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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

PETITION FOR DETERMINATION OF NEED

REGARDING THE DANIA BEACH CLEAN ENERGY CENTER UNIT 7

DIRECT TESTIMONY OF EZRA D. HAUSMAN, PH.D.

ON BEHALF OF THE SIERRA CLUB

DOCKET NO. 20170225-EI

DECEMBER 8, 2017

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I. Professional Qualifications

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

A. My name is Ezra D. Hausman, Ph.D. I am an independent consultant doing business as Ezra Hausman Consulting, operating from offices at 77 Kaposia Street, Auburndale, Massachusetts 02466.

Q. Are you providing any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits.[1]

Exh. No.	Description
EDH-1	Resume of Ezra D. Hausman, Ph.D.
EDH-2	Gavin Bade & Peter Maloney, Utility Dive, *Updated: Tucson Electric Signs Solar + Storage PPA for 'Less Than 4.5¢/kWh'* (May 2017), *available at* https://www.utilitydive.com/news/updated-tucson-electric-signs-solar-storage-ppa-for-less-than-45kwh/443293/
EDH-3	JEA, *Agenda Item Summary: Universal Solar Expansion and Land Acquisition* (Oct. 2017)
EDH-4	Pierce Schuessler, Solar Energy Industries Association, *Comment on Proposed 2017 Second Revised and Restated Stipulation and Settlement Agreement in Docket No. 20170183* (Oct. 2017)
EDH-5	EnerNOC, Inc., *ISO-New England Awards EnerNOC Landmark Contract to Improve Grid Reliability in Southwest Connecticut* (Apr. 2004)
EDH-6	Moody's, *Global Renewables Focus* (Sep. 2017)
EDH-7	Mark Bolinger et al., Lawrence Berkeley National Laboratory, *Utility-Scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (Sep. 2017), *available at* https://emp.lbl.gov/sites/default/files/utility-scale_solar_2016_report.pdf
EDH-8	Chris Neme & Jim Grevatt, Energy Futures Group, *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments* (Jan. 2015), *available at* http://www.neep.org/sites/default/files/products/EMV-Forum-

[1] As I cite to certain discovery responses and deposition testimony, the relevant pages are being provided as exhibits as well.

	Geo-Targeting_Final_2015-01-20.pdf
EDH-9	Rachel Wilson & Bruce Biewald, Synapse Energy Economics, *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans* (June 2013), *available at* http://www.raponline.org/wp-content/uploads/2016/05/rapsynapse-wilsonbiewald-bestpracticesinirp-2013-jun-21.pdf
EDH-10	Navigant Consulting, Inc., for Eastern Interconnection States' Planning Council and National Association of Regulatory Utility Commissioners, *Transmission Planning White Paper* (2014), available at https://pubs.naruc.org/pub.cfm?id=53A151F2-2354-D714-519F-53E0785A966A
EDH-11	New England Power Pool, *Order on Rehearing and Accepting Compliance Filing*, FERC Docket Nos. ER04-335-001 and ER04-335-002 (May 2004), *available at* https://www.ferc.gov/eventcalendar/Files/20040528153559-er04-335-001.pdf
EDH-12	PJM Interconnection, LLC, *Load Management Performance Report* 2015/2016 (Aug. 2016), *available at* http://www.pjm.com/~/media/markets-ops/dsr/2015-2016-dsr-activity-report-20151221.ashx
EDH-13	PJM Interconnection, LLC, *RPM 101: Overview of Reliability Pricing Model* (Apr. 2017), *available at* http://pjm.com/~/media/training/nerc-certifications/markets-exam-materials/rpm/rpm-101-overview-of-reliability-pricing-model.ashx

Q. What is your educational and professional background?

A. I hold a BA in Psychology from Wesleyan University, an MS in Environmental Engineering from Tufts University, an SM in Applied Physics from Harvard University, and a PhD in Atmospheric Chemistry from Harvard University. I have been involved in analysis of both regulated and restructured electricity markets for approximately 20 years.

I have worked as an independent consultant and expert based on my expertise and experience in energy economics and environmental science since 2014. From 2005 until early 2014, I was employed at Synapse Energy Economics, Inc., a research and consulting company located in Cambridge, Massachusetts, where I served most recently as Vice President and Chief Operating Officer. From 1998 through 2004 I served as a Senior Associate at Tabors Caramanis and Associates (TCA) of Cambridge, Massachusetts. In 2004, TCA was acquired by Charles River Associates (CRA), where I remained until 2005.

I provide expert consulting services in several areas relating to energy markets and energy market regulation on the state, regional, and federal levels; energy dispatch and planning modeling, quantification of the economic and environmental benefits of displaced emissions; and treatment of energy efficiency and renewable energy in electricity and capacity markets. I have provided testimony and/or appeared before public utility commissions or legislative committees in Arizona, Idaho, Illinois, Iowa, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Mississippi, Missouri, New Hampshire, New Jersey, Nevada, South Dakota, Vermont, and Washington State, as well as at the federal level. I have also provided expert representation for stakeholders at the PJM ISO, the California ISO, the Midwest ISO, and at the FERC. While most of my testimony and analytical work has centered on issues concerning electricity market economics, I have also brought my expertise as a scientist to bear on cases involving energy efficiency programs and greenhouse gas regulation and mitigation in the electric sector.

I have provided a detailed resume including a detailed list of my testimony, publications, presentations, and reports, as Hausman Exhibit 1.

Q. Have you previously testified before the Florida Public Service Commission?

A. No.

II. Purpose of Testimony, Summary of Findings, and Recommendations

Q. What is the purpose of your testimony?

A. I address Florida Power & Light Company's (hereafter, "FPL" or "Company") request that the Florida Public Service Commission (hereafter, "Commission") grant an affirmative determination of need for a 1,163 megawatt (hereafter MW) gas combined cycle (hereafter, "CC") unit in June 2022. FPL plans to build what it calls the Dania Beach Clean Energy Center Unit 7 (hereafter, DBEC) at FPL's Lauderdale plant site in Broward County, Florida, four years after retiring two existing Lauderdale units (hereafter, Units 4 and 5) at that site in 2018.

My testimony assesses FPL's stated reasons for its request under the factors this Commission uses to assess the need for new power plants.

Q. Please summarize your findings.

A. I find that FPL failed to perform a comprehensive and rigorous analysis of alternatives for meeting its reliability requirements. Had it done so, it would have found lower-cost, lower-risk, and lower-emissions options, relative to DBEC, that meet reliability requirements and promote fuel diversity. FPL did not identify these options because its analyses of alternatives were inadequate, based on flawed assumptions, and inconsistent with industry best practices, and were thus too flawed to serve as justification for the proposed investment of $888 million of customer funds on DBEC.

I further find that the Company's request is premature, given its own projection of sufficient resources at least through 2024, and the availability of abundant lower cost and lower risk resources for meeting the Company's needs in the ensuing years. Although FPL contends that building DBEC several years in advance of any reliability need will save customers money, I find that this conclusion is based on a flawed and misleading analysis, and that in fact it costs less to delay DBEC.

Q. What are your recommendations for the Commission in this proceeding?

A. I recommend that the Commission deny FPL's petition for an affirmative determination of need for DBEC in June 2022. Based on my review of the information provided to date and relevant industry information, it is clear that DBEC is not needed at that time, and may never be needed under the factors this Commission uses to determine need in this context.

First, 2024, not 2022, is the first year in which FPL has identified a projected, unmet system reliability need—and that need is for 54 MW,[2] as opposed to the 1,163 MW proposed by FPL. Second, given the unmet system need identified by FPL, FPL has not shown that DBEC is the most cost-effective alternative available to meet that need, because FPL did not credibly perform the routine review of all available alternatives, including low-cost, straightforward alternatives such as incremental additions of solar and demand-side resources.[3] As I will explain, FPL's exceedingly narrow review of just two delay scenarios

[2] Under FPL's 20% reserve margin requirement. See Exhibit SRS-2 to the direct testimony of Dr. Steven Sim. FPL's reserve margin criteria are discussed in detail in my testimony.

[3] I will use the term "demand-side resources" to refer to the measures that are currently included in FPL's demand-side management programs (DSM) as well as other distributed, customer-sited resources such as energy efficiency, demand response, conservation, and customer-owned rooftop solar photovoltaics (PV).

reveals that FPL's plan to build DBEC in 2022 would cost *more* than simply delaying DBEC by one or two years. Nor has FPL shown that DBEC promotes fuel diversity in Florida or in FPL's generation fleet, whereas alternatives could substantially reduce customers' exposure to the wide-ranging costs and risks of FPL's heavy reliance on gas. Finally, FPL has not shown that it has adequately explored or developed either renewable generation options or conservation measures as alternatives to DBEC.

III. Structure of My Testimony

Q. How is your testimony organized?

A. My testimony is organized around the factors that this Commission uses to review the need for new power plants, which are set out in Section 403.519, Florida, Statutes. Specifically, I address these factors:

- Whether FPL has established a need for DBEC in 2022 for system reliability purposes;
- Whether FPL has established that DBEC is the most cost-effective alternative available;
- Whether FPL has established a need for DBEC for fuel diversity purposes; and
- Whether FPL has established that renewables and conservation measures are utilized to the extent reasonably available under its plan to build DBEC in 2022.

Finally, I offer my recommendations for Commission action on this matter.

IV. Need for System Reliability

Q. What reliability need(s) has FPL identified?

A. FPL identified two future reliability needs. One is a projected regional imbalance in Southeast Florida (Broward and Miami-Dade counties) after 2030; or as early 2025, if Units 4 and 5 retire in 2018.[4] The other is a projected shortfall in system-wide reserves as early as 2024, again if Units 4 and 5 retire in 2018.[5]

Q. Please elaborate on the regional imbalance in Southeast Florida.

A. FPL identified a balance between the need for capacity to serve peak load in the Southeast Florida region of its service area (in Broward and Miami-Dade counties) net of capacity located in this region, versus available firm transmission capacity to deliver out-of-region energy to customers. Put simply, this is a balance between the import *requirement* under peak load conditions, and the import *capability* of the system under the same conditions. If the projected import requirement exceeds the import capability, there is an imbalance, which can be resolved one of three ways: (1) reducing load in the Southeast Florida area; (2) increasing generation that can serve the area; or (3) relieving a transmission constraint through transmission enhancements or other technical or operational means.

Q. You said FPL projected an imbalance in Southeast Florida in 2030 or as early as 2025. Briefly elaborate on these two timeframes.

A. Any imbalance in Southeast Florida has been significantly forestalled by the construction of the Corbett-Sugar-Quarry (CSQ) line, which FPL anticipates to be in service by mid-2019.[6] According to FPL's witness Dr. Sim, the CSQ line "can address the regional need from mid-2019 through the year 2030 (assuming

[4] Direct Testimony of Dr. Steven R. Sim, page 18 at lines 5-7.
[5] Ibid. at lines 1-2.
[6] Ibid., page 29 at line 5.

no other changes in projected load, generation, and/or transmission capability)."[7] Alternatively, if Units 4 & 5 retire in 2018, FPL projects imbalance conditions may arise in Southeast Florida as early as 2025.[8]

Q. Please briefly elaborate on the other reliability need identified by FPL.

A. FPL projects this need based on two system-wide reliability criteria. The first criterion is that the combined accredited capacity of all resources on FPL's system, including its demand-side management programs (hereafter, DSM), must equal or exceed 120% of projected peak load (hereafter, 20% reserve margin). The second criterion is that the accredited capacity of generation resources alone, excluding DSM, must equal or exceed 110% of forecasted peak load. FPL refers to this second criterion as its "generation-only reserve margin" (hereafter, GRM).

Q. Has FPL explained its use of GRM as an additional reliability criterion?

A. No, FPL has not. But FPL's move to adopt GRM only a few years ago[9] is unprecedented in Florida, unprecedented in other jurisdictions where I have worked, and inconsistent with the record of demand-side resources providing excellent reliability services.[10] By nonetheless using GRM, FPL arbitrarily discounts the reliability attributes of demand-side resources, thereby skewing FPL's analysis toward additional supply-side resources even when those resources may provide little to no incremental reliability benefit.

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[7] Ibid., at lines 9-11.

[8] Ibid., at lines 16-17.

[9] Deposition of Dr. Steven R. Sim on November 29, 2017, page 154 at lines 9-11 ("[The GRM] is one that FPL uses and that the Commission is aware of, and we've been using it now for, ballpark, three, four years.").

[10] For example, performance of DSM capacity resources in PJM is reported in the PJM Annual Load Management Performance Report. *See* PJM Interconnection, LLC, *Load Management Performance Report 2015/2016* (Aug. 2016), *available at* http://www.pjm.com/~/media/markets-ops/dsr/2015-2016-dsr-activity-report-20151221.ashx.

Q. You said FPL projects a shortfall in its reserves as early as 2024. Please elaborate on the timing and magnitude of this shortfall.

A. Under a 20% reserve margin criterion and FPL's load forecast, FPL anticipates a shortfall of 20MW in 2026, if Units 4 and 5 are operating, and 54 MW in 2024, if Units 4 and 5 retire in 2018. FPL projects that the shortfall will grow in subsequent years, as shown in Exhibit SRS-2 sponsored by FPL witness Dr. Sim.

Q. What is your opinion of FPL's reliability criteria?

A. FPL uses extremely conservative reliability criteria. The industry standard for reliability is to have sufficient reserves to achieve a loss of load probability (hereafter, LOLP) of one day in ten years.[11] Beyond this level the marginal increased reliability benefit diminishes rapidly, as the risk of capacity-related failure becomes vanishingly small.[12] While FPL also considers the one-day-in-ten-years LOLP standard, the Company's two reserve margin criteria discussed above are more stringent – they mislead FPL to over-procure capacity that is not

[11] For example, see Navigant Consulting, Inc., for Eastern Interconnection States' Planning Council and National Association of Regulatory Utility Commissioners, *Transmission Planning White Paper* 24 (2014), available at https://pubs.naruc.org/pub.cfm?id=53A151F2-2354-D714-519F-53E0785A966A ("The utility industry, for decades, has used a LOLE of one day in ten years as the primary means for setting target reserve margins and capacity requirements in resource adequacy analyses.").

[12] This may be seen, at least conceptually, in the "Variable Resource Requirement" (VRR) curves used by some capacity market operators to represent the decreasing marginal value of increased reserve margins over the standard requirement. *See* PJM Interconnection, LLC, *RPM 101: Overview of Reliability Pricing Model* 25-30 (Apr. 2017), *available at* http://pjm.com/~/media/training/nerc-certifications/markets-exam-materials/rpm/rpm-101-overview-of-reliability-pricing-model.ashx; *see also* Deposition of Steven R. Sim on November 29, 2017, page 156 at lines 12-13 (stating that, at least in theory, there are diminishing returns on reliability improvements from increases to generation reserves).

needed to meet the industry LOLP standard.[13]

1. There Is No System Reliability Need for the Project

Q. Do you agree that DBEC is needed in 2022 to meet a regional imbalance in Southeast Florida and FPL's reserve shortfalls?

A. No. DBEC is not needed in 2022 for regional balance or system reliability because FPL expects its existing resources to be more than adequate to meet both of these needs at least until 2024.[14]

Q. Is the potential for either a shortfall in reserves before 2024 or a regional imbalance in Southeast Florida earlier than 2025, due to unexpected circumstances, a sufficient justification for placing DBEC in service in 2022?

A. No. As FPL has acknowledged,[15] load forecasts and other expectations about the future are inherently uncertain, and the date at which a shortfall in reserves or a regional imbalance could arise could be earlier or later than the Company anticipates. However, this uncertainty does not justify placing DBEC in service in 2022, two to three years earlier than any anticipated need. FPL has not

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[13] Florida Public Service Commission, *Review of the 2017 Ten-Year Site Plans of Florida's Electric Utilities* 51 (Nov. 2017), *available at* http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/TenYearSitePlans/2017/Review.pdf ("Between the two reliability indices, LOLP and reserve margin, the reserve margin requirement is typically the controlling factor for the addition of capacity."); *see also* Deposition of Dr. Steven R. Sim on November 29, 2017, page 155 at line 25 through page 156 at line 1 ("Loss of load probability is not driving our resource needs, it is the other two.").

[14] Deposition of Steven R. Sim on November 29, 2017, page 161 at lines 11-24.

[15] Florida Power & Light Company, *Response to Sierra Club Interrogatory Number 16 in Docket No. 20170225-EI* (Nov. 2017) ("The window of opportunity could potentially extend past 2025, *e.g.*, due to either Summer peak load being lower than forecasted and/or to greater than forecasted available capacity in the region."); *see also* Deposition of Steven R. Sim on November 29, 2017, page 78 at lines 9-10 ("I don't need to do analysis to postulate that the load forecast could change.").

even analyzed or assigned a probability for those occurrences.[16] In fact, in its review of 2017 Ten Year Site Plans (hereafter "TYSP"), the Commission found that Florida utilities have consistently and often dramatically *over* predicted load with a five- to six-year lead time.[17] The inevitable uncertainty around load forecasts is one of the primary reasons that resource planning is performed using a reserve margin – as a contingency against load forecast errors. FPL's 20% planning reserve margin more than adequately accommodates this type of uncertainty. Further, there are a number of less costly and readily available alternatives to meet FPL's system reliability needs on a short-term basis should those needs arise earlier than currently projected, as discussed in the next section of my testimony.

2. There Are Lower Cost Alternatives that Meet Future System Reliability Needs as They Arise

Q. What can FPL do to resolve or forestall its projected system reserve shortfall and projected imbalance in Southeast Florida?

A. FPL has many options, such as incremental additions of large-scale solar and demand-side resources, as well as short-term power purchase agreements. Various energy storage technologies, including batteries, can also help meet reserve margins because they can be used to store energy during off-peak periods and make it available to the system during peak times. All of these resources can help resolve regional imbalance, too, if they are sited in, or electrically connected

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[16] Deposition of Steven R. Sim on November 29, 2017, page 162, lines 6-10.

[17] Florida Public Service Commission, *Review of the 2017 Ten-Year Site Plans of Florida's Electric Utilities* 25-35 (Nov. 2017), *available at* http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/TenYearSitePlans/2017/Review.pdf.

to, the Southeast Florida region. FPL can even meet its reliability needs via additional transmission, as it has with the CSQ line now under construction, or possibly through operational changes that enhance import capability under peak load conditions. As I will explain further below, these alternatives to DBEC likely could meet FPL's reliability needs at a lower cost than placing DBEC in service in 2022.

Q. What are the benefits of meeting reliability needs incrementally as they arise?

A. There are many benefits to taking an incremental approach. This would allow FPL and the Commission additional time to use updated load projections, rather than committing to large expenditures on supply side generation years before it is needed to meet uncertain long-term forecasts of growth.[18] This approach would benefit customers by deferring, reducing, or even avoiding expensive supply-side generation additions, protecting them from overpaying now for excess capacity with little to no marginal reliability benefit that is not needed until a later date. Delaying or avoiding DBEC also benefits customers by allowing FPL and its customers to benefit from improvements in performance and costs for solar, storage, and even CC units in the future.

V. Most Cost-Effective Alternative

Q. Why does FPL claim the proposed DBEC project is cost-effective?

A. FPL claims that, over the life of the project, building and operating DBEC

[18] This is an issue often referred to as "lumpy" generation additions – the fact that economies of scale for large fossil generators force utilities to over-procure capacity and customers to bear unnecessary costs until load growth restores appropriate reserve margins. Lumpiness is not a significant factor for clean energy and DSM resources that are typically procured in smaller increments.

is cheaper than continuing to operate Units 4 and 5. FPL also claims that, relative to DBEC, it would cost more to place solar (PV) and storage in service on the same time frame, with the same firm capacity, and in similar locations.[19] Finally, FPL claims that placing DBEC in service in 2022 is cheaper than doing so one or two years later.[20]

Q. Do you agree that placing DBEC in service in 2022 is the most cost-effective way to meet FPL's reliability requirements?

A. No. For reasons that I will explain, I conclude that FPL's own analyses show that placing DBEC in service in 2022 is not the most cost-effective alternative available. I further identify additional alternatives to DBEC that FPL failed to consider, but that could serve customers with less cost, less risk, and lower emissions of pollutants to the environment.

1. FPL Has Failed to Show that the Project is the Most Cost-Effective Alternative

Q. What flaws have you identified in FPL's analyses of alternatives to its proposed project?

A. Based on my review of FPL's filings, discovery responses, and deposition testimony to date, I find that FPL's analyses are fundamentally flawed in the following ways: (i) FPL did not use a resource planning model in any meaningful way to evaluate the economics of alternate resource plans; (ii) FPL did not issue a request for proposals or conduct any other comparable, rigorous investigation of alternatives on the market that could meet its reliability needs; (iii) FPL

[19] Direct Testimony of Dr. Steven R. Sim, page 35 at lines 22-23 through page 36 at lines 1-11.
[20] Direct Testimony of Dr. Steven R. Sim, page 36 at lines 19-23 through page 37 at lines 1-12.

considered overly and unnecessarily constrained options; (iv) FPL imposed irrational and costly assumptions on its two "delay" scenarios; and (v) FPL failed to meaningfully consider demand-side resources.

Q. Please describe the purpose of a resource planning model.

A. Very briefly, a resource planning model is a computer simulation used to find the least-cost mix of resources that will meet the user's needs for energy and capacity over the duration of a predefined study period. The model and its use should be flexible enough to test a wide range of resource combinations. Users routinely run the model under a range of possible future conditions, such as higher or lower load growth, higher or lower fuel prices, and so forth. In this way a least-cost plan can be found that meets the utility's needs under a range of possible future conditions.

Q. Did FPL engage in the type of modeling analysis you describe? Why or why not?

A. No. While FPL has routinely used the EGEAS model to develop its ten-year site plans,[21] it did not use this model in its 2017 analysis. Moreover, in its 2016 analysis, FPL only applied the EGEAS model in the first of four iterations.[22] Yet even in that first iteration, FPL restricted the resource options in the model to "just combined cycles and combustion turbines.[23] FPL explains its abandonment of the model by claiming that "[t]he need to simultaneously solve for both FPL

[21] Florida Power & Light Company, Ten Year Power Plant Site Plan 2017-2026 at 57 (Apr. 2017) ("FPL utilized the UPLAN production cost model and a Fixed Cost Spreadsheet, and/or the EGEAS optimization model, to perform the system economic analyses of the resource plans.").

[22] Deposition of Dr. Steven R. Sim on November 29, 2017, page 86 at lines 4-25 through page 89 at lines 1-17.

[23] Ibid., page 88 at lines 4-5.

system and SE Florida region requires a new analysis approach."[24] However, it is best practice to use a modeling study as a component of any analyses aimed at least-cost resource planning.[25]

Here, for example, FPL could fix imports into Southeast Florida as a boundary condition, and use EGEAS or a similar model, but allow the model to select from a wide range of resources, to find candidate plans within the region. This would be a standard use of the model. Had FPL used this approach, it could have identified lower-cost resource plans, likely including demand-side resources, large- and small-scale solar, and storage, to meet its regional and system-wide needs.

Q. You said use of a resource planning model is one component of least-cost planning. What are other strategies that help utilities ensure they are procuring least-cost resources for their customers?

A. Another important strategy for least-cost procurement is the investigation of market conditions. This is particularly critical today because conditions are changing so rapidly and dramatically throughout the industry. One of the best ways to investigate current market conditions is to issue resource-neutral requests for proposals (RFPs), and to allow independent market participants the opportunity to propose solutions to reliability needs at lower cost than utility-

[24] Florida Power & Light Company, *2016 Southeastern Florida Study: Results To-Date* 6 (Dec. 2016); *see also* Deposition of Dr. Steven R. Sim on November 29, 2017, page 86 at lines 10-21.
[25] Rachel Wilson & Bruce Biewald, Synapse Energy Economics, *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans* (June 2013), *available at* http://www.raponline.org/wp-content/uploads/2016/05/rapsynapse-wilsonbiewald-bestpracticesinirp-2013-jun-21.pdf.

identified and implemented solutions.[26]

A classic example of this, derived from a situation that is similar in many respects to FPL's situation, was the 2004 Southwest Connecticut "Gap RFP" to find solutions to an import constraint into a congested and high-cost region of Connecticut. The solution ultimately accepted by both the market operator and the Federal Energy Regulatory Commission (FERC) was a third-party contract to provide demand response services, which delayed the need for any transmission or generation solution for several years.[27]

Q. Do you have reason to believe that an RFP process might have yielded lower-cost options than FPL considered in its 2017 analyses?

A. Yes. As FPL must be aware, its unregulated affiliate, NextEra Energy Resources (NEER), is an industry leader in providing low-cost solar solutions in the form of power purchase agreements (hereafter, "PPA") to utilities. For example, NEER recently announced a PPA with Tucson Electric Power delivering a combined solar and storage solution for under $0.045 per kWh, with solar portions priced at under $0.03 per kWh.[28] This would be cost competitive with or superior to new gas-fired resources on a levelized cost basis, and provides

[26] Chris Neme & Jim Grevatt, Energy Futures Group, *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments* (Jan. 2015), *available at* http://www.neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf.

[27] New England Power Pool, *Order on Rehearing and Accepting Compliance Filing*, FERC Docket Nos. ER04-335-001 and ER04-335-002 (May 2004), *available at* https://www.ferc.gov/eventcalendar/Files/20040528153559-er04-335-001.pdf; EnerNOC, Inc., *ISO-New England Awards EnerNOC Landmark Contract to Improve Grid Reliability in Southwest Connecticut* (Apr. 2004).

[28] Gavin Bade & Peter Maloney, Utility Dive, *Updated: Tucson Electric Signs Solar + Storage PPA for 'Less Than 4.5¢/kWh'* (May 2017), *available at* https://www.utilitydive.com/news/updated-tucson-electric-signs-solar-storage-ppa-for-less-than-45kwh/443293/.

far greater fuel diversity benefits. These low costs are consistent with the findings of a 2017 nationwide survey of solar PPA process published by the US Department of Energy (DOE).[29]

Q. Have you found evidence of solar PPAs with similar pricing available in Florida?

A. Yes. For example, JEA recently completed three rounds of solar RFPs. JEA's Managing Director and CEO, Mr. Paul E. McElroy, found that "the price of utility-scale solar PPAs has declined from $75/MWh on average in 2016 to near JEA's current fuel charge of $32.50/MWh today."[30] In other words, below the cost of fuel for gas-fired generation, indicating that solar PPAs are already competitive with new and even existing gas-fired generation. Mr. McElroy subsequently recommended to his Board of Directors that "JEA pursue new universal solar PPAs at or below JEA's current fuel rate to take advantage of lower universal solar prices. Universal solar allows JEA to lock in current, competitive low energy prices for a portion of our generation requirements, reducing JEA's reliance on fossil fuels and providing some protection to JEA customers against future changes in volatile fuel and purchase power."[31]

Based on JEA's successful experience with solar PPAs, it seems likely that FPL would have similarly found low-cost solar PPA opportunities had it

[29] Mark Bolinger et al., Lawrence Berkeley National Laboratory, *Utility-Scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* § 2.3 (Sep. 2017), available at https://emp.lbl.gov/sites/default/files/utility-scale_solar_2016_report.pdf.

[30] JEA, Agenda Item Summary: Universal Solar Expansion and Land Acquisition (Oct. 2017).

[31] Ibid.

issued a solicitation to the market.[32] However, the Company does not appear to have even considered this alternative.

Q. Can market solicitations be used to acquire DSM resources, such as demand response, to meet reliability needs?

A. Yes. Several examples of this are discussed in a recent paper by the Northeast Energy Efficiency Partnership.[33] The flourishing of demand-side resources is also one of the great success stories of the organized capacity markets, where demand resource participation by independent, third-party aggregators far exceeded initial expectations - reducing fuel use, saving consumers billions of dollars, and averting the need for many power plants.[34] FPL itself has a history of using DSM to meet reliability needs, having reduced cumulative summer peak by approximately 4,843 MW and eliminated the need to construct the equivalent of approximately 15 new 400 MW generating units between 1978 and 2016.[35] Until FPL conducts such a market solicitation itself, or

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[32] Further evidence of this is found in Pierce Schuessler, Solar Energy Industries Association, *Comment on Proposed 2017 Second Revised and Restated Stipulation and Settlement Agreement in Docket No. 20170183* (Oct. 2017). The comment asserts that, as compared to the cost cap on solar applicable to the solar to which DEF commits -- on a weighted average cost of all project basis, no greater than $1,650 per kilowatt alternating current ("kWac"), "ratepayers would be better served if, instead of building its own solar facilities, Duke were to procure this additional generation through third party power purchase agreements, or by the purchase of completed projects developed by third parties. We believe that either option would allow for the addition of solar capacity at a lower cost than generation developed and constructed by Duke." Ibid.

[33] Chris Neme & Jim Grevatt, Energy Futures Group, *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments* (Jan. 2015), available at http://www.neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf.

[34] *See generally* PJM Interconnection, LLC, *Reliability Pricing Model Base Residual Auction Reports*, available at http://www.pjm.com/markets-and-operations/rpm.aspx. For example, the 2019/2020 auction yielded 10,348 MW of demand response resources.

[35] Florida Power & Light Company, Ten Year Power Plant Site Plan 2017-2026 at 24 (Apr. 2017).

performs a comparably rigorous investigation of the market for demand-side resources, there is no reason to believe the Company's assertions that incremental cost-effective demand-side resources are unavailable.

Q. In summary, what is your recommendation for how FPL should devise, analyze, and implement the most cost-effective alternative available?

A. I recommend that FPL take the following steps:

- Determine appropriate reserve margin criterion and regional resource needs using a loss-of-load probability of 0.01.
- Use market solicitations to ascertain availability and cost of additional resource options.
- Use a resource planning model to devise and test cost-effective plans for meeting both its system-level reliability constraint and resource needs in sub-regions, allowing the model to select the optimal resources from a full range of options, and using multiple runs of the model to test alternative resource plans under a range of future conditions.
- Schedule resource development, including demand-side resources, to address resource needs at the time they are projected to materialize, and do not subject customers to unnecessary costs for resources long before they are needed for reliability purposes. One crucial means of achieving this is to rely on smaller, incremental resources to meet incremental needs. This approach helps match resource procurement to the actual timing and magnitude of resource needs, thereby avoiding the costs of over-supply and capturing the savings associated with the continuous cost and performance improvements across resource options.
- Use RFPs in the final procurement process to try to reduce the cost of resources when they are ultimately procured.

2. To Identify the Most Cost-Effective Alternative, FPL Should Have, But Did Not, Evaluate Numerous Alternatives Available to FPL

Q. What alternatives to DBEC did FPL consider in its 2017 analyses?

A. FPL considered just one realistic alternative to its plan to build DBEC by 2022. Under the alternative that FPL calls "Plan 1," Units 4 and 5 would operate until at least 2061 and FPL would enter into a new PPA in 2026, add a new combined cycle unit outside of Southeast Florida in 2027, and add other resources in later years. Plan 1 may be seen as a "base case" scenario under which existing units are supplemented by new resources as the need for them arises.

In addition to Plan 1, FPL presented its proposed plan (Plan 2); a plan that purported to test the option of relying on clean energy resources (Plan 3); and two plans that purported to test the option of delaying DBEC by one or two years (Plan 4 and Plan 5, respectively.)

Q. Do you have concerns with how FPL designed its proposed Plan 2?

A. Yes. Under FPL's proposed plan, Plan 2, Units 4 and 5 would be retired in 2018 and DBEC would be constructed at the same site and brought into operation in 2022. Plan 2 is suboptimal because the new unit would be brought on line two to three years prior to any reliability requirement for this unit at all, and five years before FPL projects a need for its full capacity. FPL also failed to explore whether other resources, such as higher levels of DSM, solar, or batteries, could defer, reduce, or avoid its projected need for DBEC. Indeed, FPL did not even seek to take advantage of improvements it expects in both the cost and performance of CC units. As attested to by Dr. Sim, "we see combined cycle costs dropping. In fact, we think that in the next few years we're going to see the very first combined cycle with a heat rate below 6,000. That's on the horizon."[36] Yet FPL would needlessly place DBEC in service without waiting for those efficiency benefits, even though there is no reliability or cost benefit to doing so.

Q. Please describe FPL's additional analyses of delaying construction of DBEC for one or two years.

A. These plans, denoted Plan 4 and Plan 5 in materials provided in Discovery,[37] purported to test the impact of bringing DBEC on line one and two years later, in 2023 and 2024, respectively. However, in constructing these plans FPL also assumed a delay in the retirement of Units 4 and 5 by the same amount of time, incurring substantial additional capital and maintenance costs[38] for units that it had already determined were not needed for any reliability reason once the CSQ line is in place.[39] Referring to these two plans, Dr. Sim reported that "the delays were projected to increase CPVRR costs to FPL's customers by approximately $12 million for a one-year delay, and by approximately $38 million for a two-year delay."[40] FPL did not examine a plan in which the Units 4 and 5 retire in 2018 as planned, while DBEC or other capacity additions are delayed beyond 2022.[41]

My own review of FPL's analyses of Plans 4 and 5 shows that a different

[36] Deposition of Dr. Steven R. Sim on November 29, 2017, page 56 at lines 12-16.

[37] FPL provided spreadsheet calculations for its plans and sensitivity tests in response to Sierra Club Production Request No. 18.

[38] Direct Testimony of Dr. Steven R. Sim, page 27 at 1-2 ("[C]ontinued operation of the existing Lauderdale Units 4 & 5 is projected to incur significant costs both in the near-term and in later years.").

[39] Ibid., page 29 at lines 11-14 and Exhibit SRS-2.

[40] Ibid., page 37 at lines 8-11.

[41] Deposition of Dr. Steven R. Sim on November 29, 2017, page 197 at lines 24-25 through page 198 at lines 1-5.

conclusion is warranted. All of the additional costs found in Plans 4 and 5, relative to Plan 2, stem from FPL's choice to delay the retirement of Units 4 and 5 by one or two years, and not from any delay in DBEC's in-service date. In fact, by FPL's own calculations, delaying DBEC by one or two years while retiring Units 4 and 5 in 2018 (just like in Plan 2) would cost less than Plan 2. FPL's contention that delaying DBEC imposes additional costs is therefore unsubstantiated.

Q. Why did FPL choose to delay the retirement of Units 4 and 5 in Plans 4 and 5, if the continued operation of those units is not needed for reliability purposes?

A. Dr. Sim merely notes that FPL designed Plans 4 and 5 "to maintain the same roughly 4-year period in which a major Southeastern Florida generation component would be missing as is assumed in Plan 2."[42] However, Dr. Sim makes clear that with the CSQ line in place, Units 4 and 5 can be retired in 2018 without any projected imbalance or reserve margin issues arising until 2024 and 2025, respectively,[43] and thus the four-year window is not needed to address the reliability needs raised by FPL. Nonetheless, FPL's Plans 4 and 5 assume this four-year window would extend the operation of Units 4 and 5 until 2019 or 2020, independent of a reliability need. Moreover, there is no apparent reason why four years is any kind of "magic number," except that it is the amount of time that would occur under FPL's proposed plan.[44] It appears that FPL has arbitrarily and

[42] Direct Testimony of Dr. Steven R. Sim, page 37 at lines 1-3.
[43] Ibid., page 29 at lines 7-17.
[44] *See* Deposition of Dr. Steven R. Sim on November 29, 2017, page 178 at lines 6-12.

superficially tried to make its plans as similar as possible, but in so doing has forgone the opportunity for more rigorous and meaningful analysis of what is most cost effective for customers. In my experience, I have never seen a resource planning exercise where alternative plans were constrained to have such an arbitrary similarity to each other that is independent of any established reliability constraint.

Q. Please describe Plan 3.

A. Plan 3 appears to have been an exercise to determine the cost of replicating Plan 2 as closely as possible, but using large-scale solar,[45] small-scale solar, and energy storage to replicate DBEC. This plan is unrealistic and illogical for many reasons. First, there is no need to match two plans "megawatt for megawatt" to have a meaningful economic comparison. As indicated below, FPL itself implicitly admits this. Second, FPL should structure its plans to meet exogenous goals, not to match FPL's proposed DBEC plan. Third, Plan 3 would fail to take advantage of the inherent flexibility of using smaller, incremental resources to cost-effectively meet reliability requirements. Fourth, Plan 3 illogically schedules these resources in ways that would be both unrealistic and unduly expensive, front-loading large quantities of the most expensive resources as early as 2018.[46]

[45] FPL refers to utility-scale solar projects as "universal" solar, and I adopt that convention here.
[46] For example, Exhibit SRS-3 of Direct Testimony of Dr. Steven R. Sim shows that under Plan 3, FPL would build 100 MW of storage in 2018 and an additional 200 MW in 2019. This is far beyond the Company's current experience with storage, as described in Direct Testimony of Dr. Steven R. Sim, page 23: "FPL is currently evaluating battery performance with its work in its smaller scale storage testing (several MW) and under its larger 50 MW Storage Pilot Program."

Q. Did Dr. Sim explain the design of Plan 3?

A. Dr. Sim describes Plan 3 as assuming that "a sufficient amount of PV and batteries [are] added in the Southeastern Florida region by 2022 to approximate the incremental 1,163 MW of firm capacity that is added in the region in Plan 2 by the new 2x1 CC unit."

In response to Sierra Club Interrogatory No. 13, FPL explained that:

> Plan 3 was designed to provide an equivalent amount of firm capacity from a combination of solar and storage in the Southeastern Florida region with the same timing, which would result in an equivalent level of system and regional reliability with the two plans, notwithstanding any practical limitations of siting and operating an unprecedented level of universal and distributed generation solar PV and energy storage in this region.

In response to Commission Staff Interrogatory No. 19, FPL further noted that:

> Because DBEC Unit 7 will contribute 1,163 MW of firm capacity in Southeastern Florida by mid-2022 in Plan 2, FPL selected an equivalent amount of firm capacity from a combination of solar and storage sited in Southeastern Florida by mid-2022 for Plan 3. The objective was to have an "apples to apples" comparison in which Plan 3, at least in theory, would be identical to Plan 2 in regard to both system and regional reliability.

Q. Does this explanation make sense to you?

A. No. Not only does this make no sense from a resource planning perspective, it is inconsistent with FPL's other analyses. Plans 1, 4, and 5 are not "identical" to Plan 2 in regard to annual reserve margins or regional balance, and FPL had no problem presenting an economic comparison between these plans and Plan 2.[47] In my extensive experience participating in and reviewing resource planning processes, I do not believe I have ever seen a plan devised to use solar

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[47] *See, e.g.*, Deposition of Dr. Steven R. Sim on November 29, 2017, page 119 at lines 7-13 (stating that FPL believes it conducted a meaningful economic comparison between Plans 1 and 2 in its 2017 analysis).

and storage to replicate the location, timing, and capacity characteristics of a gas unit, and I can see no purpose that it serves, other than as an example of how a poorly-conceived plan can be unduly costly for customers. As discussed above, FPL's plans should be designed to meet identified reliability or other needs exogenous to its preferred plan design, and not to replicate that plan.

Q. How did FPL explain the sequence in which resources would be added under Plan 3?

A. In response to Sierra Club Interrogatory No. 4, FPL claimed that "[a]n estimated maximum projected amount of universal PV that could be sited in Southeastern Florida was selected first. This selection is based on the fact that universal solar is the most cost-effective way to utilize solar energy on FPL's system." However, this is not how the resource plan is presented in Exhibit SRS-3, nor is it the sequence represented in the model files supplied in response to Sierra Club Production Request No. 18. These files make clear that, in fact, Plan 3 calls for the more costly small-scale solar resources (referred to by FPL as distributed generation solar) constructed first, while the less costly universal solar is installed no earlier than the last year of resource builds in 2022.[48] This sequencing is illogical because it would impose unnecessary costs on FPL's customers.

Q. Do you have any other concerns about FPL's design of Plan 3?

A. Yes. FPL chose not only to limit large-scale solar to a few sites identified

[48] *See* Florida Power & Light Company, *2017 FCSS 3- DBEC - Plan 3 - Solar+Batt - Worksheet "Gen"* (provided in response to Sierra Club Production Request No. 18) (showing that battery storage and DG solar are placed in service beginning in 2018, while universal solar is placed in service beginning in 2022).

by FPL, but also limited the size of each site to no more than 74.5 MW of solar. In his deposition, Dr. Sim explained that FPL defines universal solar as solar PV installations with capacity of either 74.5 MW or 60 MW.[49] Dr. Sim further stated that FPL does not look to universal solar beyond 74.5 MW--the "sweet spot"--because (i) "if you go to 75 megawatts or greater, you're subject to the Florida bid rule, and you would be required to put the project out for bid," and (ii) 74.5 MW "falls within this window . . . [in which] you're gaining the economies of scale."[50] The first reason proffered by Dr. Sim for FPL's focus on 74.5 MW--Florida's bidding rule--is an inappropriate consideration in a resource planning process, and suggests that FPL may not be seeking least-cost resources or sufficiently protecting customer interests in either its self-build or its market-based resource options. Dr. Sim acknowledged that it is possible that there are sites that can accommodate more than 74.5 MW of universal solar, but that 74.5 MW "is the maximum amount that our company is interested in pursuing for universal solar."[51]

The second reason proffered by Dr. Sim also confirms that FPL may not be seeking least-cost resources. If 74.5 MW is within a window for economies of scale, FPL should examine other parts of that window too, rather than focusing its gaze on one point that may be financially profitable for the Company, but not yield least-cost service to customers.

[49] Deposition of Dr. Steven R. Sim on November 29, 2017, page 64 at lines 4-11.
[50] Ibid., page 122 at lines 14-16 and page 179 at lines 14-25 through page 180 at lines 1-4.
[51] Ibid., page 123 at lines 14-16.

Q. Do you have any further concerns about FPL's design of Plan 3?

A. Yes. FPL also arbitrarily limited the incremental demand-side resources in Plan 3 to the level set by the Commission in a prior docket.[52] This is yet another unreasonable and illogical constraint that is tailor-made to make FPL's purported "clean energy" alternative appear unduly costly, when in fact a well-designed clean energy alternative could save customers money.

Likewise, FPL failed to assess alternate plans including solar without storage, even though such a plan was among the four most economic plans in FPL's 2016 analysis.[53] FPL further affirmed that the only reason that the Company added storage to Plan 3 was an attempt to mimic the characteristics of DBEC[54] - and not to address any identified reliability need.

Given this unconventional, uneconomic, and illogical design, it is not surprising that Plan 3 turned out to be the most expensive of the plans considered by FPL.[55] Moreover, this plan was not designed based on FPL's reliability requirements, and does not serve any resource planning or evaluation of alternatives purpose that I can see.

Q. Is there a better way to examine the feasibility of clean energy resources to meet FPL's reliability needs?

A. Yes. Instead of Plan 3, FPL should devise a plan that meets its reliability

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[52] Ibid., page 164 at lines 1-11.

[53] Deposition of Dr. Steven R. Sim on December 4, 2017, page 26 at lines 21-25 through page 27 at lines 1-5.

[54] Deposition of Dr. Steven R. Sim on November 29, 2017, page 100 at lines 11-24.

[55] Exhibit SRS-4 to Direct Testimony of Dr. Steven R. Sim shows FPL's conclusion that Plan 3 would cost approximately $1.29 billion more than Plan 2 on Cumulative Present Value of Revenue Requirements (CPVRR) basis between 2017 and 2061.

needs at the lowest possible cost, including clean-energy resources such solar, storage, and DSM, integrated into its existing portfolio. FPL should test these options using a resource planning model such as EGEAS. FPL itself recognizes the validity of this reasoning, even though it failed to adhere to it here. Dr. Sim, FPL's expert on resource planning, explains that FPL's integrated resource planning process "*first*, determine[s] our resource needs," then "[w]e look at available resource options that could meet those resource needs . . . ."[56]

Q. In summary, what is the difference between your recommended strategy of using clean energy resources to delay or avoid DBEC, versus the plan analyzed by FPL which replaced DBEC with a combination of solar energy and storage?

A. FPL's Plan 3, evaluated as part of its 2017 analyses, would use a combination of solar and storage, both installed beginning as early as 2018 (long before any reliability arises), to try to fully replicate the operations and impact of DBEC. Further, the Company made the plan appear even more costly by building the most expensive resources early, thereby both frontloading unduly high costs and foregoing the opportunity to take advantage of declining resource prices. Plan 3 included no additional demand-side resources beyond the level currently required, and, as discussed earlier, was not designed to respond optimally to FPL's actual reliability needs.

The approach I am suggesting is to start with FPL's projected reliability needs, *i.e.*, a reserve shortfall and a regional imbalance projected to occur in 2024

[56] Deposition of Dr. Steven R. Sim on November 29, 2017, page 43 at lines 13-15 (emphasis added).

and 2025, respectively, and to find the least-cost combination of resources such as demand-response, small-scale solar, large-scale solar, and perhaps storage, to forestall those reliability shortfalls one or two years at a time. Because such resources are inherently constructed in smaller increments, there is no need or reason to construct the equivalent of 1,163 MW of firm capacity when the reliability need is far smaller. Where FPL's Plan 3 is high-cost, high-risk and inconsistent with good utility resource planning practice, the approach I recommend is low-cost and low-risk, and would allow the Company to get the maximum benefit of technology and cost improvements over time.

3. Declining Cost of Solar and Storage Resources

Q. Earlier you discussed the low cost of solar and solar+storage PPAs, and stated that you expect the prices for solar and storage resources to continue to decline. What is your evidence in support of this expectation?

A. Numerous observers in the energy industry, the financial industry, and government have noted the precipitous decline in costs for these resources, and the likelihood that they will continue to fall in the future. For example, a September 18, 2017 publication from Moody's Investor Service [57] stated the following:

> **Renewable energy costs have fallen dramatically and will continue to do so.** Economies of scale and improving efficiencies have caused steep falls in capital costs, and hence levelized cost of energy (LCOE), from solar and wind. And those declines are continuing, especially for solar, where panel prices have fallen over 20% since late 2016.
>
> **Energy storage and offshore wind costs are declining faster than expected.** Most forecasts have historically underestimated the pace of declines in renewable energy

[57] Moody's, *Global Renewables Focus* (Sep. 2017).

> capital costs and appear to be doing so now for offshore wind and energy storage. Both technologies have already reached prices predicted for 2020. They are just beginning their global spread, and greater economies of scale will spur further price reductions.

Further, the Lawrence Berkeley National Laboratory (LBNL) study referenced above[58] quantified the rapid growth of solar installations throughout the United States, including the dominance of this resource in many interconnection queues, along with improving performance and falling prices. The LBNL study reports that "[m]edian installed PV project prices within a sizable sample have steadily fallen by two-thirds since the 2007-2009 period, to $2.2/WAC (or $1.7/WDC) for projects completed in 2016. The lowest 20th percentile of projects within our 2016 sample (of 88 PV projects totaling 5,497 MWAC) were priced at or below $2.0/WAC, with the lowest-priced projects around $1.5/WAC."[59]

Figure 18 from the LBNL report, reproduced here as Figure 1, shows this dramatic trend reflected in solar PPA prices over the last decade.

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[58] Mark Bolinger et al., Lawrence Berkeley National Laboratory, *Utility-Scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (Sep. 2017), *available at* https://emp.lbl.gov/sites/default/files/utility-scale_solar_2016_report.pdf.

[59] Ibid. at ii.

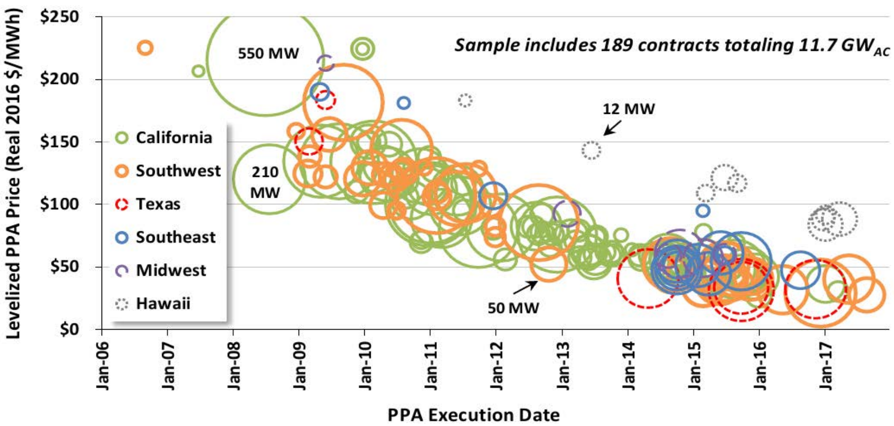

Figure 18. Levelized PPA Prices by Region, Contract Size, and PPA Execution Date: Full Sample

Figure 1. Declining solar PPA prices throughout the United States. Size of circles reflects size of PPA (MW)

Q. In addition to the industry expectations of decreasing costs for solar and storage resources described above, have you seen evidence that FPL itself anticipates lower costs for solar and storage resources in the future?

A. Yes. The Company's scenario valuation files for its 2017 analyses, provided in response to Sierra Club Production Request No. 18, show the Company's expectations for declining capital costs for small-scale solar and storage resources. I have summarized these costs in Figure 2 below on a 2017 NPVRR basis. (I have not provided the quantity of MW for the universal solar resource because it was not specified in the referenced file.) These expectations are corroborated by Dr. Sim, who explained that "we see costs for supply options and for other key aspects generally declining over time."[60] Indeed, according to Dr. Sim, "there will be plenty of opportunities in the future for emerging technologies as they prove themselves to be integrated into the resource plan."[61]

[60] Deposition of Dr. Steven R. Sim on November 29, 2017, page 54 at lines 15-17.
[61] Ibid. at lines 18-21.

Yet by seeking to place DBEC in service before it is needed, FPL would subvert those opportunities.

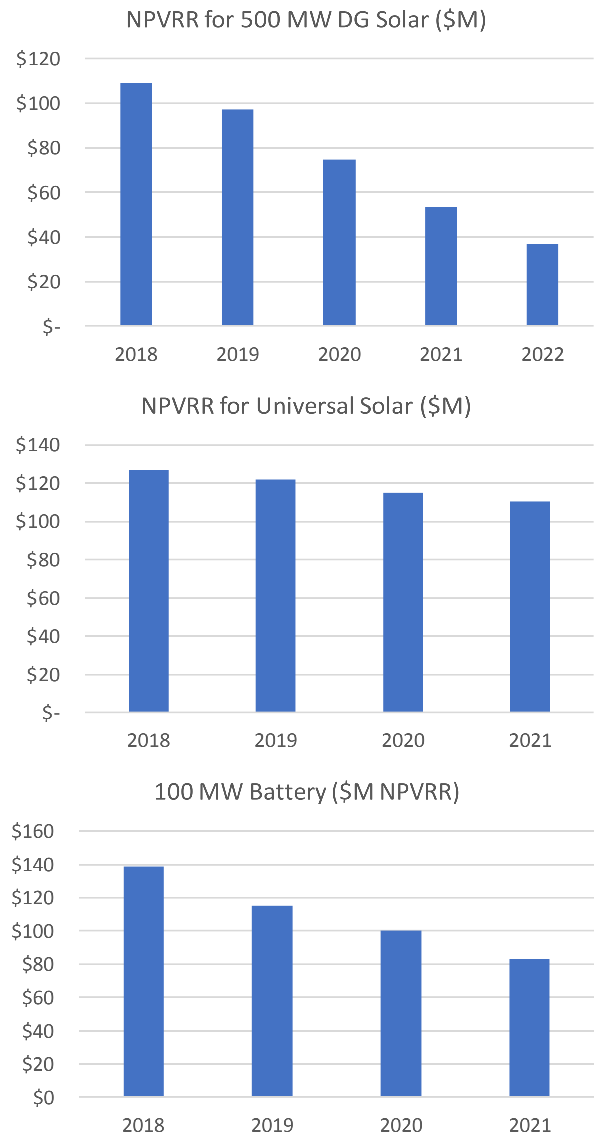

Figure 2. FPL-estimated NPVRR for solar and storage technology by installation year. Based on model input files provided in response to Sierra Club Production Request No. 18.

4. There Is No Benefit To Building the Plant Before It Is Needed

Q. If there is no identified reliability need until 2024 or 2025, why is FPL proposing to bring the Dania Beach project on line in 2022?

A. According to Dr. Sim, "The result of the 2017 analyses was that retiring existing Lauderdale Units 4 & 5 in late 2018, followed by a modernization of the site by June 1, 2022 with a 2x1 CC unit (DBEC Unit 7), was projected to be the most economic option for FPL's customers."[62] As noted above, FPL further performed two model runs that Dr. Sim claims tested whether a one- or two-year delay in the project would benefit customers. Dr. Sim concluded that "a delay of the mid-2022 in-service date of DBEC Unit 7 is projected to be uneconomic for FPL's customers."[63]

Q. Did you analyze the cost impacts produced by these analyses?

A. Yes. As described by Dr. Sim, in addition to delaying DBEC by either one or two years from FPL's proposed mid-2022 operational date, "[i]n both scenarios, the retirement of Lauderdale Units 4 & 5 was also assumed to be delayed by either one year or two years, respectively, to maintain the same roughly 4-year period in which a major Southeastern Florida generation component would be missing as is assumed in Plan 2."[64] FPL found that both of these plans were modestly more costly ($12 million and $38 million total, respectively, over a 44-year planning horizon) than Plan 2. However, FPL did not disaggregate these CPVRR differences into costs associated with delaying the retirements of Units 1 and 2, as compared to other costs or savings associated

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[62] Direct Testimony of Dr. Steven R. Sim, page 8 at lines 5-8.
[63] Ibid., page 37 at lines 11-12.
[64] Ibid., page 36 at lines 22-23 through page 37 at lines 1-3.

with the timing of DBEC, so its conclusion that these costs are due to delaying DBEC is unfounded..

Q. Are you able to disaggregate these costs, based on materials provided by the Company?

A. I can disaggregate the relative costs and savings of each plan sufficiently to address this question based on FPL's response to Sierra Club's Production Request No. 18. Specifically, FPL's response, consisting of numerous spreadsheets, allows me to determine the share of certain "fixed" (non-volumetric) costs that are associated with the Units 4 and 5 vs. DBEC under each plan. I have summarized these costs in Table 1.

While I am not able to assign all cost differences to either the delay in DBEC operations or the delayed retirement of Units 4 and 5 (note "non-Unit Specific" costs in Table 1), this much is clear: according to FPL's own analysis, the costly part of Plans 4 and 5 is that they delay the retirement of the Units 4 and 5. Delaying this retirement by one year will cost customers at least $33 million on a CPVRR basis, and delaying retirement by two years will cost at least $74 million on a CPVRR basis. These numbers are twice as high or more compared to the $12 million and $38 million FPL claims it will cost customers for its composite plans including on a one- or two-year delay, respectively. This means that delaying DBEC without also delaying Units 4 and 5 *reduces* the calculated costs of these plans and, consequently, produces customer savings. Table 1 also shows that, contrary to Dr. Sim's assertion, FPL's analysis finds that delaying DBEC by one or two years would actually *save* customers $33 million or $63 million dollars, respectively.

Table 1. Costs/(Savings) associated with Plans 4 (1-year delay) and 5 (2-year delay) Relative to Plan 2.

Unit	Cost Category	Plan 2	Plan 4	Plan 5	Cost of 1-Year Delay (Plan 4 vs. Plan 2)	Cost of 2-Year Delay (Plan 5 vs. Plan 2)
Delay Construction of Dania Beach Unit 7						
	Generation Capital	$960	$942	$926	($18)	($34)
	Generation Fixed O&M	$91	$86	$82	($5)	($9)
	Capital Replacement Charges	$162	$152	$142	($10)	($20)
	Dania Beach Total	**$1,213**	**$1,180**	**$1,150**	**($33)**	**($63)**
Delay Retirement of Lauderdale Units 4 and 5						
	Generation Capital	$0	$0	$0	$0	$0
	Generation Fixed O&M	$7	$15	$24	$8	$17
	Capital Replacement Charges	($25)	($8)	$17	$17	$42
	Lauderdale Units NBV	($52)	($44)	($37)	$8	$15
	Lauderdale Units Total	**($70)**	**($37)**	**$4**	**$33**	**$74**
Non-Unit Specific						
	Firm Gas Transport	$944	$944	$944	$0	$0
	System Net Fuel	$47,561	$47,573	$47,588	$12	$27
	Startup + VOM	$652	$651	$652	($1)	$0
	Emissions Costs	$9,577	$9,577	$9,577	$0	$0
	Non-Unit Specific Costs Total	**$58,734**	**$58,745**	**$58,761**	**$11**	**$27**

Q. What are the implications of your finding that delaying DBEC actually saves money for customers?

A. This finding is important not only because it suggests that FPL can save customers tens of millions of dollars by delaying DBEC. This result also strongly suggests that the longer FPL can delay constructing the plant, the more customers will save, suggesting that delaying the plant is consistent with least-cost resource planning principles. To the extent that FPL can develop the resource options I have discussed earlier in my testimony – demand-side resources, large- and small-scale solar, and storage – to forestall the need for DBEC, the better customers will be served. As I noted earlier, and as is reflected in FPL's model files, the cost and performance of solar generation and storage have been improving rapidly and are expected to continue to improve for some time to come. It is certainly possible that were FPL to start down the road of relying on low-cost clean energy resources and DSM, it could indefinitely delay expenditure of customer resources on an unneeded gas plant, and truly enhance its fuel diversity.

Finally, were rigorous planning and modeling eventually to demonstrate that FPL needs a new gas unit, it is likely that the delay would allow FPL to procure an even more efficient technology than DBEC. As Dr. Sim noted, "we think that in the next few years we're going to see the very first combined cycle with a heat rate below 6,000."[65] Yet by seeking to place DBEC in service before it is needed, FPL would disrupt that opportunity.

5. Illustrative Alternative Plan

Q. Have you created an alternative plan to FPL's Plan 3 that demonstrates a lower-cost way to use clean energy resources to meet FPL's reliability needs?

A. Yes. However, let me say at the outset that this is intended only as an illustrative example, and I do not claim to have thoroughly analyzed all of the reliability and feasibility aspects of this plan. My point is to illustrate that FPL can maintain its 20% reserve margin by deploying clean energy resources when they are needed to meet reliability requirements, and not in a way that imposes spurious costs by attempting to mimic a resource with very different practical, operational, and financial characteristics such as a gas-fired CC.

The illustrative plan I have prepared is presented and compared to FPL's

[65] Deposition of Dr. Steven R. Sim on November 29, 2017, page 56 at lines 13-15.

Plan 3 in Table 2. As may be seen in the table, my alternative plan relies on a smaller amount of solar and storage resources, implemented years later than under FPL's Plan 3. I have also included a modest amount of demand response (DR) in 2025, although as suggested above, I believe that if FPL were to issue an RFP for demand response resources it would find a much greater volume available at a reasonable cost. To calculate reserve margins, I have made the same assumptions FPL made regarding the capacity value of solar - 54% for the first 265 MW, and 35% thereafter – although I do not endorse what seems to me to be a very conservative assumption in this area.[66] Unlike FPL's plan, the alternative plan does not maintain up to 1,550 MW of unneeded and costly capacity above and beyond FPL's already conservative 20% reserve margin.

[66] After 5 p.m. on December 7, 2017, the day before this testimony was due to be filed, FPL provided as a late supplemental response to Sierra Club Production Request No. 18 a workbook purporting to support its declining capacity credit assumptions. As noted in the text, I have applied these assumptions but I do not endorse them.

Table 2. FPL's Plan 3 Compared to Illustrative Alternative Plan.

	Plan 3				Alternative Plan				
Year	DG Solar	Universal Solar	Storage	MW Above 20% Reserve Margin	DG Solar	Universa l Solar	Storage	DR	MW Above 20% Reserve Margin
2018	150		100	494				0	313
2019	150		200	524				0	69
2020	125		200	998				0	299
2021	100		200	1,311				50	427
2022	75	433	55	1,546				0	429
2023				1,399				50	332
2024				1,113		149		0	127
2025				707	300	284	150	50	147
2026				263	300		150	50	8

Q. Can you analyze what this illustrative plan would cost, relative to FPL's Plans 2 and 3?

A. I cannot. I do not have access to FPL's UPLAN model to calculate operational costs, nor do I know what resource costs might be available to FPL for either self-build or PPA offers for these resources in the indicated years. I do know that the capital costs would be many hundreds of millions of dollars less than under FPL's Plan 3 in an NPVRR basis, and could be cost competitive with Plan 2. It is also certainly possible that, should FPL issue a market solicitation for additional DR, they would yield even more of this low-cost resource than I have included in the plan shown in Table 2. I provide this example to illustrate that FPL's Plan 3 was not designed to yield the lowest cost scenario for relying on clean energy resources, and cannot be used to disqualify the cost effectiveness of a clean energy plan without substantial additional analysis.

Q. What factors could make a plan like the one you have proposed less costly than FPL's Plan 2?

A. A number of factors would strongly affect the costs of an alternative, clean energy plan that FPL should evaluate to determine the ultimate costs of this alternative. None of these factors appear to have been evaluated in developing FPL's clean energy alternative, Plan 3, but rigorous consideration of these factors could yield an alternative that costs less than, or is at least competitive with, DBEC. Unfortunately, because I do not have access to the models and information held by FPL, I am unable to quantify these factors for the Commission. These factors include:

- Using the minimum amount of new storage required each year to ensure both adequate reserve margins and regional balance under such a plan. Storage should be used incrementally, and FPL should take as much advantage as possible of ongoing rapid improvements in cost and performance. FPL should not, as it did in Plan 3 of its 2017 analysis, add storage to mimic resources from another plan being evaluated.[67]
- Using the maximum amount of universal solar, as opposed to DG solar, that FPL could include in its plan. This inquiry should be informed by RFPs to allow third-party providers to propose universal solar options that the Company has not considered. It should not involve consideration of size limits in Florida's bidding rules.[68]
- Using other approaches to meet its regional balance needs, beyond siting additional generation and storage in Southeast Florida. I have already discussed the value of DSM in this regard, including DR that could be procured from third-party aggregators through an RFP process. FPL should also consider operational and transmission upgrade options that could increase its import capability into the region.

VI. Need for Fuel Diversity and other Concerns

1. The Project Exacerbates FPL's Reliance on Gas

Q. What fuel diversity need does FPL propose to address in its Petition?

A. FPL argues that the proposed DBEC will enhance the Company's fuel diversity because of the unit's "high level of fuel efficiency."[69]

Q. Do you find that DBEC will enhance FPL's fuel diversity?

A. I do not agree that DBEC is an effective way to enhance FPL's fuel diversity and supply reliability relative to alternative solutions available to the company. In fact, DBEC would extend FPL's reliance on gas into the indefinite

[67] *See* Deposition of Dr. Steven R. Sim on November 29, 2017, page 100 at lines 11-24.
[68] *See* ibid., page 122 at lines 14-16 and page 179 at lines 14-25 through page 180 at lines 1-4.
[69] Direct Testimony of Dr. Steven R. Sim, page 12 at 6.

future. As seen in Figure 3, use of gas in Florida has increased by approximately a factor of four since 2000, and it is currently projected to increase through the next decade; this single fuel "remains the dominant fuel over the planning horizon, with usage in 2016 at approximately 63 percent of the state's net energy for load (NEL)."[70] For FPL, the situation is even more extreme: gas currently accounts for 71% of its generation, a figure that the proposed project would aggravate and perpetuate into the future.[71]

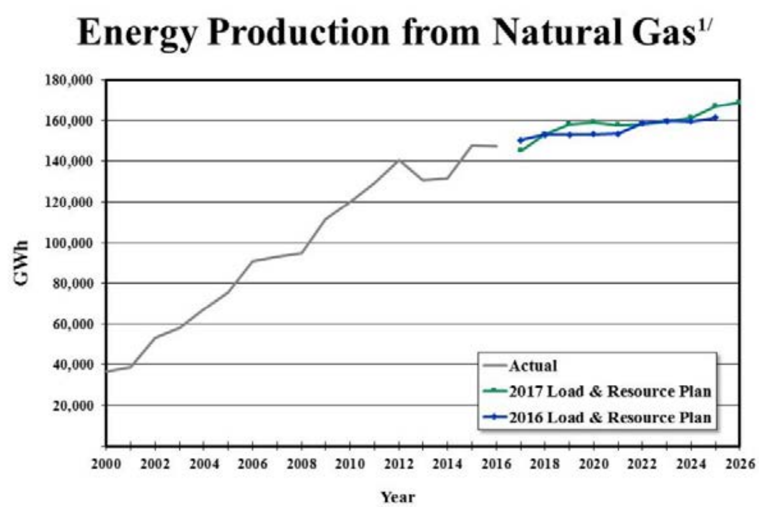

Figure 3. From Florida PSC review of utility 2017 TYSPs, page 3.

The DBEC project would be larger than the existing Lauderdale units, run many more hours per year, and produce more Megawatt Hours (MWh) from gas.[72] Further extending the Company's reliance on a single, CO_2-intensive fuel with high levels of historic volatility does not effectively advance the cost-

[70] Florida Public Service Commission, *Review of the 2017 Ten-Year Site Plans of Florida's Electric Utilities* 3 (Nov. 2017), *available at* http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/TenYearSitePlans/2017/Review.pdf.
[71] Ibid. at 51.
[72] *See* Deposition of Dr. Steven R. Sim on November 29, 2017, page 140 at lines 19-24.

hedging benefits of reducing the Company's exposure to fuel availability and cost. Conversely, any plan that relied more heavily on fuel-free resources such as solar generation and DSM would far more effectively reduce FPL's exposure to the higher fuel and emissions costs associated with gas.

2. Alternatives Can Help Reduce FPL's Reliance on Gas and Promote FPL's Fuel Diversity

Q. Have you seen evidence that FPL recognizes zero-fuel cost resources as an effective way to promote fuel diversity?

A. Yes. In his direct testimony, Dr. Sim describes how FPL is "pursuing cost-effective solar energy as a means to enhance fuel diversity on its system."[73] This is a far more reasonable and effective way to reduce FPL's exposure to future fuel and emissions costs than extending its reliance on natural gas.

VII. Conclusion

Q. What are your conclusions regarding the need for DBEC for system reliability purposes?

A. DBEC is not needed for system reliability purposes in 2022, when the Company proposes to bring it on line; nor has the company demonstrated that the project meets any reliability need that could not be equally well met, at lower cost, with alternative, incremental clean energy resources.

Q. What are your conclusions regarding whether DBEC is the most cost-effective alternative available?

A. Building DBEC in 2022 is clearly not the most cost-effective alternative, as the Company's own analysis establishes that delaying DBEC by one or two

[73] Direct Testimony of Dr. Steven R. Sim, page 12 at lines 12-13.

years (while retiring Units 4 and 5 in 2018) would cost less than bringing DBEC on line in 2022. Further, customer interests would be better served if the FPL delayed the project not only for the one or two years that FPL's analysis shows would save customers money, but for as long as possible, and perhaps indefinitely, through the strategic, incremental use of clean energy resources. FPL has not followed rigorous analytical techniques or good utility practice in its development and analysis of alternatives, so the Commission cannot reasonably conclude that FPL's proposal is the most cost-effective option.

Q. What are your conclusions regarding whether DBEC comports with the need for fuel diversity?

A. Extending FPL's, and Florida's, already disproportionate reliance on natural gas is not an effective or reasonable way to promote fuel diversity and supply reliability. These goals could be much more effectively advanced through reliance on technology that is not reliant on imported fuel and that is immune to any future emission-related costs.

Q. What are your conclusions regarding utilizing renewable and conservation measures to the extent reasonably available under the Company's proposal?

A. I have demonstrated that FPL's purported analysis of renewable and conservation measures was fatally flawed because it was limited to a single alternative plan that was illogical, hobbled by artificial constraints, and almost tailor-made to appear unduly costly for FPL's customers. I have also demonstrated how low-cost renewables could be used to further delay, or perhaps eliminate, the need for DBEC. Based on this analysis, I conclude that FPL has made no serious effort to use renewables and conservation measures to the extent reasonably available as part of its plan.

Q. What are your recommendations for the Commission in this matter?

A. I recommend that the Commission deny FPL's request for an affirmative determination of need in this matter.

Q. Does this conclude your testimony?

A. Yes.

Sierra Club Expert Testimony Exhibit List
Docket No. 20170225-EI

Exh. No.	Description
EDH-1	Resume of Ezra D. Hausman, Ph.D.
EDH-2	Gavin Bade & Peter Maloney, Utility Dive, *Updated: Tucson Electric Signs Solar + Storage PPA for 'Less Than 4.5¢/kWh'* (May 2017), *available at* https://www.utilitydive.com/news/updated-tucson-electric-signs-solar-storage-ppa-for-less-than-45kwh/443293/
EDH-3	JEA, *Agenda Item Summary: Universal Solar Expansion and Land Acquisition* (Oct. 2017)
EDH-4	Pierce Schuessler, Solar Energy Industries Association, *Comment on Proposed 2017 Second Revised and Restated Stipulation and Settlement Agreement in Docket No. 20170183* (Oct. 2017)
EDH-5	EnerNOC, Inc., *ISO-New England Awards EnerNOC Landmark Contract to Improve Grid Reliability in Southwest Connecticut* (Apr. 2004)
EDH-6	Moody's, *Global Renewables Focus* (Sep. 2017)
EDH-7	Mark Bolinger et al., Lawrence Berkeley National Laboratory, *Utility-Scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (Sep. 2017), *available at* https://emp.lbl.gov/sites/default/files/utility-scale_solar_2016_report.pdf
EDH-8	Chris Neme & Jim Grevatt, Energy Futures Group, *Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments* (Jan. 2015), *available at* http://www.neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf
EDH-9	Rachel Wilson & Bruce Biewald, Synapse Energy Economics, *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans* (June 2013), *available at* http://www.raponline.org/wp-content/uploads/2016/05/rapsynapse-wilsonbiewald-bestpracticesinirp-2013-jun-21.pdf
EDH-10	Navigant Consulting, Inc., for Eastern Interconnection States' Planning Council and National Association of Regulatory Utility Commissioners, *Transmission Planning White Paper* (2014), available at https://pubs.naruc.org/pub.cfm?id=53A151F2-2354-D714-519F-53E0785A966A

EDH-11	New England Power Pool, *Order on Rehearing and Accepting Compliance Filing*, FERC Docket Nos. ER04-335-001 and ER04-335-002 (May 2004), *available at* https://www.ferc.gov/eventcalendar/Files/20040528153559-er04-335-001.pdf
EDH-12	PJM Interconnection, LLC, *Load Management Performance Report* 2015/2016 (Aug. 2016), *available at* http://www.pjm.com/~/media/markets-ops/dsr/2015-2016-dsr-activity-report-20151221.ashx
EDH-13	PJM Interconnection, LLC, *RPM 101: Overview of Reliability Pricing Model* (Apr. 2017), *available at* http://pjm.com/~/media/training/nerc-certifications/markets-exam-materials/rpm/rpm-101-overview-of-reliability-pricing-model.ashx
EDH-14	Excerpts of Deposition of Dr. Steven R. Sim on November 29, 2017
EDH-15	Excerpts of Deposition of Dr. Steven R. Sim on December 4, 2017
EDH-16	Florida Power & Light Company, *Response to Sierra Club Interrogatory Number 16 in Docket No. 20170225-EI* (Nov. 2017)
EDH-17	Florida Power & Light Company, *2016 Southeastern Florida Study: Results To-Date* (Dec. 2016)
EDH-18	Florida Power & Light Company, *2016 SE Florida Study CPVRR Ranking of All Resource Plans*
EDH-19	Florida Power & Light Company, *2017 FCSS 3- DBEC - Plan 3 - Solar+Batt - Worksheet "Summary"*
EDH-20	Florida Power & Light Company, *2017 FCSS 3- DBEC - Plan 3 - Solar+Batt - Worksheet "Gen"*
EDH-21	Florida Power & Light Company, *Solar Revenue Requirement for Plan 3 - Worksheet "Cap Rev Req for FCSS"*
EDH-22	Excerpts of Florida Power & Light Company, *Ten Year Power Plant Site Plan 2017-2026* (Apr. 2017)
EDH-23	Excerpts of Florida Public Service Commission, *Review of the 2017 Ten-Year Site Plans of Florida's Electric Utilities* (Nov. 2017), *available at* http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/TenYearSitePlans/2017/Review.pdf

EDH-1

Ezra D. Hausman, Ph.D.

I am an independent consultant in energy and environmental economics.

I have worked for 20 years as an electricity market expert with a focus on market design and market restructuring, environmental regulation in electricity markets, and pricing of energy, capacity, transmission, losses and other electricity-related services. I have performed market analysis, provided expert testimony, led workshops and working groups, made presentations and participated on panels, and provided other support to clients in a number of areas, including:

- Economic analysis, price forecasting, and asset valuation in electricity markets
- Dispatch and planning model analyses, and review of modeling studies
- Electricity and generating capacity market design and analysis
- Energy efficiency program and cost/benefit analysis
- Integrated Resource Planning and portfolio analysis
- Economic analysis of environmental and other regulations, including regulation of greenhouse gas emissions, in electricity markets
- Quantification, regulation and mitigation of greenhouse gas emissions associated with the supply and demand sides of the U.S. electricity sector
- Quantification of the economic and environmental benefits of displaced emissions associated with energy efficiency and renewable energy initiatives
- Expert representation and participation in stakeholder processes
- Clean Air Act determinations and enforcement.

I have prepared reports and offered other expert services on these and other related topics for clients including federal and state agencies; offices of consumer advocate; legislative bodies; cities and towns; non-governmental organizations; foundations; industry associations; and resource developers.

I previously served as Vice President and Chief Operating Officer of Synapse Energy Economics, Inc. of Cambridge, Massachusetts. In addition to my consulting portfolio, this management role entailed responsibility for day-to-day operations of the company including overseeing finance, HR, communications & marketing, quality assurance, client service, and professional development of staff. I had overall responsibility for ensuring that project managers and project teams had the tools, information, and training they needed to successfully serve client's needs and to produce high-quality deliverables on time and on budget. I was also a resource available to any of our clients to address any issues of customer service, quality, or any other issues.

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I hold a Ph.D. in atmospheric science from Harvard University, an S.M. in applied physics from Harvard University, an M.S. in water resource engineering from Tufts University, and a B.A. in psychology from Wesleyan University.

PROFESSIONAL EXPERIENCE

Ezra Hausman Consulting, Newton, MA. President, March 2014 – Present.
I provide research, analysis, expert testimony, and policy support services in regulatory, litigation, and stakeholder processes covering a wide range of electric sector and electriciuty market issues. The focus of my consulting work includes:

- Interaction of air quality and environmental regulations with electricity markets
- Analysis and implementation of the Clean Power Plan and other greenhouse gas rules
- Clean Air Act enforcement support
- Long-term electric power system planning and market design
- Energy efficiency and renewable energy programs and policies
- Avoided emissions analysis
- Regulation and mitigation of greenhouse gas emissions
- Consumer and environmental protection
- Efficient pricing of generating and transmission capacity
- Market power and market concentration analysis in electricity markets
- Economic analysis of electricity industry regulation and restructuring

Synapse Energy Economics Inc., Cambridge, MA.
Chief Operating Officer, March 2011 – February 2014;
Vice President, July 2009 – February 2014;
Senior Associate, 2005-2009.

- Conducted research, wrote reports, and presented expert testimony pertaining to consumer, environmental, and public policy implications of electricity industry regulation. Provided expert support and representation in planning, greenhouse gas mitigation, and other stakeholder processes.
- As Vice President and Chief Operating Officer, I was also responsible for day-to-day operations of the company, quality assurance, client service, and professional development of staff.

Charles River Associates (CRA), Cambridge, MA. Senior Associate, 2004-2005
CRA acquired Tabors Caramanis & Associates in October, 2004.

Tabors Caramanis & Associates, Cambridge, MA. Senior Associate, 1998-2004
As a member of the modeling group, developed and maintained dispatch modeling capability in support of electricity market consulting practice.

Performed modeling and analysis of electricity markets, generation and transmission systems. Projects included:

- Several market transition cost-benefit studies for development of Locational Marginal Price (LMP) based markets in US electricity markets
- Long-term market forecasting studies for valuation of generation and transmission assets,
- Valuation of financial instruments relating to transmission system congestion and losses
- Modeling and analysis of hydrologically and electrically interconnected hydropower system operations
- Natural gas market analysis and price forecasting studies
- Co-developed an innovative approach to hedging financial risk associated with transmission system losses of electricity
- Designed, developed and ran training seminars using a computer-based electricity market simulation game, to help familiarize market participants and students in the operation of LMP-based electricity markets.
- Developed and implemented analytical tools for assessment of market concentration in interconnected electricity markets, based on the "delivered price test" for assessing market accessibility in such a network
- Performed regional market power and market power mitigation studies
- Performed transmission feasibility studies for proposed new generation and transmission projects in various locations in the US
- Provided analytical support for expert testimony in a variety of regulatory and litigation proceedings, including breach of contract, bankruptcy, and antitrust cases, among others.

Global Risk Prediction Network, Inc., Greenland, NH. Vice President, 1997-1998
Developed private sector applications of climate forecast science in partnership with researchers at Columbia University. Specific projects included a statistical assessment of grain yield predictability in several crop regions around the world based on global climate indicators (Principal Investigator); a statistical assessment of road salt demand predictability in the United States based on global climate indicators (Principal Investigator); a preliminary design of a climate and climate forecast information website tailored to the interests of the business community; and the development of client base.

Hub Data, Inc., Cambridge, MA. Financial Software Consultant, 1986-1987, 1993-1997
Responsible for design, implementation and support of analytic and communications modules for bond portfolio management software; and developed software tools such as dynamic data compression technique to facilitate product delivery, Windows interface for securities data products.

Abt Associates, Inc., Cambridge, MA. Environmental Policy Analyst, 1990-1991
Quantitative risk analysis to support federal environmental policy-making. Specific areas of research included risk assessment for federal regulations concerning sewage sludge disposal

and pesticide use; statistical alternatives to Most-Exposed-Individual risk assessment paradigm; and research on non-point sources of water pollution.

Massachusetts Water Resources Authority, Charlestown, MA. Analyst, 1988-1990
Applied and evaluated demand forecasting techniques for the Eastern Massachusetts service area. Assessed applicability of various techniques to the system and to regional planning needs; and assessed yield/reliability relationship for the eastern Massachusetts water supply system, based on Monte-Carlo analysis of historical hydrology.

Somerville High School, Somerville, MA. Math Teacher, 1986-1987
Courses included trigonometry, computer programming, and basic math.

EDUCATION

Ph.D., Earth and Planetary Sciences. Harvard University, Cambridge, MA, 1997

S.M., Applied Physics. Harvard University, Cambridge, MA, 1993

M.S., Civil Engineering. Tufts University, Medford, MA, 1990

B.A., Wesleyan University, Psychology. Middletown, CT, 1985

FELLOWSHIPS, AWARDS AND AFFILIATIONS

UCAR Visiting Scientist Postdoctoral Fellowship, 1997

Postdoctoral Research Fellowship, Harvard University, 1997

Certificate of Distinction in Teaching, Harvard University, 1997

Graduate Research Fellowship, Harvard University, 1991-1997

Invited Participant, UCAR Global Change Institute, 1993

House Tutor, Leverett House, Harvard University, 1991-1993

Graduate Research Fellowship, Massachusetts Water Resources Authority, 1989-1990

Teaching Fellowships:

> **Harvard University:** *Principles of Measurement and Modeling in Atmospheric Chemistry; Hydrology; Introduction to Environmental Science and Public Policy; The Atmosphere.*
>
> **Wesleyan University:** *Introduction to Computer Programming; Psychological Statistics; Playwriting and Production.*

Community Service

Academic Mentor and Athletic Coach, SquashBusters Boston, 2014 - Ongoing
Judge, Cleantech Open innovation competitions, 2015-2016
President, Burr Elementary School Parent Teacher Organization, 2005-2007

EXPERT TESTIMONY AND SERVICES

Idaho Public Utilities Commission (Case No. AVU-E-17-01) - Ongoing
Expert witness on behalf of the Sierra Club in Avista Corporation rate case.

Iowa Utilities Board (Docket No. RPU-2017-0002) - Ongoing
Expert witness on behalf of the Sierra Club for Interstate Power and Light petition for ratemaking principles for proposed 500 MW wind project.

Washington Utilities and Transportation Commission (Dockets UE-170033 and UG-170034) – Ongoing
Expert witness on behalf of the Sierra Club in Puget Sound Energy (PSE) rate case.

New Jersey Division of Rate Counsel – 2016-Ongoing
General policy and stakeholder support on matters related to energy efficiency, renewable energy, and electrification of transportation in New Jersey.

New Jersey Board of Public Utilities – 2014-Ongoing
Expert witness on behalf of the New Jersey Division of Rate Counsel, reviewing and providing testimony on cost effectiveness and program design of various New Jersey gas utility energy efficiency programs.

Clean Power Plan Modeling in PJM and MISO – Ongoing
Participation on behalf of the Sustainable FERC Project in ISO initiative to model scenarios for state compliance with federal greenhouse gas mitigation rules.

California ISO/PacifiCorp Market Integration - Ongoing
Technical support to Sierra Club in stakeholder review and participation in all relevant proceedings in California.

United States Department of Justice – US District Court Dallas, TX Division (U.S. vs. Luminant Generation Company, LLC, and Big Brown Power Company, LLC) – Ongoing
Expert witness on behalf of the United States Department of Justice on clean air act enforcement case.

United States Department of Justice – US District Court for the Eastern District of Missouri (Civil Action No. 4:11-CV-00077) – 2013-2016
Expert witness on behalf of the United States Department of Justice on successful prosecution of clean air act case.

Missouri Public Service Commission (Case No. EO-2015-0084) – 2014-2015
Expert services in support of Sierra Club's participation in integrated resource planning process.

Missouri Public Service Commission (File No. ER-2014-0258) – 2014-2015

Expert witness on behalf of the Sierra Club in Ameren Missouri rate case.

Arizona Corporation Commission (Docket No. E-01345A-11-0224) – 2014
Expert witness on behalf of the Sierra Club regarding Arizona Public Service petition for rate treatment for acquisition of an additional ownership share of the Four Corners generating units.

Missouri Public Service Comission (Docket No. ET-2014-0085) – 2013
Testimony on behalf of the Missouri Solar Energy Industries Association regarding Union Electric (d/b/a Ameren Missouri) motion to suspend payment of solar rebates.

Missouri Public Service Comission (Docket No. ET-2014-0059 and ET-2014-0071) – 2013
Testimony on behalf of the Missouri Solar Energy Industries Association regarding Kansas City Power and Light Company's motions to suspend payment of solar rebates.

Eastern Interconnect Planning Collaborative (EIPC) – 2012-2013
Expert support on behalf of coalition of NGO stakeholders in transmission and resource planning process, including development and review of modeling assumptions and interim results, and development of comments.

Puget Sound Energy (PSE) – 2012-2013
Expert participant in PSE's 2013 IRP stakeholder process on behalf of the Sierra Club.

Washington Utilities and Transportation Commission (Docket Nos. UE-111048 and UG-111049) – 2011
Testimony on behalf of the Sierra Club regarding the cost of operating the Colstrip power plant and other power procurement issues.

Kansas Corporation Commission (Docket No. 11-KCPE-581-PRE) - 2011
Presented written and live testimony on behalf of the Sierra Club regarding Kansas City Power and Light request for predetermination of ratemaking principles.

Vermont Department of Public Service - 2011
Provided scenario analysis of the costs and benefits of various electric energy resource scenarios in support of the state Comprehensive Energy Plan.

Massachusetts Department of Energy Resources – 2009-2011
Served as expert analyst and modeling coordinator for analysis related to implementation of the Massachusetts Global Warming Solutions Act.

Iowa Office of Consumer Advocate – 2010-2011
Assisted Consumer Advocate in evaluating a proposed power purchase agreement for the output of the Duane Arnold nuclear power station.

Missouri Public Service Commission (Docket No. EW-2010-0187) – 2010
Expert participant on behalf of the Sierra Club in stakeholder process to develop a "demand side investment mechanism" in Missouri.

Louisiana Public Service Commission (Docket No. R-28271 Subdocket B) – 2009-2010
Expert participant on behalf of the Sierra Club in Renewable Portfolio Standard Task Force considering RPS for Louisiana.

Joint Fiscal Committee of the Vermont Legislature – 2008-2010
Serving as lead expert advising the Legislature on economic issues related to the possible recertification of the Vermont Yankee nuclear power plant.

Town of Littleton, NH – 2006-2010
Serving as expert witness on the value of the Moore hydroelectric facility.

Nevada Public Service Commission (Docket No. 08-05014) – August 2008
Presented prefiled and live testimony on behalf of Nevadans for Clean Affordable Reliable Energy regarding the proposed Ely Energy Center and resource planning practices in Nevada.

Mississippi Public Service Commission (Docket No. 2008-AD-158) – August 2008
Presented written and live testimony on behalf of the Sierra Club regarding the resource plans filed by Entergy Mississippi and Mississippi Power Company.

Kansas House of Representatives - Committee on Energy and Utilities – February 2008
Presented testimony on behalf of the Climate and Energy Project of the Land Institute of Kansas on a proposed bill regarding permitting of power plants. Focus was on the risks and costs associated with new coal plants and on their contribute to global climate change.

Vermont Public Service Board (Docket No. 7250) – 2006-2008
Prepared report and testimony in support of the application of Deerfield Wind, LLC. For a Certificate of Public Good for a proposed wind power facility.

Iowa Utilities Board (Docket No. GCU-07-1) – October, 2007 – January 2008
Presented wrtten and live testimony on behalf of the Iowa Office of Consumer Advocate regarding the science of global climate change and the contribution of new coal plants to atmospheric CO_2.

Nevada Public Service Commission (Docket No. 07-06049) – October 2007
Presented prefiled direct testimony on behalf of Nevadans for Clean Affordable Reliable Energy regarding treatment of carbon emissions costs and coal plant capital costs in utility resource planning.

Massachusetts General Court, Joint Committee on Economic Development and Emerging Technologies – July 2007
Presented written and live testimony on climate change science and the potential benefits of a revenue-neutral carbon tax in Massachusetts.

Town of Rockingham, VT – 2006-2007
Served as expert witness on the value of the Bellows Falls hydroelectric facility.

South Dakota Public Utilities Commission (Case No EL05-22) – June 2006
Minnesota Public Utilities Commission (Docket TR-05-1275) – December 2006
Submitted prefiled and live testimony on the contribution of the proposed Big Stone II coal-fired generator to atmospheric CO_2, global climate change and the environment of South Dakota and Minnesota, respectively.

Arkansas Public Service Commission (Docket No. 06-070-U) – October 2006
Submitted prefiled direct testimony on inclusion of new wind and gas-fired generation resources in utility rate base.

Federal Energy Regulatory Commission (Docket Nos. ER055-1410-000 and EL05-148-000) – May-Sept 2006

- Participant in settlement hearings on proposed capacity market structure (the Reliability Pricing Model, or RPM) on behalf of State Consumer Advocates in Pennsylvania, Ohio and the District of Columbia
- Invited participant on technical conference panel on PJM's proposed Variable Resource Requirement (VRR) curve
- Filed Pre- and post-conference comments and affidavits with FERC
- Participated in numerous training and design conferences at PJM on RPM implementation.

Illinois Pollution Control Board (Docket No. R2006-025) – June-Aug 2006
Prefile and live testimony presented on behalf of the Illinois EPA regarding the costs and benefits of proposed mercury emissions rule for Illinois power plants.

Long Island Sound LNG Task Force – January 2006
Presentation of study on the need for and alternatives to the proposed Broadwater LNG storage and regasification facility in Long Island Sound.

Iowa Utilities Board (Docket No. SPU-05-15) – November 2005
Presented written and live testimony on whether Interstate Power and Light's should be permitted to sell the Duane Arnold Energy Center nuclear facility to FPLE Duane Arnold, Inc., a subsidiary of Florida Power and Light.

PUBLICATIONS AND REPORTS

Hausman, E., The Worst of Both Worlds: Why the Ohio Legislature's OVEC Bailout Bill would Harm Consumers, Impede Competition, Increase Pollution, and Impair the Health and Welfare of Ohioans for Decades. White paper produced on behalf of The Sierra Club, June 2017.

Hausman, E., Risks and Opportunities for PacifiCorp - State Level Findings: Utah, Produced on behalf of the Sierra Club, October 2014.

Hausman, E., Risks and Opportunities for PacifiCorp - State Level Findings: Oregon, Produced on behalf of the Sierra Club, October 2014.

Hausman, E., Risks and Opportunities for PacifiCorp in a Carbon Constrained Economy, Produced on behalf of the Sierra Club, October 2014.

Luckow, P., E. Stanton, B. Biewald, J. Fisher, F. Ackerman, E. Hausman, 2013 Carbon Dioxide Price Forecast, Synapse Energy Economics, November 2013.

Stanton, E., T. Comings, K. Takahashi, P. Knight, T. Vitolo, E. Hausman, Economic Impacts of the NRDC Carbon Standard: Background Report prepared for the Natural Resources Defense Council, Synapse Energy Economics for NRDC, June 2013

Comings T., P. Knight, E. Hausman, Midwest Generation's Illinois Coal Plants: Too Expensive to Compete? (Report Update) Synapse Energy Economics for Sierra Club, April 2013

Stanton E., F. Ackerman, T. Comings, P. Knight, T. Vitolo, E. Hausman, Will LNG Exports Benefit the United States Economy? Synapse Energy Economics for Sierra Club, January 2013

Chang M., D. White, E. Hausman, Risks to Ratepayers: An Examination of the Proposed William States Lee III Nuclear Generation Station, and the Implications of "Early Cost Recovery" Legislation, Synapse Energy Economics for Consumers Against Rate Hikes, December 2012

Wilson R., P. Luckow, B. Biewald, F. Ackerman, and E.D. Hausman**,** *2012 Carbon Dioxide Price Forecast*, Synapse Energy Economics, October 2012.

Fagan B., M. Chang, P. Knight, M. Schultz, T. Comings, E.D. Hausman, and R. Wilson, *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region*. Synapse Energy Economics for Energy Future Coalition, May 2012.

Hausman, E.D., T. Comings, "*Midwest Generation's Illinois Coal Plants: Too Expensive to Compete?* Synapse Energy Economics for Sierra Club, April 2012.

Hausman, E.D., T. Comings, and G. Keith, *Maximizing Benefits: Recommendations for Meeting Long-Term Demand for Standard Offer Service in Maryland*. Synapse Energy Economics for Sierra Club, January 2012.

Keith G., B. Biewald, E.D. Hausman, K. Takahashi, T. Vitolo, T. Comings, and P. Knight, *Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011* Synpase Energy Economics for Civil Society Institute, November 2011.

Chang M., D. White, E.D. Hausman, N. Hughes, and B. Biewald, *Big Risks, Better Alternatives: An Examination of Two Nuclear Energy Projects in the U.S.* Synpase Energy Economics for Union of Concerned Scientists, October 2011.

Hausman E.D., T. Comings, K. Takahashi, R. Wilson, and W. Steinhurst, *Electricity Scenario Analysis for the Vermont Comprehensive Energy Plan 2011.* Synapse Energy Economics for Vermont Department of Public Service, September 2011.

Wittenstein M., E.D. Hausman, *Incenting the Old, Preventing the New: Flaws in Capacity Market Design, and Recommendations for Improvement.* Synapse Energy Economics for American Public Power Association, June 2011.

Johnston L., E.D. Hausman, B. Biewald, R. Wilson, and D. White. *2011 Carbon Dioxide Price Forecast.* Synapse Energy Economics White Paper, February 2011.

Hausman E.D., V. Sabodash, N. Hughes, and J. I. Fisher, *Economic Impact Analysis of New Mexico's Greenhouse Gas Emissions Rule.* Synapse Energy Economics for New Energy Economy, February 2011.

Hausman E.D., J. Fisher, L. Mancinelli, and B. Biewald**.** *Productive and Unproductive Costs of CO_2 Cap-and-Trade: Impacts on Electricity Consumers and Producers.* Synapse Energy Economics for National Association of Regulatory Utility Commissioners, National Association of State Utility Consumer Advocates, National Rural Electric Cooperative Association, and American Public Power Association, July 2009.

Peterson P., E. Huasman, R. Fagan, and V. Sabodash, *Report to the Ohio Office of Consumer Counsel, on the value of continued participation in RTOs. Filed under Ohio PUC Case No. 09-90-EL-COI*, May 2009.

Schlissel D., L. Johnston, B. Biewald, D. White, E. Hausman, C. James, and J. Fisher, *Synapse 2008 CO_2 Price Forecasts.* July 2008.

Hausman E.D., J. Fisher and B. Biewald, *Analysis of Indirect Emissions Benefits of Wind, Landfill Gas, and Municipal Solid Waste Generation.* Synapse Energy Economics Report to the Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, U.S. Environmental Protection Agency, July 2008.

Hausman E.D. and C. James, *Cap and Trade CO_2 Regulation: Efficient Mitigation or a Give-away?* Synapse Enegy Ecomics presentation to the ELCON Spring Workshop, June 2008.

Hausman E.D., R. Hornby and A. Smith, *Bilateral Contracting in Deregulated Electricity Markets.* Synapse Energy Economics for the American Public Power Association, April 2008.

Hausman E.D., R. Fagan, D. White, K. Takahashi and A. Napoleon, *LMP Electricity Markets: Market Operations, Market Power and Value for Consumers.* Synapse Energy Economics for the American Public Power Association's Electricity Market Reform Initiative (EMRI) symposium, "Assessing Restructured Electricity Markets" in Washington, DC, February 2007.

Hausman E.D. and K. Takahashi, *The Proposed Broadwater LNG Import Terminal Response to Draft Environmental Impact Statement and Update of Synapse Analysis.* Synapse Energy Economics for the Connecticut Fund for the Environment and Save The Sound, January 2007.

Hausman E.D., K. Takahashi, D. Schlissel and B. Biewald, *The Proposed Broadwater LNG Import Terminal: An Analysis and Assessment of Alternatives.* Synapse Energy Economics for the Connecticut Fund for the Environment and Save The Sound, March 2006.

Hausman E.D., P. Peterson, D. White and B. Biewald, *RPM 2006: Windfall Profits for Existing Base Load Units in PJM: An Update of Two Case Studies*. Synapse Energy Economics for the Pennsylvania Office of Consumer Advocate and the Illinois Citizens Utility Board, February 2006.

Hausman E.D., K. Takahashi, and B. Biewald, *The Glebe Mountain Wind Energy Project: Assessment of Project Benefits for Vermont and the New England Region*. Synapse Energy Economics for Glebe Mountain Wind Energy, LLC., February 2006.

Hausman E.D., K. Takahashi, and B. Biewald, *The Deerfield Wind Project: Assessment of the Need for Power and the Economic and Environmental Attributes of the Project.* Synapse Energy Economics for Deerfield Wind, LLC., January 2006.

Hausman E.D., P. Peterson, D. White and B. Biewald, *An RPM Case Study: Higher Costs for Consumers, Windfall Profits for Exelon*. Synapse Energy Economics for the Illinois Citizens Utility Board, October 2005.

Hausman E.D. and G. Keith, *Calculating Displaced Emissions from Energy Efficiency and Renewable Energy Initiatives*. Synapse Energy Economics for EPA website 2005

Rudkevich A., E.D. Hausman, R.D. Tabors, J. Bagnal and C Kopel, *Loss Hedging Rights: A Final Piece in the LMP Puzzle*. Hawaii International Conference on System Sciences, Hawaii, January, 2005 (accepted).

Hausman E.D. and R.D. Tabors, *The Role of Demand Underscheduling in the California Energy Crisis*. Hawaii International Conference on System Sciences, Hawaii, January 2004.

Hausman E.D. and M.B. McElroy, *The reorganization of the global carbon cycle at the last glacial termination.* Global Biogeochemical Cycles, *13*(2), 371-381, 1999.

Norton F.L., E.D. Hausman and M.B. McElroy, *Hydrospheric transports, the oxygen isotope record, and tropical sea surface temperatures during the last glacial maximum*. Paleoceanography, *12,* 15-22, 1997.

Hausman E.D. and M.B. McElroy, *Variations in the oceanic carbon cycle over glacial transitions: a time-dependent box model simulation*. Presented at the spring meeting of the American Geophysical Union, San Francisco, 1996.

PRESENTATIONS AND WORKSHOPS

American Public Power Association: Invited expert participant in APPA's roundtable discussion of the current state of the RTO-operated electricity markets. October 2013.

California Long-Term Resource Adequacy Summit (Sponsored by the California ISO and the California Public Utility Commission): Panelist on "Applying Alternative Models to the California Market Construct." February 26, 2013.

ELCON 2011 Fall Workshop: "Do RTOs Need a Capacity Market?" October 2011.

Harvard Electricity Policy Group: Presentation on state action to ensure reliability in the face of capacity market failure. February 2011.

NASUCA 2010 Annual Conference: "Addressing Climate Change while Protecting Consumers." November 2010.

NASUCA Consumer Protection Committee: Briefing on the Synapse report entitled, "Productive and Unproductive Costs of CO_2 Cap-and-Trade." September 2009.

NARUC 2009 Summer Meeting: Invited speaker on topic: "Productive and Unproductive Costs of CO2 Cap-and-Trade." July, 2009.

NASUCA 2008 Mid-Year Meeting**:** Invited speaker on the topic, "Protecting Consumers in a Warming World, Part II: Deregulated Markets." June 2008.

Center for Climate Strategies: Facilitator and expert analyst on state-level policy options for mitigating greenhouse gas emissions. Serve as facilitator/expert for the Electricity Supply (ES) and Residential, Commercial and Industrial (RCI) Policy Working Groups in the states of Colorado and South Carolina. 2007-2008.

NASUCA 2007 Mid-Year Meeting**:** Invited speaker on the topic, "Protecting Consumers in a Warming World" June 2007.

ASHRAE Workshop on estimating greenhouse gas emissions from buildings in the design phase: Participant expert on estimating displaced emissions associated with energy efficiency in building design. Also hired by ASHRAE to document and produce a report on the workshop. April, 2007.

Assessing Restructured Electricity Markets An American Public Power Association Symposium: Invited speaker on the history and effectiveness of Locational Marginal Pricing (LMP) in northeastern United States electricity markets, February, 2007.

ASPO-USA 2006 National Conference: Invited speaker and panelist on the future role of LNG in the U.S. natural gas market, October, 2006.

Market Design Working Group: Participant in FERC-sponsored settlement process for designing capacity market structure for PJM on behalf of coalition of state utility consumer advocates, July-August 2006.

NASUCA 2006 Mid-Year Meeting**:** Invited speaker on the topic, "How Can Consumer Advocates Deal with Soaring Energy Prices?" June 2006.

Soundwaters Forum, Stamford, CT: Participated in a debate on the need for proposed Broadwater LNG terminal in Long Island Sound, June 2006.

Energy Modeling Forum: Participant in coordinated academic exercise focused on modeling US and world natural gas markets, December 2004.

Massachusetts Institute of Technology (MIT): Guest lecturer in Technology and Policy Program on electricity market structure, the LMP pricing system and risk hedging with FTRs. 2002-2005.

LMP: The Ultimate Hands-On Seminar. Two-day seminar held at various sites to explore concepts of LMP pricing and congestion risk hedging, including lecture and market simulation exercises. Custom seminars held for FERC staff, ERCOT staff, and various industry groups. 2003-2004.

Learning to Live with Locational Marginal Pricing: Fundamentals and Hands-On Simulation. Day-long seminar including on-line mock electricity market and congestion rights auction, December 2002.

LMP in California. Led a series of seminars on the introduction of LMP in the California electricity market, including on-line market simulation exercise. 2002.

Resume updated October 2017

EDH-2

Utility DIVE

BRIEF

Updated: Tucson Electric signs solar + storage PPA for 'less than 4.5¢/kWh'

By **Gavin Bade**, **Peter Maloney** • May 23, 2017

Dive Brief:

- Tucson Electric Power has signed a power purchase agreement for a solar-plus-storage system at "an all-in cost significantly less than $0.045/kWh over 20 years," according to a company official. Exact prices are confidential, but a release pegged the PPA for the solar portion of the project at below $0.03/kWh.

- The project calls for a 100 MW solar array and a 30 MW, 120 MWh energy storage system, both developed by an affiliate of NextEra Energy. If the pricing proves accurate, it would represent a major cost reduction for combined storage facilities since the signing of the last significant PPA — a $0.11/kWh Hawaii contract in January.

- The PPA would confirm a forecast in Arizona's proposed "Clean Peak Standard" that solar-plus-storage facilities could compete with gas peakers on price. But TEP does not support the proposal, now on hold with regulators, and Energy Supply Director Carmine Tilghman said batteries do not provide the same capabilities as peaker plants.

Dive Insight:

TEP is moving ahead with plans for an array of renewable energy resources and energy storage initiatives, even as the state's regulatory framework adjusts to the new resources.

Last fall, Arizona's utility consumer advocate proposed the Clean Peak Standard, seeking to allow energy storage charged by renewables to compete with gas-powered peaker plants.

That proposal noted a 2015 solar-plus-storage PPA signed in Hawaii for $0.145/kWh. At that price, it posited, the clean generation could compete with conventional peakers in Arizona, which produce power close at to $0.20/kWh.

The proposal was endorsed by a sitting regulator and spawned two bills for similar market constructions in California.

If the combined solar and storage PPA price provided by Tilghman proves accurate, it would confirm the proposal's assumption that dispatchable renewables can challenge peakers on price. But this week, the Arizona Corporation Commission put the proceeding on hold last week until a final decision is made on net metering rates in a separate utility rate case.

That's welcome news to Tilghman, who said it's a mistake to compare batteries to peaker plants.

"Storage provides the ability to simulate 'load' by allowing us to charge during the day and minimize the 'duck curve' issues, but [batteries] still have significant limitations to both peak shaving (which can easily be longer than 4 hrs) and use (1 cycle per day)," he wrote to Utility Dive in an email. "They each have a purpose and should not be compared to each other and as replacement for one another."

With or without the standard, TEP is moving ahead on storage. The utility has three storage demonstration projects under way totaling about 22 MW, and is including storage in its integrated resource plan that is headed for a hearing late next month, according to TEP spokesman Joe Barrios.

TEP is working toward sourcing 30% of its electric power from renewable resources by 2030, and it sees storage as a way of smoothing out the intermittency of solar and wind power.

The newly announced project “speaks to the idea that the cost of large-scale solar is going down” and getting more feasible for utilities, said Barrios.

The NextEra affiliate will take advantage of the 30% federal investment tax credit for both the solar and storage facilities, with the "less than $0.045/kWh" being the price to the utility, Tilghman confirmed.

The most recent major solar-plus-storage PPA was signed at $0.11/kWh by the Kauai Island Utility Cooperative in January. That project — 28 MW of solar and 100 MWh of batteries — will displace the utility's current oil-fired baseload generation.

The TEP project, slated for a site owned by the city of Tucson, is set to be online by the end of 2019. It would be TEP's largest dedicated renewable energy resource.

This post has been updated to confirm that the developer will monetize the federal ITC for both the solar and storage facilities.

Recommended Reading:

Electric Power & Light
Tucson Electric Power to buy cheap solar power from solar-storage project

EDH-3

Return to Agenda

EDH-3 Page 1

V. B. 2.
10/17/2017

Building Community

AGENDA ITEM SUMMARY

October 2, 2017

SUBJECT:	**UNIVERSAL SOLAR EXPANSION AND LAND ACQUISITION**

Purpose: ☐ Information Only ☒ Action Required ☐ Advice/Direction

Issue: The price of universal solar photovoltaic (PV) Power Purchase Agreements (PPAs) has declined from $75/MWh on average in 2016 to current pricing near JEA's fuel rate of $32.50/MWh. Staff is proposing a significant expansion at this time of universal solar for JEA's generation portfolio. In connection with this expansion, four tracts of land have been identified as being suitable to host solar facilities of at least 50 MW each. Two of these tracts are currently owned by JEA and the remaining two are available for purchase.

Significance: Staff recommends that JEA pursue new universal solar PPAs at or below JEA's current fuel rate to take advantage of lower universal solar prices. Universal solar allows JEA to lock in current, competitive low energy prices for a portion of our generation requirements, reducing JEA's reliance on fossil fuels and providing some protection to JEA customers against future changes in volatile fuel and purchase power costs. This expansion will increase JEA's solar footprint by over 600% compared to existing and planned solar facilities, making Jacksonville one of the top solar communities in the country.

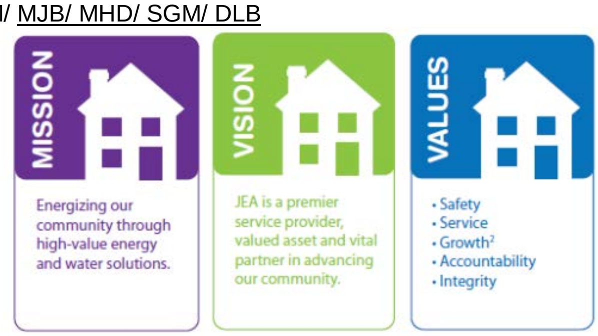
Effect: This universal solar expansion supports JEA's Energy Mix Policy. JEA will own the land for the solar facilities, ensuring that the land will remain available for future solar applications. These new projects will also help lower the cost of JEA's SolarSmart offering, and allow for further expansion through the new proposed JEA SolarMax rate.

Cost or Benefit: PPA costs will either offset JEA's fossil fuel expense or be recovered by JEA SolarSmart/SolarMax subscriptions. Staff is requesting a delegated authorization to acquire land to be used for these solar developments. It is a benefit to our customers and the environment, as we lock in low renewable energy prices and add a substantial amount of carbon-free generation to JEA's generation portfolio.

Recommended Board action: Staff recommends the Board delegate authorization to the Managing Director to execute the land purchases needed for the solar developments described above by adopting the attached Resolution 2017-36. The resolution has been prepared by staff and approved by JEA's Chief Legal Officer.

For additional information, contact: Steve McInall, (904) 665-4309 or John McCarthy, (904) 665-5544

Submitted by: PEM/ MJB/ MHD/ SGM/ DLB



Commitments to Action

1 Earn Customer Loyalty

2 Deliver Business Excellence

3 Develop an Unbeatable Team

INTER-OFFICE MEMORANDUM

October 2, 2017

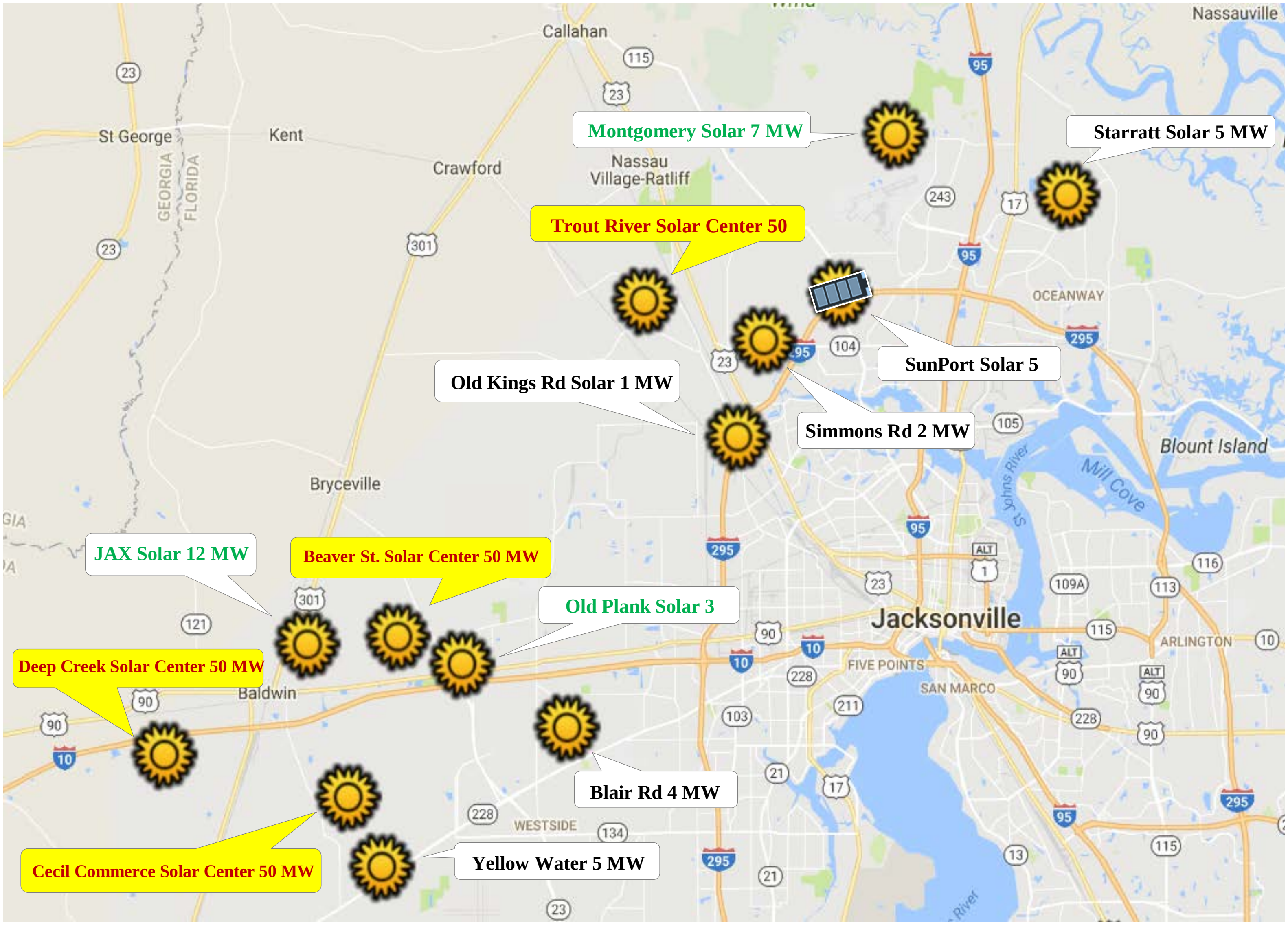
SUBJECT:	**UNIVERSAL SOLAR EXPANSION AND LAND ACQUISTION**
FROM:	Paul E. McElroy, Managing Director/CEO
TO:	JEA Board of Directors

BACKGROUND:
JEA has a strong history of supporting solar research and incentivizing solar deployments. In 2002, JEA implemented a Solar Incentive Program to help encourage the acceptance and deployment of solar energy systems. In 2009, JEA signed a Power Purchase Agreement (PPA) with Jacksonville Solar, LLC for a 12 MW rated solar photovoltaic (PV) farm located on the city's Westside. Also in 2009, JEA established a 10 MW Net Metering program designed to encourage the installation of private solar PV systems until such time when PV solar systems achieved commercial viability. In 2014, JEA implemented a Solar Policy, which supported the addition of up to 38 MW of solar PV resources in the JEA territory using a set of PPAs. From this initiative, JEA has 27 MW of utility-scale solar PV projects planned for 2017 and an additional 5 MW planned for 2018. In 2016, JEA pledged its participation in the Florida Alliance for Advancing Solar and Storage Technology Readiness (FAASSTeR) with other Florida Municipal Utilities, the Florida Municipal Electric Association (FMEA), the Florida Office of Energy, Nhu Energy, and the U.S. Dept. of Energy. The objective of this effort is to enable FMEA member utilities to grow solar PV in their territories to over 10 percent of power capacity by 2024. Finally, in 2017 JEA initiated the JEA SolarSmart rate, providing all JEA customers the ability to access to solar resources.

DISCUSSION:
The price of utility-scale solar PPAs has declined from $75/MWh on average in 2016 to near JEA's current fuel charge of $32.50/MWh today. It is recommended that JEA pursue new universal solar PPAs at or below JEA's current fuel rate to take advantage of lower universal solar prices. Universal solar allows JEA to lock in current, competitive low energy prices for a portion of our generation requirements, reducing JEA's reliance on fossil fuels and providing some protection to JEA customers against future changes in volatile fuel and purchase power. This proposed expansion will increase JEA's solar footprint by over 600% compared to existing and planned solar facilities, making Jacksonville one of the top solar communities in the country. The construction of the new solar developments is expected to be completed by the end of 2020.

Four tracts of land have been identified as suitable to host solar facilities of at least 50 MW each. Two of the tracts are owned by JEA, and the remaining two are available for purchase. The JEA-owned parcels are the Peterson and Miller tracts. They were purchased in 2000 and 2001 under a Jacksonville initiative known as the Preservation Project. At that time, the JEA Board stipulated that should the property be improved with utility facilities, JEA would substitute a similar property. The parcels proposed for purchase provide sites for new solar development and for offsets for solar development on its existing sites. The total cost of acquisition of the additional properties will not exceed fifty million dollars ($50,000,000). The four proposed new solar sites are highlighted in yellow on the map on the following page.

Consistent with JEA's Real Estate Procurement Directive and real estate industry practice, staff will secure an appraisal of the value of property, and negotiate acquisition terms and pricing for the tracts of land. JEA shall not acquire these properties at a price greater than the appraised value.



**Yellow highlighted sites expected to commission by end of 2019/early 2020. Sites not highlighted are the 32 MW awarded through JEA's Phase 1 -3 Solar RFPs. Sites in green font are already online and producing*

RECOMMENDATION:

Staff recommends that the Board delegate authorization to the Managing Director to execute the land purchases needed for the solar developments described above by adopting the attached Resolution 2017-36. The resolution has been prepared by staff and approved by JEA's Chief Legal Officer.

____

Paul E. McElroy, Managing Director/CEO

PEM/MJB/MHD/SGM/DLB

Resolution 2017-36

A RESOLUTION TO DELEGATE AUTHORITY TO NEGOTIATE AND EXECUTE REAL ESTATE PURCHASE AGREEMENTS FOR UNIVERSAL SOLAR PROGRAM TO THE MANAGING DIRECTOR/CEO IN ACCORDANCE WITH JEA CHARTER SECTION 21.10

WHEREAS, after consideration by JEA, staff has recommended JEA pursue additional universal solar opportunities within JEA service territory; and

WHEREAS, certain real estate parcels have been identified in JEA service territory that can accommodate the JEA universal solar projects; and

WHEREAS, JEA staff will negotiate acceptable terms and conditions for the purchase of the needed parcels of real estate; and

WHEREAS, the total cost for the acquisition of the needed parcels of real estate shall not exceed fifty million dollars ($50,000,000).

WHEREAS, the JEA Charter, Section 21.10, provides that the JEA Board may delegate the authority to an officer, agent or employee of JEA by resolution to execute purchase and sale agreements.

BE IT RESOLVED by the JEA Board of Directors that:

1. JEA acquire the necessary real property associated with JEA's universal solar expansion program under terms and conditions satisfactory for the intended use by JEA.
2. The Board hereby delegates to the Managing Director/CEO the authority to execute all transaction documents required for the acquisition of real estate for JEA's universal solar expansion program.
3. The total acquisition cost of all real property necessary for JEA's universal solar expansion program shall not exceed fifty million dollars ($50,000,000) without additional approval by the JEA Board of Directors.

Dated this ____ day of October 2017.

JEA

By: ________________________________

G. Alan Howard, Chair

Attest:

____

Reverend Frederick Newbill, Secretary

Approved as to form:

____

Jody Brooks, Chief Legal Officer

EDH-4

Solar Energy Industries Association®

October 25, 2017

Thank you for the opportunity to comment on the proposed 2017 Second Revised and Restated Stipulation and Settlement Agreement. My name is Pierce Schuessler and I am commenting on behalf of the Solar Energy Industries Association (SEIA), a trade association that represents over 1000 members in the solar industry. Our members include many utility-scale solar developers who are ready, willing and able to deliver clean, low-cost solar energy to the people of Florida, including the customers of Duke Energy Florida. Our comments are limited to the section of the settlement agreement dealing with the proposed Solar Base Rate Adjustment beginning on page 24 of the Agreement.

As you know, the Agreement proposes a solar base rate adjustment that would authorize cost recovery for Duke's proposed construction of approximately 700 megawatts of solar generation between now and 2022. Under the Agreement, the weighted average cost of all projects for which cost recovery would be authorized would be capped at $1,650 per kilowatt.

We appreciate Duke's commitment to incorporate more solar resources into its generation portfolio. However, we submit that ratepayers would be better served if, instead of building its own solar facilities, Duke were to procure this additional generation through third party power purchase agreements, or by the purchase of completed projects developed by third parties. We believe that either option would allow for the addition of solar capacity at a lower cost than generation developed and constructed by Duke.

In the case of third-party power purchase agreements, independent generators can fully utilize federal tax incentives and pass significant savings along to ratepayers. With respect to projects developed and built by independent parties, construction risks are put on the shoulders of the project developers instead of the ratepayer. When the independent developer sells power to the utility or sells a completed project, the developer guarantees a fixed price per megawatt up front. So if there are construction cost overruns or project delays, it may cut into the developer's margins but the ratepayer isn't harmed. That's not necessarily so when Duke builds its own solar facilities. In that case, unless the cost-overrun is determined by the Commission to be unreasonable, it will get included in the rate base and be passed on to ratepayers. Although the 2017 Agreement would cap Duke's costs at $1650 per kilowatt, that cost significantly exceeds the cost at which an experienced developer can build a utility-scale project in 2017, and those costs may come down further in the future. In addition, Duke would be able to earn a return on top of that amount, whereas the independent developer's price is an all-inclusive number.

The Settlement Agreement does provide that Duke "will consider" buying projects from third parties, but it does not require it to do so, or to conduct a competitive process that includes third party projects to ensure that it is getting the best price for ratepayers. By contrast, it is required to utilize a competitive solicitation process to select contractors and equipment and materials. Ratepayers would be best served if that same competitive process was used to select the increased solar generation called for by the Agreement.

In conclusion, SEIA believes that when a utility purchases power or acquires projects from independent developers rather than building projects itself, it's a win for the ratepayer. Before approving the 2017 Agreement, we ask that you require an examination of the reduced cost to ratepayers that would result if instead of building its own solar projects, Duke were required to competitively procure either power or finished projects from third parties. Thank you.

600 14th Street, NW · Suite 400 · Washington, DC 20005 · 202.682.0556(T) · 202.682.0559(F) · www.SEIA.org

EDH-5

April 27, 2004

ISO-New England Awards EnerNOC Landmark Contract to Improve Grid Reliability in Southwest Connecticut

BOSTON, MA - EnerNOC, Inc. is proud to announce its selection by ISO New England (ISO-NE) to provide Demand Response capacity to the Southwest Connecticut region over the next four years. Less than a year removed from the greatest blackout in U.S. history, the announcement is part of a larger initiative to improve service reliability in energy-constrained regions. The cutting-edge technology and services EnerNOC provides will go a long way toward providing area residents and businesses with adequate power during peak energy periods.

The announcement marks the culmination of a highly competitive RFP process. ISO-NE initiated the RFP to secure resources that will make the electricity grid more reliable specifically in Southwest Connecticut, where the energy situation is dire as a result a sub-par energy transmission infrastructure. The resources identified by ISO-NE include both emergency generation and reductions in electricity use. Only seven firms were awarded contracts in the RFP, and of these, EnerNOC was the only firm nominated to recruit yet-unidentified owners of backup generators and electric customers willing to shed load. If all targets are met on schedule, the contract could be worth several million dollars per year through at least 2008.

By winning its RFP bid, EnerNOC advanced its mission to offer innovative energy solutions. The terms of the contract allow EnerNOC to pass significant financial rewards on to its customers, particularly early adopters of EnerNOC's proprietary technology.

"This award from ISO-NE will allow us to improve our value proposition – which was already incredibly strong," says David Brewster, EnerNOC's President and COO, "while at the same time making the power grid much stronger and more resilient for all electricity customers in Southwest Connecticut." Stephen G. Whitley, ISO New England's Senior Vice President and Chief Operating Officer, concurs. "The inadequacy of Southwest Connecticut's electricity system makes these short-term measures necessary to ensure reliability, particularly during the summer months when the Southwest corner of the state is vulnerable to power disruptions. These resources are intended to help fill a reliability gap until a long-term solution to Southwest Connecticut's reliability problem is in place."

EnerNOC's next task is to finish recruiting commercial and industrial customers to participate in the initiative. "The biggest challenge is getting people to understand how simple the process really is. All our customers have to do is make their capacity available. We'll do the rest," says EnerNOC's Brewster, "We're basically sitting on a multi-million-dollar check. We're just looking for the right customers to share it with."

About ISO New England:

ISO New England is a not-for-profit corporation responsible for the day-to-day reliable operation of the region's bulk power generation and transmission system. For more information, visit www.iso-ne.com.

About EnerNOC:

EnerNOC is the nation's premier full-service demand response provider. For more information, visit www.EnerNOC.com or call 1-888-EnerNOC.

EDH-6

Global Renewables Focus

SEPTEMBER 18, 2017

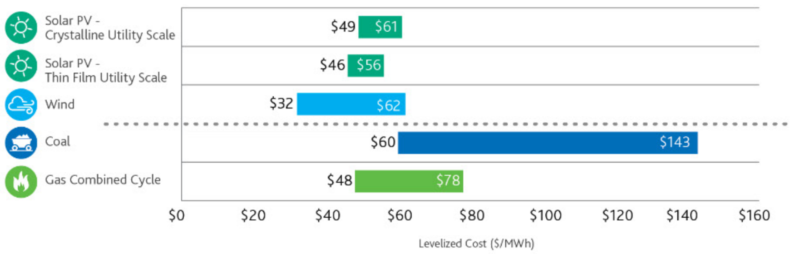
For more information on the renewable energy sector and broader ESG considerations in fixed income markets, visit esg.moodys.io

FEATURE ARTICLES

Falling renewable costs will ease path to compliance with Paris climate agreement

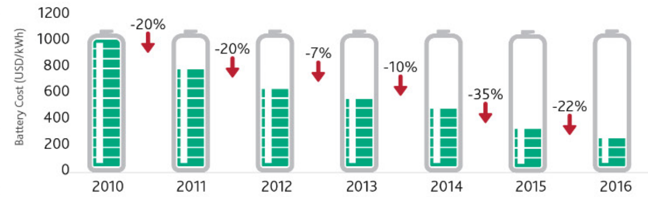
Sharp declines in costs for wind, solar and other emerging energy technologies will make it less expensive for countries to achieve their carbon reduction commitments under the 2015 accord.

Solar and wind are both competitive with fossil generation



Source: Lazard's Levelized Cost of Energy Analysis - Version 10.0, December 2016

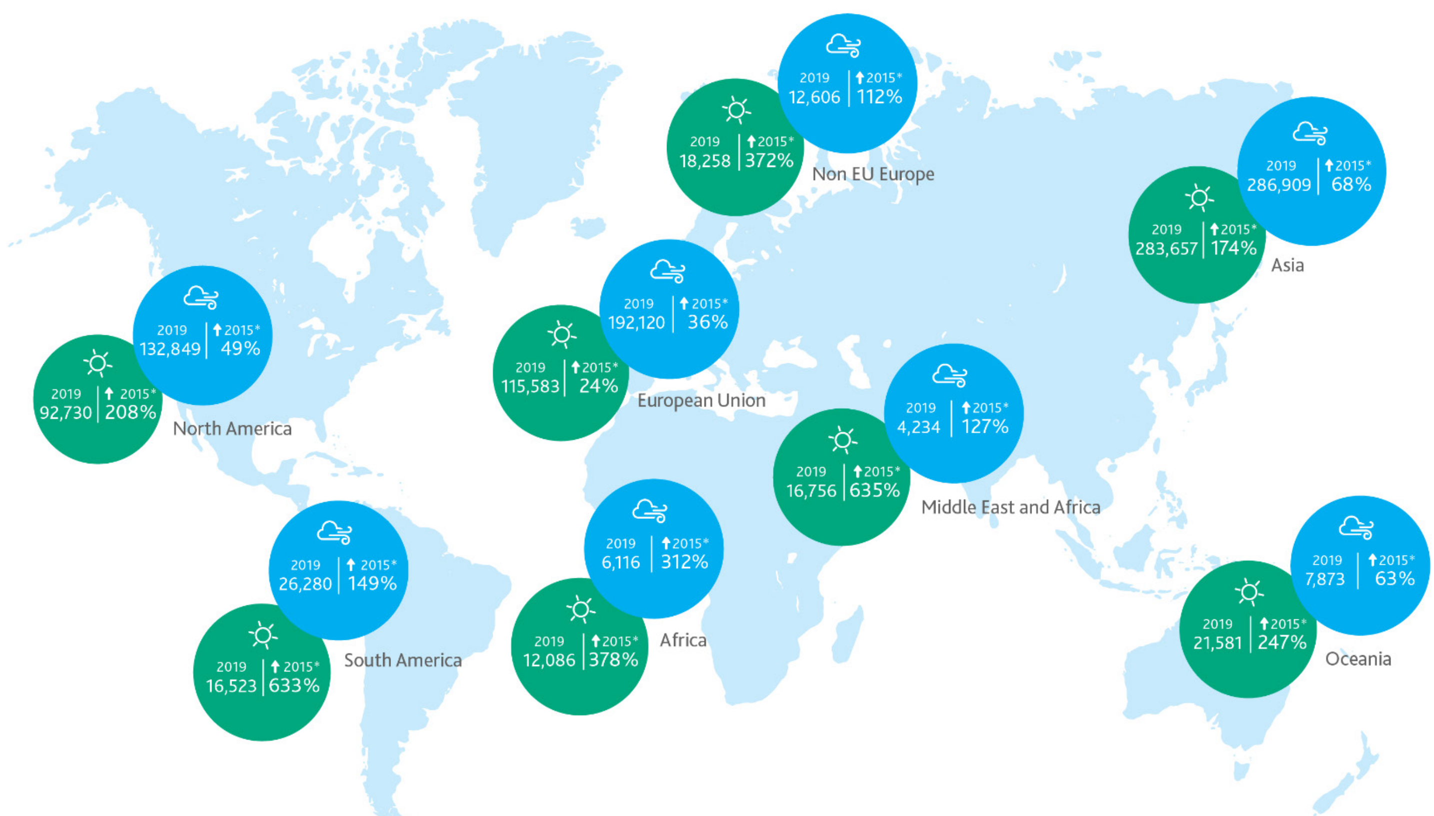
Prices for battery storage have declined significantly; benefits from economies of scale expected to continue



Source: Bloomberg New Energy Finance

Forecasts for solar and wind power installation

Forecasted Solar Installs by Region (MW) | Forecasted Wind Installs by Region (MW)



Sources: Moody's Investors Service, Bloomberg New Energy Finance

*Forecasted increase from 2015

MOODY'S INVESTORS SERVICE

Renewable Energy - Global: Falling cost of renewables reduces risks to Paris Agreement compliance

Originally published on 6 September 2017

Wind and solar energy costs have declined by 60%-80% since 2010 and other emerging renewable technologies are now exhibiting similar trends. This is driving growth in the sector that is based on economics rather than just subsidies or mandates. It is also making it less expensive for countries to achieve their carbon-reduction commitments, or Nationally Determined Contributions (NDC), under the 2015 Paris climate agreement.

» **Renewable energy costs have fallen dramatically and will continue to do so.** Economies of scale and improving efficiencies have caused steep falls in capital costs, and hence levelized cost of energy (LCOE), from solar and wind. And those declines are continuing, especially for solar, where panel prices have fallen over 20% since late 2016.

» **Energy storage and offshore wind costs are declining faster than expected.** Most forecasts have historically underestimated the pace of declines in renewable energy capital costs and appear to be doing so now for offshore wind and energy storage. Both technologies have already reached prices predicted for 2020. They are just beginning their global spread, and greater economies of scale will spur further price reductions.

» **Integrating renewables into the grid imposes additional costs, but they vary by country and are becoming more manageable.** Renewables are intermittent resources with integration costs that are growing as penetration rises, especially for wind. Smaller markets, island grids, or markets with less developed transmission face higher costs than larger, well developed grids. Utilities are also learning to manage these risks better with improved wind forecasting, upgrading transmission and improving grid flexibility.

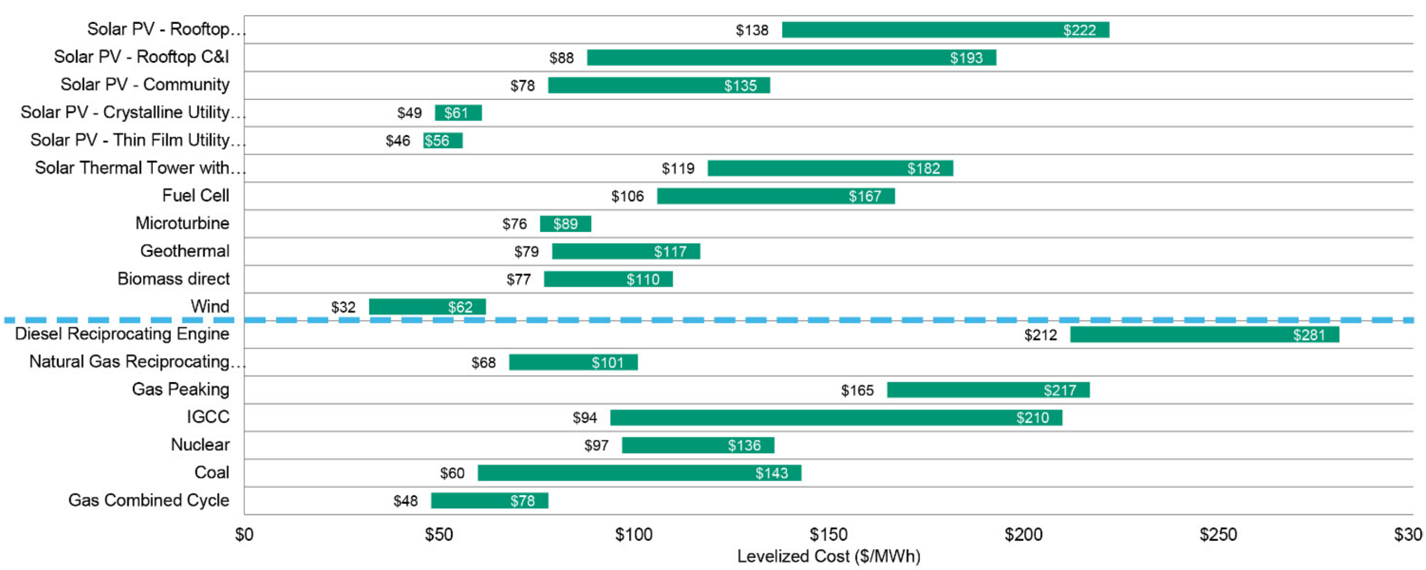
» **Falling costs for renewable energy are reducing risks to Paris Agreement compliance.** Renewables have gone from being a subsidized “supplement” to the central focus of national energy policies of many countries, reaching parity with conventional sources in many parts of the world. Falling renewable energy costs are increasing countries' willingness and ability to adopt policies that will help them achieve their commitments under the Paris Agreement.

» **US exit from the Paris accord is unlikely to materially affect the global emissions trajectory.** US greenhouse gas emissions will likely continue to decline despite the US government’s stated intention to withdraw from the Paris accord. Any deviation in the global emissions pathway would likely be small and fall in line with the uncertainty inherent in long-term projections. However, any further tightening beyond the current NDCs will be hard to achieve without US participation.

EXHIBIT 1

Solar and wind are both competitive with fossil generation

Unsubsidized Levelized Cost of Energy comparison



Note: (1) Assumes 60% debt at 8% and 40% equity at 12%. Analysis excludes integration costs for intermittent technologies. (2) Wind represents onshore wind.
Source: Lazard's Levelized Cost of Energy Analysis - Version 10.0, December 2016

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Renewable Energy – Global: Renewables sector risks shift as competition reduces reliance on government subsidy

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- **More countries are procuring renewable energy capacity through competitive auctions, as the need for subsidies falls.** We view a lower reliance on subsidies as positive for renewable energy generators, as over time it alleviates the cost for end consumers and relieves the political pressure on governments to address affordability concerns. If competition overheats, however, the risks from aggressive bidding may be credit negative in the absence of mitigating factors.
- **Competitive auctions signal a change in the sector's economic drivers.** Governments kick-started the initial strong sector growth, with subsidies tailored to a technology's specific costs. Now, renewables are increasingly having to compete not only with each other but also conventional generation. The cash flows of these projects are no longer driven by government-determined subsidies.
- **Renewable generation costs have fallen sharply.** In some countries, including India and Mexico, renewables are now cost competitive relative to conventional fossil fuel generation. The cost decline reflects (1) cheaper equipment, with solar benefitting from the most dramatic fall; (2) economies of scale, particularly for the offshore wind sector where turbine sizes have increased; and (3) the current low interest rate environment, together with a compression in risk premia for renewables debt and equity.
- **Recent auctions have produced record low prices, but bids reflect important variations in generators' risk profiles.** Aside from the strength of the solar or wind resource, the risks and bid strategies depend upon the terms and conditions of the tariff, horizon to commissioning deadline, grid capacity and risk of curtailment, counterparty credit quality, construction and operating synergies, and finance costs.
- **Evolving sector dynamics present both opportunities and risks for stakeholders.** Use of newer technologies to maximise production introduces additional construction and operating risks. The increasing exposure of renewables to more variable revenues, as they require lower or no subsidy on top of market prices, is a credit negative. Power purchase agreements may dampen this risk, but the availability and duration of such contracts will vary. Large, diversified project sponsors will be better placed to bid competitively, benefitting from learning effects, pricing power, and efficiencies in operational management.

EXHIBIT 1
Aside from capex and resource, a number of other considerations influence observed renewable energy bid variations across markets

Source: Moody's Investors Service

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GB Regulated Energy Networks: Energy storage to enable a more sustainable electricity transmission grid

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The widespread deployment of energy storage will help National Grid Electricity Transmission plc (NGET, A3 stable), the GB system operator (SO) and English transmission owner (TO), as well as Scottish TOs Scottish Hydro Electric Transmission plc (SHETL, A3 stable, owned by SSE plc) and SP Transmission plc (SPT, Baa1 positive, owned by Iberdrola SA) to handle the challenges created by growing renewable energy output in a cost-efficient way, a credit positive. By slowing the growth of transmission network charges, batteries will reduce the longer-term risk of political and regulatory interventions in the sector, as well as providing opportunities for near-term outperformance on cost allowances and operational incentives.

» **Batteries will ease pressure on balancing costs from rising renewable penetration.** As wind and solar generating capacity continues to increase in Great Britain, NGET will face escalating costs and challenges in maintaining a stable transmission network. Battery storage and other sources of flexibility will allow far larger amounts of renewable capacity to be integrated at costs around current levels.

» **Batteries will reduce need for investment in the transmission network.** By allowing demand to be served with lower total capacity, and by providing cheaper options for reinforcing the network, battery storage will reduce the required investment in the transmission network. Batteries connected to the transmission grid will provide TOs with alternatives to conventional network reinforcement, and allow more efficient use of existing assets through reducing peak demand. When connected behind the meter, batteries will smooth the peaky generation profile of wind farms and solar PV plants.

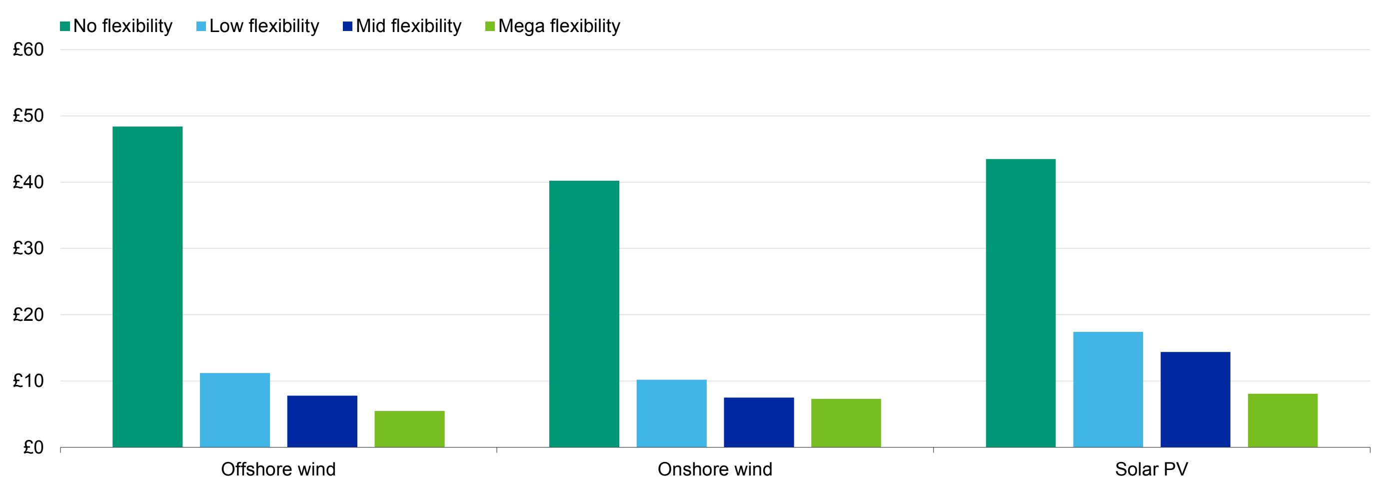
» **A lower-cost grid provides direct and indirect benefits for SO and TOs.** NGET as SO will earn modest incentives for keeping the national transmission grid in balance, and all three transmission owners will benefit in the near-term from delivering grid reinforcement at lower cost. In the longer term, TOs will benefit from more moderate growth of the industry's Regulated Asset Value (RAV) and consequent charges to customers, because it will reduce the risk of political or regulatory interventions.

» **Low risk of British electricity transmission assets becoming stranded.** Although growth of distributed storage will contribute to ongoing declines in volumes carried by the transmission network, the transmission networks will remain central to the British power system. NGET's role as system operator will become even more important as greater coordination between transmission and distribution networks becomes necessary.

EXHIBIT 1

Flexibility significantly lowers the marginal cost of adding renewables

Estimated system integration costs in 2030 (£/MWh)



Note: System integration costs for renewable technologies vs. nuclear.

Source: Strbac and Aunedi

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Renewable Energy – China: Favorable policy environment drives growth in China's renewable energy sector

Originally published on 6 September 2017

Growth in China's (A1 stable) renewable energy sector will continue to be driven by the ambitious 13th Five-Year Plan targets set by the government and its commitment to the Paris Agreement. China forecasts that the installed capacity from key renewable energy sources will reach at least 660GW in 2020 and the government has launched numerous regulatory directives to support the sector. Grid curtailment and overreliance on government subsidies are the near-term industry challenges, while a downtrend in tariffs will not have a material financial impact on renewable energy companies.

» **Strategic importance of renewable energy has been increasing in recent years.** This is due to the country's rising awareness of the need to combat air pollution and to reduce its reliance on coal fired power. China expects the share of non-fossil fuels will reach 38% in 2017 and we see this rising further to around 40% in 2020. At end 2016, renewable energy accounted for roughly 35% of national installed capacity.

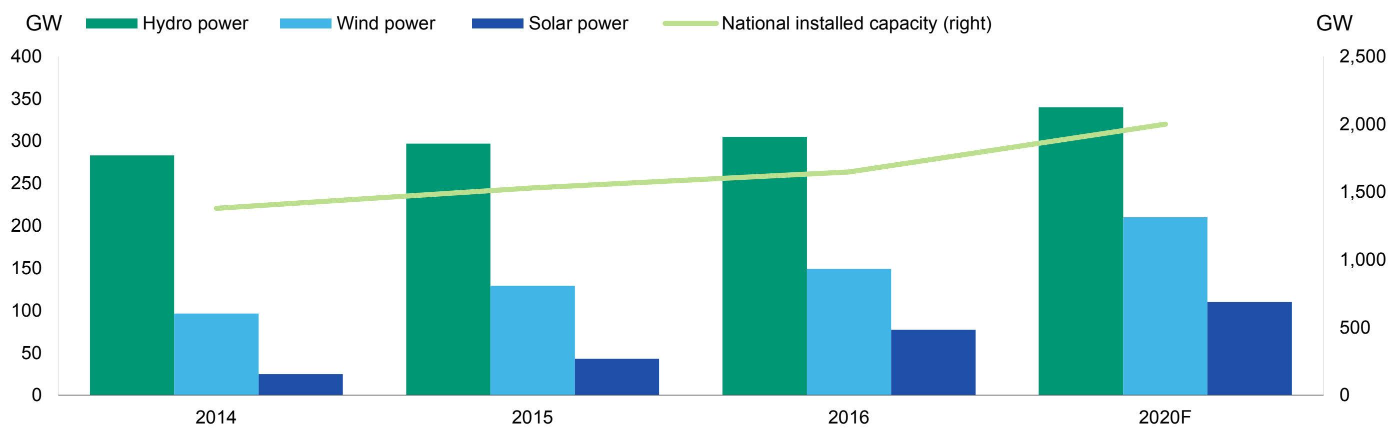
» **Commitment to reduce carbon risk drives government targets and policies, thereby fostering the development of renewable energy.** The Paris Agreement signed in 2016 reflects China's commitment to reduce carbon emissions. China's 13th Five-Year Plan (2016-2020) targets to increase the installed capacity of key renewable energy sources to at least 660GW in 2020, from 531GW in 2016. Correspondingly, the government has launched numerous regulatory directives and policies in recent years. We expect the favorable operating environment will continue to drive sector growth over the next five years.

