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October 31, 2013

Ms. Mary Jo Kunkle
Michigan Public Service Commission
6545 Mercantile Way
P. O. Box 30221
Lansing, MI 48909

RE: MPSC Case N° U-17429

Dear Ms. Kunkle:

The following is attached for paperless electronic filing:

**Corrected Direct Testimony of Jonathan Wallach on Behalf of the
Natural Resources Defense Council**

Corrected Exhibit NRD-11

E-Service List

The only change in Corrected Exhibit NRD-11 from the version filed earlier this week is to modify the header which incorrectly marked this as "Exhibit NRD-29."

Sincerely,

Christopher M. Bzdok
chris@envlaw.com

xc: Parties to Case No. U-17429
James Clift, MEC (james@environmentalcouncil.org)
Rebecca Stanfield, NRDC (rstanfield@nrdc.org)
Resource Insight: Jonathan Wallach (jwallach@resourceinsight.com) and
Ben Griffiths (bgriffiths@resourceinsight.com)
George Evans (georgeevans@evanspowerconsulting.com)

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the Application of)
Consumers Energy Company for)
Approval of a Certificate of Necessity)
for the Thetford Generating Plant)
pursuant to MCL 460.6s and for related)
accounting and ratemaking authorizations)

Case No. U-17429

Corrected
DIRECT TESTIMONY OF
JONATHAN WALLACH
ON BEHALF OF
THE NATURAL RESOURCES DEFENSE COUNCIL

Resource Insight, Inc.

OCTOBER 28, 2013

1 **I. Introduction and Summary**

2 **Q: Please state your name, occupation, and business address.**

3 A: My name is Jonathan F. Wallach. I am Vice President of Resource Insight,
4 Inc., 5 Water Street, Arlington, Massachusetts.

5 **Q: Please summarize your professional experience.**

6 A: I have worked as a consultant to the electric-power industry since 1981.
7 From 1981 to 1986, I was a research associate at Energy Systems Research
8 Group. In 1987 and 1988, I was an independent consultant. From 1989 to
9 1990, I was a senior analyst at Komanoff Energy Associates. I have been in
10 my current position at Resource Insight since September of 1990.

11 Over the past thirty years, I have advised clients on a wide range of
12 economic, planning, and policy issues including: electric-utility restructuring;
13 wholesale-power market design and operations; transmission pricing and
14 policy; market valuation of generating assets and purchase contracts; power-
15 procurement strategies; risk assessment and management; integrated resource
16 planning; cost allocation and rate design; and energy-efficiency program
17 design and planning.

18 My resume is attached as Exhibit NRD-3.

19 **Q: Have you testified previously in utility regulatory proceedings?**

20 A: Yes. I have testified in more than sixty federal, provincial, or state
21 proceedings in the U.S. and Canada. I include a detailed list of my previous
22 testimony in Exhibit NRD-3.

23 **Q: Please summarize your experience with regard to integrated resource**
24 **planning and risk management.**

1 A: During my thirty years working as an economic consultant, I have evaluated
2 and formulated numerous utility integrated resource plans in jurisdictions
3 throughout the U.S. and Canada. I have also conducted economic evaluations
4 and risk assessments of utility proposals to build or purchase new generating
5 capacity, including gas combined-cycle generation. Finally, I have advised
6 clients and sponsored expert testimony with regard to the risk profiles of
7 resource portfolios and authored a major study of long-term costs and risks of
8 resource portfolios for residential default-service load.

9 **Q: On whose behalf are you testifying?**

10 A: I am testifying on behalf of the Natural Resources Defense Council
11 (“NRDC”).

12 **Q: Are you sponsoring any exhibits?**

13 A: Yes. I am sponsoring the following exhibits:

- 14 • Exhibit NRD-3: Resume of Jonathan Wallach, Resource Insight, Inc.
- 15 • Exhibit NRD-4: John D. Quackenbush and Steve Bakkal, *Readying*
16 *Michigan to Make Good Energy Decisions: Renewable Energy,*
17 *Draft, September 20, 2013*
- 18 • Exhibit NRD-5: Discovery Response 17429-NRDC-CE-337 (with
19 attachment: US Solar PV Cost Outlook, Trends and Analysis:
20 2013-2020)
- 21 • Exhibit NRD-6: Discovery Response 17429-ST-CE-234
- 22 • Exhibit NRD-7: Discovery Responses 17429-NRDC-CE-472-475 (with
23 attachment: CEC RFP 09-30-13)
- 24 • Exhibit NRD-8: NPV Cost Results
- 25 • Exhibit NRD-9: Below-the-Line Adjustments to G. Evans runs (see NRD-
26 2)

- 1 • Exhibit NRD-10: Synapse Energy Economics, 2012 Carbon Dioxide Price
2 Forecast (October 4, 2012)
- 3 • Exhibit NRD-11: U.S. Dept. of Energy, *2012 Wind Technologies Market*
4 *Report* (excerpt)

5

6 **Q: What is the purpose of your testimony?**

7 A: On July 12, 2013, Consumers Energy Company (“Consumers” or “the
8 Company”) filed an application requesting that the Commission issue three
9 certificates of necessity (“CON”) for the proposed construction of a 700MW
10 natural gas-fired combined-cycle plant in Thetford Township (“Thetford
11 Plant”).¹ In support of its application, the Company filed an Integrated
12 Resource Plan (“IRP”) that purports to demonstrate that: (1) there is a need
13 for new capacity to reliably serve the Company’s load starting in 2016 due to
14 the plan to suspend operations at seven of the Company’s smaller coal-fired
15 power plants (“Seven Small Coal Units”); and (2) the identified need for new
16 capacity is most reasonably and economically met with the proposed
17 Thetford Plant commencing operation in 2017.²

¹ Specifically, the Company is requesting the following CONs: (1) a CON that the power to be supplied as a result of the proposed construction of the Thetford Plant is needed; (2) a CON that the size, fuel type, and other design and operating characteristics of the proposed Thetford Plant represent the most reasonable and prudent means of meeting that power need; and (3) a CON that the estimated capital costs of and the financing plan for the proposed Thetford Plant, including, but not limited to, the costs of siting and licensing the new facility and the estimated cost of power from the new electric generation facility will be recoverable in rates from Consumers Energy’s customers, subject to MCL 460.6s(4)(c).

² *2013 Integrated Resource Plan*, filed as Exhibit A-50 (DFR-1) to *Direct Testimony of David F. Ronk, Jr. on behalf of Consumers Energy Company*, Case No. U-17429, July, 2013.

1 This testimony describes my assessment of both of these determinations
2 by the Company, based on my review of the Company's filing and responses
3 to discovery. My analysis of the Company's determinations also relies on the
4 analysis presented in the direct testimony of Chris Neme, an expert witness
5 in this proceeding regarding the opportunity to increase energy-efficiency
6 savings beyond levels assumed by the Company in the IRP. In addition, I rely
7 on the results of a number of alternative Strategist model runs, as presented
8 in the direct testimony of George Evans, an expert witness in this proceeding.

9 **Q: Did you have access to all relevant information when you conducted**
10 **your analysis?**

11 A: No. The Company issued a Request for Proposals for the sale of currently
12 operating generation assets to Consumers on September 30, 2013 ("2013
13 RFP") and received responsive offers on October 15, 2013. The Company
14 has not yet responded to discovery from NRDC requesting copies of such
15 offers, so I have not yet had the opportunity to determine whether these offers
16 are viable and economic alternatives to the proposed Thetford Plant. I may
17 supplement this testimony once I have had the opportunity to evaluate the
18 responses to this latest Request for Proposals.

19 **Q: Please describe the Company's IRP analysis.**

20 A: There were essentially four stages to the Company's IRP analysis. First,
21 Consumers determined its annual capacity requirement and identified a need
22 for new reserve capacity based on its forecasts of: (1) peak demand
23 requirements; (2) reserve requirements; and (3) available capacity from
24 existing generating assets and power purchase contracts. Second, the
25 Company identified and developed cost and performance assumptions for a
26 variety of generating resource options, including the proposed Thetford Plant,

1 for meeting the identified need for new capacity. Third, the Company
2 developed forecasts of input fuel prices and other operating costs and
3 performance parameters for existing resources and new resource options.
4 Finally, Consumers used the Strategist simulation software in an attempt to
5 identify the portfolio of existing and new resources that meets energy and
6 capacity needs at the lowest net present value over a 28-year study period
7 from 2013 to 2040.

8 **Q: Please summarize your findings and conclusions regarding the**
9 **Company's IRP.**

10 A: The Company has not met its burdens to demonstrate that there is a need to
11 for the reserve capacity to be provided by the proposed Thetford Plant or that
12 the proposed Thetford Plant would be the most reasonable and prudent means
13 for meeting any identified need.

14 The Company's IRP is flawed in two respects. First, Consumers has
15 identified a need for new reserve capacity in 2016 and beyond based on an
16 assumption that the Company will permanently retire the Seven Small Coal
17 Units. However, Consumers has not committed to permanently retiring, or
18 even suspending operations at these units. In the absence of a binding
19 retirement commitment, the Company has not demonstrated a need for
20 additional reserve capacity.

21 Second, even assuming that the Seven Small Coal Units are
22 permanently retired, Consumers has not shown that the proposed Thetford
23 Plant is the least-cost means for meeting the identified resource need in 2016
24 and beyond. In particular, the Company's IRP analysis failed to consider
25 whether investment in energy-efficiency resources beyond that assumed by
26 the Company, the purchase of existing generation assets, investment in new

1 renewable resources, or some combination of these resource options ~~would~~
2 could meet the identified need at a cost comparable to or lower than the
3 proposed Thetford Plant.

