ENVIRONMENTAL LAW & POLICY CENTER
Protecting the Midwest's Environment and Natural Heritage

August 21, 2019

Ms. Kavita Kale
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P.O. Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-20471

Dear Ms. Kale:

The following is attached for paperless electronic filing:

Direct Testimony of James Gignac, Eric Woychick, Kevin Lucas, Joseph Daniel, and Will Kenworthy on behalf of the Environmental Law & Policy Center, the Ecology Center, the Solar Energy Industries Association, the Union of Concerned Scientists, and Vote Solar, and Direct Testimony of Anna Sommer on behalf of the Environmental Law & Policy Center, the Ecology Center, the Solar Energy Industries Association, the Union of Concerned Scientists, and Vote Solar and the Michigan Energy Innovation Business Council

Exhibits ELP-1 through ELP-76

Proof of Service

Sincerely,

Margrethe K. Kearney

Margrethe Kearney
Environmental Law & Policy Center
mkearney@elpc.org

cc: Service List, Case No. U-20471

1514 Wealthy Street SE, Suite 256 • Grand Rapids, MI 49506
(773) 726-8701 • www.ELPC.org
David C. Wilhelm, Chairperson • Howard A. Learner, Executive Director
Chicago, IL • Columbus, OH • Des Moines, IA • Duluth, MN • Grand Rapids, MI
Jamestown, ND • Madison, WI • Sioux Falls, SD • Washington, D.C.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
DTE ELECTRIC COMPANY	)	Case No. U-20471
for approval of its integrated resource plan	)	
pursuant to MCL 460.6t, and for other relief	)	

DIRECT TESTIMONY OF

JAMES P. GIGNAC

ON BEHALF OF

THE ENVIRONMENTAL LAW & POLICY CENTER,
THE ECOLOGY CENTER,
THE SOLAR ENERGY INDUSTRIES ASSOCIATION,
THE UNION OF CONCERNED SCIENTISTS,
AND
VOTE SOLAR

AUGUST 21, 2019

I. STATEMENT OF QUALIFICATIONS

Q: Please state your name and business address.

A: My name is James P. Gignac. My business address is 1 N. LaSalle St., Suite 1904, Chicago, Illinois, 60602.

Q: By whom are you employed and in what capacity?

A: I am employed by the Union of Concerned Scientists ("UCS") as Lead Midwest Energy Analyst. In this role, I conduct research and analysis to advance understanding of renewable and other energy technologies, policies, and markets, and to evaluate energy resource and climate change mitigation options in the electricity sector.

Q: Please describe the Union of Concerned Scientists.

A: The Union of Concerned Scientists was founded in 1969 by scientists and students at the Massachusetts Institute of Technology. UCS employs scientists, analysts, and engineers to develop and implement innovative, practical solutions to some of the most pressing problems that society faces today—from developing sustainable ways of feeding, powering, and transporting humanity to reducing the threat of nuclear war. UCS's mission is to put rigorous, independent science to work by combining technical analysis and effective advocacy to create policy solutions for a healthy, safe, and sustainable future.[1]

Q: Please describe your personal and educational background and professional affiliations.

A: I was born in Rochester Hills, Michigan, and graduated from Romeo Senior High School in Romeo, Michigan. I received a B.A. in History and Political Science from Albion

[1] For more information, including UCS's history and mission statement, visit: https://www.ucsusa.org/about-us.

College located in Albion, Michigan. I earned a Juris Doctorate from Harvard Law School located in Cambridge, Massachusetts. I have been licensed to practice law by the Supreme Court of the State of Illinois since 2005.

Q: Please describe your professional background.

A: I am an analyst and attorney with over fourteen years of experience in the environmental and energy fields. I support UCS's efforts to promote the understanding and adoption of clean energy alternatives in the Midwest and nationally. I joined UCS after serving as Environmental and Energy Counsel and an Assistant Attorney General to the Office of Illinois Attorney General Lisa Madigan. In this capacity I was responsible for representing the office and the state in environmental, energy, and utility regulatory matters—including rulemakings and enforcement cases. I began my career as an environmental attorney representing private sector clients and subsequently worked for a national environmental organization, assisting efforts related to coal-fired power plants in Midwest states including Michigan. My resume is included as Exhibit JPG-1 (ELP-1).

Q: Have you previously testified before this Commission as an expert?

A: Yes. I provided direct written testimony in Case No. U-20165, *In the matter of the application of Consumers Energy Company for approval of its integrated resource plan pursuant to MCL 460.6t and for related accounting and ratemaking relief*.

Q: Have you provided testimony or comment in other proceedings or venues?

A: With the Union of Concerned Scientists and the Illinois Attorney General's Office, I submitted pre-filed testimony to the Illinois Pollution Control Board and appeared for cross-examination as a testifying witness in a rulemaking proceeding involving state air pollution standards for coal-fired power plants. *In the Matter of: Amendments to 35 Ill.*

Adm. Code 225.233 Multi-Pollutant Standards (MPS), R18-20. With the Illinois Attorney General's Office, I prepared comments on and presentations to the Illinois Commerce Commission regarding renewable energy matters such as net metering and grid integration of wind and solar power; I assisted with petitions and comments to the Federal Energy Regulatory Commission ("FERC") regarding capacity markets and grid resiliency matters; I prepared comments to the Illinois Department of Natural Resources' rulemaking on high-volume hydraulic fracturing; and I appeared as a witness in state legislative hearings with respect to 2016 legislation on the Illinois Renewable Portfolio Standard.

Q: Are you sponsoring any exhibits?

A: Yes, I am sponsoring the following exhibits:

- Exhibit ELP-1: Resume of James P. Gignac

II. PURPOSE OF TESTIMONY

Q: On whose behalf are you appearing in this case?

A: I am testifying on behalf of the Environmental Law & Policy Center, the Ecology Center, the Union of Concerned Scientists, the Solar Energy Industries Association, and Vote Solar ("the coalition").

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to: (1) Introduce the witnesses testifying on behalf of our coalition and the subject matter of their testimony; (2) Summarize our coalition's evaluation of DTE Electric Company's ("DTE" or "the Company") integrated resource plan filing; (3) Set forth our coalition's position that the Commission should deny the IRP and direct DTE to revise its analysis in accordance with the recommendations detailed in our coalition's testimony.

Q: Who is presenting testimony in this case for the coalition?

A: In addition to myself, the following individuals are providing direct testimony on behalf of the coalition:

- Dr. Eric Woychik is an executive consultant with Strategy Integration, LLC. His testimony critiques DTE's "starting point" approach especially as it relates to omitted costs of the Belle River and Monroe coal-fired units. Dr. Woychik also examines other issues including declining costs of clean energy resources, growth in electric vehicles, and ramping needs.
- Kevin Lucas is the Director of Rate Design for the Solar Energy Industries Association. Mr. Lucas explores in detail how numerous aspects of DTE's IRP affect its proposed course of action resulting in underutilization of solar resources in the near-term and increased costs in the long-term. He also highlights how DTE is foregoing an opportunity to modernize its peaking resources with clean solar plus storage resources.
- Joseph Daniel is a Senior Energy Analyst with the Union of Concerned Scientists. His testimony focuses on the modeling of existing resources, the treatment of energy efficiency or energy waste reduction (EWR), and topics related to energy affordability and the health impacts of coal-fired power plants.
- Will Kenworthy is Regulatory Director, Midwest for Vote Solar. His testimony provides an analysis of the voluntary green pricing programs within the IRP; specifically, he reviews the existing programs and the extent to which they are

relied upon to achieve the plan's goals. Mr. Kenworthy makes recommendations with respect to DTE's reliance on voluntary programs to achieve required objectives.

- Anna Sommer is a Principal with Energy Futures Group. She discusses Strategist modeling she performed for this case, explains key aspects of Strategist's capabilities, and opines on options for DTE's future modeling efforts.

III. OVERVIEW OF COALITION TESTIMONY

Q: How does DTE summarize its proposed course of action (PCA)?

A: DTE Witness Pfeuffer states that "[t]he Company's PCA includes a focus on more clean energy, and less coal." SGP-13. She goes on to state that the PCA supports DTE's "commitment to 50 percent clean energy by 2030 and to reduce carbon emissions by more than 80 percent by 2040." *Id*. Ending coal use, increasing clean energy technologies, and reducing carbon emissions are laudable goals that our organizations support. However, as explained in greater detail below, the way in which DTE structured and conducted its IRP is so fundamentally flawed that the Commission must reject the filing and direct the Company to amend its analysis. As our witnesses explain, doing so will ensure that coal plants are not being operated longer than they should and that investments in clean energy options are being pursued sooner and at the lowest cost.

Q: What are the general themes of the coalition's testimony presented today?

A: A significant portion of our testimony focuses on DTE's formulation of its starting point and the numerous problems that flow from that flawed foundation. For example, the Belle River and Monroe coal plants were assumed to operate until 2030 and 2040, respectively, without a full consideration of their complete costs. In several ways, the

IRP modeling was effectively prevented from choosing other more cost-effective resources. At the same time, our witnesses show how DTE consistently over-estimated the costs of solar while under-valuing and under-utilizing energy efficiency. Furthermore, DTE overly relies on voluntary renewable programs and foregoes the opportunity to explore modernization of its peaker plants with cleaner resources. Finally, another key theme in our testimony is DTE's failure to acknowledge and respond to the inherent limitations of the Strategist model. Our witnesses conclude that the Commission should reject DTE's IRP and direct the Company to revise its analysis in accordance with several recommendations summarized below. Doing so will help ensure coal plants are not operating longer than they should and that clean energy resources are not being postponed to the detriment of ratepayers and future grid needs.

Q: How did DTE structure its IRP?

A: As stated by DTE Witness Pfeuffer, "[t]he Company started with what is referred to as the starting point" and "used it as a basis for each of [its] four [modeling] scenarios." SGP-26. Witness Woychik explains that DTE did not base its "starting point" on least cost; instead it plugged in its current plans and state of affairs, including its planned retirement dates for existing units, its plans for new units, its renewable and energy waste reduction plans, and planned changes to its demand response program. For example, with respect to coal units, DTE Witness Mikulan sets forth the starting point retirement schedule, with the Belle River plant assumed to operate until 2029-2030 and the Monroe plant assumed to operate until 2040. LKM-37.

Q: What did this structural approach lead to?

A: Witness Lucas points out that this approach resulted in DTE fixing—or "hardcoding"—most of these resource parameters into its modeling. This led to a forecast of no "persistent capacity need" until 2030, when DTE plans to retire the Belle River coal units. Witness Woychik explains that, due to no capacity need being shown until Belle River's retirement, DTE's plan assumes that any further capacity value is zero, which severely limits the use of resources—including competitively solicited resources—that may otherwise be considered economic.[2] In other words, the model is prevented from selecting more cost-effective measures or courses of action to later replace starting point resources like the Belle River and Monroe coal plants. Similarly, as discussed by Witness Daniel, DTE forced its modeling to over-rely on existing, company-owned resources, which produced sub-optimal results and portfolios with inflated present value of revenue requirement.

Witness Lucas goes on to explain how DTE configured Strategist to only add new resources when there is a capacity need and that this narrow approach prevents the model from adding "superfluous" resources that might reduce the net present value revenue requirement (NPVRR). Witness Lucas concludes that DTE's hardcoding of resources did not result in a true resource optimization because the path was predetermined.

Q: What else did DTE's "starting point" approach do?

A: Witness Woychik explains that DTE side-steps the economics of the resources put into the starting point, leaving out numerous costs. For instance, with respect to the Belle

---

[2] Witness Sommer provides additional discussion of how DTE's starting point resources distort its modeling results since there can be no avoided capacity cost derived from Strategist when DTE's near-term supply plan meets all the Company's forecasted capacity needs until the retirement of Belle River.

River and Monroe coal units, all costs should have been included, such as environmental retrofits, fuel price risk, and coal ash management costs. Witness Woychik explains that the Monroe and Belle River plants should be evaluated more completely, including all costs and expected upgrades, across the full 20-year period; otherwise, the IRP is inconsistent with least-cost planning and forecloses assessment of new resources that may be viable, lower-cost options. Witness Woychik also points out that DTE's approach includes false definitions of dispatch order and run-times of selected starting point resources; essentially assuming units will run all the time thereby distorting the subsequent calculations that form the basis of other new resource selections going forward.

Q: Please summarize Witness Daniel's discussion of the must-run designation.

A: Witness Daniel explains that DTE overused a setting in Strategist referred to as the "must-run" designation in its modeling. This designation forces the model to accept a certain amount of energy and capacity from existing company-owned resources regardless of economics. In other words, the model is forced to serve load with the existing resources even when it is uneconomic to do so, and the must-run designation prevents the model from turning off higher-cost units.

Witness Daniel explains the practice of self-committing—another market term related to designating a unit must-run—and discusses several analyses calling into question the economic rationale of coal plant operators running their plants at above-market costs. Witness Daniel provides examples of operators finding they can produce significant savings from running coal plants only part of the year. He concludes that DTE should have removed the must-run designation for its non-nuclear thermal units, which would have allowed the Company to evaluate the economic competitiveness of those resources as compared to market purchases or replacement.

Indeed, Witness Daniel discusses a model run conducted by Witness Sommer in which she was asked to remove the must-run designation from all DTE-owned power plants except the Fermi nuclear plant. The modeling results demonstrate that removing the must-run constraint reduces the amount of generation at several of DTE's units and allows the model to produce more economically efficient results.

Q: How were the costs of renewables treated in DTE's starting point approach?

A: Witness Lucas explains that DTE left out all the costs associated with its renewable buildout, instead basing its starting point renewables build on outdated cost estimates—not on any modeling runs—and did not conduct any analysis on the relative benefits of wind and solar. Witness Lucas asserts that DTE should have examined portfolios of earlier, increased wind and solar resources in its model, as well as explore how those additions can advance the retirement of the Belle River units.

Witness Kenworthy similarly observes that DTE's starting point included no analysis of the financial or economic value of accelerating or expanding the scope of the renewable energy buildout and that DTE's plans did not rely on modeling conducted in the IRP to select the renewables resources proposed in the PCA.

Q: What other issues do the coalition's witnesses discuss?

A: In addition to the issues identified above, our testimony examines the following deficiencies of DTE's IRP:

<u>Costs of Solar</u>:

Witness Lucas provides extensive testimony demonstrating how DTE consistently overestimates the cost of solar energy in its modeling. He points out that DTE arbitrarily selected solar input values from multiple data sources, impacting the three major inputs for solar: capital costs, operation and maintenance (O&M) costs, and capacity factors. When paired with a questionable inflation adjustment, Witness Lucas concludes that DTE's flawed methodology results in overstating the levelized cost of energy (LCOE) of solar by 39% (*i.e.*, instead of $69.48/MWh, solar should have been modeled at $50.09/MWh). Further, DTE failed to model single-axis tracking systems despite its claim to have done so, instead simulating less effective fixed-tilt systems with lower DC/AC ratios. For all these reasons, Witness Lucas finds that the modeled scenarios were likely biased against solar deployment, particularly in the early years of the PCA, resulting in low near-term deployment. Witness Lucas describes the results of an alternative modeling run addressing basic solar assumption flaws which shows that building substantially more solar in the near-term would be optimal.

<u>Energy Waste Reduction (EWR)</u>:

Witness Daniel examines how DTE's IRP analysis undervalues the benefits of EWR. It excludes or underestimates the benefits EWR has in avoiding transmission and distribution (T&D) capital costs; energy and demand line losses; energy costs; and capacity costs. By underestimating these benefits, EWR looks less cost-effective, skewing DTE's analysis against EWR. As noted by DTE Witness Bilyeu, EWR has benefit-cost rations above 1.0 at all levels of EWR, even up to the 2.5% level which produces $1.37 of benefits for every $1 of costs. KLB-22.

Peaking Resources:

Witness Lucas examines how DTE lack of analysis with respect to its peaking fleet constitutes a major omission from the IRP. He points out that DTE assumed its peaker plants—despite many of them being very old and suffering from high outage rates—would continue to operate for another 20 years with no analysis of their fixed or variable costs. Witness Lucas explains "that solar and solar plus storage installations are operationally and technically able to provide peaking service and that the Company should seriously consider replacing some of the most outdated peakers with new, zero-carbon resources."

Ramping Resources:

Witness Woychik explains that greater amounts of distributed energy resources (DERs), such as demand response and battery storage, would likely be economic absent the Belle River and Monroe coal units. The result of DTE's IRP is to postpone the introduction of these more flexible resources which are needed to further integrate wind and solar energy. Witness Woychik concludes that the delay of these flexible resource additions likely increases costs by limiting the use of these ramping resources at the MISO level.

Competitive Procurement:

Witness Lucas examines how DTE's choice to own all renewable assets will inflate costs for customers. He urges the Commission to consider requiring DTE to competitively procure third-party power purchase agreements (PPAs) to meet a sizable fraction of its future capacity requirements and require DTE to sign PPAs for all Voluntary Green Pricing (VGP) program capacity.

Witness Kenworthy similarly points out that DTE only modeled utility-owned VGP programs and ignores the opportunity for customers to benefit from customer-sited distributed generation and the benefits of competitive markets for meeting customer demand for clean energy.

<u>Reliance on Voluntary Renewable Programs</u>:

Witness Kenworthy discusses concerns over DTE's proposed reliance on Voluntary Green Pricing (VGP) programs. Beyond the starting point amounts and renewable resources needed to meet the company's carbon commitments, the PCA relies upon customers selecting premium priced VGP programs for additional renewable resources rather than evaluating replacement of existing resources with renewables for economic reasons. Witness Kenworthy describes how the programs need to be improved in ways that provide greater transparency and a fuller value of the energy and capacity value of the renewable facilities that are developed for the programs. Witness Kenworthy also provides several observations on general principles for evaluating utility distributed generation programs like VGP and describes how VGP can be used to ensure access to benefits of clean energy by low-income households and communities.

<u>All-Source Request For Proposals (RFP)</u>:

Witness Kenworthy explains DTE should have conducted an all-source RFP prior to conducting the modeling that lead to this development of its plan.

<u>Electric Vehicles</u>:

Witness Woychik discusses how DTE generally understates growth in electric vehicles and ways in which its forecast should be updated.

<u>Limitations of Strategist</u>:

Witness Woychik asserts that while DTE uses Strategist to model its resource plan, DTE does not explain that the model is unable to account for the timing of resource retirements; the need for ramping resources; the rapid declines in the costs of certain resources such as storage batteries, solar photovoltaic generation, and wind power; or uncertainties in weather, loads, and prices/costs. Witness Woychik notes that Strategist cannot harness the necessary inputs to calculate outputs of key interest, including the timing, ramping, and declining costs of competing resources, and thus the comparative economics of resource options. Witness Sommer's testimony further describes the general limitations of Strategist and how modelers can seek to address them, which DTE did not pursue fully.

Finally, Witness Lucas concludes that Strategist is not able to "provide a robust optimization of DTE's system that is reflective of modern technologies such as energy storage, that properly accounts for non-linear cost changes that solar is experiencing, and that dynamically solves for the best time to retire DTE's coal assets to the favor of its customers."

<u>Energy affordability</u>:

Witness Daniel introduces the concept of energy affordability and highlights that Department of Energy (DOE) data indicates that the average family living below the federal poverty line in Michigan spends 17% of their annual income on electricity. Meanwhile, Michiganders above the federal poverty line spend just 3% of annual income on electricity. Witness Daniel explains that a greater prioritization of Energy Waste Reduction (EWR), especially programs that focus on low- to moderate-income households, is a key component to making electricity affordable. Witness Daniel also discusses how pollution from coal-fired power plants is linked to increased energy-related costs. By alleviating the health burden that DTE's coal plants impose on the local community, the Commission could indirectly make energy more affordable in Michigan.

IV. CONCLUSION AND RECOMMENDATIONS

Q: What should the Commission do in this case?

A: Based on the testimony summarized above, the Commission should reject the IRP pursuant to MCL 460.6t(8), which provides that the Commission shall not approve an IRP unless it "represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs." Additional and more specific recommendations from individual witnesses are set forth below.

Witness Woychik:

DTE's proposed IRP fails to define a reasonable and prudent process to provide energy and capacity. The Commission should direct DTE to: (1) Fully consider the economics of the Belle River and Monroe coal units and not bundle the plants into its starting point scenario and not ignore their fixed operations and maintenance (O&M) costs; (2) Include the $500 million in coal plant environmental mitigation costs in this IRP analysis instead of leaving them to future proceedings; (3) Achieve the balance of factors outlined under Michigan's IRP statute; (4) Update its electric vehicle growth forecast; (5) Properly recognize the rapidly declining costs of battery storage, solar photovoltaics, wind, and integrated behind-the-meter resources; (6) Better balance its scenario analysis to avoid biases toward selecting either the Belle River coal units or Gas CCGT; (7) Acknowledge the need for ramping and properly recognize the pervasive cost declines in competing clean energy resources.

Witness Lucas:

DTE has failed to justify its proposed course of action (PCA) through a robust, unbiased analysis. The Commission should reject the IRP and direct DTE to refile its IRP using a modern tool that can simulate how the grid functions with today's (and tomorrow's) technology without the structural limitations of Strategist. The Commission should require DTE to support its proposals based on optimized modeled results and not simply allow DTE to hardcode its preferred plan and solve for replacement capacity in one year out of twenty. The Commission should further require DTE to revisit its solar cost assumptions, properly model single-axis tracker systems, include a robust analysis of the viability of its aging peaker fleet, and develop a PCA that is informed by the modeling from DTE's IRP filing. The Commission should also require strong competition in resource acquisition for the benefit of DTE's customers that includes limitations on the share of new renewable assets that DTE can own. This percentage can vary based on the ultimate purpose of the renewable asset, with the Commission balancing incentives to DTE for pursuing laudable public policy goals such as reducing CO2 emissions while acting strongly to prevent customers from overpaying for renewable energy or facing too much risk while acting as the cost recovery backstop for those same assets.

Witness Daniel:

The Commission should reject DTE's IRP and direct the company to reconduct its modeling process and to use the results to inform the creation of its proposed course of action (PCA). In addition to the modeling recommendations made by other witnesses, Witness Daniel recommends that the Commission should direct DTE to modify its modeling approach to: (1) Remove must-run constraints from all thermal plants except Fermi; (2) Include Energy Waste Reduction (EWR) levels equivalent to 2.5% or greater in all modeling runs; (3) Adjust load reductions from EWR using a 10.2% line loss factor; and (4) Include avoided Transmission & Distribution (T&D) values for EWR no less than $7/kW in all runs and consider the use of a $100/kW avoidable T&D value as a proxy for a more reasonable value.

<u>Witness Kenworthy</u>:

DTE's proposed course of action (PCA) suffers from numerous deficiencies with regards to its consideration of the renewable resources in the Voluntary Green Pricing (VGP) programs. The Commission should require the Company to address the following issues: (1) During the biennial review of DTE's VGP programs required in April 2020, the programs should be updated to properly reflect fair compensation to participating customers; (2) The renewable resources included in DTE's starting point for its IRP should be informed by the results of the IRP modeling to determine the most effective mix of renewables to meet DTE's future Renewable Portfolio Standard (RPS), VGP, and carbon reduction requirements and commitments; (3) DTE should be required to conduct rigorous potential adoption evaluations of all segments of the VGP programs prior to including voluntary programs in its PCA; (4) DTE should be required to evaluate the opportunity to increase adoption of behind-the-meter distributed energy resources to cost-effectively reduce load; (5) DTE should be required to consider opportunities for third-party owned resources to fulfill all renewable energy requirements, including VGP programs; (6) DTE should consider the use of VGP programs to ensure access to clean energy for low-income households and communities; and (7) DTE should be required to conduct an all-source request for proposals prior to developing a revised PCA that reflects the opportunity for renewable resources to replace existing resources in its generation portfolio.

<u>Witness Sommer</u>:

Looking ahead to future planning dockets, there is an opportunity to move from the Strategist model to one with greater resource optimization and dispatch capabilities. However, accessibility and transparency are essential in any new model, including the: (1) Ability to provide the entirety of the modeling database in a format that is readable without a model license; (2) Existence of a well-documented manual, available to non-licensees, that details the logic of the model, the definitions of the inputs and outputs, and provides guidance on its use; and (3) Ability to license the model at a reasonable cost if a license is not otherwise provided by the utility.

Q. Does this conclude your testimony?

A. Yes.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
DTE ELECTRIC COMPANY	)	Case No. U-20471
for approval of its integrated resource plan	)	
pursuant to MCL 460.6t, and for other relief	)	

EXHIBIT OF

JAMES P. GIGNAC

ON BEHALF OF

THE ENVIRONMENTAL LAW & POLICY CENTER,
THE ECOLOGY CENTER,
THE SOLAR ENERGY INDUSTRIES ASSOCIATION,
THE UNION OF CONCERNED SCIENTISTS,
AND
VOTE SOLAR

AUGUST 21, 2019

JAMES P. GIGNAC

1 N. LaSalle St. #1904 | Chicago, Illinois 60602 | (773) 941-7916 | jgignac@ucsusa.org
https://www.ucsusa.org/bio/james-gignac | www.linkedin.com/in/jgignac

EXPERIENCE

Lead Midwest Energy Analyst, Union of Concerned Scientists, Chicago, IL

(March 2018-Present). Conduct research and analysis to advance understanding of renewable and other energy technologies, policies, and markets, and to evaluate energy resource and climate change mitigation options in the electricity sector. Write and edit technical reports, fact sheets, and other materials to document and communicate research results; prepare regulatory and legislative comments and testimony; develop policy and legislative proposals; meet with policymakers, regulators, and stakeholders; represent UCS and its positions at public forums.

Environmental and Energy Counsel and Assistant Attorney General to the Office of Illinois Attorney General Lisa Madigan, Chicago, IL

(Nov. 2011-March 2018). Summary: Served as assistant attorney general in advanced special counsel role; handled select regulatory, legislative, and litigation matters with an emphasis on renewable energy, coal, nuclear, efficiency, and climate change issues; explored and evaluated new matters and cases; served as liaison to external stakeholders and groups; interacted with government officials and decision-makers; frequently appeared before state and regional gatherings to speak and present on energy and environmental issues.

Examples of specific roles/efforts:

- Provided expert advice to the Attorney General and senior staff on environmental and energy policy matters;
- Prepared comments, testimony, and draft language for legislative and state commissions and agencies;
- Spearheaded Illinois participation in multi-state attorneys general matters involving federal issues such as: Clean Power Plan litigation, methane regulation, DOE efficiency standards, and other Clean Air Act rules;
- Advised re: Volkswagen $3 billion environmental mitigation trust fund and zero emission vehicle program;
- Focused on implementation of new renewable energy programs in Illinois, especially low-income solar.

Midwest Director, Sierra Club's Beyond Coal Campaign, Chicago, IL

(June 2008-Oct. 2011). Coordinated legal, grassroots organizing, and communications activities to prevent new coal plant projects and to replace existing coal capacity with clean energy solutions; served as coal working group leader for regional network of foundations and advocacy organizations.

Associate, Mayer Brown LLP, Chicago, IL

(Sept. 2005-May 2008). Represented wide variety of private sector clients in environmental litigation, regulatory, and transactional matters, including chemical, railroad, real estate, manufacturing, mining, and wind energy industries.

Judicial Law Clerk, Alaska Supreme Court, Anchorage, AK

(Sept. 2004-Sept.2005). Assisted with all aspects of resolving appellate litigation.

EDUCATION

Harvard Law School, J.D. (2004) (Dean's Award, Community Leadership)

Albion College, B.A., History and Political Science (2001) (*summa cum laude*; Phi Beta Kappa)

TESTIMONY IN REGULATORY AND LEGISLATIVE PROCEEDINGS

- Pre-Filed Testimony on Behalf of the Environmental Law & Policy Center, Environmental Defense Fund, Natural Resources Defense Council, Respiratory Health Association, and Sierra Club Before the Illinois Pollution Control Board in *In the Matter of: Amendments to 35 Ill. Adm. Code 225.233 Multi-Pollutant Standards (MPS)*, R18-20 (December 10, 2018).
    - Testifying Witness at Hearing (January 29, 2019)
- Direct Testimony on Behalf of the Environmental Law & Policy Center, Ecology Center, Union of Concerned Scientists, and Vote Solar Before the Michigan Public Service Commission in *In the Matter of the Application of Consumers Energy Company for Approval of Its Integrated Resource Plan*, Case No. U-20165 (October 12, 2018)
- Pre-Filed Testimony on Behalf of the Illinois Attorney General's Office Before the Illinois Pollution Control Board in *In the Matter of: Amendments to 35 Ill. Adm. Code 225.233 Multi-Pollutant Standards (MPS)*, R18-20 (December 11, 2017)
    - Responses to Pre-Filed Questions (January 12, 2018)
    - Testifying Witness at Hearings (January 17-18, 2018)
    - Responses to Questions (February 16, 2018)
    - Testifying Witness at Hearing (March 7, 2018)

- Testimony Before the State of Illinois House of Representatives Renewable Energy & Sustainability Committee, Hearing on Consumer and Public Health Impacts of Utilizing Renewable Energy Sources and Increased Energy Efficiency Programs (April 29, 2015)

COMMENTS IN REGULATORY PROCEEDINGS

- Comments on Behalf of Union of Concerned Scientists to the Illinois Power Agency Regarding Updates to Long-Term Renewable Resources Procurement Plan (July 2019)
- Illinois Commerce Commission *NextGrid* Process, Multiple Written Comment Submissions and Participation in Working Groups on Behalf of Union of Concerned Scientists (June-September 2018)
- Comments on Behalf of Union of Concerned Scientists, et al. to the Illinois Commerce Commission's Distributed Generation Valuation and Compensation Workshop (July 27, 2018 and March 30, 2018)
- Comments on Behalf of the Illinois Attorney General's Office to the Illinois Commerce Commision Workshops Regarding Resource Adequacy in MISO Zone 4 (January 30, 2018 and November 30, 2017)
- Verified Reply to Responses to Objections to the Illinois Commerce Commission on the *Illinois Power Agency Petition for Approval of the Long-Term Renewable Resources Procurement Plan*, Docket No. 17-0838 (January 25, 2018); Response to Objections (January 11, 2018)
- Comments on Behalf of the Illinois Attorney General's Office to the Illinois Power Agency Regarding the Draft Long-Term Renewable Resources Procurement Plan (November 13, 2017)
- Comments on Behalf of the Illinois Attorney General, et al. to the Federal Energy Regulatory Commission in *Grid Reliability and Resiliency Pricing*, Docket No. RM18-1 (October 23, 2017)
- Comments on Behalf of the Illinois Attorney General's Office to the Illinois Power Agency Regarding Development of Long-Term Renewable Resources Procurement Plan (July 5, 2017)
- Comments on Behalf of the Illinois Attorney General's Office to the U.S. Department of Justice on the Proposed Partial Consent Decree in *In re: Volkswagen "Clean Diesel" Marketing, Sales Practices, and Products Liability Litigation*, Case No: MDL No. 2672 CRB (JSC) (August 5, 2016)
- Response Comments on Behalf of the People of the State of Illinois Before the Illinois Pollution Control Board in *In the Matter of Amendments to 35 Ill. Adm. Code Part 214, Sulfur Limitations, Part 217 Nitrogen Oxides Limitations, and Part 225, Control of*

Emissions From Large Combustion Sources, R-15-21 (September 11, 2015); Initial Comments (August 28, 2015)

- Verified Initial Comments on Behalf of the People of the State of Illinois Before the Illinois Commerce Commission in *Amendment of 83 Ill. Adm. Code 465 [Net Metering]*, ICC Docket No. 15-0273 (June 24, 2015); Verified Reply Comments (July 27, 2015)
- Complaint to Federal Energy Regulatory Commission, *Challenging the MISO 2015-16 Planning Resource Auction Rate for Zone 4 as Unjust and Unreasonable*, Docket No. EL15-71 (May 28, 2015); Response to Motions to Dismiss and Answer (July 17, 2015); Answer (August 14, 2015)
- Post-Hearing Comments to the Illinois Pollution Control Board in *In the Matter of: Coal Combustion Waste (CCW) Surface Impoundments at Power Generating Facilities: Proposed New 35 Ill. Adm. Code 841*, R14-10 (October 20, 2014)
- Comments to the Illinois Department of Natural Resources on Proposed Administrative Rules for the Hydraulic Fracturing Regulatory Act (62 Ill. Adm. Code 245 and 240.796) (January 2, 2014)
- Comments to the Illinois Pollution Control Board in *Illinois Power Holdings, LLC v. Illinois Environmental Protection Agency*, PCB 14-10 (Variance-Air) (September 24, 2013)
- Comments to the Illinois Power Agency on the 2013 Draft Procurement Plan (September 14, 2012)
- Comments to the Illinois Pollution Control Board in *Ameren Energy Resources v. Illinois Environmental Protection Agency*, PCB 12-126 (Variance-Air) (July 23, 2012); Post-Hearing Comments (August 10, 2012)

PRESENTATIONS

- Illinois Climate and Energy Activities: Federal and State, Chicago Bar Association (Chicago, IL) (February 21, 2018)
- Illinois Commerce Commission Renewable Energy Policy Session (Chicago, IL) (July 12, 2017)
- The Changing Electricity Grid: Issues and Opportunities for State Attorney General Offices, National Association of Attorneys General (Charlotte, NC) (March 17, 2016)
- Clean Power Plan Litigation, Chicago Bar Association (Chicago, IL) (March 2016)
- Closing and Redeveloping Power Plant Sites: Lessons from the Chicago Area, American Bar Association (Chicago, IL) (October 29, 2015)

- Clean Power Plan Update, Illinois State Bar Association (Chicago, IL) (October 21, 2015)
- Clean Power Plan Implementation, Air & Waste Management National Conference (Rosemont, IL) (September 2015)
- Air Regulatory Update & Clean Power Plan Implementation, Midwest Environmental Enforcement Association (Madison, WI) (July 1, 2015)
- Nuclear Power Update, Midwest Environmental Enforcement Association (Madison, WI) (July 1, 2015)
- Petroleum Coke Regulation, Illinois State Bar Association (Chicago, IL) (April 2015)
- Climate Adaptation and Environmental Law, Chicago Bar Association (Chicago, IL) (February 24, 2015)
- Illinois Fracking Regulations, Illinois Institute for Continuing Legal Education (Chicago, IL) (January 2015)
- Illinois Air Update, Lake Michigan Association of Air & Waste Management (Oak Brook, IL) (November 12, 2014)
- Moderator to Illinois State Bar Association Panel on Illinois Renewable and Energy Efficiency Portfolio Standards Panel (Chicago, IL) (March 2014)
- Carbon Pollution and the Clean Air Act: Where We've Been and Where We're Going, Chicago Bar Association (Chicago, IL) (February 25, 2014)
- High-Volume Horizontal Fracturing Regulation in Illinois, Illinois State Bar Association (Chicago, IL) (March 2013)
- Update on Clean Air Act Regulatory Activity and Current Events in the Electricity Sector, Midwest Environmental Enforcement Association (Jefferson City, MO) (June 28, 2012)
- Update on Recent Clean Air Act Rulemakings and Litigation, Chicago Bar Association (Chicago, IL) (March 21, 2012)

PUBLICATIONS

Co-Author, *Achieving a Clean Energy Transition in Illinois: Economic and Public Health Benefits of Replacing Coal Plants in Illinois with Local Clean Energy Alternatives*, The Electricity Journal (31) (2018) 52-59.

Co-Author, *Soot to Solar: Illinois' Clean Energy Transition*, Union of Concerned Scientists (2018)

Blog posts available at: https://blog.ucsusa.org/author/james-gignac

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t, and for other relief	))))	Case No. U-20471

DIRECT TESTIMONY OF

DR. ERIC C. WOYCHIK

ON BEHALF OF

THE ENVIRONMENTAL LAW AND POLICY CENTER,
THE ECOLOGY CENTER,
THE SOLAR INDUSTRIES ASSOCIATION,
THE UNION OF CONCERNED SCIENTISTS,
AND
VOTE SOLAR

AUGUST 21, 2019

Direct Testimony of Dr. Eric C. Woychik in DTE's IRP, U-20471

Table of Contents

I. Background and Qualifications

Q: What are your background and qualifications with respect to integrated resource planning (IRP) in the United States and elsewhere?

A: I have worked on evaluation and development of integrated resource plans ("IRPs"), earlier referred to as least-cost plans, since the early 1980s, formulated IRP methods, was lead author of the California Standard Practice Manual ("SPM") for demand side cost effectiveness in 1983, led evaluation of the resource plans for all California investor-owned utilities from 1985 to 1990, published numerous papers and articles on IRP methods and tools, was appointed to Chair the Least Cost Planning group at National Association of Regulatory Commissioners in 1988, and have worked on electric and gas market formation in the context of IRPs since 1982. I have experience working on these issues in (at least) fifteen U.S. states, six Canadian provinces, and (over) fifteen other countries. I have become an expert and thought leader on regulatory policy, investment strategy, business models, geospatial valuation, wholesale energy markets, transformational change, and smart grid development. Altogether, I have more than forty years of experience in helping to develop clean energy and traditional markets with utilities, technology providers, control operators, energy companies, stakeholder groups, and state and national regulatory bodies. I have served in roles as Executive Consultant, CAISO Board member, Commissioner Advisor, developer, and a number of senior company positions, such as with Synergic Resources Corporation, Black & Veatch, Comverge, and Itron. I hold a B.S in Environmental Policy Analysis and Planning from the University of California, Davis; an M.A. in Economics from New Mexico State

University; and a Doctorate of Management (D.M.) from Case Western Reserve University.

Q: What are some of the papers and publications you have authored or co-authored?

A: A subset of IRP-related papers and publications I have authored or co-authored includes:

- Distributed Energy Optimization: Steps and Results for Customer Value Capture in Layers, CRRI-Rutgers 32nd Annual Conference, Monterey California 26-28 June 2019 (coauthored)
- Smart Grids: Infrastructure, Technology, and Solutions, 2nd Addition, Stuart Borlase, Editor, CRC Press, 2018 (author of multiple chapters on markets, policy, and future vision).
- To Integrate and Optimize the Grid: Locate and Customize Distributed Energy Resources, Advanced Workshop in Regulation and Competition, CRRI-Rutgers, 30th Annual Western Conference, Monterey, CA, 28 June 2017 (coauthored).
- Integration and Optimization of Distributed Energy Resources; Big Data Analytics do the Job, Advanced Workshop in Regulation and Competition, CRRI-Rutgers, 36th Annual Eastern Conference, Annapolis, MD, 1 June 2017 (coauthored).
- *Seven Conditions Justify Smart Grid Investments*, Public Utilities Fortnightly, January 2017.
- Steps to Integrate and Optimize DERs, NARUC ERE Staff Subcommittee Webinar, 1 June 2016.
- Assessing Electric Utility Potential for a Distributed Energy Future – Scope and Scale from Value-Added Integration and Optimization, Advanced Workshop in Regulation

and Competition: CRRI-Rutgers, 35th Annual Eastern Conference, Shawnee on Delaware, Pennsylvania, 11-13 May 2016, (coauthored).

- Utility Efficiencies with Distributed Energy Resources: Scope, Scale, and Dynamic Benefits, Edison Electric Institute, Alternative Regulation Group, Webinar, 11 April 2016.
- Locational Net Benefits Analysis: To Integrate and Optimize Distributed Energy Resources for Maximum Value, LNBA Methodology and Demonstration Workshop, California Public Utilities Commission, San Francisco, CA, 1 February 2016.
- The Integration and Optimization of DSM: Extraordinary Benefits when the Orchestra Plays Together, AESP National Conference, Orlando, Florida, 9-12 February 2015 (coauthored).
- IDSM Cost-Effectiveness: What Happened Outside of California? Results from Duke Energy, NVE, Avista … presentation in CPUC R. 14-10-003, 22 January 2015.
- Methods & Tools to Accomplish Distribution Resources Planning, CPUC DRP Workshop, presentation in CPUC R.14-08-013, 8 January 2015.
- Valuing Integrated Demand Side Management (IDSM) for Improved Cost Effectiveness, DistribuTech Conference, San Antonio, TX, 28 January 2014 (coauthored).
- *Integrated Demand Side Management Cost-Effectiveness: Is Valuation the Major Barrier to New "Smart-Grid" Opportunities?* American Council for an Energy-Efficient Economy, Monterey, CA 12-17 August 2012 (coauthored).
- *Integrated Demand-Side-Management Cost-Effectiveness Framework*, IDSM Task Force, San Francisco, CA, May 2011.

- *An Integrated Analysis of the Electricity Market: Does More Knowledge Enable Market Manipulation?* 8th Global Conference on Business and Economics, (Coauthored), Rome, Italy, 13 October 2007.
- *Toward a Standard Practice Approach to Integrated Least-Cost Utility Planning,* Public Utilities Fortnightly, Volume 121 No. 5, March 1988.
- *Integrated Least-Cost Electricity Planning Under Uncertainty: Issues and Progress*, Workshop on Energy Resources Planning for Electricity, Honolulu, Hawaii, May 1987.
- *Least-Cost Resource Plan Integration under Uncertainty: Toward a Standard Practice Approach*, California Public Utilities Commission, September 1986.
- *Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs,* Joint Report of the California Public Utilities Commission and the California Energy Commission, 1982 (co-authored).
- *Perspectives and Issues in Least-Cost Planning: Toward a Standard Practice Approach*, Least-Cost Energy Planning in the Midwest: A Symposium, Electric Power Research Institute, March, 1982.

Q: Have you previously provided expert testimony on IRP and related energy topics?

A: Yes, I have done so since the mid-1980’s on numerous occasions domestically (U.S.) and internationally. Most recently, I provided testimony before this Commission in the Consumers’ Energy Company IRP proceeding U-20165.

II. <u>DTE’s Proposed IRP Fails to Devise a Reasonable and Prudent Process to Provide Energy and Capacity</u>

Q: How does DTE Electric Company ("DTE") describe the process used to create its IRP?

A: According to Sharon G. Pfeiffer in her testimony at SGP-25, "the Company conducted analyses to identify the most reasonable and prudent means to meet the projected resource requirements in the next five years, with modeling showing potential resource selections through 2040. The size and timing of the Company's expected surpluses or shortfalls in a particular year were based on:

1. Forecasts of the operations of the Company's existing generating assets and their planned retirement dates,
2. Planned generating additions including renewables, the BWEC, and Ludington Pumped Storage upgrades,
3. Forecasted impacts of EWR and demand response programs, and
4. Forecasts for demand and energy sales."

The Company analyzed four scenarios in Strategist and evaluated many small changes in individual variables, referred to as sensitivities. The reference for all of these scenarios and sensitivities was DTE's "Starting Point" or base case. While DTE asserts that, with over 138 model runs, its IRP was robust, DTE's IRP process in fact contained a number of flaws that call the results into question.

Q: What approvals does DTE seek in this case?

A: Through its application, DTE explains that it is seeking the following from the Commission:

1. Approval of the DTE Electric 2019 Integrated Resource Plan for the years 2020 – 2035;

2. Acknowledgement that DTE Electric does not have a persistent capacity need for the next ten (10) years;

3. Cost pre-approval for the Company's proposed EWR investments and resources through 2022, which will be consistent with the Company's next EWR Plan filing in 2019 for the period 2020 through 2021;

4. Cost pre-approval for the Company's proposed DR investment and resources beyond the projected test year in the current Electric general rate case, U-20162, and extending through 2022, which will be consistent with future Electric general rate cases; and

5. Cost pre-approval for the Company's proposed CVR/VVO pilot investment and resources through 2022, which will be consistent with future Electric general rate cases.

Q: Can you briefly describe how DTE performs its modeling?

A: DTE created a "Starting Point" scenario and used it as a basis for each of the four scenarios. As DTE Witness Pfeiffer explains: "The Company started with what is referred to as the starting point, and used it as a basis for each of the four scenarios." (SGP-26, L 9-11) DTE's Starting Point is made up of its "current state and current plans." According to DTE: "This includes the current retirement dates, approved new units, current state of the renewable plan, 1.5% EWR, and planned demand response program changes." (LKM-75 L 4-7) What this means is that the Company's current plan for the future – its "starting point" – has been set in stone, and cannot be changed.

Q: What does DTE include in the Starting Point resource plan?

A: The starting point resource plan was comprised of the following resources:

- *1.5% EWR savings target*
- *732 MW in 2019 increasing up to 863 MW total DR in 2024 and beyond*
- *855 MW incremental wind and 538 MW incremental solar between 2019 - 2030*
- *300MW incremental wind and 2,000 MW incremental solar between 2031-2040*
- *300 MW VGP wind in 202115*
- *1,150 MW BWEC CCGT addition in 2022*
- *34 MW Dearborn CHP addition in 2020*
- *Retirement dates:18*
- *River Rouge in 2020*
- *St. Clair 1-3, 6 in 2022*
- *St. Clair 7, Trenton 9 in 2023*
- *Belle River 1 in 2029*
- *Belle River 2 in 2030*
- *Monroe coal units before 2040* (LKM-75, L 10-25)

Q: Did DTE ever alter its Starting Point assumptions?

A: No. They did "refresh" the assumptions underlying its capacity position, but these changes were not meaningful in light of the inherent flaws in selecting and characterizing the costs of specific starting point resources. (SGP-26)

Q: Is the process DTE conducted consistent with standard practice to demonstrate that an IRP represents the most reasonable and prudent means of meeting the utility's energy and capacity needs?

A: No it is not. My testimony discusses specific flaws in DTE's process, though that does not foreclose the possibility that the IRP has additional flaws. One significant flaw in DTE's process is that the Company fails to include the following costs in its IRP:

- Updated fixed O&M costs in resource plan selection process, for example in the cases of Belle River and Monroe coal units where these costs are about $500M in environmental retrofits.
- Replacement power costs for energy and capacity when Belle River and Monroe coal units are planned to be out in 2028 through 2030 to conduct the $500M in environmental retrofits.
- Costs for DTE's future ramping needs, which are roughly outlined in DTE's testimony of witness Judy Chang of the Brattle Group.
- All related costs, including the above costs, over a twenty (20) year analysis period, as required by the Commission IRP parameters published by the Commission.[1]

Q: Does the DTE IRP meet the statutory requirement to project costs of different types of fuels, including peak demand reduction and waste reduction where cost-effective?[2]

A: No, DTE fails to provide an integrated approach to consider all fuels. For example, DTE's modeling, by its own admission, lacks the capability to evaluate optimization of fuel and resource mix. Full integration (interaction of all resources) and optimization (of all resources), including all costs and benefits, is required to determine best-practice resource plan options, with as few limitations as possible. Both integration and

[1] U-18418 November 21, 2017 Order at 85.
[2] 6t v. order

optimization are required to choose the most economic resources, but in practical terms DTE's modeling is inadequate to achieve either of these critical needs.

Specifically, DTE explains that it has the following limitations in its modeling:

- DTE defines "resource addition limits" with Strategist (Proview), which mute transparency about what resources should be added or retired. (Ex. 3, pp 84-84, LKM)
- "It is uncertain how much, if any, capacity will be available in the market for the Company to purchase 10 years from now. Due to this uncertainty in the capacity market, zero capacity purchases was the general assumption for optimization modeling." (DTE IRP at pg. 123)
- DTE cannot perform retirement analysis of its peaker units. (ELPPE-4:51g)
- DTE cannot differentiate fixed from variable O&M costs. ((ELPCDE-4.51a-d)
- DTE cannot capture solar-storage interactions; "…due to limitations with the Strategist model, we were not able to charge the battery exclusively with solar in the model…" (DTE IRP at pg. 138)

Furthermore, DTE's IRP fails to define the tradeoffs between resources, including tradeoffs between Company resources and those that can be used on the customer side of the meter. Moreover, the IRP fails to focus on scenarios that vary the forward costs or prices of resources, especially resources that face rapidly declining costs. From now until 2040, renewable resources, battery storage, smart inverters, energy efficiency, demand response, and electric vehicle charging will increasingly be integrated and optimized on both sides of the customer meter, producing much lower costs and much greater value. Neither does DTE's IRP adequately address these points nor does it meet generally accepted approaches to provide optimization of the resource mix, integration of all resources, and optimization of all costs and benefits. As a result, DTE does not define the economic tradeoffs between resource options in meaningful ways, or define the proper timing and approach to retire and replace specific resources.

Q: Does DTE admit that its Starting Point resources were hard coded into the Strategist model runs so that IRP analysis of the starting point resources, including renewables, failed to evaluate or capture the cost effectiveness of these renewable generation options?

A: Yes. This was confirmed by DTE in its data request responses ELPCDE-13.88g and 13.88f ("Confirmed…").

Q: Are the implications of DTE's analysis the same for the Monroe coal units with respect to their responses in ELPCDE-13.88g and 13.88f, that the Monroe coal resources were hard coded into Strategist model runs so that cost effectiveness was not performed?

A: Yes, the Monroe coal units were apparently treated the same as other Starting Point resources; they were not compared in terms of cost effectiveness to other possible resources using Strategist.

A. DTE "Papers-Over" the Economics of Belle River and Monroe Coal Units by Bundling these Plants in its "Starting Point Scenario" and Ignoring the Coal Units' Fixed O&M

Q: Is DTE's Starting Point based on a least-cost resource test, and are there Net Present Value Revenue Requirements (NPVRR) calculations for this starting point set of resources?

A: DTE's choice of starting point resources is not based on least-cost resources or a comparison of NPVRR. Least variable cost should include: (i) incremental heat-rate multiplied by expected fuel costs; (ii) variable operations and maintenance costs (O&M), iii) incorporate planned and forced outage rates (lost production); and (iv) should include coal ash disposal costs. Least-cost from a total cost basis would include the above variable costs, plus fixed costs, including fixed O&M cost, which in the case of coal plants may include environmental mitigation costs (such as replacing and updating scrubbers, coal ash mitigation, etc.), and rate-base earnings. Least-cost scenario comparisons are traditionally based on the sum of total revenue requirements or NPVRR.[3] However, DTE does not base its choice of starting point resources on least variable cost, least total cost, or a comparison of NPVRR to show least cost.

Q: Why is it important to base the Starting Point on least total cost?

A: The Starting Point is used as the base-case or classic "but-for" case to test resource plan expansion. It becomes "the case to beat" in terms of total costs or NPVRR. If the base case is itself flawed the foundation of the IRP is flawed, because it is not comprised of the least-cost mix of resources. It appears that DTE's starting point and modeling are designed to prevent new resources from replacing the base case or starting point resources. In this situation, the IRP does not properly identify the future least-cost resource mix. Rather, it becomes an exercise in justifying resources that are included in the base case regardless of their cost. If so, the DTE IRP serves only to prop up the Company's choice of Starting Point resources, even though those resources are not least cost.

[3] A suitable reference is H. Stoll, Least Cost Electric Utility Planning, J. Wiley, 1989, pp. 544-575.

Q: How does DTE justify its choice of resources in the Starting Point?

A: DTE uses other assumptions to justify the resources included in the Starting Point resource mix. For example, DTE justifies including the Monroe coal units because they have the lowest heat rate. DTE does not include Monroe because it is least total cost, and DTE entirely excludes the $450M in Monroe environmental retrofit costs from consideration in the decision to use Monroe as a Starting Point resource. DTE's assumptions regarding Belle River are less clear, although the Company did subject Belle River to a rudimentary test, as a sensitivity case, for retirement. It appears that the Company included Belle River in the Starting Point because it does not plan to retire those units until 2029. It is clear that the Monroe coal resources are not included in the Starting Point based on "least cost" assumptions, and related fixed O&M costs of $455 million are ignored.

Q: Using the Starting Point resources, does DTE identify a future capacity need?

A: DTE does not discuss whether it has a future capacity need, but rather whether it has what the Company refers to as "a persistent capacity need." The Company does not identify a "persistent capacity need" until the 2029 and 2030 timeframe with the retirement of Belle River. (LKM-27) DTE perceives the availability of capacity for purchase ten years from now as very uncertain, for the following reasons:

- Unknown continued operation of capacity resources owned by Independent Power Producers (IPP)
- Potential changes to the MISO capacity market construct
- Uncertain generator unit performance

- Projected decrease in the amount of Effective Load Carrying Capability (ELCC) assigned to solar units
- Unknown import capacity availability outside LRZ, or if available the cost-effectiveness
- Unknown Effective Capacity Import Limit (ECIL) as discussed by Witness Burgdorf.

(LKM 27-28)

Thus, it appears that DTE does not fully understand its need for Belle River as capacity, but attempted to justify Belle River using the simple NPVRR spreadsheet model.

Q: How does DTE's choice of Starting Point resources impact its IRP?

A: DTE's choice of Starting Point resources "papers-over" the economics of these resources because it does not include important information on resource costs, such as variable O&M and fixed O&M, including major environmental mitigation costs that will be incurred by those units. It also includes false definitions of dispatch order (unit commitment) and run-times of selected starting point resources, essentially assuming that these units will run all the time (short of planned and forced outages); these units are not dispatched economically. DTE may work to self-schedule these units or submit them as "must-offer" resources, but dispatch order and run times will ultimately be determined by MISO. Grid security (reliability) and power quality must be maintained, as well as the avoidance of "criteria violations." As a result, the assumptions about dispatch order and run times with he Belle River and Monroe coal units are expected to distort the subsequent calculations that form the basis of other new resource selections going forward. If either or both the Belle River or the Monroe coal units were not in place the set of resource options would most certainly be quite different. DTE's Starting Point assumptions also preclude competitive solicitation of new capacity resources. "Given the Company does not anticipate a need for additional capacity in the short-term planning horizon, there is no need or requirement to issue an RFP to third parties to supply capacity resources." Thus, with respect to energy, capacity, ancillary services, or any combination of these, DTE does not even solicit resources – new resources are screened-out -- because these coal units are initially inserted as starting point resources.

Q: How does DTE's failure to include resource cost information for Starting Point resources affect its IRP?

A: First, DTE has assumed that capacity value ($/kW-year) is zero with Belle River and Monroe coal units in place as starting point resources. Second, Monroe and Belle River were not subject to a dynamic economic analysis (such as with Strategist). Lower cost resources, especially given DTE's choice of relatively high cost assumptions for renewables and DER, are not fully considered (though DTE has more recently evaluated lower cost solar PV as a sensitivity case). Third, environmental mitigation costs to achieve compliance in 2022-23 are not included in the evaluation of these units, the missing $500M. Moreover, DTE's approach is inconsistent with least-cost planning, is inconsistent with use of the NPVRR approach, and forecloses assessment of new resources that may be viable, lower-cost options.

By including Monroe and Belle River as fixed Starting Point resources with understated costs, the Company will not show a capacity need until Belle River is retired. The practical implication is that DTE's resource plan assumes that further capacity value beyond the Starting Point is largely zero. This assumption then falsely indicates zero value for capacity costs avoided, severely limiting the use of resources that may otherwise be considered economic or cost-effective.

DTE's Starting Point approach distorts subsequent resource plan analysis because it is built on falsely lower costs. DTE's models and modeling will never choose to replace the Starting Point resources – specifically Monroe and Belle River – with more cost-effective resources in the future. These Starting Point resources are simply assumed to be in the resource mix going forward. This is to DTE's advantage, as the Company can benefit from increased profits by retaining rate base earnings, including rate base earnings from undepreciated capital in the Belle River and Monroe coal units for environmental mitigation. As DTE can thus gain greater profits this appears to bias the modeling and the IRP results.

With these limitations, customer costs will remain higher, without abate, as lower costs resources will be excluded from use. With the Belle River and Monroe plants in place longer than is appropriate, DTE's modeling does not represent the proper least cost analysis. A proper least cost plan would enable the $500M in environmental mitigation costs to be incorporated, to include all fixed and variable O&M, in order to further equate the value of old versus new resource options.

As more DERs, including demand response (DR) and battery storage, would likely be economic absent Belle River and Monroe coal units, the introduction of these more flexible resources will be postponed. These more flexible resources are needed to integrate wind and solar PVs.

The delay of these flexible resource additions, thus, seems likely to further increase costs by limiting the use of these ramping resources at the MISO level.

Q: Are you aware of how this issue was treated in the development of IRP rules by the Commission?

A: Yes. I reviewed the November 21, 2017 Commission Order in Case No. U-18418, implementing the 2016 Section 6t(1) IRP provisions. I also reviewed comments submitted to the docket in that case. While DTE seems to suggest the utilities can dictate which unit retirements are evaluated, the Commission made it clear in its November 21, 2017 Order that it found value in utilities allowing models to retire company-owned assets based on economics.[4] While the Commission stopped short of requiring utilities to allow the model to select retirement of company-owned resources in all scenarios, the Commission explicitly gave utilities that flexibility and recognized that "valuable insights may be gained by allowing the model to retire units based on economics."[5]

Q: Should DTE have conducted a more thorough economic analysis of its remaining coal units?

A: Yes. Regardless of whether it was technically required, the Commission rightly recognized that there are situations in which an IRP process cannot be successfully accomplished without modeling an excessive number of resources retirement scenarios. DTE's process, however, directly undermines the objectives of the IRP, backing in assumptions to preclude proper economic analysis of the Belle River and Monroe units. If DTE seeks to claim it only modeled scenarios requested by the Commission in the instant proceeding, this is an abdication of responsibility, especially for the starting point set of resources. Moreover, experience with IRP modeling and results generally instructs

[4] Case No. U-18418, November 21, 2017, Order at 38.
[5] *Id*. at 57.

all involved that the sequence of resource additions is important. It should be based on relative resource economics from most to least economic in order to meet locational reliability needs. The short-run (marginal cost) summary of this approach in ISO/RTO market terms reflects least-cost to most-cost in a bid-stack (security-constrained economic dispatch). This general method is then elevated to comparisons of total cost for decisions about system-based long-run resource expansion, such as with use of NPVRR. DTE simply did not make the expected comparisons on a system basis across all resource options including its remaining coal units.

Q: Did DTE perform any analysis modeling retirement of the Monroe coal units?

A: DTE did not model the early retirement of Monroe. DTE decided that it would not model retirement of Monroe at all apparently because ”the four units at Monroe are the most efficient in the DTE fleet in terms of heat rate and rate of NOX and SO2 emission” LKM-60. DTE seems to believe the Company gets a “pass” to forgo meaningful economic analysis of the Monroe units, in part by designating these units as Starting Point resources.

Q: Has DTE ever modeled coal plant retirements?

A: Yes. “In 2016, [DTE] performed an economic analysis of the Tier 2 coal units (SGP-32) required to comply with the revised environmental regulations [which] showed that retirement of River Rouge Unit 3, St. Clair Units 1-4, St. Clair 3 Units 6-7, and Trenton Channel Unit 9 were favorable for customers compared to the capital investment and expenses required to safely operate and maintain these units and comply with the revised environmental regulations that were expected to be in effect in 2023. In 2017, the Company announced that [these] plants would be retired by 2023.” (SGP-33)

Q: Could that type of analysis be performed on Monroe?

A: Yes, but DTE did not conduct this analysis for Monroe. Instead, DTE characterized the Monroe coal plants as "starting point" resources which were not subject to economic assessment. In this way DTE was able to step past the question of whether the Monroe units should be retired.

Q: Do the Belle River and Monroe coal plants face the same environmental regulations as the previously mentioned coal plants that are slated for retirement in 2023?

A: Yes, the Belle River and Monroe plants face the same environmental regulations. Notably, Belle River and Monroe coal units are expected to incur an additional $500 M in costs to comply with related environmental regulations if they continue operation into 2023 and beyond.

Q: Were these Monroe coal environmental retrofit costs discussed or considered when DTE determined these should be "Starting Point" resources as part of the initial portfolio?

A: It appears not. DTE gave the Monroe coal plants a green light, separate from scrutiny of the fixed O&M or environmental capital costs ($455 M), much less the overall economics of these units.

Q: Is fuel price risk used to determine the Starting Point set of resources?

A: No it is not; weighted fuel price risk is addressed later. Even though this price risk may be significant for coal, it is not considered or used to evaluate DTE's starting point resources.

Q: In your opinion, would the Monroe coal units likely be sustained in the resource mix if not initially placed in the Starting Point resource mix, but instead tested against other resources?

A: I think it is likely they would not, based on my assessment of the trajectory of costs for renewable and DER resources. Monroe coal units operate with very low capacity factors (less than 50%), are almost 50 years old, are inflexible (i.e., cannot ramp up and down rapidly or significantly), and face uncertain environmental requirements, as well as criteria pollution and GHG costs. That said, DTE is the party in the best position to model this properly based on total costs, if it fully defines all of its costs and potential benefits in an unbiased manner. Standard practice in resource planning would avoid artificially inserting the Monroe coal units into the starting point resource mix. Moreover, when evaluating plant retirements, at minimum the following costs should be included:

- Fixed O&M including capitalized maintenance expenses
- Variable O&M
- Coal ash disposal costs
- Replacement power (energy and capacity) during planned outages, including retrofit equipment (to expend environmental capital costs)
- Replacement power (energy and capacity) during forced outages
- Environmental mitigation (retrofit) costs.

B. DTE Pushes the $500M in Coal Plant Environmental Mitigation Costs Into Future Proceedings Ignoring These Costs In the IRP Economic Analysis

Q: Has DTE estimated environmental mitigation costs for its coal power plants?

A: Yes, DTE provides a specific breakdown of the environmental capital costs that will be incurred, including for example those capital costs that will be incurred if Belle River coal units remain in service beyond 2022.

Q: Does 2022 have particular relevance here?

A: Yes. it does. For example, post 2022 the Monroe coal units will be required to meet at least the cooling water intake requirements (section 316(b) of the Clean Water Act) and the Environmental Protection Agency water discharge or effluent limitation guidelines (ELG), as discussed by DTE witness Berry Marietta.

Q: How does the Company incorporate Environmental Retrofit costs for coal plants into its IRP?

A: As described above, the Company does not include any of these costs in its Starting Point. This precludes Belle River and Monroe from being properly evaluated in other scenarios. The only time DTE considers these environmental mitigation costs is after the 5 year resource plan evaluation period, which corresponds with their short-term PCA. In other words, DTE cuts off the time period for their short-term PCA just before the environmental mitigation costs are incurred, ensuring that the Monroe and Belle River plants are never truly considered based on economics that include the $500M in environmental mitigation cost.

Q: Does DTE expect the current environmental requirements to change?

A: No. DTE does not expect its power plant environmental requirements to change. As witness S.G. Pfeuffer explains: *Although portions of the ELG are currently under reconsideration by the EPA, there are significant portions of the ELG that are unchanged, and the impacts of the regulations on the Company are not expected to* *change. Additionally, there has been tightening of NAAQS standards in regions that impact DTE Electric coal plants.* (SGP-32)

Q: According to DTE witness Marietta do the requirements for ELG impact DTE's plans for the Belle River and Monroe coal units?

A: Yes, witness Marietta contends that "under the Company's plan, ELG regulations will impact Belle River and Monroe Power Plants as they are not planned for retirement until after 2023." (BJM-6) According to witness Marietta, after evaluation of several options, DTE determined that the "impact of these rules was a key factor in the decision … to retire these units," and once-through cooling requirements present additional impacts for certain plants such as Monroe. Moreover, according to DTE witness Marietta "Monroe Power Plant will likely be required to install new cooling water intake screens and install a fish return system. **(**BJM-10)

Q: What are environmental capital cost impacts on the Belle River and Monroe coal units?

A: According to DTE witness Marietta, the impacts on DTE's remaining coal power plants are shown in the following table of Environmental Capital Costs to keep these units in place after 2022:

Regulation	Capital Cost (M$)		
	Belle River	Monroe	Tier 2
ELG	$55	$334	--
316(b)	$1	$30	--
CCR	--	$91	$9

This amounts to $455 M for the Monroe units and $56 M for the Belle River units.

Q: Has replacement of capacity been a focus of DTE's coal plant retirement in the short term?

A: Yes, with three power plants retiring, DTE seeks to focus the PCA on the first 5 years and ensure it can replace the capacity of the retiring coal plants, as well as Belle River.

Q: Is DTE's approach to look at Monroe coal units in 5 years appropriate and consistent with Commission guidance regarding the length of the analysis?

A: No. It appears that DTE ignored the 20 year analysis window. As DTE witness Pfeuffer explains "the Company conducted analyses to identify the most reasonable and prudent means to meet the projected resource requirements in the next five years, with modeling showing potential resource selections through 2040." (SGP-25) Yet the Belle River and Monroe coal units are used as "starting point" resources while ignoring the multi-million-dollar environmental retrofit costs that are slated as requirements just after the 5-year window.

The Monroe and Belle River plants should be evaluated more completely, including all costs and expected upgrades, across the full 20-year period. DTE did not do this.

Q: Do you agree with DTE that its IRP portfolio scenarios are robust based on modeling and risk analysis?

A: No. DTE's efforts to provide multiple scenarios and resource screening are wholly inappropriate, in part as they rely on continued use of the Monroe and Belle River plants. The results of these runs cannot be meaningful if based on a flawed Starting Point set of resources and short-term (less than 5 year) time frame. DTE's Witness Mikulan argues for a number of "special circumstances" that indicate the opposite. But it is simply wrong to 1) ignore the actual assumptions that should go into a starting point or base-case resource mix, and then 2) set aside use of the NPVRR for the duration of resource, based on the argument that the resource mix can be considered in a subsequent resource plan proceeding.

C. DTE's IRP Does Not Achieved The Balance Outlined Under Michigan Statute

Q: Does DTE use appropriate techniques to accomplish effective resource plan integration and optimization, to achieve the balance required by MCL 460.6t(5)(a)-(o) and MCL 460.6t(8)?

A: No, it does not, though DTE claims to the contrary in its Application (pg. 3). As described above, DTE takes short-cuts, such as ignoring key costs in its Starting Point and improperly shortening resource cost and benefit time frames. DTE also ignores integration of direct locational resource needs and costs on the distribution system; ignores the need to fully integrate the benefits and costs of all resources; uses "optimization" methods that are incomplete and not widely accepted, while at the same time allowing modeling limitations to be used to truncate analysis and results; and fails to recognize the limitations of the Strategist model.

Q: What does proper resource integration and optimization accomplish beyond what DTE has provided?

A: First, integration of the resource options is performed to define the interaction of resources, such as the use of less flexible baseload generation with more flexible demand side resources (DERs) and power purchases. Second, optimization of the resource portfolio occurs at two levels, i) at the investment stage to define the best options in terms of cost and risk and ii) to define how the set of resources should be optimally dispatched near real time especially to handle contingencies (uncertain events). Integration and optimization are specifically aimed to provide the least cost resource mix given resource interactive effects, risk, and uncertainty. Critical risks and uncertainties include weather, loads, resource performance, and prices/costs.

Q: Does DTE identify limitations in the use of Strategist?

A: No. While the Company uses Strategist to model its resource plan, DTE does not explain that Strategist is unable to account for: (i) timing of resource retirements; (ii) the need for ramping resources; (iii) rapid declines in the costs of certain resources such as storage batteries, solar photo-voltaic generation, and wind power; or (iv) uncertainties in weather, loads, and prices/costs. Moreover, Strategist cannot harness needed inputs to calculate the outputs of key interest, including the timing, ramping, the declining costs of competing resources, and thus the comparative economics of resource options. Moreover, the set of Strategist runs provided by DTE seem virtually meaningless as the model does not capture the key features of ramping resources, which will be critical in the near-term future.

D. DTE's IRP Vastly Underestimates Growth in Electric Vehicles

Q: Does DTE generally understate growth in electric vehicles, which in turn reduces EV load control and the amount of recognized load management?

A: Yes. DTE truncates its electric vehicle ("EV") growth forecasts. DTE does this both by use of older research (showing less growth) and its choice to say no to higher growth assumptions. This reduces the amount of EV load control that is available to DTE. DTE likewise fails to acknowledge the declining costs for demand response (e.g., EV charging), behind-the-meter storage, in front-of-meter storage, as well as the declining costs of solar PVs, and wind to charge storage. Moreover, these cost trajectories cannot be properly evaluated with DTE's Strategist model, as explained above.

Q: Would resource choices be different under higher growth scenarios such as for EVs?

A: Yes. A critical assumption is DTE's choice to say that capacity has virtually $0 (zero) value, pointing to low electricity growth. Even level-2 (220v) EV chargers increase electrical capacity needs as each draws about at least 7-8 kW. EV growth in Michigan and in the DTE footprint is expected to accelerate rapidly in less than 5 years. Resource choices would be targeted at locations where EV growth is substantial, which has historically been in pockets within regions. This incremental demand will compel capacity costs to be much greater than zero, and the demand for energy will also be greater.

Q: Is the electric vehicle forecast credible; does it reflect expected outcomes?

A: No, the DTE EV forecast is old, out-of-time, and uses non-traditional methods. DTE's witness Mr. Leuker uses references that rely on old data. His electric vehicle forecast relies on a source that was completed in 2016.[6] Mr. Leuker also uses references completed in 2017.[7] The declining costs of EVs, use of EV load management, and value of time-of-use rates with EVs – each which benefit from inevitable scale economies -- are all largely ignored by DTE.

---

[6] Footnote 4 "The Impact of Electric Vehicles on the Grid Customer Adoption, Grid Load and Outlook" GTM Research. GTM Research is the market analysis and advisory arm of Greentech Media. (DATE: 18 Oct 2016). MBL-11 (Leuker)

[7] Footnote 3: "Plug-in Electric Vehicle Sales Forecast Through 2025 and the Charging Infrastructure Required" Edison Electric Institute (DATE: June 2017) MBL-11 (Leuker)

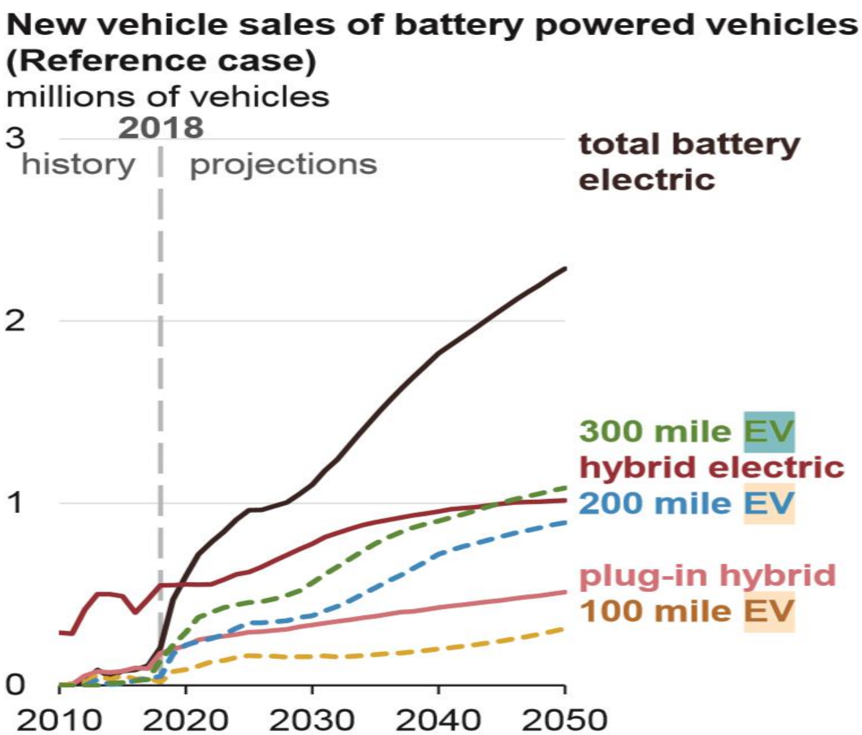
Q: Do the resources cited by Mr. Leuker logically support his forecast of electric vehicles?

A: No. Mr. Leuker uses dated references to a national study (EEI) to adjust to what he says, inaccurately, is "Michigan's current electric vehicle volume." Mr. Leuker's approach constrains electric vehicle charging to prior circumstances, which directly ignore the boom in electric vehicle growth DTE will face immediately in coming years. His focus is largely on a residential sector in the past, which falls very short of the need to explain future changes that will be both rapid and impactful. Moreover, Mr. Leuker fails to explain just what kind of electric vehicles are included in his forecast; are they residential (only), hybrid, short-range, long-range, all electric vehicles, all of these types? (MBL 1 – 23).

Q: Does Mr. Leuker rely on a linear forecast when the market for electric vehicles is anything but linear, as it accelerates rapidly over time?

A: Yes, while the electric vehicle industry is transformed daily to show a constant acceleration over the next ten years, Mr. Leuker's approach to forecast electric vehicle adoption is akin to driving while looking in the rear-view mirror; one fails to see the changes going on down the road into our future.

In contrast, the U.S. Energy Information Administration explains in its recent reference case how the full set of battery electric vehicles will rapidly grow, as shown graphically below:



Q: Did DTE's witness rely on an updated forecast to reestablish the load-based starting point, given his reliance on dated studies?

A: No, Mr. Leuker explains that he did not update his forecast as reliance on alternative forecast bands, which he states are linear, would capture any need to update his forecast. It appears that Mr. Leuker is simply unfamiliar with rapid, non-linear growth, which is occurring with electrification of both transportation and buildings.

Q: When Mr. Leuker explains forecast accuracy, and the forecast benchmarking process, are his methods confined to traditional electricity forecasts, as compared to electric vehicle forecasts?

A: Yes, Mr. Leuker describes the electric load forecast as though it behaves in the same way as an electric vehicle forecast. But with EVs and electrification of buildings, the traditional electric load forecast changes significantly.

Q: Does Mr. Leuker recognize the high electricity loads that are directly imposed on the grid by electric vehicles? Does he define different charging level impacts such as for "level-two" charging of cars or small trucks?

A: No, he appears to be unaware that level-two charging, which can make use of a 220V residential electric dryer plug, draws between 7 to 8 kW of instantaneous power to charge a battery that may require 75 kWhs (to travel 300 + miles) for a single charge. These electric vehicle charging loads are greater than almost any other load a residential house or small commercial building would typically serve.

Q: Does Mr. Leuker make out-of-date conclusions about electric vehicles, such as charging patterns, based on outdated information?

A: Yes, Mr. Leuker claims, for example, that "Electric vehicles represent about 1.5 percent of light-duty vehicle sales" using "early 2018" forecasts, (pg. 97) and "the Bloomberg New Energy Finance (BNEF) 2017 long term EV outlook" endorsed a "linear growth" forecast for EVs. As the graph in A37 above shows, the growth of EVs is anything but linear. A recent Forbes article presents these three nonlinear scenarios for EV growth, which I commend to the Commission:

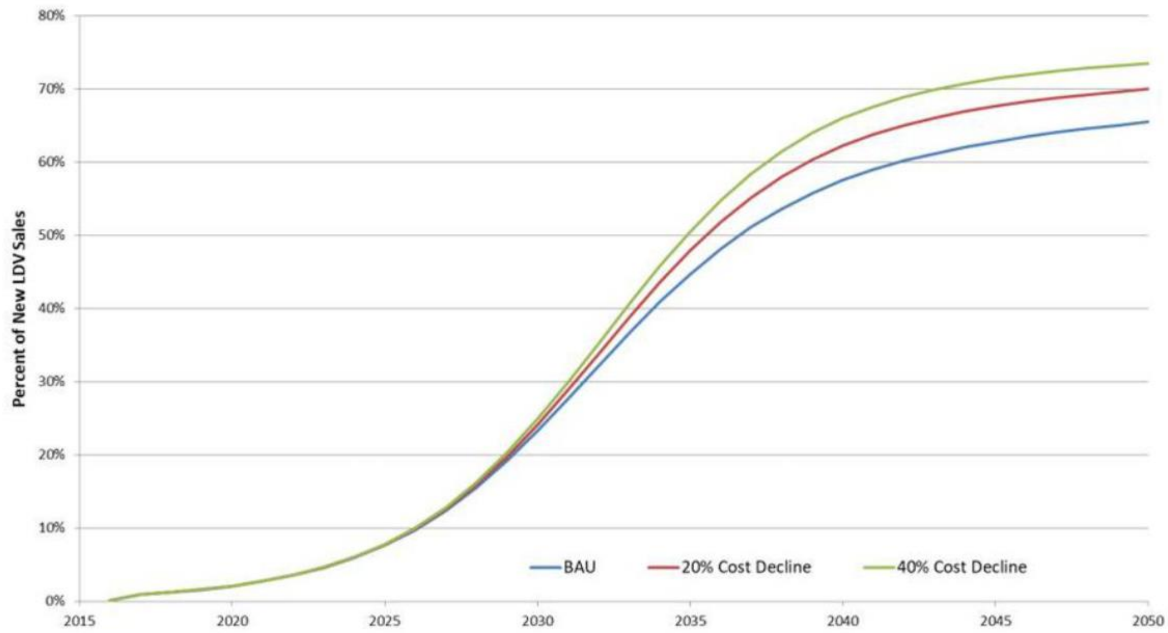


Figure 3. EVs' share of U.S. LDV sales under three scenarios: BAU, a gradual cost decline reaching 20% (relative to BAU) in 2050, and a cost decline reaching 40% in 2050.

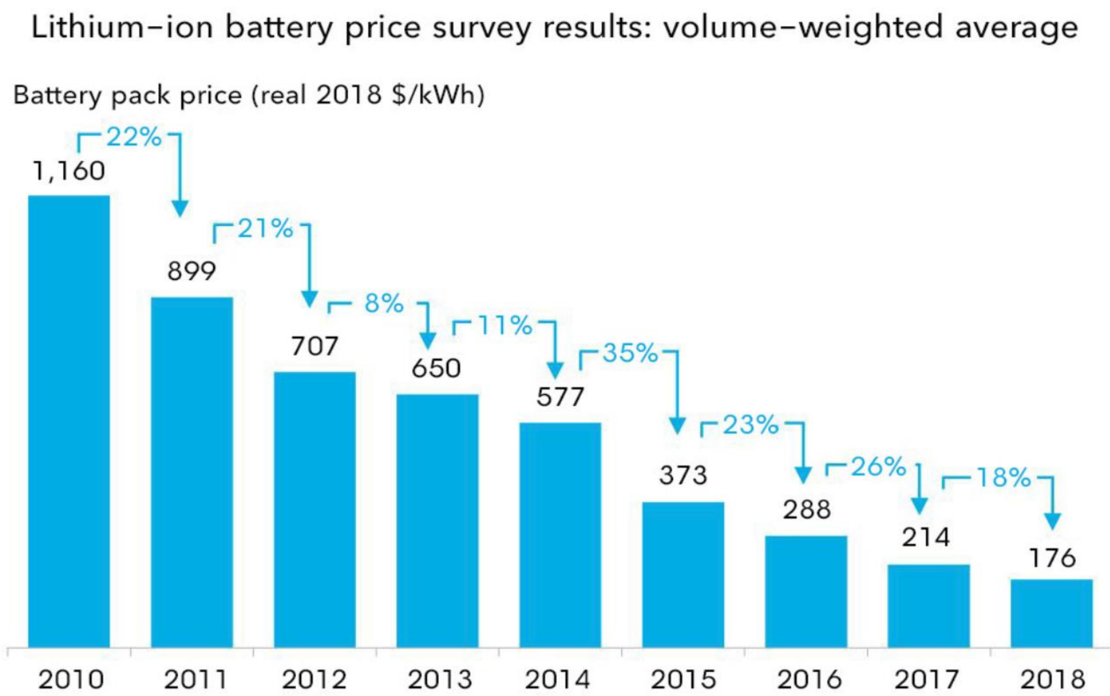
EV share of U.S. LDV sales to 2050 under three EV price scenarios ENERGY INNOVATION

E. DTE's IRP Fails to Recognize the Rapidly Declining Costs of Storage Batteries, Solar PVs, Wind, and Integrated Behind-the-Meter Resources

Q: Does DTE provide meaningful projections of battery storage as a resource?

A: No, DTE fails to recognize that the costs of batteries and battery storage, like the costs of wind, PVs, and electric vehicles, are declining rapidly each year. A recent example of this is provided by Bloomberg[8], based on its battery price survey, which tracks the annual declining costs of batteries from 2010 to 2018:[9]

[8] Bloomberg in this testimony refers to "BloombergNEF (BNEF), Bloomberg's primary research service, covers clean energy, advanced transport, digital industry, innovative materials and commodities."
[9] *See*, https://about.bnef.com/blog/behind-scenes-take-lithium-ion-battery-prices/.



Source: BloombergNEF

Q: How much have battery and wind costs declined since 2018?

A: According to a more recent Bloomberg (BNEF) report "the benchmark levelized cost of electricity,[1] or LCOE, for lithium-ion batteries has fallen 35% to $187 per megawatt-hour since the first half of 2018. Meanwhile, the benchmark [Levelized Cost of Energy or LCOE] for offshore wind has tumbled by 24%."[10]

Q: More recently, what does Bloomberg say about the costs of renewable resources, including battery storage?

A: Bloomberg explains as follows:

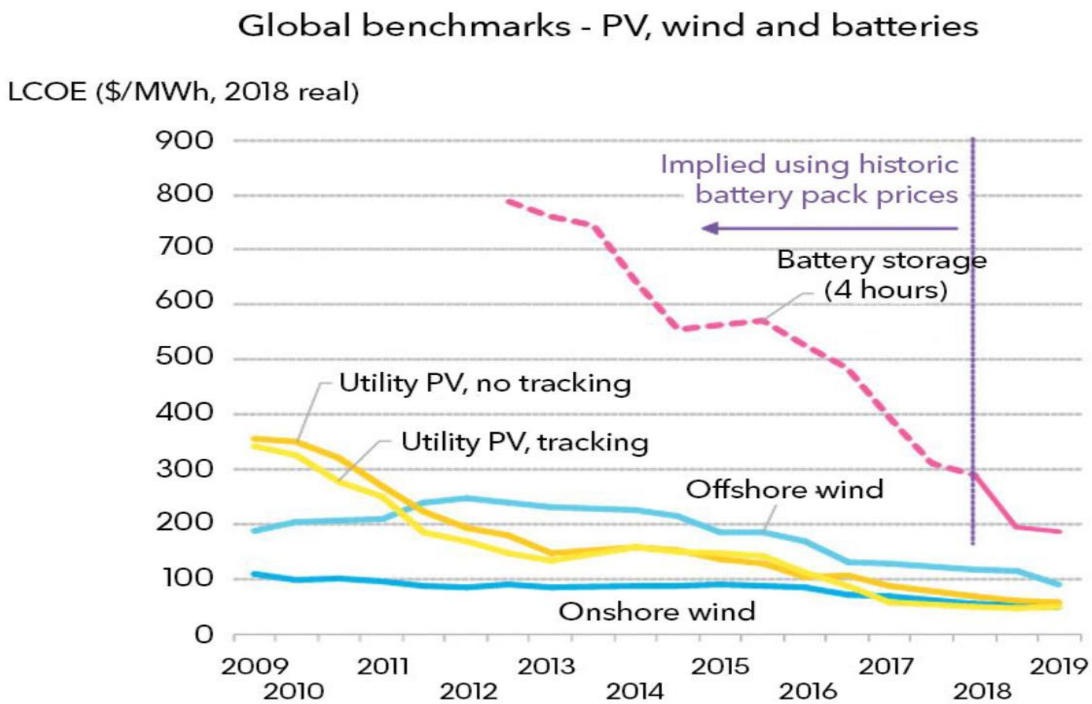
> Our analysis shows that the LCOE per megawatt-hour for onshore wind, solar PV and offshore wind have fallen by 49%, 84% and 56% respectively since 2010. That for lithium-ion battery storage has dropped by 76% since 2012, based on recent project costs and historical battery pack prices. The most striking finding in this LCOE Update, for the first-half of 2019, is on

[10] *See*, https://about.bnef.com/blog/battery-powers-latest-plunge-costs-threatens-coal-gas/.

> the cost improvements in lithium-ion batteries. These are opening up new opportunities for them to balance a renewables-heavy generation mix.[11]

Q: Does Bloomberg show these changes in costs in graphical terms?

A: Yes, to further illustrate these points Bloomberg provides this graphic of global energy cost benchmarks in light of battery pack (storage) costs:



Q: How does Bloomberg develop these cost estimates?

A: As Bloomberg explains, "LCOE analysis is based on information on real projects starting construction and proprietary pricing information from suppliers. Its database covers nearly 7,000 projects across 20 technologies."[12]

Q: How do the LCOE numbers in the graphic above (A80) compare to the costs for coal, wind, PVs, and battery storage provided in DTE's resource plan?

[11] Ibid.
[12] Ibid.

A: DTE's costs for these resources are not updated or refreshed so that valid comparisons can be made of resource costs in current (2019) terms.[13] The DTE cost categories posted for specific resources are as follows:

- Coal generation
- CCGT generation
- Solar PV utility scale.
- Wind generation
- Storage batteries utility scale
- Demand Response
- Energy Efficiency
- Solar PVs customer scale
- Storage batteries customer scale
- Conservation Voltage Reduction[14]

Q: Do you agree with the projections of DTE's CEO, specifically that wind and solar generation are cheaper than coal generation so will dramatically and rapidly reduce carbon emissions (as explained by Gerry Anderson)?

A: Yes, moreover, I agree with Mr. Anderson that DTE's coal plants are aging, it makes sense for DTE to move on, and that wind and solar continue to improve in terms of economics.

[13] Testimony of Sharon K. Pfeuffer, SGP-1 to SGP-24 and Exhibit DTE IRP, Matthew T. Paul, MTP-1 to MTP-24, Terri L. Schroeder, TLS-1 to TLS-23, K. l. BIlyen, KIB-4 to KIB-42, K..O. Farrell, KIV-1 to KIF-25, Yuji Zhou, YZ-1 to YZ-24, Marcus B. Leuker, MBL-1 to MBL-23, Justin M. Hunnell, JMH-1 TO jmh-15, Ryan C. Rratt, RCP-1 to RCP-15, Shawn D. Burgoff, SDB-1 to SDB-17, Berry Marietta, BJM-1 to BKM-17, Don M. Stanczak, DMS-1 to DMS-10, Judy W. Chang, JWC-1 to JWC-10.

[14] Ibid.

Q: Do you agree with DTE's CEO that this is a fundamental change, and that DTE will be "making big moves in a time frame that not all that long ago people thought was unlikely"?[15]

A: Yes, I generally agree with these statements by Mr. Anderson that fundamental changes are on the horizon, but this IRP does not fully reflect those changes. Moving to clean energy should rest on sound economics and proper comparison of resources. With proper analysis, it is likely that clean energy will rapidly displace much dirtier sources that are harmful for the environment.

Q: Do these major clean energy cost reductions, which have been occurring steadily for decades, seriously threaten the economics of coal and gas-fired generation?

A: Absolutely. These cost reductions do indeed threaten, in fact imperil, the future for coal and gas generation. The LCOE of gas and coal generation are in excess of integrated renewable and battery storage systems now, which suggests DTE should rely on renewables, storage batteries, demand response, and energy efficiency.

Q: Are there examples of integrated battery storage plus wind or battery storage plus solar generation at low competitive prices?

A: Yes, Xcel Energy has received wind-plus-storage bids at an average price of $21 per megawatt-hour (2.1 cents per kWh). Idaho Power's 20-year PPA at a published price of $21.175 per megawatt-hour. (https://www.greentechmedia.com/articles/read/record-

[15] *The changes are being made faster than initially planned, Anderson said, and the moves won't result in rate hikes for DTE's customers.* L. N. Flemming, DTE Energy speeds up closing of coal-fired plants, The Detroit News, Published 6:48 p.m. ET March 28, 2019 | Updated 8:00 p.m. ET March 28, 2019, https://www.detroitnews.com/story/news/local/michigan/2019/03/28/dte-energy-speeds-up-closing-coal-fired-plants/3303608002/

low-solar-plus-storage-price-in-xcel-solicitation#gs.e02e3f) There are other recent battery storage and renewable projects between $21 and $27.25 per megawatt-hour for long-term PPAs. (https://www.greentechmedia.com/articles/read/idaho-power-signs-super-low-solar-ppa-to-buoy-100-clean-energy-plans#gs.dzzhqp)

Q: Is ramping capacity, both up and down, much needed in the DTE resource mix going forward?

A: Yes, ramping capacity will be increasingly required as DTE relies more on renewable resources, including wind and solar generation.

Q: Can wind plus storage and solar plus storage resources provide flexibility, specifically to enable major ramping needs, both up and down?

A: Yes, storage batteries provide substantial flexibility, particularly to provide ramping, up and down, if authorized to be deployed.

Q: How does DTE determine ramping requirements for internal purposes so that it can dispatch resources to meet loads, especially intra-hour?

A: DTE apparently does not internally estimate or calculate ramping requirements it can provide, which is surprising. Rather DTE relies on MISO. In response to ELPCDR 2.41, DTE explained as follows: "During actual operations, DTE does not determine the specific resources selected by MISO to provide the necessary ramp capability and ancillary services to address variability of net load." (ELPCDE-2-41)

Q: What is your estimate of the value of added ramping flexibility offered by wind plus storage or solar plus storage facilities, which Belle River and Monroe coal units cannot provide?

A: This ramping capacity will be more valuable than traditional system Resource Adequacy (RA) as it can be i) local RA, as compared to system RA, in areas where ramping is more in demand, and ii) flexible RA that can respond faster and for a specific duration to meet MISO needs, including intra-hour needs (to avoid criteria violations and system-level outages).

Q: What are the modeling implications of DTE's removal of fixed O&M costs in the Starting Point resource mix?

A: As a result, Strategist does not properly calculate the avoided costs, to provide reference cost/price levels for resource selection, nor will it properly calculate the avoided capacity costs, in reference to resource selection or market cost/price levels. The overall results are that the DTE Starting Point scenario assumptions, calculated by Strategist, will severely understate the threshold needs for new resources, falsely showing a set of resources to be uneconomic, such as energy efficiency, storage, demand response, and as well solar and wind resources.

Q: Is DTE in error with excluding fixed O&M costs, including environmental capital costs, in DTE's Strategist analysis, while it says total costs are the metric to compare new and existing resources. If so, does DTE "stack the deck" in favor of existing resources, against new resources, by at the same time adding fixed O&M resources to all new resource additions?

A: The problem this creates is very obvious; in so doing DTE understates, again, the costs of the existing DTE resources mix in comparison to the costs of new resources to be considered.

Q: How then do the economics of continued operation of Belle River and Monroe coal units compare to wind plus storage or solar plus storage units that are being used at the present?

A: The Belle River and Monroe coal units appear to generate energy at bus-bar costs (without losses) of approximately $29/MWH, face likely increases in variable O&M (with increased environmental mitigation), have lower capacity factors, and relatively high forced outage rates. Increasingly, wind, solar PVs, and batteries can provide energy and capacity, including significant ramping capacity, at lower total costs. In short, Belle River and Monroe in comparison to new alternatives are too expensive. DTE could acquire wind plus storage or solar plus storage and place these units in service in the next two to four years; these options look to be more than competitive.

F. DTE's Scenario Analysis Seems Slanted to Select Either Belle River Coal Units or Gas CCGT

Q: Does DTE witness Pfeffer misstate the Commission's directive to in "DTE Electric Company's integrated resource plan filing…include an additional scenario that evaluates a portfolio consisting of energy efficiency, renewable energy, demand response, storage, and other non-fossil fuel options, ramping up over the years preceding 2029, that could augment the approved natural gas combined cycle plant in 2022, and replace the capacity and energy lost due to the retirement of the Belle River Power Plant"? Page 127 U-18419.

A: Yes, witness Pfeffer's testimony truncates and so misstates to say "the Commission directed the Company to: … include an additional scenario evaluating a specific portfolio ramping up over the years preceding 2029, that could replace the capacity and energy lost due to the retirement of the Belle River Power Plant…" (SGP-10 to 11)

Q: Why is this truncation and misstatement important?

A: It indicates that DTE is not interested to perform the analysis requested by the Commission, specifically to "[evaluate] <u>a portfolio consisting of energy efficiency, renewable energy, demand response, storage, and other non-fossil fuel options</u>, ramping up over the years preceding 2029" to replace the Belle River coal units.

Q: What did DTE do in its attempt to address the Commission's directive?

A: DTE provided a Belle River retirement analysis, but it does not follow the Commission's directives to "[evaluate] a portfolio consisting of energy efficiency, renewable energy, demand response, storage, and other non-fossil fuel options, ramping up over the years preceding 2029." Instead, DTE evaluates the capacity need "optimized with the Strategist® model and filled with IRP alternatives including the coal units themselves, running for an additional four years, until 2029/2030." (LKM-87-88)

Q: Are there significant differences between critical cleaner energy scenarios, which promise lower costs and a fixed cost "fuel hedge," compared to the Belle River scenario?

A: No. The NPVRR cost differences are not significant with DTE's renewable and DER assumptions that are very conservative (LKM-87). The situation changes, however, if more updated assumptions are used that reflect major renewable and DER costs declines. The Belle River retirement sensitivity shows with greater EWR, DR, and wind to back-out Belle River coal units, the cost is only $55M greater in NPVRR (0.45 percent). DTE witness Mikulan states this succinctly as follows: "The lowest cost plan that replaced

Belle River contained DR and wind in the ET scenario at a cost increase of $55 million NPVRR." (LKM-107, Table 31) Similarly, even with the 24% electric vehicle (EV) sales growth increase (Bloomberg) the N-scenario costs decline by $540M. (LKM 89-90)

Q: Do you recommend adoption of the Gas CCGT proposals offered by DTE in this case?

A: I do not for a set of reasons. First, gas price risk – of higher gas costs – was not considered in the main scenarios compared in the DTE IRP, which were summarized in witness Mikulan's testimony. The cost of gas price hedging is also not included in these scenarios. Risk is considered only in a separate sensitivity. Second, costs related to criteria pollution impacts and GHG impacts are not directly compared in various main scenarios. Third, the locational aspects of DTE's ramping needs, discussed by DTE witness Chang, cannot be met but at most for one location (where the plant is located). DTE will no doubt need a more distributed set of resources to address its ramping needs as more renewables and DER resources are installed. Fourth, large central station generation with a 30 year life will no doubt be "under water" economically – "out of the money" and thus stranded -- as the price trajectories of renewables and DERs show, a situation now faced even for hydro generation in other jurisdictions. Moreover, it will be difficult and costly to purchase hedging to counter this substantial, otherwise expected risk.

Q: Do you basically agree with DTE's summary of the key drivers of the results in the four main scenarios?

A: Yes, in some ways. As DTE explains, "[t]he four key drivers of these variances were: Future CO2 regulation and resulting CO2 prices, EWR incentive cost, Gas price forecast uncertainty, Wind and solar power's assumed cost and operating characteristics. A variance in any one of the above four drivers was capable of changing the least-cost plan results on its own . . . the drivers' costs are changing rapidly, leading to future uncertainty." (LKM-116) I agree the variances in these four drivers show any one of them can change the perceived best outcome.

Q: Do you recommend qualifications to DTE's summary of the key drivers of scenario variances?

A: Yes, a set of qualifications seem appropriate, as follows:

1) CO2 prices are discussed as a driver, but neither is natural gas leakage – a more powerful GHG – discussed or included in the NPVRR, nor are criteria pollutants (NOx, SOX, PM2.5) discussed, but both environmental cost categories should be;

2) EWR incentive costs should be allowed to be greater than 50% (DTE's current cap) in specific targeted situations, such as to lower building loads in high grid cost locations;

3) natural gas price uncertainty is a very important driver, not addressed in the four scenario analysis;

4) major wind and solar price declines are certain and predictable, but not addressed in the 4 scenario analysis, nor are declines in DER prices recognized as we enable the Internet of things; and

5) battery storage integrated with renewables is not a focus point of DTE's key drivers and should be.

In this light, it seems imprudent to leave Bell River coal units in place until 2030.

III. DTE's Evidence Shows Need for Ramping but Fails to Recognize Pervasive Cost Declines in Competing Clean Resources

Q: Was any load flow analysis considered or used in the evaluation?

A: No, apparently the only analysis done was "a stochastic analysis to assess the resource adequacy [and] an operational simulation of the MISO market…for the years 2031 and 2040…"

Q: Is a conclusion drawn about voltage level deficiencies?

A: Yes, DTE's witness states, "existing generation facilities currently operating in Zone 7 provide valuable voltage support to maintain transmission reliability and import capability to Zone 7 from the rest of MISO. As they retire, specific investments may be needed to restore Zone 7's CIL to current levels. If any future decline in Zone 7's [Capacity Import Limit or CIL] were not addressed, the zone's resource adequacy could be adversely affected." (Pg. 6 of J. Chang's direct testimony).

Q: Without load flow analysis or greater resort to MISO's transmission evaluation process does the DTE evidence have a studied basis to make its conclusions about voltage level needs in 2031 and 2040?

A: No, DTE does not provide or even develop technical information or analysis about potential voltage level deficiencies in this record to form the basis for its conclusions on this matter, except by conjecture. Moreover, it appears that the DTE analysis relies on an older view that wholesale generator momentum or inertia is essential as greater amounts of renewable resources are deployed (which purportedly lack this inertia). This ignores the more modern view that a host of distributed and utility renewable, storage battery, and smart inverter technologies will increasingly provide voltage support, replacing the momentum or inertia previously viewed as only available from rotating mechanical systems.

Q: With respect to the risk of reliability for DTE is there a crux or focus point that the DTE analysis claims is most important?

A: Yes, the DTE analysis claims the focus should be on DTE's ability to use Ludington and flexible DR as these resources are "very valuable." The Brattle report provided for DTE explains: "All the simulated outcomes for the scenarios analyzed depend greatly on assumed ability for Zone 7 to leverage Ludington and flexible DR. Thus, these two types of resources, while very valuable, will present risks for how well Zone 7 can meet its reliability standards for [Loss of Load Expectation or LOLE]." (Brattle Report at pg. 18.)

Q: How are DTE's operational needs evaluated going forward?

A: "We simulate the MISO system by co-optimizing the energy market and six types of ancillary services products (regulation up/down, spinning reserve, supplemental reserve, and ramping capability up/down). This is generally consistent with the way MISO operates its system." (Pg. 21.)

Q: Does DTE believe it will face high risks by 2031 in terms of the need for resource adequacy or ramping capacity?

A: No, but by 2040 DTE suggests that additional ramping needs will be required. "From our operational simulations of the MISO market for 2031 and 2040, we find that MISO Zone 7 would be able to integrate and harness available renewable resources in 2031. However, by 2040, the system's ability to integrate available renewable resources and harness their full benefits could be degraded significantly. This is evidenced by increases in negatively priced hours—reaching almost 10% for the year in real-time by 2040, and by increasing renewable generation curtailments, which rise to approximately 1% of total renewable generation output capability for 2040."

Q: Is there a positive implication from the conclusion that there would be "increases in negatively priced hours – reaching almost 10% for the year in real-time by 2040?

A: Yes, there are a number of positive implications, which at the same time seem likely to reduce the curtailment of renewables – "spilling" of zero marginal cost energy. Most importantly, storage batteries and electric vehicles (EVs) can take advantage of negative or low-priced energy. In both cases, greater capacity can be made available from this "excess" energy production. The excess energy can charge storage batteries that, with declining costs, are then used increasingly for ramping capacity and other related services.

Q: Does DTE elaborate on the frequency of lower priced hours for MISO energy and do you agree with the implications presented?

