. It is particularly important for the millions of Americans whose jobs do not provide paid sick leave and who risk losing their jobs if they miss work too often

• The proposed rule would also prevent 12,200 hospital admissions and emergency room visits; 4,500 cases of chronic bronchitis; and 5,100,000 days when people must restrict their activities each year

If you then add the negative health care costs from non-mercury particulate pollution (a separate form of pollution traceable directly to coal powered thermoelectric power generation), that separate negative economic impact is **$120-280 Billion**, ***ANNUALLY.***

See data set on non-mercury particulate pollution below as reflected in the EPA Cross State Air Pollution Rule (CSAPR)

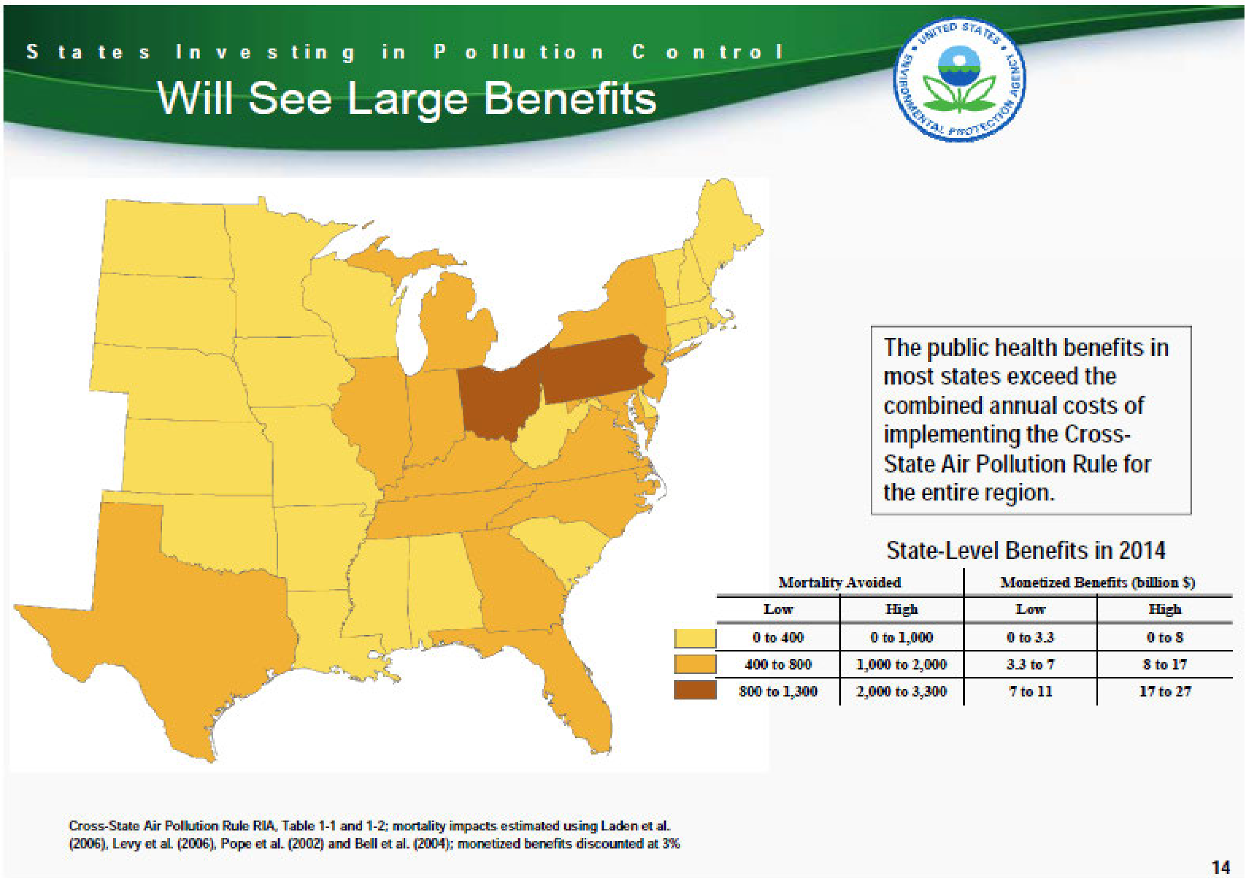
Estimated Annual Number of Adverse Health Effects Avoided Due to Implementing the CSAPR*

Health Effect	**Number of Cases Avoided**
Premature mortality	13,000 to 34,000
Non-fatal heart attacks	15,000
Hospital and emergency department visits	19,000
Accute bronchitis	19,000
Upper and lower respiratory symptoms	420,000
Aggravated asthma	400,000
Days when people miss work or school	1.8 million

The final CSAPR rule yields $120 to $280 billion in ***ANNUAL*** health and environmental benefits in 2014, including the value of avoiding 13,000 to 34,000 premature deaths.

Each state will see different results and attain greater or lesser economic benefits attributable to CRA eligible renewable energy or energy efficiency projects.

Below is a rough guide to the potential savings in each state, with emphasis on eastern states where coal power is most prominent.



To further illustrate one state, the state of Georgia, please see the attached, study entitled “Full Cost of Coal.”

This study shows the per capita health care cost economic burden directly associated with coal fired power generation in the state of Georgia ranges from between $300-$800 per person in Georgia regardless of their economic status, status as taxpayer, employment status (and for other states it will be even greater). Yet this burden disproportionately falls on the low and moderate income almost like an indirect annual and perpetual tax.

Therefore, with such costs in mind, if examiners were to cumulate that total cost, by multiplying the per capita cost of fossil fuel use, multiply that by the population in the relevant low and moderate income area, and then divide that total by the amount of energy saved through renewable energy or energy efficiency being considered by the examiners, then the examiners would be able to measure the annual positive economic impact due to the specific renewable energy or energy efficiency project being examined.

That total, multiplied over either the lifetime of the low or moderate income population, or the actual physical life of the energy efficiency or renewable energy project or program, when also combined with the actual jobs impact and other economic impacts associated with that energy efficiency or renewable energy project or program would give a much truer and accurate picture of the positive economic impact of a renewable energy or energy efficiency program or project in that low or moderate income area than a mere jobs only analysis as is currently being made under the current rules.

These types of impacts are they type of impacts that examiners should consider when assessing either renewable energy or energy efficiency projects for CRA qualification and approval.

Such consideration is clearly in the direct and indirect interest of low and moderate income individuals and areas where both the economy and every person is being impacted favorably by such borrowings.

CONCLUSION: ***CRA must support renewable energy and energy efficiency related borrowing/investment, and the fact that this pollution and these negative economic impacts are born by all, should not prevent such investments from meeting CRA requisites.***

Simply because low and moderate income individuals don't breathe different air or drink different water than the middle or upper income individuals who are their neighbors should not prevent the Agencies from supporting such investments through the CRA as not exclusively or sufficiently benefitting low and moderate income persons or areas.

Q17. Should loans for renewable energy or energy-efficient equipment or projects that support the development, rehabilitation, improvement, or maintenance of community facilities that serve low- or moderate-income individuals be considered under the CRA regulations?

Yes. For all the reasons cited supra, infra, and others too numerous to list here for this purpose.

Again, while this commentator fully supports the proposed regulations and Q & A as proposed, the guidance as proposed is the MINIMUM the Agencies should approve.

When the factors submitted along with these comments are considered, I trust that the Agencies will see that the most equitable means of achieving the intent of the proposed guidance is to also broaden the scope of the proposed regulations to include, but not limit, the activities eligible for CRA to not just affordable housing or “community facilities” as the current guidance so narrowly defines that scope.

Q18. Do the proposed revisions make clear which energy-efficiency activities would be considered under the CRA regulations?

No. While clear for a very narrow class of CRA applicants, the proposed revisions lend themselves to a far to narrow interpretation.

As stated above, the reference to “affordable housing or community facility” is ultimately unclear and in the case of “affordable housing” can even be a circular reference given that affordable housing is already defined as “community development” and because in many cases including renewable energy or energy efficiency in an affordable housing project actually entails treating much, if not all, of the renewable energy and energy efficiency equipment or materials as part of either the physical structure of the housing and/or the federal income tax basis of the affordable housing tax credit, in a number of cases this new guidance says and does nothing new.

If “energy efficiency” also includes ‘renewable energy’ then I would propose language making it clear that a considered activity would further include the borrowing to, or providing of capital to a facility that uses the technology defined as eligible under either Internal Revenue Code Section 45 or 48 as was then in effect on 12/31/13.

I further suggest that the Agencies also make it clear that regardless of whether the renewable energy or energy efficiency activity is twinned with an affordable housing or community facility that such activity shall remain eligible for all of the above previously stated reasons in addition to others which were not stated but may be evidently relevant upon further consideration by the agencies.

“Connecting the Dots” - Toward More Responsive CRA Regulations

1. The Agencies correctly concur that: “ … Communities may use sustainable energy sources to reduce the cost of providing services [and that] Communities also may incorporate the development of related industries into local development plans to support job creation initiatives.”[5]

2. The Agencies also correctly concur that consideration of the indirect benefits of renewable energy or energy efficiency must also be considered[6].

These points, taken together, make the case for a broader scope to the Q & A concerning renewable energy and energy-efficiency than is set forth in the current draft of the proposed Q & A.

In order for the Agencies to consistently remain responsive to this nation’s low and moderate income communities through both the CRA and PWI authority, all while having the most efficient and effective positive economic impact, I believe the proposed Q & A should directly take into consideration some key, nay CRITICAL but reasonable assumptions about the future of renewable energy in America and the impact of the renewable energy industry on the low and moderate income communities across the nation.

Specifically, I request that the agencies do not underweight the importance of renewable energy or energy efficiency to residents of low and moderate income areas, as it is our view that the Q & A as proposed do exactly that: underweight the direct and indirect importance of renewable energy or energy efficiency to residents of low and moderate income areas

[5] Community Reinvestment Act; interagency Questions and Answers Regarding Community Reinvestment, OCC Docket ID OCC-2014-0021 at Page 30 (B).
[6] Id.

Comments to “Community Reinvestment Act: Interagency Questions and Answers Regarding Community Reinvestment”

Agency Name: OCC

Docket ID OCC-2014-0021

Date Submitted: November 7, 2014

I respectfully request increased weight for renewable energy and energy efficiency in these Q and A because I fear that the historic focus on jobs as a measure of policy success is now directly hampering compliance with the CRA and dampening its actual ultimate success.

To be sure, CRA in the context of affordable housing is an overwhelming policy success and as long as affordable housing in mentioned in the same regulatory sentence with ANY other economic activity, both activities will, by definition be a joint success. Yet that success is saying less about that other non-housing activity and rather more about the affordable housing portion given that the other activity is ancillary to the affordable housing.

Another concern I have arises from the fact that the regulations make ancient reference to “permanent jobs.” Yet America now finds itself in an economy where a great number of businesses and employers are overtly avoiding the creation of full time jobs and often seeking to classify their workers as independent contractors when not doing everything in their power to classify actual employees as part-time.

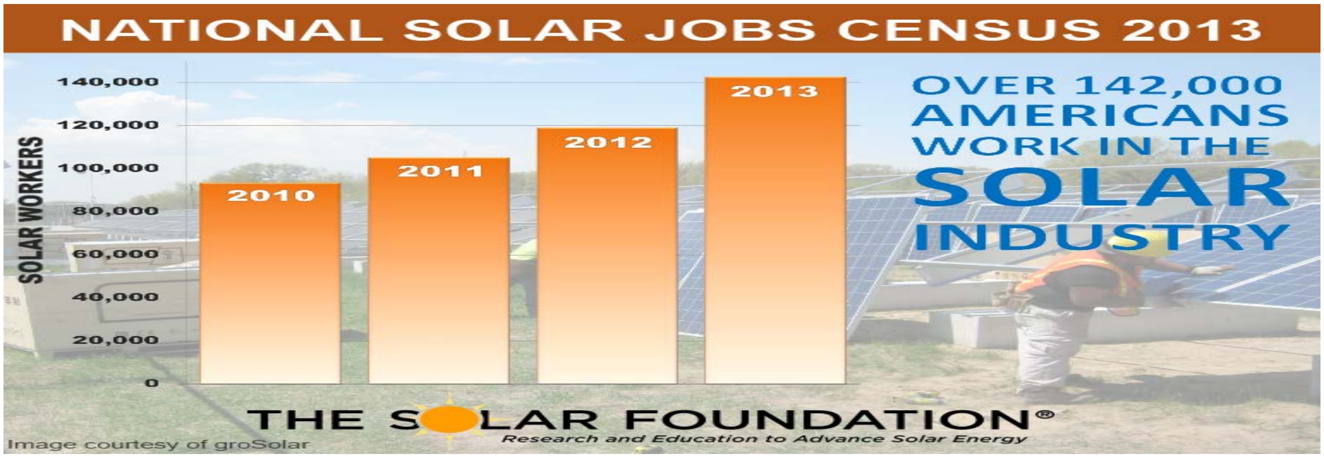
Thus, it would appear that the ancient practice of pegging regulatory compliance to a focus on permanent jobs is not at all correctly aligned with today’s U.S. economic trends nor aligned with the protracted period of recession that the U.S. economy still remains in and is expected to remain in for many years to come.

Yet, when one analyzes where jobs were created during the current recession, what one finds is that the renewable energy sector, most notably the wind energy and solar energy sectors were among the nation’s strongest employers during the time of the worst economic downturn since the great depression of the 1929.[7]

[7] See, http://www.awea.org/Resources/Content.aspx?ItemNumber=6386. See also, http://thesolarfoundation.org/research/national-solar-jobs-census-2013

Additional General Considerations

Renewable Energy Jobs Data of Which the Agencies Should be Aware[8]:



- Seventy-seven percent of the nearly 24,000 new solar workers since September 2012 are new jobs, rather than existing positions that have added solar responsibilities, representing 18,211 new jobs created.

- This comparison indicates that since data were collected for Census 2012, one in every 142 new jobs in the U.S. was created by the solar industry, and many more were saved by creating additional work opportunities for existing employees.

- Installers added the most solar workers over the past year, growing by 22%, an increase of 12,500 workers.

- Solar employment is expected to grow by 15.6% over the next 12 months, representing the addition of approximately 22,240 new solar workers. Forty-five percent of all solar establishments expect to add solar employees during this period.

- Employers from each of the solar industry sectors examined in this study expect significant employment growth over the next 12 months, with nearly all of them projecting percentage job growth in the double-digits.

- Approximately 91% of those who meet the definition of a “solar worker” (those workers who spend at least 50% of their time supporting solar-related activities) spent 100% of their time working on solar.

[8] Id @ The Solar Foundation, link in Supra, note 3.

- Wages paid by solar firms are competitive, with the average solar installer earning between $20.00 (median) and $23.63 (mean) per hour, which is comparable to wages paid to skilled electricians and plumbers and higher than average rates for roofers and construction workers. Production and assembly workers earn slightly less, averaging $15.00 (median) to $18.23 (mean) per hour, slightly more than the national average for electronic equipment assemblers.

- The solar industry is a strong employer of veterans of the U.S. Armed Services, who constitute 9.24% of all solar workers – compared with 7.57% in the national economy. Solar employs a slightly larger proportion of Latino/Hispanic and Asian/Pacific Islander workers than the overall economy.

As previously sated, our second concern with the focus on jobs arises from the fact that there does not seem to be a definition of what a “permanent” job is in this regulatory context.

While I am not opposed to using permanent jobs as ***A*** measure, I do not feel that permanent jobs should be ***THE*** sole, or even the primary criteria, for determining or measuring CRA compliance when renewable energy or energy efficiency is concerned. Such an ancient metric appears today, to be outdated, or at least, out of sync with current employment trends across the U.S. As technology improves, automation reduces labor intensity due to modernization.

Therefore, in the case of renewable energy and energy-efficiency, where the economic impact is both real and substantial, I believe a much more relevant measure for purpose of the CRA would be direct and indirect economic impact on individuals of low and moderate income in a low and moderate income area or region.

For example, if a person of low or moderate income, living in low or moderate income area, is unemployed or underemployed, their access to energy efficiency programs and technology, and their access to renewable energy technology, will enable them to directly or indirectly benefit economically from energy cost savings.

Therefore, from the perspective of the low or moderate income family, the ability of that low or moderate income person or family to monthly save money on their otherwise unavoidable energy costs is economically equivalent to that low or moderate income person or family getting a part time job, getting or a salary increase, or a job promotion with salary increase. Economically, there is no material difference as it impacts that person’s monthly family budget in the same way on an after tax basis.

Moreover, the money that a low or moderate income person saves on energy expenses will almost invariably be spent in that person’s low and moderated income community, thus stimulating the economy in the same way that a new job might, but without the extra local cost burdens that new job creation entails, such as additional infrastructure or public services required to serve such persons.

While energy savings are not a direct substitute for new jobs in every case, in many, if not most cases, the economic impact due to cost savings from renewable energy and energy efficiency is identical. The trend for increased cost of energy is well documented by the Federal Reserve. See materials below on that point. Thus a recurring energy savings equates to an economic multiplier.

Therefore, because the dollars in the pocket of a low and moderate income person that are attributable to either renewable energy, energy efficiency, or both, all spend the same, whether that dollar is sourced to their personal energy savings versus increased earnings from some new job or an existing job makes little day to day economic difference to that low income person. Every dollar they save on energy consumption is a dollar they can spend for food, clothing, shelter, medicine or family and childcare, money that is available for spending in that low and moderate income community and which will get spent in that community.

As long as less residents in low and moderate income areas suffer from increased levels of unemployment or underemployment, one of the best economic policies the Agencies could support would be loans and allowed investment in energy efficiency and renewable energy regardless of the existing metric of permanent job creation, retention or improvement, however those terms are defined for purposes of CRA.

Clearly, when both permanent job creation, retention and/or improvement arise through the use of community development loans or investments by regulated institutions, such metrics do and should remain valid considerations. I do support new job creation, retention and improvement.

However, as written, the current regulations are outdated and deficient as to their original purpose and overall intent, namely, to show positive economic impact in the lives of low and moderate income individuals.

As written, interpreted and implemented, a community development loan that supports a dozen new “permanent” or “retained” jobs could be approved, while a renewable energy project that would save 50 low income families money on their energy costs for the next 20 years (e.g., the life of a solar energy system) would not be approved, unless that solar system also happened to be attached to a section 42 affordable housing projects.

In light of this fact, I respectfully suggest that if the overall positive economic impact, i.e., the energy savings from either an energy efficiency or renewable energy project can reasonably be expected to lower the energy costs of low or moderate income persons in a low or moderate income area, then such a renewable energy project or energy efficiency project should be independently eligible for Community Development Loans to the same extent that any other presently eligible project would be and I respectfully request that the Q & A make such a policy clear by stating such a rule clearly in the published regulations.

Merely publishing the policy objectives to this end may help, but unless the regulations are clear, unless stand-alone renewable energy or energy efficiency project financings are expressly listed as being eligible for CRA, the Q & A will be unacceptably ineffective as it pertains to meeting the needs of low and moderated income individuals.

Moreover, because most if not all energy efficiency or renewable energy project by definition involve construction, installation and other labor, there will virtually always be a job or job retention or improvement component to nearly all such projects to some worthwhile degree.

For examples, see Appendices A and B attached.

Keeping CRA Up To Date and Currently Relevant

I have observed, and continue to see, macro changes in the energy sector within the continental United States.

These changes are on the verge of reaching a “tipping point.” Some if fact believe, the “tip” has already occurred.

Given the present economic cost structures in the renewable energy sectors, most particularly, the solar photovoltaic (PV) industry, by the time these proposed questions become effective (approximately 12 months from the closing of the comment period), I believe that within 5 years of that period, renewable energy technology, particularly solar PV, will be either cost-competitive or less expensive than conventional energy utility-provided electricity in a number of U.S. jurisdictions and in a significant portion of low and moderate income areas.

That reality is currently at play in today’s free market environment where current systemic economics make renewable energy such as solar PV the first choice by a growing number of individuals for meeting their essential electricity requirements[9].

However, that first choice is not always a practical first choice for low and moderate income residents, and thus, just as the case of affordable housing, the Agencies will also need to step up to help low and moderate income Americans exercise their equal right to basic economic autonomy as expressed by their ability to save money on energy costs if not directly purchase, lease, or use of renewable energy or energy efficiency technology to meet the daily demands in their lives.

Failure of federal policies, such as the CRA and PWI polices, to keep pace with the energy requirements of low and moderate income members of society will dampen and eventually harm the ability of low and moderate income individuals to maintain the standard of living that both CRA and PWI policies are expressly intended to advance. If the Agencies support the policy goals of self-respect, individual autonomy and family protection through affordable housing, then the Agencies can support these same goals though supporting energy costs savings by low and moderate income individuals.

The fast developing and quickly evolving energy market place has finally caught up with the Agencies, and it now imposes the highest level of duty upon the Agencies to address the needs of low and moderate income individuals not only today, at the time these Q & A’s are being considered, but during the time the current regulatory approval process for these questions is ongoing, end then, beyond.[10]

[9] http://www.seia.org/research-resources/solar-industry-data
[10] http://thesolarfoundation.org/research/national-solar-jobs-census-2013

We are now seeing improvements in both energy efficiency and renewable energy technology and cost reductions that continue to accelerate at a rate faster than the existing regulatory process of the Agencies.[11]

Therefore, even though I clearly support the Q & A on energy efficiency and renewable energy, as proposed, finalizing these Q & As, will be too little too late. They will be immediately out of date as it pertains to energy efficiency and renewable energy.

As proposed, these questions are merely catching up to where the affordable housing industry was 8 years ago (specifically as it relates to solar technology and IRC §42 affordable housing, particularly in California).

And as previously stated, while I absolutely, unequivocally support and approve the questions currently under consideration precisely because they begin the process of catching up with the markets, they really and only merely serve to catch the Agencies up to where the affordable housing industry has been for more than 8 years and largely ignore the non-affordable housing energy efficiency and renewable energy sectors, which are in fact the largest sector of the renewable energy and energy efficiency market and the largest job creation sector.[12]

I therefore respectfully request the Agencies to not only enact the Q&A as proposed, but to also additionally, distinctly, clearly, and expressly broaden the language and text of the regulations so that it is clearly stated that residential, commercial, industrial, and even utility scale renewable energy or energy efficiency projects may be eligible for CRA and PWI approval under the Community Development Loans regulations by virtue of their “community development component” and that either the 8th and last bullet point under proposed answer to § __.12(h) –1: A1 contain this additional clarification, or that a new, 9th bullet point be added in order to make such a clarification.

What is Community Renewable Energy?

Community Solar

Shared renewable energy arrangements allow several energy customers to share the benefits of one local renewable energy power plant. When the power is supplied strictly by solar energy, it is sometimes called “community solar.” The shared renewables project pools investments from multiple members of a community and provides power and/or financial benefits in return. Shared renewables projects are often located on public or jointly-owned property, and can be an easier way for renters and condominium owners to benefit from a local solar energy project. See, http://www.seia.org/policy/distributed-solar/shared-renewablescommunity-solar.

[11] See, Lazard’s Levelized Cost of Energy Analysis – Version 8.0 at, http://www.seia.org/sites/default/files/resources/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf#overlay-context=research-resources/lazards-levelized-cost-energy-analysis-v80

[12] See, http://www.renewableenergyworld.com/rea/news/article/2014/01/solar-jobs-growing-ten-times-faster-than-national-average-employment-growth

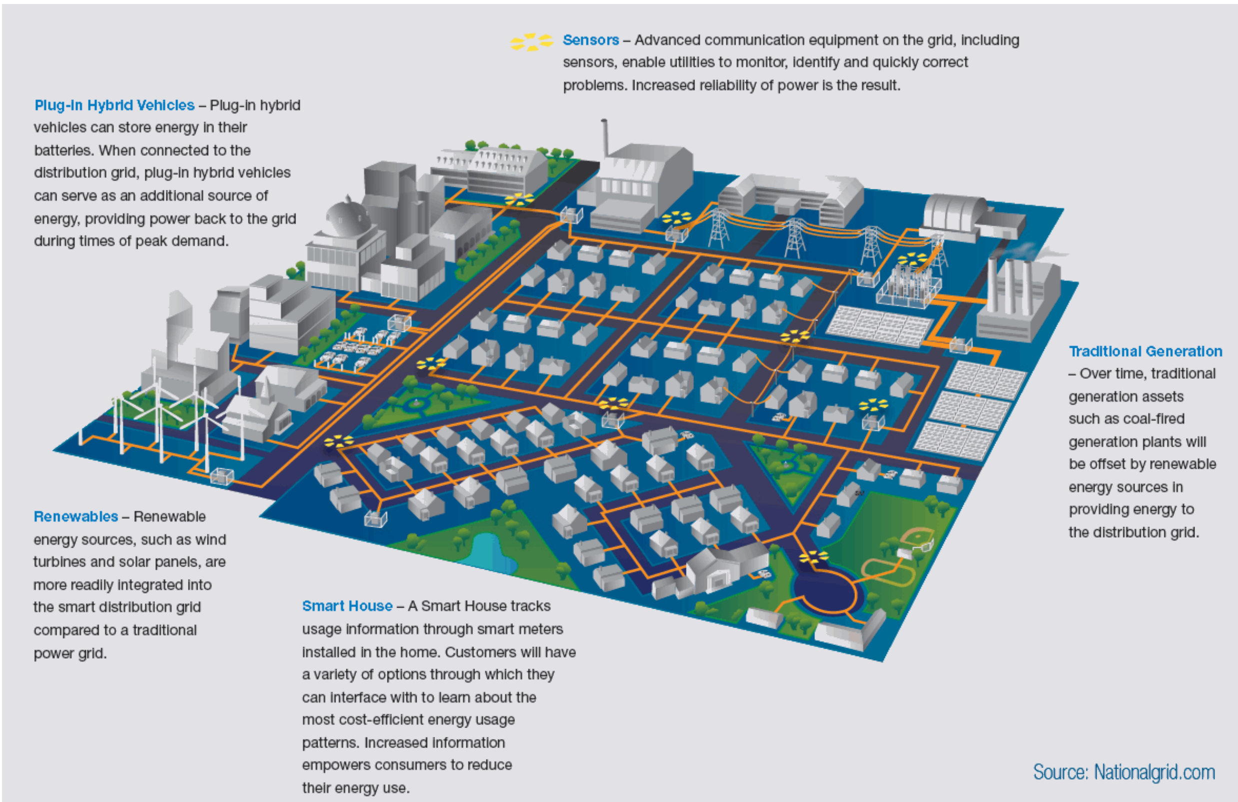
Community Wind

While most wind power projects are owned by companies with limited local ties, community wind projects are owned by the local community. Community wind projects are defined by an ownership model instead of by the type or size of turbine. Community wind projects have multiple applications and can be used by schools, hospitals, businesses, farms, ranches, or community facilities to supply local electricity. Rural electric cooperatives or municipal utilities can own community wind projects and use them to diversify electricity supplies. Community wind projects can also consist of groups of local individuals who form independent power producer groups or limited liability corporations to sell the power the turbines produce to a local electricity supplier. See, http://www.nrel.gov/docs/fy13osti/56386.pdf.

What is a Microgrid?

A microgrid is a smaller power grid that can operate either by itself or connected to a larger utility grid. Microgrids can serve areas as small as a few houses, all the way up to large military installations. A microgrid senses the quality of the power flowing through the grid. In the event of an outage, it can disconnect from the grid at a moment's notice. It can also leverage solar, wind, or stored energy to supplement a dip in the current power supply. If things are running smoothly with the regional grid, a microgrid generating electricity from renewable sources can export that clean energy to the grid for everyone's use. See, http://www.nrel.gov/news/features/feature_detail.cfm/feature_id=1980.

Graphic Showing Example of MicroGrid – Sandia National Lab



<u>What is the Value of Solar (VOS) – A New and Important Economic Impact in Low and Moderate Income Areas</u>

The methodology, known as Value of Solar Methodology, takes into consideration the unique nature of solar PV generation in which systems produce electricity on peak, produce power at the location of use, do not require continuous fuel purchases, and have significant security and environmental advantages over fossil fuels. These characteristics generally increase the value of solar electricity as they allow utilities to avoid the costs of fuel, plant O&M, generation, reserve capacity, transmission, and distribution in their centralized assets[13].

[13] http://www.growsolar.org/toolbox/value-solar-methodology/, see also, http://www.growsolar.org/wp-content/uploads/2014/04/eLab-DER-Benefit-Cost-Deck_2nd-Edition_130903.pdf, and see, http://www.growsolar.org/wp-content/uploads/2014/04/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG.pdf

While the value of solar is being determined in real time in multiple public electrical utility areas across the nation, with differing methods and values being determined based on local facts and circumstances, we are now seeing both electric utilities and their state regulators making positive VOS determinations, thus making clear that the value of solar is not only real, but material, and recognized by both utilities and their regulators as a bona fide economic value.

Therefore, while the precise value of solar may vary depending on jurisdictional facts and circumstances, the fact of value, and the fact that such value benefits low and moderate income individuals is the key take away from the attached appendices.

For specific and recent VOS analysis see appendices for the Mississippi and Wisconsin VOS analysis.

The Relationship Between Renewable Energy, CRA and Using the NMTC Map To Correlate Solar and Low and Moderate Income Areas and Individual Solar Systems

An interactive map (link below) serves as a useful tool in determining the New Markets Tax Credit (NMTC) eligibility of a project and as such, the map can be used for CRA purposes as well.

Because NMTC projects are CRA eligible, renewable energy projects located in NMTC eligible areas should be CRA eligible too.

http://www.cohnreznick.com/NMTC-Mapping-Tool

If the Agencies overlay the above NMTC map with the following state's data on the location of renewable energy projects, you will find a certain degree of overlap.

One such tool is provided by NYSERDA, which has created a database for solar projects Under NY-Sun

The NYSERDA –NY database contains information compiled on almost 10,000 solar projects over the last 10 years.

A map of installation locations and bar graphs of installed capacity organized by market segment and county are some of the features of the database.

The GPS coordinates of each solar system are provided as well.

The data is publicly available and can be accessed through Open NY at. https://data.ny.gov/Energy-Environment/Solar-Photovoltaic-PV-Incentive-Program-Beginning-/3x8r-34rs

Thus, the conclusion may easily be drawn that by permitting regulated institutions to obtain CRA credit for making community development loans for renewable energy projects that are located in low and moderate income areas of regions, the policy objectives and both the spirit and the law of CRA may be achieved.

Moving Toward Consistency Of Federal Banking, Energy And Public Health Policy

The environmental benefits are local, because the water is used locally, and emissions are generated at a point source in the community. Yet given the mobile nature of air and water, the community benefits are regional as well as local, and in some cases, such as greenhouse gases, the impact is national. Hence, a broad definition is uniquely warranted in the case of renewables.

Because most U.S. fossil fuel based electrical generation facilities are located in either rural, remote, and economically disadvantaged geographical regions throughout America, OCC support of renewable energy generation through the OCCs PWI and CRA authority will contribute to increased renewable energy generation, support the stabilization or net reduction of fossil fuel generation, which in turn will stabilize or decrease air and water pollution in economically disadvantaged areas where corresponding healthcare costs due to pollution related illness is historically most prominent.

There is a direct link between physical and economic health. Economically disadvantaged citizens have higher healthcare costs as a proportion of their income. Therefore, it ought to be the policy of the OCC that support of investment in and lending to renewable energy projects directly improves the health of economically disadvantaged Americans and therefore, warrants express support by the OCC as permitted community development.

Community development involves public infrastructure, I would recommend that the electricity infrastructure is on equal footing and of equal importance to roads, bridges, rail and waterways.

failure by the OCC to expressly codify its overt support for investments in and lending to renewable energy projects will represent a contravention of current federal energy policy, contravention of current energy regulatory policy, and given the EPA data showing nationwide and material negative national healthcare impacts attributable to fossil fuel based electrical energy production also, contravene the current administration’s federal healthcare policy.

ASSESMENT AREA CONSIDERATIONS

Because renewable energy has a direct and immediate impact on improving air and water quality in addition to improving water quantity, investments in and lending to renewable energy projects by definition impact virtually every rural, remote, and economically disadvantaged area across the entire United States, with the possible exception of Alaska. Therefore, renewable energy related lending does in fact have an immediate or direct benefit to an institution’s assessment area.

In addition, the OCC should expressly state that investments in or lending to renewable energy projects shall be deemed to provide an immediate or direct benefit to the institution’s assessment area notwithstanding the fact that improvements to public health might occur only after renewable energy generating facilities have operated for some time and may be measurable only after the actual retirement of competing fossil fuel based electrical generating facilities.

MULTI-STATE AREAS

By definition, investing in or lending to renewable energy projects benefits multistate areas as well as individuals in the broader statewide or regional areas that includes their traditional assessment area and thus, they should receive the same consideration as an activity directly benefitting the institution’s assessment area.

If codified, these precepts actually enhance, support, and strengthen OCC policy historically, currently, and prospectively, in part because these precepts remain consistent with the OCC’s understanding of what is meant by the term “regional area.”

NATIONAL OR REGIONAL FUNDS

Accordingly, these precepts also support the OCC’s policy of encouraging investments in national or regional funds, while attempting to require such investments ultimately impact the institution’s assessment area.

Because certain renewable energy technologies may operate more effectively for the public good in certain geographical regions of the United States, e.g. wind versus solar, and because certain geographical regions may retire or replace fossil fuel fired electrical generation resources on differing timetables, it is appropriate to allow OCC regulated institutions physically located in an assessment area with relatively slower renewable energy investment activity to nonetheless invest in or lend to such activity in other geographical regions to the extent that the electricity generated as a result of such investment or lending is transmittable to or otherwise made available to a utility in that institution’s regional assessment area. For example, an OCC regulated institution in Georgia making an investment in or lending to a solar facility in the Midwest feeding solar electricity into the grid which connects to the TVA which in turn connects to the grid in Georgia should qualify.

In order for an institution to demonstrate that an investment in a nationwide fund met the primary purpose of community development with a direct or indirect benefit on one or more of the institution’s assessment areas or its broader statewide or regional area, the institution need only provide information showing that its investment supported the construction or operation of renewable energy facilities whose output is measurable in megawatts given that the economic and healthcare damages associated with fossil fuel generation is also measurable in megawatts.

Additional Indirect Benefits of Renewable Energy and Energy-Efficiency of Which the Agencies Must Be Aware – EPA Public Health Data

Improved public health is another factor that the Agencies must consider when assessing community impact for purposes of CRA.

Giving a regulate institution CRA credit for creating a new job in a coal mine where the worker life expectancy is likely to be reduced due to black-lung disease is an example of a policy that fails by its own success.

Therefore, it is precisely because of the dramatic improvements to public health that are enabled by renewable energy that the Agencies must take such economic impact data into consideration. Moreover, it is precisely because of the magnitude of the public health impact that the Agencies should favor awarding CRA credit to stand alone renewable energy projects in low and moderated income areas.

The Health Care Savings Data

Introduction to the Federal EPA Public Health Data.

America derives the majority of the electricity that drives the U.S. Economy from fossil fuels, hydro-power and nuclear power.

Of the three sources, fossil fuels are the predominate source.

Of the fossil fuels, coal and natural gas are the most prominent.

Of those two, coal remains prominent (see attached FED report) despite the current shift toward using more natural gas. And because coal combustion is highly pollutive, the negative public health impacts attributable to coal fired thermo-electric power plant operation are now well documented.

The range of toxins known to be associated with coal fired power plant operation is startling, and too expansive to be covered here. However, the EPA, since 2011, has undertaken to assess the negative public health impacts associated with just two of the many categories of pollutants known to be sourced to the electric power industry.

Those two pollutants are:

1. Mercury
2. Particulates

To assess the magnitude of the health care costs forced upon society in the U.S. directly associated with coal fired electrical power production, the EPA conducted and publicly releases two studies.

The first, concerning the negative public health impacts of coal fired power plant mercury emissions, bearing the acronym MATS (for Mercury Air Toxics Study).

The second study, concerning the negative public health impacts of coal fired power plant particulate emissions, bearing the acronym CSAPR (Cross State Air Pollution Rule).

Each study was limited to only one of the many forms of known pollutants associated with coal power production, and each study did not include the health care damages covered by the other study.

Therefore, the economic impacts of each study are, when added, cumulative.

Lastly, the EPA recently announced rule 111(d), known as the greenhouse gas (GHG) rules. These rules don’t directly measure the negative public health damage due to toxic mercury or particulate pollutants, but rather, measure, among other things, the public health damage associates with CO2 green house gas, climate change, and he overlap between the implicit reductions in GHG, reduced fossil fuel combustion, and reduced pollution due to reduced coal and other fossil fuel combustion.

What the EPA Data Shows

Resources

http://www.epa.gov/mats/pdfs/presentation.pdf

http://www.epa.gov/mats/pdfs/20111221facilitiesmap.pdf

http://www.epa.gov/mats/pdfs/20111221PowerPlantsLikelyCoveredbyMATS.pdf

CSAPR EPA Data

Resources

http://www.epa.gov/crossstaterule/

http://www.epa.gov/crossstaterule/whereyoulive.html

http://www.epa.gov/crossstaterule/pdfs/CSAPRFactsheet.pdf

Green House Gas Data – EPA Rule 111(d)

Interrelated with MATS and CSAPR, the new EPA rules to limit greenhouse gas emissions will prevent thousands of deaths and hospitalizations and hundreds of heart attacks every year, according to a new study from researchers at Harvard, Syracuse, and Boston universities.

The study, entitled Health Co-Benefits of Carbon Standards for Existing Power Plants, estimates that new EPA regulations to limit greenhouse gas emissions will annually prevent 3,500 premature deaths, 1,000 hospitalizations for heart and lung disease, and 220 heart attacks each year. Annually.

The study shows that the biggest impact would be in “rust belt” states and Texas, hotspots for fossil fuel electrical power generation.

See study, http://www.chgeharvard.org/sites/default/files/userfiles2/Health%20Co-Benefits%20of%20Carbon%20Standards.pdf.

Another report evaluates the Clean Power Plan, proposed by the U.S. Environmental Protection Agency, from the perspective of how it might impact consumers.[14]

[14] http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Analysis_Group_EPA_Clean_Power_Plan_Report.pdf

EPA's Clean Power Plan: State Plans and Consumer Impacts

Table ES-10. Summary of Estimated Monetized Benefits, Compliance Costs, and Net Benefits for the Proposed Guidelines –2030 (billions of 2011$) [a]

	Option 1– state	
	3% Discount Rate	7% Discount Rate
Climate Benefits [b]		
5% discount rate	$9.5	
3% discount rate	$31	
2.5% discount rate	$44	
95th percentile at 3% discount rate	$94	
Air pollution health co-benefits [c]	$27 to $62	$24 to $56
Total Compliance Costs [d]	$8.8	
Net Benefits [e]	$49 to $84	$46 to $79
Non-Monetized Benefits	Direct exposure to SO_2 and NO_2 2.1 tons of Hg and 590 tons of HCl Ecosystem effects Visibility impairment	
	Option 1– regional	
	3% Discount Rate	7% Discount Rate
Climate Benefits [b]		
5% discount rate	$9.3	
3% discount rate	$30	
2.5% discount rate	$44	
95th percentile at 3% discount rate	$92	
Air pollution health co-benefits [c]	$25 to $59	$23 to $54
Total Compliance Costs [d]	$7.3	
Net Benefits [e]	$48 to $82	$46 to $77
Non-Monetized Benefits	Direct exposure to SO_2 and NO_2 1.7 tons of Hg and 580 tons of HCl Ecosystem effects Visibility impairment	

[a] All estimates are for 2030, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimates in this summary table reflect global impacts from CO_2 emission changes and do not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total social costs are approximated by the illustrative compliance costs which, in part, are estimated using the Integrated Planning Model for the proposed option and a discount rate of approximately 5%. This estimate also includes monitoring, recordkeeping, and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global SCC at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

Electrical Energy Industry Forecast

Federal Reserve Board Analysis – Energy Sector Economic Forecast

See original at, http://www.kc.frb.org/publicat/econrev/pdf/12q1Snead.pdf.

This report predicts shifts in the U.S. electricity mix from coal use to natural gas and renewable energy. In fact, the report states that “Renewable energy capacity is projected to increase 67 percent (from 122,400 MW to 203,300 MW) by 2035, ultimately accounting for 20 percent of capacity.” Per this report, not only is the U.S. electricity mix expected to shift more towards natural gas and renewables, but the report suggests that renewable energy is expected to play a materially significant role as part of this overall shift and in the U.S.' future electricity mix.

This report also indicates the growing importance of distributed renewable energy because it projects substantial cost and price increases for utility provided power. Though these increases will affect the nation as a whole, it will likely disproportionately impact low and moderate income areas. As grid power costs increase, consumer protection, particularly for low and moderate income areas, can best be obtained by DG renewable energy. Solar energy can help offset the disproportionate impact of cost increases facing low and moderate income areas. Therefore, policies that support investment in such projects should be supported.

Low and moderate income areas can significantly benefit from solar energy. It can help reduce electricity costs and also improve quality of life. Most power plants and oil refineries are located in either rural, remote, and economically disadvantaged geographical regions throughout America and low-income households pay a greater percentage of their income for electric costs. Specifically, these households pay 9.2% more than the average household, according to the Department of Health and Human Services. Incorporating solar energy into these communities can not only help stabilize energy costs, but also alleviate some of the strain on low-income budgets.

However, because many low to moderate income individuals rent (and not own) single-family and multi-family homes, installing solar on those properties is not usually an option. Community solar can serve as a solution in these situations, as it is ideal for tenants who are wanting to reduce their electric costs. As such, I respectfully request the Agencies to consider expanding the proposed Q&A to include community solar.

Job Creation From Renewable Energy

Per, http://www.ucsusa.org/clean_energy/our-energy-choices/renewable-energy/public-benefits-of-renewable.html#.VDgdw1ItC9I:

Compared with fossil fuel technologies, which are typically mechanized and capital intensive, the renewable energy industry is more labor-intensive. This means that, on average, more jobs are created for each unit of electricity generated from renewable sources than from fossil fuels.

Renewable energy already supports thousands of jobs in the United States. For example, in 2011, the wind energy industry directly employed 75,000 full-time-equivalent employees in a variety of capacities, including manufacturing, project development, construction and turbine installation, operations and maintenance, transportation and logistics, and financial, legal, and consulting services. More than 500 factories in the United States manufacture parts for wind turbines, and the amount of domestically manufactured equipment used in wind turbines has grown dramatically in recent years: from 35 percent in 2006 to 70 percent in 2011.

Other renewable energy technologies employ even more workers. In 2011, the solar industry employed approximately 100,000 people on a part-time or full-time basis, including jobs in solar installation, manufacturing, and sales; the hydroelectric power industry employed approximately 250,000 people in 2009; and in 2010 the geothermal industry employed 5,200 people.

Increasing renewable energy has the potential to create still more jobs. In 2009, the Union of Concerned Scientists conducted an analysis of the economic benefits of a 25 percent renewable energy standard by 2025; it found that such a policy would create more than three times as many jobs as producing an equivalent amount of electricity from fossil fuels—resulting in a benefit of 202,000 new jobs in 2025.

In addition to the jobs directly created in the renewable energy industry, growth in renewable energy industry creates positive economic "ripple" effects. For example, industries in the renewable energy supply chain will benefit, and unrelated local businesses will benefit from increased household and business incomes.

In addition to creating new jobs, increasing our use of renewable energy offers other important economic development benefits. Local governments collect property and income taxes and other payments from renewable energy project owners.

These revenues can help support vital public services, especially in rural communities where projects are often located. Owners of the land on which wind projects are built also often receive lease payments ranging from $3,000 to $6,000 per megawatt of installed capacity, as well as payments for power line easements and road rights-of-way. Or they may earn royalties based on the project's annual revenues. Similarly, farmers and rural landowners can generate new sources of supplemental income by producing feedstocks for biomass power facilities.

UCS analysis found that a 25 by 2025 national renewable electricity standard would stimulate $263.4 billion in new capital investment for renewable energy technologies, $13.5 billion in new

> landowner income biomass production and/or wind land lease payments, and $11.5 billion in new property tax revenue for local communities.
>
> Renewable energy projects therefore keep money circulating within the local economy, and in most states renewable electricity production would reduce the need to spend money on importing coal and natural gas from other places. Thirty-eight states were net importers of coal in 2008—from other states and, increasingly, other countries: 16 states spent a total of more than $1.8 billion on coal from as far away as Colombia, Venezuela, and Indonesia, and 11 states spent more than $1 billion each on net coal imports.

Furthermore, according to a study[15], solar jobs provide the greatest job multipliers in the energy sector, meaning that when one job is created in an industry, it leads to the creation of further employment. Specifically, for every GWh of solar power generated, there is approximately one job created per year. Fossil fuels generate less than 0.25 jobs per GWh generated.

Please see attached Appendices for additional job creation studies.

<u>Public Resource Preservation</u>

Merchant or privately owned renewable energy projects, regardless of size or scale, directly serve the community in which they generate clean energy.

The positive community impact is lasting.

Public utilities and IOUs using fossil or nuclear fuels force the spreading of economic and environmental risk amongst their investors and always claim public resources, most often without compensation to the community, namely air and water resources.

Non-utility owned renewable projects do not claim air or water resources, and thus serve their communities over decades.

[15] http://mpaenvironment.ei.columbia.edu/files/2014/06/GRIDAlternativesProject.Final_.pdf

Appendix A:

Solar Jobs Study for the Camilla Solar Farm Development Project

The Economic and Workforce Development Impacts of

The Camilla Solar Farm Development Project

Prepared for:

Solar Design and Development

By:

Richard Clinch, Ph.D.

Date:

April 2012

1.0 Introduction and Summary

Solar Design and Development retained Richard Clinch, PhD Director of Economic Research at the Jacob France Institute of the Merrick School of Business at the University of Baltimore (JFI) to analyze the economic[16] and workforce development implications of the development of the Camilla Solar Farm Development Project on the Georgia economy.[17] The two goals of this analysis are:

1. To prepare and present information on the economic and workforce development impacts resulting from the construction and operation of the Camilla Solar Farm Development Project; and
2. To analyze the impact of the construction and operation of the Camilla Solar Farm Development Project in terms of creating employment opportunities for low income residents in Georgia as a component of the use of New Market Tax Credits (NMTC) to support this project.

The Camilla Solar Farm Development Project will have the following impacts:

- The construction and operation of the Camilla Solar Farm Development Project will directly create 133.7 FTE construction-related jobs and partially support 2.8 FTE operational jobs maintaining and servicing the solar facility[18];
- The construction expenditures associated with the Camilla Solar Farm Development Project will generate $38.7 million in economic activity in Georgia, and when multiplier effects are included, create 344.1 FTE jobs earning $15.6 million in employee earnings;
- Once the Camilla Solar Farm Development Project is constructed and operational it will generate more than $2.4 million per year in electricity sales;
- The annual operations and maintenance spending on in-State labor, maintenance and equipment will support 2.8 FTE Solar Maintenance Technicians and when multiplier effects are included support 4.6 FTE workers statewide, earning $248,820 and

[16] This analysis does not assess the extent to which the Camilla Solar Farm Development Project competes with or substitutes for other development activity. Thus, this analysis measures the relationship between this development activity and the larger State of Georgia economy.

[17] The development is located in Mitchell County, Georgia; however, the National Renewable Energy Lab’s (NREL) Jobs and Economic Development Impact (JEDI) model used is only available at the State level. As described in the Methodology Section below, this state-level model was used because it was created to analyze the impacts of the highly specialized solar and other renewable energy sector projects.

[18] The NREL-JEDI Model estimated jobs on a Full Time Equivalent (FTE) basis with one job equaling 1 FTE person year of 2,080 hours. The main economic impact of a solar facility is from its construction and a higher number of persons will be employed – but only on a part-time basis – on the construction site. Job impacts are presented on an FTE basis in order to better understand the actual number of jobs created on an annualized basis.

increase economic activity in Georgia by $434,746. The facility will generate an estimated $187,500 in annual property taxes; and

- Seventy-nine percent (79%) of the direct and multiplier effect jobs created by the construction of the Camilla Solar Farm Development Project are low-skilled jobs accessible to low income residents, and an estimated 70% have access to retirement benefits and 76% have access to medical benefits. All of the direct jobs created by the operation of the solar facility will have access to benefits.

2.0 The Community Economic Impact of the Construction and Operation of the Camilla Solar Farm Development Project

The Camilla Solar Farm Development Project is a 15 MW solar facility that is proposed for development in Mitchell County, Georgia by Solar Design and Development. The construction and operational cost inputs to the modeling analysis for this project were provided by Solar Design and Development and included the following:

- For pre-development construction-related impacts, the input to the NREL-JEDI Model[19] modeling was the actual $42.4 million construction budget for the Camilla Solar Farm Development Project; and
- The annual operational impacts of the Camilla Solar Farm Development Project were estimated by the NREL-JEDI Model modeling based on the annual 15 MW capacity of the facility, with in-State operational expenditures and job creation estimated by the JEDI model based on the operational characteristics of similar facilities.

Based on these inputs, Richard Clinch, PhD used the NREL-JEDI Model to estimate the economic, employment and employee earnings impacts of the construction and operation of the Camilla Solar Farm Development Project on the Georgia economy.

Table 1

Camilla SFDP Facility

Construction and Operational Information

Item	
Project Development Cost	$48,024,510
Construction Cost	$42,402,867
Generation Capacity	15
Operational Revenue (2015)	$2,417,633

[19] For a description of the model – see the Methodology Section below.

Annual Operating Costs	$487,500
Operational Job Creation	2.8

Source: Solar Design and Development

As presented in Table 2, the $42.4 million in construction expenditures associated with the construction of the Camilla Solar Farm Development Project will generate $38.7 million in economic activity in Georgia, create or support 344.1FTE jobs earning $15.6 million in employee earnings. A total of 133.7 FTE on-site, construction-related jobs are estimated to be created over the construction of the Camilla Solar Farm Development Project. It is important to note that the NREL-JEDI model only includes the amount of spending it estimates as likely to occur locally – in the market being studied. Because of the highly specialized nature of solar power plant construction, a large share of the machinery and equipment associated with the development of a project are likely to be imported from outside of the region, and are, therefore, not counted in the economic and job impacts analysis.

Table 2

Camilla SFDP Facility

Economic Impacts of Construction Expenditures

(Jobs and 2012$)

Construction Phase	**Annual Jobs**	**Annual Earnings (2010$)**	**Annual Output (2010$)**
Project Development and Onsite Labor Impacts	133.7	$7,156,142	$11,778,023
Construction and Installation Labor	59.7	$3,863,675	--
Construction and Installation Related Services	74.0	$3,292,467	--

Module and Supply Chain Impacts	123.7	$5,229,613	$16,010,000
Induced Impacts	86.7	$3,187,696	$10,948,086
Total Impacts	344.1	$15,573,451	$38,736,110
Average Employee Earnings per Job ($s)	$45,255		

Source: JEDI Model

The ongoing economic activity generated in the Georgia economy by the operation of the Camilla Solar Farm Development Project is presented in Table 3. Once the Camilla Solar Farm Development Project is constructed and operational it will generate approximately $2.4 million in electricity sales. The annual operations and maintenance spending on in-State labor and maintenance and equipment will support 2.8 FTE Solar Maintenance Technicians and when multiplier effects are included support 4.6 FTE workers statewide, earning $248,820 and increase economic activity in Georgia by $434,746. The facility will generate an estimated $187,500 in annual property taxes. It is again important to note that, as with construction impacts, the NREL-JEDI model only includes the on-site operational, maintenance, and support expenditures estimated as likely to occur in the region being studied.

Table 3

Camilla SFDP Facility

Economic Impacts of Operations

(Jobs and 2012$)

Operational Phase	**Annual Jobs**	**Annual Earnings (2010$)**	**Annual Output (2010$)**
Onsite Labor Impacts			
PV Project Labor Only	2.8	$167,186	$167,186
Local Revenue and Supply Chain Impacts	1.0	$51,161	$162,894
Induced Impacts	0.8	$30,473	$104,665
Total Impacts	4.6	$248,820	$434,746
Annual Property Tax Revenues	$187,500		

Source: JEDI Model

3.0 NMTC Impacts of the Construction of the Camilla Solar Farm Development Project

The NMTC program’s goal is that funded projects will have a positive community development and economic impact on distressed communities. One of the key benefits tracked by the program is the number of jobs for low-income persons that are created or maintained. In the Community Impact portion of the NMTC funding application, applicants are asked to present the number of Jobs Created or Maintained by any predevelopment/construction and properties developed by QLICIs for planned investments. This analysis will present the results of the job impact estimates for the project presented above in a format applicable to the NMTC Program’s goals.[20]

There is no generally accepted means of estimating the number of jobs held or that could be held by low-income individuals. This analysis, therefore, estimates the number of jobs created that is low-skill and therefore, accessible in terms of skills profiles to low income populations, who generally have lower levels of educational attainment and job skills. This was accomplished by using an occupational matrix based on U.S. Bureau of Labor Statistics (BLS) occupational employment developed by IMPLAN. This matrix allows for the estimation of the occupational profile of the jobs estimated by the IMPLAN model. Each of the occupations in the matrix has been coded according to the minimum level of education and/or training required to fill a position using BLS data (http://www.bls.gov/emp/empeted1.htm). This allows for the estimation of low-skilled jobs, which for the purposes of this analysis includes any occupation requiring less than an Associate’s Degree.

As presented in Table 4, the construction and operation of the Camilla Solar Farm Development Project will create 114 FTE construction-related low-skilled jobs accessible to low-income individuals and, when multiplier effects are included, a total of 273 low-skilled jobs accessible to low-income individuals over the construction period. Because of the small number of jobs (just 2.8 FTE jobs) created by the Project’s operational and maintenance spending, the low skilled analysis and occupational benefits analysis was not conducted for operational spending. However, the solar technicians involved in both the installation and the operational maintenance of solar facilities are open to lower skilled workers who complete specialized training at a community college or career school and will receive benefits.

Table 4

NMTC Impact Calculations

The Low-Skilled Jobs and Benefits Associated with the Jobs Created or Maintained by the Camilla SFDP Facility

Item	Project Development and Onsite Labor Impacts	Supply Chain and Induced Impacts	Total Jobs

[20] This is based on the 2010 NMTC application. Future applications may require different community impact calculations.

Pre-Development or Construction	134	210	344
Low-Skilled Jobs	114	159	273
Estimated Jobs with Retirement Benefit	93	147	241
Estimated Jobs with Medical Benefit	104	158	262
Percentage of Jobs			
Low-Skilled Jobs	85%	75%	79%
Estimated Jobs with Retirement Benefit	70%	70%	70%
Estimated Jobs with Health Care Benefit	78%	75%	76%

Source: Richard Clinch, IMPLAN and U.S. Bureau of Labor Statistics

The CDFI Fund is also interested in the quality of the jobs to be created by investments. The data from the occupational employment analysis conducted were used to estimate the access to benefits for the jobs created, based on the BLS Employee Benefits in the U.S. Report[21], which presents data on benefits by summary occupation and industry. Estimates on the quality of jobs created by the Camilla Solar Farm Development Project were included in this community economic impact analysis, which found that 70% of the jobs created by the construction of the Camilla Solar Farm Development Project offer access to retirement benefits and 76% offer access to medical benefits. There is no way of estimating the number of jobs providing employee stock programs, but according to the ESOP Association[22] 10% of workers nationally have access to stock purchase plans.