4 In fact, Strategist modeling conducted by Mr. Evans indicates that
5 replacing the proposed Thetford Plant with combinations of these additional
6 resource options would substantially reduce the cost of meeting the identified
7 resource need. Specifically, the results of Mr. Evans's Strategist analysis
8 show that the Company could achieve savings of up to \$1 billion by
9 investing in a portfolio that combines additional cost-effective energy-
10 efficiency savings (as specified by Mr. Neme), purchases of existing capacity,
11 wind resources, and/or spot purchases of capacity instead of in a portfolio
12 that includes the proposed Thetford Plant in 2017. Consequently, the
13 proposed Thetford Plant does not represent the most reasonable and prudent
14 means for meeting the identified need in 2016 and beyond.

15 **Q: What do you recommend with regard to the Company's application for**
16 **certificates of necessity for the proposed Thetford Plant?**

17 A: The Commission should deny the Company's request for certificates of
18 necessity at this time. As noted above, Consumers has failed to meet its
19 burdens to show a need for new reserve capacity or to show that the proposed
20 Thetford Plant is the most reasonable and prudent means for meeting the
21 identified need in 2016 and beyond. To the contrary, I find that the identified
22 need could be met at lower cost with a portfolio that combines additional
23 cost-effective energy-efficiency savings (as specified by Mr. Neme),
24 purchases of existing capacity, wind resources, and/or spot purchases of
25 capacity.

1 In addition, if Consumers wants to proceed with the construction of new
2 generation plant or the purchase of existing capacity, it should be directed to:

- 3 • Evaluate the feasibility and cost-effectiveness of increasing Energy
4 Optimization budgets to achieve the savings levels recommended in Mr.
5 Neme's direct testimony.
- 6 • Report on its evaluation of the offers submitted in response to the 2013
7 RFP.
- 8 • File an updated IRP that: (1) incorporates the peak-demand and energy
9 savings achievable with additional cost-effective Energy Optimization
10 spending; (2) includes as resource options the asset offers submitted in
11 response to the 2013 RFP; and (3) evaluates scenarios for increasing
12 investments in wind and utility-scale photovoltaic resources.

13 II. Determination of Need

14 **Q: How will the suspension of operations at the Seven Small Coal Units in**
15 **2016 affect the Company's need for reserve capacity?**

16 A: According to Figure 21 of the IRP, the suspension of operations will create an
17 installed capacity ("ICAP") shortfall in 2016 of 1,057 MW. In other words,
18 without the capacity from the Seven Small Coal Units, the total installed
19 capacity on Consumer's system will fall short of the Company's forecast of
20 capacity obligation for 2016 (i.e., forecast peak demand plus forecast ICAP
21 reserve requirement) by 1,057 MW. Stated in terms of unforced capacity
22 ("UCAP"), the Company forecasts that the UCAP obligation for 2016 (i.e.,

1 forecast peak demand plus forecast UCAP reserve requirement) will exceed
2 total system UCAP by 839 UCAP MW or Zonal Resource Credits (“ZRC”).³

3 **Q: Does the Company expect the capacity shortfall to increase over time?**

4 A: Yes. Assuming permanent retirement of the Seven Small Coal Units, and
5 assuming no new capacity is added to the system, the Company expects that
6 the shortfall will grow by more than 50% to 1,281 ZRCs by 2026, primarily
7 as a result of a forecasted growth in peak demand.⁴

8 **Q: How does the Company’s forecast of capacity need account for**
9 **reductions in demand growth due to spending on energy-efficiency**
10 **programs?**

11 A: As discussed further by Mr. Neme, the Company’s load forecasts incorporate
12 Consumer’s estimates of energy and peak-demand savings achievable with
13 Energy Optimization (“EO”) program spending up to amounts prescribed in
14 the *Clean, Renewable, and Efficient Energy Act* of 2008.

15 However, as addressed in detail by Mr. Neme, the Company’s load
16 forecast does not incorporate cost-effective and achievable energy and peak-
17 demand savings beyond the amounts prescribed in the Act.

18 **Q: Has the Company reasonably demonstrated a need for new reserve**
19 **capacity in 2016 and beyond?**

20 A: No. The Company’s determination of need in 2016 and beyond is premised
21 on the assumption that the Seven Small Coal Units will be permanently
22 retired. However, Consumers has not committed to permanently retiring, or

³ One megawatt of unforced capacity, or one ZRC, is equal to one megawatt of installed capacity multiplied by the quantity one minus the forced outage rate.

⁴ I have not reviewed the Company’s load-forecasting methodology and therefore am not offering an opinion on the reasonableness of the Company’s load forecast.

1 even suspending operations at these units.⁵ There would no longer be a need
2 to add reserve capacity in 2016 or thereafter in the amounts forecasted by the
3 Company, if Consumers were to reverse its decision to suspend operations at
4 the Seven Small Coal Units in 2016 or were to resume operations after a
5 period of suspension.

6 **Q: Would it be reasonable to permanently retire the Seven Small Coal**
7 **Units?**

8 A: Yes. According to the Company, it would be less expensive to permanently
9 retire the Seven Small Coal Units in 2016 than it would be to comply with
10 the Mercury and Air Toxics Standard (“MATS”) and continue operation of
11 these plants until their scheduled retirement dates.⁶ It would therefore be
12 more beneficial to ratepayers for the Seven Small Coal Units to be
13 permanently retired in 2016 than for the Company to incur the costs to
14 comply with MATS.

15 **III. Resource Options**

16 **Q: What resource options did Consumers consider in its IRP?**

17 A: In addition to the proposed Thetford plant, the Company evaluated and
18 modeled in Strategist a number of generation options for meeting forecasted

⁵ In his direct testimony in this proceeding, Company witness Timothy J. Sparks states that “if Consumers Energy does not proceed with construction of the Thetford Plant on the proposed schedule, the Company may have to revisit its decision to suspend operations at the Seven Small Coal Units.” *Direct Testimony of Timothy J. Sparks on behalf of Consumers Energy Company*, Case No. U-17429, July, 2013, p. 15, ll. 12-14.

⁶ *Direct Testimony of David F. Ronk, Jr. on behalf of Consumers Energy Company*, Case No. U-17429, July, 2013, p. 11, ll. 2-6.

1 resource needs over the planning horizon. These options include new gas
2 combined cycle (“CC”), gas combustion turbine (“CT”), nuclear, coal steam,
3 coal gasification combined cycle, and utility-scale wind. In addition, the IRP
4 modeled an option to purchase spot capacity starting in 2017 priced at the
5 Company’s forecast of capacity market prices.⁷

6 **Q: Should the Company have evaluated any other resource options in its**
7 **Strategist modeling?**

8 A: Yes. The IRP should have considered the following viable and potentially
9 economic resource options:

- 10 • Additional investment in energy-efficiency resources.
- 11 • Utility-scale solar photovoltaic (“PV”) generation.
- 12 • Purchases of existing generation assets located in Zone 7.

13 **Q: What is the basis for the energy-efficiency savings included in the**
14 **Company’s Strategist modeling?**

15 A: As discussed by Mr. Neme, the Company’s forecast of energy-efficiency
16 savings assumes annual savings equivalent to 1% of load, until such time as
17 the cost to achieve this level of savings exceeds the limit prescribed in the
18 *Clean, Renewable, and Efficient Energy Act*. Beyond that point, the Company
19 forecasts savings achievable with continued spending at the statutory limit.

20 **Q: To what extent could Consumers increase savings from energy-efficiency**
21 **resources in its service territory?**

22 A: As discussed in detail by Mr. Neme, the Company could procure substantial
23 additional reductions to customer load by increasing its spending on cost-

7 The capacity deficiency in 2016 was assumed to be filled with a spot purchase of ~~839~~
~~ZRCs~~850 MW of capacity at the Company’s estimate of the 2016 capacity market price.

1 effective energy-efficiency efforts beyond the statutory limit. By 2016, Mr.
2 Neme estimates that the Company could feasibly increase peak-demand
3 savings by almost 150 MW, equivalent to about 156 ZRCs or almost 20% of
4 the total capacity deficiency in that year. By 2026, Mr. Neme forecasts
5 additional peak savings of almost 520 MW, equivalent to about 546 ZRCs or
6 more than 40% of that year's capacity deficiency.

7 **Q: What is the potential for utility-scale PV in Michigan?**

8 A: According to Exhibit NRD-4, a recent draft report by the Department of
9 Licensing and Regulatory Affairs and the Michigan Energy Office, the
10 technical potential for utility-scale PV in Michigan exceeds 30 GW.⁸ The
11 Company could add more than 300 MW of utility-scale PV to its system by
12 tapping a mere 1% of that potential.

13 **Q: Why did the Company not consider utility-scale PV as a potential option**
14 **for meeting its resource need?**

15 A: According to ~~its~~ Exhibit NRD-5, which is the Company's response to
16 Discovery Request 17429-NRDC-CE-337, Consumers did not include utility-
17 scale PV as a resource option, because "the Company does not consider
18 utility scale solar to be competitive with dispatchable generation resources or
19 the wind resources included in the IRP." In other words, the Company did not
20 model utility-scale PV as a resource option in its Strategist modeling, because
21 it presumed that this option would never be selected by Strategist in any year
22 of the study period.

⁸ Exhibit NRD-4, John D. Quackenbush and Steve Bakkal, *Readying Michigan to Make Good Energy Decisions: Renewable Energy*, Draft, September 20, 2013, Table 2, p. 22.