» **Grid curtailment and overreliance on government subsidies are the key industry challenges.** Wind and solar power's curtailment rates reached a record-high in 2016, but government policies and guidance on capacity utilization and capacity additions will gradually ease the problem. The income shortfall in the renewable energy fund and the resultant delays in distribution of subsidies will increase renewable energy companies' working capital requirement and thereby their leverage.

» **Wind and solar power tariffs are on a downward trend in the near term, but the financial impact on renewable energy companies is manageable.** The downtrend in tariffs will increase price competitiveness against conventional power sources and pave the way for grid parity in the future. It also echoes China's reforms to liberalize the power market in the long term. The negative financial impact of tariff reductions on renewable energy companies will be offset by declining equipment costs and increasing capacity utilization.

EXHIBIT 1

Renewable energy capacity continuing to grow



Sources: Moody's Investors Service, China Electricity Council

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India: Strong growth prospects for renewables, but challenges from offtakers, evolving policy framework

Originally published on 26 June 2017

The Indian renewable energy market is likely to see strong growth over many years as India focuses on "greening" its energy mix, in line with commitments under the Paris agreement signed in December 2015. However, we also see challenges for renewable energy projects, notably weak off-taker credit quality and an evolving regulatory framework, as well as financing, execution risks, and aggressive bidding.

» **Emission reduction commitments will lead to a sharp rise in renewable energy capacity.** India targets 40% cumulative installed capacity to come from non-fossil fuel sources by 2030, from 30% currently, to meet its emission reduction commitments. The country plans to grow substantially its renewable energy capacity to 175GW by 2022, from 57GW currently. This growth will be driven by both the public and private sector.

» **Weak credit quality of off-takers is a key challenge.** State-owned distribution companies, the key off-takers for most renewable projects, typically have weak financial profiles, a key challenge for developers such as Neerg Energy (Ba3 stable). While there is no history of defaults under power purchase agreements (PPAs), payment delays are quite common.

» **Policy framework for renewables continues to evolve.** This presents a risk for renewable projects. For example, adherence to Renewable Purchase Obligations (RPOs) has been limited, leading to lower demand for renewable energy. Notwithstanding this, the Feed-in-Tariff (FiT) and competitive bidding guidelines for wind and solar projects are well established in India, thereby improving revenue visibility over the life of the PPAs.

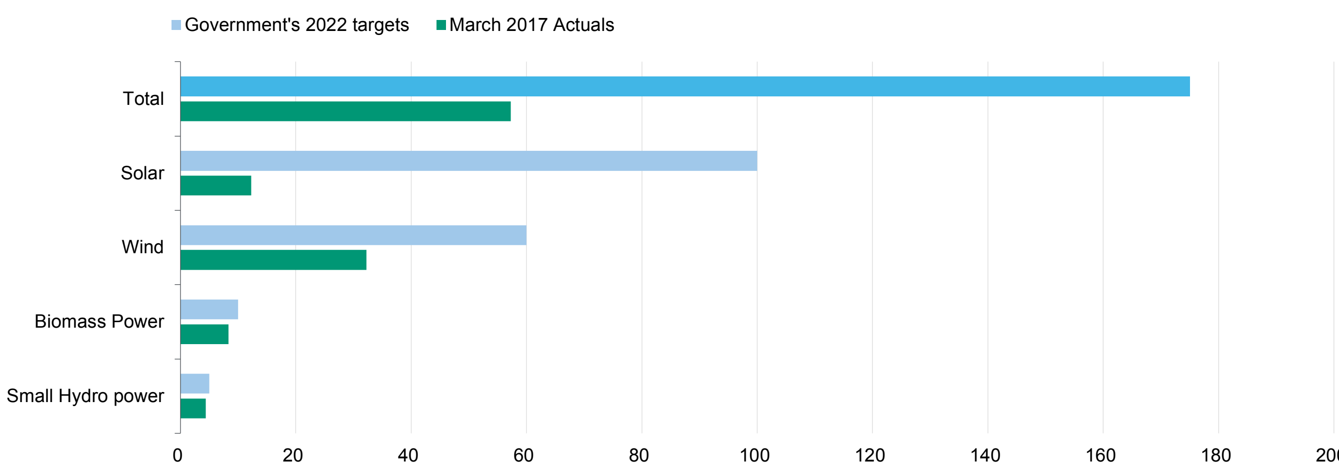
» **Execution risks from substantial capacity growth.** A large rise in renewable energy capacity would bring execution challenges including land acquisition, establishing resource quality, grid connectivity and availability. Low tariffs for recent solar auctions have cut the margin of error on cost assumptions, project delays, equipment quality, payment delays and curtailment. However, the sharp ongoing fall in panel prices partly mitigates these risks.

» **Foreign currency financing constrained by limited hedging products.** India needs to invest close to USD 150 billion to meet its 2022 renewable energy targets. With domestic banks constrained in their lending to renewable projects, foreign capital will play an important role in the future. Currently, a key hindrance is the limited hedging products available to fully cover the currency risk from PPAs being denominated in INR.

EXHIBIT 1

Indian government's ambitious renewable energy targets

Renewable Energy Capacity, GW



Sources: Moody's Investors Service, Government of India, Ministry of New and Renewable Energy

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Latin America: Compelling fundamentals and carbon reduction targets drive renewables growth

Originally published on 6 September 2017

Hydropower may be the dominant source of energy generation in some Latin American countries, but it is alternative renewable sources—onshore wind, solar photovoltaic, geothermal and biomass thermal-fired plants—that will enable the region to increase the share of carbon-free power in its energy mix as countries seek to hit carbon-emission reduction targets.

» **Renewable sources will account for a growing portion of the planned electricity supply in Latin America.** We estimate that the installed capacity of alternative renewables will double from 37 gigawatts to 75 gigawatts through 2025 on a consolidated basis in seven select countries in the region.

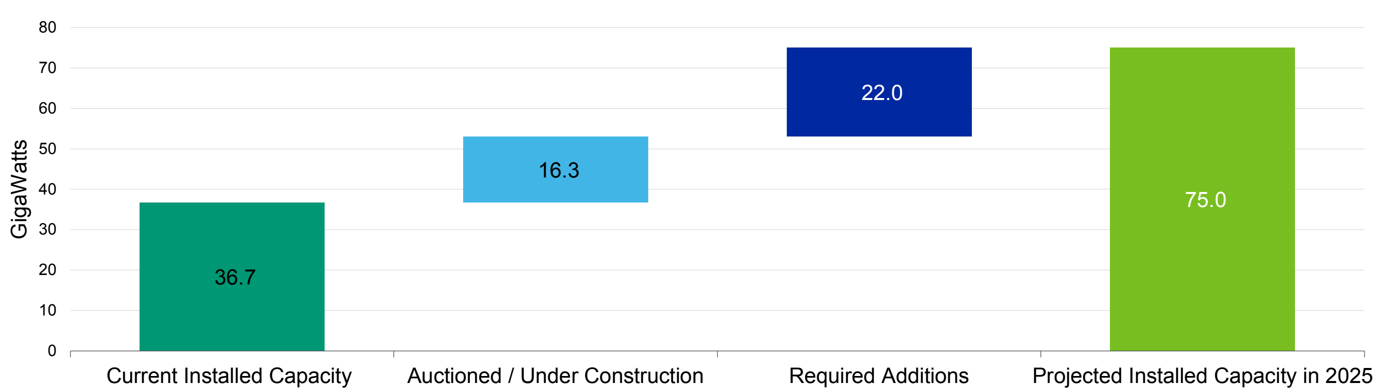
» **Ambitious carbon reduction commitments will drive renewables development.** Nearly all Latin American countries committed under the Paris Agreement to mitigate climate change through carbon reduction policies. Argentina and Mexico have the most ambitious carbon targets, while Uruguay is well placed to meet its goal with clean energy representing 97% of electricity output in 2016. Brazil has a large pipeline of renewables projects in construction, but subdued economic growth has put a pause on new auctions.

» **Compelling fundamentals and long-term contracts also support renewables growth.** Strong natural resources deriving from favorable climate conditions, a rapid decline in technology costs, supportive regulatory policies and fiscal incentives are facilitating the implementation of clean-energy sources across the region. From a credit perspective, Chile has the most favorable investment environment, due to the stability of its legal and institutional framework. In Peru, growing maturity on renewable auctions support lower price trends.

» **Renewable power projects are not insulated from risks.** Transmission bottlenecks, macroeconomic uncertainties, a trend of lower auction prices and increasing financing costs could all affect returns on investment and hinder the penetration of renewable resources.

» **Credit impact of grid diversification on incumbent thermal-fired generation companies will vary by country.** Incumbent power generators in Argentina, Chile and Uruguay are more exposed than their peers in Brazil, Peru and Colombia. Companies such as AES Gener S.A. (Baa3 stable), Empresa Electrica Angamos S.A. (Baa3 stable), Genneia S.A. (B3 positive) and Albanesi S.A. (B3 positive) have the largest exposure to long-term stranded asset risk.[1]

EXHIBIT 1
Expected addition in renewable power across Argentina, Brazil, Chile, Colombia, Mexico, Peru and Uruguay through 2025



Source: Moody's Investors Service

Endnote

[1] Coal and other and other fossil fuel thermal facilities carry a risk of becoming stranded, as the alternative renewable as the world engages in clean energy output. The financial risk on stranded assets relates to the potential economic loss arising from those being converted into a liability.

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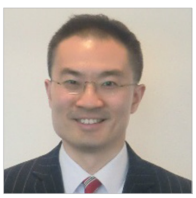

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EDH-7

Utility-Scale Solar 2016

An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States

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September 2017

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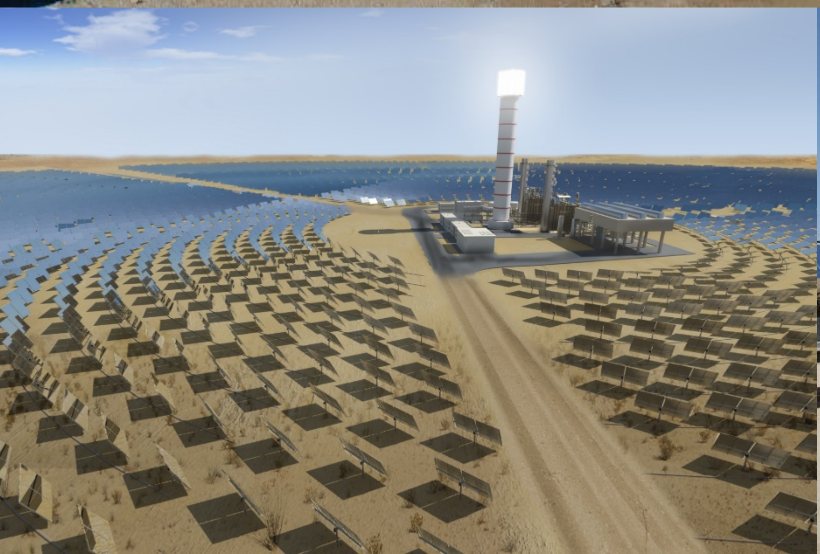

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List of Acronyms

AC	Alternating Current
c-Si	Crystalline Silicon
COD	Commercial Operation Date
CPV	Concentrating Photovoltaics
CSP	Concentrating Solar (Thermal) Power
DC	Direct Current
DIF	Diffuse Horizontal Irradiance
DNI	Direct Normal Irradiance
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EPC	Engineering, Procurement & Construction
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GHI	Global Horizontal Irradiance
FiT	Feed-in Tariff
ILR	Inverter Loading Ratio
ISO	Independent System Operator
ITC	Investment Tax Credit
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized Cost of Energy
MW	Megawatt(s)
NCF	Net Capacity Factor
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
PII	Permitting, Interconnection & Inspection
PPA	Power Purchase Agreement
PV	Photovoltaics
REC	Renewable Energy Credit
RTO	Regional Transmission Organization
TOD	Time of Delivery

Executive Summary

The utility-scale solar sector—defined here to include any ground-mounted photovoltaic ("PV"), concentrating photovoltaic ("CPV"), or concentrating solar thermal power ("CSP") project that is larger than 5 MW_{AC} in capacity—has led the overall U.S. solar market in terms of installed capacity since 2012. In 2016, the utility-scale sector installed more than 2.5 times as much new capacity as did the residential and commercial sectors combined, and is expected to maintain its market-leading position for at least another five years, driven in part by the December 2015 extension of the 30% federal investment tax credit ("ITC") through 2019. With seven new states having added their first utility-scale solar project in 2016, more than half of all states, representing all regions of the country, are now home to one or more utility-scale solar installations. For the first time ever, solar was the largest source of new U.S. capacity additions in 2016, accounting for 38% of all new capacity added to the grid, ahead of both natural gas and wind (utility-scale solar accounted for 70% of this 38%). This unprecedented and ongoing solar boom makes it difficult—yet more important than ever—to stay abreast of the latest utility-scale market developments and trends.

This report—the fifth edition in an ongoing annual series—is intended to help meet this need, by providing in-depth, annually updated, data-driven analysis of the utility-scale solar project fleet in the United States. Drawing on empirical project-level data from a wide range of sources, this report analyzes not just installed project prices—i.e., the traditional realm of most solar economic analyses—but also operating costs, capacity factors, and power purchase agreement ("PPA") prices from a large sample of utility-scale solar projects throughout the United States. Given its current dominance in the market, utility-scale PV also dominates much of this report, though data from CPV and CSP projects are also presented where appropriate.

Some of the more-notable findings from this year's edition include the following:

- ***Installation Trends:*** Among the total population of utility-scale PV projects from which data samples are drawn, several trends are worth noting due to their influence on (or perhaps reflection of) the cost, performance, and PPA price data analyzed later. For example, the use of solar tracking devices (overwhelmingly single-axis, east-west tracking—though a few dual-axis tracking projects have come online in Texas in recent years) dominates 2016 installations with nearly 80% of all new capacity. In a reflection of the ongoing geographic expansion of the market beyond California and the high-insolation Southwest, the median long-term insolation level at newly built project sites declined again in 2016. While new fixed-tilt projects are now seen predominantly in less-sunny regions (GHI < 5 $kWh/m^2/day$), tracking projects are increasingly pushing into these same regions. Meanwhile, the median inverter loading ratio—i.e., the ratio of a project's DC module array nameplate rating to its AC inverter nameplate rating—has stabilized in 2016 at 1.3 for both tracking and fixed-tilt projects.

- ***Installed Prices:*** Median installed PV project prices within a sizable sample have steadily fallen by two-thirds since the 2007-2009 period, to $\$2.2/W_{AC}$ (or $\$1.7/W_{DC}$) for projects completed in 2016. The lowest 20^{th} percentile of projects within our 2016 sample (of 88 PV projects totaling 5,497 MW_{AC}) were priced at or below $\$2.0/W_{AC}$, with the lowest-priced projects around $\$1.5/W_{AC}$. Projects using single-axis trackers had an upfront cost premium of about \$0.15/W_{AC} compared to fixed-tilt installations. Overall price dispersion across the entire sample and across geographic regions decreased significantly in 2016.

- ***Operation and Maintenance ("O&M") Costs:*** What limited empirical O&M cost data are publicly available suggest that PV O&M costs were in the neighborhood of \$18/kW_{AC}-year, or \$8/MWh, in 2016. These numbers—from an extremely limited sample—include only those costs incurred to directly operate and maintain the generating plant, and should not be confused with total operating expenses, which would also include property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead.

- ***Capacity Factors:*** The cumulative net AC capacity factors of individual projects in a sample of 260 PV projects totaling 8,733 MW_{AC} range widely, from 15.4% to 35.5%, with a sample mean of 25.8%, a median of 26.3%, and a capacity-weighted average of 27.3%. This project-level variation is based on a number of factors, including the strength of the solar resource at the project site, whether the array is mounted at a fixed tilt or on a tracking mechanism, the inverter loading ratio, degradation, and curtailment. Changes in at least the first three of these factors drove mean capacity factors higher from 2010-vintage (at 22.0%) to 2013-vintage (at 26.9%) projects, where they've remained fairly steady among both 2014-vintage (at 26.2%) and 2015-vintage (at 26.5%) projects as an ongoing increase in the prevalence of tracking has been offset by a build-out of lower resource sites. Turning to other technologies, the three CPV projects in our sample have been underperforming relative to similarly situated PV projects and, in at least two cases, ex-ante expectations. Likewise, although several CSP projects in the United States are seemingly matching ex-ante capacity factor expectations, at least three others—each beset by shut-downs of varying duration in 2016—continue to underperform relative to projected long-term, steady-state levels.

- ***PPA Prices:*** Driven by lower installed project prices and improving capacity factors, levelized PPA prices for utility-scale PV have fallen dramatically over time, by \$20-\$30/MWh per year on average from 2006 through 2012, with a smaller price decline of ~\$10/MWh per year evident from 2013 through 2016. Most recent PPAs in our sample—including many outside of California and the Southwest—are priced at or below \$50/MWh levelized (in real 2016 dollars), with a few priced as aggressively as ~\$30/MWh. Though impressive in pace and scale, these falling PPA prices have been offset to some degree by declining wholesale market value within high penetration markets like California, where in 2016 a MWh of solar generation was worth just 83% of a MWh of flat, round-the-clock generation within CAISO's real-time wholesale energy market. Adding battery storage is one way to at least partially restore the value of solar, and a recent PPA in Arizona for a 100 MW PV project coupled with 30 MW of 4-hour battery storage—priced at just \$45/MWh, with storage accounting for roughly one-third of the price—suggests that PV plus battery storage is becoming more cost-effective, and could thrive in the coming years.

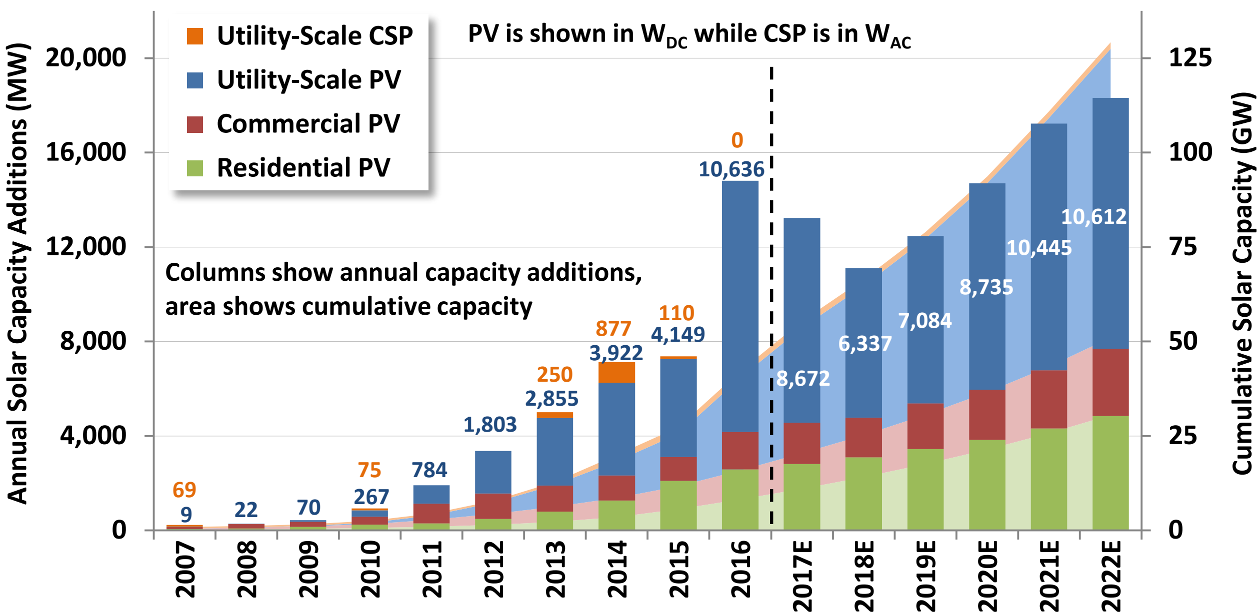
Looking ahead, the amount of utility-scale solar capacity in the development pipeline suggests continued momentum and a significant expansion of the industry in future years. At the end of 2016, there were at least 121.4 GW of utility-scale solar power capacity within the interconnection queues across the nation, 83.3 GW of which first entered the queues in 2016 (presumably encouraged by the December 2015 ITC extension). Moreover, the growth within these queues is widely distributed across all regions of the country: California and the Southeast each account for 23% of the 83.3 GW, followed by the Northeast (17%), the Southwest (16%), the Central region (12%), Texas (6%) and the Northwest (3%). Though not all of these projects will ultimately be built, the widening geographic distribution of solar projects within these queues is as clear of a sign as any that the utility-scale market is maturing and expanding outside of its traditional high-insolation comfort zones.

Finally, this year's edition of the report includes a number of new elements worth briefly highlighting:

- For the first time, we've included capacity factor and PPA price data for projects located in Hawaii, which has been a pioneer in implementing projects that include PV plus battery storage.
- A new Figure 2 shows solar's historical contribution to overall U.S. capacity additions for the country as a whole.
- A new Table 1 shows solar penetration rates (calculated as in-state solar generation as a percentage of both total in-state generation and in-state load) for the "top ten" states in 2016.
- Section 2.2 incorporates confidential installed price data obtained from the EIA under a non-disclosure agreement for PV projects that achieved commercial operations in 2013-2015, bolstering our confidence in the quality of our data in those years.
- We've included three text boxes in the PPA price section (Section 2.5) that explore (1) the declining wholesale market value of solar in California (including curtailment data); (2) the specifications and PPA prices from the first three PV plus battery storage projects to enter our sample; and (3) the levelized cost of energy ("LCOE") of utility-scale PV, as compared to PPA prices.
- We've set up several data visualizations that are housed on the home page for this report: https://utilityscalesolar.lbl.gov. There you can also find a data workbook corresponding to the report's figures, a slide deck, and (eventually) a webinar recording.

1. Introduction

"Utility-scale solar" refers to large-scale photovoltaic ("PV"), concentrating photovoltaic ("CPV"), and concentrating solar thermal power ("CSP") projects that typically sell solar electricity directly to utilities or other buyers, rather than displacing onsite consumption (as has been the more-traditional application for PV in the commercial and residential markets).[1] Although utility-scale CSP has a much longer history than utility-scale PV (or CPV),[2] and saw substantial new deployment between 2013 and 2015, the utility-scale solar market in the United States has been dominated by PV over the past decade. By the end of 2016, there was more than nine times as much utility-scale PV capacity operating in the United States as there was CSP capacity. PV's increasing dominance follows explosive growth in recent years, culminating in a deployment spike of more than 10.6 GW_{DC} of utility-scale PV in 2016 (Figure 1).



Source: GTM/SEIA (2010-2017), LBNL's "Tracking the Sun" and "Utility-Scale Solar" databases

Figure 1. Historical and Projected PV and CSP Capacity by Sector in the United States[3]

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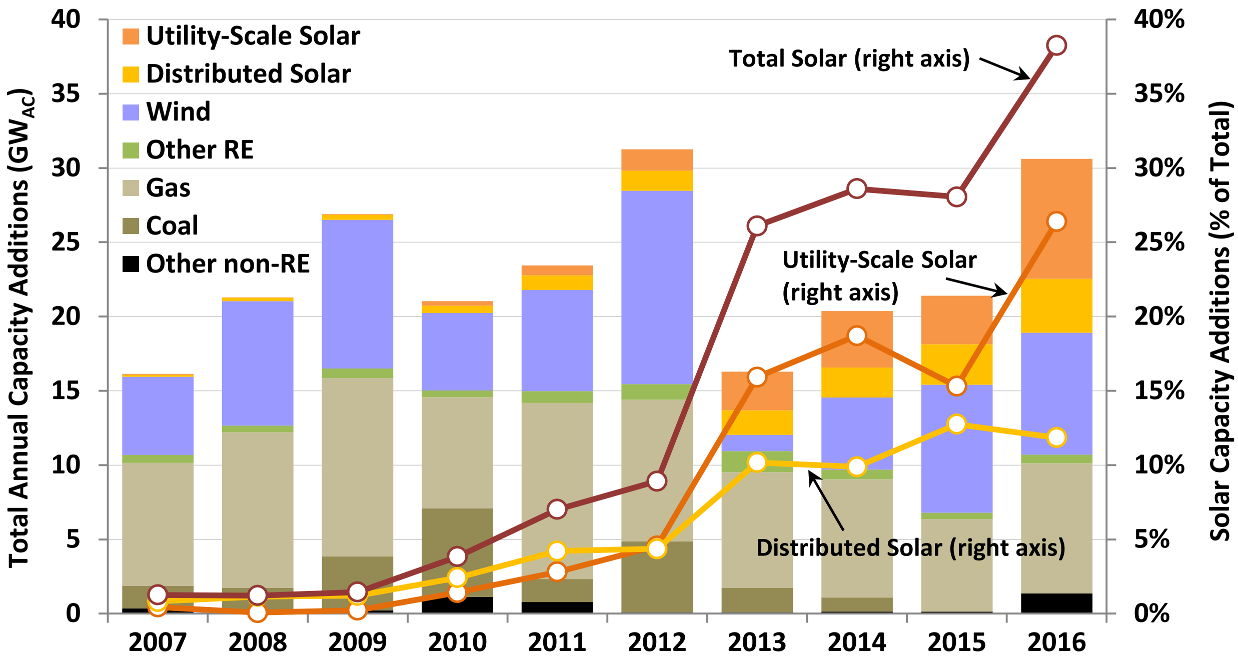
[1] PV and CPV projects use silicon, cadmium-telluride, or other semi-conductor materials to directly convert sunlight into electricity through the photoelectric effect (with CPV using lenses or mirrors to concentrate the sun's energy). In contrast, CSP projects typically use either parabolic trough or, more recently, "power tower" technology to produce steam that powers a conventional steam turbine.

[2] Nine large parabolic trough projects totaling nearly 400 MW_{AC} began operating in California in the late 1980s/early 1990s, whereas it was not until 2007 that the United States saw its first PV project in excess of 5 MW_{AC}.

[3] GTM/SEIA's definition of "utility-scale" reflected in Figure 1 is not entirely consistent with how it is defined in this report (see the text box—*Defining "Utility-Scale"*—in this chapter for a discussion of different definitions of "utility-scale"). In addition, the PV capacity data in Figure 1 are expressed in DC terms, which is not consistent with the AC capacity terms used throughout the rest of this report (the text box—*AC vs. DC*—at the start of Chapter 2 discusses why AC capacity ratings make more sense for utility-scale PV projects). Despite these inconsistencies, the data are nevertheless useful for the purpose of providing a general sense for the size of the utility-scale market and demonstrating relative trends between different market segments and technologies.

Led by the utility-scale sector, solar power has comprised a sizable share—more than 25%—of all generating capacity additions in the United States in each of the past four years. In 2016, it constituted 38% of all U.S. capacity additions (with utility-scale solar accounting for 26%) and was the largest source of new capacity, ahead of both natural gas and wind (Figure 2).[4]



Source: ABB, AWEA, GTM/SEIA, Berkeley Lab

Figure 2. Relative Contribution of Generation Types to Annual Capacity Additions

Utility-scale PV's strong showing in 2016 was due, in part, to what had been, up until late-December 2015, a scheduled end-of-2016 reversion of the 30% federal investment tax credit ("ITC") to 10%. The December 2015 extension of the 30% ITC through 2019 brought several other changes as well. For non-residential projects (including utility-scale), the prior requirement that a project be "placed in service" (i.e., operational) by the reversion deadline was relaxed to enable projects that merely "start construction" by the deadline to also qualify. Moreover, rather than reverting from 30% directly to 10% in 2020, the credit will instead gradually phase down to 10% over several years: to 26% in 2020, 22% in 2021, and finally 10% for projects that start construction in 2022 or thereafter.[5]

Despite a substantial amount of new capacity having been "pulled forward" into 2016 in order to capture the credit before its originally scheduled expiration, with the long-term extension of the ITC in place, the utility-scale PV market is expected to remain strong at least through the early 2020s. This unprecedented and ongoing boom in the utility-scale market makes it increasingly

[4] Data presented in Figure 2 are based on gross capacity additions, not considering retirements. Furthermore, they include only the 50 U.S. states, not U.S. territories, and rely on GTM/SEIA's definition of utility-scale solar (as described in the text box on page 4).

[5] In addition, any project that qualified for a higher-than-10% ITC by starting construction prior to 2022 must also be placed in service by the end of 2023 in order to retain that higher credit; otherwise the credit drops to 10%.

difficult—yet, at the same time, more important than ever—to stay abreast of the latest developments and trends.

This report—the fifth edition in an ongoing annual series—is designed to help identify and track important trends in the market by compiling and analyzing the latest empirical data from the rapidly growing fleet of utility-scale solar projects in the United States. As in past years, this fifth edition maintains our definition of "utility-scale" to include any ground-mounted project with a capacity rating larger than 5 MW_{AC} (the text box on the next page describes the challenge of defining "utility-scale" and provides justification for the definition used in this report). As in the previous edition, we break out coverage of PV and CSP into separate chapters (Chapters 2 and 3, respectively), to simplify reporting and enable readers who are more interested in just one of these technologies to more-quickly access what they need.[6] Within each of these two chapters, we first present installation and technology-related trends (e.g., module and mounting preferences, inverter loading ratios, troughs vs. towers, etc.) among the existing fleet, before turning to empirical data on installed project prices (in $/W terms), operation and maintenance ("O&M") costs, project performance (as measured by capacity factor), and power purchase agreement ("PPA") prices (the text box on this page—*A Note on the Data Used in this Report*—provides information about the sources of these data). Chapter 4 then concludes with a brief look ahead.

A Note on the Data Used in this Report

The data sources mined for this report are diverse, and vary depending on the type of data being analyzed, but in general include the Federal Energy Regulatory Commission ("FERC"), the U.S. Energy Information Administration ("EIA"), state and federal incentive programs, state and federal regulatory commissions, industry news releases, trade press articles, and communication with project owners and developers. In most cases, the data are drawn from a sample, rather than the full universe, of solar power projects installed in the United States. Sample size varies depending on the technology (PV vs. CSP) and the type of data being analyzed, and not all projects have sufficiently complete data to be included in all data sets. Furthermore, the data vary in quality, both across and within data sources. As such, emphasis should be placed on overall trends, rather than on individual data points. Finally, each section of this document primarily focuses on historical market data, with an emphasis on 2016; with some limited exceptions (including Figure 1 and Chapter 4), the report does not discuss forecasts or seek to project future trends.

Finally, we note that this report complements several other related studies and ongoing research activities at LBNL and elsewhere. Most notably, LBNL's annual *Tracking the Sun* report series analyzes the latest trends in residential and commercial PV project pricing, while NREL's PV system cost benchmarks are based on bottom-up engineering models of the overnight capital cost of residential, commercial, and utility-scale systems (the text box on page 20 provides more information on NREL's utility-scale cost benchmarks). All of this work is funded by the Department of Energy's ("DOE") SunShot Initiative, which aims to reduce utility-scale solar's levelized cost of electricity ("LCOE") to $30/MWh (in 2016 dollars) by 2030. Most of LBNL's solar-related work can be found at emp.lbl.gov/projects/solar, while information on the SunShot Initiative can be found at energy.gov/eere/sunshot/sunshot-initiative.

[6] Select data pertaining to the few CPV projects in our sample continue to be presented, where warranted, along with the corresponding data for PV projects in Chapter 2.

Defining "Utility-Scale"

Determining which electric power projects qualify as "utility-scale" (as opposed to commercial- or residential-scale) can be a challenge, particularly as utilities begin to focus more on distributed generation. For solar PV projects, this challenge is exacerbated by the relative homogeneity of the underlying technology. For example, unlike with wind power, where there is a clear difference between utility-scale and residential wind turbine technology, with solar, very similar PV modules to those used in a 5 kW residential rooftop system might also be deployed in a 100 MW ground-mounted utility-scale project. The question of where to draw the line is, therefore, rather subjective. Though not exhaustive, below are three different—and perhaps equally valid—perspectives on what is considered to be "utility-scale":

- Through its Form EIA-860, the Energy Information Administration ("EIA") collects and reports data on all generating plants of at least 1 MW of capacity, regardless of ownership or whether interconnected in front of or behind the meter (note: this report draws heavily upon EIA data for such projects).
- In their *Solar Market Insight* reports, Greentech Media and SEIA ("GTM/SEIA") define utility-scale by offtake arrangement rather than by project size: any project owned by or that sells electricity directly to a utility (rather than consuming it onsite) is considered a "utility-scale" project. This definition includes even relatively small projects (e.g., 100 kW) that sell electricity through a feed-in tariff ("FiT") or avoided cost contract (Munsell 2014).
- At the other end of the spectrum, some financiers define utility-scale in terms of investment size, and consider only those projects that are large enough to attract capital on their own (rather than as part of a larger portfolio of projects) to be "utility-scale" (Sternthal 2013). For PV, such financiers might consider a 25 MW (i.e., ~$50 million) project to be the minimum size threshold for utility-scale.

Though each of these three approaches has its merits, this report adopts yet a different approach: utility-scale solar is defined herein as any ground-mounted solar project that is larger than 5 MW_{AC} (separately, ground-mounted PV projects of 5 MW_{AC} or less, along with roof-mounted systems of all sizes, are analyzed in LBNL's annual "Tracking the Sun" report series).

This definition is grounded in consideration of the four types of data analyzed in this report: installed prices, O&M costs, capacity factors, and PPA prices. For example, setting the threshold at 5 MW_{AC} helps to avoid smaller projects that are arguably more commercial in nature, and that may make use of net metering and/or sell electricity through FiTs or other avoided cost contracts (any of which could skew the sample of PPA prices reported later). A 5 MW_{AC} limit also helps to avoid specialized (and therefore often high-cost) applications, such as carports or projects mounted on capped landfills, which can skew the installed price sample. Meanwhile, ground-mounted systems are more likely than roof-mounted systems to be optimally oriented in order to maximize annual electricity production, thereby leading to a more homogenous sample of projects from which to analyze performance, via capacity factors. Finally, data availability is often markedly better for larger projects than for smaller projects (in this regard, even our threshold of 5 MW_{AC} might be too small).

Some variation in how utility-scale solar is defined is natural, given the differing perspectives of those establishing the definitions. Nevertheless, the lack of standardization does impose some limitations. For example, GTM/SEIA's projections of the utility-scale market (shown in Figure 1) may be useful to readers of this report, but the definitional differences noted above (along with the fact that GTM/SEIA reports utility-scale capacity in DC rather than AC terms) make it harder to synchronize the data presented herein with their projections. Similarly, institutional investors may find some of the data in this report to be useful, but perhaps less so if they are only interested in projects larger than 20 MW_{AC}.

Until consensus emerges as to what makes a solar project "utility-scale," a simple best practice is to be clear about how one has defined it (and why), and to highlight any important distinctions from other commonly used definitions—hence this text box.

2. Utility-Scale Photovoltaics (PV)

At the end of 2016, 427 utility-scale (i.e., ground-mounted and larger than 5 MW_{AC}) PV projects totaling 16,439 MW_{AC} were fully online in the United States.[7] Nearly 45% of this capacity—i.e., 146 projects totaling 7,385 MW_{AC}—achieved commercial operation in 2016. The next five sections of this chapter analyze large samples of this population, focusing on installation and technology trends, installed prices, operation and maintenance costs, capacity factors, and finally, PPA prices. Sample size varies by section, and not all projects have sufficiently complete data to be included in all five samples and sections.

For reasons described in the text box below, all capacity numbers (as well as other metrics that rely on capacity, like $/W installed prices) are expressed in AC terms throughout this report, unless otherwise noted. In addition, all data involving currency are reported in constant or real U.S. dollars—in this edition, 2016 dollars.[8]

AC vs. DC: AC Capacity Ratings Are More Appropriate for Utility-Scale Solar

Because PV modules are rated under standardized testing conditions in direct current ("DC") terms, PV project capacity is also commonly reported in DC terms, particularly in the residential and commercial sectors. For utility-scale PV projects, however, the alternating current ("AC") capacity rating—measured by the combined AC rating of the project's inverters—is more relevant than DC, for two reasons:

1) All other conventional and renewable utility-scale generation sources (including concentrating solar thermal power, or CSP) to which utility-scale PV is compared are described in AC terms—with respect to their capacity ratings, their per-unit installed and operating costs, and their capacity factors.

2) Utility-scale PV project developers have, in recent years, increasingly oversized the DC PV array relative to the AC capacity of the inverters (described in more detail in later sections of this chapter, and portrayed in Figure 7). This increase in the "inverter loading ratio" boosts revenue (per unit of AC capacity) and, as a side benefit, increases AC capacity factors. In these cases, the difference between a project's DC and AC capacity ratings will be significantly larger than one would expect based on conversion losses alone, and since the project's output will ultimately be constrained by the inverters' AC rating, the project's AC capacity rating is the more appropriate rating to use.

Except where otherwise noted, this report defaults to each project's AC capacity rating when reporting capacity (MW_{AC}), installed costs or prices ($/$W_{AC}$), operating costs ($/kW_{AC}-year), and AC capacity factor.

[7] Because of differences in how "utility-scale" is defined (e.g., see the text box at the end of Chapter 1), the total amount of capacity in the PV project population described in this chapter cannot necessarily be compared to other estimates (e.g., from GTM Research and SEIA (2017)) of the amount of utility-scale PV capacity online at the end of 2016. For instance, Figure 5 shows that a lower amount of utility-scale PV capacity was installed in 2015 than in 2014, which stands in contrast to GTM Research and SEIA, but is the result of these definitional differences (in addition to our policy of including in each calendar year only those PV projects that have become fully operational).

[8] Conversions between nominal and real dollars use the implicit gross domestic product ("GDP") deflator. Historical conversions use the actual GDP deflator data series from the U.S. Bureau of Economic Analysis, while future conversions (e.g., for PPA prices) use the EIA's projection of the GDP deflator in *Annual Energy Outlook 2017* (Energy Information Administration (EIA) 2017).

2.1 Installation and Technology Trends Among the PV Project Population (427 projects, 16,439 MW_{AC})

Before progressing to analysis of project-level data on installed prices, operating costs, capacity factors, and PPA prices, this section analyzes trends in utility-scale PV project installations and technology configurations among the *entire population* of PV projects from which later data samples are drawn. The intent is to explore underlying trends in the characteristics of this fleet of projects that could potentially influence the cost, performance, and/or PPA price data presented and discussed in later sections.

States with utility-scale PV projects now outnumber those without

Figure 3 overlays the location of every utility-scale PV project in the LBNL population (including four CPV projects) on a map of solar resource strength in the United States, as measured by global horizontal irradiance ("GHI").[9] Figure 3 also defines the regions that are used for regional analysis throughout this report. Individual project markers indicate mounting and module type, delineating between projects with arrays mounted at a fixed tilt versus on tracking devices that follow the position of the sun,[10] and between projects that use crystalline silicon ("c-Si") versus thin-film (primarily cadmium-telluride, or "CdTe") modules. Figure 4, meanwhile, provides a sense for how regional deployment of utility-scale solar has evolved over time.

As shown in Figure 3, most of the projects (and capacity) are located in California and the Southwest, where the solar resource is the strongest (and where state-level policies such as renewable portfolio standards, and in some cases state-level tax credits, have encouraged utility-scale solar development). Figure 4 shows that through 2014, all other regions regularly accounted for just a small amount of total new (and cumulative) capacity. But starting in 2015 and then again in 2016, these other regions besides California and the Southwest burst onto the scene, contributing ~30% of all new capacity in each year (up from ~10% in 2013 and 2014). Conversely, California's share of the market dropped from 69% and 76% in 2013 and 2014 to 47% and 40% in 2015 and 2016, respectively.[11]

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[9] Global Horizontal Irradiance (GHI) is the total solar radiation received by a surface that is held parallel to the ground, and includes both direct normal irradiance (DNI) and diffuse horizontal irradiance (DIF). DNI is the solar radiation received directly by a surface that is always held perpendicular to the sun's position (i.e., the goal of dual-axis tracking devices), while DIF is the solar radiation that arrives indirectly, after having been scattered by the earth's atmosphere. The GHI data represent average irradiance from 1998-2009 (Perez 2012).

[10] All but eight of the 263 PV projects in the population that use tracking systems use horizontal single-axis trackers (which track the sun from east to west each day). In contrast, five recently built PV projects in Texas by OCI Solar, along with three CPV projects (and two CSP power tower projects described later in Chapter 3), use dual-axis trackers (i.e., east to west daily *and* north to south over the course of the year). For PV, where direct focus is not as important as it is for CPV or CSP, dual-axis tracking is a harder sell than single-axis tracking, as the roughly 10% boost in generation (compared to single-axis, which itself can increase generation by ~20%) often does not outweigh the incremental capital and O&M costs (plus risk of malfunction), depending on the PPA price.

[11] Despite its declining market share, no state has ever added more utility-scale PV capacity in a single year than California did in 2016, with nearly 3 GW_{AC} spread among nearly 50 new utility-scale PV projects.

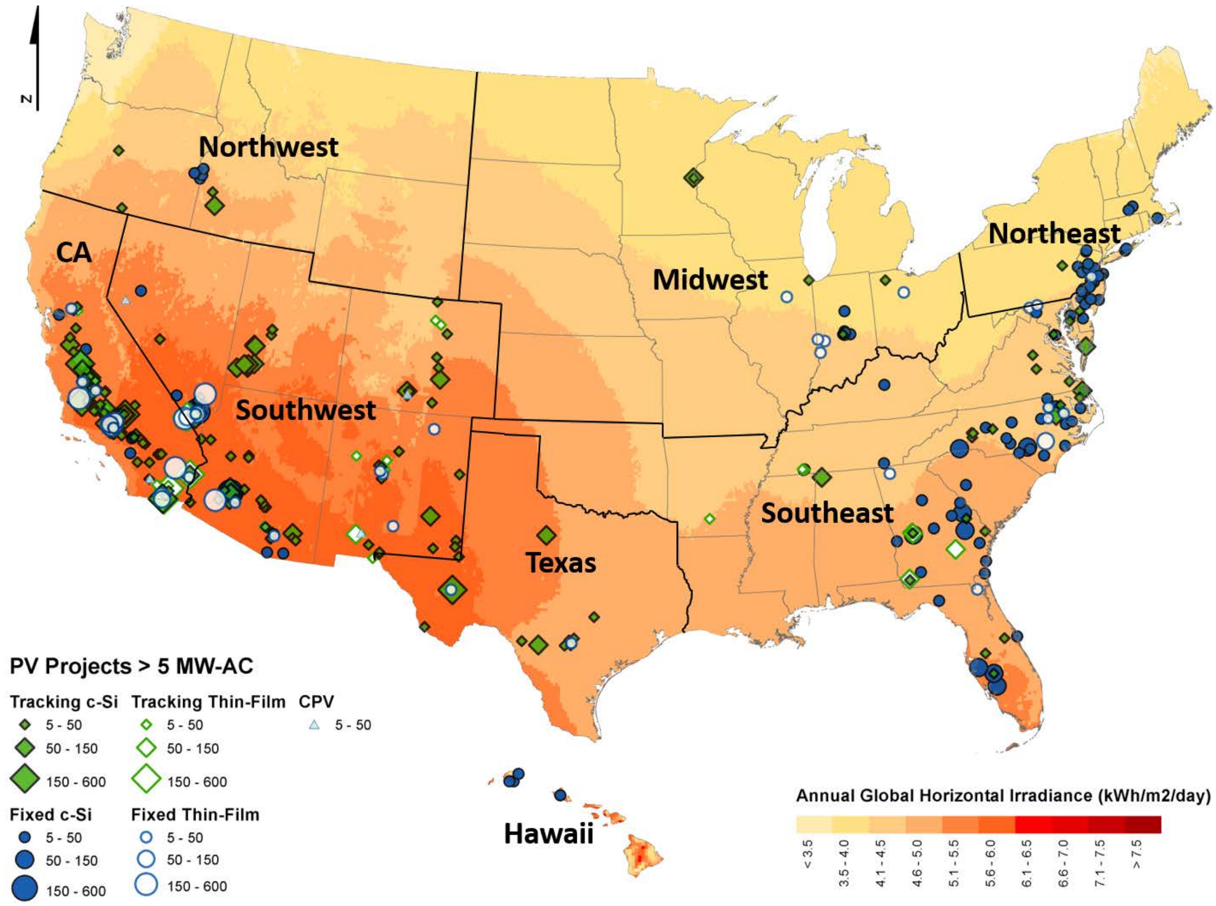


Figure 3. Map of Global Horizontal Irradiance (GHI) and Utility-Scale PV Projects

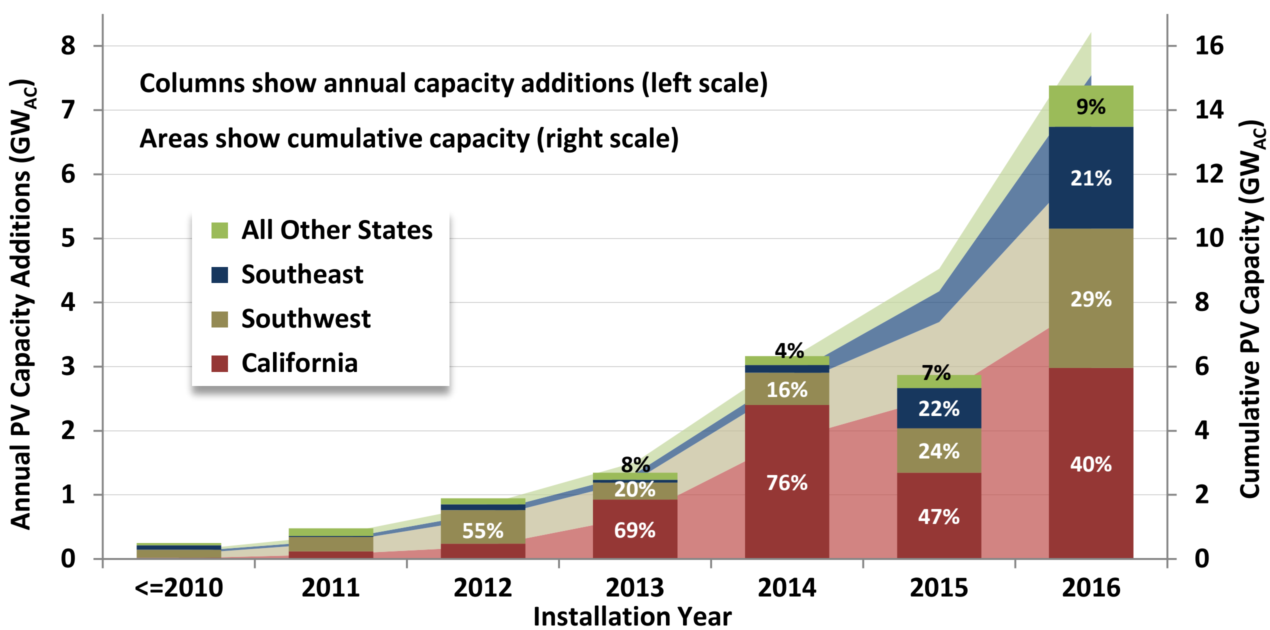


Figure 4. Annual and Cumulative Utility-Scale PV Capacity by U.S. Region

With the Northwest region's first utility-scale PV projects coming online in 2016, utility-scale solar is now present in all seven regions in the mainland United States and Hawaii. Seven new states—the most new entrants ever in a single year—added their first utility-scale PV projects in 2016,[12] bringing the total to 29 states—i.e., more than half of all states—that are now home to utility-scale solar projects larger than 5 MW_{AC}.

Table 1. U.S. Solar Power Rankings in 2016: the Top 10 States

State	Solar generation as a % of in-state generation		Solar generation as a % of in-state load	
	All Solar	Utility-Scale Solar Only	All Solar	Utility-Scale Solar Only
California	12.6%	8.3%	9.8%	6.5%
Hawaii	8.5%	1.0%	8.7%	1.0%
Vermont	8.2%	4.0%	2.8%	1.4%
Nevada	6.8%	5.8%	7.4%	6.4%
Massachusetts	6.0%	2.2%	3.7%	1.4%
Arizona	4.4%	2.9%	6.1%	4.0%
New Jersey	3.5%	1.3%	3.7%	1.4%
North Carolina	3.1%	2.9%	3.0%	2.9%
New Mexico	3.0%	2.4%	4.2%	3.5%
Utah	2.7%	2.3%	3.4%	2.9%
Rest of U.S.	*0.3%*	*0.1%*	*0.3%*	*0.1%*
TOTAL U.S.	**1.3%**	**0.8%**	**1.4%**	**0.9%**

Source: EIA's Electric Power Monthly (February 2017)

With recent growth, some states have realized or are approaching 10% solar energy penetration. Table 1 lists the top 10 states based on actual solar generation in 2016—for all market segments as well as just utility-scale[13]—divided by total in-state electricity generation (left half of table) and in-state load (right half). When considering the entire solar market (i.e., both distributed and utility-scale), California and Hawaii top the list regardless of whether penetration is based on total generation or total load, while other states—most notably Vermont—move up or down the list depending on how penetration is calculated. In 2016, five states achieved solar penetration levels of 6% or higher when total solar penetration is based on generation (four states topped 6% when penetration is based on load), while solar penetration across the entire United States stood

[12] Oregon energized its first seven projects in 2016 (a total of 63 MW_{AC}) while two large projects (totaling 120 MW_{AC}) came online in neighboring Idaho. Minnesota (107 MW_{AC}) entered our map with the aptly named North Star Solar Project (for now, the northern-most utility-scale PV project in our database) and the first tranche of the Aurora project portfolio. Representative of the strong growth in the Southeast, Virginia (137 MW_{AC}), Alabama (75 MW_{AC}), Kentucky (10 MW_{AC}), and South Carolina (7 MW_{AC}) all brought their first utility-scale solar projects online in 2016.

[13] The distinction between utility-scale solar and the rest of the market in Table 1 is based on the EIA's 1 MW_{AC} capacity threshold, which differs from the 5 MW_{AC} threshold adopted in this report.

at 1.3-1.4%.[14] Penetration rates for just utility-scale are, of course, lower than for the market as a whole, with California and Nevada leading the pack.

Tracking c-Si projects dominate 2016 additions

Figure 5 shows the same data as Figure 4, but broken out by technology configuration (mounting and module type) rather than location. The percentage of newly built projects using tracking increased from 63% in 2015 to 71% in 2016 (in capacity terms, from 70% in 2015 to 79% in 2016). Although tracking has been the dominant mounting choice for c-Si projects for roughly six years now (as tracking costs have come down, reliability has improved, and the 30% ITC has helped defray the incremental up-front cost), the pairing of tracking with thin-film modules is a more-recent phenomenon, driven in large part by significant improvements in the efficiency of CdTe modules in recent years.[15] As was the case for the first time in 2014, more new thin-film projects used tracking (15 projects) than fixed-tilt mounts (6 projects) in 2016 as well. Furthermore, as in 2015, the *capacity* of new thin-film projects using tracking (1,107 MW_{AC}) again surpassed that of fixed-tilt thin-film projects (620 MW_{AC}) by a wide margin in 2016.

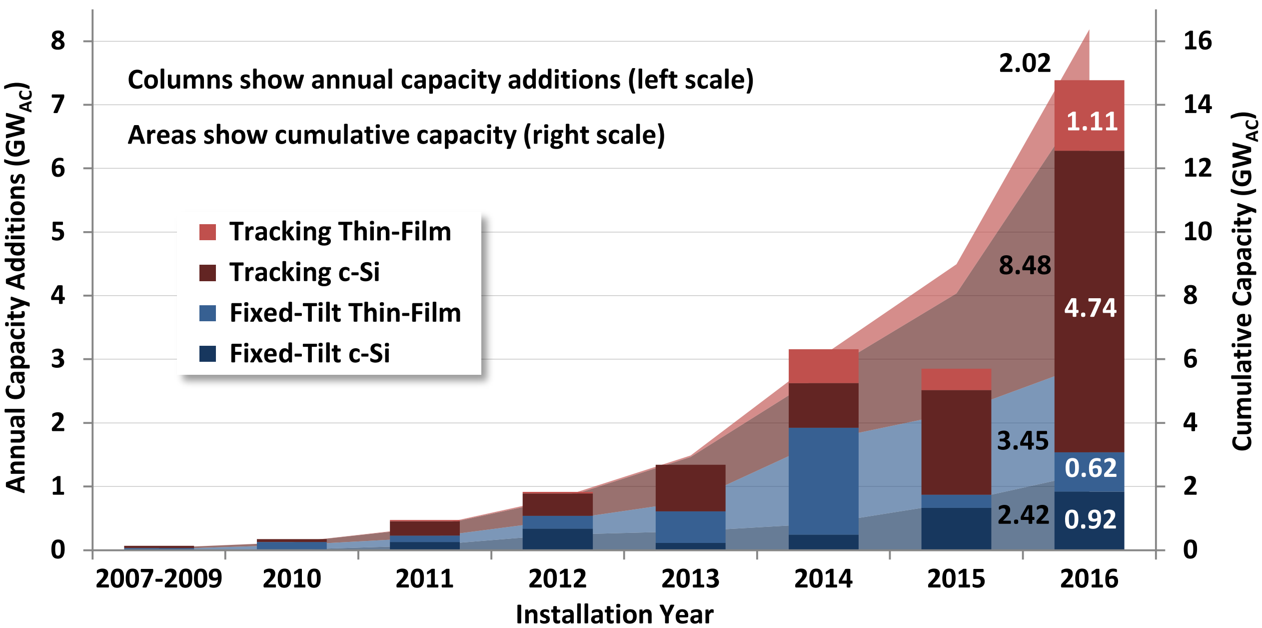


Figure 5. Annual and Cumulative Utility-Scale PV Capacity by Module and Mounting Type

[14] These 2016 penetration numbers do not fully capture the generation contribution of the large amount of new solar power capacity added during 2016, particularly if added towards the end of the year.

[15] Prior to 2014, only two thin-film tracking projects had ever been built in the United States, in stark contrast to more than one hundred c-Si tracking projects. Tracking has not been as common among thin-film projects historically, largely because the lower efficiency of thin-film relative to c-Si modules in the past required more land area per nameplate MW—a disadvantage exacerbated by the use of trackers. In recent years, however, leading thin-film manufacturer First Solar has increased the efficiency of its CdTe modules at a faster pace than its multi-crystalline silicon competitors, such that at the end of 2016, First Solar's CdTe module efficiency stood at 16.6%, roughly on par with multi-crystalline at ~16%-17% (though both still lag *mono*-crystalline modules by several percentage points—e.g., SunPower's E20 series at 20.5% or the mono PERC modules of Trina, Jinko and Canadian Solar at ~18.5%).

As was also the case in 2015, c-Si modules were the dominant choice for utility-scale solar additions in 2016, with 5.66 GW_{AC} of new capacity broadly distributed between Trina Solar (22% market share), Jinko Solar (14%), Canadian Solar (14%), SunPower (8%), and a number of other manufacturers having a market share of less than 5% each. In contrast, First Solar, which manufactures CdTe modules, accounts for nearly all (97%) of the 1.73 GW_{AC} of new thin-film capacity added to the project population in 2016, with the remainder (45 MW_{AC}) coming from Solar Frontier, a Japanese manufacturer of "CIGS" (copper indium gallium selenide) modules.

Figure 5 also breaks down the composition of *cumulative* installed capacity as of the end of 2016. Tracking projects (of any module type) account for 64% of the cumulative installed utility-scale PV capacity through 2016, while c-Si modules are used in 67% of cumulative capacity. Breaking these cumulative capacity statistics out by both module *and* mounting type, the most common combination was tracking c-Si (8,479 MW_{AC} from 219 projects), followed by fixed-tilt thin-film (3,448 MW_{AC} from 46 projects), fixed-tilt c-Si (2,423 MW_{AC} from 117 projects), and finally tracking thin-film (2,024 MW_{AC} from 40 projects).

More PV projects at lower insolation sites, fixed-tilt mount less common in sunny areas

Figures 3 and 4 (earlier) provide a general sense for *where* and in what type of solar resource regime utility-scale solar projects within the population are located (Figure 3), as well as *when* these projects achieved commercial operation (Figure 4). Figure 6 further refines the picture by showing the median site-specific long-term average annual GHI (in kWh/m^2/day) among new utility-scale PV projects built in a given year. Knowing how the average resource quality of the project fleet has evolved over time is useful, for example, to help explain observed trends in project-level capacity factors by project vintage (explored later in Section 2.4).

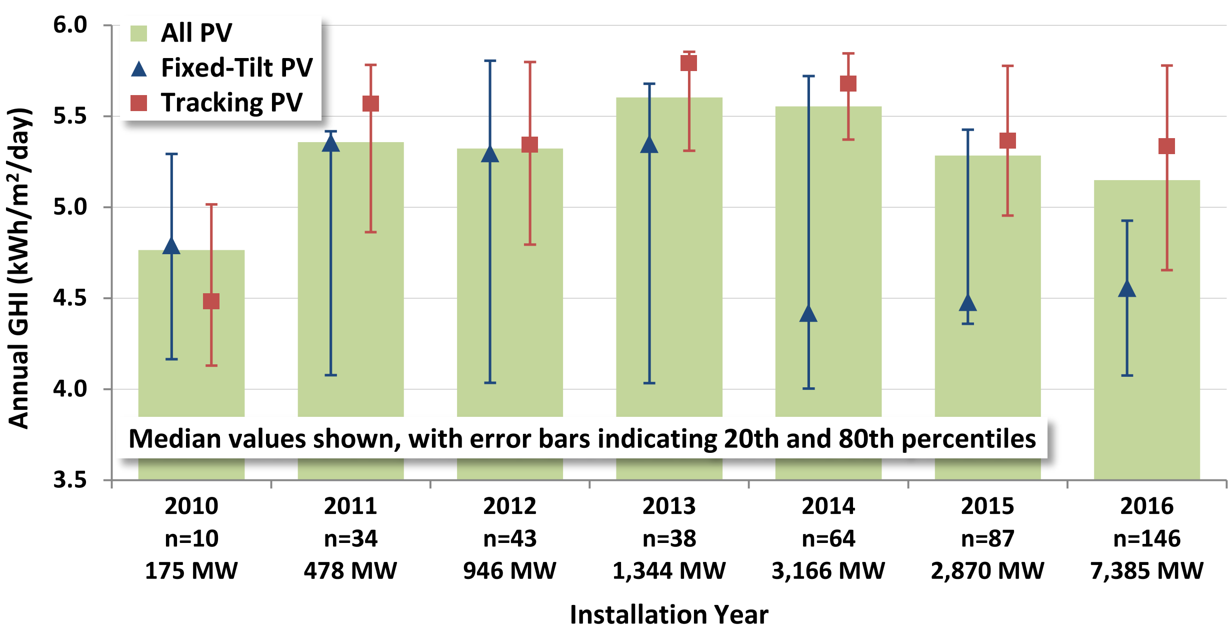


Figure 6. Trends in Global Horizontal Irradiance by Mounting Type and Installation Year

Until 2013, the median GHI among all utility-scale PV projects (shown by the green columns) had generally increased with project vintage, suggesting an ongoing concentration of projects located in solar-rich California and the Southwest. Since then, however, large-scale PV projects have been increasingly deployed in less-sunny areas as well, resulting in a decline in the median solar resource among new projects, from a high of 5.60 kWh/m^2/day among 2013-vintage projects to 5.15 kWh/m^2/day among projects built in 2016.

Moreover, the map in Figure 3 shows a preponderance of tracking projects in California and the Southwest, compared to primarily fixed-tilt c-Si projects in the lower-irradiance East. This split can also be seen in Figure 6 via the notable differences between the 20th percentile GHI numbers for fixed-tilt and tracking projects, with the former commonly as low as 4 kWh/m^2/day across most vintages, compared to much higher levels for tracking projects. The wide range of insolation among fixed-tilt projects reflects the fact that most projects in the lower-GHI regions of the United States are fixed-tilt, yet very large fixed-tilt projects (often using CdTe thin-film technology[16]) have historically also been built in high-GHI areas like California and the Southwest. Although there were still a few of these large legacy projects that came online in 2016 in the Southwest, the majority of fixed-tilt installations are now relegated to less-sunny regions. One exception to this general rule of thumb involves several 2016 fixed-tilt installations in Florida, Georgia and South Carolina.

In contrast, tracking projects have historically been concentrated in California and the Southwest, but single-axis tracking technology has increasingly been deployed in less-sunny regions as well, particularly since 2014. Notably, the northern-most PV projects that came online in Minnesota in 2016 have elected to use tracking, reflecting decreasing price differences between fixed-tilt and tracking projects that are further explored in Section 2.3.

To complement and facilitate the interpretation of the solar resource numbers in Figure 6, Table 2 provides the median GHI and 20th-80th percentile range by region among our project sample.

Table 2. Typical GHI Range of PV Projects by Region

Region	Installed Projects (#)	Cumulative Capacity (MW_{AC})	Median GHI Resource (kWh/m^2/day)	20th-80th Percentiles (GHI)
Southwest	107	4,504	5.6	5.3 – 5.8
California	157	8,040	5.6	5.3 – 5.8
Hawaii	4	36	4.9	4.6 – 5.4
Texas	14	569	4.8	4.8 – 5.6
Northwest	9	183	4.6	4.5 – 4.7
Southeast	86	2,549	4.5	4.4 – 4.7
Midwest	18	244	4.0	3.9 – 4.0
Northeast	32	313	4.0	3.9 – 4.0

[16] The apparent preference for thin-film (primarily CdTe) modules in Desert Southwest projects is driven primarily by CdTe's greater tolerance for high-temperature environments (as well as relatively low land prices in the desert, which helped to mitigate CdTe's historical efficiency deficit). In its online blog (First Solar 2016), First Solar claims that its CdTe technology provides greater energy yield (per nameplate W) than c-Si at high/normal operating temperatures, due to its lower power temperature coefficient of -0.28%/°C for Series 4 modules (compared to something more like -0.40%/°C for most c-Si modules).

Developers continued to favor larger module arrays relative to inverter capacity

Another project-level characteristic that can influence both installed project prices and capacity factors is the inverter loading ratio ("ILR"), which describes a project's DC capacity rating (i.e., the sum of the module ratings under standardized testing conditions) relative to its aggregate AC inverter rating.[17] With the cost of PV modules having dropped precipitously (more rapidly than the cost of inverters), many developers have found it economically advantageous to oversize the DC array relative to the AC capacity rating of the inverters. As this happens, the inverters operate closer to (or at) full capacity for a greater percentage of the day, which—like tracking—boosts the capacity factor,[18] at least in AC terms (this practice will actually *decrease* the capacity factor in DC terms, as some amount of power "clipping" will often occur during peak production periods).[19] The resulting boost in generation (and revenue) during the shoulder periods of each day outweighs the occasional loss of revenue from peak-period clipping (which may be largely limited to the sunniest months).

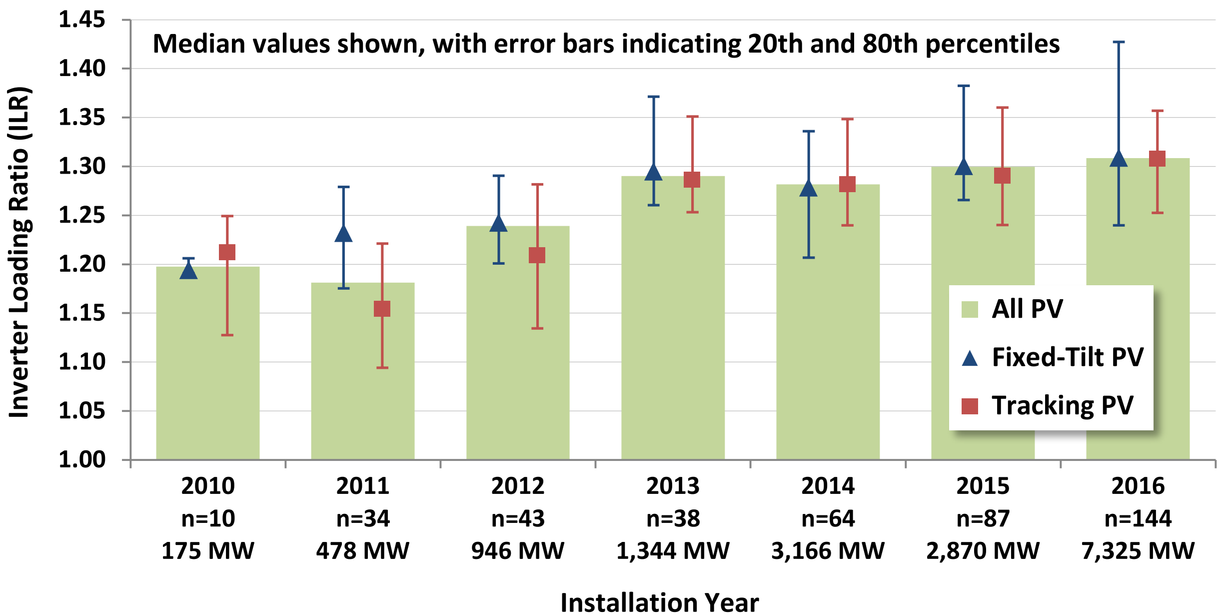


Figure 7. Trends in Inverter Loading Ratio by Mounting Type and Installation Year

[17] This ratio is referred to within the industry in a variety of ways, including: DC/AC ratio, array-to-inverter ratio, oversizing ratio, overloading ratio, inverter loading ratio, and DC load ratio (Advanced Energy 2014; Fiorelli and Zuercher - Martinson 2013). This report uses inverter loading ratio, or ILR.

[18] This is analogous to the boost in capacity factor achieved by a wind turbine when the size of the rotor increases relative to the turbine's nameplate capacity rating. This decline in "specific power" (W/m^2 of rotor swept area) causes the generator to operate closer to (or at) its peak rating more often, thereby increasing capacity factor.

[19] Power clipping, also known as power limiting, is comparable to spilling excess water over a dam (rather than running it through the turbines) or feathering a wind turbine blade. In the case of solar, however, clipping occurs electronically rather than physically: as the DC input to the inverter approaches maximum capacity, the inverter moves away from the maximum power point so that the array operates less efficiently (Advanced Energy 2014; Fiorelli and Zuercher - Martinson 2013). In this sense, clipping is a bit of a misnomer, in that the inverter never really even "sees" the excess DC power—rather, it is simply not generated in the first place. Only *potential* generation is lost.

Figure 7 shows the median ILR among projects built in each year, both for the total PV project population (green columns) and broken out by fixed-tilt versus tracking projects. Across all projects, the median ILR has increased over time, from around 1.2 in 2010 to 1.31 in 2016. Fixed-tilt projects have historically featured higher ILRs than tracking projects, consistent with the notion that fixed-tilt projects have more to gain from boosting the ILR in order to achieve a less-peaky, “tracking-like” daily production profile. Since 2013, however, the median ILR of tracking and fixed-tilt projects has been nearly the same (although the 80^{th} percentile has been higher for fixed-tilt than tracking projects in 2013, 2015, and most notably 2016).

2.2 Installed Project Prices (361 projects, 14,469 MW_{AC})

This section analyzes installed price data from a large sample of the overall utility-scale PV project population described in the previous section.[20] It begins with an overview of installed prices for PV (and CPV) projects over time, and then breaks out those prices by mounting type (fixed-tilt vs. tracking), system size, and region. A text box at the end of this section compares our top-down empirical price data with a variety of estimates derived from bottom-up cost models.

Sources of installed price information include the Energy Information Administration (EIA),[21] the Treasury Department's Section 1603 Grant database, data from applicable state rebate and incentive programs, state regulatory filings, FERC Form 1 filings, corporate financial filings, interviews with developers and project owners, and finally, the trade press. All prices are reported in real 2016 dollars.

In general, only fully operational projects for which all individual phases were in operation at the end of 2016 are included in the sample[22]—i.e., by definition, our sample is backward-looking and therefore may not reflect installed price levels for projects that are completed or contracted in 2017 and beyond. Moreover, reported installed prices within our backward-looking sample may reflect transactions (e.g., entering into an Engineering, Procurement, and Construction or "EPC" contract) that occurred several years prior to project completion. In some cases, those transactions may have been negotiated on a forward-looking basis, reflecting anticipated future costs at the time of project construction. In other cases, they may have been based on contemporaneous costs (or a conservative projection of costs), in which case the reported installed price data may not fully capture recent fluctuations in component costs or other changes in market conditions. For these reasons, the data presented in this chapter may not correspond to recent price benchmarks for utility-scale PV, and may differ from the average installed prices reported elsewhere (Fu, Feldman, and Margolis 2017; GTM Research and SEIA 2017). That said, the text box at the end of this section suggests fairly good agreement between our empirical installed price data and other published modeling estimates, once timing is taken into account.

Our sample of 361 PV (and CPV) projects totaling 14,469 MW_{AC} for which installed price estimates are available represents 85% of the total number of PV projects and 88% of the amount of capacity in the overall PV project population described in Section 2.1. Focusing just on those PV projects that achieved commercial operation in 2016, our sample of 88 projects totaling 5,497 MW_{AC} represents 60% and 74% of the total number of 2016 projects and capacity in the population, respectively.

[20] Installed "price" is reported (as opposed to installed "cost") because in many cases, the value reported reflects either the price at which a newly completed project was sold (e.g., through a financing transaction), or alternatively the fair market value of a given project—i.e., the price at which it would be sold through an arm's-length transaction in a competitive market.
[21] New to the 2016 edition of this report is the inclusion of confidential project-level installed cost data for projects built in 2013-2015, obtained from the EIA under a non-disclosure agreement.
[22] In contrast, later sections of this chapter do present data for individual phases of projects that are online, or (in the case of Section 2.5 on PPA prices) even for phases of projects or entire projects that are still in development and not yet operating.

Median prices fell to \$2.2/W_{AC} (\$1.7/W_{DC}) in 2016

Figure 8 shows installed price trends for PV projects completed from 2007 through 2016 in both DC and AC terms. Because PV project capacity is commonly reported in DC terms (particularly in the residential and commercial sectors), the installed cost or price of solar is often reported in \$/W_{DC} terms as well (Barbose and Darghouth 2017; GTM Research and SEIA 2017). As noted in the earlier text box (*AC vs. DC*), however, this report analyzes utility-scale solar in AC terms. Figure 8 shows installed prices in both \$/W_{DC} and \$/W_{AC} terms in an attempt to provide some continuity between this report and others that present prices in DC terms. The remainder of this document, however, reports sample statistics exclusively in AC terms, unless otherwise noted.

As shown, median utility-scale PV prices (solid lines) within our sample have declined fairly steadily in each year, to \$2.2/W_{AC} (\$1.7/W_{DC}) in 2016. This represents a price decline of more than 65% since the 2007-2009 period (and nearly 60% since 2010). The lowest-priced projects in our 2016 sample of 88 PV projects were ~\$1.5/W_{AC} (~\$1.1/W_{DC}), with the lowest 20th percentile of projects falling from \$2.2/W_{AC} in 2015 to \$2.0/W_{AC} in 2016 (i.e., from \$1.6/W_{DC} to \$1.5/W_{DC}).

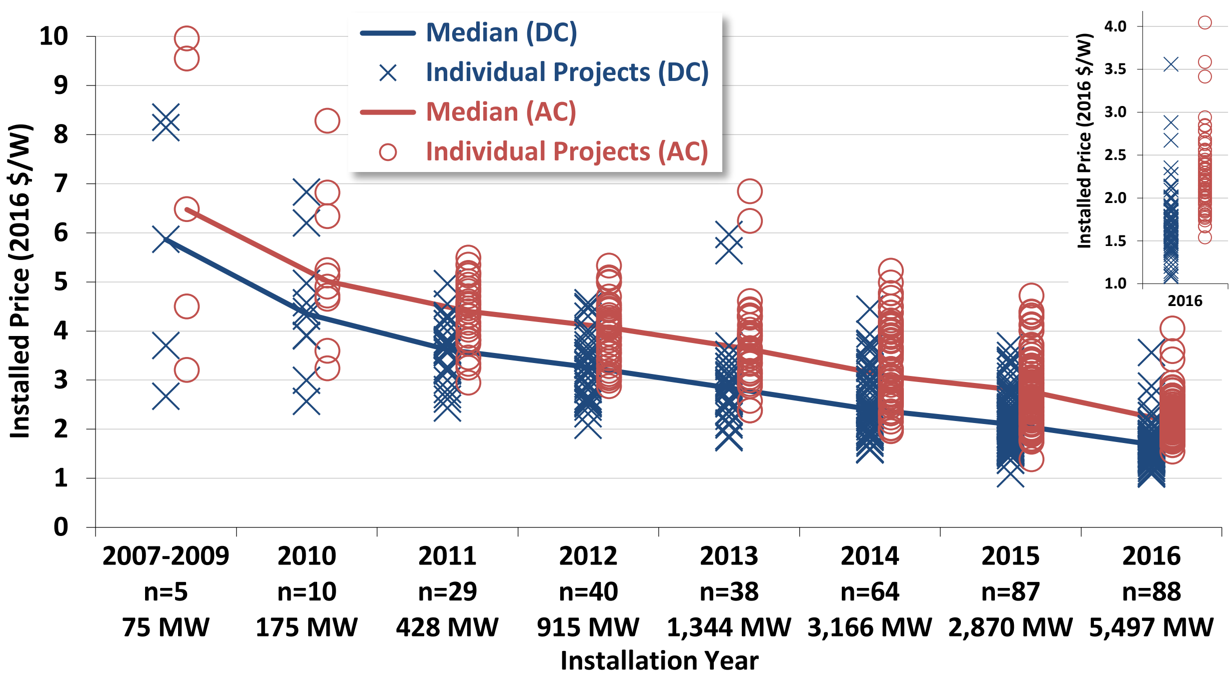


Figure 8. Installed Price of Utility-Scale PV and CPV Projects by Installation Year

Figure 9 shows histograms drawn from the same sample, with an emphasis on the changing distribution of installed prices (which are reported only in \$/W_{AC} terms from here on) over the last five years. The steady decline in installed prices by project vintage is evident as the mode of the sample (i.e., the price bin with the most projects, forming the "peak" of each curve) shifts to the left from year to year. Additionally, the portion of the sample that falls into relatively high-priced bins (e.g., \$2.75-\$5.75/W_{AC}) decreases with each successive vintage, while the portion that falls into relatively low-priced bins (e.g., \$1.25-\$2.75/W_{AC}) increases. The "width" of the curves also narrows somewhat over time, indicating that the pricing within each successive vintage becomes less heterogeneous. This has become especially true for 2016 installations, the year with the lowest price dispersion and the highest concentration within the narrow price bin of $1.75-$2.25/W_{AC}.

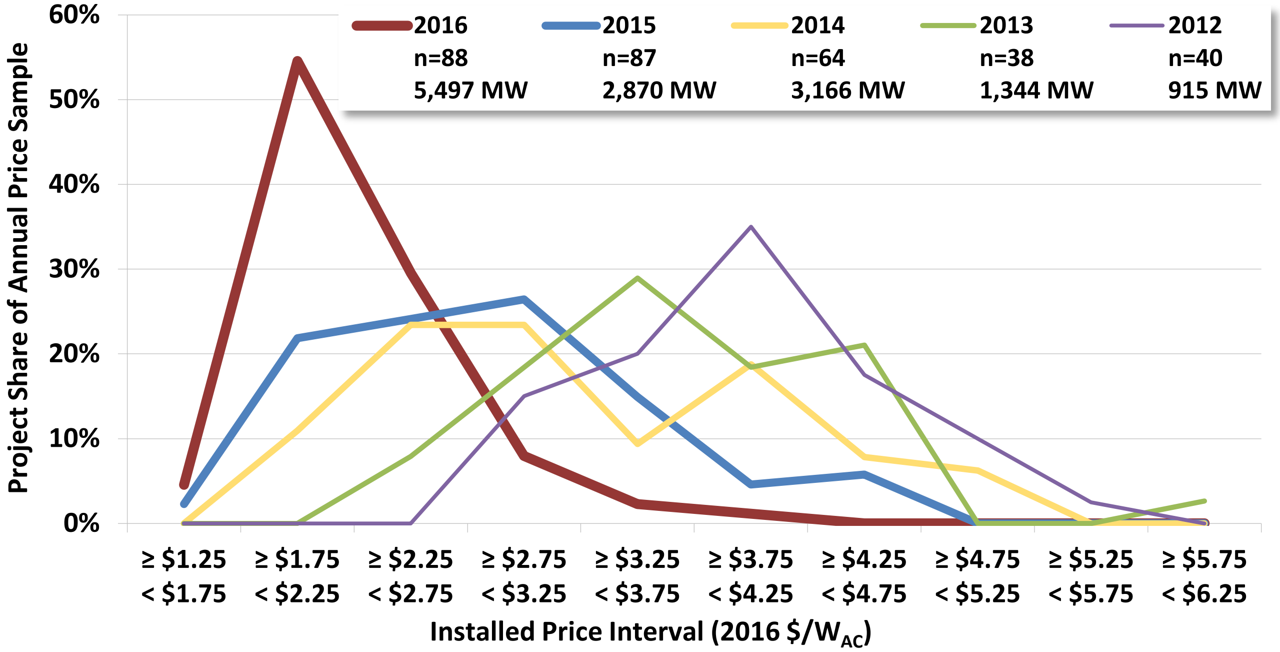


Figure 9. Distribution of Installed Prices by Installation Year

Tracking projects often command a price premium over fixed-tilt installations

While median prices in the sample have declined over time, Figure 8 shows that there has been a considerable spread in individual project prices within each year. One contributor to this price variation could be whether projects are mounted at a fixed tilt or on a tracking system. Figure 10 breaks out installed prices over time by mounting type, and finds that projects using trackers were $0.15/$W_{AC}$ more expensive (at the median) than fixed-tilt projects in 2016. Though once quite large (in 2010 and earlier), this tracker premium has been rather modest since 2011. As shown later in Section 2.4, this slightly higher up-front expenditure for tracking results in greater energy production (and hence revenue), which typically outweighs the added cost, helping to explain the recent surge in tracking projects, even among the most-northerly projects in our sample (e.g., in Minnesota).

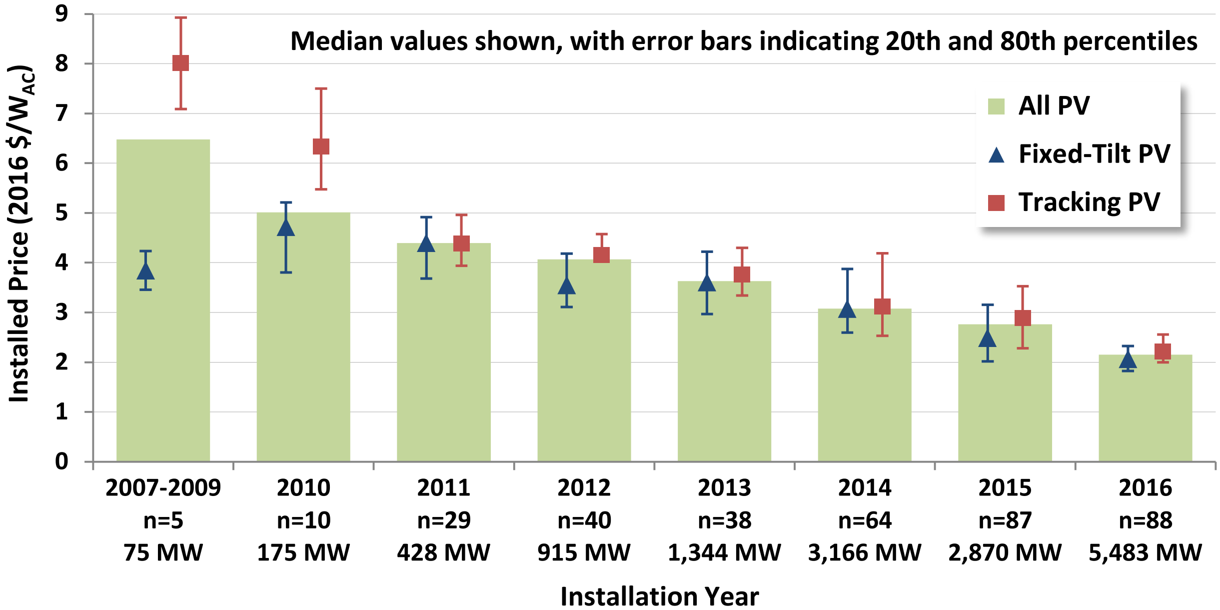


Figure 10. Installed Price of Utility-Scale PV by Mounting Type and Installation Year

Evidence of economies of scale remains elusive

Differences in project size may also explain some of the variation in installed prices seen in Figure 8, as PV projects in the sample range from 5.5 MW_{AC} to 300 MW_{AC}. Figure 11 investigates price trends by project size, focusing on just those PV projects in the sample that became fully operational in 2016, in order to minimize the potentially confounding influence of price reductions over time.

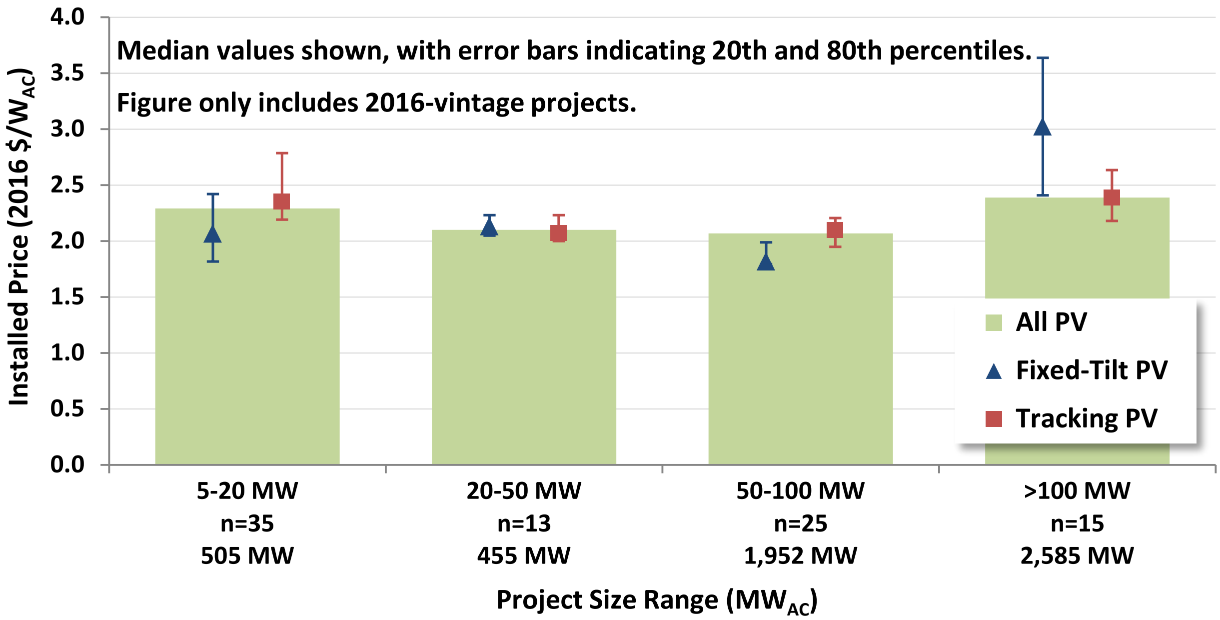


Figure 11. Installed Price of 2016 PV Projects by Size and Mounting Type

As has been the case in previous editions of this report, it is difficult to find clear indications of economies of scale among our latest project sample. That said, this year there are at least some suggestions of scale economies among the first three project size bins shown in Figure 11, with median prices dropping from $2.29/$W_{AC}$ (5-20 MW_{AC}) to $2.10/$W_{AC}$ (20-50 MW_{AC}) to $2.07/$W_{AC}$ (50-100 MW_{AC}).

Moving beyond those first three bins, however, the median installed price then *rises* to $2.4/$W_{AC}$ among the 15 projects that exceed 100 MW_{AC}. In other words, just like in last year's edition of this report (among the sample of 2015-vintage projects), the 2016 sample shown in Figure 11 once again suggests price *penalties* for projects larger than 100 MW_{AC} (although the price penalty is much less pronounced in 2016 in comparison to previous years).[23] Two factors may contribute to these apparent *dis*economies of scale for very large projects. First, it may be that these very large projects often face greater administrative, regulatory, and interconnection costs than do smaller projects, and these costs are not fully offset by other size-driven savings like hardware procurement or a more-streamlined use of installation labor. A second explanation may be that very large projects take longer to build, and may therefore reflect higher module and EPC costs dating back further in time.

System prices vary by region

In addition to price variations due to technology and perhaps system size, prices also differ by geographic region. This variation may, in part, reflect the relative prevalence of different system design choices (e.g., the greater prevalence of tracking projects in California and the Southwest) that have cost implications. In addition, regional differences in labor and land costs, soil conditions or snow load (both of which have structural, and therefore cost, implications), or simply the balance of supply and demand, may also play a role. As shown in Figure 12 (which uses the regional definitions shown earlier in Figure 3), the overall regional price variation declined between 2015 and 2016.

The first installations in the Northwest were comparatively slightly more expensive, perhaps explained by an absence of previously established installation infrastructure. California prices saw a strong decline and are now much closer to the national median. As in previous years, the Southwest and the Southeast have lower prices than the national median, although their price lead has shrunk from about $0.36/$W_{AC}$ in 2015 to $0.05/$W_{AC}$ in 2016. Despite its nascent state, the Midwest is the region with the lowest prices in 2016, at $1.9/$W_{AC}$, although cost estimates for the Northeast, the Midwest and Northwest should be considered with caution, as the sample size for all three regions is rather small. Due to the low number of observations, projects in Hawaii and Texas are not reported in Figure 12.

[23] These empirical findings are, to some extent, in conflict with recent modeling work from NREL (Fu, Feldman, and Margolis 2017) that models the cost of projects in construction in Q1 2017 (that are not yet commercially operable). NREL projects a $0.4/$W_{DC}$ cost advantage for a 100 MW_{DC} utility-scale PV plant over a 5 MW_{DC} project. However, the analysis does not correct for the potentially longer development times associated with the larger project, which could diminish the cost advantage when prices are indexed by commercial operation date.

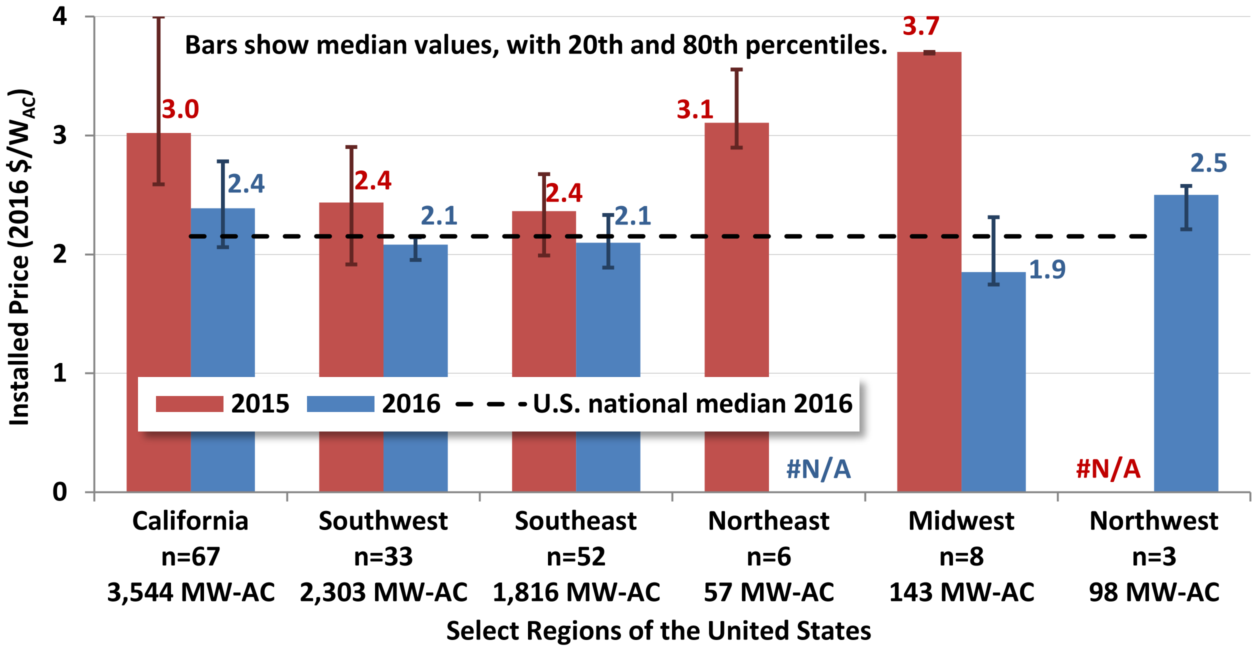


Figure 12. Median Installed PV Price by Region in 2015 and 2016

Finally, the text box on the next page compares our top-down empirical price data with a variety of estimates derived from bottom-up cost models.

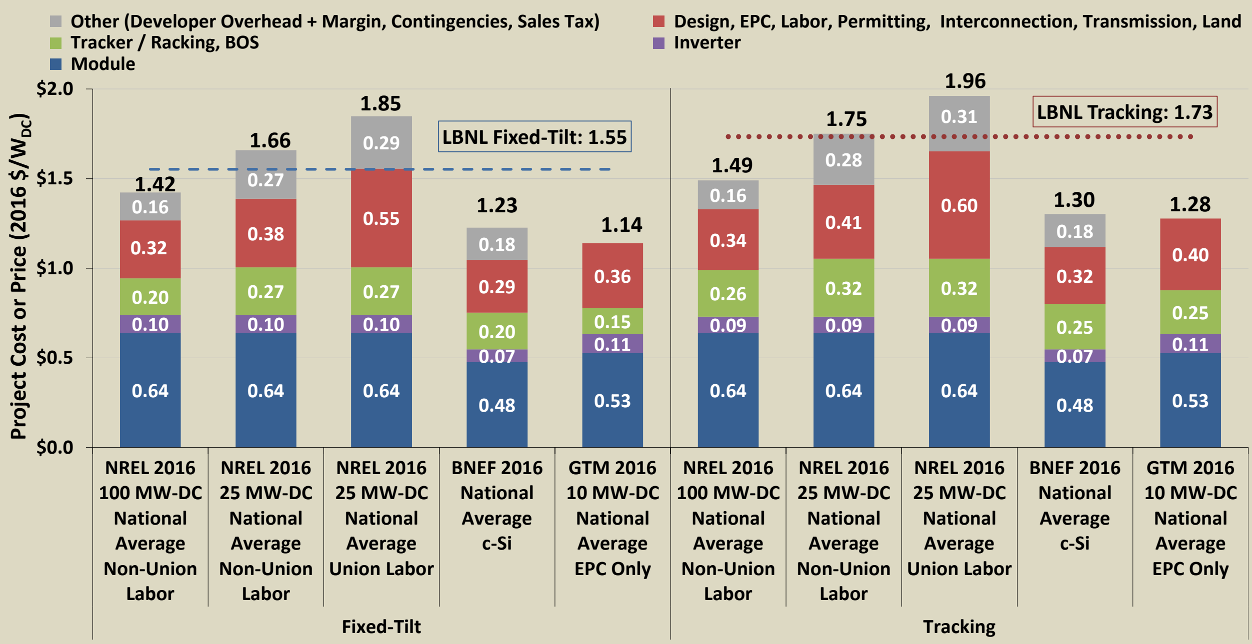
Bottom-Up versus Top-Down: Different Ways to Look at Installed Project Prices

The installed prices analyzed in this report generally represent empirical *top-down* price estimates gathered from sources (e.g., corporate financial filings, FERC filings, the Treasury's Section 1603 grant database, the EIA) that typically do not provide more granular insight into component costs. In contrast, several publications by NREL (Fu, Feldman, and Margolis 2017), BNEF (Bromley and Serota 2016), and Greentech Media (GTM Research and SEIA 2017) take a different approach of modeling total installed prices via a *bottom-up* process that aggregates modeled cost estimates for various project components to arrive at a total installed cost or price. Each type of estimate has both strengths and weaknesses—e.g., top-down estimates often lack component-level detail but benefit from an empirical reality check that captures the full range of diverse projects in the market, while bottom-up estimates provide more detail but rely on modeling, typically of idealized or "best in class" projects.

A second potential source of disparity between these installed price estimates is differences in the "time stamp." LBNL reports the installed price of projects in the year in which they achieve commercial operation, while GTM and BNEF may instead refer to EPC contract execution dates or to projects under construction that have not yet been completed (such projects enter our sample in later years). NREL also provides more of a forward-looking estimate (in the figure below, we account for this timing mismatch by showing NREL's 1Q16, rather than current, numbers).

Notwithstanding these potential timing issues, the figure below compares the top-down median 2016 prices for fixed-tilt ($1.55/W$_{DC}$) and tracking ($1.73/W$_{DC}$) projects in the LBNL sample with various bottom-up modeled cost estimates from the three sources noted above. Each bottom-up cost estimate is broken down into a common set of cost categories, which we defined rather broadly in order to capture slight differences in how each source reports costs (note that not all sources provided estimates for all cost categories). Finally, costs are shown exclusively in $/W$_{DC}$, which is how they are reported in these other sources.

Although GTM's relatively low cost estimates stand out as potential outliers, they represent only turnkey EPC costs—i.e., they exclude permitting, interconnection, and transmission costs, as well as developer overhead, fees, and profit margins—which perhaps explains the difference. LBNL's top-down empirical estimates reflect a mix of union and non-union labor and span a wide range of project sizes and prices.[i] Finally, economies of scale of $0.24-26/W$_{DC}$ are reflected in NREL's bottom-up modeled cost estimates for a 100 MW$_{DC}$ project (relative to a 25 MW$_{DC}$ project).



[i] For fixed-tilt projects, LBNL's median project size is 23 MW$_{DC}$ and the price range is $1.08-$3.56/W$_{DC}$. For tracking projects, the comparable numbers are 74 MW$_{DC}$ and $1.24-$2.88/W$_{DC}$.

2.3 Operation and Maintenance Costs (30 projects, 546 MW_{AC})

In addition to up-front installed project prices, utility-scale solar projects also incur ongoing operation and maintenance ("O&M") costs, which are defined here to include only those direct costs to operate and maintain the generating plant itself. In other words, O&M costs—at least as reported here—exclude payments such as property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead (all of which contribute to *total operating expenses*). This section reviews and analyzes the limited data on O&M costs that are in the public domain.

Empirical data on the O&M costs of utility-scale solar projects are hard to come by. Few of the utility-scale solar projects that have been operating for more than a year are owned by regulated investor-owned utilities, which FERC requires to report (on Form 1) the O&M costs of the power plants that they own.[24] Even fewer of those investor-owned utilities that do own utility-scale solar projects actually report operating cost data in FERC Form 1 in a manner that is useful (if at all). For example, at least historically, some investor-owned utilities have not reported empirical O&M costs for individual solar projects, but instead have reported average O&M costs across their entire fleet of PV projects, pro-rated to individual projects on a capacity basis. This lack of project-level granularity requires us to analyze solar O&M costs on an aggregate utility level rather than an individual project level. Table 3 describes our O&M cost sample and highlights the growing cumulative project fleet of each utility.

Table 3. Operation and Maintenance Cost Sample (cumulative over time)

Year	PG&E		PNM[25]		Nevada Power		Georgia Power		APS[26]		PSEG[27]		FP&L	
	# of MW_{AC}	# of projects	# of MW_{AC}	# of projects	# of MW_{AC}	# of projects	# of MW_{AC}	# of projects	# of MW_{AC}	# of projects	# of MW_{AC}	# of projects	# of MW_{AC}	# of projects
2011									51	3			110	3
2012	50	3	8	2					96	4			110	3
2013	100	6	30	4					136	6			110	3
2014	N/A	N/A	55	7					168	7			110	3
2015	150	9	95	11					191	9			110	3
2016	150	9	95	11	16	1	36	2	237	10	44	3	110	3
predominant technology	Fixed-Tilt c-Si		4 Fixed-Tilt, 7 Tracking		Tracking c-Si		Fixed-Tilt c-Si		Tracking c-Si		Fixed-Tilt c-Si		mix of c-Si and CSP	

[24] FERC Form 1 uses the "Uniform System of Accounts" to define what should be reported under "operating expenses"—namely, those operational costs of supervision and engineering, maintenance, rents, and training (and therefore excluding payments for property taxes, insurance, land royalties, performance bonds, various administrative and other fees, and overhead).

[25] PNM only reports fleet-wide average O&M costs, weighing each of their projects by its MW_{AC} capacity

[26] APS reports O&M costs in FERC Form 1 only in an aggregated manner across customer classes (residential, commercial, and utility-scale). For lack of better data, we use their 237 MW_{AC} of total PV capacity (including residential and commercial) as a proxy for the 10 utility-scale solar plants with a combined capacity of 221 MW_{AC}.

[27] PSEG only reports a fleet-wide average of O&M cost which may include other non-utility-scale solar projects in addition to its large landfill solar projects.

Despite these limitations, Figure 13 shows average utility fleet-wide annual O&M costs for this small sample of projects in $/kW$_{AC}$-year (PV, blue solid line) and $/MWh (PV, red dashed line). The error bars represent both the lowest and the highest utility fleet-wide PV cost in each year. The yellow dotted line, meanwhile, shows the annual O&M costs of FP&L's 75 MW CSP plant (in $/kW-year terms only, because this project provides steam to a co-located combined cycle gas plant). Although this chapter focuses on PV projects, we have included this lone CSP plant here largely for the sake of expediency, given that it is the only CSP project for which we have O&M cost data. Not surprisingly, its O&M costs—which may not even be fully representative if they reflect just the solar collector field and not the power block of the gas-fired combined cycle plant—are well above those of the PV projects shown.

Average O&M costs for the cumulative set of PV plants within this sample have steadily declined from about $31/kW$_{AC}$-year (or $19/MWh) in 2011 to about $16/kW$_{AC}$-year ($7/MWh) in 2015, but rose in 2016 to $18/kW$_{AC}$-year ($8/MWh). And while the average O&M expense across all utilities has increased slightly in 2016, the utilities with the highest- and lowest-cost fleets have been able to lower their relative costs in both $/kW-year and $/MWh terms (see error bars). This general declining trend potentially indicates that utilities are capturing economies of scale as their PV project fleets grow over time. In 2016, all but three out of 15 PV projects in the sample (i.e., in those instances where we have project-level rather than aggregate utility data) had O&M costs of less than $20/kW$_{AC}$-year (or $11/MWh).

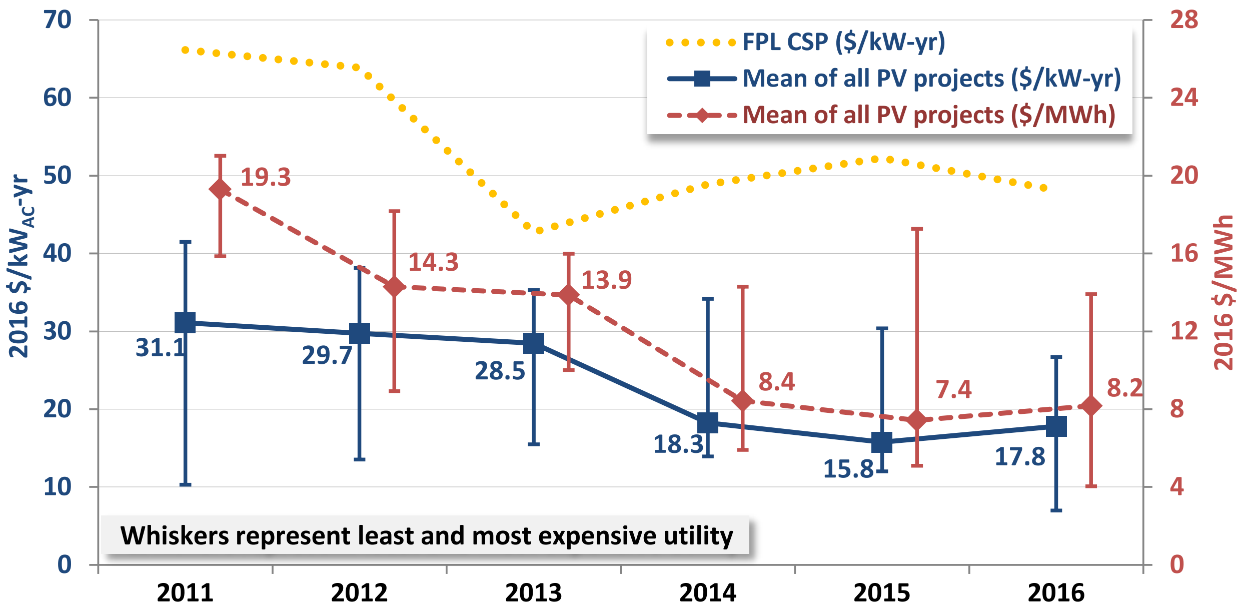


Figure 13. Empirical O&M Costs Over Time for Growing Cumulative Sample of Projects

As utility ownership of operating solar projects increases in the years ahead (and as those utilities that already own substantial solar assets but do not currently report operating cost data hopefully begin to do so, as required in FERC Form 1), the sample of projects reporting O&M costs should grow, potentially allowing for more interesting analyses in future editions of this report.

2.4 Capacity Factors (260 projects, 8,733 MW_{AC})

At the close of 2016, more than 260 utility-scale PV projects in the United States had been operating for at least one full year, and in some cases for as many as nine years, thereby enabling the calculation of capacity factors.[28] Sourcing empirical net generation data from FERC Electric Quarterly Reports, FERC Form 1, Form EIA-923, and state regulatory filings, this chapter presents net AC capacity factor data for 260 PV projects totaling 8,733 MW_{AC}. This 8.7 GW_{AC} sample represents a significant increase from the 5.9 GW_{AC} sample for which capacity factor data were analyzed in last year's edition of this report, driven in large part by new projects that began operating in 2015.

The capacity factors of individual projects in this sample range widely, from 15.4% to 35.5%, with a sample mean of 25.8%, a median of 26.3%, and a capacity-weighted average of 27.3%. Notably, these are *cumulative* capacity factors—i.e., calculated over as many years of data as are available for each individual project (up to a maximum of nine years, from 2008 to 2016, in this case), rather than for just a single year (though for projects completed in 2015, only a single full calendar year of data—2016—exists at present). Furthermore, they are also expressed in *net*, rather than *gross*, terms—i.e., they represent the output of the project net of its own consumption. Finally, they are calculated in AC terms (i.e., using the MW_{AC} rather than MW_{DC} nameplate rating),[29] yielding higher capacity factors than if reported in DC terms,[30] but allowing for direct comparison with the capacity factors of other generation sources (e.g., wind energy or thermal energy sources), which are also calculated in AC terms.

Wide range in capacity factors reflects differences in insolation, tracking, and ILR

Figure 14 presents the cumulative net AC capacity factors of each project in the sample (see the circle markers) broken out by three key project characteristics that a recent statistical analysis (Bolinger, Seel, and Wu 2016) found to explain more than 90% of the variation in utility-scale PV project capacity factors. These characteristics include the estimated strength of the long-term solar resource at each site (measured in GHI with units $kWh/m^2/day$), whether the array is mounted at a fixed tilt or on a tracking mechanism, and the DC capacity of the array relative to the AC inverter rating (i.e., the inverter loading ratio, or ILR).[31] The blue-shaded columns show the mean cumulative capacity factor within each individual bin.

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[28] Because solar generation is seasonal (greater in the summer than in the winter), capacity factor calculations are performed in full-year increments.

[29] The formula is: Net Generation (MWh_{AC}) over Single- or Multi-Year Period / [Project Capacity (MW_{AC}) * Number of Hours in that Same Single- or Multi-Year Period].

[30] For example, a project with a 30% capacity factor in AC terms would have a 25% capacity factor in DC terms at an inverter loading ratio of 1.20, and a 20% capacity factor in DC terms at an inverter loading ratio of 1.50.

[31] Instead of using capacity factors to gauge project performance, some analysts prefer to use the "performance ratio"— defined as "the ratio of the electricity generated to the electricity that would have been generated if the plant consistently converted sunlight to electricity at the level expected from the DC nameplate rating" (Dierauf et al. 2013). Because the performance ratio takes into account many of the variables explored in this section—e.g., fixed-tilt vs. tracking mounts, variations in insolation, DC capacity ratings, etc.—it can provide a more precise measure of how a project is performing *in light of its specific circumstances*. In this report, however, we are specifically interested in exploring the full range of empirical project performance experienced in the market, as well as the specific circumstances that drive it, and therefore prefer to focus on capacity factors, which do not filter out this

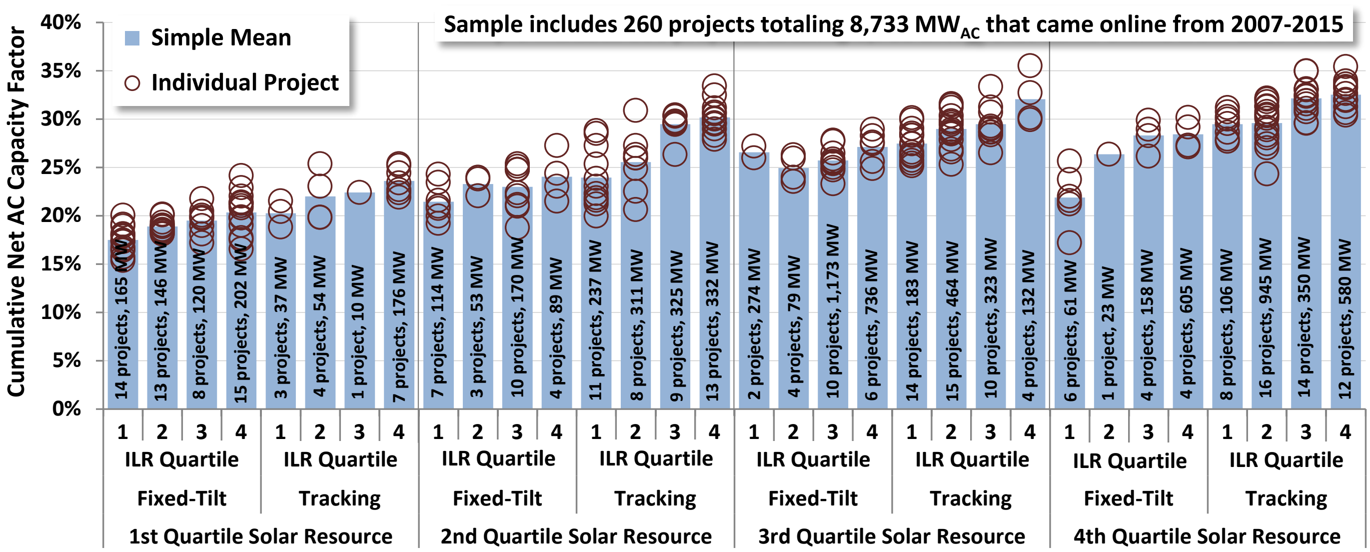

Figure 14. Cumulative Capacity Factor by Resource Strength, Fixed-Tilt vs. Tracking, and Inverter Loading Ratio[32]

Each of the three drivers of capacity factor explored in Figure 14 is discussed in turn below.

- **Solar Resource:** Based on its geographic coordinates, each project in the sample is associated with a long-term average global horizontal irradiance (GHI) value derived from the map shown earlier in Figure 3. Figure 14 then parses the sample into solar resource quartiles that have the following thresholds: <4.52, 4.52-5.37, 5.37-5.74, and ≥5.74 kWh/m^2/day GHI. Sixty-five projects fall into each resource quartile, though capacity is concentrated in the third (39%) and fourth (32%) quartiles, with only 10% of capacity within the first quartile. Not surprisingly, projects sited in stronger solar resource areas tend to have higher capacity factors, all else equal. The difference can be substantial: the mean capacity factors in the highest resource bin, for example, average 8 percentage points higher (in absolute terms) than their counterparts in the lowest resource bin (with the range extending from 4 to 10 percentage points depending on fixed-tilt versus tracking and the inverter loading ratio).

- **Fixed-Tilt vs. Tracking:** 111 projects in the sample (totaling 4,168 MW_{AC}) are mounted at a fixed-tilt, while the remaining 149 (totaling 4,564 MW_{AC}) utilize tracking

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information. In addition, some of the information required to calculate performance ratios—e.g., site-specific insolation during the period of interest—is not readily accessible, making capacity factors a more expedient choice for this report.

[32] Figure 14 (as well as the rest of this section) excludes three CPV projects: the 5.04 MW_{AC} Hatch project (online since late-2011), the 30 MW_{AC} Cogentrix Alamosa project (online since early 2012), and the 6.3 MW_{AC} Desert Green project (online since late-2014). If plotted in Figure 14, these three projects would fall into the 29th, 14th, and 32nd bins, respectively, where their cumulative capacity factors of 18.1%, 24.0%, and 26.8% would fall below the respective PV bin means of 29.5%, 25.5%, and 32.5% (despite the CPV projects' use of dual-axis tracking, which should provide an advantage over the overwhelmingly single-axis PV sample). Based on this comparison to similarly situated PV projects, Hatch in particular seems to be underperforming (at just 18.1%, compared to the PV average of 29.5%). Earlier editions of this report provide additional details about the specifications and performance of the Hatch and Cogentrix Alamosa PV projects.

(overwhelmingly horizontal single-axis east-west tracking, with the exception of four dual-axis tracking projects located in Texas). Tracking boosts average capacity factor by 3-5 percentage points on average (in absolute terms), depending on the resource quartile (i.e., 3% within the 1st resource quartile, 5% in the 4th resource quartile), and 4% on average across all four resource quartiles. This finding that the benefit of tracking increases at higher insolation levels is consistent with results from Bolinger et al. (2016), and also explains why there are many more fixed-tilt (50) than tracking (15) projects in the lowest insolation quartile and many more tracking (50) than fixed-tilt (15) projects in the highest insolation quartile of Figure 14.

- **Inverter Loading Ratio (ILR):** Figure 14 breaks the sample down further into ILR quartiles: <1.21, 1.21-1.26, 1.26-1.32, and ≥1.32. Again, each quartile houses roughly 65 projects, but capacity is concentrated in the third (30%) and fourth (33%) quartiles. The effect of a higher ILR on average capacity factor is noticeable: across all four resource quartiles and fixed/tracking bins, the absolute percentage point difference in capacity factor between the fourth and first inverter loading ratio quartiles is as high as 7% (with an average of 4% across all bins).

Beyond the three drivers depicted in Figure 14, additional explanatory factors, such as array tilt and azimuth, will also play an obvious role in influencing capacity factors, particularly for fixed-tilt projects. Given that we focus only on ground-mounted utility-scale projects, however, our operating assumption is that these two fundamental parameters will tend to be equally optimized across all projects to maximize energy production. Although this assumption may become increasingly tenuous as PV's grid penetration increases,[33] the fact that we lack solid data on project-level tilt and azimuth prevents further analysis of these two fundamental variables at present.

Finally, Figure 15 presents similar information as in Figure 14, but in a slightly different way. Instead of accounting for the strength of the solar resource via insolation quartiles (as in Figure 14), Figure 15 breaks out cumulative capacity factors for both fixed-tilt and tracking projects on a regional basis (with regions as defined earlier in Figure 3)—for those readers who prefer to think geographically rather than in terms of insolation. For the sake of simplicity, Figure 15 also ignores ILR differences. Given what we know about insolation levels regionally (see Figure 3 and Table 2), the results are not surprising: capacity factors are lowest in the Northeast and Midwest and highest in California and the Southwest. Although sample size is small in some regions, the greater benefit of tracking in the high-insolation regions is evident, as are the greater number of tracking projects in those regions (whereas the relatively low-insolation Northeast and Midwest samples include more fixed-tilt than tracking projects).

[33] For example, at higher penetration levels, time-of-day pricing factors may shift to more-heavily favor the late afternoon hours, which could encourage developers of fixed-tilt projects to orient them in a more westerly direction.

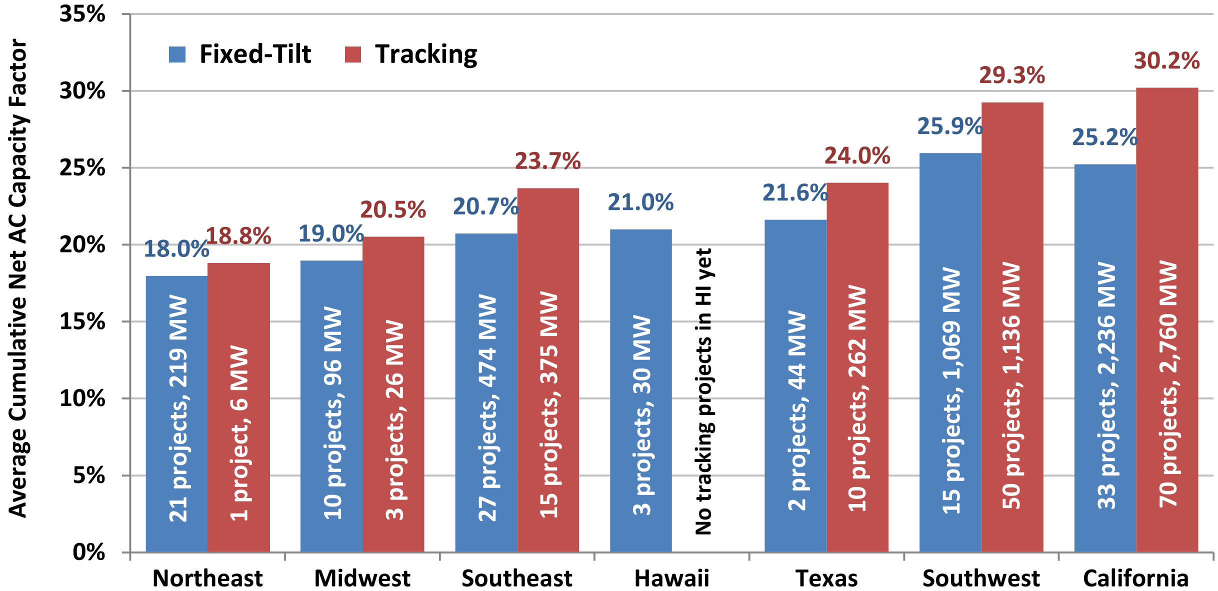

Figure 15. Cumulative Capacity Factor by Region and Fixed-Tilt vs. Tracking

More recent project vintages exhibit higher capacity factors

Although one might initially expect improvements in PV module efficiency over time to boost the capacity factors of more recent project vintages, this is a misunderstanding. As module efficiency increases, developers either use fewer modules to reach a fixed amount of capacity (thereby saving on balance-of-system and land costs as well) or, alternatively, use the same number of modules to boost the amount of capacity installed on a fixed amount of land (directly reducing at least $/W_{DC}$ costs, if not also $/W_{AC}$ costs). As a result, for PV more than for other technologies like wind power, efficiency improvements over time show up primarily as cost savings rather than as higher capacity factors. Any increase in capacity factor by project vintage is, therefore, most likely attributable to a time trend in one of the other variables examined above—e.g., towards higher inverter loading ratios or greater use of tracking, or a buildout of higher insolation sites—as well as performance degradation and perhaps resource variability.

Figure 16 tests this hypothesis by breaking out the average net capacity factor (both cumulative and in 2016) by project vintage across the sample of projects built from 2010 through 2015 (and by noting the relevant average project design parameters within each vintage). Capacity factors have improved gradually and steadily with each new project vintage from 2010 through 2013, driven by commensurate (though in some cases sporadic) increases in each of the three design parameters shown: ILR, percentage of projects using tracking, and GHI. However, 2014- and 2015-vintage projects show essentially no change in average capacity factor from those built in 2013, due to relatively small, and in some cases offsetting, movement in the underlying design parameters.[34]

[34] For example, the percentage of newly built projects using tracking increased from 54% in 2013 to 67% in 2015, but the average site-specific long-term GHI declined from 5.29 to 5.11 kWh/m^2/day. Meanwhile, the average ILR drifted only slightly higher, from 1.28 to 1.30.

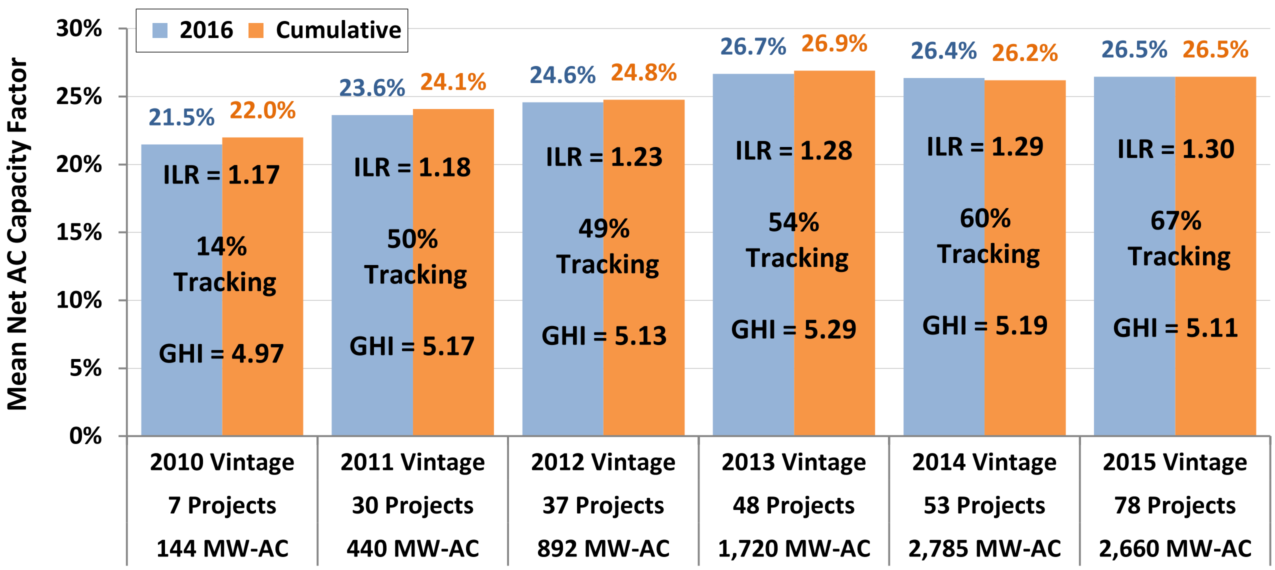

Figure 16. Cumulative and 2016 Capacity Factor by Project Vintage: 2010-2015 Projects

Two other factors could plausibly contribute to the general increase in average capacity factor by vintage (at least through 2013-vintage projects) seen in Figure 16: inter-year variation in the strength of the solar resource and performance degradation over time (as more recent project vintages have had less time to degrade). The former could play a role if insolation at these project sites were significantly stronger in more recent years (e.g., 2015-2016) than in earlier years (e.g., 2011-2014). If this were the case, then 2015-vintage projects, for example, might be expected to exhibit higher cumulative capacity factors than older projects, given that 2016 is the only applicable performance year for a 2015-vintage project.

Two findings, however, suggest that inter-year resource variation is *not* contributing to the upward trend seen in Figure 16. First, ex-post annual solar resource data (Vaisala 2013, 2014, 2015, 2017) finds that 2013-2016 were actually *below-normal* (2013-15) or *normal* (2016) insolation years in California and the Southwest, where most utility-scale PV projects are located (65% of the projects and 82% of the capacity in our capacity factor sample are located in these two regions). Second, the blue columns in Figure 16 measure capacity factors across vintages during the same single year—2016—yet show essentially the same upward trend as the orange columns that measure cumulative capacity factors, suggesting that ILR, GHI, and tracking (and perhaps degradation—addressed in the next section) are the true drivers.

Performance degradation is evident, but is difficult to assess and attribute at the project level

Finally, the possibility of performance degradation has been mentioned several times in the preceding text as a potential driver of project-level capacity factors. Unfortunately, degradation is difficult to assess, and even more difficult to attribute, at the project-level, in large part because its impact over limited time frames is likely to be rather modest and swamped by other factors. For example, over a 9-year period (i.e., the maximum number of full calendar years that any project in our sample has been operating to date), a representative degradation rate of

0.5%/year would reduce an initial net AC capacity factor of 30.0% to 28.8% in the ninth year (all else equal). This 120 basis point reduction in capacity factor over nine years is rather trivial in comparison to, and could easily be overwhelmed by, the impact of other factors, such as curtailment or inter-year variation in the strength of the solar resource.

Nevertheless, some amount of degradation is widely expected (e.g., module manufacturers commonly build degradation into their performance guarantees, and many power purchase agreements for utility-scale PV projects also account for degradation when projecting output over time[35]), and so should not be ignored as a possible driver of cumulative capacity factor. To that end, Figure 17 graphs the median (with 20th and 80th percentile bars), simple average, and capacity-weighted average capacity factors over time, where time is defined as the number of full calendar years after each individual project's commercial operation date (COD), and where each project's capacity factor is indexed to 100% in year one (in order to focus solely on changes to each project's capacity factor over time, rather than on absolute capacity factor values).

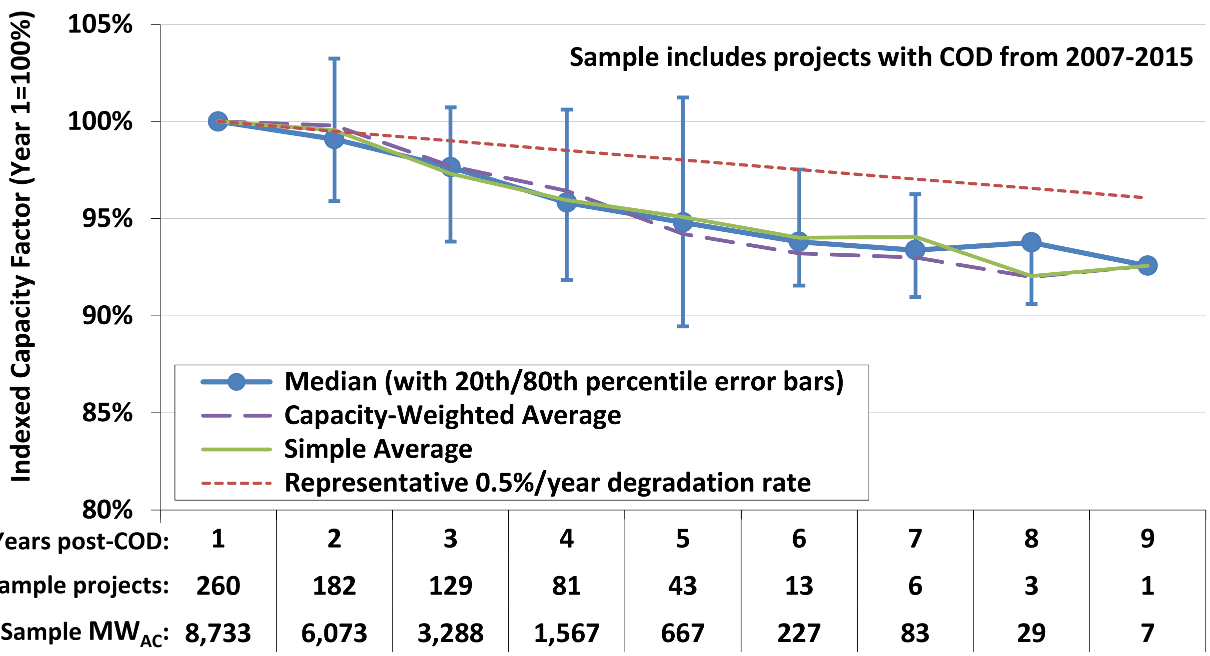

Figure 17. Changes in Capacity Factors Over Time Suggest Performance Degradation

At first glance, Figure 17 suggests that performance degradation has been considerably worse than the 0.5%/year rule of thumb that is commonly assumed (and that is depicted by the dashed red line).[36] However, a number of caveats are in order. First, no attempt has been made to correct for inter-year variation in the strength of the solar resource. Although the potential impact of this omission is likely muted by the fact that year three (for example) for one project

[35] For example, within a sub-sample of 30 utility-scale PV PPAs totaling 3,350 MW_{AC} that were collected for the next section of this report, contractual not-to-exceed degradation rates range from 0.25%-1.0% per year, with a sample mean of 0.6%/year and a median of 0.5%/year.

[36] The fact that the 80th percentile error bar exceeds 103% in year two could partly reflect the initial production ramp-up period that is sometimes experienced by solar projects as they work through and resolve initial "teething" issues during their first year of operations.

will be a different calendar year than year three for another project, inter-year resource variation could still play a role—particularly with several below-normal insolation years in a row, like California and the Southwest reportedly experienced from 2013-15 (Vaisala 2013, 2014, 2015, 2016, 2017).

Second, curtailment has increasingly affected the output of some solar projects in high penetration markets like California and Hawaii, and could be influencing the trends in Figure 17. As discussed later in the text box on page 35, nearly 235 GWh, or 1.1% of the total potential solar generation within the California ISO market in 2016, was curtailed for one reason or another. To place this amount of curtailed solar energy in perspective, it is equivalent to the annual output of a hypothetical 95 MW_{AC} PV project operating at an average California capacity factor of 28.20%. Absent this curtailment, the average 2016 capacity factor among our California sample would have been more than half a percentage point higher than it was, increasing from 28.20% to 28.75%. This difference in capacity factor is similar to the effect of four years of performance degradation at a rate of 0.5%/year, and could certainly explain some of the apparent degradation seen in Figure 17.

Finally, the project sample is not the same in each year shown along the x-axis of Figure 17, and shrinks rapidly as the number of post-COD years increases, reflecting the relative youth of the utility-scale PV market. This sampling heterogeneity could be complicating interpretation.

In short, though Figure 17 presumably does reflect some amount of module-level performance degradation, other factors such as curtailment and inter-year variation in the strength of the solar resource also likely play a role. Teasing apart these various influences is beyond the scope of this high-level exploration.

2.5 Power Purchase Agreement (PPA) Prices (189 contracts, 11,677 MW_{AC})

The cost of installing, operating, and maintaining a utility-scale PV project, along with its capacity factor—i.e., all of the factors that have been explored so far in this report—are key determinants of a project's levelized cost of energy ("LCOE") as well as the price at which solar power can be profitably sold through a long-term power purchase agreement ("PPA"). Relying on data compiled from FERC Electric Quarterly Reports, FERC Form 1, EIA Form 923, and a variety of regulatory filings, this section presents trends in PPA prices among a large sample of utility-scale PV projects in the U.S., including 189 contracts totaling 11,677 MW_{AC}. A text box on page 41 also explores the LCOE of utility-scale PV in the United States, and compares it to these empirical PPA prices.

The population from which this PPA price sample is drawn includes only those utility-scale projects that sell electricity (as well as the associated capacity and renewable energy credits or "RECs") in the wholesale power market through a long-term, bundled PPA. Utility-owned projects, as well as projects that benefit from net metering or customer bill savings, are therefore not included in the sample. We also exclude those projects that unbundle and sell RECs separately from the underlying electricity, because in those instances the PPA price alone does not reflect the project's total revenue requirements (on a post-incentive basis). PPAs resulting from Feed-in Tariff ("FiT") programs are excluded for similar reasons—i.e., the information content of the pre-established FiT price is low (most of these projects do not exceed the 5 MW_{AC} utility-scale threshold anyway). The same holds true for "avoided cost" contracts with non-negotiated or "standard offer" pricing (also known as "PURPA" or "QF" contracts),[37] which are FiT-like in nature and, in some states, also involve unbundling RECs. In short, the goal of this chapter is to learn how much post-incentive revenue a utility-scale solar project requires to be viable.[38] As such, the PPA price sample comes entirely from utility-scale projects that sell bundled energy, capacity, and RECs to utilities (both investor-owned and publicly-owned utilities) or other offtakers through long-term PPAs resulting from competitive solicitations or bilateral negotiations.[39] All that said, projects that do not meet these requirements and so are

[37] The Public Utility Regulatory Policies Act, or PURPA, was signed into law in 1978 and requires utilities to purchase electricity from "qualifying facilities" (including solar and wind projects smaller than 80 MW) at prices that represent their "avoided cost"—i.e., what they would pay for the same amount of electricity generated by a non-qualifying facility. In recent years, PURPA has come under fire in some states that are experiencing a large influx of wind and solar projects seeking avoided cost contracts (for more information, see the text box—*Trend to Watch: The Rise (and Fall?) of "Avoided Cost" Markets*—in the 2014 edition of this report (Bolinger and Seel 2015)).

[38] Using PPA prices for this purpose reflects an implicit assumption that PPA prices will always be sufficient to cover all costs and provide a normal rate of return. This may not always be the case, however, if projects underperform relative to expectations or have higher-than-anticipated operating costs. In general, the project sponsor and investors bear these risks (to varying degrees, depending on the specifics of their contractual arrangements).

[39] Because all of the PPAs in the sample include RECs (i.e., transfer them to the power purchaser), we need not worry too much about REC price trends in the unbundled REC market. It is, however, worth noting that some states have implemented REC "multipliers" for solar projects (whereby each solar REC is counted as more than one REC for RPS compliance purposes), while others have implemented solar "set-asides" or "carve-outs" (requiring a specific portion of the RPS to be met by solar) as a way to encourage solar power development specifically. In these instances, it is possible that utilities might be willing to pay a bit more for solar through a bundled PPA than they otherwise would be, either because they need to in order to comply with a solar set-aside, or because they know that each bundled solar REC has added value (in the case of a multiplier). So even though REC prices do not directly

excluded from the PPA price sample can still contribute to an understanding of utility-scale PV's LCOE, and as such are still included in the LCOE calculations described within the text box on page 41.

For each of the contracts in the sample,[40] we have collected the contractually locked-in PPA price data over the full term of the PPA,[41] and have accounted for any escalation rates and/or time-of-delivery ("TOD") pricing factors employed.[42] The PPA prices presented in this section, therefore, reflect the full revenue available to (and presumably in many cases, the minimum amount of revenue required by[43]) these projects over the life of the contract—at least on a post-incentive basis. In other words, these PPA prices do reflect the receipt of federal tax incentives (e.g., the 30% investment tax credit or cash grant, accelerated tax depreciation)[44] and state incentives (e.g., grants, production incentives, various tax credits), and would be higher if not for these incentives.[45,46] As such, the levelized PPA prices presented in this section should *not* be equated with a project's unsubsidized LCOE; the text box on page 41 calculates the latter and

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affect the analysis in this report, policy mechanisms tied to RECs might still influence bundled PPA prices in some cases—presumably to the upside.

[40] In general, each PPA corresponds to a different project, though in some cases a single project sells power to more than one utility under separate PPAs, in which case two or more PPAs may be tied to a single project.

[41] The minimum PPA term in the sample is 3 years, though this contract (along with several other short-term contracts like it) covers just the first few years of a project that has a longer-term PPA with a different counterparty starting in 2019. The maximum PPA term is 34 years, the mean is 22.5 years, the median is 21.0 years, and the capacity-weighted average is 22.9 years.

[42] In cases where PPA price escalation rates are tied to inflation, the EIA's projection of the U.S. GDP deflator from *Annual Energy Outlook 2016* is used to determine expected escalation rates. For contracts that use time-of-delivery pricing and have at least one year of operating history, each project's average historical generation profile is assumed to be replicated into the future. For those projects with less than a full year of operating history, the generation profiles of similar (and ideally nearby) projects are used as a proxy until sufficient operating experience is available.

[43] In a competitive "cost-plus" pricing environment—where the PPA price is just sufficient to recoup initial capital costs, cover ongoing operating costs, and provide a normal rate of return—PPA prices will represent the minimum amount of revenue required by a project. In contrast, "value-based" pricing occurs when the project developer or owner is able to negotiate a higher-than-necessary PPA price that nevertheless still provides value to the buyer.

[44] In addition to the other federal incentives listed, eleven projects within the sample also received DOE loan guarantees through the Section 1705 program. In all eleven cases, however, the projects had already executed PPAs by the date on which the loan guarantee was awarded, suggesting that the guarantee did not affect the PPA price.

[45] For example, taking a simplistic view (i.e., not considering financing effects), the average PPA price could be as much as 50% higher (i.e., 30%/(1 minus the federal tax rate)) if there were no federal investment tax credit ("ITC"). Without the ITC, however, the resulting increase in PPA prices would be mitigated by the fact that sponsors with tax appetite could then leverage up their projects more heavily with cheap debt, while sponsors without tax appetite would be able to forego expensive third-party tax equity in favor of cheaper forms of capital, like debt. Because of these financing shifts, the PPA price would not increase by 50%, but rather more like 35-40% in the case of a sponsor with tax appetite, and by roughly 20% in the case of a sponsor without tax appetite that currently relies on third-party tax equity to monetize the ITC (Bolinger 2014).

[46] Though there is too much variety in state-level incentives to systematically quantify their effect on PPA prices here, one example is New Mexico's refundable Production Tax Credit, which has provided a credit of varying amounts per MWh (averaging $27/MWh) of solar electricity produced over a project's first ten years. One PPA for a utility-scale PV project in New Mexico allows for two different PPA prices—one that is $43.50/MWh higher than the other, and that goes into effect only if the project does not qualify for the New Mexico PTC. Based on New Mexico's top corporate tax rate of 7.6%, a $43.50/MWh price increase due to loss of New Mexico's PTC seems excessive (a more appropriate 20-year adjustment would seemingly have been roughly half that amount), but nevertheless, this is one tangible example of how state incentives can reduce PPA prices.

compares it to the former, and finds that PPA prices are consistently lower than LCOE estimates, as expected.

PPA prices have fallen dramatically, in all regions of the country

Figure 18 shows trends in the levelized (using a 7% real discount rate) PPA prices from the full PV contract sample over time. Each bubble in Figure 18 represents a single PPA, with the color of the bubble representing the region in which the underlying project is located,[47] the area of the bubble corresponding to the size of the contract in MW_{AC}, and the placement of the bubble reflecting both the levelized PPA price (along the vertical y-axis) and the date on the which the PPA was executed (along the horizontal x-axis).[48]

Figure 19, meanwhile, is essentially the same as Figure 18, except that it focuses only on those PPAs that were signed since the start of 2015. The purpose of Figure 19 is to provide greater resolution on the most-recent time period, which otherwise appears a bit crowded in Figure 18.

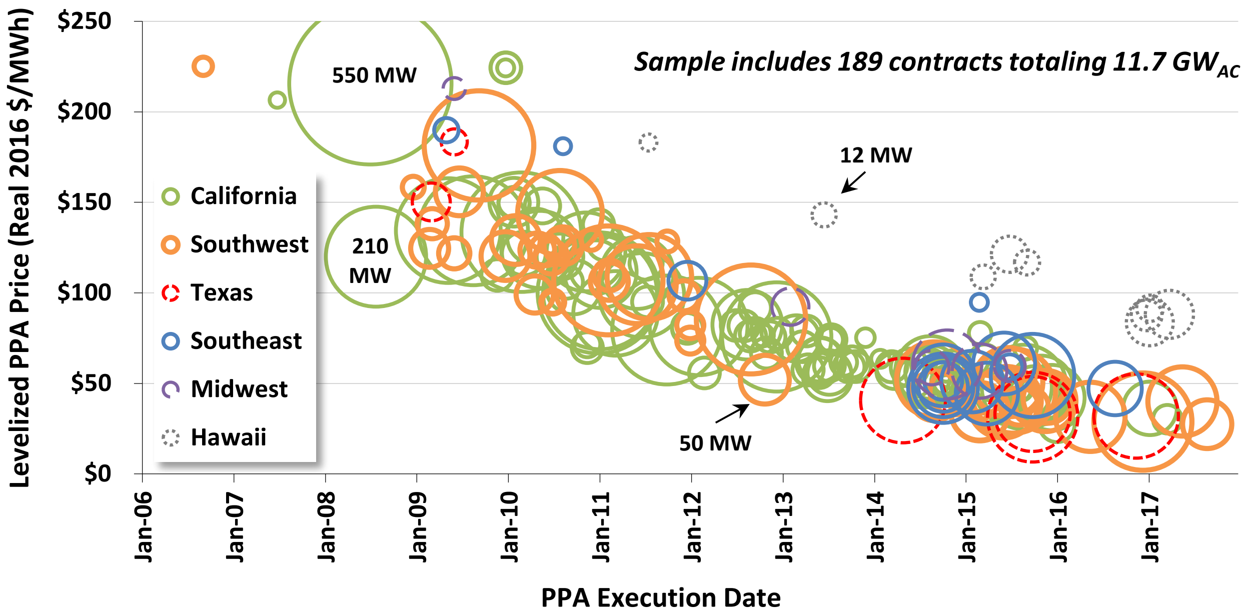


Figure 18. Levelized PPA Prices by Region, Contract Size, and PPA Execution Date: Full Sample

[47] Figure 18 excludes the single northeastern PPA in our sample—a 32 MW_{AC} project on Long Island that was signed in June 2010 and that has a real levelized price of ~$290/MWh (in 2016 dollars)—and we do not yet have PPA price data for any projects in the northwest region.

[48] Because PPA prices reflect market expectations at the time a PPA is executed—which could be two years or more in advance of when the project achieves commercial operation—the PPA execution date is more relevant than the commercial operation date when analyzing PPA prices. For those interested in viewing average PPA prices by commercial operation date, however, Figure 21 breaks it out both ways.

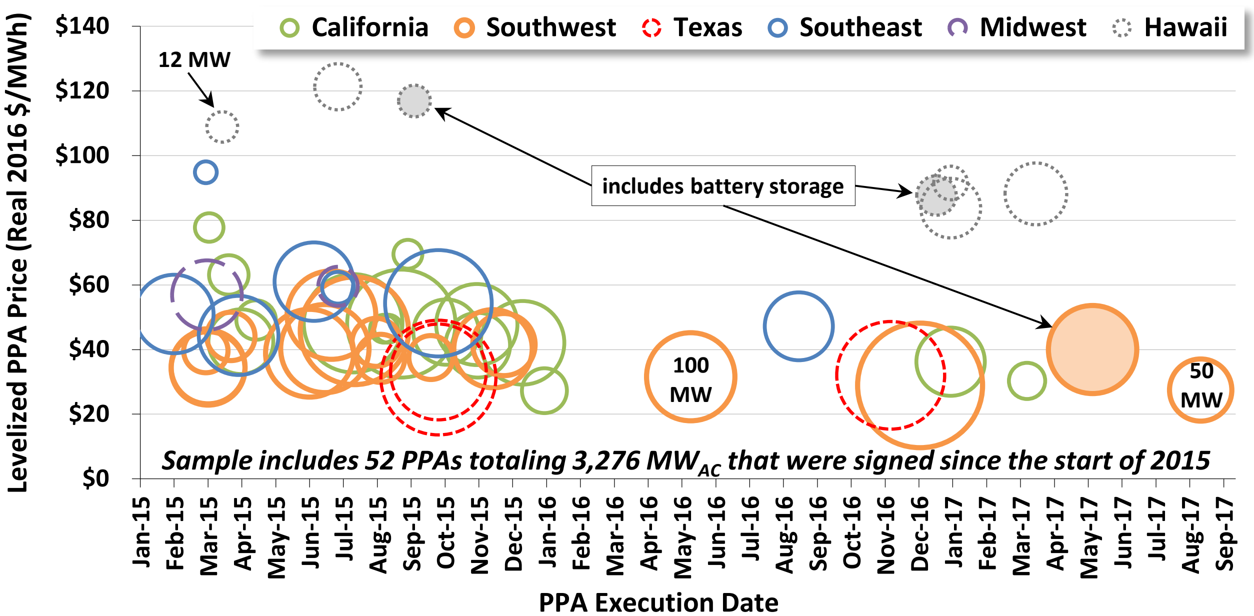


Figure 19. Levelized PPA Prices by Region, Contract Size, and PPA Execution Date: 2015-2017 (YTD) Contracts Only

A number of aspects of Figures 18 and 19 are worth highlighting:

- ***PPA pricing has declined steadily and significantly over time.*** As recently as 2011, solar PPA prices in excess of $100/MWh were quite common. Five years later, most PPAs in the sample are priced at or below $50/MWh levelized (in real, 2016 dollars), with a few priced as aggressively as ~$30/MWh. Though this price decline is impressive in terms of both scale and pace, it is also worth noting that in some markets with high solar penetration, the *wholesale market value* of solar energy has also declined over time as solar penetration has increased; the text box on page 35 explores this value decline within the United States' largest solar market, California.