A: The DTE report explains as follows: "As prices become significantly more negative, it becomes more economic to curtail renewable generation output than to turn down other generation resources. At this point, the system has excess generation and cannot harness its full benefits." I agree there will be more incidence of low and negatively priced hours for energy through MISO, but see this as a major positive as this is the result of more zero marginal cost renewable energy production. I do not agree with the DTE implications that "the system…cannot harness its full benefits." This "excess generation" in DTE terms is provided by zero marginal cost resources that can be fully used with storage batteries, EVs, and strategic demand response, including virtual storage (to pre-heat and pre-cool). In the time frame from say 2022 to 2040, storage batteries, EVs, and demand response will be used much more to achieve grid system integration and optimization.[16]

Q: What does DTE suggest in the DTE report about the prices for ramping and related ancillary services?

A: The DTE report states as follows:

- *In our operational simulations, we observe a significant increase in the market prices for regulation service between 2031 and 2040.*
- *When there are high demands on regulation services, it signifies that the system is using higher costs resources to ramp up and down at the last minute.*
- *The high prices observed for regulation services shown in our simulations, therefore, further corroborates* [sic] *the observations made in the prior section, and highlight the fact that the system is beginning to deplete the resources that have the ability to ramp up when needed.*

Q: Does the DTE Report provide a well-grounded forecast of the possible prices for ramping and ancillary services?

A: No, it does not. The DTE report provides its "simulations of the MISO regulation ancillary services product" in a range from $15 to $50 per MWh. (Brattle Report, pg. 30) As the DTE evidence notes, MISO's regulation ancillary service product is neither Reg-Up, nor is it Reg-Down. It is what is sometimes referred to as the "symmetrical frequency regulation product" as it is expected to move more or less symmetrically around the 60 Hertz cycle to ensure frequency regulation; in this sense it is the lower value frequency regulation product, compared to separate Reg-Up and Reg-Down frequency regulation

[16] See generally, E. Woychik, H. Chen, D. Erickson, *The Dynamics of Wholesale and Distributed Energy Markets*, Smart Grids: Advanced Technologies and Solutions, Second Edition, CRC Press, 2018.

products.[17] Finally, DTE fails to ground its forecast of ramping needs in load-flow analysis that directly impacts ramping needs.

Q: Does MISO assume the symmetrical frequency regulation product is for ramping, such as to address 5 minute between hour generation-load balancing?

A: Not at all; rather symmetrical frequency regulation it is meant to be used to limit "Area Control Error" (ACE) in short to keep the alternating current (AC) grid system "clock" as close to correct as possible. Some generators are on "Automatic Generation Control" (AGC) to provide response to ACE as a standard symmetrical service. That said, symmetrical frequency regulation can be used to correct for ramping needs, though frequency regulation is typically an excessively fast response (sub-second to 5 seconds) when much slower adjustments to balance the grid can be used, such as DTE recommends with its pumped storage hydro plant.

Q: Do the DTE witness Judy Chang (of Brattle), and the related Brattle report, make similar mischaracterizations in this composite testimony, such as to say that MISO's Resource Adequacy (RA) is needed and does the DTE witness confuse ramping energy with ramping capacity, such as by forecasting frequency regulation service in MWHs when it makes the case for need of ramping capacity in MWs (as from pumped hydro storage)?

A: Yes, the DTE witness and the related report have these things quite muddled, conflated, and as a result the DTE evidence is unclear about what is actually needed and recommended going forward. More ramping capacity may indeed be required, some at faster availability times than MISO's current RA, as explained in the DTE report.

[17] The Brattle Report at footnote 37 explains, "MISO does not differentiate between RegUp and RegDn." Pg. 30

Q: Does the DTE witness and report properly explain the locational MISO requirements for frequency regulation as an ancillary service (which must be FERC approved)?

A. No, instead DTE's evidence suggests that it is risky to rely on resources outside of DTE's footprint or Zone 7. "In our simulations, we find that Zone 7 would rely on neighboring zones significantly (particularly for imports) to balance Zone 7's supply and demand..." (Brattle Report at Pg. 31) But in fact MISO-wide frequency regulation needs can be addressed outside the DTE service territory (Zone 7) just as easily as it can inside DTE's territory (Zone 7), as frequency regulation corrected any place in the MISO grid system is equally effective.[18] Accordingly frequency regulation does not usually have a locational requirement.

Q: Why does the DTE evidence jump to the conclusion that Combustion Turbines (CTs) will be used more for ramping to load follow[19], as the typical CT does not ramp or follow load, but is dispatched to specific set points or "preferred operating points" (POPs)?

A: It is often misunderstood; CTs do not seamlessly ramp or move up and down to deliver ramping capacity, but are dispatched to POPs, as when they more off POPs they both lose plant efficiency and increase environmental emissions (e.g., NOx).[20] Lack of knowledge about the actual operation of CTs is the likely problem. Incorrectly, the DTE report states as follows: "dispatchable gas-fired CTs in Zone 7 would **increasingly be used to**

[18] Frequency regulation is "lagged" across the MISO system, at any point or node, only by the speed of light.
[19] The terms "load follow" are meant by this witness to indicate net load following of both supply, including renewables, and demand, to address net load curve needs.
[20] When a CT is dispatched to a higher level, deviating output little around POPs, a wide set of other plants are used that can follow load to meet ramping requirements. The Ludington Pumped Hydro unit would not face these constraints and could ramp to load follow much more directly.

provide ramping services to compensate for more variable net load." (Brattle Report, pg. 32, emphasis in the original).[21] CTs are not easily used as ramping resources unless specially fitted to have broader range around POPs, which severely compromise thermal efficiency, reduce cost effective operation, and limit operation to periods when energy prices spike to high levels.

Q: Are integrated renewable and storage battery systems now viewed as primary sources of ramping product, both for ramping energy and capacity?

A: Yes, and as explained in other parts of this testimony, the costs of integrated solar PV plus battery and wind plus battery systems are dropping rapidly. These systems will also be increasingly available to remedy voltage and reliability needs at the wholesale grid, local, and distribution levels.

Q: What are the implications of this rapid decline in costs for renewable plus battery integrated systems, and the availability of these systems, both at customer-side of the meter and at utility scale.

A: It is not difficult to see that by the time that the DTE analysis suggests greater ramping will be needed, around 2031 through 2040, that DTE will face these circumstances:

- Dramatically lower costs for integrated renewable plus battery systems that provide voltage/VAR correction, locational capacity needs, and low-cost ramping energy/capacity.
- Greater integration of wholesale grid needs and distribution grid needs, enabled significantly by the low cost availability of distributed and utility scale renewable plus storage systems.

[21] INSERT FOOTNOTE TEXT!!!!!

- Increased use of virtual storage by pre-cooling and pre-heating buildings, which reduce the costs of ramping and voltage/VAR correction.
- The ability to meet customer and grid needs at lower costs through integration and optimization of distributed energy resources.

Q: What are the projected costs of battery storage systems in 2020 and beyond?

A: Battery storage systems, for example to supply four-hour resources, are projected to fall to $220 per kWh by 2040.[22] As electricity markets mature to properly price these assets and technology costs rapidly decline, utility-scale deployment alone is expected to reach 220 GW by 2040.

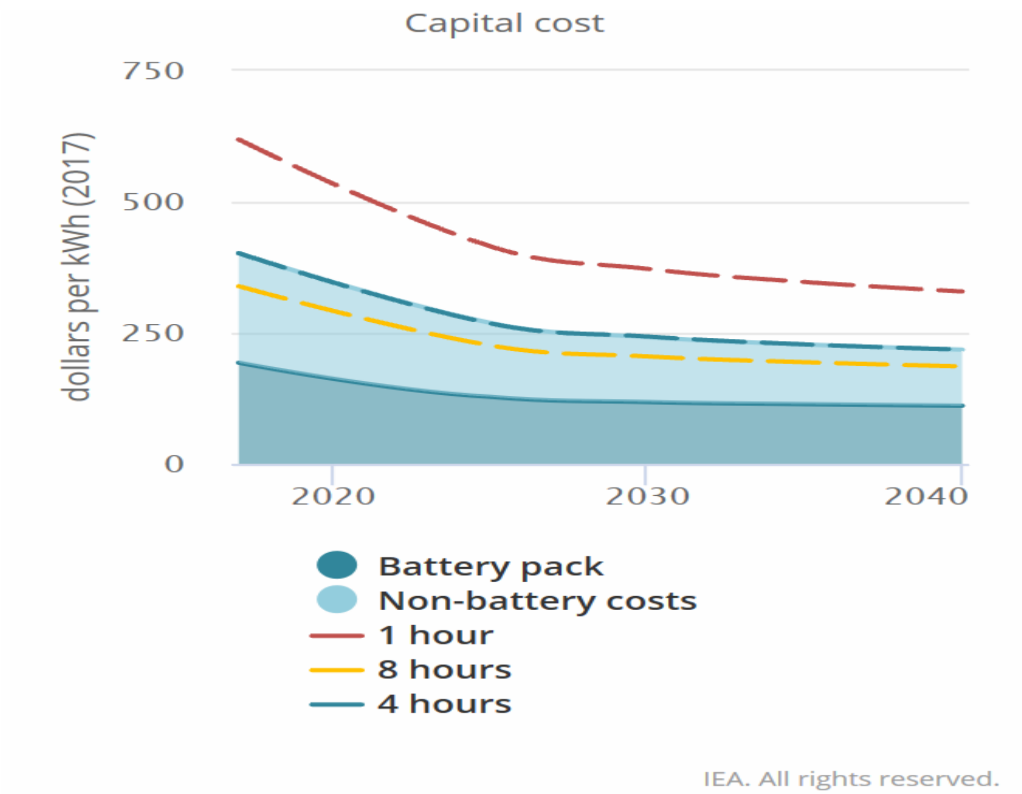
Q: Does "option value" play a role in the use of new renewable and battery storage systems, and if so why?

A: Option value, which is partially reflected in financial options but can be simply also understood as the number of options, some in the future so unknown, where renewable and battery storage systems can be used. Option value is indeed a major driver of scale and scope for these systems, to further lower related costs, including through options to buy-down the original costs.[23] Battery storage resources can be used, optionally, for flexible ramping, voltage/VAR support, locational capacity, instructed energy, emergency capacity, locational constraints, Resource Adequacy, frequency regulation including separately Reg-Up and Reg-Down, as well as symmetrical frequency regulation, operating reserves, market arbitrage, black-start capability, and system peaking capacity.

[22] See, International Energy Agency, Deployment and Costs of Utility-Scale Battery Storage Systems in the New Policies Scenario, February 2019, at https://www.iea.org/newsroom/news/2019/february/battery-storage-is-almost-ready-to-play-the-flexibility-game.html.
[23] In "electricity market speak" this option value includes intrinsic and extrinsic market value.

Q: What does the International Energy Agency ("IEA") project the trajectory of capital costs to be for battery packs out to 2040?

A: The following graph shows this expected cost trajectory for 1 hour, 4 hour, and 8 hour battery systems. Even where there are no significant environmental requirements, battery plus renewable systems will be fully replacing peaking capacity and ramping needs immediately.



Q: Does the DTE testimony discuss the need for voltage support to maintain transmission reliability and import capability?

A: Yes, but voltage support at the grid level requires load flow analysis, which was generally not performed as part of the DTE analysis.

Q: Is load flow analysis important to understand voltage support needs at the grid level?

A: It is essential to know what the sources of potential voltage needs may be at the transmission level, especially with expected increased use of renewables, distributed energy resources, and electrification, which is the case for DTE.

Q: If load flow analysis is not performed, can conclusions about voltage needs be properly supported?

A: No, load flow analysis is critical to define how voltage and volts-amps-reactive (VAR) or power factor needs will change, especially at the distribution level, as voltage and VAR vary almost entirely at locational levels, such as to define where voltage-support must-run generation may be needed.

Q: Can voltage/VAR correction be provided by solar and storage battery smart inverters at specific locations, and if so did DTE provide any analysis of this?

A: Voltage/VAR correction can be provided by solar and storage battery smart inverters, which can operate automatically to provide voltage/VAR correction, providing a new source of value from distributed and utility scale resources. DTE did not evaluate these sources of "ancillary services" that are so important to voltage/VAR as we proceed to the new distributed energy future.

Q: What is your opinion about both the availability and the cost of this set of highly locational voltage/VAR resources?

A: Voltage/VAR, and as well capacity and frequency regulation, are currently and will be increasingly widely available from smart inverters at relatively low cost, as new smart inverter standards make these innovative technologies available at scale. Smart inverters are required adjuncts with the use of cost-effective solar photo-voltaic and storage battery resources which are rapidly declining in costs.

Q: What are the implications of the DTE evidence for DTE in this case?

A: The DTE evidence points properly to the need for additional ramping energy and capacity, but fails to account for the major declines in costs of competing clean resources that can be available to meet these ramping needs. CTs, CCGTs, and traditional pumped hydro are all simply too expensive to deploy compared to integrated renewable and storage battery systems. Moreover, as integrated renewable and storage battery systems can be installed locationally, particularly to meet specific voltage/VAR and capacity needs at both transmission and distribution levels, these resources have greater option value.

Q: Does this suggest that the resource needs recommended for DTE by the Brattle evidence are too prescriptive and too narrowly focused on expensive fossil and traditional pumped storage resources?

A: Yes, it does; renewable resources can be more fully used, to net substantially lower overall costs, while providing a full range of customer, transmission grid, and distribution grid resources, particularly to enable greater reliability, system flexibility, lower costs, and at the same time reduce renewable resource curtailments.

IV. Conclusion

Q: What are your conclusions in light of the evidence reviewed?

A: In the light of evidence I draw a set of conclusions from the DTE evidence as follows:

- DTE's Proposed IRP Fails to Devise a Reasonable and Prudent Process to Provide Energy and Capacity;

- DTE "Papers-Over" the Economics of Belle River and Monroe Coal Units by Bundling these Plants in a "Starting Point Scenario" and Ignoring Fixed O&M;
- DTE Pushes the $500M in Coal Plant Environmental Mitigation Costs Into Future Proceedings Ignoring These Costs In this IRP Economic Analysis;
- DTE's IRP Does Not Achieve The Balance Outlined Under Michigan Statute;
- DTE's IRP Vastly Underestimates Growth in Electric Vehicles;
- DTE's IRP Fails to Recognize the Rapidly Declining Costs of Storage Batteries, Solar PVs, Wind, and Integrated Behind-the-Meter Resources;
- DTE's Scenario Analysis Seems Slanted to Select Either Belle River Coal Units or Gas CCGT;
- DTE's Evidence Shows Need for Ramping but Fails to Recognize Pervasive Cost Declines in Competing Clean Resources.

Q: Does this conclude your testimony?

A: Yes.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
DTE ELECTRIC COMPANY	)	Case No. U-20471
for approval of its integrated resource plan	)	
pursuant to MCL 460.6t, and for other relief	)	

EXHIBITS OF

ERIC WOYCHICK

ON BEHALF OF

THE ENVIRONMENTAL LAW & POLICY CENTER,
THE ECOLOGY CENTER,
THE SOLAR ENERGY INDUSTRIES ASSOCIATION,
THE UNION OF CONCERNED SCIENTISTS,
AND
VOTE SOLAR

AUGUST 21, 2019

DR. ERIC WOYCHIK

Senior Vice President, Executive Consultant

Regulatory Policy & Ratemaking Analysis
Lecturer and Speaker
Market Valuation
Expert Testimony
International Electricity & Gas Market Structure
Smart Grid Development, Investment, Business & Market Strategy

Education:

Doctorate in Management, Case Western Reserve University (Energy Market Game Theory)
M.A. Economics, New Mexico State University (Network Industries)
B.S. Environmental Policy Analysis and Planning, University of California, Davis (Clean Energy)

Total Years of Experience: 40

Selected Professional Roles:
Executive Consultant. Advisor & Founder, Strategy Integration, LLC 1992-present
Partner & Co-founder, The Energy Collaborative, 2013-2018
Executive Consultant & Senior Principal, Itron, Inc. 2011-2013
Director, Utility Strategy Practice, Black & Veatch, Inc. 2009-2011
Vice President. Regulatory Affairs & Senior Development Director, Comverge, Inc. 2004-2009
Senior Principal, Policy & Regulatory Strategy, Synergic Resources Corp, 1990-1992
Commissioner Advisor, Cal. Public Utilities Commission, 1985-1990

Association/Board Memberships:
IEEE – Advanced Technology
American Economic Association
Community Options for Families & Youth, Board, 2008-present
CS Lewis Society, Board, 2007-12
Demand Response and Smart Grid Coalition, Board, 2008-2010
California Independent System Operator, Board, 1999-2002

Hobbies: Hiking, bicycling, fishing

Dr. Woychik is an expert and thought leader on regulatory policy, investment strategy, business models, geospatial valuation, wholesale energy markets, transformational change, and smart grid development. This includes more than 40 years of experience with over 45 countries to develop clean energy and traditional markets with utilities, technology providers, control operators, energy companies, stakeholder groups, and state and national regulatory bodies. Areas of focus include smart grid integration, optimization, the geospatial business case, business model development, transactive energy, and the utility of the future. Dr. Woychik has been an expert witness in over fifty regulatory and civil proceedings on energy resources, markets, and valuation.

Representative Experience

Regulatory Policy & Ratemaking Analysis

Recent projects include leadership roles in California's regulatory proceedings on Distribution Resource Plans, Integrated Demand Side Resources, and the Demand Response Settlement. Other projects have included a comprenehsive energy efficiency portfolio review (California's $3.2B utility spend), new clean energy and rate-case policy (e.g., for Entergy), marginal-cost rate design/revenue allocation, cost-of-service and productivity analysis, transmission expansion, generation expansion and refurbishment, demand-side management, and distribution line extension policy. A subset of these related efforts follows:

- Extensive policy, program, and regulatory consulting on energy efficiency, demand response, distributed generation, storage, integrated demand-side management (IDSM), and water-energy-nexus.
- Panel design and moderator for utility incentive ratemaking to address risk and performance.
- Co-developed incentives for performance-based ratemaking in San Diego Gas & Electric proceedings.
- Provide financial basis for demand-side strategy based on consumer choice, cost-effectiveness, production cost modeling, and discounted-cash-flow at Southern California Edison.
- Developed underground distribution line-extension build-out strategy and policy in California.
- Advised on advanced energy metering implementation and policy in the U.S.
- Extensive expert witness testimony on energy utility distribution and line-extension build-out.
- State Commissioner Advisor and manager of numerous general rate case and project proceedings.
- Co-developed and implemented the groundbreaking equal percentage marginal-cost (EPMC) revenue allocation and rate design process and related rates for California electric utilities.
- Energy Analyst, Local Government Energy Planning Handbook, Cal. Energy Commission, 1982-83.
- Chair and Co-chair, City of Davis Electricity Load Management Committee, 1979-80.

Lecturer and Speaker

Dr. Woychik has been a guest lecturer or speaker at Case Western Reserve University, Harvard University, Lawrence Berkeley Laboratories, Michigan State University, New Mexico State University, University of California Berkeley, University of California Davis, University of California Santa Barbara, University of Georgia, Saint Mary's College, and numerous conferences.

Market Valuation

Develop and apply methods to value and define resource and technology portfolios based on market metrics:

- Ongoing advisor to international financial investors engaged with smart grid and energy companies.
- Business plan analysis and development focusing on determination of marginal value and uncertainty.
- Business case analysis of distributed resources and electricity markets for Africa (Ghana, South Africa), Asia (China, Hong Kong, India, Indonesia, Japan), Australia (New South Wales, Victoria, Tasmania, Western Australia), Central Asia (Armenia, Romania, Kazakhstan, Kirgizstan, Tajikistan), Europe (Denmark, England, Finland, Holland, Norway, Hungary, Scotland, Sweden, Poland, Ukraine, Wales.), Russia (5 regions), and North America (6 Canadian provinces, Mexico, Puerto Rico, and 39 U.S. states).
- Valuation of U.S. utility company merger for a large international energy company, focusing on integration of options across multiple RTOs/ISOs.
- Develop model components and methods for smart grid and demand-side management valuation with over one-hundred utility clients.
- Integrated demand-side management (IDSM) cost-effectiveness white paper with California utilities and Public Utilities Commission.
- Demand-side management and smart-grid integration based on probabilistic methods for investor-owned utilities.
- Photovoltaic and battery system optimization and market valuation.
- Photovoltaic system integration, valuation, and cost-effectiveness.
- Financial valuation of all demand-side opportunities for Southern California Edison, based on detailed production costs, capacity, and financial modeling.
- Detailed economic modeling of supply and demand-side options, including consumer adoption for numerous utilities in the U.S., Canada, Australia, Europe, and India.
- Testimony on the economic and regulatory drivers to value a large portfolio of electricity and gas assets in the U.S., Canada, and U.K.
- Economic and option value methods to value demand response for Comverge and a host of other demand-side vendors and utilities.
- Co-author of the original California Standard Practice Manual (SPM) for cost-effectiveness of conservation and load-management (1982).
- Economic valuation of all building energy efficiency, demand response, and solar thermal options for all California building types.
- Development and administration of avoided cost (standard offer) contracts for California's independent power development.
- Economic and rate-impact valuation methodology for all demand-side options in Eastern Australia (New South Wales and Victoria).
- Economic and financial valuation of independent power facilities in Indonesia.
- Economic and rate-impact valuation methodology for demand-side options in Hawaii.

Expert Witness Testimony and Litigation Support

Testimony and litigation support provided on over fifty occasions including work in these situations:

- Valuation of an independent power producer's 30 GW portfolio of plant and gas assets (in U.S., Canada, and U.K.) based on forward energy markets, modeling, and regulatory policies.
- Development of demand response valuation, ramping capacity need, capacity goals, baseline methodology, dynamic pricing, and GHG reduction for Alternative Energy Resources/Comverge, Inc.
- Development of energy policy mechanisms for demand-side management, shareholder incentives, contribution to lost margin, cost-recovery, smart-grid, pricing, policy, and planning for Entergy Corp.
- Define the implications for competition, resource planning, and direct/retail access in Arizona.
- Justify the cost-effectiveness of electricity end-use appliances, efficiency standards, modeling, and assumptions in a Department of Energy Proceeding for the Edison Electric Institute.
- Recommend the electric market redesign, congestion pricing, and market valuation of reliability-must-run generation in two proceedings before the Alberta Energy Utilities Board for the Firm Group.
- Integration of demand response in PJM, ISONE, MISO, including market design and rules, comprehensive market attributes, and pricing, for Demand Response Supporters and Comverge Inc.
- Recommendations on electricity markets, the dispatchable benefits of demand response, multi-market and locational benefits, in Maryland, Nevada, Pennsylvania, and Texas, for Comverge, Inc.
- Provide best practices in competitive electricity transmission, pricing, and generation markets, as well as competitive gas transmission and gas commodity pricing, for Western Australia.

International Electricity and Gas Market Structure

An international expert on competitive electricity and gas reform since the mid-1980's:

- Expert Advisor, competitive market risk assessment, business planning and financial analysis, Russian Federal Grid Company.
- Executive Consultant to China Light & Power on options for smart grid and demand-side business case scenarios (full-scale roll-out).
- Electricity market advisor for Romania to prepare for EU membership.
- Comparison of Northern European and Western U.S. electricity markets.
- Team leader for 9-country Europe project on electric market structure options (comparing 7 major competitive electricity markets).
- Team leader to provide grid code for Kazakhstan Electricity Grid Co.
- Chief of Party and strategist to develop and implement electricity markets in Central Asia to link Kazakhstan, Kirgizstan, and Tajikistan with Afghanistan, Pakistan, and India.
- Deregulation and competition; New Brunswick Power, Canada.
- Team leader at Kazakhstan Electricity Grid Co. collaboration with California Independent System Operator on market structure formation, to create workable competitive energy and capacity markets.
- Team leader for power sector reform evaluation, Ukraine, Belarus, and Moldova.
- Advisor on electric market legislation and privatization in Ukraine.
- Electric power restructuring and regulatory reform for Ghana.
- Consumer access through POOLCO, comparison of England/Wales pool model and bilateral contracts models, California IOU.
- Comparison of international competitive market models, cost-of-service, and performance-based-ratemaking for Russia's RAO UES.
- Principles, objectives, & strategy for competitive gas reform in Western Australia.
- Principles, objectives, & strategy for competitive electricity reform in Western Australia.
- Five electric industry reform assessments for Russia, comparing electricity market models from England/Wales, Scotland, New Zealand, Norway, U.S. (managing noted experts from U.K. National Grid, Southern California Edison, and American Electric Power).
- Energy transmission access and pricing for Western Australia, Energy Implementation Group.

- Strategy and analysis for Russian gas industry reform and energy efficiency, World Bank.
- Strategy for preferred electric & gas markets in Australia (New South Wales, Victoria, and Tazmania).
- Electricity market analysis for Norway's Statkraft and Oslo Lysverker.
- Use of demand-side management in electricity markets for Scandinavian consortium of Denmark, Finland, Norway, and Sweden (ASEA).
- Recommendations on legislation and market structure to create Norway's groundbreaking competitive electricity market (for Northern Europe).
- Evaluation of England/Wales electricity market protocols and uplift rules, and comparison of England/Wales and Scotland markets.
- Cost-effectiveness of market and demand-side options for Victoria and New South Wales, Australia.
- Alternative generation valuation, contracting & pricing in Indonesia.

Smart Grid Development, Investment, Business & Market Strategy

This includes work on solutions, strategy, and business models, and policy for, among others, the following:

- Austin Energy
- British Columbia Hydro
- California Independent System Operator
- California Integrated Distributed Energy Resources (IDER) process
  - Competitive Solication Working Group
  - Cost-Effectiveness Working Group
  - Integrated Capacity Analysis and Locational Net Benefits Analysis Working Groups
- Central Maine Power
- China Light & Power
- Commonwealth Edison
- Comverge
- Detroit Edison
- Duke Energy
- Edison Electric Institute, Alternative Regulation Working Group
- Electric Power Research Institute (electric & gas smart grid options)
- Enbala Power Networks
- Energy Foundation (U.S. wide)
- Integral Analytics
- Itron (strategy and business proposition analysis on three continents)
- Investment Bankers (Australia, Canada, Europe, Japan, Korea, U.S.)
- Kauai Island Utility Coop
- National Grid (U.S.)
- Nevada Power
- NIST Transactive Energy Business and Regulatory Models WG
- OhmConnect
- San Diego Gas & Electric
- Southern California Edison
- Tendril
- U.S. Trade & Development Agency
- Vote Solar

Selected Regulatory Reports, Publications, and Presentations

Smart Grids: Infrastructure, Technology, and Solutions, 2nd Addition, Stuart Borlase, Editor, CRC Press, 2018 (author of multiple chapters on markets, policy, and future vision).

T he Poli cyma ker ' s T ool ki t: V it al Questi ons about Propose d Tra nsac ti ve Ener gy Syst ems , NIST Transactive
Energy Challenge: Business and Regulatory Models Working Group June 2017 (coauthored).

To Integrate and Optimize the Grid: Locate and Customize Distributed Energy Resources, Advanced Workshop in Regulation and Competition, 30th Annual Western Conference, Monterey, CA, 28 June 2017 (coauthored).

Integration and Optimization of Distributed Energy Resources; Big Data Analytics do the Job, Advanced Workshop in Regulation and Competition, 36th Annual Eastern Conference, Annapolis, MD, 1 June 2017 (coauthored).

Data Issues in the Modern Electricity Grid, Advanced Workshop in Regulation and Competition, 36th Annual Eastern Conference, Annapolis, MD, 1 June 2017 (coauthored).

Seven Conditions Justify Smart Grid Investments, Public Utilities Fortnightly, January 2017.

History and Future of Utility Revenue Decoupling: What Implications with New Business and Market Models? University of Illinois, Gleacher Center, Chicago, January, 2017.

Transactive Energy Models, NIST Transactive Energy Challenge: Business and Regulatory Models Working Group, September 2016 (coauthored).

Steps to Integrate and Optimize DERs, NARUC ERE Staff Subcommittee Webinar, 1 June 2016.

Assessing Electric Utility Potential for a Distributed Energy Future – Scope and Scale from Value-Added Integration and Optimization, Advanced Workshop in Regulation and Competition: 35th Annual Eastern Conference, Shawnee on Delaware, Pennsylvania, 11-13 May 2016, (coauthored).

Utility Efficiencies with Distributed Energy Resources: Scope, Scale, and Dynamic Benefits, Edison Electric Institute, Alternative Regulation Group, Webinar, 11 April 2016.

Locational Net Benefits Analysis: To Integrate and Optimize Distributed Energy Resources for Maximum Value, LNBA Methodology and Demonstration Workshop, California Public Utilities Commission, San Francisco, CA, 1 February 2016.

Developing the Plans: Four Steps Net 2x to 5x Greater Benefits, Utility Variable Generation Working Group: Fall Technical Workshop, San Diego, CA, 14 October 2015.

Electric Utility Adaptation to Disruptive Change: Dashboards for Success and Profitability by 2020? Advanced Workshop in Regulation and Competition: 34th Annual Eastern Conference, Shawnee on Delaware, Pennsylvania, 13-15 May 2015.

The Integration and Optimization of DSM: Extraordinary Benefits when the Orchestra Plays Together, AESP National Conference, Orlando, Florida, 9-12 February 2015 (coauthored).

IDSM Cost-Effectiveness: What Happened Outside of California? Results from Duke Energy, NVE, Avista … presentation in CPUC R. 14-10-003, 22 January 2015.

Methods & Tools to Accomplish Distribution Resources Planning, CPUC DRP Workshop, presentation in CPUC R.14-08-013, 8 January 2015.

Stakeholder Optimization Impacts on Utility Planning and Pricing, Advanced Workshop in Regulation and Competition, 33rd Annual Eastern Conference, Shawnee on Delaware, Pennsylvania, 14-16 May 2014 (coauthored).

Estimating the Value of Service Using Load Forecasting Models, Advanced Workshop in Regulation and Competition: 33rd Annual Eastern Conference, Shawnee on Delaware, Pennsylvania, 14-16 May 2014 (coauthored).
NV Energy Demand Response Program Insurance Value, Presentation at Nevada PUC, Las Vegas, 27 October 2014 (coauthored).

2030 Vision for 100% Clean Energy, Third Global Forum, Business As An Agent of World Benefit, 16 October 2014.

2020 Vision for Utility Business Models and Maximum Clean Energy Value, Discussion with the New York Public Service Commission, August 1, 2014.

Consumer Engagement, Cost-Effectiveness, and Valuation, Shanghai International Demand Response Workshop, 28 July 2014.

Developing New Business Models for Utilities with Renewables, Conservation and the Smart Grid, Advanced Workshop in Regulation and Competition: 27th Annual Western Conference, Monterey, California, June 26, 2014 (coauthored).

Taking the Plunge – Engaging the Water Sector as a Preferred Resource to Meet Local Energy Needs, Advanced Workshop in Regulation and Competition: 27th Annual Western Conference, Monterey, California, 26 June 2014 (coauthored).

Market Guidance for Energy Storage: Steps to Maximize Value, Strategy Integration, May 2014.

Utilities of the Future: Needed Changes in Business Strategy and Regulatory Policy, Advanced Workshop in Regulation and Competition: 33rd Annual Eastern Conference, Shawnee on Delaware, Pennsylvania, 14-16 May 2014 (coauthored).

Utility Build-out of Regional Microgrids with Advanced Analytic Methods: Local Demand Meets Maximum Value-Proposition, Advanced Workshop in Regulation and Competition: 33rd Annual Eastern Conference, Shawnee on Delaware, Pennsylvania, 14-16 May 2014 (presentation, coauthored).

Integration & Optimization of DSM: Extraordinary Benefits When the Orchestra (Energy Efficiency, Demand Response, Distributed Generation, and Storage) Plays Together, Lawrence Berkeley Laboratories, Environmental Energy Technologies Division, 27 March 2014 (coauthored).

Strategic Convening in the Energy Utility Industry: The Case of National Grid, in Organizational Generativity: The Appreciative Inquiry Summit and a Scholarship of Transformation, Advances in Appreciative Inquiry, Volume 4, 273-288, Emerald Press, 2014 (coauthored).

Valuing Integrated Demand Side Management (IDSM) for Improved Cost Effectiveness, DistribuTech Conference, San Antonio, TX, 28 January 2014 (coauthored).

Return On Equity – Making a New Case, Presentation to the Western Energy Institute Spring Symposium, Seattle, WA, 17 March 2011.

Coupling Demand-Side and ISO/RTO Services -- Not With This Market… Presentation to Harvard Electric Policy Group, Los Angeles, 25 February 2011.

New Utility Business Models and Regulatory Incentives: Options to Transform Disruptive Change and Maximize Value, Strategy Integration LLC and The Energy Collaborative, October 2013 (coauthored).

The Paradox of Leading Industry Transformation, The Energy Collaborative, July 2013 (coauthored).

Integrated Demand-Side Management Cost-Effectiveness and Optimization Methodology, Advanced Workshop in Regulation and Competition: 26th Annual Western Conference, Monterey, California, June 21, 2013 (coauthored).

Smart Grids: Infrastructure, Technology, and Solutions, Stuart Borlase, Editor, CRC Press, October, 2013 (contributor to multiple chapters).

Electric Drive By '25: How California Can Catalyze Mass Adoption of Electric Vehicles by 2025, E. Elkind, UCLA Law/UCB Law, September 2012 (contributor).

Integrated Demand Side Management Cost-Effectiveness: Is Valuation the Major Barrier to New "Smart-Grid" Opportunities? American Council for an Energy-Efficient Economy, Monterey, CA 12-17 August 2012 (coauthored).

Engaging Customers at the Touch Points: Implications for the Smart Grid Value Chain, presentation at the National Town Meeting on Demand Response + Smart Grid, Washington, D.C. 27 June 2012.

Value Mapping for Integrated Demand Side Management: A More Advanced Method for Resource Selection? 25th Annual Western Conference; Center for Research in Regulated Industries, Monterey CA, 29 June 2012 (coauthored).

Integrated Demand-Side Management Cost-Effectiveness, Association of Energy Service Professionals, Webinar Presentation, 18 December 2011.

Maximum Market Value and Maximum Customer Choice: Nar the Twain May Meet? AESP'S Fall Conference and Expo: Customer Behavior and the Smart Grid, Association of Energy Service Professionals, Dallas, TX, 4 October 2011

Reality-Based Benefit-Cost Assessment of Demand Side Management Integration: Methods to Maximize Market Capture in Organized Markets, 24th Annual Western Conference, Center for Research in Regulated Industries, Rutgers University, Monterey, CA 15-18 June 2011 (coauthored).

Integrated Demand-Side-Management Cost-Effectiveness Framework, IDSM Task Force, San Francisco, CA, May 2011.

Coupling Demand-Side and ISO/RTO Services -- Not With This Market… Presentation to Harvard Electric Policy Group, Los Angeles, 25 February 2011.

Rx for Integrated Demand-Side Management, Energy Central Webcast, 26 January 2011.

Policy Vision for the Smart Grid: Performance Metrics and Incentives for Optimal Investment, 23rd Annual Western Conference, Center for Research in Regulated Industries, Rutgers University, Monterey, CA, 23-25 June 2010.

Next Generation Benefit-Cost Analysis: Option Value for Dispatchable Smart Grid Capacity, Comverge, Inc. July 23, 2009

Next Generation Benefit-Cost Analysis: An Option Model for Dispatchable Smart Grid Capacity, Advanced Workshop in Regulation and Competition, 22nd Annual Western Conference, Monterey, CA, 19 June 2009

Case Study: Option Valuation for Fully Outsourced Southern California Edison Demand Response Contract, Connectivity Week 2009, Santa Clara, California, 8-11 June 2009

Better Electricity Pricing Logic: Enabling Full-On Customer Response, Association of Energy Service Professionals, San Diego, CA, 28 January 2009.

Optimizing Demand Response, Public Utilities Fortnightly, May 2008.

Demand Response Option Value – Maximum Benefits and Model Contract, Advanced Workshop on Regulation and Competition: 27th Annual Eastern Conference, Skytop, Pennsylvania, 14-16 May 2008.

Business Case for Demand Response Valuation: A Roadmap for Operations and Economics, Advanced Workshop in Regulation and Competition, 21st Annual Western Conference, Monterey, CA, 18 June 2008.

Smart-Grid Business Case Benefits From Legislation And Regulation: Overcoming The Barriers, Autovation Conference, Atlanta, GA, 11 June 2008.

An Integrated Analysis of the Electricity Market: Does More Knowledge Enable Market Manipulation? 7th Annual Global Conference on Business and Economics, (Coauthored), Rome, Italy, 13 October 2007.

Consumer Choice and More Complete Contracting: Removing the Barriers to Demand-Side Investment, 20th Annual Western Conference, Rutgers Advanced Workshop in Regulation and Competition, Monterey, CA, (coauthored) June, 2007.

Residential Gateway for Electricity Response: Resolve of Customer Access, System Expansion, Market Manipulation, and Environmental Goals, Social Science Network, 9 February 2007, (coauthored).

"Capacity" for the Energy Only Market: Demand Response to Educate Customers, Hedge Market Power, and Ensure Resource Adequacy, White Paper, Electric Reliability Council of Texas and the Public Utilities Commission of Texas, 28 November 2006.

Value Statement for Price Responsive Technologies, Strategy Integration Inc., August 2001.

Electric Distribution System Automation with NETCOMM: The Future: and Its Application for Mexico, XII Seminario Nacional, Sobre El Uso Racional De La Energia, November 1991, Mexico City.

An Integrated Analysis of the Electricity Market: Does More Knowledge Enable Market Manipulation? 8th Global Conference on Business and Economics, (Coauthored), Rome, Italy, 13 October 2007.

Knowledge to Game the Day-Ahead Electricity Market, Business Review Cambridge, Vol. 7, No. 1, 2007.

How Enron et al Gamed the Electricity Market: An Empirical Analysis of Trader Knowledge, 6th Global Conference on Business and Economics, Harvard University, Cambridge, MA., 15-17 October 2006 coauthored).

Work Plan for Regional (Central Asia) Electricity Markets Assistance Program (REMAP), 30 September 2006.

How Enron et al Gamed the Electricity Market: Qualitative Assessment and Quantitative Analysis, unpublished doctoral thesis, Weatherhead School of Management, Case Western Reserve University, 18 May 2006.

Toward An Interpretive Evaluation Of Electricity Markets: Comparing Western U.S And Northern Europe -- *Whether Common Knowledge Of Rationality Results In Correlated Equilibrium*, Weatherhead School Of Management, Case Western Reserve University, 10 December 2004.

Long-Term Incentives for Executives: Securing the Human Asset Base of Non-Profit Organizations, ARNOVA Conference in Los Angeles, 18 November 2004.

Strategic Reform for Debased Energy Markets: Use of Game Theory Predictions? 24th International Conference of the Strategic Management Society (co-authored) San Juan, Puerto Rico, 3 November 2004.

Remedies for Electricity Market Manipulation Through Game Theory? A Category III Research Proposal, Seventh Executive Doctoral Colloquium, Academy Of Management Conference, New Orleans, 7 August 2004.

Long-Term Incentives for Executives and Managers: Securing the Human Asset Base of Firms, Case Western Reserve University**,** 3 November 2003.

Federal Grid Company of Russia: Financial Model, Deloitte Touché Emerging Markets, July 2003 (contributor).

Federal Grid Company of Russia: Business Plan, Deloitte Touché Emerging Markets, July 2003 (contributor).

Scenarios for Energy Costs: Alameda County Water District's Risks and Opportunities, Strategy Integration Inc., 14 September 2001.

Use of Plant-Based Bid Caps to Fix the Western Electric Wholesale Markets: Summary Discussion, Strategy Integration Inc., 25, June 2001.

Sketch of CAISO's Inherent Problems, Strategy Integration Inc., 16 April 2001.

Proposal for RMR Reform: Specific Performance and Plant Availability, Strategy Integration Inc. February 2001.

Western Market Power Mitigation with Plant Bid-Caps, for California ISO Board, Strategy Integration Inc., 9 February 2001.

Power Grid Code of the Republic of Kazakhstan, for Ministry of Energy, Industry and Commerce of the Republic of Kazakhstan, Astana, 2000.

Comments of TURN and UCAN for the Blue Ribbon Panel on Use of Single-Price Auctions in the California Power Exchange, 12 December 2000.

Electricity Price Mitigation for the West: Cost-Based Bids Where Competition Fails, Strategy Integration, December 2000.

Residential Consumer Response to ISO Management's Analysis of the MSC Report on June Price Spikes, Strategy Integration Inc., October 2000.

Demand Response through Priority Service Pricing, Strategy Integration Inc., For Board of Governors, California Independent System Operator Corporation, 1 September 2000.

RMR Undermines Grid Reliability as Market Signals Become Muted, for California ISO Board of Governors, Strategy Integration Inc., March 2000.

Elements of Competitive Electricity Markets: A Primer, for United States Energy Association, Warsaw, Poland, February 2000.

California Assumptions on Market Structure: Can Common Ground be Found?, for California ISO Board of Governors, Strategy Integration Inc., January 2000.

Steps toward a Sound Basis for Ukraine Energy Legislation, for USAID, Kiev, Ukraine, 15 November 1999.

To Compete or to Use Planning in California: Locational Signals or Command and Control? California ISO Board of Governors, Strategy Integration, 12 October 1999.

Power Sector Reform Program Evaluation, Final Report, United States Agency for International Development, Regional Mission, Ukraine, Belarus and Moldova, July 1999.

The Ukraine Market for Electricity: Two Simple Problems and Three Myths, for USAID-Ukraine, Kiev, 16 May 1999.

California's Schedule Coordinator: Market Maker with Advantage? Public Utilities Fortnightly, 15 January 1998.

ISO Governance and Pricing: California's Adventure in "Blunderland", Independent Systems Operators' Conference, Denver, October 1997.

Securitization Trumps Competition, Electricity Journal, January 1997.

New Deal in California, Electricity Journal, Volume 8 Number 9, November 1996.

Competition in Transmission: *Coming Sooner or Later?* Electricity Journal, June 1996.

A California Restructuring Settlement: Will All the Parties Agree? Electricity Journal, April, 1996.

Recommendations and Principles to Address Discrimination in Market Pricing, Western Electricity Power Exchange, UCAN, February 1996.

UCAN Report on Recommended Issues for the California Energy Commission's ER '96 Proceeding, California Energy Commission, December 1995.

Transmission System Operation in a Privatized Electricity System, for RAO-UES, Russia, USAID, 17-28 July 1995.

What Model for Restructuring? The Debate in the Competitive Power Market Working Group, The Electricity Journal, July 1995 (coauthored).

Status and Direction of California's Electric Industry Restructuring: Report of the Debate in the Competitive Power Market Working Group, (coauthored), February 1995.

Electric Industry Reform: Regulation of Structural Options, The California Energy Commission's 1994 Electricity Report Proceeding, September 1994.

Guest Editorial: California Reform Needs a Lighter Touch, The Electricity Journal, July 1994.

Response of Strategy Integration to Proposed Restructuring and Reform Policies, California Public Utilities Commission, OIR-94-04-031, 011-94-04-032, 8 June 1994.

Principles for Competitive Electricity Transmission Access, Pricing, and Generation Procurement, Energy Implementation Group, Perth, Australia, 25 February 1994.

Objectives, Guidelines, and Tariff Components for Transmission Pricing, Energy Implementation Group, Perth, Australia, 20 January 1994.

Supply Side Incentives for Energy Efficiency: A Review and Comparison to Demand-Side Incentives, Electric Power Research Institute, December 1993.

21st Century Imperative for Electric Utilities: Rise and Compete or Perish, What Structure and Technology for Competitive Advantage? Strategy Integration, September 1993 (coauthored).

Electric Utility Incentive Regulation: Strategies for Sustainable Competitive Advantage? Sixth Western Conference, Rutgers University, Monterey, California, 7-9 July 1993.

The Energy Challenge for the 21st Century, The Report of the Energy Board of Review, Perth, Australia, April 1993, (contributing author).

What Vision for Demand-Side Management with Reform? Summit Round Table, Strategy Integration, March 1993.

Electric Utilities in Competition: Directions for Research and Development, Strategy Integration, 16 February 1993.

Comparative Advantages of Utilities and ESCOs in DSM, (co-authored), Strategy Integration, 5 February 1993.

Steps in California's Soft Energy Path: 1972 to 1992, Strategy Integration, August 1992.

Energy Efficiency and DSM in Latin America and the Caribbean: An Opportunity for International Cooperation, Latin American Energy Organization (OLADE), International Energy and DSM Conference, Toronto, 1992 (co-authored).

What Roles and Risks for Profit Maximizing in DSM Delivery? International Energy and DSM Conference, Toronto, 1992 (co-authored).

Northern Mexico's Rapid Growth from Air Conditioning: What Impacts from Appliance Dumping, What Solutions? International Energy and DSM Conference, Toronto, 1992 (co-authored).

DSM in Asia and Latin America, Strategy for Industrial Energy Conservation in Mexico: Financing, Demonstration, and Promotion, Energy Savings Trust, 1992, Mexico City.

Electric Marketing and Energy Efficiency: What Path for Shareholder Value? (coauthored), ACEEE Conference Proceedings, Panel 8, Paper 23, Asilomar, California, July 1992 (coauthored).

Conserve or Grow: Financial Impacts on the Utility of Alternative Resource Strategies, in New Electricity 21, Power Industry Technology and Management Strategies for the Twenty-First Century: Conference Proceedings, Tokyo, Japan, 12-14 May 1992 (coauthored).

Positioning Gas Utilities Given Restructuring: Two Scenarios for IRP, Washington Gas Least-Cost Planning Conference, Washington, DC, April 1992.

Deregulation or Incentive Regulation? -- Alternative Approaches for the Electric Utility Industry in the 1990's, 14th International Conference, Energy Development in the 1990s: Challenges Facing the Global/Pacific Markets, International Association of Energy Economics, 10 July 1991.

Economic Criteria for Resource Plan Integration: Resolve of Conflicts with Optimization and Least Cost, for Newfoundland Labrador Hydro, December 1991.

Increased Efficiency with Gas Capacity Bidding: "The Answer" for Priority Allocation and Pipeline Expansion, California Public Utilities Commission Working Paper, Vol. 2, 1991.

Alternative Regulatory Structures and their Implications for California, California Public Utilities Commission, February 1991.

Towards Optimal Multi-attribute Bidding for Electric Power, Third Annual Western Conference, Advanced Regulation and Public Utility Economics, San Diego, CA 12 July 1990.

Perspectives and Issues for Demand-Side Management in the 90's, California Public Utilities Commission, July 1990.

California's Private Power Development: Success through Arbitration and Pricing, International Workshop on Private Sector Power Generation, Jakarta, March 1989.

Value of Service and Least-Cost Planning: Writing on the Wall for Demand- Side Opportunities? ACEEE Summer Study on Energy Efficiency in Buildings, Asilomar, California, August 1988.

Perspectives and Issues in Least Coast Planning: Toward a Standard Practice Approach, Electric Power Research Institute, June 1988.

Regulatory View of Capacity Valuation in California, Energy Journal, Volume 9, 1988.

Toward a Standard Practice Approach to Integrated Least-Cost Utility Planning, Public Utilities Fortnightly, Volume 121 No. 5, March 1988.

Integrated Least-Cost Electricity Planning Under Uncertainty: Issues and Progress, Workshop on Energy Resources Planning for Electricity, Honolulu, Hawaii, May 1987.

Least-Cost Resource Plan Integration under Uncertainty: Toward a Standard Practice Approach, California Public Utilities Commission, September 1986.

Reducing the Costs of Wind Power: the Variable Speed Isosynchronous Generator, Proceedings of Windpower '85, San Francisco, CA, Aug. 27—30, 1985, pp. 576—582.

Programmatic and Implementation Issues in Quality Assurance for Diablo Canyon Units I and II: Phase I Final Report, California Public Utilities Commission, 8 February 1985.

A Preliminary Assessment of Uncertainties in Forecasting Incremental Heat Rates, California Public Utilities Commission, April 1984.

Measurement and Evaluation of the Energy Conservation Potential in California's Residential Sector, California Energy Commission Staff Report, June 1983 (contributor).

Innovative Financing for Local Government Energy Projects: Energy Savings at Little or No Cost, California Energy Commission, March 1983.

Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs, Joint Report of the California Public Utilities Commission and the California Energy Commission, 1982 (co-authored).

Perspectives and Issues in Least-Cost Planning: Toward a Standard Practice Approach, Least-Cost Energy Planning in the Midwest: A Symposium, Electric Power Research Center, March, 1982.

California's Nuclear Disposal Law Confronts the Nuclear Waste Management Dilemma: State Power to Regulate Reactors, Environmental Law, Vol. 14, 1982.

State Opportunities to Regulate Nuclear Power and Provide Alternative Energy Supplies, Part I and Part II, University of San Francisco Law Review, Vol. 15, 1981.

Amazing Politics, the Swedish Nuclear Referendum, The Ecologist, Volume 5, Number February/March 1981, Cornwall, England.

Community Peak Electricity Reduction, Soft Energy Notes, February/March 1981.

Smart Grids

Advanced Technologies and Solutions

Second Edition

Edited by

Stuart Borlase

CRC Press
Taylor & Francis Group
Boca Raton London New York

CRC Press is an imprint of the
Taylor & Francis Group, an informa business

MIX
Paper from responsible sources
FSC® C014174

CRC Press
Taylor & Francis Group
6000 Broken Sound Parkway NW, Suite 300
Boca Raton, FL 33487-2742

Printed on acid-free paper

International Standard Book Number-13: 978-1-4987-9955-3 (Hardback)

Visit the Taylor & Francis Web site at
http://www.taylorandfrancis.com

and the CRC Press Web site at
http://www.crcpress.com

Printed and bound in the United States of America by Sheridan

20 The Dynamics of Wholesale and Distributed Energy Markets

Eric Woychik
Willdan Corporation/Strategy Integration, LLC

Hong Chen
PJM Interconnection

Dave Erickson
DNV GL

CONTENTS

Decades ago, the basic idea behind wholesale electricity markets was to allow large-scale generators to have open, nondiscriminatory access to high-voltage transmission in order to sell power at competitive prices. The use of open-access high-voltage transmission, thus, defines the context for competitive wholesale markets. The smart grid ensures access to wholesale markets, which are important to monetize and make economic decisions for energy resources. Wholesale markets now include demand-side management (demand response, DR) and other forms of smart grid energy resources beyond large, central station generators. Still, wholesale electricity markets are but one part of the value chain to fully integrate smart grid resources. Retail and distributed energy markets are also critical to enable energy resources to be monetized and fully used on the distribution grid. Integration and optimization of all energy resources should be achieved across both wholesale and retail markets in order to capture the full value and all related costs for the transmission grid, distribution network, and customers, including distributed energy resources (DERs).

20.1 WHOLESALE MARKETS FOR WHOLESALE AND RETAIL RESOURCES

At the wholesale level, the Federal Energy Regulatory Commission (FERC) has approved processes to establish nondiscriminatory open access transmission [1]. In the mid- to late 1990s, FERC Orders 888 and 889 provided the rules of engagement for Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs). During this time, the term "ISO" was prominently used and "RTO" was later defined to focus more on integrating transmission grids, though these two kinds of organizations remain very similar.

The general aims of FERC's precedent setting Orders 888 and 889 were for appropriate, authorized ISO/RTO institutions to achieve the following:

1. Improve efficiencies in transmission grid management
2. Improve grid reliability
3. Remove remaining opportunities for discriminatory transmission practices
4. Improve market performance
5. Facilitate lighter-handed regulation [2].

FERC Order 888 established 11 foundational principles for ISOs/RTOs to administer open access transmission services, which are as follows:

1. The ISO's governance should be structured in a fair and nondiscriminatory manner.
2. An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.
3. An ISO should provide open access to the transmission system and all services under its control at "nonpancaked" rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a nondiscriminatory manner.
4. An ISO should have the primary responsibility of ensuring short-term reliability of grid operations. Its role in this responsibility should be well defined and should comply with applicable standards set by NERC (National Electricity Reliability Corporation) and the regional reliability council.
5. An ISO should have control over the operation of interconnected transmission facilities within its region.
6. An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.
7. The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open competitive market.
8. An ISO's transmission and ancillary services (AS) pricing policies should promote the efficient use of, and investment in, generation, transmission, and consumption. An ISO or

Regional Transmission Group (later designated RTO) of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions.
9. An ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the Commission's requirements.
10. An ISO should develop mechanisms to coordinate with neighboring control areas.
11. An ISO should establish an Alternative Dispute Resolution process to resolve disputes in the first instance [3].

Based on these ideas and principles, a group of ISOs and RTOs have been authorized to operate in the USA and Canada. Presently, over 60% of all electrical power supply is provided by ISOs/RTOs in the USA [4]. The U.S. operational requirements for RTOs and ISOs are now quite well established through additional FERC Orders [5]. ISOs/RTOs must also act consistently with NERC requirements, reliability, and safety standards for the operation of all high-voltage systems in the USA. Expanding this reach, compliance with ISO/RTO and NERC requirements has allowed for relatively seamless competitive power transactions with many of Canada's wholesale transmission organizations.

20.1.1 Primary Wholesale Products—Transmission, Energy, Capacity, and Ancillary Services

The primary products in virtually all ISOs/RTOs include the following:

- Access to the transmission system by large generators and consumers of electricity and power
- Energy as a commodity (firm and nonfirm)
- Capacity availability, though these requirements differ substantially between ISOs/RTOs

Access to the transmission grid, for buyers and sellers of electricity, requires compliance with specific technical requirements. A grid access fee is typically charged, separate from the costs charged and prices paid for electricity from an ISO/RTO.

Open access to transmission is essential for all buyers and sellers at the wholesale level. This has been extended to include *comparability* or comparable access by all market participants, including those that bring demand-side resources to the grid. Demand-side response to electricity needs at the retail and wholesale levels can be aggregated, managed, and provided as comparable services that reduce the need for competitive energy and capacity sources.

Buyers and sellers, as well as transmission owners, must pay and be paid. Systems for physical and financial settlement of electricity- and capacity-related services have been developed.

The basic products and services in the wholesale energy market are energy, capacity, and AS. Energy is the basic commodity sold through ISOs/RTOs, on an MWh basis. Firm energy is "backed" by the standard package of AS, including operating reserves (spinning and nonspinning reserve), and frequency regulation. Operating reserves, as they represent availability of power, can also be considered capacity, and are bought and sold on an MW basis. Regulation or frequency regulation is very fast response to ensure that grid frequency (Hz) is maintained at nominal frequency, 60 Hz in North America and 50 Hz in most other regions of the world.

After more than two decades, a multi-settlement market design with nodal market models is generally used in North America, with individual market variations [6]. Australia uses a one-settlement market system [7]. Figure 20.1 shows the high-level multi-settlement U.S. design, with the time frame ranging from periods that allow for planning to real-time (RT) grid operations [8].

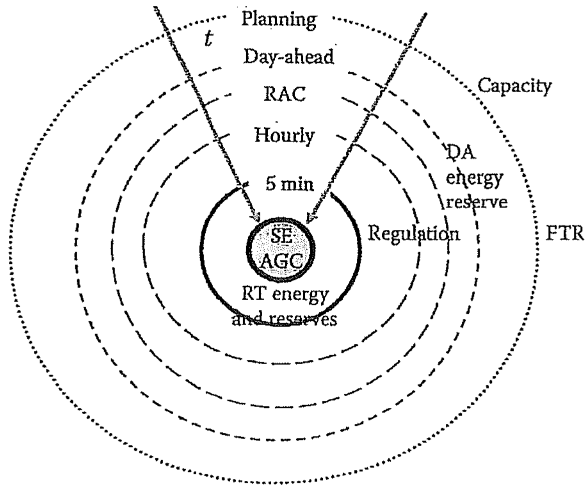


FIGURE 20.1 High-level design of the multi-settlement market in the USA. (H. Chen, *Power Grid Operation in a Market Environment: Economic Efficiency and Risk Mitigation*. © 2016. Wiley-IEEE Press. All rights reserved. With permission.)

20.1.2 Wholesale Energy Markets

Energy is typically bought and sold at a "competitive price," called the locational marginal price (LMP). The generator is paid the LMP, and the customer pays the LMP. The general model used to operate the grid is summarized as a process of *security-constrained economic dispatch*. This means that the energy resources (generators, demand-side management, DERs, etc.) must be operated to ensure that reliability (grid security) is maintained, while the energy resources are committed and dispatched (turned on/off, and ramped up/down) based on economics. The economics can be simplified to the case where progressively higher priced resources, each with a bid-price, are placed in a *bid-stack* from least to most expensive. Least-cost (bid price) energy resources are dispatched first. The ISO/RTO uses the bid-stack of available energy resources as needed in order to meet the constantly varying loads on the grid. In a given day, particularly when peak loads are relatively low, the highest bid-price generators may not be used at all. There are a set of dispatch rules promulgated in each ISO/RTO to provide sufficient transparency for market participants.

The differences in LMPs for energy, depending on the costs to provide the energy at specific grid locations, are subject to reliability requirements. The so-called criteria violations that would violate NERC rules must be avoided, as these would jeopardize reliability, most typically by overloading a transmission line or other transmission facilities, such as transformers. To avoid criteria violations, typically lower-priced generators must reduce output (or be taken off-line), while other more expensive generators must increase output (or be added to the grid), in order to avoid threats to grid reliability. This is called redispatch, since least-cost dispatch cannot be achieved for such grid configurations and energy resource locations. The difference in price between the preferred lower cost resource and the required higher cost resource, the delta, serves as a measure of increased costs, in grid terms a "congestion price." This congestion price, resulting from redispatch of the generation mix, is then the reference competitive price that "clears the market" for that location. Absent congestion at a location, redispatch is not required, and the congestion price component is zero. Grid losses are also added to the price at this location to represent "all-in" LMPs at each price-node (P-node).

LMPs are locational, time-specific, and generally have three components: energy, losses, and congestion. If the grid is not congested, the congestion component is zero. Under marginal cost pricing, there is also a loss component in LMPs.

The LMP drivers are then defined based on (1) the extent to which a particular P-node requires electricity, that is, the load at this location, (2) the availability of transmission (capacity) to serve the customer(s) at that P-node, and (3) the cost (bid-price) of generation that can satisfy local grid reliability needs. When congestion prices are consistently high at a particular location, it usually signals that additional transmission investment can eliminate these congestion prices.

This then presents an investment trade-off between the extent that congestion occurs and the costs to resolve the transmission constraint or potential criteria violation. It shows that ultimately transmission investments are a direct substitute for generation, and unregulated transmission investments can compete with unregulated generation investments [9].

In a summary, LMPs encourage the efficient use of the system and enhance reliability. In the long run, this market structure enables new generation sources to be located in areas where they will receive higher prices, signals large new users of electricity to locate where they can buy lower-cost power, and encourages the construction of new transmission facilities in areas where congestion is common in order to reduce the financial impact of congestion on electricity prices.

Under two-settlement systems, energy markets have both day-ahead (DA) markets and RT balancing markets. DA markets are cleared before each operating day, based on bid-in demand submitted by market participants. Both physical bids (generation offers and demand bids) and pure financial bids, known as "virtual bids," participate in DA markets. Virtual bids help with the convergence between DA markets and RT markets.[1] The cleared DA hourly real power schedules and prices represent binding economic commitments to market participants. DA markets secure the majority of the resources for the operating day. The market clearing timelines vary for individual markets. Rules for generation offers may also vary in different markets. Generation offer information includes availability, price and cost offers, operating parameters, such as ramp rates, startup time, shut down time, minimum run time, minimum down time, minimum and maximum generation, and so on. The system topology is based on scheduled transmission outages.

RT markets often co-optimize energy and reserves (such as regulation, primary reserves, contingency reserves) by sending out dispatch and price signals approximately every 5 min. The dispatch is based on current system status, represented by a State Estimator (SE) solution, forecasted load, generators' offer information, scheduled transactions, and system topology. There is no virtual bid in the RT market. The resulting dispatch and price signals are sent to market participants to balance system load, maintain system reserves, and resolve transmission congestions.

Both DA and RT market clearing are otherwise termed bid-based Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) processes. The objective is to ensure total production cost minimization, or total social (economic) surplus maximization, based on power balance constraint, branch flow limits, transfer interface limits, and other transmission-related limits, such as transmission security constraints. Reserve requirement constraints are also included to align with system reliability criteria and practices.

Economic unit scheduling and feasibility analysis are the two key components of the DA market. Feasibility analysis is required to ensure the physical deliverability of the 24 hourly DA schedules, and checks the network security of the economic scheduling results. Once a limit or criteria violation is identified, the corresponding constraints are then enforced into the next SCUC/SCED run. The hourly constraint sensitivities are inputted to the SCUC/SCED. These markets also determine the amounts of marginal electricity losses. To do this, hourly loss sensitivities are fed into the SCUC/SCED as well. The iteration between SCUC/SCED and the feasibility analysis is complete when no more limit violations are detected. The solution method details can be found in the study by Chen [8].

In the RT market, based on the SE solution, an AC power flow is performed for RT contingency analysis. The constraint sensitivities and loss sensitivities at the current system operation point are provided to SCUC/SCED. Binding transmission constraints indicate whether generation redispatch is actually required to relieve the congestions.

[1] There is controversy over virtual bidding for power as some claim this invites opportunistic market gaming.

In both the DA and RT markets, LMPs are generated as part of the SCED process and determined by the shadow prices of the power balance constraints and transmission security constraints.

20.1.3 Wholesale Capacity Markets

Capacity markets were created to make sure that there will be sufficient capacity to meet future peak load plus reserve margin [10–13]. They address the "missing money" issue, and create long-term price signals that attract investments for both maintaining existing capacity resources and encouraging the development of new capacity resources. To reflect limited transfer capabilities, locational capacity requirements are often set for capacity zones. Some markets, for example, PJM [10] and New England [4], have long-term forward capacity markets (3 years forward) to provide greater information into the reliability situation with sufficient lead-time so that new entrants can compete against each other and avoid overbuilding. Long-term capacity markets could also lead to higher prices because generators face a higher risk in committing to produce electricity many years in the future.

Performance-based capacity markets were recently implemented to better reward well-performing power plants and demand-side resources, which also penalize those that fail to perform when needed most [10,11]. This is to ensure that a reliable supply will be available during extreme weather or other system emergencies.

Some regions do not have capacity markets, but have resource adequacy (RA) programs, and rely on market price response, called *scarcity pricing*, to ensure long-term reliability [14,15,16]. The extent to which scarcity pricing can reduce grid loads—through price response—depends on price caps in the energy market. Higher price caps allow price response to have a greater impact on load reduction, ideally creating a "self-regulating" capacity response.

20.1.4 Wholesale Ancillary Service Markets

Specific ASs are required by NERC, including operating reserves and frequency regulation. ASs are important to support the transmission of electric power and maintain reliable operations of the system. These services generally include frequency control, spinning reserve, nonspinning reserve, replacement reserve, voltage support, and black start. Voltage support and black-start capability (from system collapse) are also unbundled as ASs in some ISOs/RTOs. Currently, these two services are still cost-based and do not use market-based price determination.

Maintaining operating reserves is essential in system operation to mitigate uncertainties caused by unit tripping, sudden load changes, and so on. Reserve markets are created to provide a market-based mechanism for the procurement of reserves on the system. Transparent price signals incentivize resources to provide flexible capability to the grid. In most U.S. markets, reserves are jointly scheduled with energy in the DA markets and RT markets. Different markets have different types of reserve products co-optimized with energy [17].

Reserve requirements are mostly predetermined based on historical data, corresponding to operation practices, for example, $N-1$ or $N-2$ contingency criteria. To address reserve deliverability issues, some markets have zonal reserve requirements, either statically or dynamically, based on actual interface flow and limits. Reserve clearing prices are derived from the shadow prices of the reserve requirement constraints. Reserve demand curves are usually defined for pricing reserves under scarcity [18].

To be in compliance with FERC Order 755 [19], performance-based regulation markets have been implemented. Resources are not only paid for their regulating capacity, they are also paid for their actual performance.

In February 2015, FERC issued a notice of proposed rulemaking (NOPR) to allow third-party provision on Primary Frequency Response Service to Balancing Authorities that may have a need for such a product to meet NERC Standard BAL-003-1 obligations [20,21]. This opens the door for market-based Primary Frequency Response products.

20.1.5 Demand Response and Storage—From Wholesale and Retail Perspectives

Wholesale markets enable retail participants to compete directly with DR, storage, and even energy efficiency (EE) in some ISOs/RTOs. The retail grid-edge, on the customer side of the meter, is increasingly leveraged by smart energy management systems that optimize customer loads and supply costs using DR, storage, EE, and PVs with smart inverters. Retail grid-edge optimization then aims to reduce wholesale supply costs, which will increasingly use strategies to reduce wholesale peak, ramping, load-following, and AS costs. This direct competition from the retail grid-edge bodes to make traditional large-scale fossil generation less economic. At the same time, DR, storage, and optimized retail grid-edge providers look to be sources of flexible wholesale grid needs.

Customer-based DR and storage can be used as multifunctional tools in wholesale competition as they have option value and can satisfy a host of functions. Dispatch of DR to precool and preheat buildings, for example, provides *virtual storage*, which will at times compete with battery storage. With greater deployment of variable renewable resources, especially solar PVs and wind, grids will need to accommodate more flexible load and storage resources. DR has been used to reduce and shift loads, but with newer technologies it can provide ramping, load-following, and even more rapid frequency response. The California DR potential study shows that there will be at least 5.2 GW of RA and 5.7 GW of DR for peak load shedding available in the state by 2025 [22]. As that study explains, a host of new DR capabilities will be needed, which can be categorized as services to provide "Shape, Shift, Shed, and Shimmy" [22]. Shape reshapes DR load profiles through price response or behavioral programs. Shift is the movement of energy consumption from times of high demand to times when there are surplus renewables. Shed is curtailment of loads to provide peak capacity, system emergency, and respond to contingency events. Shimmy is dynamic adjustment of demand ranging from seconds to an hour, to address ramping, load-following, and disturbances. While the study focuses on DR services for the wholesale market, it also takes into account DR for the retail market. The study findings, using their service categories of "Shape, Shift, Shed, and Shimmy," is summarized as follows:

- The Shape-Shift DR potential is approximately 1.8 gigawatt-hours (GWh) per day for 2025.
- Under a "conventional system peak DR" price referent cost-effectiveness framework, our findings suggest that Shed DR resources could provide ~4.2 GW of RA credit capacity in 2025.
- The Shape-Shed DR results are additive and provide an additional 1 GW of reduction (labeled "TOU/CPP"), for a total of 5.2 GW.
- Our results indicate that Shimmy load following resources are cost-competitive for ~350 MW at about $50/kW-year. Shimmy regulation DR is shown to be cost-competitive up to approximately $85/kW-year in a medium scenario, resulting in a DR potential of ~450 MW across all three California Investor Owned Utilities (IOUs).

These magnitudes of DR are substantially greater than what has been shown in prior studies of traditional DR potential. Certainly, this suggests that wholesale and distribution markets will be increasingly focused on bringing DR to customers through market platforms.

Certainly, this also demonstrates that the portfolio of behind-the-meter DR and storage-like resources is expanding for use in both wholesale and retail markets. Strategic charging of plug-in electric vehicles (PEVs), a different form of demand-side management, also shows major promise. PEVs are seen as resources that can provide vehicle-to-grid storage services, using the batteries deployed in these vehicles. Storage batteries also look promising for wholesale competition as storage costs continue to decline, much as the costs of photovoltaic panels, which can be used with batteries, have plummeted. Grid-based DR and storage will increasingly be used *comparably*—directly compared with, and valued with, supply-side generation. Smart-grid systems, big data, digitization, high-performance computing, and software developments will further enhance the use of DR and storage, both directly in wholesale grids and on the customer-side of the meter.

With the advancement of storage technologies and attractive market design, energy storage has become an excellent frequency control resources, especially in the markets where they are compensated correspondingly for their fast response performances [3]. In order to maximize the value of battery storage, however, its *option value* needs to be exercised, which requires that the resource be used for multiple market and retail applications.

20.1.6 Wholesale Market Response to Net Load—Distributed and Large-Scale Impacts

Where large amounts of variable renewable resources are interconnected to an ISO/RTO, as in California and Midwest ISO (MISO), benefits are found with grid expansion to more economically absorb these variable resources. In general, larger grid systems simply have more flexible resources that can be deployed when variable renewables either under or overproduce. Increasingly the focus then is on net load, including the load net of the renewable, self-generation, and customer management that occurs during each period.

In California, for example, from spring to fall, the net load ramps up early in the morning and then rapidly declines as the solar PV production comes on line. This eliminates the traditional peak load (noon to 6 pm), but then causes a later peak from 7 to 9 pm. It is not the traditional load that must be balanced against supply, but the net load that must be balanced against all other supply and available demand-side resources. An important consequence is that the high summer peak season (noon to 6 pm) no longer exists in California. This creates major impacts on traditional thermal electric generators that count on high-peak wholesale market prices to provide profits that accrue only during traditional summer peak periods.

20.1.7 Response to Supply–Demand in Terms of Net Load

The supply-demand market response to the changing net load conditions is most troublesome for fossil fuel generation. The net-load condition is now being used in places, such as California, where renewable sources are increasingly prominent. Fossil resources have significant variable costs, even now with dramatically lower fossil fuel prices. Variable renewable resources have very little, if any, variable costs. Moreover, variable energy resources are in essence *infra-marginal*—produce power at costs that are below the marginal costs of fossil generation when fossil resources are *on the margin.* Persistent reductions in the costs of variable renewable resources suggest there will be a much greater need for flexible resources that can respond when solar and wind do not perform. Solar and wind generation create highly variable conditions, which require more ramping and flexible resources to respond. Flexible resources are then directly compared to the net-load curve to determine feasible schedules for an ISO/RTO. Of significant concern to ISO/RTO grid operators are intra-hour (within-hour) conditions when ramping resources may be insufficient in specific circumstances. These conditions adversely impact grid reliability.

20.1.8 Market Response to the Retail Grid-Edge—Smart Grid Engaged

Wholesale markets enable retail participants in DR, storage, and even EE in some ISOs/RTOs, to compete directly. The retail grid-edge, on the customer side of the meter, is increasingly leveraged by smart energy management systems that optimize customer loads and supply costs using DR, storage, EE, and PVs with smart inverters. Retail grid-edge optimization then aims to reduce wholesale supply costs, which will increasingly use strategies to reduce wholesale peak, ramping, load-following, and AS costs. This direct competition from the retail grid-edge bodes to make traditional large-scale fossil generation less economic. At the same time, DR, storage, and optimized retail grid-edge providers look to be sources of flexible wholesale grid needs.

20.1.9 Ramping and Load Following Where Renewables Dominate?

With the increased penetration of intermittent renewable resources, such as wind and solar, which are highly variable, difficult to dispatch for the various wholesale market services, and hard to forecast as well, the smart grid will need the capability to ramp supply quickly to accommodate the increased uncertainty caused by highly variable renewable resources. In some systems, cloud covering could become the largest contingency.

To align with system operation needs, some markets are considering new reserve products, such as fast-ramping products—in seconds to one minute—to ensure sufficient ramping capability to handle expected contingencies and uncertainties, particularly in CAISO and MISO, which have large amounts of variable renewable generation.

Planning adequate reserves is important to system control, especially with increased renewable penetration. For example, the regulation reserve requirement may need to be increased to account for a larger amount of fluctuating wind power or solar power. In ERCOT, forecasted wind output is factored in setting the regulating and contingency reserve requirements. Reserve requirements are being reevaluated and adjusted in ISOs/RTOs. Dynamic reserve requirements have also been extensively discussed to capture updated system needs.

20.1.10 Market Sustainability Where Distributed and Other Renewable Resources Dominate

Where distributed and other renewables become a large part of the resource mix, thermal generation will cease being *on the margin*, and will no longer determine market prices. This is occurring in California where solar PVs are the predominant resource during what was previously the summer peak period. Bidding into wholesale ISO/RTO markets, zero-priced, even negatively priced bids on the margin severely depress market prices. Alternatively, based on the net load curve (discussed earlier), the demand for electricity during these times becomes much lower, which likewise will depress market prices. This brings into question the sustainability of fossil-based generation in ISO/RTO markets when the proportion of variable renewables becomes large, at least during traditional peak periods.

The question is whether the *writing is on the wall*—will wholesale markets continue as we know them? LMP markets were largely designed to resolve market prices based on marginal costs of thermal generation. LMPs have and will increasingly decline as more variable renewable resources are integrated into ISOs/RTOs. How can we use existing ISO/RTO market design to monetize other resources, including smart grid resources that are behind-the-meter? If thermal resources are not on the margin, since zero-variable-priced renewable resources are *infra-marginal* by comparison, how will fossil resources continue to be economic, that is, fully monetized?

Similar questions should be raised about monetizing demand-side resources, which are measured against fossil resources both in terms of LMPs and capacity prices. PJM's capacity market is largely based on the capital cost of a market-based combustion turbine (CT) proxy. With greater use of DR and DERs, the question will be asked: Why use a CT proxy to value these demand-side resources? With greater use of carbon-free or GHG-free resources, use of a CT proxy to monetize DER value may also be considered suspect. Hence, both for LMPs and for capacity, the question is whether wholesale electricity markets must be fundamentally redesigned.

Discussions about monetizing DERs at the retail level raise similar but possibly more complex questions when ISO/RTO markets must be part of the cost minimization equation. Also related are dialogs about *transactive energy*, which is meant to enable integration of the so-called *platform economics* that enable plug-and-play solutions at the customer and distribution levels. These transactive energy topics are discussed in more detail in the next chapter of this book.

20.2 DISTRIBUTED ENERGY—RESOURCE PLANNING AND MARKETS

With smart grid, the planning, investment, and operation of the distribution system change dramatically. Historically, utility investment in distribution systems ensured circuit capacity was adequate to deliver power from the bulk grid to the customer. Now, customer-owned solar PV delivers power to the distribution system, and DR from customers provides energy and capacity reduction at the bulk grid level. A host of other distributed resources, including fuel cells and energy storage, provide power that is injected at the low-voltage level and may create reverse power flows on the grid, moving power away from the customer. Platforms are being designed to host DERs at lower voltage levels to explicitly supply customers at the distribution level and to wholesale markets. An immediate objective is to monetize the *option value* of DERs, which translates to more flexible DER uses in multiple markets. Multiple opportunities have emerged, and more will result as DER needs increase across the grid. We examine both the current context and future opportunities to provide greater understanding of these new resources.

20.2.1 Context for New Distribution Planning—"Nowcasting" to the Next Decade

We first analyze what is currently in place that can form the basis for a transition to a more complete smart grid future. Utility web sites now offer smart rates, comprehensive energy upgrades, smart DR, a point system to calculate customer incentives, and financing for certain DER packages [23]. There are a multitude of demand-side energy resources, but they are organized in silos–EE, rate options, DR, and storage options are all presented independently in separate utility programs [24].

These separate silos are largely unchanged over the last 5 years or more. Information from smart meters has been available and is little used by the utilities. Capabilities include "stream-my-data" and use of home area network devices—smart thermostats, control equipment, and itemized energy usage. At the same time, utilities more than ever need grid *situational awareness* and greater control of DERs at the customer level. The array of DER options is already large and soon would be dizzying. The software to use them is here, but the communications and other capabilities are not quite at hand to choreograph clean energy results.

Many utilities are surrounded by a plethora of big data—AMI data, SCADA data, and market data. Data management, modeling, analytics, and *right metrics*[2] can enable DER and grid optimization. There is increasing awareness that additional benefits are available from increased smart grid granularity, which more fully defines grid physical limits and accordingly the economic benefits and costs. New methods are needed for assessing benefits and costs, especially in defining locational DER benefits. In California, Distribution Resource Plans are being offered to first define some of the operational characteristics of the distribution grid. This is an essential first step in maximizing the value of DERs. For example, integration capacity analysis (ICA), based on load-flow analysis, can be used to define *hosting capacity*—the amount of DER capacity that can be added to the system. A key consideration in evaluating the ICA is that when ICA incorporates tailored packages of DERs, including EE and DR, hosting capacity can be further increased. This potential for greater hosting is being ignored, however, in the haste to define locational advantages as soon as possible.

One critical question is how to specify location-specific DER packages for customers, fully valued to enable "one-stop customer shopping." This would be a tool to enable consumers to choose from packages of DERs, as well as to have a full suite of choices, incentives, and financing. In this light, what immediate steps seem appropriate? A critical step in the California agenda is to use Locational Net Benefit Analysis (LNBA) to fully define the economic value of DERs at all grid locations. Integration and optimization of the full suite of benefits at the customer level results in

[2] These can include the fully integrated and optimized net locational benefits from planning and from operations.

200% to 500% (2× to 5×) greater benefits from DERs compared to traditional spreadsheet formulations of average DER cost-effectiveness. This requires greater data granularity, use of customer-specific AMI data, and more detailed customer load-curve analysis.

These more granular results reveal additional benefits, in significant part, by "de-averaging" inputs and results.[3] Targeted focus on high-use and high-peak customers further "de-averages" to enable capture of greater benefits. Beyond these steps, the targeting of packages of DERs to specific distribution locations can solve grid constraints (load-flow), reduce capital costs, and add 100%–200% in net benefit terms. To compound these benefits, a statistical approach can be used to capture the correlation (covariance) of weather, loads, prices, and DER performance. Conservatively, this is shown to net up to 60% greater benefits, for example, for dispatchable DR in Nevada [25,26]. And finally, with distributed locational optimization of the DER portfolio both in planning and in operations, another 1× to 2× (100%–200%) in added net benefits is expected.

For these reasons, the calculation of LNBA results, including portfolio optimization in operations, should be based on granular load-flow and properly stacked locational marginal costs, which are discussed later in this section. Significant advances in valuation methodology reflect greater granularity and advanced computational methods. These methods significantly improve upon previously used spreadsheet models. The net benefits of operationally coordinated, locationally optimized, DER packages, targeted to customers at specific grid locations, seem to exceed most expectations. In contrast, current spreadsheet practices continue to use average deterministic (single-point assumption) benefits, siloed DER programs, ignore additional benefits due to integration and operational coordination, rely on average inputs, and hence fail to more fully reflect specific locational benefits.

The future calls for the acceleration of DER adoption, particularly in light of the need to more rapidly reduce greenhouse gas (GHG) levels. As greater value (such as carbon pricing) is attributed to GHG mitigation, these added benefits will further drive DER cost-effectiveness.

More complete monetization of DER integration and optimization is a critical next step. This can be accomplished by fully and assiduously defining a standard practice that incorporates the *all-in* granular, locational, incremental, and marginal costs to fully reflect appropriate values [27]. DERs at locations, including integrated and optimized DER packages, can then be directly used to value each resource (CapEx and OpEx) decision at the planning stage.

This is consistent with California's SB350 legislation that requires integrated resource planning. The intent of this legislation is to collapse the clean energy silos, accelerate renewables (to be 50% of the portfolio), double the use of EE and peak load reduction, determine the value of air quality costs and benefits, and accelerate pollution mitigation.[4] The integrated resource planning of old (1980s) was based on the best case of hourly generation marginal costs, where average transmission and distribution marginal costs were added [28,29]. Implied in the SB350 legislation is the assessment of interactive impacts among DER resources, reflected in distributed marginal costs (DMCs), which can be more fully defined with more granular data and analytics that are increasingly available.

There are a specific set of actions that should be taken now in order to maximize the benefit of DER and speed its deployment in optimal locations. These actions include:

- Optimize customer constraints, distribution constraints, and bulk grid conditions in order to fully define appropriate co-optimization benefits and costs.
- Deployed AMI systems should provide communications access for the operational coordination of DERs.

[3] California cost-effectiveness and resource valuation generally use only 16 average load shapes per year in DER cost-effectiveness calculations. Spreadsheet calculations severely limit the use of data, in contrast to more expansive computational methods. More modern cost-effectiveness calculations use at least 576 custom load shapes, and include multiple covariance effects.

[4] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350. This legislation, in part, creates the California Public Utilities Code Section 454.52, which requires an integrated resource plan.

- Refinements are needed to allocate customer DER incentives, which must also work in conjunction with customer financing of DERs. The approach proffered in EE to use rolling portfolios most likely needs to be applied to DER integration and optimization, at the customer level.

20.2.2 Real Innovation in Stacked Value Compiled as All-In Distribution Marginal Costs

The formulation of DMCs is necessarily a bottom-up process. It is based on "all-in" incremental cost differences, and comparison with DER and without DER scenarios. The net effects of DERs depend directly on the forecasts and the analytics at the grid-edge, which is at the customer premise, and extend through the distribution and bulk power systems. These forecasts begin at distribution line-sections or nodes and proceed to substations and subtransmission. This suggests the analytics directly reflect loads at the service transformer or the customer's premise. DMCs provide the equivalent of avoided (deferral) cost-based measurements that are locational, geospatially specific, with resolution down to the customer or the line-section level. To estimate net benefits in future years, all future costs must be determined as part of a base case, pre-DER scenario.

The savings from DER adoption—determined in a *with-and-without* analysis—can then be put into net-present-value or Economic Carrying Charge Rate terms. Other components are the forecasted distribution costs in the base case. These are the equivalent of locational future cost curves, analogous to those used on the supply side. Instead of power plants being deferrable, here we focus on deferrable substation capacity, circuit capacity, voltage impacts, impacts from power factor changes, and other engineering-oriented cost-based factors that determine DER hosting.

Load-flow analysis is also used to determine DER hosting capacity, and identifies the physical grid capabilities, which include conditions when reliability, voltage, and VAr limits are exceeded. Based on load-flow analysis, marginal (incremental) cost analysis is required to determine the most economic, least cost mix of DERs, with reference to the line segment, circuit, or substation, that provides the least cost outcomes, within the technical limits of the DER load-flow results. In some cases, additional spending on the grid may be optimal, such as to mitigate overvoltage with clustered PVs. These and other trade-offs can be directly analyzed to determine the overall least cost plan for implementing optimal DER portfolios.

DMCs can be separately defined, or combined, to capture value in kWh, kW, and kVAr terms. As with supply-side marginal costs, DMCs are needed to define variable short-term needs (5 min, hourly) and long-term capacity needs (1–20 years). To be accurate, DMCs require granular load forecasting coupled with software and data to predict the timing and magnitude of all related grid needs. Locational integration through power flow modeling must be coupled with economic optimization methods to determine the least cost DER mix with greater certainty. The use of DMCs enables direct comparison of the options to address specific grid needs, either through a DER-based solution or a traditional utility solution. Packages of DERs can then be integrated and optimized directly with use of respective DMCs. In this case, we are comparing the respective DMCs for each resource option based on the classic *with-and-without* analysis.

Fully formulated DMCs—which are entirely situation-specific—represent the marginal or avoided cost of alternative DER resources. Complexities remain to fully optimize alternative DER packages that can defer more costly distribution equipment. But this process can be automated and improved over time, just as simpler supply side comparisons to DERs became more advanced in the 1980s and 1990s. An advantage with this approach is that the revenue and earnings implications of DERs are easily defined with greater certainty. This can streamline the calculation of potential utility and third-party earnings, which seems especially useful to evaluate optional business models and programs. Earnings can be simply estimated as a percentage of shared savings, an approach used to define earnings for EE.

Recent analysis shows that optimal locational DER packages can directly defer major distribution capital costs (planned assets) by operating in specific ways over specific hourly periods [30–34]. There is complexity in optimizing alternative packages of DERs, though this is much simplified by the direct comparison of DMCs for resources that may defer more costly distribution/supply options. In short, this optimization can be more easily automated and transparent with the use of DMCs. DER will be viewed more positively if it is both the *least-cost* option from the utility perspective[5] and is cost-effective based on the *Total Resource Cost* test. More generally, we can use DMCs to provide a natural *loading-order* based on lowest net marginal costs to build DER packages and portfolios. This will ensure that the most economic options are deployed [35], consistent with grid reliability needs and customer-driven needs to maximize value.

Though termed locational *Distribution* Marginal Costs, the full set of *wholesale* locational components that represent kWh and kW values should also be fully included to determine total DMC values.[6] This is critical as almost all DERs have direct supply-side impacts. The combination then enables distribution grid options and wholesale supply options to be directly compared and jointly co-optimized. With the use of fully compiled DMCs, all stakeholders can benefit from more accurate distribution of resource planning decisions. The expected benefits of the DMC approach include more effective locational investments, full management of electric vehicle charging, more effective rate-design, optimized DER programs for customers and the grid, greater reliability and unbundled reliability services, and enhanced customer adoption [37,38].

DMCs can be split into two types and four categories: fixed versus variable and grid versus supply (Figure 20.2). Fixed costs are analogous to capacity credits and variable costs are analogous to energy credits. Supply costs generally remain as per KW/KWh values; however, grid costs can occur in per KVA or per kVAr terms. There is no single DMC value, per se, though one could foresee a context where 2 DMCs were feasible, a long-run fixed cost ($ per KVA) and a short-run hourly or 5 min ($ per KVAh value). These would include both the real and reactive components.

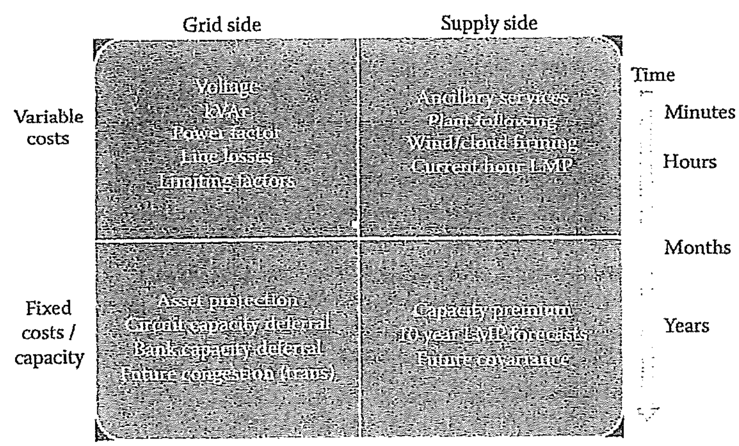


FIGURE 20.2 Four dimensions of DMCs. (From T. Osterhus, Distribution marginal prices (DMPs)" Update #6, *Integral Analytics,* 2014; R. Stevie and T. Osterhus, *DMP Methodology Applied to Value of Solar,* New York REV Proceedings, Matter No. 15-02703, Case 15-E-0751; © 2016 Integral Analytics. All Rights Reserved. With permission.)

[5] In California Standard Practice Manual terms, this means the Program Administrator Test from the utility revenue requirements perspective.

[6] Wholesale kVAr can also be added to DMC kVAr, though it will be fairly small in comparison, except for the most exceptional circumstances, such as where Reliability Must Run (RMR) generation is prescribed for Volt/VAr support.

Fully formulated DMCs can be used in the short term, as minute-by-minute values for market trading, or forecasted out many years to provide forward curves.[7] As shown in Figure 20.2, based on the four DMC dimensions, a spectrum of complementary valuation methods can be used. In different terms, we can combine DMCs that represent corresponding DER values to directly compare these options with underlying *but-for* distribution values or combined distribution and wholesale (delivered energy/power) values. This allows nuanced locational and broader wholesale values to be accurately compiled and used to compare all competing resources on a level playing field.

Geospatial distribution values and broader locational wholesale values can be accurately compiled and used to compare all competing resources on a level playing field. In different terms, nuanced locational DMC values can be used to compare all competing resources on a level playing field, based on a common framework. The potential is to combine DMCs that represent corresponding DER values to directly compare these options with underlying *but-for* distribution values or combined distribution and wholesale (delivered energy/power) values. This further enables most all related energy choices to be directly compared and thus rationalized.

Accurately compiled DMCs can be compared *with and without* DER customer incentives, rate options, and even broader scale tariff structures. Compiled DMCs, with various DER options, can also be used to value the use of microgrids within an otherwise contiguous distribution system.

20.2.3 The Components of DMC

Had utilities used DMC as the basis for Heating, Ventilation, and Air Conditioning (HVAC) incentives a decade ago, it is likely that HVAC manufacturers would not have chased the higher kW/kWh efficiency SEER levels, at the expense of costing utilities more in kVAr via the poor power factors caused by the redesigned systems. The utility rebates were solely kW/kWh focused, and the HVAC industry followed the money in their equipment designs. It is not clear if net energy savings is now occurring at the expense of the increased "hidden" costs of the poorer power factor caused by the newer HVAC units.

Using the DMC, optimal PV, DR and storage locations and the magnitude of each deployment can be identified for service transformers, line sections, or regions across the circuits. This level of specificity is only possible using actual, granular load data, and consistent with proven methods and probabilistic characterization of risk (covariance) using actual load history, weather data, and prices.

The physical and operational characteristics of the locational distribution system determine the manner in which DERs can benefit or harm the existing infrastructure. There are a number of characteristics that determine the overall DER impact including, but not limited to:

- The voltage class, radial versus networked arrangement, conductor type, impedance, geographic topology of the feeder, regulation equipment used, and operating characteristics such as reactive power management and protection schemes
- The amount, location, and timing of the DER—when it should be installed—relative to network infrastructure investments
- The DER characteristics, such as inverter-based versus machine-based DER, fixed versus variable output, and the time at which the DER provides power or energy to the grid (coincidence with load)

Several core elements are needed to fully measure the integrated benefits of DER. The primary element of the analysis is an accurate spatial forecast of energy demand by class, DER adoption, and other expected changes to the system. This forecast is needed to identify and quantify the impacts

[7] When DMCs are forecasted out for 10 years, they become the "forward tenders" often described by transactive energy advocates. DMC methods depart from transactive energy propositions, however, in that DMCs are largely cost-based, not market-based.

of various levels of additional DER on the distribution system and on the bulk power system. The analysis also includes an assessment of hosting capacity or the level of DER interconnection that can be locally accommodated without exceeding distribution system safety or power quality limits. Additionally, several categories of avoided cost are required to optimally site DERs. The analysis will consider energy, capacity, and reliability costs, both at the bulk power level from the generator to the substation, and distribution level benefits from the substation to the meter.

Simple rules can be used to further the dimension DMCs. The proper dimensioning of DMCs is essential to establish comparable *apples-to-apples* valuations across resource options and across locations. DMCs are currently used to enable granular optimization, particularly to identify specific resource needs down to the circuit or customer level. This is possible through the integration of both supply-side and distribution-side marginal/avoided costs, including kVAr (power factor and voltage), which is required to resolve distribution needs.

The appropriate value capture represented in DMC is directly related to the cost avoided. In 1970, Alfred Kahn [39] explained a set of problems with defining marginal costs that are still relevant: (1) proper specification of the time perspective and primary causality, including integration of short-run and long-run components, (2) proper specification of the incremental block/unit, and (3) how to identify the marginal costs in terms of the incremental, causal cost responsibility, particularly if significant costs are common (with functions of joint supply and separate demand).

In the case of DMCs, the distribution expansion plan largely serves as the guide to determine potentially avoidable grid and market costs, provides the time dimensions (up to 20 years) to capture respective avoided cost values, uses a consistent incremental block/unit, and defines causal cost responsibility. It should be based on granular load forecast and related power flow results. As many utilities update their 10-year distribution plans at least yearly, the distribution components of DMCs seem to be reasonably well defined. This importantly allows for adjustments to utility, customer, or vendor incentives to better motivate pursuit of the desired least cost outcomes. DER resources, such as PV and storage, are 20-year decisions. To intelligently establish policy surrounding these resources, a long-term forecast of their benefits and costs are required. Ignoring these long-run cost impacts, particularly at times when the nature and use of the existing grid are in flux, is risky to say the least. Even a guess at the long-term forward cost curves for the distribution impacts is better than existing policy, which largely motivates siloed PV adoption via the use of existing tariffs (past costs). It is analogous to driving forward with only the use of a rear view mirror. The wholesale or supply components, likewise, will change and evolve significantly through this process. Importantly, the DMC analysis can enable joint co-optimization around both the distribution grid and bulk-grid supply.

Still, the application of specific DMC components for kWh, kW, and kVAr requires careful parsing, which requires proper matching of the specific avoidable resource needs identified. The wholesale energy/power (kWh/kW) cases present little issue. The newer world of distribution-related marginal or avoided costs, however, presents little in terms of track record to go on. The easy cases are with proposed distribution resource plan solutions, which are more operationally focused on DER integration at the hourly level, or next day, at most. The more important and consequential need is to get ahead of the risks, and signal locational value to DERs, where more than 20-year-old equipment and resources are being permanently placed. These cases call for separate DMC metrics, but the long-run locational capacity value may well be the most important dimension.

Intuitively, where solar and storage are in place, the energy from solar is largely for "free" from the sun—with little or no short-run marginal cost—leaving the bulk of the utility planning problem to be a focus on long-term capacity planning. To be sure, short-run DER integration at the operational level is critical, but much of the current focus and discussion seems disproportionately on short-term operational integration; it lacks focused considerations on long-run avoidable capacity costs. Both, of course, matter.

When two or more of these dimensions are combined, in concept the concerns of Alfred Kahn may arise. This suggests concerted focus on the time frame (short-term variable and long-term fixed costs), the increment involved, and direct causality. Direct causality must be properly derived from engineering models tied to load forecasting, long-term cost estimation, and the economics of cost-benefit optimization. To capture the avoided costs of a specific distribution resource, it may make sense to combine two or more of the respective DMC values (e.g., kW and kVAr), for ease of implementation or market fluidity. With hourly or subhourly DMCs that represent a specific avoidable locational distribution resource, this combination of attributes amounts to a locational asset-specific DMC. For PVs, the long-term forward tender value will differ from that of storage, EE, and other DERs.

To test whether a package of DERs can avoid a specific distribution asset, merely compare the DMC for the package (*ex anti*) to the DMC for the distribution asset (*ex post*). With the extensive data bases and new modeling available, asset-specific DMCs can be accurately compared with DMCs for tailored DER packages with right dimensioning. Geospatial DMC modeling and optimization enable dimensional checks to ensure comparable value comparisons, which enable fast and accurate resource plan development.

The proper compilation of DMCs requires that each *with-and-without* case be comparable and accurately represent the "*but-for*" circumstances. This is essential to properly determine the DMC differences that will drive primary results, and, even more so, optimization results. Importantly then, two critical conditions must be satisfied:

1. Traditional resources must indeed be deferrable by DER resources, using accurate forecasting and cost analysis methods (comparable or better than traditional supply-side avoided cost-estimates) with causality, using correct dimensions to net this value.
2. Deferral value must be properly represented over time, time periods must match between traditional and alternative resources, and magnitudes must match, such that hourly load shape or savings shapes are made to be comparable, and new cost factors unique to the grid are standardized, including ramp rates, intermittency, voltage, power factor, and reach/protection.

At locations, this requires comparable well-designed matching of the traditional distribution and supply-side resources avoided compared to the appropriate package(s) of DER resources, and possibly the addition of new costs from new smart grid equipment (e.g., overvoltage mitigation from "too much solar" in a location). These are the modern requirements that extend Alfred Kahn's much earlier recommendations on marginal cost pricing. Just as Kahn and many others have suggested, with proper compilation of marginal costs, resource options can be directly compared and chosen, either for short-term purposes or to determine long-term choices.

The principles remain unchanged. As with traditional integrated resource plans, one must forecast loads and costs, conduct least cost optimization analysis, and use the appropriate cost at the margin-to-signal pricing and value. These same principles underlie supply cost forecasting, network power flow optimization modeling, and the derivation of wholesale LMPs at the substation. With distribution-based marginal costing, all of the costs incurred between the substation and the customer must now be considered. This is particularly critical with the influx of new grid-edge resources behind the meter or along distribution circuits. The process and methods are the same in the derivation of marginal distribution costs. The data complexity and granularity levels are necessarily greater, but these challenges are surmountable with modern computation, modeling, and data management.

20.2.4 Customer Value-of-Service to Further Optimize Planning and Markets

A conceptual methodology to integrate value-of-service for DER projects is recommended based on six steps [30,40,41,42]. The first step, as we have explained earlier, is to define the benefits for a project. This exercise requires a map of each project function into standard benefit categories. The second very critical step is to define the baseline or *but-for* case and how it is estimated. The third step is to determine the data available to quantify the benefits. The fourth step requires calculation of the quantitative estimates (from engineering, SAIFI, etc.). The fifth step is monetizing the benefits with use of economic conversion factors. The sixth step requires comparison of the baseline or *but-for* case to the proposed project case, comparing the full stack of benefits to costs. To perform this work in detail, the general benefit categories are first defined based on principal characteristics and mapped to grid/DER functions.

The second step, to define the baseline (*but-for*) case, can be very challenging. What are the baseline conditions in each case in terms of engineering or other metrics/criteria, which can then be monetized using economic metrics? What are the benefit categories, who benefits (customer, distribution grid, bulk-power), and how is each baseline indicator defined? For example, the case for circuit switching may posit the number of existing circuit switches in place and explain the impacts of current and future circuit switching given the number of circuits. Another example is to define the grid impacts of the *status quo* case on future DER hosting.

The third step is to define data available to quantify the benefits. How will the distribution grid be impacted? In some cases, outages and declines in power quality must be defined. The reliability (SAIDI/SAIFI) and power quality (Volt/VAr criteria violations) data provide direct implications, such as where new circuit switching *is not provided*, especially with greater use of DERs.

The fourth step is to provide relevant results, including calculation of the quantitative estimates (from engineering calculations, SAIFI, etc.) that can be used. A comparison of the with and without cases, based on technical parameters, is needed to reflect the change in conditions. These conditions will manifest as changes in electricity bills, customer costs, distribution costs, bulk-grid costs, power interruptions, power quality, resiliency, safety (accidents) and security, emissions, and other results. Per the example in the prior paragraph, one can define the grid impacts for the current and future cases, related to the grid expenditure (project), to increase DER hosting. These kinds of results can be compiled and explained.

Importantly, customer value of service (VOS) can be defined based on reliability benefits, and used as the metric to test the economics of distribution upgrades as well as DERs. The impact of reliability on customers is typically based on "outage costs" [43]. Without this kind of measure, it seems difficult to define the full value of grid modifications that ensure reliability. This can be a major limitation on the valuation of grid modifications. Reliability value can, however, be defined and used to define how best to balance customer reliability and grid value. As Electric Power Research Institute (EPRI) explains:

> Customer outage time could be logged by smart meters or outage management systems. These data could be compared with typical hourly loads to estimate the "load not served" during the outage. The value of the decreased load not served as a result of smart grid functions must be allocated based on the function's contribution to reducing outage minutes. By applying a VOS metric (i.e., by customer class and geographic region), the value of the load not served can be estimated as follows:
>
> $$\begin{aligned}\text{Value (\$)} = {} & [\text{Outage Time (h)} \times \text{Load Not Served (kW estimated)} \times \text{VOS(\$ / kWh)}]_{\text{Baseline}} \\ & -[\text{Outage Time (h)} \times \text{Load Not Served (kW estimated)} \times \text{VOS(\$ / kWh)}]_{\text{Project}}\end{aligned}$$
>
> An estimate of the load not served may be provided by the project at the time of reporting, or could be obtained from the baseline estimate generated when the project is established.

Overall, the marginal customer value-of-service should equal the marginal cost of service, including relevant grid costs [44]. Estimated grid interruption (outage) costs from the Lawrence Berkeley National Laboratory (LBNL) study are shown in Table 20.1.

The final step in this overall approach to monetize grid modernization and DERs is to compare the baseline or *but-for* case benefits and costs to the proposed project case. Correlation of weather, loads, and prices further adds to the robustness and valuation.