1 **Q: Was this a reasonable basis for excluding utility-scale PV from**
2 **consideration?**

3 A: No. By this standard, Consumers should not have considered the majority of
4 the resource options it evaluated, including advanced coal, IGCC, and
5 nuclear, because these options were unlikely to be selected by the Strategist
6 model (and, in fact, were never selected in the ~~BAU-optimization~~Business As
7 Usual scenario runs). Moreover, the Company failed to consider that PV
8 installed costs have been dropping and are expected to continue to decline
9 over time, potentially materially improving cost-competitiveness during the
10 IRP study period. Exhibit NRD-5 documents this trend.⁹

11 **Q: Why did the Company decide to not model the purchase of an existing**
12 **power plant as a resource option?**

13 A: On June 1, 2012, Consumers issued a Request for Proposals for the sale of
14 existing generating plant to the Company (“2012 RFP”). The Company’s
15 evaluations of the responsive offers to sell existing assets indicated that some
16 of these proposals offered long-term economic benefits that matched or
17 exceeded those offered by the proposed Thetford Plant.¹⁰ However, the
18 Company chose at that time not to move forward with any of the offers, and
19 instead to proceed with the Thetford Plant. As a result, the Company decided
20 to not evaluate the purchase of existing capacity as a resource option in the
21 IRP.

⁹ In Exhibit NRD-5, an August, 2013 publication attached to discovery response 17429-NRDC-CE-337, IHS CERA forecasts that installed costs for utility-scale PV on average will drop by almost a third over the next seven years. See, “US Solar PV Cost Outlook, Trends and Analysis: 2013-2020”, August 21, 2013..

¹⁰ For example, see Exhibit NRD-6, which is Discovery Response 17429-ST-234.

1 **Q: Why should Consumers have included the option to purchase existing**
2 **capacity in its Strategist modeling?**

3 A: By not considering the option to purchase existing assets, the Company
4 eliminated from consideration a potentially viable resource alternative to the
5 850 MW capacity market purchase assumed for 2016 in the Company's
6 Strategist modeling.

7 Moreover, notwithstanding the Company's rejection of economic offers
8 in the 2012 RFP, Consumers has again gone out to bid for the purchase of
9 existing capacity in Zone 7 with the 2013 RFP. In Exhibit NRD-7, which is
10 discovery response 17429-NRDC-CE-472, the Company acknowledges that,
11 despite the reasons for rejecting offers in the 2012 RFP, it intends to again
12 consider whether potential purchase options offer greater long-term
13 economic benefits than the proposed Thetford plant:

14 Based on the results of the 2012 solicitation described in testimony in
15 this case and the IRP analysis described in this case, Consumers Energy
16 concluded that the Thetford Project was the most reasonable and prudent
17 means of meeting the identified power supply needs. Recently,
18 Consumers Energy has heard claims that the owners of certain
19 generating plant assets may be willing to sell those assets on terms that
20 may be competitive with the construction of the Thetford Project. In
21 order to test whether those claims have any validity, Consumers Energy
22 determined to conduct the solicitation identified in the question as the
23 2013 RFP.

24 Given the potential economic viability of asset purchases, as indicated
25 in the Company's evaluation of the 2012 RFP offers and by the issuance of
26 the 2013 RFP, the option to purchase existing assets should have been
27 evaluated in the IRP.¹¹

¹¹ As noted above, I have not yet had the opportunity to review the responses to the 2013 RFP, since the Company has not yet responded to NRDC's discovery requesting these responses.

1 **IV. The Company's Strategist Modeling**

2 **Q: Please describe the Company's IRP modeling effort.**

3 A: The Company employed the Strategist software model to:

- 4 • simulate operations of the Consumers system and the broader MISO
5 energy market;
- 6 • optimize the selection of new resource options to meet reliability
7 requirements on the Consumers system and throughout the MISO
8 region; and
- 9 • forecast the cost to add or purchase capacity to meet system reserve
10 requirements, and the cost to dispatch the Company's generation
11 portfolio to meet system energy requirements.

12 The Company developed base case and sensitivity forecasts of key input
13 parameters – including customer load, EO savings, reserve requirements, fuel
14 prices, and capacity market prices – and then assembled different
15 combinations of these forecasts into five planning scenarios.¹²

16 The Company also developed forecasts of non-fuel operating costs and
17 performance characteristics for all existing generation in the MISO region
18 (including the Company's assets), as well as forecasts of capital costs and
19 operating costs and performance characteristics for each of the identified
20 resource options.

21 Based on the input assumptions specific to each planning scenario,
22 Consumers used the Strategist optimization software to select the portfolio of
23 resource options that met reserve and energy requirements in each year of the
24 study period at the lowest total net present value ("NPV") cost over the entire

¹² See Figure 7 of the IRP for the specific forecasts included in each planning scenario.

1 study period. The Company either allowed Strategist to assemble the optimal
2 portfolio among all the resource options (“full-optimization run”) or required
3 selection of a specific resource option in a specific year and then allowed
4 Strategist to find the least-cost portfolio that includes the user-specified
5 resource selection (“partial-optimization run”). In all full- or partial-
6 optimization runs, the Company specified capacity market purchases of 78
7 MW in 2013 and 850 MW in 2016 to fill the capacity deficiencies in those
8 two years.¹³

9 **Q: After 2016, did Consumers allow Strategist to select annual capacity**
10 **market purchases in the full-optimization runs?**

11 A: No. Instead, the Company conducted a number of partial-optimization runs
12 which specified an amount of capacity market purchases and then allowed
13 Strategist to optimize around those forced-in market purchases.

14 The Company does not explain in the IRP why annual capacity market
15 purchases were not included as a resource option in the full-optimization
16 runs. However, when NRDC witness Mr. Evans attempted full-optimization
17 runs with market purchases, Strategist was unable to reach an optimal
18 solution after fourteen hours of runtime, indicating that Strategist is not
19 capable of optimizing on annual purchases.

20 **Q: Did the Company make any adjustments to the NPV cost results from**
21 **the Strategist model runs?**

22 A: Yes. The Company made a number of below-the-line adjustments to the
23 Strategist NPV results to reflect costs or revenues that are not included in the

¹³ The “full-optimization” runs are not truly fully optimized, since the Company does not require Strategist to optimize the selection of annual market purchases.

1 Strategist modeling. For the Business as Usual (“BAU”) scenario runs, the
2 Company made the following adjustments:

- 3 • Reduced the NPV cost for annual revenues from the sale of system
4 capacity in excess of reserve requirements at the forecast capacity
5 market price.
- 6 • Increased the NPV cost to account for the network upgrade costs
7 incurred for new capacity supporting market purchases in 2016 and
8 thereafter.
- 9 • For runs that added the proposed Thetford Plant, reduced the NPV cost
10 to reflect partial-year operation in 2016.
- 11 • For sensitivity runs with additional EO savings, increased the NPV cost
12 to reflect incremental spending to achieve additional savings.

13 As discussed in the following section, I make comparable adjustments
14 to the NPV results from Mr. Evans’s Strategist model runs.

15 **V. NRDC Strategist Modeling**

16 **Q: Please describe Mr. Evans’s alternative Strategist analysis.**

17 **A:** At my request, Mr. Evans conducted a series of full- and partial-optimization
18 runs with various modifications to the input assumptions for the BAU
19 scenario with carbon sensitivity case (“BAU023 Case”):

- 20 • **BAU023 Incremental EO Case.** The BAU023 Case with Mr. Neme’s
21 estimate of the additional peak-demand and energy savings achievable
22 with a comprehensive and cost-effective program portfolio. Full-
23 optimization run with no capacity market purchases after 2016.
- 24 • **NRDC Reference Case.** The BAU Incremental EO Case with a revised
25 installed cost per kilowatt for new wind capacity and the addition of

1 four resource options based on the offers to sell existing capacity
2 submitted in response to the 2012 RFP. Full-optimization run with no
3 capacity market purchases after 2016.

4 • **NRDC Market Purchase Case.** Partial-optimization run of NRDC
5 Reference Case with a 500 MW capacity market purchase in every year
6 from 2017 through 2040.

7 • **NRDC Market Purchase and Wind Case.** Partial-optimization run of
8 NRDC Market Purchase Case with 500 MW of new wind capacity in
9 2017.

10 • **NRDC No 2016 Market Purchase Case.** Full-optimization run of
11 NRDC Reference Case without the 850 MW capacity market purchase
12 in 2016.

13 • **NRDC 500 MW 2016 Market Purchase.** Full-optimization run of
14 NRDC Reference Case with 500 MW capacity market purchase in
15 2016.

16 I provide the NPV cost results for each of these runs in Exhibit NRD-8.
17 The NPV values are expressed in 2013 dollars, and include the same below-
18 the line adjustments to the Strategist NPV outputs as are reflected in the
19 reported results for the Company's BAU scenario runs. I show the below-the-
20 line adjustments to each of Mr. Evans's runs in Exhibit NRD-9.

21 **Q: Please summarize the NPV cost results of the six cases that you analyzed**
22 **with the Strategist model.**

23 A: As shown in Exhibit NRD-8, all of the cases modeled by Mr. Evans have a
24 lower NPV cost than the Company's BAU023 case. The two lowest-cost
25 cases – each of which are more than \$1 billion less expensive than the
26 Company's BAU023 case – are those with portfolios that do not include the

1 proposed Thetford Plant in 2017. In these lowest-cost cases, the need for the
2 proposed Thetford Plant is deferred until 2030. The least-cost case (NRDC
3 No 2016 Market Purchase Case) meets the identified need in 2016 and
4 beyond with a portfolio of cost-effective energy efficiency savings, purchases
5 of existing capacity, and new wind capacity.

6 **A. *Modeling Assumptions***

7 **Q: Why are you assuming the carbon sensitivity for your reference**
8 **baseline?**

9 A: Despite the failure to enact Federal legislation in the last few years, it is
10 reasonable and prudent to assume that some form of controls or limits on the
11 emissions of greenhouse gases that result in CO₂ emissions costs will be
12 established during the IRP's 28-year planning horizon.