- ***Though California and the Southwest still dominate the sample, the market has expanded to other regions in recent years.*** Among the sub-sample of PPAs executed *after* 2013, 67% of the contracts representing 63% of the capacity are for projects located in either California or the Southwest, down significantly from 91% of the contracts representing 97% of the capacity within the sub-sample of PPAs executed *prior to* 2014. New markets include the Southeast (17% of post-2013 capacity in the sample), Texas (12%), Hawaii (4%), and even the sun-challenged Midwest (4%). With the exception of Hawaii, all other regions shown in Figures 18 and 19 feature PPA prices below $60/MWh.

- ***Hawaiian projects are priced at a significant premium.*** This year, for the first time, we include Hawaiian projects in our PPA price sample. As can be clearly seen in both Figures 18 and 19, Hawaiian PPAs have consistently been priced at a significant premium—of at least $40/MWh—over those in the continental United States. Although some premium is no doubt warranted given Hawaii's remote location and weaker solar resource (at least relative to California and the Southwest), the ~$40/MWh PPA price premium seen in recent years seems high. For example, Fu et al. (2015) modeled the LCOE of utility-scale PV projects throughout the United States (including Hawaii), based on differences in labor rates, installation costs, insolation, and other factors, and estimated that in 2015, a project in Kona, Hawaii would have had an LCOE that was $14-$15/MWh higher than an identical project in California's Imperial Valley, and only $7-$8/MWh higher than an identical project in Bakersfield, California. The observed levelized PPA price premium of ~$40/MWh is considerably higher than these modeled LCOE premiums, and perhaps suggests that some degree of value-based (as opposed to cost-based, or cost-plus) pricing may be occurring in Hawaii, with developers bidding to some extent against the high cost of oil-fired generation.

- ***The incremental cost of storage does not seem prohibitive.*** Also for the first time, this year our sample includes three projects designed and built with long-duration (i.e., 4-5 hours) battery storage. These three projects are distinguished in Figure 19 by having their bubbles shaded (and, more obviously, by the indicative label with arrows). Each of these projects (plus a fourth for which PPA price information is not yet available) are discussed in more detail in the text box on page 37, but here we simply note that these utility-scale PV plus storage projects do not seem to be priced at a significant premium compared to other contemporary projects located within the same region but lacking storage. This theme is explored further in the text box on page 37.

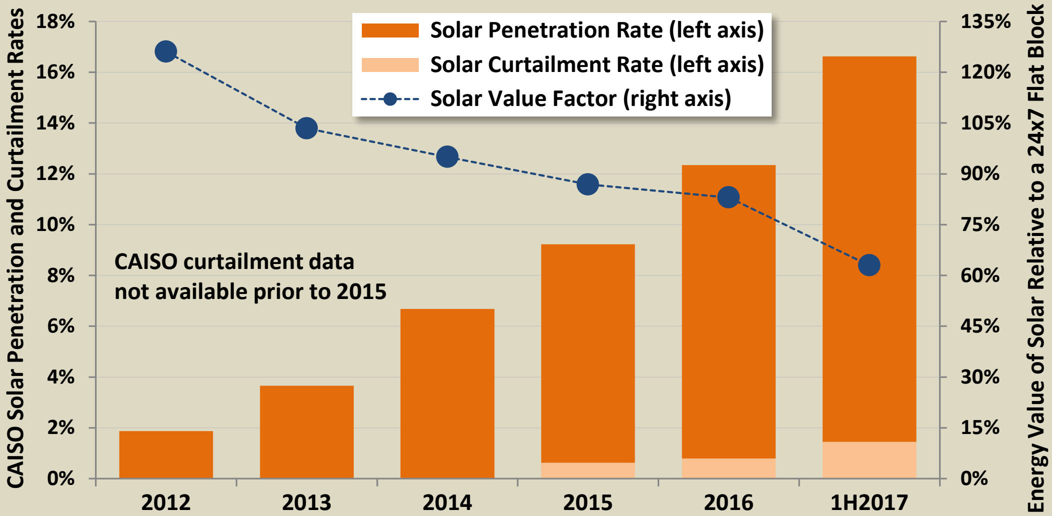
- ***Smaller projects are often equally competitive.*** Though there have recently been a number of large, low-priced contracts announced, smaller projects (e.g., in the 20-50 MW range) feature PPA prices that are, in some cases, seemingly just as competitive as larger projects. In many states, very large projects may face greater development challenges than smaller projects, including heightened environmental sensitivities and more-stringent permitting requirements, as well as greater interconnection and transmission hurdles. Once a project grows beyond a certain size, the costs of overcoming these incremental challenges may outweigh any benefits from economies of scale in terms of the effect on the PPA price.

- ***Not all of these projects are online, but barring a trade war, there is no compelling reason to think that they will not be built.*** Unlike other chapters of this report, which focus exclusively on operating projects (determined by commercial operation date), this chapter tracks PPA prices by *contract execution date*—which means including projects that are still in development—in order to provide a better picture of where the market is (or was) at any given point in time. As of August 2017, more than 90% of all projects and capacity within the PPA sample were either partially or fully operating, with the remainder representing more-recently signed contracts for projects that are still under development or construction. While it remains to be seen whether all of these projects can be profitably built and operated under the aggressive PPA price terms shown in Figures 18 and 19, the sample does not include any PPAs that have already been terminated.[49] One prominent variable in this equation is the still-to-be-determined outcome of the so-called "Section 201" trade petition to impose tariffs on imported PV modules; a successful petition could potentially increase costs for those projects that have not yet secured modules (Berg, Barati, and Wilkinson 2017), possibly leading to PPA renegotiations or even outright cancellations.

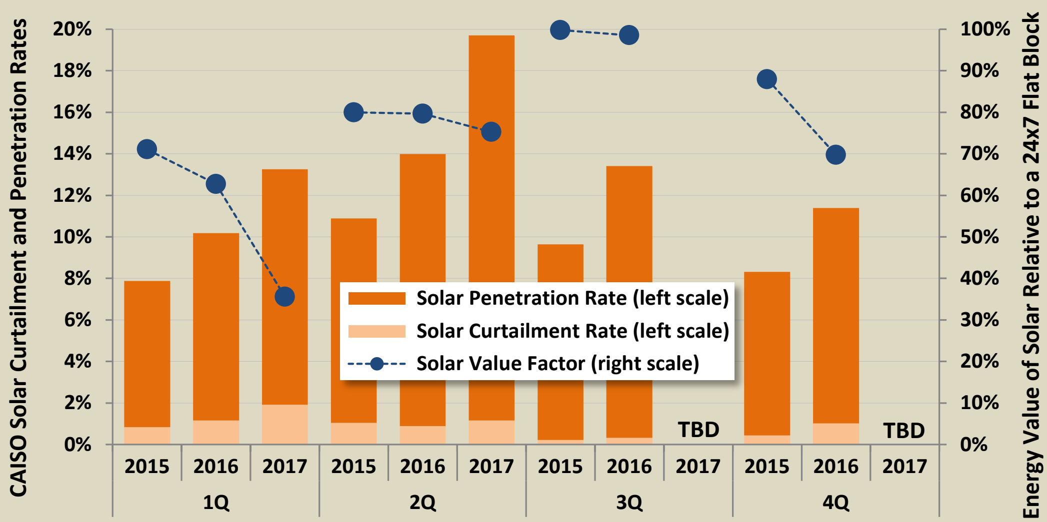
[49] There is a history of solar project and PPA cancellations in California and elsewhere, though in many cases these have involved projects using less-mature technologies (e.g., Stirling dish engines, compact linear Fresnel reflectors, and power towers). For PV projects, price revisions are perhaps a more likely risk than outright termination.

The energy value of solar has declined in America's largest solar market

Solar energy penetration (including estimates for DG solar) within the CAISO market increased from nearly 2% of load back in 2012 to more than 12% in 2016, and has increased even further so far in 2017. As solar penetration has risen, so too has the percentage of solar generation that is being curtailed—still in the low single digits (thanks in part to the west-wide energy imbalance market), but rising since data first became available in 2015.



Perhaps more worrisome, the wholesale energy value of solar within CAISO's real-time market (expressed in the two graphs here as a percentage of the simple average wholesale power price across all hours) has declined steadily. Back in 2012, when solar covered just 2% of load, the hourly generation-weighted average wholesale power price earned by solar was \$38.0/MWh, or 126% of the simple average wholesale power price across all hours. Four years later in 2016, with solar at 12% penetration, solar's value was just \$23.8/MWh, or 83% of the average wholesale price. With penetration and curtailment increasing further in 2017, this value decline is likely to continue—analysis of the first half of the year finds solar's value at \$15.8/MWh, or just 63% of the average wholesale price of \$25.1/MWh. That said, the bottom graph shows that the third and fourth quarters are typically higher-value quarters than the first and second, suggesting that the full-year 2017 numbers might not be as dire as suggested by the H1 numbers shown in the top graph.



Breaking the numbers out on a quarterly basis reveals that after a dismal 1Q17—attributable in part to a "flood" of hydropower generation—2Q17 has not been as troublesome, with curtailment on par with both 2015 and 2016 (at least in percentage terms) and solar's energy value only down slightly from prior years (despite much higher penetration in 2Q17). It remains to be seen how the 3rd and 4th quarters—typically higher-value quarters—will round out the year.

It should be noted that the decline in the value of solar in California is not necessarily indicative of other markets across the United States. Solar's energy market value depends on a variety of factors, including local solar penetration levels, electricity demand and supply patterns, and the flexibility of other generators to ramp their production up and down. For example, in ERCOT and SPP—the only two other ISOs in the country that report solar generation separately—solar's energy value in 2016 was 131% and 133% of average wholesale power prices, respectively (albeit at much lower large-scale solar penetration levels of 0.24% and 0.08%).

Figure 20 portrays the data from Figure 18 in a slightly different way, to more clearly illustrate the strong downward time trend in average pricing. The circle markers show the levelized PPA price of each individual contract grouped by the year in which the contract was signed (each circle in Figure 20 corresponds to a bubble in Figure 18; Hawaii PPAs are shaded here in orange), while the blue-shaded columns show the generation-weighted average of those individual levelized contract prices. Levelized PPA prices for utility-scale PV projects within the sample consistently fell by \$20-\$30/MWh per year on average from 2006 through 2012, with smaller price declines averaging ~\$10/MWh from 2013 through 2016.[50] The uptick in the average price among contracts executed so far in 2017 is likely attributable to the small size and make-up of the sample: three of these seven PPAs (totaling 110 MW) are for Hawaiian projects (with their apparent premium), while a fourth 100 MW project includes battery storage and would reportedly have been priced \$15/MWh lower if just solar without storage (this project is described further in the text box on the next page).

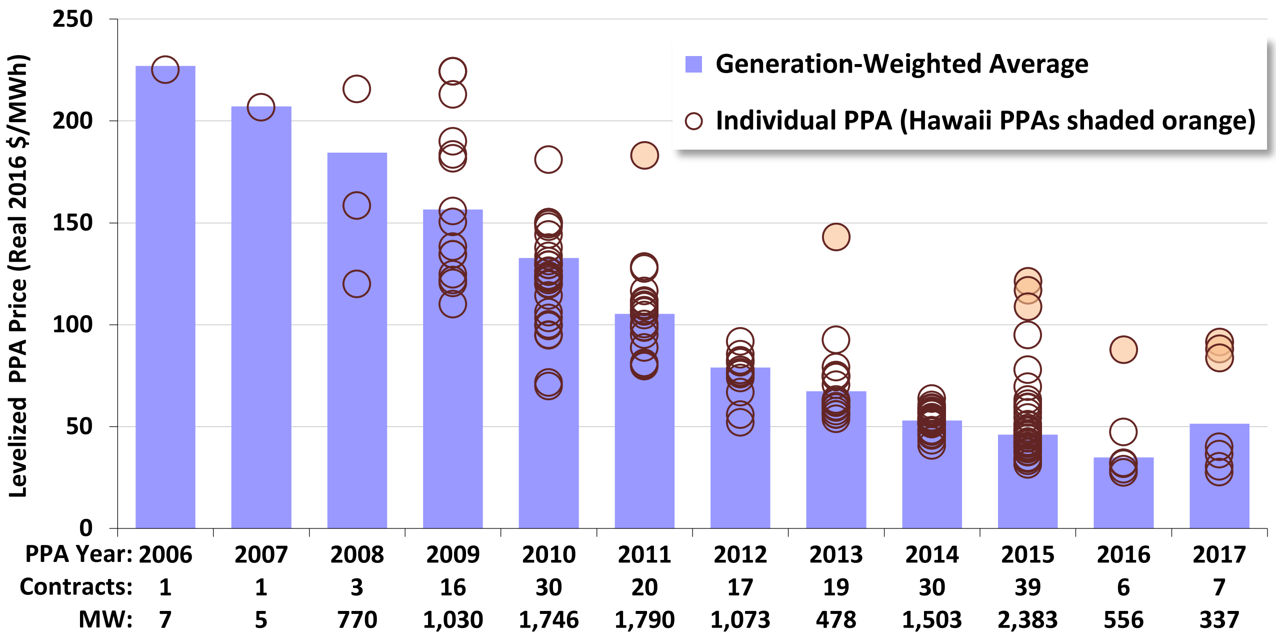


Figure 20. Levelized PV PPA Prices by Contract Vintage[51]

[50] This strong time trend complicates more-refined analysis of other variables examined in earlier chapters, such as resource strength, tracking versus fixed-tilt, inverter loading ratio, and module type. To try and control for the influence of time, one could potentially analyze these variables within a single PPA vintage, but doing so might divide the sample to the point where sample size is too small to reliably discern any differences. Furthermore, it is not clear that some of these variables should even have much of an effect on PPA prices. For example, several of the PPAs in the sample note uncertainty over whether or not tracking systems will be used, or whether c-Si or thin-film modules will be deployed. Yet the executed PPA price is the same regardless of the ultimate project configuration, suggesting that the choice of tracking versus fixed-tilt or c-Si versus thin-film is (at least in these cases) not a critical determinant of PPA pricing. This makes sense when one considers that tracking systems, for example, add up-front costs to the project (see Section 2.2) that are recouped over time through greater energy yield (see Section 2.4), thereby potentially leaving the net effect on PPA prices largely a wash.

[51] Figure 20 excludes the two CPV projects in our sample. If included, they would both fall within the 2010 bin, at levelized prices of \$109.4/MWh and \$126.9/MWh—i.e., within the range of PV projects shown.

Utility-scale PV plus battery storage starting to gain traction

To date, four integrated utility-scale PV plus battery storage projects have been announced in the United States—two in Hawaii (on the island of Kauai) and two in Arizona—with one of the Kauai projects having achieved commercial operation in early 2017. The table below provides known specs on each of these four projects/contracts, all of which will use lithium-ion technology (with at least two, and most likely three, deploying Tesla Powerpacks).

State	Project		Capacity (MW-AC)		Battery Storage		PPA Date	Expected COD	PPA Term (years)	PV Mount	Expected Capacity Factor	Levelized PPA Price (2016 $/MWh)	% of PV used to charge
	Sponsor	Offtaker	PV	Battery	Duration	MWh							
HI	Tesla	KIUC	13	13	4 hours	52	Sep-15	Apr-17	20	Fixed	~20%	~$117	>80%
HI	AES	KIUC	20	20	5 hours	100	Dec-16	Oct-18	25	Tracking	~29%	~$88	>70%
AZ	NextEra	SRP	20	10	4 hours	40	Apr-17	Mar-18	20	Tracking	~33%	N/A	~25%
AZ	NextEra	TEP	100	30	4 hours	120	May-17	Dec-19	20	Tracking	~33%	~$40	~15%

It should come as no surprise that the first two such PPAs are for projects located in an island state with an isolated grid and already-significant solar penetration. Commensurately, both Kauai projects size the battery capacity to match the PV capacity (in AC terms), and will use 70-80% (or more) of the solar energy generated in order to charge the batteries (for later discharge during evening hours). This stands in contrast to the two Arizona projects, which feature battery capacities that are 30-50% of the PV capacity (in AC terms), and that will use only 15-25% of the solar output for charging.

Levelized PPA prices are available for three of the four projects. In Kauai, the second PPA (signed roughly 16 months after the first) is priced about $30/MWh lower than the first, though is also 5 years longer in duration (which reduces the levelized price somewhat). That said, as shown in Figure 19 of the main report, PPA prices for utility-scale PV projects *without* storage in Hawaii appear to have fallen by a similar amount over this same time frame. In fact, based on Figure 19, there does not seem to be an obviously discernible difference in Hawaii between the PPA prices of projects with or without storage—an assessment that is perhaps clouded by any value-based pricing that might be occurring (as suggested in the text below Figure 19).

On the mainland, there is only one publicly available PPA price data point at present: Tucson Electric Power's (TEP's) announcement that its all-in cost will be "significantly less than" $45/MWh, and that the solar component is less than $30/MWh on its own (Maloney 2017), implying an adder of ~$15/MWh for 4 hours of storage at 30% of PV nameplate. This implied adder is consistent with NextEra's recent projection of a battery storage adder (for 4 hours at 40% of solar nameplate) of $19-29/MWh in 2016, dropping to $12-22/MWh in 2020 (NextEra Energy 2017). In the wake of the TEP announcement, ViZn Energy (a zinc-iron flow battery manufacturer) heralded its own ability to build a similar project for under $40/MWh, with a storage adder (for 4 hours at 30% of solar nameplate) of ~$14/MWh (ViZn Energy 2017).

This discussion surrounding the size of the storage adder naturally raises the question of whether the benefit of storage outweighs the incremental cost. A relatively simple modification of the solar generation data used for the analysis highlighted in the "declining energy value of solar" text box on page 35 suggests that storage is not yet cost-effective—at least in California, and considering only the value of the 4-hour energy shift—at these adder levels. Scaling the actual hourly PV generation profile down to a hypothetical 100 MW project, we subtracted 30 MW of PV generation per hour over a 5-hour period (i.e., 150 MWh total) in the middle of each day (from 10 AM-3 PM) and then added back 30 MW per hour over a 4-hour period (i.e., 120 MWh total) later in the day (from either 4-8, 5-9, or 6-10 PM—we looked at all three periods). The disparity between the 150 MWh charge and 120 MWh discharge is a crude attempt to account for an 80% round-trip efficiency. The results suggest that, at least in California, such an energy shift would have only increased the wholesale energy value of solar by ~$3/MWh in 2016—i.e., only ~20% of the indicative adder cost.

Of course, California is not Arizona; although California's "duck curve" gets all the attention, Arizona's duck curve is reportedly "far more dramatic" due to the predominant role that solar plays in that state, relative to other renewables (Maloney 2017). As such, a 4-hour energy shift may be more valuable in Arizona than it is in California. In addition, Denholm et al. (2017) point out that although PV plus battery storage was not cost-competitive with PV alone in California in 2016, the reverse will be true by 2020 as solar penetration increases. Especially for long-lived technologies (and investment decisions), such forward-looking modeling is more appropriate than a single-year historical assessment. Finally, there are other grid services—and corresponding value or revenue streams—that a battery can provide, but that are not accounted for in this back-of-the-envelope modeling exercise (which focuses solely on the 4-hour energy shift). For example, accounting for capacity value, frequency regulation, and reserves could all bolster the benefit side of the equation.

As noted earlier, some projects in our PPA price sample have not yet been built, and for those that have been built often a year or more can pass between when a PPA is signed and when the underlying project ultimately achieves commercial operation. As a result, the decline in PPA prices over time looks more erratic when viewed by commercial operation date (rather than by PPA execution date). The blue columns in Figure 21 are based on PPA execution date (and thus match those shown in Figure 20), while the orange columns show the generation-weighted average PPA price in the years in which each project achieved full commercial operation. Because 2017 is still in progress, it is labeled as provisional.[52] Though the average levelized price of PPAs signed in 2016 is ~$35/MWh, the average levelized PPA price among projects that came online in 2016 is significantly higher at ~$59/MWh; this difference was even starker in many prior years.

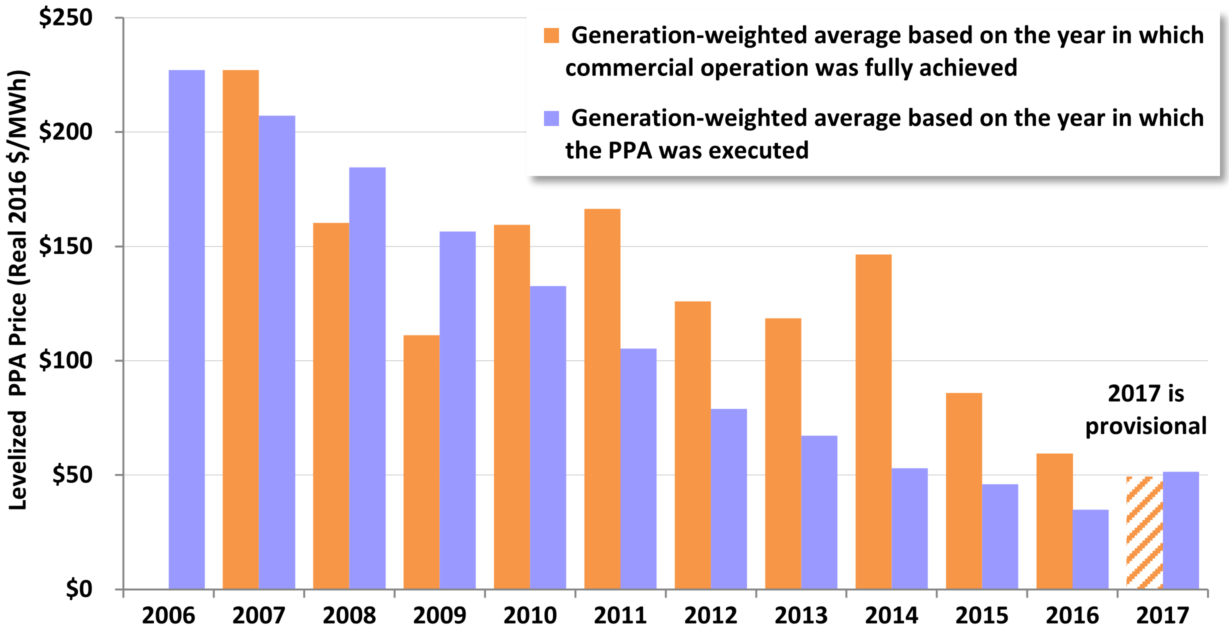


Figure 21. Average Levelized PV PPA Prices by Contract and COD Vintage

Solar's largely non-escalating and stable pricing can hedge against fuel price risk

Roughly two-thirds of the contracts (and capacity) in the PPA sample feature pricing that does *not* escalate in nominal dollars over the life of the contract—which means that pricing actually *declines* over time in real dollar terms. Figure 22 illustrates this decline by plotting over time, in real 2016 dollars, the generation-weighted average price among *all* PPAs executed within a given year (i.e., including both escalating and non-escalating contracts). In other words, for each contract vintage, Figure 22 shows the stream of generation-weighted average PPA prices over time (these are the future PPA price streams that were levelized to yield the blue-shaded columns in Figures 20 and 21).

[52] Though, for that matter, 2016 and earlier years are also still provisional in some sense, given that our sample of older PPAs will no doubt increase in future years as well, as more light is shed on pricing over time.

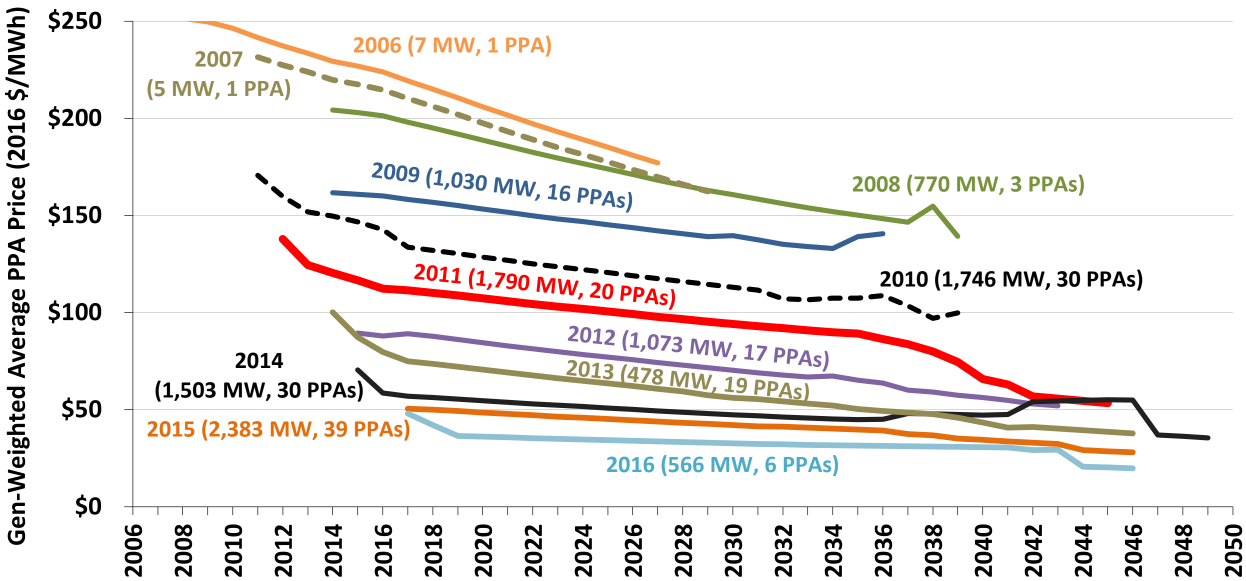


Figure 22. Generation-Weighted Average PV PPA Prices Over Time by Contract Vintage

By offering flat or even declining prices in real dollar terms over long periods of time, solar (and wind) power can provide buyers with a long-term hedge against the risk of rising fossil fuel prices (Bolinger 2013, 2017). Figure 23 illustrates this potential by plotting the future stream of average and median PV PPA prices from 29 contracts in the sample that were executed over the past two years (i.e., from July 2015 through August 2017) against a range of projections of *just the fuel costs* of natural gas-fired generation.[53] In this way, Figure 23 essentially compares the cost of *new* PV projects to the cost of *existing* gas-fired generation. This comparison is not perfect, however, given that existing gas-fired generators will also incur some small amount of non-fuel variable operating costs that are not accounted for, and may also still need to recover some portion of their initial capital costs to build the project. Nor do natural gas and solar projects have equivalent output profiles or environmental characteristics.

Nonetheless, as shown, both the generation-weighted average and median PPA prices start out well above the range of fuel cost projections in 2017, but decline (in real 2016 $/MWh terms) over time, entering the fuel cost range in 2021 and 2022, respectively, and eventually reaching the reference case fuel cost projection by the end of that decade before ultimately falling below the reference case projection by the second half of the 2030s.

[53] The national average fuel cost projections come from the EIA's *Annual Energy Outlook 2017* publication, and increase from around $3.53/MMBtu in 2017 to $6.13/MMBtu (both in 2016 dollars) in 2050 in the reference case. The upper and lower bounds of the fuel cost range reflect the low and high (respectively) oil and gas resource and technology cases. All fuel prices are converted from $/MMBtu into $/MWh using the average heat rates implied by the modeling output, which start at ~ 7.9 MMBtu/MWh in 2017 and gradually decline to ~6.9 MMBtu/MWh by 2050.

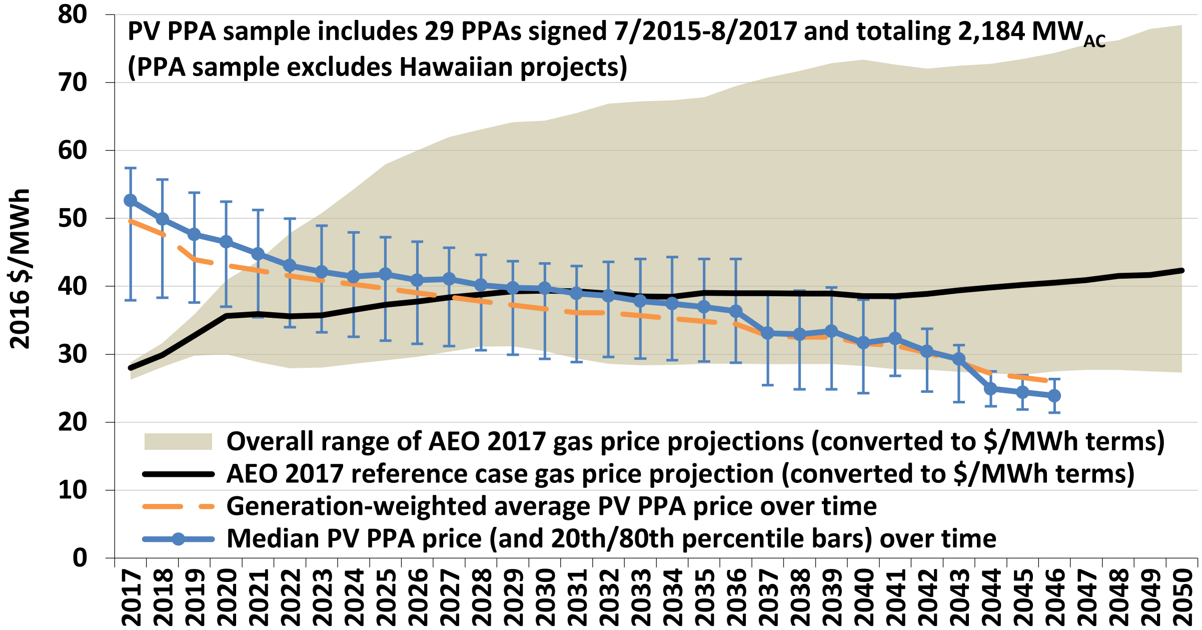


Figure 23. Average PV PPA Prices and Natural Gas Fuel Cost Projections Over Time

On a levelized basis (in real 2016 dollars) from 2017 through 2046, the PV PPA prices come to $41.6/MWh (median) and $39.5/MWh (generation-weighted average), compared to $36.2/MWh for the reference case fuel cost projection, suggesting that sustained low gas prices (and low gas price expectations) has made it difficult for PV to compete with *existing* gas-fired generation. That said, it is important to recognize that the PV PPA prices shown in Figure 23 have been contractually locked in, whereas the fuel cost projections to which they are compared are highly uncertain—actual fuel costs could end up being either lower or potentially much higher. Either way, as evidenced by the widening range of fuel cost projections over time, it becomes increasingly difficult to forecast fuel costs with any accuracy as the term of the forecast increases (Bolinger 2013, 2017).

Moreover, as noted above, the comparison laid out in Figure 23 is not entirely apples-to-apples, as it does not include the recovery of fixed capital costs that would be incurred by *new* gas-fired generators (or other non-fuel operating costs that would be incurred by both new and existing gas-fired generators), whereas the PV PPA prices are set at a level intended to be sufficient to recover *all* costs (i.e., both initial capital costs and ongoing operating costs). By one estimate, capital and non-fuel O&M costs can add $27-$54/MWh to the levelized cost of energy from a combined-cycle gas plant (Lazard 2016).

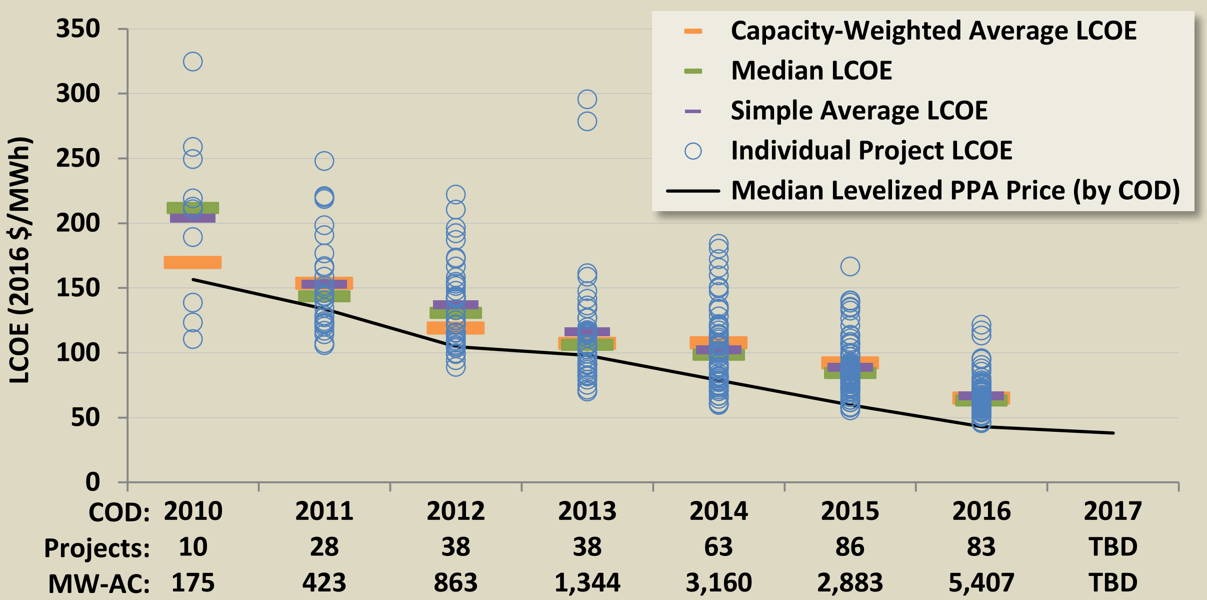
On the other hand, Figure 23 also makes no attempt to account for the operational and environmental differences between these two generation sources, or the differences in federal and state subsidies received. In particular, it is widely known that the market value of solar declines with increased solar penetration, as a result of grid integration challenges and other characteristics related to its temporal generation profile (Mills and Wiser 2013); these factors are not considered here (but are partially explored, at least within California, in the text box on page 35).

Levelized PPA prices track the LCOE of utility-scale PV reasonably well

In a competitive market, bundled long-term PPA prices can be thought of as reflecting a project's levelized cost of energy (LCOE) reduced by the levelized value of any state or federal incentives received. Hence, as a first-order approximation, project-level LCOE can be estimated simply by adding the levelized value of incentives received to levelized PPA prices. LCOE can also be estimated more directly, however, from key project data such as collected for this report—e.g., CapEx, capacity factor, and OpEx—coupled with other assumptions about financing, taxes, etc. One advantage of this more-direct approach is that it enables us to estimate LCOE for a much larger sample of projects than would be possible if starting with PPA prices. Here we use the project-level empirical data reflected throughout this report, in conjunction with other assumptions enumerated in the next paragraph, to estimate the LCOE of utility-scale PV by project and on average over time.

Our sample starts with the >14 GW_{AC} of projects for which we have compiled CapEx estimates (as presented in Section 2.2). For projects that have been operating for at least a full year and for which we have capacity factor data (as presented in Section 2.4), we rely on those empirical data. For projects where we do not yet have capacity factor data, we estimate capacity factors based on underlying project characteristics (e.g., the average long-term irradiance at the project site, whether or not tracking is used, the ILR, etc.) in conjunction with the regression formula laid out in Bolinger, Seel, and Wu (2016). In all cases, we then handicap the project-level capacity factor data to reflect a projected annual degradation rate of 0.5%/year (see footnote 35) before plugging it into the LCOE equation (which is the same equation used in Cole et al. (2016)). Total OpEx is assumed to be $30/kW-year for all projects; this assumption is higher than the average utility O&M cost numbers shown in Figure 13, but those numbers are derived from FERC Form 1 and do not reflect total OpEx (see footnote 24). The cost of equity is assumed to be 10% (after-tax) for all projects, while the cost of debt varies daily (but is averaged across each calendar year) based on the 30-year fixed-for-floating swap rate benchmark (ICE 2017) plus BNEF's (2017) estimate of the debt spread in the commercial bank market over time. The nominal after-tax weighted average cost of capital, or WACC, reflects a 60%/40% debt/equity ratio in all cases, applied to the average cost of debt and equity *in the year prior to* when each project achieves commercial operation (in an attempt to reflect the time lag between when a project is financed and built). For reference, the nominal after-tax WACC ranges from 6.46% in 2009 (for projects with a 2010 COD) to 5.66% in 2015 (for projects with a 2016 COD). Other assumptions include a 30-year project life, an inflation rate of 2.5%/year, a combined federal and state tax rate of 40%, a 5-year MACRS depreciation schedule, ***and NO investment tax credit (ITC)***. Finally, the "capital recovery factor" and "project finance factor" are calculated (from various data and assumptions already noted above) per the formulas in Cole et al. (2016).

The figure below shows the results of this exercise, with both project-level and central estimate LCOEs plotted alongside median levelized PPA prices (from a smaller sample than indicated for LCOE, and in this case levelized over 30 years to match the LCOE term and then plotted by COD, rather than execution, year). In general, the central LCOE estimates closely follow the declining PPA price trend seen here (and elsewhere in this section), suggesting a relatively competitive market for PPAs. Median PPA prices are universally lower than the central LCOE estimates because of the value of the 30% ITC (plus any state-level incentives), which is passed through to offtakers in the form of lower prices (by ~$20/MWh in recent years). Looking ahead, the median levelized PPA price among a small sample of 11 projects totaling 427 MW that are likely to achieve commercial operations in 2017 suggests a further decline in LCOE.



3. Utility-Scale Concentrating Solar Thermal Power (CSP)

This chapter largely follows the same format as the previous chapter, but focuses on CSP rather than PV projects.[54] Isolating these two different technologies in this way simplifies reporting and enables readers who are more interested in just one of these technologies to more-quickly access what they need. So as not to lose the value of being able to easily compare the two technologies when presented side by side, however, we have endeavored to include reference data points from our PV sample in many of the CSP-focused graphs in this chapter.

Because no new CSP plants were built (or were under construction, or even officially announced) in the United States in 2016, only the capacity factor section (Section 3.3) contains new data—i.e., capacity factors in 2016—compared to last year's edition of this report. That said, all other sections have been updated (e.g., by adjusting dollar years, by adding or revising relevant commentary) as appropriate.

3.1 Technology and Installation Trends Among the CSP Project Population (16 projects, 1,781 MW_{AC})

After the nearly 400 MW_{AC} SEGS I-IX parabolic trough buildout in California in the 1980s and early 1990s, no other utility-scale CSP project was built in the United States until the 68.5 MW_{AC} Nevada Solar One trough project in 2007. This was followed a few years later by the 75 MW_{AC} Martin project in 2010 (also a trough project, feeding steam to a co-located combined cycle gas plant in Florida).

A more-concentrated burst of CSP deployment occurred in the three-year period from 2013 to 2015. In 2013, the 250 MW_{AC} Solana trough project, which includes 6 hours of molten salt storage capacity, came online in Arizona. In 2014, three additional CSP projects came fully online in California: two more trough projects (Genesis and Mojave, each 250 MW_{AC}) and the first large-scale "solar power tower" project in the United States (Ivanpah at 377 MW_{AC}); none of these three projects includes thermal storage. A second 110 MW_{AC} solar power tower project with 10 hours of built-in thermal storage—Crescent Dunes in Nevada—finished major construction activities in 2014 and became commercially operational in 2015.

In the wake of this buildout—totaling 1,237 MW_{AC}—of new CSP capacity from 2013-2015, no other utility-scale CSP projects have been built in the United States, nor are any projects moving towards construction. Moreover, two of the oldest CSP plants in the United States—SEGS I and II, which came online in the mid-1980s—were decommissioned in 2015, following 30 years of service. The remaining SEGS plants (III-IX) are owned by a different entity and continue to operate.

[54] One notable exception is that this chapter does not include a section on O&M prices. As noted in Section 2.3, we only have empirical O&M cost data for a single CSP project (the 75 MW_{AC} Martin trough project in Florida), and so opted to present those data along with the PV O&M cost data in Figure 13.

Figure 24 overlays the location of each utility-scale CSP project on a map of solar resource strength in the United States, as measured by direct normal irradiance ("DNI"), which is a more appropriate measure of insolation than GHI for CSP projects.[55] With the exception of the 2010 project in Florida (75 MW_{AC}), all other CSP projects in the United States have been deployed in California (1,237 MW_{AC}) and the Southwest (250 MW_{AC} in Arizona and 179 MW_{AC} in Nevada), where the DNI resource is strongest.

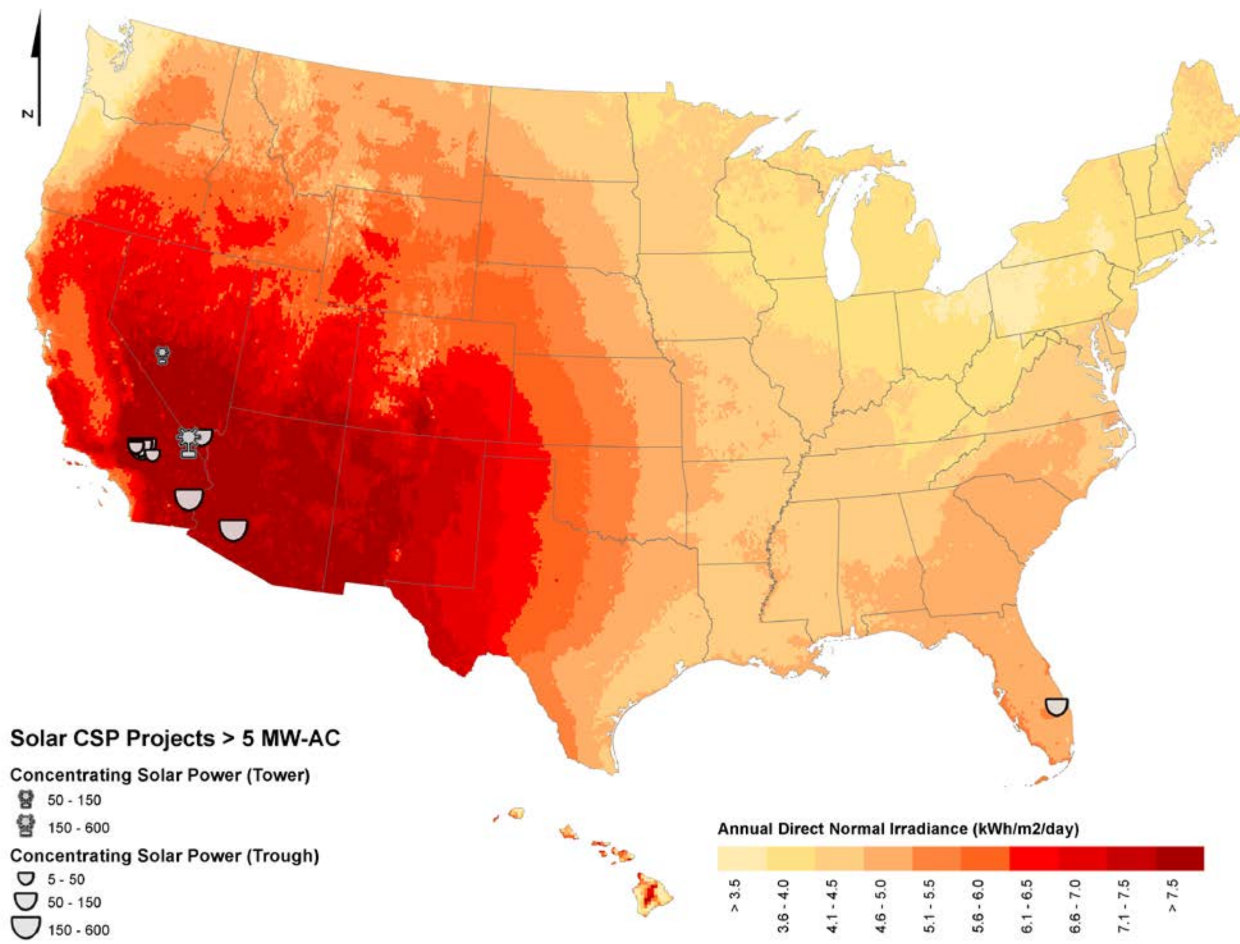


Figure 24. Map of Direct Normal Irradiance (DNI) and Utility-Scale CSP Project Locations

3.2 Installed Project Prices (7 projects, 1,381 MW_{AC})

The CSP installed price sample excludes the nine SEGS projects built several decades ago, but includes all other CSP projects, totaling 1,381 MW_{AC}, that were commercially operational at the end of 2016 and larger than 5 MW_{AC}. Five of these seven projects feature parabolic trough technology (one of which has 6 hours of molten salt thermal storage capabilities), while the two most recently built projects use power tower technology (one project consisting of a total of 3

[55] DNI is the solar radiation received directly by a surface that is always held perpendicular to the sun's position in the sky. The DNI data represent average irradiance from 1998-2009 (Perez 2012).

solar towers without long-term storage, the other featuring just one tower but with 10 hours of molten salt storage).

Figure 25 breaks down these various CSP projects by size, technology and commercial operation date (from 2007 through 2015),[56] and also compares their installed prices to the median installed price of PV (from Figure 8) in each year from 2010 through 2016. The small sample size makes it difficult to discern any trends. In 2014, for example, two equal-sized trough systems using similar technology (and both lacking storage) had significantly different installed prices ($5.25/W_{AC}$ vs. $6.31/W_{AC}$). Meanwhile, the 2013 Solana trough system with six hours of storage was (logically) priced above both 2014 trough projects (at $6.95/W_{AC}$), while the 2014 power tower project was priced at the higher end of the range of the two trough projects built that same year. The most recent addition to our sample is the Crescent Dunes project, which faced a prolonged testing and commissioning phase that delayed commercial operation by roughly a year. The estimated cost of this project, which features 10 hours of molten salt storage, is the highest in our sample, at $8.98/W_{AC}$.

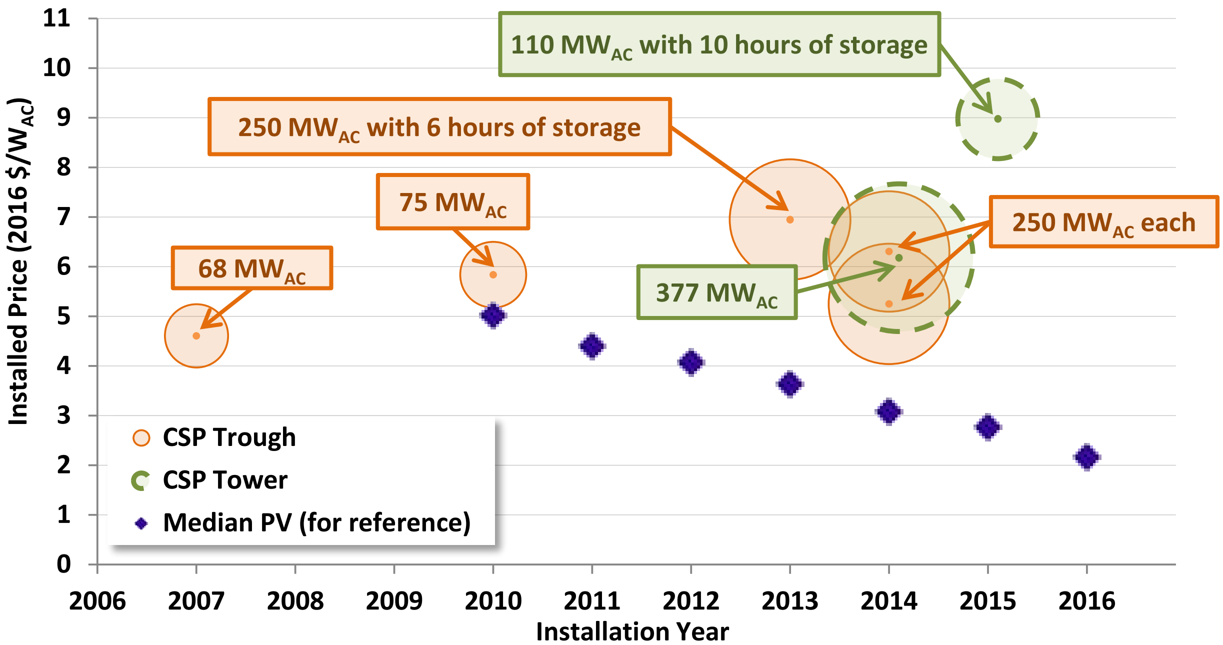


Figure 25. Installed Price of CSP Projects by Technology and Installation Year

Since 2007, CSP prices do not seem to have declined over time in the United States, which stands in stark contrast to the median PV prices included in the figure. Of course, the CSP sample is small, and features several different technologies and storage capabilities, which complicates comparisons.

[56] The installed CSP prices shown in Figure 25 represent the entire project, including any equipment or related costs to enable natural gas co-firing.

3.3 Capacity Factors (13 projects, 1,654 MW_{AC})

Figure 26 shows the net capacity factors by calendar year from just the solar portion (i.e. no augmentation with natural gas or fuel oil is included in Figure 26[57]) of our CSP project sample. The nine SEGS projects are grouped within the green and red shaded areas as indicated, rather than broken out individually. For comparison purposes, the average capacity factor in each calendar year from our sample of PV projects located in California, Nevada, and Arizona—i.e., the three states in which the CSP projects in our sample reside—are also shown.

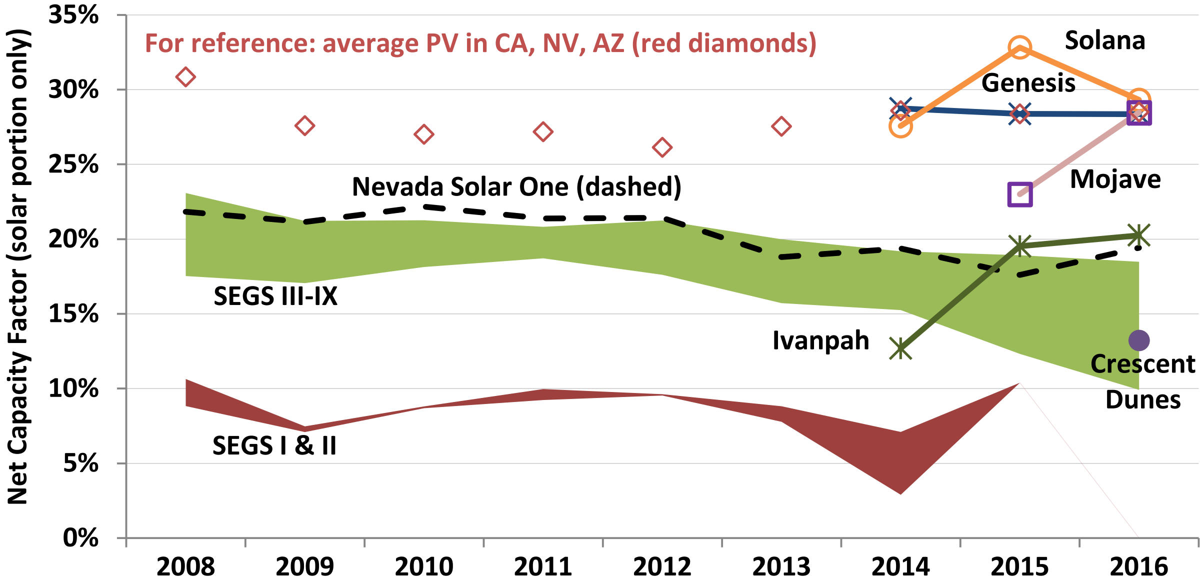


Figure 26. Capacity Factor of CSP Projects (Solar Portion Only) Over Time

A few points are worth highlighting:

- The two "power tower" projects—Ivanpah and Crescent Dunes—experienced closures that negatively impacted performance in 2016. In the spring of 2016, misaligned heliostats caused a portion of Ivanpah's Unit 3 tower to catch on fire, requiring roughly one-third of the plant's capacity to come offline for more than a month. Then, in late-October 2016, Crescent Dunes was forced to shut down following the discovery of what was reportedly a small leak in one of the molten salt tanks used for thermal storage; the repair took more than eight months, during which time the plant did not operate (Brean 2017). As a result of these

[57] Many of these projects also use gas-fired turbines to supplement their output (e.g., during shoulder months, into the evening, or during cloudy weather). In the case of Nevada Solar One, for example, gas-fired generation has boosted historical capacity factors by twenty to forty basis points depending on the year (e.g., from 19.4% solar-only to 19.8% gas-included in 2016), with gas usage most often peaking in the spring and fall (shoulder months). The SEGS projects use relatively more gas-fired generation, which boosted their aggregate capacity factors by 190-370 basis points in 2016, depending on the project. The Ivanpah power tower project also burns gas primarily to keep its steam turbines sufficiently warm overnight and to generate the morning's first steam, both of which significantly shorten each day's ramp-up period; the amount of total generation attributable to burning gas at Ivanpah is limited to 5%, and has reportedly been under that threshold to date (Kraemer 2016).

closures, 2016 capacity factors at both projects were significantly below long-term expectations of ~27% and ~50%, respectively.

- Solana—i.e., the 250 MW solar trough project with 6 hours of thermal storage—performed at a lower capacity factor than in 2015, and well below long-term expectations of >40%. This project too was reportedly hit by a brief closure following storm damage from a micro-burst on July 29, 2016, which was expected to reduce availability for several months thereafter (Stern 2016). More recently, two transformer fires reportedly cut output in half during the peak insolation months of July and August 2017 (Stern 2017), suggesting that performance goals may be missed again in 2017.
- Genesis (250 MW_{AC} trough with no storage) maintained its 2014 and 2015 capacity factors into 2016 (at 28.4%, right on expectations), while the slightly newer but otherwise very similar Mojave project (also a 250 MW_{AC} trough with no storage) improved significantly upon its 2015 performance, largely matching expectations (and Genesis) in 2016.
- Both of these newer trough projects without storage (Genesis and Mojave) performed significantly better in 2016 than the existing fleet of eight older trough projects (also without storage) in the sample, including the seven SEGS plants (SEGS III-IX, totaling 349 MW_{AC}) that have been operating in California for at least twenty-five years, and the 68.5 MW_{AC} Nevada Solar One trough project that has been operating in Nevada since mid-2007.[58]
- The Solana, Genesis, and (in 2016) Mojave projects have been able to match (or, in the case of Solana in 2015, exceed) the average capacity factor among utility-scale PV projects across California, Nevada, and Arizona. All other CSP projects shown in Figure 26 have exhibited significantly lower capacity factors.

Looking ahead, we'll continue to watch for improvements from Ivanpah (following the May 2016 fire and subsequent brief closure), Crescent Dunes (though not in 2017, as the late-2016 shut-down lasted throughout the first half of 2017), and Solana as they attempt to dial up performance to match pre-construction estimates.

3.4 Power Purchase Agreement (PPA) Prices (6 projects, 1,301 MW_{AC})

The PPA price sample for CSP projects includes six of the seven projects built since the turn of the century (the 75 MW_{AC} Martin trough project in Florida, which was built in 2010, is owned by a utility, and so does not have a PPA). Contract terms range from 20 to 30 years, with both a median and mean term of 25 years.

PPA prices from five of these six projects are shown in Figure 27 (along with the de-emphasized PV PPA price sample from utility-scale PV projects located in California, Nevada, and Arizona, for reference). The sixth, Nevada Solar One, is excluded in order to make the figure more

[58] One additional parabolic trough project—the 75 MW_{AC} Martin project in Florida—is excluded from the analysis due to data complications. Specifically, since 2011, the Martin project has been feeding steam to a co-located combined cycle gas plant, and a breakdown of the amount of generation attributable to solar versus gas is not readily available.

readable, given that its PPA was executed in late-2002 (and later amended in 2005). Nevada Solar One's levelized PPA price of ~$193/MWh (in real 2016 dollars) is the highest in our sample, though not by much.

Most of these CSP contracts appear to have been competitive with utility-scale PV projects in their home states at the time they were executed. Since then, however, PPA prices from utility-scale PV projects have declined significantly, and CSP has not been able to keep pace. As a result, there have been no new CSP PPAs executed in the United States since 2011, and a number of previously-executed CSP contracts have been either canceled or converted to PV technology.

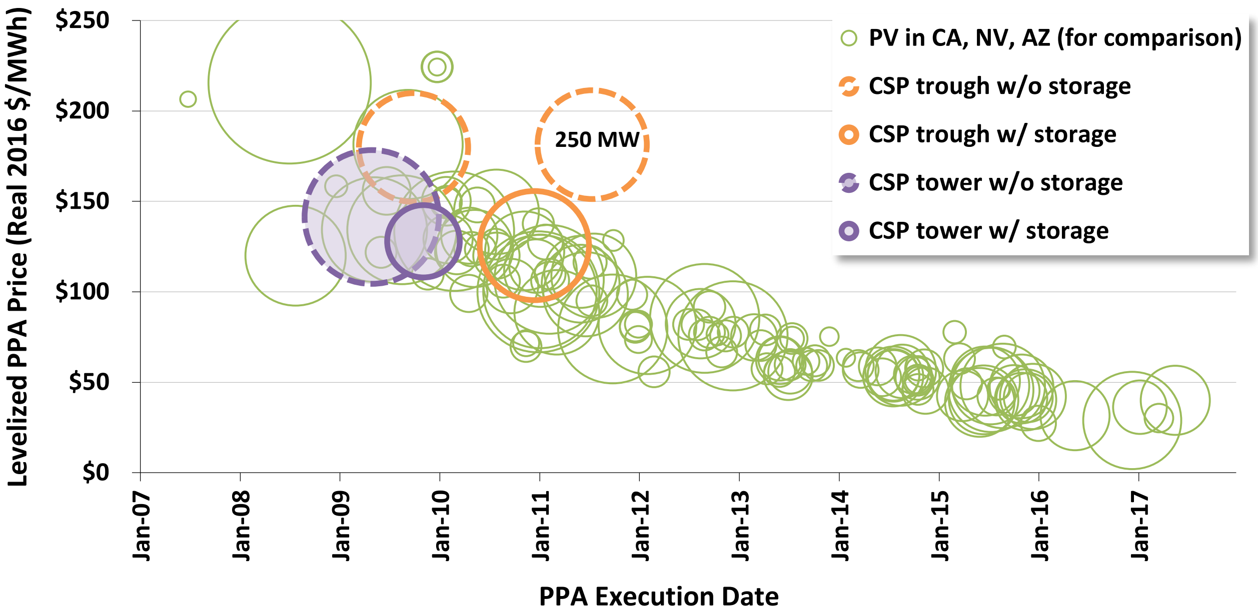


Figure 27. Levelized PPA Prices by Technology, Contract Size, and PPA Execution Date

4. Conclusions and Future Outlook

This fifth edition of LBNL's annual *Utility-Scale Solar* series paints a picture of an increasingly competitive utility-scale PV sector, with installed prices having declined significantly since 2007-2009, relatively modest O&M costs, solid performance with improving capacity factors, and record-low PPA prices of around $30/MWh (levelized, in real 2016 dollars) in a few cases and under $50/MWh on average—even in areas outside of the traditional strongholds of California and the Southwest. Meanwhile, the other principal utility-scale solar technology, CSP, has also made strides in recent years—e.g., deploying several large projects featuring new trough and power tower technologies and demonstrating thermal storage capabilities—but has struggled to meet performance expectations in some cases, and is otherwise finding it difficult to compete in the United States with increasingly low-cost PV. As a result, there were no new CSP projects either online or under construction in 2016.

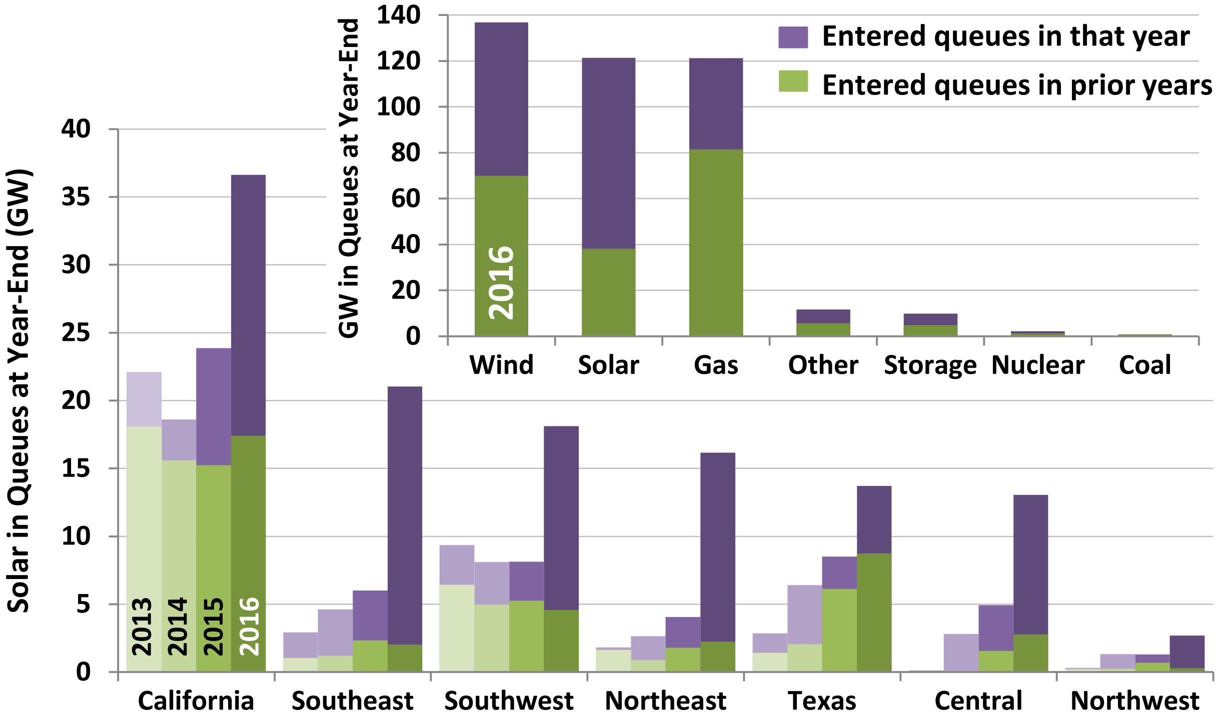
Looking ahead, December 2015's long-term extension of the 30% ITC through 2019 (along with the switch to a "start construction" rather than "placed in service" deadline), with a gradual phase down to 10% thereafter, should ensure continued momentum for the next few years. Data on the amount of utility-scale solar capacity in the development pipeline support this view, and also suggest a significant expansion of the industry—both in terms of volume and geographic distribution—in the coming years. For example, Figure 28 shows the amount of solar power (and, in the inset, other resources) working its way through 35 different interconnection queues administered by independent system operators ("ISOs"), regional transmission organizations ("RTOs"), and utilities across the country as of the end of 2016.[59] Although placing a project in the interconnection queue is a necessary step in project development, being in the queue does not guarantee that a project will actually be built[60]—as a result, these data should be interpreted with caution. That said, efforts have been made by the FERC, ISOs, RTOs, and utilities to reduce the number of speculative projects that have, in previous years, clogged these queues, and despite its inherent imperfections, the amount of solar capacity in the nation's interconnection queues still provides at least some indication of the amount of planned development.

At the end of 2016, there were 121.4 GW of solar power capacity (of any type—e.g., PV, CPV, or CSP) within the interconnection queues reviewed for this report—***more than six times the installed utility-scale solar power capacity in our entire project population at that time.*** These

[59] The queues surveyed include the California ISO, Los Angeles Department of Water and Power, Electric Reliability Council of Texas (ERCOT), Western Area Power Administration, Salt River Project, PJM Interconnection, Arizona Public Service, Southern Company, NV Energy, PacifiCorp, Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), Duke/Progress Energy, Public Service Company of Colorado, Public Service Company of New Mexico, and 20 other queues with lesser amounts of solar. To provide a sense of sample size and coverage, the ISOs, RTOs, and utilities whose queues are included here have an aggregated non-coincident (balancing authority) peak demand of ~85% of the U.S. total. Figure 28 only includes projects that were active in the queue at the end of 2016 but that had not yet been built; suspended projects are not included.

[60] It is also worth noting that while most of the solar projects in these queues are probably utility-scale in nature, the data are not uniformly (or even commonly) consistent with the definition of "utility-scale" adopted in this report. For example, some queues are posted only to comply with the Large Generator Interconnection Procedures in FERC Order 2003 that apply to projects larger than 20 MW, and so presumably miss smaller projects in the 5-20 MW range. Other queues include solar projects of less than 5 MW (or even less than 1 MW) that may be more commercial than utility-scale in nature. It is difficult to estimate how these two opposing influences net out.

121.4 GW—83.3 GW of which first entered the queues in 2016—represented 30% of all generating capacity within these selected queues at the time, just behind wind power at 34% and essentially tied with natural gas, also at 30% (see Figure 28 inset). The end-of-2016 solar total is also 64.6 GW higher than the 56.8 GW of solar that were in the queues at the end of 2015, demonstrating that the solar pipeline was more than replenished in 2016, despite the record amount of new solar capacity that came online (and therefore exited these queues) in 2016.



Source: Exeter Associates review of interconnection queue data

Figure 28. Solar and Other Resource Capacity in 35 Selected Interconnection Queues

The larger graph in Figure 28 breaks out the solar capacity by state or region, to provide a sense of where in the United States this pipeline resides (as well as how that composition has changed going back to 2013). Perhaps not surprisingly (given the map of solar resource and PV project location shown in Figure 3 earlier), 45% of the total solar capacity in the queues at the end of 2016 is within California (30%) and the Southwest region (15%). This combined 45% is down from 56% at the end of 2015, 60% at the end of 2014, and 80% at the end of 2013, however, and is yet another indication that the utility-scale solar market is spreading to new states and regions beyond California and the Southwest. The Southeast, for example, surpassed the Southwest in terms of solar in the queues at the end of 2016, and the Northeast and Central regions, along with Texas, all showed strong growth in solar project pipelines in 2016.

Though not all of the 121.4 GW of planned solar projects represented in Figure 28 will ultimately be built, as shown earlier in Figure 1, analysts expect strong growth in new installations averaging 8.6 GW per year over the next six years, driven in part by the long-term extension of the 30% ITC, coupled with utility-scale PV's declining costs. Of course, accompanying all of this new solar capacity will be substantial amounts of new cost, price, and performance data, which we hope to collect and analyze in future editions of this report.

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Data Sources

Much of the analysis in this report is based on primary data, the sources of which are listed below (along with some general secondary sources), broken out by data set:

Technology Trends: Form EIA-860, FERC Form 556, state regulatory filings, the National Renewable Energy Laboratory ("NREL"), the Solar Energy Industries Association ("SEIA"), interviews with project developers and owners, trade press articles

Installed Prices: Form EIA-860, Section 1603 grant data from the U.S. Treasury, FERC Form 1, data from applicable state rebate and incentive programs, state regulatory filings, company financial filings, interviews with developers and owners, trade press articles, and data previously gathered by NREL

O&M Costs: FERC Form 1 and state regulatory filings (empirical data)

Capacity Factors: FERC Electric Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings

PPA Prices: FERC Electric Quarterly Reports, FERC Form 1, Form EIA-923, state regulatory filings, company financial filings, trade press articles

In addition, the individual reference documents listed below provided additional data and/or helped to inform the analysis.

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Appendix

Total PV Population

State	Size Range (MW_{AC})	Year Range	2016 Sample		Total Population	
			# of Projects	Total MW_{AC}	# of Projects	Total MW_{AC}
AL	75 - 75	2016 - 2016	1	75	1	75
AR	13 - 13	2015 - 2015	0	0	1	13
AZ	5 - 290	2011 - 2016	7	381	37	1,491
CA	5 - 586	2009 - 2016	49	2,978	157	8,040
CO	5 - 120	2007 - 2016	7	225	13	368
DE	10 - 12	2011 - 2012	0	0	2	22
FL	5 - 75	2009 - 2016	4	229	9	288
GA	6 - 146	2013 - 2016	14	726	23	956
HI	6 - 12	2012 - 2016	1	7	4	36
ID	40 - 80	2016 - 2016	2	120	2	120
IL	8 - 20	2010 - 2012	0	0	2	28
IN	5 - 10	2013 - 2016	3	16	12	92
KY	10 - 10	2016 - 2016	1	10	1	10
MA	6 - 15	2014 - 2016	1	15	3	35
MD	6 - 20	2012 - 2016	3	31	7	80
MN	7 - 100	2016 - 2016	2	107	2	107
NC	7 - 81	2010 - 2016	9	349	32	899
NJ	5 - 18	2010 - 2016	6	46	26	227
NM	5 - 70	2010 - 2016	3	165	25	439
NV	10 - 255	2007 - 2016	6	723	20	1,396
NY	10 - 32	2011 - 2016	1	10	2	41
OH	8 - 10	2010 - 2011	0	0	2	18
OR	6 - 10	2016 - 2016	7	63	7	63
PA	10 - 10	2012 - 2012	0	0	1	10
SC	7 - 7	2016 - 2016	1	7	1	7
TN	8 - 16	2012 - 2016	2	24	5	63
TX	6 - 158	2010 - 2016	2	264	14	569
UT	20 - 80	2015 - 2016	10	680	12	810
VA	17 - 80	2016 - 2016	4	137	4	137
Total	**5 - 586**	**2007 - 2016**	**146**	**7,385**	**427**	**16,439**

Total CSP Population

State	Size Range (MW_{AC})	Year Range	2016 Sample		Total Population	
			# of Projects	Total MW_{AC}	# of Projects	Total MW_{AC}
AZ	250	2013	0	0	1	250
CA	34 - 377	1986 - 2014	0	0	10	1,234
FL	75	2010	0	0	1	75
NV	69 - 110	2007 - 2015	0	0	2	179
Total	**34 - 377**	**1986 - 2015**	**0**	**0**	**14**	**1,737**

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Utility-Scale Solar Project Page with data files and interactive visualizations:

https://utilityscalesolar.lbl.gov

All EMP renewable energy publications:

https://emp.lbl.gov/reports/re

QR Code to all EMP solar publications:

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Disclaimer

EDH-8

Northeast Energy Efficiency Partnerships

Energy Efficiency as a T&D Resource:

Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments

January 9, 2015

Chris Neme & Jim Grevatt, Energy Futures Group

About NEEP & the Regional EM&V Forum

REGIONAL EVALUATION,
MEASUREMENT & VERIFICATION FORUM

NEEP was founded in 1996 as a non-profit whose mission is to serve the Northeast and Mid-Atlantic to accelerate energy efficiency in the building sector through public policy, program strategies and education. Our vision is that the region will fully embrace energy efficiency as a cornerstone of sustainable energy policy to help achieve a cleaner environment and a more reliable and affordable energy system.

The Regional Evaluation, Measurement and Verification Forum (EM&V Forum or Forum) is a project facilitated by Northeast Energy Efficiency Partnerships, Inc. (NEEP). The Forum's purpose is to provide a framework for the development and use of common and/or consistent protocols to measure, verify, track, and report energy efficiency and other demand resource savings, costs, and emission impacts to support the role and credibility of these resources in current and emerging energy and environmental policies and markets in the Northeast, New York, and the Mid-Atlantic region.

About Energy Futures Group

EFG is a consulting firm that provides clients with specialized expertise on energy efficiency markets, programs and policies, with an emphasis on cutting-edge approaches. EFG has worked with a wide range of clients – consumer advocates, government agencies, environmental groups, other consultants and utilities – in more than 25 states and provinces.

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Acknowledgements

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This report benefitted from the contributions of the many professionals who are designing, implementing, testing, and regulating the use of energy efficiency and other non-wires approaches as alternatives to traditional T&D construction. We especially thank the following for giving us their assistance:

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The generous contributions of time and knowledge from those listed above made the report possible, but any fault for errors or mischaracterizations that it may contain lies with the authors alone.

[1] See: http://www.neep.org/sites/default/files/EMV-Forum_Geotargeting_Subcommittee-List_12-5-14.pdf.

I. Introduction

Improvements in the efficiency of energy use in homes and businesses can provide substantial benefits to the consumers who own, live in and work in the buildings. They can also reduce the need for capital investments in electric and gas utility systems – benefits that accrue to all consumers whether or not they participate in the efficiency programs. This report focuses on the role efficiency can play in deferring utility transmission and distribution (T&D) system investments. In particular, it addresses the role that intentional targeting of efficiency programs to specific constrained geographies – either by itself or in concert with demand response, distributed generation and/or other "non-wires alternatives" (NWAs)[2] – can play in deferring such investments. The report focuses primarily on electric T&D deferral, since that is where efforts in this area have focused to date. However, the concepts should be equally applicable to natural gas delivery infrastructure.

The report builds on a report published by the Regulatory Assistance Project (RAP) nearly three years ago.[3] Selected portions of the text of the RAP report – particularly for older case studies for which no update was necessary – have been re-used here. Several of the case studies highlighted in the RAP report have evolved considerably in the intervening years. There are also new case studies on which to report. This report documents these experiences and highlights some important new developments in the field that the recent experience has brought to light. In addition, to address the interests of the Regional EM&V Forum project funders, this report also includes an explicit set of policy recommendations or "guidelines".

The remainder of the report is organized as follows:

> **Section II: Efficiency as a T&D Resource** – summarizes the magnitude and drivers of T&D investment in the U.S., and provides an introduction to the concept of geo-targeting efficiency programs to defer some such investments.
>
> **Section III: Summaries of Examples** – provides high level summaries of about a dozen examples across the U.S. in which geographically targeted efficiency has been employed and/or is in the process of being employed, either alone or in combination with other NWAs, in order to defer more traditional T&D investments.

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[2] We use the term "non-wires alternatives" (NWAs) throughout this paper when referring to a range of alternatives to investment in the T&D system. That term is synonymous with "non-wires solutions", "non-transmission alternatives" (when referring to just the transmission portion of T&D), "grid reliability resources", "distributed energy resources", and other terms sometimes used by other parties. It should be noted that "non-wires" is an imperfect, "shorthand" term that is intended to refer to alternatives to a wide range of traditional T&D infrastructure investments, many of which – e.g. substations and/or transformers – are not really "wires".

[3] Neme, Chris and Rich Sedano, *"U.S. Experience with Efficiency as a Transmission and Distribution System Resource"*, Regulatory Assistance Project, February 2012.

Section IV: Detailed Case Studies – provides more detailed discussions of four of those examples which offer unique insights.

Section V: Cross-Cutting Observations and Lessons Learned – summarizes key conclusions the authors have drawn from the case studies examined in the report.

Section VI: Policy Recommendations – presents four policies that state governments should consider pursuing if they would like to effectively advance consideration of non-wires alternatives to traditional T&D investments.

Section VII: Bibliography **–** provides a list of all of the documents referenced in the report.

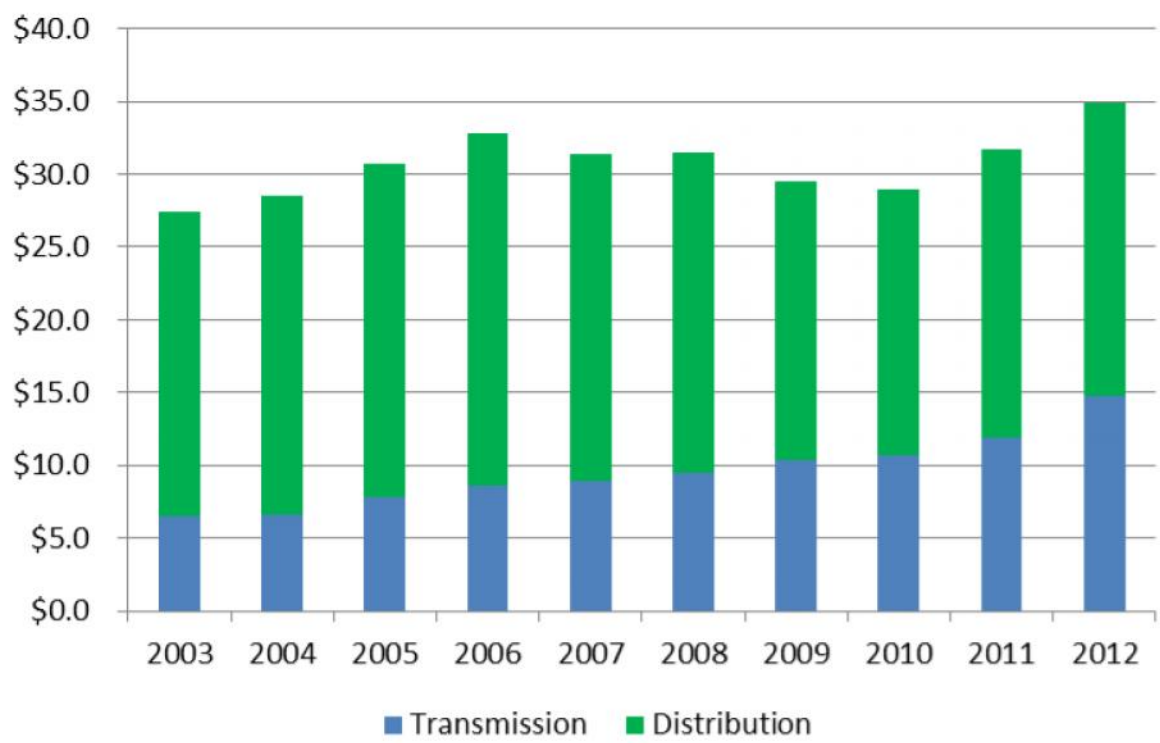
Appendices – contain excerpts from legislation in Vermont, Maine and California; regulatory standards for Rhode Island; and screening forms for Vermont that underpin those states' current requirements to consider and, where appropriate, promote non-wires alternatives.

II. Energy Efficiency as a T&D Resource

Context – Historic and Future Electric Utility T&D Investments

As Figure 1 shows, T&D investments by investor-owned electric utilities, which collectively account for approximately two-thirds of electricity sales in the U.S., have averaged a little more than $30 billion a year over the past decade. If public utilities[4] were investing at a comparable rate, total national investment would have been on the order of $45 billion per year.

Figure 1: T&D Investment by U.S. Investor-Owned Utilities (Billions of 2012 Dollars)[5]



That level of investment is expected to continue or increase in the future, with studies suggesting that the industry will spend an average of roughly $45 billion per year over the next two decades.[6,7] That would represent approximately 60% of forecasted utility capital investment.[8]

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[4] Public utilities include municipal utilities, rural electric cooperatives and the Tennessee Valley Authority.
[5] Edison Electric Institute, Statistical Yearbook of the Electric Power Industry 2012 Data, Table 9.1.
[6] Chupka, Marc et al. (The Brattle Group), *Transforming America's Power Industry: The Investment Challenge 2010-2030*, prepared for the Edison Foundation, November 2008. Harris Williams & Co., *Transmission and Distribution Infrastructure*, a Harris Williams & Co. White Paper, Summer 2014 (http://www.harriswilliams.com/sites/default/files/industry_reports/ep_td_white_paper_06_10_14_final.pdf?cm_mid=3575875&cm_crmid=e5418e44-29ef-e211-9e7f-00505695730e&cm_medium=email)
[7] Note that the ultimate cost to electric ratepayers may be significantly greater, since ratepayers will pay a rate of return on all investments made by regulated utilities.
[8] Chupka, Marc et al. (The Brattle Group), *Transforming America's Power Industry: The Investment Challenge 2010-2030*, prepared for the Edison Foundation, November 2008.

As discussed below, only a portion of T&D investment could potentially be deferred through deployment of energy efficiency and/or other non-wires alternatives. Data on the portion of U.S. T&D investment that might be deferrable are not currently available.

When Efficiency Programs Can Affect T&D Investments

T&D investments are driven by a number of different factors. Among these are:

- The need to replace aging T&D infrastructure;
- The need to address unexpected equipment failures;
- The need to connect new generation – this is particularly important for renewable electric generation that is often sited in somewhat remote locations, but can also be true for other types of electric generation;
- A desire to provide access to more economic sources of energy and peak capacity; and
- The need to address load growth.

Needless to say, some of these needs would not be significantly affected by the customer investments in energy efficiency or the programs that promote such investments. In particular, investments related to the condition of a T&D asset – whether equipment has failed due to a defect or natural disaster or whether it is just too old and/or has become insufficiently reliable – are largely unaffected by the level of end use efficiency. In that context, it is worth noting that one of the reasons some are predicting national investment in electric T&D infrastructure to be substantial in the coming years is that much of the existing infrastructure is old. For example, it is estimated that approximately 70% of transformers are over 25 years old (relative to a useful life of 25 years), 60% of circuit breakers are over 30 years old (relative to a useful life of 20 years), 70% of transmission lines are 25 years old or older ("approaching the end of their useful life"), and more than 60% of distribution poles were installed 40 to 70 years ago (i.e. are approaching or have surpassed expected useful life of 50 years).[9] All told, the electric utility industry has estimated that between 35% and 48% of T&D assets either currently or will soon need to be replaced simply because of their age and/or condition.[10]

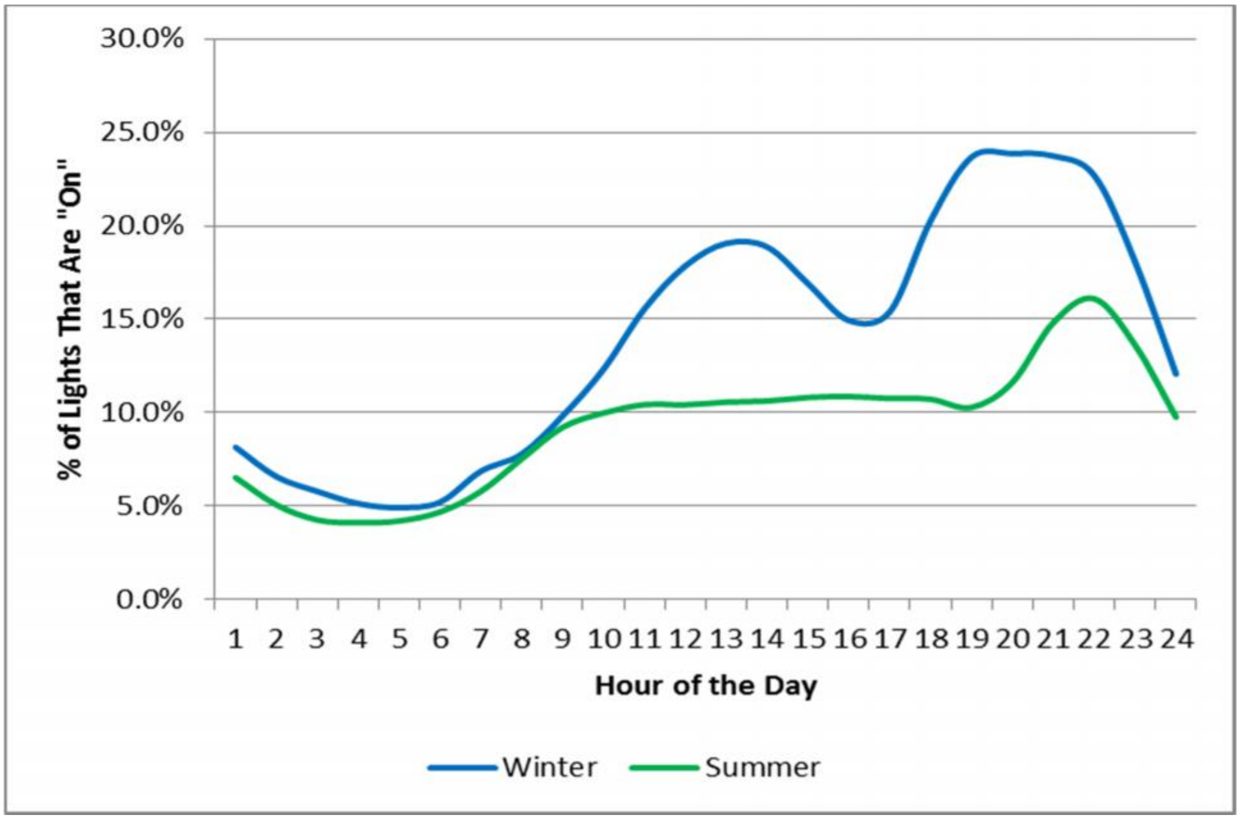
On the other hand, energy efficiency programs can defer T&D investments whose need is driven, at least in part, by economic conditions and/or growing peak loads. In that context, it is important to note that even if total electricity sales are not growing, peak load may be. Also, even if peak loads in a region are not growing *in aggregate*, they may be growing in a portion of the region to the point where they may be putting stress on the system.

[9] Harris Williams & Co., *Transmission and Distribution Infrastructure*, a Harris Williams & Co. White Paper, Summer 2014 (http://www.harriswilliams.com/sites/default/files/industry_reports/ep_td_white_paper_06_10_14_final.pdf?cm_mid=3575875&cm_crmid=e5418e44-29ef-e211-9e7f-00505695730e&cm_medium=email).
[10] Ibid.

How Efficiency Programs Can Affect T&D Investments

Different elements of the T&D system can experience peak demand at different times of day and even in different seasons. Thus, the extent to which an efficiency program can help defer a T&D investment will depend on the hour and season of peak and the hourly and seasonal profile of the efficiency program's savings. For example, as shown in Figure 2, a program to promote the sale and purchase of compact fluorescent light bulbs (CFLs) provides some energy savings during every hour of the day (when sales are spread across many thousands of customers), but greater savings in winter than in summer and more savings in the evening than during the day.

Figure 2: Average Hourly CFL Usage Patterns[11]



Because different programs provide different levels of savings at different times and in different seasons, the *mix* of efficiency programs also matters. For example, as Table 1 illustrates, the same hypothetical mix of efficiency programs would have different impacts on three hypothetical electric substations which experience peak demands in different seasons and during different times of day because of the different mixes of customers that they serve. However, it is also worth noting that the differences across the portfolio of programs is not as great as across

[11] Nexus Market Research, *Residential Lighting Markdown Impact Evaluation*, submitted to Markdown and Buydown Program Sponsors in Connecticut, Massachusetts, Rhode Island and Vermont, January 20, 2009 (from Figures 5-1 and 5-2).

any individual program. This is the result of diversification, as the lower impact from one program is offset by a higher impact from another at the time of a given substation peak.

Table 1: Hypothetical Efficiency Program Portfolio Impacts on Different Substation Peaks

				Annual Peak MW Savings by Program			
Substation	Customer Mix	Peak Season	Peak Hour	Residential CFLs	Residential A/C	Commercial Lighting Retrofits	Total
A	Primarily Business	Summer	3:00 PM	0.4	0.9	0.7	2.0
B	Primarily Residential	Summer	7:00 PM	0.4	1.4	0.3	2.1
C	Primarily Residential w/Electric Heat	Winter	7:00 PM	1.0	0.0	0.4	1.4

Finally, the level of savings that the mix of programs provides also has important implications for whether any T&D investment deferral is possible and, if it is, how long a deferral the efficiency programs will provide. This is illustrated in the hypothetical example depicted in Table 2. In this example, the existing electric substation load is 90 MW and its maximum capacity is 100 MW, so capacity will need to be added by the year load is projected to exceed that level. The first scenario depicted is one in which there are no efficiency programs offered to customers served by the substation (i.e. a “business as usual” scenario). It assumes 3% annual growth in substation peak load. The other three scenarios depict different levels of efficiency program savings, presented in increments of 0.5 percentage point reductions in annual peak load growth relative to the “business as usual” or “no efficiency” scenario. In this example, the substation capacity would need to be upgraded in four years (2018) in the business as usual scenario. The degree to which the efficiency programs defer the need for the upgrade varies with the level of savings achieved, ranging from a one year deferral (to 2019) for savings sufficient to reduce the peak growth rate by 0.5% each year (i.e. from 3.0% to 2.5%) to an eight year deferral (to 2026) for savings sufficient to reduce the peak growth rate by 2.0% annually (i.e. from 3.0% to 1.0%). Clearly, if savings were greater than 2.0% per year, the need for the substation upgrade would be deferred beyond the time horizon depicted in the table.

Table 2: Illustrative Impact of Savings Level (MW) on Deferral of Substation Upgrade

Level of Savings	Net Growth Rate	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
No EE programs	3.0%	90	93	95	98	101	104	107	111	114	117	121	125	128
0.5% savings/year	2.5%	90	92	95	97	99	102	104	107	110	112	115	118	121
1.0% savings/year	2.0%	90	92	94	96	97	99	101	103	105	108	110	112	114
1.5% savings/year	1.5%	90	91	93	94	96	97	98	100	101	103	104	106	108
2.0% savings/year	1.0%	90	91	92	93	94	95	96	96	97	98	99	100	101

Passive Deferrals vs. Active Deferrals

Energy efficiency programs can lead to deferrals of T&D investments in two ways: passive deferral and active deferral. We define those two concepts as follows:

> **Passive deferral**: when system-wide efficiency programs, implemented for broad-based economic and/or other reasons rather than with an intent to defer specific T&D projects, nevertheless produce enough impact to defer specific T&D investments.
>
> **Active deferral**: when geographically-targeted efforts to promote efficiency – *intentionally designed to defer specific T&D projects* – meet their objectives.

Passive deferrals, almost by definition, will occur to some degree in any jurisdiction that has system-wide efficiency programs of any significance. However, as noted above, the degree and value of passive deferral will obviously be heavily dependent on the scale and longevity of the programs. The benefits may be modest, deferring a small number of planned investments a year or two. They can be also quite substantial. For example, Consolidated Edison (Con Ed), the electric utility serving New York City and neighboring Westchester County, recently estimated that including the effects of its system-wide efficiency programs in its 10-year forecast reduced capital expenditures by more than $1 billion.[12] Similarly, since it began integrating long-term forecasts of energy efficiency savings into its transmission planning in 2012, the New England ISO has identified over $400 million in previously planned transmission investments in New Hampshire and Vermont that it is now deferring beyond its 10 year planning horizon.[13]

The benefits of such passive deferrals are sometimes reflected in average statewide or utility service territory-wide avoided T&D costs. Such avoided costs – along with avoided costs of energy and system peak capacity – are commonly used to assess whether efficiency programs are cost-effective (usually a regulatory requirement for funding approval). At the most general level,

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[12] Gazze, Chris and Madlen Massarlian, "Planning for Efficiency: Forecasting the Geographic Distribution of Demand Reductions", in *Public Utilities Fortnightly*, August 2011, pp. 36-41.

[13] The initial March 2012 estimate was $265.4 million in deferred projects. In June 2013 an additional $157 million in projects was deferred (Personal communication from Eric Wilkinson, ISO New England, 11/6/14. Also see: George, Anne and Stephen J. Rourke (ISO New England), "ISO on Background: Energy Efficiency Forecast", December 12, 2012; and ISO New England, 2013 Regional System Plan, November 7, 2013).

estimates of avoided T&D costs are typically developed by dividing the portion of forecast T&D capital investments that are associated with load growth (i.e., excluding the portion that is associated with replacement due to time-related deterioration or other factors that are independent of load), by the forecast growth in system load. Such estimates can vary considerably, often as a function of the utilities' assumptions regarding how much investment is deferrable. For example, in New England, utility estimates of avoided T&D costs currently range from about $30 per kW-year (CL&P) to about $200 per kW-year (National Grid – Massachusetts).[14]

Like passive deferrals, the benefits of active deferrals are a function of the value of each year of deferral and the length of the deferral. However, because the deferral of a specific T&D investment is the primary objective rather than by-product of the efficiency programs, benefits are always very project-specific. Examples of such benefits are provided in the following sections of this report.

It is important to recognize that deferred T&D investments – whether passive or active – are a subset of the benefits of the efficiency programs that produced the deferral. Efficiency programs always also provide energy savings to participating customers, reductions in line losses, and environmental emission reductions. They also typically provide system peak capacity savings, reduced risk of exposure to fuel price volatility and, particularly in jurisdictions with competitive energy and/or capacity markets, price suppression benefits.

Applicability to Natural Gas Infrastructure

Though this report focuses primarily on the role that efficiency programs can play in actively deferring *electric* T&D investments, the concepts are just as applicable to gas T&D infrastructure investments. That is, natural gas efficiency programs are likely to be passively deferring some gas T&D investments and, under the right circumstances – e.g. for load-related T&D needs, with enough lead time, etc. – should be viable options for deferring some gas T&D investments.

The passive deferral benefits of gas efficiency programs have either not been widely studied or not been widely publicized. However, there are at least a couple of examples worth noting. First, Vermont Gas Systems (VGS) routinely includes the impacts of its efficiency programs in its integrated resource planning (IRP). As noted in its revised 2012 IRP, efficiency programs are forecast to not only reduce gas purchases, but also contribute to "delayed transmission investment during the term of (the) plan."[15] In its 2001 plan, VGS was even more explicit, concluding that its efficiency programs would produce sufficient peak day savings to delay implementation of at least one transmission system looping project by one year.[16]

[14] Hornby, Rick et al. (Synapse Energy Economics), *Avoided Energy Supply Costs in New England: 2013 Report*, prepared for the Avoided Energy Supply Component (AESC) Study Group, July 12, 2013.
[15] Vermont Gas Systems, Inc., *REVISED Integrated Resource Plan*, 2012.
[16] Vermont Gas Systems, Inc., *Integrated Resource Plan*, 2001.

We are not aware of any publicly available documentation of examples in which a gas utility has used geographically-targeted efficiency programs to *actively defer* a T&D investment. However, there may be growing interest in this topic. For example, following a hotly contested proceeding on a very large gas pipeline project, the Ontario Energy Board recently concluded that geographically-targeted efficiency and demand response programs might have been able to mitigate the need for a portion of the project designed to meet growing loads in downtown Toronto, but "significant uncertainties", mostly related to time limitations and to Enbridge Gas' (the local gas utility's) lack of information on and experience with assessing peak demand impacts of its efficiency programs, led it to approve the project as proposed. However, the Board also stated that "further examination of integrated resource planning" is warranted and that it "expects applicants to provide more rigorous examination of demand side alternatives" in all future proposals for significant T&D investments.[17] In a very different context, some parties have suggested that geographic targeting of gas efficiency programs to areas near gas-fired electric generating stations could help alleviate pipeline congestion that is driving up the winter cost of electricity in parts of New England.[18] It is conceivable that such efforts might also help defer the need for some gas T&D investments.

NEEP will be undertaking a 2015 scoping project to document what gas system planners would need to assess the potential viability of demand-side alternatives to gas T&D investments.

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[17] Ontario Energy Board, *Decision and Order*, EB-2012-0451, in the matter of an application by Enbridge Gas Distribution, Inc. Leave to Construct the GTA Project, January 30, 2014.
[18] Schlegel, Jeff, "Winter Energy Prices and Reliability: What Can EE Do to Help Mitigate the Causes and Effects on Customers", June 11, 2014.

III. Summaries of Examples

Though far from widespread, a number of jurisdictions have tested and/or are in the process of testing the role that geographically-targeted efficiency programs could play in cost-effectively deferring electric T&D investments. In this section of the report we briefly summarize examples of such efforts from ten different jurisdictions. More detailed discussion of some of these examples follows in the next section.

Bonneville Power Administration (under consideration in 2014)

The Bonneville Power Administration (BPA) has periodically considered energy efficiency and other non-wires alternatives to transmission projects over the past two decades. One notable example was in the early 1990s. At the time the Puget Sound area received more than three-quarters of its peak energy (i.e., during times of high demand for electric heat) via high voltage transmission lines that crossed the Cascade mountain range. BPA studies concluded the region could experience a voltage collapse – or blackout or brownout – if one of the lines failed during a cold snap.[19] The level of risk "violated transmission planning standards."[20] The traditional option for addressing this reliability concern would have been to build additional high voltage transmission lines over the Cascades into the Puget Sound area. However, BPA and the local utilities chose instead to pursue a lower cost path that included adding voltage support to the transmission system (e.g., "series capacitors to avoid building additional transmission corridors over the Cascades") and more intensive deployment of energy efficiency programs that focused on loads that would help avoid voltage collapse. The voltage support was by far the most important of these elements.[21] The project, known as the Puget Sound Area electric Reliability Plan, ended up delaying construction of expensive new high voltage transmission lines for at least a decade.[22] Indeed, no new cross-Cascade transmission lines have been built to date.[23]

Several years later, BPA invested in a substantial demand response initiative in the San Juan Islands to address reliability concerns after the newest of three underwater cables bringing power to the islands was accidentally severed. The initiative ran for five years and succeeded in keeping loads on the remaining cables at appropriate levels until a new cable was added.

[19] U.S. Department of Energy, Bonneville Power Administration, Public Utility District Number 1 of Snohomish County, Puget Sound Power & Light, Seattle City Light and Tacoma City Light, "Puget Sound Reinforcement Project: Planning for Peak Power Needs", Scoping report, Part A, Summary of Public Comments, July 1990.

[20] Bonneville Power Administration Non-Construction Alternatives Roundtable, "Who Funds? Who Implements?" Subcommitee, "Non-Construction Alternatives – A Cost-Effective Way to Avoid, Defer or Reduce Transmission System Investments", March 2004.

[21] Indeed, though the plan included additional investments in efficiency, the additional capacitors, coupled with the addition of some local combustion turbines, were likely enough to defer the transmission lines even without the additional efficiency investments (personal communication with Frank Brown, BPA, 11/7/11).

[22] Bonneville Power Administration, "Non-Wires Solutions Questions & Answers" fact sheet.

[23] The system has been significantly altered over the past two decades as a result of substantial fuel-switching from electric heat to gas heat, the addition of significant wind generating capacity (much of it for sale to California) and other factors. Thus, today, BPA has more "North-South issues" than "East-West issues" (personal communication with Frank Brown, BPA, 11/7/11).

Although BPA has since commissioned several studies to assess non-wires alternatives to traditional transmission projects, it has not yet pursued any additional now-wires projects. BPA is currently in the process of rebooting and revamping their corporate approach to non-wires alternatives. That has included a restructuring of where this function is situated within the organization. Prior to 2012 the non-wires team at BPA was part of the Energy Efficiency team, but in early 2013 it became a corporate level function in an attempt to better integrate strategic planning for non-wires approaches across the organization by bridging the energy efficiency and resource planning functions.

BPA is also re-assessing the threshold criteria used to determine whether a project might be a good candidate for a non-wires approach. In the past, projects needed to be planned to be at least eight years in the future, and have a cost of at least $5M to be considered for a non-wires alternative. Currently the BPA team feels that an eight-year lead time is too long, because it allows too much time for projects to change in significant ways before they would be implemented. With this in mind they are now focusing on projects that are planned for five years out, feeling that this allows sufficient time to deploy non-wires resources while still providing greater surety that the project's expected need is reasonable. BPA has also reduced its minimum cost threshold from $5M to $3M.

The lead time and cost criteria are used as a "stage one" filter to identify potential NWA candidate projects. Once stage one selection is complete, a "stage two" analysis is undertaken. In stage two analysis BPA considers more specifically the types of customers in the affected load areas, and identifies the types of non-wires alternatives that could potentially be applicable and effective. Once this team has identified strong project candidates, recommendations are made to the executive team regarding projects to pursue. Once executive approval is obtained, the project would then move to a different branch of BPA for execution.

As in the Northeast there are significant unanswered questions about how future non-wires alternatives to transmission projects will be funded. Currently, transmission construction projects are socialized over a large customer base, but a similar cost-allocation mechanism has not yet been identified that would allow costs of non-wires alternatives to be similarly allocated. BPA is currently considering approaches to address this issue.

California: PG&E (early 1990s pilot, new efforts in 2014)

One of the most widely publicized of the early T&D deferral projects was the Pacific Gas and Electric (PG&E) Model Energy Communities Program, commonly known as the "Delta project". The project ran from July 1991 through March 1993. Its purpose was to determine whether the need for a new substation that would otherwise be required to serve a growing "bedroom community" of 25,000 homes and 3000 businesses could be deferred through intensive efficiency investments. The largest portion of the project's savings was projected to come from a residential retrofit program targeted to homes with central air conditioning. Under the initial design, participating homes would receive free installation of low cost efficiency measures (e.g., CFLs, low flow showerheads, water heater blankets) during an initial site visit and be scheduled for follow up work with major measures such as duct sealing, air sealing, insulation, sun screening and air conditioner tune-ups. More than 2700 homes received such major measures. Later, the program changed its focus to promoting early replacement of older, inefficient central air conditioners with new efficient models. Other components of the Delta project included commercial building retrofits, a residential new construction program and a small commercial new construction program.

Evaluations suggested that the project produced 2.3 MW of peak demand savings. The savings did come at a higher cost than expected – roughly $3900 per kW. This can likely be attributed to a couple of key factors. First, the project had an extremely compressed timeframe. It was planned and launched within six months; the implementation phase was less than two years. A second related factor was that some of the efficiency strategies produced much lower levels of savings than initially estimated. Because of the compressed timeframe for the project, the switch in emphasis to the better performing program strategies could not occur early enough to keep total costs per kW at more reasonable levels. For example, the residential shell and duct repair efforts were initially projected to generate nearly 1.8 MW of peak demand savings but, in the end, produced only about 0.2 MW at a cost of over $16,000 per kW. In contrast, the early replacement residential central air conditioners produced 1.0 MW of peak savings – about 2.5 times the original forecast of about 0.4 MW – at a cost of about $900 per kW. The final evaluation of the project suggested that the savings achieved succeeded in deferring the need for the substation for at least two years.[24]

No other projects of this kind appear to have been pursued in California until very recently. Passage of Assembly Bill 327 in October 2013 required utilities to assess the locational benefits and costs of distributed resources (including efficiency), identify economically optimal locations for them, and put in place plans for their deployment. In response, PG&E started looking at specific capacity expansion projects at the distribution substation level that could be deferred if they could reduce load growth. The Company leveraged circuit-specific, 10-year, geo-spatial load forecasts[25] and identified roughly 150 distribution capacity expansion projects that would be needed over the next 5 years— and started developing criteria that would be useful in helping them select the potential deferral projects with the greatest likelihood of success. To narrow down the list, they focused on projects that:

- Were growth related rather than needed because of equipment maintenance issues;
- Had a projected in-service date at least 3 years into the future; and
- Had a projected normal operating deficiency of 2 MW or less at substation level to ensure that they would be realistically achievable in a two-year timeframe.

[24] Pacific Gas and Electric Company Market Department, *"Evaluation Report: Model Energy Communities Program, Delta Project 1991-1994"*, July 1994.
[25] Using Integral Analytics proprietary "LoadSEER" software.

Applying these criteria reduced the number of projects being considered to about a dozen. PG&E then looked at each of the remaining projects more closely to better understand which customers were connected to those feeders and what their load profiles were like to determine if the needed reductions could be reasonably secured over the next two years. Through this process they ultimately selected four projects for which to deploy non-wires alternatives, including energy efficiency, for 2014-15. By the end of 2015 they expect to be able to show significant progress in developing their understanding of the strengths and potential limitations of these non-wires approaches, which will allow them to better integrate NWA approaches into future planning efforts. This current effort is discussed more thoroughly in the next section – detailed case studies – of this report.

Maine (2012 to present)

In 2010, the Maine Public Utilities Commission approved a settlement agreement reached by Central Maine Power and a variety of other parties regarding a large transmission system upgrade project. A key condition of the settlement was that there would be a pilot project to test the efficacy of non-wires alternatives. The first such pilot was to be in the Boothbay region. Another condition was that the non-wires pilot would be administered by an independent third party. Grid Solar, an active participant in case, was selected to be the administrator.

The Boothbay pilot began in the Fall of 2012 with the release of an RFP designed to procure 2.0 MW of non-wires resources. Rather than solicit a purely least cost mix of resources, the project aimed to ensure that a mix of resource types would be procured and tested by establishing desired minimums of 250 kW for each of four different resource categories: energy efficiency, demand response, renewable distributed generation and non-renewable distributed generation. A second RFP was issued in late May of 2013 after one of the original winning bids withdrew due to challenges in acquiring financing. As of the Summer of 2014, 1.2 MW of non-wires resources, including approximately 350 kW of efficiency resources, were deployed and operational; another 500 kW was expected to be operational by late 2014. Due to revised load forecasts that total of 1.7 MW is all that is now expected to be needed to defer the transmission investment. The cumulative revenue requirement for the non-wires solution is now forecast to be approximately one-third of what the cost would have been for the transmission solution. This project, as well as recent legislation that requires assessment and deployment of less expensive non-wires solutions in the future, is discussed in greater detail in the next section of this report.

Michigan: Indiana & Michigan/AEP (2014)

Indiana and Michigan (I&M), a subsidiary of American Electric Power (AEP), is currently forecasting that it will need to invest in an upgrade to a transformer at its substation in Niles, Michigan. The substation serves about 4400 residential customers, nearly 600 commercial customers and about 60 industrial customers. Peak load on the substation is currently 23.2 MW. It is forecast to grow by about 200 kW per year, though system planners need to address a possibility that peak loads will grow by 5% above normal weather levels – i.e. 210 kW per year.

I&M is currently considering a pilot project to use more aggressive efforts to promote energy efficiency investments to offset load growth and thereby defer the transformer upgrade. The efficiency program offerings would build on the system wide programs that are already offered across I&M's Michigan service territory, including both increased rebates for customers in Niles and more aggressive customer outreach and marketing efforts. There may also be efforts to explore integration of efficiency offerings with promotion of demand response and distributed generation.

Nevada: NV Energy (late 2000s)

In 2008 NV Energy faced a situation in a relatively rural portion of its service territory, east of Carson City, in which growth in demand was going to need to be met by either running the locally situated but relatively expensive Fort Churchill generating station more frequently or constructing a 30 mile, 345 kVA transmission line and new substation to bring less expensive power from the more efficient Tracy generating facility (situated further north, about 20 miles east of Reno) to the region. When the local county commission began expressing concerns about permitting construction of the substation, regulators instructed the Company to increase the intensity of its DSM efforts in the targeted region as an alternative to meeting the area's needs economically:

> *"…the concentration of DSM energy efficiency measures in Carson City, Dayton, Carson Valley and South Tahoe has the potential to reduce the run time required for the Ft. Churchill generation units. The increased marketing costs and increased incentives and subsequent reduction in program energy savings required to attain an increased participation in the smaller market area are estimated to be more than offset by reduced fuel costs. Sierra Pacific, d.b.a. NV Energy, will make a reasonable effort within the approved DSM budget and programs to concentrate DSM activities in this area…"*[26]

NV Energy pursued a variety of efforts to focus its existing efficiency programs more intensely on the Fort Churchill area through increased marketing and, in one case (Commercial building retrofit program), higher financial incentives.[27] It also offered an "Energy Master Planning Service" to the Carson City and Douglas County School districts, though both declined the service. Of these efforts, NV Energy's second refrigerator collection and recycling program (including a new element of CFL distributions) and the commercial retrofit program were together responsible for the vast majority of the increased DSM savings in the region.[28]

At the same time as these efficiency efforts were launched, NV Energy's transmission staff began re-conductoring the existing 120 kVA line to the region to increase its carrying capacity. The economic recession also hit at the same time, dampening growth. As a result, the Company

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[26] Jarvis, Daniel et al., "*Targeting Constrained Regions: A Case Study of the Fort Churchill Generating Area*", 2010 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 178-189

[27] Sierra Pacific Power Company, 2010 Annual Demand Side Management Update Report, July 1, 2010, pp. 6-9.

[28] Ibid. and Jarvis et al.

has not had to revisit the need for either the additional power line and substation or increasing the run time of the Fort Churchill generating station. The project has also facilitated the beginnings of "rich conversations" between demand resource planners and transmission planners within the Company.[29]

New York: Con Ed (2003 to present)

Consolidated Edison (Con Ed), the electric utility serving New York City and neighboring Westchester County, has been perhaps the most aggressive in the US in integrating end use energy efficiency into T&D planning. Geographically targeted investment in efficiency at Con Ed began in 2003, when growth in demand was causing a number of Con Ed's distribution networks to approach their peak capacity. In its initial pilot phase, the Company established contracts with three ESCOs to provide load reductions in nine networks areas: five in midtown Manhattan, three in Brooklyn and one in The Bronx. In subsequent phases, four different ESCOs were contracted to deliver load reductions in 21 additional network areas: 13 in Manhattan, four on Staten Island and four in Westchester County. ESCOs were allowed to bid virtually any kind of permanent load reduction. However, through 2010, the only cost-effective bids submitted and accepted were solely for the installation of efficiency measures. All told, between 2003 and 2010, the Company employed geographically targeted efficiency programs to defer T&D system upgrades in more than one third of its distribution networks. The resulting savings were very close to forecast needs and provided more than $300 million in net benefits to ratepayers.[30] In some cases, the efficiency investments not only deferred T&D upgrades, but bought enough time to allow the utility to refine load forecasts to the point where some of the capacity expansions may never be needed.

After these successful distribution deferral projects were completed in 2012, Con Ed experienced a brief hiatus from non-wires projects simply because there were no distribution upgrade projects being planned that would meet the criteria for non-wires approaches (see detailed case study in following section for discussion of these criteria). That changed in the summer of 2013, when an extended heat wave placed severe capacity pressure on areas of Brooklyn and Queens, causing Con Ed to identify a greatly accelerated need for upgrades to its system in these areas. Con Ed subsequently decided to request approval for approximately $200M in investments to defer distribution system upgrades related to these capacity constraints.

That proposal was also made in the context of strong signals coming from New York's regulators indicating a pending re-structuring of the electric utility industry in the state, with a much greater expectation that in the near future the utilities will be responsible for taking advantage of all available resources for managing the grid in the most economic manner. In

[29] Personal communication with Larry Holmes, NV Energy, 11/9/11.
[30] Gazze, Chris, Steven Mysholowsky, Rebecca Craft, and Bruce Appelbaum., "Con Edison's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction", in Proceedings of the ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 117-129; updated estimates provided by Chris Gazze, formerly of Con Ed, February 11, 2011.

Commission Staff's view, this includes deploying all manner of Distributed Energy Resources (DERs) to their cost-effective levels. This viewpoint is clearly reflected in ConEd's Brooklyn-Queens filing and the associated RFI that ConEd has issued that includes an extraordinary level of flexibility regarding the creative use of non-wires approaches. The Brooklyn-Queens project is discussed in much greater detail in the following "detailed case studies" section of this report.

New York: Long Island Power Authority (2014)

PSEG Long Island[31] has submitted a proposed long-term plan to the Long Island Power Authority (LIPA) for its approval.[32] The plan includes initiatives designed to defer substantial transmission upgrades in the Far Rockaway region in southern Long Island and the South Fork region in eastern Long Island. Both include a proposed RFP to procure peak load relief, with any type of demand side measure – including energy efficiency – being eligible as long as it is commercially proven, is measurable and verifiable and is not duplicative of other programs already proposed for the areas.

In the case of the Far Rockaway region, the effort would be designed to help defer what would otherwise be a transmission reinforcement between the towns of East Garden City and Valley Stream in 2019. LIPA has already issued and received responses to an RFP for new generation, energy storage and demand response (GSDR) resources which may satisfy some or all of the need in the area. Thus, the proposed new RFP for demand-side resources is essentially a contingency plan. If deployed, it would seek to acquire 25 MW of "guaranteed capacity relief". PSEG Long Island has stated that the RFP process would be similar to Con Ed's process for addressing its Brooklyn-Queens constraint.

In the case of the South Fork region, the effort would be designed to help defer a $294 million capital investment in (primarily) new underground transmission cables and substation upgrades over the next eight years ($97 million by 2017 and the other $197 million through 2022). Approximately 20 MW of coincident peak capacity is needed by 2018, with more required in later years. It is expected that some of this need will be addressed by acquisition of storage resources through the GSDR RFP described above and 21.6 MW (nameplate capacity)[33] of solar PV procured through a different initiative. The RFP for demand side resources would seek at least 13 MW of guaranteed load relief, unless a parallel effort to acquire peak savings through a residential Direct Load Control program RFP acquires enough load control resources in the South Fork area to reduce the need.

[31] PSEG Long Island is currently contracted to provide all aspects of LIPA's utility services, other than procurement of supply resources. Starting in January 2015, it will also be responsible for supply procurement as well.
[32] PSEG Long Island, *"Utility 2.0 Long Range Plan Update Document"*, prepared for the Long Island Power Authority, October 6, 2014.
[33] That equates to more like 10 MW of coincident peak capacity and even less in early evening hours when demand in the region is still very high (personal communication with Michael Voltz, PSEG Long Island, November 13, 2014).

As of the writing of this report, these efforts are just proposals. They are expected to be considered for approval by the Long Island Power Authority Board in December 2014.[34]

Oregon: Portland General Electric (early 1990s)

In 1992, Portland General Electric (PGE) began planning the launch of a pilot initiative to assess the potential for using DSM to cost-effectively defer distribution system upgrades; implementation began in early 1993.[35] The pilot focused on several opportunities for deferring both transformer upgrades planned for large commercial buildings and grid network system upgrades planned for downtown Portland, Oregon. The projects were identified from a review of PGE's five-year transmission and distribution plan. Though the PGE system was winter-peaking, downtown Portland was summer-peaking so the focus would be on efficiency measures that reduced cooling and other summer peak loads. To be successful, deferrals would need to be achieved in one to three years, with the lead time varying by project. In each case, the value of deferring the capital improvements was estimated. The estimates varied by area, but averaged about $35 per kW-year.[36]

Two different strategies were pursued. In the case of the individual commercial buildings, where peak demand reductions of several hundred kW per building were needed to defer transformer upgrades, the utility relied on existing system-wide DSM programs, but target marketed the programs to the owners of the buildings of interest using sales staff that already had relationships with the building owner or property management firm. For the grid network system objectives, where peak reductions of 10% to 20% for entire 10 to 15 block areas were needed, the utility contracted with ESCOs to deliver savings. The ESCO contracts had two-tier pricing structures designed to encourage comprehensive treatment of efficiency opportunities and deep levels of savings. The first tier addressed savings up to 20% of a building's electricity consumption. The second tier was a much higher price for savings beyond 20%.[37]

The results of the pilot were mixed. For example, savings in one of the targeted commercial buildings was nearly twice what was needed, deferring and possibly permanently eliminating the need for a $250,000 upgrade. However, savings for another building fell short of the amount of reduction needed to defer its transformer upgrade. While other options were being explored to bridge the gap, an unexpected conversion from gas to electric cooling of the building "eliminated any opportunity to defer the upgrade."[38]

The results for the first grid area network targeted were also very instructive. Of the 100 accounts in the area, the largest 20 accounted for more than three-quarters of the load. By

[34] Personal communication with Michael Voltz, PSEG Long Island, November 11, 2014.
[35] Personal communication with Rick Weijo, Portland General Electric, August 10, 2011.
[36] Weijo, Richard O. and Linda Ecker (Portland General Electric), "Acquiring T&D Benefits from DSM: A Utility Case Study", Proceedings of 1994 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 2.
[37] Ibid.
[38] Ibid.

ultimately treating 12 of those 20, the ESCOs contracted by PGE actually succeeded in reducing load through efficiency measures by nearly 25% in just one year. That was substantially more than the 20% estimated to be necessary to defer the need for a distribution system upgrade. However, the utility's distribution engineering staff decided to proceed with construction of the upgrade before the magnitude of the achieved savings was known because they did not have sufficient confidence that the savings would be achieved and be reliable and persistent. It is also worth noting that the utility's marketing staff who were managing the ESCO's work were not even made aware of the decision to proceed with the construction until after it had begun – a telling indication of the lack of communication and trust between those responsible for energy efficiency initiatives and those responsible for distribution system planning.[39]

Despite some notable successes with its pilot, PGE has not subsequently pursued any additional efforts to defer distribution system upgrades through energy efficiency.[40]

Rhode Island: National Grid (2012 to present)

In 2006, Rhode Island adopted a "System Reliability Procurement" policy that required utilities to file plans every three years. Guidelines detailing what to include in those plans were developed by the state's Energy Efficiency and Resource Management Council (EERMC) and National Grid and approved by regulators in 2011 (see Appendix D). The guidelines make clear that plans must consider non-wires alternatives, including energy efficiency, whenever a T&D need meets all of the following criteria:

- It is not based on asset condition;
- It would cost more than $1 million;
- It would require no more than a 20% reduction in peak load to defer; and
- It would not require investment in the "wires solution" to begin for at least 36 months.[41]

For such cases, the plans must include analysis of financial impacts, risks, the potential for synergistic benefits, and other aspects of both wires and non-wires alternatives.

Based on these guidelines, National Grid proposed an initial pilot project in late 2011. The project was designed to test whether geographically targeted energy efficiency and demand response could defer the need for a new substation feeder to serve 5200 customers (80% residential, the remainder small businesses) in the municipalities of Tiverton and Little Compton. The pilot began in 2012 with the objective of deferring the $2.9 million feeder project for at least four years (i.e. from an initial estimated need date of 2014 until at least 2018). The load

[39] Ibid.
[40] Personal communication with Rick Weijo, Portland General Electric, August 10, 2011.
[41] These criteria are identical to internal guidelines National Grid had developed in 2010/2011 (personal communication with Lindsay Foley, National Grid, December 22, 2014).

reduction necessary to permit the deferral was estimated to be 150 kW in 2014, rising to about 1000 kW in 2018.[42]

The pilot was designed to leverage National Grid's statewide efficiency programs in a couple of ways. First, the Company is more aggressively marketing those statewide programs to customers in Tiverton and Little Compton. Second, it is using the same vendor that manages its statewide residential and small commercial efficiency retrofit programs to promote demand response measures in the two towns. Because the substation's peak load is in the summer, there is a strong emphasis on addressing cooling loads. Initially, the demand response offering was a wi-fi programmable controllable thermostat for homes with central air conditioning. However, when the saturations of central air proved to be lower than expected, the pilot was broadened to include demand response-capable plug load control devices for window air conditioners. Marketing of the program offerings was limited to "direct contact" with customers in the affected towns. National Grid recently reported to state regulators that the need for the new feeder has been pushed out from 2014 to 2015, suggesting that the peak load reduction that has been realized thus far has been large enough to defer the investment by one year.[43]

Vermont (mid-1990s pilot, statewide effort 2007 to present)

In 1995, Green Mountain Power (GMP), Vermont's second largest investor-owned electric utility at that time, launched an initiative – the first of its kind in the state – to defer the need for a new distribution line in the Mad River Valley – a region in the central part of the state made famous by the Sugarbush and Mad River ski resorts. Sugarbush, which was already the largest load on the line, had announced plans to add up to 15 MW of load associated with a new hotel, a new conference center and additional snow-making equipment. The existing line could not accommodate that kind of increase. Ensuing negotiations between GMP, Sugarbush and the state's ratepayer advocate ultimately led to an alternative solution in which Sugarbush would ensure that load on the distribution line – not just its load, but the total load of all customers – would not exceed the safe 30 MW level, and GMP would invest in an aggressive effort to promote investment in energy efficiency among all residential and business customers in the region. To meet its end of the bargain, GMP filed and regulators approved four efficiency programs targeted to the Mad River Valley, including a large commercial/industrial retrofit program, a small commercial/industrial retrofit program, a residential retrofit program that focused on homes with electric heat and hot water, and a residential new construction assessment fee program which imposed a mandatory fee on all new homes being constructed in the valley. The fee program paid for a home energy rating and offered both repayment of the fee and an additional incentive for building the home efficiently. The project as a whole came close to achieving its overall savings goal.

[42] Anthony, Abigail (Environment Northeast) and Lindsay Foley (National Grid), "Energy Efficiency in Rhode Island's System Reliability Planning", 2014 ACEEE Summer Study on Energy Efficiency in Buildings, Volume 10.
[43] Ibid.

Since that early project, Vermont has invested significant efforts in developing a thoughtful methodology for assessing the prudence of non-wired alternatives to capital investments in poles and wires. The Vermont Public Service Board (PSB) issued orders in Docket 7081 that established expectations for analysis of non-transmission alternatives, and in Docket 6290 for non-wires alternatives to distribution and sub-transmission projects. While the requirements vary slightly, similar approaches are used for both distribution and transmission needs. The state's distribution utilities and Vermont Electric Power Company (VELCO), the state's electric transmission provider, submit twenty-year forecasts of potential system constraints and construction projects as part of utility Integrated Resource Plans (IRPs) and a Long Range Transmission Plan (LRTP) every three years. The forecasts are updated annually. The forecasts include preliminary assessments of the applicability of non-wires alternatives based on criteria that have been agreed upon by Vermont System Planning Committee (VSPC), a statewide collaborative process for addressing electric grid reliability planning.[44] The VSPC helps Vermont fulfill an important public policy goal: to ensure that the most cost-effective solution gets chosen, whether it is a poles-and-wires upgrade, energy efficiency, demand response, generation, or a hybrid solution. The work of the VSPC is carried out by a broad cross section of stakeholders, including representatives from utilities, regulators, environmental advocates and Efficiency Vermont, and follows a highly prescribed process to assure that potential solutions are reviewed comprehensively.[45]

The current collaborative planning process was developed in response to Act 61, the 2005 legislation that clearly establishes the basis for the Public Service Board to require long range consideration of non-wires solutions as alternatives to T&D construction. Act 61 emerged in part as a result of public, regulatory, and legislative frustration with the Northwest Reliability Project, a transmission upgrade project that the Board ultimately felt it had to approve because, when permit applications were submitted there was no longer sufficient lead time to fairly consider NWAs. Act 61 also removed statutory spending caps for Efficiency Vermont, authorizing the Board to establish appropriate budgets. When the Board ordered budgets to increase beginning in 2007, it also required that a portion of the increase be devoted to special efforts to obtain additional savings in areas that the utilities had indicated had the potential to become constrained. Five geographic areas were initially targeted. At the time the Board required this geographic targeting effort primarily as a proof of concept, to assess Efficiency Vermont's ability to increase targeted savings while a better planning process was developed. Efficiency Vermont employed a number of program strategies in pursuit of their geographic goals, including enhanced account management approaches for commercial customers, a direct-install lighting program for small businesses, aggressive promotion of retail efficient lighting including community-based marketing approaches, and enhanced efforts to increase shell efficiency or fuel-switch electric heating customers. Vermont's process for evaluating the potential for non-

[44] http://www.vermontspc.com/
[45] http://www.vermontspc.com/library/document/download/599/GTProcessMap_final2.pdf

wires solutions is discussed in much greater detail in the following “detailed case studies” section of this report.

IV. Detailed Case Studies

1. Con Ed

Early History with Non-Wires Alternatives

Con Ed arguably has more on the ground experience with using geographically targeted energy efficiency to defer or avoid T&D investments than any other utility in North America. This geographically targeted investment in efficiency began in 2003, when growth in demand was causing a number of Con Ed's distribution networks to approach their peak capacity. Given the density of its customer base in and around New York City, much of the company's system is underground, making upgrades expensive and disruptive. Thus, the Company began to assess whether it would be feasible and cost-effective to defer such upgrades through locally-targeted end use efficiency, distributed generation, fuel-switching and other demand-side investments. At least initially, the focus was on projects "with need dates that were up to five years out and…required load relief that totaled less than 3% to 4% of the predicted network load."[46] However, a decision was later made to proceed with geographically-targeted demand resource investments whenever it was determined that such investments were likely to be both feasible and cost-effective.

For these early projects, the Company chose to contract out the acquisition of demand resources to energy service companies (ESCOs). To address reliability risks its contracts contained both "significant upfront security and downstream liquidated damage provisions", as well as rigorous measurement and verification requirements, including 100% pre- and post-installation inspections. Contract prices were established through a competitive bidding process, with the Company's analysis of the economics of deferment being used to establish the highest price it would be willing to pay for demand resources. Those threshold prices varied from network to network. When the amount of demand resources bid at prices below the cost-effectiveness threshold were insufficient to defer T&D upgrades, supply-side improvements were pursued instead.

In its initial pilot phase, the Company established contracts with three ESCOs to provide load reductions in nine network areas: five in midtown Manhattan, three in Brooklyn and one in The Bronx. In subsequent phases, four different ESCOs were contracted to deliver load reductions in 21 additional network areas: 13 in Manhattan, four on Staten Island and four in Westchester County. Though ESCOs were allowed to bid virtually any kind of permanent load reduction, all of the accepted bids were solely for the installation of efficiency measures. All told, between 2003 and 2010, the Company employed geographically targeted efficiency programs to defer T&D system upgrades in more than one third of its distribution networks.

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[46] Gazze, Chris, Steven Mysholowsky, Rebecca Craft, and Bruce Appelbaum., "Con Edison's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction", in Proceedings of the ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 117-129.

This approach had considerable success. In aggregate the level of peak load reduction for Phase 1, which ran through 2007, was approximately 40 MW – or 7 MW less than the contracted level.[47] As a result, Con Ed collected considerable liquidated damages from participating ESCOs. Load reductions in subsequent phases were close to those contracted in aggregate. Those aggregate results masked some differences across network areas. In particular, reductions in areas dominated by residential loads with evening peaks were achieved ahead of schedule while "ESCOs targeting commercial customers in daytime peaking networks struggled somewhat due to the economic recession."[48] On the other hand, the economic recession also had the effect of dampening baseline demand, offsetting most of the efficiency program shortfalls.[49] This highlights an important benefit of some efficiency programs – their savings can be tied, in part, to the same factors (e.g. the vitality of the economy) that cause demand growth to rise or fall. Put another way, participation in some efficiency programs tends to increase when load is growing more quickly and decrease when load is not growing quickly.

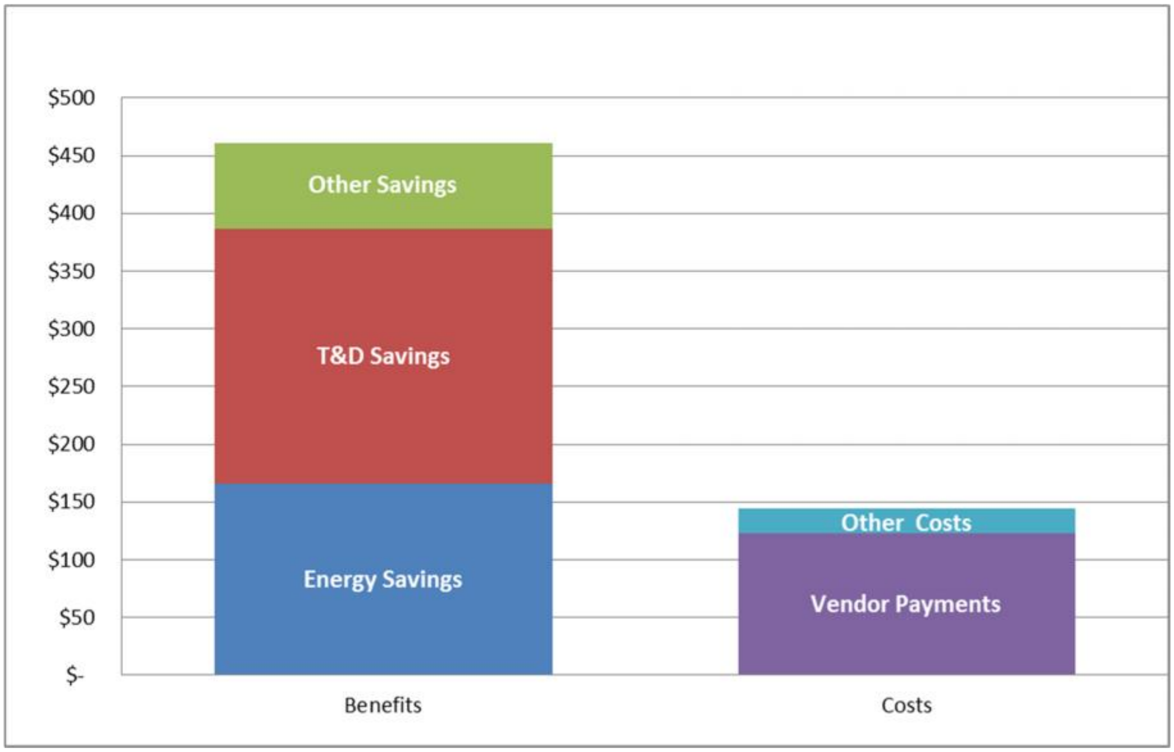
Another benefit of efficiency programs is that they can create a hedge against load growth uncertainty. As Con Ed put it:

> *"…using DSM to defer projects bought time for demand uncertainty to resolve, leading to better capital decision making. Moreover, widespread policy and cultural shifts favoring energy efficiency may further defer some projects to the point where they are never needed…In fact, Con Edison has projected that in the absence of this program it would have installed up to $85 million in capacity extensions that may never be needed."*[50]

As Figure 3 shows, from 2003 to 2010, Con Ed estimated that it saved more than $75 million when comparing the full costs of its geographically targeted efficiency programs to just the T&D costs that were avoided. When other efficiency benefits (e.g., energy savings and system capacity savings) were also considered, the efficiency investments were estimated to have saved Con Ed and its customers more than $300 million. It should be noted that these estimates include the benefits of the longer-than expected deferrals and even outright elimination of the need for some T&D projects that resulted from the downside hedge against forecasting uncertainty described above. The benefits of just the planned deferrals – i.e. what would have been realized had the projects only been deferred as initially forecast – were lower.

[47] Data obtained from graph in Gazze, Mysholowsky, Craft and Appelbaum (2010).
[48] Gazze, Mysholowsky, Craft and Appelbaum (2010).
[49] Gazze, Mysholowsky, Craft and Appelbaum (2010).
[50] Gazze, Chris et al., "Con Ed's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction", in Proceedings of the ACEEE 2010 Summer Study on Energy Efficiency in Buildings, Volume 5, pp. 117-129.

Figure 3: NPV of Net Benefits of Con Ed's 2003-2010 Non-Wires Projects[51]

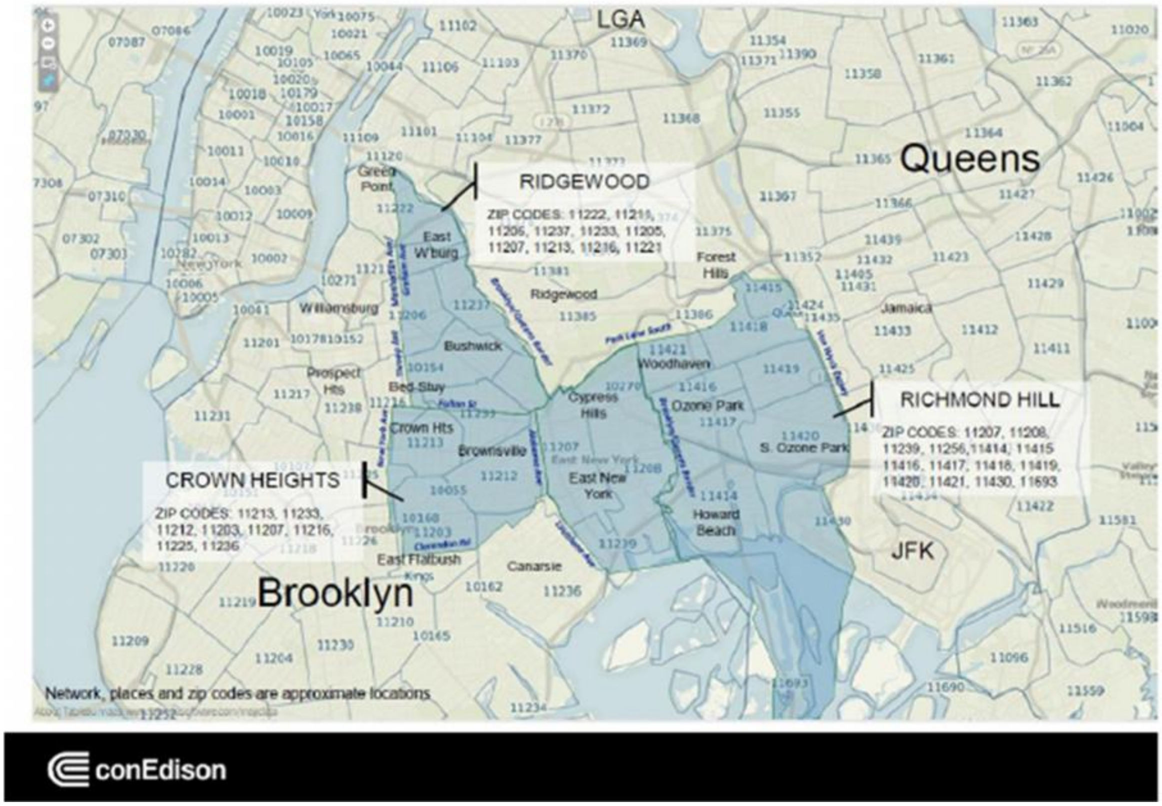


The Next Big Step - $200 Million Brooklyn-Queens Project

Building on this experience, in the summer of 2014 Con Ed requested regulatory approval to invest approximately $200M in a number of different approaches aimed at mitigating the immediate need for system reinforcement in areas of Brooklyn and Queens that surfaced during an extended heat wave in the summer of 2013 (see Figure 4).

[51] Cost and benefit data provided by Chris Gazze, February 11, 2011. Note that "other costs" includes program administration ($2.9 million), M&V ($9.2 million) and customer costs ($9.9 million).

Figure 4: Targeted Brooklyn-Queens Networks[52]



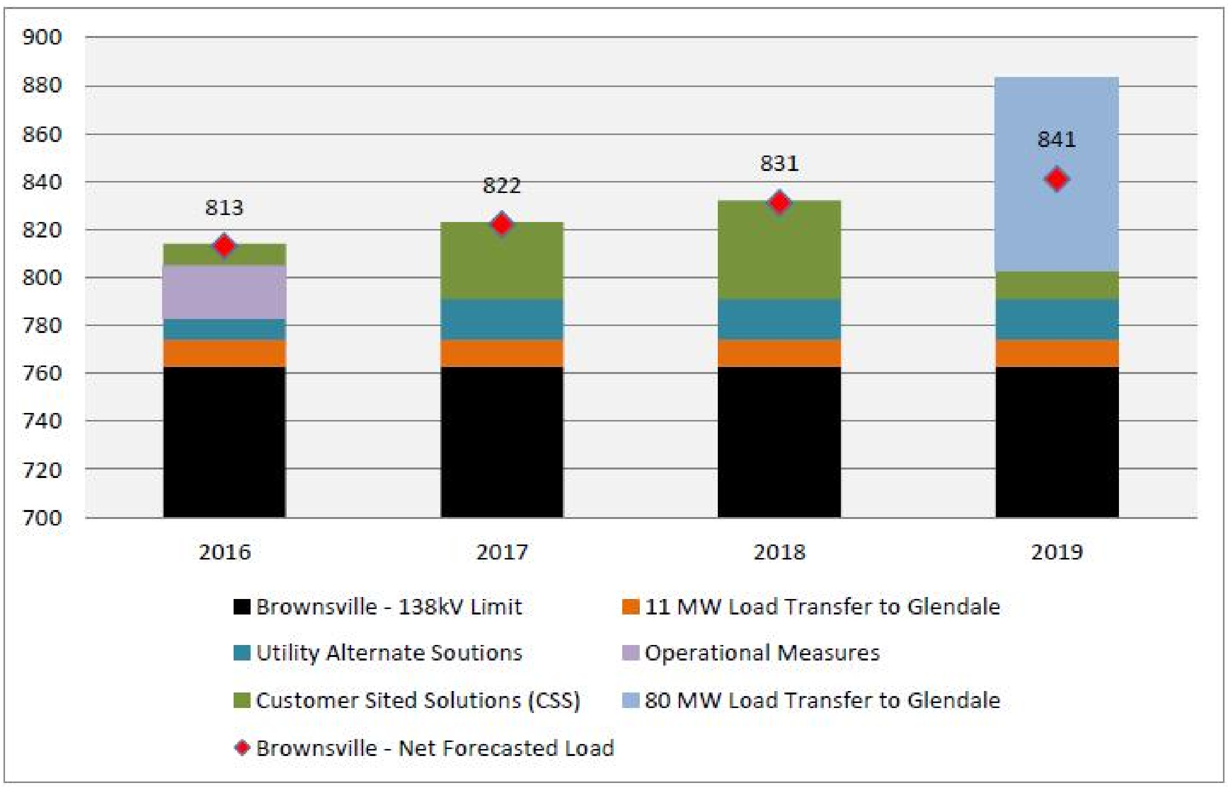
Con Ed knew that there would be capacity constraints in these areas in the future, but the extreme weather placed severe capacity pressure on the sub-transmission feeders that feed the Brownsville No.1 and No.2 substations (serving areas of Brooklyn and Queens), causing Con Ed to identify a greatly accelerated need for upgrades to its system in these areas.[53] Rather than proceeding with a traditional construction solution, Con Ed's proposal calls for it to achieve 41 MW in customer side solutions and another 11 MW of capacity savings through "non-traditional utility side solutions" between 2016 and 2018. This will be combined with another 11 MW of load transfers and 6 MW from the installation of new capacitors that will be operational by 2016 to meet the increased demand during this period. To be clear, Con Ed views these measures as a deferral, rather than a replacement strategy, that will allow delaying the construction of a new substation and associated other improvements from 2017 until 2019. Future upgrades at two other substations are expected to extend this deferral until 2026.[54]

[52] Consolidated Edison Company of New York Request for Information, July 15, 2014, p.11.
[53] Personal communication with Michael Harrington of Con Ed, July 24, 2014.
[54] Data regarding Con Ed's proposal are from Consolidated Edison Company of New York, Inc. Brownsville Load Area Plan, Case 13-E-0030, August 21, 2014. http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=13-e-0030, filing # 518

The overall expected project cost of the combination of the $200M in customer-side and utility-side investments, along with costs associated with the load transfers, new capacitors, and upgrades at the two other substations is not available in the documents reviewed in preparing this paper. However, Con Ed does say that the cost of the alternative purely "poles and wires" solution would be about $1 billion."[55] This traditional solution would include "…expansion of Gowanus 345kV switching station into a new 345/138kV step-down station…and…construction of an area substation and new sub-transmission feeders that would have been constructed and in service by the summer of 2017…."[56]

Figure 5 below illustrates the annual contribution of each component that combined will provide the needed load relief for the Brownsville Load Area in Brooklyn and Queens. Both traditional "poles and wires" solutions and non-traditional alternatives are needed to meet the anticipated load. The blue "utility alternate solutions" and the green "customer-sited solutions" together make up the NWAs for which Con Ed has sought approval.

Figure 5: Brownsville Load Area Plan by Component: 2016-2019 [57]



[55] Brownsville Load Area Plan, p.10
[56] Brownsville Load Area Plan, p.10
[57] Brownsville Load Area Plan, p.22

Con Ed's past success with implementing non-wires solutions gives it what is perhaps a unique, experience-based level of confidence in the effectiveness of alternatives to distribution construction. Likely of equal importance in Con Ed's decision to request approval for the Brooklyn-Queens project are the strong signals coming from New York's regulators, initially through feedback in a rate case[58] and later reinforced through proposals to re-structure the electric utility industry in New York. In particular, New York's Public Service Commission Staff have indicated that they foresee that in the near future the utilities will be held increasingly responsible for managing the grid in the most economic manner. In Commission Staff's view, outlined in *Reforming the Energy Vision* (REV),[59] this includes deploying all manner of cost-effective Distributed Energy Resources (DERs), in an environment where their benefits are accurately measured and given full attribution. The REV proceeding is currently underway in New York and the outcomes are undecided at the time of this writing, but clearly Con Ed has reflected anticipated changes in the regulatory framework in its Brooklyn-Queens filing, which will provide the most comprehensive test to date of the principles outlined in the REV.

Consistent with its regulatory filing, Con Ed issued an RFI in July of 2014 under the title "*Innovative Solutions to Provide Demand Side Management to Provide Transmission and Distribution System Load Relief and Reduce Generation Capacity Requirements*". The RFI allows for an extraordinary level of flexibility regarding the creative use of non-wires approaches:

> *"Respondents are encouraged to submit alternative, creative proposals for DSM marketing, sales, financing, implementation, and maintenance, or transaction structures and pricing formulas that will achieve the demand reductions sought and maximize value to Con Edison's customers."*[60]

While the Brooklyn-Queens project is receiving much attention for its unprecedented scale and ambition as a non-wires project, a concurrent evolution in several aspects of Con Ed's overall approach to non-wires alternatives may be even more important in the long run. Four recent developments are particularly noteworthy:

- **Management structure**: Con Ed's management of analysis and deployment of non-wires alternatives has been elevated to higher level in the Company and become more integrated/inter-disciplinary;
- **Data-driven tools**: Con Ed is developing data driven tools to enable much more sophisticated analysis of non-wires options; and

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[58] Personal communication with Michael Harrington, Con Ed, December 9, 2014.
[59] NYS Department of Public Service Staff, *"Reforming the Energy Vision"*, Case 14-M-0101, 4/24/2014. http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/ATTK0J3L.pdf/Reforming%20The%20Energy%20Vision%20(REV)%20REPORT%204.25.%2014.pdf
[60] Consolidated Edison Company of New York Request for Information, July 15, 2014, p.6

- **Research to support tools**: Con Ed is investing in research to generate data necessary to support the use of those tools.
- **Proposed shareholder incentive mechanism**: Con Ed has proposed a new mechanism for enabling shareholders to profit from investment in non-wires alternatives.