[21] Data are for March 2011 – see http://www.bls.gov/ncs/ebs/sp/ebnr0017.pdf .
[22] http://www.esopassociation.org/media/media_statistics.asp

The results of the occupational analysis conducted for the construction of the Camilla Solar Farm Development Project are presented in Table 5, which presents an analysis of the jobs by level of education and training required, and Table 6, which presents a list of jobs created in the leading occupations for the construction of the project. Because of the small number (just 2.8) of FTE jobs created by the Project’s operational and maintenance spending, an occupational analysis was not conducted – but the solar technician jobs supported by the project can be accessible to low income individuals who complete a specialized training course.

Table 5

Employment by Educational Level

For the Construction of the

Camilla SFDP Facility

Item	Project Development and Onsite Labor Impacts	Module and Supply Chain Impacts	Induced Impacts	Total	% of Total
Total	**133.7**	**123.7**	**86.7**	**344.1**	100%
First Professional Degree	0	2	2	3	1%
Doctoral Degree	0	0	1	1	0%
Master's Degree	0	1	1	2	1%
Degree plus work Experience	5	6	3	15	4%
Bachelor's Degree	14	20	8	43	12%
Associate Degree	0	4	4	8	2%
Postsecondary vocational award	1	7	5	13	4%
Work experience in a related occupation	20	9	6	34	10%

Long-term on-the-job training	39	6	3	48	14%
Moderate-term on-the-job training	43	30	14	87	25%
Short-term on-the-job training	11	38	42	90	26%

Note: Totals may not sum due to rounding.

Source: IMPLAN and U.S. Bureau of Labor Statistics

Table 6

Top 15 Occupations

For the Jobs Created by the Construction of

Camilla SFDP Facility

Occupation	Number of Jobs	Education Level
Carpenters	28	Long-term on-the-job training
Construction laborers	21	Moderate-term on-the-job training
First-line supervisors/managers of construction trades and extraction workers	14	Work experience in a related occupation
Office clerks, general	8	Short-term on-the-job training
Construction managers	8	Bachelor's degree
Retail salespersons	7	Short-term on-the-job training
Truck drivers, heavy and tractor-trailer	6	Moderate-term on-the-job training
Bookkeeping, accounting, and auditing clerks	6	Moderate-term on-the-job training
General and operations managers	6	Bachelor's plus experience
Executive secretaries and administrative assistants	6	Moderate-term on-the-job training
Cashiers, except gaming	6	Short-term on-the-job training
Secretaries, except legal, medical, and executive	6	Moderate-term on-the-job training
Laborers and freight, stock, and material movers, hand	5	Short-term on-the-job training
Civil engineers	5	Bachelor's degree

Janitors and cleaners, except maids and housekeeping cleaners	5	Short-term on-the-job training

Source: IMPLAN and U.S. Bureau of Labor Statistics

4.0 Methodology

This analysis used the National Renewable Energy Lab’s (NREL) Jobs and Economic Development Impact (JEDI) model. Information about this model is available at http://www.nrel.gov/analysis/jedi/about_jedi.html. This model is available for free from the NREL, and can be regionalized. The NREL-JEDI model for Georgia was used in this analysis. The JEDI model can be used to estimate the economic impacts of constructing and operating power generation (including solar) and biofuel plants at the local (usually state) level.

JEDI estimates the number of jobs and economic impacts to a local area that could reasonably be supported by a power generation project, based on project-specific or default inputs (derived from industry norms). The JEDI model’s data are based on interviews with industry experts and project developers. Economic multipliers contained within the model are derived from Minnesota IMPLAN Group's IMPLAN Professional model. Project specific total costs were used in this analysis, but they were distributed into specific areas using the JEDI model’s defaults. The JEDI model’ jobs, earnings, and output impact estimates are distributed across three categories:

- Project Development and Onsite Labor Impacts;
- Local Revenue, Equipment, and Supply Chain Impacts; and
- Induced Impacts.

The construction and operation of solar and other renewable energy projects is highly specialized. The JEDI model was used in this analysis because it is based on actual data on construction and operational expenditures associated with renewable power projects, while the more widely used economic models – such as RIMS II and IMPLAN – would include the construction and operation of renewable power projects in highly diversified sectors that would lack detailed information on actual spending patterns. The JEDI model is only available at the state level, while other models can be targeted geographically on a county or even zip code; however, it does contain more accurate, industry specific data on which to estimate impacts.

Appendix B:

Solar Jobs Study for the Camp Solar Farm Development Project

The Economic and Workforce Development Impacts of

The Camp Solar Farm Development Project

Prepared for:

Solar Design and Development

By:

Richard Clinch, Ph.D.

Date:

April 2012

5.0 Introduction and Summary

Solar Design and Development retained Richard Clinch, PhD Director of Economic Research at the Jacob France Institute of the Merrick School of Business at the University of Baltimore (JFI) to analyze the economic[23] and workforce development implications of the development of the Camp Solar Farm Development Project on the Georgia economy.[24] The two goals of this analysis are:

3. To prepare and present information on the economic and workforce development impacts resulting from the construction and operation of the Camp Solar Farm Development Project; and
4. To analyze the impact of the construction and operation of the Camp Solar Farm Development Project in terms of creating employment opportunities for low income residents in Georgia as a component of the use of New Market Tax Credits (NMTC) to support this project.

The Camp Solar Farm Development Project will have the following impacts:

- The construction and operation of the Camp Solar Farm Development Project will directly create 35.7 FTE construction-related jobs and partially support 0.7 FTE operational jobs maintaining and servicing the solar facility[25];
- The construction expenditures associated with the Camp Solar Farm Development Project will generate $10.3 million in economic activity in Georgia, and when multiplier effects are included, create 91.8 FTE jobs earning $4.2 million in employee earnings;
- Once the Camp Solar Farm Development Project is constructed and operational it will generate more than $640,000 per year in electricity sales;
- The annual operations and maintenance spending on in-State labor, maintenance and equipment will support 0.7 FTE Solar Maintenance Technicians and when multiplier effects are included support 1.2 FTE workers statewide, earning $66,352 and increase

[23] This analysis does not assess the extent to which the Camilla Solar Farm Development Project competes with or substitutes for other development activity. Thus, this analysis measures the relationship between this development activity and the larger State of Georgia economy.

[24] The development is located in Mitchell County, Georgia; however, the National Renewable Energy Lab’s (NREL) Jobs and Economic Development Impact (JEDI) model used is only available at the State level. As described in the Methodology Section below, this state-level model was used because it was created to analyze the impacts of the highly specialized solar and other renewable energy sector projects.

[25] The NREL-JEDI Model estimated jobs on a Full Time Equivalent (FTE) basis with one job equaling 1 FTE person year of 2,080 hours. The main economic impact of a solar facility is from its construction and a higher number of persons will be employed – but only on a part-time basis – on the construction site. Job impacts are presented on an FTE basis in order to better understand the actual number of jobs created on an annualized basis.

economic activity in Georgia by $115,932. The facility will generate an estimated $50,000 in annual property taxes; and

- Seventy-nine percent (79%) of the direct and multiplier effect jobs created by the construction of the Camp Solar Farm Development Project are low-skilled jobs accessible to low income residents, and an estimated 70% have access to retirement benefits and 76% have access to medical benefits. All of the direct jobs created by the operation of the solar facility will have access to benefits.

6.0 The Community Economic Impact of the Construction and Operation of the Camp Solar Farm Development Project

The Camp Solar Farm Development Project is a 4 MW solar facility that is proposed for development in Meriwether County, Georgia by Solar Design and Development The construction and operational cost inputs to the modeling analysis for this project were provided by Solar Design and Development and included the following:

- For pre-development construction-related impacts, the input to the NREL-JEDI Model[26] modeling was the actual $12.8 million construction budget for the Camp Solar Farm Development Project; and
- The annual operational impacts of the Camp Solar Farm Development Project were estimated by the NREL-JEDI Model modeling based on the annual 4 MW capacity of the facility, with in-State operational expenditures and job creation estimated by the JEDI model based on the operational characteristics of similar facilities.

Based on these inputs, Richard Clinch, PhD used the NREL-JEDI Model to estimate the economic, employment and employee earnings impacts of the construction and operation of the Camp Solar Farm Development Project on the Georgia economy.

Table 1

Camp SFDP Facility

Construction and Operational Information

Item	
Project Development Cost	$12,806,536
Construction Cost	$11,307,431
Generation Capacity	4
Operational Revenue (2015)	$644,702
Annual Operating Costs	$130,000
Operational Job Creation	0.7

Source: Solar Design and Development

As presented in Table 2, the $12.8 million in construction expenditures associated with the construction of the Camp Solar Farm Development Project will generate $10.3 million in

[26] For a description of the model – see the Methodology Section below.

economic activity in Georgia, create or support 91.8 FTE jobs earning $4.2 million in employee earnings. A total of 35.7 FTE on-site, construction-related jobs are estimated to be created over the construction of the Camp Solar Farm Development Project. It is important to note that the NREL-JEDI model only includes the amount of spending it estimates as likely to occur locally – in the market being studied. Because of the highly specialized nature of solar power plant construction, a large share of the machinery and equipment associated with the development of a project are likely to be imported from outside of the region, and are, therefore, not counted in the economic and job impacts analysis.

Table 2

Camp SFDP Facility

Economic Impacts of Construction Expenditures

(Jobs and 2012$)

Construction Phase	**Annual Jobs**	**Annual Earnings (2010$)**	**Annual Output (2010$)**
Project Development and Onsite Labor Impacts	35.7	$1,908,305	$3,140,806
Construction and Installation Labor	15.9	$1,030,313	--
Construction and Installation Related Services	19.7	$877,991	--
Module and Supply Chain Impacts	33.0	$1,394,563	$4,269,333
Induced Impacts	23.1	$850,052	$2,919,490
Total Impacts	91.8	$4,152,920	$10,329,629
Average Employee Earnings per Job ($s)	$45,255		

Source: JEDI Model

The ongoing economic activity generated in the Georgia economy by the operation of the Camp Solar Farm Development Project is presented in Table 3. Once the Camp Solar Farm Development Project is constructed and operational it will generate approximately $640,000 in electricity sales. The annual operations and maintenance spending on in-State labor and maintenance and equipment will support 0.7 FTE Solar Maintenance Technicians and when multiplier effects are included support 1.2 FTE workers statewide, earning $66,352 and increase economic activity in Georgia by $115,932. The facility will generate an estimated $50,000 in annual property taxes. It is again important to note that, as with construction impacts, the NREL-JEDI model only includes the on-site operational, maintenance, and support expenditures estimated as likely to occur in the region being studied.

Table 3

Camp SFDP Facility

Economic Impacts of Operations

(Jobs and 2012$)

Operational Phase	**Annual Jobs**	**Annual Earnings (2010$)**	**Annual Output (2010$)**
Onsite Labor Impacts			
PV Project Labor Only	0.7	$44,583	$44,583
Local Revenue and Supply Chain Impacts	0.3	$13,643	$43,438
Induced Impacts	0.2	$8,126	$27,911
Total Impacts	1.2	$66,352	$115,932
Annual Property Tax Revenues	$50,000		

Source: JEDI Model

7.0 NMTC Impacts of the Construction of the Camp Solar Farm Development Project

The NMTC program’s goal is that funded projects will have a positive community development and economic impact on distressed communities. One of the key benefits tracked by the program is the number of jobs for low-income persons that are created or maintained. In the Community Impact portion of the NMTC funding application, applicants are asked to present the number of Jobs Created or Maintained by any predevelopment/construction and properties developed by QLICIs for planned investments. This analysis will present the results of the job impact estimates for the project presented above in a format applicable to the NMTC Program’s goals.[27]

There is no generally accepted means of estimating the number of jobs held or that could be held by low-income individuals. This analysis, therefore, estimates the number of jobs created that is low-skill and therefore, accessible in terms of skills profiles to low income populations, who generally have lower levels of educational attainment and job skills. This was accomplished by using an occupational matrix based on U.S. Bureau of Labor Statistics (BLS) occupational employment developed by IMPLAN. This matrix allows for the estimation of the occupational profile of the jobs estimated by the IMPLAN model. Each of the occupations in the matrix has been coded according to the minimum level of education and/or training required to fill a position using BLS data (http://www.bls.gov/emp/empeted1.htm). This allows for the estimation of low-skilled jobs, which for the purposes of this analysis includes any occupation requiring less than an Associate’s Degree.

As presented in Table 4, the construction and operation of the Camp Solar Farm Development Project will create 30.4 FTE construction-related low-skilled jobs accessible to low-income individuals and, when multiplier effects are included, a total of 72.7 low-skilled jobs accessible to low-income individuals over the construction period. Because of the small number of jobs (less than one FTE job) created by the Project’s operational and maintenance spending, the low skilled analysis and occupational benefits analysis was not conducted for operational spending. However, the solar technician involved in both the installation and the operational maintenance of solar facilities are open to lower skilled workers who complete specialized training at a community college or career school and will receive benefits.

Table 4

NMTC Impact Calculations

The Low-Skilled Jobs and Benefits Associated with the Jobs Created or Maintained by the Camp SFDP Facility

Item	Project Development and Onsite Labor Impacts	Supply Chain and Induced Impacts	Total Jobs

[27] This is based on the 2010 NMTC application. Future applications may require different community impact calculations.

Pre-Development or Construction	35.7	56.1	91.8
Low-Skilled Jobs	30.4	42.3	72.7
Estimated Jobs with Retirement Benefit	24.9	39.3	64.2
Estimated Jobs with Medical Benefit	27.7	42.3	69.9
Percentage of Jobs			
Low-Skilled Jobs	85%	75%	79%
Estimated Jobs with Retirement Benefit	70%	70%	70%
Estimated Jobs with Health Care Benefit	78%	75%	76%

Source: Richard Clinch, IMPLAN and U.S. Bureau of Labor Statistics

The CDFI Fund is also interested in the quality of the jobs to be created by investments. The data from the occupational employment analysis conducted were used to estimate the access to benefits for the jobs created, based on the BLS Employee Benefits in the U.S. Report[28], which presents data on benefits by summary occupation and industry. Estimates on the quality of jobs created by the Camp Solar Farm Development Project were included in this community economic impact analysis, which found that 70% of the jobs created by the construction of the Camp Solar Farm Development Project offer access to retirement benefits and 76% offer access to medical benefits. There is no way of estimating the number of jobs providing employee stock programs, but according to the ESOP Association[29] 10% of workers nationally have access to stock purchase plans.

[28] Data are for March 2011 – see http://www.bls.gov/ncs/ebs/sp/ebnr0017.pdf .
[29] http://www.esopassociation.org/media/media_statistics.asp

The results of the occupational analysis conducted for the construction of the Camp Solar Farm Development Project are presented in Table 5, which presents an analysis of the jobs by level of education and training required, and Table 6, which presents a list of jobs created in the leading occupations for the construction of the project. Because of the small number (less than 1) of FTE jobs created by the Project’s operational and maintenance spending, an occupational analysis was not conducted – but the solar technician job supported by the project can be accessible to low income individuals who complete a specialized training course.

Table 5

Employment by Educational Level

For the Construction of the

Camp SFDP Facility

Item	Project Development and Onsite Labor Impacts	Module and Supply Chain Impacts	Induced Impacts	Total	% of Total
Total	**35.7**	**33.0**	**23.1**	**91.8**	100%
First Professional Degree	0.0	0.4	0.4	1	1%
Doctoral Degree	0.0	0.0	0.2	0	0%
Master's Degree	0.0	0.3	0.3	1	1%
Degree plus work Experience	1.4	1.7	0.8	4	4%
Bachelor's Degree	3.8	5.4	2.1	11	12%
Associate Degree	0.1	1.2	1.0	2	2%
Postsecondary vocational award	0.3	2.0	1.3	4	4%
Work experience in a related occupation	5.4	2.3	1.5	9	10%

Long-term on-the-job training	10.4	1.6	0.8	13	14%
Moderate-term on-the-job training	11.4	8.1	3.6	23	25%
Short-term on-the-job training	2.9	10.1	11.1	24	26%

Note: Totals may not sum due to rounding.

Source: IMPLAN and U.S. Bureau of Labor Statistics

Table 6

Top 11 Occupations

For the Jobs Created by the Construction of

Camp SFDP Facility

Occupation	Number of Jobs	Education Level
Carpenters	7	Long-term on-the-job training
Construction laborers	6	Moderate-term on-the-job training
First-line supervisors/managers of construction trades and extraction workers	4	Work experience in a related occupation
Office clerks, general	2	Short-term on-the-job training
Construction managers	2	Bachelor's degree
Retail salespersons	2	Short-term on-the-job training
Truck drivers, heavy and tractor-trailer	2	Moderate-term on-the-job training
Bookkeeping, accounting, and auditing clerks	2	Moderate-term on-the-job training
General and operations managers	2	Bachelor's plus experience
Executive secretaries and administrative assistants	2	Moderate-term on-the-job training
Cashiers, except gaming	2	Short-term on-the-job training

Source: IMPLAN and U.S. Bureau of Labor Statistics

Comments to “Community Reinvestment Act: Interagency Questions and Answers Regarding Community Reinvestment”

Agency Name: OCC

Docket ID OCC-2014-0021

Date Submitted: November 7, 2014

8.0 Methodology

This analysis used the National Renewable Energy Lab's (NREL) Jobs and Economic Development Impact (JEDI) model. Information about this model is available at http://www.nrel.gov/analysis/jedi/about_jedi.html. This model is available for free from the NREL, and can be regionalized. The NREL-JEDI model for Georgia was used in this analysis. The JEDI model can be used to estimate the economic impacts of constructing and operating power generation (including solar) and biofuel plants at the local (usually state) level.

JEDI estimates the number of jobs and economic impacts to a local area that could reasonably be supported by a power generation project, based on project-specific or default inputs (derived from industry norms). The JEDI model's data are based on interviews with industry experts and project developers. Economic multipliers contained within the model are derived from Minnesota IMPLAN Group's IMPLAN Professional model. Project specific total costs were used in this analysis, but they were distributed into specific areas using the JEDI model's defaults. The JEDI model' jobs, earnings, and output impact estimates are distributed across three categories:

- Project Development and Onsite Labor Impacts;
- Local Revenue, Equipment, and Supply Chain Impacts; and
- Induced Impacts.

The construction and operation of solar and other renewable energy projects is highly specialized. The JEDI model was used in this analysis because it is based on actual data on construction and operational expenditures associated with renewable power projects, while the more widely used economic models – such as RIMS II and IMPLAN – would include the construction and operation of renewable power projects in highly diversified sectors that would lack detailed information on actual spending patterns. The JEDI model is only available at the state level, while other models can be targeted geographically on a county or even zip code; however, it does contain more accurate, industry specific data on which to estimate impacts.

Appendix C:

Federal Reserve Bank - Electricity Production Under Carbon Constraints: Implications for the Tenth District

Electricity Production Under Carbon Constraints: Implications for the Tenth District

By Mark C. Snead

Coal is the dominant fuel used to produce electricity in the United States, accounting for almost half of production. Although coal is cheap and abundant domestically, the burning of coal releases greenhouse gases (GHG) and particulates. In response, many states have increased the use of cleaner alternative fuels, primarily natural gas and renewable energy. However, roughly half of the states still rely heavily on coal to generate electricity.

In the Federal Reserve's Tenth District, six of seven states are coal-dependent, generating two-thirds or more of their electricity from coal. Coal-intensive states face regulatory risk from increased restrictions on GHG emissions. Forecasts suggest GHG restrictions would rapidly accelerate the use of cleaner fuels, but would require extensive and expensive changes in the mix of generation capacity in many states.

This article examines the potential impact of national GHG restrictions on Tenth District energy producers and consumers. The findings suggest that GHG restrictions would lead to a structural change in the mix of fuels used to generate electricity in most District states, as well as increase electricity costs to District consumers. District natural gas

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Mark C. Snead is vice president and Denver branch executive at the Federal Reserve Bank of Kansas City. This article is on the bank's website at ***www.KansasCityFed.org.***

producers would benefit from increased gas consumption, but not as much as emerging natural gas producers in other areas of the country. District coal producers, particularly in Wyoming, would face sharply reduced domestic demand for coal.

The first section of the article examines trends in electricity production and fuel use in the United States and Tenth District states. The second section describes recent U.S. Department of Energy (DOE) forecasts for energy use and production, including a scenario with national GHG restrictions. The third section examines potential impacts of GHG restrictions on District electricity producers and consumers. The fourth section identifies possible spillover effects for District coal and natural gas producers.

I. U.S. AND TENTH DISTRICT ELECTRICITY FUEL USE TRENDS

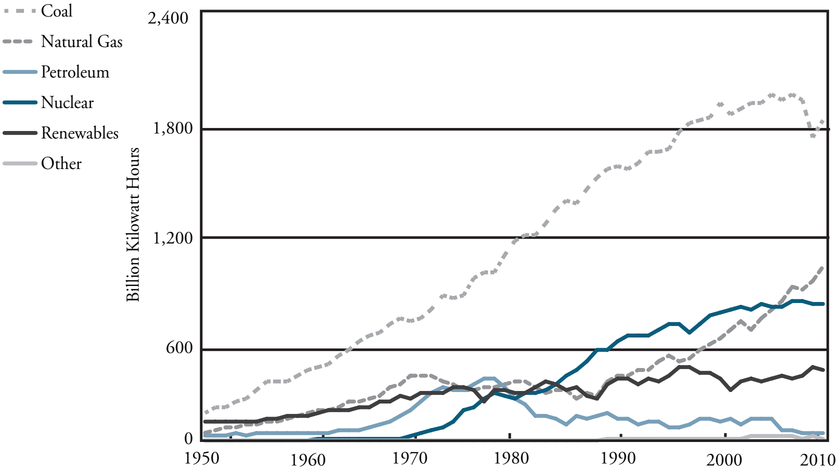
Historically, the United States has relied on coal for about half of its electricity needs, with a mix of petroleum, natural gas, nuclear power, and renewable energy accounting for the rest. Shares of these fuels have shifted over time in response to market and regulatory forces. In recent years, the growth of coal consumption has slowed and use of natural gas and renewable energy has grown. In contrast, the Tenth District continues to rely heavily on coal and much less on other fuels than the nation.[1]

Historical U.S. electricity fuel use patterns

The modern U.S. electricity fuel mix began to take shape in the late 1940s with the use of large-scale generators fired by coal, natural gas, and petroleum (Charts 1 and 2). *Coal* quickly became the dominant fuel. By the 1950s, it had captured a 50-percent share of U.S. electrical generation. Coal steadily gained share until the late 1960s when petroleum use surged and the nuclear power sector emerged. Coal use accelerated again in the 1980s, despite growing concerns about emissions (Hansen and others 1981). Coal's share peaked in 1987 at 58 percent, but has since declined steadily to around 45 percent under rising regulatory pressure. Today, coal remains inexpensive and abundant. The U.S. Energy Information Administration (EIA) estimates a domestic supply of more than 200 years at current mining rates.

Chart 1

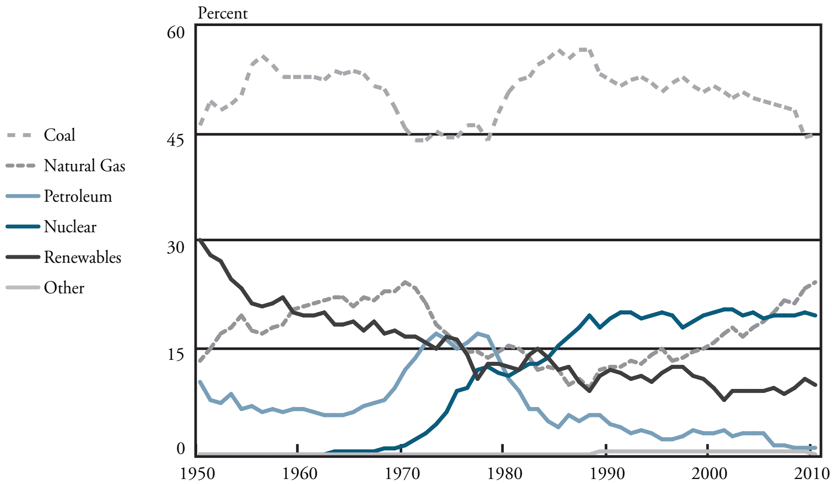
ELECTRICITY PRODUCTION BY FUEL TYPE (1950-2010)



Source: EIA, Annual Energy Outlook 2011

Chart 2

FUEL SHARE IN ELECTRICITY PRODUCTION (1950-2010)



Source: EIA, Annual Energy Outlook 2011

Petroleum-fired generation expanded rapidly in the 1940s, but quickly lost favor to cheaper coal and natural gas. Petroleum surged again in the late 1960s amid strong domestic crude oil production. That trend reversed in the 1970s as global crude prices increased and domestic production declined. By 1985, petroleum was mostly gone from the electricity fuel mix and had been redirected to meet growing demand for transportation fuels.

Natural gas use grew amid increased demand for electricity in the 1950s and 1960s. By 1970, natural gas had a share of 25 percent. But regulatory pressure, declining domestic production, and rising prices contributed to a sharp decline throughout the 1970s and 1980s.[2] By 1987, the share of natural gas bottomed at 10 percent before it rebounded as tighter emissions restrictions were placed on coal.[3] By 2010, growing domestic supplies and lower prices returned natural gas to a share of nearly 25 percent. Recent production gains from shale and tight gas formations have reduced concerns about future natural gas supplies (DOE 2011j). In fact, electricity providers recently surpassed industrial firms as the largest single end-users of natural gas in the United States (EIA 2011b).

Nuclear power emerged in the late 1960s from technology developed during World War II. Nuclear power quickly gained share at the expense of coal and natural gas, reaching a 10-percent share by the mid-1970s. Nuclear power diversified the fuel mix amid uncertainty about energy supplies following the Arab oil embargo in 1973-74. A second wave of nuclear power plant construction pushed the nuclear share to 20 percent by 1990. Nuclear has retained that share even though no reactors have been built in the United States since 1996. Expanded use of nuclear generation faces environmental opposition and concerns about safety following accidents at Three Mile Island (1979), Chernobyl (1986), and Fukushima Daiichi (2011) in Japan. However, the Nuclear Regulatory Commission recently gave final approval to a new reactor design planned for construction in several states (Smith 2011).

Renewable energy sources transitioned from hydroelectric generation as the category's primary source in the last century to today's portfolio of wind, solar, and biofuels. Hydroelectric generation has slowly increased over time, but its share of total generation has declined steadily since the 1940s. Since 2001, hydroelectric generation has maintained its low share of 7 percent. Interest in cleaner, renewable energy sources grew in the 2000s. By 2010, the use of utility-scale wind power boosted the renewables share to nearly 11 percent. Energy from solar thermal and photovoltaic sources is coming online slowly and contributes a negligible share of total power production. Biomass generation is also early in its development, but the use of waste heat from biofuel (ethanol) production is expected to rapidly increase its share.

U.S. fuel use shifted again during the 2007-09 recession as domestic electricity consumption contracted with worsening economic conditions. Coal use fell sharply for the first time in the modern electric power era. Coal's share of less than 45 percent was the lowest since the 1970s. Power producers increasingly switched to natural gas and wind energy during the recession in response to low natural gas prices and federal wind tax incentives. Coal use has rebounded only slightly in the recovery, leaving the 2010 U.S. electricity fuel mix at approximately 45 percent coal, 24 percent natural gas, 20 percent nuclear, 10 percent renewable energy, and 1 percent other fuels.

Tenth District fuel mix

Despite pressures to replace coal with cleaner fuels, few of the recent national trends appear in the Tenth District fuel mix. Most District states are far more reliant on coal and use much less natural gas and renewable energy to generate electricity than the nation.

In 2010, almost 70 percent of electricity generated in the District was derived from coal, versus 45 percent nationally (Table 1). Only Oklahoma has reduced its reliance on coal (43.7 percent share) to near the national share. Conversely, coal is the dominant electricity fuel in Wyoming and Missouri, where their respective shares of 89.4 percent and 81.3 percent are second and eighth in the nation. Wyoming's coal dependency is the result of it being the nation's largest coal producer, coupled with low transportation costs to state power plants. Missouri recently extended its commitment to coal when it opted to add a large coal-fired generating plant to meet growing electricity demand. The remaining District states of Colorado, Kansas, Nebraska, and New Mexico still depend on coal for about two-thirds of their electricity. Kansas and Nebraska have not greatly altered their recent coal use, but Colorado and

Table 1

U.S. AND TENTH DISTRICT ELECTRICITY PRODUCTION BY FUEL TYPE (2010)

Generation by Fuel Type (Gigawatt Hours)

State	Coal	Natural Gas	Nuclear	Renewable	Petroleum	Other	Total
Colorado	34,965	11,498	0	5,089	12	91	51,656
Kansas	32,505	2,788	9,556	3,467	104	0	48,419
Missouri	75,341	4,799	8,996	3,345	128	79	92,689
Nebraska	23,340	434	11,054	882	31	66	35,807
New Mexico	25,618	8,515	0	2,083	45	33	36,294
Oklahoma	31,630	34,034	0	6,510	16	160	72,350
Wyoming	42,532	508	0	4,215	56	284	47,596
Tenth District	265,931	62,575	29,606	25,592	392	715	384,811
U.S.	1,850,750	981,815	806,968	402,548	36,925	41,022	4,120,028

Percent Share of Generation

State	Coal	Natural Gas	Nuclear	Renewable	Petroleum	Other	Total
Colorado	67.7	22.3	0.0	9.9	0.0	0.2	100
Kansas	67.1	5.8	19.7	7.2	0.2	0.0	100
Missouri	81.3	5.2	9.7	3.6	0.1	0.1	100
Nebraska	65.2	1.2	30.9	2.5	0.1	0.2	100
New Mexico	70.6	23.5	0.0	5.7	0.1	0.1	100
Oklahoma	43.7	47.0	0.0	9.0	0.0	0.2	100
Wyoming	89.4	1.1	0.0	8.9	0.1	0.6	100
Tenth District	69.1	16.3	7.7	6.7	0.1	0.2	100
U.S.	44.9	23.8	19.6	9.8	0.9	1.0	100

Source: EIA (EIA-923 Survey)

New Mexico have cut their dependency and plan to shutter older, higher emitting coal plants.

The national shift toward natural gas has been replicated in only three District states—Colorado, New Mexico, and Oklahoma. Each is a major natural gas producer and has made a commitment to greater natural gas usage. Oklahoma produced nearly half of its electricity from natural gas in 2010, surpassing coal as the state's top electricity fuel. Colorado and Nebraska each reached the national natural gas share of about 25 percent in 2010. In contrast, Wyoming, with a share of about 1 percent, is the only major natural gas producing state not to embrace its use.[4]

Like Wyoming, the remaining District states—Kansas, Missouri, and Nebraska—use very little natural gas but are the only District states with nuclear power. The share of nuclear energy in power generation ranges from 10 percent in Missouri to 30 percent in Nebraska. Kansas—with a share of 20 percent—is similar to the national average. The lack of nuclear power in other District states reflects a continued appetite for coal and natural gas, but also limited water availability and environmental opposition to nuclear power, particularly in the Mountain states of Colorado and New Mexico. The three nuclear states in the District nonetheless remain dependent on coal for an average of 70 percent of their total electricity needs.

The District share of renewable energy has long lagged the nation. Historically, this reflects a lack of significant hydroelectric generation potential. Colorado has matched the nation in achieving a 10-percent renewable share, followed by Oklahoma and Wyoming with 9-percent shares. Kansas and New Mexico have shares of 7 percent and 6 percent, respectively, while Missouri and Nebraska have shares of less than 4 percent. Despite its lag in renewable share, the District possesses high potential for wind and solar development.[5] The District also has added significant wind capacity in recent years.[6] Most of the District's wind generation capacity is in Colorado, Kansas, Oklahoma, and Wyoming, each with 1,000 megawatts to 1,500 megawatts (MW) of wind capacity.[7]

II. FORECASTS OF ELECTRICITY PRODUCTION THROUGH 2035

Given trends in the U.S. electricity fuel mix, this section examines recent DOE forecasts for electricity use and production through 2035. The forecast assumes coal use will rise long term and share roughly equally with natural gas and renewable energy in meeting future electricity demand. An alternative scenario (GHG case) evaluates the case of a national price applied to future carbon dioxide (CO_2) emissions.[8] The CO_2 price triggers a realignment of electricity fuel use and generating capacity in the United States and raises electricity prices to end users.

Reference case

DOE's 2011 Annual Energy Outlook (EIA 2011b) provides a comprehensive model-based forecast of U.S. energy use and production through 2035. The reference case assumes current environmental standards and market conditions remain largely in place, and that no additional federal regulations explicitly limiting GHG emissions from power plants are enacted.[9]

In this generally stable environment, the U.S. electricity fuel mix undergoes little change through 2035 (Charts 3 and 4). Total coal usage remains flat through 2015, but then resumes steady growth through 2035, maintaining a share near 45 percent. Total natural gas usage remains near current levels through 2025 in response to rising natural gas prices, but then expands to a 25-percent share by 2035. Nuclear generation rises slightly through 2020, but declines from a 20-percent share to a 15-percent share through 2035 as additional nuclear power plants are retired. Renewable energy gains the greatest long-term share in the reference case, increasing steadily from 11 percent in 2010 to 15 percent by 2035.[10] Overall, the predicted U.S. electricity fuel mix under the reference case shifts slightly from nuclear to renewable energy through 2035, leaving the fuel mix at 44 percent coal, 25 percent natural gas, 15 percent renewable energy, 15 percent nuclear power, and 1 percent other fuels. The stable fuel mix produces little price volatility, as real electricity prices in 2009 dollars are expected to remain near 9 cents per kilowatt hour (kWh) through 2035 (Chart 5).

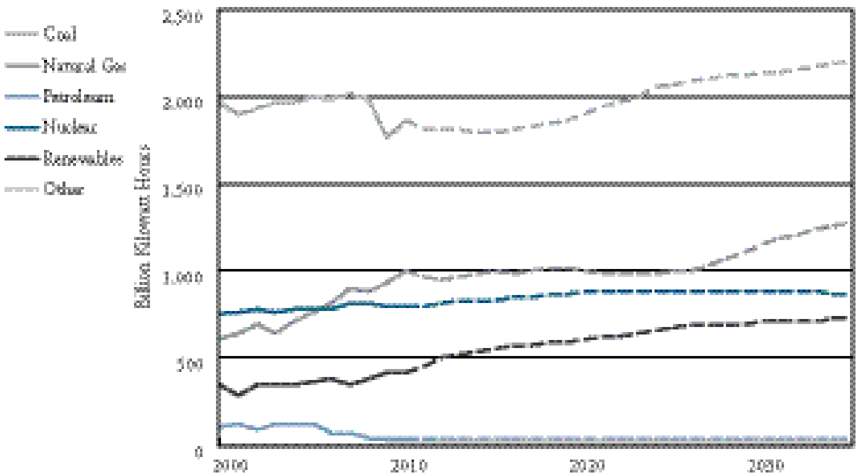
GHG case

DOE projects a dramatically different outcome for electricity producers and consumers under nationwide GHG restrictions. The scenario reflects a significant national effort to reduce GHG emissions that results in a restructuring of the U.S. electric power generation mix.[11] In the GHG case, a price of $25 per ton in 2009 dollars is applied to CO_2 emissions beginning in 2013, and increased to $77 per ton in 2035.[12] Total CO_2 emissions originating in the electric power sector decline to 45 percent of 2010 levels by 2035. The enactment of the CO_2 price is assumed to only slightly reduce the average annual growth rate in U.S. real gross domestic product (GDP) through 2035 (EIA 2011b).

In the GHG scenario, total electricity generation grows 15 percent from 2010 to 2035—a slowdown from 25 percent in the reference case. The lower production estimate reflects the response of consumers to higher electricity costs. Real electricity prices climb steadily beginning

Chart 3

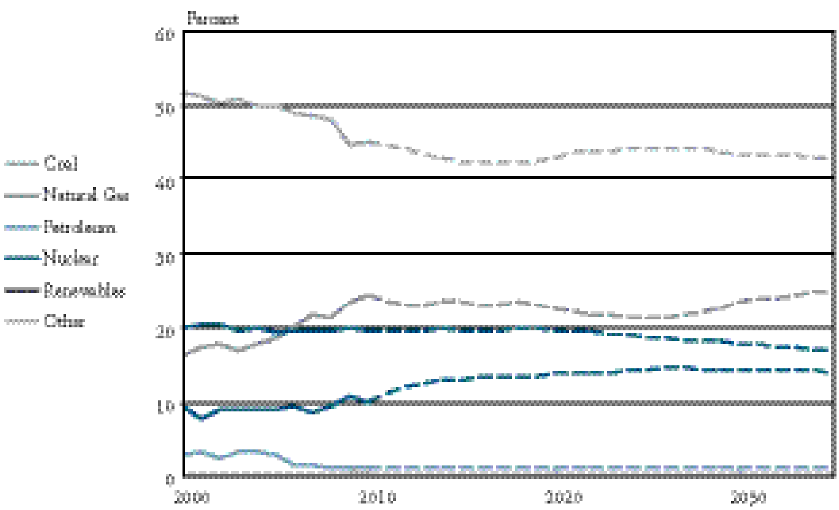
FORECAST OF ELECTRICITY PRODUCTION BY FUEL TYPE (2010-35)



Source: EIA, Annual Energy Outlook 2011

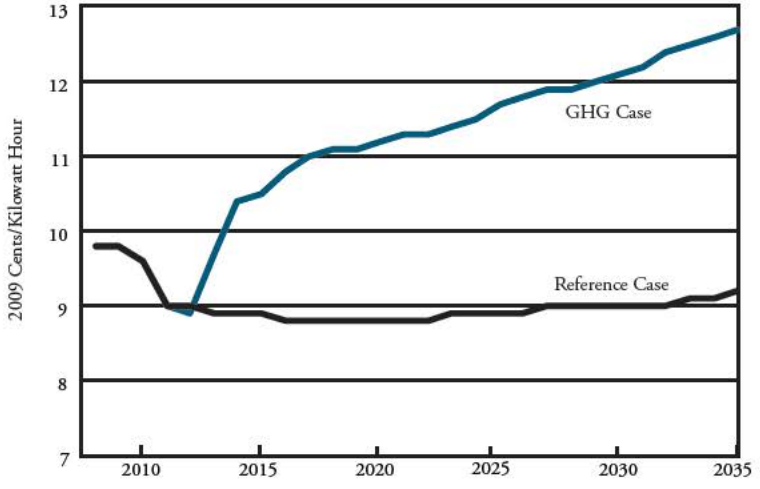
Chart 4

FORECAST OF FUEL SHARE IN ELECTRICITY PRODUCTION (2010-35)



Source: EIA, Annual Energy Outlook 2011

Chart 5
FORECASTS OF REAL ELECTRICITY PRICES
Average of All Uses



2011 Reference and economy-wide greenhouse gas (GHG) cases.
Source: EIA, Annual Energy Outlook 2011

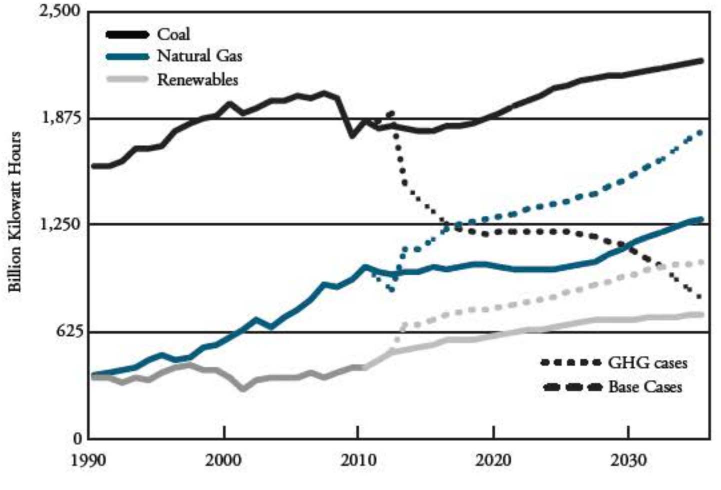
in 2013 from 9.8 cents per kWh in 2009 to 12.8 cents per kWh by 2035, an increase of roughly 30 percent (Chart 5). The price increase results from a shift by electricity providers toward more expensive fuels, the pass through of costs to alter the existing generation mix, and the price applied to CO_2 emissions.

Most of the emissions reductions are achieved through a shift from coal to natural gas and renewable energy (Charts 6 and 7). The shift from coal is rapid and substantial. Total coal use falls one-third below 2010 levels by 2018, and ultimately falls more than 60 percent below 2010 levels by 2035 (Chart 6). To offset the decline in coal, natural gas use increases by about one-third by 2017 and replaces coal as the dominant electricity fuel as early as 2015. By 2035, total natural gas and renewable energy use increase by 80 percent and 150 percent, respectively. Natural gas reaches a 38-percent share of electricity generation and renewables reach a 22-percent share, both well above coal's eventual 17-percent share in 2035. Nuclear energy's share is assumed to increase slightly through 2035, mostly due to nuclear generation capacity added after 2030. Overall, U.S. electricity generation is substantially less carbon-intensive in the GHG case, having shifted to 38 percent natural

Chart 6

FORECASTS OF ELECTRICITY PRODUCTION BY FUEL TYPE (2010-35)

Base and GHG Cases

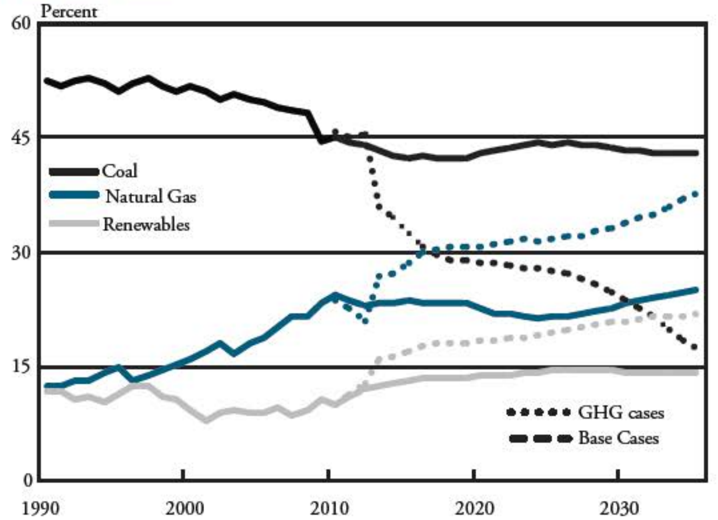


Source: EIA, Annual Energy Outlook 2011

Chart 7

FORECASTS OF FUEL SHARE BY FUEL TYPE (2010-35)

Base and GHG Cases



Source: EIA, Annual Energy Outlook 2011

gas, 22 percent renewable energy, 22 percent nuclear power, 17 percent coal, and 1 percent other fuels by 2035.

Projected changes in generation capacity in the GHG case

To accommodate DOE's projected shift in fuel mix in the GHG case, U.S. power producers must substantially restructure the existing mix of generation capacity. Total generating capacity is roughly unchanged through 2035. However, a sharp reduction in coal-fired capacity is offset by increased use of renewable energy and modern natural gas combined-cycle (NGCC) plants capable of base load generation.[13]

DOE projects that U.S. coal capacity will decline 40 percent from 2009 levels by 2016, mostly through a surge in retirements of existing coal plants. These retirements would eliminate 12 percent of total capacity and reduce coal's share from 30 percent to 18 percent by 2035. An equivalent 40-percent reduction in District coal capacity would require the retirement of 18 percent of total District capacity. For the District to achieve the projected U.S. coal share of 18 percent, more than 60 percent of existing District generating capacity would have to be retired.

Most coal-intensive states would face a similar prospect of retiring half or more of their existing coal-fired capacity to match the projected U.S. coal share. Nonetheless, the realized impact of coal plant retirements would likely be eased by the age of the existing coal-fired fleet. Nearly two-thirds of national and District coal generating capacity is at least 30 years old and approaching the end of its useful economic life (EIA 2011d).

Reductions in coal capacity in the GHG case are largely offset by a 16-percent (65,000 MW) increase in capacity at modern NGCC plants. This added capacity is about 40 percent of the NGCC capacity added in the past decade. Recent DOE estimates suggest that a typical advanced NGCC generator with a rated capacity of 400 MW has an estimated "overnight capital cost" of roughly $1 million per MW (EIA 2010).[14] Based on these specifications, the GHG case suggests a need for 160 new advanced NGCC systems nationally at an estimated cost of $400 million each. The added plants would raise the national share of NGCC generation to the projected 21-percent level.[15] Utilization rates at existing NGCC plants would also rise with their share of base load generation.

At the District level, the current share of natural gas capacity (37.5 percent) is only slightly below the national share (39.2 percent). However, only a little more than half of the natural gas capacity added in the District since 1990 is at NGCC plants. To match the projected 21 percent U.S. share, District power producers would need an additional 8,000 MW of NGCC capacity (a 72-percent increase). This is equivalent to about 20 additional NGCC plants in the District.

Renewable energy capacity is projected to increase 67 percent (from 122,400 MW to 203,300 MW) by 2035, ultimately accounting for 20 percent of capacity.[16] Nearly all of the projected renewable capacity is wind generation and would approximately triple existing wind capacity in the United States.

Although the Tenth District currently has nearly double the U.S share of wind capacity (6.1 percent versus 3.3 percent), achieving the 20 percent national renewable share would require slightly more than a tripling of current District wind capacity. The District would have to add about 12,500 MW, or 8,300 wind turbines, based on the historical District average capacity of 1.5 MW per turbine.[17] DOE estimates that a standard onshore wind generator with a rated capacity of 1 MW has an estimated overnight capital cost of roughly $2.4 million (EIA 2010).

III. IMPACTS ON DISTRICT POWER PRODUCERS AND CONSUMERS

Predicted shifts in the U.S. electricity mix under the GHG scenario raise concerns for District electricity producers and consumers. Sharp reductions in coal use would require substantial restructuring of the electricity generation mix in most District states. DOE projections also suggest that average electricity prices nationally would increase to levels near current prices in states that use the least coal. High coal dependency among District states suggests the possibility of rapid and substantial increases in electricity prices.

Impact of fuel mix changes on Tenth District capacity

The projected shift from coal to natural gas and renewable energy will require substantial changes in the District's generation mix. Table

Table 2

TENTH DISTRICT GENERATING CAPACITY BY FUEL TYPE (2009)

Megawatts, Summer Nameplate Capacity

	Percent Share of Generating Capacity by Fuel Type					
State	Coal	Natural Gas	Nuclear	Renewable	Petroleum	Other
Colorado	38.4	41.0	0.0	19.0	1.4	0.1
Kansas	41.3	36.8	9.3	8.1	4.5	0.0
Missouri	53.9	26.9	5.7	7.3	6.1	0.0
Nebraska	49.8	24.1	16.1	4.9	5.0	0.1
New Mexico	49.8	41.3	0.0	8.5	0.4	0.1
Oklahoma	25.6	63.0	0.0	10.8	0.3	0.4
Wyoming	78.4	1.6	0.0	18.6	0.1	1.4
Tenth District	44.7	37.5	4.0	10.8	2.8	0.2
U.S.	30.5	39.2	9.9	13.2	5.3	1.9
U.S. GHG Case (2035)	18.0	45.3	12.7	19.5	2.4	2.1

Source: EIA (EIA-860 Survey and 2011 Annual Energy Outlook)

2 compares the current share of generation capacity by fuel type for each District state to projected U.S. fuel shares in 2035. The data show District states would face challenges in altering their existing capacity to match predicted changes in the national generation mix. Concerns include a high share of coal capacity, a lack of existing NGCC capacity, and limited renewable energy potential.

Among District states, only Oklahoma (25.6 percent) is near the projected 18 percent national coal share of capacity for 2035. Meeting the U.S. share would require the retirement of relatively few Oklahoma coal plants. The remaining District states, however, have significant excess coal capacity relative to the U.S. Coal's share in Missouri, Nebraska, and New Mexico is about 50 percent. In Colorado and Kansas, the share is near 40 percent. The coal share in those states is more than double the projected national share in the GHG case. Wyoming's coal share of nearly 80 percent is more than four times the projected national share. Retiring a large number of coal plants would be needed to meet the projected national share in Missouri, Nebraska, New Mexico, Colorado, Kansas, and Wyoming.

Heavy investment in modern natural gas-fired plants would also be required in most District states. Of the District's 11,000 MW of NGCC capacity added since 1990, half is in Oklahoma.[18] These additions place Oklahoma above the projected U.S. share of 21 percent for NGCC generation. Matching the projected national share would require more than doubling NGCC capacity in Missouri and a fourfold increase in Nebraska. Both Kansas and Wyoming would face significant costs to install the required NGCC capacity. Wyoming has little installed natural gas capacity of any type.

The ability of District states to meet the projected 20 percent renewable share of capacity in the GHG case also is mixed. Colorado and Wyoming already have high renewable shares near 20 percent. However, the remaining District states would have to increase their renewable capacity twofold to fourfold to achieve the projected U.S. share of 20 percent in 2035. Wind generation potential in the District is adequate to match the projected U.S. renewable share, but the potential is not equal across the states. Almost 80 percent of the District's installed wind capacity is in Colorado, Kansas, Oklahoma, and Wyoming.[19] These states each have between 1,000 MW and 1,500 MW of installed wind capacity, or 650 to 1,000 wind turbines.

District state shifts

Predicting each District state's adjustment to GHG restrictions is complicated by the lack of an existing national framework to govern energy production and delivery. Such a framework could be used to allocate the projected national capacity changes and carbon reductions among the states.[20] The existing state and regional regulatory framework sheds little light on how DOE's GHG case would be implemented. Nevertheless, an overview of the current fuel mix and existing generation portfolio suggests the potential ability of each District state to adapt to GHG constraints.

Colorado is highly coal intensive relative to national standards but already has redirected some electricity production to natural gas and renewable energy. Its coal share is now only slightly above the national share, but producers still generate two-thirds of the state's electricity with coal. Modern NGCC plants comprise 14 percent of generating capacity, and renewable energy mandates have helped Colorado far exceed the national share of renewable capacity. There is large untapped potential for wind and solar in Colorado, particularly wind potential along the Front Range and in the eastern plains. Although coal remains important in power generation, Colorado is relatively well positioned to adapt to future GHG constraints.

Kansas must balance excess coal capacity and limited NGCC capacity with strong wind potential and existing nuclear power. Coal is more than 40 percent of generating capacity and fuels two-thirds of the electricity generated statewide. Kansas has significant existing natural gas capacity but none is modern NGCC generation. Although the renewable share of generating capacity in Kansas is well below the national share, western Kansas has widespread areas well suited for future utility-scale wind generation. The 10 percent nuclear share gives Kansas another option for low-carbon electricity going forward. Continued high coal use and lack of NGCC capacity will challenge Kansas.

More than half of **Missouri's** generating capacity is coal-fired, which could leave the state saddled with significant excess coal-fired capacity under national GHG constraints. Missouri also generates more than 80 percent of its electricity from coal and has recently expanded its coal capacity. The state also has only half the national share of NGCC generating capacity. Missouri uses very little renewable energy and has relatively little future wind and solar potential. The lack of renewable potential is partly offset by nuclear power, which gives the state an additional low-carbon option in the future. Overall, Missouri is among the group of states that would likely face the most substantial challenges under GHG restrictions.

Nebraska's advantage under GHG constraints is that it generates 30 percent of its electricity from carbon-free nuclear power. However, 65 percent of the state's electricity is still derived from coal. Similar to Missouri and New Mexico, roughly half of Nebraska's generating capacity remains coal-fired, and the state could be left with significant excess coal-fired capacity under GHG constraints. Generation from modern NGCC plants and renewable energy each accounts for only 5 percent of generation. Nebraska uses relatively little renewable energy despite widespread areas with moderate wind generation potential. Nuclear power would aid Nebraska's adjustment to emission constraints, but high coal usage suggests that the state would face considerable challenges.

New Mexico remains coal-intensive, with 70 percent of its electricity production coal-fired. However, like Colorado, the state has already opted to close some of its highest emitting coal plants. The state has also made a considerable commitment to natural gas generation, with current NGCC capacity at 17.5 percent of total capacity. The overall renewable share in New Mexico is currently below the national share, but there is substantial untapped solar and wind generation potential across the state. New Mexico's existing NGCC capacity and renewable potential leave the state relatively well positioned to reduce its coal usage under GHG constraints.

Overall, **Oklahoma** is best positioned among the District states to adapt to projected capacity changes under GHG constraints. Coal represents only 25 percent of total generating capacity in the state, well below the national share. Oklahoma already has a large installed base of NGCC plants and ready access to local sources of natural gas. Nearly half of the state's electricity is currently generated from natural gas. The state's renewable share of capacity is near the national share, and the western portions of Oklahoma will support substantially more utility-scale wind generation. Oklahoma's transition would likely mirror the overall national shift as projected in DOE's GHG case.

Wyoming remains the most coal-dependent state in the District and one of the most coal-dependent states nationally. The state's electricity base lacks diversification, with wind the only other major source of generating capacity in the state. The large base of wind generation gives Wyoming a renewable energy share well above the nation, and the state is home to some of the nation's best onshore wind generation potential. However, Wyoming has negligible installed natural gas capacity of any type despite being a major natural gas producer. Wyoming's near exclusive dependence on coal suggests that its electricity producers would face substantial hurdles in adapting the state's generation base to national GHG constraints.

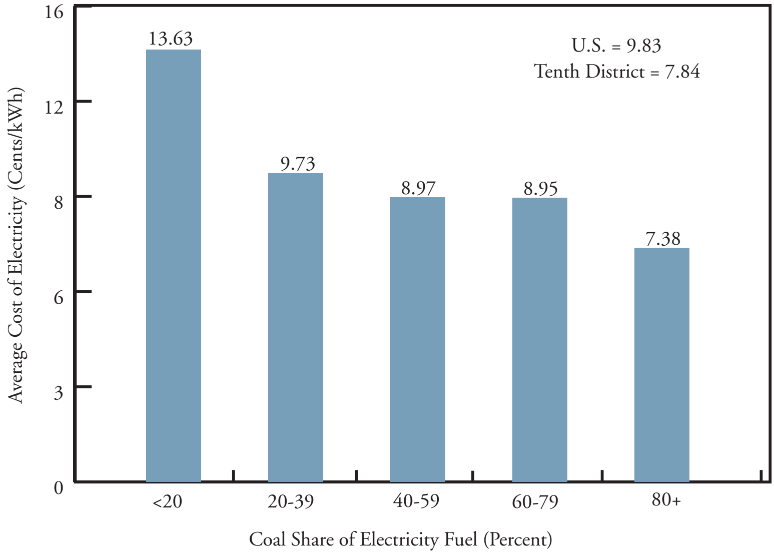
Cost of electricity

The shift from coal in the GHG case is expected to significantly increase average electricity prices. Historically, electricity prices have depended on coal's share in the generation fuel mix, with the most coal-intensive states generally having the lowest electricity costs. Chart 8 shows the general inverse relationship between coal share and electricity price across states.