13 For example, on June 25, 2013, President Obama issued a memorandum
14 to the U.S. EPA directing the agency to use its authority under the Clean Air
15 Act to issue proposed carbon "standards, regulations, or guidelines, as
16 appropriate" to "address carbon pollution from modified, reconstructed and
17 existing power plants and build on State efforts to move toward a cleaner
18 power sector," specifying that the proposed rules should be issued by June 1,
19 2014, with final rules published by June 1, 2015 and state implementation
20 plans submitted to EPA by June 30, 2016.¹⁴ The EPA is in the process of
21 developing the proposed rules, is conducting listening sessions to take public

¹⁴ See <http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards>.

1 input on the issue, and has issued a set of questions for state regulators to
2 consider in developing recommendations for the proposed rule.¹⁵

3 In Exhibit NRD-10, a 2012 study, Synapse Energy Economics
4 concluded that the price of carbon would range from \$15-\$30 per ton in
5 2020, and escalate to between \$35 and \$90 per ton in 2040 depending on the
6 stringency of a national regime for regulating carbon emissions.

7 **Q: Please describe your revision to the Company's assumption regarding**
8 **new wind installed costs.**

9 A: For the NRDC case runs, I requested that Mr. Evans reduce the installed cost
10 for new wind facilities from \$2,237/kW to \$1,950/kW (2013\$). This latter
11 estimate is based on Exhibit NRD-11, a U.S. Department of Energy survey of
12 project installation costs that shows an average installed cost for projects
13 located in the Great Lakes region of about \$1,940/kW (2012\$).¹⁶ Although
14 the DOE survey shows steep declines in average installed costs in the last
15 few years and indicates that further declines are anticipated, I conservatively
16 assume that installed costs remain constant over the study period.

17 **Q: How did Mr. Evans model the purchase of currently operating**
18 **generation assets as a resource option?**

19 A: I identified four offers in response to the 2012 RFP – two combined-cycle
20 plants and two combustion-turbine plants – as potential resource options.¹⁷ At

¹⁵ See <http://www2.epa.gov/sites/production/files/2013-09/documents/20130923statequestions.pdf>.

¹⁶ [Exhibit NRD-11](#), U.S. Department of Energy, *2012 Wind Technologies Market Report*, August, 2013, p. 32.

¹⁷ There were five offers of existing capacity in total. I did not model one of those offers because of uncertainties regarding current contractual arrangements between the Company and this asset.

1 my request, Mr. Evans modeled each of these resource options with an
2 installed cost set at the offer price plus inflation to the year of purchase.¹⁸
3 Because these assets were already included in the Strategist inputs as
4 merchant generators, Mr. Evans modeled the purchase as a transfer to the
5 Company's generation portfolio without any changes to the input
6 assumptions for these assets regarding operating costs and performance.
7 However, Mr. Evans shortened the remaining life for these assets, in order to
8 limit the total operating life to thirty years.

9 **Q: Why did you set the amount of capacity market purchases to 500 MW in**
10 **the NRDC Market Purchase Case?**

11 A: As discussed above, the Strategist model is incapable of optimizing annual
12 market purchases. Moreover, it would have been too time-consuming to
13 attempt manual optimization. I therefore decided to mimic the Company's
14 modeling of market purchases and simply set a fixed amount for such
15 purchases in each year. I set that amount to 500 MW, because this amount
16 was less than the capacity deficiency in each year and would therefore allow
17 for the selection of other resource options to meet a portion of the capacity
18 deficiency.

19 ***B. Modeling Results***

20 **Q: Why did you direct Mr. Evans to run the BAU023 Incremental EO**
21 **Case?**

22 A: We ran this case to test whether the additional spending to achieve the
23 incremental savings could be justified solely on the basis of the generation

¹⁸ For the purposes of these Strategist runs, it was assumed that the Company could purchase these assets anytime between 2014 and 2017.

1 costs avoided by these incremental savings.¹⁹ As indicated in Exhibit NRD-9,
2 Mr. Neme is forecasting additional EO spending of about \$1.5 billion (2013
3 NPV) over the 28-year study period. Yet, as indicated in Exhibit NRD-8, this
4 additional spending of \$1.5 billion in the BAU023 Incremental EO Case
5 results in a \$628 million reduction in the total NPV cost relative to the
6 BAU023 Case. Thus, the additional \$1.5 billion EO spending yields avoided
7 generation savings of about \$2.1 billion, for a net benefit of about ~~\$600~~628
8 million.²⁰ This result shows that the additional spending recommended by
9 Mr. Neme is cost-effective, even when not accounting for avoided
10 transmission and distribution costs or other economic benefits from energy-
11 efficiency investments.

12 **Q: Please describe in greater detail the results of the Strategist run of the**
13 **NRDC Reference Case.**

14 A: As indicated in Exhibit NRD-8, Strategist continues to select the proposed
15 Thetford Plant in 2017 and does not select any of the asset purchase options
16 in the NRDC Reference Case. However, as a result of the reduction in new
17 wind installed cost, this run selects a total of 1,000 MW of new wind in the
18 second half of the study period, double the amount selected in the BAU023
19 Incremental EO Case run.²¹ Even with this additional wind, the total NPV

¹⁹ This is only a partial measure of the economic benefits from Mr. Neme's forecast of additional spending on energy-efficiency resources. Other benefits include avoided transmission and distribution costs and the mitigation of fuel-price and other risks associated with conventional power supply.

²⁰ The net benefit is actually greater than ~~\$600~~628 million, because the net-benefit calculation does not account for generation costs avoided by incremental EO savings that persist after additional program spending ceases in 2040.

²¹ Exhibit NRD-2 sponsored by Mr. Evans shows the resource additions in each year of the study period for each of his Strategist runs.

1 cost for the NRDC Reference Case is about \$119 million less than for the
2 BAU023 Incremental EO Case.²²

3 **Q: What is the impact of assuming 500 MW of capacity market purchases**
4 **starting in 2017 in the NRDC Market Purchase Case?**

5 A: With annual market purchases of 500 MW of capacity, Strategist defers
6 selection of the Thetford Plant to 2030. Although the NPV cost for this case
7 appears to be about \$84 million more than for the NRDC Reference Case, it
8 is likely that this difference is exaggerated by the fact that Strategist is not
9 capable of optimizing the selection of market purchases in each year. I
10 therefore interpret this result to indicate that a resource portfolio with annual
11 purchases of 500 MW (or less with optimization) would be no more
12 expensive than a resource portfolio with the proposed Thetford Plant in 2017.

13 A resource portfolio with market purchases would also be more flexible
14 than one with the proposed Thetford Plant in 2017. Relying on market
15 purchases to meet a portion of the expected capacity deficiency would
16 provide the Company with the flexibility to respond to unexpected changes
17 in load growth or unexpected delays in bringing new resources online.

18 **Q: What is the impact of combining 500 MW of annual market purchases**
19 **with 500 MW of new wind in 2017, as in the NRDC Market Purchase**
20 **and Wind Case?**

²² These savings relative to the BAU023 Incremental EO Case are due to the combined effect of: (1) the reduction in capital costs associated with the 500 MW of new wind capacity common to both cases; (2) the reduction in system costs attributable to the capital and energy costs avoided by the additional 500 MW of new wind capacity in the NRDC Reference Case; and (3) the increase in capital and O&M costs attributable to the additional 500 MW of new wind capacity in the NRDC Reference Case.

1 A: As with the NRDC Market Purchase Case, the combination of 500 MW of
2 market purchases and 500 MW of new wind in 2017 defers the selection of
3 the Thetford Plant until 2030. In addition, the addition of 500 MW of wind in
4 2017 leads to the selection of an additional 1,200 MW of wind over the study
5 period.

6 Adding 500 MW of new wind in 2017 increases the total NPV cost
7 relative to the NRDC Market Purchase Case by only \$171 million. This may
8 be a reasonable price to pay to obtain the environmental and risk-mitigation
9 benefits associated with the addition of 1,700 MW of new wind to the
10 Company's resource portfolio.

11 **Q: What was the rationale for running the NRDC No 2016 Market**
12 **Purchase Case?**

13 A: Mr. Evans ran the NRDC No 2016 Market Purchase Case to determine
14 whether meeting the 2016 capacity deficiency with an asset purchase rather
15 than an 850 MW market purchase would produce a lower-cost resource
16 portfolio.

17 As indicated in Exhibit NRD-8, removing the 850 MW market purchase
18 not only reduces the total NPV cost by about \$340 million relative to the
19 NRDC Reference Case, but also defers selection of the Thetford Plant to
20 2030. Instead, Strategist selects one of the CT purchase options in 2016 and
21 advances the selection of 200 MW of new wind to 2016.

22 In other words, the results of this run demonstrate that the identified
23 resource need in 2016 and beyond could be met with a portfolio of energy-
24 efficiency resources, asset purchases, and wind resources at a lower total cost
25 than with a portfolio that includes the Thetford Plant in 2017.

1 **Q: What is the impact of assuming a 500 MW market purchase in 2016 in**
2 **the NRDC 500 MW 2016 Market Purchase Case?**

3 A: The results of this case are similar to those for the NRDC No 2016 Market
4 Purchase Case. In this case, replacing the 850 MW market purchase with a
5 500 MW market purchase reduces the total NPV cost by about \$325 million
6 relative to the NRDC Reference Case, defers selection of the Thetford Plant
7 to 2030, and instead selects one of the CT purchase options in 2016.
8 However, in contrast with the NRDC No 2016 Market Purchase Case, this
9 case does not advance the selection of wind to 2016.²³

10 Thus, the identified resource need in 2016 and beyond could be met
11 with a portfolio of energy-efficiency resources, asset purchases, and capacity
12 market purchases at a lower total cost than with a portfolio that includes the
13 Thetford Plant in 2017. However, the economic benefits from this portfolio
14 fall short of those from a portfolio that relies on wind resources rather than
15 capacity market purchases, as in the NRDC No 2016 Market Purchase Case.

16 **Q: Does this conclude your direct testimony?**

17 A: Yes, at this time. However, I reserve the right to supplement my testimony to
18 address outstanding responses by the Company to NRDC discovery.

