May 19, 2014

**VIA E-FILING**

Carlotta S. Stauffer
Director, Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 130199-EA Florida Power & Light Company
Docket No. 130200-EI Duke Energy Florida, Inc.
Docket No. 130201-EI Tampa Electric Company
Docket No. 130202-EI Gulf Power Company

Dear Ms. Stauffer:

I have enclosed the Environmental Defense Fund's Direct Testimony of Dr. James Fine, to be filed in the above-referenced dockets. Should you have any questions regarding this filing, please contact me at (513) 226-9558.

Very truly yours,

/s/ John Finnigan

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**Counsel for Petitioner**
**Environmental Defense Fund**

## CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy and correct copy of the Environmental Defense Fund's Direct Testimony of Dr. James Fine was served on this 19th day of May, 2014, via electronic mail on:

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/s/ John Finnigan

______________________________

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**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

**ENVIRONMENTAL DEFENSE FUND**

**DIRECT TESTIMONY OF DR. JAMES FINE**

**DOCKET NOS. 130199-EI, 130200-EI, 130201-EI & 130202-EI**

## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is James Fine. My business address is Environmental Defense Fund, 123 Mission Street, 28th Floor, San Francisco, California 94105.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am employed as Director of Energy Research and Senior Economist, Clean Energy Program by the Environmental Defense Fund ("EDF").

**Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.**

A. I received my B.S. in Economics from the University of Pennsylvania Wharton School in 1989, and my Ph.D. from the University of California Berkeley, Energy and Resources Group, in 2003. I have over 20 years of experience working in the field of energy economics, with over the last three years spent primarily on clean energy issues. I consulted with M.Cubed and Envair from 1994 to 2007 and was an assistant and adjunct professor at the University of San Francisco. Since 2009, I have worked closely with the California Public Utilities Commission and with the California investor-owned utilities on many clean energy issues, including resource planning, energy efficiency and demand response, renewable energy and smart grid deployment. I serve as lead economist in EDF's work on smart clean energy policies.

**Q. WHAT ARE YOUR RESPONSIBILITES AS DIRECTOR OF ENERGY RESEARCH AND SENIOR ECONOMIST, CLEAN ENERGY PROGRAM FOR ENVIRONMENTAL DEFENSE FUND?**

A. I am responsible for developing and supporting policies and practices that appropriately value energy goods and services.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. I offer testimony to inform the decision analyses used by the Commission in setting goals for the Florida Energy Efficiency and Conservation Act ("FEECA"), and to improve the realized cost-effectiveness of programs to encourage "promoting an increased use of renewable energy resources and low-carbon emission electric power plants." At the heart of my comments is my conclusion, based on a wealth of reliable evidence, that continued and enhanced investment in distributed solar photovoltaic ("PV") programs is good policy for Florida. I observe that program cost-effectiveness evaluations thus far have been too conservative because they are insufficiently inclusive of all costs and benefits. As well, I offer a variety of recommendations to support market momentum for distributed solar PV, while evolving the program to enable it to equitably achieve scales of significance.

I observe that cost trend for distributed residential and small commercial solar PV is converging quickly on cost parity with retail electricity rates. Once average electricity rates exceed the costs of distributed solar PV, adoption rates in Florida are very likely to follow those of California, Hawaii, North Carolina, among other states, which have experienced greater than 30% per annum growth in installed solar PV capacity over the past several years.

I recommend several strategies to both continue to provide avenues for low-cost distributed solar PV to reach the marketplace, and for incentives to ratchet downward as capital costs continue to decline while keeping in place funds to support distributed solar PV investments by vulnerable or other special needs electricity customers.

I provide recommendations about how to more accurately and equitably account for the costs and benefits of clean renewable energy resources. In pursuit of a more comprehensive representation of distributed solar PV values, I comment on the forecasted values for carbon dioxide compliance costs used by the utilities in developing their conservation plans. I also make several recommendations regarding the utilities' distributed solar PV programs, including strategies to enhance the cost-effectives of programs and a recommendation for the Commission to develop a more comprehensive method for valuing distributed solar PV resources using a full "value of solar" (VOS) analysis. Under this approach, the Commission would identify all the costs and benefits attributable to distributed solar PV generation and develop a value for each element of cost and benefit, the net result representing the value of distributed solar PV generation.

The value calculated for distributed solar PV using a VOS method can inform a variety of decisions for all actors in the utility sector: regulators, utilities, third-party service providers and utility customers. For utilities submitting applications to public service commissions, and for the commissions themselves, the VOS net and associated components will be useful for benchmarking and cost-effectiveness evaluations. For customers, third parties and innovators, the VOS will be a clear price signal. For meeting state and federal goals, and avoiding the effects of climate change, the VOS is a payment mechanism which will enable clean distributed PV solar to get to significant scales of quickly and fairly.

Finally, I recommend that the Commission consider developing a pilot program where the utilities would be able to invest in and earn a return on distributed solar PV programs, as an incentive to make greater investments in these programs.

**Q. PLEASE EXPLAIN THE BACKGROUND OF THIS PROCEEDING.**

A. The purpose of this proceeding is for the Commission to set numeric goals for the Florida utilities under FEECA. The Commission is required under Section 366.82, Florida Statutes to adopt goals to increase the efficiency of energy consumption, reduce and control the growth rates of electric consumption and weather-sensitive peak demand, and "encourage" development of demand-side renewable energy resources. The statute requires the Commission to review a utility's conservation goals no less than every five years. The statute was amended in 2008 to direct the Commission to include goals "to encourage development of demand-side renewable energy resources." Section 366.82(2), Florida Statutes.

## II <u>POLICY OBJECTIVES</u>

**Q. WHAT POLICY OBJECTIVES SHOULD THE COMMISSION CONSIDER IN DECIDING WHETHER TO APPROVE A DEMAND-SIDE RENEWABLE ENERGY RESOURCES PLAN IN THE UTILITY CONSERVATION PLANS?**

A. There are six policy goals for the Commission to consider in addition to ensuring Florida consumers receive electricity in a safe, adequate and reliable manner:

1. Encourage development of zero-carbon demand-side renewable energy resources as required by Section 366.82(2), Florida Statutes.

2. Conform to the State Comprehensive Plan.
3. Design programs which may help Florida comply with the recently reinstated EPA Cross-State Air Pollution Rule and the EPA's upcoming greenhouse gas ("GHG") pollution standards for existing fossil fuel plants.
4. Consider the costs and benefits of any distributed solar PV program per FEECA. Section 366.82(3), Florida Statutes.
5. Take actions to avoid the effects of climate change and put Florida on a trajectory to bring GHG emissions to 1990 levels by 2050
6. Prepare the energy system – and its users – for "circumstances of disrupted energy supplies or unexpected price surges".

**Q. WHAT PROVISIONS OF THE STATE COMPREHENSIVE PLAN RELATE TO A DEMAND-SIDE RENEWABLE ENERGY RESOURCE PLAN?**

A. The State Comprehensive Plan was amended in 2008 to specifically include an objective to increase low-carbon resources. The relevant sections of the State Comprehensive Plan are set forth below, with the 2008 amendment language in capital letters, as contained in Section 187.201, Florida Statutes:

> (10) AIR QUALITY.—
>
> (a) Goal.--Florida shall comply with all national air quality standards by 1987, and by 1992 meet standards which are more stringent than 1985 state standards.
>
> (b) Policies.—
>
> 1. Improve air quality and maintain the improved level to safeguard human health and prevent damage to the natural environment.
>
> * * *

3. Reduce sulfur dioxide and nitrogen oxide emissions and mitigate their effects on the natural and human environment.

4. Encourage the use of alternative energy resources that do not degrade air quality.

5. Ensure, at a minimum, that power plant fuel conversion does not result in higher levels of air pollution.

6. ENCOURAGE THE DEVELOPMENT OF LOW-CARBON-EMITTING ELECTRIC POWER PLANTS.

(11) ENERGY.—

(a) Goal.--Florida shall reduce its energy requirements through enhanced conservation and efficiency measures in all end-use sectors AND SHALL REDUCE ATMOSPHERIC CARBON DIOXIDE BY, while at the same time promoting an increased use of renewable energy resources AND LOW-CARBON-EMITTING ELECTRIC POWER PLANTS.

(b) Policies.—

1. Continue to reduce per capita energy consumption.

2. Encourage and provide incentives for consumer and producer energy conservation and establish acceptable energy performance standards for buildings and energy consuming items.

* * *

5. Reduce the need for new power plants by encouraging end-use efficiency, reducing peak demand, and using cost- effective alternatives.

6. Increase the efficient use of energy in design and operation of buildings, public utility systems, and other infrastructure and related equipment.

7. Promote the development and application of solar energy technologies and passive solar design techniques.

* * *

9. Promote the use and development of renewable energy resources AND LOW-CARBON-EMITTING ELECTRIC POWER PLANTS.

> 10. Develop and maintain energy preparedness plans that will be both practical and effective under circumstances of disrupted energy supplies or unexpected price surges.

**Q. ARE YOU AWARE OF ANY OTHER POLICY CONSIDERATIONS WHICH APPLY?**

A. Yes, in enacting FEECA, the Florida legislature stated: "Since solutions to our energy problems are complex, the Legislature intends that the use of solar energy, renewable energy sources, highly efficient systems, cogeneration, and load-control systems be encouraged." Section 366.81, Florida Statutes.

**Q. HOW MIGHT FLORIDA BE ABLE TO USE A DEMAND-SIDE RENEWABLE RESOURCES PROGRAM AS A COMPLIANCE TOOL UNDER U.S. EPA REGULATIONS?**

A. On April 29, 2014, the United States Supreme Court reinstated the U.S. EPA's Cross-State Air Pollution Rule. *Environmental Protection Agency v. EME Homer City Generation, L.P.,* Case Nos. 12-1182 and 12-1183 (Opinion and Order) (April 29, 2014). This ruling means that fossil fuel generators in Florida may face additional compliance obligations with respect to ozone and particulate matter ("PM") precursor pollutant emissions. Enhancing distributed solar PV resources could provide an additional avenue by which utilities could mitigate their compliance obligations because (a) load-side strategies can be geared to avoid using the most emissions intensive resources, thereby providing additional flexibility to the generator, and (b) conservation and self-generation will reduce to load served by fossil fuel generators to inherently limit cost risks associated with compliance. Investments in utility-scale low and zero-carbon generation resources in pursuit of renewable portfolio standard requirements will also avoid investments in new fossil fuel generation that produces ozone precursors and both primary and precursor PM emissions.

In addition, the EPA will soon issue new GHG standards for existing fossil fuel plants and Florida may be able to use its renewable energy policies as an important compliance tool. Florida would be wise to hedge against the compliance cost risks from new EPA GHG standards by enacting policies that encourage zero carbon distributed solar PV programs, as well as other demand-side programs such as energy efficiency and demand response. These programs may increase the options available to fossil fuel generators to comply with new EPA GHG standards.

On June 25, 2013, President Obama issued a Presidential Memorandum directing the EPA to issue GHG emission rules for fossil fuel power plants. The EPA has already issued GHG emissions rules for new fossil fuel plants. The Presidential Memorandum directs the EPA to issue the new rules for existing fossil fuel power plants by June 1, 2014 and to finalize the rules by June 1, 2015. States will be required to submit state plans implementing the standards in compliance with the guidelines by June 30, 2016. EPA officials and industry and non-governmental/environmental stakeholders have been discussing the methods available for states to comply with these standards. There has been widespread discussion among the stakeholders that the EPA framework should be flexible and accommodate the successful deployment of renewable energy, distributed generation, and demand-side energy efficiency at the state level which has secured significant reductions in carbon pollution – and that the EPA framework should facilitate further deployment of these cost-effective strategies to secure the carbon pollution reductions required by EPA's guidelines.

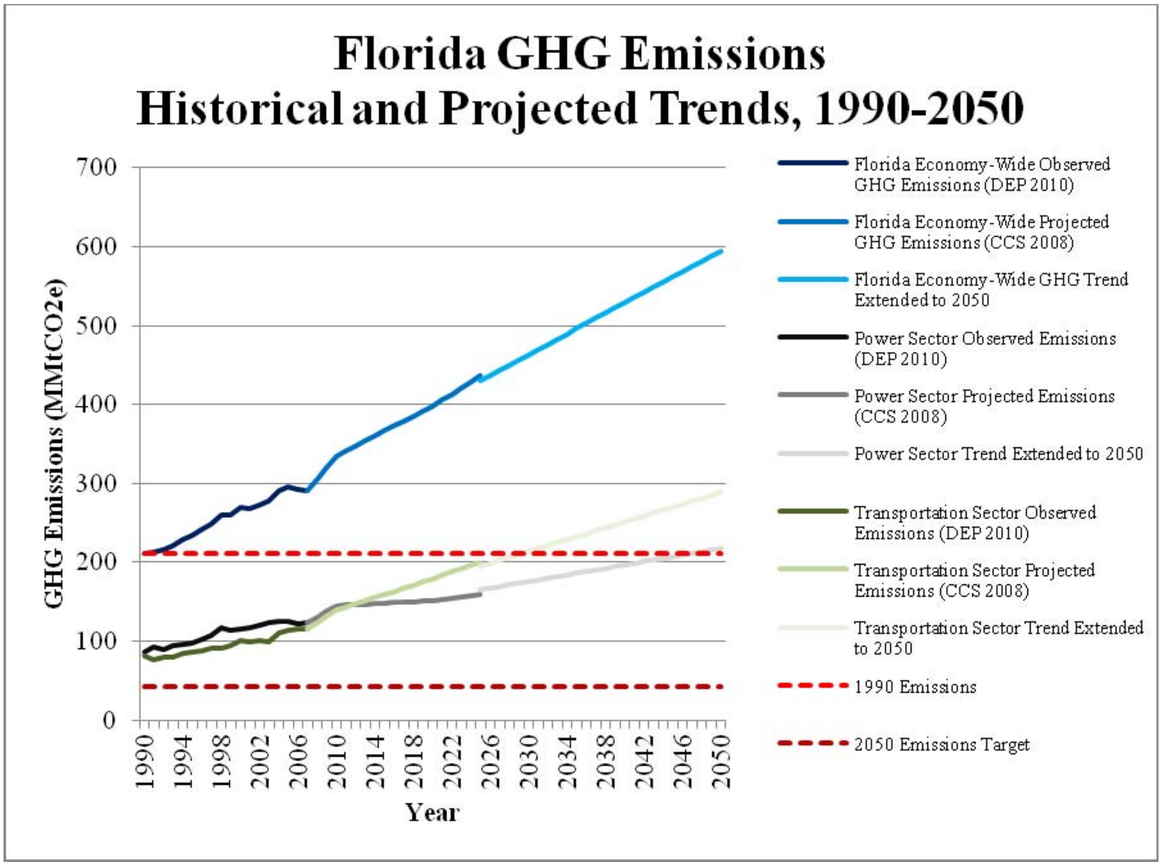
Based on these discussions, it appears that states may be able to use renewable energy and demand-side management policies and carbon reductions to comply with the new carbon pollution standards for existing fossil fuel power plants. With clear foresight that new rules for GHG emissions are on the horizon, it is imperative to utilize all available cost-effective clean energy resources now, and to plan for it at scales of significance. Florida utilities' future compliance costs can be mitigated by putting strong, scalable clean energy policy in place now.

**Q. HOW IMPORTANT WOULD IT BE FOR FLORIDA IF STATES ARE ALLOWED TO USE THEIR RENEWABLE ENERGY AND DEMAND-SIDE MANAGEMENT POLICIES TO COMPLY WITH THE NEW GHG EMISSIONS RULES?**

A. It would be very important. According to the U.S. Energy Information Administration, Florida ranks as the fifth highest state in the country for carbon emissions from fossil fuel plants. U.S. EPA, *State and Local Climate and Energy Program: State Energy CO2 Emissions.* If Florida can use renewable energy policies and demand-side management policies to comply with these rules, these mechanisms will provide another set of tools to mitigate rate impacts and could be evaluated against alternative compliance strategies for cost-effectiveness.

The following graph shows historical trends, near-term forecasts, long-term trajectories and GHG stabilization goals for Florida. Clearly, recent trends within both the energy sector and the broader Florida economy are not on target to meet GHG emissions cap goals for 2030 or 2050 that are in line with scientific consensus about "stabilization" levels of emissions. Indeed, in 2007 Governor Crist and the state legislature acknowledged these goals, eventually establishing a 2050 target of 80% below 1990 levels.

For Florida to have any feasible pathway toward stabilization would require significant de-carbonization of the electricity sector while electrifying the transportation sector. Recent emissions trends suggest that the state is going in the wrong direction as emissions are rising. If emissions continue to rise at the current trajectory then emissions will be closer to 600 MMtCO2e, about 15 times more than needed stabilization levels. In fact, current trajectories indicate that emissions from the energy sector or transportation sector would alone will surpass economy-wide emissions in 1990 and are already well above the economy-wide 2050 goal.



**Q. ARE GREENHOUSE GAS EMISSIONS FROM FOSSIL FUEL PLANTS HAVING AN IMPACT ON FLORIDA?**

A. Yes. The recently released National Climate Assessment (available at http://nca2014.globalchange.gov/report) (last viewed May 10, 2014) reports on the impacts of climate change on the United States, now and in the future. This report was prepared by a team of more than 300 experts guided by a 60-member Federal Advisory Committee and was extensively reviewed by the public and experts, including federal agencies and a panel of the National Academy of Sciences. The report describes numerous impacts of climate change on Florida. One noteworthy impact is sea level rise. The report states that the global sea level has risen about eight inches since reliable record keeping began in 1880, and is projected to rise another one to four feet by 2100. This has resulted in a new condition known as "sunny day flooding" in parts of Florida, particularly Miami Beach, where inland flooding occurs from sea level rise, without any rain. A recent New York Times article describes this phenomenon. *Miami Finds Itself Ankle-Deep in Climate Change Debate* New York Times (May 7, 2014) (available at: http://www.nytimes.com/2014/05/08/us/florida-finds-itself-in-the-eye-of-the-storm-on-climate-change.html?_r=1) (last viewed May 9, 2014). These are recent findings but they corroborate growing evidence, such as research by the Florida Oceans and Coastal Council (see http://www.floridaoceanscouncil.org/reports/Climate_Change_and_Sea_Level_Rise.pdf) (last viewed May 15, 2014).

## III. FORECASTS OF CARBON DIOXIDE COMPLIANCE COSTS USED IN THE UTILITIES' MODELING

**Q. DID YOU REVIEW THE UTILITIES' FORECASTS OF CARBON DIOXIDE COMPLIANCE COSTS USED IN THEIR MODELING?**

A. Yes.

**Q. WHAT COMMENTS DO YOU HAVE ABOUT THE VALUES THE UTILITIES USED IN THEIR FORECASTS OF CARBON DIOXIDE COMPLIANCE COSTS?**

A. In my opinion, the utilities' forecasts were too low. For example, in Dr. Sims' forecast at Exhibit SRS-7, he forecasts carbon dioxide compliance costs of zero through 2021, then relatively low levels of compliance costs beginning in 2022. Yet a study entitled *Analysis of the Impact of The President's Climate Action Plan on the Cost of Electricity in Florida* (September 25, 2013) presented to the National Association of Regulatory Utility Commissions and attached as Exhibit JF-1 states at page 6 that the forecasted compliance costs for FP&L are $238 million by 2020 and $249 million by 2021, and increasing steadily thereafter. This most recent study is one of many indicating that Florida will experience very high costs from global warming and that fast actions, along with action at the global scale, can avert these impacts. For another example, see work by Stanton and Ackerman, and included as Attachment JF-2 (http://www.floridaoceanscouncil.org/reports/Climate_Change_and_Sea_Level_Rise.pdf) (last viewed May 15, 2014). In addition to forecasting billions of dollars in lost tourism revenue, land loss and ecosystem destruction from sea level rise and more damage from hurricanes, they forecast increased demand for electricity, mostly to stay cool in a warming climate.

> High temperatures will increase demands for **electricity**, primarily to supply air conditioning. The extra power plants and the electricity they generate are not cheap; the annual costs of inaction are $5 billion in 2050 and $18 billion in 2100, as reported in Table ES-1 above. The same temperature increases will also degrade the performance of power stations and transmission lines, making them operate less efficiently; partly as a result, every additional degree Fahrenheit of warming will cost consumers an extra $3 billion per year by 2100. Increased demand for electricity also has severe implications for water resources, as all coal, oil, gas, and nuclear power plants must be cooled by water. The business-as-usual case will only intensify Florida's looming **water** crisis…" (pg. vii)

I therefore recommend that the utilities re-run their alternative scenarios for their conservation plans using more comprehensive carbon compliance forecasts. One approach the Commission may adopt to encourage distributed solar PV resources is to represent the full costs borne by society when carbon and other greenhouse gases are emitted. The EPA and White House have recently revisited guidance on the appropriate value to use in representing the social costs of carbon and arrived at values shown in the table that appropriate depend on an individual's choice of discount rate, as shown in the table below. (http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf) (last viewed May 15, 2014).

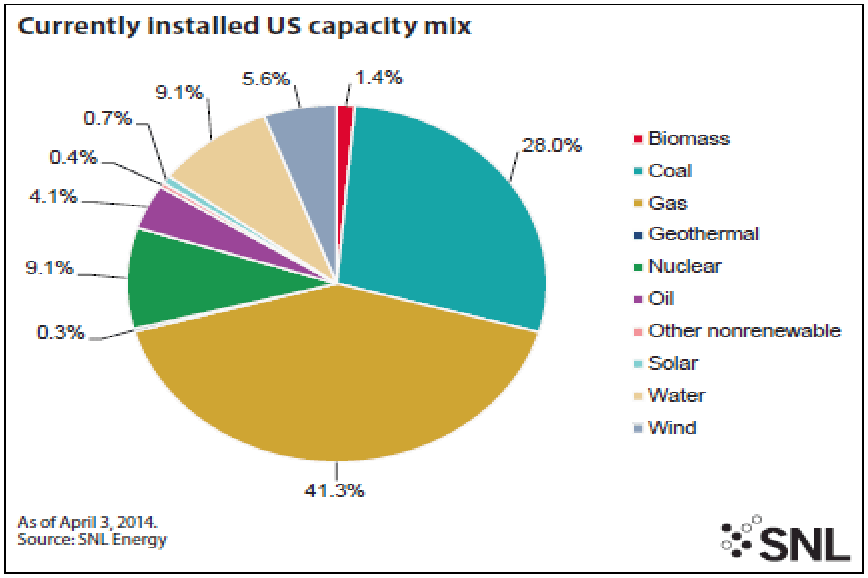
**Revised Social Coast of $CO_2$, 2010-2050 (in 2007 dollars per metric ton of $CO_2$)**

| Discount Rate Year | 5.0% Avg | 3.0% Avg | 2.5% Avg | 3.0% 95th |
|---|---|---|---|---|
| 2010 | 11 | 33 | 52 | 90 |
| 2015 | 12 | 38 | 58 | 109 |
| 2020 | 12 | 43 | 65 | 129 |
| 2025 | 14 | 48 | 70 | 144 |
| 2030 | 16 | 52 | 76 | 159 |
| 2035 | 19 | 57 | 81 | 176 |
| 2040 | 21 | 62 | 87 | 192 |
| 2045 | 24 | 66 | 92 | 206 |
| 2050 | 27 | 71 | 98 | 221 |

## IV. TRENDS IN SOLAR GENERATION

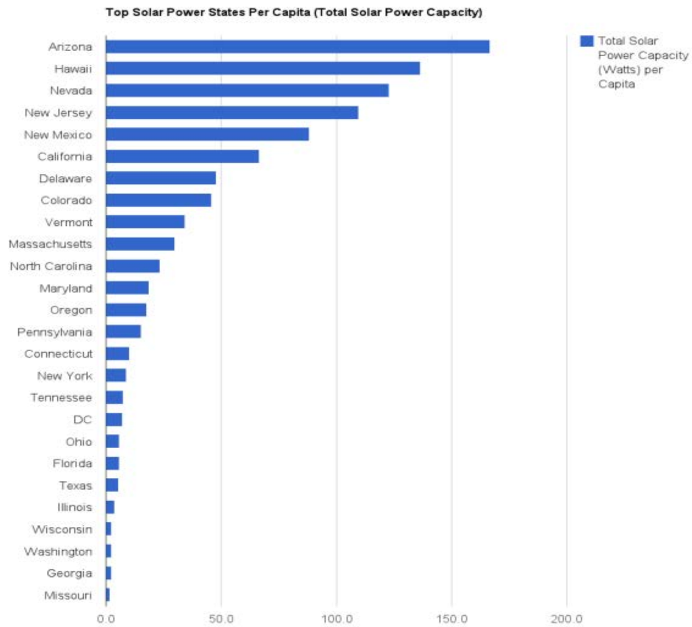
**Q. HOW MUCH SOLAR CAPACITY IS THERE IN THE U.S. TODAY?**

A. Solar currently makes up less than one percent of the installed generating capacity in the U.S., as shown below:




**Q. WHERE DOES FLORIDA RANK IN SOLAR GENERATION COMPARED TO OTHER STATES?**

A. Florida ranks near the bottom among states in solar capacity per capita, as shown below:




Source: http://cleantechnica.com/2013/06/25/solar-power-by-state-solar-rankings-by-state/ (last visited May 9, 2014).

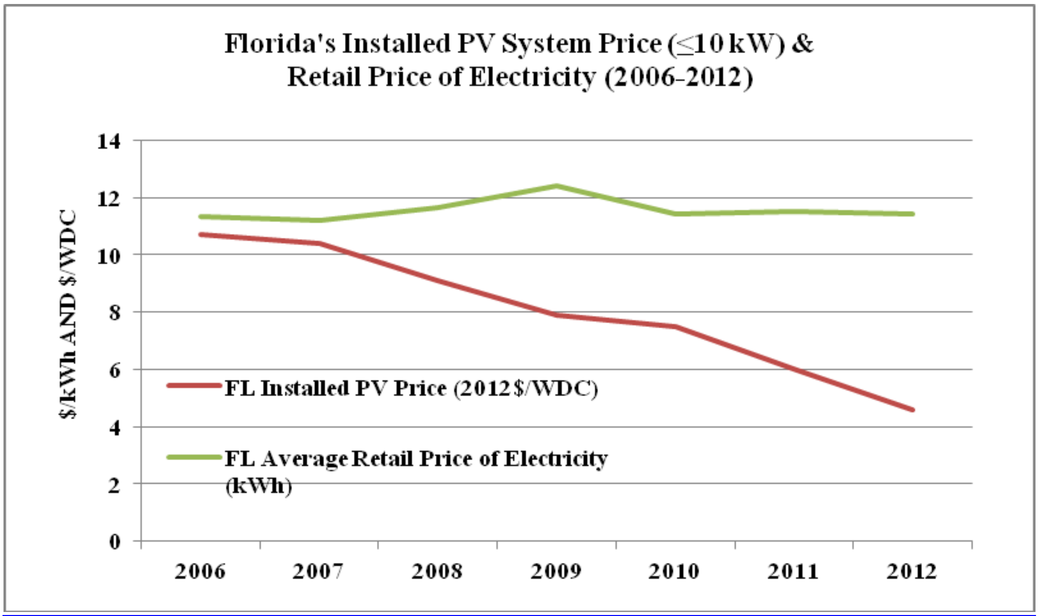
**Q. WHAT ARE THE COST TRENDS FOR DISTRIBUTED SOLAR PV GENERATION AND THE VALUE PROPOSITION FOR SOLAR PV INVESTMENT**

A. According to the Interstate Renewable Energy Council, *Annual Update and Trends:*

> **Lower Installed Costs.** The total installed cost for distributed installations fell 12 percent in 2012 and has fallen 33 percent over the past three years. The cost decline is even greater for utility installations. Falling module costs is the primary reason for the cost declines, but all cost components have fallen, including inverter costs and soft costs such as permitting.

The other side of the solar PV investment equation is the cost of electricity from the traditional sources. While distributed solar PV costs have been declining precipitously, electricity rates, demand and thus monthly bills have been climbing. According to EIA data, in 2012, the average price for electricity in Florida was $11.42 per kWh, which is the 22nd highest price for electricity in the US (the average price was $12.30). However, with relatively high consumption (1,080.821 kWh per month), the average monthly utility bill for Florida residents ranked 9th in the country ($123.45), and it has grown quickly. . The average monthly bill in 2012 by contrast was $105.86. See graph below and attached. (Source: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CCkQFjAA&url=http%3A%2F%2Fwww.eia.gov%2Felectricity%2Fsales_revenue_price%2Fpdf%2Ftable5_a.pdf&ei=7NB0U5nyE4ijsQTtx4HgBg&usg=AFQjCNE5g9aPKKuqdIp5VbpaCUlJ2XNwQw&sig2=c6g3lQMD8znZ4CuCcs_16Q&bvm=bv.66917471,d.cWc) (last viewed May 15, 2014).

The point at which electricity rates from the utility exceed the levelized cost of installed distributed solar PV will signal when incentives are no longer necessary for the average utility customer. While special types of customers may merit consideration for additional funding assistance to “go solar,” a system-wide incentive program available to all customers will be obviated. Forecasts informed by recent trends indicate distributed solar PV will achieve cost parity before the end of this decade in Florida. The graph below shows that the installed cost of small-scale (*i.e.*, less than 10 kilowatt capacity) distributed solar PV is well below the bundled retail rate (which of course includes more than just the cost of energy).




## IV. RESULTS OF FLORIDA DISTRIBUTED GENERATION PILOT PLAN

**Q. DID YOU REVIEW THE UTILITIES' FILINGS REGARDING THEIR DISTRIBUTED SOLAR PV PILOT PROGRAMS?**

A. Yes.

**Q. HOW MUCH DID THE DISTRIBUTED SOLAR PV PROGRAMS COST?**

A. The utility witnesses reported cost decreases during the three years the distributed solar PV programs were in effect, as shown below (prices are per watt; "C" denotes combined residential and commercial costs; "R" denotes residential cost):

| **Company** | **2011** | **2013** |
|---|---|---|
| FP&L (R) | $5.40 | $4.10 |
| Duke (R) | $6.31 | $5.19 |
| TECO (C) | $5.50 | $3.419 |
| Gulf Power (C) | $5.54 | $3.42 |

**Q. HOW DID CUSTOMERS RESPOND TO THE DISTRIBUTED SOLAR PV INCENTIVES?**

A. The utility witnesses also reported that they paid $2.00/watt incentive for the residential PV solar program and a sliding scale incentive for the commercial PV solar program. The utilities reported that these incentives are subscribed by customers very quickly after the enrollment period begins. In fact, the Commission's February 2014 *Annual Report on Activities Pursuant to the Florida Energy Efficiency and Conservation Act* states at p. 23:

> Many of the programs offering rebates for installing residential solar PV systems were subscribed to capacity just hours after approval, demonstrating high customer demand for subsidies for this type of solar technology. The subscription rate additionally implies that financial incentives offered to customers who install PV systems could still be effective, even at a reduced incentive level.

Earlier in my testimony I provided information about trends for both retail electricity rates and residential scale distributed solar PV. Clearly, these trends favor increased investments in distributed solar PV. It is no wonder the utilities have experienced very strong customer interest in the incentive program. It is also obvious that the amount of incentive for average or above-average electricity consuming homes can be ratcheted downward over time.

**Q. WHAT PAYBACK PERIOD DID THE COMPANIES USE TO DETERMINE THE COST-EFFECTIVENESS OF THESE PROGRAMS?**

A. The Companies stated that they used a two-year payback period.

**Q. HOW DID THE COMPANIES VALUE THE DISTRIBUTED SOLAR PV SYSTEMS FOR PURPOSES OF THEIR COST-EFFECTIVENESS ANALYSIS?**

A. The Companies used the installed capacity cost of the PV solar units to determine the cost-effectiveness of the program.

## V. RECOMMENDATIONS

**Q. WHAT RECOMMENDATIONS DO YOU HAVE FOR THE COMPANIES' DISTRIBUTED SOLAR PV PROGRAMS?**

A. I recommend that the Companies continue with their existing distributed solar PV programs at least at the same level of total program funding established by the Commission in the 2009 case but with a goal toward ratcheting the incentive for average, non-special needs customers downward as installed distributed solar PV grows. One good example of an adaptive incentive program for rooftop solar is provided by California's Solar Initiative. I also recommend that the Companies make several enhancements to their programs, as discussed in more detail below. I also recommend that the Commission consider implementing a utility-owned commercial rooftop PV program, as an incentive for utilities to make greater investments in distributed PV solar generation, and provide a competitive bidding system for distributed solar PV companies as a means to use competitive pressure to bring down bids while enabling utilities to "certify" solar PV installers for the benefit of risk-averse customers looking into a self-generation investment.

**Q. PLEASE DESCRIBE THE CHANGES YOU RECOMMEND FOR THE COMPANIES' DISTRIBUTED SOLAR PV PROGRAMS.**

A. I recommend that the Companies make the following changes: (1) test competitive bidding practices by conducting a utility-sponsored request for proposals ("RFP"); (2) develop a plan for adjusting the level of incentives as distributed solar PV achieves cost parity; (3) use a longer payback period to measure cost-effectiveness; (4) implement on-bill repayment to reduce the financing costs; and (5) use a different valuation method which reflects the full costs and benefits provided by distributed PV solar.

With respect to my fifth recommendation, I advise that Florida should undertake a process similar to Minnesota's to review options and provide guidance on the best method to value distributed solar PV (and, by extension, other distributed energy resources ("DER")). This approach is the best way to maximize cost-effective DER in the near term without compromising equity standards because it has the potential to minimize cross-subsidization between the with and without distributed solar PV customers. The VOS method adopted in Minnesota has the potential to achieve scales of significance, whereas net energy metering and other more simplistic mechanisms may not be structured for high levels of penetration.

**Q. PLEASE EXPLAIN YOUR RECOMMENDATION REGARDING COMPETITIVE BIDDING PRACTICES.**

A. The utilities' programs are incentive-based programs. Customers who wish to participate in the programs select a developer to install a distributed solar PV system, and enroll with the utility's distributed solar PV program to receive an incentive payment. The incentive payment helps defray the customer's cost of installing a distributed solar PV system. The program could be augmented by creating a list of utility-certified installers. The utility could issue an RFP from developers to bid on the installation costs and financing terms to install distributed solar PV systems in the utility's service territory. The utility would select the bidders which offer the lowest and best terms without compromising on quality requirements. The utility's customers could select a developer from this list. This could help drive down the costs of the distributed solar PV systems with both competitive pressures to inspire innovation and least-cost offerings and, once certified by the utility, lower costs of customer acquisition for the solar company.

**Q. IS THERE ANY EVIDENCE THAT INTRODUCING COMPETITIVE BIDDING COULD HELP DRIVE DOWN THE PROGRAM COSTS?**

A. Yes. Duke Energy Florida witness Helena Guthrie submitted Exhibit HG-16. This is a report of average residential and non-residential installed prices of solar PV systems by state for the fourth quarter of 2013. This report shows that the leading state for the lowest cost for residential solar PV systems is Wisconsin, with an installed cost under $3.00/watt. By contrast, the lowest cost the Florida utilities obtained for their distributed solar PV program for residential customers was FP&L's cost of $4.10/watt. This shows that the Florida utilities have a significant room for improvement in driving down the costs of their programs. One way to drive the costs down would be to introduce competitive bidding.

**Q. PLEASE EXPLAIN YOUR RECOMMENDATION REGARDING ADJUSTING THE LEVEL OF INCENTIVES.**

A. The utilities report that when they allow customers to enroll for incentive payments for the distributed solar PV systems, the incentives are fully subscribed within a very short time period, in some cases within hours after the enrollment period opens. This suggests that the incentives might be too high. The utilities should test using lower levels of incentives through a variety of means, including competitive bidding and careful tracking of installed PV capacity and costs. This is supported by the Commission's 2014 Annual Report on the FEECA program, which I discussed earlier in my testimony.

**Q. PLEASE EXPLAIN YOUR RECOMMENDATION REGARDING USING A LONGER PAYBACK PERIOD TO DETERMINE THE COST-EFFECTIVENESS OF THE DISTRIBUTED SOLAR PV PROGRAM.**

A. The utilities used a two-year payback period to determine the cost-effectiveness of the distributed solar PV program. Solar panels have a longer useful life than two years. For example, SunPower offers a 25-year warranty on its solar panels (*see* The SunPower Combined 25-Year Warranty, http://global.sunpower.com/products/solar-panels/warranty/) (last viewed May 10, 2014). Similarly, the California PUC recently proposed to establish a 20-year lifetime for solar PV projects currently enrolling into the net energy metering program. (*See* Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues. CPUC, Rulemaking 12-11-005).

I recommend that the utilities use a longer payback period to measure the program's cost-effectiveness that better aligns with the useful life of the distributed solar PV investment.

**Q. PLEASE EXPLAIN YOUR RECOMMENDATION REGARDING ON-BILL REPAYMENT.**

A. On-bill repayment ("OBR") can provide an opportunity for residential, commercial and industrial property owners to finance energy efficiency and distributed energy improvements with capital provided by non-utility third-party investors. Under OBR, a third-party investor, like a bank, loans money to a utility's customer to make one or more energy efficiency or distributed energy improvements. The loan is repaid through the customer's utility bill. The repayment obligation runs with the meter, meaning that it survives transfers in ownership and occupancy, which allows for longer term loans with lower interest rates that better align with the payback schedules of investments. The program can work for single-family, multi-family, commercial and industrial buildings.

**Q. WHAT BENEFITS WOULD AN OBR PROGRAM PROVIDE?**

**A**. The benefits of OBR include:

- Customer access to lower-cost capital for energy efficiency or distributed energy improvements (OBR loans often come at lower interest rates because of the credit enhancing impact of tying the loan to the customer's utility bill);
- Acceleration of clean energy investments and emissions reductions;
- Deferral or elimination of new generation capacity and reduced use of higher-cost generation for ratepayers.
- No direct costs to taxpayers or ratepayers;
- Reduced program costs through a scalable platform and standardized processes; and
- Job creation.

**Q. HAVE ANY OTHER STATES ADOPTED OBR PROGRAMS?**

A. Yes. California, Connecticut, Hawaii and New York have adopted OBR programs.

**Q. PLEASE EXPLAIN YOUR RECOMMENDATION REGARDING USING A DIFFERENT VALUATION METHOD WHICH REFLECTS THE BENEFITS PROVIDED BY DISTRIBUTED SOLAR PV SYSTEMS.**

A. I recommend that the Commission should establish a formal process for more precisely valuing the costs and benefits associated with distributed solar PV resources. The valuation established by this process could be used for determining the cost-effectiveness of the distributed solar PV programs and for setting level of payment for distributed generation owners.

**Q. PLEASE DESCRIBE THE INDUSTRY STUDIES WHICH REPORT ON THE COSTS AND BENEFITS ATTRIBUTABLE TO DISTRIBUTED SOLAR PV RESOURCES.**

A. Many of these studies are described in a meta-analysis *A Review of Solar PV Benefit and Cost Studies* Electricity Innovation Lab, Rocky Mountain Institute (April 2013). The Minnesota Department of Commerce recently recommended using a VOS tariff in: *Minnesota Value of Solar: Methodology,* Minnesota Department of Commerce, Division of Energy Resources (April 1, 2014). I have attached a copy of these reports to my testimony as Exhibits JF-3 and JF-4, respectively. These studies generally report that distributed solar PV provides many benefits which should be accounted for in assessing the cost-effectiveness of these systems. The VOS can address uncompensated costs to utility in the net energy metering tariff construct, and is inherently more equitable to all ratepayers. In addition, the Louisiana Public Service Commission issued a request for proposals at its March 12, 2014 meeting to hire a consultant to determine the cost and benefits of residential solar PV systems in Louisiana.

I recommend that this Commission follow a process similar to the Minnesota process for adopting a distributed solar PV valuation method. In adopting the study, the Minnesota Public Utilities Commission explained the process followed by the Minnesota Department of Commerce to develop its distributed solar valuation methodology:

> The statute required that the Department consult stakeholders with experience and expertise in power systems, solar energy, and electric utility ratemaking regarding the proposed methodology, underlying assumptions and preliminary data.’
>
> The Department contracted with Clean Power Research to help develop the methodology. Clean Power Research has experience analyzing and developing solar PV valuation methodologies for other public agencies,

> and for utilities. The Department also implemented a public engagement process involving four public workshops and solicitation of written comments over a period of months. Dozens of individuals and entities participated in the Department's process, including utilities, solar power installers, renewable energy advocates, and other organizations with relevant experience and expertise.
>
> The Department did not adopt every suggestion or recommendation made by participants. However, the Department did modify its proposal in response to some recommendations, and adequately justified its reasons for not doing so in response to others. The Commission received no complaints about the process and several participants in the process commended the Department for its open, transparent approach. The Commission concludes that the Department's extensive engagement efforts fulfilled its obligation to consult.[1]

**Q. WHAT FACTORS SHOULD THE COMMISSION CONSIDER IN DEVELOPING A NEW VALUATION FOR DISTRIBUTED SOLAR PV RESOURCES?**

A. I recommend that the Commission generally use as a starting point the Minnesota VOS protocol because this methodology was undertaken through an open and transparent process developed with the input of many knowledgeable and experienced electric industry stakeholders. The factors used in this methodology include the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value. Other known and measurable evidence of the cost or benefit of solar operation to the utility may be incorporated into the methodology, including credit for locally manufactured or assembled energy systems, systems installed at high-value locations on the distribution grid. Minn. Stat. § 216B.164(10)(f) (2013).

**Q. HAVE UTILITIES CITED SOME OF THESE TYPES OF BENEFITS TO SUPPORT THEIR REQUESTS TO APPROVE DISTRIBUTED SOLAR PV PROGRAMS IN OTHER STATES?**

[1] *In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. § 216B.164, subd. 10€ and (f),* Docket No. E-999/M-14-65 (Order at 9) (Apr. 1, 2014) (footnotes omitted).

A. Yes. Duke Energy Florida's affiliate in North Carolina advocated for consideration of some of these benefits when it applied to the North Carolina Utilities Commission for approval of a utility-owned distributed solar PV program in Docket No. E-7, Sub 856. I have attached the testimony of Duke witness Owen Smith from that proceeding to my testimony as Exhibit JF-4. Mr. Smith argued for approval of Duke's distributed solar PV program in North Carolina, even though the projected cost was $8.50/watt (Exhibit JF-5, Smith testimony at p. 14). Mr. Smith explained the benefits of Duke Energy Carolinas' proposed distributed solar PV program as follows:

> **Q: PLEASE SUMMARIZE THE BENEFITS OF THE PROGRAM.**
>
> A: There are many benefits of this program and they include the following:
>
> - The Program will result in the production of renewable energy that will help enable Duke Energy Carolinas to comply with its REPS obligations and, along with the power to be purchased from Sun Edison pursuant to a recent purchase power agreement, will specifically help the Company meet its obligations under the solar carve out of the REPS for the next few years.
>
> - The Program will enable the Company to understand the impact of distributed generation on its system. The Company believes that solar PV distributed generation will become much more prevalent in the future, and this Program will enable the Company to better understand any concerns and opportunities that can arise with the introduction of distributed generation.
>
> - The Program will enable the Company to develop and enhance competencies as owners and operators of renewable generation facilities. This competency will benefit customers because the Company will become capable of building and owning renewable resources rather than relying solely on power purchase agreements. In cases where there may be no viable or attractively priced power purchase options available to the Company, this competency will be especially beneficial.
>
> - The distributed nature of this program promotes energy security. The electricity produced under this Program is emission free.

- The Program will promote economic development in North Carolina by attracting investment and creating jobs in the growing solar industry. The Program can drive down the cost of solar PV installations in North Carolina through standardizing inspection requirements and leveraging volume purchases.

- The Program enables the Company's customers to directly participate in the development of renewable resources in North Carolina.

*Application of Duke Energy Carolinas, LLC For Approval of Solar Photovoltaic Distributed Generation Program*, Docket No. E-7, Sub 856 (Direct Testimony of Owen A. Smith at pp. 16-17) (filed July 25, 2008).

Florida is different from North Carolina in that North Carolina has a renewable portfolio standard and Florida does not. Nevertheless, the other benefits cited by Duke Energy should apply equally well in Florida as in North Carolina, and support maintaining the distributed solar PV program.

**Q. HOW DO YOUR RECOMMENDATIONS ALIGN WITH THE POLICY OBJECTIVES FOR DEMAND-SIDE RENEWABLE ENERGY RESOURCES PLANS IN THE UTILITY CONSERVATION PLANS, AS DESCRIBED EARLIER IN YOUR TESTIMONY?**

A. I believe my recommendations are well-aligned with these policy objectives. Florida has articulated a clear policy in favor of demand-side renewable energy programs as a means of reducing carbon emissions from fossil fuel plants. My recommendations should help demonstrate the reasonableness of the distributed solar PV programs.

**Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING UTILITY-OWNED DISTRIBUTED SOLAR PV PROGRAMS?**

A. Yes. I recommend that the Commission develop a pilot program for utility-owned distributed solar PV programs. These programs could compete with the incentive-based programs currently in effect. Allowing the utilities to own the distributed solar PV systems on customer property would permit them to rate base these investments and earn a return. This may provide a greater incentive for utilities to promote these systems. FEECA provides that the Commission should consider allowing utility incentives for their conservation plans. In my opinion, this would be a reasonable incentive to encourage the utilities to deploy distributed solar PV systems. As I described earlier in my testimony, Duke Energy promoted a utility-owned distributed solar PV program in North Carolina when the cost was $8.50/watt. If a utility-owned distributed solar PV benefitted customers when the price was $8.50/watt, then such a program would surely benefit customers when the cost is closer to $3.50/watt.

**Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes.

# Analysis of the Impact of "The President's Climate Action Plan "on the Cost of Electricity in Florida

September 25, 2013

## Introduction:

This workbook is created to estimate the impact of "The President's Climate Action Plan" on electricity cost in Florida. In particular, an objective in the presidential report calls for a 17% economy-wide reduction in CO2 emissions from 2005 levels by the year 2020. A 17% economy-wide reduction in CO2 emissions requires a 30% reduction in CO2 emissions in the power sector.[1] The cost components under consideration in this study as well as the underlying assumptions are detailed below. The cost impacts are described in terms of the impact to a customer's electricity bill.

## Assumptions and Methodology:

1. Due to coal's emission rate, replacing coal-fired generation was the method used to achieve the CO2 reduction. Natural gas was then used as the first choice of fuel that would displace future coal use.
2. Data from U.S. Energy Information Administration (EIA) were used to compute the amount of $CO_2$ emitted by the power sector during the reference year (2005) in the U.S. and in Florida.
3. In 2005, Florida power plants contributed about 5.52% to the total $CO_2$ emissions in the U.S. power industry.
4. The targeted amounts of $CO_2$ reduction levels were computed for the U.S. and for Florida during the study year (2020).
5. The emission rates of each coal units and the actual and projected amount of CO2 (in 2005, 2012 and 2020) emitted by Florida IOUs were evaluated to determine the actual amounts of emissions that are required to be reduced to satisfy the target 30% reduction by 2020. Then, the average heat rates and the emission factors were used to convert tons of CO2 reduction required in Florida to megawatt-hours (MWh) of electricity fuel-switched from coal to natural gas and solar in Florida.[2]
6. In estimating the production cost[3] differential as a result of fuel switching, following analyses were performed:
   a. Two variables were considered — coal and natural gas price forecasts in 2020.
   b. Three levels were considered for each fuel — low price forecast, medium price forecast, and high price forecast.
   c. Three cases were evaluated for each scenarios described in 6a — (i) EIA fuel forecasts case which used fuel price forecasts in EIA's Annual Energy Outlook 2013, (ii) Florida case which used the Florida IOU's fuel price forecasts,[2] and (iii) Ohio fuel price forecasts case which used the fuel price forecasts presented in Ohio Study.
7. Affected coal-fired units will be replaced by conventional natural gas-fired combined cycle (NGCC) or CO2-free solar units, on January 1, 2020, in order to achieve the 30% CO2 reduction target in 2020.
8. All the NGCC and solar units will be installed overnight on December 31, 2019, (in terms of the capital investments).
9. All the NGCC and solar units would have service life of 35 and 30 years, respectively, based on the current depreciation convention of similar units in Florida; and they would be depreciated using whole life rate assuming no further plant activity.
10. All the coal-fired units will be dismantled overnight on December 31, 2019 (in terms of dismantlement cost analysis).
11. This cost analysis takes consideration of the following cost factors:
    a. The overnight construction cost of the NGCC and solar units, are assumed to be recovered over the units' service life using whole life rate for depreciation.
    b. Fuel cost. It is the cost difference between burning coal and burning natural gas (including transportation costs). Fuel price forecast was obtained from filings in Docket No. 130009-EI. This analysis does not address other force as well as the transportation costs to deliver the fuel to each unit.
    c. Fixed O&M cost. It is the difference in the fixed O&M cost between operating the coal-fired units and operating the NGCC units. Sources of the parameters of the generating units are the EIA Updated Capital Cost Estimates for Electricity Generation Plants, Nov. 2010, and filing in Docket No. 130009-EI.
    d. Variable O&M cost. It is the difference in the variable O&M cost between operating the coal-fired units and operating the NGCC units.
    e. Total O&M cost. It is the difference in the total O&M cost between operating the coal-fired units and operating the NGCC and solar units. Sources of the parameters of the generating units are the EIA Updated Capital Cost Estimates for Electricity Generation Plants, Nov. 2010, and filing in Docket Nos. 130007 and 130009-EI.
    f. Depreciation cost. It is the difference between the depreciation expense of the NGCC or solar units and the depreciation expense of the coal units.
    g. Stranded investments on coal plants. It is the unrecovered capital cost of the coal units due to early retirements on December 31, 2019.
    h. Deficient dismantlement fund. It is the shortage of funds used to dismantle the replaced coal units. In a normal course, the dismantlement fund will be collected through a unit's service life. Due to the earlier retirement, the accrual of the dismantlement fund will not be sufficient to dismantle that coal unit.
    i. Required return on investment. It is the difference between the returns on the investments of NGCC or solar units plus the carrying charges of the stranded investments associated with the replaced coal units and the returns of the coal units if they will not be replaced by the NGCC or solar units.
    j. All capital cost are assumed to be booked on January 1 of the year that the unit goes into service..
    k. All costs are allocated on energy basis, no demand chargers assumed.

6. Required returns on investments are calculated for each IOU using the Commission-approved ratios as of 2013.
7 For the non-regulated utilities, weighted cost of capital of the IOUs were assumed because no detailed data were available for the coal plants of the non-regulated utilities in terms of the investment, plant balance, reserve, average service life, average remaining life, net salvage, depreciation rate, dismantlement cost, reserve balance, ROE, etc..

**Note:**

1. Per Ohio's study, this statistic is based on Future 8 results in EISPC study.
2. Data source: Docket Nos. 130001-EI, 130007-EI.
3. The production cost presented in Ohio's study includes the cost of fuel and the variable O&M. For the purpose of comparison, the first part of this study uses the same cost components. The total costs associated with achieving the 30% CO2 reduction goal are addressed in the second part of this study.

# Study Findings:

1 In 2005, Florida power plants contributed 5.27% to the total CO2 emissions in the U.S. power industry. The target amount of CO2 reduction in 2020, which is 30% reduction from 2005 emission level, for the Florida power sector would be 38.2 million metric tons. Refer to page 7 for details.

2. Due to the IOUs' continuous improvement of their generation fleets, the amount of CO2 emissions from the IOUs' plants would have been reduced by approximately by 4.4 million metric tons, or 4.55%, in 2020 from the 2005 level without any coal to natural gas switching. As the result, the actual targeted CO2 reduction amount becomes 36.5 million metric tons. Refer to pages 8 and 11 for details.

3. Assuming the use of CO2 emission-free generation to replace coal generation, Florida would need to switch approximate 34.9 million MWh of coal energy. But because natural gas generation also emits CO2, using coal to natural gas fuel switching to achieve the target of 30% CO2 reduction, Florida would need to replace roughly 61.6 million MWh of coal-fired generation by the year 2020. Refer to pages 8 and 9 for details.

4. The total of the IOUs' coal-fired units generated energy, however, would only be 37.2 million MWh; and the entire state would only have 59.3 million MWh energy generated by coal in 2020. Therefore, Florida cannot solely rely on switching coal to natural gas to achieve the CO2 reduction target as in the Ohio's case. Refer to pages 8 and 9 for details.

5. Staff has evaluated various fuel switching combinations within the state's generating fleet, and decided that the most cost-effective way to achieve the CO2 reduction target in Florida would be switching approximately 0.27 Million MWh Coal generation to solar generation plus replacing the remaining 59.02 million MWh coal generation to NGCC-generated. Refer to page 8 for details.

6. Parallel to the Ohio's study, staff has calculated the electricity production cost increases in Florida due to fuel switching from coal to natural gas. For the "medium coal-medium gas" scenario, the electricity production cost increase and the associated bill impact would approximately be as follows, for details refer to pages 4, 5 and 12.

| (Production Cost) | Florida's Finding | | Ohio's Finding | |
|---|---|---|---|---|
| | Production Cost | Bill Impact | Production Cost | Bill Impact |
| Assuming Ohio's fuel price forecast | $981 Million | 0.43 Cents/KWh | $773 Million | 0.56 Cents/KWh |
| Assuming Florida's fuel price forecast | $678 Million | 0.30 Cents/KWh | | |

7. Staff has also estimated the impact of "The President's Climate Action Plan" on the overall cost of electricity in Florida, and the associated bill impacts to the affected customers. It would approximately be as follows, details refer to pages 6 and 13.

| (Total Cost) | Florida's Finding | | |
|---|---|---|---|
| | Overall Cost in 2020 | Average Bill Impact | Total Cost for 2020-2030 |
| Assuming Florida's fuel price forecast | $2,327 Million | 1.02 Cents/KWh ($10.2/1,000 KWh) | $29,220 Million |

## Contents

**Reference Page**

**Table 1-a: Results Based on EIA's Fuel Price Forecasts**

| Electricity Production Cost Increases in Florida due to Fuel Switching from Coal to Natural Gas or Solar for Achieving 30% CO2 Reduction in 2020 | | | |
|---|---|---|---|
| Price Scenarios | Low Gas ($5.53/mmBtu) | Medium Gas ($5.65/mmBtu) | High Gas ($5.81/mmBtu) |
| Low Coal ($2.79/mmBtu) | $546,692,223.73 | $596,625,638.97 | $663,203,525.96 |
| Medium Coal ($2.90 mmBtu) | $477,561,249.73 | $526,501,555.58 | $594,072,551.96 |
| High Coal (3.03/mmBtu) | $395,861,007.73 | $445,794,422.97 | $512,372,309.96 |

**Table 1-b: Results Based on EIA's Fuel Price Forecasts Adjusted to Florida Case**

| Electricity Production Cost Increases in Florida due to Fuel Switching from Coal to Natural Gas or Solar for Achieving 30% CO2 Reduction in 2020 | | | |
|---|---|---|---|
| Price Scenarios | Low Gas ($6.25/mmBtu) | Medium Gas ($6.38/mmBtu) | High Gas ($6.57/mmBtu) |
| Low Coal ($3.03/mmBtu) | $696,794,896.9 | $753,219,656.13 | $828,452,668.43 |
| Medium Coal ($3.15 mmBtu) | $621,787,790.12 | **$678,212,549.34** | $753,445,561.64 |
| High Coal (3.29/mmBtu) | $533,143,027.55 | $589,567,786.77 | $664,800,799.07 |

**Table 1-c: Results Based on the Fuel Price Forecasts Used in the Ohio's Study**

| Electricity Production Cost Increases in Florida due to Fuel Switching from Coal to Natural Gas or Solar for Achieving 30% CO2 Reduction in 2020 | | | |
|---|---|---|---|
| Price Scenarios | Low Gas ($5.00/mmBtu) | Medium Gas ($6.15/mmBtu) | High Gas ($8.00/mmBtu) |
| Low Coal ($2.25/mmBtu) | $665,523,209.07 | $1,144,051,771.82 | $1,913,858,590.15 |
| Medium Coal ($2.51 mmBtu) | $502,122,725.07 | **$980,651,287.82** | $1,750,458,106.15 |
| High Coal ($2.90/mmBtu) | $257,021,999.07 | $735,550,561.82 | $1,505,357,380.15 |

**Table 1-a: Results Based on EIA's Fuel Price Forecasts**

| Electricity Production Cost Increases in Florida due to Fuel Switching from Coal to Natural Gas or Solar for Achieving 30% CO2 Reduction in 2020 | | | |
|---|---|---|---|
| Price Scenarios | Low Gas ($5.53/mmBtu) | Medium Gas ($5.65/mmBtu) | High Gas ($5.81/mmBtu) |
| Low Coal ($2.79/mmBtu) | $547,685,333.13 | $597,618,748.37 | $664,196,635.36 |
| Medium Coal ($2.90 mmBtu) | $478,554,359.13 | $528,487,774.37 | $595,065,661.36 |
| High Coal (3.03/mmBtu) | $396,854,117.13 | $446,787,532.37 | $513,365,419.36 |

**Table 1-b: Results Based on EIA's Fuel Price Forecasts Adjusted to Florida Case**

| Electricity Production Cost Increases in Florida due to Fuel Switching from Coal to Natural Gas or Solar for Achieving 30% CO2 Reduction in 2020 | | | |
|---|---|---|---|
| Price Scenarios | Low Gas ($6.25/mmBtu) | Medium Gas ($6.38/mmBtu) | High Gas ($6.57/mmBtu) |
| Low Coal ($3.03/mmBtu) | $697,788,006.3 | $754,212,765.53 | $829,445,777.83 |
| Medium Coal ($3.15 mmBtu) | $622,780,899.51 | **$679,205,658.74** | $754,438,671.04 |
| High Coal (3.29/mmBtu) | $534,136,136.94 | $590,560,896.17 | $665,793,908.47 |

**Table 1-c: Results Based on the Fuel Price Forecasts Used in the Ohio's Study**

| Electricity Production Cost Increases in Florida due to Fuel Switching from Coal to Natural Gas or Solar for Achieving 30% CO2 Reduction in 2020 | | | |
|---|---|---|---|
| Price Scenarios | Low Gas ($5.00/mmBtu) | Medium Gas ($6.15/mmBtu) | High Gas ($8.00/mmBtu) |
| Low Coal ($2.25/mmBtu) | $666,516,318.47 | $1,145,044,881.22 | $1,914,851,699.55 |
| Medium Coal ($2.51 mmBtu) | $503,115,834.47 | **$981,644,397.22** | $1,751,451,215.55 |
| High Coal ($2.90/mmBtu) | $258,015,108.47 | $736,543,671.22 | $1,506,350,489.55 |

**Table 2-a: Results Based on EIA's Fuel Price Forecasts**

| Net Impacts, in cents/KWh, on Average Customers' Electricity Bill in Florida due to Fuel Switching from Coal to Natural Gas or Solar[1] | | | |
|---|---|---|---|
| Price Scenarios | Low Gas ($5.53/mmBtu) | Medium Gas ($5.65/mmBtu) | High Gas ($5.81/mmBtu) |
| Low Coal ($2.79/mmBtu) | 0.24 | 0.26 | 0.29 |
| Medium Coal ($2.90 mmBtu) | 0.21 | 0.23 | 0.26 |
| High Coal (3.03/mmBtu) | 0.02 | 0.19 | 0.22 |

**Table 2-b: Results Based on EIA's Fuel Price Forecasts Adjusted to Florida Case**

| Net Impacts, in cents/KWh, on Average Customers' Electricity Bill in Florida due to Fuel Switching from Coal to Natural Gas or Solar[1] | | | |
|---|---|---|---|
| Price Scenarios | Low Gas ($6.25/mmBtu) | Medium Gas ($6.38/mmBtu) | High Gas ($6.57/mmBtu) |
| Low Coal ($3.03/mmBtu) | 0.30 | 0.33 | 0.36 |
| Medium Coal ($3.15 mmBtu) | 0.27 | **0.30** | 0.33 |
| High Coal (3.29/mmBtu) | 0.23 | 0.26 | 0.29 |

**Table 2-c: Results Based on the Fuel Price Forecasts Used in thet Ohio's Study**

| Net Impacts, in cents/KWh, on Average Customers' Electricity Bill in Florida due to Fuel Switching from Coal to Natural Gas or Solar[1] | | | |
|---|---|---|---|
| Price Scenarios | Low Gas ($5.00/mmBtu) | Medium Gas ($6.15/mmBtu) | High Gas ($8.00/mmBtu) |
| Low Coal ($2.25/mmBtu) | 0.29 | 0.50 | 0.84 |
| Medium Coal ($2.51 mmBtu) | 0.22 | **0.43** | 0.76 |
| High Coal ($2.90/mmBtu) | 0.11 | 0.32 | 0.66 |

| | |
|---|---|
| Projected Retail Sales in 2020 (GWh)[2] | 228,824 |

**Note:**
1. Assuming: (i) all the $CO_2$ reduction will be achieved by coal to natural gas or solar fuel-switching; (ii) the cost associated with each coal unit to natural gas unit switching will be incurred by the customers of the affected utilities, (iii) the cost associated with coal unit to solar unit switching will be incurred by all the customers of the state.
2. Data source: IOUs' sales forecasts in 2013 Ten Year Site Plans.

**Table 2-a: Results Based on EIA's Fuel Price Forecasts**

| Net Impacts, in cents/KWh, on Average Customers' Electricity Bill in Florida due to Fuel Switching from Coal to Natural Gas or Solar[1] | | | |
|---|---|---|---|
| Price Scenarios | Low Gas ($5.53/mmBtu) | Medium Gas ($5.65/mmBtu) | High Gas ($5.81/mmBtu) |
| Low Coal ($2.79/mmBtu) | 0.24 | 0.26 | 0.29 |
| Medium Coal ($2.90 mmBtu) | 0.21 | 0.23 | 0.26 |
| High Coal (3.03/mmBtu) | 0.02 | 0.20 | 0.22 |

**Table 2-b: Results Based on EIA's Fuel Price Forecasts Adjusted to Florida Case**

| Net Impacts, in cents/KWh, on Average Customers' Electricity Bill in Florida due to Fuel Switching from Coal to Natural Gas or Solar[1] | | | |
|---|---|---|---|
| Price Scenarios | Low Gas ($6.25/mmBtu) | Medium Gas ($6.38/mmBtu) | High Gas ($6.57/mmBtu) |
| Low Coal ($3.03/mmBtu) | 0.30 | 0.33 | 0.36 |
| Medium Coal ($3.15 mmBtu) | 0.27 | **0.30** | 0.33 |
| High Coal (3.29/mmBtu) | 0.23 | 0.26 | 0.29 |

**Table 2-c: Results Based on the Fuel Price Forecasts Used in thet Ohio's Study**

| Net Impacts, in cents/KWh, on Average Customers' Electricity Bill in Florida due to Fuel Switching from Coal to Natural Gas or Solar[1] | | | |
|---|---|---|---|
| Price Scenarios | Low Gas ($5.00/mmBtu) | Medium Gas ($6.15/mmBtu) | High Gas ($8.00/mmBtu) |
| Low Coal ($2.25/mmBtu) | 0.29 | 0.50 | 0.84 |
| Medium Coal ($2.51 mmBtu) | 0.22 | **0.43** | 0.77 |
| High Coal ($2.90/mmBtu) | 0.11 | 0.32 | 0.66 |

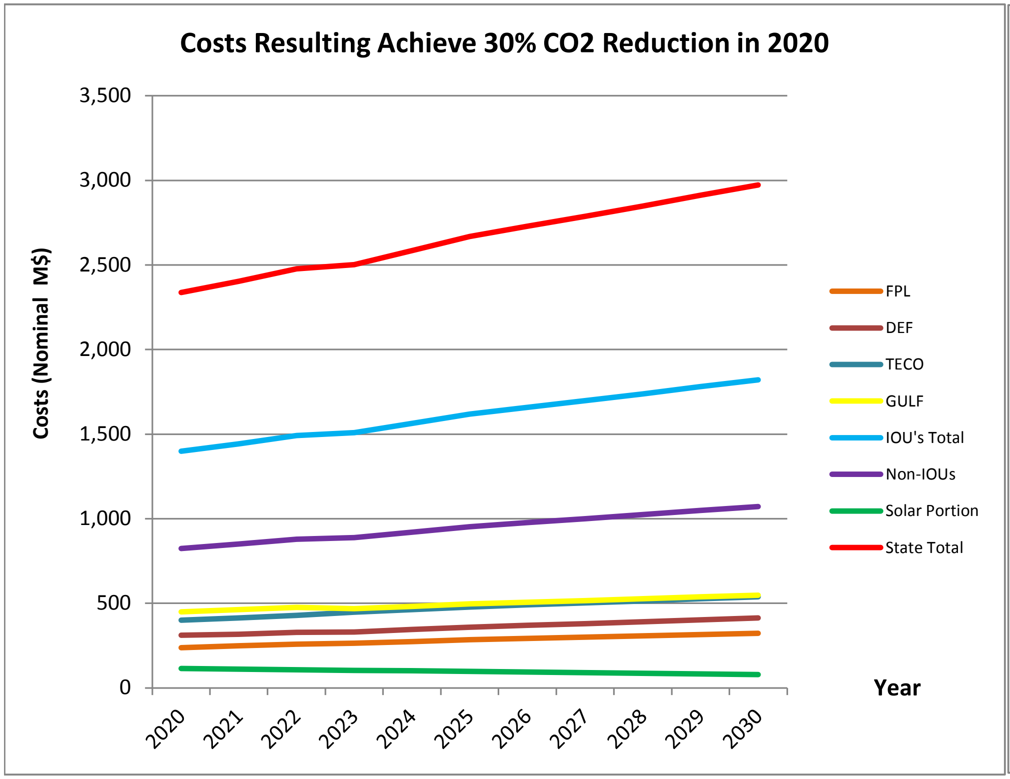
| | |
|---|---|
| Projected Retail Sales in 2020 (GWh)[2] | 228,824 |

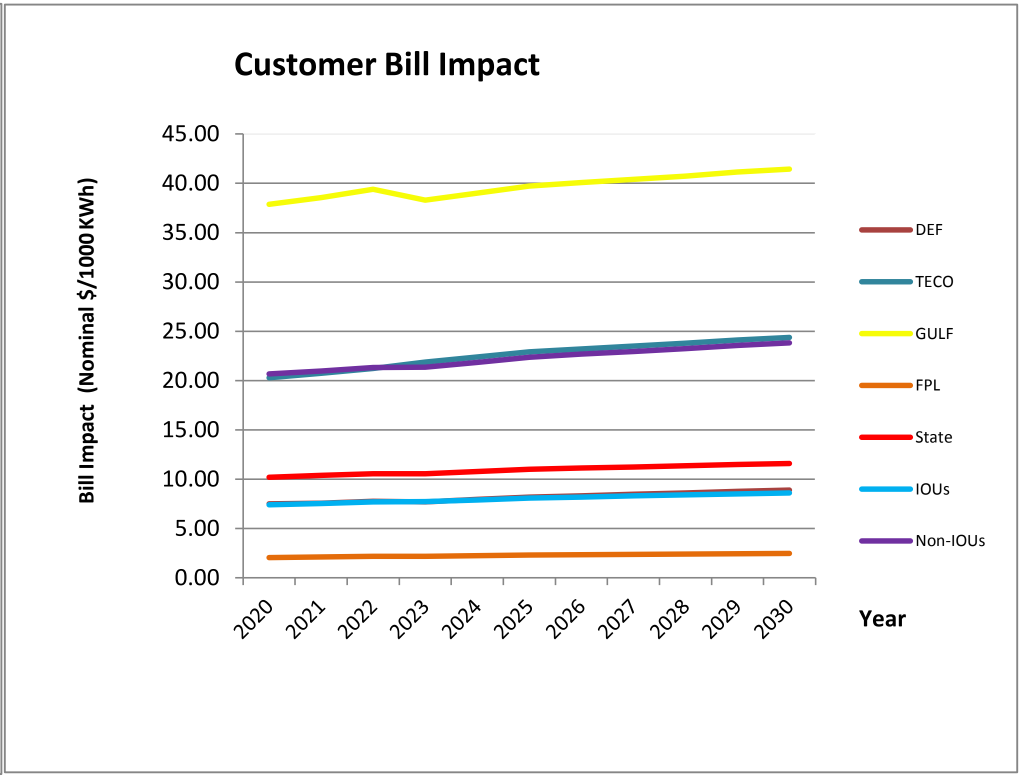
**Note:**
1. Assuming: (i) all the $CO_2$ reduction will be achieved by coal to natural gas or solar fuel-switching; (ii) the cost associated with each coal unit to natural gas unit switching will be incurred by the customers of the affected utilities, (iii) the cost associated with coal unit to solar unit switching will be incurred by all the customers of the state.
2. Data source: IOUs' sales forecasts in 2013 Ten Year Site Plans.

## Table 3: Total Costs Resulting from Coal Unit to NGCC or Solar Unit Conversion for Achieving 30% CO2 Reduction by 2020

| Utility | Estimated Costs (nominal million $) | | | | | | | | | | | | NPV |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | Total | |
| **FPL** | 238.2 | 249.1 | 258.1 | 263.9 | 274.2 | 284.7 | 292.5 | 300.1 | 307.6 | 315.1 | 321.9 | **3,105** | **1,819** |
| **DEF** | 311.2 | 317.7 | 328.8 | 330.9 | 344.6 | 358.6 | 369.4 | 379.9 | 390.7 | 402.3 | 413.1 | **3,947** | **2,163** |
| **TECO** | 400.7 | 413.8 | 428.3 | 446.7 | 462.2 | 478.2 | 490.0 | 501.5 | 513.4 | 526.4 | 538.2 | **5,199** | **2,849** |
| **GULF** | 448.6 | 461.6 | 476.2 | 468.0 | 482.0 | 496.5 | 506.5 | 516.2 | 526.2 | 537.4 | 547.5 | **5,467** | **3,431** |
| **Total-IOUs** | 1,399 | 1,442 | 1,491 | 1,509 | 1,563 | 1,618 | 1,658 | 1,698 | 1,738 | 1,781 | 1,821 | **17,719** | **11,058** |
| **Non-IOUs** | 824 | 849 | 878 | 889 | 921 | 953 | 977 | 1,000 | 1,024 | 1,049 | 1,072 | **10,436** | **6,513** |
| **Solar portion** | 115 | 111 | 108 | 104 | 100 | 97 | 93 | 90 | 86 | 83 | 79 | **1,066** | **699** |
| **Grand Total** | **2,337** | **2,403** | **2,478** | **2,502** | **2,584** | **2,668** | **2,729** | **2,787** | **2,848** | **2,913** | **2,972** | **29,220** | **18,270** |

| Utility | Estimated Customer Bill Impact (nominal $/1,000 KWh) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| **FPL** | 2.05 | 2.13 | 2.18 | 2.20 | 2.26 | 2.32 | 2.36 | 2.39 | 2.42 | 2.46 | 2.48 |
| **DEF** | 7.52 | 7.58 | 7.75 | 7.72 | 7.95 | 8.18 | 8.33 | 8.47 | 8.62 | 8.78 | 8.91 |
| **TECO** | 20.29 | 20.73 | 21.21 | 21.88 | 22.39 | 22.91 | 23.22 | 23.50 | 23.79 | 24.12 | 24.39 |
| **GULF** | 37.87 | 38.55 | 39.41 | 38.30 | 39.01 | 39.74 | 40.09 | 40.40 | 40.73 | 41.14 | 41.45 |
| **W. Average-IOUs** | **7.40** | **7.55** | **7.71** | **7.72** | **7.91** | **8.09** | **8.20** | **8.31** | **8.41** | **8.52** | **8.61** |
| **Non-IOUs** | **20.67** | **20.98** | **21.33** | **21.35** | **21.86** | **22.38** | **22.68** | **22.96** | **23.25** | **23.56** | **23.82** |
| **Solar Portion** | **0.50** | **0.48** | **0.46** | **0.44** | **0.42** | **0.40** | **0.38** | **0.36** | **0.34** | **0.33** | **0.31** |
| **Total W. Average** | **10.21** | **10.38** | **10.56** | **10.55** | **10.78** | **11.00** | **11.13** | **11.24** | **11.36** | **11.49** | **11.59** |


Costs Resulting Achieve 30% CO2 Reduction in 2020
Costs (Nominal M$)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
Year
FPL
DEF
TECO
GULF
IOU's Total
Non-IOUs
Solar Portion
State Total


Customer Bill Impact
Bill Impact (Nominal $/1000 KWh)
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
Year
DEF
TECO
GULF
FPL
State
IOUs
Non-IOUs

## Table 3a: Total Costs Resulting from a Coal to NGCC Conversion for Achieving 30% CO2 Emission Reduction in 2020

| Utility | Estimated Costs (nominal million $) | | | | | | | | | | | | NPV |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | Total | |
| FPL | 238.2 | 249.1 | 258.1 | 263.9 | 274.2 | 284.7 | 292.5 | 300.1 | 307.6 | 315.1 | 321.9 | **3,105** | **1,819** |
| DEF | 311.2 | 317.7 | 328.8 | 330.9 | 344.6 | 358.6 | 369.4 | 379.9 | 390.7 | 402.3 | 413.1 | **3,947** | **2,163** |
| TECO | 400.7 | 413.8 | 428.3 | 446.7 | 462.2 | 478.2 | 490.0 | 501.5 | 513.4 | 526.4 | 538.2 | **5,199** | **2,849** |
| GULF | 448.6 | 461.6 | 476.2 | 468.0 | 482.0 | 496.5 | 506.5 | 516.2 | 526.2 | 537.4 | 547.5 | **5,467** | **3,431** |
| **TOTAL** | **1,399** | **1,442** | **1,491** | **1,509** | **1,563** | **1,618** | **1,658** | **1,698** | **1,738** | **1,781** | **1,821** | **17,719** | **11,058** |

| Utility | Estimated Residential Customer Bill Impact[1] (nominal $/1,000 KWh) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| FPL | 2.05 | 2.13 | 2.18 | 2.20 | 2.26 | 2.32 | 2.36 | 2.39 | 2.42 | 2.46 | 2.48 |
| DEF | 7.52 | 7.58 | 7.75 | 7.72 | 7.95 | 8.18 | 8.33 | 8.47 | 8.62 | 8.78 | 8.91 |
| TECO | 20.29 | 20.73 | 21.21 | 21.88 | 22.39 | 22.91 | 23.22 | 23.50 | 23.79 | 24.12 | 24.39 |
| GULF | 37.87 | 38.55 | 39.41 | 38.30 | 39.01 | 39.74 | 40.09 | 40.40 | 40.73 | 41.14 | 41.45 |
| **Weighted Average** | **7.40** | **7.55** | **7.71** | **7.72** | **7.91** | **8.09** | **8.20** | **8.31** | **8.41** | **8.52** | **8.61** |

| Utility | Estimated Commercial Customer Bill Impact[1] (nominal $/7,000 KWh) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| FPL | 14.38 | 14.9 | 15.2 | 15.4 | 15.8 | 16.2 | 16.5 | 16.7 | 17.0 | 17.2 | 17.4 |
| DEF | 52.61 | 53.0 | 54.3 | 54.0 | 55.6 | 57.2 | 58.3 | 59.3 | 60.3 | 61.4 | 62.4 |
| TECO | 142.02 | 145.1 | 148.5 | 153.2 | 156.7 | 160.4 | 162.5 | 164.5 | 166.5 | 168.8 | 170.7 |
| GULF | 265.12 | 269.8 | 275.9 | 268.1 | 273.1 | 278.2 | 280.6 | 282.8 | 285.1 | 288.0 | 290.1 |
| **Weighted Average** | **51.8** | **52.9** | **54.0** | **54.0** | **55.3** | **56.7** | **57.4** | **58.1** | **58.9** | **59.7** | **60.3** |

| Utility | Estimated Industrial Customer Bill Impact[1] (nominal $/150,000 KWh) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| FPL | 308 | 319 | 326 | 330 | 339 | 348 | 354 | 359 | 364 | 369 | 372 |
| DEF | 1,127 | 1,136 | 1,163 | 1,157 | 1,192 | 1,227 | 1,250 | 1,271 | 1,293 | 1,316 | 1,337 |
| TECO | 3,043 | 3,109 | 3,182 | 3,282 | 3,359 | 3,436 | 3,482 | 3,525 | 3,568 | 3,618 | 3,659 |
| GULF | 5,681 | 5,782 | 5,911 | 5,745 | 5,852 | 5,960 | 6,014 | 6,060 | 6,110 | 6,171 | 6,217 |
| **Weighted Average** | **1,110** | **1,133** | **1,157** | **1,158** | **1,186** | **1,214** | **1,231** | **1,246** | **1,261** | **1,278** | **1,292** |

**Note**:
1. This analysis allocated additional costs over energy, no costs were allocated on demand charges.

# Impact on Bills from NGCC Conversion

## Current Monthly Bills as of July 2013

| | Residential | Commercial | Industrial |
|---|---|---|---|
| | | 75 kW | 150 kW |
| | 1,000 kWh | 7,000 kWh | 150,000 kWh |
| Florida Power & Light Company | $93.23 | $1,191 | $12,943 |
| Duke Energy Florida | $113.16 | $943 | $13,882 |
| Tampa Electric Company | $100.02 | $1,232 | $13,943 |
| Gulf Power Company | $115.91 | $993 | $14,548 |

## Bills with NGCC Conversion Costs[1] - Year 1

| | Residential | Commercial | Industrial |
|---|---|---|---|
| | | 75 kW | 500 kW |
| | 1,000 kWh | 7,000 kWh | 150,000 kWh |
| Florida Power & Light Company | $95.28 | $1,205 | $13,251 |
| Duke Energy Florida | $120.68 | $995 | $15,009 |
| Tampa Electric Company | $120.31 | $1,374 | $16,986 |
| Gulf Power Company | $141.47 | $1,172 | $18,381 |

## Change in Bills

| | Residential | Commercial | Industrial |
|---|---|---|---|
| | | 75 kW | 150 kW |
| | 1,000 kWh | 7,000 kWh | 150,000 kWh |
| Florida Power & Light Company | $2.05 | $14.4 | $308 |
| Duke Energy Florida | $7.52 | $52.6 | $1,127 |
| Tampa Electric Company | $20.29 | $142.0 | $3,043 |
| Gulf Power Company | $25.56 | $178.9 | $3,833 |

**Note**:
1. This analysis allocated additional costs over energy, no costs were allocated on demand charges.

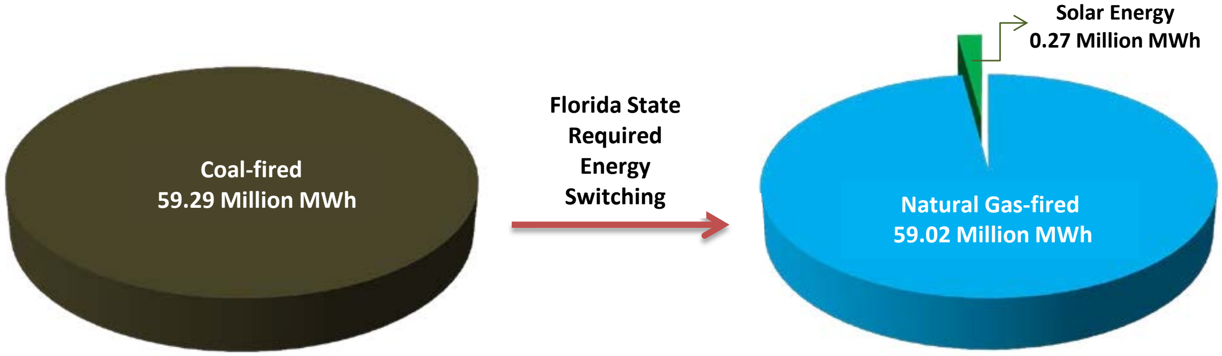
## Table 4: Carbon Dioxide Emissions from the Power Industry (2005 - 2020)

**(Million Metric Tons of CO2)**

| | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1 U.S. Electric Power Sector[1,2]** | | | | | | | | | | | | | | | | |
| Coal | 1984.0 | 1954.0 | 1987.0 | 1959.0 | 1741.0 | 1827.61 | 1718.02 | 1530.29 | 1587.52 | 1590.10 | 1574.03 | 1475.67 | 1519.97 | 1552.09 | 1589.90 | 1610.31 |
| Petroleum Products | 102.0 | 56.0 | 55.0 | 40.0 | 34.0 | 32.67 | 25.41 | 15.88 | 15.73 | 15.81 | 15.85 | 15.14 | 13.18 | 13.35 | 13.26 | 13.37 |
| Natural Gas | 319.0 | 338.0 | 372.0 | 362.0 | 373.0 | 398.82 | 410.67 | 501.98 | 444.89 | 439.12 | 437.76 | 474.45 | 456.80 | 449.48 | 447.91 | 445.90 |
| Other (c) | 11.0 | 12.0 | 11.0 | 12.0 | 11.0 | 11.66 | 11.44 | 11.44 | 11.44 | 11.44 | 11.44 | 11.44 | 11.44 | 11.44 | 11.44 | 11.44 |
| **Total** | **2416.0** | **2360.0** | **2425.0** | **2373.0** | **2159.0** | **2270.8** | **2165.5** | **2059.6** | **2059.6** | **2056.5** | **2039.1** | **1976.7** | **2001.4** | **2026.4** | **2062.5** | **2081.0** |
| **2 Florida Electric Power Sector[3]** | | | | | | | | | | | | | | | | |
| Coal | 60.9 | 63.0 | 65.4 | 62.9 | 52.6 | 58.1 | 35.18 | 37.88 | 35.99 | 34.99 | 43.00 | 44.06 | 44.42 | 45.61 | 47.22 | 47.25 |
| Petroleum Products | 31.9 | 20.2 | 17.2 | 10.9 | 8.3 | 8.5 | 0.54 | 0.55 | 0.54 | 0.54 | 0.56 | 0.56 | 0.56 | 0.56 | 0.57 | 0.58 |
| Natural Gas | 34.6 | 40.5 | 42.2 | 43.5 | 49.6 | 53.0 | 71.85 | 65.85 | 69.61 | 69.83 | 68.81 | 66.50 | 65.85 | 66.12 | 66.39 | 67.01 |
| **Total** | **127.4** | **123.8** | **124.8** | **117.3** | **110.6** | **119.6** | **107.56** | **104.28** | **106.15** | **105.36** | **112.37** | **111.12** | **110.83** | **112.30** | **114.18** | **114.84** |
| **3 % of Florida Power Plants contributed to the total CO2 emission in the US power industry in 2005** | **5.27%** | | | | | | | | | | | | | | | **5.52%** |
| **4 Target amount of CO2 reduction level for the US power sector in 2020 (30% reduction from 2005 level)** | | | | | | | | | | | | | | | | **724.8** |
| **5 Target amount of CO2 reduction level for the Florida power sector in 2020 (30% reduction from 2005 level)** | | | | | | | | | | | | | | | | **38.2** |

**Note:**

1. 2005-2009 data from EIA Monthly Energy Outlook, Table 12.6, Carbon Dioxide Emissions from Energy Consumption: Electric Power Sector.
2. 2010-2020 data from Annual Energy Outlook 2013, utilizing the reference case.
3. Includes emissions from geothermal power and non-biogenic emissions from municipal waste.




## Table 5: Required Coal-generated to Natural Gas-generated or Solar Energy Switching by 2020

| | (Million Metric Tons) | (Million MWh) |
|---|---|---|
| Target amount of CO2 reduction for Florida power sector | 38.208 | |
| Actual CO2 reduction required[1] | 33.760 | |
| Needed coal-fired energy switch if replace coal by emission-free fuel | | 34.936 |
| Needed coal-fired energy switch if replace coal by natural gas[2] | | 61.548 |
| Total projected coal energy produced by the IOUs in 2020[3] | | 37.145 |
| Total projected coal energy (state-wide) in 2020[3] | | 59.289 |
| **Δ (i.e. Not enough by state-wide coal to NGCC switching to achieve the reduction target)** | | 2.259 |
| CO2 reduction achieved by switch all coal in the state to natural gas | 33.654 | |
| Shortage from the targeted reduction | 0.106 | |
| Addressing the shortage by using emission-free energy to replace coal energy | | 0.110 |
| Actual coal energy to solar energy replacement needed[4] | | 0.266 |
| Actual CO2 reduction achieved by switching coal to solar energy | 0.257 | |
| Actual coal energy to natural gas generated energy replacement | | **59.023** |
| The amount of coal energy to natural gas generated energy switching by the IOUs | | 37.145 |
| The amount of coal energy to natural gas generated energy switching by the Non-IOUs | | 21.878 |
| CO2 reduction achieved by the actual coal to natural gas switching | 33.503 | |
| Total CO2 reduction achieved | 33.760 | |

**Note:**

1.Due to the continuous improvement of their generating fleets, the total CO2 emitted from the IOUs' plants will have been reduced by 4.57% from the 2005 level in 2020 without any fuel switching. Refer to page 11 for details.

2. Because natural gas-fired generating units will also emit CO2, Florida would need to switch more coal-fired energy from being generated by coal to being generated by natural gas in the year 2020 to achieve the target of 30% CO2 reduction.

3. Source of data: utilities' Ten year Site Plans filed in 2013.

4. Staff reviewed FPL's solar profile, details refer to page 27 of this workbook, and decided that the type of 25 MW PV with tracking system solar plan is the most cost-effective alternative, among the existing solar units in the state, that could be used to replace the coal plant.

| Coal | N Gas | Solar | |
|---|---|---|---|
| 59.289 | 59.023 | 1.26 | (using bigger number for a better visual effect) |

## Table 6. Coal Energy Profile[1]

(GWH)

| Utility | 2005 | 2012 | 2020 | Δ (2020-2005) |
|---|---|---|---|---|
| FPL | 5,765 | 4,745 | 6,890 | 19.51% |
| DEF | 15,834 | 10,003 | 8,777 | -44.57% |
| TECO | 8,705 | 9,720 | 10,566 | 21.38% |
| GULF | 12,907 | 5,391 | 10,912 | -15.46% |
| City of Tallahassee | 0 | | 0 | 0 |
| Florida Municipal Power Agency | 1,496 | | 1,078 | -27.94% |
| Gainesville Regional Utilities | 1,467 | | 494 | -66.33% |
| JEA | 5,794 | | 5,444 | -6.04% |
| Lakeland Electric | 1,572 | | 1,046 | -33.46% |
| Orlando Utilities Commission | 5,590 | | 4,725 | -15.47% |
| Seminole Electric Cooperative | 9,784 | | 9,357 | -4.36% |
| **Florida Total** | 68,914 | | **59,289** | -13.97% |
| Non-IOU Total | 25,703 | | 22,144 | |
| IOUs Total | 43,211 | 29,859 | **37,145** | -14.04% |
| **IOU + JEA's St John 1&2 and Scherer 4** | | | **42,002** | |
| % of IOUs' Coal Energy | 62.70% | | 62.65% | -0.08% |

## Table 6c. JEA's Coal Profile[2]

| Plant Name | Unit | Net Winter Capacity (GWH) | % |
|---|---|---|---|
| Northside | 1 | 293 | 32.6% |
| | 2 | 293 | |
| St Johns river | 1 | 510 | 56.7% |
| | 2 | 510 | |
| Scherer | 4 | 194 | 10.8% |
| ∑ | | 1,800 | |
| **St John & Scherer Total** | | **1,606** | **89.2%** |

## Table 8: Ownership Share

| | | Ownership[2] FPL | Ownership[2] JEA |
|---|---|---|---|
| **St Johns River** | 1 | 20% | 80% |
| | 2 | | |
| **Scherer** | 4 | 76.36% | 23.64% |

## Table 6-a: Non-IOU Retail Sales Projection (GWH)

| | **2020** | **2011** | **2012** |
|---|---|---|---|
| Florida Municipal Power Agency | 6,196 | 6,268 | 6,369 |
| Gainesville Regional Utilities | 1,752 | 1,757 | 1,764 |
| JEA | 5,973 | 6,003 | 6,030 |
| Lakeland Electric | 3,160 | 3,187 | 3,251 |
| Orlando Utilities Commission | 6,708 | 6,800 | 6,895 |
| Seminole Electric Cooperative | 16,067 | 16,468 | 16,879 |
| Total | 39,856 | 40,483 | 41,188 |

**Note:**

1. Data source: utilities' Ten Year Site Plans, filed in 2005 and 2013, respectively.
2. JEA's Ten Year Site Plan filed in 2013.

## Table 7: CO2 Emission-Coal Plants

| | | | | | | Emission Rate of Coal[1] | | | | | Emission amount due to coal energy | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | (lb/MWh) | | | (Metric Ton/MWh) | | (Metric Ton/MWh) | | | |
| **Utility** | **Coal Plant Name** | **Unit No.** | **Unit Type** | **Capacity** | **Ave. Net Heat Rate** | **2005** | **current** | **2020** | **2005** | **2020** | **2005** | **2020** | **Δ** | **%** |
| FPL | St Johns | 1 | ST | 130 | 10,459 | 1,958 | 1,946 | 2,186 | 0.8881 | 0.9916 | | | | |
| | | 2 | ST | 130 | 12,219 | 2,129 | 2,157 | 2,170 | 0.9657 | 0.9843 | | | | |
| | Scherer | 4 | ST | 651 | 10,290 | 2,035 | 2,240 | 2,215 | 0.9231 | 1.0047 | | | | |
| | W. Ave. | | | | | 2,037 | 2,186 | 2,204 | 0.9242 | 0.9999 | | | | |
| | | | | 911 | | | | | | | 5,327,787 | 6,889,430 | 1,561,643 | 29.3% |
| DEF | Crystal River | 1 | Boiler | 372 | 10,268 | 1,870 | 2,158 | 2,158 | 0.8482 | 0.97885 | | | | |
| | | 2 | | 503 | 10,005 | 1,901 | 1,958 | 1,958 | 0.8623 | 0.88813 | | | | |
| | | 4 | | 721 | 9,541 | 2,120 | 2,155 | 2,155 | 0.9616 | 0.97749 | | | | |
| | | 5 | | 721 | 9,698 | 2,202 | 2,050 | 2,050 | 0.9988 | 0.92986 | | | | |
| | W. Ave. | | | | | 2,058 | 2,080 | 2,080 | 0.9334 | 0.9435 | | | | |
| | | | | 2317 | | | | | | | 14,779,749 | 8,281,018 | -6,498,731 | -44.0% |
| TECO | BB | 1 | | 395 | 9,785 | 2,229 | 2,251 | 2,251 | 1.0111 | 1.0210 | | | | |
| | | 2 | | 395 | 9,644 | 2,246 | 2,045 | 2,045 | 1.0188 | 0.9276 | | | | |
| | | 3 | | 365 | 9,902 | 2,190 | 2,402 | 2,402 | 0.9934 | 1.0895 | | | | |
| | | 4 | | 417 | 9,634 | 2,210 | 2,187 | 2,187 | 1.0024 | 0.9920 | | | | |
| | Polk | 1 | | 220 | 7,944 | 1,533 | 1,504 | 1,504 | 0.6954 | 0.6822 | | | | |
| | W. Ave. | | | | | 2,135 | 2,130 | 2,130 | 0.9684 | 0.9660 | | | | |
| | | | | 1792 | | | | | | | 8,429,840 | 10,207,153 | 1,777,313 | 21.1% |
| GULF | Crist | 4 | | 75 | 10,358 | 2,070 | 2,203 | 2,203 | 0.9389 | 0.9993 | | | | |
| | | 5 | | 75 | 10,113 | 2,004 | 2,250 | 2,250 | 0.9090 | 1.0206 | | | | |
| | | 6 | | 288 | 9364 | 2026 | 2271 | 2271 | 0.9190 | 1.0301 | | | | |
| | | 7 | | 465 | 10107 | 2230 | 2173 | 2173 | 1.0115 | 0.9857 | | | | |
| | Smith | 1 | | 162 | 9940 | 2135 | 2030 | 2030 | 0.9684 | 0.9208 | | | | |
| | | 2 | | 195 | 10144 | 2146 | 2042 | 2042 | 0.9734 | 0.9262 | | | | |
| | Daniel | 1 | | 255 | 9715 | 2319 | 2218 | 2218 | 1.0519 | 1.0061 | | | | |
| | | 2 | | 255 | 9696 | 2341 | 2271 | 2271 | 1.0619 | 1.0301 | | | | |
| | W. Ave. | | | | | 2,252 | 2,159 | 2,159 | 1.0216 | 0.9792 | | | | |
| | | | | 1770 | | | | | | | 13,185,425 | 10,685,570 | -2,499,855 | -19.0% |
| **W. Ave.**<br>**Sum** | | | | 6790 | | 2126 | 2128 | **2130** | | | | | | |
| **IOUs' total emission amount from the coal plants** | | | | | | | | | | | 41,722,801 | **36,063,171** | -5,659,630 | |

| **Metric Ton** | **lb** |
|---|---|
| 0.4536 | 1,000 |
| 1 | 2204.6226 |

## Table 7-a: CO2 Emission-Other Plants

| | Emission Rate of Coal & Some Oil Units[1] | | | | | **Emission Reduction by Switching to CC in 2020** |
|---|---|---|---|---|---|---|
| | (lb/MWh) | | | (Metric Ton/MWh) | | |
| **Unit Type** | **2005** | **2012** | **2020** | **2005** | **2020** | **(Metric Ton/MWh)** |
| **Coal** | 2126 | 2128 | **2130** | 0.96439 | 0.96633 | **0.56763** |
| **CC** | | | **879** | | 0.39871 | |
| **Oil** | | | 2148 | | 0.97432 | **0.57561** |

**Note**:

1. Average rate of the generation type, based on IOUs' responses to staff discovery in Docket No. 130007-EI.

**Table 7-b: Natural Gas Generation Emission Rate**

| | CC | GT/CT | | |
|---|---|---|---|---|
| FPL | 834 | 1248 | | |
| | 898/1129 | 1248 | | |
| | 806 | 1079 | | |
| | 738 | 1126 | | |
| | 1062 | 1193 | | |
| | 1064 | 1518 | | |
| | 763 | 1731 | | |
| | 854 | 1746 | | |
| | 854 | 1735 | | |
| | 806 | | | |
| | 805 | | | |
| | 802 | | | |
| | 805 | | | |
| | **849** | **1403** | 1126 | |
| DEF | 824 | 1651 | | |
| | 830 | 1685 | | |
| | 837 | 1660 | | |
| | 788 | 2217 | | |
| | 881 | 2093 | | |
| | 860 | 2102 | | |
| | 1132 | 1627 | | |
| | | 1626 | | |
| | | 1675 | | |
| | | 1662 | | |
| | | 1716 | | |
| | | 1580 | | |
| | | 1530 | | |
| | | 1519 | | |
| | | 1544 | | |
| | | 1393 | | |
| | | 1395 | | |
| | | 1132 | | |
| | **879** | **1901** | 1390 | |
| TECO | 845 | 1057 | | |
| | 863 | 1111 | | |
| | | 1097 | | |
| | | 1117 | | |
| | | 1109 | | |
| | **854** | **1084** | 969 | |
| | 836 | 1111 | | |
| | | 1097 | | |
| | | 1117 | | |
| | | 1504 | | |
| | | 1109 | | |
| Gulf | **836** | **1187.6** | 1187.6 | 1168.184 |

## Table 8: Utilities' CO2 Emission Amount

| | **CO2 Emission Amount[1] (Metric Ton)** | | | | **Required 30% - 2020 reduction** | **Allowed emission amount in 2020** | **Difference vs. projected 2020 CO2 emission amount** (which equals to the amount of CO2 needs to be reduced) | | **Statewide required 30%-2020 reduction** |
|---|---|---|---|---|---|---|---|---|---|
| | 2005 | 2020 | Δ | % | | | | | |
| **FPL** | 44,930,742 | 43,287,000 | -1,643,742 | -3.66% | 13,479,223 | 31,451,519 | 11,835,481 | 26.34% | |
| **DEF** | 28,245,706 | 23,643,323 | -4,602,383 | -16.29% | 8,473,712 | 19,771,994 | 3,871,329 | 13.71% | |
| **TECO** | 14,834,551 | 16,457,551 | 1,623,000 | 10.94% | 4,450,365 | 10,384,186 | 6,073,365 | 40.94% | |
| **GULF** | 9,785,257 | 9,986,687 | 201,430 | 2.06% | 2,935,577 | 6,849,680 | 3,137,007 | 32.06% | |
| **Others[3]** | | **-26,103** | | | | | | | |
| **∑** | 97,796,256 | 93,348,458 | **-4,447,798** | -4.55% | 29,338,877 | 68,457,379 | 24,917,182 | 25.48% | **33,759,916.7** |
| **Total CO2 Emission Reduction Amount by Retiring all IOUs' Coal Units[2]** | | | | | | | | | 36,063,171 |
| Shortage from the Florida state-required CO2 reduction amount | | | | | | | | | -2,303,254 |

**Note**:

1. Data source: companies' responses to staff data request in 2013 Ten Year Site Plans.
2. Based on IOUs' projections, derived from data the IOUs presented in their responses to staff discovery in Docket No. 130007-EI.
3. Including CO2 from the combustion of landfill gas which is excluded from EPA GHG reporting.

## Table 9: Fuel Costs Due to Replacing Coal by Natural Gas or Solar for Achieving 30% CO2 Reduction by 2020

| Fuel Price Scenarios | | | Fuel Price ($/mmBtu) |
|---|---|---|---|
| EIA Projection Case | Bituminous Coal | Low | 2.79 |
| | | Medium | 2.90 |
| | | High | 3.03 |
| | Natural Gas | Low | 5.53 |
| | | Medium | 5.65 |
| | | High | 5.81 |
| Florida Case | Bituminous Coal | Low | 3.03 |
| | | Medium | 3.15 |
| | | High | 3.29 |
| | Natural Gas | Low | 6.25 |
| | | Medium | 6.38 |
| | | High | 6.57 |
| Ohio Case | Coal | Low | 2.25 |
| | | Medium | 2.51 |
| | | High | 2.90 |
| | Natural Gas | Low | 5.00 |
| | | Medium | 6.15 |
| | | High | 8.00 |

| Heat Rate[1] | (mmBtu/MWh) |
|---|---|
| Coal | 10.6 |
| Natural Gas | 7.05 |
| Required Switching | (Million MWh) |
| Coal to Natural Gas | 59.02 |

| EIA Fuel Price Case | Fuel Switching Cost (Million $) | Florida Fuel Price Case | Fuel Switching Cost (Million $) | Ohio Fuel Price Case | Fuel Switching Cost (Million $) |
|---|---|---|---|---|---|
| **Low Gas -Low Coal** | | **Low Gas -Low Coal** | | **Low Gas -Low Coal** | |
| Cost of Coal (Million$) | 1,745.54 | Cost of Coal (Million$) | 1,893.92 | Cost of Coal (Million$) | 1,407.70 |
| Cost of NG (Million$) | 2,301.10 | Cost of NG (Million$) | 2,600.24 | Cost of NG (Million$) | 2,080.56 |
| Δ (Million$) | **547.69** | Δ (Million$) | **697.79** | Δ (Million$) | **666.52** |
| **Low Gas -Medium Coal** | | **Low Gas -Medium Coal** | | **Low Gas -Medium Coal** | |
| Cost of Coal (Million$) | 1,814.37 | Cost of Coal (Million$) | 1,968.59 | Cost of Coal (Million$) | 1,570.36 |
| Cost of NG (Million$) | 2,301.10 | Cost of NG (Million$) | 2,600.24 | Cost of NG (Million$) | 2,080.56 |
| Δ (Million$) | **478.55** | Δ (Million$) | **622.78** | Δ (Million$) | **503.12** |
| **Low Gas -High Coal** | | **Low Gas -High Coal** | | **Low Gas -High Coal** | |
| Cost of Coal (Million$) | 1,895.70 | Cost of Coal (Million$) | 2,056.83 | Cost of Coal (Million$) | 1,814.37 |
| Cost of NG (Million$) | 2,301.10 | Cost of NG (Million$) | 2,600.24 | Cost of NG (Million$) | 2,080.56 |
| Δ (Million$) | **396.85** | Δ (Million$) | **534.14** | Δ (Million$) | **258.02** |
| **Medium Gas -Low Coal** | | **Medium Gas -Low Coal** | | **Medium Gas -Low Coal** | |
| Cost of Coal (Million$) | 1,745.54 | Cost of Coal (Million$) | 1,893.92 | Cost of Coal (Million$) | 1,407.70 |
| Cost of NG (Million$) | 2,351.03 | Cost of NG (Million$) | 2,656.67 | Cost of NG (Million$) | 2,559.09 |
| Δ (Million$) | **597.62** | Δ (Million$) | **754.21** | Δ (Million$) | **1,145.04** |
| **Medium Gas -Medium Coal** | | **Medium Gas -Medium Coal** | | **Medium Gas -Medium Coal** | |
| Cost of Coal (Million$) | 1,814.37 | Cost of Coal (Million$) | 1,968.59 | Cost of Coal (Million$) | 1,570.36 |
| Cost of NG (Million$) | 2,351.03 | Cost of NG (Million$) | 2,656.67 | Cost of NG (Million$) | 2,559.09 |
| Δ (Million$) | **528.49** | Δ (Million$) | **679.21** | Δ (Million$) | **981.64** |
| **Medium Gas -High Coal** | | **Medium Gas -High Coal** | | **Medium Gas -High Coal** | |
| Cost of Coal (Million$) | 1,895.70 | Cost of Coal (Million$) | 2,056.83 | Cost of Coal (Million$) | 1,814.37 |
| Cost of NG (Million$) | 2,351.03 | Cost of NG (Million$) | 2,656.67 | Cost of NG (Million$) | 2,559.09 |
| Δ (Million$) | **446.79** | Δ (Million$) | **590.56** | Δ (Million$) | **736.54** |
| **High Gas -Low Coal** | | **High Gas -Low Coal** | | **High Gas -Low Coal** | |
| Cost of Coal (Million$) | 1,745.54 | Cost of Coal (Million$) | 1,893.92 | Cost of Coal (Million$) | 1,407.70 |
| Cost of NG (Million$) | 2,417.61 | Cost of NG (Million$) | 2,731.90 | Cost of NG (Million$) | 3,328.89 |
| Δ (Million$) | **664.20** | Δ (Million$) | **829.45** | Δ (Million$) | **1,914.85** |
| **High Gas -Medium Coal** | | **High Gas -Medium Coal** | | **High Gas -Medium Coal** | |
| Cost of Coal (Million$) | 1,814.37 | Cost of Coal (Million$) | 1,968.59 | Cost of Coal (Million$) | 1,570.36 |
| Cost of NG (Million$) | 2,417.61 | Cost of NG (Million$) | 2,731.90 | Cost of NG (Million$) | 3,328.89 |
| Δ (Million$) | **595.07** | Δ (Million$) | **754.44** | Δ (Million$) | **1,751.45** |
| **High Gas -High Coal** | | **High Gas -High Coal** | | **High Gas -High Coal** | |
| Cost of Coal (Million$) | 1,895.70 | Cost of Coal (Million$) | 2,056.83 | Cost of Coal (Million$) | 1,814.37 |
| Cost of NG (Million$) | 2,417.61 | Cost of NG (Million$) | 2,731.90 | Cost of NG (Million$) | 3,328.89 |
| Δ (Million$) | **513.37** | Δ (Million$) | **665.79** | Δ (Million$) | **1,506.35** |

**Note:**

1. The heat rates are the average values of the 4 IOU's current coal units based on IOU's schedules filed in Docket No. 130001-EI.