The eight states with a coal share of 80 percent or more had an average cost of only 7.38 cents per kWh, 25 percent below the 9.83 cents per

Chart 8

COST OF ELECTRICITY BY SHARE OF COAL GENERATION (2010)



Note: Tenth District states highlighted in black.
Source: EIA

kWh price nationally. This group of highly coal-intensive states includes the District states of Missouri and Wyoming. Wyoming generated 89 percent of its electricity from coal in 2010 and had the lowest electricity cost among the group at 6.20 cents per kWh—almost 40 percent below the U.S. average. Across all Tenth District states, the price of electricity averaged only 7.84 cents per kWh in 2010, 20 percent less than the U.S. average. Electricity prices increase to approximately 9 cents per kWh for the two groups of states using 40 percent to 59 percent and 60 percent to 79 percent coal, and rise rapidly again as the share of coal falls below 40 percent. The average cost in those states using 20 percent to 39 percent coal in 2010 was 9.73 cents per kWh—32 percent higher than the most coal-intensive group (80 percent or more).

The comparatively high price paid for electricity in the 13 states using less than 20 percent coal provides insight into expected prices under GHG restrictions for the most coal-intensive states. Electricity averaged 13.63 cents per kWh in these states in 2010, almost 40 percent higher than in states using 20 percent to 39 percent and nearly double the average cost paid in the most coal-intensive group.[21] These low-coal states currently pay the highest electricity costs but already closely approximate the projected generation mix under the GHG case. They are significantly less carbon-intensive overall and release at least one-third less CO_2 per capita than the nation as a whole (Snead and Jones 2010). Excluding Alaska and Hawaii, the remaining 11 states in the low-coal group rank among the 14 lowest emitting states based on CO_2 emissions per capita. New York, the least carbon-intensive state with only about half the CO_2 emissions per capita of the nation, had average electricity costs of 16.41 cents per kWh in 2010.

The cost of electricity in the low-coal (less than 20 percent share) states also provides a reasonableness test for DOE's projected 30 percent increase in real electricity costs from 2009 to 2035. DOE's inflation-adjusted price of 12.8 cents per kWh in 2035 is only slightly below the current average price of 13.63 cents per kWh in the low-coal states. The current price in these states, given their low share of coal generation, provides another indication that coal-dependent states can expect considerable price increases under GHG restrictions.

IV. IMPACT ON DISTRICT COAL AND NATURAL GAS PRODUCERS

The Tenth District is home to the largest coal producing state (Wyoming) and four of the six major natural gas producing states (Colorado, New Mexico, Oklahoma, and Wyoming). Predicted shifts in the U.S. electricity fuel mix under the GHG case present clear challenges for District coal producers but possible opportunities for District natural gas producers. The projected sharp decline in coal consumption by the power sector would hurt District coal producers, while increased domestic natural gas production and higher prices would benefit District natural gas producers.

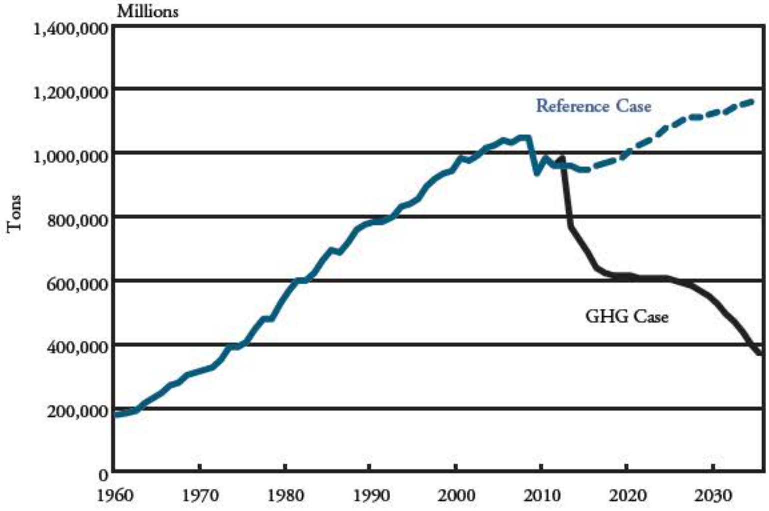
District coal producers

The magnitude of the predicted reduction in coal use in the GHG case presents a considerable challenge for District coal producers. Annual coal consumption declines by more than 60 percent—from 935 million tons in 2010 to 370 million tons in 2035 (Chart 9). Two-thirds of the decline occurs very rapidly, by 2018. The total projected decline

Chart 9

COAL CONSUMED BY THE ELECTRIC POWER SECTOR

Reference and GHG Cases



Source: EIA: 2011 Annual Energy Outlook, State Energy Data System

through 2035 reduces coal consumption in the power sector to roughly 1975 levels.

As the nation's largest coal supplier, Wyoming producers would clearly be at greatest risk under national GHG restrictions. Wyoming produced 45 percent (424 million tons) of all coal used in the U.S. power sector in 2010, including 85 percent of the coal used for electricity generation in the Tenth District (Table 3).[22] Wyoming coal is a major export product for the District, with two-thirds of the production shipped to states outside the District. At a 2010 price of $13 per ton, the annual value of Wyoming coal production reached $5.5 billion, or nearly 15 percent of state GDP. If the projected reduction in national coal use is borne heavily by Wyoming, alternative markets for coal would have to be sought to avoid a sharp blow to the state's economy.[23]

Reduced coal consumption could potentially impact District coal-producing states other than Wyoming. Six of seven District states (not Nebraska) produced coal for electricity generation in 2010 (Table 3). Production in these states totaled 41.7 million tons in 2010, about 10 percent of Wyoming's output. New Mexico produced nearly all of its own coal for electricity generation and exported substantial quantities

Table 3

COAL SUPPLY AND PURCHASES FOR ELECTRICITY PRODUCTION BY REGION (IN TONS)

Purchasing Region	Supplying Region: Colorado	Kansas	Missouri	New Mexico	Oklahoma	Wyoming	District	Non-District	Total
Colorado	8,882,867					8,544,409	17,427,276	0	17,427,276
Kansas			293,144			20,210,342	20,503,486	0	20,503,486
Missouri		74,319	52,933			42,957,263	43,084,515	1,148,787	44,233,302
Nebraska						13,788,290	13,788,290	0	13,788,290
New Mexico				14,411,710		28,968	14,440,678	0	14,440,678
Oklahoma		51			405,175	19,119,152	19,524,378	90,746	19,615,124
Wyoming						24,628,091	24,628,091	0	24,628,091
District	8,882,867	74,370	346,077	14,411,710	405,175	129,276,515	153,396,714	1,239,533	154,636,247
Non-District	10,368,752	0	0	7,164,504	0	294,350,575	311,883,831	469,737,758	781,621,589
Total	19,251,619	74,370	346,077	21,576,214	405,175	423,627,090	465,280,545	470,977,291	936,257,836

Source: EIA (EIA-923 Survey)

outside the District. Kansas and Missouri engaged in a small amount of cross-border coal trade, but both imported the bulk of their coal from Wyoming. Colorado produced about half of the coal it used in electricity generation and imported the other half from Wyoming. But Colorado exported more coal outside the District than it retained for use in-state.

Relative to Wyoming, the other coal-producing states in the District face little economic risk from GHG restrictions. New Mexico and Colorado both produced only about 20 million tons of coal in 2010, with the output in both states valued at approximately $700 million annually at recent prices. This production represents about 1.0 percent of total GDP in New Mexico and 0.3 percent in Colorado. The elimination of coal production in either state would likely have only localized impacts with little effect on overall state economic performance. In Kansas, Missouri, and Oklahoma, coal production is a very minor industry, and reduced coal usage would have few spillovers.

District natural gas producers

The District is also a major natural gas-producing region and would potentially benefit from increased natural gas usage by electricity producers. In the GHG case, added demand for natural gas by power producers is met by a projected 40 percent increase in output from 21.5 quadrillion Btu in 2009 to 30.23 quadrillion Btu in 2035 (Table 4). This estimate is 12 percent higher than projected output of 27.0 quadrillion Btu in 2035 under the reference case.

The projected rise in natural gas output is near the high end of the range of DOE production forecasts through 2035. The greatest production gains are expected in shale and tight gas formations. Production from these formations has increased by nearly 50 percent annually between 2006 and 2010 (EIA 2011j). The production gains also assume the continued use of horizontal drilling and hydraulic fracturing techniques.

The gains in production will be accompanied by rising natural gas prices (Table 4). The path of natural gas prices in 2009 dollars tracks only slightly above that in the reference case, rising steadily from $3.71 per thousand cubic feet (Mcf) in 2009 to $6.44 per Mcf in 2035. Despite recent production gains and large upward revisions in domestic natural gas reserves (Potential Gas Committee 2011), some researchers remain

Table 4
NATURAL GAS PRODUCTION AND PRICE FORECAST SCENARIOS

		2009	2015	2020	2025	2030	2035
Natural Gas Production (Quadrillion Btu)	Reference	21.50	23.01	24.04	24.60	25.75	27.00
	GHG	21.50	23.34	25.58	26.68	27.78	30.23
Wellhead Price of Natural Gas (2009 Dollars per Mcf)	Reference	3.71	4.24	4.59	5.43	5.81	6.42
	GHG	3.71	4.52	5.32	6.08	6.30	6.44

Source: EIA, 2011 Annual Energy Outlook

skeptical of the potential to maintain recent production gains without even higher natural gas prices (NETL 2008; and Berman 2009).

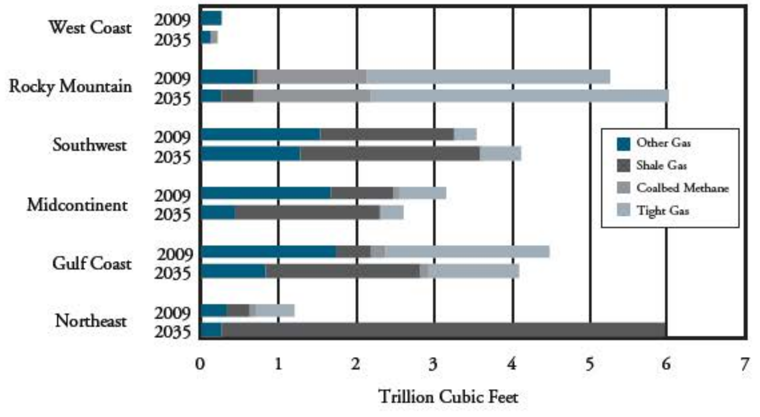
Assuming the natural gas production gains in the GHG case are realized, which producing regions of the country will benefit the most from added natural gas demand? Chart 10 summarizes DOE forecasts of domestic onshore natural gas production through 2035 by producing region and formation type. The Tenth District states are primarily located in the Rocky Mountain (Wyoming, Colorado, and western New Mexico) and Midcontinent (Kansas, Missouri, Nebraska, and Oklahoma) regions.[24]

The estimates suggest that most natural gas-producing regions of the country will benefit from added demand and higher prices, but the gains will not be evenly distributed. Most of the projected gains are in shale formations, which comprise a comparatively small share of production in the Rocky Mountain region and a rapidly growing but small share of Midcontinent production. District states are projected to participate in a 0.8 trillion cubic feet (Tcf) gain in annual output in the Rocky Mountain region through 2035, primarily from increased tight gas production. However, this gain is largely offset by an expected 0.5 Tcf decline in annual production in the Midcontinent region.

On balance, District producers should benefit from increased demand and higher prices for natural gas, but the region will not be the primary beneficiary. Most of the production gains are instead projected for the Northeast, primarily due to a near 500-percent increase in shale gas output projected for the Marcellus formation through 2035.

Chart 10

LOWER 48 ONSHORE NATURAL GAS PRODUCTION BY REGION, 2009 AND 2035



Source: EIA: 2011 Annual Energy Outlook

V. CONCLUSION

Recent forecasts of energy use and production under GHG restrictions highlight concerns for Tenth District electricity producers and consumers. National emission restrictions would accelerate the shift under way from coal to natural gas and renewable energy sources. Most District states have a coal-intensive electricity fuel mix and are not well prepared for national emissions restrictions. District coal and natural gas producers could also be impacted by any resulting shifts in the electricity fuel mix.

The article finds that District electricity producers would be required to make substantial shifts in fuel mix and generation capacity in order to match projected U.S. electricity generation trends under GHG restrictions. Oklahoma would have the easiest transition, followed by Colorado and New Mexico. These states have already made a major commitment to cleaner, modern natural gas-fired plants and have strong renewable energy potential. The remaining District states, especially coal-dependent Wyoming, would face substantial challenges in matching the projected U.S. shift in capacity.

The projected shift away from coal would translate into higher average electricity prices in most District states. Current electricity costs in the least coal-intensive states provide a useful benchmark for possible price increases in the most coal-intensive states. Based on this benchmark, the most coal-intensive states would be subject to the largest price increases.

District coal producers could face a sharp decline in coal demand under GHG restrictions. Wyoming, in particular, would face a large potential hit to economic activity. The added demand for natural gas by power producers under GHG restrictions is expected to produce strong gains in domestic natural gas production. However, District gas producers are expected to benefit less than other emerging gas-producing regions, particularly those in the Northeast.

ENDNOTES

[1]The Tenth District of the Federal Reserve comprises the states of Colorado, Kansas, Nebraska, Oklahoma, and Wyoming, as well as northern New Mexico and western Missouri.

[2]The Powerplant and Industrial Fuel Use Act of 1978 discouraged the use of natural gas and petroleum for electricity generation.

[3]Natural gas releases an average of 45 percent less CO_2 than coal under stationary combustion (EIA 2011n). However, the full life-cycle emissions of producing, transporting, and burning natural gas may be greater than implied by DOE combustion-based emissions estimates (Jaramillo and others 2007; Howarth and others 2011).

[4]The natural gas-producing states of Texas and Louisiana have shares of about 40 percent.

[5]Wind capacity maps are at DOE (2011). Wind and solar potential maps are at NREL (2011).

[6]Most District states have policies that mandate or encourage minimum levels of renewable fuels in future electricity production. Colorado, Kansas, Missouri, and New Mexico have enforceable mandates, and Oklahoma has a nonenforceable statewide renewable energy goal. Wyoming and Nebraska have no mandates or goals.

[7]Wind generation remains a minor share of total electricity production capacity in these states. District wind capacity reached 6,720 MW in June 2011, or 16 percent of total U.S. wind capacity. Wind capacity of 1,000 MW is roughly equal to the generation capacity of one large modern coal-fired electric plant, though wind generators generally operate at much lower utilization rates.

[8]The reference case assumes some market reaction to potential future GHG regulation. A 300 basis point increase in the cost of capital is assumed for investments in new coal-fired power plants if they do not employ carbon capture and sequestration technology. The same cost of capital assumption was justified in the GHG case evaluated in DOE's 2009 Annual Energy Outlook (EIA 2009a): "Although the 3-percentage-point adjustment is somewhat arbitrary, its impact in levelized cost terms is similar to that of a $15 fee per metric ton of CO_2 for investments in new coal-fired power plants without Carbon Capture and Storage (CCS)—well within the range of the results of simulations that utilities and regulators have prepared."

[9]There are two separate environmental concerns surrounding electric power emissions—noncarbon particulates such as mercury, nitrogen oxides (NOx), and sulfur dioxide (SO_2) emissions; and GHG emissions, primarily CO_2. Federal and state regulations have long addressed the impacts of particulates such as NOx and SO_2, and a number of federal efforts are under way to reduce these harmful noncarbon emissions. These programs include the Clean Air Mercury Rule

(CAMR) and the Clean Air Interstate Rule (CAIR). CAMR mandates reductions in mercury in electricity production. CAIR is a cap-and-trade program in the electric power sector that would reduce NOx and SO_2 emissions.

[10]Wind installations in the United States are expected to slow dramatically as federal tax credits expire at the end of 2012. Despite wind's rapid growth the last decade, it accounted for only slightly more than 3 percent of total electricity produced in the first half of 2011.

[11]The carbon price imposed in the GHG case is intended to achieve CO_2 reductions similar to those in the proposed American Clean Energy and Security Act of 2009. The act seeks to reduce GHG emissions to 17 percent below 2005 levels by 2020 and to 83 percent below 2005 levels by 2050. The legislation was passed by the House of Representatives but failed to move beyond debate in the Senate.

[12]The scenario does not include provisions for carbon offsets, bonus allowances, targeted allowance allocations, or increased efficiency mandates.

[13]Natural synergies exist between natural gas and renewable generation, particularly wind and solar power. These renewable sources generally require significant amounts of coal- or natural gas-fired generation on ready reserve, and faster ramp-up times for natural gas generators relative to coal make them more compatible with the intermittent nature of the sun and wind.

[14]From EIA (2011b): " 'Overnight cost' is an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through completion could be accomplished in a single day. The cost estimates for each technology were developed for a generic facility of a specific size and configuration, and assuming a location without unusual constraints or infrastructure needs. This concept is useful to avoid any impact of financing issues and assumptions on estimated costs."

[15]EIA (2011e) provides estimates of historical capacity factors by fuel source. Wind turbines operate at roughly 35 percent utilization rates and solar at 18 percent to 25 percent. Geothermal and biomass tend to produce 80 percent to 90 percent utilization rates, while hydroelectric plants operate at approximately 50 percent utilization rates. NGCC and coal-fired plants used for base load generation maintain approximately 85 percent utilization rates.

[16]Significant new biomass generation is assumed in the GHG case, primarily from the use of waste heat from biofuel (ethanol) production. However, this is not considered additional renewable capacity. Solar thermal and photovoltaic (PV) energy contributes a minor share of renewable power production.

[17]At the end of 2009, the District had nearly 3,700 wind turbines with a rated summer capacity of almost 5,500 MW.

[18]Colorado and Missouri have each added NGCC capacity of 1,850 MW since 1990; New Mexico has added 1,400 MW; and Nebraska 400 MW.

[19]Installed wind capacity was 42,432 MW in the United States and 6,720 MW in the Tenth District as of June 30, 2011 (DOE 2011). MW capacity by

District state: Colorado 1,299; Kansas 1,074; Missouri 459; Nebraska 294; New Mexico 700; Oklahoma 1,482; and Wyoming 1,412.

[20]The Tenth District stretches across four of the eight operating regions served by the North American Electric Reliability Corp. (NERC), the entity that assures reliability of the national electric system (NERC 2011). Hence, any change in the capacity mix in an individual District state must also take into consideration the overall load characteristics of the broader NERC region.

[21]Most of these low-coal states use significant amounts of relatively more expensive natural gas and nuclear generation, but also low-cost hydroelectric power. After removing the low-cost hydroelectric states—Idaho, Oregon, and Washington—from the group of states using less than 20 percent coal, the price of electricity for this group increases to 15.64 cents per kWh.

[22]Wyoming's coal output is three times higher than West Virginia, the second-ranked coal producer. However, the low energy content, or "heat rate," of Wyoming coal may lead to an overstatement of production as measured by power generation. Because Wyoming subbituminous coal has only about 70 percent of the energy per pound of Eastern coal, power producers must burn nearly 50 percent more Wyoming coal to produce the same power output as Eastern coal.

[23]Wyoming coal, especially from the Powder River Basin, could remain highly competitive relative to Eastern coal due to its low sulfur content. Sulfur dioxide emissions from coal-fired power plants are heavily regulated, and Wyoming coal contains only 0.35 percent sulfur by weight, versus 1.6 percent sulfur for Eastern coal. The favorable sulfur content per Btu and a lower price for Wyoming coal compensate for the fact that it has lower energy content.

[24]Eastern New Mexico is in the Southwest region.

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Comments to “Community Reinvestment Act: Interagency Questions and Answers Regarding Community Reinvestment”

Agency Name: OCC

Docket ID OCC-2014-0021

Date Submitted: November 7, 2014

Appendix D:

Whitepaper: Towards the Full Cost of Coal

Towards the Full Cost of Coal: A review of the recent literature assessing the negative health care externalities associated with coal-fired electricity production

Caroline Burkhard Golin
PhD Candidate, School of Public Policy
Georgia Institute of Technology
DM Smith Building
685 Cherry Street
Atlanta, GA 30332-0345
Cburkhard3@gatech.edu

Executive Summary

A critical issue in the development of cleaner and renewable energy sources is an adequate assessment and reliable estimates of the negative impacts generated from traditional energy sources (Ahmad, 1989; N. Z. Muller, and Robert Mendelsohn, 2007; Pope, 2002) In 2011, significant scientific and economic research focused on the external costs of coal-fired power generation; particularly the health care costs associated with exposure to hazardous airborne particulates, ozone (O3), and carbon dioxide (CO2) emissions. The following year, the Obama administration established the first national standards on carbon emissions from power plants. As a result, states heavily reliant on coal-power for electricity will undoubtedly need to evaluate the cost of relying on traditional energy sources versus investing in cleaner or renewable sources. This report systematically reviews the latest research on the full cost of coal, focusing specifically on the negative, external healthcare costs associated with coal-fired power generation, and applies these results to Georgia. In the first section, the he report reviews the findings of four major studies conducted in 2011 by the Environmental Protection Agency (U. S. EPA, 2011), the National Institute of Environmental Health Sciences (Gohlke et al., 2011), the Center for Health and Global and Environment (Epstein et al., 2011), and economists Nicholas Z. Muller, Robert Mendelsohn, and William Nordhaus (N. Z. Muller, Mendelsohn, & Nordhaus, 2011).These reports were chosen as they are all widely cited within the field of environmental science and economics, are the most recent reports to focus specifically on the external costs generated by coal-fired power generation, and present clear methodologies that can be applied in a state-specific scenario. In the second section, I use the methodologies of the EPA and the Center for Health and Global Environment to calculate the health care costs associated with coal-fired power production in Georgia. The Center for Health an Global Environment methodology was chosen because it monetized external healthcare cost in US dollars on a per kWh basing, lending itself more flexibility when determining a per power plant, per county, and per capita impact.

A review of the recent literature on the negative externalities associated with coal-fired power generation reveals that the true cost of coal retains a much higher price tag then the one related on the average consumer's energy bill. Economists Nicholas Z. Muller, Robert Mendelsohn, and William Nordhaus (MMN) determined that coal-fired power generation is the largest industrial contributor of external costs and the electricity produced by coal-fired power plants has a higher gross external damage per kWh than any other electricity source. These external damages range from 0.8 to 5.6 times the value added of generation, where sulphur dioxide (SO2) emissions were responsible for 87% of the gross external damages associated with coal-fired power emissions, and that 94% of the damages were because of increased mortality. Additionally, MMN concluded that when the impact from CO2 is accounted for, the gross external damage for coal power increases by nearly 25%. MMN estimated that CO2 emissions are responsible for approximately one-fourth of total air pollution damages from coal-power generation and add an additional $15 billion in external damages per year. As a result, the total gross external damage for coal-fired power generation ranges from $57 to $90 billion per year, depending on the value attributed to the "social cost of carbon" (SCC) and the region's reliance on coal-fired electricity generation. The National Institute of Environmental Health Sciences concluded that coal consumption is significantly and positively correlated with detrimental health impacts resulting from exposure to particulate matter of 10 parts per millimeter (PM10) and that increased coal consumption is associated with increased infant mortality and decreased life expectancy. The Center for Health and Global Environment at Harvard Medical School (CHGE) determined that the best and the low estimates for health damages due to air quality detriment impacts to be $187.5 billion, and $65 billion, respectively. On a plant-by-plant basis, after being normalized to electricity produced by each plant, per kWh, the additional healthcare cost of coal is on average 9.3 ¢/kWh with a low estimate of 3.2 ¢/kWh and a high of 16 ¢/kWh; the range representing the estimated external cost for the highest impacting plant to the lowest. The CHGE study also determined that the best estimate for the true cost of coal-fired electricity generation, including the economically quantifiable health costs generated from coal-power production, to be between 17.8¢/kWh and 26.89¢/kWh. The high rate included the destruction caused by land-use, mercury deposition, water, waste and atmospheric pollution, where the average was restricted just to the health impact caused by fine particulate matter. The EPA concluded that the health impacts due to particulate exposure generated in coal-fired combustion is costing Americans between $110 and $270 billion annually in adverse health care costs. Over 90% of these costs are a result of premature mortalities.

Additionally, the EPA estimates that Georgian's pay between 3.3 and 7 billion dollars in aggregate health costs annually as a result of unhealthy levels of exposure to PM2.5 and O3. Given that the current population of Georgia is approximately 9.8 million, the EPA estimates translate into every Georgian incurring between $330 and $800 per year in additional health care costs due to coal-fired power generation. Finally, when the methodology of the CHGE is applied to Georgia, the report estimates the average cost of coal-fired electricity to be 18.17 cents per kWh, when factoring in health impacts due to particulate exposure, and 26.67 cents per kWh, when factoring in the total monetized health impacts. These numbers are two to three times the current average retail cost of electricity generation in Georgia of 8.8 cents per kWh(EIA, 2010). The retail cost of electricity generation, is used in comparison, because a full-levelized cost of electricity generation (including health, environmental, resource-use impacts, etc.) has yet to be computed for the state of Georgia.

SECTION ONE: Review of research conducted in 2011 on the full cost of coal-fired power generation

ENVIRONMENTAL ACCOUNTING FOR POLLUTION IN THE UNITED STATES ECONOMY

In 2011 (N. Z. Muller et al., 2011), economists Nicholas Z. Muller, Robert Mendelsohn, and William Nordhaus (MMN), examined the air pollution damages for each industry in the United States. In their study, *Environmental Accounting for Pollution in the United States Economy*, the economists developed an integrated assessment model, Air Pollution Emission Experiments and Policy (APEEP), to quantify the health damages of air pollution emissions from coal-fired power generation in the US. The APEEP model connected the emissions of six major pollutants: sulfur dioxide (SO2), nitrogen oxides (NOx), volatile organic compounds (VOCs), ammonia (NH3), fine particulate matter (PM2.5), and coarse particulate matter (PM10 –PM2.5)) to the adverse consequences on human health.[1]

To calculate the impact of the six major emissions on adverse health effects, MMN first determined the annual concentrations of each emission. MMN incorporated the Gaussian plume model in to the APEEP for its concentration data. While this report does expand on the Gaussian plume model, it is important to note why this model in particular was utilized. The Gaussian plume model can approximate critical chemical reactions, which can cause an emitted substance to transform into different, more volatile pollutants. For example, SO2 can transform into sulfate (PM2.5) and NOx, and VOC can transform into concentrations of tropospheric ozone (O3) and nitrate (PM2.5). Additionally, the Gaussian plume model allowed the APEEP model to measure the marginal damage of emissions from each source location in the United States rather than the average damages.

To calculate human exposures, the APEEP used county populations subdivided into 19 age groups. The population was divided by age because "age is a critical determinant of human health effects (p 1661)." To measure the effect of chronic (long-term) exposures to fine particulate matter (PM2.5) on adult mortality rates, APEEP utilized the results from the ongoing study by C. Arden Pope (Pope, 2002). MMN chose to divide the population by age because they believed age was the key determinant of human health effects. The APEEP translated the emission exposures into physical health impacts with epistemological concentration-response parameters pulled from recent literature.[2] To translate health impacts into economic loss, MMN determined an economic value for premature mortality in terms of the life-years lost rather than a statistical value for death. Due to the considerable ambiguity surrounding the effect of mortality on GED, MMN estimated results using both Pope et al. (2002) study and other analysis (Francine Laden et al. 2006) in their sensitivity analysis. The value MMN attributed to premature mortality among persons in age cohort *(a)* in county (c), denoted ($V_{a,c}$), was the sum of the annual mortality risk premium *(R)* times the expected number of life-years remaining. Additionally, MMN affixed a value to future years of life and discounted and weighted each value by the probability of each age group surviving to the next time period. The equation:

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[1] MMN also looked at the effects on decreased timber and agriculture yields, reduced visibility, accelerated depreciation of materials, and reductions in recreation services. However, this report focuses on their findings related to human health.

[2] To measure the effect of chronic (long-term) and short term exposures to fine particulate matter (PM2.5) on adult mortality rates, the APEEP used the results from C. Arden Pope III et al. (2002) and Francine Laden et al. (2006). In order to capture the effect of PM2.5 on infant mortality rates, the APEEP model used the findings from the recent study by Tracey J. Woodruff, Jennifer D. Parker, and Kenneth C. Schoendorf (Woodruff, 2006)APEEP also calculated the relationship between exposures to tropospheric ozone (O3) and adult mortality rates from the study by Michael L. Bell et al.(Bell, 2004) in addition to mortality effects, APEEP accounted for the relationship between exposures to air pollution and a collection of acute and chronic illnesses, such as chronic bronchitis and chronic asthma (Muller and Mendelsohn 2007).

$$V_{a,c} = \sum_{t=0,\ldots,Ta,c} \left[R\Gamma_{Ta,c}(1 + \delta)^{-t}\right],$$

where $V_{a,c}$ is equal to the present value of a premature mortality of person in age-cohort (a) and in county(*c*). *R* is the annual mortality risk premium in dollars per life-year and $T_{a,c}$ is the number of life-years remaining for persons in age-cohort *(a),* in county *(c)* and δ is the discount rate. MMN determined the annual mortality risk premium *(R)* by calculating a value of R such that the present value of the expected life-years remaining equals the value of a statistical life (*VSL)* for an average worker. While this approach leads to a conclusion that is heavily weighted by the *VSL* chosen and a social value of early mortality that is higher for younger people and lower for the elderly, MMN accounted for this presumption in its sensitivity testing which is summarized later.

To obtain the volume of (E) and the location of (j) on every emission of the air pollutants of each pollutant (s) tracked, MMN relied on the U.S Environmental Protection Agency's (USEPA) National Emission Inventory (USEPA, 2010). The APEEP model estimated the marginal damage of an emission of pollutant (s), from each industry (i) from each location *(j),* $MD_{s,i,j}$. Gross External Damages (GED) is calculated by multiplying the emissions ($E_{s,i,j}$) by the location and pollutants specific marginal damage ($MD_{s,i,j}$). The equation:

$$GED_{s,i,j} = MD_{s,i,j} \times E_{s,i,j}.$$

The total GED attributed to industry (i) (for this report's concern- coal-fired power generation) is the sum of damages across the six emitted pollutants covered by APEEP and across all source locations. The equation:

$$GED_i = \sum_{j,s} MD_{s,i,j} \times E_{s,i,j}.$$

The APEEP model concluded that SO2 emissions were responsible for 87% of the GED associated with coal-fired power emissions, and that 94% of the damages were because of increased mortality. It is important to note that these qualifications were calculated with the exclusion of potential impacts from climate change, which was formalized separately. However, the effects of climate change could substantially increase the prevalence and impact of CO2 emissions on the GED associated with coal-fired power emissions (N. Z. Muller et al., 2011).

TABLE 2—GROSS EXTERNAL DAMAGES AND GED/VA RATIO BY INDUSTRY

Industry	GED/VA	GED
Solid waste combustion and incineration	6.72	4.9
Petroleum-fired electric power generation	5.13	1.8
Sewage treatment facilities	4.69	2.1
Coal-fired electric power generation	2.20	53.4
Dimension stone mining and quarrying	1.89	0.5
Marinas	1.51	2.2
Other petroleum and coal product manufacturing	1.35	0.7
Steam and air conditioning supply	1.02	0.3
Water transportation	1.00	7.7
Sugarcane mills	0.70	0.3
Carbon black manufacturing	0.70	0.4
Livestock production	0.56	14.8
Highway, street, and bridge construction	0.37	13.0
Crop production	0.34	15.3
Food service contractors	0.34	4.2
Petroleum refineries	0.18	4.9
Truck transportation	0.10	9.2

Notes: GED in $ billion per year, 2000 prices. Industries included in Table 2 have either a GED/VA ratio above 45 percent or a GED above $4 billion/year.

After calculating the *GED*, MMN measured the ratio of *GED* for coal-fired power plants to its value added (VA_i).[3] The VA data are gathered from the BEA and from the US Census Department Economic Census.. All monetary values were expressed in base year 2000 dollars. The damages were then multiplied by the quantity of emissions to compute a gross external damage impact. MMN ran five sensitivity tests. Each varied in regard to the link between exposures to PM2.5 and adult mortality rates, the value of mortality risks (which is a product of age), and the dollar value placed on the mortality risks. [4]

TABLE 4—GED FOR COAL-FIRED POWER PLANTS BY POLLUTANT AND TYPE OF DAMAGE

Pollutant/welfare endpoint	SO_2	$PM_{2.5}$	PM_{10}	NO_x	VOC	NH_3	Total
Mortality	44.20	3.53	0.00	2.75	0.03	0.09	50.6
Morbidity	1.64	0.03	0.12	0.18	0.00	0.00	1.97
Agriculture	0.00	0.00	0.00	0.37	0.00	0.00	0.37
Timber	0.00	0.00	0.00	0.02	0.00	0.00	0.02
Materials	0.06	0.00	0.00	0.00	0.00	0.00	0.06
Visibility	0.22	0.01	0.02	0.02	0.00	0.00	0.26
Recreation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	46.12	3.57	0.14	3.34	0.03	0.09	53.4

Note: GED in $ billion per year, 2000 prices.

After running five sensitivity cases, MMN compared the results of the sensitivity analysis and to the GED/VA for each perturbation (results presented in Table 3).The APEEP model showed that

[3] The VA of an industry refers to the market value of output minus the market value of inputs, not including the factors of production—labor, land, and capital.

[4] "The GED results depend on several assumptions embedded in the integrated assessment model that could be viewed as controversial and uncertain. One potential source of uncertainty is the air quality model that connects emissions to ambient concentrations. In separate analyses, the results of the air quality model used by MMN have been compared to the predictions of a state-of-the-art atmo-spheric transport and chemistry model, Community Multiscale Air Quality (CMAQ) (Byun, 2006). Given the same emissions inventory, both models produce very similar predicted concentrations of PM2.5 and O3 across the United States. That is, the APEEP model has comparable predictive capabilities as the state-of-the-art atmospheric transport model. Of course, that does not mean the air quality model is perfectly accurate across space. Both air quality models [were] not able to predict the high ambient concentrations observed at some pollution monitoring stations. This may reflect a bias in the model predictions or it may reflect a bias in the locations of the monitors. In addition to air quality modeling, the results [were] sensitive to three other assumptions in the integrated assessment model. First, the results are sensitive to the link between exposures to PM2.5 and adult mortality rates. Second, the results are sensitive to whether the value of mortality risks varies by the age of the exposed population. Third, the results are sensitive to the dollar value placed on mortality risks. We vary each of these assumptions in a sensitivity analysis. "(N. Z. Muller et al., 2011)

coal-fired power generation is the largest industrial contributor of external costs. The damages range from 0.8 to 5.6 times value added. Meaning that a one-unit increase in output of coal-fired power generation results in in additional social costs that are .8 to 5.6 times higher than the incremental revenues. Also, the electricity produced by coal-fired power plants has a higher GED per kWh than any other electricity source at 2.8 cents.

In addition to the emission impact, MMN examined the added GED if the cost of climate change was included. The costs associated with climate change were estimated by the "social cost of carbon" (SCC). Typically, the SCC is estimated in terms of CO2-equivalent emissions. While the scientific community is still conflicted on an accurate value to estimate to monetize the damage that one more ton of emission will cause over time, recent environmental economics literature estimates between $8 and $60 per ton of CO2-equivalent emissions. MMN chose a central value of $27. The damages from CO2 were estimated by multiplying the tonnage of CO2 times the social cost of carbon (Nordhaus, 2008).

Table 3—Sensitivity Analysis of Ratio of GED/VA

Industry	GED/VA Case I	GED/VA Case II	GED/VA Case III	GED/VA Case IV	GED/VA Case V
Solid waste combustion and incineration	6.72	14.66	16.75	2.31	11.01
Petroleum-fired electric power generation	5.13	10.97	13.06	1.77	8.25
Sewage treatment facilities	4.69	9.55	12.09	1.64	7.63
Coal-fired electric power generation	2.20	4.83	5.63	0.78	3.63
Dimension stone mining and quarrying	1.89	3.92	4.47	0.76	2.98
Marinas	1.51	3.27	3.84	0.53	2.46
Other petroleum and coal product mfg.	1.35	2.93	3.34	0.48	2.20
Steam and air conditioning supply	1.02	2.18	2.65	0.35	1.68
Water transport	1.00	2.08	2.43	0.35	1.62
Sugarcane mills	0.70	1.59	1.88	0.24	1.15
Carbon black mfg.	0.70	1.55	1.71	0.25	1.15
Livestock production	0.56	1.22	1.41	0.20	0.92
Highway, street, and bridge construction	0.37	0.77	0.90	0.15	0.60
Crop production	0.34	0.73	0.85	0.13	0.55
Food service contractors	0.34	0.72	0.86	0.12	0.56
Petroleum refineries	0.18	0.38	0.44	0.06	0.30
Truck transportation	0.10	0.24	0.28	0.03	0.18

Notes: Case I = baseline assumptions. Case II = employs the adult mortality dose-response function for $PM_{2.5}$ in Laden et al. (2006). Case III = employs the $6 million VSL, applied uniformly to all ages (USEPA 1999). Case IV = changes the VSL to $2 million (Mrozek and Taylor 2002). Case V = changes the VSL to $10 million VSL (Viscusi and Moore 1989). Cases IV and V employ the VSLY methodology used in Case I.

Table 5—Electric Power Generation with Carbon Dioxide Damages

Fuel type	GED/VA	GED	GED/kwh	GED*/VA	GED*	GED*/kwh
Coal	2.20	53.4	0.0280	2.83 (2.3, 3.7)	68.7 (56.8, 90.1)	0.0359 (0.0297, 0.0472)
Petroleum	5.13	1.8	0.0203	6.93 (5.5, 4.5)	2.5 (2.0, 3.4)	0.0274 (0.0219, 0.0374)
Natural gas	0.34	0.9	0.0085	1.30 (0.6, 2.7)	3.4 (1.4, 6.9)	0.0056 (0.0024, 0.0113)

Notes: GED in $ billion per year, 2000 prices. GED* is GED plus damages from CO_2 emissions using a social cost of carbon of $27/*tC*. Numbers in parentheses use a lower ($6/*tC*) and upper ($65/*tC*) bound estimate for the social cost of carbon (Nordhaus 2008b). GED/kwh and GED*/kwh expressed in $/kwh.

MMN concluded that the CO_2 impact increased the GED for coal power by nearly 25%. MMN also concluded that CO_2 emissions are responsible for approximately one-fourth of total air pollution damages from coal-power generation and add an additional $15 billion in external damages per year. As a result, the total gross external damage for coal-fired power generation ranges from $57 to 90 billion per year, depending on the value attributed to SCC and the region's reliance on coal-fired electricity generation. The study stated that, "In states that primarily rely on coal-fired power… the average GED*/kWh of coal-generated electricity is 60 percent of the average residential retail price of electricity (Epstein et al., 2011)."

ESTIMATING THE GLOBAL PUBLIC HEALTH IMPLICATIONS OF ELECTRICITY AND COAL CONSUMPTION

While it is generally accepted that increased consumption of energy is correlated with positive levels of health, the National Institute of Environmental Health Sciences (NIEH) questioned whether this assertion maintained when the electricity source was coal-fired power. As a result, the NIEH assessed the relationship between coal-fired power generation and health level by analyzing whether exposure from the greenhouse gases and air pollution associated with coal-fired power generation correlated with decreased levels of health. In *Estimating the global public health implications of electricity and coal consumption* (N. Z. Muller et al., 2011), the NIEH developed an autoregressive model of life expectancy (LE) and infant mortality (IM) based on annual coal consumption per capita, and previous year's LE or IM. The model utilized time-series data sets from 41 different countries, with variant development trajectories between 1965 and 2005. LE, IM, electricity use, coal consumption, and population data between the years of 1965 and 2005 were obtained from the Gapminder database (H, 2009) Infant mortality was defined as the number of deaths of infants < 1 year of age per 1,000 births. For data on IM and LM, UNIEF drew on published statistics from the Human Mortality Database and UNICEF (Wilmoth JR, 2009).For statistics on annual coal consumption per capita, NIEH utilized the Statistical Review of World Energy (Petroleum, 2009)

Within the autoregressive, time-series model, NIEH created thresholds for low-, mid-, and high- IM. The model thresholds were applied to each individual country data set. IM and LE data between the years of 1965 to 2005 were plotted against model results incorporating electricity use per capita for each country. The auto regression equation for each country:

$$y(t) = a_0 + a_1 u_1(t) + b_1 u_2(t) \quad + dy(t{-}1) + e(t)$$

where $y(t)$ is the average LE or IM at time t (years or mortality per 1,000 births), $u_1(t)$ is the average coal consumption per capita at time t (kilowatt hour per person per year), $u_2(t)$ is the average electricity consumption per capita at time t (kilowatt hour per person per year), y is the previous year time point (t – 1) and d is the coefficient of this parameter, $e(t)$ is the zero mean normally distributed noise, and a_1 and b_1 are the coefficients being estimated.

When focusing specifically on coal-fired electricity generation, the model separated the dependencies of LE and IM based on patterns of coal and electricity consumption. To do so the model separated the dependencies of LE or IM solely due to coal-fired electricity consumption patterns, at each time point until time t, Q (t) from the dependencies due to all other reasons, P(t). Both were modeled in their exponential functional form and those associated with the errors of predicting LE or IM at each time point until time t, that could not be captured by either P(t) or Q(t) at each time point until time t.

The parameter y (0) is the LE or IM for the initial year, 1965. The parameter (*d)* was the influence of the past values of LE or IM and past values of coal and electricity consumption on the current observed LE or IM values. For the majority of iterations, the parameter (*d)* was approximately 1 across the different model fits considered.

The model also approximated the functions *P (t)*, *Q(t)* and *E(t),* in hopes of providing a better fit for the variable impacts of the remaining parameters of the model. The parameters *a1*, *b1* represent the effect of the coal consumption per capita at all time points until year *t* and electricity consumption per capita at all time points until year *t*, respectively on the LE or IM in year *t*. The variable *a0* is approximately the linear rate of increase of LE or decrease of IM with time. The *a0* parameter roughly translates to a surrogate for yearly improvements in life expectancies and IM due to factors such as economic development, access to effective health care, and technological improvements, which varied across countries.

$$
\begin{aligned}
y(t) &= P(t) + Q(t) + E(t) \\
P(t) &= a_0(1 + d + d^2 + \ldots + d^{t-1}) + y(0)d^t \\
&\approx a_0 t + y(0): \text{if } d \approx 1
\end{aligned}
$$

$$
\begin{aligned}
Q(t) &= a_1 u_1(t) + b_1 u_2(t) + \sum_{i=1} d^i (a_1 u_1(t-i) + b_1 u_2(t-i)) \\
&\approx a_1 \sum_{i=0}^{(t-1)} u_1(t-i) + b_1 \sum_{i=0}^{(t-1)} u_2(t-i): \text{if } d \approx 1 \\
E(t) &= e(t) + \sum_{i=1}^{(t-1)} d^i e(t-i) \\
&\approx \sum_{i=0}^{(t-1)} e(t-i): \text{if } d \approx 1
\end{aligned}
$$

The time-series model predicted that increased electricity consumption was associated with reduced IM for countries that started with relatively high IM (greater than 100/1,000 live births) and low LE (less than 57 years) in 1965, whereas LE was not significantly associated with electricity consumption regardless of IM and LE in 1965. However, when controlling for electricity supply, the time-series model showed that consumption from coal actually negatively affects health. LE was inversely associated with increasing coal consumption in the mid-IM/LE countries. Finally, increased coal consumption was positively associated with increased IM and reduced LE. The table below summarizes the findings.

Table 1. Model parameter estimates (mean and 95% confidence limit) for LE and IM predicted for the three groups of countries in 1965.

Model parameter	High IM/low LE[a]	Mid-IM/LE[b]	Low IM/high LE[c]
IM (per 1,000 births)			
Intercept (a_0) change in IM per year	–0.46 (–0.97 to 0.05)	–0.397 (–0.657 to –0.137)*	–0.04 (–0.09 to 0.01)
Electricity coefficient (b_1)[d]	–0.66 (–1.02 to –0.3)*	0.10 (0.06 to 0.15)*	0.004 (0.001 to 0.007)*
Coal coefficient (a_1)[d]	–0.12 (–0.25 to 0.01)	0.00005 (–0.006 to 0.006)	0.008 (0.006 to 0.01)*
Previous year coefficient (d)[e]	0.99 (0.98 to 0.99)*	0.960 (0.958 to 0.962)*	0.953 (0.951 to 0.955)*
LE at birth (years)			
Intercept (a_0) in change in LE per year	1.2 (1.0 to 1.4)*	1.6 (1.1 to 2.2)*	–0.36 (–0.84 to 0.13)
Electricity coefficient (b_1)[d]	–0.01 (–0.07 to 0.04)	0.009 (–0.026 to 0.044)	–0.001 (–0.005 to 0.003)
Coal coefficient (a_1)[d]	–0.006 (–0.02 to 0.01)	–0.009 (–0.013 to –0.004)*	–0.002 (–0.004 to 0.001)
Previous year coefficient (d)[e]	0.988 (0.984 to 0.992)*	0.982 (0.973 to 0.991)*	1.01 (1.00 to 1.02)*

To substantiate the conclusions from the time-series model, the NIEH compared the results with the Greenhouse Gas and Air Pollution Interactions and Synergies (GAINS) model for 2005. The GAINs model integrated air pollution emissions from coal-fired power plants with health impacts to estimate the consequent of human exposure to particulate matter (PM10), and the potential life-shortening effect of this exposure (Amann M, 2008). The GAINs model linked sequence of calculations to estimate health impact. First, the model estimated the effects of energy sources and policies on air pollution emissions. The calculation was based on emission factors and available control technologies. The resulting emission inventories for air pollutants were then integrated with weather data as inputs to a global-regional chemistry transport model. The atmospheric model estimated the functional relationships between emissions of air pollutants in a given (source) region and atmospheric concentrations in other (receptor) regions. The result was a spatially explicit estimate of air pollutant concentrations at each region. The air pollution concentration estimates were combined with population distribution data to provide exposure estimates. The exposure estimates, along with baseline mortality data and external dose-response estimates pulled from epidemiological literature on PM exposure, were used to estimate health impacts (for more information on the GAINS model see Markandya, 2009).

The GAINS model results are expressed in years of life lost (YLL) over the lifetime of a cohort of adults greater than 30 years of age, using dose–response estimates of premature mortality identified in adults (Pope, 2002). Since the results from the AR model coefficients were expressed in terms of change in LE or IM per 1,000 kWh per capita, the NIEH had to multiple the coal consumption coefficients by the average coal consumption per capita in 2005 for the European Union (low-IM/high-LE model), China (mid-IM/LE model), and India (high-IM/low-LE model), respectively. To match the units expressed in the GAINS model results, the time-series AR results were multiplied by the average LE in 2005 in the European Union, India, and China. An alpha level of 0.05 defined statistical significance. A summary of the GAINS statistics compared to the time-series analysis is provided in the table below:

Table 3. Estimated impact, by region, of coal-fired power stations on PM emissions and YLL over the lifetime of a cohort of adults > 30 years of age: GAINS model versus AR model.

Region	Total PM_{10} emissions (kilotons)	Predicted average YLL per capita (GAINS)	Predicted average YLL (95% CI) per capita (AR model, Table 1)[a]
European Union (EU-27)	1,000	0.5	0.82 (–0.45 to –2.1)
India	7,000	2.5	0.72 (–1.60 to –3.03)
China	10,000	3.5	6.30 (3.06 to –9.53)

CI, confidence interval.
[a]Translation of the coal consumption coefficient (a_1) into units comparable to YLL per capita is described in "Materials and Methods" and entailed multiplying by estimates of average coal consumption and LE.

The GAINS model concluded that coal consumption is significantly and positively correlated with detrimental health impacts resulting from exposure to PM10. While the concentration of PM10 varied across the 41 countries, the relationship between PM10 emissions and YLL based on the GAINS model were similar across the regions.[5] More importantly, the GAINS model produced similar results in regard to YLL and consumption as the time-series analysis.

FULL COST ACCOUNTING FOR THE LIFE CYCLE OF COAL

In 2010 (Committee on Health, Costs, Production, Consumption, & Council, 2010), the National Research Council (NRC) conducted a study titled "The Hidden Costs of Energy." The NRC estimated that the total annual external damages from sulfur dioxide, nitrogen oxides, and particulate matter created by burning coal at 406 coal-fired power plants, in 2005, resulted in about $62 billion; these nonclimate damages averaged about 3.2 cents for every kilowatt-hour (kwh) of energy produced. A relatively small number of plants -- 10 percent of the total number -- accounted for 43 percent of the damages. A year later, building on the methodology employed by the NRC study, , the Center for Health and Global Environment at Harvard Medical School (CHGE) assessed the *Full cost accounting for the life cycle of coal*. The CHGE study performed a full lifecycle assessment on the aggregate public health damages from coal power generation in the United States. The CHGE study tabulated a wide range of costs associated with the full life cycle of coal, separating those that are quantifiable and monetizable; those that are quantifiable, but difficult to monetize; and those that are qualitative. The monetized impacts found for public health are damages due to climate change; health damages resulting from exposure to NOx, SO2 , PM2.5; damages from mercury emissions; fatalities of members of the public due to rail accidents during coal transport; the public health burden in Appalachia associated with coal mining; government subsidies; and lost value of abandoned mine lands. Additionally, the CHGE study incorporated the adverse impacts of land-use degradation and natural-resource contamination.

When monetizing health damages, the CHGE first aggregated statistical data on mortality cases, bronchitis cases, asthma cases, hospital admissions related to respiratory, cardiac cases, coronary obstructive pulmonary disease, chemic heart disease problems, and emergency room visits related to asthma. Next, CHGE assigned individual dose-parameters for exposure to NOx, SO2 , PM2.5 and damages from mercury emissions. Since many of the monetized dose-parameters were quantified based on the findings of different and often divergent epidemiological studies, the CHGE presented low and/or high estimates in addition to best estimates. Low and high values can indicated both uncertainty in parameters and different assumptions about the parameters that others used to calculate their estimates. Additionally, the best estimates were not weighted averages, and were derived differently for each category. When monetizing climate impacts, CHGE utilized a social cost of carbon of $30/ton of CO2equivalent (CO2e),[6] with low and high estimates of $10/ton and $100/ton. The CHGE forecasted each scenario's monetized impact using a value of statistical life (VSL) of $7.5 million in 2008 US$, the same used by the U.S. Environmental Protection Agency (EPA). The monetizable impacts were normalized to per kWh of electricity produced, based on EIA estimates of electricity produced from coal in the United States(Administration, 2010). It is

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[5] However, while the GAINS model prediction reflected the AR model prediction of YLL according to PM10 emissions for the European Union but was higher than the AR-based estimate for India and lower than that for China. This may have resulted because the GAINS model estimates YLL among persons greater than30 years of age only, whereas the AR time-series analysis estimated changes in LE from birth and therefore incorporated impacts on mortality at all ages.

[6] The CHGE used the same number as the NRC study: Research Council. 2009. *The Hidden Costs of Energy: Unpriced Consequences of Energy Production*. Washington, DC.

Table 3. The complete costs of coal as reviewed in this report in 2008 US$.

	Monetized estimates from literature (2008 US$)			Monetized life cycle assessment results (2008 US$)	
	Low	Best	High	IPCC 2007, U.S. Hard Coal	U.S. Hard Coal Eco-indicator
Land disturbance	$54,311,510	$162,934,529	$3,349,209,766		
Methane emissions from mines	$684,084,928	$2,052,254,783	$6,840,849,276	$2,188,192, 405	
Carcinogens (mostly to water from waste)					$11,775,544, 263
Public health burden of communities in Appalachia	$74,612,823,575	$74,612,823,575	$74,612,823,575		
Fatalities in the public due to coal transport	$1,807,500,000	$1,807,500,000	$1,807,500,000		
Emissions of air pollutants from combustion	$65,094,911,734	$187,473,345,794	$187,473,345,794		$71,011,655, 364
Lost productivity from mercury emissions	$125,000,000	$1,625,000,000	$8,125,000,000		
Excess mental retardation cases from mercury emissions	$43,750,000	$361,250,000	$3,250,000,000		
Excess cardiovascular disease from mercury emissions	$246,000,000	$3,536,250,000	$17,937,500,000		
Climate damages from combustion emissions of CO_2 and N_2O	$20,559,709,242	$61,679,127,726	$205,597,092,419.52	$70,442,466, 509	
Climate damages from combustion emissions of black carbon	$12,346,127	$45,186,823	$161,381,512.28	$3,739,876, 478	
Environmental Law Institute estimate 2007			$5,373, 963,368		
EIA 2007	$3,177,964,157	$3,177, 964,157			
AMLs	$8,775,282,692	$8,775, 282,692	$8,775, 282,692		
Climate total	$21,310,451,806	$63,939,503,861	$215,948,532,974		
Total	$175,193,683,964	$345,308,920,080	$523,303,948,403		

A 2010 Clean Air Task Force[56] (CATF) report, with Abt Associates consulting, lists 13,000 premature deaths due to air pollution from all electricity generation in 2010, a decrease in their estimates from previous years. They attribute the drop to 105 scrubbers installed since 2005, the year in which we based our calculations. We were pleased to see improvements reported in air quality and health outcomes. There is, however, considerable uncertainty regarding the actual numbers. Using the epidemiology from the "Six Cities Study" implies up to 34,000 premature deaths in 2010. Thus, our figures are mid-range while those of the CATF represent the most conservative of estimates.

Table 4. Total costs of coal normalized to kWh of electricity produced.