TABLE 20.1
Estimated Customer Interruption Costs per Electricity Supply Interruption Event—Average kW and Unserved kWh (U.S. 2013$) per Duration and Customer Class

	Interruption Duration					
Interruption Cost	Momentary	30 min	1 h	4 h	8 h	16 h
	Medium and Large C&I (Over 50,000 Annual kWh)					
Cost per event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7
	Small C&I (Under 50,000 Annual kWh)					
Cost per event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
	Residential					
Cost per event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

Source:

20.2.5 Software and Computation Enable DER Integration and Optimization

A primary objective for DER resources is to maximize value for customers, the distribution system, and the bulk grid. DERs are usually situated, however, within the distribution system connected to customers and lower voltage. To maximize the value of DERs requires two things: (1) long-term DER use must be planned and optimized, and (2) short-term DER use must be appropriately dispatched in order to maximize operational value, a second level of optimization.

In order to achieve maximum value and realize these two levels of optimization, DERs must be fully integrated into both distribution and bulk grid use, and they must achieve the maximum deferral and avoided cost possible. These are major challenges. Moreover, the traditional use of DERs has been as separate resources, largely in silos. Each DER resource is unique and has different characteristics. EE is relatively permanent and has a specific impact on customer load curves, which translates to specific load reductions when aggregated. Likewise, DR is unique, but has relatively limited use in terms of the number of hours of the year when it can be exercised. Distributed generation, such as solar PV, can generate only when the sun shines. Storage batteries are available only during specific hours, though they can be used flexibly, and must be charged, which provides for energy management during the discharge and charging cycles. More importantly, specific customer loads are key in determining the type of DERs required to reduce load, improve Volt/VAr, and serve frequency regulation needs.

DER value can be increased substantially if used to defer major distribution and bulk grid costs, largely capital expenditures, but also operating expenditures. When used and operated separately, each DER has different hourly impacts. This, in many cases, limits the deferral capability and value of individual DERs. When DERs are used in the right combination, with the right sizing and certainty, DERs can directly defer high-cost resources. To achieve this, however, specific packages of DERs must be configured, installed, and operated at specific locations on the grid.

DER optimization is generally more challenging than supply-side optimization. Supply-side optimization typically considers customer loads at a higher level of aggregation, at the subtransmission or price-node (P-node). Large-scale generators have specific operating characteristics (start-up, ramping, and operating costs), which enable capacity expansion and security-constrained economic dispatch to be well defined. The dynamics of transmission power flow must also be considered, especially to understand voltage constraints and possible loop-flow.

In contrast, DERs are more specific, depend on underlying customer loads, and must reflect both the physical grid architecture in detail and the integration and operation of the DER portfolio. This is significantly more complex than supply-side integration and optimization. To fully integrate and optimize DERs, each specific customer load profile must first be defined, which typically requires smart metering (AMI) data. The distribution system load flows must be accurately modeled to create the basis for underlying changes in distribution deferral (CapEx) and operations (OpEx). Wholesale grid impacts must also be determined. Specific DER packages must be designed for individual customers to achieve the desired deferral and operational benefits. And the DER portfolio must be operated to maximize the value for both the distribution and wholesale grids. This seems like *a tall order* to achieve, to fully integrate DER planning, much less to optimize both DER investment and operations.

The latest uses and capabilities of software and computation now enable these results. Big data can be managed and analyzed to resolve these objective functions, and system-wide results can be well-defined. The composite hourly and subhourly impacts of DERs can be determined based on appropriate stacking and resolution of physical grid characteristics and incremental or marginal benefits. Detailed locational load forecasting, power flow analysis, DER package determination, portfolio optimization, and DER operational optimization can all be integrated in a new process, the DER-centric distribution planning process.

The "DER-centric" distribution planning process starts with locational demand forecasting that uses acre level planning granularity and customer-specific AMI data. Customer-specific targeting of high peak demand use, high energy use, and combined effects are possible, as well as the overlay of customer-specific electricity end uses. Distribution load-flow analysis is then calibrated to determine distribution loads down to the customer line-segment level. Distribution planning assumptions for load growth are used to define specific future CapEx- and OpEx-related projects. The needs identified in the distribution planning process provide the basis for distribution deferral analysis.

Installed DER costs and locational bulk grid supply curves are needed as inputs to determine composite locational "all-in" incremental, marginal, and avoided costs. DMCs, as described earlier, encapsulate these costs. Operational optimization of selected DER packages for each location is also needed. The results of these steps are then projected forward for the duration of the planning cycle. By iterating between all-in DMCs, customer-specific loads, and DER options, customized DER packages can be determined for specific customer locations on the grid. These methods enable DER integration and optimization at the customer level.

20.2.6 Distribution and Bulk Grid—Four Steps to Iterate and Integrate

A four-step method has been developed for DER integration and iteration through research with a set of U.S. utilities. This points to progress with best practice techniques to capture maximum benefits, use new data, and fully integrate and optimize DERS with the smart grid. A 2× to 5× increase in portfolio value can be demonstrated when customers are offered the full spectrum of DER options. These four steps explain how this optimal approach is used.

When examined in detail, DERs may defer or avoid major utility grid capital and variable costs, netting very substantial benefits. Where ISOs/RTOs are in place, generation has largely become competitive, removing generation capital costs from rate base. Transmission may, for many utilities, be a significant component of the regulated utility rate base. But distribution investment has remained one of the largest fixed investments in capital, and thus a large component of the rate-base.[30]

DER investments that directly impact distribution investments are of critical concern if they have implications for reliability. Moreover, with major use of DERs, many utilities become very concerned about three directly related matters: (1) net decreases in investment (rate base) occur, (2) lost revenue (from reduced sales) results, and (3) the costs of many DER options are less than the conventional resources they are designed to replace, thereby reducing rates. With expansive use of cost-effective DERs, this now threatens to be disruptive from the utility view.

Locational DER modeling can be overlaid on distribution load flows to provide T&D assessment and enable targeting of integrated DERs. Of note, this enables the utility to identify specific (actual) distribution system capital investment deferral opportunities. It also identifies distribution assets at risk, both with and without the proposed DERs. In this way, DERs can be spatially allocated to achieve maximum benefit. Recent California legislation, AB327, adds a Public Utilities Codes Section 769, which states that electric utilities are to provide "*distribution resources plan proposals to identify optimal locations for the deployment of distributed resources cost-effective methods to maximize the locational benefits and minimize the incremental costs of [these resources].*" A key to this step is verification of locational engineering assumptions and of existing demand-side features to establish the base case. Utilities will need to get agreement from local distribution and transmission engineers about expected load flows and dynamic operations, which are then reconciled with modeling.

We now have the data, modeling, and computation capability to target DERS at the feeder and customer levels. These same capabilities also enable more granular demand forecasting. A geospatial planning approach can enable the use of map-layer hierarchies, such as those shown in Figure 20.3. Electricity load flows then are provided with geospatial mapping, consistent with customer locations, circuit maps, per-capita growth assumptions, transportation corridors, specific DERs at specific customer locations, and future land use.

The approach can then identify specific (actual) distribution system capital investment deferral opportunities down to the customer feeder level, which then allows identification of capacity and energy deferral opportunities at the specific customer building level. This includes spatial identification of distribution assets that are at risk for loss of load, and identification of the specific mix of DER and distribution assets that will provide the reliability level desired. In short, DERs can be spatially allocated to achieve maximum benefits. This approach, already being used at Duke Energy, and starting to be used at PG&E [46,47], provides distribution feeder level and customer level granularity through a series of steps. These include use of local planning assumptions and economic growth plans on a locational basis to identify asset/planning areas that have capacity surplus as well as deficiencies. Where there are deficiencies, mitigation projects can be planned and specific areas can be identified for candidate T&D project deferral opportunities.

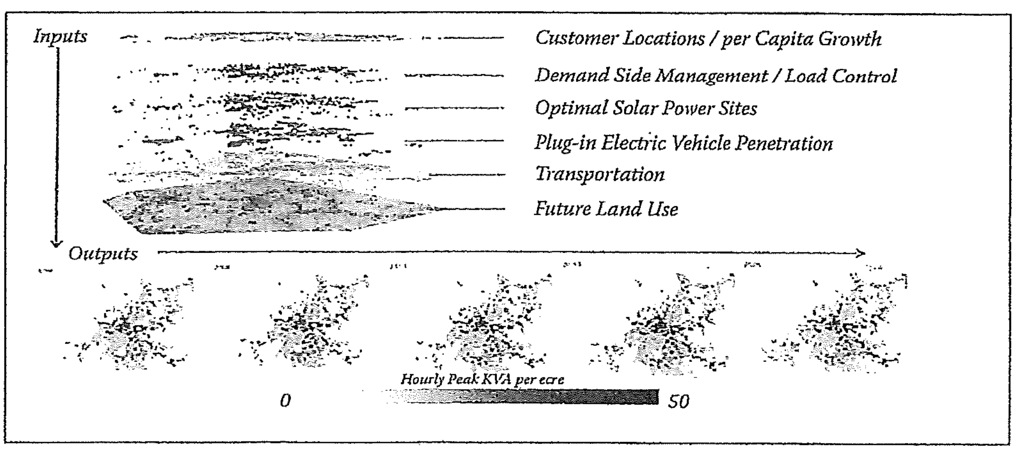


FIGURE 20.3 Map layer hierarchies for DER geospatial planning. (© 2016 Integral Analytics. All rights reserved. With permission.)

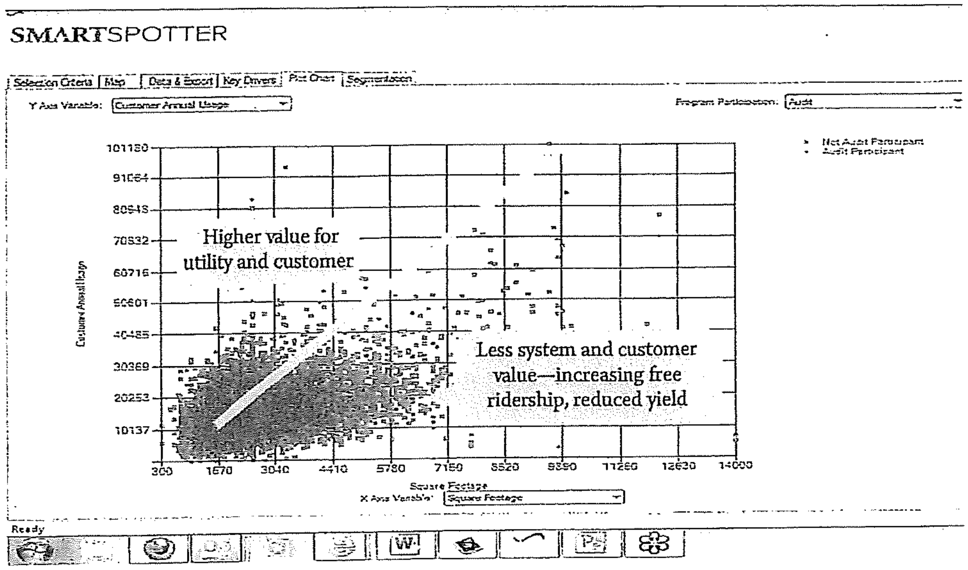


FIGURE 20.4 Locational assessment value of T&D capital cost deferral in DER planning. (© 2016 Integral Analytics. All rights reserved. With permission.)

With these areas targeted, the required DER technologies can be determined, as well as the specific savings required to defer T&D capital projects. From this, DER project portfolios can be designed to transform significant grid and generation costs into more cost-effective DER investments. This creates the specific opportunity to calculate the avoided capacity and energy cost for the specific context, at what amounts to the microgrid level, and to tailor the DER remediation to achieve the desired capital and variable cost deferral with certainty. This locational assessment then flows into the cost-effectiveness analysis to define the larger value proposition. In Figure 20.4, the areas in green signify locations where the capital cost deferral from DERs would be valued at zero, while the areas in red show capital cost deferral would be \$280/kW-year. Although the regional average project cost may be consistent with field utility information, with greater granularity we can identify the higher avoided cost areas and enable targeting of DER projects that provide major benefits.

There are four main steps in evaluating the locational value of T&D capital cost deferral in DER planning:

Step 1: *Target Marketing and Consumer Engagement*—Identify the high value participants and target-specific DER packages to these customers using interval (load-profile) and "big data." Data-driven targeting enables focus on the right customers who can deliver highest value. This method leverages vendor and usage data to increase brand lift, customer satisfaction, savings, lower average marketing costs, lower free ridership, and enables higher quality consumer engagement. Results are dramatically enhanced compared to traditional "shotgun" methods from siloed solutions.

Step 2: *Locational Distribution and Transmission Benefits*—Customer-specific impacts from transmission to the distribution feeder level show the deferral of major capital and operating costs. The portfolio can be spatially allocated across the distribution and transmission systems to achieve maximum benefit. This level of granularity enables hourly and subhourly mapping of existing and future loads. Load growth plans define distribution and transmission areas with capacity surplus and deficiencies. The portfolio can defer specific distribution and transmission project costs. This customer-level granularity increases the benefits achieved. An example based on locational capacity targeting is shown in Figure 20.5.

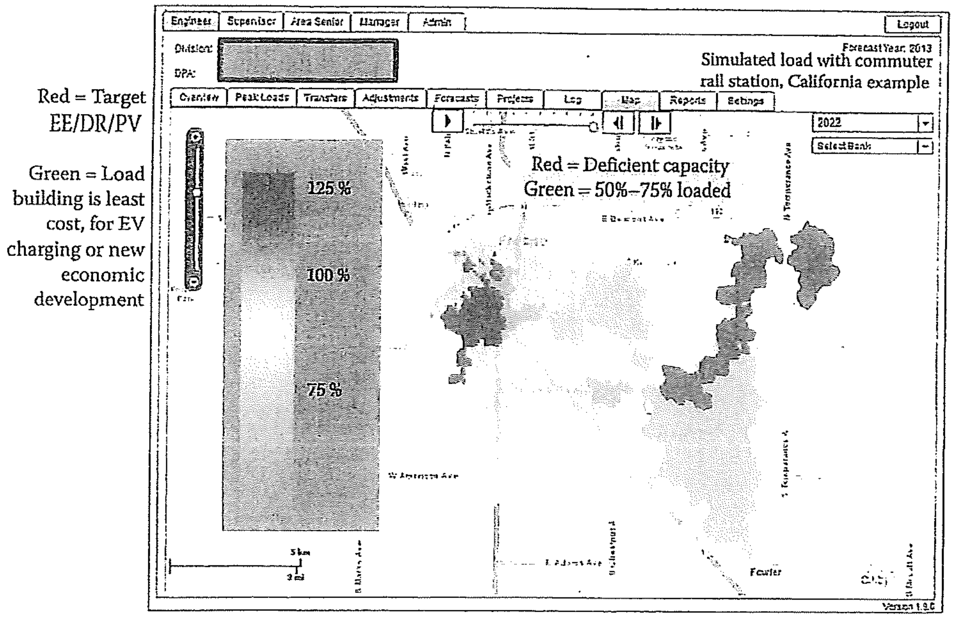


FIGURE 20.5 Locational capacity targeting. (© 2016 Integral Analytics. All rights reserved. With permission.)

Step 3: *Locational Uncertainty, Hedge, and Option Value*—This captures deviations (covariance) in expected demand, weather, demographics, commodities, prices, and combined value to reflect the probability of expected uncertainty and the benefits of reducing uncertainty. This is a major advance over use of point-source (deterministic) assumptions, based on approximate averages and linear models that largely ignore uncertainty. The results from this analysis appropriately show substantial value added.

Step 4: *Distributed Optimization to Maximize Benefits*—The ultimate optimal use of DER and smart grid measures, what is equivalent to the *Holy Grail*, is the dispatchable virtual power plant. This enables optimization of individual resources and the portfolio. This includes scheduling and dispatch of distributed resources, injection of reactive power, voltage control, loss compensation, load following, and system protection. These methods proactively predict loads, control their shapes, and manage demand. With this higher level of resource optimization, system costs are dramatically reduced for customers.

Distributed optimization enables the value of load leveling, peak shaving, load-shifting, and load reduction to be captured at the substation, transformer, feeder, and wholesale grid levels. This can, in part, be achieved across an ISO, as shown in Figure 20.6. This further enables efficiencies from the three steps previously explained.[8]

20.2.7 Option Value and Optimization

The question is how to fully define the value of optionality—availability to serve in multiple markets—from dispatchable DR capacity. In 2002, the California Public Utilities Commission directed its utilities to use option value methods to evaluate all major electricity procurement transactions.[9] Each of California's investor-owned energy utilities has continued to use option value

[8] Further explanation can be found in Reference [48].
[9] California Public Utilities Commission, D. 02-12-074, p. 17.

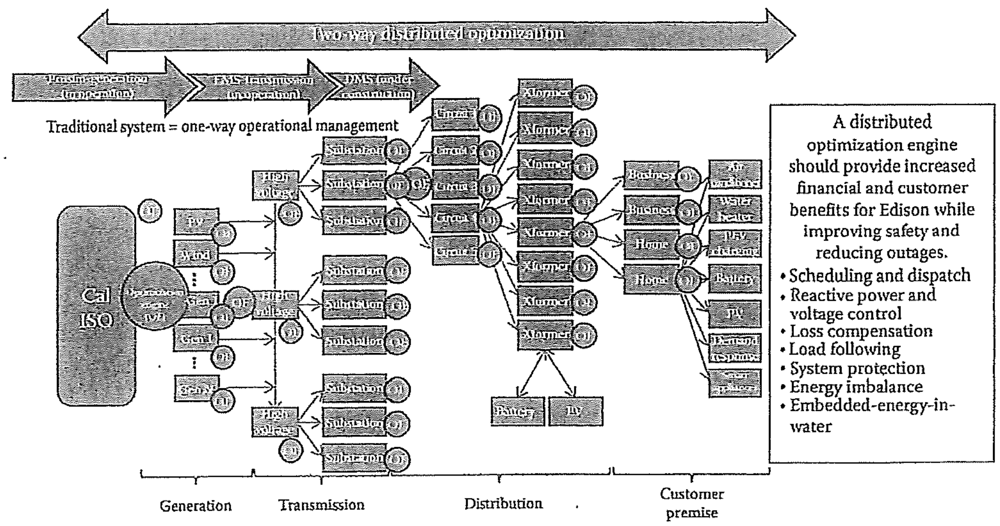


FIGURE 20.6 Optimization across CAISO. (© 2016 Integral Analytics. All rights reserved. With permission.)

methods to evaluate long-term procurement options in the CPUC's long-term procurement plan. The results are kept confidential, protected by Nondisclosure Agreements, and reviewed by a stakeholder-based Procurement Review Group.

Option value represents the availability of a resource to participate in multiple markets concurrently. A resource that can be available for use during the highest price hours and the times when reliability is most threatened is simply more valuable than a resource dedicated to a single narrow use (e.g., grid-wide emergency service). Full option value implies that the full set of benefits is available and that each potential use is valued. Option value has been used for years to value fossil generation.[10] This approach can be used to directly quantify the market benefits of dispatchable capacity. With variable wind or solar resources, dispatchable capacity must increase (or decrease) immediately to fill the gaps in order to avoid a grid outage. These supply changes result in more price volatility and greater congestion. Option value can also be extended to the distribution level, for example, where electric vehicle charging requires load-management that is provided by DR.

To fully value DR, option models are typically used that rely on traded forward curves (contracts) for energy and related price volatility at specific delivery points. Option models can be designed to directly reflect load changes, hours of availability, and price volatility. A primary assumption of traded forward contracts is that future prices converge to the prevailing energy spot price upon maturity. The value of optionality in multiple concurrent markets is based on hours of resource availability, the market value of energy, the value of reduced market volatility, and contract length. In contrast, a single snapshot of avoided capacity and energy costs cannot capture the optionality of dispatchable capacity.[11] For example, utilities often use dispatchable DR only as emergency capacity, but it can be used more widely as an *option contract* to serve multiple purposes and maximize its value [51]. Building on Table 20.1, a subset of the multiple uses of dispatchable DR includes:

- Ramping capacity (for grid needs and to integrate more renewables)
- RA and operating reserves
- Reduce capital costs
- Lower electricity prices

[10] The genesis of this is the *spark-spread* option. See References [49,50].
[11] Monte Carlo techniques can be used to augment valuation in order to capture elements of DER optionality.

- Reduce congestion costs
- Mitigate market power
- Locational arbitrage (in nodal markets)
- Reduce fuel risk
- Remove counterparty risk
- Distribution load management

20.2.8 Dynamic Capabilities Will Be Essential for Smart Grid Adaptation[12]

It is increasingly clear that dynamic capabilities are needed to develop resources that can adapt and gain competitive advantage in the smart grid space, especially to enable more effective integration and optimization. Simply put, dynamic capabilities will be essential to succeed in this new arena. New smart grid business models are and will increasingly be at the forefront. Successful firms must design and provide new products and services that reflect new competencies. These steps will, in turn, require new smart grid stakeholders to innovate in response to exogenous events (e.g., business cycles, enhanced competition, and regulatory changes), fully embrace integrated systems (that remove siloed barriers), leverage new technologies and collaborative efforts, and all of these must proceed at the speed of the market. With greater change in the business and technology environment, the advantages conferred of dynamic capabilities will be critical. Integration and optimization of electricity with water, gas, and other platform economics will become essential to enable stakeholders to gain competitive advantage. In this intense setting, dynamic capabilities will result from inimitable capabilities, rapid adaptation, flexibility, and innovation.

Five specific dynamic capabilities seem critical to capture and synthesize needed advantages. First, as in IT and electronics, specific processes are needed to define, manage, streamline, and adapt to enable smart grid product development, quality control, knowledge transfer, and technology transfer. These routines must be well orchestrated to enable dynamic efficiencies. Further development of dynamic capabilities will be essential in these areas.

Second, improved smart grid business models must be a focus, an area of continuous improvement. This is how value is delivered to customers, and it will compel customers to pay for value and convert this value into profits. New revenue and cost structures must be designed to meet customer needs, and leverage the use of market segments and channels and specific mechanisms to capture value. Smart grid-related business models will require articulation of the value proposition in terms of its scope, scale, differentiation, and consumer engagement. The related value chain structure must also realize value, revenue, and profits. Each business plan must ultimately define the way that a vendor "goes to market," including the scope and extent of the vendor's market presence. Business model adjustments must be anticipated and well executed as conditions change in the competitive landscape. These are essential business realities, and the smart grid space is no different.

Third, as David Teece explains, dynamic investment choices create competitive advantage when value chain elements are complementary, reinforce each other, and increase value [53]. This is where *cospecialized* assets can be used strategically in conjunction with each other. This is one of the integration functions that will enable greater smart grid value to be leveraged as service options and technology scope increase. Properly bundled and managed, the integration of key smart grid operations will enable new services that are further differentiated, provide greater benefit capture, and yield significant cost savings. *Cospecialized* assets will be combined to achieve system integration and innovation benefits. These smart grid systems will increasingly need to be designed, built, and sized to meet specific smart grid needs (e.g., at the substation or microgrid level). A number of smart grid integration and optimization benefits are likely to be found bundled within specific subsystem needs and opportunities. Innovation routines should be exploited that can be used to develop new cospecialization technologies. A critical outcome from this is greater focus on scope-based advantages in the smart grid.

[12] This entire section borrows heavily from the work of David Teece, including Reference [52].

Fourth, dynamic smart grid adaptation capabilities can be forged through informed orchestration of assets, new knowledge, and coordination with value chain partners. The vendor's assets, knowledge, and value chain partners can be further orchestrated to create new dynamic capabilities that generate greater value for customers and other stakeholders. A focus on consumer needs and value chain capabilities can be approached strategically to enable the vendor to use proactive smart grid adaptation and deployment.

Fifth, dynamic smart grid capabilities will originate from efficient learning and technology development across different parts of innovative vendors. The sharing of knowledge and capabilities reflects "silo busting," to monetize otherwise untapped potential. The outsourcing of functions and joint development across smart grid vendors will enable new capabilities and differentiation, and with it greater value. Thus, the development and improvement of dynamic capabilities are especially valuable, though it may be difficult at times, particularly to imitate potentially competing services and products.

With this backdrop, what do we expect by 2020 and in another decade? Contemplated are interactive smart grids that enable *plug-and-play* DERs that are fully integrated and optimized. More work is required to further develop new utility business models and exhibit tomorrow's dashboards. Transactive energy is expected to both enable trading of long-term DER forward positions and short-term interactive trades. *Superforecasting* techniques are likely to be well developed to provide greater knowledge about best future options.

REFERENCES

1. http://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp.
2. FERC Order 2000, December 20, 1999, p. 3. https://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf.
3. FERC Order 888, April 24, 1996, pp. 279–286. https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-00w.txt.
4. U.S. Energy Information. http://www.eia.gov/todayinenergy/detail.cfm?id=790.
5. http://www.ferc.gov/industries/electric/indus-act/rto/maj-ord.asp.
6. Standard Market Design (SMD) NOPR, *FERC Docket No. RM01-12-0000.* November 11, 2002.
7. https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Settlements-and-payments.
8. H. Chen, *Power Grid Operation in a Market Environment: Economic Efficiency and Risk Mitigation*, Wiley-IEEE Press, 2016.
9. E. Woychik, Competition in transmission: Coming sooner or later? *Electricity Journal*, June 1996.
10. www.pjm.com.
11. www.iso-ne.com.
12. www.misoenergy.org.
13. www.nyiso.com.
14. www.caiso.com.
15. www.spp.org.
16. www.ercot.com.
17. H. Chen and S. Bresler, Practices on real-time market operation evaluation, *IET Generation, Transmission and Distribution*, Vol. 4, No. 2, 2010, pp. 324–332.
18. W. Hogan, *A Model for a Zonal Operating Reserve Demand Curve*, October 15, 2009. http://www.whogan.com.
19. *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Docket Nos. RM11-7-000 and AD10-11-000, Order No. 755, October 20, 2011.
20. *Third-Party Provision of Primary Frequency Response Service*, Docket No. RM15-2-000, February 19, 2015.
21. *Frequency Response and Frequency Bias Setting, NERC*, February 7, 2013.
22. P. Alstone, et al, *Final Report on Phase 2 Results, 2015 California Demand Response Potential Study: Charting California's Demand Response Future*, Lawrence Berkeley National Laboratories, November 14, 2016. http://www.cpuc.ca.gov/General.aspx?id=10622.
23. http://www.pge.com/en/myhome/saveenergymoney/energysavingprograms/index.page.
24. http://www.pge.com/en/myhome/saveenergymoney/energysavingprograms/euca/faq/index.page#homeupgrade.

25. Testimony, Technical Appendix. Vol 5, *NV Energy Demand Response Program Insurance (Option) Value, Comparative Analysis and Description*, K. Skinner and H. Huang, in Docket No. 14=07, June 17, 2014.
26. *DSM Collaborative Seminar: NV Energy Demand Response Program Insurance Value*, K Skinner, E. Woychik, M. Brown, 18 September 2014.
27. T. Osterhus, Distribution marginal prices (DMPs)" Update #6, *Integral Analytics*, 2014.
28. E. Woychik, *Integrated Least-Cost Electricity Planning Under Uncertainty: Issues and Progress, Workshop on Energy Resources Planning for Electricity*, Honolulu, Hawaii, May 1987.
29. E. Woychik, *Least-Cost Resource Plan Integration under Uncertainty: Toward a Standard Practice Approach*, California Public Utilities Commission, September 1986.
30. E. Woychik, *IDSM Cost-Effectiveness: What Happened Outside of California? Results from Duke Energy, NVE, Avista*, presentation in CPUC R. 14-10-003, January 22, 2015.
31. E. Woychik, et al., *The Integration and Optimization of DSM: Extraordinary Benefits when the Orchestra Plays Together*, AESP National Conference, Orlando, FL, February 9–12, 2015.
32. K. Skinner, E. Woychik, M. Brown, H. Huang, NV Energy *Demand Response Program Insurance Value*, Presentation at Nevada PUC, Las Vegas, October 27, 2014.
33. E. Woychik and M. Martinez, *Integration and Optimization of DSM: Extraordinary Benefits When the Orchestra (Energy Efficiency, Demand Response, Distributed Generation, and Storage) Plays Together*, presentation at Lawrence Berkeley Laboratories, Environmental Energy Technologies Division, March 27, 2014.
34. R. Smith, K. Skinner, and E. Woychik, *Valuing Integrated Demand Side Management (IDSM) for Improved Cost Effectiveness*, presentation at *DistribuTech Conference*, San Antonio, TX, January 28, 2014.
35. *Integrated Distribution Planning*, Solar City Engineering, August 2015.
36. R. Stevie and T. Osterhus, *DMP Methodology Applied to Value of Solar*, New York REV Proceedings, Matter No. 15-02703, Case 15-E-0751.
37. R. Li, Q. Wu, and S. Oren, Distribution locational marginal pricing for optimal electric vehicle charging, *IEEE Transactions on Power Systems*, Vol. 29, January 2014, p. 203.
38. S. Fine, et al., *The Value in Distributed Energy: It's All About Location*, Location, ICF International, 2015.
39. A. Kahn, *The Economics of Regulation: Principles and Institutions: Volume I*, MIT Press, 1988, pp. 70–83.
40. *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects*, EPRI, January 2010.
41. S. Oren, *Area-Specific Marginal Costing for electric Utilities: A Case Study of Transmission and Distribution Costs*, Doctoral Thesis, Stanford U., September 1989.
42. M. Munasinghi, *Electric Power Economics*, Butterworths, 1990, pp. 136–137 NS pp. 23–243.
43. https://emp.lbl.gov/sites/all/files/value-of-service-reliability-final.pdf.
44. M. Munasinghi, *op sit*, pp. 236–238.
45. *EEI Financial Conference*, Alliant Energy, November 6–8, 2016. http://www.eei.org/meetings/Meeting_Documents/2016-11-FinConf-Alliant.pdf.
46. *How to Make Many Community Microgrids: The Hunters Point Model*, Clean Coalition, August 24, 2014. http://www.clean-coalition.org/site/wp-content/uploads/2014/08/EnergyEfficiencyMarkets_August-2014.pdf.
47. *The Hunters Point Project: A Model for Clean Community Power*, Clean Coalition. http://www.clean-coalition.org/site/wp-content/uploads/2014/04/Hunters-Point-27_zf-22-Apr-2014.pdf.
48. E. Woychik, M. Martinez, and K Skinner, *Integrated Demand-Side Management Cost-Effectiveness and Optimization Methodology*, Advanced Workshop in Regulation and Competition: 26th Annual Western Conference, Monterey, California, June 21, 2013. http://theenergycollaborative.com/wp-content/uploads/2013/07/Integrated_DSM1.pdf.
49. V. Kaminski, *Managing Energy Price Risk*, Risk Books, 1999.
50. A. Eydeland, K. Wolyniec, *Energy and Power Risk Management*, John Wiley, 2003.
51. *Options: Essential Concepts and Trading Strategies*, Options Institute, McGraw Hill, 1999.
52. D. Teece, *Business Models, Business Strategy, and Innovation,* Long Run Planning (Elsevier), Vol. 42, 2010.
53. D. Teece, *Dynamic Capabilities and Strategic Management*, Oxford UP, 2009, pp. 160–163.

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-4.51g
Respondent:	M. T. Paul/ L. K. Mikulan
Page:	1 of 1

Question: Please refer to ELPCDE-1.10d:

g) If DTE were to perform a retirement analysis of some of its peaker units, how would it develop the forecasted fixed and variable O&M costs?

Answer: If the Company were to perform an economic analysis, O&M cost estimates would be based on engineering judgement utilizing historical costs of the peaker fleet, along with the age, condition, operating history, and future operating and maintenance requirements of the peaker or peakers being analyzed. Variable O&M estimates would be utilized in dispatch modeling and total O&M estimates would be used in the economic analysis model for each peaker or group of peakers analyzed.

Attachments: None

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-4.51a
Respondent:	M. T. Paul
Page:	1 of 1

Question: Please refer to ELPCDE-1.10d:

a) Why does the Company not track O&M costs separately by fixed and variable categories for its peaker units or fleet?

Answer Actual O&M expenses are not tracked separately as fixed or variable because costs within those categories are not definitive and would be estimates based on engineering judgement. It would not be practical nor useful to attempt to categorize every actual O&M expense as fixed or variable.

Attachments: None

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-4.51b
Respondent:	M. T. Paul
Page:	1 of 1

Question: Please refer to ELPCDE-1.10d:

b) Is it the Company's position that it has no ability to determine either the variable or fixed O&M costs for any of its individual peaker units or facilities?

Answer: Variable and fixed O&M costs can be estimated but not definitively measured and tracked.

Attachments: None

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-4.51c
Respondent:	M. T. Paul/L. K. Mikulan
Page:	1 of 1

Question: Please refer to ELPCDE-1.10d:

c) If the Company is unable to track its individual peaker unit or facility variable and fixed O&M costs, how is it able to determine whether these units continue to be economic to operate?

Answer: When the Company performs economic analysis on generating units, O&M cost estimates are based on engineering judgement utilizing historical costs, along with the age, condition, operating history, and future operating and maintenance requirements of the unit(s) being analyzed. Variable O&M estimates are utilized in dispatch modeling and total O&M estimates are used in the economic analysis model.

Attachments: None

MPSC Case No.: U-20471
Requestor: ELPC
Question No.: ELPCDE-4.51d
Respondent: M. T. Paul
Page: 1 of 1

Question: Please refer to ELPCDE-1.10d:

d) If the Company is unable to track its individual peaker unit or facility variable and fixed O&M costs, how is it able to compute a total O&M cost for its fleet?

Answer: Total O&M costs actually incurred for the peaker fleet are recorded in the corporate accounting system.

Attachments: None

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-4.51e
Respondent:	M. T. Paul
Page:	1 of 1

Question: Please refer to ELPCDE-1.10d:

e) Provide all supporting data, including any internal reports or analyses, that were used to calculate the total O&M values in "U-20471 ELPCDE-1.10d-01 2014-2018 Peaker O&M.xlsx"

Answer: The total O&M values provided in ELPC-1.10d are directly from the Company's general ledger and are not calculated.

Attachments: None

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-4.51f
Respondent:	M. T. Paul
Page:	1 of 1

Question: Please refer to ELPCDE-1.10d:

f) Is DTE required to report unit or facility level costs to FERC? If so, how it is able to do so without tracking costs on a per unit or per facility basis?

Answer: The Company provides peaker fuel costs to FERC at the facility level. Peaker non-fuel O&M is included as part of "Other Power Generation" provided to FERC.

Attachments: None

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-13.88g
Respondent:	L. K. Mikulan/T. L. Schroeder
Page:	1 of 1

Question: Refer to Exhibit A-5.

g. Please indicate where in the Company's filing it performed any economic analyses on the specific mix of solar and wind assets as found in the Starting Point renewables and Starting Point VGPP renewables compared to alternative mixes of solar and wind assets.

Answer: The analysis as described in this question was not completed as part of this filing. The specific types of renewables builds are considered to be placeholders at this time. As the performance characterstics and costs of renewables technologies continue to evolve in the.future, the flexible PCA will be updated. Even though the Company considers these renewable builds to be placeholders, an assumption of either wind or solar was made for modeling purposes. The Company's selection of wind versus solar was based on a combination of the Company's knowledge and experience of Michigan projects that both exist and are being developed as well as the forecast of wind versus solar costs as described in response to ELPCDE 13.88a.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-13.88f
Respondent:	L. K. Mikulan/ T. L. Schroeder
Page:	1 of 1

Question: Refer to Exhibit A-5.

f. Confirm that because the Starting Point renewables and Starting Point VGP were hard-coded into the Strategist modeling, none of the Company's initial Strategist runs that were performed when the IRP was filed analyzed the cost effectiveness of the specific blend of starting point renewables as compared to other blends that attain the same levels of renewable generation. If deny, please explain.

Answer: Confirmed. See also response to ELPCDE-13.88g.

Attachments: *N/A*

15

CAPACITY RESOURCE PLANNING

Chapter 14 presented the foundations of optimal generation planning. This chapter expands on these concepts by describing key driving factors that influence the optimal capacity plan.

Capacity resource planning involves integrated "supply-side" planning and "demand-side" planning. "Supply-side" planning involves the determination of least-cost generation, transmission, and distribution equipment to serve the customer load requirements. "Demand-side" planning involves the determination of programs to manage the customer load demands and achieve least-cost system operation. Chapter 14 discussed generation "supply-side" planning, and Chapters 7 and 8 discussed demand forecasting. This chapter discusses a methodology for integrated supply-side and demand-side resource planning.

The subjects of indifference value and marginal costing are also discussed along with the impacts of small (or incremental) improvements to existing equipment.

Generation capacity projects typically have high capital investments and long economic lives and are operated in an economic and business environment that may also be subject to uncertainties. Consequently, capacity projects have considerable business risk inherent in providing the forecasted benefits. Business risk considerations are presented in this chapter to illustrate optimal planning under uncertainty and risk.

15.1 SENSITIVITY OF THE OPTIMAL MIX OF ADDITIONS

The optimal mix of capacity additions is dependent on many factors. Among them are existing generation capacity composition, fuel costs, O&M costs, plant costs, target generation reserve level, load-demand profile, load management options, and economic parameters, including fixed-charge rate and present-worth rate.

The generation system example of Section 14.6 can be used to illustrate this sensitivity. At the beginning of 1993, the power system has the following capacity:

	MW
Hydroelectric	41
Nuclear	330
Coal steam	2765
Combined-cycle	0
Oil steam	569
Gas turbine	171
Pumped storage hydro	268
	4144

The annual load factor is 68%, the minimum reserve margin target is 20%, and the utility is investor-owned. Business parameters include a 10% present-worth rate, an 18% levelized fixed-charge rate, and a 20-year economic evaluation period.

Figure 15.1 presents the optimal system addition composition for several cases when coal steam, combined-cycle, and gas turbines are the optimization candidates. The base case has 600 MW of coal additions, 300 MW of combined-cycle additions, and 200 MW of gas-turbine additions.

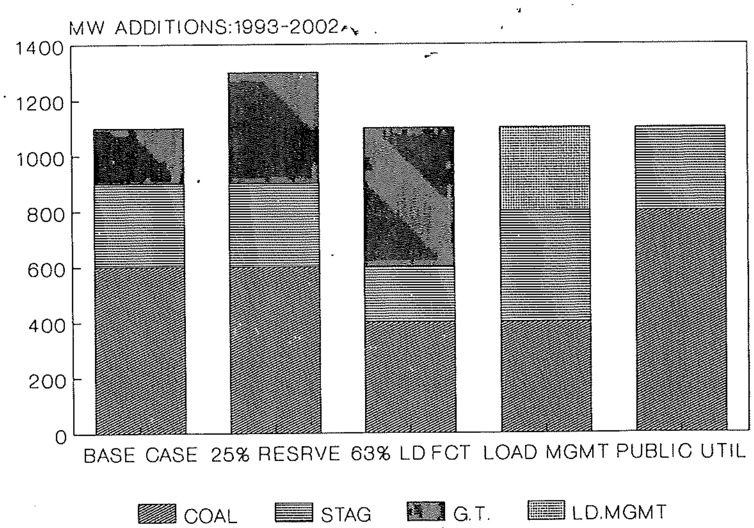


FIGURE 15.1 Sensitivity of optimal system addition composition.

If the reserve margin is increased from 20 to 25%, more capacity is required. Gas turbines are the most economical type of additional capacity to meet the peak capacity need of a higher reserve margin.

If the load factor (average-load demand/peak-load demand) is reduced from 68% to 63% while maintaining the same peak load, then the annual load *energy* is reduced. This implies that the system generation capacity factor is decreased. This leads to lower base-load (coal-steam) capacity additions and more gas-turbine additions.

A sensitivity case is performed in which 300 MW of load management is installed during the 1993–2002 time period. It is assumed that a *hypothetical* "load management" device operates for the three summer and three winter months by displacing the 6-hour period of peak load to the off-peak load periods for each day and is independent of the daily temperatures. It is also assumed that the load management devices reduce the peak load while maintaining total system energy (refer to Chapter 8 for more realistic load management device data). Therefore, it reduces the need for gas turbines. Because the load management additions were assumed to occur during the 1993–2002 time period, when only coal-unit additions were added in this example, load management displaces some of the coal-unit additions as well.

A sensitivity case was run in which the present-worth rate and fixed-charge rate were reduced to those typical of a publicly owned municipal or state-owned utility. A publicly owned utility has lower money costs and can have an 8% present-worth rate and a 13% fixed-charge rate. Lower money costs make capital-intensive plant types more economically attractive. Figure 15.1 illustrates that, in this case, gas-turbine additions are reduced to zero with a corresponding increase in capital-intensive coal plants.

15.2 INTEGRATED DEMAND–SUPPLY PLANNING

Automated generation planning simulation programs determine the optimal schedule of generation capacity additions. Input data describing conventional generating unit candidates can be characterized in terms of the generating unit size, plant cost, fuel cost, plant efficiency, plant reliability, O&M costs, and operation characteristics.

In some cases, a more "complex" generating unit candidate (such as a phased construction of a combined-cycle generating unit) cannot be characterized conveniently in terms of those parameters. In this case, a hybrid of the manual generation planning methodology and the automated generation planning methodology may be used. First, several alternative addition scenarios of the "complex" generation candidate are developed. Each scenario of the "complex" candidate addition schedule is then input as a fixed pattern of additions into the automated generation planning program. The other conventional candidate generation alternatives are then optimized based on this fixed pattern, using an automated generation planning program. The generation expansion cost of the power system is computed for each scenario. Finally, the optimal plan is determined as the scenario with the least cost.

In many cases, demand-side alternatives need evaluation as well. Demand-side alternatives may require special details that are not readily included in the planning program. Conservation programs and load management are such alternatives. A hybrid of manual and automated planning also may be used in these cases.

Studies involving demand-side alternatives require more generalized cost-objective criteria. A plan with the least total present-worth costs is *not* necessarily the best plan. An example illustrates this. Table 15.1 presents two conceptual alternative results. Both plans have the same starting-point costs in the year 1999. However, plan A is based primarily on generation additions, whereas plan B is based on significant demand conservation. The incremental megawatt-hour electricity demand growth as well as the incremental cost in year 2000 for plan B are both less. Although one might be tempted to conclude that plan B is better, the ratio of the incremental cost divided by the incremental megawatt-hour demand is higher for plan B. Similarly, the total cost per megawatt-hour is higher for plan B. Since plan A provides lower electricity costs to the consumer (7.0 $/MWh compared to 7.333 $/MWh, it is concluded that plan A is better.

When alternatives are compared that have different energy, the cost criteria must be the incremental cumulative present worth *$/MWh*. Only in the special case of equal MWh may the criteria be the incremental cumulative present worth *$ cost*.

TABLE 15.1 Demand-Side Alternatives—Example

	Plan A (Generation Additions)	Plan B (Demand Conservation)
	Starting Point	
Embedded MWH	1000	1000
Costs	5000	5000
Cost/MWh	5.0	5.0
	Incremental	
Incremental MWh growth	1000	500
Incremental cost	9000	6000
Incremental cost/MWh	9.0	12.0
	Total	
Total MWh	2000	1500
Total cost	14000	11000
Cost/MWh	7.0	7.333

15.2.1 Integrated Demand–Supply Planning Methodology

Integrated demand and supply planning is an essential utility planning process (Hirst, 1988). Demand-side alternatives influence the supply-side and the power system influences the economic merits of demand-side alternatives. In addition to utility economic issues in supply-side planning, there are customer economic issues in demand-side planning. A successful demand-side plan must meet the customer's economic criteria as well as the utility's. Figure 15.2 presents an integrated demand and supply planning methodology framework.

It is sometimes useful for preliminary screening analysis visualization to define the "cost" of an end-use alternative on a ¢/kWh basis. The procedure is to divide the annual investment charges by the annual kWh electricity saving. Candidate programs can then be sorted and arranged in a priority list beginning with the least ¢/kWh. The cumulative potential megawatt peak load reduction is plotted and contrasted with the ¢/kWh cost of supply alternatives as shown in Figure 15.3. This figure illustrates 165 MW of end-use programs are potentially economic.

The screening curve of Figure 15.3 is useful for visualization of priorities. However, it does not account for how the end-use program integrates with the utility load demand and supply. For example, an end-use program may change the load demand for only a few hours per year during the summer peak-load periods. The "cost" per kilowatt-hour may be high. However, the utility supply alternative for these peak hours has a higher cost. Thus, this end-use program is warranted, even though it would not appear beneficial based on a screening curve such as that shown in Figure 15.3. Similarly, some end-use programs with moderate "cost" per kilowatt-hour may influence the utility

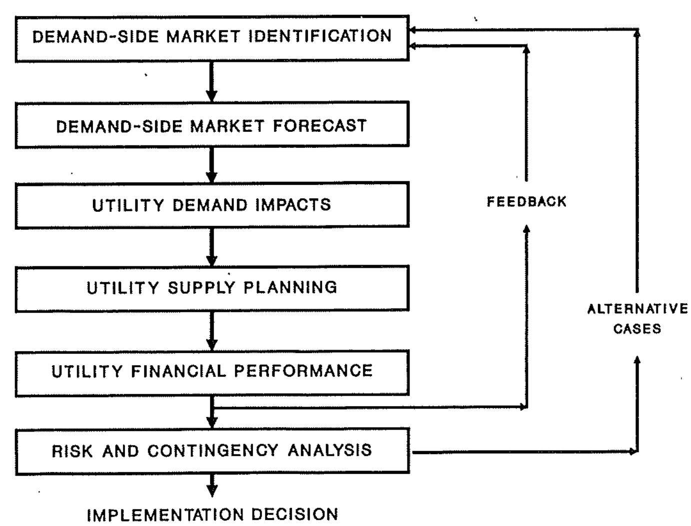


FIGURE 15.2 Integrated demand–supply planning.

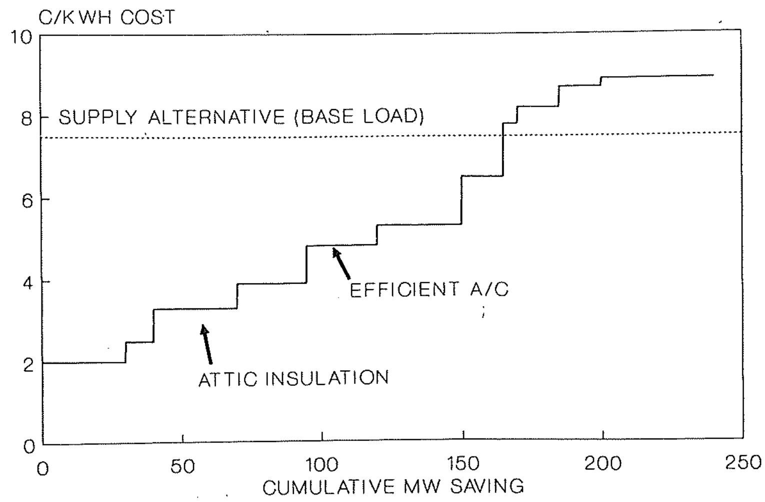


FIGURE 15.3 A demand-side screening curve useful for visualizing economic penetration.

load during periods of low utility replacement cost. While these programs appear beneficial based on a screening curve (Figure 15.3), they may be noneconomic when viewed from an integrated demand–supply analysis. Thus, an integrated demand–supply analysis is required.

The integrated demand–supply planning procedure of Figure 15.2 begins with a demand-side market identification of potential customers with specific demand-side programs. First, a candidate list of demand-side alternatives is prepared. This list might contain cycling of air conditioners, water heater control, home insulation incentive program, off-peak price discount, industrial cogeneration, or other options. Data is obtained from load research studies on the impact of each demand-side candidate on the utility (time-of-day demand, servicing requirements) as well as on the customer ("lifestyle" changes). A demand-side market forecast is then performed for each candidate on the basis of the key customer driving factors, including investment requirements, customer economic benefits, availability of financing, and lifestyle intrusion.

The utility impacts are evaluated in terms of overall load demand, supply impacts, and corporate financial performance. Because the electric utility influences the end-use consumer's decision (through electricity rates, incentive payments, and service reliability) and the end-use consumer directly influences the electric utility (by participating or not participating), a feedback interaction exists.

The final segment of this procedural structure involves implementation decisions based on corporate objectives, uncertainty, and confinement of business risks.

It is important to note that the mechanism for end-use penetration is different from that of capacity supply. In supply planning, the decision being addressed is when, how much and what type of capacity to add. In this case, the utility has complete control over the specification of the supply decision. In end-use planning, the utility must coordinate the decisions with a second party, the consumer. In end-use planning, a utility may find significant consumer inertia and, therefore, an evolutionary market penetration may result. The next several subsections amplify on the framework of Figure 15.2.

15.2.1.1 Demand-Side Market Identification. The application of end-use management involves a business relationship between the utility and the end-user (consumer). Both the utility and the end-user are impacted by this business relationship. The utility is impacted by several factors, including the manner in which the end-user consumes electricity (time-of-day; month; coincidence with generation, transmission, and distribution system load demands), servicing requirements, reliability of the end-use management device, and the dependability of the operation of the end-use management device.

This step identifies the key customer classes and their end-use energy consumption. Opportunities exist for conservation programs and electricity promotion programs. Conservation programs include efficient building insulation, lighting, space conditioning equipment, and hot water (Bulla, 1982).

Promotional programs can encourage consumers to switch from their current energy sources to electricity. The objective is to identify opportunities to increase societal economic efficiency through increased electricity usage. Promotional programs can also be aimed at increasing off-peak electricity consumption.

Customer segmentation is an important consideration in demand-side planning. It is needed because customer benefits of end-use management are not the same for all customers. Customers with electric heating may be more amenable to time-of-day (TOD) metering than nonelectric heating customers. Customers with lower family income may be more amenable to end-use management than higher-income families. Industries with a high electricity expense per unit of added value may have a greater incentive for end-use management than do industries with low electricity expense per unit of added value.

15.2.1.2 Demand-Side Market Forecast. Just as supply planning involves determining the optimal mix of alternative capacity additions (i.e., coal-steam, gas turbine, combined cycle, pumped-storage hydro, etc.), end-use planning involves determining the optimal choice of alternative end-use management candidates (controlling air conditioning and/or water heaters, TOD metering, conservation promotions, cogeneration participations, etc.). In supply planning, the key factors that lead to a mix of generation types are the significant seasonal and daily variations of load demands which, in turn, lead to initial cost versus operating cost trade-offs between alternative supply types. In end-use planning, the key factors that lead to a mix of end-use types are the significant seasonal and daily variations of load demands and the mix of customer classes on the system. Each end-use management candidate also has different utility impacts (i.e., air conditioning control impacts summer loads, while water heater control impacts loads for the entire year) along with different initial cost and operating cost characteristics.

The demand side market forecast segment of Figure 15.2 addresses issues of:

- The overall economic benefits of the end-use candidate to the electricity consumer, such as investment payback period. While economics may not be the sole driving force of end-use penetration, it almost always is a key determinant.
- The potential end-use penetration of each candidate. This is derived from many factors, including consumer economic benefits, promotional incentives, consumer life style, and advertising and marketing thrusts. Consumer surveys are one way to derive the potential penetration.
- Computation of the total hourly load changes as a result of end-use management strategy. This is performed by multiplying the number of end-use devices by the hourly kilowatt change per device, recognizing diversity.

15.2.1.2.1 Demand-Side Forecast Example. The following example illustrates a market forecast. The economic analysis has been simplified to illustrate the concepts.

Example. A summer peaking utility is considering instituting a residential efficient central air conditioner–heat-pump program. Consumers are expected to purchase 25,000 replacement and 20,000 new construction units per year, most with seasonal performance factors of (SPF) 7.5 for cooling and 2.4 for heating. The utility will offer a rebate incentive if the residential home owner installs an efficient unit with 9.0 SPF for cooling and 2.8 SPF for heating.

An efficient unit will save 1400 kWh/year of energy and 0.50-kW peak load during the summer. The more efficient unit costs the home owner an additional $450. Prior surveys have shown the home owner's purchase probability is proportional to the perceived investment payback.

Investment Payback (Years)	Purchase Probability (%)
1	95
2	90
3	50
4	20
5	5

The utility residential electric rate is 7¢/kWh, the marginal energy cost is 5¢/kWh; and the marginal generation, transmission, and distribution plant replacement capacity cost is $90/kW/year.

Calculate the expected megawatt load reduction per year if the utility provided a \$150 rebate incentive to those purchasing the efficient unit.

SOLUTION. The customer receives a \$98/year electricity savings (1400 kWh • \$0.07/kWh).

If the utility provided no rebate, the customer investment payback (ignoring discount factors) is \$450/\$98/year or 4.6 years. This has a purchase probability of 9%.

If the utility provided a \$150/kW rebate incentive, the customer investment payback is \$300/\$98/year, or 3.1 years. This has a purchase probability of 45%. Thus, the expected increase in the sale of efficient units is

$$(.47 - .09) \cdot (25{,}000 + 20{,}000 \text{ units/year}) = 17{,}100 \text{ units/year}$$

The expected megawatt peak load savings per year is 17,000 units/year • 0.5-kW units, or 8.55 MW.

The "cost" to the utility for this peak load "saving" may appear to be \$300/kW (\$150 rebate divided by a 0.5-kW benefit), thereby appearing very attractive relative to other resource alternatives. However, all the costs have not been included. From a utility cost perspective, the following calculations indicate the utility investment pay-back is 8.8 years:

Energy savings (1400 kWh • \$0.5/kWh)	\$ 70
Capacity savings (0.5 kW • \$90/kW/year)	\$ 45
Lost energy sales (1400 kW • \$0.07/kWh)	\$−98
Net savings	\$ 17
Investment	\$150
Pay-back years (\$150/\$17/year)	8.8 years

If the utility finances the investment and has a 15% annual fixed-charge rate for this investment, the annual investment charges are \$22.5/year, and the utility losses \$5.5/year per air conditioning (A/C) unit.

If a utility loses money serving one segment of customers, utility earnings decline. Conceptually, the overall utility rates will be readjusted upward at the next regulartory rate proceeding so that the utility achieves its regulated return on rate base. The net effect is that the one segment of customers become subsidized by the higher rate of the other utility customers.

In summary, if the utility were not to provide a rebate program, then only a very few high-efficiency units would be sold in the marketplace. On the other hand, if the utility provided a large rebate, many units would be sold but the utility would lose money.

What is lacking in both analysis alternatives is the overall assessment of whether the high-efficiency program is good or not good. The issue is whether overall society achieves increased economic efficiency through the program. The utility rebate and the utility revenue sales are only transfer payments from one sector to another and do not influence the overall societal economic benefits. Thus, the first step is to calculate the net societal economic benefits (see Chapter 5):

Incremental energy savings (1400 kWh • \$0.05/kWh)	\$ 70
Capacity savings (.5 kW • \$90.kW/year)	\$ 45
Net savings	\$115
Investment	\$450
Pay-back years	3.9 years

Thus, overall society would benefit with a 3.9-year investment pay-back.

Suppose that the utility rebate is adjusted so that the consumer receives a 3.9-year investment payback. Repeating the customer calculations, a utility rebate of \$67 provides a consumer pay-back of 3.9 years. The \$67 rebate also provides the utility a pay-back of 3.9 years (and a net saving of \$7/year). This pay-back leads to a 23% purchase probability with 10,350 units purchased and a 5.2-MW peak-load reduction.

Suppose that the utility rebate were varied as shown in Figure 15.4. The utility net benefit is the product of the utility net benefit per A/C unit times the number of units purchased. If the rebate is small, then the consumer investment payback years are large and the purchase probability is small. However, the utility net benefit per A/C unit is large. As the utility rebate is increased, the purchase probability increases but the utility net benefit per A/C unit decreases. Thus, there is a rebate that yields maximum utility net benefits. In this example, the value is approximately \$60. Thus, the utility has an economic incentive in this example to promote a rebate as part of the A/C program.

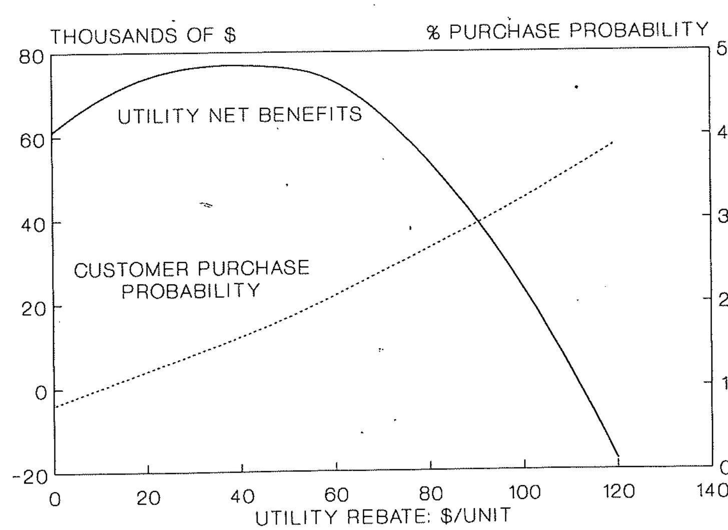


FIGURE 15.4 Utility economic net benefits are dependent on the utility rebate.

A consumer could argue the utility rebate should be $113. At this value the utility net benefit is zero. In this case all the utility costs are recovered.

From a societal perspective, each A/C unit purchased produces a net societal benefit. Thus, if more units are purchased, a greater total societal benefit is achieved. This would argue for a $113 utility rebate.

Thus the actual utility rebate determination should include all the elements of the issue and provide overall societal benefits, consumer benefits, and utility benefits. In order for the natural economic marketplace forces to work, each stakeholder must reap net benefits.

In this example, the marginal cost is greater than the average cost. Suppose that the marginal cost is less, with a utility marginal energy cost of 4¢/kWh and marginal capacity cost of $50/kW/year. The benefits to the three stakeholders with no rebate is:

	Consumer	Utility	Society
Energy savings	98	56	56
Capacity savings		25	25
Lost energy sales		−98	
Net Savings	98	−17	81
Investment	$450	0	450
Pay-back years	4.6 years		5.6 years
Investment charges	67.5		67.5
Net benefit	30.5	−17	13.5

In this case the overall society has a long pay-back, the utility loses money, and the consumer has a long pay-back. The overall societal benefit is positive, suggesting that the program leads to increased economic efficiency for overall society. However, the utility loses money and has no funds on which to offer a rebate other than to cross-subsidize the rebate from other customer's funds. But the consumer is receiving a net benefit greater than the society's net benefit, and thus no rebate is warranted.

In this case the utility might elect not to promote conservation and let the marketplace economics act undisturbed by a rebate; then the consumer purchase probability would be 9%.

Finally, suppose that the utility marginal energy cost is 3.03¢/kWh and the marginal plant replacement capacity cost is $50/kW/year. In this case, the overall societal benefits are:

Incremental energy savings (1400 kWh • $0.0303/kWh)	$42.5
Capacity savings (.5 kW • $50/kW/yr)	$25
Net savings	$67.5
Investment	$450
Pay-back years	6.7 years
Annual investment charges ($450 • .15 fixed-charge rate)	$67.5
Net societal benefit	$ 0

The net societal benefit is zero, based on a 15%/year carrying cost of the $450 additional investment. This corresponds to a 6.7 year investment pay-back. Thus, it would be concluded in this case that the efficient A/C program does not lead to overall increased societal economic efficiency. However, residential consumers would still view it as economic because their decisions are based on average residential rates, not marginal costs.

This example has utilized a simplified economic analysis procedure to illustrate the market forecasting concepts. The analysis assumed values for the power system replacement energy costs. However, these values will change depending on the penetration of end-use and supply-side programs. In addition, this analysis only examined one point in time. Power system replacement costs can markedly change through time, thus leading to changing demand-side economics. A detailed multiple-year power system simulation evaluation procedure using present worth and financial simulation analysis is necessary.

15.2.1.3 Utility Demand Impacts. The utility demand impacts segment of Figure 15.2 has three computation steps:

- Adjust load forecast by demand side management programs.
- Develop load model representations for the operations simulation model requirements (generation level, transmission level, and distribution level).
- Provide the corporate financial model with necessary load data for rate analysis and customer class segmentations.

15.2.1.4 Utility Supply Planning. For a specified end-use strategy, utility supply-side impacts may be determined by using conventional supply-side planning methods.

The four functional areas of utility supply impacts are generation, transmission, distribution, and others. The "others" function includes offices, buildings, and second businesses (such as a natural gas business). The second business may be influenced by electricity end-use alternatives. For example, the gas business of a combined electric-gas utility would be impacted by promoting electric heat pumps to displace natural gas and oil space heating.

Generation planning involves three functions: reliability, production simulation, and investment costing. In reliability evaluations it is important to account for the potential seasonal contribution of end-use management. For example, if an A/C control program results in 100 MW of load relief during the three summer months, the equivalent capacity credit (the amount of capacity that can be deferred, canceled, or sold) based on system reliability considerations can be approximately 100 MW for a strongly summer peaking utility, or it can be approximately 25 MW for a utility with equal summer and winter peaks. However, this assumes that end-use management is 100% reliable. Since some end-use management candidates are dependent on proper functioning of electronic and mechanical equipment, an appropriate equivalent forced outage rate should be used to evaluate reliability contributions of the end-use candidate.

Recent history and future projections of electric utility capital expenditures for plant and equipment typically have generation constituting 65% of the total, transmission 10%, and distribution 25%. Although average transmission contributions may be small, transmission costs from canceling or deferring a power plant due to end-use management penetration can contribute 5–20% to the overall benefits evaluation. While transmission planning typically involves time-consuming power flow, stability, and short-circuit analysis under normal and contingency cases, less detailed methods that correlate transmission expenditures to base-load generation capacity expenditures are reasonable alternatives for scoping analysis.

Distribution expenditures for long-range capital expenditure projections are typically computed by using correlative models. These models may be based on functions of residential and commercial load growth, housing and commercial completions, expected loading characteristics, and average lot sizes.

Demand-side management impacts on the distribution system can be important. One factor contributing to these impacts from end-use management is due to the residential (or distribution) peak that typically occurs 2–6 hours after the generation system peak. Some load management devices that reduce load during the generation system peak have an energy-pay-back period of several hours after the peak. Thus, the end-use device during the energy-payback period may add to the distribution peak.

15.2.1.5 Utility Financial Performance. Along with addressing traditional concerns such as providing reliable low-cost electricity, utilities must also provide service that is responsive to the financial well-being of the utility. To help meet this goal, demand-side management has several beneficial financial attributes. It can be economically attractive and not capital-intensive, and it may save capital by obviating the need for long lead-time generation and transmission capacity.

A corporate financial analysis can evaluate the overall cost of electricity, $/kWh, for each demand–supply scenario. Many corporate models have provisions for performing a cost-of-service analysis where the total costs of utility operations are allocated to the customer classes (and subclasses). The cost of service calculation can be based on marginal costs or on embedded cost concepts. After the costs of service are allocated, average customer rates are computed. This cost of service analysis forms the basis for evaluating detailed rate structure impacts (including energy charge, demand charge, and customer service charge).

The financial analysis of the integrated demand–supply plan can evaluate the utility benefits of many alternatives. These include incentive payments to consumers for end-use conservation, power purchase from industrial cogenerators, or promotional campaigns to encourage off-peak electricity sales.

In the overall framework structure presented in Figure 15.2, the integrated demand/supply planning procedure is decoupled into an optimal end-use planning procedure followed by an optimal supply planning procedure. The end-use planning procedure began with assumptions of electricity rates, incentive payments, and load management control policy. The feedback linkage provides the framework for adjusting the end-use assumptions to iteratively approach an "optimum" demand- and supply-side plan. Typically one or two iterations are required.

15.2.1.6 ***Risk and Contingency Analysis.*** Electric utility supply decisions are traditionally based on minimizing electric rates while maintaining adequate service reliability and financial performance. Other considerations entering into the decision process include short-term versus long-term cost minimization; technological risk; local economic considerations; and financial, ecological, and regulatory issues.

In the previous subtasks, the "optimal" end-use/supply plan was based on minimizing electric rates consistent with adequate service reliability and acceptable consumer lifestyle intrusion. The measurement of this plan in meeting other corporate objectives has not yet been addressed.

How are the benefits of the attractiveness of such an "optimal" plan judged? This judgment can be made only by comparing and contrasting candidate plans. As a result, another (or set of) "near-optimum" alternative candidate plan(s) needs to be generated for this comparison. This near-optimum alternative candidate plan(s) can be generated by using the same framework as illustrated in Figure 15.2. One approach is to exogenously specify one (or several) end-use penetration candidates or supply candidates and permit the framework to optimize the plan around the remaining unspecified candidates.

The major demand–supply planning decisions made by utilities involve enormous quantities of money, typically $1 billion for a large power plant. These large expenditure decisions may need to be made periodically. Utility executives need a clear perspective of the risks associated with a decision because of this immense capital expenditure. Many sensitivity and scenario cases are performed to examine and assess the risks and impacts of one uncertainty or another.

A methodology for evaluating the impacts of uncertainty would begin by reviewing the key business assumptions of the study. These assumptions are characterized in terms of their expected magnitude and probability of occurring.

For those events that are judged as having a significant magnitude-probability product, either a corrective action plan or a contingency plan is developed (events of low seriousness and low probability are pruned from further consideration). A corrective action plan is taken *now*, and modifies the optimal plan so that the magnitude impact of the potential event on the plan is modified. A contingency plan is developed so that if the event takes place, corrective actions can be taken at that time.

Corrective action plans result in a cost impact on the optimal plan even if the event does not occur. When the costs of implementing the corrective action plans are factored into the optimal plan, the plan may not necessarily by optimal. For this reason, it would be necessary to reevaluate the other candidate plans to identify whether a better candidate may be found on the basis of the costs of implementation.

An example of planning under uncertainty and risk is presented in Section 15.6.

15.2.1.7 ***Summary.*** The previous subsections illustrated a framework (Figure 15.2) for an integrated analysis of demand–supply planning. While the methodology has been presented in a general formulation, certain steps may be omitted depending on the specific application. In today's utility business environment, integrated demand–supply planning is a necessary ingredient for reliable least-cost electricity.

15.3 INDIFFERENCE VALUE CALCULATIONS

It is often desirable to calculate the utility indifference value of a technology device option. For example, consider calculating the value of the hypothetical load management option to the utility power system example of Section 15.1. The indifference value will be calculated for several megawatt target penetrations: 50, 100, 200, 300, and 400 MW. A base-case load management penetration is assumed to begin in 1997 with 100 MW. Increments of 100 MW are added each year until the target penetration amount is achieved. The generation planning evaluation was performed over the 1993 to 2007 time period.

Table 15.2 presents the results from the generation planning simulation program. The base case has a cost of $8098.1M. The 100-MW load-management case has a cost of $7990.1M. The potential savings due to load management is $99M.

Investment charges on a 100-MW load-management addition in 1997 with a cost of $100/kW (in 1993 $) is then calculated. The $100/kW value is arbi-

TABLE 15.2 Value of Load Management

	Base Case	50 MW	100 MW	200 MW	300 MW	400 MW
Present-worth cost of expansion plan excluding load management investment charges[a]	8089.1	8064.6	7990.1	7915.3	7861.8	6833.5
Potential savings[a]		24.5	99.0	173.8	227.3	255.6
Present-worth investment charges of load management at 100 $/kW[a]		7.5	14.9	29.7	44.3	58.5
Value of load management, $/kW (1993$)		329	664	585	513	436

[a]Millions of 1993 $.

trary, and is used only for computational convenience. The load management equipment escalates for 5 years (from 1993 to 1997) at 5%/year, or by a factor of 1.276. Investment charges are calculated over the study period, 1997–2007. The uniform series factor (11 years, 10%/year discount rate) is 6.5. The investment charges for 100-MW of load management costing \$100/kW in 1993 are:

$$\$100/\text{kW} \cdot 1.276 \text{ escalation} \cdot 6.50 \text{ USF} \cdot .18 \text{ fixed-charge rate} \cdot 100{,}000 \text{ kW} = \$14.9\text{M}$$

The value of load management can then be calculated as that investment cost that equals the potential savings. In the 100-MW penetration case:

$$\$14.9\text{M} \cdot \$/\text{kW} \frac{\text{value of load management}}{100 \ \$/\text{kW}} = \$99.0 \text{ M}$$

$$\text{Value of load management} = 99.0 \cdot 100/14.9 = 664 \ \$/\text{kW}$$

Figure 15.5 presents the results for other megawatt penetration values. Note that the gross economic benefits of load management decreases with increasing penetration (for penetrations 100 MW or larger). This is the general case. The benefits of any one technology typically have diminishing returns with increasing penetration.

The graph of Figure 15.5 (or Table 15.2) may be used to evaluate the optimal load management penetration level. Assuming an implementation cost of \$550/kW in 1993\$, it is economical to implement a load management penetration having a value greater than \$550/kW. In this example, the economic penetration level is between 200 and 300 MW.

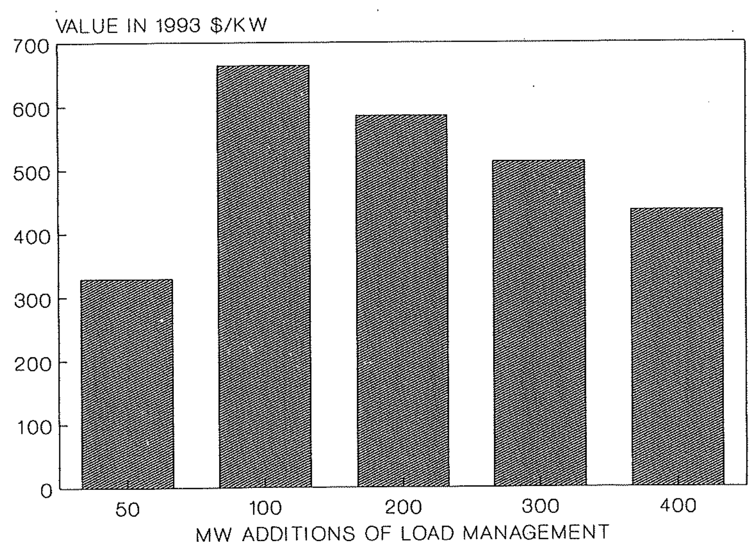


FIGURE 15.5 Sensitivity of the value of load managment with load management penetration.

The load management case of 50-MW penetration requires some clarification. It has a value of $329/kW, which is much less than the 100-MW penetration case. In this example, the generation alternatives are sized at 100 MW. Displacing the addition of a new plant provides a potential savings of $1770/kW for a coal unit or $800/kW for a combined-cycle plant. In the case of a 50-MW load management penetration, this size is not large enough to displace a generating unit. Thus, the savings from the 50-MW load management are only a result of incremental fuel and O&M cost savings. The next section further amplifies this issue.

15.4 MARGINAL COSTING

It is often necessary to know the marginal cost of operating a power system. Marginal cost is the utility cost associated with providing one additional unit of energy (or power demand). Terms such as "marginal cost," "avoided cost," "incremental cost," "decremental cost," and "replacement cost" are often used interchangeably. Marginal cost data are used in electricity rate structures, generation planning, and power purchase planning. One segment of the U.S. Public Utilities Regulatory Policies Act (PURPA) requires that utilities pay up to avoided cost rates to cogenerators and small power producers for their produced electricity.

The marginal cost of power is typically calculated by subtracting the power system's total operation costs of two simulations, a reference case and a change case in which a small power purchase (or sale) is included. The marginal cost of power is dependent on the hourly time-of-day profile of the power purchase (or sale), the utility operating system, and the term of power purchase (or sale). The term of power purchase is important because the purchase may permit the utility to defer future capacity additions.

15.4.1 Short-Term Marginal Cost

"Short-term marginal cost" refers to the condition when a power purchase (or load-demand reduction) does not result in the immediate deferment of a capacity addition in a specified year. In this case, the utility has the same installed capacity either with or without the power purchase. The marginal cost calculated in this case is referred to as the marginal "energy" cost, because the cost contributions are the result of savings in energy generation only.

Marginal cost has an hourly time-of-day (TOD) profile. Figure 15.6 illustrates a conceptual daily load profile (lower curve) and the capacity types serving the load demand. Also shown is a second (incremental) load-demand profile.

The megawatt power difference between the base and the incremental load profiles is the amount of the power purchase. The type of generating unit serving the incremental purchase is the least expensive power type available to meet the incremental purchase load demand. For example, at hour 10, the incremental power type is oil-steam because nuclear and coal-unit capacity are from hour 12 to hour 16, and the off-peak periods are from hour 0 to 12 and hour 16 to 24. Alternatively, three average time periods could be defined as the peak period from hour 12 to hour 16, the intermediate peak periods from hour 8 to hour 12 and from hour 16 to hour 22, and the off-peak periods from hour 0 to hour 8 and from hour 22 to hour 24.

15.4.2 Long-Term Marginal Cost

When a power purchase (or a load-demand reduction) can result in the deferment of a capacity addition in a specified year, then the marginal cost includes not only the short-term marginal cost (marginal energy cost) contribution but also the capacity displacement credit.

The calculation of the long-term marginal costs is dependent on the type of capacity that is displaced and the hourly TOD profile of the power purchase (or load-demand reduction).

Consider the case of a uniform marginal power purchase, or a load-demand decrease of 500 MW, as illustrated in Figure 15.7. The base-case capacity is also shown. Suppose that reliability studies indicate that a 500-MW coal unit could be canceled or deferred to some future year if a 500-MW load decrease is obtained (neglecting unit availability considerations for the moment).

Because the 500-MW marginal load decrease is exactly matched by a 500-MW coal capacity decrease, the energy generation by capacity type does not change markedly. A 500-MW uniform slice is removed from the base-load coal capacity and a 500-MW uniform slice is removed from the load. Consequently, the marginal energy cost change is small and is comprised of only the fuel and operating cost of the 500-MW coal unit, \$19/MWh in this example.

However, the capacity displacement credit is large. For a coal unit with a

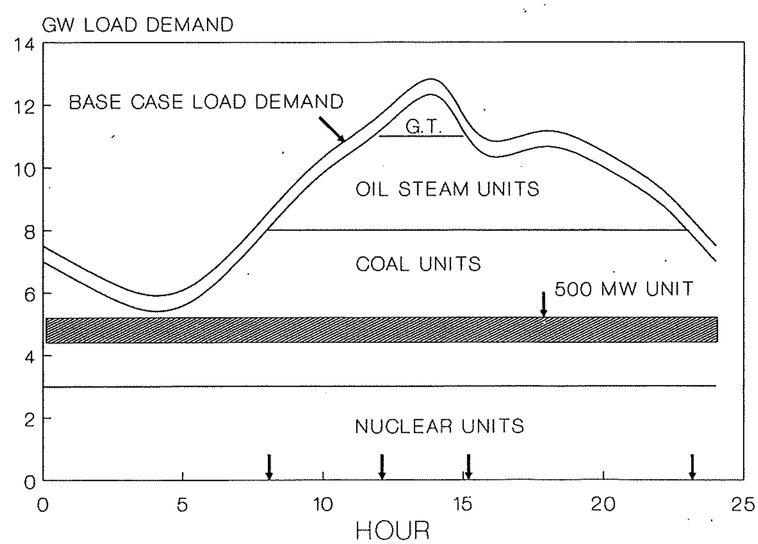


FIGURE 15.7 Impact of power purchases on long-term marginal cost.

capacity cost of $1500/kW, an 18% fixed charge rate, and 8760 hours/year of capacity displacement credit, the capacity credit is:

$$(\$1500/\text{kW})\ (.18\ \text{FCR}) \cdot 1000\ \text{kW/MW}/8760\ \text{hour/year} = \$30.8/\text{MWh}$$

Thus, the total long-term marginal cost is 30.8 + 19 = $49.8/MWh, (neglecting O&M costs).

Note that the long-term marginal cost ($49.8/MWh) is larger than the short-term average marginal energy cost of $37/MWh. This is the general rule.

Consider the same case of a 500-MW uniform marginal power purchase, but assume that 500 MW of gas-turbine capacity is displaced. The energy generation for the coal- and oil-steam unit type is the same as that calculated for the short-term marginal cost case. Long-term marginal energy generation for the gas-turbine type is influenced by the heat-rate difference between new gas turbines and the existing gas turbines, which will be assumed to be nearly zero. Thus, the long-term marginal energy cost averaged over the day is $37/MWh.

The capacity displacement value can also be calculated per kilowatt-hour of load change using a gas-turbine capital cost of $300/kW as:

$$\$300/\text{kW} \cdot .18\ \text{FCR} \cdot 1000\ \text{kW/MW}/8760\ \text{hour/year} = \$6/\text{MWh}$$

Thus, the long-term marginal cost is 37 + 6 = $43/MWh (neglecting O&M costs).

In this example, the gas-turbine displacement had the lower total marginal cost. This is dependent, however, on the specific utility power system characteristics. Thus, the long-term marginal cost depends on the type of capacity displaced by the incremental load demand or power purchase.

When gas-turbine capacity is displaced, the long-term marginal *energy* cost component is high, but the long-term marginal *capacity* cost component is low. When coal capacity is displaced, the long-term capacity cost component is high but the energy cost component is low. For a midrange capacity type, such as combined-cycle capacity, the *capacity* and *energy* components are in the medium cost range.

An example that illustrates these principles is for a 100-MW, 8760 hour/year marginal power purchase beginning in 1993 using the power system example of Section 15.1. The reference power system has two 100-MW gas turbine additions in 1993, followed by three combined-cycle units (one in each year from 1994 through 1996), followed by one coal unit per year thereafter.

The net long-term result of the marginal purchase is the cancellation of a base-load power plant. As shown in Table 15.3, the first effect of the marginal 100-MW purchase is to delay one gas turbine addition in 1993. In 1994, the marginal purchase results in the displacement of a combined-cycle unit and the replacement of a gas turbine. In 1997, a coal unit is displaced and a combined-cycle unit is replaced.

The composition of the marginal cost components is illustrated in Figure 15.8. In 1993, the principal marginal cost component is fuel cost. In 1994 and 1997, the investment charge component experiences an incremental change in 1994 and 1997 as a result of capacity displacement shifts to combined cycle

TABLE 15.3 Capacity Displacements for a 100-MW Power Purchase

Year	Reference Case	Incremental 100-MW Purchase	Change Incremental–Base
1993	2-GT	1 GT	− 1 GT
1994	1 CC	1 GT	1 GT − 1 CC
1995	1 CC	1 CC	
1996	1 CC	1 CC	
1997	1 Coal	1 CC	1 CC − 1 coal
1998	1 Coal	1 Coal	
1999	1 Coal	1 Coal	
2000	1 Coal	1 Coal	

and coal, respectively. The fuel cost component also responds to the capacity displacement shift.

15.4.3 Time-of-Day Marginal Cost

The examples presented previously were based on a marginal purchase (or load change) that occurs for 8760 hours/year. If a marginal power source operates for less than 8760/year (and during the peak and intermediate peak hours), then capacity and energy credit are different. The value per megawatt-hour of the fuel component is higher because marginal energy cost is averaged only over the peak and intermediate peak hours. The capacity credit component is also higher because capacity credits are divided by a lower megawatt-hour value.

When the marginal purchase occurs off-peak, the capacity credit component is typically zero and the only contribution is due to off-peak replacement

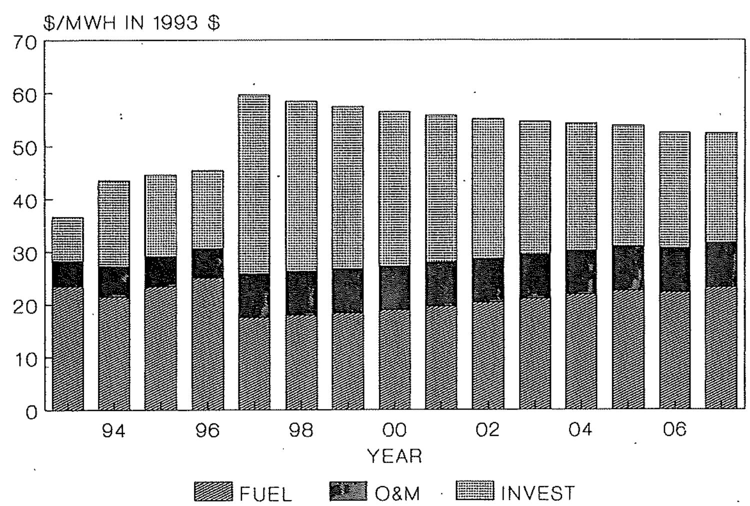


FIGURE 15.8 Annual marginal cost trend.

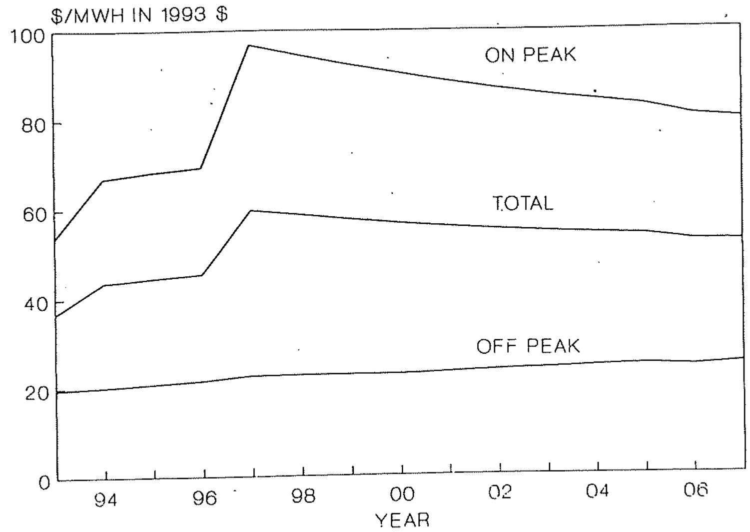


FIGURE 15.9 Marginal cost trend for 12-hour peak and 12-hour off-peak periods.

energy. Figure 15.9 illustrates the marginal cost trend for 12-hour peak and 12-hour off-peak periods, expressed in 1993 dollars. In this example, the ratio of peak to off-peak marginal cost is in the $\frac{3-5}{1}$ range.

Depending on the peak-period definition and the specific utility power system, peak marginal cost may include a contribution due only to displacing gas-turbine capacity. The off-peak contribution may include contributions from a change in the generation mix, such as changing from a combined-cycle unit to a coal unit. Figure 15.10 presents the case in which the peak period is defined

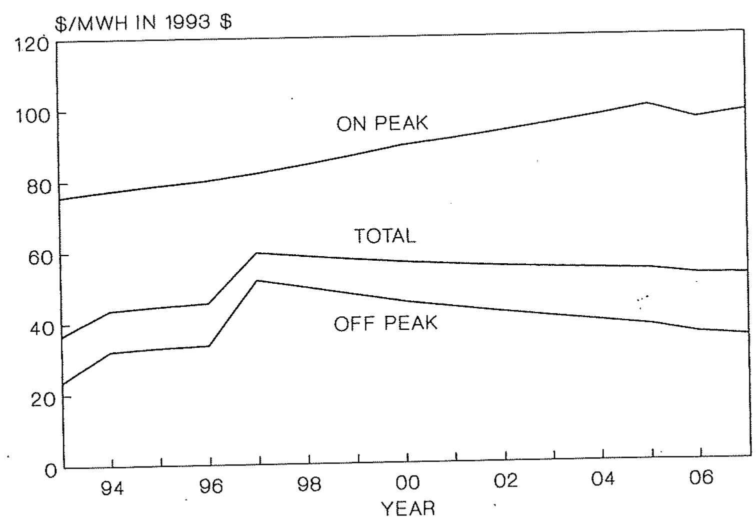


FIGURE 15.10 Marginal cost trend for 6-hour peak and 18-hour off-peak periods.

as 6 hours and the off-peak as 18 hours. The off-peak case resulted in a capacity mix change, and the peak case resulted in a gas-turbine displacement. Note, however, that the peak:off-peak price ratio is still in the $\frac{3\text{–}5}{1}$ range. These peak and off-peak marginal costs may be used in developing a TOD differentiated marginal cost rate.

While marginal costs may be expressed in \$/MWh, they may also be segmented into an energy cost component in \$/MWh and a capacity cost component \$/kW/year. The energy cost component typically includes fuel cost and variable O&M cost, and the capacity cost component typically includes investment cost changes and fixed O&M costs.

15.4.4 Intermediate-Range Marginal Costs

A power purchase (from an industrial cogenerator, e.g.) may provide reliable power, but the utility may have adequate capacity without the purchase to achieve their reliability target level. In this case, the power supplier (cogenerator) does not displace a utility capacity addition until perhaps several years into the future. From a utility avoided-cost viewpoint, the power supplier is not eligible to receive capacity credit for the power.

However, the power supplier does provide reliable power, and this results in the utility having a higher service reliability and a lower probability of customer power interruption. Because electricity consumers benefit from reduced power interruptions, the power supplier can be rewarded partial capacity credit for these benefits. The calculation of the reduced power interruptions and the consequential "societal" benefits were presented in Chapter 11, Section 11.2.

A graph of the total consumer cost of electricity is shown in Figure 15.11.

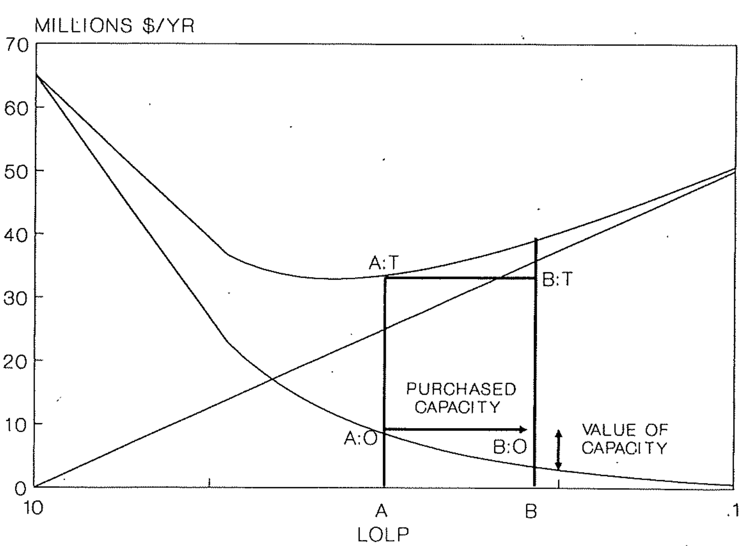


FIGURE 15.11. Total consumer cost of electricity.

The total cost is comprised of the sum of the utility cost of service (that recovered through electricity rates), and the consumer cost of outages when electricity is not supplied. The optimum value is shown at the LOLP level corresponding to the minimum total electricity cost.

Suppose that the utility has a higher reserve margin (or LOLP) than the optimum at point A in Figure 15.11. An independent power producer (or cogenerator) supplying an additional amount of capacity increases the utility reserve margin (or LOLP) to point B. The independent power producer decreases the consumer cost of outages from point A:0 to B:0. Thus, the independent power producer provides the consumer a value and can be rewarded with a payment. If the independent power producer received the total incremental value of the provided capacity, the value difference between points B:0 and A:0, the electricity rates would be adjusted upward by this same value. However, the total cost of electricity, point B:T, would be the same (as point A:T).

The value per KW of independently produced power can be calculated as:

$$\text{Value of produced power (in \$/kW/year)} =$$

$$-\frac{\partial \text{ consumer outage cost}}{\partial \text{ kW}} = -\frac{\partial \text{ consumer outages}}{\partial \text{ LOLP}} \cdot \frac{\partial \text{ LOLP}}{\partial \text{ kW}} \qquad (15.1)$$

Using the outage component of Equation (11.3) in Chapter 11 gives

$$\text{Value of produced power} =$$

$$- M \cdot \text{equivalent peak hour} \cdot \text{outcost} \cdot \frac{\partial \text{ LOLP}}{\partial \text{ kW}}$$

$$= + M \cdot \text{equivalent peak hour} \cdot \text{outcost} \cdot \frac{1}{M} \text{LOLP} \qquad (15.2)$$

where M	= inverse logarithmic slope of the LOLP realiability curve versus MW
Equivalent peak hours	= equivalent daily peak-load duration in hours
Outcost	= consumer cost of unserved energy in \$/MWh

Substituting Equation (11.4) of Chapter 11:

$$\text{LOLP}_{\text{opt}} = \left(\frac{\text{annual capacity charges}}{\text{equivalent peak hour} \cdot \text{outcost}}\right) \qquad (15.3)$$

into Equation (15.2) yields:

$$\text{Value of produced power (in \$/kW/year)} = \text{annual capacity charges} \cdot \left(\frac{\text{LOLP}}{\text{LOLP}_{\text{opt}}}\right) \tag{15.4}$$

where Annual capacity charges = annual cost of providing peaking capacity in \$/kW/year

LOLP_{opt} = optimum (least total cost) LOLP

Thus, the value of independently produced power (in \$/kW/year) is equal to the annual peaking capacity charge (in \$/kW/year) times the ratio of the current LOLP value divided by the optimum value. If the reliability in a given year is .3 days/year, the capitalized cost of peaking capacity is \$300/kW, and the utility reliability target is 1.0 day/year, then the avoided capacity cost credit is based on a capacity payment of (.3 days/day)/(1.0 days/day) • \$300/kW • .20 fixed-charge rate = \$18/kW/year.

This adjusted capacity cost credit component is added to the avoided energy cost component to compute the total marginal cost.

15.4.5 Summary

Marginal system costs are used in electricity rate design, generation planning, and power purchasing planning. Marginal costs may be calculated using power system planning programs based on daily, seasonal, and TOD bases. Figure 15.12 illustrates a conceptual trend of the real ¢/kWh marginal cost with time.

In the short-term and intermediate-term total marginal cost is comprised largely of marginal energy cost contributions. A small contribution arises from the marginal peaking capacity contribution, which increases with time accord-

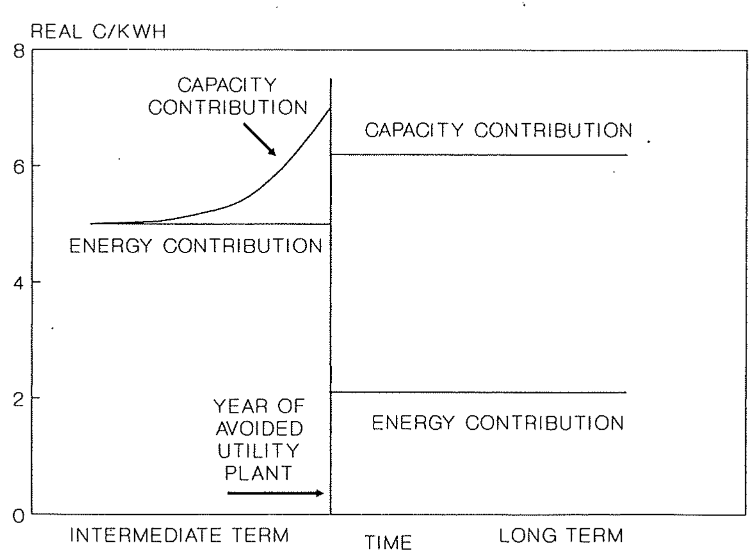


FIGURE 15.12 Conceptual trend of marginal cost versus time.

ing to Equation (15.4) until the date of the avoided utility generation plant. For years following the date of the avoided utility plant, the long-range marginal cost equations apply. In this case, energy cost contributions may be much smaller than capacity cost contributions if a capital-intensive base-load power plant is avoided.

The examples illustrated the long-term marginal cost calculations in which the utility avoided capacity were conventional power generation types, coal-steam gas turbine, and combined cycles. A utility also can construct a cogeneration plant in association with an industrial or other process steam user; hence the utility avoided capacity could also be a cogeneration plant.

15.5 SMALL IMPROVEMENT PROJECTS

Many utility economic studies require the evaluation of small improvement projects to the power system. Examples include evaluating the benefit of a new turbine rotor for a generating unit, deciding which manufacturer's product and price for a generating unit is the best, and evaluating whether to buy low-loss (but higher investment cost) distribution transformers. Hundreds of these types of evaluation may be performed each year in a utility (Felak and Stoll, 1987).

Any one of the small incremental improvement projects barely influences the overall utility economic operation. When accumulated, however, these projects can lead to noticeable economic improvements. Accounting for the incremental contribution of each project is an important economic evaluation.

Detailed methods can be used to evaluate small projects. However, in view of the small incremental changes and the number of project evaluations, it is more practical to use approximate techniques. Approximate techniques use power system sensitivity parameters derived from detailed evaluation methods. The incremental replacemental (marginal) energy cost in $/MWh is a key sensitivity parameter.

Example. A utility is purchasing a 400-MW coal-fired steam-generating unit and has received proposals from two manufacturing suppliers. The generating unit is to be installed in 1993 and will operate base load at 95% capacity factor when available. The characteristics of the two alternative proposals are:

	Alternative 1	Alternative 2
Unit size (MW)	400	410
Forced outage rate (%)	5	10
Scheduled outage rate (%)	10	10
Fuel cost (20-year levelized) ($/MBtu)	3.0	3.0
Net plant heat rate (Btu/kWh)	10,000	10,200
Plant cost (millions $)	560	540
Cost ($/kW)	1400	1350

Power system reliability (LOLP) studies found the *M*-slope to be 250 MW. Gas turbines may be used for adjusting reliability. Assume that gas turbines cost \$300/kW and have a 5% forced outage rate. The power system incremental replacement energy cost (marginal energy cost) is \$55/MWh (20-year levelized).

Determine the alternative with the lowest 20-year present-worth cost for these economic parameters:

Inflation	6%/year
Present-worth rate	10%/year
Levelized annual fixed-charge rate	\$20%/year

SOLUTION. Use alternative 1 as a reference, and calculate the economic benefits of alternative 2 relative to alternative 1.

A. Reliability. The two alternatives differ in megawatt rating and reliability. Compute the additional cost so that both alternatives contribute the same to power system reliability. Compute the generating unit load-carrying capability using Garver's formula.

	Alternative 1	Alternative 2
M-slope	250	250
Unit size (MW)	400	410
Forced outage rate (%)	5	10
Load-carrying capability	354.9	323.1
Deficiency in load-carrying capability	Reference	31.8 MW

The deficiency in load-carrying capability can be evaluated in terms of 31.8 MW of additional load-carrying capacity of gas turbines to provide backup to the alternative 2 generating units.

Because gas turbines have a 5% forced outage rate, alternative 2 would need to add 31.8 MW/$(1-.05)$ = 33.5 MW of gas turbines. These gas turbines would cost \$300/kW to install.

For equal system reliability, the alternatives are:

	Alternative 1	Alternative 2
Capacity additions	400 MW coal	410 MW coal 33.5 MW gas turbine
Cost of gas turbines	(Reference)	\$10.05M

B. Production Cost. *Evaluate production cost differences.* The average power produced by each of these two generating units is:

	Alternative 1	Alternative 2
	Replacement Energy Cost	
Forced outage rate	.05	.10
Scheduled outage rate	.10	.10
Maximum availability	(.95) • .9 = .855	.9 • .9 = .81
Energy output/year	400 • 8760 • .855 • .95 2,846,124 MWh	410 • 8760 • .81 • .95 2,763,736 MWh
Energy difference	Reference	82,388 MWh
Annual levelized replacement Energy Cost ($year @ /MWh $55)		$4,531 M/year
	Fuel Cost	
Heat rate (Btu/kWh)	10,000	10,200
Fuel cost ($/MBtu) (levelized)	3.0	3.0
Energy output (MWh)	2,846,124	2,763,736
Annual fuel cost	$85,383,720M/year	$84,570,322M/year
Annual levelized fuel cost-difference($/year)	Base	$-0.813M/year

The annual system production cost differences are summarized as:

	Alternative 1	Alternative 2
Replacement energy differences	Base	$4.531M/year
Fuel cost differences	Base	$-0.813M/year
Annual production cost difference (levelized)	Base	$3.718M/year

The annual levelized production cost can be translated into an equivalent capitalized value by dividing by the annual levelized fixed charge rate of 20%.

	Alternative 1	Alternative 2
Capitalized equivalent Production cost differences Over 20 years	Base	$18.59M

C. Total Costs. The equipment capital cost and the capitalized equivalent production cost can now be added together to obtain the total cost.

	Alternative 1	Alternative 2
Coal plant cost	\$560M	\$540M
Gas-turbine reliability costs gas turbine at \$300/kW	(Reference)	\$10.05M
Capitalized equivalent production cost difference	(Reference)	\$18.59M
Total evaluated costs	\$560M	\$568.64M

Alternative 1 is the economical choice, since it has a lower total 20-year present-worth evaluated cost. It is interesting to note that the initial choice may have been alternative 2 because it has a higher megawatt rating and a lower plant investment. However, the lower forced outage rate and better heat rate of alternative 1 leads to a lower total economic evaluation.

Generating unit upgrade (and life extension) projects may also be evaluated using an approximate incremental project evaluation methodology (McDonough, Nair, and Stoll, 1987). Upgrade projects can reduce forced outages, maintenance outages, maintenance expenses, and improve plant heat rate. The first step in these evaluations is to compute the economic value of a one-day reduction in forced and maintenance outages and a 1-Btu improvement in heat rate for the upgrade generating unit candidate.

A one-day reduction in a maintenance outage leads to a net replacement energy saving. Net replacement energy saving is the difference between the incremental production energy cost and the upgrade candidate generating unit production cost.

The benefit of a one-day maintenance outage saving is computed as:

$$\begin{aligned}
&\text{Maintenance day benefit (\$/day/year)}\\
&= (\text{MW rating}) \cdot 24 \text{ hours/day} \cdot (\text{capacity factor})\\
&\cdot [(\text{system replacement energy cost: \$/MWh})\\
&- (\text{unit fuel cost: \$/MBtu}) \cdot (\text{unit heat rate: MBtu/MWh})] \qquad (15.5)
\end{aligned}$$

(This is also referred to as "daily replacement energy benefit".)

The system replacement energy cost used in Equation (15.5) is the average value during the time of day that the upgrade candidate operates, and during the season when maintenance is performed. The capacity factor is the average unit value during the season when maintenance is performed.

A one-day reduction in a forced outage leads to a replacement energy saving (as in the maintenance outage case) *and* a replacement capacity saving. The replacement capacity saving is credited because the forced outage reduction leads to fewer capacity purchases and reduces future capacity needs. The replacement capacity saving is computed as:

$$\text{Daily capacity benefit (\$/day/year)} = \text{MW rating} \cdot \frac{\text{annual replacement capacity cost \$/MW/year}}{\text{365 days}} \tag{15.6}$$

A forced outage is random, and could occur throughout the year (365 days). Annual replacement capacity cost is multiplied by the probability of a forced outage (1/365) contributing to a replacement capacity saving. The annual replacement capacity cost in $/MW/year is the annual cost of the emergency capacity power purchases or the annual capacity cost charges of a new (peaking-type) capacity. Thus, the value of a one-day forced outage rate saving is:

$$\begin{gathered}\text{Forced day benefit (\$/day/year)} = \\ \text{daily replacement energy benefit} + \text{daily capacity benefit}\end{gathered} \tag{15.7}$$

Note that the daily replacement energy benefit [Equation (15.5)] for a forced outage may be numerically different from the maintenance day benefit, because the forced outage calculation must use capacity factor and system replacement energy cost values based on annual operating year average values, whereas the maintenance day benefit is calculated by using values typical during the period of planned maintenance.