**Table 10: Analysis of the Bill Impact Associated with the Costs Due to a Coal Unit to NGCC or Solar Unit Conversion for Achieving 30% CO2 Reduction in 2020**

| Utility | | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FPL | Net Rate Base Increase | 598.21 | 629.40 | 660.58 | 691.76 | 722.94 | 754.13 | 785.31 | 816.49 | 833.76 | 801.69 | 769.62 | 8063.9 |
| | Required net operating income (NGCC-Coal) | 38.88 | 40.91 | 42.94 | 44.96 | 46.99 | 49.02 | 51.05 | 53.07 | 54.19 | 52.11 | 50.03 | 524.2 |
| | Total Required Return - Operating Revenue | 63.50 | 66.81 | 70.12 | 73.43 | 76.74 | 80.05 | 83.36 | 86.67 | 88.50 | 85.10 | 81.69 | 855.9 |
| | Depreciation Expense (NGCC-Coal) | (31.18) | (31.18) | (31.18) | (31.18) | (31.18) | (31.18) | (31.18) | (31.18) | (17.26) | 32.07 | 32.07 | (202.6) |
| | O&M Cost | (2.70) | (2.70) | (2.70) | (2.70) | (2.70) | (2.70) | (2.70) | (2.70) | (2.70) | (2.70) | (2.70) | (29.7) |
| | Fuel Cost | 79.85 | 93.93 | 106.02 | 117.96 | 131.15 | 144.58 | 155.28 | 165.72 | 176.41 | 187.85 | 198.54 | 1,557.3 |
| | Recovery of regulatory assets (Coal) | 66.49 | 66.49 | 66.49 | 63.25 | 63.25 | 63.25 | 63.25 | 63.25 | 49.33 | 0.00 | 0.00 | 565.1 |
| | Property Tax @ 1.6% (est.) | 9.57 | 10.07 | 10.57 | 11.07 | 11.57 | 12.07 | 12.56 | 13.06 | 13.34 | 12.83 | 12.31 | 129.0 |
| | Carrying charge of regulatory assets | 52.65 | 45.73 | 38.80 | 32.09 | 25.38 | 18.66 | 11.95 | 5.24 | 0.00 | 0.00 | 0.00 | 230.5 |
| | **Total revenue requirement (Million$)** | **238.17** | **249.14** | **258.12** | **263.91** | **274.19** | **284.72** | **292.51** | **300.05** | **307.62** | **315.14** | **321.91** | **3,105.5** |
| | Estimated Retail Sales (GWh)[1] | 115,970 | 117,089 | 118,674 | 120,000 | 121,342 | 122,698 | 124,069 | 125,456 | 126,858 | 128,276 | 129,709 | 1,350,141 |
| | **Projected Bill Impact ($/1000 KWh)** | **2.05** | **2.13** | **2.18** | **2.20** | **2.26** | **2.32** | **2.36** | **2.39** | **2.42** | **2.46** | **2.48** | |
| DEF | Net Rate Base Increase | 570.52 | 598.49 | 626.45 | 654.42 | 682.38 | 710.34 | 738.31 | 766.27 | 794.24 | 822.20 | 850.17 | 7,813.8 |
| | Required net operating income (NGCC-Coal) | 41.48 | 43.51 | 45.54 | 47.58 | 49.61 | 51.64 | 53.68 | 55.71 | 57.74 | 59.77 | 61.81 | 568.1 |
| | Total Required Return - Operating Revenue | 67.73 | 71.05 | 74.37 | 77.69 | 81.01 | 84.33 | 87.65 | 90.97 | 94.29 | 97.61 | 100.93 | 927.6 |
| | Depreciation Expense (NGCC-Coal) | (27.96) | (27.96) | (27.96) | (27.96) | (27.96) | (27.96) | (27.96) | (27.96) | (27.96) | (27.96) | (27.96) | (307.6) |
| | O&M Cost | (4.54) | (4.54) | (4.54) | (4.54) | (4.54) | (4.54) | (4.54) | (4.54) | (4.54) | (4.54) | (4.54) | (49.9) |
| | Fuel Cost | 101.71 | 110.69 | 124.35 | 138.35 | 153.82 | 169.57 | 182.12 | 194.37 | 206.91 | 220.33 | 232.87 | 1,835.1 |
| | Recovery of regulatory assets (Coal) | 86.21 | 86.21 | 86.21 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 867.2 |
| | Property Tax @ 1.6% (est.) | 9.13 | 9.58 | 10.02 | 10.47 | 10.92 | 11.37 | 11.81 | 12.26 | 12.71 | 13.16 | 13.60 | 125.0 |
| | Carrying charge of regulatory assets | 78.89 | 72.63 | 66.36 | 60.83 | 55.30 | 49.77 | 44.24 | 38.71 | 33.18 | 27.65 | 22.12 | 549.7 |
| | **Total revenue requirement (Million$)** | **311.18** | **317.65** | **328.82** | **330.91** | **344.61** | **358.61** | **369.39** | **379.87** | **390.65** | **402.31** | **413.08** | **3,947.1** |
| | Estimated Retail Sales (GWh)[1] | 41,404 | 41,928 | 42,410 | 42,884 | 43,363 | 43,848 | 44,338 | 44,834 | 45,335 | 45,841 | 46,354 | 482,538.5 |
| | **Projected Bill Impact ($/1000 KWh)** | **7.52** | **7.58** | **7.75** | **7.72** | **7.95** | **8.18** | **8.33** | **8.47** | **8.62** | **8.78** | **8.91** | |
| TECO | Net Rate Base Increase | 1,180.95 | 1,187.33 | 1,193.72 | 1,200.10 | 1,206.48 | 1,212.87 | 1,219.25 | 1,225.64 | 1,232.02 | 1,238.41 | 1,244.79 | 13,341.6 |
| | Required net operating income (NGCC-Coal) | 83.73 | 84.18 | 84.63 | 85.09 | 85.54 | 85.99 | 86.45 | 86.90 | 87.35 | 87.80 | 88.26 | 945.9 |
| | Total Required Return - Operating Revenue | 136.73 | 137.47 | 138.21 | 138.95 | 139.69 | 140.43 | 141.16 | 141.90 | 142.64 | 143.38 | 144.12 | 1,544.7 |
| | Depreciation Expense (NGCC-Coal) | (6.38) | (6.38) | (6.38) | (6.38) | (6.38) | (6.38) | (6.38) | (6.38) | (6.38) | (6.38) | (6.38) | (70.2) |
| | O&M Cost | (4.92) | (4.92) | (4.92) | (4.92) | (4.92) | (4.92) | (4.92) | (4.92) | (4.92) | (4.92) | (4.92) | (54.1) |
| | Fuel Cost | 122.45 | 139.27 | 157.44 | 175.16 | 194.74 | 214.69 | 230.57 | 246.08 | 261.96 | 278.95 | 294.82 | 2,316.1 |
| | Recovery of regulatory assets (Coal) | 65.87 | 65.87 | 65.87 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 761.8 |
| | Property Tax @ 1.6% (est.) | 18.90 | 19.00 | 19.10 | 19.20 | 19.30 | 19.41 | 19.51 | 19.61 | 19.71 | 19.81 | 19.92 | 213.5 |
| | Carrying charge of regulatory assets | 68.03 | 63.50 | 58.98 | 54.12 | 49.27 | 44.42 | 39.56 | 34.71 | 29.85 | 25.00 | 20.15 | 487.6 |
| | **Total revenue requirement (Million$)** | **400.67** | **413.81** | **428.29** | **446.66** | **462.22** | **478.16** | **490.03** | **501.52** | **513.39** | **526.36** | **538.23** | **5,199.3** |
| | Estimated Retail Sales (GWh)[1] | 19,749 | 19,963 | 20,189 | 20,415 | 20,643 | 20,874 | 21,107 | 21,343 | 21,581 | 21,822 | 22,066 | 229,752 |
| | **Projected Bill Impact ($/1000 KWh)** | **20.29** | **20.73** | **21.21** | **21.88** | **22.39** | **22.91** | **23.22** | **23.50** | **23.79** | **24.12** | **24.39** | |
| GULF | Net Rate Base Increase | 991.63 | 990.04 | 988.44 | 986.85 | 985.26 | 983.66 | 982.07 | 980.47 | 978.88 | 977.28 | 975.69 | 10,820.3 |
| | Required net operating income (NGCC-Coal) | 58.61 | 58.51 | 58.42 | 58.32 | 58.23 | 58.13 | 58.04 | 57.95 | 57.85 | 57.76 | 57.66 | 639.5 |
| | Total Required Return - Operating Revenue | 95.70 | 95.55 | 95.40 | 95.24 | 95.09 | 94.93 | 94.78 | 94.63 | 94.47 | 94.32 | 94.16 | 1,044.3 |
| | Depreciation Expense (NGCC-Coal) | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 17.54 |
| | O&M Cost | (4.92) | (4.92) | (4.92) | (4.92) | (4.92) | (4.92) | (4.92) | (4.92) | (4.92) | (4.92) | (4.92) | (54.08) |
| | Fuel Cost | 126.46 | 147.87 | 170.88 | 190.12 | 211.37 | 233.02 | 250.26 | 267.09 | 284.33 | 302.77 | 320.00 | 2,504.2 |
| | Recovery of regulatory assets (Coal) | 82.83 | 82.83 | 82.83 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 748.8 |
| | Property Tax @ 1.6% (est.) | 15.87 | 15.84 | 15.82 | 15.79 | 15.76 | 15.74 | 15.71 | 15.69 | 15.66 | 15.64 | 15.61 | 173.1 |
| | Carrying charge of regulatory assets | 131.08 | 122.86 | 114.64 | 107.62 | 100.60 | 93.57 | 86.55 | 79.53 | 72.51 | 65.49 | 58.46 | 1,032.9 |
| | **Total revenue requirement (Million$)** | **448.62** | **461.63** | **476.24** | **467.99** | **482.04** | **496.49** | **506.53** | **516.16** | **526.19** | **537.42** | **547.45** | **5,466.8** |
| | Estimated Retail Sales (GWh)[1] | 11,845 | 11,975 | 12,085 | 12,220 | 12,357 | 12,495 | 12,634 | 12,776 | 12,918 | 13,063 | 13,209 | 137,576 |
| | **Projected Bill Impact ($/1000 KWh)** | **37.87** | **38.55** | **39.41** | **38.30** | **39.01** | **39.74** | **40.09** | **40.40** | **40.73** | **41.14** | **41.45** | |
| Total (IOUs) | Estimated Retail Sales (GWh)[1] | 188,968 | 190,955 | 193,358 | 195,519 | 197,704 | 199,914 | 202,148 | 204,408 | 206,692 | 209,002 | 211,338 | 2,200,007 |
| | Fuel Cost | 430 | 492 | 559 | 622 | 691 | 762 | 818 | 873 | 930 | 990 | 1,046 | 8,213 |
| | Total revenue requirement (Million$) | 1,399 | 1,442 | 1,491 | 1,509 | 1,563 | 1,618 | 1,658 | 1,698 | 1,738 | 1,781 | 1,821 | **17,719** |
| | **Weighted Average - Bill Impact ($/1000 KWh)** | **7.40** | **7.55** | **7.71** | **7.72** | **7.91** | **8.09** | **8.20** | **8.31** | **8.41** | **8.52** | **8.61** | |
| Estimated Non IOUs | Estimated Retail Sales (GWh)[1] | 39,856 | 40,483 | 41,188 | 41,648 | 42,114 | 42,585 | 43,060 | 43,542 | 44,028 | 44,520 | 45,018 | |
| | Fuel Cost | 254 | 290 | 329 | 366 | 407 | 449 | 482 | 514 | 548 | 583 | 616 | **4,837** |
| | **Total revenue requirement (Million$)** | 824 | 849 | 878 | 889 | 921 | 953 | 977 | 1,000 | 1,024 | 1,049 | 1,072 | **10,436** |
| | **Average - Bill Impact ($/1000 KWh)** | **20.67** | **20.98** | **21.33** | **21.35** | **21.86** | **22.38** | **22.68** | **22.96** | **23.25** | **23.56** | **23.82** | |
| Estimated Solar | Estimated Retail Sales (GWh)[1,2] | 228,824 | 231,438 | 234,546 | 237,167 | 239,818 | 242,498 | 245,209 | 247,949 | 250,721 | 253,523 | 256,356 | |
| | Fuel Cost | (8.88) | (9.11) | (9.36) | (9.64) | (9.90) | (10.18) | (10.43) | (10.72) | (11.03) | (11.31) | (11.62) | **(112.18)** |
| | **Total revenue requirement (Million$)** | 115 | 111 | 108 | 104 | 100 | 97 | 93 | 90 | 86 | 83 | 79 | **1,066** |
| | **Average - Bill Impact ($/1000 KWh)** | **0.50** | **0.48** | **0.46** | **0.44** | **0.42** | **0.40** | **0.38** | **0.36** | **0.34** | **0.33** | **0.31** | |
| Grand Total | Estimated Retail Sales (GWh)[1] | 228,824 | 231,438 | 234,546 | 237,167 | 239,818 | 242,498 | 245,209 | 247,949 | 250,721 | 253,523 | 256,356 | |
| | Fuel Cost | 675 | 772 | 878 | 978 | 1088 | 1200 | 1290 | 1377 | 1466 | 1562 | 1651 | **12,938** |
| | Total revenue requirement (Million$) | **2337.20** | **2402.95** | **2477.63** | **2502.47** | **2584.11** | **2667.79** | **2728.57** | **2787.22** | **2847.56** | **2912.93** | **2972.01** | **29,220** |
| | **Weighted Average - Bill Impact ($/1000 KWh)** | **10.21** | **10.38** | **10.56** | **10.55** | **10.78** | **11.00** | **11.13** | **11.24** | **11.36** | **11.49** | **11.59** | |

**Table 12-a**

| | FPL | DEF | TECO | GULF |
|---|---|---|---|---|
| Current Required Rate of Return[3] | 6.50% | 7.27% | 7.09% | 5.91% |
| NOI Multiplier[4] | 1.633 | | | |
| Property Taxes @ 1.6% (estimated) | 0.016 | | | |

**Table 12-b**

| | | | |
|---|---|---|---|
| Projected growth rate of sales | FPL | 0.965% | 1.35% |
| | DEF | 1.266% | 1.15% |
| | TECO | 1.072% | 1.12% |
| | GULF | 1.098% | 0.92% |
| Average | | 1.10% | 1.14% |
| | | 1.12% | |

**Note:**

1. Data source: 2020-2022 data from Schedule 2.2 of 2013 Ten Year Site Plan. For 2023-2030 data, 1.1% growth rate is applied which is the average growth rate of IOUs for the period.
2. Assume the cost of solar would be incurred by the customers of the entire state.
3. Current overall cost of capital using midpoint of last authorized ROE Range. Source: April 2013 ESRs.
4. Includes Regulatory Assets Fees, Income Taxes, Bad Debt Expense.

**Table 11: Analysis of the Costs Due to Coal Units to NGCC or Solar Units Conversion for Achieving 30% CO2 Reduction Starting January 1, 2020**

| Utility | Costs to be incurred resulting from the Coal to NGCC Conversions | Estimated (Nominal Million$) | | | | | | | | | | | | NPV |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | Total | |
| | Overnight Capital Investment-NGCC | 1,122 | | | | | | | | | | | | |
| | Depreciation expense (NGCC-Coal) | (31.18) | (31.18) | (31.18) | (31.18) | (31.18) | (31.18) | (31.18) | (31.18) | (17.26) | 32.07 | 32.07 | (202.6) | (151.9) |
| | Fuel Cost (Gas-Coal) | 79.85 | 93.93 | 106.02 | 117.96 | 131.15 | 144.58 | 155.28 | 165.72 | 176.41 | 187.85 | 198.54 | 1,557.3 | 866.8 |
| | Fixed O&M (NGCC-Coal) | (2.60) | (2.60) | (2.60) | (2.60) | (2.60) | (2.60) | (2.60) | (2.60) | (2.60) | (2.60) | (2.60) | (28.7) | (17.3) |
| | Variable O&M (NGCC-Coal) | (0.10) | (0.10) | (0.10) | (0.10) | (0.10) | (0.10) | (0.10) | (0.10) | (0.10) | (0.10) | (0.10) | (1.1) | (0.7) |
| **FPL** | Recovery of regulatory assets (Coal Plants) | 63.25 | 63.25 | 63.25 | 63.25 | 63.25 | 63.25 | 63.25 | 63.25 | 49.33 | 0.00 | 0.00 | 555.3 | 364.3 |
| | Deficient fund_Coal Plant Dismantlement | 3.24 | 3.24 | 3.24 | | | | | | | | | 9.7 | 8.1 |
| | Required return (NGCC-Coal) | 63.50 | 66.81 | 70.12 | 73.43 | 76.74 | 80.05 | 83.36 | 86.67 | 88.50 | 85.10 | 81.69 | 855.9 | 501.0 |
| | Carrying charge of regulatory assets | 52.65 | 45.73 | 38.80 | 32.09 | 25.38 | 18.66 | 11.95 | 5.24 | 0.00 | 0.00 | 0.00 | 230.5 | 173.5 |
| | Property taxes | 9.57 | 10.07 | 10.57 | 11.07 | 11.57 | 12.07 | 12.56 | 13.06 | 13.34 | 12.83 | 12.31 | 129.0 | 75.5 |
| | ∑ | **238.2** | **249.1** | **258.1** | **263.9** | **274.2** | **284.7** | **292.5** | **300.1** | **307.6** | **315.1** | **321.9** | **3,105** | **1,819** |
| | Overnight Capital Investment-NGCC | 1,684 | | | | | | | | | | | | |
| | Depreciation expense (NGCC-Coal) | (27.96) | (27.96) | (27.96) | (27.96) | (27.96) | (27.96) | (27.96) | (27.96) | (27.96) | (27.96) | (27.96) | (307.6) | (173.7) |
| | Fuel Cost (Gas-Coal) | 101.71 | 110.69 | 124.35 | 138.35 | 153.82 | 169.57 | 182.12 | 194.37 | 206.91 | 220.33 | 232.87 | 1,835.1 | 951.1 |
| | Fixed O&M (NGCC-Coal) | (4.37) | (4.37) | (4.37) | (4.37) | (4.37) | (4.37) | (4.37) | (4.37) | (4.37) | (4.37) | (4.37) | (48.1) | (27.2) |
| | Variable O&M (NGCC-Coal) | (0.17) | (0.17) | (0.17) | (0.17) | (0.17) | (0.17) | (0.17) | (0.17) | (0.17) | (0.17) | (0.17) | (1.8) | (1.0) |
| **DEF** | Recovery of regulatory assets (Coal Plants) | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 836.7 | 472.6 |
| | Deficient fund_Coal Plant Dismantlement | 10.14 | 10.14 | 10.14 | | | | | | | | | 30.4 | 24.8 |
| | Required return (NGCC-Coal) | 67.73 | 71.05 | 74.37 | 77.69 | 81.01 | 84.33 | 87.65 | 90.97 | 94.29 | 97.61 | 100.93 | 927.6 | 502.9 |
| | Carrying charge of regulatory assets | 78.89 | 72.63 | 66.36 | 60.83 | 55.30 | 49.77 | 44.24 | 38.71 | 33.18 | 27.65 | 22.12 | 549.7 | 346.2 |
| | Property taxes | 9.13 | 9.58 | 10.02 | 10.47 | 10.92 | 11.37 | 11.81 | 12.26 | 12.71 | 13.16 | 13.60 | 125.0 | 67.8 |
| | ∑ | **311.2** | **317.7** | **328.8** | **330.9** | **344.6** | **358.6** | **369.4** | **379.9** | **390.7** | **402.3** | **413.1** | **3,947.1** | **2,163** |
| | Overnight Capital Investment-NGCC | 2,245 | | | | | | | | | | | | |
| | Depreciation expense (NGCC-Coal) | (6.38) | (6.38) | (6.38) | (6.38) | (6.38) | (6.38) | (6.38) | (6.38) | (6.38) | (6.38) | (6.38) | (70.2) | (39.7) |
| | Fuel Cost (Gas-Coal) | 122.45 | 139.27 | 157.44 | 175.16 | 194.74 | 214.69 | 230.57 | 246.08 | 261.96 | 278.95 | 294.82 | 2,316.1 | 1,198.1 |
| | Fixed O&M (NGCC-Coal) | (4.74) | (4.74) | (4.74) | (4.74) | (4.74) | (4.74) | (4.74) | (4.74) | (4.74) | (4.74) | (4.74) | (52.1) | (29.4) |
| | Variable O&M (NGCC-Coal) | (0.18) | (0.18) | (0.18) | (0.18) | (0.18) | (0.18) | (0.18) | (0.18) | (0.18) | (0.18) | (0.18) | (2.0) | (1.1) |
| **TECO** | Recovery of regulatory assets (Coal Plants) | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 775.7 | 438.3 |
| | Deficient fund_Coal Plant Dismantlement | (4.65) | (4.65) | (4.65) | | | | | | | | | (14.0) | (11.4) |
| | Required return (NGCC-Coal) | 136.73 | 137.47 | 138.21 | 138.95 | 139.69 | 140.43 | 141.16 | 141.90 | 142.64 | 143.38 | 144.12 | 1,544.7 | 868.0 |
| | Carrying charge of regulatory assets | 68.03 | 63.50 | 58.98 | 54.12 | 49.27 | 44.42 | 39.56 | 34.71 | 29.85 | 25.00 | 20.15 | 487.6 | 305.9 |
| | Property taxes | 18.90 | 19.00 | 19.10 | 19.20 | 19.30 | 19.41 | 19.51 | 19.61 | 19.71 | 19.81 | 19.92 | 213.5 | 120.0 |
| | ∑ | **400.7** | **413.8** | **428.3** | **446.7** | **462.2** | **478.2** | **490.0** | **501.5** | **513.4** | **526.4** | **538.2** | **5,199.3** | **2,849** |
| | Overnight Capital Investment-NGCC | 2,245 | | | | | | | | | | | | |
| | Depreciation expense (NGCC-Coal) | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 | 0.00 | 11.2 |
| | Fuel Cost (Gas-Coal) | 126.46 | 147.87 | 170.88 | 190.12 | 211.37 | 233.02 | 250.26 | 267.09 | 284.33 | 302.77 | 320.00 | 2,504.2 | 1,488.4 |
| | Fixed O&M (NGCC-Coal) | (4.74) | (4.74) | (4.74) | (4.74) | (4.74) | (4.74) | (4.74) | (4.74) | (4.74) | (4.74) | (4.74) | (52.1) | (33.2) |
| | Variable O&M (NGCC-Coal) | (0.18) | (0.18) | (0.18) | (0.18) | (0.18) | (0.18) | (0.18) | (0.18) | (0.18) | (0.18) | (0.18) | (2.0) | (1.3) |
| **GULF** | Recovery of regulatory assets (Coal Plants) | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 687.9 | 438.5 |
| | Deficient fund_Coal Plant Dismantlement | 20.29 | 20.29 | 20.29 | | | | | | | | | 60.9 | 51.9 |
| | Required return (NGCC-Coal) | 95.70 | 95.55 | 95.40 | 95.24 | 95.09 | 94.93 | 94.78 | 94.63 | 94.47 | 94.32 | 94.16 | 1,044.3 | 666.5 |
| | Carrying charge of regulatory assets | 131.08 | 122.86 | 114.64 | 107.62 | 100.60 | 93.57 | 86.55 | 79.53 | 72.51 | 65.49 | 58.46 | 1,032.9 | 698.4 |
| | Property taxes | 15.87 | 15.84 | 15.82 | 15.79 | 15.76 | 15.74 | 15.71 | 15.69 | 15.66 | 15.64 | 15.61 | 173.1 | 110.5 |
| | ∑ | **448.6** | **461.6** | **476.2** | **468.0** | **482.0** | **496.5** | **506.5** | **516.2** | **526.2** | **537.4** | **547.5** | **5,466.8** | **3,431** |
| | Overnight Capital Investment-Solar | 822 | | | | | | | | | | | | |
| | Depreciation expense (Solar-Coal) | 25.45 | 25.45 | 25.45 | 25.45 | 25.45 | 25.45 | 25.45 | 25.45 | 25.55 | 25.91 | 25.91 | 280.99 | 178.9 |
| | Fuel Cost (Solar-Coal) | (8.88) | (9.11) | (9.36) | (9.64) | (9.90) | (10.18) | (10.43) | (10.72) | (11.03) | (11.31) | (11.62) | (112.18) | (70.0) |
| | O&M (Solar-Coal) | (0.11) | (0.11) | (0.11) | (0.11) | (0.11) | (0.11) | (0.11) | (0.11) | (0.11) | (0.11) | (0.11) | (1.19) | (0.76) |
| | Recovery of stranded assets (Coal Plants) | 1.95 | 1.95 | 1.95 | 1.95 | 1.95 | 1.95 | 1.95 | 1.95 | 1.85 | 1.50 | 1.50 | 20.45 | 13.24 |
| **Solar** | Deficient fund_Coal Plant Dismantlement | 0.208 | 0.208 | 0.208 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.62 | 0.53 |
| | Required return (Solar-Coal) | 81.51 | 78.81 | 76.10 | 73.40 | 70.70 | 68.00 | 65.30 | 62.60 | 59.88 | 57.13 | 54.38 | 747.81 | 491.7 |
| | Carrying charge of stranded coal assets | 2.37 | 2.18 | 2.00 | 1.82 | 1.65 | 1.48 | 1.31 | 1.13 | 0.97 | 0.85 | 0.72 | 16.48 | **11.4** |
| | Property taxes | 12.29 | 11.88 | 11.47 | 11.06 | 10.66 | 10.25 | 9.84 | 9.44 | 9.03 | 8.61 | 8.20 | 112.72 | **74.1** |
| | ∑ | **114.8** | **111.3** | **107.7** | **103.9** | **100.4** | **96.8** | **93.3** | **89.7** | **86.1** | **82.6** | **79.0** | **1,065.7** | **699** |
| **Total Cost_IOUs (Coal to NGCC)** | | 1,398.6 | 1,442.2 | 1,491.5 | 1,509.5 | 1,563.1 | 1,618.0 | 1,658.5 | 1,697.6 | 1,737.8 | 1,781.2 | 1,820.7 | **17,718.7** | **11,058** |
| **Total Cost_Non-IOUs[1] (Coal to NGCC)** | | 823.78 | 849.46 | 878.45 | 889.06 | 920.63 | 952.97 | 976.81 | 999.87 | 1,023.57 | 1,049.12 | 1,072.36 | **10,436.1** | **6,513** |
| **Cost - Solar** | | 114.8 | 111.3 | 107.7 | 103.9 | 100.4 | 96.8 | 93.3 | 89.7 | 86.1 | 82.6 | 79.0 | **1,065.7** | **699** |
| **Grand Total** | | **2,337.2** | **2,402.9** | **2,477.6** | **2,502.5** | **2,584.1** | **2,667.8** | **2,728.6** | **2,787.2** | **2,847.6** | **2,912.9** | **2,972.0** | **29,220.4** | **18,270** |
| Total IOU's Variable O&M | | (0.62) | (0.62) | (0.62) | (0.62) | (0.62) | (0.62) | (0.62) | (0.62) | (0.62) | (0.62) | (0.62) | (6.87) | (4.07) |
| Total State's Variable O&M | | (0.99) | (0.99) | (0.99) | (0.99) | (0.99) | (0.99) | (0.99) | (0.99) | (0.99) | (0.99) | (0.99) | (10.92) | (6.46) |

**Note:** 1. Estimated in proportion to the MWh coal energy displaced by the IOUs due to lack of information of these utilities in terms of the investment, plant balance, reserve, average service life, average remaining life, net salvage, depreciation rate, dismantlement cost, reserve balance, ROE, tax etc..

**Table 12: Parameters of Generating Units[1]**

| | Plant Characteristics | | Plant Costs | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Nominal Capacity (MW) | Heat Rate (Btu/kWh) | Overnight Capital | | Fixed O&M Cost | | Variable O&M Cost | |
| | | | (2010 $/kW) | ( 2013 $/kW) | (2010 $/kW) | ( 2013 $/kW) | (2010 $/kW) | ( 2013 $/kW) |
| **Coal** | | | | | | | | |
| Single Unit Advance | 650 | 8,800 | $3,167 | $3,335 | $35.97 | $37.87 | $4.25 | $4.47 |
| Dual Unit Advance | 1,300 | 8,800 | $2,844 | $2,994 | $29.67 | $31.24 | $4.25 | $4.47 |
| Ave. of the Florida Coal Units | | 10,600 | | | | | | |
| **Natural Gas** | | | | | | | | |
| Conventional NGCC | 540 | 7,050 | $987 | $1,039 | $14.39 | $15.15 | $3.43 | $3.61 |
| Advanced NGCC | 400 | 6,430 | $1,003 | $1,056 | $14.62 | $15.39 | $3.11 | $3.27 |
| **Difference between conventional NGCC unit and single unit advanced coal unit** | | | | | | ($22.72) | | ($0.86) |

**Table 13: NGCC Units for Replacing the Coal-fired Units**

| | FPL | DEF | TECO | GULF | JEA |
|---|---|---|---|---|---|
| No. of NGCC units needed to replace the coal capacity[2] | 2 | 3 | 4 | 4 | 3 |
| Overnight capital costs (2013 M$) | 1,122 | 1,684 | 2,245 | 2,245 | 1,684 |
| Depreciation whole life rate[3] | 2.86% | | | | |
| Annual depreciation (2013 M$) | 32.07 | 48.10 | 64.14 | 64.14 | 48.10 |

**Table 14**

| | CPI[4] |
|---|---|
| 2010 | 218.056 |
| 2013 | 229.594 |
| index | 1.053 |

**Note**:

1. Source of data: EIA Updated Capital Cost Estimates for Electricity Generation Plants, Nov. 2010, except the heat rate of coal unit is the actual average heat rate based on Florida IOU's Schedule A in Docket No. 130001-EI.
2. This analysis does not address the issue of reserve margin.
3. Assuming: (a) all the coal-fired units will be replaced by the conventional NGCC units;
   (b) average service life of the NGCC will be 35 years, in light of Order No. PSC-10-0153-FOF-EI;
   (c) the NGCC units will be depreciated using whole life rate;
   (d) no further plant activity (addition, transfer, adjustment, etc.) during the period 2020 -2030.
4. Source of CPI: U.S. Department of Labor, Bureau of Labor Statistics, August 15, 2013.

**Table 15: Depreciation Expenses Due to Replacing Coal-fired Units by NGCC Units**

| Utility | Costs to be incurred resulting from the Coal to NGCC Conversions | Estimated (Nominal Million$) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| FPL | Overnight Capital Investment-NGCC | 1,122.36 | | | | | | | | | | |
| | Depreciation expenses of NGCC units | 32.07 | 32.07 | 32.07 | 32.07 | 32.07 | 32.07 | 32.07 | 32.07 | 32.07 | 32.07 | 32.07 |
| | Plant balance-NGCC | 1090.30 | 1058.23 | 1026.16 | 994.09 | 962.03 | 929.96 | 897.89 | 865.82 | 833.76 | 801.69 | 769.62 |
| | Plant balance-Coal units if not replaced | 555.33 | | | | | | | | | | |
| | Depreciation expenses of coal units if not replaced | 63.25 | 63.25 | 63.25 | 63.25 | 63.25 | 63.25 | 63.25 | 63.25 | 49.33 | 0.00 | 0.00 |
| | Recovery of regulatory assets (coal units) | 63.25 | 63.25 | 63.25 | 63.25 | 63.25 | 63.25 | 63.25 | 63.25 | 49.33 | 0.00 | 0.00 |
| | Net regulatory assets-coal units | 492.08 | 428.83 | 365.58 | 302.33 | 239.08 | 175.83 | 112.58 | 49.33 | 0.00 | 0.00 | 0.00 |
| | Δ | 32.07 | 32.07 | 32.07 | 32.07 | 32.07 | 32.07 | 32.07 | 32.07 | 32.07 | 32.07 | 32.07 |
| DEF | Overnight Capital Investment-NGCC | 1683.54 | | | | | | | | | | |
| | Depreciation expenses of NGCC units | 48.10 | 48.10 | 48.10 | 48.10 | 48.10 | 48.10 | 48.10 | 48.10 | 48.10 | 48.10 | 48.10 |
| | Plant balance-NGCC | 1635.44 | 1587.34 | 1539.24 | 1491.14 | 1443.04 | 1394.94 | 1346.84 | 1298.73 | 1250.63 | 1202.53 | 1154.43 |
| | Plant balance-Coal units if not replaced | 1140.99 | | | | | | | | | | |
| | Depreciation expenses of coal units if not replaced | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 |
| | Recovery of regulatory assets (coal units) | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 |
| | Net regulatory assets-coal units | 1,064.92 | 988.86 | 912.79 | 836.72 | 760.66 | 684.59 | 608.53 | 532.46 | 456.39 | 380.33 | 304.26 |
| | Δ | 48.10 | 48.10 | 48.10 | 48.10 | 48.10 | 48.10 | 48.10 | 48.10 | 48.10 | 48.10 | 48.10 |
| TECO | Overnight Capital Investment-NGCC | 2,245 | | | | | | | | | | |
| | Depreciation expenses of NGCC units | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 |
| | Plant balance-NGCC | 2180.59 | 2116.46 | 2052.32 | 1988.19 | 1924.05 | 1859.92 | 1795.78 | 1731.65 | 1667.51 | 1603.38 | 1539.24 |
| | Plant balance-Coal units if not replaced | 1,070.16 | | | | | | | | | | |
| | Depreciation expenses of coal units if not replaced | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 |
| | Recovery of regulatory assets (coal units) | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 | 70.52 |
| | Net regulatory assets-coal units | 999.64 | 929.13 | 858.61 | 788.09 | 717.57 | 647.05 | 576.53 | 506.01 | 435.49 | 364.97 | 294.45 |
| | Δ | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 |
| GULF | Overnight Capital Investment-NGCC | 2,245 | | | | | | | | | | |
| | Depreciation expenses of NGCC units | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 |
| | Plant balance-NGCC | 2180.59 | 2116.46 | 2052.32 | 1988.19 | 1924.05 | 1859.92 | 1795.78 | 1731.65 | 1667.51 | 1603.38 | 1539.24 |
| | Plant balance-Coal units if not replaced | $1,251.50 | | | | | | | | | | |
| | Depreciation expenses of coal units if not replaced | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 |
| | Recovery of regulatory assets (coal units) | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 | 62.54 |
| | Net regulatory assets-coal units | 1,188.96 | 1,126.42 | 1,063.88 | 1,001.34 | 938.79 | 876.25 | 813.71 | 751.17 | 688.63 | 626.09 | 563.55 |
| | Δ | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 | 64.14 |
| Total | Overnight Capital Investment-NGCC | 7,295 | | | | | | | | | | |
| | Depreciation expenses of NGCC units | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 |
| | Plant balance-NGCC | 7,087 | 6,878 | 6,670 | 6,462 | 6,253 | 6,045 | 5,836 | 5,628 | 5,419 | 5,211 | 5,003 |
| | Plant balance-Coal units if not replaced | 4017.98 | | | | | | | | | | |
| | Depreciation expenses of coal units if not replaced | 272 | 272 | 272 | 272 | 272 | 272 | 272 | 272 | 258 | 209 | 209 |
| | Recovery of regulatory assets (coal units) | 272 | 272 | 272 | 272 | 272 | 272 | 272 | 272 | 258 | 209 | 209 |
| | Net regulatory assets-coal units | 3,746 | 3,473 | 3,201 | 2,928 | 2,656 | 2,384 | 2,111 | 1,839 | 1,581 | 1,371 | 1,162 |
| | Δ | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 | 208.4 |

## Table 16: Fuel Costs Due to Replacing Coal by Natural Gas[1]

| | Heat Rate (MMBTU/MWh)[2] Coal: 10.6 NG: 7.05 | Estimated (Nominal Million$) | | | | | | | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | |
| Fuel Price | Coal ($/MMBTU) | 3.15 | 3.23 | 3.32 | 3.42 | 3.51 | 3.61 | 3.70 | 3.80 | 3.91 | 4.01 | 4.12 | |
| | NG ($/MMBTU) | 6.38 | 6.74 | 7.12 | 7.51 | 7.91 | 8.33 | 8.68 | 9.04 | 9.42 | 9.80 | 10.18 | |
| FPL | Coal Energy Need to be Replaced (GWH)[3] | 6,890 | 7,073 | 7,066 | 7,066 | 7,066 | 7,066 | 7,066 | 7,066 | 7,066 | 7,066 | 7,066 | |
| | Cost of Coal (Million$) | 230.05 | 242.17 | 248.68 | 256.17 | 262.91 | 270.40 | 277.14 | 284.63 | 292.87 | 300.36 | 308.60 | |
| | Cost of NG (Million$) | 309.90 | 336.10 | 354.71 | 374.13 | 394.06 | 414.98 | 432.42 | 450.36 | 469.29 | 488.22 | 507.15 | |
| | Δ (Million$) | 79.85 | 93.93 | 106.02 | 117.96 | 131.15 | 144.58 | 155.28 | 165.72 | 176.41 | 187.85 | 198.54 | **1557.3** |
| DEF | Coal Energy Need to be Replaced (GWH)[3] | 8,777 | 8,336 | 8,288 | 8,288 | 8,288 | 8,288 | 8,288 | 8,288 | 8,288 | 8,288 | 8,288 | |
| | Cost of Coal (Million$) | 293.05 | 285.40 | 291.67 | 300.45 | 308.36 | 317.14 | 325.05 | 333.84 | 343.50 | 352.29 | 361.95 | |
| | Cost of NG (Million$) | 394.76 | 396.09 | 416.02 | 438.81 | 462.18 | 486.72 | 507.17 | 528.20 | 550.41 | 572.61 | 594.81 | |
| | Δ (Million$) | 101.71 | 110.69 | 124.35 | 138.35 | 153.82 | 169.57 | 182.12 | 194.37 | 206.91 | 220.33 | 232.87 | **1835.1** |
| TECO | Coal Energy Need to be Replaced (GWH)[3] | 10,566 | 10,488 | 10,493 | 10,493 | 10,493 | 10,493 | 10,493 | 10,493 | 10,493 | 10,493 | 10,493 | |
| | Cost of Coal (Million$) | 352.80 | 359.09 | 369.27 | 380.39 | 390.40 | 401.53 | 411.54 | 422.66 | 434.89 | 446.02 | 458.25 | |
| | Cost of NG (Million$) | 475.25 | 498.36 | 526.71 | 555.56 | 585.15 | 616.22 | 642.11 | 668.74 | 696.85 | 724.96 | 753.07 | |
| | Δ (Million$) | 122.45 | 139.27 | 157.44 | 175.16 | 194.74 | 214.69 | 230.57 | 246.08 | 261.96 | 278.95 | 294.82 | **2316.1** |
| GULF | Coal Energy Need to be Replaced (GWH)[3] | 10,912 | 11,136 | 11,389 | 11,389 | 11,389 | 11,389 | 11,389 | 11,389 | 11,389 | 11,389 | 11,389 | |
| | Cost of Coal (Million$) | 364.35 | 381.27 | 400.80 | 412.87 | 423.74 | 435.81 | 446.68 | 458.75 | 472.03 | 484.10 | 497.38 | |
| | Cost of NG (Million$) | 490.81 | 529.15 | 571.68 | 603.00 | 635.11 | 668.84 | 696.94 | 725.84 | 756.35 | 786.87 | 817.38 | |
| | Δ (Million$) | 126.46 | 147.87 | 170.88 | 190.12 | 211.37 | 233.02 | 250.26 | 267.09 | 284.33 | 302.77 | 320.00 | **2504.18** |
| Total | Coal Energy Need to be Replaced (GWH) | 37,144 | 37,033 | 37,236 | 37,236 | 37,236 | 37,236 | 37,236 | 37,236 | 37,236 | 37,236 | 37,236 | |
| | Cost of Coal (Million$) | 1240.25 | 1267.93 | 1310.42 | 1349.89 | 1385.41 | 1424.88 | 1460.41 | 1499.88 | 1543.30 | 1582.77 | 1626.18 | |
| | Cost of NG (Million$) | 1670.72 | 1759.69 | 1869.11 | 1971.49 | 2076.50 | 2186.76 | 2278.64 | 2373.14 | 2472.90 | 2572.66 | 2672.41 | |
| | Δ (Million$) | 430.47 | 491.76 | 558.69 | 621.60 | 691.09 | 761.87 | 818.23 | 873.27 | 929.60 | 989.89 | 1046.23 | **8212.7** |

**Note 1**:
Assuming X = Total cost of burning coal, Y = Total cost of burning NG, and
Z = Fuel cost due to NG replacing coal as the fuel to generate electricity
Then X = Total coal energy needed (GWH) x unit price of coal ($/MMBTU) x Heat rate of coal (MMBTU/GWH)
Y = Total NG energy needed (GWH) x unit price of coal ($/MMBTU) x Heat rate of NG (MMBTU/GWH)
When replacing coal by NG, the amount of energy generated should be maintained.
∴ Total NG energy needed (GWH) = total coal energy needed (GWH)
∴ Z ($) = Y-X
= total energy needed (GWH)*[unit price of NG ($/MMBTU)*Heat rate of NG (MMBTU/GWH)
− unit price of coal ($/MMBTU) * Heat rate of coal (MMBTU/GWH)]

**Note 2**: The heat rates are the average values of the 4 IOU's current coal units which was derived by reviewing the IOU's schedules filed in Docket No. 130001-EI.

**Note 3**: Assuming the annual coal energy needed by each utility for the period 2023 - 2030 would be the same as what it projected for 2022.

## Table 17: Required Rate of Returns of the IOUs Due to Replacing Coal-fired Units by NGCCs[1]

| Utility | | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Net rate base -NGCC | 1,090.3 | 1,058.2 | 1,026.2 | 994.1 | 962.0 | 930.0 | 897.9 | 865.8 | 833.8 | 801.7 | 769.6 | |
| | Required net operating income -NGCC | 70.9 | 68.8 | 66.7 | 64.6 | 62.5 | 60.4 | 58.4 | 56.3 | 54.2 | 52.1 | 50.0 | |
| | Required return - NGCC | 115.7 | 112.3 | 108.9 | 105.5 | 102.1 | 98.7 | 95.3 | 91.9 | 88.5 | 85.1 | 81.7 | |
| | Net base - coal unit if not replaced | 492.1 | 428.8 | 365.6 | 302.3 | 239.1 | 175.8 | 112.6 | 49.3 | 0.0 | 0.0 | 0.0 | |
| **FPL** | Required net operating income - coal units if not replaced | 32.0 | 27.9 | 23.8 | 19.7 | 15.5 | 11.4 | 7.3 | 3.2 | 0.0 | 0.0 | 0.0 | |
| | Required return on the investment of coal units if not replaced | 52.2 | 45.5 | 38.8 | 32.1 | 25.4 | 18.7 | 11.9 | 5.2 | 0.0 | 0.0 | 0.0 | |
| | Δ (Net base increase) | 598.2 | 629.4 | 660.6 | 691.8 | 722.9 | 754.1 | 785.3 | 816.5 | 833.8 | 801.7 | 769.6 | **8,063.9** |
| | Δ (Required net operating income) | 38.9 | 40.9 | 42.9 | 45.0 | 47.0 | 49.0 | 51.0 | 53.1 | 54.2 | 52.1 | 50.0 | **524.2** |
| | Δ (Required return) | 63.5 | 66.8 | 70.1 | 73.4 | 76.7 | 80.0 | 83.4 | 86.7 | 88.5 | 85.1 | 81.7 | **855.9** |
| | Net Investment of NGCC | 1,635.4 | 1,587.3 | 1,539.2 | 1,491.1 | 1,443.0 | 1,394.9 | 1,346.8 | 1,298.7 | 1,250.6 | 1,202.5 | 1,154.4 | |
| | Return on the investment of NGCC | 118.9 | 115.4 | 111.9 | 108.4 | 104.9 | 101.4 | 97.9 | 94.4 | 90.9 | 87.4 | 83.9 | |
| | Required return - NGCC | 194.2 | 188.4 | 182.7 | 177.0 | 171.3 | 165.6 | 159.9 | 154.2 | 148.5 | 142.8 | 137.1 | |
| | Net investment of coal unit if not replaced | 1,064.9 | 988.9 | 912.8 | 836.7 | 760.7 | 684.6 | 608.5 | 532.5 | 456.4 | 380.3 | 304.3 | |
| **DEF** | Return on the investment of coal units | 77.4 | 71.9 | 66.4 | 60.8 | 55.3 | 49.8 | 44.2 | 38.7 | 33.2 | 27.6 | 22.1 | |
| | Required return on the investment of coal units if not replaced | 126.4 | 117.4 | 108.4 | 99.3 | 90.3 | 81.3 | 72.2 | 63.2 | 54.2 | 45.2 | 36.1 | |
| | Δ (Net base increase) | 570.5 | 598.5 | 626.5 | 654.4 | 682.4 | 710.3 | 738.3 | 766.3 | 794.2 | 822.2 | 850.17 | **7,813.8** |
| | Δ (Required net operating income) | 41.5 | 43.5 | 45.5 | 47.6 | 49.6 | 51.6 | 53.7 | 55.7 | 57.7 | 59.8 | 61.81 | **568.1** |
| | Δ (Required return) | 67.7 | 71.1 | 74.4 | 77.7 | 81.0 | 84.3 | 87.7 | 91.0 | 94.3 | 97.6 | 100.93 | **927.6** |
| | Net Investment of NGCC | 2,180.6 | 2,116.5 | 2,052.3 | 1,988.2 | 1,924.1 | 1,859.9 | 1,795.8 | 1,731.6 | 1,667.5 | 1,603.4 | 1,539.2 | |
| | Return on the investment of NGCC | 154.6 | 150.1 | 145.5 | 141.0 | 136.4 | 131.9 | 127.3 | 122.8 | 118.2 | 113.7 | 109.1 | |
| | Required return - NGCC | 252.5 | 245.0 | 237.6 | 230.2 | 222.8 | 215.3 | 207.9 | 200.5 | 193.1 | 185.6 | 178.2 | |
| | Net investment of coal unit if not replaced | 999.6 | 929.1 | 858.6 | 788.1 | 717.6 | 647.0 | 576.5 | 506.0 | 435.5 | 365.0 | 294.4 | |
| **TECO** | Return on the investment of coal units | 70.9 | 65.9 | 60.9 | 55.9 | 50.9 | 45.9 | 40.9 | 35.9 | 30.9 | 25.9 | 20.9 | |
| | Required return on the investment of coal units if not replaced | 115.7 | 107.6 | 99.4 | 91.2 | 83.1 | 74.9 | 66.8 | 58.6 | 50.4 | 42.3 | 34.1 | |
| | Δ (Net base increase) | 1,180.9 | 1,187.3 | 1,193.7 | 1,200.1 | 1,206.5 | 1,212.9 | 1,219.3 | 1,225.6 | 1,232.0 | 1,238.4 | 1,244.8 | **13,341.6** |
| | Δ (Required net operating income) | 83.7 | 84.2 | 84.6 | 85.1 | 85.5 | 86.0 | 86.4 | 86.9 | 87.4 | 87.8 | 88.3 | **945.9** |
| | Δ (Required return) | 136.7 | 137.5 | 138.2 | 138.9 | 139.7 | 140.4 | 141.2 | 141.9 | 142.6 | 143.4 | 144.1 | **1,544.7** |
| | Net Investment of NGCC | 2,180.6 | 2,116.5 | 2,052.3 | 1,988.2 | 1,924.1 | 1,859.9 | 1,795.8 | 1,731.6 | 1,667.5 | 1,603.4 | 1,539.2 | |
| | Return on the investment of NGCC | 128.9 | 125.1 | 121.3 | 117.5 | 113.7 | 109.9 | 106.1 | 102.3 | 98.5 | 94.8 | 91.0 | |
| | Required return - NGCC | 210.4 | 204.3 | 198.1 | 191.9 | 185.7 | 179.5 | 173.3 | 167.1 | 160.9 | 154.7 | 148.6 | |
| | Net investment of coal unit if not replaced | 1,189.0 | 1,126.4 | 1,063.9 | 1,001.3 | 938.8 | 876.3 | 813.7 | 751.2 | 688.6 | 626.1 | 563.6 | |
| **GULF** | Return on the investment of coal units | 70.3 | 66.6 | 62.9 | 59.2 | 55.5 | 51.8 | 48.1 | 44.4 | 40.7 | 37.0 | 33.3 | |
| | Required return on the investment of coal units if not replaced | 114.7 | 108.7 | 102.7 | 96.6 | 90.6 | 84.6 | 78.5 | 72.5 | 66.5 | 60.4 | 54.4 | |
| | Δ (Net base increase) | 991.6 | 990.0 | 988.4 | 986.9 | 985.3 | 983.7 | 982.1 | 980.5 | 978.9 | 977.3 | 975.7 | **10,820.3** |
| | Δ (Required net operating income) | 58.6 | 58.5 | 58.4 | 58.3 | 58.2 | 58.1 | 58.0 | 57.9 | 57.9 | 57.8 | 57.7 | **639.5** |
| | Δ (Required return) | 95.7 | 95.5 | 95.4 | 95.2 | 95.1 | 94.9 | 94.8 | 94.6 | 94.5 | 94.3 | 94.2 | **1,044.3** |

**Note**: 1. Assuming each IOU's cost rate for the period 2020-2030 will be the same as what the Commission approved rate for that IOU in 2013.

**Table 18: Analysis of the Stranded Capital Costs Associated with the Retired Coal Units**

| Utility | Plant | | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Investment | 1,064.20 | | | | | | | | | | | | | | | | | |
| | | Expense | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | | |
| | Scherer Rate: 4.6% Remaining life on Jan 2020: 9 years | Reserve | 324.24 | 373.57 | 422.91 | 472.24 | 521.57 | 570.90 | 620.23 | 669.56 | 718.89 | 768.22 | 817.55 | 866.88 | 916.21 | 965.54 | 1,014.87 | 1,064.20 | | |
| | | Net Investment | 739.96 | 690.63 | 641.30 | 591.97 | 542.64 | 493.31 | 443.98 | 394.65 | 345.31 | 295.98 | 246.65 | 197.32 | 147.99 | 98.66 | 49.33 | 0.00 | | |
| | | Stranded Capital | | | | | | | | 443.98 | | | | | | | | | | |
| | | Recovery | | | | | | | | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | 49.33 | | |
| | | Net Stranded Capital | | | | | | | | 394.65 | 345.31 | 295.98 | 246.65 | 197.32 | 147.99 | 98.66 | 49.33 | 0.00 | | |
| | | carrying charge | | | | | | | | 41.89 | 36.65 | 31.42 | 26.18 | 20.94 | 15.71 | 10.47 | 5.24 | 0.00 | | |
| | | ∑ | | | | | | | | 91.22 | 85.98 | 80.75 | 75.51 | 70.28 | 65.04 | 59.80 | 54.57 | 49.33 | | |
| FPL | | Investment | 385.16 | | | | | | | | | | | | | | | | | |
| | | Expense | 13.92 | 13.92 | 13.92 | 13.92 | 13.92 | 13.92 | 13.92 | 13.92 | 13.92 | 13.92 | 13.92 | 13.92 | 13.92 | 13.92 | 13.92 | | | |
| | St. Johns River Rate: 3.6% Remaining life on Jan 2020: 8 years | Reserve | 190.29 | 204.21 | 218.13 | 232.05 | 245.97 | 259.89 | 273.81 | 287.73 | 301.65 | 315.56 | 329.48 | 343.40 | 357.32 | 371.24 | 385.16 | | | |
| | | Net Investment | 194.88 | 180.96 | 167.04 | 153.12 | 139.20 | 125.28 | 111.36 | 97.44 | 83.52 | 69.60 | 55.68 | 41.76 | 27.84 | 13.92 | 0.00 | | | |
| | | Stranded Capital | | | | | | | | 111.36 | | | | | | | | | | |
| | | Recovery | | | | | | | | 13.92 | 13.92 | 13.92 | 13.92 | 13.92 | 13.92 | 13.92 | 13.92 | | | |
| | | Net Stranded Capital | | | | | | | | 97.44 | 83.52 | 69.60 | 55.68 | 41.76 | 27.84 | 13.92 | 0.00 | | | |
| | | Carrying charge | | | | | | | | 10.34 | 8.87 | 7.39 | 5.91 | 4.43 | 2.96 | 1.48 | 0.00 | | | |
| | | ∑ | | | | | | | | 24.26 | 22.78 | 21.31 | 19.83 | 18.35 | 16.87 | 15.40 | 13.92 | | | |
| | Subtotal | | | | | | | | | 115.48 | 108.77 | 102.06 | 95.34 | 88.63 | 81.91 | 75.20 | 68.49 | | | |
| | | Investment | 2,344.58 | | | | | | | | | | | | | | | | | |
| | | Expense | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 |
| | CR Units 4&5 Rate: 3.2% Remaining life on Jan 2020: 15 years | Reserve | 747.19 | 823.26 | 899.33 | 975.39 | 1,051.46 | 1,127.52 | 1,203.59 | 1,279.65 | 1,355.72 | 1,431.79 | 1,507.85 | 1,583.92 | 1,659.98 | 1,736.05 | 1,812.11 | 1,888.18 | 1,964.25 | 2,040.31 |
| | | Net Investment | 1,597.38 | 1,521.32 | 1,445.25 | 1,369.18 | 1,293.12 | 1,217.05 | 1,140.99 | 1,064.92 | 988.86 | 912.79 | 836.72 | 760.66 | 684.59 | 608.53 | 532.46 | 456.39 | 380.33 | 304.26 |
| DEF[6] | | Stranded Capital | | | | | | | | 1,140.99 | | | | | | | | | | |
| | | Recovery | | | | | | | | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 | 76.07 |
| | | Net Stranded Capital | | | | | | | | 1,064.92 | 988.86 | 912.79 | 836.72 | 760.66 | 684.59 | 608.53 | 532.46 | 456.39 | 380.33 | 304.26 |
| | | Carrying charge | | | | | | | | 77.42 | 71.89 | 66.36 | 60.83 | 55.30 | 49.77 | 44.24 | 38.71 | 33.18 | 27.65 | 22.12 |
| | Subtotal | | | | | | | | | 153.49 | 147.96 | 142.43 | 136.90 | 131.37 | 125.84 | 120.31 | 114.78 | 109.25 | 103.72 | 98.19 |
| | | Investment | 1,917.20 | | | | | | | | | | | | | | | | | |
| | | Expense | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 |
| | BB Units 1-4 Rate: 3.0% Remaining life on Jan 2020: 15, 18, 21, 30 yrs respectively | Reserve | 696.08 | 754.23 | 812.38 | 870.52 | 928.67 | 986.82 | 1,044.97 | 1,103.12 | 1,161.27 | 1,219.42 | 1,277.57 | 1,335.71 | 1,393.86 | 1,452.01 | 1,510.16 | 1,568.31 | 1,626.46 | 1,684.61 |
| | | Net Investment | 1,221.12 | 1,162.97 | 1,104.82 | 1,046.68 | 988.53 | 930.38 | 872.23 | 814.08 | 755.93 | 697.78 | 639.64 | 581.49 | 523.34 | 465.19 | 407.04 | 348.89 | 290.74 | 232.59 |
| | | Stranded Capital | | | | | | | | 872.23 | | | | | | | | | | |
| | | Recovery | | | | | | | | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 | 58.15 |
| | | Net Stranded Capital | | | | | | | | 814.08 | 755.93 | 697.78 | 639.64 | 581.49 | 523.34 | 465.19 | 407.04 | 348.89 | 290.74 | 232.59 |
| | | Carrying charge | | | | | | | | 57.72 | 53.60 | 49.47 | 45.35 | 41.23 | 37.10 | 32.98 | 28.86 | 24.74 | 20.61 | 16.49 |
| | | ∑ | | | | | | | | 115.87 | 111.74 | 107.62 | 103.50 | 99.38 | 95.25 | 91.13 | 87.01 | 82.89 | 78.76 | 74.64 |
| TECO | | Investment | 524.44 | | | | | | | | | | | | | | | | | |
| | | Expense | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 |
| | Polk Unit 1 Rate: 2.4% Remaining life on Jan 2020: 16 years | Reserve | 252.28 | 264.65 | 277.02 | 289.39 | 301.76 | 314.13 | 326.50 | 338.87 | 351.24 | 363.61 | 375.98 | 388.36 | 400.73 | 413.10 | 425.47 | 437.84 | 450.21 | 462.58 |
| | | Net Investment | 272.16 | 259.79 | 247.42 | 235.05 | 222.68 | 210.30 | 197.93 | 185.56 | 173.19 | 160.82 | 148.45 | 136.08 | 123.71 | 111.34 | 98.97 | 86.60 | 74.23 | 61.85 |
| | | Stranded Capital | | | | | | | | 197.93 | | | | | | | | | | |
| | | Recovery | | | | | | | | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 | 12.37 |
| | | Net Stranded Capital | | | | | | | | 185.56 | 173.19 | 160.82 | 148.45 | 136.08 | 123.71 | 111.34 | 98.97 | 86.60 | 74.23 | 61.85 |
| | | Carrying charge | | | | | | | | 10.97 | 10.24 | 9.50 | 8.77 | 8.04 | 7.31 | 6.58 | 5.85 | 5.12 | 4.39 | 3.66 |
| | | ∑ | | | | | | | | 23.34 | 22.61 | 21.88 | 21.14 | 20.41 | 19.68 | 18.95 | 18.22 | 17.49 | 16.76 | 16.03 |
| | Subtotal | | | | | | | | | 139.20 | 134.35 | 129.50 | 124.64 | 119.79 | 114.94 | 110.08 | 105.23 | 100.37 | 95.52 | 90.67 |
| | | Investment | 1,498.80 | | | | | | | | | | | | | | | | | |
| | | Expense | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 |
| | Crist Units 4-7 Rate: 6.8% Remaining life on Jan 2020: 5, 7, 16, 19 years respectively | Reserve | 325.77 | 372.69 | 419.61 | 466.53 | 513.45 | 560.37 | 607.30 | 654.22 | 701.14 | 748.06 | 794.98 | 841.90 | 888.82 | 935.74 | 982.66 | 1,029.59 | 1,076.51 | 1,123.43 |
| | | Net Investment | 1,173.03 | 1,126.11 | 1,079.19 | 1,032.27 | 985.34 | 938.42 | 891.50 | 844.58 | 797.66 | 750.74 | 703.82 | 656.90 | 609.98 | 563.05 | 516.13 | 469.21 | 422.29 | 375.37 |
| | | Stranded Capital | | | | | | | | 891.50 | | | | | | | | | | |
| | | Recovery | | | | | | | | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 | 46.92 |
| | | Net Stranded Capital | | | | | | | | 844.58 | 797.66 | 750.74 | 703.82 | 656.90 | 609.98 | 563.05 | 516.13 | 469.21 | 422.29 | 375.37 |
| | | Carrying charge | | | | | | | | 49.91 | 47.14 | 44.37 | 41.60 | 38.82 | 36.05 | 33.28 | 30.50 | 27.73 | 24.96 | 22.18 |
| | | ∑ | | | | | | | | 96.84 | 94.06 | 91.29 | 88.52 | 85.74 | 82.97 | 80.20 | 77.42 | 74.65 | 71.88 | 69.11 |
| | | Investment | 268.89 | | | | | | | | | | | | | | | | | |
| | | Expense | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 |
| | Daniel 6 & 7 Rate: 1.6 % Remaining life on Jan 2020: 23 and 27 years respectively | Reserve | 147.28 | 151.48 | 155.67 | 159.86 | 164.06 | 168.25 | 172.44 | 176.64 | 180.83 | 185.02 | 189.22 | 193.41 | 197.60 | 201.80 | 205.99 | 210.18 | 214.38 | 218.57 |
| | | Net Investment | 121.61 | 117.42 | 113.22 | 109.03 | 104.84 | 100.64 | 96.45 | 92.26 | 88.06 | 83.87 | 79.68 | 75.48 | 71.29 | 67.09 | 62.90 | 58.71 | 54.51 | 50.32 |
| | | Stranded Capital | | | | | | | | 96.45 | | | | | | | | | | |
| | | Recovery | | | | | | | | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 | 4.19 |
| | | Net Stranded Capital | | | | | | | | 92.26 | 88.06 | 83.87 | 79.68 | 75.48 | 71.29 | 67.09 | 62.90 | 58.71 | 54.51 | 50.32 |
| | | Carrying charge | | | | | | | | 5.45 | 5.20 | 4.96 | 4.71 | 4.46 | 4.21 | 3.97 | 3.72 | 3.47 | 3.22 | 2.97 |
| | | ∑ | | | | | | | | 70.45 | 70.20 | 69.96 | 69.71 | 69.46 | 69.21 | 68.97 | 68.72 | 68.47 | 68.22 | 67.97 |
| | | Investment | 178.52 | | | | | | | | | | | | | | | | | |
| Gulf | | Expense | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 |
| | Smith Units 1-2 Rate: 2.9% Remaining life on Jan 2020: 11 and 13 years respectively | Reserve | 90.80 | 95.96 | 101.12 | 106.28 | 111.44 | 116.60 | 121.76 | 126.92 | 132.08 | 137.24 | 142.40 | 147.56 | 152.72 | 157.88 | 163.04 | 168.20 | 173.36 | 178.52 |
| | | Net Investment | 87.72 | 82.56 | 77.40 | 72.24 | 67.08 | 61.92 | 56.76 | 51.60 | 46.44 | 41.28 | 36.12 | 30.96 | 25.80 | 20.64 | 15.48 | 10.32 | 5.16 | 0.00 |
| | | Stranded Capital | | | | | | | | 56.76 | | | | | | | | | | |
| | | Recovery | | | | | | | | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 | 5.16 |
| | | Net Stranded Capital | | | | | | | | 51.60 | 46.44 | 41.28 | 36.12 | 30.96 | 25.80 | 20.64 | 15.48 | 10.32 | 5.16 | 0.00 |
| | | Carrying charge | | | | | | | | 3.05 | 2.74 | 2.44 | 2.13 | 1.83 | 1.52 | 1.22 | 0.91 | 0.61 | 0.30 | 0.00 |
| | | ∑ | | | | | | | | 8.21 | 7.90 | 7.60 | 7.29 | 6.99 | 6.68 | 6.38 | 6.07 | 5.77 | 5.46 | 5.16 |
| | | Investment | 360.46 | | | | | | | | | | | | | | | | | |
| | | Expense | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 |
| | | Reserve | 116.08 | 122.34 | 128.61 | 134.88 | 141.14 | 147.41 | 153.67 | 159.94 | 166.21 | 172.47 | 178.74 | 185.01 | 191.27 | 197.54 | 203.80 | 210.07 | 216.34 | 222.60 |
| | Scherer Unit 1 Rate: 1.7% Remaining life on Jan 2020: 33 years | Net Investment | 244.39 | 238.12 | 231.86 | 225.59 | 219.32 | 213.06 | 206.79 | 200.52 | 194.26 | 187.99 | 181.72 | 175.46 | 169.19 | 162.93 | 156.66 | 150.39 | 144.13 | 137.86 |
| | | Stranded Capital | | | | | | | | 206.79 | | | | | | | | | | |
| | | Recovery | | | | | | | | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 | 6.27 |
| | | Net Stranded Capital | | | | | | | | 200.52 | 194.26 | 187.99 | 181.72 | 175.46 | 169.19 | 162.93 | 156.66 | 150.39 | 144.13 | 137.86 |
| | | Carrying charge | | | | | | | | 11.85 | 11.48 | 11.11 | 10.74 | 10.37 | 10.00 | 9.63 | 9.26 | 8.89 | 8.52 | 8.15 |
| | | carrying charge total | | | | | | | | 70.27 | 66.57 | 62.88 | 59.18 | 55.48 | 51.79 | 48.09 | 44.39 | 40.70 | 37.00 | 33.31 |
| | | ∑ | | | | | | | | 18.12 | 17.75 | 17.38 | 17.01 | 16.64 | 16.27 | 15.90 | 15.52 | 15.15 | 14.78 | 14.41 |
| | Subtotal | | | | | | | | | 193.61 | 189.92 | 186.22 | 182.53 | 178.83 | 175.13 | 171.44 | 167.74 | 164.05 | 160.35 | 156.65 |
| Total Carrying charge | | | | | | | | | | 327.02 | 302.90 | 278.78 | 254.66 | 230.54 | 206.42 | 182.30 | 158.18 | 135.54 | 118.14 | 100.73 |
| Grand Total | | | | | | | | | | 601.79 | 580.99 | 560.20 | 539.41 | 518.61 | 497.82 | 477.03 | 456.23 | 373.67 | 359.59 | 345.51 |

**Note**:
1. Assuming there will be no plant activity (addition, retirement, transfer, etc.) starting from 1/1/2013.
2. Assuming there will be no reserve activity (removal, salvage, transfer, etc.) starting from 1/1/2013.
3. Depreciation rates for 2014 - 2019 are those that currently effective and approved by the Commission.
4. Stranded capital investment associated with a retired unit will be recovered within the service life of that unit.
5. Cost of the stranded capital investment is calculated using the average AFUDC rate referring to page 13.
6. This calculation does not address the depreciation of DEF's Crystal River units 1 and 2. DEF's last Commission-approved Depreciation Study assumed a 2020 retirement date for these two units. Based on a Revised and Restated Stipulation and Settlement Agreement currently presenting before the Commission, and if approved, DEF may allowed to recover in 2021 any remaining net book value existing at December 31, 2020 (details refers to Docket No. 130208-EI).

**Table 19: Analysis of the Dismantlement Costs Associated with the Retired Coal Units[1]**

| Utility | | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FPL | Dismantlement Cost | 68.55 | | | | | | | | | | | | | | | | | |
| | Reserve | 52.09 | 53.21 | 54.34 | 55.46 | 56.58 | 57.70 | 58.82 | | | | | | | | | | | |
| | Accrual | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | 1.12 | | | | | | | | | | | |
| | Deficient amount | 16.46 | 15.33 | 14.21 | 13.09 | 11.97 | 10.85 | 9.72 | | | | | | | | | | | |
| | Stranded Capital | | | | | | | | 9.72 | | | | | | | | | | |
| | Recovery | | | | | | | | 3.24 | 3.24 | 3.24 | | | | | | | | |
| | carrying charge | | | | | | | | 0.42 | 0.21 | 0.00 | | | | | | | | |
| | ∑ | | | | | | | | 3.66 | 3.45 | 3.24 | | | | | | | | |
| DEF[5] | Dismantlement Cost | 63.73 | | | | | | | | | | | | | | | | | |
| | Reserve | 21.89 | 23.79 | 25.69 | 27.59 | 29.50 | 31.40 | 33.30 | | | | | | | | | | | |
| | Accrual | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | 1.90 | | | | | | | | | | | |
| | Deficient amount | 41.85 | 39.94 | 38.04 | 36.14 | 34.24 | 32.34 | 30.43 | | | | | | | | | | | |
| | Stranded Capital | | | | | | | | 30.43 | | | | | | | | | | |
| | Recovery | | | | | | | | 10.14 | 10.14 | 10.14 | | | | | | | | |
| | carrying charge | | | | | | | | 1.48 | 0.74 | 0.00 | | | | | | | | |
| | ∑ | | | | | | | | 11.62 | 10.88 | 10.14 | | | | | | | | |
| TECO | Dismantlement Cost | 48.39 | | | | | | | | | | | | | | | | | |
| | Reserve | 67.58 | 66.71 | 65.83 | 64.96 | 64.09 | 63.22 | 62.35 | | | | | | | | | | | |
| | Accrual | (0.87) | (0.87) | (0.87) | (0.87) | (0.87) | (0.87) | (0.87) | | | | | | | | | | | |
| | Deficient amount | (19.18) | (18.31) | (17.44) | (16.57) | (15.69) | (14.82) | (13.95) | | | | | | | | | | | |
| | Stranded Capital | | | | | | | | (13.95) | | | | | | | | | | |
| | Recovery | | | | | | | | (4.65) | (4.65) | (4.65) | | | | | | | | |
| | carrying charge | | | | | | | | (0.66) | (0.33) | 0.00 | | | | | | | | |
| | ∑ | | | | | | | | (5.31) | (4.98) | (4.65) | | | | | | | | |
| Gulf | Dismantlement Cost | 229.71 | | | | | | | | | | | | | | | | | |
| | Reserve | 136.93 | 142.25 | 147.57 | 152.89 | 158.21 | 163.53 | 168.85 | | | | | | | | | | | |
| | Accrual | 5.32 | 5.32 | 5.32 | 5.32 | 5.32 | 5.32 | 5.32 | | | | | | | | | | | |
| | Deficient amount | 92.79 | 87.47 | 82.14 | 76.82 | 71.50 | 66.18 | 60.86 | | | | | | | | | | | |
| | Stranded Capital | | | | | | | | 60.86 | | | | | | | | | | |
| | Recovery | | | | | | | | 20.29 | 20.29 | 20.29 | | | | | | | | |
| | carrying charge | | | | | | | | 2.40 | 1.20 | 0.00 | | | | | | | | |
| | ∑ | | | | | | | | 22.69 | 21.49 | 20.29 | | | | | | | | |
| Total deficient fund | | | | | | | | | 29.02 | 29.02 | 29.02 | | | | | | | | |
| Total carrying charge | | | | | | | | | 3.64 | 1.82 | 0.00 | | | | | | | | |
| Total | | | | | | | | | 29.00 | 27.39 | 25.78 | | | | | | | | |

**Note:**

1. Assuming the cost of dismantlement for each affected coal unit will not be changed in the period 2014-2019. In reality, however, it increases almost every year.
2. This calculation does not address the salvages of the dismantled coal units.
3. Assuming the deficient dismantlement fund will be recovered within three years (2020-2022).
4. Cost of the deficient dismantlement fund is calculated using the average AFUDC rate referring to page 13.
5. This calculation does not address the dismantlement cost associated with Crystal River units 1 and 2. DEF's last Commission-approved Depreciation Study assumed a 2020 retirement date for these two units. Based on a Revised and Restated Stipulation and Settlement Agreement currently presenting before the Commission, and if approved, DEF may be allowed to recover in 2021 any remaining net book value existing at December 31, 2020 (details refers to Docket No. 130208-EI).

## Table 20: FPL 25 MW PV Solar Profile[1]

| | |
|---|---|
| Solar Energy Needed (Million MWh) | 0.266 |
| Capacity Needed (MW) | 128 |
| Total Overnight Construction Cost (Million $) | 822 |
| **Unit Construction Cost ($/KW)** | **6,430** |
| Fuel Saving (Million $) | (13.60) |
| Total O&M Cost (Million $) | 4.50 |
| **Unit O&M Cost ($/KW)** | 35.21 |
| Total Cost of Generation (Million $) | 94 |
| Net Generation Cost (Million $) | 80 |
| Depreciation Whole Life Rate | 3.3% |
| Annual Depreciation ( 2013 Million $) | 27.40 |

## Table 21: Solar Fuel Price

| Heat Rate (MMBTU/MWh)[2] | 2020 Fuel Price Projection | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Coal: 10.6 | Florida Case[3] | | | EIA Case[3] | | | Ohio Case[3] | | |
| NG: 7.05 | Low | Medium | High | Low | Medium | High | Low | Medium | High |
| Coal ($/MMBTU) | 3.03 | 3.15 | 3.29 | 2.79 | 2.90 | 3.03 | 2.25 | 2.51 | 2.90 |
| Solar ($/MMBTU) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Coal Replaced (GWH)[3] | 266 | 266 | 266 | 266 | 266 | 266 | 266 | 266 | 266 |
| Cost of Coal (Million$) | 8.54 | 8.87 | 9.27 | 7.87 | 8.18 | 8.55 | 6.35 | 7.08 | 8.18 |
| Cost of Solar (Million$) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Δ (Million$) | (8.54) | (8.87) | (9.27) | (7.87) | (8.18) | (8.55) | (6.35) | (7.08) | (8.18) |

## Table 21-a: Cost of Solar Units

| Solar | Total cost | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Cost | Overnight Capital Investment-Solar | 822 | | | | | | | | | | | |
| | Depreciation expense (Solar-Coal) | 25.45 | 25.45 | 25.45 | 25.45 | 25.45 | 25.45 | 25.45 | 25.45 | 25.55 | 25.91 | 25.91 | 280.99 |
| | Fuel Cost (Solar-Coal) | (8.88) | (9.11) | (9.36) | (9.64) | (9.90) | (10.18) | (10.43) | (10.72) | (11.03) | (11.31) | (11.62) | (112.18) |
| | O&M (Solar-Coal) | (0.11) | (0.11) | (0.11) | (0.11) | (0.11) | (0.11) | (0.11) | (0.11) | (0.11) | (0.11) | (0.11) | (0.11) |
| | Recovery of stranded assets (Coal Plants) | 1.95 | 1.95 | 1.95 | 1.95 | 1.95 | 1.95 | 1.95 | 1.95 | 1.85 | 1.50 | 1.50 | 20.45 |
| | Deficient fund_Coal Plant Dismantlement | 0.208 | 0.208 | 0.208 | | | | | | | | | |
| | Required return (Solar-Coal) | 81.51 | 78.81 | 76.10 | 73.40 | 70.70 | 68.00 | 65.30 | 62.60 | 59.88 | 57.13 | 54.38 | 747.8 |
| | Carrying charge of stranded assets | 2.37 | 2.18 | 2.00 | 1.82 | 1.65 | 1.48 | 1.31 | 1.13 | 0.97 | 0.85 | 0.72 | 16.5 |
| | Property taxes | 12.29 | 11.88 | 11.47 | 11.06 | 10.66 | 10.25 | 9.84 | 9.44 | 9.03 | 8.61 | 8.20 | 112.7 |
| | ∑ | **114.8** | **111.3** | **107.7** | **103.9** | **100.4** | **96.8** | **93.3** | **89.7** | **86.1** | **82.6** | **79.0** | **1,065.7** |
| **Solar** | **Depreciation** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **Total** |
| Depreciation | Overnight Capital Investment-Solar | 822.12 | | | | | | | | | | | |
| | Depreciation expenses of Solar units | 27.40 | 27.40 | 27.40 | 27.40 | 27.40 | 27.40 | 27.40 | 27.40 | 27.40 | 27.40 | 27.40 | 301.44 |
| | Plant balance-Solar | 794.72 | 767.31 | 739.91 | 712.50 | 685.10 | 657.70 | 630.29 | 602.89 | 575.48 | 548.08 | 520.68 | 7234.66 |
| | Plant balance-Coal units if not replaced | 28.78 | | | | | | | | | | | 28.78 |
| | Depreciation expenses of coal units if not replaced | 1.95 | 1.95 | 1.95 | 1.95 | 1.95 | 1.95 | 1.95 | 1.95 | 1.85 | 1.50 | 1.50 | 20.45 |
| | Recovery of stranded coal assets (coal units) | 1.95 | 1.95 | 1.95 | 1.95 | 1.95 | 1.95 | 1.95 | 1.95 | 1.85 | 1.50 | 1.50 | 20.45 |
| | Net stranded assets-coal units | 26.83 | 24.88 | 22.93 | 20.98 | 19.02 | 17.07 | 15.12 | 13.17 | 11.32 | 9.82 | 8.32 | **189.47** |
| **Solar** | **Capital cost** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **Total** |
| Capital Cost | Net rate base -Solar | 794.7 | 767.3 | 739.9 | 712.5 | 685.1 | 657.7 | 630.3 | 602.9 | 575.5 | 548.1 | 520.7 | |
| | Required net operating income-Solar | 51.7 | 49.9 | 48.1 | 46.3 | 44.5 | 42.8 | 41.0 | 39.2 | 37.4 | 35.6 | 33.8 | |
| | Required return - Solar | 84.4 | 81.4 | 78.5 | 75.6 | 72.7 | 69.8 | 66.9 | 64.0 | 61.1 | 58.2 | 55.3 | |
| | Net base - coal unit if not replaced | 26.83 | 24.88 | 22.93 | 20.98 | 19.02 | 17.07 | 15.12 | 13.17 | 11.32 | 9.82 | 8.32 | |
| | Required net operating income - coal units if not replaced | 1.74 | 1.62 | 1.49 | 1.36 | 1.24 | 1.11 | 0.98 | 0.86 | 0.74 | 0.64 | 0.54 | |
| | Required return on the investment of coal units if not replaced | 2.85 | 2.64 | 2.43 | 2.23 | 2.02 | 1.81 | 1.61 | 1.40 | 1.20 | 1.04 | 0.88 | |
| | Δ (Net base increase) | 767.9 | 742.4 | 717.0 | 691.5 | 666.1 | 640.6 | 615.2 | 589.7 | 564.2 | 538.3 | 512.4 | **7,045.2** |
| | Δ (Required net operating income) | 49.9 | 48.3 | 46.6 | 44.9 | 43.3 | 41.6 | 40.0 | 38.3 | 36.7 | 35.0 | 33.3 | **457.9** |
| | Δ (Required return) | 81.5 | 78.8 | 76.1 | 73.4 | 70.7 | 68.0 | 65.3 | 62.6 | 59.9 | 57.1 | 54.4 | **747.8** |

| | Heat Rate (MMBTU/MWh)[2] | Estimated (Nominal Million$) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Coal: 10.6 | | | | | | | | | | | | |
| | NG: 7.05 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | Total |
| **Fuel Price** | Coal ($/MMBTU) | 3.15 | 3.23 | 3.32 | 3.42 | 3.51 | 3.61 | 3.70 | 3.80 | 3.91 | 4.01 | 4.12 | |
| | Solar ($/MMBTU) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | |
| **Fuel Cost** | Coal Energy Need to be Replaced (GWH) | 266 | 266 | 266 | 266 | 266 | 266 | 266 | 266 | 266 | 266 | 266 | |
| | Cost of Coal (Million$) | 8.88 | 9.11 | 9.36 | 9.64 | 9.90 | 10.18 | 10.43 | 10.72 | 11.03 | 11.31 | 11.62 | |
| | Cost of Solar (Million$) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | |
| | Δ (Million$) | (8.88) | (9.11) | (9.36) | (9.64) | (9.90) | (10.18) | (10.43) | (10.72) | (11.03) | (11.31) | (11.62) | (112.2) |

1. Based on FPL's filing in Docket Nos. 100007-EI, 110007-EI, 120007-EI, 130007-EI. Cost does not include the expenses of purchasing or renting the land of the solar plants.
2. The heat rates are the average values of the 4 IOU's current coal units which was derived by reviewing the IOU's schedules filed in Docket No. 130001-EI.
3. Refer to page 1, 6c for details.

**Table 22: Estimated Status of Investor-Owned Utility Coal Generation in 2020[1]**

| Utility | Plant Name | Unit # | Location | Unit Type | Pri. Fuel Type | Pri. Fuel Trans. | Alt. Fuel Type | Alt. Fuel Trans. | Alt Fuel Storage (Days Burn) | Commercial In-Service Mo. | Commercial In-Service Year | Expected Retirement Mo. | Expected Retirement Year | Net (MW) Sum | Net (MW) Win | Status | Heat Rate (BTU/kWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| - | **All Investor-Owned Utilities** | | | | | | | | | | | | **ALL IOU TOTAL:** | **6,081** | **6,146** | | |
| - | **Florida Power & Light Company** | | | | | | | | | | | | **FPL TOTAL:** | **896** | **911** | | |
| FPL | Scherer (Joint Ownership) | 4 | Monroe, GA | ST | BIT | RR | --- | --- | 0 | 7 | 1988 | --- | ------- | 642 | 651 | OP | 10,544 |
| FPL | St. Johns River (Joint Ownership) | 1 | Duval | ST | BIT | RR | PC | WA | 0 | 4 | 1987 | --- | ------- | 127 | 130 | OP | 10,472 |
| FPL | St. Johns River (Joint Ownership) | 2 | Duval | ST | BIT | RR | PC | WA | 0 | 7 | 1988 | --- | ------- | 127 | 130 | OP | 9,610 |
| - | **Duke Energy Florida** | | | | | | | | | | | | **PEF TOTAL:** | **1,422** | **1,442** | | |
| PEF | Crystal River | 4 | Citrus | ST | BIT | WA | BIT | RR | 0 | 12 | 1982 | --- | ------- | 712 | 721 | OP | 10,503 |
| PEF | Crystal River | 5 | Citrus | ST | BIT | WA | BIT | RR | 0 | 10 | 1984 | --- | ------- | 710 | 721 | OP | 10,669 |
| - | **Tampa Electric Company** | | | | | | | | | | | | **TEC TOTAL:** | **1,762** | **1,792** | | |
| TECO | Big Bend | 1 | Hillsborough | ST | BIT | WA | BIT | RR | 0 | 10 | 1970 | --- | ------- | 385 | 395 | OP | 10,479 |
| TECO | Big Bend | 2 | Hillsborough | ST | BIT | WA | BIT | RR | 0 | 4 | 1973 | --- | ------- | 385 | 395 | OP | 10,391 |
| TECO | Big Bend | 3 | Hillsborough | ST | BIT | WA | BIT | RR | 0 | 5 | 1976 | --- | ------- | 365 | 365 | OP | 10,637 |
| TECO | Big Bend | 4 | Hillsborough | ST | BIT | WA | BIT | RR | 0 | 2 | 1985 | --- | ------- | 407 | 417 | OP | 10,437 |
| TECO | Polk | 1CA | Polk | CA | WH | NA | NA | NA | 0 | 9 | 1996 | --- | ------- | 220 | 220 | OP | 10,704 |
| - | **Gulf Power Company** | | | | | | | | | | | | **GPC TOTAL:** | **2,001** | **2,001** | | |
| GPC | Crist | 4 | Escambia | ST | BIT | WA | NG | PL | 0 | 7 | 1959 | --- | ------ | 75 | 75 | OP | 11,692 |
| GPC | Crist | 5 | Escambia | ST | BIT | WA | NG | PL | 0 | 6 | 1961 | --- | ------ | 75 | 75 | OP | 11,370 |
| GPC | Crist | 6 | Escambia | ST | BIT | WA | NG | PL | 0 | 5 | 1970 | --- | ------ | 299 | 299 | OP | 10,709 |
| GPC | Crist | 7 | Escambia | ST | BIT | WA | NG | PL | 0 | 8 | 1973 | --- | ------ | 475 | 475 | OP | 11,387 |
| GPC | Daniel (Joint Ownership) | 1 | Jackson, MS | ST | BIT | RR | RFO | TK | 0 | 9 | 1977 | --- | ------ | 251 | 251 | OP | 10,439 |
| GPC | Daniel (Joint Ownership) | 2 | Jackson, MS | ST | BIT | RR | RFO | TK | 0 | 6 | 1981 | --- | ------ | 251 | 251 | OP | 10,413 |
| GPC | Lansing Smith | 1 | Bay | ST | BIT | WA | --- | --- | 0 | 6 | 1965 | --- | ------ | 162 | 162 | OP | 10,800 |
| GPC | Lansing Smith | 2 | Bay | ST | BIT | WA | --- | --- | 0 | 6 | 1967 | --- | ------ | 195 | 195 | OP | 11,104 |
| GPC | Scherer (Joint Ownership) | 3 | Monroe, GA | ST | BIT | RR | --- | --- | 0 | 1 | 1987 | --- | ------ | 218 | 218 | OP | 10,588 |

**Table 22-a: Existing Investor-Owned Utility Coal-Fired Generating Units (12/31/2012) - 2013 FRCC Load & Resource Plan[2]**

| Utility | Plant Name | Unit # | Location | Unit Type | Pri. Fuel Type | Pri. Fuel Trans. | Alt. Fuel Type | Alt. Fuel Trans. | Alt Fuel Storage (Days Burn) | Commercial In-Service Mo. | Commercial In-Service Year | Expected Retirement Mo. | Expected Retirement Year | Net (MW) Sum | Net (MW) Win | Status |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| - | **All Investor-Owned Utilities** | | | | | | | | | | | | **ALL IOU TOTAL:** | **7,029** | **7,100** | |
| - | **Florida Power & Light Company** | | | | | | | | | | | | **FPL TOTAL:** | **896** | **911** | |
| FPL | Scherer (Joint Ownership) | 4 | Monroe, Ga | ST | BIT | RR | --- | --- | 0 | 7 | 1988 | --- | ------- | 642 | 651 | OP |
| FPL | St. Johns River (Joint Ownership) | 1 | Duval | ST | BIT | RR | PC | WA | 0 | 4 | 1987 | --- | ------- | 127 | 130 | OP |
| FPL | St. Johns River (Joint Ownership) | 2 | Duval | ST | BIT | RR | PC | WA | 0 | 7 | 1988 | --- | ------- | 127 | 130 | OP |
| - | **Duke Energy Florida** | | | | | | | | | | | | **PEF TOTAL:** | **2,291** | **2,317** | |
| PEF | Crystal River | 1 | Citrus | ST | BIT | RR | BIT | WA | 0 | 10 | 1966 | 4 | 2016 | 370 | 372 | OP |
| PEF | Crystal River | 2 | Citrus | ST | BIT | RR | BIT | WA | 0 | 11 | 1969 | 4 | 2016 | 499 | 503 | OP |
| PEF | Crystal River | 4 | Citrus | ST | BIT | WA | BIT | RR | 0 | 12 | 1982 | --- | ------- | 712 | 721 | OP |
| PEF | Crystal River | 5 | Citrus | ST | BIT | WA | BIT | RR | 0 | 10 | 1984 | --- | ------- | 710 | 721 | OP |
| - | **Tampa Electric Company** | | | | | | | | | | | | **TEC TOTAL:** | **1,762** | **1,792** | |
| TECO | Big Bend | 1 | Hillsborough | ST | BIT | WA | BIT | RR | 0 | 10 | 1970 | --- | ------- | 385 | 395 | OP |
| TECO | Big Bend | 2 | Hillsborough | ST | BIT | WA | BIT | RR | 0 | 4 | 1973 | --- | ------- | 385 | 395 | OP |
| TECO | Big Bend | 3 | Hillsborough | ST | BIT | WA | BIT | RR | 0 | 5 | 1976 | --- | ------- | 365 | 365 | OP |
| TECO | Big Bend | 4 | Hillsborough | ST | BIT | WA | BIT | RR | 0 | 2 | 1985 | --- | ------- | 407 | 417 | OP |
| TECO | Polk | 1CA | Polk | CA | WH | NA | NA | NA | 0 | 9 | 1996 | --- | ------- | 59 | 45 | OP |
| TECO | Polk | 1CT | Polk | CT | OG | WA | DFO | TK | 43 | 9 | 1996 | --- | ------- | 161 | 175 | OP |
| - | **Gulf Power Company** | | | | | | | | | | | | **GPC TOTAL:** | **2,080** | **2,080** | |
| GPC | Crist | 4 | Escambia | ST | BIT | WA | NG | PL | 0 | 7 | 1959 | --- | ------ | 75 | 75 | OP |
| GPC | Crist | 5 | Escambia | ST | BIT | WA | NG | PL | 0 | 6 | 1961 | --- | ------ | 75 | 75 | OP |
| GPC | Crist | 6 | Escambia | ST | BIT | WA | NG | PL | 0 | 5 | 1970 | --- | ------ | 288 | 288 | OP |
| GPC | Crist | 7 | Escambia | ST | BIT | WA | NG | PL | 0 | 8 | 1973 | --- | ------ | 465 | 465 | OP |
| GPC | Daniel | 1 | Jackson, Ms | ST | BIT | RR | RFO | TK | 0 | 9 | 1977 | --- | ------ | 255 | 255 | OP |
| GPC | Daniel | 2 | Jackson, Ms | ST | BIT | RR | RFO | TK | 0 | 6 | 1981 | --- | ------ | 255 | 255 | OP |
| GPC | Lansing Smith | 1 | Bay | ST | BIT | WA | --- | --- | 0 | 6 | 1965 | --- | ------ | 162 | 162 | OP |
| GPC | Lansing Smith | 2 | Bay | ST | BIT | WA | --- | --- | 0 | 6 | 1967 | --- | ------ | 195 | 195 | OP |
| GPC | Scherer | 3 | Monroe, Ga | ST | BIT | RR | --- | --- | 0 | 1 | 1987 | --- | ------ | 218 | 218 | OP |
| GPC | Scholz | 1 | Jackson, Ms | ST | BIT | RR | --- | --- | | 3 | 1953 | 4 | 2015 | 46 | 46 | OP |
| GPC | Scholz | 2 | Jackson, Ms | ST | BIT | RR | --- | --- | | 10 | 1953 | 4 | 2015 | 46 | 46 | OP |

Note: 1. Above Calculation Based on IOUs' 2013 Ten-Year Site Plan and the associated data request responses.

2. Capacity difference between the above two tables are the planned changes of the coal-fired generating units (2013 to 2022). Source: 2013 FRCC Load & Resource Plan.

**Table 23: 2013 Ten-Year Site Plan Schedule 6.1 - Fuel Consumption (Coal Entry)**

| Utility | Energy Source | | Units | Actual | | Projected | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Category | Sub-Category | | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| FPL | Coal | - | GWH | 5,634 | 4,745 | 4,884 | 5,211 | 5,931 | 5,400 | 6,069 | 6,088 | 6,609 | **6,890** | 7,073 | 7,066 |
| DEF | Coal | - | GWH | 10,809 | 10,003 | 11,761 | 11,758 | 12,003 | 10,882 | 10,952 | 10,456 | 9,926 | **8,777** | 8,336 | 8,288 |
| TECO | Coal | - | GWH | 9,657 | 9,720 | 10,049 | 9,658 | 10,099 | 10,198 | 10,473 | 10,477 | 10,486 | **10,566** | 10,488 | 10,493 |
| GULF | Coal | - | GWH | 8,090 | 5,391 | 6,099 | 6,310 | 5,996 | 7,741 | 8,994 | 9,285 | 10,164 | **10,912** | 11,136 | 11,389 |
| **SUM** | **Coal** | **-** | **GWH** | **34,190** | **29,859** | **32,793** | **32,936** | **34,029** | **34,221** | **36,488** | **36,306** | **37,185** | **37,144** | **37,033** | **37,236** |

**Table 23-a**

| Fuel Replacement: Goal to NG | | |
|---|---|---|
| NGCC Heat Rate[2] | 7,050 | BTU/kWh |
| Conversion 1 | 6.89 | MCF/MWh |
| Goal Heat Rate[3] | 10,600 | BTU/kWh |

**Note:** 1. Portion which is associated with Scherer Unit 4 and St John River Units 1 & 2.
2. Data Source: EIA Updated Capital Cost Estimates for Electricity Generation Plants, Nov. 2010.
3. Data source: Florida IOU's reports in Schedule A, Docket No. 130001-EI.

**Table 23-b: Additional Natural Gas Required to Replace Coal Generation**

| Utility | Energy Source | | Units | Actual | | Projected | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Category | Sub-Category | | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
| FPL | Natural Gas | Combined Cycle | 1000 MCF | 38,827 | 32,702 | 33,661 | 35,910 | 40,874 | 37,212 | 41,825 | 41,953 | 45,548 | **47,482** | 48,745 | 48,698 |
| DEF | Natural Gas | Combined Cycle | 1000 MCF | 74,490 | 68,936 | 81,050 | 81,029 | 82,718 | 74,996 | 75,477 | 72,060 | 68,405 | **60,484** | 57,446 | 57,116 |
| TECO | Natural Gas | Combined Cycle | 1000 MCF | 66,554 | 66,982 | 69,253 | 66,558 | 69,597 | 70,279 | 72,175 | 72,202 | 72,264 | **72,816** | 72,278 | 72,312 |
| GULF | Natural Gas | Combined Cycle | 1000 MCF | 55,752 | 37,152 | 42,031 | 43,485 | 41,321 | 53,347 | 61,982 | 63,988 | 70,045 | **75,200** | 76,744 | 78,487 |
| **SUM** | **Natural Gas** | **Combined Cycle** | **1000 MCF** | **235,623** | **205,771** | **225,995** | **226,982** | **234,511** | **235,834** | **251,459** | **250,202** | **256,262** | **255,981** | **255,212** | **256,614** |

**Table 24: Fuel Price Forecasting**[1]

| | | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Natural Gas** | nominal $ /MMBTU | 6.38 | 6.74 | 7.12 | 7.51 | 7.91 | 8.33 | 8.68 | 9.04 | 9.42 | 9.8 | 10.18 |
| **Coal** | nominal $ /MMBTU | 3.15 | 3.23 | 3.32 | 3.42 | 3.51 | 3.61 | 3.7 | 3.8 | 3.91 | 4.01 | 4.12 |

**Table 24-a: CO2 Emission Rates of Considered Fuel**[2]

| | (Lbs/MWh) | (Metric Tons/MWh)[3] | Reduced Emission Rate by Switching Coal to Gas (Metric Tons/MWh) |
|---|---|---|---|
| **Coal_Bituminous** | 2080 | 0.9434672 | 0.3900874 |
| **Coal_Sub-bituminous** | 2150 | 0.9752185 | 0.4218387 |
| **Coal_Lignite** | 2180 | 0.9888262 | 0.4354464 |
| **Natural Gas** | 1220 | 0.5533798 | |

**Table 24-b: 2020 Fuel Price Forecasts**

| | EIA Projection[4] ($/mmBtu) | Florida Case[5] ($/mmBtu) | Ohio Case[6] ($/mmBtu) |
|---|---|---|---|
| **Low Gas** | 5.53 | 6.25 | 5.00 |
| **Medium Gas** | 5.65 | **6.38** | 6.15 |
| **High Gas** | 5.81 | 6.57 | 8.00 |
| **Low Coal** | 2.79 | 3.03 | 2.25 |
| **Medium Coal** | 2.90 | **3.15** | 2.51 |
| **High Coal** | 3.03 | 3.29 | 2.90 |

**Note:**

1. Source: DEF's Fuel Forecast in Docket No. 130009-EI.
2. Source: EIA, last updated June 13, 2013.
3. 1 Lb = 4.5359 x $10^{-4}$ metric ton.
4. Source: EIA Annual Energy Outlook 2013.
5. EIA Annual Energy Outlook 2013 adjusted by average Florida IOU's fuel delivery expenses.
6. Fuel price forecasts used in Ohio's study.

## Table 25: Inputs of the Depreciation Analysis

| Utility | Plant Name | Unit # | Location | 12/31/12 Investment | 12/31/12 Reserve | ( As of January 1, 2013) Net Investment Balance | Depreciation Expense | ( As of Jan 1, 2013) Depreciation Rate* |
|---|---|---|---|---|---|---|---|---|
| - | **Florida Power & Light Company** | | | | | | | |
| FPL | Scherer (Joint Ownership) | 4 | Monroe, Ga | $1,064,204,282 | $274,913,669 | $789,290,613 | $20,692,588 | 4.6% |
| FPL | St. Johns River (Joint Ownership) | 1 | Duval | $385,163,050 | $176,368,070 | $208,794,980 | $9,698,543 | 3.6% |
| FPL | St. Johns River (Joint Ownership) | 2 | Duval | Included in Unit 1 | Included in Unit 1 | n/a | n/a | n/a |
| | | | | | | | | |
| - | **Duke Energy Florida** | | | | | | | |
| PEF | Crystal River | 1 | Citrus | $438,725,939 | $333,059,905 | $105,666,034 | $13,901,752 | n/a |
| PEF | Crystal River | 2 | Citrus | Included in Unit 1 | Included in Unit 1 | n/a | n/a | n/a |
| PEF | Crystal River | 4 | Citrus | $2,344,575,270 | $671,127,822 | $1,673,447,448 | $48,762,320 | 3.2% |
| PEF | Crystal River | 5 | Citrus | Included in Unit 4 | Included in Unit 4 | n/a | n/a | n/a |
| | | | | | | | | |
| | | | | | | | | |
| - | **Tampa Electric Company** | | | | | | | |
| TECO | Big Bend | 1 | Hillsborough | $1,917,201,000 | $637,930,000 | $1,279,271,000 | $61,338,000 | 3.0% |
| TECO | Big Bend | 2 | Hillsborough | Included in Unit 1 | Included in Unit 1 | n/a | n/a | n/a |
| TECO | Big Bend | 3 | Hillsborough | Included in Unit 1 | Included in Unit 1 | n/a | n/a | n/a |
| TECO | Big Bend | 4 | Hillsborough | Included in Unit 1 | Included in Unit 1 | n/a | n/a | n/a |
| TECO | Polk | 1CA | Polk | $524,435,000 | $239,905,000 | $284,530,000 | $18,419,000 | 2.4% |
| | | | | | | | | |
| | | | | | | | | |
| - | **Gulf Power Company** | | | | | | | |
| GPC | Crist | 4 | Escambia | $1,498,797,427 | $278,847,076 | $1,219,950,351 | $47,907,015 | 3.1% |
| GPC | Crist | 5 | Escambia | Included in Unit 4 | Included in Unit 4 | n/a | n/a | n/a |
| GPC | Crist | 6 | Escambia | Included in Unit 4 | Included in Unit 4 | n/a | n/a | n/a |
| GPC | Crist | 7 | Escambia | Included in Unit 4 | Included in Unit 4 | n/a | n/a | n/a |
| GPC | Daniel * | 1 | Jackson, Ms | $268,892,283 | $143,089,438 | $125,802,845 | $7,158,100 | 1.6% |
| GPC | Daniel * | 2 | Jackson, Ms | Included in Unit 1 | Included in Unit 1 | n/a | n/a | n/a |
| GPC | Lansing Smith | 1 | Bay | $178,517,299 | $85,640,136 | $92,877,163 | $6,010,516 | 2.9% |
| GPC | Lansing Smith | 2 | Bay | Included in Unit 1 | Included in Unit 1 | n/a | n/a | n/a |
| GPC | Scherer * | 3 | Monroe, Ga | $360,463,758 | $109,809,622 | $250,654,136 | $7,186,399 | 1.7% |
| GPC | Scholz | 1 | Jackson, Ms | $30,936,579 | $29,561,406 | $1,375,173 | $1,293,226 | n/a |
| GPC | Scholz | 2 | Jackson, Ms | Included in Unit 1 | Included in Unit 1 | n/a | n/a | n/a |

**Notes:**

1. Data are compiled using each IOU's latest Depreciation Study.
2. Numbers exclude ARO and Dismantlement.
3. Numbers are as of 12/31/12.
4. For Polk, Common & Tools Amortization are included based on Unit 1's % of total Polk, for plant, reserve, and depreciation expense.

*Effective rate

**Table 26: Existing Investor-Owned Utility Coal-Fired Generating Units Dismantlement Costs and Reserve**

| Utility | Plant Name | Unit # | Location | Commercial In-Service | | Expected Retirement | | Retirement Date | Dismantlement Cost | Study Year | Remaining Life on Jan | | Reserve Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Mo. | Year | Mo. | Year | | | | 2013 | 2020 | |
| - | **All Investor-Owned Utilities** | | | | | | **ALL IOU TOTAL:** | | | | | | |
| | | | | | | | | | | | | | |
| - | **Florida Power & Light Company** | | | | | | **FPL TOTAL:** | | | | | | |
| FPL | Scherer (Joint Ownership) | 4 | Monroe, Ga | 7 | 1988 | --- | ------- | 29-Jan | $ 43,744,940 | 2009 | 16 | 9 | $ 31,776,673 |
| FPL | St. Johns River (Joint Ownership) | 1 | Duval | 4 | 1987 | --- | ------- | 28-Jan | $ 12,401,487 | 2009 | 15 | 8 | $ 9,651,406 |
| FPL | St. Johns River (Joint Ownership) | 2 | Duval | 7 | 1988 | --- | ------- | 28-Jan | $ 12,401,487 | 2009 | 15 | 8 | $ 9,541,018 |
| Total | | | | | | | | | $ 68,547,915 | | | | $ 50,969,096 |
| | | | | | | | | | | | | | |
| - | **Duke Energy Florida** | | | | | | **PEF TOTAL:** | | | | | | |
| PEF | Crystal River | 1 | Citrus | 10 | 1966 | 4 | 2016 | Jan-20 | $ 17,300,104 | 2008 | | | $ 18,385,558 |
| PEF | Crystal River | 2 | Citrus | 11 | 1969 | 4 | 2016 | Jan-20 | $ 17,300,104 | 2008 | | | $ 18,385,558 |
| PEF | Crystal River | 4 | Citrus | 12 | 1982 | --- | ------- | Jan-35 | $ 14,566,821 | 2008 | 22 | 15 | $ 10,944,008 |
| PEF | Crystal River | 5 | Citrus | 10 | 1984 | --- | ------- | Jan-35 | $ 14,566,821 | 2008 | 22 | 15 | $ 10,944,008 |
| Total | | | | | | | | | $ 63,733,851 | | | | $ 58,659,131 |
| | | | | | | | | | | | | | |
| - | **Tampa Electric Company** | | | | | | **TEC TOTAL:** | | | | | | |
| TECO | Big Bend | 1 | Hillsborough | 10 | 1970 | --- | ------- | Jan-35 | $ 12,172,200 | 2012 | 22 | 15 | $ 16,483,342 |
| TECO | Big Bend | 2 | Hillsborough | 4 | 1973 | --- | ------- | Jan-38 | $ 12,171,700 | 2012 | 25 | 18 | $ 16,326,292 |
| TECO | Big Bend | 3 | Hillsborough | 5 | 1976 | --- | ------- | Jan-41 | $ 12,033,650 | 2012 | 28 | 21 | $ 15,645,787 |
| TECO | Big Bend | 4 | Hillsborough | 2 | 1985 | --- | ------- | Jan-50 | $ 12,010,250 | 2012 | 37 | 30 | $ 15,567,597 |
| TECO | Polk | 1CA | Polk | 9 | 1996 | --- | ------- | Jan-36 | $ 6,880 | 2012 | 23 | 16 | $ 3,554,061 |
| TECO | Polk | 1CT | Polk | 9 | 1996 | --- | ------- | | | | | | |
| Total | | | | | | | | | $ 48,394,680 | | | | $ 67,577,080 |
| | | | | | | | | | | | | | |
| - | **Gulf Power Company** | | | | | | **GPC TOTAL:** | | | | | | |
| GPC | Crist | 4 | Escambia | 7 | 1959 | --- | ------ | 24-Dec | $ 32,394,750 | 2013 | 12 | 5 | $ 13,696,878 |
| GPC | Crist | 5 | Escambia | 6 | 1961 | --- | ------ | 26-Dec | $ 32,470,750 | 2013 | 14 | 7 | $ 13,604,679 |
| GPC | Crist | 6 | Escambia | 5 | 1970 | --- | ------ | Dec-35 | $ 47,184,750 | 2013 | 23 | 16 | $ 22,615,810 |
| GPC | Crist | 7 | Escambia | 8 | 1973 | --- | ------ | Dec-38 | $ 49,612,750 | 2013 | 26 | 19 | $ 24,972,299 |
| GPC | Daniel * | 1 | Jackson, Ms | 9 | 1977 | --- | ------ | Dec-42 | $ 7,873,250 | 2013 | 30 | 23 | $ 9,839,883 |
| GPC | Daniel * | 2 | Jackson, Ms | 6 | 1981 | --- | ------ | Dec-46 | $ 7,898,750 | 2013 | 34 | 27 | $ 10,100,485 |
| GPC | Lansing Smith | 1 | Bay | 6 | 1965 | --- | ------ | 30-Dec | $ 14,763,500 | 2013 | 18 | 11 | $ 11,261,984 |
| GPC | Lansing Smith | 2 | Bay | 6 | 1967 | --- | ------ | Dec-32 | $ 15,619,500 | 2013 | 20 | 13 | $ 11,591,478 |
| GPC | Scherer * | 3 | Monroe, Ga | 1 | 1987 | --- | ------ | Dec-52 | $ 10,464,000 | 2013 | 40 | 33 | $ 5,143,641 |
| GPC | Scholz | 1 | Jackson, Ms | 3 | 1953 | 4 | 2015 | 15-Apr | $ 5,732,500 | 2013 | | | $ 7,077,656 |
| GPC | Scholz | 2 | Jackson, Ms | 10 | 1953 | 4 | 2015 | 15-Apr | $ 5,699,500 | 2013 | | | $ 7,023,813 |
| Total | | | | | | | | | $ 229,714,000 | | | | $ 136,928,607 |

**Table 27: Megawatt Generation by Coal Unit and the Amount of $CO_2$ Emission in 2012[1]**

| Utility | FPL | | | Duke | | | | Gulf | | | | | | | | | | Tampa Electric | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Plant | Scherer 4 | St. John's 1 | St. John's 2 | CR1 | CR2 | CR4 | CR5 | Crist 4 | Crist 5 | Crist 6 | Crist 7 | Scholz 1 | Scholz 2 | Smith 1 | Smith 2 | Daniel 1 | Daniel 2 | BB1 | BB2 | BB3 | BB4 | Polk 1 |
| | | | | | | | | | | | | | | | | | | | | | | |
| Jan | 261137 | 8834 | 39298 | 78819 | 50933 | 287051 | 119879 | 12968 | 12510 | 13097 | 147625 | -241 | -200 | 54180 | -556 | 18633 | 54024 | 182370 | 266190 | 211982 | 289036 | 22370 |
| Feb | 251206 | 23727 | 37527 | 94269 | 7389 | 287338 | 288878 | -922 | 26701 | -3642 | 133422 | -191 | -206 | 50839 | -472 | -1171 | -828 | 249783 | 232802 | 212105 | 279663 | -2725 |
| Mar | 18626 | 61541 | 0 | 114584 | 39795 | 401376 | 372595 | 2276 | 32081 | -3495 | 138249 | -265 | -131 | 51768 | -445 | 14519 | 101640 | 267166 | 185179 | 151091 | 294024 | 105205 |
| April | -1256 | 50088 | 48017 | 134936 | 181021 | 351927 | 316985 | 5197 | 25662 | 21001 | 129812 | -142 | -179 | 41846 | 38887 | -1245 | 137740 | 10989 | 136452 | 177651 | 236477 | 145587 |
| May | 231512 | 48402 | 48788 | 98916 | 189065 | 394088 | 347097 | -855 | 26418 | 156777 | 104870 | -296 | -157 | 32249 | 50981 | 38136 | 50675 | 4308 | 258070 | 221808 | 105642 | 97932 |
| June | 367222 | 60785 | 62649 | 108465 | 149783 | 360276 | 330791 | 5678 | 28613 | 118456 | 150473 | -248 | -172 | 52221 | -767 | 57769 | 22537 | 121312 | 236927 | 120084 | 236731 | -4275 |
| July | 436883 | 67938 | 71987 | 105583 | 167899 | 412381 | 405529 | -1546 | 24594 | 55943 | 145892 | 3075 | 2902 | 57983 | 55339 | 130008 | 45765 | 240845 | 240973 | 132924 | 181613 | 113827 |
| Aug | 360929 | 67811 | 69197 | 100411 | 157800 | 371701 | 390603 | -872 | 31036 | 77128 | 151825 | -270 | -179 | 52462 | 51886 | 63387 | 59421 | 211771 | 203358 | 192711 | 294808 | 165849 |
| Sept | 392719 | 62763 | 67227 | 91469 | 132039 | 351688 | 349109 | -1064 | 31827 | 134127 | -1646 | -242 | -169 | 21309 | 5175 | -1593 | -878 | 227394 | 150357 | 206929 | 221321 | 113512 |
| Oct | 428609 | 58858 | 57324 | 106320 | 99188 | 416683 | 266316 | -1003 | 29382 | 131626 | -717 | -228 | -157 | -651 | 52751 | 11000 | -914 | 264740 | 241512 | 187121 | 145757 | 161320 |
| Nov | 426096 | 52826 | 54025 | 36069 | 107370 | 420720 | 0 | 20893 | 11382 | 95832 | -750 | -235 | -161 | 30906 | 34164 | 83541 | -764 | 147843 | 203738 | 186394 | 203116 | 146068 |
| Dec | 334601 | 58582 | 58918 | 15726 | 135436 | 317291 | 1181 | 31543 | -669 | 98529 | 71942 | -239 | -168 | 56702 | -278 | -1215 | -567 | 225667 | 163607 | 219202 | 134039 | 110281 |
| | | | | | | | | | | | | | | | | | | | | | | |
| Total | 3508284 | 622155 | 614957 | 1085567 | 1417718 | 4372520 | 3188963 | 72293 | 279537 | 895379 | 1170997 | 478 | 1023 | 501814 | 286665 | 411769 | 467851 | 2154188 | 2519165 | 2220002 | 2622227 | 1174951 |
| FPL ∑ | 4745396 | | | | | | | | | | | | | | | | | | | | | |
| Plant ∑ | 3508284 | 1237112 | | | | | | | | | | | | | | | | | | | | |
| | 73.9% | 26.1% | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | |
| ∑ | 29588503 | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | |
| **Table 27-a: $CO_2$ Emission Amounts** | | | | | | | | | | | | | | | | | | | | | | |
| **Rate lb/MWh** | 2215 | 2180 | 2157 | 2158 | 1958 | 2155 | 2050 | 2203 | 2250 | 2271 | 2173 | 2726 | 2748 | 2030 | 22042 | 2218 | 2271 | 2251 | 2045 | 2402 | 2187 | 1504 |
| **Rate Ton/MWh** | 1.005 | 0.989 | 0.978 | 0.979 | 0.888 | 0.977 | 0.930 | 0.999 | 1.021 | 1.030 | 0.986 | 1.236 | 1.246 | 0.921 | 9.998 | 1.006 | 1.030 | 1.021 | 0.928 | 1.090 | 0.992 | 0.682 |
| **Metric Tons** | 3524798 | 615206 | 601673 | 1062610 | 1259123 | 4274101 | 2965303 | 72240 | 285291 | 922337 | 1154200 | 591 | 1275 | 462067 | 2866100 | 414268 | 481937 | 2199504 | 2336768 | 2418756 | 2601266 | 801555 |
| **∑** | 4741677 | | | 9561138 | | | | 6660306 | | | | | | | | | | 10357850 | | | | |
| **Total** | **31320972** | **(Million Lbs)** | | | | | | | | | | | | | | | | | | | | |

**Note:** 1. Calculated based on IOUs' filings in Docket o. 130001-EI.

**Table 28: Summary of Emission Reductions by FPL's Solar Plants[1] (2012)**

| | CO2 (Tons) | CO2 (Ton/MW) | Nox (Tons) | SO2 (Tons) | Hg (lbs) |
|---|---|---|---|---|---|
| DeSoto | 45,903 | 1,836 | 62 | 57 | 5 |
| Space Coast | 16,621 | 1,662 | 22 | 24 | 2 |
| Martin | 74,883 | 998 | 115 | 83 | 6 |
| Total | 137,407 | | 199 | 164 | 13 |

**Table 28-a: Generation Performance[1]**

| | Net Capacity (MW) | Net Generation (MWh) | Capacity Factor (%) | Coal Displaced (Tons) | Fuel Saving | |
|---|---|---|---|---|---|---|
| | | | | | ($) | ($/MWh) |
| DeSoto | 25 | 52,025 | 23.7% | 6,757 | 2,659,750 | 51.12 |
| Space Coast | 10 | 18,509 | 21.1% | 2,422 | 943,849 | 50.99 |
| Martin | 75 | 88,734 | 13.5% | 9,232 | 4,777,971 | 53.85 |
| Total | 110 | 159,268 | 16.5% | 18,411 | 8,381,570 | 52.63 |

**Table 28-b: Costs of Solar Plants Period of January - December 2012[1]**

| | O&M Cost | | Carrying Costs[2] ($) | Capital Costs[3] ($) | Other[4] ($) | Total Cost of Generation | | Net Cost of Generation | |
|---|---|---|---|---|---|---|---|---|---|
| | ($) | ($/KW) | | | | ($) | ($/MWh) | ($) | ($/MWh) |
| DeSoto | 880,203 | 35.2 | 14,274,086 | 5,002,510 | (1,852,032) | 18,304,767 | 351.8 | 15,645,017 | 300.7 |
| Space Cost | 197,650 | 19.8 | 6,670,993 | 2,337,335 | (772,212) | 8,433,766 | 455.7 | 7,489,917 | 404.7 |
| Martin | 4,803,324 | 64.0 | 39,713,501 | 13,347,856 | (5,074,848) | 52,789,833 | 594.9 | 48,011,862 | 541.1 |
| Total | 5,881,177 | 53.5 | 60,658,580 | 20,687,701 | (7,699,092) | 79,528,366 | 499.3 | 71,146,796 | 446.7 |

**Table 28-c: Construction Costs of Solar Plants[5]**

| | DeSoto | Space Coast | Martin | Total |
|---|---|---|---|---|
| Total Capacity (MW) | 25 | 10 | 75 | 110 |
| Plant Life (years) | 30 | 30 | 30 | |
| Technology Used | PV with tracking | PV fixed | Thermal | |
| Average Fixed Annual O&M | 1.7 | 1.0 | 3.8 | 6.5 |
| Construction Cost[6] (2013 $) | $160,761,911 | $70,633,125 | $405,249,324 | $636,644,360 |
| ($ Million/MW) | **$6.43** | **$7.06** | **$5.40** | |

Note:
1. Calculated based on FPL's filings in Docket No. 130007-EI.
2. Carrying cost represents return on average investment.
3. Capital cost represents depreciation expense on net investment.
4. Other cost represents dismantlement costs and amortization on ITC.
5. Data based on FPL's filings in Docket Nos. 110007-EI and 120007-EI
6. Based on filings in Docket Nos. 100007-EI, 110007-EI and 120007-EI. It does not include the expenses of purchasing or renting the land of the solar plants.