	Monetized estimates from literature in ¢/kWh of electricity (2008 US$)			Monetized life cycle assessment results in ¢/kWh of electricity (2008 US$)	
	Low	Best	High	IPCC 2007, U.S. Hard Coal	U.S. Hard Coal Eco-indicator
Land disturbance	0.00	0.01	0.17		
Methane emissions from mines	0.03	0.08	0.34	0.11	
Carcinogens (mostly to water from waste)					0.60
Public health burden of communities in Appalachia	4.36	4.36	4.36		
Fatalities in the public due to coal transport	0.09	0.09	0.09		
Emissions of air pollutants from combustion	3.23	9.31	9.31		3.59
Lost productivity from mercury emissions	0.01	0.10	0.48		
Excess mental retardation cases from mercury emissions	0.00	0.02	0.19		
Excess cardiovascular disease from mercury emissions	0.01	0.21	1.05		
Climate damage from combustion emissions of CO_2 and N_2O	1.02	3.06	10.20	3.56	
Climate damages from combustion emissions of black carbon	0.00	0.00	0.01	0.19	
Environmental Law Institute estimate 2007			0.27		
EIA 2007	0.16	0.16			
AMLs	0.44	0.44	0.44		
Climate total	1.06	3.15	10.7	3.75	1.54
Total	9.36	17.84	26.89		

important to note that some parameters were monetized for the entire coal production process, including mining, while others were associated only with the electricity generation. To correct for this, CHGE multiplied each derived value by the proportion of coal that was used for electrical power, which was approximately 90% in all years analyzed.

The CHGE study concluded that the best and low estimates for health damages due to air quality detriment impacts to be $187.5 billion, and $65 billion, respectively. On a plant-by-plant basis, after being normalized to electricity produced by each plant, per-kWh, the additional healthcare cost of coal was on average 9.3 ¢/kWh with a low estimate of 3.2 ¢/kWh and a high of 16 ¢/kWh.

The study also found that the best estimate for the true cost of coal, including the economically quantifiable health costs generated from coal-power production, to be between 17.8¢/kWh and 26.89¢/kWh. [7] The high rate included the destruction caused by land-use, mercury deposition, water, waste and atmospheric pollution, where the average was restricted just to the health impact caused by fine particulate matter.

[7] The NRC found aggregate health care damages of $65 billion and 3.3 ¢/kWh (NRC, 2010), the CHGE study asserted that the NRC's estimate was likely an underestimate as it utilized low estimates for increases in mortality risk with increases in PM2.5 exposure and was an outlier when compared to other studies examining the PM2.5– mortality relationship.

Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States

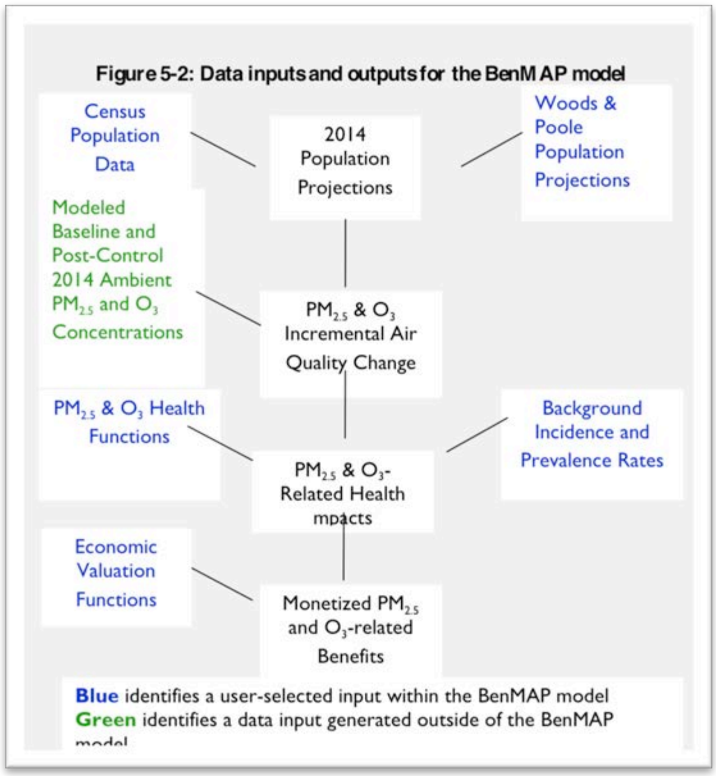

Figure 5-2: Data inputs and outputs for the BenMAP model

In 2011 (U. S. EPA, 2011), the EPA proposed a regulation to reduce particulate and ozone emission transport from power plants. In the report, *Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States,* the EPA monetized the potential health care cost savings of reducing fine particulate matter (PM2.5) and ground-level ozone (O3) for states above National Ambient Air Quality Standards (NAAQS).[8] In previous years the EPA conducted extensive analysis on the health impacts of particulate matter and attempted to aggregate the total health care impact. [i] However only recently has the EPA attempted to convert reductions in emissions of SO2 and NOx (major contributors to PM 2.5 and O3) into monetized values. The proposed regulation targeted coal-fired power plants, as many of the areas classified as 'non-attainment zones (zones that did not meet standards) were areas occupied by coal-fired power generation.

As with previous studies, the EPA used an Environmental Benefits Mapping and Analysis Program (BenMAP) to estimate the future health benefits occurring as a result of implementing alternative SO2 NAAQS levels. The model combined the findings of variant economic externality assessment models with the population demographics of 27 states and the conclusions of a photochemical air quality calculation model. A simplified diagram of the model is shown here.

Instead of modeling the impact of all chemicals associated with PM 2.5 and O3, the EPA decided to isolate the leading causal chemicals. This is primarily because years of former EPA modeling concluded that sulfur dioxide and nitrogen oxide were the two key contributors to fine particle and ozone formation and the major source of health care cost (Fann N, 2012) As a result, the EPA decided to focus its efforts on quantifying and monetizing the impacts of these two chemicals. In general sulfur dioxide contributes to the formation of fine particle pollution (PM2.5), and nitrogen oxide contributes to the formation of both PM2.5 nitrate and ground-level ozone. However, because the same previous EPA modeling also indicated that PM2.5 formation was less sensitive to NOx emission reductions on a per-μg/m3 basis, the EPA decided to focus on reducing SO2 emissions and did not quantify the NOx-related PM2.5 changes.

It is important to note that there exist several interactions between the PM2.5 precursors, which cannot be easily quantified. For example, under conditions in which SO2 levels are reduced by a substantial margin, "nitrate replacement" may occur, increasing the levels of particulate nitrate. [9] Due to the complex nature of these interactions, the EPA performed a sensitivity modeling analysis to account for potential auxiliary effects. While the sensitivity analysis will not be fully explained in this report, it is important to recognize that the EPA's approach of isolating a single chemical for assessing impact is accompanied with several uncertain assumptions.

After isolating the air quality impacts of SO2 reductions, the EPA needed to determine which areas of the country were operating with levels of SO2 and NOx concentrations that could result in negative health impacts. The EPA utilized a photochemical Community Multiscale Air Quality (CMAQ) model in conjunction with ambient monitored data, and demographic and concentration data to model a summer season average 8-hour ozone and an annual mean PM2.5 level at a 12 km grid resolution. As a result, the EPA identified 27 states that were operating with levels of PM 2.5 and ozone that could pose significant health risks. [10]

After identifying the nonattainment zones, the EPA developed a model to monetize the external health impacts of SO2 emission. The EPA first quantified the health impacts of *total* PM2.5 mass formed from the SO2 reductions. Since quantified and monetized human health impacts are highly dependent on population characteristics, the EPA incorporated demographic projections based on economic forecasting models developed by Woods and Poole, Inc. [11] To determine the concentration-response relationship or health impact (of SO2) for each health endpoint, the EPA collected several estimates from environmental and epidemiological literature. All of the variables were then quantitatively combined or pooled to derive a more robust estimate of the relationship. [12]

To monetize the concentration response parameters, the EPA had to determine the appropriate economic measure for avoiding the risk of the health impact, since reductions would take place in the future. The EPA utilized an *ex ante* Willingness to Pay (WTP) parameter for changes in risk. *Ex ante* simply means how much a person is willing to pay *beforehand* to avoid or decrease impact. Each health-impact parameter and WTP parameter was unique and based on the accordant health endpoints. However, for some health effects, such as hospital admissions, WTP estimates were generally not available. In these cases, the EPA used the cost of treatment as a primary estimate. Additionally, the EPA assumed that WTP will vary with income elasticity and that the severity of a

[9] This occurs when particulate ammonium sulfate concentrations are reduced, thereby freeing up excess gaseous ammonia. The excess ammonia is then available to react with gaseous nitric acid to form particulate nitrate. The impact of nitrate replacement is also affected by concurrent NOx reductions. NOx reductions can lead to decreases in nitrate, which competes with the process of nitrate replacement. NOx reductions can also lead to reductions in photochemical by-products which can reduce both particulate sulfate and secondary organic carbon PM concentrations.
[10] Georgia was included in this list.
[11] The Woods and Poole (WP) database contains county-level projections of population by age, sex, and race out to 2030. For more see http://www.epa.gov/air/benmap/models/benmappeerreviewresponse.pdf.
[12] For more details on methods used to pool incidence estimates, see the BenMAP Manual Appendices, which are available with the BenMAP software at http://www.epa.gov/benmap.html.

health effect is a primary determinant of the strength of the relationship between changes in real income and WTP. As a result, the BenMAP model utilized different elasticity estimates to adjust the WTP for minor health effects, severe and chronic health effects, and premature mortality. Also, for several of the health end-points there was no available health impact parameter. In such situations, the BenMap model utilized a COI estimate (lost earnings plus direct medical costs).

After calculating the health impacts and the monetized benefits of avoiding said impact (WTP), the EPA divided each by a proposed emission reduction in SO2-yielding a Benefit per-ton (BPT) estimate for PM-related SO2. An example of a health impact function is as follows:

$$\Delta y = y_o \cdot \left(e^{\beta \cdot \Delta x} - 1\right) \cdot Pop$$

where y_0 is the baseline incidence rate for the health endpoint being quantified[13]; Pop is the population affected by the change in air quality; Δx is the change in air quality (reduction in SO2); and β is the health-impact coefficient determined from the epidemiological studies.

When assessing the impact on mortality, the EPA assigned a Value of Statistical Life (VSL) for the health endpoint. The EPA used a VSL of $6.3 million and a 3 and 7 percent discount rate when valuing future mortality reductions. The EPA scenarios assumed that an increase in 5-d moving average PM10 levels, equal to 100 μg/m2, was associated with an estimated increase in deaths per day equal to 16%. The association with mortality and PM10 was largest for respiratory disease deaths, next largest for cardiovascular deaths, and smallest for all other deaths. The EPA scenarios also assumed a 1-hr ozone metric: $R2 = 0.58$, $p < 0.001$; 8-hr ozone: $R2 = 0.56$, $p < 0.001$; 24-hr ozone: $R2 = 0.48$, $p = 0.001$; and that $\mu = 0.52$, with a 95% Posterior Interval (PI) from 0.27 to 0.77. The tables below summarizes the economic valuation of each health endpoint, including mortality, and the estimated reduction as a result of the transport rule:

[13]For example, in quantifying changes in mortality would use the baseline mortality rate for the given population of interest.

Table 5-11: Unit Values for Economic Valuation of Health Endpoints (2007$)

Health Endpoint	Central Estimate of Value Per Statistical Incidence		Derivation of Distributions of Estimates
	2000 Income Level	2014 Income Level	
Premature Mortality (Value of a Statistical Life)	$7,900,000	$8,700,000	EPA currently recommends a central VSL of $6.3m (2000$) based on a Weibull distribution fitted to 26 published VSL estimates (5 contingent valuation and 21 labor market studies). The underlying studies, the distribution parameters, and other useful information are available in Appendix B of EPA's current Guidelines for Preparing Economic Analyses (U.S. EPA, 2000).
Chronic Bronchitis (CB)	$430,000	$480,000	The WTP to avoid a case of pollution-related CB is calculated as where x is the severity of an average CB case, WTP_{13} is the WTP for a severe case of CB, and $ is the parameter relating WTP to severity, based on the regression results reported in Krupnick and Cropper (1992). The distribution of WTP for an average severity-level case of CB was generated by Monte Carlo methods, drawing from each of three distributions: (1) WTP to avoid a severe case of CB is assigned a 1/9 probability of being each of the first nine deciles of the distribution of WTP responses in Viscusi et al. (1991); (2) the severity of a pollution-related case of CB (relative to the case described in the Viscusi study) is assumed to have a triangular distribution, with the most likely value at severity level 6.5 and endpoints at 1.0 and 12.0; and (3) the constant in the elasticity of WTP with respect to severity is normally distributed with mean = 0.18 and standard deviation = 0.0669 (from Krupnick and Cropper [1992]). This process and the rationale for choosing it is described in detail in the Costs and Benefits of the Clean Air Act, 1990 to 2010 (U.S. EPA, 1999b).

Nonfatal Myocardial Infarction (heart attack)			No distributional information available. Age-specific cost-of-illness values reflect lost earnings and direct medical costs over a 5-year period following a nonfatal MI. Lost earnings estimates are based on Cropper and Krupnick (1990). Direct medical costs are based on simple average of estimates from Russell et al. (1998) and Wittels et al. (1990). Lost earnings: Cropper and Krupnick (1990). Present discounted value of 5 years of lost earnings: age of onset: at 3% at 7% 25–44 $8,774 $7,855 45–54 $12,932 11,578 55–65 $74,746 66,920 Direct medical expenses: An average of: 1. Wittels et al. (1990) ($102,658—no discounting) 2. Russell et al. (1998), 5-year period ($22,331 at 3% discount rate; $21,113 at 7% discount rate)
3% discount rate			
Age 0–24	$88,709	$88,709	
Age 25–44	$99,789	$99,789	
Age 45–54	$105,040	$105,040	
Age 55–65	$183,105	$183,105	
Age 66 and over	$88,709	$88,709	
7% discount rate			
Age 0–24	$87,889	$87,889	
Age 25–44	$98,970	$98,970	
Age 45–54	$104,220	$104,220	
Age 55–65	$182,285	$182,285	
Age 66 and over	$87,889	$87,889	
Hospital Admissions			
Chronic Obstructive Pulmonary Disease (COPD)	$17,106	$17,106	No distributional information available. The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code-level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total COPD category illnesses) reported in Agency for Healthcare Research and Quality (2000) (www.ahrq.gov).
Asthma Admissions	$11,366	$11,366	No distributional information available. The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code-level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total asthma category illnesses) reported in Agency for Healthcare Research and Quality (2000) (www.ahrq.gov).
All Cardiovascular	$28,760	$28,760	No distributional information available. The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code-level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total cardiovascular category illnesses) reported in Agency for Healthcare Research and Quality (2000) (www.ahrq.gov).
All respiratory (ages 65+)	$24,157	$24,157	No distributions available. The COI point estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total COPD category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).

All respiratory (ages 0–2)	$10,402	$10,402	No distributions available. The COI point estimates (lost earnings plus direct medical costs) are based on ICD-9 code level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total COPD category illnesses) reported in Agency for Healthcare Research and Quality, 2000 (www.ahrq.gov).
Emergency Room Visits for Asthma	$385	$385	No distributional information available. Simple average of two unit COI values: (1) $311.55, from Smith et al. (1997) and (2) $260.67, from Stanford et al. (1999).
Respiratory Ailments Not Requiring Hospitalization			
Upper Respiratory Symptoms (URS)	$30	$31	Combinations of the three symptoms for which WTP estimates are available that closely match those listed by Pope et al. result in seven different "symptom clusters," each describing a "type" of URS. A dollar value was derived for each type of URS, using mid-range estimates of WTP (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. In the absence of information surrounding the frequency with which each of the seven types of URS occurs within the URS symptom complex, we assumed a uniform distribution between $9.2 and $43.1.
Lower Respiratory Symptoms (LRS)	$19	$20	Combinations of the four symptoms for which WTP estimates are available that closely match those listed by Schwartz et al. result in 11 different "symptom clusters," each describing a "type" of LRS. A dollar value was derived for each type of LRS, using mid-range estimates of WTP (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. The dollar value for LRS is the average of the dollar values for the 11 different types of LRS. In the absence of information surrounding the frequency with which each of the 11 types of LRS occurs within the LRS symptom complex, we assumed a uniform distribution between $6.9 and $24.46.
Asthma Exacerbations	$52	$54	Asthma exacerbations are valued at $45 per incidence, based on the mean of average WTP estimates for the four severity definitions of a "bad asthma day," described in Rowe and Chestnut (1986). This study surveyed asthmatics to estimate WTP for avoidance of a "bad asthma day," as defined by the subjects. For purposes of valuation, an asthma exacerbation is assumed to be equivalent to a day in which asthma is moderate or worse as reported in the Rowe and Chestnut (1986) study. The value is assumed have a uniform distribution between $15.6 and $70.8.

Acute Bronchitis	$430	$450	Assumes a 6-day episode, with the distribution of the daily value specified as uniform with the low and high values based on those recommended for related respiratory symptoms in Neumann et al. (1994). The low daily estimate of $10 is the sum of the mid-range values recommended by IEc (1994) for two symptoms believed to be associated with acute bronchitis: coughing and chest tightness. The high daily estimate was taken to be twice the value of a minor respiratory restricted-activity day, or $110.
Work Loss Days (WLDs)	Variable (U.S. median = $130)	Variable (U.S. median = $130)	No distribution available. Point estimate is based on county-specific median annual wages divided by 50 (assuming 2 weeks of vacation) and then by 5—to get median daily wage. U.S. Year 2000 Census, compiled by Geolytics, Inc.
Minor Restricted Activity Days (MRADs)	$61	$64	Median WTP estimate to avoid one MRAD from Tolley et al. (1986). Distribution is assumed to be triangular with a minimum of $22 and a maximum of $83, with a most likely value of $52. Range is based on assumption that value should exceed WTP for a single mild symptom (the highest estimate for a single symptom—for eye irritation—is $16.00) and be less than that for a WLD. The triangular distribution acknowledges that the actual value is likely to be closer to the point estimate than either extreme.
School Absence Days	$90	$90	No distribution available

[A] Due to a clerical error, the VSL estimates summarized in the proposal RIA were incorrectly reported; this error was not present in the calculation of mortality impacts.

Table 1-2: Estimated Reduction in Incidence of Adverse Health Effects of the Selected remedy (95% confidence intervals)[A]

Health Effect	*Within transport region*	*Beyond transport region*	*Total*
PM-Related endpoints			
Premature Mortality			
Pope et al. (2002) (age >30)	13,000 (5,200—21,000)	33 (5—60)	13,000 (5,200—21,000)
Laden et al. (2006) (age >25)	34,000 (18,000—49,000)	84 (31—140)	34,000 (18,000—49,000)
Infant (< 1 year)	59 (-47—160)	0.15 (-0.2—0.5)	59 (-47—160)
Chronic Bronchitis	8,700 (1,600—16,000)	23 (-5—50)	8,700 (1,600—16,000)
Non-fatal heart attacks (age > 18)	15,000 (5,600—24,000)	40 (7—72)	15,000 (5,600—24,000)
Hospital admissions—respiratory (all ages)	2,700 (1,300—4,000)	5 (2—9)	2,700 (1,300—4,000)
Hospital admissions—cardiovascular (age > 18)	5,700 (4,200—6,600)	15 (10—19)	5,800 (4,200—6,600)
Emergency room visits for asthma (age < 18)	9,800 (5,800—14,000)	21 (7—36)	9,800 (5,800—14,000)
Acute bronchitis (age 8-12)	19,000 (-630—37,000)	50 (-29—130)	19,000 (-660—37,000)
Lower respiratory symptoms (age 7-14)	240,000 (120,000—360,000)	630 (130—1,100)	240,000 (120,000—360,000)
Upper respiratory symptoms (asthmatics age 9-18)	180,000 (57,000—310,000)	480 (-25—980)	180,000 (57,000—310,000)
Asthma exacerbation (asthmatics 6-18)	400,000 (45,000—1,100,000)	1,100 (-250—2,900)	400,000 (45,000—1,100,000)
Lost work days (ages 18-65)	1,700,000 (1,500,000—1,900,000)	4,300 (3,500—5,200)	1,700,000 (1,500,000—1,900,000)
Minor restricted-activity days (ages 18-65)	10,000,000 (8,400,000—11,000,000)	26,000 (20,000—32,000)	10,000,000 (8,400,000—12,000,000)

Ozone-related endpoints				
Premature mortality				
Multi-city and NMMAPS	Bell et al. (2004) (all ages)	27 (11—42)	0.1 (0.01—0.3)	27 (11—42)
	Schwartz et al. (2005) (all ages)	41 (17—64)	0.2 (0.1—0.4)	41 (17—65)
	Huang et al. (2005) (all ages)	37 (17—57)	0.2 (0.1—0.4)	37 (17—57)
Meta-analyses	Ito et al. (2005) (all ages)	120 (78—160)	0.6 (0.3—0.9)	120 (79—160)
	Bell et al. (2005) (all ages)	87 (48—130)	0.5 (0.2—0.8)	87 (48—130)
	Levy et al. (2005) (all ages)	120 (89—150)	0.7 (0.4—0.9)	120 (90—160)
Hospital admissions—respiratory causes (ages > 65)		160 (21—280)	1.2 (0.1—2.3)	160 (21—290)
Hospital admissions—respiratory causes (ages <2)		83 (43—120)	0.5 (0.2—0.8)	84 (43—120)
Emergency room visits for asthma (all ages)		86 (-2—260)	0.4 (-0.2—1.4)	86 (-2—260)
Minor restricted-activity days (ages 18-65)		160,000 (80,000—240,000)	910 (240—1,600)	160,000 (80,000—240,000)
School absence days		51,000 (22,000—73,000)	290 (59—490)	51,000 (22,000—74,000)

[A] Estimates rounded to two significant figures; column values will not sum to total value.
[B] The negative estimates for certain endpoints are the result of the weak statistical power of the study used to calculate these health impacts and do not suggest that increases in air pollution exposure result in decreased health impacts.

After quantifying each population's health impact function (by endpoint and air quality improvement), the EPA aggregated the total benefit of power-plants reducing sulfur dioxide (SO2) emissions by 62% and nitrogen oxide (NOx) emissions by 11%. Then the EPA estimated a potential cost of implementing a reduction, the "social cost." The EPA defined the social costs as the annualized total social costs of reducing pollutants including NOx and SO2 for the EGU source category. Social costs were estimated using the MultiMarket model, to estimate economic impacts to industries outside the electric power sector. However, this model does not estimate indirect impacts associated with a regulation.

The EPA concluded that a reduction in particulate transport would yield an aggregate social benefit in 2014 of $120 to $280 billion (based on a 3 percent discount rate) and $110 to $250 billion (based on a 7 percent discount rate).[14] Specifically in regards to health care, the EPA concluded that a transport regulation would yield a benefit of $110 to $270 billion (based on a 3 percent discount rate) and $100 to $250 billion (based on a 7 percent discount rate).[15] These costs resulted from an estimated reduction in the number of PM2.5-related premature deaths in 2014 by between 13,000 and 34,000; a reduction of 15,000 non-fatal heart attacks; 8,700 fewer hospital admissions; and 400,000 fewer cases of aggravated asthma. The greatest monetary impact, and a significant proportion of the aggregate cost, resulted from the decrease in premature mortalities. The EPA concluded that premature mortalities (each monetized at $6.3 million USD) accounted for over 90% of total monetized health benefits. However, it is important to note that in prior analyses the EPA identified valuation of mortality-related benefits as the largest contributor to the range of uncertainty in monetized benefits (N. Z. Muller, and Robert Mendelsohn, 2007; Woodruff, 2006). Additionally the EPA estimated substantial additional health improvements for children from reductions in upper and lower respiratory illnesses, acute bronchitis, and asthma attacks.

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[14] Social costs [were] estimated using the MultiMarket model, the model employed by EPA in this RIA to estimate economic impacts of the industries outside the electric power sector. This model did not estimate indirect impacts associated with a regulation such as the one examined in this study. Details on the social cost estimates can be found in Chapter 8 and Appendix B of the RIA (U. S. EPA, 2011).

[15] The reduction in premature mortalities account for over 90% of total monetized benefits. Benefit estimates [were] national except for visibility that covers Class I areas. Valuation [assumed] discounting over the SAB recommended 20-year segmented lag structure (for more see Chapter 5 of study). Results [reflected] 3 percent and 7 percent discount rates ((OMB), 2003)The estimate of social benefits also [included] CO2 related benefits calculated using the social cost of carbon(for more, including monetized categories, see Chapter 5 of study)(EPA, June 2011).

Table 1-1. Summary of EPA's Estimates of Benefits, Costs, and Net Benefits of the Selected Remedy in the Transport Rule in 2014[a] (billions of 2007$)

Description	Estimate (3% Discount Rate)	Estimate (7% Discount Rate)
Social costs[b]	$0.81	$0.81
Social benefits[c,d]	$120 to $280 + B	$110 to $250 + B
Health-related benefits:	$110 to $270 + B	$100 to $250 + B
Visibility benefits[e]	$4.1	$4.1
Net benefits (benefits-costs)	$120 to $280	$110 to $250

SECTION TWO: Application of recent research's methodologies and findings to determine the cost of coal-fired power generation in Georgia

In 2011, Georgia produced over 35 GWs of coal-fired power from 10 power plants, accounting for 48% of the state's power generation ((EIA), 2012). The driving catalyst behind health care costs was the health impacts caused by fine particle air pollution generated in combustion (Force, 2010). In this section I examine the negative health impact of exposure to fine particulate air pollution from coal in Georgia, and estimates what the true cost of coal would be if these externalities were accounted for. I use the research findings of the EPA to provide a relative health cost of relying on coal in Georgia on a power plant and per capita basis. To determine a true cost of coal-fired power generation, in dollars per kilowatt-hour, the report utilizes the methodologies of the Center for Health and Global Environment at Harvard Medical School.

To determine a base estimate of the monetized impact of negative health impacts associated with coal-fired power generation, I employ the conclusions provided by the EPA in *Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States* (EPA, June 2011). A major portion of the EPA study on particulate transport focused on determining which areas of the country were operating with levels of SO2 and NOx concentrations that could result in negative health impacts. As a result, the EPA provided a profile of each state that would be forced to comply with proposed regulation. The EPA classified 25 Georgian counties as nonattainment zones for health-based standards of fine particle pollution. [16] To determine the result of operating at unhealthy levels, the EPA tabulated all the health endpoints associated with exposure to PM2.5 and O3 in Georgia, including premature mortality, and monetized the aggregate impact. In 2010 Georgia suffered from 536 mortalities, 396 hospital and emergency department visits, and 728 heart attacks as a result of unhealthy exposures to PM2.5 and O3. Other leading endpoints include acute bronchitis, upper and lower respiratory symptoms, and aggravated asthma.

Using a similar health-impact function as described earlier, the EPA estimated that Georgian's pay between 3.3 and 7 billion dollars in aggregate health costs annually as a result of unhealthy levels of exposure to PM2.5 and O3.[17] Given that the current population of Georgia is approximately 9.8 million, the EPA estimates translate into every Georgian incurring between $330 and $800 per year in additional health care costs.

To assess how these health care costs are dispersed between the coal-fired power plants, and determine what the true cost of coal would be if these externalities were accounted for on an individual's energy bill, I applied the methodology developed by the Center for Health and Global Environment's. Currently Georgia has ten, coal-fired power plants, ranging in generation capacity. The report retrieved the generation capacity of each Georgia power plant from Georgia Power. The report assumed that the coal power plants in Georgia run at 90% capacity of their total electricity capacity in kW. Then I applied the CHGE's best estimates of additional cost per Kwh due to air quality detriment impacts from particulate exposure, of 9.3 cents p/Kwh, and the low-estimate for total monetizable health care costs, of 17.8 cents p/kWh, to calculate the costs associated with the energy produced at Georgia's coal plants and determine what the true cost of coal would be if these

16 These counties include: Barrow, Bartow, Carroll, Cherokee, Clayton, Cobb, Coweta, DeKalb, Douglas, Fayette, Forsyth, Fulton, Gwinnett, Hall, Heard*, Henry, Newton, Paulding, Putnam*, Rockdale, Spalding, Walton, Chattanooga, Catoosa, Walker, Floyd , Bibb and Monroe. As a result, the Georgia power plants must reduce emissions of NOx during the Ozone Season to 1997 NASQ; reduce annual emissions of SO2 and NOx to 1997 PM2.5 NAAQS; and reduce SO2 and NOx to 2006, 24-hour PM2.5 NAAQS. The estimate total reduction of sulfur dioxide (SO2) in 2015 by 292,000 tons or 54%, and a reduction in emissions of nitrogen oxides (NOx) by 38,000 tons or 37%..

17 Cross-State Air Pollution Rule RIA, estimated using Pope, (Pope, 2002); monetized benefits discounted at 3%

externalities were accounted for. However it is important to note that the estimate provided by the CHGE range from a low of 9.3 cents per kWh in additional cost to a high 26.89 cents per kWh. I chose to utilize the best and low estimates, meaning that the numbers provided are conservative. The table below summarizes the estimated external health costs generated by each coal-fired power plant in Georgia.

Coal-Fired Power Plant	Output in GW (90% of Capacity)	Total kh 's	Added Health Cost from particulate exposure	Added Health Cost from total monetized
Bowen	28.4	682,600,000	$63,500,000	$506,000,000
Branch	1.39	33,300,000	$3,000,000	$24,700,000
Hammond	.720	17,300,000	$1,600,000	$12,800,000
Kraft	.253	6,000,000	$570,000	$4,500,000
McDonough	.441	10,600,000	$990,000	$7,800,000
McIntosh	.147	3,500,000	$330,000	$2,600,000
Mitchell	.113	2,700,000	$250,000	$2,000,000
Scherer	.676	16,200,000	$1,500,000	$12,000,000
Wansley	8.30	199,000,000	$18,500,000	$148,000,000
Yates	1.13	27,000,000	$2,500,000	$20,000,000

Estimated External Health Costs Generated from Coal-Fired Power plants in Georgia

Drawing from the Center for Health and Global Environment's conclusions, I estimated a true cost of electricity from coal-fired power generation in Georgia. Currently the average cost of coal-fired power generation is 8.87 cents per kWh. If the CHGE estimates are added to the current coal price tag of 8.87 cents per kWh, that puts the cost of electricity between 18.17 cents per kwh when factoring in health impacts due to particulate exposure, and 26.67 cents per kWh, when factoring in the total monetized health impacts.

It is important to note that these health care costs will vary significantly due to proximity to a coal-power plant, and more importantly the population's dynamics. According to the EPA, areas within 50 km of the power plant will be the most negatively impacted by particulate matter. However, areas within 100km are still considered to be highly vulnerable to the health effects associated with airborne particulate matter (Force, 2010). Additionally, negative health impacts from coal-fired power generation are especially severe for the elderly, children, the poor, minority groups, and people who live in areas downwind of multiple power plants are likely to be disproportionately exposed to the health risks and costs of fine particle pollution (USEPA, 2010).

As a result, counties in the mid-west region of Georgia are heavily impacted as they are surrounded by several coal-fired power plants. Counties with a larger population of children, the elderly, or the poor will be more negatively impacted. [18]Two counties in Georgia that can be considered highly susceptible are Meriwether and Mitchell County. Meriwether County is surrounded by coae-fired power plants and Mitchell County has a high population of lower income and elderly residents. I would therefore expect to see the health costs to be on the higher end, estimated around 26.67 cents/ kWh or possibly as high as 35.76 cents/kWh if the CHGE high estimates for health impact are applied.

Conclusion

A review of a recent literature of the negative externalities associated with coal-fired power generation reveals that the true cost of coal retains a much higher price tag than the one displayed on the average consumer's energy bill. Economists Nicholas Z. Muller, Robert Mendelsohn, and William Nordhaus (N. Z. Muller et al., 2011)determined that coal-fired power generation is the largest industrial contributor of external costs and the electricity produced by coal-fired power plants has a higher gross external damage per kWh than any other electricity source. These external damages range from 0.8 to 5.6 times the value added of generation, where SO2 emissions were responsible for 87% of the gross external damages associated with coal-fired power emissions, and that 94% of the damages were because of increased mortality. Additionally, MMN concluded that when the impact from CO2 is accounted for, the gross external damage for coal power increases by nearly 25%. MMN estimated that CO2 emissions are responsible for approximately one-fourth of total air pollution damages from coal-power generation and add an additional $15 billion in external damages per year. The National Institute of Environmental Health Sciences study (Gohlke et al., 2011) concluded that coal consumption is significantly and positively correlated with detrimental health impacts resulting from exposure to PM10 and that increased coal consumption is associated with increased infant mortality and decreased life expectancy. The Center for Health and Global Environment at Harvard Medical School (Epstein et al., 2011)determined that the best and low estimates for health damages due to air quality detriment impacts to be $187.5 billion, and $65 billion, respectively. On a plant-by-plant basis, after being normalized to electricity produced by each plant, per-kWh, the additional healthcare cost of coal was on average 9.3 ¢/kWh with a low estimate of 3.2 ¢/kWh and a high of 16 ¢/kWh. The CHGE study also determined that the best estimate for the true cost of coal, including the economically quantifiable health costs generated from coal-power production, to be between 17.8¢/kWh and 26.89¢/kWh. The high rate included the destruction caused by land-use, mercury deposition, water, waste and atmospheric pollution, where the average was restricted just to the health impact caused by fine particulate matter. The EPA concluded that the health impacts due to particulate exposure generated in coal-fired combustion is costing Americans between $110 and $270 billion annually in adverse health care costs. Over 90% of these costs are a result of premature mortalities.

Additionally, the EPA estimated that Georgian's pay between 3.3 and 7 billion dollars in aggregate health costs annually as a result of unhealthy levels of exposure to PM2.5 and O3. Given that the current population of Georgia is approximately 9.8 million, the EPA estimates translate into every Georgian incurring between $330 and $800 per year in additional health care costs due to

[18] Annual Coal Consumption (tons per year) for Generation of Electricity for Sale by Coal-Fired Power Plants in the United States (USEPA 2010a; USDOE, 2009b).

coal-fired power generation (U. S. EPA, 2011). Finally, when the methodology of the CHGE is applied to Georgia, the report estimates the average cost of coal-fired electricity to be 18.17 cents per kWh, when factoring in health impacts due to particulate exposure, and 26.67 cents per kWh, when factoring in the total monetized health impacts. These numbers are two to three times the current average retail cost of coal-fired power generation in Georgia.

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[i] In 2010, the EPA analyzed the negative health impacts caused by fine particle air pollution generated by coal-fired powered generation. Data from the EPA's Emissions & Generation Resource Integrated Database and National Emissions Inventory showed that coal-fired power generation produce more hazardous air pollution in the United States than any other industrial pollution sources as it is responsible for much of the U.S. power generation-related emissions of fine particulate matter, PM2.5 (51%), NOx (35%), and SO2 (85%). Coal-fired power plants contain 84 of the 187 hazardous air pollutant identified by EPA as posing a threat to human health and the environment.[i] The Hazardous Air pollutants emitted from coal-fired power plants include neurotoxins such as mercury and lead, corrosive substances such as hydrochloric acid, carcinogens such as arsenic and chromium, radioactive elements such as radium and thorium, and organic carbon based toxins such as dioxins and formaldehyde. Additionally, the 386,000 tons of hazardous air pollutants released annually by coal-fired power plants account for 40% of all hazardous air pollutant emissions from point sources and makes the largest point source category for hydrochloric acid, mercury, and arsenic released to air. Likewise, electricity generating stations powered by coal account for 46% of mercury, and 60% of arsenic released to the atmosphere from point sources.

These hazardous particulates are responsible for a wide range of negative health effects including damage to eyes, skin, and breathing passages; negative effects on the kidneys, lungs, and nervous system; impairment of neurological function and ability to learn; pulmonary and cardiovascular disease; adverse respiratory, reproductive, developmental, as well as cancer; and heart attacks and increased mortality. Short-term exposure to fine particle pollution is linked to cardiac effects, including increased risk of heart attack, while long-term exposure to fine particle pollution has been shown to increase the risk of death from cardiac and respiratory diseases and lung cancer, resulting in shorter life expectancy (U.S. EPA, 2011). These hazardous particulates are responsible for a wide range of negative health effects including damage to eyes, skin, and breathing passages; negative effects on the kidneys, lungs, and nervous system; impairment of neurological function and ability to learn; pulmonary

Comments to “Community Reinvestment Act: Interagency Questions and Answers Regarding Community Reinvestment”

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Appendix E:

Report: Net Metering in Mississippi – Costs, Benefits, and Policy Considerations

FILED

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MISS. PUBLIC SERVICE COMMISSION

Net Metering in Mississippi

Costs, Benefits, and Policy Considerations

Prepared for the Public Service Commission of Mississippi

September 19, 2014

2011-AD-2

AUTHORS

Elizabeth A. Stanton, PhD
Joseph Daniel
Tommy Vitolo, PhD
Pat Knight
David White, PhD
Geoff Keith

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

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.

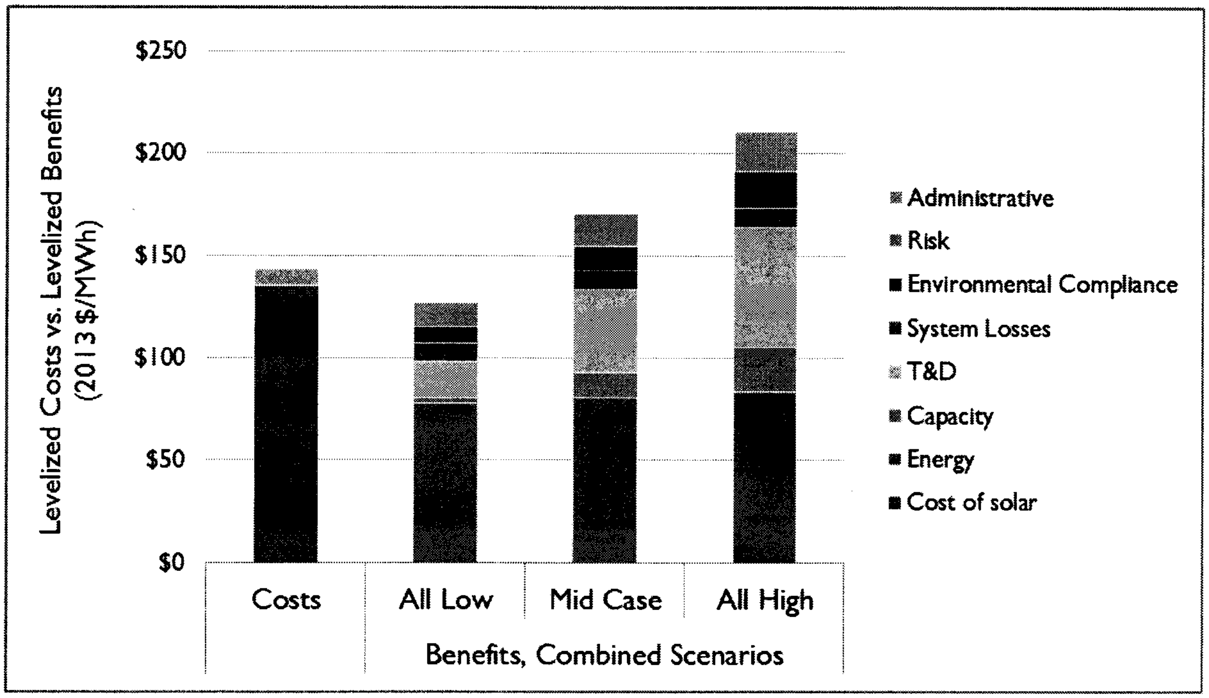
[1] Other states that do not have a net metering policy: Idaho, South Dakota, Texas, Alabama, and Tennessee.

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
[redacted]

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

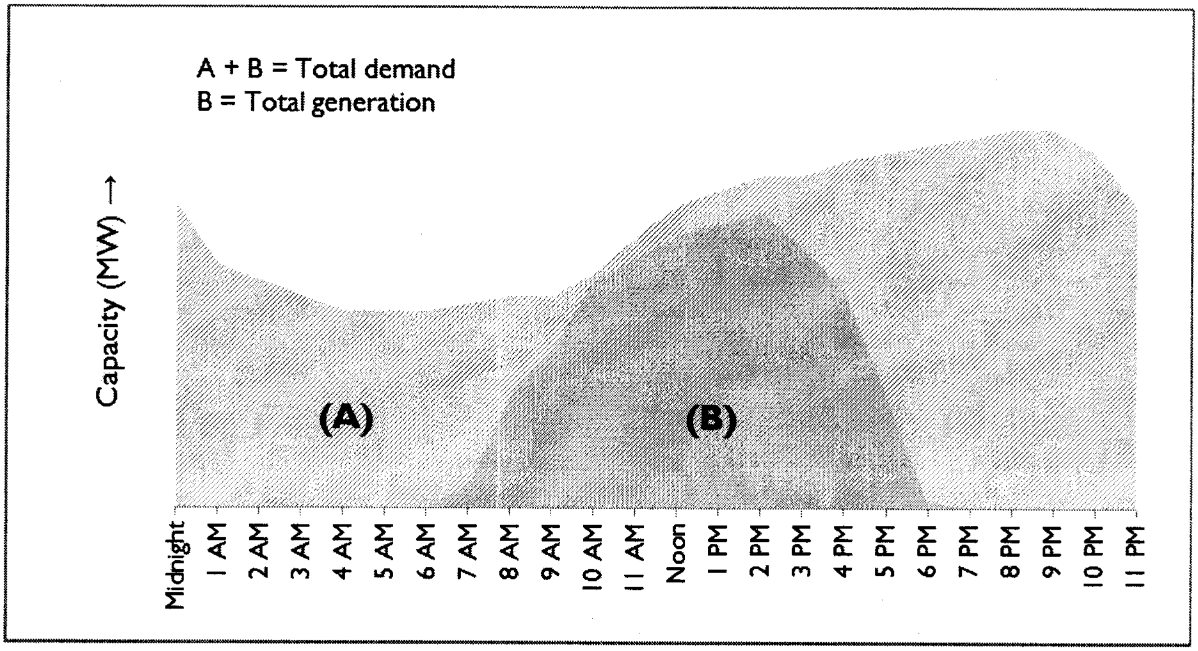
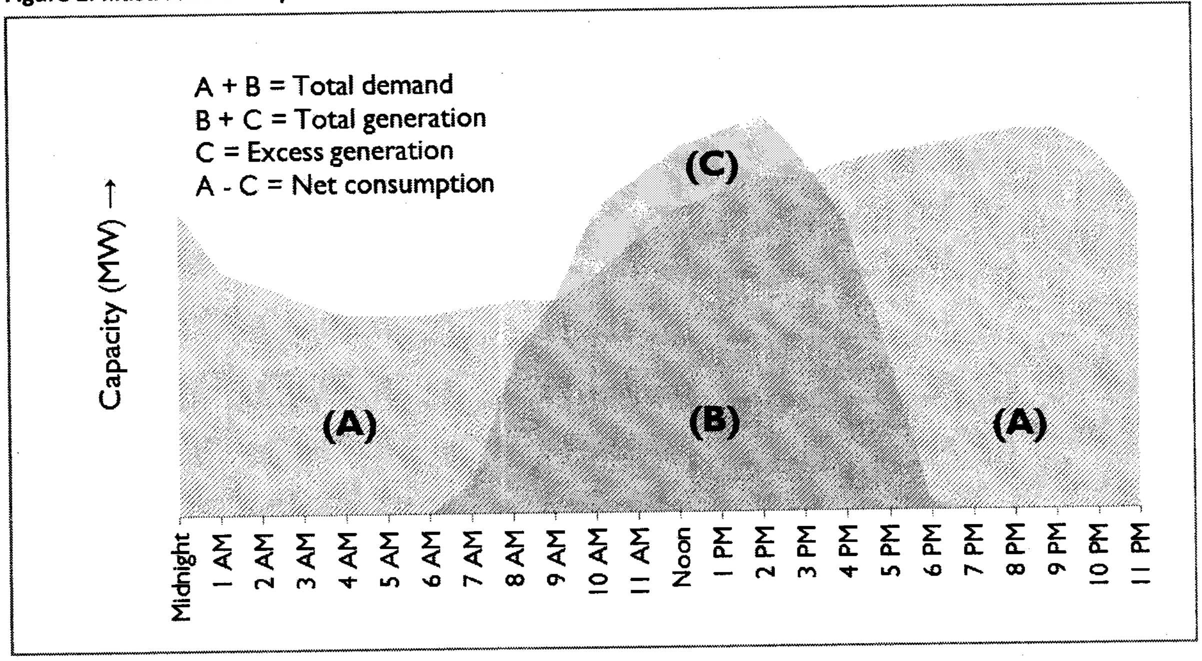


Figure 2. Illustrative example of net metered facility with excess generation



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.

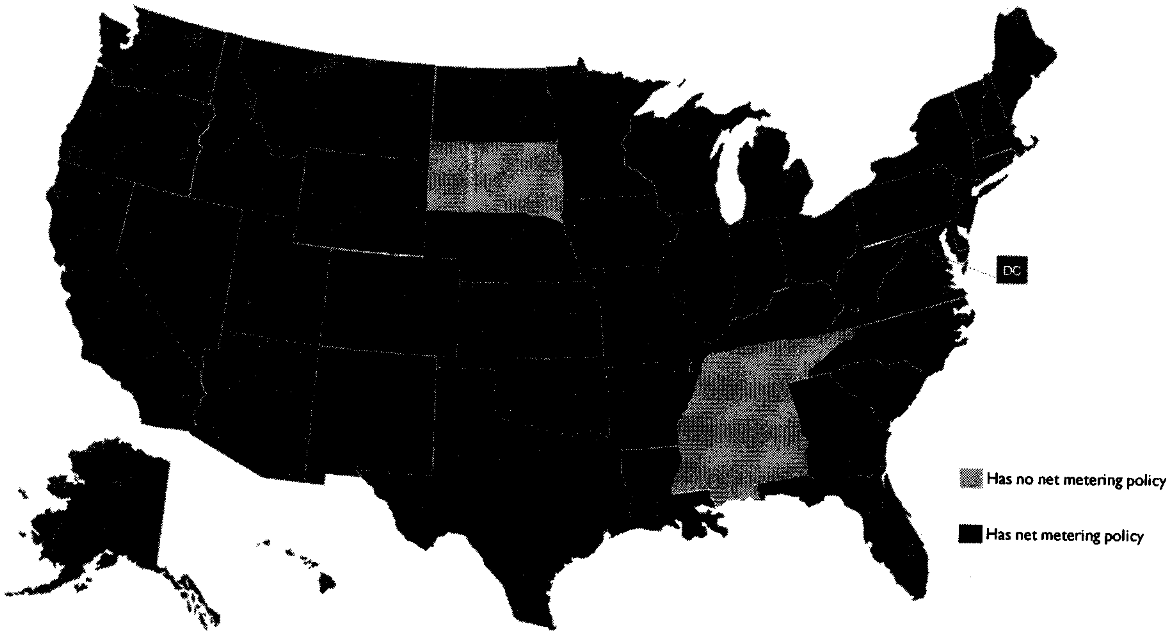
2.2. Regional Context

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.

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[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

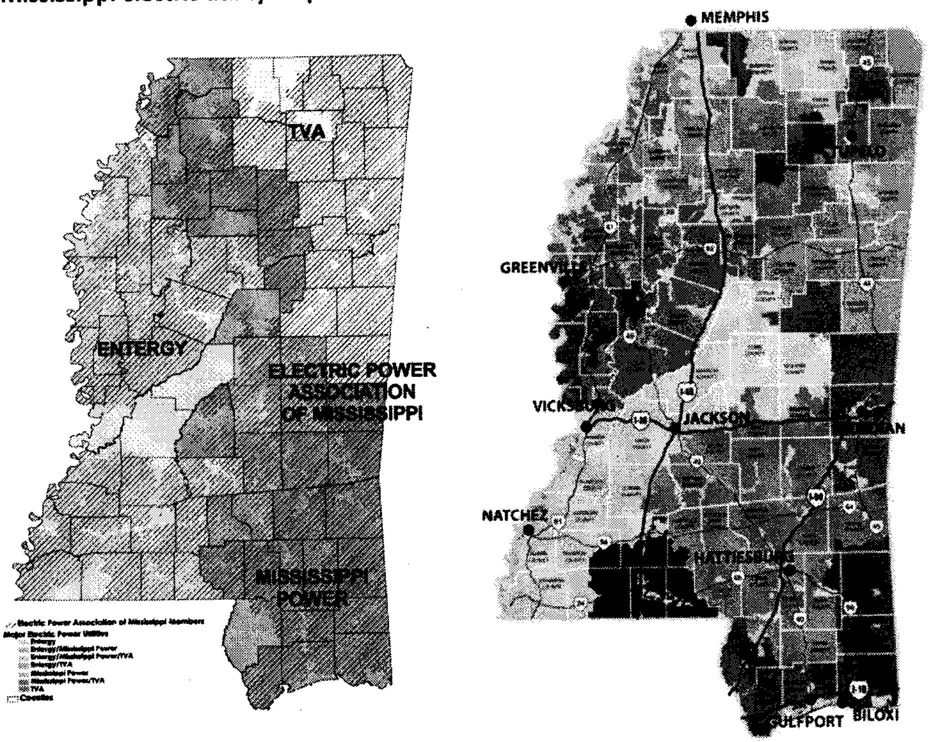
[14] Mississippi Public Service Commission, Final Order Adopting Rule, Docket No. 2010-AD-2. July 11, 2013. Original emphasis.

[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



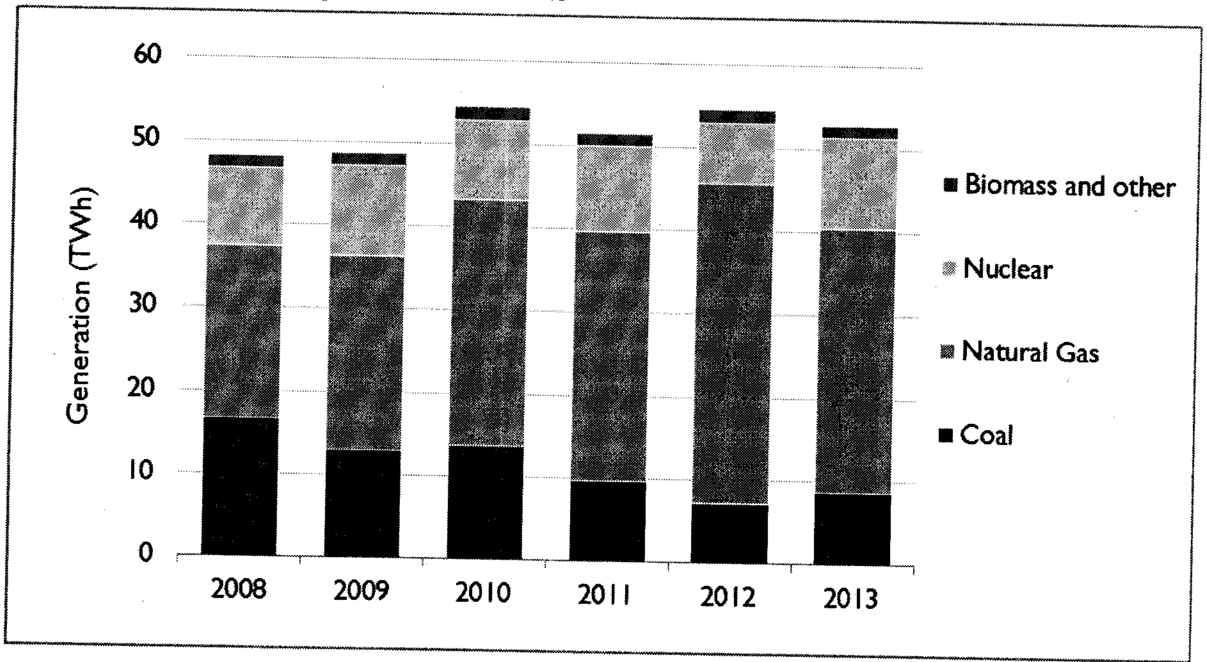
Source: Mississippi Development Authority, Electric Power Associations of Mississippi

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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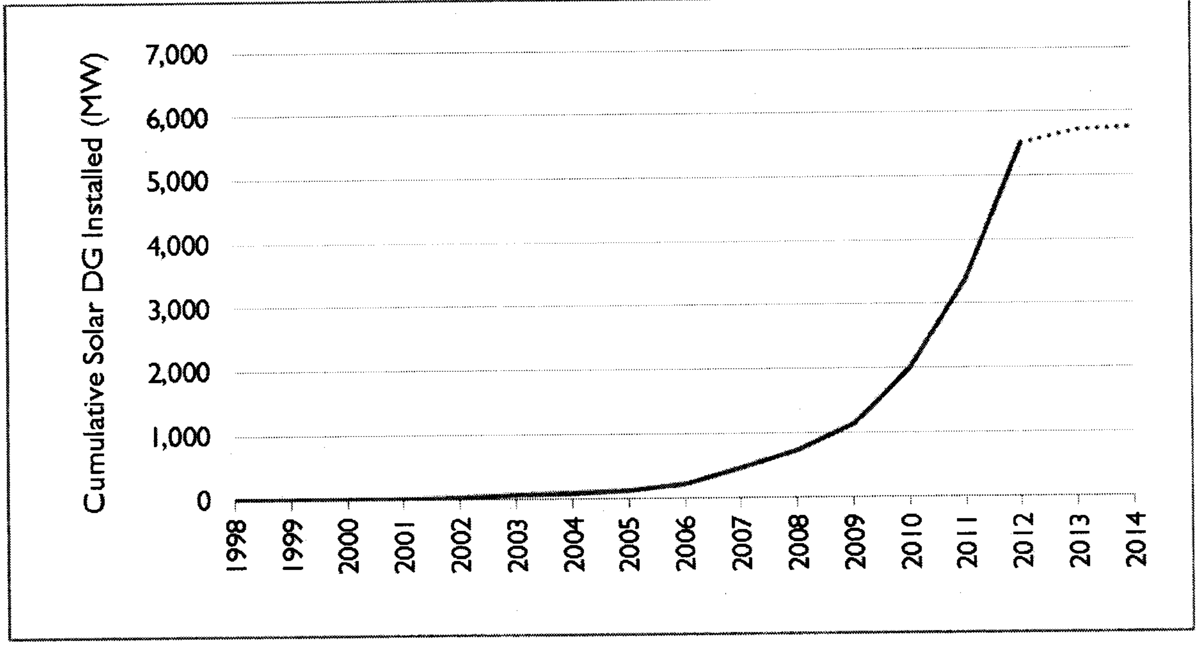
17 Energy Information Administration. 2014. "Natural Gas Gross Withdrawals and Production." Available at: http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm.