A heat-rate improvement may result in several benefits. If the generating unit fuel input is limiting on the unit (boiler-limited), then improving unit efficiency permits the unit to generate *more* MW power for the *same* fuel input. If the generating unit is output-limited (turbine-generator-limited), then improving the unit efficiency permits the unit to generate the *same* megawatt power but use *less* fuel. The case that applies is generating-unit-specific and dependent on plant design margins.

Consider the case of an output-limited generating unit (fuel savings case). The annual value of a 1-Btu heat-rate improvement is calculated as:

$$\begin{aligned}&\text{Fuel saving benefit (\$/Btu/year)}\\ &= \text{(8760 hours)} \cdot \text{(annual capacity factor)}\\ &\cdot \text{(fuel cost: \$/MBtu)} \cdot \text{(MW rating)} \cdot (.001)\end{aligned} \tag{15.8}$$

Consider the case of a fuel-limited generating unit. For the *same* fuel, additional "free" megawatt power output is produced. The additional megawatt may be used to reduce the power system's most expensive generating unit. The megawatt increase is proportional to the heat rate improvement. The megawatt increase corresponding to a one-Btu improvement is:

$$\Delta\text{MW} = \text{(MW rating)} \cdot \frac{\text{1 Btu}}{\text{unit heat rate: Btu/kWh}} \tag{15.9}$$

Thus, the annual replacement energy cost saving per Btu is:

Replacement energy cost benefit ($/Btu/year)

$$= \frac{\text{MW rating}}{\text{unit heat rate: Btu/kWh}} \cdot (\text{8760 hours}) \cdot (\text{annual capacity factor}) \cdot (\text{system replacement energy cost: \$/MWh}) \qquad (15.10)$$

In addition, there is a replacement capacity saving credit (in the fuel-limited case) because of the additional megawatts.

Replacement capacity cost benefit ($/Btu/year)

$$= \frac{\text{MW rating}}{\text{unit heat rate: Btu/kWh}} \cdot (\text{annual replacement capacity cost: \$/MW/year}) \qquad (15.11)$$

Equations (15.8) through (15.11) can be combined into one equation as:

Heat-rate saving benefit ($/Btu/year)

$$\begin{aligned}
&= \text{fuel saving benefit} \\
&\quad + \text{fuel limit} \cdot (\text{replacement energy cost benefit} \\
&\quad - \text{fuel saving benefit} + \text{replacement capacity cost benefit}) \\
&= (\text{8760 hours}) \cdot (\text{annual capacity factor}) \cdot (\text{fuel cost: \$/MBtu}) \\
&\quad \cdot (\text{MW rating}) \cdot .001 \\
&\quad + \text{fuel limit} \cdot \Big\{ \frac{\text{MW rating}}{\text{unit heat rate: Btu/kWh}} \\
&\quad \cdot (\text{8760 hours}) \cdot (\text{annual capacity factor}) \\
&\quad \cdot [(\text{system replacement energy cost: \$/MWh}) \\
&\quad - (\text{fuel cost: \$/MBtu}) \cdot (\text{unit heat rate: MBtu/MWh})] \\
&\quad + \frac{\text{MW rating}}{\text{unit heat rate: Btu/kWh}} \\
&\quad \cdot (\text{annual replacement capacity cost: \$/MW/hour}) \Big\} \qquad (15.12)
\end{aligned}$$

where Fuel limit = 0 if fuel input is not limited but power output is limited (turbine-generator-limited)

= 1 if fuel input is limited but power output is not limited (boiler-limited)

Example. A 200-MW coal-fired generating unit operating at 75% capacity factor has an asphalt insulated generator stator. In Chapter 9, the probability of a stator girth crack failure was evaluated at 32.2% over the next 10 years. For the utility to upgrade, the investment pay-back period must be less than 4 years. Should the utility upgrade the stator in 1990 using a mica-based insulation material (with practically zero failure probability)? The case parameters are:

MW rating	200 MW
Unit capacity factor	75%
Fuel cost (1990 $/MBtu)	2.0
Unit heat rate (Btu/kWh)	10,000
Replacement energy cost (1990 $/MWh)	40.0
Replacement capacity cost (1990 $/kW/year)	60.0
Annual stator failure rate (assume uniform/year)	3.22%/year
Outage repair time duration if failed	84 days
Repair costs if failed (1990$)	$200,000
Upgrade investment cost (1990$)	$800,000

The forced outage rate cost per day is calculated using Equations (15.5), (15.6), and (15.7).

$$\begin{aligned}
\text{Maintenance day benefit} &= 200 \cdot 24 \cdot .75 \cdot [55 - (2.0 \cdot 10.0)] \\
&= \$126{,}000/\text{day/year} \\
\text{Capacity day benefit} &= 200 \cdot 60{,}000/365 \\
&= \$32{,}877/\text{day/year} \\
\text{Forced day benefit} &= 126{,}000 + 32{,}877 \\
&= \$158{,}877/\text{day/year}
\end{aligned}$$

The annual expected probability weighted benefit per year is:

$$\begin{aligned}
\text{Expected annual benefit} &= .0322 \cdot (\$158{,}877/\text{day} \cdot 84 \text{ days} \\
&\quad + 200{,}000) \\
&= \$436{,}170/\text{year}
\end{aligned}$$

The investment pay-back (not including cost escalation) is (800,000/436,170) = 1.83 years. Thus, the utility should implement the generator upgrade.

In summary, this section has illustrated economic analysis procedures for use in evaluating small improvement projects.

15.6 PLANNING UNDER UNCERTAINTY

Capacity addition plans are dependent on many forecast parameters, including load demand, fuel pricing, plant cost, technology availability, environmental and regulatory requirements, and financial forecasts. Unfortunately, the forecast of these parameters is subject to uncertainty. Each has a likelihood of assuming a range of values in the future. A plan that is least-cost under a reference set of forecast parameters may not be so under an alternative set of forecast parameters. A key objective in planning is to recognize these uncertainties and to develop a plan that can be adapted to changing business conditions and be least-cost under the probability-weighted range of forecast parameters.

Planning under uncertainty is a dynamic year-by-year process. The planning process begins with parameters that are fact today. One can have only a perception of what these parameters might be in the future.

The analysis procedure generally involves identifying the potential uncertain (or risky) events and assigning a probability to the event. A planning analysis is performed that accounts for any associated corrective action plans by the utility to evaluate the impacts of the events. The impacts may then be probability-weighted, and a composite utility impact value can be computed. This process may be repeated by examining alternative or contingency plans.

15.6.1 Load Growth Uncertainty

Load-demand growth is one of the key forecast parameters that is subject to uncertainty. Load growth is influenced by many factors, including the national economy, the local economy, energy prices, and conservation. The forecast of future load growth over the midterm (5–10 years) and long term (10–30 years) is subject to broad uncertainty.

History reveals that the load growth during the 1960s averaged 7%/year on a national basis, 4.5%/year during the 1970s, and is forecast to grow at 2.5%/year through the year 2000. Utilities reported to the North American Electric Reliability Council (NERC) a 90% confidence band of load growth from 0 to 4.5%/year over a 10-year future forecast period (NERC, 1986). This broad load growth uncertainty places a significant added burden of responsibility on the utility capacity planner.

It is difficult for utilities to adapt to load-demand changes because of the long lead times associated with constructing capacity. For example, coal-fired power plants have lead times of 6 years or more, and load management programs require several years to initiate customer participation.

A load uncertainty analysis procedure is presented in Figure 15.13. Data on the load forecast and load uncertainties are translated into load growth scenarios. Load growth scenarios are a finite sample of potential load growth outcomes to be studied. Other data input is the future planned additions and

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-2.41
Respondent:	S. D. Burgdorf/L. K. Mikulan
Page:	1 of 1

Question: What resources will DTE rely upon for ramping to address the variability of net load, each year from 2020 to 2040?

Answer: During actual operations, DTE does not determine the specific resources selected by MISO to provide the necessary ramp capability and ancillary services to address variability of net load. However, an example of a DTE resource with high ramp capability that would be offered into the MISO market is the Company's Blue Water Energy Center, currently under construction.

Attachments: *None.*

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t, and for other relief	))))	Case No. U-20471

DIRECT TESTIMONY OF

KEVIN M. LUCAS

ON BEHALF OF

THE ENVIRONMENTAL LAW AND POLICY CENTER,
THE ECOLOGY CENTER,
THE SOLAR ENERGY INDUSTRIES ASSOCIATION,
UNION OF CONCERNED SCIENTISTS
AND
VOTE SOLAR

AUGUST 21, 2019

Contents

List of Tables and Figures

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A1. My name is Kevin M. Lucas. I am the Director of Rate Design at the Solar Energy Industries Association (SEIA). My business address is 1425 K St NW #1000, Washington, DC 20005.

Q2. PLEASE SUMMARIZE YOUR BUSINESS AND EDUCATIONAL BACKGROUND.

A2. I began my employment at SEIA in April 2017 as the Director of Rate Design. SEIA is the national trade association for the U.S. solar industry. SEIA works with its 1,000 member organizations to advance solar power through education and advocacy. It seeks to champion the use of clean, affordable solar in America by expanding markets, removing market barriers, strengthening the industry and educating the public on the benefits of solar energy.

As Director of Rate Design, I work with other members of SEIA's State Affairs team to engage in various regulatory dockets. I have developed testimony in rate cases on rate design and cost allocation and in integrated resource planning cases on resource cost projections and portfolio composition, worked on the New York Reforming the Energy Vision (NY-REV) proceeding on rate design and distributed generation compensation mechanisms, and performed a variety of analyses for internal and external stakeholders.

Before I joined SEIA, I was Vice President of Research for the Alliance to Save Energy (Alliance) from 2016 to 2017, a DC-based nonprofit focused on promoting technology-neutral, bipartisan policy solutions for energy efficiency in the built environment. In my role at the Alliance, I co-led the Alliance's Rate Design Initiative, a working group that consisted of a broad array of utility companies and energy efficiency products and service providers that was seeking mutually beneficial rate design solutions. Additionally, I performed general analysis and research related to state and federal policies that impacted energy efficiency (such as building codes and appliance standards) and domestic and international forecasts of energy productivity.

Prior to my work with the Alliance, I was Division Director of Policy, Planning, and Analysis at the Maryland Energy Administration, the state energy office of Maryland, where I worked between 2010 and 2015. In that role, I oversaw policy development and implementation in areas such as renewable energy, energy efficiency, and greenhouse gas reductions. I developed and presented before the Maryland General Assembly bill analyses and testimony on energy and environmental matters, and developed and presented testimony before the Maryland Public Service Commission on numerous regulatory matters.

I received a Master's degree in Business Administration from the Kenan-Flagler Business School at the University Of North Carolina, Chapel Hill, with a concentration in Sustainable Enterprise and Entrepreneurship in 2009. I also received a Bachelor of Science in Mechanical Engineering, cum laude, from Princeton University in 1998.

Q3. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION?

A3. Yes. I have submitted multiple rounds of testimony in Cases U-18419 (DTE's 2017 CON proceeding),[1] U-20162 (DTE's rate case implementing the inflow/outflow DG PV methodology),[2] and U-20165 (Consumers Energy's 2018 IRP proceeding).[3]

Q4. HAVE YOU TESTIFIED PREVIOUSLY BEFORE OTHER STATE UTILITY COMMISSIONS?

A4. Yes. I have testified before the Maryland Public Service Commission in several rate cases and merger proceedings. Additionally, I have testified before the Maryland Public Service Commission in several rulemaking proceedings, technical conferences, and legislative-style panels, covering topics such as net metering, EmPOWER Maryland (Maryland's energy efficiency resource standard), and offshore wind regulation development.

---

[1] *In the matter of the application of DTE Electric Company for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.*

[2] *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.*

[3] *In the matter of the application of Consumers Energy Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.*

I have also submitted testimony before the Public Utility Commission of Texas, the Public Utility Commission of Nevada, and the Colorado Public Utilities Commission. My complete CV is attached to my testimony.[4]

Q5. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A5. I am submitting testimony on behalf of the Environmental Law & Policy Center, the Ecology Center, the Solar Energy Industries Association, the Union of Concerned Scientists, and Vote Solar.

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A6. I address numerous aspects of DTE Electric Company (DTE or the Company) integrated resource planning (IRP) filing that ultimately affect the choice and composition of its planned course of action (PCA). I will demonstrate that these choices result in the Company proposing a PCA that in the near-term underutilizes solar energy resource and in the long-term burdens its customers with needlessly high costs for the renewable assets it does pursue. I also show that DTE is foregoing an opportunity to modernize its peaking resources with clean solar plus storage resources that can provide both peaking capacity as well as further contribute to its carbon reduction goals.

Q7. CAN YOU SUMMARIZE YOUR FINDINGS?

A7. Despite performing months of modeling and filing thousands of pages of testimony and exhibits in this case, DTE did not in fact base its proposed renewable resource buildout plan on any of its modeling results. Instead, it relied on outdated levelized cost estimates from its 2018 Renewable Energy Plan in Case U-18232 (which were in turn based on 2017 projected costs) to support its modeled renewable mix of more than 5,000 MW of renewables at a cost of over $7 billion.

DTE hardcoded these renewable builds into the model (while leaving out all of their costs), hardcoded the 2040 capacity replacement choice for Monroe, hardcoded near-term

[4] Kevin M. Lucas CV, attached as ELP-66 (KL-57).

market purchases to prevent capacity needs from arising, marked all of its aging peakers and existing coal units "must run" resources (while excluding their fixed costs), and prevented the model from reducing costs by selecting resources when there was no capacity need. Far from its modeling showing its PCAs are the most reasonable and appropriate choice across its twenty-year planning horizon, DTE's choices reduced nearly all of its initial modeling to the very narrow scope replacing Belle River in 2030. When, multiple months after its original filing and only as a response to intervenor discovery requests, DTE did update its modeling in an attempt to justify its starting point resource plan, its analysis remained critically limited and continued to not reflect a true resource optimization.

Even given these modeling restrictions, DTE consistently overestimated the cost of solar energy. It arbitrarily chose solar input values from multiple data sources, even when its main data resource contained all necessary values. This decision impacted the three major inputs for solar: capital costs, O&M costs, and capacity factors. When paired with a questionable inflation adjustment, DTE's flawed methodology results in overstating the levelized cost of energy (LCOE) of solar by 39%. Instead of $69.48/MWh, solar should have been modeled at $50.09/MWh. Further, DTE failed to model single-axis tracking systems despite its claim to have done so, instead simulating less effective fixed-tilt systems with lower DC/AC ratios. Given the high sensitivity of the modeling results to data inputs and assumptions, and when combined with other modeling assumptions that disadvantaged solar, modeled scenarios were likely biased against solar deployment, particularly in the early years of the PCA. When these assumptions were corrected in alternative modeling, adding nearly 2 GW of solar in the defined PCA window reduced costs by roughly $1 billion.

Far from analytically demonstrating that its PCA was supported by the modeling, DTE instead presents a muddled and confused analysis that required substantial effort to deconstruct. In the end, this case shows that Strategist is simply unable to provide a robust optimization of DTE's system that is reflective of modern technologies such as energy storage, that properly accounts for non-linear cost changes that solar is experiencing, and that dynamically solves for the best time to retire DTE's coal assets to the favor of its customers.

DTE's complete lack of analysis on its peaking fleet is a major omission in its IRP. The Company owns many peaking resources that are more than 50 years old and are difficult to maintain. I show that the oldest of these units are not only unreliable, but they tend to breakdown not randomly (as is modeled) but when they called upon to provide capacity during periods of high load. Despite DTE's lack of transparency about the costs of keeping these plants in operation, I show that solar and solar plus storage installations are operationally and technically able to provide peaking service and that the Company should seriously consider replacing some of the most outdated peakers with new, zero-carbon resources.

DTE's choice to own all renewable assets – including those built specifically for its Voluntary Green Pricing Program (VGPP) – will inflate the costs for its customers who wish to purchase more renewable energy. While the Company is limited by statute from offering customers direct access to competitive suppliers (which, based on the massive customer choice waiting list, many customers' preferences remain unfulfilled), it is not prevented from securing new capacity through third-party power purchase agreements (PPAs). The Commission expected DTE to perform a robust analysis on different ownership and contractual methods in this docket, but the Company has failed to provide any analysis as all.

To enable customers to better reap the benefits of low-cost renewable energy, the Commission should strongly consider requiring DTE to competitively procure third-party PPAs to meet a sizable fraction of its future capacity requirements. Further, the Commission should strongly scrutinize DTE's plan to own all VGPP capacity as these resources exist solely to meet DTE's customers' desires for affordable, clean energy. Hamstringing this program with additional costs incurred through utility ownership inappropriately allows DTE to leverage its monopoly position and will needlessly increases the costs of and reduce demand for these voluntary programs.

In the end, DTE has failed to support its PCA through its modeling or analyses or to show that it is in the best interests of its customers. The Company's starting point $7 billion renewable build was not even based on this case's analysis or modeling results. In this case, DTE's solar costs are too high and operational assumptions for its aging peakers are too optimistic. It further muddies its modeling analysis by hardcoding as initial conditions much of its intended plan. Even in its updated analysis that attempted to undo some of this rigidity, the Company effectively prevents Strategist from optimizing its fleet across all years, and with its path largely predetermined, the model has few opportunities to demonstrate that DTE's proposal is in the best interests of its customers.

The Commission should recognize these shortfalls and direct DTE to refile its IRP filing using a modern tool that can simulate how the grid functions with today's (and tomorrow's) technology without the structural limitations of Strategist. The Commission should also require DTE to support its proposals based on optimized modeled results and not simply allow the Company to hardcode its preferred plan and solve for replacement capacity in one year out of twenty, and for the Company to provide a meaningful analysis on different ownership and contractual arrangements for new capacity. Finally, it should require DTE to perform a detailed analysis of its peaker fleet to determine whether it is time to move on to a cleaner and more reliable solution for peak demand needs. In doing so, the Commission would require that DTE provide it, stakeholders, and customers a robust analysis that can truly be used to determine whether the PCA represents the most reasonable and prudent manner to meet the Company's energy and capacity needs.

II. DTE'S PCA IS NEITHER BASED ON NOR SUPPORTED BY ITS OWN MODELING

Q8. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SECTION OF YOUR TESTIMONY.

A8. In this section, I describe DTE's modeling approach in this case. Using the Company's answers to data requests, I show that the Company's PCA is not in fact based in any meaningful way on the results of its modeling. Instead, DTE predetermined nearly every aspect of its PCA resource plans prior to modeling their performance. I discus the ramifications of these choices and how DTE's supplemental modeling to address some of these issues falls short.

Q9. WHAT IS YOUR OVERALL CONCLUSION REGARDING DTE'S MODELING IN THIS CASE?

A9. Despite claiming to have more than a hundred scenarios and sensitivities examining many different potential futures, DTE's core modeling is in fact extremely limited in scope and generally unrelated to the PCA that it proposes. DTE configured Strategist, its primary modeling tool, in a manner that limited resource optimization for a single action – the replacement of Belle River capacity in 2030. DTE hardcoded its energy efficiency plan, its renewable buildout plan, forced in market purchases in early years, predetermined the 2040 build to replace Monroe, and prevented the model from adding additional resources that could have reduced costs when there was no capacity need.

DTE intentionally left out major costs, including all of the costs associated with its renewable buildout and fixed costs associated with its fossil plants. It performed no optimization of the entire planning horizon, and even when requested to remove its hardcoded starting point renewables, the Company again constrained the model to prevent a meaningful optimization. In the end, DTE's PCA was constructed not from robust modeling performed in this case but largely from DTE's prior (and out of date) assumptions on renewable costs.

DTE's renewable resource mix was also impacted by its choice to allow massive quantities of excess generation to be sold into the market without adequate consideration of the market impact on prices. In one of its PCA plans, more than $3 billion in market sales is assumed to offset the costs of running its fossil fleet. While the Company previously identified risks associated with plans that relied too heavily on the wholesale market for sales or purchases, in this case it raises no such concerns.

DTE Has Inappropriately Hard Coded Much of Its PCA Into the Model

Q10. PLEASE DESCRIBE THE MODELING APPROACH THAT DTE CLAIMED IT USED IN ITS IRP.

A10. DTE stated that it conducted several pre-modeling analyses to screen technologies for cost and market valuation to narrow the list of resources that would pass through to the detailed modeling exercise in Strategist and PROMOD. Strategist was used to calculate the net present value of the revenue requirement (NPVRR) for various portfolios and presented the results in rank order of total cost as measured by the NPVRR. DTE indicated that it did not simply select the least-cost plan for a given set of input assumptions, but considered that metric along with its "planning principles" of reliability, affordability, clean, flexible and balanced, compliant, reasonable risk, and community impact.

From here, DTE assembled its PCA for each of the four major scenarios (BAU, Reference, Emerging Technology (ET), and Environmental Policy (EP)). DTE claims that there is no capacity need until 2030 as a result of the retirement of Belle River, so it has divided its PCA into two time periods: a near-term "defined" PCA (2020-2024) and a longer-term "flexible" PCA (2025-2040). The defined PCA includes actions that backfill capacity from retiring its St. Clair, Trenton, and River Rouge coal units, including ramping up energy efficiency and demand response, as well as adding renewables for RPS compliance and the VGPP. The flexible PCA provides multiple pathways towards meeting the 2030 capacity need, which the Company states will become firmer in its next IRP.[5]

Q11. HOW DOES DTE DESCRIBE THE STRATEGIST MODEL AND ITS USE OF THIS TOOL?

[5] Mikulan Direct at 12-18.

A11. DTE describes Strategist as an "energy market simulation tool [that] develop[s] prudent resource plans that meet customers' forecasted energy and capacity demand."[6] The Company continued:

> Strategist® allowed the IRP team to address all aspects of an integrated planning study at the depth, and accuracy level required for informed decisions. Hourly chronological load patterns were recognized. Production cost simulations were comprehensive. The system employed dynamic programming to develop optimal portfolios of resources, or an optimization. Using Strategist®, all supply and demand-side resource options were considered on equal merit and different deployment schedules were used depending on the specific project, resource, or alternative's estimated approval and construction times.[7]

Q12. HOW DOES DTE DESCRIBE THE PROMOD MODEL AND ITS USE OF THIS TOOL?

A12. PROMOD is a production cost model that was used to supplement some of the Company's analysis. While Strategist simplifies its construct of the energy market, PROMOD

> simulates, on an hourly basis, the applicable market area (zone) under a variety of operating or market conditions… The core of PROMOD® is an hourly chronological dispatch algorithm that minimizes costs, while simultaneously adhering to a wide variety of operating constraints, including generating unit characteristics, transmission limits, fuel and environmental considerations, transactions, and customer demand.[8]

Q13. IN CONFIGURING STRATEGIST, DID DTE ACTUALLY SET UP THE MODEL SO THAT "ALL SUPPLY AND DEMAND-SIDE RESOURCE OPTIONS WERE CONSIDERED ON EQUAL MERIT"?

A13. No. In setting up the model, DTE included a large set of resources in its "starting point". This starting point reflects "DTE's current state and current plans. This includes the current retirement dates, approved new units, current state of the renewable plan, 1.5% EWR, and planned demand response program changes."[9] Notably, this starting point already includes major actions such as building more than 2,600 MW of renewables by 2030, building an additional 2,300 MW of renewables between 2030 and 2040, and retiring Belle River in 2029/30.[10] The Company also hardcoded several hundred MW of market capacity purchases

[6] Mikulan Direct at 62.
[7] Mikulan Direct at 63.
[8] Mikulan Direct at 63-64
[9] Mikulan Direct at 75.
[10] Exhibit A-5

between 2018 and 2020 to close a potential capacity need while several of its coal units are retired but before energy efficiency and demand response programs ramp up.[11] DTE also hardcoded in a common solution of building three natural gas combined cycle units plus market purchases in 2040 to replace the retiring Monroe plant.[12]

Q14. WITH ALL OF THESE ASSETS AND PURCHASES FORCED INTO THE MODEL, DID DTE FIND ANY CAPACITY NEED DURING THE PLANNING HORIZON?

A14. Between the various starting point assets, assumed upgrades and uprates of existing resources, hardcoded incremental energy efficiency, and hardcoded market purchases, DTE found that it had no capacity need before the retirement of Belle River in 2030.

Q15. DID DTE ALLOW THE MODEL TO BUILD UNITS IF THERE WERE NO CAPACITY NEED?

A15. No. DTE configured Strategist to only add new resources where there is a capacity need. This narrow approach prevents the model from adding "superfluous" resources that might reduce the NPVRR when there are no capacity needs.[13] For instance, it is possible that new renewable resources can provide energy at a cost that is less than the fixed and variable O&M costs, or even the variable O&M costs, of existing resources. When the new resource costs less than the fixed and variable O&M of an existing asset, it would be economic to consider retiring the existing asset if there is sufficient capacity in the rest of the system. When the new resource costs less than just the variable O&M costs, but the capacity of the resource is still needed, it would still be economical to build the new resource while running the existing resource less as this would reduce total system costs. However, by stopping the model from adding superfluous resources, DTE prevents this optimization from occurring.

---

[11] ELPCDE-16.103e, attached as Exhibit ELP-10 (KL-1).
[12] Mikulan Direct at 61.
[13] Superfluous units are those that may reduce cost but are prevented from being selected if there is no capacity need.

Q16. IF ALL OF THESE RESOURCES WERE HARDCODED INTO THE MODEL, AND IF STRATEGIST WAS PREVENTED FROM ADDING RESOURCES WHEN THERE WAS NO CAPACITY NEED, WHAT DID THE MODEL ACTUALLY SOLVE FOR?

A16. It had very little to solve for. The near-term capacity position was fixed through near-term resource choices. The 2040 capacity position was fixed through a hardcoded solution. The only opportunity that the model had to build new capacity was for the replacement of Belle River capacity in 2030. This is evident in looking at the many Strategist reports that the Company provided for its core modeling runs.[14] Across a massive variety of fuel cost forecasts, load projections, energy efficiency assumptions, and renewable resource costs, the core scenario results only ever varied in the years 2029 and 2030. In all other years, the model either built no new resources or built the predetermined resources.

Q17. IF DTE DID NOT ACTUALLY DEVELOP ITS PCA PORTFOLIO AS A RESULT OF A STRATEGIST OPTIMIZE, HOW DID IT DETERMINE THE COMPOSITION OF ITS STARTING POINT RENEWABLE BUILD?

A17. The answer is simple but astonishing. DTE did not base its starting point renewables on any modeling runs in this case, but instead based it on a now-dated LCOE analysis from its 2018 Renewable Energy Plan (REP) docket in Case U-18232, which was in turn based on even-more-dated 2017 cost estimates:

> The selection of the wind in the defined period of the PCA to achieve the renewable portfolio standard and clean energy goals outlined in the case was based 2017 NREL ATB forecasts of wind versus solar costs and their calculated LCOEs, which were calculated for the Renewable Energy Plan case (Case Number U-18232). Please see attachment for the LCOE comparison. The selection of primarily wind in the defined period of our PCA was not influenced by Strategist or Promod runs… The renewable energy assets identified for the PA 342 15% RPS, the Clean Energy and Carbon Reduction Goals were selected based on forecasted levelized cost of energy. Based on Attachment U-20471 ELPCDE-13.88a Renewable forecasted LCOEs, the costs of wind and solar became more comparable in 2024, which is when DTE Electric proposed to switch to primarily building solar.

[14] DTE did perform sensitivities related to the earlier retirement of Belle River, but my testimony here refers to the runs where Belle River retired in 2030. For instance, WP LKM-501 REF flat high - 1.5 EE adds various resources in 2029 and 2030, while WP LKM-503 REF flat high - 2 EE adds resources only in 2030.

DTE admits, despite all of the technology assumptions is used, despite all of the data manipulation it took to convert these assumptions into inputs to Strategist and PROMOD, and despite all of the modeling that it did across more than one hundred runs, that none of this influenced the creation of the starting point renewables plan in the PCA.

Q18. DID DTE AT LEAST PERFORM ANY ANALYSIS ON THE RELATIVE BENEFITS OF WIND VERSUS SOLAR IN ITS PCA?

A18. No. DTE confirmed that "because the Starting Point renewables and Starting Point VGP were hard-coded into the Strategist modeling, none of the Company's initial Strategist runs that were performed when the IRP was filed analyzed the cost effectiveness of the specific blend of starting point renewables as compared to other blends that attain the same levels of renewable generation."[15] When asked if the Company performed *any* economic analyses on the specific mix of solar and wind assets as found in the Starting Point renewables and Starting Point VGPP renewables compared to alternative mixes of solar and wind assets, the Company replied that "[t]he analysis as described in this question was not completed as part of this filing."[16]

Not only did these resources fail to emerge from an optimal or least cost simulation through Strategist, some of them have not been approved in other cases. When asked whether the Company performed a run that optimized across the entire 2019-2040 planning horizon "only forcing in the resources that have already been approved in other planning cases", the Company responded that "it has not performed these model runs with the IRP as filed."[17] When asked by Staff why it failed to perform this important analysis when the IRP was filed, the Company responded that the modeling is currently underway and "will be provided to Staff and Intervenors as soon as they are completed."[18]

[15] ELPCDE-13.88f, attached as Exhibit ELP-11 (KL-2).
[16] ELPCDE-13.88g, attached as Exhibit ELP-12 (KL-3).
[17] STDE-2.3a, attached as Exhibit ELP-13 (KL-4).
[18] STDE-2.3b Supplemental, attached as Exhibit ELP-14 (KL-5).

Q19. HAS DTE COMPLETED THE SUPPLEMENTAL MODELING THAT IT REFERRED TO ABOVE?

A19. Yes. However, as I discuss further below, its updated runs contain the same fundamental flaws that prevent it from providing a meaningful analysis of Staff's request.

Q20. DOES DTE PROVIDE AN EXPLANATION FOR WHY IT DID NOT MORE CLOSELY SCRUTINIZE THE MIX OF RESOURCES IN ITS PCA?

A20. Yes. It indicates that these resources are merely "placeholders" that will be updated in the future and that modeling assumptions were made "based on a combination of the Company's knowledge and experience of Michigan projects that both exist and are being developed as well as the forecast of wind versus solar costs as described in response to ELPCDE 13.88a."[19]

Q21. DOES THIS RESPONSE JUSTIFY THE COMPANY'S DECISION?

A21. No. DTE's decision to hardcode its starting point renewables in a particular mix of wind and solar based on little other than outdated cost assumptions contributed to the failure of this IRP to more comprehensively optimize DTE's resource portfolio. While DTE is required to file IRPs every five years, its PCA in this case includes nearly $3 billion of renewable assets that it plans to build in the next five years.[20] The Company should have made a more convincing argument in this case for its particular resource mix that it plans to pursue in the near term before its next IRP filing.

Q22. WHAT WERE THE WIND AND SOLAR LCOES IN THE 2018 REP?

A22. They varied based on the assumptions of the available tax credits that would be available to the resources. Generally, in the 2020-2021 timeframe, wind LCOEs were around $50-55/MWh, while solar LCOEs were around $65-70/MWh. After the wind PTC was assumed to expire in 2024, the wind LCOE increased to $72/MWh, and after the solar ITC was assumed to fall to 10% in 2024, the solar LCOE also increased to $72/MWh.[21]

[19] Id.
[20] See Section V *infra*.
[21] ELPCDE-13.88a, attached as Exhibit ELP-15 (KL-6).

Q23. BASED ON THIS NOW-OLD DATA POINT, IS DTE'S DECISION TO PRIMARILY MODEL WIND IN THE NEAR-TERM AND SOLAR IN THE LONG-TERM REASONABLE?

A23. No. DTE should be aware that Consumers Energy conducted a renewable energy procurement in June 2018. The results of the solicitation are still under negotiation, but Consumers indicated that the weighted average solar price of the procurement was $49.10/MWh[22] This is well below the benchmark number that DTE used to justify wind over solar in the near-term. DTE should have instead properly modeled both wind and solar resources in its model and let the optimization determine what the best outcome would be. However, even if it had done this, as I discuss in detail below, DTE's assumptions on solar were substantially flawed and may have prevented a fair comparison.

Q24. DID THE ADDED STARTING POINT RENEWABLE RESOURCES HAVE ANY COSTS ASSOCIATED WITH THEM?

A24. No. Although it added nearly 5,000 MW of new capacity in some scenarios, DTE modeled no costs associated with the new renewable builds in its starting point.[23] Despite including resources that will cost billions of dollars, all of which will be recovered from its customers, the Company decided to simply leave these costs out of its IRP modeling.

Q25. DID DTE PROVIDE A JUSTIFICATION FOR EXCLUDING THESE COSTS?

A25. Yes. DTE stated that because the costs of the starting point resources were the same across all scenarios, the costs effectively netted out in all comparisons and thus were not important to include. This was the same justification that DTE provided when it failed to model fixed costs of its fossil generation fleet and falls similarly hollow.[24]

Q26. IF THESE COSTS WERE THE SAME IN ALL SCENARIOS, WHY DOES IT MATTER THAT THEY WERE EXCLUDED FROM THE MODEL?

---

[22] Troyer Rebuttal at 22, November 5, 2018. MPSC Case No. U-20165.
[23] ABDE-3.30, attached as Exhibit ELP-16 (KL-7).
[24] ELPCDE-15.100a, attached as Exhibit ELP-17 (KL-8).

A26. It matters for several reasons. As a basic matter of transparency, it is inappropriate to exclude billions of dollars of costs from DTE's statutorily required IRP. Among the goals of the IRP process is to provide insight into the costs of the various options that can be used to meet future loads. By excluding these costs, the Commission and other intervenors are precluded from analyzing the full costs associated with DTE's various PCAs.

Additionally, DTE assumes that it will own and ratebase all of the starting point renewables. As I discuss below, this is not the only option available, but it is likely the most expensive approach. A more robust IRP process would have modeled scenarios in which DTE contracted with third parties to sign PPAs. This differential in cost could have informed the proper ownership mix for future resources. By ignoring the costs of ownership of all of the starting point renewable assets, DTE precludes parties from benefitting from this analysis.

DTE's Supplemental Modeling Does Not Fix Problematic Assumptions nor Optimize Across the Planning Horizon

Q27. DID DTE PERFORM SUPPLEMENTAL MODELING AS DISCUSSED ABOVE?

A27. Yes. Staff requested that:

> The Company perform[] a model run in each of the Michigan Integrated Resource Planning Parameters (MIRPP) scenarios that allow the model to optimize the build plans throughout the whole 2019-2040 period, only forcing in the resources that have already been approved in other planning cases, such as the Company's renewable plan or EWR plan".[25]

While DTE did perform supplemental modeling, it did not optimize the build throughout the whole planning period because of how it configured Strategist. Further, the limited optimization that it did perform still contained all the previous errors and questionable assumptions discussed elsewhere in my testimony.

Q28. HOW DID DTE PERFORM ITS SUPPLEMENTAL MODELING?

[25] STDE-2.3a, attached as Exhibit ELP-13 (KL-4).

A28. DTE updated its modeling approach to remove the "starting point" renewables that were previously hardcoded in Strategist at zero cost and created alternative resources that Strategist could select in an optimization routine. Because of Strategist limitations that no more than 1,250 combinations of resources could be modeled at any given time, DTE doubled the size of wind and solar resources, removed less economic resources such as CVR/VVO and batteries, and limited CCGT builds to four units between 2030 and 2040. DTE also broke the simulation into two stages. First, "the model was optimized until 2030" when the first capacity need emerged. The 2030 resource from lowest cost plan was then hardcoded and the model was rerun to "optimize" through 2040.[26]

Q29. DID DTE CONFIGURE STRATEGIST TO ALLOW THE MODEL TO "OPTIMIZE UNTIL 2030"?

A29. No. Despite the apparent plain language of the Company's explanation, the configuration of the model actively prevented any true optimization of resources over any time horizon. DTE continued to insert its entire aging peaker fleet and restrict "superfluous" units from being built over the entire time horizon.[27] In part because of the continued inclusion of its many old peaker units, the Company did not have a resource need except for the years around the Belle River retirement in 2030 and Monroe retirement in 2040. In all four scenarios (BAU, Reference, ET, and EP), the model only "optimized" builds in 2029/2030 and 2040. No other resource was added in any other year between 2020 and 2040. Far from considering how to reduce costs across the entire time horizon, DTE's supplemental modeling only confused matters further.

Q30. WHAT DO YOU MEAN BY THAT?

A30. In the BAU and Reference runs (which do not include substantially reduced renewable capital costs or high carbon pricing), DTE's modeling appears to suggest that it is more cost-effective to reduce the total quantity of renewable resources that are built. The BAU scenario

---

[26] STDE-2.3b Supplemental, attached as Exhibit ELP-14 (KL-5).
[27] ELPCDE-16.103k, attached as Exhibit ELP-18 (KL-9).

reduces solar from 2,525 MW of solar and 450 MW of wind to 1,000 MW of solar, while adding more demand response and a combustion turbine unit. The results lowers costs by $57 million over the original least-cost plan that included the "starting point" renewables. Under DTE's Reference scenario, solar was reduced from 2,525 MW to 1,600 MW, while wind was moderately increased from 450 MW to 600 MW. This result was $105 million less expensive than the "starting point". Each of these scenarios continued to build one NGCC unit in 2029/2030 and three NGCC units in 2040.

Q31. DOES DTE USE THESE RESULTS TO ARGUE AGAINST ITS PCA?

A31. No. DTE does indicate that the cost difference between the scenarios is small and that spacing out renewables as was done in the "starting point" is "better for constructability, cash flow, execution, possible tax credit eligibility, and project management."[28] I agree that these are benefits from ramping up renewables over time. But the model's decrease in cost with fewer renewables is undoubtably impacted by its solar cost and generation assumptions that I discuss in detail below.[29]

Q32. DID DTE UPDATE ANY OF ITS OTHER INPUT PARAMETERS IN THE SUPPLEMENTAL MODELING?

A32. No, it did not.[30] DTE's updated model contained all of the problematic assumptions that are discussed elsewhere in my testimony. Solar costs continue to be substantially overstated. The generation profile and effective load carrying capacity (ELCC)[31] for solar is reflective of a fixed-tilt system rather than a single-axis tracker. Aging and unreliable old peaker units continue to operate for an additional twenty years. Fixed O&M costs are ignored. Superfluous units were prohibited. DTE's supplemental modeling does nothing to correct

[28] STDE-2.3b Supplemental, attached as Exhibit ELP-14 (KL-5).
[29] See Section III *infra.*
[30] ELPCDE-16.103n, attached as Exhibit ELP-19 (KL-10).
[31] The ELCC is a measure of what fraction of a unit's inverter rating counts towards meeting MISO reliability requirements.

these issues, and as such does not even produce an opportunity to explore a true optimization of resources across the full planning horizon.

DTE's PCA Relies Too Heavily on Market Sales to Offset Costs and Has Not Properly Modeled Market Price Impacts

Q33. DESPITE ALL OF THE ISSUES THAT YOU DEFINED ABOVE, DID DTE ROBUSTLY ANALYZE THE MODEL RESULTS THAT OCCURRED TO REPLACE BELLE RIVER IN 2030?

A33. No, it did not. While DTE did run multiple scenarios and sensitivities that sought to understand what resources would be used to fill this single capacity need event, it did not robustly consider how the rest of its hardcoded plan would influence these results. Specifically, DTE failed to consider the reasonableness and risk associated with PCAs that produced substantially more energy than DTE needed for its own load.

Q34. WHEN STRATEGIST SELECTED RENEWABLE RESOURCES FOR THE 2029/2030 BUILDS, HOW DID THESE CHOICES IMPACT THE RESULTS?

A34. Generally, the model preferred wind resources over solar resources in many of the least-cost builds. For instance, Strategist selected to build thousands of MW of wind resources and no solar resources to meet its capacity need in 2029/30.[32] Given that wind has a much lower ELCC than solar (modeled at 11.7% for wind compared to 65%+ for single-axis tracker systems), this result is initially confusing. However, DTE provided an explanation for this result which implicates yet another modeling choice it made, which is worth quoting at length below:

> The Strategist® model selects alternatives based on how much UCAP, or firm capacity, each alternative provides. For wind, a firm capacity of 11.7% was assumed, which means that for each 100 MW of wind installed, only 11.7 MW of capacity will count as ELCC in MISO. Therefore, a large number of wind blocks were required by the Strategist® model to fill the 2029 and 2030 capacity need. While that large amount of wind may not always be available to support peak load, which is the driver of the UCAP capacity allowance, the wind alternatives in the Strategist® model produced a lot of energy, in total, compared to the amount of firm capacity they

[32] Mikulan Direct at 80-81.

> provided. This energy could then be sold to the market in the model, up to the export limit, and provided value, especially in higher markets. In contrast, filling the capacity need with solar creates less energy to sell to the market due to solar's higher ELCC combined with its lower capacity factor than wind. The resulting least-cost plans included the value of selling the excess energy produced by wind. In these runs, the optimization was run unconstrained for the renewables. That means there was no limit on the amount of wind or solar selected by the model in any one year, even if that amount feasibly could not be built in a given year.[33]

Q35. WHAT ARE SOME OF THE PROBLEMS WITH THIS APPROACH?

A35. There are several. First, as DTE freely admits, the result of the modeling run is not constrained by what could be "feasibly" built in a given year. Constructing 3.3 GW of wind in a single year is simply not realistic, but the model selected this option under some of its cost assumptions. DTE did not confirm whether the same resource mix would remain the least-cost solution if the build were instead spread out over a wider number of years.

Second, DTE's modeling configuration leads to Strategist selecting a very low capacity zero-carbon resource (wind) to meet its capacity needs while ignoring a very high capacity zero-carbon resource (solar). The overbuild only works in the model because excess energy produced by the thousands of MW of wind is assumed to all be sold into the market, and to be done so without impacting prices. This in turn produces hundreds of millions of dollars of revenue from energy market sales, which is used to offset the costs of the wind-heavy portfolios and make them appear lower in cost.

Finally, this modeling artifact may have already been superseded by updates that DTE has made but did not fully model. Subsequent to its initial IRP modeling, DTE updated the ELCC for wind from 11.7% to 16%. When asked what impact this might have on the exact scenario above, the Company indicated that "[b]ecause less wind build would be needed to fill the capacity need when given a higher capacity credit, less market value would be obtained from excess energy in the starting point runs, and it is possible higher amounts of solar may be selected instead of wind. That is, the ratio of solar to wind build could possibly

[33] Mikulan Direct at 82.

increase across the various modeling least cost plans with an increase in wind capacity credit."[34]

Q36. DOES DTE'S MODELING ASSUME THAT ITS ENERGY NEED IS ENTIRELY MET BY ITS OWN RESOURCES?

A36. No. DTE has enabled Strategist to include market sales up to the transmission capacity export limitation of 1,358 MW.[35,36] This means that if there is an excess of energy produced from its "forced in" units and the load of its customers, the model will sell the additional energy into the market and take credit for the revenue at the assumed market LMPs. Under this broad export limitation, the model could in theory export nearly 12,000 GWh of energy per year, representing more than 25% of the Company's annual customer sales.

Q37. WHAT IS THE MAGNITUDE OF THE SALES AND REVENUE ASSUMED UNDER THIS APPROACH?

A37. It varies by scenario, but because DTE has forced in so many resources, many of the modeling results show massive quantities of excess energy being sold to the market. The figures below focus on PCA Plan B under the Reference scenario, which includes the higher quantity of VGPP programs and a 1x1 NGCC for the 2029/2030 build.[37]

The balance between existing Company thermal resources, DTE's "forced in" starting point renewables, and builds for the VGPP program are shown below for 2018 and 2031 in Figures 1 and 2, respectively. DTE's total load (including pumped hydro losses) are shown on the left column, which in 2018 was just over 46,000 GWh. In 2018, thermal generation from the existing fleet of fossil and nuclear units met nearly 90% of this energy need. There were small energy debits and credits from sources such as PURPA, DTE-owned renewables, and market purchase and sales.

---

[34] ELPCDE-8.67, attached as Exhibit ELP-20 (KL-11).
[35] Mikulan Direct at 82.
[36] Exhibit A-3 at 106.
[37] Data was taken from WP LKM-622 REF PCA B - tiered

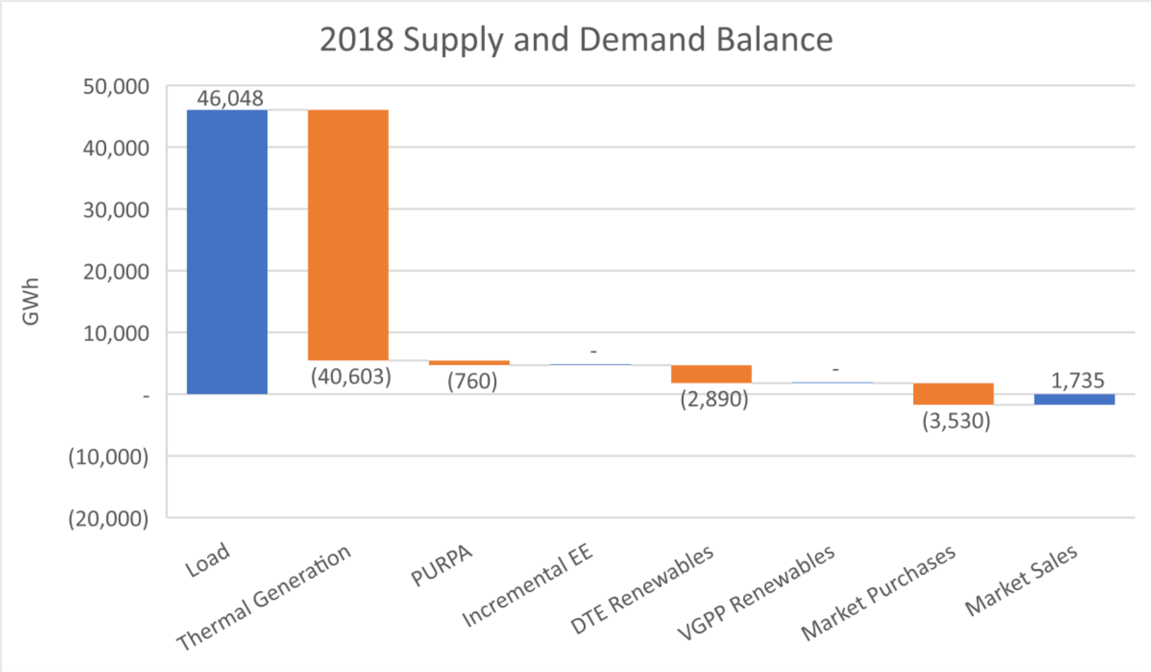


Figure 1 - 2018 Supply and Demand Balance

The situation has changed substantially by 2031 as DTE's "starting point" renewable build out is executed. Even after the retirement of Belle River, thermal energy stays roughly the same as generation from the new 1x1 NGCC backfills for Belle River (in part due to DTE's modeling decision to only run NGCC at their max or min outputs, as discussed further by Ms. Sommer). There are small contributions from PURPA projects and incremental EE (savings above the assumed baseline level), followed by a much larger contribution from "DTE Renewables" (representing the hardcoded "starting point" renewables) and "VGPP Renewables" (representing renewables for the VGPP program).

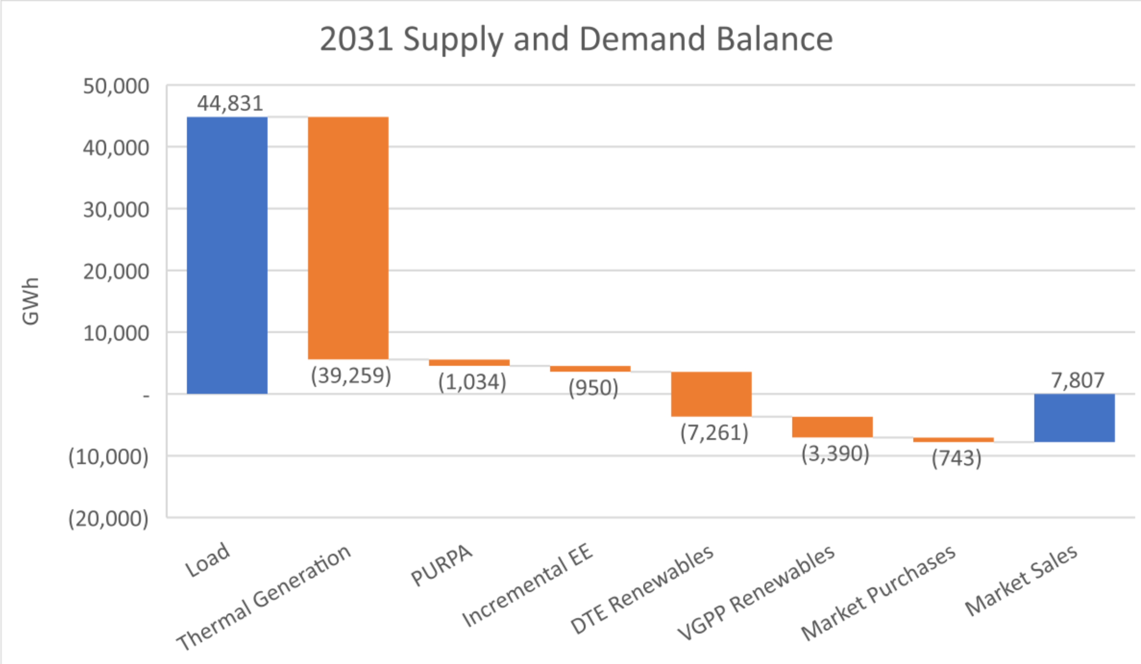


Figure 2 - 2031 Supply and Demand Balance

After adding in minimal energy market purchases, DTE is roughly 8,000 GWh long on energy. Considering DTE's energy need is just under 45,000 GWh in that year, this means that DTE is generating roughly 17.5% more energy than it needs. The model's solution? Simply assume the market can absorb all this excess energy, sell this all back into the market at projected LMPs, and count the revenue as an offset for this scenario's fuel costs.

In this scenario, that produced market revenue of $420 million in 2031 alone, offsetting almost 40% of the fuel and variable O&M costs of $1.1 billion for that year. By 2040, the model assumes $859 million of market sales, equal to 60% of the fuel and variable O&M cost of $1.44 billion. In other words, in the last year of the planning horizon, DTE is netting out well over half of the cost of running its thermal fleet through assumed sales into the market from overgeneration of renewables and running its NGCC at their maximum outputs.

Q38. OVER THE FULL SPAN OF THE MODELING HORIZON, HOW DO THESE COSTS AND ASSUMED MARKET REVENUES COMPARE?

A38. As DTE's hardcoded renewables begin to come online in 2022, the model's revenues from net sales increases from $132 million in 2022 to $385 million in 2031 to $802 million in 2040. Figure 3 below shows the four major cost categories by year for this scenario, showing the steady increase in revenues (negative costs) of the net market sales.

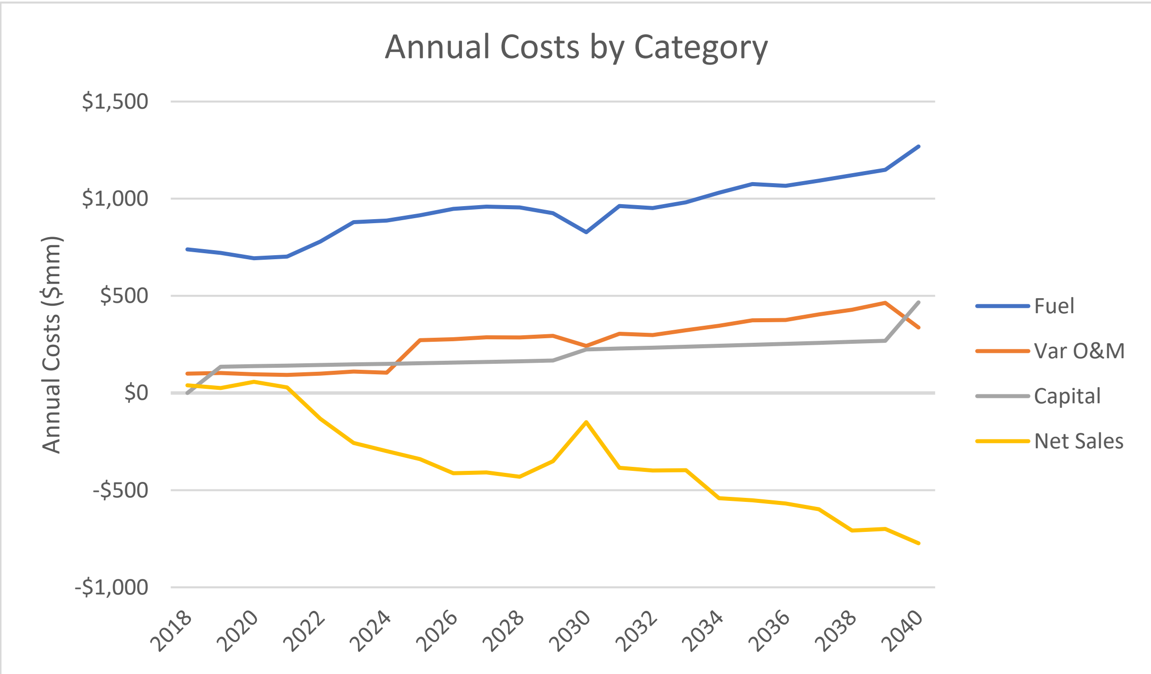


Figure 3 - Annual Costs by Category

Because the largest sales offset occurs at the end of the planning scenario, the impact on the NPVRR is somewhat muted, but still substantial. Figure 4 below shows the annual accumulated NPVRR for just the operating and capital costs (blue) compared to the net costs after the assumed market sales revenue. By 2040, the NPVRR of this scenario is $12.45 billion, but would have been $15.75 billion – $3.3 billion or 27% more – absent the offsetting revenue.

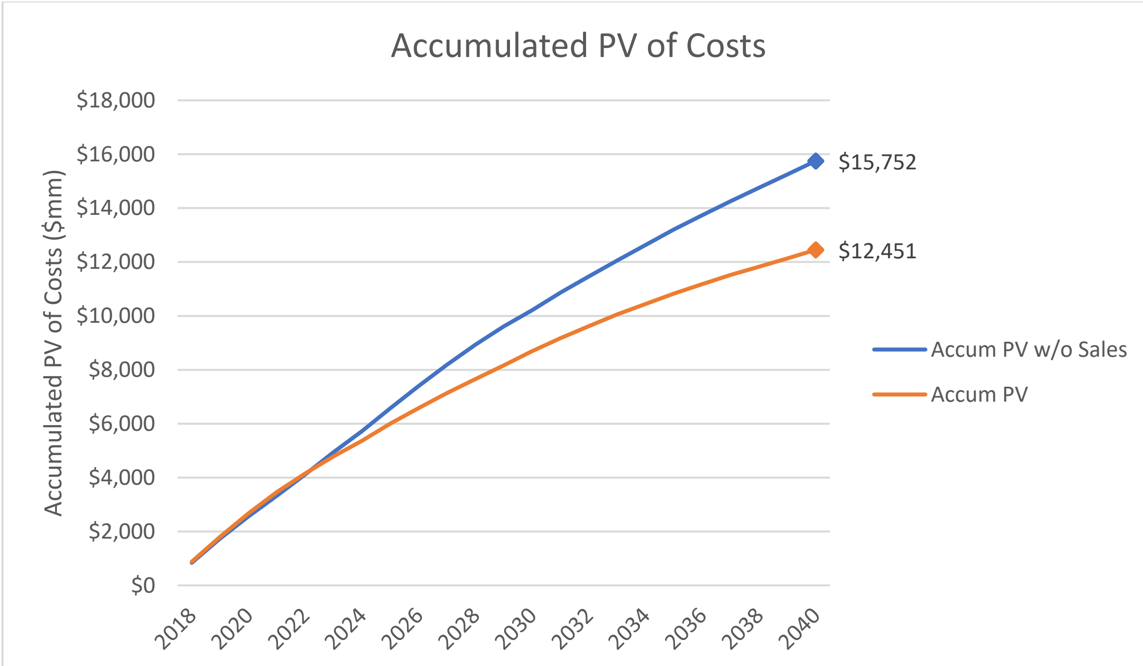


Figure 4 - Accumulated PV of Costs

Q39. DOES THIS STRATEGY CARRY ADDITIONAL RISKS COMPARED TO A MORE BALANCED SUPPLY/DEMAND PORTFOLIO?

A39. Absolutely. The $3.3 billion offset is massive compared to the scale of DTE's total costs. In the Company's testimony in its 2018 CON Case U-18419, portfolios that relied on high market purchases or sales were deemed to be more risky than those with fewer sales. "Since risks are associated with depending too much on the market, for both sales and purchases the closer to zero net purchases was preferred for these criteria."[38] In other words, DTE previously sought to minimize the exposure to the market for both purchases and sales. However, here it produces portfolios that rely heavily on market sales when plans with less exposure were only minimally more expensive.

In its updated modeling that removed its hardcoded renewable resources, DTE simulated 20 portfolios through 2030. While I discuss several issues with the updated

[38] Case U-18419, Exhibit A-4 at 211.

modeling above, the least cost plan built a 1x1 NGCC in 2030.[39] The least cost wind-only plan (2,850 MW in 2030) was 0.42% or $57 million more expensive, and the least cost solar-only plan (1,000 MW in 2030) was 1.0% or $136 million more expensive. The incremental cost of either of these alternative portfolios is a fraction of the assumed market revenue. Although year-by-year details for these portfolios were not available, it is clear that adding 1,000 MW of solar will produced substantially less excess energy than adding 2,850 MW of wind. If DTE's assumptions on the market's ability to absorb excess energy without impacting prices is even a little off, it is entirely conceivable that a solar-heavy scenario with less excess energy would have been the least-cost solution.

Q40. PRACTICALLY SPEAKING, WHO WOULD BUY THIS EXCESS ENERGY?

A40. Considering that both DTE and Consumer Energy are vertically integrated utilities with limited customer choice, it is unclear who would be in a position to purchase this excess energy. DTE only limited market sales by the transmission export limit and did not model a robust feedback loop between increasing zero-marginal-cost energy and energy prices. Producing an extra 8,000 GWh of zero-marginal-cost energy is roughly the equivalent of a 913 MW plant running around the clock. Michigan sales were 104,000 GWh in 2018, so this would represent a sizable increase in energy supply.[40]

Q41. WOULD THIS LARGE A QUANTITY OF EXCESS ENERGY HAVE AN IMPACT ON MARKET PRICES AND DID DTE ATTEMPT TO QUANTIFY IT?

A41. Given the magnitude of the excess energy, there would likely be a price impact. DTE did perform a limited analysis on the impact of high wind penetrations by calculating the difference in LMPs between Michigan and Iowa.[41] After calculating the difference in straight average price (i.e. the mean of all hours) and wind-weighted average price (i.e. the

[39] "U-20471 STDE 2.3B BAU OPTIMIZATION 2030", STDE-2.3b Supplemental, attached as Exhibit ELP-14 (KL-5).
[40] EIA Electricity Data Browser retail sales data for Michigan. Available at https://www.eia.gov/electricity/data/browser/
[41] ELPCDE-1.1d, attached as Exhibit ELP-21 (KL-12).

generation-weighted mean price of wind production), DTE found that Iowa LMPs were about 30% lower during hours with high wind production in Iowa, compared to a 3% drop in Michigan LMPs during hours with high wind production in Michigan.

The Company then increased the revenue requirement of wind resources to reflect the reduction in energy revenue from the sale of excess energy. From the model's standpoint, this approach is the equivalent of increasing the capital cost of wind farms and holding everything else equal. Unsurprisingly, this approach increased the cost of a scenario with new wind builds compared to baseline with a combined cycle unit as the wind units were assumed to be more expensive to build.

Q42. DOES THIS ANALYSIS CAPTURE THE IMPACT ON ALL RESOURCES?

A42. No. DTE does not appear to have modified LMPs at all, but rather modified the revenue requirement for new wind resources. This method ignores the impact of market prices on all other resources, including its existing thermal fleet and its "starting point" renewable resources. It is no wonder that this analysis shows an increase in cost when building more (and more expensive) wind resources.

DTE's IRP Fails to Fully Consider All Reasonable Options Available to Meet Projected Energy and Capacity Needs

Q43. WHAT ARE SOME OF THE OTHER CONFIGURATION DECISIONS THAT DTE MADE IN ITS MODELING?

A43. As I discuss in detail below, DTE's aging gas turbine and engine peaking units frequently break down when they are called into action.[42] Because of the way in which Strategist performs its analysis, the particular failure mode of these units is not captured correctly. As such, the model is likely overstating how much capacity will be available based on the historic performance of these units. Further, many of DTE's gas turbines and engines are

[42] See Section IV, *infra.*

already among the oldest in commercial operation. Despite this, DTE assumed that its aging fleet of peaker plants will be available through the entire planning period. If these units were modeled at reduced performance levels or retired prior to the end of the planning period, there would be additional capacity needs that could be optimized by new resources.

Q44. DID DTE FULLY MODEL BOTH FIXED AND VARIABLE O&M COSTS?

A44. No. Not only does DTE fail to report unit-level cost data for its peaker fleet, it claimed that "the Company does not estimate fixed O&M costs" when asked for detailed data on the Belle River units.[43] It further stated that "[t]he full costs for the DTE Electric coal units were not included in Strategist because all nonretirement analysis runs had the same retirement dates."[44]

Q45. DO YOU HAVE A SENSE OF HOW MUCH EXPENSE WAS EXCLUDED FROM DTE'S MODELING?

A45. Yes. While not a perfect apples-to-apples comparison, DTE indicates that its 2018 revenue requirement for its PCAs is $878 million, which is reflective of all of the costs that are captured in the Strategist modeling.[45] By contrast, DTE reported $1.578 billion in power production expenses on its FERC Form 1.[46] The fact that its reported expenses are 80% higher than its modeled expenses provides some insight to just how many costs have been excluded from this IRP.

Q46. DID DTE PROVIDE ANY FURTHER EXPLANATION OF WHY IT DID NOT ATTEMPT TO MORE FULLY MODEL ECONOMIC RETIREMENTS THROUGH STRATEGIST?

A46. Yes. The Company stated that it only performed the retirement analyses that it was required to.[47] It also noted that Strategist was poorly suited to perform a robust economic retirement analysis as this would have required configuring many more resources and working up costs

[43] MECNRDCSCDE-6.9, attached as Exhibit ELP-22 (KL-13).
[44] ELPCDE-15.100a, attached as Exhibit ELP-17 (KL-8).
[45] Exhibit A-8.
[46] FERC Form 1 "Electric Operation & Maintenance Expenses" for Q4 2017. Available at https://www.ferc.gov/docs-filing/forms/form-1/data.asp.
[47] ELPCDE-15.101b, attached as Exhibit ELP-23 (KL-14).

for multiple retirement years. In doing so, the modeling limitations of Strategist may have been exceeded, preventing the model from completing its runs.[48]

The limitations of Strategist should not excuse the Company from performing a more robust analysis on potential economic retirements of other units beyond those that it was required to model. By failing to consider less expensive resources, DTE may be costing its customers more than is necessary to provide safe and reliable service.

Q47. WHAT IS YOUR CONCLUSION REGARDING DTE MODELING CONFIGURATION THIS CASE?

A47. DTE's modeling approach is woefully insufficient. For the Commission to approve the IRP, DTE must show that the proposed integrated resource plan represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs.[49] DTE admits that it performed no analysis on the nearly 5 GW of renewable resources that are included in its starting point plan, instead basing it on old data from another case. By hardcoding so many resources into the model and eliminating superfluous builds, it configured and constrained the model so that only one single event triggered any optimization at all. DTE's modeling results cannot by definition support its PCA because its PCA was almost entirely constructed outside of the model. Far from analytically demonstrating that its plan is the most reasonable and prudent approach to meeting its energy and capacity needs, DTE's modeling exercise simply crunches the numbers on its predetermined outcome.

DTE failed to include billions of dollars of costs in its model. Neither the fixed O&M cost of its existing fleet were included, nor the massive spending associated with its starting point renewables. Given that these renewable resources can be procured in a manner that reduces costs for the Company's customers compared to utility ownership, simply ignoring the costs because they are common across all scenarios overlooks the potential opportunity to reduce future utility bills for DTE's customers.

[48] ELPCDE-15.100b, attached as Exhibit ELP-24 (KL-15).
[49] MCL 460.6(t)(8)(a).

DTE offers no justification for its modeling decisions, even though it was aware of the potential problems that they could create. When asked how lower cost resources would be treated by the Company's IRP modeling, DTE stated: "In the Strategist optimization modeling, a resource would have not been selected because there was no capacity need. However, knowing that the resource was economic, it can be forced into a modeling run or run in Strategist as a 'superfluous' unit to verify that the value of the alternative positively impacted the build plan economics." It continued to indicate that CVR/VVO and the VGPP renewables were forced into the model for this reason.[50]

When asked in a follow up whether any other resources were also "forced in" as superfluous units that could reduce the cost of a given modeling run, DTE confirmed that "no other resources were modeled as 'superfluous' in the Strategist model."[51] DTE configured the model to prevent the possibility that other least-cost resources would be selected, with the exception of two resources that would benefit the Company directly by increasing the rate base on which it earns a return.

While it represented that "all supply and demand-side resources options were considered on equal merit", the Company failed to carry through on this promise. Despite claiming to have done so, the Company has not properly updated its modeling to remove the bias of its hard-coded starting point build plan from its results. It has not committed to run simulations that seek to reduce operational costs even when there are no capacity needs. It has made no effort to model the fixed O&M costs of the fleet and perform a true economic retirement analysis. As a result, DTE's modeling in its entirety must be called into question. Rather than provide a level playing field on which to fairly and objectively evaluate different options, DTE has firmly planted its thumb on the scale in this case.

[50] MECNRDCSCDE-3.85, attached as Exhibit ELP-25 (KL-16).
[51] ELPCDE-8.70, attached as Exhibit ELP-26 (KL-17).

III. DTE'S MODELING APPROACH IS BIASED AGAINST SOLAR, RESULTING IN LOW NEAR-TERM DEPLOYMENT

Q48. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SECTION OF YOUR TESTIMONY.

A48. In this section, I begin with a detailed discussion of several problems with DTE's solar costs and operating assumptions. I continue by analyzing how DTE's modeling assumptions other than cost impact the results of its IRP. I discuss several problems with DTE's ELCC for PV, including its initial value and planned degradation. I also analyze how the solar generation profiles in the models differ substantially from single-axis tracking systems modeled through SAM, confirming that DTE erred and actually modeled fixed-tilt systems. Finally, I describe the results of an alternative modeling run that fixes some of these basic assumptions and shows that building substantially more solar in the near-term would be optimal.

Q49. WHAT IS THE OVERALL RESULT OF YOUR MODELING CRITIQUE ANALYSIS?

A49. DTE selectively mixes and matches source data for solar and wind capital and operation and maintenance (O&M) costs, resulting in values that are likely too high for the types of facilities that it models. When all of these individual erroneous assumptions are corrected, solar moves from a relatively expensive resource to a least-cost resource and the LCOE of solar falls from $69.48/MWh to $50.09/MWh. Additionally, the revenue requirement for company-owned solar deployed during the "defined" period of the PCA the is too high by roughly 22%. These values, when combined with numerous other solar-related input assumptions that I challenge below, results in solar becoming a much more cost-effective resource and justifies a substantially higher buildout of solar capacity.

DTE's non-cost solar modeling is highly problematic. DTE simply erred in modeling generation from fixed-tilt PV systems rather than its claimed single-axis tracker PV systems to the substantial harm of solar resources. While it did perform updated modeling shortly before this testimony was due, that analysis was too limited to meaningfully correct the potential impact on the results. The Company also utilized a non-MISO-approved ELCC methodology that was also based on fixed-tilt rather than single-axis trackers. These two factors combine to disadvantage solar in the modeling, which in turn is reflected by defined PCAs that lack nearly any solar deployment.

Given the failure of the Company to present a scenario in which properly modeled new solar resources could reduce costs to the Company's customers, I worked with Anna Sommer from Energy Futures Group to perform such modeling. Ms. Sommer used her deep knowledge of Strategist to incorporate cost and operational inputs that I derived to produce an alternative series of modeling runs. The results show that nearly 2 GW of solar can be cost-effectively deployed in the near-term years of the IRP before any consideration of replacing peaking units.

DTE's Methodology for Determining Solar Costs is Inconsistent and Misleading and Ultimately Overstates the Cost of Solar

DTE's Solar Capital Cost Assumptions are Misleading and Overstated

Q50. WHAT IS THE SOURCE FOR DTE'S 2018 SOLAR CAPITAL COSTS?

A50. DTE relies on the 2018 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) for its 2018 capital costs.[52] This report, published in July 2018, contains a detailed set of assumptions for multiple renewable and conventional technologies, including fixed-tilt and single-axis tracking solar PV systems. Further, it contains five location-specific data sets (Seattle, Chicago, Kansas City, Los Angeles, and Daggett, CA) for solar production and three different cost curves (Low, Mid, and Constant). Together, these values are used to calculate the LCOE for each technology using the financial assumptions also contained in the ATB.

Q51. WHAT COMBINATION OF LOCATION AND COST CURVE DID DTE USE?

A51. DTE used the "Chicago – Mid" scenario for its solar capital costs.

[52] https://atb.nrel.gov/

Q52. IS THIS CHOICE APPROPRIATE FOR MODELING THE BASELINE SCENARIOS IN THIS IRP?

A52. It may be a marginally appropriate choice, but it is clearly a conservative choice. Costs in the ATB do not change based on geography, so the location does not matter for this data point.[53] As explained by NREL, the ATB Mid scenario assumes "technology advances through continued industry growth, public and private R&D investments, and market conditions relative to current levels that may be characterized as 'likely,' or 'not surprising'"[54] In other words, the ATB Mid scenario is a "status quo" forecast based on the expectations that current trends in the solar industry will continue. By contrast, the ATB Constant case (which maintains a constant ratio of cost to the baseline year) and ATB Low case (which assumes "limit of surprise" technology advances, breakthroughs, increased R&D spending, and favorable changes in market condition) represent a shift from the recent trajectory of the industry.

Importantly, NREL considers the ATB Low scenario to be "not necessarily the absolute low bound" of system prices and is in fact in line with other trends and initiatives to drive PV system costs down. Considering that prices have consistently fallen faster than expectations, and that massive amounts of funding have been flowing towards the industry, assuming status quo progress as the ATB Mid scenario does might be too conservative.

Q53. WHAT ARE SOME OF THE TECHNOLOGY TRENDS OR INITIATIVES THAT MIGHT FURTHER REDUCE THE COST OF PV SYSTEMS, CONSISTENT WITH ATB'S "LOW" SCENARIO?

A53. Bifacial panel technology is just beginning to roll out. This technology places PV cells on both sides of a panel, allowing the underside to absorb reflected energy from the ground and albedo.[55] Depending on how the panels are installed, bifacial technology could increase panel output by 15%.[56] As developers become more comfortable with this technology and

[53] PV capacity factors do vary by location and impact the ATB's LCOE calculation, but DTE uses a separate source for its capacity factor value as discussed below.
[54] https://atb.nrel.gov/electricity/2018/summary.html
[55] https://www.solarpowerworldonline.com/2018/04/what-are-bifacial-solar-modules/
[56] https://www.greentechmedia.com/articles/read/bifacial-solar-modules-inch-toward-the-mainstream

begin to optimize installations to take advantage of its capabilities, bifacial panels will further drive down systems costs. This is done by increasing the amount of energy that can be captured in a given area (reducing land costs per kW) on a given structural support system (reducing balance-of-system costs per kW) for a given amount of labor (reducing labor costs per kW).

Critically, bifacial panels were just recently granted an exemption from the current Section 201 import tariffs.[57] These tariffs currently add 25% of the cost of PV panels and will step down over the next several years. Obtaining an exemption from the tariff will eliminate any price premium compared to monofacial panels and accelerate the deployment of bifacial technology. This increase in demand should incent further manufacturing investments, which will continue to drive prices down as economies of scale are realized.

Additionally, the federal Department of Energy has launched SunShot 2030, the successor to the massively successful original SunShot 2020 initiative. SunShot 2020 was a Department of Energy program launched in 2011 aimed at reducing the cost of solar energy by 75 percent by 2020. That goal was reached in 2017, three years early. Recognizing the fulfillment of its original SunShot 2020 goal, DOE formally launched SunShot 2030 in November 2016.[58] This initiative seeks to drive further reductions to the LCOE of PV through technological improvements. Specifically, it is targeting further reductions in panels costs, reductions in balance of system costs, increasing the lifespan of panels, decreasing the annual degradation of panels, and reducing fixed O&M costs. Through a combined effort, DOE is seeking to reduce the *unsubsidized* LCOE of utility-scale solar from roughly 7 cents/kWh in 2016 to 3 cents/kWh in 2030.[59]

Q54. HOW DO THESE FIGURES COMPARED TO THE 2018 ATB LOW SCENARIO?

---

[57] New Solar Opportunities for a New Decade, Energy.gov https://www.greentechmedia.com/articles/read/bifacial-modules-win-reprieve-from-u-s-solar-tariffs#gs.rn0uee
[58] https://www.energy.gov/eere/solar/sunshot-2030
[59] Id.

A54. SunShot 2030's cost goal is to reduce panel costs from \$0.65/watt to \$0.30/watt and to reduce balance of systems costs and soft costs from \$0.85/watt to \$0.55/watt. If these goals are met, PV systems would cost \$0.85/watt, or \$850/kW_{DC} in 2030. This is closely aligned with the 2018 ATB Low scenario 2030 value (adjusting for inflation) of \$823/kW_{DC}. The PV industry met the 2020 DOE SunShot goals three years early. Technology continues to improve (as demonstrated by the increased deployment of single-axis trackers, increasing panel efficiency, and bifacial modules). There is little reason to doubt that the 2030 goals are within reach, and if past is prologue, perhaps they will be met a bit early.

Q55. GIVEN THESE BACKGROUND TRENDS, WHAT IS YOUR VIEW OF DTE'S CHOICE TO USE THE ATB MID VALUES?

A55. I consider the ATB Mid scenario to be a conservative forecast that acknowledges the continued cost changes and technology improvements of the solar industry but likely overstates the cost of solar technology in the mid-term as new technology emerges and R&D breakthroughs are commercialized. Cost reductions in the ATB Mid forecast beyond 2021 continue as a substantially lower rate than recent history, with real cost reductions of roughly 1% per year compared to reductions of 5%-6% in 2020 and 2021. There is little to indicate that PV costs and innovation will nearly stop past 2021.

Q56. DOES DTE DIRECTLY USE THE ATB SOLAR CAPITAL COSTS?

A56. No. The ATB data is denominated in \$/kW_{DC} in 2016 dollars. To use these values in its model, DTE must first convert them to nominal dollars using a deflator and then convert costs to \$/kW_{AC} to bring solar costs in line with the rest of the modeled resources. DTE then uses an inverter loading ratio (ILR) of 1.3 to convert from \$/kW_{DC} to \$/kW_{AC}.[60]

Q57. IS THIS ILR REASONABLE?

[60] The inverter loading ratio represents the ratio of PV panels (in kW_{DC}) to the inverter rating in kW_{AC}. A higher ILR means that a system has more DC power "overhead" to max out the inverter AC power output. . This helps "flatten" the generation profile of the system as days and seasons shift by extending the total number of hours a system can maintain its rated inverter power output

A57. For current systems, yes. This value reflects typical installations today, and is the same value assumed in the ATB. That said, there has been a trend in utility-scale solar installations to increase the DC/AC ratio. As panels have fallen in cost, and thus represent a smaller portion of the total installed cost, it becomes economic in certain circumstances for a developer to increase the loading on inverters. While this does result in some clipping of DC energy (i.e. not all of the panel power can be used by the inverter), it increases the total AC energy that the panels produce. Further, a higher ILR increases production during early mornings and late afternoons when the sun is lower in the sky. In the case of MISO, where capacity is needed in late summer afternoons, increasing the ILR can increase the economic value of the generated PV.

Q58. WHAT IS THE RAMIFICATION OF USING THIS VALUE DESPITE TRENDS TOWARDS HIGHER ILR?

A58. A higher ILR could increase the ELCC of PV systems as it will increase the system's AC output in late-afternoon hours that form the basis of this calculation. If the value associated with both the energy and the capacity exceeds the incremental cost of adding the DC capacity, this would result in a benefit to DTE's customers that is not currently captured in the Company's modeling.

Q59. PLEASE DESCRIBE HOW DTE MODELS SOLAR RESOURCES IN STRATEGIST.

A59. Ideally, DTE would use a model that allows more flexibility in characterizing its resources. However, Strategist is unable to model non-linear price changes which are required to capture the pricing dynamic in the solar industry. Further, DTE must limit how many different resources that Strategist uses lest it fail to converge on a solution in a reasonable time.

Because of these limitations, DTE chose to use two proxy years to create the solar resources for the entire modeling timeline. The first resource, which represented solar installed between 2021 and 2024 with an assumed 30% investment tax credit (ITC), was based on 2018 costs that were inflated to represent a commercial operation date of 2024. The second resource, which represented systems installed between 2025 and 2040 with a 10% ITC, was also based on 2018 costs that were inflated to a commercial operation date of 2025. In each case, the project was assumed to be built the prior year. Thus, the resources used 2018 capital costs inflated to 2023 and 2024, respectively.

Q60. DID DTE USE THE ATB MID VALUES FOR 2023 AND 2024 IN ITS MODELING?

A60. No. Despite ATB providing a year-by-year projection of costs (which declined steeply in the early years), DTE instead used an averaging process that results in a meaningful overstatement of capital costs in the near-term relative to the ATB source material. When combined with other questionable choices such as hardcoding much of its renewable buildout, DTE's modeling "result" fails to reflect any sort of optimization based on the projected prices of its source material.

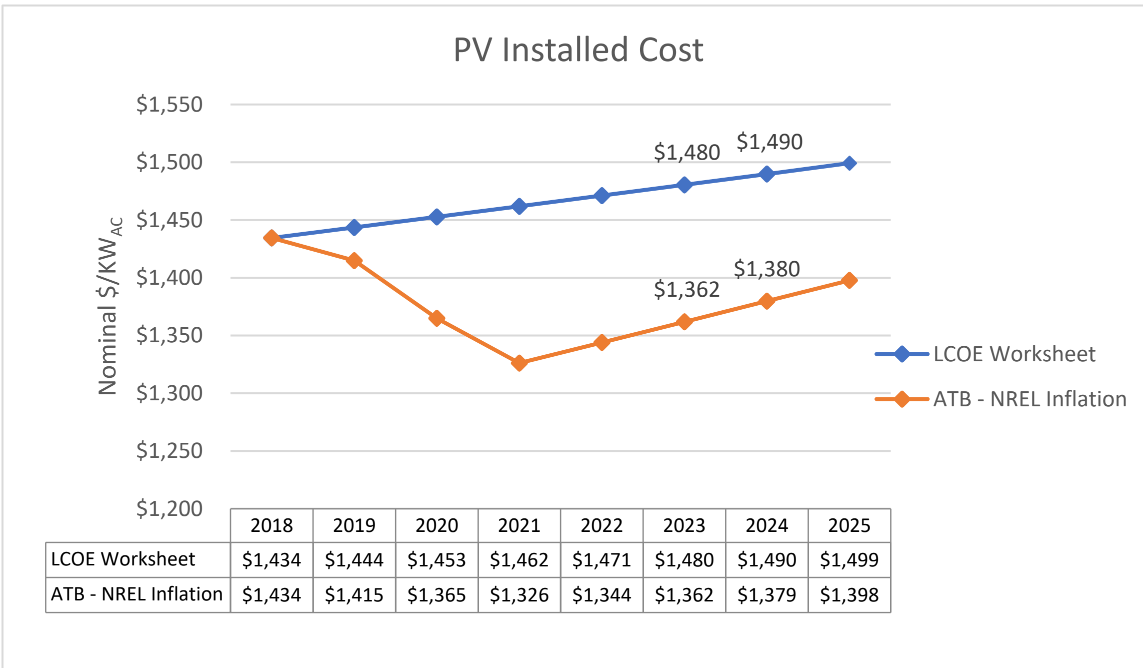
DTE first takes the 2018 PV resource cost in $2016/kW$_{DC}$ in 2016 dollars ($1,050) and converts it to a nominal 2018 value ($1,103). It does this using NREL's 2.5% inflation value, which, as discussed below, is inconsistent with the rest of DTE's analysis. This value is then converted to nominal 2018 $/kW$_{AC}$ by multiplying by the ILR of 1.3 to produce a final value of $1,434/kW$_{AC}$[61]

This value is used as a critical input to DTE's LCOE workpaper, which is in turn used to compute the revenue requirement value used in Strategist.[62] In this workpaper, the $1,434/kW$_{AC}$ value for a 2018 project is inflated to 2023 (for the 2021-2024 PV resource) and 2024 (for the 2025-2040 PV resource) using an average nominal growth factor of 0.63%. This growth factor was itself calculated separately based on the CAGR of the 2016-2050 NREL ATB capital cost values after applying the "2016 Base Year - DTE Deflator Series" series.[63] This results in a capital cost of $1,480/kW$_{AC}$ for 2023 and $1,489/kW$_{AC}$ for 2024.

Q61. HOW DO THESE VALUES COMPARE TO THE ONES FOUND DIRECTLY IN ATB?

[61] WP LKM-460 NREL Renewable Inputs
[62] WP LKM-448 LCOE
[63] WP LKM-449 Master Tech and Finance Inputs

A61. They are quite a bit higher, as seen below in Figure 5. The use of the 2016-2050 CAGR from the ATB costs hides the sizable decreases that occur in the early years of the schedule. When using NREL's 2.5% inflation value, the 2023 capital cost of $881/kW$_{DC}$ in 2016 dollars converts to $1,362/kW$_{AC}$ in nominal dollars. This is 8.0% lower than DTE's value for the same year. The corresponding 2024 capital cost calculation results in a value of $1,380/kW$_{AC}$ in nominal dollars, which is 7.3% lower than DTE's value.



	2018	2019	2020	2021	2022	2023	2024	2025
LCOE Worksheet	$1,434	$1,444	$1,453	$1,462	$1,471	$1,480	$1,490	$1,499
ATB - NREL Inflation	$1,434	$1,415	$1,365	$1,326	$1,344	$1,362	$1,379	$1,398

Figure 5 - PV Installed Costs

Q62. DOES DTE PROVIDE AN EXPLANATION FOR ITS FAILURE TO MORE DIRECTLY UTILIZE THE ATB VALUES?

A62. Yes, although it is unconvincing. DTE states as its reason the inability of Strategist to "accept non-linear escalations rates" and its desire "to keep the inputs straightforward for the LCOE model and provide Strategist with few alternatives."[64] While I understand that Strategist cannot accept non-linear escalation rates, DTE's decision to peg all future solar to

[64] ELPCDE-1.24f, attached as Exhibit ELP-27 (KL-18).

the 2018 value instead of starting with a year that more closely aligns with actual installations results in solar capital costs that are too high.

DTE also points to its obligation to model runs in which capital costs are 35% lower than the baseline as suggestive that other scenarios may provide insights to a more aggressive solar cost profile.[65] However, costs in the ATB Low scenario (which represent the "limit of surprise" cost reductions) range from 11% to 26% lower than the ATB Mid scenario in 2021 and 2030, respectively. Immediately reducing capital costs by 35% likely overstates the near-term cost reductions that are obtainable by the industry. Further, these reductions are applied to both wind and solar similarly when these technologies are on different cost trend trajectories, and the ET and EP scenarios contain many other changes in assumptions that impact the final modeling results. Simply referring to the ET or EP scenarios' lower solar costs fails to address having more reasonable solar costs in the BAU and REF scenarios. And in any case, the configuration of Strategist to include the starting point renewables and exclude superfluous units means that all of the different scenarios are optimizing for one build event in 2030 with the retirement of Belle River.

Q63. ARE WIND CAPITAL COSTS AFFECTED BY A SIMILAR TREND?

A63. No. The ATB Mid costs for land-based wind in TRG-7 (which contains Michigan) are nearly flat in constant dollars, falling only from $1,632/kW in 2016 to $1,627/kW in 2025. Because there is no steep drop to mask in the near-term, using a constant escalator does not impact wind capital costs in the same way it does solar. I do believe that the use of the NREL 2.5% inflation to inflate from 2016 to 2018 is inappropriate for wind as well as solar, but this produces a very small impact on wind costs.

Q64. WHAT DO YOU RECOMMEND WITH RESPECT TO SOLAR CAPITAL COSTS?

A64. As a primary matter, DTE capital costs should reflect the near-term projected fall in technology prices. DTE claims to use NREL's ATB Mid cost forecast, but then fails to

[65] *Id.*

utilize the actual data in the report. Due to the regulatory schedule of this case, the earliest that solar projects borne from this IRP will likely come online is late 2020 or 2021. These are much more appropriate stating points for analysis than is 2018, and reflect DTE's own believe of solar projects coming online in 2021 (as indicated by their proxy resource title of "Solar 2021-2024").

Given the limitations of Strategist to model non-linear escalation rates, I recommend that DTE model the Solar 2021-2024 resource using an average cost of those years taken directly from the NREL ATB data. For solar beyond 2025, DTE should use the 2025 data point and apply a CAGR based on the 2025-2040 growth trajectory. I will present the results of this calculation below.

DTE's Fixed O&M Costs Assumptions are Inconsistent with Public Data and are Based on an Incorrect Proxy

Q65. WHAT DATA SOURCE DID DTE USE FOR THE LAND-BASED WIND AND SOLAR CAPITAL COSTS?

A65. DTE used the 2018 NREL ATB for these values, although as discussed above it deviated from the actual data found in this document.

Q66. WHAT DATA SOURCE DID DTE USE FOR THE LAND-BASED WIND FIXED O&M COSTS?

A66. It also used the 2018 NREL ATB for this data point.

Q67. DID DTE USE THIS SAME DOCUMENT FOR THE SOLAR FIXED O&M COSTS?

A67. No. Rather than maintain consistency by using the same source for capital costs and fixed O&M costs for solar – despite doing so for wind – the Company instead used a different data source for the solar O&M costs. Specifically, DTE used NREL's 2017 Q1 U.S. Solar Photovoltaic System cost benchmark (Cost Report).[66]

Q68. HOW DID THE FIXED O&M COST ESTIMATE IN THIS REPORT COMPARE TO THE 2018 ATB?

A68. The 2018 nominal value as calculated by the Company from the 2017 Cost Report data was \$24.65/kW_{AC}-year, although it used a value of \$25.00/ kW_{AC}-year in its modeling. This

[66] WP LKM-54 REF Renewable Energy Inputs

compares to a 2018 nominal value from the ATB (using NREL's inflation assumption) of \$12.57/ kW_{AC}-year, which is roughly half of the value assumed by DTE.

Q69. HAS NREL PUBLISHED A MORE UP TO DATE COST REPORT?

A69. Yes. The 2018 Q1 version of the Cost Report was published after DTE commenced its modeling efforts.[67] However, the update is instructive as it shows a sizable 30% reduction in fixed O&M costs in a single year, from \$20.00/kW_{DC}-year in 2017 to \$14.00/kW_{DC}-year.[68] Further, it shows that fixed O&M costs have fallen in half between 2010 and 2018. Despite these obvious trends, DTE uses an already-outdated value as it baseline and increases it further in the future.

Q70. WHY DID THE COMPANY USE AN OUTDATED REPORT RATHER THAN USING THE 2018 ATB?

A70. DTE claims that NREL cited "different methodologies" when it inquired why the values for 2017 from the Cost Report were different from the NREL ATB and that the older data was "more closely aligned with Company experience."[69]

Q71. WHAT IS THE COMPANY'S EXPERIENCE WHEN IT COMES TO SOLAR PV PROJECTS?

A71. The Company owns a fleet of roof- and ground-mount systems. It lists 31 solar plants under ownership, with 20 of these being 503 kW or smaller, 12 between 503 kW and 2 MW, and two larger facilities of 28 MW and 20 MW.[70] The smaller facilities were installed between 2010 and 2017, and the two large facilities opened in May 2017. All of the ground-mount systems are fixed-tilt.[71]

Q72. HOW DO THESE PROJECTS COMPARE TO THOSE PROPOSED IN THE IRP?

A72. They are not comparable. DTE models 50 MW and 100 MW, ground mounted single-axis tracking PV systems that will be installed in 2021 or later. Aside from the economies of

---

[67] NREL 2018. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018, *available at* https://www.nrel.gov/docs/fy19osti/72399.pdf

[68] The 2018 version updated the scope of fixed O&M to include inverter replacements. This is why the 2017 value of \$18.50 from the 2017 Q1 report was updated to \$20.00 in the 2018 Q1 report.

[69] ELPCDE-1.2c, attached as Exhibit ELP-28 (KL-19).

[70] DTE Exhibit A-3 at 61.

[71] ELPCDE-5.55, attached as Exhibit ELP-29 (KL-20).

scale realized through larger projects, the future installation date will allow for continued improvements in O&M cost reductions. DTE's choice to use a higher cost from an older report because it is "more closely aligned with the Company's experience" is arbitrary as the underlying basis is irrelevant to the new solar systems that will be built.

Q73. ARE THERE DIFFERENCES IN BUSINESS MODELS THAT MIGHT DRIVE DIFFERENCES IN FIXED O&M COSTS BETWEEN DTE AND THIRD-PARTY DEVELOPERS?

A73. Yes. As a regulated utility, in addition to earning a return on the underlying solar asset regardless of its performance, DTE is authorized to pass all of its reasonable and prudent operating expenses through to its customers. As such, it does not have a profit motivation to ensure that projects are designed, operated, and maintained in a manner that maximizes output and minimizes costs. By contrast, third-party developers that sign contracts with utilities have a fixed revenue stream via the PPA contract, and thus have every incentive to optimize the project.

If there are cost overruns, the developer – not the utility – is responsible for them. If there are prolonged outages or performance issues, it is the developer – not the utility – that is responsible for them. DTE has a safety backstop where it can pass these costs on to its customers; a third-party with a PPA does not share this luxury. As I discuss later, this is one of several ways in which PPAs will result in lower total costs than utility ownership for solar projects.

Q74. DO NREL'S 2017 AND 2018 COST REPORT AND ATB PRESENT DIFFERENT VALUES FOR FIXED O&M COSTS?

A74. Yes, there are differences in the values between these reports. However, many of these differences are due to differences or changes in methodology, that once understood, can assist in selecting the correct source on which to base forecasts.

The 2017 Cost Report separated out inverter replacement costs from other fixed O&M costs. The 2018 Cost Report incorporated these values directly into the reported fixed O&M cost value, resulting in an upward step between the two reports. Additionally, the

2018 version assumed a lower income tax value of 21% compared to 35% due to the 2017 Tax Cuts and Jobs Act. Given the lower tax rate for corporations is permanently in place, it is appropriate to use the lower 21% rate for tax calculations.

The ATB uses a different methodology to calculate O&M costs. It sets the baseline fixed O&M cost as a fraction of the capital cost, based on data from the Lazard Levelized Cost of Energy report. This fraction is mostly held constant, so as capital costs fall, O&M costs fall as well. This is supported by historic data showing that these cost categories are correlated.[72]

Q75. DOES THE ATB INCLUDE DISCUSSION OF FUTURE TRENDS THAT MIGHT IMPACT FIXED O&M COSTS?

A75. Yes. When discussing its projections of fixed O&M for solar, the ATB states:

> O&M cost reductions are likely to be achieved over the next decade by a transition from manual and reactive O&M to semi-automated and fully automated O&M where possible. While many of these tasks are very site and region specific, emerging technologies have the potential to reduce the total O&M costs across all systems. For example, automated processes of sensors, monitors, remote-controlled resets, and drones to perform operations have the potential to allow O&M on PV systems to operate more efficiently at lower cost.[73]

Q76. WHAT VALUE DOES THE LAZARD LEVELIZED COST OF ENERGY REPORT USE?

A76. The Lazard Levelized Cost of Energy is an oft-cited analysis that compares costs of various technologies on an apples-to-apples basis. In the most recent version from 2018, Lazard uses a value of \$9.00 to \$12.00/kW$_{AC}$-year for its fixed O&M costs.[74] The higher value corresponds to a utility-scale single-axis tracker system, and closely corresponds to the 2018 ATB value of \$12.45/kW$_{AC}$-year. Given the proximity of these figures, the discussion of future improvements in O&M, and the outdated tax assumption from the 2017 Cost Report, it is more reasonable to use the fixed O&M values from the 2018 ATB.

---

[72] Utility-Scale PV, NREL, https://atb.nrel.gov/electricity/2018/index.html?t=su
[73] *Id.*
[74] *Lazard's Levelized Cost of Energy Analysis—Version 12.0* at 16, LAZARD, https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf.

Q77. IS THERE OTHER INFORMATION FROM THE LAZARD REPORT THAT SUPPORTS THIS CONCLUSION?

A77. Yes. When calculating the LCOE of unsubsidized utility-scale systems, Lazard shows that fixed O&M costs range from roughly 10-11% of the total unsubsidized LCOE.[75] By contrast, DTE's fixed O&M is projected to comprise 22.6% of the total unsubsidized LCOE, more than twice as much.[76] Further, comparing the absolute value of this component of $4.00-5.00/MWh from Lazard to the $18.00/MWh from DTE shows how far afield the Company's fixed O&M projection is.

Q78. WHAT VALUE DOES DTE USE FOR FIXED O&M ESCALATION?

A78. It uses the average growth rate from the 2016 DTE deflator series of 2.13%. Unlike the capital cost growth factor, which DTE based on the underlying ATB cost projections and thus accounted for technological improvement, the Company simply assumed that O&M costs would increase with general inflation. This ignores all the innovation in this space and likely overstates future fixed O&M costs.

Q79. WHEN THE 2018 ATB FIXED O&M VALUE IS USED DIRECTLY IN DTE'S LCOE WORKSHEET, HOW DO THE RESULTS COMPARE?

A79. Using my updated 2023 projections of capital and fixed O&M costs and a corrected fixed O&M escalator, I calculate a new *unsubsidized* LCOE of $59.42/MWh, with $6.07/MWh of that from fixed O&M. This represents 10.2% of the total, right in line with Lazard's estimates. DTE's choice of fixed O&M cost and escalation rate substantially overstates the impact of this cost component when compared to other reliable resources.

DTE Incorrectly Applies an Inflation Adjustment, Further Overstating Solar Costs

Q80. WHAT IS THE DOLLAR BASIS FOR EACH OF THE MAIN DATA SOURCES THAT DTE USES FOR SOLAR CAPITAL AND O&M COSTS?

---

[75] $4/MWh out of $40/MWh for the low-end estimate, and $5/MWh out of $46/MWh for the high-end estimate. Id at 12.

[76] $18.00/MWh out of $79.68/MWh. LKM-448 LCOE tab 'LCOE Chart'.

A80. The 2018 ATB, 2017 Cost Report, and 2018 Cost Report use a dollar basis of 2016, 2017, and 2018, respectively, and report all values in real dollar terms. In order to convert all of these values to the same dollar basis, one must select a convention and adjust all values for inflation. DTE has chosen a convention of nominal dollars with a 2018 baseline for its LCOE model.

Q81. How does DTE convert the 2018 ATB and 2017 Cost Report values from 2016 and 2017 real dollars to 2018 nominal dollars?

A81. DTE converts the capital costs from the 2018 ATB from 2016 to 2018 and the fixed O&M costs from the 2017 Cost Report using NREL's inflation assumption of 2.5%.[77]

Q82. How does DTE inflate the 2018 values to the 2023 and 2024 values used in the LCOE workpaper?

A82. For the capital cost assumptions, DTE takes the 2016 real values from the ATB and inflates them using the 2016 DTE Deflator series. It then calculates a constant CAGR from 2018 to 2050, which, as discussed before, masks the near-term fall in capital costs found in the underlying ATB data.[78] This nominal CAGR of 0.633% is used to escalate capital costs from 2018 to either 2023 or 2024 in the LCOE workpaper.

For the fixed O&M values, DTE uses a simple average of the year-to-year changes in the 2018 PACE Deflator series from 2018 to 2040 to produce a value of nominal escalation rate of 2.13% per year. This value is applied to the 2018 starting point to produced fixed O&M costs for 2023 and 2024 in the LCOE workpaper.

Q83. Why does DTE use three different inflation values in its analysis?

A83. It is unclear. Given that the underlying data was presented in real dollars (albeit with differing base years), it would have been most appropriate to inflate and escalate all of the

[77] WP LKM-54 REF Renewable Energy Inputs
[78] WP LKM-449 Master Tech and Financial Inputs

values using the same deflator series. Further, DTE should use the same deflator series for these values that it uses for all other values in the modeling.

Q84. IS THE USE OF THE NREL 2.5% ASSUMPTION APPROPRIATE?

A84. No. There is no justification for using NREL's values for 2016 to 2018 and then switching to a different CPI-based escalator series for 2018 and beyond. The flat 2.5% inflation assumption from NREL is inappropriate to use in DTE's modeling unless it believes that a flat inflation value of 2.5% is the right value to use for all of its assumptions. Clearly, DTE does not believe this to be the case as it uses two other deflator series that contain year-to-year variation based on the consumer price index. In fact, DTE acknowledges this as stated in Company witness Paul's testimony, where he states:

> Values for years beyond 2018 were escalated based on a governmental Consumer Price Index (CPI) utilizing 2018 as the base year. The use of this inflation mechanism is consistent with the IRP modeling process and is more fully described by Company Witness Mikulan in Exhibit A-4 section 17 of the IRP report.[79]

The 2016 DTE deflator series has values of 2.13% and 2.27% for inflation in 2017 and 2018, respectively. The 2018 PACE deflator series has values of 1.73% and 2.3% in 2017 and 2018, respectively.[80] Put together, these two series would apply a 4.4% or 4.1% adder for the 2016 DTE and 2018 PACE deflator series, respectively, when converting 2016 dollars to 2018 dollars. By contrast, applying the NREL inflation value of 2.5% for two years results in an adder of 5.1%. Although small, it does overstate the starting point of the 2018 costs used in subsequent modeling.

DTE's Modeling Assumes No Technological Progress in Solar and Underestimates Solar Capacity Factor

Q85. HOW DOES DTE CALCULATE THE CAPACITY FACTOR FOR ITS SOLAR FACILITIES?

A85. DTE's testimony and workpapers contain conflicting information. Company witness Schroeder states "DTE Electric expects future solar parks to operate at a 22.9% NCF based

[79] Paul Direct at 18-19.
[80] *Id*.

on the NREL's 2018 ATB forecasts for Chicago – Mid for single-axis tracker solar arrays."[81] This value is derived by assuming an initial DC capacity factor of 18.9%, multiplying by 1.3 (the ILR), degrading by 0.5% annually, and finally taking the average between 2020 and 2049 to produce the 22.9% value.[82] However, the LOCE workpapers used to calculate the revenue requirement use a different value of 22.5%.[83] There is no data source for this value, nor any explanation for why it differs from the other workpapers.

Q86. DID DTE HAVE AN EXPLANATION FOR THIS DISCREPANCY?

A86. DTE indicated that the 22.5% value was an older assumption that was utilized earlier in the process for the LCOE screen and stated that the updated value of 22.9% was used for Strategist modeling.[84]

Q87. HOW DOES THIS ISSUE IMPACT THE LCOE OF MODELED PV?