## Table 29: Megawatt Generation by Coal Unit in 2012[1]

| Company | FPL | | | Duke | | | Gulf | | | | | Tampa Electric | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Plant | Martin 1-2 | Martin 8 | | Bayboro | Debary | | Smith 2 | Smith CTA | Perdido | Pea Ridge 1-2 | | Bayside 1-2 | Bayside 3-6 |
| | | | | | | | | | | | | | |
| January (A4) | 18993 | 517695 | | N/A | 500 | | -556 | N/A | 2238 | N/A | | 409983 | 5096 |
| February (A4) | 11620 | 470918 | | 1589.6 | 987 | | -472 | N/A | 2092 | N/A | | 310069 | 7917 |
| March (A4) | 190476 | 660772 | | 2036.8 | 5047 | | -445 | N/A | 2202 | N/A | | 355663 | 7744 |
| April (A4) | 182564 | 613616 | | 0 | 9109 | | 38887 | N/A | 2099 | N/A | | 577863 | 10615 |
| May (A4) | 358311 | 640658 | | 394.6 | 5899 | | 50981 | N/A | 2175 | N/A | | 821271 | 9564 |
| June (A4) | 302194 | 641139 | | 448.5 | 1465 | | -767 | N/A | 2108 | N/A | | 857417 | 6465 |
| July (A4) | 350726 | 658070 | | 0 | 10945 | | 55339 | N/A | 2156 | N/A | | 862901 | 3837 |
| August (A4) | 376167 | 653392 | | N/A | 11160 | | 51886 | N/A | 1920 | N/A | | 745409 | 5294 |
| September (A4) | 358269 | 608510 | | 326.6 | 1398 | | 51705 | N/A | 2045 | N/A | | 762002 | 4638 |
| October (A4) | 255884 | 623245 | | 0 | 3358 | | 52751 | N/A | 2070 | N/A | | 575742 | 4682 |
| November (A4) | 73640 | 412563 | | 198.8 | 629 | | 34164 | N/A | 1982 | N/A | | 345075 | 4732 |
| December (A4) | 44187 | 578321 | | 0 | 718 | | -278 | N/A | 2153 | N/A | | 418392 | 7158 |
| | | | | | | | | | | | | | |
| Total | 2523031 | 7078899 | | 4994.9 | 51215 | | 333195 | 0 | 25240 | 0 | | 7041787 | 77742 |
| | | | | | | | | | | | | | |
| ∑ Old GTs | 2656982.9 | | | | | | | | | | | | |

## Table 29-a: CO2 Emission Status

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rate lb/MWh | 1736 | | | 2093 | 2248 | | | | 2280 | | | | 1111 |
| Million lbs | 4380 | | | 10 | 115 | | | | 58 | | | | 86 |
| ∑ | **4592** | | | | | | | | 58 | | | | |
| | **2.083** | | | | | | | | **0.026** | | | | |
| Emission reduction | | | | | | | | | | | | | |

**Note:** 1. Calculated based on IOUs' filings in Docket o. 130001-EI.

**Table 30: Other Sources of CO2 reductions[1]**

| FPL | 48 GTs Net Generation (MWh) | | | | Grand Total |
|---|---|---|---|---|---|
| **Plant** | Ft Myers 1-12 | Lauderdale 1-12 | Lauderdale 13-24 | Everglades 1-12 | |
| Jan | 0 | 8 | 31 | 39 | |
| Feb | 174 | 773 | 616 | 9 | |
| Mar | 0 | 427 | 483 | 2122 | |
| April | 1113 | 1145 | 7269 | 8 | |
| May | 0 | 1694 | 1651 | 55 | |
| June | 4 | 1379 | 1975 | 1068 | |
| July | 0 | 5112 | 1748 | 1071 | |
| Aug | 0 | 7158 | 3965 | 25 | |
| Sept | 437 | 164 | 1355 | 19 | |
| Oct | 22 | 86 | 36 | 18 | |
| Nov | 13 | 108 | 20 | 32 | |
| Dec | 91 | 462 | 21 | 19 | |
| | | | | | |
| **Total** | 1854 | 18516 | 19170 | 4485 | 44025 |

| **Table 30-a: CO2 Emission Status** | | | | | **If replaced by CTs** |
|---|---|---|---|---|---|
| **Rate lb/MWh** | 3796 | 2082 | 2082 | 2271 | 1220 |
| **Million lbs** | 7 | 39 | 40 | 10 | 53.7 |
| **Σ** | 96 | Million Lbs | | | |
| | 0.043 | Million metric tons | | | 0.024 |
| **Emission reduction** | | **Million metric tons** | | | **0.019** |

# FLORIDA AND CLIMATE CHANGE

## THE COSTS OF INACTION

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November 2007

# EXECUTIVE SUMMARY

In July 2007, Governor Charlie Crist established greenhouse gas emission targets for the state of Florida, including an 80 percent reduction below 1990 levels by 2050. Although achieving this target will involve nontrivial expenditures, the *failure* to avert severe climate change would have even more severe consequences for Florida, in cold hard cash as well as human and ecological impacts.

Arguments against strong action to combat climate change often implicitly assume that inaction would be cost-free — that we can chose a future without significant impacts from climate change even if emissions of carbon dioxide and other greenhouse gases continue to grow unchecked. But the overwhelming scientific consensus now holds that this rosy assumption is simply wrong, and that the more greenhouse gases are released, the worse the consequences will be.

The stakes are high, the risks of disastrous climate impacts are all too real, and waiting for more information is likely to mean waiting until it is too late to protect ourselves and our descendants. If a bad outcome is a real risk — and run-away greenhouse gas emissions lead to a very bad outcome indeed — isn't it worth buying insurance against it? We buy fire insurance for our homes, even though any one family is statistically unlikely to have a fire next year. Young adults often buy life insurance, out of concern for their families, even though they are very unlikely to die next year. Taking action to reduce greenhouse gas emissions and control climate change is life insurance for the planet, and for the species that happen to live here, *Homo sapiens* included.

This report examines the potential costs to Florida if greenhouse gas emissions continue unchecked. To do so, we compare an optimistic scenario and a pessimistic one. Under the optimistic scenario — called "rapid stabilization" — the world begins taking action in the very near future and greatly reduces emissions by mid-century with additional decreases through the end of the century. Under the pessimistic scenario — called "business-as-usual" — greenhouse gas emissions continue to skyrocket throughout the 21st century. The business-as-usual scenario is based largely on the 2007 report of the Intergovernmental Panel on Climate Change (IPCC), a panel of more than 2,000 scientists whose consensus findings are approved by all participating governments, including the United States.

The cost of inaction — the difference between these two scenarios — is the human, economic, and environmental damage that may be avoidable with vigorous, timely actions to reduce greenhouse gas emissions. Many of these costs do not have dollar-and-cents price tags; increased deaths due to more intense hurricanes,[1] or the destruction of irreplaceable ecosystems by sea-level rise or temperature increases, transcend monetary calculation. Lives, and ways of life, are at stake; the most important damages are priceless.

Other costs, which do have explicit price tags, will be enormous. Among the many climate damages discussed in this report, we have estimated monetary values for four major categories:

- loss of tourism revenue, if the more unpleasant climate of the business-as-usual case makes Florida no more attractive year-round than it is today in its slowest season (autumn);
- increased hurricane damages, due to the greater frequency of Category 4 and 5 storms predicted by many climate scientists;
- the value of residential real estate that is at risk from sea-level rise; and
- increased costs of electricity generation as temperatures and air-conditioning requirements rise.

For just these four categories — loss of tourism revenue, increased hurricane damages, at-risk residential real estate, and increased electricity costs — the annual costs of inaction are projected to total $92 billion by 2050 and $345 billion by 2100, figures that respectively would constitute 2.8 percent and 5.0 percent of the state's projected Gross State Product (see table ES-1). If estimates were included for other sectors such as agriculture, fisheries, insurances, transportation, and water systems — to say nothing of ecosystem damages — the totals would be even larger.

**Table ES-1. The Costs of Inaction**

*in billions of 2006 dollars, except percentages*

| | 2025 | 2050 | 2075 | 2100 |
|---|---|---|---|---|
| Tourism | $9 | $40 | $88 | $167 |
| Hurricanes | $6 | $25 | $54 | $104 |
| Electricity | $1 | $5 | $10 | $18 |
| Real Estate | $11 | $23 | $33 | $56 |
| **Summary: Costs of Inaction** | | | | |
| *in billions of 2006 dollars* | $27 | $92 | $184 | $345 |
| *as % of projected Florida GSP* | 1.6% | 2.8% | 3.9% | 5.0% |

## FLORIDA'S FUTURE CLIMATE

Florida's future climate depends on overall emissions of greenhouse gases today and in the decades to come, and — because carbon dioxide persists in the atmosphere for a century or more — on the impacts of accumulated past emissions. We compare two scenarios: an optimistic *rapid stabilization case* and a pessimistic *business-as-usual case*. Neither, of course, is absolutely certain to occur; predicting long-term climate outcomes is difficult, especially for an area as small as a single state. But an enormous amount is now known about the likely effects of climate change; it is far too late to wait for more information before taking action. Based on the current state of knowledge, our scenarios represent plausible extremes: what is expected to happen if the world succeeds in a robust program of climate mitigation, versus what is expected to happen if we do very little. The difference between the two is the avoidable damage to Florida. It can be seen as the benefits of mitigation, or, from an opposite perspective, the costs of inaction.

Figure ES-1. Two Future Climate Scenarios for Florida

**Rapid Stabilization Case**

Lowest emissions under discussion today

- ✓ 50% reduction in current global emissions by 2050
- ✓ 80% reduction in current U.S. emissions by 2050

Plus, good luck in the outcomes of uncertain climate impacts

- ✓ Precipitation remains constant
- ✓ Hurricane intensity remains constant

**Business-as-Usual Case**

Steadily increasing emissions throughout this century

- ✓ Modeled on the high-end of the likely range of the IPCC's A2 scenario

Plus, bad luck in the outcomes of uncertain climate impacts

- ✓ Precipitation patterns changes (less rain in Florida)
- ✓ Hurricane intensity increases

**Table ES-2. Two Future Climate Scenarios for Florida**

| | 2025 | 2050 | 2075 | 2100 |
|---|---|---|---|---|
| **Annual Average Temperature** *(in degrees Fahrenheit above year 2000 temperature)* | | | | |
| Rapid Stabilization Case | 0.6 | 1.1 | 1.7 | 2.2 |
| Business-as-Usual Case | 2.4 | 4.9 | 7.3 | 9.7 |
| **Sea-Level Rise** *(in inches above year 2000 elevation)* | | | | |
| Rapid Stabilization Case | 1.8 | 3.5 | 5.3 | 7.1 |
| Business-as-Usual Case | 11.3 | 22.6 | 34.0 | 45.3 |

## RAPID STABILIZATION CASE

With immediate, large-scale reductions in greenhouse gas emissions, and some good luck in the outcome of uncertain climate impacts, it is still possible for changes in the world's climate to remain relatively small. To keep the global average temperature from exceeding 2°F above year 2000 levels — an important threshold to avoid melting of the Greenland ice sheet and other dangerous climate impacts — we must stabilize the atmospheric concentration of carbon dioxide at 450 parts per million (ppm) or lower. In order to stabilize at 450 ppm, global emissions must reach one-half their current levels by 2050 and one-quarter of current levels by 2100. Because the United States' one-twentieth of world population bears responsibility for a full one-fifth of these emissions, U.S. emissions would have to decline 80 percent by 2050 in order to meet these goals.

In the rapid stabilization case, climate change has only moderate effects. Florida's annual average temperature increases 1°F by 2050 and 2°F by 2100, while sea levels rise by 3.5 inches by 2050 and 7 inches by 2100.

The rapid stabilization case also assumes the best results of the uncertain impacts of extreme weather: precipitation levels remain at historical levels, and extreme heat waves continue to be rare, brief events with manageable impacts in Florida. The frequency and intensity of hurricanes also remain at their historical levels, implying that in the course of an average 100 years Floridians can expect 73 hurricanes, of which 24 will be Category 3 or higher, and one year with four or more hurricanes.

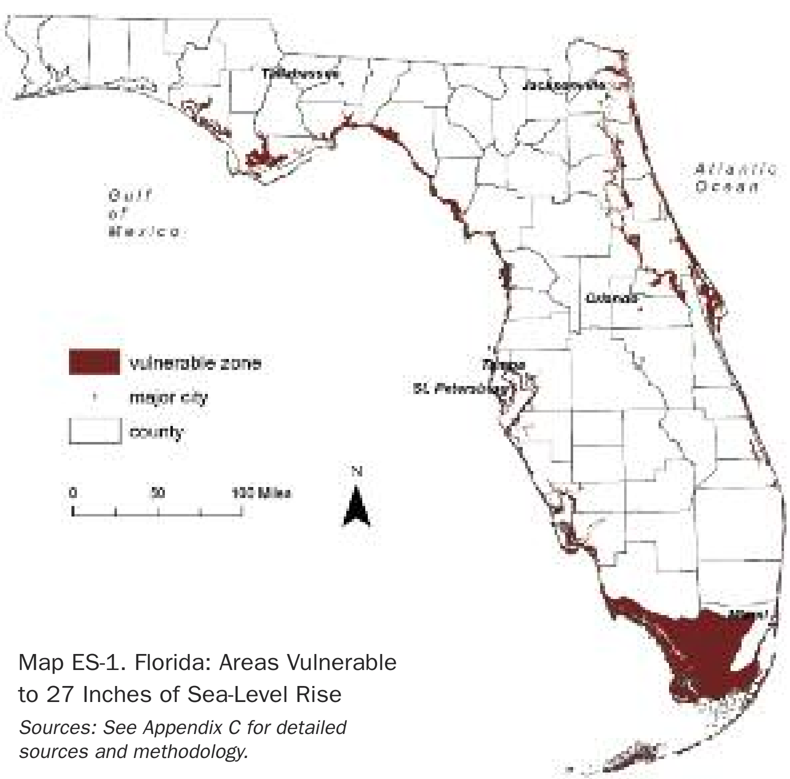
The rapid stabilization case is not a panacea. The state will still have to cope with its existing social and environmental problems, including water shortages, growing demands for electricity, the effects of hurricanes, the costs and constraints of Everglades restoration, and the impacts of ever-growing numbers of residents and visitors crowding into an already well-populated region. But at least climate change will not make these problems much worse — if we implement the rapid stabilization case by significantly reducing greenhouse gas emissions, starting soon and continuing throughout the century. Although Florida cannot itself ensure this outcome, its leadership can provide momentum toward the concerted actions that must be taken in the state, in the nation, and around the world.

## BUSINESS-AS-USUAL CASE

And what if the world fails to achieve the needed reductions in emissions? The business-as-usual case assumes steadily increasing emissions, along with bad luck with the uncertain impacts of extreme weather. Specifically, it rests on the worst of what the IPCC calls its "likely" predictions for the A2 scenario, in which atmospheric concentrations of carbon dioxide exceed the critical 450 ppm threshold by 2030 and reach 850 ppm by 2100.

In the business-as-usual case, Florida's average annual temperatures will be 5°F higher than today in 2050 and 10°F higher in 2100. Sea-level rise will reach 23 inches by 2050, and 45 inches by 2100. The estimates for sea-level rise under the business-as-usual case diverge somewhat from the A2 scenario as presented in the most recent IPCC report, which — controversially — excludes some of the feedback mechanisms that could accelerate the melting of the Greenland and Antarctic ice sheets. This area of climate science has been developing rapidly, and the business-as-usual case estimates are based the most recent work of Stephan Rahmstorf, which appeared too late for inclusion in the IPCC report.

U.S. Geological Survey (USGS) maps and Geographic Information System (GIS) technology make it possible to show an approximation of Florida's coastline at 27 inches of sea-level rise, which is projected to be reached by around 2060 in the business-as-usual case. For simplicity, we refer to land area that would be inundated in Florida with 27 inches of sea-level rise as the year 2060 "vulnerable zone." Map ES-1, left, shows the entire state of Florida with the vulnerable zone in red. (More detailed maps are available in the main body of the report.)




Map ES-1. Florida: Areas Vulnerable to 27 Inches of Sea-Level Rise

*Sources: See Appendix C for detailed sources and methodology.*

The vulnerable zone includes nine percent of Florida's current land area, or some 4,700 square miles. Absent successful steps to build up or otherwise protect them — which will be expensive and in some areas is likely impossible — these lands will be submerged at high tide. The vulnerable zone includes 99.6 percent, all but six square miles, of Monroe County (Florida's southwest tip and the Keys). It also includes 70 percent of Miami-Dade County, and 10 to 22 percent of 14 other counties. Almost one-tenth of Florida's current population, or 1.5 million people, live in this vulnerable zone; one-quarter of the affected population lives in Miami-Dade County.

The vulnerable zone also includes residential real estate now valued at over $130 billion, half of Florida's existing beaches, and 99 percent of its mangroves, as well as the following significant structures (among many others):

- 2 nuclear reactors;
- 3 prisons;
- 37 nursing homes;
- 68 hospitals;
- 74 airports;
- 82 low-income housing complexes;
- 115 solid waste disposal sites;
- 140 water treatment facilities;
- 171 assisted livings facilities;
- 247 gas stations
- 277 shopping centers;
- 334 public schools;
- 341 hazardous-material cleanup sites, including 5 Superfund sites;
- 1,025 churches, synagogues, and mosques;
- 1,362 hotels, motels, and inns; and
- 19,684 historic structures.

While efforts to protect at least some portions of the vulnerable zone will surely be taken, they may prove unavailing in some locales (and will be costly even where effective). As the Science and Technology Committee of the Miami-Dade County Climate Change Task Force recently noted, "the highly porous limestone and sand substrate of Miami-Dade County (which at present permits excellent drainage) will limit the effectiveness of widespread use of levees and dikes to wall off the encroaching sea."

Transportation infrastructure in Florida will be damaged by the effects of sea-level rise, particularly in combination with storm surges. Docks and jetties, for example, must be built at optimal heights relative to existing water levels, and rapid sea-level rise would force more frequent rebuilding. Roads, railroads, and airport runways in low-lying coastal areas all become more vulnerable to flooding as water levels rise, storm surges reach farther inward, and coastal erosion accelerates. Even roads further inland may be threatened, since road drainage systems become less effective as sea levels rise. Many roads are built lower than surrounding land to begin with, so reduced drainage capacity will increase their susceptibility to flooding during rainstorms.

Other important climate and environmental changes in the business-as-usual case include:

- **Hurricane intensity will increase**, with more Category 4 and 5 hurricanes occurring as sea-surface temperatures rise. Greater damages from more intense storms come on top of the more severe storm surges that will result from higher sea levels.
- **Rainfall will become more variable**, with longer dry spells, and will decrease by 10 percent overall, contributing to drought conditions.
- **Heat waves will become more severe and more common**, with new record temperatures and a gradual decline in nighttime cooling. The average "heat index" (temperature combined with humidity) in summer will 15–20 percent higher in much of the state. Miami will become several degrees hotter than today's Bangkok (probably the world's hottest, most humid major city at present), and daily highs in many Florida cities will exceed 90 degrees nearly two-thirds of the year.
- **Ocean temperature and acidity levels will increase**, causing coral bleaching and disease, with harmful effects on the many marine species that depend on coral ecosystems.

These effects will have significant impacts on Florida's industries and infrastructure.

**Tourism**, one of Florida's largest economic sectors, will be the hardest hit as much of the state's wealth of natural beauty — sandy beaches, the Everglades, the Keys — disappears under the waves. As noted in Table ES-1, costs of inaction are projected to total $9 billion by 2025, $40 billion by mid-century, and $167 at the end of the century.

**Agriculture, forestry and fisheries** will also suffer large losses. Well-known and economically important Florida products like orange juice and pink shrimp may become a thing of the past. And even as higher temperatures and more-irregular rainfall increase the demand for crop and livestock irrigation, freshwater supplies will become scarcer as saltwater intrusions contaminate them.

The **insurance industry** also will be affected by climate change, as it seeks to adjust to a new, riskier Florida. Florida's residents and businesses will continue to struggle to find affordable insurance coverage.

High temperatures will increase demands for **electricity**, primarily to supply air conditioning. The extra power plants and the electricity they generate are not cheap; the annual costs of inaction are $5 billion in 2050 and $18 billion in 2100, as reported in Table ES-1 above.

The same temperature increases will also degrade the performance of power stations and transmission lines, making them operate less efficiently; partly as a result, every additional degree Fahrenheit of warming will cost consumers an extra $3 billion per year by 2100.

Increased demand for electricity also has severe implications for water resources, as all coal, oil, gas, and nuclear power plants must be cooled by water.

The business-as-usual case will only intensify Florida's looming **water** crisis in other ways as well. Under hotter and drier conditions, agricultural and domestic users will need more water; the survival of irrigated winter agriculture in the state will be threatened. The one potentially vast source of fresh water, desalination of ocean water, is an expensive and technically complex process. The first large-scale facility to attempt ocean water desalination in the state, at Tampa Bay, has been plagued by technical delays and cost overruns. If enough desalination plants could be made available, the additional water needs under the business-as-usual case would add several billion dollars a year to the costs of inaction.

In both climate scenarios for Florida, climate change is likely to have important effects on the economic damages and deaths that result from **hurricanes**; in the business-as-usual case, these damages and deaths will be on a much larger scale. The cost of inaction attributable to greater hurricane damages, $25 billion by 2050 and $104 billion by 2100, as reported in Table ES-1, includes the effects of coastal development and higher population levels, sea-level rise as it impacts on storm surges, and greater storm intensity. In addition, the cost of inaction in the business-as-usual case includes an average of 19 additional deaths from hurricanes per year in 2050 and 37 additional deaths in 2100; these numbers are in addition to the deaths expected under the rapid stabilization case.

Finally, the business-as-usual case has important, and in some cases irreversible, impacts on priceless natural **ecosystems**. Hotter average temperatures, rising sea levels, changes in precipitation, increased storm damages, and increased ocean acidity and temperatures will all cause visible harm to well-known parks and other natural areas. Wholesale extinctions and ecosystem destruction are unavoidable in the business-as-usual future, and the strategy that could save the most species and ecosystems — allowing wetlands to migrate, taking over what are now dry lands — is extremely unlikely to occur, at least on a wide scale. Natural ecosystems in every corner of Florida will be affected.

And nowhere will the impacts be more devastating than in the **Everglades**. Rising sea levels under the business-as-usual case cause water to encroach 12 to 24 miles into the broad low-lying area of the Everglades, leaving the lower Everglades completely inundated. As large parts of the Everglades wetlands are converted into open water, nurseries and shelter for many fish and wildlife species will be lost. The 10°F increase in air temperature expected by 2100 will draw species northward out of the Everglades, but if current drylands are protected with seawalls this migration will be thwarted, and species will disappear from Florida, or in some cases become extinct.

These impacts on industry, infrastructure, and ecosystems — the cost of inaction — vastly outweigh expenditures on renewable energy, energy-efficient transportation and appliances, and other measures that are required to reduce emissions. If Florida makes the necessary efforts to achieve its ambitious target of 80 percent reduction in emissions by 2050, and the rest of the world follows suit with significant and immediate action, we can achieve the "rapid stabilization future." If, on the other hand, decisive climate action fails, we may well find ourselves living in the "business-as-usual future."

To reject a potential 10°F increase in temperature and 3 feet or more in sea-level rise this century, Floridians — and residents of other U.S. states and of other nations — must commit to beginning in the very near future to take steps to substantially reduce global greenhouse gas emissions. The only other available option is to place a very risky bet — that somehow, despite the most current scientific knowledge, business-as-usual emissions will not trigger a climate catastrophe. If we gamble and lose, we and our children cannot walk away from the consequences.

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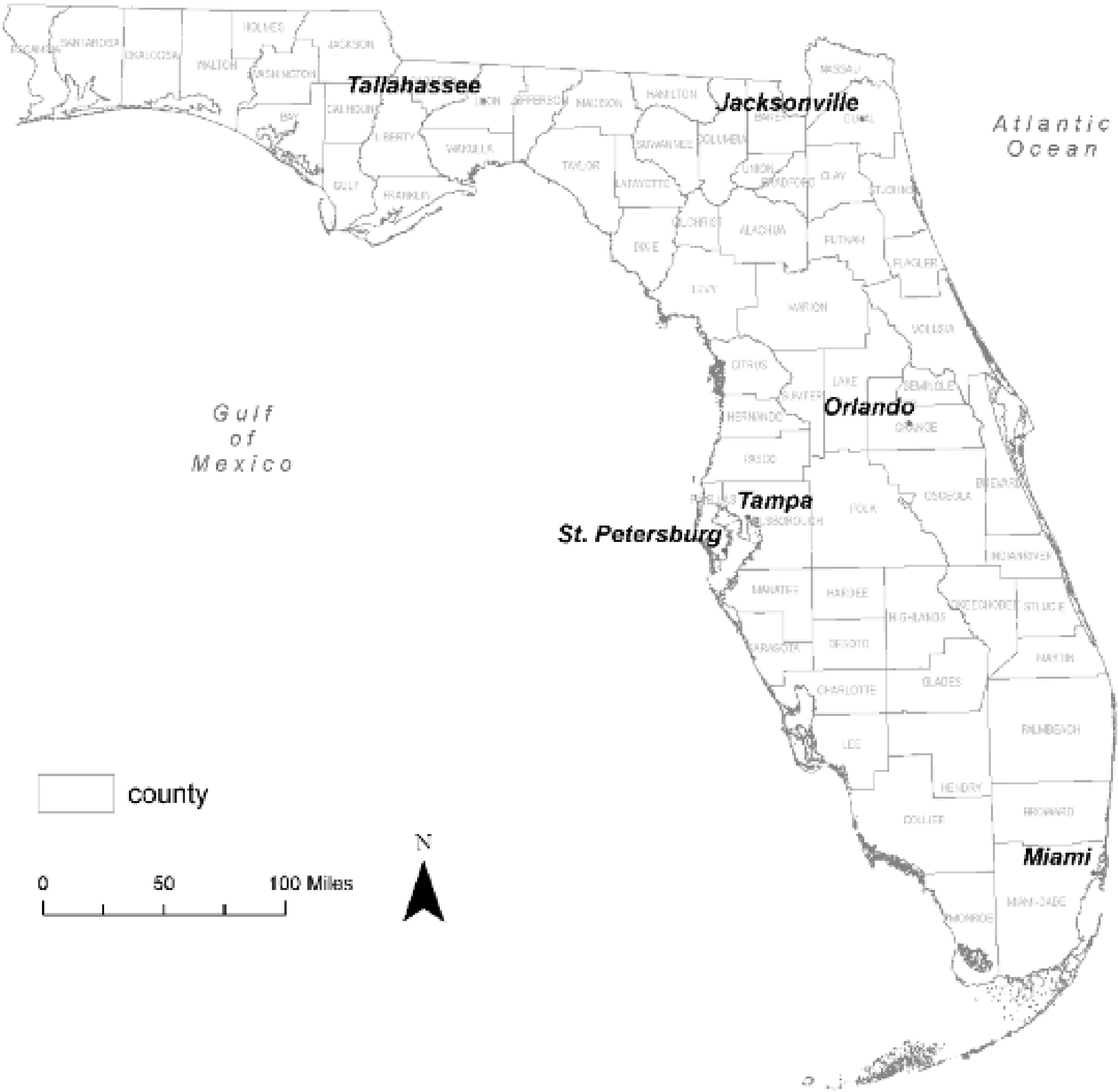



Map 1. Florida Counties Boundaries.

# I. INTRODUCTION

In July 2007, Governor Charlie Crist established greenhouse gas emission targets for the state of Florida.[2] Florida joins California, other states in the West and the Northeast, and countries around the world in supporting vigorous efforts to control climate change. In an era of droughts, heat waves, and violent storms, it is no longer possible to deny the reality of climate change, or the need for an effective response.[3]

Governor Crist's initiatives call for an 80 percent reduction in greenhouse gas emissions by 2050, an ambitious target that has been adopted by several other states and that is advocated by many scientists and civic groups.[4] Implementation of this target will require spending a noticeable amount of money. Indeed, opposition to climate policy increasingly focuses on the supposed damage to the economy that will result from reducing emissions.

**But while doing something about climate change will have nontrivial costs, this report demonstrates that doing *nothing* about climate change will itself have immense costs — both monetarily and otherwise.**

The stakes are high, the risks of disastrous climate impacts are all too real, and waiting for more information is likely to mean waiting until it is too late to protect ourselves and our descendants. If a bad outcome is a real risk — and run-away greenhouse gas emissions lead to a very bad outcome indeed — isn't it worth buying insurance against it? We buy fire insurance for our homes, even though any one family is statistically unlikely to have a fire next year. Young adults often buy life insurance, out of concern for their families, even though they are very unlikely to die next year. Taking action to reduce greenhouse gas emissions and control climate change is life insurance for the planet, and for the species that happen to live here, *Homo sapiens* included.

Florida's efforts at reining in greenhouse gas emissions are a forward-thinking, responsible contribution to resolving a global environmental crisis, but these actions are not enough to assure a stable climate for Florida. The effects of greenhouse gases are universal, like our shared atmosphere; it doesn't matter where they are emitted, the whole world feels the effects. Unfortunately, we cannot know how much climate-transforming carbon dioxide and other greenhouse gases will be emitted into the atmosphere in the coming decades. Neither can we be sure of the exact effects that these gases will have on the world's climate or ocean levels. Given a prediction about future emissions, climate scientists are able to forecast the range of probable climatic effects with some certainty, but exactly where we will fall in that range cannot be precisely specified.

### UNDERSTANDING UNCERTAINTY IN CLIMATE PROJECTIONS

Does climate science now tell us that we are uncertain about what will happen next, or that things are certain to get worse? Unfortunately, the answer seems to be yes to both.

The problem is that different levels of uncertainty are involved. No one knows how to predict next year's weather, and the year-to-year variation is enormous: there could be many hurricanes, or almost none; unusually hot temperatures, or unusually mild; more rain than average, or less. But on average, scientists are increasingly certain that we are headed towards worsening conditions.

By way of analogy, imagine that you are drawing a card from a standard deck of 52 playing cards. You have no way to predict exactly what card you will draw, but you know a lot about the odds. There is exactly one chance in four of drawing a diamond, but any individual card may be a diamond, a club, a heart, or a spade. If you draw again and again, the average number on your cards (counting aces as one, and face cards as 11, 12, and 13) will be seven, but any individual draw could be much higher or lower than the average.

Now imagine that the dealer changes some cards in the deck after each draw. If the dealer removes all of the 6, 7, and 8 cards, the *average* number you draw will remain the same, but your chance of getting an extremely high or extremely low number in any one draw will increase. If instead the dealer adds extra cards with high numbers (face cards), the average number that you draw will increase.

Climate change is like drawing a card from a changing deck. There is no way of predicting the next card you will draw from a well-shuffled deck. But the message of climate science is that the deck of climate possibilities is changing in disturbing directions, both toward more variability and more extreme outcomes, and toward worsening averages. The same logic applies in reverse: reducing greenhouse gas emissions will not guarantee better weather next year, but it will ensure that in the future we and our descendents will be able to draw from a better deck.

Will social policy succeed in reining in the emission of greenhouse gases, not just in Florida, but around the world? Will we face good luck or bad in the uncertain impacts of climate change? Even as Florida does its part by reducing greenhouse emissions, it is still necessary for Floridians to prepare for an unknown future climate. This report describes two plausible climate futures: an optimistic scenario, called the rapid stabilization case, in which total world emissions of greenhouse gases are greatly reduced beginning in the near future, and a pessimistic scenario, called the business-as-usual case, in which global emissions steadily increase throughout the 21st century. The two scenarios also reflect differing assumptions about the consequences of those emission levels.

The cost of inaction — the difference between the best and worst likely climate change impacts — is the human, economic, and environmental damages that are avoidable with vigorous, timely actions to reduce greenhouse gas emissions. This cost vastly outweighs the expenditures on renewable energy, energy-efficient transportation and appliances, and other measures that are required to reduce emissions. If Florida makes the necessary efforts to achieve its ambitious target of 80 percent reduction in emissions by 2050, and the rest of the world follows suit with significant and immediate action, we can achieve the "rapid stabilization future." If, on the other hand, decisive climate action fails, we may well find ourselves living in the "business-as-usual future."

Read on for the details: the business-as-usual scenario described here is an offer you have to re-

fuse. To reject a potential 10°F increase in temperature and 3 feet or more in sea-level rise this century, Floridians — and residents of other U.S. states and of other nations — must commit to beginning in the very near future to take steps to substantially reduce global greenhouse emissions. The only other available option is to place a very risky bet — that somehow, despite the most current scientific knowledge, business-as-usual emissions will not trigger a climate catastrophe. If we gamble and lose, we and our children cannot walk away from the consequences.

# II. FLORIDA'S FUTURE CLIMATE

Florida's future climate depends on overall emissions of greenhouse gases today and in the decades to come, and — because carbon dioxide persists in the atmosphere for a century or more — on the impacts of accumulated past emissions. We compare two scenarios: an optimistic rapid stabilization case and a pessimistic business-as-usual case. Neither, of course, is absolutely certain to occur; predicting long-term climate outcomes is difficult, especially for an area as small as a single state. But an enormous amount is now known about the likely effects of climate change; it is far too late to wait for more information before taking action. Based on the current state of knowledge, our scenarios represent plausible extremes: what is expected to happen if the world succeeds in a robust program of climate mitigation, versus what is expected to happen if we do very little. The difference between the two is the avoidable damage to Florida. It can be seen as the benefits of mitigation, or, from an opposite perspective, the costs of inaction.

The first climate future described in this report is the best that we can hope for: relatively small climate impacts that develop slowly. This scenario — the rapid stabilization case — is an optimistic estimate of what will happen if global emissions of greenhouse gases are cut in half by mid-century with further reductions thereafter. (Because cumulative per capita emissions in developed countries, particularly the U.S., vastly exceed those in the developing world, significantly greater reductions are needed from developed countries, on the order of 80 percent by 2050). The rapid stabilization case combines the lowest imaginable emissions with very good luck in uncertain climate impacts: By 2050, Florida's average annual temperature will rise just 1°F and sea-levels will rise a mere 3.5 inches.

The state will still have to cope with its existing environmental problems, including water shortages, Everglades restoration, and the impacts of ever-growing numbers of residents and visitors crowding into an already well-populated region. (Millions of people agree: Florida is a nice place to visit, and they *do* want to live there.) In this optimistic climate future, hurricanes continue

### UNDERSTANDING THE COST OF INACTION

The *cost of inaction* is the damage that society can avoid by engaging in ambitious, large-scale reductions of greenhouse gas emissions, beginning in the near future and continuing throughout the century. In this report, we estimate the cost of inaction as the costs of the pessimistic "business-as-usual case" minus the costs of the optimistic "rapid stabilization case."

The *rapid stabilization* scenario portrays the best future that we can hope for: greenhouse gas emissions are significantly reduced in the next 10 to 20 years, and continue a steady decline thereafter; as a result, the effects of climate change develop slowly and are relatively small. The rapid stabilization case, while not ideal, is a future that we can live with. Indeed, the moderate effects of climate change described in the rapid stabilization scenario are now all but unavoidable, given that many greenhouse gases persist in the atmosphere for decades and will continue to warm the planet.

In contrast, the *business-as-usual* scenario will be very hard to live with — but we and our children may be left with no other choice if greenhouse gas emissions continue to grow throughout the 21st century. In the business-as-usual future, the effects of climate change are very serious indeed: in Florida, a 10°F increase in the annual average temperature and 45 inches of sea-level rise.

The difference between these scenarios is the cost of inaction: the increased price that we will pay, and the damages that will occur, if we fail to quickly act to reduce greenhouse gas emissions, over and above the (much smaller) climate impacts that take place in the rapid stabilization scenario. The cost of inaction includes lost revenues of affected industries and the replacement of property damaged by rising waters and more intense storms. The business-as-usual scenario — and the costs that come with it — are still avoidable, but only with immediate action on a local, national, and global scale.

to strike the state at the same rate as in the past, and precipitation levels remain constant. It should be emphasized that this climate scenario is simply not possible absent significant reductions in greenhouse gas emissions, in the United States and around the world.

The second future climate scenario, or business-as-usual case, assumes emissions that continue to increase over time unchecked by public policy (often referred to as "business-as-usual" emissions), combined with bad luck in uncertain climate impacts. The business-as-usual case is represented by the high end of the "likely" range of the Intergovernmental Panel on Climate Change (IPCC) A2 scenario, which projects an increase in average annual temperature of 5°F and an increase in sea levels of 18 to 28 inches by 2050 in Florida.

The business-as-usual case goes beyond the IPCC's A2 projections to incorporate unfortunate outcomes in the hardest-to-predict areas of climate science. Florida's rainfall will decrease by 5 to 10 percent; hurricanes will be more intense and heat waves more common. In this pessimistic climate future, the challenges of Florida's population and economic growth, and its current environmental problems, become far more difficult and expensive to address. Some of the costs have price tags attached, with meaningful monetary costs: loss of a fraction of tourism revenue, or of vulnerable beach front real estate, will cost the state many billions of dollars. Some of the costs are priceless, beyond monetary valuation: more deaths as a result of more powerful hurricanes, or the irreversible destruction of unique ecosystems.

It is important to note that this pessimistic future climate is by no means a worst possible case. Greenhouse gas emissions could increase even more quickly, as represented by the IPCC's A1FI scenario. Nor is the high end of the IPCC's "likely" range a worst-case: in IPCC terminology, the "likely" range extends from the 17th to the 83rd percentile, so 17 percent of the full range of A2 projections were even worse than the highest "likely" case. Instead, the business-as-usual case is offered as the probable outcome of current trends in emissions plus some bad luck in the way our climate responds to those emissions.

Both of these future climate scenarios use the same population and economic growth projections. Florida's population was 17 million in 2005, or about 6 percent of the U.S. population. The U.S. Census Bureau forecasts that Florida's population will grow 2 percent a year through 2030, reaching 29 million, and then 0.8 percent per year through 2050, reaching 33 million.[5] Given the difficulty of projecting population change more than a half century into the future, we make

**Rapid Stabilization Case**

Lowest emissions under discussion today

- ✓ 50% reduction in current global emissions by 2050
- ✓ 80% reduction in current U.S. emissions by 2050

Plus, good luck in the outcomes of uncertain climate impacts

- ✓ Precipitation remains constant
- ✓ Hurricane intensity remains constant

**Business-as-Usual Case**

Steadily increasing emissions throughout this century

- ✓ Modeled on the high-end of the likely range of the IPCC's A2 scenario

Plus, bad luck in the outcomes of uncertain climate impacts

- ✓ Precipitation patterns changes (less rain in Florida)
- ✓ Hurricane intensity increases

Figure 1. Two Future Climate Scenarios for Florida

the conservative assumption that Florida's population will remain constant at 33 million from 2050 to 2100. Still, this is almost twice the current population.

In 2005, Florida's Gross State Product (GSP, the state-level equivalent of GDP) was just under $7 billion, and GSP per capita (a figure often used as an estimate of the state's per capita income) was $40,000.[6] Based on long-run U.S. growth rates, we project that Florida's GSP per capita will increase at a rate of 2.2 percent through 2030, slightly lower than its current annual growth rate. From 2030 through 2100, we assume a reduction to a conservative 1.5 percent annual increase.[7] Using these projections, Florida's GSP per capita will be $73,000 in 2030 and $207,000 in 2100, both in 2006 dollars.

Growth at this pace will place significant strain on the environment, with or without additional climate impacts. In some Florida neighborhoods, real estate development already seems close to filling the available space for new residential construction, but millions of additional units will be needed state-wide to house the growing population of the next few decades. Fresh water supplies are already being used at or beyond a sustainable level, but more people moving to Florida means more demand for water. Rapid economic growth has meant increasing demands for electrical generation in Florida, a trend likely continue as the state economy races through the twenty-first century; the air-conditioning demands resulting from higher average temperatures will increase pressure on the state's electrical infrastructure.

Sustaining Florida's growth, in other words, will be an ongoing economic and environmental challenge, even in the optimistic rapid stabilization case. The business-as-usual case, adding even more serious climate constraints, will make these already challenging problems much more difficult and expensive to solve.

## RAPID STABILIZATION CASE

With immediate, large-scale reductions in greenhouse gas emissions, and some good luck in the outcome of uncertain climate impacts, it is still possible for changes in the world's climate to remain relatively small. If we want a real chance of keeping the global average temperature from exceeding 2°F above year 2000 levels — an important threshold to prevent complete melting of the Greenland ice sheet and other dangerous climate impacts — we must stabilize the atmospheric concentration of carbon dioxide at 450ppm or lower.[8] In order to stabilize at 450ppm, global emissions of greenhouse gases must begin to decline by 2020, reaching one-half their current levels by 2050 and one-quarter of current levels by 2100. Because the United States' one-twentieth of world population bears responsibility for a full one-fifth of these emissions, U.S. emissions would have to decline 80 percent by 2050 in order to meet these goals (Chameides 2007). (Florida's objective of reducing greenhouse gas emissions 80 percent by 2050 is consistent with that goal.)

Of the six main scenarios that the IPCC describes as "equally probable"(Schenk and Lensink 2007), B1 has the lowest emissions, with atmospheric concentrations of carbon dioxide reaching 550 ppm in 2100. The concentration levels and temperatures of the rapid stabilization case are below the low end of the likely range presented in B1. Because there is no IPCC scenario as low as the rapid stabilization case, we have approximated the low end of the likely temperature range for atmospheric stabilization at 450 ppm of carbon dioxide using data from the Stern Review.[9]

Projected average annual temperature increases for Florida are reported in Table 1. In the rapid stabilization future, Florida's annual average temperature increases 1°F by 2050 and 2°F by 2100.

**Table 1. Average Annual Temperature Increase: Rapid Stabilization Case**

*in degrees Fahrenheit above year 2000 temperature*

| | 2025 | 2050 | 2075 | 2100 |
|---|---|---|---|---|
| Florida | 0.6 | 1.1 | 1.7 | 2.2 |
| Global Mean | 0.4 | 0.9 | 1.3 | 1.8 |

*Source: IPCC Chapters 5, 10, and 11 (Intergovernmental Panel on Climate Change 2007b); Stern Review (Stern 2006); and authors' calculations.*
*Note: Florida data is the average of the U.S. East and Caribbean regions.*

The concentration of greenhouse gases in the atmosphere will affect the climate of every city, state, and country somewhat differently. Florida's expected annual average temperature increase in the rapid stabilization case is very close to the global average, while most of the rest of the United States will experience larger temperature increases. (This is because climate change has a greater effect on temperatures closer to the poles, and less toward the equator.) The average annual temperatures that we report are an average of day and nighttime temperatures for every day of the year. A small change in annual average temperatures can mean a big difference to a local climate. Table 2 shows projected average annual temperatures for major Florida cities in the rapid stabilization case.

**Table 2. Major Cities Average Annual Temperatures: Rapid Stabilization Case**

*in degrees Fahrenheit*

| Florida City | Historical | 2025 | 2050 | 2075 | 2100 |
|---|---|---|---|---|---|
| Pensacola | 67.7 | 68.3 | 68.8 | 69.4 | 69.9 |
| Jacksonville | 68.0 | 68.6 | 69.1 | 69.7 | 70.2 |
| Orlando | 72.3 | 72.9 | 73.4 | 74.0 | 74.5 |
| Tampa | 72.3 | 72.9 | 73.4 | 74.0 | 74.5 |
| Miami | 75.9 | 76.5 | 77.0 | 77.6 | 78.1 |
| Key West | 77.8 | 78.4 | 78.9 | 79.5 | 80.0 |

*Source: 2006 city temperatures from NOAA National Climatic Data Center (National Oceanic & Atmospheric Administration 2007b); annual average temperatures increase, IPCC Chapters 5, 10, and 11 (Intergovernmental Panel on Climate Change 2007b); Stern Review (Stern 2006); and authors' calculations.*

In the best-case, rapid stabilization scenario, sea levels will still rise in the United States and around the world. Even if it were possible to stabilize the atmospheric concentration of carbon dioxide well below the target of 450 ppm, sea-levels would continue to rise gradually for centuries, because the ocean volume would continue to expand from the last 100 years of temperature increase (warmer water occupies more space than cooler water). The rapid stabilization case includes the IPCC's lowest projection for global mean sea-level rise, an increase of 3.5 inches by 2050 and 7 inches by 2100 (see Table 3).[10]

The rapid stabilization case also assumes the best results of the uncertain impacts of extreme weather: precipitation levels remain at historical levels, and extreme heat waves continue to be rare, brief events with manageable impacts in Florida. The frequency and intensity of hurricanes also remain at their historical levels. Over the last 156 years, 279 recorded hurricanes have hit the mainland United States, a little less than two hurricanes per year. If this long-term trend continues, the U.S. can expect 18 hurricanes per decade, of which 6 will be major hurricanes, reaching Category 3 or higher. Historically, four out of every ten U.S. hurricanes, and the same proportion of major hurricanes, make landfall in Florida (Blake et al. 2007).

**Table 3. Annual Average Sea-Level Rise: Rapid Stabilization Case**

*in inches above year 2000 elevation*

| | 2025 | 2050 | 2075 | 2100 |
|---|---|---|---|---|
| Sea-Level Rise | 1.8 | 3.5 | 5.3 | 7.1 |

*Source: IPCC Chapters 5, 10, and 11 (Intergovernmental Panel on Climate Change 2007b).*

These are long-term averages that do not reflect rare events like the 2004 and 2005 hurricane seasons. In each of those years, four hurricanes made landfall in Florida: Charley, Frances, Ivan, and Jeanne in 2004; and Dennis, Katrina (which hit the Florida panhandle), Rita and Wilma in 2005. Six of these hurricanes made their landfall in Florida at Category 3 or higher. There have been only 30 years since 1851 in which more than one hurricane struck Florida: and only two years, 2004 and 2005, when four hurricanes hit the state. Based on these trends, in the rapid stabilization future, in the course of an average 100 years Floridians will experience 73 hurricanes, of which 24 will be Category 3 or higher, and one year with four or more hurricanes.

## BUSINESS-AS-USUAL CASE

Climatologists project a range of outcomes that could result from business-as-usual (meaning steadily increasing) emissions. The business-as-usual case is the worst of what the IPCC calls its "likely" projections for the A2 scenario. In this scenario, atmospheric concentrations of carbon dioxide exceed the critical 450 ppm threshold by 2030 and reach 850 ppm by 2100 (Intergovernmental Panel on Climate Change 2007b). In our business-as-usual case, the worst temperature and sea-level rise impacts likely to result from the A2 greenhouse gas concentrations are combined with pessimistic assumptions about the hardest-to-predict consequences of rising temperatures: more intense hurricanes, less rainfall, more severe heat waves, and large increases in ocean temperatures and acidification.

### Temperatures rise

In the business-as-usual case, average annual temperatures increase four times as quickly as in the rapid stabilization case. Florida's annual average temperature will be 5°F higher than today in 2050 and 10°F higher in 2100. Table 4 and Table 5 show the progression of these temperatures over time. Even more important to Floridians than the change in *average* temperatures is the range of potential temperature extremes, which are much harder for climatologists to forecast. The most recent estimate of extreme temperatures for the United States was conducted in 2001 by the U.S. Global Change Research Program (USGCRP), using a scenario with slightly lower emissions than the IPCC A2. The USGCRP estimated that Florida's average July heat index (a measure of perceived heat, or temperature combined with humidity) will be an sizzling 15 to 20°F higher at the end of the century (U.S. Global Change Research Program 2001).

**Table 4. Annual Average Temperature Increase: Business-As-Usual Case**

*in degrees Fahrenheit above year 2000 temperature*

| | 2025 | 2050 | 2075 | 2100 |
|---|---|---|---|---|
| Florida | 2.4 | 4.9 | 7.3 | 9.7 |
| Global mean | 2.2 | 4.3 | 6.5 | 8.6 |

*Source: IPCC Chapters 5, 10, and 11 (Intergovernmental Panel on Climate Change 2007b).*
*Note: Florida data is the average of the U.S. East and Caribbean regions.*

**Table 5. Major Cities Annual Average Temperatures: Business-As-Usual Case**

*in degrees Fahrenheit*

| Florida City | Historical | 2025 | 2050 | 2075 | 2100 |
|---|---|---|---|---|---|
| Pensacola | 67.7 | 70.1 | 72.6 | 75.0 | 77.4 |
| Jacksonville | 68.0 | 70.4 | 72.9 | 75.3 | 77.7 |
| Orlando | 72.3 | 74.7 | 77.2 | 79.6 | 82.0 |
| Tampa | 72.3 | 74.7 | 77.2 | 79.6 | 82.0 |
| Miami | 75.9 | 78.3 | 80.8 | 83.2 | 85.6 |
| Key West | 77.8 | 80.2 | 82.7 | 85.1 | 87.5 |

*Source: 2006 city temperatures from NOAA National Climatic Data Center (National Oceanic & Atmospheric Administration 2007b); annual average temperatures increase, IPCC Chapters 5, 10, and 11 f(Intergovernmental Panel on Climate Change 2007b).*

To give these temperatures a context in which to understand them, Table 6 compares Florida cities' temperatures in the business-as-usual future to current temperatures in cities around the world. In 2100, Pensacola and Jacksonville climates will be as hot as that of today's Key West. A century from now, Orlando and Tampa will have the climate of today's Acapulco, Mexico, where the coldest month's average temperature is 79°F. Miami and Key West will have average annual temperatures several degrees hotter than Bangkok, Thailand's 83°F. Bangkok — perhaps the hottest, most humid major city in the world — has daytime temperatures that range from the high 80s to mid-90s throughout the year, while overnight lows range from the high 70s in the hottest months to the high 60s in the coolest months.[11] By 2100, Miami and Key West will be even hotter.

Or Key West would be that hot, if it were still above water. The business-as-usual case also includes rising sea levels.

**Table 6. Major Cities Annual Average Temperatures in 2100: Business-As-Usual Case**

*in degrees Fahrenheit*

| | Historical Average | Predicted in 2100 | Is like . . . today |
|---|---|---|---|
| Pensacola | 67.7 | 77.4 | Key West |
| Jacksonville | 68.0 | 77.7 | Key West |
| Orlando | 72.3 | 82.0 | Acapulco, Mexico |
| Tampa | 72.3 | 82.0 | Acapulco, Mexico |
| Miami | 75.9 | 85.6 | no comparable city |
| Key West | 77.8 | 87.5 | no comparable city |

*Source: Authors' calculations.*

## Sea-level rise

The estimates for sea-level rise under the business-as-usual case diverge somewhat from the A2 scenario as presented in the 2007 IPCC report. The authors of the IPCC 2007 made the controversial decision to exclude one of the many effects that combine to increase sea levels — the risk of accelerated melting of the Greenland and Antarctic ice sheets caused by feedback mechanisms such as the dynamic effects of meltwater on the structure of ice sheets. Without the effects of these feedback mechanisms on ice sheets, the high end of likely range of A2 sea-level rise is just 20 inches, down from approximately 28 inches in the IPCC 2001 report (Intergovernmental Panel on Climate Change 2001b).

Accelerated melting of ice sheets were excluded from the IPCC's projections not because they are thought to be unlikely or insignificant — on the contrary, these effects could raise sea-levels by hundreds of feet over the course of several millennia — but because they are extremely difficult to estimate.[12] Indeed, the actual amount of sea-level rise observed since 1990 has been at the very upper bound of prior IPCC projections that assumed high emissions, a strong response of temperature to emissions, *and* included an additional ad hoc amount of sea-level rise for "ice sheet uncertainty"(Rahmstorf 2007).

This area of climate science has been developing rapidly in the last year, but, unfortunately, the most recent advances were released too late for inclusion in the IPCC process (Kerr 2007a; b; Oppenheimer et al. 2007). A January 2007 article by Stephan Rahmstorf in the prestigious peer-reviewed journal *Science* proposes a new procedure for estimating melting ice sheets' difficult-to-predict contribution to sea-level rise (Rahmstorf 2007). For the A2 emissions scenario on which our business-as-usual case is based, Rahmstorf's estimates of 2100 sea-level rise range from 35 inches, the central estimate for the A2 scenario, up to 55 inches, Rahmstorf's high-end figure including an adjustment for statistical uncertainty. For purposes of this report, we use an intermediate value that is the average of his estimates, or 45 inches by 2100; we similarly interpolate an average of Rahmstorf's high and low values to provide estimates for dates earlier in the century (see Table 7).

**Table 7. Annual Average Sea-Level Rise: Business-As-Usual Case**

*in inches above year 2000 elevation*

| | 2025 | 2050 | 2075 | 2100 |
|---|---|---|---|---|
| Sea-Level Rise —"most likely" estimate | 8.9 | 17.7 | 26.6 | 35.4 |
| Sea-Level Rise —"worst possible" estimate | 13.8 | 27.6 | 41.3 | 55.1 |

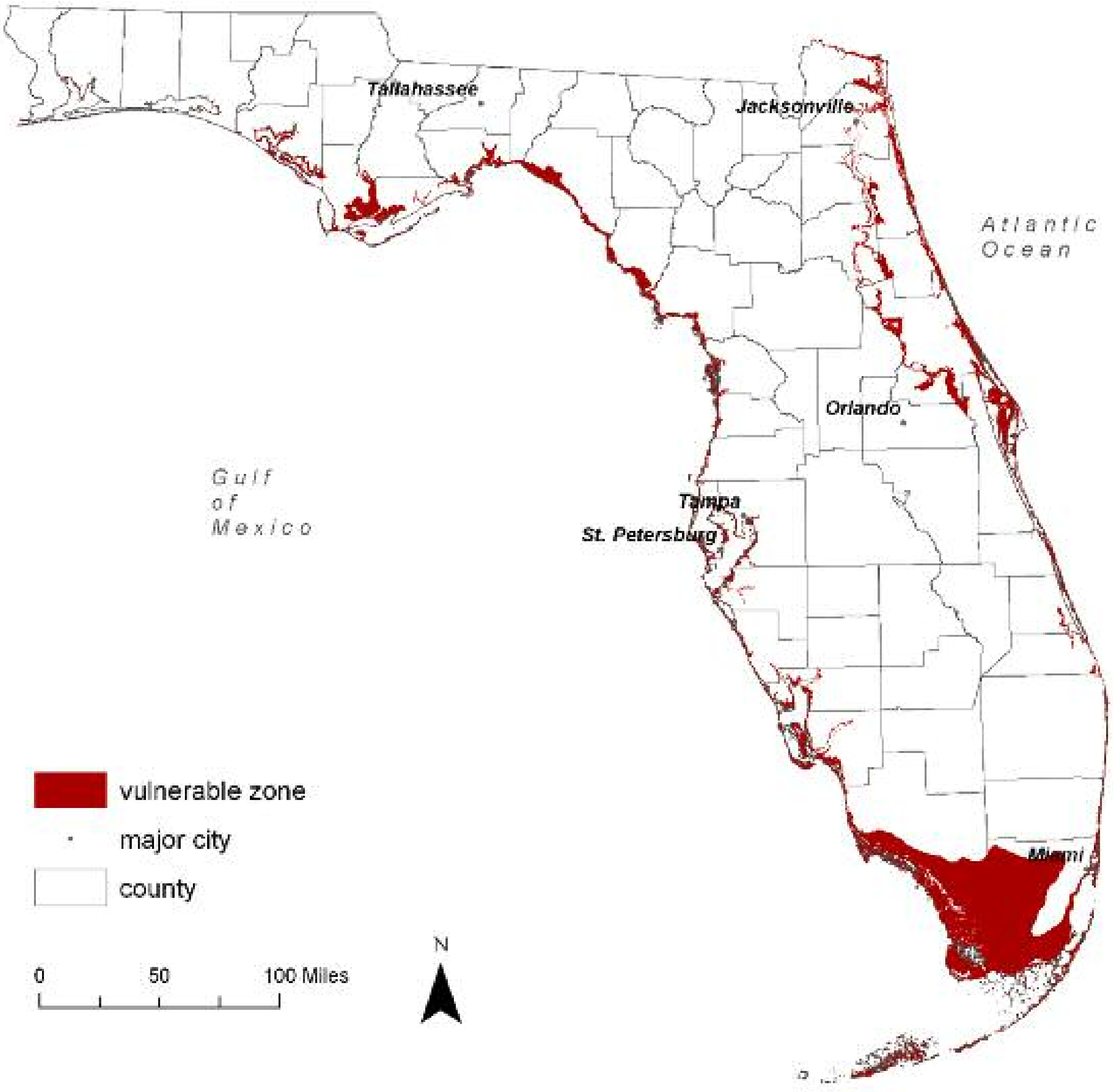
*Source (Rahmstorf 2007); authors' calculations assuming a constant rate of change throughout the century.*
*Note: Slightly different amounts of sea-level rise are expected in different locations around the world. For Florida, sea-level rise is expected to be at approximately the global average; see IPCC Chapters 5, 10, and 11 (Intergovernmental Panel on Climate Change 2007b).*

To quantify the area that may be affected by sea-level rise during the coming decades, we use U.S. Geological Survey (USGS) maps and Geographic Information System (GIS) technology that makes it possible to show a rough approximation of Florida's coastline at 27 inches of sea-level rise (see Appendix C for technical description of our GIS data). In the business-as-usual scenario using the Rahmstorf projections, this amount of sea-level increase would be reached by about 2060. We refer to land area that would be inundated in Florida with 27 inches of sea-level rise as the year 2060 "vulnerable zone."

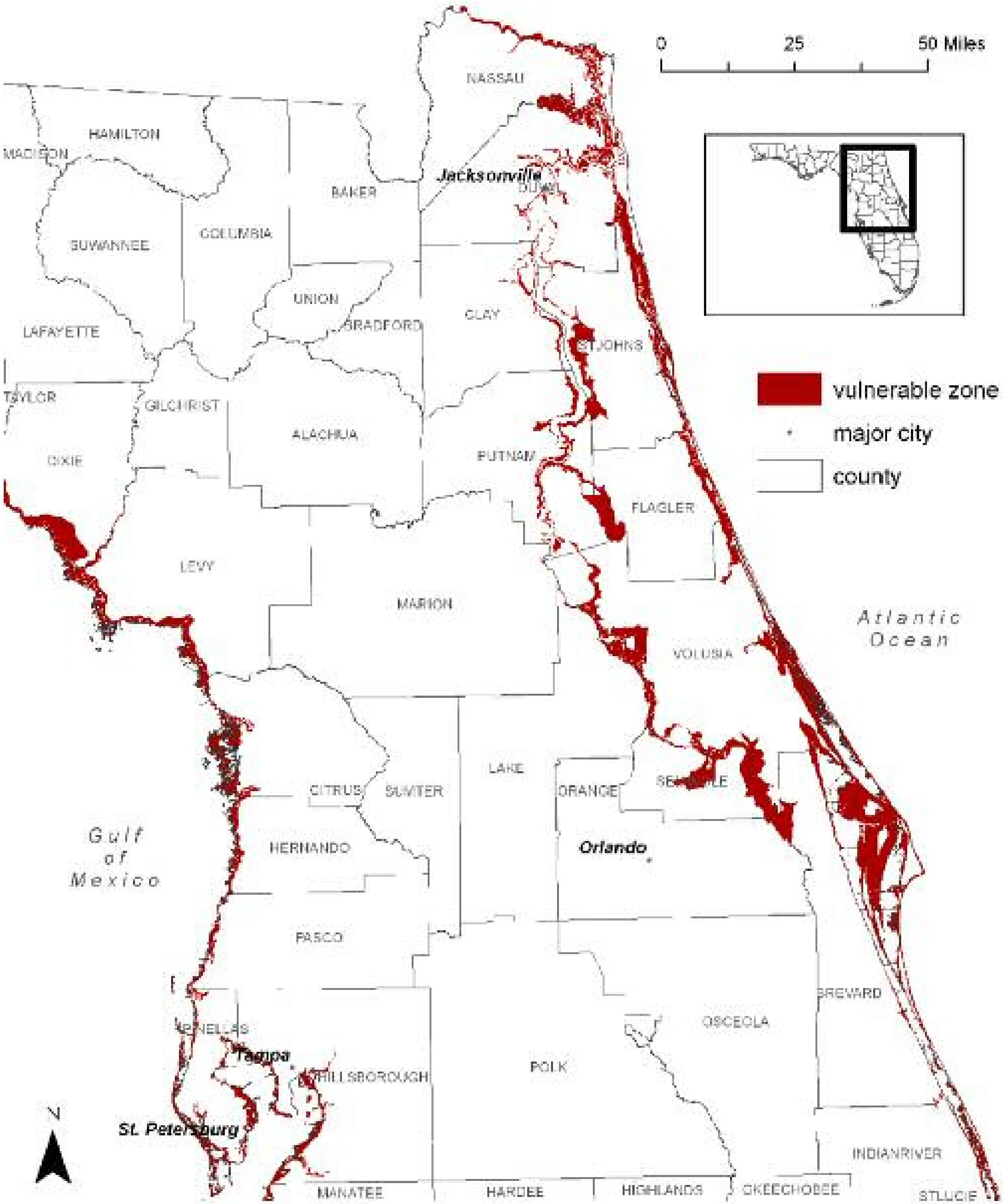
Note that while the exact *pace* of sea-level rise is not precisely quantifiable, it is virtually certain that this *amount* of sea-level rise will occur at some point if greenhouse gas emissions continue unchecked. In other words, the question is not whether Florida will need to cope with this much sea-level rise, but rather when it will need to do so.

Map 2, right, shows the entire state of Florida with the vulnerable zone in red. Map 3, Map 4, and Map 5 show the vulnerable zone for the North Peninsula, South Peninsula, and Panhandle areas of Florida in more detail. For example, if business-as-usual emissions continue, and nothing is done to build up or protect flooding lands, by 2060 nine percent of Florida's current land area — 4,700 square miles — will be in the zone vulnerable to sea-level rise, that is, submerged at high tide.

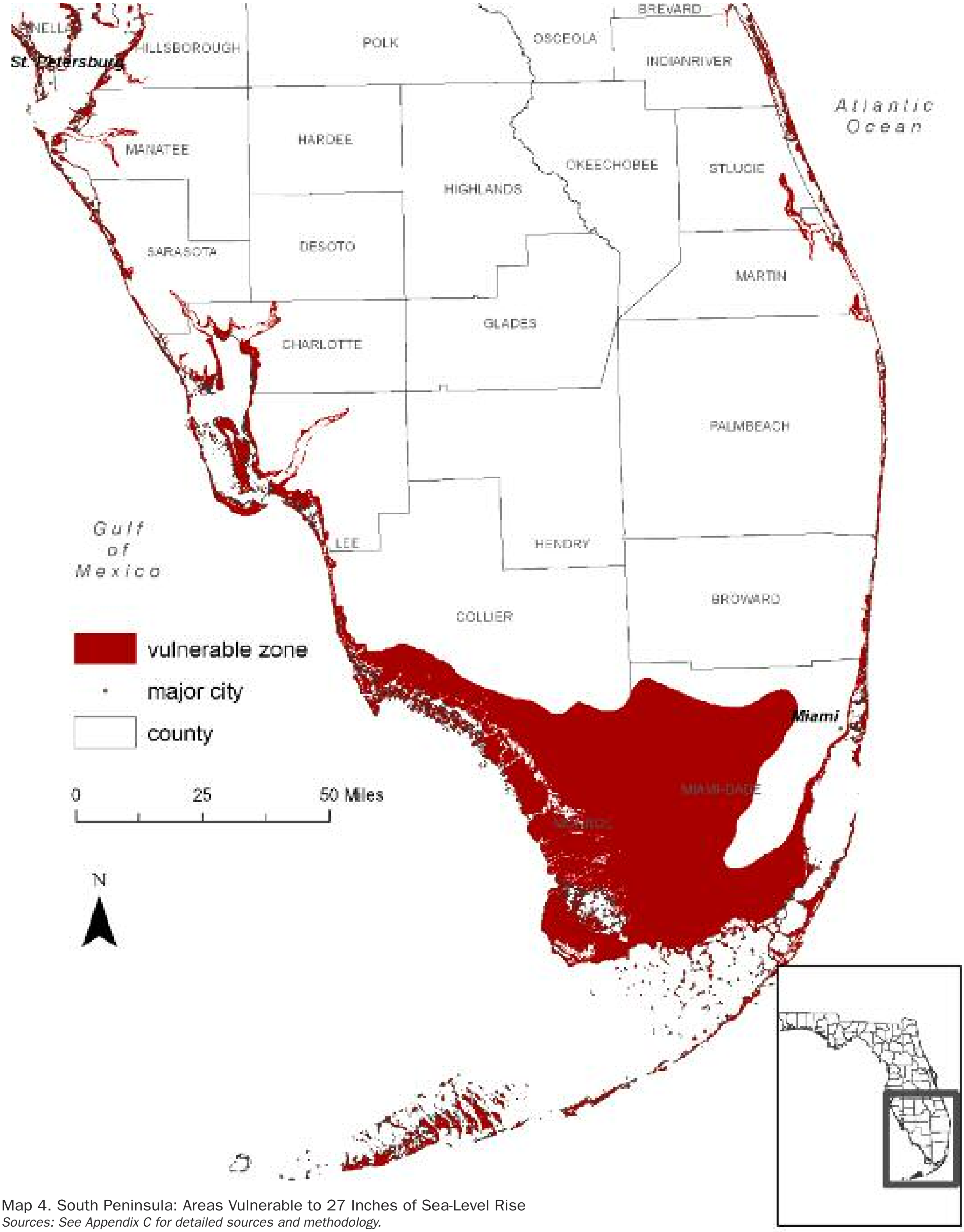
Even the best available elevation maps are limited by data collection errors and as yet unsurveyed changes in landscape. It should be emphasized that the exact borders of Florida's "vulnerable zone," that is, the area vulnerable to the first 27 inches of sea-level rise, cannot be known with certainty. The maps and data presented here are a best estimate based on the USGS dataset, and should be examined at a scale no smaller than the neighborhood or the small town. At the edges of the vulnerable zone, no map would be accurate enough to show whose backyard will be flooded.




Map 2. Florida: Areas Vulnerable to 27 Inches of Sea-Level Rise
*Sources: See Appendix C for detailed sources and methodology.*




Map 3. North Peninsula: Areas Vulnerable to 27 Inches of Sea-Level Rise
*Sources: See Appendix C for detailed sources and methodology.*




Map 4. South Peninsula: Areas Vulnerable to 27 Inches of Sea-Level Rise
*Sources: See Appendix C for detailed sources and methodology.*


Map 5. Panhandle: Areas Vulnerable to 27 Inches of Sea-Level Rise
*Sources: See Appendix C for detailed sources and methodology.*

Of course, it is likely that adaptation measures will be taken to hold back the sea for many developed or otherwise valuable properties. But as the Science and Technology Committee of the Miami-Dade County Climate Change Task Force pointed out, "the highly porous limestone and sand substrate of Miami-Dade County (which at present permits excellent drainage) will limit the effectiveness of widespread use of levees and dikes to wall off the encroaching sea." (Miami-Dade County Climate Change Task Force 2007)

Coastal lands around the state are threatened by sea-level rise, including developed areas, natural ecosystems, and agricultural lands. Two-thirds of the total vulnerable land area is currently wetlands (marshes, tidal flats, swamps, mangroves, and wetland forests) that would be converted into open water, too deep for current vegetation to survive. For example, one-third of Florida's marshlands will be flooded, as will 99 percent of the state's mangroves. The 1,100 square miles of dryland in the vulnerable area consist primarily of developed land and dryland forest. In addition, more than half of Florida's beach land area will be flooded. Table 8 reports the amount of land area in the vulnerable zone by land use. (For a further breakdown of the vulnerable area by land cover and county, see Appendix A.)

While some areas of Florida will far more affected than others, 40 of the state's 67 counties have at least 1 square mile in the vulnerable zone, and 16 counties have at least 10 percent of their land in this category (see Table 9). In Monroe County — Florida's southwest tip and the Keys — 99.6 percent of land area will be under water by 2060; that's all but 6 square miles. So too will 70 percent of Miami-Dade County, and 20 percent of Franklin and Gulf Counties on the Florida panhandle.

Almost one-tenth of Florida's current population — 1.5 million people — live in this vulnerable zone; one-quarter of the affected population lives in Miami-Dade County. Thirty-three counties currently have 1,000 or more people living in the vulnerable zone. Table 10 lists the 10 counties that currently have more than 50,000 people living in the vulnerable zone. In Monroe County, only 4,000 people live in those 6 square miles of what will remain dry land after 27 inches of sea-level rise; the remaining 95 percent of the county's current population live in areas that will (absent successful countermeasures) be inundated by 2060.

**Table 8. Selected Land Area Vulnerable to 27 Inches of Sea-Level Rise by Land Use**

| | Vulnerable Zone | |
|---|---|---|
| | square miles | percentage of vulnerable area (%) |
| Agriculture | 52 | 1.2% |
| Developed | 433 | 10.0% |
| Forest | 409 | 9.5% |
| Mangroves | 862 | 20.0% |
| Marsh and Tidal Flats | 1,827 | 42.3% |
| Other Swamp and Forested Wetland | 618 | 14.3% |
| Pasture | 7 | 0.2% |
| Sandy Beach | 29 | 0.7% |
| Scrub, Grasslands, Prairie, Sandhill | 78 | 1.8% |
| TOTAL | 4,315 | 100.0% |

*Sources: NOAA Medium Resolution Digital Vector Shoreline (U.S. Geological Survey 2007), USGS 1:250,000 Digital Elevation Model (University of Florida: GeoPlan 2007), and Historic and Projected Populations of Florida Counties (University of Florida: GeoPlan 2007).*

**Table 9. Land Area Vulnerable to 27 Inches of Sea-Level Rise by County**

| | Vulnerable Land Area (share of total land area) | Vulnerable Land Area (square miles) | Total Land Area (square miles) |
|---|---|---|---|
| **Florida Total** | **28.7%** | **4,048** | **14,080** |
| Monroe | 99.6% | 979 | 983 |
| Miami-Dade | 69.2% | 1,354 | 1,956 |
| Franklin | 21.7% | 118 | 544 |
| Gulf | 19.7% | 109 | 555 |
| Brevard | 18.5% | 187 | 1,009 |
| Collier | 18.2% | 370 | 2,026 |
| Pinellas | 17.9% | 50 | 280 |
| St.Johns | 17.5% | 107 | 611 |
| Volusia | 16.6% | 185 | 1,109 |
| Lee | 15.4% | 124 | 804 |
| Seminole | 13.3% | 41 | 307 |
| Bay | 11.6% | 89 | 768 |
| Duval | 11.2% | 87 | 776 |
| Dixie | 10.7% | 75 | 704 |
| Taylor | 10.6% | 111 | 1,042 |
| Wakulla | 10.5% | 64 | 607 |

*Sources: NOAA Medium Resolution Digital Vector Shoreline (U.S. Geological Survey 2007), USGS 1:250,000 Digital Elevation Model (University of Florida: GeoPlan 2007), and Historic and Projected Populations of Florida Counties (University of Florida: GeoPlan 2007).*

More than three-quarters of Florida's population, 444 people per square mile, live in coastal counties, while just 170 people per square mile live in inland counties, the differences partially due to large cities along the coast. In recent years, inland counties have been growing faster than shoreline counties; inland counties' population and housing stock grew 42 percent from 1990 to 2004 (Kildow 2006b; a). As sea-level rise increases, Florida's coastal population will move inland, increasing population density and transforming the landscape of the relatively rural and undeveloped interior of the state.

Sea-level rise may also have a less-obvious effect on Florida, by triggering a surge of "environmental refugees" from nearby Caribbean nations. Climate change has the potential to uproot people from their homes and their communities as villages and cities are flooded, and traditional livelihoods disrupted, especially in developing countries. Sea-level rise, desertification, greater variability in weather patterns, and unpredictable rainfall are expected to create environmental refugees around the world, and the Caribbean Basin is no exception (Bates 2002; Dlugolecki 2005; Salehyan 2005). According to a 1999 International Red Cross report, 50 million people worldwide may be displaced by the effects of climate change by 2010, making it a more significant source of refugees worldwide than violent conflict and political persecution (Roc 2006).

**Table 10. Population Living in Areas Vulnerable to 27 Inches of Sea-Level Rise**

| | Vulnerable Population (share of total population) | Vulnerable Population | Total Population |
|---|---|---|---|
| **Florida Total** | **9.4%** | **1,503,153** | **15,982,378** |
| Miami-Dade | 16.8% | 379,511 | 2,253,362 |
| Pinellas | 16.5% | 152,413 | 921,482 |
| Volusia | 20.8% | 92,267 | 443,343 |
| Brevard | 18.7% | 89,060 | 476,230 |
| Monroe | 94.9% | 75,549 | 79,589 |
| Duval | 9.2% | 71,843 | 778,879 |
| Lee | 15.7% | 69,036 | 440,888 |
| Palm Beach | 6.1% | 68,822 | 1,131,184 |
| Broward | 3.8% | 60,920 | 1,623,018 |
| Collier | 22.3% | 55,970 | 251,377 |

*Sources: NOAA Medium Resolution Digital Vector Shoreline (U.S. Geological Survey 2007), USGS 1:250,000 Digital Elevation Model (University of Florida: GeoPlan 2007), and Historic and Projected Populations of Florida Counties (University of Florida: GeoPlan 2007).*

Island nations in the Caribbean Sea would be devastated by 3 feet of sea-level rise, or more, in this century, together with higher temperatures, and more intense storms (Myers 1993; 2002; Intergovernmental Panel on Climate Change 2007b). In countries throughout the Caribbean, making a living will become harder. Most developing nations will find it difficult to pay for expensive adaptation measures like an extensive levee system, hurricane-rated construction methods, air conditioning, and an electrical system that can bear the power demands of an air conditioner in every home and business (Simms and Reid 2006). Florida's close proximity to a number of developing island nations could make it a desirable destination for environmental refugees from the Caribbean. Even if aggressive implementation of immigration controls limits the number of such refugees who actually settle in Florida, those measures themselves have serious social and ethical implications and are far from cost-free.

### Greater hurricane intensity

In the business-as-usual scenario, hurricane intensity will increase, with more Category 4 and 5 hurricanes occurring as sea-level temperatures rise. Greater damages from more intense storms would come on top of the more severe storm surges that will result from higher sea levels (Henderson-Sellers et al. 1998; Scavia et al. 2002; Anthes et al. 2006; Webster et al. 2006; Intergovernmental Panel on Climate Change 2007b).

Tropical storms and hurricanes cause billions of dollars in economic damages and tens or even hundreds of deaths each year along the U.S. Atlantic and Gulf coasts. Tropical storms, as the name implies, develop over tropical or subtropical waters. To be officially classified as a hurricane, a tropical storm must exhibit wind speeds of at least 74 miles per hour. Hurricanes are categorized based on wind speed, so that a relatively mild Category 1 hurricane exhibits wind speeds of 74 to 95 miles per hour, while an extremely powerful Category 5 hurricane has wind speeds of at least 155 miles per hour (Williams and Duedall 1997; Blake et al. 2007).

Atlantic tropical storms do not develop spontaneously. Rather, they grow out of other disturbances, such as the "African waves" that generate storm-producing clouds, ultimately seeding the hurricanes that hit Florida. Sea-surface temperatures of at least 79°F are essential to the development of these smaller storms into hurricanes, but meeting the temperature threshold is not enough. Other atmospheric conditions, such as dry winds blowing off the Sahara or the extent of vertical wind shear — the difference between wind speed and direction near the ocean's surface and at 40,000 feet — can act to reduce the strength of Florida-bound hurricanes or quell them altogether (Nash 2006).

While climate change is popularly associated with more frequent and more intense hurricanes (Dean 2007a), within the scientific community there are two main schools of thought on this subject. One group emphasizes the role of warm sea-surface temperatures in the formation of hurricanes and points to observations of stronger storms over the last few decades as evidence that climate change is intensifying hurricanes. The other group emphasizes the many interacting factors responsible for hurricane formation and strength, saying that warm sea-surface temperatures alone do not create tropical storms.

The line of reasoning connecting global warming with hurricanes is straightforward; since hurricanes need a sea-surface temperature of at least 79°F to form, an increase of sea-surface temperatures above this threshold should result in more frequent and more intense hurricanes (Landsea et al. 1999). The argument that storms will become stronger as global temperatures increase is closely associated with the work of several climatologists, including Kerry Emanuel, who finds that rising sea-surface temperatures are correlated with increasing wind speeds of tropical storms and hurricanes since the 1970s, and Peter J. Webster, who documents an increase in the number and proportion of hurricanes reaching categories 4 and 5 since 1970 (Emanuel 2005; Webster et al. 2005).

Climatologist Kevin E. Trenberth reports similar findings in the July 2007 issue of *Scientific American,* and states that, "Challenges from other experts have led to modest revisions in the specific correlations but do not alter the overall conclusion [that the number of Category 4 and 5 hurricanes will rise with climate change]"(Trenberth 2007). While these scientists project increasing storm intensity with rising temperatures, they neither observe nor predict a greater total number of storms. Thus the average number of tropical storms that develops in the Atlantic each year would remain the same, but a greater percentage of these storms would become Category 4 or 5 hurricanes.

Scientists who take the opposing view acknowledge that sea-surface temperatures influence hurricane activity, but emphasize the role of many other atmospheric conditions in the development of tropical cyclones, such as the higher wind shears that may result from global warming and act to reduce storm intensity. In addition, since hurricane activity is known to follow multidecadal oscillations in which storm frequency and intensity rises and falls every 20 to 40 years, some climate scientists — including Christopher W. Landsea, Roger A. Pielke, and J. C. L. Chan — argue that Emanuel and Webster's findings are based on inappropriately small data sets (Landsea 2005; Pielke 2005; Chan 2006). Pielke also finds that past storm damages, when "normalized" for inflation and current levels of population and wealth, would have been as high or higher than the most damaging recent hurricanes (Pielke and Landsea 1998; Pielke 2005). Thus, he infers that increasing economic damages are likely due to more development and more wealth, not to more powerful storms.

Recent articles in the *New York Times* (Dean 2007a) and the *Smithsonian Magazine* (Nash 2006) present both sides of the debate. It is difficult to say how much of the scientific community falls into either camp, although the latest IPCC report calls increasing intensity of hurricanes "likely" as sea-surface temperatures increase (Intergovernmental Panel on Climate Change 2007b). A much greater consensus exists among climatologists regarding other types of future impacts on hurricanes. Even if climate change were to have no effect on storm intensity, hurricane damages are very likely to increase over time from two causes. First, increasing coastal development will lead to higher levels of damage from storms, both in economic and social terms. Second, higher sea levels, coastal erosion, and damage of natural shoreline protection such as beaches and wetlands will allow storm surges to reach farther inland, affecting areas that were previously relatively well protected (Anthes et al. 2006).

In our business-as-usual case, the total number of tropical storms stays the same as today (and the same as the rapid stabilization case), but storm intensity — and therefore the number of major hurricanes — increases. The hurricane impacts section, later in this report, includes estimates of likely hurricane damages and deaths in both scenarios.

## Less rainfall, more drought

Florida's 2006 annual rainfall was 20 percent less than the historical average, and drought conditions continued through the first half of 2007. Across the state, rainfall for spring 2007 (March through May) averaged only 4.5 inches, compared to an average 10.4 inches of rainfall usually received in the spring (National Oceanic & Atmospheric Administration 2007b). As of mid-2007, water levels in Lake Okeechobee were at a record low (Florida Department of Agriculture and Consumer Services 2007d; Revkin 2007). The historical average annual rainfall for Florida is much greater than the 2006 level, because over the last century years of excessive rainfall have balanced out drought years (see Table 11).

**Table 11. Florida State Average Rainfall**

*in inches, three-month totals*

| | Dec–Feb | Mar–May | Jun-Aug | Sept–Dec | Annual Total |
|---|---|---|---|---|---|
| Historical Average (1896–2006) | 9 | 10 | 22 | 13 | 54 |
| 2006 Actual | 9 | 5 | 19 | 10 | 43 |
| High-impact case: 2100 predicted | 8 | 9 | 20 | 12 | 49 |

*Source NOAA National Climatic Data Center (National Oceanic & Atmospheric Administration 2007b).*
*Note: IPCC Chapters 10 and 11 (Intergovernmental Panel on Climate Change 2007b) project the upper range of precipitation decrease for Florida to be 10 percent. The 2100 projection shown here is a 10 percent reduction to the historical average.*

In the business-as-usual case, precipitation levels decrease by 10 percent annually, contributing to drought conditions. This change may seem small, especially in comparison to the current drought, but this precipitation decrease is a projected average across many years. A decrease in rainfall of 10 percent represents a long-term tendency toward drought for Florida, year after year.

Not everyone agrees that Florida is headed for lower levels of rainfall, with or without climate change. What matters most, however, is not the annual total of precipitation, but the prevalence of drought. Paradoxically, increased rainfall could be accompanied by an increase in drought conditions: more rain could fall in hurricanes and sudden downpours, while hotter temperatures could lead to faster and more complete drying out between rainfalls. Most of the consequences of decreased rainfall discussed in this report are equally applicable to a scenario where total rainfall does not decline, but drought conditions increase.

In addition to obvious impacts on water supplies, persistent droughts also tend to exacerbate wildfires. In an average year, nearly 6,000 wildfires occur in Florida, burning 175,000 acres. Before 2007, the worst Florida fire season on record was 1998, when over 400,000 acres burned (Harrison 2004); as of mid-2007, more than 520,000 acres had burned. Most wildfires take place at the

end of the winter dry season, when both surface waters and underground aquifers are at their most depleted (Beckage and Platt 2003; Florida Department of Agriculture and Consumer Services 2007d).

Though this report does not include quantitative projections of future increases in wildfires associated with our business-as-usual scenario, an increase in drought conditions due to climate change would very likely increase the acreage burned by wildfires each year — and would likewise increase associated economic costs. The cost of wildfires can be substantial. According to a USDA study, the 1998 Florida wildfires cost at least $600 million, which included $12 million in destroyed houses, businesses, cars and boats; the cost of canceling the Daytona 500 and a steep decline in tourism; and a 100 percent increase in emergency-room visits for asthma and bronchitis. The study did not include lost worker productivity and wages, the indirect costs of road closures, or the loss of uninsured property (Butry et al. 2001).

### More severe heat waves

In the business-as-usual case, heat waves become more severe and more common, with the chance of exceeding current record temperatures growing 100-fold by mid-century and a gradual disappearance of the cooling nighttime temperatures that dampen the health impacts of extremely high temperatures (Easterling et al. 1997; Kalkstein and Greene 1997; Easterling et al. 2000; Kalkstein 2000; U.S. Global Change Research Program 2001; Stott et al. 2004; Epstein and Mills 2005).

Unlike many other parts of the United States, incidents of multiple deaths in a heat wave are almost unheard of in Florida due to the prevalence of air conditioning in homes and businesses, as well as climate-appropriate architectural styles (Patton 2002). Deaths and illness from heat waves may stay at low historical levels even as Florida's average temperature and temperature extremes climb, but only if the state's air conditioning and electricity supply keep up with increasing temperatures and heat index values. Moreover, severe heat waves may well decrease the attractiveness of outdoor tourism attractions that play an important role in Florida's economy even in the summer months, such as going to the beach, fishing, scuba diving, and visiting theme parks.

### Ocean warming and acidification

The world's oceans act as a massive heat sink, storing well over half of the energy from the sun that enters the global climate system. As the atmosphere warms, so do the oceans. In the business-as-usual scenario, with air temperatures increasing by 10°F, sea surface temperatures for Florida will increase by several degrees. This temperature increase will have a serious impact on many ocean species, and will further exacerbate stresses on Florida's coral reefs. Even moderate warming causes "bleaching" as the coral lose their colorful symbiotic algae; if the stress continues long enough, the reef will to start to die off.

Historically, large-scale coral bleaching has occurred in connection with extreme El Nino weather events. El Nino events occur when wind and ocean currents in the equatorial Pacific Ocean shift, resulting in a temporary increase in sea surface temperatures in certain areas. As a result of the 1998 El Nino — the largest in recorded history — 16 percent of the world's reefs were destroyed in less than 9 months. In some regions more than 95 percent of coral organisms were killed (Wilkinson 2000). In the Florida Keys, coral bleaching events have occurred several times in the past two decades. In 1997 and 1998, most likely in connection with the El Nino, large-scale bleaching occurred (Wilkinson 2004).[13]

It is clear from these El Nino-related bleaching events that corals are very sensitive to changes

in water temperature. Bleaching may occur with a temperature increase of just a few degrees. Under the business-as-usual scenario, sea surface temperatures are likely to rise by several degrees by 2100, surpassing the temperature limits of many of the coral species that inhabit the area. As bleaching events become more frequent and severe, the coral marine ecosystem supporting fisheries will be disrupted (National Wildlife Federation and Florida Wildlife Federation 2006). Globally, coral reefs support an estimated 0.5 to 2 million species of marine organisms, including 25 percent of all known marine fish species.

Independent of its warming-related impact, carbon dioxide (the most prevalent anthropogenic greenhouse gas) also affects coral reefs by decreasing the availability of dissolved calcium carbonate, the chemical building block for coral skeletons. Specifically, as atmospheric concentrations of carbon dioxide increase, more carbon dioxide dissolves into seawater, where it forms carbonic acid. Because calcium carbonate is alkaline, the carbonic acid tends to dissolve it. Already, global average surface ocean pH is 0.1 units lower than pre-industrial values (the more acidic the water, the lower the pH).

In the business-as-usual case, the Atlantic Ocean and Caribbean Sea will experience pH reductions of 0.35 over the next century. Because the pH scale is logarithmic (i.e., each full digit indicates a 10-fold change in acidity), this reflects more than a doubling of acidity. This increase in acidity will lead to reductions in calcification rates of coral and some other hard-shelled marine organisms (Gattuso et al. 1998; Kleypas et al. 1999; Caldeira and Wickett 2003). The effects of reduced calcification in coral are weaker skeletons, slower growth rates, and an increased susceptibility to erosion. Coral reefs that have seen physical damage, especially from human activities such as dredging, will be experience more severe effects (Kleypas et al. 1999).

Both warming and acidification will have detrimental effects on Florida's coral reefs. Bleaching events due to ocean warming are likely to gain the most attention as they produce the most visible destruction, whereas decreases in calcification occur over longer periods of time and are harder to observe. Both warming and acidity-related stresses increase vulnerability to coral diseases such as white and black band disease. Ultimately the overall damage will be a combination of both effects: warming episodes will lead to the expulsion of symbiotic algae and potential coral death, while acidification will hamper re-growth. In areas where physical damage from erosion or human activities has already increased vulnerability, the effects will be most pronounced.

Impacts from acidification are not limited to coral. Marine organisms that build calcium carbonate shells (called "bio-calcification"), including plankton, constitute much of the base of the entire marine food web. Loss of these organisms has the potential to disrupt the entire aquatic food chain, threatening not only invertebrates and fishes but also marine mammals and sharks. In addition, larger crustaceans (e.g., shrimp, lobsters, and crabs) and echinoderms (e.g., starfish, sea urchins, and sea cucumbers) will have increasing difficulty forming their own calcium-carbonate shells. For some organisms, extinction thresholds are likely to be crossed this century. The calcifying phytoplankton and zooplankton that are food for many larger marine species will also suffer with acidification (Intergovernmental Panel on Climate Change 2007b).

# III. ECONOMIC IMPACTS: INDUSTRIES

Rapid growth in population and income per capita means that Florida business will be booming in the rapid stabilization case. With much more serious impacts from climate change in the business-as-usual case, some businesses will be unable to operate at their full capacity, while other industries may close up shop in Florida altogether. Tourism, one of Florida's largest economic sectors, will be the hardest hit as much of the state's wealth of natural beauty — sandy beaches, the Everglades, the Keys — disappears under the waves. Agriculture and fisheries will also suffer large losses. Well-known and economically important Florida products like orange juice and pink shrimp may become a thing of the past. The insurance industry also will be affected by climate change, as it seeks to adjust to a new, riskier Florida; Florida's residents and businesses will continue to struggle to find affordable insurance coverage.

## TOURISM

Each year visitors make 85 million trips to Florida's scenic beaches, rich marine ecosystems and abundant amusement parks, staying for an average of five nights per trip. Of these trips to Florida, 78 million are taken by domestic U.S. travelers — an astounding one trip per year for every fourth U.S. resident — and 7 million trips by international visitors, one-third of whom are Canadian. A further 13 million Florida residents take recreational trips within Florida, and many more travel on business within the state, or participate in recreational activities near their homes (VISIT FLORIDA 2007a; b).

In 2006, almost a tenth of the state economy — 9.6 percent, or $65 billion, of Florida's gross state product (GSP) — came from tourism and recreation industries including restaurants and bars; arts, entertainment and recreation facilities; lodging; air transportation; and travel agencies.

An additional $4 billion was collected in sales tax on these purchases and $500 million in the "bed tax" charged by some counties on stays in hotels, motels, vacation rental condos, and campgrounds (VISIT FLORIDA 2007a; b).

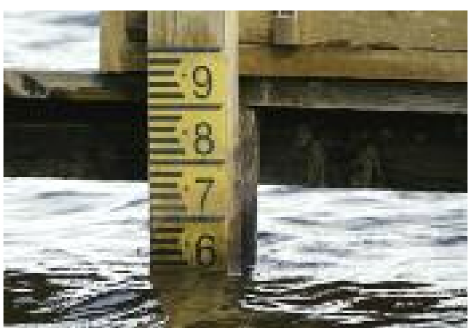
### Tourism projections: Rapid stabilization case

Tourism is the second biggest contributor to Florida's economy, after real estate. As GSP grows six-fold over the next century, we project that in the rapid stabilization case tourism and its associated taxes will remain a steady 9.6 percent of total GSP. Under these assumptions, Florida's tourism industry will bring in $317 billion in revenues in 2050. Today, approximately 980,000 people make their living in Florida's tourism and recreation sector, 6 percent of the state's population. If the same share of state residents is still employed in tourism in 2050, 1.9 million Floridians will draw paychecks from restaurants, amusement parts, hotels, airports, and travel agencies (VISIT FLORIDA 2007a; b). The gradual climate change under the rapid stabilization case should have little impact on tourism.

### Tourism projections: Business-as-usual case

In the business-as-usual case, the future of Florida's tourism industry is clouded. Florida's average temperature increases 2.5°F by 2025, 5°F by 2050, and 10 °F by 2100. In January, warmer temperatures are unlikely to scare off many tourists, but in July and August — when the average high temperature on Miami Beach will rise from 87°F to 97°F over the next century, and the July heat index (temperature and humidity combined) will increase by 15 to 20°F — Florida's already hot and sticky weather is likely to lose some of its appeal for visitors.

Sea levels in 2050 will have risen by 23 inches, covering many of Florida's sandy beaches. In theory, these beaches could be "renourished" by adding massive amounts of sand to bring them up to their former elevation — the price-tag for this costly project is discussed below — or the new coastline could be converted to beach recreation use, but only if residential and commercial properties in the zone most vulnerable to sea-level rise are not "shored up" by sea-walls or levees. With 45 inches of sea-level rise over the next century, a Florida nearly devoid of beaches in 2100 is a very real possibility.




Many of the marine habitats that bring divers, snorkelers, sportfishers, birdwatchers and campers to Florida will also be destroyed or severely degraded over the course of the next century. Sea-level rise will drown the Everglades and with it the American crocodile, the Florida panther, and many other endangered species. As Florida's shallow mangrove swamps and seagrass beds become open water — unless wetland ecosystems are permitted to migrate inland by allowing Florida's dry lands to flood — manatees and other aquatic species that rely on wetlands for food, shelter and breeding grounds will die out. Similarly, Florida's coral reefs will bleach and die off as ocean temperature and acidity increases. Tourists are unlikely to come to Florida to see the dead or dying remnants of what are today unique treasures of the natural world.

Estimates of the direct impact of hurricane damage on Florida's economy are dealt with in a separate section of this report, but there are also important indirect effects on Florida's reputation as a vacation destination. As the intensity of storms increases in the business-as-usual case, fewer visitors are likely to plan trips to Florida, especially during the July-to-November hurricane season. The possibility of being caught in a storm or forced to evacuate to a storm shelter will become a greater concern for tourists as the effects of climate change are featured more frequently on the evening news.

Under these conditions, Florida's tourism industry is almost certain to suffer; the exact decline in future revenues and employment is, however, nearly impossible to estimate with any certainty.

The calculations that follow are, therefore, a rough estimate based on a broad interpretation of existing data.

Because Florida receives just 19 percent of its tourists in October through December, the fewest visitors of all four quarters, we infer that the lowest number of trips to Florida in any month is about 5 million (VISIT FLORIDA 2007a; b).[14] We take this to be the base rate for Florida's tourism at present; the rate that is insensitive to weather. Regardless of hurricanes and sweltering summers, at least 5 million people come to Florida each month. Some come for business, some to visit amusement parks (many of which are air conditioned, though outdoor areas, including lines, obviously are not), and some — despite rain, humidity, and scorching heat — to the beach. This projection implies that three-quarters of all tourists would still come to Florida despite the worst effects of climate change, while one-quarter would go elsewhere or stay home. We make the same assumption for Florida residents' share of tourism and recreation spending: for one out of four recreational activities that Florida families would have taken part it, they will instead choose to stay in their air conditioned homes.

We assume that under the business-as-usual case, tourism and recreational activities decline gradually to 75 percent of the rapid stabilization case level by 2100. Midway through that decline, in 2050, Florida's tourism industry will bring in $40 billion less in annual revenue and employ 1 million fewer people than it would in the rapid stabilization case, a loss of 1.2 percent of GSP. The annual cost of inaction reaches $167 billion in 2100 — 2.4 percent of GSP.

**Table 12. Tourism Industry: Costs of Inaction**

| | 2025 | 2050 | 2075 | 2100 |
|---|---|---|---|---|
| **Revenue (in billions of 2006 dollars)** | | | | |
| Rapid Stabilization Case | $161 | $137 | $460 | $668 |
| Business-As-Usual Case | $152 | $277 | $372 | $501 |
| *Cost of Inaction* | $9 | $40 | $88 | $167 |
| **Revenue (as a percentage of GSP)** | | | | |
| Rapid Stabilization Case | 9.6% | 9.6% | 9.6% | 9.6% |
| Business-As-Usual Case | 9.1% | 8.4% | 7.8% | 7.2% |
| *Cost of Inaction* | 0.5% | 1.2% | 1.8% | 2.4% |
| **Employment** | | | | |
| Rapid Stabilization Case | 1,433,000 | 1,856,000 | 1,856,000 | 1,856,000 |
| Business-As-Usual Case | 928,000 | 860,000 | 797,000 | 738,000 |
| *Cost of Inaction* | 505,000 | 996,000 | 1,059,000 | 1,118,000 |

*Source Authors' calculations.*
*Note: Employment numbers remain constant after 2050 because employment is assumed in these calculations to grow proportionally with population, and the conservative assumption that Florida's population will remain constant after 2050 is used throughout this report.*

Two of the most likely strategies for partially mitigating this enormous loss to Florida's tourism industry are beach nourishment to protect existing beaches, and the facilitation of inland migration of sandy beaches and wetlands. Beach nourishment is widely recognized as a stopgap measure with many unfortunate side-effects. Sand and silt dredged from the ocean floor and placed on top of current beach ecosystems erode two to ten times more quickly than the original sand (Dixon 2007; Hauserman 2007; Skoloff 2007 ). The ecological costs of beach nourishment are also very high. Dredged material buries all beach fauna and flora, killing the existing ecosystem. The material used for beach nourishment is often unsuitable for the reintroduction of the same species, or of any species. Sea turtles, for example, have been unable to nest and lay eggs on several renourished beaches (Maurer et al. 1978; Lindquist and Manning 2001; Peterson and

Bishop 2005; Pilkey and Young 2005; Speybroeck et al. 2006).

With projected sea-level rise of 27 inches, 55 percent of Florida's 52 square miles of sandy beach will disappear under the waves by 2060. Florida spent an average of $29 million a year adding sand to eroding beaches from 2000 to 2004. More rapid sea-level rise in the business-as-usual case and more rapid erosion of dredged materials would require a far greater addition of sand in each year. Counteracting the effects of sea-level rise in 2060 by adding three cubic yards of sand to every square yard of beach would require 270 million cubic yards of sand at a cost of $2.4 billion.[15] This figure does not include normal erosion from waves, wind and rain.

And that's just for a one-time renourishment. On average, renourishment of beaches needs to take place every six to ten years. If the projected sea-level rise takes place at a constant pace and each square foot of beach, once nourished, must be nourished again every six years, the bottom line is $400 million per year in 2050, and $700 million in 2100. This calculation assumes an abundant supply of local sand. If sand is not available from sources nearby each beach needing nourishment, costs would be even higher to offset additional transportation expenses.

Building sandy beaches up to their former elevation would produce isolated sandy islands of beach that would be particularly vulnerable to constant wear by tide and wind. Even at the low estimate of the frequency of replenishment presented here, a cumulative 1.2 billion cubic yards of sand would be needed by 2050 and 4.4 billion cubic yards by 2100. This amount of sand is simply not available locally. Current nourishment efforts for many of Florida's beaches, especially those in the southeast, are already facing sand shortage and, in some cases, eroding beaches are not being replenished for want of sand (Powers 2005; Day 2007). Surely piling up sand where beaches once lay as floodwater rises all around is a losing proposition, but even if public money could be found to carry it out, reserves of nearby sand would soon be depleted, and the ever increasing cost of importing sand from out of state or out of the country is not included in the estimates presented here.

A second likely strategy for mitigating some of the losses to the tourism industry, and to irreplaceable natural ecosystems, is allowing dry lands adjacent to beaches and wetlands to be inundated. That is, to *not* protect valuable waterfront property, regardless of what has been built there. Even in our business-as-usual case, the pace of sea-level rise is slow enough for most ecosystems to migrate — growing on the inland side as dry land floods, and shrinking on the ocean side as beaches and wetlands become open water. The main obstacle to this conservation strategy is the existence of valuable dry land property on the inland edge of these ecosystems. A plan for adapting to climate change cannot both protect existing developed areas by building sea-walls and levees and at the same time allow wetland species to create new ecosystems.

Most of Florida's sandy beaches are directly adjacent to developed areas. Maintaining beaches by allowing their migration inland would require both costly beach nourishment to create sandy beaches on what is now concrete foundations, roads, and backyards. More consequentially, homes, businesses, and industrial sites would have to be abandoned to the waves.

## AGRICULTURE

Florida's farmers and livestock producers contributed $4.5 billion to the state's economy, about 1 percent of GSP, and employed 62,000 workers, or 1 percent of the state's workforce, in 2005 (Bureau of Economic Analysis 2007; Bureau of Labor Statistics 2007).[16] Florida ranked fifth in the nation in sales of all crops and second in sales of fresh vegetables in 2004 (Florida Department of Agriculture and Consumer Services 2006b).

**Table 13. Agricultural Sales and Employees, 2004**

| | Sales (millions of 2006$) | Employees |
|---|---|---|
| **Greenhouse and nursery production** | **1,738** | **23,487** |
| **Fruit and tree nuts** | **1,614** | **10,002** |
| Oranges | 1,041 | 4,322 |
| Other Citrus | 284 | 1,718 |
| Other | 288 | 3,962 |
| **Animal production** | **1,584** | **5,930** |
| Beef cattle | 473 | 1,161 |
| Dairy cattle and milk production | 461 | 2,000 |
| Other animal production | 224 | 2,034 |
| **Vegetables and melons** | **1,544** | **19,504** |
| Tomatoes | 534 | |
| Other | 1,010 | |
| **Sugarcane** | **587** | **2,141** |
| **Other field crops** | **165** | **1,394** |
| **Total Agricultural Sector** | **7,231** | **62,457** |

*Sources: Cash receipt figures from the Florida Agriculture Statistical Directory 2006 (Florida Department of Agriculture and Consumer Services 2006b); employment figures from Bureau of Labor Services, Quarterly Census of Employment and Wages (Bureau of Labor Statistics 2007).*

Florida is well known for its $1.3 billion citrus industry, located primarily in the southern half of the state. Florida oranges, grapefruits, tangerines, and other citrus fruits accounted for more than half the total value of U.S. citrus production in 2004. Oranges alone brought in $1 billion in 2004, and in 2005, Florida employed 60 percent of all U.S. orange grove workers and 40 percent of all workers in the production of other citrus fruits (Florida Department of Agriculture and Consumer Services 2006b; Bureau of Labor Statistics 2007).

Florida's fresh vegetables and non-citrus fruits are also important to the U.S. food supply. In winter, farms lie dormant in most states, but Florida's mild climate allows produce to be grown year-round. Sales of vegetables and melons totaled $1.5 billion in 2004, employing 19,500 people (Bureau of Labor Statistics 2007). Florida ranks first in the country in sales of a host of vegetables and fruits, including fresh market tomatoes, bell peppers, cucumbers, squash, and watermelons. Florida's $830 million in tomato sales accounted for almost half of all fresh tomatoes sold in the United States in 2005 (Florida Department of Agriculture and Consumer Services 2006c).

Florida is also the nation's leading sugarcane producer with $550 million in sales, more than half of the U.S total for the crop in 2004. Florida's sugarcane is grown almost entirely in the warm climate and nitrogen-rich "muck" soils surrounding Lake Okeechobee in Palm Beach, Hendry, and Broward Counties (Mulkey et al. 2005; Florida Department of Agriculture and Consumer Services 2006b; Bureau of Labor Statistics 2007). Florida's greenhouse and nursery plants ranked second in the U.S. in 2005, with $1.9 billion in sales. Greenhouses and nurseries growing house-plants, hanging baskets, garden plants, fruit trees, and cut flowers employed over 23,000 people in 2004 (U.S. Department of Agriculture 2005; Florida Department of Agriculture and Consumer Services 2006c; Bureau of Labor Statistics 2007). Florida's 1.7 million head of cattle generated $473 million in cattle and calf sales and $461 million in dairy sales in 2004. Most of Florida's cattle are sold as calves that are shipped to other states to be raised as beef cattle, although in-state feedlots are expanding. Less than 10 percent of the cattle in Florida are dairy cows, producing milk mostly for in-state consumption (U.S. Department of Agriculture 2005; Bureau of Labor Statistics 2007; Florida Department of Agriculture and Consumer Services 2007b).

### Agriculture projections: Rapid stabilization case

Despite its profitability and importance to the state and the nation, Florida's agriculture faces serious constraints even in the rapid stabilization case. There is little land remaining for expansion of agriculture; on the contrary, there is likely to be continued pressure on existing agricultural land from population growth and resulting residential development. Florida's citrus industry will continue to suffer from citrus canker, a bacterial disease that causes fruit and leaves to be shed prematurely. The citrus canker bacteria can be spread quite rapidly by wind-blown rain; hurricanes have transported the disease beyond the quarantine zones set up by farmers. The 2004 hurricanes led to the infection of 80,000 acres of commercial citrus; Hurricane Wilma in 2005 caused the disease to spread to an additional 168,000 to 220,000 acres (Schubert et al. 2001; Anderson et al. 2004; Florida Department of Agriculture and Consumer Services 2006a; d; 2007a).

Even greater pressure on agriculture will result from the scarcity of water in the state. Florida's agricultural sector is already heavily dependent on irrigation water: 80 percent of all farmed acres (excluding pasturelands) are irrigated (Marella 2004). In 2000, just under half of all freshwater withdrawals were used for agriculture (see the water system section, below). Citrus and sugarcane commanded 47 and 22 percent of agricultural water withdrawals, respectively; all vegetables, including tomatoes, used just over 10 percent; greenhouses and nurseries about 5 percent; and livestock less than 1 percent (Florida Department of Agriculture and Consumer Services 2003; Marella 2004).

**Table 14. Acres of Irrigation by Crop Type, 2000**

| | Total Acreage | Irrigated Acreage | Water Use (million gallons per day) |
|---|---|---|---|
| Citrus | 834,802 | 99% | 1,825 |
| Sugarcane | 436,452 | 93% | 857 |
| Greenhouse and nursery | 142580 | 96% | 409 |
| Vegetable Crops | 239,674 | 88% | 401 |
| Field Crops | 445,861 | 29% | 148 |
| Other Fruit Crops | 28,955 | 66% | 40 |
| Livestock | | | 32 |
| **Total Agricultural Sector** | **2,139,774** | **80%** | **3,923** |

*Source U.S. Geological Survey Scientific Investigations Report 2004 (Marella 2004)*
*Note: Greenhouse and nursery combines four subcategories of "ornamentals and grasses": field grown, greenhouse grown, container grown, and sod, but excludes pasture hay and other crops and grasses that utilize reclaimed water. Agricultural sector total does not include pasture hay.*

Total freshwater use for agriculture has trended upward in the past several decades, reaching an average of 2 billion gallons per day in 1970, 3 billion in 1980, 3.5 billion in 1990, and almost 4 billion in 2000 (Marella 2004). Furthermore, these averages mask large seasonal variations; farmers need water most at the driest times of the year, when surface water supplies are likely to be most limited. In 2000, irrigation required more than seven times as much water in April as in July (Marella 2004).

Growing demands for water for domestic and other purposes, combined with declining natural supplies and the potential requirements of Everglades restoration, could make it difficult to maintain even the current flow of irrigation water in the future (see water section). This is among the greatest challenges to sustainable development in Florida — even in the rapid stabilization case, where impacts develop relatively slowly.

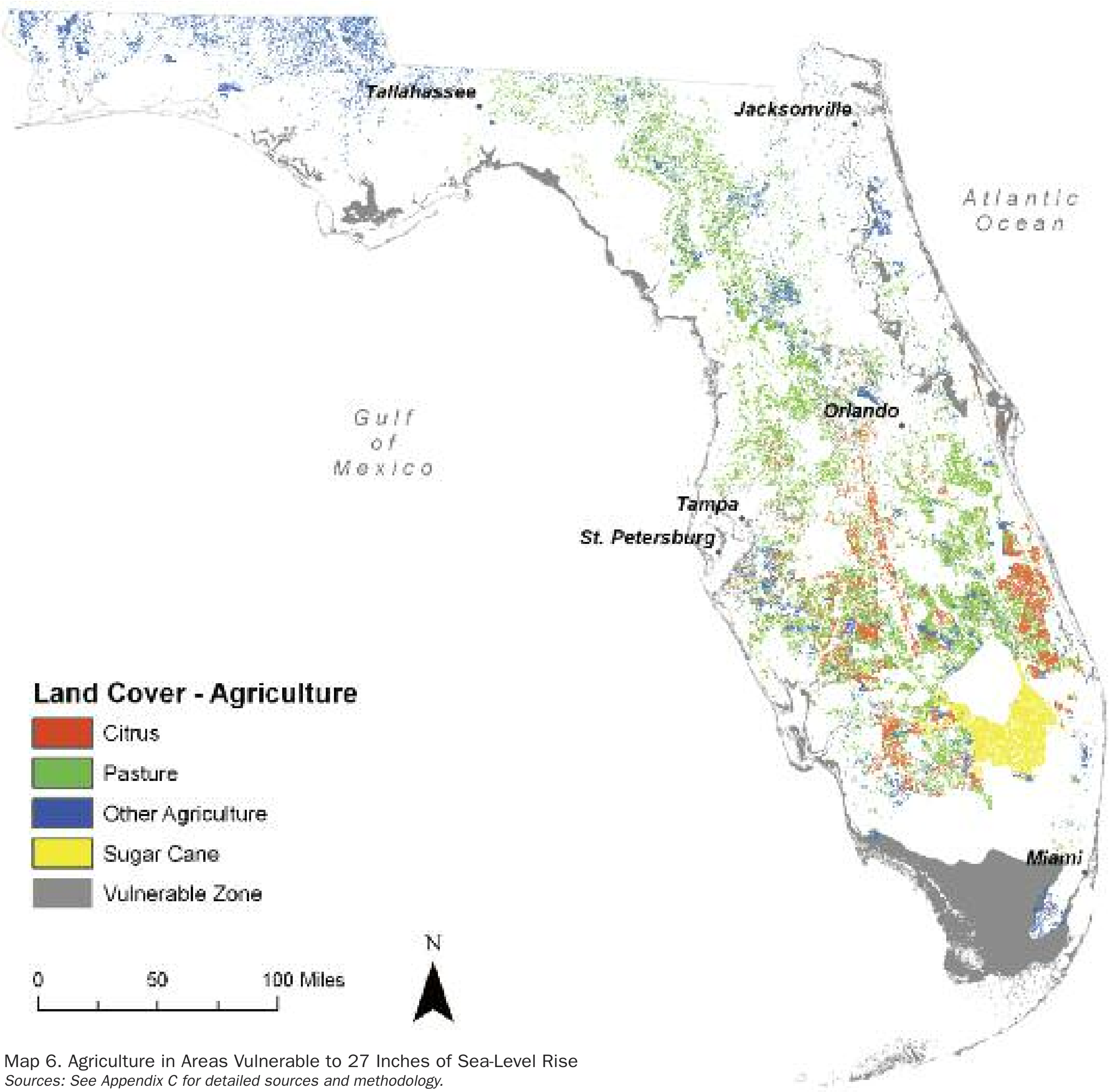
### Agriculture projections: Business-as-usual case

In the business-as-usual case, Florida's climate changes much more quickly: the state will become hotter and drier, and hurricanes and other extreme weather events will become more frequent. Temperatures climb four times as quickly in the business-as-usual case; as a result, impacts that don't arise until 2100 in the rapid stabilization case become important by 2025 in the business-as-usual case.

The warmer weather and increased carbon dioxide levels that come with climate change could, at first, have some short-term benefits for Florida agriculture. Even in Florida, farmers can face heavy damages when temperatures dip below freezing, and these losses result in higher fruit and vegetable prices across the country. Rising temperatures would, on average, mean fewer winter freezes, a welcome change for many farmers. In addition, some types of plants can photosynthesize more productively when levels of carbon dioxide are somewhat higher than at present. All the major crops grown in Florida, except sugarcane, fall into this category. The magnitude of this effect, however, is uncertain and by the end of the century the business-as-usual scenario will have reached carbon dioxide levels well beyond those which have been tested on plants.

But reduced damages from freezing and benefits from carbon dioxide fertilization are not the only effects on agriculture in the business-as-usual case, and most of the other impacts are detrimental. As temperatures increase, citrus production in South Florida will begin to decline as periods of dormant growth, necessary to the fruit's development, are reduced (Environmental Protection Agency 1997). Optimal temperatures for citrus growth are 68-86°F; at higher temperatures, citrus trees cease to grow (Ackerman 1938; Morton 1987). Production of tomatoes, too, will begin to decrease before the end of the century, as Florida's climate moves above their mean daily optimal temperature range of 68-77°F (Sato et al. 2000; U.S. Global Change Research Program 2001; Lerner 2006). Sugarcane may also suffer a reduction in yield; it belongs to a class of plants that benefit little from higher levels of carbon dioxide in the air, and it will have to compete with carbon-loving weeds (Intergovernmental Panel on Climate Change 2007a). If farmers increase herbicide use as a result, their production costs will increase accordingly, as will the environmental impacts of herbicide use. Sugarcane will also grow more slowly in the hotter, business-as-usual climate; the optimal average growing temperature for sugarcane is 77–79°F (Vaclavicek 2004).