Evolution of Management Approach

Con Ed has taken significant steps in advancing internal communications and collaboration for the Brooklyn-Queens project that are expected to apply to other projects in the future. A working group has been formed within the company specific to this project that includes members of all relevant functional areas such as energy efficiency and demand management, distribution engineering, substation planning, electric operations, and the regional engineering groups that are responsible for Brooklyn/Queens. This has been done with the sponsorship, and under the guidance of one of Con Ed's Senior Vice-Presidents, who has championed the project and who regularly chaired early project meetings. Con Ed's senior management team regards the success of the Brooklyn-Queens project as highly important, and has brought organizational focus to it in a way that we did not observe in any of the other organizations we explored.[61]

Development of New Data-Driven Analytical Tools

With a focus on system and cost management, along with the growth in efficiency and demand management technology and associated customer strategies, Con Ed identified the need for increased visibility into customer and technology potential and economics on the demand side. To address this need, Con Ed, along with Energy & Environmental Economics (E3) and Navigant, has created the Integrated Demand Side Management (IDSM) Potential Model – a dynamic, geographically specific, and technology integrated analysis tool to assess the market potential and economics of efficiency and demand management for cost effective deferral or avoidance of capital expenditures required to meet growing customer demand. The IDSM project is groundbreaking in its ability to breakdown the in-depth analysis into geographically specific electric networks to best match the needs of electric system planners.

The IDSM project goes beyond traditional efficiency measure stalwarts (lighting) to give Con Ed a view into potential deployments of all commercially available and near-term available technologies potentially applicable to the Con Ed service territory. The IDSM project will enhance Con Ed's ability to identify and market to high potential market segments to achieve efficient and effective capital project deferral projects. The model will also enable analysis of various DSM scenarios to customize and optimize project results and maximize cost effectiveness. Lastly, the IDSM project can be extended for use beyond TDSM project analysis

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[61] Maine and Vermont have addressed the cross-functional nature of successful NWA planning and implementation through collaboratives that include members of different organizations, but we are not aware of an example other than Con Ed where this level of collaboration has occurred within a single utility.

to support Con Ed's strategic planning and resource planning (forecasting) efforts by identifying the market potentials and impacts for any number of customer technology adoption scenarios.

Research to Support New Tools

Of course, analytical tools are only as good as the data put into them. Thus, Con Ed also embarked on a couple of research projects to support deployment of the IDSM.

In the first, Con Ed built up network profiles for eight test networks by collecting detailed granular customer data that accounts for building-level characteristics, and that are aggregated for up to 13 commercial and two residential segments for each electric network analyzed. Drawing from both internal billing data and external sources, the network profiles will include applicable service classes, meter information, annual and peak energy usage, air conditioning use, existing thermal storage, physical characteristics of the building, prior program participation, in-place DG/RE, end-use profiles, and more.

The second research task was a technology assessment to identify current and near-market technologies that have the potential to improve energy efficiency, support demand response, improve building operations, and maximize comfort. The assessment looked at the measures identified in a 2010 potential study, as well as additional technologies related at a minimum to lighting, controls, motors, HVAC, and thermal and battery storage. The project also looked at customer sited generation across a range of technology options.

In addition, the technology assessment included the develop of a measure specific load curve library by customer segment (e.g. 8760 and peak load curves for interior lighting measures for the retail customer segment) This tool connects the dots between the technology assessment and the network profiles to ensure the energy and demand reductions for measures being deployed for the specific customer segments are specific to the network(s) being analyzed. The tool does this by comparing the measure-segment load curves to the 8760 and peak load curves of the specific network. For example, the tool is able to assess the different impacts that residential lighting will have compared to commercial lighting in a night peaking network.

Proposal for Shareholder Incentives

Con Ed has proposed to the Commission that it defer the bulk of the costs associated with customer-side activities and recover them over a five-year amortization period, and for utility-side expenditures it has proposed ten-year recovery. Con Ed suggest that "The shorter amortization periods than those traditionally afforded in rates reflect the nature of the expenditures…where no physical asset exists".[62] Con Ed suggests that it should earn a rate of

[62] Consolidated Edison Company of New York, Inc., "*Petition for approval of Brooklyn/Queens Demand Management Program*", p.20. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bB2051869-3A4A-4A7D-BB24-D83835E2026F%7d

return equal to its overall approved rate of return, stating that "…ratemaking should make the Company indifferent to whether it invests in traditional or non-traditional solutions…."[63]

Further, Con Ed has proposed that the Commission establish up to a 100 basis point incentive on Brooklyn-Queens program investments that would be incremental to its approved rate of return so that it has a clear, direct interest in the success of the project. And lastly, the company has proposed that the Commission establish a shared savings incentive as well, with Con Ed earning 50% of the difference between the carrying costs of the traditional solution and the total annual collections for the Brooklyn-Queens program. As of this writing the Commission has not indicated how it will rule on these requests.

2. Maine (Boothbay) Pilot

Project History and Plan

In 2008, Central Maine Power proposed a $1.5 billion investment in the Maine Power Reliability Program (MPRP) to modernize and upgrade the state's transmission network. The project was challenged, with one party – GridSolar – proposing instead that the state invest in 800 MW of photovoltaics (100 MW in the first five years) to offset the need for the entire MPRP. In June of 2010, the Maine Public Utilities Commission approved a settlement agreement reached by Central Maine Power (CMP) and a variety of other parties, including GridSolar and several public interest advocates.[64] The settlement supported construction of most elements of the MPRP, but identified two areas – the Mid-Coast region and the city of Portland – where pilot projects to test the efficacy of non-transmission alternatives would be launched. The Mid-Coast pilot was later reduced to a smaller pilot in the Boothbay region, roughly 35 miles ("as the crow flies") northeast of Portland (see Figure 6 below).

[63] Ibid., p.21.
[64] Maine Public Utilities Commission, Order Approving Stipulation, Docket No. 2008-255, June 10, 2010.

Figure 6: Location of Maine (Boothbay) NTA Pilot[65]

The Boothbay pilot was to be a hybrid solution. It included some transmission system investments, including rebuilding of the Newcastle 115 kV substation ($2.8 million), installing a second 2.7 MVAR capacitor bank at Boothbay Harbor 34.5 kV bus ($0.5 million, and 2.4 MVAR power factor correction at Boothbay Harbor 12 kV level.[66] In addition, the plan initially called for approximately 2 MW of non-transmission resources to be procured (in lieu of an $18 million investment in rebuilding of a 34.5 kV line).

The settlement agreement called for an independent third party to administer the acquisition and management of the non-transmission resources. GridSolar was contracted to serve as a third party administrator. Though the selection was not based on a competitive solicitation, the Maine Public Utilities Commission did formally ask if other parties would be interested and did not receive any other expressions of interest. In a docket that is currently open, the Commission is exploring, among other things, whether there should be an independent third party administrator for such projects in the future and, if so, how such parties would be selected (see discussion on next steps below).

[65] Map copied from U.S. Department of Interior, U.S. Geological Survey, *The National Atlas of the United States of America*, www.nationalatlas.gov.
[66] Jason Rauch, Maine Public Utilities Commission, *"Maine NTA Processes and Policies"*, presentation to the Vermont System Planning Committee's NTA Workshop, October 11, 2013.

GridSolar used a competitive solicitation process to procure the non-transmission alternatives. The initial RFP was released in late September 2012. Because it was a pilot, it was decided that the Boothbay project would not solely be designed to acquire the least-cost non-wires solution for the area. Rather, it would also test the efficacy of a wide variety of alternative resource options. To that end, the RFP made clear that, to the extent feasible, GridSolar would endeavor to cost-effectively acquire (i.e. at a cost less than the transmission alternative) at least 250 kW of each of the following categories of resources:

- Energy efficiency;
- Demand response;
- Renewable distributed generation (at least half of which should be from solar PV); and
- Non-renewable distributed generation (with preference for those with no net greenhouse gas emissions).[67]

The RFP called for all bidding resources to be "on-line and commercially operable" by July 1, 2013 – just nine months after issuance of the RFP and less than six months after the expected date of contract signing – and committed to remain in service for a least three years. Contracts would guarantee payments for that three year period, with an option to extend payments for up to an additional seven years if approved by the Commission. Failure to meet the contractual deadline would result in a penalty of $2/kW-month.[68]

The RFP produced 12 bids from six different NTA providers totaling almost 4.5 MW. This included bids for efficiency, demand response, solar PV, back-up generators, and battery storage.[69] Nine of the bids were submitted for approval to the Commission. The nine bids would collectively have provided 1.98 MW spread across five different resource types – 156 kW of efficiency, 250 kWh of demand response, 338 kW of solar PV, 736 kW of back-up generators, and 500 kW of battery storage. During a January 2013 technical conference, GridSolar was given "preliminary approval" to negotiate contracts on those nine bids.[70]

In April 2013 GridSolar reported it had executed or was close to executing almost all of the contracts. The one key exception was a contract with one provider – Maine Micro Grid – who had bid all of the demand response and battery resources and a portion of the solar and back-up generator resources being recommended. While there was agreement on the contract terms, Maine Micro Grid was having difficulty securing financing for the project[71] and ultimately

[67] GridSolar, LLC, "*Request for Proposals to Provide Non-Transmission Alternatives for Pilot Project in Boothbay, Maine Electric Region*", September 27, 2012.
[68] Ibid.
[69] GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014.
[70] GridSolar, *"Implementation Plan & Final NTA Service Contracts"* (redacted version), for Docket no. 2011-138, April 5, 2013 (filed electronically on April 9, 2013.
[71] Ibid.

withdrew its bid, explaining that the limited contract commitment of three years was insufficient to satisfy investors "that the required 6-year holding period for the federal investment tax credit incentive would be satisfied."[72]

As a result, the Commission directed GridSolar to install a temporary back-up 500 kW diesel generator and issue a second RFP to fill the gap. The second RFP was issued on May 30, 2013. It produced 22 bids from ten different NTA providers totaling just over 4 MW. It too included bids for efficiency, demand response, solar PV, back-up generation and battery storage. The bid prices for all resources except energy efficiency went down in the second RFP. Even though the energy efficiency bid prices went up, efficiency resources remained by far the lowest cost resources (just by a smaller margin). After eliminating the most expensive bids, GridSolar recommended and received approval to proceed with putting in place contracts for the mix of resources summarized in Table 3. As discussed below, the final mix of NTAs contracted was slightly different from the mix shown in the table. The final contract prices were the same for the back-up generator (BUG) and demand response, but roughly $4 to $5 per kW-month higher for efficiency, solar PV and battery storage than the weighted three year prices shown in the table.[73]

Table 3: Recommended NTA Resources[74]

	RFP I*	RFP II	Totals	Pct.	Units	Weighted 3 Year Price	Weighted 10 Yr. (Levelized) Price
Efficiency	237.00	111.25	348.25	19%	7	$23.51	$10.47
Solar	168.83	106.77	275.60	15%	14	$46.05	$13.19
BUG (same)	500.00	500.00	500.00	27%	1	$17.42	$20.63
Demand Response	0.00	250.00	250.00	13%	1	$110.00	$57.65
Battery	0.00	500.00	500.00	27%	1	$163.70	$75.99
Total	905.83	1468.02	1873.85		24		

* RFP I excludes Maine Micro Grid project; Efficiency increased to reflect EMT contract option.

As of July 2014, approximately 1203 kW of NTA resources were deployed and operational.[75] An additional 500 kW battery storage unit is currently expected to be operational by the end of 2014,[76] bringing the total operational capacity to 1703 kW.[77] That is nearly 300 kW less than the

[72] GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014.
[73] GridSolar, *"Project Update: Boothbay Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, July 21, 2014.
[74] Table copied from GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014.
[75] GridSolar, *"Project Update: Boothbay Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, July 21, 2014.
[76] Personal communication with Dan Blais, GridSolar, October 14, 2014.
[77] Note that this value is about 170 kW less than shown in Table 3 above. That is because not all of the proposals initially approved for procurement were ultimately translated into contracts.

initially forecast need of 2.0 MW. However, in May 2014 Central Maine Power adjusted its forecast need for the 10-year planning horizon to be only 1.8 MW.[78] GridSolar had an option to acquire an additional 130 kW of efficiency resources from Efficiency Maine Trust. However, GridSolar, Commission Staff and other parties agreed not to pursue that option at that time, noting that it could be acquired later if necessary:

> *"A benefit of the NTA approach is that lump-investments and resource deployment can be more closely timed with need. To the extent that additional NTA resources are needed later to meet any increased load, they could be deployed at that time. The delay in investment saves ratepayers money."*[79]

Energy Efficiency Strategy

As noted above, energy efficiency resources were a key component in the mix of NTA resources procured for the Boothbay pilot, accounting for approximately one-fifth of the total NTA capacity that has been procured.

All of the efficiency resources procured to date have been provided by the Efficiency Maine Trust (EMT), the independent third party administrator of efficiency programs in the state. Before responding to the first RFP, EMT contracted for a quick high level assessment of efficiency opportunities in the region. One of the findings was that there was significant lighting efficiency potential in local small businesses, including significant opportunities to displace very inefficient incandescent lighting. Given that opportunity – and the very tight timeline originally anticipated for producing savings (contracts to be signed in January 2013 with requirements for NTAs to be operational by July 1, 2013) – EMT focused its efforts almost entirely on lighting.

EMT employed two strategies for acquiring the savings. Most importantly, it ran what it called a "direct drop" program. That involved a bulk purchase of LEDs that could replace incandescent and halogen spotlights and direct delivery of the LEDs to businesses that indicated they would install them. At the time of the delivery, EMT also assessed opportunities for more expensive upgrades. However, because many of the businesses are seasonal (relying on the summer tourism trade), both profit margins and the potential cost savings from efficiency are often modest, making it difficult to persuade them to make any substantial investments. EMT also provided an "NTA bonus" on its standard business efficiency incentives for customers in the affected region. Several businesses, including a local grocery store, took advantage of that offer.

EMT had to be careful to explain why these offers were being made, so that it was clear why only customers in the region of interest were eligible. Nevertheless, there were still some customers from just outside the region that initially expressed annoyance that they could not take

[78] Ibid.
[79] Ibid.

advantage of the NTA offers. EMT had to follow up with those customers to clarify the purpose of the program and rationale for the geographic limitations of the special offers.

It should be noted that Efficiency Maine has indicated that "it could easily have secured much more efficiency had the design of the RFP permitted more flexible bid response and longer duration commitment."[80]

Evaluation Strategy

The savings from efficiency measures in the project are estimated using the deemed values in EMT's Technical Reference Manual. As required by the RFP, those values are consistent with the values accepted for peak savings by the New England ISO in its forward capacity market.

GridSolar conducted its first test of 472 kW of active NTA resources on July 1, 2014. The BUG and demand response units were dispatched for an hour. Based on data from the units themselves, as well as data from the affected substation circuits, it appears that the capacity of these resources was as predicted.

Project Results

As noted above, to this point, the project appears to be performing as expected in terms of the magnitude of the resource being provided, though a key component for the future – battery storage – has not yet been tested.

With regards to cost, GridSolar has estimated that the project will be substantially less expensive than the transmission alternative.[81] Indeed, as shown in Figure 7, it estimates that the revenue requirements for the pilot project will be $17.6 million lower – a more than 60% savings – over the project's potential 10-year life than under the full transmission solution.[82] That is despite the intentional deployment of a range of NTAs that were not cost-optimized (so as to test a range of technology types in a pilot) and the fact that the pilot commitment to only three years of payments likely constrained potential bids. Moreover, that cost comparison is not adjusted for the substantial additional benefits that some of the NTAs provide, such as energy savings during non-peak periods.

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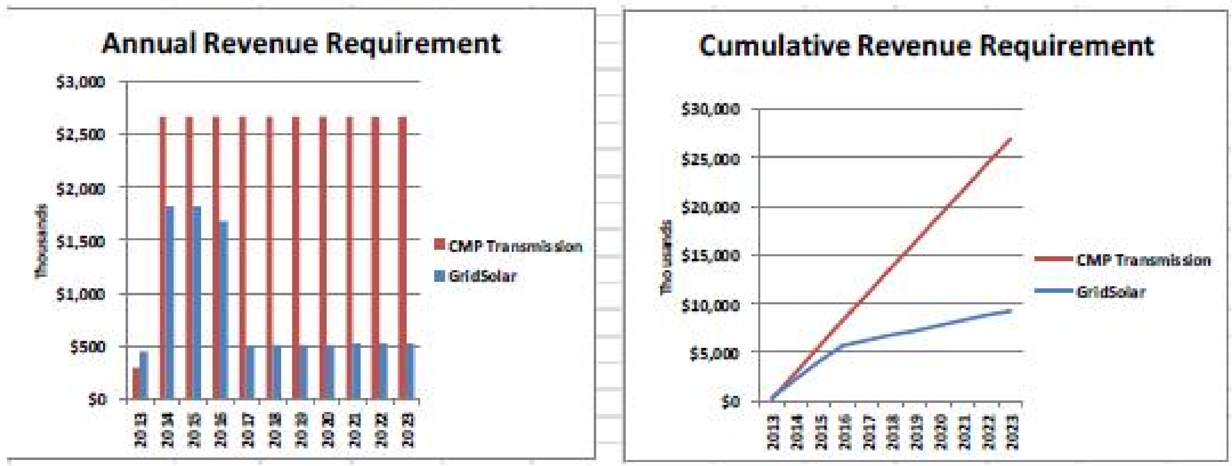
[80] GridSolar, "*Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project*", for Docket No. 2011-138, March 4, 2014.

[81] As discussed above, there is a small transmission component to the pilot project. When we refer to the transmission alternative here, we are referring just to the more substantial additional transmission investment that would have had to be made in the absence of the NTA deployments.

[82] Though this analysis only looks at a 10-year horizon, GridSolar expects that the pilot project will permanently eliminate the need for the transmission alternative (GridSolar, "*Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project*", for Docket No. 2011-138, March 4, 2014 and personal communication with Dan Blais, GridSolar, October 14, 2014.

Figure 7: Cost Comparison of Transmission and NTA Solutions for Boothbay



One other important result worth re-stating about the project is that many of the passive resources, particularly energy efficiency, were among the first to be deployed. As GridSolar noted in its March 2014 project updates, this "bought time" for other NTAs to be brought on line:

> *"…To date, the Pilot has deployed over 400 kW of passive NTA resources…These passive resources alone exceed the projected grid reliability requirements in the Boothbay subregion…for the initial years of the Pilot…the subregion will not reach the projected critical loads in which the full suite of NTA resources are needed to meet reliability requirements in the out years of the Pilot project. This demonstrates the dynamic and modular nature of NTA solutions, which be ratcheted up or down year to year, as conditions require – thus lowering net costs and preventing premature or stranded costs due to overbuilding.*

Moreover, as noted above, the ability to quickly deploy some of the NTA resources bought time to allow for an updated peak forecast which lowered the magnitude of the total NTA required to meet reliability needs from 2.0 to 1.8 MW.

The Future

In addition to continued implementation and evaluation of the Boothbay pilot, several other developments in Maine related to consideration of non-wires alternatives merit brief discussion.

First, and perhaps most importantly, the omnibus energy bill that became law in July 2013 contains important new language regarding consideration of NTAs. In particular, the bill requires the following:[83]

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[83] HP1128, LD1559, Item 1, 126th Maine State Legislature, "An Act to Reduce Energy Costs, Increase Energy Efficiency, Promote Electric System Reliability and Protect the Environment", Part C.

- No new transmission project of either (1) 69 kV or greater or (2) less than 69 kV with a project cost of at least $20 million can be built without consideration of NTAs;
- Assessment of NTAs must be performed by "an independent third party, which may be the commission or a contractor selected by the commission";
- The commission must "give preference" to NTAs when they are lower cost to ratepayers;
- When costs to ratepayers for a transmission project and NTAs are comparable, the commission must give preference to the option that produces the lowest air emissions (including greenhouse gases);
- If NTAs can address a need at lower total cost, but higher cost to ratepayers (because of socialization of the costs of transmission through ISO New England), the commission must "make reasonable efforts" to negotiate a cost-sharing agreement among the New England states that is similar to the cost-sharing treatment the transmission alternative would receive (the commission is given 180 days to negotiate such an agreement); and
- The commission is required to advocate "in all relevant venues" for similar treatment for analysis, planning and cost-sharing for NTAs and transmission alternatives.

The first NTA study required by the law is currently being undertaken in northern Maine (Docket 2014-00048). The Commission anticipates that two other potential Central Maine Power projects will trigger the study requirement.

Second, the Commission currently has an open docket in which it is considering whether to establish a permanent third party administrator of NTAs (initially Docket 2010-00267; now under Docket 2013-00519) and, if so, to establish how the administrator would be selected and overseen.[84] GridSolar has proposed that it become the state's coordinator. Other parties have some concerns. For example, Efficiency Maine Trust has expressed reservations about creating a new statewide third party administrator to manage consumer education, research and deployment of demand resources when it already plays that role for a subset of the resources (particularly energy efficiency and renewables). It has also expressed concern about inefficiencies in requiring it, as a regulated entity, to work through another regulated third party entity to get efficiency resources to be considered part of potential NTA solutions.[85] Instead, it suggests that cost-effective efficiency NTA resource be deployed in the future through the process EMT currently uses to make changes to its Triennial Plan.[86] GridSolar has itself recommended that in future projects efficiency resources should be procured "in partnership with EMT" and "outside the RFP process used to procure other NTA resources."[87]

[84] Maine calls this position a "Smart Grid Coordinator", perhaps in part because the role may be larger than just managing NTAs.
[85] Personal communication with Ian Burnes, Efficiency Maine Trust, September 17, 2014.
[86] Mr. Ian Burnes and Dr. Anne Stephenson, Direct Testimony, Docket No. 2013-00519, August 28, 2014.
[87] GridSolar, *"Interim Report: Boothbay Harbor Sub-Region Smart Grid Reliability Pilot Project"*, for Docket No. 2011-138, March 4, 2014.

3. PG&E

Legislative Requirements

PG&E, and presumably the other California electric utilities that are subject to the requirements of Assembly Bill 327 (AB 327), are in the early stages of identifying target areas that have rich potential for the deployment of non-wires alternatives. For PG&E, as these areas are identified, small pilot projects will be undertaken to test the potential for meeting growth-related needs through distributed resources rather than through construction of traditional poles and wires solutions. Signed by the Governor on October 7, 2013, AB 327 addresses several issues related to electric regulation and rates, and includes language laying out new expectations for resource planning, including the level of detail and rigor that utilities must apply. The law states that "Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources."[88] The Act further states that "…"distributed resources" means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response…." Sophisticated planning tools will be needed to meet the AB 327 requirement that these utilities must "Evaluate locational benefits and costs of distributed resources…." Until now, tools that can model distributed energy resources (DERs) have not been required.

Selection of Pilot Projects

In response to these requirements, PG&E has begun working with several vendors to explore different tools and approaches for meeting the requirement for developing locational benefits and costs and for applying these values along with load and growth forecasts to develop an optimized distributed resources deployment plan. As an approach to testing the viability of this type of planning and deployment, PG&E began looking specifically at distribution substation level projects that potentially required attention due to load growth.[89] The Company ultimately identified approximately 150 capacity expansion projects that would need to be addressed in the next five years absent any action to defer them. They then applied criteria to identify projects that would be most suitable to explore for non-wires approaches. To make this cut, projects needed to:

- Be growth-related rather than related to any type of equipment maintenance issues;
- Have projected in-service dates at least three years out from the analysis date; and
- Have projected normal operating deficiencies of 2MW or less at the substation level.

These criteria were selected for this concept-testing period to identify projects that would have a strong chance for success. Applying these criteria whittled the list down significantly— to about

[88] Section 769, California Assembly Bill 327
https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327
[89] At PG&E, distribution substations range typically serve between 5000 and 30,000 customers, with a total peak load of about between 20 MW and 100 MW (personal communication with Richard Aslin, PG&E, December 14, 2014).

a dozen remaining projects that had the potential to be candidates for NWAs. PG&E looked more closely at the connected loads and customer profiles for these remaining projects to get a more detailed sense of the types of NWAs that might be relevant in each project, and whether NWAs could realistically achieve the necessary load reductions. Through this process of careful selection, PG & E has identified four projects that it will use to test NWAs in 2014-15. By the end of 2015 they are confident that they will have a much better understanding of the opportunity to use NWAs to defer or avoid poles and wires construction projects.

Efficiency Strategies

Given that these projects are still being developed for PG & E, there is not much actual experience to report on in terms of their approach to deploying energy efficiency in the four pilot areas. PG & E has a wide array of programs in its portfolio, so at present it is not planning to develop new program offerings for targeted areas. However, it is providing significantly larger incentives for custom C&I projects in targeted areas, and is working on making the non-trivial programming changes that will allow it to make corresponding changes for prescriptive measures. Making the programming changes that will allow tracking and reporting of different incentive levels in different areas is a critical step in developing the infrastructure that will allow successful use of DERs.

For residential customers, targeted measures include pool pumps and HVAC measures, with increased incentives available through the Upgrade California initiatives. PG&E is also doing an intense marketing campaign for its residential A/C cycling demand response program, and is offering increased incentives as well. To try to make sure that messaging is going to the right customers – to avoid the possibility that ineligible customers will want to take advantage of increased incentives – PG&E is primarily marketing the programs through installation contractors rather than using any kind of broad outreach campaign.

Outreach poses challenges related to making sure that the message gets to the right customers, but one of the additional challenges that PG&E has identified is the importance of getting the right message to customers in a way that won’t cause them to worry about the lights going out. Many Californians remember rolling brownouts, and any hint that reliability is in question can evoke strong reactions. This may or may not be as much of an issue in jurisdictions that have no history of reliability issues.

Addressing Management Challenges

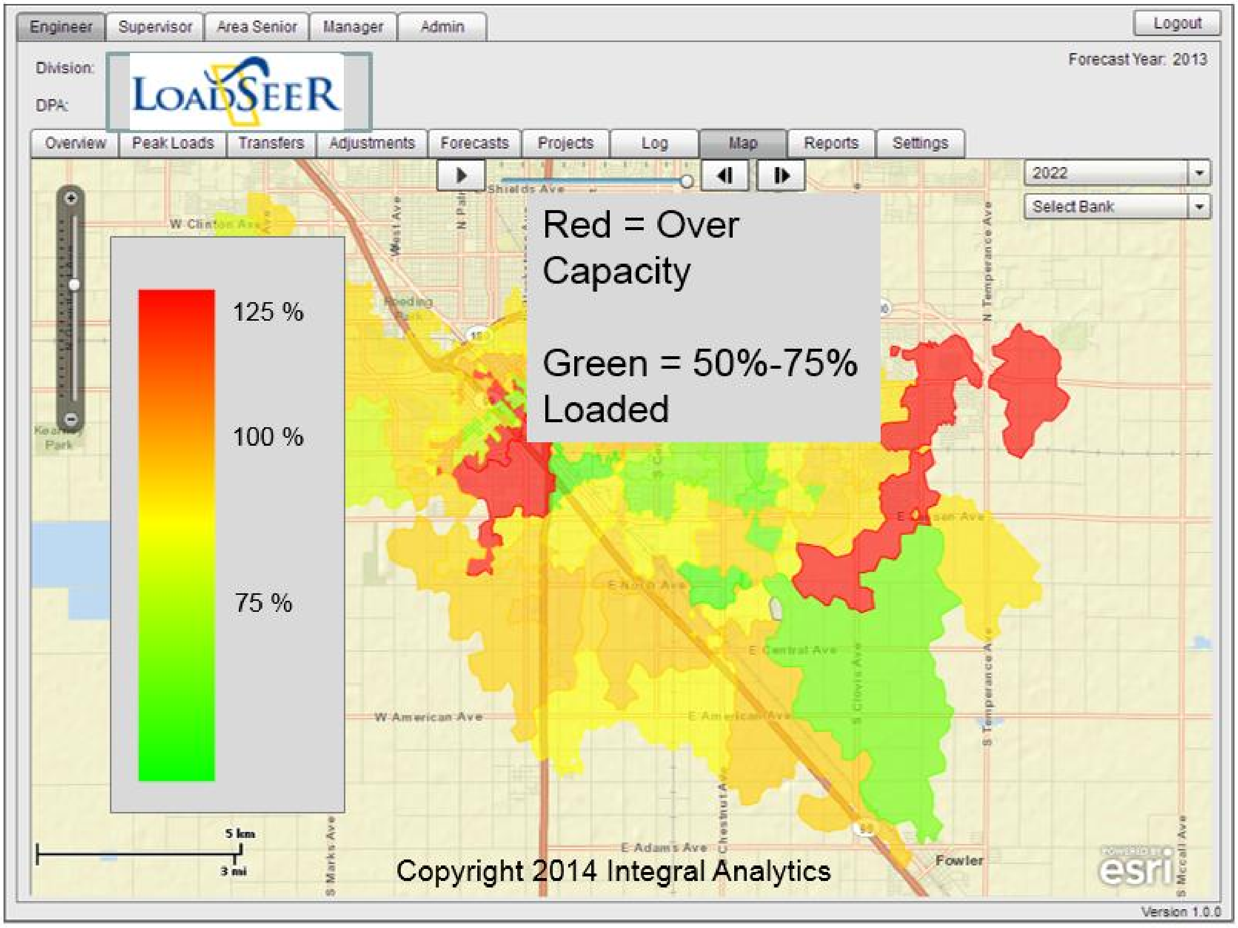
PG&E, like other utilities in this study, has identified challenges working across traditional utility organizational structures that typically have system planners operating in isolation from demand management and energy efficiency staff. PG&E, as well as other utilities with whom we talked, has found that system planners are often uncomfortable with the perceived level of uncertainty in non-wires solutions as compared with poles and wires solutions. Historically, the system planners’ primary role is to provide certainty that the lights will stay on, and so the multifaceted complexity of non-wires solutions may seem less attractive than the alternatives with which they are more familiar.

PG&E staff are exploring organizational changes that might improve the cross-functional coordination of planning for alternatives to poles and wires. One of the steps that PG&E is undertaking to address planning integration between the two groups is – for the targeted substation projects – having dedicated customer energy solutions (CES) engineers and customer relationship managers work side-by-side with the distribution planning engineering teams. They are optimistic that through building these one-on-one relationships, and by having the engineers and customer relationship managers work "across the aisle", they will be able to provide the system planners with the level of assurance they require to more fully support potential NWAs.

Use of New Data-Driven Analytical Tools

Moving forward, PG&E is likely to take greater advantage of sophisticated analytics and smart grid data to refine its analyses of the optimal locations for DER approaches. Currently it is working with a number of third party vendors and consultants to test the applicability of different data-driven approaches that will provide greater assurance to planners by better addressing the unknowns in the current planning process. One of these vendors, Integral Analytics, has already developed tools that will map and forecast loads and develop "distributed" marginal pricing (DMP) at the circuit or even customer level, with far greater precision than the locational marginal pricing (i.e. avoided costs) that are currently used to evaluate demand side management programs. These models not only map current loads, but also model loads out into the future, with the capacity to provide data-driven predictions of when loads will exceed a circuit's capacity to deliver it, as illustrated in Figure 8. DMPs will allow the development of avoided costs for specific, local areas, which will in turn allow precise analysis of the costs and benefits associated with DER projects. Moreover, the incorporation of power flow analytics below the substation can identify avoided costs that are not captured in traditional approaches (e.g. service transformer "reverse flow" risk from photovoltaics, voltage benefits, power factor value, primary vs. secondary losses, etc.) but which enhance the cost-effectiveness of most DERs, if located in the areas of higher avoided costs.

Figure 8: Illustration of Integral Analytics LoadSEER Tool



Consistent with anecdotal reports from several of the jurisdictions surveyed for this study, one of the primary benefits of considering NWAs is that refinements to the load forecasting and planning process, coupled with improved collaboration between demand-side and distribution engineering, results in planned capacity expansion projects being deferred for reasons beyond just the projected impacts of deployed DERs.

Future Evaluation

As these pilots are just being developed at the time of this writing, there have not yet been any evaluations. However, PG&E will look very closely at the results of these pilots in the hope that DER approaches will become a much more prominent tool in its approach to reliably meeting its customers' energy needs.

4. Vermont

Early History

As discussed above, Vermont successfully tested the application of non-wires alternatives in the Mad River Valley in the mid-1990s. A few years later, the state embarked on a path to establishing an independent “Efficiency Utility” – soon thereafter named Efficiency Vermont – that would be charged with delivering statewide efficiency programs. However, the order creating Efficiency Vermont made clear that the state’s T&D utilities would still be responsible for funding and implementing any additional efficiency programs that could be justified as cost-effective alternatives to investment in T&D infrastructure (though they could contract implementation to Efficiency Vermont). The Vermont Public Service Board also agreed to “initiate a collaborative process to establish guidelines for distributed utility planning”.[90] That collaborative culminated in a set of guidelines approved by the Board in 2003 in Docket 6290. Among other things, the distribution utilities were required to file integrated resource plans every three years. Those plans must identify system constraints that could potentially be addressed through non-wires alternatives.[91] The order also led to the creation of a number of “area specific collaboratives” in which opportunities for deferring specific T&D upgrades through non-wires alternatives would be explored by the utilities, the State’s Department of Public Service and other parties. However, none of those discussions led to implementation of any such alternatives.

Northwest Reliability Project

In 2003, VELCO,[92] the state’s transmission utility, formally proposed a very controversial large project – the Northwest Reliability Project – to upgrade transmission lines from West Rutland to South Burlington. As required by Vermont law, VELCO filed an analysis of non-transmission alternatives. The analysis of a scenario including a combination of aggressive geographically targeted efficiency and distributed generation had a lower societal cost than the transmission line.[93] However, that option would involve much larger capital expenditures than the transmission line. Further, whereas much of the cost of the transmission option would be socialized across the New England Power Pool (Vermont pays a very small share of the portion of costs that are socialized across the region), the cost of the alternative path would be born entirely by Vermont ratepayers due to New England ISO rules. Those concerns, coupled with VELCO’s concerns that the level of efficiency envisioned would be unprecedented, led the utility to argue in favor of the transmission option.[94] The Board ultimately approved VELCO’s proposal in early 2005, but expressed concern and frustration with VELCO’s planning process, namely that it did not consider alternatives, particularly efficiency, early enough in the process to make them truly viable options.[95]

[90] Vermont Public Service Board Order, Docket No. 5980, pp. 54-58.
[91] Vermont Public Service Board Order, Docket No. 6290.
[92] VELCO is Vermont’s electric transmission-only company, formed in 1956 to create a shared electric grid in Vermont that could increase access to hydro-power for the state’s utilities. http://www.velco.com/about
[93] La Capra Associates, “Alternatives to VELCO’s Northwest Reliability Project”, January 29, 2003.
[94] Ibid.
[95] Vermont Public Service Board, “Board Approves Substantially Conditioned and Modified Transmission System Upgrade”, press release, January 28, 2005.

Act 61 – Institutionalizing Consideration of Non-Wires Alternatives

The approval of the transmission line contributed to the passage later that year of Act 61. Among other things, Act 61:

- required state officials to advocate for promotion of least cost solutions to T&D investments and equal treatment of the allocation of costs of both traditional T&D investments and non-wires alternatives "in negotiations and policy-making at the New England Independent System Operator, in proceedings before the Federal Energy Regulatory Commission, and in all other relevant venues…"
- required VELCO to regularly file a statewide transmission plan that looks forward at least 10 years; and
- eliminated the statutory spending cap for Efficiency Vermont, instructed the Board to determine the optimal level of efficiency spending, and made clear that cost-effectively deferring T&D upgrades should be one of the objectives the Board considers in establishing the budget.

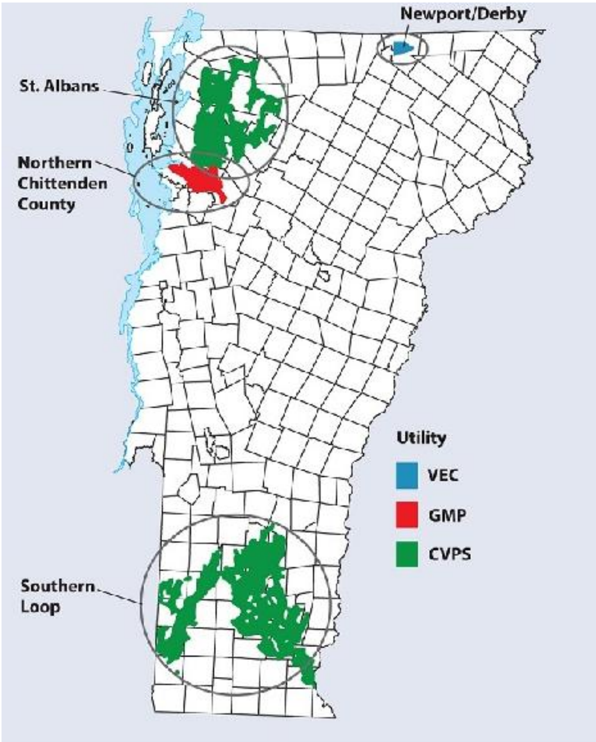
Key excerpts from Act 61 are provided in Appendix C.

Efficiency Vermont's Initial Geo-Targeting Initiative

In response to passage of Act 61, the Public Service Board increased Efficiency Vermont's budget by about $6.5 million (37%) in 2007 and $12.2 million (66%) in 2008 and ordered that all of the additional spending be focused on four geographically-targeted areas: northern Chittenden County, Newport, St. Albans, and the "southern loop" (see Figure 9).[96] Those areas had been identified by the state's utilities as areas in which there may be potential for deferring significant T&D investment. Collectively, these efforts became known as Efficiency Vermont's initial "geo-targeting" initiative. [97]

[96] Vermont Public Service Board, *Order Re: Energy Efficiency Utility Budget for Calendar Years 2006, 2007 and 2008*, 8/2/2006.
[97] Efficiency Vermont Annual Plan, 2008-2009.

Figure 9: Efficiency Vermont Geo-Targeting Regions (2007-2008)



Efficiency Vermont was given peak savings goals for these areas that represented a 7- to 10-fold increase in the peak savings it had historically been achieving in the areas through its statewide efficiency programs. To meet the goals Efficiency Vermont initiated intensive account management of large commercial and industrial customers, launched a small commercial direct install program, and locally increased marketing and promotion of CFLs.

Approximately one year into its delivery, one of the four initially targeted areas (Newport) was dropped from the geo-targeting program when the distribution utility determined that the substation whose rebuilding the program was intended to defer needed to be rebuilt for reasons other than load growth (i.e., "destabilization of the substation property due to river flooding").[98] Independent of that decision, a new target area – Rutland – was added to the program beginning in 2009.

An evaluation of the 2007-2009 geo-targeting efforts suggested the results were mixed. On the one hand, program participation was two to four times higher in the geo-targeted areas than statewide. Savings per participant were also higher – 20-25% higher for business customers and 30% higher for residential customers. The net result was summer peak savings that were three to five times higher in the first couple of years than would have been achieved under the statewide

[98] Navigant Consulting et al., *"Process and Impact Evaluation of Efficiency Vermont's 2007-2009 Geotargeting Program"*, Final Report, Submitted to Vermont Department of Public Service, January 7.

programs.[99] On the other hand, those summer peak savings were still 30% lower than Efficiency Vermont's goals for the targeted areas; winter peak savings were 60% lower than goals. Nevertheless, analysis of loads on individual feeders in geo-targeted areas suggests that geo-targeting program impacts "are detectable at the system level" and that the magnitude of savings observed at the utility system level were consistent with those estimated through evaluation of customer savings.[100]

Evaluation of the impacts of the observed peak demand reductions on the potential deferral of T&D investments was not conducted. However, Central Vermont Public Service (the state's largest utility at the time)[101] has observed that it "has not been required to schedule the deployment of additional system upgrades in Rutland, St. Albans and Southern Loop areas". While it is difficult to know the extent to which that situation should be attributed to the geo-targeting of DSM, to changes in economic conditions (i.e., the recent economic recession) and/or to other factors, the Company did recommend to the Board that geo-targeting of DSM continue.[102] One Vermont official similarly noted that

Vermont System Planning Committee

Subsequent to the passage of Act 61, the PSB initiated proceedings in Docket 7081 to develop a planning process that would ensure "full, fair and timely consideration of cost-effective non-transmission alternatives." The Public Service Board ultimately issued orders in 2007 approving an MOU between the major parties that established the Vermont System Planning Committee (VSPC) and charged it with carrying out this work.

The VSPC is a collaborative body. It brings together a wide range of viewpoints, including those of representative public stakeholders. There are six equally weighted voting contingents who are responsible for VSPC decisions on specific activities and projects:

- VELCO,
- large utilities with transmission,
- large utilities without transmission,
- other utilities without transmission,
- Efficiency Utilities (i.e. Efficiency Vermont and Burlington Electric Department) and renewable energy organizations, and
- public stakeholders.[103]

[99] Navigant Consulting et al., "Process and Impact Evaluation of Efficiency Vermont's 2007-2009 Geotargeting Program", Final Report, Submitted to Vermont Department of Public Service, January 7, 2011
[100] Navigant et al. (2011), p. 10.
[101] It was subsequently purchased and has become a part of Green Mountain Power.
[102] Silver, Morris, Counsel for Central Vermont Public Service, letter to the Vermont Public Service Board regarding "EEU Demand Resources Plan – Track C, Geotargeting", January 18, 2011.
[103] http://www.vermontspc.com/about/membership

The Public Service Board appoints the public stakeholders and the renewable energy representatives.

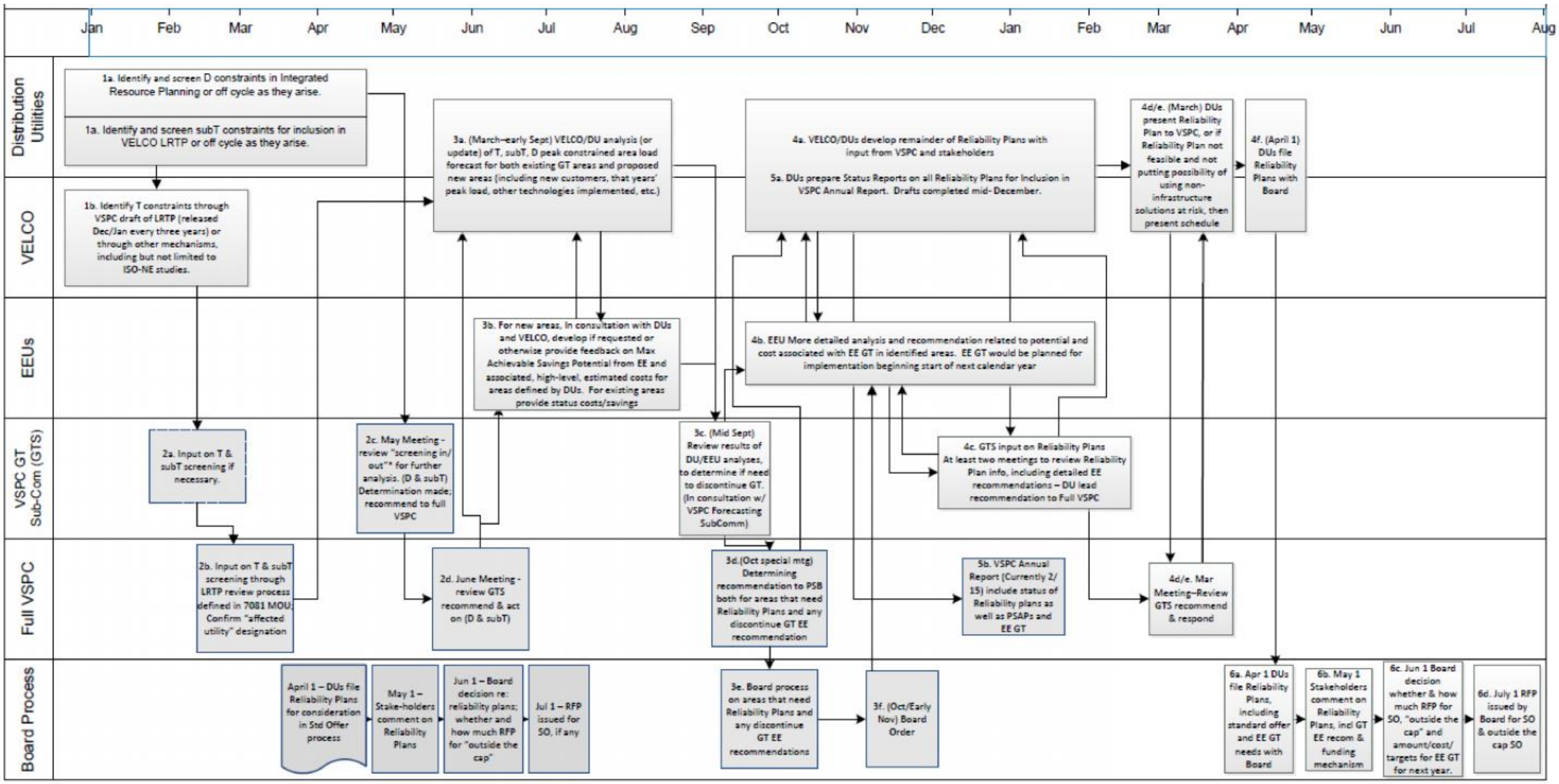
The VSPC process overcomes two significant barriers by first making sure that potential system constraints are identified as far in advance of their needed construction dates as possible, and secondly by ensuring that efficiency program planners are brought into the conversation early enough to determine whether efficiency is a viable alternative to construction given the particular customer segments that predominate in the targeted areas. Over time, the level of coordination in designing and implementing solutions has increased. In the first geographic targeting initiative undertaken by Efficiency Vermont in 2007, the state's utilities identified potentially constrained areas and then, with PSB approval, more-or-less handed the list to Efficiency Vermont. Now, with Efficiency Vermont serving as a fully participating member of the VSPC, a much more integrated approach is used, where the efficiency potential of constrained areas is investigated prior to their selection for geographically targeted efforts.

With the formation of the VSPC, significant efforts have also been invested in making sure that diverse viewpoints are represented in discussions regarding non-wires alternatives to both distribution and transmission construction. Further, a clear, well-documented and transparent process has been developed to make sure that results and decisions are firmly based on comprehensive consideration of evidence. This process has evolved over time. The current process is documented in Figure 10 below.[104]

In this process, VELCO, along with the large utilities that have transmission, is responsible for identifying bulk and predominantly bulk transmission system reliability improvement needs; the individual distribution utilities are responsible for identifying distribution and sub-transmission needs. Though they come from different dockets and legislation, in each case there is a requirement that these are identified on a three year basis, but project lists are also updated for the VSPC annually.

[104] http://www.vermontspc.com/library/document/download/599/GTProcessMap_final2.pdf

Figure 10: Vermont Geo-Targeting Process Map (as of 9/11/2013)



*"Screening" refers to the use of the Docket 7081 screening tool for bulk and predominantly bulk transmission and the Docket 6290 screening tool for subtransmission and distribution issues to determine their potential to be resolved through energy efficiency and/or alternatives such as generation or demand response (or a hybrid of transmission with efficiency and/or generation). An issue is "screened in" if it has potential for a non-wires solution and therefore requires a Reliability Plan, and "screened out" if no potential is found and, therefore, no Reliability Plan is required.

Key to abbreviations

D	distribution	LRTP	VELCO Long-Range Transmission Plan
DU	distribution utility	PSAP	project-specific action plan
EE	energy efficiency	RFP	request for proposal
EEU	energy efficiency utility	SO	standard offer
GT	geographic targeting	subT	subtransmission (subsystem)
GTS	VSPC Geotargeting Subcommittee	T	transmission (bulk/predominantly bulk)
		VSPC	Vermont System Planning Committee

As part of the development of T&D project lists, the utilities are required to use a set of "pre-screening" criteria to identify projects that might be candidates for non-wires alternatives. The key pre-screening criteria for distribution and sub-transmission projects are that the forecast "poles and wires" costs is greater than $250,000, that it is not required on an emergency basis, and that the need could be reduced by reductions in load.[105] For transmission projects to be considered for NWA approaches, the alternative needs to be projected to save at least $2.5M, needs to be able to be deferred or eliminated by a 25% or less reduction in load, does not need to be in place for at least one year into the future, and must not be needed for the purpose of meeting certain "stability" criteria related to grid performance. The VSPC reviews the utilities' initial project lists, including their pre-screening conclusions, and modifies them as appropriate. A recent example of a project list is provided in Table 4 below.

Table 4: Green Mountain Power 2014 Forecast of Distribution System Needs

Constraint	Load Growth related (Y/N)	MW Need	Year of need	Zonal identified MW available (potential study)	Further screening (Y/N)
Susie Wilson Substation Area	Yes		2037		No Continue to Monitor
Wilder - White River Junction Area	Reliability and Load Growth		2015		No
Waterbury	Reliability		2015		No
Winooski 16Y3 Feeder	No		2015		No
Hinesburg	Yes		2016		No
Dover Haystack	Yes		2015		No
Stratton	Reliability		2015		No
St Albans	Reliability and Load Growth		>10 years		Reliability Plan filed 4/2/14, Continue to Monitor
Miton	Yes		>10 years		No Continue to Monitor
Brattleboro	Yes		>10 years		No Continue to Monitor
Southern Loop	Yes		>10 years		No Continue to Monitor
Danby	Reliability and Load Growth		2016		No
Granite-Whetmore	Asset Management		2016		No
South Brattleboro	Reliability		2016		No
3309 Transmission	Reliability		2014		No Continue to Monitor / Refine the analysis
Rutland Area	Reliability		Existing Constraint		Reliability Plan filed 4/2/14, additional analysis required
Windsor Area	Reliability		2017		No

For projects that pass the initial screen, the VSPC then follows the collaboratively-developed process to consider non-wires solutions, with the efficiency and renewables alternatives given a detailed look by Efficiency Vermont and other stakeholders. To date this analysis has been

[105] http://www.velco.com/uploads/vspc/documents/ntascreening_6290.pdf

conducted with only limited use of smart grid data. Efficiency Vermont has a deep knowledge of its customer base through nearly fifteen years of program implementation, and can also easily track prior efficiency improvements that targeted customers made through participation in Efficiency Vermont initiatives. While there is diversity among Vermont's commercial and industrial customers, they are still mostly relatively small compared to the C&I base in other jurisdictions, and so far Efficiency Vermont has been able to assess these opportunities without the use of more detailed analytic tools.

Efficiency Vermont's Strategy and Planning group has been responsible for identifying opportunities to increase efficiency in targeted areas and for designing program approaches to capture that efficiency. Generally, the implementation of any geographically targeted energy efficiency alternatives has been managed by Efficiency Vermont in a manner that is highly coordinated with its other state-wide efforts. Since beginning to implement geographically targeted initiatives in 2007 Efficiency Vermont has been cognizant of the need for sensitivity when it determines to only offer certain programs to some, rather than all customers. For this reason, they have decreased the use of special incentives in targeted areas in favor of increased outreach and communications. For example, the use of account management strategies for C&I customers is increased in geographically targeted areas, meaning that smaller customers who would not have received the attention of individualized account managers in non-targeted areas do receive that attention in targeted areas. This account management approach also allows Efficiency Vermont to focus on projects that have the potential to produce higher peak savings than average, thus increasing the ability of efficiency to defer construction compared to an "average" project that did not receive this level of guidance from account managers.

Efficiency Vermont has not done competitive solicitations to identify vendors who will commit to delivering certain savings through strategies of their own devising. Rather they have designed and managed program initiatives internally, with limited use of third-party vendors to implement programs for which Efficiency Vermont has developed the parameters. However they are investigating the potential to use the targeted deployment of third-party approaches in the future, specifically those that make use of smart grid data to identify savings opportunities to engage customers who might otherwise not have been aware of them.

With the VSPC process in place, the relationship between level of effort and the amount of resource needed in a specific area is much, much stronger. Where the first of Efficiency Vermont's geographically targeted efforts involved a single goal that could be met through savings in any of several targeted areas, goals are now set that are specific to each targeted area, and that reflect the actual need in that area as determined by system planners.

The VSPC and the planning process for non-wires alternatives have matured significantly in Vermont. Conversations with the Public Service Department and Efficiency Vermont both suggest confidence in the process. Going forward, it is expected that the VSPC process will continue to be used to identify potential candidates for geographic targeting of NWAs.

V. Cross-Cutting Observations and Lessons Learned

Although the use of efficiency to meet T&D needs– either alone or in combination with other non-wires resources – is not yet widespread, it is fairly substantial and growing. That experience offers a number of insights, presented below, for jurisdictions considering the use of such resources in the future.

The Big Picture

1. Geographically Targeted Efficiency Can Defer Some T&D Investments

Projects run by Con Ed (from 2003 through 2012), Vermont (both the initial Green Mountain Power Project in the mid-1990s and more recent examples), PG&E's Delta Project in California (in the early 1990s), and portions of PGE's project in downtown Portland, Oregon (also in the early 1990s), all demonstrably achieved enough savings to defer some T&D investments for at least some period of time. Preliminary results from the first year of experience with new projects in Maine and Rhode Island suggest that they too are likely on track to defer T&D investments.

2. T&D Deferrals Can be Very Cost-Effective

The cost-effectiveness of geographically-targeted efficiency programs and other non-wires resources will unquestionably be project-specific. That said, though data on the cost-effectiveness of T&D deferrals is not available for all of the projects we have examined, the information that is available suggests that efficiency and other non-wires resources can be very cost-effective – i.e. potentially much less expensive than "poles and wires" alternatives. For example, Con Ed's evaluation suggests that its geographically targeted efficiency investments from 2003 to 2010 produced roughly $3 in total benefits for every $1 in costs; the T&D benefits alone were worth 1½ times the costs of the programs. Similarly, the revenue requirements for Maine's pilot project are forecast to be more than 60% lower than for the alternative transmission solution.

3. There Is Significant Value to the "Modular" Nature of Efficiency and Other NWAs

One of the advantages of energy efficiency and other non-wires alternatives is that they are typically very modular in nature. That is, they are usually acquired in a number of small increments – e.g. thousands of different efficiency measures across hundreds, if not thousands of different customers, across several years. In contrast, the pursuit of a "poles and wires" strategy typically requires a commitment to much larger individual investments – if not a singular investment.

The modularity of efficiency and other non-wires alternatives allows for a ramp up or a ramp down of effort, either in response to market feedback (e.g. if customer uptake is greater or lower than expected) or in response to changing forecasts of T&D need. For example, as discussed in the case study of the Maine pilot project, the magnitude of the non-wires resource needed to defer the transmission investment has declined from an initial estimate of 2.0 MW to 1.8 MW.

Moreover, perhaps in anticipation of possible future changes, a decision has been made to not yet contract for the last 0.1 MW of need because that can be addressed at a future time if it is still determined to be needed. Similarly, again as noted above, Con Ed has found that one of the biggest advantages of its non-wires projects is that they have "bought time" for the utility to better tune its forecasts, to the point in a number of cases where the T&D investments once thought to be needed are now not anticipated to ever be needed.

4. Policy Mandates Are Driving Most Deployments of NWAs

Virtually all of the examples of the use of non-wires alternatives that we have profiled in this report were at least initially driven by either legislative mandates, regulatory guidelines or types of regulatory feedback. Examples of such requirements are provided in Appendices A through D.

The importance of policy mandates may be partly indicative of the nature of the internal barriers to utility pursuit of non-wires solutions. Utilities tend to be fairly conservative institutions. That is consistent with their primary mission of "keeping the lights on". It is understandable that they would be reluctant to change practices that they know are successful in serving that mission. As noted above, there are also challenges associated with persuading system planners that demand side alternatives can also be reliable.

In addition, utilities' financial incentives are generally not well aligned with the objective of pursuing cost-effective alternatives to "poles and wires". Right now, utilities can face a choice of earning money for shareholders if they pursue a traditional T&D path (because they earn a rate of return on such capital investments) or making no money if they choose to deploy non-wires alternatives.[106] To our knowledge, Con Ed's proposal for shareholder incentives for the large new Brooklyn-Queens project is the only proposal of its kind that attempts to directly address this issue.

Implementation

5. Cross-Disciplinary Communication and Trust is Critical

This may seem self-evident, but it is critical nonetheless. T&D planners and engineers are often skeptical of the potential for end use efficiency and/or other demand resources to reliably substitute for poles, wires and other T&D "hardware". They worry that customers themselves are unreliable. Similarly, staff responsible for administration of programs that promote efficiency, load control, distributed generation or other demand resources typically do not fully

[106] Some utilities operate under capital spending caps. In such cases, the financial disincentives may be mitigated, at least in the short term, with money freed up from deployment of NWAs to defer or eliminate the need for some T&D investments effectively enabling the utility to invest in other T&D projects further down its priority list. However, if deployment of cost-effective NWAs is institutionalized, regulators could eventually respond by reducing capital spending caps.

understand the complexities of the reliability issues faced by T&D system planners. Both need to better understand the needs and capabilities of the other.

It can take time to develop the relationships and confidence necessary for efficiency program implementers and T&D system engineers to work together effectively. However, those relationships and that trust must be developed if efficiency programs are to successfully defer T&D investments.

Different jurisdictions and utilities have approached the challenge of facilitating cross-disciplinary collaboration differently. Con Ed has created a multi-disciplinary team that meets regularly under the direction of a Senior Vice President. PG&E has assigned field services engineers with customer-side experience to work side-by-side with distribution planning engineers on their pilot non-wires projects, with the expectation that the experience of working together will build trust and mutual understanding over time. Vermont's System Planning Committee serves a similar function, institutionalizing communication between system planners and those responsible for efficiency program delivery (as well as other stakeholders).

6. Senior Management Buy-in Is Invaluable

Senior management support for consideration of non-wires alternatives can be critical, if not essential, to facilitating the kind of cross-disciplinary collaboration that is necessary to be successful.

Senior management support will also be necessary to get to the point where consideration of cost-effective non-wires alternatives is routine and fully integrated into the way utilities run their businesses. As discussed further below, that, in turn, may require changes to utilities' financial incentives.

7. Smaller Is Easier

In general, all other things being equal, the smaller the size of the load reduction needed and the smaller the number of customers, the easier it is to plan and execute a non-wires solution. Smaller areas allow for greater understanding of both the customer mix and the savings or distributed generation opportunities associated with those customers. It is also generally easier to mobilize the existing demand resources delivery infrastructure (e.g. HVAC, lighting and/or other contractors) to meet a smaller need.

That is not to say that only small projects should be pursued, as the economic net benefits from larger projects also tend to be larger. Larger areas do offer one advantage: a more diverse range of customers and savings opportunities from which to choose in designing and implementing an NWA solution. A corollary to this point is that networked systems may be easier to address than radial systems because they allow for treatment of a larger number of customers to address a need. However, it is also important to recognize that larger projects with more customers over a larger geographic area will also be more complex and often require more lead time to plan and execute.

8. Distribution is Easier than Transmission

This may seem like just a corollary to the "smaller is easier", as distribution projects are generally smaller than transmission projects. However, there is more to it than that. For one thing, distribution system planning is generally less technically complex and more "linear" – 1 MW of load reduction commonly translates to 1 MW (adjusted for losses) of reduced distribution infrastructure need. In transmission planning 1 MW of load reduction in an area does not necessarily translate to 1 MW of reduced infrastructure need. In addition, distribution system planning typically involves fewer parties so decision-making is often more streamlined. Moreover, distribution reliability planning criteria can be less stringent than transmission planning criteria, so there may be opportunities to use NWAs with shorter time horizons and/or with less certainty that forecast savings will be achieved (i.e. there can be more flexibility for utilities in the timing of distribution infrastructure upgrades).

Finally, and perhaps most importantly, the cost allocations for both distribution system investments and their non-wires alternatives will typically both be fully and equally born by local ratepayers. This is in stark contrast to the allocation of transmission costs, which are governed by regional frameworks that inherently bias investments in favor of traditional "poles and wires" solutions. Typically transmission investment costs are socialized across multi-state regions, so that the state in which the transmission investment is needed pays only a portion of the project costs. In the case of non-wires alternatives, the state in which the project is deployed is made to bear all of the costs. Clearly, until this is addressed, it will continue to be challenging to implement NWAs to defer transmission projects.

9. Integrating Efficiency with Other Alternatives Will be Increasingly Common and Important

In several of the examples that we examined in this report geographically-targeted efficiency programs were enough, by themselves, to defer the traditional T&D investment. However, in some cases efficiency was effectively paired with demand response and/or other non-wires alternatives. As the projects being considered become larger and more complex and the development of non-wires solutions becomes more sophisticated, we expect such multi-pronged solutions to become more common. That is certainly the case, for example, with Con Ed's new Brooklyn-Queens project. Moreover, even a comprehensive suite of NWAs may be inadequate, by themselves, to address reliability concerns. In such cases, NWAs could potentially be paired with some T&D modifications, deferring only a portion of a larger T&D investment project.

10. "Big Data" and New Analytical Tools Enable More Sophisticated Strategies

Several of the geographic targeting projects that have occurred to date have found that the availability of savings was different from their initial expectations because their assumptions about the customers in the targeted areas were found to have been inaccurate. This was true for the Tiverton project in Rhode Island, where initial plans called for a substantial amount of demand response for residential central air conditioning systems, but where it turned out that the penetration of central air conditioning was much lower than originally expected. Similarly, Con Ed found that contractors weren't able to meet their savings targets in the later years of their initial geo-targeting efforts and attributed this to the lack of a detailed understanding of the types of customers and predominant end uses in the targeted areas.

Utilities have also faced uncertainty in assessing the cost-effectiveness of NWAs, in no small part because accurately assessing loads and growth is challenging, and utility system planners—who are responsible for assuring that the lights will stay on— may have some understandable bias towards high safety margins when assessing system capacity. Put another way, accurately valuing the economic benefits of alternatives to poles and wires approaches is not easy.

Reliable and malleable planning tools are needed that will allow more accurate modeling of loads at a much more detailed level, and that will provide a better accounting of available savings and the economic value associated with them. Understanding the opportunities available to customers within defined and specific geographies, coupled with detailed load and economic information, will allow utilities to plan NWA approaches with greater confidence and to yield greater economic benefits (i.e. from the use of more granular, locational avoided costs) in the process. In recognition of this, several utilities and third party vendors are rapidly developing tools to address these emerging needs. We are aware of efforts by Integral Analytics for PG&E and others, and by Energy + Environmental Economics (E3) for Con Ed. Navigant is also participating in projects for both of these utilities, and it is likely that others are exploring this space as well.

Integral Analytics has developed a suite of proprietary software tools specifically for the purpose of providing utilities with previously unavailable capability for assessing loads down to the acre level, and for developing avoided costs that are specific to each circuit. These tools would not only provide California utilities with the means to comply with AB327, but would also allow them to assess the need for load relief with much greater precision and to plan NWAs more reliably. Integral Analytics has made special efforts to engage distribution planners in the development of their tools, in recognition of the importance of their participation in identifying and proposing NWAs.

E3 is working closely with Con Ed, as discussed above, to develop a "Decision Tool Integrator" that will overcome the earlier challenges the utility faced in accurately assessing the availability of savings, and further will allow them to identify the combinations of non-wires and traditional approaches that will be best suited to achieving the required load relief in specific areas.

Impact Assessment

11. Impact Assessment Should Focus First on the T&D Reliability Need

Conceptually, assessment of geographically-targeted efficiency programs (and other non-wires resources for that matter) can address one or more of several key questions. Chief among them are:

1. Has the forecast T&D need changed? Has it moved further out into the future, or even been eliminated as a result of targeted programs?
2. To the extent that the forecast T&D need has changed, how much of that change is attributable to the deployment of geographically-targeted efficiency and/or other non-wires resources?
3. What is the magnitude of the T&D peak reduction (for efficiency or demand response) or production (for distributed generation or storage) that has been realized as a result of the deployment of efficiency and/or other non-wires resources? Note that the answer to this question might help inform the answer to the second question above.

To date, the principal focus of most jurisdictions' efforts to assess the impacts of NWAs has been on the first question: was the need for the T&D investment pushed out into the future? This is the most directly answerable question in the sense that it is really about how the current forecast of need has changed from the original forecast of need. It is also clearly the most important because it addresses the "bottom-line" metric that dictates whether money has been saved. In contrast, the second question – how much of the deferral is attributable to the non-wires alternatives – is challenging to address, in part because it begs the question of what "baseline" the evaluation is measuring against.

It is worth emphasizing that one of the key findings from non-wires projects has been that they often "buy time" to improve forecasts of need. Thus, one could argue that a non-wires solution should get "full credit" for a deferral even if the savings that the non-wires alternatives provided were not, by themselves, responsible for 100% of the difference between the old forecast and the new forecast of T&D need. As one Vermont official put it, in discussing a recent geo-targeting effort in the city of St. Albans:

> *"It is impossible to say that one thing deferred the project. But I would also argue that energy efficiency gave us the time to realize that we didn't need the project. As long as we follow a robust process for selecting geo-targeting areas, energy efficiency can be a 'no regrets' strategy, where even if it does not defer the project the efficiency investment is cost-effective (thanks to its avoided energy, capacity and other costs) and allows for more certainty as to the need for the infrastructure. In an energy system world where decisions must be made amidst so much uncertainty, geo-targeted efficiency's risk*

> *mitigation value increases above and beyond the risk value that we give to statewide programs."*[107]

That all said, traditional evaluation, measurement and verification (EM&V) of geographically targeted efficiency programs – both impact evaluation to determine how much T&D peak demand savings were realized and process evaluation to understand what worked well and what did not – can still provide a lot of value. However, that value may be more related to informing planning for future projects than for retrospectively "scoring" the effectiveness of the geo-targeting and/or assigning attribution for T&D deferrals.

[107] Personal communication with T.J. Poor, Vermont Public Service Department, December 23, 2014.

VI. Policy Recommendations

In virtually every jurisdiction profiled in this report, the impetus for consideration of lower cost non-wires solutions to address selected reliability needs has been driven (at least initially) by some form of government policy – either legislative requirements, regulatory requirements or feedback, or both. In this section of the report, we present what lessons learned from leading jurisdictions suggests about key policies. Specifically, we offer four policies that policy-makers should consider if they are to effectively advance consideration of alternatives – including, but not limited to geographically targeted efficiency programs – to transmission and/or distribution system investments. Note that though we use the terminology "non-wires solutions" because most of the focus of this report has been on the electricity sector, the same concepts should apply to "non-pipes solutions" for the natural gas sector.

Recommendation 1: Require Least Cost Approach to Meeting T&D Needs

This is the most basic, but also the most important policy for promoting consideration of alternatives to T&D investments. It is in place in every jurisdiction that is routinely assessing such alternatives on a routine basis. Because the barriers to non-wires alternatives – both institutional and financial – are so strong, this kind of requirement is necessary. It should be emphasized that though necessary, least cost requirements are not sufficient to ensure that economically optimal solutions to reliability needs are considered (see other policy recommendations below).

One other possible alternative would be an overhaul of the way utilities are regulated, including strong financial incentives for minimizing T&D costs imposed on ratepayers. That is the path that the state of New York appears to be pursuing. While intriguing, such a twist on the concept of performance regulation is untested and will be challenging to get right. That is not to say it should not be pursued – only that it needs to be done with great care, with regular evaluation to ensure it is producing the desired results, and perhaps with "backstop" minimum requirements to ensure that the expected and desired results are achieved.

Recommendation 2: Require Long-Term Forecast of T&D Needs

One of the keys to realizing the full benefits that efficiency, demand response, distributed generation, storage and/or other non-wires solutions can provide is ensuring that they can deployed with sufficient lead time to defer T&D investments. We have highlighted several cases in this report in which non-wires solutions could have been less expensive than the wires solutions, but were not pursued (at least in part) because of concern that there was not enough lead time to be certain that the reliability need would be met. Requiring a long-term forecast of T&D investments can significantly reduce the probability of such less than optimal outcomes. By long-term we mean at least 10 years. However, 20 years – as is currently required in Vermont – may be even better. While the accuracy of these forecasts will diminish the farther out into the future they go, a 20 year forecast will still do a better job at ensuring that insufficient lead time does not preclude deployment of cost-effective non-wires solutions.

Recommendation 3: Establish Screening Criteria for NWA Analyses

One way to help effectively institutionalize consideration of non-wires solutions is to establish a set of minimum criteria that would trigger a detailed assessment of non-wires solutions. Most of the jurisdictions discussed in this report have such criteria.

All such criteria start with a requirement that the project be load-related. As the Rhode Island guidelines put it, the need cannot be a function of the condition of the asset (e.g. to replace aging or malfunctioning equipment). Some jurisdictions, such as Vermont, have a short "form" that utilities must complete for each proposed project that provides more detail on this question.

Most jurisdictions have additional criteria related to one or more of the following:

- **Sufficient Lead Time Before Need.** The purpose of this criterion is to ensure that there is enough lead time to enable deferring a T&D investment.
- **Limits to the Size of Load Reduction Required.** The purpose of this criterion is to ensure that there is a substantial enough probability that the non-wires solution can be effective before investing in more detailed assessments. The maximum reduction can be linked to the previous criterion around lead time, as the longer the lead time the larger the reduction in load (and/or equivalent distributed generation level) that could be achieved through non-wires solutions.
- **Minimum Threshold for T&D Project Cost.** The purpose of this criterion is to ensure that the potential benefits of a T&D deferral are great enough to justify more detailed analysis.

Table 5 below provides a summary of the criteria currently in place for a number of the jurisdictions assessed in this report.

Table 5: Criteria for Requiring Detailed Assessment of Non-Wires Solutions

	Must Be Load Related	Minimum Years Before Need	Maximum Load Reduction Required	Minimum T&D Project Cost	Source
Transmission					
Vermont	Yes	1 to 3 4 to 5 6 to 10	15% 20% 25%	$2.5 Million	Regulatory policy
Maine	Yes			>69 kV or >$20 Million	Legislative standard
Rhode Island	Yes	3	20%	$ 1 Million	Regulatory policy
Pacific Northwest (BPA)	Yes	5		$3 Million	Internal planning criteria
Distribution					
PG&E (California)	Yes	3	2 MW		Internal planning criteria
Rhode Island	Yes	3	20%	$ 1 Million	Regulatory policy
Vermont	Yes		25%	$0.3 Million	Regulatory policy

Documents that lay out these requirements more formally and in more detail are provided for Vermont and Rhode Island in Appendices D, E and F.

Consistent with the integrated resource planning guideline discussed above, when projects pass such initial screening criteria, the utility should be required to conduct a more detailed assessment of the potential for reduced peak demand in the geographic area of interest through any combination of distributed resources, including additional energy efficiency, demand response, distributed generation and storage. The cost of such additional distributed resources should then be compared to their benefits. The level of depth of analysis would be a function of the magnitude of the deferral project. For projects for which the more detailed assessment suggests that greater EE and DR would have positive net benefits,[108] the utility should be required to pursue the non-wires solution.

Recommendation 4: Promote Equitable Cost Allocation for NTAs

Investments in transmission solutions to reliability needs are commonly socialized across power pools. For example, a large majority of the cost of a transmission investment in Maine can ultimately be borne by ratepayers in the other five states that are part of the New England grid. In contrast, there is no comparable mechanism to socialize the cost of non-transmission investments across the region[109] – even if they would just as effectively address the reliability

[108] As discussed earlier in the report, some NWAs, including energy efficiency, provide a number of benefits beyond deferral of T&D investments. All costs and benefits of both NWAs and traditional T&D investments should be included in any economic comparisons.

[109] Note that though there is currently no mechanism for socializing the costs of implementing NTAs, there is at least an open question as to whether the costs of *analyzing* NTAs could be socialized. Indeed, some costs of analysis of

concern at a substantially lower cost. In other words, if Maine invests in a non-transmission solution, it will have to bear the full cost of that approach. This is a huge economic barrier to consideration of cost-effective non-transmission investments. Legislation in some states now requires their state officials to advocate for equal treatment of transmission and non-transmission planning and cost allocation in negotiations with and proceedings before their independent system operators, the Federal Energy Regulatory Commission (FERC) and other bodies and fora. Excerpts from the Vermont and Maine legislative language are provided below:

> **Vermont Act 61, Section 8**
>
> "(5) The public service department, public service board, and attorney general shall advocate for these policies in negotiations and appropriate proceedings before the New England Independent System Operator, the New England Regional Transmission Operator, the Federal Energy Regulatory Commission, and all other appropriate regional and national forums. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.
>
> (6) In addressing reliability problems for the state's electric system, Vermont retail electricity providers and transmission companies shall advocate for regional cost support for the least cost solution with equal consideration and treatment of all available resources, including transmission, strategic distributed generation, targeted energy efficiency, and demand response resources on a total cost basis. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.
>
> **Maine 2013 Omnibus Energy Bill, Part C, Sec. C-7 (35-A MRSA §3132)**
>
> **<u>15. Advancement of non-transmission alternatives policies</u>**. The commission shall advocate in all relevant venues for the pursuit of least-cost solutions to bulk power system needs on a total cost basis and for all available resources, including non-transmission alternatives, to be treated comparably in transmission analysis, planning and access to funding.

The greater the number of states that have such policies in place, the greater the likelihood that this barrier will be addressed. The question of what "comparable treatment" to socialization of traditional transmission and non-transmission investments means is not necessarily a simple one. It is likely to require careful thought and discussion among a number of stakeholders. States can play an important role in pressing for and shaping such discussions.

NTAs are already indirectly socialized. For example, VELCO, Vermont's transmission utility, currently recovers costs associated with its system planners through a regional tariff. Thus, when those planners work on NTAs, the costs of that work are effectively socialized across the regional. However, to our knowledge, no entity has yet tested whether other costs of analyzing NTAs (e.g. those born by other entities in a state) are recoverable through regional tariffs.

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Appendix A: California AB 327 (excerpt)

SEC. 8. Section 769 is added to the Public Utilities Code, to read:

769. (a) For purposes of this section, “distributed resources” means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

(b) Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources. Each proposal shall do all of the following:

1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation.
2) Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.
3) Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.
4) Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.
5) Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

(c) The commission shall review each distribution resources plan proposal submitted by an electrical corporation and approve, or modify and approve, a distribution resources plan for the corporation. The commission may modify any plan as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources.

(d) Any electrical corporation spending on distribution infrastructure necessary to accomplish the distribution resources plan shall be proposed and considered as part of the next general rate case for the corporation. The commission may approve proposed spending if it concludes that ratepayers would realize net benefits and the associated costs are just and reasonable. The commission may also adopt criteria, benchmarks, and accountability mechanisms to evaluate the success of any investment authorized pursuant to a distribution resources plan.

Appendix B: Maine 2013 Omnibus Energy Bill Excerpts

An Act To Reduce Energy Costs, Increase Energy Efficiency, Promote Electric System Reliability and Protect the Environment

PART C

Sec. C-1. 35-A MRSA §3131, sub-§4-B is enacted to read:

4-B. Nontransmission alternative. "Nontransmission alternative" means any of the following methods used either individually or combined to reduce the need for the construction of a transmission line under section 3132 or transmission project under section 3132-A: energy efficiency and conservation, load management, demand response or distributed generation.

Sec. C-2. 35-A MRSA §3132, sub-§2-C, ¶¶B and C, as enacted by PL 2009, c. 309, §2, are amended to read:

B. Justification for adoption of the route selected, including comparison with alternative routes that are environmentally, technically and economically practical; ~~and~~

C. Results of an investigation by an independent 3rd party, which may be the commission or a contractor selected by the commission, of nontransmission alternatives to construction of the proposed transmission line ~~including energy conservation, distributed generation or load management~~. The investigation must set forth the total projected costs of the transmission line as well as the total projected costs of the alternatives over the effective life of the proposed transmission line; and

Sec. C-3. 35-A MRSA §3132, sub-§2-C, ¶D is enacted to read:

D. A description of the need for the proposed transmission line.

Sec. C-4. 35-A MRSA §3132, sub-§5, as enacted by PL 1987, c. 141, Pt. A, §6, is amended to read:

5. Commission approval of a proposed line. The commission may approve or disapprove all or portions of a proposed transmission line and shall make such orders regarding its character, size, installation and maintenance as are necessary, having regard for any increased costs caused by the orders. The commission shall give preference to the nontransmission alternatives that have been identified as able to address the identified need for the proposed transmission line at lower total cost to ratepayers in this State. When the costs to ratepayers in this State of the identified nontransmission alternatives are reasonably equal, the commission shall give preference to the alternatives that produce the lowest amount of local air emissions, including greenhouse gas emissions.

Sec. C-5. 35-A MRSA §3132, sub-§6, as repealed and replaced by PL 2011, c. 281, §1, is amended to read:

6. Commission order; certificate of public convenience and necessity. In its order, the commission shall make specific findings with regard to the public need for the proposed transmission line. The commission shall make specific findings with regard to the likelihood that nontransmission alternatives can sufficiently address the identified public need over the effective life of the transmission line at lower total cost. Except as provided in subsection 6-A for a high-impact electric transmission line and in accordance with subsection 6-B regarding nontransmission alternatives, if the commission finds that a public need exists, after considering whether the need can be economically and reliably met using nontransmission alternatives, it shall issue a certificate of public convenience and necessity for the transmission line. In determining public need, the commission shall, at a minimum, take into account economics, reliability, public health and safety, scenic, historic and recreational values, state renewable energy generation goals, the proximity of the proposed transmission line to inhabited dwellings and alternatives to construction of the transmission line, including energy conservation, distributed generation or load management. If the commission orders or allows the erection of the transmission line, the order is subject to all other provisions of law and the right of any other agency to approve the transmission line. The commission shall, as necessary and in accordance with subsections 7 and 8, consider the findings of the Department of Environmental Protection under Title 38, chapter 3, subchapter 1, article 6, with respect to the proposed transmission line and any modifications ordered by the Department of Environmental Protection to lessen the impact of the proposed transmission line on the environment. A person may submit a petition for and obtain approval of a proposed transmission line under this section before applying for approval under municipal ordinances adopted pursuant to Title 30-A, Part 2, Subpart 6-A; and Title 38, section 438-A and, except as provided in subsection 4, before identifying a specific route or route options for the proposed transmission line. Except as provided in subsection 4, the commission may not consider the petition insufficient for failure to provide identification of a route or route options for the proposed transmission line. The issuance of a certificate of public convenience and necessity establishes that, as of the date of issuance of the certificate, the decision by the person to erect or construct was prudent. At the time of its issuance of a certificate of public convenience and necessity, the commission shall send to each municipality through which a proposed corridor or corridors for a transmission line extends a separate notice that the issuance of the certificate does not override, supersede or otherwise affect municipal authority to regulate the siting of the proposed transmission line. The commission may deny a certificate of public convenience and necessity for a transmission line upon a finding that the transmission line is reasonably likely to adversely affect any transmission and distribution utility or its customers.

Sec. C-6. 35-A MRSA §3132, sub-§6-B is enacted to read:

6-B. Reasonable consideration of nontransmission alternatives. If the commission determines that nontransmission alternatives can sufficiently address the transmission need under subsection 6 at lower total cost, but at a higher cost to ratepayers in this State than the proposed transmission line, the commission shall make reasonable efforts to achieve within 180 days an agreement among the states within the ISO-NE region to allocate the cost of the nontransmission alternatives among the ratepayers of the region using the allocation method used for transmission lines or a different allocation method that results in lower costs than the proposed transmission line to the ratepayers of this State.

For the purposes of this section, "ISO-NE region" has the same meaning as in section 1902, subsection 3.

The subsection is repealed December 31, 2015.

Sec. C-7. 35-A MRSA §3132, sub-§15 is enacted to read:

15. Advancement of nontransmission alternatives policies. The commission shall advocate in all relevant venues for the pursuit of least-cost solutions to bulk power system needs on a total cost basis and for all available resources, including nontransmission alternatives, to be treated comparably in transmission analysis, planning and access to funding.

Sec. C-8. 35-A MRSA §3132-A is enacted to read:

§ 3132-A. Construction of transmission projects prohibited without approval of the commission

A person may not construct any transmission project without approval from the commission. For the purposes of this section, "transmission project" means any proposed transmission line and its associated infrastructure capable of operating at less than 69 kilovolts and projected to cost in excess of $20,000,000.

1. Submission requirement. A person that proposes to undertake in the State a transmission project must provide the commission with the following information:

A. Results of an investigation by an independent 3rd party, which may be the commission or a contractor selected by the commission, of nontransmission alternatives to construction of the proposed transmission project. The investigation must set forth the total projected costs of the transmission project as well as the total projected costs of the nontransmission alternatives over the effective life of the proposed transmission project; and

B. A description of the need for the proposed transmission project.

2. Approval; consideration of nontransmission alternatives. In order for a transmission project to be approved, the commission must consider whether the identified need over the effective life of the proposed transmission project can be economically and reliably met using nontransmission alternatives at a lower total cost. During its review the commission shall give preference to nontransmission alternatives that are identified as able to address the identified need for the proposed transmission project at lower total cost to ratepayers. Of the identified nontransmission alternatives, the commission shall give preference to the lowest-cost nontransmission alternatives. When the costs to ratepayers of the identified nontransmission alternatives are reasonably equal, the commission shall give preference to the alternatives that produce the lowest amount of local air emissions, including greenhouse gas emissions.

3. Exception. A transmission project that is constructed, owned and operated by a generator of electricity solely for the purpose of electrically and physically interconnecting the generator to the transmission system of a transmission and distribution utility is not subject to this section.

Appendix C: Vermont Act 61 Excerpts

Sec. 8. ADVOCACY FOR REGIONAL ELECTRICITY RELIABILITY POLICY

It shall be the policy of the state of Vermont, in negotiations and policy-making at the New England Independent System Operator, in proceedings before the Federal Energy Regulatory Commission, and in all other relevant venues, to support an efficient reliability policy, as follows:

(1) When cost recovery is sought through region-wide regulated rates or uplift tariffs for power system reliability improvements, all available resources – transmission, strategic generation, targeted energy efficiency, and demand response resources – should be treated comparably in analysis, planning, and access to funding.

(2) A principal criterion for approving and selecting a solution should be whether it is the least-cost solution to a system need on a total cost basis.

(3) Ratepayers should not be required to pay for system upgrades in other states that do not meet these least-cost and resource-neutral standards.

(4) For reliability-related projects in Vermont, subject to the review of the public service board, regional financial support should be sought and made available for transmission and for distributed resource alternatives to transmission on a resource-neutral basis.

(5) The public service department, public service board, and attorney general shall advocate for these policies in negotiations and appropriate proceedings before the New England Independent System Operator, the New England Regional Transmission Operator, the Federal Energy Regulatory Commission, and all other appropriate regional and national forums. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.

(6) In addressing reliability problems for the state's electric system, Vermont retail electricity providers and transmission companies shall advocate for regional cost support for the least cost solution with equal consideration and treatment of all available resources, including transmission, strategic distributed generation, targeted energy efficiency, and demand response resources on a total cost basis. This subdivision shall not be construed to compel litigation or to preclude settlements that represent a reasonable advance to these policies.

* * * Transmission and Distribution Planning * * *

Sec. 9. 30 V.S.A. § 218c is amended to read:

§ 218c. LEAST COST INTEGRATED PLANNING

(d)(1) Least cost transmission services shall be provided in accordance with this subsection. Not later than July 1, 2006, any electric company that does not have a designated retail service territory and that owns or operates electric transmission facilities within the state of Vermont, in conjunction with any other electric companies that own or operate these facilities, jointly shall prepare and file with the department of public service and the public service board a transmission system plan that looks forward for a period of at least ten years. A copy of the plan shall be filed with each of the following: the house committees on commerce and on natural resources and energy and the senate committees on finance and on natural resources and energy. The objective of the plan shall be to identify the potential need for transmission system improvements as early as possible, in order to allow sufficient time to plan and implement more cost-effective non-transmission alternatives to meet reliability needs, wherever feasible. The plan shall:

(A) identify existing and potential transmission system reliability deficiencies by location within Vermont;

(B) estimate the date, and identify the local or regional load levels and other likely system conditions at which these reliability deficiencies, in the absence of further action, would likely occur;

(C) describe the likely manner of resolving the identified deficiencies through transmission system improvements;

(D) estimate the likely costs of these improvements;

(E) identify potential obstacles to the realization of these improvements; and

(F) identify the demand or supply parameters that generation, demand response, energy efficiency or other non-transmission strategies would need to address to resolve the reliability deficiencies identified.

(2) Prior to the adoption of any transmission system plan, a utility preparing a plan shall host at least two public meetings at which it shall present a draft of the plan and facilitate a public discussion to identify and evaluate non-transmission alternatives. The meetings shall be at separate locations within the state, in proximity to the transmission facilities involved or as otherwise required by the board, and each shall be noticed by at least two advertisements, each occurring between one and three weeks prior to the meetings, in newspapers having general circulation within the state and within the municipalities in which the meetings are to be held. Copies of the notices shall be provided to the public service board, the department of public

service, any entity appointed by the public service board pursuant to subdivision 209(d)(2) of this title, the agency of natural resources, the division for historic preservation, the department of health, the scenery preservation council, the agency of transportation, the attorney general, the chair of each regional planning commission, each retail electricity provider within the state, and any public interest group that requests, or has made a standing request for, a copy of the notice. A verbatim transcript of the meetings shall be prepared by the utility preparing the plan, shall be filed with the public service board and the department of public service, and shall be provided at cost to any person requesting it. The plan shall contain a discussion of the principal contentions made at the meetings by members of the public, by any state agency, and by any utility.

(3) Prior to the issuance of the transmission plan or any revision of the plan, the utility preparing the plan shall offer to meet with each retail electricity provider within the state, with any entity appointed by the public service board pursuant to subdivision 209(d)(2) of this title, and with the department of public service, for the purpose of exchanging information that may be relevant to the development of the plan.

(4) (A) A transmission system plan shall be revised:

(i) within nine months of a request to do so made by either the public service board or the department of public service; and

(ii) in any case, at intervals of not more than three years.

(B) If more than 18 months shall have elapsed between the adoption of any version of the plan and the next revision of the plan, or since the last public hearing to address a proposed revision of the plan and facilitate a public discussion that identifies and evaluates nontransmission alternatives, the utility preparing the plan, prior to issuing the next revision, shall host public meetings as provided in subdivision (2) of this subsection, and the revision shall contain a discussion of the principal contentions made at the meetings by members of the public, by any state agency, and by any retail electricity provider.

(5) On the basis of information contained in a transmission system plan, obtained through meetings held pursuant to subdivision (2) of this subsection, or obtained otherwise, the public service board and the department of public service shall use their powers under this title to encourage and facilitate the resolution of reliability deficiencies through nontransmission alternatives, where those alternatives would better serve the public good. The public service board, upon such notice and hearings as are otherwise required under this title, may enter such orders as it deems necessary to encourage, facilitate or require the resolution of reliability deficiencies in a manner that it determines will best promote the public good.

(6) The retail electricity providers in affected areas shall incorporate the most recently filed transmission plan in their individual least cost integrated planning processes, and shall cooperate

as necessary to develop and implement joint least cost solutions to address the reliability deficiencies identified in the transmission plan.

(7) Before the department of public service takes a position before the board concerning the construction of new transmission or a transmission upgrade with significant land use ramifications, the department shall hold one or more public meetings with the legislative bodies or their designees of each town, village, or city that the transmission lines cross, and shall engage in a discussion with the members of those bodies or their designees and the interested public as to the department's role as public advocate.

Appendix D: Rhode Island Standards for Least Cost Procurement and System Reliability Planning (excerpt)

Chapter 2- System Reliability Procurement

Section 2.1 Distributed/Targeted Resources in Relation to T&D Investment

A. The Utility System Reliability Procurement Plan ("The SRP Plan") to be submitted for the Commission's review and approval on September 1, 2011 and triennially thereafter on September 1, shall propose general planning principles and potential areas of focus that incorporate non-wires alternatives (NWA) into the Company's distribution planning process for the three years of implementation beginning January 1 of the following year.

B. Non-Wires Alternatives (NWA) may include but are not limited to:
   a. Least Cost Procurement energy efficiency baseline services.
   b. Peak demand and geographically-focused supplemental energy efficiency strategies
   c. Distributed generation generally, including combined heat and power and renewable energy resources (predominately wind and solar, but not constrained)[110]
   d. Demand response
   e. Direct load control
   f. Energy storage
   g. Alternative tariff options

C. Identified transmission or distribution (T&D) projects with a proposed solution that meet the following criteria will be evaluated for potential NWA that could reduce, avoid or defer the T&D wires solution over an identified time period.
   a. The need is not based on asset condition.
   b. The wires solution, based on engineering judgment, will likely cost more than $1 million;
   c. If load reductions are necessary, then they are expected to be less than 20 percent of the relevant peak load in the area of the defined need;
   d. Start of wires alternative is at least 36 months in the future; and

   A more detailed version of these criteria may be developed by the distribution utility with input from the Council and other stakeholders.

D. Feasible NWAs will be compared to traditional solutions based on the following:
   a. Ability to meet the identified system needs;
   b. Anticipated reliability of the alternatives;

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[110] In order to meet the statute's environmental goals, generation technologies must comply with all applicable general permitting regulations for smaller-scale electric generation facilities.

c. Risks associated with each alternative (licensing and permitting, significant risks of stranded investment, sensitivity of alternatives to differences in load forecasts, emergence of new technologies)
d. Potential for synergy savings based on alternatives that address multiple needs
e. Operational complexity and flexibility
f. Implementation issues
g. Customer impacts
h. Other relevant factors

E. Financial analyses of the preferred solution(s) and alternatives will be conducted to the extent feasible. The selection of analytical model(s) will be subject to Public Utilities Commission review and approval. Alternatives may include the determination of deferred investment savings from NWA through use of net present value of the deferred revenue requirement analysis or the net present value of the alternatives according to the Total Resource Cost Test (TRC). The selection of an NWA shall be informed by the considerations approved by the Public Utilities Commission which may include, but not be limited to, those issues enumerated in (D), the deferred revenue requirement savings and an evaluation of costs and benefits according to the TRC. Consideration of the net present value of resulting revenue requirements may be used to inform the structure of utility cost recovery of NWA investments and to assess anticipated ratepayer rate and bill impacts.

F. For each need where a NWA is the preferred solution, the distribution utility will develop an implementation plan that includes the following:
   a. Characterization of the need
      i. Identification of the load-based need, including the magnitude of the need, the shape of the load curve, the projected year and season by which a solution is needed, and other relevant timing issues.
      ii. Identification and description of the T&D investment and how it would change as a result of the NWA
      iii. Identification of the level and duration of peak demand savings and/or other operational functionality required to avoid the need for the upgrade
      iv. Description of the sensitivity of the need and T&D investment to load forecast assumptions.
   b. Description of the business as usual upgrade in terms of technology, net present value, costs (capital and O&M), revenue requirements, and schedule for the upgrade
   c. Description of the NWA solution, including description of the NWA solution(s) in terms of technology, reliability, cost (capital and O&M), net present value, and timing.
   d. Development of NWA investment scenario(s)
      i. Specific NWA characteristics

ii. Development of an implementation plan, including ownership and contracting considerations or options
iii. Development of a detailed cost estimate (capital and O&M) and implementation schedule.

G. Funding Plan

The Utility shall develop a funding plan based on the following sources to meet the budget requirement of the system reliability procurement plan. The Utility may propose to utilize funding from the following sources for system reliability investments:

i. Capital funds that would otherwise be applied towards traditional wires based alternatives;

ii. Existing Utility EE investments as required in Section I of these Standards and the resulting Annual Plans.

iii. Additional energy efficiency funds to the extent that the NWA can be shown to pass the TRC test with a benefit to cost ratio of greater than 1.0 and such additional funding is approved;

iv. Utility operating expenses to the extent that recovery of such funding is explicitly allowed;

v. Identification of significant customer contribution or third party investment that may be part of a NWA based on benefits that are expected to accrue to the specific customers or third parties.

vi. Any other funding that might be required and available to complete the NWA.

H. Annual SRP Plan reports should be submitted on November 1. Such reports will include but are not limited to:
   a. A summary of projects where NWA were considered;
   b. Identification of projects where NWA were selected as a preferred solution; and a summary of the comparative analysis following the criteria outlined in sections (D) and (E) above;
   c. Implementation plan for the selected NWA projects;
   d. Funding plan for the selected NWA projects;
   e. Recommendations on pilot distribution and transmission project alternatives for which it will utilize selected NWA reliability and capacity strategies. These proposed pilot projects will be used to inform or revise the system reliability procurement process in subsequent plans;
   f. Status of any previously selected and approved projects and pilots;

g. Identification of any methodological or analytical tools to be developed in the year;
h. Total SRP Plan budget, including administrative and evaluation costs.

I. The Annual SRP Plan will be reviewed and funding approved by the Commission prior to implementation.

Appendix E: Vermont Non-Transmission Alternatives Screening Form (9/27/12)

*For use in screening to determine whether or not a transmission system **reliability issue** requires non-transmission alternatives (NTA) analysis in accordance with the Memorandum of Understanding in Docket 7081. Projects intended for energy market-related purposes – "economic" transmission – and other non-reliability-related projects do not fall within the scope of the Docket 7081 process.*

Identify the proposed upgrade: ____

Date of analysis: ____

1. Does the project meet one of the following criteria that define the term "impracticable" *(check all that apply)*?
   a. Needed for a redundant supply to a radial load; or ❑
   b. Maintenance-related, addressing asset condition, operations, or safety; or ❑
   c. Addressing transmission performance, e.g., addition of high-speed protection or a switch to sectionalize a line; or ❑
   d. Needed to address stability or short circuit problems;[111] or ❑
   e. Other technical reason why NTAs are impracticable. *Attach detailed justification that must be reviewed by the VSPC.* ❑

   If any box above is checked, project screens out of full NTA analysis.

2. What is the proposed transmission project's need date? ______________________
   If the need for the project is based on existing or imminent reliability criteria violations (i.e., arising within one year based on the controlling load forecast), project screens out of full NTA analysis.

[111] "Stability" refers to the ability of a power system to recover from any disturbance or interruption. Instability can occur when there is a loss of synchronism at one or more generators (rotor angle stability), a significant loss of load or generation within the system (frequency stability), or a reactive power deficiency (voltage stability). Stability problems are influenced by system parameters such as transmission line lengths and configuration, protection component type and speed, reactive power sources and loads, and generator type and configuration. Due to the nature of instability, non-transmission alternatives involving addition of generation or reduction of load will not solve these problems.

3. Could elimination or deferral of all or part of the upgrade be accomplished by a 25% or smaller load reduction or off-setting generation of the same magnitude? *(See note.)* *If "no," project screens out of full NTA analysis.*	❑ Yes ❑ No
4. Is the likely reduction in costs from the potential elimination or deferral of all or part of the upgrade greater than $2.5 million. *(See note.)* *If "no," project screens out of full NTA analysis.*	❑ Yes ❑ No
Sign and date this form. This analysis performed by: ____________________ *Print name & title* ____________________ *Company* ____________________ *Date* ____________________ *Signature*	

NTA Screening Form
Notes, examples and descriptions

Line 3 Non-transmission alternatives should be considered if the project can be altered or deferred with load reductions or off-setting generation, according to the schedule below, of existing peak load of the affected area at the time of the need for the preferred transmission alternatives. This schedule recognizes that deployment of a load reduction program in a specific area takes time to organize and implement. Therefore, the following assumptions including time and accrued load reduction should be considered when examining the load reduction:

Period	Magnitude of load reduction and/or off-setting generation
1-3 years	15% of peak load
5 years	20% of peak load
10 years	25% of peak load

Line 4 The $2.5 million is in year 2012 dollars and is adjusted for escalation in future years using the Handy Whitman transmission cost index. This threshold does not account for the expected costs of the NTAs, but rather only includes the expected savings to the cost of the transmission project.

Appendix F: Vermont Form for Selection of Distributed Utility Planning Areas (v. 28, 10/1/02)

The purpose of this form is to (1) guide the selection of DUP areas while (2) documenting which criteria apply to the decision.

Identity of the upgrade (description or project number): ______________________________

____

1.	Is the cost of the upgrade greater than $2,000,000? *(See note.)* *If so, check "Yes" and continue to Line 4; otherwise check "No" and. continue to Line* 2	Yes .☐ No ..☐
2.	Would the upgrade relieve a T&D delivery constraint in a Capacity Constrained Area? *(See note.)* *If so, check "Yes" and continue to Line* 3*; otherwise check "No" and* exclude *the expected upgrade from DU analysis.*	Yes .☐ No ..☐
3.	Is the cost of the upgrade less than $250,000? *(See note.)* *If so, check "Yes" and* exclude *the expected upgrade from DU analysis; otherwise check "No" and continue to Line 4.*	Yes .☐ No ..☐
4.	Is the upgrade driven by an emergency situation requiring the immediate replacement of equipment that has failed or is at imminent risk of failure? *If so, check "Yes" and* exclude *the upgrade from DU analysis; otherwise check "No" and continue to line 5.*	Yes .☐ No ..☐
5.	Does the upgrade constitute a minor change for the purpose of system tuning or efficiency improvements? *(See note.)* *If so, check "Yes," indicate which of the below upgrades are included (check all that apply), and* exclude *the upgrade from DU analysis. Otherwise check "No" and continue to line 6.*	Yes .☐ No ..☐
5.a	• installation or changes to relays, reclosers, fuses, switches, sectionalizers, breakers, breaker bypass switches, MOABs, capacitors, regulators, arresters, insulators, or meters	☐
5.b	• installation or replacement of underground getaways.....................................	☐

5.c	• upgrade of substation bus work..	☐
5.d	• upgrade of substation structural work, fencing, or oil containment................	☐
5.e	• installation or upgrade to SCADA	☐
5.f	• transformer swaps	☐
5.g	• addition of fans to transformers	☐
5.h	• balancing of feeder phases	☐
5.i	• replacement of deteriorated poles, crossarms, structures, poles and conduit; and replacement of wires on such equipment with the least-cost wires. *(See note.)*..	☐
5.j	• Other (please describe): ____________________ ____________________ ____________________ __________ (Attach further explanation if needed.))	☐
6.	Is the upgrade a line-reconstruction project pursuant to joint use agreements with telephone or CATV or pole-attachment tariff requirements? *If so, check "Yes" and* exclude *the upgrade from DU analysis; otherwise check "No" and continue to line 7.*	Yes .☐ No ..☐
7.	Is the upgrade the result of a customer's request for a specific equipment or service for which distributed resources would not be acceptable? *(See note.)* *If so, check "Yes," describe the situation,* ____________________ ____________________ ____________________ ____________________ *and* exclude *the expected upgrade from DU analysis; otherwise check "No" and continue to line 8.*	Yes .☐ No ..☐
8.	Is the upgrade required to remedy reliability, stability, or safety problems?	Yes .☐ No ..☐

If so, check "Yes" and continue to line 9; otherwise check "No" and skip to line 11.

9.	Could the scope and cost of the resulting project be reduced by a reduction in load level or by the installation of distributed generation? *(See note to clarify the extent of load reduction.)* *If so, check "Yes" and continue to line 10; otherwise check "No" and skip to line 11.*	Yes .☐ No ..☐
10.	Is the likely reduction in costs from the potential reduction in scope less than $250,000? *(See note.)* *If so, check "Yes" and* exclude *the upgrade from DU analysis; otherwise check "No" and continue to line 11.*	Yes .☐ No ..☐
11.	Would load reduction or generation allow for the elimination or deferral of all of the upgrade? *(See note to clarify the extent of load reduction.).* *If so, check "Yes" and proceed to* define *the scope and timing of the local DU analysis; otherwise check "No" and continue to line 12.*	Yes .☐ No ..☐
12.	Can the upgrade be implemented with different levels of capacity in the replacement equipment, with costs that could differ by more than $250,000? *If not, check "No" and* exclude *the expected upgrade from DU analysis; otherwise check "Yes" and proceed to* define *the scope and timing of the local DU analysis.*	Yes .☐ No ..☐

Remember to sign and date this form.

This analysis performed by __________________ on __________________

Name *Date*

____

Print Name

Notes, Examples, and Descriptions

Line 1	Any T&D project whose capital cost is expected to exceed $2 million (in year 2002 dollars, adjusted for inflation in future years), including any reasonably foreseeable related projects, sub-projects, and multiple phases, should be reviewed for the applicability of DUP.
Line 2	DUs may exclude from DUP analysis Non-Constrained Area Projects, as defined in the Docket No. 6290 MOU, of $2 million or less (determined as described in the note to line 1).
Line 3	Projects of less than $250,000 (in year 2002 dollars, adjusted for inflation in future years) may be excluded from DUP analysis. This step is intended to identify constrained situations in which the DU study would be disproportionately costly, compared to the budgeted project cost.
Line 5:	Minor projects that are only parts of a larger project should not be screened using this step. For example, a substation rebuild would include many of the items listed in 5.a–j, but would not be a project that is minor in size and scope. Therefore, larger projects such as substation rebuilds should be analyzed according to the criteria in lines 7 through 12.
Line 5i:	These situations do not include upgrading equipment *specifically* to *significantly* increase capacity, which should be reviewed at lines 11 and 12.
Line 7:	For example, the customer may be willing to pay for a distribution upgrade, but not for distributed resources. In other situations, the customer may be willing to pay for distributed resources, but may be unwilling to have the distributed resources on its premises, and resources elsewhere may not provide the required service.
Lines 9 and 11:	If reduction in present load by 25% and the elimination of all load growth would not affect the need for the project, or its cost, the project may be considered to be independent of load. The feasibility of the required load reductions will be reviewed in the resource-scoping stage of the DU analysis. The determination that load reductions would not avoid a particular investment can be established by reference to an approved policy (such as standards adopted to capture lost opportunities or simplify system operations). If so, indicate the document that specifies the policy.
Line 10:	This line addresses situations in which the upgrade is driven by considerations other than load growth, but the upgrade could be avoided, in whole or in part, by load reductions or distributed generation. Examples of situations in which significant costs may be avoidable, even though some part of the project is unavoidable, include the following: • Replacement of large transformers • looping projects or adding tie-lines to create first-contingency reliability

More rarely load reductions may reduce the costs of

- line relocations due to road or bridge reconstruction
- line relocations in response to local, state, or federal requests
- line rebuilds due to deterioration

Examples of situations in which loads would matter for these latter projects include (1) capacity increases planned to coincide with the relocation or rebuilding, and (2) lines that serve no customers along a considerable distance (e.g., over a mountain or through a wetland), where reduced loads at the other end of the line could be picked up by other facilities.

Lines 10 and 12: The $250,000 is in year 2002 dollars, to be adjusted for inflation in future years.

EDH-9

RAP Energy solutions for a changing world

Best Practices in Electric Utility Integrated Resource Planning

Examples of State Regulations and Recent Utility Plans

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Executive Summary

An integrated resource plan is a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period. For utilities, integrated resource planning is often quite time- and resource-intensive. Its benefits are so great, however, particularly to consumers, that utilities are frequently required by state legislation or regulation to undertake planning efforts that are then reviewed by state public utilities commissions (PUCs). (In this document, the acronym IRP is used, depending on the context, to denote either an integrated resource plan or the process of integrated resource planning.)

IRP rules governing utilities have been created in a number of ways. Bills that mandate integrated resource planning have been passed into law by state legislatures; rules have been codified under state administrative code; and state utility commissions have adopted IRP regulations as part of their administrative rules, or have ordered it to be done as a result of docketed proceedings. Although some state IRP rules have remained unchanged since they were first implemented, other states have amended, repealed, and in some cases reinstated their IRP rules. Examples can be found in the rules of Arizona, Colorado, and Oregon. Rules that have been amended recently often reflect current concerns in the electric industry—e.g., fuel costs and volatility, the effects of power generation on air and water, issues of national security, electricity market conditions, and climate change, as well as individual state concerns.

There are, however, certain subject-matter areas that are essential to resource planning on which state regulations are silent. Utilities must use their discretion in determining how best to address these areas in their resource plans. This paper provides utilities, commissions, and legislatures with guidance on these subject-matter areas. Section III summarizes three recent utility IRPs from the states mentioned above, in an effort to determine both best practices in integrated resource planning and ways in which utilities can improve their planning processes and outcomes. Section IV then presents a series of recommendations, developed from these examples, for integrated resource planning and its resulting plans.

For an IRP process to be deemed successful, it should include both a meaningful stakeholder process and oversight from an engaged public utilities commission. A successful utility's resource plan should include consideration in detail of the following elements: a load forecast, reserves and reliability, demand-side management, supply options, fuel prices, environmental costs and constraints, evaluation of existing resources, integrated analysis, time frame, uncertainty, valuing and selecting plans, action plan, and documentation. Section IV describes in detail the elements of both the process and the plan.

Introduction

As energy demand across the United States rises and falls and the generation fleet ages, utilities must plan to add and retire resources in the most cost-effective manner while meeting regional reliability standards. Integrated resource planning began in the late 1980s, as states looked for a way to respond to the oil embargos and nuclear cost overruns of the previous decade—and ever since, it has been an accepted way in which utilities can create long-term resource plans. State requirements for resource plans vary in terms, among other things, of planning horizon, the frequency with which plans must be updated, the resources required to be considered, stakeholder involvement, and the actions that public utilities commissions should take in reference to the plan (review, acknowledge, and accept or reject the plan).

As the electric industry began to restructure in the mid-1990s, integrated resource planning rules in many states were repealed or ignored. Some states have since made an effort to update IRP rules to make them applicable to current industry conditions, while other states have continued to use rules that are now out of date. This report describes IRP requirements in three states that have recently updated their regulations governing the planning process, and it reviews the most recent resource plan from the largest utility in each of those states. Rules from Arizona, Colorado and Oregon are described in detail, in order to demonstrate ways in which states can require comprehensive planning processes and resource plan outcomes from the utilities under their jurisdictions.

These particular states were chosen not only because their rules have recently been updated, but also because the guidance they provide to electric utilities offers examples of best practices in integrated resource planning. The updated rules have been designed to give thoughtful consideration to specific resources that have traditionally been ignored, and to produce outcomes that are in the best interests of both ratepayers and society as a whole. Utility resource plans from Arizona Public Service, Public Service Company of Colorado, and PacifiCorp utilize progressive methodologies and contain modern elements that contribute to the production of high-quality plans that are useful examples of superior resource planning efforts.

This report is intended to be helpful to policymakers, public utility commissions and their staff, ratepayer advocates, and the general public as they each consider the ways in which utility resource planning can best serve the public interest.

I. The Purpose and Use of Integrated Resource Planning

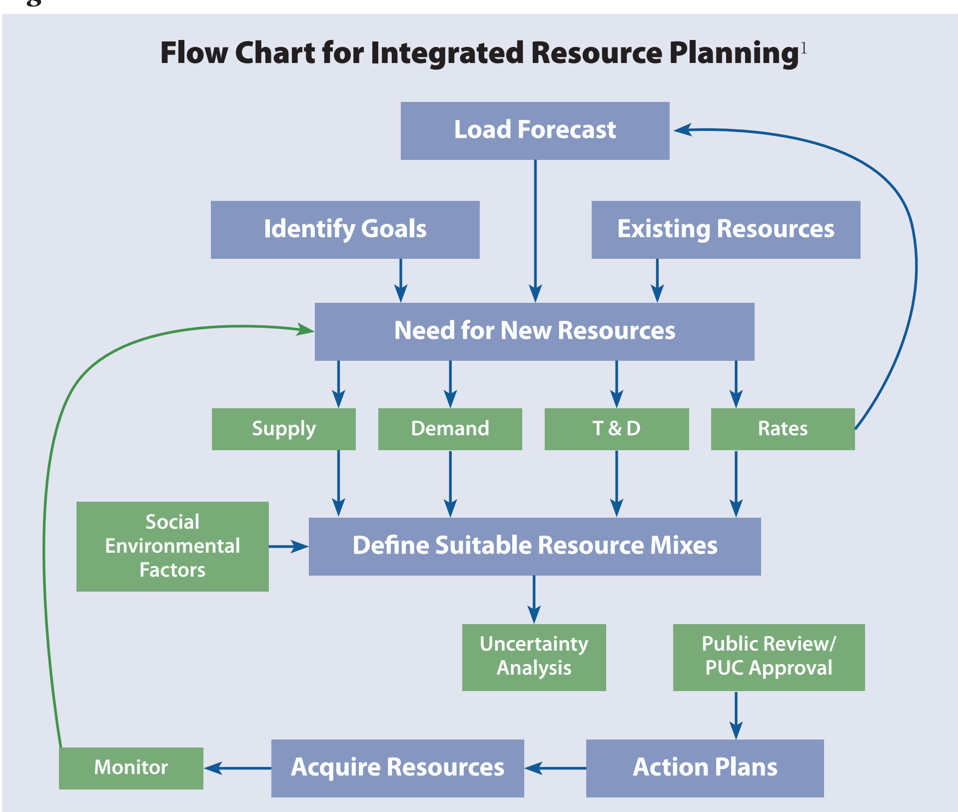
An integrated resource plan, or IRP, is a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period. Steps taken in the creation of an IRP include:

- forecasting future loads,
- identifying potential resource options to meet those future loads,
- determining the optimal mix of resources based on the goal of minimizing future electric system costs,
- receiving and responding to public participation (where applicable), and
- creating and implementing the resource plan.

Figure 1 shows these steps in a flow chart.

Integrated resource planning has many benefits to consumers, and other positive impacts on the environment. This is a planning process that, if correctly implemented, locates the lowest practical costs at which a utility can deliver reliable energy services to its customers. IRP differs from traditional planning in that it requires utilities to use analytical tools that are capable of fairly evaluating and comparing the costs and benefits of both demand- and supply-side resources.[2] The result is an opportunity to achieve lower overall costs than might result from considering only supply-side options. In particular, the inclusion of demand-side options presents more possibilities for saving fuel and reducing negative environmental impacts than might be possible if only supply-side options were considered.[3]

Figure 1



1 Hirst, E. A Good Integrated Resource Plan: Guidelines for Electric Utilities and Regulators. Oak Ridge National Laboratory. December 1992. Page 5. As it appears in Harrington, C., Moskovitz, D., Austin, T., Weinberg, C., & Holt, E. Integrated Resource Planning for State Utility Regulators. The Regulatory Assistance Project. June 1994.

2 Integrated Resource Planning for State Utility Regulators. Available at: http://www.raponline.org/document/download/id/817

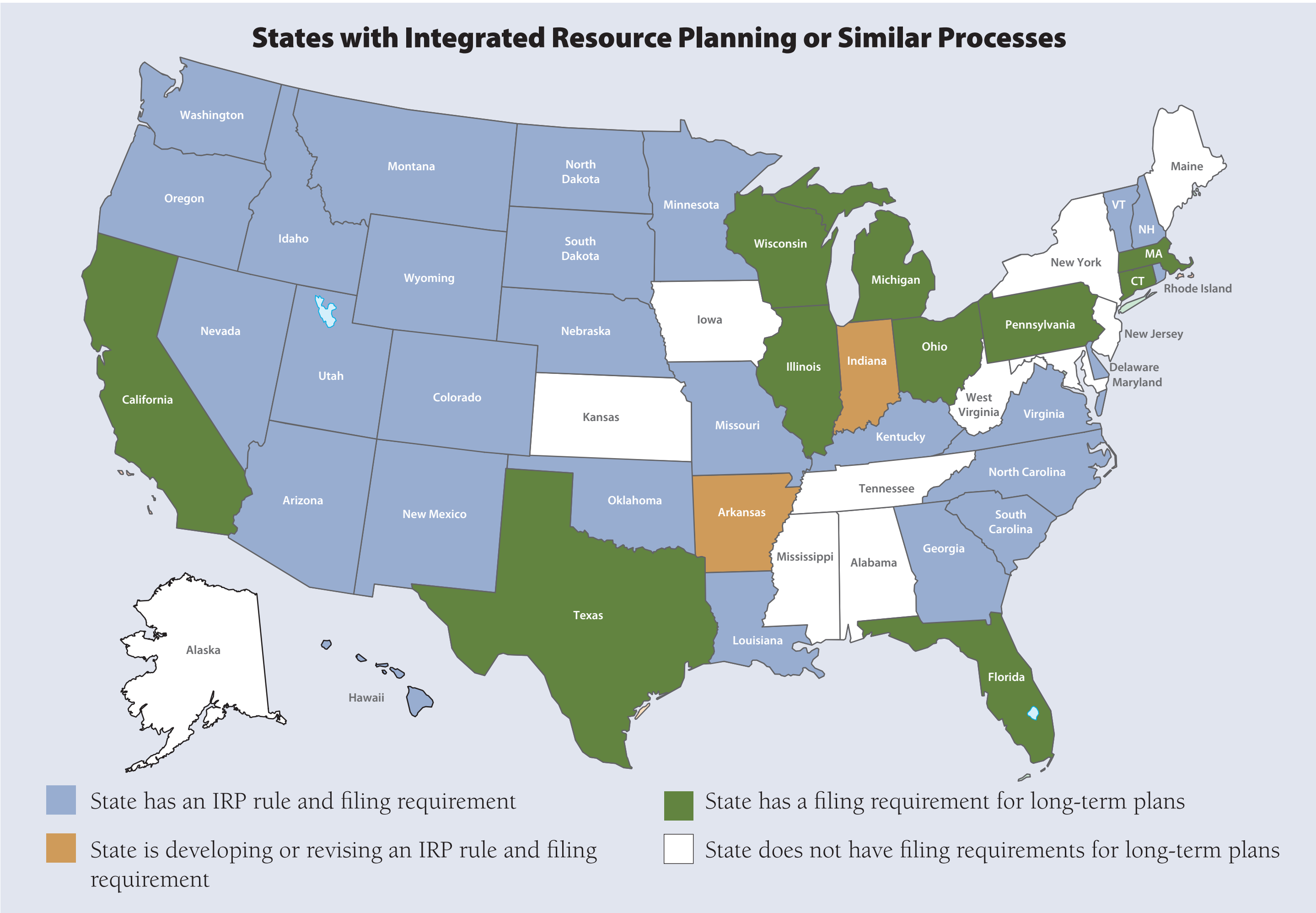
3 Kushler, M. & York, D. Utility Initiatives: Integrated Resource Planning. July 2010. American Council for an Energy-Efficient Economy. Available at: http://aceee.org/policy-brief/utility-initiatives-integrated-resource-planning

In general, IRP focuses on minimizing customers' bills rather than on rates—but an overall reduction in total resource cost achieved through the efficient use of energy will lower average energy bills. As a result, all customers benefit from the lower system costs that IRP achieves.[4]

Alternatives examined by system planners in an IRP setting include adding generating capacity (thermal, renewable, customer-owned, or combined heat and power), adding transmission and distribution lines, and implementing energy efficiency (EE) and demand response programs. Common risks that are addressed by scenario or sensitivity analyses in IRPs include fuel prices (coal, oil, and natural gas), load growth, electricity spot prices, variability of hydro resources, market structure, environmental regulations, and regulations on carbon dioxide (CO_2) and other emissions.[5]

Resource planning requirements exist in many states, but may differ significantly from state to state. Utilities that create more than one resource plan in the same state may have different processes for creating those plans and may arrive at significantly different conclusions, despite being governed by the same regulations. Figure 2 shows the states that have IRP or long-term planning requirements.[6]

Figure 2



4 Id footnote 2.

5 Hopper, C. & Goldman, N. Review of Utility Resource Plans in the West. Lawrence Berkeley National Laboratory. Presentation at the New Mexico PRC IRP Workshop, Santa Fe. June 8, 2006. Slide 17.

6 For a complete list of the rules and regulations associated with integrated resource planning in the states, see Appendix 1.

II. Examples of State Integrated Resource Planning Statutes and Regulations

State IRP rules have been established in a number of ways. In certain states, legislatures have passed bills into law mandating that utilities engage in resource planning; in others, IRP rules have been codified under state administrative code. Some state utility commissions have adopted integrated resource planning regulations as part of their administrative rules, or have ordered it through docketed proceedings. Rules can also be developed through a combination of these processes. Various state IRP rules and their individual requirements are discussed in the sections below.

A. IRP Planning Horizons

Integrated resource plans are long-term in nature, but these planning periods vary according to state regulations. Table 1 lists the length of planning horizons typically found in IRP rules, as well as the states that have implemented these various planning horizons as a part of their rules.

The most common planning horizon spans a 20 year period, with half of the IRP states mandating this planning period.

Table 1

Planning Horizons Found in IRP Rules

Planning Horizon	States with Specified Planning Horizon
10 years	Arkansas, Delaware, Oklahoma, South Dakota, Wyoming
15 years	Arizona, Kentucky, Minnesota, North Carolina, South Carolina, Virginia
20 years	Georgia, Hawaii, Idaho, Indiana, Louisiana, Missouri, Nebraska, Nevada, New Mexico, North Dakota, Oregon, Utah, Vermont, Washington
Multiple periods	Montana
Utility determined	Colorado
Not specified	New Hampshire

B. Frequency of Updates

Utility integrated resource plans must be updated periodically to reflect changing conditions with respect to load forecasts, fuel prices, capital costs, conditions in the electricity markets, environmental regulations, and other factors. IRP updates are typically required every two to three years, as shown in Table 2, below.

Montana appears twice in Table 2, as traditional utilities are required to file IRPs every two years, while restructured utilities are required to file updates every three years. There are some exceptions to the typical update requirements of

Table 2

Frequency of IRP Updates, as Determined by State Rules

Planning Horizon	States with Specified Planning Horizon
Every two years	Arizona, Delaware, Idaho, Indiana, Minnesota, Montana, New Hampshire, North Carolina, North Dakota, Oregon, South Dakota, Utah, Virginia, Washington
Every three years	Arkansas, Georgia, Hawaii, Kentucky, Louisiana, Montana, Missouri, Nevada, New Mexico, Oklahoma, South Carolina, Vermont
Every four years	Colorado
Every five years	Nebraska
Not specified	Wyoming

two to three years. Nebraska, for example, has a five year requirement for updates and is the only state to be made up entirely of public power utilities, many of which are customers of the Western Area Power Administration (WAPA). Pursuant to the Energy Policy Act of 1992, municipally-owned utilities are required to prepare resource plans every five years, but do not have to make those plans publicly available. Most Nebraska utilities must comply with both WAPA IRP requirements as well as state IRP requirements.

C. Resources Evaluated in Integrated Resource Planning

Generally, state rules mandate that utilities consider all feasible supply-side, demand-side, and transmission resources that are expected to be available within the specified planning period. Many state IRP requirements make no specifications for resources that must be evaluated beyond this. Other states have gone into further detail about the resources that should be investigated, including:

- **Delaware –** utilities shall identify and evaluate all resource options, including: generation and transmission service; supply contracts; short and long-term procurement from demand-side management (DSM), demand response (DR) and customer sited generation; resources that utilize new or innovative baseload technologies; resources that provide short or long-term environmental benefits; facilities that have existing fuel and transmission infrastructure; facilities that utilize existing brownfield or industrial sites; resources that promote fuel diversity; resources or facilities that support or improve reliability; and resources that encourage price stability.[7]
- **Indiana –** utilities shall examine: all existing supply and demand-side resources and existing transmission; all potential new utility electric plant options and transmission facilities; all technologies and designs expected to be available within the twenty-year planning period, either on a commercial scale or demonstration scale; and a comprehensive array of demand side measures, including innovative rate design.[8]
- **Kentucky –** utilities shall evaluate improvements in operating efficiency of existing facilities, demand-side programs, nonutility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities.[9]

There are state IRP rules that specify not only the resources that must be evaluated, but also the amount of weight given to a particular resource by either the utilities or the Public Service/Utilities Commissions. Colorado is one such state, and is described in more detail in later sections.

In almost all cases, state integrated resource planning rules have specific requirements for the planning horizons that should be covered, the frequency with which utility plans must be updated, and the generating resources that should be considered. Some states require nothing more, while others might also require, for example: 1) a certain number or a certain type of scenario analysis; 2) that certain types of resource cost tests be used to evaluate demand-side management policies; or 3) that externalities be considered by utilities when creating resource plans. Requirements for generating unit retirements and associated decommissioning costs are another example of something that some states might include in integrated resource planning rules, while others might not. The next section describes the discussion of this type of requirement in state IRP regulations.

D. Retirements and Decommissioning

Integrated resource planning is generally understood to be primarily concerned with the addition of resources in order to meet growing demand for electricity, and very few IRP rules mandate that utilities address end-of-life issues for generating units in their resource plans. In a summary document on integrated resource planning, the Regulatory Assistance Project states that "as utilities compare the cost of each supply- and demand-side option, they need to capture the entire life-cycle cost. This life-cycle cost means the fixed and variable costs incurred over the life of the investments: construction, operation, maintenance, and fuel costs."[10] This description does not represent the full

7 HB 6, the Delaware Electric Utility Retail Customer Supply Act of 2006.

8 170 Indiana Administrative Code 4-7-1: Guidelines for Integrated Resource Planning by an Electric Utility.

9 Kentucky Administrative Regulation 807 KAR 5:058: Integrated resource planning by electric utilities.

10 Harrington, et al. Integrated Resource Planning for State Utility Regulators. The Regulatory Assistance Project. June 1994. Page 14.

life of the investment, however, as it does not specifically include the costs associated with the retirement and decommissioning of a resource.

State IRP rules and utility filings reflect this incomplete assessment of life-cycle costs. Twenty-seven states have IRP rules and 20 of them are silent with respect to unit retirements. Utah and Colorado require that utility filings include information about the life expectancies of the generating units in the resource plans. Three states – New Mexico, North Carolina, and South Dakota – are slightly more specific, and mandate that utilities provide expected retirement dates for generating facilities. Specifically, the utilities in each of the states are required to do the following:

- **Utah –** include the life expectancy of generating resources
- **Colorado –** provide the estimated remaining useful lives of existing generation facilities without significant new investment or maintenance expense
- **New Mexico –** give the expected retirement dates for existing generating units
- **North Carolina –** provide a list of units to be retired from service (applies to both existing and planned generating facilities), with the location, capacity and expected date of retirement
- **South Dakota –** include those facilities to be removed from service during the planning period, along with the projected date of removal from service and the reason for removal

There are only two state rules that make any mention of decommissioning costs:

- Arizona rules state that if the discontinuation, decommissioning, or mothballing of any power source or the permanent derating of any generating facility is expected, the utility must provide:
  "i. Identification of each power source or generating unit involved,
  ii. The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating, and
  iii. The reasons for each discontinuation, decommissioning, mothballing, or derating."[11]
- Georgia laws and rules state that "Total cost estimates for proposed projects must include construction and non-construction related costs incurred through commercial operation, including decommissioning/dismantlement costs."[12]

Rather than being addressed in utility integrated resource plans, generating unit retirements and associated decommissioning costs are largely left to be dealt with in other cases and proceedings that are brought before Public Utilities/Service Commissions.

E. Long-term Procurement Planning Requirements

As the electric industry began to restructure in the mid-1990s, many states that had integrated resource planning requirements either repealed them with restructuring laws, or simply began to ignore them. Some states eventually replaced integrated resource planning laws with rules for resource procurement plans. A document designed to inform California's 2010 Long-Term Procurement Plan (LTPP) requirement surveys the ways in which utilities in other states create their resource plans. The document states that "[w]hile California utilities have not undertaken a full integrated resource planning effort in many years, the 2010 LTPP proceeding is considering the appropriate role of utility resource planning in procuring the resources needed to meet state policy goals."[13]

Requirements for procurement plan filings differ from requirements for integrated resource plans. Planning periods are typically ten years, with some states requiring only a five year planning period. Procurement plans are usually required to be updated every year. Because utilities

11 Arizona Corporation Commission Decision No. 71722, in Docket No. RE-00000A-09-0249. June 3, 2010. Page 13. Amends Arizona Administrative Code Title 14, Chapter 2, Article 7, "Resource Planning." Available at: http://images.edocket.azcc.gov/docketpdf/0000112475.pdf

12 Integrated Resource Planning Act of 1991 (O.C.G.A. § 46-3A-1), Amended. See also: Georgia Public Service Commission, General Rules, Integrated Resource Planning 515-3-4. Available at: http://rules.sos.state.ga.us/cgi-bin/page.cgi?g=GEORGIA_PUBLIC_SERVICE_COMMISSION%2FGENERAL_RULES%2FINTEGRATED_RESOURCE_PLANNING%2Findex.html&d=1

13 Aspen Environmental Group and Energy and Environmental Economics, Inc. Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term Procurement Planning in California - DRAFT. Prepared for the California Public Utilities Commission. September 2008. Page 1.

in these states operate in a deregulated market and do not own generation, procurement plans evaluate purchases for capacity and energy, as well as energy efficiency and other demand-side management programs.

Connecticut is one such state that used to have an integrated resource planning requirement, and now has a requirement for procurement plans. The state had IRP regulations in place by the late 1980s, but this requirement was repealed when the restructuring law (Public Act 98-28) was passed in 1998. A long-term procurement planning law then became effective in 2007 (Public Act 07-242). Plans submitted to the Connecticut Energy Advisory Board in compliance with the 2007 law have much in common with utility IRPs and have even been called "Integrated Resource Plans," though they are technically long-term procurement plans.

The following section describes the ways in which IRP rules have been made in Arizona, Colorado, and Oregon, and presents some of the specifics of each of those rules.

1. Arizona

The Arizona Corporation Commission (ACC) has been given both constitutional and statutory authority to oversee the operations of electric utilities, and to engage in rulemaking that includes the establishment of IRP regulations. Article 15 of the Arizona Constitution created the ACC, which oversees the operations of all public service corporations in the state, including investor-owned electric utilities. The Commission is given exclusive authority to establish rates, enact rules that are reasonably necessary in ratemaking, and determine what sort of regulation is reasonably necessary for effective ratemaking,[14] as established in Article 15, §3:

> *The Corporation Commission shall have full power to, and shall, prescribe just and reasonable classifications to be used and just and reasonable rates and charges to be made and collected, by public service corporations within the State for service rendered therein, and make reasonable rules, regulations, and orders, by which such corporations shall be governed in the transaction of business within the State…and make and enforce reasonable rules, regulations, and orders for the convenience, comfort, and safety, and the preservation of the health, of the employees and patrons of such corporations…*

Utility practices in Arizona are not governed by legislation or by statute, but rather through administrative code created by rulemaking proceedings of the Arizona Corporation Commission. Renewable energy requirements, distributed energy resource requirements, and integrated resource planning reporting requirements have all been established in this way.

The ACC has the authority to require that electric utilities provide reports concerning both past business activities and future plans. Integrated resource plans fall into this category. Article 15, §13 of the Arizona Constitution states that "[a]ll public service corporations… shall make such reports to the Corporation Commission, under oath, and provide such information concerning their acts and operations as may be required by law, or by the Corporation Commission." Arizona Revised Statute §40-204(A) expands on this requirement, stating that:

> *Every public service corporation shall furnish to the Commission, in the form and detail the Commission prescribes, tabulations, computations, annual reports, monthly or periodical reports of earnings and expenses, and all other information required by it to carry into effect the provisions of this title and shall make specific answers to all questions submitted by the Commission.*

Regulating and requesting information regarding the resource portfolios of electric utilities is one way in which the ACC meets its constitutional and statutory obligations to ensure that just and reasonable rates are being charged to consumers of electricity. In this pursuit, the ACC adopted the state's first Resource Planning and Procurement Rules in February 1989, requiring that utilities owning electric generation facilities file historical data every year, and 10-year resource plans every three years. The rules also provide for a Commission hearing to review these filings. In accordance with the rules, the first round of utility IRPs were filed in 1992 and hearings were held. In 1995, however, the Commission suspended the obligation of the electric utilities to file future resource plans until IRP rules could be modified to be consistent with impending electric industry competition and the passage of the retail electric competition rules.[15]

14 Arizona Corporation Comm'n v. Woods, 171 Ariz. 286, 294 ("Woods").

15 The Commission adopted retail electric competition rules in Decision No. 59943, dated December 26, 1996.

In revising the IRP rules, Commission staff were required to hold workshops, open to all stakeholders and to the public, on specific resource planning topics. These workshops:

> *Were to focus on developing needed infrastructure and a flexible, timely, and fair competitive procurement process; and were to consider whether and to what extent competitive procurement should include consideration of a diverse portfolio of purchased power, utility-owned generation, renewables, demand-side management, and distributed generation.*[16]

Following the workshops, a docket was opened for proposed rulemaking regarding resource planning, and on June 3, 2010 in Decision No. 71722, the Commission amended the Arizona Administrative Code Title 14, Chapter 2, Article 7, Resource Planning. In the most significant changes, compared to the original rules, the revised IRP rules:

- Extend the forecasting and planning horizon from 10 years to 15 years;
- Require submissions of utility IRPs every even-numbered year rather than every third year;
- Require load-serving entities to include, in their IRP, data regarding air emissions, water consumption, and tons of coal ash produced;
- Require that environmental impacts related to air emissions, solid waste, and other environmental factors and reduction of water consumption be analyzed and addressed in utility plans;
- Require that plans address costs for compliance with current and projected environmental regulations;
- Require that the resource plans include energy efficiency, to meet Commission-specified percentages;
- Require that the resource plans include renewable resources, to meet the specified percentages in Arizona Administrative Code R14-2-1804;
- Require that the resource plans include distributed energy resources, to meet the specified percentages in Arizona Administrative Code R14-2-1805;
- Require that utilities submit a work plan in every odd year that outlines the upcoming 15-year resource plan, and lays out: 1) the utility's method for assessing potential resources; 2) the sources of its current assumptions; and 3) a general outline of the procedures it will follow for public input, which includes an outline of the timing and extent of public participation and advisory group meetings that will be held before the resource plan is completed and filed.[17] Before they file the resource plan, utilities are required to provide an opportunity for public input. ACC practice also allows for public comment on the completed resource plan after it has been filed by the utility.

In the revised rulemaking proceedings emphasis was placed on diversifying the resource base in utilities' generation portfolios; on lowering costs through decreased reliance on volatile fossil-fuel based generation; and on considering and addressing environmental impacts, such as air emissions, coal ash, and water consumption.[18] Utilities must also submit a set of analyses to identify and assess the errors, risks, and uncertainties in: demand forecasts; the costs of DSM measures and power supply; the availability of sources of power; the costs of compliance with current and future environmental regulations; fuel prices and availability; construction costs, capital costs and operating costs; and any other factors the utility wishes to consider. This assessment should be done using sensitivity analysis and probabilistic modeling analysis.[19] The utility should provide a description of the ways in which these errors, risks, and uncertainties can be managed (e.g., by obtaining additional information, liming risk exposure, using incentives, creating additional options, incorporating flexibility, and participating in regional generation and transmission projects), along with a plan to do so.[20]

Following the review of the utility IRP, the Commission is required to file an order that either acknowledges the resource plan (with or without amendment) or states the reasons for not acknowledging it.

The first electric utility IRPs filed under the revised rules were submitted to the ACC in 2012. The filing from Arizona Public Service (APS) is discussed in later sections.

16 Arizona Corporation Commission. Decision No. 71722. Docket No. RE-00000A-09-0249. June 3, 2010.

17 Id.

18 Id. Page 12.

19 Arizona Corporation Commission. Decision No. 71722. Docket No. RE-00000A-09-0249. June 3, 2010. Exhibit A: Notice of Proposed Rulemaking. Page 42.

20 Id. Page 43.

2. Colorado

Title 40 of the Colorado Revised Statutes establishes the state Public Utilities Commission and gives it authority to regulate the public utilities located within the state, specifically with regard to "the adequacy, installation, and extension of the power services and the facilities necessary to supply, extend, and connect the same."[21] Title 40 also contains all of the legislative requirements with which Colorado's public utilities must comply, and prescribes the general methods by which the PUC should evaluate compliance.

The evaluation process is described in more detail in 4 Code of Colorado Regulations (CCR) 723-3: Rules Regulating Electric Utilities. This section of the code describes the rules promulgated by the Public Utilities Commission to establish the process for determining the need for additional electric resources by those electric utilities subject to the Commission's jurisdiction, and for developing cost-effective resource portfolios to meet such need reliably.[22] The rules, in their current form, were adopted in 2003 and were referred to as *least-cost planning* rules. Beginning in 2003, utilities were required to file resource plans every four years, and may file an interim plan if changed circumstances justify the filing.

Utilities may choose their own planning period, but that period must be at least 20 and no more than 40 years. Utilities may also specify the resource acquisition period they will follow, which will be between the first six and ten years of the planning period. The planning period is both the time frame for which the resource plan is developed, and the long-term period over which the net present value of revenue requirements is calculated. The resource acquisition period represents the near-term period in which the utility must actually acquire resources to meet system energy and demand requirements. For any resources they propose to acquire, utilities file needs assessments and draft requests for proposals (RFPs). The PUC may approve, deny, or order modifications to utility plans. Following PUC approval, utilities then begin the competitive bidding process to acquire the new resources needed to meet load and reserve requirements.

Over the past decade, the PUC has opened several docketed proceedings and issued emergency rules revising the least-cost planning rules to provide specific guidelines for utilities, and to ensure compliance with new legislation adopted by Colorado state government. In Decision No. C07-0829 of September 19, 2007, the PUC adopted emergency rules modifying LCP rules as required by bills enacted in the 2006 and 2007 sessions of the Colorado Legislature. In general, these bills required the PUC to consider not only the costs of new generation resources as prescribed in least-cost planning rules, but also various benefits, requiring more technical expertise and involvement from the PUC in the resource selection process.[23]

Specifically, the following bills required the associated changes:

- HB07-1037 establishes requirements for energy efficiency and demand-side management resources, and requires the PUC to shift from a least-cost planning standard to a more subjective consideration of multiple criteria "which will require substantially more Commission involvement in the resource selection process."[24] The criteria shift applies to the evaluation of all resources, not only demand-side management (DSM)[25] measures.
- HB07-1281 increases the renewable energy resources that electric utilities must acquire, necessitating greater integration between the resource planning rules and the new Renewable Energy Standards.
- SB07-100 is intended to improve the economic viability of rural renewable resources. The bill provides for the designation of energy resource zones, and for the construction of transmission infrastructure to bring energy from these zones to load centers.
- HB06-1281 requires the Commission "to give the fullest possible consideration to new clean and energy efficient technologies…(and) provides an

21 Colorado Revised Statutes 40-1-103.

22 4 Code of Colorado Regulations 723-3. Part 3: Rules Regulating Electric Utilities. Electric Resource Planning: 3601.

23 Colorado Public Utilities Commission. Decision No. C07-0829. Docket No. 07R-0368E. September 19, 2007.

24 Id. Page 7.

25 Demand-side management , or DSM, measures involve reducing electricity use through activities or programs that promote electric energy efficiency or conservation, or more efficient management of electric energy loads.

example of how the Commission can give such consideration to resources that may be in the public interest when accounting for the benefits of advancing the development of a particular resource, or when accounting for other benefits outside of a strict cost perspective."[26]

The statutory language describes some of those benefits:

The Commission shall give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases. The Commission shall consider utility investments in energy efficiency to be an acceptable use of ratepayer moneys.[27]

As a result of the various bills described above, the PUC chose to strike the term "least-cost" from the rules in all instances, changing their title to Resource Planning Rules. It also introduced the term cost-effective into the rules, defining it as "the reasonableness of costs and rate impacts in consideration of the benefits offered by new clean energy and energy-efficient technologies."[28] These and other emergency rules were adopted on a permanent basis in Decision No. C07-1101 in Docket No. 07R-419E.

Other significant changes to the Resource Planning Rules were adopted by the PUC in 2010 in response to the passage of HB10-1365, known as the Clean Air-Clean Jobs Act (CACJA). The legislative declaration of the Act states that:

The general assembly hereby finds, determines, and declares that the federal "Clean Air Act," 42 U.S.C. sec. 7401 et seq., will likely require reductions in emissions from coal-fired power plants operated by rate-regulated utilities in Colorado. A coordinated plan of emission reductions from these coal-fired power plants will enable Colorado rate-regulated utilities to meet the requirements of the federal act and protect public health and the environment at a lower cost than a piecemeal approach. A coordinated plan of reduction of emissions for Colorado's rate-regulated utilities will also result in reductions in many air pollutants and promote the use of natural gas and other low-emitting resources to meet Colorado's electricity needs, which will in turn promote development of Colorado's economy and industry.[29]

The Act required that all utilities owning or operating coal-fired generating units in Colorado file an emissions reductions plan, which may include the following elements: emission control equipment, retirement of coal-fired units, conversion of coal units to natural gas, long-term fuel agreements, new natural gas pipelines, increased utilization of existing natural gas resources, and new transmission infrastructure. The CO Department of Public Health and the Environment and the PUC were tasked with reviewing the utility filings.

Approval of the plans is contingent on several factors, including whether required emissions reductions would be achieved; whether the plan promotes economic development in the state; whether reliable electric service is preserved; and the degree to which the plan increases the utilization of natural gas or relies on energy efficiency or other low-emitting resources. Plans were to be filed by August 15, 2010, and full implementation is to occur by December 31, 2017.[30]

While required emissions reduction plans were separate from Electric Resource Plans, the PUC opted to revise and clarify Electric Resource Planning (ERP) rules to make them more consistent with the CACJA. The PUC adopted revised rules on July 29, 2010 in Decision No. C10-0958 as part of Docket No. 10R-214E. Significant changes to the rules include:

- Adoption as the policy of the state of Colorado that the PUC give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies.
- Inclusion in the resource plan of the annual water withdrawals and consumption for each new resource, and the water intensity of the generating system as a whole.
- Inclusion of the projected emissions of sulfur dioxide, nitrogen oxides, particulate matter, mercury, and

26 Id. Page 9.

27 Colorado Revised Statutes 40-2-123(1)(a).

28 Colorado Public Utilities Commission. Decision No. C07-0829. Docket No. 07R-0368E. September 19, 2007. Page 20.

29 Colorado Revised Statutes 40-3.2-203(1).

30 General Assembly of the State of Colorado. House Bill 10-1365.

carbon dioxide for new and existing generating resources.

- The Commission must consider the likelihood of new environmental regulations, and the risk of higher future costs associated with greenhouse gases, when it considers utility proposals.
- Descriptions of at least three alternate resources plans that meet the same resource need as the base plan but include proportionally more renewable energy or demand-side resources. For the purpose of risk analysis, a range of possible future scenarios and input sensitivities should be proposed for testing the robustness of the alternative plans.
- Permission for the utilities to implement cost-effective demand-side resources to reduce the need for additional resources that would otherwise need to be obtained through a competitive acquisition process.[31]

Colorado's IRP rules do not mandate public participation prior to the filing of the IRP. The rules are, however, unique in requiring that the utility, Commission staff, and the Office of Consumer Counsel agree upon an entity to act as an independent evaluator (paid for by the utility) and advisor to the Commission. The independent evaluator reviews all documents and data used by the utility in developing its resource plan, and submits a report to the Commission that contains its analysis of "whether the utility conducted a fair bid solicitation and bid evaluation process, with any deficiencies specifically reported."[32]

Following the filing of the utility's resource plan, the IRP rules state that parties in the proceeding have 45 days to file comments on the plan and on the independent evaluator's report. The utility has a chance to respond to comments, after which the Commission is required to issue a written decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan, "which decision shall establish the final cost-effective resource plan."[33] In 2011 the Colorado electric utilities filed the first electric resource plans that were consistent with these revised rules. The plan from Public Service Company of Colorado ("Public Service") is discussed in section III of this report.

3. Oregon

Oregon's IRP rules are the most straightforward of the three states examined here. The state first established resource planning rules in 1989, in Public Utility Commission Order 89-507. The order directs all energy utilities in Oregon to undertake least-cost planning, which the Commission defines in a somewhat unique way, stating that:

> *Least-cost planning differs from traditional planning in three major respects. It requires integration of supply and demand side options. It requires consideration of other than internal costs to the utility in determining what is least-cost. And it involves the Commission, the customers, and the public prior to the making of resource decisions rather than after the fact. …Least-cost planning as mandated by this order will allow the public as well as the Commission to participate in the planning process at its earliest stages.*[34]

The PUC thus identifies one of the key procedural elements of least-cost planning as allowance for significant involvement from the public and other utilities in the preparation of the resource plan, which includes opportunities for the public to contribute information and ideas as well as to receive information. The Commission's order states that "the open and collaborative character of least-cost planning may foster elevated confidence among those affected by the decisions and may make the process more responsive to demonstrated needs."[35] Substantive elements of least-cost planning are similar to those found in other states, with the PUC emphasizing the evaluation of conservation in a manner that is consistent and comparable to that of supply-side resources,[36] and with the analysis of economic, environmental, and social uncertainties.

The order also includes a concurring opinion from Commissioner Myron B. Katz, in which he discusses whether commissions, in the context of least-cost planning, should be interested in costs to utilities and ratepayers alone, or in overall costs to society. Katz suggests that utilities should seek to determine the costs for resources that include any externalities associated with those

31 Colorado Public Utilities Commission. Decision No. C10-0958. Docket No. 10R-214E. July 29, 2010.

32 4 Code of Colorado Regulations 723-3. Part 3: Rules Regulating Electric Utilities. Electric Resource Planning: 3613(b).