A87. Leaving all other values in place, the 22.5% capacity factor produces a PV LCOE of $69.48/MWh. Increasing the value to 22.9% reduces the LCOE to $68.36/MWh.[85]

Q88. WHAT ARE SOME AREAS OF INDUSTRY RESEARCH AND DEVELOPMENT TO IMPROVE THE OVERALL PERFORMANCE OF SOLAR INSTALLATIONS?

A88. In addition to the general trend of cost reductions that has been created through economies of scale and maturation of the industry, there are several technological improvements that will further increase the efficiency and lower costs of future installations. Over the past five years, single-axis trackers have quickly become dominant for utility-scale projects. Just two years ago, DTE modeled only fixed-tilt systems in its U-18419 CON application, but now it has caught up to the market and is only modeling single-axis tracking systems.

While it is appropriate to assume tracking systems in its modeling, DTE does not assume technology improvements in panel degradation will occur between now and the end

[81] Schroeder Direct at 21.
[82] WP LKM-37 REF Renewable Capacity and Energy Calculation
[83] WP LKM-448 LCOE
[84] ELPCDE-6.56b, attached as Exhibit ELP-30 (KL-21).
[85] WP LKM-448 LCOE

of the modeling period. Instead, it assumes a constant 0.5% annual degradation for its panels, regardless of the start year of the project. Research continues into ways to reduce panel degradation where even small changes compound over the 30+ year lifespan of a project. In fact, there are panels on the market today that have a warrantied average annual degradation of 0.35% after 25 years.[86]

Further, scientists recently announced a solution to a long-standing issue that caused PV panels to immediately degrade once placed into service. This issue, called light induced degradation (LID), causes PV panels to lose about 10% of its rated output (for instance, falling from 20% efficiency to 18% efficiency) in the first hours after being installed.[87] This is separate from the annual degradation that occurs as panels age. Now that the source for this initial degradation has been identified, engineering solutions can be devised that will reduce or offset this initial drop in panel efficiency. By maintaining a higher starting point, this breakthrough could lead to panels that maintain more of their output over their lifetime.

Q89. DOES DOE'S SUNSHOT 2030 TARGET PANEL DEGRADATION?

A89. Yes. DOE is targeting to extend the lifespan of panels from 30 years to 50 years and to decrease the annual degradation to 0.2% annually.[88] If one were to attain this low level of panel degradation, PV systems would still retain 94.4% of their output after 30 years, compared to retaining 86.5% of their output under a 0.5% annual degradation.

Q90. THESE IMPROVEMENT AND BREAKTHROUGHS REMAIN HYPOTHETICAL TODAY. SHOULD THEY BE INCLUDED IN DTE'S MODELING?

A90. Reductions in panel degradation do not necessarily need to be considered in this IRP cycle, but DTE should revisit these assumptions in the next IRP, similar to how DTE revisited its assumption about fixed-tilt vs. single tracker PV systems. However, these examples

---

[86] SUNPOWER, https://us.sunpower.com/commercial-solar/products/panel-warranty (last visited Aug. 21, 2019).
[87] *Solar cell defect mystery solved after decades of global effort*, PHYS, https://phys.org/news/2019-06-solar-cell-defect-mystery-decades.html.
[88] *SunShot Initiative 2030 Goals Paper and Graphics*, ENERGY.gov, https://www.energy.gov/eere/solar/downloads/sunshot-initiative-2030-goals-paper-and-graphics

demonstrate how conservative DTE's solar assumptions are. There is no reason to expect technological progress on solar to stop, and every reason to believe that panels that are actually installed in 2024 and beyond will be superior to today's models. That said, it is absolutely the case that DTE should, at a minimum, model the degradation rate of commercially available PV panels today.

Q91. IF ONE WERE TO MODEL THE LOWER ANNUAL DEGRADATION THAT IS ALREADY AVAILABLE ON COMMERCIAL PANELS TODAY, HOW WOULD THIS IMPACT THE CAPACITY FACTOR VALUE THAT DTE USES?

A91. Since panel degradation compounds over time, even a small drop from 0.5% per year to 0.35% per year has an impact. Had DTE used this value, the 22.9% capacity factor would have increased to 23.4%.

Q92. WHAT IS THE IMPACT ON THE LCOE FROM MAKING THIS CHANGE?

A92. Leaving all other values in place, using the 23.4% capacity factor would reduce the LCOE to $66.87/MWh

Q93. HYPOTHETICALLY, IF ONE WERE TO MODEL THE DOE SUNSHOT GOAL OF 0.2% DEGRADATION, HOW WOULD THIS IMPACT THE LCOE?

A93. Leaving all other values in place, this would produce a capacity factor of 23.9%, which would result in an LCOE of $65.50/MWh, nearly 6% lower than the value that DTE calculates. This shows the importance of small changes in this critical value.

Q94. DOES DTE ASSUME TECHNOLOGICAL PROGRESS IN ITS MODELING OF WIND RESOURCES?

A94. Yes. While DTE uses only two solar resources (one with the ITC and one without), the Company models five different wind resources (one for each year of 2021 to 2024 and one for 2025 and beyond). While this may have been done primarily to capture the decline in the federal production tax credit, DTE also increased the capacity factor in successive years. Systems coming online in 2021 were assigned a 33.9% capacity factor. This value increases over time, with systems installed in 2025 and beyond assigned a 38.7% capacity factor. In other words, DTE assumes that the specific output of wind will increase 14% in five years.

Q95. DO YOU DISAGREE WITH THESE VALUES?

A95. I have no reason to disagree with these values. Just like the solar industry, the wind industry continues to innovate. Taller hub heights and longer blades are increasing generation and driving down production costs. Research is ongoing in how to reduce blade deterioration and erosion over time. These improvements are enabling the wind industry to extract more energy in an area with a given resource and build in areas with lower wind resources that were not previously viable. My issue is not with DTE's acknowledging and incorporating these trends from the wind industry, but rather failing to incorporate similar improvements in the solar industry.

When These Costs are Corrected, Solar Becomes a Least-Cost Resource

Q96. HOW DOES THE COMBINATION OF THESE ASSUMPTIONS IMPACT THE PV VALUES USED IN DTE'S MODELING?

A96. Each of the assumptions produces a small reduction, which when aggregated together, results in PV becoming a low-cost resource. Using DTE's LCOE workpaper, I made adjustments to each of the values shown in Tables 1 (with the ITC) and 2 (without the ITC) below:

Variable	Original Value	Updated Value	LCOE ($/MWh)
2021-2024 – 30% ITC			**$69.48**
Use ATB Capital Costs for 2023	$1,480/kW	$1,353/kW	$64.77
Correct Capital Cost Inflation	$1,353/kW	$1,330/kW	$63.97
Use ATB Fixed O&M Costs for 2024	$28.36/kW-year	$11.54/kW-year	$53.30
Correct O&M Inflation	$11.54/kW-year	$11.36/kW-year	$53.10
Correct O&M Escalation	2.13%	0.63%	$52.05
Correct degradation/CF per Testimony	22.5%	22.9%	$51.14
Use 2018 available degradation/CF	22.9%	23.4%	$50.09
Final Value			$50.09
Final Reduction			27.9%

Table 1 - LCOE Stepdown for 2021-2024 Solar with 30% ITC

Variable	Original Value	Updated Value	LCOE ($/MWh)
2025-2040 – 10% ITC			**$77.04**
Use ATB Capital Costs for 2024	$1,489.34	$1,379.72	$72.60
Correct Capital Cost Inflation	$1,379.72	$1,352.44	$71.52
Use ATB Fixed O&M Costs for 2025	$28.97/kW-year	$11.70/kW-year	$60.75
Correct O&M Inflation	$11.70/kW-year	$11.47/kW-year	$60.42
Correct O&M Escalation	2.13%	0.63%	$59.34
Correct degradation/CF per Testimony	22.5%	22.9%	$58.31
Use 2018 available degradation/CF	22.9%	23.4%	$57.11
Final Value			$57.11
Final Reduction			25.9%

Table 2 - LCOE Stepdown for 2025-2040 Solar with 10% ITC

Individually, the reduction of the capital cost and the fixed O&M costs make the largest impact on the LCOE. However, the smaller adjustments that come from correcting escalation rates add up to a non-trivial amount. All told, the LCOE for the 30% ITC scenario falls nearly 28%, while the LCOE for the 10% ITC scenario falls almost 26%.

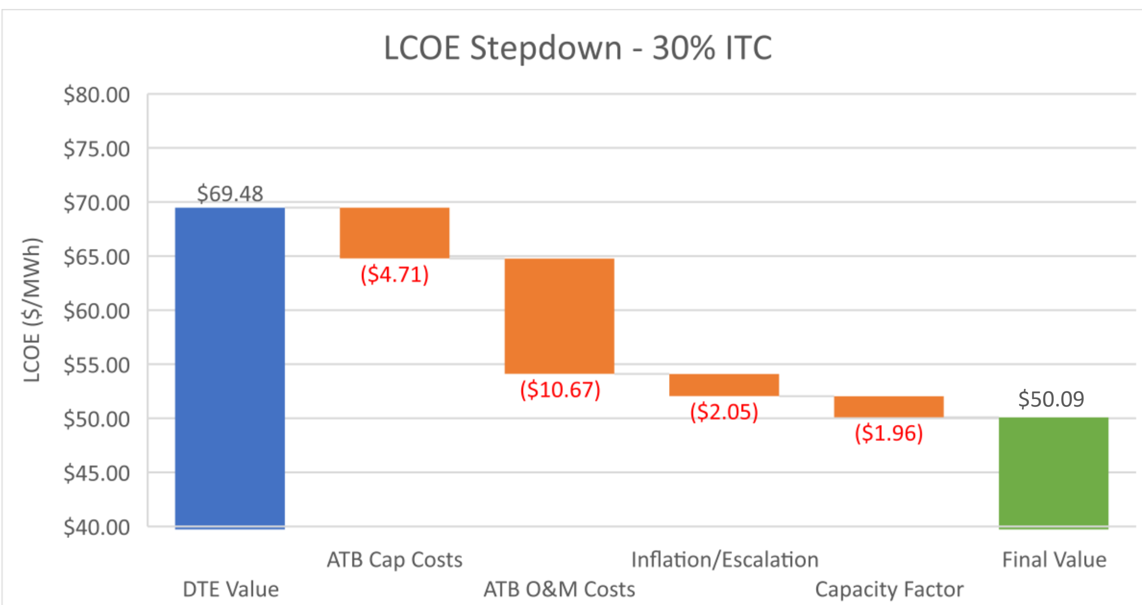


Figure 6 - LCOE Stepdown - 30% ITC

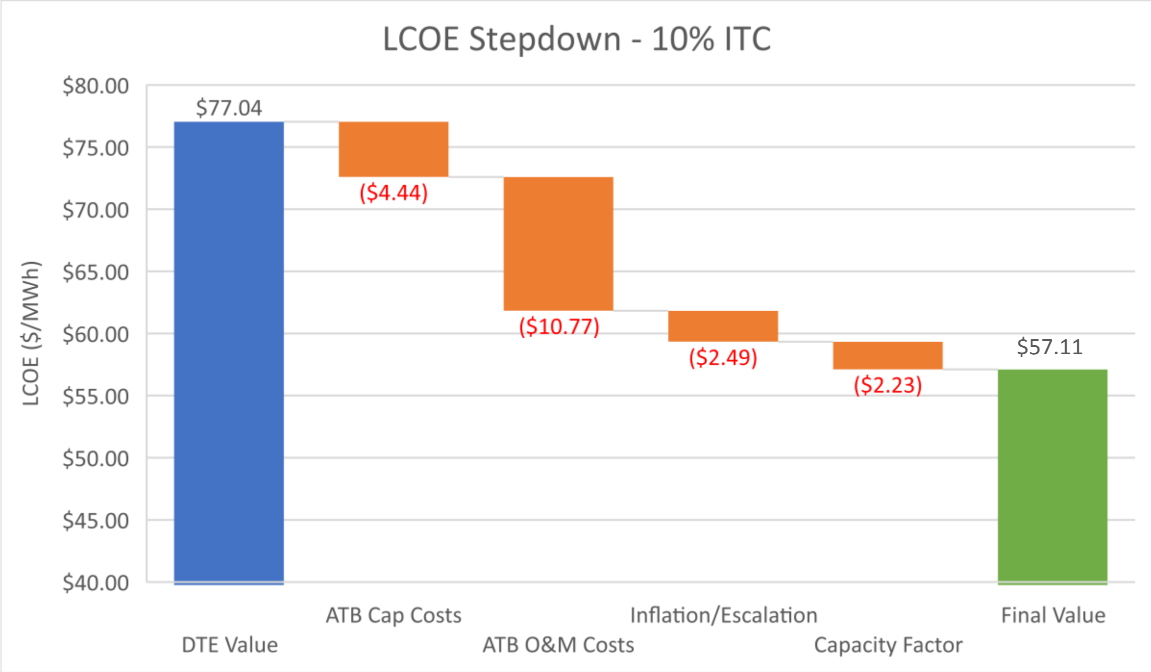


Figure 7 - LCOE Stepdown - 10% ITC

Q97. HOW DO THESE VALUES COMPARED TO THE LCOE OF OTHER TECHNOLOGIES THAT WERE MODELED?

A97. With these appropriate and reasonable adjustments, near-term solar PV becomes the lowest-cost resource for both energy and capacity needs as seen in Figure 8 below. Even after the ITC falls from 30% to 10%, solar PV remains cost-competitive with the BWEC (DTECC below), cheaper than new NGCC, and still provides lower-cost capacity than the modeled Advanced CT.

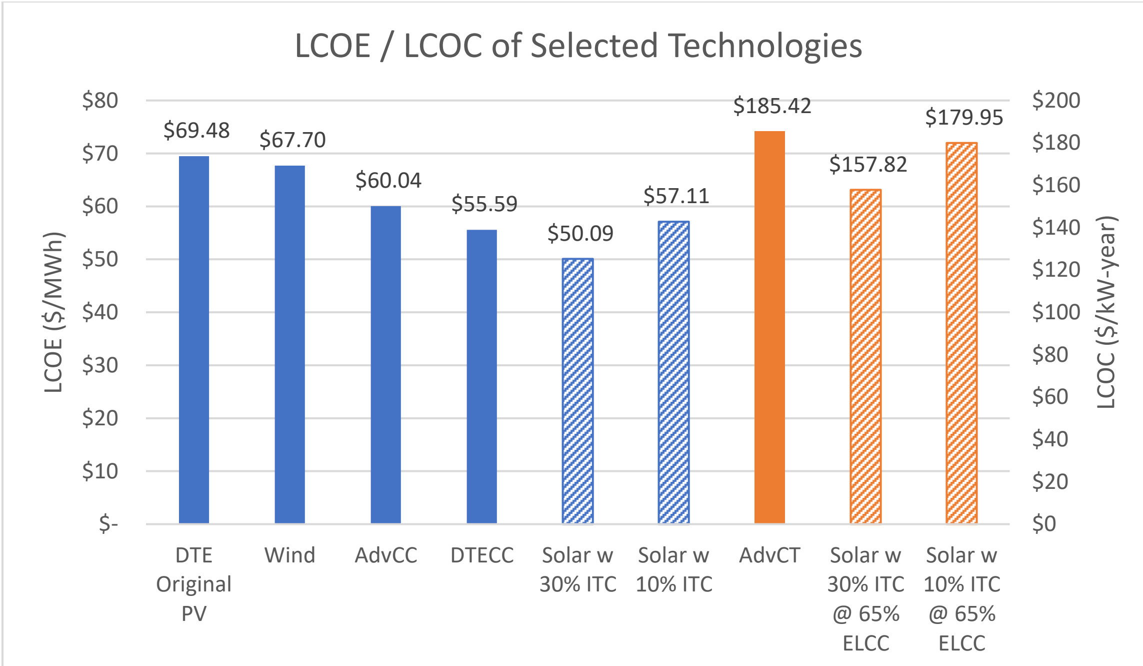


Figure 8 - LCOE and LCOC of Selected Technologies

Q98. HOW DO THESE ISSUES AFFECT THE COST OF PV AS MODELED IN STRATEGIST?

A98. While the LCOE and LCOC is useful for comparing the relative costs of PV to other technologies, Strategist incorporates solar costs through a revenue requirement. Some of the problems above (such as capital costs) directly affect the revenue requirement value, while other issues (such as capacity factor or degradation) only affect the LCOE.[89]

DTE's original 2018 revenue requirement for solar with and without the ITC was $83,031/kW and $91,335/kW, respectively. These values were escalated at a constant annual rate of 0.93% which reflects DTE's blend of and escalation rates for capital and O&M costs. By contrast, after the updates, the 2018 revenue requirement fell by 23.4% to $63,575/kW with the ITC and by 21.1% to $72,031/kW without the ITC. These values are then only escalated at 0.63%, which reflects the relative reduction of O&M costs compared to DTE's figures. This further reduces the revenue requirement in future years compared to DTE's original values by reducing the annual increase in costs.

[89] This is because the LCOE is effectively the total cost divided by the total generation. The more generation a project produces, the lower the cost per unit of generation; however, the total costs do not change.

Q99. WHAT CONCLUSIONS DO YOU DRAW FROM THIS ANALYSIS?

A99. DTE's PCA builds only 11 MW of solar projects (as part of solar + storage pilots) inside the 30% ITC window. It does not propose any large-scale solar systems until 2025, and only ramps up to substantial annual capacity additions in 2031.[90] DTE indicates that the choice to essentially ignore solar in the defined PCA period was not influenced by the Strategist or PROMOD runs in this docket, but was instead based on projected LCOEs of solar and wind technologies from its March 2018 Renewable Energy Plan filing.[91]

By relying on out-of-date assumptions from a previous case rather than robustly refreshing its analysis of solar costs, DTE has failed to reset its prior assumptions on the near-term costs of renewable energy. In doing so, the Company has ignored the substantial near-term reduction in solar capital and O&M costs that is embedded in the 2018 ATB data. Had it performed a more robust analysis, the Company would have had better data on which to determine its near-term renewable buildout plan.

The analysis that DTE did perform substantially overstates the costs of solar PV – even before considering the additional costs that utility ownership imposes. By failing to appropriately use the data sources it claims to use for capital costs, by arbitrarily selecting out-of-date fixed O&M costs, by misapplying inflation and escalation rates to these figures, and by failing to model currently-available degradation rates, DTE inflates solar LCOEs by 35% to 39%. This translates into an overstatement of revenue requirements in Strategist, which could cause the model to select less solar than is optimal or increase costs for modeling runs that do select solar. These results could have influenced the Company to update its previous renewable energy assumptions for its near-term buildout.

---

[90] WP LKM-4 PCA Renewable Capacity and Energy Calculation
[91] ELPCDE-13.88a, attached as Exhibit ELP-15 (KL-6).

DTE's ELCC Assumptions are Premature and Based on Fixed-Tilt Systems rather than Single-Axis Tracking Systems

Q100. WHAT IS ELCC AND WHY IS IT SIGNIFICANT?

A100. The effective load carrying capability (ELCC) is a measure of how well resources can meet the peaks in system load. For intermitted generation such as solar and wind, the ELCC is multiplied by the system rating to determine how many zonal resource credits (ZRCs) a unit is credited in the MISO resource adequacy construct. MISO currently employs a different methodology for wind and solar, but is evaluating changing the solar methodology to reflect the change in solar's ability to meet peak load as additional solar is added to the MISO grid.

Q101. WHAT IS THE CURRENTLY APPROVED METHODOLOGY FOR CALCULATING SOLAR ELCC?

A101. MISO bases the calculation on the average performance of a PV system from 3-6 PM EDT during June, July, and August of the three previous years.[92] The default value for a system that has not established this performance level is 50%. For new systems without 30 days of consecutive summer operation, only the first year will be set at the default of 50% ELCC, with the second year's ELCC based on the historic performance of the first year and the third year's ELCC based on the average performance of the first two years' of historic performance.

For new systems with 30 days of consecutive summer operation, the unit will not receive the 50% default but instead will use that summer's data to set the ELCC for the first year, and will use the average output of the first and second year for the second year's ELCC, and so on until three years of rolling performance data is available.[93] Under this approach, new tracking systems can have at most one year where their ELCC is 50% based on the

[92] From the MISO Resource Adequacy Business Practice Manual BPM-011r21 (Effective 2/20/2019): "Solar photovoltaic (PV) resources will have their annual UCAP value determined based on the 3 year historical average output of the resource for hours ending 15, 16, and 17 EST for the most recent Summer months (June, July, and August)." Manual at 4.2.3.1. Available at https://www.misoenergy.org/legal/business-practice-manuals/

[93] Manual at 4.2.3.1 and Appendix V. Available at https://www.misoenergy.org/legal/business-practice-manuals/

system-wide default value. All subsequent values will be based on actual performance, which likely will substantially exceed 50%.

Q102. HOW DID DTE MODEL SOLAR ELCC IN ITS IRP?

A102. DTE used a 50% ELCC value until 2024, at which point the ELCC was stepped down 2% per year until it reached 30% in 2033, where it remained for the balance of the evaluation period.[94]

Q103. IS THE 50% ELCC THE CORRECT STARTING POINT FOR THE TYPES OF SYSTEMS THAT DTE PROPOSES?

A103. No. The 50% ELCC may be an appropriate default for fixed-tilt systems but is inappropriate for single-axis tracking systems. I confirmed with MISO personnel that the 50% value corresponds to fixed-tilt systems and not single-axis tracking systems.[95] Further, the only way a new tracker system can be assigned the 50% value is if it does not have 30 consecutive days of summer operation, and then the 50% value only applies for one year. As I have demonstrated above, single-axis tracking systems perform substantially better during summer afternoons and will rapidly exceed the 50% default. Using TMY data from the better sites in Michigan produced an ELCC under MISO's current methodology of 65.8%. This means that single-axis trackers earn over 30% more capacity credit than do fixed-tilt systems.

Q104. HAS MISO APPROVED AN UPDATED METHODOLOGY THAT INCLUDES A STEP-DOWN IN THE ELCC VALUE?

A104. No. The methodology that DTE implemented in its modeling continues to be under discussion at MISO.[96] DTE's inclusion of the step down based on initial workgroup discussions is premature. Further, in MISO's analysis, the ELCC step-down rate is a function of solar penetration. However, DTE has on its own defined the timeline over which penetration levels might increase to produce the corresponding drop in ELCC.

[94] WP LKM-37 REF Renewable Capacity and Energy Calculation
[95] Lucas MISO communication, attached as Exhibit ELP-31 (KL-22).
[96] See e.g https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment

Q105. DID DTE PERFORM ANY ANALYSES ON THE VALIDITY OF THE ELCC DECLINE ASSUMPTIONS?

A105. No, it did not.[97] DTE's only support of this decision is a statement that "[t]his practice is consistent with MISO forecasts of declining solar ELCC."[98]

Q106. HOW DO YOU RECOMMEND DTE MODEL THE ELCC?

A106. DTE should change its ELCC methodology. The Company's decision to model single-axis tracking systems at the 50% level, despite this value being based on fixed-tilt and only available for a system for one year, and then stepping down this value based on an unapproved MISO methodology based on its own arbitrary timeline is entirely unsupported.

Instead, DTE should model the ELCC at 65.8%, consistent with well-performing sites across the Lower Peninsula. If the Commission feels that MISO is more likely than not to implement its step-down methodology, then it can direct DTE to use a step-down from this higher starting point. However, it is unclear whether the ELCC of single-axis trackers will degrade in the same way as fixed-tilt systems given their ability to produce power at later hours.

Despite its Claim to Model Single-Axis Tracking Systems, DTE Has In Fact Modeled Fixed-Tilt Systems

Q107. WHAT TYPES OF SOLAR SYSTEMS DID DTE CONSIDER IN ITS IRP?

A107. DTE considered both fixed-tilt and single-axis solar PV tracking systems along with solar thermal in its initial technology screen, but ultimately determined that single-axis tracking systems were the most cost-effective of the solar technologies.[99] All subsequent discussion and modeling of solar from the Company assumed that single-axis tracking systems with a 1.3 ILR would be utilized.[100]

[97] ABDE-2.11b, attached as Exhibit ELP-32 (KL-23).
[98] Mikulan Direct at 50.
[99] Exhibit A-4.
[100] Schroeder Direct at 21.

Q108. DID YOU ANALYZE THE UNDERLYING SOLAR GENERATION DATA THAT DTE USED IN ITS IRP?

A108. Yes. I found three different Company data sources that showed hourly solar production. The first was WP LKM-19 REF PCA PROMOD Inputs, which contained a full 8,760 solar generation profile. The second was extracted from the reference Strategist files and contained a 168-hour (one-week) generation profile for each month of the year. The final was contained in workpaper JWC-02 of Brattle Group witness Chang and represented an average of six different Michigan locations. I also analyzed hourly generation profiles from NREL's SAM model for both fixed-tilt and single-axis tracking systems using TMY data for the same six locations to remain consistent with DTE's weather information approach.[101]

Q109. WHAT DID YOU FIND FROM THIS ANALYSIS?

A109. All three DTE hourly generation data sources appear to model fixed-tilt systems rather than single-axis tracking systems. Further, all three DTE sources were inconsistent with each other in a manner that suggested that different models or input values were used to produce the data for each generation profile.

Q110. HOW DID YOU ARRIVE AT THIS CONCLUSION?

A110. In response to a data request, DTE provided the SAM data file used by the Brattle Group.[102] This file clearly shows that a fixed-tilt system with a 1.2 ILR was simulated. The Brattle Group report states "[w]e model generation for all of Zone 7 based on current generating units and assume additions/retirements reported in DTE's IRP and Consumers Energy's PCA" and notes that its cases "closely align[] with DTE's PCA Pathway[s]".[103]

---

[101] For single-axis tracking systems, I used the PVWatts model in SAM with a DC to AC ratio of 1.3, Inverter size set to 10 MW_{AC}, Array Type set to 1 Axis Tracking, Tilt set to 0 degrees (horizontal), and Azimuth set to 180 degrees. All other values were left as defaults. For fixed-tilt systems, I used the PVWatts model in SAM with a DC to AC ratio of 1.2, Inverter size set to 10 MW_{AC}, Array Type set to Fixed Open Rack, Tilt set to 33 degrees, and Azimuth set to 180 degrees. These values match the default values from SAM 2017.9.5 that DTE used in its modeling.

[102] ELPCDE-9.76d Supplemental, attached as Exhibit ELP-33 (KL-24).

[103] Exhibit A-47 at 13-14.

DTE also provided a PVSYST report representing the parameters that was used to generate the PROMOD and Strategist generation profiles.[104] DTE indicated that the Strategist generation profile was derived from the underlying PROMOD profile.[105] This report shows a south-facing, fixed-tilt system with a 30-degree tilt.

DTE's IRP narrative repeatedly indicated that it used single-axis tracking systems with 1.3 ILR, so the use of a fixed-tilt system with a lower ILR in its modeling is clearly inconsistent. This affected Strategist and PROMOD modeling that formed the basis of the PCA, as well as the Brattle Group's analysis on renewable integration.

Q111. DID YOU EVALUATE THE UNDERLYING DATA AS WELL?

A111. Yes. After inspecting the hourly generation profile of the different sources, I confirmed that the monthly generation profile of each of DTE's three sources more closely matched the generation profile of the SAM fixed-tilt data than the SAM single-axis tracking data. Further, telltale characteristics found in single-axis tracking system output (such as lower peak values in winter and wider "shoulders" in summer) were notably lacking from DTE's data. The difference in generation in late afternoon hours is quite large between the data sets, suggesting that the impact on the analyses could be meaningful.

Figure 9 below shows the average generation profiles for the month of February for each source. The three DTE profiles and the SAM fixed tilt profile are similar, reaching peak output in the 50-60% range. Despite it being winter, this is possible as panels in fixed-tilt systems are pointed towards the south and capture more direct light from the low sun. By contrast, the panels on single-axis tracking systems are horizontal and experience a much larger angle of incidence from sunlight during winter months, reducing their peak power output. This is clear in the SAM 1 Axis line where the panel attains a peak output of 44% of its rated capacity.

---

[104] ELPCDE-12.81a, attached as Exhibit ELP-34 (KL-25), ELPCDE-12.82b, attached as Exhibit ELP-35 (KL-26).
[105] Id.

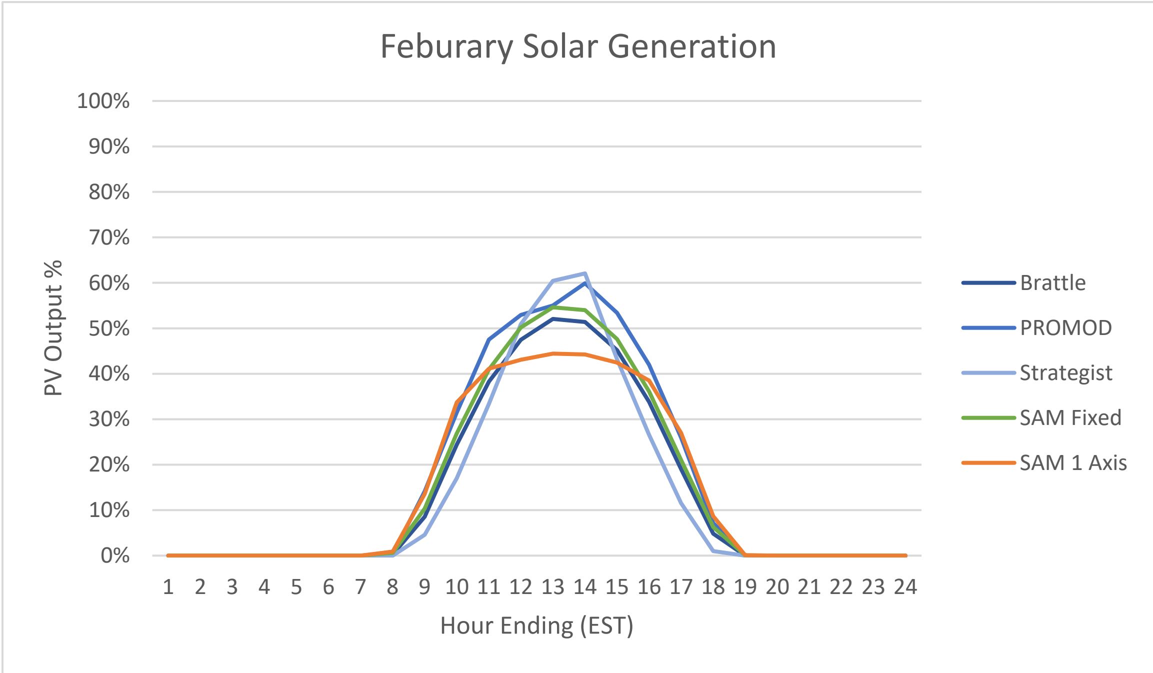


Figure 9 - February PV Generation Profile

The differences in June in Figure 10 are even more stark. As daylight increases in duration, and the sun gets higher in the sky, the horizontal orientation of the single-axis tracker system becomes a benefit. Further, the ability to follow the sun through the daylight hours shows up as a substantial increase in morning and afternoon production. The tracker outputs comparable levels of power two hours earlier and two hours later than fixed-tilt systems. Again, DTE's three data sources align much more closely with the SAM fixed-tilt data set and diverge significantly from the single-axis tracker.

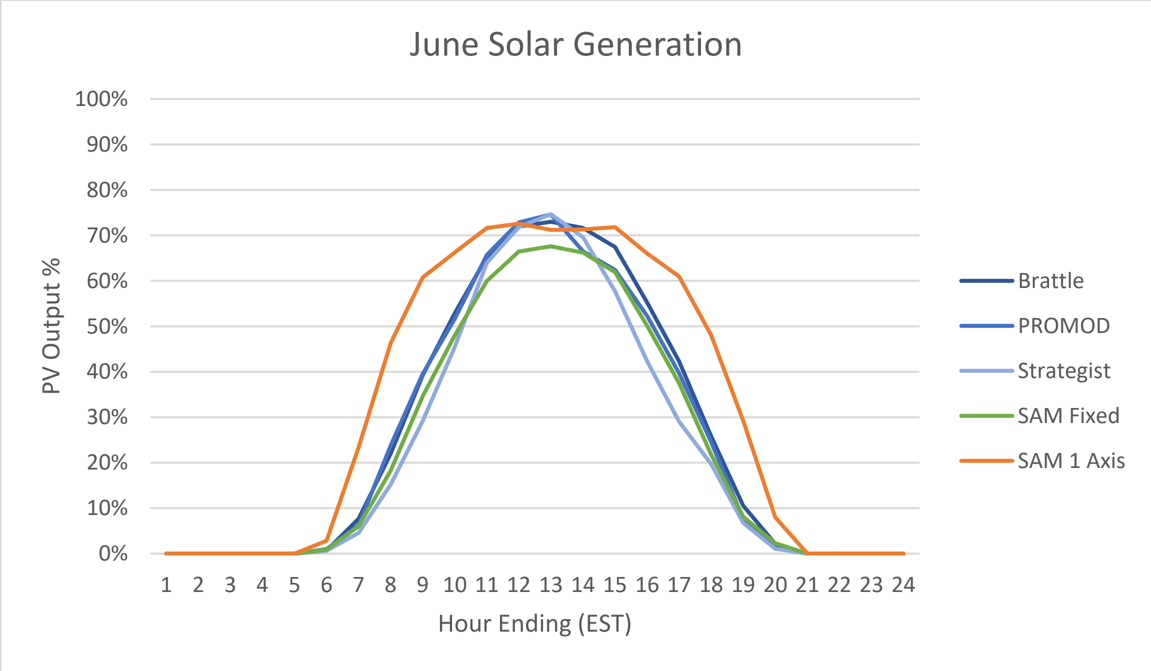


Figure 10 - June PV Generation Profiles

Finally, when comparing the average annual profile in Figure 11, the distinction remains. By averaging each month, the shape of the three DTE data sets and the SAM fixed tilt converge, while the profile of the SAM single-axis remains clearly distinct. It appears clear from this data that DTE did not in fact include single-axis tracking systems in its modeling.

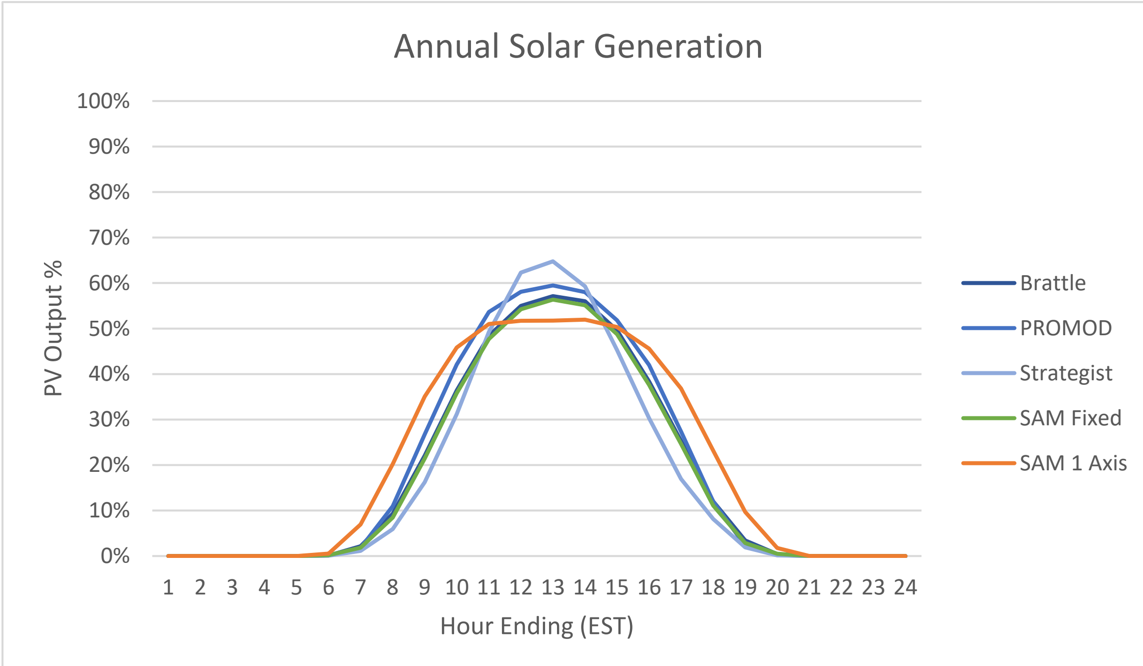


Figure 11 - Annual PV Generation Profiles

Q112. WHAT IS THE IMPLICATION OF THIS OVERSIGHT?

A112. The incremental generation from single-axis trackers over fixed-tilt systems for summer months is shown below in Figure 12 and highlights the substantial additional generation in the late afternoon hours. Failing to properly model these systems will have several likely impacts on DTE's modeling.

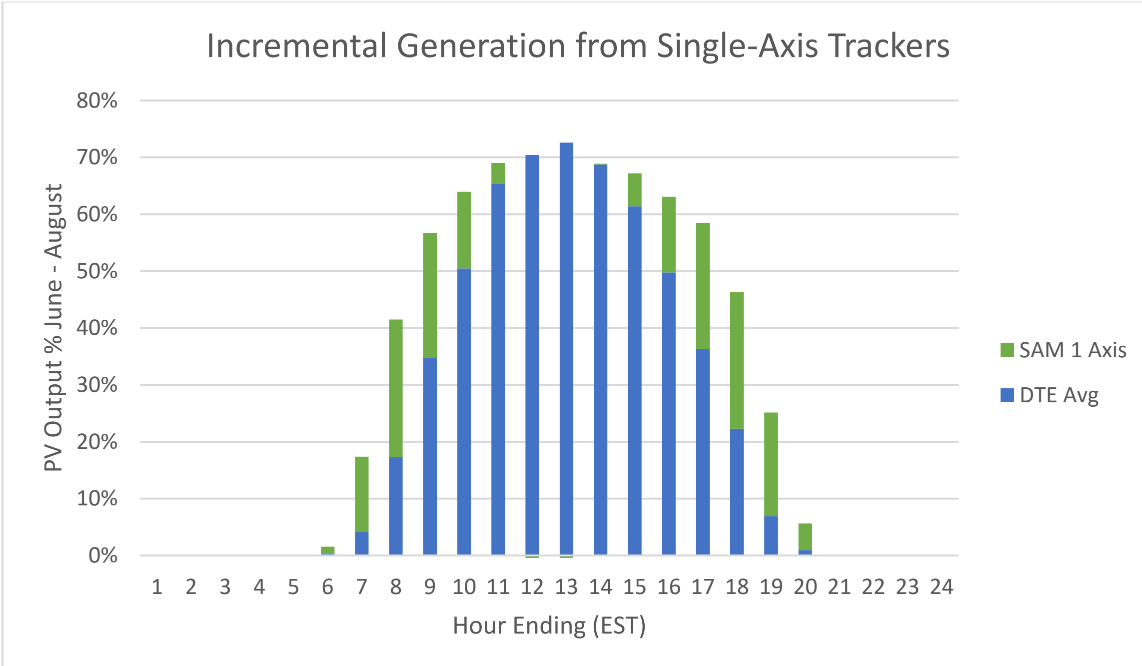


Figure 12 - Incremental Generation from Single-Axis Trackers

First, the annual generation for fixed-tilt systems is consistently lower than for single-axis tracking systems. DTE modeled a levelized capacity factor for single-axis trackers at 22.5% (which as discussed previously is likely conservative), more than 20% higher than its value of 18.5% for fixed-tilt.[106] This means that annual solar generation is reduced by almost 20%, which reduces the corresponding revenue from market sales of solar energy by roughly 20%. Additionally, single-axis trackers produce more energy in the late summer afternoons when MISO energy prices are higher. This further depresses the revenue that solar would earn by missing out on this higher-priced energy.

Second, single-axis trackers will have a higher ELCC based on MISO's currently approved methodology, as discussed previously. Since Strategist and PROMOD build resources to meet capacity needs, properly modeled single-axis tracking systems would contribute more capacity at a lower cost and could make solar-heavy resources portfolios more economic compared to fixed-tilt systems.

[106] WP LKM-448 LCOE.

Finally, Brattle's Renewable Integration analysis analyzed the loss of load expectation for future high-renewable scenarios. In summer afternoons when load peaks, single-axis trackers provide roughly 10-25% more output on an absolute basis than do fixed-tilt systems. In 2031, Brattle assumes roughly 6,000 GW of solar resources will be online.[107] Had Brattle correctly modeled trackers, this means that between 600 MW and 1,500 MW of capacity might have been available to meet demand. Given peak demand in Zone 7 was roughly 20,000 MW, this represents a substantial increase in available capacity during high peak hours.[108]

Q113. AFTER YOU PERFORMED THIS ANALYSIS, DID DTE ADMIT THAT IT DID NOT MODEL SINGLE-AXIS TRACKING SYSTEMS?

A113. Yes. In response to discovery issued after my analysis, DTE stated that it did not model single-axis tracking systems, but instead took the hourly generation profile of a fixed-tilt system and scaled it up so that the annual generation was equivalent to the single-axis tracking system.[109] This explains why the generation profile of DTE's Strategist and PROMOD systems follows the SAM fixed-tilt system curve but is slightly higher in many hours.

Q114. Did DTE perform any supplemental modeling using the correct single-axis load shape?

A114. Yes. It reran several selected scenarios based on the updated modeling performed for Staff discussed below. DTE's analysis of its result follows:

> The difference in the NPVRR of the select runs was 0.02% on average and the build plans generated by the Strategist optimization did not change. As a result, the impact of using the fixed tilt shape remained immaterial. This result can be explained by the firm capacity and modeled solar energy remaining constant for each solar resource regardless of shape indicating that the shape itself has minimal effect on the PVRR and least cost build plan. The results of the IRP, the Strategist and PROMOD modeling, and the resulting PCA choices were not affected by the solar shape used.[110]

---

[107] Exhibit A-47 at 15.
[108] *Id*. at 12.
[109] ELPCDE-15.97d, attached as Exhibit ELP-36 (KL-27).
[110] MECNRDCSCDE-8.32, attached as Exhibit ELP-37 (KL-28).

Q115. DO YOU AGREE WITH THIS ASSESSMENT?

A115. No. Although DTE claims that the load shape had minimal impact on the analysis, it does not appear that the Company updated the ELCC of PV in Strategist to correspond to that of a single-axis tracker as indicated by the statement that "firm capacity … remained constant for each solar resource regardless of its shape." This is further supported by the Company's confirmation that aside from alternating the starting point renewables and changing the size of the renewable resources, DTE did not make any changes to other modeling inputs in the updated Staff modeling on which these runs were based.[111]

By maintaining the incorrect 50% ELCC value, instead of a more accurate 65% figure, the updated scenarios install roughly 23% more solar than is needed to obtain the same aggregate solar capacity value. This in turn increases costs compared to a properly modeled single-axis tracking system and renders DTE's updated analysis incomplete. Absent an analysis showing both the updated load shape and the increased ELCC value that comes along with it, DTE's has not shown that "the results IRP, the Strategist and PROMOD modeling, and the resulting PCA choices were not affected by the solar shape used."

When Solar Costs and Other Assumptions are Corrected, Modeling Shows that More Solar will be Deployed

Q116. PLEASE PROVIDE A SUMMARY OF ALL OF THE MODELING ISSUES YOU HAVE DISCUSSED THUS FAR.

A116. DTE's questionable modeling decisions extend throughout its IRP. Sometimes these decisions were based on internal staff choices, and sometimes they were a function of the limitations of the modeling software that DTE chose to use. The list below covers the topics that I have discussed in my testimony. I do not cover the numerous assumptions that are

[111] ELPCDE-16.103n, attached as Exhibit ELP-19 (KL-10).

embedded in DTE's load forecast or its demand-side management programs, each of which could be subject to similar scrutiny.

- General Modeling Assumptions
  - Initial modeling forced in thousands of MW of "starting point" renewables that were based on outdated LCOE assumptions
  - Model was prevented from adding "superfluous" units that may reduce costs
  - Fixed O&M costs of existing coal units were not included
  - All costs of "starting point" renewables were initially excluded
  - DTE did not perform any modeling on third-party resource ownership
  - Supplemental modeling did not correct input assumptions or "superfluous" unit restriction
- Solar Costs and Assumptions
  - Solar capital costs do not reflect the actual NREL ATB values
  - Solar capital costs do not reflect the near-term decline that is found in the NREL ATB forecast
  - Solar O&M costs are substantially overstated and well out of alignment with other industry data sources
  - DTE incorrectly modeled fixed-tilt systems rather than single-axis tracker systems
  - The modeled ELCC is reflective of a fixed-tilt system rather than a single-axis tracker system
  - DTE models a decline in ELCC that has not yet been approved by MISO
  - The timeline over which the ELCC declines in the model is arbitrary
- DTE Peaker Fleet
  - DTE assumes its old peaker fleet will continue to operate at its current capacity
  - Peaker outages are not modeled as seasonal, nor do they reflect the tendency for units to fail under high load conditions
  - DTE did not adequately consider S+S resources to replace its aging peaker fleet

Q117. HAS AN ATTEMPT BEEN MADE TO CORRECT SOME OR ALL OF THESE ISSUES TO DETERMINE WHAT THE RESULTING IMPACT WOULD BE?

A117. Yes. Anna Sommer from Energy Futures Group was retailed by ELPC to perform alternative modeling in this case. Ms. Sommer performed a run that sought to understand how using more appropriate solar inputs and assumptions would affect the modeling results. Ms. Sommer used as her starting point the supplemental modeling that DTE performed in response to Staff's request that was discussed previously.

Q118. WHAT WERE THE KEY CHARACTERISTICS OF THAT MODELING RUN?

A118. In this run, DTE removed all of its hardcoded renewable starting point resources and instead modeled them as individual resources that Strategist could select. It reran its baseline with all of these resources (and their costs) included to determine the costs under the updated configuration. It then removed these assets and developed a least-cost plan (LCP) in two stages. As discussed before, DTE's updated model did not correct the solar generation profile or enable superfluous units, and thus only built resources for the 2030 and 2040 retirements of Belle River and Monroe. The two builds were similar, although the updated LCP contained fewer renewables and cost slightly less.[112] DTE's baseline and least cost plan is summarized below in Table 3:

	DTE Ref Original LCP	**Updated Ref LCP**
EE Assumption	1.5% EWR	1.5% EWR
2030 Build	1 CCGT 259 MW DR Starting point renewables: 150 MW wind, 525 MW Solar	1 CCGT 308 MW DR 600 MW wind
2040 Build	3 CCGT 683 MW Purchase Starting point renewables: 300 MW wind, 2000 MW Solar	3 CCGT 1 CT 1,600 MW Solar 652 Purchase
NPVRR ($mm)	$14,451	$14,346

Table 3 - DTE Updated Modeling Results

Q119. HOW DID MS. SOMMER MODIFY THIS RUN?

A119. Ms. Sommer updated key solar input data, including using my calculations for revenue requirement, ELCC, and load shape discussed previously. Because Ms. Sommer was faced with the same Strategist limitations as was DTE, she was not able to use the model to simply optimize across the entire time horizon with unlimited superfluous units. Using an incremental approach that hardcoded additional renewable units, described in Ms. Sommer's testimony, she developed two portfolios that each contain a large solar buildout in 2024 and either 1.5% (consistent with the Reference scenario) or 1.75% EE (consistent with the BAU scenario).[113]

Q120. WHAT WAS THE RESULT OF THESE RUNS?

---

[112] STDE-2.3b, attached as Exhibit ELP-38 (KL-29).
[113] See Sommer Direct.

A120. In the modeling run with 1.75% EE (STDE 2.3b 2040 Reference Case Ren + 1.75% EE), 1,800 MW of solar was added in 2024, along with 150 MW of wind in 2025. The 2040 build built less solar but was otherwise similar to DTE's. Even though there was sufficient capacity from these resources to retire Belle River early, the 2030 retirement date was not modified. The resulting portfolio had a NPVRR of $13.37 billion, nearly $1 billion less expensive than DTE's comparable run.

In the modeling run with 1.5% EE (STDE 2.3b 2040 Reference Case Ren + 1.5% EE), one more solar unit was required to meet the 2030 capacity need, and one more solar unit was built for the 2040 capacity need. The resulting portfolio was roughly equal in cost to the 1.75% EE run and totaled $13.28 billion, more than $1 billion lower than DTE's updated plan. These results are summarized below in Table 4.

	DTE Updated Ref LCP	**STDE 2.3b 2040 Reference Case Ren + 1.75% EE**	**STDE 2.3b 2040 Reference Case Ren + 1.5% EE**
EE Assumption	1.5% EWR	1.75% EWR	1.50% EWR
2024/2025 Build		1,800 MW Solar 150 MW wind	1,900 MW Solar 150 MW
2030 Build	1 CCGT 308 MW DR 600 MW wind		
2040 Build	3 CCGT 1 CT 1,600 MW Solar 652 MW Purchase	3 CCGT 1 CT 200 MW Solar 652 MW Purchase VPP 92 MW TOU 167 DMD 49	3 CCGT 1 CT 300 MW Solar 662 MW Purchase VPP 92 MW TOU 167 DMD 49
NPVRR ($mm)	$14,346	$13,365	$13,278

Table 4 - DTE Updated Modeling Results

Q121. DO THESE RESULTS INDICATE THAT YOU SUPPORT EITHER A 1.5% OR 1.75% ENERGY EFFICIENCY TARGET?

A121. No. I do not opine on the proper level of energy efficiency in this case. The 1.5% and 1.75% were selected simply to mirror the levels used in the BAU and Reference cases.

Q122. DOES THE SIGNIFICANT REDUCTION IN SOLAR BUILD IN 2040 IN THE RENEWABLES + 1.75% PLAN CONTRIBUTE SUBSTANTIALLY TO THIS DIFFERENCE?

A122. No. While the Renewables + 1.75% plan does build 1,400 MW less solar in 2040, because the purchases are so far in the future, the net present value impact is not substantial. In the DTE Updated Ref LCP, the 2040 builds contributed $503 million in NPV to the NPVRR. By contrast, the 2040 builds in the Renewables + 1.75% contributed $423 million in NPV to the NPVRR. Thus, only $80 million of the nearly $1 billion in cost difference was attributable to the 2040 builds, meaning that the vast majority of savings comes from the earlier replacement of capacity with solar.

Q123. DO SOME OF THE ISSUES YOU IDENTIFIED IN DTE'S MODELING PERSIST IN MS. SOMMER'S MODELING?

A123. Yes. As discussed further by Ms. Sommer and Mr. Joseph Daniel of Union of Concerned Scientists, DTE's modeling contained a number of questionable configuration choices related to the must-run status of units and the level at which units were dispatched.[114] These runs do not correct those problematic assumptions, and thus produce results that share some of those same characteristics such as a high single-year buildout and over-reliance on market sales to offset thermal generation costs.

Q124. DOES THIS FACT DIMINISH THE FINDINGS OF THE SOMMER PORTFOLIOS?

A124. No. The purpose of the Sommer portfolios was to demonstrate that when solar was properly configured as a resource that it could produce a portfolio that included substantially more solar development in the "defined" PCA timeline and also reduced total system costs. The results were not marginally less expensive, but substantially so. Given that the modeling artifacts affect both runs, the roughly $1 billion reduction in cost in the Sommer portfolios demonstrate that increased solar deployment is primary cause of the NPVRR reduction.

Q125. WHAT RECOMMENDATIONS DO YOU HAVE AS A RESULT OF THIS MODELING?

[114] Id., Daniel Direct.

A125. The Commission should require DTE to more closely analyze the potential benefits of substantially increasing solar deployment in the defined PCA period to allow its customers to benefit from the cost savings of capturing the higher levels of the federal ITC.

IV. DTE'S COMPLETE FAILURE TO ANALYZE ITS PEAKER FLEET MISSES AN OPPORTUNITY TO REPLACE AGING, UNRELIABLE UNITS WITH CLEAN PEAKING ASSETS

Q126. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SECTION OF YOUR TESTIMONY.

A126. In this section, I discuss DTE's peaker fleet characteristics, including age, run time, outage frequency, and modeled results. I seek to understand the Company's cost tracking approach with little success. From there, I discuss broader industry trends of utilities leveraging solar and solar plus storage (S+S) assets to meet their peak demand needs. Finally, I analyze DTE's system load and modeled PV generation under actual 2015-2017 weather conditions and show that solar and S+S could fulfill the operational requirements needed to meet DTE's peak load.

Q127. WHAT ARE THE OVERALL RESULTS OF YOUR PEAKER FLEET ANALYSIS?

A127. As a first matter, DTE's total failure to consider how robust its aging peaker fleet is a major shortfall of the IRP. Many of DTE's units are more than 50 years old, and as demonstrated below, suffer from high outage rates that worsen during high-usage periods. Despite this, DTE states that "it has not made a decision to retire any peaking units at this time" and makes these units available through the entire 2019-2040 time horizon with no degradation in outage rates.[115]

DTE should have taken a closer look at its peaker fleet in this IRP. Its filing contains zero analysis on the fleet and assumes that all units – even those that are already among the oldest in the nation of their type – will continue to operate for another 20 years. Further, its failure to track fixed and variable costs limits the ability to perform robust financial analyses on the units to determine whether they remain economic to operate.

[115] ELPCDE-1.10a, attached as Exhibit ELP-39 (KL-30), WP LKM-19 REF PCA PROMOD Inputs

To evaluate how well alternatives such as solar or S+S could replace DTE's peaking capacity, it is critical to understand how the peaking fleet operates. The Company's three types of peakers (old gas turbines, old engines, and new gas turbines) operate in substantially different ways. While the new turbine facilities run for extended periods of time at or near their maximum output, old turbine and engine facilities often run in short spurts at reduced or fractional power levels.

DTE's old gas turbines, as a group, are much more unreliable than its new gas turbines and even its old engines. Further, they tend to experience unforced outages during the same months when DTE most needs their capacity. Between 20% and 25% of the total nameplate capacity of the old turbines are unavailable during peak winter and summer load months. This pales in comparison to new turbines, which experience unforced outages of roughly 1.5% in peak summer months and 6% in peak winter months (much of which was driving by one extended outage).

The deficient peaker analysis continues into DTE's modeling. The software package and modeling inputs used in this case did not properly account for the seasonal variation in outages and did not reflect the correlation of outages with periods of usage. By failing to properly model these factors, the model likely assumes more peaking generation will be available to meet load than had outage patterns been accurately incorporated.

Turning to the load and generation analysis, I demonstrate that single-axis tracking systems are well-positioned to serve DTE's peak load. I analyze solar generation using actual weather data from 2015, 2016, and 2017 and compare PV generation to system load during these same years. By itself, solar provides substantial power during peak load hours in the summer. Further, the evening drop-off in solar production is matched quite well to the ramp down of system load.

Adding storage to PV systems can enhance the performance of solar assets even further. With a relatively modest battery system, DTE could either gross up PV production to its rated output or extend the duration of the output of the PV system given that day's weather patterns. There is ample sunlight early in the day that can be used to recharge the battery, enabling DTE to configure S+S systems to qualify for the federal ITC.

My analysis clearly shows that DTE does not operate "generic" peaking resource as suggested by its modeling and that DTE's fleet contains some of the oldest operating gas turbines and engines in the country. When comparing system load, solar output, and peaker fleet dispatch, the data show that some of these old units could be successfully replaced by solar and S+S assets. DTE's failure to consider solar and S+S as peaking resources that could cost-effectively meet peak load and replace expensive and fragile peakers in its IRP is a major oversight.

DTE's Peaker Fleet Contains Many Old Units

Q128. PLEASE DESCRIBE THE COMPOSITION OF DTE'S PEAKER FLEET.

A128. DTE's peaker fleet contains 84 individual units at 18 facilities that have a combined summer capacity rating of 2,033 MW. The bulk of the fleet's capacity is from natural gas-powered turbines, and there are 10 reciprocating internal combustion engine (engine) facilities (each with multiple units) that in total produce 128 MW of capacity. The fleet is roughly bifurcated by age; 5 facilities were constructed 17-20 years ago, 1 is 38 years old, and the remaining 12 facilities are between 48 and 53 years old. The high-level characteristics of these three categories are shown below in Table 5.

Category	Old Turbines	Old Engines	New Turbines
Installation Years	1966 - 1971	1967 - 1981	1999 - 2002
Capacity-Weighted Age	52	48.8	18.5
Total Facilities	5	10	5
Total Units	27	41	16
Total MW (Nameplate)	450 MW	111 MW	1,794 MW
Total MW (Summer)	366 MW	128 MW	1,539 MW
Average Nameplate	16.7 MW	2.7 MW	112 MW
2016-2018 Capacity Factor	0.51%	0.32%	9.34%

Table 5 - Peaker Fleet Characteristics

Q129. WHAT ARE THE MAIN OPERATING CHARACTERISTICS OF EACH OF THESE TYPES OF PEAKERS?

A129. There are ten old engine facilities that consist of multiple 2.7 MW (typically 5 units) reciprocating internal combustion engine units that operate on fuel oil.[116] These units can be dispatched individually, as seen by the variation in power generation and outage information. DTE's engine facilities show substantial variation in their hourly power output, suggesting that they have a wide operating range. DTE's engine units also run for shorter periods of time (sometimes only one hour), and in total had a class capacity factor of 0.32%. In the five years between 2014 and 2018, fully 40% (21 instances out of 50) of the facilities ran for less than 100 hours in a given year, and 80% (40 instances out of 50) of the facilities ran for less than 200 hours in a given year.[117]

DTE has five facilities with old turbines that run on either natural gas or fuel oil, with one unit (Northeast 12-1) able to use both fuels. Most of the old turbines have a nameplate rating of 16 MW, several have nameplate ratings between 19 and 24 MW, and two have nameplate ratings of 42 MW. Unlike the old engine facilities, which produce a wide variation in power output, DTE's old turbines tend to be dispatched at specific output levels. While they tend to run for longer periods of time than the old engines, the old turbine fleet still ran for very few hours. This class had an average capacity factor of 0.51% from 2016-2018, with many units running for less than 50 hours a year.

DTE's new turbines are very different from either the old engines or the old turbines. Spread across five facilities, these units are much larger (two 71 MW units, ten units between 85 and 90 MW, and six units between 179 and 196 MW) than the other peakers. They all run on natural gas and run substantially more often than either type of the old peakers. The new

[116] Exhibit A-12.
[117] ELPCDE-1.10b, attached as Exhibit ELP-40 (KL-31).

turbines are most often dispatched at or near full power and show very little flexibility in dispatch. DTE's new peakers had an average capacity factor of 9.34%.

Q130. HOW DOES THE AGE OF DTE'S FLEET COMPARE TO ALL OTHER GAS TURBINE AND ENGINE PEAKERS?

A130. DTE's engine fleet is remarkably old, as shown in Figure 13 below. Nearly 90% of DTE's engines came online in 1971 or prior. By comparison, only 14% of all engines currently operating in the U.S. came online in the same year or earlier. Similarly, DTE's old gas turbines are among the oldest in operation. 366 MW, or roughly 20% of DTEs gas peakers, came online in 1971 or before.[118] By comparison, only 6% of all currently operating combustion turbines came online in that same year. While DTE does have more modern peakers, a sizable share of its fleet is among the oldest units of that type in operation.

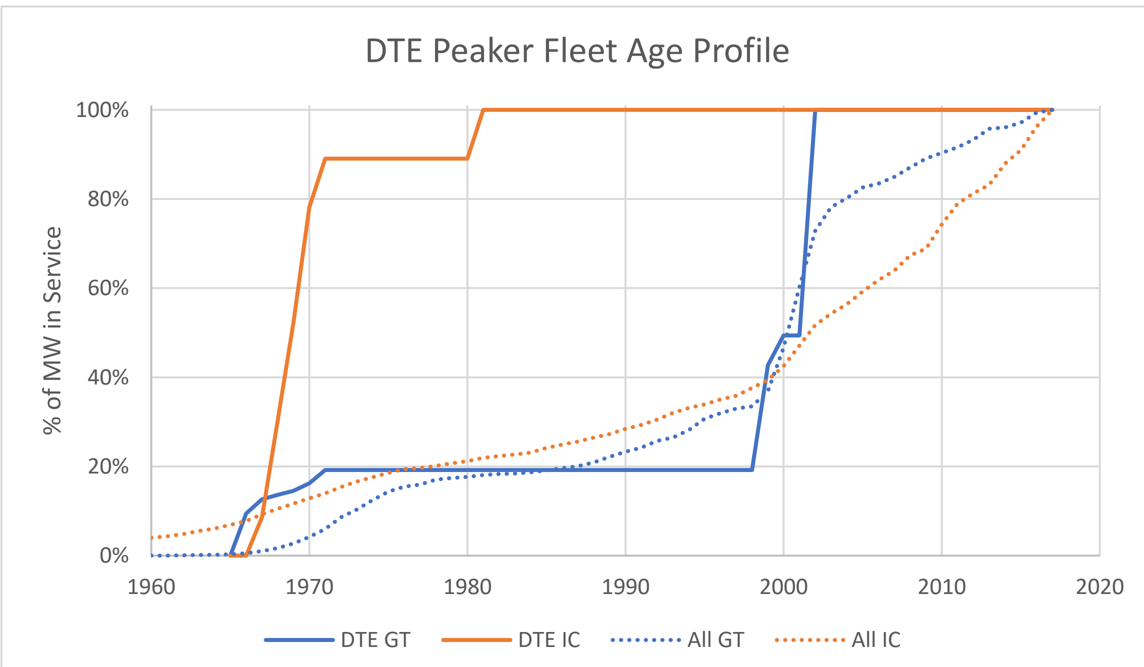


Figure 13 - DTE Peaker Fleet Age Profile

Q131. HAVE YOU PERFORMED AN ANALYSES ON THE HISTORIC OPERATING CHARACTERISTICS AND RELIABILITY OF THE PEAKER FLEET?

[118] Exhibit A-12

A131. Yes. In response to a data request, DTE provided three years' worth of hourly generation and unit-level outage data.[119] Using this data, I performed several analyses that sought to understand how the peaker fleet performed in the hours in which system demand was highest. I also investigated performance trends between the three main types of peakers: old gas turbines, old engines, and new turbines.

Q132. PLEASE DESCRIBE HOW YOU PERFORMED THIS ANALYSIS.

A132. I began with two main datasets. The first was a data set of hourly generation by unit for 2016-2018. The second was a list of unforced outages by unit with a start time, and end time, and the total hours of the outage. To these datasets, I added information from the U.S. Energy Information Administration's (EIA) EIA-860 form data. This data set contains key characteristics of generators at the unit level, including nameplate capacity, net summer capacity, and commercial operation date.[120]

For the generation analysis, I analyzed both total generation and the number of hours providing capacity by category type. I aggregated the generation by unit into a category total generation by month and by hour of day. This shows the trends of when each type of unit was dispatched, as well as the magnitude of generation that was called. I also inspected the duration and output levels of individual unit calls, breaking the dispatch instances into capacity levels (e.g. 4 hours at 50-75% of unit capacity). This analysis is used later to demonstrate that solar and S+S assets could be used to meet the energy needs (i.e. duration at a given dispatch capacity) of much of the old peaker fleet.

For the outage analysis, the data provided covered 2016 to 2018 as well.[121] I mapped the consolidated outage data into hourly outage information for each unit. This expanded data was then used to analyze the overall performance of the different peaker categories,

[119] ELPCDE-4.49a, attached as Exhibit ELP-41 (KL-32).
[120] https://www.eia.gov/electricity/data/eia860/
[121] Some outages that ran into 2016 commenced in prior calendar years. The start time of these outages were adjusted to 1/1/2016 to prevent overcounting outage hours.

examining the frequency, timing, and magnitude of the capacity loss from unplanned outages.

The Historical Operating Modes of DTE's Peaking Units Vary Considerably by Age and Type Demonstrating There Is No Generic Peaker Resource

Q133. WHAT IS THE TYPICAL LOAD PROFILE OF DTE'S SYSTEM?

A133. In order to determine when peakers are most likely to be dispatched, I analyzed DTE's historic load profile for the system. Figure 14 below shows the 2016-2018 load for DTE's system.[122] Each band on this and subsequent figures represents 10% of the difference between the maximum and minimum hour/month values. All hours are shown in "hour ending" format in eastern standard time, meaning no adjustment was made for daylight savings time. Also, to better visualize the relative size of summer and winter load and generation, the charts begin in April.

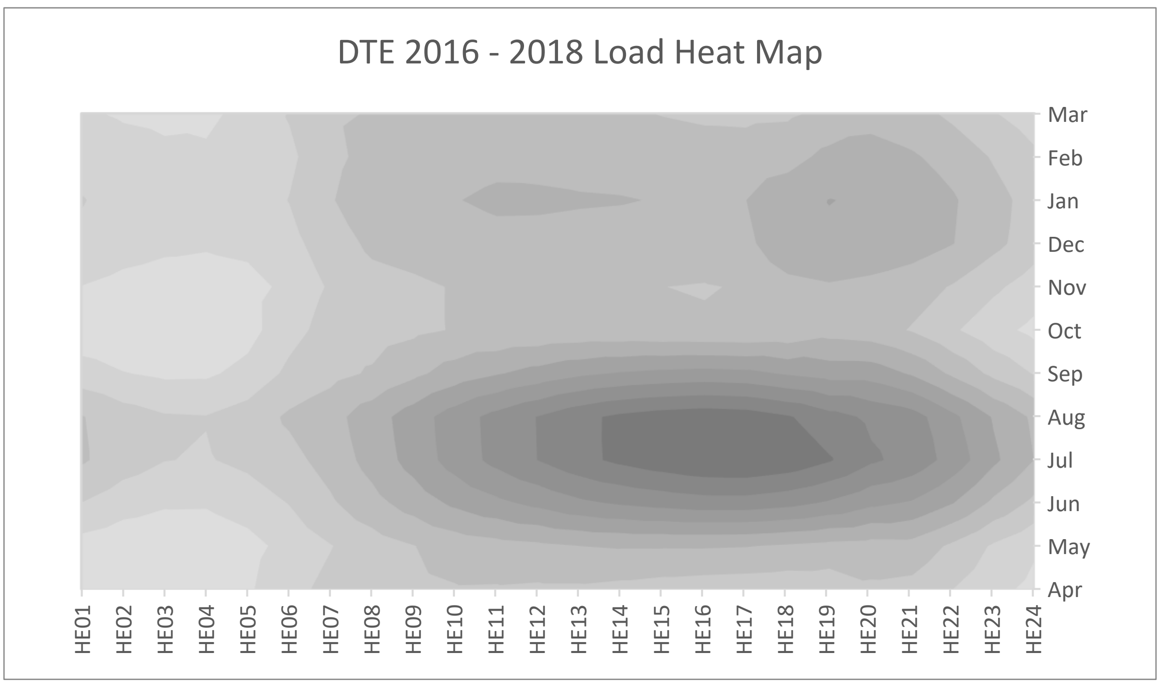


Figure 14 - DTE 2016-2018 Load Heat Map

[122] ELPCDE 8.75, attached as Exhibit ELP-42 (KL-34).

DTE's system is typical of a summer-peaking utility. In recent years, the average peak demand was roughly 7.8 GW in July afternoons. Spring and fall demand are much lower, with daytime maximum loads topping out around 5.5 GW. Winter loads increase in December through February, focused on mornings and evenings. DTE's winter peak load in recent years was about 6.0 GW, or roughly 23% lower than summer peak load.

Q134. HOW WERE DTE'S PEAKERS TYPICALLY DISPATCHED IN RESPONSE TO THIS LOAD PROFILE?

A134. As expected, DTE's peaker fleet was primarily dispatched during summer afternoons, however there were distinct differences between the old units and the new units.

Figure 15 below shows the heat map of generation for the old gas turbine peakers. While generation generally follows the peak load periods of the summer, the old turbines run much more often in September than one might expect based on load patterns. In fact, generation in September afternoons was 2-3 times higher than corresponding periods in the peak load months July and August. When asked about this seeming anomaly, DTE indicated that "market prices in September afternoons during 2017 and 2018 were higher than the market prices in typical summer peak load months. These units were committed for either economics or for reliability."[123] The old turbines were more dispatched for more hours per day in January, although the total generation was still lower than summer months.

[123] ELPCDE-8.73, attached as Exhibit ELP-43 (KL-35).

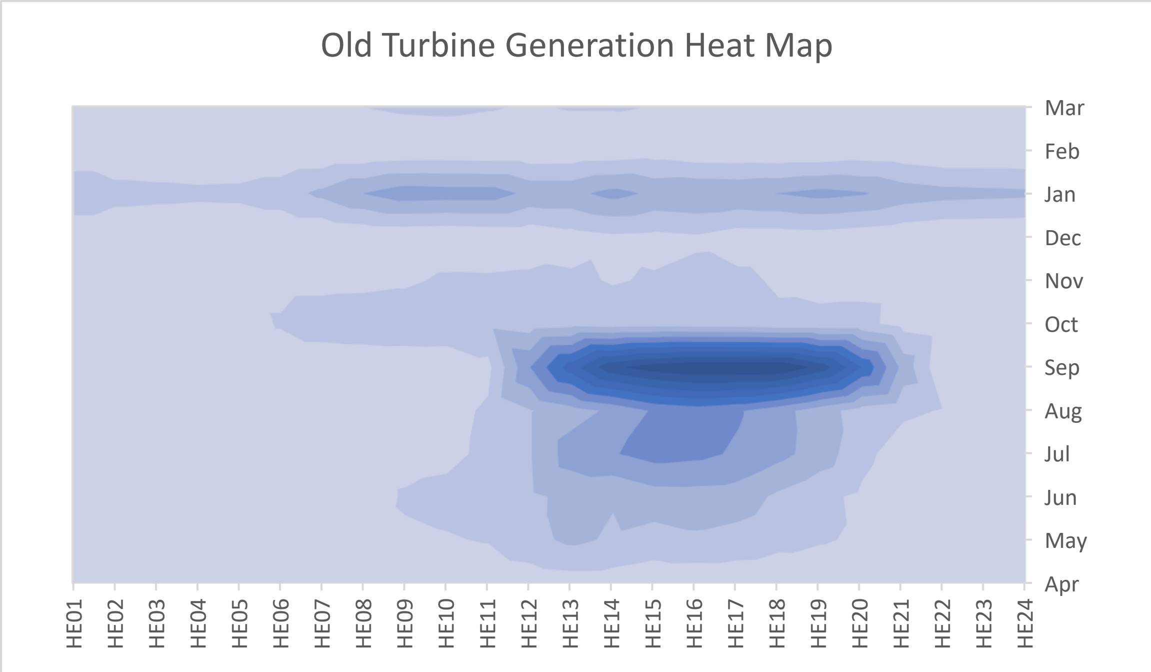


Figure 15 - Old Turbine Generation Heat Map

Figure 16 below shows the same data for the old engine fleet. In general, the old engines were dispatched between HE12 and HE19 in July through September. To a lesser degree, the engine fleet was dispatched in cold January mornings and evenings, although the total generation in those hours were roughly 15-25% of August afternoons.

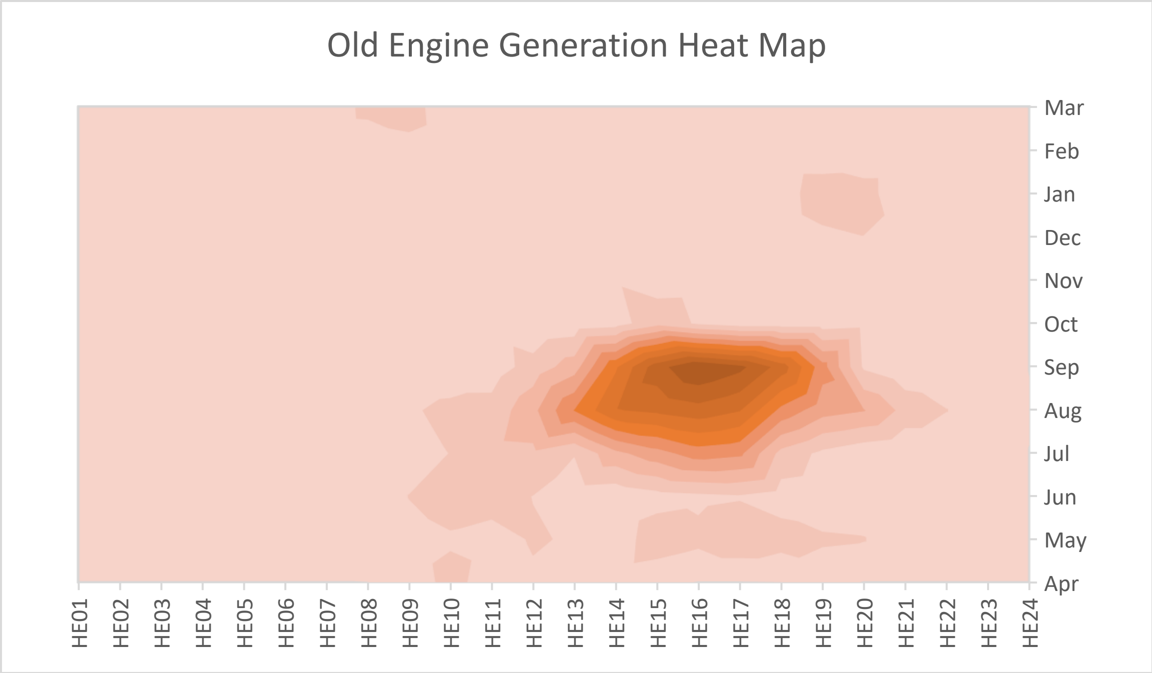


Figure 16 - Old Engine Generation Heat Map

Finally, Figure 17 below displays data for the new turbine peaker fleet. The summer generation peak is clearly visible; however, the new units are dispatched much more frequently in the shoulder months of the year.

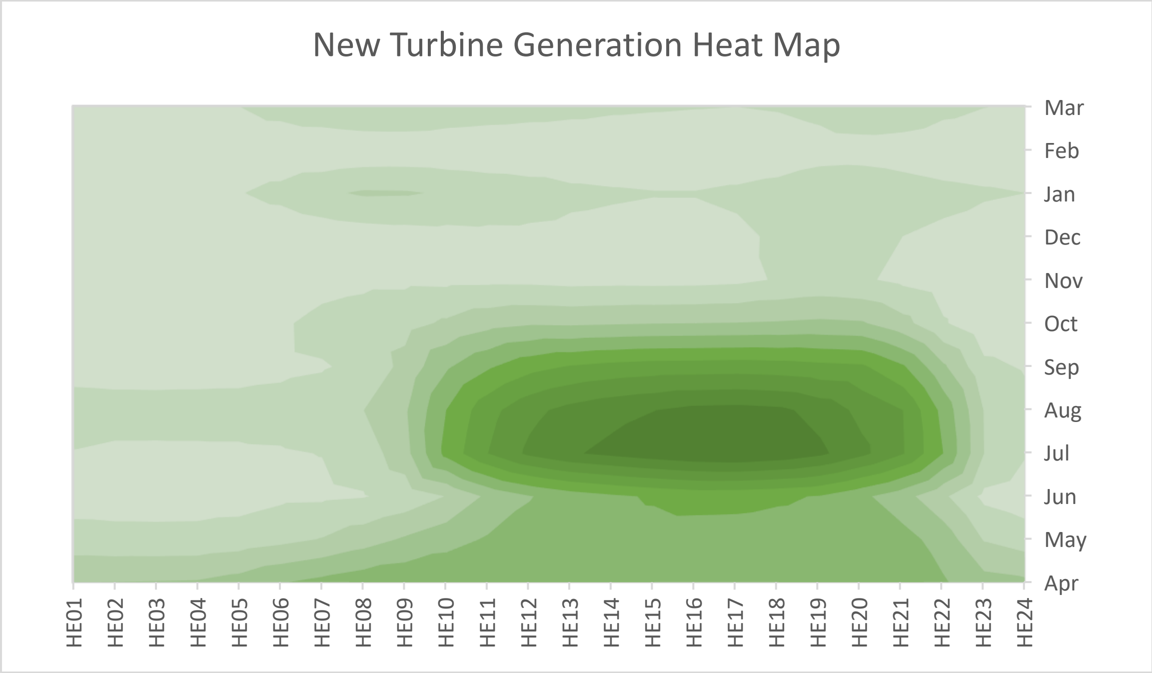


Figure 17 - New Turbine Generation Heat Map

Q135. WHEN THE UNITS ARE DISPATCHED, DO THEY ALL RUN AT 100% OF THEIR OUTPUT?

A135. No. Each type of peaker shows a different power output profile. Old turbines show more variation and more hours at lower generation set points. Engines have the most variability, reflecting the operating flexibility of reciprocating engine technology. New turbines are often dispatched near their maximum output levels and rarely at levels below 80% of their summer capacity.

Figure 18 below shows a histogram of the output of each old turbine as a percentage of its net summer capacity.[124] The spikes around 25% and 40% are due instances of Fermi peakers running for many consecutive days (and weeks) at reduced levels for local voltage support during transmission system work by ITC [125] Aside from these spikes, there is a slight bump between 85% and 95% output, and very little time spent at other levels.

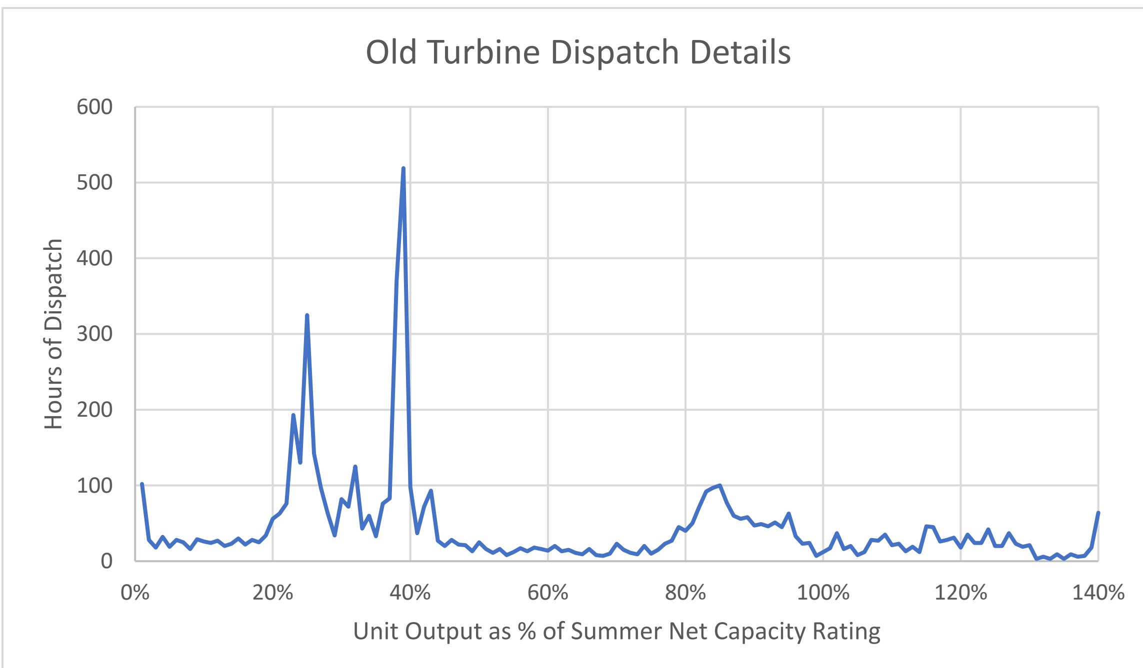


Figure 18 - Old Turbine Dispatch Details

---

[124] Data is not normalized for weather. Because the summer net capacity is smaller than the nameplate capacity of the unit, there are hours in which the actual generation exceeds this rating. These hours occur in the winter and shoulder when the units are more thermodynamically efficient and may not be operating environmental restriction technologies.
[125] ELPCDE-8.66a, attached as Exhibit ELP-44 (KL-35).

Old engines show much more variation in their operating mode as seen in Figure 19 below. This could be due in part to the more flexible operating characteristics of the engines compared to gas turbines.[126] It also might reflect how DTE reports this data, as engine facilities are reported as one facility despite having multiple individual units that can be individually run.

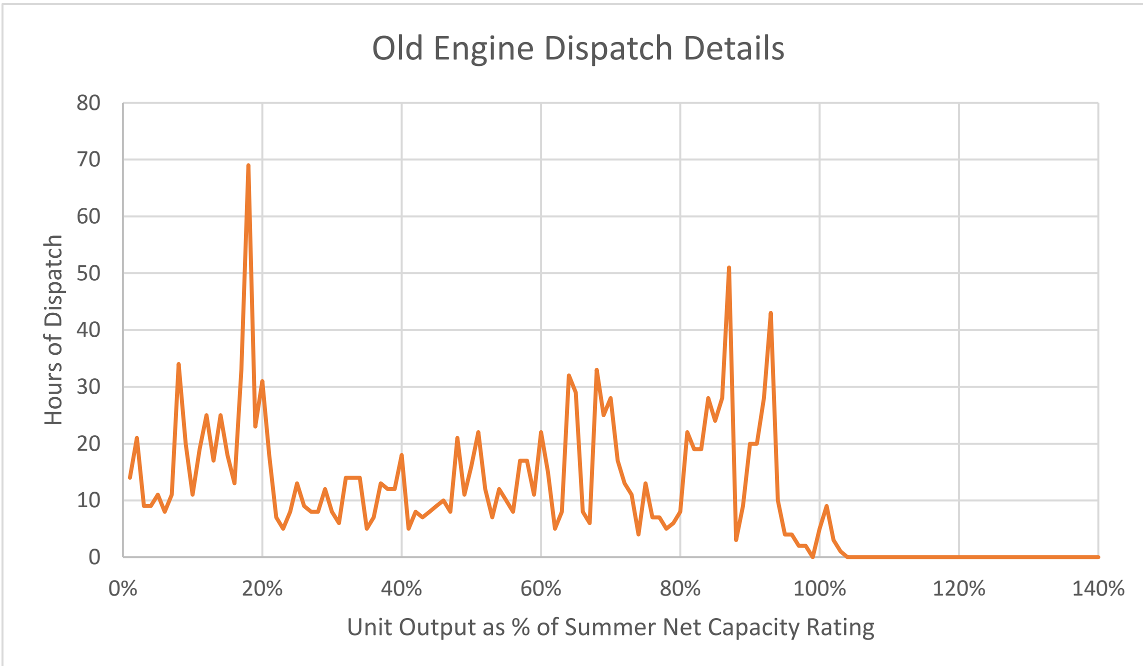


Figure 19 - Old Engine Dispatch Details

Finally, new turbines show a strikingly different generation profile in Figure 20 below. The units are almost always dispatched at or near their maximum power levels. The band from roughly 90% to 105% of net summer capacity reflects the temperature impact on power output as these units ran many hours in both summer and winter. The spike at 84% is primarily due to this set point being frequently used for overnight generation. New turbines were almost never dispatched outside of these two major points.

[126] It is possible that some of the higher variation of the engine data is a result of more “stub” hours in which the unit was operating for less than the full hour. However, a manual inspection of the data confirms that the set points of the units have substantial variation even during their “steady state” output across multiple hours.

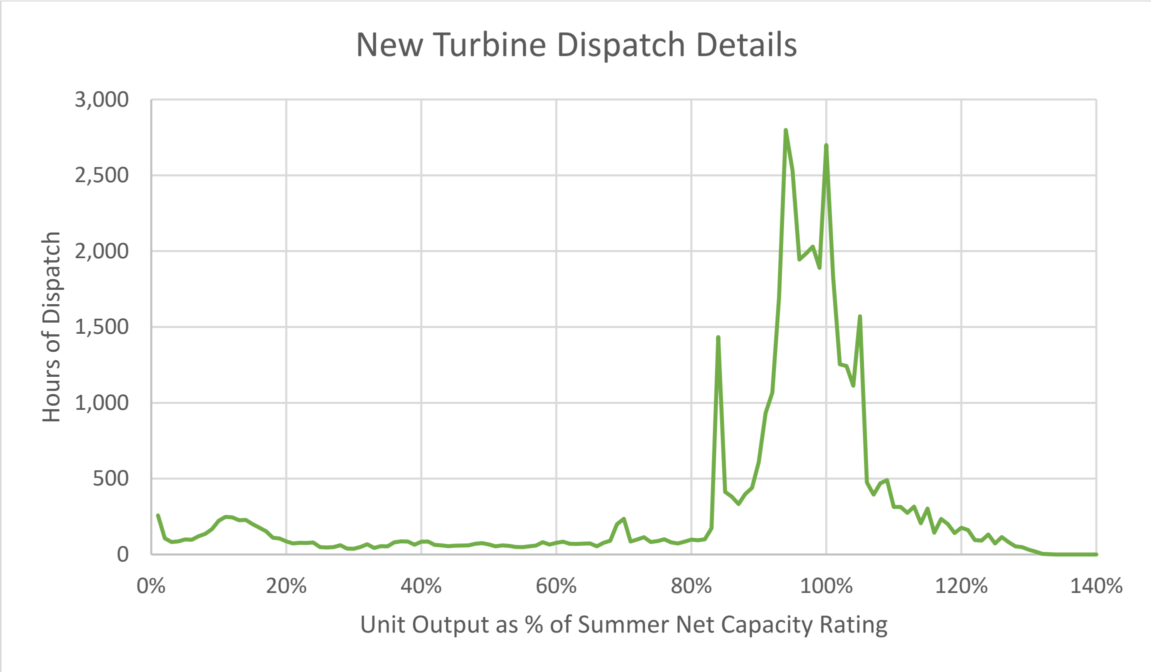


Figure 20 - New Turbine Dispatch Details

Q136. THE DATA ABOVE SHOWS THE AVERAGE GENERATION ACROSS THREE YEARS. DID YOU ALSO INVESTIGATE HOW INDIVIDUAL UNITS WERE DISPATCHED?

A136. Yes. In addition to producing fleet averages for each type of peaker, I analyzed how individual peaker units were dispatched. To do this, I determined how many consecutive hours a unit was dispatched. I further analyzed the set point of the unit as there were many instances in which a unit was run at less than its full power output (e.g. a unit was dispatched at 31% of its summer rating for multiple hours in a row).

Q137. WERE YOU REQUIRED TO MAKE ANY ADJUSTMENTS TO THE UNDERLYING GENERATION DATA TO PERFORM THIS ANALYSIS?

A137. Yes. Because the data was at an hourly resolution, it also included hours in which the units were either starting up or shutting down, or operated at the dispatch point for less than an hour. I adjusted for this by determining the approximate set point for a given dispatch and counting all hours in which the generator output was at least 80% of this figure. For instance, suppose a particular unit showed generation representing 14%, 63%, 63%, 63%, and 13% of its summer capacity in consecutive hours. Because the first and last hours were not at least

80% of the set point (in this case, 63%), this event would be counted as being "dispatched" for three consecutive hours.

Q138. WHAT DID YOUR ANALYSIS SHOW?

A138. The three types of peakers are utilized in very different ways. As is suggested by the preceding charts, the new turbines are dispatched more frequently and for more hours. When they are dispatched, they most often run for nine or more consecutive hours. Further, there were times in the data set when these peakers ran for days or weeks consecutively. By contrast, the old turbines were often run for short durations, although they were more likely to have long run times in the summer months. The old engines were primarily run for short durations (four hours or less) throughout the year. Figure 21 below summarizes the seasonal dispatch by type and duration for the peaker fleet.[127]

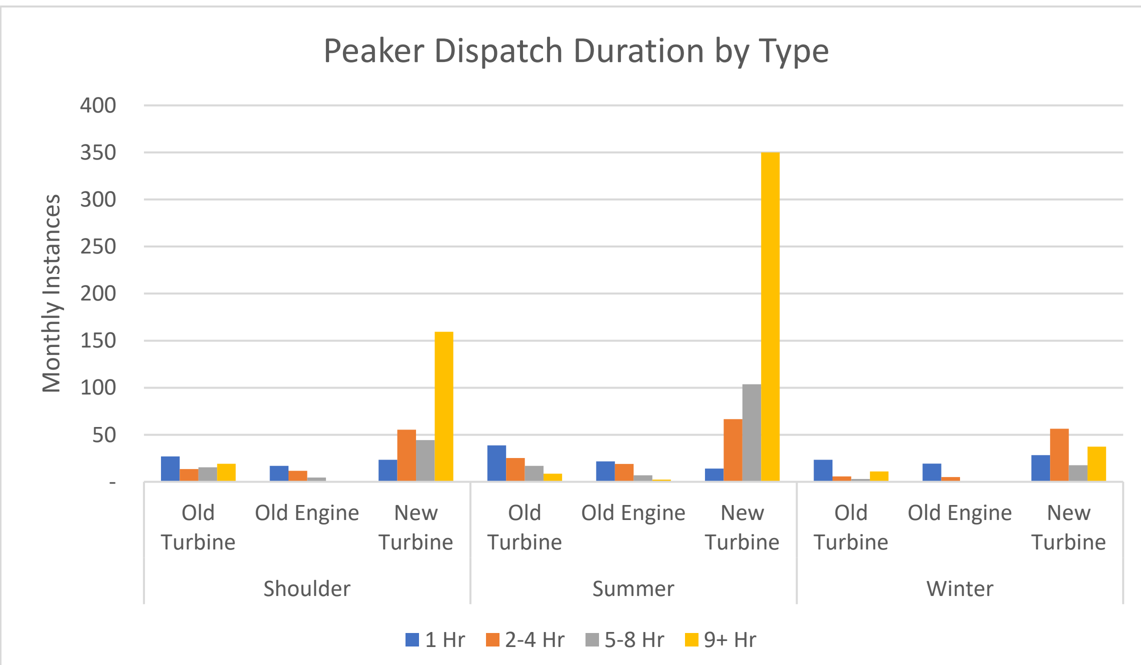


Figure 21 - Peaker Dispatch Duration by Type

Q139. WERE YOU ABLE TO DETERMINE WHETHER THERE WERE CORRELATIONS BETWEEN THE DURATION OF DISPATCH AND LEVEL OF DISPATCH?

[127] Seasons were defined based on monthly peak loads. Summer is June – August, winter December – February, and shoulder months the remainder.

A139. Yes. The final analysis I performed on this data set was to investigate the mix between the level of dispatch and the duration of dispatch. For this analysis, I grouped the duration of a specific dispatch based on the highest output reached in that call. For instance, if a unit were dispatched for three consecutive hours at 40%, 40%, and 35% of summer net capacity levels, it would be counted as a "2-4 hour" dispatch at the "25-50%" level.

Again, there were discrete trends between the three peaker types. Figure 22 below shows that when dispatched for short durations, old turbines were frequently dispatched at lower power levels or ran for less than a full hour. This is shown in the broad distribution of blue "1 Hour" results across all seasons. Longer duration dispatches in shoulder months were found at both lower output levels (25-50%) and higher output levels (>75%). In both the summer and winter, the bulk of dispatches were at high output levels, although there is still a wide variation in the dispatch duration.

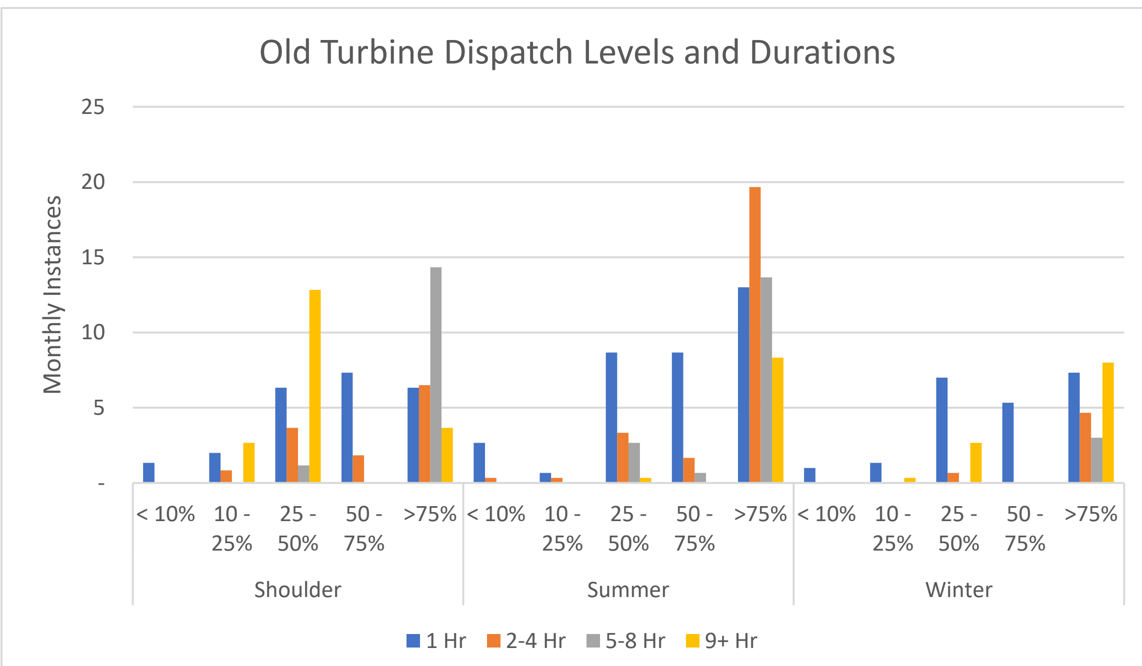


Figure 22 - Old Turbine Dispatch Levels and Duration

Old engines are typically dispatched for short periods throughout the year, with Figure 23 below demonstrating that most dispatches were at or under 4 hours in duration. Power output also varied significantly, again reflecting the wide operating range of the engines. There was also less seasonal variation with the engines being dispatched throughout the year.

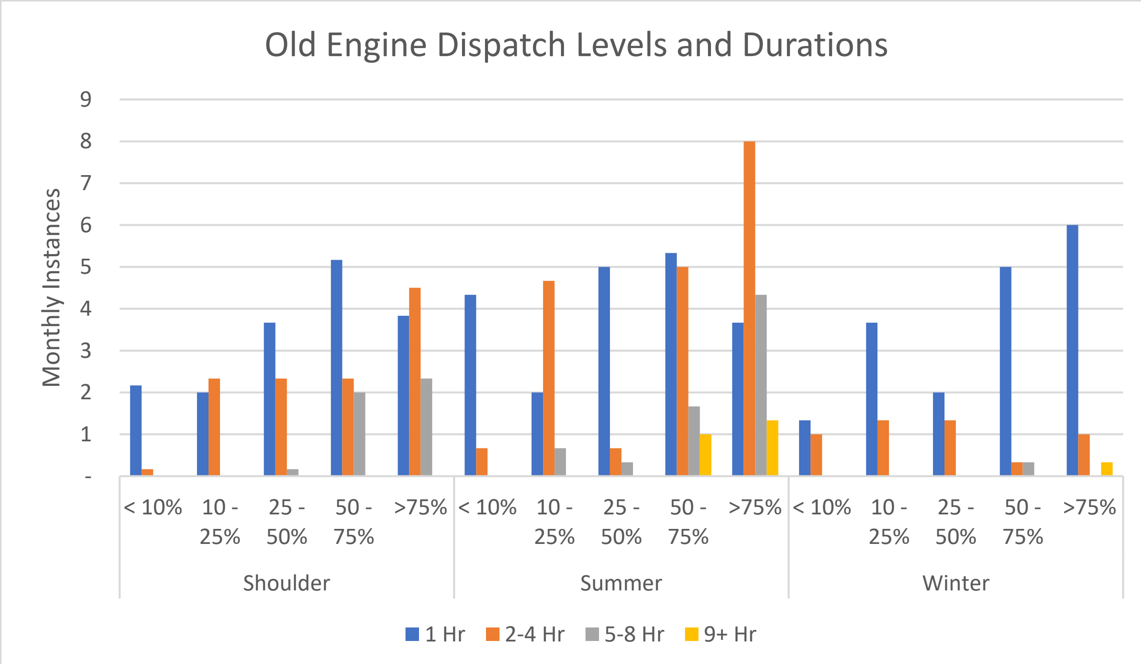


Figure 23 - Old Engine Dispatch Levels and Duration

Both types of old peakers show markedly different results than the new peakers. Figure 24 below shows how the new peakers are almost exclusively dispatched at high power output levels primarily during the summer months. There were many instances in which a new turbine was dispatched all hours in a particular day, and often these were in runs of multiple days of non-stop operation. My analysis counts each day in these operating modes as a separate dispatch instance, so the count of long-term dispatches is somewhat overstated. That said, whether a unit is running for one 24-hour period or multiple 24-hour periods, it clearly represents a break from how the Company's old units are dispatched.

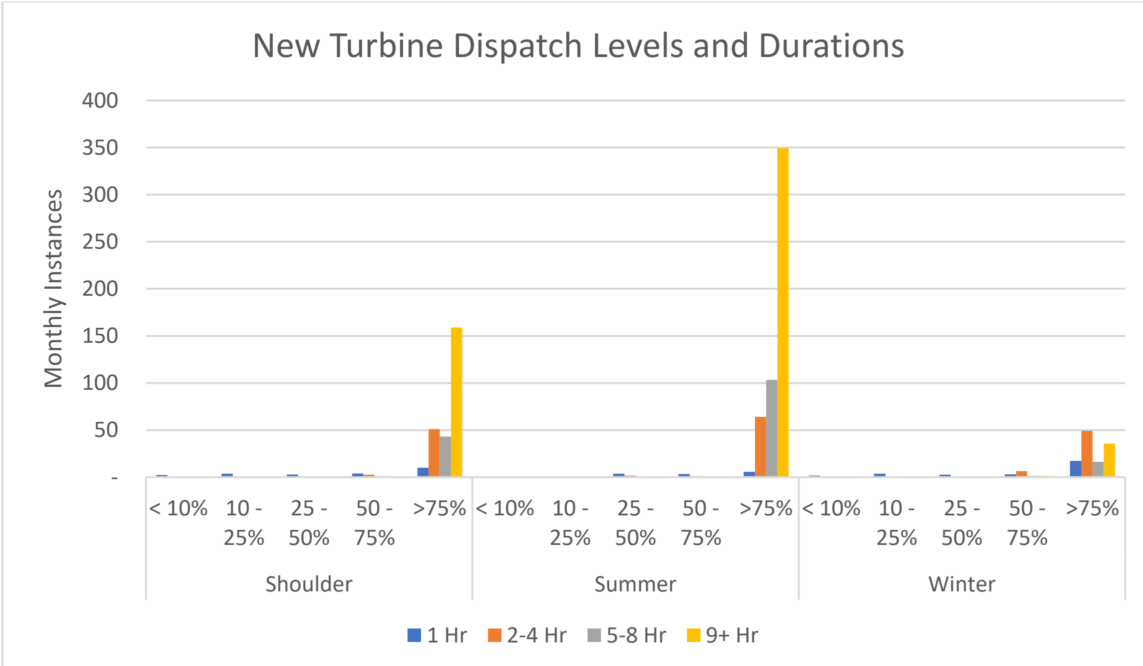


Figure 24 - New Turbine Dispatch Levels and Durations

Q140. WHAT DO YOU CONCLUDE FROM THE ANALYSIS OF GENERATION AND RUN TIME OF THE PEAKER FLEET?

A140. When one is considering alternatives to this capacity, it is critical to understand how the peaking fleet operates. My analysis clearly shows that there is no "generic" peaking resource in DTE's fleet and that some of these resources are better candidates for replacement by solar or solar plus storage resources based on their historical operation. DTE's old peaking units operate in a fundamentally different manner than its new turbines. While the new turbines run for extended periods of time at or near their maximum output, the old turbines and engines often run in short spurts at reduced power levels.