Even those agricultural commodities that thrive in higher temperatures and higher concentrations of carbon dioxide are at risk from other consequences of climate change, including the



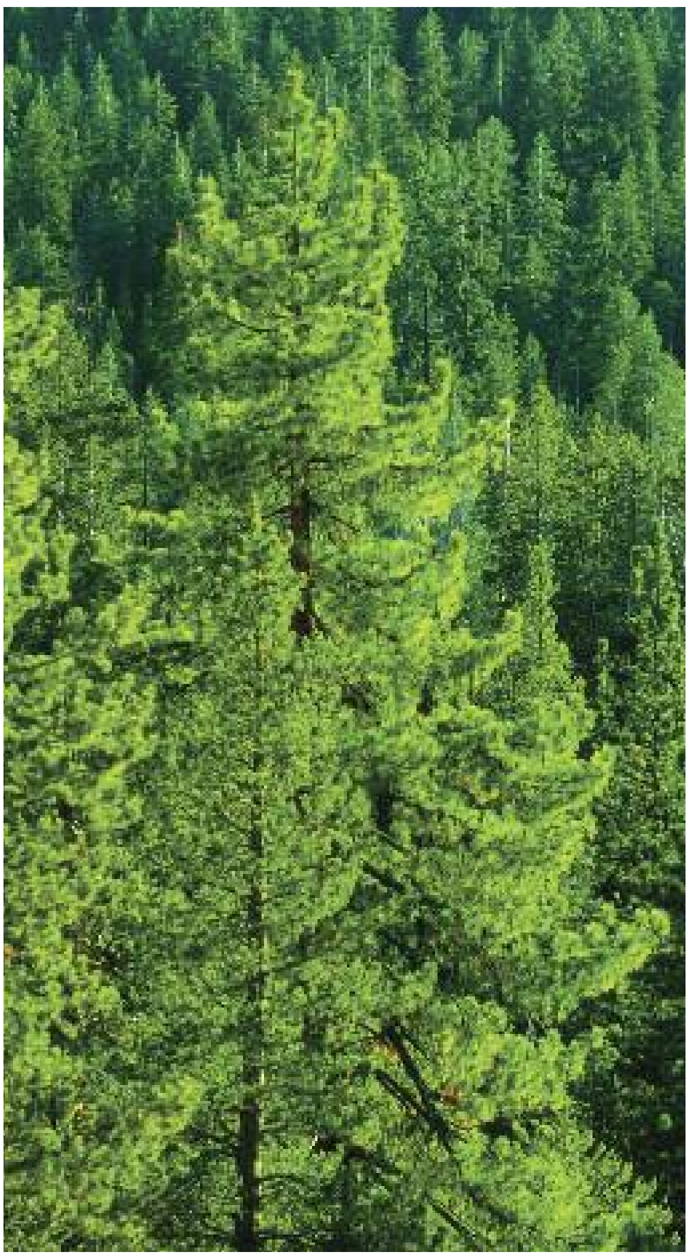

Map 6. Agriculture in Areas Vulnerable to 27 Inches of Sea-Level Rise
*Sources: See Appendix C for detailed sources and methodology.*

northward shift of some pest insects and weed species (Intergovernmental Panel on Climate Change 2001a). Flooding from sea-level rise is another concern. With 27 inches of sea-level rise in 2060, 4,500 acres of current pasture, 7,000 acres of citrus groves and 26,000 acres of other farmlands will be inundated (see Map 6).

Florida also has a long history of severe crop damage from hurricanes, and more intense storms may cause still greater losses. The 2004 hurricane season, for example, caused extensive damage to citrus groves, decreasing yields by 17 percent in the following year. In Indian River County, where Hurricanes Francis and Jeanne both struck, citrus production dropped by 76 percent, and several other counties lost 40 to 50 percent of their crop (Florida Department of Agriculture and Consumer Services 2006b). Sugarcane is another vulnerable crop; flooding from hurricanes can easily damage sugarcane roots when moisture levels become too high (Natural Resources Defense Council and Florida Climate Alliance 2001).

Climate change's biggest threat to Florida agriculture, however, may be increased water requirements for irrigation of crops and for livestock, accompanied by a decreased supply of freshwater. In addition to the water problems discussed above, higher temperatures will result in greater irrigation needs, as more water is lost to increased evaporation from the soil and transpiration from plants, while 5 to 10 percent less rainfall reaches plants in our business-as-usual case. In a statistical analysis of USDA data, we found that Florida citrus and sugarcane require approximately 5 and 7 percent more water, respectively, for each degree (Fahrenheit) of mean temperature increase (U.S. Department of Agriculture 2003).[17]

## FORESTRY



Forestry and forest product industries contributed approximately $3.5 billion to Florida's GSP and provided an estimated 30,000 jobs in 1997 (Hodges et al. 2005; U.S. Census Bureau 2007).[18] Florida's forestry industry output ranks 22nd in the nation, producing a wide variety of timber and related products, like paper, mulch, and plywood (Hodges and Mulkey 2003; Hodges et al. 2005; Florida Department of Agriculture and Consumer Services 2007c). Almost half of the state's land area is covered by forest, adding up to roughly 29,000 square mile, mostly in northern Florida (Natural Resources Defense Council and Florida Climate Alliance 2001; Florida Department of Agriculture and Consumer Services 2007c). Four-fifths of Florida's forested land is privately owned (Natural Resources Defense Council and Florida Climate Alliance 2001).

With climate change, the distribution of forest species will be affected. Many will experience increased productivity from higher levels of atmospheric carbon dioxide. For some species, temperatures will increase beyond their tolerance for survival. Higher temperatures will increase water stress from more evapotranspiration (water loss through leaves) and decreased soil moisture (Natural Resources Defense Council and Florida Climate Alliance 2001). Sea-level rise will threaten coastal and low-lying forests.

Each species has different tolerances for temperature and precipitation, and thus will respond differently to climatic variations. Tree species that currently coexist may migrate together to areas more closely matching their optimal climate, or the species composition of forests may change as some trees are able to migrate faster than others, or to tolerate a greater range of climatic conditions. In the northern and panhandle regions of the state, the current mixed conifer and hardwood forests are likely to shift northward out of the state as temperatures rise. This could make way for tropical ever-green broadleaf forests moving northward, or if drier conditions prevail, existing forests could be reduced and dry tropical savanna or pasture could take over. Another Florida ecosystem, the dry tropical savanna, could actually increase in forest density as it becomes more of a seasonal tropical forest (Environmental Protection Agency 1997).

Florida's loblolly-shortleaf pines and longleaf-slash pines will be adversely affected in the business-as-usual case as increases in temperatures surpass the upper limits of these species' optimal growth temperatures — 73 to 81°F (McNulty et al. 1996; Iverson and Prasad 2001). In contrast, oak trees, including oak-hickories and oak-pines, will be positively affected, as they thrive at higher temperatures (Iverson and Prasad 2001). Higher temperature, therefore, will lead to a replacement of loblolly-shortleaf pines with oak-pines in Florida (Iverson and Prasad 2001).

In general, the migration of forest ecosystems is not as simple as a uniform northward shift. Many forests will be unable to migrate because they are adjacent to developed or agricultural lands. Instead of moving with their accustomed climate, these forests will decline in health and productivity. Even where forests have the physical space to shift, there may be increased costs for the forestry industry as commercial forests move further away from current processing plants.

With less annual precipitation and a higher possibility of drought, forests will grow weaker. This added stress will make them more susceptible to pests and diseases. Due to their shorter life cycles and mobility, pests and diseases are likely to respond to the warmer temperatures by spreading their ranges and to do so at a quicker rate than trees can migrate.

## FISHERIES

Florida's recreational fishing industry is of great importance to the state economy. Every year, more than 6.5 million people go on 27 million fishing trips in Florida, landing 187 million fish; another 90 million are captured in catch-and-release programs (Hauserman 2006). In 2005, anglers spent an estimated $4.6 billion in Florida on equipment, access fees, and other trip-related expenses, such as food and lodging; three-quarters of this was spent on saltwater fishing trips, the rest on freshwater fishing (Florida Fish and Wildlife Conservation Commission 2005a).[19] Florida has become a premiere fishing destination, accounting for more than 10 percent of total U.S. recreational fishing expenses (U.S. Fish & Wildlife Service 2007a). Popular year-round saltwater fishing destinations in Florida include Indian River Lagoon, Apalachicola Bay, Tampa Bay, and the Florida Keys. Fishers come in hopes of landing prized gamefish such as spotted seatrout, redfish (or red drum), snook, tarpon, and marlin. The most widely caught species in 2006 included herring, mullet, pinfish, blue runner, Spanish mackerel, kingfish, spotted seatrout, and gray snapper (National Oceanic & Atmospheric Administration 2007a). In addition, Florida is the top scuba diving destination in the U.S., and one of the five most popular diving sites in the world; coral reefs and the associated fish provide the major attraction for divers.

Commercial fishing also takes place in the state, although on a smaller scale. In 2005, the dockside value of fish caught in Florida totaled $174 million, just over 4 percent of the value of all U.S. seafood in 2005 (National Ocean Economics Program 2007b). There are probably several thousand people employed in commercial fishing, although the exact number is uncertain.[20] While at least 150 varieties of fish and shellfish are caught for sale, more than half of the commercial catch is shrimp, crab, and lobster, worth a total of $98 million in 2005 (National Oceanic & Atmospheric Administration 2007a). Florida shrimp, crab, and lobster represented about 11, 8 and 4 percent, respectively, of the value of the U.S. catch of those products in 2005. In particular, 95 percent of U.S. pink shrimp, 99 percent of Florida stone claw crab, and all Caribbean spiny lobster is Florida-caught (National Oceanic & Atmospheric Administration 2007a). Among finfish, the top four varieties in 2005 — grouper, snapper, mackerel, and mullet — brought in $45 million, or 27 percent of commercial fishing sales (National Oceanic & Atmospheric Administration 2007a). Moreover, some of these fish are found primarily in Florida: the state accounted for 86 percent of all U.S. grouper sales in 2005, and 62 percent of the mullet market.

Other fish-related industries, including seafood processing, seafood markets, and fish hatcheries and aquaculture, have a larger economic impact than commercial fishing, with an estimated combined contribution of $530 million to the state economy in 2004 (National Ocean Economics Program 2007a). The seafood markets and processing industries are not entirely dependent on Florida's own catch, since a large portion of seafood processed in Florida has been imported — over 80 percent by weight in 2004 (Kildow 2006b).

The impacts of climate change on recreational fishing are included in the discussion of tourism, so no separate estimates of losses are developed here to avoid double-counting. For the commercial fishing industry, there will be greater losses under the business-as-usual scenario, compared to the rapid stabilization scenario. The most important single variety, pink shrimp (comprising 15 percent of Florida's commercial fishing catch), is still imperfectly understood, but years of warm water temperatures and intense hurricanes have led to unusually low pink shrimp catches (Ehrhardt and Legault 1999). The business-as-usual scenario, of course, will make such conditions more common. In view of the small size of the commercial fishing industry, no estimate of the value of losses is calculated here. This does not mean, however, that climate change is irrelevant to fishing.

Overfishing has already led to declining fish populations in Florida, and climate change will exacerbate the problem by destroying crucial habitats (Florida Fish and Wildlife Conservation Commission 2005b; Schubert et al. 2006). In particular, climate change will have devastating effects on the coral reef and estuarine wetland ecosystems on which many fish species depend.

Coral reefs provide food, shelter, and breeding grounds to a number of recreationally and commercially important fish in Florida, including king and Spanish mackerel, red and yellowtail snapper, red grouper, and spiny Caribbean lobster (National Oceanic & Atmospheric Administration 2007a). In addition, larger species such as marlin are often attracted to the reefs to eat smaller reef-dwellers. As discussed above in the scenario section, warmer ocean temperatures and increased acidity, both resulting from climate change, will cause enormous, potentially fatal harm to coral reefs.[21]

Estuaries, which provide habitat to 70 percent of Florida's fish and shellfish species at some point in their life cycles, are severely threatened by climate change as well (Florida Department of Environmental Protection 2004a; Levina et al. 2007). Estuaries — areas where freshwater from the land mixes with seawater, such as river deltas and bays — host various types of wetlands along Florida's coast, including salt marshes, mangroves, and seagrass beds. Some important recreational fish, like the pinfish, spotted seatrout, and pompano, spend most of their lives in estuaries. Shellfish, like crabs, oysters, and shrimp, rely on the nutrients in freshwater for their growth, making the mix of fresh and saltwater in estuaries critical to their production (Florida Fish and Wildlife Conservation Commission). For many other fish, including those that spend their adult lives in the open sea, estuaries provide nursery grounds for their young. Mullet and grouper, for example, spawn offshore and let tides and currents carry their eggs to estuaries. Saltmarshes, seagrass beds, or mangrove roots then provide both food and protection from prey for the young fish.

Larger predators have difficulty passing through the closely knit grasses and roots, and in some cases cannot survive in the lower salinity water (Florida Department of Environmental Protection 2004b). Even fish that do not live in estuaries may be dependent on fish that do for food. Loss of estuarine habitats can cause ripple effects throughout the marine food chain (National Wildlife Federation and Florida Wildlife Federation 2006).

As sea levels rise, estuarine wetlands will be inundated and vegetated areas will be converted to open water (Levina et al. 2007). If sea levels rise gradually and coastal development does not prevent it, the wetlands and the species they support could migrate landward (Brooks et al. 2006). But rapid sea-level rise combined with structures built to protect human development, such as seawalls, prevent landward migration, causing estuarine habitats to be lost altogether. The 27 inches of sea-level rise projected in the business-as-usual scenario by 2060 is more than enough to turn most estuarine wetlands into open water.

More intense hurricanes also threaten to damage estuarine habitats. During Hurricane Andrew, large quantities of sediment from inland sources and coastal erosion were deposited in marshes, smothering vegetation (Scavia et al. 2002). The high winds of hurricanes also pose a direct threat to mangrove forests, knocking down taller trees and damaging others (Doyle et al. 2003).

## INSURANCE

Insurance companies are, by their nature, gamblers, betting on what's going to happen to you. They make money if their guesses about the dangers you face are roughly correct, and the premiums they charge you are greater than the claims that you, on average, collect from them. They lose if they set their premiums so low that they are unable to pay their customers' claims, or so high that people stop buying insurance.

In Florida, selling property insurance means betting on the size of hurricane damages. The insurance industry has made mistakes in both directions, at times setting premiums too low to cover claims, and at other times charging more than their customers can afford. Under the best of circumstances — in the rapid stabilization scenario — hurricane damages will continue to vary widely from year to year, and the industry will need to take a long-term perspective to avoid bouncing between very low and very high rates.

Under the business-as-usual scenario, with about the same number of hurricanes but more of them reaching Category 4 or 5, damages will be higher on average, and also more variable from year to year. With greater uncertainty it will be easier for the industry to make a wrong bet, in either direction, and it will be harder for homeowners to pay the increased average cost of insurance. Greater and greater public subsidies will be required as private insurers raise their rates, or leave the market.

The challenge of making a multi-year gamble on hurricane damages seems to call for big businesses that can afford to take the long view. What has happened, though, is that many of the largest insurance firms in the country have folded their cards and left the riskiest parts of the Florida market after some of the memorable hurricanes of recent years. Smaller, state-based insurance firms, an increasingly important part of the industry, do not have the resources to provide adequate coverage for hurricane damages on their own. As a result, the state and federal governments have been drawn into subsidizing Florida property insurance. But even with the subsidies, homeowners who decided where to live, and how much house they could afford, at a time of much lower rates are now being squeezed by the drastic increase in premiums.

It looks like an attractive market: among U.S. states, Florida's property insurance industry is second only to California's in value of premiums sold (Florida Office of Insurance Regulation 2006). In Florida, property insurance is provided by leading private companies such as State Farm and Allstate, as well as smaller companies active only in Florida; by a state-created not-for-profit insurer called Citizens' Property Insurance Corporation; and by the federal government's National Flood Insurance Program (NFIP). Homeowners living on the coast often have one policy from a private insurer covering general threats such as theft or fire, another from Citizens to cover wind risk from hurricanes, and a third from NFIP for flood damage.

Before Hurricane Andrew hit in 1992, many property insurers, eager to increase their market shares, were charging rates that proved too low to pay for the claims filed after the storm. These low rates made high risk areas look misleadingly attractive and affordable, encouraging investment in real estate. (Many of the "investors" were middle-class households who could not afford to move again when rates went up.) As a result of Andrew, Florida insurers faced $15.5 billion in claims, and 12 insurance companies went bankrupt (Florida Office of Insurance Regulation 2006; Scott 2007). Premiums went up by an average of 82 percent across the state (Wilson 1997).

For the companies that remained in the state's insurance industry, the rate increases were enough to restore financial health. From 1996 to 2006, the loss ratio for Florida insurers was less than 70 percent of all premiums collected, meaning that insurers paid less than seventy cents in claims out of every dollar of premiums. Florida's loss ratio was only two percentage points higher than the average for all insurers nationwide (Florida Office of Insurance Regulation 2007a; Hundley 2007).

Insurance companies were somewhat better prepared for the massive storms of 2004 and 2005, although one large Florida-based insurer, Poe Financial Group, was bankrupted, and many other companies dropped their policies in vulnerable parts of Florida to limit their exposure to future storms. Rate increases after these storms roughly doubled the average premium charged across the state, according to a spokesperson for the Florida Office of Insurance Regulation (Kees 2007). These increases brought the loss ratio down to 45 percent in 2006, allowing insurers to rapidly recoup their losses from 2004 and 2005 (Florida Office of Insurance Regulation 2007b). But despite the higher rates, several of the larger insurance companies continued to move out of the Florida market: the two largest insurers, State Farm Group and Allstate Insurance Group, reduced their share of the market from 50.9 percent in 1992 to 29.9 percent in 2005 (Grace and Klein 2006). Although a few large national firms remain in Florida, 12 of the state's top 15 insurers sell only Florida residential property insurance (Florida Office of Insurance Regulation 2006).

For many Florida homeowners, this means that rates have skyrocketed in recent years. Stanley Dutton, a Florida resident who was profiled in *Newsweek,* said he was selling his house on Florida's panhandle after his premiums increased from $394 in 2000 to $5,479 in 2006 (Breslau 2007). *USA Today* reported in 2006 that Key West homeowner Teri Johnston's wind storm premium on her 1,500 square foot home had quadrupled since 2004 to $11,856, and that rate included an $18,000 deductible (Adams 2006). While these are extreme cases, the impact on the average homeowner has been hard enough.

The state government plays an active role in Florida insurance markets, and has expanded its involvement in response to recent hurricane activity. One key role of the state is to regulate insurers' activities to prevent sudden abandonment of policyholders or unfair premium hikes. All rate increases are subject to public hearings and require regulatory approval; companies wishing to cancel policies must provide 90 days' notice and some assurance that their withdrawal is "not hazardous to policyholders or the public" (Florida State Legislature 2006; Kees 2007). Companies have pursued a strategy of dropping the policyholders with the riskiest properties, which allows them to reduce their risk and improve their expected level of profitability without requiring state approval for rate increases (Grace and Klein 2006; Florida Office of Insurance Regulation 2007b).

The state has also played an ever-growing role as an insurer of last resort for homeowners who cannot find private insurance. Prior to Hurricane Andrew, the state acted as an insurer of last resort through the Florida Windstorm Underwriting Association (FWUA), but only to a limited set of customers. When thousands of customers were dropped after Andrew, a new insurer of last resort was set up called the Residential Property and Casualty Joint Underwriting Association (JUA), which grew to 936,000 policies in September of 1996, before shrinking again as new private insurers moved into the state (Wilson 1997). The FWUA and JUA merged in 2002 to become Citizens' Property Insurance Corporation, partly in response to private insurers' demands that the government assume some of their wind risk. After the 2004 and 2005 storms, many more customers were dropped by private insurers and picked up by Citizens, raising the number of its policy holders to over 1.3 million. In June 2007, a new bill was passed which freezes Citizens' rates until January 1, 2009 and allows policyholders of private companies to switch to Citizens if their private insurer charges 15 percent more than the state's rates. With these changes, the number of properties insured by Citizens is projected to reach 2 million by the end of 2007 (Liberto 2007).

The state increasingly has also taken on the role of providing reinsurance for private insurance companies. After the wave of bankruptcies following Hurricane Andrew, the state government set up the Florida Hurricane Catastrophe Fund, or CAT Fund for short, to provide a limited level of reinsurance to private insurers, which would cover a portion of their claims in the event of a hurricane. The rates charged were below private market rates for reinsurance, especially after the storms of 2005 nearly doubled private reinsurance rates (Florida Office of Insurance Regulation 2007a). In January 2007, the state injected more money into the CAT fund, expanding it from $16 billion to $28 billion, and required private insurers to purchase more reinsurance through them, and to pass on the savings to customers through lower rates (Florida Office of Insurance Regulation 2007a). The projected savings, however, did not materialize.

One impact of this expanded government role in insurance markets is that the state's potential liability in the event of a large hurricane has increased. In 2005, the state had to bail out Citizens, which had a $1.4 billion deficit; this was done through a combination of a charge on all insurance companies, which is passed on to policyholders, and a payment from the state budget of $750 million (Kees 2007). With the expansion of Citizens and the increase in subsidized reinsurance, the state could be left with an even larger bill in the event of another big storm.

All these changes have increased the amount that the state government effectively subsidizes property insurance rates. Citizens' rates may not appear artificially low to policyholders, but according to a spokesman for the organization, the rates necessary for the premiums of homeowners in high risk coastal areas to cover their own claims would be entirely prohibitive (Scott

2007). In addition, the federal government provides flood insurance through NFIP that is often pegged at rates too low to break even with claims. The nationwide effects of Hurricane Katrina left NFIP bankrupted 10 times over by the $16 billion it paid in flood claims.

In Florida's insurance industry, an already bad situation will be made much worse if climate impacts intensify. Under the rapid stabilization scenario, continuing the current frequency and intensity of storms, the industry might be able to muddle along with the current arrangements, premiums, and state and federal subsidies. Under the business-as-usual scenario, with more intense storms, as well as higher sea levels that will increase the height of storm surges, the insurance crisis will become more severe. Either premiums or subsidies, or likely both, will have to increase to cover the rising average costs of storm damages. As storms intensify, private firms are likely to continue withdrawing from the market for Florida property insurance, leaving the government — that is, the taxpayers — with an increasingly expensive drain on public resources.

The cost of hurricane damages, discussed later in this report, will be borne in large part by property owners, through increased premiums and/or reduced coverage, and by state and federal governments through subsidies to insurance companies. Increased insurance costs and increased storm damages will contribute to a decline in property values, worsening climate damages to the real estate industry. There is no way to predict the monetary cost of the business-as-usual scenario to the private insurance industry — except to note that even the least skillful gambler, after losing enough times in a row, will eventually leave the table.

# IV. ECONOMIC IMPACTS: INFRASTRUCTURE

Even without climate change, Florida's public and private infrastructure will take an enormous amount of investment in order to keep up with a near doubling of population in the next 50 years. In the rapid stabilization case, the impacts of climate change for the 21st century are about the same as the changes during the 20th century. Almost all of Florida's infrastructure will be able to weather slowly rising temperatures and slowly rising seas with routine maintenance and new construction, activities that would be necessary regardless of a changing climate. In the business-as-usual case, however, Florida's infrastructure will suffer very serious damages. On top of the pressure of rapid growth, roads and power plants, schools and reservoirs, shopping malls and airports all will suffer damage from climate change. Nine percent of the state's current land area will be under water. Saltwater will also intrude into freshwater storage. High temperatures will increase demands for electricity. The costs of business-as-usual emissions will be high, and at times, Florida's infrastructure may fail to provide necessary services to state residents.

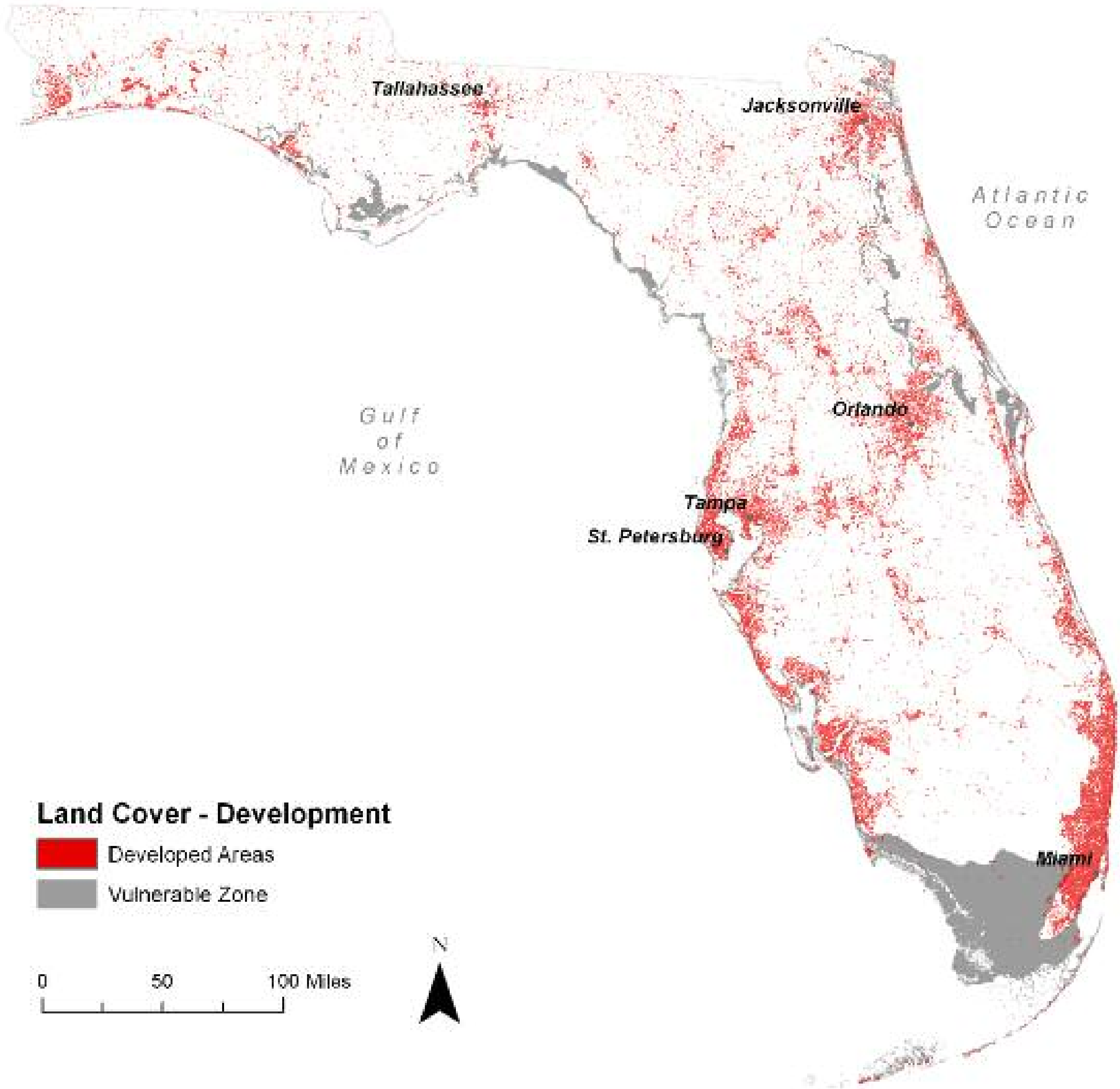
## REAL ESTATE

The effects of climate change will have severe consequences for Florida's real estate. If nothing were done to hold back rising waters, sea-level rise would simply inundate many properties in low-lying, coastal areas. Even those properties that remained above water would be more likely to sustain storm damage, as encroachment of the sea allows storm surges to reach inland areas that were not previously affected. The land area vulnerable to inundation if sea levels were to rise 27 inches, as the business-as-usual scenario projects by 2060, currently contains over 900,000 housing units worth an estimated total of $130 billion.[22] This figure does not account for anticipated growth in population, incomes, and therefore in real estate as well, over coming decades; the value of vulnerable real estate in 2060 will be much larger.

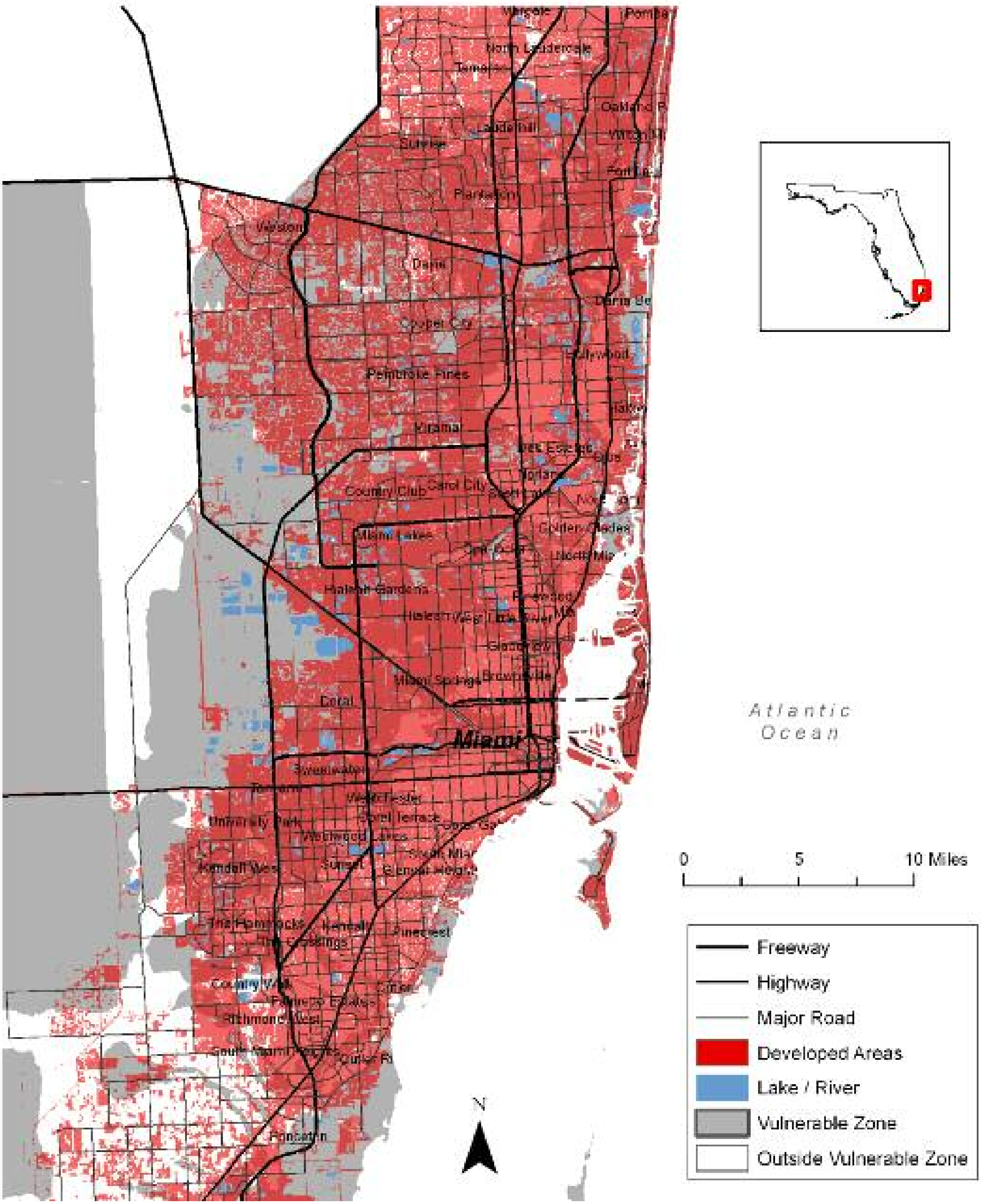
**Table 15. Housing Units Currently in Areas Vulnerable to 27 Inches of Sea-Level Rise**

| | Number of housing units in vulnerable zone | County median value for owner-occupied homes (2006 dollars) | Value of real estate in vulnerable zone (million 2006 dollars) |
|---|---|---|---|
| **All Florida** | **916,861** | **$118,478** | **$129,117** |
| Miami-Dade | 190,770 | $145,171 | $27,694 |
| Monroe | 48,973 | $282,380 | $13,829 |
| Pinellas | 97,457 | $112,976 | $11,010 |
| Collier | 47,473 | $196,683 | $9,337 |
| Palm Beach | 52,196 | $158,283 | $8,262 |
| Broward | 51,623 | $150,556 | $7,772 |
| Lee | 57,292 | $132,176 | $7,573 |
| Volusia | 52,689 | $102,205 | $5,385 |
| Brevard | 47,656 | $110,517 | $5,267 |
| Sarasota | 37,407 | $100,800 | $3,771 |
| Manatee | 25,723 | $139,785 | $3,596 |
| St.Johns | 22,493 | $142,829 | $3,213 |
| Duval | 30,555 | $104,898 | $3,205 |
| Martin | 17,702 | $178,420 | $3,158 |
| St.Lucie | 18,997 | $140,371 | $2,667 |
| Bay | 22,145 | $109,463 | $2,424 |
| Charlotte | 18,391 | $113,561 | $2,089 |
| Hillsborough | 16,650 | $114,380 | $1,904 |
| Indian River | 11,732 | $121,756 | $1,428 |
| Flagler | 8,262 | $136,039 | $1,124 |
| Pasco | 9,745 | $93,190 | $908 |
| Nassau | 3,662 | $148,332 | $543 |
| Seminole | 3,823 | $124,098 | $474 |
| Clay | 3,604 | $126,907 | $457 |
| Escambia | 3,640 | $100,332 | $365 |
| Putnam | 3,807 | $80,195 | $305 |
| Franklin | 2,008 | $123,278 | $248 |
| Citrus | 1,913 | $98,810 | $189 |
| Wakulla | 1,506 | $112,624 | $170 |
| Hernando | 1,647 | $102,205 | $168 |
| Santa Rosa | 746 | $185,444 | $138 |
| Gulf | 1,357 | $90,380 | $123 |
| Walton | 913 | $112,859 | $103 |
| Lake | 439 | $117,776 | $52 |
| Taylor | 663 | $77,268 | $51 |
| Okaloosa | 338 | $118,478 | $40 |
| Levy | 374 | $88,741 | $33 |
| Dixie | 389 | $72,234 | $28 |
| Orange | 102 | $125,854 | $13 |

*Source Florida Geographic Data Library (University of Florida: GeoPlan 2007)*




Map 7. Developed Land in Areas Vulnerable to 27 Inches of Sea-Level Rise
*Sources: See Appendix C for detailed sources and methodology.*




Map 8. Miami/Fort Lauderdale: Areas Vulnerable to 27 Inches of Sea-Level Rise
*Sources: See Appendix C for detailed sources and methodology.*

There are 6,400 square miles of developed area in Florida. Of this, 433 square miles, or 6.8 percent, are in the vulnerable area in the business-as-usual scenario. Miami-Dade County, the most populous county, will have almost 70 percent of its total land area flooded, including 73 square miles of residential neighborhoods, commercial districts, and industrial properties. In Monroe County, all of the Florida Keys will be under water in 2060 in the business-as-usual scenario.

In addition, to residential properties worth $130 billion, the vulnerable zone includes other valuable — and otherwise significant — facilities throughout the state:

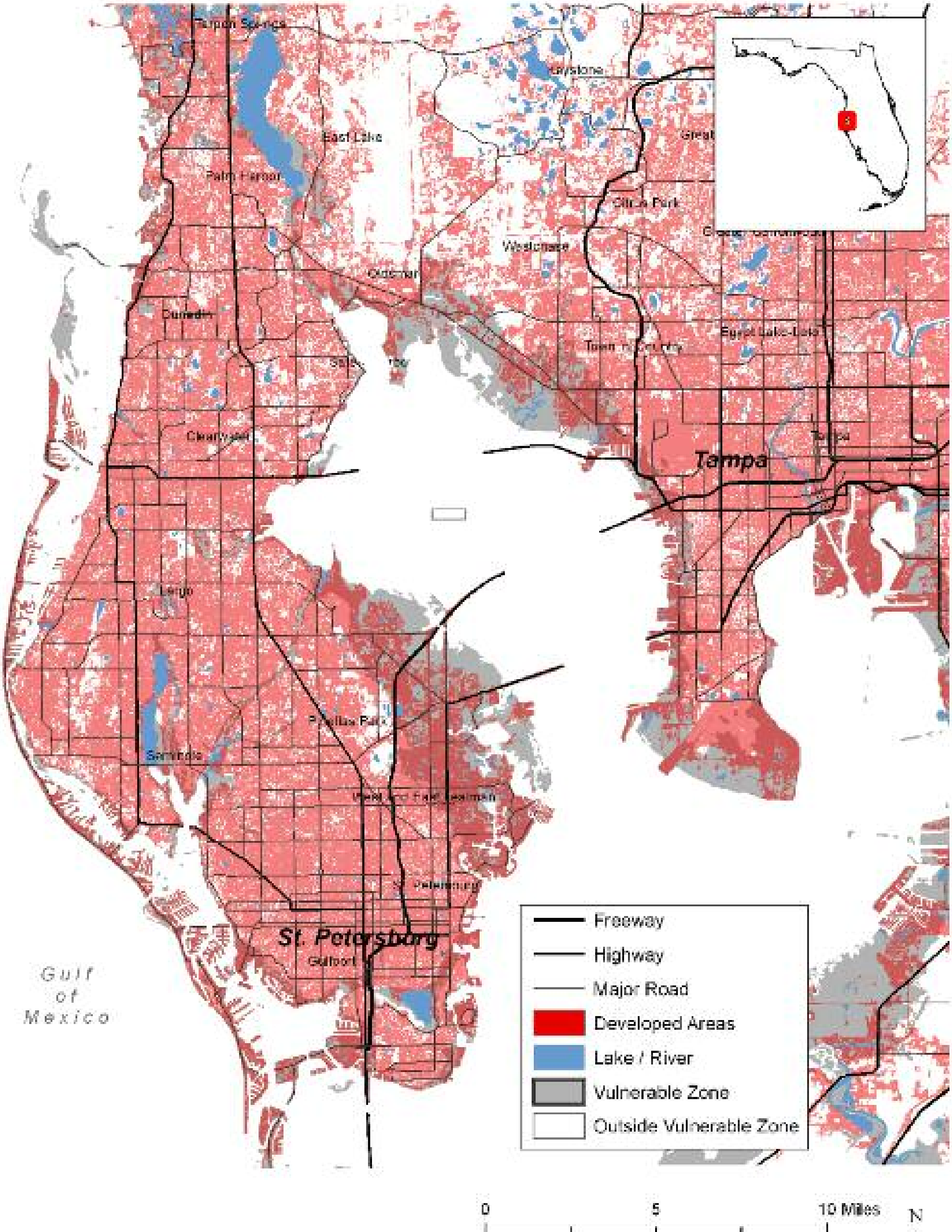
- 2 nuclear reactors;
- 3 prisons;
- 37 nursing homes;
- 68 hospitals;
- 74 airports;
- 82 low-income housing complexes;
- 115 solid waste disposal sites;
- 140 water treatment facilities;
- 171 assisted livings facilities;
- 247 gas stations
- 277 shopping centers;
- 334 public schools;
- 341 hazardous materials sites, including 5 superfund sites;
- 1,025 churches, synagogues, and mosques;
- 1,362 hotels, motels, and inns; and
- 19,684 historic structures.

More intense hurricanes, in addition to sea-level rise, will increase the likelihood of both flood and wind damage to properties throughout the state. The cost of insuring homes against wind damage has already risen so high that many private insurance companies are unwilling to sell coverage at any price, forcing residents to rely on Citizens, the state-created insurance company (Scott 2007). Post-storm flood damage is generally even costlier than damage from high winds, creating the need for both structural repair and replacement of the contents of homes and buildings. But even with insurance to cover damages, the costs of the time and stress involved in repairing a storm-damaged home are high. Mobile homes, which represent 12 percent of Florida residences, but even higher shares in some of the most vulnerable counties — 19 percent in Monroe, 20 percent in Franklin, and 25 percent in Gulf County — are at particular risk from the effects of stronger storms. While the values of these homes constitute only a small fraction of the value of all coastal real estate at risk from climate change, their residents may be least economically prepared to cope with damages.

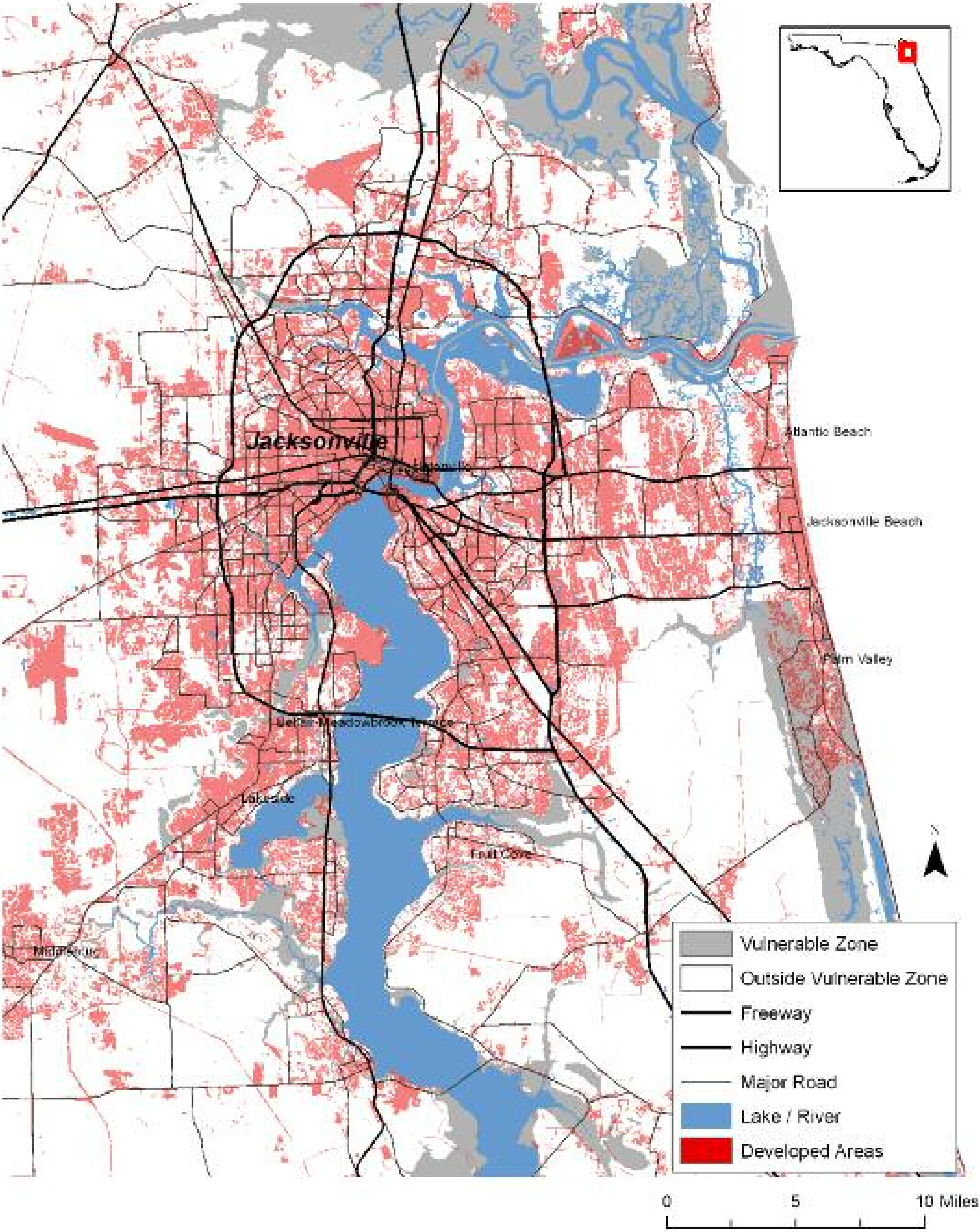
With two simplifying assumptions, it is possible to estimate the value of real estate at risk from sea level rise. First, we assume that the value of real estate will grow uniformly in all parts of the state, in proportion to GSP, throughout this century. Second, we assume that the fraction of the state's residential property at risk is proportional to the extent of sea-level rise. Then, starting from the calculation of $130 billion of residential real estate, as of 2000, that would be vulnerable to 27 inches of sea-level rise, it is possible to project the effects of both scenarios through 2100. The results are shown in Table 16. The cost of inaction — that is, the annual increase in the value of residential real estate at risk of inundation — rises from $11 billion in 2025 to $56 billion in 2100, or almost 1 percent of GSP. And sea levels will continue to rise beyond 2100.

No one expects coastal property owners to wait passively for these damages to occur; those who can afford to do so will undoubtedly seek to protect their properties. But all the available methods for protection against sea-level rise are problematical and expensive. It is difficult to imagine any of them being used on a large enough scale to shelter all of Florida from the rising seas of the 21st century, under the business-as-usual case.

Elevating homes and other structures is one way to reduce the risk of flooding, if not hurricane-induced wind damage. A FEMA estimate of the cost of elevating a frame-construction house on a slab-on-grade foundation by two feet is $58 per square foot, after adjustment for inflation, with an added cost of $0.93 per square foot for each additional foot of elevation (Federal Emer-




Map 9. Tampa/St Petersburg: Areas Vulnerable to 27 Inches of Sea-Level Rise
*Sources: See Appendix C for detailed sources and methodology.*



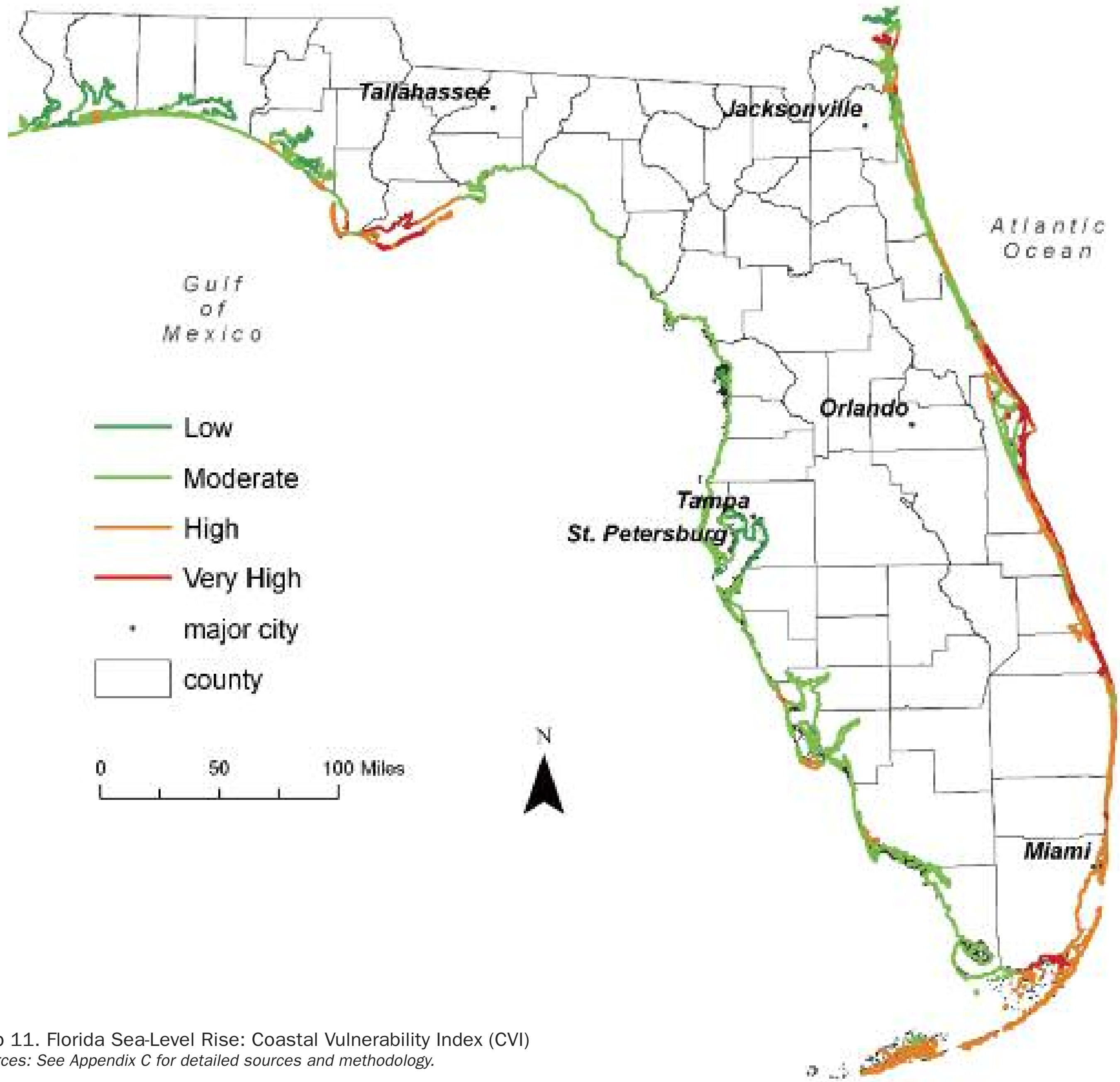

Map 10. Jacksonville: Areas Vulnerable to 27 Inches of Sea-Level Rise
*Sources: See Appendix C for detailed sources and methodology.*

**Table 16. Residential Real Estate at Risk from Sea-Level Rise, Without Adaptation**

*annual increases in value at risk*

| | 2025 | 2050 | 2075 | 2100 |
|---|---|---|---|---|
| **Damages (in billions of 2006 dollars)** | | | | |
| Rapid Stablization Case | 2 | 4 | 6 | 10 |
| Business-as-Usual Case | 13 | 27 | 39 | 66 |
| Cost of inaction | 11 | 23 | 33 | 56 |
| **Damages (as percent of GSP)** | | | | |
| Rapid Stablization Case | 0.12% | 0.13% | 0.13% | 0.15% |
| Business-as-Usual Case | 0.79% | 0.82% | 0.81% | 0.95% |
| Cost of inaction | 0.67% | 0.69% | 0.68% | 0.80% |

*Source: Authors' calculations.*




Map 11. Florida Sea-Level Rise: Coastal Vulnerability Index (CVI)
*Sources: See Appendix C for detailed sources and methodology.*

gency Management Agency 1998). A house with a 1,000 square foot footprint would thus cost $58,000 to elevate by two feet. It is not clear whether building elevation is applicable to multistory structures; at the least, it is sure to be more expensive and difficult.

Another strategy for protecting real estate from climate change is to build seawalls to hold back rising waters. There are a number of ecological costs associated with building walls to hold back the sea, including accelerated beach erosion and disruption of nesting and breeding grounds for important species, such as sea turtles, and preventing the migration of displaced wetland species (National Oceanic & Atmospheric Administration 2000b). In order to prevent flooding to developed areas, some parts of the coast would require the installation of new seawalls. Estimates for building or retrofitting seawalls range widely, from $300 to $4,000 per linear foot (Yohe et al. 1999; U.S. Army Corps of Engineers 2000; Kirshen et al. 2004; Dean 2007b).

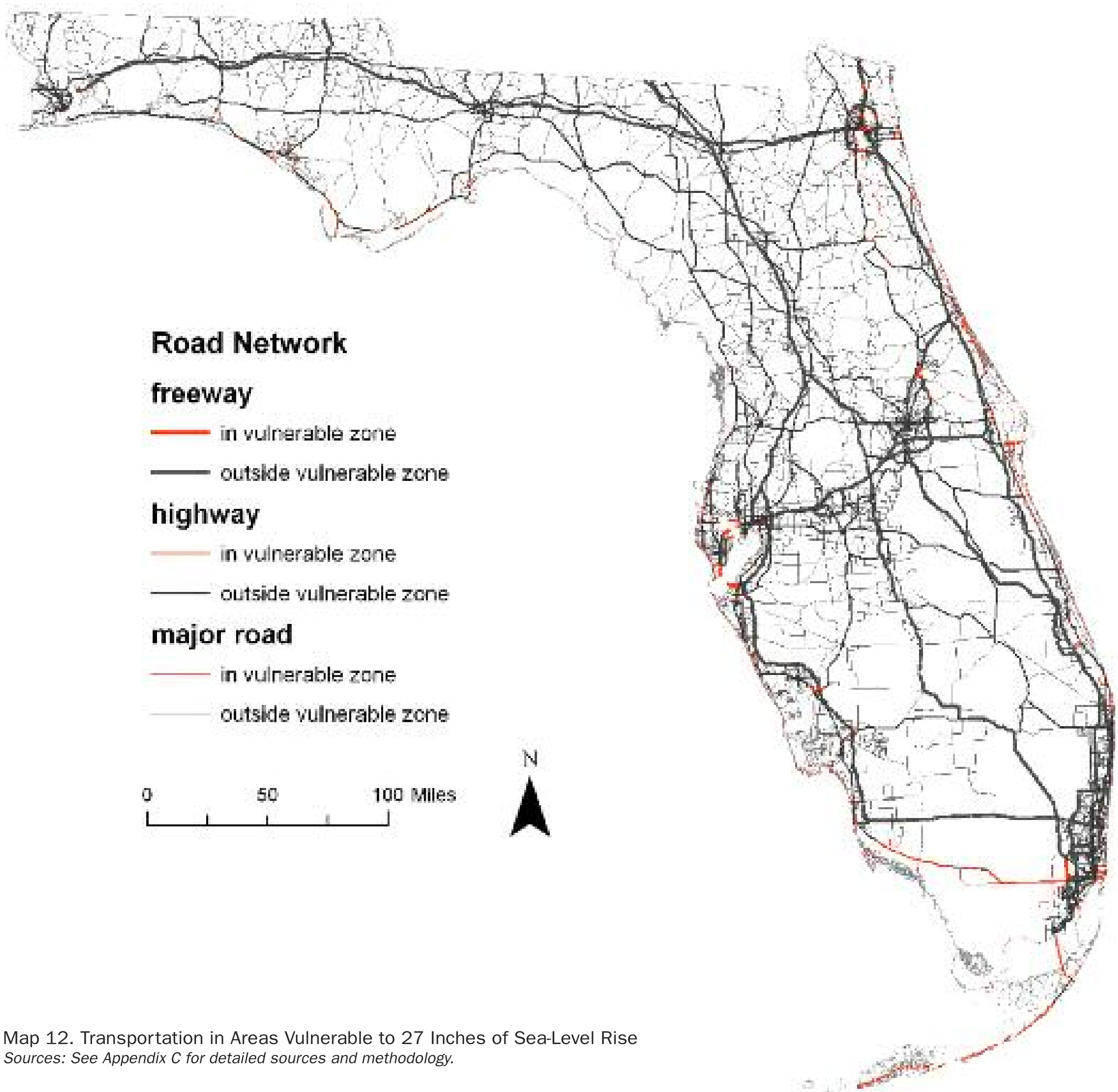
The United States Geological Survey (USGS) has created an index to rate the vulnerability of U.S. shoreline to sea-level rise, taking into consideration tides and erosion, as well as elevation (U.S. Geological Survey 2000). According to their assessment out of 4,000 miles of total Florida shoreline, 1,250 miles are in the "high" vulnerability category and 460 miles are in the "very high" category. If just these 1,700 miles of shoreline were protected with seawalls, and construction costs averaged $1,000 per linear foot (or a bit over $5 million per mile), the total cost would be just under $9 billion. The 4,000 total miles of shoreline assumed by USGS, however, do not take into account Florida's many channels and inlets, which make the actual coastline much longer. (Conversely, other estimates of the length of Florida's coast-line range down to 1,350 or fewer miles; the varying estimates reflect the different resolution at which the measurements are made.). The actual coastline length, when these features are accounted for, is 22,000 miles.[23] If seawalls were needed for 42 percent of Florida's actual coastline (the share of very high and high vulnerability coastline under the USGS definition), or 9,200 miles, the cost would be $49 billion. In other words, constructing seawalls sufficient for statewide protection would be an engineering megaproject, several times the size of the long-term Everglades restoration effort.

Yet another approach involves beach nourishment, bringing in sand as needed to replenish and raise coastal beaches (which as noted above can have major environmental impacts). A major analysis of the costs of protecting the US coastline from sea-level rise, conducted by EPA in 1989, relied heavily on restoring and building up beaches (Titus et al. 1991). The study projected that most of the sand would need to be dredged up more than five miles offshore. It estimated the cost of sand to protect Florida against 39 inches of sea-level rise (a level reached in 2087 in the business-as-usual case) would be between $6 billion and $30 billion in 2006 dollars, depending on assumptions about the quantity and cost of sand. As with statewide seawall construction, beach nourishment on this scale would be a mammoth engineering project, with uncertain environmental impacts of its own.

In short, while adaptation, including measures to protect the most valuable real estate, will undoubtedly reduce sea-level rise damages below the amounts shown in Table 16, there is no single, believable technology or strategy for protecting the vulnerable areas throughout the state.

## TRANSPORTATION

Transportation infrastructure in Florida will be damaged by the effects of sea-level rise, particularly in combination with storm surge. Many types of transportation infrastructure, including port facilities, airport runways, railways, and especially roads, are at risk. Docks and jetties, for example, must be built at optimal heights relative to existing water levels, and more rapid sea-level rise may force more frequent rebuilding. Roads, railroads, and airport runways in low-lying coastal areas all become more vulnerable to flooding as water levels rise, storm surges reach farther inward, and coastal erosion accelerates. Even roads further inland may be threatened, since road drainage systems become less effective as sea levels rise. Many roads are built lower than surrounding land to begin with, so reduced drainage capacity will increase their susceptibility to flooding during rainstorms (Titus 2002).




Map 12. Transportation in Areas Vulnerable to 27 Inches of Sea-Level Rise
*Sources: See Appendix C for detailed sources and methodology.*

### Table 17. Roads and Railroads in Areas Vulnerable to 27 Inches of Sea-Level Rise

| | Limited Access Highways (miles) | Other Highways (miles) | Major Roads (miles) | Railroads (miles) |
|---|---|---|---|---|
| **Florida Total** | **75.5** | **390.8** | **1972.4** | **181.3** |
| Bay | | 8.4 | 43.1 | 3.6 |
| Brevard | 5.7 | 25.4 | 213.2 | 51.5 |
| Broward | | 2.0 | 36.0 | 1.5 |
| Charlotte | 1.9 | 6.1 | 51.4 | 3.5 |
| Citrus | | | 12.7 | |
| Clay | | 3.1 | 11.4 | 2.0 |
| Collier | | 46.4 | 101.4 | 2.3 |
| Dixie | | | 20.1 | |
| Duval | 11.5 | 16.5 | 84.9 | 20.6 |
| Escambia | | 1.0 | 70.0 | 5.4 |
| Flagler | | 2.9 | 32.9 | 0.7 |
| Franklin | | 17.4 | 76.5 | 2.1 |
| Gulf | | 9.5 | 17.1 | 10.2 |
| Hernando | | | 10.5 | |
| Hillsborough | 6.6 | 9.8 | 13.6 | 15.2 |
| Indian River | | 0.6 | 52.1 | 0.2 |
| Lake | | | 2.2 | |
| Lee | 1.4 | 3.5 | 97.5 | 1.5 |
| Levy | | | 3.8 | |
| Manatee | 8.8 | 3.3 | 40.6 | 2.8 |
| Martin | | 2.6 | 43.3 | 4.5 |
| Miami-Dade | 14.0 | 55.6 | 211.9 | 8.2 |
| Monroe | | 95.3 | 59.1 | |
| Nassau | 1.3 | 1.2 | 8.5 | 3.9 |
| Okaloosa | | 0.2 | 0.1 | |
| Orange | | 0.4 | | |
| Palm Beach | | 6.6 | 80.1 | 1.9 |
| Pasco | | 0.7 | 10.8 | |
| Pinellas | 10.9 | 12.5 | 104.9 | 1.5 |
| Putnam | | 5.4 | 10.6 | 3.6 |
| Santa Rosa | 0.9 | 0.7 | 3.5 | 0.6 |
| Sarasota | 0.1 | 12.0 | 44.2 | |
| Seminole | 6.7 | 0.4 | 14.2 | 2.4 |
| St.Johns | | 3.2 | 128.8 | 4.7 |
| St.Lucie | | 1.6 | 103.7 | |
| Taylor | | | 9.6 | |
| Volusia | 5.6 | 27.1 | 134.3 | 27.3 |
| Wakulla | | 6.6 | 11.5 | |
| Walton | | 2.5 | 2.0 | |

*Sources: road network data from US Streets Dataset (Environmental Systems Research Institute 2005) and Rail Network dataset (Federal Railroad Administration and Research and Innovative Technology Administration's Bureau of Transportation Statistics 2006); vulnerable zones data from NOAA Medium Resolution Digital Vector Shoreline (U.S. Geological Survey 2007), USGS 1:250,000 Digital Elevation Model (University of Florida: GeoPlan 2007), and Historic and Projected Populations of Florida Counties (University of Florida: GeoPlan 2007).*
*Note: Limited access highways are accessed via a ramp and/or numbered exits, like all Interstates and some intrastate highways.*

One response to the threat of inundated transportation infrastructure is to simply elevate it to keep pace with the sea-level rise. While elevation may be less expensive than letting rising waters wash out entire highways, it does not come cheap. One estimate put the average cost of elevating roads at $2 million per mile (Dean 2007b). With over 2,400 miles of existing highway and other major roads at risk of inundation with 27 inches of sea-level rise, the cost of elevating just these roads sums to over $4.8 billion. This total does not take into account the millions of miles of city streets in Florida's vulnerable areas that would need to be elevated, nor does it consider the many additional miles and lanes of roads that will likely be built as Florida's population doubles over the next 50 years.

Elevating roads, however, may cause other problems. Streets are built lower than surrounding residential and commercial property so that water from the land can drain into the street. Elevating the roads can prevent this drainage. In such cases, it becomes necessary to raise surrounding lots along with the street, so that relative heights are preserved (Titus 2002).

## ELECTRICITY

The electricity sector in Florida encompasses 138 power plants,[24] representing over 56 gigawatts (GW) of capacity. (A gigawatt is a million kilowatts.) The system relies heavily on power plants that burn natural gas (33 percent) and coal (29 percent); oil and nuclear power (12 percent each) make up the remainder of generation. [25] Planned new plants will primarily burn natural gas, and it is expected that oil plants will be converted to burning gas or phased out by 2015. The state's electricity market is growing rapidly, following the burgeoning population. Floridians were projected to draw a peak demand of nearly 47 GW in 2007, 3 percent higher than the peak of 2006 (North American Electric Reliability Corporation 2006). These increasing demands on the energy sector are expected to be strained by global climate change, at significant cost to Florida's consumers.

Florida's power plants are spread statewide, and some date back to the 1950s. Early power plants were built near the coastline; the size of new plants increased dramatically through the early 1980s, culminating with the large Turkey Point, Crystal River, and St. Lucie nuclear plants, and Manatee and Martin natural gas plants. From the mid-1980s, new plants were primarily smaller natural gas generators, concentrated in central Florida between Tampa and Orlando.[26] The transmission system reflects the location of power plants, with large lines extending down the center of eastern and western coastal counties. As coal plants have become less attractive politically, financially, and environmentally, the state has increased its reliance on natural gas plants, causing concern about the lack of diversity in Florida's energy portfolio (Platts 2007).

Florida's electricity market has been affected by rising gas and oil prices, which have caused electricity prices to jump from 6.9 to 8.8 cents per kilowatt-hour (kWh) between 2000 and 2005.[27] The U.S. Energy Information Administration (EIA) estimates that energy prices will stabilize at approximately 8.1 cents per kWh over the next two decades if oil prices settle at $60 a barrel (far below the price at the time of this writing). In short, Florida's electricity is expensive, and high energy prices can be expected well into the future, even without the added strain of climate change.

Among the impacts of climate change projected in the IPCC 2007 report, several will affect electricity demand, generation, and distribution capacity in Florida, including:

- Warmer and more frequent hot days and nights
- An increase in the frequency of heat waves
- More intense hurricanes
- Possible coastal flooding from storms surges and sea-level rise
- Changes in the availability of water

Generally, the energy sector is expected to be strained along three axes: temperature, demography, and topography.

- **Temperature:** While much of Florida experiences over a half year of comfortable temperatures between 70 and 85°F, the state has the warmest daily average temperatures in the nation, and summers are hot and humid (O'Brien and Zierden 2001). In 2005, 74 days had highs of 90°F or more, while winter highs dropped below 70°F on only 19 days. Already, these temperatures mean that air conditioners run through much of the year; as further discussed below, they also mean that power plants are using significant energy to cool equipment, and power lines are operating less efficiently than they would in a cooler climate. Rising temperatures will dramatically increase demand and further degrade system-wide efficiencies.
- **Demography:** The population of Florida is growing quickly, and aging even more rapidly. Currently 18 percent of residents are over 65, and this is expected to rise to 27 percent by 2030 (U.S. Census Bureau 2004a). An older population, highly dependent on air conditioning, will ensure that energy demand remains tightly coupled to temperature. With more frequent heat waves, there may be a need for costly emergency energy infrastructure to reduce heat-related injuries or illness. Without mitigation, the increasing number of Florida customers will stretch current infrastructure, particularly when power demands peak.
- **Topography:** Numerous power plants and transmission lines are close to the coastline, exposing significant energy infrastructure, and thus power system reliability, to storm damage in the near future, even without the more intense hurricanes that climate change may produce (Florida Public Service Commission 2006).

### Electricity demand projections

In the rapid stabilization case, electricity demand will rise due to rapid demographic growth and increasing demands for electricity from residential and commercial consumers; climate change will play only a minor role. The Florida Public Service Commission recorded an increase in residential use per capita of 7 percent between 1995 and 2005, and has projected future increases of 0.84 percent per year (Murelio 2003). The EIA projects a 0.76 percent annual increase in commercial use per capita until 2030. Residential housing, amongst the fastest growing sectors in the state, will consume increasing electricity for lighting, air conditioning, and entertainment. The EIA estimates that after lighting, the largest use of residential electricity is for air conditioning, a factor which is expected to grow through 2030 at nearly 1 percent per year (Energy Information Administration 2007). Coupled with Florida's rapid demographic growth, the Florida Reliability Coordinating Council (FRCC) expects an annual compounded growth rate of 2.4 percent in summer peak demand and 2.8 percent in total state energy consumption between now and 2015.

Based on this picture of a rapidly growing state population and economy, we project average annual growth in electricity demand, from 2005 through 2100, of 1.54 percent — before considering any effects of temperature changes.

A review of Florida's electricity generation by hour indicates that it is closely correlated with temperature.[28] Generation rises at both low and high temperatures to meet heating and cooling demand, respectively, and is lowest at approximately 67 °F (see Figure 2). In 2005, 85 percent of the hours of the year were above 67°F, a percentage that will rise to 93 percent by 2050 and to 96 percent by 2100. All other things being equal, therefore, we would expect a steep increase in electricity demand in line with warming.

In the business-as-usual case, average annual temperatures rise over 9.7°F by 2100, causing a much more noticeable impact on the electricity system. On the one hand, this will ease the pres-

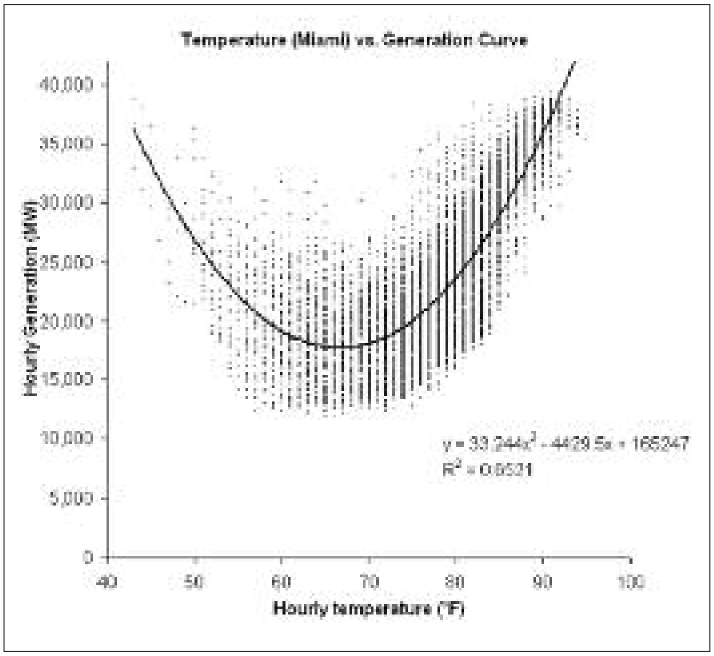



Figure 2. Hourly Fossil Generation in Florida versus Hourly Temperatures in Miami

*Sources: Hourly power generation derived from 2005 Environmental Protection Agency (EPA) Clean Air Markets data for FRCC fossil units (Environmental Protection Agency 2007a); hourly temperature from Miami International Airport derived from National Oceanographic and Atmospheric Administration (NOAA) National Climate Data Center (NCDC) (National Oceanic & Atmospheric Administration 2007b).*
*Note: Each dot represents an hour of the year; vertical "lines" are multiple dots at the same temperature.*

sure of winter demand for heating, a major factor in Florida's electricity use at present. In 2003, winter demand prompted the state to issue an advisory while local utilities asked consumers to conserve power (Murelio 2003). On the other hand, air conditioning demand on scorching days in the summer will quickly push up against the limits of system capacity. In 2005, 74 days had highs exceeding 90°F. This may climb to more than 90 days a year by 2020, 150 days by 2050, and nearly two-thirds of the year by 2100.

In the rapid stabilization case, where a temperature increase of only 2.2°F is expected by 2100, warming will add only 0.07 percent to electricity demand growth each year, for a combined annual growth rate of just over 1.6 percent. By 2100, we project Florida's total electricity demand will be about 4.5 times as large as in 2005.

For the business-as-usual case, we project that warming will add an average of 0.34 percent to the growth of electricity demand each year, for a combined annual growth rate of 1.88 percent. By 2100, we project Florida's total electricity demand will be about 5.9 times as large as in 2005. There is a large gap between the size of the electricity system in the two scenarios: by 2100 the difference between the two scenarios amounts to 1.4 times the amount of electricity the state produced in 2005.

## Electricity supply projections

Unfortunately, the same high temperatures that cause electricity demand to spike also impair the efficiency of power system components, including central generating stations as well as transmission and distribution equipment.

- **Generators:** Due to their inability to cool components as quickly, thermal generators have lower efficiency at higher ambient temperatures. When air temperatures rise above design expectations, they are unable to produce as much power. For example, in gas turbines, performance decreases with increasing temperatures, and power output drops off significantly over 100°F. In Florida's current system, gas and oil systems lose approximately 1 percent efficiency for every 4°F temperature increase.[29] Florida relies heavily on seawater to cool power plants; increases in ocean temperature reduce the cooling efficiency, and thus impair generation efficiency. At a New York nuclear plant, generation efficiency drops rapidly if river water used for cooling rises above 50 to 60°F; output drops by as much as 2 to 4 percent when water temperatures reach 85°F (Powers 2003). While these declines in efficiency in may appear relatively small, the losses can have dramatic consequences across the system, particularly in heat waves when these resources are needed most urgently.
- **Transmission Lines:** When the amount of electricity carried over transmission lines increases (for example on a hot day when people are using air-conditioning), power lines heat up, stretch, and sag. An overloaded power line can sag so much that it comes in contact with a tree, or close to the ground, creating a short-circuit as electricity is discharged, and potentially leading to power outages. Higher ambient temperatures also decrease the maximum current carrying capacity of transmission and distribution lines.

The effect of high temperatures on power system components was highlighted during the widespread power system outages in the summer of 1999. On July 6th, a heat wave with sustained

temperatures of 100°F caused overloads and cable failures, knocking out power to 68,000 customers (U.S. Department of Energy 2000). Outages in New York City were due to heat-related failures in connections, cables and transformers. In the South Central region, power plants were not able to produce as much power as predicted, leading to system failures. Small inefficiencies at multiple power plants added up to losses equivalent to 500 megawatts.

To calculate costs for the two scenarios, we constructed a simple simulation of electricity demand and supply in Florida to 2100. The model accounts for changes in population, per capita demand, and temperature, but holds fuel prices and the cost of new power plants constant.[30] For the rapid stabilization scenario, the simulation assumes a slowly changing fuel mix, migrating towards increasing efficiency measures and use of renewable energy sources such as wind power, while phasing out oil and coal. With increasing petroleum scarcity, adoption of policies to reduce greenhouse-gas emissions, and resulting demand for better efficiency and widespread renewable energy sources, we can envision a cleaner portfolio with coal use falling steadily by 2100, and use of oil for electricity generation discontinued by 2050. In place of fossil fuels, the cleaner portfolio relies on rigorous new conservation measures that will reduce demand by 40 percent, along with expanded renewable electricity production, supplying 30 percent of electricity demand by 2100.

Such changes are entirely in line with Governor Crist's Executive Orders on climate change of July 2007; indeed, in order to meet the governor's targets for reduced greenhouse gas emissions, as set out in those orders, a massive shift to energy efficiency and renewable energy sources will be necessary. A June 2007 report from the American Council for an Energy-Efficient Economy (ACEEE) argues that Florida can afford to do even more than the cleaner portfolio used in our simulation (Eliot 2007).

For the business-as-usual case, on the other hand, we assumed that the state will satisfy the growing demand for electricity by maintaining the current fuel mix. In this scenario, Florida will need to build approximately five gas plants, four oil plants, and one coal plant in Florida *every year* for the foreseeable future. Even assuming that it was possible to obtain regulatory approval for all these facilities, and to site and construct them and the associated transmission lines, it is uncertain where adequate cooling water would be obtained (see discussion below). And the costs of securing those approvals, and siting and constructing those plants and transmission lines, would inevitably lead to price increases.

We estimate that in the business-as-usual case, the *annual* cost of power in Florida will rise to $43 billion in 2050 and to $78 billion by 2100 (see Table 18). A substantial portion of this growth can be attributed to booming population and energy demand, and is required even in the rapid stabilization case, but the difference between the two scenarios accounts for an added $18 billion a year by 2100. By the end of the century, every additional degree Fahrenheit of warming will cost electricity consumers an extra $3 billion per year.

According to the simulation, the increasing population and demand for power in the business-as-usual scenario will require an untenable 1500 new sources of generation, nearly 400 more than would be required in the rapid stabilization case.[31] Significant new construction may be required in any case to supply electricity for Florida's growing economy, but the costs will be much higher under business-as-usual than under the rapid stabilization scenario.

**Table 18. Electricity Sector: Costs of Climate Change**

*in billions of 2006 dollars*

| | 2025 | 2050 | 2075 | 2100 |
|---|---|---|---|---|
| Rapid stabilization case | 22.4 | 37.6 | 48.1 | 60.2 |
| Business as usual case | 23.5 | 42.5 | 58.4 | 78.2 |
| Cost of inaction | 1.1 | 4.9 | 10.3 | 18.1 |

*Source Authors' calculations, see text.*

In the business-as-usual scenario, the electric system has to adapt not only to gradual average temperature increases, but to increasing temperature variability as well, presenting additional challenges and expenses to the energy sector. Highly variable temperatures require a greater number of expensive peaking power plants to be online — that is, plants that sit idle most of the time, but provide enough electrical generation capacity to meet peak demand for cooling on hot summer afternoons. As a result, both the costs of generation and the overall size of the power grid in Florida will be larger than would be needed in the absence of climate change.

### Vulnerability to extreme weather

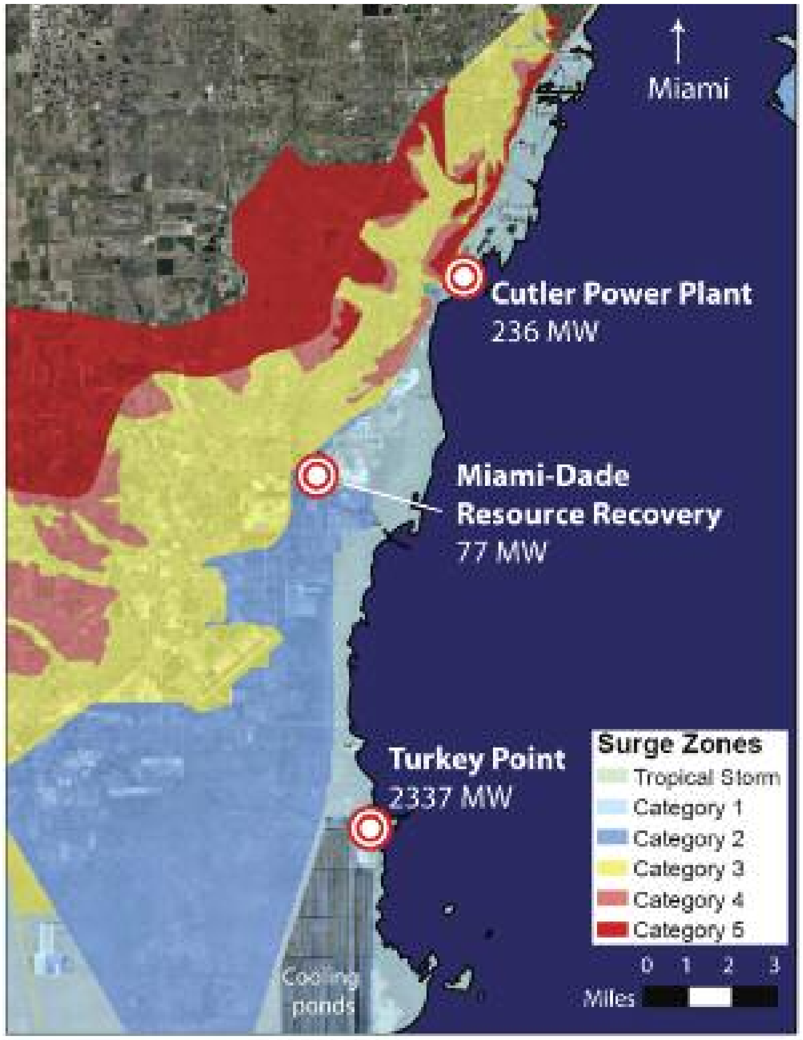
Not included in these figures are costs associated with the impacts of rising sea levels and more-intense hurricanes. Infrastructure vulnerability to storm damage has already been keenly felt in Florida during the 2004 and 2005 hurricane seasons. The four hurricanes that struck the state during each of those two years resulted in damage restoration costs for Florida's privately owned electric utilities of over $1.2 billion in 2004 and $0.9 billion in 2005 — to say nothing of the stresses on those utilities' customers from being with electricity for days or weeks at a time.

**Table 19. Hurricane Impacts on Florida's Electric Utilities**

| | 2004 Hurricanes | | | | 2005 Hurricanes | | | |
|---|---|---|---|---|---|---|---|---|
| | Charley | Frances | Ivan | Jeanne | Dennis | Katrina | Rita | Wilma |
| Hurricane category | 4 | 2 | 3 | 3 | 3 | 2 | 2 | 3 |
| Florida sustained winds (mph) | 145 | 105 | 130 | 120 | 120 | 80 | 62 | 125 |
| Number of Utility Restoration Personnel | 19,860 | 21,172 | 6,430 | 27,320 | 5,353 | 14,820 | 546 | 19,121 |
| Customer Power Outages (thousands) | 1,800 | 4,500 | 400 | 3,500 | 500 | 1,200 | 25 | 3,551 |

*Sources: Florida Division of Emergency Management, Hurricane Impact Report (Florida Division of Emergency Management 2004); Florida Division of Emergency Management, Draft Hurricane Impact Report (Florida Division of Emergency Management 2007).*

Currently there are 15 plants, representing 22 percent of Florida's total generation capacity (13 GW) located in storm surge zones for Category 1 hurricanes, and up to 36 plants (over 37.8 percent of capacity) are vulnerable to Category 5 hurricanes. Some of Florida's largest coastal resources are also the most vulnerable, as estimated from the state's "surge zones" (Florida State Emergency Response Team 2006). In Miami-Dade County, the huge Turkey Point nuclear plant and two other significant power plants are well within the zone vulnerable to surges from even moderate storms (see Map 13). The surge zones shown in Map 13 are already vulnerable to storm surges under current conditions, and will be increasingly at risk from even the modest sea level rise in the rapid stabilization scenario. The business-as-usual scenario will bring much greater risks to these and adjacent areas, due to much greater sea level rise and increased intensity of storms.




Map 13. Principal Miami-area Power Plants at Risk from Storm Surges

*Sources: See Appendix C for detailed sources and methodology.*

**Table 20. Statewide Energy Capacity Vulnerable to Hurricane Storm Surge**

| | Tropical | Hurricane Category | | | | |
|---|---|---|---|---|---|---|
| | Storm | 1 | 2 | 3 | 4 | 5 |
| Vulnerable plants | 2 | 15 | 19 | 28 | 29 | 36 |
| Capacity (GW) | 3.1 | 12.7 | 14.7 | 16.9 | 16.9 | 22.4 |
| % of state capacity | 5.20% | 21.50% | 24.90% | 28.60% | 28.60% | 37.80% |

*Sources: Storm surge zones from Florida Department of Community Affairs, Division of Emergency Management (Florida State Emergency Response Team 2006), power plant locations and data from 2006 EPA Emissions & Generation Resource Integrated Database (eGRID) (Environmental Protection Agency 2007b).*

## WATER SYSTEM

The recent record-breaking drought to the contrary, Florida is generally a wet state. It averages 54 inches of rainfall per year, a level matched only by a few other states in the Southeast, and by Hawaii. Huge aquifers can be found under all regions of the state, and many areas have abundant surface water as well. Indeed, most of south Florida was a vast wetland less than 100 years ago; agricultural and residential development was dependent on the massive drainage efforts of the first part of the twentieth century. Ironically, Florida succeeded all too well in getting rid of its former "excess" of water — leading to recent shortages, as well as a long and expensive process of environmental restoration.

The abundance of rainfall is deceptive. Precipitation is not evenly distributed throughout the year, but is heavily concentrated in the rainy season — for most of the state, June through September. In that hot, wet period, most of the rainfall, as much as 39 of the 54 inches, evaporates before it can be used. Demand for water, on the other hand, is highest during the dry months of the winter and spring, driven by the seasonal peak in tourism and by the profitability of irrigated winter agriculture.

In 2000, Florida used 12,000 million gallons per day (mgd) of salt water and 8,200 mgd of fresh water; the salt water is used almost exclusively for power plant cooling requirements (Marella 2004). Of the fresh water, 3,100 mgd came from surface water, and 5,100 from groundwater, or aquifers. Surface water is taken from a number of sources throughout the state, however, more than 40 percent of all surface water use occurs in Palm Beach and Hendry Counties, the two counties directly south of Lake Okeechobee. Most surface water, statewide, is used for irrigation.

Groundwater comes, above all, from the immense Floridan Aquifer that underlies the entire state. There were withdrawals from the Floridan Aquifer in all but one county in 2000, accounting for 62 percent of the state's groundwater supply (Marella 2004). Although reachable everywhere in the state, the Floridan Aquifer is of greatest use to central, northern, and northwestern Florida. In the south it is located much farther underground, and its water is more brackish. The Biscayne Aquifer, which lies above the Floridan Aquifer in the southeast, provided 17 percent of the state's groundwater, in Miami-Dade, Broward, and parts of Palm Beach County. Smaller aquifers elsewhere supplied the rest.

Reclaimed wastewater is a small but growing source, replacing about 200 mgd of fresh water in 2000. In addition, more than 100 desalination plants are in operation around the state, almost all used to reduce the salinity of brackish groundwater. Most are quite small, but there are a handful of 10-40 mgd plants (Florida Department of Environmental Protection 2007a). The first large-scale attempt at the more difficult and expensive task of desalination of ocean water, the new Tampa Bay facility, is discussed below.

As shown in Table 21, more than half of the fresh water used in Florida is for irrigation — including both agriculture and "recreational irrigation" of golf courses, sports fields, parks, cemeteries, and public spaces. (Related household uses, such as watering lawns, are included in "public supply" or "domestic self-supplied" water.)

**Table 21. Water Use, 2000**

| | Fresh water (mgd) | | | Salt water (mgd) | | |
|---|---|---|---|---|---|---|
| | Ground | Surface | Total | Ground | Surface | Total |
| Public supply | 2,200 | 240 | 2,440 | – | – | – |
| Domestic self-supplied | 200 | – | 200 | – | – | – |
| Commercial-industrial | 430 | 130 | 560 | – | – | – |
| Agricultural | 1,990 | 1,930 | 3,920 | – | – | – |
| Recreational irrigation | 230 | 180 | 410 | – | – | – |
| Power generation | 30 | 630 | 660 | – | 11,950 | 11,950 |
| **TOTALS** | **5,080** | **3,110** | **8,190** | **-** | **11,950** | **11,950** |

*Source: U.S. Geological Survey Scientific Investigations Report 2004 (Marella 2004)*

In 2002, Florida had 2.31 million acres of harvested cropland, of which 1.70 million acres, or 74 percent, were irrigated.[32] The irrigated area represented 5 percent of the total land area of the state. Citrus fruits, sugar cane, greenhouse and nursery crops, and vegetables account for most of the irrigated area, and most of the irrigation water use, as shown in Table 14 (see agriculture section, above). Recreational irrigation, accounting for about 5 percent of all fresh water use, is primarily for golf course irrigation, although other uses are also included. Recreational use of fresh water has been growing rapidly in recent years (Marella 2004).

After irrigation, the largest category of water use is the public water supply, at 30 percent of the fresh water total. Per capita usage in 2000 amounted to 174 gallons per day for the population served by the public water supply (most but not all of the state), just below the national average of 180 gallons per day. Public supply includes some commercial, industrial, and public uses (e.g., firefighting), as well as household use. Florida's household use of public water supply averaged 106 gallons per person per day in 2000, down from 144 gallons per person per day in 1980 as a result of conservation efforts that have already been implemented (Marella 2004).

### Water system projections: Rapid stabilization case

Even under the best of circumstances — under the rapid stabilization scenario, with minimal damages due to climate change — Florida's rapid economic and demographic growth is headed for a collision with the lack of additional water. The Department of Environmental Protection projects an increase in water requirements of 22 percent by 2025 (Florida Department of Environmental Protection 2007b). Looking farther ahead, if agricultural water use remains constant, since there is little land for agricultural expansion, and if all other water uses grow in proportion to population, then by 2050 the state would need 12,800 mgd of fresh water.[33] This is a 57 percent increase over water use in 2000, a quantity that appears to be impossible to provide from existing fresh-water sources. At the current cost of desalination, $3 per 1,000 gallons (see below), the additional water needed by 2050 would cost almost $6 billion per year — if it were available.

Groundwater supplies are already encountering limits. The water level in the Floridan Aquifer has been dropping for decades (Marella and Berndt 2005); it can no longer meet the growing needs of many parts of the state. Meanwhile, the state has turned down Miami-Dade County's request for a big increase in its withdrawals from the Biscayne Aquifer, which is also under stress; the county will instead be forced to invest in expensive alternatives such as a high-tech wastewater disinfection plant (Goodnough 2007). Surface water supplies are limited in most areas, and will be further constrained in south Florida by the long-term effort to restore the Everglades ecosystem.

Floridians, therefore, can look forward to more intensive conservation efforts, such as strict limits on lawn watering, combined with promotion of alternative vegetation that requires less water than a grassy lawn. Water constraints are a major threat to the future of Florida's agriculture, by far the biggest user of water. Even the new proposals for sugar cane-based bioethanol, designed to reduce greenhouse gas emissions, will require continuing massive flows of water for irrigation.

New water supplies will increasingly mean new investment in more expensive alternative sources. New reservoirs are being built wherever possible, including underground storage of fresh water in some cases. Wastewater treatment is a growth industry in the state. Many areas have access to brackish ground water, aquifers that are less salty than ocean water but too salty for untreated use. In order to use these inferior supplies, communities have to build and operate desalination plants.

While traditional ground and surface water supplies often cost less than $1 per 1,000 gallons, desalination of brackish water can cost up to $3 per 1,000 gallons.[34] And the drawbacks of desalination are not limited to cost alone. The process results in large volumes of waste water requiring disposal; with the reverse osmosis process, used in almost all existing plants, 100 gallons of brackish water is turned into about 75 gallons of potable water and 25 gallons of briny byproduct. The brine is often pumped underground, or mixed with other wastewater to dilute it (Reeves

2007). Desalination also requires large amounts of energy; reverse osmosis consists of forcing water, at very high pressure, through thousands of fine-mesh filters. Additional reliance on desalination would increase the demand for electricity, which in turn would increase the demand for cooling water for power plants.

The one truly abundant potential source of fresh water, desalination of sea water, is even more expensive and problematical. It has been implemented on a small scale in the southern Keys, but at a cost of $5 per thousand gallons, desalination remains more expensive than bringing in water from the mainland via pipeline (Reid 2007). Industry sources estimate the costs of ocean desalination at $3 to $8 per thousand gallons.[35] The state's first large-scale ocean desalination plant was built for Tampa Bay Water, a regional authority in one of the most water-scarce regions. It has been plagued by technical problems, multi-year delays, and cost overruns, reaching a cost of $158 million by the time it began operation in 2003. The plant hopes to reach its design capacity of 25 mgd of fresh water, with costs a little above $3 per thousand gallons, by the end of 2007 (Barnett 2007; Reid 2007). In view of the problems with the Tampa Bay plant, no one else in Florida is rushing to build a similar facility.

Although costs of ocean desalination have come down in recent years, there are a wide range of problems that limit the appeal of the process, even when it runs smoothly. Plant construction may degrade the shoreline environment; sea water intake may do further damage to the ocean floor; the discharge of very salty brine may harm the local ocean environment; chemicals used in pretreatment of sea water add contaminants to the waste water; and the plants require large amounts of energy (Yuhas and Daniels 2006). Both brine disposal and energy needs are much greater with ocean desalination than with brackish water plants.

Finally, while the Tampa Bay plant is large compared to previous desalination efforts, it is small compared to Florida's water needs. To meet the growth in the demand for water through 2050 (as projected above), 186 Tampa-sized plants would be needed — more than one new plant coming on line every three months, from now through 2050.

In short, there are no believable supply-side options for providing this much water; most of the gap will have to be filled by conservation and reduction in demand.

### Water system projections: Business-as-usual case

Meeting Florida's water needs will be challenging, even in the absence of climatic change. The business-as-usual climate scenario will make a bad situation much worse, with average temperatures rising by 10°F, rainfall decreasing from 54 to 49 inches per year, and sea levels rising by almost four feet, over the course of the twenty-first century.

Hotter, drier conditions will increase the demand for water for irrigation and other outdoor uses, while at the same time decreasing supplies. Surface water flows will be diminished by the decreased rainfall and increased evaporation. Ground water supplies will also gradually diminish, as less rainfall and more evaporation means less water percolating down through the soil to recharge the aquifers. The decreased rainfall will not be uniform and predictable from year to year; rather, there will be more frequent droughts, resembling the conditions of 2001 and 2007. With water levels in Lake Okeechobee and elsewhere dropping under drought conditions, the water supplies for much of south Florida, and much of the state's agriculture, are at risk.

Rising sea levels will lead to increased salt water infiltration into aquifers, particularly since water levels in the aquifers are dropping and fresh water recharge is diminishing. Thus ground water supplies, which provide most of the state's drinking water, will tend to become brackish.

Rising sea levels will also block the traditional water flow through the Everglades ecosystem, which is slowly being reconstructed at great expense. By 2100, in the business-as-usual scenario, all of Monroe County and two-thirds of Miami-Dade County will be inundated; the southern Everglades, including the national park, will no longer be a fresh-water ecosystem. This change will be an ecological catastrophe for most of the species that now inhabit the southern Everglades. It will also have incalculable, but likely extremely disruptive, effects on fresh water flows throughout southern Florida, placing surface water supplies at risk.

This description of expected impacts makes it clear that climate change will cause expensive damages to Florida's water supply, but does not give rise to any precise dollar estimate. For an approximation of supply costs, suppose that climate change means that more of the demand for water has to be met at $3 per thousand gallons, a typical cost for desalination of brackish ground water, and also an optimistic cost for ocean desalination (the estimated costs at Tampa Bay, once it is running smoothly; or the low end of the desalination industry's cost projections).

Desalination is energy-intensive, so its cost will be even higher if electricity prices rise. At the present-day cost of $3 per thousand gallons, 1 mgd for a full year costs $1.1 million. Even under the rapid stabilization scenario, many parts of Florida may be facing costs of this magnitude for any future increases in water supply. The business-as-usual scenario will reduce the current supplies of fresh water, requiring more reliance on new supplies at $3 per thousand gallons. If the business-as-usual scenario means that an additional 50 percent of current surface water supplies had to be replaced (in addition to the new sources needed in the rapid stabilization case) at a cost of $3 per thousand gallons, the cost increase due to business-as-usual conditions would be $1.8 billion per year. The greater danger is that water will not be available even at this price, and that environmental damages resulting from sea-level rise, and from the operation of desalination plants, will cause incalculably larger harms.

# V. IMPACTS OF HURRICANES

In both the rapid stabilization and business-as-usual future climate outlooks for Florida, climate change is likely to have important effects on the economic damages and deaths that result from hurricanes. In order to calculate Florida's hurricane-related costs over the next 100 years for each scenario, we took into account coastal development and higher population levels, sea-level rise as it impacts on storm surges, and (for the business-as-usual case only) greater storm intensity. The calculation is described here in general terms, and in more precise mathematical detail in Appendix B.

## HURRICANE DAMAGE PROJECTIONS


We used hurricanes striking Florida from 1990 to 2006 as a baseline in estimating the average economic damages and number of deaths for different categories of hurricanes[36] (see Appendix D for details on Category 4 and 5 hurricanes striking Florida during this period). Based on hurricane trends over the last 150 years, Florida can expect to suffer four out of ten mainland U.S. hurricanes and two-thirds of all mainland U.S. Category 5 storms. In an average 100 years, that's 28 in Category 1, 21 in Category 2, 19 in Category 3, four in Category 4, and one or two Category 5 hurricanes. These probabilities were applied to the average damages and deaths established for each category in order to estimate the impacts of an "average hurricane year." Given no change to the frequency or intensity of hurricanes striking Florida, the expected impact from Florida's hurricanes in an average year is $3.7 billion (in 2006 dollars) and 8 deaths (at the 2006 level of population).[37]

**Table 22. Hurricanes Striking Florida from 1990 to 2006**

| Hurricane Category | Average Impacts 1990 to 2006 | | Annual | Impacts in an Average Year | |
|---|---|---|---|---|---|
| | Damages (billions of 2006$) | Deaths (scaled to 2006) | Probability of Occurance | Damages (billions of 2006$) | Deaths (scaled to 2006) |
| 1 | $0.7 | 6 | 0.28 | $0.2 | 2 |
| 2 | $3.9 | 15 | 0.21 | $0.8 | 3 |
| 3 | $7.0 | 6 | 0.19 | $1.3 | 1 |
| 4 | $15.7 | 34 | 0.04 | $0.6 | 1 |
| 5 | $62.9 | 57 | 0.01 | $0.8 | 1 |
| **Total** | | | **0.72** | **$3.7** | **8** |

*Sources: The large majority of data were taken from (Blake et al. 2007; National Hurricane Center 2007); a few data points were added from (CNN 1998; National Climatic Data Center 2005; National Association of Insurance Commissioners 2007).*
*Note: Where discrepancies existed, the NHC(National Hurricane Center 2007) data were used. NAIC (National Association of Insurance Commissioners 2007) data — used for two data points — are insured damages only; following the convention documented in NHC (National Hurricane Center 2007), these insured damages were double to estimate total damages.*

We consider three factors that may increase damages and deaths resulting from future hurricanes; each of these three factors is independent of the other two. The first is coastal development and population growth — the more property and people that are in the path of a hurricane, the higher the damages and deaths (Pielke and Landsea 1998). Second, as sea levels rise, even with the intensity of storms remaining stable, the same hurricane results in greater damages and deaths from storm surges, flooding, and erosion (Pielke Jr. and Pielke Sr. 1997). Third, hurricane intensity may increase as sea-surface temperatures rise; this assumption is used only for the business-as-usual case (Emanuel 2005; Webster et al. 2005; Intergovernmental Panel on Climate Change 2007b).

Florida's projected population level and per capita Gross State Product (GSP) — identical for the rapid stabilization and business-as-usual scenarios — were calculated for each year from 2010 to 2100.[38] Following Pielke and Landsea (1998) hurricane damages are assumed to be proportional to GSP; this logic is extended to treat hurricane deaths as proportional to state population.

The projected sea-level rise, above year 2000 levels, for Florida in the rapid stabilization and business-as-usual cases was calculated for each year. In the rapid stabilization case, sea-level rise reaches 7 inches in 2100, and for the business-as-usual case, 45 inches. Nordhaus (2006) estimates that for every meter of sea-level rise, economic damages from hurricanes double, controlling for other kinds of impacts.

Nordhaus (2006) also estimates the impact of increasing atmospheric carbon dioxide levels and sea-surface temperatures on storm intensity and economic damages. According to his calculations, every doubling of atmospheric carbon dioxide results in a doubling of hurricane damages — independent of the effects of sea-level rise. Projected carbon dioxide levels were calculated for the business-as-usual case for each year (the rapid stabilization case assumes that hurricane intensity will remain constant).

Combining these effects together, Florida's projected hurricane damages for the year 2050 is $24 billion and 18 deaths for the rapid stabilization case, and $49 billion — 1.5 percent of GSP — and 37 deaths in the business-as-usual case. The annual cost of inaction is $25 billion and 19 extra deaths in 2050 and $104 billion and 37 extra deaths in 2100.

**Table 23: Hurricanes Striking Florida: Cost of Inaction**

| | 2025 | 2050 | 2075 | 2100 |
|---|---|---|---|---|
| **Damages (in billions of 2006 dollars)** | | | | |
| Rapid Stabilization Case | $12 | $24 | $37 | $55 |
| Business-As-Usual Case | $18 | $49 | $90 | $159 |
| *Cost of Inaction* | *$6* | *$25* | *$54* | *$104* |
| **Damages (as a percentage of GSP)** | | | | |
| Rapid Stabilization Case | 0.7% | 0.7% | 0.8% | 0.8% |
| Business-As-Usual Case | 1.1% | 1.5% | 1.9% | 2.3% |
| *Cost of Inaction* | *0.4%* | *0.7%* | *1.1%* | *1.5%* |
| **Deaths** | | | | |
| Rapid Stabilization Case | 14 | 18 | 19 | 20 |
| Business-As-Usual Case | 21 | 37 | 47 | 57 |
| *Cost of Inaction* | *7* | *19* | *28* | *37* |

*Source: Authors' calculations.*

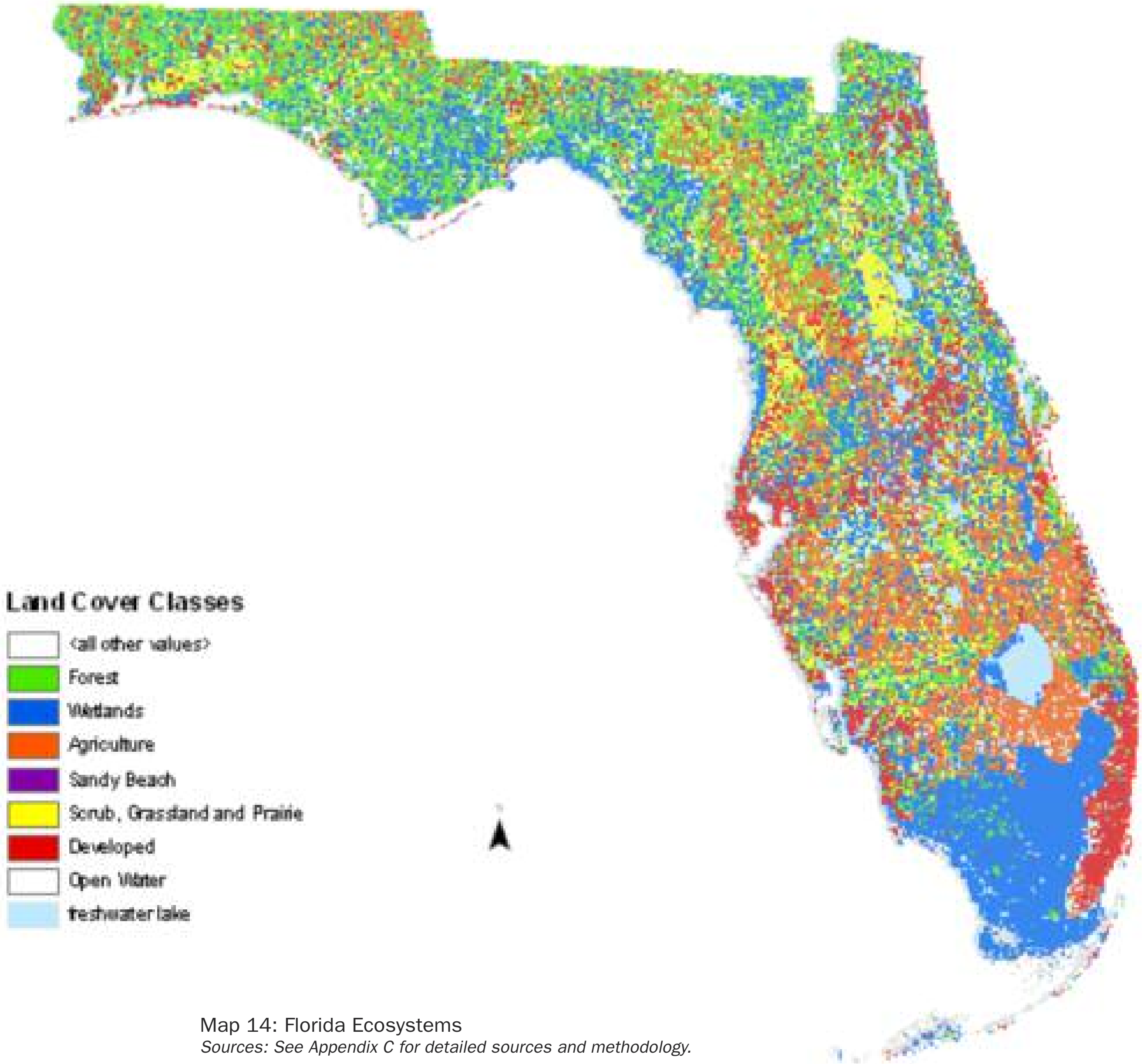
# VI. ECOSYSTEMS

The economic damage that Florida will suffer in the business-as-usual case seems high enough even without any reckoning for the impacts of climate change on priceless natural ecosystems. Wholesale extinctions and ecosystem destruction are unavoidable in the business-as-usual future, and the strategy that could save the most species and ecosystems — allowing wetlands to migrate, taking over what are now dry lands — is extremely unlikely to occur, at least on a wide scale.

## SEA-LEVEL RISE

Much of Florida's shoreline is made up of richly diverse coastal habitats, including estuaries, saltwater marshes, tidal flats, sandy beaches and barrier islands. All these habitats are at risk of disappearing under the waves as the seas around Florida rise 45 inches by 2100 in the business-as-usual case. Some of the species that live in these ecosystems may find it possible to migrate inland as waters rise, establishing new ecosystems along the new coastline. Many other species will be unable to adopt new territories, blocked by shoreline protections like seawalls, designed to maintain today's shoreline and land use.

Coastal estuaries will be among the ecosystems hardest hit by sea-level rise (Savarese et al. 2002; Intergovernmental Panel on Climate Change 2007b; Levina et al. 2007). These wetlands constitute one of Florida's most critical ecosystems. In estuaries, freshwater meets saltwater, creating a variety of habitats that can only exist in the resulting brackish water, such as mangroves swamps, saltwater marshes, tidal flats, seagrass beds, and oyster bars. Estuaries serve as nurseries and provide critical refuge and food sources for about 90 percent of Florida's most important recreational and commercial fish and shellfish species, as well as waterfowl and other wildlife. Wetlands also




Map 14: Florida Ecosystems
*Sources: See Appendix C for detailed sources and methodology.*

help filter pollutants, improving water quality; protect the coastline from storm surges and floods; and protect uplands from saltwater intrusion, among many other ecosystems functions that benefit human society (National Oceanic & Atmospheric Administration 2000a; National Wildlife Federation and Florida Wildlife Federation 2006).

Mangrove forests are an estuarine habitat that dominates much of southern Florida's subtropical coast. Many protected inner bays are mangrove-rimmed estuaries, a distinctive feature of the Everglades with its mixture of salt and freshwater. Fish such as snook and schoolmasters migrate in and out depending on the salinity of the water. Florida's mangrove forests are particularly important because they provide nurseries and shelter for many fish and wildlife species. Among the young protected

**CASE STUDY: TEN THOUSAND ISLANDS**

The Ten Thousand Island National Wildlife Refuge on the southwest coast of Florida is part of the largest expanse of mangrove forest in North America. The southern two-thirds of the 35,000 acre refuge protects mangrove habitat in the tidal fringes and numerous keys, while the northern third harbors saltwater marsh, ponds, and small coastal hammocks of coastal forest composed of oak, cabbage palms and tropical hardwoods.

Seagrass beds and mangrove swamps in the Ten Thousand Islands and Florida Bay serve as vital nursery grounds for roughly 200 species of marine fish, and the area is a critical refuge for dozens of bird species. Notable threatened and endangered species include West Indian manatee, bald eagle, peregrine falcon, wood stork, and the Atlantic loggerhead sea turtle. Estuarine wetlands like the Ten Thousand Islands are particularly sensitive to rising sea levels because of their low elevation (Savarese et al. 2002). As a result, the region's entire estuarine and wetland system could experience radical change in the next century, with the dramatic loss of pristine wetland ecosystems.

in this habitat are the gray snappers, an important commercial fish, and loggerhead turtles. The diversity of the mangrove ecosystem includes not only fish, invertebrates, amphibians, and reptiles, but also a variety of birds, such as egrets, roseate spoonbills, and the southern bald eagle, and mammals, such as manatees and an occasional bobcat or Florida panther. In recent years, as more of this habitat disappears, endangered species like the American crocodile will be increasingly threatened. Mangrove ecosystems protect the shoreline from erosion and dissipate the energy of storms, creating a natural barrier to storm surges from hurricanes (Savarese et al. 2002; Brooks et al. 2006).

Saltwater marshes, comprised mostly by grasses and other grass-like plants, occur in the zone between low and high tides. Most of Florida's saltmarshes occur on the Gulf Coast from Apalachicola to Tampa Bay to Cedar Key, and from Daytona Beach northward on the Atlantic Coast. They serve as natural filters and provide important habit for waterfowl and other wildlife (National Wildlife Federation and Florida Wildlife Federation 2006). The saltwater marshes create a safe nursery environment because larger fish cannot swim between the tightly packed grasses.

Tidal flats are areas of broad, flat land created by tides. They are generally composed of sandy or muddy soils and provide important sources of food for birds and other wildlife. They also play an important role in purifying pollutants that come from shore (National Wildlife Federation and Florida Wildlife Federation 2006). Many of the animal species that live in the tidal flats of Florida are similar to those that live in the mangrove ecosystem. Invertebrates like the queen conch, the Florida sea cucumber, and blue crab spend their lives in the mud while birds such as the yellow-crowned night-heron, Florida mottled duck, and marlin also make their home in tidal flats.

Estuaries, bays and other coastal and marine ecosystems already have been radically altered by human development, leading to significant declines in fish and wildlife populations. The construction of flood control and water diversion projects that alter natural freshwater flows into these ecosystems and raise nutrient concentrations and salinity have contributed to the loss of one-third of Florida's seagrass beds and half of its saltmarsh, mangrove and other wetland habitat. Across the United States, half of all estuaries now show significant levels of nitrate-driven eutrophication — increases in organic matter and a related depletion of oxygen in the water — leading to decreased water clarity, more frequent and harmful algae blooms and degraded sea grasses and corals (National Oceanic & Atmospheric Administration 2000a; Scavia et al. 2002; National Wildlife Federation and Florida Wildlife Federation 2006).

Rapid sea-level rise would further threaten estuarine habitats. Rising water levels would impact these critical ecosystems in two interconnected ways: inundation, as coastal wetlands become open water; and inability to migrate inland, due to barriers from human development and habitat fragmentation. The combined impact of inundation and impeded migration will be a substantial loss of coastal estuarine habitat. Historically, coastal wetland habitat such as mangroves have expanded inland or upward by accumulating sediment and peat in order to keep pace with sea-level rise (Michener et al. 1997; National Oceanic & Atmospheric Administration 2000a). In the absence of barriers to migration, wetlands will continue to encroach upslope and inland as soils are persistently inundated. Meanwhile, freshwater marsh and swamp habitats of the interior Everglades system and elsewhere will be displaced. Mangrove swamps, in turn, would be converted to shallow marine habitats in open water (National Oceanic & Atmospheric Administra-

**CASE STUDY: FLORIDA'S SANDY BEACHES AND BARRIER ISLANDS**

Many of Florida's larger barrier islands are inhabited and are popular tourist destinations, such as Clearwater Beach and Treasure Island, in the Tampa Bay area, and Miami Beach, Sunny Isles Beach, and the Bay Harbor Islands in the Miami area. Further up the Gulf Coast, St. George's Island and other barrier islands protect several parts of the panhandle. Under the business-as-usual scenario, the great majority of these islands will be completely inundated. Barrier islands face more complicated impacts from sea-level rise than ordinary coastlines because they tend migrate as sand is either eroded or accumulated. The protective buffer that these islands provide from storm surges also protects estuaries. Mudflats and marshlands mix with lagoons and bays, creating a variety of habitats for wildlife. When the lagoonal area between the islands shrinks and grows, and barrier islands shift their position, the salinity level of the water — a critical characteristics for many species — changes. The most vulnerable habitats are saltmarshes and tidal flats along the Gulf Coast and in South Florida, which contain a large portion of Florida's wildlife diversity (National Wildlife Federation and Florida Wildlife Federation 2006).

tion 2000a; Scavia et al. 2002; Doyle et al. 2003; Lodge 2005; Brooks et al. 2006; National Wildlife Federation and Florida Wildlife Federation 2006; Levina et al. 2007). In Waccasassa Bay State Preserve on Florida's Gulf coast, sea-level rise would increase saltmarsh, at the expense of coastal forests (Castaneda and Putz 2007), and in the Big Bend region of northwest Florida, large areas of marshland would be converted to open water as forest is converted to marsh. Some marshlands could migrate into forested zones, but overall, net terrestrial habitat would be lost to an open water environment (Doyle 1997).