²³ Over the study period, the same amount of wind (1,000 MW) in total is selected in the NRDC 500 MW 2016 Market Purchase Case as in the NRDC Reference Case and NRDC No 2016 Market Purchase Case.

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2012 WIND TECHNOLOGIES MARKET REPORT

AUGUST 2013



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2012 Wind Technologies Market Report

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4. Cost Trends

This chapter presents empirical data on both the upfront and operating costs of wind projects in the United States. It begins with a review of wind turbine prices, followed by total installed project costs, and then finally O&M costs. Later chapters present data on wind project performance and then the price at which wind energy is being sold.

Wind Turbine Prices Remained Well Below Levels Seen Several Years Ago

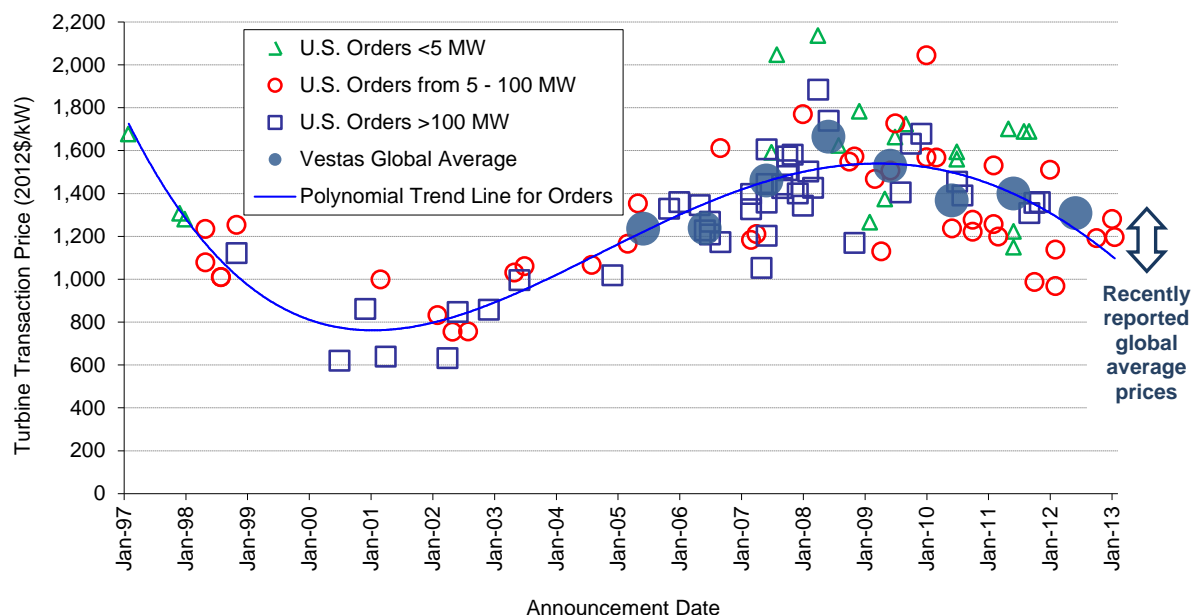
Wind turbine prices have dropped substantially in recent years, despite continued technological advancements that have yielded increases in hub heights and especially rotor diameters. This downward pricing pressure continued in 2012, partly a result of reduced demand expectations for 2013 and stiff competition among and low margins for turbine OEMs and equipment suppliers.

Berkeley Lab gathered price data for 102 U.S. wind turbine transactions totaling 27,000 MW announced from 1997 through the beginning of 2013, including 12 transactions (2,630 MW) announced in 2011 but just six transactions (350 MW) announced since that time. Sources of turbine price data vary, but many derive from press releases and news reports. Most of the transactions included in the Berkeley Lab dataset likely include turbines, towers, delivery to site, and limited warranty and service agreements.⁴¹ Nonetheless, wind turbine transactions differ in the services included (e.g., whether towers and installation are provided, the length of the service agreement, etc.), turbine characteristics (and therefore performance), and the timing of future turbine delivery, driving some of the observed intra-year variability in transaction prices.

Unfortunately, collecting data on U.S. wind turbine transaction prices is a challenge: in 2012, relatively few new wind turbine transactions were announced, only a fraction of which publicly revealed pricing data. In part as a result, Figure 19—which depicts these U.S. wind turbine transaction prices—also presents data from Vestas on that company’s global average turbine pricing from 2005 through 2012, as reported in Vestas’ financial reports (with an average annual exchange rate used to convert to U.S. dollars); and a range of recent global average wind turbine prices for both older turbine models (smaller rotors, lower hub height) and new models (larger rotors, higher hub height), as reported by Bloomberg NEF (2013b).

After hitting a low of roughly \$700/kW from 2000 to 2002, average wind turbine prices increased by approximately \$800/kW (more than 100%) through 2008, rising to an average of more than \$1,500/kW. The increase in turbine prices over this period was caused by several factors, including a decline in the value of the U.S. dollar relative to the Euro; increased materials, energy, and labor input prices; a general increase in turbine manufacturer profitability due in part to strong demand growth and turbine and component supply shortages; increased costs for turbine warranty provisions; and an up-scaling of turbine size, including hub height and rotor diameter (Bolinger and Wiser 2011).

⁴¹ Because of data limitations, the precise content of many of the individual transactions is not known.



Source: Berkeley Lab

Figure 19. Reported Wind Turbine Transaction Prices over Time

Since 2008, wind turbine prices have declined substantially, reflecting a reversal of some of the previously mentioned underlying trends that had earlier pushed prices higher as well as increased competition among manufacturers and a shift to a buyer's market. As shown in Figure 19, our limited sample of recently announced U.S. turbine transactions shows pricing in the \$950–\$1,300/kW range. Bloomberg NEF (2013b) reports global average pricing for contracts signed in 2012 at slightly less than \$1,100/kW for older turbine models and slightly more than \$1,300/kW for turbines that feature larger rotors and higher hub heights. Bloomberg NEF (2013b) further reports U.S. average pricing of \$1,140/kW for contracts signed in 2012. Data from Vestas on that company's global average pricing largely confirm these basic trends and conclusions.

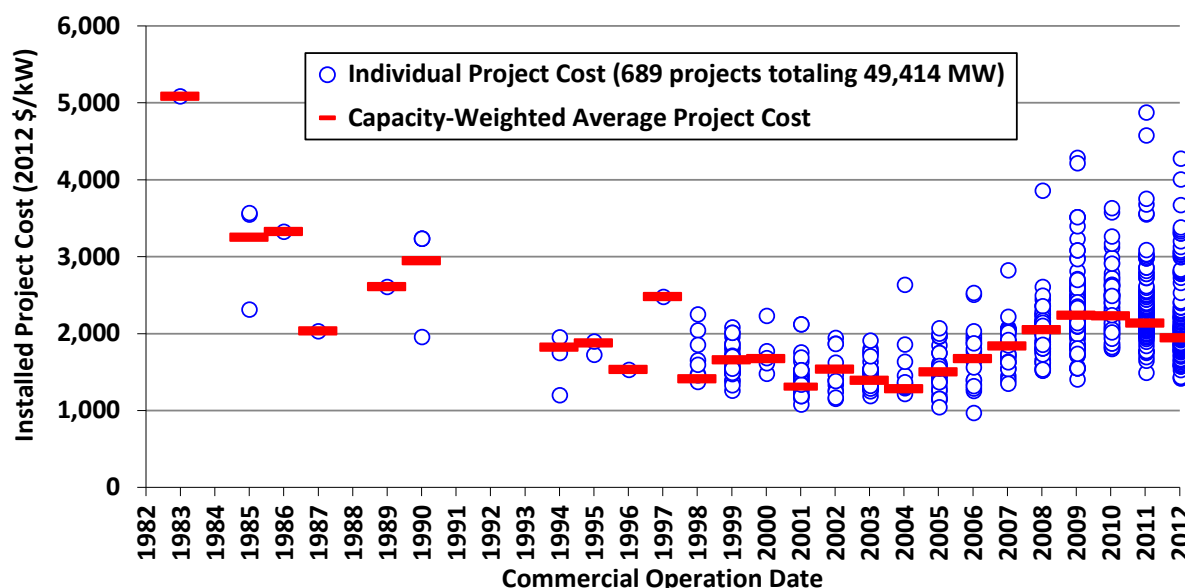
Overall, these figures suggest price declines of roughly 20%–35% since late 2008. Moreover, these declines have been coupled with improved turbine technology (e.g., witness the recent and continued growth in average hub heights and rotor diameters in Figure 16) and more-favorable terms for turbine purchasers (e.g., reduced turbine delivery lead times and less need for large frame-agreement orders, longer initial O&M contract durations, improved warranty terms, and more-stringent performance guarantees). These price reductions and improved terms have exerted downward pressure on total project costs and wind power prices, whereas increased rotor diameters and hub heights would be expected to improve capacity factors and further reduce wind power prices.

Reported Installed Project Costs Continued to Trend Lower in 2012

Berkeley Lab compiles data on the total installed cost of wind power projects in the United States, including data on 118 projects completed in 2012 totaling 9,414 MW, or 72% of the wind power capacity installed in that year. In aggregate, the dataset (through 2012) includes 689

completed wind power projects in the continental United States totaling 49,414 MW and equaling roughly 82% of all wind power capacity installed in the United States at the end of 2012. In general, reported project costs reflect turbine purchase and installation, balance of plant, and any substation and/or interconnection expenses. Data sources are diverse, however, and are not all of equal credibility, so emphasis should be placed on overall trends in the data rather than on individual project-level estimates.