However, the analysis above only shows the post-hoc result of the fleet's generation when the units were available to produce power. To complete the picture of how well the peaker fleet meets the needs of DTE's system, one must also analyze how reliable individual units were and how often they were offline due to unexpected outages.

DTE's Old Units are Unreliable and Perform Worse as High Load Periods Persist

Q141. WHAT WAS THE SECOND ANALYSIS THAT YOU PERFORMED ON THE PEAKER FLEET?

A141. The second analysis focused on the unplanned outage data for the peaker fleet. I began this analysis by expanding aggregated unit-level unplanned outage data (i.e. unit outage start and stop timecode) into an hourly outage map by unit for 2016 to 2018. With this information, I explored the frequency of unit outages to determine how the various peaker types performed and whether there were performance trends that varied with system load. Note that this analysis does not cover planned outages due to scheduled maintenance (around which the utility can schedule), but outages that were not explicitly factored into its operations planning procedures.

Old Units Have Long and More Frequent Outages

Q142. HOW OFTEN AND HOW LONG DID THESE UNITS SUFFER FROM UNPLANNED OUTAGES?

A142. Outage information was provided at the unit level (i.e. each of the five Belle River engine units had individual outage data), allowing for a detailed analysis. Aggregate outage information is included below in Table 6. Between 2016 and 2018, there were 757 unplanned outages across the 84 peaker units. Old turbines had the most individual unit outages, followed by old engines and new turbines. In the bottom rows, extended outages that exceeded one month were excluded to eliminate the large impact on total hours for a given peaker type.

Peaker Type	**Old Turbine**	**Old Engine**	**New Turbine**
Total Units	41	27	16
Total Data			
Outages	327	255	175
Outage Hours	234,601	60,096	12,785
Avg. Outage Duration	717.4	235.7	73.1
Avg. Outage / Unit / Yr	2.7	3.1	3.6
Outages < 1 Month			
Outages	277	234	174
Outage Hours	29,278	24,561	6,754
Avg. Outage Duration	105.7	105	38.8
Avg. Outage / Unit / Yr	2.3	2.9	3.6

Table 6 - Aggregate Outage Information

Focusing on the outages that lasted less than one month, each of the 41 old turbines experienced on average 2.3 outages per year that lasted for about 4.5 days. This is similar to the frequency and duration of outages under one month for the old engine fleet. New peakers failed at a slightly higher rate (3.6 times per year on average) but were brought back into service much faster (39 hours vs. 105 hours). Figure 25 below shows the information for the individual outages. Old turbines performed the worst of the group, with the longest and most frequent outages. Note the left axis shows outage hours in a logarithmic format.

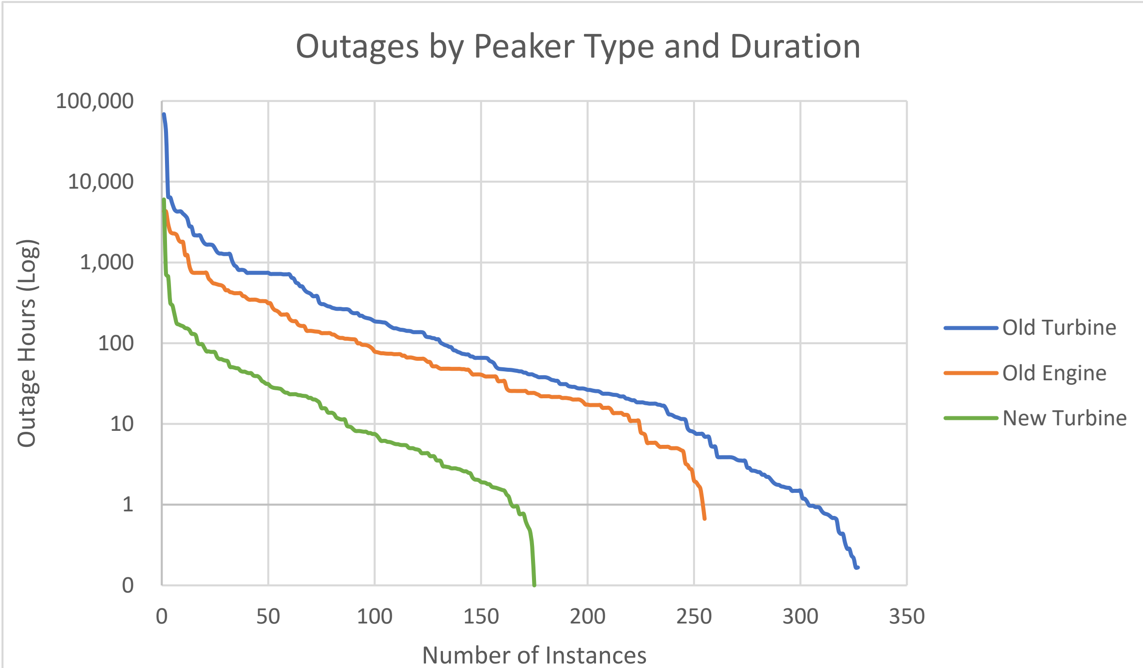


Figure 25 - Outages by Peaker Type and Duration

Q143. WHAT WERE SOME OF THE CHARACTERISTICS OF THE INDIVIDUAL UNIT-LEVEL OUTAGES THAT YOU FOUND?

A143. For the remainder of the analysis, any outage that began before 2016 was adjusted to begin on January 1, 2016. This eliminated the impact of extremely long outages on the data set.[128] As expected from the unplanned nature of these outages, there was a wide variety of outage frequency and duration. Individual units would go offline for hours, days, or weeks, and then come back online as they were repaired.

Figure 26 below shows a typical outage pattern for one year for two facilities, Putnam (a five-unit old engine facility) and Northeast 11 (a four-unit old turbine facility). Most of the outages lasted a few hours or days, but several stretched into weeks. Sometimes Putnam suffered individual engine outages, reducing its available capacity but not taking its entire

[128] For instance, one unit, Superior 11-4, was listed as being out of service for more than 7.5 years.

facility offline. Other times, the entire facility was taken offline and was not available to produce any power.

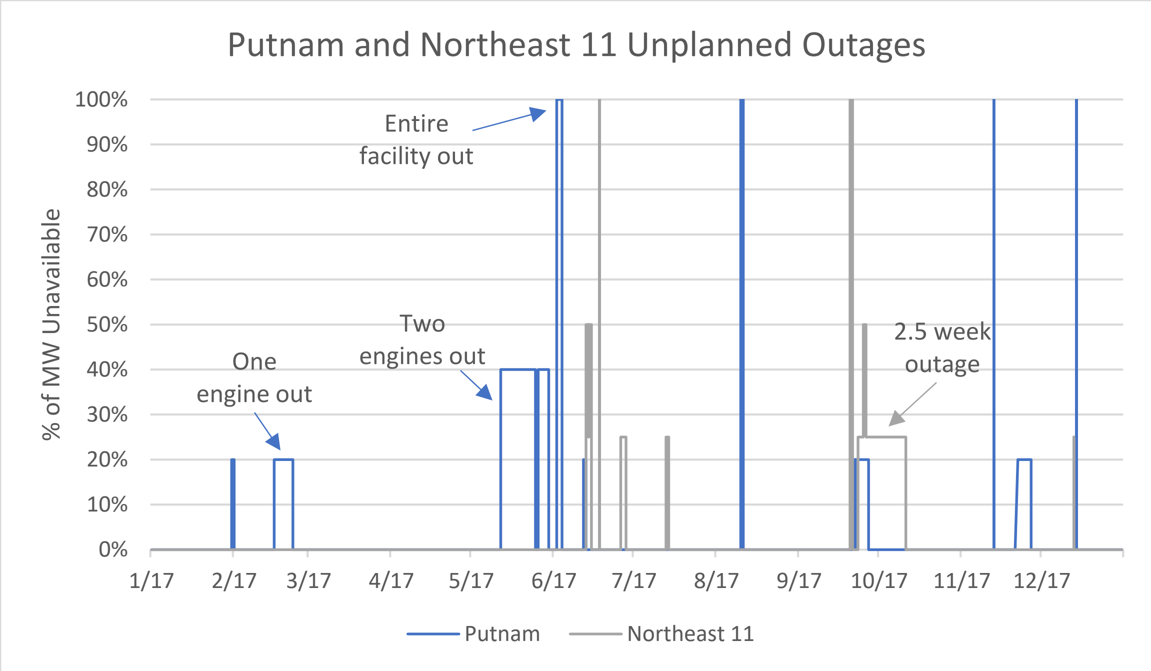


Figure 26 - Putnam and Northeast 11 Unplanned Outages

Q144. EXTENDING THIS ANALYSIS TO THE ENTIRE FLEET, WHAT INFORMATION ARE YOU ABLE TO GLEAN FROM THE OUTAGE DATA?

A144. There were many hours in which a substantial fraction of the generating capacity from the old engines and old turbines were offline from unplanned outages. Figure 27 below shows three years' worth of unit-level outage data broken by peaker type. The data shows the total fraction of total capacity of that peaker type that is unavailable due to unplanned outages.

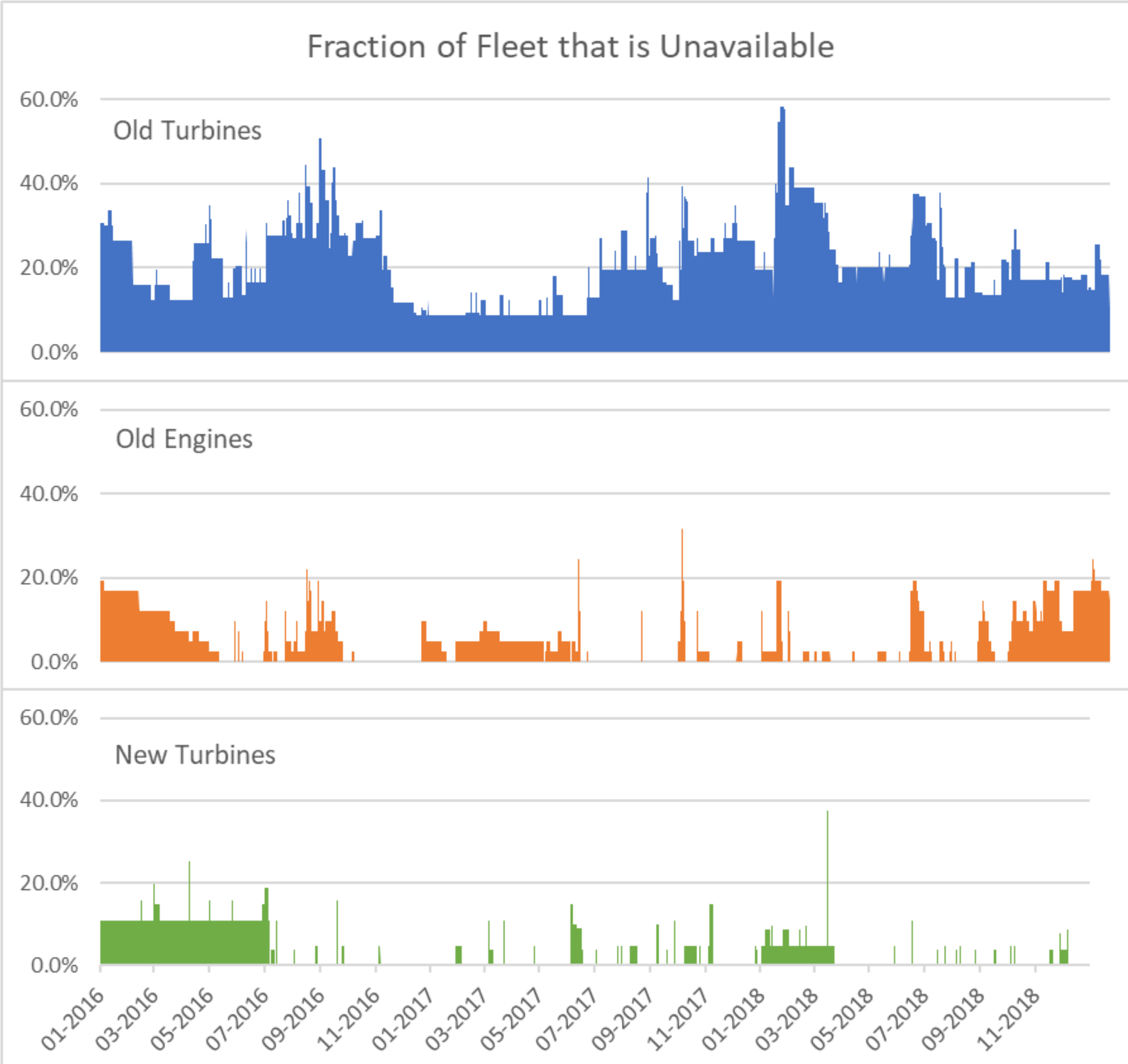


Figure 27 - Aggregate Outages by Peaker Type

The data clearly show that DTE's old turbines perform markedly worse than its old engines and new turbines. There was not a single hour between 2016 and 2018 where the entire old turbine fleet was available to serve load. The old engines had stretches of problematic performance, but as a whole performed better than the old turbines. The new turbine fleet experienced two extended outages, which skewed its average values. Outside of these two outages, the fleet was largely available to serve load.

Figure 28 below shows the outage duration curve for the fleet. Over three years, the old turbines – on average – experienced a loss of capacity from unplanned outages of 20.9%.

However, 15% of the time at least 30% of the fleet was offline, and more than 50% of the old peaker capacity was unavailable for 237 hours over three years. The old engines had a much lower average outage rate of 5.0%, but still had hundreds of hours in which many units were offline. The new peaker fleet performed better but still experienced several long-term outages that put its average outage rate at 3.2%. As I will show later, the periods of high outages are not necessarily independent of system conditions.

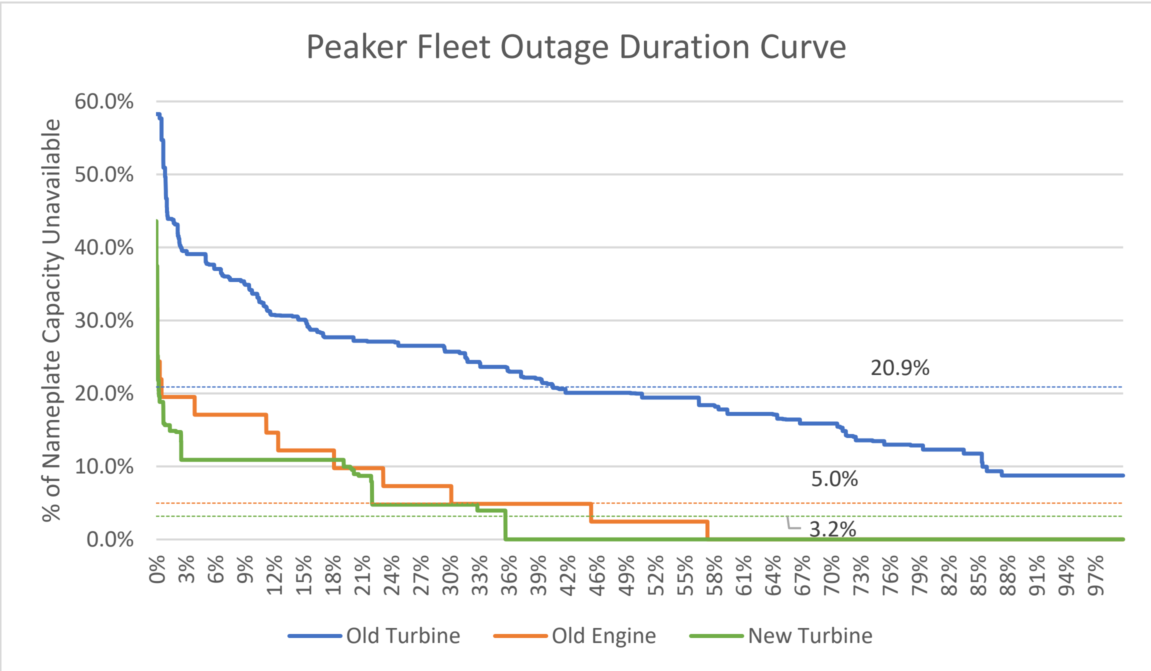


Figure 28 - Peaker Fleet Outage Duration Curve

Figure 29 below shows the same data as Figure 28 above, but denominated in MW of capacity to provide additional context to the scale of the issues. While the new turbines perform better as a fraction of their total capacity, even small percentage outages can cause large quantifies of MW to be offline.

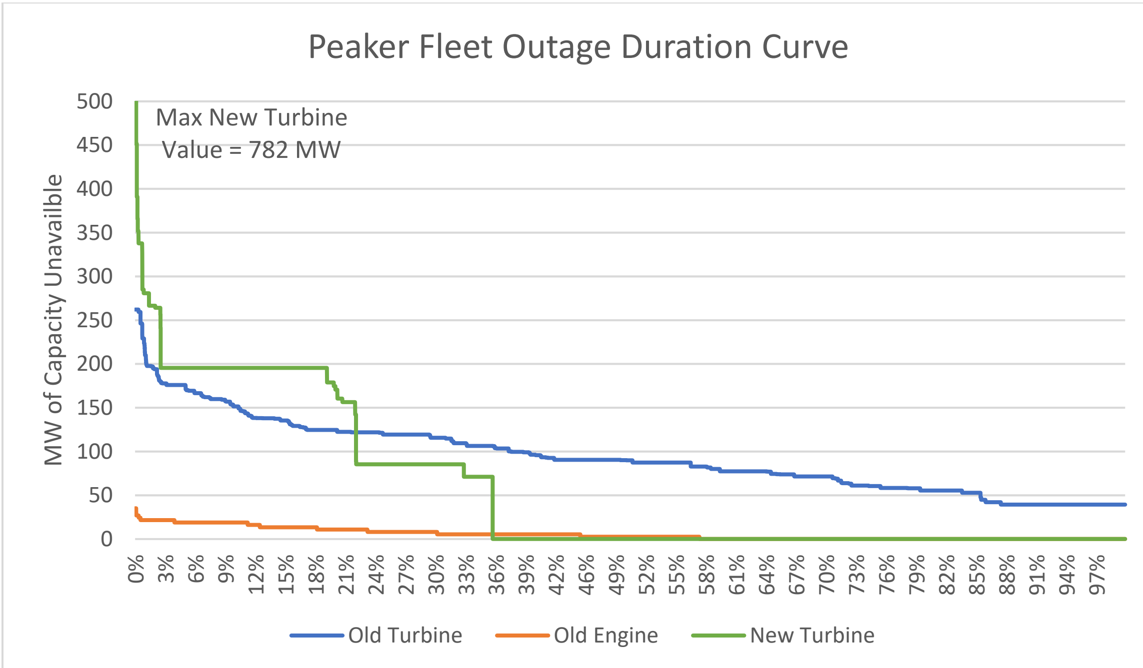


Figure 29 - Peaker Fleet Outage Duration Curve – MW

Finally, Figure 30 below shows the total fleet coincident outage duration curve, that is, a rank order of the total MW outages across all peaker types during any given hour. As expected, due to their large individual unit size, new peaker outages drive the total fleet outage level. Old turbine and old engine turbines occur throughout the hours, and generally appear to be uncorrelated with the new turbine outages.

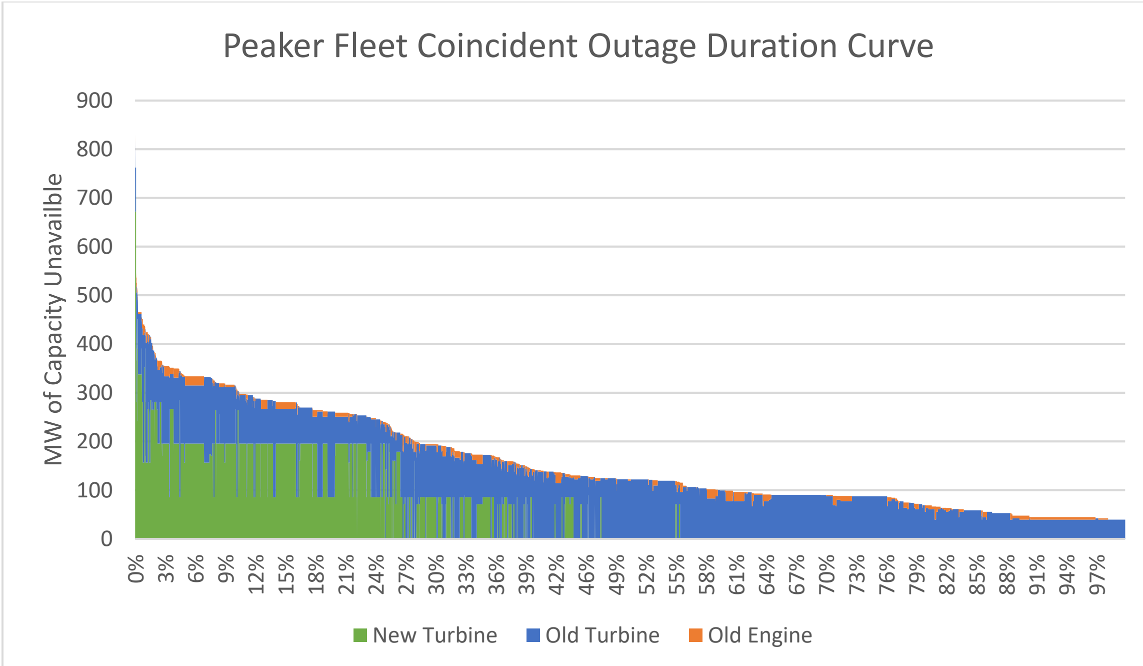


Figure 30 - Peaker Fleet Coincident Outage Duration Curve

There is a Distinct Seasonality to Old Unit Outages

Q145. WERE THE OUTAGES SPREAD UNIFORMLY THROUGHOUT THE YEAR?

A145. No. There is a distinct seasonality to the outages for the old turbines and old engines. Unfortunately, this seasonality is correlated with the times when the peaker plants are most needed to meet summer and winter loads. Figure 31 below shows by month the fraction of each peaker type's capacity that was unavailable. The old turbines failed during peak load months in the summer as well as peak winter load months of January and February. Old engines also performed worse in the winter than other times of the years. The new peakers had some seasonal variation, with more outages in the first half of the year than the second.

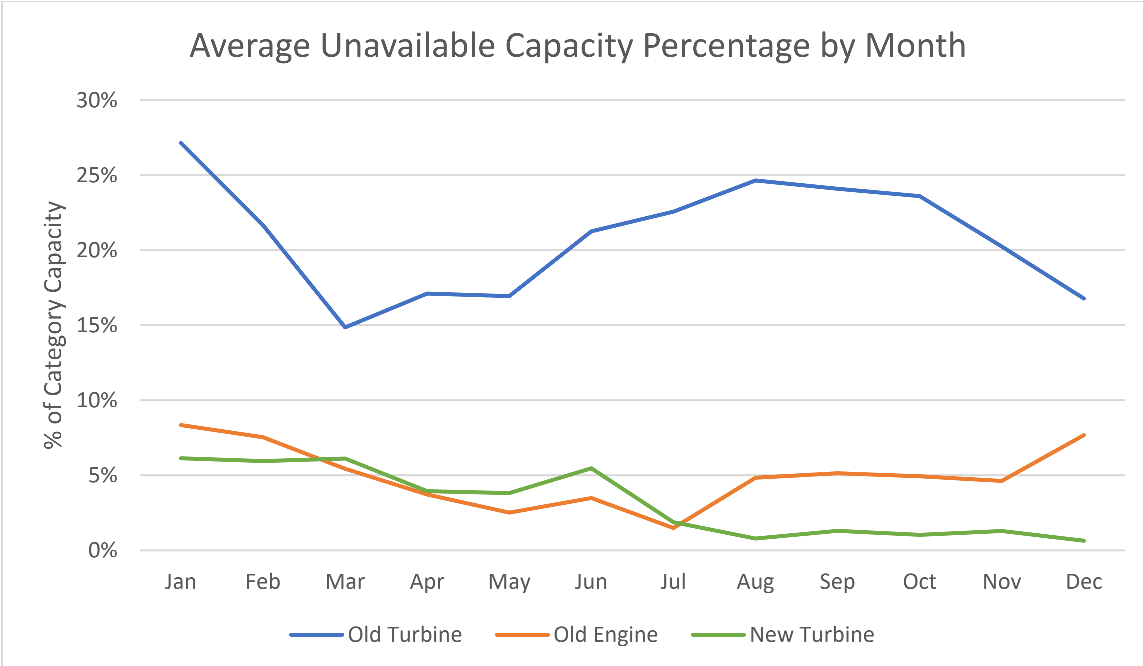


Figure 31 - Average Unavailable Capacity Percentage by Month

From an absolute capacity perspective, the lack of performance of the old turbines is notable. Figure 32 below shows the average MW that were unavailable in any given hour in a month across the three years of data. This averaging smooths the monthly outages across years, so for each year where performance was better than average, there was a year when performance was worse. The yearly data points are shown in the dashed lines, indicating how much variability exists between years.

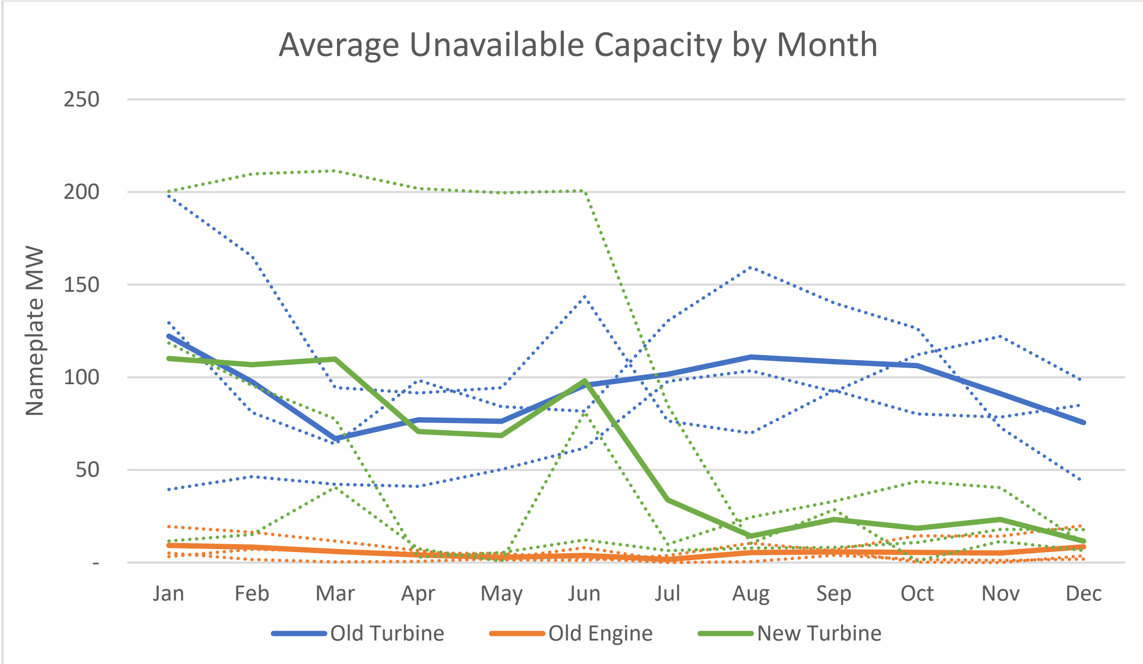


Figure 32 - Average Unavailable Capacity by Month

DTE's Old Peaker Outages are Highly Correlated with Usage and Consistently Fail When Needed

Q146. ARE OUTAGES FROM THE PEAKER FLEET RANDOM?

A146. No, they are anything but random. DTE's outage data shows that there are seasonal patterns to the peaker outages, with more failures in summer and winter months than in spring or fall. This is unsurprising as these units are more likely to fail when they are running than when they are sitting idle, and these units run more often in the summer and winter than in the shoulder seasons.

However, it is also clear from the data that the old peakers frequently fail when they are run. A troubling pattern occurs repeatedly throughout the three years' worth of generation and outage data. DTE's old peaking units are dispatched, begin to run, and then fail. As units are brought back online, other units fail. DTE is playing a constant game of whack-a-mole with outages during the exact times when the fleet is being called on to perform.

Q147. WHAT ANALYSIS DID YOU PERFORM TO SHOW THIS?

A147. I aggregated generation and outages data for each peaker type on an hour-by-hour basis for 2016 to 2018. Far from being random, simply running the Company's old turbines and engines caused a notable increase in failures. When plotted against each other, this trend clearly emerges. While the full data set is too large to visibly plot on one graph, I have included excerpts from the graph below in Figure 33.

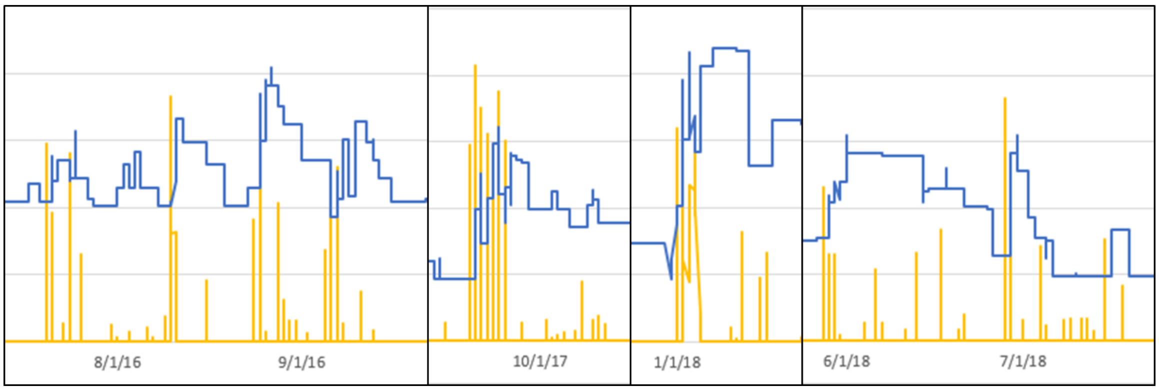


Figure 33 - Selected Old Turbine Generation and Outages

This graph shows generation and outages for the old turbine fleet for selected periods of time. Generation is in yellow, with each bar representing the maximum output of the fleet in a given day. Total outages in MW of capacity are plotted in blue. As units fail, the blue line rises; as units are repaired, the blue line falls. The trend is unmistakable: following periods of generation, units fail and go offline. Workers repair the units and bring them back on. When the fleet is called on the next time, more units fail. This sudden increase and gradual step-down pattern is present for old turbines through the entire data set, in all seasons.

Q148. ARE THE OTHER TYPES OF PEAKERS SIMILARLY AFFECTED?

A148. Old turbines show similar outage problems, although there are more times when the fleet is dispatched where units do not fail. That said, when the old engine fleet is dispatched at high levels or for multiple days in a row, there is a higher chance that a unit failure will follow.

New turbines did not show this behavior. As mentioned previously, the bulk of the total outage hours in the new turbine fleet were from two long-term failures. The new turbine fleet was often dispatched for many days with no failures, and when failures occurred, they were repaired quickly.

Q149. WHEN YOU COMBINE BOTH OLD ENGINES AND OLD TURBINES, DO THESE TRENDS CONTINUE TO APPEAR?

A149. Yes. Figure 34 below shows the full three-year data set with outages in blue and generation in orange. When total generation increased, as it did in summer 2016, September 2017, and January 2018, total outages spiked. The unavailability issue was so great that maximum coincident generation of old turbines and old engines at any time between 2016 and 2018 was 266 MW, less half of the total capacity of 561 MW of these units.

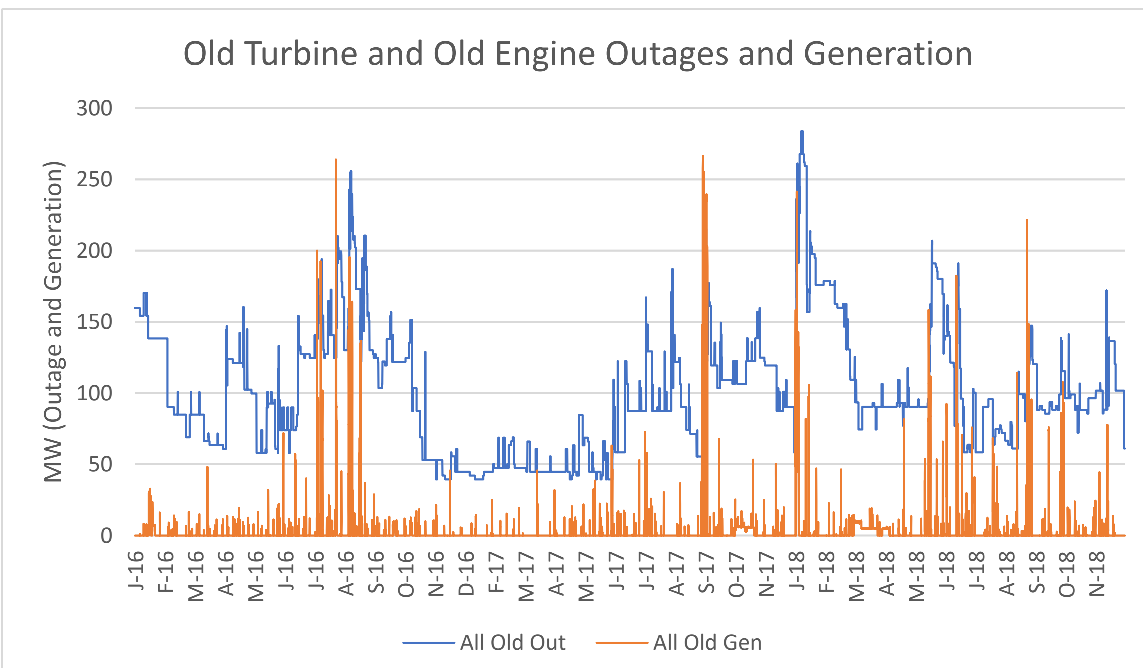


Figure 34 - Old Turbine and Old Engine Outages and Generation

Q150. IS THERE ONE PARTICULAR PERIOD OF TIME THAT HIGHLIGHTS THIS ISSUE?

A150. Yes. The week from September 19 to 26, 2017 exemplifies the reliability issues that DTE has with its old turbine and old engine units. This week brought unseasonably high temperatures to the Detroit area, and system load increased correspondingly. DTE's peaker fleet was called into action, with some of its new turbines running around the clock. Figure 35 below shows the total system load along with the peaker generation by type. This is the exact type of high-load period when peaker units are called upon to provide capacity and ancillary services, and reliable operation during extended heat waves is critical to continue to serve customer's heightened electricity needs. The new turbines provided the most power during this stretch, but the old turbines were dispatched seven consecutive days and the old engines ran 5 out of 6 days.

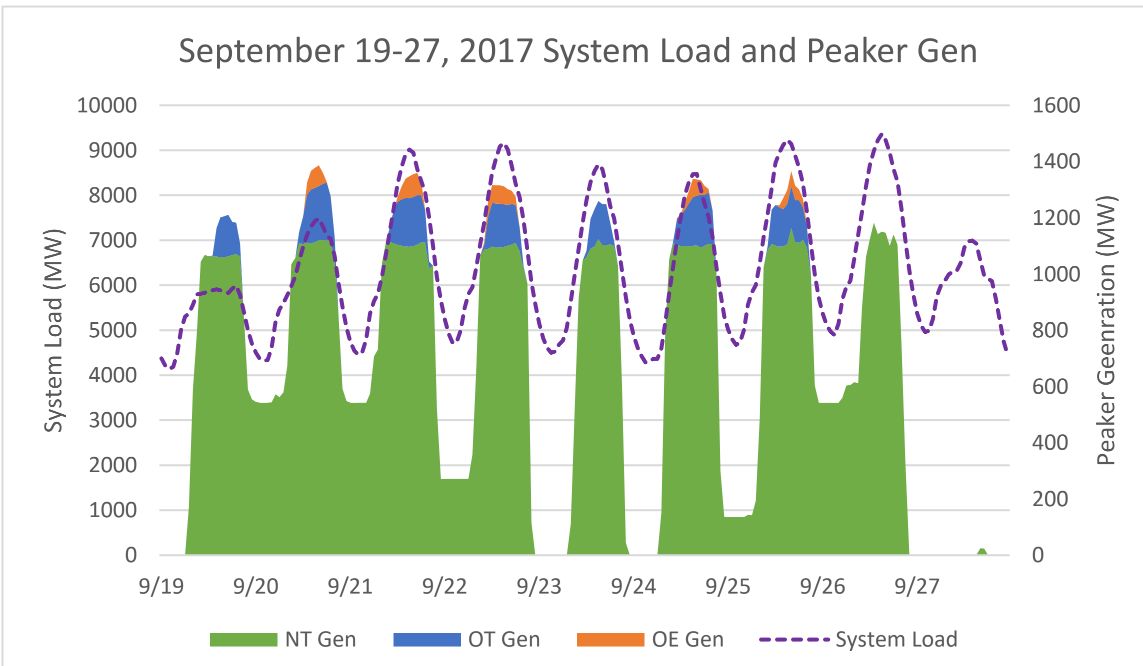


Figure 35 - September 19-27, 2017 System Load

The old peaker units experienced substantial failures during this heat wave. Over the three years between 2016 and 2018, the old turbines and old engines averaged 2.1 and 1.6 outages per week, respectively. But during this heat wave when they were most needed, there were 15 failures of individual old turbine units and 18 failures of individual old engine turbines. Figure 36 shows the individual failures of the units plotted as MW of capacity that went out of service. While DTE's plant managers did work hard to restore these units to service, there were 16 units that failed, were fixed, and failed again within this stretch of heavy operation. At the peak, more than 215 MW of these units – 43.5% of the net summer capacity – was offline and unable to meet DTE's load.

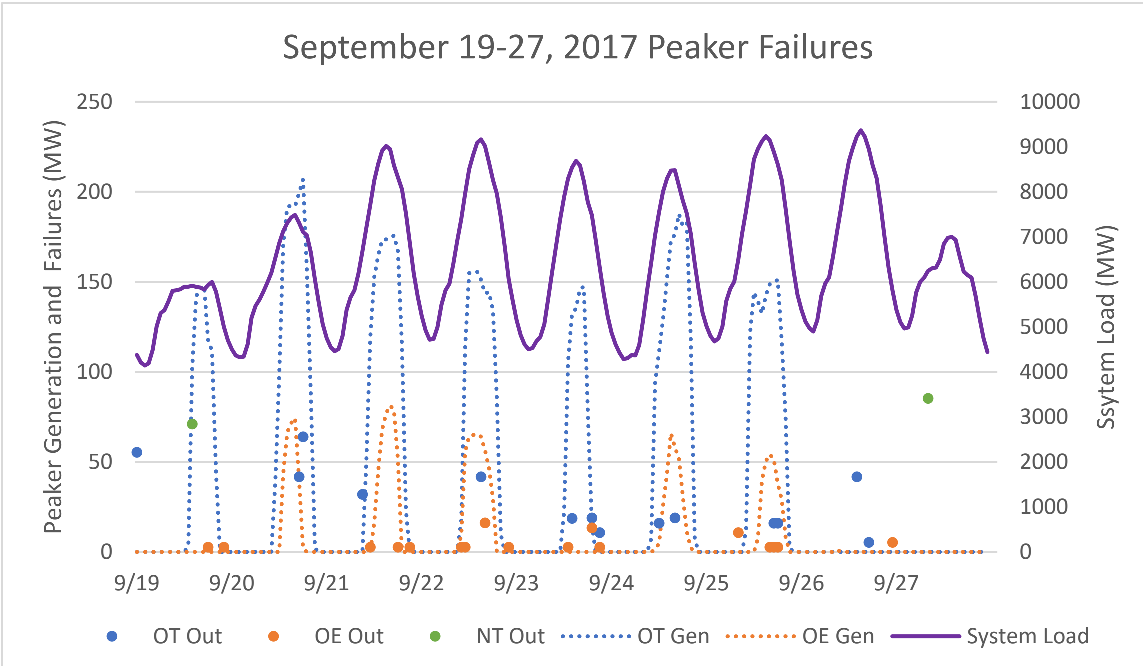


Figure 36 - September 19-27, 2017 Peaker Failures

Q151. WHAT IS YOUR GENERAL CONCLUSION ABOUT THE RELIABILITY OF THE PEAKER FLEET?

A151. After my thorough analysis of DTE's peaker generation and outage data, I found that there exists a wide variation between the different types of peakers in DTE's fleet. Its new peakers have generally performed well based on fleet-average figures. Two prolonged outages worsened its average metrics, but the full fleet was available for much of the three-year period. Old engines performed worse than the new turbines, but because of their small, modular nature, more of the total generating capacity was available when individual units went down unexpectedly. The old turbines had by far the worst performance. Units experienced prolonged and frequent outages, and the fleet's capacity was unavailable four times as often as the old engine peakers.

My analysis also shows that annual averages of individual units and facilities fail to account for issues such as long-term outages. Further, there is nothing random about the outages. There was a strong seasonality to outages for the old turbines, and to a lesser degree for the old engines. Even worse, old turbine and old engine units were much more likely than new peakers to break after periods of operation. As may be expected from running one of the oldest sets of gas turbines and engines in the country, DTE's old units break more often when called upon to perform.

DTE's Modeling of its Peaker Fleet Understates the Chance of Failure During High Load Conditions

Q152. HOW DID DTE MODEL FORCED OUTAGE RATES FOR ITS PEAKER FLEET?

A152. DTE modeled forced outages at the facility level, using a single constant value for each month between 2019 and 2040.[129] There is no seasonal variation, and no assumed increase in outages as units age. The oldest gas turbine currently operating anywhere in the entire country was installed in 1957 and is 62 years old. By 2040, the youngest of DTE's old turbines will be 69 years old, and the oldest 74 years old. Put another way, DTE's modeling assumes the same availability in 20 years from an entire fleet that will then be older than the oldest unit in operation.

Further, while this and other similar input worksheets contain variation in 2016 and 2017, it is unclear how the 2018 and forward data was calculated. It is not an average of the previous data, nor consistently determined (e.g. a ratio of 2017 outages) across units. For instance, the Dean peaker (DEAPKR) has an outage rate of 6.2% and 5.2% in 2016 and 2017, respectively, and is modeled from 2018 to 2040 at an 8.1% outage rate. At the same time, the Fermi, Slocam, and Superior peakers (collectively, PK OTHER 2) have a 22.3% and 25.6% outage rate in 2016 and 2017, respectively, but use a modeled rate from 2018 to 2040 of 21.3%. When asked about this discrepancy, DTE simply indicated that "2016-2017 data was not used in the modeling runs as all modeling started in 2018."[130]

[129] WP LKM-19 REF PCA PROMOD Inputs
[130] ELPCDE-11.79a, attached as Exhibit ELP-45 (KL-36)

Despite this lack of transparency on how the historic outages translate into modeled outages, DTE does model high outage rates for some of its old peaking units. The 63 MW Hancock 11 units have a modeled forced outage rate of 36.1%. The 77 MW Northeast 11/12 units are not much better, with a modeled forced outage rate of 28.2%. Another 104 MW spread between Fermi, Slocum, and Superior is modeled with a forced outage rate of 21.3%, although these units' performance in 2017 was worse with a forced outage rate of 25.6%.[131]

Q153. HOW DOES STRATEGIST INCORPORATE FORCED OUTAGE DATA?

A153. Strategist "is a probabilistic model that utilizes a representation of the load duration curve (LDC) and the input forced outage rates of the generators to determine both the expected generation of the unit and the expected remaining load for subsequent generators to serve."[132] Put another way, Strategist does not solve sequential hours of an actual load profile with generators either being available or unavailable to meet load. Instead, it sorts load from a modeled 168-hour load profile from highest load to lowest load, and performs a mathematical operation similar to an expected value calculation based on the generator's capacity and forced outage rate to determine how much load is served by each generator and how much remains to be served.[133]

Strategist's methodology does not mirror the actual dispatch of units to meet sequential hours of load. In practice, a unit is either available or not, and when it does offline, it is offline for a defined period of time in which is unable to serve load. The forced outage rate information captures the average result of this, but as discussed above, annual averages often hide seasonal fluctuations in availability or mask frequent short outages. DTE did not model any seasonal variation to its units, using the same forced outage rate data for each unit for a given year.[134]

[131] WP LKM-19 REF PCA PROMOD Inputs
[132] ELPCDE-10.77c, attached as Exhibit ELP-46 (KL-37).
[133] In concept, this is similar to calculating the expected generation from a unit, subtracted that value from the load to produce the expected remaining load, and moving to the next generation unit.
[134] WP LKM-19 REF PCA PROMOD Inputs

Q154. IS STRATEGIST ABLE TO ACCOUNT FOR THE TENDENCY OF OLD PEAKERS TO FAIL WHEN THEY ARE RUN?

A154. No. Because Strategist does not solve sequential hours, there is no ability for the model to correlate outages with load or with the duration of the current dispatch. When asked how outages that may correlate with system load, previous outages, or other factors are incorporated into Strategist, DTE replied "the concepts of 'randomness,' prior hour, or prior day are not applicable to how Strategist applies the FOR."[135]

Strategist is simply unable to duplicate the historic patterns of performance of DTE's old peaker fleet. By using averages outage rates instead of seasonal values, and by being incapable of correlating outages to system load or prior failures, it is highly likely that Strategist is overestimating the performance of its old peaker units and allowing them to contribute more capacity to meeting peak load conditions than would occur under real-world conditions.

Q155. HOW DOES PROMOD INCORPORATE FORCED OUTAGE DATA?

A155. PROMOD works fundamentally differently from Strategist. Instead of using a load duration curve methodology, PROMOD uses a Monte Carlo simulation. In this method, hourly load profiles are analyzed sequentially with system variables (e.g. load profile, solar generation, and generator state) determined by random draws based on the variables statistical descriptors (i.e. statistical distribution, average, and standard deviation). This methodology does more closely capture real-world performance as outage duration is determined for each unit. If a unit is determined to be randomly out of service (based on the units' forced outage rate), it will remain out of service for the requisite number of hours (based on the outage duration distribution).[136]

---

[135] ELPCDE-10.77f, attached as Exhibit ELP-47 (KL-38).
[136] ELPCDE-10.77e, attached as Exhibit ELP-48 (KL-39).

Q156. IS PROMOD ABLE TO ACCOUNT FOR THE TENDENCY OF OLD PEAKERS TO FAIL WHEN THEY ARE RUN?

A156. No. While PROMOD more closely simulates real-world outages than Strategist, DTE did not configure any seasonality to the unit outage rate. Similarly, the nature of the Monte Carlo outage draws was not correlated to system load, so the tendency for old peakers to fail when placed into service is not robustly modeled.[137] These modeling parameters again increase the chance that old peakers are deemed by the model to be available during high load periods than their real-world data suggest.

DTE's Failure to Track Costs for Individual Units Creates a Major Transparency Problem

Q157. HOW DOES DTE TRACK O&M COSTS FOR ITS PEAKER FACILITIES?

A157. When asked to provide a breakdown of historic fixed and variable O&M costs for its peaker units, DTE stated: "Actual O&M costs are tracked and reported at the peaker fleet level. Actual O&M costs are not separated by fixed and variable."[138] When asked to provide a O&M and capital costs breakdown between base, major maintenance, and environmental categories, it also claimed that this information "exists at the peaker fleet level and not at the unit level."[139]

Incredibly, the Company claimed that it has no visibility into the costs to run and maintain individual facilities, some of which provide hundreds of MW of power and cost more than one hundred million dollars to build. It also claims that it cannot separate fixed O&M costs (such as insurance) from variable costs (such as lubricants).

Q158. WHY IS THIS PROBLEMATIC?

A158. It is problematic for several reasons. First, any analysis on whether to continue to maintain and operate an individual facility or whether to retire the facility must be based in part on the

[137] ELPCDE-10.77f, attached as Exhibit ELP-47 (KL-38).
[138] ELPCDE-1.10d, attached as Exhibit ELP-49 (KL-40).
[139] ELPCDE-2.29, attached as Exhibit ELP-50 (KL-41).

underlying fixed and variable costs. DTE's retirement analysis for its baseload units relied heavily on this information – rightfully so – as any analysis lacking detailed, unit-level data cannot be considered robust.

Second, the distinction between fixed and variable costs is important to understanding the value that a facility is providing when compared to other alternatives. Suppose two units have the same capacity total cost of energy, but one of the units has lower variable costs and higher fixed costs than the other. If one were to consider retiring one of these units, a simple analysis on the amount of capacity and total cost of energy of the units would be insufficient to distinguish which is best to maintain. If the remaining unit will run more often as the result of the retirement, then selecting the unit with the lower variable costs may be the better option. However, to perform this analysis, the breakdown between variable and fixed costs is required.

Finally, the lack of transparency and access to this data is problematic for the Commission and outside parties to scrutinize whether DTE is making decisions that are in the best interests of its customers. Without this information, I was not able to perform a robust analysis on the relative economic merit of continuing to operate all of the existing peaker units or selectively retiring old units and replacing them with other sources of capacity and energy.

Q159. DID DTE PROVIDE ANY JUSTIFICATION FOR ITS DECISION NOT TO PERFORM ANY ANALYSIS ON RETIRING ITS PEAKER FLEET?

A159. Yes. DTE claimed that it was not retiring any peaker units "because these units provide many required functions to the electrical grid, distribution system, and power plant sites including, but not limited to, energy, capacity, voltage support, ramping energy, spinning reserves, supplemental reserves, station power, and black start."[140]

[140] STDE-13.14d, attached as Exhibit ELP-51 (KL-42).

Q160. ARE DTE'S OLD PEAKERS THE ONLY RESOURCES THAT ARE CAPABLE OF PROVIDING THESE SERVICES?

A160. No. Resources such as solar are able to provide many of these functions (e.g. providing energy and capacity), and S+S resources are able to provide even more (e.g. ramping energy and voltage support). The Company admits as much, noting that "[i]n discovery response STDE-13.14d, the Company is claiming the peakers listed in Exhibit A-12 are the only existing Company assets that can provide the site-specific functions listed in STDE-13.14d."[141]

Q161. WAS THERE ANY OTHER REASON THAT DTE DID NOT PERFORM A RETIREMENT ANALYSIS ON ITS OLD PEAKERS?

A161. Yes. DTE states "[i]n preparing for this IRP, the Company analyzed retirement for the units that were required by filing requirements to have retirement analysis."[142] It appears absent specific directives to perform such analyses, DTE did not proactively consider analyzing its many aging units.

DTE Should Consider Deployment of Solar and S+S to Replace its Aging and Unreliable Peakers

Solar is More Cost Competitive than New Advanced Combustion Turbines

Q162. IF DTE WERE TO RETIRE SOME OF ITS AGING PEAKER UNITS, WHAT RESOURCES SHOULD BE CONSIDERED FOR REPLACEMENT?

A162. Based on the frequency and duration that DTE's old turbines and old engines run, DTE has several options. It could replace these units with gas turbine peakers, modern RICE units, or with solar and S+S installations.

Q163. DID DTE PERFORM ANY ANALYSES ON THESE RESOURCES?

[141] ELPCDE-15.101a, attached as Exhibit ELP-52 (KL-43).
[142] ELPCDE-15.101b, attached as Exhibit ELP-23 (KL-14).

A163. It performed some. The LCOE of RICE units were substantially higher than gas turbine peakers, and thus were screened out of further analysis early in the process.[143] It performed detailed analysis on standalone solar facilities, but not for the purposes of replacing peaking generation. It did not perform any detailed analysis on S+S resources with the exception of proposing a pilot program to install and run a 11.4 MW S+S project.

Q164. WHAT WERE THE CHARACTERISTICS OF THE MODELED GAS TURBINE PEAKER?

A164. DTE modeled a 237 MW "advanced combustion turbine" unit with a projected capacity factor of 17%. This unit produced a levelized cost of capacity (LCOC) of $185.42/kW-year and a LCOE of $124.51/MWh.

Q165. HOW DOES THIS COMPARE TO THE CAPACITY AND GENERATION OF THE OLD TURBINE AND OLD ENGINE FLEET IN RECENT YEARS?

A165. When they are not offline from high unplanned outages, the old turbines and old engines provide a total nameplate capacity of 551 MW of nameplate capacity and 494 MW of net summer capacity. However, because of extensive outages and reliability problems, these units did not provide more than 267 MW of power during any single hour between 2016 and 2018. The total generation from 2016 to 2018 of these units was just under 70,000 MWh. This means that these units ran at an average capacity factor of just 0.48%.

Q166. HAVE ANY OF DTE'S NEW TURBINES RUN AT A 17% CAPACITY FACTOR?

A166. While individual units exceeded this level for single year periods, none attained this average level over multiple years. About half of DTE's new turbine units ran at an average capacity factor of 5-6% from 2014 to 2018, with the other half running on average roughly 8% and 12% of the time.

Q167. BASED ON THE COSTS THAT DTE MODELS FOR NEW ADVANCED CT UNITS, DO YOU BELIEVE THAT THESE UNITS WOULD ACTUALLY RUN AT A 17% CAPACITY FACTOR?

[143] Exhibit A-3 at 119.

A167. No, I do not. DTE provides a breakdown of the variable and fixed costs for the advanced CT unit. Variable costs (fuel and O&M) alone are $63.31/MWh.[144] That is, even if one doesn't include capital cost recovery, taxes, fixed O&M, and DTE's profits, the cost to produce energy is roughly double the current average LMPs in MISO. While LMPs do spike during some hours of the year, it is exceedingly unlikely that the advanced CT will find a market for nearly 1,500 hours a year of prices this high. In fact, DTE's modeled BAU LMPs (which are higher than the Reference scenario) only exceed $63.31/MWh an average of 100 hours a year from 2018 to 2022. While gas prices are projected to increase in the future (driving up LMPs), the gas price for the new advanced CTs will also increase. This will tend to depress the number of hours that the unit is economically dispatched.

The much more likely scenario is that these units will be dispatched less and run less often, which will increase the LCOE as more fixed costs will be recovered over fewer MWh. If one were to reduce the capacity factor of this unit to be more in line with DTE's current new turbines, the LCOE would increase to $227.16/MWh at a 6% capacity factor and $147.84/MWh at a 12% capacity factor.

Q168. HOW DO THESE FIGURES COMPARED TO YOUR UPDATED SOLAR COSTS?

A168. After making the updates discussed previously in my testimony, I calculate the LCOC and LCOE of single-axis PV systems as $104.10/kW-year and $50.80/MWh, respectively. However, because PV does not provide the same capacity credit as a CT, it must be adjusted. Using a 65% ELCC for single-axis tracking systems produces a LCOC of $160.15/kW-year.[145]

When compared to the advanced CT, solar produces an adjusted LCOC that is 14% lower and an LCOE that is nearly 60% lower. When compared against the LCOE using more realistic capacity factors for the advanced CT, the LCOE benefit of solar increases even

[144] WP LKM-448 LCOE
[145] The derivation of the 65% figure is discussed in Section III *infra*.

further. This is important as solar generation has zero variable costs (and thus its production can be cost-effectively sold into MISO's wholesale market at any time) and zero emissions (and thus is protected from upside cost risks associated with carbon pricing). So while a PV project that is replacing peakers is primarily used to provide power, it will also be able to reduce DTE's energy costs through its zero marginal cost energy. This is not a benefit that DTE's customers receive from the advanced CT unit.

S+S is Increasingly Cost Effective and is Being Utilized by Utilities Across the Country

Q169. HAVE THERE BEEN TRENDS IN THE INDUSTRY RELATED TO SOLAR AND S+S INSTALLATIONS PROVIDING PEAKING CAPACITY?

A169. Yes. Energy storage is increasingly being paired with solar to provide firmer capacity and to extend the ability of a solar-powered facility to meet summer evening loads. When coupled with tracking systems with high inverter load ratios, batteries can soak up additional DC power that would have been curtailed by the inverter and use this energy to extend operations after the sun goes down.[146]

Several utilities have begun to shift peaking capacity responsibility away from gas turbines and toward solar and S+S. Arizona Public Service recently announced a plan to add 850 MW of energy storage by 2025 to extend the operations of its solar plants into the evening. Some of these assets will be installed on existing solar facilities, while others will be built from scratch.[147] Florida Power and Light (FPL) also announced a major energy storage project, a 409 MW / 900 MWh battery that will be powered by its solar facilities and be online in the early 2020s. This system will provide peaking resources and allow FPL to

[146] Systems with higher inverter load ratios produce more DC power than can be converted by the inverter. By coupling a battery on the DC side of the inverter, extra energy that would have been lost in the inverter can instead be stored in the battery while the inverter continues to be supplied with 100% of its power rating.
[147] *Arizona utility's 950MW solar-plus-storage plan: 'clean energy and clean air'*, ENERGY STORAGE NEWS, https://www.energy-storage.news/news/arizona-utilitys-950mw-solar-plus-storage-plan-clean-energy-and-clean-air

retire two aging gas plants.[148] FPL owner NextEra Energy projects that even after the ITC expires in 2023, new unsubsidized PV will cost $30/MWh and new S+S will cost $40/MWh.[149]

NV Energy has signed multiple S+S contracts, and just recently announced yet another RFP result that will add 1,200 MW of solar and 590 MW of battery storage to its grid. One developer indicated that its 300 MW PV and 135 MW / 540 MWh storage project was contracted at $35/MWh.[150] These are consistent with other S+S projects that NV Energy recently signed, including a 200 MW PV with a 50 MW / 200 MWh battery at $34.87/MWh, a 100 MW PV project with a 25 MW / 100 MWh battery at $36.94/MWh, another 100 MW PV project with a 25 MW / 100 MWh battery at $30.94/MWh. The battery premium ranges between $4.50/MWh and $6.50/MWh over standalone storage. All of these projects will be online in the next two to three years.[151]

Q170. DESPITE THE FACT THAT OTHER UTILITIES ARE MOVING FORWARD WITH THOUSANDS OF MW OF S+S PROJECTS, DID DTE SERIOUSLY CONSIDER S+S IN ITS IRP?

A170. No. DTE claimed that because batteries were not selected in any least cost plan, that "[c]urrently, lithium-ion storage batteries and lithium-ion storage batteries and solar are uneconomical and limited in operational availability."[152] This clearly flies in the face of announcements from all over the country related to the pending deployment of S+S resources by other vertically integrated utilities in the next 2-5 years. While it is true that the solar

---

[148] *Florida Power & Light's Huge Solar-Plus-Storage System the 'New Norm' for Utilities*, GREENTECH MEDIA, https://www.greentechmedia.com/articles/read/florida-power-light-to-build-409-megawatt-solar-powered-battery-system#gs.m58b8d
[149] *Investor Conference 2019* at 135, NEXTERA ENERGY, http://www.investor.nexteraenergy.com/~/media/Files/N/NEE-IR/news-and-events/events-and-presentations/2019/06-20-2019/june-2019-investor-presentation.pdf.
[150] *NV Energy Announces 'Hulkingly Big' Solar-Plus-Storage Procurement*, GREENTECH MEDIA, https://www.greentechmedia.com/articles/read/nv-energy-signs-a-whopping-1-2-gigawatts-of-solar-and-590-megawatts-of-stor#gs.m5bfn7
[151] Docket No 18-06__, Application of Nev. Power Co., Pub. Util. Comm. Of Nev., http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2018-6/30441.pdf.
[152] Mikulan Direct at 70.

resource in Michigan is lower than in Arizona, the incremental cost of storage should not vary based on solar insolation.

I have already shown that standalone storage competes against any other technology on an energy basis and is cheaper than an advanced CT on a capacity basis even when DTE owns the projects. The premium that storage commands in other contracts is relatively small, adding roughly 15-20% to the total cost of the PPA. NV Energy's projects are expected to produce 2,700 MWh per MW, about 35% more than the 2,000 MWh per MW that DTE projects for its projects. If one were to gross up the NV Energy PPAs to reflect the same costs being spread over less energy, comparable S+S PPAs would be $40-50/MWh range. This is actually lower than my estimate for company-owned projects.

Q171. ARE THERE OTHER REASONS TO CONSIDER DEPLOYING S+S PROJECTS EARLY IN THE IRP TIMEFRAME?

A171. Yes. Storage that is installed with solar qualifies for the federal investment tax credit (ITC) of 30%. The ITC will soon step down, falling to 26% in 2020, 22% in 2021, and 10% in 2022. However, projects that spend a designated fraction of project costs can "safe harbor" the ITC based on the year in which the project commenced construction. DTE should strive to maximize the ITC for S+S projects by installing them as early as possible.

Q172. IS DTE PROPOSING ANY S+S IN ITS IRP?

A172. Yes. DTE does propose 11.4 MW of S+S project and indicates that it will perform several pilots with these projects that will investigate how well this resource is suited to tasks such as power quality improvement, ancillary services, and energy arbitrage.[153] However, providing peak capacity is not even on the list of tasks that DTE believes it should be studying, despite the industry clearly moving in this direction and the technology being clearly able to provide this service.

[153] Mikulan Direct at 73.

Solar and S+S Can Help Meet DTE's Peak Load

Q173. DID YOU PERFORM ANY ANALYSES ON HOW WELL SOLAR AND S+S COULD MEET DTE'S PEAK LOAD?

A173. Yes. I performed several analyses that evaluated the performance of solar and S+S during DTE's peak load. Using NREL's System Advisor Model (SAM), I first modeled the output of PV systems using "typical meteorological year" (TMY) weather files to match the methodology that DTE used in its modeling. I investigated the performance at the six locations utilized in the Brattle Report model, as well as additional locations with solar data in MISO Zone 7.[154] This analysis provides insight into the expected performance of PV systems at different locations in the Lower Peninsula.

Secondly, I modeled the output of single axis tracking PV systems using weather files that were specific to 2015-2017. Using actual weather files, rather than TMY weather files, are critical when comparing PV performance to historic load data. TMY weather files use monthly data from different years to represent the typical weather pattern of a given location. However, because system load in summer is highly correlated to hot, sunny afternoons, one cannot use TMY weather files to compare historic PV output during hot hours to historic system load of a given historic year.

Q174. PLEASE DESCRIBE YOUR TMY ANALYSIS AND RESULTS.

A174. Using the same input values that DTE claims to have used, I modeled single-axis tracking systems at the six locations that the Brattle Group used in its Renewable Integration analysis as well as at 20 other locations located in the Lower Peninsula. I calculated the output during the MISO-defined hours that are used in the ELCC calculation. The results of this analysis are below in Figure 37. ELCCs ranged from a high of 69.9% in Muskegon to 54% at Oakland County Airport, and a straight average performance of 62.7%.

[154] The six locations were Ann Arbor, Detroit, Flint, Grand Rapids, Kalamazoo, and Lansing. ELPCDE-9.76b, attached as Exhibit ELP-53 (KL-44).

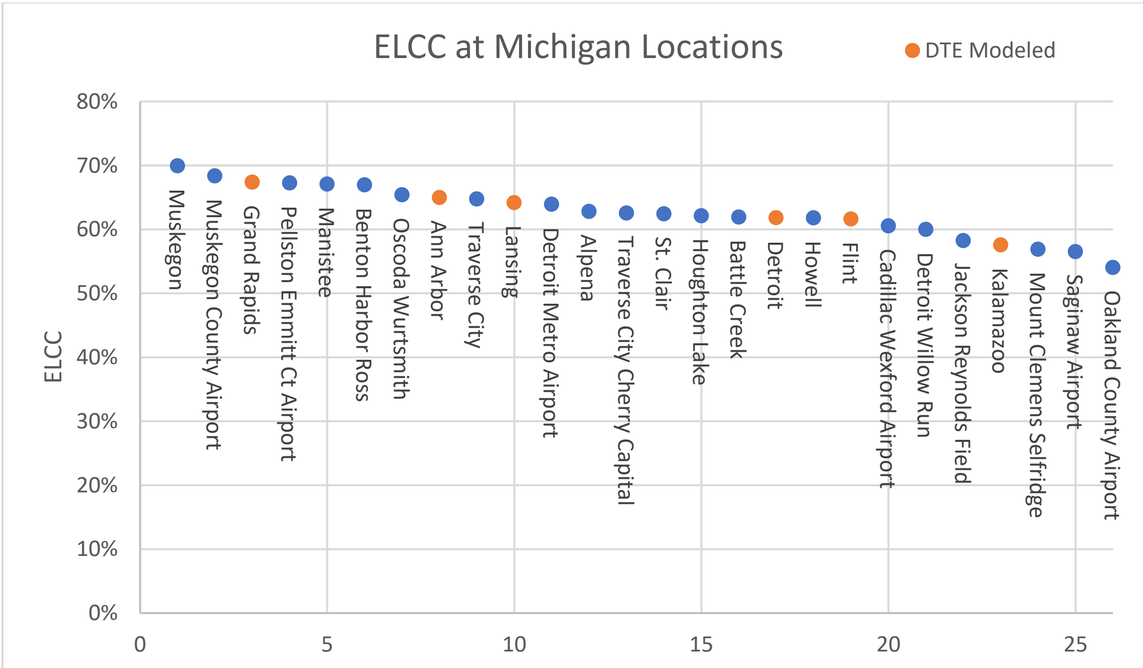


Figure 37 - ELCC at Michigan Locations

Q175. DO YOU BELIEVE THE STRAIGHT AVERAGE VALUE IS THE CORRECT VALUE TO USE FOR THE ELCC?

A175. No. Solar should be developed where it is most valuable. Since a considerable fraction of solar's value comes from providing capacity, DTE and developers will seek out locations that provide the best overall solar resource for both energy and capacity. Of the six locations that were selected by the Brattle Group, three were below average and would be less likely to be selected for actual development.

I recommend DTE use the average of the top 50% of locations. This produces an ELCC value of 65.8% while still providing substantial geographic variation to smooth out PV generation's short-term variability.

Q176. PLEASE SUMMARIZE THE RESULTS OF YOUR 2015-2017 WEATHER DATA ANALYSIS.

A176. Using the 2015-2017 weather files, I found that single-axis tracker solar performs very well during hours when DTE's system is experiencing high loads. During periods of extended heavy load, solar was producing a very high percentage of its rated capacity during and after the daily peak hour. Under MISO capacity guidelines that analyze performance during summer afternoons, single-axis tracking systems output an average of 69.2% of their inverter rating.

Adding storage to solar enhances the performance of these facilities even further. On those hot summer afternoons, power demand typically peaks between 4 and 6 PM EDT (3 and 5 PM EST), although there are many summer days in which the system peaks earlier. Importantly, system load falls quickly after the peak hour in a given day. Storage can extend the reach of PV to meet these later demands, as shown below.

Q177. WHAT ARE SOME OF THE CHARACTERISTICS OF DTE'S SYSTEM LOAD?

A177. DTE is a summer peaking utility. Figure 38 below shows monthly usage and peak demand from 2016 and 2017.[155] Peak demand in 2016 was 10.5 GW in August, while 2017 values were slightly lower at 9.8 GW in July. Winter peak demand was substantially lower, maxing out at 6.7 GW in December 2016 and 6.6 GW in December 2017. These values are roughly 34% lower than the summer peak demand. Given the magnitude of the difference in peak demand between summer and winter, and that DTE's old peakers run primarily in the summer months, I focus the remainder of this analysis on summer months (defined here as June through September).

[155] Load data from ELPCDE-8.75. While DTE did provide 2018 system data, 2018 weather files were not available for SAM and thus my analysis focused on 2016 and 2017.

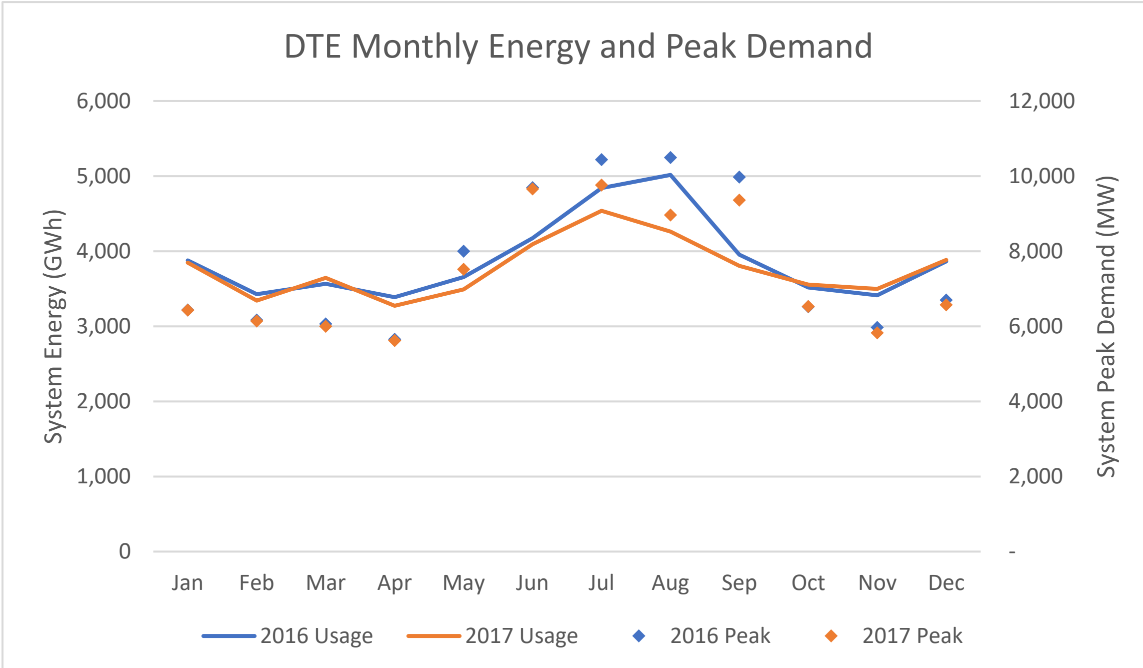


Figure 38 - DTE Monthly Energy and Peak Demand

Q178. WHAT DO DAILY LOADS LOOK LIKE IN THE SUMMER?

A178. Daily loads follow a predictable pattern, as shown in Figure 39 below for 2016 for the months of June ("6") to September ("9"). Daily minimums fall overnight, with a gradual growth until the late afternoon hours. The peak passes and load falls through the evening and overnight. Note that this and following charts use the "hour ending" convention using Eastern Standard Time. That is, the value for "14" on the chart indicates the hour between 1 PM and 2 PM EST (hour ending 14:00 or 2 PM EST), or 2 PM and 3 PM under daylight saving time.[156]

[156] SAM outputs data in EST format for 8,760 hours. DTE 2016 load data was adjusted to conform to EST format.

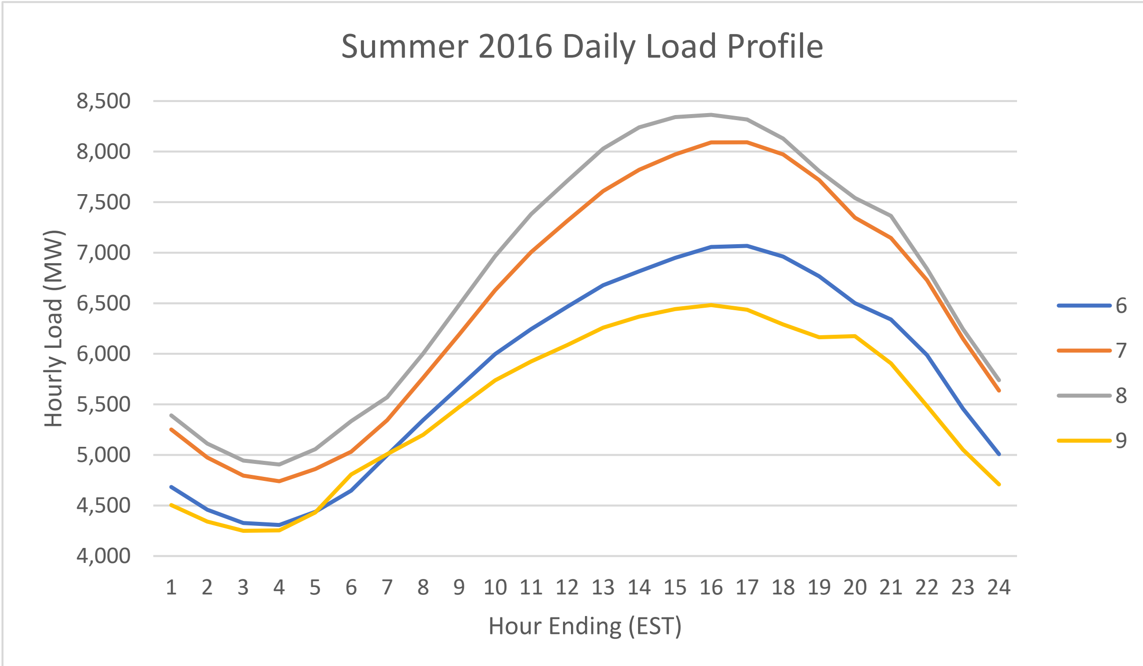


Figure 39 - 2016 Summer Daily Load Profile

Q179. IN WHAT HOURS DOES DTE'S SYSTEM TYPICALLY PEAK EACH DAY IN THE SUMMER?

A179. DTE's system peaks most often in HE16 and HE17 EST (4-5 and 5-6 PM EDT). Figure 40 below shows the total count of daily peaks for summer months from 2016 to 2017 along with modeled average PV production during the same hours. PV generation over the two-year average was extremely stable at roughly 70% of peak inverter rating from HE10 to HE16 before falling slightly to 63% in HE17. Further, DTE's system peaks earlier in the day (HE10-HE15) much more often when solar output is consistently high than later in the day (HE18-HE21). This shows that on average PV is available to serve substantial load during hours in which DTE's system peaks each day.

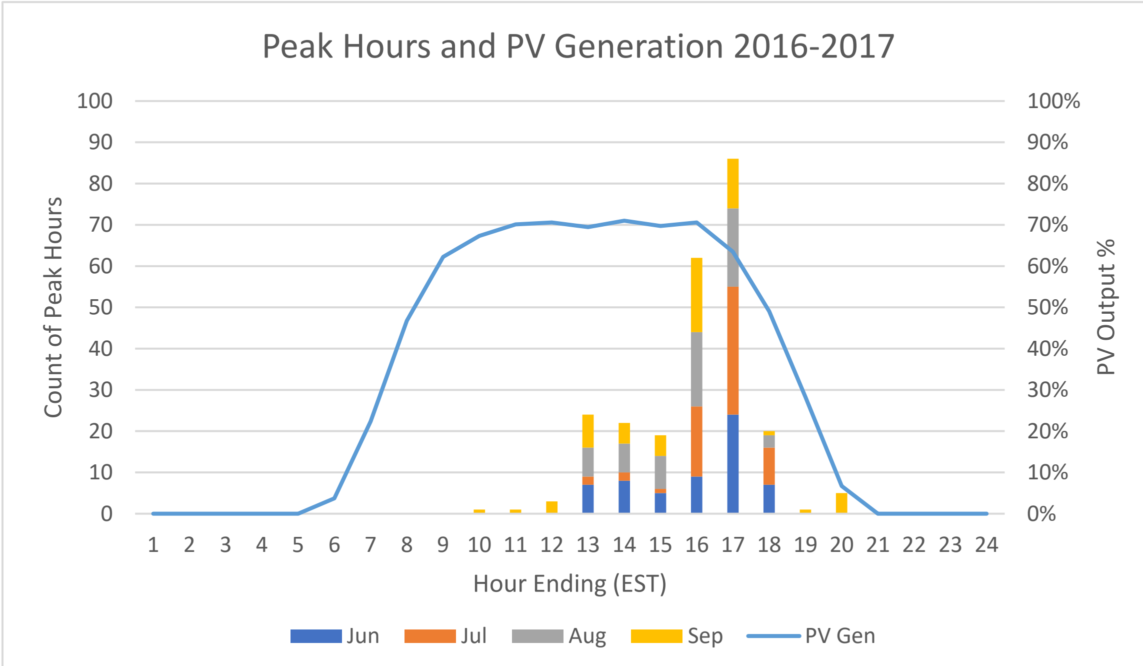


Figure 40 - Peak Hours and PV Generation 2015-2017

Q180. HOW DID STANDALONE SOLAR PERFORM DURING AND AROUND THE PEAK HOURS?

A180. Solar performed very well. One of the benefits of single-axis tracking systems is the trackers extend meaningful solar generation into the evening hours. Figure 41 below shows the system load and PV generation (as a percentage of PV capacity) during a July 2017 high-load period. Output from the tracker system approaches its daily max in the mid-morning and stays there until the mid-afternoon. While PV production on July 22 was below average, because of the cloudy weather, the system load was more than 1.8 GW lower than the peak demand of this week and put substantially less stress on capacity resources.

For the four peak load days in this stretch, a modeled PV system produced an average of 82% of its capacity during the peak hour of each day. Two hours after the peak, solar was still producing on average 53% of its capacity. Although this is a drop in performance, the average fall in system load between the peak hour and two hours later was 399 MW. This means that until DTE has at least 1,390 MW of PV on its system, the average fall in system load two hours after the daily peak was higher than the drop off in PV production in those same hours. Put another way, the rolloff in solar production is well-matched to the ramp down of system load for substantial quantities of PV.

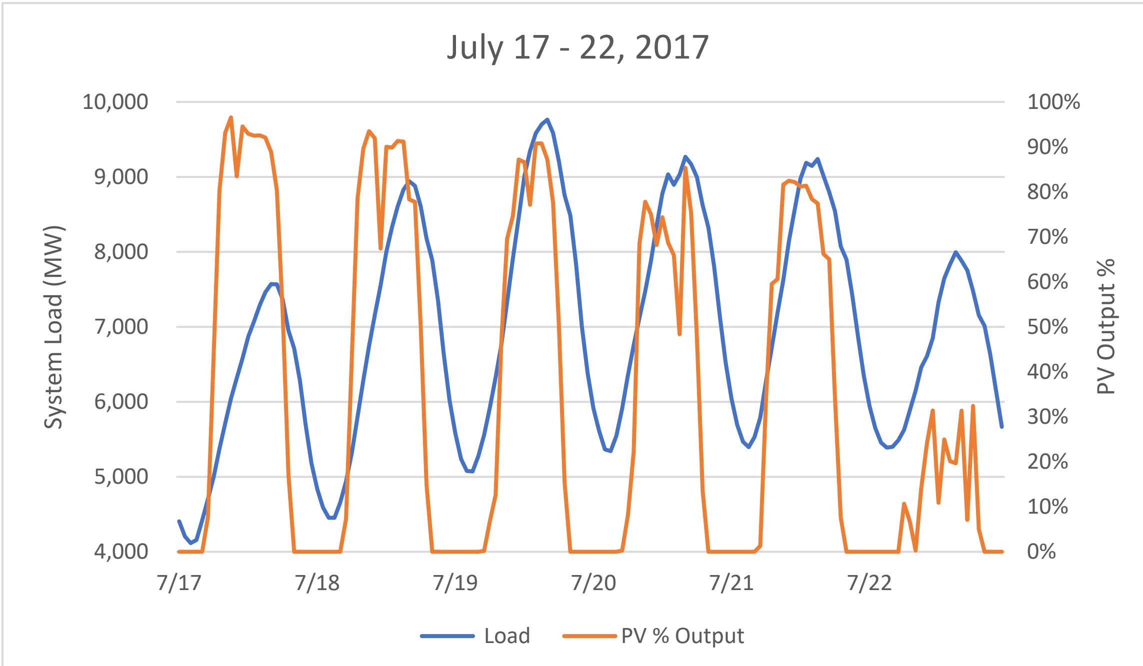


Figure 41 - July 2017 Load and PV Generation

Figure 42 shows the same data for the September 2017 period that was previously analyzed. While DTE's old peakers performed poorly during this heat wave, solar would have performed well despite the unseasonably late date of the high-load event. During the peak hour of the six high-load days, PV still produced an average of 67% of its rated capacity. Production did fall off more steeply two hours after the event, with solar producing 21% of its capacity. However, the load two hours after the peak fell more abruptly as well, dropping an average of 481 MW. The solar generation fall off would exceed the average drop in load only if DTE had more than 1,030 MW of PV on its system.

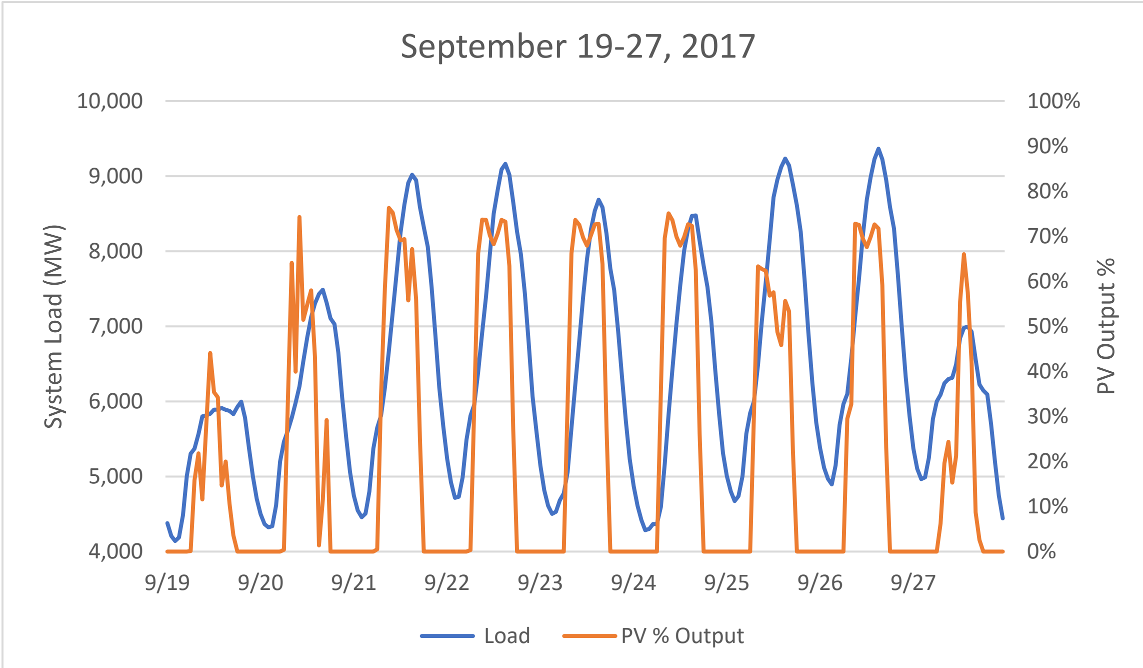


Figure 42 - September 2017 Load and PV Generation

Q181. HOW WOULD ADDING BATTERIES IMPACT THE PERFORMANCE DURING THESE TIMES?

A181. Adding storage would do two things. First, the battery could be charged from the solar production (a requirement to claim the federal ITC for storage) during early morning hours, when system demand is low and solar resources are not necessarily needed to meet load. Then, as the peak approaches, the battery can be discharged to either increase the output of the facility during the peak hours (e.g. move from 82% to 100% of rated capacity) or to extend the duration of solar production (e.g. extend the time at which the system produces a given percentage of its rated capacity). In either case, the S+S system is able to increase the value that it brings to the grid. Further, since the solar still maintains a larger fraction of its generation for several hours after the peak, a paired battery can be smaller in power and energy ratings and still successfully firm up the PV generation.

Q182. DO DTE'S PEAK HOURS AND LOAD SHAPES FOR OTHER PERIODS GENERALLY MIRROR THE TWO EXAMPLES ABOVE?

A182. Yes. I extended my analysis of output during peak load hours to all summer days. Figure 43 below shows the average PV output plotted against peak load hours for 2016, and 2017. The horizontal axis shows a descending sort of each individual hour's load as a percentage of the year's maximum load. The vertical axis shows the average output during the peak hour of the days up to that point. For hours in which system load was within 5% of the peak, single axis tracking systems averaged an output of 68% and 76% and of their rated capacity in 2016 and 2017, respectively. Performance remained around 67% of rated output in 2016 and 69% of rated output in 2017 for hours with a top 10% load.

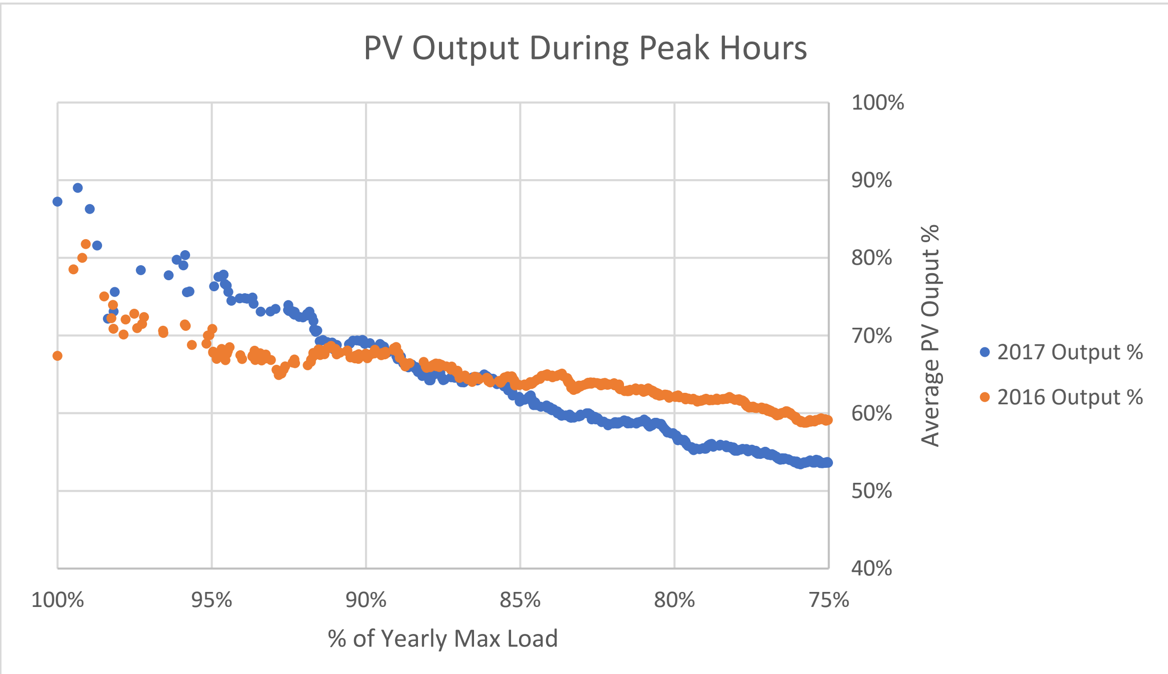


Figure 43 - PV Output During Peak Hours

Q183. ALTHOUGH MISO IS CONSIDERING A CHANGE TO ITS ELCC CALCULATION METHODOLOGY FOR FUTURE YEARS, DID YOU ANALYZE THE PV PERFORMANCE UNDER THE CURRENT RULES FOR 2015-2017 WEATHER DATA?

A183. Yes. While the solar ELCC revisions are being studies, MISO currently calculates the ELCC as the average performance during summer afternoons.[157] The average performance of the PV system during these hours was 66.5%, 73.4%, and 67.6% in 2015, 2016, and 2017, for a three-year average of 69.2%.

Q184. WOULD STORAGE HELP INCREASE THE ELCC VALUE FURTHER?

A184. Yes. The decline in ELCC under MISO's proposed methodology as more solar is added to the system is a byproduct of the coincident nature of PV generation. While broad geographic distribution of PV systems can help eliminate short-duration generation variability, installing more solar on the system generally adds more power during roughly the same hours. As the generation in these hours grows, the net system peak shifts to later hours when solar does not produce as much.

However, whether under MISO's current or proposed methodology, adding storage to a PV facility will increase the ELCC. Under the current methodology, the storage system can be charged during late morning and early afternoon hours and discharged during peak afternoon hours. This can firm the output of the PV system in the instance that the afternoon is cloudy and bring total output between PV and storage closer to the inverter rating of the system. Under MISO's proposed methodology, adding storage will allow solar generation to be shifted later in the evening. This extends the hours during which S+S can meet the new – and later – system peak load, and thus will increase the ELCC relative to solar alone.

Q185. WHAT ARE YOUR FINAL RECOMMENDATIONS WITH RESPECT TO DTE'S PEAKER FLEET?

A185. I recommend that the Commission direct DTE to perform a robust analysis of its aging peaker fleet, with a focus on the economics and performance of its old turbine units. As part of this analysis, DTE should consider using solar and S+S assets to replace some of its old units. Doing so could bring benefits to DTE's customers through the use of cleaner, zero-carbon peaking resources.

[157] *Supra* 91.

V. DTE'S DECISION TO OWN ALL RENEWABLE ASSETS WILL BURDEN ITS CUSTOMERS WITH EXCESS COSTS

Q186. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SECTION OF YOUR TESTIMONY.

A186. In this section, I discuss the mechanisms that make Company-owned projects more expensive than third-party resources. I also critique DTE's plan to own all of the VGPP projects, despite these not being required for reliability, RES, or capacity purposes. I briefly discuss why DTE's proposal to reduce the standard offer contract for PURPA generators is flawed, and end with a recommendation that the Commission establish minimum levels of third-party ownership for the benefit of DTE's customers.

Q187. WHAT ARE THE OVERALL RESULTS OF YOUR RENEWABLE ASSET OWNERSHIP ANALYSIS?

A187. DTE's plan to own all of the renewable assets in its PCA is unsupported from a policy standpoint. The Company plans renewables for three categories: statutory requirements, voluntary CO_2 reduction goals, and projected VGPP demand. Regardless of the ultimate purpose of the renewable assets, company-owned projects will be more expensive than projects contracted through third-party PPAs. Despite this, DTE performed no meaningful analysis between the costs and benefits of company ownership versus PPAs (including PURPA qualifying facilities).

The Commission anticipated seeing this exact analysis in IRP, as indicated in its July 18, 2019, order in DTE's Renewable Energy Plan in Case U-18232. While it reasoned that the REP did not require a detailed analysis of system ownership options, it was expected in this case because "[b]y statute, the IRP is intended to be a comprehensive look at supply-side resources needed to meet a utility's additional generation capacity needs."[158] Unfortunately, DTE has again failed to provide this analysis for the Commission to consider.

[158] Order dated July 18, 2019, Case No. U-18232 at 25.

The Commission should consider limiting the amount of capacity that DTE can own depending on the purpose of the asset. For statutory renewables, it may be reasonable for the Company to own a higher percentage of the renewable assets, although DTE's customers may benefit from reduced prices through third-party procurement. For CO_2 reduction goals, the Commission should consider further limiting the quantity of Company-owned renewables to mitigate the policy cost while still providing an incentive for the Company to pursue a worthwhile policy goal. For VGPP demand, the Commission should heavily scrutinize DTE's plan to own the assets to prevent the Company from pressing its monopoly position and instead should focus on provide renewable energy for its customers at the lowest possible cost.

DTE Again Failed to Analyze Third-Party PPAs as a Viable Option

Q188. WHAT IS THE OWNERSHIP STRUCTURE THAT DTE PROPOSES FOR ITS NEW RESOURCES IN THIS CASE?

A188. DTE proposes to own all of the new renewable assets in its plan, including those for the VGPP.[159] This means that for all of the resources that are built or purchased for the RES or carbon reduction goals, the cost would go into DTE's rate base and the Company would earn a return of and return on its equity from all customers. The Company would recover the costs of the VGPP assets from the VGPP participants, but it would still calculate the cost based on fully recovering its capital and earning a profit.

Q189. HAS THE ISSUE OF DTE'S OWNERSHIP OF RENEWABLE RESOURCES BEEN DISCUSSED IN OTHER CASES?

A189. Yes. This issue was at the core of DTE's 2018 Renewable Energy Plan (REP) in Case No. U-18232. In that case, as with this one, DTE proposed to own all of the assets that would be used to meet its statutory obligations or for its VGPP program. It used similar language

[159] ELPCDE-1.20e, attached as Exhibit ELP-54 (KL-45).

about the benefits of ownership as it did in this case, for instance, referencing its "top quartile" operations in turbine availability.[160] As with this case, DTE provided no analysis on the viability of other contractual methods, such as contracting for unbundled RECs, contracting through PPAs, or taking advantage of RECs from PURPA QFs.[161] In fact, the ALJ found this lack of analysis to be so troubling that she stated "[b]ased on the record in this case, however, this PFD concludes that DTE Electric's failure to present any analysis of third-party alternatives is a "fatal flaw" warranting rejection of the company's plan."[162]

Q190. DID THE COMMISSION ACCEPT THE PFD'S RECOMMENDATION TO REJECT THE COMPANY'S PLAN?

A190. No, but the Commission did modify the plan in agreement with some of the ALJ's criticisms. Specifically, the Commission noted that the lack of analysis of alternatives to company ownership was problematic: "The Commission agrees with the ALJ that DTE Electric has not sufficiently supported its entire plan to rely exclusively on company-owned generation assets, and to limit participation in the company's RFP to build-transfer contracts only."[163] It approved several company-owned wind projects that were underway that "with respect to these specific company-owned wind generation assets that qualify for the full PTC."[164]

Q191. DID THE COMMISSION HAVE THE SAME VIEW OF PROJECTS THAT DO NOT QUALIFY FOR THE FULL PTC?

A191. No, it did not. It stated:

> With respect to the company-owned wind generation that is projected to be built farther out in the plan period and will thus, not qualify for the full PTC, the Commission finds that there is insufficient evidence on the record to approve this portion of the proposed REP at this time. The company has demonstrated the savings that will accompany projects qualifying for 100% of the PTC, but the absence of those savings for company-owned generation raises questions for the Commission as

[160] PFD dated May 19, 2019, Case U-18232 at 34.
[161] *Id.* at 35.
[162] *Id.* at 43.
[163] Order dated July 18, 2019, Case No. U-18232 at 21.
[164] *Id.* at 22.

> to whether company-owned generation can be cost-effective when compared with alternative sources of generation."[165]

Q192. DID THE COMMISSION FIND THAT THE REP WAS THE APPROPRIATE VENUE TO MORE FULLY EXPLORE THIS ISSUE?

A192. No. The Commission found that the REP statute does "not explicitly require a utility to include alternatives to company-owned generation in its REPs" but continued to note that this analysis would have been "especially important to such regulatory determinations given the dollar amounts at stake, the dynamic nature of energy markets and technologies, and the potential for cost savings from examining all options, including different technologies and ownership models as part of the company's overall resource portfolio."[166]

Q193. WHERE DID THE COMMISSION EXPECT THIS DISCUSSION OF ALTERNATIVE TO TAKE PLACE?

A193. It expected it to take place in this case. The Commission wrote:

> Consistent with the ALJ, the Commission's concern with respect to the analysis of alternatives goes beyond PURPA and REC-only purchases. The Commission stresses the need to fully evaluate approving over $95 million in ICC of new renewable generation. Therefore, as part of its approval with changes consented to by the company, the Commission defers a final determination on the proposed renewable generation assets not qualifying for the full PTC until the Commission issues a final order in DTE Electric's IRP proceeding, Case No. U-20471. By statute, the IRP is intended to be a comprehensive look at supply-side resources needed to meet a utility's additional generation capacity needs. See, MCL 460.6t(1)(f).
>
> As such, the Commission will examine DTE Electric's proposed renewable generation not approved in this order in the IRP, enabling the Commission to look at the proposed projects along with other renewable technologies with the aid of a fully developed and more robust evidentiary record. The Commission notes the importance of comparing technologies as the renewable energy technology landscape is quickly evolving and the company should consider expanding the inputs to its bidding parameters to be inclusive of these changes.

Given the Commission's concern about needing to more fully evaluate a $95 million cost, DTE's failure to provide any meaningful analysis of more than $3 billion in renewable assets is simply unacceptable.

---

[165] *Id*.
[166] *Id*. at 23.

Q194. DID DTE COMMIT IN THIS CASE TO FOLLOWING A COMPETITIVE PROCUREMENT PROCESS FOR THESE NEW RENEWABLE ASSETS?

A194. No. DTE stated: "The Company expects to continue its historical practice of utilizing competitive bidding when implementing renewable sourcing strategies. However, it is too early for the Company to speculate about the details of such sourcing strategies or associated RFP details that will be implemented six or more years in the future."[167]

Q195. DID THE COMPANY CONSIDER CONTRACTING WITH THIRD PARTIES THROUGH PPAS OR PURPA QF PURCHASES TO MEET SOME OR ALL OF ITS RENEWABLE RESOURCE REQUIREMENT?

A195. No, it did not. As with the REP plan, DTE provided no analysis of alternative ownership structures. Instead, DTE justified its position by stating "[t]here are significant benefits to customers from owned assets, including decreased performance risk (DTE Electric is a top quartile operator), long-term benefits to customers after the asset's depreciated life, decreased contract risk including risk of termination and change of ownership, and reduced balance sheet impacts from long term liabilities."[168]

Q196. DID DTE PROVIDE ADDITIONAL DETAILS ON WHAT IT MEANS BY TOP QUARTILE OPERATOR?

A196. Yes. DTE does appear to operate its renewable assets competently based on attaining a top quartile ranking on fleet availability for at least one year, but the Company cannot confirm whether this was influenced on the relative newness of its renewable fleet.[169]

Q197. DID DTE PERFORM ANY ANALYSES RELATED TO THE RELATIVE COSTS OF COMPANY-OWNED PROJECTS AS COMPARED TO THIRD-PARTY PPA PROJECTS?

A197. No, DTE has not performed any such analysis.[170]

---

[167] STDE-2.1, attached as Exhibit ELP-55 (KL-46).
[168] *Id.*
[169] ELPCDE-6.57a, attached as ELP-56 (KL-47), ELPCDE-6.57e, attached as Exhibit ELP-57 (KL-48).
[170] ELPCDE-3.44c, attached as Exhibit ELP-58 (KL-49).

Q198. DID DTE PERFORM ANY ECONOMIC ANALYSIS ON THE LONG-TERM BENEFITS THAT ACCRUE TO ITS CUSTOMERS AFTER THE ASSET'S DEPRECIATED LIFE COMPARED TO THE COSTS INCURRED DURING ITS USEFUL LIFE?

A198. No, DTE has not performed any such analysis.[171]

Q199. HAS THE COMPANY QUANTIFIED THE SUPPOSED PERFORMANCE RISK DECREASE ASSOCIATED WITH COMPANY OWNERSHIP?

A199. No, DTE has not performed any such analysis.[172]

Q200. HAS THE COMPANY QUANTIFIED THE SUPPOSED LONG-TERM BENEFITS TO CUSTOMERS AFTER THE ASSET'S DEPRECIATED LIFE FROM COMPANY OWNERSHIP?

A200. No, DTE has not performed any such analysis.[173]

Q201. HAS THE COMPANY QUANTIFIED THE SUPPOSED DECREASE IN CONTRACT RISK INCLUDING RISK OF TERMINATION AND CHANGE OF OWNERSHIP FROM COMPANY OWNERSHIP?

A201. No, DTE has not performed any such analysis.[174]

Q202. HAS THE COMPANY QUANTIFIED THE SUPPOSED BENEFITS OF REDUCING BALANCE SHEET IMPACTS FROM LONG TERM LIABILITIES CAUSED BY COMPANY OWNERSHIP?

A202. No, DTE has not performed any such analysis.[175]

Q203. IN SHORT, DID DTE PERFORM ANY ANALYSIS TO SHOW THAT COMPANY OWNERSHIP IS DEMONSTRABLY BETTER OR LESS EXPENSIVE THAN PPAS FOR ITS CUSTOMERS?