## SALTWATER INTRUSION

As sea levels rise, saltwater intrudes on freshwater stored underground in natural aquifers, threatening not only water supplies but also a number of ecosystems, including coastal freshwater lakes and low-lying coastal forests, where even minor intrusion of saltwater can have measurable impacts.

Already, native palms in the Waccasassa Bay State Preserve on Florida's Gulf Coast and pine trees in the Keys have been damaged or are dying off from exposure to saltwater associated with sea-level rise (Ross et al. 1994). The regeneration of cabbage palm, red cedar and other coastal trees in the Big Bend region of the Florida Panhandle has also been hampered by saltwater intrusion (Williams et al. 1999). As sea-level rise continues, the species and landscape diversity of low-lying coastal areas and island ecosystems such as the Florida Keys and Big Bend will decline as diverse upland communities are replaced by mangroves.

## HIGHER TEMPERATURES AND LESS RAINFALL

Higher average temperatures and lower precipitation rates under the business-as-usual scenario will have especially damaging effects on forested areas in the state's temperate Panhandle and freshwater systems such as natural lakes, streams and wetlands in central and northern parts of the state. Studies modeling species loss in Florida show that biodiversity would be extremely susceptible to increasing temperatures (Dohrenwend and Harris 1975; Harris and Cropper 1992). A 3.5°F increase in temperature — a level reached by 2035 in the business-as-usual scenario — would lead to extensive loss of natural range by ecologically important temperate trees and shrubs; coupled with less rain, much of the state's naturally forested areas would degrade to open scrub or dry grasslands (Box et al. 1999; Crumpacker et al. 2001).

Species at the southern end of their temperature limit will find it difficult to adapt to 10°F in

**CASE STUDY: BIG BEND NATIONAL WILDLIFE REFUGE**

The Big Bend coast of north and central Florida includes more than 120,000 acres of undisturbed coastal wetlands and saltmarshes that abut vast coastal forests, with a shallow surrounding seabed that stretches miles into the Gulf of Mexico. One-fifth of all estuarine wetlands along the U.S. coastline of the Gulf are in Florida's Big Bend, including five national wildlife refuges: wetlands in the Lower Suwannee Refuge; diverse beaches, coastal marshes and upland forests in the Cedar Keys Refuge; and prime estuarine habitat in Chassahowitzka Refuge. Big Bend is home to a diversity of wildlife, like the manatee, loggerhead sea turtle, white ibis, and black bear. The effects of rising sea levels and saltwater intrusion already can be observed at Big Bend in the stands of dead cabbage palms that populate the seaward edge of the saltmarshes (Williams et al. 1999). Other Big Bend tree species, like southern red cedar, live oak and sugarberry, have also proved vulnerable to salt exposure through tidal inundation. The retreat of coastal forest as sea levels rise may be hastened by the loss of saltwater marsh, which plays a buffering effect by filtering saltwater.

a century, and most of Florida's 119 native fish species could be eliminated from the state altogether (Mulholland et al. 1997; National Wildlife Federation and Florida Wildlife Federation 2006). At the same time, Florida's subtropical species, like mangroves and snook, could migrate northwards and inland with warmer temperatures, so long as human development and habitat fragmentation does not impede their expansion. Opportunistic non-native species, including introduced tropical fish and invasive plants such as the Australian pine tree and the Brazilian pepper shrub, are expected to expand their range as a result of higher temperatures, possibly suppressing native species in the process (Mulholland et al. 1997; National Wildlife Federation and Florida Wildlife Federation 2006).

Florida's temperate forests will face two different types of impacts: loss of species, and contraction of natural range. Forest ecosystems are expected to lose about one-third of their species in the northern peninsula, and one-fifth in the western Panhandle (Crumpacker et al. 2001). Reductions in geographical range compound the loss of biodiversity.

Florida's mixed conifer and hardwood forests, located in the panhandle and northern sections of the state, are expected to retreat northward to Georgia and Alabama (Environmental Protection Agency 1997). The natural distribution of woody plants in Florida is strongly controlled by climate factors — in particular by winter temperatures — and not soil type or precipitation levels. In general, the ranges for temperate woody species are expected to contract with warming and drying, while ranges for subtropical species will shift or expand northward, or inland, or both (Environmental Protection Agency 1997; Box et al. 1999). Woody species would experience range contractions of between 76 and 97 percent in the Florida Panhandle and between 30 and 65 percent in the upper peninsula by 2035 in our business-as-usual case. Even the 2°F increase that we forecast for 2020 is expected to reduce the range of some species. Shortleaf pine, American beech and black willow will suffer range reductions of 90 to 100 percent, while southern red oak, swamp chestnut oak and southern magnolia will lose 23 to 40 percent of their range.

Species adapted to both temperate and sub-tropical climates, like the cabbage palmetto, will only experience a very slight increase in range, while subtropical native species currently endemic to southern Florida — Florida poison tree, pigeon-plum and Florida stranger fig — will experience large expansions in range if unimpeded by human development and other factors. Aggressive native, heat-tolerant plant species that already range throughout most of Florida — such as the saw palmetto and the southern bayberry — are likely to increase their density in response to warming and exert significant negative competitive pressure on other native species (Box et al. 1999).

**CASE STUDY: OSCEOLA NATIONAL FOREST**

Northeastern Florida's Osceola National Forest, 50 miles west of Jacksonville, contains two thousand acres of pine-flatwood forest and cypress-hardwood swamps. The Osceola is home to a rich ecosystem of diverse species including the endangered red-cockaded woodpecker and the alligator. In addition to playing a critical conservation role, these forested woodlands and swamps provide a wide range of valuable recreational activities for thousands of Florida residents and out-of-state visitors each year, including camping, hiking, swimming, fishing, and hunting. The Osceola will experience dramatic changes with global warming under the business-as-usual case, including a significant reduction in forested range and the loss of 55 percent of its species by 2030 (Crumpacker et al. 2001).

### CASE STUDY: OKEFENOKEE NATIONAL WILDLIFE REFUGE

Okefenokee National Wildlife Refuge, located in southeast Georgia and northern Florida, is North America's largest swamp, covering 438,000 acres. Most of the swamp is classified as a freshwater wetland, abutted by large tracts of riparian forest (mixed and pure cypress stands, blackgum forest, bay forest), swamp islands and prairie habitats. More than 200 species of birds have been identified in the refuge, including several endangered species such as the red-cockaded woodpecker, American bald eagle, and the wood stork. Rainfall plays a central role in the life of freshwater ecosystems. In Florida's Okefenokee Swamp, rain accounts for fully 95 percent of the water in the Swamp, with 80 percent returned to the atmosphere through evaporation and transpiration (U.S. Fish & Wildlife Service 2007b). The increasing frequency of droughts would affect the swamp's rich mosaic of vegetation and the density and distribution of its wildlife. Threatened and endangered species sheltered in the refuge would be hardest hit by such changes.

Freshwater ecosystems will also be affected in important ways by higher temperatures and less rainfall. Longer growing seasons, fewer and less severe freezes and higher temperatures year-round will reduce the habitat of cool-water species and encourage the expansion of subtropical species northward, including several exotic nuisance species currently confined to southern Florida. Reduced water quality due to lower concentrations of dissolved oxygen and increased drying of riparian wetland soils as a result of shorter flooding periods will have negative impacts on freshwater wetlands (Mulholland et al. 1997). Many native, temperate fish species will be lost and replaced with exotic subtropical species.

More intermittent rainfall and high summer temperatures will have significant impacts on streams and rivers, eventually lowering biodiversity in these critical ecosystems (Mulholland et al. 1997). Increased salinity and other downstream impacts on estuarine ecosystems are also expected (Scavia et al. 2002). Greater freshwater withdrawal to meet human needs will exacerbate the impact on freshwater and estuarine ecosystems. In north Florida, warm temperate lakes are projected to undergo substantial changes as warming shifts the conditions to a subtropical environment, increasing productivity and nutrient cycling rates as well as protozoa and bacteria populations. Subtropical blooms of blue-green algae and other exotics, now primarily confined to subtropical lakes, will expand northward (Mulholland et al. 1997).

## SEVERE HURRICANES

Mangrove forests, freshwater marshes, and coral reefs are all vulnerable to hurricane damage. Since mangroves occupy intertidal coastal areas — between the high and low tide marks — they are particularly susceptible to hurricane winds and storm surges. Damage can range from defoliation to tree blowdowns. As hurricanes become more intense, studies indicate that mangrove trees will become shorter and forests will contain a higher proportion of red mangroves, which have a higher tolerance for salt water than other mangrove species (Doyle et al. 2003). Evidence from past hurricanes show that with extreme events some mangrove forests may be destroyed altogether, as happened in Hurricane Donna in 1960, which reached so far inland that what had been thriving mangrove forests were left without any vegetation.

Freshwater and brackish marshes are also impacted by hurricanes, with storm surges transporting unhealthy amounts of saltwater and sediment into these environments. During Hurricane Andrew, for example, storm surges dumped large quantities of sediment into low-salinity marshlands, smothering vegetation. Hurricane-induced erosion caused similar problems with the distribution of substrate and seaweed around the marshes, likewise suffocating plants. In freshwater marshes the introduction of too much additional saltwater caused salt burn of vegetation, harming or killing the plants by exceeding their salinity tolerance (Scavia et al. 2002). The salinity levels in fresh marshes can remain elevated for a year or more after hurricanes, resulting in long-term changes in plant communities (National Oceanic & Atmospheric Administration 2000a).

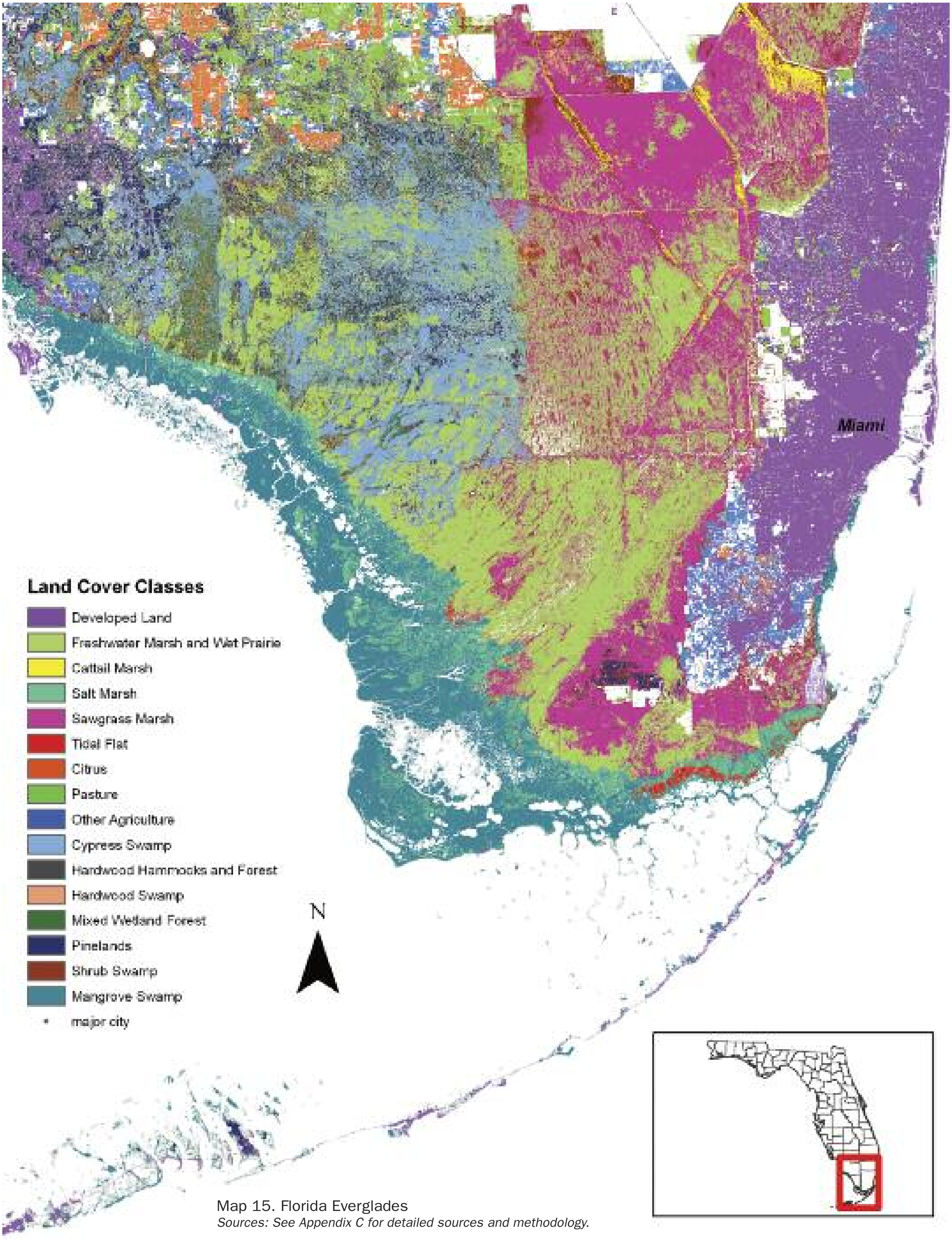
## IRREVERSIBLE IMPACTS: THE EVERGLADES EXAMPLE

The irreversible ecosystem impacts of unconstrained climate change are best illustrated by the effects on Florida's signature ecosystem: the Everglades.

The Florida Everglades, in the southern tip of the state, is a United Nations' World Heritage Site and a unique treasure of the natural world. The Everglades encompasses a cornucopia of natural environments: freshwater marshes; wetland tree islands; cypress heads, domes, and dwarf cypress forests; tropical hardwood hammocks; pinelands; mangrove swamps and mangrove islands; coastal saline flats, prairies, and forests; tidal creeks and bays; and shallow, coastal marine waters (Lodge 2005). These diverse Everglades habitats sustain more than 11,000 species of seed-bearing plants — including 25 different orchids — 350 kinds of birds, 150 types of fish, and innumerable invertebrates (World Wildlife Fund 2007b).

The Everglades once spanned 4,000 square miles of South Florida, from the Kissimmee Chain of Lakes just south of Orlando, down the River of Grass all the way to Florida Bay and the Keys. After a long and sordid history of attempts to drain land, together with the installation of water-diverting structures, 70 percent of natural water flow through the Everglades has been diverted, and the Everglades is now half its original size. This unparalleled, and in hindsight ill-conceived, engineering project has affected the timing and distribution of the Everglades' freshwater: the current water cycle no longer meets needs of plants and animals that live there. Water quality has also deteriorated due to heavy loads of phosphorus, nitrogen, and mercury that flow from agricultural and urban sources. A Comprehensive Everglades Restoration Plan (CERP) is currently being implemented in an attempt to restore this ecosystem. Put in place by the Water Resources Development Act of 1992, CERP was approved by Congress in 1999. This program sets out to restore, preserve, and protect the Everglades while still providing flood protection and supplies of freshwater (Lodge 2005; World Wildlife Fund 2007a).

As sea levels rise, water may encroach 12 to 24 miles into the broad low-lying area of the Everglades, leaving the lower Everglades completely inundated. Currently, approximately one-third of the Everglades lies within the vulnerable zone, at risk from 27 inches of sea-level rise by 2060 in the business-as-usual case. The planned investment in Everglades' restoration is necessary to keep this ecosystem resilient enough to withstand global warming. If business-as-usual emissions continue, however, significant portions of the Everglades will be flooded and lost to the sea. As much




Map 15. Florida Everglades
*Sources: See Appendix C for detailed sources and methodology.*

of the Everglades' wetlands are converted into open water, nurseries and shelter for many fish and wildlife species will be lost. In addition, mangroves protect the shoreline from erosion and trap sediments and debris, and loss or migration of this ecosystem will greatly alter the Everglades' ecology (Natural Resources Defense Council and Florida Climate Alliance 2001; Titus and Richman 2001). The 10°F increase in air temperature expected by 2100 will draw species northward out of the Everglades, but if current drylands are protected with seawalls this migration will be thwarted, and species will disappear from Florida, or in some cases made extinct. More intense hurricanes will weaken the ecosystems within the Everglades and may render some species more vulnerable to pests or disease.

Florida is an important reservoir of biodiversity in the United States, with a rich mix of temperate and subtropical ecosystems. The Everglades is projected to lose one-quarter to one-third of its species richness due to climate change (Crumpacker et al. 2001). For example, the Everglades is the breeding ground for the endangered American Crocodile. As sea levels rise and temperatures increase, the northward shift of mangrove forests may disrupt crocodile breeding patterns and nesting areas for this species may become repeatedly flooded, increasing the mortality rate (U.S. National Park Service 1999; University of Florida: Florida Museum of Natural History 2002).

# APPENDIX A. FLORIDA LANDCOVER BY COUNTY IN VULNERABLE ZONE

| | | | AREA IN VULNERABLE ZONE BY LAND COVER (square miles) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total Area (square miles) | Vulnerable Zone (square miles) | Developed | Bare Soil, Clearcut, or Extractive | Citrus | Pasture | Other Agriculture | Forest | Scrub, Grassland, Prairie, or Sandhill | Sandy Beach | Marsh and Tidal Flats | Mangroves | Swamp and Forested Wetland | Open Water |
| Miami-Dade | 1983 | 1374 | 73 | 24 | 1 | 2 | 22 | 24 | 1 | 0 | 959 | 101 | 61 | 73 |
| Monroe | 1055 | 1051 | 29 | 0 | 0 | 0 | 0 | 26 | 0 | 1 | 323 | 493 | 76 | 102 |
| Collier | 2039 | 378 | 25 | 1 | 0 | 0 | 5 | 15 | 1 | 0 | 85 | 134 | 86 | 25 |
| Volusia | 1220 | 274 | 23 | 1 | 0 | 1 | 0 | 32 | 8 | 1 | 36 | 9 | 54 | 108 |
| Brevard | 1052 | 200 | 35 | 0 | 7 | 0 | 0 | 55 | 19 | 2 | 38 | 6 | 4 | 33 |
| Duval | 852 | 159 | 19 | 1 | 0 | 0 | 0 | 12 | 2 | 1 | 39 | 0 | 3 | 80 |
| Stjohns | 663 | 157 | 15 | 2 | 0 | 1 | 5 | 27 | 4 | 1 | 25 | 0 | 23 | 54 |
| Lee | 837 | 150 | 26 | 1 | 1 | 0 | 1 | 18 | 3 | 2 | 6 | 54 | 2 | 36 |
| Franklin | 552 | 126 | 4 | 1 | 0 | 0 | 0 | 24 | 3 | 5 | 28 | 0 | 48 | 13 |
| Gulf | 569 | 117 | 2 | 1 | 0 | 0 | 0 | 21 | 4 | 2 | 8 | 0 | 69 | 10 |
| Putnam | 827 | 117 | 6 | 1 | 0 | 0 | 4 | 12 | 2 | 0 | 0 | 0 | 26 | 65 |
| Taylor | 1050 | 113 | 1 | 3 | 0 | 0 | 0 | 18 | 2 | 0 | 37 | 0 | 45 | 6 |
| Bay | 773 | 90 | 18 | 2 | 0 | 0 | 0 | 30 | 7 | 4 | 12 | 0 | 12 | 7 |
| Charlotte | 726 | 85 | 13 | 0 | 0 | 0 | 0 | 3 | 2 | 0 | 11 | 24 | 1 | 31 |
| Dixie | 715 | 79 | 1 | 4 | 0 | 0 | 0 | 11 | 3 | 0 | 32 | 0 | 21 | 7 |
| Wakulla | 617 | 70 | 3 | 1 | 0 | 0 | 0 | 14 | 2 | 0 | 32 | 0 | 9 | 8 |
| Seminole | 345 | 68 | 2 | 0 | 1 | 1 | 0 | 5 | 1 | 0 | 13 | 0 | 15 | 29 |
| Nassau | 664 | 64 | 2 | 0 | 0 | 0 | 0 | 3 | 0 | 0 | 31 | 0 | 4 | 23 |
| Levy | 1137 | 63 | 0 | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 43 | 0 | 3 | 12 |
| Flagler | 508 | 53 | 7 | 0 | 0 | 1 | 0 | 10 | 3 | 0 | 6 | 0 | 10 | 16 |
| Pinellas | 287 | 51 | 29 | 1 | 0 | 0 | 0 | 6 | 1 | 1 | 1 | 7 | 0 | 6 |
| Manatee | 762 | 42 | 10 | 0 | 0 | 1 | 1 | 3 | 1 | 0 | 3 | 7 | 1 | 14 |
| Hillsborough | 1070 | 39 | 13 | 0 | 0 | 0 | 0 | 3 | 1 | 0 | 5 | 9 | 1 | 6 |
| Clay | 644 | 39 | 3 | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 0 | 6 | 25 |
| Citrus | 624 | 37 | 1 | 0 | 0 | 0 | 0 | 3 | 0 | 0 | 19 | 0 | 2 | 12 |
| Martin | 665 | 33 | 10 | 0 | 0 | 0 | 0 | 3 | 2 | 1 | 0 | 3 | 2 | 12 |
| Stlucie | 578 | 30 | 10 | 0 | 0 | 0 | 0 | 3 | 1 | 1 | 1 | 7 | 2 | 4 |
| Sarasota | 578 | 27 | 15 | 0 | 0 | 0 | 0 | 3 | 1 | 1 | 2 | 1 | 1 | 4 |
| Palmbeach | 2217 | 23 | 16 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 1 | 0 | 4 |
| Lake | 1157 | 21 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 16 | 3 |
| Indianriver | 514 | 20 | 7 | 0 | 0 | 0 | 0 | 2 | 0 | 1 | 1 | 5 | 1 | 2 |
| Hernando | 490 | 17 | 1 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 9 | 0 | 0 | 6 |
| Broward | 1219 | 15 | 11 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 2 |
| Pasco | 765 | 13 | 3 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 4 | 1 | 0 | 4 |
| Orange | 1003 | 10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 0 | 3 | 1 |
| Escambia | 671 | 10 | 2 | 0 | 0 | 0 | 0 | 1 | 0 | 2 | 1 | 0 | 0 | 3 |
| Santarosa | 1024 | 7 | 1 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 3 | 0 | 0 | 2 |
| Jefferson | 612 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 1 |
| Walton | 1069 | 5 | 1 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 1 | 0 | 1 | 1 |
| Liberty | 843 | 5 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 4 | 0 |
| Okaloosa | 942 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 |
| Marion | 1662 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |

# APPENDIX B. HURRICANE DAMAGES METHODOLOGY

## POPULATION AND DEVELOPMENT

Florida's projected population level and GSP (in 2006 dollars) were calculated for each year from 2010 to 2100. Following Pielke and Landsea (1998) hurricane damages are treated as proportional to GSP; in addition, this logic is expanded upon to treat hurricane deaths as proportional to state population. The resulting sets of population factors and development factors for each year are applied to the expected value of Florida's hurricane deaths and damages, respectively:

$$(1)\ PopFactor_{yr} = \frac{Population_{yr}}{Population_{2000}}$$

$$(2)\ DevFactor_{yr} = \frac{Population_{yr} * PerCapitaGSP_{yr}}{Population_{2000} * PerCapitaGSP_{2000}}$$

## SEA-LEVEL RISE

The projected sea-level rise, above year 2000 levels, for Florida in the rapid stabilization and business-as-usual cases was calculated for each of the modeled years. In the rapid stabiliztaion case, sea-level rise reaches 180mm in 2100, and for the business-as-usual case, 1150mm. Nordhaus (2006) estimates that for every meter of sea-level rise, economic damages from hurricanes double, controlling for other kinds of impacts. To arrive at this estimate, Nordhaus constructs a geographic grid with elevations and capital stock values (assumed to be proportional to average income) for each cell. Using this grid, he models incremental sea-level rise and makes the assumption that damages are proportional to vulnerable capital stock. In modeling Florida impacts, Nordhaus' estimated impact is used both for economic damages, as he intended, and for hurricane deaths. Sea-level rise (SLR) factors, by year, for each of the two scenarios, are constructed based on this estimate:

$$(3)\ RSSLRFactor_{yr} = 1 + (RSSLR_{yr}) / 1000$$

$$(4)\ BAUSLRFactor_{yr} = 1 + (BAUSLR_{yr}) / 1000$$

## STORM INTENSITY

Nordhaus (2006) also estimates the impact of increasing atmospheric $CO_2$ levels and sea-surface temperatures on storm intensity and economic damages. Based on a Monte Carlo (random) draw of storm frequency and intensity, Nordhaus estimates the expected damages from future hurricanes. He assumes that storm frequency will remain at the historical average, but maximum wind speeds will increase by 9 percent with a doubling of atmospheric $CO_2$. Using a regression analysis of past hurricanes, Nordhaus finds that hurricane power rises as the cube of maximum wind speed (a result confirmed by existing literature) and that hurricane damages rise as the cube of hurricane power. According to his calculations, every doubling of atmospheric $CO_2$ results in a doubling of hurricane damages — independent of the effects of sea-level rise. Again, Nordhaus estimate impacts are for economic damages, but are used here for deaths as well. Projected $CO_2$ levels were calculated for the business-as-usual case for all modeled years (the rapid stabilization case assumes that hurricane intensity will remain constant). Business-as-usual storm intensity (SI) factors for each year are as follows:

$$(5)\ BAUSIFactor_{yr} = \frac{BAUCO2Concentration_{yr}}{BAUCO2Concentration_{2000}}$$

## COMBINED EFFECTS OF ALL IMPACTS

Future economic damages from Florida's hurricanes are calculated by adjusting the expected value (EV) of hurricane damages upwards, using the development factor, rapid stabilization or business-as-usual sea-level rise factor, and (for the business-as-usual case only) storm intensity factor:

$$(6)\ RS\text{-}Damage_{yr} = EVDamage_{yr} * DevFactor_{yr} * RS\text{-}SLRFactoryr$$

$$(7)\ BAU\text{-}Damage_{yr} = EVDamage_{yr} * PopFactor_{yr} * (BAU\text{-}SLRFactor_{yr} + BAU\text{-}SIFactor_{yr})$$

Future economic deaths from Florida's hurricanes are calculated by adjusting the expected value of hurricane deaths using the population factor, rapid stabilization or business-as-usual sea-level rise factor, and (for the business-as-usual case only) storm intensity factor:

$$(8)\ RS\text{-}Deaths_{yr} = EVDeaths_{yr} * PopFactor_{yr} * RS\text{-}SLRFactor_{yr}$$

$$(9)\ BAU\text{-}Deaths_{yr} = EVDeaths_{yr} * PopFactor_{yr} * (BAU\text{-}SLRFactor_{yr} + BAU\text{-}SIFactor_{yr})$$

# APPENDIX C. GIS METHODOLOGY

Unless otherwise noted, all data used in this study were downloaded from the Florida Geographic Data Library (FGDL) website: http://www.fgdl.org/

## ELEVATION MAPPING

To estimate the impact of sea-level rise on land area, populations, and public and private assets and infrastructure, we began with a 1:250,000 Digital Elevation Model (DEM) map of the State of Florida, and divided the state into "vulnerable" and "not vulnerable" zones demarcated by 1.5 meters of elevation and other factors described by Titus and Richman (2000) as corresponding to 27 inches of sea-level rise.[39] We used USGS 1:250,000 DEM (90m cells) for statewide elevation processing and analysis.

The data sets that went into this processing were:

- NOAA Medium Resolution Digital Vector Shoreline (Filename: allus80k.shp). Downloaded from the USGS Coastal and Marine Geology Program Internet Map Server — Atlantic and East Coast (http://coastalmap.marine.usgs.gov/regional/contusa/eastcoast/atlanticcoast/data.html). We clipped the allus80k.shp file to a smaller file that included the entire Florida coast plus additional margins to the north and west, to ensure that no coastline was left out. We then projected this clipped shoreline into the coordinate system used by the Florida Geographic Data Library.
- USGS 1:250,000 DIGITAL ELEVATION MODEL (Filename: USGSDEM). Downloaded from the Florida Geographic Data Library (http://www.fgdl.org/)
- HISTORIC AND PROJECTED POPULATIONS OF FLORIDA COUNTIES (Filename: CNTPOP_2004). Downloaded from the Florida Geographic Data Library (http://www.fgdl.org/)

The USGS DEM original elevation values ranged from 0–114 (meters). These were reclassified using the ArcGIS "reclass" function as follows:

0 = 0
1 = 1
2 = 2
3 = 3
4 – 114 = 4

We used the raster-mask environmental setting to mask out any cells falling outside of the *NOAA Medium Resolution Digital Vector Shoreline* polygon boundary. This was necessary in order to mask out zero elevation values in the DEM that were offshore. The result is a re-classed digital elevation model where the 0-3 elevation values match the original for those cells inside the NOAA shoreline; values from 4 meters and higher are all set to 4, and zero values outside the NOAA shoreline are set to NO DATA through the masking operation. The cell size remains 90 meters. All remaining data cells coded 0 or 1 were coded as being within the vulnerable zone ("in"). All remaining data cells coded as 3 or 4 were coded as being outside the vulnerable zone ("out"). We call this *vulnfin*.

## RASTER TO VECTOR DATA CONVERSION

In order to overlay the vulnerable zone on other GIS layers, we converted the processed DEM data to a vector polygon data format. This inevitably results in some loss of spatial data accuracy, and at large scales ("zoomed in" to show small areas in detail) the data appears very pixilated and jagged. The result is v*uln_in_out_poly*.

## DATA PROCESSING

The vulnerable zones polygon data layer was processed in three different ways, one for census data processing, a second way for all other facilities and infrastructure, and a third for land cover. These are described below.

### Population analysis and demographic data processing

Our base data on populations and demographics are from the U.S. Census 2000's blkgrp2000_sum3 dataset, which we downloaded from FGDL.

Throughout our analysis, we assume that populations are homogenously distributed across each census block group. Thus, to estimate the population vulnerable to sea-level rise in a given block group, we multiply the percent land area vulnerable (i.e., total area less area covered by inland lakes and waterways) in that block group by the group's total population. This simplifying assumption was necessary because more detailed data on population density is not publicly available from the U.S. Census Bureau.

We used the following process to remove coastal and inland waterways from our demographic analysis:

1. For inland waters, we used the HYDROS data layer from FGDL and selected out codes for water and streams, exporting these to their own data layer, called *hydros_water_selected*.
2. We then used the ERASE function to erase *hydros_water_selected* from *blkgrp2000_sum3* to get each block group's dry area only. The resulting layer is called: *blockgrp2000_sum3_inlandwaters_erased*.
3. To eliminate coastal waters, we then clipped *blockgrp2000_sum3_inlandwaters_erased* by *countypop2004* to estimate only the dry-land areas of census block groups. The resulting layer is: *blockgrp2000_sum3_inlandwaters_erased_clipped_by_countypop2004*.
4. In the attribute table, we then calculated two new fields:
   a. area_dry = dry area (square meters)
   b. acres_dry = dry acres for each census block group.
5. The field "original acres" has the acres of the entire block before water and ocean were taken out.
6. We then used the "INTERSECT" operation with the *vuln_in_out_poly data set* to generate the vulnerable zone for each block group. The resulting layer is: *blockgrp2000_sum3_inlandwaters_erased_clipped_by_countypop2004_intersect_vuln_in_out_poly*.
7. We then created new attributes for this layer:
   a. vuln_zone: 0 and 1 = vulnerable area; 3 and above = not vulnerable)
   b. zone_area = area of each blockgroup_vulnerability zone in square meters
   c. zone_acres = area of each blockgroup_vulnerability zone in acres
   d. zone_fract = zone_area/area_dry. This can be used to allocate population and other raw numbers data to zones.

Because populations and assets are highly concentrated in urban areas, we used more detailed data from the National Elevation Dataset (NED) to generate elevation maps of the Jacksonville, Tampa Bay-St. Petersburg, Miami-Dade County, and Ft. Lauderdale areas. However, these were not used in the data extraction or analysis portion of the project, only for maps.

## FACILITIES AND INFRASTRUCTURE

To process facilities and infrastructure, we intersected the *vuln_in_out_poly* data set with the FGDL's county boundary data set *(cntbnd)* and calculated a zone fraction for each IN and OUT based on recalculated areas. This data set was then used as the overlay data set for all facilities and infrastructure. Note that inland water bodies were not eliminated from this data layer.

All data related to facilities and infrastructure were downloaded from the Florida Geographic Data Library website, with the exception of roads data which came from StreetMap USA (ESRI). In our analysis of point data on facilities such as schools and medical centers, minor data loss was incurred when points fell on the border between two vulnerability zones. In most cases the number of points involved was negligible (5 religious centers lost from a population of 20,735; 5 lodging facilities lost out of 4650; 1 medical facility lost out of 13,381; 1 assisted rental home out of 1664), and in no case did it significantly effect our results.

## LAND COVER

For calculating the various types of land cover square miles, we used the FGDL's Habitat and Landcover data set (GFCHAB_03). We reclassed the *vulnfin* raster data layer into 1=vulnerable and 0=not vulnerable, and then multiplied this through the landcover raster data set. The result was a landcover data set for covering only land cover in the vulnerable zones. From this we could calculate area for each land cover in the vulnerable zone.

## COASTLINE ANALYSIS

We generated a map based on the U.S. Geological Survey's Coastline Vulnerability Index (CVI) data (http://woodshole.er.usgs.gov/project-pages/cvi/) and estimated the number miles of each class of coastline vulnerable to sea-level rise in each coastal county. Because shoreline data sets vary widely in scale, the estimated miles generated by GIS software from coastline data sets also varies widely.

## MAP SOURCES

**Map ES-1 and Map 2. Florida: Areas Vulnerable to 27 Inches of Sea-Level Rise**
Sources: NOAA Medium Resolution Digital Vector Shoreline (U.S. Geological Survey 2007), USGS 1:250,000 Digital Elevation Model (University of Florida: GeoPlan 2007), and Historic and Projected Populations of Florida Counties (University of Florida: GeoPlan 2007).

**Map 3. North Peninsula: Areas Vulnerable to 27 Inches of Sea-Level Rise**
Sources: NOAA Medium Resolution Digital Vector Shoreline (U.S. Geological Survey 2007), USGS 1:250,000 Digital Elevation Model (University of Florida: GeoPlan 2007), and Historic and Projected Populations of Florida Counties (University of Florida: GeoPlan 2007).

**Map 4. South Peninsula: Areas Vulnerable to 27 Inches of Sea-Level Rise**
Sources: NOAA Medium Resolution Digital Vector Shoreline (U.S. Geological Survey 2007), USGS 1:250,000 Digital Elevation Model (University of Florida: GeoPlan 2007), and Historic and Projected Populations of Florida Counties (University of Florida: GeoPlan 2007).

**Map 5. Panhandle: Areas Vulnerable to 27 Inches of Sea-Level Rise**
Sources: NOAA Medium Resolution Digital Vector Shoreline (U.S. Geological Survey 2007), USGS 1:250,000 Digital Elevation Model (University of Florida: GeoPlan 2007), and Historic and Projected Populations of Florida Counties (University of Florida: GeoPlan 2007).

**Map 6. Agriculture in Areas Vulnerable to 27 Inches of Sea-Level Rise**
Sources: NOAA Medium Resolution Digital Vector Shoreline (U.S. Geological Survey 2007), USGS 1:250,000 Digital Elevation Model (University of Florida: GeoPlan 2007), and Historic and Projected Populations of Florida Counties (University of Florida: GeoPlan 2007).

**Map 7. Developed Land in Areas Vulnerable to 27 Inches of Sea-Level Rise**
Sources: NOAA Medium Resolution Digital Vector Shoreline (U.S. Geological Survey 2007), USGS 1:250,000 Digital Elevation Model (University of Florida: GeoPlan 2007), and Historic and Projected Populations of Florida Counties (University of Florida: GeoPlan 2007).

**Map 8. Miami/Fort Lauderdale: Areas Vulnerable to 27 Inches of Sea-Level Rise**
Sources: NOAA Medium Resolution Digital Vector Shoreline (U.S. Geological Survey 2007), USGS 1:250,000 Digital Elevation Model (University of Florida: GeoPlan 2007), and Historic and Projected Populations of Florida Counties (University of Florida: GeoPlan 2007).

**Map 9. Tampa/St Petersburg: Areas Vulnerable to 27 Inches of Sea-Level Rise**
Sources: NOAA Medium Resolution Digital Vector Shoreline (U.S. Geological Survey 2007), USGS 1:250,000 Digital Elevation Model (University of Florida: GeoPlan 2007), and Historic and Projected Populations of Florida Counties (University of Florida: GeoPlan 2007).

**Map 10. Jacksonville: Areas Vulnerable to 27 Inches of Sea-Level Rise**
Sources: NOAA Medium Resolution Digital Vector Shoreline (U.S. Geological Survey 2007), USGS 1:250,000 Digital Elevation Model (University of Florida: GeoPlan 2007), and Historic and Projected Populations of Florida Counties (University of Florida: GeoPlan 2007).

**Map 11. Florida Sea-Level Rise: Coastal Vulnerability Index (CVI)**
Source Coastal Vulnerability to Sea-Level Rise (Hammar-Klose and Theiler 2001).

**Map 12. Transportation in Areas Vulnerable to 27 Inches of Sea-Level Rise**

Sources: road network data from US Streets Dataset (Environmental Systems Research Institute 2005); vulnerable zones data from NOAA Medium Resolution Digital Vector Shoreline (U.S. Geological Survey 2007), USGS 1:250,000 Digital Elevation Model (University of Florida: GeoPlan 2007), and Historic and Projected Populations of Florida Counties (University of Florida: GeoPlan 2007).

**Map 13. Principal Miami-area Power Plants at Risk from Storm Surges**
Source Background map from Google Earth. For other data, see sources to Table 19.

**Map 14. Ecosystems in Areas Vulnerable to 27 Inches of Sea-Level Rise**
Source FDEP Ecological Regions dataset (Florida Department of Environmental Protection 2001).

**Map 15. Florida Everglades**
Source FDEP Ecological Regions dataset (Florida Department of Environmental Protection 2001).

# APPENDIX D. PAST CATEGORY 4 AND 5 HURRICANES

The Saffir/Simpson categories rate storms from 1, the least powerful tropical storm to be rated a hurricane, to 5, storms with wind speeds of at least 155 mph. On August 25, 2005, Katrina first made landfall in southern Florida as a Category 1 hurricane, causing fatalities and significant economic damage. After reaching Category 5 intensity over the central Gulf of Mexico, Katrina weakened to Category 3 before striking Florida's northern Gulf coast, Mississippi, and Louisiana (National Hurricane Center 2007). Katrina has been billed as the costliest and the third deadliest hurricane to strike the United States with $144 billion (scaled to 2006 dollars) in damage costs and at least 1833 deaths. In Florida alone, damages reached $1.9 billion and 14 people were killed. Most destruction occurred when Katrina hit Louisiana and Mississippi, leaving coastal communities in these states in ruins. In Florida, heavy rains flooded some neighborhoods, primarily in Miami-Dade County, and structures were damaged by strong winds and tornadoes (National Hurricane Center 2007).

Only two storms in mainland U.S. history were responsible for more deaths than Katrina. By far the most deadly mainland U.S. storm was Texas' Galveston Hurricane of 1900, a Category 4 storm that caused an estimated 8,000 deaths and untold economic damage to what was then a port city of national importance. Despite warnings issued by the U.S. Weather Bureau, very few on the Texas coast sought shelter or evacuated. By the time the hurricane slammed into Galveston on September 8, 1900, it had winds of 135 mph and storm surges of 8 to 15 feet, which flooded the whole of Galveston Island. The surge knocked buildings off their foundations, destroying over 3,600 homes and the telegraph lines and bridges to the mainland (National Hurricane Center 2007).

The second deadliest storm, Florida's Lake Okeechobee storm of 1928, was a Category 4 hurricane that caused a storm surge on this large inland lake, flooding the surrounding countryside (Blake et al. 2007; National Hurricane Center 2007). The Lake Okeechobee hurricane roared ashore at Palm Beach on September 16, 1928 with 125 mph winds, after killing more than 1,000 people in Puerto Rico and Guadelupe. Lake Okeechobee lies 40 miles inland, but rain from the storm, coming at the end of a rainy summer, filled the lake to the brim and a storm surge broke the dike surrounding the lake in several places. Water flooded several hundred square miles of farmland below, sweeping away everything in its path and causing the deaths of almost two thousand people, three-quarters of whom were black migrant field workers (South Florida Sun-Sentinel 2007).

The most recent Category 4 storm to strike Florida was Hurricane Charley, which struck the southwestern coast with 150 mph winds on August 13, 2004. The National Hurricane Center issued warnings for the Florida Keys and Cape Sable area a day before Charley swept through, prompting a call for the evacuation of 1.9 million people along the Florida west coast, including 380,000 in the Tampa Bay area and 11,000 in the Keys. Strong waves and surges caused severe beach erosion and dune damage. On Captiva Island, off Florida's southwest coast, 6.5 foot storm surges caused erosion that produced a new quarter-mile inlet now known as Charley's cut. In Charlotte County, Charley damaged or destroyed thousands of homes, knocked down thousands of trees, and left more than 2 million people without power. Charley was responsible for 33 deaths in the United States and 5 in the Caribbean. Total estimated losses amount to $14 billion dollars, including destruction of as much as a quarter of the total citrus crop (National Hurricane Center 2007).

Only three Category 5 hurricanes have struck the continental United States in the 156 years for which detailed records exist. The 1935 "Labor Day" storm in the Florida Keys is the first Category 5 hurricane on record. The most intense hurricane ever to hit the United States, the Labor Day storm killed 408 people in the Keys, including 259 World War I veterans living in three Civilian Conservation Corps camps while they built the Overseas Highway. It also destroyed Henry Flagler's railroad, which connected Key West to the mainland, and is said to have cleared every tree and every building off Matecumbe Key (South Florida Sun-Sentinel 2007).

A second Category 5 storm, Hurricane Camille, made landfall on the Mississippi coast on August 17, 1969, ripping down power lines and pounding low-lying areas of southeastern Louisiana and Alabama with winds of 190 mph and a peak storm surge of 24 feet. Thousands were left homeless as Camille flattened nearly everything on the coast of Mississippi and caused additional deaths and flooding inland while crossing into Virginia. The combination of winds, surges, flash floods and rain caused 256 deaths, including 143 on the Gulf Coast (National Hurricane Center 2007; South Florida Sun-Sentinel 2007).

The final Category 5 hurricane is still well remembered by many Floridians. Hurricane Andrew made landfall on August 23, 1992 over the Turkey Point area south of Miami. The worst storm to hit Florida in recent memory, it forced 700,000 people in Southern Florida to be evacuated; a quarter million people were left homeless, and 44 lives were lost. The storm achieved hurricane strength over the Bahamas before sweeping over Southern Florida, where it caused storm surges of 17 feet on Biscayne Bay and led to sustained winds of 140 mph and peak gusts of 169 mph at Coral Gables (Pielke Jr. and Pielke Sr. 1997; South Florida Sun-Sentinel 2007). Communities south of Miami were devastated, with some described as "ground zero after a nuclear blast — minus the radiation."[40] Twelve percent of all homes in Dade Country were completely destroyed, including 90 percent of all the mobiles homes in southern Dade County. The storm nearly wiped out Florida's fruit tree nursery industry — with serious damage to 800 private tree nurseries — and led to major losses for many Dade County businesses. The Federal government poured in billions of dollars worth of aid, including tent cities for thousands, battlefield kitchens to feed 72,000 people, 600,000 ready-made meals from the Persian Gulf War, a field hospital, water, and blankets. Twenty-three thousand armed-services members were brought in to help with the largest relief effort Florida has ever seen. Estimates of the total damage suffered hover around $25 billion (in 1992 dollars — the same share of Florida's 2006 economy would have been $63 billion), half of which was issued by the insurance industry on private property claims. Andrew also tore through the Everglades National Forest, causing untold damage to its pristine wetland ecology (Pielke Jr. and Pielke Sr. 1997; Blake et al. 2007).

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# NOTES

1 Throughout this report, "more intense" hurricanes refers to hurricanes of increased intensity, not of increased frequency.

2 On July 13, 2007, Florida Governor Crist issued Executive Order 07-127, which established statewide greenhouse gas emission reduction targets of 2000 levels by 2017, 1990 levels by 2025, and 80 percent below 1990 levels by 2050. http://www.flgov.com/pdfs/orders/07-127-emissions.pdf

3 This report makes no attempt to summarize the science of climate change. Good starting points are the Global Warming virtual exhibit by the U.S. National Academy of Science's Koshland Museum (http://www.koshland-science-museum.org/exhibitgcc/index.jsp) and the introductory page of the Real Climate web site http://www.realclimate.org/index.php/archives/2007/05/start-here/.

4 According to Environmental Defense' former Chief Scientist Bill Chameides (now Dean of the Nicholas Institute at Duke University), in order to meet these global goals U.S. emissions would have to decline by 10 to 30 percent of current levels by 2020 and 60 to 80 percent of current levels by 2050 (Chameides 2007).

5 The U.S. Census Bureau projects that national population levels will grow at an average of 0.8 percent annually through 2050. Florida's population is expected to grow more rapidly: 2 percent increase per year through 2030 (U.S. Census Bureau 2004a; b). The Census' state-level predictions end at 2030; we apply the projected U.S. rate of population growth thereafter.

6 All dollar figures adjusted for inflation using the Bureau of Labor Statistics' Consumer Price Index and reported as year 2006 dollars.

7 On average, U.S. GDP per capita has grown 2.2 percent annually since 1929, with the highest decadal growth rate in the 1940s — 4.1 percent per year — and the lowest growth rate in the 1950s — 1.7 percent per year. In the 1990s, U.S. GDP per capita grew by 2.0 percent per year, but the average annual growth rate since 2000 has been 0.9 percent. Florida's GSP per capita grew 2.5 percent from 1997 (the earliest data year available) to 2005, and 2.8 percent from 2000 to 2005.

8 An increase in global mean temperature of 2.3°F beyond year 2000 levels is considered an important tipping point. At greater increases in temperature, the Greenland Ice Sheet is very likely to melt entirely and irreversibly, causing 20 feet of sea-level rise over several centuries. Remaining below 2.3°F would require a stabilization of atmospheric carbon dioxide at 450ppm CO2 (or 500ppm CO2-equivalent including other greenhouse gases) (Intergovernmental Panel on Climate Change 2007b; UN Foundation and Sigma Xi 2007).

9 We used the average of Stern's (Stern 2006) 450ppm and 550ppm CO2-equivalent stabilization paths, as roughly equivalent to 450ppm CO2; Stern's emission scenarios included about 50 ppm CO2-equivalent of other greenhouse gases, so they correspond to 400 and 500 ppm of CO2 alone. The low end of the likely temperature range — or the 17th percentile — is a linear interpolation between the 5th and 50th percentiles. We assume 1.1°F in temperature increase from preindustrial times to year 2000. Stern's estimates are for global mean temperatures; we estimated regional U.S. temperatures using the same ratios of regional to global as the low end of the likely range of the IPCC's B1 scenario.

10 In the rapid stabilization case sea-level rise is primarily the result of thermal expansion, the slow expansion of the ocean as past temperature increases to surfaces waters very gradually warm the lower ocean. Thermal expansion from past emissions is now unavoidable. For this reason, we take the low end of the likely range for the IPCC's B1 scenario (Intergovernmental Panel on Climate Change 2007b) — 7 inches by 2100 — as a good approximation of sea-level rise in the rapid stabilization case. Slightly different amounts of sea-level rise are expected in different locations around the world. For Florida, sea-level rise is expected to be at approximately the global average; see IPCC (Intergovernmental Panel on Climate Change 2007b) Ch. 5, 10, and 11.

11 International temperatures are from the WorldClimate website (Hoare 2005).

12 When the IPCC's little-published estimate of sea-level rise from melting is combined with other more predictable, and better publicized, effects — like thermal expansion — the total sea-level rise for the high end of the A2 likely range increases from 20 inches to 25 inches by 2100 (Intergovernmental Panel on Climate Change 2007b).

13 Large numbers of coral were affected and many were likely killed, however. Due to a lack of appropriate monitoring, precise statistics are not known.

14 Monthly data on Florida's tourism is not available. October, November, and December each receive, on average, 6.3 percent of 85 million visitors, or 5.3 million people per month.

15 The authors' survey of recent beach nourishment projects in Florida shows that the average project places sand 9 feet deep at a cost of $9 per cubic yard (Powers 2005; Bistyga 2007; Day 2007; Morgan 2007; Pickett 2007; Volusia County n.d.).

16 All values in 2006 dollars. Sales are greater than the contribution to GSP, cited in the text; an industry's contribution to GSP is its sales, or cash receipts, less its purchases from other firms.

17 A Florida Irrigation Guide published by the USDA (U.S. Department of Agriculture 2003) gives estimates for the total water consumed (in inches) by region and type of plant for each month, along with the monthly mean temperature for the region. Citrus and sugarcane water consumption data by zone and month were each regressed on mean temperatures to find the percent water increase needed with a 1°F increase in temperature; $r^2$ values were above 0.90 in both cases.

18 All values in 2006 dollars.

19 All values in 2006 dollars.

20 According to official reports, there were only 428 people working in the fishing industry in 2005, but over 30,000 commercial fishing permits were sold to self-employed fishers (Bureau of Labor Statistics 2007; Florida Fish and Wildlife Conservation Commission 2007). With a total catch valued at $174 million, employment of only 428 commercial fishers would imply a catch of about $400,000 per person, which seems too high; on the other hand, 30,000 commercial fishers would average less than $6,000 each, which seems too low.

21 See also (Scavia et al. 2002).

22 The valuation of property is based on the 2000 Census: median owner-occupied property values by county, from the Census, were multiplied by the number of each county's housing units in the vulnerable zone, and then converted to 2006 dollars. Sources for vulnerable zone data: NOAA Medium Resolution Digital Vector Shoreline (U.S. Geological Survey 2007), USGS 1:250,000 Digital Elevation Model (University of Florida: GeoPlan 2007), and Historic and Projected Populations of Florida Counties (University of Florida: GeoPlan 2007).

23 Authors' calculation, from the GIS software and maps used in this report.

24 As of 2004: EPA eGRID (Environmental Protection Agency 2007b).

25 Percentages represent fuel use by total generation in 2005. Percentages do not add up to 100% because some generation is from non-qualified sources (Florida Public Service Commission 2006).

26 Environmental Protection Agency. *Emissions and Generation Resource Integrated Database (eGRID), 2006.* Available online at http://www.epa.gov/cleanenergy/egrid/index.htm

27 Energy Information Administration. *Electric Power Annual, 2006:* Table 4.5. Receipts, Average Cost, and Quality of Fossil Fuels for the Electric Power Industry, 1994 through 2005; available online at http://7www.eia.doe.gov/cneaf/electricity/epa/epat4p5.html; and 1990 - 2006 Average Price by State by Provider (EIA-861); available online at http://www.eia.doe.gov/cneaf/electricity/epa/average_price_state.xls

28 Hourly power generation derived from 2005 Environmental Protection Agency (EPA) Clean Air Markets data for FRCC fossil units (Environmental Protection Agency 2007a). Hourly temperature from Miami International Airport derived from National Oceanographic and Atmospheric Administration (NOAA) National Climate Data Center (NCDC) (National Oceanic & Atmospheric Administration 2007b).

29 Annual Energy Outlook 2007 (Energy Information Administration 2007): Table 39. Cost and Performance Characteristics of New Central Station Electricity Generating Technologies.

30 Annual Energy Outlook 2007 (Energy Information Administration 2007): Table 6. Electric Power Delivered Fuel Prices and Quality for Coal, Petroleum, Natural Gas, 1990 through 2005 (n 2005 dollars); Table 39. Cost and Performance Characteristics of New Central Station Electricity Generating Technologies.

31 Florida's current 138 power plants are comprised of 566 generators, which are clustered into plants. Of the 1500 generators, about 1000 are 50 MW wind projects, which could each be comprised of clusters of 15-30 turbines.

32 Calculated from US Agricultural Census, 2002. In addition, 120,000 acres of pasture and other farmland were irrigated, for a total irrigated farm area of 1.82 million acres.

33 Under the scenario assumptions, Florida's population is 2.09 times as large in 2050 as in 2000. As shown in Table 14, fresh water demand in 2000 was 3,920 mgd for agriculture and 4,270 mgd for all other uses. If the latter category is constant in per capita terms, it grows to 8,920 mgd by 2050.

34 In 2004 a University of Florida researcher announced a new technology which could reduce desalination costs from $3.00 to $2.50 per thousand gallons (Davis 2004). The American Membrane Technology Association, an industry group devoted to promoting desalination plants, estimates the costs of desalina-

tion of brackish water at $1.50 - $3.00 per thousand gallons (American Membrane Technology Association 2007).

35 American Membrane Technology Association (see previous note).

36 Data for Hurricane Jeanne (2004) was omitted because of large discrepancies between data sources.

37 For the purposes of these calculations, damages and deaths caused by each hurricane were scaled up to 2006 levels using Florida's gross state product (GSP) and Florida's population, respectively, as inflators.

38 All model inputs and results in 2006 dollars.

39 Titus and Richman 2001.

40 A quote attributed to a National Guardsman in (Pielke Jr. and Pielke Sr. 1997) and (Elgiston 1992).

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# FLORIDA AND CLIMATE CHANGE

## THE COSTS OF INACTION

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**November 2007**

Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

# A REVIEW OF SOLAR PV BENEFIT & COST STUDIES

2nd Edition

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Electricity Innovation Lab
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# ABOUT THIS DOCUMENT

***This report is a 2nd edition released in September 2013. This second edition updates the original with the inclusion of Xcel Energy's May 2013 study,* Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado*, as well as clarifies select descriptions and charts.***

## TABLE OF CONTENTS



## OBJECTIVE AND ACKNOWLEDGEMENTS

The objective of this e-Lab discussion document is to assess what is known and unknown about the categorization, methodological best practices, and gaps around the benefits and costs of distributed photovoltaics (DPV), and to begin to establish a clear foundation from which additional work on benefit/cost assessments and pricing structure development can be built.

Building on initial research conducted as part of Rocky Mountain Institute's (RMI) DOE SunShot funded project, Innovative Solar Business Models, this e-Lab work product was prepared by RMI to support e-Lab and industry-wide discussions about distributed energy resource valuation. e-Lab is a joint collaboration, convened by RMI, with participation from stakeholders across the electricity industry. e-Lab is not a consensus organization, and the views expressed in this document do not necessarily represent those of any individual e-Lab member or supporting organizations. Any errors are solely the responsibility of RMI.

e-Lab members and advisors were invited to provide input on this report. The assessment greatly benefited from contributions by the following individuals: Stephen Frantz, Sacramento Municipal Utility District (SMUD); Mason Emnett, Federal Energy Regulatory Commission (FERC); Eran Mahrer, Solar Electric Power Association (SEPA); Sunil Cherian, Spirae; Karl Rabago, Rabago Energy; Tom Brill and Chris Yunker, San Diego Gas & Electric (SDG&E); and Steve Wolford, Sunverge.

## WHAT IS e-LAB?

The Electricity Innovation Lab (e-Lab) brings together thought leaders and decision makers from across the U.S. electricity sector to address critical institutional, regulatory, business, economic, and technical barriers to the economic deployment of distributed resources.

In particular, e-Lab works to answer three key questions:

- How can we understand and effectively communicate the costs and benefits of distributed resources as part of the electricity system and create greater grid flexibility?
- How can we harmonize regulatory frameworks, pricing structures, and business models of utilities and distributed resource developers for greatest benefit to customers and society as a whole?
- How can we accelerate the pace of economic distributed resource adoption?

A multi-year program, e-Lab regularly convenes its members to identify, test, and spread practical solutions to the challenges inherent in these questions. e-Lab has three annual meetings, coupled with ongoing project work, all facilitated and supported by Rocky Mountain Institute. e-Lab meetings allow members to share learnings, best practices, and analysis results; collaborate around key issues or needs; and conduct deep-dives into research and analysis findings.

# EXECUTIVE SUMMARY

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# EXECUTIVE SUMMARY

## THE NEED

- The addition of distributed energy resources (DERs) onto the grid creates new opportunities and challenges because of their unique siting, operational, and ownership characteristics compared to conventional centralized resources.
- Today, the increasingly rapid adoption of distributed solar photovoltaics (DPV) in particular is driving a heated debate about whether DPV creates benefits or imposes costs to stakeholders within the electricity system. But the wide variation in analysis approaches and quantitative tools used by different parties in different jurisdictions is inconsistent, confusing, and frequently lacks transparency.
- Without increased understanding of the benefits and costs of DERs, there is little ability to make effective tradeoffs between investments.

## OBJECTIVE OF THIS DOCUMENT

- The objective of this e-Lab discussion document is to assess what is known and unknown about the categorization, methodological best practices, and gaps around the benefits and costs of DPV, and to begin to establish a clear foundation from which additional work on benefit/cost assessments and pricing structure design can be built.
- This discussion document reviews 16 DPV benefit/cost studies by utilities, national labs, and other organizations. Completed between 2005 and 2013, these studies reflect a significant range of estimated DPV value.

## KEY INSIGHTS

- No study comprehensively evaluated the benefits and costs of DPV, although many acknowledge additional sources of benefit or cost and many agree on the broad categories of benefit and cost. There is broad recognition that some benefits and costs may be difficult or impossible to quantify, and some accrue to different stakeholders.
- There is a significant range of estimated value across studies, driven primarily by differences in local context, input assumptions, and methodological approaches.
    - **Local context**: Electricity system characteristics—generation mix, demand projections, investment plans, market structures—vary across utilities, states, and regions.
    - **Input assumptions**: Input assumptions—natural gas price forecasts, solar power production, power plant heat rates—can vary widely.
    - **Methodologies**: Methodological differences that most significantly affect results include (1) resolution of analysis and granularity of data, (2) assumed cost and benefit categories and stakeholder perspectives considered, and (3) approaches to calculating individual values.
- Because of these differences, comparing results across studies can be informative, but should be done with the understanding that results must be normalized for context, assumptions, or methodology.
- While detailed methodological differences abound, there is general agreement on overall approach to estimating energy value and some philosophical agreement on capacity value, although there remain key differences in capacity methodology. There is significantly less agreement on overall approach to estimating grid support services and currently unmonetized values including financial and security risk, environment, and social value.

# EXECUTIVE SUMMARY (CONT'D)

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## IMPLICATIONS

- Methods for identifying, assessing and quantifying the benefits and costs of DPV and other DERs are advancing rapidly, but important gaps remain to be filled before this type of analysis can provide an adequate foundation for policymakers and regulators engaged in determining levels of incentives, fees, and pricing structures for DPV and other DERs.

- In any benefit/cost study, it is critical to be transparent about assumptions, perspectives, sources and methodologies so that studies can be more readily compared, best practices developed, and drivers of results understood.

- While it may not be feasible to quantify or assess sources of benefit and cost comprehensively, benefit/cost studies must explicitly decide if and how to account for each source of value and state which are included and which are not.

- While individual jurisdictions must adapt approaches based on their local context, standardization of categories, definitions, and methodologies should be possible to some degree and will help ensure accountability and verifiability of benefit and cost estimates that provide a foundation for policymaking.

- The most significant methodological gaps include:
    - **Distribution value:** The benefits or costs that DPV creates in the distribution system are inherently local, so accurately estimating value requires much more analytical granularity and therefore greater difficulty.
    - **Grid support services value:** There continues to be uncertainty around whether and how DPV can provide or require additional grid support services, but this could potentially become an increasingly important value.
    - **Financial, security, environmental, and social values:** These values are largely (though not comprehensively) unmonetized as part of the electricity system and some are very difficult to quantify.

## LOOKING AHEAD

- Thus far, studies have made simplifying assumptions that implicitly assume historically low penetrations of DPV. As the penetration of DPV on the electric system increases, more sophisticated, granular analytical approaches will be needed and the total value is likely to change.

- Studies have largely focused on DPV by itself. But a confluence of factors is likely to drive increased adoption of the full spectrum of renewable and distributed resources, requiring a consideration of DPV's benefits and costs in the context of a changing system.

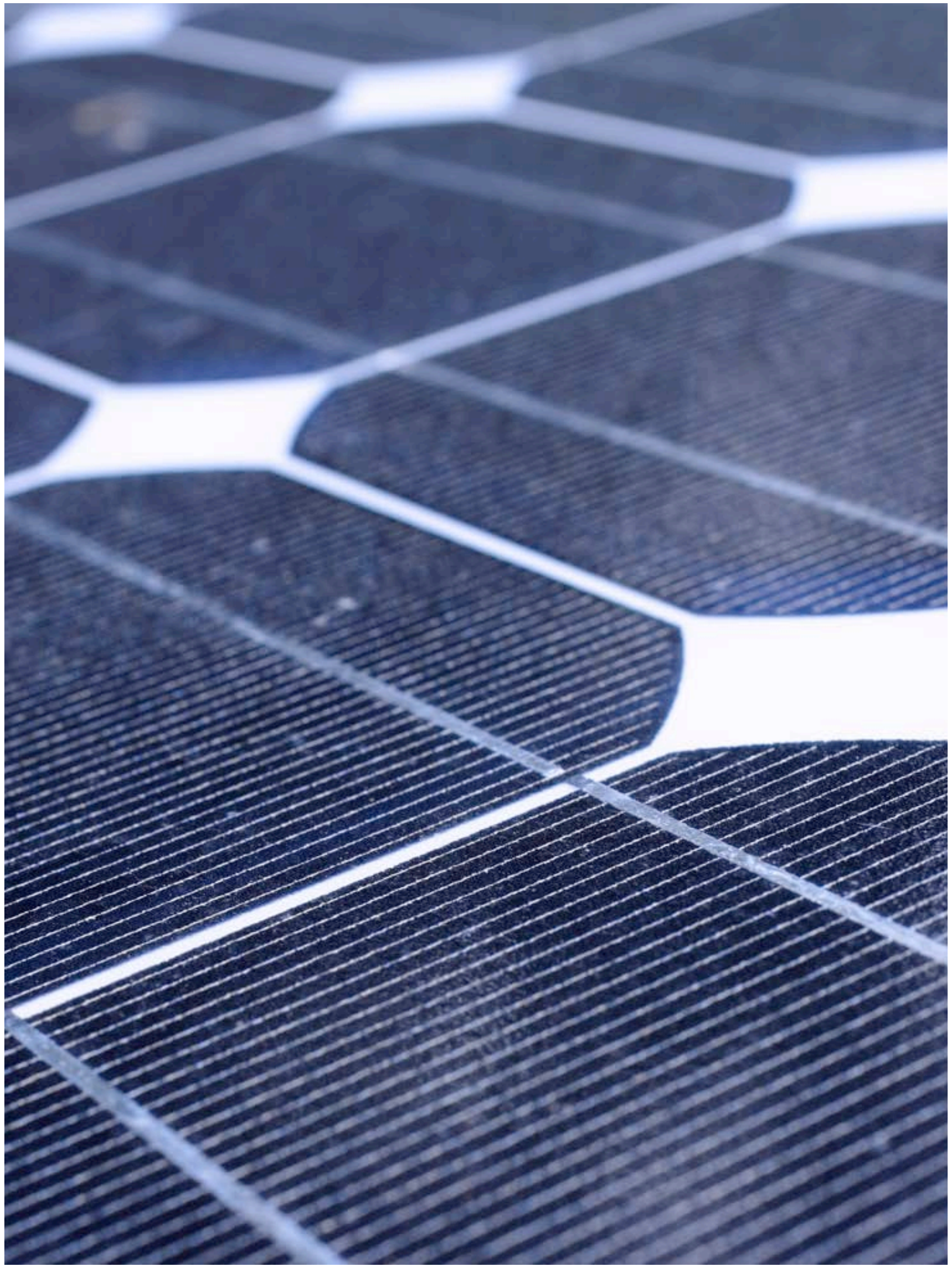
- With better recognition of the costs and benefits that all DERs can create, including DPV, pricing structures and business models can be better aligned, enabling greater economic deployment of these resources and lower overall system costs for ratepayers.

# FRAMING THE NEED

01

# FRAMING THE NEED

- A confluence of factors including rapidly falling solar prices, supportive policies, and new approaches to finance are leading to a steadily increasing solar PV market.
  - In 2012, the US added 2 GW of solar PV to the nation's generation mix, of which approximately 50% were customer-sited solar, net-metered projects.[1]
  - Solar penetrations in certain regions are becoming significant. About 80% of customer-sited PV is concentrated in states with either ample solar resource and/or especially solar-friendly policies: California, New Jersey, Arizona, Hawaii and Massachusetts.[2]
- The addition of DPV onto the grid creates new challenges and opportunities because of its unique siting, operational, and ownership characteristics compared to conventional centralized resources. The value of DPV is temporally, operationally and geographically specific and varies by distribution feeder, transmission line configuration, and composition of the generation fleet.
- Under today's regulatory and pricing structures, multiple misalignments along economic, social and technical dimensions are emerging. For example, in many instances pricing mechanisms are not in place to recognize or reward service that is being provided by either the utility or customer.
- Electricity sector stakeholders around the country are recognizing the importance of properly valuing DPV and the current lack of clarity around the costs and benefits that drive DPV's value, as well as how to calculate them.
- To enable better technical integration and economic optimization, it is critical to better understand the services that DPV can provide and require, and the benefits and costs of those services as a foundation for more accurate pricing and market signals. As the penetration of DPV and other customer-sited resources increases, accurate pricing and market signals can help align stakeholder goals, minimize total system cost, and maximize total net value.



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1. Solar Electric Power Association. June 2013. *2012 SEPA Utility Solar Rankings,* Washington, DC.
2. Ibid.

# DPV IN THE BROADER CONTEXT OF DISTRIBUTED ENERGY RESOURCES

**DISTRIBUTED ENERGY RESOURCES (DERs):** demand- and supply-side resources that can be deployed throughout an electric distribution system to meet the energy and reliability needs of the customers served by that system. DERs can be installed on either the customer side or the utility side of the meter.

## TYPES OF DERs:

### Efficiency

Technologies and behavioral changes that reduce the quantity of energy that customers need to meet all of their energy-related needs.

### Distributed generation

Small, self-contained energy sources located near the final point of energy consumption. The main distributed generation sources are:

- Solar PV
- Combined heat & power (CHP)
- Small-scale wind
- Others (i.e., fuel cells)

### Distributed flexibility & storage

A collection of technologies that allows the overall system to use energy smarter and more efficiently by storing it when supply exceeds demand, and prioritizing need when demand exceeds supply. These technologies include:

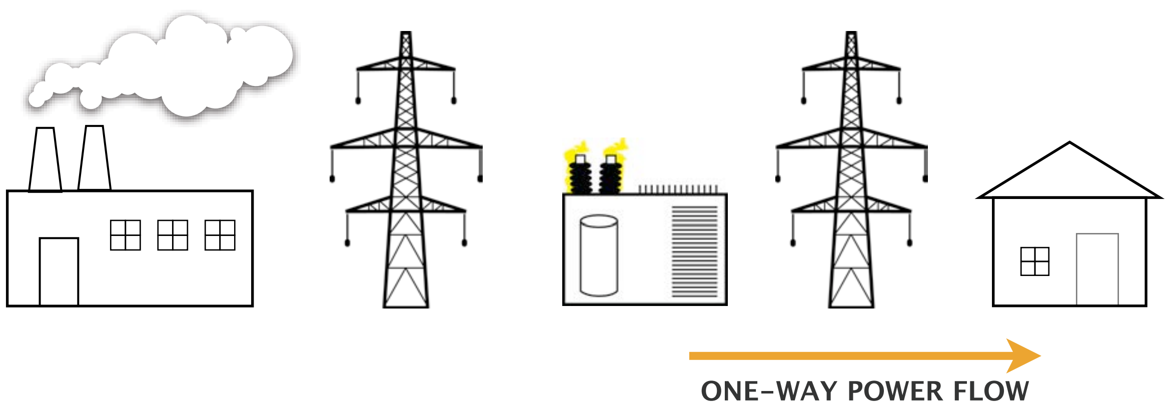
- Demand response
- Electric vehicles
- Thermal storage
- Battery storage

### Distributed intelligence

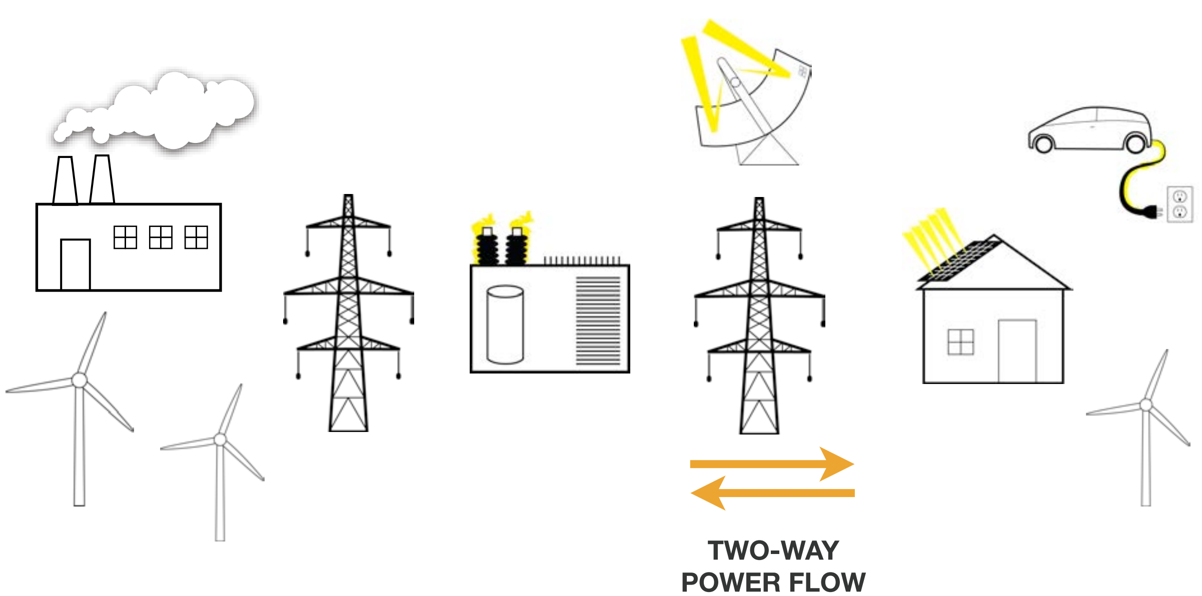
Technologies that combine sensory, communication, and control functions to support the electricity system, and magnify the value of DER system integration. Examples include:

- Smart inverters
- Home-area networks
- Microgrids

## CURRENT SYSTEM/VALUE CHAIN:




## FUTURE SYSTEM/VALUE CONSTELLATION:




## WHAT MAKES DERs UNIQUE:

### Siting

Smaller, more modular energy resources can be installed by disparate actors outside of the purview of centrally coordinated resource planning.

### Operations

Energy resources on the distribution network operate outside of centrally controlled dispatching mechanisms that control the real-time balance of generation and demand.

### Ownership

DERs can be financed, installed or owned by the customer or a third party, broadening the typical planning capability and resource integration approach.

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# STRUCTURAL MISALIGNMENTS

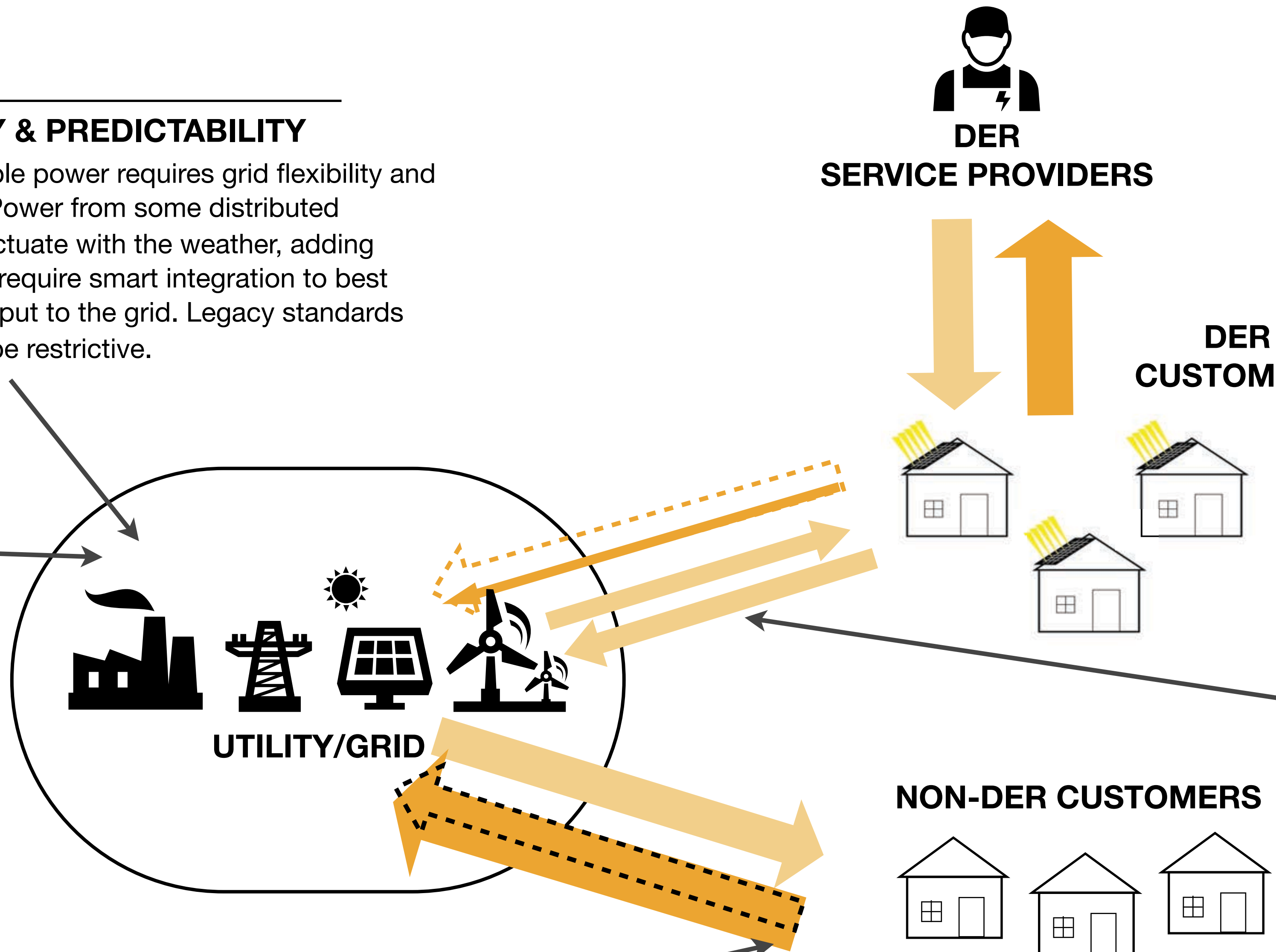
## TODAY, OPERATIONAL AND PRICING MECHANISMS DESIGNED FOR AN HISTORICALLY CENTRALIZED ELECTRICITY SYSTEM ARE NOT WELL-ADAPTED TO THE INTEGRATION OF DERS, CAUSING FRICTION AND INEFFICIENCY

### FLEXIBILITY & PREDICTABILITY

Providing reliable power requires grid flexibility and predictability. Power from some distributed renewables fluctuate with the weather, adding variability, and require smart integration to best shape their output to the grid. Legacy standards and rules can be restrictive.

### LOCATION & TIME

Limited feedback loop to customers that the costs or benefit of any electricity resource, especially DERs, vary by location and time.




### BENEFIT AND COST RECOGNITION AND ALLOCATION

Mechanisms are not in place to transparently recognize or compensate service (be it monetized grid services like energy, capacity or balancing supply and demand, or less consistently monetized values, such as carbon emissions savings) provided by the utility or the customer. To the utility, revenue from DER customers may not match the cost to serve those customers. To the customer, bill savings or credit may not match the value provided.

### SOCIAL PRIORITIES

Society values the environmental and social benefits that DERs could provide, but those benefits are often externalized and unmonetized.

### SOCIAL EQUITY

If costs are incurred by DER customers that are not paid for, those costs would be allocated to the rest of customers. Conversely, DER customers also provide benefits to other customers and to society.

$$ service

Adapted from RMI, Net Energy Metering, Zero Net Energy And The Distributed Energy Resource Future: Adapting Electric Utility Business Models For The 21st Century

# STRUCTURAL MISALIGNMENTS IN PRACTICE

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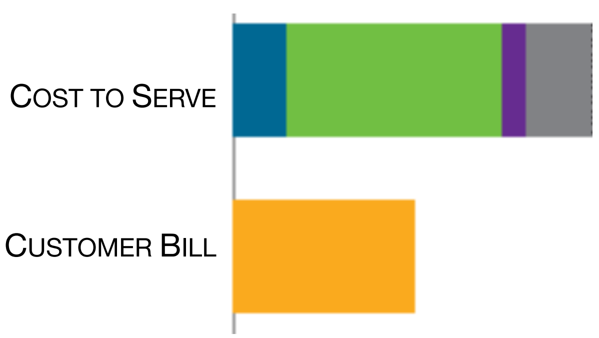
## THESE STRUCTURAL MISALIGNMENTS ARE LEADING TO IMPORTANT QUESTIONS, DEBATE, AND CONFLICT

### VALUE UNCERTAINTY...


**WHAT IF A DPV CUSTOMER DOES NOT PAY FOR THE FULL COST TO SERVE THEIR DEMAND?**




**WHAT IF A DPV CUSTOMER IS NOT FULLY COMPENSATED FOR THE SERVICE THEY PROVIDE?**


### ...DRIVES HEADLINES...


### ...RAISING KEY QUESTIONS

- What benefits can customers provide? Is the ability of customers to provide benefits contingent on anything?
- What costs are incurred to support DPV customer needs?
- What are the best practice methodologies to assess benefits and costs?
- How should externalized and unmonetized values, such as environmental and social benefits, be recognized?
- How can benefits and costs be more effectively allocated and priced?

# SETTING THE STAGE

defining value
categories of value
stakeholder implications

02

# SETTING THE STAGE

- When considering the total value of DPV or any electricity resource, it is critical to consider the types of value, the stakeholder perspective and the flow of benefits and costs–that is, who incurs the costs and who receives the benefits (or avoids the costs).

- For the purposes of this report, value is defined as net value, i.e. benefits minus costs. Depending upon the size of the benefit and the size of the cost, value can be positive or negative.

- A variety of categories of benefits or costs of DPV have been considered or acknowledged in evaluating the value of DPV. Broadly, these categories are: energy, system losses, capacity (generation, transmission and distribution), grid support services, financial risk, security risk, environmental and social.

- These categories of costs and benefits differ significantly by the degree to which they are readily quantifiable or there is a generally accepted methodology for doing so. For example, there is general agreement on overall approach to estimating energy value and some philosophical agreement on capacity value, although there remain key differences in capacity methodology. There is significantly less agreement on overall approach to estimating grid support services and currently unmonetized values including financial and security risk, environment, and social value.

- Equally important, the qualification of whether a factor is a benefit or cost also differs depending upon the perspective of the stakeholder. Similar to the basic framing of testing cost effectiveness for energy efficiency, the primary stakeholders in calculating the value of DPV are: the participant (the solar customer); the utility; other customers (also referred to as ratepayers); and society (taxpayers are a subset of society).

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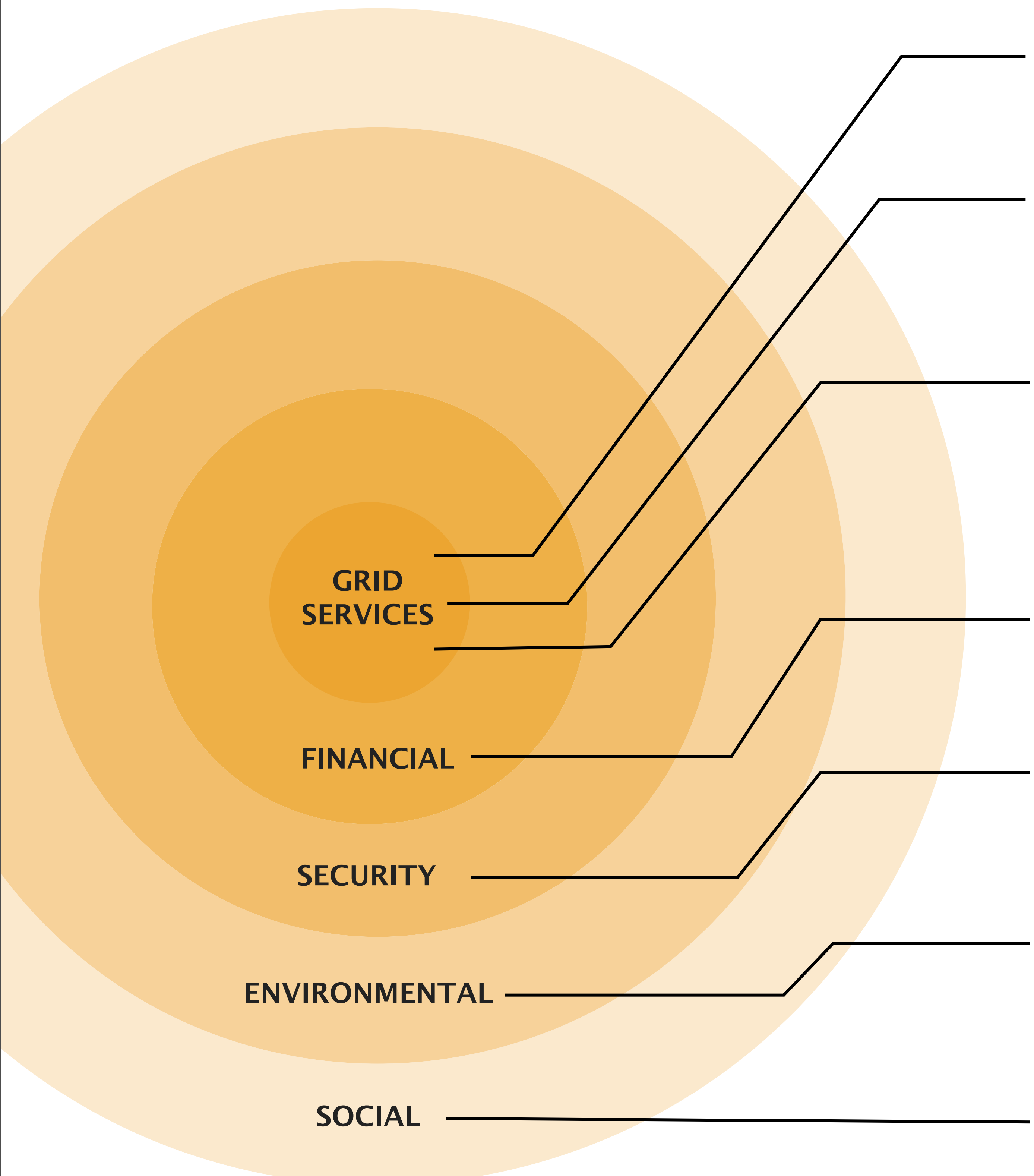
# BENEFIT & COST CATEGORIES

For the purposes of this report, **value is defined as net value, i.e. benefits minus costs.** Depending upon the size of the benefit and the size of the cost, value can be positive or negative. A variety of categories of benefits or costs of DPV have been considered or acknowledged in evaluating the value of DPV. Broadly, these categories are:




### ENERGY
- energy
- system losses

### CAPACITY
- generation capacity
- transmission & distribution capacity
- DPV installed capacity

### GRID SUPPORT SERVICES
- reactive supply & voltage control
- regulation & frequency response
- energy & generator imbalance
- synchronized & supplemental operating reserves
- scheduling, forecasting, and system control & dispatch

### FINANCIAL RISK
- fuel price hedge
- market price response

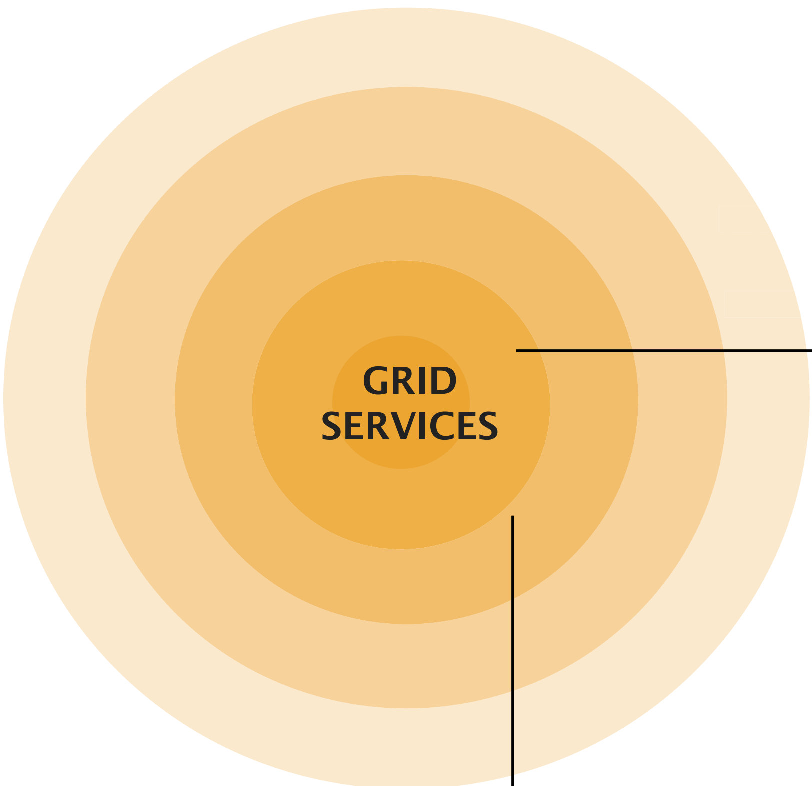
### SECURITY RISK
- reliability & resilience

### ENVIRONMENTAL
- carbon emissions ($CO_2$)
- criteria air pollutants ($SO_2$, $NO_x$, PM)
- water
- land

### SOCIAL
- economic development (jobs and tax revenues)

# BENEFIT & COST CATEGORIES DEFINED






## ENERGY

Energy value of DPV is positive when the solar energy generated displaces the need to produce energy from another resource at a net savings. There are two primary components:

- **Avoided Energy** - The cost and amount of energy that would have otherwise been generated to meet customer needs, largely driven by the variable costs of the marginal resource that is displaced. In addition to the coincidence of solar generation with demand and generation, key drivers of avoided energy cost include (1) fuel price forecast, (2) variable operation & maintenance costs, and (3) heat rate.

- **System Losses** - The compounded value of the additional energy generated by central plants that would otherwise be lost due to inherent inefficiencies (electrical resistance) in delivering energy to the customer via the transmission and distribution system. Since DPV generates energy at or near the customer, those losses are avoided. Losses act as a magnifier of value for capacity and environmental benefits, since avoided energy losses result in lower required capacity and lower emissions.

## CAPACITY

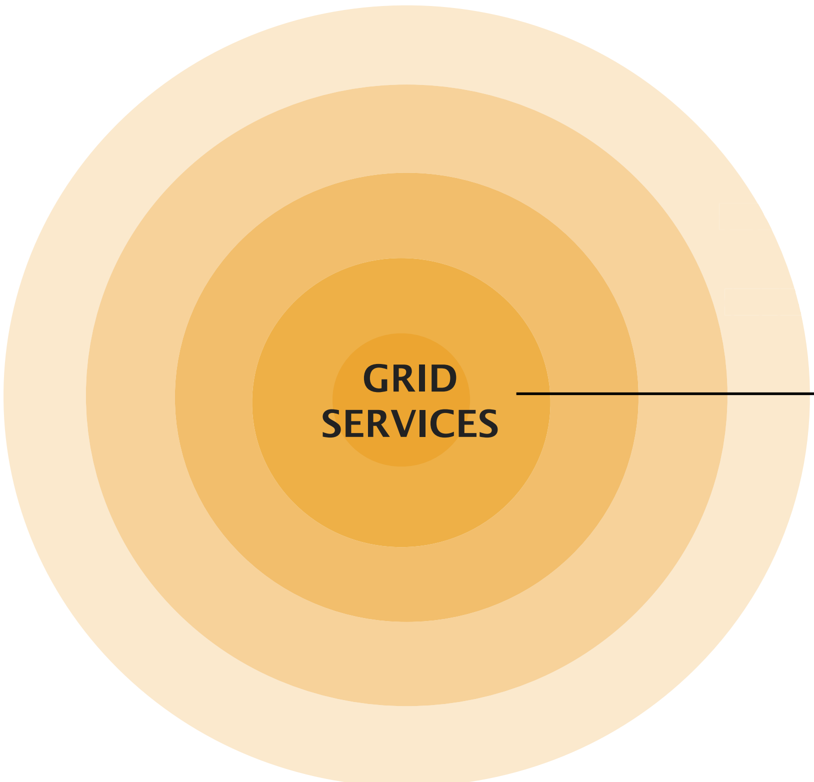
Capacity value of DPV is positive when the addition of DPV defers or avoids more investment in generation, transmission, and distribution assets than it incurs. There are two primary components:

- **Generation Capacity** - The cost of the amount of central generation capacity that can be deferred or avoided due to the addition of DPV. Key drivers of value include (1) DPV's effective capacity and (2) system capacity needs.

- **Transmission & Distribution Capacity** - The value of the net change in T&D infrastructure investment due to DPV. Benefits occur when DPV is able to meet rising demand locally, relieving capacity constraints upstream and deferring or avoiding T&D upgrades. Costs occur when additional T&D investment is needed to support the addition of DPV.

# BENEFIT & COST CATEGORIES DEFINED






## GRID SUPPORT SERVICES

Grid support value of DPV is positive when the net amount and cost of grid support services required to balance supply and demand is less than would otherwise have been required. Grid support services, which encompass more narrowly defined ancillary services (AS), are those services required to enable the reliable operation of interconnected electric grid systems. Grid support services include:

- **Reactive Supply and Voltage Control**— Generation facilities used to supply reactive power and voltage control.

- **Frequency Regulation**—Control equipment and extra generating capacity necessary to (1) maintain frequency by following the moment-to-moment variations in control area load (supplying power to meet any difference in actual and scheduled generation), and (2) to respond automatically to frequency deviations in their networks. While the services provided by regulation service and frequency response service are different, they are complementary services made available using the same equipment and are offered as part of one service.

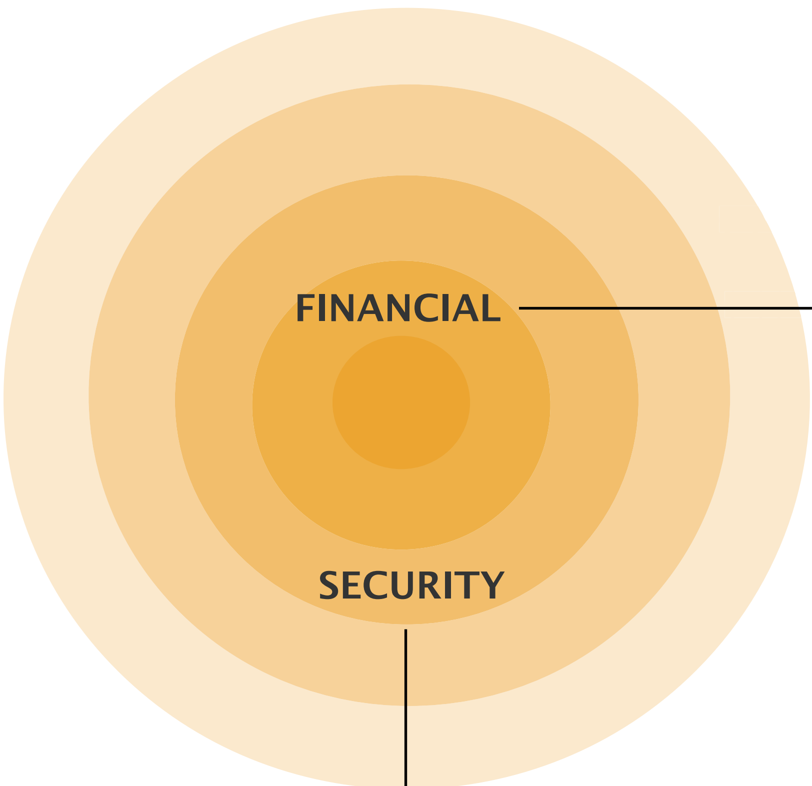
- **Energy Imbalance**—This service supplies any hourly net mismatch between scheduled energy supply and the actual load served.

- **Operating Reserves**—Spinning reserve is provided by generating units that are on-line and loaded at less than maximum output, and should be located near the load (typically in the same control area). They are available to serve load immediately in an unexpected contingency. Supplemental reserve is generating capacity used to respond to contingency situations that is not available instantaneously, but rather within a short period, and should be located near the load (typically in the same control area).

- **Scheduling/Forecasting**—Interchange schedule confirmation and implementation with other control areas, and actions to ensure operational security during the transaction.

# BENEFIT & COST CATEGORIES DEFINED






## FINANCIAL RISK

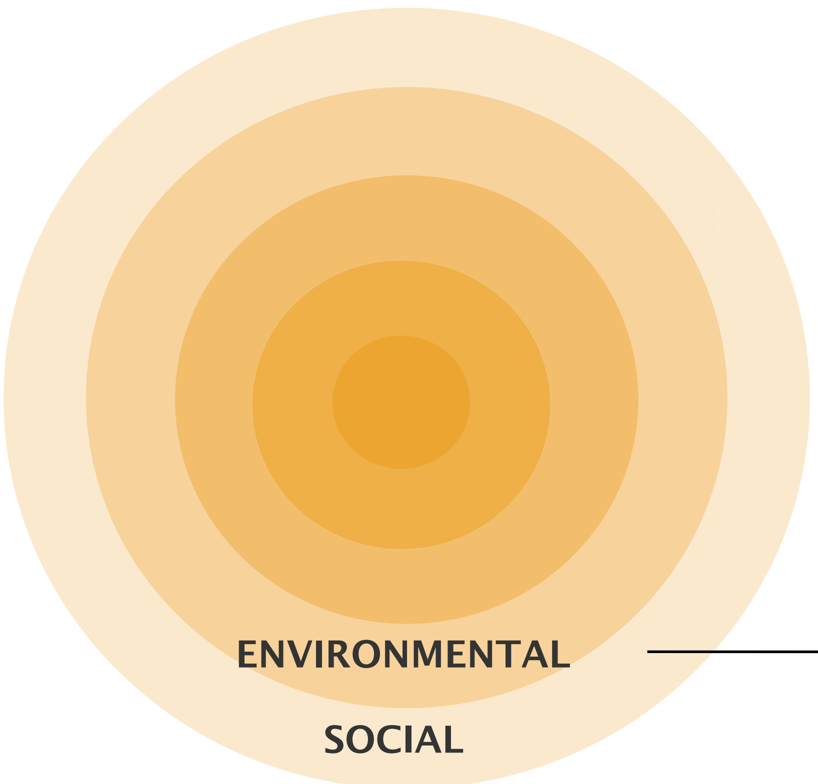
Financial value of DPV is positive when financial risk or overall market price is reduced due to the addition of DPV. Two components considered in the studies reviewed are:

- **Fuel Price Hedge** - The cost that a utility would otherwise incur to guarantee that a portion of electricity supply costs are fixed.
- **Market Price Response** - The price impact as a result of DPV's reducing demand for centrally-supplied electricity and the fuel that powers those generators, thereby lowering electricity prices and potentially commodity prices.

## SECURITY RISK

Security value of DPV is positive when grid reliability and resiliency are increased by (1) reducing outages by reducing congestion along the T&D network, (2) reducing large-scale outages by increasing the diversity of the electricity system's generation portfolio with smaller generators that are geographically dispersed, and (3) providing back-up power sources available during outages through the combination of PV, control technologies, inverters and storage.

# BENEFIT & COST CATEGORIES DEFINED




## ENVIRONMENTAL

Environmental value of DPV is positive when DPV results in the reduction of environmental or health impacts that would otherwise have been created. Key drivers include primarily the environmental impacts of the marginal resource being displaced. There are four components of environmental value:

- **Carbon** - The value from reducing carbon emissions is driven by the emission intensity of displaced marginal resource and the price of emissions.

- **Criteria Air Pollutants** - The value from reducing criteria air pollutant emissions—$NO_X$, $SO_2$, and particulate matter—is driven by the cost of abatement technologies, the market value of pollutant reductions, and/or the cost of human health damages.

- **Water** - The value from reducing water use is driven by the differing water consumption patterns associated with different generation technologies, and is sometimes measured by the price paid for water in competing sectors.

- **Land** - The value associated with land is driven by the difference in the land footprint required for energy generation and any change in property value driven by the addition of DPV.

- **Avoided Renewable Portfolio Standard costs (RPS)** - The value derived from meeting electricity demand through DPV, which reduces total demand that would otherwise have to be met and the associated renewable energy that would have to be procured as mandated by an RPS.

## SOCIAL

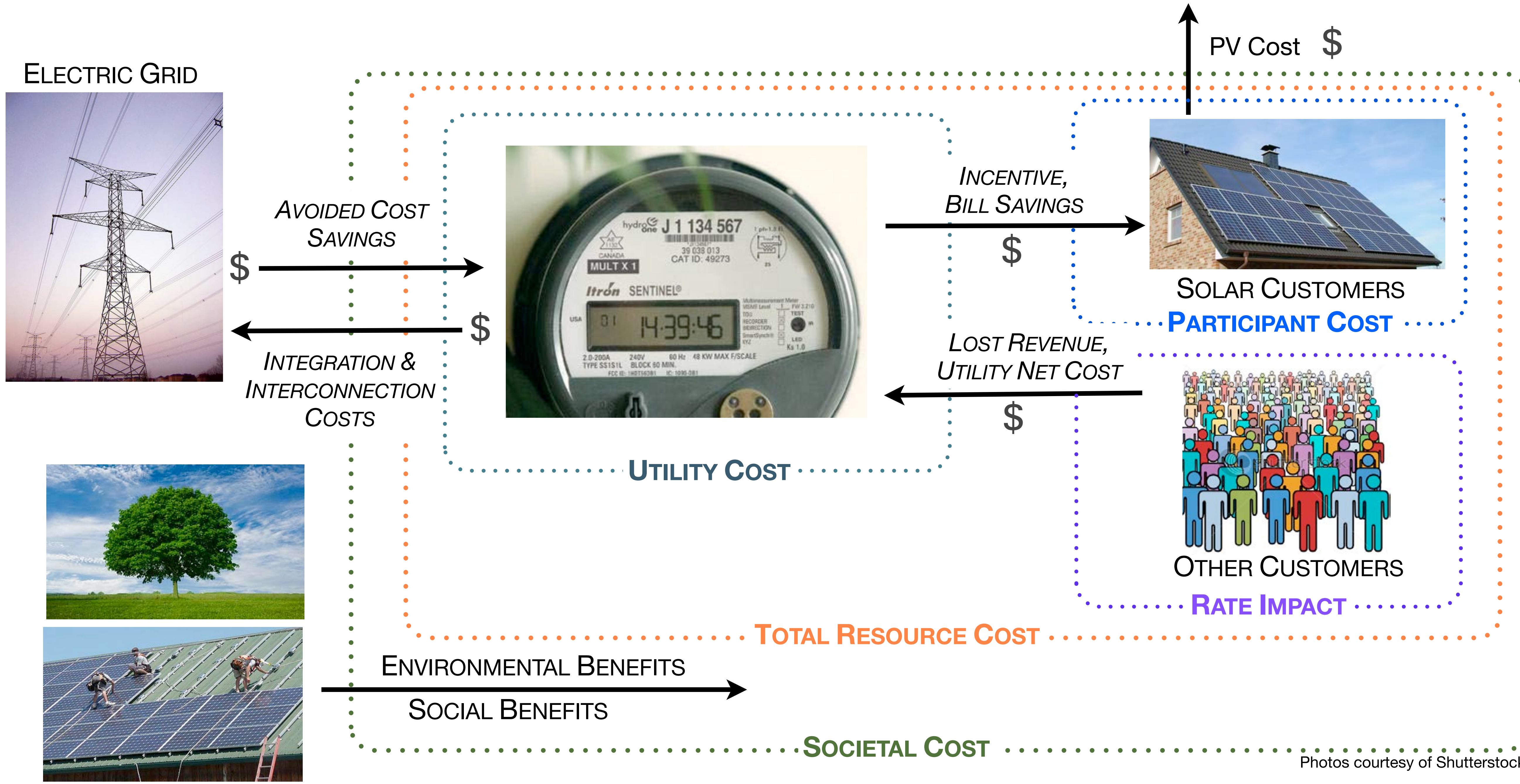
The studies reviewed in this report defined social value in economic terms. The social value of DPV was positive when DPV resulted in a net increase in jobs and local economic development. Key drivers include the number of jobs created or displaced, as measured by a job multiplier, as well as the value of each job, as measured by average salary and/or tax revenue.

# FLOW OF BENEFITS AND COSTS

## BENEFITS AND COSTS ACCRUE TO DIFFERENT STAKEHOLDERS IN THE SYSTEM

The California Standard Practice Manual established the general standard for evaluating the flow of benefits and costs of energy efficiency among stakeholders. This framework was adapted to illustrate the flow of benefits and costs for DPV.

SOLAR PROVIDER




Photos courtesy of Shutterstock

# STAKEHOLDER PERSPECTIVES

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| stakeholder perspective | | factors affecting value |
|---|---|---|
| PV CUSTOMER  | "I want to have a predictable return on my investment, and I want to be compensated for benefits I provide." | Benefits include the reduction in the customer's utility bill, any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received. Costs include cost of the equipment and materials purchased (inc. tax & installation), ongoing O&M, removal costs, and the customer's time in arranging the installation. |
| OTHER CUSTOMERS  | "I want reliable power at lowest cost." | Benefits include reduction in transmission, distribution, and generation, capacity costs; energy costs and grid support services. Costs include administrative costs, rebates/ incentives, and decreased utility revenue that is offset by increased rates. |
| UTILITY  | "I want to serve my customers reliably and safely at the lowest cost, provide shareholder value and meet regulatory requirements." | Benefits include reduction in transmission, distribution, and generation, capacity costs; energy costs and grid support services. Costs include administrative costs, rebates/ incentives, decreased revenue, integration & interconnection costs. |
| SOCIETY  | "We want improved air/water quality as well as an improved economy." | The sum of the benefits and costs to all stakeholder, plus any additional societal and environmental benefits or costs that accrue to society at large rather than any individual stakeholder. |

Photos courtesy of Shutterstock

# ANALYSIS FINDINGS

03

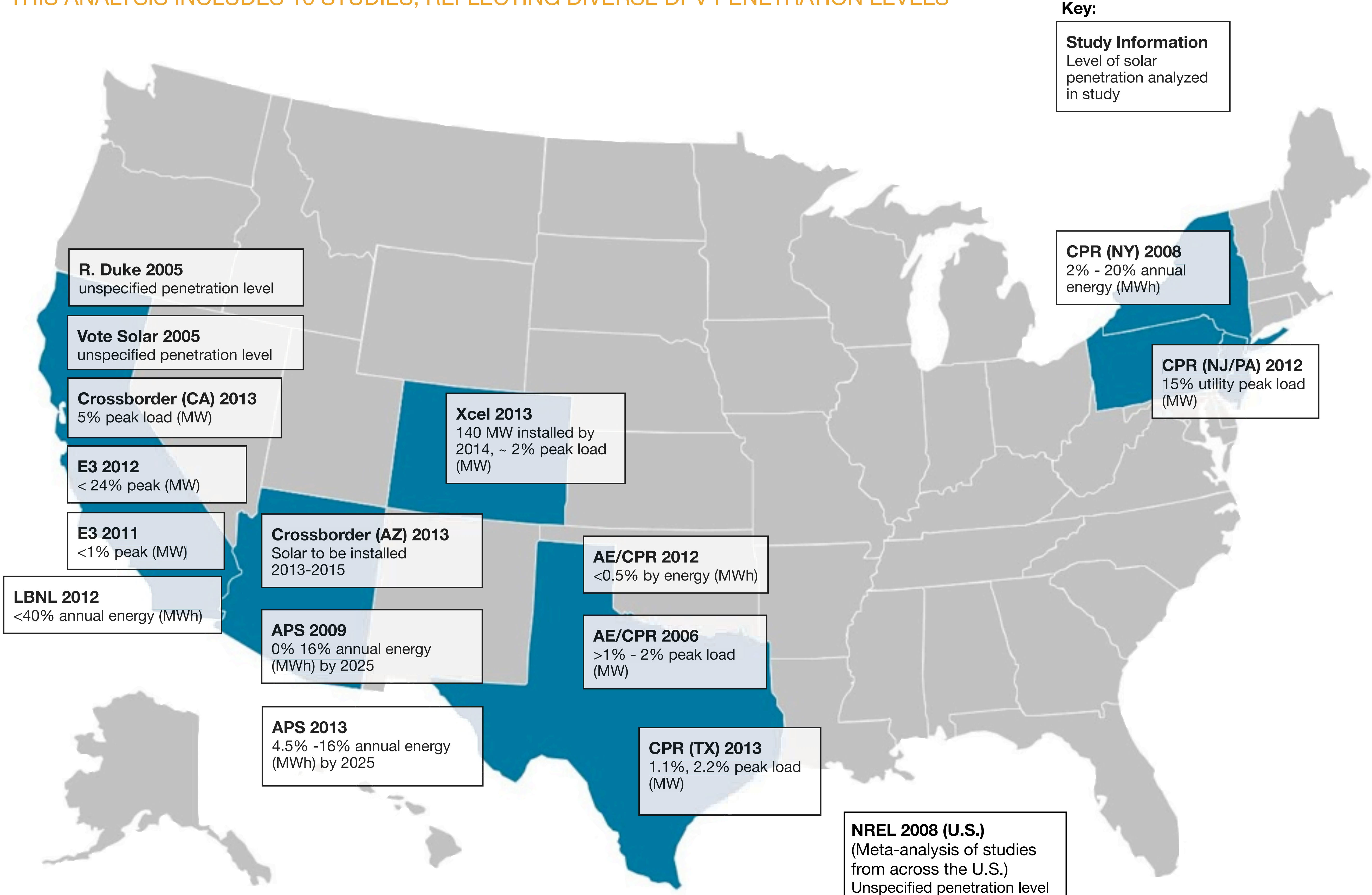
analysis overview

summary of benefits and costs

detail: categories of benefit and cost

# ANALYSIS OVERVIEW

## THIS ANALYSIS INCLUDES 16 STUDIES, REFLECTING DIVERSE DPV PENETRATION LEVELS



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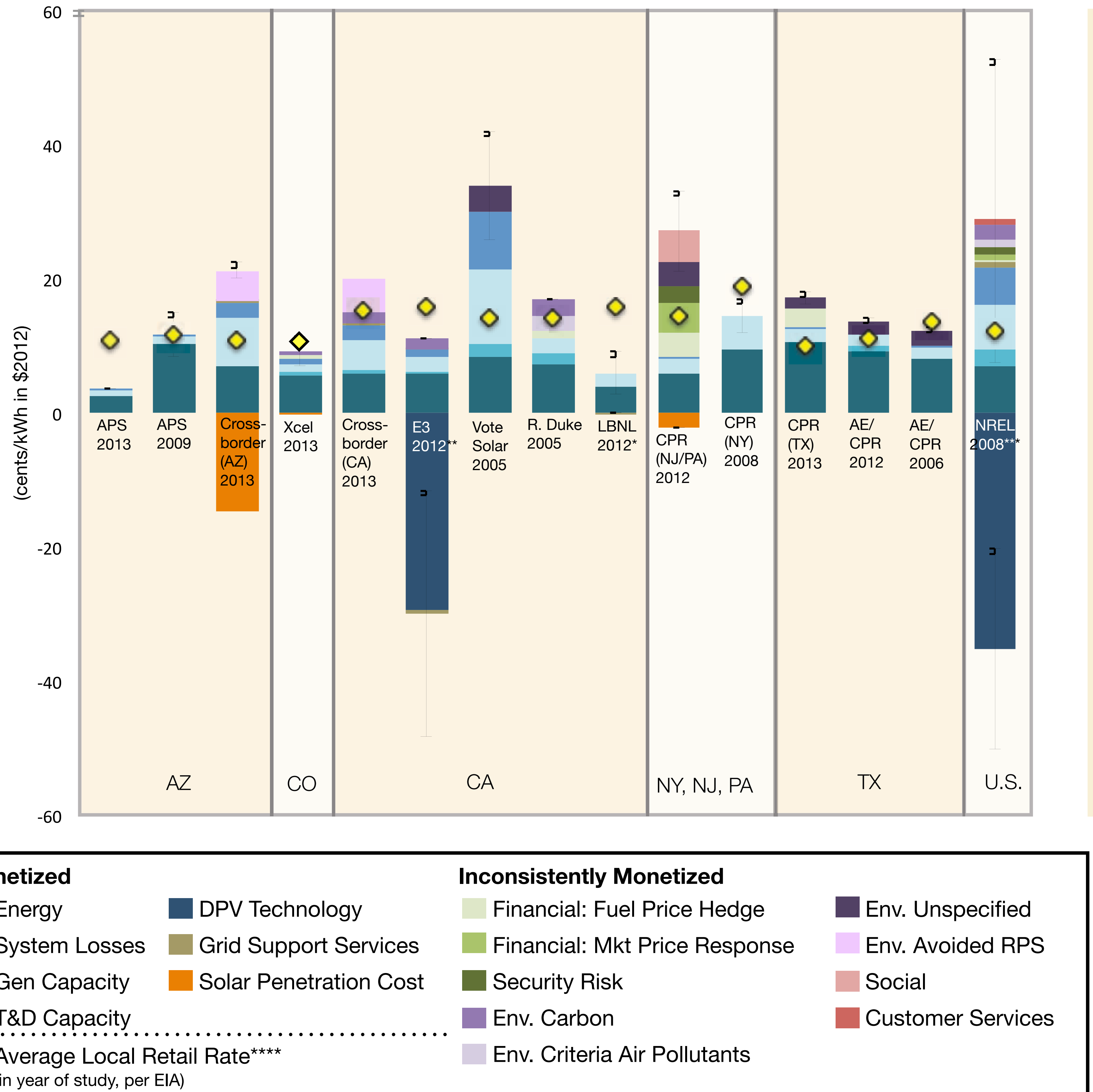
# SUMMARY OF DPV BENEFITS AND COSTS

## BENEFITS AND COSTS OF DISTRIBUTED PV BY STUDY




### INSIGHTS

- No study comprehensively evaluated the benefits and costs of DPV, although many acknowledge additional sources of benefit or cost and many agree on the broad categories of benefit and cost.
- There is a significant range of estimated value across studies, driven primarily by differences in local context, input assumptions, and methodological approaches.
- Because of these differences, comparing results across studies can be informative, but should be done with the understanding that results must be normalized for context, assumptions, or methodology.
- While detailed methodological differences abound, there is general agreement on overall approach to estimating energy value, although there remain key differences in capacity methodology. There is significantly less agreement on overall approach to estimating grid support services and currently unmonetized values including financial and security risk, environment, and social value.