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:

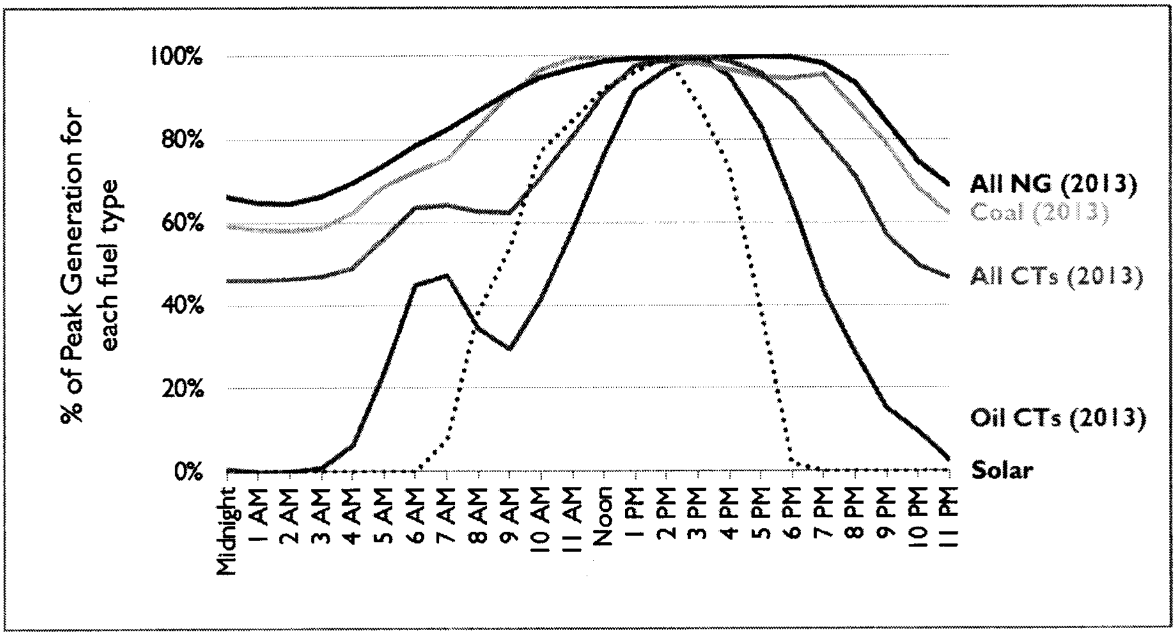
- **Modeling years:** One-year time steps from 2015 to 2039, with results provided both on an annual and a 25-year levelized basis. A 25-year analysis was chosen to reflect typical effective lifespans of solar panels.
- **Technology used for net metering:** Solar rooftop only.
- **Geographic resolution 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

[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.

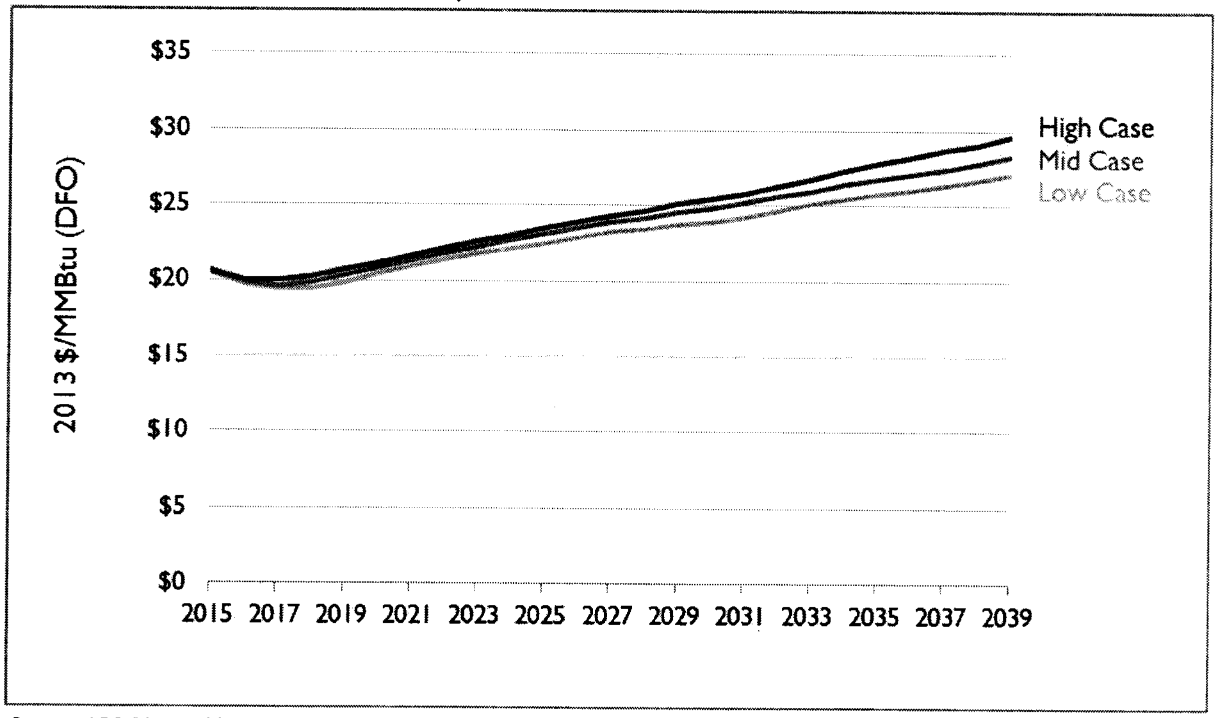
performance of roof- or ground-mounted solar facilities. The calculator, which uses geographically specific data, provides hour-by-hour data including irradiance, DC output, and AC output. PVWatts® only had one location in Mississippi—Meridian—and this was used as a sample for our hourly data and to 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

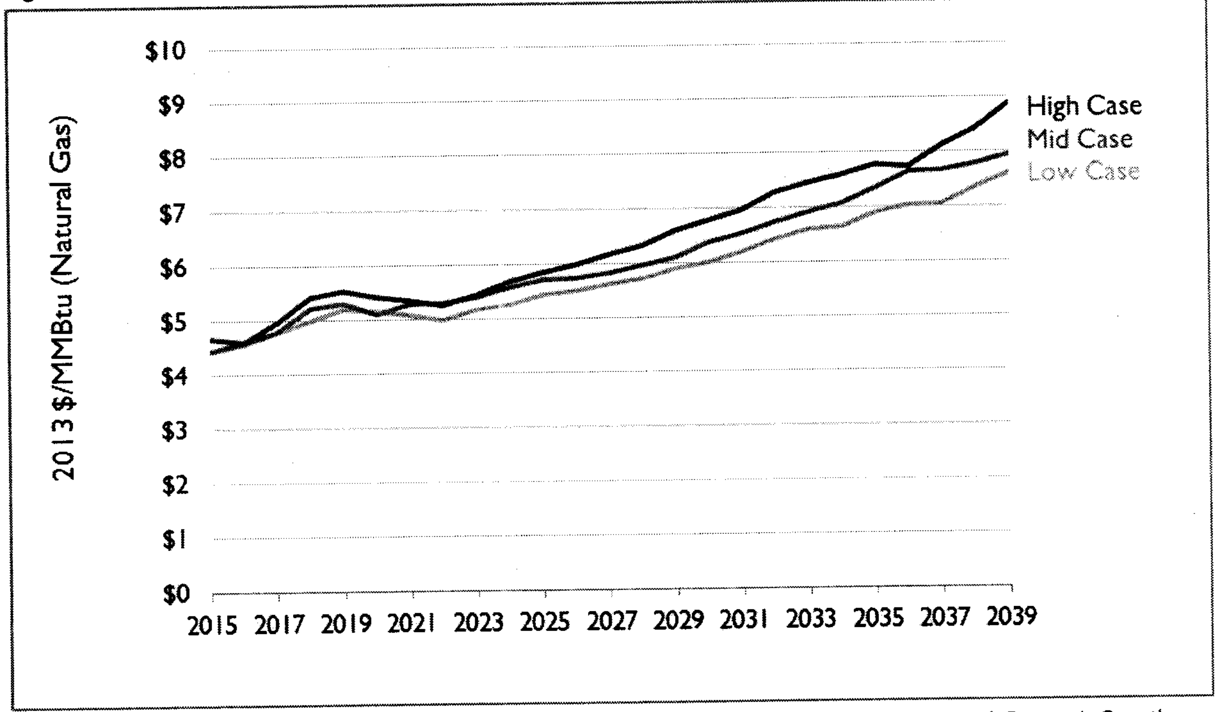
Our model assumes that net metered solar rooftop generation displaces oil- and natural gas-fired units. Consequently, fuel cost forecasts are a critical driver of avoided energy costs. The model uses fuel data price forecasts from AEO 2014 specific to the East South Central region (see Figure 8 and Figure 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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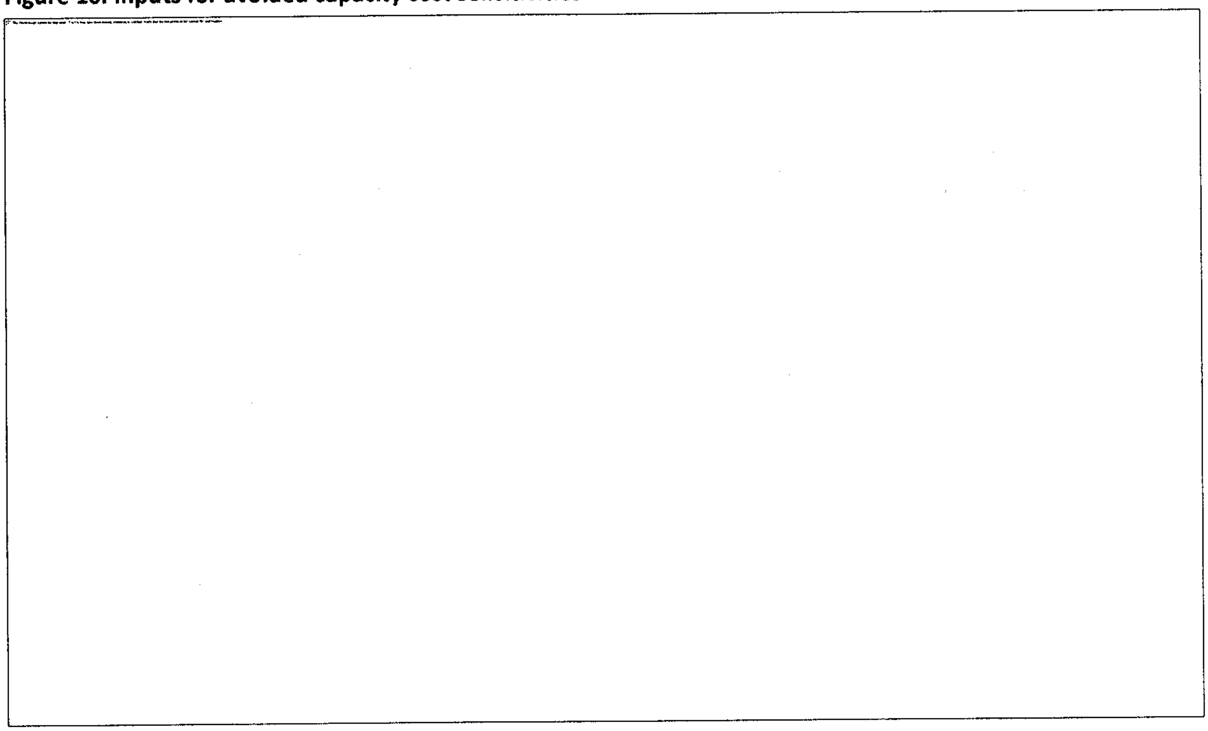
[22] EIA. 2012. EIA 860 2012. Available at: http://www.eia.gov/electricity/data/eia860/xls/eia8602012.zip.

[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



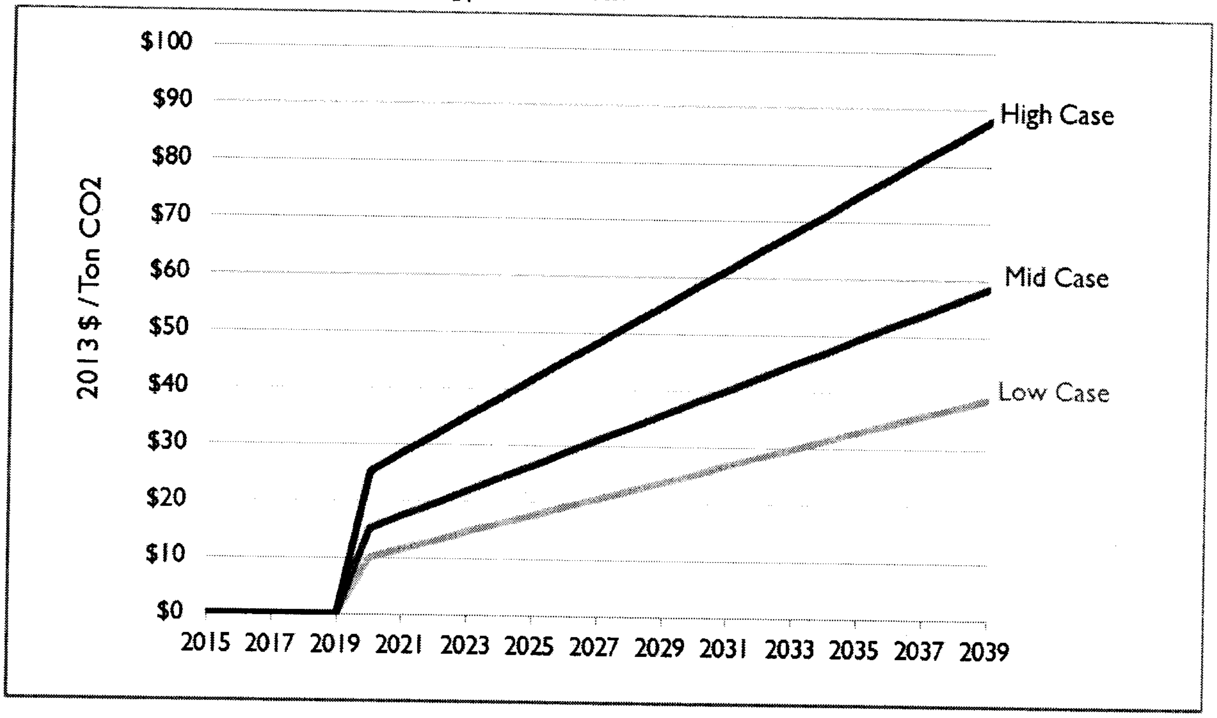
[25] PJM Planning Period Parameters 2017-2018. Available at: http://pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-planning-period-parameters.ashx. MISO calculates gross CONE but not net CONE.

[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.

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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.

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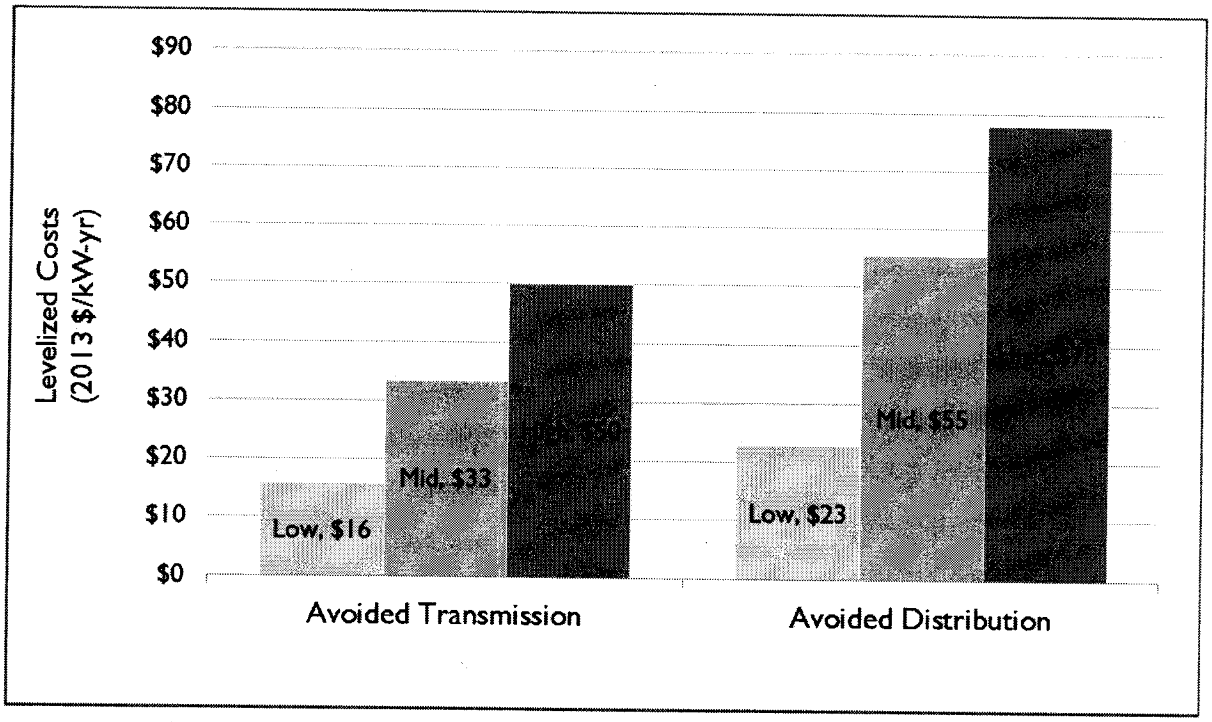
[32] The values in this database are consistent with a 2013 review of avoided T&D costs of distributed solar in New York, New Jersey, Pennsylvania, Texas, Colorado, Arizona, and California. See: Hansen, L., V. Lacy, D. Glick. 2013. *A Review of Solar PV Benefit and Cost Studies, 2nd Edition*. Rocky Mountain 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.

[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

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[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 Kempler 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

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[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.

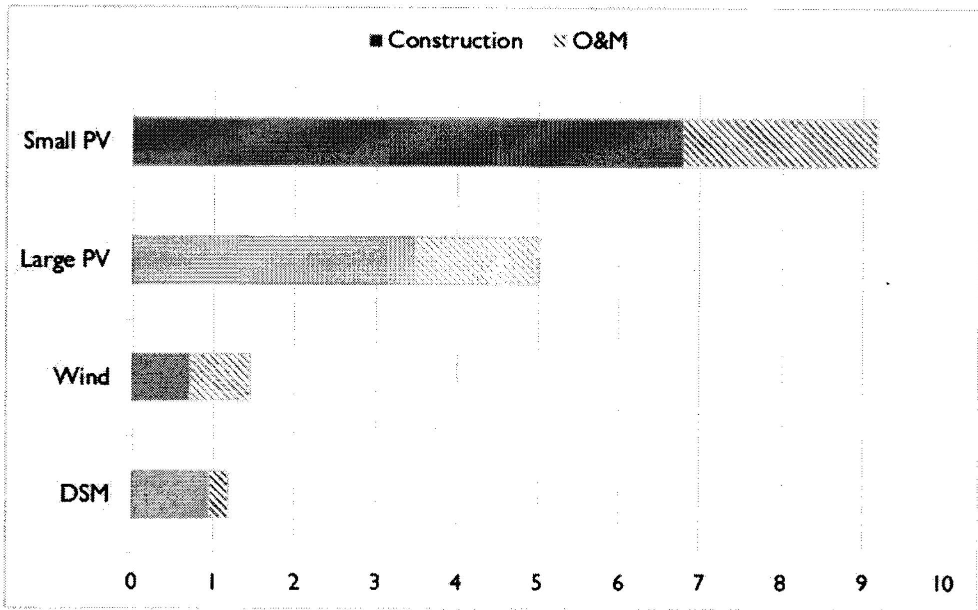
[43] Frayer, J., S. Keane, J. Ng. 2013. *Estimating the Value of Lost Load.* Prepared by London Economics on behalf of the Electric Reliability Council of Texas, Inc. Available at: http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf.

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.

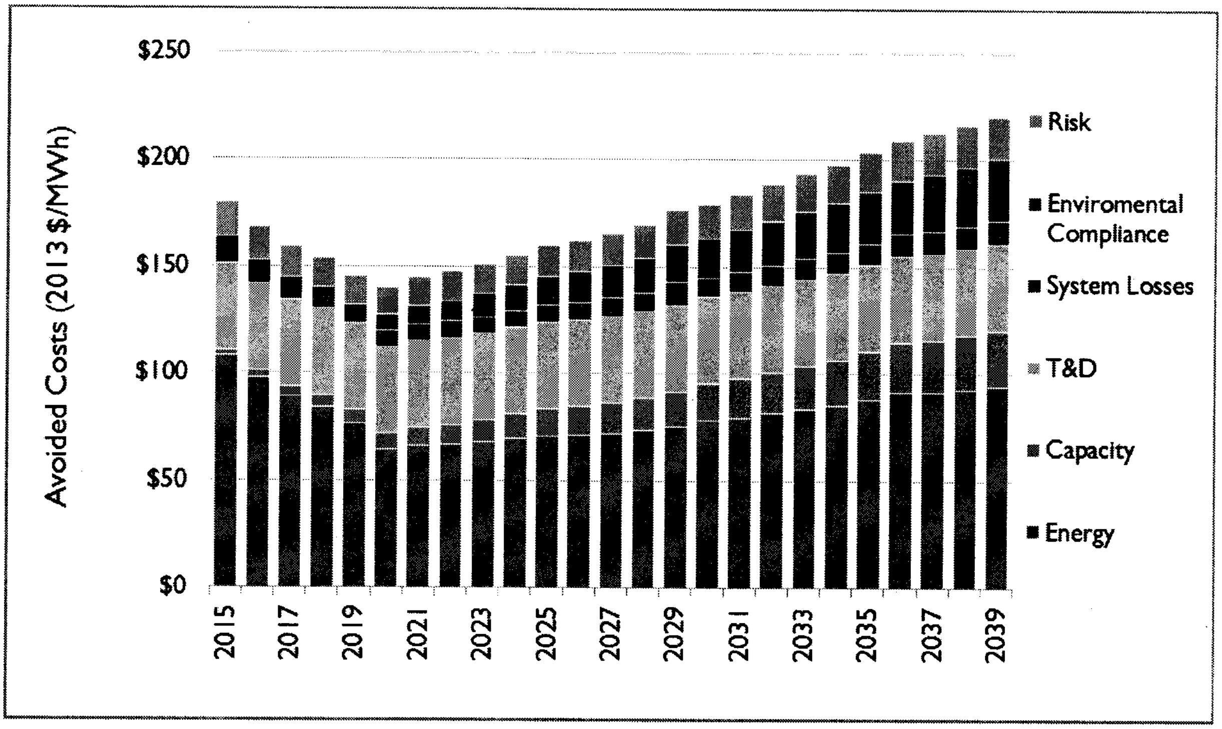
4.1. Policy Case Benefits

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.

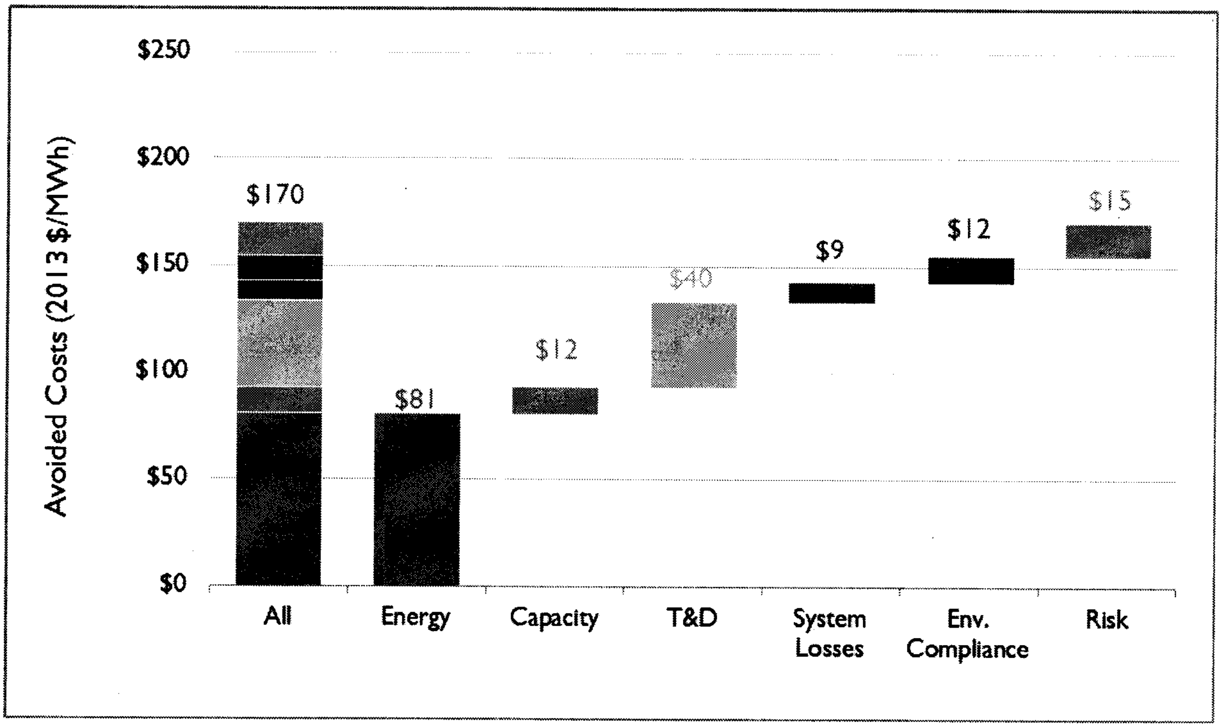
Figure 14. Annual potential benefits (avoided costs) of solar net metering in Mississippi



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

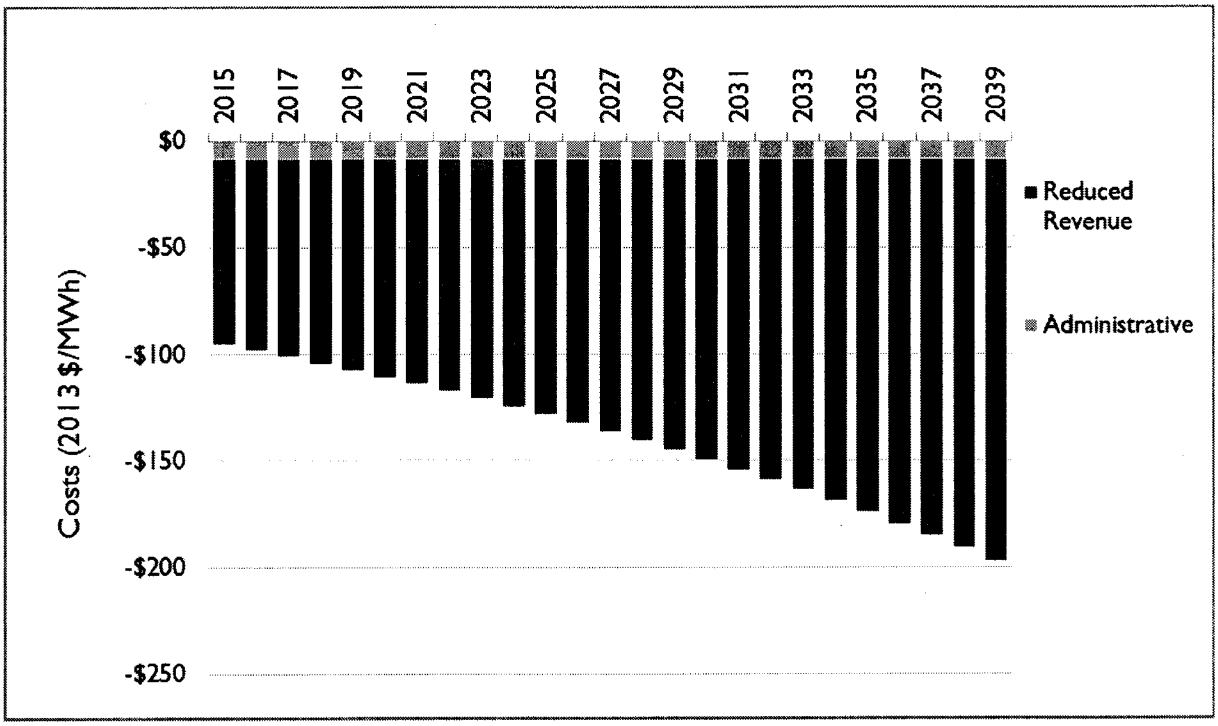


4.2. Policy Case Costs

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

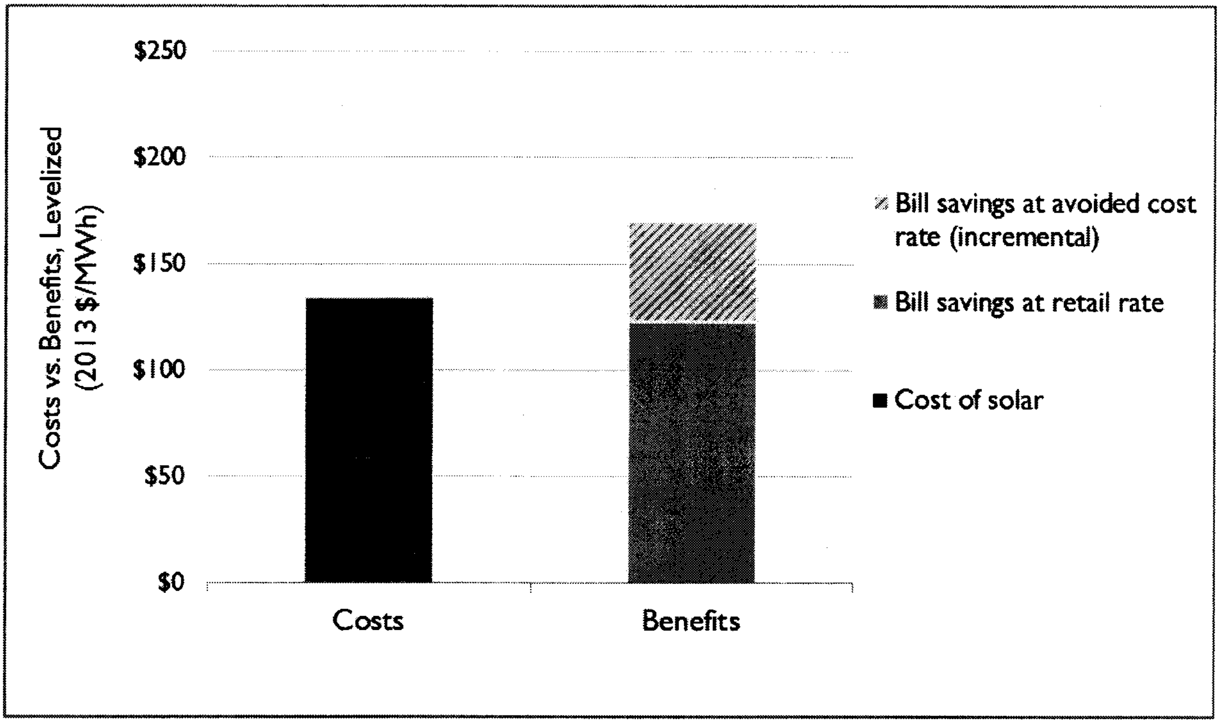
We performed cost-effectiveness analyses on a representative net metering program in Mississippi using several methods (refer to Section 2.3 above). Here we discuss:

- 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.

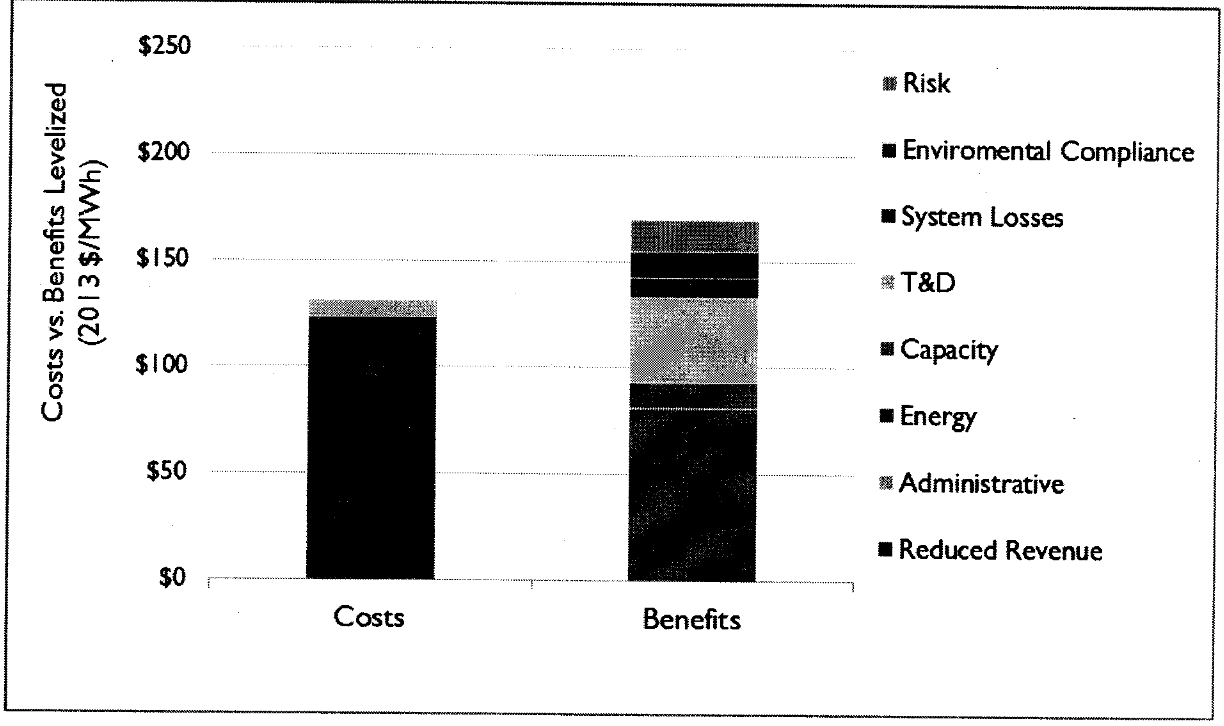
For these reasons, in this analysis we have chosen to use neither of these screening tests to investigate the impacts of net metering from the utility perspective.

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

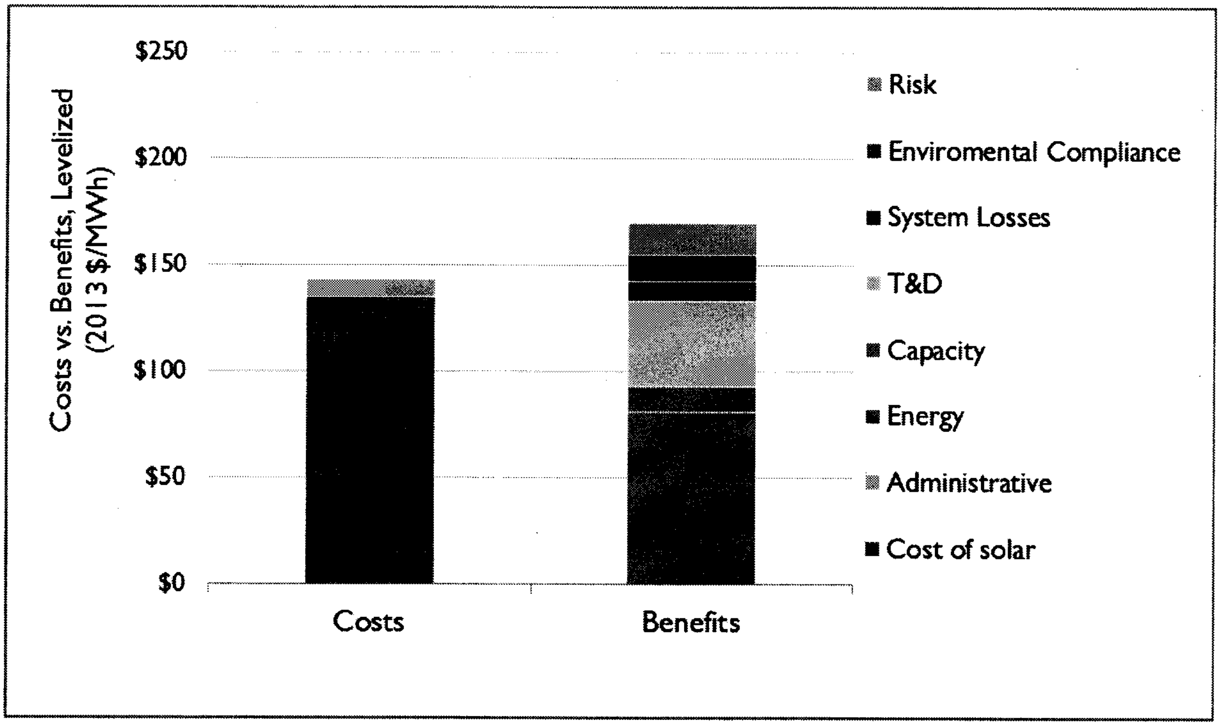


Total Resource Perspective

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

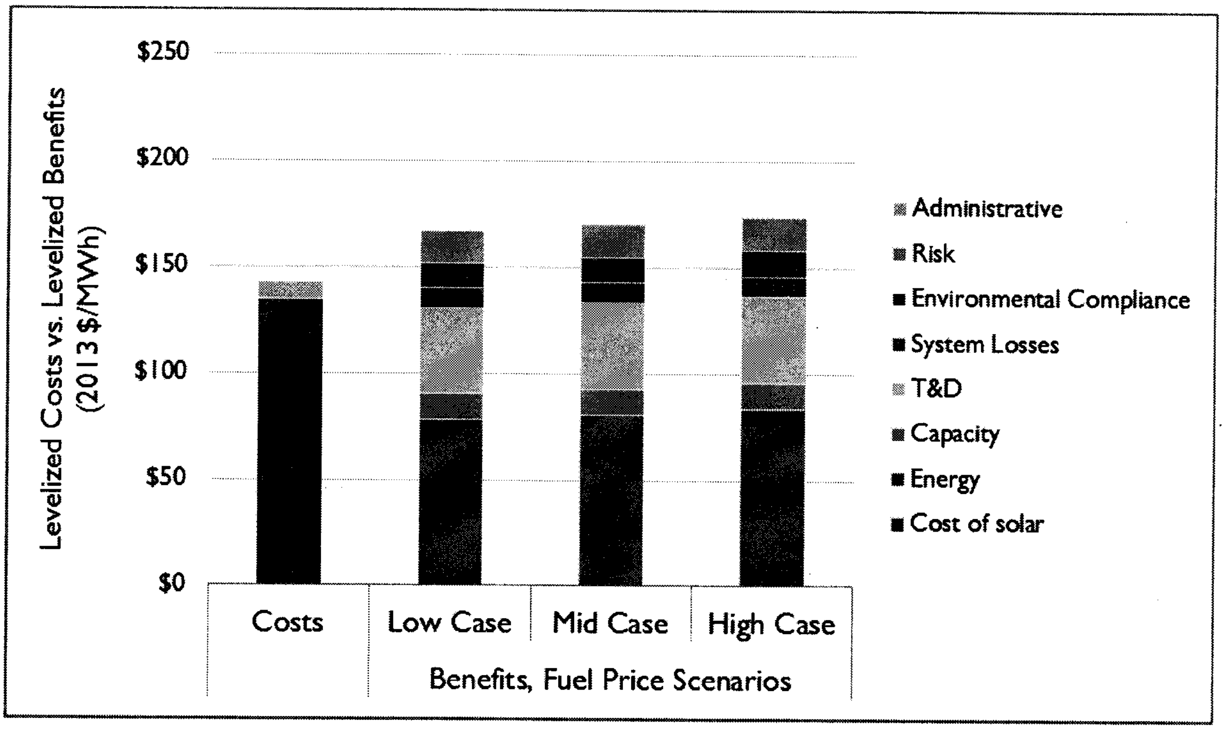


Table 8. Avoided energy benefits and TRC test benefit/cost ratios under fuel price sensitivities

	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

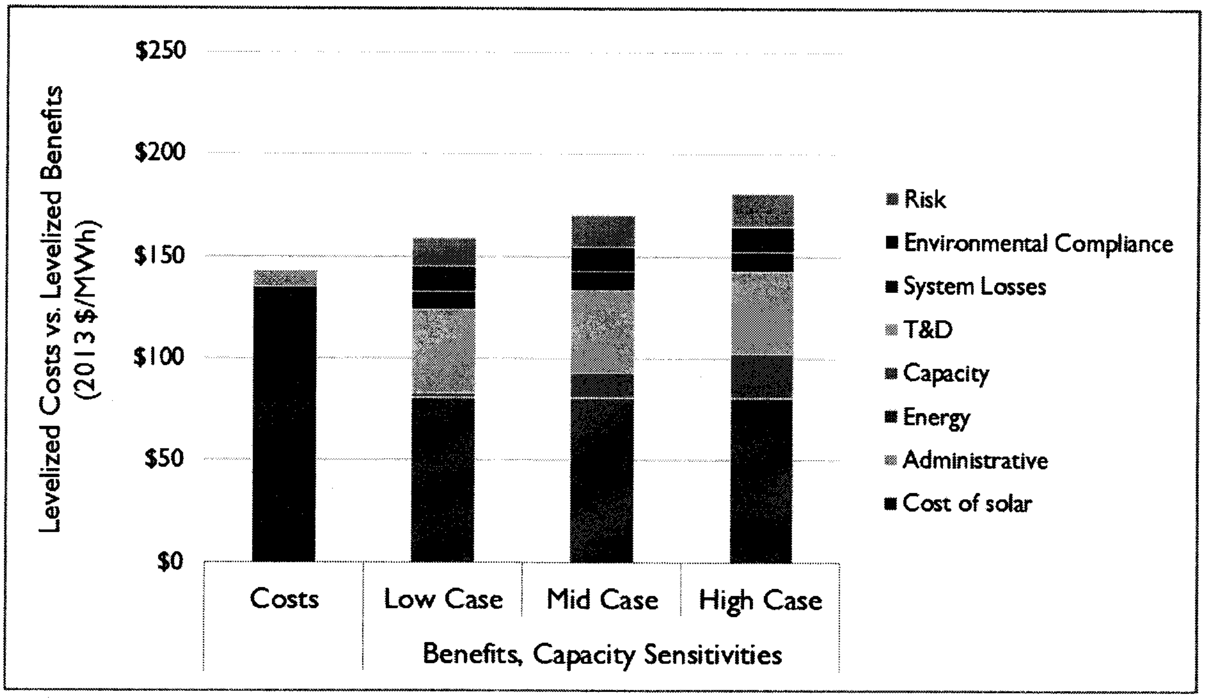


Table 9. Avoided capacity benefits and TRC test benefit/cost ratios under capacity value sensitivities

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

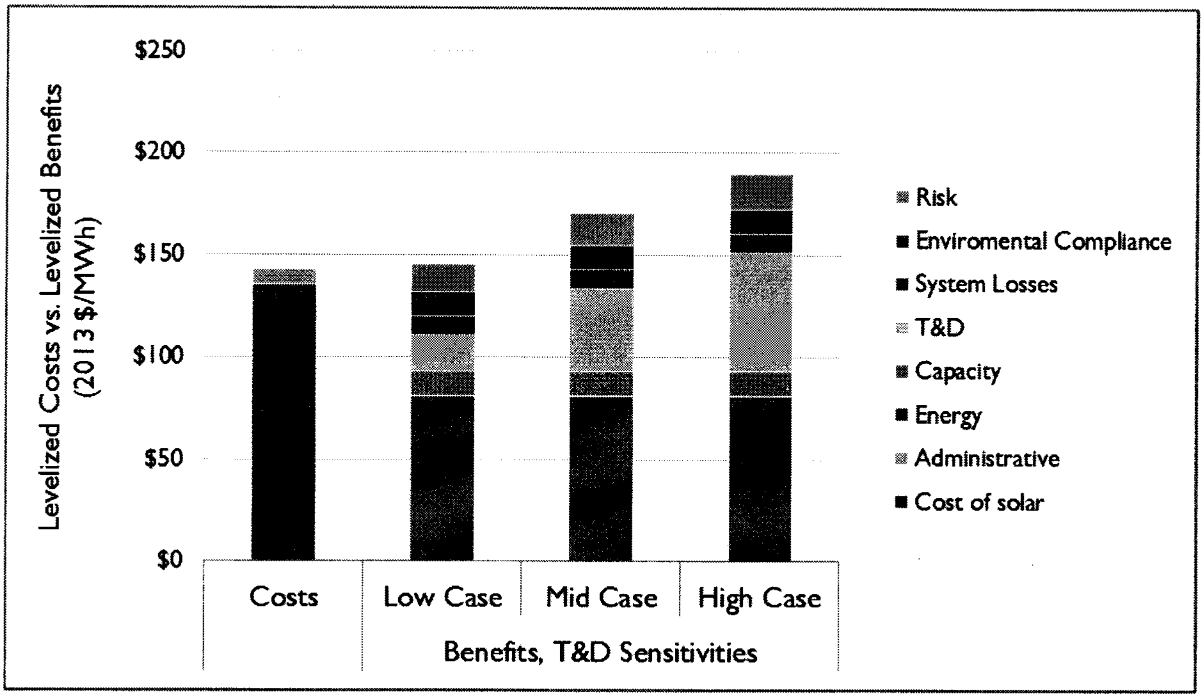


Table 10. Avoided T&D benefits and TRC test benefit/cost ratios under avoided T&D cost sensitivities

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

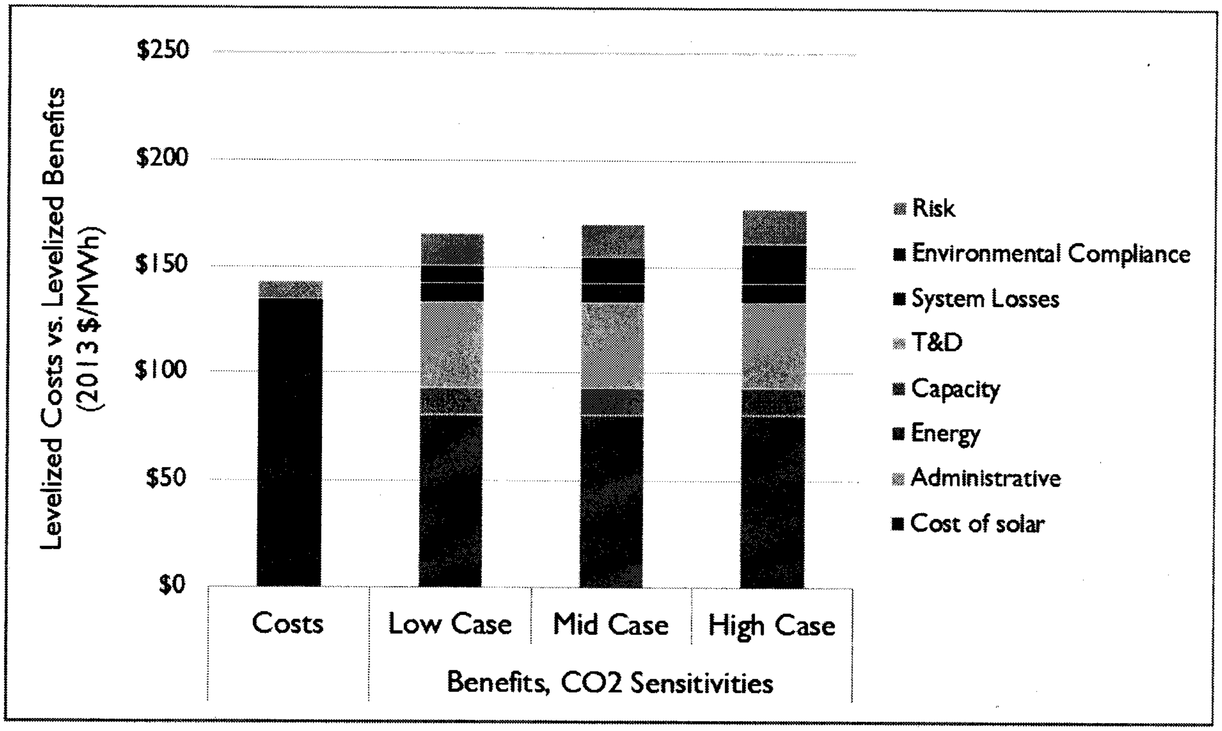


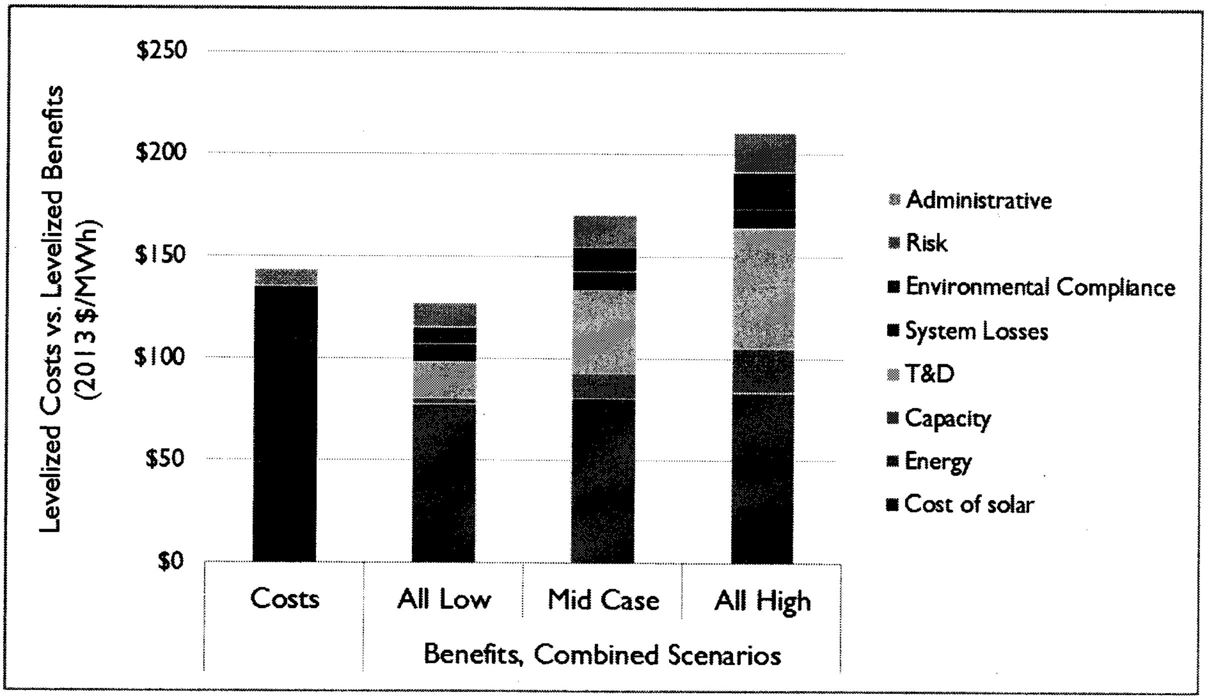
Table 11. Avoided environmental compliance costs and TRC benefit/cost ratios under CO_2 cost sensitivities

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.

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[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

Portfolio	Expected Cost ($M)	Difference from BAU: *Million Dollars*	Difference from BAU: *Percent*	$TVaR_{90}$ ($M)	Spread Between $TVaR_{90}$ and Expected Cost: *Million Dollars*	Spread Between $TVaR_{90}$ and Expected Cost: *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)

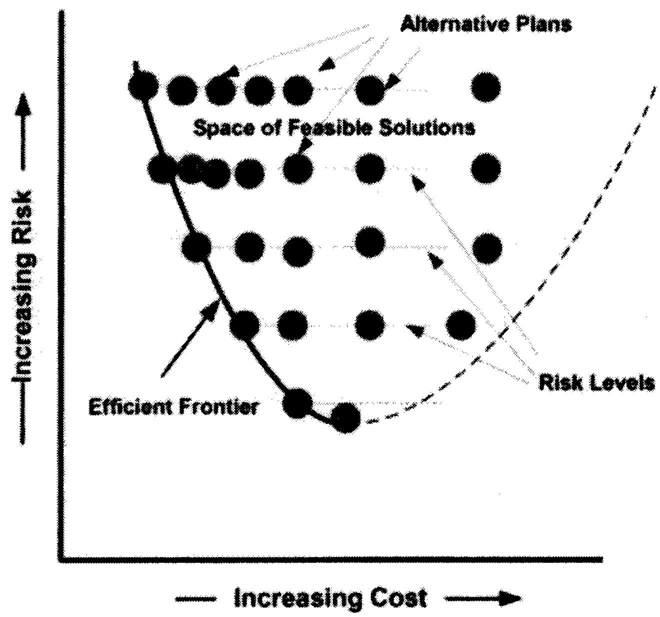
The Northwest Power and Conservation Council (NWPCC) has been assessing and developing plans for the future of energy resources in the Northwest region every five years since the organization was

[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.

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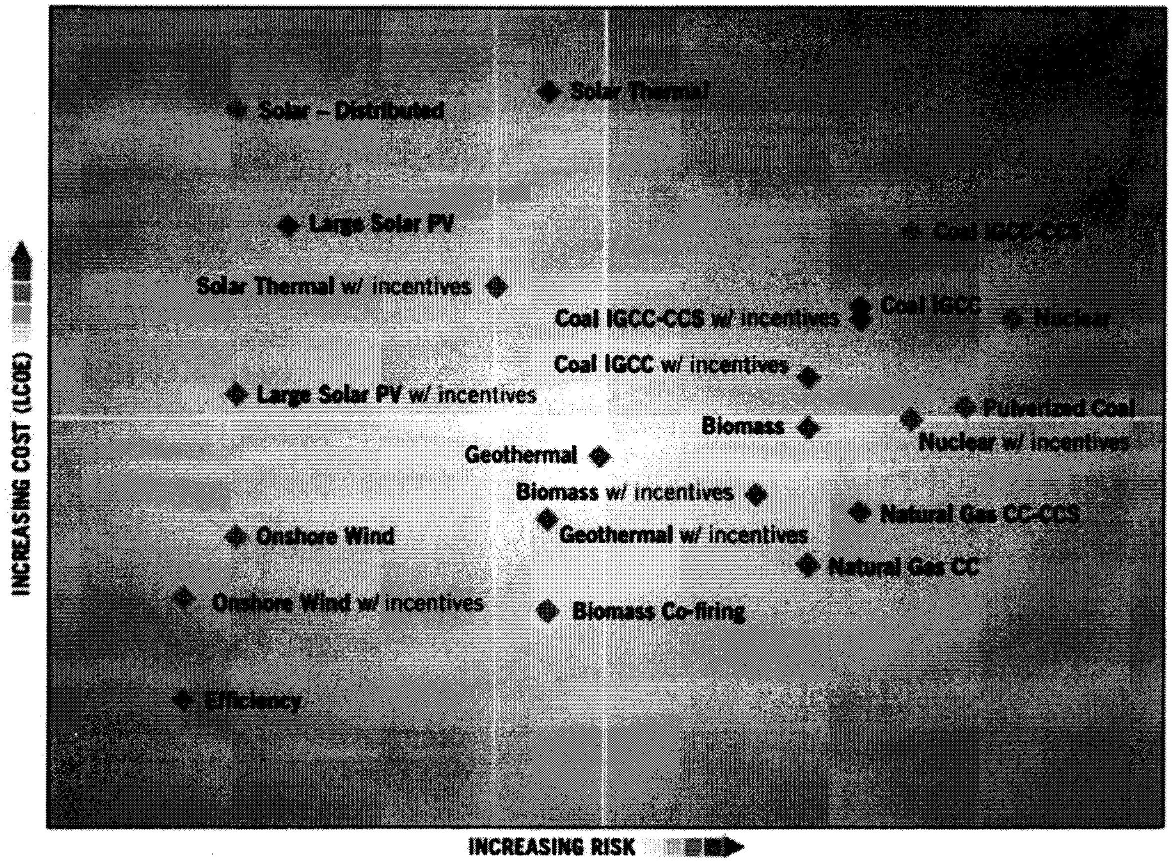
[63] Binz, R., R. Sedano, D. Furey, D. Mullen. 2012. *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know.* Ceres. Available at: http://www.ceres.org/resources/reports/practicing-risk-aware-electricity-regulation/view.