As shown in Figure 20, the average installed costs of wind power projects declined from the beginning of the U.S. wind industry in California in the 1980s through the early 2000s, before following turbine prices higher through the latter part of the last decade. Whereas turbine prices peaked in 2008/2009, however, project-level installed costs appear to have peaked in 2009/2010. That changes in average installed project costs would lag changes in average turbine prices is not surprising and reflects the normal passage of time between when a turbine supply agreement is signed (the time stamp for Figure 19) and when those turbines are actually installed and commissioned (the time stamp for Figure 20).⁴²



Source: Berkeley Lab (some data points suppressed to protect confidentiality)

Figure 20. Installed Wind Power Project Costs over Time

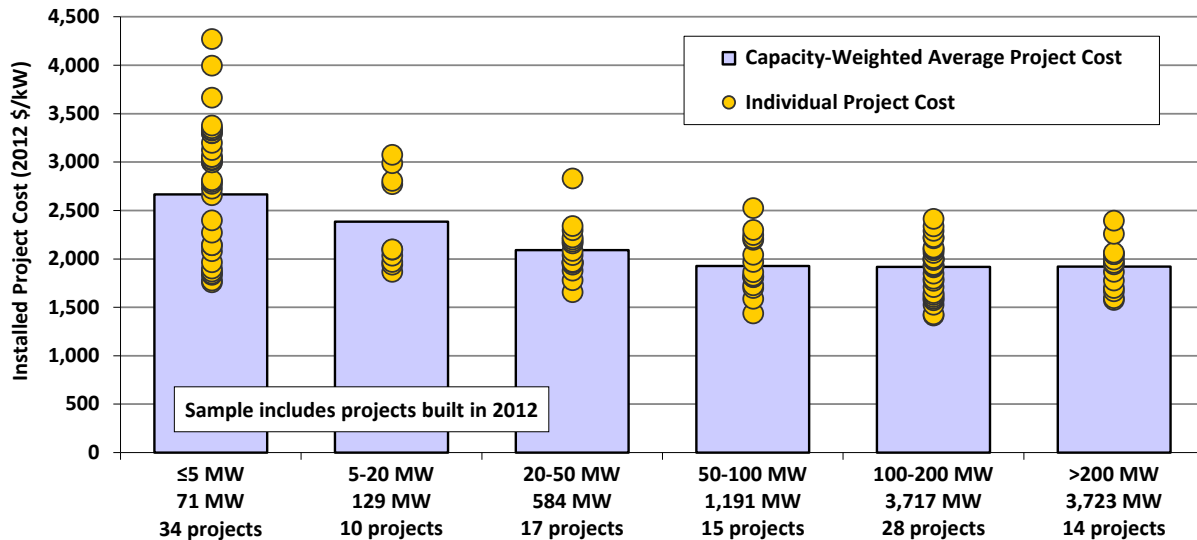
In 2012, the capacity-weighted average installed project cost stood at roughly \$1,940/kW, down almost \$200/kW from the reported average cost in 2011 and down almost \$300/kW from the apparent peak in average reported costs in 2009 and 2010. Anecdotal indications from a handful of projects currently under construction and anticipating completion in 2013 suggest that average installed costs may decline further in 2013.⁴³

⁴² On the other hand, since 2009, Figure 20 partly reflects installed cost estimates derived from publicly available data from the Section 1603 cash grant program. In some cases (although exactly which are unknown), the Section 1603 grant data likely reflect the fair market value rather than the installed cost of wind power projects; in such cases, the installed cost estimates shown in Figure 20 will be artificially inflated.

⁴³ Learning curves have been used extensively to understand past cost trends and to forecast future cost reductions for a variety of energy technologies, including wind energy. Learning curves start with the premise that increases in

Installed Costs Differed By Project Size, Turbine Size, and Region

Average installed wind power project costs exhibit economies of scale, especially at the lower end of the project size range. Figure 21 shows that—among the sample of projects installed in 2012—there is a steady drop in per-kW average installed costs when moving from projects of 5 MW or less to projects in the 50–100 MW range. As project size increases beyond 100 MW, economies of scale appear to be less prevalent.



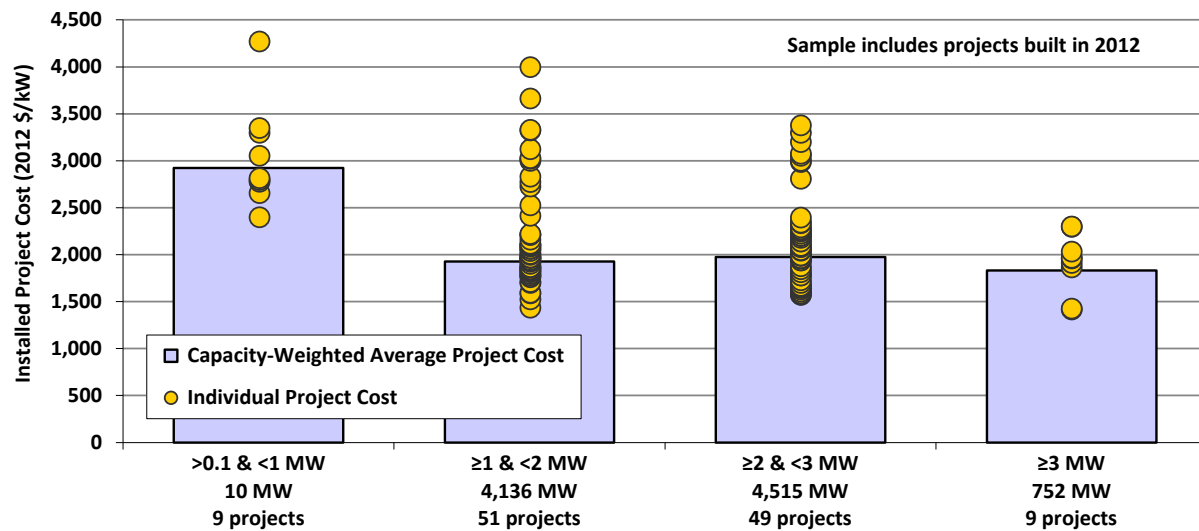
Source: Berkeley Lab

Figure 21. Installed Wind Power Project Costs by Project Size: 2012 Projects

Another way to look for economies of scale is by turbine size (rather than by project size), on the theory that a given amount of wind power capacity may be built less expensively using fewer, larger turbines as opposed to more, smaller turbines. Figure 22 explores this relationship and illustrates that here too some economies of scale are evident as turbine size increases.⁴⁴

the cumulative production or installation of a given technology lead to a reduction in its costs. The principal parameter calculated by learning curve studies is the learning rate: for every doubling of cumulative production/installation, the learning rate specifies the associated percentage reduction in costs. Based on the installed cost data presented in Figure 20 and global cumulative wind power installations, learning rates can be calculated as follows: 7.2% (using data from 1982 through 2012) or 14.1% (using data only during the period of steadily declining cost, 1982–2004).

⁴⁴ There is likely some correlation between turbine size and project size, at least at the low end of the range of each. In other words, projects of 5 MW or less are more likely than larger projects to use individual turbines of less than 1 MW. As such, Figures 21 and 22—both of which show scale economies at small project or turbine sizes, diminishing as project or turbine size increases—could both be reflecting the same influence, making it difficult to tease out the unique influences of turbine size from project size.



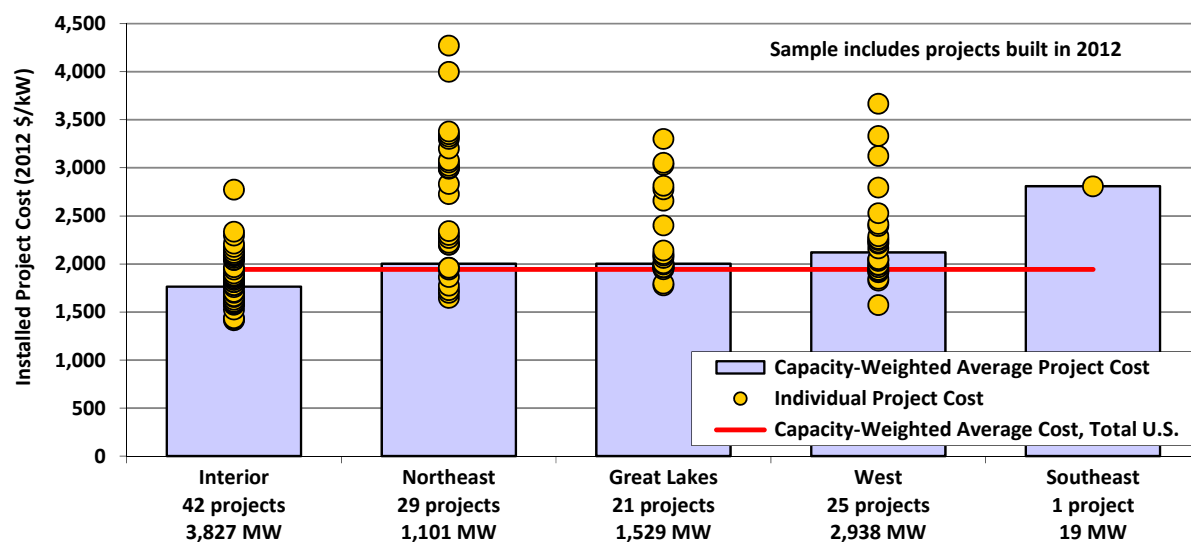
Source: Berkeley Lab

Figure 22. Installed Wind Power Project Costs by Turbine Size: 2012 Projects

Regional differences in average project costs are also apparent and may occur due to variations in development costs, transportation costs, siting and permitting requirements and timeframes, and other balance-of-plant and construction expenditures as well as variations in the turbines deployed in different regions (e.g., use of low-wind-speed technology in regions with lesser wind resources). Considering only projects in the sample that were installed in 2012, Figure 23 breaks out project costs among the five regions defined in Figure 24.⁴⁵ The Interior region—with both the largest sample and the fewest outliers—was the lowest-cost region on average, with average costs of \$1,760/kW, while the Southeast was the highest-cost region (although with a sample of just one project); the other three regions all came in relatively close to the nationwide average of roughly \$1,940/kW.⁴⁶