* The LBNL study only gives the net value for ancillary services
** E3's DPV technology cost includes LCOE + interconnection cost
*** The NREL study is a meta-analysis, not a research study. Customer Services, defined as the value to customer of a green option, was only reflected in the NREL 2008 meta-analysis and not included elsewhere in this report.
****Average retail rate included for reference; it is not appropriate to compare the average retail rate to total benefits presented without also reflecting costs (i.e., net value) and any material differences within rate designs (i.e., not average).
Note: E3 2012 study not included in this chart because that study did not itemize results. See page 47.

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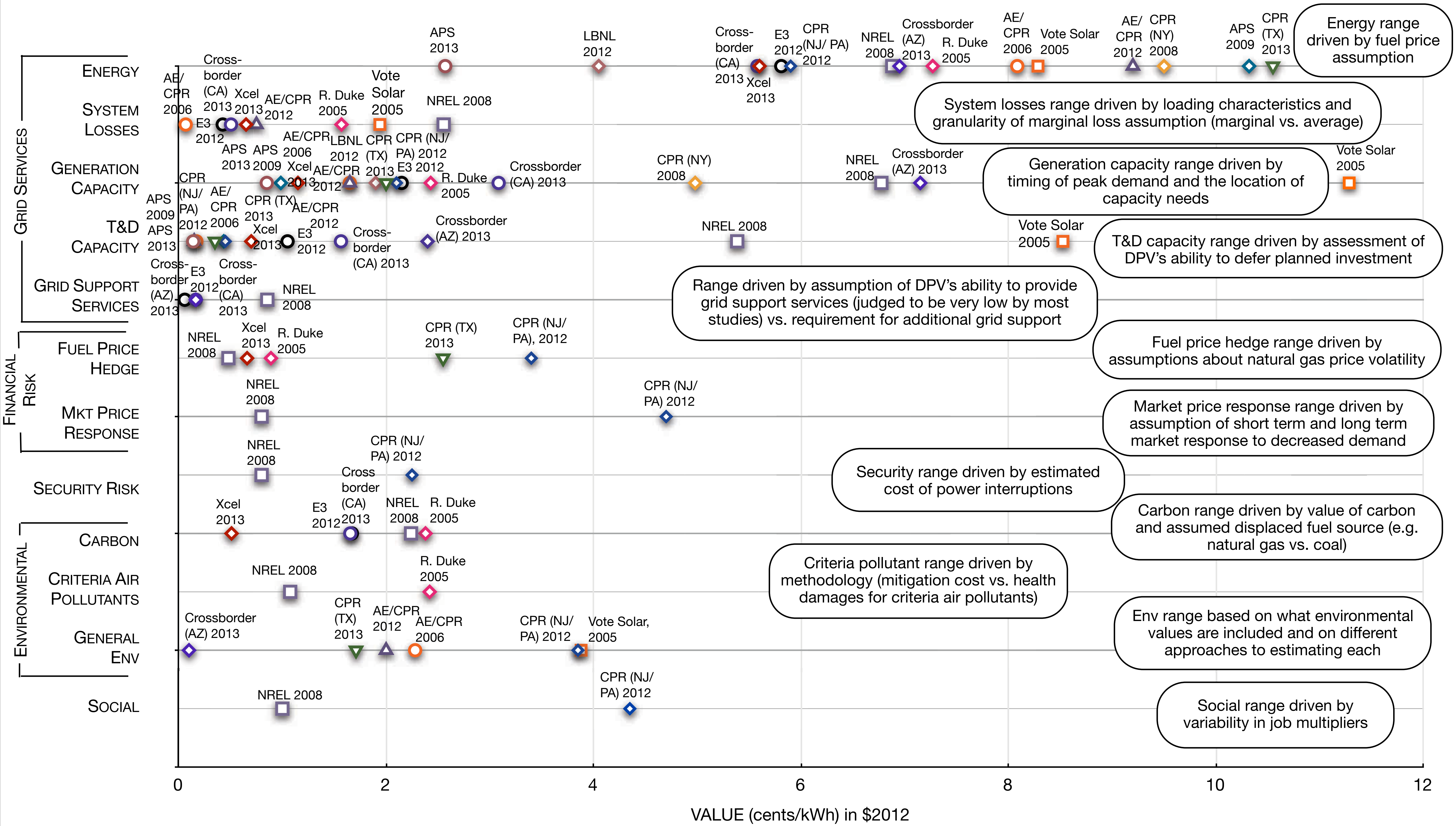
# BENEFIT ESTIMATES

## THE RANGE IN BENEFIT ESTIMATES ACROSS STUDIES IS DRIVEN BY VARIATION IN SYSTEM CONTEXT, INPUT ASSUMPTIONS, AND METHODOLOGIES

### PUBLISHED AVERAGE BENEFIT ESTIMATES*




*For the full range of values observed see the individual methodology slides.

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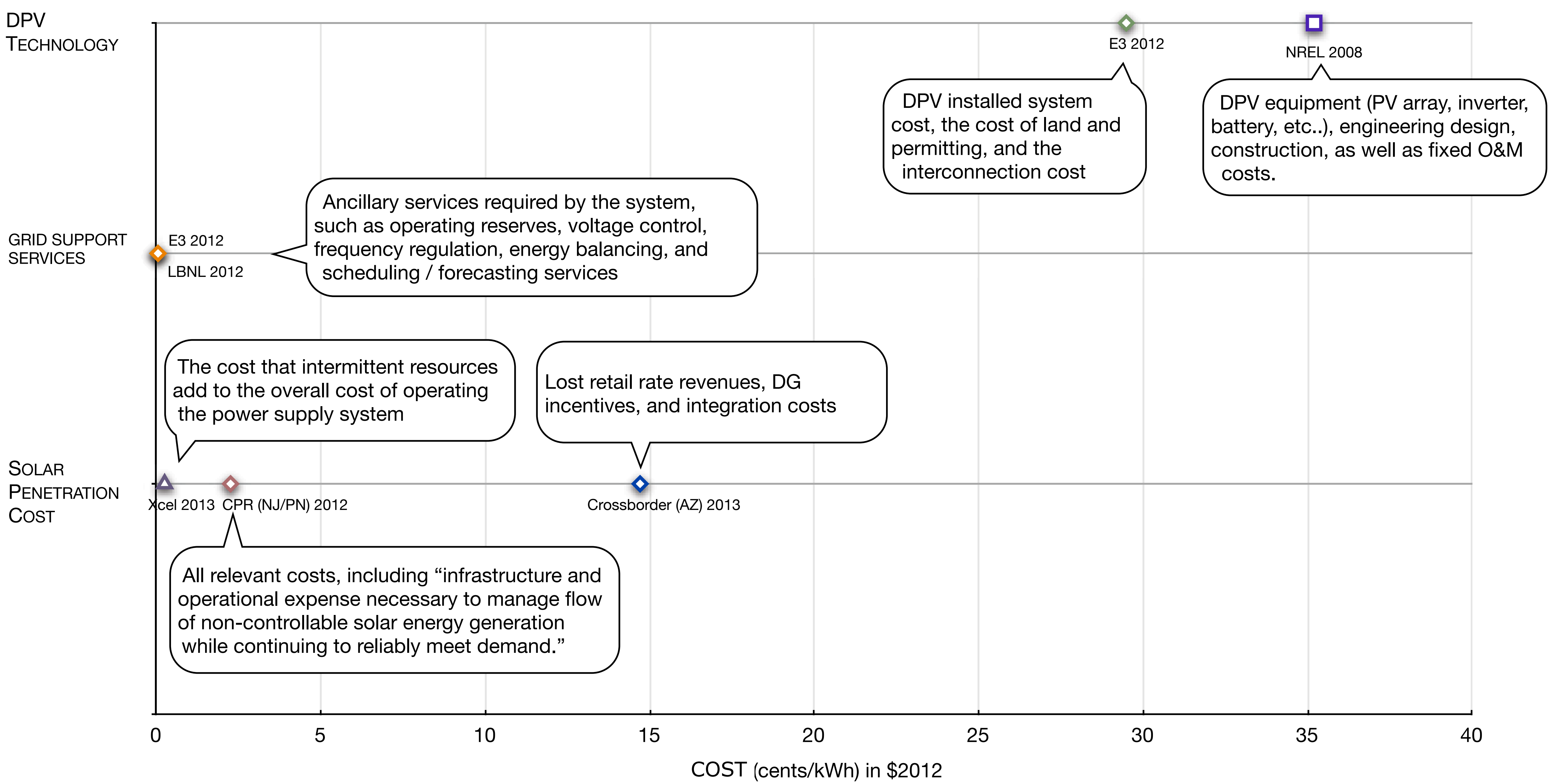
# COST ESTIMATES

## COSTS ASSOCIATED WITH INCREASED DPV DEPLOYMENT ARE NOT ADEQUATELY ASSESSED

### PUBLISHED AVERAGE COST VALUES FOR REVIEWED SOURCES




Other studies (for example E3 2011) include costs, but results are not presented individually in the studies and so not included in the chart above. Costs generally include costs of program rebates or incentives paid by the utility, program administration costs, lost revenue to the utility, stranded assets, and costs and inefficiencies associated with throttling down existing plants.

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# ENERGY

## VALUE OVERVIEW

Energy value is created when DPV generates energy (kWh) that displaces the need to produce energy from another resource. There are two components of energy value: the amount of energy that would have been generated equal to the DPV generation, and the additional energy that would have been generated but lost in delivery due to inherent inefficiencies in the transmission and distribution system. This second category of losses is sometimes reflected separately as part of the system losses category.

## APPROACH OVERVIEW

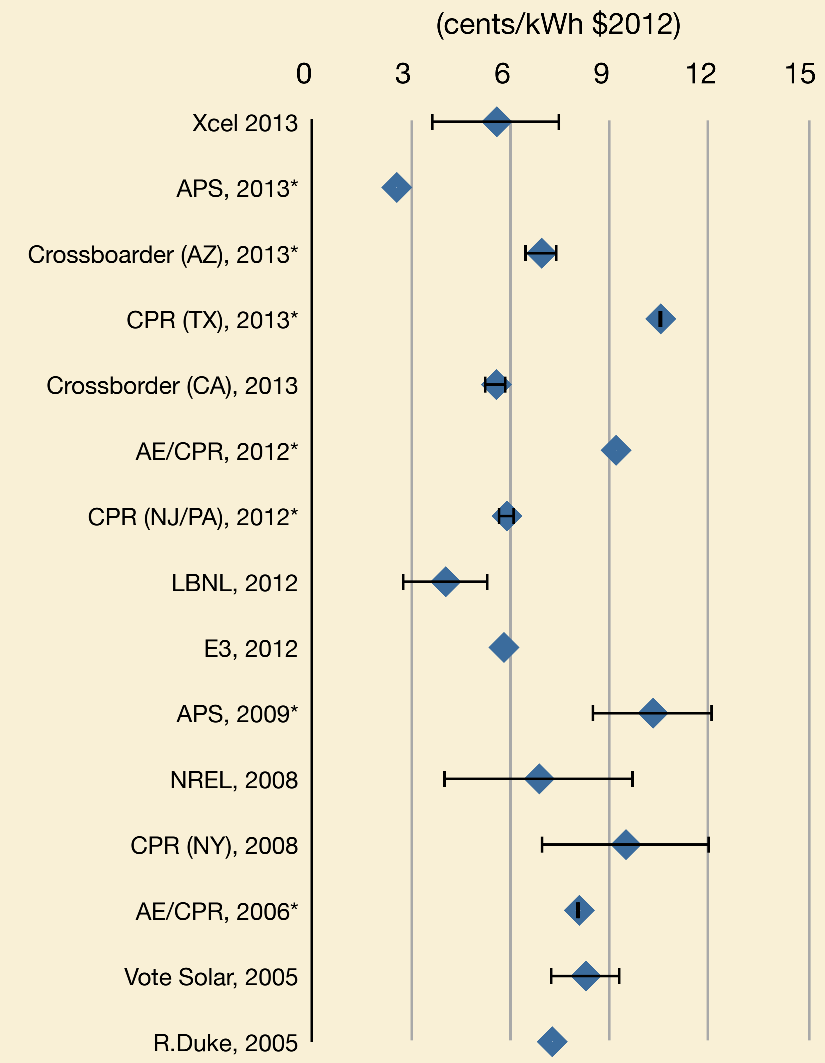
There is broad agreement on the general approach to calculating energy value, although numerous differences in methodological details. Energy is frequently the most significant source of benefit.

- Energy value is the avoided cost of the marginal resource, typically assumed to be natural gas.
- Key assumptions generally include fuel price forecast, operating & maintenance costs, and heat rate, and depending on the study, can include system losses and a carbon price.

## WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Market structure** - Some Independent System Operators (ISOs) and states value capacity and energy separately, whereas some ISOs only have energy markets without capacity markets. ISOs with only energy markets may reflect capacity value in the energy price.
  - **Marginal resource characterization** - Studies in regions with ISOs may calculate the marginal price based on wholesale market prices, rather than on the cost of the marginal power plant; different resources may be on the margin in different regions or with different solar penetrations.
- **Input Assumptions:**
  - **Fuel price forecast** - Since natural gas is usually on the margin, most studies focus on natural gas prices. Studies most often base natural gas prices on the New York Mercantile Exchange (NYMEX) forward market and then extrapolate to some future date (varied approaches to this extrapolation), but some take a different approach to forecasting, for example, based on Energy Information Administration projections.
  - **Power plant efficiency** - The efficiency of the marginal resource significantly impacts energy value; studies show a wide range of assumed natural gas plant heat rates.
  - **Variable operating & maintenance costs** - While there is some difference in values assumed by studies, variable O&M costs are generally low.
  - **Carbon price** - Some studies include an estimated carbon price in energy value, others account for it separately, and others do not include it at all.
- **Methodologies:**
  - **Study window** - Some studies (for example, APS 2013) calculate energy value in a sample year, whereas others (for example, Crossborder (AZ) 2013) calculate energy value as a levelized cost over 20 years.
  - **Marginal resource characterization** - Studies take one of three general approaches: (1) DPV displaces energy from a gas plant, generally a combined cycle, (2) DPV displaces energy from one type of plant (generally a combined cycle) off-peak and a different type of plant (generally a combustion turbine) on-peak, (3) DPV displaces the resource on the margin during every hour of the year, based on a dispatch analysis.

## ENERGY BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES




* = value energy savings that result from avoided energy losses

Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

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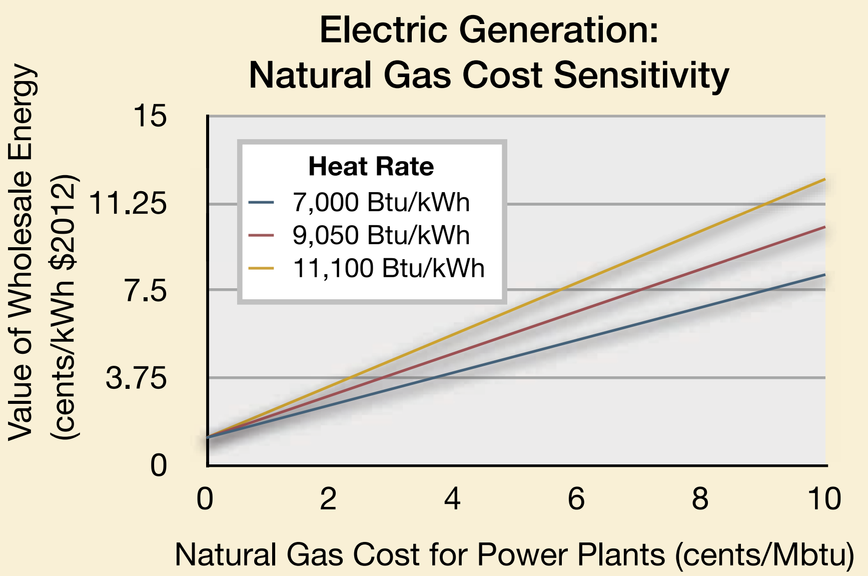
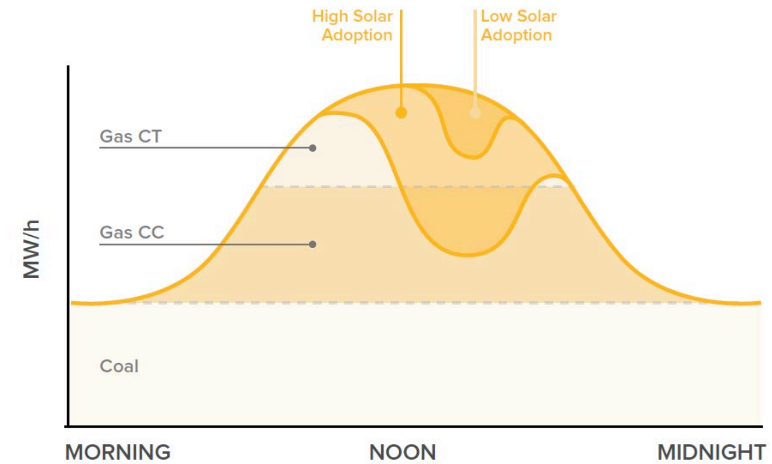
# ENERGY (CONT'D)

## SENSITIVITIES TO KEY INPUT ASSUMPTIONS




## INSIGHTS & IMPLICATIONS

- Accurately defining the marginal resource that DPV displaces requires an increasingly sophisticated approach as DPV penetration increases.




*The resources that DPV displaces depends on the dispatch order of other resources, when the solar is generated, and how much is generated.*

More accurate, more complex

| Marginal Resource Characterization | Pros | Cons |
|---|---|---|
| Single power plant assumed to be on the margin (typically gas CC) | Simple; often sufficiently accurate at low solar penetrations | Not necessarily accurate at higher penetrations or in all jurisdictions |
| Plant on the margin on-peak/plant on the margin off-peak | More accurately captures differences in energy value reflected in merit-order dispatch | Not necessarily accurate at higher penetrations or in all jurisdictions |
| Hourly dispatch or market assessment to determine marginal resource in every hour | Most accurate, especially with increasing penetration | More complex analysis required; solar shape and load shape must be from same years |

- Taking a more granular approach to determining energy value also requires a more detailed characterization of DPV's generation profile. It's also critical to use solar and load profiles from the same year(s), to accurately reflect weather drivers and therefore generation and demand correlation.

- In cases where DPV is displacing natural gas, the NYMEX natural gas forward market is a reasonable basis for a natural gas price forecast, adjusted appropriately for delivery to the region in question. It is not apparent from studies reviewed what the most effective method is for escalating prices beyond the year in which the NYMEX market ends.

## LOOKING FORWARD

As renewable and distributed resource (not just DPV) penetration increases, those resources will start to impact the underlying load shape differently, requiring more granular analysis to determine energy value.

# SYSTEM LOSSES

## VALUE OVERVIEW

System losses are a derivation of energy losses, the value of the additional energy generated by central plants that is lost due to inherent inefficiencies (electrical resistance) in delivering energy to the customer via the transmission and distribution system. Since DPV generates energy at or near the customer, that additional energy is not lost. Energy losses act as a magnifier of value for capacity and environmental benefits, since avoided energy losses result in lower required capacity and lower emissions.

## APPROACH OVERVIEW

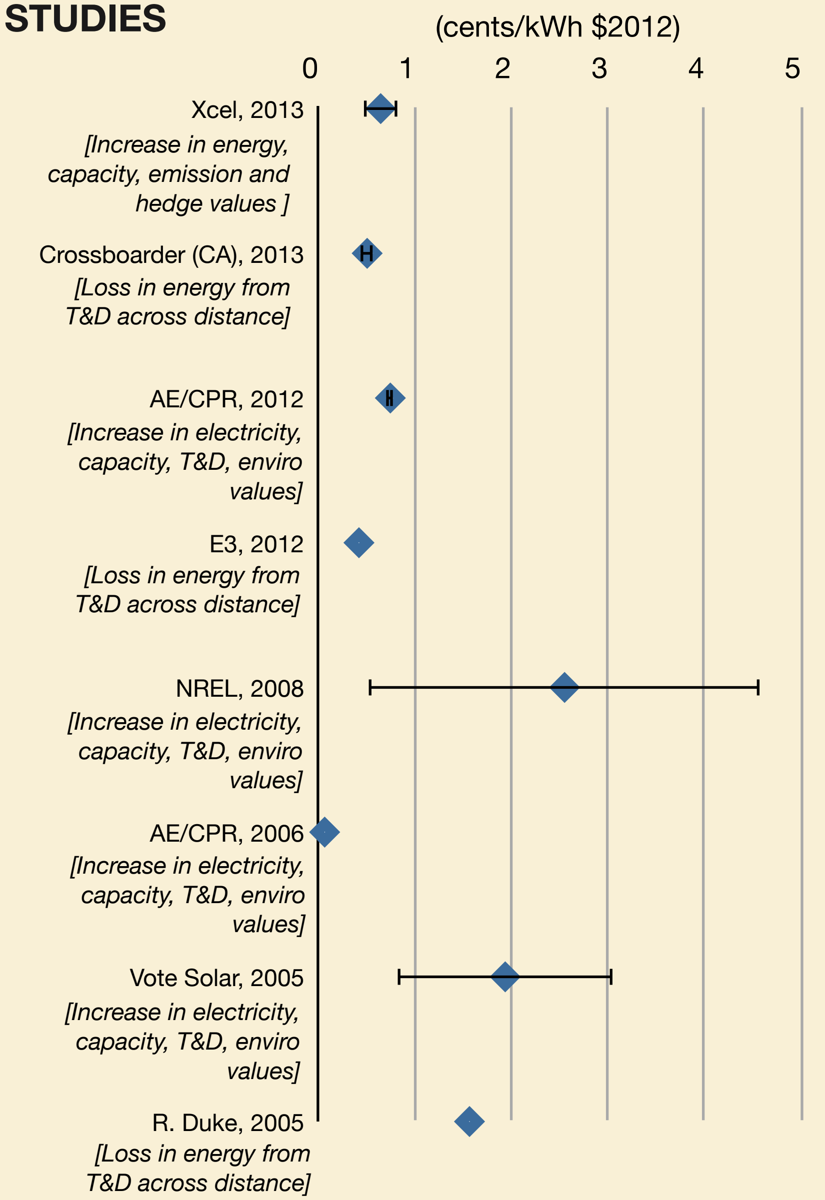
Losses are generally recognized as a value, although there is significant variation around what type of losses are included and how they are assessed. Losses usually represent a small but not insignificant source of value, although some studies report comparatively high values.

- Energy lost in delivery magnifies the value of other benefits, including capacity and environment.
- Calculate loss factor(s) (amount of loss per unit of energy delivered) based on modeled or observed data.

## WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Congestion** - Because energy losses are proportional to the inverse of current squared, the higher the utilization of the transmission & distribution system, the greater the energy losses.
  - **Solar characterization**—The timing, quantity, and geographic location of DPV, and therefore its coincidence with delivery system utilization, impacts losses.
- **Input Assumptions:**
  - **Losses** - Some studies estimate losses by applying loss factors based on actual observation, others develop theoretical loss factors based on system modeling. Further, some utility systems have higher losses than others.
- **Methodologies:**
  - **Types of losses recognized** - Most studies recognize energy losses, some recognize capacity losses, and a few recognize environmental losses.
  - **Adder vs. stand-alone value** - There is no common approach to whether losses are represented as stand-alone values (for example, NREL 2008 and E3 2012) or as adders to energy, capacity, and environmental value (for example, Crossborder (AZ) 2013 and APS 2013), complicating comparison across studies.
  - **Temporal & geographic characterization** - Some studies apply an average loss factor to all energy generated by DPV, others apply peak/off-peak factors, and others conduct hourly analysis. Some studies also reflect geographically-varying losses.

### SYSTEM LOSSES BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES




Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

# SYSTEM LOSSES (CONT'D)

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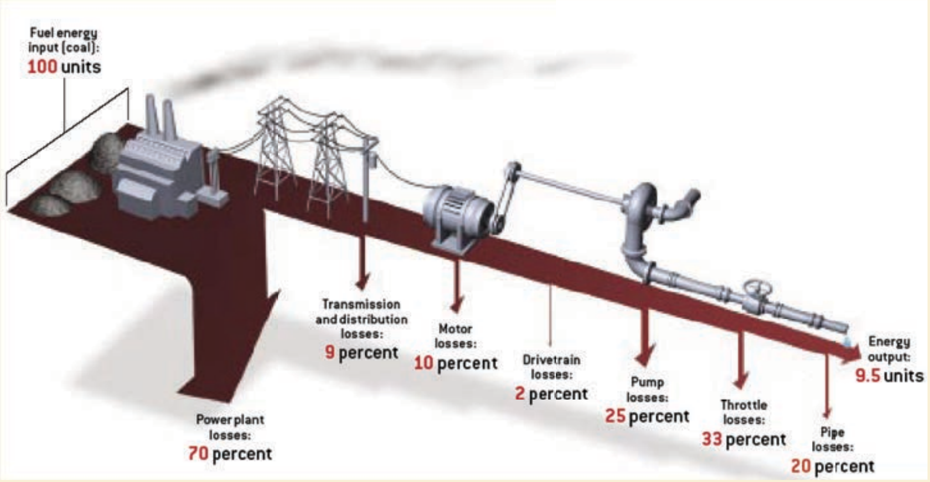
### WHAT ARE SYSTEM LOSSES?

Some energy generated at a power plant is lost as it travels through the transmission and distribution system to the customer. As shown in the graphic below, more than 90% of primary energy input into a power plant is lost before it reaches the end use, or stated in reverse, for every one unit of energy saved or generated close to where it is needed, 10 units of primary energy are saved.




For the purposes of this discussion document, relevant losses are those driven by inherent inefficiencies (electrical resistance) in the transmission and distribution system, not those in the power plant or customer equipment. Energy losses are proportional to the square of current, and associated capacity benefit is proportional to the square of reduced load.

### INSIGHTS & IMPLICATIONS

- All relevant system losses—energy, capacity, and environment—should be assessed.
- Because losses are driven by the square of current, losses are significantly higher during peak periods. Therefore, when calculating losses, it's critical to reflect marginal losses, not just average losses.
- Whether or not losses are ultimately represented as an adder to an underlying value or as a stand-alone value, they are generally calculated separately. Studies should distinguish these values from the underlying value for transparency and to drive consistency of methodology.

### LOOKING FORWARD

Losses will change over time as the loading on transmission and distribution lines changes due to a combination of changing customer demand and DPV generation.

# GENERATION CAPACITY

## VALUE OVERVIEW

Generation capacity value is the amount of central generation capacity that can be deferred or avoided due to the installation of DPV. Key drivers of value include (1) DPV's effective capacity and (2) system capacity needs.

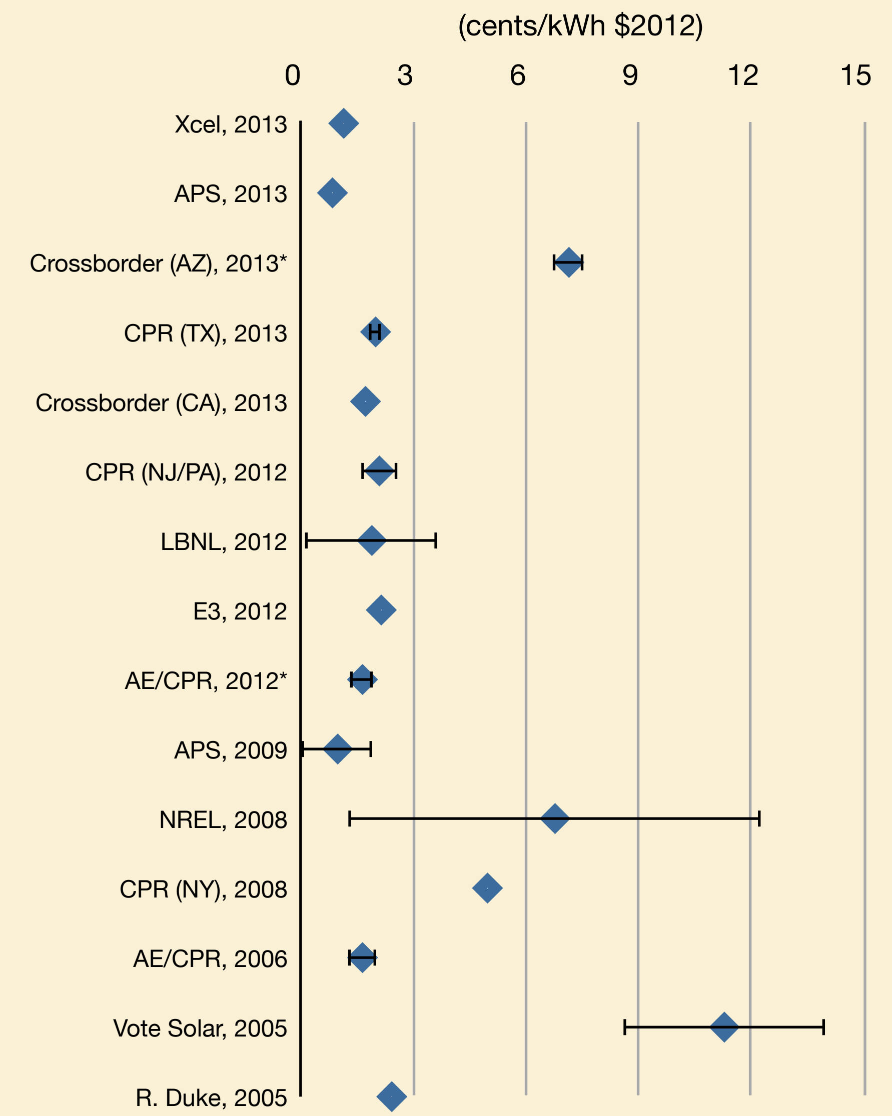
## APPROACH OVERVIEW

Generation capacity value is the avoided cost of the marginal capacity resource, most frequently assumed to be a gas combustion turbine, and based on a calculation of DPV effective capacity, most commonly based on effective load carrying capability (ELCC).

## WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Load growth/generation capacity investment plan** - The ability to avoid or defer generation capacity depends on underlying load growth and how much additional capacity will be needed, at what time.
  - **Solar characteristics** - The timing, quantity, and geographic location of DPV, and therefore its coincidence with system peak, impacts DPV's effective capacity.
  - **Market structure** - Some ISOs and states value capacity and energy separately, whereas some ISOs only have energy markets but no capacity markets. ISOs with only energy markets may reflect capacity value as part of the energy price. For California, E3 2012 calculates capacity value based on "net capacity cost"—the annual fixed cost of the marginal unit minus the gross margins captured in the energy and ancillary service market.
- **Input Assumptions:**
  - **Marginal resource** - Most studies assume that a gas combustion turbine, or occasionally a gas combined cycle, is the generation capacity resource that could be deferred. What this resource is and its associated capital and fixed O&M costs are a primary determinant of capacity value.
- **Methodologies:**
  - **Formulation of DPV effective capacity** - There is broad agreement that DPV's effective capacity is most accurately determined using an ELCC approach, which measures the amount of additional load that can be met with the same level of reliability after adding DPV. There is some variation across studies in ELCC results, likely driven by a combination of underlying solar resource profile and ELCC calculation methodology. The approach to effective capacity is sometimes different when considering T&D capacity.
  - **Minimum DPV required to defer capacity** - Some studies (for example, Crossborder (AZ) 2013) credit every unit of effective DPV capacity with capacity value, whereas others (for example, APS 2009) require a certain minimum amount of solar be installed to defer an actual planned resource before capacity value is credited.
  - **Inclusion of losses** - Some studies include capacity losses as an adder to capacity value rather than as a stand-alone benefit.

### GENERATION CAPACITY BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES




* = value includes generation capacity savings that result from avoided energy losses

Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

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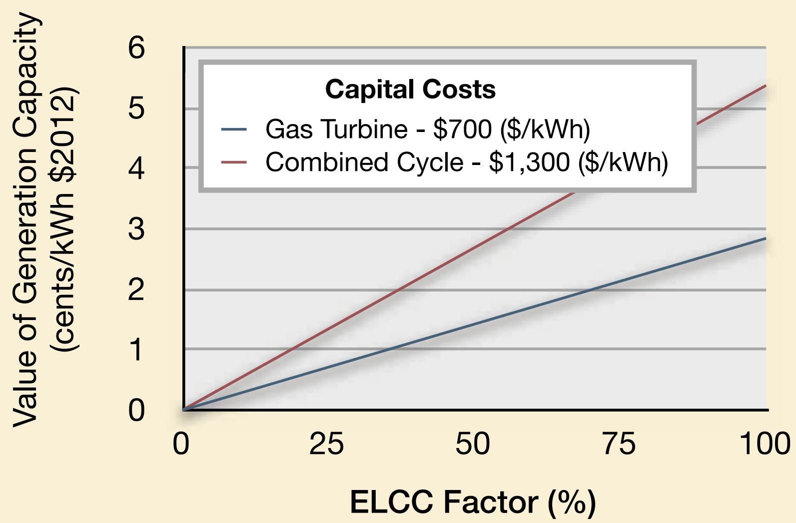
# GENERATION CAPACITY (CONT'D)

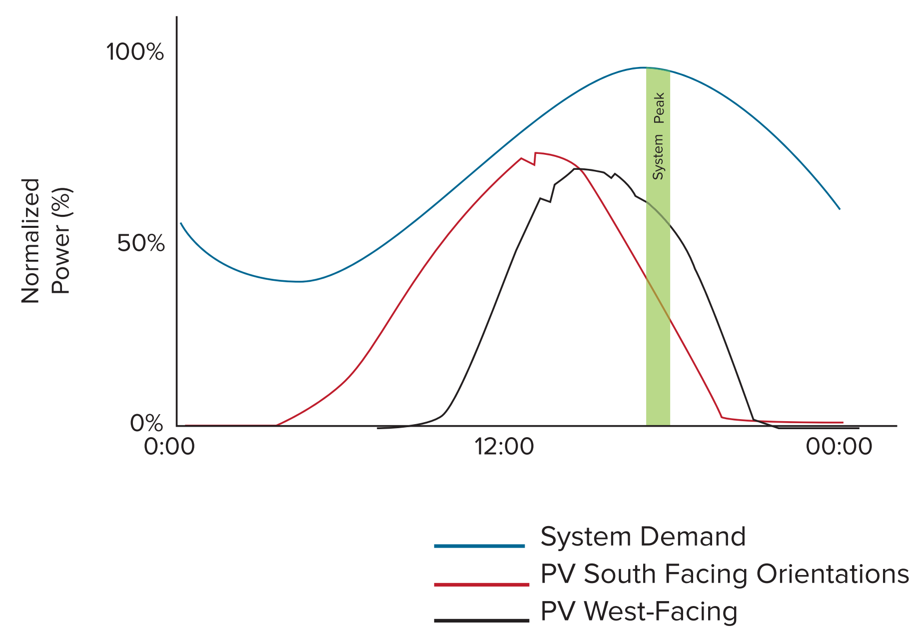
## SENSITIVITIES TO KEY INPUT ASSUMPTIONS

Sensitivity of Generation Capacity Value to the ELCC Factor




## INSIGHTS & IMPLICATIONS

- Generation capacity value is highly dependent on the correlation of DPV generation to load, so it's critical to accurately assess that correlation using an ELCC approach, as all studies reviewed do. However, varying results indicate possible different formulations of ELCC.




*While effective load carrying capacity (ELCC) assesses DPV's contribution to reliability throughout the year, generation capacity value will generally be higher if DPV output is more coincident with peak.*

- The value also depends on whether new capacity is needed on the system, and therefore whether DPV defers new capacity. It's important to assess what capacity would have been needed without any additional, expected, or planned DPV.

- Generation capacity value is likely to change significantly as more DPV, and more renewable and distributed resources of all kinds are added to the system. Some amount of DPV can displace the most costly resources in the capacity stack, but increasing amounts of DPV could begin to displace less costly resources. Similarly, the underlying load shape, and therefore even the concept of a peak could begin to shift.

## LOOKING FORWARD

Generation capacity is one of the values most likely to change, most quickly, with increasing DPV penetration. Key reasons for this are (1) increasing DPV penetration could have the effect of pushing the peak to later in the day, when DPV generation is lower, and (2) increasing DPV penetration will displace expensive peaking resources, but once those resources are displaced, the cost of the next resource may be lower. Beyond DPV, it's important to note that a shift towards more renewables could change the underlying concept of a daily or seasonal peak.

# TRANSMISSION & DISTRIBUTION CAPACITY

### VALUE OVERVIEW

The transmission and distribution (T&D) capacity value is a measure of the net change in T&D infrastructure as a result of the addition of DPV. Benefits occur when DPV is able to meet rising demand locally, relieving capacity constraints upstream and deferring or avoiding transmission or distribution upgrades. Costs are incurred when additional transmission or distribution investment are necessary to support the addition of DPV, which could occur when the amount of solar energy exceeds the demand in the local area and increases needed line capacity.

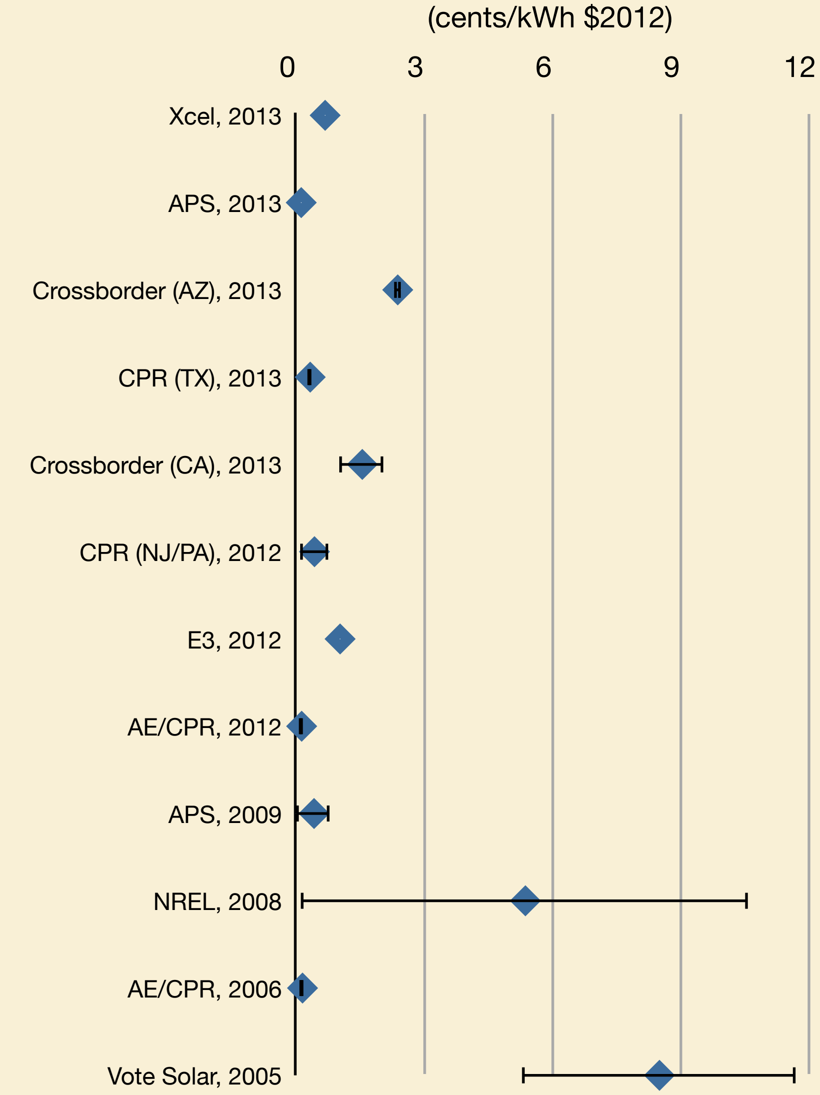
### APPROACH OVERVIEW

The net value of deferring or avoiding T&D investments is driven by rate of load growth, DPV configuration and energy production, peak coincidence and effective capacity. Given the site specific nature of T&D, especially distribution, there can be significant range in the calculated value of DPV. Historically low penetrations of DPV has meant that studies have primarily focused on analyzing the ability of DPV to defer transmission or distribution upgrades and have not focused on potential costs, which would likely not arise until greater levels of penetration. Studies typically determine the T&D capacity value based on the capital costs of planned expansion projects in the region of interest. However, the granularity of analysis differs.

### WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Locational characteristics** - Transmission and distribution infrastructure projects are inherently site-specific and their age, service life, and use can vary significantly. Thus, the need, size and cost of upgrades, replacement or expansion correspondingly vary.
  - **Projected load growth/T&D capacity investment plan** - Expected rate of demand growth affects the need, scale and cost of T&D upgrades and the ability of DPV to defer or offset anticipated T&D expansions. The rate of growth of DPV would need to keep pace with the growth in demand, both by order of magnitude and speed.
  - **Solar characteristics** - The timing of energy production from DPV and its coincidence with system peaks (transmission) and local peaks (distribution) drive the ability of DPV to contribute as effective capacity that could defer or displace a transmission or distribution capacity upgrade.
  - **The length of time the investment is deferred** -The length of time that T&D can be deferred by the installation of DPV varies by the rate of load growth, the assumed effective capacity of the DPV, and DPV's correlation with peak. The cost of capital saved will increase with the length of deferment.
- **Input Assumptions:**
  - **T&D investment plan characteristics -** Depending upon data available and depth of analysis, studies vary by the level of granularity in which T&D investment plans were assessed–project by project or broader generalizations across service territories.
- **Methodologies:**
  - **Accrual of capacity value to DPV** - One of the most significant methodological differences is whether DPV has incremental T&D capacity value in the face of "lumpy" T&D investments (see implications and insights).
  - **Losses -** Some studies include the magnified benefit of deferred T&D capacity due to avoided losses within the calculation of T&D value, while others itemize line losses separately.

**T&D CAPACITY BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES**




* = value includes T&D capacity savings that result from avoided energy losses

Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

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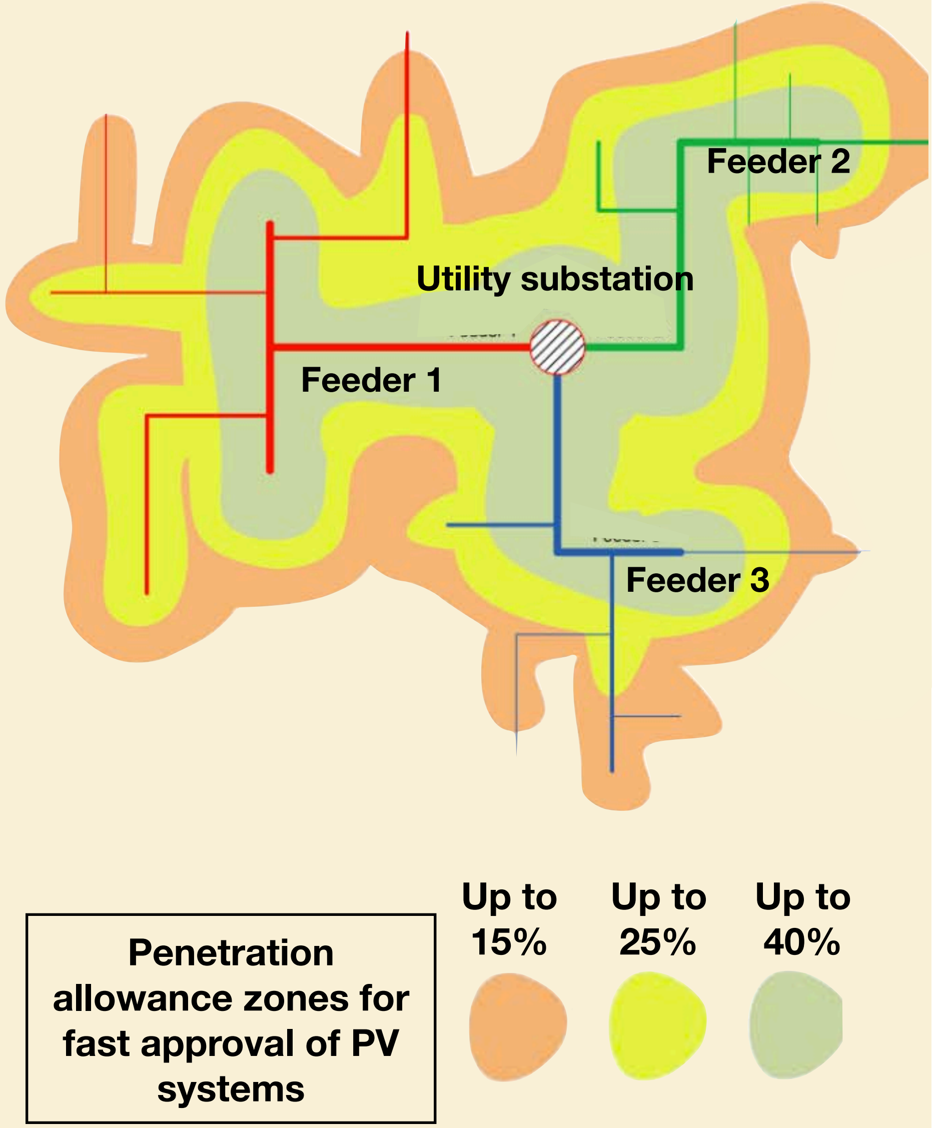
# TRANSMISSION & DISTRIBUTION CAPACITY (CONT'D)

## LOCATIONAL CONSIDERATIONS AT THE DISTRIBUTION LEVEL




Adapted from Coddington, M. et al, *Updating Interconnection Screens for PV System Integration*

## INSIGHTS & IMPLICATIONS

- Strategically targeted DPV deployment can relieve T&D capacity constraints by providing power close to demand and potentially deferring capacity investments, but dispersed deployment has been found to provide less benefit. Thus, the ability to access DPV's T&D deferral value will require proactive distribution planning that incorporates distributed energy resources, such as DPV, into the evaluation.

- The values of T&D are often grouped together, but they are unique when considering the potential costs and benefits that result from DPV.
  - While the ability to defer or avoid transmission is still locational dependent, it is less so than distribution. Transmission aggregates disparate distribution areas and the effects of additional DPV at the distribution level typically require less granular data and analysis.
  - The distribution system requires more geographically specific data that reflects the site specific characteristics such as local hourly PV production and correlation with local load.

- There are significantly differing approaches on the ability of DPV to accrue T&D capacity deferment or avoidance value that require resolution:
  - How should DPV's capacity deferral value be estimated in the face of "lumpy" T&D investments? While APS 2009 and APS 2013 posit that a minimum amount of solar must be installed to defer capacity before credit is warranted, Crossborder (AZ) 2013 credits every unit of reliable capacity with capacity value.
  - What standard should be applied to estimate PV's ability to defer a specific distribution expansion project? While most studies use ELCC to determine effective capacity, APS 2009 and APS 2013 use the level at which there is a 90% confidence of that amount of generation.

## LOOKING FORWARD

Any distributed resources, not just DPV, that can be installed near the end user to reduce use of, and congestion along, the T&D network could potentially provide T&D value. This includes technologies that allow energy to be used more efficiently or at different times, reducing the quantity of electricity traveling through the T&D network (especially during peak hours).

# GRID SUPPORT SERVICES

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## VALUE OVERVIEW

Grid support services, also commonly referred to as ancillary services (AS) in wholesale energy markets, are required to enable the reliable operation of interconnected electric grid systems, including operating reserves, reactive supply and voltage control; frequency regulation; energy imbalance; and scheduling.

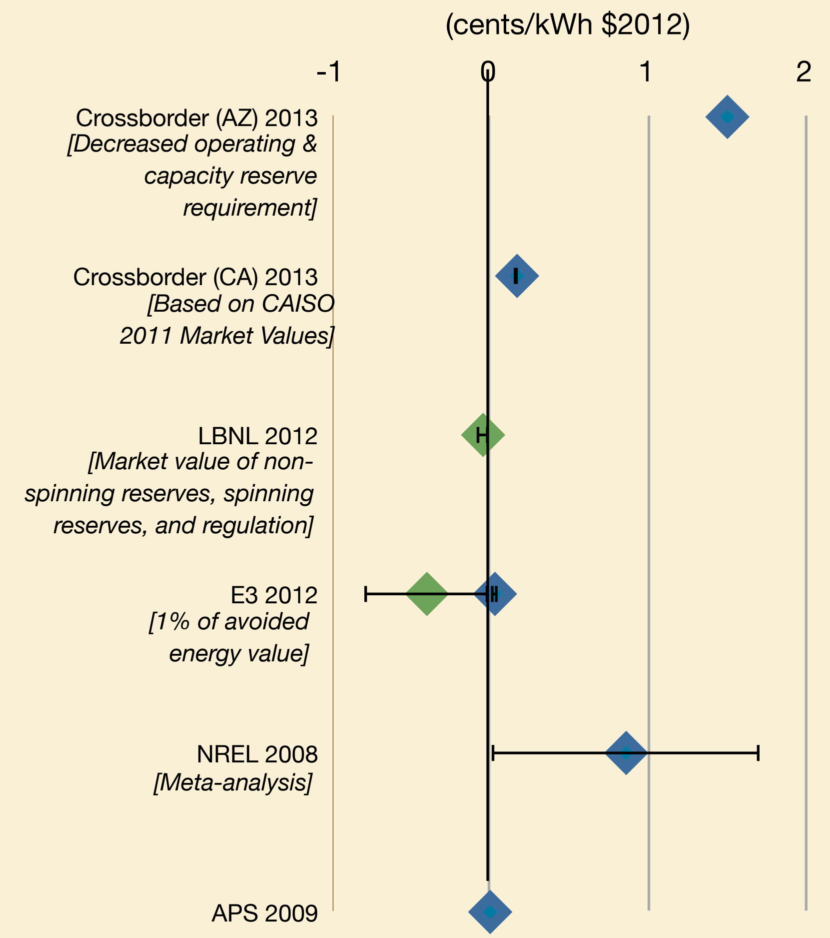
## APPROACH OVERVIEW

There is significant variation across studies on the impact DPV will have on the addition or reduction in the need for grid support services and the associated cost or benefit. Most studies focus on the cost DPV could incur in requiring additional grid support services, while a minority evaluate the value DPV could provide by reducing load and required reserves or the AS that DPV could provide when coupled with other technologies. While methodologies are inconsistent, the approaches generally focus on methods for calculating changes in necessary operating reserves, and less precision or rules of thumb are applied to the remainder of AS, such as voltage regulation. Operating reserves are typically estimated by determining the reliable capacity for which DPV can be counted on to provide capacity when demanded over the year.

## WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Reliability standards and market rules** - The standards and rules for reliability that govern the requirements for grid support services and reserve margins differ. These standards directly impact the potential net value of adding DPV to the system.
  - **Availability of ancillary services market** - Where wholesale electricity markets exist, the estimated value is correlated to the market prices of AS.
  - **Solar characteristics** - The timing of energy production from DPV and it's coincidence with system peaks differs locationally.
  - **Penetration of DPV** - As PV penetrations increase, the value of its reliable capacity decreases and, under standard reliability planning approaches, would increase the amount of system reserves necessary to maintain reliable operations.
  - **System generation mix** - The performance characteristics of the existing generation mix, including the generators ability to respond quickly by increasing or decreasing production, can significantly change the supply value of ancillary services and the value.
- **Methodologies:**
  - **Effective capacity of DPV** - The degree that DPV can be depended on to provide capacity when demanded has a direct effect on the amount of operating reserves that the rest of the system must supply. The higher the "effective capacity," the less operating reserves necessary.
  - **Correlating reduced load with reduced ancillary service needs** - Crossborder (AZ) 2013 calculated a net benefit of DPV based on 1) load reduction & reduced operating reserve requirements; 2) peak demand reduction and utility capacity requirements.
  - **Potential of DPV to provide grid support with technology coupling** - While the primary focus across studies was the impact DPV would have on the need for additional AS, NREL 2008 & AE/CPR 2006 both noted that DPV could provide voltage regulation with smart inverters were installed.

## GRID SUPPORT SERVICES BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES




Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

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# GRID SUPPORT SERVICES (CONT'D)

| Grid Support Services | The potential for DPV to provide grid support services (with technology modifications) |
|---|---|
| REACTIVE SUPPLY AND VOLTAGE CONTROL | **(+/-)** PV with an advanced inverter can inject/consume VARs, adjusting to control voltage |
| FREQUENCY REGULATION | **(+/-)** Advanced inverters can adjust output frequency; standard inverters may |
| ENERGY IMBALANCE | **(+/-)** If PV output < expected, imbalance service is required. Advanced inverters could adjust output to provide imbalance |
| OPERATING RESERVES | **(+/-)** Additional variability and uncertainty from large penetrations of DPV may introduce operations forecast error and increase the need for certain types of reserves; however, DPV may also reduce the amount of load served by central generation, thus, reducing needed reserves. |
| SCHEDULING / FORECASTING | **(-)** The variability of the solar resource requires additional forecasting to reduce uncertainty |

## INSIGHTS & IMPLICATIONS

- As with large scale renewable integration, there is still controversy over determining the net change in "ancillary services due to variable generation and much more controversy regarding how to allocate those costs between specific generators or loads." (LBNL 2012)
- Areas with wholesale AS markets enable easier quantification of the provision of AS. Regions without markets have less standard methodologies for quantifying the value of AS.
- One of the most significant differences in reviewed methodological approaches is whether the necessary amount of operating reserves, as specified by required reserve margin, decreases by DPV's capacity value (as determined by ELCC, for example). Crossborder (CA) 2013, E3 2012 and Vote Solar 2005 note that the addition of DPV reduces load served by central generation, thus allowing utilities to reduce procured reserves. Additional analysis is needed to determine whether the required level of reserves should be adjusted in the face of a changing system.
- Studies varied in their assessments of grid support services. APS 2009 did not expect DPV would contribute significantly to spinning or operating reserves, but predicted regulation reserves could be affected at high penetration levels.

## LOOKING FORWARD

Increasing levels of distributed energy resources and variable renewable generation will begin to shift both the need for grid support services as well as the types of assets that can and need to provide them. The ability of DPV to provide grid support requires technology modifications or additions, such as advanced inverters or storage, which incur additional costs. However, it is likely that the net value proposition will increase as technology costs decrease and the opportunity (or requirements) to provide these services increase with penetration.

# FINANCIAL: FUEL PRICE HEDGE

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## VALUE OVERVIEW

DPV produces roughly constant-cost power compared to fossil fuel generation, which is tied to potentially volatile fuel prices. DPV can provide a "hedge" against price volatility, reducing risk exposure to utilities and customers.

## APPROACH OVERVIEW

More than half the studies reviewed acknowledge DPV's fuel price hedge benefit, although fewer quantify it and those that do take different, although conceptually similar, approaches.

- In future years when natural gas futures market prices are available, using those NYMEX prices to develop a natural gas price forecast should include the value of volatility.
- In future years beyond when natural gas futures market prices are available, estimate natural gas price and volatility value separately. Differing approaches include:
    - Escalating NYMEX prices at a constant rate, under the assumption that doing so would continue to reflect hedge value (Crossborder (AZ) 2013); or
    - Estimating volatility hedge value separately as the value or an option/swap, or as the actual price adder the utility is incurring now to hedge gas prices (CPR (NJ/PA 2012), NREL 2008).

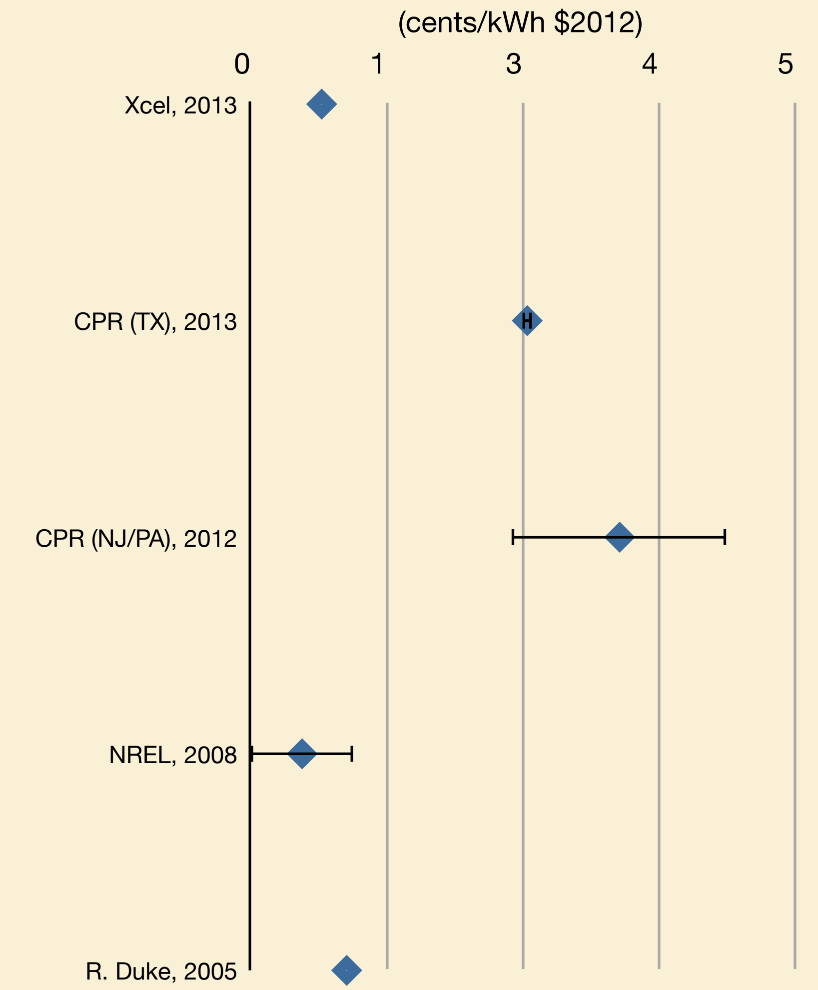
## WHY AND HOW VALUES DIFFER

- **System Context:**
    - **Marginal resource characterization** - What resource is on the margin, and therefore how much fuel is displaced varies.
    - **Exposure to fuel price volatility** - Most utilities already hedge some portion of their natural gas purchases for some period of time in the future.
- **Methodologies:**
    - **Approach to estimating value** - While most studies agree that NYMEX futures prices are an adequate reflection of volatility, there is no largely agreed upon approach to estimating volatility beyond when those prices are available.

## INSIGHTS & IMPLICATIONS

- NYMEX futures market prices are an adequate reflection of volatility in the years in which it operates.
- Beyond that, volatility should be estimated, although there is no obvious best practice. Further work is required to develop an approach that accurately measures hedge value.

### FUEL PRICE HEDGE BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES




Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

# FINANCIAL: MARKET PRICE RESPONSE

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## VALUE OVERVIEW

The addition of DPV, especially at higher penetrations, can affect the market price of electricity in a particular market or service territory. These market price effects span energy and capacity values in the short term and long term, all of which are interrelated. Benefits can occur as DPV provides electricity close to demand, reducing the demand for centrally-supplied electricity and the fuel powering those generators, thereby lowering electricity prices and potentially fuel commodity prices. A related benefit is derived from the effect of DPV's contribution at higher penetrations to reshaping the load profile that central generators need to meet. Depending upon the correlation of DPV production and load, the peak demand could be reduced and the marginal generator could be more efficient and less costly, reducing total electricity cost. However, these benefits could potentially be reduced in the longer term as energy prices decline, which could result in higher demand. Additionally, depressed prices in the energy market could have a feedback effect by raising capacity prices.

## APPROACH OVERVIEW

While several studies evaluate a market price response of DPV, distinct approaches were employed by E3 2012, CPR (NJ/PN) 2012, and NREL 2008.

## WHY AND HOW VALUES DIFFER

- **Methodologies:**
  - **Considering market price effects of DPV in the context of other renewable technologies** - E3 2012 incorporated market price effect in its high penetration case by adjusting downward the marginal value of energy that DPV would displace. However, for the purposes of the study, E3 2012 did not add this as a benefit to the avoided cost because they "assume the market price effect would also occur with alternative approaches to meeting [CA's] RPS."
  - **Incorporating capacity effects** -
    - E3 2012 represented a potential feedback effect between the energy and capacity by assuming an energy market calibration factor. That is, it assumes that, in the long run, the CCGT's energy market revenues plus the capacity payment equal the fixed and variable costs of the CCGT. Therefore, a CCGT would collect more revenue through the capacity and energy markets than is needed to cover its costs, and a decrease in energy costs would result in a relative increase in capacity costs.
    - CPR (NJ/PA) 2012 incorporates market price effect "by reducing demand during the high priced hours [resulting in] a cost savings realized by all consumers." They note "that further investigation of the methods may be warranted in light of two arguments...that the methodology does address induced increase in demand due to price reductions, and that it only addresses short-run effects (ignoring the impact on capacity markets)."

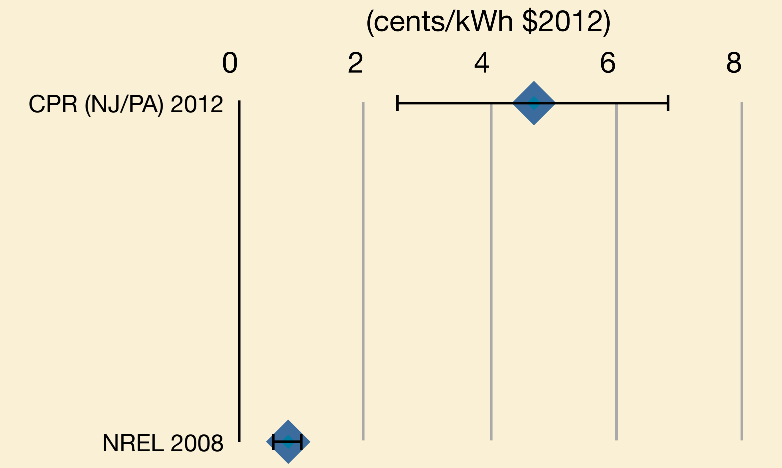
## INSIGHTS & IMPLICATIONS

- The market price reduction value only assesses the initial market reaction of reduced price, not subsequent market dynamics (e.g. increased demand in response to price reductions, or the impact on the capacity market), which has to be studied and considered, especially in light of higher penetrations of DPV.

## LOOKING FORWARD

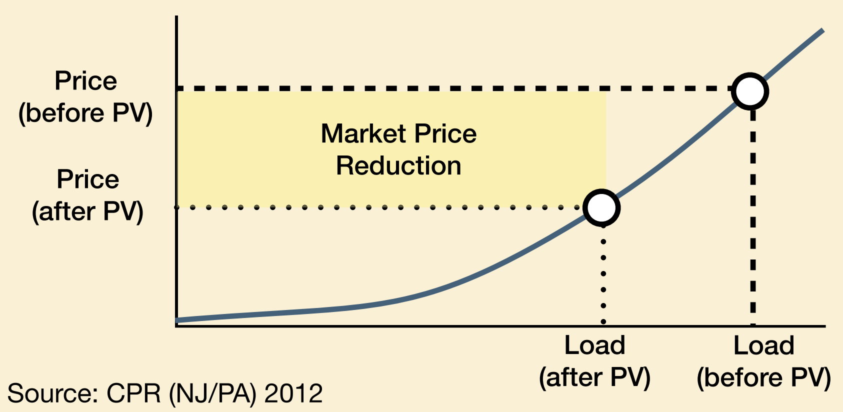
Technologies powered by risk-free fuel sources (such as wind) and technologies that increase the efficiency of energy use and decrease consumption would also have similar effects.

## MARKET PRICE RESPONSE BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES




Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs. Also, E3 2012 is not included in this chart because this study did not provide an itemized value for market price response,

## MARKET PRICE VS. LOAD




Source: CPR (NJ/PA) 2012

# SECURITY: RELIABILITY AND RESILIENCY

## VALUE OVERVIEW

The grid security value that DPV could provide is attributable to three primary factors, the last of which would require coupling DPV with other technologies to achieve the benefit:

1) The potential to reduce outages by reducing congestion along the T&D network. Power outages and rolling blackouts are more likely when demand is high and the T&D system is stressed.
2) The ability to reduce large-scale outages by increasing the diversity of the electricity system's generation portfolio with smaller generators that are geographically dispersed.
3) The benefit to customers to provide back-up power sources available during outages through the combination of PV, control technologies, inverters and storage.

## APPROACH OVERVIEW

While there is general agreement across studies that integrating DPV near the point of use will decrease stress on the broader T&D system, most studies do not calculate a benefit due to the difficulty of quantification. CPR 2012 and 2011 did represent the value as the value of avoided outages based on the total cost of power outages to the U.S. each year, and the perceived ability of DPV to decrease the incidence of outages.

## INSIGHTS & IMPLICATIONS

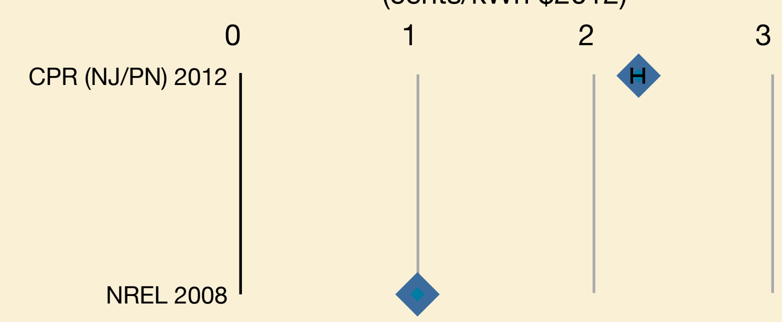
- The value of increased reliability is significant, but there is a need to quantify and demonstrate how much value can be provided by DPV. Rules-of-thumb assumptions and calculations for security impacts require significant analysis and review.

- Opportunities to leverage combinations of distributed technologies to increase customer reliability are starting to be tested. The value of DPV in increasing suppling power during outages can only be realized if DPV is coupled with storage and equipped with the capability to island itself from the grid, which come at additional capital cost.

## LOOKING FORWARD

Any distributed resources that can be installed near the end user to reduce use of, and congestion along, the T&D network could potentially reduce transmission stress. This includes technologies that allow energy to be used more efficiently or at different times, reducing the quantity of electricity traveling through the T&D network (especially during peak hours). Any distributed technologies with the capability to be islanded from the grid could also play a role.

## RELIABILITY AND RESILIENCY BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES




Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

### Disruption Value* Range by Sector
**(cents/kWh $2012)**

| Sector | Min | Max |
|---|---|---|
| Residential | 0.028 | 0.41 |
| Commercial | 11.77 | 14.40 |
| Industrial | 0.4 | 1.99 |

*Source: The National Research Council, 2010*

*Disruption value is a measure of the damages from outages and power-quality events based on the increased probability of these events occurring with increasing electricity consumption.

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# ENVIRONMENT: CARBON DIOXIDE

## VALUE OVERVIEW

The benefits of reducing carbon emissions include (1) reducing future compliance costs, carbon taxes, or other fees, and (2) mitigating the heath and ecosystem damages potentially caused by climate change.

## APPROACH OVERVIEW

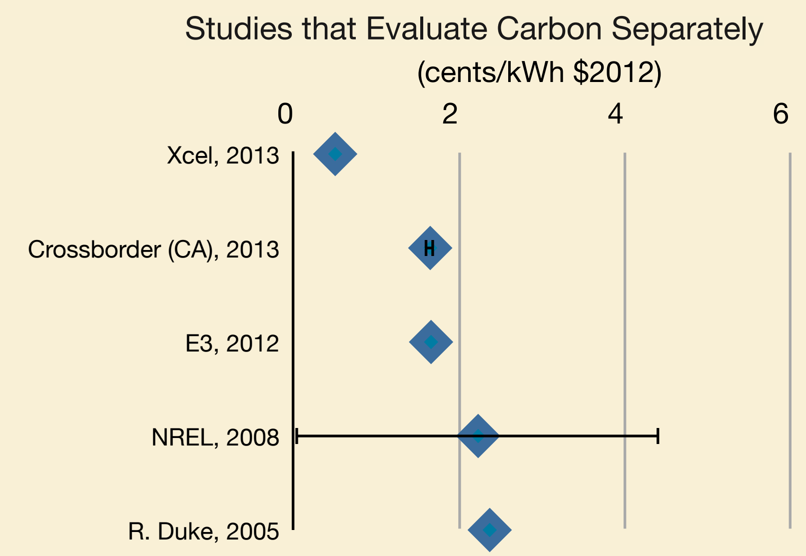
By and large, studies that addressed carbon focused on the compliance costs or fees associated with future carbon emissions, and conclude that carbon reduction can increase DPV's value by more than two cents per kilowatt-hour, depending heavily on the price placed on carbon. While there is some agreement that carbon reduction provides value and on the general formulation of carbon value, there are widely varying assumptions, and not all studies include carbon value.

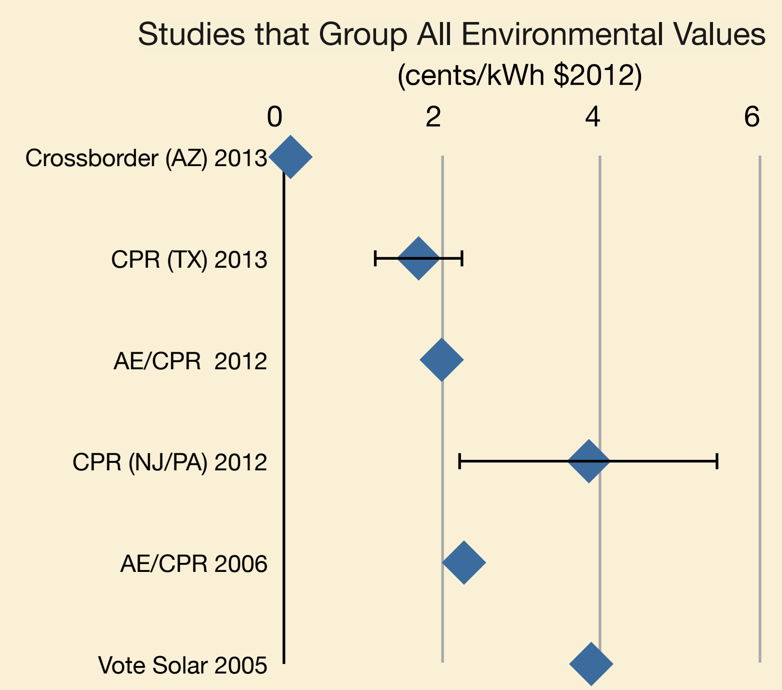
Carbon reduction benefit is the amount of carbon displaced times the price of reducing a ton of carbon. The amount of carbon displaced is directly linked to the amount of energy displaced, when it is displaced, and the carbon intensity of the resource being displaced.

## WHY AND HOW VALUES DIFFER

- **System Context:**
  - **Marginal resource characterization** - Different resources may be on the margin in different regions or with different solar penetrations. Carbon reduction is significantly different if energy is displaced from coal, gas combined cycles, or gas combustion turbines.
- **Input Assumptions:**
  - **Value of carbon reduction** - Studies have widely varying assumptions about the price or carbon. Some studies base price on reported prices in European markets, others on forecasts based on policy expectations, others on a combination. The increased uncertainty around U.S. Federal carbon legislation has made price estimates more difficult.
  - **Heat rates of marginal resources** - The assumed efficiency of the marginal power plant is directly correlated to amount of carbon displaced by DPV.
- **Methodologies:**
  - **Adder vs. stand-alone value** - There is no common approach to whether carbon is represented as a stand-alone value (for example, NREL 2008 and E3 2012) or as an adder to energy value (for example, APS 2013).
  - **Marginal resource characterization** - Just as with energy (which is directly linked to carbon reduction), studies take one of three general approaches: (1) DPV displaces energy from a gas plant, generally a combined cycle, (2) DPV displaces energy from one type of plant (generally a combined cycle) off-peak and a different type of plant (generally a combustion turbine) on-peak, (3) DPV displaces whatever resource is on the margin during every hour of the year, based on a dispatch analysis.

## ENVIRONMENTAL BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES




Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.

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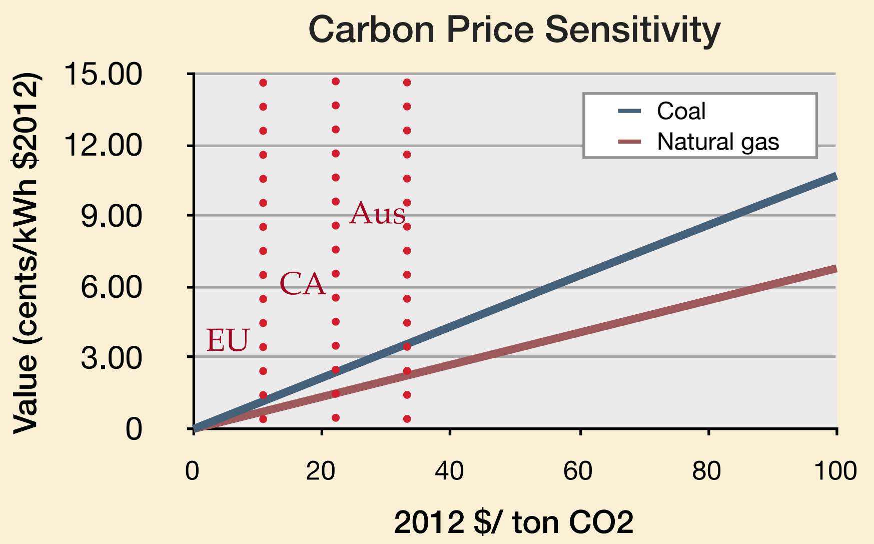
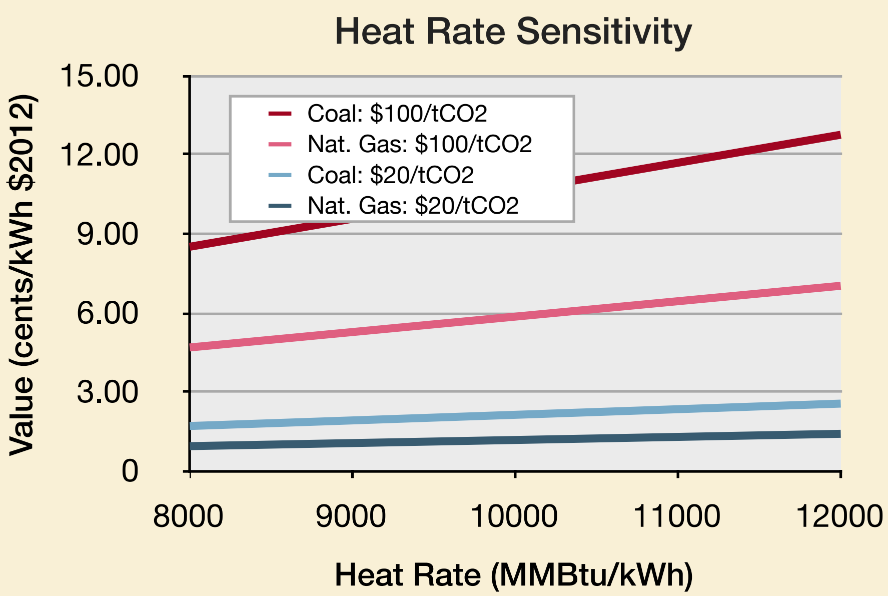
# ENVIRONMENT: CARBON DIOXIDE
(CONT'D)

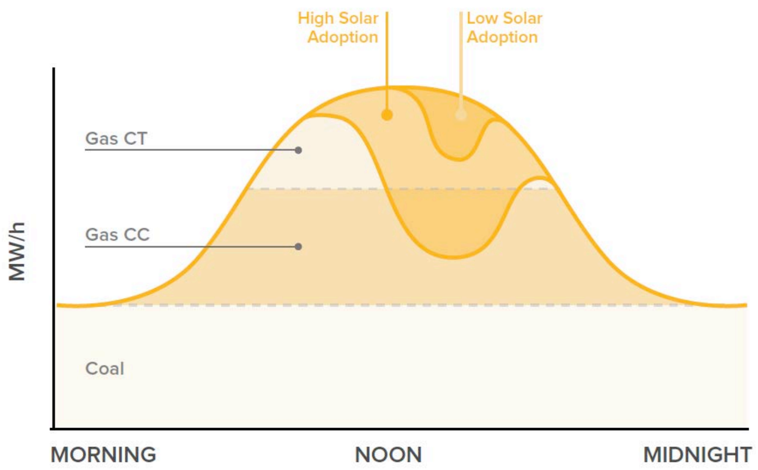
## SENSITIVITY TO KEY INPUT ASSUMPTIONS




## INSIGHTS & IMPLICATIONS

- Just as with energy value, carbon value depends heavily on what the marginal resource is that is being displaced. The same determination of the marginal resource should be used to drive both energy and carbon values.




*The amount of carbon DPV displaces depends on the dispatch order of other resources, when the solar is generated, and how much is generated.*

- While there is little agreement on what the $/ton price of carbon is or should be, it is likely non-zero.

## LOOKING FORWARD

While there has been no federal action on climate over the last few years, leading to greater uncertainty about potential future prices, many states and utilities continue to value carbon as a reflection of assumed benefit. There appears to be increasing likelihood that the U.S. Environmental Protection Agency will take action to limit emissions from coal plants, potentially providing a more concrete indicator of price.

# ENVIRONMENT: OTHER FACTORS

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In addition to carbon, DPV has several other environmental benefits (or potentially costs) that, while commonly acknowledged, are included in only a few of the studies reviewed here. That said, there is a significant body of thought for each outside the realm of DPV cost/benefit valuation, some of which is referenced below.

## CRITERIA AIR POLLUTANTS

**SUMMARY:** Criteria air pollutants ($NO_X$, $SO_2$, and particulate matter) released from the burning of fossil fuels can produce both health and ecosystem damages. The economic cost of these pollutants is generally estimated as:

1. The compliance costs of reducing pollutant emissions from power plants, or the added compliance costs to further decrease emissions beyond some baseline standard; and/or

2. The estimated cost of damages, such as medical expenses for asthma patients or the value of mortality risk, which attempts to measure willingness to pay for a small reduction in risk of dying due to air pollution.

**VALUE:** Crossborder (AZ) 2013 estimated the value of criteria air pollutant reductions, based on APS's Integrated Resource Plan, as $0.365/MWh, and NREL 2008 as $0.2-14/MWh (2012$). CPR (NJ/PA) 2012 and AE/CPR 2012 also acknowledged criteria air pollutants, but estimate cost based on a combined environmental value.

**RESOURCES:**

Epstein, P., Buonocore, J., Eckerle, K. et al., *Full Cost Accounting for the Life Cycle of Coal*, 2011.

Muller, N., Mendelsohn, R., Nordhaus, W., *Environmental Accounting for Pollution in the US Economy.* American Economic Review 101, Aug. 2011. pp. 1649 - 1675.

National Research Council. *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use,* 2010.

## AVOIDED RENEWABLE PORTFOLIO STANDARD (RPS)

**SUMMARY:** Investments in DPV can help the utility meet a state Renewable Portfolio Standards (RPS) / Renewable Energy Standards (RES) in two ways:

1. As DPV is installed and energy use from central generation correspondingly decreases, the amount of renewable energy the utility is required to purchase to meet an RPS/RES decreases.

2. Depending on the RPS/RES requirements, customer investment in DPV can translate into direct investments in renewables that utilities do have to make if they are able to receive credit, such as through Renewable Energy Certificates (RECs).

**VALUE:** Crossborder (AZ) 2013 estimated the avoided RPS cost, based on the difference between the revenue requirements for a base scenario and a high renewables scenario in APS's Integrated Resource Plan, as $45/MWh. Crossborder (CA) estimated the avoided RPS cost, based on the cost difference forecast between RPS-eligible resources and the wholesale market prices, at $50/MWh.

**RESOURCES:**

Beach, R., McGuire, P., *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service.* Crossborder Energy May, 2013.

Beach, R., McGuire, P., *Evaluating the Benefits and Costs of Net Energy Metering for Residential Customers in California.* Crossborder Energy, Jan. 2013.

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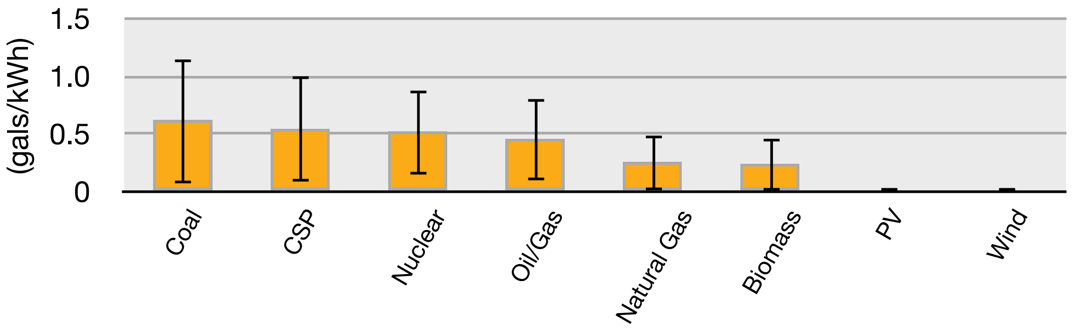
# ENVIRONMENT: OTHER FACTORS

In addition to carbon, DPV has several other environmental benefits (or potentially costs) that, while commonly acknowledged, are included in only a few of the studies reviewed here. That said, there is a significant body of thought for each outside the realm of DPV cost/benefit valuation, some of which is referenced below.

## WATER

**SUMMARY:** Coal and natural gas power plants withdraw and consume water primarily for cooling. Approaches to valuing reduced water usage have focused on the cost or value of water in competing sectors, potentially including municipal, agricultural, and environmental/recreational uses.

**WATER CONSUMPTION BY TECHNOLOGY**




*Source: Fthenakis*

**VALUE:** The only study reviewed that explicitly values water reduction is Crossborder (AZ) 2013, which estimates a $1.084/MWh value based on APS's Integrated Resource Plan.

### RESOURCES:

Tellinghulsen, S., *Every Drop Counts.* Western Resources Advocates, Jan. 2011.

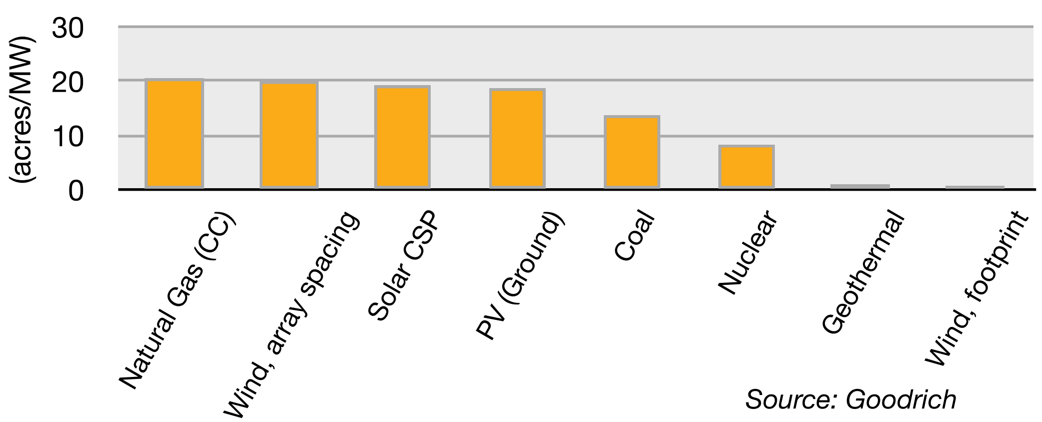
Fthenakis, V., Hyungl, C., *Life-cycle Use of Water in U.S. Electricity Generation.* Renewable and Sustainable Energy Review 14, Sept. 2010. pp.2039-2048.

## LAND

**SUMMARY:** DPV can impact land in three ways:

1) Change in property value with the addition of DPV,
2) Land requirement for DPV installation, or
3) Ecosystem impacts of DPV installation.

**LIFE-CYCLE LAND USE BY TECHNOLOGY**




*Source: Goodrich*

**VALUE:** None of the studies reviewed explicitly estimate land impacts.

### RESOURCES:

*Goodrich et al. Residential, Commercial, and Utility Scale Photovoltaic (V) System Prices in the United States: Current Drivers and Cost-Reduction Opportunities. NREL. February 2012. Pages 14, 23—28*

# SOCIAL: ECONOMIC DEVELOPMENT

## VALUE OVERVIEW

The assumed social value from DPV is based on any job and economic growth benefits that DPV brings to the economy, including jobs and higher tax revenue. The value of economic development depends on number of jobs created or displaced, as measured by a job multiplier, as well as the value of each job, as measured by average salary and/or tax revenue.

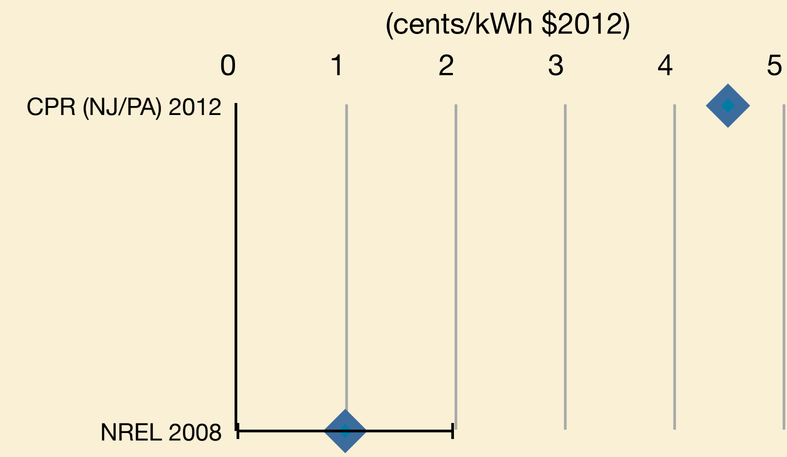
## APPROACH OVERVIEW

Very few studies reviewed quantify employment and tax revenue value, although a number of them acknowledge the value. CPR (NJ/PN) 2012 calculated job impact based on enhanced tax revenues associated with the net job creation for solar vs conventional power resources. The 2011 study included increased tax revenue, decreased unemployment, and increased confidence for business development economic growth benefits, but only quantified the tax revenue benefit.

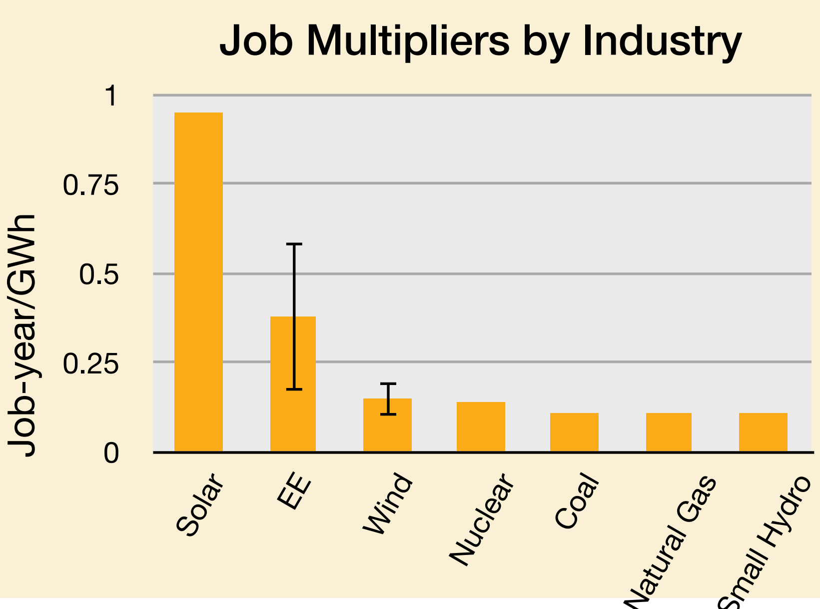
## IMPLICATIONS AND INSIGHTS

- There is significant variability in the range of job multipliers.
- Many of the jobs created from PV, particularly those associated with installation, are local, so there can be value to society and local communities from growth in quantity and quality of jobs available. The locations where jobs are created are likely not the same as where jobs are lost. While there could be a net benefit to society, some regions could bear a net cost from the transition in the job market.
- While employment and tax revenues have not generally been quantified in studies reviewed, E3 2011 recommends an input-output modeling approach as an adequate representation of this value.

## ECONOMIC DEVELOPMENT BENEFIT AND COST ESTIMATES AS REPORTED BY REVIEWED STUDIES




Note: Benefits and costs are reflected separately in chart. If only benefits are shown, study did not represent costs.




Sources: Wei, 2010

## RESOURCES:

*Wei, M., Patadia, S., and Kammen, D., Putting Renewables and Energy Efficiency to Work: How Many Jobs Can the Energy Industry Generate in the US? Energy Policy 38, 2010. pp. 919-931.*

*Brookings Institute, Sizing the Clean Economy: A National and Regional Green Jobs Assessment, 2011.*

# STUDY OVERVIEWS

04

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# SECTION STRUCTURE

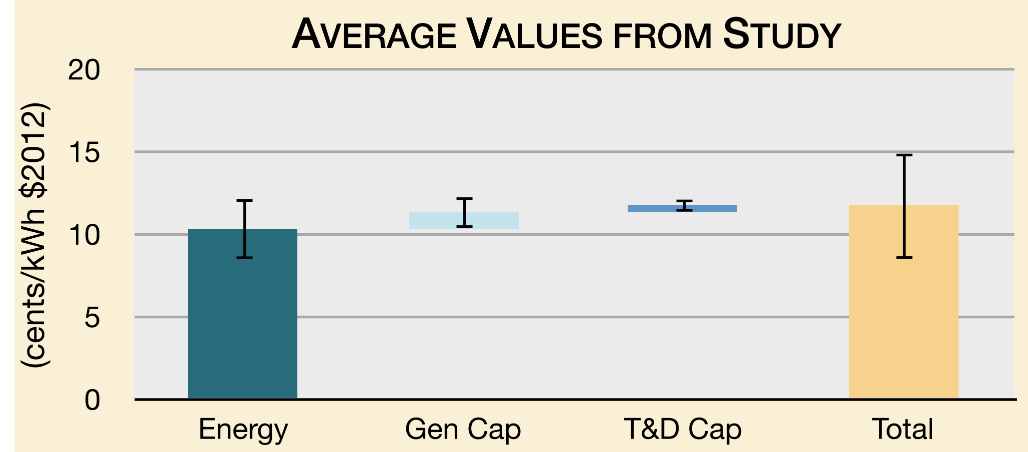
## KEY COMPONENTS INCLUDED IN EACH STUDY OVERVIEW

| STUDY CHARACTERISTICS | |
|---|---|
| STUDY OBJECTIVE | *A brief overview of the stated purpose of the study* |
| GEOGRAPHIC FOCUS | *Geographic region analyzed* |
| SYSTEM CONTEXT | *Relevant characteristics of the electricity system analyzed* |
| LEVEL OF SOLAR ANALYZED | *Solar penetrations analyzed, by energy or capacity* |
| STAKEHOLDER PERSPECTIVE | *Stakeholder perspectives analyzed (e.g., participant, ratepayer, society)* |
| GRANULARITY OF ANALYSIS | *Level of granularity reflected in the analysis as defined by:*<br>*● Solar characterization - How the solar generation profile is established (e.g., actual insolation data v. modeled, time correlated to load)*<br>*● Marginal resource/losses characterization - Whether the marginal resources and losses are calculated on a marginal hourly basis v. average*<br>*● Geographic granularity - Approach to estimating locationally-dependent benefits or costs (e.g., distribution feeders)* |
| TOOLS USED | *Key modeling tools used in the analysis* |

### Highlights

*The Highlights section includes key observations about the study's approach, key drivers of results, and findings.*

### OVERVIEW OF VALUE CATEGORIES




*The chart above depicts the average values by category explored in each study.*

*The Overview of Value Categories section includes brief assessments of the study's approach, relevant assumptions, and findings for each value category included.*

# RW BECK FOR ARIZONA PUBLIC SERVICE, 2009
## DISTRIBUTED RENEWABLE ENERGY OPERATING IMPACTS & VALUATION STUDY

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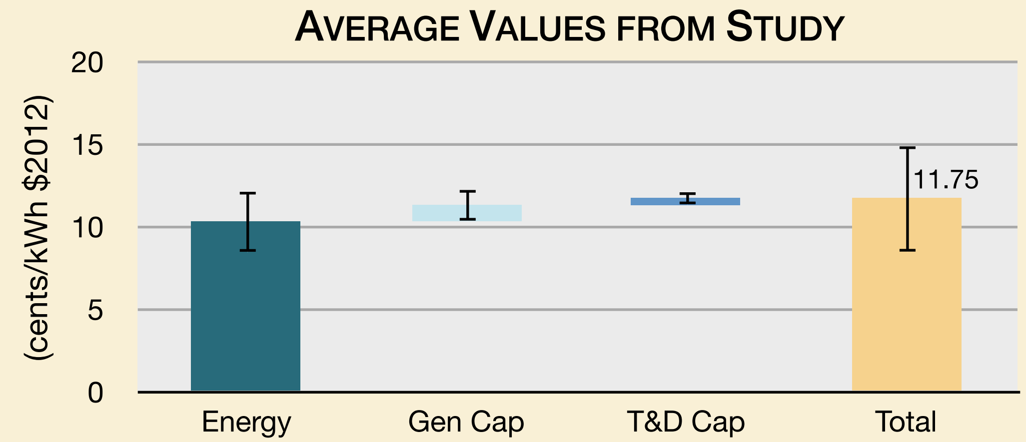
| STUDY CHARACTERISTICS | |
|---|---|
| STUDY OBJECTIVE | To determine the potential value of DPV for Arizona Public Service, and to understand the likely operating impacts. |
| GEOGRAPHIC FOCUS | Arizona Public Service territory |
| SYSTEM CONTEXT | Vertically integrated IOU, 15% RPS by 2025 with 30% distributed resource carveout |
| LEVEL OF SOLAR ANALYZED | 0-16% by 2025 (by energy) |
| STAKEHOLDER PERSPECTIVE | Ratepayers |
| GRANULARITY OF ANALYSIS | • Solar characterization - Hourly TMY data, determined to be good approximation of calendar year data in a comparison<br>• Marginal resource/losses characterization - Calculated based on hourly PROMOD simulation; theoretical hourly loss analysis; actual APS investment plan<br>• Geographic granularity - Screening analysis of specific feeders; example constrained area and greenfield area analyzed |
| TOOLS USED | SAM 2.0; ABB's Feeder-All; EPRI's Distribution System Simulator; PROMOD |

### Highlights

- Value was measured incrementally in 2010, 2015, and 2025. The study approach combined system modeling, empirical testing, and information review, and represents one of the more technically rigorous approaches of reviewed studies.
- A key methodological assumption in the study is that generation, transmission, and distribution capacity value can only be given to DPV when it actually defers or avoids a planned investment. The implications are that a certain minimum amount of DPV must be installed in a certain time period (and in a certain location for distribution capacity) to create value.
- The study determines that total value decreases over time, primarily driven by decreasing capacity value. Increasing levels of DPV effectively pushes the system peak to later hours.
- The study acknowledged but did not quantify a number of other values including job creation, a more sustainable environment, carbon reduction, and increased worker productivity.

## OVERVIEW OF VALUE CATEGORIES




**this chart represents the present value of 2025 incremental value, not a levelized cost*

**Energy:** Energy provides the largest source of value to the APS system. Value is calculated based on a PROMOD hourly commitment and dispatch simulation. DPV reduces fuel, purchased power requirements, line losses, and fixed O&M. The natural gas price forecast is based on NYMEX forward prices with adjustment for delivery to APS's system.

**Generation Capacity**: There is little, but some, generation capacity value. Generation capacity value does not differ based on the geographic location of solar, but generation capacity investments are "lumpy", so a significant amount of solar is needed to displace it.

Capacity value includes benefits from reduced losses. Capacity value is determined by comparing DPV's dependable capacity (determined as the ELCC) to APS's generation investment plan.

**T&D Capacity:** There is very little distribution capacity value, and what value exists comes from targeting specific feeders. Solar generation peaks earlier in the day than the system's peak load, DPV only has value if it is on a feeder that is facing an overloaded condition, and DPV's dependable capacity diminishes as solar penetration increases. Distribution value includes capacity, extension of service life, reduction in equipment sizing, and system performance issues.

There is little, but some, transmission capacity value since value does not differ based on the geographic location of solar, but transmission investments are "lumpy", so a significant amount of solar is needed to displaced it. Transmission value includes capacity and potential detrimental impacts to transient stability and spinning resources (i.e., ancillary services).

T&D capacity value includes benefits from reduced losses, modeled with a combination of hourly system-wide and feeder-specific modeling. T&D capacity value is determined by comparing DPV's dependable capacity to APS's T&D investment plan. For T&D, as compared to generation, dependable capacity is determined as the level of solar output that will occur with 90% confidence during the daily five hours of peak during summer months.

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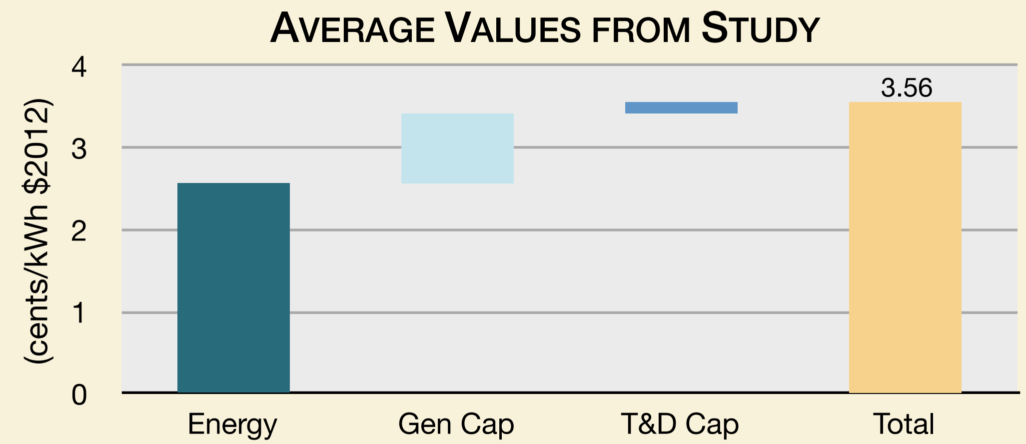
# SAIC for Arizona Public Service, 2013
## *2013 Updated Solar PV Value Report*

| Study Characteristics | |
|---|---|
| STUDY OBJECTIVE | To update the valuation of future DPV systems in the Arizona Public Service (APS) territory installed after 2012. |
| GEOGRAPHIC FOCUS | Arizona Public Service territory |
| SYSTEM CONTEXT | Vertically integrated IOU, 15% RPS by 2025 with 30% distributed resource carve out, peak extends past sunset |
| LEVEL OF SOLAR ANALYZED | 4.5-16% by 2025 (by energy) |
| STAKEHOLDER PERSPECTIVE | Ratepayers |
| GRANULARITY OF ANALYSIS | • Solar characterization - Hourly 30-year TMY data; coupled with production characteristics of actual installed systems<br>• Marginal resource/losses characterization - Calculated based on hourly PROMOD simulation and APS investment plan as in 2009 study; average energy loss and system peak demand loss factors as recorded by APS<br>• Geographic granularity - Screening analysis of existing feeders with >10% PV; based on that, determination of number of feeders where PV could reduce peak load from above 90% to below 90% |
| TOOLS USED | PVWatts; EPRI's DSS Distribution Feeder Model; PROMOD |

### Highlights

- Value was measured incrementally in 2015, 2020, and 2025.
- DPV provides less value than in APS's 2009 study, due to changing power market and system conditions. Energy generation and wholesale purchase costs have decreased due to lower natural gas prices. Expected $CO_2$ costs are significantly lower due to decreased likelihood of federal legislation. Load forecasts are lower, meaning reduced generation, distribution and transmission capacity requirements.
- The study notes the potential for increased value (primarily in T&D capacity) if DPV can be geographically targeted in sufficient quantities. However, it notes that actual deployment since the 2009 study does not show significant clustering or targeting.
- Like the 2009 study, capacity value is assumed to be based on DPV's ability to defer planned investments, rather than assuming every installed unit of DPV defers capacity.

## OVERVIEW OF VALUE CATEGORIES




**this chart represents the present value of 2025 incremental value, not a levelized cost*

**Energy:** Energy provides the largest source of value to the APS system. Value is calculated based on a PROMOD hourly commitment and dispatch simulation. DPV reduces fuel, purchased power requirements, line losses, and fixed O&M. The natural gas price forecast is based on NYMEX forward prices with adjustment for delivery to APS's system. Energy losses are included as part of energy value, and unlike the 2009 report, are based on a recorded average energy loss.

**Generation Capacity**: Generation capacity value is highly dependent on DPV's dependable capacity during peak. Generation capacity value is based on PROMOD simulations, and results in the deferral of combustion turbines. Benefits from avoided energy losses are included as part of capacity value, and unlike the 2009 report, are based on a recorded peak demand loss. Like the 2009 study, generation capacity value is based on an ELCC calculation.

**T&D Capacity:** The study concludes that there are an insufficient number of feeders that can defer capacity upgrades based on non-targeted solar PV installations to determine measurable capacity savings. Distribution capacity savings can only be realized if distributed solar systems are installed at adequate penetration levels and located on specific feeders to relieve congestion or delay specific projects, but solar adoption has been geographically dispersed. Distribution value includes reduced losses, capacity, extended service life, and reduced equipment sizing.

Transmission capacity value is highly dependent on DPV's dependable capacity during peak. No transmission projects can be deferred more than one year, and none past the target years. As with the 2009 study, DPV dependable capacity for the purposes of T&D benefits is calculated based on a 90% confidence of generation during peak summer hours. Benefits from avoided energy losses are included.

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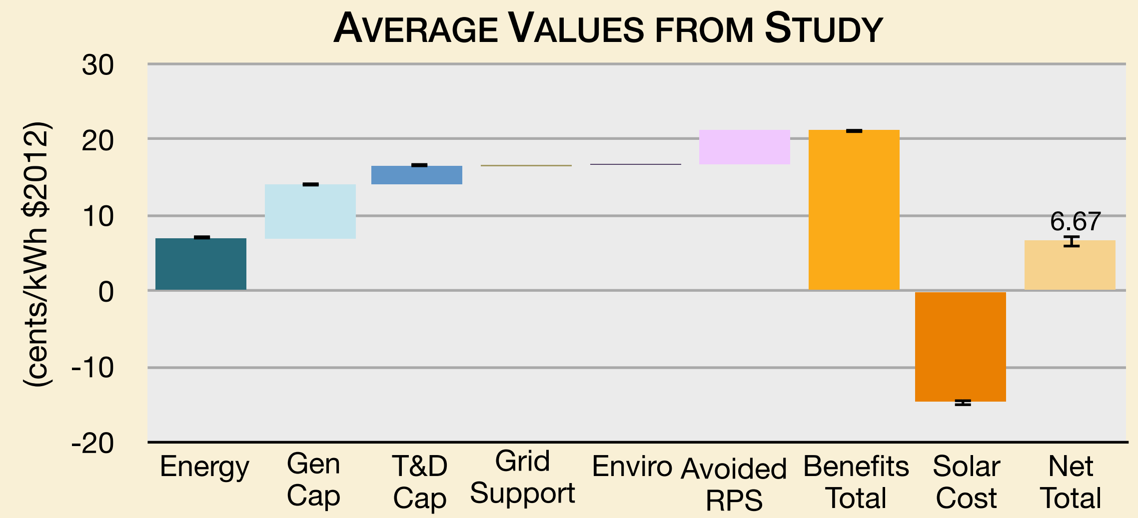
# CROSSBORDER ENERGY, 2013
## *THE BENEFITS AND COSTS OF SOLAR DISTRIBUTED GENERATION FOR ARIZONA PUBLIC SERVICE*

| STUDY CHARACTERISTICS | |
|---|---|
| STUDY OBJECTIVE | To determine how demand-side solar will impact APS's ratepayers; a response to the APS 2013 study. |
| GEOGRAPHIC FOCUS | Arizona Public Service territory |
| SYSTEM CONTEXT | Vertically integrated IOU, 15% RPS by 2025 |
| LEVEL OF SOLAR ANALYZED | DPV likely to be installed between 2013-2015; estimated here to be approximately 1.5% |
| STAKEHOLDER PERSPECTIVE | Ratepayers |
| GRANULARITY OF ANALYSIS | • Solar characterization - Not stated<br>• Marginal resource/losses characterization - For energy, expected operating cost of a CT in peak months and CC in non-peak months; for capacity, fixed costs of a CT; marginal line loss factor from APS 2009<br>• Geographic granularity - Assumption that distribution investment can be deferred on 50% of feeders, based on APS 2009 conclusion that 50% of feeders show potential for reducing peak demand |
| TOOLS USED | Secondary analysis based on SAIC and APS detailed modeling |

### Highlights

- The benefits of DPV on the APS system exceed the cost by more than 50%. Key methodological differences between this study and the APS 2009 and 2013 studies include:
    - Determining value levelized over 20 years, as compared to incremental value in test years.
    - Crediting capacity value to every unit of solar DG installed, rather than requiring solar DG to be installed in "lumpy" increments.
    - Using ELCC to determine dependable capacity for generation, transmission, and distribution capacity values, as compared to using ELCC for generation capacity and a 90% confidence during peak summer hours for T&D capacity.
    - Focusing on solar installed over next few years years, rather than examining whether there is diminishing value with increasing penetration.
- The study notes that DPV must be considered in the context of efficiency and demand response—together they defer generation, transmission, and distribution capacity until 2017.

## OVERVIEW OF VALUE CATEGORIES




**Energy:** Avoided energy costs are the most significant source of value. APS's long-term marginal resource is assumed to be a combustion turbine in peak months and a combined cycle in off-peak months, and avoided energy is based on these resources. The natural gas price forecast is based on NYMEX forward market gas prices, and the study determines that it adequately captures the fuel price hedge benefit. Key assumptions: $15/ton carbon adder, 12.1% line losses included in the energy value.

**Generation Capacity**: Generation capacity value is calculated as DPV dependable capacity (based on DPV's near-term ELCC from APS's 2012 IRP) times the fixed costs of a gas combustion turbine. Every installed unit of DPV receives that capacity value, based on the assumption that, when coupled with efficiency and demand response, capacity would have otherwise been needed before APS's planned investment.

**T&D Capacity:** T&D capacity value is calculated as DPV dependable capacity (ELCC) times APS's reported costs of T&D investments. Like generation capacity, every installed unit is credited with T&D capacity, with the assumption that 50% of distribution feeders can see deferral benefit. The study notes that APS could take a proactive approach to targeting DPV deployment, thereby increasing distribution value.

**Grid Support (Ancillary Services):** DPV in effect reduces load and therefore reduces the need for ancillary services that would otherwise be required, including spinning, non-spinning, and capacity reserves.

**Environmental:** DPV effectively reduces load and therefore reduces environmental impacts that would otherwise be incurred. Lower load means reduced criteria air pollutant emissions and lower water use (carbon is included as an adder to energy value).