[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.

Comments to “Community Reinvestment Act: Interagency Questions and Answers Regarding Community Reinvestment”

Agency Name: OCC

Docket ID OCC-2014-0021

Date Submitted: November 7, 2014

Appendix F:

Report: PV Value Analysis for We Energies

PV VALUE ANALYSIS FOR WE ENERGIES

Prepared by:

Benjamin L. Norris
Thomas E. Hoff
Richard Perez

Clean Power Research
www.cleanpower.com

October 2009

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

EXECUTIVE SUMMARY

INTRODUCTION

We Energies is providing financial incentives to commercial customers under its 2007-2008 “Solar Electric Development” pilot program. The program is expected to stimulate the installation of 1 MW_{AC} of customer-owned photovoltaic (PV) systems.

We Energies contracted with Clean Power Research (CPR) to support this program by performing the following tasks:

- Evaluate ownership scenarios to determine if the systems should be customer-owned, third-party-owned, or utility-owned.[1]
- Design an incentive structure to stimulate the installation of 1 MW_{AC} of PV.
- Provide software services, including PowerClerk®, SolarAnywhere®, and PVSimulator™, to assist in the administration of the Solar Electric Development program.
- Assess the value of PV to We Energies at a specific point in time.

The ownership scenario analysis and incentive structure analysis are documented in separate reports[2] and the software services provide ongoing administrative support to the program.

OBJECTIVE

The objective of this report is to present the results of the value analysis from the perspective of We Energies at a specific point in time. The value of PV to We Energies will change over time. Other utilities that have performed similar studies typically reassess value as economic factors change. It is recommended that We Energies also reassess value as economic factors change.

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[1] The study concluded that systems should be customer-owned. The recent change in the federal investment tax credit becoming available to utilities, however, may alter the optimal system ownership structure.

[2] The two reports are (1) "PV Ownership Scenarios at We Energies: A Comparison of Customer, Third Party, and Utility Ownership", August 26, 2006; and (2) "1 MW Solar Program: PV Incentive Design for We Energies", November 14, 2006. Both reports are prepared by Clean Power Research for We Energies.

The value of PV to We Energies includes the following value components:

- Generation Value
- Environmental Value
- Fuel Price Hedge Value
- Distribution Value
- Transmission Value
- Loss Savings Value

The Executive Summary is divided into three parts. The first part describes the scenarios evaluated. The second part presents the results. The third part discusses the details.

SCENARIOS

Detailed value analyses were performed for all combinations of seven PV system configurations at three locations. Thus, the study summarizes the results of twenty-one scenarios.

PV SYSTEM CONFIGURATIONS

A wide variety of PV system configurations are readily available in the market. PV modules can be fixed (i.e., they remain in the same location throughout the year) or tracking (i.e., they follow the sun). Fixed systems are often oriented to maximize energy production, such as facing south at an angle corresponding to the latitude. Other designs, however, may be used to take into account the building architecture (e.g., modules are aligned with roof slope) or to bias output for energy delivery at a particular time of day. Tracking systems produce more energy than fixed systems by following the sun but are more costly to install and maintain. Both 1-axis and 2-axis tracking systems are used, although 1-axis tracking systems are more common due to their relative simplicity.

The value analysis was performed for seven representative PV system configurations:

- Fixed configurations
  - Horizontal (fixed PV with no tilt)
  - South-30 (south-facing fixed PV tilted at 30°)
  - SW-30 (southwest-facing fixed PV tilted at 30°)
  - West-30 (west-facing fixed PV tilted at 30°)
  - West-45 (west-facing fixed PV tilted at 45°)
- Tracking configurations
  - 1-Axis (north-south 1-axis tracking PV with no tilt)
  - 1-Axis Tilt (north-south 1-axis tracking PV with 30° tilt)

Locations

Time- and location-specific hourly solar data from SolarAnywhere were combined with ambient temperature and wind speed data and then processed through PVSimulator to produce hourly PV system output for each of the seven PV system configurations. The data were produced for Appleton, Waukesha, Racine, and Milwaukee.

A screening procedure was used to select three distribution system study areas for a detailed value analysis. The study areas included:

- Merton
- Albers
- Union Grove

RESULTS

Table ES-1 presents the PV value per unit of installed PV capacity ($ per kW_{AC}) broken down by the individual value components for each of the seven PV system configurations at the three study areas. Table ES-2 converts the total PV value from units of installed PV capacity to units of energy ($ per kWh). Figure ES-1 and Figure ES-2 summarize the information from Tables ES-1 and ES-2 graphically. Figure ES-1 presents the total value per unit of installed PV capacity and Figure ES-2 presents the total value per unit of energy.

Figure ES-1 indicates that total value is strongly influenced by PV system orientation but not by location. This raises the question about whether the value is based mainly on the amount of energy produced or on some other factor. Figure ES-2 provides the answer to this question and indicates that PV value is almost linearly related to PV system energy production regardless of system configuration or location.

The conclusion of this analysis is that, for the time period during which the study was conducted, the estimated value of PV for We Energies over the PV system's 30-year lifetime was approximately $0.15 per kWh.

Figure ES-3 presents the results by value component and system configuration for the Merton Substation location. Figure ES-3 indicates that Generation, Environmental, and Fuel Price Hedge Value components comprise the highest portion of total value.

Table ES-1. Value components by PV system configuration and location ($/kW$_{AC}$).

	1 Axis	*1 Axis Tilt*	*South-30*	*SW-30*	*West-30*	*West-45*	*Horiz*
Generation Value							
Merton	1,522	1,682	1,338	1,273	1,080	1,001	1,134
Albers	1,536	1,691	1,340	1,282	1,095	1,017	1,144
Union Grove	1,536	1,691	1,340	1,282	1,095	1,017	1,144
Environmental Value							
Merton	1,321	1,458	1,134	1,062	891	822	960
Albers	1,343	1,477	1,144	1,075	907	838	973
Union Grove	1,343	1,477	1,144	1,075	907	838	973
Fuel Price Hedge Value							
Merton	680	751	584	547	459	423	494
Albers	692	761	589	554	467	432	501
Union Grove	692	761	589	554	467	432	501
Distribution Value							
Merton	145	143	45	129	149	149	70
Albers	49	49	11	30	39	45	16
Union Grove	147	145	43	92	116	132	56
Transmission Value							
Merton	49	47	25	40	47	48	31
Albers	39	39	18	28	33	36	20
Union Grove	53	51	25	39	46	49	31
Loss Savings Value							
Merton	124	135	103	103	90	85	90
Albers	77	85	65	63	55	51	56
Union Grove	134	146	110	109	96	91	96
Total Value							
Merton	3,842	4,217	3,229	3,154	2,716	2,527	2,778
Albers	3,737	4,101	3,168	3,033	2,595	2,419	2,710
Union Grove	3,905	4,270	3,252	3,152	2,726	2,557	2,801

Table ES-2. Total value per unit of energy by PV system configuration ($/kWh).

	1 Axis	*1 Axis Tilt*	*South-30*	*SW-30*	*West-30*	*West-45*	*Horiz*
Merton	0.1539	0.1531	0.1507	0.1572	0.1614	0.1628	0.1533
Albers	0.1473	0.1470	0.1466	0.1493	0.1515	0.1528	0.1475
Union Grove	0.1539	0.1530	0.1505	0.1552	0.1592	0.1616	0.1524

Figure ES-1. Total value per unit of installed PV capacity by system configuration and location.

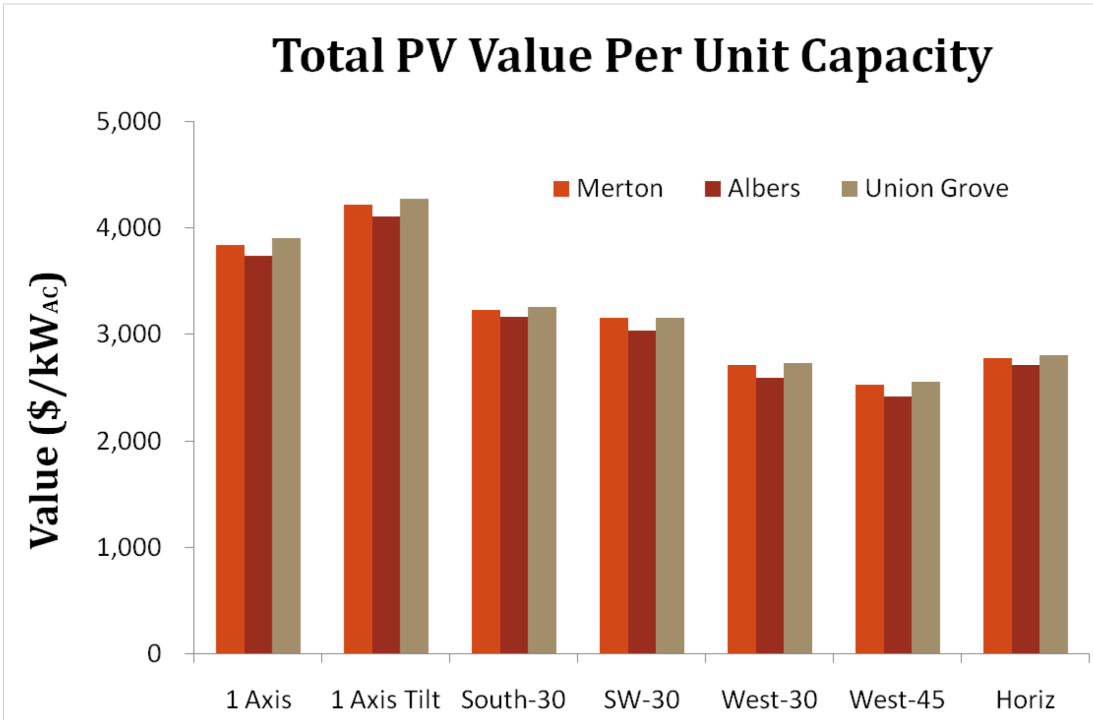


Figure ES-2. Total value per unit of energy by system configuration and location.

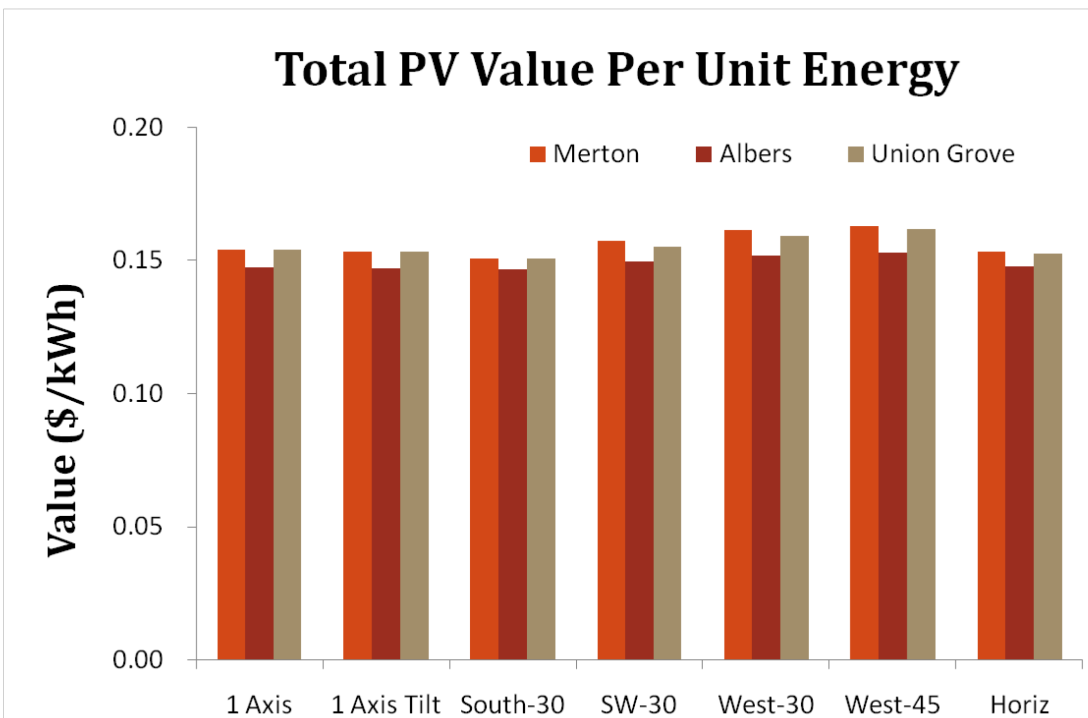
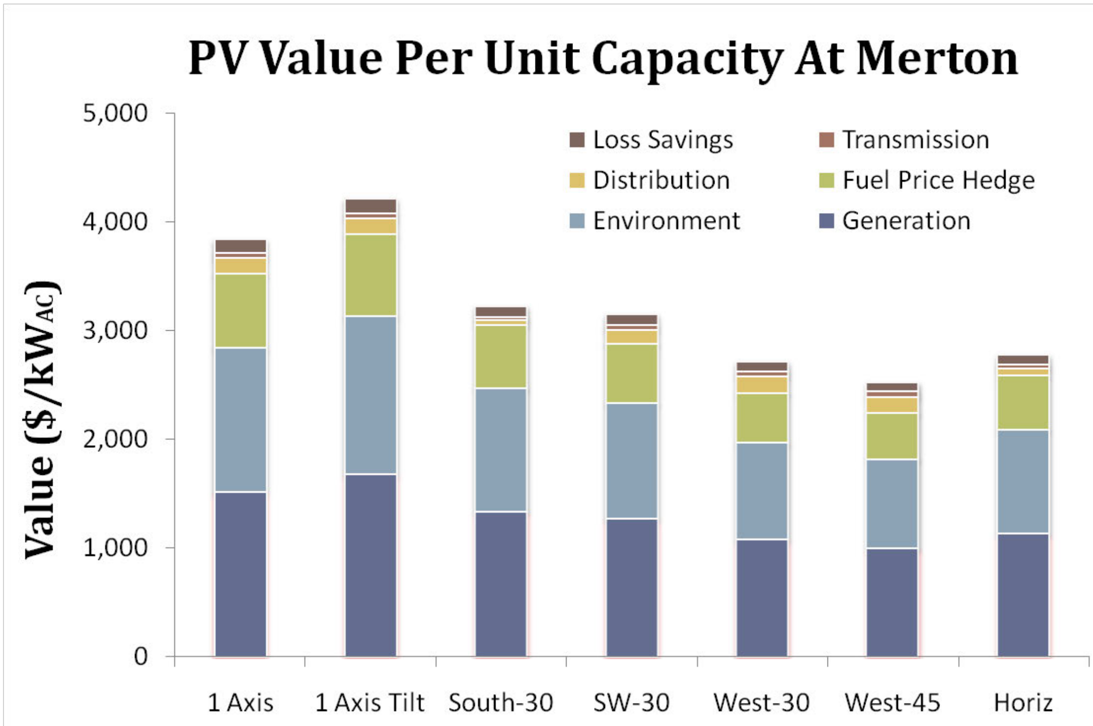


Figure ES-3. Value per unit of installed PV capacity by configuration for Merton Substation.



Discussion

This section describes the value components in more detail.

Generation Value

Generation Value is the benefit that We Energies derives from PV's offset of We Energies' wholesale energy purchases. More specifically, each kWh that PV generates at the customer's site is one less kWh that We Energies needs to purchase or generate. (Note that energy loss savings are accounted for separately in the Loss Savings section.)

The cost savings vary according to the PV system location and the time of the energy production. We Energies participates in the Midwest ISO. Thus, Midwest ISO day-ahead market clearing prices were used for the analysis. The Midwest ISO market employs a Locational Marginal Pricing (LMP) methodology where prices vary by location and hour. LMPs represent the cost of energy generation on a $ per MWh basis. Capacity benefits are considered to be small and were not included in the study even though PV also provides generation capacity benefits.

Historical LMPs from pricing nodes nearby to the locations under consideration were used in combination with modeled PV production in three We Energies distribution areas. The hourly

LMPs were multiplied by the corresponding hourly PV system output. The results were summed for the year and the present worth of the 30-year value stream was calculated using We Energies' discount rate of 8.52 percent.

Environmental Value

PV provides environmental benefits by contributing toward We Energies renewable portfolio standard (RPS) obligations. The utility's requirements for either generating or purchasing renewable energy are reduced when PV systems generate electricity. The environmental benefit for this study is the value of avoided purchases of renewable resource credits (RRCs) to meet the utility's required RPS percentages.

An investigation of established renewable energy credit (REC) markets outside of Wisconsin indicates that current pricing for solar RECs in compliance states[3] with source qualifications similar to Wisconsin's is about $50 per MWh. This value was applied to the annual PV production and the results discounted over the 30-year life.

Fuel Price Hedge Value

Electricity in Wisconsin is primarily generated from coal, nuclear, natural gas, and petroleum. Electricity prices throughout the state are subject to uncertainty because fuel prices fluctuate over time. The cost of electricity generated from PV, however, is constant and fixed over the 30-year PV system life since it is not dependent upon fuels other than solar energy. Thus, PV provides a "hedge" against future fuel price uncertainty.

The method used to quantify this benefit is loosely based on the Black–Scholes options pricing model. The method is documented more fully in a PV valuation analysis conducted by CPR for Austin Energy in 2006.[4]

The essence of the method is that price volatility from conventional power plants is captured in the futures pricing of fuel commodity markets. Owning a PV system provides "risk-free" electricity and thus is equivalent to holding a futures contract for the purchase of future energy at a known price.

[3]REC pricing is investigated in eight states for this study. Only the closest source classes are used since the definitions of allowable technologies are generally not identical between states.

[4] "The Value of Distributed Photovoltaics to Austin Energy and the City of Austin", Clean Power Research, 2006. This report can be found at www.cleanpower.com.

The analysis focused exclusively on natural gas because PV is assumed to offset natural gas at the margin. Futures prices for NYMEX natural gas were discounted using risk-free yields of Treasury notes having comparable maturity dates. A similar discounting was performed using price forecasts and the standard We Energies discount rate, representing the energy value. The hedge value is the difference between the risk-free energy value and the conventional energy value.

Distribution Value

PV reduces the burden on the distribution system because it is a distributed generation source and less electricity is required from the substation. PV appears as a "negative load" during the daylight hours from the perspective of the distribution operator. PV may be considered as distribution capacity from the perspective of the distribution planner, provided that PV generation occurs at the time of the local distribution peak.

Locating PV capacity in an area of growing loads allows a utility planner to defer capital investments in distribution equipment such as substations and lines. The Distribution Value was determined by calculating the avoided cost of money due to the capital deferral.

The analysis first determined the value of an ideal, perfectly dispatchable generation source by quantifying the cost of future capacity increases needed to meet anticipated load growth. Next, the "effective" PV capacity was calculated by comparing the original annual peak load (without PV) against the annual net peak load (original less PV output). Multiplying the perfect capacity value times the load match factor results in the Distribution Value of PV.

The analysis was performed using detailed technical information and cost estimates for three distribution expansion projects at Merton SS Relief, Albers SS Z3154 Capacity Increase, and Union Grove SS Relief. Results suggest that Distribution Values were relatively low relative to other value components, primarily due to a poor load match.

Transmission Value

We Energies incurs operating costs from its transmission provider based on monthly peak demand at its distribution substations. We Energies realizes cost savings when PV is able to reduce the peak demand. The Transmission Value is the value of these savings.

Monthly demand reduction was estimated using hourly measured feeder/substation loads and PV generation. The difference between the monthly peak load without PV and the monthly peak load with PV is the demand reduction against which the transmission access charge was applied. Monthly savings were summed, and 30-year discounted values were calculated. Transmission Values were low relative to other value components, primarily due to a poor load match.

Loss Savings Value

Distributed generation technologies reduce system losses by generating power at the point of consumption. This reduces transmission and distribution losses that would otherwise be incurred from central generation sources. The analysis treats loss savings as indirect benefits that "magnify" the value of other benefits.

For example, the generation benefit provided by PV represents the avoided cost of generating the electricity that is used by the customer. We Energies saves the cost of generating or purchasing a kWh at the point of production for every kWh produced by PV. We Energies also avoids the need for supplemental energy to account for losses.

Loss savings were calculated on a marginal, not an average, basis.[5] Marginal loss factors were calculated on an hourly basis using historical hourly loads and average loss data. Separate factors were calculated for distribution and transmission since the treatment of losses differs by benefit category (generation, hedge value, etc.). For example, Transmission Value is defined by peak loads occurring at the distribution substation, so only losses saved in the distribution system were relevant in the evaluation of this benefit. There are no loss savings associated with the environmental benefits. Location (central or distributed) does not enter into the analysis because the Environmental Value is based on the number of RECs that the system produces rather than the amount of energy that the system produces.

Hourly values for each benefit were calculated twice: first by assuming no losses and then by assuming calculated losses. The difference between the two results is the Loss Savings Value.

CONCLUSIONS

The following conclusions can be drawn from these results:

- Value per unit of installed PV ***capacity*** (\$ per kW_{AC}) was approximately linearly related to energy production for the variations configurations and thus value per unit of ***energy*** (\$ per kWh) was relatively independent of location and configuration.
- Value per unit of energy was calculated to be about \$0.15 per kWh over the PV system's 30-year lifetime. This value is sensitive to the data (especially the value of energy) that was used at the time of the study and should be interpreted within that context.

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[5] Marginal losses are the losses related to the next marginal increment of load. They are much higher than average losses due to the I^2R nature of losses. For example, if the average losses at 100% load are 10%, the marginal losses might be 20%.

- There was significant variation in value related to system configuration due to the difference in the amount of annual energy production.
- There was minimal variation in value related to system location.
- Generation, Environmental, and Fuel Price Hedge Value components comprised the highest portion of total value.
- Transmission and Distribution Value components were small in comparison to other components.
- Loss Savings Value was small but not insignificant.

Next Steps

- The results of this study are sensitive to the LMPs used. The following table compares some statistics of the LMPs used in the study to the LMP statistics for the period September 2008 through August 2009. A comparison of the two shows that the LMPs have changed significantly. There is a need to rerun this study to obtain a better reflection of the current value of PV as the LMPs change.

	LMPs used in Study			*LMPs year ending Aug. 2009*		
Node	***Max***	***Min***	***Avg***	***Max***	***Min***	***Avg***
GERMANOT1	273.24	4.83	48.72	144.12	-21.69	30.74
PARIS01S1	199.72	5.20	48.36	142.46	-24.51	30.29
PLPRG41	195.59	4.96	45.67	139.39	-38.79	29.10

- The MISO LMPs only reflect energy value and do not include capacity value. The value of generation capacity is very low at this time and is not included in the economic valuation. Future studies should include the generation capacity value of PV.
- We Energies RRC are not currently tradable outside of Wisconsin. This analysis assumes that RECs can be traded across state lines. Further evaluation is required to assess this.
- The Transmission Value depends upon whether PV is claimed as a generation resource or as negative load. This analysis assumed that PV was operating as negative load and that ATC prices are not reallocated as a result of the installation of PV. PV as a generation resource or ATC price reallocation will require a different analysis.

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TABLES

1. INTRODUCTION

We Energies is providing incentives to commercial customers for approximately 1 MW_{AC}[6] of photovoltaics (PV) in its service territory under its "Solar Electric Development" program. We Energies contracted with Clean Power Research (CPR) to support this program by performing the following tasks:

- Evaluate ownership scenarios to determine if the systems should be customer-owned, third-party-owned, or utility-owned.[7]
- Design an incentive structure to stimulate the installation of 1 MW_{AC} of PV.
- Provide software services, including PowerClerk®, SolarAnywhere®, and PVSimulator™, to assist in the administration of the Solar Electric Development program.
- Assess the value of PV to We Energies at a specific point in time.

CPR has completed the ownership scenario analysis and incentive structure, covered in separate reports[8] and has provided the software services to assist in program administration. The fourth portion of the work, the value analysis, is the subject of this report.

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[6] We Energies uses the following definition for the AC rating of a PV system: the total DC module rating at PVUSA Test Conditions (about 90 percent of standard test conditions) times inverter efficiency (about 95 percent efficiency) times a 90 percent loss factor to account for mismatch, wiring, and other losses. Thus, a nameplate (DC) rating of 1.3 kW_{DC} is approximately equal to 1.0 kW_{AC}. (i.e., 1.3 x 0.9 x 0.95 x 0.9 = 1.0).

[7] The study concluded that systems should be customer-owned. The recent change in the federal investment tax credit becoming available to utilities, however, may alter the optimal system ownership structure.

[8] The two reports are (1) "PV Ownership Scenarios at We Energies: A Comparison of Customer, Third Party, and Utility Ownership", August 26, 2006; and (2) "1 MW Solar Program: PV Incentive Design for We Energies", November 14, 2006. Both reports are prepared by Clean Power Research for We Energies.

The analysis is divided into the following value components:

- Generation Value
- Environmental Value
- Fuel Price Hedge Value
- Distribution Value
- Transmission Value
- Loss Savings Value

PV offers benefits in each of these value categories. The analysis describes and quantifies each in the chapters that follow.

The distribution analysis is presented first because it defines the three study locations used in the remainder of the study. In addition, the selection of solar resource data and ISO pricing node (Chapter 3) is based on the study locations.

The economic assumptions used through the report are presented in Table 1.

Table 1. Economic assumptions.

Discount Rate (nominal)	8.52%
Escalation	2.50%
PV System Life (years)	30

2. DISTRIBUTION VALUE

INTRODUCTION

Utilities need to anticipate when existing local distribution capacity will be exhausted and plan accordingly for new capacity increases in areas of growing electrical load. Capacity might be provided for in a variety of ways including: constructing new substations, replacing older conductors with larger conductors that have higher ampacities, or increasing the operating voltage of distribution circuits. These improvements represent utility capital investments in the form of materials and labor.

Distributed generation (DG) resources, such as PV, have the potential to relieve utility loading constraints by supplying local loads that would otherwise be supplied by the utility grid. DG resources have the potential to reduce peak loads on the substations or distribution feeders, thus delaying the timing of construction projects. DG resources provide cost savings due to the time value of capital investments, even for capital deferrals as short as one year.

Deferral value is calculated using the relation in Equation (1).

$$Value = \underbrace{\left(\frac{X}{L}\right)}_{Average\ Cost} \times \underbrace{\left(\frac{r}{1+r}\right)}_{Value\ of\ Money} \times \underbrace{M}_{Load\ Match} \qquad (1)$$

where Value is expressed in \$/kW, X is the present value cost of the distribution expansion plan over the study period (\$), L is the annual load growth (kW), r is the real discount rate, and M is a factor that corresponds to the effective peak load reduction provided by the DG system.[9]

Each kW of peak load for a "perfect" DG resource (M=1) is offset by a kW of generation. The load match for a non-dispatchable resource such as PV, however, must be determined by an analysis of time-correlated generation loads relative to distribution loads. Thus, the value is determined by calculating the economic value assuming a perfect load match (M=1) and then by adjusting the result to reflect the actual load match.

[9] A detailed derivation of this equation is presented in T. E. Hoff, *Identifying Distributed Generation and Demand Side Management Investment Opportunities*, The Energy Journal: 17(4) (September 1996).

Project Descriptions

We Energies provided the following expansion cost estimates for five critically-loaded areas in their distribution system.

Merton SS Relief

Location	Towns of Merton and Lisbon, Waukesha County. Area located north and east of Village of Sussex.
Description	Convert 8.32 kV feeder 35951 to operation at 24.9 kV, bypassing 24.9-8.32 kV Merton SS. Result is reduction of 2.58 MVA for Merton SS, based on 2006 peak of 9.61 MVA for the substation on 8/1/06, hour ending 18:00.
Estimated Project Cost	$2,089,000 (Accounting model - 80% Capital, 12% O&M, 8% Removal)
Peak Capacity	Merton SS - 7.50 MVA (Based on single contingency planning)
Measured Peak	9.61 MVA (9.25 MW, 3.01 MVAR)
Load Growth Rate	4.0%
Capacity Required to Defer Upgrade	Need to reduce Merton SS load to less than 110% of capacity initially, then offset all load growth. This translates to 1800 kW in 2007, then 400 kW per year in 2008, 2009, 2010, and 2011. By 2012, the relief from the planned distribution project will have been exhausted and a new project needed.

Albers SS Z3154 Capacity Increase

Location	City of Kenosha, Town of Somers, Kenosha County.
Description	Reconductor/rebuild 3.3 circuit miles of 24.9 kV overhead construction from 1/0 Cu to 336 ACSR. Result is an increase in Summer Normal rating of Z3154 from 315 Amps to 379 Amps.
Estimated Project Cost	$466,000 (Accounting model - 80% Capital, 12% O&M, 8% Removal)
Peak Capacity	Albers Z3154 - 315 Amps (Summer Normal), 380 Amps (Summer Emergency)
Measured Peak	367 Amps (15.99 MW, 3.59 MVAR at 25.8 kV)
Load Growth Rate	3.0%
Capacity Required to Defer Upgrade	Need to reduce Z3154 load to less than 95% of Summer Normal rating, then offset all load growth. This translates to 3000 kW in 2007, then 480 kW per year in 2008 and 2009. By 2010, the relief from the planned distribution project will have been exhausted and a new project needed.

New Holland SS Feeder

Location	Project in Town of Holland, but affected area is primarily in Town of Lima. Both are in Sheboygan County, southwest of the City of Sheboygan.
Description	Rebuild or reinsulate about 5 miles of existing 8.32 kV feeder to create new Holland 24.9 kV feeder to supply Oostburg SS and a large industrial customer and provide a backup supply for Gibbsville SS. Provides capacity required to supply Gibbsville SS load during an outage for Lyndon SS or Lyndon feeder Z53794.
Estimated Project Cost	$466,000 (Accounting model - 80% Capital, 12% O&M, 8% Removal)
Peak Capacity	Holland Z66471 - 250 Amps (Summer Normal), 300 Amps (Summer Emergency), Lyndon Z53794 - 448 Amps (Summer Normal), 448 Amps (Summer Emergency)
Projected 2006 Peak	316 Amps (14.1 MVA at 25.8 kV) for intact system, 418 Amps (18.7 MVA at 25.6 kV) during outage of Lyndon SS.
Load Growth Rate	3.0%
Capacity Required to Defer Upgrade	Need to reduce feeder Z53794 load in area around Gibbsville SS by about 5000 kW, then offset all load growth (350 kW per year) in future years.

Six Mile SS Relief

Location	Town of Caledonia, Racine County, north of the City of Racine.
Description	Convert portion of 8.32 kV feeders 12752 to operation at 24.9 kV, bypassing 24.9-8.32 kV Six Mile SS. Result is a load reduction of 1.0 MVA for Six Mile SS, based on 2006 peak of 12.79 MVA for the substation on 7/31/06, hour ending 18:00.
Estimated Project Cost	$1,160,000 (Accounting model - 80% Capital, 12% O&M, 8% Removal)
Peak Capacity	8.75 MVA (Based on single contingency planning)
Measured Peak	12.79 MVA (12.02 MW, 4.38 MVAR)
Load Growth Rate	4.0%
Capacity Required to Defer Upgrade	Need to reduce Six Mile SS load to less than 110% of capacity initially, then offset all load growth. This translates to 3000 kW in 2007. Note that planned project only removes 1.0 MVA of load. An additional system project will likely be needed in 2008.

Union Grove SS Relief

Location	Town of Yorkville, Racine County, north of the Village of Union Grove.
Description	Convert majority of 8.32 kV feeder 35451 to operation at 24.9 kV, bypassing 24.9-8.32 kV Union Grove SS. Result is a load reduction of 2.0 MVA for Union Grove SS, based on 2006 peak of 10.49 MVA for the substation on 7/31/06, hour ending 18:00.
Estimated Project Cost	$1,616,000 (Accounting model - 80% Capital, 12% O&M, 8% Removal)
Peak Capacity	Union Grove SS - 8.72 MVA (Based on single contingency planning)
Measured Peak	10.49 MVA (10.16 MW, 2.59 MVAR)
Load Growth Rate	4.0%
Capacity Required to Defer Upgrade	Need to reduce Union Grove SS load to less than 110% of capacity initially, then offset all load growth. This translates to 1000 kW in 2007, then 400 kW per year in 2008, 2009, and 2010. By 2011, the relief from the planned distribution project will have been exhausted and a new project needed.

Project Analysis

Overload Conditions Result in Unfavorable Economics

Each of the projects presented above represent real overload conditions that We Energies must solve in order to ensure reliable system operation. The conventional planning approach is described. We Energies also recognizes that an alternative approach using DG could also suffice, at least as a temporarily measure. We Energies presents the DG capacity requirements for the first year (to meet basic planning constraints) and future years (to meet expected load growth).

The initial 2007 capacity requirements in each of these projects is large due to the fact that overload conditions were already observed in 2006. For example, the measured 9.61 MVA peak loads at Merton Substation have already exceed its 7.50 MVA capacity. We Energies estimates that a minimum of 1800 kW of DG would have to be installed in 2007 in order to ensure reliability equivalent to the voltage conversion project and to defer the project from 2007 to 2008. In addition, 400 kW of additional capacity would be required for subsequent years to meet expected load growth were the project to be delayed for multiple years.

The capacity value of DG under these conditions is small. The Merton SS cost that could be deferred for one year using the We Energies accounting model[10] is \$2.089 million x 88% = \$1.84 million. Applying Equation (1) with the We Energies 8.52% discount rate, a "load growth" rate of 1800 kW, and M=1 (a "perfect" load match) results in an \$80/kW value for an ideal DG resource. The actual value would be less, depending upon the actual load match to be calculated later under the technical analysis.

Capacity Valuation Approach Without Overload Conditions

The low DG capacity value is partly due to the existing overload conditions. Thus, it is natural to pose the question: *What is the value of installing DG in an area that is approaching capacity limits but not yet overloaded?*

The analysis would offer a more realistic valuation if it was broadened to include planning areas not necessarily facing 2007 upgrades because third party DG projects are not generally targeted at planning areas facing current year upgrades. Such an analysis would also more accurately

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[10] Under the We Energies accounting model in 2006, 12% of the project cost is considered O&M. Assuming that this cost would be incurred regardless of the decision to proceed with the project, the remaining 88% (including the 8% "removal" costs) are considered capital costs under this analysis. Changes in the cost model for system improvement projects need to be reflected in the valuation model.

reflect the reality that utilities generally do not use anticipated third party DG installations in their load forecasts or rely upon them in their expansion plans.

The present analysis is therefore formulated to quantify the economic value of capacity under the following assumptions:

- We Energies does not rely upon DG in its planning to meet critical loads.
- DG capacity will reduce peak loads. Once installed, DG will impact load measurements and forecasts, and it will defer capital projects, provided that the installed DG capacity is greater than or equal to the rate of load growth.
- DG is installed in areas that have not exceeded capacity limits.
- DG output is perfectly matched to load (this assumption is modified later in technical analysis).

DG Capacity Requirements

Detailed expansion project cost estimates for planning areas that have not yet reached capacity limits may not be available. The approach used in the present analysis is to use the data provided from the five representative projects and to recast the planning scenarios as if the DG alternatives were installed in years prior to the overload.

For example, the *Merton SS Relief* project could have been deferred for one year if 400 kW of DG capacity were added in 2006, 2005, or earlier to the area served by Merton Substation (that is, if the load growth could have been offset for one year): the measured peak loads 9.61 MVA measured in August 2006 would not have been reached until August 2007. The project planning and approval process triggered by the Merton measurements would not have been triggered until a year later.

The 400 kW of DG, while not planned by the utility, would have effectively caused a one-year project deferral. For simplicity, it is assumed that the DG was installed in 2006 and the present value of the deferred cost is the same as the 2007 cost estimate. *The valuation of capacity is therefore calculated as before, except using the load growth rate of 400 kW instead of the 1800 kW necessary for a 2007 DG installation.*

Project Data Summaries

The **Merton SS Relief** project represents a capital cost of \$2.089 million. The 12 percent O&M cost is removed from this value. Thus, the potential deferral amount is \$2.089 million x 88% = \$1.84 million. 400 kW of DG capacity are required to offset annual load growth and defer the project one year.

A similar approach is taken for the **Albers SS Z3154 Capacity Increase** line reconductoring project. DG would be installed on line Z3154 fed by Albers Substation to reduce loading on that feeder and defer the need for reconductoring. The potential capital deferral amount is $466,000 x 88% = $410,000. The annual load growth is 480 kW.

The **New Holland SS Feeder** project presents a difficulty for the analysis. In this case, the new Holland 24.9 kV feeder would serve a dual purpose: supplying local loads (Oostburg SS and an industrial customer) and providing an alternate feed to Gibbsville SS in the event of a loss of supply from Lyndon. DG would not be able to serve as a backup supply. It is concluded that DG is not a true alternative and the deferral benefit is zero.

We Energies does indicate that a large DG installation (5000 kW) would provide relief as a temporary measure (presumably, the existing Gibbsville SS could be alternately fed from another, limited backup source). Additional future DG capacity (350 kW per year), however, would be required due to constraints of the existing backup feed.

This analysis is intended to capture the benefits of all future deferrals by shifting the timeline of capital investments. A single year deferral has very little value, especially for such a large DG capacity requirement (5000 kW) and such a small avoided cost ($460,000). Furthermore, it is not reasonable to expect that DG capacity will be increased each year to further cover the shortfall, especially when We Energies is not in control of DG in its planning process. It is concluded that DG is not a suitable solution for this case.

The **Six Mile SS** project has a potential capital deferral amount of $1,160,000 x 88% = $1,020,000. The annual load growth is 12.02 MW x 4% = 480 kW.

The **Union Grove SS Relief** project has a potential capital deferral amount of $1,616,000 x 88% = $1,420,000. The annual load growth is 400 kW.

These project data are summarized in Table 2.

Table 2. Project cost summary.

Project	***Total Cost***	***Deferrable Cost***	***Required Capacity (kW)***
Merton SS Relief	$2,089,000	$1,838,320	400
Albers SS Z3154 Capacity Increase	$466,000	$410,080	480
New Holland SS Feeder	$466,000	$0	N/A
Six Mile SS	$1,160,000	$1,020,800	480
Union Grove SS Relief	$1,616,000	$1,422,080	400

Recurring Future Upgrades

The impacts of future upgrade requirements are considered next. The load relief provided by the upgrade in the above projects is only temporary. Future upgrades will be required as load continues to grow when the new, higher, capacity limit is reached.

For example, the **Merton SS Relief** project is expected to reduce the substation load from the measured 9.61 MVA by 2.58 MVA to 7.03 MVA. Loads will continue to grow in the area served by the substation at its rate of 4% per year until its rated capacity of 7.50 MVA is reached again, at which time another capacity increase could be required. For conservatism, however (to minimize DG deferral value), it is assumed that the 7.50 MVA threshold is not the one that will trigger the next upgrade. Instead, given that the measured 9.61 MVA load was the 2006 defining event, it is assumed that loads would again have to reach 9.61 MVA again to trigger a future upgrade.

The following relation can be used to estimate the number of years (N) until the substation rating (C_{max}) is reached at a constant rate of growth[11] (g), starting with the load level expected after the upgrade (C_{new}). $C_{\max} \quad C_{new}(1+g)^N$. Solving for N,

$$N \quad \frac{\ln(C_{\max}/C_{new})}{\ln(1+g)} \qquad (2)$$

Equation (2) suggests that N = 8 years (rounded up from 7.97 years) using data for the **Merton SS Relief** project with Cmax = 7.50 MVA, Cnew = 7.03 MVA, and g = 4% per year. Thus, once the capital investment is made, another one would be expected in another 8 years.

This method provides a means of estimating the time until the next capacity increase is required. It does not, however, provide an accurate cost estimate. Utilities do not plan eight years into the future, so it is impossible to determine what technical plan might be called for at that time. For simplicity, this analysis assumes that the cost of the future upgrade will be the same as the 2007 upgrade in real terms ($1.84 million). Additional upgrade costs may well be below the original upgrade cost, so future analyses may need to refine this methodology.

In addition, other upgrades would be expected even further into the future as capacity limits are reached. Indeed, it is possible to envision a series of upgrades in the future, each about N years

[11] Actual growth rates may not be constant, but rather “S” shaped. Future analyses may wish to consider this in more detail.

apart, as loads continue to grow. The value of deferring such future upgrades diminishes rapidly, however, due to the time value of money.

All future upgrades over the 30-year PV system life are considered in this analysis. Thus, in the **Merton SS** example, it is assumed that a capacity increase will be required every 8 years and the first such upgrade in the series would occur halfway into this interval at year 4. Note that this is different from the actual We Energies expansion plan (upgrade in 2007) since the purpose is only to use the project cost, rating, and growth rate data as representative of typical locations at We Energies that are not facing overload conditions.

The planned **Albers SS Z3154 Capacity Increase** does not reduce load. Instead, the line ampacity is increased from 315 A (Summer Normal) to 379 A. The actual load would remain at the measure peak of 367 A. Equation (2) is applied (using Amperes instead of MVA) with Cmax = 379 A, Cnew = 367 A, and g = 3%. The result is that a new capacity increase will be required in 2 years.

Other projects are treated similarly and the results are shown in Table 3. This table presents the calculation of the number of years to upgrade, the future expansion scenario (first upgrade is in year N/2) and the corresponding present worth factor (PWF) for the series. Note: this method of accounting for future distribution system capacity costs may overstate costs.

Results

The results are presented in Table 4. This table uses the PWF from Table 3 to calculate the present worth of all future capacity increases, and applies Equation (1) to calculate the deferral value for M=1 (perfect load match).

Values range from $0/kW (the New Holland SS feeder in which DG is not able to serve as a substitute) to $719/kW. The average value is $353/kW which is assumed to be a typical "perfect" distribution capacity value for DG at We Energies.

Table 3. Future upgrades.

Project	Load Growth Rate (%/yr)	Substation or Feeder Capacity (MVA or A)	Substation or Feeder Loading After Upgrade (MVA or A)	Units (MVA or A)	Number of years between equiv. upgrades	Upgrade Year					PWF
Merton SS Relief	4%	9.61	7.03	MVA	8	4	12	20	28		2.822
Albers SS Z3154 Capacity Increase	3%	379	367	A	2	1	3	5	7	9	3.808
New Holland SS Feeder					N/A						0.000
Six Mile SS	4%	12.79	11.79	MVA	3	2	5	8	11	14	3.355
Union Grove SS Relief	4%	10.49	8.49	MVA	6	3	9	15	21	27	2.382

Table 4. Deferral value (perfect load match).

Project	Deferrable Cost ($)	PWF	Present Worth ($)	Load (kW)	[r/(1+r)]	M	Value ($/kW)
Merton SS Relief	$1,838,320	2.822	5,187,218	400	0.0555	1	719
Albers SS Z3154 Capacity Increase	$410,080	3.808	1,561,534	480	0.0555	1	180
New Holland SS Feeder	$0	0.000	0	N/A	0.0555	1	0
Six Mile SS	$1,020,800	3.355	3,425,055	480	0.0555	1	396
Union Grove SS Relief	$1,422,080	2.382	3,386,829	400	0.0555	1	470
Average							353

Solar Production Data

Dr. Richard Perez at The State University of New York provided four years (2003, 2004, 2005, and 2006) of hourly PV production data based on satellite imagery and PV system modeling for the four locations as shown in Table 5.

Table 5. Locations of PV production data

Location	***Latitude***	***Longitude***
Appleton	44° 15' N	88° 23' W
Milwaukee (airport)	42° 57' N	87° 54' W
Racine	42° 43' N	87° 51' W
Waukesha	43° 1' N	88° 14' W

Modeled PV system output was performed for seven system orientations for each of the four locations. The configurations include:

- Fixed configurations
    - Horizontal (fixed PV with no tilt)
    - South-30 (south-facing fixed PV tilted at 30°)
    - SW-30 (southwest-facing fixed PV tilted at 30°)
    - West-30 (west-facing fixed PV tilted at 30°)
    - West-45 (west-facing fixed PV tilted at 45°)

- Tracking configurations
    - 1-Axis (north-south 1-axis tracking PV with no tilt)
    - 1-Axis Tilt (north-south 1-axis tracking PV with 30° tilt)

Hourly PV production (8760 hours) was on the basis of kW_{AC} for a 1 MW_{AC} PV system (or, alternatively, W_{AC} for a 1 kW_{AC} PV system). The total number of data sets therefore was: 4 locations x 7 orientations x 4 years = 112 sets, each with 8760 hours of sequential data.

SUBSTATION LOAD

Substation Data

Substation load data was provided by We Energies in spreadsheet format for the five project sites in the date range 9/23/05 to 9/22/06. The format of the data files varied, but generally included phase voltage, phase current, and phase real (kW) and reactive (kVAR) power. For simplicity, only the real power data was retained, and these were combined for phases and feeders as necessary to obtain hourly values of total substation real power.

Times were assumed to be Central Standard Time (CST). No change in time values was observed for CDT.

Each file had some missing or erroneous data as described below.

Merton Substation data was provided for feeders 35951, 35961, and 35962. Bad or missing data was found for 4 hours out of the total 8760 hours, and these were replaced with data from the previous hour. The real power (kW) was combined from all three feeders.

Albers line Z3154 data was processed by We Energies including a calculation of power from the phase voltages and currents. There was no missing data in the set provided.

New Holland data was not used since the T&D benefit is assumed to be zero as described previously.

Six Mile Substation data was rejected due to a significant amount of missing data: 25 percent of the data was missing for feeder 12750 and 17 percent was missing for feeder 12760.

Union Grove Substation data included two feeders. Feeder 35450 had one hour of missing data, and this was replaced with data from the previous hour. Feeder 35460 had 17 hours of contiguous missing data, starting 3/19/06 23:00, and this was replaced with the corresponding hours of the previous day. Also, this feeder had one other hour of missing data that was replaced with data from the previous hour.

Time and Geographical Correlation

It was necessary to time-correlate the substation and PV data sets for the grid analysis work. Only the 2005-2006 PV data were used since the substation data were provided for the year beginning 9/23/05 (day 266).

Hourly PV data were available at the half-hour points in Central Standard Time. Substation data were provided on the hour mark. By inspection, there were no missing hours or repeated hours during the transition between Daylight Savings Time and Standard Time, so Central Standard

Time was assumed for all substation data. The hours were matched so that 00:30 PV data was paired with 01:00 of substation data, 01:30 was paired with 02:00, and so on.

It was then necessary to correlate the geographical locations of the PV and substation data. This was done by proximity as shown in Table 6.

Table 6. Geographic correlation between PV and substation data.

Project	***Location***	***Solar Data Source***
Merton SS Relief	Towns of Merton and Lisbon, Waukesha County	Waukesha
Albers SS Z3154 Capacity Increase	City of Kenosha, Town of Somers, Kenosha County	Racine
Union Grove SS Relief	Town of Yorkville, Racine County	Racine

Only three locations are used for further analysis throughout the remainder of the report. These three locations include Merton, Albers, and Union Grove. Table 7 presents the annual energy produced per unit of installed capacity and Table 8 presents the capacity factors for the three locations and seven system configurations.

Table 7. Annual energy (kWh/kW_{AC}).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	1,789	1,974	1,535	1,438	1,206	1,112	1,299
Albers	1,819	2,000	1,548	1,456	1,228	1,135	1,317
Union Grove	1,819	2,000	1,548	1,456	1,228	1,135	1,317

Table 8. Capacity factor (%).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	20.4%	22.5%	17.5%	16.4%	13.8%	12.7%	14.8%
Albers	20.8%	22.8%	17.7%	16.6%	14.0%	13.0%	15.0%
Union Grove	20.8%	22.8%	17.7%	16.6%	14.0%	13.0%	15.0%

LOAD MATCHING

It is possible to determine the load match using the time- and geographically-correlated substation loads and PV production simulations. This analysis calculates the “effective capacity” of the PV system.

There are several methods described in the literature for determining effective capacity. One common method is the “Effective Load Carrying Capability”. This measure captures the relationship between a unit’s output and the hourly system load in order to determine the constant load increase that the utility system can carry due to the new resource while maintaining the same level of reliability. The method uses a statistical technique using all hours of the year.

We Energies decided at a project kickoff meeting that the present analysis should evaluate capacity by considering the load relief provided by PV during only the single peak hour of the year. This is the most conservative of all PV capacity methods in use.

Methodology

The following methodology was carried out for each of the three sites where load data were determined to be reliable (Table 6). Loads were time-correlated with simulated PV production data for each hour of the sample year. PV production included the seven configurations assuming a 1 MW_{AC} PV system. Net loads (substation load minus PV production) were then calculated. A 24-hour sample of this data is presented in Table 9 for Merton substation on the peak day (August 1, 2006), although the data included all 8760 hours of the sample year.

Load data were then sorted to determine the peak load for the year. Since the hour of the original peak (without PV) may be different than the “new” peak (with PV), the net load for each configuration was sorted separately, breaking the temporal relationship between the data. The resulting load duration curves (LDCs) are presented in Figure 1, Figure 2, and Figure 3.

Results

The results are presented in Table 10. The peak load for Merton Substation without PV was 9125 kW. The peak load would be reduced to 8923 kW if a 1-Axis tracker rated at 1 MW_{AC} was located in the region served by this substation. This is a net load reduction of 202 kW. Therefore, the effective capacity of the PV system is 202 kW, or 20 percent of the system rating. Similar calculations are performed for the other configurations as shown.

The South-30 orientation produced the lowest results in all configurations considered (6 to 9 percent). The most effective orientations are the single-axis trackers (20 to 31 percent) and the west-facing systems (21 to 28 percent).

Analysis

To better understand these results, consider the PV output curves for the peak day at Merton Substation (August 1, 2006) presented in Figure 4. The south-facing and horizontal system peak in the middle of the day, while the west-facing systems peak toward the end of the day. Tracking systems have a broad output over more hours.

The loads and net loads with PV are presented in Figure 5 for the Merton Substation. This substation peaks at the end of the day just before the sun sets. This significantly favors the west-facing and tracking systems. Similar results are seen in Figure 6 and Figure 7 for Albers and Union Grove.

Table 9. Merton substation peak load and PV output (August 1, 2006).

		Load	PV Simulated Output							Net Load						
Date	Time	No PV	1 Axis	1 Axis Tilt	South-30	SW-30	West-30	West-45	Horiz	1 Axis	1 Axis Tilt	South-30	SW-30	West-30	West-45	Horiz
8/1/2006	1:00	5510	0	0	0	0	0	0	0	5510	5510	5510	5510	5510	5510	5510
8/1/2006	2:00	5082	0	0	0	0	0	0	0	5082	5082	5082	5082	5082	5082	5082
8/1/2006	3:00	4740	0	0	0	0	0	0	0	4740	4740	4740	4740	4740	4740	4740
8/1/2006	4:00	4535	0	0	0	0	0	0	0	4535	4535	4535	4535	4535	4535	4535
8/1/2006	5:00	4465	34	33.5	0	0	0	0	0.25	4431	4432	4465	4465	4465	4465	4465
8/1/2006	6:00	4602	233.5	228.5	29.25	2	2	2	44	4369	4374	4573	4600	4600	4600	4558
8/1/2006	7:00	4962	585.75	571.25	167.25	21.75	8.5	9.5	218.25	4376	4391	4795	4940	4954	4953	4744
8/1/2006	8:00	5403	781	768.5	367.5	117.25	45.5	14.75	393	4622	4635	5036	5286	5358	5388	5010
8/1/2006	9:00	5785	840.25	844.75	565.5	335.25	199.75	49	549.75	4945	4940	5220	5450	5585	5736	5235
8/1/2006	10:00	6187	870	901.5	744	544.25	386.5	193	692.75	5317	5286	5443	5643	5801	5994	5494
8/1/2006	11:00	6814	857.5	918.5	856.25	711	557.25	386.5	781.75	5957	5896	5958	6103	6257	6428	6032
8/1/2006	12:00	7248	852.5	936	924.25	841	705	574	836	6396	6312	6324	6407	6543	6674	6412
8/1/2006	13:00	7717	843.75	926.5	914.75	902.25	800.5	717.75	828.5	6873	6791	6802	6815	6917	6999	6889
8/1/2006	14:00	7940	851.75	911.75	849	906.25	847	812.25	776	7088	7028	7091	7034	7093	7128	7164
8/1/2006	15:00	8177	859.5	891.25	733	857.5	846	855.5	683	7318	7286	7444	7320	7331	7322	7494
8/1/2006	16:00	8502	836.25	840.75	565.5	744.75	781.75	829.5	549.75	7666	7661	7937	7757	7720	7673	7952
8/1/2006	17:00	8910	724	711	353.75	551.5	626.5	695.25	376.5	8186	8199	8556	8359	8284	8215	8534
8/1/2006	18:00	**9125**	472.5	459.25	150.75	294.25	379.75	437.5	187.5	8653	8666	8974	8831	8745	8688	8938
8/1/2006	19:00	8826	105.75	102	2.25	30	84	97.5	9	8720	8724	8824	8796	8742	8729	8817
8/1/2006	20:00	8618	0	0	0	0	0	0	0	8618	8618	8618	8618	8618	8618	8618
8/1/2006	21:00	8151	0	0	0	0	0	0	0	8151	8151	8151	8151	8151	8151	8151
8/1/2006	22:00	7620	0	0	0	0	0	0	0	7620	7620	7620	7620	7620	7620	7620
8/1/2006	23:00	6929	0	0	0	0	0	0	0	6929	6929	6929	6929	6929	6929	6929
8/1/2006	24:00:00	5958	0	0	0	0	0	0	0	5958	5958	5958	5958	5958	5958	5958

Figure 1. Merton Substation load duration curve.