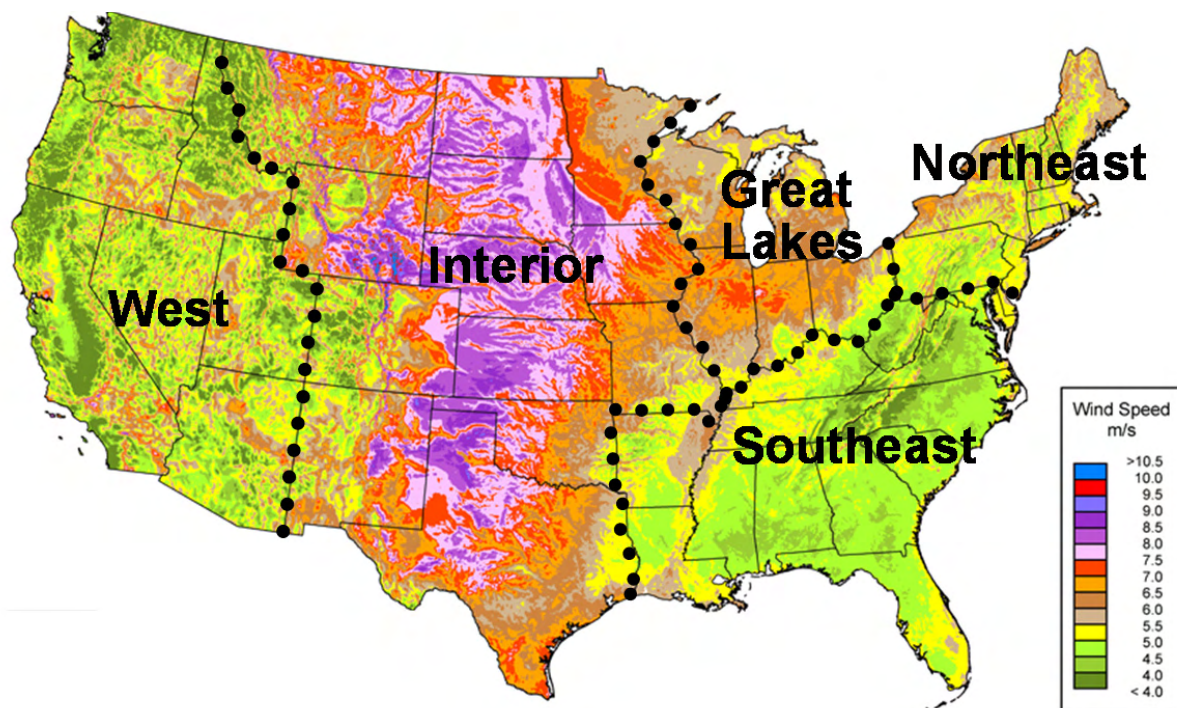
⁴⁵ The five broad regions defined in Figure 24 represent a shift from the eight smaller regions examined in previous editions of this report. This change was made in an effort to ensure sufficient sample size within individual regions and to differentiate more clearly between regions based on the relative strength of the wind resource; this clearer delineation becomes more useful in later sections of the report that are focused on capacity factor and power sales prices. For reference, the 60 GW of wind installed in the United States at the end of 2012 is apportioned among the five regions shown in Figure 24 as follows: Interior (34,695 MW), West (13,191 MW), Great Lakes (7,175 MW), Northeast (3,820 MW), and Southeast (735 MW). The remaining installed U.S. wind power capacity is located in Hawaii (206 MW), Puerto Rico (125 MW), and Alaska (59 MW) and is typically excluded from our analysis sample due to the unique issues facing wind development in these three isolated states/territories.

⁴⁶ Graphical presentation of the data in this way should be viewed with some caution, as numerous other factors also influence project costs, and those are not controlled for in Figure 23.



Source: Berkeley Lab

Figure 23. Installed Wind Power Project Costs by Region: 2012 Projects



Source: AWS Truepower, National Renewable Energy Laboratory

Figure 24. Regional Boundaries Overlaid on a Map of Average Annual Wind Speed at 80 Meters

Operations and Maintenance Cost Varied By Project Age and Commercial Operations Date

Operations and maintenance costs are a significant component of the overall cost of wind energy and can vary substantially among projects. Anecdotal evidence and recent analysis (Lantz 2013) suggest that unscheduled maintenance and premature component failure in particular continue to be key challenges for the wind power industry.

Unfortunately, publicly available market data on actual project-level O&M costs are not widely available. Even where data are available, care must be taken in extrapolating historical O&M costs given the dramatic changes in wind turbine technology that have occurred over the last two decades, not least of which has been the up-scaling of turbine size (see Figure 16). Berkeley Lab has compiled limited O&M cost data for 138 installed wind power projects in the United States, totaling 9,022 MW in capacity, with commercial operation dates of 1982 through 2011. These data cover facilities owned by both IPPs and utilities, although data since 2004 are exclusively from utility-owned projects. A full time series of O&M cost data, by year, is available for only a small number of projects; in all other cases, O&M cost data are available for just a subset of years of project operations. Although the data sources do not all clearly define what items are included in O&M costs, in most cases the reported values include the costs of wages and materials associated with operating and maintaining the facility, as well as rent.⁴⁷ Other ongoing expenses, including general and administrative expenses, taxes, property insurance, depreciation, and workers' compensation insurance, are generally not included. As such, the following figures are not representative of *total* operating expenses for wind power projects; the last few paragraphs in this section include data from other sources that demonstrate higher total operating expenses. Given the scarcity, limited content, and varying quality of the data, the results that follow may not fully depict the industry's challenges with O&M issues and expenditures; instead, these results should be taken as indicative of potential overall trends. Note finally that the available data are presented in \$/MWh terms, as if O&M represents a variable cost; in fact, O&M costs are in part variable and in part fixed. Although not presented here, expressing O&M costs in units of \$/kW-year yields qualitatively similar results to those presented in this section.

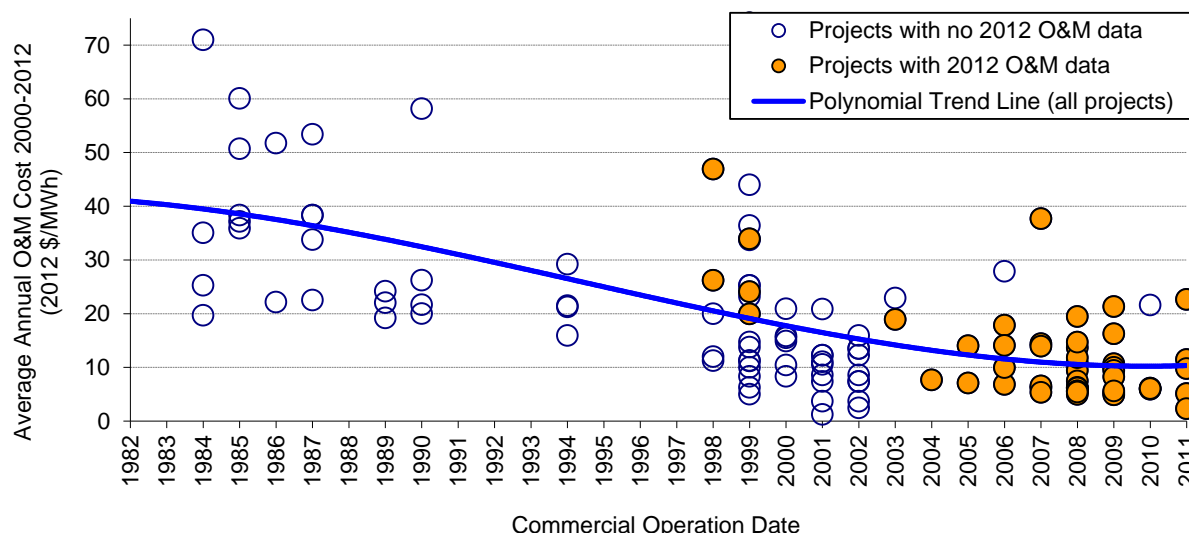
Figure 25 shows project-level O&M costs by commercial operation date.⁴⁸ Here, each project's O&M costs are depicted in terms of its average annual O&M costs from 2000 through 2012, based on however many years of data are available for that period. For example, for projects that reached commercial operation in 2011, only year 2012 data are available, and that is what is shown in the figure.⁴⁹ Many other projects only have data for a subset of years during the 2000–

⁴⁷ The vast majority of the recent data derive from FERC Form 1, which uses the Uniform System of Accounts to define what should be reported under "operating expenses" – namely, those operational costs associated with supervision and engineering, maintenance, rents, and training. Though not entirely clear, there does appear to be some leeway within the Uniform System of Accounts for project owners to capitalize certain replacement costs for turbines and turbine components and report them under "electric plant" accounts rather than maintenance accounts. If this occurs, the operating expenses reported in FERC Form 1 and presented in Figures 25 and 26 will not capture total operating costs.

⁴⁸ For projects installed in multiple phases, the commercial operation date of the largest phase is used; for re-powered projects, the date at which re-powering was completed is used.

⁴⁹ Projects installed in 2012 are not shown because only data from the first full year of project operations (and afterwards) are used, which in the case of projects installed in 2012 would be year 2013 (for which data are not yet available).

2012 timeframe, either because they were installed after 2000 or because a full time series is not available, so each data point in the chart may represent a different averaging period within the overall 2000–2012 timeframe. The chart highlights the 51 projects, totaling 5,269 MW, for which 2012 O&M cost data were available; those projects have either been updated or added to the chart since the previous edition of this report.