**Renewable Value:** DPV helps APS meet its Renewable Energy Standard, thereby lowering APS's compliance costs.

**Solar Cost:** Since the study takes a ratepayer perspective, costs included are lost retail rate revenues, incentive payments, and integration costs.

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# XCEL ENERGY FOR PUBLIC SERVICE COMPANY OF COLORADO, 2013
## *COSTS AND BENEFITS OF DISTRIBUTED SOLAR GENERATION ON THE PUBLIC SERVICE COMPANY OF COLORADO SYSTEM*

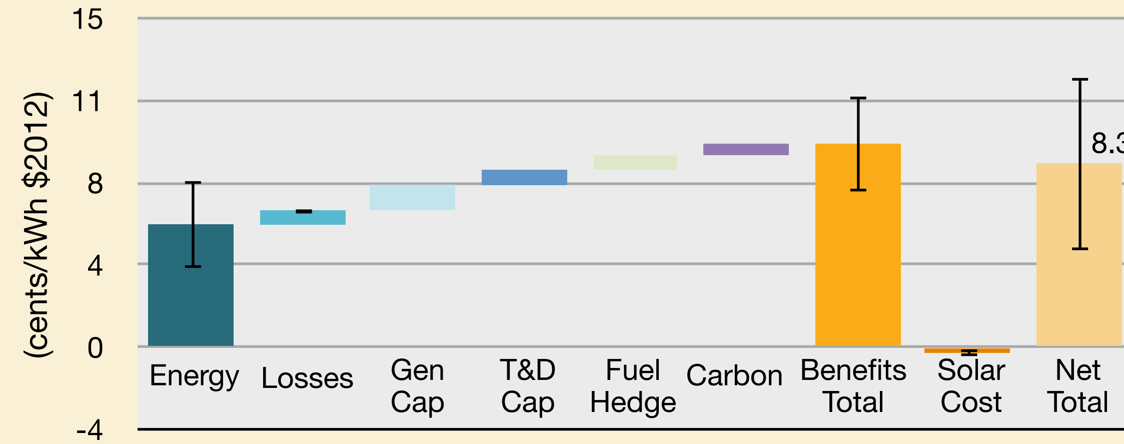
| STUDY CHARACTERISTICS | |
|---|---|
| STUDY OBJECTIVE | To determine the costs and benefits of DPV on the Public Service Company of Colorado's electric power supply system at current penetration levels and projections for near-term penetration levels. |
| GEOGRAPHIC FOCUS | Public Service Company of Colorado's territory |
| SYSTEM CONTEXT | Vertically integrated IOU, 30% RPS by 2020 (includes DG standard) |
| LEVEL OF SOLAR ANALYZED | 2012 DPV solar capacity: 59 MW; Est penetration in 2014: 140 MW installed by 2014 |
| STAKEHOLDER PERSPECTIVE | System (excludes participant expenses (PV cost), solar program administration costs, or program incentive payments) |
| GRANULARITY OF ANALYSIS | • Solar characterization - Single TMY2 hourly generation profile weighted to represent entire 59 MW of DPV on PSCO's system used to calculate avoided energy costs & certain components of distribution system analysis; Historical meter data from 9 PV systems in 2009, 14 systems in 2010 (each >250 kW) used to estimate DPV capacity credit<br>• Marginal resource/losses characterization - Calculated based on hourly PROMOD simulation; theoretical hourly loss analysis<br>• Geographic granularity - Hourly feeder level data from small subset of feeders extrapolated to system |
| TOOLS USED | ProSym; NREL's TMY2 data sets using PV Watts |

## Highlights

- The study concludes that the most significant avoided cost from DPV (>90%) is from avoided energy costs.
- Energy value was calculated by comparing ProSym simulations with and without DPV, and the results were highly sensitive to assumed natural gas price forecasts. To estimate annual avoided energy costs, ProSym modeling used a single TMY2 generation profile (weighted by distribution of PV across PSCO's system), which was non-serially correlated with system load data.
- For the study, Xcel updated its ELCC calculations that are used to estimate capacity credit for DPV. In comparison to its previous 2009 ELCC study, the updated capacity credit for DPV across the four solar zones used is roughly 30% lower. The capacity credits range from 27%-32% for fixed installations and 40%-46% for tracking PV.

## OVERVIEW OF VALUE CATEGORIES

### AVERAGE VALUES FROM STUDY




**Energy:** Costs are calculated on a marginal basis using ProSym hourly commitment and dispatch simulation using the TMY2 data set. The variable costs include fuel, variable O&M, and generation unit start costs. ProSym simulation implies DPV tends to primarily displace generation that is blend of an efficient CC unit (7 MMBtu/MWh) and a less efficient CT (10 MMBtu/MWh) through 2035. It is noted that, through 2017, DPV displaces a mix of gas-fired and coal-fired generation (before coal is retired in 2017).

**System Losses:** Avoided T&D lines losses were assumed to achieve savings in energy, emissions, fuel hedge value and generation capacity. Distribution line losses were estimated using actual hourly feeder load data for the 58 feeders that represent 55% of DPV generation, and using an estimated value for the remainder. Average distribution losses were used to estimate savings from energy, emission & hedge value, and on a peak basis for generation capacity. Transmission line losses, based on annual, DPV generation-weighted values, were used to calculate energy, emissions, and hedge value, whereas avoided generation capacity was based on losses incurred across top 50 load hours.

**Generation Capacity:** Avoided generation capacity costs are based on the market price of capacity until 2017, and after that (because of incremental need) based on the economic carrying charge of a generic CT's capital and fixed O&M costs. The avoided generation capacity cost is credited to DPV based on a ELCC study (historical system load and solar generation patterns for 2009 and 2010).

**T&D Capacity:** DPV is assumed to defer distribution feeder capital investment by 1 to 2 years only if the existing feeder's peak load is at or near the feeder's capacity and the feeder's peak load is decreased by ~10%.

**Fuel Price Hedge Value:** While the study notes the approach taken in other benefit/ cost studies to estimate fuel price hedge value from NYMEX fuel price forecasts, it is not explicitly stated how the fuel price hedge was ultimately estimated.

**Carbon:** Annual tons of $CO_2$ emissions avoided by DPV as calculated by the ProSym avoided cost case simulations. Change in marginal emissions over time driven by planned changes in generation fleet (primarily retirement of 1,300 MW coal in 2017).

**Solar Cost:** Defined as "Integration Costs," or "costs that DPV adds to the overall cost of operating the Public Service power supply system based on inefficiencies that arise when the actual net load differs from the day-ahead forecasted net load." These costs are composed of electricity production costs levelized over 20 years.

# ENERGY AND ENVIRONMENTAL ECONOMICS, INC. (E3), 2011
# *CALIFORNIA SOLAR INITIATIVE COST-EFFECTIVENESS EVALUATION*



| STUDY CHARACTERISTICS | |
|---|---|
| STUDY OBJECTIVE | "To perform a cost-effectiveness evaluation of the California Solar Initiative (CSI) in accordance with the CSI Program Evaluation Plan." |
| GEOGRAPHIC FOCUS | California |
| SYSTEM CONTEXT | Study: CSI program, retail net metering<br>CA: 33% RPS, ISO market |
| LEVEL OF SOLAR ANALYZED | 1,940 MW program goal (<1% of 2016 peak load) |
| STAKEHOLDER PERSPECTIVE | Participants (DPV customers), Ratepayers, Program Administrator, Total Resource, Society |
| GRANULARITY OF ANALYSIS | • Solar characterization - Hourly PV output profiles based on metered and simulated PV output data<br>• Marginal resource/losses characterization - Energy: historical hourly day-ahead market price shapes (CAISO); Capacity: fixed cost of a new CT less net energy, AS revenues (see Overview box); Energy loss factors by TOU period, season; Capacity loss factors at peak periods<br>• Geographic granularity - Major climate zones for each IOU; costs from utility rate case filings used as proxy for long-run marginal cost T&D investment avoided |
| TOOLS USED | E3 Avoided Cost Calculator (2011) |

## Highlights

- The study concludes that DPV is not expected to be cost-effective from a total resource or rate impact perspective during the study period, but that participant economics will not hinder CSI adoption goals. Program incentives support participant economics in the short-run, but DPV is expected to be cost-effective for many residential customers without program incentives by 2017. The study suggests that the value of non-economic benefits of DPV should be explored to determine if and how they provide value to California.

- The study focuses on seven benefits including energy, line losses, generation capacity, T&D capacity, emissions, ancillary services, and avoided RPS purchases. It focuses on costs including net energy metering bill credits, rebates/incentives, utility interconnection, costs of the DG system, net metering costs, and program administration.

- The study assesses hourly avoided costs in each of California's 16 climate zones to reflect varying costs in those zones, and calculates benefits and costs as 20-year levelized values. It uses E3's avoided cost model.

## OVERVIEW OF VALUE CATEGORIES

*This study assesses overall cost-effectiveness based on five cost tests (participant cost test, ratepayer impact measure, program administrator cost, total resource cost, and societal cost) as defined in the California Standard Practices Manual, and presents total rather than itemized results. Therefore, individual results are not shown here in a chart.*

**Energy:** Hourly wholesale value of energy measured at the point of wholesale energy transaction. Natural gas price is based on NYMEX forward market and then on a long-run forecast of natural gas prices.

**System Losses:** Losses between the delivery location and the point of wholesale energy transaction. Losses scale with energy value, and reflect changing losses at peak periods.

**Generation Capacity:** Value of avoiding new generation capacity (assumed to be a gas combustion turbine) to meet system peak loads, including additional capacity avoided due to decreased energy losses. DPV receives the full value of avoided capacity after the resource balance year. Value is less in the short-run (before the resource balance year) because of CAISO's substantial planning reserve margin.

**T&D Capacity:** Value of deferring T&D capacity to meet peak loads.

**Grid Support Services (Ancillary Services):** Value based on historical ancillary services market prices, scaled with the price of natural gas. Individual ancillary services included are regulation up, regulation down, spinning reserves, and non-spinning reserves, and value is based on how a load reduction affects the procurement of each AS.

**Avoided RPS:** Value is the incremental avoided cost of purchasing renewable resources to meet California's RPS.

**Environmental:** Value of $CO_2$ reduction, with $/ton price based on a meta-analysis of forecasts. Unpriced externalities (primarily health effects) were valued at $0.01-0.03/kWh based on secondary sources.

**Social:** The study acknowledges that customers who install DPV may also install more energy efficiency, but does not attempt to quantify that value. The study also acknowledges potential benefits associated with employment and tax revenues and suggests that an input-output model would be an appropriate approach, although these benefits are not quantified in this study.

# ENERGY AND ENVIRONMENTAL ECONOMICS, INC. (E3), 2012
## *TECHNICAL POTENTIAL FOR LOCAL DISTRIBUTED PHOTOVOLTAICS IN CALIFORNIA*

Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

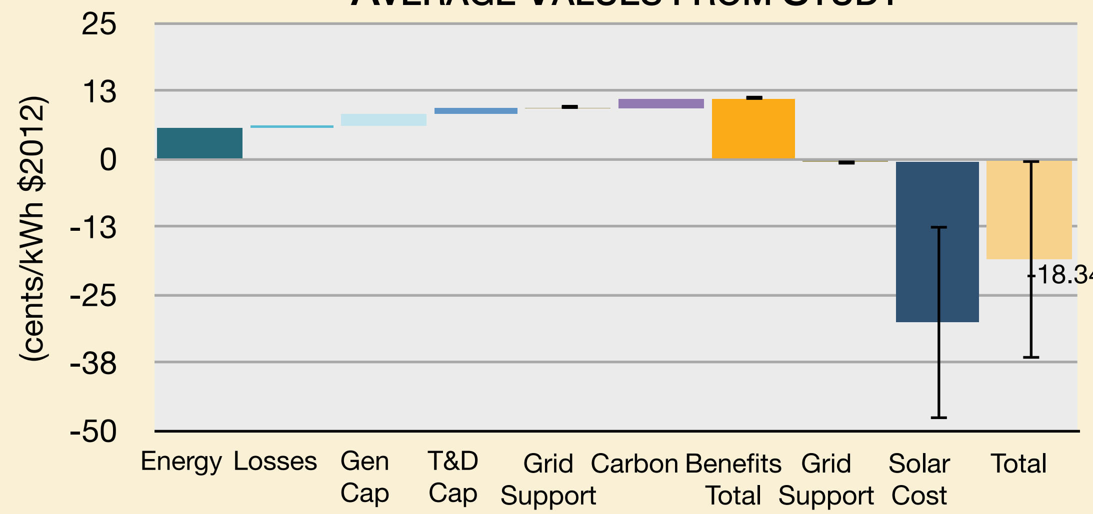
| STUDY CHARACTERISTICS | |
|---|---|
| STUDY OBJECTIVE | To estimate the technical potential of local DPV in California, and the associated costs and benefits. |
| GEOGRAPHIC FOCUS | California |
| SYSTEM CONTEXT | California's 3 investor-owned utilities (IOU): PG&E, SDG&E, SCE |
| LEVEL OF SOLAR ANALYZED | < 24% system peak load |
| STAKEHOLDER PERSPECTIVE | Total resource cost (TRC) |
| GRANULARITY OF ANALYSIS | • Solar characterization - Simulated hourly PV output for each configuration (horizontal, fixed tilt, tracking) for each substation based on 2010 weather<br>• Marginal resource/losses characterization - Energy: historical hourly day-ahead market price shapes (CAISO); Capacity: fixed cost of a new CT less net energy, AS revenues (see Overview box); Energy loss factors by TOU period, season; Capacity loss factors at peak periods<br>• Geographic granularity - Compared hourly load at the individual substation level to potential PV generation at the same location at 1,800 substations |
| TOOLS USED | E3 Avoided Cost Calculator |

### Highlights

- Local DPV is defined as PV sized such that its output will be consumed by load on the feeder or substation where it is interconnected. Specifically, the generation cannot backflow from the distribution system onto the transmission system.
- The process for identifying sites included using GIS data to identify sites surrounding each of approximately 1,800 substations in PG&E, SDG&E and SCE. The study compared hourly load that the individual substation level to potential DPV generation at the same location.
- Cost of local distributed DPV increases significantly with Investment Tax Credit (ITC) expiration in 2017.
- When DPV is procured on a least net cost basis, opportunities may exist to locate in areas with high avoided costs. In 2012, a least net cost procurement approach results in net costs that are approximately $65 million lower assuming avoided transmission and distribution costs can be realized. These benefits carry through to 2016 for the most part, but disappear by 2020, when all potential has been realized regardless of cost.

## OVERVIEW OF VALUE CATEGORIES

### AVERAGE VALUES FROM STUDY




**Energy:** Estimate of hourly wholesale value of energy adjusted for losses between the point of wholesale transaction and delivery. Annual forecast based on market forwards that transition to annual average market price needed to cover the fixed and operating costs of a new CCGT, less net revenue from day-ahead energy, ancillary service, and capacity markets. Hourly forecast derived based on historical hourly day-ahead market price shapes from CAISO's MRTU system.

**System Losses:** Losses between the delivery location and the point of wholesale energy transaction. Losses scale with energy value, and reflect changing losses at peak periods.

**Generation Capacity:** In the long-run (after the resource balance year), generation capacity value is based on the fixed cost of a new CT less expected revenues from real-time energy and ancillary services markets. Prior to resource balance, value is based on a resource adequacy value.

**T&D Capacity:** Value is based on the "present worth" approach to calculate deferment value, incorporating investment plans as reported by utilities.

**Grid Support Services (Ancillary Services):** Value based on the value of avoided reserves, scaling with energy.

**Carbon:** Value of $CO_2$ emissions, based on an estimate of the marginal resource and a meta-analysis of forecasted carbon prices.

**Solar Cost -**The installed system cost, the cost of land and permitting, and the interconnection cost

*E3's components of electricity avoided costs include generation energy, line losses, system capacity, ancillary services, T&D capacity, environment.

Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

# CROSSBORDER ENERGY FOR VOTE SOLAR INITIATIVE, 2013

## *EVALUATING THE BENEFITS AND COSTS OF NET ENERGY METERING IN CALIFORNIA*

| STUDY CHARACTERISTICS | |
|---|---|
| STUDY OBJECTIVE | "To explore recent claims from California's investor-owner utilities that the state's NEM policy causes substantial cost shifts between energy customers with Solar PV systems and non-solar customers, particularly in the residential market." |
| GEOGRAPHIC FOCUS | California |
| SYSTEM CONTEXT | 33% RPS, retail net metering, increasing solar penetration, ISO market |
| LEVEL OF SOLAR ANALYZED | Up to 5% of peak (by capacity) |
| STAKEHOLDER PERSPECTIVE | Ratepayers |
| GRANULARITY OF ANALYSIS | • Solar characterization - Used PVWatts to produce hourly PV outputs at representative locations<br>• Marginal resource/losses characterization - Based on E3 avoided cost model (Sept 2011), which determines hourly energy market values and capacity based on CT (since resource balance year not used in this study)<br>• Geographic granularity - Major climate zones for each IOU; costs from utility rate case filings used as proxy for long-run marginal cost T&D investment avoided |
| TOOLS USED | E3 Avoided Cost Calculator (2011), PVWatts |

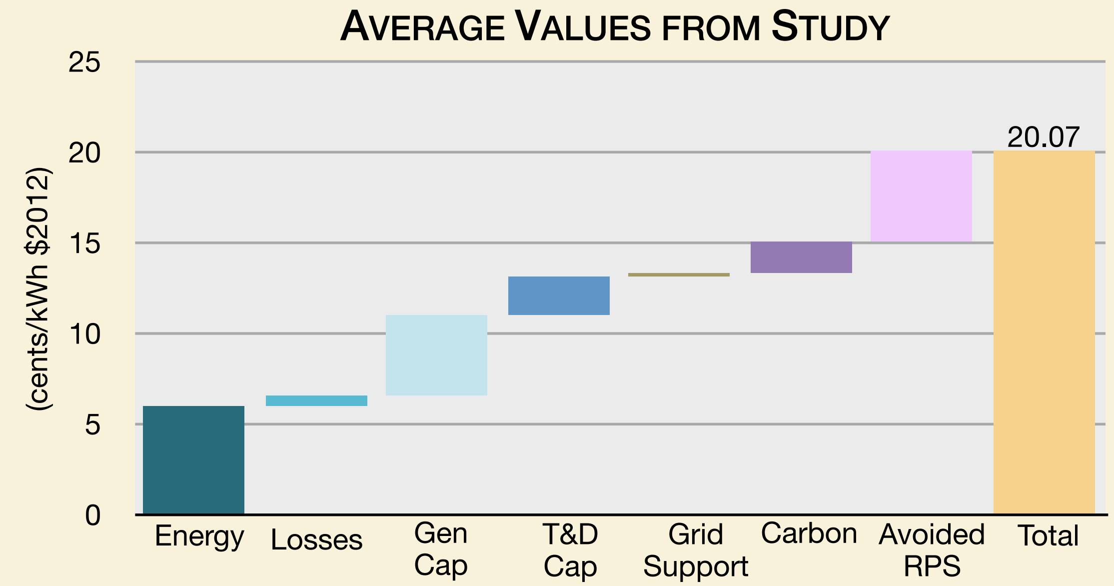
### Highlights

- The study concludes that "on average over the residential markets of the state's three big IOUs, NEM does not impose costs on non-participating ratepayers, and instead creates a small net benefit." This conclusion is driven by "recent significant changes that the CPUC has adopted in IOUs' residential rate designs" plus "recognition that [DPV]...avoid other purchases or renewable power, resulting in a significant improvement in the economics of NEM compared to the CPUC's 2009 E3 NEM Study."

- The study focused on seven benefits: avoided energy, avoided generation capacity, reduced cost for ancillary services, lower line losses, reduced T&D investments, avoided RPS purchases, and avoided emissions. The study's analysis reflects costs to other customers (ratepayers) from "bill credits that the utility provides to solar customers as compensation for NEM exports, plus any incremental utility costs to meter and bill NEM customers." These costs are not quantified and levelized individually in the report, so they are not reflected in the chart to the right.

- The study bases its DPV value assessment on E3's avoided cost model and approach. It updates key assumptions including natural gas price forecast, greenhouse gas allowance prices, and ancillary services revenues, and excludes the resource balance year approach (the year in which avoided costs change from short-run to long-run). The study views the resource balance year as inconsistent with the modular, short lead-time nature of DPV. The study only considered the value of the exports to the grid under the utility's NEM program.

## OVERVIEW OF VALUE CATEGORIES




**Energy:** Wholesale value of energy adjusted for losses between the point of the wholesale transaction and the point of delivery. Crossborder adjusted natural gas price forecast and greenhouse gas price forecast.

**System Losses:** The loss in energy from transmission and distribution across distance.

**Generation Capacity:** The cost of building new generation capacity to meet system peak loads. Crossborder does not use E3's "resource balance year" approach, which means that generation capacity value is based on long-run avoided capacity costs.

**T&D Capacity:** The costs of expanding transmission and distribution capacity to meet peak loads.

**Grid Support Services (Ancillary Services):** The marginal cost of providing system operations and reserves for electricity grid reliability. Crossborder updated assumed ancillary services revenues.

**Carbon:** The cost of carbon dioxide emissions associated with the marginal generating resource.

**Avoided RPS:** The avoided net cost of procuring renewable resources to meet an RPS Portfolio that is a percentage of total retail sales due to a reduction in retail loads.

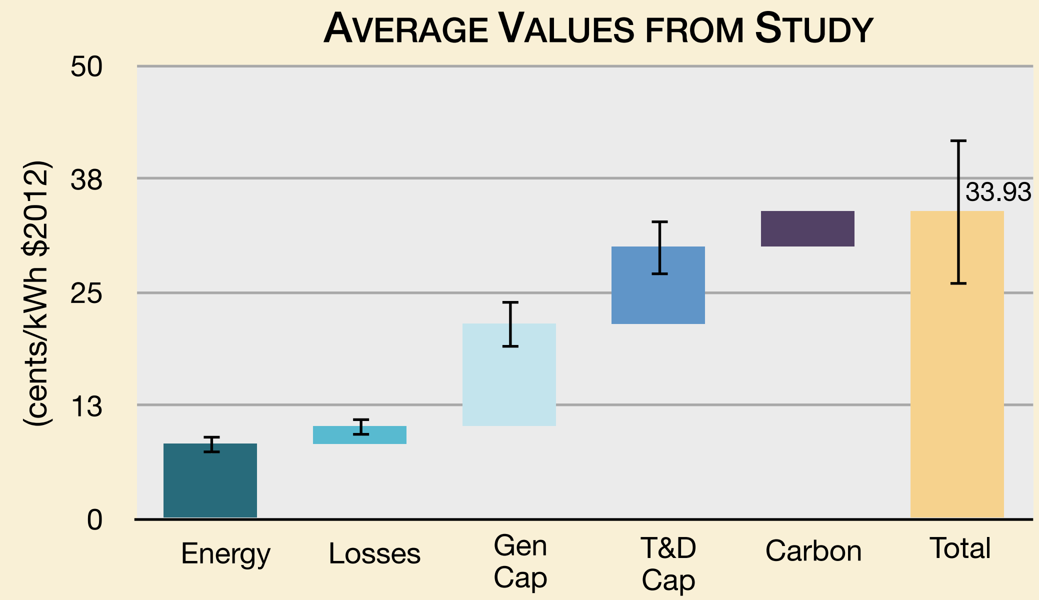
# VOTE SOLAR INITIATIVE, 2005
## *QUANTIFYING THE BENEFITS OF SOLAR POWER FOR CALIFORNIA*

| STUDY CHARACTERISTICS | |
|---|---|
| STUDY OBJECTIVE | To provide a quantitative analysis of key benefits of solar energy for California. |
| GEOGRAPHIC FOCUS | California |
| SYSTEM CONTEXT | California's 3 investor-owned utilities (IOU): PG&E, SDG&E, SCE |
| LEVEL OF SOLAR ANALYZED | Unspecified |
| STAKEHOLDER PERSPECTIVE | Utility, ratepayer, participant, society |
| GRANULARITY OF ANALYSIS | • Solar characterization - Assumed average solar PV ELCC to be 50% from range of 36%-70% derived from NREL study[1]<br>• Marginal resource/losses characterization - Assumed natural gas generation plant on margin both for peak demand and non-peak periods<br>• Geographic granularity - Not considered in this study |
| TOOLS USED | Spreadsheet analysis |

### Highlights

- The study concluded that the value of on-peak solar energy in 2005 ranged from $0.23 - 0.35 /kWh.
- The analysis looks at avoided costs under two alternative scenarios for the year 2005. The two scenarios vary the cost of developing new power plants and the price of natural gas.
  - Scenario 1 assumed new peaking generation will be built by the electric utility at a cost of capital of 9.5% with cost recovery over a 20 year period; the price of natural gas is based on the 2005 summer market price (average gas price)
  - Scenario 2 assumed new peaking generation will be built by a merchant power plant developer at a cost of capital of 15% with cost recovery over a 10 year period; the price of natural gas is based on the average gas price in California for the period of May 2000 through June 2001 (high gas price – 24% higher)
- While numerous unquantifiable benefits were noted, five benefits were quantified:
  1) Deferral of investments in new peaking power capacity
  2) Avoided purchase of natural gas used to produce electricity
  3) Avoided emissions of $CO_2$ and $NO_x$ that impact global climate and local air quality
  4) Reduction in transmission and distribution system power losses
  5) Deferral of transmission and distribution investments that would be needed to meet growing loads.
- The study assumed that, "in California, natural gas is the fuel used by power plants on the margin both for peak demand periods and non-peak periods. Therefore it is reasonable to assume the solar electric facilities will displace the burning of natural gas in all hours that they produce electricity."

### OVERVIEW OF VALUE CATEGORIES




**Energy:** Avoided fuel and variable O&M. Natural gas fuel price multiplied by assumed heat rate of peaking power plant (9360 MMBtu/kWh). Assumed value of consumables such as water and ammonia to be approximately 0.5 cents/ kWh. For non-peak, average heat rates of existing fleet of natural gas plants were used for each electric utility's service area. Assumed heat rates: PG&E: 8740 MMBtu/kWh, SCE - 9690 MMBtu/kWh, SDG&E – 9720 MMbtu/kWh.

**System Losses:** Solar assumed to be delivered at secondary voltage. The summer peak and the summer shoulder loss factors are used to calculate the additional benefit derived from solar power systems because of their location at load.

**Generation Capacity:** Cost of installing a simple cycle gas turbine peaking plant multiplied by DPV's ELCC and a capital recovery factor, converted into costs per kilowatt hour by expected hours of on-peak operation.

**T&D Capacity:** One study area was selected for each utility to calculate the value of solar electricity in avoiding T&D upgrades. To simplify the analysis the need for T&D upgrades was assumed to be driven by growth in demand during 5% of the hours in a year. The 50% ELCC was used used in calculating the value of avoided T&D upgrades.

**Carbon:** Assumed to be the avoided air emissions, $CO_2$ and NOx, created from marginal generator (natural gas). $CO_2$ = $100/ton; NOx = $.014/kWh

1 "Solar Resource-Utility Load-Matching Assessment," Richard Perez, National Renewable Energy Laboratory, 1994

# RICHARD DUKE, ENERGY POLICY, 2005

## *ACCELERATING RESIDENTIAL PV EXPANSION: DEMAND ANALYSIS FOR COMPETITIVE ELECTRICITY MARKETS*

eLab Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

| STUDY CHARACTERISTICS | |
|---|---|
| STUDY OBJECTIVE | To quantify the potential market for grid-connected, residential PV electricity integrated into new houses built in the US. |
| GEOGRAPHIC FOCUS | California and Illinois |
| SYSTEM CONTEXT | California: 33% RPS, mostly gas generation; Illinois: mostly coal generation |
| LEVEL OF SOLAR ANALYZED | not stated; assumed low |
| STAKEHOLDER PERSPECTIVE | System |
| GRANULARITY OF ANALYSIS | • Solar characterization - Single estimated insolation for two states analyzed<br>• Marginal resource/losses characterization - For energy, marginal resource is a natural gas plant in California and a cola plant in Illinois. For capacity, marginal resource is a gas turbine in both states. Losses based on average and peak loss factors estimated in secondary sources.<br>• Geographic granularity - Transmission and distribution system impacts not accounted for since they are site specific |
| TOOLS USED | High level, largely based on secondary analysis |

### Highlights

- Total value varies significantly between the two regions studied largely driven by what the off-peak marginal resource is (gas vs coal). Coal has significantly higher air pollution costs, although lower fuel costs.
- The study notes that true value varies dramatically with local conditions, so precise calculations at a high-level analysis level are impossible. As such, transmission and distribution impacts were acknowledged but not included.

## OVERVIEW OF VALUE CATEGORIES

### AVERAGE VALUES FROM STUDY

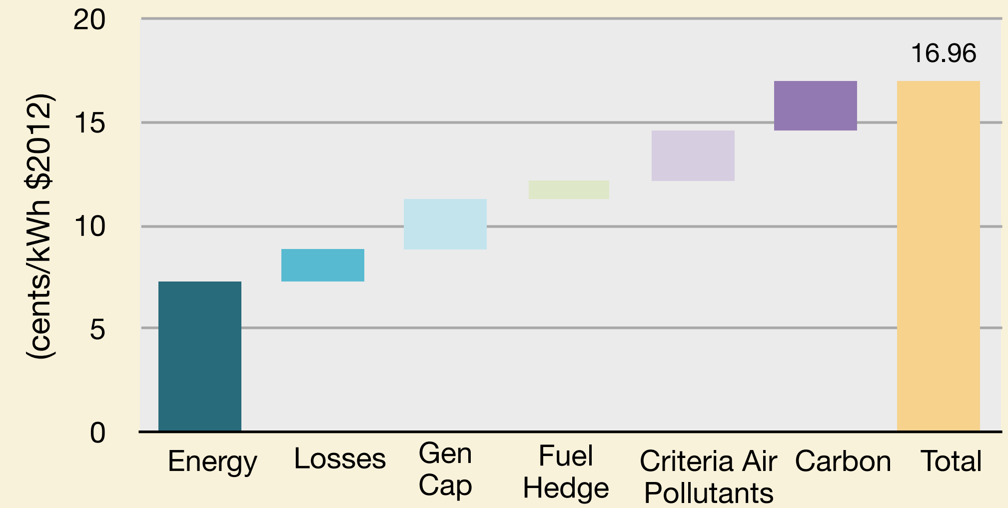



**Chart data only reflects California assessment for comparison*

**Energy:** Energy value is based on the marginal resource on-peak (gas combustion turbine) and off-peak (inefficient gas in California, and coal in Illinois). Fuel prices are based on Energy Information Administration projections, and levelized.

**System Losses:** Energy losses are assumed to be 7-8% off-peak, and up to twice that on-peak. Losses are only included as energy losses.

**Generation Capacity**: Generation capacity value is based on the assumption that the marginal resource is always a gas combustion turbine. Effective capacity is based on an ELCC estimate from secondary sources.

**Fuel Price Hedge Value:** Hedge value is estimated based on the market value to utilities of a fixed natural gas price for up to 10 years based on market swap data. The hedge is assumed to be additive since EIA gas prices were used rather than NYMEX futures market.

**Criteria Air Pollutants:** Criteria air pollutant reduction value is based on avoided costs of health impacts, estimated by secondary sources.

**Carbon:** Carbon value is the price of carbon (estimated based on European market projections) times the amount of carbon displaced.

Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

# LAWRENCE BERKELEY NATIONAL LAB, 2012

## *CHANGES IN THE ECONOMIC VALUE OF VARIABLE GENERATION AT HIGH PENETRATION LEVELS: A PILOT CASE STUDY OF CALIFORNIA*

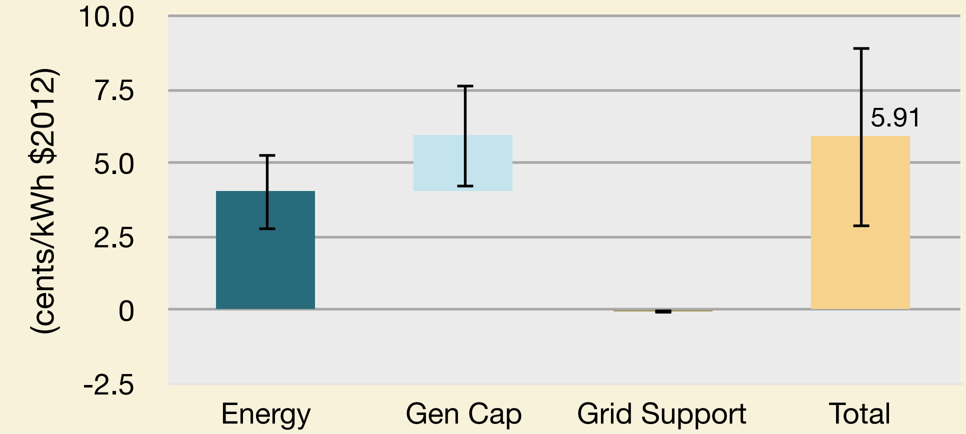
| STUDY CHARACTERISTICS | |
|---|---|
| STUDY OBJECTIVE | To quantify the change in value for a subset of economic benefits (energy, capacity, ancillary services, DA forecasting error) that results from using renewable generation technologies (wind, PV, CSP, & Thermal Energy Storage) at different penetration levels. |
| GEOGRAPHIC FOCUS | Loosely based on California |
| SYSTEM CONTEXT | 33% RPS, ISO market |
| LEVEL OF SOLAR ANALYZED | Up to 40% (by energy) |
| STAKEHOLDER PERSPECTIVE | System |
| GRANULARITY OF ANALYSIS | • Solar characterization - Hourly satellite derived insolation data from National Solar Research Database, 10 km x 10 km granularity, NREL SAM model<br>• Marginal resource/losses characterization - For energy and capacity, modeled hourly market prices, reflecting day-ahead, real-time, and ancillary services<br>• Geographic granularity - Not considered in this study |
| TOOLS USED | Customized model that evaluates long-run investment decisions and short-term dispatch and operations |

### Highlights

- The marginal economic value of solar exceeds the value of flat block power at low penetration levels, largely attributable to generation capacity value and solar coincidence with peak.
- The marginal value of DPV drops considerably as the penetration of solar increases, initially, driven by a decrease in capacity value with increasing solar generation. At the highest renewable penetrations considered, there is also a decrease in energy value as DPV displaces lower cost resources.
- The study notes that it is critical to use an analysis framework that addresses long-term investment decisions as well as short-term dispatch and operational constraints.
- Several costs and impacts are not considered in the study, including environmental impacts, transmission and distribution costs or benefits, effects related to the lumpiness and irreversibility of investment decisions, uncertainty in future fuel and investment capital costs, and DPV's capital cost.

## OVERVIEW OF VALUE CATEGORIES

### AVERAGE VALUES FROM STUDY




**Energy:** Energy value decreases at high penetrations because the marginal resource that DPV displaces changes as the system moves down the dispatch stack to a lower cost generator. Energy value is based on the short-run profit earned in non-scarcity hours (those hours where market prices are under $500/MWh), and generally displaces energy from a gas combined cycle. Fuel costs are based on Energy Information Administration projections.

**Generation Capacity:** Generation capacity value is based on the portion of short-run profit earned during hours with scarcity prices (those hours where market price equals or exceeds $500/MWh). Effective DPV capacity is based on an implied capacity credit as a result of the model's investment decisions, rather than a detailed reliability or ELCC analysis.

**Grid Support (Ancillary Services):** Ancillary services value is the net earnings from selling ancillary services in the market as well as paying for increased ancillary services due to increased short-term variability and uncertainty.

# CLEAN POWER RESEARCH, 2012

## *THE VALUE OF DISTRIBUTED SOLAR ELECTRIC GENERATION TO NEW JERSEY AND PENNSYLVANIA*

Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

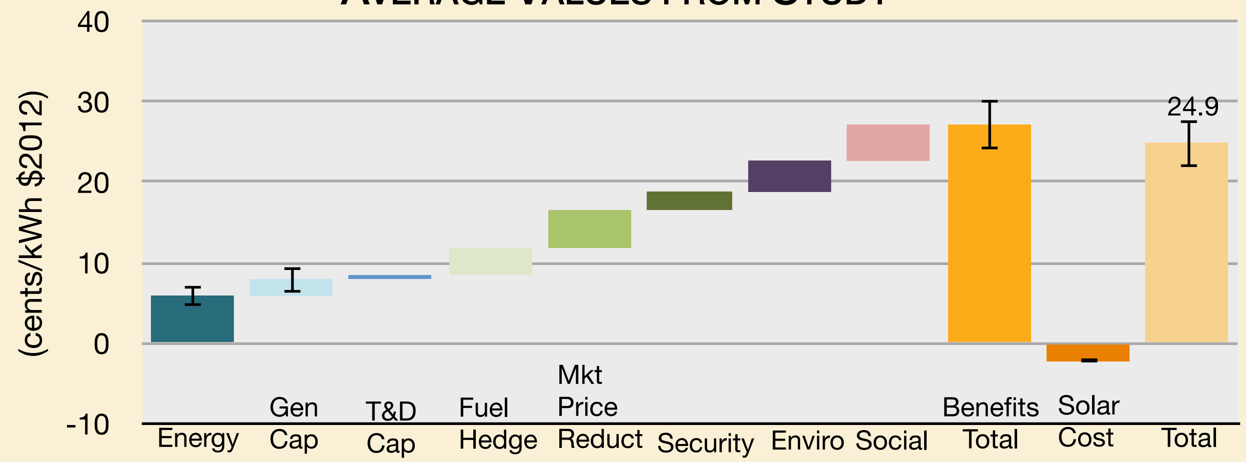
| STUDY CHARACTERISTICS | |
|---|---|
| STUDY OBJECTIVE | To quantify the cost and value components provided to utilities, ratepayers, and taxpayers by grid-connected, DPV in Pennsylvania and New Jersey. |
| GEOGRAPHIC FOCUS | 7 cities across PA and NJ |
| SYSTEM CONTEXT | PJM ISO |
| LEVEL OF SOLAR ANALYZED | 15% of system peak load, totaling 7 GW across the 7 utility hubs |
| STAKEHOLDER PERSPECTIVE | Utility, ratepayers, taxpayer |
| GRANULARITY OF ANALYSIS | • Solar characterization - Hourly estimates based on SolarAnywhere (satellite-derived irradiance data and simulation model with a 10 km x 10 km pixel resolution)<br>• Marginal resource/losses characterization - For energy and capacity, marginal resource assumed to be CT; Marginal loss savings calculated, although methodology unclear<br>• Geographic granularity - Locational marginal price node |
| TOOLS USED | Clean Power Research's Distributed PV Value Calculator; Solar Anywhere, 2012 |

### Highlights

- The study evaluated 10 benefits and 1 cost. Evaluated benefits included: Fuel cost savings, O&M cost savings, security enhancement, long term societal benefit, fuel price hedge, generation capacity, T&D capacity, market price reduction, environmental benefit, economic development benefit. The cost evaluated was the solar penetration cost.
- The analysis represents the value of PV for a "fleet" of PV systems, evaluated in 4 orientations, each at 7 locations (Pittsburgh, PA; Harrisburg, PA; Scranton, PA; Philadelphia, PA; Jamesburg, NJ; Newark, NJ; and Atlantic City, NJ), spanning 6 utility service territories, each differing by: cost of capital, hourly loads, T&D loss factors, distribution expansion costs, and growth rate.
- The total value ranged from \$256 to \$318/MWh. Of this, the highest value components were the Market Price Reduction (avg \$55/MWh) and Economic Development Value (avg \$44/MWh).
- The moderate generation capacity value is driven by a moderate match between DPV output and utility system load. The effective capacity ranges from 28% to 45% of rated output (in line with the assigned PJM value of 38% for solar resources).
- Loss savings were not treated as a stand-alone benefit under the convention used in this methodology. Rather, the loss savings effect is included separately for each value component.

## OVERVIEW OF VALUE CATEGORIES

### AVERAGE VALUES FROM STUDY




**Energy:** Fuel and O&M cost savings. PV output plus loss savings times marginal energy cost, summed for all hrs of the year, discounted over PV life (30 years). Marginal energy costs are based on fuel and O&M costs of the generator most likely operating on the margin (assumed to be a combined cycle gas turbine). Assumed natural gas price forecast: NYMEX futures years 0-12; NYMEX futures price for year 12 x 2.33% escalation factor. Escalation rate assumed to be the same as the rate of wellhead price escalation from 1981-2011.

**Generation Capacity:** Capital cost of displace generation times PV's effective load carrying capability (ELCC), taking into account loss savings.

**T&D Capacity:** Expected long-term T&D system capacity upgrade cost, divided by load growth, times financial term, times a factor that represents match between PV system output (adjusted for losses) and T&D system load. In this study, T&D values were based on utility-wide average loads, which may obscure higher value areas.

**Fuel Price Hedge Value**: Cost to eliminate the fuel price uncertainty associated with natural gas generation through procurement of commodity futures. The value is directly related to the utility's cost of capital.

**Market Price Reduction:** Value to customers of the reduced cost of wholesale energy as a result of PV installation decreasing the demand for wholesale energy. Quantified through an analysis of the supply curve and reduction in demand, and the accompanying new market clearing price.

**Security Enhancement Value:** Annual cost of power outages in the U.S. times the percent (5%) that are high-demand stress type that can be effectively mitigated by DPV at a capacity penetration of 15%.

**Social (Economic Development Value):** Value of tax revenues associated with net job creation for solar vs conventional power generation. PV hard and soft cost /kW times portion of each attributed to local jobs, divided by annual PV system energy produced, minus CCGT cost/kW times portion attributed to local jobs divided by annual energy produced. Levelized over the 30 year lifetime of PV system, adjusted for lost utility jobs, multiplied by tax rate of a \$75K salary, multiplied by indirect job multiplier.

**Environmental:** Environmental cost of a displaced conventional generation technology times the portion of this technology in the energy generation mix, repeated and summed for each conventional generation sources displaced by PV. Environmental cost for each generation source based on costs of GHG, SOx / NOx emissions, mining degradations, ground-water contamination, toxic releases and wastes. etc...as calculated in several environmental health studies.

Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

# Clean Power Research & Solar San Antonio, 2013
## *The Value of Distributed Solar Electric Generation to San Antonio*

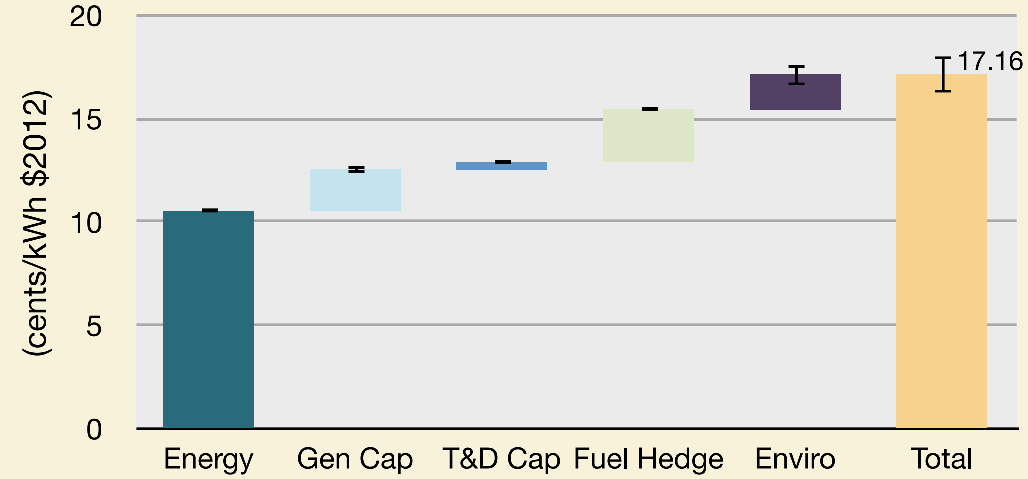
| STUDY CHARACTERISTICS | |
|---|---|
| STUDY OBJECTIVE | To quantify the value provided by grid-connected, DPV in San Antonio from a utility perspective. |
| GEOGRAPHIC FOCUS | CPS Energy territory |
| SYSTEM CONTEXT | Municipal utility |
| LEVEL OF SOLAR ANALYZED | 1.1-2.2% of peak load (by capacity) |
| STAKEHOLDER PERSPECTIVE | Utility |
| GRANULARITY OF ANALYSIS | • Solar characterization - Hourly estimates based on SolarAnywhere (satellite-derived irradiance data and simulation model with a 10 km x 10 km pixel resolution) to provide time- and location-correlated PV output with utility loads<br>• Marginal resource/losses characterization - For energy and capacity, marginal resource assumed to be an "advanced gas turbine"; losses calculated on marginal basis<br>• Geographic granularity - Not specified |
| TOOLS USED | Clean Power Research's SolarAnywhere, PVSimulator, DGValuator |

### Highlights

- The study concludes that DPV provides significant value to CPS Energy, primarily driven by energy, generation capacity deferment, and fuel price hedge value. The study is based solely on publicly-available data; it notes that results would be more representative with actual financial and operating data. Value is a levelized over 30 years.
- The study notes that value likely decreases with increasing penetration, although higher penetration levels needed to estimate this decrease were not analyzed.
- The study acknowledged but did not quantify a number of other values including climate change mitigation, environmental mitigation, and economic development.

## OVERVIEW OF VALUE CATEGORIES

### Average Values from Study




**Energy:** The study shows high energy value compared to other studies, driven by using EIA's "advanced gas turbine" with a high heat rate as the marginal resource. The natural gas price forecast is based on NYMEX forward market gas prices, then escalated at a constant rate. Energy losses are included in energy value, and are calculated on an hourly marginal basis.

**Generation Capacity**: Generation capacity value is DPV's effective capacity times the fixed costs of an "advanced gas turbine", assumed to be the marginal resource. Effective capacity based on ELCC; the reported ELCC is significantly higher than other studies. Every installed unit of DPV is given generation capacity value.

**T&D Capacity:** The study takes a two step approach: first, an economic screening to determine expansion plan costs and load growth expectations by geographic area, and second, an assessment of the correlation of DPV and load in the most promising locations.

**Fuel Price Hedge:** The study estimates hedge value as a combination of two financial instruments, risk-free zero-coupon bonds and a set of natural gas futures contracts, to represent the avoided cost of reducing fuel price volatility risk.

**Environmental:** The study quantified environmental value, as shown in the chart above, but did not include it in its final assessment of benefit since the study was from the utility perspective.

# AUSTIN ENERGY & CLEAN POWER RESEARCH, 2006
## *THE VALUE OF DISTRIBUTED PHOTOVOLTAICS IN AUSTIN ENERGY AND THE CITY OF AUSTIN*

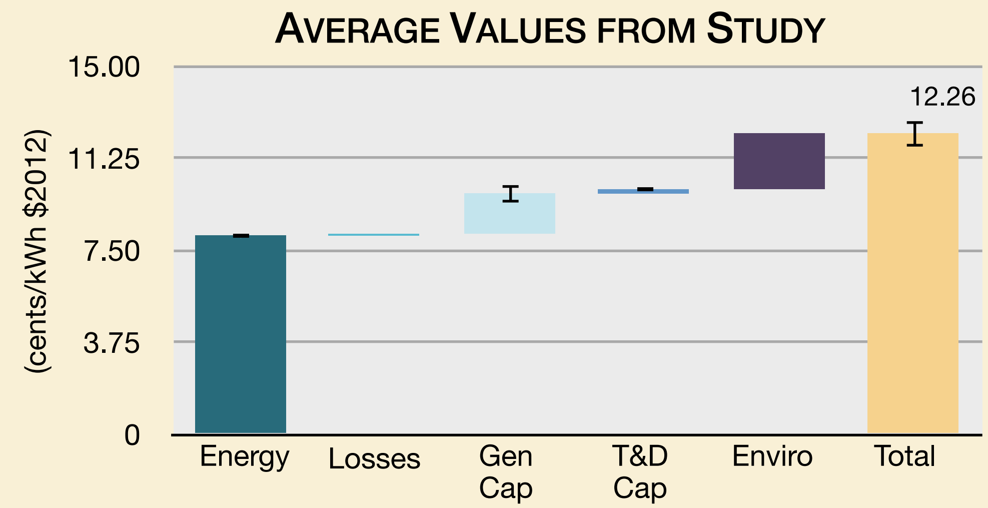
Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

| STUDY CHARACTERISTICS | |
|---|---|
| STUDY OBJECTIVE | To quantify the comprehensive value of DPV to Austin Energy (AE) in 2006 and document methodologies to assist AE in performing analysis as conditions change and, to apply to other technologies |
| GEOGRAPHIC FOCUS | Austin, TX |
| SYSTEM CONTEXT | Municipal utility |
| LEVEL OF SOLAR ANALYZED | >1% - 2%* system peak load |
| STAKEHOLDER PERSPECTIVE | Utility, ratepayer, participant, society |
| GRANULARITY OF ANALYSIS | • Solar characterization - Hourly PV output simulated for select PV configurations using irradiance data from hourly geostationary satellites; Validated using ground data from several climatically distinct locations including Austin, TX<br>• Marginal resource/losses characterization - Energy: based on internal marginal energy cost provided by AE;<br>• Geographic granularity - PV capacity value (ELCC) estimated system wide; Informed distribution avoided costs with area-specific distribution expansion plans "broken down by location and by the expenditure category" |
| TOOLS USED | Clean Power Research internal analysis; satellite solar data; PVFORM 4.0 for solar simulation; AE's load flow analysis for T&D losses |

### Highlights

- The study evaluated 7 benefits–energy production, line losses, generation capacity, T&D capacity, reactive power control (*grid support*), environment, natural gas price hedge (*financial*), and disaster recovery (*security*).
- The analysis assumed a 15 MW system in 7 PV system orientations, including 5 fixed and 2 single-axis.
- Avoided energy costs are the most significant source of value (about two-thirds of the total value), which is highly sensitive to the price of natural gas.
- Distribution capacity deferral value was relatively minimal. AE personnel estimated that 15% of the distribution capacity expansion plans have the potential to be deferred after the first ten years (assuming growth rates remain constant). Therefore, the study assumed that currently budgeted distribution projects were not deferrable, but the addition of PV could possibly defer distribution projects in the 11th year of the study period.
- Two studied values were excluded from the final results:
  - While reactive power benefits was estimated, the value ($0-$20/kW) was assumed not to justify the cost of the inverter that would be required to access the benefit (estimated cost not included).
  - The value of disaster recovery could be significant, but more work is needed before this value can be explicitly captured.

## OVERVIEW OF VALUE CATEGORIES




**Energy**: PV output plus loss savings times marginal energy cost. Marginal energy costs are based on fuel and O&M costs of the generator most likely operating on the margin (typically, a combined cycle gas turbine).

**System Losses:** Computed differently depending upon benefit category. For all categories, loss savings are calculated hourly on the margin.

**Generation Capacity:** Cost of capacity times PV's effective load carrying capability (ELCC), taking into account loss savings.

**Fuel price Hedge**: Cost to eliminate the fuel price uncertainty associated with natural gas generation through procurement of commodity futures. Fuel price hedge value is included in the energy value.

**T&D Capacity:** Expected long-term T&D system capacity upgrade cost, divided by load growth, times financial term, times a factor that represents match between PV system output (adjusted for losses) and T&D system load.

**Environmental:** PV output times REC price—the incremental cost of offsetting a unit of conventional generation.

*ELCC was evaluated from 0%-20%; however, the ELCC estimate for 2% penetration was used in final value.

# AUSTIN ENERGY & CLEAN POWER RESEARCH, 2012
## *DESIGNING AUSTIN ENERGY'S SOLAR TARIFF USING A DISTRIBUTED PV CALCULATOR*

Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

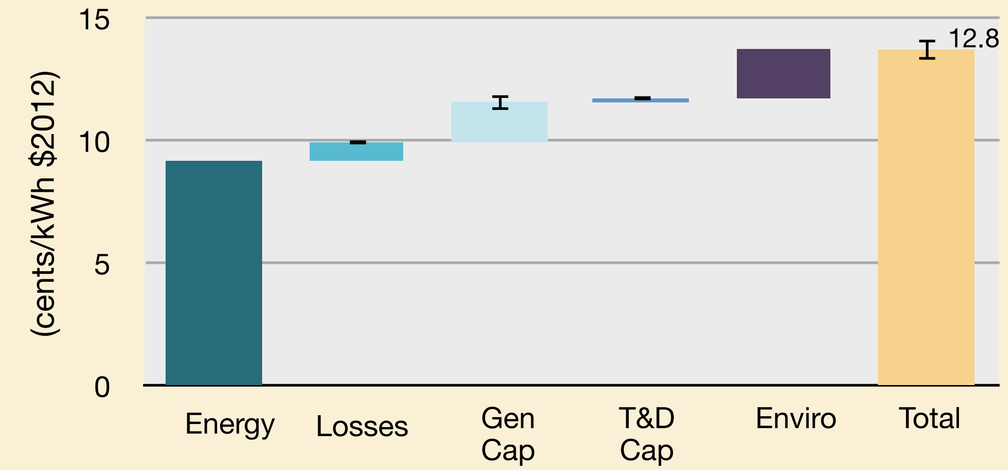
| STUDY CHARACTERISTICS | |
|---|---|
| STUDY OBJECTIVE | To design a residential solar tariff based on the value of solar energy generated from DPV systems to Austin Energy |
| GEOGRAPHIC FOCUS | Austin, TX |
| SYSTEM CONTEXT | Municipal utility with access to ISO (ERCOT) |
| LEVEL OF SOLAR ANALYZED | Assumed to be 2012 levels of penetration (5 MW)[1] < 0.5% penetration by energy[2] |
| STAKEHOLDER PERSPECTIVE | Utility |
| GRANULARITY OF ANALYSIS | Assumed to replicate granularity of AE/CPR 2006 study |
| TOOLS USED | Clean Power Research's Distributed PV Value Calculator; Solar Anywhere, 2012 |

### Highlights

- The study focused on 6 benefits–energy, generation capacity, fuel price hedge value (included in energy savings), T&D capacity, and environmental benefits–which represent "a 'break-even' value...at which the utility is economically neutral to whether it supplies such a unit of energy or obtains it from the customer." The approach, which builds on the 2006 CPR study, is "an avoided cost calculation at heart, but improves on [an avoided cost calculation]... by calculating a unique, annually adjusted value for distributed solar energy."
- The fixed, south-facing PV system with a 30-degree tilt, the most common configuration and orientation in AE's service territory of approximately 1,500 DPV systems, was used as the reference system.
- As with the AE/CPR 2006 study, avoided energy costs are the most significant source of value, which is very sensitive to natural gas price assumptions.
- The levelized value of solar was calculated to total $12.8/kWh.
- Two separate calculation approaches were used to estimate the near term and long term value, combined to represent the "total benefits of DPV to Austin Energy" over the life time of a DPV system.
  - For the the near term (2 years) value of DPV energy, A PV output weighted nodal price was used to try to capture the relatively good correlation between PV output and electricity demand (and high price) that is not captured in the average nodal price.
  - To value the DPV energy produced during the mid and long term–through the rest of the 30-year assumed life of solar PV systems–the typical value calculator methodology was used.

### OVERVIEW OF VALUE CATEGORIES

AVERAGE VALUES FROM STUDY




**Energy:** DPV output plus loss savings times marginal energy cost. Marginal energy costs are based on fuel and O&M costs of the generator most likely operating on the margin (typically, a combined cycle gas turbine).

**System Losses:** Computed differently depending upon benefit category. For all categories, loss savings are calculated hourly on the margin.

**Generation Capacity:** Cost of capacity times PV's effective load carrying capability (ELCC), taking into account loss savings.

**Fuel Price Hedge Value**: Cost to eliminate the fuel price uncertainty associated with natural gas generation through procurement of commodity futures. Fuel price hedge value is included in the energy value.

**T&D Capacity:** Expected long-term T&D system capacity upgrade cost, divided by load growth, times financial term, times a factor that represents match between PV system output (adjusted for losses) and T&D system load.

**Environmental:** PV output times Renewable Energy Credit (REC) price—the incremental cost of offsetting a unit of conventional generation.

Sources:
1) http://www.austinenergy.com/About%20Us/Newsroom/Reports/solarGoalsUpdate.pdf
2) http://www.austinenergy.com/About%20Us/Newsroom/Reports/2012AnnualPerformanceReportDRAFT.pdf

# NAVIGANT CONSULTING FOR NREL, 2008
## *PHOTOVOLTAICS VALUE ANALYSIS*

eLab
Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

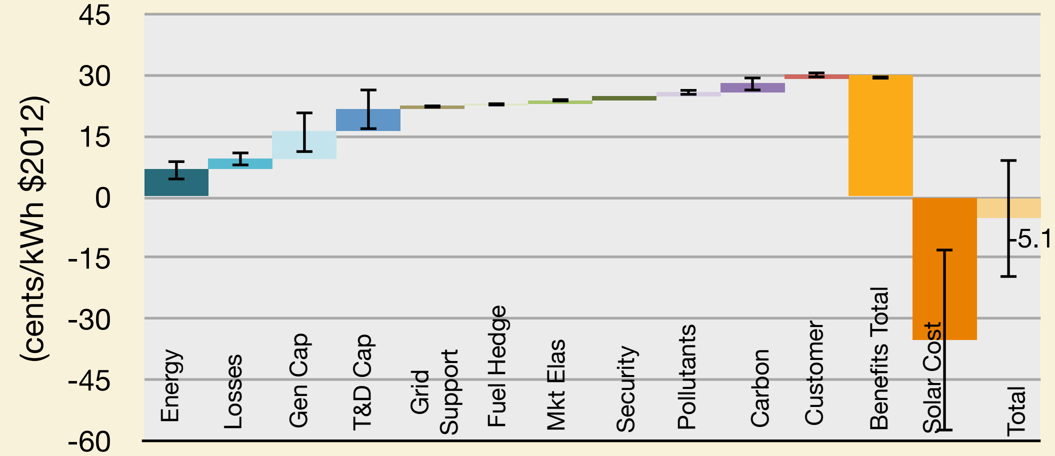
| STUDY CHARACTERISTICS | |
|---|---|
| STUDY OBJECTIVE | To summarize and describe the methodologies and range of values for the costs and values of 19 services provided or needed by DPV from existing studies. |
| GEOGRAPHIC FOCUS | Studies reviewed reflected varying geographies; case studies from TX, CA, MN, WI, MD, NY, MA, and WA |
| SYSTEM CONTEXT | n/a |
| LEVEL OF SOLAR ANALYZED | n/a |
| STAKEHOLDER PERSPECTIVE | Participating customers, utilities, ratepayers, society |
| GRANULARITY OF ANALYSIS | This study is a meta-analysis, so reflects a range of levels of granularity. |
| TOOLS USED | Custom-designed Excel tool to compare results and sensitivities |

## Highlights

- There are 19 key values of distributed PV, but the study concludes that only 6 have significant benefits (energy, generation capacity, T&D costs, GHG emissions, criteria air pollutant emissions, and implicit value of PV).
- Deployment location and solar output profile are the most significant drivers of DPV value.
- Several values require additional R&D to establish a standardized quantification methodology.
- Value can be proactively increased.

## OVERVIEW OF VALUE CATEGORIES

### AVERAGE VALUES FROM STUDY




**Energy:** Energy value is fuel cost times the heat rate plus O&M costs for the marginal power plant, generally assumed to be natural gas.

**System Losses:** Avoided loss value is the amount of loss associated with energy, generation capacity, T&D capacity, and environmental impact, times the cost of that loss.

**Generation Capacity**: Generation capacity value is the capital cost of the marginal power plant times the effective capacity (ELCC) of DPV.

**T&D Capacity:** T&D capacity value is T&D investment plan costs times the value of money times the effective capacity, divided by load growth, levelized.

**Grid Support Services (Ancillary Services):** Ancillary services include VAR support, load following, operating reserves, and dispatch and scheduling. DPV is unlikely to be able to provide all of these.

**Financial (Fuel Price Hedge, Market Price Response):** Hedge value is the cost to guarantee a portion of electricity costs are fixed. Reduced demand for electricity decreases the price of electricity for all customers and creates a customer surplus.

**Security:** Customer reliability in the form of increased outage support can be realized, but only when DPV is coupled with storage.

**Environment (Criteria Air Pollutants, Carbon):** Value is either the market value of penalties or costs, or the value of avoided health costs and shortened lifetimes. Carbon value is the emission intensity of the marginal resource times the value of emissions.

**Customer:** Value to customer of having green option, as indicate by their willingness to pay.

**Solar cost:** Costs include capital cost of equipment plus fixed operating and maintenance costs.

# SOURCES

05

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|---|---|---|
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| Beach, R., McGuire, P., The Benefits and Costs of Solar Distributed Generation for Arizona Public Service. Crossborder Energy May, 2013. | | Crossborder Energy |
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# ACRONYMS

AE - Austin Energy
APS - Arizona Public Service
AS - Ancillary Services
CCGT - Combined Cycle Gas Turbine
CHP - Combined Heat and Power
CPR - Clean Power Research
CT - Combustion Turbine
DER - Distributed Energy Resource
DPV - Distributed Photovoltaics
E3 - Energy + Environmental Economics
eLab - Electricity Innovation Lab
ELCC - Effective Load Carrying Capacity
FERC - Federal Energy Regulatory Commission
ISO - Independent System Operator
LBNL - Lawrence Berkeley National Laboratory
NREL - National Renewable Energy Laboratory
NYMEX - New York Mercantile Exchange
PV - Photovoltaic
RMI - Rocky Mountain Institute
SDG&E - San Diego Gas & Electric
SEPA - Solar Electric Power Association
SMUD - Sacramento Municipal Utility District
T&D - Transmission & Distribution
TOU - Time of Use

# Minnesota Value of Solar: Methodology

Minnesota Department of Commerce,

Division of Energy Resources


APRIL 1, 2014*

*reformatted on April 9, 2014

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## Legal Notice from Clean Power Research

# Executive Summary

Minnesota passed legislation[1] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The Department of Commerce (Commerce) was assigned the responsibility of developing and submitting a methodology for calculating the VOS tariff to the PUC by January 31, 2014. Utilities adopting the VOS will be required to follow this methodology when calculating the VOS tariff. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology, and additionally held four public workshops to develop, present, and receive feedback.

The 2013 legislation specifically mandated that the VOS legislation take into account the following values of distributed PV: energy and its delivery; generation capacity; transmission capacity; transmission and distribution line losses; and environmental value. The legislation also mandated a method of implementation, whereby solar customers will be billed for their gross electricity consumption under their applicable tariff, and will receive a VOS credit for their gross solar electricity production.

The present document provides the methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input, and guidance from Commerce. It includes a detailed example calculation for each step of the calculation.

Key aspects of the methodology include:

- A standard PV rating convention
- Methods for creating an hourly PV production time-series, representing the aggregate output of all PV systems in the service territory per unit capacity corresponding to the output of a PV resource on the margin
- Requirements for calculating the electricity losses of the transmission and distribution systems
- Methods for performing technical calculations for avoided energy, effective generation capacity and effective distribution capacity
- Economic methods for calculating each value component (e.g., avoided fuel cost, capacity cost, etc.)
- Requirements for summarizing input data and final calculations in order to facilitate PUC and stakeholder review

Application of the methodology results in the creation of two tables: the VOS Data Table (a table of utility-specific input assumptions) and the VOS Calculation Table (a table of utility-specific total value of

[1] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

solar). Together these two tables ensure transparency and facilitate understanding among stakeholders and regulators.

The VOS Calculation Table is illustrated in Figure ES-1. The table shows each value component and how the gross economic value of each component is converted into a distributed solar value. The process uses a component-specific load match factor (where applicable) and a component-specific loss savings factor. The values are then summed to yield the 25-year levelized value.

Figure ES-1. VOS Calculation Table: economic value, load match, loss savings and distributed PV value.

| 25 Year Levelized Value | Economic Value ($/kWh) | X | Load Match (No Losses) (%) | X | (1 | + | Distributed Loss Savings (%) | ) | = | Distributed PV Value ($/kWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| Avoided Fuel Cost | E1 | | | | | | DLS-Energy | | | V1 |
| Avoided Plant O&M - Fixed | E2 | | ELCC | | | | DLS-ELCC | | | V2 |
| Avoided Plant O&M - Variable | E3 | | | | | | DLS-Energy | | | V3 |
| Avoided Gen Capacity Cost | E4 | | ELCC | | | | DLS-ELCC | | | V4 |
| Avoided Reserve Capacity Cost | E5 | | ELCC | | | | DLS-ELCC | | | V5 |
| Avoided Trans. Capacity Cost | E6 | | ELCC | | | | DLS-ELCC | | | V6 |
| Avoided Dist. Capacity Cost | E7 | | PLR | | | | DLS-PLR | | | V7 |
| Avoided Environmental Cost | E8 | | | | | | DLS-Energy | | | V8 |
| Avoided Voltage Control Cost | | | | | | | | | | |
| Solar Integration Cost | | | | | | | | | | |
| | | | | | | | | | | Lev. VOS |

As a final step, the methodology calls for the conversion of the 25-year levelized value to an equivalent inflation-adjusted credit. The utility would then use the first year value as the credit for solar customers, and would adjust each year using the latest Consumer Price Index (CPI) data.

# Contents

# Introduction

### Background

Minnesota passed legislation[2] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The Department of Commerce (Commerce) was assigned the responsibility of developing and submitting a methodology for calculating the VOS tariff to the PUC by January 31, 2014. Utilities adopting the VOS will be required to follow this methodology when calculating the VOS rate. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology, and additionally held four public workshops to develop, present, and receive feedback.

The present document provides the VOS methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input and guidance from Commerce.

### Purpose

The State of Minnesota has identified a VOS tariff as a potential replacement for the existing Net Energy Metering (NEM) policy that currently regulates the compensation of home and business owners for electricity production from PV systems. As such, the adopted VOS legislation is not an incentive for distributed PV, nor is it intended to eliminate or prevent current or future incentive programs.

While NEM effectively values PV-generated electricity at the customer retail rate, a VOS tariff seeks to quantify the value of distributed PV electricity. If the VOS is set correctly, it will account for the real value of the PV-generated electricity, and the utility and its ratepayers would be indifferent to whether the electricity is supplied from customer-owned PV or from comparable conventional means. Thus, a VOS tariff eliminates the NEM cross-subsidization concerns. Furthermore, a well-constructed VOS tariff could provide market signals for the adoption of technologies that significantly enhance the value of electricity from PV, such as advanced inverters that can assist the grid with voltage regulation.

### VOS Calculation Table Overview

The VOS is the sum of several distinct value components, each calculated separately using procedures defined in this methodology. As illustrated in Figure 1, the calculation includes a gross component value, a component-dependent load-match factor (as applicable for capacity related values) and a component-dependent Loss Savings Factor.

[2] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

For example, the avoided fuel cost does not have a load match factor because it is not dependent upon performance at the highest hours (fuel costs are avoided during all PV operating hours). Avoided fuel cost does have a Loss Savings Factor, however, accounting for loss savings in both transmission and distribution systems. On the other hand, the Avoided Distribution Capacity Cost has an important Load Match Factor (shown as Peak Load Reduction, or 'PLR') and a Loss Savings Factor that only accounts for distribution (not transmission) loss savings.

Gross Values, Distributed PV Values, and the summed VOS shown in Figure 1 are all 25-year levelized values denominated in dollars per kWh.

Figure 1. Illustration of the VOS Calculation Table

| 25 Year Levelized Value | Economic Value ($/kWh) | X | Load Match (No Losses) (%) | X | (1 | + | Distributed Loss Savings (%) | ) | = | Distributed PV Value ($/kWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| Avoided Fuel Cost | E1 | | | | | | DLS-Energy | | | V1 |
| Avoided Plant O&M - Fixed | E2 | | ELCC | | | | DLS-ELCC | | | V2 |
| Avoided Plant O&M - Variable | E3 | | | | | | DLS-Energy | | | V3 |
| Avoided Gen Capacity Cost | E4 | | ELCC | | | | DLS-ELCC | | | V4 |
| Avoided Reserve Capacity Cost | E5 | | ELCC | | | | DLS-ELCC | | | V5 |
| Avoided Trans. Capacity Cost | E6 | | ELCC | | | | DLS-ELCC | | | V6 |
| Avoided Dist. Capacity Cost | E7 | | PLR | | | | DLS-PLR | | | V7 |
| Avoided Environmental Cost | E8 | | | | | | DLS-Energy | | | V8 |
| Avoided Voltage Control Cost | | | | | | | | | | |
| Solar Integration Cost | | | | | | | | | | |
| | | | | | | | | | | Lev. VOS |

# VOS Rate Implementation

## Separation of Usage and Production

Minnesota's VOS legislation mandates that, if a VOS tariff is approved, solar customers will be billed for all usage under their existing applicable tariff, and will receive a VOS credit for their gross solar energy production. Separating usage (charges) from production (credits) simplifies the rate process for several reasons:

- Customers will be billed for all usage. Energy derived from the PV systems will not be used to offset ("net") usage prior to calculating charges. This will ensure that utility infrastructure costs will be recovered by the utilities as designed in the applicable retail tariff.
- The utility will provide all energy consumed by the customer. Standby charges for customers with on-site PV systems are not permitted under a VOS rate.
- The rates for usage can be adjusted in future ratemaking.

## VOS Components

The definition and selection of VOS components were based on the following considerations:

- Components corresponding to minimum statutory requirements are included. These account for the "value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value."
- Non-required components were selected only if they were based on known and measurable evidence of the cost or benefit of solar operation to the utility.
- Environmental costs are included as a required component, and are based on existing Minnesota and federal externality costs.
- Avoided fuel costs are based on long-term risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel, as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments.
- Credit for systems installed at high value locations (identified in the legislation as an option) is included as an option for the utility. It is not a separate VOS component but rather is implemented using a location-specific distribution capacity value (the component most affected by location). This is addressed in the Distribution Capacity Cost section.
- Voltage control and solar integration (a cost) are kept as "placeholder" components for future years. Methodologies are not provided, but these components may be developed for the future. Voltage control benefits are anticipated but will first require implementation of recent changes to national interconnection standards. Solar integration costs are expected to be small, but possibly measureable. Further research will be required on this topic.

Table 1 presents the VOS components selected by Commerce and the cost basis for each component. Table 2 presents the VOS components that were considered but not selected by Commerce. Selections were made based on requirements and guidance in the enabling statute, and were informed by stakeholder comments (including those from Minnesota utilities; local and national solar and environmental organizations; local solar manufacturers and installers; and private parties) and workshop discussions. Stakeholders participated in four public workshops and provided comments through workshop panels, workshop Q&A sessions and written comments.

Table 1. VOS components included in methodology.

| Value Component | Basis | Legislative Guidance | Notes |
|---|---|---|---|
| **Avoided Fuel Cost** | Energy market costs (portion attributed to fuel) | Required (energy) | Includes cost of long-term price risk |
| **Avoided Plant O&M Cost** | Energy market costs (portion attributed to O&M) | Required (energy) | |
| **Avoided Generation Capacity Cost** | Capital cost of generation to meet peak load | Required (capacity) | |
| **Avoided Reserve Capacity Cost** | Capital cost of generation to meet planning margins and ensure reliability | Required (capacity) | |
| **Avoided Transmission Capacity Cost** | Capital cost of transmission | Required (transmission capacity) | |
| **Avoided Distribution Capacity Cost** | Capital cost of distribution | Required (delivery) | |
| **Avoided Environmental Cost** | Externality costs | Required (environmental) | |
| **Voltage Control** | Cost to regulate distribution (future inverter designs) | | Future (TBD) |
| **Integration Cost**[3] | Added cost to regulate system frequency with variable solar | | Future (TBD) |

[3] This is not a value, but a cost. It would reduce the VOS rate if included.

Table 2. VOS components not included in methodology.

| Value Component | Basis | Legislative Guidance | Notes |
|---|---|---|---|
| **Credit for Local Manufacturing/ Assembly** | Local tax revenue tied to net solar jobs | Optional (identified in legislation) | |
| **Market Price Reduction** | Cost of wholesale power reduced in response to reduction in demand | | |
| **Disaster Recovery** | Cost to restore local economy (requires energy storage and islanding inverters) | | |

### Solar Penetration

Solar penetration refers to the total installed capacity of PV on the grid, generally expressed as a percentage of the grid's total load. The level of solar penetration on the grid is important because it affects the calculation of the Effective Load Carrying Capability (ELCC) and Peak Load Reduction (PLR) load-match factors (described later).

In the methodology, the near-term level of PV penetration is used. This is done so that the capacity-related value components will reflect the near-term level of PV penetration on the grid. However, the change in PV penetration level will be accounted for in the annual adjustment to the VOS. To the extent that PV penetration increases, future VOS rates will reflect higher PV penetration levels.

### Marginal Fuel

This methodology assumes that PV displaces natural gas during PV operating hours. This is consistent with current and projected MISO market experience. During some hours of the year, other fuels (such as coal) may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption that is not expected to materially impact the calculated VOS tariff. However, if future analysis indicates that the assumption is not warranted, then the methodology may be modified accordingly. For example, by changing the methodology to include displacement of coal production, avoided fuel costs may decrease and avoided environmental costs may increase.

## Economic Analysis Period

In evaluating the value of a distributed PV resource, the economic analysis period is set at 25 years, the assumed useful service life of the PV system[4]. The methodology includes PV degradation effects as described later.

## Annual VOS Tariff Update

Each year, a new VOS tariff would be calculated using current data, and the new resulting VOS rate would be applicable to all customers entering the tariff during the year. Changes such as increased or decreased fuel prices and modified hourly utility load profiles due to higher solar penetration will be incorporated into each new annual calculation.

Customers who have already entered into the tariff in a previous year will not be affected by this annual adjustment. However, customers who have entered into a tariff in prior years will see their Value of Solar rates adjusted for the previous year's inflation rate as described later.

Commerce may also update the methodology to use the best available practices, as necessary.

## Transparency Elements

The methodology incorporates two tables that are to be included in a utility's application to the Minnesota PUC for the use of a VOS tariff. These tables are designed to improve transparency and facilitate understanding among stakeholders and regulators.

- **VOS Data Table.** This table provides a utility-specific defined list of the key input assumptions that go into the VOS tariff calculation. This table is described in more detail later.
- **VOS Calculation Table.** This table includes the list of value components and their gross values, their load-match factors, their Loss Savings Factors, and the computation of the total levelized value.

## Glossary

A glossary is provided at the end of this document defining some of the key terms used throughout this document.

[4] NREL: Solar Resource Analysis and High-Penetration PV Potential (April 2010). http://www.nrel.gov/docs/fy10osti/47956.pdf

# Methodology: Assumptions

## Fixed Assumptions

Table 3 and Table 4 present fixed assumptions, common to all utilities and incorporated into this methodology, that are to be applied to the calculation of 2014 VOS tariffs. These may be updated by Commerce in future years as necessary when performing the annual VOS update. Table 4 is described in more detail in the Avoided Environmental Cost subsection. Table terms can be found in the Glossary.

The general escalation rate is calculated as the average annual inflation rate over the last 25 years. The methodology uses the U.S. Bureau of Labor Statistics' Urban Consumer Price Index (CPI) data.

To retrieve Urban CPI data follow these steps:

1. Go to the U.S. Bureau of Labor Statistics's Top Picks for Consumer Price Index – All Urban Consumers[5]

2. Select " U.S. All items, 1982-84=100 - CUUR0000SA0". Click the "Retrieve Data" button near the bottom of the page.

3. Across from "Change Output Options", change the "from" and "to" years to capture the last 25 years of annual average CPI data. For example, a VOS rate calculated in 2014 would enter 1998 ("from" year) and 2013 ("to" year). Click on "go" to generate the data for this time period.

4. Select the annual average CPI numbers for the first and last year of the 25 year period. These numbers are under the "Annual" column. For example, the 1988 annual CPI factor is 118.3, and the 2013 factor is 232.957.

5. Use the annual CPI factors in equation (1) to calculate the 25 year average annual inflation rate.

$$25yrAvgAnnualInflation = \left(\frac{AnnualAvg_{year(-1)}\ UCPI}{AnnualAvg_{year(-26)}\ UCPI}\right)^{1/(25)} - 1 \tag{1}$$

$$25yrAvgAnnualInflation = \left(\frac{AnnualAvg_{2013}\ UCPI}{AnnualAvg_{1998}\ UCPI}\right)^{1/(25)} - 1 = \left[\left(\frac{232.957}{118.300}\right)^{1/25} - 1\right] = 2.75\% \tag{2}$$

[5] CPI data can currently be found at: http://data.bls.gov/cgi-bin/surveymost?cu

Table 3. Fixed assumptions used in Methodology's Example VOS calculations

| | | | | | | |
|---|---|---|---|---|---|---|
| **Guaranteed NG Fuel Prices** | | | | | | |
| **Year** | | | | **Environmental Externalities** | | |
| 2014 | $3.93 | $ per MMBtu | | Environmental discount rate (nominal) | 5.83% | per year |
| 2015 | $4.12 | $ per MMBtu | | Environmental costs | (shown in separate table) | |
| 2016 | $4.25 | $ per MMBtu | | | | |
| 2017 | $4.36 | $ per MMBtu | | **Economic Assumptions** | | |
| 2018 | $4.50 | $ per MMBtu | | General escalation rate | 2.75% | per year |
| 2019 | $4.73 | $ per MMBtu | | | | |
| 2020 | $5.01 | $ per MMBtu | | | | |
| 2021 | $5.33 | $ per MMBtu | | **Treasury Yields** | | |
| 2022 | $5.67 | $ per MMBtu | | 1 Year | 0.13% | |
| 2023 | $6.02 | $ per MMBtu | | 2 Year | 0.29% | |
| 2024 | $6.39 | $ per MMBtu | | 3 Year | 0.48% | |
| 2025 | $6.77 | $ per MMBtu | | 5 Year | 1.01% | |
| | | | | 7 Year | 1.53% | |
| **PV Assumptions** | | | | 10 Year | 2.14% | |
| PV degradation rate | 0.50% | per year | | 20 Year | 2.92% | |
| PV life | 25 | years | | 30 Year | 3.27% | |
| | | | | | | |
| | | | | | | |

Table 4. Environmental externality costs by year.

| Year | Analysis Year | $CO_2$ Cost ($/MMBtu) | PM10 Cost ($/MMBtu) | CO Cost ($/MMBtu) | $NO_x$ Cost ($/MMBtu) | Pb Cost ($/MMBtu) | Total Cost ($/MMBtu) |
|---|---|---|---|---|---|---|---|
| 2014 | 0 | 1.939 | 0.069 | 0.000 | 0.013 | 0.000 | 2.022 |
| 2015 | 1 | 2.046 | 0.071 | 0.000 | 0.013 | 0.000 | 2.131 |
| 2016 | 2 | 2.158 | 0.073 | 0.000 | 0.014 | 0.000 | 2.245 |
| 2017 | 3 | 2.274 | 0.075 | 0.000 | 0.014 | 0.000 | 2.363 |
| 2018 | 4 | 2.395 | 0.077 | 0.000 | 0.015 | 0.000 | 2.487 |
| 2019 | 5 | 2.521 | 0.079 | 0.000 | 0.015 | 0.000 | 2.615 |
| 2020 | 6 | 2.652 | 0.082 | 0.000 | 0.015 | 0.000 | 2.749 |
| 2021 | 7 | 2.788 | 0.084 | 0.000 | 0.016 | 0.000 | 2.888 |
| 2022 | 8 | 2.930 | 0.086 | 0.000 | 0.016 | 0.000 | 3.032 |
| 2023 | 9 | 3.077 | 0.089 | 0.000 | 0.017 | 0.000 | 3.182 |
| 2024 | 10 | 3.230 | 0.091 | 0.000 | 0.017 | 0.000 | 3.338 |
| 2025 | 11 | 3.390 | 0.093 | 0.000 | 0.018 | 0.000 | 3.501 |
| 2026 | 12 | 3.555 | 0.096 | 0.000 | 0.018 | 0.000 | 3.669 |
| 2027 | 13 | 3.653 | 0.099 | 0.000 | 0.019 | 0.000 | 3.770 |
| 2028 | 14 | 3.830 | 0.101 | 0.000 | 0.019 | 0.000 | 3.950 |
| 2029 | 15 | 4.014 | 0.104 | 0.000 | 0.020 | 0.000 | 4.138 |
| 2030 | 16 | 4.205 | 0.107 | 0.000 | 0.020 | 0.000 | 4.332 |
| 2031 | 17 | 4.404 | 0.110 | 0.000 | 0.021 | 0.000 | 4.534 |
| 2032 | 18 | 4.610 | 0.113 | 0.000 | 0.021 | 0.000 | 4.744 |
| 2033 | 19 | 4.824 | 0.116 | 0.000 | 0.022 | 0.000 | 4.962 |
| 2034 | 20 | 5.047 | 0.119 | 0.000 | 0.023 | 0.000 | 5.189 |
| 2035 | 21 | 5.278 | 0.123 | 0.000 | 0.023 | 0.000 | 5.424 |
| 2036 | 22 | 5.518 | 0.126 | 0.000 | 0.024 | 0.000 | 5.668 |
| 2037 | 23 | 5.768 | 0.129 | 0.000 | 0.024 | 0.000 | 5.922 |
| 2038 | 24 | 6.027 | 0.133 | 0.000 | 0.025 | 0.000 | 6.185 |

See explanation in the Avoided Environmental Cost section.

### Utility-Specific Assumptions and Calculations

Some assumptions and calculations are unique to each utility. These include economic assumptions (such as discount rate) and technical calculations (such as ELCC). Utility-specific assumptions and calculations are determined by the utility, and are included in the VOS Data Table, a required transparency element.

The utility-specific calculations (such as capacity-related transmission capital cost) are determined using the methods described in this methodology.

An example VOS Data Table, showing the parameters to be included in the utility filing for the VOS tariff, is shown in Table 5. This table includes values that are given for example only. These example values carry forward in the example calculations.

Table 5. VOS Data Table (EXAMPLE DATA) — required format showing example parameters used in the example calculations.

| | Input Data | Units |
|---|---|---|
| **Economic Factors** | | |
| Start Year for VOS applicability | 2014 | |
| Discount rate (WACC) | 8.00% | per year |
| **Load Match Analysis (see calculation method)** | | |
| ELCC (no loss) | 40% | % of rating |
| PLR (no loss) | 30% | % of rating |
| Loss Savings – Energy | 8% | % of PV output |
| Loss Savings – PLR | 5% | % of PV output |
| Loss Savings – ELCC | 9% | % of PV output |
| **PV Energy (see calculation method)** | | |
| First year annual energy | 1800 | kWh per kW-AC |
| **Transmission (see calculation method)** | | |
| Capacity-related transmission capital cost | $33 | $ per kW-yr |

| | Input Data | Units |
|---|---|---|
| **Power Generation** | | |
| Peaking CT, simple cycle | | |
| Installed cost | 900 | $/kW |
| Heat rate | 9,500 | BTU/kWh |
| Intermediate peaking CCGT | | |
| Installed cost | 1,200 | $/kW |
| Heat rate | 6,500 | BTU/kWh |
| Other | | |
| Solar-weighted heat rate (see calc. method) | 8000 | BTU per kWh |
| Fuel Price Overhead | $0.50 | $ per MMBtu |
| Generation life | 50 | years |
| Heat rate degradation | 0.100% | per year |
| O&M cost (first Year) - Fixed | $5.00 | per kW-yr |
| O&M cost (first Year) - Variable | $0.0010 | $ per kWh |
| O&M cost escalation rate | 2.00% | per year |
| Reserve planning margin | 15% | |
| **Distribution** | | |
| Capacity-related distribution capital cost | $200 | $ per kW |
| Distribution capital cost escalation | 2.00% | per year |
| Peak load | 5000 | MW |
| Peak load growth rate | 1.00% | per year |

# Methodology: Technical Analysis

## Load Analysis Period

The VOS methodology requires that a number of technical parameters (PV energy production, effective load carrying capability (ELCC) and peak load reduction (PLR) load-match factors, and electricity-loss factors) be calculated over a fixed period of time in order to account for day-to-day variations and seasonal effects, such as changes in solar radiation. For this reason, the load analysis period must cover a period of at least one year.

The data may start on any day of the year, and multiple years may be included, as long as all included years are contiguous and each included year is a complete one-year period. For example, valid load analysis periods may be 1/1/2012 0:00 to 12/31/2012 23:00 or 11/1/2010 0:00 to 10/31/2013 23:00.

Three types of time series data are required to perform the technical analysis:

- **Hourly Generation Load:** the hourly utility load over the Load Analysis Period. This is the sum of utility generation and import power needed to meet all customer load.
- **Hourly Distribution Load:** the hourly distribution load over the Load Analysis Period. The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses).
- **Hourly PV Fleet Production:** the hourly PV Fleet production over the Load Analysis Period. The PV fleet production is the aggregate generation of all of the PV systems in the PV fleet.

All three types of data must be provided as synchronized, time-stamped hourly values of average power over the same period, and corresponding to the same hourly intervals. Data must be available for every hour of the Load Analysis Period.

PV data using Typical Meteorological Year data is not time synchronized with time series production data, so it should not be used as the basis for PV production.

Data that is not in one-hour intervals must be converted to hourly data (for example, 15-minute meter data would have to be combined to obtain 1-hour data). Also, data values that represent energy must be converted to average power.

If data is missing or deemed erroneous for any time period less than or equal to 24 hours, the values corresponding to that period may be replaced with an equal number of values from the same time interval on the previous or next day if it contains valid data. This data replacement method may be used provided that it does not materially affect the results.

## PV Energy Production

### *PV System Rating Convention*

The methodology uses a rating convention for PV capacity based on AC delivered energy (not DC), taking into account losses internal to the PV system. A PV system rated output is calculated by multiplying the number of modules by the module PTC rating[6] [as listed by the California Energy Commission (CEC)[7]] to account for module de-rate effects. The result is then multiplied by the CEC-listed inverter efficiency rating[8] to account for inverter efficiency, and the result is multiplied by a loss factor to account for internal PV array losses (wiring losses, module mismatch and other losses).

If no CEC module PTC rating is available, the module PTC rating should be calculated as 0.90 times the module STC rating[9]. If no CEC inverter efficiency rating is available, an inverter efficiency of 0.95 should be used. If no measured or design loss factor is available, 0.85 should be used.

To summarize: [10]

Rating (kW-AC) = [Module Quantity] x [Module PTC rating (kW)] x [Inverter Efficiency Rating] x [Loss Factor]

### *Hourly PV Fleet Production*

Hourly PV Fleet Production can be obtained using any one of the following three options:

1. Utility Fleet - Metered Production. Fleet production data can be created by combining actual metered production data for every PV system in the utility service territory, provided that there are a sufficient number of systems[11] installed to accurately derive a correct representation of aggregate PV production. Such metered data is to be gross PV output on the AC side of the

[6] PTC refers to PVUSA Test Conditions, which were developed to test and compare PV systems as part of the PVUSA (Photovoltaics for Utility Scale Applications) project. PTC are 1,000 Watts per square meter solar irradiance, 20 degrees C air temperature, and wind speed of 1 meter per second at 10 meters above ground level. PV manufacturers use Standard Test Conditions, or STC, to rate their PV products.
[7] CEC module PTC ratings for most modules can be found at:
http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php
[8] CEC inverter efficiency ratings for most inverters can be found at:
http://www.gosolarcalifornia.ca.gov/equipment/inverters.php
[9] PV manufacturers use Standard Test Conditions, or STC, to rate their PV products. STC are 1,000 Watts per square meter solar irradiance, 25 degrees C cell temperature, air mass equal to 1.5, and ASTM G173-03 standard spectrum.
[10] In some cases, this equation will have to be adapted to account for multiple module types and/or inverters. In such cases, the rating of each subsystem can be calculated independently and then added.
[11] A sufficient number of systems has been achieved when adding a single system of random orientation, tilt, tracking characteristics, and capacity (within reason) does not materially change the observed hourly PV Fleet Shape (see next subsection of PV Fleet Shape definition).

system, but before local customer loads are subtracted (i.e., PV must be separately metered from load). Metered data from individual systems is then aggregated by summing the measured output for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

2. Utility Fleet, Simulated Production. If metered data is not available, the aggregate output of all distributed PV systems in the utility service territory can be modeled using PV system technical specifications and hourly irradiance and temperature data. These systems must be deployed in sufficient numbers to accurately derive a correct representation of aggregate PV production. Modeling must take into account the system's location and each array's tracking capability (fixed, single-axis or dual-axis tracking), orientation (tilt and azimuth), module PTC ratings, inverter efficiency and power ratings, other loss factors and the effect of temperature on module output. Technical specifications for each system must be available to enable such modeling. Modeling must also make use of location-specific, time-correlated, measured or satellite-derived plane of array irradiance data. Ideally, the software will also support modeling of solar obstructions.
   - To make use of this option, detailed system specifications for every PV system in the utility's service territory must be obtained. At a minimum, system specifications must include:
     - Location (latitude and longitude)
     - System component ratings (e.g., module ratings an inverter ratings)
     - Tilt and azimuth angles
     - Tracking type (if applicable)
   - After simulating the power production for each system for each hour in the Load Analysis Period, power production must be aggregated by summing the power values for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

3. Expected Fleet, Simulated Production. If neither metered production data nor detailed PV system specifications are available, a diverse set of PV resources can be estimated by simulating groups of systems at major load centers in the utility's service territory with some assumed fleet configuration. To use this method, one or more of the largest load centers in the utility service territory may be used. If a single load center accounts for a high percentage of the utility's total load, a single location will suffice. If there are several large load centers in the territory, groups of systems can be created at each location with capacities proportional to the load in that area.
   - For each location, simulate multiple systems, each rated in proportion to the expected capacity, with azimuth and tilt angles such as the list of systems presented in Table 6. Note

that the list of system configurations should represent the expected fleet composition. No method is explicitly provided to determine the expected fleet composition; however, a utility could analyze the fleet composition of PV fleets outside of its territory.

Table 6. (EXAMPLE) Azimuth and tilt angles

| System | Azimuth | Tilt | % Capacity |
|---|---|---|---|
| **1** | 90 | 20 | 3.5 |
| **2** | 135 | 15 | 3.0 |
| **3** | 135 | 30 | 6.5 |
| **4** | 180 | 0 | 6.0 |
| **5** | 180 | 15 | 16.0 |
| **6** | 180 | 25 | 22.5 |
| **7** | 180 | 35 | 18.0 |
| **8** | 235 | 15 | 8.5 |
| **9** | 235 | 30 | 9.0 |
| **10** | 270 | 20 | 7.0 |

- Simulate each of the PV systems for each hour in the Load Analysis Period. Aggregate power production for the systems is obtained by summing the power values for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.
- If the utility elects to perform a location-specific analysis for the Avoided Distribution Capacity Costs, then it should also take into account what the geographical distribution of the expected PV fleet would be. Again, this could be done by analyzing a PV fleet composition outside of the utility's territory. An alternative method that would be acceptable is to distribute the expected PV fleet across major load centers. Thereby assuming that PV capacity is likely to be added where significant load (and customer density) already exists.
- Regardless of location count and location weighting, the total fleet rating is taken as the sum of the individual system ratings.

### *PV Fleet Shape*

Regardless of which of the three methods is selected for obtaining the Hourly PV Fleet production, the next step is divide each hour's value by the PV Fleet's aggregate AC rating to obtain the PV Fleet Shape. The units of the PV Fleet Shape are kWh per hour per kW-AC (or, equivalently, average kW per kW-AC).

### *Marginal PV Resource*

The PV Fleet Shape is hourly production of a Marginal PV Resource having a rating of 1 kW-AC.

### *Annual Avoided Energy*

Annual Avoided Energy (kWh per kW-AC per year) is the sum of the hourly PV Fleet Shape across all hours of the Load Analysis Period, divided by the numbers of years in the Load Analysis Period. The result is the annual output of the Marginal PV Resource.

$$Annual\ Avoided\ Energy\ (kWh) = \frac{\sum Hourly\ PV\ Fleet\ Production_h}{NumberOfYearsInLoadAnalysisPeriod} \tag{3}$$

- Defined in this way, the Annual Avoided Energy does not include the effects of loss savings. As described in the Loss Analysis subsection, however, it will have to be calculated for the two loss cases (with losses and without losses).

## Load-Match Factors

Capacity-related benefits are time dependent, so it is necessary to evaluate the effectiveness of PV in supporting loads during the critical peak hours. Two different measures of effective capacity are used:

- Effective Load Carrying Capability (ELCC)
- Peak Load Reduction (PLR)

Near term PV penetration levels are used in the calculation of the ELCC and PLR values so that the capacity-related value components will reflect the near term level of PV penetration on the grid. However, the ELCC and PLR will be re-calculated during the annual VOS adjustment and thus reflect any increase in future PV Penetration Levels.

### *Effective Load Carrying Capability (ELCC)*

The Effective Load Carrying Capability (ELCC) is the measure of the effective capacity for distributed PV that can be applied to the avoided generation capacity costs, the avoided reserve capacity costs, the avoided generation fixed O&M costs, and the avoided transmission capacity costs (see Figure 1).

Using current MISO rules for non-wind variable generation (MISO BPM-011, Section 4.2.2.4, page 35)[12]: the ELCC will be calculated from the PV Fleet Shape for hours ending 2pm, 3pm, and 4pm Central Standard Time during June, July, and August over the most recent three years. If three years of data are unavailable, MISO requires “a minimum of 30 consecutive days of historical data during June, July, or August” for the hours ending 2pm, 3pm and 4pm Central Standard Time.

The ELCC is calculated by averaging the PV Fleet Shape over the specified hours, and then dividing by the rating of the Marginal PV Resource (1 kW-AC), which results in a percentage value. Additionally, the ELCC must be calculated for the two loss cases (with and without T&D losses, as described in the Loss Analysis subsection).

### *Peak Load Reduction (PLR)*

The PLR is defined as the maximum distribution load over the Load Analysis Period (without the Marginal PV Resource) minus the maximum distribution load over the Load Analysis Period (with the Marginal PV Resource). The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses). In calculating the PLR, it is not sufficient to limit modeling to the peak hour. All hours over the Load Analysis Period must be included in the calculation. This is because the reduced peak load may not occur in the same hour as the original peak load.

The PLR is calculated as follows. First, determine the maximum Hourly Distribution Load (D1) over the Load Analysis Period. Next, create a second hourly distribution load time series by subtracting the effect of the Marginal PV Resource, i.e., by evaluating what the new distribution load would be each hour given the PV Fleet Shape. Next, determine the maximum load in the second time series (D2). Finally, calculate the PLR by subtracting D2 from D1.

In other words, the PLR represents the capability of the Marginal PV Resource to reduce the peak distribution load over the Load Analysis Period. PLR is expressed in kW per kW-AC.

Additionally, the PLR must be calculated for the two loss cases (with distribution losses and without distribution losses, as described in the Loss Analysis subsection).

[12] https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

### Loss Savings Analysis

In order to calculate the required Loss Savings Factors on a marginal basis as described below, it will be necessary to calculate ELCC, PLR and Annual Avoided Energy each twice. They should be calculated first by *including* the effects of avoided marginal losses, and second by *excluding* them. For example, the ELCC would first be calculated by including avoided transmission and distribution losses, and then re-calculated assuming no losses, i.e., as if the Marginal PV Resource was a central (not distributed) resource.

The calculations should observe the following

Table 7. Losses to be considered.

| Technical Parameter | Loss Savings Considered |
|---|---|
| **Avoided Annual Energy** | Avoided transmission and distribution losses for every hour of the load analysis period. |
| **ELCC** | Avoided transmission and distribution losses during the MISO defined hours. |
| **PLR** | Avoided distribution losses (not transmission) at peak. |

When calculating avoided marginal losses, the analysis must satisfy the following requirements:

1. Avoided losses are to be calculated on an hourly basis over the Load Analysis Period. The avoided losses are to be calculated based on the generation (and import) power during the hour and the expected output of the Marginal PV Resource during the hour.

2. Avoided losses in the transmission system and distribution systems are to be evaluated separately using distinct loss factors based on the most recent study data available.

3. Avoided losses should be calculated on a marginal basis. The marginal avoided losses are the difference in hourly losses between the case without the Marginal PV Resource, and the case with the Marginal PV Resource. Avoided average hourly losses are not calculated. For example, if the Marginal PV Resource were to produce 1 kW of power for an hour in which total customer load is 1000 kW, then the avoided losses would be the calculated losses at 1000 kW of customer load minus the calculated losses at 999 kW of load.

4. Distribution losses should be based on the power entering the distribution system, after transmission losses.

5. Avoided transmission losses should take into account not only the marginal PV generation, but also the avoided marginal distribution losses.

6. Calculations of avoided losses should not include no-load losses (e.g., corona, leakage current). Only load-related losses should be included.

7. Calculations of avoided losses in any hour should take into account the non-linear relationship between losses and load (load-related losses are proportional to the square of the load, assuming constant voltage). For example, the total load-related losses during an hour with a load of 2X would be approximately 4 times the total load-related losses during an hour with a load of only X.

### Loss Savings Factors

The Energy Loss Savings Factor (as a percentage) is defined for use within the VOS Calculation Table:

$$Annual\ Avoided\ Energy_{WithLosses} = Annual\ Avoided\ Energy_{WithoutLosses}\left(1 + Loss\ Savings_{Energy}\right) \tag{4}$$

Equation 5 is then rearranged to solve for the Energy Loss Savings Factor:

$$Loss\ Savings_{Energy} = \frac{Annual\ Avoided\ Energy_{WithLosses}}{Annual\ Avoided\ Energy_{WithoutLosses}} - 1 \tag{5}$$

Similarly, the PLR Loss Savings Factor is defined as:

$$Loss\ Savings_{PLR} = \frac{PLR_{WithLosses}}{PLR_{WithoutLosses}} - 1 \tag{6}$$

and the ELCC Loss Savings Factor is defined as:

$$Loss\ Savings_{ELCC} = \frac{ELCC_{WithLosses}}{ELCC_{WithoutLosses}} - 1 \tag{7}$$

# Methodology: Economic Analysis

The following subsections provide a methodology for performing the economic calculations to derive gross values in $/kWh for each of the VOS components. These gross component values will then be entered into the VOS Calculation Table, which is the second of the two key transparency elements.

Important Note: The economic analysis is initially performed as if PV was centrally-located (without loss-saving benefits of distributed location) and with output perfectly correlated to load. Real-world adjustments are made later in the final VOS summation by including the results of the loss savings and load match analyses.

## Discount Factors

By convention, the analysis year 0 corresponds to the year in which the VOS tariff will begin. As an example, if a VOS was done in 2013 for customers entering a VOS tariff between January 1, 2014 and December 31, 2014, then year 0 would be 2014, year 1 would be 2015, and so on.

For each year *i*, a discount factor is given by

$$DiscountFactor_i = \frac{1}{(1 + DiscountRate)^i} \quad (8)$$

The *DiscountRate* is the utility Weighted Average Cost of Capital.

Similarly, a risk-free discount factor is given by:

$$RiskFreeDiscountFactor_i = \frac{1}{(1 + RiskFreeDiscountRate)^i} \quad (9)$$

The *RiskFreeDiscountRate* is based on the yields of current Treasury securities[13] of 1, 2, 3, 5, 7, 10, 20, and 30 year maturation dates. The *RiskFreeDiscountRate* is used once in the calculation of the Avoided Fuel Costs.

Finally, an environmental discount factor is given by:

$$EnvironmentalDiscountFactor_i = \frac{1}{(1 + EnvironmentalDiscountRate)^i} \quad (10)$$

[13] See http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

The *EnvironmentalDiscountRate* is based on the 3% *real* discount rate that has been determined to be an appropriate societal discount rate for future environmental benefits.[14] As the methodology requires a nominal discount rate, this 3% *real* discount rate is converted into its equivalent 5.61% nominal discount rate as follows:[15]

$$NominalDiscountRate = (1 + RealDiscountRate) \times (1 + GeneralEscalationRate) - 1 \qquad (11)$$

The *EnvironmentalDiscountRate* is used once in the calculation of the Avoided Environmental Costs.

PV degradation is accounted for in the economic calculations by reductions of the annual PV production in future years. As such, the PV production in kWh per kW-AC for the marginal PV resource in year I is given by:

$$PVProduction_i = PVProduction_0 \times (1 - \mathrm{PVDegradationRate})^i \qquad (12)$$

where PVDegradationRate is the annual rate of PV degradation, assumed to be 0.5% per year – the standard PV module warranty guarantees a maximum of 0.5% power degradation per annum. $PVProduction_0$ is the Annual Avoided Energy for the Marginal PV Resource.

PV capacity in year *i* for the Marginal PV Resource, taking into account degradation, equals:

$$PVCapacity_i = (1 - \mathrm{PVDegradationRate})^i \qquad (13)$$

### Avoided Fuel Cost

Avoided fuel costs are based on long-term, risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments.

PV displaces energy generated from the marginal unit, so it avoids the cost of fuel associated with this generation. Furthermore, the PV system is assumed to have a service life of 25 years, so the uncertainty in fuel price fluctuations is also eliminated over this period. For this reason, the avoided fuel cost must take into account the fuel as if it were purchased under a guaranteed, long term contract.

[14] http://www.epa.gov/oms/climate/regulations/scc-tsd.pdf
[15] http://en.wikipedia.org/wiki/Nominal_interest_rate

The methodology provides for three options to accomplish this:

- **Futures Market.** This option is described in detail below, and is based on the NYMEX NG futures with a fixed escalation for years beyond the 12-year trading period.

- **Long Term Price Quotation.** This option is identical to the above option, except the input pricing data is based on an actual price quotation from an AA-rated NG supplier to lock in prices for the 25-year guaranteed period.

- **Utility-guaranteed Price.** This is the 25-year fuel price that is guaranteed by the utilities. Tariffs using the utility guaranteed price will include a mechanism for removing the usage fuel adjustment charges and provide fixed prices over the term.

Table 8 presents the calculation of the economic value of avoided fuel costs.

For the Futures Market option, Guaranteed NG prices are calculated as follows. Prices for the first 12 years are based on NYMEX natural gas futures quotes. These quotes are published daily by the CME Group.[16]

Guaranteed NG prices are calculated by following these steps:

1. First, monthly prices are determined by averaging the 30 days of NYMEX prices for each month, starting with the most recent 30 daily prices and then repeating the same 30-day averaging for every other contract month of the 12 year period. If a utility calculating a VOS rate does not have historical daily NYMEX prices already collected internally they can obtain this data by recording quotes for 30 days. The timing of the data collection should be accounted for in planning the VOS rate calculation.

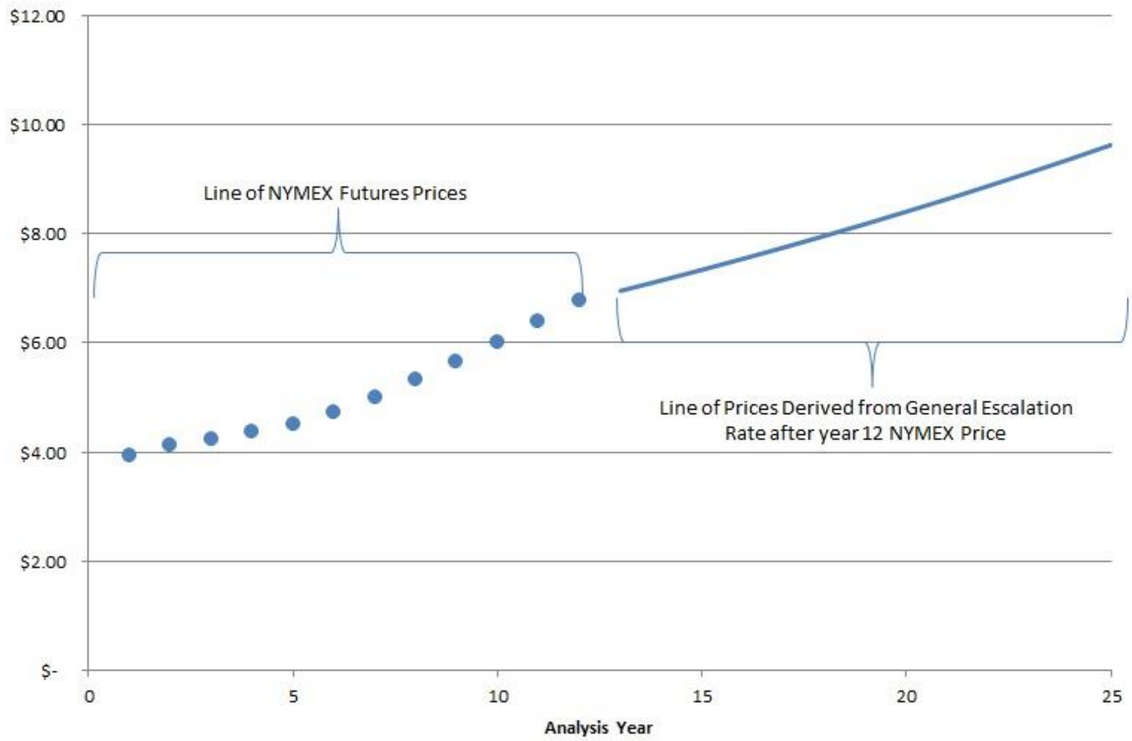
2. Then, the monthly prices are averaged to give a 12-month average in $ per MMBtu, resulting in the first 12 annual prices in the set of 25 annual prices. Prices for years beyond this NYMEX limit are calculated by applying the general escalation rate. An assumed fuel price overhead amount, escalated by year using the general escalation rate, is added to the fuel price to give the burnertip fuel price.

3. Prices for years 13 through 25 are calculated by escalating the year 12 annual average NYMEX quote by the general escalation rate annually for each year.

The guaranteed fuel prices for the methodology's example calculation are shown in figure 2 below.

[16] CME Group's Natural Gas (Henry Hub) Physical Futures Quotes can be found at: http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html.

Figure 2. (EXAMPLE) Guaranteed Fuel Prices




The first-year solar-weighted heat rate is calculated as follows:

$$SolarWeighedHeatRate_0 = \frac{\sum HeatRate_j \times FleetProduction_j}{\sum FleetProduction_j} \qquad (14)$$

where the summation is over all hours *j* of the load analysis period, *HeatRate* is the actual heat rate of the plant on the margin, and *FleetProduction* is the Fleet Production Shape time series.

The solar-weighted heat rate for future years is calculated as:

$$SolarWeighedHeatRate_i = SolarWeighedHeatRate_0 \times (1 + \mathrm{HeatRateDegradationRate})^i \qquad (15)$$

The utility price in year *i* is:

$$UtilityPrice_i = \frac{BurnertipFuelPrice_i \times SolarWeighedHeatRate_i}{10^6} \qquad (16)$$

where the burnertip price is in $ per MMBtu and the heat rate is in Btu per kWh.

Utility cost is the product of the utility price and the per unit PV production. These costs are then discounted using the risk free discount rate and summed for all years. A risk-free discount rate (fitted to the US Treasury yields shown in Table 3) has been selected to account for the fact that there is no risk in the avoided fuel cost.

The VOS price (shown in red in Table 8) is the levelized amount that results in the same discounted amount as the utility price for the Avoided Fuel Cost component.

Table 8. (EXAMPLE) Economic Value of Avoided Fuel Costs.

| Year | Guaranteed NG Price | Burnertip NG Price | Heat Rate | Prices | | p.u. PV Production | Costs | | Discount Factor | Disc. Costs | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Utility | VOS | | Utility | VOS | | Utility | VOS |
| | ($/MMBtu) | ($/MMBtu) | (Btu/kWh) | ($/kWh) | ($/kWh) | (kWh) | ($) | ($) | (risk free) | ($) | ($) |
| 2014 | $3.93 | $4.43 | 8000 | $0.035 | $0.056 | 1,800 | $64 | $101 | 1.000 | $64 | $101 |
| 2015 | $4.12 | $4.64 | 8008 | $0.037 | $0.056 | 1,791 | $67 | $100 | 0.999 | $66 | $100 |
| 2016 | $4.25 | $4.77 | 8016 | $0.038 | $0.056 | 1,782 | $68 | $100 | 0.994 | $68 | $99 |
| 2017 | $4.36 | $4.90 | 8024 | $0.039 | $0.056 | 1,773 | $70 | $99 | 0.986 | $69 | $98 |
| 2018 | $4.50 | $5.05 | 8032 | $0.041 | $0.056 | 1,764 | $72 | $99 | 0.971 | $70 | $96 |
| 2019 | $4.73 | $5.30 | 8040 | $0.043 | $0.056 | 1,755 | $75 | $98 | 0.951 | $71 | $94 |
| 2020 | $5.01 | $5.60 | 8048 | $0.045 | $0.056 | 1,747 | $79 | $98 | 0.927 | $73 | $91 |
| 2021 | $5.33 | $5.94 | 8056 | $0.048 | $0.056 | 1,738 | $83 | $97 | 0.899 | $75 | $88 |
| 2022 | $5.67 | $6.29 | 8064 | $0.051 | $0.056 | 1,729 | $88 | $97 | 0.872 | $76 | $85 |
| 2023 | $6.02 | $6.66 | 8072 | $0.054 | $0.056 | 1,721 | $92 | $96 | 0.842 | $78 | $81 |
| 2024 | $6.39 | $7.04 | 8080 | $0.057 | $0.056 | 1,712 | $97 | $96 | 0.809 | $79 | $78 |
| 2025 | $6.77 | $7.44 | 8088 | $0.060 | $0.056 | 1,703 | $103 | $96 | 0.786 | $81 | $75 |
| 2026 | $6.95 | $7.64 | 8097 | $0.062 | $0.056 | 1,695 | $105 | $95 | 0.762 | $80 | $72 |
| 2027 | $7.14 | $7.86 | 8105 | $0.064 | $0.056 | 1,686 | $107 | $95 | 0.737 | $79 | $70 |
| 2028 | $7.34 | $8.07 | 8113 | $0.065 | $0.056 | 1,678 | $110 | $94 | 0.713 | $78 | $67 |
| 2029 | $7.54 | $8.29 | 8121 | $0.067 | $0.056 | 1,670 | $112 | $94 | 0.688 | $77 | $64 |
| 2030 | $7.75 | $8.52 | 8129 | $0.069 | $0.056 | 1,661 | $115 | $93 | 0.663 | $76 | $62 |
| 2031 | $7.96 | $8.76 | 8137 | $0.071 | $0.056 | 1,653 | $118 | $93 | 0.637 | $75 | $59 |
| 2032 | $8.18 | $9.00 | 8145 | $0.073 | $0.056 | 1,645 | $121 | $92 | 0.612 | $74 | $56 |
| 2033 | $8.41 | $9.24 | 8153 | $0.075 | $0.056 | 1,636 | $123 | $92 | 0.587 | $72 | $54 |
| 2034 | $8.64 | $9.50 | 8162 | $0.078 | $0.056 | 1,628 | $126 | $91 | 0.563 | $71 | $51 |
| 2035 | $8.88 | $9.76 | 8170 | $0.080 | $0.056 | 1,620 | $129 | $91 | 0.543 | $70 | $49 |
| 2036 | $9.12 | $10.03 | 8178 | $0.082 | $0.056 | 1,612 | $132 | $90 | 0.523 | $69 | $47 |
| 2037 | $9.37 | $10.30 | 8186 | $0.084 | $0.056 | 1,604 | $135 | $90 | 0.504 | $68 | $45 |
| 2038 | $9.63 | $10.59 | 8194 | $0.087 | $0.056 | 1,596 | $138 | $89 | 0.485 | $67 | $43 |
| | | | | | | | **Validation: Present Value** | | | **$1,826** | **$1,826** |

### Avoided Plant O&M – Fixed

Economic value calculations for fixed plant O&M are presented in Table 9. The first year fixed value is escalated at the O&M escalation rate for future years.