A203. No. Aside from having a relatively high fleet availability rating, DTE has not provided any economic or operational analysis on why Company ownership is better than third-party PPAs for its customers. While it provided some hypothetical reasons that this may be the case, the Company did not actually perform any analyses to support its position. Given the

---

[171] ELPCDE-3.44e, attached as Exhibit ELP-59 (KL-50).
[172] ELPCDE-3.44f, attached as Exhibit ELP-60 (KL-51).
[173] *Id.*
[174] *Id.*
[175] *Id.*

Commission's anticipation of these analyses given the "comprehensive" nature of the IRP, the oversight is particularly troubling.

Q204. HAS THE ISSUE OF THIRD-PARTY PPAS COME UP IN OTHER RECENT IRPS?

A204. Yes. Consumers Energy's recent IRP in Case U-20165 discussed this issue extensively. Many parties provided testimony on the merits of allowing third-party competition in addition to utility-ownership of new capacity. In the end, the Commission approved a settlement agreement that required DTE to sign PPAs for at least 50% of its new capacity.[176]

Q205. GIVEN THIS, WHY DO YOU BELIEVE THAT DTE PROPOSES TO OWN ALL OF THE RENEWABLE ASSETS?

A205. I believe the reason is straightforward: owning the assets allows DTE to earn more profits to pass on to its shareholders. DTE did not perform any analysis on the supposed benefits of utility ownership as specifically compared to PPAs or PURPA QFs. The Company also did not perform any analysis on any other alternatives to utility ownership that could have provided different incentives for pursuing third-party PPAs. DTE was certainly aware of the arguments on alternative ownership structures and incentives put forth by Consumers Energy, but chose not to incorporate any such testimony in its case. Instead, it proposed an ownership structure that maximizes the profit opportunity for its shareholders at the expense of its customers and failed to provide to the Commission an "especially important" analysis.

Utility-Owned Resources are More Expensive than Third-Party Owned Resources

Q206. WHAT IS THE SCALE IN CAPACITY AND COST OF THE RENEWABLE ASSETS THAT DTE PROPOSES IN ITS VARIOUS PCAS?

A206. DTE's PCAs range in terms of the timing and total build out of renewables, but in all cases, there is a substantial ramp up of renewable resources in both the near term (2019-2024) and the mid- to long-term (2025-2040). DTE plans to build three categories of renewables. The

[176] Order dated June 7, 2019, MPSC Case U-20165.

first is to meet its statutory renewable energy requirements. The second is to meet its self-imposed voluntary carbon reduction goals. The final type is to supply its proposed VGPP programs.

Table 7 below summarizes the proposed total solar and wind buildouts for each of these schedules above and beyond the Company's 2018 existing resources.[177] DTE's various proposals would result in the Company building roughly 5 GW of new renewables by 2040.[178] Using DTE's own capital cost estimates, this represents an additional $7.2 billion in capital expense.

	MW				Dollars ($mm)			
	15% RES	CO_2	VGPP	Total	15% RES	CO_2	VGPP	Total
2019-2024	**716**	**200**	**865**	**1,781**	**$1,307**	**$345**	**$1,387**	**$3,039**
Solar	11	50	250	311	$12	$53	$263	$328
Wind	704	150	615	1,469	$1,295	$292	$1,124	$2,711
2019-2040	**716**	**2,975**	**1,390**	**5,081**	**$1,307**	**$3,928**	**$1,956**	**$7,191**
Solar	11	2,525	775	3,311	$12	$2,913	$833	$3,758
Wind	704	450	615	1,769	$1,295	$1,015	$1,124	$3,434

Table 7 - DTE PCA Renewable Buildout

While DTE has maintained that its long-term plans are more flexible, the Company has indicated that it plans to pursue its "defined" activities in the near term (2019-2024). In the next five years, DTE proposes to build up to 1.8 GW of new renewable capacity at an estimated incremental cost of approximately $3.0 billion.

Q207. HOW MANY OF THESE RENEWABLES ARE FOR DTE'S RENEWABLE REQUIREMENTS, FOR ITS CARBON REDUCTION GOALS, AND FOR ITS VGPP PROGRAMS?

A207. In the defined PCA timeframe, VGPP renewable projects comprise a substantial portion of DTE's planned build. DTE plans to build 716 MW for its renewable requirements at an estimated cost of $1.3 billion to meet its statutory obligations in the defined PCA time

[177] Data for the VGPP represents the more aggressive PCA A&B Pathway.
[178] Exhibit A-18.

horizon. It proposes an additional 200 MW for its carbon reduction goals at an estimated cost of $345 million. Finally, it proposes up to 865 MW of new renewables for the VGPP at an estimated cost of $1.4 billion.

In the long term, DTE's carbon reduction self-builds become the dominant policy source for new renewables. The Company plans nearly 3 GW of new renewables for these goals at a projected cost of $3.9 billion. This is coupled with a total VGPP estimate of 1.4 GW at a projected cost of $2 billion.

Q208. ARE WIND AND SOLAR PROJECTS DISTRIBUTED EQUALLY DURING THESE TIME FRAMES?

A208. No. DTE's RES and carbon goal self-builds and VGPP builds differ substantially between the two time frames. In the "defined" PCA, almost all self-builds and VGPP builds are wind projects. In the less aggressive VGPP PCAs, only 11 MW out of 1,631 MW is solar. By contrast, in the "flexible" portion of the PCA (2025 – 2040), nearly all new build is solar.

Q209. DID THE COMPANY HAVE ANY EXPLANATION FOR THIS SWITCH IN RESOURCE MIX?

A209. As discussed previously, the renewable buildout plan was not determined or influenced by any modeling performed in this case. Instead, DTE relied on even more out-of-date LCOE projections from its previous RES case to select mostly wind in the early years and mostly solar in the later years.[179]

Results From Competitive Procurements Show How Far PPA Prices Have Fallen

Q210. WHILE NREL'S ATB CONTAINS COST DECLINE PROJECTIONS, HAVE THERE BEEN OBSERVABLE TRENDS IN THE MARKET THAT SHOW HOW SOLAR PRICING HAS CHANGED?

A210. Yes. Prices for PPAs have been falling for years as PV panel prices fall and financial entities become more familiar with project development. Figure 44 below shows data on PPA prices from Berkeley Lab based on PPAs signed through 2018. The downward trend is unmistakable and has continued consistently across all regions.

[179] ELPCDE-13.88a, attached as Exhibit ELP-15 (KL-6), ELPCDE-13.88c, attached as Exhibit ELP-61 (KL-52).

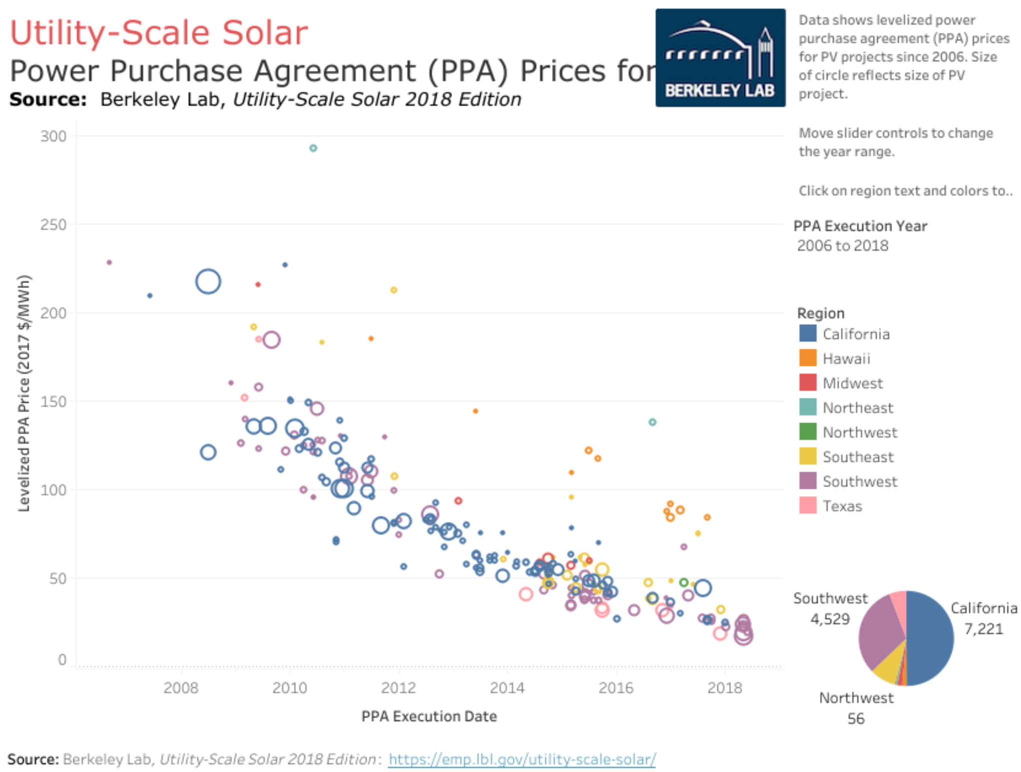


Figure 44 - Berkeley Lab PPA Price History

Q211. HAVE THESE DOWNWARD TRENDS CONTINUED IN 2019?

A211. Yes. PPA prices have continued to fall in 2019. I already discussed recent S+S PPAs that have been priced in the low- to mid-$30/MWh range, but there are many other examples of competitive procurements that have led to very low solar pricing. Los Angeles Department of Water and Power just signed a two-phase 25-year PPA that will purchase solar power for $19.97/MWh from a 400 MW project and purchase stored energy from a 100 MW / 400 MWh battery at an additional $13.00/MWh.[180] NV Energy signed a 25-year PPA for 300 MW of solar at a fixed price of $23.75/MWh.[181] JEA in Jacksonville, Florida, signed PPAs

---

[180] *Los Angeles seeks record setting solar power price under 2¢/kWh*, PV MAGAZINE, https://pv-magazine-usa.com/2019/06/28/los-angeles-seeks-record-setting-solar-power-price-under-2%C2%A2-kwh/.

[181] *Would you pay 1.795¢/kWh for solar power in 2043?*, PV MAGAZINE, https://pv-magazine-usa.com/2018/06/12/would-you-pay-1-795%C2%A2-kwh-for-solar-power-in-2043/.

for 250 MW of projects for a fixed 25-year price of $26.00/MWh, which was 20% lower than its cost of providing energy to its customers.[182]

Q212. DO YOU HAVE ANY EXAMPLES OF PROJECT PRICES CLOSER TO MICHIGAN?

A212. Yes. While the prices listed above are for locations with better solar resources than Michigan, PPA prices in Michigan remain considerably lower than DTE's estimated LCOE. Consumers Energy issued an RFP in June 2018. The results of the solicitation are still under negotiation, but Consumers indicated that the weighted average price of the procurement was $49.10/MWh[183]

Power marketer LevelTen Energy produces a quarterly report of PPA prices around the country. In its latest 2019 Q1 report, LevelTen Energy lists the P25 PPA price for solar at $45.60/MWh for Michigan Hub. This is considerably higher than the $34.20/MWh at the Minnesota Hub, possibly reflecting the relative maturity and competitiveness of the Minnesota market compared to the Michigan market given comparable solar insolation values.[184,185]

Third-Party PPAs Will Be Less Expensive than Company-Owned Projects

Q213. DO YOU BELIEVE THAT THIRD-PARTY PPAS WOULD BE ABLE TO PROVIDE LESS EXPENSIVE ENERGY AND CAPACITY TO DTE'S CUSTOMERS THAN COMPANY-OWNED PROJECTS?

A213. Yes. DTE's modeling suggested that single-axis tracker PV will have a LCOE of nearly $70/MWh. I have already shown why this figure is substantially overstated, and using my updated assumptions, DTE-owned projects might cost roughly $50/MWh. However, competitive procurements for third-party PPAs are already well below this benchmark in and around Michigan.

---

[182] *Florida and Jacksonville race forward with solar power*, JACKSONVILLE BUSINESS JOURNAL, https://www.bizjournals.com/jacksonville/news/2018/12/13/florida-and-jacksonville-race-forward-with-solar.html.

[183] Troyer Rebuttal at 22, November 5, 2018. MPSC Case No. U-20165.

[184] *Q2 2019 PPA Price Index*, LEVEL10 ENERGY https://cdn2.hubspot.net/hubfs/4108426/LevelTen%20Energy%20Q2%202019%20PPA%20Price%20Index.pdf.

[185] Michigan has 99 MW of operational PV compared to 795 MW in Minnesota. EIA 860-M, April 2019, https://www.eia.gov/electricity/data/eia860m/

There are four primary reasons for this which I discuss in further detail below: NREL ATB 2018 capital cost assumptions are likely higher than market prices, but not materially so; DTE will earn a return on the asset, on top of developer profit already included in the sales price; DTE will fully depreciate the project over 30 years; and regulatory accounting requirements prevent DTE from realizing federal investment tax credit (ITC) savings in the same way as third-party developers. Together, these factors explain why, for a given overnight cost of a PV system, utility-owned systems are likely to be more expensive for DTE's customers than third-party PPAs.

Q214. PLEASE EXPLAIN THE FIRST FACTOR (NREL CAPITAL COST ASSUMPTIONS) IN MORE DETAIL.

A214. Capital costs are the primary cost driver in PV projects as there are no fuel costs and O&M costs are minimal. Using NREL's 2018 ATB capital cost forecast is likely conservative, but the near-term pricing is in line with other recent project announcements. If prices follow the NREL ATB Low scenario, systems might cost about 10% less in 2021 than my assumptions. This could reduce the LCOE of company-owned projects somewhat, but it will not drive further large reductions.

Q215. PLEASE EXPLAIN THE SECOND FACTOR (DTE EARNING A RETURN) IN MORE DETAIL.

A215. In a competitive solicitation for company-owned projects, a solar developer will determine its cost to design, engineer, permit, and construct a PV system and sell it to DTE as a turnkey transaction. All of the developer's costs, including a profit, will be included in the sales price. Once the Company has purchased the project, it will put it into its rate base, where it will be authorized to earn an additional return on and return of its capital. In other words, despite the project being almost entirely de-risked (i.e. the project will be fully operational on day one with fresh warranties on all hardware), DTE will earn its full return on equity – plus more revenue for the taxes on the profit.

Customers are paying a profit to both the developer (embedded in the sales price) as well as to DTE (through its return on equity), even though the project risk is not duplicated between the two parties. This structure needlessly increases the costs of providing energy and capacity to the Company's customers.

Q216. PLEASE EXPLAIN THE THIRD FACTOR (DTE'S DEPRECIATION ASSUMPTIONS) IN MORE DETAIL.

A216. Even if DTE is able to obtain good pricing on purchased projects through competitive solicitations, the Company intends to depreciate its solar projects over a 30-year period. In this time, DTE will recover all of its capital costs (including a return on equity, interest on debt, and the capital itself) plus all O&M costs. But at the end of the 30-year period, DTE will still have an asset with substantial value. Although PV panels do degrade over time, modern, high-efficiency panels available today have performance warranties that assure that output in year 30 will still be roughly 89% of the output in year 1. In other words, the system will only produce 11% less energy in year 30 and will continue to produce energy for years and decades beyond that.

Third-party developers know this and price their PPAs accordingly. Rather than try to recoup all costs and profits in a 30-year period, they develop proformas on longer time frames with the expectation that the assets will still have substantial residual value at the end of the contract period. If DTE signs a PPA with a developer who recovers its costs over a longer time period, DTE's customers will benefit during the contract period with lower costs. At the end of the 30-year PPA, DTE could simply sign a new PPA with the latest technology in place at the time. By comparison, a DTE-owned project will have higher costs per MWh of generation during the 30-year period and could require additional capital spending to upgrade to the then-current technology.

Q217. PLEASE EXPLAIN THE FINAL FACTOR (ITC ACCOUNTING) IN MORE DETAIL.

A217. Regulatory accounting rules require that utilities treat the federal ITC differently than private developers. While a third-party developer can monetize the federal ITC on the front end of the project, a utility, which is bound by these accounting rules, is required to monetize the credit over the life of a project. While the amount of the tax credit is the same in each case, because of the time-value of money, the ITC is worth more to a third-party developer than to DTE. This in turn allows the third-party developer to offer a lower PPA price to DTE than DTE can to its own customers.

Q218. HAS THE LOWER COST OF PPAS RELATIVE TO COMPANY OWNERSHIP BEEN DEMONSTRATED IN MICHIGAN?

A218. Yes. In a report analyzing the implementation and cost effectiveness of the Renewable Energy Standard, the Commission noted: "“for each year in which there were both company-owned projects and purchased power agreements, the weighted average cost of the purchased power agreements was lower than the company-owned projects in that respective year."[186]

Q219. WHAT IS THE AGGREGATE IMPACT OF THESE FACTORS WHEN IT COMES TO COMPANY-OWNED PROJECTS?

A219. Simply put, Company-owned projects are going to be more expensive than third-party PPAs. The PCAs included in this IRP contemplate procuring between $6.7 billion and $7.8 billion of renewable projects. The Commission is not obligated to provide DTE an ever-increasing opportunity to increase its profits and should closely scrutinize DTE's ability to rate-base all of these projects. As I discuss below, there is a logical distinction between the types of projects that DTE is proposing (RES, voluntary carbon reduction, and VGPP) and the share of assets that DTE should be authorized to own.

The Commission Should Strongly Scrutinize DTE's Proposal to Own VGPP Resources

Q220. WHAT IS DTE'S STATED PURPOSE FOR THE VGPP?

A220. DTE indicates that it wishes to grow its VGPP programs to "enable our customers who are pursuing their own carbon-reduction efforts."[187] The Company continues, "[c]ustomers of all

[186] MPSC, Report on the Implementation and Cost Effectiveness of the PA 295 Renewable Energy Standard, February 15, 2017, p. 19
[187] Exhibit A-3 at 86.

types have a clear interest in having options for procuring renewable energy, and DTE will continue to provide customers with the opportunity to do so."[188]

DTE's Customers Have Limited Choice for Renewable Procurement

Q221. DO YOU BELIEVE THAT GREEN PRICING PROGRAMS SUCH AS THE PROPOSED VGPP REPRESENT GOOD POLICY?

A221. Yes, as long as they are properly implemented. DTE is seeing demand from its customers that mirrors trends across the country as more individuals, companies, and local governments wish to increase the share of renewable energy that they utilized. As of July 2019, 188 companies have committed to RE100, an organization whose members (including General Motors, Kellogg's, and Walmart) have made commitments to procure 100% renewable energy.[189] More than 90 cities and ten counties have also made similar commitments.[190] It is clear that the demand for renewable energy such as wind and solar exceeds many state RPS policies such as Michigan's, which tops out at 15% in 2029. Green pricing programs can help fill the gap between what the utility is required to offer and what companies want. However, it is critical that policy makers structure such programs in a way that reduces customer costs and fosters competition.

Q222. WHAT ARE SOME WAYS THAT CUSTOMERS CAN PROCURE MORE RENEWABLE ENERGY THAN STATE POLICY REQUIRES?

A222. In restructured markets, customers can simply go straight to the market and contract with competitive suppliers for renewable energy. Unfortunately, this option is very limited in Michigan as only 10% of load (and only for commercial customers) can be met through customer choice. Given that DTE's customer choice queue is more than 70%

---

[188] Schroeder Direct at 13.
[189] *The world's most influential companies, committed to 100% renewable power*, RE100, http://there100.org/re100
[190] *100% Commitments in Cities, Counties, & States*, SIERRA CLUB, https://www.sierraclub.org/ready-for-100/commitments.

oversubscribed, there is little opportunity for customers to obtain 100% renewable energy through a competitive market in the near term.[191]

Another method is for communities to aggregate their load and issue RFPs for renewable resources on behalf of their customer base. Community Choice Aggregation (CCA), as this policy is known in California, has allowed groups of customers to procure 100% renewable portfolios in advance of the state's timeline.[192] By leveraging the scale of entire communities, CCAs have been able to obtain competitive pricing for wind and solar assets. Unfortunately, CCAs have not been authorized by Michigan's legislature, so this option is not available for DTE's customers.

Q223. WHAT ARE THE OPTIONS AVAILABLE TO DTE'S CUSTOMERS WITHIN THE REGULATORY CONSTRUCT THAT EXISTS IN MICHIGAN?

A223. DTE is a regulated monopoly with legislative authorization to supply 90% of its customers' demand. Given the massive oversubscription of its customer choice program, customers who would now desire to move away from their default service functionally have no choice and are limited to DTE's supply options. The Company has two primary methods to meet the demand of its captive customers. It can contract with third parties through PPAs or it can build or purchase and own renewable assets. In this IRP, DTE has proposed to own all the assets, including those for voluntary customer goals.

The Commission Must Robustly Project DTE Customers from Exercises of Market Power that Could Arise Through VGPP Implementation

Q224. ARE THE RENEWABLE RESOURCES THAT DTE PLANS FOR THE VGPP REQUIRED TO MEET STATUTORY RENEWABLE ENERGY GOALS?

---

[191] DTE has 3,436,695 MWh worth of allotments in its Cap Tracking System, against a current cap of 4,707,178 MWh. https://newlook.dteenergy.com/wps/wcm/connect/dte-web/quicklinks/electric-choice-supplier/cap-tracking-system

[192] https://www.greentechmedia.com/articles/read/how-community-choice-aggregation-fits-into-californias-clean-energy-future#gs.pmp0xm

A224. No. The VGPP resources are above and beyond the assets that DTE plans to meet its statutory RPS requirement of 15% and its clean energy requirement of 35% as required by Sec. 1 of PA 342.[193] DTE's VGPP proposal simply offers an option to its customer to procure more renewable energy that they would otherwise be provided through statutory requirements.

Q225. ARE THE RENEWABLE RESOURCES THAT DTE PLANS FOR THE VGPP INTENDED TO MEET ITS MISO CAPACITY OBLIGATIONS?

A225. No. While the VGPP programs will provide capacity to DTE to help meet its MISO capacity obligations, the Company has not proposed renewable generation as core to meeting its future load. In all of its PCAs, when the Company found that it had a capacity need, it chose to build either a natural gas combined cycle unit or purchase capacity from the market.[194] This is in contrast to Consumers Energy's approach that would build renewables specifically to meet its capacity obligation and would not build new natural gas combined cycle units.

Q226. ARE THE RENEWABLE RESOURCES THAT DTE PLANS FOR THE VGPP REQUIRED TO MEET COMPANY'S OWN CLEAN ENERGY AND CARBON REDUCTION GOALS?

A226. No. By definition, a VGPP resource that goes towards a customer's clean energy obligation cannot also be used to meet the Company's clean goals as this would result in double counting. DTE plans to add nearly 3,000 MW of renewable assets (which it also proposes to own) that are earmarked for its voluntary clean energy and carbon reduction goals.[195] But the VGPP resources are above and beyond those as well.

Q227. IF DTE DOES NOT NEED TO BUILD THE VGPP RESOURCES FOR STATUTORY REASONS, NOR FOR CAPACITY REASONS, NOR TO MEET ITS CLEAN ENERGY AND CARBON REDUCTION GOALS, WOULD YOU CONSIDER THOSE RESOURCES CRITICAL TO THE CORE FUNCTION OF DTE'S BUSINESS?

---

[193] Schroder Direct at 11.
[194] Exhibit A-5
[195] Exhibit A-18

A227. No. Clearly, DTE must comply with statutory obligations and must plan for and maintain a system that can reliably meets its load. I applaud DTE's corporate goals to reduce its carbon footprint and increase its clean energy goals, although, as discussed below, I do not believe that DTE should be allowed to own all of those resources. And while offering a VGPP to its customers helps meet demand that Michigan's regulatory structure otherwise prevents easy access to, DTE should not be able to take advantage of its monopoly position in the implementation of this program and instead should be limited in its ability to own and profit from the VGPP assets.

Q228. CAN YOU ELABORATE ON WHAT YOU MEAN BY THIS?

A228. DTE's regulatory compact with Michigan and its customers requires it to do certain things, including comply with laws and regulations and maintain a safe and reliable system. In building its system to meet these performance goals, DTE must request and receive permission from the Commission to recover its costs, and its profits are subject to the Commission's determination. These actions exist to maintain pressure on DTE's behavior that would typically be exerted by competitive forces but are by definition missing in a regulated monopoly structure. If DTE wants to move beyond its core provision of services, the Company – and its proposed assets – should be subject to more scrutiny.

DTE's customers (other than those commercial customers fortunate enough to have secured access to the limited customer choice) have no other options in their supply. If DTE is allowed to own, recover costs, and profit from its VGPP resources, it will be effectively transferring money from its customers to its shareholders simply because its customers have a laudable desire to increase their renewable energy purchases. DTE should be required to meet this demand in the most cost-effective way possible, which in this case, is through procurement of third-party PPAs.

Q229. WHAT IS THE CURRENT AND PROPOSED PREMIUM FOR DTE'S GREEN PRICING PROGRAM?

A229. DTE charges customers a flat fee for the green pricing program and then credits the customer based on the wholesale market revenue that the energy produces. DTE's current program for residential and commercial customers charges a fee of 7.2 cents / kWh.[196] The customers receive a credit based on the Company's power supply costs (less transmission) for energy plus 75% of the cost of new entry as determined by MISO for the project's qualified capacity.[197] In 2019, this credit was worth 3.3 cents / kWh, making the net cost of the program 3.9 cents / kWh. Considering DTE's 2017 average residential and commercial retail rate was 15.5 cents / kWh and 10.3 cents / kWh, respectively, this represents a substantial price premium.[198]

Its proposed program for large customers (LCVGP) appears to be less expensive but still represents a substantial premium. The credit for the large customers is less generous, consisting of an energy rate equal to the real-time LMP and a capacity credit equal to the MISO PRA clearing price.[199] Given that the PRA clearing price has remained substantially under the cost of new entry, the credit provided to large customers will likely be smaller than that given to smaller customers. DTE indicates that several full-service customers have been provided a gross cost estimate of 4.5 cents / kWh for its upcoming VGPP program.[200] Even assuming the same credit level as the small VGPP program (which is likely too high), this represents an approximate price premium of 1.2 cents / kWh. This is substantially higher than the cost of RECs, which DTE has retired at an average cost of 0.35 cents / kWh and 0.26 cents / kWh in 2017 and 2018, respectively.[201] It is true that corporate customers are increasingly desiring to procure renewable energy rather than just retiring RECs, but charging roughly 4-5 times more for the privilege is excessive.

Q230. HOW DOES DTE PROPOSE THAT VGPP RESOURCES ARE PAID FOR?

[196] https://newlook.dteenergy.com/wps/wcm/connect/dte-web/quicklinks/migreenpower
[197] DTE Standard Contract Rider 17, available at https://www.michigan.gov/documents/mpsc/dtee1cur_579203_7.pdf
[198] In EIA Form 861 2017, DTE reports residential revenues of $2.31 billion and sales of 14,885 GWh and commercial revenues of $1.80 billion and sales of 17,456 GWh. This converts to an average rate of 15.52 and 10.31 cents/kWh, respectively. Available at https://www.eia.gov/electricity/data/eia861/
[199] DTE Standard Contract Rider 19, available at https://www.michigan.gov/documents/mpsc/dtee1cur_579203_7.pdf
[200] ELPCDE-7.62a, attached as Exhibit ELP-64 (KL-55).
[201] ELPCDE-15.96l, attached as Exhibit ELP-63 (KL-54).

A230. DTE proposes that the subscribers to the VGPP should be solely responsible for the costs associated with the resources, hence the premium prices listed above.[202] This is a reasonable position, as the projects are being built for the explicit purpose of meeting certain customers' voluntary goals. Unlike assets required to meet statutory renewable requirements or to maintain safe and reliable service, VGPP resource costs should not be recovered from all customers.

Q231. WHAT HAPPENS IF THE CUSTOMERS WHO HAVE EXPRESSED INTEREST IN THE VGPP PROGRAM DO NOT CONTINUE TO PARTICIPATE IN THE PROGRAM?

A231. DTE states that six customers have signed five-year binding contracts that will be the offtakers of the proposed LCVGP renewables planned in the next several years. However, there is no obligation for these customers to renew past their five-year term.[203] If these customers choose to drop out of the program, and no other customers wish to pay the substantial premium incurred through DTE's ownership structure, the costs will simply be passed on to all of DTE's other customers.[204] Thus, despite DTE's position that non-participants will bear no costs of the VGPP renewables, it is entirely possible that this will occur. Given this risk, even with the proposed cost recovery structure, the Commission should insist that DTE minimize costs for its customers choosing this path.

Q232. WHY IS THAT?

A232. In a competitive market, DTE's customers would have many choices from whom to procure their renewable energy and would be able to do so at competitive prices. The only reason that DTE's customers cannot choose this option is because of statutory limitations that exist in regulatory structure's such as Michigan's. In exchange for granting DTE a regulated monopoly, Michigan is authorized – and obligated – to affect regulations that duplicate the

[202] Mikulan Direct at 136.
[203] ELPCDE-7.62c, attached as Exhibit ELP-64 (KL-55).
[204] ELPCDE-15.96m, attached as Exhibit ELP-65 (KL-56).

role that competitive forces would otherwise provide. DTE should not be allowed to earn economic rents on its captive market in the form of inflated VGPP prices.

Further, while it is possible that DTE will continue to find large customers who wish to pay the premium beyond the initial five-year term of these projects, should this fail to occur, the backstop plan is to charge all customers for these projects. The Commission must consider this possibility and proactively work to minimize the cost to existing and future customers that might incur these costs.

Q233. WHAT DO YOU RECOMMEND THE COMMISSION DO REGARDING THE VGPP PROGRAM?

A233. But for DTE customers' voluntary desires to procure more renewable energy, the VGPP would not exist. DTE's customers who wish to exceed the statutory minimum for renewable energy should not be punished for living or operating in a location that does not provide adequate competitive supply options. Because of this, DTE should be allowed to meet the increasing demand of its customers for renewable resources. But DTE should not be excessively rewarded for providing a service that its customers want and that competitive markets would have otherwise provided. Further, because all of DTE's customers provide the funding backstop for these projects should the customers price support fail to sustain through the full life of the project, the Commission should direct DTE to minimize costs of this program to minimize risks to future customers.

I recommend the Commission authorize the VGPP but require that DTE competitively procure all VGPP resources through third-party PPAs. As discussed previously, third-party PPAs are inherently more cost-effective for DTE's customers as it allows private companies to monetize the ITC faster, to amortize costs over a longer time, and to forego the duplication of profit. The Commission should allow the Company recovery of all reasonable administrative costs associated with the program, but should closely monitor its marketing spend to prevent excesses. The Commission should also consider allowing DTE to earn an incentive on these PPAs, but this incentive should be much smaller than the profit it would earn through its typical return on equity given the voluntary nature of these assets.

The Commission Should Establish Minimum Levels of Third-Party PPAs for Resources Designed to Meet DTE's Voluntary Carbon Reduction Goals

Q234. DO YOU BELIEVE IT APPROPRIATE FOR DTE TO OWN SOME SHARE OF RENEWABLE RESOURCES DESIGNED TO MEET ITS CARBON REDUCTION GOALS?

A234. Yes. The VGPP resources would not exist but for voluntary demand from individuals and companies and are designed to meet the private benefits of these entities. However, the Company's clean energy and carbon reduction goals are different. Absent a state or federal goal for carbon reduction that would force DTE's compliance, the Company's actions to build more zero-carbon resources represents an incremental public good for its entire customer base. While these resources are not needed for statutory or regulatory compliance, nor to maintain a safe and reliable power grid, they do provide benefits for all DTE's customers in the form of reduced carbon and criteria pollutant emissions.

Q235. HAS THE COMMISSION RECENTLY RULED ON AN APPROPRIATE OWNERSHIP STRUCTURE FOR NEW RENEWABLE ASSETS?

A235. Yes. The Commission recently approved a Settlement Agreement (SA) in Case No. U-20165, Consumers Energy's (CE) most recent IRP filing.[205] In contrast to DTE's position in this IRP, CE did not propose to build any new fossil fuel power plants over the entire planning period but instead proposed to meet is future load obligations solely through renewable resources and demand-size management. The SA stipulated that CE be authorized to own up to 50% of the renewable assets that were being procured to meet its capacity need.

[205] Order dated June 7, 2019 in Case No. U-20165.

Q236. GIVEN THIS, WHAT OWNERSHIP SHARE WOULD YOU RECOMMEND THE COMMISSION APPROVE IN THIS CASE FOR RESOURCES AIMED AT MEETING THE COMPANY'S VOLUNTARY CARBON EMISSION REDUCTION GOALS?

A236. I recommend the Commission allow the DTE to own between one-quarter and one-third of the resources aimed at voluntarily reducing the Company's carbon reduction goals and require third-party PPAs be used to fill the remaining need. This represents a balanced middle ground between the SA approval of 50% of resources designed to meet CE's capacity and reliability needs, and my recommendation that DTE own none of the VGPP resources. Given that DTE plans to build nearly 3 GW of renewables worth roughly $4 billion for this purpose, even a 25% share would provide $1 billion worth of new capital investment on which DTE can earn profits, an appropriate reward for pursuing its carbon reduction goals and providing a public good for its customers.

DTE's Proposal to Reduce its QF Standard Offer Contract to 150 kW should be Denied

Q237. DOES DTE PROPOSE TO MAKE ANY CHANGES TO ITS PURPA TARIFF?

A237. Yes. DTE proposes to reduce the size of eligible qualifying facilities (QFs) that can qualify for its Standard Offer contract from 550 kW to 150 kW.[206] The Company claims that because the State has set a 150 kW limit for eligibility for participation in the distributed generation (DG) program under MCL 460.1173, "therefor, it appears that the legislature intended to treat customers with generator facilities smaller than 150 kWs different from those with generation facilities with larger capacity."[207]

Q238. WHAT IS THE MICHIGAN DG PROGRAM THAT IS REFERENCED BY CE?

A238. It is the State's net energy metering program designed for customer-sited systems that interconnect behind the customer's electric meter. The most common type of system that participates in net metering programs is residential rooftop solar.

[206] Stanczk Direct at 9.
[207] Id at 9-10.

Q239. DO DG CUSTOMERS AND PURPA CUSTOMERS SHARE MANY CHARACTERISTICS?

A239. No. DG systems are connected behind the customer's meter. Generation and consumption are not separately tracked or billed. While DG customers are required to sign an interconnection agreement, there is no separate contract to provide energy or capacity. DG customers are compensated through net metering, where exported energy is credited against future use based on retail rates. While Michigan is making changes to its net metering compensation mechanism, it is not proposing to move to anything similar to PURPA.

On the other hand, PURPA projects are often stand-alone and are not typically connected behind a customer's meter. QFs are not designed to primarily offset a customer's own load but rather to provide energy and capacity to DTE. Projects sign offtake agreements with DTE and are compensated based on wholesale avoided costs, not retail rates.

Q240. DOES DTE'S REFERENCE TO THE DG PROGRAM'S 150 KW LIMIT MATTER FOR PURPA?

A240. No. The programs serve different customers, provide different services to DTE, and are compensated through different contractual mechanisms. In fact, one can reasonably argue that setting a size limit for access to the retail DG program implies that larger systems should be shifted to another program such as PURPA. Rather than supporting a comparable 150 kW limit on PURPA, it is a much more logical conclusion that projects over 150 kW should be served by PURPA. And the most cost-effective manner to manage PURPA QFs – for both DTE and the QF owner – is through the Standard Offer contract. Unnecessarily reducing the applicability to this contract based on a statutory limit from an entirely different context would snot benefit DTE's customers.

Q241. HAS THE COMMISSION RULED ON THIS ISSUE BEFORE?

A241. Yes. The Commission recently directed DTE to make available the Standard Offer Tariff to projects 550 kW or less.[208] At the time it issued its order, the Commission had seen nearly

[208] Rehearing Order dated December 20, 2018, MPSC Case No. U-18091.

identical arguments from Consumers Energy in its own IRP filing.[209] The Commission was not persuaded then by this argument, and should not be persuaded now.

Q242. WHAT DO YOU RECOMMEND WITH REGARD TO THE SYSTEM SIZE FOR THE STANDARD OFFER TARIFF?

A242. It should remain at 550 kW. The Commission has just ruled on this issue, reducing the cap from 2 MW to 550 kW. Given the lack of progress on PURPA QFs in DTE's territory, reducing the Standard Offer size further at this point is unwarranted.

[209] Troyer Direct at 40, June 15, 2018. MPSC Case No U-20165.

VI. CONCLUSION

Q243. PLEASE SUMMARIZE THE ARGUMENTS YOU PRESENTED IN YOUR TESTIMONY.

A243. DTE's IRP and PCA suffer from numerous issues. In the modeling itself, the Company filed its IRP having hardcoded its preferred "starting point" for nearly all resources, much of which was not even based on modeling from this case. This included more than 5 GW of renewables at a project cost of more than $7 billion. Not only did this resource mix not emerge from a modeled optimization, Strategist was prevented from adding new resources in any year in which there was no capacity need, even if doing so would have reduced costs. While the Company did provide some updated modeling that was supposed to address this issue, it failed to configure Strategist in a way that allowed the model to do so.

Solar costs were too high and deviated from the source material that the Company claimed it used. Solar generation was erroneously modeled as inferior fixed-tilt configurations despite the Company acknowledging the benefits of single-axis tracking systems. The Company also inappropriately discounted the capacity credit that solar facilities would earn based on the wrong system configuration and an unapproved ELCC methodology.

DTE's modeling contained numerous non-solar issues as well. DTE failed to present any analysis or modeling of its aging peaker fleet and inappropriately assumed that many units more than half a century old will continue to provide power for the next twenty years. Further, DTE's lack of proper cost accounting prevented the Company or intervenors from presenting a cost-based analysis on the economic viability of individual peaker units. The modeling parameters that evaluated potential outages were uncorrelated to the performance of these units and failed to incorporate the fact that the oldest peakers failed most often under high system loads. When combined, these issues make it likely that the modeling tools overestimated the availability of the peaking fleet to perform under high-load scenarios.

DTE failed to consider how solar and S+S could be used to replace its aging peaker capacity, and its lack of consideration of how solar and S+S can provide peaking capacity is clearly outside the trends of the utility industry. I show that solar and S+S is well-positioned to contribute to DTE's peak load needs both from a timing and duration perspective. By including more clean peaking assets, DTE could further reduce its reliance on old, unreliable units while also benefiting from zero-carbon energy.

Finally, the Company's insistence that it owns all of the new renewable assets – even those destined to serve the private benefits of its customers – lacks policy justification. The Commission anticipated a robust analysis of different ownership structures in this case to explore this issue, but DTE's filing is completely devoid of such an analysis. Absent any sort of policy or analytical support, DTE should not be allowed to press its advantage of being a monopoly provider of supply to all residential customers and functionally all non-residential customers looking to purchase more renewable energy. Instead, the Commission should consider placing appropriate limits on the ownership parameters for new renewable resources designed to meet statutory renewable energy goals, voluntary Company-wide carbon reduction goals, or provide resources for the proposed VGPP. Likewise, the Commission should reject DTE's request to further reduce eligibility to the standard offer contract to systems of only 150 kW or less.

Q244. WHAT ARE YOUR FINAL RECOMMENDATIONS?

A244. DTE has failed to justify its PCA through a robust, unbiased analysis. I recommend the Commission reject the Company's IRP and require it to revisit its solar cost assumptions, properly model single-axis tracker systems, include a robust analysis of the viability of its aging peaker fleet, and develop a PCA that is actually informed by the modeling from DTE's IRP filing. The Company must also perform an analysis of different ownership and contracting structures to meet its various statutory and voluntary renewable energy goals. With these updates, the Commission and other interested parties will have the data and analysis needed to develop a PCA that is truly in the interests of DTE's customers.

When the resources are ultimately selected through this process, the Commission should require strong competition in resource acquisition for the benefit of DTE's customers that includes limitations on the share of new renewable assets that the Company can own. This percentage can vary based on the ultimate purpose of the renewable asset, with the Commission balancing incentives to DTE for pursuing laudable public policy goals such as reducing CO_2 emissions while acting strongly to prevent customers from overpaying for renewable energy or facing too much risk while acting as the cost recovery backstop for those same assets.

Q245. DOES THIS CONCLUDE YOUR TESTIMONY?

A245. Yes.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
DTE ELECTRIC COMPANY	)	Case No. U-20471
for approval of its integrated resource plan	)	
pursuant to MCL 460.6t, and for other relief	)	

EXHIBITS OF

KEVIN LUCAS

ON BEHALF OF

THE ENVIRONMENTAL LAW & POLICY CENTER,
THE ECOLOGY CENTER,
THE SOLAR ENERGY INDUSTRIES ASSOCIATION,
THE UNION OF CONCERNED SCIENTISTS,
AND
VOTE SOLAR

AUGUST 21, 2019

KEVIN M. LUCAS

SOLAR ENERGY INDUSTRIES ASSOCIATION

Mr. Lucas is Director of Rate Design for the Solar Energy Industries Association (SEIA). SEIA is the national trade association for the U.S. solar industry. SEIA works with its 1,000 member organizations to advance solar power through education and advocacy. It seeks to champion the use of clean, affordable solar in America by expanding markets, removing market barriers, strengthening the industry and educating the public on the benefits of solar energy.

Since 2010, Mr. Lucas has worked in the energy and environment industry focusing on policies such as renewable energy, energy efficiency, and greenhouse gas reduction. In his role at SEIA, Mr. Lucas develops expert witness testimony for rate cases, integrated resource plans, and other regulatory proceedings. He is actively involved in the New York Reforming the Energy Vision docket, with a focus on distributed energy resource valuation and rate design. Prior to joining SEIA, Mr. Lucas worked for the Alliance to Save Energy, a Washington DC-based nonprofit focused on reducing energy use in the built environment. Before the Alliance, he worked for the Maryland Energy Administration, the state energy office, on numerous legislative and regulatory issues and developed and presented testimony before the Maryland General Assembly and the Maryland Public Service Commission.

Prior to entering the energy and environment field, Mr. Lucas was a manager at Accenture, a leading consulting firm. Mr. Lucas implemented enterprise resource planning software for Fortune 500 companies in industries such as consumer electronics, oil and gas, and manufacturing.

AREAS OF EXPERTISE

- Renewable Energy Policy Analysis: extensive experience analyzing renewable energy policy issues and communicating results to both expert and general audiences.
- Energy Efficiency Policy Analysis: detailed understanding of energy efficiency policies, including the development of potential studies and utility efficiency program design and implementation.
- Quantitative Analysis: deep expertise in quantitative analysis across a broad range of topics including analyzing financial and operational data sets, constructing models to explore electricity industry data, and incorporating original analysis into expert witness testimony.
- Energy Markets: studies interaction of renewable energy and energy efficiency policies with wholesale market operation and price impacts.
- Legislative Analysis: reviews legislation related to energy issues to discern potential impacts on markets, utilities, and customers.

EDUCATION

Mr. Lucas holds a Masters of Business Administration from the University of North Carolina, Kenan-Flagler Business School (2009) and a Bachelor of Science in Engineering, Mechanical Engineering from Princeton University (1998).

ACADEMIC HONORS

- Beta Gamma Sigma Honor Society
- Paul Fulton Fellowship, Kenan-Flagler Business School
- Graduated *cum laude* from Princeton University

EXPERT WITNESS TESTIMONY

Public Utilities Commission of the State of Colorado

- Docket 17A-0797E – *Public Service Company - Accelerated Depreciation - AD/RR*
  - Advocating for appropriate structure to utilize renewable energy funds to support the early retirement of coal facilities and to continue to support distributed resources

Maryland Public Service Commission

- Case 9153, 9154, 9155, 9156, 9157, 9362 - *In the Matter Of Maryland Utility Efficiency, Conservation And Demand Response Programs Pursuant To The Empower Maryland Energy Efficiency Act Of 2008*
  - Multiple filings regarding the design and implementation of Maryland's energy efficiency portfolio standard

- Case 9271 - *In re the Merger of Exelon Corp. & Constellation Energy Grp., Inc.*
  - Analysis of renewable energy commitments in merger proposal

- Case 9311 - *In re the Application of Potomac Elec. Power Co. for an Increase in its Retail Rates for the Distrib. of Elec. Energy*
  - Supporting the implementation of a limited cost tracker to accelerate reliability investments after 2012 Derecho

- Case 9326 - *In re the Application of Balt. Gas & Elec. Co. for Adjustments to its Elec. & Gas Base Rates.*
  - Supporting the implementation of a limited cost tracker to accelerate reliability investments after 2012 Derecho

- Case 9361 - *In re the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc.*
  - Policy analysis of merger proposal

Michigan Public Service Commission

- Case U-18419 – *In the matter of the application of DTE ELECTRIC COMPANY for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.*
  - Arguing against DTE Electric's proposal to construct a new natural gas combined cycle generating facility and instead meet its future capacity and energy needs with a distributed portfolio of solar, wind, energy efficiency, and demand response.
- Case U-20162 – *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*
  - Arguing against DTE Electric's proposal for a net energy metering successor tariff that improperly undervalued the contribution of distributed solar.

- Case U-20165 - *In the matter of the application of Consumers Energy Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.*
    - Discussing Consumers Energy Company's integrated resource plan, arguing for advancing the deployment of solar to meet its capacity requirements, arguing against Consumers' proposed financial compensation mechanism for third-party PPA contracts, supporting a robust PURPA market, and supporting transparent and equitable competitive procurement guidelines.

Public Utility Commission of Nevada

- Docket Nos. 17-06003 & 17-06004 Phase III – Rate Design – *Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.*
    - Arguing against Nevada Power Company's proposal to increase fixed customer charge

Public Utility Commission of Texas

- Docket 46831 – *Application of El Paso Electric Company to change rates*
    - Critiquing El Paso Electric's proposal to implement a three-part rate for residential and small commercial net metered customers

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-16.103e
Respondent:	L. K. Mikulan
Page:	1 of 1

Question: Please refer to the Company's response to STDE-2.3b and the Company's updated modeling.
e) Confirm that in U-20471 STDE 2.3B BAU OPTIMIZATION 2030, the Company forced in market capacity purchases of 300 MW, 100 MW, and 200 MW in 2018, 2019, and 2020, respectively. If deny, please indicate what the line item "3 Cap Purc" on page 59 of the report indicates.

Answer: Confirmed.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-13.88f
Respondent:	L. K. Mikulan/ T. L. Schroeder
Page:	1 of 1

Question: Refer to Exhibit A-5.

f. Confirm that because the Starting Point renewables and Starting Point VGP were hard-coded into the Strategist modeling, none of the Company's initial Strategist runs that were performed when the IRP was filed analyzed the cost effectiveness of the specific blend of starting point renewables as compared to other blends that attain the same levels of renewable generation. If deny, please explain.

Answer: Confirmed. See also response to ELPCDE-13.88g.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-13.88g
Respondent:	L. K. Mikulan/T. L. Schroeder
Page:	1 of 1

Question: Refer to Exhibit A-5.

g. Please indicate where in the Company's filing it performed any economic analyses on the specific mix of solar and wind assets as found in the Starting Point renewables and Starting Point VGPP renewables compared to alternative mixes of solar and wind assets.

Answer: The analysis as described in this question was not completed as part of this filing. The specific types of renewables builds are considered to be placeholders at this time. As the performance characterstics and costs of renewables technologies continue to evolve in the.future, the flexible PCA will be updated. Even though the Company considers these renewable builds to be placeholders, an assumption of either wind or solar was made for modeling purposes. The Company's selection of wind versus solar was based on a combination of the Company's knowledge and experience of Michigan projects that both exist and are being developed as well as the forecast of wind versus solar costs as described in response to ELPCDE 13.88a.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	Staff
Question No.:	STDE-2.3a
Respondent:	L. K. Mikulan
Page:	1 of 1

Question: The Company has indicated the inclusion of several resources as a starting point of its IRP from the 2019-2040 timeframe.

a) Has the Company performed a model run in each of the Michigan Integrated Resource Planning Parameters(MIRPP) scenarios that allow the model to optimize the build plans throughout the whole 2019-2040 period, only forcing in the resources that have already been approved in other planning cases, such as the Company's renewable plan or EWR plan?

Answer: No, the Company had not performed these model runs with the IRP as filed.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	Staff
Question No.:	STDE-2.3b
Respondent:	L. K. Mikulan
Page:	1 of 7

Question: The Company has indicated the inclusion of several resources as a starting point of its IRP from the 2019-2040 timeframe.

b) If the Company has not performed model runs as described in question 9, would the Company run each of the MIRPP scenarios (not the corresponding sensitivities), allowing the model to optimize the entire planning period given the Company's expected retirements discussed in this case? If yes, when would that information be available for Staff and intervenor to review? If no, why is the Company unwilling to provide transparency as to what the build plan would look like if the model could fully optimize throughout the study period?

Original Answer: Yes. This modeling is currently underway. The results will be provided to Staff and Intervenors as soon as they are completed.

Supplementary Answer: At Staff's request, the Company has now completed the modeling that removed the starting point renewables, shown in Table 1 below, from the optimization. "Starting point renewables" are defined as the renewables beyond the current state REP requirement of 15%, which includes the renewables associated with the Company's carbon reduction goals (50% by 2030 and 80% by 2040) and the clean energy goal of 25% renewables by 2030, as further described on page 36 of my revised testimony. This was done by converting the renewables that were previously modeled as zero cost transactions and "forced in" to every Strategist run, to Strategist alternatives and assigning the alternatives an associated PVRR cost. The original least-cost plans were forced into Strategist for each of the three MIIRP scenarios and the DTE Reference scenario. Then the starting point renewables were "turned off" in Strategist and the model optimized the build plans. The results of the original least-cost plan can be compared to the results of the revised least-cost plan run (which excludes the starting point renewables) for each of the four scenarios as run for STDE-2.3b. See results in Tables 2 thru 5 below.

MPSC Case No.: U-20471
Requestor: Staff
Question No.: STDE-2.3b
Respondent: L. K. Mikulan
Page: 2 of 7

Table 1: Starting Point Renewables converted to Strategist Alternatives

	wind MW	Solar MW	Strategist name
2024	150		WP24(1)
2025		50	S25-(1)
2026		75	S26 (1)
2027		100	S25-(2)
2028			
2029		100	S25-(2)
2030		200	S100(1)
2031	100	200	S100(1), W100(1)
2032		200	S100(1)
2033		200	S100(1)
2034	100	200	S100(1), W100(1)
2035		200	S100(1)
2036		200	S100(1)
2037	100	200	S100(1), W100(1)
2038		200	S100(1)
2039		200	S100(1)
2040		200	S100(1)
by 2030 (MW)	150	525	
by 2040 (MW)	300	2000	

The first year of capacity need remains in 2029, coincident with the Belle River retirement, after removing the starting point renewables, although the capacity short position does increase from -159 MW short in the original runs to -303 MW short in the STDE-2.3b runs. Similarly, the short position increases from -585 MW in the original runs to -796 MW in 2030 in the STDE-2.3b runs after the starting point renewables are removed and replaced with alternatives. 2030 has the largest short position throughout the 2030's until 2040. Due to the timing of the capacity short, the Strategist model had to solve for 2029 and 2030 and then again in 2040. This is similar to the original scenario runs. It should be noted that no additional scenarios (beyond the four described above), sensitivities, or risk analyses were performed.

MPSC Case No.: U-20471
Requestor: Staff
Question No.: STDE-2.3b
Respondent: L. K. Mikulan
Page: 3 of 7

There is a major difference in the STDE-2.3b runs from the original modeling that needs to be pointed out. In the original runs, three CCGT units were forced in 2040, along with market purchases, so the model did not optimize the 2040 build. In the STDE-2.3b runs, we thought it prudent to optimize for 2040 in recognition of the starting point renewables that were removed. Given the large amount of capacity needed in 2040 due to the Monroe retirement, the model had to be reconfigured to allow it to solve for 2040.

There is approximately 3,000 MW of capacity that needs to be filled in 2040. The Strategist model fills this need considering all feasible combinations of resources. The Company's version of Strategist is limited to 1,250 different combinations of resource alternatives to fill the capacity need. If this number is exceeded, then the model will not solve.

The following modeling techniques were applied in the Strategist model in order for the model to solve for 2040:

1. Block size for solar and wind optimization alternatives were doubled to 200 MW and 300 MW respectively. Increasing the block size generates less states (or combinations of resources) in Strategist.
2. CCGTs were constrained to four total between 2030 and 2040. This is also consistent with the CO_2 reduction goal levels.
3. Some of the less economic or smaller alternatives were "turned off" in the model. These included CVR/VVO, Lithium Ion battery, and the ability to select more than one CT.
4. Capacity purchases of the same amount in the least-cost plan in 2040 were allowed in the optimization runs.
5. Two separate optimizations were run for each scenario. First the model was optimized until 2030. Then the least-cost plan from the 2030 optimization was forced into the model and the 2040 optimization was performed.

MPSC Case No.:	U-20471
Requestor:	Staff
Question No.:	STDE-2.3b
Respondent:	L. K. Mikulan
Page:	4 of 7

Table 2: ET scenario results

	ET Original least cost plan (LCP)	ET LCP with no assumed starting point renewables (STDE-2.3b LCP)
	2% EWR	2% EWR
2030 build	1050 MW Wind + (starting point renewables: 150 MW wind, 525 MW Solar)	2850 Wind
2040 Build	3 CCGT, 825 MW Purchase + (starting point renewables: 300 MW wind, 2000 MW Solar)	3 CCGT, 1200 MW Solar, 259 MW DR, 778 Purchase
PVRR ($M)	$12,805	$12,849
delta PVRR ($M)		$44
	Original LCP lower cost	

Table 3: EP scenario results

	EP Original LCP	EP LCP with no assumed starting point renewables (STDE2.3b LCP)
	1.75% EWR	1.75% EWR
2030 build	3150 MW Wind + (starting point renewables: 150 MW wind, 525 MW Solar)	3750 Wind, 400 MW Solar
2040 Build	3 CCGT, 827 MW Purchase + (starting point renewables: 300 MW wind, 2000 MW Solar)	3 CCGT, 308 MW DR, 1000 MW Solar, 816 MW Purchase
PVRR ($M)	$13,173	$13,202
delta PVRR ($M)		$29
	Original LCP lower cost	

MPSC Case No.: U-20471
Requestor: Staff
Question No.: STDE-2.3b
Respondent: L. K. Mikulan
Page: 5 of 7

Table 4: BAU scenario results

	BAU Original LCP	BAU LCP with no assumed starting point renewables (STDE-2.3b LCP)
	2% EWR	2% EWR
2030 build	CCGT + (starting point renewables: 150 MW wind, 525 MW Solar)	CCGT
2040 Build	3 CCGT, 534 MW Purchase + (starting point renewables: 300 MW wind, 2000 MW Solar)	3 CCGT, 259 MW DR, CT, 1000 MW Solar, 510 MW Purchase
PVRR ($M)	$13,563	$13,506
delta PVRR ($M)		($57)
		STDE-2.3b LCP lower cost

Table 5: DTE REF scenario results

	DTE REF Original LCP	REF LCP with no assumed starting point renewables (STDE-2.3b LCP)
	1.5% EWR	1.5% EWR
2030 build	CCGT, 259 MW DR + (starting point renewables: 150 MW wind, 525 MW Solar)	CCGT, 308 MW DR, 600 MW wind
2040 Build	3 CCGT, 683 MW Purchase + (starting point renewables: 300 MW wind, 2000 MW Solar)	3 CCGT, CT, 1600 MW Solar, 652 Purchase
PVRR ($M)	$14,451	$14,346
delta PVRR ($M)		($105)
		STDE-2.3b LCP lower cost

MPSC Case No.: U-20471
Requestor: Staff
Question No.: STDE-2.3b
Respondent: L. K. Mikulan
Page: 6 of 7

Note, the PVRR values presented above for the "Original LCP" are not comparable to the PVRR values presented in my testimony for the same scenario LCPs due to the fact that the Renewables now have associated PVRR costs, whereas in testimony the renewables were modeled as zero cost transactions. In the ET and EP scenarios, the original least-cost plan, which included starting point renewables, was lower cost than the STDE-2.3b least-cost plan which excluded the starting point renewables. In the REF and BAU scenarios, the STDE-2.3b least-cost plan was lower cost than the original least-cost plan.

In all scenarios, the difference between the least-cost plans with and without the starting point renewables were all within $105M of each other. In certain circumstances, deviations from an optimized plan should be taken into consideration and selectively pursued. Examples include:

1. Ramping in renewables over a longer period of time is better for constructability, cash flow, execution, possible tax credit eligibility, and project management
2. Energy market value of renewables is achieved earlier
3. Costs, incentives, technologies, capacity factors, and capacity credits of renewables are still evolving rapidly. Changes in these assumptions for both wind and solar could cause the currently proposed plan to deviate from the optimal 2030 build plan as modeled in 2019. The ability to monitor these developing items is in line with the Company's proposed flexible PCA.

Attachments: The following Non-Confidential attachments are available for download from the Company's Discovery Portal using the hyperlink below.

https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U-204712019IRPPublic/default.aspx

U-20471 STDE 2.3b BAU LCP.txt

U-20471 STDE 2.3b BAU OPTIMIZATION 2030.txt

U-20471 STDE 2.3b BAU OPTIMIZATION 2040.txt

U-20471 STDE 2.3b REF LCP.txt

U-20471 STDE 2.3b REF OPTIMIZATION 2030 txt

MPSC Case No.:	U-20471
Requestor:	Staff
Question No.:	STDE-2.3b
Respondent:	L. K. Mikulan
Page:	7 of 7

U-20471 STDE 2.3b REF OPTIMIZATION 2040.txt

U-20471 STDE 2.3b ET LCP.txt

U-20471 STDE 2.3b ET OPTIMIZATION 2030.txt

U-20471 STDE 2.3b ET OPTIMIZATION 2040.txt

U-20471 STDE 2.3b EP LCP.txt

U-20471 STDE 2.3b EP OPTIMIZATION 2030.txt

U-20471 STDE 2.3b EP OPTIMIZATION 2040.txt

U-20471 STDE 2.3b Renewable capacity and energy.xls

The following Confidential Strategist Modeling files are available for download from the Company's Discovery Portal to those whom have properly executed a Non-disclosure agreement subject to the protective order in this case and who hold a Strategist® License, using the hyperlink below.

https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U-204712019IRPLicenseHolders/default.aspx

NDA U-20471 STDE 2.3b BAU LCP.sav

NDA U-20471 STDE 2.3b BAU OPTIMIZATION 2030.sav

NDA U-20471 STDE 2.3b BAU OPTIMIZATION 2040.sav

NDA U-20471 STDE 2.3b REF LCP.sav

NDA U-20471 STDE 2.3b REF OPTIMIZATION 2030.sav

NDA U-20471 STDE 2.3b REF OPTIMIZATION 2040.sav

NDA U-20471 STDE 2.3b ET LCP.sav

NDA U-20471 STDE 2.3b ET OPTIMIZATION 2030.sav

NDA U-20471 STDE 2.3b ET OPTIMIZATION 2040.sav

NDA U-20471 STDE 2.3b EP LCP.sav

NDA U-20471 STDE 2.3b EP OPTIMIZATION 2030.sav

NDA U-20471 STDE 2.3b EP OPTIMIZATION 2040.sav

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-13.88a
Respondent:	L. K. Mikulan/ T. L. Schroeder
Page:	1 of 1

Question: Refer to Exhibit A-5.

a. In the "Defined" period of the IRP, nearly all new capacity is wind, with very little solar. What was the basis for this decision? How, if at all, was this decision influenced from the various Strategist or PROMOD runs?

Answer: The selection of the wind in the defined period of the PCA to achieve the renewable portfolio standard and clean energy goals outlined in the case was based 2017 NREL ATB forecasts of wind versus solar costs and their calculated LCOEs, which were calculated for the Renewable Energy Plan case (Case Number U-18232). Please see attachment for the LCOE comparison. The selection of primarily wind in the defined period of our PCA was not influenced by Strategist or Promod runs.

Refer to the attachment below:

Attachments: The document listed below is available for download at the following hyperlink:

https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U-204712019IRPPublic/default.aspx

U-20471 ELPCDE-13.88a Renewable forecasted LCOEs

MPSC Case No.:	U-20471
Requestor:	ABATE
Question No.:	ABDE-3.30
Respondent:	L. K. Mikulan
Page:	1 of 1

Question: Please confirm that DTE modeled starting point renewable resources (as described on page 75 of Ms. Mikulan's direct testimony) in the Strategist modeling and in the IRP at $0 cost. If this is not accurate, please provide a detailed narrative, explaining how the costs of these starting point renewable resources were modeled.

Answer: Confirmed.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-15.100a
Respondent:	L. K. Mikulan
Page:	1 of 1

Question: Please refer to Exhibit A-13 and WP LKM-621 REF PCA A – tiered. Total base and major maintenance O&M for DTE's coal units from Exhibit A-13 is $1.04 billion. Only $268 million of this is captured as variable O&M costs in WP LKM-621 REF PCA A – tiered.

a) Why did the Company not include the full O&M cost for DTE's coal units in Strategist?

Answer: The full costs for the DTE Electric coal units were not included in Strategist because all nonretirement analysis runs had the same retirement dates. The full costs of the coal units when compared run to run would be a net zero difference. Only the variable O&M was included in Strategist for the coal units to account for dispatch. The full costs, however, were included in the Belle River Retirement sensitivities in Strategist because alternative retirement dates were analyzed.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-16.103k
Respondent:	L. K. Mikulan
Page:	1 of 1

Question: Please refer to the Company's response to STDE-2.3b and the Company's updated modeling.
k) Did the Company consider enabling superfluous units as part of its updated modeling? If so, does the Company plan to perform this analysis and when will it be made available? If not, why not?

Answer: Yes, this was considered but the Company ultimately decided to use the methodology that was presented in the STDE-2.3b Supplemental response. The Company has no plans to perform Strategist optimizations with superfluous units enabled at this time. In the original modeling, the starting point renewables were not needed for capacity, rather to meet environmental goals (25% renewables by 2030 and CO_2 reduction). These starting point renewables could be considered "superfluous." The Company has not determined whether the updated STDE-2.3b optimizations meet the environmental goals, although, on a preliminary basis, it is likely that the CO_2 goals are met in some scenarios. The 25% renewables by 2030 goal was not met due to not having the banked RECs because of delaying the renewables build until the year of capacity need (2030), but we recognize that a large renewable build would actually be built over time (such as reflected in our flexible PCA pathways) rather than all at once in the year of a capacity need.

The Company did not enable superfluous units because Staff's request was for (emphasis added):

"Has the Company performed a model run in each of the Michigan Integrated Resource Planning Parameters(MIRPP) scenarios that allow the model to optimize the build plans throughout the whole 2019-2040 period, ***only forcing in the resources that have already been approved in other planning cases, such as the Company's renewable plan or EWR plan?"***

The Company interpreted that the purpose of Staff's question was meant to provide a comparison that didn't include additional resources to the economics of the starting point renewables, which could be considered superfluous.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-16.103n
Respondent:	L. K. Mikulan
Page:	1 of 1

Question: Please refer to the Company's response to STDE-2.3b and the Company's updated modeling.
n) Aside from alternating the starting point renewables and changing the size of the renewable resources, did DTE make any changes to other modeling inputs, such as the load forecast, generation profile of solar, or the capital and O&M costs of renewable resources? If so, please provide a detailed list of inputs that were changed.

Answer: No, there were no changes to the load forecast or generation profile of solar. However, the cost of renewable resources in total cost (PVRR) were increased as a function of the change in size. i.e, $/kW capital cost was the same, but $PVRR entered into Strategist increased due to larger block size.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-8.67
Respondent:	L. K. Mikulan
Page:	1 of 1

Question: Please refer to the Company's response to MECNRDCSCDE-3.29a. Please provide a narrative discussion of the likely impacts to the modeling results (including MW of wind selected, market revenue from excess wind sales, and NPVRR of scenarios that contained wind resources) that occurred by changing the wind capacity credit from 11.7% to 16%. Please note this is not asking the Company to perform any new analyses, but rather to use its best judgement on how this change would impact modeling results.

Answer: In the starting point runs, the highest amount of wind picked for any of the four scenario least cost plans plan was 3,150 MW in the EP scenario. With an increase of firm capacity for each installed unit of wind, less capacity, or number of installed units, would be needed to fill the total required capacity for wind. In my judgement, wind with a higher capacity credit would still be selected where it was selected in the starting point runs with the lower capacity credit (Updated runs for EP and ET scenarios), but less wind in terms of number of installed units would be selected, on the order of 27% less. For example, in the EP least cost plan, 3,150MW is selected in the starting point using the wind 11.7% capacity credit. If 16% capacity credit was used, the model would need 3,150*(0.117/0.16) = 2,300 MW to fill the need with wind, or (3,150 – 2,300)/3,150 = 27% less.

Because less wind build would be needed to fill the capacity need when given a higher capacity credit, less market value would be obtained from excess energy in the starting point runs, and it is possible higher amounts of solar may be selected instead of wind. That is, the ratio of solar to wind build could possibly increase across the various modeling least cost plans with an increase in wind capacity credit.

The capacity credit that wind and solar will achieve in the future is a large uncertainty, or risk, that may drive differences in the least cost build selections of wind vs. solar. The strength of the PCA in the post 2024 timeframe lies in its flexibility and adaptability to mitigate the uncertainties associated with future assumptions, including MISO's future capacity credit allocation methods for various resources.

Attachments: *none*

MPSC Case No.: U-20471
Requestor: ELPC
Question No.: ELPCDE-1.1d
Respondent: L. K. Mikulan/Legal
Page: 1 of 2

Question: Please refer to Mikulan Direct Testimony at 82.

d) Did DTE perform any analysis on how the excess generation impacts market prices? If, so please provide all documents and analyses related to this impact.

Answer: DTE Electric objects for the reasons that the information consists of confidential, proprietary research, or commercial information belonging to DTE Electric, the disclosure of which would cause DTE Electric and its customers competitive or commercial harm or the request seeks information that is the confidential or proprietary information of others, acquired by DTE Electric pursuant to a contract or license that prohibits disclosure. Subject to this objection, and without waiver thereof, the Company answers as follows:

To analyze the impacts of excess wind generation on market prices, a wind congestion sensitivity was run on the ET scenario using two approaches. The first approach was to take the least of the LMPs from the Iowa wind heavy market (2014-2016) and apply that differential to the forecasted LMPs in the ET scenario. Historical data from Iowa was considered since Iowa has a high level of wind penetration. The second approach was to take an average of the LMPs from the Iowa market (2014-2016) and apply the differential to forecasted LMPs in the ET scenario. The two input files, SAVs, and the output Strategist files are listed below.

ET - Wind Congestion sensitivity _ LOWEST MARKET METHOD			
EWR level	**29/30 Build**	**PVRR, $M**	**delta, $M**
1.75%	167 MW DR 1800 MW WIND	12,237	
1.75%	308 MW DR 600 MW Wind	12,207	-30
1.75%	414 MW 1x1 CCGT	12,137	-100

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-1.1d
Respondent:	L. K. Mikulan/Legal
Page:	2 of 2

ET - Wind Congestion sensitivity _ AVERAGE MARKET METHOD			
EWR level	**29/30 Build**	**PVRR, $M**	**delta, $M**
1.75%	167 MW DR 1800 MW WIND	12,199	
1.75%	259 MW DR 900 MW Wind	12,189	-10
1.75%	414 MW 1x1 CCGT	12,137	-62

Attachments: The documents listed below are available for download at the following hyperlink: https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U204712019IRPPublic/default.aspx

U 20471-ELPC 1.1d_ET Wind Sensitivity Inputs (Lowest market method).xlsx
U 20471-ELPC 1.1d_ET Wind Sensitivity Inputs (Average method).xlsx
U 20471-ELPC 1.1d_ET Planning Period Comparison (Lowest Market method).txt
U 20471-ELPC 1.1d_ET Planning Period Comparison (Average method).txt

The documents listed below are only being provided to those who have signed a non-disclosure agreement pursuant to the protective order in this case and also have entered into a license agreement for Strategist. For those individuals, the documents are available for download at the following hyperlink: https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U-204712019IRPLicenseHolders/default.aspx

NDA U-20471 ELPCDE-1.1d ET - 1.75% EE WIND CONGESTION RATIO - (LOWEST MKT).sav
NDA U-20471 ELPCDE-1.1d ET - 1.75% EE WIND CONGESTION RATIO - (AVERAGE MKT).sav

MPSC Case No.:	U-20471
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-6.9]
Respondent:	M. T. Paul/L. K. Mikulan
Page:	1 of 1

Question: Please provide the Company's current annual estimates of fixed O&M costs for the Belle River plant (by unit) for the years 2018 through 2030.

Answer: The Company does not estimate fixed O&M costs. The case filing includes the Company's most recent estimate of total O&M cost through 2030. Please see Exhibits A-13 thru A-16 for total O&M costs.

Attachments: All non-confidential workpapers were included on the discs that were provided to parties at the pre-hearing conference on April 26, 2019. In addition, the workpapers can be accessed at the following hyperlink under MECNRDCSCDE-1: https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U-204712019IRPPublic/default.aspx

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-15.101b
Respondent:	S. G. Pfeuffer / M. T. Paul
Page:	1 of 1

Question: Please refer to the Company's response to STDE-13.14d.

b) Why did the Company not perform any analyses on whether it could replace its aging peaker fleet with new, clean resources that also provide the functions listed in the Company's DR response to STDE-13.14d?

Answer: In preparing for this IRP, the Company analyzed retirement for the units that were required by filing requirements to have retirement analysis. This included all of the coal units with the exception of the most efficient coal units.

Attachments: None

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-15.100b
Respondent:	L. K. Mikulan
Page:	1 of 2

Question: Please refer to Exhibit A-13 and WP LKM-621 REF PCA A – tiered. Total base and major maintenance O&M for DTE's coal units from Exhibit A-13 is $1.04 billion. Only $268 million of this is captured as variable O&M costs in WP LKM-621 REF PCA A – tiered.

b) Did the Company perform any modeling that allowed Strategist to select the optimal retirement year of its coal fleet based on an economic analysis of the full cost (including all O&M) of maintaining the coal fleet units? If not, why did it not perform this analysis?

Answer: The Tier 2 and Belle River retirement analyses were performed using the total costs of the coal units to be retired and specific retirement dates. The Belle River retirement analysis was performed using the full costs and allowed the model to select the optimal retirement date from two possibilities. The Company did not perform modeling that allowed Strategist to select the optimal retirement date from more than two possibilities for several reasons:

- A Strategist alternative for each retirement year and each unit being optimized would have to be created. Multiple Strategist alternatives would be needed due to variances in multiple factors including outage schedules, fixed O&M, ongoing capital, and others.
- A separate PVRR cost build up for each unit would have to be calculated for each retirement year.
- When there are multiple units at one plant, there are additional considerations with common equipment and shared labor costs that would need to be considered in the PVRR cost build up. This would add more Strategist alternatives to properly account for and optimize multiple variations of unit groupings and different retirement orders.
- Having too many alternatives in Strategist can either slow down the runs or eliminate states.
- The Belle River Retirement optimization on the ET scenario had 582 build plans generated for a 2-unit plant with specific retirement dates. Adding years or number of units being studied will increase the number of build plans created exponentially with each addition. For example, if a third retirement date was added to the optimization for the 2-unit plant, (units still retiring 1 year apart) the number of build

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-15.100b
Respondent:	L. K. Mikulan
Page:	2 of 2

- Plans considered would approximately double to 1,164; adding a fourth possible retirement date would exceed the maximum 1,250 build plans that Strategist can handle (582*3 = 1,746 > 1,250)

The Tier 2 retirements and the Belle River retirement analyses considered all the above listed costs accurately and considered hundreds of build plans.

Attachments: *none*

MPSC Case No.:	U-20471
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-3.85
Respondent:	L. K. Mikulan
Page:	1 of 1

Question: Suppose that a new generation resource can be owned and operated or that power can be purchased through a new long-term contract at less than the cost of energy (as measured by LMP) that would be displaced by that resource but the Company has no capacity need. Explain how that resource would have been treated in the Company's IRP modeling and whether it would have been selected for inclusion in the PCA.

Answer: If an alternative technology has better than market value, it would have been rated highly in the market valuation screening. In the Strategist optimization modeling, a resource would have not been selected because there was no capacity need. However, knowing that the resource was economic, it can be forced into a modeling run or run in Strategist as a "superfluous" unit to verify that the value of the alternative positively impacted the build plan economics.

An example of such a resource was the CVR/VVO program. The program rated highly in the market valuations, was not selected in the optimization due to in part to its small size, therefore was not selected as an optimized resource so it was subsequently forced into the PCA for pathways A and C.

The voluntary renewables programs were also forced into the PCA pathways.

Attachments: *N/A*

MPSC Case No.: U-20471
Requestor: ELPC
Question No.: ELPCDE-8.70
Respondent: L. K. Mikulan
Page: 1 of 1

Question: Please refer to the Company's response to MECNRDCSCDE-3.85. Aside from the CVR/VVO and VGPP renewables, were any other superfluous resources modeled as options in any other run? If so, please identify what runs uses other superfluous resources, what superfluous resources were modeled, and how many and what type of superfluous resources were selected by the runs. If not, please explain why DTE did not seek to understand if superfluous resources could reduce the Company's NPVRR despite the Company not having a capacity need.

Answer: No other resources were modeled as "superfluous" in the Strategist modeling. The Company limited the resources modeled as "superfluous" to reduce both the number of states that are generated and overall runtime of the Strategist modeling. The capacity position after 2023 is positive (see Exhibit A-7) and growing due to the additions of the starting point renewables to meet the clean energy and low CO2 goal, DR, and EWR increase to 1.75%. These resources are already putting the fleet above needed capacity in many years, therefore, potentially adding even more resources could be considered excessive.

Attachments: *none*

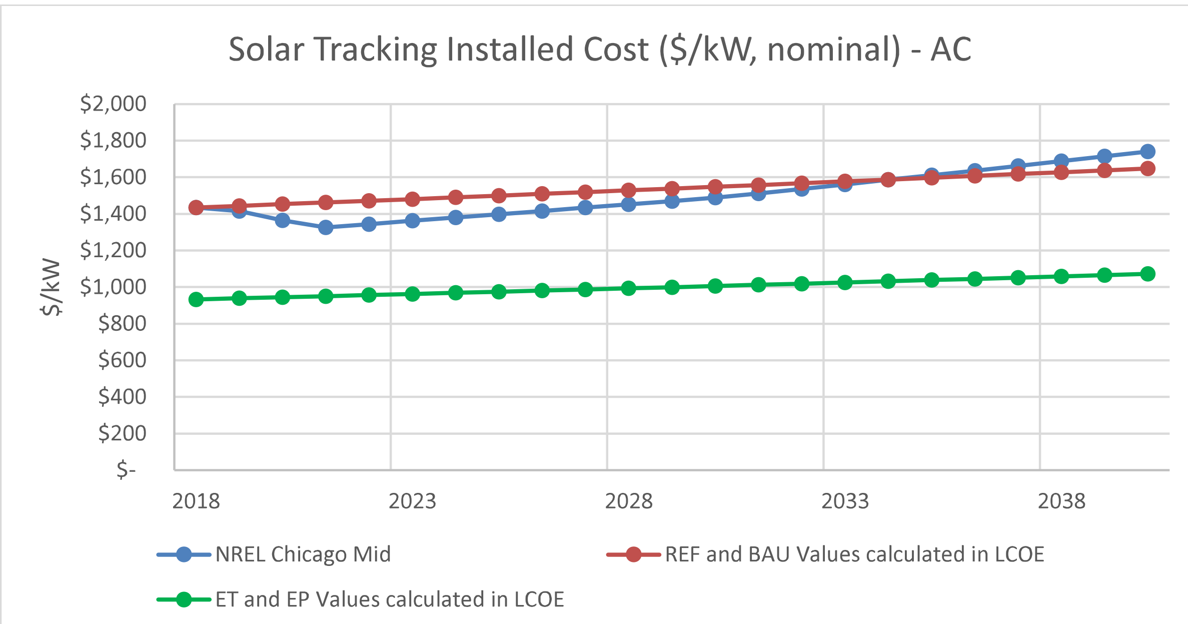
MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-1.24f
Respondent:	L. K. Mikulan
Page:	1 of 2

Question: Refer to WP LKM-460 NREL Renewable Inputs and WP LKM-448 LCOE.

f) Why did DTE not directly utilize the future capital costs from the NREL 2018 ATB report and instead create its own assumption about future cost increases?

Answer: DTE Electric used NREL 2018 assumptions and applied an average NREL escalation rate for solar. This method was utilized to keep the inputs straightforward for the LCOE model and to provide Strategist with fewer alternatives. Strategist does not accept non-linear escalation rates associated with technology alternatives. To accommodate non-linear escalation rates, a different technology alternative would have had to be input each year into Strategist. The 35% reduction in solar capital costs in the EP and ET scenarios utilized costs lower than the NREL Chicago Mid Installed Costs ($/kW, nominal). Please see the graph below also provided in attachment U-20471 ELPCDE-1.24f Graph of Solar installed Costs. As shown in the graph, in the year 2030 (the year the model was solving for) the difference in installed cost between NREL and the REF scenario is only 4%.

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-1.24f
Respondent:	L. K. Mikulan
Page:	2 of 2



Attachments: The document listed below are available for download at the following hyperlink: https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U204712019IRPPublic/default.aspx

U-20471 ELPCDE-1.24f Graph of Solar installed Costs

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-1.2c
Respondent:	T. L. Schroeder/ L. K. Mikulan
Page:	1 of 1

Question: Please refer to Schroder Direct Testimony at 19-22.

c) Why did DTE not use the 2017 NREL ATB for the solar fixed O&M cost when it used this source for other solar and wind costs, including the fixed O&M for wind projects?

Answer: NREL cited “different methodologies” when DTE Electric inquired why the 2017 actuals from the benchmarking study were different from the NREL ATB forecast. DTE Electric used the Q1 2017 U.S. Solar Photovoltaic System cost benchmark for fixed solar O&M because it was more closely aligned with Company experience.

Attachments: *None.*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-5.55]
Respondent:	T. L. Schroeder
Page:	1 of 1

Question: Please refer to ELPCDE 1.2d. Are any of the ground mount projects single-axis tracking systems? If so, please identify which are single-axis tracking systems.

Answer: No. However, the following ground-mounted projects have some of their capacity on dual-axis tracking systems:

Scio Township
University of Michigan – Institute of Science

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-6.56b]
Respondent:	L. K. Mikulan
Page:	1 of 1

Question: Please refer to Schroeder Direct at 21, WP LKM-37, WP LKM-448, and WP LKM-449. Schroder Direct states: "DTE Electric expects future solar parks to operate at a 22.9% NCF based on the NREL's 2018 ATB forecasts for Chicago – Mid for single-axis tracker solar arrays." WP LKM-37 shows the derivation of this value on tab "Solar" rows 8 and 9. However, the capacity factor used in WP LKM-449 (Master Tech and Finance Inputs) and LKM-448 (LCOE) use a lower value of 22.5%.

b) What witness discussed or provided support for the lower 22.5% value?

Answer: No witness discussed or provided support for the lower value. This value was an earlier assumption that was used in the LCOE screening analysis completed early in the IRP process as supported in workpapers LKM-449 and LKM-448 LCOE UPDATED. The Solar capacity factor was later updated to 22.9% as shown in workpaper LKM-37, for the IRP Strategist Optimization modeling.

Attachments: *none*

From: Kunjal Yagnik
To: Kevin Lucas
Cc: Tony Hunziker
Subject: RE: [EXT] Question on MTEP19 Futures ELCC values
Date: Friday, June 14, 2019 11:29:43 AM
Attachments: image001.png
image002.png
image003.png
image004.png
image005.png

Kevin,

For MTEP analysis, MISO used fixed-tilt system due to the availability of the dataset. For future MTEP cycles, MISO may consider mix of fixed-tilt as well as systems with sun tracking. The decreases in the ELCC were results of Renewable Integration Impact Assessment (RIIA) study by MISO and results were presented in the stakeholder forum. Presentation can be found at: https://cdn.misoenergy.org/20180418%20PAC%20Item%2003d%20RIIA174068.pdf

For upcoming MTEP cycle, we are organizing workshops on this and other such topics. You can join the workshop discussions.

Please let me know if you have any further questions.

Kunjal Yagnik
Policy Studies Engineer II
MISO |3850 N Causeway Blvd, Ste 442, Metairie 70002
504-846-7117 (direct) | 504-689-7120 (fax) | 551-689-6751 (cell)
kyagnik@misoenergy.org
www.misoenergy.org

From: Kevin Lucas <KLucas@SEIA.org>
Sent: Wednesday, June 12, 2019 5:12 PM
To: Tony Hunziker <ahunziker@misoenergy.org>
Subject: [EXT] Question on MTEP19 Futures ELCC values

Hi Tony,

I was reviewing the June 13, 2018 MTEP19 Futures deck that was presented to the Planning Advisory Committee, in which you were listed as the point of contract. One of the proposed updates will step down the ELCC for solar resources from 50% to 30% over ten years. Can you confirm that the 50% starting point is based on fixed-tilt systems? Have you performed any analysis for the corresponding value for single-axis tracking systems? Finally, has this step down schedule been approved by the relevant MISO committee?

Thanks in advance for your response,
Kevin

Kevin Lucas

Director of Rate Design

www.seia.org

klucas@seia.org

Direct: (202) 556-2899
1425 K Street, NW | Suite 1000
Washington, D.C. | 20005

What's Happening at SEIA:
Solar Power International & Energy Storage International | Sept. 23-26 | Salt Lake City, UT
SEIA is ushering in The Solar+ Decade

MPSC Case No.:	U-20471
Requestor:	ABATE
Question No.:	ABDE-2.11b
Respondent:	L. K. Mikulan/ T. L. Schroeder
Page:	1 of 1

Question: Please refer to Ms. Mikulan's direct testimony at page 50, lines 17-23.

b. Has DTE conducted any studies on the validity of this declining ELCC assumption? If so please provide.

Answer: No, DTE has not conducted any studies on the ELCC decline.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-9.76d
Respondent:	Supplemental
	J. W. Chang
Page:	1 of 1

Question: Please refer to Exhibit A-47, "Integrating Renewable into Lower Michigan's Electricity Grid" by The Brattle Group.

d) Provide all configuration data (e.g. location, system nameplate size, system configuration (fixed tilt, single-axis tracking, etc.), DC/AC rating, etc.) that is required to exactly reproduce each solar generation profile data found in "Workpaper JWC-02 - Figure 3.xlsx" tab "Solar Profiles" with the tool indicated in question 76(a) above.

Supplemental Answer:

As noted in response to ELCPDE-9.76b, the solar generation profiles were accessed through NREL SAM Tool Version 2017.9.5. In this version, we selected the "Photovoltaic (detailed) No financial model" option. We then selected the six locational weather files listed with their NREL IDs in our response to ELCPDE-9.76b. As explained in that response, these weather files are based on NREL's National Solar Radiation Database (NSRDB) as of August 22, 2018.

For each location-specific weather file, we set the "Desired array size" under "System Sizing" field within the "System Design" tab, to 5GWdc (i.e., 5,000,000 kWdc). No other changes to the default parameters in the System Design tab or other tabs were made.
Enclosed is our SAM_System_Settings.sam file, which can be read into the SAM tool Version 2017.9.5, and be used with the each of the location-specific weather files we listed in our response to ELCPDE-9.76b. This System Settings file contains the settings we used.

Original Answer: See response to ELPCDE-9.76.b. The remaining configuration data used to develop our solar shapes were the NREL default settings upon download for the NREL SAM Tool (Version 2017.9.5). For the Array size, we specified the desired size at 5GWdc. Note that new release of NREL's SAM tool may reflect different default input values. New SAM tool releases also incorporate updated weather irradiance data files from NREL's (NSRDB). The SAM tool version we used to develop the six locational solar TMY shapes can be downloaded from NREL's website.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-12.81a
Respondent:	L. K. Mikulan/
	T. L. Schroeder
Page:	1 of 1

Question: Please refer to the hourly solar generation profile found in WP LKM-14 REF PCA PROMOD Inputs, tab "Purchases", cells BB30:BZ395.

a) What is the source of this data?

Answer: Please see attachments 'U-20471 ELPCDE-12.81a Shape Data' and 'U-20471 ELPCDE-12.81a Parameters'.

Attachments: The documents listed below is available for download at the following hyperlink:
https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U-204712019IRPPublic/default.aspx

U-20471 ELPCDE-12.81a Shape Data
U-20471 ELPCDE-12.81a Parameters

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-12.82b
Respondent:	L. K. Mikulan/
	T. L. Schroeder
Page:	1 of 1

Question: Please refer to the Strategist Reference case.

b) What is the source of this data?

Answer: The source is the same as the PROMOD data. The Strategist data was translated from PROMOD using Powerbase which converts 8760 hourly data to typical week data. Please see ELPCDE-12.81a for source information.

Upon reviewing the data for this discovery response, it was noticed that there appears to be a minor amount of erroneous data in hour two of day one of the solar shape. The IRP team determined that this data was not a result of the powerbase translation and the impact of this data is immaterial.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-15.97d
Respondent:	L. K. Mikulan
Page:	1 of 1

Question: Please refer to the Company's response to ELPCDE-12.81a and Schroeder Direct at 21.

d) Confirm that DTE mistakenly utilized generation profiles from a fixed-tilt PV system with a 1.187 DC/AC rating in its PROMOD and Strategist modeling. If deny, please explain the discrepancy between the generation profiles derived from this PVSYST report and the IRP narrative.

Answer: Not Confirmed. The Company utilized the generation profile from a fixed-tilt PV system with a 1.187 DC/AC rating in PROMOD and Strategist Modeling. The generation profile was scaled such that the equivalent annual energy output of an assumed single-axis tracking system with a 1.30 DC/AC rating was modeled in PROMOD and Strategist.

Attachments: N/A

MPSC Case No.:	U-20471
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-8.32
Respondent:	L. K. Mikulan/Legal
Page:	1 of 3

Question: It appears that the SOLAR-All Transaction Hourly Profile was used to represent the solar output from all existing solar, planned solar, and potential resource additions. Since most existing solar is fixed-tilt, and Ms. Mikulan represents that fixed-tilt solar was screened out and single-axis solar was used for future resources, please explain how this profile was used to represent both types of solar systems.

Answer: DTE Electric objects to the request as it seeks information that is either the confidential and proprietary commercial information of DTE Electric or of others acquired by DTE Electric via a license that does not allow dissemination to non-licensed parties. In further answer and without waiving the objection the Company states as follows:

A capacity factor of 22.9% was used for single axis tracking systems, and a lower capacity factor of 18.5% was used for fixed tilt systems in the LCOE screening. The desired capacity factor was applied to the same hourly solar shape and the resulting annual solar energy scaled to be consistent with the desired capacity factor. Upon completion of the modeling, it was identified that the shape used was that of fixed tilt, as opposed to single-axis tracking solar. A delta analysis was performed at that time on a few select runs and the difference in shape was considered immaterial. Those modeling runs were not retained.

To support this discovery response, another delta analysis was completed for seven select Strategist runs. All solar was changed; both the Strategist alternatives and the solar that was forced in as transactions, if applicable. The difference in the NPVRR of the select runs was 0.02% on average and the build plans generated by the Strategist optimization did not change. As a result, the impact of using the fixed tilt shape remained immaterial. This result can be explained by the firm capacity and modeled solar energy remaining constant for each solar resource regardless of shape indicating that the shape itself has minimal effect on the PVRR and least cost build plan. The results of the IRP, the Strategist and PROMOD modeling, and the resulting PCA choices were not affected by the solar shape used.

MPSC Case No.:	U-20471
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-8.32
Respondent:	L. K. Mikulan/Legal
Page:	2 of 3

In the table below are the results of the modeling of seven selected runs with both the fixed tilt shape and the single axis tracking shape. The first six runs were from the STDE2.3b supplemental modeling. The STDE 2.3b modeling was used because there was resource selection in 2030 and 2040 in those runs whereas the original scenario optimizations only had resource optimization in 2029-2030. The last run shows the BAU all solar run with the single axis tracking shape. This run has the most solar of any build plan in the IRP and shows that the solar shape used is immaterial.

Comparison of solar shapes used in modeling

Run	FIXED TILT, NPVRR $M	SINGLE AXIS TRACKING, NPVRR $M	Delta NPVRR, $M	% of original
BAU LCP	13,563	13,558	-4.8	0.035%
BAU 2030 OPT	13,506	13,505	-0.3	0.002%
BAU 2040 OPT	13,506	13,505	-0.5	0.004%
ET LCP	12,805	12,800	-4.9	0.039%
ET 2030 OPT	12,887	12,887	0.0	0.000%
ET 2040 OPT	12,849	12,849	-0.2	0.002%
BAU All Solar	12,496	12,488	-8.1	0.065%

Attachments: The documents listed below are available for download at the following hyperlink:
https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U204712019IRPPublic/default.aspx

MPSC Case No.:	U-20471
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-8.32
Respondent:	L. K. Mikulan/Legal
Page:	3 of 3

U-20471 MECNRDCSCDE 8.32 (STDE 2.3b) BAU LCP-Single tracking.TXT
U-20471 MECNRDCSCDE 8.32 (STDE 2.3B) BAU OPTIMIZATION 2030-Single tracking.TXT
U-20471 MECNRDCSCDE 8.32 (STDE 2.3B) BAU OPTIMIZATION 2040 RERUN-Single tracking.TXT
U-20471 MECNRDCSCDE 8.32 (STDE 2.3B) ET LCP-Single tracking.TXT
U-20471 MECNRDCSCDE 8.32 (STDE 2.3B) ET OPTIMIZATION 2030-Single tracking.TXT
U-20471 MECNRDCSCDE 8.32 (STDE 2.3B) ET OPTIMIZATION 2040-Single tracking.TXT
U-20471 MEC8.32 WP LKM -804 BAU -2.0 EWR-Single tracking (Plan 7).TXT
U-20471 MECNRDCSCDE 8.32 1-axis tracking_load profile.xlsx
U-20471 MECNRDCSCDE 8.32 Seasonal_Transaction_Capacity.xlsx
U-20471 MECNRDCSCDE 8.32 Solar Shape - Delta Analysis.xlsx

The following Confidential Strategist Modeling files are available for download from the Company's Discovery Portal to those who have properly executed a Non-disclosure agreement subject to the protective order in this case and who hold a Strategist® License, using the hyperlink below.
https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U-204712019IRPLicenseHolders/default.aspxx
U-20471 MEC 8.32 (STDE 2.3b) BAU LCP-Single tracking.SAV
U-20471 MEC 8.32 (STDE 2.3B) BAU OPTIMIZATION 2030-Single tracking.SAV
U-20471 MEC 8.32 (STDE 2.3B) BAU OPTIMIZATION 2040_RERUN-Single tracking.SAV
U-20471 MEC 8.32 (STDE 2.3B) ET LCP-Single tracking.SAV
U-20471 MEC 8.32 (STDE 2.3B) ET OPTIMIZATION 2030-Single tracking.SAV
U-20471 MEC 8.32 (STDE 2.3B) ET OPTIMIZATION 2040-Single tracking.SAV
U-20471 MEC 8.32 WP LKM -804 BAU - 2.0 EWR-Single tracking.SAV

MPSC Case No.:	U-20471
Requestor:	Staff
Question No.:	STDE-2.3b
Respondent:	L. K. Mikulan
Page:	1 of 1

Question: The Company has indicated the inclusion of several resources as a starting point of its IRP from the 2019-2040 timeframe.

b) If the Company has not performed model runs as described in question 9, would the Company run each of the MIRPP scenarios (not the corresponding sensitivities), allowing the model to optimize the entire planning period given the Company's expected retirements discussed in this case? If yes, when would that information be available for Staff and intervenor to review? If no, why is the Company unwilling to provide transparency as to what the build plan would look like if the model could fully optimize throughout the study period?

Answer: Yes. This modeling is currently underway. The results will be provided to Staff and Intervenors as soon as they are completed.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-1.10a
Respondent:	M. T. Paul
Page:	1 of 1

Question: Please refer to Paul Exhibit A-12. For each unit, for each individual year from 2014 to 2018:

a) Provide the expected years of remaining operating life.

Answer: The Company has not made a decision to retire any peaking units at this time.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-1.10b
Respondent:	M. T. Paul
Page:	1 of 1

Question: Please refer to Paul Exhibit A-12. For each unit, for each individual year from 2014 to 2018:

b) Provide number of hours that the unit ran.

Answer: Please see attachment. Some units are grouped per Company standard reports.

Attachments: The document listed below is available for download at the following hyperlink: https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U204712019IRPPublic/default.aspx

U-20471 ELPCDE-1.10b-01 2014-2018 Peaker Run Hours.xlsx

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-4.49a
Respondent:	M. T. Paul
Page:	1 of 1

Question: Please refer to Exhibit A-12. For each unit, provide the following for each year between 2016 through 2018:

a) Total number of starts.

Answer: To the extent the information is available in the Company's database, please see the "Peaker Starts" attachment. Peaker hourly net generation for 2016-2018 has also been included, from which total number of starts can be estimated.

Attachments: The document listed below is available for download at the following hyperlink: https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U204712019IRPPublic/default.aspx

U-20471 ELPCDE-4.49a-01 Peaker Starts 2016-2018
U-20471 ELPCDE-4.49a-02 Peaker Hourly Net Gen 2016
U-20471 ELPCDE-4.49a-03 Peaker Hourly Net Gen 2017
U-20471 ELPCDE-4.49a-04 Peaker Hourly Net Gen 2018

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-8.75
Respondent:	M. B. Leuker/S. D. Burgdorf
Page:	1 of 1

Question: Please provide hourly system load data for 2016, 2017, and 2018.

Answer: See attachment U-20471 ELPCDE-8.75 2016-2018 System Load.xls.

Attachments: The following document is available for download at the following hyperlink:

https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U-204712019IRPPublic/default.aspx

U-20471 ELPCDE-8.75 2016-2018 System Load.xls

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-8.73
Respondent:	S. D. Burgdorf
Page:	1 of 1

Question: Please refer to the Company's response to ELPCDE-4.49a. In the 2016-2018 generation worksheets, there is a notable increase in September generation from legacy gas turbine peaker (e.g. those installed before 1990) when compared to August and October. The average output of these units in September afternoons is 2-3 times higher than the average output in August afternoons. Is this increase in legacy gas turbine peaker output due to any specific Company activities, such as scheduling refueling of Fermi nuclear plant or performing major maintenance on its other large generating facilities? If so, please describe these activities. If not, please provide the Company's best guess as to why these units ran so much more frequently in September 2016, 2017, and 2018 than in the typical peak load months of July and August.

Answer: In 2016, these Peakers did not generate more in September than in the normal peak load months.

The market prices in September afternoons during 2017 and 2018 were higher than the market prices in typical summer peak load months. These units were committed for either economics or for reliability.

Attachments: *None.*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-8.66a
Respondent:	S. D. Burgdorf
Page:	1 of 1

Question: Please refer to the Company's response to ELPCDE-1.2d and ELPCDE 1.10b. The Enrico Fermi peaker facility had an "expenses per net kWh" of $0.4601/kWh in the 2017 Q4 FERC Form 1, which is by far the highest of the gas turbine facilities in DTE's fleet. In ELPCDE 1.10b, the Company shows an increase of hours of operation of Fermi from 206 in 2015 to 1,800 in 2018, compared to run times under 400 hours for other older units. FERC Form 1 data also shows that other older units were "connected to load" for many fewer hours, despite having lower total running costs.

a) What was the cause of the increase in run hours in recent years?

Answer: These peakers were operated for local voltage support due to ITC work in the area. Peakers at different locations could not support the local voltage needs of the Fermi area.

Attachments: **None.**

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-11.79a
Respondent:	M. T. Paul/L. K. Mikulan
Page:	1 of 1

Question: Please refer to the Company's response to ELPCDE-7.64a and WP LKM-14 REF PCA PROMOD Inputs.

a) On the "FOR" tab of WP LKM-14, the values for the forced outage rate do not correspond to the values in the attachment to ELPCDE-7.64a. For example, Hancock 12-1 / 12-2 in ELPCDE-7.64a has a random outage factor of 8.0% in 2016 and 21.3% in 2017, but the corresponding PK HAN 2 in LKM-14 has a forced outage rate of 16.2% in 2016 and 14.9% in 2017. Please reconcile these two files.

Answer: It appears that this question is referencing WP LKM-19 and not WP LKM-14.

The two sets of data referenced in the question are not equivalent and cannot be reconciled because they represent different metrics. LKM-19 provides random outage rate data which is being compared to random outage factor data provided in ELPCDE-7.64a. Random outage rate and random outage factor are different by definition.

The "Forced Outage Rate" modeling input table provided in WP LKM-19 intentionally contains "random outage rate" data. The Company utilizes random outage rate data in the "Forced Outage Rate" input table to account for maintenance outages in the Company's forecast.

In WP LKM-19 the random outage rate data is *forecasted* data while the ELPCDE-7.64a random outage factor data is *actual* results. Additionally, the LKM-19 2016-2017 data was not used in the modeling runs as all modeling started in 2018.

Attachments: None

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-10.77c
Respondent:	L. K. Mikulan
Page:	1 of 1

Question: Please refer to WP LKM-19 and Strategist and PROMOD modeling of unit-level or facility-level forced outage information.

c) Please provide a narrative description of how Strategist and PROMOD use the forced outage rates found in WP LKM-19 on tab "FOR". Please include a discussion of how forced outage durations are also factored into these models.

Answer: Strategist is a probabilistic model that utilizes a representation of the load duration curve (LDC) and the input forced outage rates of the generators to determine both the expected generation of the unit and the expected remaining load for subsequent generators to serve. The probabilistic method of determining the expected generation of the unit thus takes into account the forced outage rate and is mathematically equivalent to enumerating all the possible outage and availability state combinations of all the units in the system and their probability of occurrence. In Strategist, which uses the probabilistic method, forced outage durations are not considered, just the probabilities of all the states based on the forced outage rates.

PROMOD, on the other hand, uses the Monte Carlo method of random draws to determine the outage state of the generator in any given hour. The Monte Carlo method can, if a sufficient number of draws are performed, asymptotically approach the same result as the probabilistic method. In PROMOD, using the Monte Carlo method, each random draw will have very specific hours that each unit is out of service. That "mean time to repair" or forced outage duration is either entered in by the user or PROMOD defaults to values it has built in to it for different generating unit types. The Company uses a feature called "Intellidraw" which calculates the number of outages needed based on the input outage duration input or default value, prorated up or down, to match the input forced outage rate annually.

Attachments: *none*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-10.77f
Respondent:	L. K. Mikulan
Page:	1 of 1

Question: Please refer to WP LKM-19 and Strategist and PROMOD modeling of unit-level or facility-level forced outage information.

f) Is the chance that a unit is undergoing a forced outage in a given hour correlated to any other factor, such as system load, whether the unit was running in the previous hour or day, or whether the unit was experiencing an outage in the previous hour or day? If so, please provide a description of such correlations.

Answer: Strategist is a probabilistic model that utilizes a representation of the load duration curve (LDC) and the input forced outage rate of the generators to determine both the expected generation of the unit and the expected remaining load for subsequent generators to serve. Therefore, the concepts of "randomness," prior hour, or prior day are not applicable to how Strategist applies the FOR.