Source: Berkeley Lab; seven data points suppressed to protect confidentiality

Figure 25. Average O&M Costs for Available Data Years from 2000–2012, by Commercial Operation Date

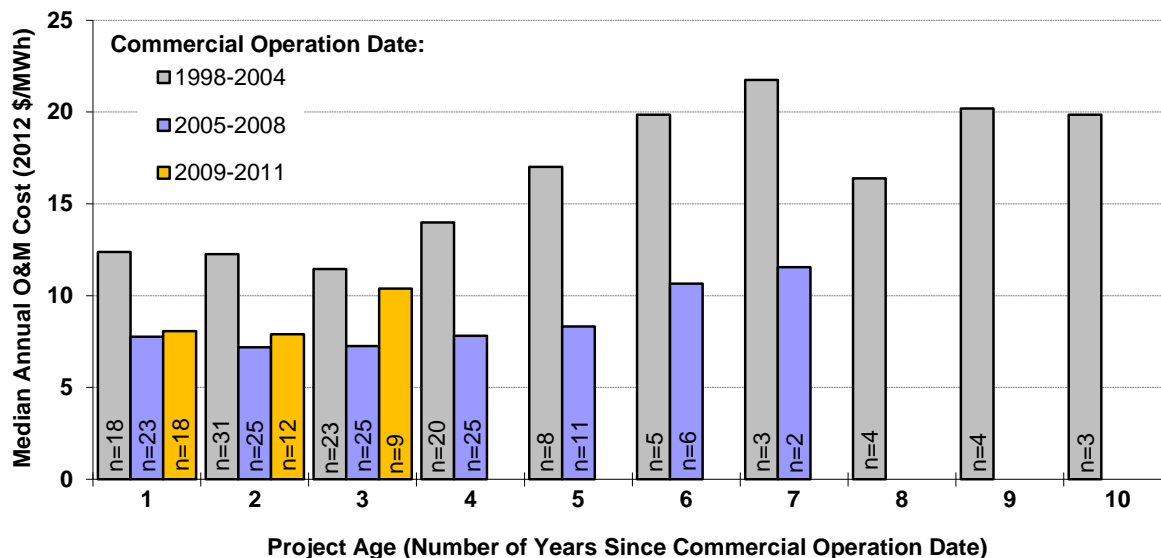
The data exhibit considerable spread, demonstrating that O&M costs (and perhaps also how O&M costs are reported by respondents) are far from uniform across projects. However, Figure 25 suggests that projects installed within the past decade have, on average, incurred lower O&M costs than those installed earlier. Specifically, capacity-weighted average 2000–2012 O&M costs for the 24 projects in the sample constructed in the 1980s equal \$34/MWh, dropping to \$23/MWh for the 37 projects installed in the 1990s, and to \$10/MWh for the 74 projects installed since 2000.⁵⁰ This drop in O&M costs may be due to a combination of at least two factors: (1) O&M costs generally increase as turbines age, component failures become more common, and manufacturer warranties expire;⁵¹ and (2) projects installed more recently, with larger turbines and more sophisticated designs, may experience lower overall O&M costs on a per-MWh basis.

⁵⁰ If expressed instead in terms of \$/kW-year, capacity-weighted average 2000–2012 O&M costs were \$66/kW-year for projects in the sample constructed in the 1980s, dropping to \$55/kW-year for projects constructed in the 1990s, to \$28/kW-year for projects constructed in the 2000s, and to \$25/kW-year for projects constructed since 2010. Somewhat consistent with these observed O&M costs, Bloomberg NEF (2013d) reports the cost of 5-year full-service O&M contracts as having declined from \$43/kW-year in the 2007–2009 period to less than \$25/kW-year in early 2013. An NREL analysis based on data from DNV KEMA and GL Garrad Hassan covering roughly 10 GW of operating wind projects also shows average levels of expenditure consistent with the Berkeley Lab dataset, at least when focusing on turbine and balance-of-plant O&M costs for projects commissioned in the 2000s (Lantz 2013).

⁵¹ Many of the projects installed more recently may still be within their turbine manufacturer warranty period, and/or may have capitalized O&M service contracts within their turbine supply agreement. Projects choosing the Section 1603 cash grant over the PTC may have had a particular incentive to capitalize service contracts (18 projects totaling roughly one-third of the sample capacity installed since 2000 were installed from 2009–2011 – i.e., within the period

Although limitations in the underlying data do not permit the influence of these two factors to be unambiguously distinguished, to help illustrate key trends, Figure 26 shows median annual O&M costs over time, based on project age (i.e., the number of years since the commercial operation date) and segmented into three project-vintage groupings. Data for projects under 5 MW in size are excluded, to help control for the confounding influence of economies of scale. Note that, at each project age increment and for each of the three project vintage groups, the number of projects used to compute median annual O&M costs is limited and varies substantially (from 3 to 31 data points per project-year for projects installed from 1998 through 2004, from 2 to 25 data points per project-year for projects installed from 2005 through 2008, and from 9 to 18 data points per project-year for projects installed from 2009 through 2011).

With these limitations in mind, Figure 26 shows an upward trend in project-level O&M costs as projects age, although the sample size after year 4 is limited. In addition, the figure shows that projects installed more recently (from 2005–2008 and/or 2009–2011) have had, in general, lower O&M costs than those installed in earlier years (from 1998–2004), at least for the first 7 years of operation. Parsing the “recent project” cohort into two sub-periods, however, reveals that projects installed from 2009–2011 had higher median O&M costs than those installed from 2005–2008 (though cost differences are small, particularly in the first two years operations, and sample size is limited). This last finding is consistent with a recent National Renewable Energy Laboratory (NREL) analysis based on data from GL Garrad Hassan covering the first two years of operations for more than 3 GW of operating wind capacity (Lantz 2013); that analysis also suggests that turbine O&M costs may have actually increased among projects installed after 2008. In contrast, the Bloomberg NEF (2013d) data mentioned in footnote 50 portrays *lower* O&M costs since the 2007–2009 period.



Source: Berkeley Lab; medians shown only for groups of two or more projects, and only projects >5 MW are included

Figure 26. Median Annual O&M Costs by Project Age and Commercial Operation Date

of eligibility for the Section 1603 grant – though only two of these eighteen projects actually elected the grant over the PTC). In either case, reported O&M costs will be artificially low.

As indicated previously, the data presented in Figures 25 and 26 include only a subset of total operating expenses. In comparison, the financial statements of public companies with sizable U.S. wind project assets indicate markedly higher total operating costs. Specifically, two companies—Infigen and EDP Renováveis (EDPR), which together represented approximately 4,730 MW of installed capacity at the end of 2012 (nearly all of which has been installed since 2000)—report total operating expenses of \$23.2/MWh and \$23.9/MWh, respectively, for their U.S. wind project portfolios in 2012 (EDPR 2013, 2012; Infigen 2013, 2012, 2011).⁵² These total operating expenses are more than twice the \$10/MWh average O&M cost reported above for the 74 projects in the Berkeley Lab data sample installed since 2000.

This disparity in operating costs between these two project owners and the Berkeley Lab data sample reflects, in large part, differences in the scope of expenses reported. For example, Infigen breaks out its total U.S. operating expense in 2012 (\$23.2/MWh) into four categories: asset management and administration (\$4.0/MWh), turbine O&M (\$10.6/MWh), balance of plant (\$2.4/MWh), and other direct costs (\$6.1/MWh). Among these four categories, the combination of turbine O&M and balance of plant (\$13/MWh in total) is likely most comparable to the scope of data reported in the Berkeley Lab sample. Similarly, EDPR breaks out its total U.S. operating costs in 2012 (\$23.9/MWh) into three categories: supplies and services, which “includes O&M costs” (\$15.1/MWh); personnel costs (\$3.8/MWh); and other operating costs, which “mainly includes operating taxes, leases, and rents” (\$5.1/MWh). Among these three categories, the \$15.1/MWh for supplies and services is probably closest in scope to the Berkeley Lab data. Confirming these basic findings, the recent NREL analysis based on data from DNV KEMA on plants commissioned before 2009 shows *total* operating expenditures of \$40–\$60/kW-year depending on project age, with turbine and balance-of-plant O&M costs representing roughly half of those expenditures (Lantz 2013).

Finally, Infigen—whose 1,089-MW U.S. wind portfolio has remained unchanged since 2009—reports a significant escalation in total average operating costs over the past 3 years: an 11% increase from \$19.7/MWh in 2010 to \$21.9/MWh in 2011, followed by another 6% increase to \$23.2/MWh in 2012 (all expressed in 2012 dollars). Meanwhile, EDPR’s U.S. operating costs escalated 8% from \$22.8/MWh in 2010 to \$24.6/MWh in 2011, before falling 3% to \$23.9/MWh in 2012 (again, all in 2012 dollars). The fact that EDPR has been adding new projects to its U.S. portfolio over this period (e.g., roughly 200 MW added in both 2011 and 2012) complicates analysis of changes to its operating costs based on project age. Nonetheless, the overall trend apparent in the Infigen data is directionally consistent with the previously reported Berkeley Lab sample and with the NREL analysis, both of which show increased O&M costs as projects age.

⁵² Infigen’s operating expenses could be considered to be higher than indicated, given that reported costs do not include certain capital expenditures related to the replacement of turbines and/or turbine components among its portfolio of U.S. wind projects.

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the Application of Consumers Energy Company for Approval of a Certificate of Necessity for the Thetford Generating Plant pursuant to MCL 4.60.6s and for related accounting and ratemaking authorizations.

Case N^o: U-17429

ALJ Sharon L. Feldman

ELECTRONIC SERVICE LIST

On the date below, an electronic copy of **Direct Testimony of Jonathan Wallach on Behalf of the Natural Resources Defense** and **Exhibits NRD-3 through NRD-11** was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

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