Similarly, PV capacity has an initial value of one during the first year because it is applicable to PV systems installed in the first year. Note that effective capacity (load matching) is handled separately, and this table represents the "ideal" resource, as if PV were able to receive the same capacity credit as a fully dispatchable technology.

The utility cost is the fixed O&M cost times the PV capacity divided by the utility capacity. Utility prices are the cost divided by the PV production. Costs are discounted using the utility discount factor and are summed for all years.

The VOS component value is calculated as before such that the discounted total is equal to the discounted utility cost.

Table 9. (EXAMPLE) Economic value of avoided plant O&M – fixed

| | | | | Prices | | | Costs | | | Disc. Costs | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | O&M Fixed | Utility Capacity | PV Capacity | Utility | VOS | p.u. PV Production | Utility | VOS | Discount Factor | Utility | VOS |
| | ($/kW) | (p.u.) | (kW) | ($/kWh) | ($/kWh) | (kWh) | ($) | ($) | | ($) | ($) |
| 2014 | $5.00 | 1.000 | 1.000 | $0.003 | $0.003 | 1800 | $5 | $6 | 1.000 | $5 | $6 |
| 2015 | $5.11 | 0.999 | 0.995 | $0.003 | $0.003 | 1791 | $5 | $6 | 0.926 | $5 | $6 |
| 2016 | $5.21 | 0.998 | 0.990 | $0.003 | $0.003 | 1782 | $5 | $6 | 0.857 | $4 | $5 |
| 2017 | $5.32 | 0.997 | 0.985 | $0.003 | $0.003 | 1773 | $5 | $6 | 0.794 | $4 | $5 |
| 2018 | $5.43 | 0.996 | 0.980 | $0.003 | $0.003 | 1764 | $5 | $6 | 0.735 | $4 | $4 |
| 2019 | $5.55 | 0.995 | 0.975 | $0.003 | $0.003 | 1755 | $5 | $6 | 0.681 | $4 | $4 |
| 2020 | $5.66 | 0.994 | 0.970 | $0.003 | $0.003 | 1747 | $6 | $6 | 0.630 | $3 | $4 |
| 2021 | $5.78 | 0.993 | 0.966 | $0.003 | $0.003 | 1738 | $6 | $6 | 0.583 | $3 | $3 |
| 2022 | $5.91 | 0.992 | 0.961 | $0.003 | $0.003 | 1729 | $6 | $6 | 0.540 | $3 | $3 |
| 2023 | $6.03 | 0.991 | 0.956 | $0.003 | $0.003 | 1721 | $6 | $6 | 0.500 | $3 | $3 |
| 2024 | $6.16 | 0.990 | 0.951 | $0.003 | $0.003 | 1712 | $6 | $6 | 0.463 | $3 | $3 |
| 2025 | $6.29 | 0.989 | 0.946 | $0.004 | $0.003 | 1703 | $6 | $6 | 0.429 | $3 | $2 |
| 2026 | $6.42 | 0.988 | 0.942 | $0.004 | $0.003 | 1695 | $6 | $6 | 0.397 | $2 | $2 |
| 2027 | $6.55 | 0.987 | 0.937 | $0.004 | $0.003 | 1686 | $6 | $6 | 0.368 | $2 | $2 |
| 2028 | $6.69 | 0.986 | 0.932 | $0.004 | $0.003 | 1678 | $6 | $6 | 0.340 | $2 | $2 |
| 2029 | $6.83 | 0.985 | 0.928 | $0.004 | $0.003 | 1670 | $6 | $6 | 0.315 | $2 | $2 |
| 2030 | $6.97 | 0.984 | 0.923 | $0.004 | $0.003 | 1661 | $7 | $6 | 0.292 | $2 | $2 |
| 2031 | $7.12 | 0.983 | 0.918 | $0.004 | $0.003 | 1653 | $7 | $6 | 0.270 | $2 | $1 |
| 2032 | $7.27 | 0.982 | 0.914 | $0.004 | $0.003 | 1645 | $7 | $5 | 0.250 | $2 | $1 |
| 2033 | $7.42 | 0.981 | 0.909 | $0.004 | $0.003 | 1636 | $7 | $5 | 0.232 | $2 | $1 |
| 2034 | $7.58 | 0.980 | 0.905 | $0.004 | $0.003 | 1628 | $7 | $5 | 0.215 | $2 | $1 |
| 2035 | $7.74 | 0.979 | 0.900 | $0.004 | $0.003 | 1620 | $7 | $5 | 0.199 | $1 | $1 |
| 2036 | $7.90 | 0.978 | 0.896 | $0.004 | $0.003 | 1612 | $7 | $5 | 0.184 | $1 | $1 |
| 2037 | $8.07 | 0.977 | 0.891 | $0.005 | $0.003 | 1604 | $7 | $5 | 0.170 | $1 | $1 |
| 2038 | $8.24 | 0.976 | 0.887 | $0.005 | $0.003 | 1596 | $7 | $5 | 0.158 | $1 | $1 |
| | | | | | | | **Validation: Present Value** | | | **$67** | **$67** |

## Avoided Plant O&M – Variable

An example calculation of avoided plant O&M is displayed in Table 10. Utility prices are given in the VOS Data Table, escalated each year by the O&M escalation rate. As before, the per unit PV production is shown with annual degradation taken into account. The utility cost is the product of the utility price and the per unit production, and these costs are discounted. The VOS price of variable O&M is the levelized value resulting in the same total discounted cost.

Table 10. (EXAMPLE) Economic value of avoided plant O&M – variable.

| | Prices | | | Costs | | | Disc. Costs | |
|---|---|---|---|---|---|---|---|---|
| Year | Utility ($/kWh) | VOS ($/kWh) | p.u. PV Production (kWh) | Utility ($) | VOS ($) | Discount Factor | Utility ($) | VOS ($) |
| 2014 | $0.001 | $0.001 | 1,800 | $2 | $2 | 1.000 | $2 | $2 |
| 2015 | $0.001 | $0.001 | 1,791 | $2 | $2 | 0.926 | $2 | $2 |
| 2016 | $0.001 | $0.001 | 1,782 | $2 | $2 | 0.857 | $2 | $2 |
| 2017 | $0.001 | $0.001 | 1,773 | $2 | $2 | 0.794 | $1 | $2 |
| 2018 | $0.001 | $0.001 | 1,764 | $2 | $2 | 0.735 | $1 | $2 |
| 2019 | $0.001 | $0.001 | 1,755 | $2 | $2 | 0.681 | $1 | $1 |
| 2020 | $0.001 | $0.001 | 1,747 | $2 | $2 | 0.630 | $1 | $1 |
| 2021 | $0.001 | $0.001 | 1,738 | $2 | $2 | 0.583 | $1 | $1 |
| 2022 | $0.001 | $0.001 | 1,729 | $2 | $2 | 0.540 | $1 | $1 |
| 2023 | $0.001 | $0.001 | 1,721 | $2 | $2 | 0.500 | $1 | $1 |
| 2024 | $0.001 | $0.001 | 1,712 | $2 | $2 | 0.463 | $1 | $1 |
| 2025 | $0.001 | $0.001 | 1,703 | $2 | $2 | 0.429 | $1 | $1 |
| 2026 | $0.001 | $0.001 | 1,695 | $2 | $2 | 0.397 | $1 | $1 |
| 2027 | $0.001 | $0.001 | 1,686 | $2 | $2 | 0.368 | $1 | $1 |
| 2028 | $0.001 | $0.001 | 1,678 | $2 | $2 | 0.340 | $1 | $1 |
| 2029 | $0.001 | $0.001 | 1,670 | $2 | $2 | 0.315 | $1 | $1 |
| 2030 | $0.001 | $0.001 | 1,661 | $2 | $2 | 0.292 | $1 | $1 |
| 2031 | $0.001 | $0.001 | 1,653 | $2 | $2 | 0.270 | $1 | $1 |
| 2032 | $0.001 | $0.001 | 1,645 | $2 | $2 | 0.250 | $1 | $0 |
| 2033 | $0.001 | $0.001 | 1,636 | $2 | $2 | 0.232 | $1 | $0 |
| 2034 | $0.001 | $0.001 | 1,628 | $2 | $2 | 0.215 | $1 | $0 |
| 2035 | $0.002 | $0.001 | 1,620 | $2 | $2 | 0.199 | $0 | $0 |
| 2036 | $0.002 | $0.001 | 1,612 | $2 | $2 | 0.184 | $0 | $0 |
| 2037 | $0.002 | $0.001 | 1,604 | $3 | $2 | 0.170 | $0 | $0 |
| 2038 | $0.002 | $0.001 | 1,596 | $3 | $2 | 0.158 | $0 | $0 |

| Validation: Present Value | Utility | VOS |
|---|---|---|
| | **$24** | **$24** |

## Avoided Generation Capacity Cost

The solar-weighted capacity cost is based on the installed capital cost of a peaking combustion turbine and the installed capital cost of a combined cycle gas turbine, interpolated based on heat rate:

$$Cost = Cost_{CCGT} + (HeatRate_{PV} - HeatRate_{CCGT}) \times \frac{Cost_{CT} - Cost_{CCGT}}{HeatRate_{CT} - HeatRate_{CCGT}} \quad (17)$$

Where $HeatRate_{PV}$ is the solar-weighted heat rate calculated in equation ( 14 ).

Using equation ( 17 ) with the CT/CCGT heat rates and costs from the example VOS Data Table, we calculated a solar-weighted capacity cost of $1,050 per kW. In the example, the amortized cost is $86 per kW-yr.

Table 11 illustrates how utility costs are calculated by taking into account the degrading heat rate of the marginal unit and PV. For example, in year 2015, the utility cost is $86 per kW-yr x 0.999 / 0.995 to give $85 for each unit of effective PV capacity. Utility prices are back-calculated for reference from the per unit PV production. Again, the VOS price is selected to give the same total discounted cost as the utility costs for the Generation Capacity Cost component.

Table 11. (EXAMPLE) Economic value of avoided generation capacity cost.

| | | | | Prices | | | Costs | | | Disc. Costs | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Capacity Cost | Utility Capacity | PV Capacity | Utility | VOS | p.u. PV Production | Utility | VOS | Discount Factor | Utility | VOS |
| | ($/kW-yr) | (p.u.) | (kW) | ($/kWh) | ($/kWh) | (kWh) | ($) | ($) | | ($) | ($) |
| 2014 | $86 | 1.000 | 1.000 | $0.048 | $0.048 | 1800 | $86 | $87 | 1.000 | $86 | $87 |
| 2015 | $86 | 0.999 | 0.995 | $0.048 | $0.048 | 1791 | $85 | $86 | 0.926 | $79 | $80 |
| 2016 | $86 | 0.998 | 0.990 | $0.048 | $0.048 | 1782 | $85 | $86 | 0.857 | $73 | $73 |
| 2017 | $86 | 0.997 | 0.985 | $0.048 | $0.048 | 1773 | $85 | $85 | 0.794 | $67 | $68 |
| 2018 | $86 | 0.996 | 0.980 | $0.048 | $0.048 | 1764 | $84 | $85 | 0.735 | $62 | $62 |
| 2019 | $86 | 0.995 | 0.975 | $0.048 | $0.048 | 1755 | $84 | $84 | 0.681 | $57 | $57 |
| 2020 | $86 | 0.994 | 0.970 | $0.048 | $0.048 | 1747 | $84 | $84 | 0.630 | $53 | $53 |
| 2021 | $86 | 0.993 | 0.966 | $0.048 | $0.048 | 1738 | $83 | $84 | 0.583 | $49 | $49 |
| 2022 | $86 | 0.992 | 0.961 | $0.048 | $0.048 | 1729 | $83 | $83 | 0.540 | $45 | $45 |
| 2023 | $86 | 0.991 | 0.956 | $0.048 | $0.048 | 1721 | $83 | $83 | 0.500 | $41 | $41 |
| 2024 | $86 | 0.990 | 0.951 | $0.048 | $0.048 | 1712 | $82 | $82 | 0.463 | $38 | $38 |
| 2025 | $86 | 0.989 | 0.946 | $0.048 | $0.048 | 1703 | $82 | $82 | 0.429 | $35 | $35 |
| 2026 | $86 | 0.988 | 0.942 | $0.048 | $0.048 | 1695 | $82 | $81 | 0.397 | $32 | $32 |
| 2027 | $86 | 0.987 | 0.937 | $0.048 | $0.048 | 1686 | $81 | $81 | 0.368 | $30 | $30 |
| 2028 | $86 | 0.986 | 0.932 | $0.048 | $0.048 | 1678 | $81 | $81 | 0.340 | $28 | $27 |
| 2029 | $86 | 0.985 | 0.928 | $0.048 | $0.048 | 1670 | $81 | $80 | 0.315 | $25 | $25 |
| 2030 | $86 | 0.984 | 0.923 | $0.048 | $0.048 | 1661 | $80 | $80 | 0.292 | $23 | $23 |
| 2031 | $86 | 0.983 | 0.918 | $0.049 | $0.048 | 1653 | $80 | $79 | 0.270 | $22 | $21 |
| 2032 | $86 | 0.982 | 0.914 | $0.049 | $0.048 | 1645 | $80 | $79 | 0.250 | $20 | $20 |
| 2033 | $86 | 0.981 | 0.909 | $0.049 | $0.048 | 1636 | $80 | $79 | 0.232 | $18 | $18 |
| 2034 | $86 | 0.980 | 0.905 | $0.049 | $0.048 | 1628 | $79 | $78 | 0.215 | $17 | $17 |
| 2035 | $86 | 0.979 | 0.900 | $0.049 | $0.048 | 1620 | $79 | $78 | 0.199 | $16 | $15 |
| 2036 | $86 | 0.978 | 0.896 | $0.049 | $0.048 | 1612 | $79 | $77 | 0.184 | $14 | $14 |
| 2037 | $86 | 0.977 | 0.891 | $0.049 | $0.048 | 1604 | $78 | $77 | 0.170 | $13 | $13 |
| 2038 | $86 | 0.976 | 0.887 | $0.049 | $0.048 | 1596 | $78 | $77 | 0.158 | $12 | $12 |
| | | | | | | | **Validation: Present Value** | | | **$958** | **$958** |

### Avoided Reserve Capacity Cost

An example of the calculation of avoided reserve capacity cost is shown in Table 12. This is identical to the generation capacity cost calculation, except utility costs are multiplied by the reserve capacity margin. In the example, the reserve capacity margin is 15%, so the utility cost for 2014 is calculated as $86 per unit effective capacity x 15% = $13. The rest of the calculation is identical to the capacity cost calculation.

### Avoided Transmission Capacity Cost

Avoided transmission costs are calculated the same way as avoided generation costs except in two ways. First, transmission capacity is assumed not to degrade over time (PV degradation is still accounted for). Second, avoided transmission capacity costs are calculated based on the utility's 5-year average MISO OATT Schedule 9 charge in Start Year USD, e.g., in 2014 USD if year one of the VOS tariff was 2014. Table 13 shows the example calculation.

Table 12. (EXAMPLE) Economic value of avoided reserve capacity cost.

| Year | Capacity Cost | Gen. Capacity | PV Capacity | Prices Utility | Prices VOS | p.u. PV Production | Costs Utility | Costs VOS | Discount Factor | Disc. Costs Utility | Disc. Costs VOS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | ($/kW-yr) | (p.u.) | (kW) | ($/kWh) | ($/kWh) | (kWh) | ($) | ($) | | ($) | ($) |
| 2014 | $86 | 1.000 | 1.000 | $0.007 | $0.007 | 1800 | $13 | $13 | 1.000 | $13 | $13 |
| 2015 | $86 | 0.999 | 0.999 | $0.007 | $0.007 | 1791 | $13 | $13 | 0.926 | $12 | $12 |
| 2016 | $86 | 0.998 | 0.994 | $0.007 | $0.007 | 1782 | $13 | $13 | 0.857 | $11 | $11 |
| 2017 | $86 | 0.997 | 0.986 | $0.007 | $0.007 | 1773 | $13 | $13 | 0.794 | $10 | $10 |
| 2018 | $86 | 0.996 | 0.971 | $0.007 | $0.007 | 1764 | $13 | $13 | 0.735 | $9 | $9 |
| 2019 | $86 | 0.995 | 0.951 | $0.007 | $0.007 | 1755 | $13 | $13 | 0.681 | $9 | $9 |
| 2020 | $86 | 0.994 | 0.927 | $0.007 | $0.007 | 1747 | $13 | $13 | 0.630 | $8 | $8 |
| 2021 | $86 | 0.993 | 0.899 | $0.007 | $0.007 | 1738 | $13 | $13 | 0.583 | $7 | $7 |
| 2022 | $86 | 0.992 | 0.872 | $0.007 | $0.007 | 1729 | $12 | $12 | 0.540 | $7 | $7 |
| 2023 | $86 | 0.991 | 0.842 | $0.007 | $0.007 | 1721 | $12 | $12 | 0.500 | $6 | $6 |
| 2024 | $86 | 0.990 | 0.809 | $0.007 | $0.007 | 1712 | $12 | $12 | 0.463 | $6 | $6 |
| 2025 | $86 | 0.989 | 0.786 | $0.007 | $0.007 | 1703 | $12 | $12 | 0.429 | $5 | $5 |
| 2026 | $86 | 0.988 | 0.762 | $0.007 | $0.007 | 1695 | $12 | $12 | 0.397 | $5 | $5 |
| 2027 | $86 | 0.987 | 0.737 | $0.007 | $0.007 | 1686 | $12 | $12 | 0.368 | $4 | $4 |
| 2028 | $86 | 0.986 | 0.713 | $0.007 | $0.007 | 1678 | $12 | $12 | 0.340 | $4 | $4 |
| 2029 | $86 | 0.985 | 0.688 | $0.007 | $0.007 | 1670 | $12 | $12 | 0.315 | $4 | $4 |
| 2030 | $86 | 0.984 | 0.663 | $0.007 | $0.007 | 1661 | $12 | $12 | 0.292 | $4 | $3 |
| 2031 | $86 | 0.983 | 0.637 | $0.007 | $0.007 | 1653 | $12 | $12 | 0.270 | $3 | $3 |
| 2032 | $86 | 0.982 | 0.612 | $0.007 | $0.007 | 1645 | $12 | $12 | 0.250 | $3 | $3 |
| 2033 | $86 | 0.981 | 0.587 | $0.007 | $0.007 | 1636 | $12 | $12 | 0.232 | $3 | $3 |
| 2034 | $86 | 0.980 | 0.563 | $0.007 | $0.007 | 1628 | $12 | $12 | 0.215 | $3 | $3 |
| 2035 | $86 | 0.979 | 0.543 | $0.007 | $0.007 | 1620 | $12 | $12 | 0.199 | $2 | $2 |
| 2036 | $86 | 0.978 | 0.523 | $0.007 | $0.007 | 1612 | $12 | $12 | 0.184 | $2 | $2 |
| 2037 | $86 | 0.977 | 0.504 | $0.007 | $0.007 | 1604 | $12 | $12 | 0.170 | $2 | $2 |
| 2038 | $86 | 0.976 | 0.485 | $0.007 | $0.007 | 1596 | $12 | $12 | 0.158 | $2 | $2 |
| | | | | | | | **Validation: Present Value** | | | **$144** | **$144** |

Table 13. (EXAMPLE) Economic value of avoided transmission capacity cost.

| Year | Capacity Cost | Trans. Capacity | PV Capacity | Prices Utility | Prices VOS | p.u. PV Production | Costs Utility | Costs VOS | Discount Factor | Disc. Costs Utility | Disc. Costs VOS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | ($/kW-yr) | (p.u.) | (kW) | ($/kWh) | ($/kWh) | (kWh) | ($) | ($) | | ($) | ($) |
| 2014 | $33 | 1.000 | 1.000 | $0.018 | $0.018 | 1800 | $33 | $33 | 1.000 | $33 | $33 |
| 2015 | $33 | 1.000 | 0.995 | $0.018 | $0.018 | 1791 | $33 | $33 | 0.926 | $30 | $30 |
| 2016 | $33 | 1.000 | 0.990 | $0.018 | $0.018 | 1782 | $33 | $33 | 0.857 | $28 | $28 |
| 2017 | $33 | 1.000 | 0.985 | $0.018 | $0.018 | 1773 | $33 | $33 | 0.794 | $26 | $26 |
| 2018 | $33 | 1.000 | 0.980 | $0.018 | $0.018 | 1764 | $32 | $32 | 0.735 | $24 | $24 |
| 2019 | $33 | 1.000 | 0.975 | $0.018 | $0.018 | 1755 | $32 | $32 | 0.681 | $22 | $22 |
| 2020 | $33 | 1.000 | 0.970 | $0.018 | $0.018 | 1747 | $32 | $32 | 0.630 | $20 | $20 |
| 2021 | $33 | 1.000 | 0.966 | $0.018 | $0.018 | 1738 | $32 | $32 | 0.583 | $19 | $19 |
| 2022 | $33 | 1.000 | 0.961 | $0.018 | $0.018 | 1729 | $32 | $32 | 0.540 | $17 | $17 |
| 2023 | $33 | 1.000 | 0.956 | $0.018 | $0.018 | 1721 | $32 | $32 | 0.500 | $16 | $16 |
| 2024 | $33 | 1.000 | 0.951 | $0.018 | $0.018 | 1712 | $31 | $31 | 0.463 | $15 | $15 |
| 2025 | $33 | 1.000 | 0.946 | $0.018 | $0.018 | 1703 | $31 | $31 | 0.429 | $13 | $13 |
| 2026 | $33 | 1.000 | 0.942 | $0.018 | $0.018 | 1695 | $31 | $31 | 0.397 | $12 | $12 |
| 2027 | $33 | 1.000 | 0.937 | $0.018 | $0.018 | 1686 | $31 | $31 | 0.368 | $11 | $11 |
| 2028 | $33 | 1.000 | 0.932 | $0.018 | $0.018 | 1678 | $31 | $31 | 0.340 | $10 | $10 |
| 2029 | $33 | 1.000 | 0.928 | $0.018 | $0.018 | 1670 | $31 | $31 | 0.315 | $10 | $10 |
| 2030 | $33 | 1.000 | 0.923 | $0.018 | $0.018 | 1661 | $30 | $30 | 0.292 | $9 | $9 |
| 2031 | $33 | 1.000 | 0.918 | $0.018 | $0.018 | 1653 | $30 | $30 | 0.270 | $8 | $8 |
| 2032 | $33 | 1.000 | 0.914 | $0.018 | $0.018 | 1645 | $30 | $30 | 0.250 | $8 | $8 |
| 2033 | $33 | 1.000 | 0.909 | $0.018 | $0.018 | 1636 | $30 | $30 | 0.232 | $7 | $7 |
| 2034 | $33 | 1.000 | 0.905 | $0.018 | $0.018 | 1628 | $30 | $30 | 0.215 | $6 | $6 |
| 2035 | $33 | 1.000 | 0.900 | $0.018 | $0.018 | 1620 | $30 | $30 | 0.199 | $6 | $6 |
| 2036 | $33 | 1.000 | 0.896 | $0.018 | $0.018 | 1612 | $30 | $30 | 0.184 | $5 | $5 |
| 2037 | $33 | 1.000 | 0.891 | $0.018 | $0.018 | 1604 | $29 | $29 | 0.170 | $5 | $5 |
| 2038 | $33 | 1.000 | 0.887 | $0.018 | $0.018 | 1596 | $29 | $29 | 0.158 | $5 | $5 |
| | | | | | | | **Validation: Present Value** | | | **$365** | **$365** |

## Avoided Distribution Capacity Cost

Avoided distribution capacity costs may be calculated in either of two ways:

- **System-wide Avoided Costs**. These are calculated using utility-wide costs and lead to a VOS rate that is “averaged” and applicable to all solar customers. This method is described below in the methodology.

- **Location-specific Avoided Costs**. These are calculated using location-specific costs, growth rates, etc., and lead to location-specific VOS rates. This method provides the utility with a means for offering a higher-value VOS rate in areas where capacity is most needed (areas of highest value). The details of this method are site specific and not included in the methodology, however they are to be implemented in accordance with the requirements set for the below.

### *System-wide Avoided Costs*

System wide costs are determined using actual data from each of the last 10 years and peak growth rates are based on the utility’s estimated future growth over the next 15 years. The costs and growth rate must be taken over the same time period because the historical investments must be tied to the growth associated with those investments.

All costs for each year for FERC accounts 360, 361, 362, 365, 366, and 367 should be included. These costs, however, should be adjusted to consider only capacity-related amounts. As such, the capacity-related percentages shown in Table 14 will be utility specific.

Table 14. (EXAMPLE) Determination of deferrable costs.

| Account | Account Name | Additions ($) [A] | Retirements ($) [R] | Net Additions ($) = [A] - [R] | Capacity Related? | Deferrable ($) |
|---|---|---|---|---|---|---|
| | **DISTRIBUTION PLANT** | | | | | |
| 360 | Land and Land Rights | 13,931,928 | 233,588 | 13,698,340 | 100% | 13,698,340 |
| 361 | Structures and Improvements | 35,910,551 | 279,744 | 35,630,807 | 100% | 35,630,807 |
| 362 | Station Equipment | 478,389,052 | 20,808,913 | 457,580,139 | 100% | 457,580,139 |
| 363 | Storage Battery Equipment | | | | | |
| 364 | Poles, Towers, and Fixtures | 310,476,864 | 9,489,470 | 300,987,394 | | |
| 365 | Overhead Conductors and Devices | 349,818,997 | 22,090,380 | 327,728,617 | 25% | 81,932,154 |
| 366 | Underground Conduit | 210,115,953 | 10,512,018 | 199,603,935 | 25% | 49,900,984 |
| 367 | Underground Conductors and Devices | 902,527,963 | 32,232,966 | 870,294,997 | 25% | 217,573,749 |
| 368 | Line Transformers | 389,984,149 | 19,941,075 | 370,043,074 | | |
| 369 | Services | 267,451,206 | 5,014,559 | 262,436,647 | | |
| 370 | Meters | 118,461,196 | 4,371,827 | 114,089,369 | | |
| 371 | Installations on Customer Premises | 22,705,193 | | 22,705,193 | | |
| 372 | Leased Property on Customer Premises | | | | | |
| 373 | Street Lighting and Signal Systems | 53,413,993 | 3,022,447 | 50,391,546 | | |
| 374 | Asset Retirement Costs for Distribution Plant | 15,474,098 | 2,432,400 | 13,041,698 | | |
| TOTAL | | 3,168,661,143 | 130,429,387 | 3,038,231,756 | | $856,316,173 |

Cost per unit growth ($ per kW) is calculated by taking all of the total deferrable cost for each year, adjusting for inflation, and dividing by the kW increase in peak annual load over the 10 years.

Future growth in peak load is based on the utility's estimated future growth over the next 15 years. It is calculated using the ratio of peak loads of the fifteenth year (year 15) and the peak load from the first year (year 1):

$$GrowthRate = \left(\frac{P_{15}}{P_1}\right)^{1/14} - 1 \tag{18}$$

If the resulting growth rate is zero or negative (before adding solar PV), set the avoided distribution capacity to zero.

A sample economic value calculation is presented in Table 15. The distribution cost for the first year ($200 per kW in the example) is taken from the analysis of historical cost and estimated growth as described above. This cost is escalated each year using the rate in the VOS Data Table.

For each future year, the amount of new distribution capacity is calculated based on the growth rate, and this is multiplied by the cost per kW to get the cost for the year. The total discounted cost is calculated ($149M) and amortized over the 25 years.

PV is assumed to be installed in sufficient capacity to allow this investment stream to be deferred for one year. The total discounted cost of the deferred time series is calculated ($140M) and amortized.

Utility costs are calculated using the difference between the amortized costs of the conventional plan and the amortized cost of the deferred plan. For example, the utility cost for 2022 is ($14M - $13M)/54MW x 1000 W/kW = $14 per effective kW of PV. As before, utility prices are back-calculated using PV production, and the VOS component rate is calculated such that the total discounted amount equals the discounted utility cost.

### *Location-specific Avoided Costs*

As an alternative to system-wide costs for distribution, location-specific costs may be used. When calculating location-specific costs, the calculation should follow the same method of the system-wide avoided cost method, but use local technical and cost data. The calculation should satisfy the following requirements:

- The distribution cost VOS should be calculated for each distribution planning area, defined as the minimum area in which capacity needs cannot be met by transferring loads internally from one circuit to another.
- Distribution loads (the sum of all relevant feeders), peak load growth rates and capital costs should be based on the distribution planning area.

- Local Fleet Production Shapes may be used, if desired. Alternatively, the system-level Fleet Production Shape may be used.
- Anticipated capital costs should be evaluated based on capacity related investments only (as above) using budgetary engineering cost estimates. All anticipated capital investments in the planning area should be included. Planned capital investments should be assumed to meet capacity requirements for the number of years defined by the amount of new capacity added (in MW) divided by the local growth rate (MW per year). Beyond this time period, which is beyond the planning horizon, new capacity investments should be assumed each year using the system-wide method.
- Planning areas for which engineering cost estimates are not available may be combined, and the VOS calculated using the system-wide method.

Table 15. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

| | | Conventional Distribution Planning | | | | Deferred Distribution Planning | | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Distribution Cost | New Dist. Capacity | Capital Cost | Disc. Capital Cost | Amortized | Def. Dist. Capacity | Def. Capital Cost | Disc. Capital Cost | Amortized |
| | ($/kW) | (MW) | ($M) | ($M) | $M/yr | (MW) | ($M) | ($M) | $M/yr |
| 2014 | $200 | 50 | $10 | $10 | $14 | | | | $13 |
| 2015 | $204 | 50 | $10 | $9 | $14 | 50 | $10 | $9 | $13 |
| 2016 | $208 | 51 | $11 | $9 | $14 | 50 | $10 | $9 | $13 |
| 2017 | $212 | 51 | $11 | $9 | $14 | 51 | $11 | $9 | $13 |
| 2018 | $216 | 52 | $11 | $8 | $14 | 51 | $11 | $8 | $13 |
| 2019 | $221 | 52 | $11 | $8 | $14 | 52 | $11 | $8 | $13 |
| 2020 | $225 | 53 | $12 | $7 | $14 | 52 | $12 | $7 | $13 |
| 2021 | $230 | 53 | $12 | $7 | $14 | 53 | $12 | $7 | $13 |
| 2022 | $234 | 54 | $13 | $7 | $14 | 53 | $12 | $7 | $13 |
| 2023 | $239 | 54 | $13 | $6 | $14 | 54 | $13 | $6 | $13 |
| 2024 | $244 | 55 | $13 | $6 | $14 | 54 | $13 | $6 | $13 |
| 2025 | $249 | 55 | $14 | $6 | $14 | 55 | $14 | $6 | $13 |
| 2026 | $254 | 56 | $14 | $6 | $14 | 55 | $14 | $6 | $13 |
| 2027 | $259 | 56 | $15 | $5 | $14 | 56 | $14 | $5 | $13 |
| 2028 | $264 | 57 | $15 | $5 | $14 | 56 | $15 | $5 | $13 |
| 2029 | $269 | 57 | $15 | $5 | $14 | 57 | $15 | $5 | $13 |
| 2030 | $275 | 58 | $16 | $5 | $14 | 57 | $16 | $5 | $13 |
| 2031 | $280 | 59 | $16 | $4 | $14 | 58 | $16 | $4 | $13 |
| 2032 | $286 | 59 | $17 | $4 | $14 | 59 | $17 | $4 | $13 |
| 2033 | $291 | 60 | $17 | $4 | $14 | 59 | $17 | $4 | $13 |
| 2034 | $297 | 60 | $18 | $4 | $14 | 60 | $18 | $4 | $13 |
| 2035 | $303 | 61 | $18 | $4 | $14 | 60 | $18 | $4 | $13 |
| 2036 | $309 | 62 | $19 | $4 | $14 | 61 | $19 | $3 | $13 |
| 2037 | $315 | 62 | $20 | $3 | $14 | 62 | $19 | $3 | $13 |
| 2038 | $322 | 63 | $20 | $3 | $14 | 62 | $20 | $3 | $13 |
| 2039 | $328 | | | | | 63 | $21 | $3 | |
| | | | | $149 | | | | $140 | |

CONTINUED Table 15. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

| | | Costs | | | Disc. Costs | | Prices | |
|---|---|---|---|---|---|---|---|---|
| Year | p.u. PV Production | Utility | VOS | Discount Factor | Utility | VOS | Utility | VOS |
| | (kWh) | ($) | ($) | | ($) | ($) | ($/kWh) | ($/kWh) |
| 2014 | 1800 | $16 | $15 | 1.000 | $16 | $15 | $0.009 | $0.008 |
| 2015 | 1791 | $15 | $15 | 0.926 | $14 | $14 | $0.009 | $0.008 |
| 2016 | 1782 | $15 | $15 | 0.857 | $13 | $13 | $0.009 | $0.008 |
| 2017 | 1773 | $15 | $15 | 0.794 | $12 | $12 | $0.009 | $0.008 |
| 2018 | 1764 | $15 | $15 | 0.735 | $11 | $11 | $0.009 | $0.008 |
| 2019 | 1755 | $15 | $15 | 0.681 | $10 | $10 | $0.008 | $0.008 |
| 2020 | 1747 | $15 | $15 | 0.630 | $9 | $9 | $0.008 | $0.008 |
| 2021 | 1738 | $15 | $15 | 0.583 | $9 | $8 | $0.008 | $0.008 |
| 2022 | 1729 | $14 | $14 | 0.540 | $8 | $8 | $0.008 | $0.008 |
| 2023 | 1721 | $14 | $14 | 0.500 | $7 | $7 | $0.008 | $0.008 |
| 2024 | 1712 | $14 | $14 | 0.463 | $7 | $7 | $0.008 | $0.008 |
| 2025 | 1703 | $14 | $14 | 0.429 | $6 | $6 | $0.008 | $0.008 |
| 2026 | 1695 | $14 | $14 | 0.397 | $6 | $6 | $0.008 | $0.008 |
| 2027 | 1686 | $14 | $14 | 0.368 | $5 | $5 | $0.008 | $0.008 |
| 2028 | 1678 | $14 | $14 | 0.340 | $5 | $5 | $0.008 | $0.008 |
| 2029 | 1670 | $13 | $14 | 0.315 | $4 | $4 | $0.008 | $0.008 |
| 2030 | 1661 | $13 | $14 | 0.292 | $4 | $4 | $0.008 | $0.008 |
| 2031 | 1653 | $13 | $14 | 0.270 | $4 | $4 | $0.008 | $0.008 |
| 2032 | 1645 | $13 | $14 | 0.250 | $3 | $3 | $0.008 | $0.008 |
| 2033 | 1636 | $13 | $14 | 0.232 | $3 | $3 | $0.008 | $0.008 |
| 2034 | 1628 | $13 | $14 | 0.215 | $3 | $3 | $0.008 | $0.008 |
| 2035 | 1620 | $13 | $14 | 0.199 | $3 | $3 | $0.008 | $0.008 |
| 2036 | 1612 | $13 | $13 | 0.184 | $2 | $2 | $0.008 | $0.008 |
| 2037 | 1604 | $12 | $13 | 0.170 | $2 | $2 | $0.008 | $0.008 |
| 2038 | 1596 | $12 | $13 | 0.158 | $2 | $2 | $0.008 | $0.008 |
| 2039 | | | | | | | | |

| Validation: Present Value | $166 | $166 |
|---|---|---|

### Avoided Environmental Cost

Environmental costs are included as a required component and are based on existing Minnesota and federal externality costs. $CO_2$ and non-$CO_2$ natural gas emissions factors (lb per MM BTU of natural gas) are from the EPA[17]and NaturalGas.org.[18] Avoided environmental costs are based on the federal social cost of $CO_2$ emissions[19] plus the Minnesota PUC-established externality costs for non-$CO_2$ emissions.[20]

The externality cost of $CO_2$ emissions shown in Table 4 are calculated as follows. The Social Cost of Carbon ($CO_2$) values for each year through 2050 are published in 2007 dollars per metric ton.[21] These costs are adjusted for inflation (converted to current dollars), converted to dollars per short ton, and then converted to cost per unit fuel consumption using the assumed values in Table 16.

For example, the $CO_2$ externality cost for 2020 (3.0% discount rate, average) is $43 per metric ton of $CO_2$ emissions in 2007 dollars. This is converted to current dollars by multiplying by a CPI adjustment factor; for 2014, the CPI adjustment factor is of 1.13.[22] The resulting $CO_2$ costs per metric ton in current dollars are then converted to dollars per short ton by dividing by 1.102. Finally, the costs are escalated using the general escalation rate of 2.75% per year to give $54.76 per ton. The $54.76 per ton of $CO_2$ is then divided by 2000 pounds per ton and multiplied by 117.0 pounds of $CO_2$ per MMBtu = $3.204 per MMBtu in 2020 dollars.

Table 16. Natural Gas Emissions.

| | NG Emissions (lb/MMBtu) |
|---|---|
| $PM_{10}$ | 0.007 |
| CO | 0.04 |
| $NO_X$ | 0.092 |
| Pb | 0.00 |
| $CO_2$ | 117.0 |

[17] http://www.epa.gov/climatechange/ghgemissions/ind-assumptions.html and http://www.epa.gov/ttnchie1/ap42/
[18] http://www.naturalgas.org/environment/naturalgas.asp
[19] See http://www.epa.gov/climatechange/EPAactivities/economics/scc.html, technical support document appendix, May 2013.
[20] "Notice of Updated Environmental Externality Values," issued June 5, 2013, PUC docket numbers E-999/CI-93-583 and E-999/CI-00-1636.
[21] The annual Social Cost of Carbon values are listed in table A1 of the Social Cost of Carbon Technical Support Document. The Technical Support Document can be found at: http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf.
[22] The CPI adjustment factor can be calculated through the Bureau of Labor Statistics CPI inflation calculator. The calculator can be found at: http://data.bls.gov/cgi-bin/cpicalc.pl.

Pollutants other than $CO_2$ are calculated using the Minnesota externality costs using the following method. Externality costs are calculated as the midpoint of the low and high values for the urban scenario, adjusted to current dollars, and converted to a fuel-based value using Table 16. Each utility may select the set of non-$CO_2$ externality values that is most appropriate for their service territory (e.g. urban or metropolitan fringe or rural).

For the example, MN PUC's published 2012 urban externality values for PM10 are $6,291 per ton (low case) and $9,056 per ton (high case). These are averaged to be ($6291+$9056)/2 = $7674 per ton of PM10 emissions. For 2020, these are escalated using the general escalation rate of 2.75% per year to $9,533 per ton. The $9,533 per ton of PM10 is then divided by 2000 pounds per ton and multiplied by 0.007 pounds of PM10 per MMBtu to arrive at a PM10 externality cost of $0.033 per MMBtu. Similar calculations are done for the other pollutants.

In the example shown in Table 17, the environmental cost is the sum of the costs of all pollutants. For example, in 2020, the total cost of $3.287 per MMBtu corresponds to the 2020 total cost in Table 4. This cost is multiplied by the heat rate for the year (see Avoided Fuel Cost calculation) and divided by $10^6$ (to convert Btus to MMBtus), which results in the environmental cost in dollars per kWh for each year. The remainder of the calculation follows the same method as the avoided variable O&M costs but using the environmental discount factor (see Discount Factors for a description of the environmental discount factor and its calculation).

### Avoided Voltage Control Cost

This is reserved for future updates to the methodology.

### Solar Integration Cost

This is reserved for future updates to the methodology.

Table 17. (EXAMPLE) Economic value of avoided environmental cost.

| Year | Env. Cost | Heat Rate | Prices: Utility | Prices: VOS | p.u. PV Production | Costs: Utility | Costs: VOS | Discount Factor | Disc. Costs: Utility | Disc. Costs: VOS |
|---|---|---|---|---|---|---|---|---|---|---|
| | ($/MMBtu) | (Btu/kWh) | ($/kWh) | ($/kWh) | (kWh) | ($) | ($) | | ($) | ($) |
| 2014 | 2.022 | 8000 | $0.016 | $0.027 | 1,800 | $29 | $48 | 1.000 | $29 | $48 |
| 2015 | 2.131 | 8008 | $0.017 | $0.027 | 1,791 | $31 | $48 | 0.945 | $29 | $45 |
| 2016 | 2.245 | 8016 | $0.018 | $0.027 | 1,782 | $32 | $47 | 0.893 | $29 | $42 |
| 2017 | 2.363 | 8024 | $0.019 | $0.027 | 1,773 | $34 | $47 | 0.844 | $28 | $40 |
| 2018 | 2.487 | 8032 | $0.020 | $0.027 | 1,764 | $35 | $47 | 0.797 | $28 | $37 |
| 2019 | 2.615 | 8040 | $0.021 | $0.027 | 1,755 | $37 | $47 | 0.753 | $28 | $35 |
| 2020 | 2.749 | 8048 | $0.022 | $0.027 | 1,747 | $39 | $46 | 0.712 | $28 | $33 |
| 2021 | 2.888 | 8056 | $0.023 | $0.027 | 1,738 | $40 | $46 | 0.673 | $27 | $31 |
| 2022 | 3.032 | 8064 | $0.024 | $0.027 | 1,729 | $42 | $46 | 0.636 | $27 | $29 |
| 2023 | 3.182 | 8072 | $0.026 | $0.027 | 1,721 | $44 | $46 | 0.601 | $27 | $27 |
| 2024 | 3.338 | 8080 | $0.027 | $0.027 | 1,712 | $46 | $46 | 0.567 | $26 | $26 |
| 2025 | 3.501 | 8088 | $0.028 | $0.027 | 1,703 | $48 | $45 | 0.536 | $26 | $24 |
| 2026 | 3.669 | 8097 | $0.030 | $0.027 | 1,695 | $50 | $45 | 0.507 | $26 | $23 |
| 2027 | 3.770 | 8105 | $0.031 | $0.027 | 1,686 | $52 | $45 | 0.479 | $25 | $21 |
| 2028 | 3.950 | 8113 | $0.032 | $0.027 | 1,678 | $54 | $45 | 0.452 | $24 | $20 |
| 2029 | 4.138 | 8121 | $0.034 | $0.027 | 1,670 | $56 | $44 | 0.427 | $24 | $19 |
| 2030 | 4.332 | 8129 | $0.035 | $0.027 | 1,661 | $59 | $44 | 0.404 | $24 | $18 |
| 2031 | 4.534 | 8137 | $0.037 | $0.027 | 1,653 | $61 | $44 | 0.382 | $23 | $17 |
| 2032 | 4.744 | 8145 | $0.039 | $0.027 | 1,645 | $64 | $44 | 0.361 | $23 | $16 |
| 2033 | 4.962 | 8153 | $0.040 | $0.027 | 1,636 | $66 | $44 | 0.341 | $23 | $15 |
| 2034 | 5.189 | 8162 | $0.042 | $0.027 | 1,628 | $69 | $43 | 0.322 | $22 | $14 |
| 2035 | 5.424 | 8170 | $0.044 | $0.027 | 1,620 | $72 | $43 | 0.304 | $22 | $13 |
| 2036 | 5.668 | 8178 | $0.046 | $0.027 | 1,612 | $75 | $43 | 0.287 | $21 | $12 |
| 2037 | 5.922 | 8186 | $0.048 | $0.027 | 1,604 | $78 | $43 | 0.272 | $21 | $12 |
| 2038 | 6.185 | 8194 | $0.051 | $0.027 | 1,596 | $81 | $42 | 0.257 | $21 | $11 |
| | | | | | | **Validation: Present Value** | | | **$629** | **$629** |

# VOS Example Calculation

The gross economic value, load match, distributed loss savings factor, and distributed PV value are combined in the required VOS Levelized Calculation Chart. An example is presented in Figure 2 using the assumptions made for the example calculation. Actual VOS results will differ from those shown in the example, but utilities will include in their application a VOS Levelized Calculation Chart in the same format. For completeness, Figure 3 (not required of the utilities) is presented showing graphically the relative importance of the components in the example.

Figure 3. (EXAMPLE) VOS Levelized Calculation Chart (Required).

| 25 Year Levelized Value | Economic Value ($/kWh) | Load Match (No Losses) (%) | Distributed Loss Savings (%) | Distributed PV Value ($/kWh) |
|---|---|---|---|---|
| Avoided Fuel Cost | $0.056 | | 8% | $0.061 |
| Avoided Plant O&M - Fixed | $0.003 | 40% | 9% | $0.001 |
| Avoided Plant O&M - Variable | $0.001 | | 8% | $0.001 |
| Avoided Gen Capacity Cost | $0.048 | 40% | 9% | $0.021 |
| Avoided Reserve Capacity Cost | $0.007 | 40% | 9% | $0.003 |
| Avoided Trans. Capacity Cost | $0.018 | 40% | 9% | $0.008 |
| Avoided Dist. Capacity Cost | $0.008 | 30% | 5% | $0.003 |
| Avoided Environmental Cost | $0.027 | | 8% | $0.029 |
| Avoided Voltage Control Cost | | | | |
| Solar Integration Cost | | | | |
| | | | | $0.127 |

Having calculated the levelized VOS credit, an inflation-adjusted VOS can then be found. An EXAMPLE inflation-adjusted VOS is provided in Figure 5 by using the general escalation rate as the annual inflation rate for all years of the analysis period. Both the inflation-adjusted VOS and the levelized VOS in Figure 5 represent the same long-term value. The methodology requires that the inflation-adjusted (real) VOS be used and updated annually to account for the current year's inflation rate.

To calculate the inflation-adjusted VOS for the first year, the products of the levelized VOS, PV production and the discount factor are summed for each year of the analysis period and then divided by the sum of the products of the escalation factor, PV production, and the discount factor for each year of the analysis period, as shown below in Equation ( 17).

Figure 4. (EXAMPLE) Levelized value components.

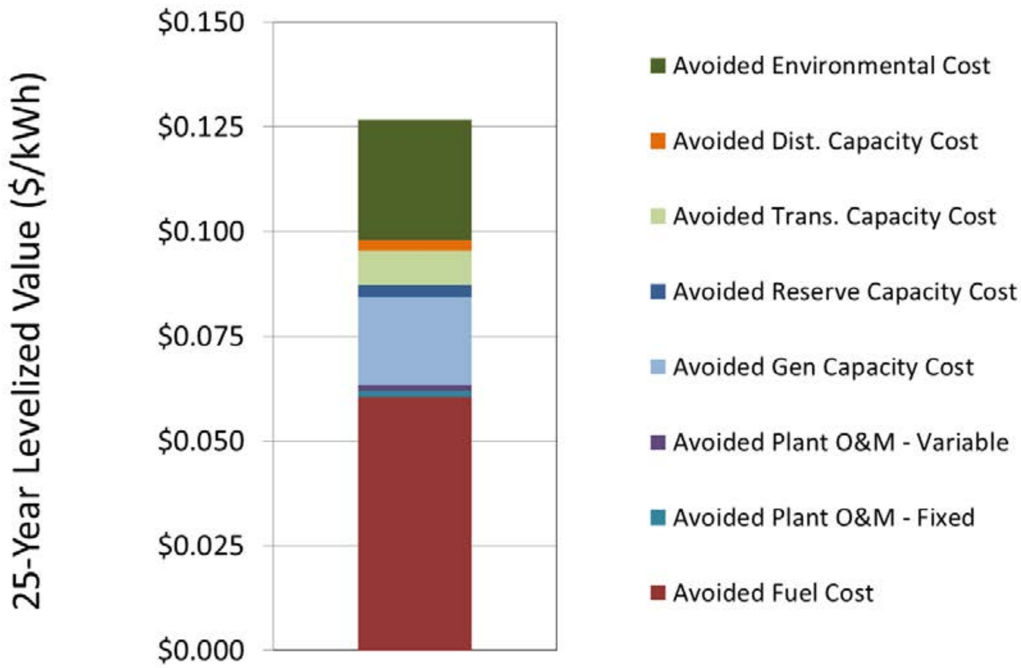
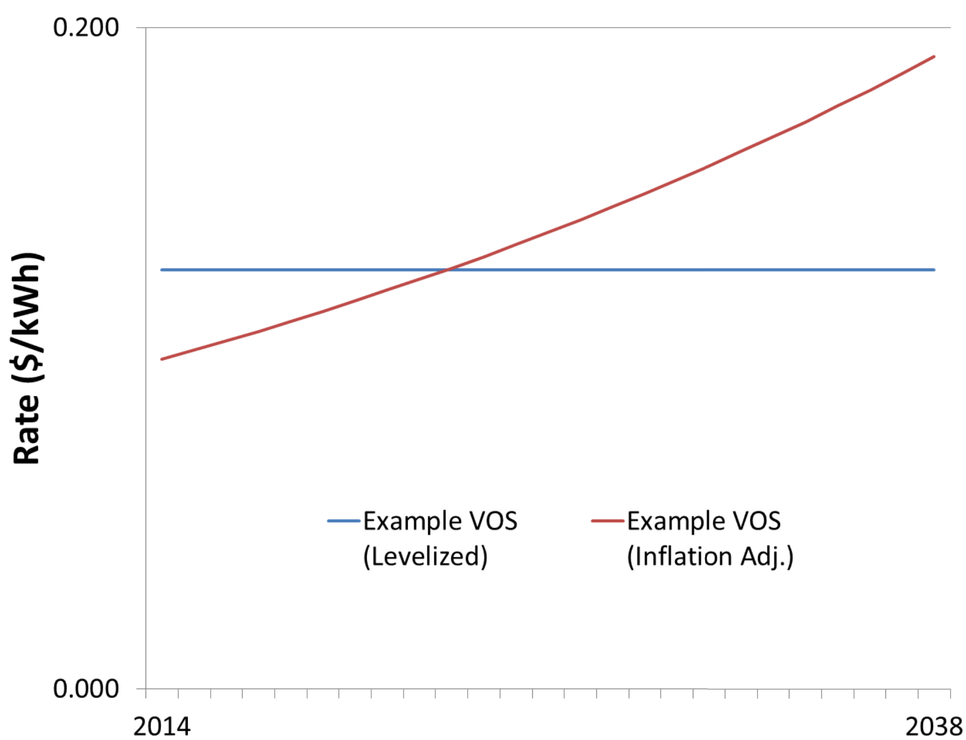



Figure5. (EXAMPLE) Inflation-Adjusted VOS.



$$InflationAdjustedVOS_{Year0}\left(\frac{\$}{kWh}\right) \tag{19}$$

$$= \frac{\sum_i LevelizedVOS \times PVProduction_i \times DiscountFactor_i}{\sum_i\ EscalationFactor_i \times PVProduction_i \times DiscountFactor_i}$$

Once the first-year inflation-adjusted VOS is calculated, the value will then be updated on an annual basis in accordance with the observed inflation-rate. Table 18 provides the calculation of the EXAMPLE inflation-adjusted VOS shown in Figure 5. In this EXAMPLE, the inflation rate in future years is set equal to the general escalation rate of 2.75%.

Table 18. (EXAMPLE) Calculation of inflation-adjusted VOS.

| Year | Discount Factor | Escalation Factor | Example VOS (Levelized) | Disc. | Example VOS (Inflation Adj.) | Disc. |
|---|---|---|---|---|---|---|
| 2014 | 1.000 | 1.000 | 0.127 | 0.127 | 0.100 | 0.100 |
| 2015 | 0.926 | 1.027 | 0.127 | 0.117 | 0.102 | 0.095 |
| 2016 | 0.857 | 1.056 | 0.127 | 0.109 | 0.105 | 0.090 |
| 2017 | 0.794 | 1.085 | 0.127 | 0.101 | 0.108 | 0.086 |
| 2018 | 0.735 | 1.115 | 0.127 | 0.093 | 0.111 | 0.082 |
| 2019 | 0.681 | 1.145 | 0.127 | 0.086 | 0.114 | 0.078 |
| 2020 | 0.630 | 1.177 | 0.127 | 0.080 | 0.117 | 0.074 |
| 2021 | 0.583 | 1.209 | 0.127 | 0.074 | 0.121 | 0.070 |
| 2022 | 0.540 | 1.242 | 0.127 | 0.068 | 0.124 | 0.067 |
| 2023 | 0.500 | 1.276 | 0.127 | 0.063 | 0.127 | 0.064 |
| 2024 | 0.463 | 1.311 | 0.127 | 0.059 | 0.131 | 0.061 |
| 2025 | 0.429 | 1.347 | 0.127 | 0.054 | 0.134 | 0.058 |
| 2026 | 0.397 | 1.384 | 0.127 | 0.050 | 0.138 | 0.055 |
| 2027 | 0.368 | 1.422 | 0.127 | 0.047 | 0.142 | 0.052 |
| 2028 | 0.340 | 1.462 | 0.127 | 0.043 | 0.146 | 0.050 |
| 2029 | 0.315 | 1.502 | 0.127 | 0.040 | 0.150 | 0.047 |
| 2030 | 0.292 | 1.543 | 0.127 | 0.037 | 0.154 | 0.045 |
| 2031 | 0.270 | 1.585 | 0.127 | 0.034 | 0.158 | 0.043 |
| 2032 | 0.250 | 1.629 | 0.127 | 0.032 | 0.162 | 0.041 |
| 2033 | 0.232 | 1.674 | 0.127 | 0.029 | 0.167 | 0.039 |
| 2034 | 0.215 | 1.720 | 0.127 | 0.027 | 0.172 | 0.037 |
| 2035 | 0.199 | 1.767 | 0.127 | 0.025 | 0.176 | 0.035 |
| 2036 | 0.184 | 1.815 | 0.127 | 0.023 | 0.181 | 0.033 |
| 2037 | 0.170 | 1.865 | 0.127 | 0.022 | 0.186 | 0.032 |
| 2038 | 0.158 | 1.917 | 0.127 | 0.020 | 0.191 | 0.030 |
| | | | | 1.461 | | 1.461 |

# Glossary

Table 19. Input data definitions

| Input Data | Used in Methodology Section | Definition |
|---|---|---|
| **Annual Energy** | PV Energy Production | The annual PV production (kWh per year) per Marginal PV Resource (initially 1 kW-AC) in the first year (before any PV degradation) of the marginal PV resource. This is calculated in the Annual Energy section of PV Energy Production and used in the Equipment Degradation section. |
| **Capacity-related distribution capital cost** | Avoided Distribution Capacity Cost | This is described more fully in the Avoided Distribution Capacity Cost section. |
| **Capacity-related transmission capital cost** | Avoided Transmission Capacity Cost | The cost per kW of new construction of transmission, including lines, towers, insulators, transmission substations, etc. Only capacity-related costs should be included. |
| **Discount rate (WACC)** | Multiple | The utility's weighted average cost of capital, including interest on bonds and shareholder return. |
| **Distribution capital cost escalation** | Avoided Distribution Capacity Cost | Used to calculate future distribution costs. |
| **ELCC (no loss), PLR (no loss)** | Load Match Factors | The "Effective Load Carrying Capability" and the "Peak Load Reduction" of a PV resource expressed as percentages of rated capacity (kW-AC). These are described more fully in the Load Match section. |
| **Environmental Costs** | Avoided Environmental Cost | The costs required to calculate environmental impacts of conventional generation. These are described more fully in the Avoided Environmental Cost section |

| Input Data | Used in Methodology Section | Definition |
|---|---|---|
| **Environmental Discount Rate** | Avoided Environmental Cost | The societal discount rate used to calculate the present value of future environmental costs. |
| **Fuel Price Overhead** | Avoided Fuel Cost | The difference in cost of fuel as delivered to the plant and the cost of fuel as available in market prices. This cost reflects transmission, delivery, and taxes. |
| **General escalation rate** | Avoided Environmental Cost, Example Results | The annual escalation rate corresponding to the most recent 25 years of CPI index data[23], used to convert constant dollar environmental costs into current dollars and to translate levelized VOS into inflation-adjusted VOS. |
| **Generation Capacity Degradation** | Avoided Generation Capacity Cost | The percentage decrease in the generation capacity per year |
| **Generation Life** | Avoided Generation Capacity Cost | The assumed service life of new generation assets. |
| **Guaranteed NG Fuel Prices** | Avoided Fuel Cost | The annual average prices to be used when the utility elects to use the Futures Market option. These are not applicable when the utility elects to use options other than the Futures Market option. They are calculated as the annual average of monthly NYMEX NG futures[24]. |
| **Heat rate degradation** | Avoided Generation Capacity Cost | The percentage increase in the heat rate (BTU per kWh) per year |

[23] www.bls.gov.

[24] See for example http://futures.tradingcharts.com/marketquotes/NG.html.

| Input Data | Used in Methodology Section | Definition |
|---|---|---|
| **Installed cost and heat rate for CT and CCGT** | Avoided Generation Capacity Cost | The capital costs for these units (including all construction costs, land, ad valorem taxes, etc.) and their heat rates. |
| **Loss Savings (Energy, PLR, and ELCC)** | Loss Savings Analysis | The additional savings associated with Energy, PRL and ELCC, expressed as a percentage. These are described more fully in the Loss Savings section. |
| **O&M cost escalation rate** | Avoided Plant O&M – Fixed, Avoided Plant O&M – Variable | Used to calculate future O&M costs. |
| **O&M fixed costs** | Avoided Plant O&M – Fixed | The costs to operate and maintain the plant that are not dependent on the amount of energy generated. |
| **O&M variable costs** | Avoided Plant O&M – Variable | The costs to operate and maintain the plant (excluding fuel costs) that are dependent on the amount of energy generated. |
| **Peak Load** | Avoided Distribution Capacity Cost | The utility peak load as expected in the VOS start year. |
| **Peak load growth rate** | Avoided Distribution Capacity Cost | This is described more fully in the Avoided Distribution Capacity Cost section. |
| **PV Degradation** | Equipment Degradation Factors | The reduction in percent per year of PV capacity and PV energy due to degradation of the modules. The value of 0.5 percent is the median value of 2000 observed degradation rates.[25] |

[25] D. Jordan and S. Kurtz, "Photovoltaic Degradation Rates – An Analytical Review," NREL, June 2012.

| Input Data | Used in Methodology Section | Definition |
|---|---|---|
| **PV Life** | Multiple | The assumed service life of PV. This value is also used to define the study period for which avoided costs are determined and the period over which the VOS rate would apply. |
| **Reserve planning margin** | Avoided Reserve Capacity Cost | The planning margin required to ensure reliability. |
| **Solar-weighted heat rate** | Avoided Fuel Costs | This is described in the described in the Avoided Fuel Costs section. |
| **Start Year for VOS applicability** | Multiple | This is the first year in which the VOS would apply and the first year for which avoided costs are calculated. |
| **Transmission capital cost escalation** | Avoided Transmission Capacity Cost | Used to adjust costs for future capital investments. |
| **Transmission life** | Avoided Transmission Capacity Cost | The assumed service life of new transmission assets. |
| **Treasury Yields** | Escalation and Discount Rates | Yields for U.S. Treasuries, used as the basis of the risk-free discount rate calculation.[26] |
| **Years until new transmission capacity is needed** | Avoided Transmission Capacity Cost | This is used to test whether avoided costs for a given analysis year should be calculated and included. |

[26] See http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

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JUL 25 2008
Clerk's Office
N.C. Utilities Commission

July 25, 2008

Ms. Renné C. Vance, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

RE: Docket No. E-7, Sub 856

Dear Ms. Vance:

Enclosed for filing are the original and 30 copies of Duke Energy Carolinas, LLC's Direct Testimonies of Janice D. Hager, Jane L. McManeus, Owen A. Smith and Ellen T. Ruff in the above referenced docket.

Sincerely,

Robert W. Kaylor

Robert W. Kaylor By KE

Enclosures

cc: Parties of Record

Full Dist. MH

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 856

| | |
|---|---|
| Application of Duke Energy Carolinas, LLC For Approval of Solar Photovoltaic Distributed Generation Program And for Approval of Proposed Method of Recovery of Associated Costs | DIRECT TESTIMONY OF JANICE D. HAGER DUKE ENERGY CAROLINAS, LLC |

## I. INTRODUCTION AND PURPOSE

**Q: PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH DUKE ENERGY CORPORATION.**

A: My name is Janice D. Hager, and my business address is 526 South Church Street, Charlotte, North Carolina. I am Managing Director, Integrated Resource Planning and Environmental Strategy for Duke Energy Corporation's ("Duke Energy") operating utilities, including Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company").

**Q: WHAT ARE YOUR CURRENT JOB RESPONSIBILITIES?**

A: I have responsibility for integrated resource planning and environmental compliance planning for Duke Energy Corporation's regulated electric utilities, including Duke Energy Carolinas. In that role, I oversee the long-term resource planning for Duke Energy's Carolinas and Midwest operations, as well as planning for environmental compliance. Duke Energy's long-range resource planning process is conducted separately for each of the operating utilities.

**Q: PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL AFFILIATIONS.**

A: I am a civil engineer, having received a Bachelor of Science in Engineering from the University of North Carolina at Charlotte. I began my career at Duke Power Company in 1981 and have had a variety of responsibilities across the Company in areas of piping analyses, nuclear station modifications, new generation licensing, rates, and regulatory affairs. I am a registered Professional Engineer in North Carolina and South Carolina.

**Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?**

A: Yes, I have testified before the North Carolina Utilities Commission ("Commission") on several occasions. I most recently appeared to present testimony in support of Duke Energy Carolinas' Energy Efficiency Plan, Docket No. E-7, Sub 831.

**Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to discuss how Duke Energy Carolinas' proposed solar photovoltaic ("PV") distributed generation program (the "Program") conforms to the Company's most recent integrated resource plan ("IRP" or "Annual Plan") as required by Commission Rule R8-61(b).

## II. THE PROGRAM CONFORMS TO THE COMPANY'S ANNUAL PLAN

**Q: WHEN WAS DUKE ENERGY CAROLINAS' MOST RECENT ANNUAL PLAN FILED IN NORTH CAROLINA?**

A: The Company filed the 2007 Annual Plan (the "2007 Annual Plan") with the Commission on November 15, 2007, in Docket No. E-100, Sub 114. In its application for approval of the Program filed on June 6, 2008, the Company requested that the Commission take judicial notice of the 2007 Annual Plan. In presenting the application at the Commission Staff Conference on July 7, 2008, the Public Staff stated that it did not oppose the Commission taking judicial notice of the 2007 Annual Plan. I therefore have not included another copy of the 2007 Annual Plan with my testimony. I note that item (2) of Commission Rule R8-61(b) requires information and testimony on the extent to which the proposed construction of the solar generating facilities under the Program conforms to the Company's most recent biennial report. The Company's first biennial report is required to be filed with this Commission by Sept. 1, 2008. In light of this fact, I will discuss instead in my testimony how the application conforms to the 2007 Annual Plan.

**Q: PLEASE DESCRIBE THE PURPOSE OF THE COMPANY'S ANNUAL PLAN?**

A: Duke Energy Carolinas' Annual Plan is developed with the objective of meeting customers' needs for a highly reliable energy supply at the lowest reasonable cost. Annually, Duke Energy Carolinas develops a resource plan for meeting customers' energy needs. The resource plan considers a combination of (1) existing power contracts, (2) existing and new generation, and (3) customer options, including demand-side management ("DSM") programs and energy efficiency ("EE") programs.[1] The Annual Plan has traditionally been filed with the Commission and the Public Service Commission of South Carolina on an annual basis. Going forward, as required by the Commission's recently updated rules, a biennial plan will be filed with this Commission in even numbered years, and a short term action plan will be filed annually.

**Q. PLEASE PROVIDE AN OVERVIEW OF THE INTEGRATED RESOURCE PLANNING PROCESS FOR DUKE ENERGY CAROLINAS' 2007 ANNUAL PLAN.**

[1] In this testimony, I use the terms DSM to refer to load management programs such as air conditioning load control or industrial interruptible programs and EE to refer to conservation programs.

A. Duke Energy Carolinas has been engaged in integrated resource planning since the late 1980s. The annual planning process begins with a 20-year load forecast. The forecast includes projections of summer and winter peak demands, as well as energy use. Information is gathered for Duke Energy Carolinas' existing resources, including Company-owned generation, purchased power agreements, and DSM/EE resources. The information includes items such as capacity rating, heat rate, fuel costs and emission allowance costs. Data is gathered on the costs of additional resource options to meet customer needs. Such data includes lead times for construction, capacity costs, fixed and variable operating and maintenance costs and emissions costs for generation, as well as the costs of demand-side options. Quantitative analyses are conducted to identify combinations of options that will meet customer energy needs (plus reserve margin) while minimizing the costs to customers. The 2007 Annual Plan incorporates a target planning reserve margin of 17%, which Duke Energy Carolinas' experience has shown to be sufficient based on the prevailing expectations of reasonable lead times for the development of new generation, siting of transmission facilities and procurement of purchased capacity. These quantitative analyses enable the Company to identify potential portfolios that can be tested under base assumptions, and for sensitivities and scenarios around those base assumptions.

**Q. ARE DECISIONS REGARDING RESOURCE PLANNING MADE ON THE BASIS OF QUANTITATIVE ANALYSES ALONE?**

A. No. Consistent with the responsibility to meet customer energy needs in a reliable and economic manner, the Company's resource planning approach includes both quantitative analysis and qualitative considerations. Quantitative analysis provides insights on the potential impacts of future risks and uncertainties associated with fuel prices, load growth rates, capital and operating costs, and other variables. Qualitative perspectives such as the importance of fuel diversity, the Company's environmental profile, the stage of technology deployment, and regional economic development are also important factors to consider as long-term decisions are made regarding new resources. In the context of this proceeding, compliance with the North Carolina Renewable Energy and Energy Efficiency Standards ("REPS") is both a quantitative and a qualitative consideration. It is quantitative in that there are quantitative analyses of the cost of meeting the REPS. It is qualitative in that the decision on the resources selected to meet the REPS is not made purely on economics, but with consideration of factors such as portfolio diversity.

Company management uses all of these perspectives and analyses to ensure that Duke Energy Carolinas will meet near-term and long-term customer needs, while maintaining flexibility to adjust to evolving economic, environmental, and operating circumstances in the future. The environment for planning the Company's system has never been more dynamic. As a result, the Company believes prudent planning for customer needs requires a plan that is robust under many possible future scenarios, and maintains a number of options to respond to many potential outcomes of major planning uncertainties (e.g., federal greenhouse gas emission legislation).

**Q. DID DUKE ENERGY CAROLINAS CONSIDER RENEWABLE ENERGY RESOURCES IN DEVELOPING THE 2007 ANNUAL PLAN?**

A. Yes. Because of North Carolina's recent enactment of the REPS, Duke Energy Carolinas modified its consideration of renewable energy resources. In previous annual plans, resources were screened on economics. Therefore, renewable resources were screened out due to their higher cost than traditional supply-side resources. In the 2007 Annual Plan, renewable resources were screened separately to identify the most cost-effective resources among the renewable options. For the Carbon Case with CO2 regulation, the Renewable Portfolio Standard assumptions are based on the REPS requirements. The assumptions for planning purposes are as follows:

<u>Overall Requirements/Timing</u>

- 3% of 2011 load by 2012
- 6% of 2014 load by 2015
- 10% of 2017 load by 2018
- 12.5% of 2020 load by 2021

A portion of the REPS requirements was also assumed to be provided by EE and DSM, co-firing biomass in some of Duke Energy Carolinas' existing units, and by purchasing Renewable Energy Certificates (RECs) from out of state, as allowed in the legislation. These requirements were applied to all native loads served by Duke Energy Carolinas (i.e., both retail and wholesale, and regardless of the location of the load) to take into account the potential that a Federal RPS may be imposed that would affect all loads. Accordingly, the 2007 Annual Plan includes 160 MWs of renewable energy by 2012 and about 1000 MWs by 2020.

**Q: HOW DOES THE PROGRAM CONFORM TO THE COMPANY'S ANNUAL PLAN?**

A: The integrated resource planning process for the 2007 Annual Plan demonstrates that a combination of renewable resources, DSM/EE programs, and additional baseload, intermediate, and peaking generation are required over the next twenty years to reliably meet customer demand and the REPS requirements.

Duke Energy Carolinas' 2007 forecast shows average annual growth in summer peak demand of 1.6 percent, winter peak demand growth of 1.4 percent, and the average territorial energy growth rate of 1.4 percent. This equates to an average annual growth rate of approximately 350 MWs per year of capacity and 1,500,000 megawatt-hours per year of energy. In addition, we have some existing resources that will no longer be available to meet our customers' needs. Each MW of capacity that is no longer available must be replaced with new capacity, either from supply-side or demand-side resources. Accordingly, the 2007 Annual Plan identifies the need for an additional 990 MWs by 2010 and 10,680 MW of new resources to meet customers' energy needs by 2027. As shown in the Company's 2007 Annual Plan, Duke Energy Carolinas currently has no Company-owned solar PV generation facilities among its generation resources. Implementation of the Program, therefore, would allow the Company to diversify its resources used to reliably meet the energy needs of its customers.

Additionally, the Program will allow the Company to partially fulfill its obligations under the REPS imposed by Senate Bill 3.

**Q. IN CONCLUSION, ARE THE SOLAR PV GENERATION FACILITIES PROPOSED UNDER THE PROGRAM NEEDED AND CONSISTENT WITH DUKE ENERGY CAROLINAS' 2007 ANNUAL PLAN?**

A. Yes. The facilities are an important and necessary part of Duke Energy Carolinas' plans for meeting customer capacity and energy needs. I believe that the Company's application is in the public convenience and necessity, and I ask that the Commission approve it.

**Q: DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A: Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 856

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| | ) | |
| Application of Duke Energy Carolinas, LLC | ) | DIRECT TESTIMONY OF |
| For Approval of Solar Photovoltaic | ) | JANE L. MCMANEUS |
| Distributed Generation Program | ) | DUKE ENERGY CAROLINAS, LLC |
| And for Approval of Proposed Method of | ) | |
| Recovery of Associated Costs | ) | |

## I. INTRODUCTION AND PURPOSE

**Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A: My name is Jane L. McManeus, and my business address is 526 South Church Street, Charlotte, North Carolina.

**Q: WHAT IS YOUR POSITION WITH DUKE ENERGY CAROLINAS, LLC?**

A: I am Director, Rates for Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company"). Duke Energy Carolinas is a wholly-owned subsidiary of Duke Energy Corporation ("Duke Energy").

**Q: WHAT ARE YOUR PRESENT RESPONSIBILITIES AT DUKE ENERGY CAROLINAS?**

A: I am responsible for managing Duke Energy Carolinas' fuel recovery processes, providing regulatory support for retail and wholesale rates, and providing guidance on compliance with regulatory conditions and codes of conduct.

**Q: PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL AFFILIATIONS.**

A: I graduated from Wake Forest University with a Bachelor of Science in Accountancy and received a Master of Business Administration degree from the McColl Graduate School of Business at Queens University of Charlotte. I am a certified public accountant licensed in the state of North Carolina, and am a member of the Southeastern Electric Exchange Rates and Regulation Section and the EEI Rate and Regulatory Analysts group. I began my career with Duke Energy Carolinas in 1979 as a staff accountant and have held a variety of positions in the finance organizations. From 1994 until 1999, I served in financial planning and analysis positions within the electric transmission area of Duke Power. I was named Director, Asset Accounting for Duke Power in 1999, and appointed to Assistant Controller in 2001. As Assistant Controller, I was responsible for coordinating Duke Power's operational and strategic plans, including development of the annual budget and performing special studies. I joined the Rate Department in 2003 as Director, Rate Design and Analysis. Beginning in April 2006, I became Director, Regulatory Accounting and Filings, leading the regulatory accounting, cost of service, regulatory filings (including fuel and fuel-related costs filings) and revenue analysis functions for Duke Energy Carolinas. I began my current position in the Rate Department in October 2006.

Q: **HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?**

A: Yes, I have testified before the North Carolina Utilities Commission (the "Commission") on several occasions. I most recently appeared to present testimony in support of Duke Energy Carolinas' Fuel Filing, Docket No. E-7, Sub 847.

Q: **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to (1) provide an overview of Duke Energy Carolinas' proposed cost recovery model for its proposed solar photovoltaic ("PV") distributed generation program (the "Program"); (2) estimate the impact of the program on residential customer bills; and (3) describe how the Program's costs relate to the annual customer class per-account caps specified in Senate Bill 3, the statute that established North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard ("REPS").

## II. COST RECOVERY AND RATE IMPACT OF PROGRAM

**Q: WHAT METHODOLOGY IS THE COMPANY PROPOSING FOR RECOVERY OF THE COST OF THE PROGRAM?**

A: As explained in Witness Ruff's testimony, the Program directly responds to the North Carolina General Assembly's mandate to promote the development of renewable energy, and contributes to the "Solar Carve Out" requirement in Senate Bill 3. The Company, therefore, proposes to recover the cost of the Program through the cost recovery mechanism provided for in Senate Bill 3 and the rules the Commission has adopted under that statute (N.C. Gen. Stat. § 62-133.7(h) and Commission Rule R8-67(e)). The Company plans to invest approximately $100 million to install the solar facilities, and between $700,000 and $1.3 million annually to operate and maintain the facilities. The Company believes that these expenditures are reasonable and prudent costs that will be incurred in order to comply with the requirements of the REPS (and specifically, N.C. Gen. Stat. § 62-133.7 (b), (d), (e) and (f)), and therefore meet the definition of incremental costs as defined in N.C. Gen. Stat. § 62-133.7(h)(1), to the extent the costs exceed the Company's avoided costs. As such, the Company proposes to recover the excess of the Program costs above its approved levelized avoided costs through the annual rider provided for in Commission Rule R8-67(e)(2). Annual Program costs will be determined on a levelized basis, using a fixed charge rate applied to the investment, and compared to levelized avoided cost to determine the annual incremental costs. The Company's recovery of its incremental costs through this annual rider is capped based on specified per account annual charges for each customer class. The Company expects that the cost of this Program would represent roughly 40% of the annual cost cap in 2010 and 2011, declining to approximately 25% in 2012 and approximately 10% in 2015.

**Q: IS THE COMPANY REQUESTING A RATE CHANGE AT THIS TIME?**

A: No, the Company is not requesting a rate change at this time. Commission Rule R8-67 allows the Company to request a change in rates to recover its prudently incurred REPS compliance costs by requesting approval to charge an annual increment or decrement as a rider to its rates. Such request is to be made in the same time frame as the Company's proposed fuel rate changes under Rule R8-55. The Company would expect to make its request to recover its incremental costs of this Program in early 2009. Given the newness of Senate Bill 3 and its related rules, however, the Company requests that the Commission affirm that its proposed approach is acceptable before the Company moves forward with the Program.

**Q: WHAT IS THE EXPECTED IMPACT ON A RESIDENTIAL CUSTOMER'S MONTHLY BILL?**

A: The recovery of the Company's incremental costs of the Program (equal to the levelized annual costs of the Program in excess of the Company's currently approved levelized avoided costs) will result in a REPS rider increment to base rates of approximately $0.34 per month per residential customer account.

Because the Company will incur other costs to comply with the REPS, recovery of the incremental costs of this Program will be only one component of the Company's proposed REPS rider to recover all incremental costs of meeting the REPS requirements, subject to the annual per-account cost caps set forth in N.C. Gen. Stat. § 133.7 (h) (4). The Company expects to implement any proposed REPS rider increment or decrement as a "flat rate" fee or credit due to problems of insufficient cost recovery associated with a rate per kwh methodology. The Company filed comments on this issue in Docket E-2, Sub 930 on July 8, 2008. In its application in this Docket on June 6, 2008, the Company stated the impact to residential customers in the form of a typical residential customer bill of 1,000 kwh, which is an historically common approach to expressing customer rate impacts. The Company, however, seeks to correct and make clear by this testimony that it plans to use the "flat rate" approach in order to achieve full recovery of its incremental costs of compliance with the REPS requirements.

**Q: WHEN DOES THE COMPANY EXPECT TO MAKE ITS NEXT AVOIDED COST FILING?**

A: The Company expects to update its avoided costs in the upcoming biennial proceeding under Docket E-100, Sub 117.

**Q: DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A: Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 856

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| | ) | |
| Application of Duke Energy Carolinas, LLC | ) | DIRECT TESTIMONY OF |
| For Approval of Solar Photovoltaic | ) | OWEN A. SMITH |
| Distributed Generation Program | ) | DUKE ENERGY CAROLINAS, LLC |
| And for Approval of Proposed Method of | ) | |
| Recovery of Associated Costs | ) | |

## I. INTRODUCTION AND PURPOSE

**Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A: My name is Owen A. Smith, and my business address is 400 South Tryon Street, Charlotte, North Carolina.

**Q: WHAT IS YOUR POSITION WITH DUKE ENERGY CORPORATION?**

A: I am Director, Corporate Strategic Initiatives and Regulated Renewables Strategy for Duke Energy Corporation ("Duke Energy").

**Q: PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL AFFILIATIONS.**

A: I am a graduate of East Carolina University with a Bachelor of Arts in Industrial/Organizational Psychology and a Minor in Business Administration. I also have a Master's degree in Business Administration from Wake Forest University.

Q: **PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.**

A: I joined Duke Energy Corporation in 2002 as a Commercial Associate. I have held positions in Corporate Strategy, Treasury, Mergers & Acquisitions, Market Research, and Renewable Energy Strategy. I assumed my current position in November 2007.

**Q: WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?**

A: I have two primary sets of responsibilities. First, I am accountable for the renewable energy strategy for Duke Energy's regulated businesses, including Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company") and our utility operating companies in Indiana, Ohio, and Kentucky. This includes pursuing renewable generation initiatives, customer programs, and compliance with renewable energy requirements. Second, I have responsibilities with respect to facilitating Duke Energy Corporation's long-range strategic planning process. I have held the responsibilities regarding corporate strategic planning since October of 2006, and I assumed the renewables responsibilities in November of 2007 as an expansion of my role.

**Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?**

A: No.

**Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. On June 6, 2008, Duke Energy Carolinas filed an Application for Approval of a Solar Photovoltaic ("PV") Distributed Generation Program and for Approval of Proposed Method of Recovery of Associated Costs (the "Application"). The purpose of my testimony is to provide a detailed description of Duke Energy Carolinas' proposed solar PV distributed generation program (the "Program"), including the Program design, anticipated Program costs, and expected Program benefits.

## II. PROGRAM DESIGN AND COMPONENTS

**Q: PLEASE BRIEFLY DESCRIBE THE PROGRAM.**

A: Duke Energy Carolinas proposes to invest, over a two-year period, approximately $100 million to install, own and operate new solar PV distributed generation facilities to produce energy to serve its customers. Specifically, the Program involves installation of multiple solar PV generating facilities in the Company's North Carolina service territory. The facilities are expected to have a total combined capacity of approximately 20 megawatts direct current ("MWDC"). The generating facilities will be installed on both customer- and Company-owned property in the Company's North Carolina service area. Each facility is expected to have a useful life of approximately 20-25 years, and a capacity factor of 13 to 20 percent (based on the direct current ("DC") rated capacity of 20 MW), or 17 to 25 percent (based on the alternating current ("AC") rated capacity of 16-17 MW). The specific capacity factor of each facility will depend largely on how it is installed. For example, flat and fixed tilt roof mounts typically have lower capacity factors than two-axis tracking systems that optimize production and are typically ground mounted.

The Program will enable the Company to partially meet its obligations under the recently established Renewable Energy and Energy Efficiency Portfolio Standards ("REPS"), and the REPS set-aside for solar energy resources in particular. The Program also will facilitate the Company's evaluation of the impact of significant distributed generation on the Company's electric system. In addition, the Program will allow the Company to explore the nature of solar distributed generation offerings desired by customers, fill knowledge gaps to enable successful, wide-scale deployment of solar PV distributed generation technologies, and promote the commercialization of the solar market in North Carolina through utility ownership. The Program will enable Duke Energy Carolinas to serve more of its load with renewable resources and help offset the use of other generation resources and potential power purchases.

**Q: WHY IS THE CAPACITY OF THE SOLAR PV GENERATION FACILITIES MEASURED IN MEGAWATTS DIRECT CURRENT?**

A: Solar PV modules produce DC. The capacity output of the modules to be installed under the Program, therefore, is measured and referred to in my testimony and that of other Company witnesses in terms of DC capacity unless specifically noted otherwise. This is consistent with solar industry practice. The DC power produced by the modules must be converted to AC power with an inverter in order to be used in the Company's distribution and transmission systems. After conversion to AC power, the effective total installed capacity of 20 MWDC is expected to be 16 – 17 megawatt AC ("MWAC").

**Q: PLEASE DESCRIBE THE SOLAR PV TECHNOLOGY TO BE USED UNDER THE PROGRAM.**

A: The scale of the Program allows for multiple types of installations in multiple locations. Such an approach will enable the Company to thoroughly assess the solar opportunities in North Carolina to determine the most cost-effective and best-performing options for future deployments. There currently are several competing technologies in the PV module market, including but not limited to Crystalline Silicon, Concentrating Photovoltaic, and various forms of Thin Film technologies. The Company plans to deploy several types of PV technologies in order to compare cost, performance, and reliability data that it will use to distill the true cost ($/MWh) for each technology in its North Carolina service territory. This data will enable the Company to select the best performing and/or least cost options for future deployment of solar PV systems.

Additionally, different localities have diverse requirements for the commissioning and installation of solar PV systems (e.g., engineering drawings, permits, inspections, etc.). Through deployment of a substantial number of solar PV distributed generation systems in the Company's North Carolina service territory, the Company expects to identify, collect, and analyze varying local requirements, which the Company hopes will yield benefits such as:

- Development of recommendations to simplify and standardize requirements for PV system installation;
- Reduced administrative burden for utilities, local authorities, and installers;
- Lower installed costs as installation efficiencies are gained; and
- Education and familiarization with solar PV facility installation for local inspection authorities.

**Q: BRIEFLY DESCRIBE THE SOLAR PV INSTALLATIONS.**

A: Between 80-90% of the Program's installed capacity will consist of large scale ground-mounted facilities and rooftop installations on large commercial or industrial buildings, with individual facilities in this category ranging from 500 kW to 3 MW. Up to 10% of the Program's installed capacity will be medium scale rooftop or ground-mounted facilities with individual facilities in this category ranging in size from 15 kW to 500 kW. Structures that would fit into this medium category include schools, office buildings, and multi-family structures. Commercial or industrial structures that are not suitable for large scale installations due to size or other factors may also be included in this medium category. Small scale facilities on residential rooftops, ranging from 1.5 to 5 kW in capacity will comprise the remainder of the Program up to 10% of the Program's total capacity.

**Q: PLEASE LIST THE VARIOUS COMPONENTS OF THE SOLAR PV GENERATION FACILITIES.**

A: Each solar PV generating facility will consist of the following basic components which are necessary to produce electricity: (1) PV modules, (2) one or more inverters, (3) AC and DC disconnects, (4) interconnection equipment, and (5) racking and mounting equipment and electrical conduit.

**Q: PLEASE DESCRIBE THE FUNCTION OF A PV MODULE.**

A: PV modules consist of photovoltaic cells which convert sunlight into direct current and are arranged and packaged to produce a desired voltage and current appropriate for an inverter. The modules are typically connected in series in a "string" to achieve the desired voltage. Two or more "strings" are then connected in parallel to form an "array," which provides the desired voltage and current to the inverter. The PV modules generate DC power, which must be converted to AC power for use in the Company's distribution or transmission system.

**Q: PLEASE DESCRIBE THE FUNCTION OF AN INVERTER.**

A: The inverter is an electronic device that converts the DC power produced by the solar array into AC power suitable for use on the transmission or distribution grid. Inverters also typically contain an automatic disconnect function that serves to isolate the PV facility from the grid in the event of a grid outage. This is a safety feature that prevents the PV facility from back feeding energy into the grid during outages when power lines may be down or utility personnel may be working to restore electric service.

**Q: WHAT ARE AC AND DC DISCONNECTS?**

A: Disconnects provide a means of isolating the DC or AC power from other components of the solar PV facility or the grid in order to conduct maintenance or repair to the PV system, other interconnection facilities, or the grid.

**Q: WHAT IS THE PURPOSE OF INTERCONNECTION EQUIPMENT?**

A: Interconnection equipment, such as metering, transformers, circuit breakers, fuses, and switches serve to connect the PV system to the electric grid and to disconnect the PV system from the electric grid when required for maintenance or repair.

**Q: DESCRIBE THE FUNCTION OF RACKING OR MOUNTING EQUIPMENT AND ELECTRICAL CONDUIT AS THEY RELATE TO THE GENERATING FACILITIES.**

A: Racking or mounting equipment and electrical conduit are used as necessary to securely connect, align, and protect the PV modules, inverters, disconnects, and interconnection wiring.

**Q: WILL THE SOLAR PV FACILITIES CONTAIN TECHNOLOGY THAT MINIMIZES THE REFLECTION OF SOLAR RAYS?**

A: Yes. As a general rule, PV facilities are designed to minimize reflective glare, as the principal purpose of solar PV panels is to absorb as much sunlight as possible. This is generally accomplished through an anti-reflective coating on the PV module. Concentrating PV ("CPV") technology, however, is somewhat of an exception to this generality. CPV technology utilizes mirrors or lenses to concentrate sunlight onto a smaller solar PV cell. In applications where mirrors are used, the mirrors intentionally reflect sunlight, and that sunlight is directed with precision at a specific point in close proximity to the mirrors themselves. CPV technology is most commonly used in ground-mounted applications. It is the Company's intention to utilize CPV technology in a small number of ground-mounted projects if the Company receives credible and reasonably priced proposals to do so. The majority of installed capacity under the Program will be flat panel PV modules that will include the anti-reflective features described above.

**Q: HOW DOES THE COMPANY PLAN TO INTEGRATE THE PROGRAM INTO ITS EXISTING POWER GRID?**

A: Each PV facility that is installed under the Program will follow the Company's interconnection standards that are required for any distributed generators connecting to the grid. System impact studies will be performed for PV installations when deemed necessary to determine the appropriate level of interconnection. These studies will determine if the installation is better served by interconnecting to transmission or distribution facilities, and if additional modifications are required. Factors used in determining the appropriate level of interconnection will include the cost of interconnection, the impact of the PV facility on the performance of the power grid, and the impact to customers.

**Q: HOW WOULD THE COMPANY DETERMINE WHERE FACILITIES ARE INSTALLED UNDER THE PROGRAM?**

A: The Company will seek customers who own large warehouses, commercial and industrial establishments, office buildings, single family homes, multi-family structures (such as apartment or condominium buildings), subdivisions, schools, or other property to participate in the Program. Upon approval of the Program, customers who desire to offer their property as host sites for solar PV installations can contact Duke Energy Carolinas directly to request inclusion in the Program. Smith Exhibit 1 (a copy of which is Attachment A to the Company's Application) represents a form of the tariff ("Solar Photovoltaic Distributed Generation Program (NC)") setting forth the terms and conditions that the Company intends to offer to customers with businesses, homes, and other property that may be suitable for the installation of a solar PV facility. As described in the Program Tariff, the Program will be available on a limited and voluntary basis, at the Company's option, to customers in owner-occupied individually metered single-family residences, or owners of other property, suitable for the installation of a solar PV system. The Company will work with customers to determine whether a solar PV generating facility is a viable option for their home, business, or land. Factors that the Company will consider in making that determination include, but are not limited to, the age of the roof in question, the angle and orientation of the roof or the slope and orientation of the land, the presence of trees and other solar obstructions, and whether the roof in question can support the weight of the solar PV generating facility. To date, the Company has been contacted by more than 200 customers seeking to be host sites for the Program. Additionally, more than 30 solar PV entities (including installers, manufacturers, and other suppliers of PV services or products) have contacted the Company to express their desire to be selected for Program fulfillment.

The Company also will evaluate siting one or more facilities on Company-owned property. In these cases, the Company will consider the same site characteristics noted above, but the customer tariff would not apply.

**Q: DESCRIBE THE GENERAL PROVISIONS OF SMITH EXHIBIT 1, THE TARIFF THAT WOULD GOVERN CUSTOMERS' PARTICIPATION IN THE PROGRAM?**

A: The general provisions of the tariff are as follows:

- The Company will install a solar PV system on the owner's property under a separate lease agreement with the owner;
- The maximum number of customers served under the Program will be the number required to achieve approximately 20 MWDC of installed PV capacity, of which up to 10% will be installed on single-family residences and the remainder will be installed on nonresidential establishments, multi-family structures, or other property;

- The maximum installed capacity of the PV systems will be 5 kW for single family residences and 3000 kW for nonresidential establishments or other property; and
- The Company reserves the right to limit the total installed PV capacity and/or the number of customers served under this Program on the same retail distribution circuit.

The terms of the agreement between the Company and each individual customer will be set forth in the lease agreement.

**Q: ARE THERE ANY EXPECTED ENVIRONMENTAL IMPACTS OF THE SOLAR PV FACILITIES?**

A: The environmental impacts of the Program are positive in nature. The Company's generation of electricity from the solar PV facilities will not produce any emissions such as NOx, SOx, Hg, particulates, or CO2. For example, the clean energy that the Program is expected to deliver will help avoid at least 15,600 tons of CO2 emissions each year. Additionally, solar PV facilities are quiet and, accordingly, noise pollution is not an issue.

**Q: PLEASE DESCRIBE HOW PRINCIPAL CONTRACTORS AND SUPPLIERS FOR THE CONSTRUCTION OF THE SOLAR PV FACILITIES WILL BE SELECTED.**

A: At this time, contractors and suppliers for the Program have not been selected. The Company is preparing a request for proposals ("RFP") that will be initiated in August 2008. This RFP will provide a competitive bidding process from which the Company will be able to select the best proposals to fulfill the needs of the

Program. Through this RFP, the Company will seek to establish agreements with reputable parties that have proven capabilities with respect to sourcing or manufacturing the required PV components, installation, and maintenance services. Ideally, the Company will establish agreements with a select number of entities that can provide "turnkey" services that could include site assessments, installation of PV systems, and maintenance agreements. The Company also will consider arrangements where a particular party may offer to perform only some of these functions.

## III. PROGRAM SCHEDULE AND COSTS

**Q: WHAT ARE THE COMPANY'S ESTIMATES OF THE CONSTRUCTION COSTS FOR THE SOLAR PV FACILITIES?**

A: As specified in the Application, the Company will spend an estimated $100 million over a two-year period to construct approximately 20 MWDC of distributed generation solar PV facilities.

**Q: WHAT IS THE PROJECTED COST OF EACH MAJOR COMPONENT OF THE SOLAR PV FACILITIES?**

A: Based upon the Company's review of research from public and private sources, we estimate the current cost of each major component of a typical residential PV facility is as follows:

PV Modules .................................................... $4.75 / DC watt

Inverter ........................................................ $0.75 / DC watt

Balance of System (wiring, conduit, racking, etc.) ...........$0.50 / DC watt

Labor ...........................................................$1.25 / DC watt

General & Administrative ..........................................$1.25 / DC watt

Total ..............................................................$8.50 / DC watt

For larger system sizes, volume efficiencies are gained and lower $ / watt costs are achieved, particularly in the areas of General & Administrative (which is primarily a fixed cost), Balance of System, and Labor, but also, to a lesser extent in Modules and Inverters. For example, for installations of approximately 250kW to 500kW, research indicates current total costs are approximately $6.50 / watt. For large systems (>1 MW), research indicates current total costs of approximately $5.00 / watt are being achieved.

The costs illustrated above are indicative of current pricing. Our research indicates, and we expect, a downward trend in PV system component pricing during the period of implementation of the Program. The RFP referenced earlier, however, is the method by which the Company will obtain firm pricing commitments from suppliers.

Q: **WHAT IS THE PROJECTED SCHEDULE FOR INCURRING THESE COMPONENT AND FACILITY COSTS?**

A: The Company intends to incur the costs of the Program over a 2-year period following approval from the Commission. For planning purposes, the Company assumes that it will spend 40% ($40 million) of the capital in 2009 and spend the remaining 60% ($60 million) in 2010. The Company projects that the installed capacity would be proportionate with the dollars spent (i.e., approximately 8 MW of capacity would be installed in 2009 and the remaining 12 MW would be installed in 2010).

**Q: WHAT ARE THE ANTICIPATED FUTURE OPERATING COSTS, INCLUDING THE ANTICIPATED IN-SERVICE EXPENSES ASSOCIATED WITH THE GENERATING FACILIITES FOR THE 12-MONTH PERIOD OF TIME FOLLOWING COMMENCEMENT OF COMMERCIAL OPERATIONS OF THE SOLAR PV FACILITIES?**

A: The Company anticipates spending between $700,000 and $1.3 million annually to operate and maintain the facilities and to compensate host sites for use of their property.

## IV. ELIGIBILITY OF THE PROGRAM FOR TAX BENEFITS

**Q: WHAT TAX BENEFITS ARE AVAILABLE FOR THE PROGRAM?**

A: The Company expects the Program to be eligible for certain State and Federal tax benefits that collectively will reduce the Program's overall costs substantially. One tax benefit comes from the North Carolina renewable energy investment tax credit of 35% on the amount of the investment. A second tax benefit comes from the Federal five-year accelerated tax depreciation benefit. These tax benefits are substantial and already available to the Company today. Additionally, North Carolina Senate Bill 1878 has passed both chambers and now awaits the Governor's signature. It is the Company's understanding that the Governor intends to sign this bill, which will modify a number of property tax provisions, including an exclusion from property tax for 80% of the appraised value of an installed solar electric system, which would further reduce the costs of the Program. Another potential future tax benefit is a federal investment tax credit of 30%. This benefit is currently available to non-utilities and is due to decrease from 30% to 10% at the end of 2008 unless extended by Congress. Proposed legislation in Congress would extend the duration of this tax credit at the 30% level and also make it available to utilities. This potential statutory change would provide additional benefits to the Program.

**Q: PLEASE SUMMARIZE THE BENEFITS OF THE PROGRAM.**

A: There are many benefits of this program and they include the following:

- The Program will result in the production of renewable energy that will help enable Duke Energy Carolinas to comply with its REPS obligations and, along with the power to be purchased from Sun Edison pursuant to a recent purchase power agreement, will specifically help the Company meet its obligations under the solar carve out of the REPS for the next few years.
- The Program will enable the Company to understand the impact of distributed generation on its system. The Company believes that solar PV distributed generation will become much more prevalent in the future, and this Program will enable the Company to better understand any concerns and opportunities that can arise with the introduction of distributed generation.
- The Program will enable the Company to develop and enhance competencies as owners and operators of renewable generation facilities. This competency will benefit customers because the Company will become capable of building and owning renewable resources rather than relying solely on power purchase agreements. In cases where there may

be no viable or attractively priced power purchase options available to the Company, this competency will be especially beneficial.

- The distributed nature of this program promotes energy security.
- The electricity produced under this Program is emission free.
- The Program will promote economic development in North Carolina by attracting investment and creating jobs in the growing solar industry.
- The Program can drive down the cost of solar PV installations in North Carolina through standardizing inspection requirements and leveraging volume purchases.
- The Program enables the Company's customers to directly participate in the development of renewable resources in North Carolina.

## V. <u>APPROVALS</u>

**Q: WHY IS THE COMPANY REQUESTING A BLANKET CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY ("CPCN") AS OPPOSED TO A CPCN FOR EACH SOLAR PV FACILITY?**

A: The Company requests a blanket CPCN in this Application because the precise location of the facilities cannot be specified at this time and waiting to determine such locations before filing multiple applications for individual CPCNs would unduly delay and raise the costs of the Program. In short, the Company believes that approval of a "blanket" CPCN will ensure that the Program is implemented efficiently and without delay. It also will ensure that the benefits of the Program are realized in a timely fashion.

**Q: OTHER THAN APPROVAL FROM THIS COMMISSION, ARE THERE OTHER APPROVALS REQUIRED BEFORE THE PROGRAM MAY BE IMPLEMENTED?**

A: Each PV installation will be subject to various permitting and inspection requirements. These requirements vary at the local level based on location. The Company will comply with all such requirements for all PV installations.

## VI. REPS COMPLIANCE FILINGS

**Q: DOES THE COMPANY INTEND TO INCLUDE THE ELECTRICITY TO BE PRODUCED UNDER THE PROGRAM IN ITS REPS COMPLIANCE PLAN WHEN IT SUBMITS ITS PLAN ANNUALLY TO THE COMMISSION?**

A: Yes.

**Q: WILL THE COMPANY REGISTER FACILITIES CONSTRUCTED UNDER THE PROGRAM AS REQUIRED BY COMMISSION RULE R8-66?**

A: Yes.

**Q: DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A: Yes.

**SMITH EXHIBIT 1**

Duke Energy Carolinas, LLC North Carolina Original (Proposed) Leaf No. 150

SOLAR PHOTOVOLTAIC
DISTRIBUTED GENERATION PROGRAM (NC)

AVAILABILITY (North Carolina Only)

This program is available on a limited and voluntary basis, at the Company's option, to customers in owner-occupied individually metered single-family residences, or owners of other property, suitable for the installation of a solar photovoltaic (PV) system.

GENERAL PROVISIONS

- The Company will install a PV system on the owner's property, under a separate lease agreement with the owner.
- The maximum number of customers served under this program will be the number required to achieve 20,000 kW (DC) of installed PV capacity, of which up to 10% will be installed on single-family residences and the remainder will be installed on nonresidential establishments or other property.
- The maximum installed capacity of the PV system will be 5 kW for residences and 3000 kW for nonresidential establishments or other property.
- The Company reserves the right to limit the number of customers served under this program on the same retail distribution circuit.

CONTRACT

The terms of the agreement will be set forth in the lease agreement with the customer.

North Carolina Original (Proposed) Leaf No. 150
Effective
NCUC Docket No. E-7, Sub

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 856

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| Application of Duke Energy Carolinas, LLC | ) | DIRECT TESTIMONY OF |
| For Approval of Solar Photovoltaic | ) | ELLEN T. RUFF |
| Distributed Generation Program | ) | DUKE ENERGY CAROLINAS, LLC |
| And for Approval of Proposed Method of | ) | |
| Recovery of Associated Costs | ) | |

## I. INTRODUCTION AND PURPOSE

**Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A: My name is Ellen T. Ruff, and my business address is 526 South Church Street, Charlotte, North Carolina.

**Q: WHAT IS YOUR POSITION WITH DUKE ENERGY CAROLINAS, LLC?**

A: I am President of Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company"). Duke Energy Carolinas is a wholly-owned subsidiary of Duke Energy Corporation ("Duke Energy").

**Q: PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL AFFILIATIONS.**

A: I am a graduate of Simmons College with a Bachelor of Arts in Business. I also have a Juris Doctor degree from the University of North Carolina at Chapel Hill, and have completed the Harvard Business School's Advanced Management Program. I am a member of the North Carolina State Bar, the Mecklenburg County Bar, and the American Bar Association. I serve on the Board of Directors of Aqua America, Inc., the Board of Directors and Executive Committee of the North Carolina Chamber, and the North Carolina Economic Development Board. I also serve on the regional Board of Directors of United Way, and am serving as Chair of the United Way Regional Campaign for 2008.

**Q: PLEASE DESCRIBE YOUR BUSINESS BACKGROUND AND EXPERIENCE.**

A: I joined Duke Power Company (now known as Duke Energy Carolinas) in 1978 as an attorney in the Legal Department. I was named Vice President and General Counsel of Electric Operations following the creation of the Duke Energy Corporation in 1997. I was named Vice President and General Counsel of Corporate, Gas and Electric Operations in January 1999, and Senior Vice President and General Counsel in February 2001. I was appointed Senior Vice President of Asset Management for Duke Power, a division of Duke Energy Corporation, in August 2001. I became Senior Vice President of Power Policy and Planning in February 2003, and Group Vice President of Power Policy and Planning in March 2004. I became Group Vice President of Planning and External Relations for Duke Power in March 2005. I assumed my current position in April 2006.

**Q: WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?**

A: I lead Duke Energy Carolinas' regulated electric utility business in North Carolina and South Carolina, which serves more than 2.3 million customers.

**Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?**

A: Yes, I have testified before this Commission on numerous occasions. I most recently presented testimony in support of Duke Energy Carolinas' Energy Efficiency Plan, Docket No. E-7, Sub 831.

**Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. On June 6, 2008, Duke Energy Carolinas filed an Application for Approval of a Solar Photovoltaic ("PV") Distributed Generation Program and for Approval of Proposed Method of Recovery of Associated Costs (the "Application"). The purpose of my testimony is to discuss the importance of the requested approval and to outline some of the benefits of Duke Energy Carolinas' proposed solar PV distributed generation program (the "Program"). In addition to my testimony, Witness Smith provides a detailed discussion of the Program design and Program costs. Witness Hager describes how the proposed construction of solar generation facilities under the Program conforms to the utility's most recent annual plan. Witness McManeus explains the cost recovery proposal for the Program as well as the potential rate impacts of the Program.

## II. PROGRAM DESCRIPTION AND RATIONALE

**Q: PLEASE BRIEFLY DESCRIBE THE PROGRAM.**

A: The Company proposes to invest $100 million over two years to install numerous solar PV facilities throughout its service territory to generate electric energy to serve its customers. We anticipate that the total generating capacity of these facilities would be 20 megawatts direct current (MWDC). When operating at peak capacity, the facilities installed under the Program will generate enough electricity to power approximately 2600 homes in the Carolinas.

**Q: WHY IS DUKE ENERGY CAROLINAS PURSUING THE PROGRAM?**

A: The Company is pursuing this program primarily to comply with the Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") established by the North Carolina General Assembly in 2007 as part of Senate Bill 3. The REPS is a set of standards specifying that electric public utilities in North Carolina must supply their retail customers with a certain amount of electricity from renewable sources or reduce consumption of electricity through energy efficiency measures by a certain date. The Company anticipates increasing its reliance on renewable energy generation resources to serve its customers over time. Accordingly, the Company is committed to supporting the development of solar PV technology into a flourishing and self-sustaining industry that can complement more conventional technologies to supply the electricity needs of the Company's customers. The Program also will enable Duke Energy Carolinas to evaluate the impact of distributed generation of a significant scale on the Company's electric system.

## III. REPS COMPLIANCE

**Q: DOES SENATE BILL 3 SPECIFY A SCHEDULE FOR COMPLYING WITH THE REPS REQUIREMENTS?**

A: Yes it does. Under Senate Bill 3, each electric public utility in the State must comply with the REPS requirement according to the following schedule:

| Calendar Year | REPS Requirement |
|---|---|
| 2012 | 3% of 2011 N.C. retail sales |
| 2015 | 6% of 2014 N.C. retail sales |
| 2018 | 10% of 2017 N.C. retail sales |
| 2021 and thereafter | 12.5% of 2020 N.C. retail sales |

**Q: DOES THE REPS INCLUDE "SET ASIDES" FOR ANY PARTICULAR RENEWABLE RESOURCES?**

A: Yes, the REPS includes "set asides" or "carve outs" for solar energy, swine waste and poultry waste resources. With respect to solar, it provides that beginning with the year 2010, each electric public utility must satisfy its REPS requirement in part with a combination of new solar electric facilities and new metered solar thermal energy facilities that use one or more of certain specified applications. This requirement is sometimes referred to as the "Solar Set Aside" or the "Solar Carve Out". The Solar Carve Out requires compliance according to the following schedule:

| Calendar Year | Requirement for Solar Resources |
|---|---|
| 2010 | 0.02% N.C. retail sales |
| 2012 | 0.07% N.C. retail sales |
| 2015 | 0.14% N.C. retail sales |
| 2018 | 0.20% N.C. retail sales |

**Q: HOW MAY A UTILITY COMPLY WITH THE REPS REQUIREMENTS?**

A: Subject to certain limitations, an electric public utility may meet the REPS requirements by doing one or more of the following: (1) generating electric power at a new renewable energy facility; (2) using a renewable energy resource to generate electric power at a generating facility (other than the generation of electric power from waste heat derived from the combustion of fossil fuel); (3) implementing energy efficiency measures to reduce electricity consumption; (4) purchasing electric power from a new renewable energy facility; and (5) purchasing renewable energy certificates derived from new renewable energy facilities. Additionally, Senate Bill 3 allows a utility to carry forward renewable energy generated in one year that exceeds the compliance requirements of that year into a future year.

**Q: DOES THE COMPANY'S PROGRAM COMPLY WITH THE REPS REQUIREMENTS IN GENERAL AND THE SOLAR CARVE OUT PROVISIONS IN PARTICULAR?**

A: Yes, the Program complies with the REPS requirements as well as the solar carve out provisions. The solar PV facilities the Company proposes to install under the Program are "renewable energy facilities" as defined by Senate Bill 3 and, therefore, may be used to comply with the REPS requirements. Thus, the Program will enable Duke Energy Carolinas to partially fulfill its REPS obligations in general and the Solar Carve Out in particular. As Company witness Smith explains, the Company intends to include the Program in its REPS compliance plan when such plan is filed with the Commission annually pursuant to Commission Rule R8-67. The Company also will register facilities constructed under the Program as required by Commission Rule R8-66.

## IV. PROGRAM BENEFITS

**Q: WHAT ARE SOME OF THE BENEFITS OF THE PROGRAM?**

A: In addition to helping the Company meet its REPS obligations, overall, the Program will promote the development of renewable energy in the State of North Carolina. As Witness Smith explains, the Company proposes to invest $100 million to install several hundred facilities around the Company's North Carolina service territory with a generating capacity totaling approximately 20 MWDC. Despite the significant federal and state tax incentives available for investments in solar resources, there were, as of June 6, 2008 (the date of the Company's initial application in this docket), only approximately 60 customer-installed solar generation facilities in the Company's territory with a total installed capacity of approximately 300 kilowatts. We believe that by getting involved on such a large scale, the Company can help promote the development of solar generation resources in North Carolina. Also, as explained in Ms. Hager's testimony, the Program will, in a modest way, help diversify the resources the Company uses to reliably meet the energy needs of its customers. Importantly, the development of renewable resources and the diversification of energy supply resources are among the specific goals enumerated by the General Assembly in enacting Senate Bill 3.

**Q: WILL THE PROGRAM BENEFIT CUSTOMERS IN OTHER WAYS?**

A: Yes. As Witness Smith explains, the generating facilities will be installed on both customer and Company-owned property in the Company's North Carolina service area. The distributed nature of the generation of electricity under the Program will enable the Company to develop competency as an owner of solar renewable assets, leverage volume purchases, build relationships with PV developers, manufacturers, and installers, and gain invaluable experience with the installation and operation of multiple types of solar distributed generation facilities. Developing competencies in these areas mean that ultimately, the Company will not be dependent solely on power purchases to meet the requirements of the Solar Carve Out.

**Q: WHY DOES THE COMPANY BELIEVE THAT THIS APPLICATION IS JUSTIFIED BY THE PUBLIC CONVENIENCE AND NECESSITY?**

A: Duke Energy Carolinas believes that its decision to invest in the Program is justified by the public convenience and necessity for all the reasons provided in my testimony and that of the other Company witnesses. In short, implementation of the Program is prudent and the Company's Program is designed to serve the public interest. It will enable the Company to meet its obligations under the REPS, serve the electricity needs of its customers, and diversify its generation resource mix as well as that of the State in general. It also will encourage economic development, private investment in renewable energy, and improve the air quality, among other benefits.

**Q: DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A: Yes.

## CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC's Direct Testimonies of Janice D. Hager, Jane L. McManeus, Owen A. Smith and Ellen T. Ruff in Docket No. E-7, Sub 856, has been served by electronic mail (e-mail), hand delivery or by depositing a copy in the United States Mail, first class postage prepaid, properly addressed to parties of record.

This the 25th day of July, 2008.

Robert W. Kaylor

Robert W. Kaylor
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