33 4 Code of Colorado Regulations 723-3. Part 3: Rules Regulating Electric Utilities. Electric Resource Planning: 3613(e).

34 Public Utility Commission of Oregon. Order No. 89-507. Docket No. UM 180. April 20, 1989.

35 Id. Page 3.

36 Id. Page 7.

resources, stating that "[a] resource should be deemed cost-effective and thus eligible for selection if its costs are lower than the costs of alternative resources assuming a market in which all costs, including environmental costs, are reflected in resource price tags."[37]

Subsequent PUC Orders 07-002, 08-339, and 09-041 (which became O.A.R. 860-027-0400) updated planning guidelines and requirements, and changed least-cost planning terminology to integrated resource planning, in recognition of the fact that there are many risks and uncertainties associated with any portfolio that must be weighed, and that least-cost is not the only criterion for selecting the best resource portfolio. This emphasis on the importance of risk in integrated resource planning is one way in which Oregon differs from some other states. The emphasis is placed in the forefront of the revised rules, with Guideline 1(b) stating that "(r)isk and uncertainty must be considered."[38] *Risk* is defined as a measure of the bad outcomes associated with a resource plan, while *uncertainty* is a measure of the quality of information about an event or outcome. Recognizing risks that are general to the electric industry and those that are specific to Oregon, the rules specify that, at a minimum, the following sources of risk must be considered in utility resource plans: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gases, as well as any additional sources of risk and uncertainty.[39]

In order to quantify these risks, utilities should calculate two different measures of the present value of revenue requirement risk (PVRR). The first should measure the variability of resulting PVRR costs under the different scenarios, and the second should measure the severity of any bad outcomes.[40] The primary goal of Oregon's IRP planning process is thus "the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[41] A portfolio of resources with the lowest expected cost before the inclusion of various risks may in fact have higher costs than other resource portfolios once those risks are considered.

The goal of the Oregon PUC in amending its rules was for utilities to identify the lowest-cost resource plan over the specified planning horizon by balancing both cost and risk. The Commission declines to mandate how the measures of PVRR risk be defined, instead leaving it up to the utilities and to "the interactive process of developing an IRP to make the best assessment of appropriate risk measures."[42] Unlike in Arizona, which requires that utilities create a plan to manage specific risks, Oregon requires that utilities take risks, their probabilities of occurrence, and the likelihood of bad outcomes into their choice of preferred resource plan.

These subsequent orders make few other substantive changes to the rules established in order 89-507, but instead add detail on the information and analysis that the PUC wanted in order to acknowledge utility resource plans. Notable changes include:

- The requirement that each utility ensure that a conservation potential study is done periodically for its entire service territory.
- The requirement that demand response and distributed generation be evaluated similarly to more traditional supply-side resources.
- The requirement that utilities include the expected regulatory compliance costs for various pollutants, that a range of potential CO_2 costs be analyzed,[43] and that sensitivity analyses be performed on a range of costs for nitrogen oxides, sulfur oxides, and mercury, if applicable.[44]

Order 07-002 also details the nature of public involvement in the IRP process, stating that the public and other utilities should be allowed significant involvement in the preparation of an IRP—that they should be allowed to contribute information and ideas, and to make relevant inquiries of the utility formulating the plan. The utility should also make a draft IRP available for public review

37 Id. Page 12.

38 Public Utility Commission of Oregon. Order No. 07-002. Docket No. UM 1056. January 8, 2007. Appendix A. Page 1.

39 Id.

40 Id. Appendix A. Page 2.

41 Id. Appendix A. Pages 1-2.

42 Id. Page 7.

43 From zero to $40 (1990$), as established in Order No. 93-695.

44 Public Utility Commission of Oregon. Order No. 07-002. Docket No. UM 1056. January 8, 2007.

45 Id. Page 8.

and comment before filing a final version with the PUC.[45]

Following submission of the integrated resource plan, intervening parties and Commission staff have six months to complete and file written comments on it. In advance of the deadline for written comments, the utility must also present the results of its resource plan to the Commission at a public meeting. The Commission then acknowledges the plan or returns it to the utility with comments. It may allow the utility to revise its resource plan before issuing an acknowledgement order.[46]

The IRP rules are careful to point out that acknowledgement of the IRP does not guarantee favorable ratemaking treatment later on, but that the acknowledgement simply means the plan seemed reasonable at the time it was reviewed by the Commission.[47] PacifiCorp, operating in Oregon as Pacific Power, is expected to file its 2013 IRP this year, but that plan was not available in time for inclusion in this paper. PacifiCorp's 2011 IRP is discussed in later sections.

46 Id. Page 9.

47 Id. Page 2.

III. Examples of Best Practices in Utility Integrated Resource Plans

A. Arizona Public Service

Arizona Public Service (APS) is the state's largest electric utility, and has been serving retail and wholesale consumers since 1886. In March 2012, APS filed the first formal resource plan in 17 years with the Arizona Corporation Commission. This IRP was also the first to be filed under the ACC's revised rules, as described in section II.A.

From the time when the Corporation Commission issued the final IRP rules to the date that APS filed its resource plan, the utility was "engaging key stakeholders to gain an understanding and appreciate of their areas of concern."[48] A series of workshops held during 2010 and 2011 sought to both inform and gather input from interested stakeholders on future resource decisions. The workshop topics included the resource fleet and transmission system; load forecasts; energy efficiency; smart grid; demand response; utility water consumption; fuel supplies and markets; technology options and costs; externalities; resource procurement; portfolios and sensitivities; and metrics and monetization costs for water, sulfur oxides, particulate matter, and nitrogen oxides. Approximately 35 to 50 stakeholders participated in each meeting, and several stakeholders were also invited to give presentations in some of the topic areas mentioned above.[49]

APS also contracted with the Morrison Institute at Arizona State University to conduct a series of four "Informed Perception Project" surveys on customer preferences and concerns regarding the energy resource options available to APS. Results showed that APS customers "favored an increase in the use of renewable energy resources, such as solar and wind, and were interested in both the environmental impacts and reliability of energy choices."[50]

Over the course of the 15-year planning period, with the assumption that migration to the state and individual electricity consumption will return to historic highs, APS has forecast 3% average annual growth in nominal electricity requirements through 2027. Energy efficiency and distributed generation, in the form of rooftop solar installations, will help offset some of this growth, but APS expects that it will need to add additional conventional supply-side resources, in the form of natural gas-fired generation, in 2019. APS created four resource portfolios to evaluate: a base case, a "four corners contingency," an "enhanced renewable" case, and a "coal retirement" case. Figure 3 shows the details of those plans.

Each of the resource plans created by APS were analyzed using a production simulation model, PROMOD IV, which dispatches the energy resources in each of the portfolios and generates system costs, or the likely future revenue requirements, associated with each. Calculation of system revenue requirements demonstrated that the APS base case portfolio was the most cost-effective of the resource plans evaluated. APS also monitors specific metrics to provide a context for comparing and evaluating the portfolios. In addition to revenue requirements, those metrics include fuel diversity, capital expenditures, natural gas burn, water use, and CO_2 emissions.

APS selected major cost inputs and evaluated several sensitivity scenarios, setting the assumptions for these variables higher and/or lower to test the impacts on the specific metrics being evaluated. These major cost inputs include natural gas prices, CO_2 prices, production and investment tax credits for renewable resources, energy efficiency costs, and monetization of SO_2, NO_x, PM, and water. APS also created low-cost and high-cost scenarios,

48 Arizona Public Service. 2012 Integrated Resource Plan. March 2012. Page 2.

49 Id. Page 25.

50 Id.

Figure 3:

Portfolios Considered in the APS 2012 IRP[51]

	Base Case (2012 Resource Plan)	Four Corners Contingency	Enhanced Renewable	Coal Retirement
Description	*Plan includes APS closing Four Corners units 1-3 and purchasing SCE's share of units 4-5; continues the current trajectory of EE and RE compliance*	*Contingency plan depicting the retirement of the Four Corners coal-fired plant; energy replaced by additional natural gas resources*	*Assumes 30% (after EE/DE) of energy needs met by renewable resources; include the consummation of the Four Corners transaction*	*Assumes APS retires all coal-fired generation; energy replaced with a combination of natural gas and renewable resources*
Resource Contributions *(2027 Peak Capacity Contribution/ % Energy Mix)*				
Nuclear	1,146 MW 18.7%MWh	1,146 MW 18.7% MWh	1,146 MW 18.7% MWh	1,146 MW 18.7% MWh
Coal	1,932 MW 26% MWh	962 MW 12.7% MWh	1,932 MW 26% MWh	0MW 0MWh
Natural Gas and Demand Response	7,424 MW 26.3% MWh	8,394 MW 39.6% MWh	7,138 MW 20.7%MWh	9,188 MW 46.3% MWh
Renewable Energy (RE) & Distributed Energy (DE)	1,141 MW 13.7% MWh	1,141 MW 13.7% MWh	1,427 MW 22.8% MWh	1,308 MW 19.7% MWh
Energy Efficiency (EE)	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh

which incorporate the low and high values for all of the variables mentioned above rather than testing them on an individual basis. The results of the sensitivity analysis showed that the four corners contingency and coal retirement portfolios have the most variability in terms of net present value of revenue requirements, which fluctuate 11-12% as compared to 6-7% for the base case and enhanced renewable portfolios. Natural gas price changes caused the largest impact on sensitivity results.

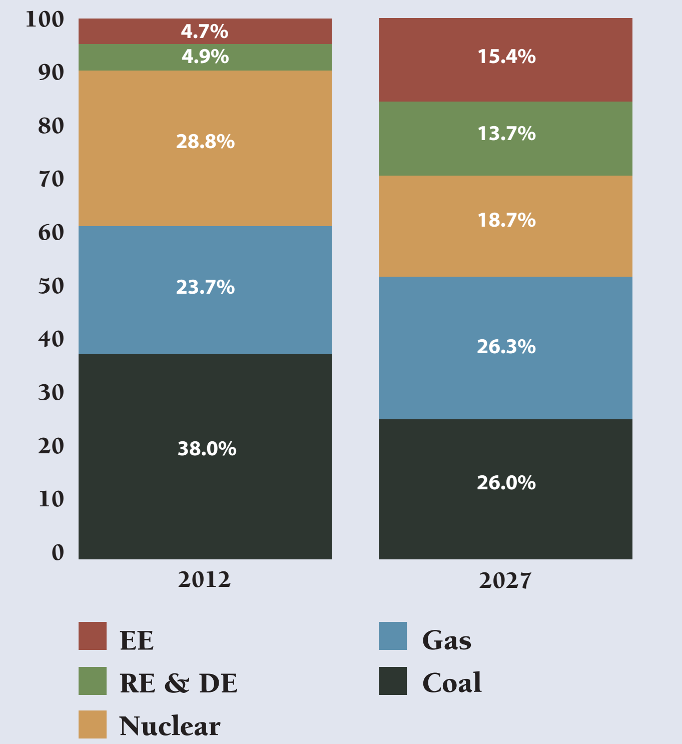
Under the base case plan, APS achieves compliance with energy efficiency requirements and slightly exceeds compliance levels for renewable energy. Consistent with the intent of the revised rules, APS's reliance on coal-fired generating resources drops by 12% between 2012 and 2027. Use of natural gas increases slightly over the course of the planning period under this scenario, but by 2027, no single fuel source makes up more than approximately 26% of the APS resource mix. Figure 4 shows the energy mix in 2027 compared to 2012 under the base case portfolio.

APS had approximately 600 MW of excess capacity in 2012, heading into the summer peak. In the short term—over the next three years—the company planned to continue to pursue energy efficiency and renewable energy resources. During the intermediate term, years four to 15 of the planning period, APS plans to add 3,700 MW of natural gas capacity and 749 MW of renewable capacity. However, "[i]n the event that solar, wind, geothermal, or other renewable resources change in value and become a

51 Id. Page 44. Arizona Public Service Company hired Black and Veatch Corporation to conduct a Solar Photovoltaic (PV) Integration Cost Study report that provides the company with an estimate for the incremental operating reserves necessary to integrate geographically diverse PV development in the APS service territory, and quantifies the anticipated incremental cost to provide the reserve capacity and energy services. "Solar Photovoltaic Integration Cost Study," B&V Project No. 174880 (November 2012).

Figure 4

Energy Mix Under The APS Base Case Portfolio[52]



more viable and cost-effect option than natural gas, future resource plans may reflect a balance more commensurate to the enhanced renewable portfolio."[53]

APS should be commended for several elements of its 2012 IRP. The first of those is the comprehensive stakeholder process, which included workshops covering most, if not all, of the topic areas that are vital to comprehensive integrated resource plans. Not only were stakeholders invited to listen and offer feedback, they were also invited to present their points of view on a subset of these important issues. In the IRP itself, APS provides all non-confidential input and output data for stakeholder review.

Second, APS continues to pursue energy efficiency, renewable energy, and distributed generation resources in each of the resource portfolios it analyzed, meeting or exceeding ACC-specified goals and consistent with the Commission finding that:

> *Continued reliance on fossil generation resources without the addition of renewable generation resources is inadequate and insufficient to promote and safeguard the security, convenience, health, and safety of electric utilities' customers and the Arizona public and is thus unjust, unreasonable, unsafe, and improper.*[54]

APS has also analyzed portfolios that meet the Commission goals of promoting fuel and technology diversity as the utility lowers its reliance on coal-fired generation and increases its use of energy efficiency and renewable energy resources.

Third, APS takes environmental costs into account when evaluating its resource plans. The company uses a CO_2 adder consistent with the assumption that federal regulation of CO_2 will occur within the 15-year planning period. In sensitivity scenarios, APS analyzes alternative prices for CO_2 emissions, and also includes adders for SO_2, NO_x, PM, and water. Emissions cost and water consumption are also two metrics by which APS evaluates its resource portfolios. Water in particular is a resource that has not been given much consideration in utility integrated resource planning in past decades, in this and in other jurisdictions—but it is especially important for Arizona and other states in the arid parts of the country, as it may at times act as a constraining resource on electric power generation.

While APS has indeed done an admirable job in its 2012 Integrated Resource Plan, there are several areas in which the utility can still improve. The first is with respect to its load forecast. APS assumes a return to very high levels of load growth, at 3% per year for a total of 55% growth in energy consumption over the planning period. Load growth is one variable that can be highly uncertain. APS even states that "weather, population growth, economic trends, and energy consumptions behaviors are among the key variables that impact the Company's view of future resource needs. Accurately forecasting any one of these variables over a 15-year period is a challenge. Accurately forecasting them all is impossible."[55]

52 Id. Page 45.

53 Id. Page 64.

54 Arizona Public Service. 2012 Integrated Resource Plan. Page 13.

55 Id. Page 18.

Changes in the forecast can lead to significant changes in the quantity and type of resources needed in a utility's portfolio. For this reason, utilities engaged in resource planning typically analyze sensitivity cases that use at least two (low and high) alternative load forecasts. APS admitted that "a challenge more specific to the APS service territory is load-growth uncertainty,"[56] and yet the company analyzed only a single load forecast—one that the company admits is more than triple the average growth of electricity demand in the United States.[57]

The second improvement that APS could make to its IRP process relates to the creation of the utility's resource portfolios. Often, in integrated resource planning, utilities will use resource optimization models—e.g., EGEAS, Strategist, or System Optimizer—to create resource portfolios. The user inputs data on peak and energy demand, reserve margins, fuel prices, emissions prices, capital and operating cost of both supply and demand resources, etc., and the optimization model will select the number and type of resources to be added over time to make up the least-cost plan. These models will also perform a simplified system dispatch in order to generate system revenue requirements over the planning period. Rather than using an optimization model to select the ideal resource portfolios, APS hand-selected the resource mix for each portfolio. Under this method, it is possible that a lower-cost resource plan exists that APS has not identified.

This is particularly true in the sensitivity analyses that the company conducted. As described above, natural gas prices led to the greatest variance in system revenue requirements in the sensitivity analyses. Had an optimization model been used to evaluate scenarios with high natural gas prices, one might see the model select fewer natural gas-fired resources in favor of increased renewable or energy efficiency. Similarly, in sensitivity scenarios that look at decreased costs for energy efficiency, an optimization model might select additional quantities of energy efficiency to be added to the resource mix. Some of the supply-side resources selected using base EE costs might then not be required, as additional EE would lower both peak and energy demand.

On page 104 of its IRP, APS presents a table of residential and non-residential EE programs that were rejected because program costs were higher than benefits. In sensitivity scenarios where lower EE costs were evaluated, some of these measures that were rejected may have met cost-effectiveness tests and been selected for inclusion in utility resource portfolios.

B. Public Service Company of Colorado

The October 2011 IRP filing from Public Service Company of Colorado ("Public Service") was filed shortly after the company's filing that addressed the Clean Air-Clean Jobs Act. In the CACJA plan ultimately approved by the Colorado PUC, Public Service will retire 600 MW of base-load coal generation, fuel switch from coal to natural gas at another 450 MW of coal generation, and install emission controls at three other coal units by the year 2017. Additionally, as part of two separate filings, the company planned for the installation of 900 MW of additional wind and 30 MW of new solar by the end of 2012. These additions, repowerings, and retirements, along with the current weak growth in Colorado's economy, led Public Service to project a resource need of only 292 MW of additional generation capacity by 2018.

Public Service developed a "least-cost baseline case" resource portfolio, designed to meet resource needs during the Resource Acquisition Period from 2012 to 2018 at the lowest measurement of present value of revenue requirements. The utility also developed eight alternative plans that evaluate increasing amounts of renewable and distributed generation resources. These resource portfolios were evaluated using the Strategist model from the period of 2011-2050, and are shown in Figure 5.

Public Service evaluated the baseline case and the eight alternative cases under several sensitivity scenarios, altering the price of CO_2 emissions, renewable tax incentives, natural gas prices, and level of sales. Figure 6 shows the results of the analysis for the first three variables.

Public Service concludes from its analysis that existing and planned resources would be sufficient to meet the forecasted energy requirements of its system, but that natural gas-fired combustion turbines (CTs) would be required to provide the capacity necessary to maintain reserve margins. The company also concludes that adding

56 Id. Page 20.

57 Id. Page 18.

Figure 5

Least-Cost Baseline Case and Alternative Plans During the Resource Acquisition Period (RAP) From Public Service Company of Colorado's 2011 IRP[58]

		Level A				Level B			
RAP Resource	1 Baseline	A2 Wind	A3 PV	A4 Battery	A5 Solar Thermal	B2 Wind	B3 PV	B4 Battery	B5 Solar Thermal
Thermal Resources	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	1 CT 173 MW	1 CT 173 MW	1 CT 173 MW
Wind		200 MW	200 MW	200 MW	200 MW	800 MW	800 MW	800 MW	800 MW
Solar			25 MW	25 MW	25 MW		100 MW	100 MW	100 MW
Battery				25 MW				100 MW	
Solar Thermal					50 MW				125 MW

Figure 6

Sensitivity Results for Co₂, Tax Incentives, and Gas Prices From Public Service Company of Colorado's 2011 IRP[59]

		Level A				Level B			
		A2 Wind	A3 PV	A4 Battery	A5 Solar Thermal	B2 Wind	B3 PV	B4 Battery	B5 Solar Thermal
Alternative Plan 2011-2050 PVRR Deltas from Baseline Case ($Millions)									
	Starting Assumptions	$98	$105	$160	$298	$427	$489	$672	$881
Sensitivities	CO_2 3-Source Low Esc	$9	$10	$65	$182	$75	$113	$297	$455
Sensitivities	CO_2 3-Source	$7	$8	$62	$178	$63	$101	$285	$441
Sensitivities	CO_2 Early ($20 in 2017)	($36)	($38)	$17	$124	$117	$92	$98	$223
Sensitivities	Low Gas	$164	$179	$238	$393	$671	$760	$979	$1,204
Sensitivities	High Gas	$21	$19	$72	$183	$151	$176	$369	$503
Sensitivities	PTC Wind	($97)	($90)	($35)	$103	$312	($251)	($67)	$142
Sensitivities	10% ITC Solar PV	$98	$119	$174	$312	$427	$546	$729	$938
Sensitivities	30% ITC Solar Thermal	$98	$105	$160	$235	$427	$489	$672	$741

58 Public Service Company of Colorado. 2011 Electric Resource Plan: Volume 1. October 31, 2011. Pp. 1-38.

59 Id. Pp. 1-41.

renewable generating resources would increase system costs under both baseline and sensitivity assumptions.[60] The results of the sensitivity analysis shown in Figure 6 seem to indicate, however, that if the production tax credit (PTC)[61] for wind were to be extended, there would be some benefit to adding additional wind generation, as shown by the decline in present value of revenue requirements in this scenario relative to the base case.

Given the results of the resource analysis, Public Service proposes to utilize a competitive All-Source Solicitation to acquire the resources needed to meet planning reserve margin targets. The solicitation would seek both short-term and long-term power supply proposals, with a preference for short-term contracts. Public Service lists several uncertainties that it will face over the coming years: future environmental regulations, changing technology costs, tax credits that impact the relative costs of generation alternatives, fuel prices, and economic growth in its service territory.[62] Given these uncertainties and the relatively small resource need, the shorter-term power urchase agreements would allow the utility to wait and see if and how uncertainties can be resolved before adding new generation facilities to its resource mix. The company will also offer enough self-build power supply proposals into the solicitation process to meet the needs over the resource acquisition period.

These proposals would ensure that at least one portfolio could be developed with company-owned facilities, and that generating capacity will be expanded at existing sites. Public Service requests that the PUC allow it to conduct periodic solicitations for additional renewable energy, if and when markets become most favorable to customers; but it reports no plans to add additional renewables over the acquisition period. The company states that, "[t]o the extent the Commission desires to see portfolios from the Phase 2 process that contain increasing levels of renewable or Section 123 Resources the Commission should direct the Company to do so in its Phase 1 order."[63]

Public Service's 2011 IRP is comprehensive, thorough, and a good example of effective resource planning. Resource planning in Colorado is driven by: 1) the state Legislature, as statutes dictate the content of state IRP rules; 2) by interveners, whose comments and suggestions during IRP processes can lead to changes in both rules and content of utility resource plans; and 3) by the PUC, which oversees the process and may require that utilities revise resource plans in specific ways prior to receiving Commission approval. The input and oversight from these three entities, combined with the utilities' expertise, leads to the inclusion of several notable elements in the resource plan that demonstrate additional issues of concern in Colorado.

First, recognizing that acquiring necessary resources does not always go according to plan, the utility creates and describes a series of the more common contingency events—e.g., bidders withdrawing proposals, transmission development delays, higher than anticipated electric demand, etc.—and develops plans to address them if they occur.[64]

Second, Public Service acknowledges that its planned volume of wind installations (2,100 MW by 2012) creates specific challenges and requirements that much lower volumes of renewables would not. Because wind output can be variable and uncertain, there may be additional flexibility requirements on an electric system—i.e., there must be a certain amount of generation that can be brought on-line within a 30-minute period in order to respond to changes in renewable output. Public Service conducts an assessment of the need for flexible resources in its IRP's general assessment of need.

Flexibility studies are not a part of traditional integrated resource planning, but Public Service is responding to unique circumstances in its service territory by incorporating this type of study in its resource planning. Utilities sometimes cite the variability and uncertainty of wind and other renewables as reasons *not* to pursue these types of resources in their portfolios; Public Service shows,

60 Id. Pp. 1-43.

61 The federal renewable energy production tax credit (PTC) provides a per-kilowatt-hour tax credit for electricity generating by various types of renewable energy resources and sold by the taxpayer to an unrelated person during the taxable year. The PTC was originally enacted in 1992 and has been extended several times, most recently in January 2013 as part of the American Taxpayer Relief Act of 2012 (H.R. 6, Sec 407). Currently, the PTC for wind resources for which construction began prior to December 31, 2013 is 2.3 cents/kWh.

62 Id. Pp. 1-5.

63 Id. Pp. 1-49.

64 Id. Pp. 1-59.

however, that these challenges can be planned for in a reasonable way and are not a reason to avoid renewable additions.

Finally, traditional integrated resource planning does not pursue short-term strategies, such as market purchases that may buy time in the hope that some uncertainties will be resolved."[65] The Public Service IRP does just that, however, by making shorter-term resource acquisition decisions and preserving "decisions involving new generation facilities to a point in the future when we see how these uncertainties are resolved."[66]

While Public Service should be applauded for its integration of renewables to date, it is unclear from the company's IRP whether it truly views renewable generating technologies as a system resource as opposed to an obligation established by the state legislature and the PUC. As mentioned above, Public Service has no plans to pursue additional renewable acquisitions during the next seven years, even though sensitivity analyses show that additional wind generation may be beneficial to ratepayers if the production tax credit were to be extended. The company does ask that it be granted permission to conduct solicitations for renewables outside of the resource planning process if it determines that market conditions are "favorable," but it gives no indication as to what favorable market conditions might look like. An evaluation of the market conditions favorable to renewables would be very helpful in the context of resource planning, and could be included in future IRPs or updates from Public Service.

C. PacifiCorp

Of the three utilities examined here, PacifiCorp is unique in that it operates across six states—Oregon, Washington, California, Idaho, Utah, and Wyoming, five of which have IRP or other long-term planning requirements.[67] This gives PacifiCorp the additional challenge of planning on a system-wide basis while meeting each of the resource-acquisition mandates and policies in the states where it operates. The company evaluates a 20-year study period, but focuses on the first ten years (2011-2020) in its assessment of resource need.

In that ten-year planning period, PacifiCorp forecasts that system peak load will grow at 2.1% per year (2.4% for

65 Chupka, M,, Murphy, D. & Newell, S. *Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches.* Brattle Group. 2008. Page 2.

66 Public Service Company of Colorado. *2011 Electric Resource Plan: Volume 1.* October 31, 2011. Pp. 1-5.

67 Wyoming does not have its own IRP obligation, but instead mandates that any utility serving in the state that is required to submit an IRP in another jurisdiction also file that IRP with the Wyoming PSC.

68 Id. Page 8.

Figure 7

Resource Additions in the Preferred Portfolio—PacifiCorp's 2011 IRP[68]

Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
CCCT F Class	-	-	-	625	-	597	-	-	-	-	1,222
CCCT H Class	-	-	-	-	-	-	-	-	475	-	475
Coal Plan Turbine Upgrades	12	19	6	-	-	18	-	8	-	-	63
Wind, Wyoming	-	-	-	-	-	-	-	300	300	200	800
CHP-Biomass	5	5	5	5	5	5	5	5	5	5	50
DSM, Class 1	6	70	57	20	97	-	-	-	-	-	250
DSM, Class 2	108	114	110	118	122	124	126	120	122	125	1,189
Oregon Solar Programs	4	4	4	3	3	-	-	-	-	-	18
Micro Solar – Water Heating	-	4	4	4	4	4	4	4	-	-	28
Firm Market Purchases	350	1,240	1,429	1,190	1,149	775	822	967	695	995	N/A

the eastern system peak and 1.4% for the western system peak), and that energy requirements will grow by 1.8% per year. Resource deficits will begin in the first year, with PacifiCorp being short 326 MW in 2011. This deficit grows to 3,852 MW by 2020. In the near-term, shortages will be met with DSM, renewables, and market purchases, but new baseload and intermediate generating units begin to be added to the resource mix in 2014.[69] Figure 7 shows the proposed resource additions.

If PacifiCorp were to proceed with these proposed resource additions, by 2020 its capacity mix would be as shown in Figure 8. In this scenario, traditional thermal resources still make up two-thirds of PacifiCorp's capacity mix; DSM makes up just over 13%, and renewables make up 2.6%.

As Figure 9 shows, PacifiCorp's energy mix looks slightly different under its preferred portfolio. The percentage of total energy generated from coal-fired resources drops by 26% between 2011 and 2020, while the amount of energy from gas-fired resources more than doubles. Even with the significant drop in generation from coal, energy from thermal resources makes up 61% of PacifiCorp's total energy. DSM makes up 11% of the energy mix, with another 11% coming from renewable resources. Hydroelectric power and energy purchases make up the bulk of the remaining energy.

Of the three utilities examined in this report, PacifiCorp's portfolio modeling process is the most comprehensive. It uses a model called System Optimizer, which has the capability to determine capacity expansion plans, to run a production cost simulation of each optimized portfolio, and to perform a risk assessment on these portfolios.

Figure 9

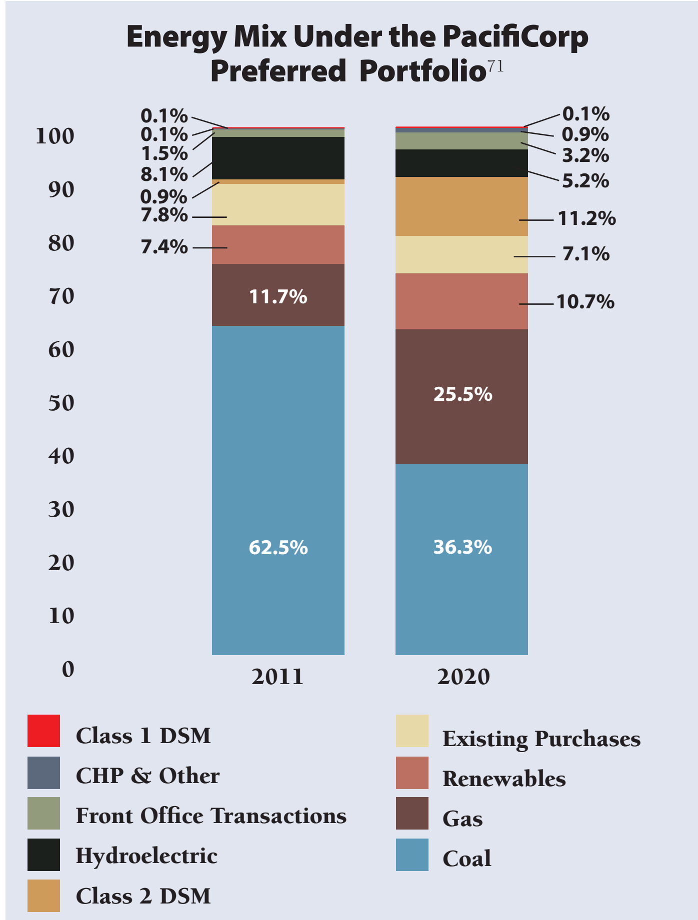
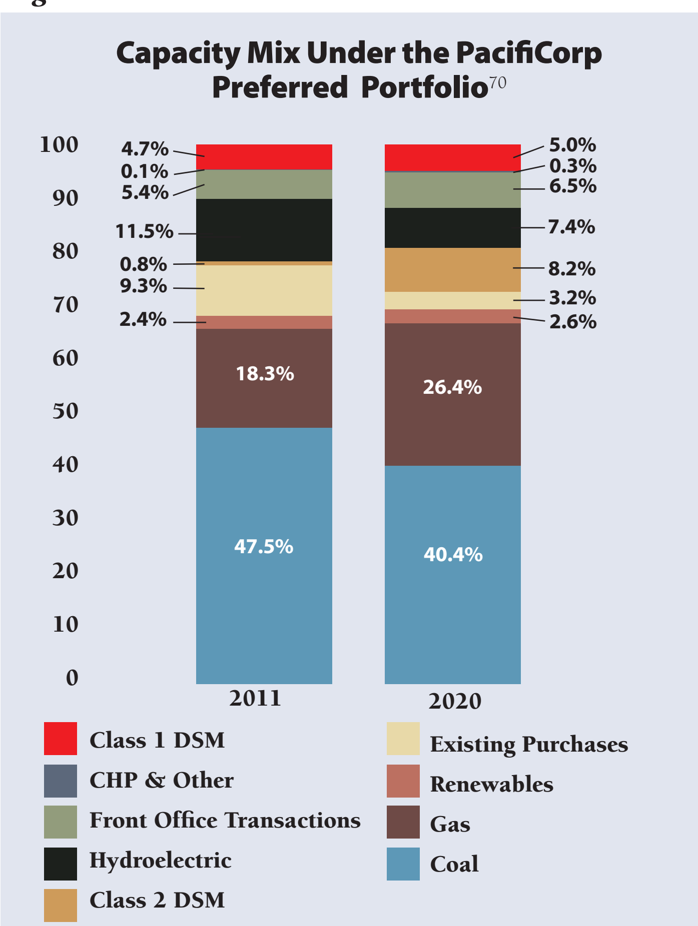


Figure 8



69 PacifiCorp. 2011 *Integrated Resource Plan: Volume 1.* March 31, 2011. Page 83.

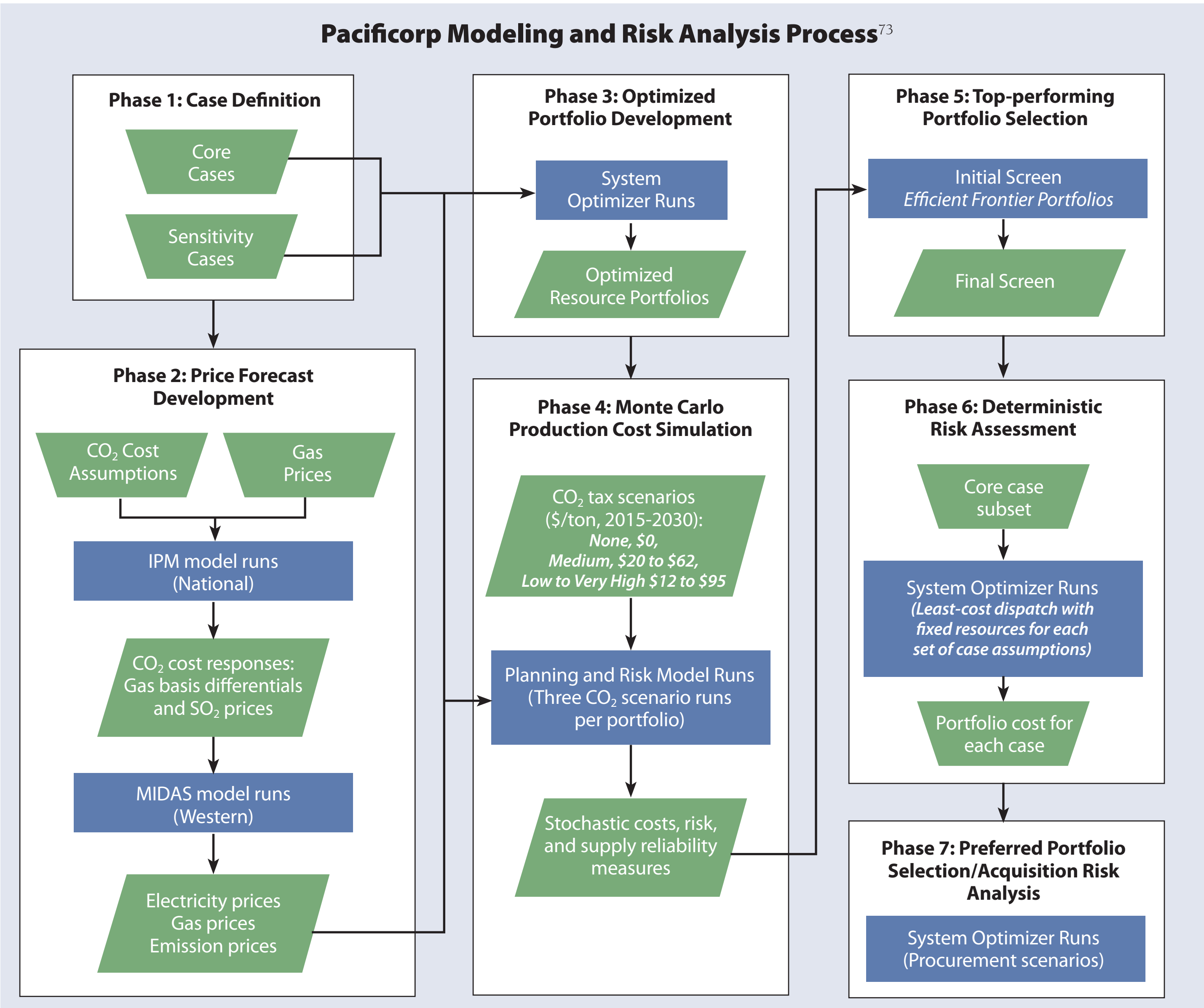
70 Id. Page 10.

71 Id. Page 13.

Altogether, PacifiCorp defined 67 input scenarios for portfolio development. These looked at alternative transmission configurations, CO_2 price levels and regulation types, natural gas prices, and renewable resource policies. Sensitivity cases examined additional incremental costs for coal plants, alternative load forecasts, renewable generation costs and incentives, and DSM resource availability. Top resource portfolios were determined on the basis of the combination of lowest average portfolio cost and worst-case portfolio cost resulting from 100 simulation runs. Final portfolios were selected after considering such criteria as risk-adjusted portfolio cost, 10-year customer rate impact, CO_2 emissions, supply reliability, resource diversity, and uncertainty and risk surrounding greenhouse gas and RPS policies.[72]

Figure 10 shows PacifiCorp's schematic of its modeling process. PacifiCorp is one of the only utilities in the country that models energy efficiency resources as supply-side resources, rather than as load modifiers. The utility provides the model with specific quantities of energy efficiency at given costs, and allows those efficiency resources to compete against the other resources from

Figure 10



72 Id. Page 153.

73 Id. Page 155.

which the model is able to select. PacifiCorp's efficiency resource information in its 2011 IRP is based on a 2010 energy efficiency potential study that provided an estimate of the size, type, timing, location, and cost of the demand-side resources that are technically available in PacifiCorp's service territory. Data for more than 18,000 measures were available after the resources were separated by customer segment, facility type, and unique EE measures.

Energy efficiency measures are called Class 2 DSM, while capacity-based measures are separated into two categories: Class 1 DSM includes dispatchable demand-response programs, and Class 3 DSM includes pricing programs. Focusing on Class 2 DSM measures, PacifiCorp consolidated them into nine cost bundles grouped by levelized cost for inclusion in the modeling, and 1,400 supply curves were modeled for the IRP.[74]

Energy efficiency measures performed well in the modeling, representing the largest resource added through 2030 across all portfolios with cumulative capacity additions exceeding 2,500 MW in the preferred portfolio. The inclusion of such large quantities of energy efficiency creates huge cost savings to ratepayers. If energy efficiency were not included in PacifiCorp's resource portfolio, the utility would have to meet electric load by adding 2,500 MW of supply-side resources at much greater cost.

Although PacifiCorp's portfolio modeling process is comprehensive and well-executed, system resource modeling in general is only as good as the *input assumptions* used to generate the portfolios. The most significant area in need of improvement in the PacifiCorp IRP process relates to the input assumptions and analysis regarding the company's coal fleet—or, rather, the lack of analysis presented on this in the IRP. This lack of analysis began during the stakeholder process. In comments that it submitted, the Sierra Club states that it actively participated in the stakeholder input process, and raised many of the issues discussed in those comments. "The company did not respond to any requests for data related to the topics addressed in these comments, choosing instead to provide only a small amount of materials in the final draft, just days before the company submitted the final IRP."[75]

PacifiCorp's 26 coal-fired boilers make up almost two thirds of its generation. To keep these units running while meeting stricter federal air pollution standards, the company would have to spend $1.57 billion in environmental capital cost from 2011 to 2020, in addition to $1.2 billion that it invested before 2011. Operating costs would raise the total cost to customers to $4.2 billion, or $360 million on an annual basis by 2030.[76] PacifiCorp, however, makes no mention of these current compliance obligations or any future costs in the 2011 IRP or its appendices. The utility failed to disclose the costs that would be faced by its coal fleet in its 2011 IRP, and failed to do a comprehensive analysis of the economics of each of its coal-fired generating units. Absent this analysis, the resource portfolios analyzed by the company cannot be considered to be truly "optimized."

It is highly likely that PacifiCorp could add additional renewable resources to its portfolio. As discussed above, Public Service Company of Colorado had 2,100 MW of wind capacity alone on its system at the end of 2012, and they are a single utility operating in one state. PacifiCorp's territory covers portions of six states, many with large amounts of renewable potential. PacifiCorp's service territory also borders other states with large amounts of renewable potential, and the company could enter into long-term contracts for renewable energy. The company states in the IRP that it commissioned a study on geothermal potential, yet its resource portfolio does not include any anticipated geothermal energy or capacity during the study period.

74 Lamont, D. & Gerhard, J. The Treatment of Energy Efficiency in Integrated Resource Plans: A Review of Six State Practices. Regulatory Assistance Project. January 2013. Pp. 6-8.

75 Sierra Club's Preliminary Comments in the Matter of PacifiCorp 2011 Integrated Resource Plan before the Public Utility Commission of Oregon. LC 52. August 25, 2011.

76 Opening Comments of the Citizens' Utility Board of Oregon in the Matter of PacifiCorp 2011 Integrated Resource Plan before the Public Utility Commission of Oregon. LC 52.

IV. Recommendations for Prudent Integrated Resource Planning

Prudent integrated resource planning involves both the process of creating and sharing the resource plan with stakeholders, and the elements that are analyzed and included in the plan itself. This section provides recommendations, for both the IRP process and the resulting resource plan, that are designed to result in responsible and comprehensive utility integrated resource plans.

A. Integrated Resource Planning Process

Integrated resource planning processes differ from state to state. The ideal process begins with the determination of the IRP guidelines or rules. Integrated resource planning rules were first established in many states in the late 1980s or early 1990s; Oregon's first rules, for example, were established by PUC order in 1989. Significant changes have occurred since then. During the mid- to late 1990s, electric restructuring moved many utilities away from traditional resource planning in favor of market-based provision of electric supply; and today, climate change, national security, and volatility in fuel and commodity markets can make it difficult to determine the best way in which to supply electricity to consumers. Integrated resource planning rules should thus be reexamined periodically, to make sure they reflect the current conditions and challenges associated with providing reliable electric service at reasonable costs.

Arizona began the process of changing its rules after retail competition was instituted in the state by the Corporation Commission—and although the rules took over a decade to be revised and put into effect, the current regulations have been designed to address the issues that are of concern today. When IRP rules are reexamined, state commissions should open proceedings that are open to the public, and stakeholders should be allowed to offer input on the ways in which rules should be revised, as well as to review and comment on any draft documents that are issued. All three of the state IRP rules examined here have gone through this process, and in drafting revised rules, each of the state commissions carefully considered the feedback offered by interveners and adopted recommendations from both public interest groups and utilities.

1. Resource Plan Development

Stakeholder group involvement is equally important when it is time for a utility to develop its integrated resource plan. As was discussed in section III.A., APS detailed its stakeholder process in its 2012 IRP. During the two-year period that preceded the filing of the plan, the utility held various workshops where stakeholders received updates on the inputs to be used, and were able to offer feedback and even give presentations on these various inputs. Stakeholders were also surveyed to determine their preferences with regard to the energy resources selected by APS. Not only does this stakeholder process inform the content of the resource plan that is ultimately filed by the utility; it can also help to inform the review process once the filing has been made.

Other states have also recognized the benefits of stakeholder involvement in IRP and developed model processes. In its *Resource Planning Guidelines for Electric Utilities,* the Arkansas Public Service Commission suggests that utilities establish a Stakeholder Committee to assist in preparing resource plans that "should be broadly representative of retail and wholesale customers, independent power suppliers, marketers, and other interested entities in the service area."[77] The members of this committee would review utility objectives, assumptions, and estimated needs early in the planning cycle, and would submit a report along with the utility's resource plan. Committee members may also submit additional comments to the Commission, which may

77 Arkansas Public Service Commission. *Resource Planning Guidelines for Electric Utilities.* June 2007.

require the utility to re-evaluate its plan to address these comments.[78]

In Hawaii, IRP rules were designed to attempt to maximize public participation in the planning process. In each county within its service territory, the utility is required to organize advisory groups made up of representatives of public and private entities whose interests are affected by the utility's resource plan—including state and county agencies and environmental, cultural, business, and community interest groups. The rules specify that "(a)n advisory group should be representative of as broad a spectrum of interests as possible."[79]

Whether required by IRP rules or not, it is good practice for a utility to convene a stakeholder group, or to hold public meetings that are open to all interested parties, before creating and submitting its resource plan. These meetings are useful both to provide information and invite feedback on the input assumptions and the process that the utility is using in its resource planning, and to help ensure that the resulting plan is relevant and reflects the interests of ratepayers and the general public.

2. Resource Plan Review

Many state utility commissions are quasi-judicial boards that rely on the rules of civil procedure and allow for participation and intervention from different organizations and members of the public (provided they have standing in the proceeding, or an ability to assist the commission in making decisions). After a utility has filed its resource plan, the state PUC should open a proceeding that allows stakeholders to review and submit written comments on the filing. This feedback should be taken into account during the review by the PUC and its staff. Commissions should take an active role in assessing the validity of the inputs used by the utilities in their filings, the resulting outcomes, and whether these are consistent with both the IRP rules and the state's energy policies and goals.

In Kentucky, for example, the IRP rules specify that once a utility's IRP has been received, the Commission should develop a procedural schedule allowing for submission of written interrogatories to the utility by commission staff and any interveners, written comments by staff and interveners, and responses to these interrogatories and comments by the utility. The Commission may convene conferences to discuss the filed IRP if it wishes to do so. Following a review of the plan and intervener comments, Commission staff will issue a report summarizing its review and offering recommendations to the utility for subsequent IRP filings.[80]

Of the states examined in this report, the Colorado PUC has taken on a particularly active role in determining whether utility resource choices were in the public interest. The PUC did so, for example, in its review of Public Service Company of Colorado's 2010 DSM Plan, when it rejected the energy efficiency goals proposed by the company and instead asked that the utility adopt goals recommended by an intervener—the Southwest Energy Efficiency Project—that were approximately 130% of the goals in place at the time.[81] These EE goals were then incorporated into the 2011 IRP, in the calculation of resource need as one of the input modeling assumptions.[82]

Many states, though not all, require that utility plans be available to interveners and/or members of the public for review and participation in resource planning dockets. This signals to both stakeholders and utilities that the IRP process should be collaborative, and that stakeholders can and do offer valuable insights and opinions into resource planning that should be taken into account by utilities when developing their plans. Active oversight and participation by the state PUC is critical to ensuring that comments and proposals by interveners are reviewed, considered fully, and incorporated into utility resource plans when reasonable.

78 Id.

79 Public Utilities Commission, State of Hawaii. *A Framework for Integrated Resource Planning.* Revised May 22, 1992.

80 807 KAR 5:058. Integrated Resource Planning by Electric Utilities.

81 Colorado Public Utilities Commission. Decision No. C11-0442. Docket No. 10A-554EG. March 30, 2011.

82 *The Treatment of Energy Efficiency in Integrated Resource Plans.* Page 15.

B. Integrated Resource Plans

A good electric system IRP should include, at a minimum:

Load forecast

A company's load forecast (annual peak and energy) is one of the major determinants of the quantity and type of resources that must be added in a utility's service territory over a given time period, and has always been the starting point for resource planning. Projections of future load should be based on realistic assumptions about local population changes and local economic factors[83] and should be fully documented. Resource needs can rise or fall dramatically over a short period of time, and frequent, up-to-date load forecasts are necessary for utilities to be able to adequately assess the quantity and type of additional resources that might be needed in a specific planning period.

In Colorado, for example, at the time of Public Service's CACJA filing in mid-2010, the company was projecting a resource need of approximately 1,000 MW by 2018. At the time of its IRP filing in October 2011, the projection of resource need had dropped to 292 MW as a result of the economic recession and the success of DSM and solar programs.[84] In order to help plan for any future changes in load, utilities should model a range of possible load forecasts, not just a reference case.

Reserves and reliability

Reliability is typically defined as having capacity equal to the forecasted peak demand, plus a reserve margin during the hours in which that peak demand is expected to occur. Reserve requirements should provide for adequate capacity based on a rigorous analysis of system characteristics and proper treatment of intermittent resources. The system characteristics affecting reliability and reserve requirements include load shape, generating unit forced-outage rates, generating unit maintenance-outage requirements, number and size of the generating units in a region or service territory, transmission interties with neighboring utilities, and availability and effectiveness of intervention procedures.[85]

Demand-Side Management

Many state IRP statutes or regulations include in the definition of integrated resource planning an evaluation of energy conservation and efficiency. Even so, "[w]hile demand-side resources have always been a conceptual part of IRP, in practice they have not always been an important focus."[86, 87] As generation from traditional supply-side resources is growing more costly and energy efficiency measures are becoming less expensive, however, demand-side alternatives have gained a greater number of advocates across the United States.

Not only is energy efficiency often the lowest-cost resource available to system planners, it can also mitigate a variety of risks, such as that of impending carbon legislation and other environmental regulations affecting air and water quality. In addition to offsetting energy consumption, implementing EE measures can lead to a deferral in costly transmission and distribution investments.[88]

In the IRPs of most utilities, demand-side resources are included only up to the point that statutory goals are met, or mandatory levels of investment are included. Resource planners often incorporate the effects of those demand-side policies as adjustments ("decrements") to their forecasts of future load requirements. However,

83 State and Local Energy Efficiency Action Network. *Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures.* September 2011. Page 5.

84 Public Service Company of Colorado. *2011 Electric Resource Plan: Volume 1.* October 31, 2011. Pp. 1-5.

85 Biewald, B. & Bernow, S. *Electric Utility System Reliability Analysis: Determining the Need for Generating Capacity.* Boston: Energy Systems Research Group. 1988.

86 Chupka, M., Murphy D. & Newell, S. *Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches.* Brattle Group. 2008. Page 3.

87 Demand response, which is another type of demand-side resource, is considered in utility IRPs even less frequently than is efficiency. A full discussion of how demand response is included or excluded in IRPs is beyond the scope of this report.

88 *The Treatment of Energy Efficiency in Integrated Resource Plans.* Page 15.

"The best IRPs create levelized cost curves for demand-side resources that are comparable to the levelized cost curves for supply-side resources. … By developing cost curves for demand-side options, planners allow the model to choose an optimum level of investment. So if demand-side resources can meet customer demand for less cost than supply-side resources, as is frequently the case, this approach may result in more than the minimum investment levels required under other policies."[89]

The three integrated resource plans discussed in this report each deal with energy efficiency in different ways. In Arizona, the Corporation Commission has set a demand-side management standard, and each of the portfolios analyzed in the IRP from Arizona Public Service assume full compliance with that standard.[90] Public utilities are required to achieve annual energy savings of at least 22% by 2020, and savings (measured as a percent of retail energy sales) should increase incrementally in each calendar year prior to 2020.[91] In its IRP, APS has calculated the number of MWh of energy savings needed to be compliant with Commission standards, and has imported these targets into the IRP as a load decrement over the planning horizon.

Colorado's Energy Efficiency Resource Standard (EERS) was established by Colorado House Bill 07-1037 and codified under the Code of Colorado Regulations §40-3.2-104. The law requires that the Colorado Commission set savings goals for energy and peak demand for the state's investor-owned utilities, but specifies minimum savings goals of at least 5% of both retail energy sales and peak demand from a 2006 baseline. Utilities are required to submit DSM plans, which are then reviewed and approved by the Commision, or approved with modifications. The plan that is ultimately approved may require levels of DSM that are higher than the minimum savings goals that have previously been established. Similar to APS, in its most recent IRP, Public Service took the most recent utility-specific DSM goals approved by the Commission and imported them into the IRP process as a load decrement, reducing the resource need over the planning period.

PacifiCorp is subject to EERS requirements in Washington and California. In 2006 in Washington, voters passed Initiative 937, which requires that electric utilities serving more than 25,000 customers undertake all cost-effective energy conservation. Beginning in 2010, utilities must do an assessment of all the achievable cost-effective conservation potential in even-numbered years.[92] Alternatively, efficiency targets may be based on a utility's most recent integrated resource plan, provided that plan is consistent with the resource plan for the Northwest Power and Conservation Council.[93]

California Assembly Bill 2021, enacted in 2006, called for a 10% reduction in electricity consumption within 10 years. It also required that the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and other interested parties develop a statewide estimate of all cost-effective electricity savings, develop efficiency and demand reduction targets for the next 10 years, and update the study every three years. Goals were developed by the CPUC in 2008 for years 2012 through 2020, and each of the three investor-owned utilities in the state has distinct requirements for electricity savings and demand reduction.[94]

89 State and Local Energy Efficiency Action Network. Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures. September 2011. Page 6.

90 Arizona Public Service. 2012 Integrated Resource Plan. March 2012. Page 36.

91 Arizona Corporation Commission. Decision No. 71819. Docket No. RE-00000C-09-0427. August 10, 2010.

92 Chapter 19.285 of the Revised Code of Washington (RCW): Energy Independence Act.

93 The Northwest Power and Conservation Council (NWPCC) is a regional entity that helps the states in the Pacific Northwest ensure an affordable and reliable energy system while maintaining fish and wildlife health in the Columbia River Basin. One responsibility of the NWPCC is to publish a 20-year electric plan that serves as a guide for Bonneville Power and its customer utilities in the region. The regional plan drives best practices in energy efficiency and is a reference against which utility plans may be measured. In the Sixth Power Plan, published in 2010, the NWPCC recommended that energy efficiency be deployed aggressively such that it meets 85% of new demand for electricity over the next 20 years.

94 California Public Utilities Commission. Decision 08-07-047. Rulemaking 06-04-010. July 31, 2008.

In California, PacifiCorp is also subject to a separate "loading order" requirement that requires utilities to first meet growth in energy demand through energy efficiency and demand response. Only after all cost-effective demand-side measures have been taken should the utilities consider adding conventional generation technologies.[95] PacifiCorp's 2011 IRP creates levelized cost curves for demand-side resources, as described above and in previous sections, and is a good example of this type of energy efficiency modeling effort. This type of modeling may be too costly to be feasible for some utilities, but it is important that consideration of various levels of DSM savings be given in integrated resource planning in order to give stakeholders confidence that all cost-effective DSM has been included in utility resource plans.

Supply options

A full range of supply alternatives should be considered in utility IRPs, with reasonable assumptions about the costs, performance, and availability of each resource. There can be uncertainties regarding the availability and costs of raw materials and skilled labor, construction schedules, and future regulations. Because these cost uncertainties can affect technologies in different ways, it is prudent to model a range of possible costs and construction lead times for supply alternatives. And because planning periods examined in IRPs are typically a decade or more, it is also prudent to evaluate supply technologies that are not currently feasible from a cost perspective, but may become so later in the planning period.

Fuel prices

Coal prices have been on the rise in recent years, and natural gas prices have historically been quite volatile. Fuel prices can shift as a result of demand growth, climate legislation, development of export infrastructure, and supply conditions.[96] It is thus extremely important to use reasonable, recent, and consistent projections of fuel prices in integrated resource planning.

Environmental costs and constraints

Utility IRPs should include a projection of environmental compliance costs—including recognition, and evaluation where possible—of all reasonably expected future regulations. At this time, the EPA has announced several upcoming environmental regulations. A final version of the Mercury and Air Toxics Standards (the "MATS" Rule) has been released, and rules are pending for Coal Combustion Residuals ("CCR"), cooling water intake structures under the Clean Water Act ("316(b)"), updates to the National Ambient Air Quality Standards ("NAAQS"), and new Effluent Limitation Guidelines.

Within the next three to five years, certain generating units may also become subject to new requirements under the Clean Air Act's Regional Haze Program, sometimes known as the BART rule because it requires installation of "best available retrofit technology." The Cross-State Air Pollution Rule, which would have required emissions reductions of SO_2 and NO_x in many states but was vacated by the US Court of Appeals for the DC Circuit in 2012, may return in a revised form at some point in the future.[97] Finally, greenhouse-gas emissions limits for electric generating units may come into effect in the next decade.[98]

These rules, both individually and in combination, have the potential to dramatically change the electric power industry. Utilities, in their IRP filings, need to acknowledge these rules and prepare for them as best they can through evaluations of emissions allowance costs, emission controls, and changes to resource portfolios. Few utilities now do this in a comprehensive manner. Of those discussed here, APS does the best job in its IRP by providing a discussion of each of the rules and its potential impacts on APS operations. The process could be improved through analysis of different compliance strategy scenarios.

Existing resources

Examination of existing resources in utility IRPs has become especially important as the mandated emission

95 See California Assembly Bills 1890 and 995. Similar loading order requirements exist in a few other states. See for example Connecticut Public Act No. 07-242, Section 51: An Act Concerning Electricity and Energy Efficiency.

96 *Reviving Integrated Resource Planning.* Page 6.

97 Colburn, K., et al. "Least-Risk Planning: The Homer City Decision Increases Uncertainty—but Rewards Forward Thinking." Public Utilities Fortnightly, November 2012.

98 EPA has proposed but not yet finalized greenhouse gas emission limits for newly constructed power plants. After those rules are finalized, EPA is required under the Clean Air Act to develop standards for existing power plants.

reductions associated with the MATS rule, discussed above, have led to utility decisions across the country to install pollution control retrofits, repower, or retire their coal units. PacifiCorp drew the ire of stakeholders and the Oregon PUC by not including this type of analysis for its coal-fired units in its 2011 IRP. All types of modifications to existing resources should be included in a utility's analysis of the optimum resource portfolio.

Integrated analysis

There are various reasonable ways to model plans, generally requiring the use of optimization or simulation models. Common models used throughout the industry include Strategist, EGEAS, System Optimizer, MIDAS, AURORA, PROMOD, and Market Analytics. These models are supplied to utilities by various third-party vendors.

It is important that the integrated model does not inadvertently exclude combinations of options that deserve consideration. This might occur in one of two ways. The first is in the instances that future resource portfolios are user-defined, rather than selected by an industry model. This is one of the criticisms of the Arizona Public Service IRP: the use of production cost modeling without an optimization component may have resulted in a less than optimal addition of supply- and demand-side resources over time.

The second way in which this may occur is if users constrain optimization models so that a model may not, given the cost, select the quantity of a specific resource that it may want. For example, a utility may constrain a model in such a way that it is only allowed to add 100 MW of wind generation over the resource planning period; but depending on the nature of the utility's electric system, the model may want to add additional wind resources. In this way, a combination of resources that deserves consideration may be excluded.

Time frame

The study period for IRP analysis should be sufficiently long to incorporate much of the operating lives of any new resource options that may be added to a utility's portfolio—typically at least 20 years—and should consider an "end effects" period to avoid a bias against adding generating units late in the planning period. Arizona rules require a 15-year planning period, Oregon a 20-year planning period, and Colorado a utility-specified planning period of between 20 and 40 years. Of the rules examined here, only Oregon explicitly states that an end effects period should be considered.

Uncertainty

At a minimum, important and uncertain input assumptions should be tested with high and low cases to assess the sensitivity of results to changes in input values. These assumptions include, but are not limited to, load forecasts, fuel prices, emissions allowance prices, environmental regulatory regimes, costs and availability of demand-side management measures, and capital and operating costs for new generating units.[99] The types of inputs listed are common to most utilities across the United States, but there are additional input assumptions that are regional or local in nature.

As discussed in the section on Oregon's IRP rules, its PUC requires utilities to model cases that vary the amount of hydroelectric output in the region. Utilities in states like Arizona, New Mexico, or Florida may want to examine

99 Decisions in the face of uncertainty come with degrees of risk. A recent study by CERES entitled, "Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know (How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility Resource Selection) concludes that it is "essential that regulators understand the risks involved in resource selection, correct for biases inherent in utility regulation, and keep in mind the long-term impact that their decisions will have on consumers and society. To do this, regulators must look outside the boundaries established by regulatory tradition." According to CERES, "risk arises when there is potential harm from an adverse event that can occur with some degree of probability." Risks for electric system resources have both time-related (i.e., the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers) and cost-related aspects (the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations). Practicing Risk-Aware Regulation (April 2012) at 20-21 http://www.ceres.org/resources/reports/practicing-risk-aware-electricity-regulation

cases that vary the amount of solar output when doing long-term planning. Utilities located in arid regions, or those owning a significant number of generation assets that are dependent on the availability of a water source for power plant cooling, may want to analyze scenarios where water is scarce or is at too high a temperature to be useful for cooling. Individual utilities must determine those input assumptions that are subject to variability, and model sensitivity cases accordingly to properly account for risks and uncertainties that they face.

Performing single-factor sensitivities may not, however, be very informative. Many cases may warrant more sophisticated techniques, such as probabilistic techniques or those that combine uncertainties. "Testing candidate resource solutions against scenarios that address the range of plausible future trajectories of external factors, and their interrelationships, can more effectively support planning in an uncertain environment."[100]

Valuing and selecting plans

There are often multiple stages of running scenarios and screening in developing an IRP, and there are various reasonable ways to approach this. Traditionally, the present value of revenue requirements is the primary metric that is analyzed, and minimized, in utility IRPs. This metric alone may not, however, sufficiently address uncertainties. It may be useful also to evaluate plans along other dimensions like environmental cost or impact, fuel diversity, impact on reliability, rate or bill increases, or minimization of risk.

It is essential that the IRP process be executed in a manner that applies the selected metrics in a reasonably transparent and logical manner, without inappropriately screening out resources options or plans that deserve consideration at the next stage. Note also that it is highly unlikely that a single resource portfolio will be the best choice on every metric evaluated. A resource portfolio that performs well across several metrics, but perhaps is not the top performer on any single metric, may in fact be the best choice for utility planners.

Action plan

Even though IRPs should have a longer study period, a good plan will include a specific discussion of the implications of the analysis for near-term decisions and actions, and will also include specific plans for getting those near-term items accomplished. Demand-side measures take time to implement, and supply-side resources require months or years of lead time to permit and construct. Utilities must thus provide a thorough discussion of the steps they plan to take to implement, acquire, or construct resources that will meet energy and peak demand needs in their service territories in the three- to five-year period after the plan is filed. The availability of these near-term resources has a direct effect on the resources needed throughout the remainder of the planning period; so it is prudent for the utility to detail the ways in which it will go about acquiring the resources described in its IRP.

Documentation

A proper IRP will include discussion of the inputs and results, and appendices with full technical details. Only items that are truly sensitive business information should be treated as confidential, because such treatment can hinder important stakeholder input processes.

100 Reviving Integrated Resource Planning. Page 4.

V. Conclusion

Utility integrated resource planning has been in effect in various parts of the United States for more than 25 years. While some utilities are regulated by the original IRP rules developed more than a decade ago, many states have updated their IRP rules to reflect current conditions and concerns in regional and national electricity markets. In states where this has occurred, IRPs filed by utilities tend to be more comprehensive and to exhibit more of the "best practices" in utility resource planning that have been described in this report.

Nonetheless, there are still many ways in which utilities can improve both their resource planning processes and the plans that are generated as a result of these processes. Engaged stakeholders and state public utilities commissions can provide oversight to this process, helping to promote resource choices that lead to positive outcomes for society as a whole.

Appendix: State IRP Statutes and Rules

Arizona

Arizona Corporation Commission Decision No. 71722, in Docket No. RE-00000A-09-0249. June 3, 2010.[101]

Arkansas

Arkansas PSC. "Resource Planning Guidelines for Electric Utilities." Approved in Docket 06-028-R. January 4, 2007.[102] Rules are currently under review and updates have been proposed.

Colorado

Colorado PUC. 4 CCR 723-3, Part 3: Rules Regulating Electric Utilities. Decision No. C10-1111. Docket No. 10R-214E. November 22, 2010.[103]

Delaware

HB 6, the Delaware Electric Utility Retail Customer Supply Act of 2006.[104]

Georgia

Integrated Resource Planning Act of 1991 (O.C.G.A. § 46-3A-1), Amended.[105]

Georgia Public Service Commission. General Rules. Integrated Resource Planning 515-3-4.[106]

Hawaii

Public Utilities Commission, State of Hawaii, A Framework for Integrated Resource Planning, March 9, 1992.[107]

Idaho

Idaho Public Utilities Commission Order No. 22299, in Case No. U-1500-165.[108]

Indiana

170 Indiana Administrative Code 4-7-1: Guidelines for Integrated Resource Planning by an Electric Utility. New draft rules have been proposed in docket IURC RM 11-07.[109]

Kentucky

KY Administrative Regulation 807 KAR 5:058. Integrated Resource Planning by Electric Utilities. Relates to KRS Chapter 278.[110]

Louisiana

Louisiana Public Service Commission Corrected General Order. Docket No. R-30021. Decided at the Commission's March 21, 2012 Business and Executive Session.[111]

Minnesota

MN Statute §216B.2422.[112]

MN Rules Part 7843.[113]

Missouri

Rules of Dept. of Economic Development. Division 240 - PSC. Chapter 22—Electric Utility Resource Planning (4 CSR 240.22).[115]

Montana

Montana's Integrated Least-Cost Resource Planning and Acquisition Act (§§ 69-3-1201-1206, Montana Code Annotated).[116]

Administrative Rules of Montana 38.5.2001-2016, adopted by the Montana PSC, for traditional utilities.[117]

Administrative Rules of Montana 38.5.8201-8227, adopted by the Montana PSC, for restructured utilities.[118]

Nebraska

Nebraska Revised Statute 66-1060.[119]

Nevada

NRS 704.741.[120]

New Hampshire

Title XXXIV Public Utilities, Chapter 378: Rates and Charges, Section 38: Least Cost Energy Planning.[121]

New Mexico

Integrated Resource Plans for Electric Utilities, Title 17, Chapter 7, Part 3.[122]

North Carolina

North Carolina Utilities Commission Rule R8-60: Integrated Resource Planning and Filings.[123]

North Dakota

North Dakota PSC Order issued on January 27, 1987 in Case No. 10,799. Amended on March 11, 1992 in Case No. PU-399-91-689.[124]

Oklahoma

Title 165: Oklahoma Corporation Commission. Chapter 25: Electric Utility Rules, Subchapter 37: Integrated Resource Planning.[125]

Oregon

Oregon PUC Order No. 07-002, Entered January 8, 2007.[126]

South Carolina

Code of Laws of South Carolina, Chapter 37, Section 58 37 40. Integrated resource plans.[127]

Public Service Commission of South Carolina Order No. 91-885 in Docket No. 87-223-E. October 21, 1991.[128]

South Dakota

SL 1977, Ch. 390, § 23. Chapter 49-41B-3.[129]

Administrative Rule Chapter 20:10:21, Energy Facility Plans.[130]

Utah

Report and Order on Standards and Guidelines. Docket No. 90-2035-01. Issued June 18, 1992.[131]

Vermont

30VSA Sec 218c - Statute establishing least-cost integrated resource planning.[132]

Public Service Board Order of 4/16/1990 initiating the IRP progress (Docket No. 5270).[133]

Public Service Board Order of 7/16/2002 (Docket No. 6290).[134]

Virginia

Code of Virginia § 56-597 - § 56-599.[135]

Washington

Washington Administrative Code 480-100-238: Integrated Resource Planning.[136]

Wyoming

Wyoming Public Service Commission Rule 253 (submitted July 22, 2009), and associated Guidelines for Staff Review.[137]

101 This Decision amends Arizona Administrative Code, Title 14, Chapter 2, Article 7: Resource Planning. It is available at: http://images.edocket.azcc.gov/docketpdf/0000112475.pdf

102 Arkansas guidelines available at: http://www.sosweb.state.ar.us/elections/elections_pdfs/register/june_07/126.03.07-003.pdf

103 Colorado PUC Decision available at: https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=10R-214E

104 Delaware legislation available at: http://legis.delaware.gov/LIS/lis143.nsf/vwLegislation/HB+6/$file/legis.html?open

105 Georgia annotated code available at: http://www.lexisnexis.com/hottopics/gacode/Default.asp

106 Georgia PSC rules available at: http://rules.sos.state.ga.us/cgi-bin/page.cgi?g=GEORGIA_PUBLIC_SERVICE_COMMISSION%2FGENERAL_RULES%2FINTEGRATED_RESOURCE_PLANNING%2Findex.html&d=1

107 Hawaii PUC Framework available at: http://www.heco.com/vcmcontent/Integrated%20Resource/IRP/PDF/IRP_Framework_052292.pdf

108 Idaho PUC Order available at: http://www.puc.state.id.us/search/orders/dtsearch.html

109 Indiana Administrative Code available at: http://www.in.gov/legislative/iac/title170.html

110 Indiana docket RM#11-07 available at: http://www.in.gov/iurc/2689.htm

111 Kentucky Administrative Regulation available at: http://www.lrc.ky.gov/kar/807/005/058.htm

112 Louisiana PUC Order available at: Rules from Arizona, Colorado and Oregon are described in detail in order to demonstrate ways in which states require comprehensive planning processes and resource plan outcomes from the utilities under their jurisdictions.

113 Minnesota Statute available at: https://www.revisor.mn.gov/statutes/?id=216B.2422

114 Minnesota rules available at: https://www.revisor.mn.gov/rules/?id=7843

115 Missouri rules available at: http://www.sos.mo.gov/adrules/csr/current/4csr/4c240-22.pdf, Final Order of Rulemaking was issued on March 3, 2011, as part of the Missouri Public Service Commission Rulemaking Case No. EX-2010-0254. That amendment is available at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EX-2010-0254&attach_id=2011015905

116 Montana Annotated Code available at: http://data.opi.mt.gov/bills/mca_toc/69_3_12.htm

117 Montana Administrative Rules available at: http://www.mtrules.org/gateway/ChapterHome.asp?Chapter=38.5

118 Montana Administrative Rules available at: http://www.mtrules.org/gateway/ChapterHome.asp?Chapter=38.5

119 Nebraska Statute available at: http://nebraskalegislature.gov/laws/statutes.php?statute=66-1060

120 Nevada Statute available at: http://www.leg.state.nv.us/nrs/NRS-704.html#NRS704Sec741

121 New Hampshire Statute available at: http://www.gencourt.state.nh.us/rsa/html/NHTOC/NHTOC-XXXIV-378.htm

122 New Mexico PRC Rule available at: http://www.pnm.com/regulatory/pdf_electricity/irp_electricity.pdf

123 North Carolina PUC Rule available at: http://ncrules.state.nc.us/ncac/title%2004%20-%20commerce/chapter%2011%20-%20utilities%20commission/04%20ncac%2011%20r08-60.pdf

124 North Dakota PSC Order available at: http://www.raponline.org/docs/RAP_NDElectricResourceLongRangePlanningSurvey2005_09_17.pdf

125 Oklahoma Rule available at: http://www.occeweb.com/rules/2010Ch35ElectricpermanentMasterRuleseff7-11-10searchable.pdf

126 Oregon PUC Order available at: http://apps.puc.state.or.us/orders/2007ords/07-002.pdf

127 South Carolina Code available at: www.scstatehouse.gov/code/t58c037.docx

128 South Carolina PSC Order available at: http://dms.psc.sc.gov/pdf/orders/DF4FC4A9-EB41-2CB4-D44614AD02D02B8D.pdf

129 South Dakota Statute available at: http://legis.state.sd.us/statutes/DisplayStatute.aspx?Statute=49-41B-3&Type=Statute

130 South Dakota Rule available at: http://legis.state.sd.us/rules/DisplayRule.aspx?Rule=20:10:21

131 Utah Order available at: http://www.airquality.utah.gov/Public-Interest/Current-Issues/Regionalhazesip/RegionalHazeTSDdocs/Utah_PSC_Integrated_Planning_Rules.pdf

132 Vermont Statute available at: http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=005&Section=00218c

133 Public Service Board Orders issued prior to 1996 are not available online.

134 Vermont PSB Order available at: http://www.state.vt.us/psb/orders/2002/files/6290phaseIIextensionorder.pdf

135 Virginia Statute - content begins at: http://leg1.state.va.us/cgi-bin/legp504.exe?000+cod+56-597

136 Washington Administrative Code available at: http://apps.leg.wa.gov/wac/default.aspx?cite=480-100-238

137 Wyoming PSC Rule available at: http://legisweb.state.wy.us/ARULES/2009/AR09-043.htm; Guidelines for Staff Review available at: http://psc.state.wy.us/htdocs/electric/ElectricIRPGuidelines7-10.pdf

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EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

Transmission Planning White Paper

January 2014

Navigant Consulting, Inc.
For EISPC and NARUC

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January 2014

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1 Introduction

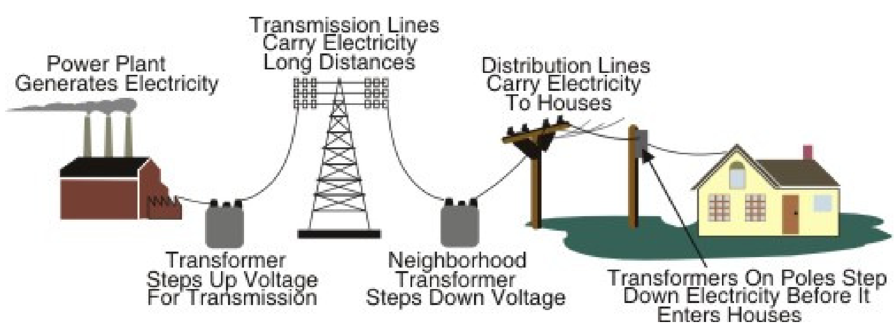
The U.S. electric transmission system is an engineering marvel critical to our economy and way of life. The details can be complex, but the basics are not—the transmission system is designed to reliably and efficiently deliver electricity from where it is generated to where it is distributed to customers. This Transmission Planning White Paper is designed to help policymakers understand the basic technology, economics, and regulations that underlie the planning of today's electric transmission system.

In the 1830s, a seemingly simple discovery was made that would profoundly change everyday life. Moving a magnet through a coil of wire generated electricity, the flow of electrons, in the wire.[1] Nearly all of today's electricity power plants use this same concept. Wind, water flowing in a river, and boiling water to create steam are some of the various means used by today's power plants to turn turbines that spin magnets within coils of wire to generate electricity. This is the **generation** of electricity. Electricity is difficult to store economically; thus, it needs to be generated when it is needed. When you turn on your light switch, a power plant must respond and increase its generation of electricity instantly.

Historically, it has been less expensive to generate electricity at large, centralized power plants, which can be hundreds of miles from where the electricity is used, than with small local generators. The electricity generated at these power plants is transmitted through the **transmission** system, a network of interconnected high-voltage lines. Transmission lines are designed to transmit a large amount of electricity while minimizing the amount of lost energy, and are interconnected with each other to make the system more reliable. The U.S. interstate highway system is analogous to the transmission system. In an interconnected network, if a line or power plant goes out of service, another pathway or power plant can take its place.

Lower-voltage lines are connected via substations to the high-voltage transmission system to distribute electricity to the exact location where it is needed, such as homes, offices, stores, and factories. These lower-voltage lines form the electric **distribution** system. Local roads and streets are analogous to the electric distribution system.

Figure 1. Electric Power Generation, Transmission, and Distribution Diagram



Source: U.S. Energy Information Administration

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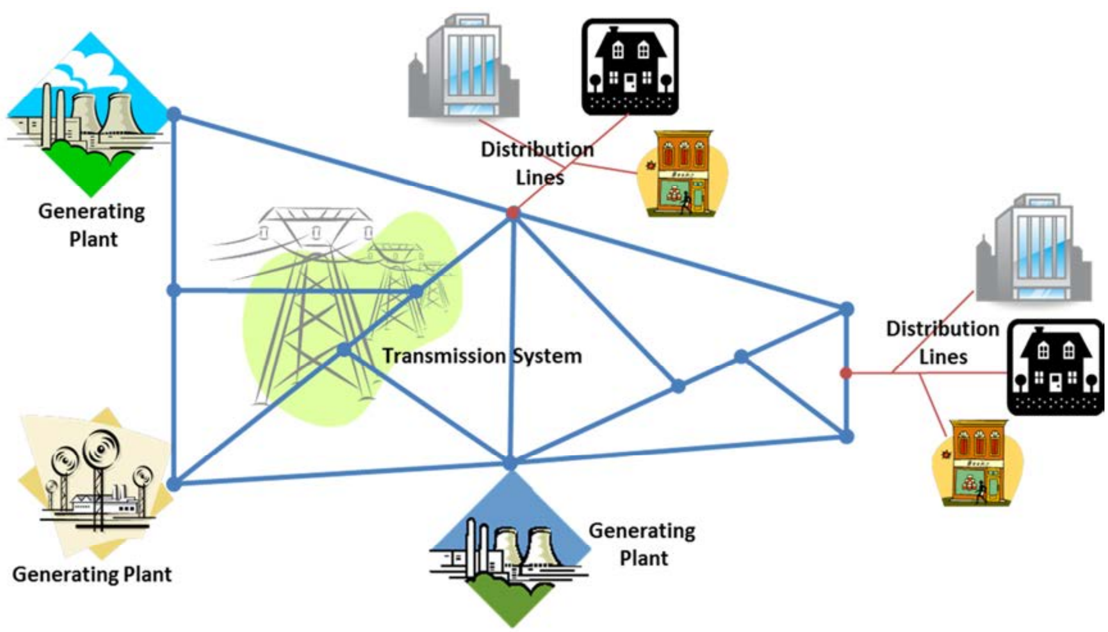
Figure 1 illustrates the basic components of the interconnected electric system. There are substations at each connection point on the system, such as between a power plant and transmission lines, from one transmission line to another, or between transmission lines and distribution lines. Substations use transformers to adjust voltage levels up or down and can disconnect or reconnect portions of the system.

While Figure 1 is useful for understanding the basic components of the electric system, it does not capture the interconnected nature of the transmission network as illustrated in Figure 2. The thick blue lines in Figure 2 represent interconnected transmission lines. These transmission lines provide multiple pathways for the electricity generated by distant power plants to flow to individual distribution systems, thus increasing reliability.

Figure 2. Simplified Representation of the Transmission System



Source: Navigant

Just like traffic jams on an interstate highway, a transmission line can become congested if the power being transmitted over the line reaches the physical limit of the line. Normally, this is not a problem, as the electricity flows over other interconnected transmission lines that are not congested, or power plants located on the congested side of the line are turned down to generate less and power plants on the uncongested side are turned up to generate more. The congestion may yield additional energy losses as the electricity travels over greater distances, or additional fuel costs for generating plants as higher cost plants are turned on, but the system continues to operate reliably.

However, too much power flow can cause the protective circuitry for the line to trip the line off (like the circuit breaker in a residential home) to prevent damage to the transmission line. A transmission line

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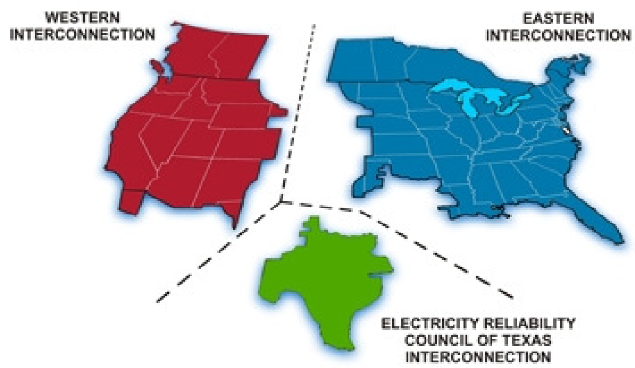
that trips off will immediately result in the transfer of the power traveling on that line to other interconnected lines, possibly overloading these other lines as well, and potentially creating outages over wide areas—a cascading outage. Similarly, a power plant suddenly shutting off will require other power plants to instantly increase their output, or other plants to come on line, potentially causing a line operating near its limit to suddenly exceed this limit and trip off, creating an outage. Thus, the power flows on the interconnected transmission system must be monitored and managed carefully around the clock, and the system must be designed and planned to handle these types of contingencies.

As illustrated in Figure 3, the U.S. transmission system has evolved into three major interconnected systems (power grids or interconnections) in the 48 contiguous states: (1) the Eastern Interconnection (states east of the Rocky Mountains), (2) the Western Interconnection (from the Pacific Ocean to the Rocky Mountain states), and (3) the Texas Interconnection (also called the Electric Reliability Council of Texas [ERCOT]). These systems generally operate independently of each other, although there are limited links between them. The Eastern and Western Interconnections are fully integrated with most of Canada. The Eastern interconnection has links to the Quebec Province power grid, while parts of Mexico have limited connection to the Texas and the Western interconnections.

Figure 3. U.S. Interconnections



Source: U.S. Energy Information Administration (EIA)

Just like the siting, permitting, and building of an interstate highway is more expensive and difficult than it is for a local road, siting, permitting, and building a transmission line is more expensive and difficult than it is for a distribution line. And just as eliminating all traffic congestion by building new highways would be prohibitively expensive, eliminating all congestion on the transmission system would be prohibitively expensive. Planning a reliable, cost-effective transmission system must consider and balance numerous issues, including siting, construction costs, direction of power flows, congestion, energy losses, new power plant locations, new and changing demands for electricity, public policy considerations, and how all of the costs incurred will be recovered.

Planning for the transmission system is complicated by the fact that electricity flows instantaneously over all available pathways on the interconnected transmission system according to physical laws. As can be seen even in a simplified diagram like Figure 2, there are multiple pathways from any one point on the transmission system to another. The flow of electricity on the transmission system from a generating plant to a distribution system will be proportionally higher on those pathways with the least resistance or "impedance" (usually the most direct highest voltage lines), but electricity will flow on all available pathways.

Thus, transmitting electricity from one point to another on the transmission system will have an impact on all available pathways, not just the most direct route. This is in contrast to, for example, natural gas,

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in which the gas from a specific well can be traced as it travels at a relatively low speed through one specific pipe to another until it reaches its destination. As a result, an electric utility continually faces "loop flows" on its transmission system resulting from normal activity or emergency incidents on transmission systems that can be located hundreds of miles away. The fundamental nature of electricity flow on an interconnected transmission system must be incorporated into all facets of transmission operations, planning, and policy.

This Transmission Planning White Paper is written primarily for those who are new to electric transmission issues.[2] The focus is on understanding transmission technology, economics, and regulation at a basic level and how state policymakers can influence transmission planning and policy. The next chapter provides background and discusses recent events that make transmission so important to our society today.

Key policies and rules from the Federal Energy Regulatory Commission (FERC) related to transmission are discussed in the third chapter. The process for building a new or upgrading an existing transmission line is described in detail in chapter four, including the role of state authorities and other entities involved in this process. Chapter five describes the typical process undertaken to plan the future of the transmission system. A discussion of how transmission is paid for is provided in chapter six, along with a discussion of current transmission cost allocation issues and methodologies. Chapter seven provides a high-level overview of the physical characteristics of the existing transmission system, and trends for future transmission technology development. The final chapter provides specific action items for state officials involved in transmission policy decisions.

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2 Why Has Transmission Become So Important?

The transmission system has always been crucial to providing reliable, low-cost electric service to customers. Today, the transmission system has become even more important in allowing access to a diverse generation supply, including renewable sources of power, and enabling competition among power plants. This chapter discusses the historical development of transmission and why transmission continues to be of critical importance today.

2.1 *Historical Development*

2.1.1 Early History

The opening of Thomas Edison's Pearl Street station in lower Manhattan in 1882 launched the modern electric utility industry. By 1887, there were 121 Edison power stations scattered across the United States delivering direct current (DC) electricity to customers. But DC had a great limitation—power plants could only send DC electricity about a mile at the low voltages being used.[3]

It was well known that much less energy would be lost if high-voltage transmission lines could be used. In the late 1880s, William Stanley and George Westinghouse developed cost-effective transformers to increase and decrease the voltage of alternating current (AC) electricity. Now, electricity from distant, but efficient power plants could travel with little loss of energy on high-voltage AC lines before being stepped down safely to lower voltages near consumers. AC electric systems went on to become the standard in the U.S. and throughout the world.

Around the beginning of the twentieth century, there were over 4,000 individual electric utilities in the U.S., each operating in isolation.[4] As electric generation and transmission technology dramatically improved, it encouraged growth, consolidation of the industry, and expansion into more and more cities, and across a wider geographic area. Over time, in what became known as the Regulatory Compact, these privately owned consolidated utilities were granted monopoly franchises with exclusive service territories by states, in exchange for an obligation to serve customers within that territory at rates for service based on state-regulated, cost-of-service ratemaking.[5] Among the first states to regulate electric utilities were Georgia, New York, and Wisconsin, which established state public service commissions in 1907.[6]

Despite the lure of exclusive franchises, some areas were inevitably less financially attractive than others. Under the Rural Electrification Act of 1935, service was extended to unserved, or underserved, rural areas, which also gave rise to rural electric cooperatives in many areas of the U.S. During the presidency of Franklin D. Roosevelt (1933 to 1945), funding accelerated the development of municipal electric systems, and a number of government-owned hydroelectric power facilities were built, with publicly owned utilities given priority to the output of these facilities.

In 1920, the Federal Water Power Act was passed to coordinate the initial development of these hydroelectric projects. This act created the Federal Power Commission (FPC), now FERC. Following

Figure 4. Early History

- **1882:** Edison's Pearl Street Station in Manhattan
- **1890s:** Low-cost AC voltage transformers developed, long-distance transmission lines feasible
- **1900s:** Over 4,000 local low-voltage systems in U.S.
- **1920:** Federal Power Commission (FPC) created
- **1927:** First tight power pool forms in PA and NJ
- **1930s:** Emergence of federal hydro-power and public power
- **1935:** Federal Power Act, Rural Electrification Act, PUHCA

Source: Navigant

U.S. Supreme Court rulings that states could not regulate interstate transmission as it imposed a direct burden on interstate commerce,[7] in 1935 the law was renamed the Federal Power Act and the FPC's regulatory jurisdiction was expanded to include all interstate electricity transmission and sales of power for resale.

By 1907, Samuel Insull of Chicago Edison had acquired 20 other utility companies and renamed his firm Commonwealth Edison. In the 1920s, electric utilities began to exploit the use of holding companies, not to improve operating efficiency through consolidation, but as a speculative exercise. While the operating companies were subject to state regulation, the holding companies were not. By the end of the 1920s, ten utility systems controlled three-fourths of the United States' electric power business and the size and complexities of these multistate holding companies had made state regulation ineffective.[8]

In response to the collapse of several of these large, multistate electric utility holding company systems during the Great Depression, the Public Utility Holding Company Act (PUHCA) was passed in 1935, giving the Securities and Exchange Commission (SEC) responsibility for regulating utility holding companies. Among other things, PUHCA limited the geographic spread of utility holding companies, the types of business they may enter, and unnecessary corporate layers, as well as prohibiting sales of goods or services between holding company affiliates at a profit.

Thus, as shown in Figure 4, by 1935 the electric utility industry in the United States had become formally regulated at both the state and federal levels.

2.1.2 Initial Transmission Planning and the Formation of Tight Power Pools

Transmission was initially conceived and planned as a direct link between a generating plant and the distribution system serving the demand or "load." As the demand for electricity grew, particularly in the post-World War II era, electric utilities found it more efficient to interconnect their transmission systems. In this way, they could share the benefits of building larger and, often, jointly owned generators to serve their combined electricity demand at the lowest possible cost, and to avoid building duplicative power plants. By increasing access to additional power plants, interconnection also reduced the amount of extra capacity that each utility had to hold to assure reliable service.[9]

Throughout most of the twentieth century, growing demand and the accompanying need for new power plants resulted in an ever-increasing need for higher voltage interconnections to transport the additional power longer distances. In 1969, the world's first 765-kilovolt (kV) transmission line was energized between Ohio and Kentucky.[10]

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Despite the expansion of the interconnected transmission system, a local utility generally would plan its transmission system as if the utility were an island or isolated from other utility systems. In effect, the presumption was that neighboring transmission would be available to provide electricity for assistance during emergency conditions, but for day-to-day operations, the generating and transmission system of the local utility needed to be robust enough to provide reliable electricity service on a stand-alone basis.

Starting in the 1920s with utilities in Pennsylvania, New Jersey and (later) Maryland (PJM), certain regions of the country began to form "tight power pools" in which the member utilities pooled their generation and transmission resources to minimize generating plant fuel costs by centrally dispatching plants over the pool footprint.[11] The savings were shared among the member utilities and transmission was collectively planned to allow for delivery of power throughout the pool. Tight power pools also eventually formed in Michigan, New England, and New York.[12] These tight pools were the precursors to the centralized energy markets in today's regional transmission organizations.

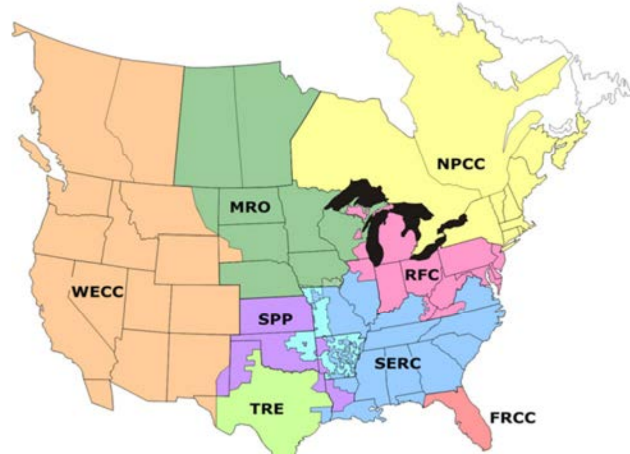
In addition to the formation of tight power pools, connections between individual utilities expanded to become the three interconnections that exist in the United States today: Eastern Interconnection (which includes parts of Canada), Western Interconnection (which includes parts of Canada and Mexico), and ERCOT. The three interconnections are shown above in Figure 3.

2.1.3 Northeast Blackouts of 1965 and 2003 and the Creation of NERC and Reliability Standards

Throughout most of the twentieth century, individual power systems developed and designed their own criteria for reliability. Following the Northeast Blackout of 1965, in which large portions of the Northeast U.S. and Ontario lost power for up to 13 hours, the North American Electric Reliability Council and regional reliability councils were voluntarily formed. These organizations later became the North American Electric Reliability Corporation (NERC) and the Regional Entities (see Figure 5).

One of NERC's roles was to establish overall reliability criteria. NERC's original planning criteria were general in nature—guidelines as to what topics the regional councils should address in creating their regional criteria. Across the nation, systems came together to establish regional reliability councils, until collectively they encompassed essentially all of the continental U.S. and Canada. The primary role of the regional reliability councils was to establish and maintain uniform reliability criteria to be applied in the planning and operation of their respective systems.

Figure 5. NERC Regional Entities



Source: NERC

Prior to 2005, compliance with NERC reliability standards was voluntary. After a blackout in the Northeast affected over 50 million people in August 2003, the Energy Policy Act of 2005 (EPAct) was

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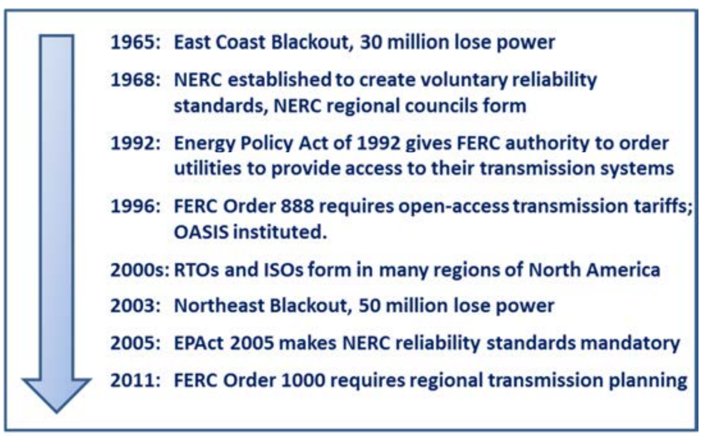
enacted, eliminating the voluntary nature of the NERC reliability standards. FERC was charged with the ultimate oversight of electric reliability of the bulk power system (BPS). FERC finalized rules on the certification of an electric reliability organization (ERO) and on procedures for the establishment, approval, and enforcement of mandatory electric reliability standards, and certified NERC as the ERO in 2006.[13] NERC, along with its regional entities, develops mandatory reliability standards subject to FERC approval, monitors industry participants' compliance with these standards, trains and certifies industry personnel, and can levy penalties for noncompliance.

2.1.4 Emergence of Open Access to the Transmission System

Through the 1980s, transmission systems were owned and operated by the local utility within its franchised service territory, and interconnected with neighboring utility transmission systems. Typically, the local utility only transmitted power on its transmission system from its own power plants or contractually purchased power from neighboring utilities. The Public Utility Regulatory Policies Act of 1978 (PURPA) required utilities to purchase power from non-utility generators when economic to do so, which, for the first time, allowed non-utility generation access to the transmission system to deliver power to the local utility.

Figure 6. Time Line 1965–2011



Source: Navigant

In response to ongoing concerns regarding obtaining access to utility transmission systems, the Energy Policy Act of 1992 gave FERC the explicit authority to order utilities to provide access to their transmission systems to other utilities and to non-utilities. As shown in Figure 6, in 1996 FERC issued Order No. 888, which required transmission owners to provide transmission service to other suppliers of electricity on the same terms and conditions as they provide it to themselves. FERC's objective was to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the nation's electricity consumers.[14] The resulting tariffs became known as Open Access Transmission Tariffs (OATTs). Timely and accurate day-to-day information about the transmission system was also made available to all transmission users through the implementation of the Open Access Same-Time Information System (OASIS), in accordance with FERC Order No. 889.

Open access to the transmission system allowed non-utility "merchant" generating plants to deliver and sell power to wholesale customers using the utility-owned transmission system, and paved the way for the emergence of competitive generation markets.

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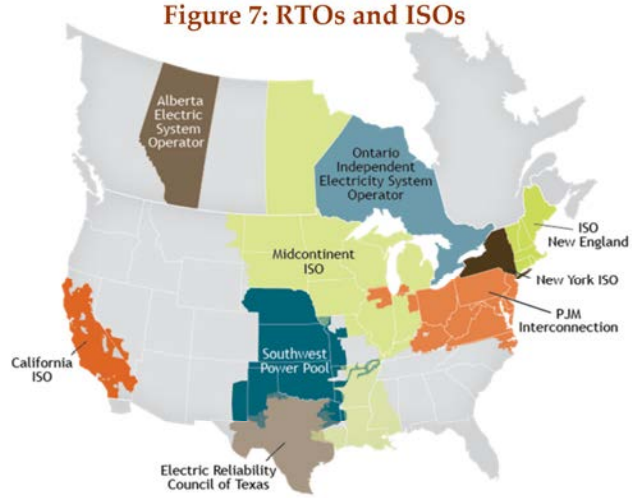
2.1.5 Formation of ISOs and then RTOs

Independent System Operators (ISOs) grew out of Orders Nos. 888/889, issued in 1996, where FERC suggested the concept of an ISO as one way for existing tight power pools to satisfy the requirement of providing nondiscriminatory access to transmission. Subsequently, in Order No. 2000, issued in 1999, FERC encouraged the voluntary formation of Regional Transmission Organizations (RTOs) to administer the transmission grid on a regional basis throughout North America (including Canada).

FERC Order No. 2000 delineated 12 characteristics and functions that an entity, such as an ISO, must satisfy in order to become a RTO, including four minimum characteristics: (1) independence from market participants; (2) appropriate scope and regional configuration; (3) possession of operational authority for all transmission facilities under the RTO's control; and (4) exclusive authority to maintain short-term reliability. Voluntary RTOs and ISOs have formed in many regions of the U.S. (see Figure 7), including California (CAISO), Southwest (Southwest Power Pool [SPP]), Midwest (MISO), Mid-Atlantic (PJM), New York (NYISO), New England (ISO-NE), and Texas (ERCOT). Similar organizations operate in the Canadian provinces of Alberta (Alberta Electric System Operator) and Ontario (Independent Electricity System Operator). For ease of reference, the term RTO is used herein to encompass RTOs and ISOs.

RTOs do not own transmission facilities. They operate the transmission system in accordance with NERC and regional reliability criteria on behalf of their member transmission owners, administer the regional OATT, ensure non-discriminatory access to the transmission system, and manage and plan for the reliability of the transmission system. Transmission owners within an RTO continue to be compensated for their transmission investment, and operation and maintenance (O&M) costs through cost-based rates approved by FERC. RTOs also perform transmission planning to ensure that transmission will be reliable as demand grows and generating plants are added or retired throughout their footprint.

Figure 7: RTOs and ISOs



Source: ISO/RTO Council (IRC)

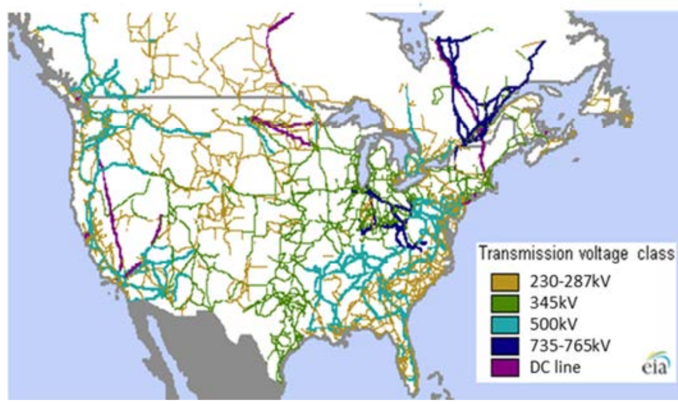
RTOs typically operate regional wholesale energy markets or power exchanges, in which generators offer to provide energy and the lowest cost offers are accepted as long as the transmission system can reliably deliver the power. In these markets, energy prices on the transmission system (locational marginal prices) will vary whenever there is congestion on the transmission system and low-cost power plants in one region cannot fully reach the demand in another. The resulting higher energy prices within congested regions provide an economic signal for new generating plants to be located in the high-priced area, or for additional transmission to be constructed to alleviate the congestion. Most RTOs also provide financial instruments, known as Financial Transmission Rights or Transmission Congestion

Contracts, which allow market participants to hedge the cost of congestion. Managing transmission congestion through these economic signals limits the need for Transmission Loading Relief procedures, in which transactions can be physically curtailed to maintain transmission system security.

2.2 Transmission System Structure and Planning Today

Today, the U.S. transmission system has over 445,000 miles of high-voltage (100 kV and above) transmission lines.[15] Figure 8 shows the transmission lines in North America that are 230 kV and above. The system today remains predominately under cost-based regulation, with transmission owned by individual utilities within defined service territories. While most transmission is owned by vertically integrated utilities that also own distribution systems and often generation, the transmission systems in some service territories are owned by independent transmission companies that hold only transmission assets.

Figure 8. North American Transmission System (230 kV and above)



Source: U.S. Energy Information Administration

Many utility-owned transmission systems are under the operational control of an RTO, while many others remain operated by the individual transmission-owning utilities. There are also merchant transmission lines, in which particular segments of the transmission system are constructed and owned by independent companies, who charge market-based rates for the use of their lines.

Whether part of an RTO or not, transmission systems are planned to reliably meet projected demand on a regional basis. FERC Order No. 1000, issued in 2011, requires each public utility transmission provider to participate in a regional transmission planning process, and coordinate with each neighboring transmission planning region to determine if there are cost-effective solutions to their mutual transmission needs. For a more detailed discussion of the transmission planning process, see Chapter 5.

While the planning of the transmission system is regional in nature, most transmission facilities will continue to be constructed and owned by the local transmission utility. However, FERC Order No. 1000 also instituted rules in which certain types of new regional transmission facilities approved in a regional plan could be constructed and owned by third parties potentially selected under competitive bidding.

2.2.1 Use of DC on the Transmission System

Direct current flows on a wire constantly in only one direction. Alternating current travels in a wave, with the flow of current changing direction back and forth about 60 times per second. Since the majority of the power system is AC, DC systems require a converter to convert power from AC to DC as it enters the DC power line and to reconvert it from DC to AC as it reenters the AC system. Despite the significant expense required for converter stations and the energy lost in the conversion, DC plays an

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important role in the transmission system, including inter-ties between the three U.S. interconnections and in high-voltage lines as shown in Figure 9.

DC Ties. DC ties are used today to connect the three interconnections in the U.S. The power transmitted across a DC tie can be controlled precisely, meaning that the cascading impact of outages that exist within an interconnected transmission network can be "stopped" at the DC tie between two grid interconnections. In effect, while power can flow on the DC ties, the AC waves within the two power grids remain electrically isolated and do not need to be synchronized. There are presently six "back-to-back" AC/DC/AC interconnections between the Western and Eastern Interconnections and two such interconnections between the Texas Interconnection and the Eastern Interconnection.

Figure 9. How DC Is Used Today

- **DC Ties: Inter-ties between the three U.S. Interconnections**
- **HVDC Lines: Long-distance high-voltage lines from one single point to another**

Source: Navigant

HVDC Lines. DC also can be useful for transmitting the electricity long distances from one specific point to another. At equally high voltages, a high-voltage DC (HVDC) line will have smaller power losses than a comparable AC line, which over long distances can potentially more than pay for the required costly converter stations. This is especially true for underwater and underground lines. Moreover, the ability to precisely control the amount of power on a DC line helps ensure that only those that contract and pay for a DC line can transmit power over the line. As a result, many of the recently installed and proposed HVDC lines are "merchant" transmission lines. HVDC lines are in place between the Pacific Northwest and Southern California, Utah and Southern California, North Dakota and Minnesota, and Long Island and Connecticut, among other places.

2.3 *New Expectations for Transmission*

Today, the transmission system is more important than ever, and is being called upon to address many cutting-edge issues, including:

- **Expanded access to power from a diverse portfolio of sources for improved reliability**
  Electricity is provided today by generating plants fired by coal or natural gas, nuclear, and renewables such as hydro, wind, and solar. Each generation resource faces varying risks from environmental regulations, fuel price volatility, intermittency, and maintenance outages. The geographic reach and integration of these sources of generation provided by the transmission system helps mitigate the risks from the use of any single type of power.

- **Expanded opportunities for lower cost power**
  Each of the various sources of generation has a different cost profile, and this cost profile can change over time. The wide footprints of expanded transmission systems allow the lowest cost power at any particular time to be delivered to distant points where it is consumed. The expanded transmission system also allows competitive generation markets to function across broad RTO/ISO regions.

- **Expanded access to mitigate economic ramifications of increasingly stringent environmental regulation**

Coal-fired electric plants in particular are the focus of increasingly stringent environmental regulations, and the economic costs of replacing the plants that may be retired can often be mitigated through transmission interconnections to other available sources.

- **Expanded access to foster state policies regarding renewable energy that may require long-distance transmission**
  Many of the best sources for renewable energy (e.g., wind in the Great Plains or off-shore) tend to require long-distance, extra-high-voltage transmission to deliver the power to distant load centers with limited energy losses. Meeting renewable energy standards thus requires an assessment of both renewable generation sources and the associated build-out of the transmission system.

- **Distribution generation and microgrids**
  Distributed generation, locating small generators at or near where the electricity is used, circles back to the beginning of the electric industry, and given technical advances has the potential to reduce the need for transmission and increasingly provide benefits in energy savings, avoided line losses, and improved power quality. Microgrids use advanced smart grid technologies and distributed energy resources to create localized grids that can operate autonomously if needed, typically during extreme weather events.[16] The interplay between transmission, microgrids, and distributed generation will be an important economic and policy issue facing state regulators in the upcoming years.

3 Federal Energy Regulatory Commission Policy and Rules

3.1 FERC Jurisdiction and Legal Requirements

Under the Federal Power Act, FERC regulates the transmission of electric energy and the sales of electric energy at wholesale in interstate commerce by public utilities. For FERC purposes, "public utility" is defined by the statute as "any person who owns or operates facilities subject to the jurisdiction of the Commission" which are those "facilities used for the transmission of electric energy in interstate commerce or for sales of electric energy at wholesale in interstate commerce."[17]

FERC does not regulate government-owned utilities or most cooperatives, which are often referred to as "non-jurisdictional" entities. Due to limited or nonexistent transmission connections with other states, the Texas Interconnection, along with the entire states of Alaska and Hawaii, are not subject to FERC regulation. Areas considered outside of FERC's responsibility include regulation of the provision of retail electricity to consumers and approvals for the physical construction of electric generation, transmission, or distribution facilities.

Figure 10: Key Transmission-Related FERC Orders

1996: Order No. 888 requires open-access transmission tariffs

1999: Order No. 2000 establishes requirements for RTOs

2006: Order No. 679 establishes incentives for transmission infrastructure investment

2007: Order No. 693 approves first set of legally enforceable NERC reliability standards.

2007: Order No. 890 requires coordinated, open and transparent regional transmission planning processes

2011: Order No. 1000 requires:
- Transmission providers to participate in regional plans
- Neighboring regions to coordinate transmission plans
- Regional and interregional cost allocation methods
- Elimination of ROFR for regional transmission projects

Source: Navigant

Under Section 205 of the Federal Power Act (FPA), the rates, terms, and conditions for interstate transmission filed at FERC must be "just and reasonable" and "not unduly discriminatory or preferential". In practice, this means that rates must be based on a regulated cost of service or the result of a competitive market, and similarly situated customers must be treated similarly. In approving rates, terms, and conditions, unlike state public utility commissions (PUCs), FERC is not required to determine the best outcomes or balance the interest of parties.

3.2 FERC Policy to Prohibit Discriminatory Use of the Transmission System

Key transmission-related FERC Orders over the last two decades are summarized in Figure 10. Because access to the transmission system is required for generating plants to deliver and sell power to wholesale customers, FERC is particularly concerned with discriminatory use of the transmission system. In a competitive marketplace, access to transmission has the potential to be used to limit the participation of independent generators. Since 1996, under FERC Order No. 888, transmission owners have been required by FERC to offer open access to their systems under a standardized cost-based Open-Access Transmission Tariff. Through the OATT, independent generators and their wholesale customers can reserve transmission to serve their needs on any available transmission path. Since 1996, many non-jurisdictional transmission-owning entities have voluntarily submitted OATTs under a "reciprocity" approach, in which FERC conditions the use of open-access services to those entities that offer comparable transmission services in return.

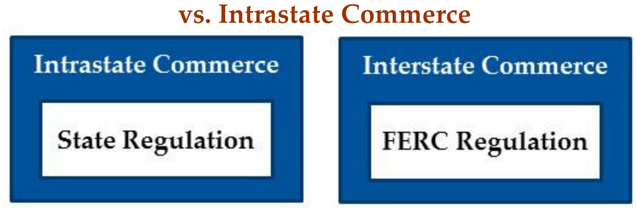
Available transfer capability (ATC) is the transfer capability remaining on a transmission provider's transmission system that is available for further commercial activity over and above already committed uses. ATC is a critical factor in assessing whether a specific competitive purchase or sale of energy using the provider's transmission system can be made at any given time. While determining whether a transmission path has available capacity might appear to be a straightforward examination of existing contracts, electricity on the interconnected transmission network flows according to physical laws, not contracts. Available path capacity is dependent on a number of factors, including the transmission lines in-service and where electricity is being generated and used. This makes the ATC calculations reliant on non-public information about ongoing system operations.

In response, FERC requires that transmission operations must be kept functionally separate for transmission owners that also own generation or distribution, and that any information passed out by the transmission owner must be publicly posted for all entities to see. Functional separation is designed to help prevent a transmission owner from providing preferential access to its transmission system. In Order No. 890 issued in 2007, FERC addressed and tightened a number of rules to address potential discrimination by transmission providers, including a requirement for consistent and transparent calculations of ATC, and a coordinated, open, and transparent planning process.

3.3 Regulatory Authority and the Overlap Between Wholesale and Retail Markets

The allocation of regulatory authority between the federal government and the states is distinguished by what constitutes *inter*state and *intra*state commerce (see Figure 11). State regulation extends to most areas of utility operations, rates, and end-user issues (intrastate commerce). Federal regulation generally relates to the wholesale side of the utility business, including interstate transmission and sales of electricity for resale.

Figure 11. Regulation of Interstate vs. Intrastate Commerce



Source: Navigant

Defining what is and what is not interstate commerce when considering an interconnected transmission system makes the allocation of regulatory authority between the federal government and the states complicated. In Order No. 888, FERC established a seven-factor test for identifying local distribution facilities that would not be classified as transmission. These factors include proximity to retail customers; lines that are generally radial in character; facilities in which power flows in, but rarely out; where power is not transported on to another market; and lower voltages.

Under Order No. 888, FERC regulates unbundled transmission transactions for FERC-jurisdictional public utilities. That is, if transmission service is charged to retail customers through a distinct rate

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separately from other services, FERC regulates the rate that is charged. In contrast, if transmission services charges to retail customers are bundled together in retail rates with other services, such as generation or distribution services, the states continue to regulate this bundled retail rate (see Chapter 6).

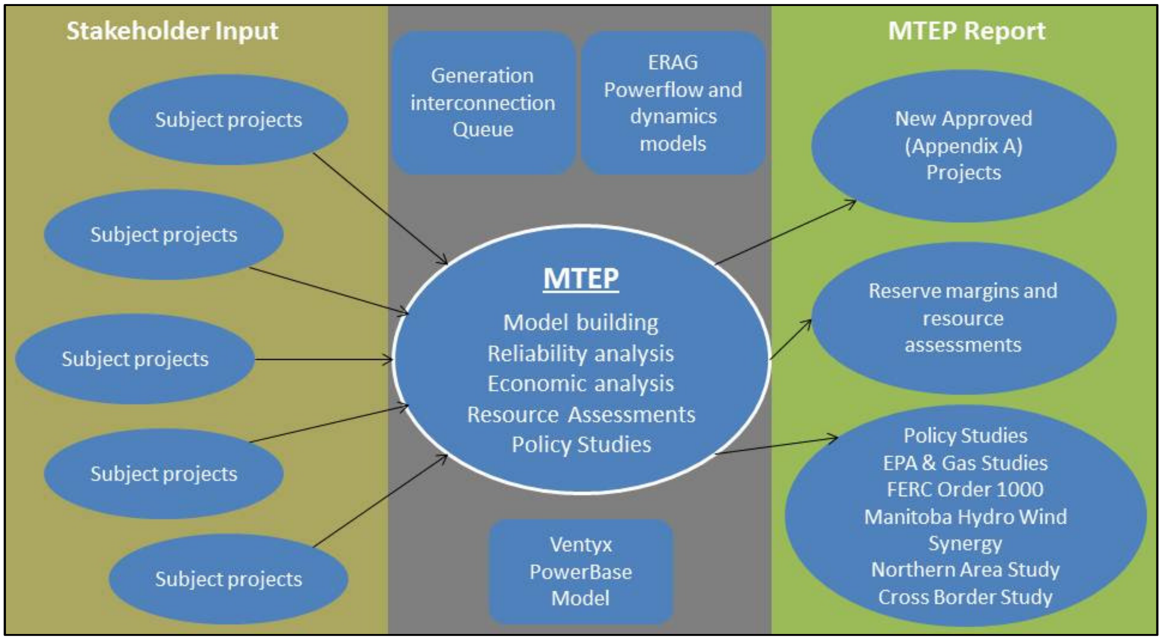
3.4 FERC Transmission Investment Incentives

The Energy Policy Act of 2005 added a new section, 219, to the Federal Power Act. FERC implemented section 219 by issuing Order No. 679, which established incentive-based rate treatments for new transmission capacity seen as particularly challenging to construct. These projects include those that apply new technologies, relieve chronic or severe grid congestion, or allow access to the wholesale market for constrained generation resources. The incentives have included higher returns on equity, rate recovery during the construction period, and other items. In the first six years of Order No. 679, FERC evaluated more than 85 incentive applications representing over $60 billion in transmission investment. These incentives have created some concerns with state regulators about the resulting rate impact of the incentives on retail customers, and ensuring that transmission is evaluated on an equal footing with generation, demand response and other options in resource planning. Over time, FERC has continued to clarify and adjust its transmission incentive policies.[18]

3.5 FERC and Broad Regional Transmission Planning

In the last decade, transmission planning has begun to encompass broader regions. In areas where RTOs have formed, transmission planning is coordinated through centralized processes administered by the RTO, including, for example, the annual Midcontinent Independent System Operator, Inc. (MISO) Transmission Expansion Plan (MTEP) and PJM's annual Regional Transmission Expansion Plan (RTEP). Transmission upgrades to mitigate identified reliability criteria violations, provide increased market efficiency, or facilitate public policy objectives such as Renewable Portfolio Standards (RPS) are examined in the RTO transmission plans for their feasibility, impact, and costs, culminating in one plan for the entire RTO footprint. The process steps used to create the MISO MTEP are illustrated in Figure 12. A more detailed discussion of transmission planning can be found in Chapter 5

Figure 12. The MISO MTEP Process



Source: MISO

FERC, in Order No. 890 issued in 2007 and Order No. 1000 issued in 2011, further advanced the regional transmission planning process. FERC Order No. 890 promoted increased, open, transparent, and coordinated transmission planning on local and regional levels. Under FERC Order No. 1000, transmission planning regions must have in place processes to coordinate planning with neighboring transmission planning regions to evaluate inter-regional solutions that may be more efficient or cost-effective than regional solutions. For projects selected in the regional processes that involve one or more regions pursuant to these inter-regional procedures, a cost allocation process between the regions must be in place. Other than the required coordination process, there is no requirement to produce a formal inter-regional transmission plan.

FERC Order No. 1000 also envisions transmission developers competing for the right to build certain types of new transmission facilities. For transmission projects subject to regional cost allocation that are not upgrades to existing facilities, FERC determined that incumbent utilities may not have a right of first refusal (ROFR) to construct these facilities.[19] The Order allows, but does not require, competitive bidding for potential solutions to an identified transmission need.

In Order No. 1000, FERC stated that the requirements of the Order do not affect state regulations regarding the construction of transmission facilities, including authority over siting or permitting. Implementation of Order 1000 is ongoing, and a number of important questions regarding the interrelationship between state authority over transmission siting, inclusion of new projects in a regional transmission plan, and the integrated resource planning of generation and transmission at the state level, will be addressed by federal and state policymakers.

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For a description of key policies and orders related to the history and evolution of FERC, see Appendix G.

3.6 NERC Rules

FERC also oversees NERC as the ERO under the Federal Power Act. In turn, NERC delegates compliance monitoring and enforcement oversight to its eight regional entities (see Figure 5 in Chapter 2). The Reliability Standards are grouped into broad categories relating to the operation and planning of the NERC-defined Bulk Electric System (BES). The BES is generally comprised of transmission elements operated at a voltage of 100 kV or above, and does not include facilities used in the local distribution of electric energy. The BPS as defined in the Federal Power Act is distinct and more expansive than the BES as defined by NERC.[20]

Within the United States, other than Alaska and Hawaii, all users, owners, and operators of the BES must comply with the Reliability Standards. Currently, there are more than 100 Reliability Standards applicable and mandatory. For a description of key NERC policies and rules, as well as potential changes in these policies, see Appendix H.

3.7 Related DOE Policies

While the majority of siting authority currently lies with the states, there are instances where federal approvals are required. The Energy Policy Act of 2005 established a limited role for the U.S. Department of Energy (DOE) and FERC in transmission siting. The act directed DOE to conduct triannual congestion studies within the Eastern and Western interconnections and allowed DOE to designate "transmission corridors" in locations that had "national interest" implications. The act also granted FERC secondary authority over transmission siting in these corridors, which may not be exercised by FERC unless the state where the facility would be sited lacks the authority to issue the permit or the state has withheld approval of the permit for more than one year (see Chapter 4 for more detail). DOE also funds and promotes new transmission technologies and issues permits for international cross-border transmission lines. For a further description of key DOE policies, see Appendix I.

4 Process for Building a Transmission Line

Historically, transmission lines were planned by local utilities to serve local needs. The lines seldom crossed state borders as they were designed to deliver electricity from power plants to load centers. Over time, transmission lines were constructed to interconnect with neighboring utility systems to increase reliability and for access to lower cost electricity.

Today, with the emergence of regional transmission planning, "Planning Coordinators" integrate and evaluate transmission plans within their NERC-defined regions. New transmission lines can be developed by the local utility or an independent "merchant" transmission developer. While the process for building a transmission line has evolved, the basic steps are familiar:

1. A need for a new transmission line is identified in the transmission planning process by conducting technical and economic studies.
2. The transmission developer does the following:
    a. Performs a study of possible siting routes for the identified transmission line
    b. Seeks permission from state and federal agencies to build the line
    c. Obtains financing for the line and builds the line

Transmission planning is the process of identifying areas of the current transmission grid that are in need of expansion to maintain reliability and to accommodate new generation and/or growing load. Planning is the big picture process of assessing the robust nature and reliability of the grid, and is discussed in greater detail in Chapter 5. In contrast, transmission siting is the process of determining specifically where new transmission projects will be located. It includes considerations such as investigating environmental impacts, obtaining rights-of-way, and complying with local zoning ordinances. Siting becomes a particularly complex process when a line crosses through two or more states, across federal lands, protected ecosystems or in scenic or historic areas.

Building a transmission line requires the involvement of a number of parties, including state and federal authorities, Planning Coordinators, utilities, merchant transmission developers, and affected stakeholders. The role played by each of the parties in this process is discussed in turn below.

4.1 Role of State Authorities

The primary regulatory responsibility for the siting of transmission lines resides with the individual states. Each state has its own process for granting permission to build power lines. State siting approval allows the transmission developer to build a transmission line and if necessary to use the power of eminent domain to do so. Eminent domain is the power to take private property for public use following the payment of just compensation to the owner of the property. New transmission lines are rarely popular with nearby residents, and alternative routes are sometimes proposed that may cover more distance or cover more difficult terrain. Public utility commissions or dedicated state siting authorities must consider a number of factors, including the overall need for a new transmission line, environmental impacts, property rights, and cost.

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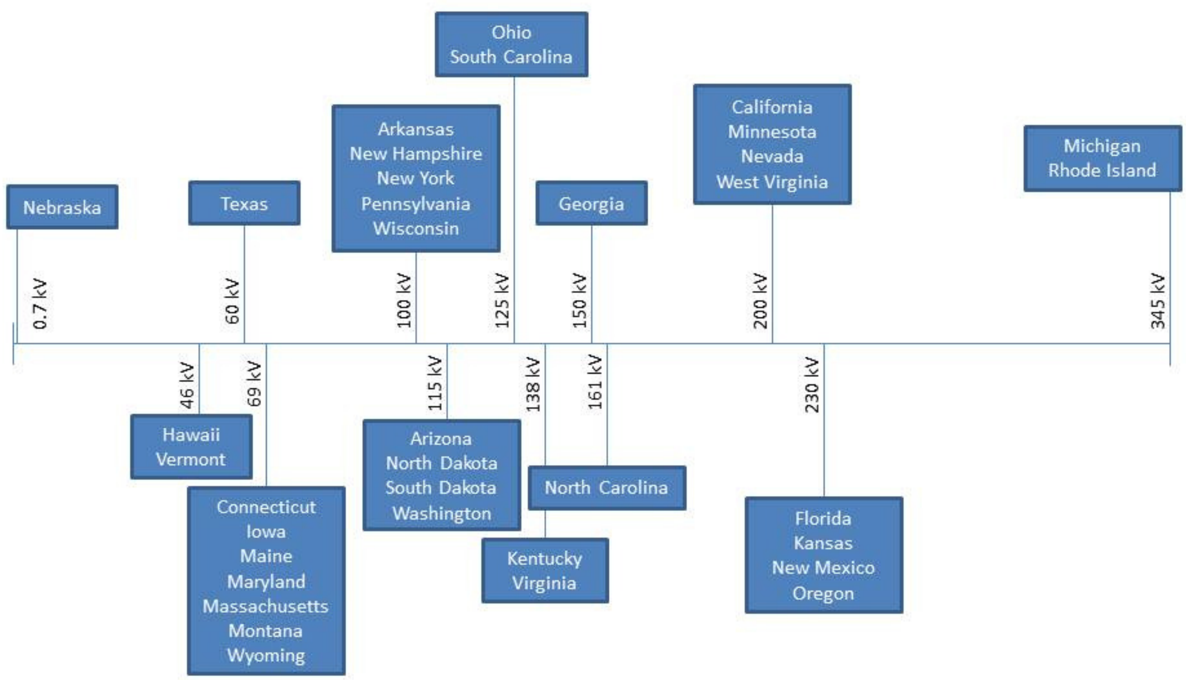
A mix of state and local government agencies wield jurisdiction over the siting approval process in each state, and there is no universal approach to the way states approve the siting of new transmission lines. For example, a number of states consolidate siting approval under a single agency, such as a PUC. Some states, such as Connecticut and Ohio, have a dedicated energy siting authority that approves major generation and transmission facilities. In a few states, utilities are required only to give notice of intent to build a transmission line; after a specified period, if no challenges are raised, the utility may proceed with acquisition of any needed rights-of-way and construction. Other states use a voltage or size threshold such as 100 or 200 kV for siting approvals to be required, as illustrated in Figure 13. Most states require that hearings be held in the affected counties or towns. In certain states, there is a statute with a specific period of time to review and rule on the siting application.

Figure 13. Summary by State of Line Voltage Thresholds for Requiring Permitting



Source: Navigant (data from Edison Electric Institute, State Generation & Transmission Siting Directory. October 2013)

Although state siting and permitting processes vary, there are some commonalities. Transmission developers submit an application to the state that includes an analysis of the need for the new line (e.g., to ensure grid reliability or connect new generation), cost estimates, and at least one proposed route. The state approval process often begins with granting overall approval for the line and any necessary environmental permits. The commission or siting authority in the state holds hearings, usually in one or more of the impacted communities, to determine the exact route of the line, addresses landowner and community concerns, and discusses alternatives to the transmission developer's proposed route.

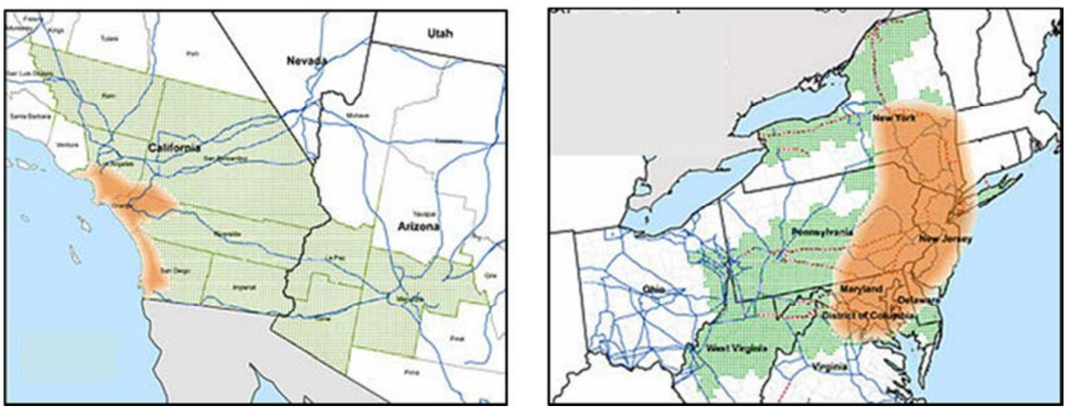
Most states combine their need and siting approvals into one decision from the PUC or siting body. For lines that cross private land, the state's siting body often has the power to grant eminent domain authority to the transmission developer, a power often assigned with the siting certificate.[21]

See Appendix B for additional information on the siting approval processes in the various states.

4.2 Role of Federal Authorities

National Corridors. Under the Energy Policy Act of 2005, which added section 216 to the FPA, FERC has the authority to consider a transmission line application and issue a permit to construct electric transmission facilities located in a National Interest Electric Transmission Corridor (National Corridor). DOE has identified two National Corridors, one in the Mid-Atlantic area and one covering Southern California and part of western Arizona (the green and orange shaded areas in Figure 14). In 2011, the U.S. Court of Appeals for the Ninth Circuit vacated DOE's National Corridor designations and remanded the cases to the DOE for further proceedings.[22]

Figure 14. Southwest and Mid-Atlantic National Corridors



Source: DOE

For a proposed National Corridor project, FERC has permitting authority (sometimes referred to as "FERC backstop siting authority") if a state withholds siting approval for more than one year, does not have the authority to site transmission facilities, or cannot consider interstate benefits. The backstop authority cannot be exercised if a state commission denies an application to site a transmission facility within one year after the date the application is submitted, even though the facility would be located within a national interest transmission corridor.[23] If the proposed facilities are located in a state that has authority to approve the siting of the facilities and consider its interstate benefits, the project developer must file an application with that state. The developer must be engaged in the state process for at least one year prior to initiating a filing process with FERC.

As part of the process, FERC staff conducts an environmental analysis to identify the potential environmental impacts of the proposed project and reasonable alternatives as required by the National Environmental Policy Act (NEPA). Under NEPA, FERC is required to analyze all reasonable alternatives, even if the alternative does not fall under FERC's jurisdiction. Thus, FERC can look at a wide range of non-transmission alternatives (e.g., local generation, DSM, and energy storage), in addition to transmission line route alternatives, as part of the environmental review process. In order to issue a permit, FERC must find that the proposed project does the following:

- Is located in a National Corridor designated by DOE
- Is in the public interest
- Will significantly reduce transmission congestion and protect and benefit consumers
- Is consistent with sound national energy policy and will enhance energy independence

Presidential Permits. DOE is responsible for reviewing presidential permit applications and determining whether to grant a permit for electric transmission facilities that cross the U.S. international border. A presidential permit authorizes the applicant to construct, operate, maintain, and connect the U.S. portion of the project at the international border. Applications for presidential permits are evaluated based on the impacts that a project could have on the environment pursuant to NEPA and the operating reliability of the U.S. electric system.

Federal Land. For new transmission lines that cross federal land, additional federal approvals are required. DOE coordinates a Rapid Response Team for Transmission comprised of nine federal agencies, including FERC, the U.S. Environmental Protection Agency (EPA), and the Departments of Interior, Agriculture, Commerce, and Defense, to expedite the federal approvals needed for the siting of transmission.

4.3 Role of Planning Coordinators

Historically, utility control areas were established by vertically integrated utilities to operate their individual power systems in a secure and reliable manner and provide for their customers' electricity needs. The traditional control area balanced its load with its generation, implemented interchange schedules with other control areas, and ensured transmission reliability. Balancing load with generation required that control area generation plus net interchange energy (energy imported from neighboring utilities minus energy exported) matched at all times the control area demand for electricity. In general, transmission planners for each control area ensured that: (1) reliability would be maintained during contingency conditions, and (2) no cascading outages (outages that cannot be restrained from spreading to other areas) would occur during credible multiple contingency conditions.

As utilities began to provide transmission service to other entities, the control area also began to perform the function of transmission service provider through tariffs or other arrangements. Beginning in the early 1990s with the advent of open transmission access and restructuring of the electric utility industry to facilitate the operation of wholesale power markets, the functions performed by control areas began to change to reflect the newly emerging industry structure. In particular, the developing power markets were requiring regional transmission reliability assessment and dispatch solutions beyond the functions that utility control areas had traditionally performed.[24]

In response, NERC formally created the role of Planning Coordinators (also known as Planning Authorities) that include RTOs, government power authorities, and electric utilities who have taken on the responsibility of coordinating, facilitating, integrating, and evaluating transmission facilities. Today, there are approximately 80 NERC Planning Coordinators, 10 of which are ISOs/RTOs.[25] Each Planning Coordinator is responsible for assessing the reliability of its assigned region, and coordinating planning with adjoining regions.

Planning Coordinators evaluate, develop, document, and report on expansion plans for each individual transmission planning area within the Planning Coordinator regional boundaries. The Planning Coordinator must also assess whether the integrated transmission plan meets reliability needs, and, if not, provide alternative solutions.

4.4 Role of Utilities

Most transmission lines continue to be developed and owned by utilities operating under cost-of-service rates. The utility is responsible for seeking permission to build the new line from the appropriate state and local authorities, and for providing a demonstration of need and the appropriateness of the proposed route. The demonstration of need for the line often comes through the analysis and recommendations included in the regional transmission plans in which the utility operates and/or through an integrated resource planning (IRP) process, which simultaneously considers all resource options available to the vertically integrated utility (see Chapter 5). Once approved, the utility must raise the funds to construct the line, generally through a combination of internal cash flow and the issuance of bonds, and engage and oversee contractors to design and build the line.

The utility generally will act as the transmission planner for its local area within a Planning Coordinator's regional boundaries. The utility will work closely with the Planning Coordinator to integrate its local transmission planning process with the regional process. Transcos that own the transmission system in some service territories under FERC-regulated cost-of-service ratemaking follow the same process as vertically integrated utilities when seeking siting approval for a new line. FERC has defined a Transco as a stand-alone transmission company that has been approved by FERC and that sells transmission services at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility.[26]

4.5 Role of Merchant Transmission Developers

Merchant transmission providers are private companies that finance and own transmission facilities independent of generation developers or customer-serving utilities. Merchant transmission projects are defined as those for which the costs of constructing the proposed transmission facilities are recovered through negotiated rates instead of the cost-based rates used by utilities.[27] Like utility projects, merchant transmission projects must obtain state (and federal) siting approval. Unlike utility projects, merchant transmission providers must recoup their costs through access charges paid by generators and/or load-serving utilities. Given the need to control access to the line to those that are paying for the line, merchant transmission projects have been largely comprised of long-distance or submarine HVDC lines since their inception in the last decade.

Merchant transmission developers face the same state siting approval process as utilities, although the regulatory agencies involved and filing requirements may differ somewhat. For example, Kentucky has a separate state siting board for merchant projects. Given the long-distance and/or undersea nature of many merchant transmission projects, federal siting approvals are often required as well.

4.6 Impact on Roles from FERC Order No. 1000

As discussed in Chapter 3, under FERC Order No. 1000, the potential solutions for meeting regional transmission needs may become subject to competitive bidding by utilities and merchant transmission developers, although such bidding is not required. In response, the ownership profile of the transmission system in any particular region may become increasingly comprised of multiple parties.

FERC Order No. 1000 defined several terms to help better capture these multiple roles. FERC defined an "incumbent transmission developer/providers" as an entity that develops a transmission project within its own retail distribution service territory or footprint. [28] The use of the phrase "or footprint" is meant to convey that an entity can be an incumbent transmission provider/developer without having a retail distribution service territory.[29] As such, a Transco (see definition in Section 4.4) that owns the transmission system in a specific service territory would be the incumbent transmission provider in that service territory.

FERC defined a "nonincumbent transmission developer" as an entity that either: (1) does not have a retail distribution service territory or footprint; or (2) is a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint.[30] Merchant transmission developers, which recover costs through negotiated rates instead of cost-based rates, are a subset of nonincumbent transmission developers.[31] Nonincumbent transmission developers also include developers who recover costs through FERC-approved cost-based rates.

5 Transmission Planning

Transmission planning is the process of identifying areas of the current transmission grid, or Bulk Electric System, that are in need of expansion to cost-effectively maintain reliability and accommodate new generation and/or growing load. The BES is generally comprised of transmission elements operated at 100 kV or above, and does not include the distribution system.[32]

Figure 15. Planning Elements for Maintaining System Reliability

Transmission Security: The transmission system can continue to operate normally even when there is a generating plant or transmission line outage.

Resource Adequacy: Sufficient generating and demand-side resources are available to meet the electric demand of end-use customers at all times.

Source: Navigant

As shown in Figure 15, there are two basic planning elements for maintaining the reliability of the Bulk Electric System—transmission security and resource adequacy. Transmission security ensures reliable system operation in the face of contingencies such as the loss of generation or transmission. Resource adequacy ensures that there will be adequate generation or demand-side resources to meet the aggregate electric energy demand requirements of customers at all times.[33] Each planning element is discussed in turn below.

Transmission Security. The transmission system is expected to maintain its integrity and continue to operate without a major disruption even when a component fails. The security of the transmission system is primarily achieved by ensuring that the outage of any single system component will not cause a cascading outage (an outage that cannot be restrained from spreading to other areas). A system that is resistant to the outage of any one component is said to be "N-1" secure.[34] Additionally, the system should remain within the applicable emergency thermal ratings and voltage limits (see Chapter 7) after an additional single contingency (N-1-1) condition.[35] N-1 security is fundamental to system operation and achieving this level of security is generally accepted to be required, regardless of cost. However, once the goal is to make the system N-2 or N-3 secure (resistant to the outage of any 2 or 3 components), cost and other similar considerations enter the picture. Operators have traditionally handled the threat of multiple contingencies adaptively. For example, operators may dispatch more generation closer to loads when storms approach and the likelihood of an outage increases.[36]

Resource Adequacy is defined as the ability of the electric system to supply the aggregate electric demand and energy requirements of end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages on the system. Underlying most resource adequacy standards (for example, in setting a target margin) are criteria set by the NERC Regional Entities, typically a "1 day in 10 years Loss of Load Expectation (LOLE)".[37] LOLE means the expected number of days in the year when the peak demand exceeds the available generating and demand-side resources. The utility industry, for decades, has used a LOLE of one day in ten years as the primary means for setting target reserve margins and capacity requirements in resource adequacy analyses. Fundamentally, a LOLE reliability standard involves evaluating the trade-off between the cost to

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customers of installing and maintaining additional back-up resources in comparison to the cost to customers of incurring additional electricity outages.[38]

5.1 Interrelated Nature of Transmission Planning

Transmission security has historically been the primary focus of transmission planning, while resource adequacy has historically been the primary focus of resource planning—the planning of adequate supplies of generation and demand-side resources. For example, the analysis supporting a recommendation by a vertically integrated utility to build a new gas-fired generating plant to meet a forecasted increase in the demand for electricity by retail customers on the utility's system would be an example of traditional resource planning. The additional transmission facilities that might be needed to keep the transmission system stable and secure with the new gas-fired plant in service would be an example of traditional transmission planning. For this traditional type of transmission planning, the planning horizon has been typically shorter than that used for resource planning.

Over time, transmission has become planned more formally in an integrated manner with resource planning, as the least-cost, most reliable solution for meeting electricity demand can include generation, transmission, and/or demand-side resources. For example, building generation within a congested transmission area or "load pocket" may be less expensive than building new transmission facilities to mitigate the congestion. Building long-distance transmission lines to gather energy from distant renewable resources must consider both the cost of the transmission line and the cost and efficiency of the distant renewable resources in comparison to the cost and efficiency of nearby renewable resources. Building transmission to support a gas-fired power plant at a distant location may be less economical than building a gas pipeline to allow the gas-fired power plant to be located closer to the load.

In non-RTO regions, the interrelationship between generation, transmission, and demand-side resources is generally handled through an IRP process, which simultaneously considers all options available to the vertically integrated utility. In an RTO region, with multiple parties owning generation, transmission, and serving load, the RTO planning process assesses the impacts of forecasted firm loads, existing generation and transmission assets, and anticipated new generation and transmission facilities to integrate transmission options with generation and demand response projects. See, for example, the MISO MTEP process described in Section 3.5, Figure 12.

5.2 Reliability and Efficiency in Transmission Planning

The objective of transmission planning is to evaluate transmission investment options to reliably and economically deliver power from generation sources to anticipated loads. The relationship of these two key drivers of transmission planning, reliability and economic efficiency, in planning for the transmission security and resource adequacy of the Bulk Electric System, is illustrated in Table 1, and discussed in turn below.

Table 1. Planning for the Bulk Electric System

	Transmission Planning	Resource Planning
Reliability	*Transmission Security:* Contingencies Will Not Cause Cascading Outages	*Resource Adequacy:* Enough Generation and Demand-side Resources to Meet Customer Demand
Economic Efficiency	*Integrated Planning* of Transmission with Generation and Demand-side Resource Alternatives to Minimize Costs	

Source: Navigant

Reliability in Transmission Planning. Reliability analyses are conducted to help ensure the security of the transmission system in serving all existing and projected firm transmission use, including existing and projected native load growth as well as firm transmission service. These studies typically extend 10 to 15 years into the future and variously entail single and multiple contingency testing for violations of established NERC reliability criteria regarding stability (the ability of the system to remain stable if a disturbance such as a generating unit outage occurs), thermal line loadings, and voltage limits (see Chapter 7). Regional and local reliability criteria may also be applicable in certain areas. Areas not in compliance with the standards are identified and enhancement plans to achieve compliance are developed. Transmission upgrades to mitigate identified reliability criteria violations are then examined for their feasibility, impact, and comparative costs, culminating in a recommended plan.

Economic Efficiency in Transmission Planning. Transmission planning for economic efficiency focuses on building new transmission lines designed primarily to achieve the economic delivery of power rather than ensuring reliability. Transmission facilities that economically relieve historical or projected transmission congestion and allow lower-cost power to flow to consumers are often candidates. In evaluating a proposed project's economic benefits, the reduction in the costs of supplying electricity and, in an RTO, the prices paid by load-serving entities are examined through production cost modeling across all hours of the year. In an RTO, a proposed transmission solution's economic savings typically must exceed its projected costs by at least 25 percent to be recommended.[39] In vertically integrated markets, integrated resource planning assesses resource options considering both the cost of generation and the transmission expansion needed to access the resource and dispatch it economically.

Reliability projects are proposed because reliability standards are projected to be violated. Economic projects are proposed not because reliability standards are violated, but because there is an economic benefit. In some regions, more comprehensive "multi-benefit" evaluation approaches are being developed to evaluate proposed transmission projects that incorporate standard reliability and economic efficiency measures, but also consider such items as avoided energy and capacity costs due to reduced physical losses and the value provided in limiting costs during times of extreme events and system contingencies.

5.3 Risk Analysis in Transmission Planning

Traditional transmission planning methods are typically deterministic; that is, outcomes are precisely determined through known relationships among states and events, without any consideration of random variation or uncertainty regarding key parameters. A power system model representing the transmission and generation system is developed. The model has the ability to show how the system responds to things such as increases in load, addition or removal of generation sources, and addition or removal of transmission elements. The model indicates when parts of the system are stressed beyond their safe operating limits. Certain inputs to the model, such as the initial conditions assumed for the period to be tested, are developed by transmission planners based on power system conditions and their experience.

The risk created by uncertainty is typically assessed with scenarios, such as an evaluation of a high and low demand case. Under a deterministic approach, contingencies are considered, but not the probability of occurrence. For example, the N-1 criterion requires that the system be able to tolerate the outage of any one component. Even if an outage or contingency is highly unlikely, the criterion is still generally applied because system failure when a component is lost is unacceptable.[40]

While deterministic methods serve the industry relatively well, fundamental changes in the use of transmission have led to an increased focus on evaluating risk in transmission planning. For example, the Western Electricity Coordinating Council provides an option to member systems to categorize their N-1, N-2, and N-3 contingencies based on the historical frequency of outages of the transmission facilities. These fundamental changes in the use of transmission include the increasing cost of transmission facilities, uncertainties concerning the location of new resources and retirement of older generators, increasingly stringent environmental regulations requiring changes to the resource mix, the need to integrate large amounts of variable energy resources, more dynamic electric loads, and the lead times to construct major facilities.

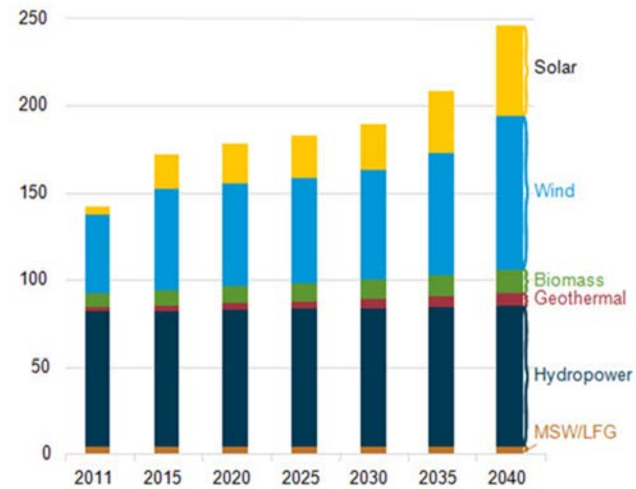
These fundamental changes have together led to significantly more complex and less predictable use of transmission facilities, thereby increasing risk. Risk-based approaches include information on the likelihood of an event occurring along with the magnitude of the event. Industry research is underway to better understand and assess risk in performing transmission planning, and risk analysis is likely to become an increasingly institutionalized part of transmission planning in the future.

5.4 Transmission Planning and Intermittent Resources

As public policies and regulations on greenhouse gas emissions and Renewable Portfolio Standards (RPS) are developed throughout North America, and as the economics of renewable resources continue to improve, the addition of renewable generation into the bulk power system is expected to grow considerably. As shown in Figure 16, the U.S. Energy Information Administration (EIA) projects that solar and wind capacity will increase by 46 and 42 gigawatts (GW), respectively, by 2040. This increasing commitment to renewable resources offers benefits such as new generation resources, fuel diversification, and greenhouse gas reductions. However, renewable commitments present significant new challenges to maintaining bulk power system reliability, as the expected significant increase in variable generation additions likely will increase the amount of uncertainty faced by a system operator.[41]

Reliably integrating high levels of variable resources (wind, solar, and some forms of hydro) into the bulk power system will require significant changes to traditional methods used for system planning and operation. To improve system reliability, the industry has already begun development of new planning methods and techniques that include the characteristics of variable generation assets. For example, storage technologies, if economical and properly planned and implemented, can provide the flexibility to accommodate large amounts of variable resources as an alternative to the construction of more conventional flexible generation resources or transmission.[42]

Figure 16. EIA Projection of Renewable Electric Generation Capacity by Energy Source (gigawatts)



Source: EIA Annual Energy Outlook

Large-scale integration of variable generation likely will increase the short-term variability of the supply of generation and the uncertainty of future system conditions. To ensure reliability, transmission facilities will be expected to interconnect variable energy resources, accommodate the variable generation output across a broad geographical region and resource portfolio, and allow the delivery when needed of back-up generation to equalize supply and demand.