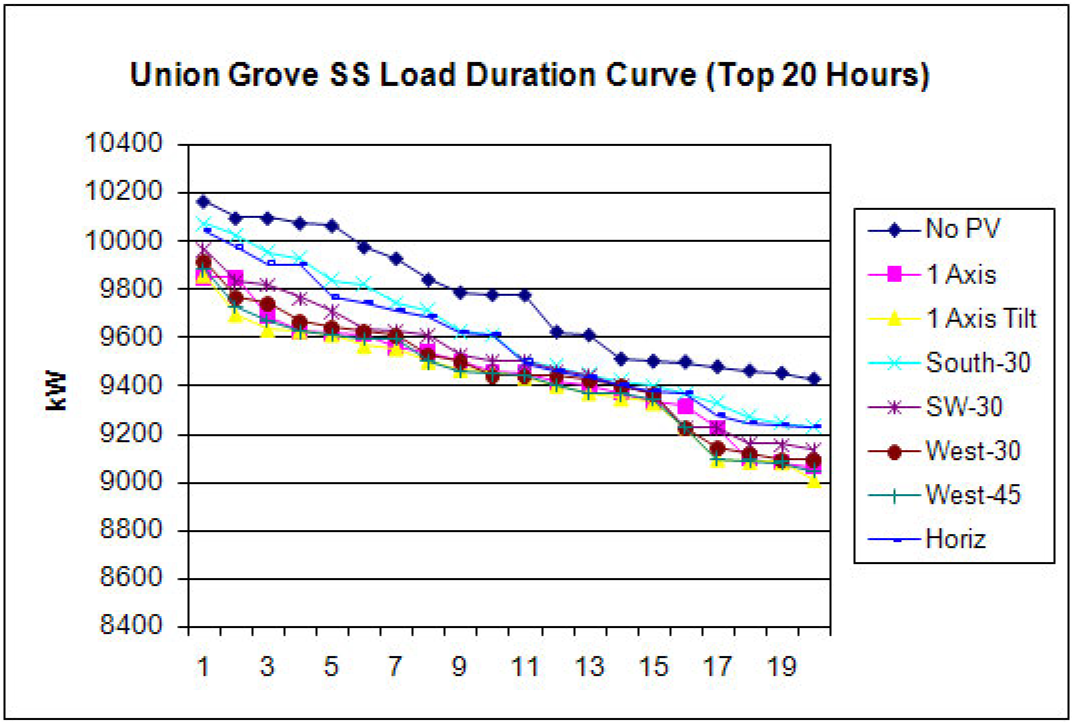


Figure 2. Albers Substation load duration curve.

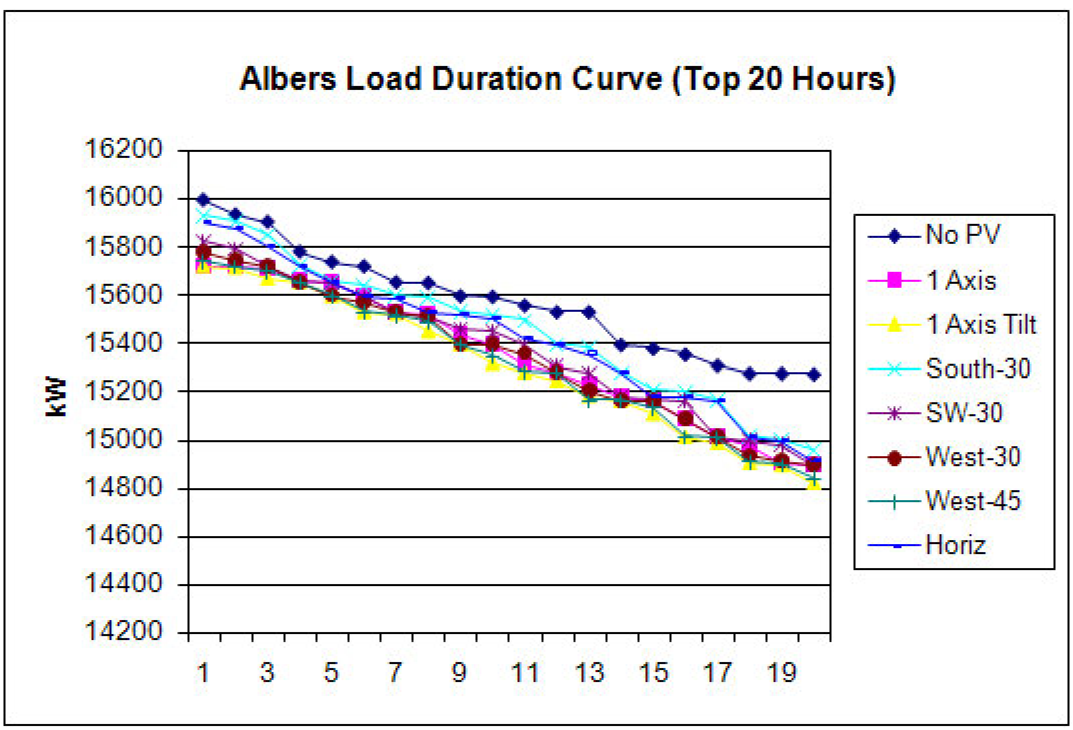


Figure 3. Union Grove Substation load duration curve.

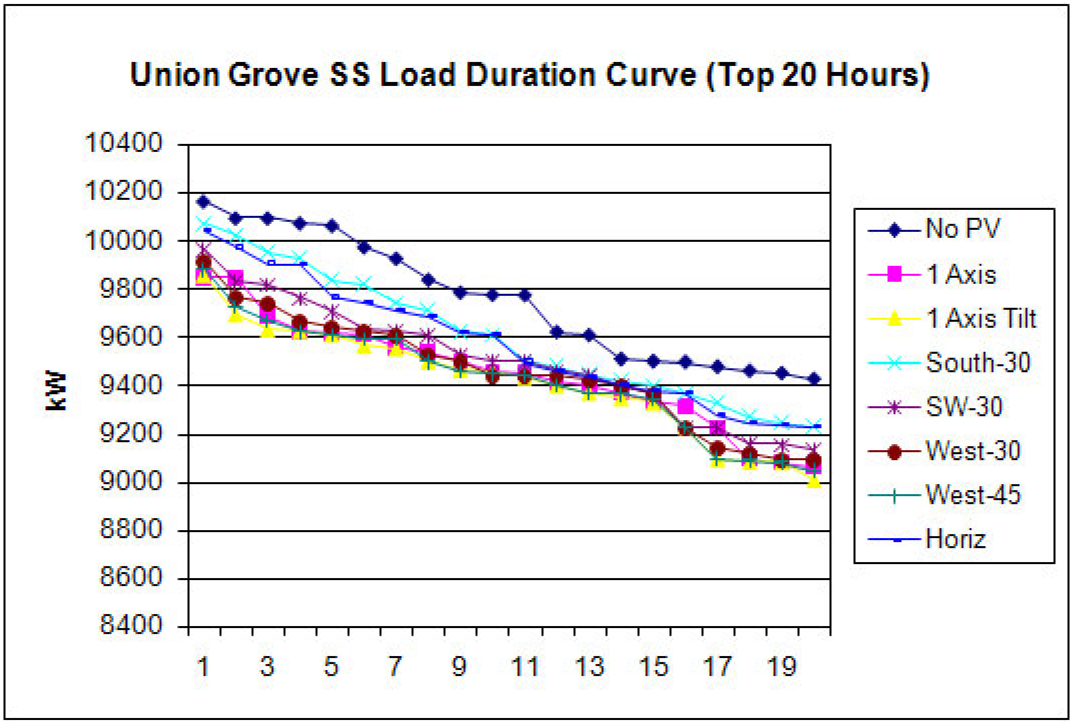


Table 10. Effective capacity calculation.

	No PV	1 Axis	1 Axis Tilt	South-30	SW-30	West-30	West-45	Horiz
MERTON								
Top LDC hour (kW)	9125	8923	8926	9063	8945	8918	8918	9028
Peak Reduction (kW)		202	199	62	180	207	207	98
Effective Capacity (%)		20%	20%	6%	18%	21%	21%	10%
ALBERS								
Top LDC hour (kW)	15990	15717	15717	15928	15824	15774	15740	15901
Peak Reduction (kW)		273	273	62	167	216	251	89
Effective Capacity (%)		27%	27%	6%	17%	22%	25%	9%
UNION GROVE								
Top LDC hour (kW)	10161	9848	9853	10069	9965	9915	9881	10042
Peak Reduction (kW)		313	308	92	197	246	281	119
Effective Capacity (%)		31%	31%	9%	20%	25%	28%	12%

Figure 4. PV output curves, peak day, Merton Substation.

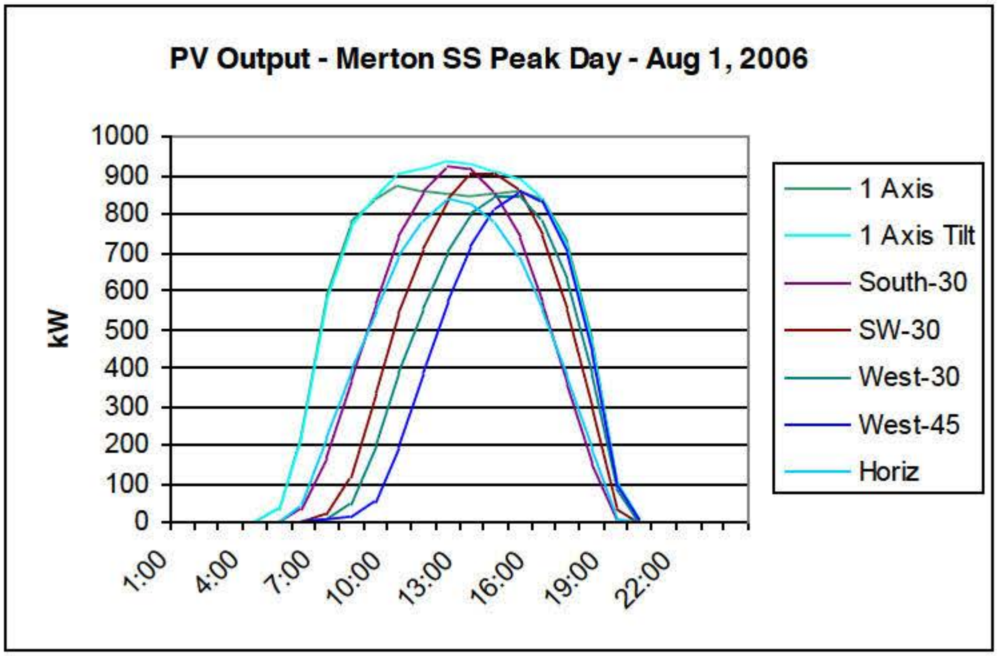


Figure 5. Loads and net loads on Merton peak day (August 1, 2006).

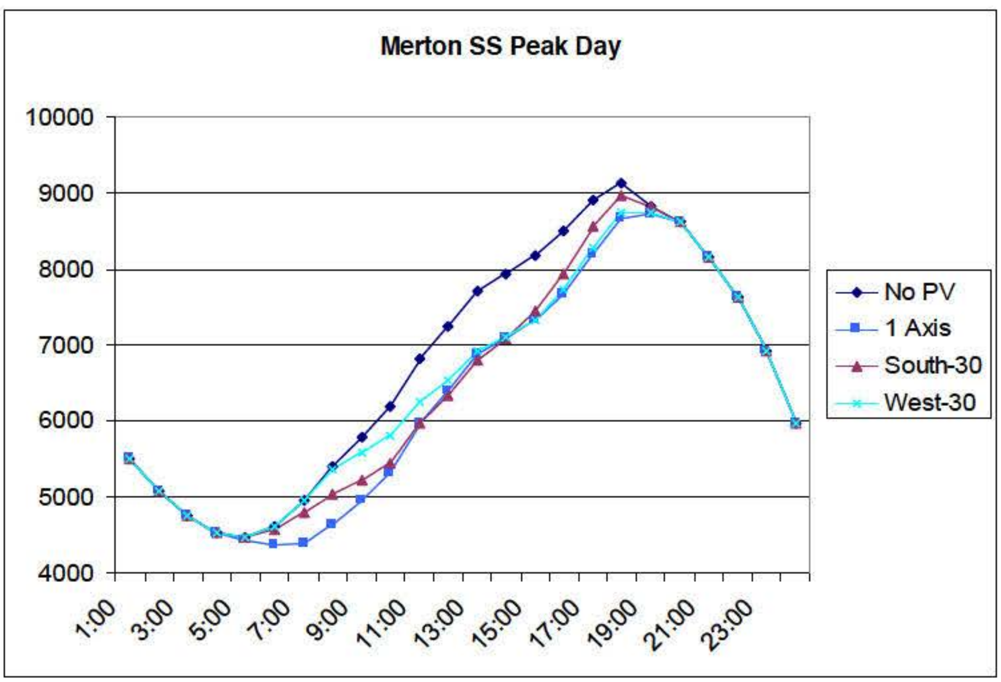


Figure 6. Loads and net loads on Albers peak day (August 1, 2006).

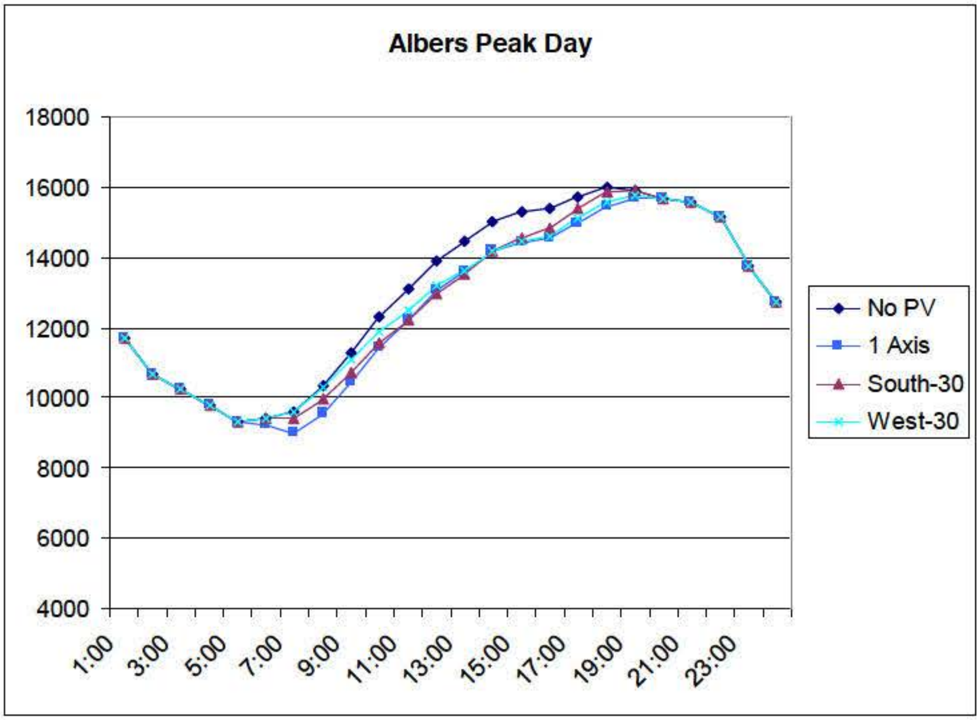
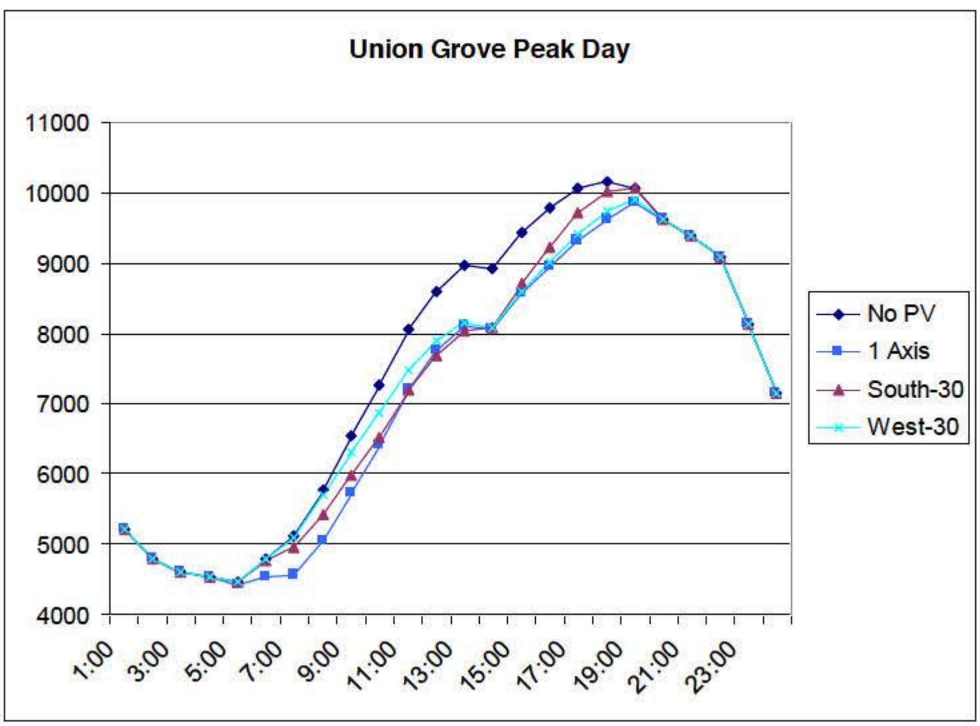


Figure 7. Loads and net loads on Union Grove peak day (July 31, 2006).



Load Shifting

It is possible that the effective capacity could be improved if some form of load shifting were available. This might be accomplished with rate design, efficiency, or storage. The analysis considered the impact of a 5 percent peak reduction to explore the effects of load shifting. The calculations for the peak day at Merton Substation are presented in Table 11.

The peak load in this case occurs at hour 18:00 and is 9125 kW. A 5 percent reduction (456 kW) is assumed, and the new peak of 8669 kW is taken as the new peak load. Adjacent hours are adjusted to retain the 8669 kW peak, and a corresponding mid-day increase is added such that the total energy of the load shifting is zero.

The new (shifted) load, and the new net loads (shifted with PV) are shown for selected configurations in Figure 8. Load shifting, however, does not produce a corresponding increase in effective PV capacity since the peak still occurs at the end of the day. Similar results are presented in Figure 9 and Figure 10 for Albers and Union Grove, respectively. Numeric values are presented in Table 12.

The main issue is that peak loads are occurring at the end of the day. By “flattening” these peaks through some form of load shifting, the peak-shifting benefit is achieved (in this example, a 5 percent peak load reduction). PV, however, is not able to provide additional peak load reduction on the net loads. This is because, for these locations of study, the output of PV does not correspond well with the peak. The peak – and shifted peak – is during hours of low or no PV output.

Table 11. Load Shifting – Merton Substation.

Date	Time	No PV	Load Shift	New Load
8/1/2006	1:00	5510		5510
8/1/2006	2:00	5082		5082
8/1/2006	3:00	4740		4740
8/1/2006	4:00	4535		4535
8/1/2006	5:00	4465		4465
8/1/2006	6:00	4602		4602
8/1/2006	7:00	4962		4962
8/1/2006	8:00	5403		5403
8/1/2006	9:00	5785		5785
8/1/2006	10:00	6187		6187
8/1/2006	11:00	6814	-241	7055
8/1/2006	12:00	7248	-456	7704
8/1/2006	13:00	7717	-157	7874
8/1/2006	14:00	7940		7940
8/1/2006	15:00	8177		8177
8/1/2006	16:00	8502		8502
8/1/2006	17:00	8910	241	8669
8/1/2006	18:00	**9125**	456	**8669**
8/1/2006	19:00	8826	157	8669
8/1/2006	20:00	8618		8618
8/1/2006	21:00	8151		8151
8/1/2006	22:00	7620		7620
8/1/2006	23:00	6929		6929
8/1/2006	24:00:00	5958		5958

Table 12. Effective PV capacity with load shifting.

	No PV	1 Axis	1 Axis Tilt	South-30	SW-30	West-30	West-45	Horiz
MERTON								
Top LDC hour (kW)	8669	8618	8618	8667	8639	8618	8618	8660
Peak Reduction (kW)		51	51	2	30	51	51	9
Effective Capacity (%)		5%	5%	0%	3%	5%	5%	1%
ALBERS								
Top LDC hour (kW)	15191	15191	15191	15191	15191	15191	15191	15191
Peak Reduction (kW)		0	0	0	0	0	0	0
Effective Capacity (%)		0%	0%	0%	0%	0%	0%	0%
UNION GROVE								
Top LDC hour (kW)	9653	9621	9621	9651	9621	9621	9621	9624
Peak Reduction (kW)		32	32	2	32	32	32	29
Effective Capacity (%)		3%	3%	0%	3%	3%	3%	3%

Figure 8. Load shifting for Merton Substation.

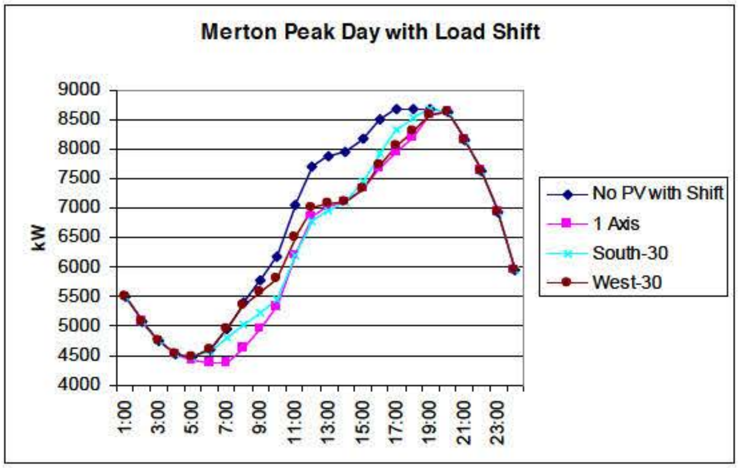


Figure 9. Load shifting for Albers.

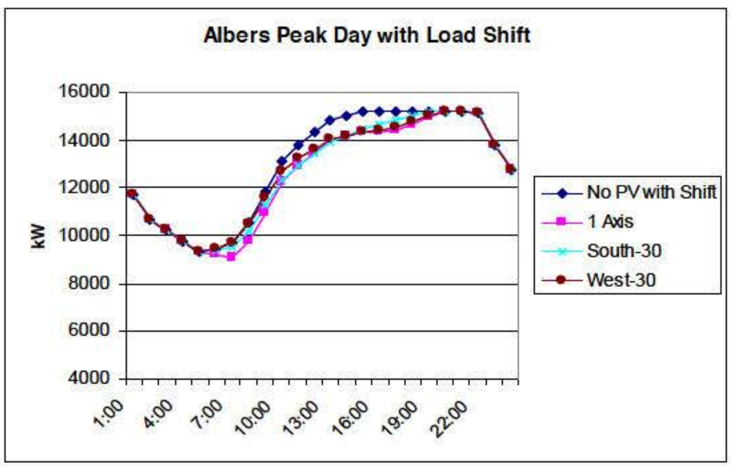
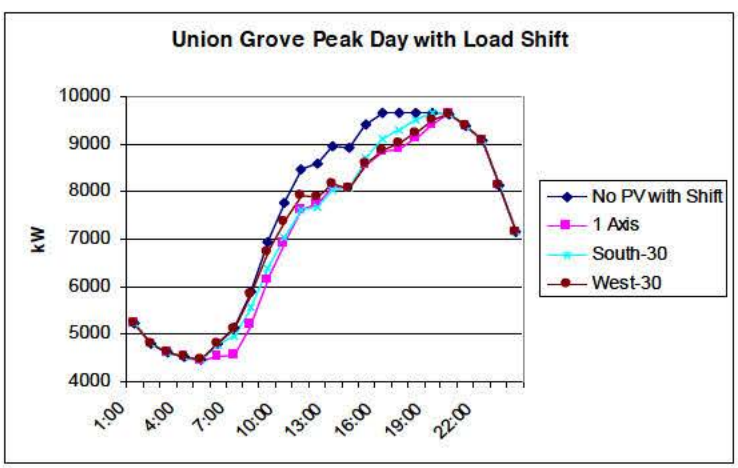


Figure 10. Load shifting for Union Grove Substation.



Load Control with PV

Another way to manage peak loads is through remote utility load control (LC). This practice has been proposed as a complementary technology to PV, since the "hybrid" PV with LC system would perform better than each technology in isolation.

Table 13 illustrates how 1 MW of LC could be used (without PV) for the area served by the Merton Substation. The peak load of 9125 kW is reduced to 8125 kW, and this level is maintained through selective LC in adjacent hours. In this case, 7 hours of LC are needed to cap the peak at 8125 kW.

Table 13. Load control at Merton Substation (1 MW).

Date	Time	No PV no LC	LC	Net Load (w/o PV)
38930	1:00	5510		5510
38930	2:00	5082		5082
38930	3:00	4740		4740
38930	4:00	4535		4535
38930	5:00	4465		4465
38930	6:00	4602		4602
38930	7:00	4962		4962
38930	8:00	5403		5403
38930	9:00	5785		5785
38930	10:00	6187		6187
38930	11:00	6814		6814
38930	12:00	7248		7248
38930	13:00	7717		7717
38930	14:00	7940		7940
38930	15:00	8177	52	8125
38930	16:00	8502	377	8125
38930	17:00	8910	785	8125
38930	18:00	9125	1000	8125
38930	19:00	8826	701	8125
38930	20:00	8618	493	8125
38930	21:00	8151	26	8125
38930	22:00	7620		7620
38930	23:00	6929		6929
38930	24:00:00	5958		5958

However, with PV in the area, some of this energy is displaced by the PV, reducing the LC requirements imposed by the utility. Table 14 shows the amount of LC (in kWh) required to reduce the peak load by 1 MW. For example, 3434 kWh of LC energy would be required at Merton Substation to reduce the peak load by 1 MW. With a 1-axis tracker, the amount is only 1703 kW, a reduction of 50 percent. The amount of reduction depends upon the power generation characteristics of the PV configuration and the shape of the load curve.

The PV system can be combined with LC as a hybrid system to be considered as a “firm” source of power. In this case, for example, 1 MW of power would always be available, regardless of the solar resource in any hour. The cost of the LC project implementation would have to be considered and this would reduce the benefit.

Table 14. Load control requirements to achieve 1 MW peak load reduction.

	No PV	1 Axis	1 Axis Tilt	South-30	SW-30	West-30	West-45	Horiz
MERTON								
Required Load Control (kW)	3434	1703	1733	2498	2129	1915	1775	2432
% Reduction in LC		50%	50%	27%	38%	44%	48%	29%
ALBERS								
Required Load Control (kW)	4797	2552	2570	3596	3085	2854	2663	3503
% Reduction in LC		47%	46%	25%	36%	41%	44%	27%
UNION GROVE								
Required Load Control (kW)	4399	1991	2023	3080	2511	2288	2107	2992
% Reduction in LC		55%	54%	30%	43%	48%	52%	32%

Distribution Capacity Value with Load Match

Table 4 presented the value of capacity when there is a perfect load match (M=1). These results are repeated in the first row for each location in Table 15. The value of capacity of a perfect resource can now be adjusted to reflect the effect of the actual load match. Table 15 presents the calculations in which the perfect match values are scaled by the actual match. These results are based on effective capacity using only the single peak hour for each location and do not reflect load shifting or load control methodologies.

Table 15. Distribution capacity value per unit of installed PV capacity ($\$/kW_{AC}$).

	1 Axis	1 Axis Tilt	South-30	SW-30	West-30	West-45	Horiz
MERTON							
Perfect Value, M=1 ($/kW)	719	719	719	719	719	719	719
Effective Capacity (%)	20%	20%	6%	18%	21%	21%	10%
Effective Value ($/kW)	145	143	45	129	149	149	70
ALBERS							
Perfect Value, M=1 ($/kW)	180	180	180	180	180	180	180
Effective Capacity (%)	27%	27%	6%	17%	22%	25%	9%
Effective Value ($/kW)	49	49	11	30	39	45	16
UNION GROVE							
Perfect Value, M=1 ($/kW)	470	470	470	470	470	470	470
Effective Capacity (%)	31%	31%	9%	20%	25%	28%	12%
Effective Value ($/kW)	147	145	43	92	116	132	56

CONCLUSIONS

The area expansion plan costs were used in this study as an indicator of expected future upgrade costs as loads approach capacity limits. The effective distribution capacity values were calculated for three areas using actual load data and simulated PV system output: Merton, Albers, and Union Grove.

Capacity values range from $11/kW to $149/kW, depending on location and PV system configuration. These values are driven by the following factors:

- The Albers location is a line reconductoring project with a low capital cost ($466,000).
- In all cases, the peak falls very late in the day when the PV output is declining. This is especially true for south-facing systems that have a low effective capacity for all three sites.
- The values assume a PV-only solution. Other methods, such as combining systems with load control or storage, were not considered in the results.

3. GENERATION VALUE

INTRODUCTION

Generation Value is the benefit that We Energies derives from PV's offset of We Energies' wholesale energy purchases: each kWh that PV generates at the customer's site is one less kWh that We Energies needs to purchase. The value of PV in providing generation capacity and energy derives from its ability to offset wholesale MISO energy purchases by We Energies.

Generation Energy Value

The cost savings of power generation is among the key benefits provided by distributed PV to utilities. Each unit of energy produced by PV allows the utility to avoid corresponding generation or power purchases.

Most PV valuation studies in the past have quantified this benefit by determining the value of generation capacity and energy separately, and most use the utility's own generation fleet as the basis of valuation. In this study, the value is based on the avoided cost of power purchases from the wholesale market, the Midwest ISO. The avoided cost of power purchases represents the cost of energy. Capacity benefits are considered to be small and are not included in the study even though PV also provides generation capacity benefits.

Power Markets

The Midwest ISO operates both a day-ahead market and a real-time energy market to facilitate scheduling and unit dispatching. The markets are based on centralized dispatch, using a Locational Marginal Pricing (LMP) methodology to optimize power flows. There is also a financial transmission rights (FTR) market that provides participants with an opportunity to hedge against day-ahead congestion costs. These three markets operate independently.

Clearing prices from the day-ahead market were used to value solar energy production for purposes of this study. The PV output may be considered a relatively reliable source of energy in the sense that it impacts the utility's load forecasts each day in a regular and predictable manner. Forecasts are made using daily load profiles, or more accurately "net" loads, that include the beneficial impacts of PV. Therefore, the scheduled power demanded in the day-ahead market with PV in the distribution system is reduced according to the amount of PV on the system. The FTR market was not relevant to this study.

The Midwest ISO day-ahead market is a forward market where hourly clearing prices are calculated for each hour of the next operating day based on the concept of LMPs. The market is cleared using computer programs[12] to satisfy various energy demand bid requirements and supply requirements. The results of the market clearing include hourly LMP values and hourly demand and supply quantities.

Locational Marginal Pricing (LMP)

The Federal Energy Regulatory Commission (FERC) has endorsed an LMP model of wholesale electricity pricing[13], and this model is employed by the Midwest ISO. Historical hourly LMP clearing prices from the Midwest ISO were used in the present study as the basis of energy value from PV.

LMPs vary by time and location due to physical limitations, congestion, and loss factors[14] and can be separated into three pricing components: the Marginal Energy Cost (MEC), the Marginal Congestion Component (MCC) and the Marginal Loss Component (MLC). Historical values for each of these three components are available from the Midwest ISO. Only the total value (LMPs), however, are of interest in this study.

LMP AND PV PRODUCTION DATA

LMP Data

LMP data were downloaded from the Midwest ISO website.[15] Historical data are available from April 2005 to the present in separate files for each day of the year. For the study period of 9/23/05 through 9/22/06, 365 csv data files were downloaded. Each daily file contains about 4500 sets of 24-hour pricing data including LMP, MCC, and MLC from about 1500 pricing nodes. The pricing data are in units of U.S. dollars per MWh.

A real-time pricing contour (updated every 5 minutes) such as the one shown in Figure 11, is provided on the Midwest ISO website. This map, accessed through an Adobe SVG plug-in viewer,

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[12] Security-Constrained Unit Commitment (SCUC) and Security-Constrained Economic Dispatch (SCED).

[13] An excellent overview of locational marginal pricing is available from the National Regulatory Research Institute at http://www.nrri.ohio-state.edu/Electric/LMP-Primer.

[14] Market Concepts Study Guide, Version 3.0, December 2005, Midwest ISO.

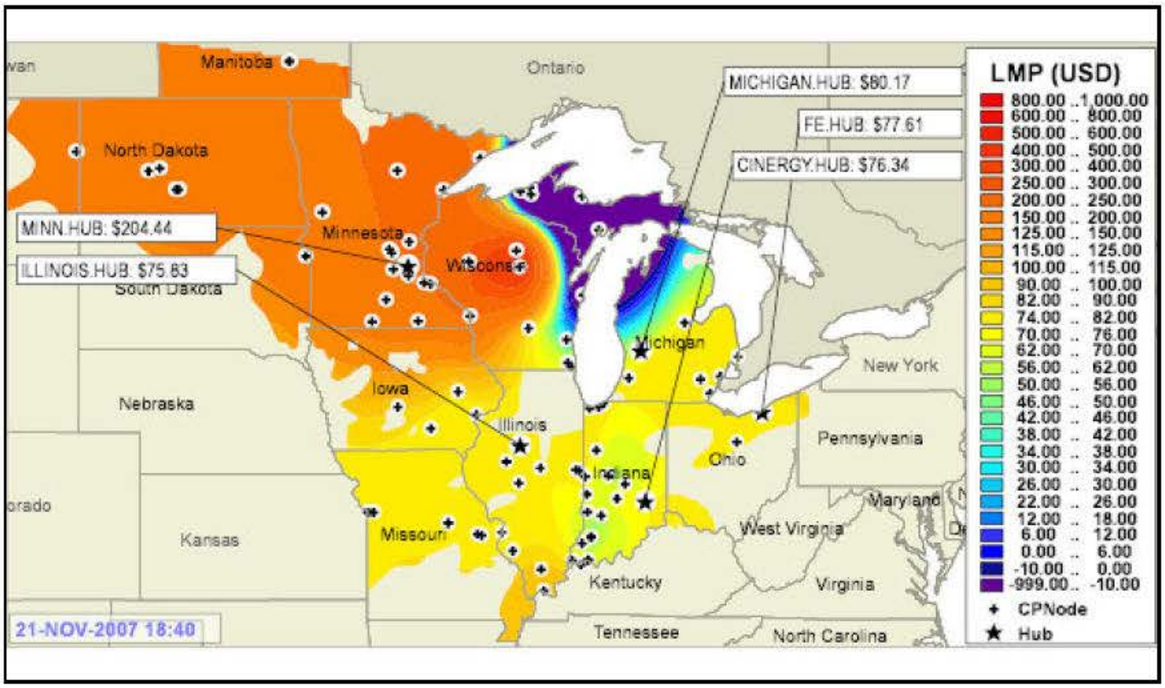
[15] www.midwestiso.org.

allows the user to highlight selected nodes to see the pricing components during the current interval. Three nodes were identified from this map in the study area of interest:

- GERMANOT1
- PARIS01S1
- PLPRG41

These nodes correspond approximately to Waukesha, Racine, and Kenosha counties, respectively.

Figure 11. Midwest ISO pricing contours.



A Microsoft Excel Visual Basic program was written to open these data files, search for the three nodes of interest, and transpose the hourly data to a separate data file of 8760 LMPs for each node.

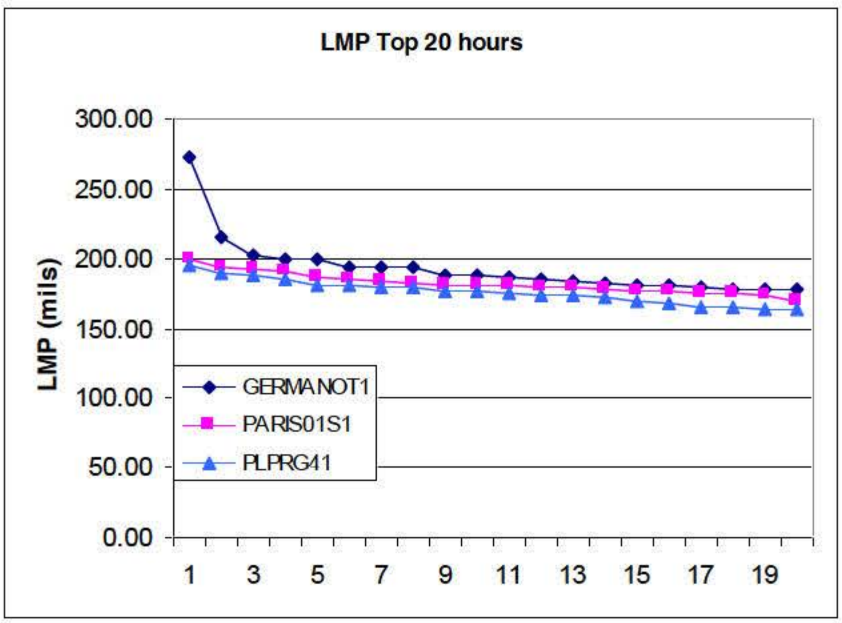
RESULTS

LMP Pricing

The top 100 hours of pricing over the one-year period are presented for each respective node in Figure 12. The prices appear to track reasonably closely with the exception of the top two hours for GERMANOT1. The minimum, maximum and average prices for the three nodes are presented in Table 16.

The valuation could be performed for each of the three pricing nodes separately. The PARIS01S1 node, however, was selected as a representative pricing node for all locations.[16] This simplifying assumption was made because the PARIS01S1 node: tracks the other two nodes; eliminates the two high priced hours of GERMANOT1; has an average price in the middle of the other two; and pricing variation is not significant overall.

Figure 12. LMP Top 100 Hours.



[16] PARIS01S1 is not necessarily representative of what We Energies would use to design a tariff. WEC-South is more representative of what We Energies pays MISO for purchase of energy to serve load.

Table 16. LMP pricing statistics for three nodes ($/MWh).[17]

Node	***Max***	***Min***	***Avg***
GERMANOT1	273.24	4.83	48.72
PARIS01S1	**199.72**	**5.20**	**48.36**
PLPRG41	195.59	4.96	45.67

The LMP pricing has changed significantly since the analysis was performed. The new values are presented in Table 17 for completeness. An analysis using current values would change the Generation Value of PV.

Table 17. Updated LMP pricing statistics ($/MWh, year ending August 2009).

Node	***Max***	***Min***	***Avg***
GERMANOT1	144.12	-21.69	30.74
PARIS01S1	**142.46**	**-24.51**	**30.29**
PLPRG41	139.39	-38.79	29.10

Generation Energy Value

The objective of this chapter is to determine the generation energy value from PV systems located in the distribution area of the three project sites. Table 6 presents the sources of solar data used for the three locations. All three locations use pricing data from the PARIS01S1 node. For example, a PV system in the area of the Albers project is assumed to perform as a PV system at Racine and the value of offset wholesale energy purchases is based on pricing at PARIS01S1.

The value of the first year's energy produced by a PV system in any given hour is the product of the system's output (MWh) and the value of energy at the Midwest ISO pricing node ($/MWh). These values are summed for each hour of the year:

$$Value(\$/yr) \quad \sum_{Hour\ 1}^{8760} Energy_{Hour}(MWh) x LMP_{Hour}(\$/MWh)$$

[17] The LMPs are dependent upon when the study is performed.

This equation was applied using the PV production data and LMP pricing data as described above for nominal 1 kW_{AC} PV systems oriented in the seven configurations. The results are presented in Table 18.

Table 18. First-year Generation Value ($/kW-yr).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	103	114	91	86	73	68	77
Albers	104	114	91	87	74	69	77
Union Grove	104	114	91	87	74	69	77

The economic assumptions in Table 1 were then used to escalate the prices over the life of the system and discount them using the We Energies discount rate. The resulting Generation Values in $/$kW_{AC}$ are presented in Table 19.

Table 19. Generation Value per unit of installed PV capacity ($/$kW_{AC}$).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	1,522	1,682	1,338	1,273	1,080	1,001	1,134
Albers	1,536	1,691	1,340	1,282	1,095	1,017	1,144
Union Grove	1,536	1,691	1,340	1,282	1,095	1,017	1,144

ANALYSIS

The generation energy value provided by PV at We Energies ranged from about $1,000 per kW_{AC} to about $1,700 per kW_{AC}. The highest values, as expected, came from tracking systems because they produce the highest energy. Value provided at Albers and Union Grove are identical because both are calculated using the same PV production and LMP data sources. On an energy basis, the variation in $/kWh value is very small among all cases, suggesting that the energy value is driven primarily by the quantity of energy production.

Match Between PV Output and Pricing

The values appear lower relative to comparable studies performed elsewhere. To better understand why, the match between PV output and pricing was examined. First, the idealized case of a perfect match between PV output and price was considered. For example, a 1-axis tracking system at Merton produces 1,789 kWh annually per kW of installed capacity (see Table 7). Suppose that this energy was produced at exactly the optimal pricing hours. The PV system would deliver energy at its maximum rated output during the highest LMP hours only. In this example, a 1 kW PV system would produce 1 kW for the 1789 highest price hours.

LMPs at the PARIS01S1 pricing node were sorted by value and the “maximum price match” Generation Values were calculated by assuming all energy was produced during the highest price hours. The results are presented in Table 20. Another calculation can be made to show the value if all the energy were spread equally over all 8760 hours. This is presented in Table 21. Finally a calculation of the “minimum price match” using the lowest LMP hours is presented in Table 22.

Table 20. Generation Value - maximum price match ($/kW$_{AC}$).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	2,392	2,570	2,137	2,034	1,781	1,676	1,885
Albers	2,421	2,595	2,150	2,053	1,806	1,701	1,904
Union Grove	2,421	2,595	2,150	2,053	1,806	1,701	1,904

Table 21. Generation Value - baseload match ($/kW$_{AC}$).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	1,278	1,410	1,097	1,027	861	795	928
Albers	1,299	1,429	1,106	1,040	877	810	941
Union Grove	1,299	1,429	1,106	1,040	877	810	941

Table 22. Generation Value – minimum price match ($/kW$_{AC}$).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	560	635	464	427	345	313	378
Albers	572	645	468	434	352	320	384
Union Grove	572	645	468	434	352	320	384

An examination of these results suggests that the match between PV output and pricing is highly significant. The Generation Value for a 1-axis tracker at Merton in the maximum case is 4.3 times the Generation Value of the minimum case. Similar results are seen for the other configurations and locations.

Seasonal Price Match

The analysis above suggests that the timing of PV output relative to LMPs is critical. The hourly match was considered for four sample days by season at Merton to better understand the price/output relationship (LPM node PARIS01S1, PV data source Waukesha).

Figure 13 presents the daily LMP profiles at node PARIS01S1 on March 21, June 21, September 21, and December 21, representing four seasons. There is a significant price peak in the late evening hours for each non-summer season. The summer price peak occurs at the end of the day. Autumn pricing, the lowest price season, is relatively flat. Winter offers the highest pricing by a significant amount.

By comparison, energy output of a South-30 PV system at Waukesha is shown for the same days in Figure 13. PV output drops to zero in every season except summer before the pricing peak. The highest seasonal prices in December are met with the lowest PV output. PV output in spring and autumn are the highest, but the prices are the lowest during these seasons. June provides a reasonably good match between LMPs and solar output, but the magnitude of PV output is small. The value of PV in offsetting wholesale power purchases is limited for these reasons.

Table 23 quantifies this result beyond the four sample days by showing the best and worst possible price/output correlations for a 30-South PV system at Merton. The best theoretical case would be if all of the PV system energy (1,535 kWh per year per kW) was generated during the highest price hours of the year. If PV output were perfectly matched to price, it would deliver its full rated power output during the 1,535 hours of highest LMP. Conversely, the theoretically worst case would be if all the energy were generated during the 1,535 hours of lowest price.

Figure 13. Seasonal pricing at PARIS01S1.

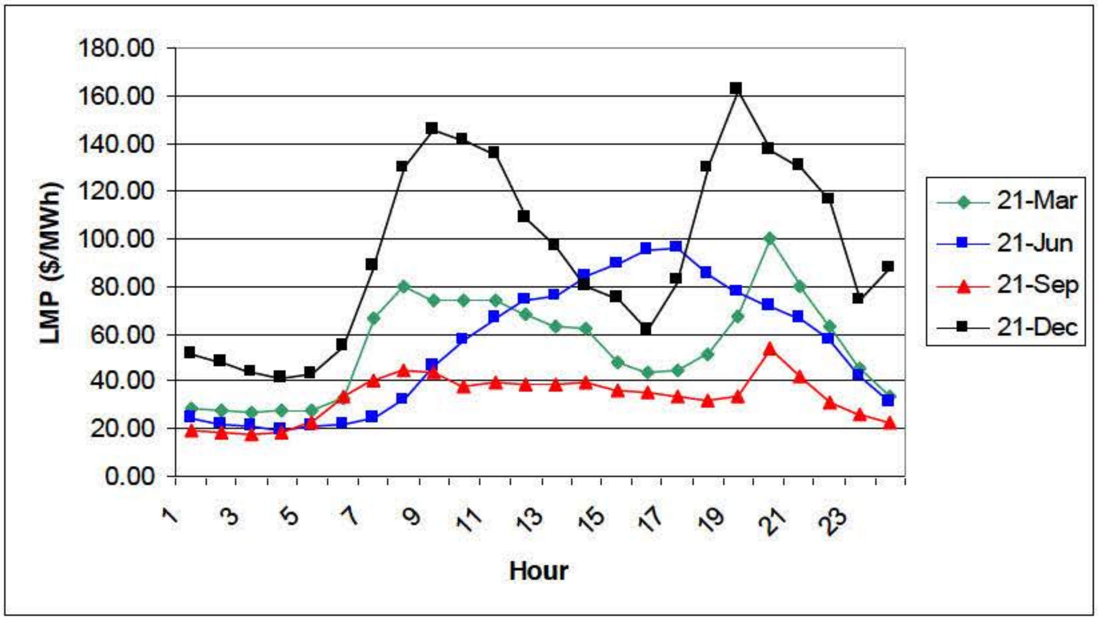


Figure 14. Seasonal output at Waukesha.

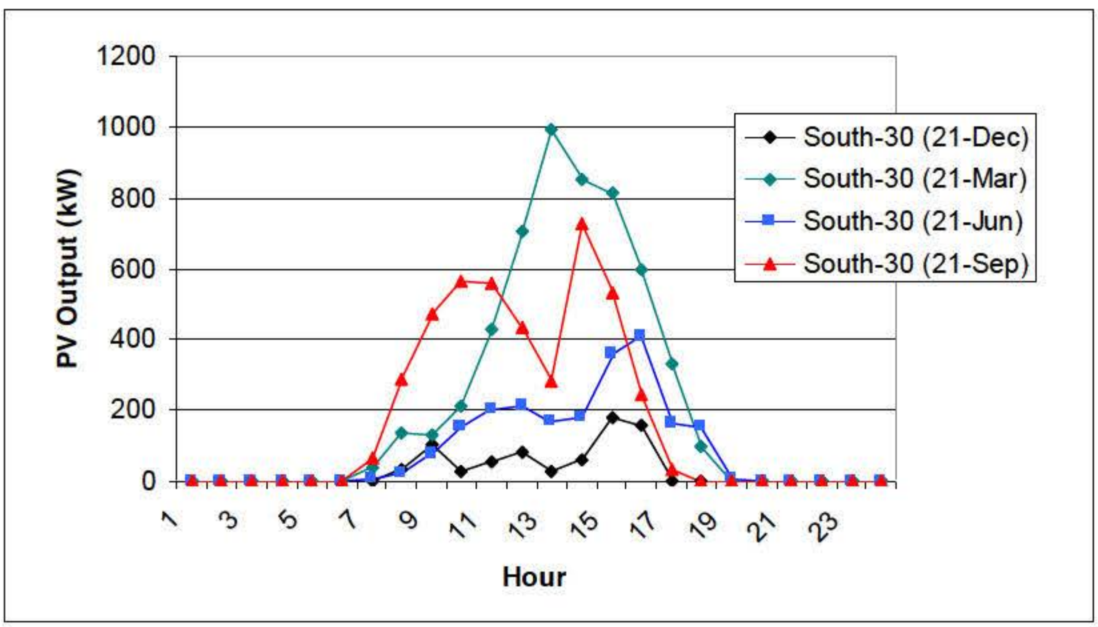


Table 23 highlights these two extremes of “high range” and “low range” by sorting LMP from highest price hour to lowest price hour for the year. The high range represents the 1,535 hours of highest price. LMP varies in this range from $70.05 to $199.72 per MWh, and the average price is $94.22. So, the theoretical maximum value would be $94.22/MWh x 1535 h / 1000 = $2,137/kW. This would be the value of a perfectly dispatchable generator with perfect foreknowledge of the pricing, dispatched to give the same capacity factor as PV. A similar calculation can be done to derive the theoretical worst case of $463.

The actual value of PV ($1,338/kW) is therefore 63 percent of the theoretically maximum possible value. PV provides 63 percent of the energy value as compared to a fully dispatchable generator with the same capacity factor.

Table 23. Highest and lowest value match at Merton.

	High Range			Low Range		
	Upper Limit	Lower Limit	Range Average	Upper Limit	Lower Limit	Range Average
LMP Sort Rank	1	1535		7225	8760	
LMP ($/MWh)	199.72	70.05	94.22	25.17	5.20	20.43
Generation Value ($/kW)			2,137			463

CONCLUSIONS

The Generation Value analysis leads to several observations and conclusions:

- The Generation Value at We Energies for the locations of interest ranged from about $1,000/kW$_{AC}$ to $1,700/kW$_{AC}$, depending upon system configuration.
- Value at Albers and Union grove were identical because they are close geographically. The analysis used the same solar resource and pricing node. Results for Merton were similar.
- LMPs for the three pricing nodes considered in this analysis were very close, and only one node was used in order to simplify the analysis.

4. ENVIRONMENTAL VALUE

INTRODUCTION

Several approaches could be taken to quantify the Environmental Value of PV. The value could be defined as the premium customers are willing to pay for renewable energy as compared to conventional sources. Alternatively, the value could be derived by estimating the health care cost savings from reduced air pollution. While such approaches would be attempts to quantify the true value, they would be subject to numerous complications, and it is likely that the models and numeric assumptions would not have been broadly accepted.

Furthermore, such approaches focus on the value to society, outside the obligations of the utility in providing electric power. The financial impact to We Energies would not, for example, be directly affected by such health care savings. For these reasons, the societal approaches are not used.

We Energies does, however, have direct financial impacts related to its state-mandated renewable portfolio standards (RPS) obligations. PV provides direct cost savings to the utility by contributing toward these obligations. Therefore, for the purposes of this study, the value of PV in providing environmental benefits is defined as its ability to contribute towards the We Energies RPS.

Wisconsin Renewable Portfolio Standard

Wisconsin has passed several laws over the past decade related to a statewide renewable portfolio standard (RPS) to ensure integration of renewable resources in its energy portfolio.[18] The current law, passed in March 2006, establishes the requirement that 10 percent of electricity sold in the state be derived from eligible sources. Table 24 is a summary of the requirements by year.

Compliance by individual electric providers is based on a Renewable Resources Credit (RRC) tracking and trading program verified and administered by the Midwest Renewable Energy Tracking System (M-RETS). [19]

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[18] Refer to http://www.ucsusa.org/assets/documents/clean_energy/Wisconsin.pdf for a summary of the Wisconsin RPS by the Union of Concerned Scientists.

[19] APX was selected by the PSC to provide the system for tracking RRCs. M-RETS is located at http://www.m-rets.com. In addition to this responsibility, M-RETS tracks RECs for other Midwestern states and provinces.

Table 24. Wisconsin RPS schedule.

Year	Renewable Generation Requirement
2006 – 2009	Each electric provider may not decrease its renewable energy percentage below the electric provider's baseline renewable percentage (average of renewable percentage during the period 2001-03).
2010	Each electric provider shall increase its renewable energy percentage so that it is at least 2 percentage points above the electric provider's baseline renewable percentage.
2011 – 2014	Each electric provider may not decrease its renewable energy percentage below the electric provider's renewable energy percentage required in 2010.
2015, and thereafter	Each electric provider shall increase its renewable energy percentage so that it is at least 6 percentage points above the electric provider's baseline renewable percentage. By 12/31/15, Wisconsin must achieve the goal of having 10 percent of all electric energy consumed in the state being renewable energy.

RRC PRICING

The value analysis centers on the value of the Wisconsin RRC because We Energies is able to save the cost of purchasing RRCs from other parties to the extent that PV generates renewable energy and We Energies can own the RRC.

RRC/REC Pricing Comparisons

Published pricing sources for similar products in other states may be used to estimate pricing for Wisconsin RRCs. REC products (and prices) vary considerably making it important to understand the definitions of the products under comparison.

The impact of REC definitions is apparent in considering the three REC classes defined by the New Jersey RPS. "Class I" renewable energy is defined as electricity derived from solar energy, wind energy, wave or tidal action, geothermal energy, landfill gas, anaerobic digestion, fuel cells using renewable fuels, and some sustainable biomass. "Class II" renewable energy is defined as electricity generated by hydropower facilities no greater than 30 megawatts (MW), and resource-recovery facilities. Solar RECs (SRECs) are also defined in a separate class. The RPS defines required percentages of each class by year through 2021. Table 25 presents current pricing[20] for these three types of RECs. The SREC is by far the most expensive. This may be explained by the higher technology cost, the lack of supply, or the high demand among energy providers striving to meet their RPS solar requirement.

Table 25. New Jersey REC prices ($/MWh).

	Bid	*Offer*	*Last*	*Date*
Solar (SREC)	$250.00	$275.00	$265.00	6/12/08
Class I	$3.50	$9.00	$7.75	6/27/08
Class II	No Bid	$1.00	$0.60	6/20/08

It is important, therefore, to recognize the sensitivity of price to REC technology definitions in estimating the prices of the Wisconsin RRCs. There is also a differentiation between "voluntary" RECs (that may be used, for example, to meet voluntary utility or corporate clean energy goals) and "compliance" RECs (that must be obtained to meet state laws, and are typically more expensive). Compliance RECs are used in this analysis because the Wisconsin RRCs are used to comply with the state RPS.

REC Prices

Table 26 presents a set of current prices for RECs comparable to the Wisconsin RRC. These are compliance (non-voluntary) products exchanged through various brokers and trading systems. Monitoring and tracking is performed through state agencies, similar to M-RETS.

The pricing comparison is intended to be indicative of prices under the RRC definition even though the definitions of qualifying sources are not identical. For reference, Table 27 describes the qualifying sources[21] for the Wisconsin RRC and the other RECs in the price comparison.

[20] Pricing data is taken from the "REC Markets" June 2008 Monthly Market Update from Evolution Markets, http://www.evomarkets.com.

[21] Data taken from the DSIRE database, http://www.dsireusa.org.

Table 26. Compliance RECS ($ per MWh).

REC	***Bid***	***Offer***	***Last***	***Date***
CT Class I Certificate (2008)	$40.00	$46.50	$45.00	6/26/08
MA Class I Certificate (2008)	$46.00	$52.50	$51.75	5/19/08
TX (2008)	$4.00	$5.25	$5.75	3/12/08
NJ Class I (2008/09)	$17.50	$22.00	$20.00	6/23/08
DE (2007)	$10.00	$15.00	$13.75	6/27/08
RI (2008)	$40.00	$50.00	$48.00	7/28/07
MD Tier I (2008)	$0.90	$1.75	$1.10	04/22/08
DC Tier 1 (2008)	$0.50	$1.75	$1.15	02/19/08

Table 27. Comparison of qualifying sources by REC.