At low variable generation penetration levels, traditional approaches toward sequential expansion of the transmission network and managing wind variability in Balancing Authorities may be satisfactory. However, at higher penetration levels, a regional and multi-objective perspective for transmission planning, including the identification of concentrated variable generation zones, may be needed.[43]

In particular, larger balancing areas or participation in wider-area balancing management may be needed to enable high levels of variable resources, thereby allowing impacts on resources facing unfavorable weather in one area to be mitigated by resources in the broader region facing normal and/or favorable weather conditions. New transmission planning models will be needed to optimize new technologies, such as storage, demand response, and the incorporation of flexible resources.

5.5 Current and Future Transmission Planning Models

Commonly used transmission models today include, among others, Power System Simulator for Engineering (PSS/E) and Positive Sequence Load Flow (PSLF) transmission planning software licensed from Siemens PTI and GE, respectively. These and other similar programs, e.g., PowerWorld, simulate, analyze, and optimize power system performance. Transmission planners use these tools to satisfy a variety of NERC and approved regional compliance requirements. Using these models, transmission planners can analyze transfer limits and simulate the transfer of large blocks of power across the transmission grid and the import or export of power to neighboring systems.

Although some of the existing transmission planning software allow probabilistic analysis, future transmission planning tools are likely to more fully incorporate probabilistic risk analysis, including capturing the impact of uncertainty associated with generating unit and transmission system performance, weather-related demand volatility, resource intermittency, economic growth, fuel prices, and public policies. Full co-optimization of resource (generation and demand response) and transmission planning within one planning model is a longer-term objective, likely requiring advancements in simulation software, credible input data for probabilities, and additional research.

A common understanding among grid operators/planners, as well as confidence in simulation tools results, is predicated on an accurate and shared database regarding key parameters and capabilities of existing and planned facilities. Further development and refinement of a shared data set with mechanisms regarding timely updates and accountability for accuracy from owners/operators will help improve the efficiency and effectiveness of grid operations and long-range planning.

6 Paying for Transmission

Transmission is ultimately paid for through the rates charged to end-use customers. For retail customers, transmission typically represents only about 10 percent of their total bill.[44] The process by which the cost of building and maintaining transmission facilities is recovered in rates is made more complex by the interconnected nature of the transmission system and the overlapping transmission rate responsibilities of federal and state authorities. Whether and how much customers located in one area should pay for the cost of interconnected transmission facilities located in another area is often subject to contention. Transmission ratemaking is further complicated by the fact that electricity travels through the transmission system according to physical laws and not on a defined "contract path" from one point directly to another.

Summarized below is a basic overview of how rates are set to recover transmission costs, followed by a review of how regional transmission project costs are allocated to end-use customers.

6.1 Rate Recovery

6.1.1 Retail Rates for Transmission

For vertically integrated utilities charging bundled rates (generation, transmission, and distribution costs recovered together as a bundled rate) to their retail customers, the bundled retail rates are set by the state public utility commission, as FERC has not claimed jurisdiction over the pricing of transmission within bundled retail rates.[45] Typically, along with the utility's retail customers, wholesale transmission customers also will use the utility's transmission system. A retail allocation factor will be developed (e.g., share of peak demand on the transmission system) to allocate a share of the utility's transmission assets and operating costs to retail customers in deriving bundled retail rates.

For utilities charging an unbundled transmission rate directly to retail customers, the retail rate will fully recover the charges to retail customers incurred under the utility's FERC-approved Open Access Transmission Tariff. Unbundled retail rates are typically instituted in states with retail open access, whereby retail customers are permitted to shop for electricity from retail energy suppliers other than the incumbent utility and have the incumbent utility or local distribution company deliver the electricity (see Figure 17).[46] Depending on the state, the utility's FERC-approved OATT charges may be collected from retail customers by the local utility or the alternative retail energy supplier.

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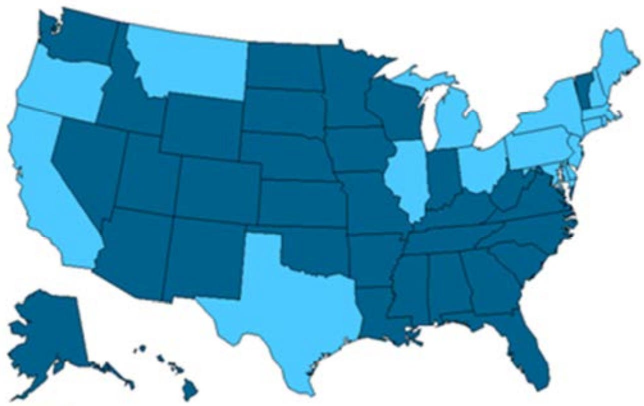
Figure 17. Electricity Retail Choice States



Source: EIA, data as of 2010

Differences between unbundled retail rates for transmission and the transmission-related share of bundled retail rates will arise from a number of items, including potential differences between FERC and the state public utility commission with respect to capital structure, return on equity, and the treatment of Construction Work in Progress. Rate incentives granted by FERC under FERC Order No. 679 can also contribute to these differences (see Section 3.4).

6.1.2 FERC OATT Wholesale Rates for Transmission

A transmission-owning utility will have wholesale customers, such as municipalities, power marketers, and neighboring utilities, who pay to use the utility's transmission system using FERC-approved, cost-based rates under the utility's OATT. In the OATT, the annual transmission revenue requirement is usually divided by the peak demand on the transmission system, often "1CP" (highest single "coincident peak" in the year in megawatts [MW]), to determine rates given that a primary driver of transmission costs is reliably meeting projected peak demand.

FERC OATT rates are updated periodically, often annually, if the utility is using "formula rates". If so, the rates are updated by formula using data filed in the utility's FERC Form 1. Alternatively, if "stated rates" are being used, the current OATT rates remain in effect until a new rate filing is made and approved at FERC. There are three main types of transmission service offered under a utility's OATT:

- Network Integration Transmission Service (NITS) allows a transmission customer to integrate, plan, economically dispatch, and regulate its generating resources to serve its customers in a manner comparable to the way the transmission provider uses its transmission system to serve its own retail or "native load" customers. NITS is often used by municipalities and other transmission-dependent utilities and usually involves delivery to the network customer's distribution system at multiple delivery points.

- <u>Firm Point-to-Point (PTP)</u> allows delivery from one specific point of receipt (the source) to another point of delivery (the sink) on the transmission system. One use, among many, of this service is to deliver a share of the energy from a jointly owned generating plant located in a neighboring balancing area to the balancing area where the plant owner's retail customers are located. Firm transmission service is intended to be available at all times to the maximum extent practicable. Firm PTP reservations are available on a daily, weekly, monthly, annual or multi-year basis. For a request for new firm PTP transmission service to be approved by the transmission provider, transfer capability must be available to provide the service. If not available, a system impact study can be requested to identify the transmission upgrades needed to be completed for the service to be approved.

- <u>Non-Firm Point-to-Point</u> is reserved and scheduled on an as-available basis for periods ranging from one hour to one month and is subject to curtailment or interruption prior to NITS and Firm PTP reservations. This service is commonly used by, among others, power marketers or neighboring utilities involved in short-term economic purchases and sales of energy. Non-firm reservations are available for periods from one hour to one month. Non-firm transmission revenues are credited back to network and firm point-to-point customers in setting transmission rates.

These transmission service types are summarized in Table 2.

Table 2. Main Types of Transmission Service

	Network Integration	Firm Point to Point	Non-Firm Point to Point
Often Used By:	Municipalities and other Transmission-Dependent Utilities	Many entities, including owners and purchasers of external capacity	Many entities, including power marketers and neighboring utilities
Defined Path?	No, allows use of provider's entire transmission system, which is planned to incorporate the customer's resources and demand.	Source to Sink	Source to Sink, scheduled on an as-available basis
How Firm?	Highest	Highest	Subject to curtailment prior to Network and Firm PTP

Source: Navigant

6.1.3 The Path from Transmission Line Costs to Rates

The process for recovery of transmission costs incurred by a FERC-jurisdictional utility in rates depends on whether its retail rates are bundled or unbundled, and whether the utility is part of an RTO. A basic overview is shown in Figure 18, and further illustrative examples are discussed below.

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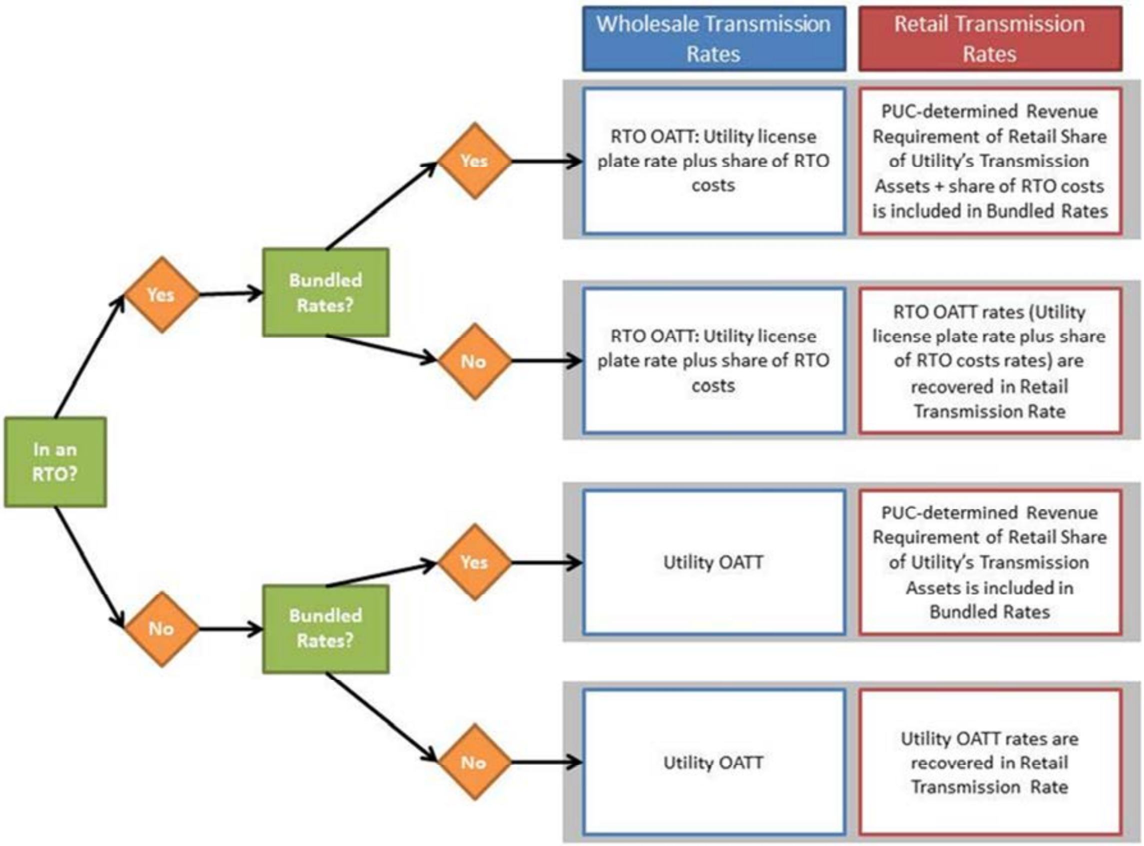
Figure 18. Simplified Overview of How Utility Transmission Costs Are Recovered in Rates



Source: Navigant

A utility not in an RTO builds a new transmission line in the utility's transmission system. In the utility's next OATT filing, the capital and operating costs of the line are included in the derivation of the FERC OATT revenue requirement and the corresponding rates for wholesale transmission customers.[47] Bundled retail rates are generally in effect for utilities not in an RTO, and the utility will include the retail share of the capital and operating costs of the new line in its next base rate filing at the state public utility commission. If unbundled retail transmission rates are used, the utility's OATT rates would be recovered from the utility's retail customers through the unbundled rate and collected either by the utility or an alternative retail energy supplier.

A utility in an RTO builds a new transmission line in the utility's transmission system. The capital and operating costs of the line are included in the derivation of the utility's FERC transmission revenue requirement, often through an annual formula rate update. The utility's transmission revenue requirement and peak demand are typically used to create a "license plate" transmission rate for the utility's system in the RTO's OATT. (A postage stamp transmission rate may alternatively be assessed; see next section.) A license plate rate means that the rate paid is based on the delivery point (sink). All RTO wholesale transmission customers pay the RTO OATT rates designed to recover costs incurred at the RTO level, such as losses, ancillary services, and RTO administrative costs. A utility with bundled

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retail rates will include the retail share of the capital and operating costs of the new line in its next base rate filing at the public utility commission. If unbundled retail transmission rates are used, the RTO OATT rates would be recovered from the utility's retail customers through the unbundled rate and collected either by the utility or an alternative retail energy supplier.

A Transco builds a new transmission line in the Transco's "incumbent" transmission system. The Transco recovers these costs through its FERC-approved OATT transmission rates assessed to the local distribution utility or to alternative retail energy suppliers. If the Transco's transmission system is part of an RTO, the OATT charges are assessed through the RTO's OATT.

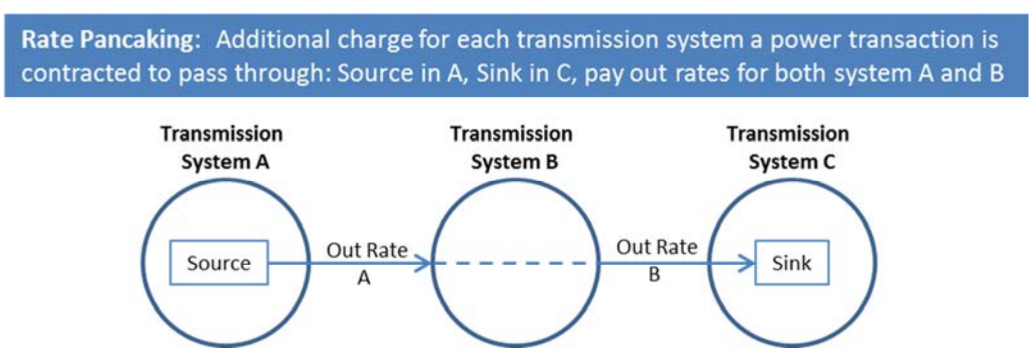
A utility contracts capacity on a merchant transmission line. The merchant line will be paid by the utility per the negotiated rates in the contract, subject to FERC approval, and the costs will be recovered in the utility's retail rates. Only those parties that enter into a contract with the merchant line would pay for the line.

6.2 Pancaked, License Plate, and Postage Stamp Rates

FERC policy in recent years has actively discouraged the pancaking of transmission rates, and encouraged a single transmission rate over broad regions.

Rate pancaking occurs when a transmission customer is charged separate access charges for each utility service territory crossed by the transmission customer's power transaction (see Figure 19). Pancaking discourages long-distance transmission transactions regardless of the value of the transaction to consumers. In response, FERC has required RTOs to eliminate rate pancaking within its borders. Within RTOs, a single transmission charge is assessed for transactions within the RTO (based on the delivery point or sink). For transactions that pass through or out of the RTO, a single regional through or out rate (RTOR) is usually assessed. The RTOR is sometimes waived between RTOs, for example, between MISO and PJM.

Figure 19. Rate Pancaking Example



Source: Navigant

With postage stamp rates, all transmission customers in the RTO pay a uniform rate regardless of where a transaction sources or sinks within the RTO, just as a single postage stamp is used for first-class letters whether sent to a local or distant address. FERC encourages RTOs to establish one uniform access

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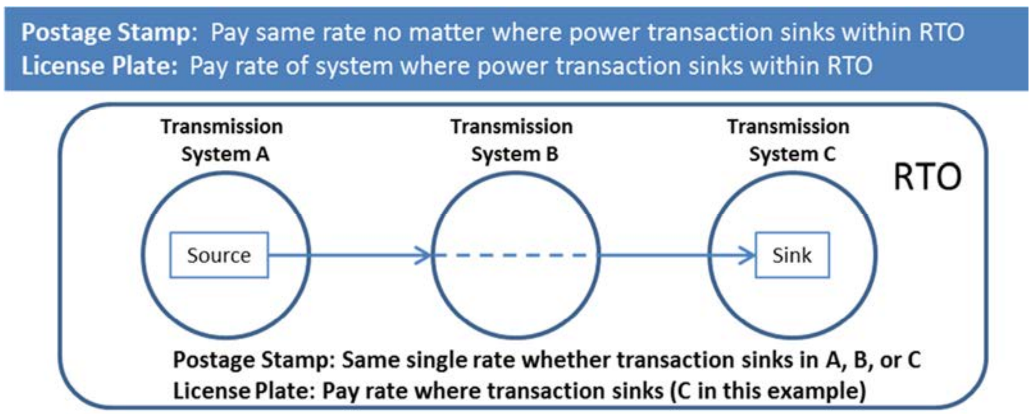
charge for all transmission customers. However, FERC has recognized that this approach may result in cost shifting (i.e., lower-cost transmission providers would see a rate increase, and higher cost providers a rate decrease). As such, FERC allows license plate rates within the RTO in which the applicable rate is based on the revenue requirement of the utility transmission system in which the power is delivered (sinks). The name is derived from the fact that a car with a license plate from a single state has access to all of the nation's roads (see Figure 20). Concerns regarding the cost shifting inherent in postage stamp rates are similarly a concern with respect to transmission cost allocation, as discussed below.

Figure 20. RTO Postage Stamp and License Plate Rate Example



Source: Navigant

6.3 Regional Transmission Cost Allocation

RTOs have developed FERC-approved cost-allocation methods for allocating the costs of regional transmission projects to individual transmission systems or "zones" within the RTO. These costs are often recovered from transmission customers under a separate RTO OATT schedule, such as PJM's Schedule 12, and remitted to the transmission developer. Under FERC Order No. 1000, regional cost sharing will likely be in place for all transmission-owning utilities, whether in an RTO or not.

FERC has noted that issues of cost allocation are some of the most contentious and difficult issues that face the industry and FERC. They are contentious because the transmission costs to be allocated are usually precise, concrete, and quantifiable whereas the benefits that arise from the improved transmission grid are generally difficult to quantify with precision, involving a greater need for prediction about the future use and operation of electric systems.[48] As a general matter, FERC has required that regional cost allocation methods must meet certain principles, including that allocated costs be "roughly commensurate" with estimated benefits, and that those who do not benefit from transmission do not have to pay for it. There are a number of cost allocation methods in place within RTOs today, and they generally fall into the following four categories:

Broad Socialization. The costs of higher voltage transmission lines within an RTO are often allocated equally (i.e., socialized) to all load in the RTO based on the energy (megawatt-hours) withdrawn from the transmission system or on the peak demand (MW) on the transmission system. Support for socialization rests on broadly based benefits provided by these higher voltage facilities in helping relieve multiple transmission constraints over long distances, multiple zones, and long periods of time. As an example, the costs of MISO's Multi-Value Projects and ISO-NE's Pool Transmission Facilities are allocated using this method, along with 300-kV and above projects in SPP.[49]

Flow-Based. The costs of constructing lower voltage transmission facilities within an RTO are often allocated using a flow-based method, in which a model is used to determine: 1) the load in each zone's contribution to the flow of power that contributed to the reliability violation being solved by the new facilities, or 2) the load in each zone's contribution to the flow of power on the new facilities. This allocation method is a form of "beneficiary pays"; that is, those that benefit from the new facilities pay for them.

Economic Value. For transmission lines added for economic efficiency purposes, the economic value of the new line provided to each zone as determined in economic modeling of the system (e.g., based upon impacts to locational prices or cost savings to load) is sometimes used to allocate the cost of the line to individual transmission zones. This allocation method is another form of beneficiary pays.

Localized. The costs of projects below a specific cost threshold (for example, $5 million in PJM) or installed to solve a local reliability issue are often simply allocated to the local transmission zone in which the facilities are constructed.

As illustrated in Table 3, broad socialization and localized cost allocation methods are relatively easy to administer and are easy for stakeholders to understand. In contrast, flow-based and economic value cost allocation methods usually require complex modeling and thus are more difficult to administer and understand.[50] However, flow-based and economic value methods more directly address whether those that are benefiting from the transmission expansion are paying for it.

Table 3. Overview of Cost Allocation Methods

	Broad Socialization	Flow-Based	Economic Value	Localized
Facility-types typically allocated	High-voltage long distance lines	Lower-voltage facilities solving regional reliability issues	Lines constructed for economic efficiency reasons	Low-cost projects solving local reliability issues
Administrative ease & understandability	Easy/simple	Harder, need complex reliability modeling	Harder, need complex economic modeling	Easy/simple
Directly quantifies whether those that benefit are paying?	No, unless modeling is also performed	Yes	Yes	Not needed

Source: Navigant

In practice, each RTO uses a mix of each of these cost allocation methods, usually differentiating by the voltage of the new facilities, the cost of the new facilities, and whether the new facilities are being constructed for reliability or economic efficiency purposes.

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6.3.1 Order No. 1000 Regional Transmission Cost Allocation Considerations

Under FERC Order No. 1000, each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation. Under FERC Order No. 1000, "non-public utility" transmission providers, that is, transmission providers not under FERC jurisdiction such as transmission owning cooperatives and municipalities, are also encouraged to participate in a regional planning process.[51]

The goal of the regional transmission plan is to identify transmission facilities that meet the region's reliability, economic, and public policy-related needs more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning processes.

Under FERC Order No. 1000, the regional cost allocation method used must satisfy six regional cost allocation principles:

1. Costs are allocated in a manner roughly commensurate with estimated benefits.
2. Costs are not involuntarily allocated to those who receive no benefits.
3. Method includes clearly defined benefit-to-cost thresholds that do not exceed 1.25 (i.e., the threshold itself cannot exceed 1.25, where 1.25 means benefits are 25% higher than costs. If the threshold is set, for example, at 1.15, then projects with benefits more than 15% above costs would be included.).
4. Costs are allocated solely within the affected transmission planning region; however, the regional planning process must identify upgrades that may be required in another region and, if the original region agrees to bear the costs associated with these upgrades, there must be provisions for allocating the costs of the upgrades among the beneficiaries in the original region.
5. The methods for determining benefits and beneficiaries are transparent with adequate documentation provided to allow a stakeholder to determine how they were applied to a proposed transmission facility.
6. Different cost allocation methods for different types of facilities are set out clearly and explained in detail.

The specific cost allocation methods developed by each transmission provider under FERC Order No. 1000 will follow these principles, and likely involve a mix of the allocation methods noted above, along with potential consideration of the costs avoided by local transmission projects that may be displaced by a more economic and cost-effective regional transmission project.

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7 Physical and Technical Characteristics of Transmission

A number of individual components, including lines, cables, support structures, transformers, and substations, collectively comprise the physical transmission system. Electricity flows through this system in accordance with physical laws. The basic physical components of the transmission system and the technical operation of this system are discussed in turn below.

7.1 Physical System

7.1.1 Transmission lines

Transmission lines come in two basic varieties: overhead lines and underground (or undersea) cables.

Overhead lines represent the vast majority of transmission lines, and are considerably less expensive to construct than underground cables. The main design consideration for overhead lines is the choice of conductor type and size, which must balance the need to minimize energy losses, cost, and the weight that must be carried by support structures. While copper is a better conductor, it has been overtaken by aluminum, which is lighter and cheaper.[52] There have been continual innovations which allow the specific conductor type and size to be optimized for its intended use.

Figure 21. Overhead Lines Supports

Source: OSHA Electric Power Illustrated Glossary

There are many possible types of support structures for overhead transmission lines (see, for example, Figure 21). Typically, transmission lines are supported on structures made out of steel lattice, tubular steel, wood, and/or concrete. The main function of support structures is to keep the conductors from contacting each other or other objects such as trees, including when the conductors sag due to high temperatures caused by resistive heating and/or high ambient temperatures.[53] See Appendix D for an explanation of resistive heating, among other technical terms used in this chapter.

Underground cables are used where overhead lines are inappropriate due to environmental or land use considerations, such as in high-density urban areas or ecologically sensitive areas. Cables are insulated and are typically routed through underground conduits, and often require cooling systems to dissipate heat. Cables may use copper instead of aluminum, balancing the greater cost of copper against its superior conductivity and lower resistive heating. Undersea (submarine) cables are usually made of copper, and may be surrounded by oil or an oil-soaked medium, then encased in insulating material to protect from corrosion.[54]

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7.1.2 Transformers and Substations

Transformers are used to change voltage levels in AC circuits, allowing transmission at high voltages to minimize losses, and to convert to low voltages at the customer end for safety. Transformers step up the voltage from generator to transmission system, and step it down, often in several stages, before reaching the desired end-user voltage, such as 120 volts for households.[55]

Substations. Large transformers are housed in substations, where sections of a transmission and distribution system operating at different voltages are joined. Larger substations have a manned control room, while smaller substations often operate automatically. In addition to transformers, important substation equipment includes switchgear, circuit breakers, relays, and other protective equipment, and capacitor and reactor banks used to provide reactive power support.[56]

Converter stations to convert power from AC to DC and from DC to AC are also located on the transmission system where there are HVDC lines and DC ties.

7.1.3 Communications, Monitoring, and Control Systems

System conditions must be continuously monitored and controlled, and, increasingly, these activities are automated. Supervisory control and data acquisition (SCADA) systems combine remote sensing of system conditions, such as load flow and temperature, with remote control over operations. For example, control center SCADA systems control key generators through automatic generator control (AGC), and can change the topology of the transmission and distribution network by remotely opening or closing circuit breakers. This monitoring and control is enabled by dedicated phone systems (often fiber-optic based), microwave radio, and/or power line carrier signals.[57]

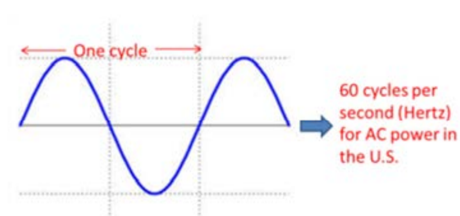
7.2 *Key Technical Aspects in Reliably Operating the Transmission System*

In operating the transmission system, there are a number of overriding concerns that are continuously monitored to allow for reliable operation. These include managing flows to stay within preestablished limits on transmission lines and maintaining voltages and frequencies on the transmission system within a desired range. See Appendix D for a basic overview of the underlying terms important to understanding electricity flows. Summarized below are some of the key aspects involved in operating the transmission system reliably.

7.2.1 Frequency, Voltage, Current, and Power

Almost all bulk electric power in the United States is generated, transported, and consumed in an alternating current network. In an AC electrical system, voltage and current pulsate (described mathematically by sine waves) at the system frequency (in North America this is 60 hertz, or 60 cycles per second) (see Figure 22).

Figure 22. Example "Sine Wave" for AC



Source: Navigant

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Voltage is a measure of the potential energy in an electric charge, and current is a measure of the average rate at which electric charges are flowing. Voltage (measured in volts) is analogous to pressure in a water system, while current (measured in amperes) is analogous to the rate of water flow.[58] In the simplest case, for DC circuits, power is the algebraic product of voltage and current, as shown in Figure 23. As the formula implies, for the same amount of power, one can have a higher voltage and lower current, or a lower voltage and higher current. While the formulas for AC power are more complex (see Appendix D), this same general relationship between voltage and current still holds. Because higher current is associated with greater energy losses (e.g., from heating of the wires), higher voltages are used on the transmission system to reduce current and thereby minimize these losses.

Figure 23. Formula for DC Circuits

Power = Voltage x Current

Source: Navigant

AC systems produce and consume two kinds of power: real power (measured in watts) and reactive power (measured in volt-amperes reactive, or var). Real power accomplishes useful work (e.g., running motors and lighting lamps). Reactive power supports the voltages that must be controlled for system reliability. By way of analogy, imagine walking to a destination on a long trampoline. The effort needed to maintain your balance while pulsating up and down is analogous to reactive power (maintain control), while the work done in moving forward (your goal, and thus the "useful" work) is analogous to real power.

7.2.2 Limits and Regulation

As electricity is generated at generating stations and flows to load over the transmission system, the system must be operated to manage a number of key items in real time.

Managing Flow Limits. The flow of electricity on the transmission system must be continually monitored to ensure that the flows through transmission facilities do not exceed preestablished limits established using reliability criteria. These limits include:

- Thermal limits. The capacity of transmission lines, transformers, and other equipment is determined by temperature limits. If these limits are exceeded, the equipment can be damaged or destroyed. For example, when a transmission line heats up, the metal expands and the line sags, potentially coming into contact with surrounding objects, causing a fault. Instead of a single thermal limit, dynamic or seasonal ratings are sometimes used. For example, transmission lines can carry more current on cold, windy days without direct sunlight.
- Stability limits. The stability limit of a transmission line is the maximum amount of flow through the line for which the transmission system will remain stable if a disturbance (e.g., a generating unit outage) occurs.

Voltage Regulation. Voltage regulation keeps voltages throughout the electric system within defined limits and is important for proper operation of electric power equipment and to maintain the ability of the system to withstand disturbances. Reactive power is critical to maintaining voltages on the AC system. Inadequate reactive power supply lowers voltage; as voltage drops, current must increase to maintain the power supplied. If current increases too much, transmission lines trip, or go offline, potentially overloading other lines and possibly causing cascading failures. If voltage drops too low, some generators will automatically disconnect to protect themselves and customer equipment may malfunction.

Reactive power may be supplied by several different sources, including transmission equipment (e.g., capacitors) and generating plants. A generating plant typically produces a mixture of real and reactive power. System operators can adjust the output of either type of power from a generating plant at short notice to meet changing conditions. Because reactive power losses become significant over longer distances, voltage-control equipment supplying reactive power must be dispersed throughout the system and located close to where the voltage support is needed.

Frequency Regulation. Controlling frequency on the interconnected electric system requires precisely matching generation to load. From hours to months in advance, the dispatch of generating units and power exchanges with other systems is matched with load demands based on factors such as historical load patterns, weather predictions, and maintenance schedules. However, at the scale of minutes to seconds, frequency is maintained by governors and AGC, which precisely controls the power output of certain generators that are able to respond rapidly to changes in load.

7.2.3 Ancillary Services

FERC has defined ancillary services as those services necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system.[59] The ancillary services defined by FERC in Order No. 888 are shown in Figure 24.

Figure 24. FERC-Defined Ancillary Services in Order No. 888

1. Scheduling, system control and dispatch
2. Reactive supply and voltage control
3. Regulation and frequency response service
4. Energy imbalance service
5. Operating reserve – synchronized
6. Operating reserve – supplemental

Source: Navigant

As shown, ancillary services include the voltage control (reactive power) and regulation (AGC) services discussed above. Operating reserves, first synchronized (or "spinning") and then, if needed, supplemental, are used to restore the generation and load balance in the event of a contingency such as the sudden, unexpected loss of a generator. Generators that can restart the grid after a blackout also provide a vital ancillary service.

Power generators provide many of these ancillary services and generally are paid to provide them. FERC has encouraged, and RTOs have been gradually introducing, markets for many of these ancillary services. For example, PJM currently provides regulation, energy imbalance, synchronized reserve, and supplemental operating reserve through market-based mechanisms.[60]

7.3 Power Flow and Modeling

In AC power systems, power flows do not necessarily follow a specified transmission path—for example, from seller in system A to buyer in system B—but divide themselves among various connected transmission paths according to the voltage levels and impedances of the path. In general, these phenomena are referred to as circulating power, loop flows, and parallel path flows. What is important for the reliability of an interconnected system is that operators know the sources and destinations of all transactions and where the power will physically flow, and are able to calculate the resulting reliability risks.[61]

These risks are assessed through power flow models, also called load flow models. These models are used to compute voltages and flows of real and reactive power through all branches of the system. Power flow models account for loop flows, and make it possible to understand how much power will actually flow on transmission lines under a given set of circumstances. Modelers vary the initial conditions—for instance, adding a proposed new generator to the network—and determine the impact on power flows throughout the system. [62]

Contingencies are modeled with a power flow model, and if the model results indicate a problem, planners and operators must address it, typically by adding new generation and/or transmission capacity, or by changing operational procedures. To run power flow models requires that each bus and line in the system be thoroughly described, requiring a great deal of input data. The real and reactive power consumption at each load bus, the impedance of each line and transformer, and the generating capacity of all generators must be known. [63]

Power flow models are used by NERC to calculate a transfer distribution factor (TDF) for individual power transfers—effectively, the percentage of the power that flows on each "flowgate" on the system. A flowgate is a designated point on the transmission system mathematically capturing one or more monitored transmission lines or elements. If a flowgate is overloaded, transactions with TDF values greater than 5 percent on the overloaded flowgate can be curtailed.[64]

7.4 Next Generation Transmission System

A number of technical advancements are taking place that will drive transmission development in upcoming years. These include the use of Flexible AC Transmission Systems (FACTS), further development of a smarter grid enabling advance system monitoring and control, the use of advanced materials and superconductors in transmission lines, and maintaining cyber security.

7.4.1 Advanced System Monitoring, Visualization, and Control

Research and development is ongoing into tools to improve advanced system monitoring, visualization, control, and operations to ease congestion and provide a greater degree of security. These systems will enable grid operators to react swiftly before a local disturbance can cascade into a larger problem, using sensors for measuring system conditions and computerized monitoring equipment that enables system operators to "see" the grid in real time and make necessary adjustments.

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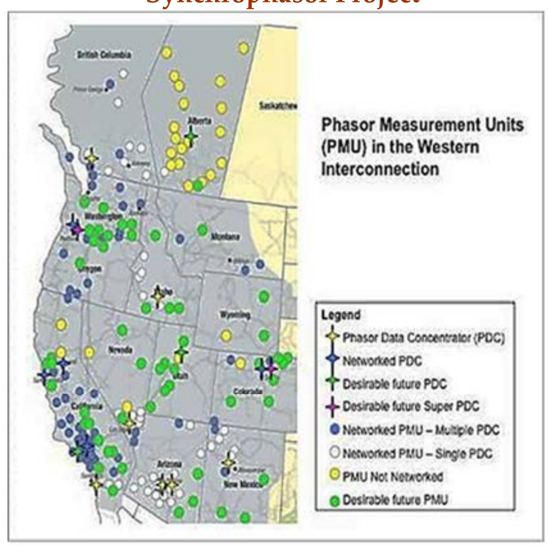
In particular, synchrophasor technology is expected to offer automated controls for transmission and demand response as well as great benefits for integrating renewable and intermittent resources, increasing transmission system throughput, and improving system modeling and planning. Synchrophasors are precise electrical grid measurements of values such as voltage or power that are available from monitors called phasor measurement units (PMUs). These measurements are taken at high speed (30 observations per second), and each measurement is time-stamped according to a common time reference.[65]

Time stamping allows synchrophasors from different areas to be time-aligned and combined together, providing a detailed and internally consistent operational picture of the entire interconnection. This picture can help grid operators detect disturbances that would have been impossible to see with older SCADA systems, which typically collect one measurement every 2-4 seconds.[66] The Western Interconnection Synchophasor Project is illustrated in Figure 25.

The availability of more detailed data about system conditions from devices, such as PMUs for wide area visibility and advanced meter infrastructure for dynamic pricing and demand response, can be a great benefit for electric system reliability and flexibility. However, this large volume of data poses its own set of challenges. Shifting operational data analytics from a traditionally offline environment to real-time situational awareness to measurement-based, fast control will require significant advancements in algorithms and computational approaches. DOE is coordinating research on the advanced modeling that will be required by these systems.[67]

Figure 25. Western Interconnection Synchrophasor Project



Source: BPA.gov

7.4.2 Advanced Materials and Superconductors

Additional research and testing is ongoing into improvements in throughput of electricity over existing transmission corridors by using advanced composite materials for new overhead conductors and high-temperature superconducting cables.

Superconducting cables are cooled cryogenically to remove the resistance to the flow of electricity, cutting down on the losses that typically occur during transmission. Superconducting fault current limiters (FCLs) can dissipate a surge of current on utility distribution and transmission networks. Under normal circumstances, these FCLs are invisible to the system, having nearly zero resistance to the steady-state current; however, when there is an excess of electricity, the FCL intervenes and dissipates the surge, thus protecting the other transmission equipment on the line.[68]

Research and testing is also ongoing in developing a high-strength, high-temperature overhead conductor. One example is aluminum conductor composite reinforced, which can increase the current-carrying capacity of a transmission line by 1.5 to 3 times over that of conventional conductors, without the need for tower modification or re-permitting.[69]

7.4.3 Cyber Security

Cyber security is a serious and ongoing challenge for the energy sector, and the electricity transmission and delivery system in particular. As the U.S. moves forward with the modernization of its transmission systems, it is critical that infrastructure protection be built into these decision-making processes. In 2006, NERC adopted the Critical Infrastructure Protection (CIP) standards. The standards establish the minimum requirements to ensure the security of electronic information exchange to support the reliability of the bulk power system. Since then, a number of updates have been issued, with version 5 approved by the FERC in November 2013.[70]

New technologies are continuously changing the landscape for physical access to the electricity transmission and delivery system. Smart technologies are introducing millions of new intelligent components to the system infrastructure that communicate and control energy delivery in much more advanced ways than in the past. New infrastructure components and the increased use of mobile devices in energy infrastructure environments introduce new digital vulnerabilities and additional physical access points. New applications, such as managing energy consumption, involve new stakeholders and require protection of private customer and energy market information. [71]

The U.S. electric industry has established a goal that by 2020, resilient energy delivery systems will be designed, installed, operated, and maintained to survive a cyber incident while sustaining critical functions. The strategies to achieve this vision confront the formidable technical, business, and institutional challenges that lie ahead in protecting critical systems against increasingly sophisticated and persistent cyber attacks.[72]

8 Action Items for State Officials

State officials face unique challenges when addressing transmission policy. As described throughout this white paper, electric transmission systems are interconnected and thus regional and multistate in nature. However, state officials are generally focused on the specific state which they represent. Recognizing that state statutes are difficult to change and that state officials will need to develop policy within the paradigm of existing state law, which may not be consistent with federal and regional initiatives, the following are intended as suggestions that states may wish to consider. Most importantly, effective state involvement in transmission policy will likely be contingent upon involvement in both jurisdictional utility planning processes and broad regional transmission planning.

8.1 Meaningful State Involvement in Broad Regional Transmission Planning

As this white paper makes clear, transmission planning is not a localized issue, and likely will evolve to encompass broader regions and even entire interconnections in the future. State involvement in regional transmission planning processes will be beneficial in understanding the costs and benefits of a transmission project on a regional as well as a local basis, how public policy goals of the state and surrounding states are being implemented through the transmission planning process, and how issues such as renewable power, demand-side alternatives, and smart grid are being considered in the process. Some state-level policies have been integral in shaping the economic landscape for these issues, such as RPS and net metering policies that make demand-side generation more economically attractive.

State collaboration can help foster and produce consistent and coordinated direction to regional analyses and planning. Significant state input and direction increases the probability that the outputs of transmission planning processes will be useful to state-level officials, whose decisions may determine whether proposals that arise from such analyses become actual investments. States, because of their Constitutional and legal authorities (including siting and cost recovery), arguably offer the most important perspective to ensure an appropriate weighing of all resource options of transmission in comparison to other resources, including generation, new transmission technologies such as smart grid, demand response, distributed generation, energy storage, and energy efficiency. This objective perspective should be valuable to utilities and stakeholders as they consider controversial issues.

Each RTO has a mechanism for state involvement in the process. For example, the Organization of MISO States, Inc., coordinates regulatory oversight among the states, including recommendations to MISO, the MISO Board of Directors, FERC, other relevant government entities, and state commissions. Given the importance that broad regional transmission planning will have on the electricity system in each individual state, each state should seek to carve out a meaningful role in the planning process at each jurisdictional utility and the regional Planning Coordinator for those utilities, including, where applicable, the RTO/ISOs operating in the state.

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8.2 Encourage Continued Improvement in Jurisdictional Utility Planning Practices

States should be ideally suited to facilitate the planning of transmission (and other resources) by Planning Coordinators (RTOs/ISOs, utilities) by encouraging their jurisdictional utilities to acquire the requisite data to support state-of-the-art load forecasting and planning tools, and perform ongoing maintenance and quality control of the data. States should also encourage best practices for measurement and verification of demand response (as well as energy efficiency, distributed generation and energy storage) and encourage reporting of that information. States should also continue to encourage jurisdictional utilities to give appropriate consideration to important risk factors (such as fuel costs, load growth, economic drivers, and capital costs), and incorporate all types of resources (transmission, generation, demand response, non-utility generation, energy efficiency, and energy storage) in their planning processes.

8.3 Encourage Stakeholder Involvement in the Transmission Planning Process

States individually or collectively should encourage broad stakeholder involvement in regional planning. Stakeholder involvement will help provide long-run support and understanding for regional planning methodologies and recommendations. For example, in Illinois, Commonwealth Edison established a smart grid advisory panel to review and advise the company on smart grid investment. Similar stakeholder groups could be developed for regional transmission planning.

Regional transmission planning processes on occasion will yield recommendations for the construction of transmission facilities with broad regional benefits, but limited benefits to any individual state. Educating stakeholders in understanding the transmission planning process, and the corresponding expected benefits in terms of reliability and economics from being part of a broad regional process, likely will be helpful in considering the costs and benefits of any individual project.

8.4 Harmonization of State Siting Processes with Wholesale Markets

States should consider the possibility of harmonizing their siting process with the wholesale markets. By way of example, since RTOs/ISOs have transmission planning processes in place, it may be in the interest of a state to be an active participant in that process to better ensure the state's interests are considered. This logic may be beneficially extended to state siting authorities. Collaboration may well prove to be beneficial to both the state and the RTO/ISO.

8.5 Harmonization of Retail Rate Structures with Wholesale Markets

States should consider, to the extent practicable, harmonizing retail rate structures with the wholesale markets. Since a portion of the costs that a retail customer incurs emanate from the wholesale market, there is a rationale for having retail rate structures take advantage of the opportunities afforded by the wholesale market price structure. RTOs/ISOs have short-term pricing intervals, which could facilitate retail rates that include components based on real-time pricing that can provide price signals important to encouraging cost-effective demand response. Other wholesale market structures may offer price signals that could facilitate retail rate initiatives and similarly improve resource decisions. Such rate structuring would need to be carefully considered and instituted, as retail rates in many states reflect historical embedded costs, which will not generally align with the marginal cost pricing inherent in wholesale markets.

8.6 States and "Cooperative Federalism"

States should consider "cooperative federalism" to work with federal agencies on resource development. States have primary authority over resource development, but FERC has relatively new responsibilities for reliability and on matters of interstate transmission and interstate pipelines. As such, states should consider collaborating more with federal agencies to better ensure that states' and national policy needs are being fully considered. For example, states should consider expanding their involvement in FERC proceedings and rulemakings such as tariffs, mergers, and NERC policies such as resource adequacy.

8.7 State Coordination with and Between Gas and Electric Utilities

States may also find it beneficial to work with both gas and electric industries to ensure coordination of operations and planning and the interplay between electric transmission lines and gas pipelines. It may be, for example, that states could foster the development of natural gas infrastructure that would better enable the state to fulfill its obligations to provide both electric and natural gas service.

Appendix A Who Builds, Owns, and Operates Transmission?

As opposed to the small geographic footprint of traditional, central power generation stations, transmission lines have a much wider and more diverse geographic presence. This appendix summarizes who builds and owns transmission, and the different entities that interact with these entities. For an overview of the transmission planning process, see Chapter 5

Transmission Owners

Several different kinds of organizations own transmission facilities.

Vertically integrated utilities are those that own generation, transmission, and distribution and provide service to retail customers. These entities can be investor-owned utilities, publicly owned electric companies (i.e. municipal or federal utilities), or customer-owned electric companies (i.e. cooperatives). Vertically integrated utilities are the most traditional type of transmission owners.

There are also traditional regulated utilities that own transmission and distribution and provide service to retail customers, but do not own generation. These utilities are sometimes referred to as "T&D utilities".

Transcos. FERC has defined a Transco as a stand-alone transmission company that has been approved by FERC and that sells transmission services at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility.[73] While the Transco is a stand-alone transmission company, FERC does permit the affiliation with another public utility that may own generation or distribution assets.[74] Transcos often own transmission within a defined service territory with the costs recovered under FERC-approved, cost-based rates.

Merchant transmission developers. Merchant transmission projects are defined as those for which the costs of constructing the proposed transmission facilities are recovered through negotiated rates instead of cost-based rates.[75] Owners of merchant transmission must recoup their costs through negotiated access charges paid by generators and/or load-serving utilities. A merchant transmission developer assumes all financial risk for developing its transmission project and constructing the proposed transmission.[76]

Under FERC Order No. 1000, the potential solutions for meeting regional transmission needs may become subject to competitive bidding by utilities and merchant transmission developers. In response, the ownership profile of the transmission system in any particular region may become increasingly comprised of multiple parties. FERC Order No. 1000 defined several terms to help better capture these multiple roles.

- Incumbent transmission developer/provider. An entity that develops a transmission project within its own retail distribution service territory or footprint.[77] The use by FERC of the phrase "or footprint" is meant to convey that an entity can be an incumbent transmission

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provider/developer without having a retail distribution service territory.[78] As such, a Transco that owns the transmission system in a specific service territory would be the incumbent transmission provider in that service territory.

- Nonincumbent transmission developer. An entity that either: (1) does not have a retail distribution service territory or footprint; or (2) is a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint.[79] Merchant transmission developers, which recover costs through negotiated rates instead of cost-based rates, are a subset of nonincumbent transmission developers.[80] Nonincumbent transmission developers also include developers who recover costs through FERC-approved, cost-based rates.

- Non-public utility transmission providers (NTPs) are transmission providers not under FERC jurisdiction such as transmission-owning cooperatives and municipalities.[81]

Planning Coordinators

Planning Coordinators (also known as Planning Authorities) include RTOs, government power authorities, and electric utilities who have taken on the responsibility of coordinating, facilitating, integrating, and evaluating transmission facilities. Each Planning Coordinator is responsible for assessing the reliability of its assigned region, and coordinating planning with adjoining regions. Planning Coordinators evaluate, develop, document, and report on expansion plans for each individual transmission planning area within the Planning Coordinator regional boundaries. The Planning Coordinator must also assess whether the integrated transmission plan meets reliability needs, and, if not, provide alternative solutions.

Planning Coordinators also investigate the viability of constructing transmission lines for economic reasons. Through this process, the transmission plans for each Planning Coordinator's assigned region are integrated and evaluated to ensure that the regional transmission system will be reliable and that economic factors are considered. Utilities generally will act as the transmission planner for their local areas within a Planning Coordinator's regional boundaries. The utilities work closely with the Planning Coordinator to integrate their local transmission planning process with the regional process.

Transmission Operators, Reliability Coordinators, and ISOs/RTOs

Transmission Operators are responsible for the reliable operation and maintenance of the transmission system within their purview. Transmission Operator is a NERC-defined and registered entity; Transmission Operators can also be Transmission Owners and/or Reliability Coordinators.

Reliability Coordinators perform similar duties but sometimes for a wider area that covers multiple transmission operators. Reliability Coordinators also analyze the day-ahead dispatch plan of each Balancing Authority within its territory to assure that transmission reliability is not jeopardized. Transmission Operators develop transmission maintenance schedules based on the maintenance plans of the Transmission Owner(s) and provide these schedules to the Reliability Coordinator for review.

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Reliability Coordinators review transmission and generation outage schedules to identify reliability concerns.

For areas with an RTO/ISO, the RTO/ISO registers as both the Reliability Coordinator and Transmission Operator with NERC, and assigns some of the Transmission Operator tasks to its members.

Generators

The owners of generating plants rely on transmission to get the power they generate to end-use customers. They secure long-term access to transmission by acquiring transmission rights, either physical or financial. Generators are responsible for paying to interconnect to the grid. They are responsible for building and owning the equipment needed for them to tie into the transmission system, as well as for paying for upgrades to the transmission system that are required for their project to reliably be connected to the grid.

FERC requires that all generators be provided access to the transmission grid through an Open Access Transmission Tariff (OATT). In addition to requiring an OATT, FERC also works to ensure open access to transmission by requiring, through Orders 888, 889, and 890, that all generators on the grid be provided the same level of information about the transmission system in real time through the Open Access Same-Time Information System (OASIS).

Distribution Companies

Utilities that own distribution networks and provide service to retail customers, but do not own generation or transmission, are called distribution-only utilities or transmission-dependent utilities. The term distribution company is broader, referring to any company that provides service to retail customers. Distribution companies include distribution-only utilities as well as companies that own transmission (called transmission and distribution utilities) and those that own transmission and generation (called vertically integrated utilities). Distribution companies need transmission in order to get the power generated by generating plants to their customers.

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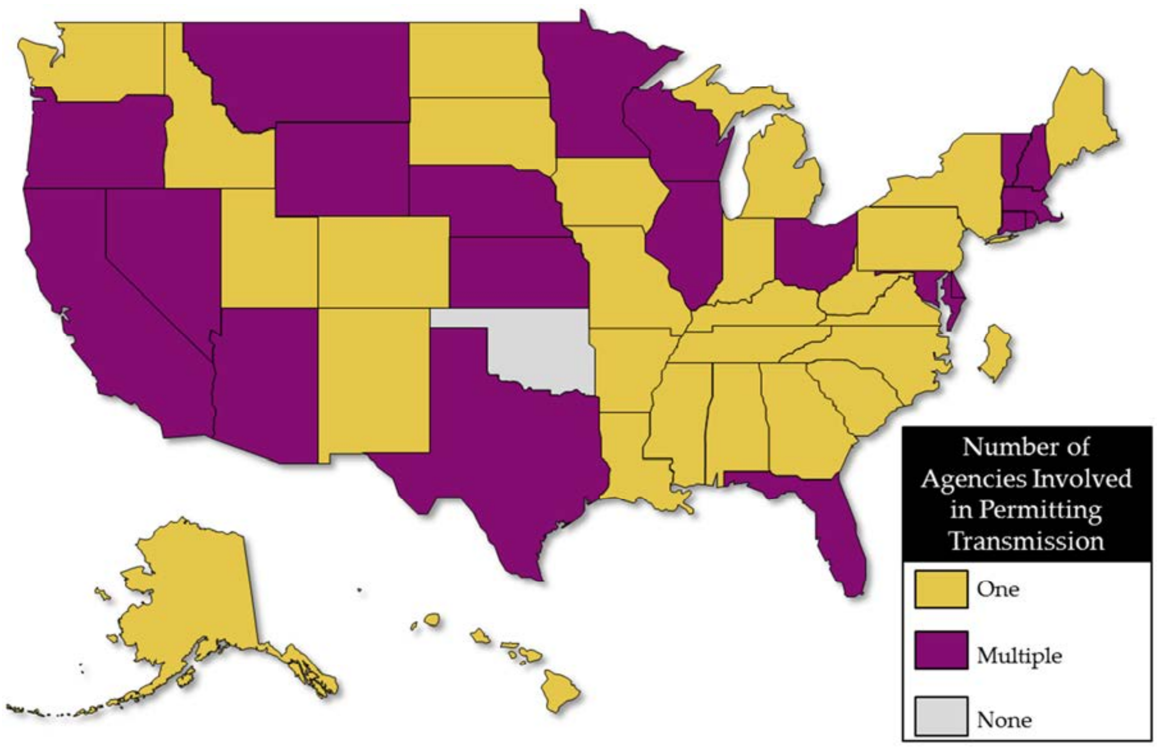
Appendix B Overview of State Transmission Siting and Approval Process

Siting of transmission projects is the regulatory responsibility of the states; only those projects that pass through federal lands, international borders, or National Corridors require regulatory approvals at the federal level. Each state develops its own set of regulations for siting transmission lines within its borders. As shown in Figure 26, most states authorize either one or multiple agencies with oversight of siting transmission projects although the project characteristics that require any specific agency's involvement differ among states.

Figure 26. State Transmission Permitting Process – Number of State Agencies Involved



Source: Navigant (data from Edison Electric Institute, State Generation & Transmission Siting Directory. October 2013)

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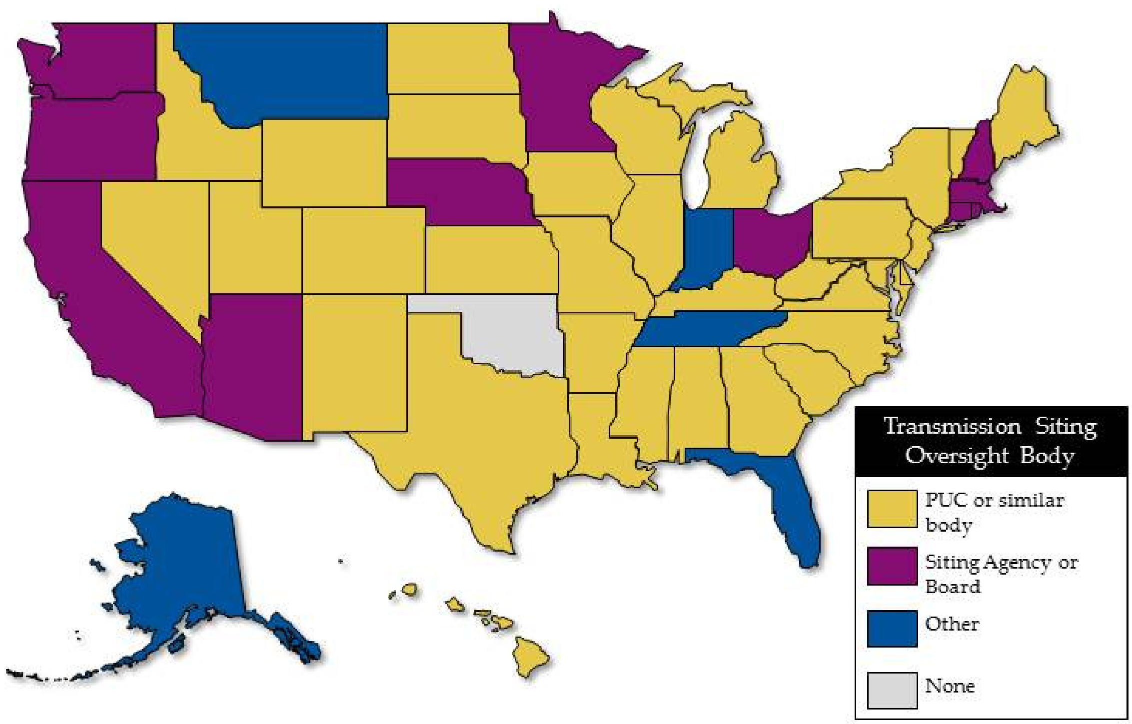
The agency that is the sole or primary agency overseeing the transmission permitting process varies state by state. As shown in Figure 27, many states place the state Public Utility Commission (PUC) or similar body (such as a Public Service Commission or Corporation Commission) in charge of permitting transmission.

In other states a siting board or siting agency is tasked with permitting transmission. These siting agencies are typically made up of members from various related state agencies, such as the PUC and the environmental state agency, and sometimes include governor-appointed representatives from industry and/or public advocates.

In a few states, the primary agency overseeing transmission permitting does not fall into either of these categories, and is typically the environmental state agency or, in the case of Tennessee, a federal entity (the Tennessee Valley Authority).

Figure 27. State Transmission Permitting Process – Primary Agency Involved



Source: Navigant (data from Edison Electric Institute, State Generation & Transmission Siting Directory. October 2013)

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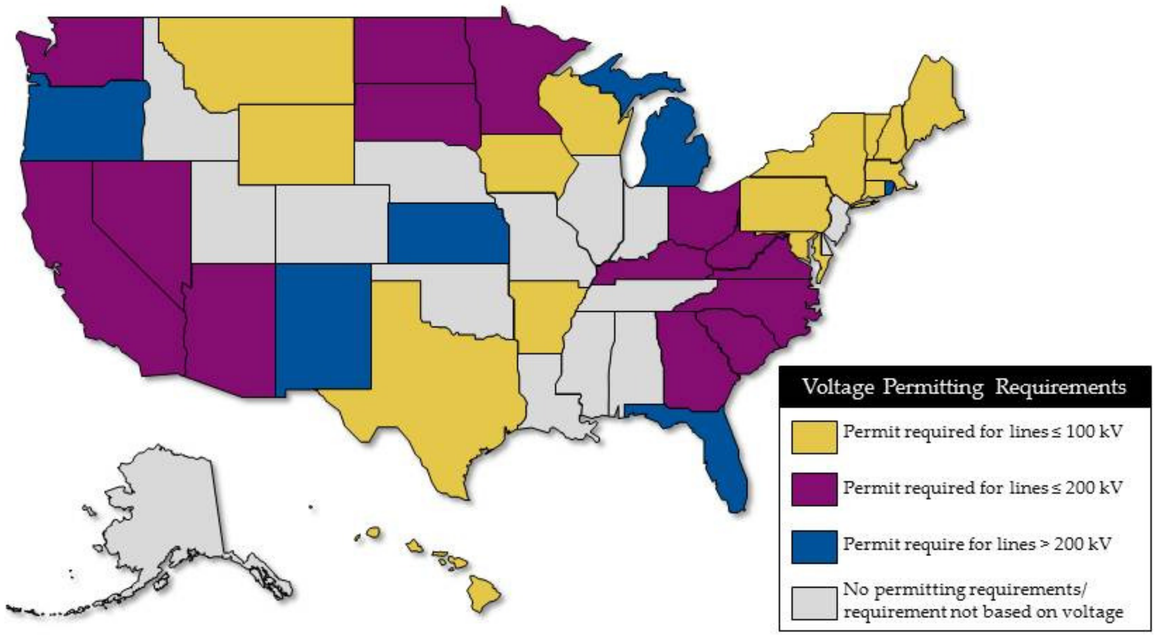
Some states require that all transmission lines be permitted before they begin construction, but others either only have requirements for lines of certain voltage levels or have additional requirements for lines of certain voltage levels. An overview of the states with voltage-based transmission siting requirements can be seen in Figure 28 and Table 4.

Figure 28. State Transmission Permitting by Voltage Level



Source: Navigant (data from Edison Electric Institute, State Generation & Transmission Siting Directory, October 2013)

Table 4. State Transmission Permitting by Voltage

No Voltage Specification	46 to 69 kV	100 kV	115 to 138 kV	150 to 200 kV	230 kV	345 kV
Alabama Alaska Colorado Delaware Idaho Illinois Indiana Louisiana Mississippi Missouri Nebraska New Jersey Oklahoma Tennessee Utah	Connecticut Hawaii Iowa Maine Maryland Massachusetts Montana Texas Vermont Wyoming	Arkansas New Hampshire New York Pennsylvania Wisconsin	Arizona Kentucky North Dakota Ohio South Carolina South Dakota Virginia Washington	California Georgia Minnesota Nevada North Carolina West Virginia	Florida Kansas New Mexico Oregon	Michigan Rhode Island

Source: Navigant (data from Edison Electric Institute, State Generation & Transmission Siting Directory. October 2013)

For a detailed description of the transmission siting and approval prices in each state, see the source used for this appendix: Edison Electric Institute's (EEI's) *State Generation & Transmission Siting Directory*.

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Appendix C The Cost of Building Transmission

Transmission is expensive to build, and costs vary widely based on a number of characteristics of any given transmission project. Costs differ based on the voltage of the line, the length of the line, the terrain, and the equipment used to connect one line to another. Costs also differ based on the transmission structures on which the lines are strung, and the right of way needed for the transmission line, as well as a variety of other potential characteristics specific to any given project.

The costs provided in Table 5 for different line voltages and other components are taken from the 2012 Eastern Interconnection Planning Collaborative (EIPC) Phase II report.[82] The figures cited in Table 5 are "base costs," and there were significant variations in these costs among the various EIPC regions. Specific transmission costs will vary significantly across the country depending upon location, population density, geographical terrain, and local siting requirements.

Table 5. Example Transmission Costs for New Facilities

Line/Description	Unit	Base Cost
<230 kV Single Circuit Line, 300 MW Capability	$/Mile	$1,100,000
230 kV Single Circuit Line, 600 MW Capability	$/Mile	$1,150,000
230 kV Single Circuit Line, 900 MW Capability	$/Mile	$1,580,000
230 kV Double Circuit Line, 1,200 MW Capability	$/Mile	$1,800,000
345 kV Underground Line, 500 MW Capability	$/Mile	$19,750,000
345 kV Single Circuit Line, 900 MW Capability	$/Mile	$2,100,000
345 kV Single Circuit Line, 1,800 MW Capability	$/Mile	$2,500,000
345 kV Underground Line, 1,800 MW Capability	$/Mile	$25,000,000
345 kV Double Circuit Line, 3,600 MW Capability	$/Mile	$2,800,000
345 kV Underground Line, 3,600 MW Capability	$/Mile	$28,000,000
500 kV Single Circuit Line, 2,600 MW Capability	$/Mile	$3,450,000
765 kV Single Circuit Line, 4,000 MW Capability	$/Mile	$5,550,000
500 kV HVDC Bi-pole Line, 3,500 MW Capability	$/Mile	$1,600,000
<230 kV Substation, 4 Bay	$	$7,750,000
230 kV Substation, 4 Bay	$	$9,500,000
345 kV Substation, 4 Bay	$	$16,000,000
500 kV Substation, 4 Bay	$	$26,500,000
765 kV Substation, 4 Bay	$	$44,000,000
230 kV Transformer	$	$5,500,000

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Line/Description	Unit	Base Cost
345 kV Transformer	$	$8,500,000
500 kV Transformer	$	$22,750,000
765 kV Transformer	$	$42,500,000
High-Voltage Direct Current Terminal (both ends)	$	$550,000,000

Source: 2012 EIPC Phase II Report

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Appendix D Simplified Explanation of Basic Technical Electricity Terms

Electric power comes in two forms: alternating current (AC) and direct current (DC). In power systems, AC is generally a sine wave, while DC is a constant value. These forms are characterized by the behavior of their waveforms: AC alternates between positive and negative polarity with respect to ground, while DC does not. By the beginning of the twentieth century, AC power systems became standard worldwide.

Frequency. Frequency is the rate at which AC changes from positive to negative polarity, measured in cycles per second, or hertz (Hz). There are currently two widespread world standards for power system frequency: 50 Hz in most of Europe and Asia, and 60 Hz in North America.

Voltage. Voltage is the difference in electric potential between two points in an electric circuit. A difference in potential causes electric charges to flow from one place to another. Voltage is measured in volts (V). In an AC system, the voltage oscillates in a sine wave; thus, the voltage is generally measured in terms of an averaging mechanism root-mean-square (RMS).

AC RMS Voltage. RMS voltage is obtained by squaring the values of the voltage over one complete sine-wave cycle, determining its average value, and then taking the square root of that average. The result is that $V_{RMS} = V_{PEAK} / \sqrt{2} = 0.707\ V_{PEAK}$. For a U.S. household system that oscillates between positive and negative 170 volts (the V_{PEAK}), the $V_{RMS} = 0.707\ (170\ V) = 120$ volts. Thus, the common designation of a household electric outlet as "120 volts AC" refers to the RMS value of the voltage. The voltages of power system components, such as transformers and transmission lines, are also generally given in RMS terms.

Current. Current is the flow rate of electric charge. In an electric circuit, charge flows from a point of higher voltage to a point of lower voltage through a conductor, just as water flows from a higher spot to a lower one through a pipe. Current is measured in amperes. As is the case for voltage, AC currents are generally described in terms of their RMS values.

Resistance and Conductance. Conductance describes the ability of an object, such as an electric wire, to allow electric currents to flow. The opposite of conductance is resistance, which describes how much the object resists the flow of current. Resistance is measured in ohms (Ω). For a given material, the longer the wire is, the greater its resistance, and the larger in diameter the wire is, the smaller its resistance.

Resistive Losses. When current flows against a resistance, some of its energy is lost in the form of heating. Very high voltages are used in transmission in order to reduce resistive losses. In general, line losses are inversely proportional to the square of the sending voltage; this is true for AC lines as well as DC.

Impedance, Reactance, Inductance, and Capacitance. AC circuits involve not only resistance but other physical phenomena that impede the flow of current. These are inductance and capacitance, referred to collectively as reactance. When AC currents pass through a reactance, some of the energy is temporarily stored in electro-magnetic fields. Voltage decreases when current flows across a reactance, just as it does

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across a resistance. For AC circuits, passing through an inductance causes an AC current waveform to fall behind, or lag, the voltage waveform. Passing through a capacitance causes AC current to move ahead of, or lead, the voltage. Equivalent amounts of capacitance and inductance cancel each other out.

Ohm's Law. Ohm's Law describes the relationship between voltage (V), current (I), and resistance (R) across any element of a DC electric circuit: $V = I*R$. Thus, for a fixed value of resistance, if the voltage is made larger, the current will decrease, and vice versa.

Power and Energy. Power is the rate of energy flow over time, that energy being measured in watts (W). For a DC circuit, the power passing through any element of the DC circuit is the product of the voltage across it and the current passing through it (Ohm's Law). The energy delivered by a power system is measured in watt-hours. See below for AC power.

AC Power Components: Real, Reactive, and Apparent. For AC systems, there are three kinds of power: real, reactive, and apparent. Real power is what is consumed by resistances, and is measured in watts. Reactive power is consumed by reactances, and is measured in volt-amperes reactive, or VAR. Apparent power is the complex sum of real and reactive power, and is measured in volt-amperes, or VA. Real power accomplishes useful work (e.g., running motors and lighting lamps). Reactive power supports the voltages that must be controlled for system reliability. Apparent power is what must be supplied by the generators in a power system to meet the system's electrical load, whereas end use is generally measured in terms of real power only.

Loads and Power Factors. An electrical load is the power drawn by an end-use device or customer connected to the power system. Loads can be resistive or reactive, and are often a combination of both. The extent to which a load is resistive is measured by its power factor (p.f.). Power factor is equal to the cosine of the phase angle difference between the current and voltage waveforms through the load: $\text{p.f.} = \cos \phi$. When the power factor is at its maximum value of one, the load is purely resistive. The smaller the power factor, the greater the reactive power component of the load. Inductive loads, such as electric motors, have a lagging power factor, and are said to consume reactive power. Capacitive loads have a leading power factor and are said to be sources of reactive power.

Calculating Power in AC Systems. For an AC circuit, the apparent power passing through an element of the AC circuit is the product of the RMS voltage across it and the RMS current passing through it. (This is the analog to the DC power calculation noted above.) The apparent power can be separated into its reactive and real power components using the power factor. Real power (watts) is equal to the product of the RMS voltage, the RMS current, and the power factor. Reactive power (vars) is equal to the product of the RMS voltage, the RMS current, and the $\sin \phi$ (where ϕ is the phase difference between the current and voltage waveforms). Reactive loads can have a large effect on line losses, because the current flowing through a line, and the associated heating, is a function of apparent power (reactive power plus real power) rather than just real power.

Three-Phase Systems. Residential current is generally single-phase AC power, but the rest of the power system from generation to secondary distribution employs three-phase AC. This means that transmission lines have three separate conductors, each carrying one-third of the power. The waveforms of the voltage in each phase are separated by 120°. That is, taking one voltage as the reference, the other two voltages are delayed in time by one-third and two-thirds of one cycle of the electric current. There are two major reasons that three-phase power became dominant. The first is that as long as the electrical loads on each phase are kept roughly balanced, only three wires are required to transmit power. Normally, any electric circuit requires both an "outbound" and "return" wire to make a complete circuit. Balanced three-phase circuits provide their own return; thus, only three, rather than six, wires are required to transmit the same amount of power as three comparable single-phase systems. Second, three-phase motors can be smaller and more efficient than comparable single-phase equipment.

Voltage in Three-Phase Systems. The voltage in 3-phase systems can be specified in two different ways. One is phase to ground, which is the voltage between any one of the three phases and ground. The other is phase to phase, which is the voltage between any two of the three phases. Power lines are conventionally described by their phase to phase voltage, also called the line voltage. Phase to phase voltage is greater than phase to ground voltage by a factor of the square root of three. Thus, a 500 kV line has a phase to phase voltage of 500 kV, and a phase to ground voltage of 500 kV/√3 = 289 kV. In both cases, the voltage referred to is the RMS value.

Power in Three-Phase Systems. The amount of power transmitted in a three-phase system is three times the power in each line. For example, the apparent power transmitted by a 500 kV circuit with a current of 1,000 amperes (1 kA), is √3 * 500 kV * 1 kA, or 866 MVA. The real and reactive components can be calculated easily if the load power factor or phase difference is known (see above).

See the main source for this Appendix: "Multi-Dimensional Issues in International Electric Power Grid Interconnections", Chapter 2, "Technical Aspects of Grid Interconnection", published by the United Nations, Department of Economic and Social Affairs, Division for Sustainable Development, for a more in-depth explanation of the above terms.

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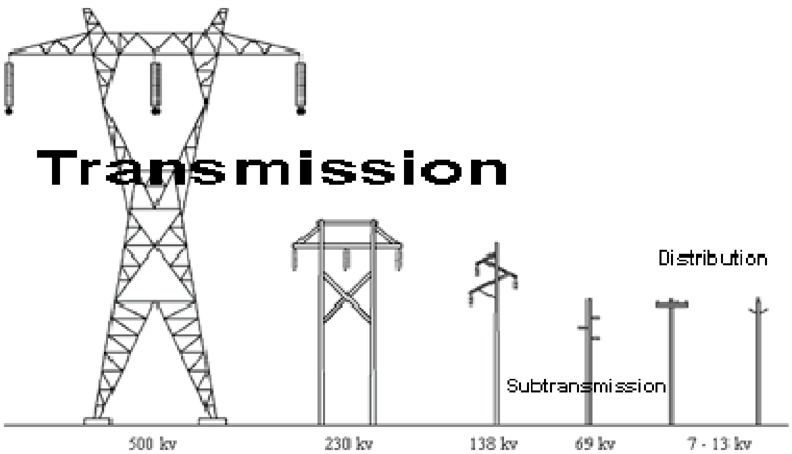
Appendix E Pictures of Transmission Facilities

This appendix provides diagrams and pictures of some of the main components that make up the transmission (and distribution) system.

Figure 29. Transmission Structures



Source: OSHA Electric Power Illustrated Glossary

Figure 30. Transmission Substation

Source: OSHA Electric Power Illustrated Glossary

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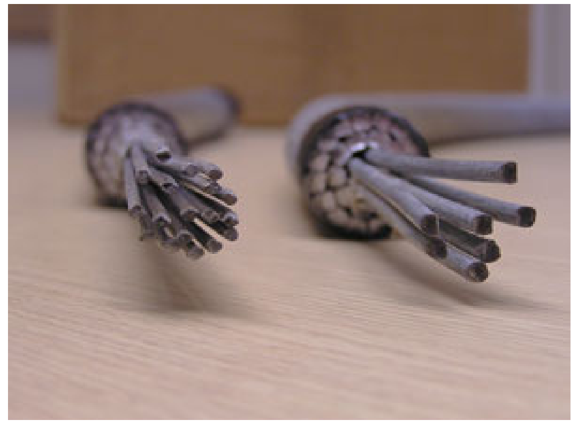
Figure 31. Distribution Station

Source: OSHA Electric Power Illustrated Glossary

Figure 32. Overhead Cable



Source: Minnesota Public Radio

Figure 33. Pole-type Current Transformer

Source: OSHA Electric Power Illustrated Glossary

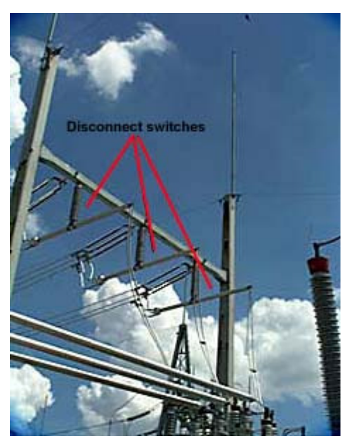
Figure 34. 400-kV Current Transformer

Source: OSHA Electric Power Illustrated Glossary

Figure 35. Power Transformers

Source: OSHA Electric Power Illustrated Glossary

Figure 36. Substation Disconnect Switches



Source: OSHA Electric Power Illustrated Glossary

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Figure 37. High-Voltage Underground Cables

Source: OSHA Electric Power Illustrated Glossary

Figure 38: Air Circuit Breaker

Source: OSHA Electric Power Illustrated Glossary

Figure 39. Capacitor Bank

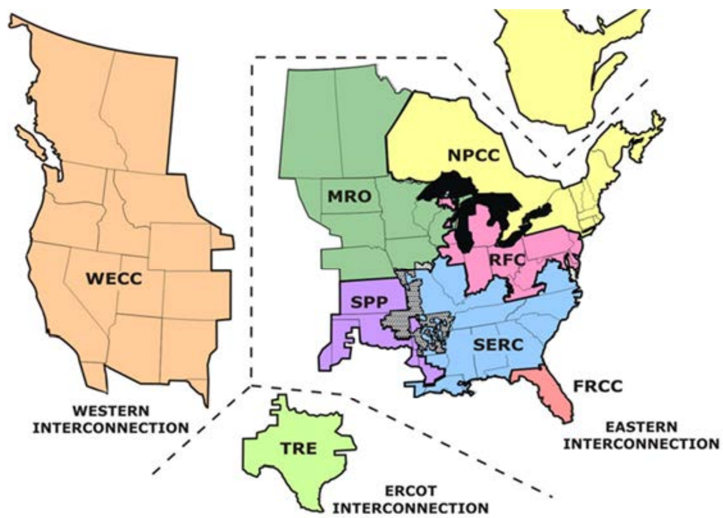
Source: OSHA Electric Power Illustrated Glossary

Figure 40. Circuit Switches

Source: OSHA Electric Power Illustrated Glossary

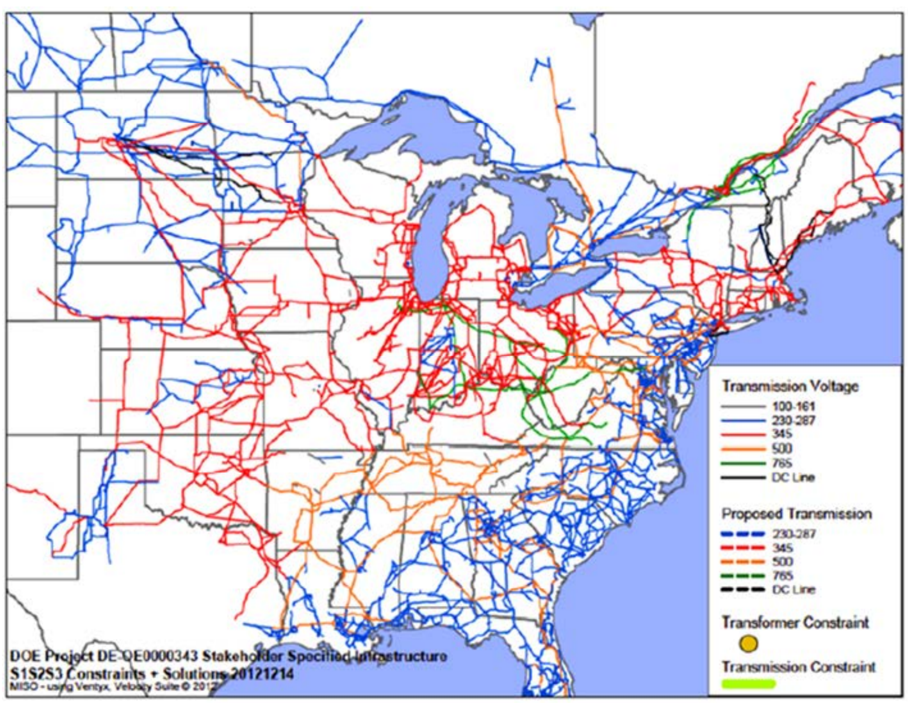
Appendix F Map of NERC Regions and U.S. Interconnections

Figure 41. U.S. Interconnections and NERC Regions



Source: NERC

Figure 42. Eastern Interconnection Transmission (230 kV and above)



Source: EIPC (Existing and stakeholder specified transmission, Phase 2 Report, Figure A1-1)

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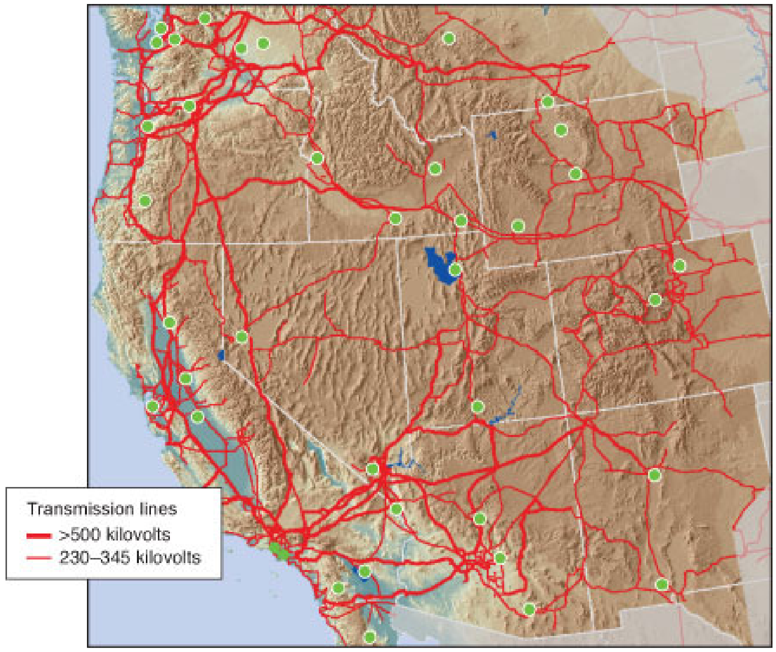
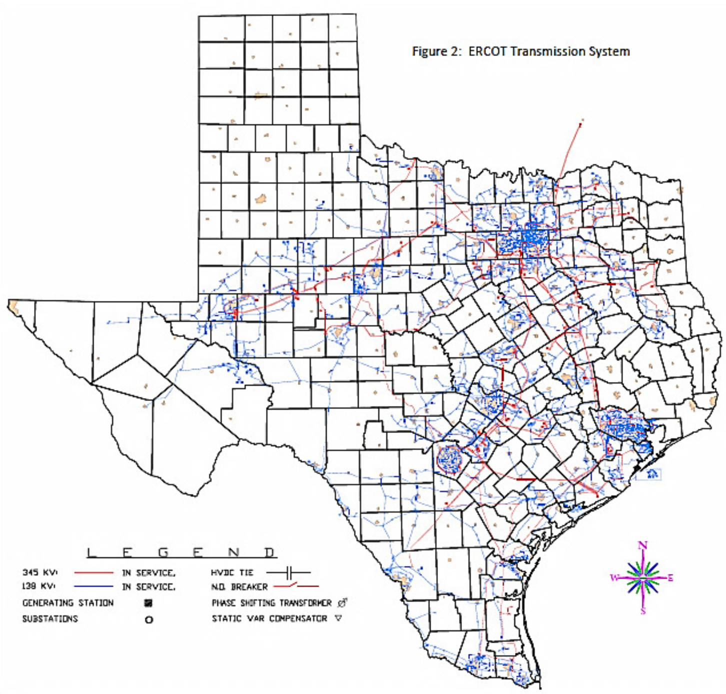
Figure 43. Western Interconnection Transmission (230 kV and above)



Source: Lawrence Livermore National Laboratory

Figure 44. Texas Interconnection



Source: ERCOT

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Appendix G The Evolution of FERC Electricity Policy and Rules

The Federal Energy Regulatory Commission (FERC) is a federal agency housed in the U.S. Department of Energy. In 1920, Congress established the Federal Power Commission (FPC) to coordinate hydroelectric projects under federal control. In 1928, Congress voted to give the FPC funds to permanently hire their borrowed staff. Two years later, the Federal Power Act established a five-member, bipartisan commission to run the FPC. FERC was created in 1977 by Department of Energy Organization Act. FERC took the place of the Federal Power Commission, which was dissolved by that same act.

This appendix provides a timeline and brief overview of the legislation and regulatory orders related to FERC's regulation of the electric system.

For further details, see the main source for this timeline at http://www.ferc.gov/students/ferc/history.asp.

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1920 – Federal Power and Water Act

In 1920 the Federal Power and Water Act established the Federal Power Commission (FPC), which included the Secretaries of War, Interior, and Agriculture.

1935 – Federal Power Act

In 1935 the Federal Power Act (FPA) assigned the regulation of interstate wholesale electricity transactions to the FPC. The FPA also:

- Changed the makeup of the FPC to five commissioners nominated by the President to serve five year terms; no more than three commissioners are to be from the same political party
- Encouraged voluntary interconnection between utilities
- Required wholesale rates and contracts be filed and regulated based on the cost to provide service and a reasonable return

1935 – Public Utility Holding Company Act

Also in 1935 the Public Utility Holding Company Act (PUHCA) required that utility holding companies either limit their services to one state, and thus be regulated by that state, or file with and be regulated by the Securities Exchange Commission (SEC). Under PUHCA, utility holding companies could not own non-utility businesses.

- Most utility holding companies chose to limit themselves to one state to avoid regulation by the SEC

1977 – Department of Energy Organization Act

In 1977 the Department of Energy Organization Act established the Department of Energy (DOE), dissolved the FPC, and gave its oversight authority to a new entity within the DOE: the Federal Energy Regulatory Commission (FERC).

1978 – Public Utilities Regulatory Policies Act

In 1978 the Public Utilities Regulatory Policies Act (PURPA) was passed in response to a number of events and trends, including the oil embargo, perceived natural gas shortages, increases in the cost to build nuclear electric generation, and the impacts of environmental regulation on power plants. A few highlights of PURPA are (1)Utilities were required to buy power from Qualified Facilities (QFs) at a price set by the state regulator; (2) Gave FERC the authority to require one utility to provide another utility with transmission service, if it was in the public interest; (3) Strengthened FERC's ability to order interconnections based on public interest

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1992 – Energy Policy Act

The goal of the Energy Policy Act of 1992 (EPAct 92) was to encourage market-based approaches. The EPAct 92:

- Modifies PUHCA and FPA
- Exempts some generators from PUHCA and PURPA
- Requires utilities to provide transmission service to other utilities for sale or resale of electricity
- Requires utilities to enlarge their transmission system where necessary
- Sets a target for an open access transmission system where transmission owners are compensated for use of their system

1996 – FERC Orders 888 and 889

FERC issued Orders 888 and 889 in response to the EPAct 92. The orders were designed to remove obstacles to competition in wholesale energy markets by requiring open access to transmission. Specifically, the orders: (1) Require utilities to file an OATT, use the OATT for their own generation, and develop an OASIS system, and (2) Clarify the definition of an ISO

1999 – FERC Order 2000

FERC Order 2000, issued in 1999, encourages the voluntary formation of RTOs and places them in charge of tariff design, OASIS, transmission planning, and interregional coordination.

2005 – Energy Policy Act

The Energy Policy Act of 2005 (EPAct05) repealed PUHCA, exempted utilities from buying power from QFs that have access to a market, and strengthened FERC's authority to require interconnections and one utility to provide transmission service to another.

2006 – FERC Orders 670, 671, 672, 679, 681, 688, and 689

FERC issued a number of orders in 2006:

1. FERC Order 670 – anti-fraud, anti-manipulation rules
2. Order 671 – tighter QF thermal efficiency requirements
3. Order 672 – formation of ERO
4. Order 679 – transmission pricing reforms to encourage infrastructure investment
5. Order 681 – requires long-term firm transmission rights be made available in markets
6. Order 688 – eliminated ownership restrictions of QFs
7. Order 689 – construction permits for transmission siting rules

2007 – FERC Orders 697 and 890

In 2007, FERC issued:

- Order 697 – addressed market power in generation and transmission companies
- Order 890 – amends Orders 888/889, updates the pro forma OATT, requires 9 principles of transmission planning: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation for new projects

2010 – FERC Order 1000

Order 1000, issued by FERC in 2011, places a number of requirements on transmission planners, including:

- Each public utility transmission provider must participate in a regional transmission planning and cost allocation process, and coordinate with each neighboring transmission planning region to determine if there are cost-effective solutions to their mutual transmission needs
- Regional cost allocation process must satisfy 6 principles
- Local and regional transmission planning must take public policy into account
- Removal of the Right of First Refusal (ROFR) from tariffs

Implementation of Order 1000 is ongoing, and a number of important questions regarding the interrelationship between state authority over transmission siting, inclusion of new projects in a regional transmission plan, and the integrated resource planning of generation and transmission at the state level will be addressed by federal and state policymakers.

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Appendix H Overview of NERC

The North American Electric Reliability Corporation (NERC) is the FERC-designated Electricity Reliability Organization (ERO) for the United States. NERC develops and enforces reliability standards; monitors the Bulk-Power System (BPS); assesses adequacy annually via a 10-year forecast and winter and summer forecasts; audits owners, operators, and users for preparedness; and educates and trains industry personnel.

According to the NERC website:

> *The North American Electric Reliability Corporation is a not-for-profit entity whose mission is to ensure the reliability of the Bulk-Power System in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the Bulk-Power System through system awareness; and educates, trains and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada and the northern portion of Baja California, Mexico. NERC is the electric reliability organization for North America, subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada. Entities under NERC's jurisdiction are the users, owners and operators of the Bulk-Power System, which serves more than 334 million people.*

Congress created an ERO through the Energy Policy Act of 2005. The Federal Energy Regulatory Commission (FERC) certified NERC as the ERO on July 20, 2006, and provides governmental oversight. NERC also is subject to oversight by governmental authorities in Canada. In addition, industry stakeholders participate in NERC's processes through various committees and subgroups.

NERC develops, implements, and enforces mandatory Reliability Standards for the Bulk-Power System in accordance with Section 215 of the Federal Power Act. The statute requires users, owners, and operators of the Bulk-Power System in the United States to be subject to FERC-approved NERC Reliability Standards. This includes the development of standards designed to ensure the protection of cyber assets that may impact the reliable operations of the transmission grid.

NERC assesses and reports on the reliability and adequacy of the North American Bulk-Power System divided into the eight Regions. The users, owners, and operators of the Bulk-Power System within these areas account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.

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NERC defines a reliable Bulk-Power System as one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the amount of available electricity. NERC divides reliability into two categories:

- **Adequacy:** Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. Resources refer to a combination of electricity generating and transmission facilities that produce and deliver electricity, and demand-response programs that reduce customer demand for electricity. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.

- **Security:** For decades, NERC and the bulk power industry defined system security as the ability of the Bulk-Power System to withstand sudden, unexpected disturbances, such as short circuits or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by manmade physical or cyber attacks. The Bulk-Power System must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.

NERC is governed by a Board of Trustees comprised of 10–12 independent trustees and the president and chief executive officer of NERC. Trustees have expertise in electricity operations and reliability; legal, market, financial and regulatory matters; and familiarity with regional system operation issues. Trustee selection reflects geographic diversity. Trustees are independent of the industry and must commit to serving the public interest and representing the reliability concerns of the entire North American electricity system. Trustees are elected by the Member Representatives Committee and serve for a term of three years. NERC is overseen by the Federal Energy Regulatory Commission and governmental authorities in Canada.

NERC Reliability Standards

Within the United States, other than Alaska and Hawaii, all users, owners, and operators of the BES must comply with the Reliability Standards. The complete text of these standards can be downloaded from NERC's website (www.nerc.com).

NERC's standards fall into the following categories, each represented by an abbreviation in the NERC Standard Number.

- BAL: Resource and Demand Balancing
- CIP: Critical Infrastructure Protection
- COM: Communications
- EOP: Emergency Preparedness and Operations
- FAC: Facilities Design, Connections, and Maintenance
- INT: Interchange Scheduling and Coordination
- IRO: Interconnection Reliability Operations and Coordination
- MOD: Modeling, Data, and Analysis
- NUC: Nuclear Plant Interface Coordination
- PER: Personnel Performance, Training, and Qualifications
- PRC: Protection and Control
- TOP: Transmission Operations
- TPL: Transmission Planning
- VAR: Voltage and Reactive

NERC laid out, in their 2014-2016 Reliability Standards Development Plan, their strategy for reaching a "steady-state" of reliability standards by the end of 2015, which they define as "a stable set of clear, concise, high-quality, and technically sound Reliability Standards that are results-based, including retirement of requirements that do little to promote reliability."

New, modification to, or retirement of standards are driven by FERC directives, priority rankings by NERC's Steering Committee, and the results of an Independent Expert Review Panel (IERP) report completed in 2013. NERC posts a spreadsheet tracking its ongoing project schedule and status on its website (www.nerc.com). NERC's prioritization for 2014 is shown in Table 6.

Table 6. NERC Reliability Standards Development Plan

Prioritization	Project Number	Project Title
High	2008-02	Undervoltage Load Shedding
	2009-02	Real-Time Reliability Monitoring and Analysis Capabilities
	2013-03	Geomagnetic Disturbance Mitigation Measured (Stage 2)
	2009-03	Emergency Operations
Medium	2007-11	Disturbance Monitoring
	2010-05.2	Phase 2 of Protection System Misoperations: SPS/RAS
		Periodic Review of BAL-004, -005, and -006
	2012-09	IRO Review
Low	2010-02	Connecting New Facilities to the Grid
	2010-08	Functional Model Glossary Revisions
	2012-13	NUC Review
Pending Input	2007-17.3	Protection System Maintenance and Testing Auxiliary Relays
	2010-13.3	Generator Relay Loadability Stable Power Swings

Source: NERC Reliability Standards Development plan 2014-2016, approved by Board of Trustees November 7, 2013

For additional information, see www.NERC.com.

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Appendix I Overview of DOE Transmission-Related Activities

Among many other objectives, the U.S Department of Energy (DOE) has made modernizing the nation's energy infrastructure a priority. The Office of Electricity Delivery and Energy Reliability (OE) is the lead office at DOE with respect to electricity transmission issues. OE's mission is to lead national efforts to modernize the electric grid; enhance security and reliability of the infrastructure; and facilitate recovery from disruptions to the energy supply. OE's main activities in each area are summarized below.

Advanced Grid Integration. Fosters the deployment of smart grid systems and technologies to enhance the reliability, efficiency, and security of the electric power grid. Since 2009, under the American Recovery and Reinvestment Act of 2009 (ARRA), DOE and the electricity industry have jointly invested over $7.9 billion in 99 cost-shared Smart Grid Investment Grant (SGIG) projects involving more than 200 participating electric utilities and other organizations to modernize the electric grid, strengthen cybersecurity, improve interoperability, and collect an unprecedented level of data on smart grid operations. OE is managing these projects through completion in 2015.

Power Systems Engineering Research and Development. Works to accelerate discovery and innovation in electric transmission and distribution technologies and create "next generation" devices, software, tools, and techniques to help modernize the electric grid. Projects are planned and implemented in concert with partners from other federal programs; electric utilities; equipment manufacturers; regional, state, and local agencies; national laboratories; and universities. Current priorities include Smart Grid research and development, energy storage, and cybersecurity for energy delivery systems.

Energy Infrastructure Modeling and Analysis. Supports the development of a reliable, secure, resilient, and advanced U.S. energy infrastructure through activities such as electric system modeling, synchrophasor-based tool development, transmission reliability research, reliability assessments, energy security modeling and visualization, and energy infrastructure risk analyses (see Chapter 7).

National Electricity Delivery. Provides technical assistance to states, regional entities, and tribes to help them develop and improve their programs, policies, and laws that will facilitate the development of reliable and affordable electricity infrastructure. Also authorizes the export of electricity, issues permits for the construction of cross-border transmission lines, and is leading efforts to improve the coordination of federal transmission permitting on federal lands, as follows:

- **Coordination of Federal Transmission Authorizations** under section 216(h) to the Federal Power Act, which requires that DOE act as the lead agency for purposes of coordinating all applicable federal authorizations and related environmental reviews required to site an electric transmission facility.

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- **Interconnection-Wide Transmission Planning Initiative.** DOE is promoting collaborative long-term analysis and planning for the Eastern, Western and Texas electricity interconnections, which will help states, utilities, grid operators, and others prepare for future growth in energy demand, renewable energy sources, and Smart Grid technologies. This represents the first-ever effort to take a collaborative, comprehensive look across each of the three transmission interconnections to assess transmission needs for future electricity scenarios.
- **Energy Corridors on Federal Lands.** DOE, the U.S. Bureau of Land Management, and other cooperating federal agencies have released a Draft Programmatic Environmental Impact Statement supporting designation of energy transport corridors on federal lands in 11 western states.
- **National Electric Transmission Congestion Study.** OE performs ongoing analysis of the Eastern and Western Interconnects to identify major electric transmission constraints. The Energy Policy Act (EPAct) of 2005 requires DOE to publish a National Electric Transmission Congestion Study every three years (see Chapter 4).
- **Presidential Permits and Export Authorizations.** OE authorizes the export of electric energy to Canada and Mexico and issues permits for the construction, connection, operation, and/or maintenance of electric transmission facilities at the international border (see Chapter 4).
- **Federal Power Act Section 202(c) Emergency Orders.** Under FPA section 202(c), during the continuance of a war in which the U.S. is engaged or when an emergency exists, the Secretary of Energy may require by order temporary connections of facilities, and generation, delivery, interchange, or transmission of electricity as the Secretary determines will best meet the emergency and serve the public interest. 16 U.S.C. § 824a(c).

Infrastructure Security and Energy Restoration. Leads efforts for securing the U.S. energy infrastructure against all hazards, reducing the impact of disruptive events, and responding to and facilitating recovery from energy disruptions, in collaboration with industry and state and local governments. Works with the Department of Homeland Security, the Federal Energy Regulatory Commission, and other national, regional, state, and local government and commercial organizations to:

- Support the national critical infrastructure protection program
- Analyze infrastructure vulnerabilities and recommend preventive measures
- Help other agencies prepare for and respond to energy emergencies and minimize the consequences of an emergency
- Conduct emergency energy operations during a declared emergency or national security special event in accordance with the National Response Plan
- Develop, implement, and maintain a national energy cyber security program

See http://energy.gov/oe/office-electricity-delivery-and-energy-reliability for more information.

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Appendix J Glossary of Terms

This appendix defines terms related to transmission and transmission planning. For further reading, see the following resources, which were used to develop this glossary:

- *Edison Electric Institute Glossary of Electric Industry Terms published April 2005*
- *Energy Central Glossary available online at http://www.energycentral.com/reference/glossary*
- *NERC Glossary of Terms Used in NERC Reliability Standards updated October 30, 2013 and available online at http://www.nerc.com/files/glossary_of_terms.pdf*
- *PJM Glossary available online at http://www.pjm.com/Home/Glossary.aspx*
- *Transmission Hub Transmission 101: Glossary available online at http://transmissionhub.com/transmission-101/glossary.php*
- *U.S. Energy Information Administration (EIA) Electricity Glossary available online at http://www.eia.gov/tools/glossary/?id=electricity*

Additional sources include the American Public Power Association (APPA), Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), New York Independent System Operator (NYISO), Independent System Operator of New England (ISO-NE), and Jack Casazza and Frank Delea's Understanding Electric Power Systems: An Overview of the Technology, the Marketplace, and Government Regulations (published by IEEE and Wiley in 2010).

A

Adequacy: the ability of the electric system to supply the aggregate electrical demand and energy requirements of end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Aggregator: any marketer, broker, public agency, city, county, or special district that combines the loads of multiple end-use customers in negotiating the purchase of electricity, the transmission of electricity, and other related services for these customers.

Allowance for Funds Used During Construction (AFUDC): an amount recorded by a company to represent the cost of those funds used to finance construction work in progress.

Alternating Current (AC): electric current that periodically reverses direction, usually 100 or 120 times per second (50 or 60 cycles per second or 50/60 Hz) (See also Current, and Direct Current).

Ampere (amp): unit of measure of an electric current, proportional to the quantity of electrons flowing through a conductor past a given point in one second (one amp is produced by an electric force of 1 volt acting across a resistance of 1 ohm, or one coulomb passing in one second).

Ancillary Services: services necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system; may include black start service, load regulation, spinning reserve, non-spinning reserve, replacement reserve, frequency response service, and voltage support.

Apparent Power: the product of the voltage (volts) and current (amperes) of a circuit, comprises both real and reactive power and is generally divided by 1,000 and designated in kilovoltamperes (kVA).

Area Control Error (ACE): instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency bias.

Automatic Generation Control: equipment that automatically adjusts the output of generation units in a control area to keep generation and load in balance in real time and to maintain its interchange schedule in addition to its share of frequency regulation.

Auxiliary Power Supply: the power required for operation of generation station accessory equipment necessary for the operation of a generating station.

Availability: a measure of time a generating unit, transmission line or other facility is capable of providing service, whether or not it actually is in service.

Available Transfer Capacity (ATC): a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin (See Transfer Capability).

Avoided Cost: the minimum amount an electric utility is required to pay an independent power producer, under the PURPA regulations of 1978, equal to the costs the utility calculates it avoids in not having to produce that power.

B

Balancing Authority: the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within its area, and supports interconnection frequency in real time.

Base Load Generation: the part of electricity demand which is continuous, and does not vary over a 24-hour period; or the minimum amount of electric power delivered or required over a given period of time at a steady rate.

Black Start Capability: the ability of a generating unit or station of being started without an outside electrical power supply.

Blackout: loss of the electric power to an area.

British Thermal Unit (Btu): the amount of heat energy required to raise the temperature of one pound of water by 1 degree Fahrenheit at one atmosphere pressure.

Brownout: a system voltage reduction in response to a shortage of power relative to demand; though service is not disrupted completely, causes, for example, a dimming of lights.

Bulk Power System: a term commonly applied to the portion of an electric system that includes electrical generation resources and the bulk transmission system (lines operated at voltages of 100 kV or higher).

Bundled Utility Service: where energy, transmission, and distribution services, as well as ancillary and retail services, are provided by one entity.

C

Customer Average Interruption Duration Index (CAIDI): the average length of an interruption, weighted by the number of customers affected, for customers interrupted during a specific time period:

$$CAIDI = \frac{\sum Customer\ Interruption\ Durations}{Total\ Number\ of\ Customer\ Interruptions}$$

Capacitor: a device that helps improve the efficiency of the flow of electricity through distribution lines by reducing energy losses. It is installed in substations and on poles. Usually it is installed to correct an unwanted condition in an electrical system.

NAVIGANT

Capacity: generator capacity: The maximum output, commonly expressed in megawatts (MW), that a generating unit, generating station, or other electrical apparatus can supply to system load, adjusted for ambient conditions (See also Nameplate Capacity).

Capacity Benefit Margin (CBM): amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

Capacity Factor: the ratio of the total energy generated by a generating unit for a specified period to the maximum possible energy it could have generated if operated at the maximum capacity rating for the same specified period, expressed as a percent.

Capacity Margin: the margin of capability available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen loads, calculated as the difference between net capability and system maximum load requirements (peak load):

$$Capacity\ Margin = \frac{Resources - Peak\ Firm\ Demand}{Resources}$$

(See also Reserve Margin).

Capacity Market: market that provides economic incentives to attract investment in new and existing supply-side, and often demand-side, capacity resources as needed to maintain bulk power system reliability requirements (See also Forward Capacity Market, Installed Capacity Market, and Reliability Pricing Model).

Capacity Reserve: the amount of generating capacity a central power system must maintain to meet peak loads.

Certificate of Public Convenience and Necessity: a special permit, commonly issued by a state commission, which allows a utility to engage in business, construct facilities or perform some other service. The commission involved may attach any reasonable terms and conditions that public convenience and necessity may require (name used for this certificate and its precise definition may vary by state).

Cogeneration: see Combined Hear and Power (CHP).

Coincident Peak Demand: the sum of two or more peak loads that occur in the same time interval (See also non-coincident peak demand).

Combined Heat and Power (CHP): the simultaneous production of electric energy and useful thermal energy for industrial, commercial, heating or cooling purposes.

Congestion: a condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules for electricity transmission simultaneously.

Construction Work in Progress (CWIP): a subaccount in the utility plant section of the balance sheet representing the sum of the balances of work orders for utility plant in process of construction but not yet placed in service.

Contract Path: a specific contiguous electrical path from a Point of Receipt to a Point of Delivery for which transfer rights have been contracted.

Copper Sheet: a hypothetical electrical system in which all generator and loads are interconnected without transmission congestion or losses.

NAVIGANT

Critical Energy Infrastructure Information (CEII): specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that relates details about the production, generation, transmission, or distribution of energy; could be useful to a person planning an attack on critical infrastructure; is exempt from mandatory disclosure under the Freedom of Information Act; and gives strategic information beyond the location of the critical infrastructure.

Current: a measure of the velocity of the flow of electric charge, measured in amperes or amps.

Curtailment: a reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

D

Day-Ahead Market: a day-ahead forward market in which market participants may submit offers to sell and bids to buy energy and ancillary services. The results are posted daily and are financially binding.

Day-Ahead Schedule: schedule, prepared by a Scheduling Coordinator or the Independent System Operator before the beginning of a trading day, that indicates the levels of generation and demand scheduled for each settlement period for that trading day.

Demand: the rate at which electric energy is used at a given instant or averaged over a designated interval of time, typically measured in kilowatts (kW) or megawatts (MW).

Demand Response (DR): changes in electric use by resources on the demand side (end-use customers) from normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices, or when system reliability is jeopardized.

Derating: a decrease in the available capacity of an electric generating unit, commonly due to system or equipment modification, or environmental, operational, or reliability considerations.

Direct Current (DC): the movement of an electric charge from negative to positive that flows continuously in only one direction (See also Current and Alternating Current (AC)).

Distributed Generation: a small generator, typically 10 megawatts or smaller, that is sited at or near load, that is attached to the distribution grid, and can serve as a primary or backup energy source; technologies include combustion turbines, reciprocating engines, fuel cells, wind generators, and photovoltaics.

Distribution Factor: the portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility or Flowgate.

Distribution System: the network of wires and equipment that is dedicated to delivering electric energy from the transmission system to an end user at a lower voltage than the transmission system.

Disturbance: an unplanned event that produces an abnormal system condition.

Diversity: characteristic of a variety of electric loads where individual maximum demands usually occur at different times (See also Load Diversity).

Diversity Factor: the ratio of the sum of the non-coincident maximum demands of two or more loads to their coincident maximum demand for the same period.

E

Economic Dispatch: the start-up, shutdown, and operation of individual generating units to obtain the most economical production of electricity for customers.

Electric Reliability Council of Texas (ERCOT): the Independent System Operator (ISO) for approximately 85% of the State of Texas.

Element: any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section.

Embedded Cost: monies already spent for investment in plant and operating expenses.

Energy: broadly defined, energy is the ability to do work; electrical energy is generated by a generator, which converts other forms of energy into electrical energy that is then transmitted through the electric transmission and distribution systems.

Energy Efficiency: the ratio of service or output provided to energy input (e.g., lumens to watts in the case of light bulbs); services provided can include buildings-sector end uses such as lighting, refrigeration, and heating, industrial processes, or vehicle transportation; differs from conservation in that it provides energy reductions without sacrifice of service.

Energy Information Administration (EIA): since October 1977, the Energy Information Administration (EIA) of the Department of Energy (DOE) has been responsible for collecting and publishing statistical data on energy production, consumption, prices, resources, and projections of supply and demand.

Energy Policy Act 2005 (EPAct): addressed energy production in the United States, including: energy efficiency, renewable energy, oil and gas, coal, Tribal energy, nuclear matters and security, vehicles and motor fuels, including ethanol, hydrogen, electricity, energy tax incentives, hydropower and geothermal energy, and climate change technology; the EPAct reaffirmed a commitment to wholesale power markets, strengthened FERC's regulatory tools, and provided for the development of a stronger energy infrastructure (See Chapter 3 and Appendix G).

Energy Policy Act of 1992: a comprehensive federal act generally designed to improve the efficiency of energy use in the United States, which created a new class of power generators, exempt wholesale generators, that are exempt from the provisions of the Public Utility Holding Company Act (PUHCA) of 1935 and grants the authority to FERC to order and condition access by eligible parties to the interconnected transmission grid (see Chapter 3 and Appendix G).

Energy Services Company: an energy entity that provides service to a retail or end-use customer.

Equivalent Forced Outage Rate (EFOR): the proportion of hours in a year that a unit is unavailable because of forced outages.

Expected Unserved Energy (EUE): the expected amount of energy curtailment per year due to demand exceeding available capacity, usually expressed in MWh.

Extra High Voltage: generally, voltage of 345,000 volts (345kV) or higher.

F

FACTS (Flexible Alternative Current Transmission System): a power electronic based system and other static equipment that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability.

Fault: a physical condition, such as a short circuit, a broken wire, or an intermittent connection, that results in the failure of a component or facility of the transmission system to transmit electrical power in a manner for which it was designed.

Federal Energy Regulatory Commission (FERC): an independent regulatory agency within the U.S. Department of Energy (DOE) which regulates the transmission and wholesale sales of electricity in interstate commerce and administers accounting and financial reporting regulations and conduct of jurisdictional companies.

NAVIGANT

Federal Power Act (FPA): enacted in 1920, and amended in1935, the Act established guidelines for the federal regulation of a utility's sales in interstate commerce. The Federal Energy Regulatory Commission (FERC) is now charged with the administration of this law.

Federal Power Commission (FPC): the predecessor agency of the Federal Energy Regulatory Commission (FERC), the FPC was created by the Federal Water Power Act on June 10, 1920 and was originally charged with regulating the electric power and natural gas industries; it was abolished on September 30, 1977, when the U.S. Department of Energy (DOE) was created, and its functions were divided between the DOE and FERC.

Feeder: an electric line for supplying electric energy within an electric service area or sub-area.

FERC: see Federal Energy Regulatory Commission.

Firm Capacity: power-producing capacity intended to be available at all times during the period covered by a commitment, even under adverse conditions (See also Non-Firm Capacity).

Firm Transmission Service: transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or other event beyond the control of the owner or operator of the facility (See also Non-Firm Transmission Service and Point-to-Point Transmission Service).

Fixed Costs: costs that do not change or vary with usage, output, or production.

Flowgate: designated point on the transmission system mathematically capturing one or more monitored transmission lines or elements.

Forced Outage: the shutdown of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the generating equipment is unavailable for load due to unanticipated breakdown.

Forced Outage Rate: the percentage of time that a power system, or a component of that system such as a generating unit, is unavailable due to unexpected equipment failures.

Forward Capacity Market (FCM): capacity market administered by the Independent System Operator of New England (ISONE).

Franchised Service Territory: area in which a utility system is required to or has the right to supply electric service to ultimate customers.

Frequency: the number of cycles per second through which an alternating current passes, generally standardized in the United States electric utility industry at 60 cycles per second (60 hertz) (See also Alternating Current).

Frequency Response: either the ability of a system or elements of the system to react or respond to a change in system frequency; or the sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 hertz (MW/0.1 Hz).

Functional Unbundling: a rate design or corporate organization that offers generation, transmission, or distribution services as stand-alone services with separate charges.

G

Generation Availability Data System (GADS): a computer program and database used for entering, storing, and reporting generating unit data concerning outages and unit performance.

Generation Shift Factor: characteristic that describes a generator’s impact on a flowgate.

Gigawatt (GW): a unit of power equal to one billion watts or 1,000 megawatts; one gigawatt of electricity generated would power between 800,000 and one million homes.

Gigawatt Hours (GWh): a unit of measurement used to describe the amount of electricity produced or consumed; one gigawatt-hour is equal to one billion watt-hours or 1,000 megawatt hours.

Grid: an interconnected network of electric transmission lines, and related facilities.

Gross Generation: the total amount of electric energy produced by the generating units in a generation station(s) measured at the generator terminals.

H

Heat Rate: a measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour (kWh), computed by dividing the total energy content of fuel burned for electric generation by the resulting net generation:

$$Heat\ Rate = \frac{Energy\ content\ of\ fuel\ (Btu)}{Net\ generation\ (kWh)}$$

(See also Incremental Heat Rate).

Hertz (HZ): a unit of electricity system frequency equal to one cycle per second (See also Frequency).

Holding Company: usually means a Corporation (parent company) that directly or indirectly owns a majority or all of the voting securities of one or more electric utility companies; unless an exemption is available, under the Public Utility Holding Company Act (PUHCA) all holding companies whose subsidiaries are engaged in the electric utility business or in retail distribution of natural manufactured gas must register with the Securities and Exchange Commission (SEC) and limit the operations of each holding company system to a "single integrated public utility system" with only "such other businesses as are reasonably incidental or economically necessary or appropriate to the operations of [the]...system," and comply with various regulations regarding the financing and operation of the holding company system (See also Public Utility Holding Company and Public Utility Holding Company Act).

Hourly System Lambda: a term, commonly given to the incremental cost that results from the economic dispatch calculation, which represents the cost of the next kilowatt hour that could be produced from economical dispatchable units on the system.

Hub: a group of nodes, also called buses, within a pre-determined region and at which individual Locational Marginal Prices (LMPs) are calculated, for which the individual LMP values are averaged to create a single pricing reference.

I

Impedance: a characteristic of a circuit that is representative of the combined resistance and reactance of that circuit.

Inadvertent Interchange: difference between net actual energy flow and net scheduled energy flow into or out of a Balancing Area.

Incremental Cost: the component of the total cost of generator operation that varies as the output varies; the cost of the next increment of generation (the next megawatt), expressed in dollars per megawatt hour or in mills per kilowatt-hour (See also Marginal Cost).

Incremental Heat Rate: the rate of a change in heat input per unit of time to the corresponding change in power output (See also Heat Rate).

Incumbent transmission developer/provider: an entity that develops a transmission project within its own retail distribution service territory or footprint See Nonincumbent transmission developer/provider).

Independent power producer (IPP): a corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation of electricity for use primarily by the public, and that is not an electric utility.

NAVIGANT

Independent Transmission Company: a stand-alone, for-profit transmission business; can be project-focused (focus on individual merchant or regulated transmission projects), can own and operate existing regulated transmission systems, and can refer to transmission companies affiliated with incumbent utilities that look beyond the incumbent's footprint.

Independent System Operator (ISO): an independent, federally regulated entity established to coordinate regional transmission in a non-discriminatory manner and ensure the safety and reliability of the electric system (See also Regional Transmission Organization).

Installed Capacity (ICAP): generating capacity that is physically on the ground and has a defined value.

Installed Capacity (ICAP) Market: capacity market administered by the New York Independent System Operator (NYISO).

Integrated Resource Planning: a process by which utilities and regulatory commissions assess the cost of, and choose among, various resource options.

Interchange: energy or capacity transferred from one electric company or power pool to another.

Interchange Transaction: an agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.

Interconnection: a connection between two electric systems permitting the transfer of electric energy in either direction. Additionally, an interconnection refers to the facilities that connect a non-utility generator (including a distributed generation facility) to a control area or system.

Interstate Commerce (FERC definition): sales where transportation of natural gas, oil, or electricity crosses state boundaries. Interstate sales are subject to FERC jurisdiction.

Inverter: a circuit for converting direct current (DC) electrical power to alternating current (AC).

Investor Owned Utility (IOU): a privately-owned electric utility whose stock is publicly traded. It is rate regulated and authorized to achieve an allowed rate of return.

ISO: see Independent System Operator.

K

Kilovolt Ampere (kVA): one kilovolt ampere equals 1,000 volt amperes (See Volt Amperes).

Kilowatt (KW): a unit of power that is equal to 1,000 watts.

Kilowatt Hours (KWh): the basic unit of electric energy equal to one kilowatt (kW) of power supplied to or taken from an electric circuit steadily for one hour; one kWh equals 1,000 watt-hours.

L

Load Center: a limited geographical area where large amounts of power are used by customers.

Load Diversity: the condition that exists when the peak demands of a variety of electric customers occur at different times.

Load Duration Curve: a nonchronological, graphical summary of demand levels with corresponding time durations using a curve, which plots demand magnitude (power) on one axis and percent of time that the magnitude occurs on the other axis.

Load Factor: the ratio of the average load supplied to the peak or maximum load during a designated period; may also be derived by multiplying the kWh in a given period by 100, and dividing by the product of the maximum demand in kW and the number of hours in the same period.

Load Following: an electric system's process of regulating its generation to follow the changes in the customers' demand.

Load Forecasting: estimate of electrical demand or energy consumption at some future time.

NAVIGANT

Load Pocket: an area on the electrical system that, because of transmission limitations, must have internal generation resources available because the area cannot be served entirely by external sources.

Load Profiles: information on a customer's usage over a period of time, usually a 24-hour period.

Load Shape: a curve on a chart showing power (kW) supplied (on the horizontal axis) plotted against time of occurrence (on the vertical axis), and illustrating the varying magnitude of the load during the period covered.

Load Shift Factor: a factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored flowgate.

Load Shifting: a load shape objective that involves moving loads from peak periods to off-peak periods.

Load-Serving Entity: an entity that secures energy and transmission service to serve the electrical demand and energy requirements of its end-use customers.

Local Distribution Utility (LDU): the utility that delivers electricity to a retail customer's home or business along the distribution poles, wires and other necessary equipment, that the LDU either owns or operates.

Locational Marginal Price (LMP): the hourly integrated market clearing marginal price for energy at the location the energy is delivered or received.

Loop Flow: the unscheduled use of another utility's transmission resulting from movement of electricity along multiple paths in a grid, whereby power might be physically delivered through any of a number of possible paths that are not easily controlled.

Loss of Load Expectation (LOLE): a reliability measure that shows the expected number of days in the year when the daily peak demand exceeds the available generating capacity, obtained by calculating the probability of daily peak demand exceeding the available capacity for each day and adding these probabilities for all the days in the year (referred to as Loss of Load Hours or Hourly Loss of Load Expectation if hourly demands are used in the calculation instead of daily peak demands).

Loss of Load Hours (LOLH): a reliability measure that shows the expected number of hours in the year when the hourly peak demand exceeds the available generating capacity, obtained by calculating the probability of hourly peak demand exceeding the available capacity for each hour and adding these probabilities for all the hours in the year.

Loss of Load Probability (LOLP): a reliability measure that shows the probability of daily peak demand exceeding the available generating capacity in a year, i.e. Loss of Load Expectation (LOLE) shown as a percentage (can also be calculated for Loss of Load Hours).

Losses: the general term applied to energy and capacity lost in the operation of an electric system, which occur principally in the form of waste-heat on the transmission and distribution system.

M

Maintenance Outages: the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility.

Marginal Cost: the cost to the utility of providing the next (marginal) kilowatt-hour of electricity, irrespective of sunk costs; the price to be paid for kilowatt-hours above and beyond those supplied by presently available generating capacity (See also Incremental Cost).

NAVIGANT

Market Monitors: independent organizations responsible for monitoring compliance with the rules, standards, procedures, and practices of energy markets.

Market Power: the ability of any market trader with a large market share to significantly control or affect price by withholding production from the market, limiting service availability, or reducing purchases.

Maximum Demand: highest demand of the load within a specified period of time.

Mcf: one thousand cubic feet (of gas).

Megawatt Hours (MWh): a unit of measurement used to describe the amount of electricity produced or consumed, equal to one million watt-hours or one thousand kilowatt-hours.

Megawatts (MW): a unit of power, equal to one million watts or one thousand kilowatts; MWe refers to electric output from a generator, MWt to thermal output from a reactor or heat source (e.g., the gross heat output of a reactor itself, typically three times the MWe figure).

Merchant Generation: generation not owned and operated by an electric utility and that sells its output to wholesale customers.

Merchant Transmission: transmission not owned and operated by an electric utility and that sells its transmission capacity to wholesales customers.

Municipally-Owned Utility: a power utility system owned and operated by a local jurisdiction, such as a city, county, irrigation district, drainage district, or a political subdivision or agency of a State.

N

NAESB: see North American Energy Standards Board.

Nameplate Capacity: the full-load continuous rating of a generator, prime mover, or other electrical equipment under specified conditions as designated by the manufacturers.

Native Load: the end-use customers that the Load-Serving Entity is obligated to serve.

NERC: see North American Electric Reliability Corporation.

Net Capability: see Net Summer Capability and Net Winter Capability.

Net Generation: gross generation less kilowatt-hours used at the generating station(s) (See also Gross Generation).

Net Summer Capability: the steady hourly output which generating equipment is expected to supply to system load (exclusive of auxiliary) power as demonstrated by test at the time of summer peak demand.

Net Winter Capability: the steady hourly output which generating equipment is expected to supply to system load (exclusive of auxiliary) power as demonstrated by test at the time of winter peak demand.

Network Integration Transmission Service: a service that allows a transmission customer to use the entire transmission network to deliver power from one or more generating sources to one or more customer loads.

Non-Coincident Peak Demand: the sum of two or more individual demands which do not occur in the same demand interval; meaningful only when considering demands within a limited period of time, such as day, week, month, or season, and usually for not more than one year.

Non-Firm Capacity: power-producing capacity supplied or available under an arrangement that does not have the guaranteed continuous availability feature of firm capacity (See also Firm Capacity).

NAVIGANT

Non-Firm Transmission Service: point-to-point transmission service reserved and/or scheduled on an as-available basis (See also Firm Transmission Service and Point-to-Point Transmission Service).

Nonincumbent transmission developer: an entity that either: (1) does not have a retail distribution service territory or footprint; or (2) is a public utility transmission provider that proposes a transmission project outside of its existing retail distribution service territory or footprint, where it is not the "incumbent" for purposes of the project.

Non-Spinning Reserve: an ancillary service that provides operating reserve not connected to the system but capable of serving demand within a specific time, or interruptible load that can be removed from the system in a specified time; generally, that specified time is ten minutes (See also Capacity Reserve and Spinning Reserve).

North American Electric Reliability Corporation (NERC): a nonprofit corporation formed in 2006 as the successor to the North American Electric Reliability Council established to develop and enforce mandatory reliability standards for the bulk electric system, with the fundamental goal of maintaining and improving the reliability of that system; NERC consists of regional reliability entities covering the interconnected power regions of the contiguous United States, Canada, and Mexico and is subject to audit by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.

North American Energy Standards Board (NAESB): energy industry organization that serves as a forum for the development and promotion of standards in an effort to provide a seamless marketplace for wholesale and retail natural gas and electricity, as recognized by its customers, business community, participants, and regulatory entities.

O

Obligation to Serve: the obligation of a utility to provide electric service to any customer who seeks that service, and is willing to pay the rates set for that service.

Off-Peak Energy: energy supplied during periods of relatively low system demands as specified by the supplier (See also On-Peak Energy).

Ohm: the unit of measurement of electrical resistance; one ohm is the resistance of a circuit element when a voltage of one volt is applied and results in a current of one ampere.

Ohm's Law: the relationship between voltage, current, and resistance or impedance; for Direct Currents voltage equals current multiplied by resistance:

$$Voltage\ (V) = Current\ (I) \times Resistance\ (R)$$

for Alternating Currents impedance replaces resistance, such that voltage equals current multiplied by impedance:

$$Voltage\ (V) = Current\ (I) \times Impedance\ (Z)$$

One Day in 10 Years Resource Adequacy Standard: resource adequacy criterion where the load is expected to be curtailed no more than once every ten years (See also Reliability Measures).

On-Peak Energy: energy supplied during periods of relatively high system demands as specified by the supplier.

Open Access Same Time Information Service (OASIS): an electronic information system that allows users to instantly receive data on the current operating status and transmission capacity of a transmission provider; standards for OASIS were established by FERC in Order No. 889.

NAVIGANT

Open Access Transmission Tariff (OATT): electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission (FERC) requiring the Transmission Service Provider to furnish all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.

P

Pancaked Transmission Rates: the accumulation of multiple transmission access fees charged transmission consumers by each owner of the transmission lines on which the power flows.

Peak Demand: the maximum load, or usage, of electrical power occurring in a given period of time, typically a day.

Peaking Generation: a generating unit normally operated only during the hours of highest daily, weekly, or seasonal loads; usually designed to meet the portion of load that is above base load.

Planned Outages: the shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule.

Planning Authority: the responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.

Planning Coordinator: see Planning Authority.

Planning Reserve Margin: an industry standard that measures the amount of generation capacity available to meet expected demand in the planning horizon.

Point-to-Point Transmission Service: a service that allows the customer to utilize a specified amount of transmission capacity to transmit power from designated points of receipt to designated points of delivery; a separate service agreement would be required and a separate charge generally would be paid for each pairing of a receipt point with a delivery point under this service (See also Firm Transmission Service and Non-Firm Transmission Service).

Power Factor: the ratio of real power (kW) to apparent power (kVA) at any given point and time in an electrical circuit, generally expressed as a percentage ratio.

Power Flow Model: a computerized algorithm that simulates the behavior of the electric system under a given set of conditions and used to compute voltages and flows of real and reactive power through all branches of the system.

Power Pools: two or more interconnected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance programs; can be tight (a group of electric companies that provide reciprocal transmission and/or power generating service for each other, coordinate their planning operations, and generally utilize central dispatch of generating plants) or loose (any multilateral arrangement other than a tight power pool or holding company arrangement).

Probabilistic Risk Assessment (PRA): risk assessment practice that uses probability distributions to characterize variability or uncertainty in risk estimates.

Provider of Last Resort: a legal obligation (traditionally given to utilities) to provide service to a customer where competitors have decided they do not want that customer's business.

NAVIGANT

Pseudo Tie: a telemetered reading or value that is updated in real time and used as a tie line flow in the Automatic Generation Control/Area Control Error equation but for which no physical tie or energy metering actually exists; the integrated value is used as a metered MWh value for interchange accounting purposes.

Public Utility Holding Company: see Holding Company.

Public Utility Holding Company Act (PUHCA): enacted by the U.S. Congress in 1935 to regulate the large interstate holding companies that monopolized the electric utility industry during the early 20th century (See also Holding Company).

Public Utility Regulatory Policies Act (PURPA): one of five bills signed into law on November 8, 1978, as the National Energy Act, PURPA promotes energy efficiency and increased use of alternative energy sources by encouraging companies to build cogeneration facilities and renewable energy projects by obligating utilities to purchase power from such facilities (called qualifying facilities or QFs); states set the prices and quantities of power the utilities must buy from such facilities (See also Qualifying Facilities).

PUHCA: see Public Utility Holding Company Act.

PURPA: see Public Utility Regulatory Policies Act.

Power Purchase Agreement (PPA): a contract entered into by an independent power producer and an electric utility that specifies the terms and conditions under which electric power will be generated and purchased.

Q

Quick Start Units: generating units with the ability to synchronize and load quickly, generally within 10 minutes.

Qualifying Facility (QF): a cogeneration, renewable energy, or small power production facility that meets certain size, fuel use, ownership, operating, and efficiency criteria established by FERC pursuant to PURPA and has filed with FERC for QF status or has self-certified; QFs are physical generating facilities (See also Public Utility Regulatory Policies Act).

R

Ramping: changing the loading level of a generator in a constant manner over a fixed time (e.g., ramping up or ramping down).

Rate Base: the value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority; generally represents the value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost.

Rate Class: a group of customers identified as a class and subject to a rate different from the rates of other groups.

Rate Structures: the design and organization of billing charges by customer class to distribute the revenue requirement among customer classes and rating period.

Rating: the operational limits of an electric system, facility, or element under a set of specified conditions.

Reactive Power: the portion of electricity, measured in volt amperes or kilovolt amperes, that establishes and sustains the electric and magnetic fields of alternating-current equipment, it must be supplied to most types of magnetic equipment, such as motors and transformers, and is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage.

Regional Reliability Organizations: regional organizations charged with maintaining system reliability even during abnormal bulk power conditions such as outages and unexpectedly high loads.

Regional Transmission Organization: an entity authorized by the federal government as a neutral, independent party to coordinate movement and trade of wholesale electricity across a high-voltage electric grid (See also Independent System Operator).

Regulated Frequency: the frequency that, over a period of time, is regulated to maintain the average frequency at some predetermined value, done in such a way that the deviations from their predetermined value are always small.

Regulating Reserve: generation capable of increasing or decreasing its output in response to a regulating control signal to control for frequency deviations.

Regulation Service: an ancillary service that provides for following the moment-to-moment variations in the demand or supply in a control area and maintaining regulated frequency.

Reliability: the degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired, which may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.

Reliability Coordinator: the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations.

Reliability Measures: characteristics of an electric system used to measure reliability, such as Expected Unserved Energy (EUE), Loss of Load Expectation (LOLE), Loss of Load Hours (LOLH), and Loss of Load Probability (LOLP).

Reliability Pricing Model (RPM): PJM's capacity market used to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEP) process (See also Capacity Market).

Renewable Portfolio Standard (RPS): a mandate, or goal, set to require or promote the use of renewable resources for electric generation. The Standard generally states that a certain percentage of a retail electric provider's overall or new generating capacity or energy sales must be derived from renewable resources, with the percentage increasing gradually over time.

Reserve: see Capacity Reserve.

Reserve Margin: the percentage of installed capacity exceeding the expected peak demand during a specified period, calculated as:

$$Reserve\ Margin = \frac{Resources - Peak\ Firm\ Demand}{Peak\ Firm\ Demand}$$

(See also Capacity Margin).

Reserve Sharing Group: a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group.

Resistance: a material's opposition to the flow of electric current, measured in ohms (Ω)
(See also Ohm's Law).

Resource Adequacy: insuring that sufficient electric generation, transmission and demand response infrastructure are available to allow each regional transmission organization or independent transmission provider to balance available generation resources with load requirements at all times.

Resource Planner: the entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area (See also Transmission Planner).

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Retail Competition: a system under which more than one electric provider can offer to sell to retail customers, and retail customers are allowed to choose more than one provider from whom to purchase their electricity.

Revenue Requirements: the sum total of the revenues required to pay all operating and capital costs of providing service.

Right of First Refusal (ROFR): the right to construct, own and propose cost recovery for any new transmission project that is located within an incumbent transmission owner's service territory and approved for inclusion in a transmission plan developed through FERC guidelines; FERC Order 1000 stated that it is unjust and unreasonable to grant incumbent transmission providers a federal right of first refusal with respect to certain transmission projects because doing so may result in the failure to consider more efficient or cost-effective solutions to regional needs and, in turn, result in the inclusion of higher-cost solutions in the regional plan.

Rights of Way: a corridor of land on which electric lines may be located; the Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines on the land.

RTO: see Regional Transmission Organization.

Rural Electric Cooperative (REC or REMC): a nonprofit, customer-owned electric utility that distributes power in a rural area.

S

Security: the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Security Constrained Economic Dispatch: defined in the Energy Policy Act of 2005 as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities".

Security Coordinator: see Reliability Coordinator

Single Phase Service: service of small electrical loads of residential customers, small commercial customers, and streetlights at 120V/240V and requires less and simpler equipment and infrastructure to support and tends to be less expensive to install and maintain.

Sink: delivery point of a transmission line, also referred to as the Output-, Receiving-, or Load-End.

Siting: the process of determining the ideal location for infrastructure such as transmission lines and generation facilities.

Source: source of electricity on a transmission line, also referred to as the Input-, Generator-, Transmitter-, or Sending-End.

Spinning Reserve: generating units connected to the electrical system and ready to take load, or operating below their rated level (See also Non-Spinning Reserve).

Stability: the ability of a power system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.

Standards of Conduct: standards for transmission providers that were strengthened and simplified through FERC Order No. 717, issued October 16, 2008; the Standards include three primary rules:

- The "independent functioning rule" requires transmission function and marketing function employees to operate independently of each other.
- The "no-conduit rule" prohibits passing transmission function information to marketing function employees.
- The "transparency rule," imposes posting requirements to help detect any instances of undue preference.

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Substation: a high-voltage electric system facility used to switch generators, equipment, and circuits or lines in and out of a system and to change AC voltages from one level to another, and/or change alternating current to direct current or direct current to alternating current.

Supervisory Control and Data Acquisition (SCADA): a system of remote control and telemetry used to monitor and control the electric system.

Surge: a sudden change in an electrical system's voltage that is capable of damaging electrical equipment, the most severe of which are caused by lightning.

System Average Interruption Duration Index (SAIDI): measure of system reliability defined as the minutes of sustained outages per customer per year.

System Average Interruption Frequency Index (SAIFI): measure of system reliability defined as the number of sustained outages per customer per year.

System Operating Limit: the value (such as MW, MVar, amperes, frequency, or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

T

Telemetering: the ability to read a meter from a distance using electronic communications devices.

Terawatt: one trillion watts.

Thermal Rating: the maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements; the capacity or transmission lines, transformers and other equipment is determined by these temperature limits.

Three Phase: electric energy transmitted by three or four wires at relatively high voltages with sinusoidal AC waves that are slightly out-of-phase by 120 degrees so that one is always positive; three-phase AC is the standard for the modern electric power system.

Tie Line: a circuit connecting Balancing Authority Areas.

Tolling: a charge for transmission service.

Total Transfer Capability (TTC): a best estimate of the total transmission or transfer capability of a defined path in a specific direction at a given time.

Transco: a stand-alone transmission company that has been approved by FERC and that sells transmission services at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility.

Transfer Capability: the measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions; units are in terms of electric power, generally expressed in MW; the transfer capability from "Area A" to "Area B" is not generally equal to the transfer capability from "Area B" to "Area A".

Transfer Distribution Factor (TDF): see Distribution Factor.

Transformer: an electromagnetic device for changing the voltage level of alternating current electricity.

Transient: a momentary change or imbalance in an electric or control system; the term can also refer to a change in nuclear reactor coolant system temperature and/or pressure due to a change in power output of the reactor.

Transmission: an interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

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Transmission Availability Data System (TADS): a nation-wide system developed by NERC to collect data about transmission.

Transmission Corridor: land zoned to be available for future electricity transmission projects; or a geographic area where transmission congestion or constraints adversely affect consumers.

Transmission Customer Transmission Loading Relief (TLR): a NERC procedure developed for the Eastern Interconnection to mitigate overloads on the transmission system by allowing reliability coordinators to request the curtailment of transactions that are causing parallel flows through their system.

Transmission Planner: the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority Area (See also Resource Planner).

Transmission Planning: the process of analyzing future reliability and determining future transmission project needs (See also Transmission Planner).

Transmission Reliability Margin (TRM): the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure; TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

Transmission Voltages: typically 69,000 V or 69 kV up to 765,000 V or 765 kV.

U

Unbundling: selling various component parts of a product or service separately, usually at a price that reflects costs for only that component of the product or service, for instance selling energy service separately from transmission and distribution service.

Undue Discrimination: for power, a criterion for determining illegal rates or service under the Federal Power Act.

Unforced Capacity (UCAP): in the New York Independent System Operator (NYISO), UCAP is the percentage of installed capacity (ICAP) that is available at any given time; UCAP is the unit used for buying and selling capacity on NYISO's ICAP market.

Uplift Charge: hourly and daily charges to all buyers of energy on the wholesale market to cover the cost of administering the hourly and day-ahead markets, respectively, as well as a monthly charge to cover planning.

V

Value of Lost Load (VOLL): the value that represents a customers' willingness to pay for reliable electricity service, generally measured in dollars per unit of power (i.e. $/kWh or $/MWh).

Variable Costs: costs that change or vary with usage, output or production.

Vertically-Integrated Utility: a utility that owns all the different aspects of making, selling, and delivering a product or service, for instance a utility that owns its own generating plants, transmission system, and distribution lines to provide all aspects of electric service to its customers.

Volt: a unit of measure of voltage; if steadily applied to a circuit having a resistance of one ohm, will produce a current one ampere (See also Voltage).

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Volt Ampere: a unit of measure of apparent power (See also Apparent Power).

Volt Ampere Reactive (VARs): a unit of measure of reactive power (See also Reactive Power).

Voltage: a measure of the potential energy in an electric charge; also the force or push of electricity and the effective potential difference between any two conductors or between a conductor and ground.

Voltage Control: the control of transmission voltage through adjustments in generator reactive output and transformer taps, and by switching capacitors and inductors on the transmission and distribution systems.

Voltage Reduction: any intentional reduction of system voltage by 3 percent or greater for reasons of maintaining the continuity of service of the bulk electric power supply system.

Voltage Support: an ancillary service that is required to maintain transmission and distribution voltages on the grid within acceptable limits.

W

Watt: the unit of electrical power equal to one ampere under a pressure of one volt; also equal to 1/746 horse power.

Watt-Hour: one watt of power expended for one hour.

Western Electricity Coordinating Council (WECC): one of the ten regional reliability councils that make up the North American Electric Reliability Corporation (NERC), formerly called the Western Systems Coordinating Council.

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Endnotes

[1] This phenomenon is called electromagnetic induction. See, for example, http://www.ndt-ed.org/EducationResources/HighSchool/Electricity/electroinduction.htm for the basic physics behind this discovery.
[2] The topics and chapters in this white paper follow in part those used in National Council on Electric Policy, "Electricity Transmission, A Primer," June 2004.
[3] PBS, "The American Experience, Edison's Miracle of Light, AC/DC What's the Difference," http://www.pbs.org/wgbh/amex/edison/sfeature/acdc.html.
[4] EIA Energy in Brief, "What is the electric power grid, and what are some challenges it faces?," http://www.eia.gov/energy_in_brief/article/power_grid.cfm.
[5] In a series of cases, beginning with *Munn v. Illinois, 94 U.S. 113 (1876)*, the U.S. Supreme Court began to expand the application of the concept of "public interest" by saying there are certain businesses that are "clothed with a public interest", which may justify government regulation.
[6] EIA, "Annual Outlook for U.S. Electric Power, 1985," DOE/EIA-0474(85) (August 1985), page 3.
[7] In general terms, when intrastate commerce has a substantial effect on interstate commerce, Congress may regulate the activity pursuant to the Commerce Clause. See http://nationalparalegal.edu/conlawcrimproc_public/CongressionalPowers/SubstantialEffect.asp.
[8] PBS, "Frontline, Public vs. Private Power: from FDR to Today," http://www.pbs.org/wgbh/pages/frontline/shows/blackout/regulation/timeline.html.
[9] EIA Energy in Brief, "What is the electric power grid, and what are some challenges it faces?," http://www.eia.gov/energy_in_brief/article/power_grid.cfm.
[10] American Electric Power, "Transmission," http://www.aep.com/about/IssuesAndPositions/transmission/.
[11] PJM, "PJM History," http://www.pjm.com/about-pjm/who-we-are/pjm-history.aspx.
[12] ISO-New England, "History," http://www.iso-ne.com/aboutiso/co_profile/history/; Analysis Group, "The New York Independent System Operator: A Ten-Year Review," April 12, 2010; Michigan Public Service Commission, Case No. U-11290, "Electric Restructuring Staff Market Power Discussion Paper," June 5, 1998.
[13] FERC, "Fact Sheet, Energy Policy Act of 2005," August 8, 2006.
[14] FERC Order No. 888, Final Rule, April 24, 1996, Summary.
[15] James Fama, "Keeping the Electricity Moving: NERC Guards the Bulk Power Grid," ASME, March 2011.
[16] DOE, "Top 9 Things You Didn't Know About America's Power Grid," September 20, 2013, http://energy.gov/articles/top-9-things-you-didnt-know-about-americas-power-grid.
[17] 16 USC 824(e). See FERC, "An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities in the United States," Lawrence R. Greenfield, Associate General Counsel – Energy Markets, Office of the General Counsel; and FERC Order No. 667-A, paragraph 31.
[18] FERC Docket No. RM11-26-000, "Promoting Transmission Investment Through Pricing Reform," November 15, 2012.
[19] FERC Order No. 1000, page 226.
[20] In FERC Order No. 743, FERC clarified that the term Bulk Power System (BPS), used in the FPA, was distinct and more expansive than the NERC-defined term, BES, which determines the enforcement applicability of the Reliability Standards. See "Revision to Electric Reliability Organization Definition of Bulk Electric System," 133 FERC ¶ 61,150 (Order No. 743) (Nov. 2010) at page 36.
[21] National Governors Association, "State Strategies for Accelerating Transmission Development for Renewable Energy," January 20, 2012.
[22] Calif. Wilderness Coalition v. U.S. Department of Energy, No. 08-71074 (9th Cir. Feb. 1, 2011).

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[23] *Piedmont Envtl Council v. FERC*, 558 F.3d 304 (4th Cir. 2009).
[24] NERC, "Reliability Functional Model, Version 5," November 2009, page 6.
[25] NERC, "2012 Summer Reliability Assessment," pages 162-3.
[26] FERC Order No. 679, paragraph 201.
[27] FERC Order No. 1000, paragraph 119.
[28] FERC Order No. 1000, paragraph 225.
[29] FERC Order No. 1000-A, paragraph 420.
[30] FERC Order No. 1000, paragraph 225.
[31] FERC, "Order on Rehearing and Clarification," Primary Power LLC, Docket No. ER10-253-001, July 19, 2012, page 2, paragraph 1, footnote 5.
[32] NERC, "Project 2010-17 Definition of Bulk Electric System," November 8, 2013.
[33] NYISO, "NYISO 2012 Reliability Needs Assessment," September 2012, page 26.
[34] DOE, "National Transmission Grid Study, Issue Paper: Transmission System Operation and Interconnection," May 2002, page A-6.
[35] PJM, "Manual 14B," section 2.3.8.
[36] DOE, "National Transmission Grid Study, Issue Paper: Transmission System Operation and Interconnection," May 2002, page A-6.
[37] For example, in NPCC, "The probability (or risk) of disconnecting firm load due to resource deficiencies shall be, on average, not more than one day in ten years as determined by studies conducted for each Resource Planning and Planning Coordinator Area." See NPCC, "Reliability Reference Directory # 1 Design and Operation of the Bulk Power System," (December 2009), section 5.1.1.
[38] See Astrape Consulting, "The Economic Ramifications of Resource Adequacy White Paper" prepared for EISPC/NARUC, January 2013.
[39] PJM, "Manual 14B," section 1.5.2.
[40] DOE, "National Transmission Grid Study, Issue Paper: Transmission System Operation and Interconnection," May 2002, page A-11.
[41] NERC, "2013 Long-Term Reliability Assessment, Continued Integration of Variable Generation," pages 22-27.
[42] Ibid.
[43] Ibid.
[44] PJM, "A Survey of Transmission Cost Allocation Issues, Methods and Practices," 2010.
[45] New York v. FERC (00-568) 535 U.S. 1 (2002) 225 F.3d 667.
[46] In some retail open-access states (e.g., New York), transmission rates are bundled with distribution rates and recovered under retail tariffs.
[47] Note that these FERC-related examples would not apply to the Texas Interconnection, Alaska or Hawaii, which are not under FERC jurisdiction.
[48] FERC, Docket No. EL5-121-008, "Order on Rehearing," March 31, 2013.
[49] FERC, Docket No. ER10-1069-000, Southwest Power Pool, Inc., "Order Accepting Tariff Revisions," June 17, 2010.
[50] PJM, "A Survey of Transmission Cost Allocation Issues, Methods and Practices," 2010.
[51] FERC Order No. 1000, paragraph 819 and FERC Order No. 1000-A, paragraph 772.
[52] United Nations, Department of Economic and Social Affairs, Division for Sustainable Development, "Multi-Dimensional Issues in International Electric Power Grid Interconnections, Chapter 2: Technical Aspects of Grid Interconnection".
[53] Ibid.
[54] Ibid.
[55] Ibid.

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[56] Ibid.

[57] Ibid.

[58] FERC Staff Report, "Reactive Power Supply and Consumption," Docket No. AD05-1-000, Feb. 4, 2004, Chapter 1.

[59] http://www.ferc.gov/market-oversight/guide/glossary.asp.

[60] Monitoring Analytics, "2013 Quarterly State of the Market Report for PJM: January through September", Section 9.

[61] United Nations, Department of Economic and Social Affairs, Division for Sustainable Development, "Multi-Dimensional Issues in International Electric Power Grid Interconnections, Chapter 2: Technical Aspects of Grid Interconnection".

[62] Ibid.

[63] Ibid.

[64] NAESB, "Transmission Loading Relief Business Practices – Eastern Interconnection".

[65] DOE, Office of Electricity Delivery and Energy Reliability, "Summary of the North American SynchroPhaser Initiative (NASPI) Activity Area".

[66] Ibid.

[67] DOE, Office of Electricity Delivery & Energy Reliability, "Advanced Modeling Grid Research Program," http://energy.gov/oe/technology-development/advanced-modeling-grid-research-program.

[68] DOE, Office of Electricity Delivery and Energy Reliability, "Superconductivity Program Overview".

[69] DOE, Office of Electricity Delivery and Energy Reliability, "Transmission Reliability Program".

[70] NERC, "Cyber Security Standards Transition Guidance," April 11, 2013; FERC, Docket No. RM13-5-000, "Version 5 Critical Infrastructure Protection Reliability Standards," November 22, 2013.

[71] Energy Sector Control Systems Working Group, "Roadmap to Achieve Energy Delivery Systems Cybersecurity," September 2011.

[72] Ibid.

[73] FERC Order No. 679, paragraph 201.

[74] FERC Order No. 679, paragraph 202.

[75] FERC Order No. 1000, paragraph 116.

[76] FERC Order No. 1000, paragraph 163.

[77] FERC Order No. 1000, paragraph 225.

[78] FERC Order No. 1000-A, paragraph 420.

[79] FERC Order No. 1000, paragraph 225.

[80] FERC, Docket No. ER10-253-001, "Order on Rehearing and Clarification," July 19, 2012, page 2, paragraph 1, footnote 5.

[81] FERC Order No. 1000, paragraph 819 and FERC Order No. 1000-A, paragraph 772.

[82] EIPC, "Phase II Report, Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios," Section 5.0, December 2012, http://www.eipconline.com/Phase_II_Documents.html.

EDH-11

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell and Joseph T. Kelliher.

New England Power Pool Docket Nos. ER04-335-001
ER04-335-002

ORDER ON REHEARING AND
ACCEPTING COMPLIANCE FILING

(Issued May 28, 2004)

I. Introduction

1. In this order, we grant in part and deny in part requests for rehearing of our order conditionally accepting changes to New England Power Pool (NEPOOL) Market Rule 1.[1] We also accept a compliance filing made in response to that order. This order benefits customers by clarifying the scope of the February 27 Order.

II. Background

2. On December 23, 2003, NEPOOL filed changes to NEPOOL Market Rule 1-NEPOOL Standard Market Design. The proposed changes to Market Rule 1 added a new section 10 entitled, "Gap RFPs for Reliability Purposes." Specifically, the proposed changes to Market Rule 1 would apply whenever ISO New England, Inc. (ISO-NE) determines the need for requests for proposals (RFPs) to address near-term reliability concerns while long-term solutions are being implemented. New section 10 would allow ISO-NE to issue Gap RFPs and enter into contracts awarded pursuant to the Gap RFP program,[2] with informational filings at the Commission for both the Gap RFP and the resulting contracts.

3. The February 27 Order conditionally accepted NEPOOL's proposed changes for filing. In pertinent part, it determined as follows:

> The Commission is concerned that as filed the proposed language is very broad and could lead to ISO-NE becoming the entity that contracts for new supplies whenever new resources are needed to meet the reliability needs of

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[1] New England Power Pool, 106 FERC ¶ 61,190 (2004) (February 27 Order).

[2] Id. at P 2-4.

> the region. Additionally, these changes would occur without Commission review, since all filings would be made as informational filings that do not require prior Commission approval. We are currently examining the issue of whether [independent system operators] and [regional transmission organizations] should be responsible for procuring new supplies. Consequently, while we are examining this issue, we are unwilling to authorize such a broad program for ISO-NE to acquire resources. Rather, we believe the proposed authority to obtain necessary resources must be reviewed by the Commission on a case by case basis, rather than left to the discretion of ISO-NE after consultation with the NEPOOL Reliability Committee. Therefore, we will condition our acceptance on revisions to the language of new section 10 to provide that ISO-NE will obtain Commission approval to issue a Gap RFP at least 60 days prior to the date it intends to issue the RFP. For the same reasons, and consistent with section 205 of the Federal Power Act, 16 U.S.C. § 824d (2000), we will also require the successful bidder to file for approval of the rates to be charged under the supply arrangement to the extent that such contracts are for jurisdictional services.[[3]]

4. Timely requests for rehearing of the February 27 Order were filed by PSEG Energy Resources & Trade LLC (PSEG), and NEPOOL and ISO-NE (filing jointly). On April 13, 2004, NEPOOL and ISO-NE filed an answer to PSEG's request for rehearing. On April 27, 2004, PSEG filed an answer to NEPOOL and ISO-NE's answer. PSEG argues that NEPOOL and ISO-NE's answer should be rejected as impermissible. Alternatively, if the Commission permits NEPOOL and ISO-NE's answer, then PSEG requests that its answer be permitted.[4] On May 3, 2004, the Connecticut Department of Public Utility Control filed a letter expressing support for the results of the Southwest Connecticut RFP and the February 27 Order.

5. In its request for rehearing, PSEG argues that the Commission erred by not imposing additional safeguards to ensure that the Gap RFP program does not exceed its appropriate scope and that the program is conducted fairly. First, PSEG argues that the Commission should specify that the need for the Gap RFP would be based on the same reliability criteria as any Locational Installed Capacity (LICAP) program that is used to

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[3] Id. at P 8 (footnote omitted).

[4] We will deny NEPOOL and ISO-NE's answer and PSEG's answer, because our Rules of Practice and Procedure prohibit answers to requests for rehearing and similarly disfavor answers to answers. See 18 C.F.R. §§ 385.213(a)(2), 385.713(d) (2003).

determine locational purchase requirements.[5] PSEG argues that the implementation of the Gap RFP mechanism and the LICAP mechanism must be consistent and applied in a coordinated manner. PSEG further argues that ISO-NE should be required to implement a definite sunset date for the Gap RFP program and any related Gap RFP contracts, based on the implementation of the LICAP program.

6. Second, PSEG argues that the Commission should require ISO-NE, following the acceptance of input through a stakeholder process, to modify its tariff to explain in detail how the Gap RFP process will be conducted. PSEG proposes criteria for the selection process. PSEG also contends that the current selection process gives ISO-NE too much discretion.

7. Third, PSEG argues that the Commission should eliminate the February 27 Order's requirement that the winning bidder obtain prior Commission approval of any jurisdictional rates and, instead, require that ISO-NE demonstrate that the winning bid met PSEG's suggested RFP requirements and that the RFP selection criteria were properly applied. PSEG asserts that bidders with market-based rate authority should be able to enter into jurisdictional contracts without receiving prior Commission approval of the rates. According to PSEG, because the Commission has already determined that a seller with market-based rate authority does not possess the ability to exercise market power, the rates determined through a properly designed, competitive RFP process should be deemed just and reasonable. Further, with respect to the Gap RFP process utilized by ISO-NE for Southwest Connecticut,[6] PSEG argues that ISO-NE's tariff requires that the Gap RFP process be "competitive;" if that cannot be demonstrated based on the record, the resultant rates under the Gap RFP contracts will not be in conformance with the filed rate and would not meet the general standards for market-based rates.

8. NEPOOL and ISO-NE request clarification of the February 27 Order with respect to the implementation of the required changes to section 10 of Market Rule 1. First, they request clarification that the Commission did not intend to require the filing either of "any contracts with municipally-owned entities"[7] or of contracts that relate to load

[5] PSEG notes that, on March 1, 2004, in Docket No. ER03-563-030, ISO-NE filed a proposed long-term LICAP mechanism for New England. The Commission will address ISO-NE's LICAP proposal in an order issued in that proceeding.

[6] When NEPOOL filed the Gap RFP proposal, ISO-NE had already issued the Southwest Connecticut RFP and the contracts would be for reliability needs this summer. Thus, the Commission allowed that process to go forward. February 27 Order, 106 FERC ¶ 61,190 at P 10.

[7] We interpret "any contracts with municipally-owned entities," to refer to contracts in which municipally-owned entities are the winning sellers/bidders.

response and other forms of conservation and load management. Second, NEPOOL and ISO-NE request clarification whether any filings that are to be made should be submitted on a confidential basis, or whether they should be publicly available.

9. On March 29, 2004, in Docket No. ER04-335-002, NEPOOL submitted a compliance filing pursuant to the February 27 Order. Notice of NEPOOL's compliance filing was published in the Federal Register,[8] with motions to intervene and protests due on or before April 19, 2004. None was filed.

III. Discussion

A. Rehearing

10. PSEG has belatedly raised issues concerning whether the Gap RFP and LICAP programs should have consistent reliability criteria, its suggested criteria for the Gap RFP process and its concerns about the Southwest Connecticut RFP. PSEG never protested the original filing. In fact, PSEG filed comments urging the Commission to accept the original filing.[9] Thus, PSEG had an opportunity to raise, but failed to raise, these issues prior to the Commission's February 27 Order. Absent compelling reasons, we typically do not consider arguments raised for the first time on rehearing.[10] Accordingly, we need not address these arguments.

11. While we need not consider PSEG's arguments, we find that, even if they were properly before us, they are unpersuasive. Regarding PSEG's concerns about the process and criteria for future Gap RFPs, PSEG is not aggrieved by the February 27 Order. As the order determined, ISO-NE would have to file for approval of future Gap RFP proposals prior to their issuance, which will allow for parties to comment on, and the Commission to impose conditions on, such RFPs before they are issued. Further, imposing conditions generically would be inconsistent with the Commission's decision to review future Gap RFPs case-by-case. The fact that PSEG believes that its proposed selection criteria would be an improvement upon the ISO-NE's selection criteria also does not support requiring ISO-NE to adopt PSEG's suggestions. In the February 27 Order, the Commission found that the proposed tariff provisions, as modified, were acceptable in light of the Commission's ability to review individual Gap RFPs prior to issuance and its ability to review jurisdictional contracts resulting from any Gap RFP. With regard to the Southwest Connecticut RFP, which seeks 300 MW of quick-start

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[8] 69 Fed. Reg. 18,895 (2004).

[9] February 27 Order, 106 FERC ¶ 61,190 at P 6.

[10] See, e.g., Carolina Power & Light Co., 106 FERC ¶ 61,141 at P 15 & n.7 (2004), and the cases cited therein.

capacity in Southwest Connecticut for the summer of 2004, it would be unduly disruptive to that process and would adversely affect reliability in that area to revisit the selection criteria at this late stage of that process -- particularly where the concerns are belatedly raised.

12. We also deny PSEG's request to replace the February 27 Order's requirement that the winning bidder make a filing seeking Commission approval of any contract for jurisdictional services with a requirement that ISO-NE demonstrate that it has met the criteria suggested by PSEG. In this regard, PSEG argues that the rates of a public utility with pre-existing market-based rate authorization are presumptively just and reasonable because the Commission has already determined that such utility lacks market power. The Commission has held that long-term power sales agreements entered into pursuant to previously granted market-based rate tariffs are not traditional FPA section 205 filings but are submitted for information purposes only. That is, the filing of such agreements does not serve as a vehicle to challenge the justness and reasonableness of either the agreements themselves or the underlying market-based rate authority.[11] However, the Gap RFP program is a new and unique program. The contracts resulting from future Gap RFPs would not serve as a vehicle to revisit previously granted market-based rate authority, but they would instead provide a vehicle to review matters such as whether the selection of the winning bidder/seller in the Gap RFP was in accordance with the authorized RFP process or whether the resulting contract is consistent with the Gap RFP. Therefore, our review of any jurisdictional contracts resulting from any future Gap RFPs, as well as of the Gap RFPs themselves, under section 205 of the FPA, will ensure that any rates, terms and conditions are reasonable. Moreover, as the February 27 Order stated, the Commission is still examining the issue of whether ISOs and RTOs should be responsible for procuring new supplies, and we will have opportunities to revisit this topic again as our thinking evolves.[12]

13. With respect to NEPOOL and ISO-NE's request for clarification concerning what contracts should be filed, we clarify that where municipally-owned entities are the winning sellers/bidders, they need not file such contracts, because they are exempt from regulation as public utilities under section 201(f) of the FPA.[13] Consistent with our practice of not requiring individual contracts under load response programs to be filed, we also will not require winning bidders for conservation and load management to file

[11] See, e.g., GWF Energy LLC and Southern Co. Services, Inc., 97 FERC ¶ 61,297 at 62,390-91 (2001), reh'g denied, 98 FERC ¶ 61,330 at 62,390-91 (2002).

[12] The role of the ISO in the procurement of power is a topic more generally raised in Docket No. ER03-563-030, mentioned supra note 5.

[13] 16 U.S.C. § 824(f) (2000).

such contracts.[14] With respect to the issue of confidentiality, the FPA as well as the Commission's precedent require contracts for jurisdictional services to be filed in non-confidential, unredacted form.[15] Therefore, such contracts must be filed in non-confidential, unredacted form.

B. NEPOOL's Compliance Filing

14. In the compliance filing, NEPOOL has revised section 10 of Market Rule 1 to provide for broader Commission oversight of the Gap RFP and resulting contracts in accordance with the Commission's directive in the February 27 Order. Accordingly, we will accept the compliance filing, as ordered below.

The Commission orders:

(A) The requests for rehearing of the February 27 Order are hereby granted in part and denied part, as discussed in the body of this order.

(B) NEPOOL's compliance filing is hereby accepted, as discussed in the body of this order.

By the Commission. Commissioner Kelly not participating.

(S E A L)

Linda Mitry,
Acting Secretary.

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[14] See generally PJM Interconnection, L.L.C., 99 FERC ¶ 61,139 (2002).

[15] 16 U.S.C. § 824d (2000); see, e.g., ISO New England, Inc., 103 FERC ¶ 61,018 at P 7 (2003).

EDH-12

Load Management Performance Report 2015/2016

August 2016

pjm

PJM has made all efforts possible to accurately document all information in this report. However, PJM cannot warrant or guarantee that the information is complete or error free. The information seen here does not supersede the PJM Operating Agreement or the PJM Tariff both of which can be found by accessing: http://www.pjm.com/documents/agreements/pjm-agreements.aspx

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Contents

Executive Summary

Load Management Demand Resources (DR) have the ability to participate as a capacity resource in the PJM capacity market (Reliability Pricing Model or RPM) or to support a Load Serving Entity's Fixed Resource Requirement (FRR) plan. There were three DR products available during the 2015/2016 Delivery Year: Limited DR, Summer Extended DR, and Annual DR. This is the second Delivery Year that the Summer Extended and Annual products were available.

A Curtailment Service Provider (CSP) is the PJM member that nominates the end use customer location(s) as a capacity resource and is fully responsible for the performance of the resource. Load Management products are required to respond to PJM Pre-Emergency or Emergency Load Management events, based on the availability period for each product (see Table 2: DR product availability), or receive a penalty. PJM may declare Emergency Load Management events outside the required availability window but does not measure capacity compliance in such cases (resources are eligible for emergency energy revenue if they reduce load). Load Management that is not dispatched during its availability period must perform a mandatory test to demonstrate it can meet its capacity commitment or receive a penalty.

Table 1 shows both the mandatory event and test performance values for the past 7 delivery years. In the years where there was more than one event, the event performance is the event MW weighted average of all of the events. PJM Load Management events outside the mandatory compliance period are excluded from the results. There were no Load Management events in the 2015/16 delivery year. Test performance was 134%. Historically, test performance has been substantially higher than event performance which is largely a function of the difference in the test requirements compared to what a resource must do when dispatched during Load Management Event.

Table 1: Annual performance summary. Only events with mandatory compliance are included.

Delivery year	Event performance	Test performance
2009/10	No Events	118%
2010/11	100%	111%
2011/12	91%	107%
2012/13	104%	116%
2013/14	94%	129%
2014/15	No Events	144%
2015/16	No Events	134%

Overview

PJM Interconnection, L.L.C. procures capacity for its system reliability through the Reliability Pricing Model (RPM). The sources for meeting system reliability are divided into four groups:

1) Generation Capacity

2) Transmission Upgrades

3) Load Management (Pre-Emergency and Emergency Demand Resources)

4) Energy Efficiency

There were three Load Management Products available during the 2015/16 Delivery Year[1]: Limited DR, Extended Summer, and Annual. The availability period for each of the products is in Table 2. By default, the interruptions must be implemented within thirty minutes of notification by PJM. Those resources that cannot be fully implemented within thirty minutes of notification and qualify for an exception may respond within either 60 or 120 minutes depending on their capabilities and the exception they qualify for.

Table 2: DR product availability window.

DR Product	Max. interruptions	Max. event duration (hrs)	Availability period	Availability Hours (EPT)
Limited	10	6	June – September Non-NERC Hol. Wkdys.	12PM – 8PM
Extended Summer	Unlimited	10	June – October, May	10AM – 10PM
Annual	Unlimited	10	June – October, May	10AM – 10PM
			November - April	6AM – 9PM

DR compliance can be more complex to measure than compliance for generation resources meeting their capacity obligations. In order to ensure the reliability service for which a resource is paid has actually been provided, PJM utilizes three different types of measurement and verification methodologies. DR Resources can choose the most appropriate of the following measurement methodologies:

- Direct Load Control (DLC) – Load Management for non-interval metered customers which is initiated directly by a Curtailment Service Provider's (CSP) market operations center, employing a communication signal to cycle HVAC or water heating equipment. This is traditionally done for residential consumers and requires the necessary statistical studies as outlined in PJM Manual 19 or other PJM approved measurement and verification methodology.
- Firm Service Level (FSL) – Load Management achieved by a customer reducing its load to a pre-determined level upon the notification from the CSP's market operations center. The customer must be able

[1] The Delivery Year for the capacity construct corresponds to PJM's Planning Year which runs each year from June 1 until May 31 of the following year.

to reduce load below the pre-determined level which must be lower than the amount of capacity reserve for the customer as represented by the peak load contribution (PLC).

- Guaranteed Load Drop (GLD) – Load Management achieved by a customer reducing its load below the PLC when compared to what the load would have been absent the PJM event or test.

Participation Summary

The capacity numbers in this report are in terms of either Installed Capacity (ICAP) or Unforced Capacity (UCAP) depending upon which is most relevant. PJM calculates the Resource amounts required to meet the reliability standard in terms of UCAP which is also utilized to measure compliance with a RPM commitment. PJM determines the UCAP value of different types of Resources based on methods described in the PJM manuals.

Figure 1 shows Load Management Commitments by Delivery Year from 2007/08 through 2018/19 based on what cleared in the RPM auctions (BRA, IAs, and CP Transition Auctions) or as part of a LSEs FRR plan. Load Management participation in the PJM capacity market substantially increased from the 2007/08 Delivery Year through the 2011/12 Delivery Year, then declined, and has marginally increased since 2012/13. The final commitment values for the next three Delivery Years are uncertain since the values can still be adjusted in the Incremental Auctions and via Replacement Capacity Transactions and Transition Mechanisms. For the 2015/16 Delivery Year, Load Management capacity commitments represented 10,927 MW of ICAP while total registered Load Management represented 11,635 MW. Registered Emergency DR may be in excess of the commitment if the CSP has indicated they have the potential to deliver an amount that is higher than their actual commitment[2].

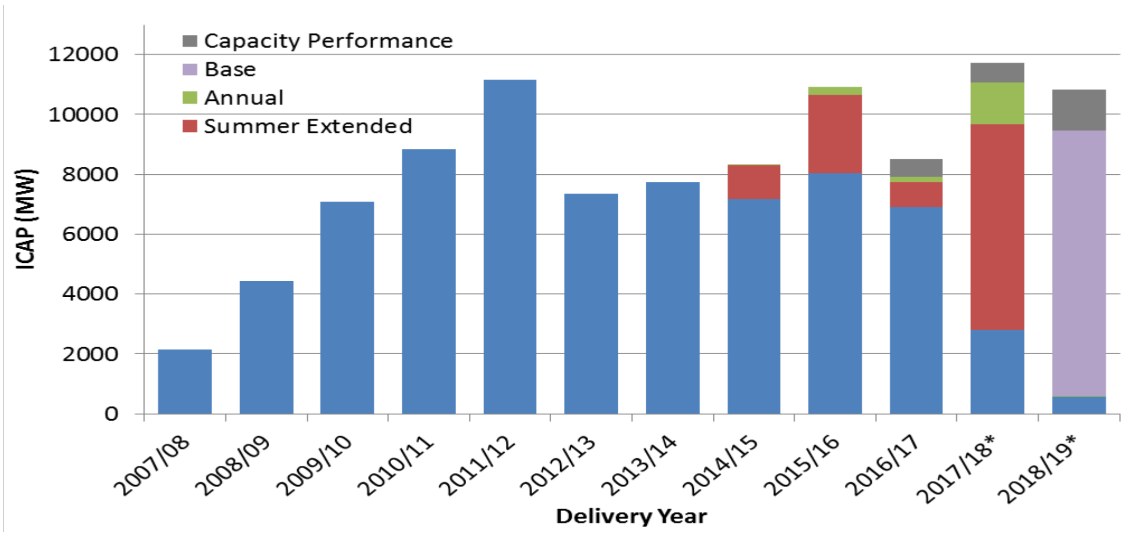

Figure 1: Load Management capacity commitment in ICAP (RPM and FRR) for each Product type. Asterisk indicates that future commitment may change based on replacement transactions, Incremental Auctions, etc.

[2] For example, a CSP may clear 10 MW of resources in an RPM auction but register 11 MW load reduction capability by end use customers to fulfill such commitment.

Table 3 shows the committed ICAP by Product Type (Limited, Extended Summer, Annual) for each of the 20 PJM zones for the 2015/16 Delivery Year. 69 PJM members or affiliates operate as a Curtailment Service Provider and over 2 million end use customers across almost every segment (residential, commercial, industrial, government, education, agricultural, etc.) participate as Load Management resources.

Table 3: Committed ICAP (MW) by Product Type and Zone for the 2015/16 Delivery Year.

Zone	Annual DR	Extended Summer DR	Limited DR	Total
Atlantic City Electric (AECO)		72	58	130
American Electric Power (AEP)	82	84	1571	1737
Allegheny Power (APS)	13	184	550	746
American Transmissions Systems Inc. (ATSI)	52	440	554	1046
Baltimore Gas and Electric (BGE)	5	63	694	762
Commonwealth Edison (COMED)	16	534	1053	1603
Dayton Power & Light (DAY)	15	15	145	175
Duke Energy Ohio & Kentucky (DEOK)		96	210	306
Dominion Virginia Power (DOM)	57	90	740	887
Delmarva Power & Light (DPL)		91	207	298
Duquesne Light (DUQ)	1	34	135	171
East Kentucky Power Cooperative (EKPC)			132	132
Jersey Central Power & Light (JCPL)		48	126	173
Metropolitan Edison (METED)		82	190	271
PECO (PECO)		161	316	476
Pennsylvania Electric Company (PENELEC)		59	228	287
Pepco (PEPCO)		205	330	535
Pennsylvania Power & Light (PPL)	0	240	533	774
Public Service Enterprise Group (PSEG)	24	108	252	384
Rockland Electric Company (RECO)		0	7	7
Total	**266**	**2603**	**8033**	**10902**

Load Management resources are registered by Lead Time, Product Type, Measurement Method, Program Type, and Resource Type. Figure 2 shows the breakdown of Committed ICAP for each item. This is the first year that the 30 minute lead time was mandatory. 60 or 120 minute lead times could be used if a resource qualified for an exception. The energy offer cap is $1,849/MWh for 30 minute, $1425/MWh for 60 minute and $1,100/MWh for 120 minute. 63% of resources were able to respond in 30 minutes, while 32% qualified for a 120 minute exception, and the remaining 5% qualified for a 60 minute exception.

The Product Type commitment level is determined by what is cleared in the RPM auctions. 74% of committed ICAP was Limited, 2% is Annual, and the remaining 24% is Extended Summer (see Figure 2). The compliance measurement method is 94% Firm Service Level (FSL), 2% Guaranteed Load Drop and 4% Non-interval Direct Load Control (legacy direct load control without interval metering).

Figure 2 shows that 97% of committed ICAP is registered as Load Management DR Full. The remaining 3% is registered as Capacity Only. Load Management Full resources receive both a capacity revenue stream as well as an emergency energy revenue when there is Load Management event. Capacity Only means that resource receives capacity payments but is not eligible for emergency energy payments during Load Management events and is typically only used for some legacy EDC related tariff requirements or for registrations that participate with two different CSPs.

Load Management resource designations are split into Pre-Emergency and Emergency. The default designation is Pre-Emergency; Figure 2 shows that 82% of committed ICAP fell into this category. The Emergency classification is for those resources that use behind the meter generation and have environmental restrictions that permit them to run only during PJM emergency conditions. 18% of resources met this condition.

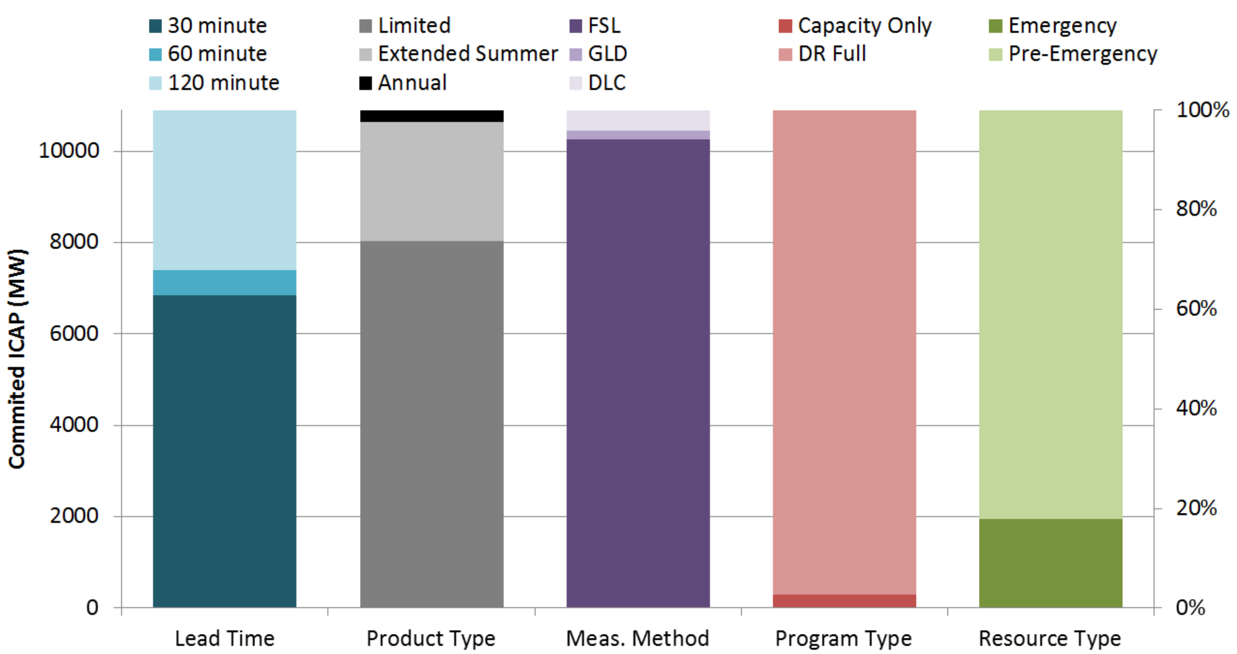

Figure 1: Committed ICAP for DR by Resource Type, Lead Time, Program Type, and Measurement Method for the 2015/16 Delivery Year.

Test Requirement Overview

If a Load Management Registration is not called in a mandatory Load Management event, the CSP must test the Registration. The Load Management Test is initiated by a Curtailment Service Provider (CSP) that has a capacity commitment. The CSP must simultaneously test all Registrations of the same product type in a Zone if PJM has not called a mandatory event for those Registrations. If a PJM-initiated Load Management Event is called for those Registrations during the product availability period, there is no test requirement and no Test Failure Charges would be assessed to a CSP for those registrations.

The timing of a Load Management Test is intended to represent the conditions when a PJM-initiated Load Management event might occur in order to assess performance during a similar period. The Limited Product must be tested on a non-holiday weekday from June – September between 12PM and 8PM of that Delivery Year. The Extended and Annual Products must be tested on a non-holiday weekday in June – October or May from 10AM – 10PM. All of a CSP's committed DR Registrations in the same Zone and Product that have not been called in a PJM initiated event are required to test at the same time for a one hour period. The requirement to test all resources in a zone simultaneously is necessary to ensure that test conditions are as close to realistic as possible. It is requested that the CSP notify PJM of intent to test 48 hours in advance to allow coordination with PJM dispatch.

There is not a limit on the number of tests a CSP can perform. However, a CSP may only submit data for one test to be used by PJM to measure compliance. If the CSP's Zonal Resources collectively achieve a reduction greater than 75% of the CSP's committed MW volume during the test, the CSP may choose to retest the Resources in that Zone that failed to meet their individual nominated value.

Load Management Resources are assessed a Test Failure Charge if their test data demonstrates that they did not meet their commitment level. The Test Failure Charge is calculated based on the CSP's Weighted Daily Revenue Rate which is the amount the CSP is paid for their RPM commitments in each Zone. The Weighted Daily Revenue Rate takes into consideration the different prices DR can be paid in the same Zone. For example, a CSP can clear DR in the Base Residual and/or Incremental Auctions in the same Zone, all of which are paid different rates. The penalty rate for under-compliance is the greater of 1.2 times the CSP's Weighted Daily Revenue Rate or $20 plus the Weighted Daily Revenue Rate. If a CSP didn't clear in a RPM auction in a Zone, the CSP-specific Revenue Rate will be replaced by the PJM Weighted Daily Revenue Rate for such Zone.

Test Performance

Since there were no Load Management events during the 2015/2016 Delivery Year, all resources that are committed for the Delivery Year were required to perform tests to assess their performance capability. 10,902 MW (ICAP) were committed as Load Management Resources. The net result of the testing was 3,675 MW of over-compliance or a performance level of 134% across all zones. Table 4 shows the results by product. The zonal level results for all products combined are in Table 5. The net result for each zone is over-compliance, however there were some individual CSPs whose tests resulted in under compliance.

Table 4: Load Management commitments, compliance, and test performance (ICAP) by product, DY2015/16

Product	Committed ICAP (MW)	Reduction (MW)	Over/under performance (MW)	Performance (%)	Re-test (%)
Limited	8,033	10,691	2,658	133	3
Extended Summer	2,603	3,575	971	137	0
Annual	266	312	46	117	4
Total	**10,902**	**14,577**	**3,675**	**134**	**3**

Table 5: Load Management commitments, compliance, and test performance (ICAP by Zone, DY2015/16)

Zone	Committed ICAP (MW)	Reduction (MW)	Over/under performance (MW)	Performance (%)	Re-test (%)
AECO	131	144	14	111	6
AEP	1,737	2,051	314	118	1
APS	746	835	88	112	3
ATSI	1,046	1,451	405	139	5
BGE	762	1,611	849	211	1
COMED	1,603	1,813	210	113	0
DAY	175	219	44	125	0
DEOK	306	374	68	122	0
DOM	887	1,048	161	118	4
DPL	295	731	437	248	0
DUQ	171	210	40	123	0
EKPC	132	143	11	108	0
JCPL	173	200	27	116	1
METED	271	310	39	114	11
PECO	479	562	83	117	1
PENELEC	287	329	42	115	9
PEPCO	535	1,248	713	233	0
PPL	774	859	84	111	12
PSEG	384	429	45	112	1
RECO	7	9	2	125	0
Total	**10,902**	**14,577**	**3,675**	**134**	**3**

Test Failure Charges for the 2015/16 Delivery Year are applied on an individual CSP/Zone basis for settlement purposes. However, the Test Failure Charges are reported on an aggregate basis here to preserve confidentiality. The weighted average Penalty Rate for the 2015/16 Delivery Year is $167/MW-day ($140 last year). The annual penalties for under-compliance total about $6.3M which will be allocated to RPM LSEs pro-rata based on their Daily

Load Obligation Ratio ($2.7M last year). Therefore, the under-compliance penalties are about 0.69% of the total Load Management credits ($900 M) in RPM this year compared to 0.40% ($685 M of credits) last year. Table 6 below shows Penalties by Product for the 2015/2016 Delivery Year.

Table 6: Load Management Test Penalties by Product, DY2015/16

Product	Penalties $	Shortfall (MW)	Average Weighted Penalty Rate ($/MW-day)	Penalties as % of Total LM Credits ($900M)
Limited	$5,899,249	97	$166	0.65%
Extended Summer	$113,775	2	$164	0.01%
Annual	$250,620	4	$185	0.03%
Total	**$6,263,643**	**103**	**$167**	**0.69%**

EDH-13

RPM 101
Overview of Reliability Pricing Model

Agenda

- Introduction
- Resource Adequacy
- Demand in RPM
- Supply in RPM
- Auction Structure
- Auction Clearing
- Resource Clearing Prices
- CTRs & ICTRs/CTR & ICTR Credit Rates
- Zonal Capacity Prices
- RTO/Zonal/LSE Unforced Capacity Obligations
- Committed Resource Obligations in Delivery Year
- Changes for 2020/2021 Delivery Year

RPM 101 Objectives

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- Describe the purpose of the Reliability Pricing Market (RPM)
- Explain demand and supply in RPM
- Explain the RPM auction process
- Explain the pricing structure within the PJM capacity market (RPM)
- Explain participant obligations within the PJM capacity market (RPM)
- Describe changes to RPM coming in the 2020/2021 Delivery Year

Disclaimer:

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Introduction

Capacity vs. Energy

Capacity

- A commitment of a resource to provide energy during PJM emergency under the capped energy price.
- Capacity revenues paid to committed resource whether or not energy is produced by resource.
- Daily product

Energy

- Generation of electrical power over a period of time
- Energy revenues paid to resource based on participation in PJM's Day-Ahead & Real-Time Energy Markets
- Hourly product

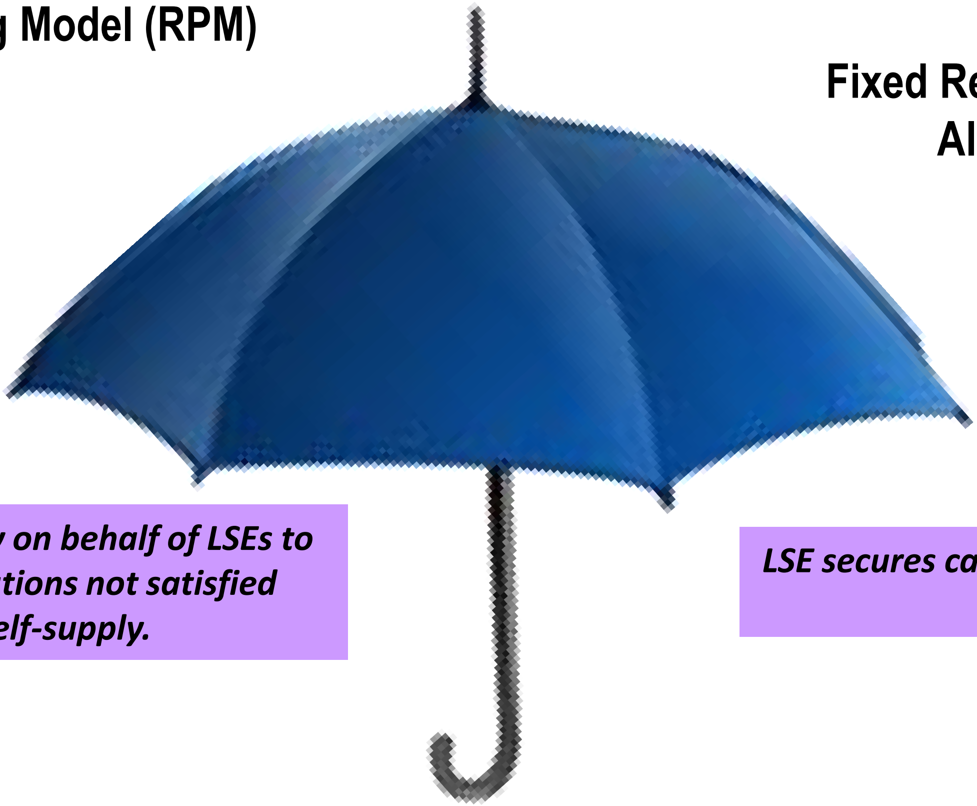
Capacity, energy & ancillary services revenues are expected, in the long term, to meet the fixed and variable costs of generation resources to ensure that adequate generation is maintained for reliability of the electric grid.

How PJM Secures Capacity

Reliability Pricing Model (RPM)

Fixed Resource Requirement Alternative (FRR)

(opt-out of RPM)



PJM secures capacity on behalf of LSEs to satisfy load obligations not satisfied through self-supply.

LSE secures capacity to satisfy their load obligation.

What is the RPM?

- Reliability Pricing Model (RPM) is PJM's resource adequacy construct
- RPM is part of an integrated approach to ensuring long-term resource adequacy and competitively priced delivered energy
- RPM aligns the price paid for capacity with overall system reliability requirements
- RPM includes pricing to recognize and quantify the locational value of capacity and the operational value of capacity
- RPM provides forward investment signals

Objectives of RPM

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- Secure resource commitments to meet system peak loads three years in the future
- Provide three year forward pricing which is aligned with reliability requirements and which adequately values all capacity resources
- Provide transparent information to all participants far enough in advance for actionable response

Purpose of RPM is to enable PJM to obtain sufficient resources to reliably meet the needs of electric consumers within PJM

RPM Capacity Performance Product

- Capacity Performance Resources must be capable of sustained, predictable operation that allows resource to be available to provide energy and reserves throughout the Delivery Year
- Subject to Non-Performance Charge assessed during Performance Assessment Hours which are (triggered by an Emergency Action) throughout the entire Delivery Year
- Only product type in RPM beginning in 2020/2021 Delivery Year

RPM Capacity Performance

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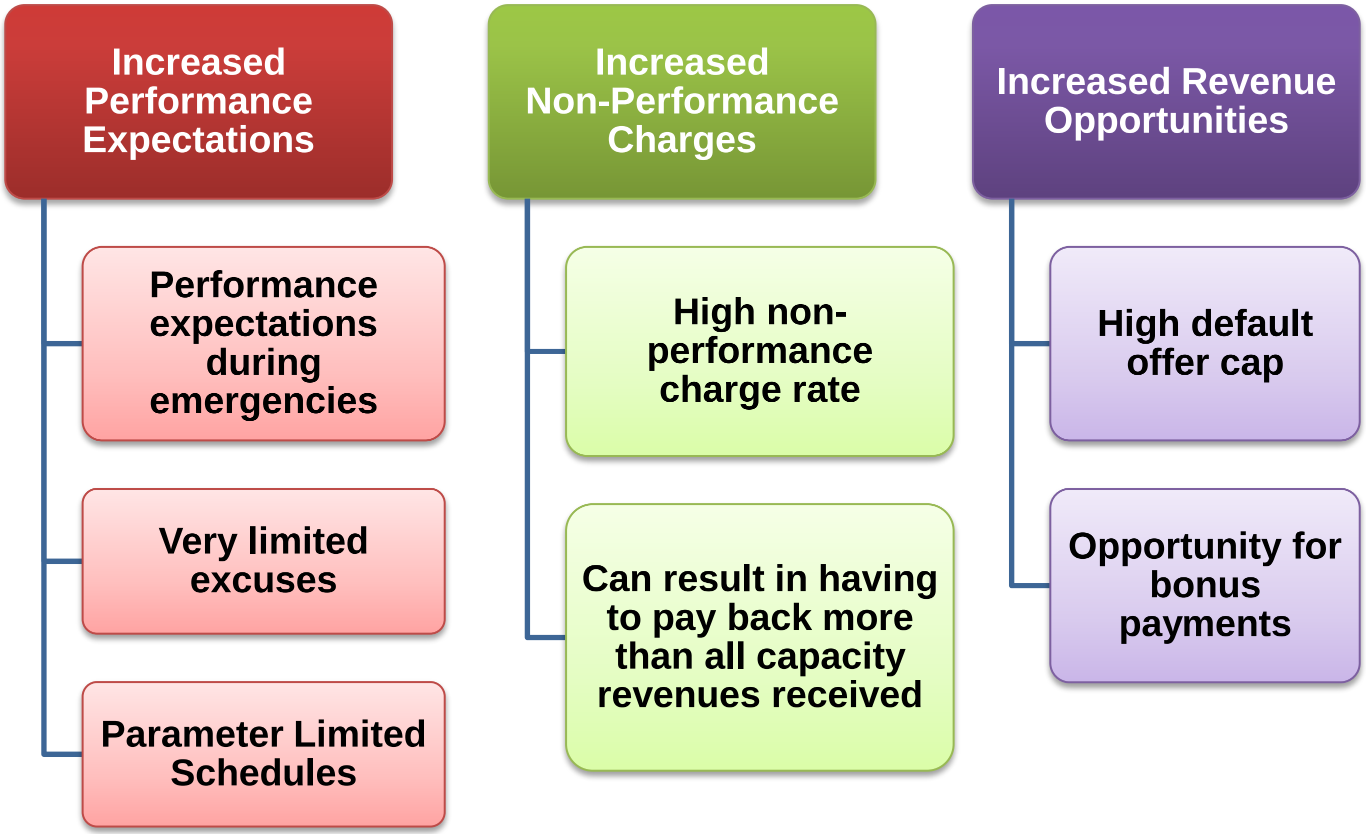


FRR Entities Opt out of RPM for __________ years.

a) Three
b) Five
c) One
d) Ten

Capacity Performance is the only product type in RPM beginning in which Delivery Year?

a) 2017/2018

b) 2018/2019

c) 2019/2020

d) 2020/2021

Resource Adequacy

Resource Adequacy Overview

The purpose of PJM RTO resource adequacy is to determine the amount of Capacity Resources that are required to serve the forecast load and satisfy the PJM reliability criterion

The reliability criterion is based on **Loss of Load Expectation** (LOLE) not exceeding one occurrence in ten years

The resource requirement to meet the reliability criterion is expressed as the **Installed Reserve Margin** (IRM) as a percentage of forecast peak load

Common Terminology in RPM

- **Installed Capacity (ICAP)** value of a unit is based on the summer net dependable rating of a unit as determined in accordance with PJM's Rules and Procedures.
- **Unforced Capacity (UCAP)** value of a unit is the installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating.

UCAP = ICAP x (1-EFORd)

- **Equivalent Demand Forced Outage Rate (EFORd)** is a measure of the probability of a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to operate.

UCAP Concept is extended to value demand resources, energy efficiency resources, qualifying transmission upgrades in RPM.

Installed Reserve Margin & Forecast Pool Requirement

Installed Reserve Margin (IRM)

Used to establish level of **installed** capacity resources that will provide acceptable level of reliability

Forecast Pool Requirement (FPR)

- Used to establish level of **unforced** capacity resources that will provide acceptable level of reliability

FPR = (1 + IRM)*(1 - pool-wide avg. EFORd)

Example: 2020/2021 Base Residual Auction

IRM = 16.6%, Forecast Peak Load = 153,915.0 MW, Pool-wide avg. EFORd = 0.0659

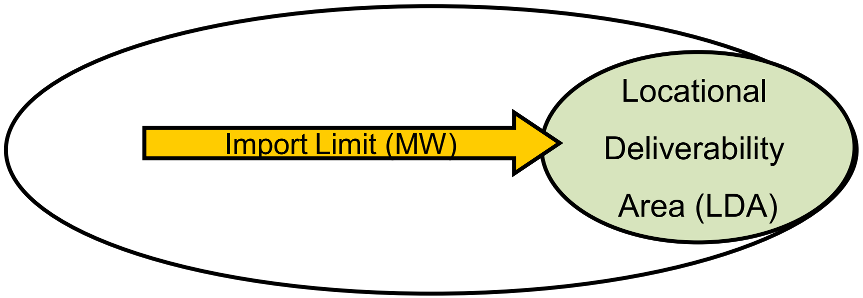
ICAP Requirement = Forecast Peak Load * (1+ IRM) =179,464.9 MW

FPR = (1+0.166)*(1- 0.0659) = 1.0892

UCAP Requirement = Forecast Peak Load * FPR = 167,644.2 MW

Locational Deliverability Areas (LDAs)

- PJM determines sub-regions (i.e., Locational Deliverability Areas (LDAs)) and respective LDA Reliability Requirements to be modeled in RPM Auctions to recognize and quantify the locational value of capacity within the PJM region.
- Modeled Locational Deliverability Areas (LDAs) are determined by comparing the import limit of a LDA (CETL) to the amount of capacity that needs to be imported into a LDA to meet the reliability criterion (CETO).



CETL = Capacity Emergency Transfer Limit

CETO = Capacity Emergency Transfer Objective

Criteria for Modeling LDA in RPM Auction

- An LDA is modeled if:
  - LDA has CETL < 1.15 CETO
  - LDA had locational price adder in any of three immediately preceding BRAs
  - LDA is likely to have a locational price adder based on a PJM analysis using historic offer price levels
  - LDA is EMAAC, SWMAAC, and MAAC

LDAs modeled in a Base Residual Auction are modeled in the Incremental Auctions for the Delivery Year.

An LDA that does not meet the criteria above may be modeled if PJM identifies reliability concerns with LDA.

Locational Deliverability Areas

RTEPP has currently identified 27 sub-regions as potential
Locational Deliverability Areas (LDAs)

- Regions
  - Western PJM (ComEd, AEP, Dayton, DLCO, APS, ATSI, Duke)
  - Mid-Atlantic Area Council (MAAC) Region
  - Eastern MAAC (PSE&G, JCP&L, PECO, AE, DPL & RECO)
  - Southwestern MAAC (PEPCO & BGE)
  - Western MAAC (Penelec, MetEd, PPL)
- Zones
  - AE, AEP, APS, ATSI, BGE, ComEd, Dayton, DLCO, Dominion, DPL, Duke, EKPC, JCPL, MetEd, PECO, Penelec, PEPCO, PPL, PSEG
- Sub-Zones
  - PSEG Northern Region (north of Linden substation)
  - DPL Southern Region (south of Chesapeake and Delaware Channel)
  - Cleveland (within ATSI)

PJM required to file with FERC before adding a new LDA.

Capacity Import Limits (CILs) (2017/2018 - 2019/2020 DYs)

- Locational constraints that limit the delivery of external generation from areas outside of PJM region
- CILs determined for PJM Region and five external source zones:
  - **Northern Zone:** NYISO & ISONE
  - **Western Tier 1 Zone:** MISO East, MISO West & OVEC
  - **Western Tier 2 Zone:** MISO Central & MISO South
  - **Southern Tier 1 Zone:** TVA & LGEE
  - **Southern Tier 2 Zone:** VACAR (non-PJM)

2020/2021 BRA Planning Parameters

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2020-2021 RPM Base Residual Auction Planning Parameters		#47825914	2/13/2017
	RTO	**Notes:**	
Installed Reserve Margin (IRM)	16.6%	2016 IRM Study	
Pool-Wide Average EFORd	6.59%	2016 IRM Study	
Forecast Pool Requirement (FPR)	1.0892	2016 IRM Study	
Preliminary Forecast Peak Load	153,915.0	Load data: from 2017 Load Report with adjustments due to load served outside PJM.	

							Locational Deliverability Are			
	RTO	**MAAC**	**EMAAC**	**SWMAAC**	**PS**	**PS NORTH**	**DPL SOUTH**	**PEPCO**	**ATSI**	**A**
CETO	NA	-7,000.0	3,650.0	2,900.0	5,900.0	2,620.0	1,230.0	1,540.0	4,660.0	
CETL (see Note 2 below)	NA	7,199.0	10,968.0	9,747.0	8,497.0	4,881.0	1,850.0	7,625.0	9,814.0	
Reliability Requirement	167,644.2	66,385.0	36,921.0	15,486.0	11,797.0	6,023.0	2,999.0	7,978.0	15,610.0	
Total Peak Load of FRR Entities (see Note 1 below)	0.0	0	0	0	0	0	0	0	0	
Preliminary FRR Obligation	0.0	0	0	0	0	0	0	0	0	
Reliability Requirement adjusted for FRR	**167,644.2**	**66,385.0**	**36,921.0**	**15,486.0**	**11,797.0**	**6,023.0**	**2,999.0**	**7,978.0**	**15,610.0**	
Gross CONE, $/MW-Day (UCAP Price)	$394.43	$394.55	$393.93	$401.04	$393.93	$393.93	$393.93	$401.04	$391.30	
Net CONE, $/MW-Day (UCAP Price)	**$292.95**	**$252.40**	**$283.10**	**$202.43**	**$306.92**	**$306.92**	**$254.97**	**$226.53**	**$261.17**	
EE Addback (UCAP) (to be provided prior to the auction)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Variable Resource Requirement Curve:										
Point (a) UCAP Price, $/MW-Day	$439.43	$394.55	$424.65	$401.04	$460.38	$460.38	$393.93	$401.04	$391.76	
Point (b) UCAP Price, $/MW-Day	$219.71	$189.30	$212.33	$151.82	$230.19	$230.19	$191.23	$169.90	$195.88	
Point (c) UCAP Price, $/MW-Day	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Point (a) UCAP Level, MW	167,356.6	66,271.1	36,857.7	15,459.4	11,776.8	6,012.7	2,993.9	7,964.3	15,583.2	
Point (b) UCAP Level, MW	171,813.7	68,036.1	37,839.3	15,871.2	12,090.4	6,172.8	3,073.6	8,176.4	15,998.2	
Point (c) UCAP Level, MW	180,296.6	71,395.2	39,707.5	16,654.8	12,687.3	6,477.6	3,225.3	8,580.1	16,788.1	
Nominated PRD Value, MW	558.0	558.0	58.0	500.0	0.0	0.0	23.0	170.0	0.0	
VRR Curve adjusted for PRD:										
Point (a1) UCAP Price, $/MW-Day	$439.43	$394.55	$424.65	$401.04			$393.93	$401.04		
Point (b1) UCAP Price, $/MW-Day	$219.71	$189.30	$212.33	$151.82			$191.23	$169.90		

2020-2021 Parameters | Net CONE | Key Transmission Upgrades

The product transacted in the RPM Market is called __________.

a) Installed Capacity

b) Unforced Capacity

c) Hard Drive Capacity

d) Expensive

A LDA is modeled <u>only</u> when the CETL is less than 1.15 times CETO

a) True

b) False

Demand in the Reliability Pricing Model

Demand in RPM

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- Demand curve(s) are defined in advance of a Base Residual Auction based on Variable Resource Requirement curve concept

- Demand curve(s) for 1st, 2nd, and 3rd Incremental Auctions are built based on locational buy bids that are submitted by participants and any buy bids that are submitted by PJM

- Demand curve(s) for Conditional Incremental Auction are built based on buy bid that is submitted by PJM

- PJM Buy Bids are defined in advance of a Scheduled or Conditional Incremental Auction

What is the VRR?

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The Variable Resource Requirement (VRR) Curve is a <u>downward sloping demand curve</u> that relates the maximum price for a given level of capacity resource commitment relative to reliability requirements

- The price is higher when the resources are less than the reliability requirement and lower when the resources are in excess
- VRR Curves are defined for the PJM RTO and for each constrained Locational Deliverability Area (LDA) modeled within the PJM region

VRR Parameters

The Variable Resource Requirement Curves for the PJM Region and each LDA are based on the following parameters defined prior to the RPM Auctions:

- Target Level of Reserve
- Cost of New Entry
- Net Energy & Ancillary Services (E&AS) Revenue Offset

Variable Resource Requirement (VRR) Curve

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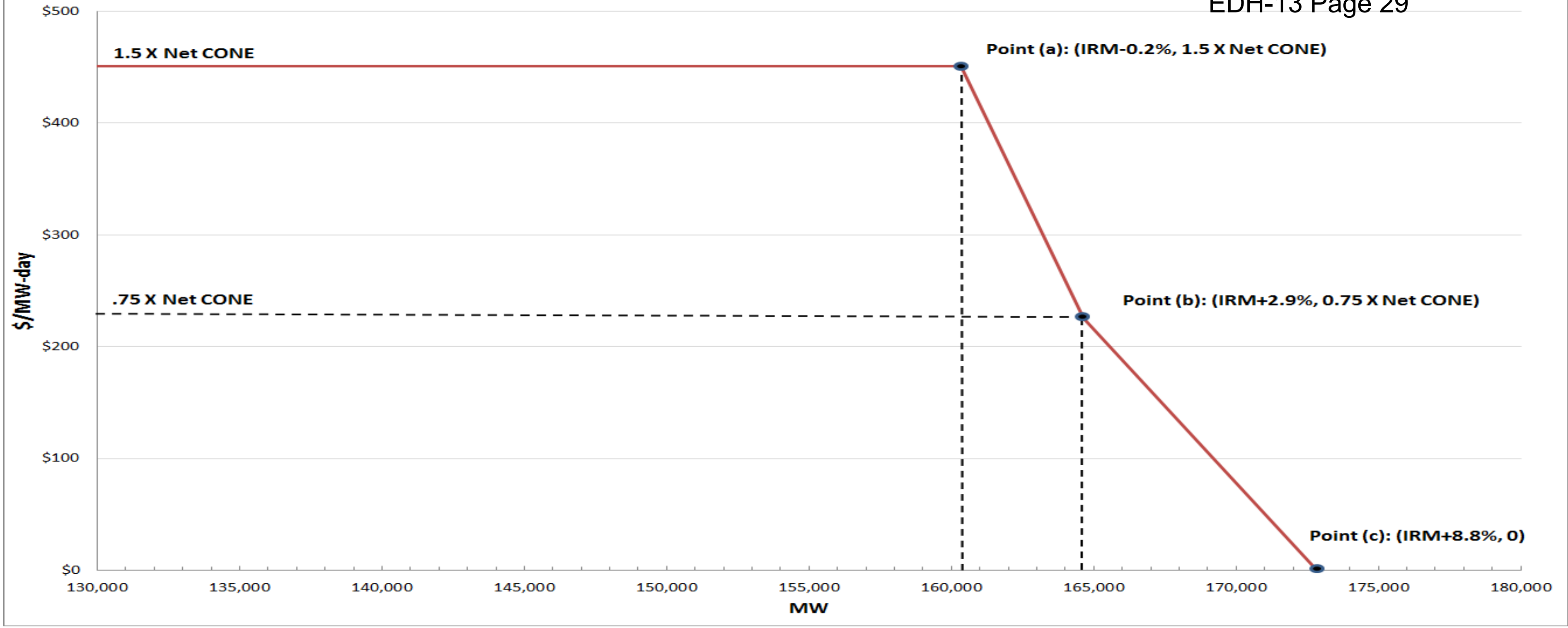

A VRR Curve is defined for the PJM Region & each LDA

2020/2021 BRA Planning Parameters

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2020-2021 RPM Base Residual Auction Planning Parameters			#47825914		2/13/2017			
	RTO	Notes:						
Installed Reserve Margin (IRM)	16.6%	2016 IRM Study						
Pool-Wide Average EFORd	6.59%	2016 IRM Study						
Forecast Pool Requirement (FPR)	1.0892	2016 IRM Study						
Preliminary Forecast Peak Load	153,915.0	Load data: from 2017 Load Report with adjustments due to load served outside PJM.						

		Locational Deliverability Are							
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO	ATSI
CETO	NA	-7,000.0	3,650.0	2,900.0	5,900.0	2,620.0	1,230.0	1,540.0	4,660.0
CETL (see Note 2 below)	NA	7,199.0	10,968.0	9,747.0	8,497.0	4,881.0	1,850.0	7,625.0	9,814.0
Reliability Requirement	167,644.2	66,385.0	36,921.0	15,486.0	11,797.0	6,023.0	2,999.0	7,978.0	15,610.0
Total Peak Load of FRR Entities (see Note 1 below)	0.0	0	0	0	0	0	0	0	0
Preliminary FRR Obligation	0.0	0	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	**167,644.2**	**66,385.0**	**36,921.0**	**15,486.0**	**11,797.0**	**6,023.0**	**2,999.0**	**7,978.0**	**15,610.0**
Gross CONE, $/MW-Day (UCAP Price)	$394.43	$394.55	$393.93	$401.04	$393.93	$393.93	$393.93	$401.04	$391.30
Net CONE, $/MW-Day (UCAP Price)	**$292.95**	**$252.40**	**$283.10**	**$202.43**	**$306.92**	**$306.92**	**$254.97**	**$226.53**	**$261.17**
EE Addback (UCAP) (to be provided prior to the auction)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Variable Resource Requirement Curve:									
Point (a) UCAP Price, $/MW-Day	$439.43	$394.55	$424.65	$401.04	$460.38	$460.38	$393.93	$401.04	$391.76
Point (b) UCAP Price, $/MW-Day	$219.71	$189.30	$212.33	$151.82	$230.19	$230.19	$191.23	$169.90	$195.88
Point (c) UCAP Price, $/MW-Day	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Point (a) UCAP Level, MW	167,356.6	66,271.1	36,857.7	15,459.4	11,776.8	6,012.7	2,993.9	7,964.3	15,583.2
Point (b) UCAP Level, MW	171,813.7	68,036.1	37,839.3	15,871.2	12,090.4	6,172.8	3,073.6	8,176.4	15,998.2
Point (c) UCAP Level, MW	180,296.6	71,395.2	39,707.5	16,654.8	12,687.3	6,477.6	3,225.3	8,580.1	16,788.1
Nominated PRD Value, MW	558.0	558.0	58.0	500.0	0.0	0.0	23.0	170.0	0.0
VRR Curve adjusted for PRD:									
Point (a1) UCAP Price, $/MW-Day	$439.43	$394.55	$424.65	$401.04			$393.93	$401.04	
Point (b1) UCAP Price, $/MW-Day	$219.71	$189.30	$212.33	$151.82			$191.23	$169.90	

2020-2021 Parameters | Net CONE | Key Transmission Upgrades

PJM Buy Bids in Scheduled Incremental Auctions

- PJM Buy Bids in an Incremental Auction may be due to:
  - Increase in RTO/LDA Reliability Requirement (RR) beyond a threshold (500 MW or 1% of prior RR). Threshold does not apply for 3rd IA
    - If parent LDA meets threshold, an increase in the child LDA RR will be reflected even if the child LDA does not meet the threshold
  - Inclusion of entire uncleared portion of the updated VRR Curve (i.e., entire Updated VRR Curve Increment) if prior auction's (RTO/LDA RR – STRPT) exceeds total capacity committed in all prior auction's by the threshold
- The determination of the PJM Buy Bid quantity in scheduled IA also considers the uncleared PJM Buy Bids/Sell Offers from prior IA
- PJM Buy Bid prices based on Updated VRR Curve Increment
- PJM Buy Bids are defined in advance of the Incremental Auction

Updated VRR Curve Increment/Decrement

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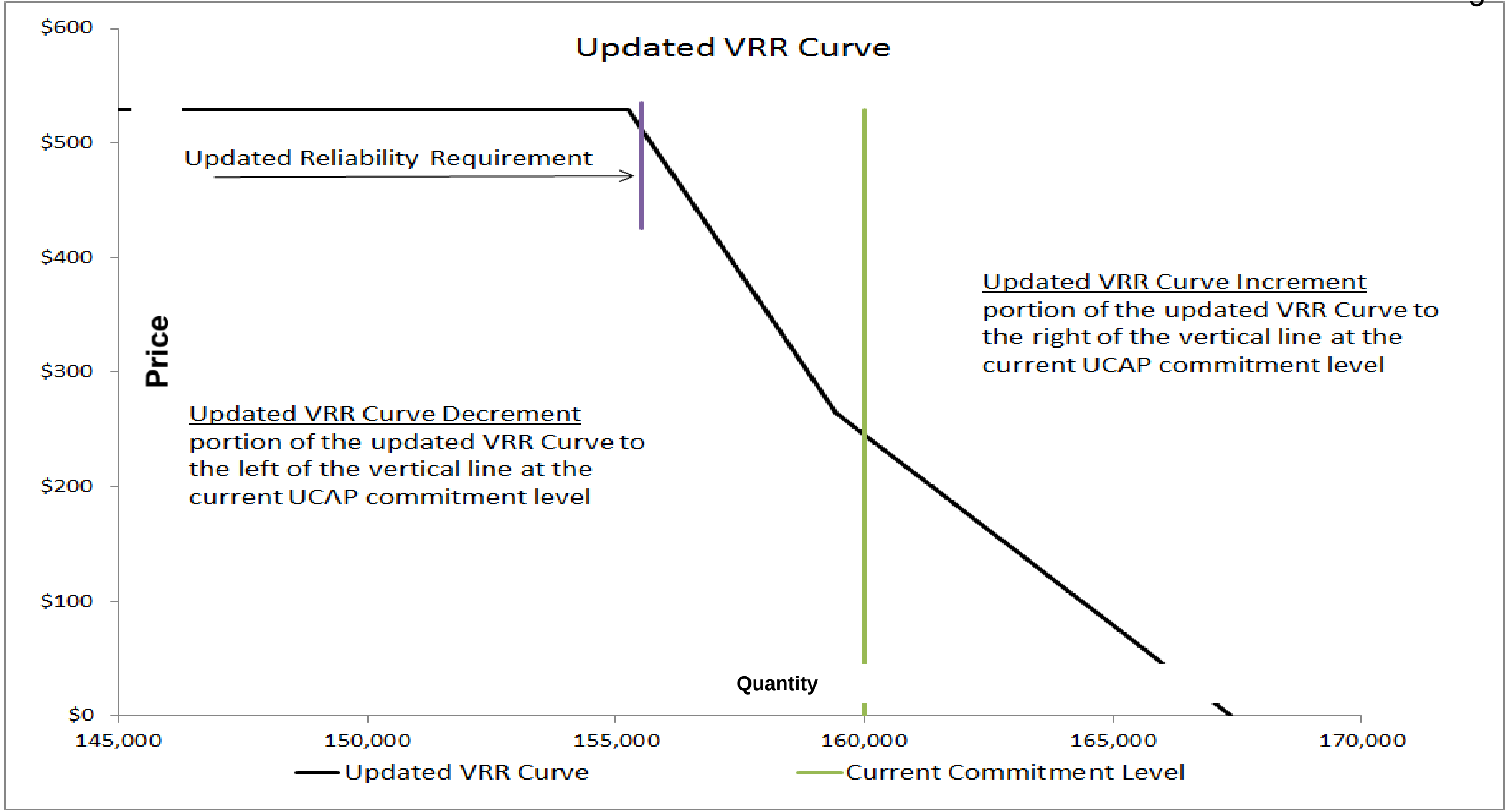

VRR Curve Increment - MAAC

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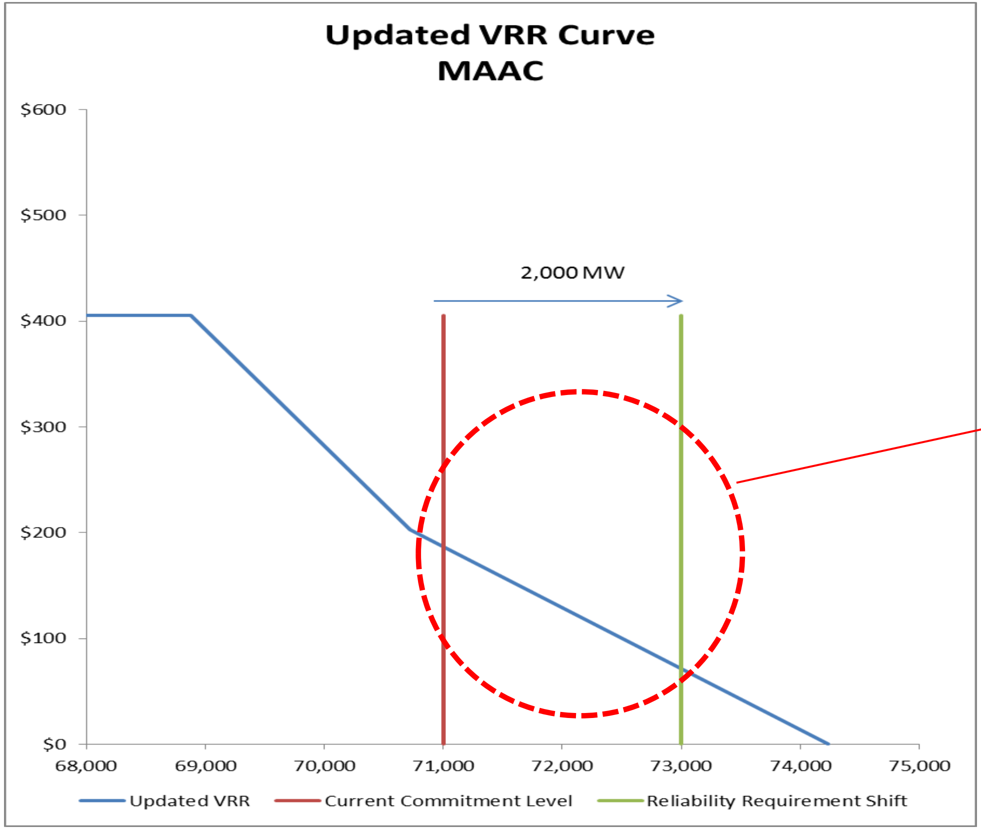

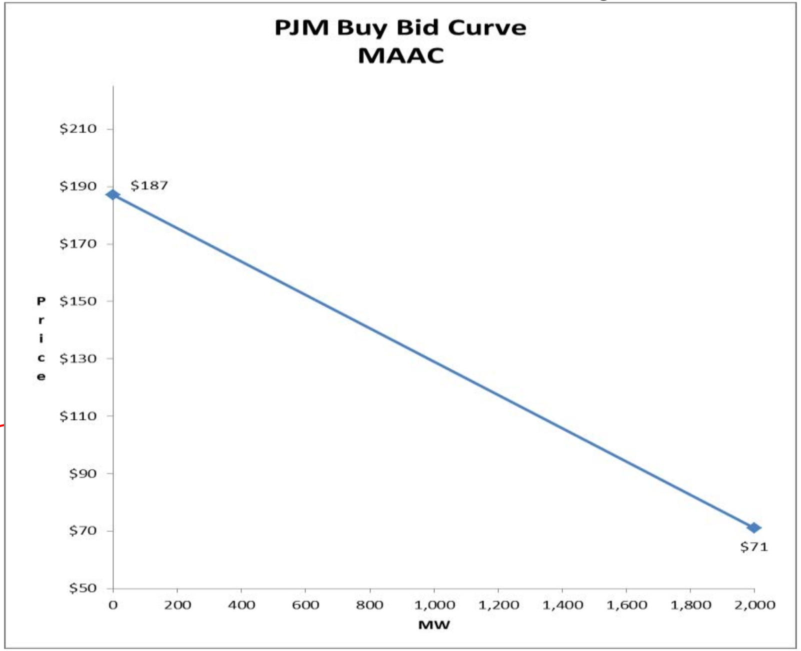

Demand Curve in Conditional Incremental Auction

- Conditional Incremental Auctions may be held if the in service date of a backbone transmission upgrade that was modeled in the Base Residual Auction is announced as delayed by Office of the Interconnection beyond July 1 of the Delivery Year for which it was modeled and the delay causes reliability criteria violation
- If conducted, the demand curve will be a single buy bid entered by PJM for the required MWs at 1.5 times the Net CONE in the LDA with the reliability criteria violation
- PJM will seek to procure any remaining capacity amount not procured in Conditional Incremental Auction in the next scheduled Incremental Auction

The VRR Curve is constructed using a quantity of MW defined by the Reliability Requirement at a cost defined by__________.

a) eBAY

b) NET CONE

c) Last Auction's Clearing Price

d) CONE

If the load forecast for a Delivery Year increases, PJM may submit a(n) ______ into an Incremental Auction.

a) Increase in EFORd
b) Sell Offer
c) Panicked Tweet
d) Buy Bid

Supply in the Reliability Pricing Model

Supply in RPM Auction

- Supply of unforced capacity is procured to meet the demand as a function of the clearing of RPM Auctions
- Supply curve is defined based on the resource-specific offers submitted by providers
  - Supply curve for Incremental Auctions may include locational non-unit specific sell offers submitted by PJM to release commitments
- Supply that is procured in the RPM multi-auction clearing ensures that sufficient resources are committed to meet the reliability requirement

Supply Resources in RPM

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Generation
- Existing/Planned
- Internal/External

Demand Resources
- Existing/Planned

Energy Efficiency Resource
- Existing/Planned

Aggregate Resource
- Existing/Planned

Qualifying Transmission Upgrade
- Existing/Planned

Participation by Resource Providers

- Participation is voluntary for resource providers with:
  - External generation;
  - Planned generation (includes new units and upgrades to existing unit not yet in service that have not cleared at an unmitigated price in a prior Delivery Year);
  - Existing demand resources;
  - Planned demand resources;
  - Energy Efficiency resources;
  - Qualifying Transmission Upgrades.

Aggregate Resource – Commercial Aggregation (Effective 2018/2019 Delivery Year)

- Capacity Resources which may not, alone, meet the requirements of a Capacity Performance product, may combine their capabilities and offer as a single Aggregate Resource
  - Applies to Intermittent Resources, Capacity Storage Resources, Demand Resources, Energy Efficiency Resources, and Environmentally-Limited Resources
- Resources being combined must reside in a single Capacity Market Seller account

Seasonal Capacity Performance Resources (Effective 2020/2021 Delivery Year)

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Summer-Period CP Resources

- Summer Period DR
- Summer Period EE
- Capacity Storage Resource
- Intermittent Resource
- Environmentally-Limited Resource

- Available June-October & May of DY (summer-period)
- If clear, Auction Credit & commitment for summer-period only

Winter-Period CP Resources

- Capacity Storage Resource
- Intermittent Resource*
- Environmentally-Limited Resource*

* May request additional CIRs for winter-period for DY and offer additional ICAP value in winter-period

- Available November-April (winter-period)
- If clear, Auction Credit & commitment for winter-period only

What is the Value of a Resource?

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Resource Type	Capacity Value
Generation Resource	Summer Net Dependable Rating, converted to Unforced Capacity (UCAP)
DR, & EE Resources	UCAP Equivalent is calculated (based on load reduction amount, Forecast Pool Requirement (FPR)
Transmission Upgrade	Valued in terms of an increase in import capability into a constrained LDA

UCAP Calculation

Installed Capacity (ICAP) is converted to unforced capacity (UCAP) with the following formulas:

- Generation: $UCAP_{Generation} = (1 - EFORd)\ X\ ICAP$
- Demand Response: $= ICAP\ X\ ForecastPoolRequirement$
- Energy Efficiency: $CAP_{EE} = ICAP\ X\ ForecastPoolRequirement$

Demand Resource Product Type Requirements

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Requirement	Limited DR (Prior to 18/19 DY)	Extended Summer DR (Prior to 18/19 DY)	Annual DR (Prior to 18/19 DY)	Base (18/19 & 19/20 DY only)	Capacity Performance (Effective 18/19 DY)	Summer Period Seasonal DR (Effective 20/21 DY)
Availability	Any weekday, other than NERC holidays, during June – Sept. period of DY	Any day during June- October period and following May of DY	Any day during DY (unless on an approved maintenance outage during Oct. - April)	Any day during June-September of DY	Any day during DY (unless on an approved maintenance outage during Oct.-April)	Any day during June-October period and following May of DY
Maximum Number of Interruptions	10 interruptions	Unlimited	Unlimited	Unlimited	Unlimited	Unlimited
Hours of Day Required to Respond *(Hours in EPT)*	12:00 PM – 8:00 PM	10:00 AM – 10:00 PM	Jun – Oct. and following May: 10 AM – 10 PM Nov. – April: 6 AM- 9 PM	10:00 AM – 10:00 PM	Jun – Oct. and following May: 10 AM – 10 PM Nov. – April: 6 AM- 9 PM	Jun – Oct. and following May: 10 AM – 10 PM
Maximum Duration of Interruption	6 Hours	10 Hours	10 Hours	10 Hours	No limit	No limit

PJM Sell Offers in Incremental Auctions

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- PJM Sell Offers in an Incremental Auction to release commitments may be due to:
  - Decrease in RTO/LDA Reliability Requirement(s) beyond the threshold
  - Need to release commitments in the parent LDA of an LDA with a reliability violation in the Scheduled IA that occurs after a Conditional IA
- The determination of the PJM Sell Offer quantity in scheduled IA also considers uncleared PJM Buy Bid/Sell Offer from prior IA
- PJM Sell Offer prices based on Updated VRR Curve Decrement
- PJM Sell Offers are defined in advance of Incremental Auction

Updated VRR Curve Increment/Decrement

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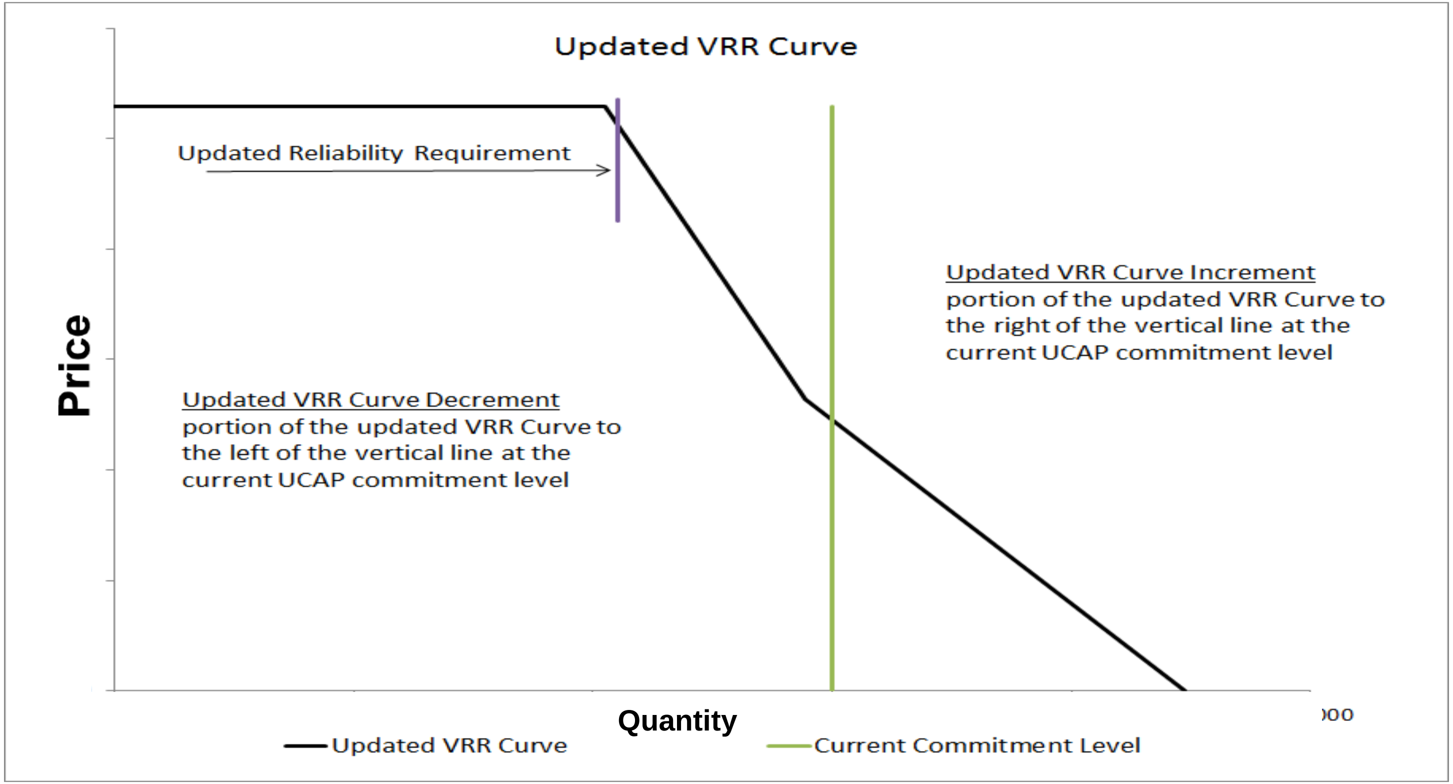
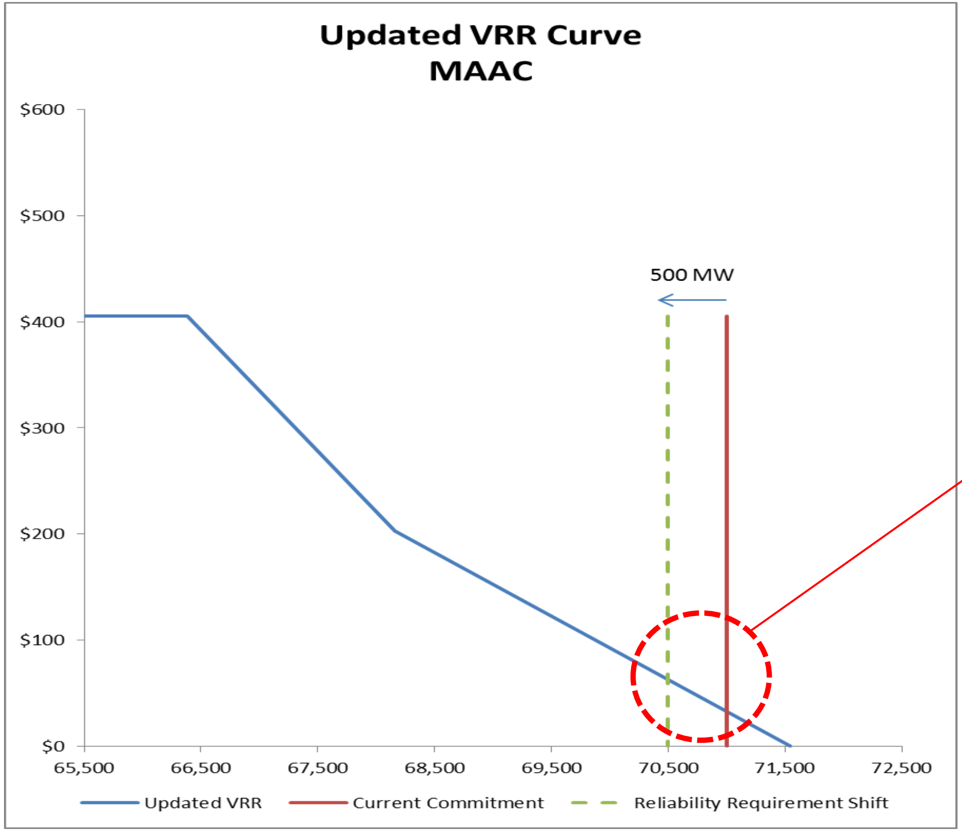
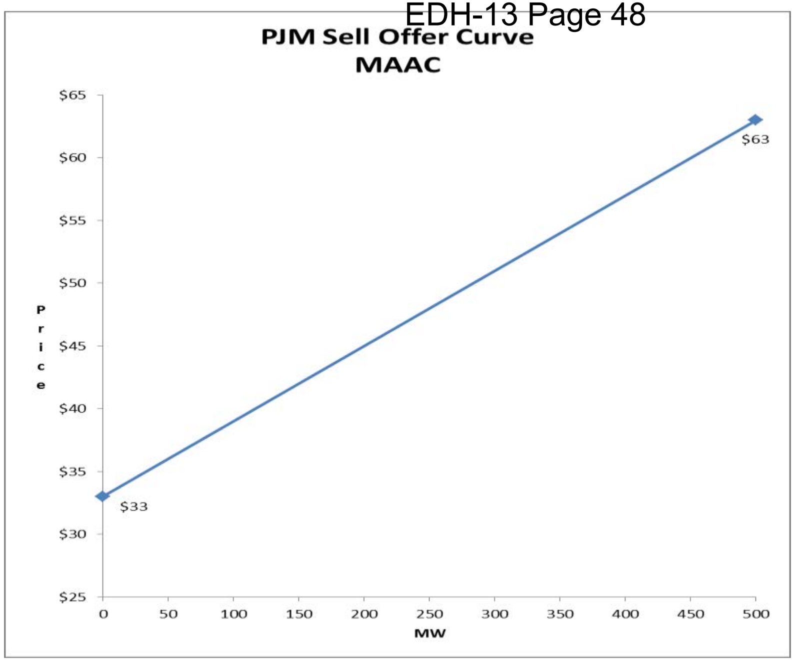


VRR Curve Decrement - MAAC





Energy Efficiency Resources are dispatched by PJM during emergencies.

a) True

b) False

Only generators located inside the PJM market footprint may participate in RPM__________.

a) True

b) False

Planned DR resources are not allowed to participate in an RPM auction

a) True

b) False

Auction Structure

RPM Auction Schedule

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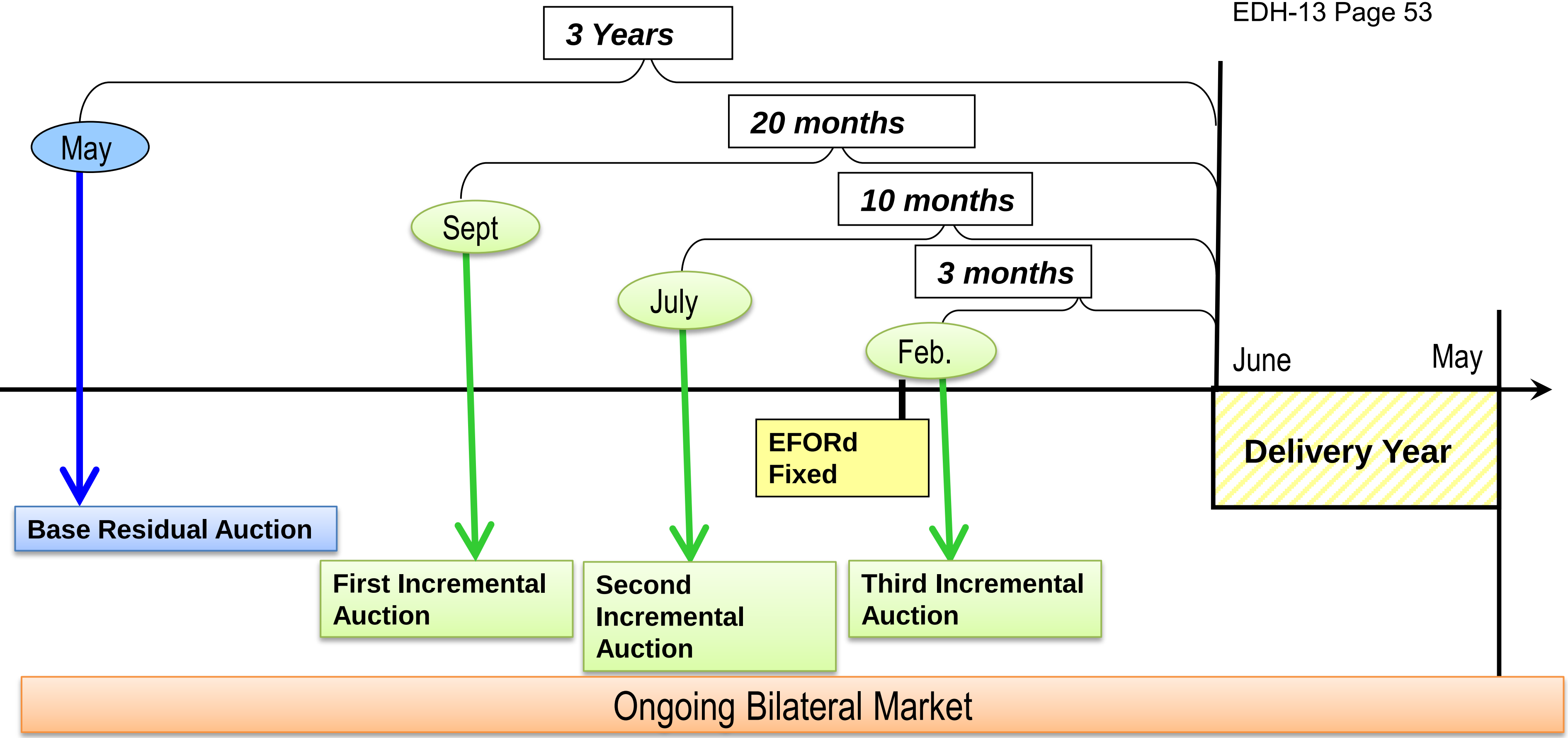

Overview of RPM Auctions

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Activity	Purpose	Cost of Procurement
Base Residual Auction	Procurement of RTO Obligation less an amount reserved for short term resources (prior to 18/19 DY), less FRR Obligation	Allocated to LSEs through Locational Reliability Charge
1st Incremental Auction 2nd Incremental Auction 3rd Incremental Auction	Allows for: (1) replacement resource procurement (2) increases and decreases in resource commitments due to reliability requirement adjustments; and (3) deferred short-term resource procurement (prior to 18/19 DY)	Allocated to resource providers that purchased replacement resources and LSEs through Locational Reliability Charge
Conditional Incremental Auction	Procurement of additional capacity in a LDA to address reliability problem that is caused by a significant transmission line delay	Allocated to LSEs through Locational Reliability Charge

Sell Offers / Buy Bids

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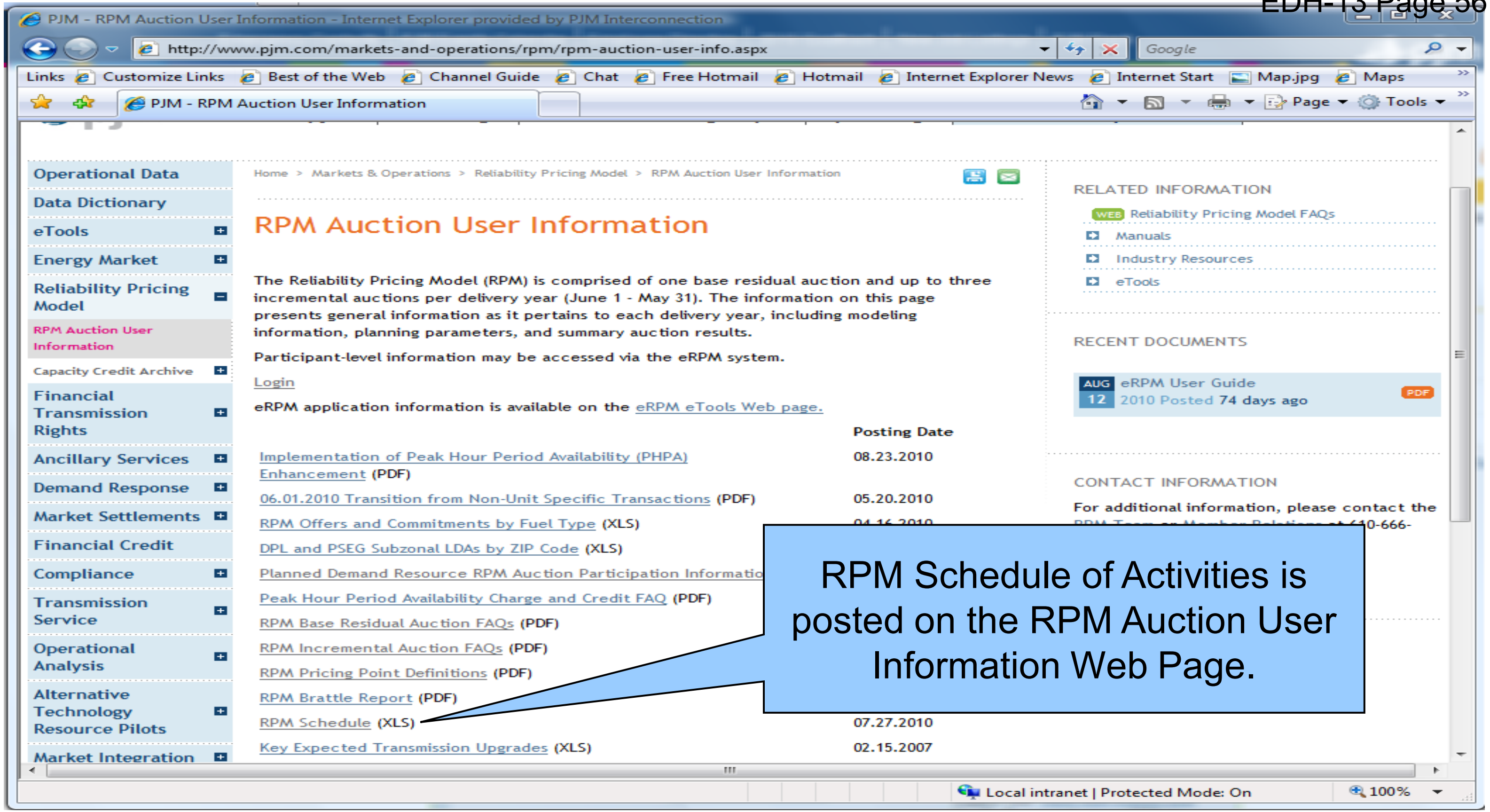
- Sell Offers and Buy Bids for the Base Residual and Incremental Auctions must be submitted in PJM's eRPM system
  - Sell offers and buy bids are only accepted during a fixed bidding window which is open for at least five business days
  - The bidding window for an auction will be posted on the PJM website
- Sell offers and buy bids may not be changed or withdrawn after the bidding window for an auction is closed

RPM Schedule of Activities



RPM Schedule of Activities is posted on the RPM Auction User Information Web Page.

Sell Offers

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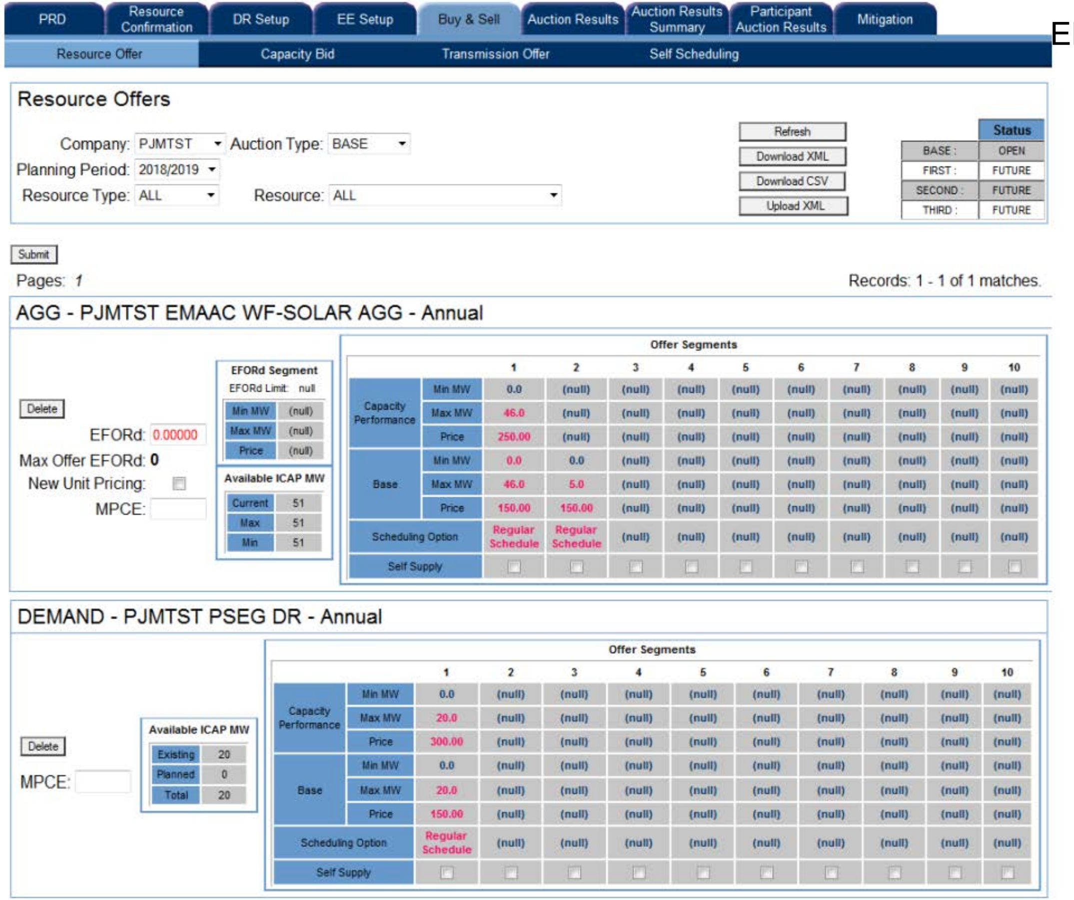
PRD | Resource Confirmation | DR Setup | EE Setup | Buy & Sell | Auction Results | Auction Results Summary | Participant Auction Results | Mitigation

Resource Offer | Capacity Bid | Transmission Offer | Self Scheduling

Resource Offers

Company: PJMTST   Auction Type: BASE
Planning Period: 2018/2019
Resource Type: ALL   Resource: ALL

Refresh | Download XML | Download CSV | Upload XML

	Status
BASE :	OPEN
FIRST :	FUTURE
SECOND :	FUTURE
THIRD :	FUTURE

Submit

Pages: 1   Records: 1 - 1 of 1 matches.

AGG - PJMTST EMAAC WF-SOLAR AGG - Annual

Delete
EFORd: 0.00000
Max Offer EFORd: 0
New Unit Pricing:
MPCE:

EFORd Segment
EFORd Limit: null

Min MW	(null)
Max MW	(null)
Price	(null)

Available ICAP MW

Current	51
Max	51
Min	51

Offer Segments

		1	2	3	4	5	6	7	8	9	10
Capacity Performance	Min MW	0.0	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
	Max MW	46.0	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
	Price	250.00	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
Base	Min MW	0.0	0.0	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
	Max MW	46.0	5.0	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
	Price	150.00	150.00	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
Scheduling Option		Regular Schedule	Regular Schedule	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
Self Supply											

DEMAND - PJMTST PSEG DR - Annual

Delete
MPCE:

Available ICAP MW

Existing	20
Planned	0
Total	20

Offer Segments

		1	2	3	4	5	6	7	8	9	10
Capacity Performance	Min MW	0.0	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
	Max MW	20.0	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
	Price	300.00	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
Base	Min MW	0.0	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
	Max MW	20.0	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
	Price	150.00	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
Scheduling Option		Regular Schedule	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
Self Supply											

Buy Bids

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PRD | Resource Confirmation | DR Setup | EE Setup | Buy & Sell | Auction Results | Auction Results Summary | Participant Auction Results

Resource Offer | Capacity Bid | Transmission Offer | Self Scheduling

Capacity Bids

Company: PJMTST
Planning Period: 2018/2019
Product Type: ALL
Auction Type: FIRST
LDA: ALL

Refresh | Download XML | Download CSV | Upload XML

	Status
BASE :	CLEARED
FIRST :	CANCELLED
SECOND :	FUTURE
THIRD :	FUTURE

Capacity Bids

Delete | Submit

LDA	Product Type		1	2	3	4	5	6	7	8	9	10
ATSI	Base	MW	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
		Price	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
ATSI	Base DR/EE	MW	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
		Price	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
ATSI	Capacity Performance	MW	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
		Price	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
ATSI-CLEVELAND	Base	MW	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
		Price	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
ATSI-CLEVELAND	Base DR/EE	MW	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
		Price	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
ATSI-CLEVELAND	Capacity Performance	MW	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
		Price	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
BGE	Base	MW	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)
		Price	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)	(null)

Market Power Mitigation

- Existing generation capacity resources must offer into each RPM Auction (prevent physical withholding)
- Application of Market Seller Offer Caps to existing generation capacity resource sell offers (prevent economic withholding)
- Application of Minimum Offer Price Rule (MOPR) to planned generation capacity resource sell offers (prevent buyer-side market power)

RPM Auctions begin _____ years prior to the Delivery Year?

a) 1

b) 2

c) 3

d) 5

Buy bids or sell offers may be changed during the auction bidding window

a) True

b) False

Auction Clearing

Auction Clearing Mechanism

- RPM Auctions use an optimization-based market clearing algorithm
- This algorithm has the objective of minimizing capacity procurement costs given
  - Supply Offers
  - Demand Curves
  - Locational Constraints
  - Resource Constraints
- The clearing price for each LDA is determined by the optimization algorithm

Clearing Mechanism

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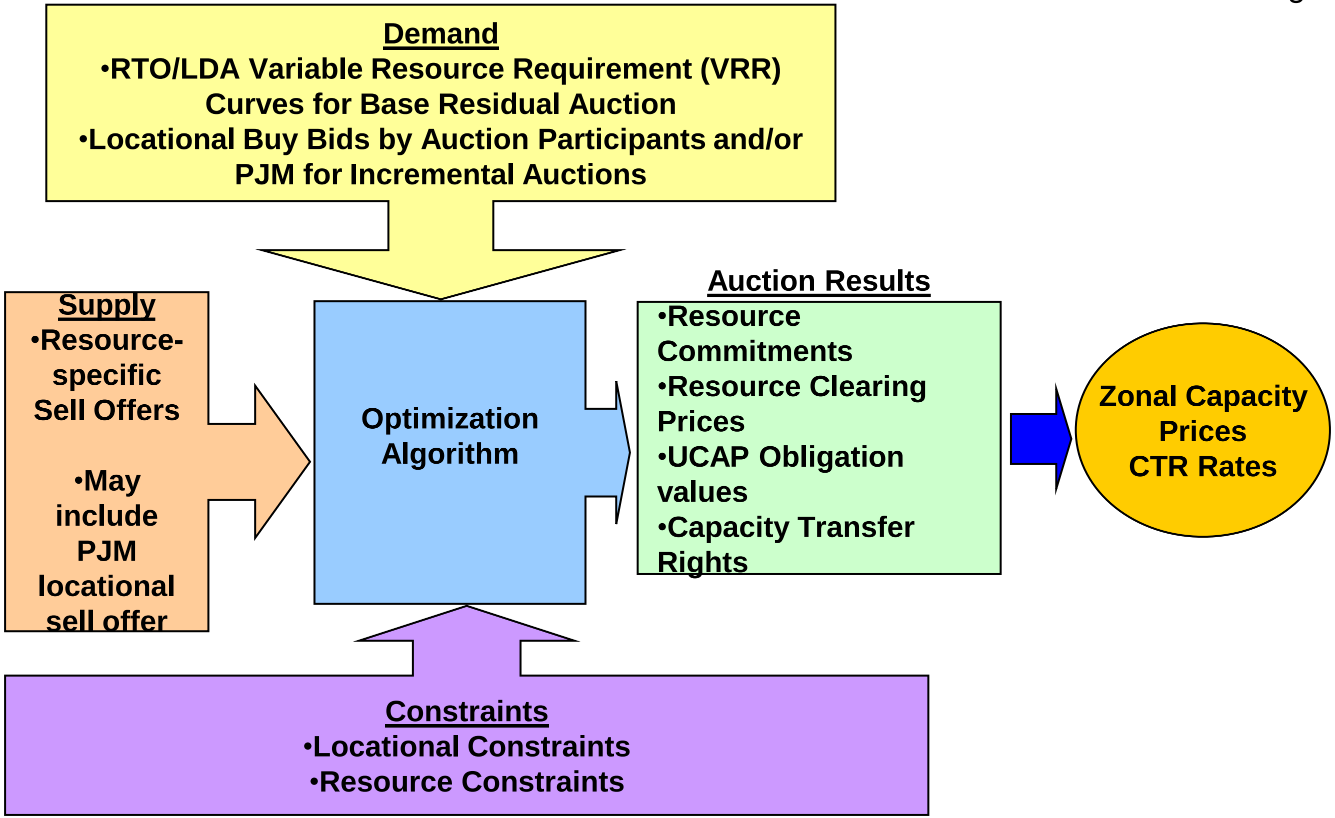

Resource Constraints in RPM Auctions

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2014/2015 - 2016/2017	•**Minimum Annual Resource Requirement**-minimum amount of Annual Resources to be procured •**Minimum Extended Summer Resource Requirement**-minimum amount of Extended Summer Demand Resources and Annual Resources to be procured
2017/2018	•**Limited Resource Constraint** – maximum amount of Limited DR to be procured •**Sub-Annual Resource Constraint** – maximum amount of Limited DR & Extended Summer DR to be procured
2018/2019 - 2019/2020	•**Base Capacity DR Constraint** – maximum amount of Base Capacity DR and Base Capacity EE to be procured •**Base Capacity Resource Constraint** – maximum amount of Base Capacity DR, Base Capacity EE, and Base Capacity Generation to be procured
2020/20201 & beyond	• Cleared quantity of Summer-Period CP Resources = Cleared quantity of Winter-Period CP Resource

Updated Auction Clearing Process (Beginning 2020/2021 Delivery Year)

- Auction clearing algorithm will clear all annual CP sell offers, summer-period CP sell offers, and winter-period CP sell offers simultaneously to minimize bid-based cost of satisfying the reliability requirements of the RTO and each modeled LDA subject to all applicable requirements and constraints, including:
  - LDA CETL values
  - Total cleared summer-period sell offers must exactly equal total cleared winter-period sell offers across the entire RTO (new constraint to ensure that seasonal CP sell offers clear to form annual CP commitments)

The RPM auction clearing algorithm uses an objective function to maximize capacity costs

a) True

b) False

Resource Clearing Prices

Resource Clearing Price

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- The **Resource Clearing Price** (RCP) for Generation Resources, Demand Resources, and EE Resources within each LDA is the sum of :

  (1) the marginal value of system capacity; (2) Locational Price Adder(s), if any in such LDA; (3) Limited Resource Price Decrements, if any in such LDA; and Sub-Annual Resource Price Decrements, if any in such LDA; (4) Base and Base DR/EE Price Decrements, if any in such LDA.

Resource Clearing Price in LDA	=	Marginal Value Of System Capacity	+	Locational Price Adder(s)*	+	Limited Resource Price and Sub-Annual Resource Price Decrement (2017/2018 only) Applicable for Limited DR only and Limited DR & Extended Summer DR respectively	+	Base Price and Base DR/EE Price Decrement (2018/2019 – 2019/2020) Applicable to Base & Base DR/EE

**Adder with respect to immediate higher level LDA*

- Marginal value of system capacity is clearing price for Annual/Capacity Performance Resources within the Rest of the RTO.

RCP may not be equal to Final Zonal Capacity Price. RCP (price paid to resources) and Final Zonal Capacity Price (price paid by LSEs) are different terms in RPM.

Auction Clearing Prices – 2019/2020 BRA

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2019/2020 BRA Resource Clearing Results

Resource Clearing Prices

LDA/External Source Zone	System Marginal Price* [$/MW-day]	Locational Price Adder (Decrement)** [$/MW-day]	Capacity Performance Resource Clearing Price [$/MW-day]	Base Capacity Resource Price Decrement in LDA [$/MW-day]	Base Capacity Resource Clearing Price [$/MW-day]	Base Capacity Demand Resource Price Decrement in LDA [$/MW-day]	Base Capacity DR/EE Resource Clearing Price [$/MW-day]
RTO	$100.00	$0.00	$100.00	($20.00)	$80.00	$0.00	$80.00
MAAC	$100.00	$0.00	$100.00	($20.00)	$80.00	$0.00	$80.00
EMAAC	$100.00	$19.77	$119.77	($20.00)	$99.77	$0.00	$99.77
SWMAAC	$100.00	$0.00	$100.00	($20.00)	$80.00	$0.00	$80.00
PS	$100.00	$0.00	$119.77	($20.00)	$99.77	$0.00	$99.77
PSNORTH	$100.00	$0.00	$119.77	($20.00)	$99.77	$0.00	$99.77
DPLSOUTH	$100.00	$0.00	$119.77	($20.00)	$99.77	$0.00	$99.77
PEPCO	$100.00	$0.00	$100.00	($20.00)	$80.00	($79.99)	$0.01
ATSI	$100.00	$0.00	$100.00	($20.00)	$80.00	$0.00	$80.00
ATSI-CLEVELAND	$100.00	$0.00	$100.00	($20.00)	$80.00	$0.00	$80.00
COMED	$100.00	$102.77	$202.77	($20.00)	$182.77	$0.00	$182.77
BGE	$100.00	$0.30	$100.30	($20.00)	$80.30	$0.00	$80.30
PL	$100.00	$0.00	$100.00	($20.00)	$80.00	$0.00	$80.00
NORTH ***	NA	NA	NA	NA	NA	NA	NA
WEST 1 ***	NA	NA	NA	NA	NA	NA	NA
WEST 2 ***	NA	NA	NA	NA	NA	NA	NA
SOUTH 1 ***	NA	NA	NA	NA	NA	NA	NA
SOUTH 2 ***	NA	NA	NA	NA	NA	NA	NA

*System Marginal Price is the clearing price for Capacity Performance Resources in unconstrained area of RTO.

** Locational Price Adder (positive number) is with respect to the immediate higher level LDA. Locational Price Decrement (negative number) is with respect to the unconstrained area of RTO.

A resources clearing price is based on the marginal system value, any locational price adder if applicable and product specific price decrement, if applicable.

a) True

b) False

Regional differences in capacity auction clearing prices are typically caused by ______.

a) Weather

b) Generator Outages

c) Lunar Phase

d) Transmission Constraints

Capacity Transfer Rights

Why Capacity Transfer Rights

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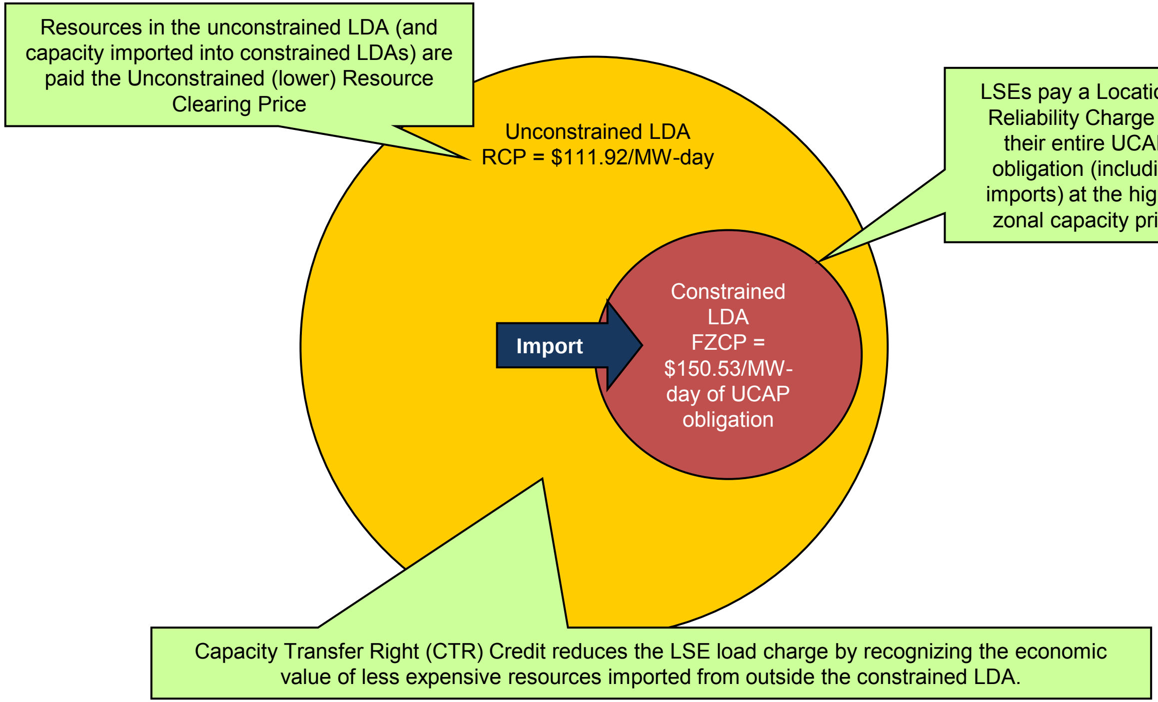

How are CTR Rates Determined?

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Rate	Equation	When posted?
Base Zonal CTR Credit Rate ($/MW-day of obligation)	= Base Economic Value of CTRs allocated to LSEs in a zone from BRA/Base Zonal UCAP Obligation	With BRA clearing results
Final Zonal CTR Credit $/MW-day of obligation)	= Final Economic Value of CTRs allocated to LSEs in a zone as determined after the Final IA/Final Zonal UCAP Obligation	With Final IA clearing results
Final CTR Settlement Rate ($/MW-day of CTRs)	= Final Economic value of CTRs allocated to LSEs in a zone as determined after the Final IA/Final Zonal CTRs allocated to LSEs	With Final IA clearing results
Final Sink LDA ICTR Settlement Rate ($/MW-day of ICTRs) • Participant-Funded Project ICTRs • Regional Project ICTRs	= Final Economic Value of ICTRs in Sink LDA/Final ICTRs MWs in Sink LDA	With Final IA clearing results

CTR credits are used to recognize the value of less expensive resources imported from outside the constrained LDA.

a) True

b) False

Zonal Capacity Prices

When are Zonal Prices Determined?

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Base Residual Auction Results

- Preliminary Zonal Capacity Prices
- Base Zonal Capacity Transfer Right (CTR) Credit Rate

Incremental Auction Results

- Adjusted Zonal Capacity Prices
- Adjusted Zonal CTR Credit Rates

Final Incremental Auction Results

- Final Zonal Capacity Prices
- Final Zonal CTR Credit Rates

Locational Reliability Charge = Daily Zonal UCAP Obligation * Final Zonal Capacity Price

Final Zonal Capacity Prices

Final Zonal Capacity Prices are calculated such that the:

Payments		**Charges**
Total Payments to: • Incremental CTR Holders • Resources cleared in all Auctions, except resources cleared as replacement capacity • Cleared QTUs • LSEs receiving CTRs	=	Total amount of Locational Reliability Charges (assessed to loads)

Example of Final Zonal Capacity Prices

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3rd Incremental Auction						
Final Zonal UCAP Obligation	Adjusted Zonal Capacity Price ($/MW-day)	Final CP Transition IA Cost Component ($/MW-day)	Final Zonal Capacity Price with CP Transition IA Cost Component ($/MW-day)	Final Zonal CTR Credit Rate ($/MW-UCAP Obligation-day)	Final Zonal Net Load Price ($/MW-day)	Zone
2,766.6	$123.42	$39.86	$163.27	$0.00	$163.27	AE
11,891.8	$61.76	$39.86	$101.62	$0.00	$101.62	AEP **
9,652.0	$61.76	$39.86	$101.62	$0.00	$101.62	APS
14,084.2	$114.67	$39.86	$154.53	$21.30	$133.23	ATSI
7,570.5	$123.42	$39.86	$163.27	$0.00	$163.27	BGE
24,100.9	$61.76	$39.86	$101.62	$0.00	$101.62	COMED
3,668.8	$61.76	$39.86	$101.62	$0.00	$101.62	DAYTON

Committed Resource Obligations

Energy Market Offer Requirements

- All generation resources that have an RPM Resource Commitment must offer into PJM's Day Ahead Energy Market
- Demand Resources that have an RPM Resource Commitment must be registered in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Response Program
  - and thus available for dispatch during PJM declared emergency events

Resource Performance Measures

Assessment	Purpose
RPM Commitment Compliance	Determines if sufficient unforced capacity on resource during DY to meet its RPM commitments
Peak-Hour Period Availability	Measures if generation resource was available during critical peak-hour periods during DY
Summer/Winter Capability Testing	Determines if generation resource demonstrated its ICAP commitment amount through summer and winter testing
PSM Compliance	Determines if generation resource took an unapproved planned or maintenance outage during peak season period
Load Management Event Compliance	Determines if committed demand resource reduced load during a PJM-initiated LM event
Load Management Test Compliance	In the absence of a PJM-initiated LM event, this assessment determines if committed demand resource reduced load during a CSP-initiated test
EE M&V Audit	Confirms the Nominated EE Value and CP value of an EE Resource through a post-installation M&V audit
Non-Performance Assessment	Evaluate the performance of committed capacity resources during Emergency conditions

Assessments for Annual, Extended Summer DR, & Limited DR Commitments

Generation Resource
- Commitment Compliance
- Peak Hour Period Availability*
- Generation Rating Test*
- Peak Season Maintenance Compliance**

Demand Resource (DR)
- Commitment Compliance
- Load Management Event Compliance
- Load Management Test Compliance

Energy Efficiency Resource (EE)
- Commitment Compliance
- Measurement & Verification Audit

** Not applicable to wind and solar resources*
*** Not applicable to hydro and intermittent resources*

Assessments for CP & Base Commitments

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- **Generation Resource**
  - Commitment Compliance
  - Non-Performance Assessment
  - Generation Rating Test*
- **Demand Resource (DR)**
  - Commitment Compliance
  - Non-Performance Assessment
  - Load Management Test Compliance
- **Energy Efficiency Resource (EE)**
  - Commitment Compliance
  - Measurement & Verification Audit
  - Non-Performance Assessment

** Not applicable to wind and solar resources*

LSE Obligations

LSE Obligations in RPM

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- PJM procures capacity on behalf of LSEs through RPM Auctions to satisfy their daily UCAP obligations during the DY
- LSEs will automatically be assessed a Locational Reliability Charge for load served during the DY
- LSEs are not required to participate in RPM Auctions
  - An LSE may choose to offer resources in RPM Auctions and use any Auction Credits received to offset the Locational Reliability Charges

How are Final UCAP Obligations Determined?

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When Determined?	Final RTO UCAP Obligation
After clearing of the final IA for the DY	Total amount of MWs cleared in Buy Bids submitted by PJM across all RPM Auctions less the total amount of MWs cleared in Sell Offers submitted by PJM across all Incremental Auctions.

When Determined?	Final Zonal UCAP Obligation
After clearing of the final IA for the DY	Zonal allocation of the Final RTO UCAP Obligation

Obligation Peak Load – Annual Allocation

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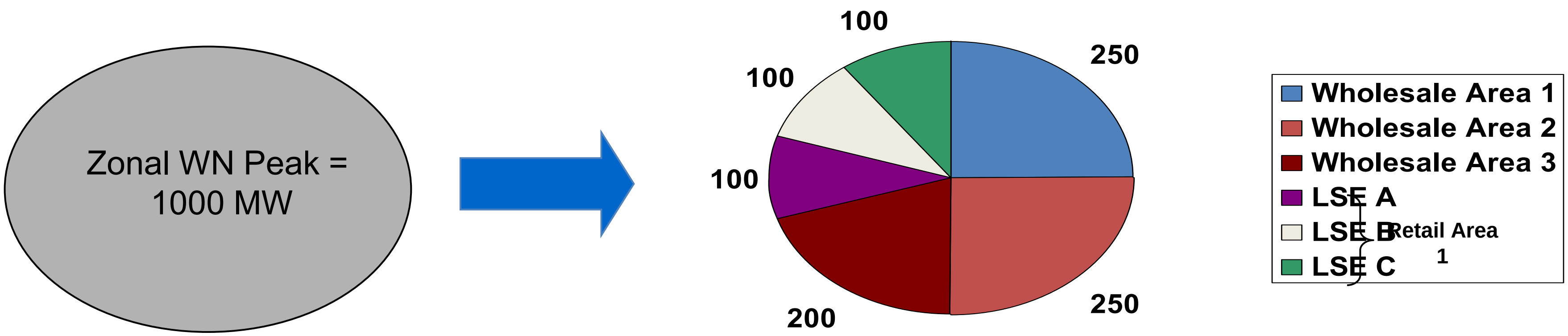
- Each PJM Electric Distribution Company (EDC) is responsible for allocating the previous summer's weather normalized peak to end-use customers in the zone (both retail and wholesale) by Dec. 31 prior to the start of the Delivery Year.

Often referred to as a "PLC" or "capacity ticketing" process.



Obligation Peak Load allocation for a zone/area is constant and effective for the entire Delivery Year

Obligation Peak Load – Daily Allocation

- Areas with Retail Choice can modify LSE share on a daily basis by uploading XML files to eRPM.

- XML Uploads must be submitted by EDC at least 36 hours prior to the start of the operating day.

LSE UCAP Obligation

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Obligation Peak Load in Zone/Area	*	Final Zonal RPM Scaling Factor	*	Forecast Pool Requirement (FPR)

- LSE UCAP Obligations are assessed daily based on load served during Delivery Year
- Daily UCAP Obligation is locked 36 hours prior to the start of the operating day
- FPR used is the final value updated prior to the Third Incremental Auction

Locational Reliability Charges

Locational Reliability Charge =

LSE Daily Zonal UCAP Obligation * **Final Zonal Capacity Price**

- Each RPM LSE that serves load in a PJM Zone or load outside PJM using PJM resources (i.e., Non-Zone Network Load) during the Delivery Year must pay a Locational Reliability Charge.
- Charges calculated daily and billed weekly during Delivery Year.

The Electric Distribution Companies (EDCs) upload the load serving responsibility of suppliers in their zone to PJM each day.

a) True

b) False

Changes for 2020/2021 Delivery Year

Enhanced Aggregation Filing

- Enhance Capacity Performance aggregation rules
- Establish winter Capacity Interconnection Rights for eligible resources
- Modify Demand Resource Measurement & Verification Rules

Updated Aggregate Resource Business Rules

- Allow Intermittent, Capacity Storage Resources, DR, EE, and environmentally limited resources that are located in different LDAs to form an Aggregate Resource
  - Aggregate Resource will be modeled in smallest modeled LDA common to underlying resources
- Total committed quantity on Aggregate Resource allocated to underlying resources on monthly basis and updated no later than last day of month preceding delivery month
  - Quantity allocated to an individual resource cannot exceed the CIR value/UCAP value of the individual resource
  - If total committed quantity on Aggregate Resource increases/decreases due to replacement capacity transactions, must increase/decrease the the allocation of commitment to the underlying resources by a commensurate amount

Updated Aggregate Resource Business Rules *(Cont'd)*

- Performance of an Aggregate Resource for a given PAH is based on the net of the performance of the individual underlying resources that were required to perform during the PAH (i.e. the resources located in the PAH area)
- The Non-Performance Charge Rate for an under-performing Aggregate Resource is based on the rate associated with the LDA in which the under-performing underlying resources are located weighted by the under-performance MW quantity of such resources
- The stop-loss of the Aggregate Resource is based on the Non-Performance Charge Rate associated with the LDA in which the Aggregate Resource was modeled in the RPM Auction

Seasonal Capacity Performance Resources (Effective 2020/2021 Delivery Year)

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Summer-Period CP Resources

- Summer Period DR
- Summer Period EE
- Capacity Storage Resource
- Intermittent Resource
- Environmentally-Limited Resource

- Available June-October & May of DY (summer-period)
- If clear, Auction Credit & commitment for summer-period only

Winter-Period CP Resources

- Capacity Storage Resource
- Intermittent Resource*
- Environmentally-Limited Resource*

* May request additional CIRs for winter-period for DY and offer additional ICAP value in winter-period

- Available November-April (winter-period)
- If clear, Auction Credit & commitment for winter-period only

Update Sell Offer Requirements

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CP Offer Segment (Annual)

- Specify Min & Max MW offered & offer price
- Up to 10 segments
- Each segment clears independently
- MWs offered/cleared for entire DY

Seasonal CP Offer Segment (Summer or Winter)

- Specify Max MW offered & offer price (flexible offer)
- Up to 10 segments
- Each segment clears independently
- MWs offered/cleared for entire seasonal period

GEN - PJMTST GENERATOR WF

EFORd:	0
Max Offer EFORd:	0
New Unit Pricing:	☐

Available ICAP MW

	Annual	Summer	Winter
Current	13	13	40
Max	13	13	40
Min	13	13	40

		1	2	3
Capacity Performance (Annual)	Min MW	8.0	0.0	(null)
	Max MW	8.0	5.0	(null)
	Price	50.00	75.00	(null)
Scheduling Option		Regular	Regular	(null)
Self Supply		☐	☐	☐
Capacity Performance (Seasonal) [Select Control] - Winter	Max MW	20	7	(null)
	Price	60.00	80.00	(null)
Self Supply		☐	☐	☐

Total MWs offered across CP Offer segments <= Annual Max Available ICAP

Total MWs offered across all segments <= Seasonal Max Available ICAP

All sell offer segments are separate and independent of each other and all segments may potentially clear the auction. NOT COUPLED OFFERS

Update Auction Clearing Process

- Auction clearing algorithm will clear all annual CP sell offers, summer-period CP sell offers, and winter-period CP sell offers simultaneously to minimize bid-based cost of satisfying the reliability requirements of the RTO and each modeled LDA subject to all applicable requirements and constraints, including:
  - LDA CETL values (same as today)
  - Total cleared summer-period sell offers must exactly equal total cleared winter-period sell offers across the entire RTO (new constraint to ensure that seasonal CP sell offers clear to form annual CP commitments)

Update Nominated DR Value calculation for FSL/GLD customer on CP registration

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FSL Customer (2017/2018 – 2019/2020 DYs)

- Nominated DR Value = lesser of: (a) PLC – [Summer FSL * loss factor] or (b) [Winter Peak Load * Winter Weather Adjustment Factor – Winter FSL] * loss factor
- Nominated DR Value effective for entire DY

FSL Customer (Effective 2020/2021 DY)

- Nominated DR Value for summer-period = PLC-[Summer FSL * loss factor]
- Nominated DR Value for non-summer period = lesser of: (a) PLC – [Summer FSL * loss factor] or (b) [Winter Peak Load * Winter Weather Adjustment Factor – Winter FSL] * loss factor
- If registration indicates Summer-Period DR Only, Nominated DR Value for non-summer period = 0

GLD Customer (2017/2018 – 2019/2020 DYs)

- Nominated DR Value = lesser of: (a) summer GLD amount* loss factor or (b) winter GLD amount * loss factor
- Nominated DR Value effective for entire DY
- Nominated DR Value shall not exceed PLC

GLD Customer (Effective 2020/2021 DY)

- Nominated DR Value for summer-period =summer GLD amount * loss factor
- Nominated DR Value for non-summer period = lesser of: (a) summer GLD amount * loss factor or (b) winter GLD amount * loss factor
- If registration indicates Summer-Period DR Only, Nominated DR Value for non-summer period = 0
- Nominated DR Value for both summer & non-summer period shall not exceed PLC

- CSP determines Winter Peak Load based on customer's peak load between hours ending 7:00 EPT through 21:00 EPT on each of PJM defined 5CP days from December through February two Delivery Years prior to the DY for which registration is submitted
- PJM calculates and posts Zonal Winter Weather Adjustment Factor.

Contact Information:

PJM Client Management & Services

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Toll Free Telephone: (866) 400-8980

Website: www.pjm.com

Member ? Community

The Member Community is PJM's self-service portal for members to search for answers to their questions or to track and/or open cases with Client Management & Services

EDH-14

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Re: Petition for determination of need
for Dania Beach Clean Energy Center
Unit 7, by Florida Power & Light
Company
____/

DEPOSITION OF STEVEN R. SIM, D.ENV.

Taken on Behalf of the Sierra Club

DATE TAKEN: Wednesday, November 29, 2017
TIME: 8:57 a.m. - 4:17 a.m.
PLACE: 4800 North Federal Highway
Suite 301-E
Boca Raton, Florida 33431

Examination of the witness taken before:
Darline Marie West, Registered Professional Reporter
Florida Professional Reporter

plans as opposed to resource options?
A. We conduct resource plans from looking at our projected resource needs and then evaluating one or more resource options in order to create a resource plan. So resource options, if you wish to think of them as the building blocks of a resource plan, probably not a bad way to think about it.
Q. Does FPL conduct integrated resource planning?
A. Yes.
Q. What does that mean?
A. In my opinion, it is a process by which we look at our -- first, determine our resource needs. We look at available resource options that could meet those resource needs, a wide variety of resource options. We then analyze the resource options by placing them in various resource plans and then analyze them for both economics and noneconomic aspects in order to select what we think is the resource plan that all else equal, results in the lowest electric rates for our customers.
Q. What are the relevant non-economic factors?
A. There are probably several that come to mind quickly: One of those would be the maturity of the technology. Another would be field diversity.

environmental compliance costs have generally tended to grow over time. Although in the last couple of years we're seeing the projection of environmental compliance costs, lower growth than what we've seen in the past.

Q. And what about the risks associated with better supply options materializing in the future. How do you account for that?

MR. DONALDSON: Object to the form.

What do you mean by "better supply options"?

BY MS. CSANK:

Q. Lower costs, lower risk supply options, for example.

A. I would say that what we see now is, we see costs for supply options and for other key aspects generally declining over time. We see that because there is continued load growth on our system, there will be plenty of opportunities in the future for emerging technologies as they prove themselves to be integrated into the resource plan.

But what we are trying to analyze today is what our current projections of resource needs are and what given scenarios of fuel costs and environmental compliance costs, what is projected to projects going up over time as we grab the cheapest cost land. In Southeast Florida land costs are exceedingly high to where the land component of universal solar is, almost in order of magnitude higher, than it is in the SOBRA sites that -- we have currently gone through the SOBRA docket this year. So, therefore, there are certain components that can go up. There are certain components that could go down. Overall, we see the general trend in solar coming down to a point, but we think that levels off.

We also see other aspects very important to resource planning cost dropping, we see combined cycle cost dropping. In fact, we think that in the next few years we're going to see the very first combined cycle with a heat rate below 6,000. That's on the horizon. We see natural gas prices continuing to drop. We see environmental compliance costs. Current projections show those are lower than what they were projected to be a year ago and lower than they were projected to be a year before that.

So this isn't a situation in which we see one group of competitors having lower costs. Everybody's competing against everybody else. And everybody is trying to get lower cost, more efficiency, et cetera. And we're happy to take generation solar. We looked at large batteries, we looked at small batteries.

Q. Can I pause you, please?

Could you define "universal solar"?

A. Essentially utility scale solar, the same type that we are doing in our SOBRA, the 74.5 megawatt PV or slightly lower. I believe we looked at 60 megawatts at a site or two.

Q. Anything of a different size that you consider universal solar?

A. No. Sixty and 74.5.

Q. And "distributed solar," how do you define that?

A. This would be PV located on commercial customers' rooftops, where FPL owns the PV facility and the utility -- and the output from the PV facility goes directly into the grid, just as if it were a universal solar generator.

Q. Is there any other type of distributed solar that you investigated for the purposes of this docket?

A. We had looked previous at residential PV in our 2014 DSM goals analysis and in the five years before that, the 2009 DSM goals. And in the intervening years, between those two goals docket, we area.

Q. Why is there reason to believe that that wouldn't be the case?

A. Can you clarify why that wouldn't be the case?

Q. Or have you done any analysis to verify whether those conditions would or would not be obtained?

A. I don't need to do analysis to postulate that the load forecast could change. The forecast of peak load in Southeast Florida certainly can change from what we currently have now. It's certainly a possibility that available generation, either inside the region or outside the region could change.

But given -- let me clarify my answer. Given the load forecast we're operating under, given the projection of available generation, then the CSQ -- if we assume no changes to those can occur on paper, the CSQ line is projected to address the imbalance through the period of the 2020s.

Q. And by through the period of 2020s, specifically you mean through 2030?

A. Or to 2030, give or take a year.

Q. Okay. And so once FPL had made the decision -- it made the decision to pursue the CSQ analysis?

A. No, I did not see that result. But the result would not have surprised me.

Q. So in the 2016 analysis, FPL selected certain resource plans, right?

A. We evaluated certain resource plans, yes.

Q. But it was FPL itself that identified the resource plans to be evaluated?

A. Yes.

Q. Can a model select optimal resource options for FPL system?

A. In general, yes. In this particular situation, there was no model that we have or that we could identify that would simultaneously solve for our system resource needs and our Southeast Florida imbalance. We looked for such models. We talked to consultants. We were unable to identify a model that could do that. So we utilized the models we had, creating resource plans that we thought addressed all of the logical candidate resource options, and performed the evaluations.

Q. Was there a way to run the model to optimize resource options, generate resource plans, and then subsequently screen for these additional factors that FPL deemed relevant?

A. Walk me through that again, please.

Q. So you -- my understanding of what you said is that no single model could do resource optimization that took into consideration all of the factors that be you deemed relevant.

So what I'm asking is, was there a way to use resource modeling to develop optimal resource plans and then subject those to subsequent analyses separate and apart from the model to get at those factors that FPL deemed relevant that the model couldn't, for whatever reason, get at?

A. I think the answer is, partially, yes. Let me explain. In Iteration No. 1, we actually used our GS model, which is a system optimization model to create resource plans to address the system need only. I discussed that in my testimony. It created a fairly large number of resource plans.

We compared that to what we had created ourselves, ahead of the EGAS -- E-G-A-S -- model. And we pretty much were able to identify on our own what the candidates where. Based on that, we decided to proceed for the rest of the analyses, creating the resource plans, using the same approach we used for the first without the EGAS model.

Q. So in the EGAS model, you did not develop resource plans consisting of solar and/or batteries?

A. That's correct. Because we were using it for the first iteration. That's where we started. And that was just combined cycles and combustion turbines.

Q. Those were the model inputs or outputs?

A. Those were the resource options we input into the model and ask it to select resource plans with those options being located outside of Southeast Florida. That was merely the first of the four iterations.

Q. Right. So, to confirm, you did not do modeling that allowed the model to select the optimal resources?

A. No. We did. With the EGAS in Iteration 1, it could -- the EGAS model could not address both the Southeast Florida and the system resource needs. It's a model designed to address system resource needs.

We tested the EGAS model to see if it could come up with combinations that were better than what we created on our own, looking at the sites and the different types of combined cycles and combustion turbines. We concluded it did not give us anything we had not earlier created, and therefore, we did not proceed with the EGAS model further. The EGAS model could not have selected transmission facilities in any case, and, therefore, it was of limited use.

Q. Just so to make sure I understand, you did not do EGAS model runs that had, for example, PV and/or batteries as inputs, correct?

A. That is correct. We moved away from the EGAS model midway through Iteration No. 1 and we did not use it for the remaining iterations, because there was no need to.

Q. How did you determine there was no need for that?

A. We compared what we had created on our own, looking at combinations of resource options and sites with what EGAS did, and we found that we had selected on our own all of the best candidate sites of resource plans.

Q. Could you have run EGAS without inputting in the technologies such as CCs and CTs to see what the model would have picked in terms of technologies?

A. I'm sorry. Repeat, please.

Q. Is it possible, in the EGAS model, to do model runs where it is not an exogenous input, technology is not an input, but, rather, the model selects the optimal technologies to meet FPL's system correct?

A. I don't believe that was your question as I understood it. I thought you -- your question was, has the resource need changed from the time we filed the testimony and petition to now, and the answer to that question was, no, that has not changed. It did change from 2016 to 2017, as indicated in my testimony, when I said that we used updated forecasts of load, fuel, environmental compliance costs, et cetera.

Q. So what would have -- what change spurred FPL to add storage to this resource plan, the one that was ranked fourth in the 2016 analysis?

A. We were attempting to match megawatt for megawatt so that there were no differences in the amount of system megawatts that would be added and megawatts added in Southeast Florida between the Dania Beach plan, Plan 2, in 2017 analysis, and Plan 3. In order to make them equal in terms, at least on paper, in regard to both system and regional reliability, we needed to match megawatts for megawatts. We had run out of PV that was considered to be doable/reasonable in Southeast Florida and turned to storage.

Q. Was the matching the projects to these four, is Plan 3 more expensive than that project?

A. I can't compare them directly because they use completely different fuel cost forecasts, completely different load forecasts, completely different environmental compliance costs. So I cannot answer that question.

Q. Are Plan 1 and Plan 2 economically comparable?

A. We compared them economically and found that Plan 2 was 337 million CPVRR less expensive than Plan 1.

Q. And that was a meaningful comparison?

A. Yes. We believe so.

Q. So please refer to page 33 of your testimony.

A. I'm there.

Q. What is the basis for the assumption that there are a total of six sites in Southeastern Florida that are suitable for universal solar in the region?

A. The basis for that is feedback from our project development group that has been scouring the State of Florida for suitable sites for universal solar. They informed us in 2016 and repeated it in 2018 -- '17, rather, that there was at most six sites question slightly, because I think there's a better way to answer it. We have determined that the universal solar sites in general won't exceed 74.5 megawatts of main plate capacity, So we look for sites where you could put that much PV. I believe the project development team has found five such sites in Southeast Florida and one site where you could put slightly less 60 megawatts. But you want something within that size range to maximize the economics of universal solar.

Q. When you say "in general," are some of those sites able to accommodate more than 74.5 megawatts?

A. We don't look to go beyond 74.5. We think that is, in essence, the sweet spot for universal solar.

Q. Do you analyze the -- do you analyze universal solar at a higher amount than 74.5 megawatts?

A. I am sure that those analyses have taken place in the past. I have not been involved in those analyses. I'm sure that sizes smaller and sizes larger were considered at some point along the way.

Q. Do you analyze multiples of 74.5-megawatt universal solar?

A. We do in our SOBRA docket, and we do in our analyses that we carried out in 2016 and 2017. We analyzed all of the available six sites in Southeast Florida.

Q. Is it possible that there are sites that can accommodate a larger capacity of solar than 74.5 megawatts that you have not considered for universal solar?

A. It is -- again, it is possible -- let me back up.

I do not know in regard to Southeast Florida because I have not inspected the sites. What I've been told is, there are sites -- five sites that could accommodate 74.5, and that is the maximum amount that our company is interested in pursuing for universal solar.

Q. Okay. So you mentioned that FPL assumed that distributed solar would be added by entering 30-year leases with commercial customers to allow for the FPL-owned solar facilities; is that correct?

A. Yes.

Q. How much did FPL assume that it would pay for those leases?

A. Subject to check, it was, I believe, in the $30 range, $30 per kw, I believe. But subject to

answer --
A. I hope so.
Q. -- of the total megawatt hour that FPL expects to serve to its customers over the life of the project in Plan 2 -- we were talking about Plan 1, now Plan 2 -- would percentage to be attributable to the Dania Beach project?
A. I have never calculated that. I --
Q. Would that be calculated in the U-Plan?
A. Yes.
Q. Okay. During Dania Beach's projected life-span, does FPL assume that Dania Beach was -- or does -- does FPL's analysis reflect the fact that during Dania Beach's projected life-span that the Dania Beach project would serve more megawatt hours than would Lauderdale 4 and 5 under Plan 1?
A. Let me repeat back what I think the question was.
Will the Dania Beach combine cycle projected to supply more megawatt hours over its life than if we kept Lauderdale 4 and 5 running for the same length of time?
Q. Correct.
A. The answer's yes.
Q. "The answer's yes." Thank you.

A. We utilize both of our reserve margin criteria. One of those is a 20 percent minimum total reserve margin criteria. The other is a minimum of 10 percent generation only reserve margin criteria.

Q. Are either of these criteria mandatory?

A. The minimum 20 percent total reserve margin criteria is mandated by our Commission.

Q. And the generation reserve only margin?

A. It is one that FPL uses and that the Commission is aware of, and we've been using it now for, ballpark, three, four years.

Q. Just so the record is clear, I meant to say generation only reserve margin.

A. Understood. Thank you.

Q. Did FPL analyze any resource options or resource plans without the generation only reserve margin?

A. We performed that analysis in response to staff Interrogatories. So the answer's yes.

Q. And remind us, please, what was the scope of resource plans which you undertook that analysis?

A. It was essentially to rerun Plans 1, 2, and 3 from the 2017 analysis without the generation only reserve margin criteria.

Q. Would it be possible to rerun the analysis of other resource plans without the generation only reserve margin criteria?

A. Would it be possible? Yes. Have we done so? No.

Q. Why not?

A. There was no need.

Q. Why not?

A. I think what you'll find when you look at the responses to staff's Interrogatories, there is essentially no change in the outcome for Plans 1, 2, and 3 without the generation reserve margin. It is a minor player in this and essentially only change the amount of PPAs for which there are no costs being assumed in the analysis.

Q. Did FPL analyze any resource plans under the maximum loss of load probability of 0.1 day per year?

A. We do not analyze any plans in -- in these -- for this docket, because we do loss of load probability calculations at the beginning of each year to determine what -- which of our three reliability criteria, 20 percent total reserve margin, 10 percent generation only reserve margin, or cost of load probability is driving our resource needs. Loss of load probability is not driving our

resource needs, it is the other two.
Q. Does increasing reserve margin necessarily improve reliability?
A. All else equal, yes.
Q. Are there diminishing returns on reliability improvements from increases to generation reserves?
A. Can you repeat the question, please?
Q. Are there diminishing returns on reliability improvements from increases to generation reserves?
A. I would say at least in theory at some point, yes, there would be diminishing returns.
Q. At what point would that be?
A. There is no one set answer for that.
Q. Okay.
A. I would certainly say that if one is in a situation where one is increasing reliability through higher reserve margins and resulting in lower cost to a utilities customer. As is the case with Dania Beach. That is certainly not a point of diminishing returns. I'd say our customers are benefitting both economically and benefitting with a greater system and regional reliability.
Q. Can you quantify the reliability benefits

sentence correctly. What I was trying to indicate is whether you look at the top half or the bottom half, if you look at the 20 percent reserve margin and the 20 percent reserve margin columns, the first year of need and the amount of need is -- well, it's identical in terms of first year need, and it's very similar in terms of the amount of need.

Q. Thank you for the clarification.

A. And I'll work on my writing skills.

Q. We all need to.

So, in other words, even if there are capacity additions such as the project that are delayed, FPL projects that it will meet its reserve margin criteria in 2022 and in 2023?

A. It would meet its minimum criteria value with -- assuming no changes in generation, load, or DSM.

Q. And even if such capacity additions like the project are delayed, your projections are that there is no system imbalance issue until 2025?

A. Agreed. Again, subject to no changes in regard to actual load, actual DSM, and actual generation being different than what is currently being projected that many years out.

Q. And we've heard this before, but I just want to confirm, is there a material risk that those other conditions would change?

A. I interpret your question to mean, is there a possibility that those could change? The answer is, yes, they're forecasts.

Q. Do you know what the likelihood is that those conditions will change? Is that something that you've analyzed?

A. No. We do not assign a probability to those occurrences.

MS. CSANK: Okay. Give me a moment. I'm trying to streamline some of these questions.

MR. COX: Sure.

THE WITNESS: Thank you.

BY MS. CSANK:

Q. So going back, Dr. Sim, to your exhibit, SRS Exhibit 2, I want to spend a bit of time on the column that identifies the projected DSM additions. And by my calculation, this column shows and the -- the entries by year in this column, column 6, show the same values in both tables, correct?

A. Yes. And they should.

Q. And what this shows is that there will be 55 megawatts of DSM added in 2017, correct? Sorry.

slightly by projected attrition in our load control programs, primarily our residential load control program.

Q. And could you please explain why you chose the quantities that appear in SRS-2 for DSM additions over this period of time?

A. Yes. We assume that our current DSM goals that run through, I believe, 2024 are going to be met in terms of the signups, because goals have not yet been set for years past 2024. We assumed it would be the same level of incremental signups through 2030.

Q. The Commission's last goal setting was premised on a particular avoided unit on FPL system, correct?

A. I believe it was at least primarily set on one specific generating unit, yes.

Q. Do you recall what that unit was, Dr. Sim?

A. Subject to check, I believe it was 2019 combined cycle.

Q. How does that unit compare to FPL's current -- what would be FPL's current avoided unit?

MR. COX: Could you clarify "current avoided unit"? Does that assume with the need filing that we've made or is that pre-filing? I guess, is a better and you replace the generating capacity. So don't put us at any more risk than what you're already doing in regard to meeting unforeseen circumstances. We had, roughly, a four-year window, let's keep it at that.

Q. Why is four years the magic number of years?

A. We're taking the units out, Lauderdale 4 and 5, in late 2018 and the Dania Beach unit would be in midyear of 2022, roughly, four years. So that is just the general time frame I used here in this discussion.

Q. So you didn't analyze any other arrangements in terms of when the retirements would occur as compared to when new generation would be added in 2017?

A. I don't believe that's what I said. I discussed it with our system operators, and their preference would be, let's not extend the four-year window beyond what it currently is. Let's try to maintain that constant to minimize risk as unforeseen circumstances.

Q. What forms their preference?

A. Decades and decades of operating the system.

Q. Besides their wisdom and experience, is there any other documented analytical basis for their preference?

A. I do not know. I rely upon their input in matters such as this.

Q. Did they --

A. But I -- but I certainly trust their experience, because they have to operate the system day in day out, 365 days a year. And it may help to remind folks that we operate the grid not just for FPL, we operate the grid for the entire peninsula of Florida. So they have the responsibility not just for FPL and its customers, but for the state.

Q. Turning back to another assumption that you discussed with my colleague. You said that 74.5 megawatts solar -- large scale solar is the sweet spot for FPL.

What informs that sizing?

A. I think there are a couple of considerations there: One is that above a certain level of megawatts within a range, the economics for universal solar have been analyzed and have been set as being -- as it falls within this window, that is -- you're gaining the economies of scale. 74.5 is within that range.

The other one that comes to mind is, if you go 75 megawatts or greater, you're subject to the Florida bid rule, and you would be required to put the project out for bid.

Q. Is it true that there are numerous solar projects in FPL's interconnection queue which are of larger scale?

A. I do not know. I have not looked at the interconnection queue in some time.

Q. Isn't it also true that FPL has announced that it has purchased land equivalent to building at 4 gigawatts of solar?

A. Subject to check, I would say that's probably accurate. Last I heard was three-and-a-half gigawatts. But that number keeps growing, so...

Q. Do you know where that land is located across FPL's service area?

A. My understanding, from talking to the project development folks, is, the vast majority, if not exclusive, is outside of the Southeast Florida region, simply due to the availability of land and certainly the cost of the land, which is much, much cheaper outside of those two county areas.