	Solar PV	**Solar Thermal Electric**	**Wind**	**Tidal/Wave**	**Ocean Thermal**	**Fuel Cells (Renewable Fuels)**	**Fuel Cells (Non-renewable Fuels)**	**Hydro**	**Biomass**	**Geothermal**
Wisconsin	•	•	•	•		•		•	•	•
Connecticut Class I	•	•	•	•	•	•	•	•	•	
Massachusetts Class I	•	•	•	•	•	•		•	•	•
Texas	•	•	•	•				•	•	•
New Jersey Class I	•	•	•	•		•			•	•
Delaware	•	•	•	•		•		•	•	
Rhode Island	•	•	•	•	•			•	•	•
Maryland Tier I	•	•	•	•	•	•		•	•	•
District of Columbia Tier I	•	•	•	•	•	•			•	•

Prices vary over a wide range, from $1 to $52 per MWh. The range could be due to a number of factors, such as:

- Demand varies depending upon the aggressiveness of the current year state RPS targets. States with high demand may have higher prices.
- Demand varies based on installed capacity. States with historically supportive policies may have more installed renewable resources.
- Renewable resource varies by region. This would especially be true in the case of wind power. States with favorable wind conditions (such as Texas) have more installed renewable capacity and higher capacity factors, both of which would drive down prices.
- Differences between qualifying renewable source definitions.

RESULTS

This section determines the Environmental Value from PV systems located in the distribution area at the three project sites. The REC value is assumed to be $50 per MWh. This is the highest comparable REC value in Table 26. The highest value is taken because, even though it is out-of-state, it drives the price in Wisconsin. Suppliers of Wisconsin RRCs (PV system owners) can choose to supply out-of-state markets instead, shrinking local supply until prices are comparable. In addition, We Energies could sell its title to renewable attributes out-of-state rather than use them for local RPS requirements.[22] The value is defined by this out-of-state market price in either case.

The value of the first year's energy produced by a PV system in any given hour is the product of the REC value ($/MWh) and the system output (MWh). These values are summed for each hour of the year:

$$Value(\$/yr) \quad REC(\$/MWh)\sum_{Hour\ 1}^{8760} Energy_{Hour}(MWh)$$

This equation was applied using the assumed REC value and PV production data as described above for nominal 1 kW_{AC} PV systems. The results are presented in Table 28.

[22] Most states grant out-of-state generators eligibility in meeting RPS goals with the provision that the energy is also sold in-state. For example, Massachusetts, Rhode Island, and Connecticut use NEPOOL-GIS certificates to document RPS compliance. While rules provide for external generators outside the NE-ISO to participate, they require that the energy be delivered into the control area. This analysis presumes such requirements are met.

Table 28. First-year Environmental Value ($/kW-yr).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	89	99	77	72	60	56	65
Albers	91	100	77	73	61	57	66
Union Grove	91	100	77	73	61	57	66

The economic assumptions shown in Table 1 were then used to escalate the prices over the life of the system and discount them using the We Energies discount rate. The resulting Environmental Values are presented in Table 29.

Table 29. Environmental Value per unit of installed PV capacity ($/kW$_{AC}$).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	1,321	1,458	1,134	1,062	891	822	960
Albers	1,343	1,477	1,144	1,075	907	838	973
Union Grove	1,343	1,477	1,144	1,075	907	838	973

CONCLUSIONS

The Environmental Value analysis yielded several observations and conclusions:

- The value of the environmental benefit was derived from the ability to offset purchases of renewable resource credits (RRCs) to meet the utility RPS percentages.
- Out-of-state markets provided a wide range of REC value, from about $1 to $52 per MWh for compliance RECs having source qualifications roughly comparable to the Wisconsin RRC. There are a number of possible reasons for this variation, and the price-setting maximum of $50 per MWh was assumed for this analysis.
- The environmental benefit to We Energies (based on estimated solar performance at Waukesha and Racine TMY sites) ranged from $822/kW$_{AC}$ for a fixed West-45 based system to $1,477/kW$_{AC}$ for a tilted 1-axis tracking system.

5. FUEL PRICE HEDGE VALUE

INTRODUCTION

Electricity in the state of Wisconsin is primarily generated from coal, nuclear, natural gas, and petroleum. The electricity prices throughout the state are subject to uncertainty because the prices of these fuels fluctuate over time. The cost of electricity generated from PV, however, is constant and fixed over the 30-year system life since it is not dependent upon fuels other than solar energy. PV provides a “hedge” against future fuel price uncertainty.

APPROACH

Introduction

PV offsets current and future electric power generation needs and helps to stabilize future generation costs when it is a component of a utility’s resource mix. Generation from PV is not dependent upon coal, oil, natural gas, or other fuels that may be subject to future price volatility whether owned by the utility or directly by the end-use customer. Therefore, PV displaces ongoing energy commodity purchases and reduces the price uncertainty of those purchases.

PV provides a “hedge” against future fuel price uncertainty. The method used to quantify this benefit is loosely based on the Black–Scholes options pricing model and is documented more fully in a PV valuation analysis conducted by CPR for Austin Energy in 2006.[23]

The essence of this method is that fuel price volatility is captured in commodities futures pricing. Energy from PV systems offsets conventional power plant generation. In this sense, PV provides “risk-free” energy over its useful service life, and its ongoing energy production is equivalent to holding futures contracts for purchase of energy. The valuation methodology segregates the energy value from the purely financial risk avoidance benefit, the Fuel Price Hedge Value.

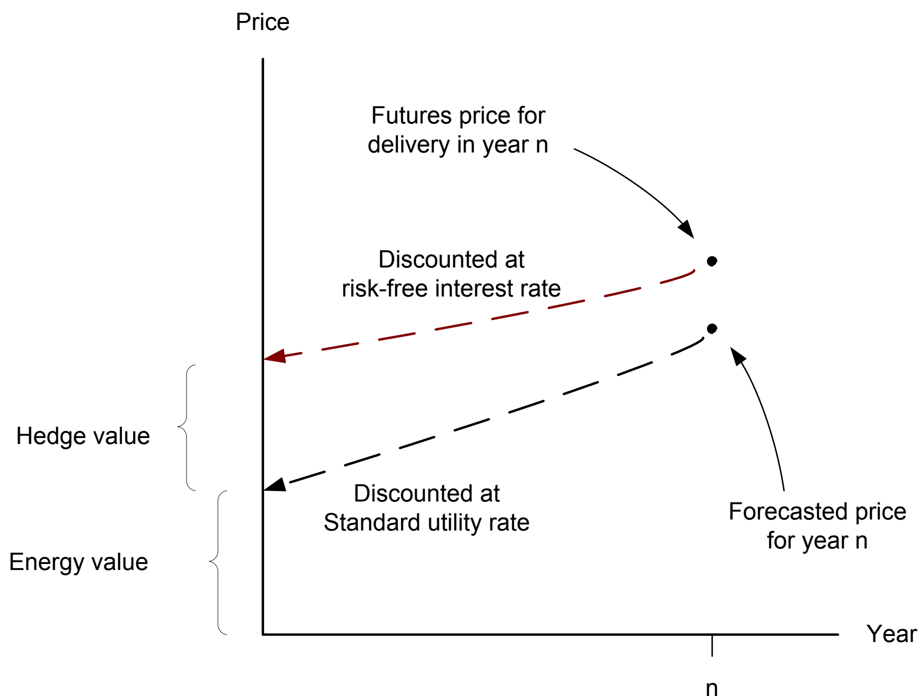
Figure 15 illustrates the calculation of hedge value for a commodity fuel such as natural gas. The risk-free value of the fuel can be determined by discounting the futures price at the risk-free interest rate, such as the yield of a Treasury note. The risk-free rate is used because the fuel could be guaranteed for a specified delivery date using the vehicle of the futures contract. The

[23] “The Value of Distributed Photovoltaics to Austin Energy and the City of Austin”, Clean Power Research, 2006. This report can be found at www.cleanpower.com.

conventional energy value (subject to price uncertainty) is determined separately by discounting the forecasted price using the standard utility discount rate.

The difference between the risk-free value and the conventional energy value is the hedge value. It can be thought of as a "price premium" over the energy commodity itself.

Figure 15. Hedge valuation concept.



Wisconsin Energy Sources

Table 30 shows the primary energy sources for power generation in Wisconsin. Coal, petroleum, natural gas, and nuclear fuels are all subject to future price uncertainty and could be modeled using the method described above. In particular, most of the state's electricity is from coal (65 percent) and nuclear (19.8 percent), so that the benefit of offsetting these fuels is potentially high.

PV systems would not offset the generation from coal and nuclear plants because they are generally used for baseload generation while PV is used for peaking resources.

Electricity from petroleum is a relatively small contribution in Wisconsin (1.4 percent). The only petroleum plants in the state are Units 3 and 4 at French Island Generating Plant in Lacrosse,[24] each burning No. 2 fuel oil. Petroleum futures prices could be used for this analysis based on NYMEX heating oil (trading symbol HO) which is identical to No. 2 distillate. Settlement prices, however, are only available covering delivery dates up to three years into the future, limiting the accuracy of results. Therefore, petroleum is also excluded from the analysis.

Futures prices for natural gas are available for delivery dates as far as 12 years into the future. The analysis assumed that PV would offset electricity from natural gas plants.

Futures Prices

Figure 16 presents natural gas futures prices (trading symbol NG) from the New York Mercantile Exchange (NYMEX).[25] Settlement prices are in dollars per mmBTU and represent future deliveries to Henry Hub. These prices were used to quantify the natural gas price hedge offered by PV. NG futures prices show a strong seasonal variation. Annual average prices were used for simplicity.

[24]See http://en.wikipedia.org/wiki/List_of_power_stations_in_Wisconsin. The two units are each 100 MW simple cycle combustion turbines (Westinghouse Model 501B2) built in 1974.

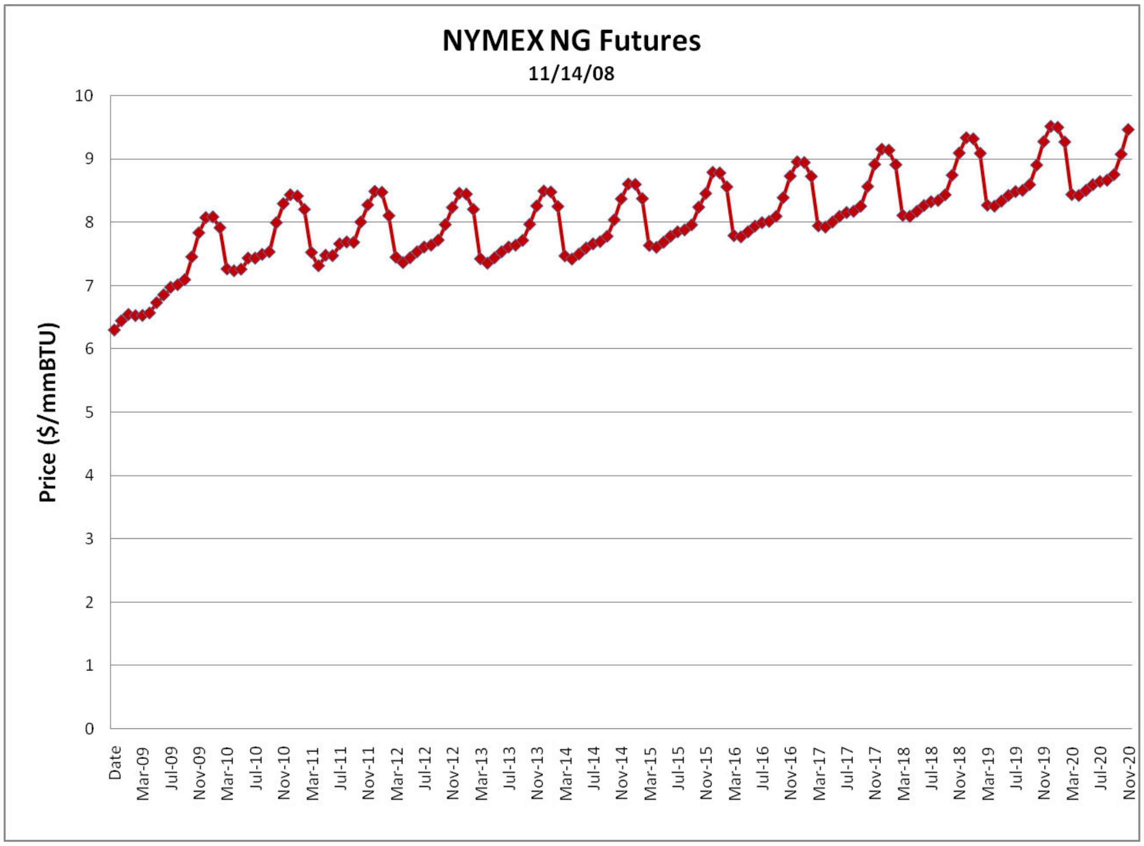
[25] Futures data taken from the Wall Street Journal, online edition, http://online.wsj.com, 11/1/4/06.

Table 30. State of Wisconsin electric generation by primary energy source.[26]

Energy Source	MWh	(%)
Electric Utilities	51,914,755	84.2
Coal	38,866,178	63.1
Petroleum	591,486	1.0
Natural Gas	2,114,624	3.4
Nuclear	8,560,416	13.9
Hydroelectric	1,446,192	2.3
Other Renewables	259,408	0.4
Pumped Storage	-	-
Other	76,451	0.1
IPPs and CHP	9,725,088	15.8
Coal	1,176,558	1.9
Petroleum	275,343	0.4
Natural Gas	3,244,886	5.3
Nuclear	3,673,099	6.0
Hydroelectric	232,406	0.4
Other Renewables	1,089,301	1.8
Other	33,495	0.1
Total Electric Industry	61,639,843	100.0
Coal	40,042,736	65.0
Petroleum	866,829	1.4
Natural Gas	5,359,510	8.7
Nuclear	12,233,515	19.8
Hydroelectric	1,678,598	2.7
Other Renewables	1,348,709	2.2
Pumped Storage	-	-
Other	109,946	0.2

[26] Source (2006): http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept05wi.xls

Figure 16. NYMEX natural gas futures prices.



RESULTS

Heat Rate

Wisconsin statewide average heat rates for natural gas plants was determined using the data in Table 31 for 2007. There were 43,977 million cubic feet of natural gas consumed in 2007 to produce 5,359,510 MWh. The average heat rate was calculated as 8435 BTU/kWh assuming a natural gas energy content of 1028 BTU per cubic foot.[27]

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[27] http://en.wikipedia.org/wiki/Natural_gas.

Table 31. State of Wisconsin natural gas consumption by end use.[28]

	MMcf
Pipeline & Distribution Use	3,109
Volumes Delivered to Consumers	369,283
Residential	120,567
Commercial	86,342
Industrial	118,396
Vehicle Fuel	65
Electric Power	43,977
Total Consumption	372,457

Hedge Value – Yearly Basis

Table 32 presents the hedge value for each year of the 30-year life of PV. The annual average prices for the 12 years of available NYMEX NG futures are in column (2) and wholesale electricity prices at the point of generation (corresponding to the average heat rate) are in column (3). These electricity prices represent the fuel cost component of electricity only – not the capacity or O&M cost components.

Risk-free discount rates were based on U.S. Treasury notes of varying maturation dates, corresponding to the yields of column (4). Discount factors were calculated in column (5) using these yields, and the discounted risk-free value is shown in column (6).

A similar set of calculations are shown using EIA forecasted prices in column (7) and the We Energies discount rate in column (9). These calculations show the discounted energy value.

[28] Source (2006): http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_SWI_a.htm

Table 32. Hedge value by year.

Treasury Security	Year	(1) Heat Rate (BTU/kWh)	(2) Futures Price ($/mmBtu)	(3) = (2) x (1) Electricity Price ($/kWh)	(4) Discount Rate (Risk-free)	(5) Discount Factor	(6) = (3) x (5) Discounted Value ($/kWh)	(7) Forecast Price ($/mmBTU)	(8) = (7) x (1) Electricity Price ($/kWh)	(9) Discount Rate (Standard)	(10) Discount Factor	(11) = (8) x (10) Discounted Value ($/kWh)
	2008	8435	6.295	0.053	0.0%	100.0%	0.053	7.231	0.061	0.00%	100.0%	0.061
2-year Note	2009	8435	6.877	0.058	1.2%	98.8%	0.057	7.348	0.062	8.52%	92.1%	0.057
2-year Note	2010	8435	7.664	0.065	1.2%	97.6%	0.063	6.902	0.058	8.52%	84.9%	0.049
2-year Note	2011	8435	7.842	0.066	1.2%	96.4%	0.064	6.561	0.055	8.52%	78.2%	0.043
5-year Note	2012	8435	7.831	0.066	2.3%	91.2%	0.060	6.369	0.054	8.52%	72.1%	0.039
5-year Note	2013	8435	7.833	0.066	2.3%	89.2%	0.059	6.160	0.052	8.52%	66.4%	0.035
5-year Note	2014	8435	7.891	0.067	2.3%	87.1%	0.058	5.987	0.051	8.52%	61.2%	0.031
5-year Note	2015	8435	8.051	0.068	2.3%	85.2%	0.058	5.865	0.049	8.52%	56.4%	0.028
10-year Note	2016	8435	8.220	0.069	3.7%	74.6%	0.052	5.820	0.049	8.52%	52.0%	0.026
10-year Note	2017	8435	8.383	0.071	3.7%	71.9%	0.051	5.892	0.050	8.52%	47.9%	0.024
10-year Note	2018	8435	8.561	0.072	3.7%	69.3%	0.050	5.972	0.050	8.52%	44.1%	0.022
10-year Note	2019	8435	8.728	0.074	3.7%	66.8%	0.049	6.055	0.051	8.52%	40.7%	0.021
10-year Note	2020	8435	8.900	0.075	3.7%	64.4%	0.048	5.948	0.050	8.52%	37.5%	0.019
	2021	8435						5.817	0.049	8.52%	34.5%	0.017
	2022	8435						5.951	0.050	8.52%	31.8%	0.016
	2023	8435						6.083	0.051	8.52%	29.3%	0.015
	2024	8435						6.250	0.053	8.52%	27.0%	0.014
	2025	8435						6.391	0.054	8.52%	24.9%	0.013
	2026	8435						6.558	0.055	8.52%	23.0%	0.013
	2027	8435						6.605	0.056	8.52%	21.2%	0.012
	2028	8435						6.864	0.058	8.52%	19.5%	0.011
	2029	8435						7.058	0.060	8.52%	18.0%	0.011
	2030	8435						7.220	0.061	8.52%	16.5%	0.010
	2031	8435						7.242	0.061	8.52%	15.3%	0.009
	2032	8435						7.263	0.061	8.52%	14.1%	0.009
	2033	8435						7.285	0.061	8.52%	12.9%	0.008
	2034	8435						7.307	0.062	8.52%	11.9%	0.007
	2035	8435						7.329	0.062	8.52%	11.0%	0.007
	2036	8435						7.351	0.062	8.52%	10.1%	0.006
	2037	8435						7.373	0.062	8.52%	9.3%	0.006
	2038	8435						7.395	0.062	8.52%	8.6%	0.005

Hedge Value – 30 Years

The 30-year hedge premium is presented in Table 33. The discounted values were summed over the 12-year period for which the risk-free data were available for both the risk-free and conventional cases. The hedge premium was calculated to be 59 percent of the energy value. This percentage was assumed to be valid across the 30-year PV system life.

Table 33. Hedge premium.

	12 years	30 years
Risk Free	0.722	
Standard	0.454	0.644
Hedge Premium	59%	59%

The Fuel Price Hedge Value was calculated in Table 34 by multiplying the hedge premium percentage by the 30-year energy value and the annual energy production (Table 7).

Table 34. Fuel Price Hedge Value per unit of installed PV capacity ($/kW$_{AC}$).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	680	751	584	547	459	423	494
Albers	692	761	589	554	467	432	501
Union Grove	692	761	589	554	467	432	501

CONCLUSIONS

The hedge value analysis resulted in several observations and conclusions:

- Hedge Value represents the “price premium” associated with the risk-avoidance benefit offered by PV.
- The Hedge Value ranged from $423 to $761 per installed kW$_{AC}$ of PV. The range is dependent on PV orientation and location because of the varying energy outputs.

6. TRANSMISSION VALUE

INTRODUCTION

We Energies incurs operating costs from its transmission provider based on monthly peak demand at its distribution substations. We Energies realizes cost savings when PV is able to reduce the peak demand. The Transmission Value is the value of these savings.

APPROACH

Avoided Transmission Costs

American Transmission Company (ATC) is a transmission-only utility that serves the Upper Peninsula of Michigan, the eastern half of Wisconsin, and portions of Illinois. ATC plans, constructs, operates, and maintains its transmission assets to serve electricity producers and distribution companies.

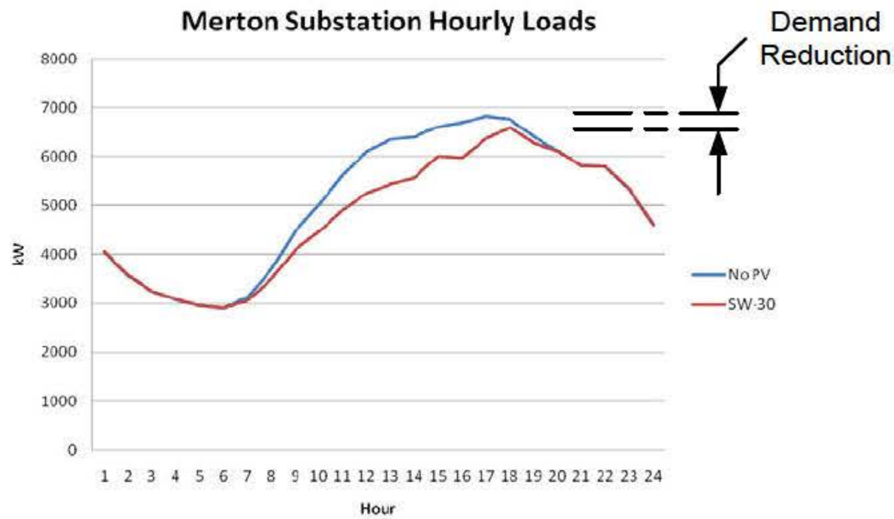
We Energies pays monthly transmission access fees[29] to ATC of about $3.155 per kW of peak monthly demand. PV located in the distribution system may lower overall costs to We Energies by reducing peak demands.

Calculating Demand Reduction

Figure 17 presents hourly loads at Merton Substation for two scenarios: (1) without PV; and (2) with a 1 MW_{AC} PV facility oriented southwest with a 30° tilt angle. The data without PV were measured on June 17, 2007, the day having the highest peak hourly load for the month. The data with PV represent the "net" load that would have been measured, had such a facility been available in the load area served by that substation.

[29] Paul Schumacher, Nov. 2008.

Figure 17. Merton Substation (June 17).



The PV system produced power during the peak hour. Thus, it also would have saved transmission costs by reducing the peak monthly load at Merton. The PV system would have shifted the monthly peak from 17:00 to 18:00. Depending on load shapes and PV output, the new peak hour could occur on a different day entirely. The demand reduction is defined by the difference between peak monthly load, with and without PV regardless of when the new peak occurs.

PV provides the greatest reductions in demand when its output coincides with loads. There is little or no demand reduction at all when the peak occurs at the end of the day or at night.

The transmission savings was calculated by applying the charge ($/kW) to the demand reduction (kW). The overall value for the year was found by summing up the value for each month separately:

$$Value(\$/yr) = \sum_{Month=1}^{12} TransmissionCharge(\$/kW) x DemandReduction_{Month}(kW)$$

RESULTS

The objective of this section is to determine the Transmission Value from PV systems located in the distribution area of the three project sites.

Monthly demand reductions, the hour of day that the peak occurred, and the total demand reduction for the year are presented for Merton Substation in Figure 18. These are expressed as the reduction in peak demand (kW) for a 1 MW_{AC} system. Demand reductions only occur during the months of May through August because of the late timing of the peak load. For example, in April, the peak load occurred at 20:00 hours.

Tracking systems are most effective with the highest demand reduction in August for a 1-axis tracking system without tilt (tilting the tracker to the latitude angle optimizes annual energy production, not summer production). West and southwest-facing systems provide the greatest demand reduction for the fixed systems since these provide a better load match.

The 1-axis tracking system provides a total of 1,046 kW of demand reduction on an annual basis. By comparison, a "perfect match" of PV would provide 1000 kW of demand reduction each month for a total of 12,000 kW for the year.

Economic assumptions are presented in Table 1 and Transmission Values are presented in Table 35.

Table 35. Transmission Value per unit of installed PV capacity ($\$/kW_{AC}$).

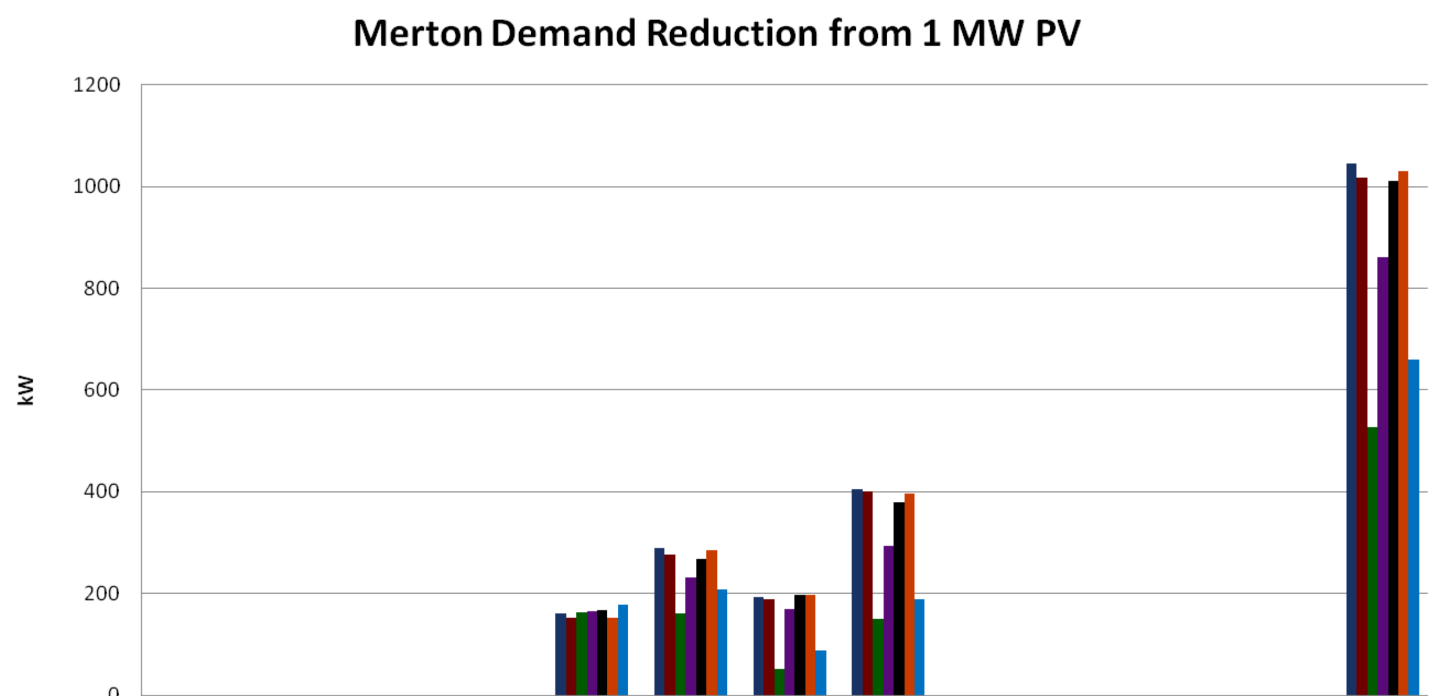
	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	49	47	25	40	47	48	31
Albers	39	39	18	28	33	36	20
Union Grove	53	51	25	39	46	49	31

Conclusions

The Transmission Value analysis produced several observations and conclusions:

- PV reduced transmission demand during the months of May, June, July, and August.
- The peaks occurred too late in the evening (7 pm – 8 pm) during the rest of the year for PV to provide load reduction.
- Tracking systems and west-facing systems were more effective at reducing peaks because the peaks occurred late in the day even during the summer months.
- Transmission Values were low relative to other PV benefits. The maximum benefit was $\$53/kW_{AC}$ for a 1-axis tracking system at Union Grove, primarily due to the poor load match.
- Distribution Value was covered separately.

Figure 18. Merton demand reduction.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Peak	18:00	19:00	19:00	20:00	15:00	17:00	18:00	18:00	20:00	20:00	19:00	19:00	
1 Axis	0	0	0	0	161	289	192	405	0	0	0	0	1046
1 Axis Tilt	0	0	0	0	152	277	189	401	0	0	0	0	1019
South-30	0	0	0	0	164	161	52	151	0	0	0	0	528
SW-30	0	0	0	0	166	231	170	294	0	0	0	0	861
West-30	0	0	0	0	166	268	197	380	0	0	0	0	1011
West-45	0	0	0	0	153	285	197	397	0	0	0	0	1031
Horiz	0	0	0	0	179	207	88	188	0	0	0	0	661

7. LOSS SAVINGS VALUE

APPROACH

Introduction

Distributed generation technologies reduce system losses by generating power at the point of consumption rather than the point of generation. Loss savings are treated in this analysis as indirect benefits in that they "magnify" the value other benefits and are accounted for in a separate loss savings category.

For example, the generation benefit provided by PV represents the avoided wholesale cost of generating the electricity consumed by the customer. We Energies saves the cost of generating or purchasing a kWh at the point of production for every kWh produced by PV. In addition, We Energies avoids the need to produce supplemental energy to account for losses since PV produces electricity at the point of consumption.

Appropriate loss savings factors need to be determined to calculate the Loss Savings Value. A detailed derivation of these factors was done in a separate study conducted for Austin Energy by CPR[30] in 2006. This study uses the same methodology. The key points of the derivation include:

- Loss savings calculations should be performed on a marginal basis rather than an average basis; performing the analysis using average system losses substantially underestimates the Loss Savings Value.
- Energy-related and capacity-related benefits should be calculated on a marginal basis.
- Loss savings should be calculated relative to the DG location rather than to a central generation location. [31]

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[30] "The Value of Distributed Photovoltaics to Austin Energy and the City of Austin", Clean Power Research, 2006. This report can be found at www.cleanpower.com. See Appendix B for the Marginal Loss Savings derivation.

[31] For example, if T&D losses were reported to be 10 percent of the energy produced by central generation, then the loss savings provided by DG would be 0.1/(1 - 0.1) = 11 percent of the energy produced by DG. In this respect, 100 kWh produced by DG would be equivalent to 111 kWh of central generation because it would avoid 11 kWh of losses.

Transmission versus Distribution Loss Savings

The present study deviates from the Austin Energy study in one respect. Selected benefits (e.g., generation) have loss savings associated with distribution only, while other benefits (e.g., Fuel Price Hedge) have loss savings associated with transmission and distribution. The previously-calculated generation benefit, for example, included transmission loss savings since LMPs included transmission loss factors and were defined at physical nodes immediately before entering the distribution system.

Table 36 summarizes whether loss savings are associated with the distribution system only (D), the combined transmission-distribution system (T&D), or neither (N/A). Generation, transmission, and distribution loss savings only include distribution losses since these benefits were effectively valued at the point of connection to the transmission system (not at the generation source). Generation costs, for example, used LMP pricing at the pricing node, after transmission losses. Transmission pricing is taken at the distribution substation (not at the power plant). Fuel Price Hedge loss savings takes into account distribution and transmission losses because they are evaluated relative to the point of generation. The Environmental benefit has no loss savings because the value is derived from the amount of energy produced by PV, regardless of location.

Table 36. Loss characterization by benefit category.

	Merton	***Albers***	***Union Grove***
Generation	D	D	D
Transmission	D	D	D
Distribution	D	D	D
Environment	N/A	N/A	N/A
Fuel Price Hedge	T&D	T&D	T&D

Average Losses

Transmission losses into the WEC area were obtained from the Midwest ISO[32] as shown in Table 37. These losses corresponded to the time of average load. The average load losses were scaled to a value representing 100 percent load using the relation:[33]

$$Average\ Percent\ \ Losses_t \quad \eta_T \left(\frac{P_t^0}{P_T^0} \right)$$

where η is the percent losses at the time of the system average load, T represents the time of the average load and t represents the time of the peak. Hourly We Energies system load data[34] was analyzed for the power ratio, and the average, peak and peak/average ratio are shown in Table 38. The result of the calculation is shown as the average transmission losses at 100 percent load in Table 37.

Table 37. Transmission losses.

Average (average load)	1.90%
Average (100% load)	3.34%

Table 38. We Energies system load (kW).

Average	3,454,643
Peak	6,086,000
Peak/Average Ratio	1.76

[32] Transmission loss factors were taken from http://www.midwestiso.org/publish/Document/1d6630_11a6da4545e_-7f640a48324a?rev=1. Percentage losses were averaged across all transmission paths into area WEC.

[33] See the Austin Energy study, Appendix B (“Marginal Loss Savings”), equation 8.

[34] Provided by Eric Rogers to Drew Szabo on March 20, 2007, covering the period September 2003 through August 2006. For consistency with the other benefit calculations, system loads only from the period of 9/23/05 to 9/22/06 are used, with the 22 days of September 2006 taken from the identical days of 2005.

Distribution losses are presented in Table 39 for the three study areas of interest, as calculated at the 100 percent load condition by the We Energies Distribution Operations Department.[35] The distribution system in the areas of interest consists of two levels. The first level is a 24.9 kV distribution system and the second an 8.32 kV distribution system. The 24.9 kV system is supplied by 138 kV transmission and feeds all classes of customers directly (through utilization transformers), as well as providing supply to We Energies 24.9-8.32 kV substations.

Merton and Union Grove substations are all 24.9-8.32 kV substations supplied from a 24.9 kV feeder. Therefore, distribution losses include the 8.32 kV feeders, 24.9-8.32 kV substation transformers, the 24.9 kV feeders and the 138-24.9 kV substation transformers. Albers feeder projects involve only 24.9 kV feeders. Therefore, losses on the 8 kV feeders and 24.9-8.32 kV transformers would not be applicable.

The T&D upgrades associated with the projects listed below would reduce energy losses. No account was made for this fact in the study.

Table 39. Distribution losses.

	Merton	***Albers***	***Union Grove***
8.32 kV feeders	1.8%		1.8%
24.9/8.32 kV transformer	0.7%		0.7%
24.9 kV feeders	2.0%	2.0%	2.0%
138/24.9 kV transformer	0.4%	0.4%	0.4%
Average losses (100% load)	4.9%	2.4%	4.9%

[35] Data provided by John Nesbitt, 11/15/06.

Hourly Loss Factors

Next, the losses saved were considered from the perspective of the customer-generator. Marginal loss factors were calculated for each hour during the year because the benefits were calculated using hourly values and the loss factors varied hourly depending upon the load. The loss factors represent marginal loss savings—defined as the change in generation per unit change in consumption. The calculation is based on the relation[36]

$$LF_i \quad \frac{dP_i^0}{dP_i^1} \quad \left(\frac{1}{1-\eta_T \left(\frac{P_i^0}{P_T^0} \right)} \right)^2$$

where, *T* represents the time of the peak, *i* represents the hour, and η_T is the average loss percentage at the peak hour.

Separate hourly loss factors were calculated for transmission and distribution. The distribution loss factors represent the losses between the distribution substation and the customer, while the transmission loss factors represent the losses between a typical generator on the system and the distribution substation. The combined T&D hourly loss factor is:

$$LF_{T\&D_i} = LF_{T_i} \times LF_{D_i}$$

Loss Savings Percentages

Loss savings percentages for each benefit were calculated as follows. The loss savings percentage for generation represents the percentage increase in the $/kW$_{AC}$ generation benefit value associated with avoided losses. It is calculated as:

$$LS_{gen} = \frac{\sum_i LF_{D_i} \times LMP_i \times E_i - \sum_i LMP_i \times E_i}{\sum_i LMP_i \times E_i}$$

The baseline Generation Value determined previously corresponds to the second term in the numerator. The value for each hour is the product of the LMP for that hour and the energy generated by PV. However, the actual Generation Value, including the effect of losses in the

[36] See the Austin Energy study, Appendix B (“Marginal Loss Savings”), equation 20.

distribution system, is represented by the first term in the numerator. The percentage is calculated to facilitate the presentation of losses as a separate benefit category.

Both transmission and distribution benefits represent the effective capacity of the PV system as measured at the distribution substation and were calculated using the distribution loss factors. The environmental and fuel price hedge benefits, on the other hand, were calculated from the combined T&D loss factors.

RESULTS

Loss savings percentages were calculated in Table 40 using the above equations and summed over the year. Notice that the percentages are higher for the Fuel Price Hedge Value since these include both transmission and distribution losses. Also note that Albers percentages are noticeably lower than the other locations due to the higher voltages.

Table 40. Loss savings percentages by value component and configuration.

Generation Value	***1 Axis***	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	4.2%	4.2%	4.1%	4.3%	4.4%	4.5%	4.2%
Albers	2.3%	2.3%	2.2%	2.3%	2.4%	2.4%	2.3%
Union Grove	4.6%	4.6%	4.5%	4.7%	4.8%	4.9%	4.6%
Transmission Value							
Merton	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
Albers	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Union Grove	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Distribution Value							
Merton	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
Albers	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Union Grove	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Hedge Value							
Merton	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%
Albers	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%	5.9%
Union Grove	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%

The Loss Savings Value was calculated by applying these percentages to the previously calculated benefits as shown in Table 41. For example, the Generation Value for a 1-axis tracking system at Merton was determined previously to be \$1,522/kW_{AC}. Applying the loss savings of 4.2 percent (from Table 40) resulted in a loss savings for this benefit of \$64/kW. Repeating this calculation for the other four benefits and summing resulted in a total Loss Savings Value of \$226/kW.

Table 41. Loss Savings Value per unit of installed PV capacity (\$/kW_{AC}).

	1 Axis	***1 Axis Tilt***	***South-30***	***SW-30***	***West-30***	***West-45***	***Horiz***
Merton	124	135	103	103	90	85	90
Albers	77	85	65	63	55	51	56
Union Grove	134	146	110	109	96	91	96

8. SUMMARY AND CONCLUSIONS

SUMMARY

The objective of this report is to present the results of the value analysis from the perspective of We Energies at a specific point in time. The individual value components are summarized in Table 42, including Generation, Transmission, Distribution, Environmental, Fuel Price Hedge, and Loss Savings Values. Each of these are presented by location and PV system configuration. Table 43 levelizes the results to a per unit energy value. Figure 19 and Figure 20 present the total values graphically in terms of per unit of installed capacity and per unit of energy. Figure 21 presents the value components for Merton substation for the various configurations and Figure 22 presents the value components for a South-30 configuration at the three locations.

CONCLUSIONS

For the time period during which this study was conducted, this analysis leads to the following conclusions:

- Value per unit of installed PV ***capacity*** (\$ per kW_{AC}) was approximately linearly related to energy production for the variations configurations and thus value per unit of ***energy*** (\$ per kWh) was relatively independent of location and configuration.
- Value per unit of energy was about \$0.15 per kWh over the PV system's 30 year lifetime. This value is sensitive to the data (especially the value of energy) that was used at the time of the study and should be interpreted within that context.
- There was significant variation in value that is related to system configuration due to the difference in the amount of annual energy production.
- There was minimal variation in value that is related to system location.
- Generation, Environmental, and Fuel Price Hedge Value components comprised the highest portion of total value.
- Transmission and Distribution Value components were small in comparison to other components.
- Loss Savings Value was small but not insignificant.

Table 42. Value components per unit of installed capacity by location and configuration ($\$/kW_{AC}$).

	1 Axis	*1 Axis Tilt*	*South-30*	*SW-30*	*West-30*	*West-45*	*Horiz*
Generation Value							
Merton	1,522	1,682	1,338	1,273	1,080	1,001	1,134
Albers	1,536	1,691	1,340	1,282	1,095	1,017	1,144
Union Grove	1,536	1,691	1,340	1,282	1,095	1,017	1,144
Environmental Value							
Merton	1,321	1,458	1,134	1,062	891	822	960
Albers	1,343	1,477	1,144	1,075	907	838	973
Union Grove	1,343	1,477	1,144	1,075	907	838	973
Fuel Price Hedge Value							
Merton	680	751	584	547	459	423	494
Albers	692	761	589	554	467	432	501
Union Grove	692	761	589	554	467	432	501
Distribution Value							
Merton	145	143	45	129	149	149	70
Albers	49	49	11	30	39	45	16
Union Grove	147	145	43	92	116	132	56
Transmission Value							
Merton	49	47	25	40	47	48	31
Albers	39	39	18	28	33	36	20
Union Grove	53	51	25	39	46	49	31
Loss Savings Value							
Merton	124	135	103	103	90	85	90
Albers	77	85	65	63	55	51	56
Union Grove	134	146	110	109	96	91	96
Total Value							
Merton	3,842	4,217	3,229	3,154	2,716	2,527	2,778
Albers	3,737	4,101	3,168	3,033	2,595	2,419	2,710
Union Grove	3,905	4,270	3,252	3,152	2,726	2,557	2,801

Table 43. Value components per unit of energy by location and configuration ($/kWh).

	1 Axis	1 Axis Tilt	South-30	SW-30	West-30	West-45	Horiz
Generation Value							
Merton	0.0610	0.0611	0.0625	0.0634	0.0642	0.0645	0.0625
Albers	0.0605	0.0606	0.0620	0.0631	0.0639	0.0642	0.0622
Union Grove	0.0605	0.0606	0.0620	0.0631	0.0639	0.0642	0.0622
Environmental Value							
Merton	0.0529	0.0529	0.0529	0.0529	0.0529	0.0529	0.0529
Albers	0.0529	0.0529	0.0529	0.0529	0.0529	0.0529	0.0529
Union Grove	0.0529	0.0529	0.0529	0.0529	0.0529	0.0529	0.0529
Fuel Price Hedge Value							
Merton	0.0273	0.0273	0.0273	0.0273	0.0273	0.0273	0.0273
Albers	0.0273	0.0273	0.0273	0.0273	0.0273	0.0273	0.0273
Union Grove	0.0273	0.0273	0.0273	0.0273	0.0273	0.0273	0.0273
Distribution Value							
Merton	0.0058	0.0052	0.0021	0.0065	0.0089	0.0096	0.0039
Albers	0.0019	0.0018	0.0005	0.0015	0.0023	0.0028	0.0009
Union Grove	0.0058	0.0052	0.0020	0.0045	0.0068	0.0083	0.0030
Transmission Value							
Merton	0.0020	0.0017	0.0011	0.0020	0.0028	0.0031	0.0017
Albers	0.0015	0.0014	0.0008	0.0014	0.0019	0.0023	0.0011
Union Grove	0.0021	0.0018	0.0012	0.0019	0.0027	0.0031	0.0017
Loss Savings Value							
Merton	0.0050	0.0049	0.0048	0.0051	0.0054	0.0054	0.0049
Albers	0.0031	0.0030	0.0030	0.0031	0.0032	0.0032	0.0031
Union Grove	0.0053	0.0052	0.0051	0.0054	0.0056	0.0057	0.0052
Total Value							
Merton	0.1539	0.1531	0.1507	0.1572	0.1614	0.1628	0.1533
Albers	0.1473	0.1470	0.1466	0.1493	0.1515	0.1528	0.1475
Union Grove	0.1539	0.1530	0.1505	0.1552	0.1592	0.1616	0.1524

Figure 19. Total value per unit of installed PV capacity by system configuration and location.

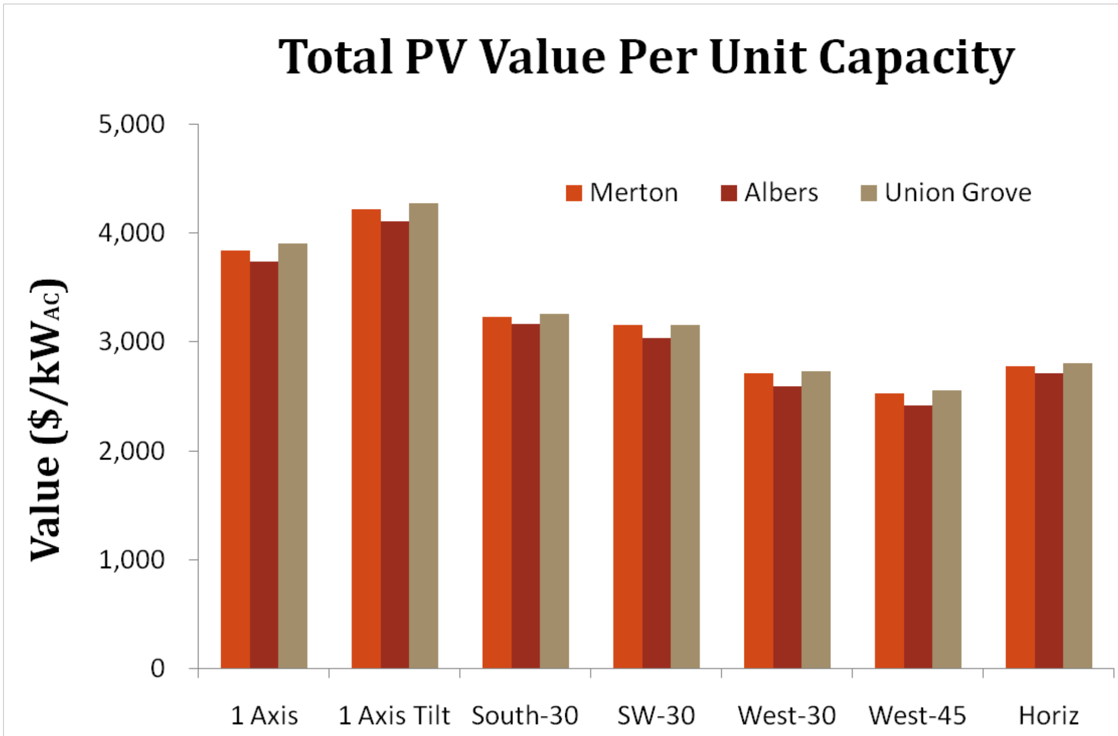


Figure 20. Total value per unit of energy by configuration and location.

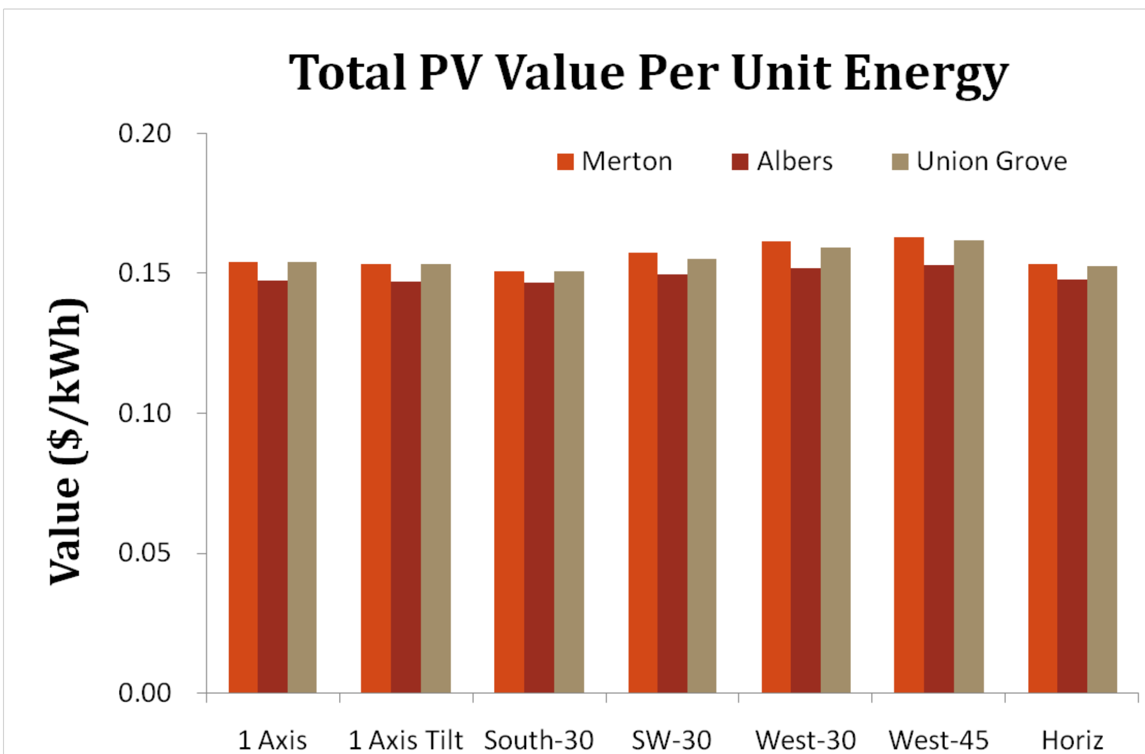


Figure 21. Value per unit of installed PV capacity by configuration for Merton Substation.

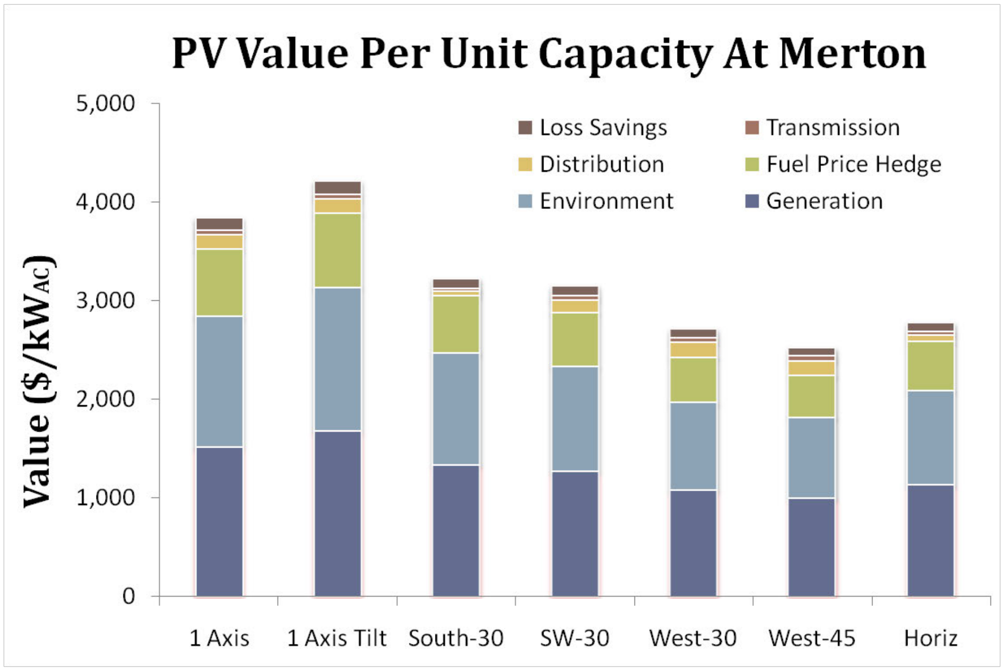
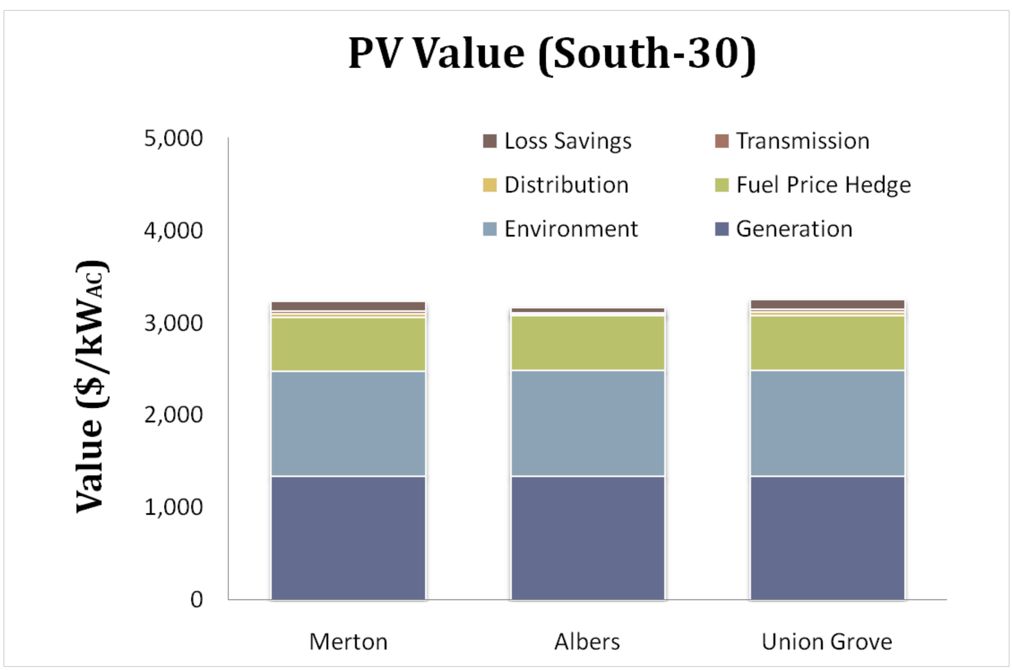


Figure 22. Value per unit of installed PV capacity by location (South-30 orientation).



NEXT STEPS

The following cautions must be observed in considering these results:

- The results of this study are sensitive to the LMPs used. The following table compares some statistics of the LMPs used in the study to the LMP statistics for the period September 2008 through August 2009. A comparison of the two shows that the LMPs have changed significantly. There is a need to rerun this study to obtain a better reflection of the current value of PV as the LMPs change.

	LMPs used in Study			*LMPs year ending Aug. 2009*		
Node	***Max***	***Min***	***Avg***	***Max***	***Min***	***Avg***
GERMANOT1	273.24	4.83	48.72	144.12	-21.69	30.74
PARIS01S1	199.72	5.20	48.36	142.46	-24.51	30.29
PLPRG41	195.59	4.96	45.67	139.39	-38.79	29.10

- The MISO LMPs only reflect energy value and do not include capacity value. The value of generation capacity is very low at this time and was not included in the economic valuation. Future studies should include the generation capacity value of PV.
- We Energies RRC are not currently tradable outside of Wisconsin. This analysis assumes that RECs can be traded across state lines. Further evaluation is required to assess this.
- The Transmission Value depends upon whether PV is claimed as a generation resource or as negative load. This analysis assumed that PV was operating as negative load and that ATC prices are not reallocated as a result of the installation of PV. PV as a generation resource or ATC price reallocation will require a different analysis.