Q. Is there any study of land prices for land that would be suitable for utilities scale solar in

Can you explain what those numbers -- what assumptions those numbers are based on?

A. They're based on a number of assumptions. Some of the key assumptions were that there would be a change in the installed cost of the Dania Beach unit if we moved the unit back from 22 to first 23 and then to 24. There was also a change in the operational costs.

We had discussed earlier that we assumed that there would be -- we would maintain a four-year window from the time of retirement. So in the original analysis with a mid '22 Dania Beach in-service date, the Lauderdale 4 and 5 units were projected to cease operation and be retired in late 2018. We assumed that in the one year delay, they would continue to operate until late 2019 along with associated operating costs for that additional year. And in the two-year delay, the same thing. They would continuing operating not -- out to late 2020 with one more year of operational cost. And then there are fuel impacts on the system from the delay in bringing in the Dania Beach unit. So those are the three primary drivers.

Q. I'm sorry. I was just going to ask -- and based on your answer, I assume you did not do an analysis with looking at continuing to retire the Fort Lauderdale 4 and 5 units in '18 and bringing in the Dania units a year later or two years later? Is that my understanding from your response?

A. That is correct. And as we had discussed earlier, that was based on system operators' guidance, in that they did not wish to be without that amount of generating capacity in the region for more than four years. They thought that was placing both additional risk on the system, both FPL and peninsula of Florida.

Q. Is that's the Southeastern regional low risk?

A. It is both a -- I would say primarily -- no. I would say first a Southeast Florida risk. And if they were to have transmission system difficulties in such a large load pocket, those transmission difficulties -- system difficulties could spread northward.

MS. CHRISTENSEN: Okay. All right. I think that answered or clarified my understanding of the numbers. So I appreciate it. Thank you, Dr. Sim.

THE WITNESS: You're welcome.

MS. CSANK: May I, following up on

EDH-15

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

RE: PETITION FOR DETERMINATION OF NEED FOR DANIA BEACH CLEAN ENERGY CENTER UNIT 7, BY FLORIDA POWER & LIGHT COMPANY	Docket No. 20170225-EI Served: Dec. 1, 2017

DEPOSITION OF DR. STEVEN R. SIM

Pages 1 through 80

Monday, December 4, 2017
10:12 a.m. - 12:31 p.m.

FLORIDA POWER & LIGHT COMPANY
700 Universe Boulevard
Juno Beach, Florida 33408

Stenographically Reported By:
WANDA D. GOOD, CERTIFIED COURT REPORTER

Q. So, and just to make sure that I'm following, Dr. Sim, how would I -- how would I track independently the attrition rate and -- and -- and be able to on my own reach the DSM megawatt numbers in your reserve margin sheets, which I believe were referenced, for example, in your Exhibit SRS2 to your pre-filed testimony of October 20?

A. If you'll give me just a moment, let me check one item.

Q. Standing by. Thank you.

A. Off the top of my head, I am not aware of an independent piece of paper that would show you that calculation; however, one could request that in a new discovery request, and we would -- excuse me. We would then provide the calculations showing the incremental megawatts from the 2015 DSM plan approved by the Florida Public Service Commission, and we would show the degradation and projected degradation in our load management programs which could get you to the DSM values that are shown on Exhibit SRS2.

Q. Okay. And overall, in Iteration Number 3, Dr. Sim, what was the most economic plan?

A. Of the five plans that were analyzed, the most economic plan was Plan Number 3, which was the plan that involved 983 megawatts of solar facilities

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that would be sited within the Southeastern Florida region, followed by or accompanied by new combined cycles sited outside of the Southeast Florida region that would come in in 2026 and I believe it was 2029, respectively.

Q. All right. I couldn't hear the second date. You said 2026 and --

A. 2029. This is shown --

Q. Did FP&L consider --

A. This is shown --

Q. Yes, go ahead.

A. -- Slide 37 of the deck.

Q. Okay. Great. And I just want to make sure the record was clear. Thank you, Dr. Sim.

And this plan, Plan Number 3, contains no small solar, otherwise known as distributed generation solar, correct?

A. That is incorrect. As labeled at the top of the column on Slide 37, it is labeled "large and small solar." If you go back to Slide 33, we said there was approximately 433 megawatts of large solar. Go back to Slide 37. There's 983 megawatts of total solar, so that would have included -- the difference is 550 megawatts of small-scale or DG solar.

Q. And in -- in the 2016 study, did FP&L

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QUESTION:
Please explain and quantify the likelihood that "the window of opportunity in which to replace the regional capacity lost by retiring the Lauderdale units" will close subsequent to 2025, *see* Sim Testimony at 29, including the factors germane to that likelihood, and identify the potential timeframe and time range in which that window could close subsequent to 2025, and associated likelihood, and identify all documents that support or reflect the information presented in your answer.

RESPONSE:
The window of opportunity could potentially extend past 2025, *e.g.*, due to either Summer peak load being lower than forecasted and/or to greater than forecasted available capacity in the region. However, as discussed in FPL's response to Sierra Club's First Set of Interrogatories No. 15, because FPL's examination and analyses showed that a mid-2022 in-service date for DBEC Unit 7 was more economic for FPL's customers than either a mid-2023 or mid-2024 in-service date, no projection of the likelihood of a different Summer peak load and/or available generation was needed or performed. When evaluating the reliability of electric service for all of FPL's customers, and particularly in such a large region as Southeastern Florida, the focus should properly be on ensuring reliability for those customers. For that reason, even if the economics of a delay scenario were equal to that of the mid-2022 in-service date scenario, a mid-2022 in-service date should be chosen. However, as the economics of the mid-2022 in-service date are superior to those of a mid-2023 or mid-2024 scenario. Consequently, it is in the best interests of FPL's customers to complete the modernization of the Lauderdale site with DBEC Unit 7 entering service in mid-2022 to maintain reliability and ensure the maximum economic benefits associated with the Dania Beach Project. No additional documents beyond those discussed in FPL's response to Sierra Club's First Set of Interrogatories No. 14 were needed to support or reflect the information presented in this answer.

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12 14 2016 DRAFT

2016 Southeastern Florida Study: Results To-Date

Corporate Real Estate, EMT, Engineering & Construction, Environmental Services, Power Delivery, Project Development, and Resource Assessment & Planning

December 15, 2016

~~PRIVILEGED AND CONFIDENTIAL~~
~~Attorney-Client Communication / Attorney Work Product~~

Presentation Overview

- **Background and Scope, Key Assumptions, and Analysis Approach**
- **Analysis Iteration # 1: Fossil Generation Outside of SE Florida Region**
- **Analysis Iteration # 2: Fossil Generation Inside SE Florida Region**
- **Analysis Iteration # 3: Renewable & Storage Options Inside SE Florida Region**
- **Analysis Iteration # 4: Incorporates Retirements**
- **Overall Conclusions**

 ~~Draft Attorney-Client Work Product Privileged & Confidential~~

FPL

Background and Scope

- FPL's typical integrated resource planning (IRP) process identifies the timing and magnitude of resource needs for the entire FPL system, then determines the most economical way to meet those system needs while keeping in mind various system concerns
- One of these system concerns is maintaining a balance between load, generation, and transmission import capability in Miami-Dade and Broward counties (i.e., the "SE Florida region")
- This balance can be maintained in 3 ways: (1) building new generation in SE Florida, (2) building new transmission lines to import power from north of the region into SE Florida, and/or (3) lowering SE Florida load
- Previous generation additions (Turkey Point 5, WCEC 1-3, Turkey Point nuclear uprates, etc.) have addressed the SE Florida imbalance issue enough to defer the concern for a number of years
- However, based on the 2016 TYSP assumptions, SE Florida load and generation were projected to be out of balance as early as 2023 and FPL's total system need requires resources by 2024

Consequently, FPL began analyses in mid-2016 to examine resource plans that could simultaneously address the resource needs for both the FPL system overall and the SE Florida region

Key Assumptions

- A "simultaneous solution" analysis is more complex, and more time consuming, than typical IRP analyses
- This requires a "freezing" of assumptions for the duration of the study
- Most of the assumptions are identical to those in FPL's 2016 TYSP including: (i) load forecast, (ii) fuel cost forecast, (iii) CO2 compliance cost forecast, (iv) DSM projections, (v) the 2016 PV and 2019 CC additions, and (vi) financial parameters (ROE, discount rate, etc.)
- In addition, the following new assumptions were used:
  - Regarding nuclear, Turkey Point Units 6 & 7 are assumed not to enter service prior to 2030*
  - Regarding solar, approximately 1,700 MW (Nameplate) of new PV is assumed to be added by 2023 with all of it at specific sites outside the SE Florida region *(this encompasses the 300 MW shown in the 2016 TYSP plus 1,400 MW more)*
  - All CC additions, including the 2019 Okeechobee CC, are assumed to be 1,751 MW (unless otherwise noted)

* This assumption is based on : (i) the 2016 NCR filing information regarding a "pause" before preconstruction begins, and (ii) the desire to examine the SE Florida imbalance issue without TP 6 & 7 because these units would fully address the issue for a number of years once the units are in-service

The assumption of 1,700 MW of additional PV delays the FPL system resource need

- The incremental PV delays FPL's system need from 2024 to 2025 (and results in a total system need of approx. 3,500 MW thru 2030)

SE Florida Study: Reserve Margin Projections

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
						Total Reserve Margin			Generation Only Reserve Margin		
Year	Unit Additions	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Reserves MW	%	MWs Above / (Below) Total RM MW	Reserves MW	%	MWs Above / (Below) 10% Gen-Only MW
2019	Okeechobee CC	28,551	24,893	2,041	22,852	5,699	24.9	1,129	3,658	14.7	1,169
2020	300 MW Solar	27,995	25,206	2,088	23,117	4,877	21.1	254	2,789	11.1	268
2021		28,142	25,316	2,136	23,180	4,962	21.4	326	2,825	11.2	294
2022	OCEC Inc MW *	28,272	25,540	2,185	23,355	4,916	21.1	245	2,732	10.7	178
2023	1,414 MW Solar *	28,898	25,833	2,234	23,599	5,299	22.5	579	3,065	11.9	482
2024		28,895	26,180	2,284	23,896	4,999	20.9	220	2,715	10.4	97
2025		28,892	26,572	2,334	24,238	4,654	19.2	(194)	2,320	8.7	(337)
2026		28,889	27,068	2,384	24,684	4,206	17.0	(731)	1,822	6.7	(885)
2027		28,883	27,665	2,434	25,231	3,652	14.5	(1,394)	1,218	4.4	(1,549)
2028		28,880	28,225	2,484	25,741	3,140	12.2	(2,008)	656	2.3	(2,167)
2029		28,878	28,805	2,534	26,271	2,607	9.9	(2,647)	73	0.3	(2,808)
2030		28,875	29,398	2,584	26,814	2,061	7.7	(3,301)	(523)	-1.8	(3,462)

* These capacity changes are presented in a way to facilitate comparison to FPL's 2016 TYSP

Therefore, the analyses assumed FPL's 1st system need is in 2025 and the analyses address subsequent needs through the year 2030

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FPL

The need to simultaneously solve for both FPL system and SE Florida region requires a new analysis approach

- FPL knows of no existing planning model that can simultaneously solve for two such needs; therefore a new approach with 4 analysis iterations was used:

Iteration # 1:

- Examines CCs and CTs outside SE Florida to meet system needs and transmission facilities needed for system integration and/or to address the regional imbalance

Iteration # 2:

- Expands to examine CCs and CTs sited inside the SE Florida region and resulting changes in needed transmission facilities

Iteration # 3:

- Further expands to examine smaller-scale (PV, batteries, DSM etc.) options sited within the SE Florida region and resulting changes in needed transmission facilities

Iteration # 4:

- Incorporates potential retirements of existing units

This approach also accounted for projected gas pipeline expansions that would be needed to serve new generating units

Each iteration involves work by multiple departments that is partly sequential, partly in parallel

- The general work flow for each iteration consists of 5 economic analysis steps:
    1. CRE, EMT, E&C, Power Delivery, ENV, DSM, Operations, Project Development, and RAP identifies resource options appropriate for the specific iteration
    2. RAP develops resource plans that consist of these resource options, identifies the most promising resource plans, and provides these plans to Power Delivery and EMT
    3. Power Delivery performs load flow analyses of these plans to determine needed transmission integration facilities for each plan, then develops cost projections for these facilities
    4. EMT develops costs for needed expansion of gas pipelines
    5. RAP incorporates the transmission and pipeline costs with its own projections of resource plan costs (fuel, emissions, generation capital, etc.) to create a Total Cost projection for each resource plan
- The plans are also reviewed from a non-economic or risk perspective

The best resource plan(s) from each iteration will be retained and will help guide the work for subsequent iterations

FPL

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- Analysis Iteration # 4: Incorporates Retirements
- Overall Conclusions

8 candidate sites located outside of the SE Florida region were initially considered for Iteration # 1 analyses

- Of these 8 candidates, 3 sites were selected for the analyses: (i) Okeechobee, (ii) Martin, and (iii) Hendry *(the 5 other sites - Putnam, Sanford, DeSoto, Ft. Myers, and the ICL Martin site – were not analyzed for various reasons)*
- One new CC (1,751 MW) and several pairs of CTs (469 MW per pair) were assumed to be feasible at the Okeechobee and Martin sites
- Due to the Hendry land agreement with the Seminole tribe, a maximum of only 2,200 MW of new generation (equivalent to one CC and only one pair of CTs) was assumed at Hendry
- The projected costs for the CCs at each site are similar except for gas pipelines; a Hendry CC requires a new pipeline costing approx. $300 million (overnight cost) while the other two sites require only low cost laterals
- Due to the need for a new pipeline to Hendry, the team assumed no CTs would be sited at Hendry unless a CC unit was built there first

Capacity at Hendry has the potential to lower SE Florida regional transmission costs, thus it has the potential to partially offset the pipeline costs to Hendry

72 resource plans were created and initially analyzed

- RAP's EGEAS optimization model was used to create, and perform preliminary economic analyses of, resource plans consisting of CCs and CTs at these 3 sites through 2030
- 53 resource plans were created which focused on addressing FPL's system resource needs which begin in 2025; thus these plans first added new generation in 2025
- Because new generation at Hendry was projected to have the potential to assist the SE Florida imbalance,19 additional plans assuming a Hendry CC was added in 2023 were created
- The preliminary economic analyses performed with the EGEAS model established an economic ranking of each of the two sets of plans
- Based partly on the results from these preliminary economic analyses, and partly on their potential for reducing SE Florida regional transmission costs, RAP and Power Delivery identified 12 of these plans as the most promising

Analyses then continued for these 12 resource plans

9 of the 12 plans have new generation beginning in 2025 and 3 plans have new generation at Hendry beginning in 2023

Southeastern Florida Study Resource Plans: Analysis Iteration #1

Year	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Plan 6	Plan 7	Plan 8	Plan 9	Plan 10	Plan 11	Plan 12
2023										Hendry CC	Hendry CC	Hendry CC
2024												
2025	Martin CC	Okee CC	Martin CC	Okee CC	Hendry CC	Hendry CC	Martin CC	Okee CC	Hendry CC			
2026												
2027												
2028	Okee CC	Martin CC	Hendry CC	Hendry CC	Martin CC	Okee CC	Okee 2 CT	Okee 2 CT	Hendry 2 CT	Martin CC	Okee CC	Hendry 2 CT
2029							Okee 4 CT	Okee 4 CT	Okee 4 CT			Okee 4 CT
2030							Okee 2 CT	Okee 2 CT	Okee 2 CT			Okee 2 CT

These 12 plans were then sent to Power Delivery for load flow analyses and transmission costing work while RAP continued its economic analyses

[redacted]

[redacted]

Summary of Transmission Planning findings for the 12 resource plans to meet needs through 2030 (Iteration # 1):

- Pre-established assumptions for PV and viable fossil sites for combined cycle and simple cycle CTs affected needs of both Resource Planning (RAP) and Power Delivery
- Previously stated transmission need in 2023 (+/- 1yr) deferred to 2025 time frame coinciding with RAP need for system needs
  - Due to solar at Hendry and changes in dispatch with additional solar
- Projects identified are variations of familiar major projects such as Terrytown, Sheridan, and Andytown-Quarry
- Nine (9) individual transmission projects were developed for cost estimating to provide input for CPVRR calculation of each Resource Plan
- Preferred resource plans analyzed include those that construct the Corbett-Sugar-Quarry 500 kV project (CSQ) with the 2025 generation (OCEC #2 or MR #9 CC) to increase transfer capability into Miami-Dade and Broward and gain additional benefit to CIP-014 station(s)

Transmission projects have been developed to address the SE Florida imbalance in all 12 resource plans for Iteration #1

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Several types of costs were calculated for each of these 12 resource plans

- A Generation & Fuel Cost was developed by RAP, using its UPLAN model and Fixed Cost Spreadsheet, to account for system fuel costs, system emission costs, new generation fixed and variable costs, and transmission interconnection capital costs
- A gas Pipeline Cost was developed by EMT and/or E&C
- A Transmission Integration Cost was developed by Power Delivery/RAP to account for various types of transmission costs
- These transmission costs accounted for: (i) integrating the new generation into the transmission system, (ii) addressing any remaining imbalance in SE Florida by increasing import capability into the region, and, as needed, (iii) modifying the transmission interconnection costs for new generation that had been initially provided to RAP
- Then the three types of costs mentioned above were summed to develop a Resource Plan Total Cost value for each resource plan
- This Resource Plan Total Cost accounts for the years 2017 through 2061 and is expressed as CPVRR costs in millions of dollars, discounted back to 2017

The next three slides present the projected costs and rankings of the plans as each type of cost is accounted for

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The economic ranking of resource plans based solely on the Generation & Fuel Costs is shown below

SE Florida Study: Economic Results for Iteration #1: Without Pipeline or Transmission Integration Costs
(CPVRR, millions, 2017$, 2017-2061)

Economic Rank:	1	2	3	4	5	6	7	8	9	10	11	12
Year	Plan 2	Plan 1	Plan 4	Plan 6	Plan 3	Plan 5	Plan 11	Plan 10	Plan 8	Plan 7	Plan 9	Plan 12
2023							Hendry CC	Hendry CC				Hendry CC
2024												
2025	Okee CC	Martin CC	Okee CC	Hendry CC	Martin CC	Hendry CC			Okee CC	Martin CC	Hendry CC	
2026												
2027												
2028	Martin CC	Okee CC	Hendry CC	Okee CC	Hendry CC	Martin CC	Okee CC	Martin CC	Okee 2 CT	Okee 2 CT	Hendry 2 CT	Hendry 2 CT
2029									Okee 4 CT	Okee 4 CT	Okee 4 CT	Okee 4 CT
2030									Okee 2 CT	Okee 2 CT	Okee 2 CT	Okee 2 CT
(1) Generation & Fuel Costs	94,901	94,902	94,936	94,942	94,943	94,948	95,006	95,012	95,418	95,425	95,455	95,519
(2) Pipeline Costs *	0	0	0	0	0	0	0	0	0	0	0	0
(3) Transmission Integration Costs *	0	0	0	0	0	0	0	0	0	0	0	0
(4) Resource Plan Total Costs	**94,901**	**94,902**	**94,936**	**94,942**	**94,943**	**94,948**	**95,006**	**95,012**	**95,418**	**95,425**	**95,455**	**95,519**
(5) Difference from Lowest Cost Plan	0	1	34	41	42	47	105	111	517	524	553	618

** Pipeline and tranmission integration costs are only for the new units identified in each plan (not for filler units)*

At this stage, the economics of at least 6 plans are relatively close

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After accounting for Pipeline Costs, the relative economics of the resource plans change significantly

SE Florida Study: Economic Results for Iteration #1: Without Transmission Integration Costs
(CPVRR, millions, 2017$, 2017-2061)

Economic Rank:	1	2	3	4	5	6	7	8	9	10	11	12
Year	**Plan 1**	**Plan 2**	**Plan 3**	**Plan 4**	**Plan 5**	**Plan 6**	**Plan 10**	**Plan 11**	**Plan 7**	**Plan 8**	**Plan 9**	**Plan 12**
2023							Hendry CC	Hendry CC				Hendry CC
2024												
2025	Martin CC	Okee CC	Martin CC	Okee CC	Hendry CC	Hendry CC			Martin CC	Okee CC	Hendry CC	
2026												
2027												
2028	Okee CC	Martin CC	Hendry CC	Hendry CC	Martin CC	Okee CC	Martin CC	Okee CC	Okee 2 CT	Okee 2 CT	Hendry 2 CT	Hendry 2 CT
2029									Okee 4 CT	Okee 4 CT	Okee 4 CT	Okee 4 CT
2030									Okee 2 CT	Okee 2 CT	Okee 2 CT	Okee 2 CT
(1) Generation & Fuel Costs	94,902	94,901	94,943	94,936	94,948	94,942	95,012	95,006	95,425	95,418	95,455	95,519
(2) Pipeline Costs *	20	23	232	255	268	288	295	315	24	47	292	319
(3) Transmission Integration Costs *	0	0	0	0	0	0	0	0	0	0	0	0
(4) Resource Plan Total Costs	**94,922**	**94,924**	**95,174**	**95,190**	**95,216**	**95,230**	**95,307**	**95,321**	**95,450**	**95,466**	**95,747**	**95,838**
(5) Difference from Lowest Cost Plan	0	2	253	268	294	308	385	399	528	544	825	916

** Pipeline and tranmission integration costs are only for the new units identified in each plan (not for filler units)*

Plans with CCs at Martin & Okeechobee are now the most economic

The addition of Transmission Integration Costs does not significantly change the economic ranking of the resource plans

SE Florida Study: Economic Results for Iteration #1
(CPVRR, millions, 2017$, 2017-2061)

Economic Rank:	1	2	3	4	5	6	7	8	9	10	11	12
Year	Plan 1	Plan 2	Plan 3	Plan 5	Plan 4	Plan 6	Plan 10	Plan 11	Plan 7	Plan 8	Plan 9	Plan 12
2023							Hendry CC	Hendry CC				Hendry CC
2024												
2025	Martin CC	Okee CC	Martin CC	Hendry CC	Okee CC	Hendry CC			Martin CC	Okee CC	Hendry CC	
2026												
2027												
2028	Okee CC	Martin CC	Hendry CC	Martin CC	Hendry CC	Okee CC	Martin CC	Okee CC	Okee 2 CT	Okee 2 CT	Hendry 2 CT	Hendry 2 CT
2029									Okee 4 CT	Okee 4 CT	Okee 4 CT	Okee 4 CT
2030									Okee 2 CT	Okee 2 CT	Okee 2 CT	Okee 2 CT
(1) Generation & Fuel Costs	94,902	94,901	94,943	94,948	94,936	94,942	95,012	95,006	95,425	95,418	95,455	95,519
(2) Pipeline Costs *	20	23	232	268	255	288	295	315	24	47	292	319
(3) Transmission Integration Costs *	319	317	466	425	453	425	430	430	319	486	434	438
(4) Resource Plan Total Costs	**95,241**	**95,241**	**95,641**	**95,641**	**95,643**	**95,655**	**95,737**	**95,750**	**95,769**	**95,952**	**96,181**	**96,276**
(5) Difference from Lowest Cost Plan	0	0	400	400	402	414	496	509	528	711	940	1,035

** Pipeline and tranmission integration costs are only for the new units identified in each plan (not for filler units)*

For Iteration # 1, the most economic resource plans have a CC at both Martin and Okeechobee

Several conclusions were drawn from the results of the Iteration # 1 analyses

- After the resource plans were developed, Power Delivery's analyses found that the assumption of 1,700 MW (Nameplate) of additional PV, including three 75 MW projects in Hendry county whose sites have the PV connecting to 500 kV lines, defers the SE Florida regional imbalance
- As a result, the originally projected start date for the imbalance was delayed from 2023 to 2025, thus eliminating any advantage that could have been gained by siting a CC at Hendry in 2023
- Thus resource plans with a Hendry CC, whether in 2023 or 2025, were significantly disadvantaged in Iteration # 1 analyses due to the need for a new gas pipeline to that site plus significant transmission costs for the greenfield site
- The most economic resource plan from Iteration # 1 has CC units at Martin and Okeechobee
- As shown on the prior slide, transmission costs – while significant – were not the determining factor among these resource plans

Having identified the most economic plans in which all new generation is sited outside of SE Florida, the analysis shifted to examine new CC & CT generation inside the SE Florida region in Iteration # 2

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Presentation Overview

- Background and Scope, Key Assumptions, and Analysis Approach
- Analysis Iteration # 1: Fossil Generation Outside of SE Florida Region
- Analysis Iteration # 2: Fossil Generation Inside SE Florida Region
- Analysis Iteration # 3: Renewable & Storage Options Inside SE Florida Region
- Analysis Iteration # 4: Incorporates Retirements
- Overall Conclusions

4 sites inside the SE Florida region were selected as potential sites for new CC and CT generation in Iteration # 2

- The 4 sites are: (i) Turkey Point, (ii) Andytown, (iii) Miami-Dade Limestone Producers Association Site (MDLPAS)* and (iv) Fort Lauderdale (for a potential repowering)
- Regarding the Turkey Point site, significant questions from an NRC "nuclear hazard" perspective exist regarding whether new gas-fired capacity utilizing a new gas pipeline and additional gas could be permitted at this site
- However, for this specific study these questions were ignored in order to perform a "what if" economic analysis of new gas-fired capacity at this site
- In addition to the 4 SE Florida sites listed above, the Hendry site was retained for further analyses in Iteration # 2 because: (i) new capacity sited at Hendry will help address the SE Florida imbalance issue, and (ii) the site is near the assumed pipeline route for other options
- The resource options examined in Iteration # 2 were new CCs and CTs

Most of the combinations of technology and site will require additional gas provided by a new gas pipeline

* The MDLPAS site is not owned by FPL

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These assumptions relate to environmental permitting of CCs and CTs, particularly in Miami-Dade county

- The first assumption is that a total of only 2,250 MW of new CC and/or CT capacity at the selected sites in Miami-Dade county (the equivalent of 1 CC and 2 CTs) is likely able to be permitted in the county
  - This assumption is primarily due to impact of particulate emissions on Everglades National Park
- The second assumption is that it appears to be possible to permit, both in Miami-Dade and Broward counties, oil-fired CTs that run up to approximately 3,000 hours/year if a CO catalyst is installed
  - The possibility of oil-fired CTs was looked at in order to examine the possibility of whether a meaningful amount of capacity could be sited in the SE Florida region without having to build a new pipeline down from Martin to Broward and/or Miami-Dade
  - The oil-fired CTs were examined in conjunction with a possible repowering of the Fort Lauderdale site that would use FGT gas

Based on these assumptions, 14 resource plans were developed for analysis in Iteration # 2

Four of the 14 plans (# 4, 5, 13, & 14) add capacity earlier than 2025 to prepare for a repowering of Ft. Lauderdale

SE Florida Study: Resource Plans for Iteration # 2

Year	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Plan 6	Plan 7	Plan 8	Plan 9	Plan 10	Plan 11	Plan 12	Plan 13	Plan 14
2023	---	---	---	---	---	---	---	---	---	---	---	---	2 CTs at Andytown & 2 CTs at Turkey Point. * (Remove Lauderdale CCs)	---
2024	---	---	---	2 CTs at Andytown & 2 CTs at Turkey Point. * (Remove Lauderdale CCs)	2 CTs at Andytown & 2 CTs at Turkey Point. ** (Remove Lauderdale CCs)	---	---	---	---	---	---	---	---	2 CTs at Andytown and 2 CTs at Turkey Point.** (Remove Lauderdale CCs)
2025	Hendry CC	Hendry CC	Hendry CC	Hendry CC	Hendry CC	Turkey Point CC	Turkey Point CC	Andytown CC	Andytown CC	Andytown CC	MDLPAS CC	MDLPAS CC	---	Hendry CC & Hendry 2 CTs
2026	---	---	---	---	---	---	---	---	---	---	---	---	Ft Lauderdale Repower (1,751 MW)	---
2027	---	---	---	---	---	---	---	---	---	---	---	---	---	---
2028	Andytown CC	Turkey Point CC	MDLPAS CC	Ft Lauderdale Repower (1,751 MW)	Ft Lauderdale Repower (1,200 MW) & 2 CTs at Hendry	Andytown CC	Hendry CC	Turkey Point CC	MDLPAS CC	Hendry CC	Andytown CC	Hendry CC	Hendry CC	Ft Lauderdale Repower (1,200 MW)
2029	---	---	---	---	---	---	---	---	---	---	---	---	---	---
2030	---	---	---	---	---	---	---	---	---	---	---	---	---	---

* Both pairs of CTs will run oil until a new pipeline is built from Hendry to a repowered Fort Lauderdale CC (1,751 MW). At that time the CTs will run on gas.

** Both pairs of CTs will run on oil throughout. The repowered Fort Lauderdale CC (1,200 MW) will use FGT gas.

Two plans (#5 & #14) do not require a new pipeline into SE Florida

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A ranking based solely on generation & fuel appears below

SE Florida Study: Economic Results for Iteration #2: Without Pipeline or Transmission Integration Costs
(CPVRR, millions, 2017$, 2017-2061)

Economic Rank:	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Year	**Plan 3**	**Plan 1**	**Plan 12**	**Plan 10**	**Plan 9**	**Plan 11**	**Plan 13** [1]	**Plan 4** [1]	**Plan 2**	**Plan 7**	**Plan 8**	**Plan 6**	**Plan 5** [1]	**Plan 14** [1]
2023	---	---	---	---	---	---	2 CTs at Andytown & 2 CTs at Turkey Point. [2] (Remove Lauderdale CCs)	---	---	---	---	---	---	---
2024	---	---	---	---	---	---	---	2 CTs at Andytown & 2 CTs at Turkey Point. [2] (Remove Lauderdale CCs)	---	---	---	---	2 CTs at Andytown & 2 CTs at Turkey Point. [3] (Remove Lauderdale CCs)	2 CTs at Andytown and 2 CTs at Turkey Point.[3] (Remove Lauderdale CCs)
2025	Hendry CC	Hendry CC	MDLPAS CC	Andytown CC	Andytown CC	MDLPAS CC	---	Hendry CC	Hendry CC	Turkey Point CC	Andytown CC	Turkey Point CC	Hendry CC	Hendry CC & Hendry 2 CTs
2026	---	---	---	---	---	---	Ft Lauderdale Repower (1,751 MW)	---	---	---	---	---	---	---
2027	---	---	---	---	---	---	---	---	---	---	---	---	---	---
2028	MDLPAS CC	Andytown CC	Hendry CC	Hendry CC	MDLPAS CC	Andytown CC	Hendry CC	Ft Lauderdale Repower (1,751 MW)	Turkey Point CC	Hendry CC	Turkey Point CC	Andytown CC	Ft Lauderdale Repower (1,200 MW) & 2 CTs at Hendry	Ft Lauderdale Repower (1,200 MW)
2029	---	---	---	---	---	---	---	---	---	---	---	---	---	---
2030	---	---	---	---	---	---	---	---	---	---	---	---	---	---
(1) Generation & Fuel Costs	95,045	95,046	95,057	95,060	95,128	95,129	95,165	95,171	95,321	95,372	95,406	95,444	95,508	95,539
(2) Pipeline Costs *	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(3) Transmission Integration Costs *	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(4) Resource Plan Total Costs	**95,045**	**95,046**	**95,057**	**95,060**	**95,128**	**95,129**	**95,165**	**95,171**	**95,321**	**95,372**	**95,406**	**95,444**	**95,508**	**95,539**
(5) Difference from Lowest Cost Plan	-	1	13	15	83	84	121	127	277	328	362	399	463	494

** Pipeline and transmission integration costs are only for the new units identifided in each plan (not for filler units)*

[1] Includes projected annual operational costs for existing Lauderdale units 4 & 5 as avoided costs from retiring these units

[2] Both pairs of CTs will run oil until a new pipeline is built from Hendry to a repowered Fort Lauderdale CC (1,751 MW). At that time the CTs will run on gas.

[3] Both pairs of CTs will run on oil throughout. The repowered Fort Lauderdale CC (1,200 MW) will use FGT gas.

At this stage, at least 6 plans are reasonably close to each other

The order of the best 6 plans is rearranged with pipeline costs

SE Florida Study: Economic Results for Iteration #2: Without Transmission Integration Costs
(CPVRR, millions, 2017$, 2017-2061)

Economic Rank:	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Year	**Plan 1**	**Plan 11**	**Plan 9**	**Plan 10**	**Plan 3**	**Plan 12**	**Plan 14[1]**	**Plan 13[1]**	**Plan 4[1]**	**Plan 5[1]**	**Plan 8**	**Plan 2**	**Plan 6**	**Plan 7**
2023	---	---	---	---	---	---	---	2 CTs at Andytown & 2 CTs at Turkey Point. [2] (Remove Lauderdale CCs)	---	---	---	---	---	---
2024	---	---	---	---	---	---	2 CTs at Andytown and 2 CTs at Turkey Point.[3] (Remove Lauderdale CCs)	---	2 CTs at Andytown & 2 CTs at Turkey Point. [2] (Remove Lauderdale CCs)	2 CTs at Andytown & 2 CTs at Turkey Point. [3] (Remove Lauderdale CCs)	---	---	---	---
2025	Hendry CC	MDLPAS CC	Andytown CC	Andytown CC	Hendry CC	MDLPAS CC	Hendry CC & Hendry 2 CTs	---	Hendry CC	Hendry CC	Andytown CC	Hendry CC	Turkey Point CC	Turkey Point CC
2026	---	---	---	---	---	---	---	Ft Lauderdale Repower (1,751 MW)	---	---	---	---	---	---
2027	---	---	---	---	---	---	---	---	---	---	---	---	---	---
2028	Andytown CC	Andytown CC	MDLPAS CC	Hendry CC	MDLPAS CC	Hendry CC	Ft Lauderdale Repower (1,200 MW)	Hendry CC	Ft Lauderdale Repower (1,751 MW)	Ft Lauderdale Repower (1,200 MW) & 2 CTs at Hendry	Turkey Point CC	Turkey Point CC	Andytown CC	Hendry CC
2029	---	---	---	---	---	---	---	---	---	---	---	---	---	---
2030	---	---	---	---	---	---	---	---	---	---	---	---	---	---
(1) Generation & Fuel Costs	95,046	95,129	95,128	95,060	95,045	95,057	95,539	95,165	95,171	95,508	95,406	95,321	95,444	95,372
(2) Pipeline Costs *	496	440	454	544	575	585	268	641	650	373	655	780	662	826
(3) Transmission Integration Costs *	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(4) Resource Plan Total Costs	**95,542**	**95,569**	**95,581**	**95,604**	**95,620**	**95,642**	**95,807**	**95,807**	**95,822**	**95,881**	**96,062**	**96,102**	**96,106**	**96,198**
(5) Difference from Lowest Cost Plan	-	26	39	61	78	100	264	264	279	338	519	559	563	656

** Pipeline and transmission integration costs are only for the new units identified in each plan (not for filler units)*

[1] Includes projected annual operational costs for existing Lauderdale units 4 & 5 as avoided costs from retiring these units

[2] Both pairs of CTs will run oil until a new pipeline is built from Hendry to a repowered Fort Lauderdale CC (1,751 MW). At that time the CTs will run on gas.

[3] Both pairs of CTs will run on oil throughout. The repowered Fort Lauderdale CC (1,200 MW) will use FGT gas.

Pipeline cost inclusion results in wider separation between the best 6 plans and the remaining plans

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Inclusion of integration costs clarify the best Iteration # 2 plan

SE Florida Study: Economic Results for Iteration #2
(CPVRR, millions, 2017$, 2017-2061)

Economic Rank:	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Year	**Plan 11**	**Plan 12**	**Plan 1**	**Plan 9**	**Plan 10**	**Plan 3**	**Plan 13[1]**	**Plan 4[1]**	**Plan 14[1]**	**Plan 6**	**Plan 5[1]**	**Plan 8**	**Plan 7**	**Plan 2**
2023	---	---	---	---	---	---	2 CTs at Andytown & 2 CTs at Turkey Point. [2] (Remove Lauderdale CCs)	---	---	---	---	---	---	---
2024	---	---	---	---	---	---	---	2 CTs at Andytown & 2 CTs at Turkey Point. [2] (Remove Lauderdale CCs)	2 CTs at Andytown and 2 CTs at Turkey Point.[3] (Remove Lauderdale CCs)	---	2 CTs at Andytown & 2 CTs at Turkey Point. [3] (Remove Lauderdale CCs)	---	---	---
2025	MDLPAS CC	MDLPAS CC	Hendry CC	Andytown CC	Andytown CC	Hendry CC	---	Hendry CC	Hendry CC & Hendry 2 CTs	Turkey Point CC	Hendry CC	Andytown CC	Turkey Point CC	Hendry CC
2026	---	---	---	---	---	---	Ft Lauderdale Repower (1,751 MW)	---	---	---	---	---	---	---
2027	---	---	---	---	---	---	---	---	---	---	---	---	---	---
2028	Andytown CC	Hendry CC	Andytown CC	MDLPAS CC	Hendry CC	MDLPAS CC	Hendry CC	Ft Lauderdale Repower (1,751 MW)	Ft Lauderdale Repower (1,200 MW)	Andytown CC	Ft Lauderdale Repower (1,200 MW) & 2 CTs at Hendry	Turkey Point CC	Hendry CC	Turkey Point CC
2029	---	---	---	---	---	---	---	---	---	---	---	---	---	---
2030	---	---	---	---	---	---	---	---	---	---	---	---	---	---
(1) Generation & Fuel Costs	95,129	95,057	95,046	95,128	95,060	95,045	95,165	95,171	95,539	95,444	95,508	95,406	95,372	95,321
(2) Pipeline Costs *	440	585	496	454	544	575	641	650	268	662	373	655	826	780
(3) Transmission Integration Costs *	56	82	183	162	157	186	203	203	337	56	314	162	82	186
(4) Resource Plan Total Costs	**95,625**	**95,724**	**95,726**	**95,743**	**95,760**	**95,806**	**96,010**	**96,025**	**96,143**	**96,162**	**96,195**	**96,223**	**96,280**	**96,288**
(5) Difference from Lowest Cost Plan	-	98	101	118	135	181	384	400	518	537	570	598	655	662

** Pipeline and transmission integration costs are only for the new units identified in each plan (not for filler units)*

[1] Includes projected annual operational costs for existing Lauderdale units 4 & 5 as avoided costs from retiring these units

[2] Both pairs of CTs will run oil until a new pipeline is built from Hendry to a repowered Fort Lauderdale CC (1,751 MW). At that time the CTs will run on gas.

[3] Both pairs of CTs will run on oil throughout. The repowered Fort Lauderdale CC (1,200 MW) will use FGT gas.

The plan with CCs at MDLPAS and Andytown emerges as the most economic resource plan for Iteration # 2

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The following conclusions can be drawn from the analyses of the Iteration # 2 resource plans

- The most economic resource plan from the Iteration # 2 analyses, consisting of one new CC at MDLPAS and another CC at Andytown, has a projected CPVRR cost of $95,625 million
- This projected CPVRR cost is $384 million <u>more expensive</u> than the most economic plan from Iteration # 1: a CC at Martin followed by a CC at Okeechobee (or vice versa)
- The primary reason for this is that the most economic plan from Iteration # 2 - plus 11 of the other 13 resource plans analyzed in Iteration # 2 - require an expensive new gas pipeline that would be built from Martin into the SE Florida region
- In other words, the analyses show that it is more economic to build new generation outside of the SE Florida region – and address the regional imbalance with new transmission (primarily the Corbett-Sugar-Quarry line) – than it is to build new fossil generation inside the SE Florida region which requires an expensive new gas pipeline

The focus of the analyses now shifts to examine the economics of solar and/or batteries that might be sited in the SE Florida region

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Presentation Overview

- **Background and Scope, Key Assumptions, and Analysis Approach**
- **Analysis Iteration # 1: Fossil Generation Outside of SE Florida Region**
- **Analysis Iteration # 2: Fossil Generation Inside SE Florida Region**
- **Analysis Iteration # 3: Renewable & Storage Options Inside SE Florida Region**
- **Analysis Iteration # 4: Incorporates Retirements**
- **Overall Conclusions**

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Iteration # 3 examined a variety of solar and battery options *

- Two general types of solar options and two general types of battery options, were utilized in the Iteration # 3 analyses:
  - **Large solar:** Two FPL-owned sites (Turkey Point-Homestead at 60 MW and Krome at 74.5 MW), plus 4 hypothetical sites in SE Florida of 74.5 MW each, for a total of ~ 433 MW (nameplate)
  - **Small solar:** Individual PV projects ranging from 0.25-to-2.0 MW each, sited on commercial and industrial rooftop and parking canopies, in amounts ranging from 50-to-100 MW per year
  - **Large battery:** 4-hour duration projects from 20-to-150 MW each at a number of (mostly) FPL-owned sites, for a maximum of ~ 1,350 MW
  - **Small battery:** Unsited generic 4-hour duration projects between 10-to-30 MW each connected to distribution feeders/substations for a maximum of ~ 1,800 MW
- In addition, a variety of assumptions were made in the Iteration # 3 analyses

* The amount of incremental, cost-effective DSM capability in the SE Florida region not already accounted for in FPL's DSM Plan was projected to be small and for this reason the Iteration # 3 analyses focused solely on solar and/or batteries.

Some assumptions were specific to the type of project, including (but not limited to) the following:

- **For Large Solar:**
  - Potential unsited large solar projects were limited to a total of 4 due to uncertainties around acquiring suitable land in SE Florida
  - The $18 million land cost at the Krome site was considered a sunk cost and was not included in the analyses
- **For Small Solar:**
  - No land purchases are assumed; costs for 30-year leases of parking and rooftop space are included in the analyses
- **For Large Batteries:**
  - Specific sites were selected for large projects
  - The Andytown site would host three 150 MW battery projects; if implemented this would eliminate the site as a potential CC site
- **For Large and Small Batteries:**
  - A roundtrip battery efficiency of 90% was assumed
  - Battery benefits include capacity deferral & variable cost (fuel, VOM, emissions, etc.) savings (including fuel savings sensitivity)
  - 30-year replenishment costs were assumed

Other assumptions were more general in nature

- **Re Firm Capacity:**
  - Each battery MW is considered as 100% firm (100 MW of batteries was assumed to be 100 MW of firm capacity)
  - However, due to FPL's current projection of declining firm contribution for PV as PV levels increase, 100 MW nameplate of PV was assumed to range from 41 to 33 MW of firm capacity
- **Re Distribution Benefits:**
  - Small batteries, because they are integrated into the distribution system, are credited with distribution benefits of $118/kW if sited in Miami-Dade and $67/kW if sited in Broward (based on DSM values)
  - Solar is assumed to get no distribution benefits due to its intermittent output
- **Re Meeting Remaining Capacity Needs:**
  - Any new CC capacity additions that would be needed to meet the capacity need that remained after the solar and/or battery additions were assumed to be the Okeechobee CC unit first, followed by the Martin CC unit

Portfolios of the solar and battery options were developed first, then resource plans were created around the portfolios

- Three different types of portfolios of solar and/or battery options were developed:
  - Battery only (or battery intensive)
  - Solar only
  - Battery and solar
- Certain portfolios were primarily designed to address the SE Florida regional need; however, solar and/or batteries' firm capacity contributions served to defer CC additions that were needed to meet the remaining system need
- Other portfolios (consisting of higher levels of solar and batteries) were designed to not only address the SE Florida regional need, but to address much, if not all, of the FPL system need

Five resource plans were eventually developed for analysis in Iteration # 3

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The following 5 resource plans were developed for analysis in Iteration # 3

Year	Plan 1: Large Battery			Plan 2: Small Battery Only			Plan 3: Large & Small Solar			Plan 4: Solar & Batteries			Plan 5: Solar & Batteries		
	Battery MW	Solar MW	CC MW	Battery MW	Solar MW	CC MW	Battery MW	Solar MW	CC MW	Battery MW	Solar MW	CC MW	Battery MW	Solar MW	CC MW
2020	0	0	---	0	0	---	0	50	---	0	50	---	0	0	---
2021	0	0	---	0	0	---	0	125	---	0	125	---	0	0	---
2022	0	0	---	0	0	---	0	110	---	0	110	---	0	0	---
2023	0	0	---	0	0	---	0	100	---	0	50	---	0	0	---
2024	0	0	---	0	0	---	0	100	---	0	50	---	0	0	---
2025	200	135	---	200	0	---	0	398	---	0	348	---	200	135	---
2026	150	0	1,751	200	0	1,751	0	100	1,751	600	50	---	575	0	---
2027	200	0	---	300	0	---	0	0	---	605	50	---	0	0	1,751
2028	350	0	---	200	0	---	0	0	---	600	50	---	0	0	---
2029	200	0	---	200	0	---	0	0	1,751	600	50	---	270	0	---
2030	225	0	1,751	300	0	1,751	0	0	---	590	50	---	450	298	---
MW (Nameplate) =	**1,325**	**135**	**3,502**	**1,400**	**0**	**3,502**	**0**	**983**	**3,502**	**2,995**	**983**	**0**	**1,495**	**433**	**1,751**

Plans 1 – 3 are primarily focused on the SE Florida regional need; Plans 4 & 5 also address system needs

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A ranking of these 5 plans based solely on generation and fuel appears below

SE Florida Study: Economic Results for Iteration #3: Without Pipeline or Transmission Integration Costs
(CPVRR, millions, 2017$, 2017-2061)

	Plan 1: Large Battery Intensive			Plan 2: Small Battery Only			Plan 3: Large & Small Solar Only			Plan 4: Solar & Batteries			Plan 5: Solar & Batteries		
Year	Battery MW	Solar MW	CC MW	Battery MW	Solar MW	CC MW	Battery MW	Solar MW	CC MW	Battery MW	Solar MW	CC MW	Battery MW	Solar MW	CC MW
2020	0	0	---	0	0	---	0	50	---	0	50	---	0	0	---
2021	0	0	---	0	0	---	0	125	---	0	125	---	0	0	---
2022	0	0	---	0	0	---	0	110	---	0	110	---	0	0	---
2023	0	0	---	0	0	---	0	100	---	0	50	---	0	0	---
2024	0	0	---	0	0	---	0	100	---	0	50	---	0	0	---
2025	200	135	---	200	0	---	0	398	---	0	348	---	200	135	---
2026	150	0	1,751	200	0	1,751	0	100	1,751	600	50	---	575	0	---
2027	200	0	---	300	0	---	0	0	---	605	50	---	0	0	1,751
2028	350	0	---	200	0	---	0	0	---	600	50	---	0	0	---
2029	200	0	---	200	0	---	0	0	1,751	600	50	---	270	0	---
2030	225	0	1,751	300	0	1,751	0	0	---	590	50	---	450	298	---
MW (Nameplate) =	**1,325**	**135**	**3,502**	**1,400**	**0**	**3,502**	**0**	**983**	**3,502**	**2,995**	**983**	**0**	**1,495**	**433**	**1,751**
(1) Generation & Fuel Costs (w/o solar & battery fixed costs)	$94,537			$94,722			$93,629			$93,388			$94,125		
(1a) Battery fixed costs	$928			$1,162			$0			$2,260			$1,088		
(1b) Solar fixed costs	$132			$0			$1,575			$1,538			$428		
(2) Pipeline Costs *	---			---			---			---			---		
(3) Transmission Integration Costs *	---			---			---			---			---		
(4) Resource Plan Total Costs	$95,597			$95,884			$95,204			$97,186			$95,641		
(5) Difference from Lowest Cost Plan	$393			$680			$0			$1,982			$437		

** Pipeline and transmission integration costs are only for the new units identified in each plan (not for filler units)*

The "all solar" plan, Plan 3, is the most economic of these 5 plans at this stage

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Inclusion of pipeline costs does not significantly change the picture

SE Florida Study: Economic Results for Iteration #3: Without Transmission Integration Costs
(CPVRR, millions, 2017$, 2017-2061)

	Plan 1: Large Battery			Plan 2: Small Battery Only			Plan 3: Large & Small Solar			Plan 4: Solar & Batteries			Plan 5: Solar & Batteries		
Year	Battery MW	Solar MW	CC MW	Battery MW	Solar MW	CC MW	Battery MW	Solar MW	CC MW	Battery MW	Solar MW	CC MW	Battery MW	Solar MW	CC MW
2020	0	0	---	0	0	---	0	50	---	0	50	---	0	0	---
2021	0	0	---	0	0	---	0	125	---	0	125	---	0	0	---
2022	0	0	---	0	0	---	0	110	---	0	110	---	0	0	---
2023	0	0	---	0	0	---	0	100	---	0	50	---	0	0	---
2024	0	0	---	0	0	---	0	100	---	0	50	---	0	0	---
2025	200	135	---	200	0	---	0	398	---	0	348	---	200	135	---
2026	150	0	1,751	200	0	1,751	0	100	1,751	600	50	---	575	0	---
2027	200	0	---	300	0	---	0	0	---	605	50	---	0	0	1,751
2028	350	0	---	200	0	---	0	0	---	600	50	---	0	0	---
2029	200	0	---	200	0	---	0	0	1,751	600	50	---	270	0	---
2030	225	0	1,751	300	0	1,751	0	0	---	590	50	---	450	298	---
MW (Nameplate) =	**1,325**	**135**	**3,502**	**1,400**	**0**	**3,502**	**0**	**983**	**3,502**	**2,995**	**983**	**0**	**1,495**	**433**	**1,751**
(1) Generation & Fuel Costs (w/o solar & battery fixed costs)	$94,537			$94,722			$93,629			$93,388			$94,125		
(1a) Battery fixed costs	$928			$1,162			$0			$2,260			$1,088		
(1b) Solar fixed costs	$132			$0			$1,575			$1,538			$428		
(2) Pipeline Costs *	$22			$22			$22			$0			$21		
(3) Transmission Integration Costs *	-			-			-			-			-		
(4) Resource Plan Total Costs	$95,619			$95,906			$95,226			$97,186			$95,662		
(5) Difference from Lowest Cost Plan	$393			$680						$1,960			$436		

** Pipeline and transmission integration costs are only for the new units identified in each plan (not for filler units)*

Plan 3 remains the most economic of these 5 plans at this point

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The “all solar” Plan 3 emerges as the best plan from Iteration # 3

SE Florida Study: Economic Results for Iteration #3
(CPVRR, millions, 2017$, 2017-2061)

	Plan 1: Large Battery			Plan 2: Small Battery Only			Plan 3: Large & Small Solar			Plan 4: Solar & Batteries			Plan 5: Solar & Batteries		
Year	Battery MW	Solar MW	CC MW	Battery MW	Solar MW	CC MW	Battery MW	Solar MW	CC MW	Battery MW	Solar MW	CC MW	Battery MW	Solar MW	CC MW
2020	0	0	---	0	0	---	0	50	---	0	50	---	0	0	---
2021	0	0	---	0	0	---	0	125	---	0	125	---	0	0	---
2022	0	0	---	0	0	---	0	110	---	0	110	---	0	0	---
2023	0	0	---	0	0	---	0	100	---	0	50	---	0	0	---
2024	0	0	---	0	0	---	0	100	---	0	50	---	0	0	---
2025	200	135	---	200	0	---	0	398	---	0	348	---	200	135	---
2026	150	0	1,751	200	0	1,751	0	100	1,751	600	50	---	575	0	---
2027	200	0	---	300	0	---	0	0	---	605	50	---	0	0	1,751
2028	350	0	---	200	0	---	0	0	---	600	50	---	0	0	---
2029	200	0	---	200	0	---	0	0	1,751	600	50	---	270	0	---
2030	225	0	1,751	300	0	1,751	0	0	---	590	50	---	450	298	---
MW (Nameplate) =	**1,325**	**135**	**3,502**	**1,400**	**0**	**3,502**	**0**	**983**	**3,502**	**2,995**	**983**	**0**	**1,495**	**433**	**1,751**
(1) Generation & Fuel Costs (w/o solar & battery fixed costs)	$94,537			$94,722			$93,629			$93,388			$94,125		
(1a) Battery fixed costs	$928			$1,162			$0			$2,260			$1,088		
(1b) Solar fixed costs	$132			$0			$1,575			$1,538			$428		
(2) Pipeline Costs *	$22			$22			$22			$0			$21		
(3) Transmission Integration Costs *	$11			$11			$264			$0			$0		
(4) Resource Plan Total Costs	$95,630			$95,917			$95,490			$97,186			$95,662		
(5) Difference from Lowest Cost Plan	$140			$427			$0			$1,696			$172		

** Pipeline and transmission integration costs are only for the new units identified in each plan (not for filler units)*

The addition of batteries in 4 of these plans contributed to significantly higher net costs

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The following conclusions can be drawn from the analyses of the Iteration # 3 resource plans

- The most economic resource plan from the Iteration # 3 analyses is Plan 3 which consists of 983 MW of PV (but no batteries) sited in the SE Florida region, with a resulting delay of the Okeechobee and Martin CC units
- Plan 3 has a projected CPVRR cost of $95,490 million which is $249 million CPVRR more expensive than the most economic plan from Iteration # 1: a CC at Martin followed by a CC at Okeechobee (or vice versa)
- In addition, this plan still requires the addition of the CSQ transmission line that addresses the SE Florida imbalance issue for virtually all of the 10-year study period, essentially negating any near-term “need” to site PV in the SE Florida region where land costs are high
- In regard to batteries, Plan 2 from this iteration adds 1,400 MW of small batteries, but no PV, and it is much more expensive: $676 million CPVRR more expensive than the most economic plan
- The best plan with batteries, Plan 1 consisting of 1,325 MW of large batteries and 135 MW of PV, is $389 million CPVRR more expensive than the most economic plan

Presentation Overview

- Background and Scope, Key Assumptions, and Analysis Approach
- Analysis Iteration # 1: Fossil Generation Outside of SE Florida Region
- Analysis Iteration # 2: Fossil Generation Inside SE Florida Region
- Analysis Iteration # 3: Renewable & Storage Options Inside SE Florida Region
- Analysis Iteration # 4: Incorporates Retirements
- Overall Conclusions

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Two questions were raised during executive review of the results of Iterations # 1 and # 2

- The first question is:
  1) *If the Corbett-Sugar-Quarry (CSQ) 500 kV transmission line is put into service as soon as possible, do the economics of the best plan improve by repowering the existing Lauderdale CC units?*

- Relevant considerations for this question include:
  - The earliest the CSQ line can be brought into service is likely the end of 2018, so removal of the existing Lauderdale CC units could not begin until the beginning of 2019
  - Due to space considerations, the existing Lauderdale CC units must be removed prior to construction of a new CC unit
  - Because the existing units comprise 884 MW, their removal will require roughly 250 MW of new capacity be added to the system in 2020, then maintained at 100 MW until mid-2022 *(the earliest practical date for a Lauderdale repowering),* by PPAs

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A modified version of one of the most economic plans, Plan 2 from Iteration # 1, was used to address the first question

	Early Fort Lauderdale Retirement Question (1)	(2)
	Resource Plan 2 (from Iteration # 1)	Modified Plan 2 to Address Early PFL Retirement Question
Year	**Unit Additions**	**Unit Additions**
2018	---	CSQ line in-service 12/31/2018
2019	OCEC	OCEC; Lauderdale 4 & 5 retired 1/1/2019
2020	300 MW Solar	250 MW PPA; 300 MW Solar
2021	---	100 MW PPA
2022	OCEC Incremental MW	OCEC Incremental MW; Ft. Lauderdale 2x1 CC (1,163 MW)
2023	1,414 MW Solar	1,414 MW Solar
2024	---	---
2025	Okeechobee CC; CSQ line in-service 1/01/2025	100 MW PPA
2026	---	Okeechobee CC
2027	---	---
2028	Martin CC	Martin CC
2029	---	---
2030	---	---

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The other question relates to potential early retirement of existing 800 MW units

- The second question is:
  2) Again assuming that the CSQ line is brought in-service as soon as possible, are the economics of the best plan improved by repowering both of the 800 MW units at either the Martin or Manatee sites (but not at both sites)?

- Relevant considerations for this question include:
  - The total capacity lost by retiring either pair of units – 1,626 MW at Martin or 1,618 MW at Manatee – is roughly equivalent to a new CC unit of 1,751 MW)
  - The Martin site has an advantage over the Manatee site because of its easy access to all three natural gas pipelines
  - Conversely, a repowering of the Manatee site may have negative transmission implications for 3rd parties
  - Because there is sufficient space at the Martin site, a new CC could be built before Martin 1 & 2 are retired and removed

The decision was made to examine a potential repowering of existing Martin units 1 & 2

A modified version of the other most economic plans, Plan 1 from Iteration # 1, was used to address this second question

	Retirement of Two 800 MW Units Question (1)	(2)
	Resource Plan 1 (from Iteration # 1)	Modified Plan 1 to Address Retirement of Two 800 MW Units
Year	Unit Additions	Unit Additions
2018	---	CSQ line in-service 12/31/2018
2019	OCEC	OCEC
2020	300 MW Solar	300 MW Solar
2021	---	Martin 1 & 2 retired; new Martin CC # 1 added
2022	OCEC Incremental MW	OCEC Incremental MW
2023	1,414 MW Solar	1,414 MW Solar
2024	---	---
2025	Martin CC; CSQ line in-service 1/01/2025	Martin CC
2026	---	---
2027	---	---
2028	Okeechobee CC	Okeechobee CC
2029	---	---
2030	---	---

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The analyses results of these plans are as follows*:

SE Florida Study: Economic Results for Iteration # 4
(CPVRR, millions, 2017$, 2017-2061)

	Early Fort Lauderdale Retirement Question	
	(1) Resource Plan 2 (from Iteration # 1)	(2) Modified Plan 2 to Address Early PFL Retirement Question
Year	**Unit Additions**	**Unit Additions**
2018	---	CSQ line in-service 12/31/2018
2019	OCEC	OCEC; Lauderdale 4 & 5 retired 1/1/2019
2020	300 MW Solar	250 MW PPA; 300 MW Solar
2021	---	100 MW PPA
2022	OCEC Incremental MW	OCEC Incremental MW; Ft. Lauderdale 2x1 CC (1,163 MW)
2023	1,414 MW Solar	1,414 MW Solar
2024	---	---
2025	Okeechobee CC; CSQ line in-service 1/01/2025	100 MW PPA
2026	---	Okeechobee CC
2027	---	---
2028	Martin CC	Martin CC
2029	---	---
2030	---	---
(1) Generation & Fuel Costs	**94,902**	**94,964**
(2) Pipeline Costs	**20**	**22**
(3) Transmission Integration Costs	**319**	**401**
(4) Resource Plan Total Costs	**95,241**	**95,387**
(5) Difference from Lowest Cost Plan	**0**	**146**

	Retirement of Two 800 MW Units Question	
	(1) Resource Plan 1 (from Iteration # 1)	(2) Modified Plan 1 to Address Retirement of Two 800 MW Units
Year	**Unit Additions**	**Unit Additions**
2018	---	CSQ line in-service 12/31/2018
2019	OCEC	OCEC
2020	300 MW Solar	300 MW Solar
2021	---	Martin 1 & 2 retired; new Martin CC # 1 added
2022	OCEC Incremental MW	OCEC Incremental MW
2023	1,414 MW Solar	1,414 MW Solar
2024	---	---
2025	Martin CC; CSQ line in-service 1/01/2025	Martin CC
2026	---	---
2027	---	---
2028	Okeechobee CC	Okeechobee CC
2029	---	---
2030	---	---
(1) Generation & Fuel Costs	**94,901**	**95,275**
(2) Pipeline Costs	**23**	**19**
(3) Transmission Integration Costs	**317**	**502**
(4) Resource Plan Total Costs	**95,241**	**95,796**
(5) Difference from Lowest Cost Plan	**0**	**555**

* The Net Book Value (NBV) capital cost impact of early retirement of these units was unavailable at the time the analyses were performed

The Lauderdale repowering scenario is significantly closer to being economically competitive than is the Martin repowering scenario

The results of the Iteration # 4 analyses lead to the following conclusions/considerations:

- The best of the two repowering plans, the Lauderdale repowering plan, is $146 million more expensive than the two most economic plans (Okeechobee CC/Martin CC or vice versa) from prior iterations
- However, the Lauderdale repowering plan has the next lowest CPVRR cost, beating 30 of the other 32 resource plans that were analyzed
- Therefore, the Lauderdale repowering option is worthy of further analysis that considers at least the following:
  - The difference in the assumed CSQ line in-service dates (2025 in the two most economic plans vs. 2018 in the Lauderdale repowering plan) results in a cost differential of approx. $80 million CPVRR; thus if a decision were to be made that the CSQ line should be added earlier, the economics of Lauderdale repowering would be improved
  - The analysis used an off-the-shelf look at what near-term operational costs (capital replacement and O&M) are currently projected for existing Lauderdale units 4 & 5; a longer-term, more detailed projection of operational costs could be considered
  - The as yet unaccounted for NBV capital cost impact could be significant and is being developed

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- Analysis Iteration # 4: Incorporates Retirements
- Overall Conclusions

The key conclusions from the analyses of the 33 resource plans analyzed in the SE Florida Study are:

1) Re the SE Florida regional need:
   Based on the analyses of 33 resource plans, it is more economic to address the SE Florida regional need by constructing the CSQ transmission line to import power into the region rather than to build new generation – fossil or renewable – in the region

2) Re the FPL system need:
   - The 5 most economic resource plans from the study are*:

Economic Ranking	Iteration No.	Plan No.	Description of Resource Plan	CPVRR Cost (millions)	CPVRR Difference from Best Plan (millions)
1	1	1	Martin CC in 2025, Okeechobee CC in 2028	95,241	0
2	1	2	Okeechobee CC in 2025, Martin CC in 2028	95,241	0
3	4	1	Lauderdale 4&5 retired in 2019, 250 MW PPA in 2020, 100 MW PPA in 2021, Lauderdale CC (1,200 MW) in 2022, 100 MW PPA in 2025, Okeechobee CC in 2026, Martin CC in 2028	95,387	146
4	3	3	983 MW of PV in SE Florida, Okeechobee CC in 2026, Martin CC in 2029	95,490	249
5	2	11	MDLPAS CC in 2025, Andytown CC in 2028	95,625	384

* A CPVRR economic ranking of all 33 plans is presented at the end of the Appendix

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The key conclusions from the analyses are (Continued):

2) Re the FPL system need (Continued):
   - The top two rows of this table show that the most economic fossil fuel options with which to meet FPL's system need are CC units at the Martin and Okeechobee sites
   - The third row of the table shows the Lauderdale repowering plan was the next most economic plan which, as discussed earlier, is worthy of further analyses (which is underway)

3) Re Solar & batteries:
   - The fourth row of the table shows the economics of 983 MW of PV sited in the SE Florida region (the study was not designed to examine additional solar – beyond the ~ 1,700 MW of PV that was assumed in all 33 resource plans – that might be sited outside of SE Florida)
   - However, the economics of this plan suggest analysis of more PV sited outside of SE Florida (which is underway)
   - Although the battery scenarios examined in this study were not economic, the results should be useful in identifying areas for potential refinement for batteries

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Appendix

Economic Results Summary for Iteration #1
(CPVRR, millions, 2017$, 2017-2061)

	Generation Capital FPL (Millions)	Generation Fixed O&M (Millions)	TX Interconnection Capital FPL (Millions)	Capital Replacement Charges (Millions)	Short Term Purchase (Millions)	Total Fuel/VOM/Startup/ Emission Costs (Millions)	(1) Generation & Fuel Costs (Millions)	(2) Pipeline Capital Costs * (Millions)	Total Generation & Fuel + Pipeline Costs (Millions)	(3) Transmission Integration Costs * (Millions)	(4) Resource Plan Total Costs (Millions)	(5) Difference from Lowest Cost Plan (Millions)
Plan 1	$5,846	$386	$378	$838	$12	$87,443	$94,902	$20	$94,922	$319	95,241	0
Plan 2	$5,845	$386	$378	$838	$12	$87,443	$94,901	$23	$94,924	$317	95,241	0
Plan 3	$5,853	$409	$390	$838	$12	$87,443	$94,943	$232	$95,174	$466	95,641	400
Plan 4	$5,845	$407	$391	$838	$12	$87,443	$94,936	$255	$95,190	$453	95,643	402
Plan 5	$5,853	$412	$392	$838	$12	$87,443	$94,948	$268	$95,216	$425	95,641	400
Plan 6	$5,846	$411	$393	$838	$12	$87,443	$94,942	$288	$95,230	$425	95,655	414
Plan 7	$5,552	$385	$432	$743	$12	$88,302	$95,425	$24	$95,450	$319	95,769	528
Plan 8	$5,544	$384	$433	$743	$12	$88,302	$95,418	$47	$95,466	$486	95,952	711
Plan 9	$5,552	$410	$435	$743	$12	$88,302	$95,455	$292	$95,747	$434	96,181	940
Plan 10	$5,971	$420	$399	$856	$12	$87,356	$95,012	$295	$95,307	$430	95,737	496
Plan 11	$5,964	$419	$400	$856	$12	$87,356	$95,006	$315	$95,321	$430	95,750	509
Plan 12	$5,670	$418	$443	$761	$12	$88,215	$95,519	$319	$95,838	$438	96,276	1,035

** Pipeline and tranmission integration costs are only for the new units identified in each plan (not for filler units)*

FPL

Economic Results Summary for Iteration #2
(CPVRR, millions, 2017$, 2017-2061)

	Generation and Land Capital (Millions)	Generation Fixed O&M (Millions)	TX Interconnection Capital FPL (Millions)	Capital Replacement Charges (Millions)	Short Term Purchase (Millions)	Total Fuel/VOM/ Startup/Emission Costs (Millions)	(1) Generation & Fuel Costs (Millions)	(2) Pipeline Capital Costs * (Millions)	Total Generation + Pipeline Costs (Millions)	(3) Transmission Integration Costs * (Millions)	(4) Resource Plan Total Costs (Millions)	(5) Difference from Lowest Cost Plan (Millions)
Plan 1	$5,924	$434	$389	$838	$12	$87,449	$95,046	$496	$95,542	$183	$95,726	$101
Plan 2	$5,884	$434	$704	$838	$12	$87,449	$95,321	$780	$96,102	$186	$96,288	$662
Plan 3	$5,852	$434	$416	$838	$12	$87,493	$95,045	$575	$95,620	$186	$95,806	$181
Plan 4	$6,216	$363	$399	$684	$12	$87,498	$95,171	$650	$95,822	$203	$96,025	$400
Plan 5	$6,217	$372	$416	$664	$12	$87,826	$95,508	$373	$95,881	$314	$96,195	$570
Plan 6	$5,968	$434	$723	$838	$12	$87,469	$95,444	$662	$96,106	$56	$96,162	$537
Plan 7	$5,897	$434	$738	$838	$12	$87,454	$95,372	$826	$96,198	$82	$96,280	$655
Plan 8	$5,972	$434	$682	$838	$12	$87,469	$95,406	$655	$96,062	$162	$96,223	$598
Plan 9	$5,940	$434	$393	$838	$12	$87,511	$95,128	$454	$95,581	$162	$95,743	$118
Plan 10	$5,941	$434	$381	$838	$12	$87,454	$95,060	$544	$95,604	$157	$95,760	$135
Plan 11	$5,928	$434	$399	$838	$12	$87,518	$95,129	$440	$95,569	$56	$95,625	$0
Plan 12	$5,857	$434	$413	$838	$12	$87,504	$95,057	$585	$95,642	$82	$95,724	$98
Plan 13	$6,191	$354	$392	$663	$17	$87,547	$95,165	$641	$95,807	$203	$96,010	$384
Plan 14	$6,243	$373	$420	$666	$12	$87,825	$95,539	$268	$95,807	$337	$96,143	$518

FPL

Economic Results Summary for Iteration #3
(CPVRR, millions, 2017$, 2017-2061)

	Generation and Land Capital (Millions)	Generation Fixed O&M (Millions)	TX Interconnection Capital FPL (Millions)	Capital Replacement Charges (Millions)	Short Term Purchase (Millions)	Firm Gas Transport Costs (Millions)	Total Fuel/VOM/Startup/ Emission Costs (Millions)	(1) Generation & Fuel Costs (Millions)	(2) Pipeline Capital Costs (Millions)	Total Generation & Fuel + Pipeline Costs (Millions)	(3) Transmission Integration Costs (Millions)	(4) Resource Plan Total Costs (Millions)	(5) Difference from Lowest Cost Plan (Millions)
Plan 1	**$6,419**	**$405**	**$368**	**$851**	**$12**	**$28**	**$87,514**	**$95,597**	**$22**	**$95,619**	**$11**	**$95,630**	**$140**
Plan 2	**$6,607**	**$396**	**$355**	**$760**	**$12**	**$37**	**$87,717**	**$95,884**	**$22**	**$95,906**	**$11**	**$95,917**	**$427**
Plan 3	**$6,956**	**$600**	**$410**	**$803**	**$12**	**($63)**	**$86,486**	**$95,204**	**$22**	**$95,226**	**$264**	**$95,490**	**$0**
Plan 4	**$7,367**	**$587**	**$308**	**$648**	**$12**	**$28**	**$88,236**	**$97,186**	**$0**	**$97,186**	**$0**	**$97,186**	**$1,696**
Plan 5	**$6,249**	**$396**	**$354**	**$751**	**$12**	**$28**	**$87,851**	**$95,641**	**$21**	**$95,662**	**$0**	**$95,662**	**$172**

FPL

Economic Results Summary for Iteration #4
(CPVRR, millions, 2017$, 2017-2061)

	Generation and Land Capital (Millions)	Generation Fixed O&M (Millions)	TX Interconnection Capital FPL (Millions)	Capital Replacement Charges (Millions)	Short Term Purchase (Millions)	Total Fuel/VOM/Star Emission Costs (Millions)	(1) Generation & Fuel Costs (Millions)	(2) Pipeline Capital Costs * (Millions)	Total Generation + Pipeline Costs (Millions)	(3) Transmission Integration Costs * (Millions)	(4) Resource Plan Total Costs (Millions)	(5) Difference from Lowest Cost Plan (Millions)
Iteration#4 Plan - Lauderdale Retirement	$6,500	$332	$390	$634	$23	$87,084	$94,964	$22	$94,986	$401	$95,387	$0
Iteration#4 Plan - Martin Retirement	$7,066	$332	$453	$931	$12	$86,480	$95,275	$19	$95,294	$502	$95,796	$409

Economic Ranking of All Resource Plans Evaluated in the SE Florida Study: 1 through 16					
Economic Ranking	**Iteration No.**	**Plan No.**	**Description of Resource Plan**	**CPVRR Cost (millions)**	**CPVRR Difference from Best Plan (millions)**
1	1	1	Martin CC in 2025, Okeechobee CC in 2028	95,241	0
2	1	2	Okeechobee CC in 2025, Martin CC in 2028	95,241	0
3	4	1	Lauderdale 4&5 retired in 2019, 250 MW PPA in 2020, 100 MW PPA in 2021, Lauderdale CC (1,200 MW) in 2022, 100 MW PPA in 2025, Okeechobee CC in 2026, Martin CC in 2028	95,387	146
4	3	3	983 MW of PV in SE Florida, Okeechobee CC in 2026, Martin CC in 2029	95,490	249
5	2	11	MDLPAS CC in 2025, Andytown CC in 2028	95,625	384
6	3	1	1,175 MW of batteries and 135 MW of PV in SE Florida, Okeechobee CC in 2026, Martin CC in 2030	95,630	389
7	1	3	Martin CC in 2025, Hendry CC in 2028	95,641	400
8	1	5	Hendry CC in 2025, Martin CC in 2028	95,641	400
9	1	4	Okeechobee CC in 2025, Hendry CC in 2028	95,643	402
10	1	6	Hendry CC in 2025, Okeechobee CC in 2028	95,655	414
11	3	5	1,495 MW of batteries and 433 MW of PV in SE Florida, Okeechobee CC in 2027	95,662	421
12	2	12	MDLPAS CC in 2025, Hendry CC in 2028	95,724	483
13	2	1	Hendry CC in 2025, Andytown CC in 2028	95,726	485
14	1	10	Hendry CC in 2023, Martin CC in 2028	95,737	496
15	2	9	Andytown CC in 2025, MDLPAS CC in 2028	95,743	502
16	1	11	Hendry CC in 2023, Okeechobee CC in 2028	95,750	509

FPL

Economic Ranking of All Resource Plans Evaluated in the SE Florida Study: 17 through 33					
Economic Ranking	**Iteration No.**	**Plan No.**	**Description of Resource Plan**	**CPVRR Cost (millions)**	**CPVRR Difference from Best Plan (millions)**
17	2	10	Andytown CC in 2025, Hendry CC in 2028	95,760	519
18	1	7	Martin CC in 2025, Okeechobee CTs (2 in 2028, 4 in 2029, and 2 in 2030)	95,769	528
19	4	2	Martin CC added and Martin 1 & 2 retired in 2021, Martin CC in 2025, Okeechobee CC in 2028	95,796	555
20	2	3	Hendry CC in 2025, MDLPAS CC in 2028	95,806	565
21	3	2	1,200 MW of batteries in SE Florida, Okeechobee CC in 2026, Martin CC in 2030	95,917	676
22	1	8	Okeechobee CC in 2025, Okeechobee CTs (2 in 2028, 4 in 2029, and 2 in 2030)	95,952	711
23	2	13	2 CTs at Andytown & 2 CTs at TP in 2024, retire Lauderdale 4&5 in 2023, Lauderdale repower (1,751 MW) in 2026, Hendry CC in 2028	96,010	769
24	2	4	2 CTs at Andytown & 2 CTs at TP in 2024, retire Lauderdale 4&5 in 2024, Hendry CC in 2025, Lauderdale repower (1,751 MW) in 2028	96,025	784
25	2	14	2 CTs at Andytown & 2 CTs at TP in 2024, retire Lauderdale 4&5 in 2024, Hendry CC and 2 CTs in 2025, Lauderdale repower (1,200 MW) in 2028	96,143	902
26	2	6	TP CC in 2025, Andytown CC in 2028	96,162	921
27	1	9	Hendry CC in 2025, Hendry 2 CT in 2028, and Okeechobee CTs (4 in 2029 and 2 in 2030)	96,181	940
28	2	5	2 CTs at Andytown & 2 CTs at TP in 2024, retire Lauderdale 4&5 in 2024, Hendry CC in 2025, Lauderdale repower (1,200 MW) and Hendry 2 CTs in 2028	96,195	954
29	2	8	Andytown CC in 2025, TP CC in 2028	96,223	982
30	1	12	Hendry CC in 2023, Hendry 2CT in 2028, Okeechobee CTs (4 in 2029 and 2 in 2030)	96,276	1,035
31	2	7	TP CC in 2025, Hendry CC in 2028	96,280	1,039
32	2	2	Hendry CC in 2025, TP CC in 2028	96,288	1,047
33	3	4	2,995 MW of batteries and 983 MW of PV in SE Florida (No CCs)	97,186	1,945

FPL.

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Economic Ranking of All Resource Plans Evaluated in the SE Florida Study

(Preliminary Ranking 12 01 2016)

Economic Ranking	Iteration No.	Plan No.	Description of Resource Plan	Needs New Gas Pipeline?	Includes CSQ Transmisison Line? (1)	CPVRR Cost (millions)	CPVRR Difference from Best Plan (millions)
1	1	1	Martin CC in 2025, Okeechobee CC in 2028	No	Yes	95,241	0
2	1	2	Okeechobee CC in 2025, Martin CC in 2028	No	Yes	95,241	0
3	4	1	Lauderdale 4&5 retired in 2019, 250 MW PPA in 2020, 100 MW PPA in 2021, Lauderdale CC (1,200 MW) in 2022, 100 MW PPA in 2025, Okeechobee CC in 2026, Martin CC in 2028	No	Yes	95,387	146
4	3	3	983 MW of PV in SE Florida, Okeechobee CC in 2026, Martin CC in 2029	No	~~No~~ Yes	95,490	249
5	2	11	MDLPAS CC in 2025, Andytown CC in 2028	Yes	No	95,625	384
6	3	1	1,175 MW of batteries and 135 MW of PV in SE Florida, Okeechobee CC in 2026, Martin CC in 2030	No	No	95,630	389
7	1	3	Martin CC in 2025, Hendry CC in 2028	Yes	Yes	95,641	400
8	1	5	Hendry CC in 2025, Martin CC in 2028	Yes	Yes	95,641	400
9	1	4	Okeechobee CC in 2025, Hendry CC in 2028	Yes	Yes	95,643	402
10	1	6	Hendry CC in 2025, Okeechobee CC in 2028	Yes	Yes	95,655	414
11	3	5	1,495 MW of batteries and 433 MW of PV in SE Florida, Okeechobee CC in 2027	No	No	95,662	421
12	2	12	MDLPAS CC in 2025, Hendry CC in 2028	Yes	No	95,724	483
13	2	1	Hendry CC in 2025, Andytown CC in 2028	Yes	No	95,726	485
14	1	10	Hendry CC in 2023, Martin CC in 2028	Yes	Yes	95,737	496
15	2	9	Andytown CC in 2025, MDLPAS CC in 2028	Yes	No	95,743	502
16	1	11	Hendry CC in 2023, Okeechobee CC in 2028	Yes	Yes	95,750	509
17	2	10	Andytown CC in 2025, Hendry CC in 2028	Yes	No	95,760	519
18	1	7	Martin CC in 2025, Okeechobee CTs (2 in 2028, 4 in 2029, and 2 in 2030)	No	Yes	95,769	528
19	4	2	Martin CC added and Martin 1 & 2 retired in 2021, Martin CC in 2025, Okeechobee CC in 2028	No	Yes	95,796	555
20	2	3	Hendry CC in 2025, MDLPAS CC in 2028	Yes	No	95,806	565
21	3	2	1,200 MW of batteries in SE Florida, Okeechobee CC in 2026, Martin CC in 2030	No	No	95,917	676
22	1	8	Okeechobee CC in 2025, Okeechobee CTs (2 in 2028, 4 in 2029, and 2 in 2030)	No	Yes	95,952	711
23	2	13	2 CTs at Andytown & 2 CTs at TP in 2024, retire Lauderdale 4&5 in 2023, Lauderdale repower (1,751 MW) in 2026, Hendry CC in 2028	Yes	No	96,010	769
24	2	4	2 CTs at Andytown & 2 CTs at TP in 2024, retire Lauderdale 4&5 in 2024, Hendry CC in 2025, Lauderdale repower (1,751 MW) in 2028	Yes	No	96,025	784
25	2	14	2 CTs at Andytown & 2 CTs at TP in 2024, retire Lauderdale 4&5 in 2024, Hendry CC and 2 CTs in 2025, Lauderdale repower (1,200 MW) in 2028	Yes	No	96,143	902
26	2	6	TP CC in 2025, Andytown CC in 2028	Yes	No	96,162	921
27	1	9	Hendry CC in 2025, Hendry 2 CT in 2028, and Okeechobee CTs (4 in 2029 and 2 in 2030)	Yes	No	96,181	940
28	2	5	2 CTs at Andytown & 2 CTs at TP in 2024, retire Lauderdale 4&5 in 2024, Hendry CC in 2025, Lauderdale repower (1,200 MW) and Hendry 2 CTs in 2028	Yes	No	96,195	954
29	2	8	Andytown CC in 2025, TP CC in 2028	Yes	No	96,223	982
30	1	12	Hendry CC in 2023, Hendry 2CT in 2028, Okeechobee CTs (4 in 2029 and 2 in 2030)	Yes	No	96,276	1,035
31	2	7	TP CC in 2025, Hendry CC in 2028	Yes	No	96,280	1,039
32	2	2	Hendry CC in 2025, TP CC in 2028	Yes	No	96,288	1,047
33	3	4	2,995 MW of batteries and 983 MW of PV in SE Florida (No CCs)	No	No	97,186	1,945

(1) In the 2019-2030 time period

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EXHIBIT 1
WIT: SIM
DATE: 11/29/17
DARLINE MARIE WEST, RPR

DBCEC 003942

EDH-19

Case name: 2017 Dania Beach Energy Center FC - Plan 3 - Okee28 Solar+Storage | **Date:** 10/13/2017

Note: do not enter data in this table

	Year	Annual Discount Factor 7.57%	Generation Capital FPL (Millions)	Land Capital (Millions)	Transmission Interconnection Costs (Millions)	Transmission TX Integration Costs (Millions)	Pipeline Capital Costs (Millions)	Generation Fixed O&M (Millions)	Capital Replacement Charges (Millions)	Firm Gas Transport Costs (Millions)	Lauderdale Units NBV (Millions)	Short Term Purchase (Millions)	Total Fixed Costs (Millions)	System Net Fuel (Millions)	Startup + VOM Costs (Millions)	Emission Costs (Millions)	Total Fuel/VOM Startup/Emissions Costs (Millions)	Total Annual Costs (Millions)	NPV Total Annual Cost (Millions)	NPV Cumulative Total Costs (Millions)		Avg Rate Impact $/1000 KWH
1	**2017**	1.000	0	0	0	0	0	0	0	0	0	0	0	2,187	39	2	2,228	**2,228**	**2,228**	2,228	**2017**	19.54
2	**2018**	0.930	81	0	0	4	0	16	-3	0	-8	0	89	2,059	27	1	2,088	**2,177**	**2,024**	4,252	**2018**	18.90
3	**2019**	0.864	172	0	0	49	0	17	1	0	-35	0	204	2,354	33	1	2,388	**2,592**	**2,240**	6,492	**2019**	22.39
4	**2020**	0.803	245	0	1	47	0	25	3	0	-32	0	287	2,326	31	1	2,357	**2,645**	**2,125**	8,617	**2020**	22.64
5	**2021**	0.747	299	0	1	45	0	31	2	0	2	0	380	2,506	29	1	2,536	**2,916**	**2,178**	10,795	**2021**	25.01
6	**2022**	0.694	375	25	11	43	0	38	4	0	2	0	497	2,351	30	1	2,382	**2,879**	**1,999**	12,794	**2022**	24.57
7	**2023**	0.645	344	25	10	41	0	38	5	0	3	0	465	2,504	30	1	2,535	**3,000**	**1,936**	14,730	**2023**	25.43
8	**2024**	0.600	316	25	10	40	0	38	6	0	3	0	438	2,653	30	1	2,683	**3,121**	**1,873**	16,603	**2024**	26.20
9	**2025**	0.558	295	25	10	38	0	39	7	18	4	0	435	2,789	34	1	2,823	**3,258**	**1,817**	18,420	**2025**	27.19
10	**2026**	0.519	277	25	9	37	0	39	7	18	8	0	420	2,937	33	1	2,972	**3,391**	**1,759**	20,179	**2026**	28.05
11	**2027**	0.482	261	25	9	35	1	40	8	57	15	13	465	3,063	35	1	3,099	**3,564**	**1,718**	21,896	**2027**	29.33
12	**2028**	0.448	386	25	18	34	5	45	9	57	16	0	594	3,155	37	117	3,310	**3,904**	**1,749**	23,646	**2028**	31.84
13	**2029**	0.417	431	25	23	32	5	45	10	118	15	0	703	3,308	43	141	3,492	**4,195**	**1,747**	25,393	**2029**	33.73
14	**2030**	0.387	394	25	22	31	5	45	10	160	14	8	712	3,480	45	251	3,776	**4,488**	**1,738**	27,131	**2030**	35.51
15	**2031**	0.360	361	25	21	29	5	48	21	160	-18	0	651	3,537	50	331	3,918	**4,569**	**1,645**	28,776	**2031**	35.60
16	**2032**	0.335	341	25	20	28	4	45	21	160	-15	0	629	3,508	58	414	3,980	**4,608**	**1,542**	30,319	**2032**	35.42
17	**2033**	0.311	448	25	27	26	4	53	23	160	-12	0	753	3,752	65	568	4,385	**5,138**	**1,599**	31,917	**2033**	39.19
18	**2034**	0.289	584	25	35	25	4	56	25	160	-11	0	903	3,899	64	718	4,680	**5,584**	**1,615**	33,532	**2034**	42.14
19	**2035**	0.269	699	25	42	25	4	59	32	160	-8	0	1,037	4,081	64	881	5,025	**6,062**	**1,630**	35,162	**2035**	45.20
20	**2036**	0.250	903	25	55	24	4	64	38	160	-6	0	1,267	4,435	57	1,082	5,574	**6,841**	**1,710**	36,872	**2036**	50.48
21	**2037**	0.232	971	25	59	23	4	66	58	160	-6	0	1,359	4,565	58	1,222	5,845	**7,205**	**1,674**	38,546	**2037**	52.73
22	**2038**	0.216	1,042	25	62	23	4	71	70	160	-5	0	1,452	4,726	59	1,391	6,175	**7,627**	**1,647**	40,194	**2038**	55.21
23	**2039**	0.201	1,056	25	63	22	3	88	82	160	-4	0	1,495	4,892	61	1,579	6,532	**8,027**	**1,612**	41,806	**2039**	57.50
24	**2040**	0.187	1,117	25	67	21	3	78	89	160	-1	0	1,559	5,018	62	1,769	6,849	**8,408**	**1,570**	43,375	**2040**	59.53
25	**2041**	0.174	1,130	25	68	20	3	88	106	160	-1	0	1,599	5,183	63	1,940	7,186	**8,785**	**1,525**	44,900	**2041**	61.60
26	**2042**	0.161	1,192	25	72	20	3	85	123	160	-1	0	1,678	5,374	63	2,119	7,556	**9,234**	**1,490**	46,390	**2042**	64.13
27	**2043**	0.150	1,312	25	79	19	3	94	152	160	-1	0	1,843	5,667	62	2,393	8,122	**9,965**	**1,495**	47,884	**2043**	68.56
28	**2044**	0.139	1,432	25	87	18	3	98	171	160	-1	0	1,992	5,890	62	2,643	8,594	**10,586**	**1,476**	49,360	**2044**	72.15
29	**2045**	0.130	1,438	25	87	18	2	106	209	160	-1	0	2,045	6,086	64	2,890	9,040	**11,084**	**1,437**	50,797	**2045**	74.85
30	**2046**	0.120	1,497	25	91	17	2	107	223	160	-1	0	2,121	6,246	64	3,133	9,443	**11,564**	**1,393**	52,190	**2046**	77.37
31	**2047**	0.112	1,502	25	91	16	2	133	242	160	0	0	2,171	6,428	65	3,409	9,902	**12,073**	**1,352**	53,543	**2047**	80.04
32	**2048**	0.104	1,435	25	87	16	2	110	269	160	0	0	2,103	6,556	67	3,669	10,292	**12,396**	**1,291**	54,833	**2048**	81.44
33	**2049**	0.097	1,370	25	84	15	2	123	301	160	0	0	2,079	6,688	68	3,949	10,705	**12,784**	**1,237**	56,071	**2049**	83.23
34	**2050**	0.090	1,309	25	80	14	2	108	318	160	0	0	2,015	6,821	70	4,250	11,142	**13,157**	**1,184**	57,255	**2050**	84.90
35	**2051**	0.084	1,251	25	77	13	2	136	345	160	0	0	2,009	6,958	72	4,356	11,386	**13,395**	**1,121**	58,375	**2051**	85.67
36	**2052**	0.078	1,186	25	74	13	2	116	371	160	0	0	1,946	7,097	74	4,465	11,636	**13,582**	**1,056**	59,432	**2052**	86.11
37	**2053**	0.072	1,135	0	71	12	2	137	410	160	0	0	1,926	7,239	75	4,577	11,891	**13,817**	**999**	60,431	**2053**	86.84
38	**2054**	0.067	1,087	0	68	12	1	122	420	160	0	0	1,870	7,384	77	4,691	12,152	**14,023**	**942**	61,373	**2054**	87.37
39	**2055**	0.062	1,041	0	65	11	1	153	441	160	0	0	1,872	7,531	79	4,809	12,419	**14,291**	**893**	62,266	**2055**	88.28
40	**2056**	0.058	998	0	63	11	1	125	469	160	0	0	1,826	7,682	81	4,929	12,692	**14,518**	**843**	63,109	**2056**	88.91
41	**2057**	0.054	956	0	60	10	1	143	468	160	0	0	1,798	7,835	83	5,052	12,971	**14,769**	**797**	63,907	**2057**	89.69
42	**2058**	0.050	916	0	58	9	0	122	478	160	0	0	1,742	7,992	85	5,178	13,256	**14,998**	**753**	64,659	**2058**	90.31
43	**2059**	0.047	877	0	55	0	0	146	486	160	0	0	1,724	8,152	88	5,308	13,548	**15,272**	**713**	65,372	**2059**	91.19
44	**2060**	0.043	839	0	53	0	0	126	499	160	0	0	1,676	8,315	90	5,441	13,845	**15,521**	**673**	66,045	**2060**	91.92
45	**2061**	0.040	802	0	51	0	0	144	492	160	0	0	1,649	8,481	92	5,577	14,150	**15,799**	**637**	66,682	**2061**	92.79
		Total NPV =	**$6,493**	**$217**	**$319**	**$391**	**$21**	**$643**	**$678**	**$918**	**($52)**	**$10**	**$9,637**	**$46,981**	**$594**	**$9,471**	**$57,045**	**66,682**				

EDH-20

DBCEC 001287

Case name:	2017 Dania Beach Energy Center FC - Pl	Date:	10/13/17	Generation Capital Costs

		Universal Solar	Battery	Okeechobee	Repower 2	&5 Cont O	peline Capi	Integration Cap	L Repower 202	DG Solar	L Repower 202	0	0	0	0	Eq Filler
	I/S year	2022	2018	2028	2022	2017	2025	2018	2023	2018	2024	0	0	0	0	2033
	No of units	1	1	1	0	1	0	1	0	1	0	0	0	0	0	1
	Gencap $ refyr	2022	2018	2026	2022	2017	2025	2018	2023	2018	2024	0	0	0	0	2025
	Escalator	1.000	1.000	1.051	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.000	0.000	0.000	0.000	1.218
	Total															
2017	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	81	0	28	0	0	0	0	0	0	53	0	0	0	0	0	0
2019	172	0	75	0	0	0	0	0	0	97	0	0	0	0	0	0
2020	245	0	114	0	0	0	0	0	0	130	0	0	0	0	0	0
2021	299	0	146	0	0	0	0	0	0	153	0	0	0	0	0	0
2022	375	63	147	0	0	0	0	0	0	166	0	0	0	0	0	0
2023	344	57	134	0	0	0	0	0	0	153	0	0	0	0	0	0
2024	316	51	123	0	0	0	0	0	0	143	0	0	0	0	0	0
2025	295	47	113	0	0	0	0	0	0	135	0	0	0	0	0	0
2026	277	43	104	0	0	0	0	0	0	129	0	0	0	0	0	0
2027	261	41	96	0	0	0	0	0	0	124	0	0	0	0	0	0
2028	386	39	78	150	0	0	0	0	0	119	0	0	0	0	0	0
2029	431	38	51	227	0	0	0	0	0	115	0	0	0	0	0	0
2030	394	36	27	219	0	0	0	0	0	111	0	0	0	0	0	0
2031	361	35	7	212	0	0	0	0	0	107	0	0	0	0	0	0
2032	341	34	0	205	0	0	0	0	0	103	0	0	0	0	0	0
2033	448	33	0	198	0	0	0	0	0	98	0	0	0	0	0	119
2034	584	31	0	191	0	0	0	0	0	94	0	0	0	0	0	181
2035	699	30	0	185	0	0	0	0	0	90	0	0	0	0	0	175
2036	903	29	0	178	0	0	0	0	0	86	0	0	0	0	0	169
2037	971	28	0	172	0	0	0	0	0	81	0	0	0	0	0	163
2038	1,042	29	0	166	0	0	0	0	0	85	0	0	0	0	0	157
2039	1,056	28	0	160	0	0	0	0	0	80	0	0	0	0	0	152
2040	1,117	26	0	153	0	0	0	0	0	75	0	0	0	0	0	147
2041	1,130	25	0	147	0	0	0	0	0	70	0	0	0	0	0	142
2042	1,192	24	0	141	0	0	0	0	0	65	0	0	0	0	0	137
2043	1,312	22	0	135	0	0	0	0	0	61	0	0	0	0	0	132
2044	1,432	21	0	128	0	0	0	0	0	56	0	0	0	0	0	127
2045	1,438	19	0	122	0	0	0	0	0	52	0	0	0	0	0	122
2046	1,497	18	0	116	0	0	0	0	0	48	0	0	0	0	0	117
2047	1,502	16	0	110	0	0	0	0	0	44	0	0	0	0	0	112
2048	1,435	15	0	104	0	0	0	0	0	32	0	0	0	0	0	107
2049	1,370	14	0	100	0	0	0	0	0	21	0	0	0	0	0	102
2050	1,309	13	0	97	0	0	0	0	0	12	0	0	0	0	0	97
2051	1,251	12	0	93	0	0	0	0	0	5	0	0	0	0	0	92
2052	1,186	2	0	90	0	0	0	0	0	1	0	0	0	0	0	87
2053	1,135	0	0	87	0	0	0	0	0	0	0	0	0	0	0	83
2054	1,087	0	0	83	0	0	0	0	0	0	0	0	0	0	0	80
2055	1,041	0	0	80	0	0	0	0	0	0	0	0	0	0	0	77
2056	998	0	0	76	0	0	0	0	0	0	0	0	0	0	0	74
2057	956	0	0	73	0	0	0	0	0	0	0	0	0	0	0	72
2058	916	0	0	70	0	0	0	0	0	0	0	0	0	0	0	69
2059	877	0	0	66	0	0	0	0	0	0	0	0	0	0	0	66
2060	839	0	0	63	0	0	0	0	0	0	0	0	0	0	0	63
2061	802	0	0	60	0	0	0	0	0	0	0	0	0	0	0	61
2062	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2063	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2064	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2065	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2066	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2067	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2068	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2069	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2070	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2071	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CPVRR	6,493	334	786	949	0	0	0	0	0	1,306	0	0	0	0	0	515

Note: do not enter data in this table

Filler	Filler	Filler	Filler	Filler	Filler	Filler	Filler	Filler	0	0	0	0	0	0	0	0	0	0	0	0	0
2034	2035	2036	2038	2040	2042	2043	2044	2046	0	0	0	0	0	0	0	0	0	0	0	0	0
1	1	2	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	2025	2025	2025	2025	2025	2025	2025	2025	0	0	0	0	0	0	0	0	0	0	0	0	0
1.249	1.280	1.312	1.379	1.448	1.522	1.560	1.599	1.680	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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86	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
131	88	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
126	134	181	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
122	130	275	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
118	125	266	95	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
114	121	257	145	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
110	117	248	140	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
106	113	239	135	152	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
103	109	231	130	147	105	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
99	105	224	126	142	160	108	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
96	102	216	122	137	154	164	111	0	0	0	0	0	0	0	0	0	0	0	0	0	0
92	98	208	117	132	149	158	168	0	0	0	0	0	0	0	0	0	0	0	0	0	0
88	94	201	113	128	144	152	162	116	0	0	0	0	0	0	0	0	0	0	0	0	0
85	91	193	110	123	139	147	156	176	0	0	0	0	0	0	0	0	0	0	0	0	0
81	87	186	106	119	134	142	151	170	0	0	0	0	0	0	0	0	0	0	0	0	0
78	83	178	102	115	130	138	146	164	0	0	0	0	0	0	0	0	0	0	0	0	0
74	80	171	98	111	125	133	141	159	0	0	0	0	0	0	0	0	0	0	0	0	0
70	76	163	94	107	121	128	136	153	0	0	0	0	0	0	0	0	0	0	0	0	0
67	72	155	90	103	116	124	132	148	0	0	0	0	0	0	0	0	0	0	0	0	0
63	68	148	86	98	112	119	127	143	0	0	0	0	0	0	0	0	0	0	0	0	0
60	65	140	82	94	108	115	122	138	0	0	0	0	0	0	0	0	0	0	0	0	0
58	61	133	78	90	103	110	118	133	0	0	0	0	0	0	0	0	0	0	0	0	0
56	59	126	74	86	99	106	113	129	0	0	0	0	0	0	0	0	0	0	0	0	0
54	57	121	70	82	95	101	109	124	0	0	0	0	0	0	0	0	0	0	0	0	0
52	55	117	66	77	90	97	104	119	0	0	0	0	0	0	0	0	0	0	0	0	0
50	53	113	64	73	86	92	99	114	0	0	0	0	0	0	0	0	0	0	0	0	0
48	51	109	61	70	81	88	95	109	0	0	0	0	0	0	0	0	0	0	0	0	0
46	49	105	59	67	77	83	90	104	0	0	0	0	0	0	0	0	0	0	0	0	0
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345	327	620	277	247	219	206	193	168	0	0	0	0	0	0	0	0	0	0	0	0	0

0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
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0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
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0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*1*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*2*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*3*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*4*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*5*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*6*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*7*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*8*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*9*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*10*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*11*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*12*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*13*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*14*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*15*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*16*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*17*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*18*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*19*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*20*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*21*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*22*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*23*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*24*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*25*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*26*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*27*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*28*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*29*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*30*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*31*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*32*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*33*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*34*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*35*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*36*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*37*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*38*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*39*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*40*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*41*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*42*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*43*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*44*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*45*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*46*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*47*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*48*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*49*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*50*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*51*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*52*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*53*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*54*
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*55*

0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

EDH-21

DBCEC 001458

	DG Solar 2018 - 250 KW	DG Solar 2018 - 300 KW	DG Solar 2018 - 500 KW	DG Solar 2019 - 250 KW	DG Solar 2019 - 300 KW	DG Solar 2019 - 500 KW	DG Solar 2020 - 250 KW	DG Solar 2020 - 300 KW	DG Solar 2020 - 500 KW	DG Solar 2021 - 250 KW	DG Solar 2021 - 300 KW	DG Solar 2021 - 500 KW	DG Solar 2022 - 250 KW
Quantity	1	1	1	1	1	1	1	1	1	1	1	1	1
2017	-	-	-	-	-	-	-	-	-	-	-	-	-
2018	18,672,850.8	17,818,110.0	16,188,845.2	-	-	-	-	-	-	-	-	-	-
2019	16,294,275.7	15,548,413.0	14,126,686.4	18,101,667.3	17,236,758.8	15,588,072.9	-	-	-	-	-	-	-
2020	15,041,178.0	14,352,675.3	13,040,285.4	15,950,844.0	15,188,703.2	13,735,912.6	15,285,304.1	14,539,091.4	13,116,672.3	-	-	-	-
2021	14,129,727.3	13,482,945.8	12,250,082.8	14,614,003.0	13,915,737.2	12,584,705.1	13,843,897.8	13,168,053.1	11,879,768.3	11,851,994.9	11,239,212.2	10,069,691.6	-
2022	13,346,394.2	12,735,469.4	11,570,954.6	13,659,009.2	13,006,373.6	11,762,321.6	12,419,870.9	11,813,545.7	10,657,777.9	10,734,350.1	10,179,352.9	9,120,118.3	8,756,406.7
2023	12,659,149.2	12,079,682.7	10,975,132.3	12,847,208.1	12,233,360.8	11,063,247.0	11,440,756.6	10,882,230.7	9,817,577.4	9,630,181.1	9,132,272.6	8,181,994.2	7,927,158.2
2024	12,164,080.7	11,607,275.7	10,545,921.5	12,142,801.5	11,562,611.2	10,456,654.2	10,628,484.5	10,109,612.9	9,120,547.9	8,870,990.6	8,412,334.5	7,536,970.8	7,107,981.5
2025	11,765,100.3	11,226,558.5	10,200,016.6	11,653,184.0	11,096,387.9	10,035,024.9	9,941,344.2	9,456,018.0	8,530,896.9	8,241,167.1	7,815,074.7	7,001,860.1	6,546,642.9
2026	11,366,119.9	10,845,841.2	9,854,111.6	11,270,961.0	10,732,427.7	9,705,877.3	9,504,467.1	9,040,468.9	8,156,002.6	7,708,368.7	7,309,823.6	6,549,184.0	6,081,993.5
2027	10,967,139.5	10,465,124.0	9,508,206.7	10,888,737.9	10,368,467.5	9,376,729.7	9,192,721.7	8,743,942.6	7,888,486.7	7,369,620.8	6,988,589.9	6,261,377.1	5,689,861.1
2028	10,568,159.2	10,084,406.7	9,162,301.7	10,506,514.9	10,004,507.3	9,047,582.1	8,880,976.4	8,447,416.3	7,620,970.8	7,127,898.2	6,759,365.0	6,056,004.7	5,442,762.5
2029	10,169,178.8	9,703,689.5	8,816,396.8	10,124,291.9	9,640,547.2	8,718,434.5	8,569,231.0	8,150,890.0	7,353,454.9	6,886,175.5	6,530,140.1	5,850,632.2	5,268,180.9
2030	9,770,198.4	9,322,972.3	8,470,491.8	9,742,068.9	9,276,587.0	8,389,286.9	8,257,485.6	7,854,363.7	7,085,939.0	6,644,452.8	6,300,915.2	5,645,259.8	5,093,599.3
2031	9,371,218.0	8,942,255.0	8,124,586.9	9,359,845.9	8,912,626.8	8,060,139.3	7,945,740.3	7,557,837.5	6,818,423.1	6,402,730.2	6,071,690.3	5,439,887.4	4,919,017.7
2032	8,972,237.7	8,561,537.8	7,778,681.9	8,977,622.8	8,548,666.6	7,730,991.7	7,633,994.9	7,261,311.2	6,550,907.2	6,161,007.5	5,842,465.4	5,234,515.0	4,744,436.1
2033	8,573,257.3	8,180,820.6	7,432,777.0	8,595,399.8	8,184,706.4	7,401,844.1	7,322,249.5	6,964,784.9	6,283,391.3	5,919,284.8	5,613,240.5	5,029,142.6	4,569,854.5
2034	8,174,276.9	7,800,103.3	7,086,872.0	8,213,176.8	7,820,746.3	7,072,696.5	7,010,504.1	6,668,258.6	6,015,875.4	5,677,562.1	5,384,015.6	4,823,770.2	4,395,272.9
2035	7,775,296.5	7,419,386.1	6,740,967.1	7,830,953.8	7,456,786.1	6,743,548.8	6,698,758.8	6,371,732.3	5,748,359.5	5,435,839.5	5,154,790.7	4,618,397.8	4,220,691.3
2036	7,376,316.2	7,038,668.8	6,395,062.1	7,448,730.7	7,092,825.9	6,414,401.2	6,387,013.4	6,075,206.0	5,480,843.6	5,194,116.8	4,925,565.8	4,413,025.4	4,046,109.7
2037	6,977,335.8	6,657,951.6	6,049,157.2	7,066,507.7	6,728,865.7	6,085,253.6	6,075,268.0	5,778,679.7	5,213,327.7	4,952,394.1	4,696,340.9	4,207,653.0	3,871,528.1
2038	7,242,486.4	6,910,965.1	6,279,035.4	7,384,145.6	7,031,326.7	6,358,784.4	6,386,229.3	6,074,460.2	5,480,170.8	5,233,745.2	4,963,145.3	4,446,694.5	4,108,287.7
2039	6,777,092.9	6,466,874.8	5,875,552.2	6,938,298.9	6,606,782.8	5,974,847.9	6,022,591.7	5,728,575.0	5,168,124.9	4,951,786.1	4,695,764.3	4,207,136.4	3,904,324.5
2040	6,311,699.5	6,022,784.5	5,472,068.9	6,492,452.1	6,182,238.9	5,590,911.3	5,658,954.1	5,382,689.8	4,856,079.1	4,669,827.0	4,428,383.3	3,967,578.3	3,700,361.4
2041	5,846,306.0	5,578,694.2	5,068,585.6	6,046,605.4	5,757,694.9	5,206,974.8	5,295,316.5	5,036,804.6	4,544,033.3	4,387,867.9	4,161,002.3	3,728,020.2	3,496,398.3
2042	5,380,912.5	5,134,603.8	4,665,102.3	5,600,758.6	5,333,151.0	4,823,038.2	4,931,678.9	4,690,919.5	4,231,987.5	4,105,908.8	3,893,621.3	3,488,462.1	3,292,435.2
2043	5,000,966.3	4,772,049.5	4,335,699.5	5,154,911.9	4,908,607.1	4,439,101.7	4,568,041.3	4,345,034.3	3,919,941.7	3,823,949.7	3,626,240.3	3,248,904.0	3,088,472.1
2044	4,621,020.1	4,409,495.1	4,006,296.6	4,790,923.5	4,562,010.4	4,125,656.7	4,204,403.7	3,999,149.1	3,607,895.9	3,541,990.5	3,358,859.3	3,009,345.9	2,884,509.0
2045	4,241,073.8	4,046,940.7	3,676,893.7	4,426,935.2	4,215,413.6	3,812,211.8	3,907,530.8	3,716,769.2	3,353,142.4	3,260,031.4	3,091,478.3	2,769,787.8	2,680,545.8
2046	3,861,127.6	3,684,386.3	3,347,490.8	4,062,946.9	3,868,816.9	3,498,766.8	3,610,657.8	3,434,389.3	3,098,388.8	3,029,840.6	2,873,189.0	2,574,213.1	2,476,582.7
2047	3,481,181.4	3,321,832.0	3,018,088.0	3,698,958.6	3,522,220.1	3,185,321.8	3,313,784.9	3,152,009.4	2,843,635.3	2,799,649.8	2,654,899.7	2,378,638.4	2,310,421.9
2048	512,683.4	489,215.6	444,482.4	3,334,970.2	3,175,623.4	2,871,876.8	3,016,912.0	2,869,629.4	2,588,881.8	2,569,459.0	2,436,610.4	2,183,063.7	2,144,261.1
2049	-	-	-	491,150.5	467,683.0	422,949.4	2,720,039.0	2,587,249.5	2,334,128.3	2,339,268.1	2,218,321.2	1,987,488.9	1,978,100.3
2050	-	-	-	-	-	-	400,587.8	381,031.6	343,753.7	2,109,077.3	2,000,031.9	1,791,914.2	1,811,939.5
2051	-	-	-	-	-	-	-	-	-	310,609.8	294,550.4	263,900.3	1,645,778.7
2052	-	-	-	-	-	-	-	-	-	-	-	-	226,813.9
2053	-	-	-	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-	-	-	-
2055	-	-	-	-	-	-	-	-	-	-	-	-	-
2056	-	-	-	-	-	-	-	-	-	-	-	-	-
2057	-	-	-	-	-	-	-	-	-	-	-	-	-
2058	-	-	-	-	-	-	-	-	-	-	-	-	-
2059	-	-	-	-	-	-	-	-	-	-	-	-	-
2060	-	-	-	-	-	-	-	-	-	-	-	-	-

1	1	5	1				FCSS		
DG Solar 2022 - 300 KW	DG Solar 2022 - 500 KW	GenericA 2022	Turkey Point 2022		22 total	Check	DG Solar Total	Universal Solar Total	1000000
-	-	-	-		-		-	-	
-	-	-	-	-	52,679,805.9	3,913,638,238.81	52,679,805.9	-	
-	-	-	-	-	96,895,874.1		96,895,874.1	-	
-	-				130,250,666.4		130,250,666.4	-	
-	-	-	-	-	153,029,819.3		153,029,819.3	-	
8,303,405.5	7,439,924.2	10,463,959.3	10,214,088.8	-	228,039,160.1		165,505,274.9	62,533,885.2	
7,517,057.1	6,735,349.1	9,473,002.3	9,246,795.1	-	209,734,163.9		153,122,357.3	56,611,806.6	
6,740,259.5	6,039,331.6	8,494,081.2	8,291,249.8	-	193,807,514.4		143,045,858.8	50,761,655.7	
6,207,960.9	5,562,387.5	7,823,278.1	7,636,464.9	-	182,032,479.6		135,279,624.3	46,752,855.3	
5,767,349.6	5,167,595.8	7,268,019.2	7,094,465.1	-	172,495,153.8		129,060,592.5	43,434,561.3	
5,395,503.6	4,834,418.5	6,799,418.6	6,637,054.3	-	164,573,074.6		123,938,927.4	40,634,147.2	
5,161,188.4	4,624,470.0	6,504,134.3	6,348,821.1	-	158,364,016.9		119,494,524.2	38,869,492.7	
4,995,638.5	4,476,135.9	6,295,508.2	6,145,176.9	-	152,875,735.8		115,253,017.7	37,622,718.0	
4,830,088.6	4,327,801.8	6,086,882.2	5,941,532.6	-	147,387,454.6		111,011,511.3	36,375,943.4	
4,664,538.8	4,179,467.7	5,878,256.1	5,737,888.3	-	141,899,173.5		106,770,004.8	35,129,168.7	
4,498,988.9	4,031,133.6	5,669,630.0	5,534,244.1	-	136,410,892.4		102,528,498.3	33,882,394.1	
4,333,439.1	3,882,799.4	5,461,003.9	5,330,599.8	-	130,922,611.2		98,286,991.8	32,635,619.4	
4,167,889.2	3,734,465.3	5,252,377.8	5,126,955.5	-	125,434,330.1		94,045,485.3	31,388,844.8	
4,002,339.4	3,586,131.2	5,043,751.8	4,923,311.3	-	119,946,048.9		89,803,978.8	30,142,070.1	
3,836,789.5	3,437,797.1	4,835,125.7	4,719,667.0	-	114,457,767.8		85,562,472.3	28,895,295.5	
3,671,239.7	3,289,463.0	4,626,499.6	4,516,022.7	-	108,969,486.7		81,320,965.9	27,648,520.8	
3,895,750.8	3,490,626.9	4,909,428.7	4,792,195.8	-	114,625,193.7		85,285,854.2	29,339,339.5	
3,702,339.4	3,317,328.6	4,665,691.6	4,554,278.8	-	108,220,157.2		80,337,420.4	27,882,736.8	
3,508,928.1	3,144,030.4	4,421,954.4	4,316,361.9	-	101,815,120.7		75,388,986.6	26,426,134.0	
3,315,516.7	2,970,732.1	4,178,217.3	4,078,445.0	-	95,410,084.1		70,440,552.9	24,969,531.3	
3,122,105.4	2,797,433.8	3,934,480.1	3,840,528.1	-	89,005,047.6		65,492,119.1	23,512,928.5	
2,928,694.0	2,624,135.6	3,690,742.9	3,602,611.1	-	82,841,074.6		60,784,748.8	22,056,325.7	
2,735,282.7	2,450,837.3	3,447,005.8	3,364,694.2	-	76,907,398.8		56,307,675.8	20,599,723.0	
2,541,871.3	2,277,539.0	3,203,268.6	3,126,777.3	-	71,161,285.2		52,018,164.9	19,143,120.2	
2,348,460.0	2,104,240.7	2,959,531.4	2,888,860.3	-	65,560,014.9		47,873,497.4	17,686,517.5	
2,190,895.3	1,963,061.4	2,760,968.3	2,695,038.7	-	60,334,477.9		43,834,597.9	16,499,880.0	
2,033,330.6	1,821,882.1	2,562,405.1	2,501,217.1	-	47,806,124.5		32,492,881.9	15,313,242.6	
1,875,765.9	1,680,702.7	2,363,841.9	2,307,395.4	-	35,229,452.1		21,102,847.0	14,126,605.1	
1,718,201.2	1,539,523.4	2,165,278.8	2,113,573.8	-	25,036,028.3		12,096,060.7	12,939,967.7	
1,560,636.5	1,398,344.0	1,966,715.6	1,919,752.1	-	17,227,150.0		5,473,819.8	11,753,330.2	
215,080.0	192,713.6	271,044.0	264,571.7	-	2,254,399.2		634,607.5	1,619,791.8	
-	-	-	-	-	-		-	-	
-	-	-	-	-	-	3,913,638,239	-	-	
-	-	-	-	-	-		-	-	
-	-	-	-	-	-		-	-	
-	-	-	-	-	-		-	-	
-	-	-	-	-	-		-	-	
-	-	-	-	-	-		-	-	
-	-	-	-	-	-		-	-	
					$1,639,310,993.80	$1,639.31	$1,305,685,273.57	$333,625,720.24	
							$1,639,310,993.80		

EDH-22

Ten Year Power Plant Site Plan
2017 – 2026

FPL

I.C Demand Side Management (DSM)

FPL has thoroughly explored and implemented cost-effective DSM programs since 1978, and has consistently been among the leading utilities nationally in achieving substantial DSM efficiencies. These programs include a number of innovative conservation/energy efficiency and load management initiatives. Importantly, FPL's DSM efforts through 2016 have resulted in a cumulative Summer peak reduction of approximately 4,843 MW at the generator and an estimated cumulative energy saving 78,400 Gigawatt-Hour (GWh) at the generator. After accounting for the 20% total reserve margin requirements, FPL's highly effective DSM efforts through 2016 have eliminated the need to construct the equivalent of approximately 15 new 400 MW generating units. Also, it is important to note that FPL has achieved these significant DSM accomplishments while minimizing the DSM-based impact on electric rates for all of its customers. FPL's DSM Goals for the 2015 through 2024 timeframe were established by the FPSC in December 2014. FPL continues to account for these DSM Goals in its planning process and extends that annual level of DSM beyond the year 2024.

these resource options and resource plans in system economic analyses that aim to account for all of the impacts to the FPL system from the competing resource options/resource plans. In FPL's 2016 and early 2017 resource planning work, after the resource plans were developed, FPL utilized the UPLAN production cost model and a Fixed Cost Spreadsheet, and/or the EGEAS optimization model, to perform the system economic analyses of the resource plans. FPL may also use other spreadsheet models to further analyze the resource plans.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on FPL's electricity rate levels, with the general objective of minimizing FPL's projected levelized system average electric rate (*i.e.*, a Rate Impact Measure or RIM methodology). In analyses in which the DSM contribution has already been determined through the same IRP process and/or FPSC approval, and therefore the only competing options are new generating units and/or purchase options, comparisons of competing resource plans' impacts on both electricity rates and system revenue requirements will yield identical outcomes in regard to the relative rankings of the resource options being evaluated. Consequently, the competing options and resource plans in such cases can be evaluated on a system cumulative present value revenue requirement (CPVRR) basis.

FPL also includes other factors in its evaluation of resource options and resource plans. Although these factors may have an economic component or impact, they are often discussed in quantitative but non-economic terms, such as percentages, tons, etc., rather than in terms of dollars. FPL often refers to these factors as "system concerns," which include (but are not limited to) maintaining/enhancing fuel diversity in the FPL system and maintaining a regional balance between load and generating capacity, particularly in the Southeastern Florida counties of Miami-Dade and Broward. In conducting the evaluations needed to determine which resource options and resource plans are best for FPL's system, the non-economic evaluations are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan. These and other factors are discussed later in this chapter in section III.C.

Step 4: Finalizing FPL's Current Resource Plan

The results of the previous three fundamental steps are typically used to develop FPL's current resource plan. The current resource plan is presented in the following section.

EDH-23

REVIEW OF THE

2017 TEN-YEAR SITE PLANS

OF FLORIDA'S ELECTRIC UTILITIES

FLORIDA
PUBLIC
SERVICE
COMMISSION

NOVEMBER 2017

Renewable Generation

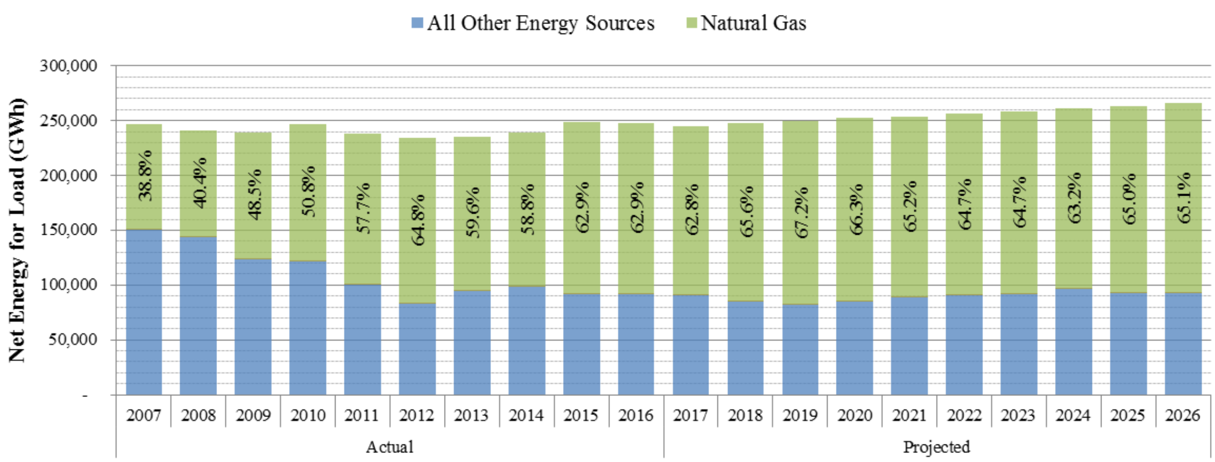
Renewable resources continue to expand in Florida, with approximately 2,206 MW of renewable generating capacity currently installed in Florida. The majority of installed renewable capacity is represented by biomass, solar, and municipal solid waste, making up approximately 71 percent of Florida's renewables. Other major renewable types, in order of capacity contribution, include waste heat, wind, landfill gas, and hydroelectric. Notably, Florida had 141 MW of demand-side renewable energy systems installed and using net metering at the end of 2016, an increase in capacity of 30.6 percent from 2015.

Over the next 10 years, Florida's electric utilities have reported that 4,204 MW of additional renewable generation is planned in Florida, excluding any potential demand-side renewable energy additions. Over three-quarters of the projected capacity additions are solar photovoltaic generation. Some utilities are including a portion of these solar resources as a firm resource for reliability considerations. Reasons given for these additions are a continued reduction in the price of solar facilities, availability of utility property with access to the grid, and actual performance data obtained solar demonstration projects. If these conditions continue, cost-effective forms of renewable generation will continue to improve the state's fuel diversity and reduce dependence on fossil fuels.

Traditional Generation

Generating capacity within the State of Florida is anticipated to grow to meet the increase in customer demand, with approximately 8,850 MW of new utility-owned generation added over the planning horizon. This figure represents a decrease from the previous year, which estimated the need for about 12,127 MW new generation. Natural gas remains the dominant fuel over the planning horizon, with usage in 2016 at approximately 63 percent of the state's net energy for load (NEL). Figure 2 below illustrates the use of natural gas as a generating fuel for electricity production in Florida. Natural gas usage is expected to grow slowly.

Figure 2: State of Florida - Natural Gas Contribution to Energy Consumption



Source: 2007-2017 FRCC Load and Resource Plan sales forecasts. The error rates calculated based on the data provided in last years' and this years' TYSPs continue showing across the board declines in forecast error rates made between one to six years prior, compared to the forecast error rates related to 2009-2013 sales forecasts. Additionally, both of the last and the current years' one year ahead forecasts bear negative error rates (under-forecast), with the current TYSP showing an even smaller error rate.

Table 5: TYSP Utilities - Accuracy of Retail Energy Sales Forecasts – Annual Analysis (Analysis of Annual and Three-Year Average of Three- to Five- Prior Years)

Year	Annual Forecast Error Rate (%)						3-5 Year Error (%)	
	Years Prior						Average	Absolute Average
	6	5	4	3	2	1		
2006	-3.29%	-0.03%	1.03%	2.30%	2.43%	2.37%	**1.10%**	**1.12%**
2007	0.57%	2.26%	3.49%	3.59%	4.20%	3.05%	**3.11%**	**3.11%**
2008	7.02%	8.40%	8.56%	9.97%	9.24%	8.34%	**8.98%**	**8.98%**
2009	11.95%	12.15%	14.48%	13.91%	12.68%	10.18%	**13.51%**	**13.51%**
2010	12.93%	15.57%	14.89%	13.70%	10.55%	-0.73%	**14.72%**	**14.72%**
2011	21.56%	20.79%	20.09%	17.02%	3.79%	0.08%	**19.30%**	**19.30%**
2012	26.31%	25.97%	23.04%	8.47%	3.90%	3.71%	**19.16%**	**19.16%**
2013	28.55%	26.29%	10.00%	5.98%	5.58%	2.97%	**14.09%**	**14.09%**
2014	27.28%	9.80%	6.10%	5.73%	2.84%	2.21%	**7.21%**	**7.21%**
2015	7.29%	3.63%	3.23%	1.02%	0.00%	-1.17%	**2.63%**	**2.63%**
2016	4.49%	4.54%	2.44%	1.40%	0.35%	-0.82%	**2.79%**	**2.79%**

Source: 2001-2017 Ten-Year Site Plans

Barring any unforeseen economic crises or atypical weather patterns, average forecasted energy sales error rates in the next few years are likely to be more reflective of the error rates shown for 2015 and 2016 in Table 5 than the significantly higher error rates shown in earlier years. It is important to recognize that the dynamic nature of the economy and the weather continue to present a degree of uncertainty for Florida utilities' load forecasts, ultimately impacting the accuracy of such forecasts.

Renewable Generation

Pursuant to Section 366.91, F.S., it is in the public interest to promote the development of renewable energy resources in Florida. Section 366.91(2)(d), F.S., defines renewable energy in part, as follows:

> "Renewable energy" means electrical energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen produced from sources other than fossil fuels, biomass, solar energy, geothermal energy, wind energy, ocean energy, and hydroelectric power.

Although not considered a traditional renewable resource, some industrial plants take advantage of waste heat, produced in production processes, to also provide electrical power via cogeneration. Phosphate fertilizer plants, which produce large amounts of heat in the manufacturing of phosphate from the input stocks of sulfuric acid, are a notable example of this type of renewable resource. The Section 366.91(2)(d), F.S., definition also includes the following language which recognizes the aforementioned cogeneration process:

> The term [Renewable Energy] includes the alternative energy resource, waste heat, from sulfuric acid manufacturing operations and electrical energy produced using pipeline-quality synthetic gas produced from waste petroleum coke with carbon capture and sequestration.

Existing Renewable Resources

Currently, renewable energy facilities provide approximately 2,206 MW of firm and non-firm generation capacity, which represents 3.8 percent of Florida's overall generation capacity of 58,295 MW in 2016. Table 6 below summarizes the contribution by renewable type of Florida's existing renewable energy sources.

Table 6: State of Florida - Existing Renewable Resources

Renewable Type	MW	% Total
Biomass	583	26.4%
Municipal Solid Waste	446	20.2%
Waste Heat	306	13.8%
Solar	538	24.4%
Landfill Gas	83	3.8%
Hydro	63	2.9%
Wind[3]	188	8.5%
Renewable Total	**2,206**	**100.00%**

Source: FRCC 2017 Load & Resource Plan and TYSP Utilities Data Responses

[3]JEA's wind resources are not present in-state.

Of the total 2,206 MW of renewable generation, approximately 705 MW are considered firm, based on either operational characteristics or contractual agreement. Firm renewable generation can be relied on to serve customers and can contribute toward the deferral of new fossil fueled power plant construction. Solar generation contributes 153 MW to this total, based upon the coincidence of solar generation and summer peak demand. Changes in timing of peak demand may influence the firm contributions of renewable resources such as solar and wind.

The remaining renewable generation can generate energy on an as-available basis or for internal use (self-service). As-available energy is considered non-firm, and cannot be counted on for reliability purposes; however, it can contribute to the avoidance of burning fossil fuels in existing generators. Self-service generation reduces demand on Florida's utilities.

Non-Utility Renewable Generation

The majority of Florida's existing renewable energy generation, approximately 89 percent, comes from non-utility generators. In 1978, the US Congress enacted the Public Utility Regulatory Policies Act (PURPA). PURPA requires utilities to purchase electricity from cogeneration facilities and renewable energy power plants with a capacity no greater than 80 MW (collectively referred to as Qualifying Facilities or QFs). PURPA required utilities to buy electricity from QFs at the utility's full avoided cost. These costs are defined in Section 366.051, F.S., which provides in part that:

> A utility's "full avoided costs" are the incremental costs to the utility of the electric energy or capacity, or both, which, but for the purchase from cogenerators or small power producers, such utility would generate itself or purchase from another source.

If a renewable energy generator can meet certain deliverability requirements, it can be paid for its capacity and energy output under a firm contract. Rule 25-17.250, F.A.C., requires each IOU to establish a standard offer contract with timing and rate of payments based on each fossil-fueled generating unit type identified in the utility's TYSP. In order to promote renewable energy generation, the Commission requires the IOUs to offer multiple options for capacity payments, including the options to receive early (prior to the in-service date of the avoided-unit) or levelized payments. The different payment options allow renewable energy providers the option to select the payment option that best fits its financing requirements, and provides a basis from which negotiated contracts can be developed.

As previously discussed, large amounts of renewable energy is generated on an as-available basis. As-available energy is energy produced and sold by a renewable energy generator on an hour-by-hour basis for which contractual commitments as to the quantity and time of delivery are not required. As-available energy is purchased at a rate equal to the utility's hourly incremental system fuel cost, which reflects the highest fuel cost of generation each hour.

Customer Owned Renewable Generation

With respect to customer-owned renewable generation, Rule 25-6.065, F.A.C., requires the IOUs to offer net metering for all types of renewable generation up to 2 MW in capacity and a standard interconnection agreement with an expedited interconnection process. Net metering allows a customer, with renewable generation capability, to offset their energy usage. In 2008, the effective year of Rule 25-6.065, F.A.C., customer owned renewable generation accounted for 3 MW of renewable capacity. As of the end of 2016, approximately 141 MW of renewable capacity from nearly 16,000 systems has been installed statewide. Table 7 below summarizes the growth of customer owned renewable generation interconnections. Almost all installations are solar, with non-solar generation accounting for only 37 installations and 7.7 MW of installed capacity. The renewable generators in this category include wind turbines and anaerobic digesters.

Table 7: State of Florida - Customer-Owned Renewable Growth

Year	2009	2010	2011	2012	2013	2014	2015	2016
Number of Installations	1,625	2,833	3,994	5,302	6,697	8,581	11,626	15,994
Installed Capacity (MW)	13.0	19.9	28.4	42.2	63.0	79.8	107.5	141

Source: Annual Utility Reports

Utility-Owned Renewable Generation

Utility-owned renewable generation also contributes to the state's total renewable capacity. The majority of this generation is from solar facilities. Due to the intermittent nature of solar resources, capacity from these facilities has previously been considered non-firm for planning purposes.

In 2008, Section 366.92(4), F.S., was enacted and provides, in part, the following:

> In order to demonstrate the feasibility and viability of clean energy systems, the commission shall provide for full cost recovery under the environmental cost-recovery clause of all reasonable and prudent costs incurred by a provider for renewable energy projects that are zero greenhouse gas emitting at the point of the generation, up to a total of 110 MW statewide.

In 2008, the Commission approved a petition by FPL seeking installation of the full 110 MW across three solar energy facilities. The solar projects consisted of, a pair of solar PV facilities and a single solar thermal facility. In response to staff interrogatories, FPL estimated that the three solar facilities would cost an additional $573 million, above traditional generation costs over the life of the facilities. In 2012, Section 366.92, F.S., was revised and no longer includes the passage described above.

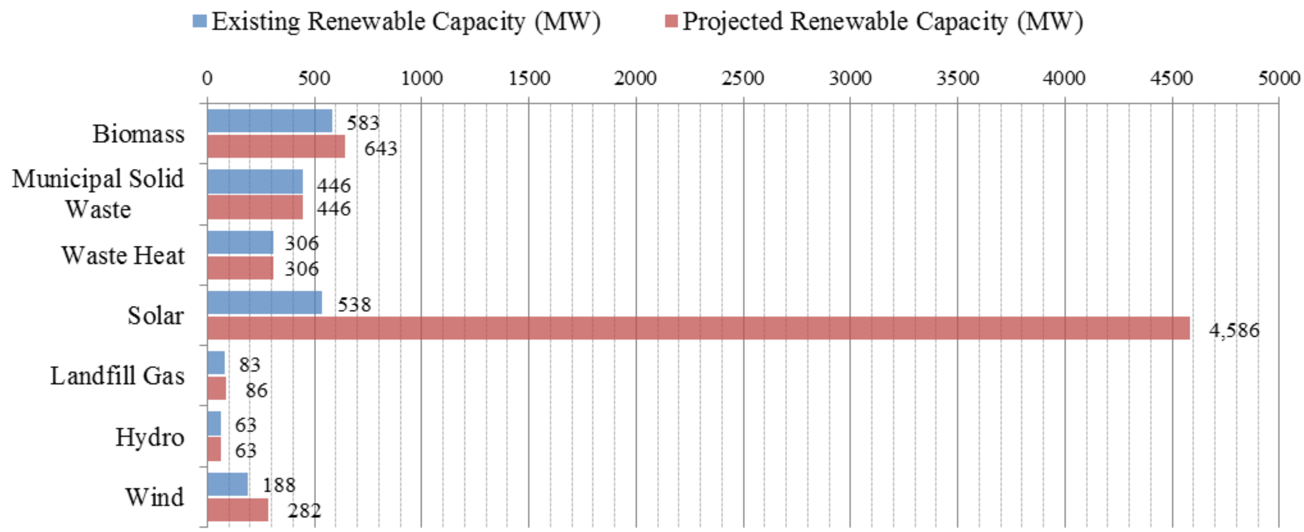
Based on actual data provided by FPL, the combined cost of generation of the three solar facilities was $0.41/kWh in 2016. These facilities make up a significant portion of the utility owned renewable generation. Since full operation began, the two solar PV facilities have operated largely as expected; however, the solar thermal facility has experienced multiple outages which have hindered its performance. In FPL's 2016 TYSP, FPL included that the Desoto and Space Coast solar facilities contributed approximately 46 percent and 32 percent, respectively, of the system's installed capacity to summer peak demand. No contribution to winter peak demand as determined from either facility.

Hydroelectric units at two sites, one owned by the City of Tallahassee Utilities, and one operated by the federal government, supply 63 MW of renewable capacity. Due to operational constraints, the City of Tallahassee does not consider its 12.3 MW of hydroelectric generation firm. The City of Tallahassee Utilities plans to retire its hydroelectric unit at the end of 2017. Because of Florida's geography, however, new hydroelectric power generation is largely limited.

Planned Renewable Resources

Florida's utilities plan to construct or purchase an additional 4,204 MW of renewable generation over the 10-year planning period, a significant increase from last year's estimated 2,005 MW projections. Figure 11 below summarizes the existing and projected renewable capacity by generation type. Solar generation is projected to have the greatest increase over the planning horizon.

Figure 11: State of Florida - Current and Projected Renewable Resources4



Source: 2017 FRCC Load & Resource Plan, TYSP Utilities Data Responses

Of the 4,204 MW of planned renewable capacity, 1,187 MW is projected to be from firm resources with 1,149 MW of that firm amount coming from solar generation. The projected firm capacity additions are from a combination of renewable contracts with non-utility generators, primarily utility-owned solar. Solar is anticipated to exceed all other renewables combined by a factor of two within the 2026 planning period.

For some existing renewable facilities, contracts for firm capacity are projected to expire within the 10-year planning horizon. If new contracts are signed in the future to replace those that expire, these resources will once again be included in the state's capacity mix to serve future demand. If these contracts are not extended, the renewable facilities could still deliver energy on an as-available basis.

[4] JEA and Gulf's wind resources are not present in-state.

As noted above, solar generation is anticipated to increase significantly over the 10-year period, with a total of 4,048 MW to be installed. This consists of 2,876 MW of utility-owned solar, 176 MW of contracted solar and 1,000 MW of as-available energy contract solar facilities. Table 8 below lists some of the utility-scale (greater than 10 MW) solar installations with in-service dates within the planning period.

Gulf has entered into purchase power agreements linked to 272 MW of wind energy produced by facilities located in Oklahoma. While the energy from the facilities may not be delivered to Gulf's system, the renewable attributes for their output are retained by the Utility for the benefit of Gulf's customers.

Table 8: TYSP Utilities - Planned Solar Installations

Year	Utility	Facility Name	Type	Capacity (MW)
2017	DEF	Suwanee Solar Facility	Utility Owned	10
2017	FPL	2017 Solar Projects	Utility Owned	298
2017	TAL	Airport 1	Purchased	20
2017	GULF	Eglin	Purchased	30
2017	GULF	Holley	Purchased	40
2017	GULF	Saufley	Purchased	50
2017	TECO	Big Bend	Utility Owned	18
			2017 Subtotal	**466**
2018	DEF	Solar 4	Utility Owned	20
2018	DEF	Solar QF 1&2	Purchased*	150
2018	FPL	2018 Solar Projects	Utility Owned	298
			2018 Subtotal	**468**
2019	DEF	Solar 5 & QF3	Utility Owned*	125
2019	FPL	Unsited Projects	Utility Owned	300
			2019 Subtotal	**425**
2020	DEF	Solar 6 & 7	Utility Owned*	150
2020	DEF	Solar 4 QF	Purchased	75
2020	FPL	Unsited Projects	Utility Owned	300
			2020 Subtotal	**525**
2021	DEF	Solar 8 & QF5	Utility Owned*	150
2021	FPL	Unsited Projects	Utility Owned	300
			2021 Subtotal	**450**
2022	DEF	Solar 9 & QF6	Utility Owned*	150
2022	FPL	Unsited Projects	Utility Owned	300
			2022 Subtotal	**450**
2023	DEF	Solar 10 & QF7	Utility Owned*	150
2023	FPL	Unsited Projects	Utility Owned	300
			2023 Subtotal	**450**
2024	DEF	Solar 8 QF	Purchased	75
2024	DEF	Solar 11 & 12	Utility Owned	150
			2024 Subtotal	**225**
2025	DEF	Solar 9 QF	Purchased	75
2025	DEF	Solar 13	Utility Owned	75
			2025 Subtotal	**150**
2026	DEF	Solar 10 QF	Purchased	75
2026	DEF	Solar 14	Utility Owned	75
			2026 Subtotal	**150**
TBD	DEF	National Solar Projects	Purchased	250
			TBD Subtotal	**250**
			Total Installations	**4,009**
***Final determination of generation type not yet decided upon.**				

Source: 2017 FRCC Load & Resource Plan, TYSP Utilities Data Responses

Renewable Outlook

Florida's renewable generation is projected to increase over the planning period. Some utilities are including a portion of solar capacity as a firm resource for reliability considerations. Reasons given for these additions are the continued reduction in price of solar facilities, availability of utility property with access to the grid, and actual performance data from FPL's pilot program. If these conditions remain, the cost-effective forms of renewable generation will continue to improve the state's fuel diversity and reduce dependence on fossil fuels.

The recent FPL base rate case resulted in a settlement agreement that was approved by the Commission, and included a provision for a Solar Bas Rate Adjustment (SoBRA) mechanism.[5] The SoBRA establishes a process by which FPL may seek approval from the Commission to recover costs for eligible solar projects. Both Duke Energy Florida, LLC and Tampa Electric Company have proposed similar SoBRA processes in their 2017 base rate case settlements which, if approved, would greatly increase their solar portfolios.[6] If approved as proposed, this could result in an additional 2,100 MW in solar generation for FPL, 755 MW for DEF, and 600 MW for TECO for a total of 3,455 MW of new solar generation. The full effects of all three SoBRA agreements will be reflected in the 2018 Ten-Year Site Plan.

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[5] Order No. PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 20160021-EI, *In re: Petition for rate increase by Florida Power & Light Company.*

[6] Docket No. 20170183-EI, *In re: Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC* and Docket No. 20170210-EI, *In re: Petition for limited proceeding to approve 2017 amended and restated stipulation and settlement agreement, by Tampa Electric Company.*

Traditional Generation

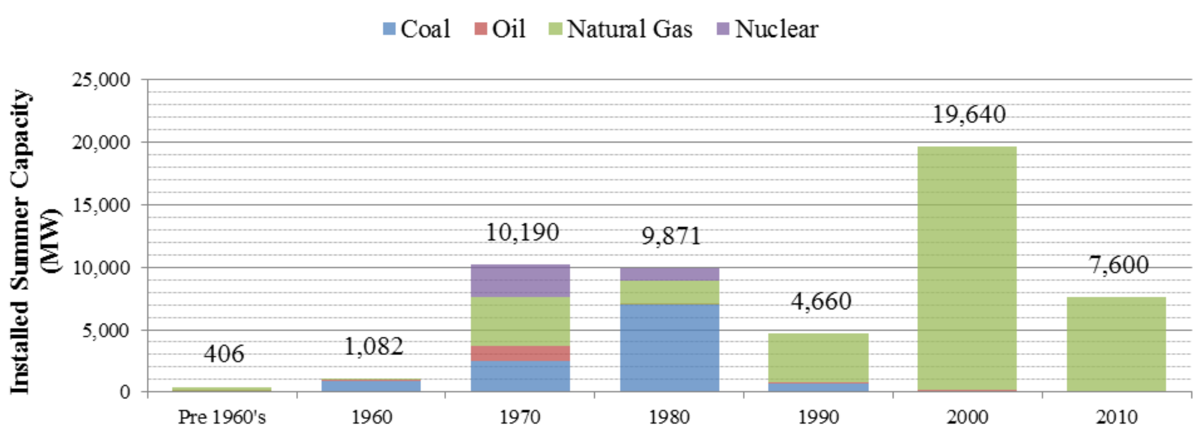
While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and turbine generators, that have been added to Florida's electric grid over the last several decades. Due to forecasted increases in peak demand, further traditional resources are anticipated over the planning period.

Florida's electric utilities have historically relied upon several different fuel types to serve customer load. Previous to the oil embargo, Florida used oil-fired generation as its primary source of electricity until the increase in oil prices made this undesirable. Since that time, Florida's electric utilities have sought a variety of other fuel sources to diversify the state's generation fleet and more reliably and affordably serve customers. Numerous factors, including swings in fuel prices, availability, environmental concerns, and other factors have resulted in a variety of capacity on Florida's electric grid. Solid fuels, such as coal and nuclear, increased during the shift away from oil-fired generation, and more recently natural gas has emerged as the dominant fuel type in Florida.

Existing Generation

Florida's generating fleet includes incremental new additions to a historic base fleet, with units retiring as they become uneconomical to operate or maintain. Currently, Florida's existing capacity ranges greatly in age and fuel type, and legacy investments continue. The weighted average age of Florida's generating units is 23 years. While the original commercial in-service date may be in excess of 60 years for some units, they are constantly maintained as necessary in order to ensure safe and reliable operation, including uprates from existing capacity, which may have been added after the original in-service date. Figure 12 below illustrates the decade current operating generating capacity was originally added to the grid, with the largest additions occurring in the 2000s.

Figure 12: State of Florida - Electric Utility Installed Capacity by Decade



Source: 2017 FRCC Load & Resource Plan

Fuel Diversity

Table 12 below shows FPL's actual net energy for load by fuel type for 2016, and the projected fuel mix for 2026. FPL relies primarily upon natural gas and nuclear for energy generation, making up approximately 94 percent of net energy for load. Consistent with its previously discussed SoBRA, FPL projects that renewable energy will provide over 4 percent of generation by 2026.

Table 12: FPL Energy Consumption by Fuel Type

Fuel Type	Net Energy for Load			
	2016		2026	
	GWh	%	GWh	%
Natural Gas	86,161	**70.8%**	89,647	**70.7%**
Coal	4,165	**3.4%**	880	**0.7%**
Nuclear	28,033	**23.1%**	28,524	**22.5%**
Oil	659	**0.5%**	36	**0.0%**
Renewable	237	**0.2%**	5,513	**4.3%**
Interchange	1,748	**1.4%**	0	**0.0%**
NUG & Other	616	**0.5%**	2,225	**1.8%**
Total	**121,619**		**126,825**	

Source: 2017 Ten-Year Site Plan

Reliability Requirements

While previously only reserve margin has been discussed, Florida's utilities use multiple indices to determine the reliability of the electric supply. An additional metric is the Loss of Load Probability (LOLP), which is a probabilistic assessment of the duration of time electric customer demand will exceed electric supply, and is measured in units of days per year. FPL uses a maximum LOLP of no more than 0.1 days per year, or approximately 1 day of outage per 10 years. Between the two reliability indices, LOLP and reserve margin, the reserve margin requirement is typically the controlling factor for the addition of capacity.

Since 1999, FPL has utilized a 20 percent planning reserve margin criterion. Figure 20 below displays the forecast planning reserve margin for FPL through the planning period for both seasons, with and without the use of demand response. As shown in the figure, FPL's generation needs are controlled by its summer peak throughout the planning period.

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for Dania Beach Clean Energy Center Unit 7, by Florida Power & Light Company	DOCKET NO. 20170225-EI DATE: December 8, 2017

CERTIFICATE OF SERVICE
Docket No. 20170225-EI

I HEREBY CERTIFY that a true and correct copy of Sierra Club's Direct Testimony of Ezra D. Hausman and attached exhibits has been furnished by electronic mail on this 8th day of December, 2017, to the following:

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