For PROMOD, the unit's availability in any one hour is determined by a Monte Carlo draw. For those units that are available in the previous hour, the draw determines if this is the start of a forced outage. For those units already on a forced outage then mean time to repair and a second draw determine if the outage is now over are performed. There is no correlation to system load.

Attachments: *none*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-10.77e
Respondent:	L. K. Mikulan
Page:	1 of 1

Question: Please refer to WP LKM-19 and Strategist and PROMOD modeling of unit-level or facility-level forced outage information.

e) If a facility has a 10% forced outage rate, does this mean that 10% of the 168 modeled hours in a given month are marked such that the unit is unavailable, or does it mean that in 10% of the hours in which the unit would have been dispatched it is marked as unavailable? If neither of these most accurately describes how the 10% forced outage rate is reflected in the modeling, please provide a description.

Answer: In Strategist, which uses a 168 hour typical week to represent each month, the method of convolution described in ELPCDE-10.77d is used so the concept of a unit's hourly availability does not apply. The expected energy calculated from this method is mathematically equivalent to a complete enumeration of all possible availability states for each unit.

In PROMOD, an hourly Monte Carlo method is employed that determines, on the basis of a random number draw, if the unit is available in this hour or not. In this case, the unit's availability in the previous hour(s) also enters into consideration whereby mean time to repair and a draw to determine the exact number of outage hours determines if the unit is also unavailable for these subsequent hours. The Company uses a feature called "Intellidraw" which calculates the number of outages needed based on the input outage duration input or default value, prorated up or down, to match the input forced outage rate annually.

Attachments: *none*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-1.10d
Respondent:	M. T. Paul
Page:	1 of 1

Question: Please refer to Paul Exhibit A-12. For each unit, for each individual year from 2014 to 2018:

d) Provide the total variable O&M costs.

Answer: Actual O&M costs are tracked and reported at the peaker fleet level. Actual O&M costs are not separated by fixed and variable. Please see the attachment.

Attachments: The following document is available for download at the following hyperlink:

https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U204712019IRPPublic/default.aspx

U-20471 ELPCDE-1.10d-01 2014-2018 Peaker O&M.xlsx

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-2.29
Respondent:	M. T. Paul
Page:	1 of 1

Question: For each peaking unit found in Paul Exhibit A-12, provide the same information that is included for each unit found in Paul Exhibit A-13. Specifically, include the O&M – Base, O&M Major Maintenance, Capital - Base Plant, and Capital – Major Environmental costs for 2018 to 2040, along with the currently-anticipated planned year of retirement.

Answer: Please see attached. The requested information exists at the peaker fleet level and not at the unit level.

The Company has not made a decision to retire any peaking units at this time.

Attachments: The document listed below is available for download at the following hyperlink:
https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U204712019IRPPublic/default.aspx

U-20471 ELPCDE-2.29-01 Peaker OM and Capital Forecast

MPSC Case No.:	U-20471
Requestor:	Staff
Question No.:	STDE-13.14d
Respondent:	M. T. Paul
Page:	1 of 1

Question: All questions below reference both Exhibit A-12 and discovery response STDE-5.7.

d. If the above analysis was not performed, please provide an explanation of the Company's decision to not retire any of the units in Exhibit A-12.

Answer: The Company has decided to not retire any of the peaking units at this time because these units provide many required functions to the electrical grid, distribution system, and power plant sites including, but not limited to, energy, capacity, voltage support, ramping energy, spinning reserves, supplemental reserves, station power, and black start.

Attachments: None

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-15.101a
Respondent:	M. T. Paul
Page:	1 of 1

Question: Please refer to the Company's response to STDE-13.14d.

a) Does DTE claim that the assets listed in Exhibit A-12 are the only assets capable of providing the required functions to the electrical grid listed in the response to STDE-13.14d?

Answer: No. In discovery response STDE-13.14d, the Company is claiming the peakers listed in Exhibit A-12 are the only existing Company assets that can provide the site-specific functions listed in STDE-13.14d.

Attachments: None

MPSC Case No.: U-20471
Requestor: ELPC
Question No.: ELPCDE-9.76b]
Respondent: J. W. Chang
Page: 1 of 1

Question: Please refer to Exhibit A-47, "Integrating Renewable into Lower Michigan's Electricity Grid" by The Brattle Group.

b) Please provide the names or IDs of the six locations that were used to generate the solar generation profiles.

Answer: The following six locations with corresponding NREL ID were used to generate the solar generation profiles. Note that these weather files are continually updated by NREL. The weather files used to develop our solar profiles were based on the NREL's National Solar Radiation Database (NSRDB) as of August 22, 2018, accessed through the SAM tool version 2017.9.5. The weather files today in SAM tool version 2017.9.5 may not be the same if NREL has since updated the weather files in the NSRDB for these locations.

City	NREL ID
Ann Arbor	USA MI Ann Arbor Municipal (TMY3)
Detroit	USA MI Detroit (TMY2)
Flint	USA MI Flint (TMY2)
Grand Rapids	USA MI Grand Rapids (TMY2)
Kalamazoo	USA MI Kalamazoo Battle Cr (TMY3)
Lansing	USA MI Lansing (TMY2)

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-1.20e
Respondent:	T. L. Schroeder
Page:	1 of 1

Question: Please refer to Mikulan Direct Tesitmony regarding the Voluntary Green Pricing program.

e) Did DTE consider signing PPAs with third-party developers to provide the renewable energy for the VGP programs? If not, please explain why.

Answer: The Company modeled all renewable energy as owned. There are significant benefits to customers from owned assets, including decreased performance risk (DTE Electric is a top quartile operator), long-term benefits to customers after the asset's depreciated life, decreased contract risk including risk of termination and change of ownership, and reduced balance sheet impacts from long term liabilities.

Attachments: *None.*

MPSC Case No.:	U-20471
Requestor:	Staff
Question No.:	STDE-2.1
Respondent:	T. L. Schroeder
Page:	1 of 1

Question: DTE's PCA contains a large amount of solar resources in the 2025-2040 timeframe. Is DTE planning to utilize a competitive bidding process to determine whether it will own the solar resources or enter into long-term PPA's? Please provide enough detail about the process DTE expects to engage in to provide Staff with a clear understanding.

Answer: It is the Company's goal to utilize renewable sourcing strategies that deliver the best value to our customers, which would include an assessment of costs, benefits, and risks, including those associated with Company ownership and/or PPAs. The Company expects to continue its historical practice of utilizing competitive bidding when implementing renewable sourcing strategies. However, it is too early for the Company to speculate about the details of such sourcing strategies or associated RFP details that will be implemented six or more years in the future.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-6.57a]
Respondent:	T. L. Schroeder
Page:	1 of 1

Question: Please refer to ELPCDE-3.44d.

a) Is the IHS Markit fleet availability data referenced for a specific year, or is it for the entire operating life of a facility, operator, or fleet?

Answer: The IHS Markit data referenced is for a specific year (2017).

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-6.57e]
Respondent:	T. L. Schroeder
Page:	1 of 1

Question: Please refer to ELPCDE-3.44d.

e) Are DTE's wind farms newer than the average wind farm analyzed by IHS Markit?

Answer: The report does not make this information known.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-3.44c
Respondent:	T. L. Schroeder
Page:	1 of 1

Question: Please refer to ELPCDE 1.20:

c) Has the Company performed a cost comparison between Company-owned projects and third-party PPA contracts for wind and solar projects? If so, provide all such analyses.

Answer: No. The Company has not performed these cost comparisons, but it does monitor third-party sources, such as the annual MPSC Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard available here:

https://www.michigan.gov/documents/mpsc/2019_Feb_15_Report_PA_295_Renewable_Energy_646445_7.pdf

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-3.44e
Respondent:	T. L. Schroeder
Page:	1 of 1

Question: Please refer to ELPCDE 1.20:

e) Has the Company performed any economic analysis on the long-term benefits that accrue to its customers after the asset's depreciated life compared to the costs incurred during its useful life?

Answer: No, the Company has not performed such an analysis.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-3.44f
Respondent:	T. L. Schroeder/
	L. K. Mikulan
Page:	1 of 1

Question: Please refer to ELPCDE 1.20:

f) Has the Company quantified the risk associated with i) decreased performance risk; ii) long-term benefits to customers after the asset's depreciated life; iii) decreased contract risk including risk of termination and change of ownership; and iv) reduced balance sheet impacts from long term liabilities? If so, provide all such analyses for each risk.

Answer: No, the Company has not quantified these risks.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-13.88c
Respondent:	L. K. Mikulan/T. L. Schroeder
Page:	1 of 1

Question: Refer to Exhibit A-5.

c. In the “Flexible” portion of the IRP, the PCAs largely switch from building wind to building solar. What was the basis for this decision? How, if at all, was this decision influenced from the various Strategist or PROMOD runs?

Answer: The selection was not based on Strategist or PROMOD runs. The renewable energy assets identified for the PA 342 15% RPS, the Clean Energy and Carbon Reduction Goals were selected based on forecasted levelized cost of energy. Based on Attachment U-20471 ELPCDE-13.88a Renewable forecasted LCOEs, the costs of wind and solar became more comparable in 2024, which is when DTE Electric proposed to switch to primarily building solar.

Refer to the attachment provided in the Company’s response to ELPCDE-88a.

Attachments: N/A

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-7.62a]
Respondent:	T. L. Schroeder
Page:	1 of 1

Question: Please refer to ABDE-2.21.

a) Have the six full-service customers been provided any estimates of the cost of the LCVGP program? If so, please provide these estimates.

Answer: Yes. The estimated cost of the LCVGP program is $45/MWh.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-15.96l
Respondent:	J. T. Bateman
Page:	1 of 1

Question: Please refer to the Company's response to ELPCDE-3.44 and ELPCDE-7.62.

l) What was the average cost of RECs that the Company retired for RES compliance purposes over the past five years?

Answer: 2014: Average cost of RECs retired in this year was $7.24
2015: Average cost of RECs retired in this year was $5.34
2016: Average cost of RECs retired in this year was $4.01
2017: Average cost of RECs retired in this year was $3.54
2018: Average cost of RECs retired in this year was $2.63

Attachments: *None.*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-7.62c]
Respondent:	T. L. Schroeder
Page:	1 of 1

Question: Please refer to ABDE-2.21.

c) If these customers have signed binding agreements, for how many years do these binding agreements require them to participate in the program?

Answer: The agreements that have been signed are for five years with the option to renew.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-15.96m
Respondent:	T. L. Schroeder
Page:	1 of 1

Question: Please refer to the Company's response to ELPCDE-3.44 and ELPCDE-7.62.

m) If the VGPP projects that support these six customers are approved, and if the six customers who have signed five-year contracts do not renew their contracts at the end of five years, and no other customers sign up to pay for the projects' incremental costs, how will the cost of the VGP program be recovered in year 6 and forward?

Answer: The LCVGP projects that support the six customers have been approved by the MPSC (see Case Number U-18232). If at any point the projects are unsubscribed, the costs will be recovered via the Renewable Energy Plan via the PSCR cost recovery mechanism.

Attachments: *N/A*

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t, and for other relief	))))	Case No. U-20471

DIRECT TESTIMONY OF

JOSEPH DANIEL

ON BEHALF OF

THE ENVIRONMENTAL LAW AND POLICY CENTER,
THE ECOLOGY CENTER,
THE SOLAR ENERGY INDUSTRIES ASSOCIATION,
THE UNION OF CONCERNED SCIENTISTS,
AND
VOTE SOLAR

AUGUST 21, 2019

Table of Contents

I. STATEMENT OF QUALIFICATIONS

Q: Please state your name and business address.

A: My name is Joseph M. Daniel. My business address is 1825 K Street NW, Suite 800, Washington, D.C. 20006.

Q: By whom are you employed and in what capacity?

A: I am employed by the Union of Concerned Scientists ("UCS") as a Senior Energy Analyst. As a Senior Energy Analyst, I conduct objective economic and technical analysis of energy policy and the electric sector. In my role, I lead research and advocacy efforts to shape state energy policies and electricity markets in order to develop a modern electric grid that can accommodate high levels of renewable energy, demand-side resources, and electric vehicles.

Q: Please describe the Union of Concerned Scientists.

A: The Union of Concerned Scientists was founded in 1969 by scientists and students at the Massachusetts Institute of Technology. UCS employs scientists, analysts, economists and engineers to develop and implement innovative, practical solutions to some the most pressing problems that society faces today—from developing sustainable ways to feed, power, and transport ourselves, to reducing the threat of nuclear war. UCS's mission is to put rigorous, independent research to work by combining technical analysis and effective advocacy to create policy solutions for a healthy, safe, and sustainable future.[1]

[1] For more information, including UCS's history and mission statement, visit: https://www.ucsusa.org/about-us.

Q: On whose behalf are you testifying?

A: I'm testifying on behalf of the Environmental Law and Policy Center, Ecology Center, Solar Energy Industries Association, the Union of Concerned Scientists, and Vote Solar.

Q: Please describe your educational background and professional affiliations.

A: I hold a Bachelor of Science in Chemical Engineering from the Florida Institute of Technology and a Masters of Public Administration in Environmental Science and Policy from Columbia University in the City of New York. I also hold a certificate in Petroleum Fundamentals from the University of Texas.

I am a member of the American Economic Association, the International Association for Energy Economists, and the US Association for Energy Economics. I also serve on the Earth Institute's Environmental Science and Policy Program Alumni Board.

Q: Please describe your professional background and work experience.

A: I have over 13 years of experience working on energy issues from engineering, regulatory, and economic perspectives. In my current work at UCS, I focus on energy system planning including integrated resource plans, avoided cost studies, power market rules, and renewable energy integration. I have applied my technical expertise on these topics in regulatory proceedings at the state, regional, and national level.

I began my career as an engineer working for Baker Petrolite (now Baker Hughes, a GE Company) where I conducted engineering studies at power plants, co-generation facilities, and petroleum refineries. I conducted engineering performance analysis at refineries across the US including Texas, Washington, Louisiana, California, Delaware, New Jersey, and Hawaii.

In 2010, I was awarded a fellowship to work with the Deputy Mayor of Tel Aviv. There, I worked with the Deputy Mayor, her staff, the office of the mayor, and the city council to help quantify and monetize the social and economic benefits of existing and proposed policies.

After Tel Aviv, I went on to graduate school where I focused on energy and environmental economics while enrolled at Columbia's School of International and Public Affairs, Environmental Science and Policy Program.

After earning my MPA, I conducted economic and technical analysis of utility plans on behalf of public interest clients while employed at Synapse Energy Economics. At Synapse, my clients included state and federal government agencies, state utility commissions, consumer advocates, rural affair advocates, and environmental advocates.

Prior to being hired by UCS, I was employed by the Sierra Club where I reviewed numerous utility filings related to utility integrated resource plans and long-term resource plans, PURPA, net-metering, energy efficiency avoided costs, and environmental compliance plans.

My resume is attached to this testimony as Exhibit ELP-67 (JD-1).

Q: Please describe your experience working on integrated resource plans.

A: I have conducted technical reviews of dozens of utility long-term resource plans, most commonly referred to as Integrated Resource Plans ("IRPs"). This includes reviewing utility assumptions pertaining to the economic and technical elements of an IRP, specifically those related to renewables costs, fuel costs, market prices, regulations, and technical capabilities of resources. It also includes reviewing the structure and framework of the modeling process. I've conducted these types of technical review for the IRPs of Consumers Energy[2], Entergy Louisiana[3], Cleco Power[4], Big Rivers Electric Cooperative[5], Colorado Springs Utilities ("CSU")[6], Kansas City Power & Light Company ("KCP&L"),[7] KCP&L Greater Missouri Operations ("GMO") Company[8], and over a dozen more utilities.

Q: Have you provided testimony or comment as an expert before this Commission?

A: Yes. In the 2018-19 Consumers Energy IRP, Case No. U-20195.

---

[2] Daniel, J. 2018. Testimony on Consumers Energy Integrated Resource Plan (IRP). Testimony to Michigan Public Service Commission. Case No. U-20165. October 15, 2018. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000030zmlAAA

[3] Daniel, J. A: Napeoleon, T. Comings, S. Fields. 2015. Comments on Entergy Louisiana's 2015 Integrated Resource Plan. Synapse Energy Economics. http://www.synapse-energy.com/sites/default/files/Entergy-2015-draft-IRP-review-15-033.pdf

[4] Daniel, J., T. Comings, J. Fisher. 2014. Comments on Preliminary Assumptions for Cleco's 2014/2015 Integrated Resource Plan. Synapse Energy Economics. Available Online: http://www.synapse-energy.com/sites/default/files/SynapseReport.2014-04.SC_.Cleco-IRP.14-045.pdf

[5] Daniel, J., F. Ackerman. 2014. Critical Gaps in the 2014 Big Rivers Integrated Resource Plan. Synapse Energy Economics. Available online: http://www.synapse-energy.com/sites/default/files/Critical%20Gaps%20in%20the%202014%20Big%20Rivers%20Integrated%20Resource%20Plan%2014-080.pdf

[6] Vitolo, T., J. Daniel. 2013. Improving the Analysis of the Martin Drake Power Plant: How HDR's Study of Alternatives Related to Martin Drake's Future Can Be Improved. Synapse Energy Economics. Available online: http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-12.SC_.HDR-Drake-Analysis.13-121.pdf

[7] Vitolo, T., P. Luckow, J. Daniel. 2013. Comments Regarding the Missouri 2013 IRP Updates of KCP&L and GMO. Synapse Energy Economics. Available online: http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-08.EJ_.KCP%26L-GMO-IRP-Updates.13-070.pdf

[8] Vitolo, T., P. Luckow, J. Daniel. 2013. Comments Regarding the Missouri 2013 IRP Updates of KCP&L and GMO. Synapse Energy Economics. Available online: http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-08.EJ_.KCP%26L-GMO-IRP-Updates.13-070.pdf

Q: Have you provided testimony or comment as an expert in other forums?

A: Yes. I presented public testimony to the EPA regarding that Agency's proposal to delay implementation of the Effluent Limitation Guidelines under the Clean Water Act, providing my expert opinion on the costs of delayed implementation.[9] I provided a declaration to the Federal Court of Appeals in *Sierra Club, et al., v. FERC*, 867 F.3d 1357 (D.C. Cir. 2017) testifying regarding the utilization of the Sabal Trail gas pipeline and the electric system's ability to meet electric demand.[10] I presented a framework for calculating avoided costs of rooftop solar projects to Commission Staff at one of the Arkansas Net-Metering Working Group meetings.[11] I have also assisted in the composition of regulatory comments in dockets across the country including Pennsylvania Avoided Costs for Demand Response,[12] and comments associated with a proceeding related to a renewable portfolio standard in New Orleans.[13]

Q: Are you sponsoring any exhibits?

A: Yes.

---

[9] Testimony on Proposal to Postpone Certain Compliance Dates for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category. Docket No. EPA-HQ-OW-2009-0819. Public Hearing in Washington, D.C. July 31, 2017.

[10] Declaration of Joseph Daniel. Sierra Club, et al., v. Federal Energy Regulatory Commission, Duke Energy Florida, et al.,. United States Court of Appeals Case #16-1329. October 31, 2017. Available online: http://blogs2.law.columbia.edu/climate-change-litigation/wp-content/uploads/sites/16/case-documents/2017/20171110_docket-16-1329_response.pdf

[11] Presentation to Arkansas Public Service Commission Staff on a Framework for Calculating Avoided Costs of Rooftop Solar. On behalf of Net Metering Working Group, Sub-Group 1. Docket No. 16-027-R, Implementation of Act 827 of 2015. Little Rock, AR. February 8, 2017

[12] Joint demand response comments on the tentative order on the Amended demand response study of: Citizens for Pennsylvania's Future; Clean Air Council; Keystone Energy Efficiency Alliance; the Sierra Club. Docket Numbers: M-2012-2289411 and M-2008-2069887 December, 2013. http://www.puc.state.pa.us/Electric/pdf/Act129/SWE_DRSFR-PF-CAC-KEEA-SC_C_111413TO.pdf

[13] The Alliance for Affordable Energy's First Comments. Responsive to Resolution R-19-109 https://www.all4energy.org/uploads/1/0/5/6/105637723/2019_06_03_ud-19-01_aae_comments_final.pdf

Exhibit ELP-67 (JD-1): Resume,

Exhibit ELP-68 (JD-2a-b): System Cost Reports (with and without Must Run) – Confidential,

Exhibit ELPC-69 (JD-3a,b,c,d) Summary of Generation - w and wo MustRun – Confidential; and,

Exhibit ELPC-70 (JD-4) Peak loads of select utilities.

II. PURPOSE OF TESTIMONY

Q: What is the purpose of your testimony?

A: Having reviewed DTE Company's ("DTE" or the "Company") IRP Application, my testimony provides insights on how the Company failed to conduct sufficiently robust planning, focusing first on one element of how the company elected to model existing resources and second on the treatment of energy efficiency or energy waste reduction ("EWR"). I go on to explain how these poor planning decisions, coupled with the flaws laid out by other experts in this docket, produce sub-optimal results, meaning results that would translate into unnecessary costs to customers. Given that Michiganders are already overly burdened by energy costs, the Commission should consider how the resource planning process could have been used to help make energy more affordable for DTE's customers.

Q: Can you summarize your testimony?

A: First, I explain how the Company's over-use on the "must-run" designation in the modeling software forced the models to produce results that are over-reliant on existing, Company-owned thermal resources which produced sub-optimal results and that are over-reliant on fossil generation.

Second, I explain how the Company's analysis undervalued the benefits of energy waste reduction and how that created the specious appearance that EWR is not cost effective. I point to evidence that these resources provide more benefits than they impose costs and are the definition of cost-effective.

Third, I explain how the utility's planned under-reliance on EWR and renewables and over reliance on fossil fuels makes electricity less affordable for Michiganders, particularly those living below the poverty line.

Finally, I provide recommendations to the Commission.

Q: Can you summarize any conclusions you reached?

A: My primary conclusion is that the company failed to conduct a proper IRP that produces optimal portfolios and failed to produce an action plan that represents the best interest of customers.

Q: Can you summarize any recommendations you have for the Commission?

A: The Commission should reject DTE's IRP and direct the Company to refile with corrected modeling to address the issues discussed in my testimony as well as make several other corrections laid out in the testimony of witnesses Woychik, Kenworthy, Gignac, and Lucas. Furthermore, in light of revelations that the Company's modeling exercises contained in the IRP did not inform the planned course of action ("PCA"), the Commission should direct the Company to reformulate a PCA.[14]

---

[14] *See* Lucas Direct Testimony at 11.

III. OVER-USE OF "MUST-RUN" DESIGNATION PRODUCES SUB-OPTIMAL RESULTS

Q: How did the Company model existing resources?

A: The Company designated many existing, company-owned thermal resources as "must-run" when conducting PROMOD and Strategist modeling (ELPCDE-14.95b). This forces the models to accept a certain amount of energy/capacity from those resources regardless of economics. The amount of capacity depends on another constraint the Company places on each unit, known as "min-cap" or "p-min." This is the percent of total nameplate capacity that a plant will operate, regardless of economic conditions. Generally, it should reflect the minimum level a power plant is capable of operating. The table below lists out the Company's units that were given a must run designation and the portion of the resources that are must-run given the minimum capacity set by DTE:

Table JD-1. DTE Must Run Resources and Minimum Capacity (p-min/min-cap) of Corresponding Resource.

Generator (Plant, Fuel)	(A) Minimum Capacity (%)	(B) Capacity (MW)	(C) = (A) x (B) "Must-run" capacity (MW)
FERMI 2 (Fermi, Nuclear)	100.00	[redacted]	[redacted]
StClair 6 (St. Clair, Coal)	69.06	[redacted]	[redacted]
MnreMI 2 (Monroe, Coal)	63.62	[redacted]	[redacted]
MnreMI 1 (Monroe, Coal)	62.00	[redacted]	[redacted]
TrntChnn 9 (Trenton Channel, Coal)	59.02	[redacted]	[redacted]
MnreMI 4 (Monroe, Coal)	56.44	[redacted]	[redacted]
MnreMI 3 (Monroe, Coal)	55.16	[redacted]	[redacted]
BllRvr 1 (Bell River, Coal)	50.68	[redacted]	[redacted]
BllRvr 2 (Bell River, Coal)	50.68	[redacted]	[redacted]
StClair 7 (St. Clair, Coal)	48.54	[redacted]	[redacted]
RverRge 3 (River Rouge, Coal)	39.45	[redacted]	[redacted]
RverRge 2 (River Rouge, Coal)	38.63	[redacted]	[redacted]
StClair 2 (St. Clair, Coal)	37.23	[redacted]	[redacted]
StClair 3 (St. Clair, Coal)	37.23	[redacted]	[redacted]
TrntChnn 7 (Trenton Channel, Coal)	21.98	[redacted]	[redacted]
Totals	--	[redacted]	[redacted]

Source: Min Cap based on ELPCDE-14.95a. Units with less than 1MW "Must-Run" capacity are omitted. Capacity derived from Strategist files.

Q: What is the effect of must-run designations?

A: This "must-run" designation forces the model to serve load with these resources even when it is uneconomic to do so. As noted by Company witness Mikulan "When a must run unit is uneconomical, it will run in the models at the minimum load, also called the Min Cap."[15] Essentially, the must run designation prevents the model from turning the unit off. A more fully optimized result would produce different results.

Q: Why does the Company model resources as must-run?

A: According to Company witness Mikulan:

---

[15] ELPCDE-14.95a.

> *For the PROMOD and Strategist modeling, all coal and nuclear generating units were modeled as "must run" in order to mimic what is done in actual practice and to be consistent with the historical operations of the coal units. In actual practice, units are only offered to MISO as must run on a case by case, period by period basis depending on each particular market (Day ahead and Real Time), unit cost, and constraint conditions at the time, except for Fermi which is must run all the time. Generally, Belle River, Monroe, River Rouge, St Clair, and Trenton 9 coal burning units are must run, in both the models and actual, unless they are offline due to an outage.*[16]

Q: Is must-run a prudent way to run power plants in the market?

A: Not necessarily. Numerous analyses have been published which call into question the economic rational "self-committing," particularly coal plants in competitive energy markets. Self-committing is another market term for the practice of designating a unit as must run. In this testimony, I'll refer to self-committing as the market practice of designating units as "must run" and use the term "must run" to describe the modeling designation in hopes to differentiate the two practices.

Q: What have those analyses found?

A: A 2017 Power Bureau analysis—commissioned by the Chamber of Commerce in Illinois—found that a local, municipal-run coal plant was operating uneconomically in the MISO system.[17] According to the report, all four of the Dalman coal-fired units (owned by the local municipal utility, City Water Light & Power—CWLP), were economical to run less than 2% of the hours in 2016, but ran between 31% and 43%

[16] Discovery response: ELPCDE-14.95b

[17] Analysis of Market Impact for Proposed EmberClear Generation Facility in Pawnee Illinois. Power Bureau on behalf of the Greater Springfield Chamber of Commerce. August 2017. Online: http://files.sj-r.com/media/news/Chamber_Report_on_EmberClear.CWLP.pdf?_ga=2.8269685.65287954.1565890309-1231436091.1565890309

of the time in that same year. Note, the report was written in 2017 but not made public until 2018.

In 2017, I authored an analysis on behalf of the Sierra Club looking at this practice in the Southwest Power Pool ("SPP") and found while some power plants were able to be economic over the course of the year, power plant owners were often self-committing coal uneconomically for long periods of times within the year, and that it may have been better for customers had the power plant owners simply purchased energy off the SPP energy market.[18]

In 2018, Bloomberg New Energy Foundation ("BNEF") also conducted an analysis of every coal-fired electric generating unit in the country. BNEF's analysis found that the majority of coal plants operate "even when they cost more to run than to replace."[19] BNEF didn't specifically call out the practice of self-committing or operating as must-run but it does discuss how coal plants will turn down—but not necessarily off—when market prices drop below coal-fried units' marginal cost of production.

Recently, the practice of self-committing has come under greater scrutiny with two state utility commissions opening up dockets on the subject, one in Minnesota[20] and

[18] Daniel, J. November 2017. https://www.sierraclub.org/sites/www.sierraclub.org/files/Backdoor-Coal-Subsidies.pdf

[19] Ryan, J. Half of All U.S. Coal Plants Would Lose Money Without Regulation. March 2018. Available online: https://www.bloomberg.com/news/articles/2018-03-26/half-of-all-u-s-coal-plants-would-lose-money-without-regulation Based on: Nelson, W., Liu, S. Half of U.S. Coal Fleet on Shaky Economic Footing: Coal Plant Operating Margins Nationwide. Bloomberg New Energy Finance. March 2018. (Subscription required)

[20] MPUC Docket No. E999/AA-17-492 and E999/AA-18-373.

one in Missouri.[21] Commissions in both states are investigating if the practice is in the consumer interest and if reforms to coal-plan operations are necessary.[22]

Q: What do the historical operations of coal plants have to do with a forward-looking integrated resource plan?

A: At the end of the day, market conditions are changing. Coal plants operators, which have historically thought of their power plants as base load units that should stay online year-round, are now finding out they can produce significant savings to customers from operating only part of the year. This changing market dynamic should force power plant owners to carefully examine the economics of their resources. Company's should not presume that resources, once operated year-round as baseload, will remain economical if operated in that same manner going forward.

Q: What should the Company have done?

A: The Company should have removed the must-run designation for many of the non-nuclear thermal units. Doing so would have allowed them to evaluate the economic competitiveness of those resources as compared to market purchases or replacement. As noted by the aforementioned Power Bureau report:

> *[The] model showed that the CWLP generation resources – if priced at the marginal cost of generation - were more expensive than other resources in the MISO market, and were therefore assumed to not required to meet electricity demand in 2022.*[23]

---

[21] MPSC Case No. EW-2019-0370, https://efis.psc.mo.gov/mpsc/Docket.asp?caseno=EW-2019-0370.
[22] https://www.eenews.net/stories/1060544459
[23] Analysis of Market Impact for Proposed EmberClear Generation Facility in Pawnee Illinois. Power Bureau on behalf of the Greater Springfield Chamber of Commerce. August 2017. Online: http://files.sj-r.com/media/news/Chamber_Report_on_EmberClear.CWLP.pdf?_ga=2.8269685.65287954.1565890309-1231436091.1565890309

Applying a must run designation to coal- and gas-fired power plants, deprives utilities, including DTE in this proceeding, of making similar observation which would, presumably, precipitate the Company considering changing the way the plant operates, retiring the plant outright, or switching the plant to operating seasonally.

Q: Have coal plants chosen to switch to operating seasonally in light of changing market dynamics?

A: Yes. The trend of "seasonal operations" or "seasonal shutdowns" has been a reality for coal plants ERCOT for some time. Several coal plants have switched to seasonal operations due to increasing wind penetration and low natural gas prices. The operators of the Gibbons Creek switched to seasonal operations citing changing market conditions, noting, "it is no longer economically feasible to continue year-round operation of the facility."[24] Owners of the Martin Lake coal-fired power plant noted, "As a competitive market participant whose primary business is generating and selling wholesale power on the wholesale market, we want to operate as much of our generation as we can, but it does not make economic sense to operate a unit at a financial loss," and ultimately decided to only operate the plant during the summer, when prices were high enough to justify running the plant. [25] Finally, the Monticello coal-fired plant ran under a seasonal operation status for several years before eventually deciding to retire in 2018.[26]

[24] https://www.btutilities.com/gibbons-creek-power-plant-to-begin-seasonal-operations/
[25] https://www.bizjournals.com/dallas/news/2013/09/18/luminant-will-shut-down-martin-lake.html
[26] https://www.powermag.com/monticello-goes-under-more-coal-and-nuclear-imperiled-in-texas/

Q: Have operators of coal-fired power plants in MISO switched to seasonal operations?

A: Yes. As noted by the operators of the power plant, the Dolet Hills coal-fired power plant in Louisiana, "will transition from generating electricity year-round to seasonal, during the hottest months when demand is highest, from June to September." The Company's own estimations indicate that the switch will save customers $85 million by 2020.[27] Xcel Energy in Minnesota has also agreed to change the operations of the coal-fired Sherco Unit 2 to seasonal operations in a recent settlement.[28]

Q: What is the impact of removing the must-run designation of DTE's non-nuclear thermal units in Strategist?

A: Witness Sommer conducted a model run in which she removed the must-run designation from DTE's non-nuclear thermal units. The modeling results demonstrate that removing the must-run constraint allows the model to produce more economically efficient results, with a lower reliance on fossil fuel resources.

Q: What effect does the must run constraint have on utility costs, and the present value of revenue requirements?

A: As illustrated in the figure below, the cumulative present value by of the two plans (with and without the must run designation) varies by less than [redacted] within the period between 2019 and 2040.[29] Initially, removal of the must run constraint reduces utility

[27] Dolet Hills dispatches into both SPP and MISO. https://www.ksla.com/2018/12/05/swepco-announces-coal-mine-layoffs/

[28] https://www.utilitydive.com/news/xcel-minnesota-plans-to-retire-24-gw-of-coal-critics-say-natural-gas-has/558137/

[29] Though the must-run designation was left on for the Fermi nuclear plant, this testimony will refer to the model run that removed the must-run designation for the remaining thermal fleet as the "without must run" model run.

costs and the present value of utility costs. The cumulative present value of utility costs in 2020-2023 is lower in the scenario where the constraint was removed. The run that removed the must run constraints has a slightly higher cumulative present value [redacted] by the end of the study period in 2040.

[redacted]

Figure JD 1. Effect of removing the must run constrain on the cumulative present value of utility costs. Source: Exhibit ELP-68 JD-2a System Cost Reports (with and without Must Run) - Confidential

In any given year, except 2030, removing the must run constraint alters the utility cost in that year between [redacted] (where a negative number indicates a reduction in utility costs). The year 2030 is the one exception, where the PV of utility costs is [redacted] higher in the case without the must run constraint.

Q: Does a reduced present value justify the overuse of the must-run designation?

A: No. There are any number of circumstances where a plan could produce lower present value of revenue requirements but not be considered prudent, reasonable, or low-risk. For example, a utility modeling exercise could result in a plan wherein the lowest PRVV is produced by overbuilding gas-fired capacity and selling the excess energy and capacity to reduce PVRR. However, such a plan would be ill advised.

Q: What is the impact on removing the must-run designation on individual generators?

A: The following table details the reduction in generation over the study period from individual units.

Table JD- 2 Percent reduction in generation (MWh) over study period with and without must-run designation.[30]

Unit	MWh Reduction	Unit	MWh Reduction
RverRge 3	[redacted]	RENPKR 4	[redacted]
TrntChnn 9	[redacted]	PK HAN 1	[redacted]
MnreMI 3	[redacted]	PK HAN 2	[redacted]
PK SC 1	[redacted]	BLRPKR 1	[redacted]
StClair 6	[redacted]	PK NE 1	[redacted]
StClair 2	[redacted]	StClair 7	[redacted]
PK NE 2	[redacted]	DEAPKR 1	[redacted]
StClair 1	[redacted]	Greenwd 1	[redacted]
StClair 3	[redacted]	BllRvr 2	[redacted]
PK OTHER 1	[redacted]	PK OTHER 2	[redacted]
RROVER 3	[redacted]	MnreMI 4	[redacted]
PK NORTH 1	[redacted]	GRNPKR 1	[redacted]
RENPKR 1	[redacted]	DELPKR 1	[redacted]
MnreMI 1	[redacted]	BllRvr 1	[redacted]
RENPKR 2	[redacted]	BWEC-D 1	[redacted]
MnreMI 2	[redacted]	FERMI 2	[redacted]
RENPKR 3	[redacted]	BWEC 1	[redacted]

Source: Exhibit ELPC-XX JD-3a-d Summary of Generation - w and wo MustRun - Confidential

Some units, like Bell River 1 ("BllRvr 1") see an almost negligible difference when the must-run constraint is removed, the total generation over the study period is only reduced by [redacted] Other units see a major reduction in the total generation over the study period, like River Rouge 3 ("RverRge 3") which sees a [redacted] reduction in output

[30] These numbers were derived by taking the cumulative generation of each unit between 2018 and 2040 in the model run where the must-run designation was removed and dividing it by the cumulative generation of each unit between 2018 and 2040 in the Company's reference case run.

over just a three-year period. One unit, BWEC 1, saw a [redacted] increase in generation as a result of the must-run constraint being removed.

Figure JD-2 displays the impact removing the must run constraint can have on the operations of individual electric generating units ("EGUs").

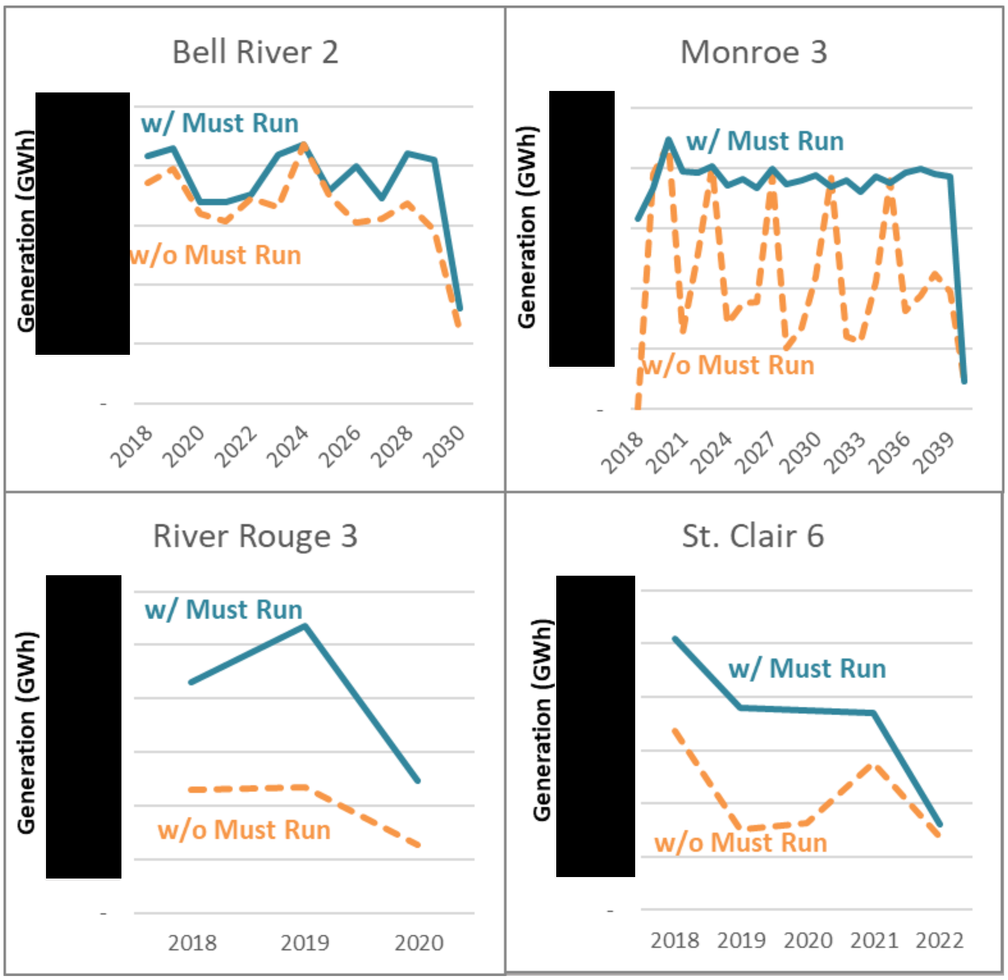


Figure JD-2: Change in generation with and without must-run constraint. Blue solid line (labeled "w/ Must Run" represents that annual generation from the unit while the orange dotted line (labeled "w/o Must Run") represents the annual generation when the must run designation is removed. Source: Exhibit ELPC 69- (JD-3d) – Confidential

As noted above, not all EGUs are affected in the same way. EGUs like River Rouge 3 and St. Clair 6 see a reduction in output in all years. Other units, like Bell River 2 and

Monroe 3, see a reduction in annual generation in some years but in other years the must-run designation doesn't impact the annual generation.

Q: Does the removal of the must-run designation impact any non-thermal generation?

A: Yes, it would appear from the modeling results that dumped energy is lower in the model run without the must-run designation.

Q: What consequences does the Company's must-run assumptions have?

A: The Company's modeling represents a future that is over-reliant on unnecessarily expensive resources and does not represent the most reasonable and prudent means of meeting the electric utility's energy needs, a requirement of IRP legislation MCL 460.6t(8). MCL 460.6t(8) provides that the Commission shall not approve an IRP unless it "represents the most reasonable and prudent means of meeting the electric utility's ***energy*** and capacity needs" (emphasis added).[31] The must-run designation prevents the model from producing results that reflect a reasonable and prudent means of meeting DTE's energy needs and therefore doesn't satisfy the requirements of the IRP rules.

IV. THE COMPANY ANALYSIS UNDERVALUES THE BENEFITS OF EWR

[31] Link: http://www.legislature.mi.gov/(S(l34nswvqmr3kobqqr5uxlfln))/mileg.aspx?page=getObject&objectName=mcl-460-6t

Q: How does the Company model EWR in the IRP?

A: DTE asserts that the Company's load forecast is embedded with 1.5% of efficiency so the Company "backs out" 1.5% of efficiency to establish a baseline. Then the Company applies the various levels of efficiency back in.

Q: Does the Company's approach to EE account for the full range of benefits that EWR provides?

A: No. The IRP underestimates many of the benefits of energy efficiency and Michigan's EWR programs.

Q: What benefits are underestimated?

A: The IRP process, as conducted by DTE, either excludes or underestimates the benefits EWR has in avoiding transmission and distribution ("T&D") capital costs, energy and demand line losses, energy costs, and capacity costs.

Q: How are avoidable T&D costs underestimated?

A: The Company has excluded any avoidable T&D costs in all but one run. Excluding the avoided T&D benefit is mathematically identical to including a $0 value for avoided T&D. The Company does recognize that EWR can contribute a monetizable value in the form of avoidable T&D costs.[32] Using a $0/kW value is an underestimation of the value of EWR and is inappropriate.

[32] Y. Zhou Direct at YZ-22

Q: Does the Company use a $0/kW value for avoided T&D in all runs?

A: No. The Company did use a $7/kW value for avoided T&D in one run; however, this value could very well still reflect an undervaluation of the benefits of EWR.

Q: How did the Company derive the $7/kW value for avoided T&D?

A: According to witness Zhou, the $7/kW value is based on data that reflects projects from between 2017 and 2018.[33] This is far from a robust way to account for avoidable T&D costs, which can see large variations from year to year. Many other jurisdictions use multi-year datasets to develop avoided T&D cost studies.[34,35,36,37]

Q: Does the Company value of $7/kW fall within the range that is typical of the industry?

A: No. When other jurisdictions have done a more comprehensive analysis they came up with larger values. In 2018, Mendota Group conducted a meta-analysis of avoided costs studies (which included the avoided T&D costs reported in states like New Hampshire, Connecticut, Massachusetts, California, Missouri, Minnesota, Illinois, Iowa, and Arizona) and found that avoidable T&D costs fell in the range of $32-$200/kW (unadjusted for inflation, but excluding jurisdictions that use $0/kW).

---

[33] Zhou Direct Testimony at YZ-21

[34] Synapse Energy Economics (Knight P., M. Chang, D. White, N. Peluso, F. Ackerman, J. Hall), Resource Insight, etc. 2018. Avoided Energy Supply Components in New England: 2018. Synapse Energy Economics and others for Avoided-Energy-Supply-Component (AESC) Study Group. https://www.synapse-energy.com/project/avoided-energy-supply-costs-new-england

[35] The Mendota Group, LLC. Benchmarking Transmission and Distribution Costs Avoided by Energy Efficiency Investments. 2014. The Mendota Group, LLC for Public Service Company of Colorado. https://mendotagroup.com/wp-content/uploads/2018/01/PSCo-Benchmarking-Avoided-TD-Costs.pdf

[36] Horli, B., S. Price, E. Cutter, Z. Ming, K. Chawla. 2016. Energy and Environmental Economics, Inc. https://www.ethree.com/wp-content/uploads/2017/01/20160801_E3_-Avoided_Cost-2016-Interim_Update.pdf

[37] PA PUC Order on 2016 Total Resource Cost (TRC) Test. Docket M-2015-2468992. Available online: http://www.puc.pa.gov/pcdocs/1367195.docx

Q: Do states with declining load typically see lower avoided cost values?

A: Not necessarily. New England, a region that has seen decreasing load and decreasing peak load, conducts an avoided cost study every two years. The semi-annual Avoided Energy Supply Components ("AESC") study analyzes a wide range of avoided costs associated with energy efficiency including avoided T&D. Avoided T&D is calculated based on data spanning between five and ten years (depending on utilities). Past studies have seen avoided T&D values as high as $200/kW and the most recent AESC has calculated a weighted average value for New England to equate to $94/kW for transmission only.[38]

California has also seen declining electric load, and the latest avoided cost numbers from the utilities in that state range from $58-$158/kW.[39]

The Pacific Northwest has similar processes to AESC, wherein the Northwest Power and Conservation Council conducts an avoided cost study that also includes an investigation of the avoided costs associated with energy efficiency. The avoided costs for T&D have recently been calculated to be in $57/kW in the most recent assessment.[40]

---

[38] Individual distribution utilities calculate the distribution component. In past studies that has brought the combined T&D values as high as $200/kW.

[39] Horii, B., S. Price, E. Cutter, Z. Ming, K. Chawla. "Avoided Costs 2016 Interim Update." August 2016. Energy and Environmental Economics, Inc. Available online: https://www.ethree.com/wp-content/uploads/2017/01/20160801_E3_-Avoided_Cost-2016-Interim_Update.pdf

[40] Jayaweera, T., M. Starrett, J. Ollis. "Memorandum to Power Committee Members: Updated Transmission & Distribution Deferral Value for the 2021 Power." March 2019. Northwest Power and Conservation Council. Available online: https://www.nwcouncil.org/sites/default/files/2019_0312_p3.pdf.

Q: Witness Zhou claims that the AESC method for calculating Avoided T&D would yield a zero-dollar value, do you agree?

A: No, I do not agree. As noted by the authors of the AESC report, in a section labeled, "Dealing with absence of system load growth," the authors explain that using a zero-dollar value is inappropriate.

> *Some utilities have experienced little or no overall growth in total load for some years and may forecast little growth in peak loads for some years. Nonetheless, a utility can have load-related investments to address parts of their service territories that are experiencing load growth. Dividing the load-related investments by zero, a negative number, or even a small positive load growth will produce meaningless results. In those situations, the utility may either use historical data from a period with load growth, or compute the avoided cost per kilowatt growth for the fraction of the system that has experienced growth. The AESC Reference case assumes a world with no new energy efficiency programs, in which the avoided costs computed for the areas with growth would be applicable to the entire utility.*[41]

Q: Does the Company cite to any other reports to support the claim that a $0/kW for avoided T&D is appropriate?

A: Yes, witness Zhou cites to page 12 of the Advance Energy Economy Institute ("AEEI") report "Economic Potential for Demand Reductions in Michigan" wherein the authors assert: "In an area with declining loads there is effectively no T&D

[41] Synapse Energy Economics (Knight P., M. Chang, D. White, N. Peluso, F. Ackerman, J. Hall), Resource Insight, etc. 2018. Avoided Energy Supply Components in New England: 2018. Synapse Energy Economics and others for Avoided-Energy-Supply-Component (AESC) Study Group. https://www.synapse-energy.com/project/avoided-energy-supply-costs-new-england

benefit associated with peak demand reductions."[42] However, the authors go on to say on the same page in the very next sentence,

> *In areas where expensive capital investments driven by load growth can be delayed or avoided, the benefits of local peak demand reduction can be quite substantial. For example, Indiana Michigan Power Company recently explored targeted demand reduction to defer load growth related transformer upgrades at its Niles, Michigan substation.* [43]

On page 11 of the report, the authors note that, "Avoided transmission benefits can take the form of delayed or deferred projects or a direct reduction in transmission payments from the IOUs to MISO." And the authors point out that, "[the] Lower Peninsula currently relies on some capacity imports, which have associated transmission charges." [44] The authors then go on to call a $0/kW value for avoided T&D "very conservative" and end up using a $20/kW value as a "medium" proxy.

Q: How do Michigan's changes in peak demand compare to California and New England?

A: Based on data retrieved via S&P Global Market Intelligence, the historical average growth rate for peak demand in New England for the past 5 years has been -0.79% and for the Cal ISO +0.76%.[45] As noted earlier, the AESC calculated that the New England states have an avoided transmission value of $94/kW. San Diego Gas &

---

[42] https://info.aee.net/hubfs/PDF/Peak-Demand-Reduction-Potential-for-Michigan021717.pdf?t=1487398737782
[43] https://info.aee.net/hubfs/PDF/Peak-Demand-Reduction-Potential-for-Michigan021717.pdf?t=1487398737782
[44] https://info.aee.net/hubfs/PDF/Peak-Demand-Reduction-Potential-for-Michigan021717.pdf?t=1487398737782
[45] S&P Global Market Intelligence collects and aggregates data from multiple sources. The summer and winter NERC and NERC sub-region peak load is collected from the North American Electric Reliability Council Energy Supply & Demand and from the EIA-411 filing and is non-coincident load.

Electric Company, which has a calculated avoided T&D of over $100/kW, has had an annual average growth rate for peak demand of -0.86%.[46]

Table JD-3. Declining peak load for select utility territories

Year	ISO New England Inc.	California ISO	San Diego Gas & Electric Co.
2018	8.39%	-7.19%	-3.68%
2017	-6.36%	8.46%	4.63%
2016	4.74%	-2.64%	-7.81%
2015	-0.02%	5.73%	-3.66%
2014	-10.72%	-0.55%	6.21%
5-year Average	-0.79%	0.76%	-0.86%

Source: Exhibit ELP-70 (JD-4): Declining peak load for select utility territories.

Q: Is the $7/kW value appropriate to use?

A: No. Use of the $7/kW value is inappropriate because it is not based on sufficiently robust analysis. At best, it would suffice as a lower bound value.

Q: How does the Company handle line losses?

A: The Company uses a line loss adjustment factor to adjust the energy savings at the customer meter.

Q: How are lines losses underestimated?

A: The line loss adjustment factor was based on average line losses not marginal line losses.[47] As noted in a 2011 RAP study by Jim Lazar:

> *The line losses avoided by energy efficiency measures are generally underestimated. Most analysts who consider line losses at all use the system-average line losses, not the*

[46] Horii, B., S. Price, E. Cutter, Z. Ming, K. Chawla. "Avoided Costs 2016 Interim Update." August 2016. Energy and Environmental Economics, Inc. Available online: https://www.ethree.com/wp-content/uploads/2017/01/20160801_E3_-Avoided_Cost-2016-Interim_Update.pdf

[47] Bilyeu Direct at KLB-16; see also Response to Discovery Question No. MECNRDCSCDE 4.19a-b.

> *marginal line losses that are actually avoided when energy efficiency measures are installed.*[48]

As noted in the same report, line losses grow exponentially with load, so line losses at the time of peak load are considerably higher than the line losses during "average" loads. The Company's use of average line losses is not appropriate because it fails to capture the full value of reducing marginal load use. As noted by both the Regulatory Assistance Project report and the AESC report, marginal line losses are more appropriate to use and are consistently higher than average line losses.[49,50]

Q: What is an appropriate line loss factor to apply?

A: The 2011 RAP report on the use of marginal line losses for avoided costs studies concluded that marginal line losses are typically 50% greater than average line losses. The RAP report suggests using a multiplier of 1.5 to adjust average line losses into a marginal value. So, in the case of DTE, the average line losses of 6.8% would translate to a marginal line loss estimated to be 10.2%. This factor would then be applicable to adjusting annual energy loads. Marginal line losses at peak would be even higher because line losses increase at higher loads.

---

[48] Lazar, J., X. Baldwin. Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements. August 2011. Regulatory Assistance Project. Available online: https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf

[49] Lazar, J., X. Baldwin. Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements. August 2011. Regulatory Assistance Project. Available online: https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf

[50] Synapse Energy Economics (Knight P., M. Chang, D. White, N. Peluso, F. Ackerman, J. Hall), Resource Insight, etc. 2018. Avoided Energy Supply Components in New England: 2018. Synapse Energy Economics and others for Avoided-Energy-Supply-Component (AESC) Study Group. https://www.synapse-energy.com/project/avoided-energy-supply-costs-new-england

Q: How are avoided energy benefits underestimated?

A: As noted earlier in my testimony, many of the Company-owned, existing units are designated as must-run, which means that energy efficiency might displace lower cost resources before higher cost must-run units. When the must-run designation is removed, many of the more expensive must-run units run less. It is possible that additional efficiency would have even further reduced the output of these expensive units even more.

Q: How are avoided capacity benefits underestimated?

A: As noted by witnesses Woychik and Sommer, the Company did not allow the model to optimize the selection of new resources and hardwired much of the capacity addition, meaning that the model could not reduce revenue requirements through capacity addition deferrals.[51] To the extent that EWR or greater levels of EWR translate into excess capacity, the model also isn't capable of "valuing" that excess capacity and so EWR isn't credited with providing incremental value.

Q: What are the impacts of underestimating multiple EWR benefits?

A: By underestimating multiple EWR benefits, EWR looks relatively less cost-effective, and DTE's analysis is skewed against EWR.

[51] *See* generally the direct testimonies of Woychik and Lucas (vis-à-vis "starting point") and Sommer Direct testimony on superfluous units

Q: Is there evidence that EWR is cost-effective?

A: Yes, as noted by Company Witness Bilyeu, EWR 1.5%, 2%, 2.25%, and 2.5% all had benefit cost ratios above 1.0.[52] If the benefits of a resource are greater than the costs, the resource is by definition cost-effective.

Q: What should have the Company have done when modeling EE?

A: Any cost-effective EWR should be part of a base plan, in this case that would mean including 2.5% EWR in the base case because the EWR at 2.5% levels had a benefit cost ratio of 1.37. Also, the Company should have conducted additional analysis of levels of EWR even greater than the 2.5% analyzed, to examine if that would have been cost-effective (after taking account of the full range of benefits of energy efficiency).

Q: What consequences does the Company's undervalue of EWR have?

A: The Company's modeling represents a future that is under-reliant on EWR and does not represent the most reasonable and prudent means of meeting the electric utility's energy needs, a requirement of IRP legislation as set forth in MCL 460.6t(8). MCL 460.6t(8) provides that the Commission shall not approve an IRP unless it "represents the most reasonable and prudent means of meeting the electric utility's ***energy and capacity*** needs" (emphasis added).[53] By not pursue on 2.5% EWR (which has a BCA of 1.37) the Company's plan does not reflect a reasonable and prudent means of

[52] Bilyeu Direct Testimony at KLB-22

[53] http://www.legislature.mi.gov/(S(l34nswvqmr3kobqqr5uxlfln))/mileg.aspx?page=getObject&objectName=mcl-460-6t

meeting DTE's energy needs and capacity needs and therefore doesn't satisfy the requirements of the IRP rules.

V. DTE PLAN FAILS TO ADDRESS ENERGY AFFORDABILITY

Q: What is the current state of energy affordability in Michigan?

A: Energy affordability is a difficult metric to measure and is a function of how expensive energy is, what other necessities a consumer spends money on, and how high an individual's income is. The Commission has direct influence on how expensive energy is, and to the extent the electric sector has externalities that don't show up on customers' bills, Commission decisions can result in customers incurring additional costs related to those externalities.

At present, average electric rates in MI are the 11th highest in the US, but Michigan electric bills are the 11th lowest. Overall, energy burden is about average for the average customer.[54] However, the energy burden for low- and moderate-income ("LMI") households is much higher. Data from DOE indicates that the average family living below the federal poverty line in Michigan spends 17% of their annual income on electricity compared to just 3% on average for Michiganders above the federal poverty line.[55]

Q: How are EWR and energy affordability related?

A: EWR lowers the bills of customers, and it can even be targeted to LMI households,

---

[54] MI is ranked 24th (out of 50 states + DC) in terms of energy burden. https://blog.ucsusa.org/joseph-daniel/state-electricity-affordability-rates-vs-bills-vs-burden
[55] https://www.energy.gov/eere/slsc/maps/lead-tool

which means it is a key component to making electricity affordable and should be a priority for both the Commission and the Company. As noted by a recent study from the University of Michigan:

> *Major federal policies include Low Income Home Energy Assistance Program (LIHEAP), and the Weatherization Assistance Program (WAP). While many states such as Michigan have legislated bill-payment assistance programs, policy targeting the reduction of energy waste at the household level presents an alternative approach that empowers households facing energy poverty and reduces the home energy affordability gap.*[56]

The study notes, that despite Michigan's EWR program having to date a benefit-cost-ratio of over 4 to 1, EWR that targets low income populations remain underfunded. The report goes on to say:

> *From an energy justice perspective, energy efficiency policies have the significant potential to reduce energy poverty and the home energy affordability gap, but is shown here, that these policies are susceptible to furthering social inequities. As energy efficiency forms an integral role in planning for state energy demands, it is essential that policy makers, regulatory agencies and utility companies examine the impact from a social perspective in order to reach a more just energy future.* [57]

Therefore, EWR benefits shouldn't be *maximized*; rather, all cost-effective energy efficiency and EWR should be pursued. LMI targeted EWR could be "less cost effective" than other EWR measures which could translate into the appearance of

[56] Stacey, B., T. Reames. Social Equity in State Energy Policy: Indicators for Michigan's Energy Efficiency Programs. 2017. University of Michigan School for Environment and Sustainability. https://justurbanenergy.files.wordpress.com/2017/12/equity-in-energy-efficiency-investment-and-savings-report-2017.pdf

[57] Stacey, B., T. Reames. Social Equity in State Energy Policy: Indicators for Michigan's Energy Efficiency Programs. 2017. University of Michigan School for Environment and Sustainability. https://justurbanenergy.files.wordpress.com/2017/12/equity-in-energy-efficiency-investment-and-savings-report-2017.pdf

those measures having "diminishing returns" but those returns are meaningful and important for LMI customers.

Q: Are there other ways the utility can increase energy affordability?

A: Yes, by reducing pollution from local power plants.

Q: How is pollution related to affordability?

A: DTE's coal plants emit significant amounts of particulate matter, sulfur dioxide, and nitrogen oxides. Coal also contains lead, mercury, arsenic, and other toxins, that readily enter the community environment's air and water. Numerous studies have concluded those pollutants from power plants have a negative impact on health and associated cost.[58] These health costs are incurred by the local community and can have significant economic costs. For example, according to the Clean Air Task Force's 2018 "Toll from Coal" study, the Belle River coal plant's 2016 emissions resulted in estimated health impacts of 114 premature deaths, 72 heart attacks, and 695 asthma attacks per year.[59] Asthma attacks, hospital visits, and the other externalities that coal plants impose on the local community have a negative financial impact on the community. Those medical costs, in turn, make electricity less affordable. The more a family has to spend on life-saving medicine and medical procedures, the less likely they are to be capable of paying their electric bill. By alleviating the health burden that DTE's coal plants impose on the local community, the Commission could make energy more affordable in Michigan.

---

[58] https://www.catf.us/educational/coal-plant-pollution/

[59] https://www.tollfromcoal.org/#/map/(title:6034//detail:6034//map:6034/MI)

VI. RECOMMENDATIONS CONCERNING APPROVAL, MODIFICATIONS, AND FUTURE IRPS.

Q: Do you have any other recommendations for the Commission?

A: Yes, the Commission should reject the Company's IRP outright and direct the Company to reconduct the entire IRP modeling process and to use the results of the modeling exercise to inform the formation of the preferred course of action.

Q: What modifications should the Company make to the modeling?

A: The Commission should offer clear direction that the Company's new modeling produces results that are consistent with IRP statute on producing least cost least risk plans. Such an order should include the following recommendations:

1. Remove must-run constraints from all thermal power plants except Fermi.
2. Include EWR levels equivalent to 2.5% or greater in all modeling runs (scenarios and sensitivities).
3. Adjust load reductions from energy efficiency using a 10.2% line-loss factor.
4. a. Include an avoided T&D values for EWR no less than $7/kW in all runs; and

   b. Consider using a $100/kW avoidable T&D value as a proxy for a more reasonable avoidable T&D value.

Q: Does this conclude your testimony?

A: Yes.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
DTE ELECTRIC COMPANY	)	Case No. U-20471
for approval of its integrated resource plan	)	
pursuant to MCL 460.6t, and for other relief	)	

EXHIBITS OF

JOE DANIEL

ON BEHALF OF

THE ENVIRONMENTAL LAW & POLICY CENTER,
THE ECOLOGY CENTER,
THE SOLAR ENERGY INDUSTRIES ASSOCIATION,
THE UNION OF CONCERNED SCIENTISTS,
AND
VOTE SOLAR

AUGUST 21, 2019

Joseph M. Daniel
Union of Concerned Scientists
Washington, D.C.
jdaniel@ucsusa.org

Professional Experience

Union of Concerned Scientists, Washington, D.C. *Senior Energy Analyst*, 2018 – Present
- Works on efforts to modernize power grids and helps advance science-based public policy
- Leads research and advocacy efforts at state public utility commissions
- Conducts analysis that helps shape electricity markets and policies to develop a more flexible and modern electric grid that can accommodate high levels of renewable energy, demand-side resources, and electric vehicles while reducing carbon emissions and reliance on fossil fuels

Sierra Club, Washington, D.C. *Electric Sector Analyst*, 2016 – 2018
- Served as lead analyst on federal policy, natural gas, coal economics, and energy markets
- Responsible for conducting economic analysis of federal regulations including: Clean Power Plan, Effluent Limitation Guidelines, Regional Haze, Cross-State Air Pollution Rule, and NAAQS
- Reviewed utility rate cases, integrated resource plans, and long term planning

Synapse Energy Economics Inc., Cambridge, MA. *Associate*, 2013 –2015
- Led researching efforts and conducted primary analysis on the electric industry including utility forecasting, regulatory compliance, and distributed energy resources
- Used optimization models to conduct long term utility analysis
- Modeled costs and benefits of energy efficiency and rooftop scale solar

Independent Consultant, New York, NY. 2011 – 2013
- Analyzed technical and economic drivers for “Green Palm Oil Production” for ETG
- Designed and developed mathematical models for the STAR Community Index
- Assisted in building budget plans and developing fundraising strategies for the Coalition on the Environment and Jewish Life

Environmental Law & Policy Center, Madison, WI. *Policy and Science Intern*, 2011
- Investigated consequences of state policy changes related to wind turbine siting regulations
- Initiated research for a report to quantify jobs created by Wisconsin wind and solar energy industries
- Analyzed regional economic impacts of USDA grant data associated with renewable energy provisions of the 2008 Farm Bill

Tel Aviv – Yafo Municipality, Tel Aviv, Israel. *Research Assistant to Deputy Mayor*, 2010
- Presented urban sustainability case studies and best practices to municipal
- Worked with public- and private-sector partners to define metrics for a governmental Green Business Certification Program
- Investigated US and European greenhouse gas emission reduction policies and programs

Baker Hughes - Baker Petrolite (Industrial Division), Honolulu, HI. *Engineer II*, 2006 – 2010
- Managed daily operation of the primary account on the island, worth over $1.8 million annually
- Monitored performance metrics, analyzed project performance, calculated energy and cost savings related to efficiency upgrades
- Consulted with customers on reducing environmental impacts of facilities

Joseph M. Daniel
Union of Concerned Scientists
Washington, D.C.
jdaniel@ucsusa.org

EDUCATION

Columbia University – School of International Public Affairs, New York, NY
Master of Public Administration in Environmental Science and Policy, 2012

University of Texas, Austin, TX
PETEX Petroleum Fundamentals Program, 2007

Florida Institute of Technology – College of Engineering, Melbourne, FL
Bachelor of Science in Chemical Engineering, 2006

TESTIMONY AND EXPERT COMMENT

Daniel, J. 2018. Testimony on Consumers Energy Integrated Resource Plan (IRP). Testimony to Michigan Public Service Commission. Case No. U-20165. October 15, 2018.

Daniel, J. 2017. Declaration of Joseph Daniel. Sierra Club, et al., v. Federal Energy Regulatory Commission, Duke Energy Florida, et al.,. United States Court of Appeals Case #16-1329. October 31, 2017.

Daniel, J. 2017. Testimony on Proposal to Postpone Certain Compliance Dates for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category. Docket No. EPA-HQ-OW-2009- 0819. Public Hearing in Washington, D.C. July 31, 2017.

Daniel, J. A. Napeoleon, T. Comings, S. Fields. 2015. *Comments on Entergy Louisiana's 2015 Integrated Resource Plan*. Synapse Energy Economics for Sierra Club.

Daniel, J., T. Comings, J. Fisher. 2014. *Comments on Preliminary Assumptions for Cleco's 2014/2015 Integrated Resource Plan*. Synapse Energy Economics for Sierra Club.

Vitolo, T., P. Luckow, J. Daniel. 2013. *Comments Regarding the Missouri 2013 IRP Updates of KCP&L and GMO*. Synapse Energy Economics for Earthjustice

Stanton, E. A., F. Ackerman, J. Daniel. *Comments on the 2013 Technical Update of the Social Cost of Carbon*. Synapse Energy Economics for the Environment, Economics and Society Institute.

REPORTS AND PAPERS

Daniel, J. 2018. Out-of-merit generation of coal-fired power plants in Organized Competitive Markets. US Association of Energy Economics.

Daniel, J. 2017. Backdoor Subsidies for Coal in the Southwest Power Pool. Sierra Club.

Daniel, J. 2017. Natural gas is repeating coal's mistakes. Natural Gas & Electricity 33/10, ©2017 Wiley Periodicals, Inc., a Wiley company.

Daniel, J. 2016. Estimating Utility Avoided Costs Without Utility-Specific Data. *Natural Gas & Electricity 32*/8, ©2016 Wiley Periodicals, Inc., a Wiley company

Joseph M. Daniel
Union of Concerned Scientists
Washington, D.C.
jdaniel@ucsusa.org

Jackson, S., P. Luckow, E. A. Stanton, A. Horowitz, P. Peterson, T. Comings, J. Daniel, T. Vitolo. 2016. *Reimagining Brayton Point: A guide to assessing reuse options for the Somerset community*. Synapse for Prepared for Coalition for Clean Air South Coast, Clean Water Action, and Toxics Action Center.

Whited, M., T. Wolf, J. Daniel. 2016. *Caught in a Fix*. Synapse Energy Economics for Consumers Union.

Luckow, P., T. Vitolo, J. Daniel. 2015. *Remodeling the Grid Challenges, Solutions, and Costs Associated with Integrating Renewable Resources*. Synapse Energy Economics.

Luckow, P., T. Vitolo, J. Daniel. 2015. *A Solved Problem: Existing Measures Provide Low-Cost Wind and Solar Integration*. Synapse Energy Economics.

Biewald, B., J. Daniel, J. Fisher, P. Luckow, J.A. Napoleon, N. Santen, K. Takahashi. 2015. Air Emissions Displaced by Energy Efficiency and Renewable Energy. Synapse Energy Economics.

Knight, P., J. Daniel 2015. *Forecasting Coal Unit Competitiveness: Coal Retirement Assessment Using Synapse's Coal Asset Valuation Tool (CAVT) - 2015 Update*. Synapse Energy Economics.

Ackerman, F., J. Daniel. 2015. *The True Costs of Generic Drug Regulation*. Synapse Energy Economics for the American Association of Justice.

Vitolo, T., J. Fisher, J. Daniel. 2015. *Dallman Units 31/32: Retrofit or Retire?* Synapse Energy Economics for the Sierra Club.

Stanton, E. A., P. Knight, J. Daniel, B. Fagan, D. Hurley, J. Kallay, E. Karaca, G. Keith, E. Malone, W. Ong, P. Peterson, L. Silvestrini, K. Takahashi, R. Wilson. 2015. *Massachusetts Low Gas Demand Analysis: Final Report*. Synapse Energy Economics for the Massachusetts Department of Energy Resources.

Fields, S., E. A. Stanton, P. Knight, B. Biewald, J. Daniel, S. Jackson, E. Karaca, J. Rosenkranz, K. Takahashi. 2014. *Calculating Alabama's 111(d) Target*. Synapse Energy Economics for the Southern Environmental Law Center.

Fields, S., E. A. Stanton, P. Knight, B. Biewald, J. Daniel, S. Jackson, E. Karaca, J. Rosenkranz, K. Takahashi. 2014. *Calculating Georgia's 111(d) Target*. Synapse Energy Economics for the Southern Environmental Law Center.

Fields, S., E. A. Stanton, P. Knight, B. Biewald, J. Daniel, S. Jackson, E. Karaca, J. Rosenkranz, K. Takahashi. 2014. *Alternate Scenarios for 111(d) Implementation in North Carolina*. Synapse Energy Economics for the Southern Environmental Law Center.

Stanton, E. A., J. Daniel, T. Vitolo, P. Knight, D. White, G. Keith. 2014. *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations*. Synapse Energy Economics for the Public Service Commission of Mississippi.

Luckow, P., J. Daniel, S. Fields, E. A. Stanton, B. Biewald. 2014. "CO_2 Price Forecast: Planning for Future Environmental Regulations." *EM Magazine*, June 2014, 57-59.

Daniel, J., F. Ackerman. 2014. *Critical Gaps in the 2014 Big Rivers Integrated Resource Plan*. Synapse Energy Economics for Sierra Club.

Joseph M. Daniel
Union of Concerned Scientists
Washington, D.C.
jdaniel@ucsusa.org

Keith, G., S. Jackson, J. Daniel, K. Takahashi. 2014. *Idaho's Electricity Sources: Current Sources and Future Potential*. Synapse Energy Economics for the Idaho Conservation League.

Ackerman, F., J. Daniel. 2014. *(Mis)understanding Climate Policy: The Role of Economic Modelling*. Synapse Energy Economics for Friends of the Earth (England, Wales & Northern Ireland) and WWF-UK.

Hurley, D., P. Knight, J. Daniel, S. Fields. 2014. *Brayton Point Capacity Payment Requirement Analysis*. Synapse Energy Economics for Consumer Advocates of New England.

Comings, T., J. Daniel, P. Knight, T. Vitolo. 2014. *Air Emission and Economic Impacts of Retiring the Shawnee Fossil Plant*. Synapse Energy Economics for the Kentucky Environmental Foundation.

Daniel, J., S. Fields, and D. Hurley. 2014. *Memorandum Regarding an Updated Economic Analysis of Schiller Station Coal Units*. Synapse Energy Economics for the Conservation Law Foundation.

Vitolo, T., J. Daniel. 2013. *Improving the Analysis of the Martin Drake Power Plant: How HDR's Study of Alternatives Related to Martin Drake's Future Can Be Improved*. Synapse Energy Economics for Sierra Club.

Stanton, E. A., J. Daniel, F. Ackerman, S. Jackson. 2013. *Review of EPA's June 2013 Steam Electric Effluent Limitations and Guidelines (40 CFR Part 423)*. Synapse Energy Economics for Earthjustice, Environmental Integrity Project, and Sierra Club.

Knight, P., B. Biewald, J. Daniel. 2013. *Displacing Coal: An Analysis of Natural Gas Potential in the 2012 Electric System Dispatch*. Synapse Energy Economics for Energy Foundation.

Daniel, J., Dr. E. Hansen, K. Pearson, et al. 2012. *Kathmandu Valley Cultural Tourism Competitiveness Assessment and Action Plan*. The Economic Transformation Group for The World Bank.

Ahn, A., P. Bothole, J. Daniel, et al. 2012. *Building the First Sustainability Rating System for Local Governments*. Columbia University School of International and Public Affairs for The STAR Community Index.

Broffman, A., F. Chen, J. Daniel, et al. 2011. *Analysis of the New York Solar Industry Development and Jobs Act of 2012*. The Earth Institute at Columbia University.

Presentations

Daniel, J. 2019. *How Do You End a Billion Dollar Bailout*. Columbia University's Earth Institute. New York, NY.

Daniel, J. 2019. *Ten Things Aspiring Energy Analysts Ought to Know*. Columbia University - School of International and Public Affairs. New York, NY.

Daniel, J. 2018. *The Coal Bailout Nobody is Talking About*. National Association of Consumer Advocates Annual Meeting 2018. Orlando, FL.

Daniel, J. 2018. *Out-of-merit generation of coal-fired power plants in Organized Competitive Markets*. Joint Conference of the US Association for Energy Economics and the International Association of Energy Economics.Washington, D.C.

Joseph M. Daniel
Union of Concerned Scientists
Washington, D.C.
jdaniel@ucsusa.org

Daniel, J. 2017. *A Framework for Valuing Rooftop Solar*. On behalf of Net Metering Working Group, Sub-Group 1. Docket No. 16-027-R, Implementation of Act 827 of 2015. Little Rock, AR.

Daniel, J. 2017. *Introduction to the Electric Grid*. School of International and Public Affairs at Columbia University. New York, NY

Daniel, J. 2017. *Data Driven Advocacy*. The Earth Institute at Columbia University. New York, NY

Daniel, J. 2015. *Balancing Policies to Protect Consumers*. EUCI "Net Metering 2.0" seminar, 2015. Anaheim, CA.

Daniel, J., T. Vitolo. 2015. *Implementing Net Metering to Meet Policy Objectives*. EUEC 2015. San Diego, CA.

Ahn, A., P. Bothole, J. Daniel, et al. 2012. *Building the First Sustainability Rating System for Local Governments*. Columbia University School of International and Public Affairs for The STAR Community Index. The Earth Institute at Columbia University. New York, NY

Broffman, A., F. Chen, J. Daniel, et al. 2011. *Analysis of the New York Solar Industry Development and Jobs Act of 2012*. The Earth Institute at Columbia University. New York, NY

CONFIDENTIAL

See System Cost Reports (w and wo Must Run).xslx

CONFIDENTIAL

Generation with and without Must Run – Conf.xlsx

S&P Global
Market Intelligence

System Loads

RegionalLevel : Planning Area
Region : California Independent System Operator, ISO New England Inc., San Diego Gas & Electric Co.
Years : 2018, 2017, 2016, 2015, 2014, 2013

NERC Region Code	Summer Peak Load (MW)	Winter Peak Load (MW)	Peak Day	Year
NPCC	NA	NA	NA	2018
NE	NA	NA	NA	2018
ISO New England Inc.	25,980	20,662	8/29/2018	2018
WECC	NA	NA	NA	2018
CAMX	NA	NA	NA	2018
California Independent System Operator	46,310	34,750	7/25/2018	2018
San Diego Gas & Electric Co.	4,377	3,355	8/9/2018	2018
NPCC	NA	NA	NA	2017
NE	NA	NA	NA	2017
ISO New England Inc.	23,968	20,524	6/13/2017	2017
WECC	NA	NA	NA	2017
CAMX	NA	NA	NA	2017
California Independent System Operator	49,900	39,247	9/1/2017	2017
San Diego Gas & Electric Co.	4,544	4,371	9/1/2017	2017
NPCC	NA	NA	NA	2016
NE	NA	NA	NA	2016
ISO New England Inc.	25,596	19,647	8/12/2016	2016
WECC	NA	NA	NA	2016
CAMX	NA	NA	NA	2016
California Independent System Operator	46,007	32,816	7/27/2016	2016
San Diego Gas & Electric Co.	4,343	3,490	9/26/2016	2016
NPCC	NA	NA	NA	2015
NE	NA	NA	NA	2015
ISO New England Inc.	24,437	20,583	7/29/2015	2015
WECC	NA	NA	NA	2015
CAMX	NA	NA	NA	2015
California Independent System Operator	47,255	41,601	9/10/2015	2015
San Diego Gas & Electric Co.	4,711	4,312	9/9/2015	2015
NPCC	NA	NA	NA	2014
NE	NA	NA	NA	2014
ISO New England Inc.	24,443	21,334	7/2/2014	2014
WECC	NA	NA	NA	2014
CAMX	NA	NA	NA	2014
California Independent System Operator	44,694	37,904	9/15/2014	2014
San Diego Gas & Electric Co.	4,890	3,837	9/16/2014	2014
NPCC	NA	NA	NA	2013
NE	NA	NA	NA	2013
ISO New England Inc.	27,379	21,453	7/19/2013	2013
WECC	NA	NA	NA	2013
CAMX	NA	NA	NA	2013
California Independent System Operator	44,941	33,446	6/28/2013	2013
San Diego Gas & Electric Co.	4,604	3,357	8/30/2013	2013

	ISO New England Inc.	California Independent System Operator	San Diego Gas & Electric Co.
2018	25980	46310	4377
2017	23968	49900	4544
2016	25596	46007	4343
2015	24437	47255	4711
2014	24443	44694	4890
2013	27379	44941	4604

Year	ISO New England Inc.	California ISO	San Diego Gas & Electric Co.
2018	8.39%	-7.19%	-3.68%
2017	-6.36%	8.46%	4.63%
2016	4.74%	-2.64%	-7.81%
2015	-0.02%	5.73%	-3.66%
2014	-10.72%	-0.55%	6.21%
5-year Avg.	-0.79%	0.76%	-0.86%

The summer and winter NERC and NERC sub-region peak load is collected from the North American Electric Reliability Council Energy Supply & Demand (NERC ES&D), from the EIA-411 filing and is non-coincident load.Due to the lag in data presentation by the NERC,S&P Global Market Intelligence has elected to show the summer and winter forecast NERC and NERC sub-regional load and will then update the page to reflect actual reported NERC data when it becomes available.

The Planning Area data presented in the tables does not reflect the complete hourly/rolled up electric load existing in the NERC region or NERC sub-region, but rather the NERC area and sub-regional planning area electric coincident loads that have been submitted to the Federal Energy Regulatory Commission (FERC) per the FERC 714 filing.Not all electric load by planning area is available to public disclosure and Alaskan and Hawaiian total loads are not submitted for the EIA-411.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief	))))	Case No. U-20471

DIRECT TESTIMONYOF
WILLIAM D. KENWORTHY

ON BEHALF OF

THE ENVIRONMENTAL LAW AND POLICY CENTER,
THE ECOLOGY CENTER,
THE UNION OF CONCERNED SCIENTISTS,
THE SOLAR ENERGY INDUSTRIES ASSOCIATION,
AND
VOTE SOLAR

AUGUST 21, 2019

Table of Contents

I. Name and Qualifications

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is William ("Will") D. Kenworthy. My business address is 18 South Michigan Avenue, Suite 1200, Chicago, Illinois 60603.

Q: ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A: I appear here in my capacity as an expert witness on behalf of the Environmental Law & Policy Center ("ELPC"), Vote Solar, the Union of Concerned Scientists, the Solar Energy Industries Association, and the Ecology Center.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: I serve as Regulatory Director, Midwest for Vote Solar. I oversee policy development and implementation related to large scale and distributed solar generation in the region. I also review regulatory filings, perform technical analyses, and testify in commission proceedings on issues relating to solar generation.

Vote Solar is an independent 501(c)3 nonprofit working to repower the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally. Vote Solar is not a trade organization nor does it have corporate members.

Q: PLEASE SUMMARIZE YOUR QUALIFICATIONS, EXPERIENCE AND EDUCATION.

A: I have nearly 30 years of experience in the energy industry in both the public and private sector working in the renewable energy business and in energy policy. Of that experience, I spent 8 years in solar energy project development working primarily on commercial and industrial distributed solar projects in the Midwest.

Prior to Vote Solar, I was Managing Director – Midwest for Microgrid Energy, where I was responsible for leading the Company's expansion of their solar project development capabilities into markets in the Midwest. As a solar project developer, I analyzed financial and economic aspects of projects. This involved understanding all aspects of project finance and economics for our customers, partners and financiers. My project development experience includes project finance, rate analysis, economic modelling, risk assessment, regulatory compliance, sales, and customer relations.

During my tenure at Microgrid Energy, we completed the Solar Chicago program, a residential bulk purchase program, as well as a number of commercial projects ranging in size from 25 kW to 2 MW. Prior to that, I was a partner with Tipping Point Renewable Energy based in Dublin, Ohio, where we developed what was at the time the largest rooftop solar project in Ohio for the City of Columbus.

In addition, my tenure at Microgrid Energy was punctuated with a one-year hiatus during which time I served as President of Infer Energy, currently Root3 Technologies. Infer Energy provided energy optimization services to large commercial and industrial energy users. We used advanced data analytics and machine learning algorithms to optimize complex energy systems.

Prior to joining the solar energy industry, I have over 20 years of experience in energy policy at the federal and state level. As a consultant, I represented electric utilities and other industry participants before Congress, the Department of Energy, the Nuclear

Regulatory Commission, the Environmental Protection Agency and the Office of Management and Budget. I began my career as a Professional Staff Member to the House Energy & Commerce Committee, where I represented Chairman John D. Dingell and other majority members of the Committee in negotiations and legislative drafting on nuclear regulatory matters, the Clean Air Act Amendments of 1990, and electric industry structure issues, among others.

I received a Master of Public & Private Management degree from the Yale University School of Management with a concentration in Regulation and Competitive Strategy. My research in graduate school focused on regulatory theory and practice. I also have a Bachelor of Science in Foreign Service from Georgetown University.

Q: HAVE YOU TESTIFIED BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION PREVIOUSLY?

A: Yes, I provided direct and rebuttal testimony in U-20162, *In the matter of the application of DTE ELECTRIC COMPANY for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*.

Q: HAVE YOU TESTIFIED OR PROVIDED COMMENTS IN SIMILAR STATE REGULATORY PROCEEDINGS?

A: Yes, I have provided testimony before the Iowa Utilities Board and provided comments in numerous proceedings before the Illinois Commerce Commission, the Illinois Power Agency, the Minnesota Public Utility Commission and the Wisconsin Public Service Commission.

II. Purpose and Summary of Testimony

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to provide an analysis of the DTE Electric Company's ("the Company" or "DTE") voluntary green pricing ("VGP") programs in its 2020 Integrated Resource Plan ("IRP"). Specifically, I will review the Company's existing programs, the extent to which they are relied upon to achieve the plan's goals, and make recommendations about the Company's reliance on voluntary programs to achieve required objectives.

Q: PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A: In Section III of the testimony, I will propose eight principles for evaluating the efficacy and value of utility-owned distributed generation programs generally. In Section IV, I will review the Company's existing renewable energy programs and describe the Company's current voluntary green pricing programs. In Section V, I will review the role of renewables generally in the Company's proposed course of action ("PCA"). In Section VI, I will examine the specific role of voluntary renewables programs in the plan. In Section VII, I will evaluate the appropriateness of the Company's use of voluntary renewables. In Section VIII, I will consider the Company's decision not to conduct an all-source Request for Proposals (RFP) to inform its modeling in this IRP. Finally, in Section IX I will summarize my findings from this testimony.

Q: PLEASE SUMMARIZE YOUR CONCERNS WITH THE COMPANY'S PROPOSED RELIANCE ON THE VOLUNTARY GREEN PRICING PROGRAMS.

A: Although the VGP programs have been found to meet the Company's obligations under the 2016 energy laws, the programs are expensive for customers and fail to meet many criteria for best practices in utility-owned distributed generation. Because they fail to deliver fair value to prospective customers, fewer customers will subscribe, thus unnecessarily limiting the potential adoption. In addition, I find that the Company's reliance on vague promises to market the program unconvincing as a planning principle. By improving the programs in a way that can provide more transparency and a fuller value of the energy and capacity value of the renewable facilities that are developed for them, the Company could ensure that the voluntary green pricing programs achieve their potential for providing access to clean energy.

In addition, I find that the Company should have conducted an all-source RFP prior to conducting the modeling that lead to this development of this plan.

As a result of the deficiencies identified in my testimony combined with the numerous other deficiencies in the Plan identified by ELPC Witnesses Woychik, Lucas, Daniel, Sommer and Gignac, I recommend that the Commission reject the plan and require the Company to present a new plan that begins with an all-source RFP and remedies the deficiencies identified by other Witnesses.

III. General Principles for Evaluating Utility Distributed Generation (UDG)

1. Utility-owned distributed generation programs should be evaluated against eight principles to achieve cost and equity for customers.

Q: PLEASE DESCRIBE WHAT YOU MEAN BY UTILITY DISTRIBUTED GENERATION (UDG).

A: For purposes of this analysis, UDG includes both distribution system connected utility-owned generation and utility-scale projects dedicated to specific distribution customers on a subscription basis. UDG includes a variety of different programs that have been proposed and implemented by utilities around the region and the country, such as:

- utility-owned community solar,
- utility-owned, customer-sited distributed generation,
- voluntary green pricing programs,
- green tariffs, and
- other similar programs.

Conversely, this category does not include:

- customer or third-party owned distributed generation,
- utility-owned wholesale generation, or
- third-party or affiliate-owned wholesale generation

UDG programs can provide benefits for all ratepayers, for the state's energy and environmental goals, and for the utility in achieving its business and sustainability goals. However, evaluation of these programs must also consider all impacts on participants and non-participants.

Q: WHAT ARE THE GENERAL PRINCIPLES THAT SHOULD GUIDE THE EVALUATION OF UTILITY-OWNED DISTRIBUTED GENERATION?

A: I recommend eight principles for evaluating Utility-owned Distributed Generation:

1. UDG should provide customer economic benefits;
2. UDG should provide access to clean energy for all customers;

3. UDG should meet customer demand for clean energy and help customers to achieve sustainability goals;
4. UDG may help the utility achieve its own carbon reduction and sustainability goals;
5. UDG should provide additionality;
6. UDG should not undermine competitive distributed or wholesale generation markets;
7. UDG should provide benefits to the grid; and
8. Regulators should closely monitor UDG programs to ensure they deliver promised benefits.

Q: HOW SHOULD THESE PRINCIPLES BE VIEWED IN THE CONTEXT OF AN OPTIMIZED UTILITY RESOURCE PLANNING EXERCISE SUCH AS AN IRP?

A: The UDG principles are not intended to supplant the statutory or regulatory guidance that drives the IRP process. Rather, they are offered to inform policy choices that the Company and the Commission make in implementing an optimized resource portfolio. Likewise, these principles are offered in the context of an emerging optimization paradigm in which much opportunities to optimize portfolios at a more granular basis are emerging. Optimizing the resource portfolio in the context of a conventional IRP process is important but should not lose sight of the values reflected in policy alternatives.

2. <u>UDG should provide customer/ratepayer benefits and leverage existing competitive markets to optimize those benefits.</u>

Q: PLEASE EXPAND ON THE PRINCIPLE OF CUSTOMER/RATEPAYER BENEFITS AND COMPETITIVE DISTRIBUTED GENERATION MARKETS.

A: In order to be considered in the public interest, utility-owned distributed solar projects must provide ratepayer benefits. In general, the economic performance of UDG programs is a function of two elements:

1. The costs of the program and how those costs are allocated and charged to participants; and
2. The credit or benefits that the participants receive through participation in the program.

In the past, costs have often exceeded the credits and as such participants paid a premium relative to otherwise applicable rates to participate in the UDG programs. Given the significant reductions in costs and the improved efficacy of renewable energy in the grid, it will become increasingly common for participating customers to realize savings compared to default rates.

Ratepayer benefits can be viewed from several perspectives:

- Participant economic savings relative to current otherwise applicable rates, i.e. whether savings are available to participants through their participation in the program;
- Equitable allocation of costs and benefits to ensure that non-participants do not bear the cost burden for the programs, at the same time ensure that UDG

programs are not providing uncompensated benefits to the utility or non-participants; and

- Ensuring least cost implementation of approved plans to provide economic efficiency and maximum grid and social benefits.

Another important element of this principle is that participants should benefit from efficient and cost-effective distributed generation resources through competitive markets. The Company should take advantage of the competitive market and the existence of the mature solar industry in developing distributed generation and put the development of the renewable energy facilities out to bid. The Company is obligated to build these facilities in the most cost-effective manner possible, and this will help ensure that customers are not overcharged for the services that they are receiving.

In addition to considering the benefits to participating customers, regulators should also be mindful of impacts on non-participating customers. Utilities, their customers, and regulators will transition to the new energy economy in coming years. Customers will increasingly enjoy access to technology and information that result in shifting usage patterns. This transition in customer usage patterns will shift the way that utility customers use energy and thus affect the traditional utility rate base. However, a customer exercising their rights to manage their own energy use through energy efficiency measures, behavioral energy use modifications, distributed energy resources or – in this analogy of utility-owned distributed generation as an extension of on-site options – does not result in their owing the utility or other customers in their class for energy not used. Regulatory models and policies must evolve to ensure that customers are not disincentivized from making beneficial changes. The energy regulatory and policy framework should ensure that all customers are able to participate and benefit from desirable changes rather than penalizing those who do make those changes and/or investments.

3. <u>UDG should provide access to clean energy markets for all on an equitable basis, especially those that have been disproportionately impacted by fossil fuels and left behind in the clean energy transition.</u>

Q: PLEASE EXPAND ON THE PRINCIPLES OF PROVIDING ACCESS TO THE CLEAN ENERGY ECONOMY FOR ALL CUSTOMERS.

A: The benefits of the clean energy economy and, in particular, the benefits of UDG should be available to all members of the public. The principles of equity and access for low-income households, communities of color, and others left behind in the transition to a clean energy economy should inform all aspects of a utility's operations, including resource planning.

Providing access to the clean energy economy is of particular importance when dealing with solar technology due to historical barriers to solar adoption for lower income customers and customers who cannot install solar on their own roofs. The advent of shared renewables programs, including community solar, and third-party financing has gone a long way to begin rectifying this inequity, but only when structured correctly. When it comes to UDG programs, there are specific design elements that can make it much easier or much harder for all households, and in particular low-income households, to participate and benefit. Not every UDG program will target every customer class, but when designing any UDG program, it is important to critically examine whether additional steps can be taken to expand access to clean energy.

In order for UDG proposals to effectively expand customer access to the clean energy economy and, specifically, to low-income customers, the proposals should follow these guidelines for a successful low-income solar program:

1. Provide immediate tangible economic benefits for low-income participants, with no up-front costs.
2. Fully compensate low-income customers for the services and benefits solar projects provide.
3. Design replicable, scalable programs for long-term program sustainability and opportunities for adjustment.
4. Complement existing programs to reduce overall household energy burden.
5. Drive local economic opportunity in underserved communities through workforce development and participation for minority- and women-owned business enterprises.
6. Prioritize community engagement throughout the program design, planning, implementation and ongoing operations, ideally through partnerships with local, community organizations.
7. In the case of utility-owned projects, ensure non-discriminatory treatment between utility- and non-utility-owned projects.
8. In the case of community solar projects, ensure subscriptions are easily portable and transferable at minimal or no cost to participants.[1]

[1] These guidelines are drawn from a forthcoming publication by ELPC, GRID Alternatives, and Vote Solar on Principles and Recommendations for Utility Participation in Solar Programs for Low-Income Customers.

While these guidelines are intended for low-income solar programs, many can improve access and outcomes for all customers.

4. <u>UDG should meet customer demands for clean energy and help them achieve their sustainability goals.</u>

Q: PLEASE EXPAND ON THE PRINCIPLE THAT UDG SHOULD MEET CUSTOMER DEMAND FOR CLEAN ENERGY AND HELP CUSTOMERS TO ACHIEVE SUSTAINABILITY GOALS?

A: Customers have well understood market preferences for using renewable energy. Customers want to reduce their own impact on the environment, and they are willing to do business with businesses and organizations that have demonstrated commitment to sustainability. As such, UDG programs should be evaluated partly on the programs' ability to satisfy that demand. At the same time, UDG programs should not be used to satisfice customer demand to the detriment of a robust customer and third-party owned DG ecosystem (see discussion of the principle of supporting competitive clean energy markets, below).

The Corporate Renewable Energy Buyers' Principles program represents large customers who have an interest in purchasing renewable energy:

> As renewable energy has become more and more cost effective and companies are setting more ambitious goals to buy it, large companies are increasingly looking for ways to contract directly for renewable energy to protect against future energy price increases and meet their climate and renewable energy goals. To meet the

scale of their goals, these companies need access to more renewable energy in more places.[2]

The Principles outlined by this organization are:

1. Greater choice in procurement options,
2. More access to cost competitive options
3. Longer-and variable-term contracts,
4. Access to new projects that reduce emissions beyond business as usual,
5. Increased access to third-party financing vehicles as well as standardized and simplified processes, contracts and financing for renewable energy projects, and
6. Opportunities to work with utilities and regulators to expand our choices for buying renewable energy.[3]

These criteria accurately reflect not only the purchasing needs and preferences of commercial and industrial customers (C&I), but generally reflect the preferences of a significant portion of residential and small business customers.

5. UDG should provide for additionality of renewable resources over and above resoures developed to meet other requirements or commitments.

Q: PLEASE EXPAND ON THE PRINCIPLE OF ADDITIONALITY.

A: UDG programs should be evaluated on whether proposed programs result in additional renewable energy projects that either meet growing demand or replace fossil fuel-powered generation. UDG programs should not simply repurpose all or a portion of renewable energy projects that have been developed at utility scale to meet regulatory

[2] Corporate Renewable Energy Buyers' Principles, https://www.buyersprinciples.org/, retrieved July 27, 2019.
[3] *Ibid.*, https://buyersprinciples.org/, retrieved July 27, 2019.

requirements (such as state renewable energy portfolio requirements) or for economic purposes to meet capacity or energy requirements.

According to the National Renewable Energy Laboratories, "the goal of green pricing is to allow customers, through individual actions, to support a greater amount of renewable energy development by their utilities."[4] Participants want to know that the costs they pay will result in meaningful renewable energy capacity additions.

6.   <u>UDG should support evolution of competitive distributed generation markets.</u>

Q: PLEASE EXPLAIN THE PRINCIPLE THAT UDG SHOULD NOT UNDERMINE COMPETITIVE DISTRIBUTED GENERATION MARKETS.

A: Distributed generation, including on-site solar, energy storage, and sophisticated energy management technologies are part of an emerging field of integrated energy strategy. Especially among large users, where energy can be a significant part of a facility's operating costs, energy services companies are increasingly integrating distributed generation as part of those strategies.

For commercial and industrial (C&I) customers (which generally includes educational institutions and municipal governments), developing a solar project is much more than just the engineering, procurement and installation of a system. Optimizing a system for a particular customer involves understanding many aspects of the customer's facilities, operations, and financial situation, including:

---

[4] Blair Swezey and Lori Bird, *Utility Green-Pricing Programs: What Defines Success?*, NREL/TP.620.29831 (2001) at p. 1, http://www.nrel.gov/docs/fy01osti/29831.pdf.

- Ability to take advantage of the tax benefits available (both the federal investment tax credit and expensing/bonus depreciation opportunities),
- Credit worthiness (impacts financing options available),
- Hedging value of the project,
- Financing and cash flow preferences,
- System design, configuration and siting considerations and preferences, and
- Load characteristics and power quality requirements.

While a utility working with its customers may be able to identify opportunities that benefit the grid or even provide economic value even with sub-optimized systems, opportunities may be missed. Clean energy businesses are focused on delivering custom energy solutions in a way that is simply out of reach of traditional utilities. By limiting the ability of the competitive market to provide distributed generation services to customers, regulators forgo opportunities for significant customer savings and undermine economic growth.

Finally, it is in the interests of customers and ratepayer that they receive the lowest cost services. When those services can be provided cost-effectively by the utility then they should, but there are a number of reasons that UDG may not be the lowest-cost alternative:

- Utility cost of capital may be higher;
- Utility depreciation requirements (fully depreciated over 25 years as opposed to a salvage value for third party financed systems); and

- Investment tax credit accounting – Utilities are required to monetize the value of tax credits over the life of a project, however the time value of money for recognizing tax credits when earned is substantial.

As such, when considering UDG proposals, the Commission should consider alternatives to utility ownership of distributed generation assets that may provide equal or greater benefits to customers. When regulators consider UDG programs they should investigate the ability of customers to implement alternatives of their own initiative on a non-discriminatory basis.

7. <u>UDG should provide economic development benefits to the state and localities.</u>

Q: PLEASE EXPAND ON THE BENEFITS TO THE PRINCIPLE OF STIMULATING THE CLEAN ENERGY ECONOMY.

A: When entering the UDG market, regulated monopoly utilities seek to enter the competitive market of distributed generation. At the same time, they may seek to preclude other players in the market from meeting customers' energy management needs and demands. UDG should not crowd out an effective and efficient distributed generation marketplace.

While ensuring a robust renewable project development and installation industry is not in the mandate of most utility regulators, maintaining a robust industry is in the public interest if it provides customers with access to economic benefits to which they would not otherwise have access. By supporting a robust market, the state can ensure that a fair market for distributed generation services is available to customers.

In addition, ensuring a vibrant clean energy economy infrastructure is in the public interest as it provides significant economic development for the state and community. The clean energy industry is among the fastest growing sectors of the economy nationally. Recent estimates are that Iowa is home to over 31,335 clean energy jobs.[5] Developing, designing, and installing distributed generation systems are a multibillion-dollar industry in the United States and competitors in these markets are adept at maximizing the value of systems to individual customers. The solar industry and the clean energy financing entities have developed significant expertise at understanding and meeting the complex project development needs and preferences of residential and C&I customers. Utilities and regulators should be taking steps to leverage that experience and expertise for the benefit of all customers.

8. UDG should be evaluated and sited on its ability to deliver grid benefits to the utility system and all utility customers.

Q: PLEASE EXPAND ON THE PRINCIPLE THAT UDG SHOULD PROVIDE BENEFITS TO THE GRID.

A: Having a utility develop distributed generation could be valuable if the utility uses the resources to improve grid services and reliability and defer or eliminate the need for other system upgrades. Indeed, utilities are well-positioned to facilitate the strategic development of distributed generation in a coordinated way to maximize grid benefits. Distributed energy resources (including renewable energy resources and energy storage devices) can provide benefits to the utility system in the form of ancillary services,

[5] Clean Jobs Midwest, https://www.cleanjobsmidwest.com/state/iowa, retrieved July 27, 2019.

avoided transmission and distribution investment, reduced congestion on distribution systems at peak times, and reduced transmission and distribution losses. As such, utilities should take into consideration the opportunity to site distributed energy resources strategically to take advantage of such benefits.

9. ***Regulators should ensure UDG programs deliver promised benefits by requiring regular reporting and closely monitoring UDG programs.***

Q: PLEASE EXPAND ON THE PRINCIPLE THAT REGULATORS SHOULD ENSURE CLOSE MONITORING AND EVALUATION OF UDG PROGRAMS.

A: UDG programs necessarily involve monopoly utilities participating in markets for distributed generation services that do not fit into the scope of the utility's natural monopoly. When a state or other entity having jurisdiction over utilities makes a determination to allow utilities to participate in these markets, the regulator has the responsibility to ensure that the utility does not exercise monopoly power in non-monopoly markets.

Ongoing reporting and evaluation will allow regulators, stakeholders, and the public to evaluate the success of various aspects of these pilot programs and consider how they could be improved. As noted above, there is significant public interest in renewables and access to a diverse range of choices. With stakeholder input, the Commission can then make informed decisions regarding revision and/or expansion of these programs. For example, a better understanding of the grid benefits of distributed energy may reveal that the current pilot could be restructured to better incentivize project participation in strategic locations on the Company's distribution grid. This could attract more participation while helping avoid or defer other utility investment to benefit all of the Company's customers. Allowing flexibility in these programs going forward, as technologies and markets change, is important for ensuring value and attractiveness to customers.

IV. Review of Existing Programs

1. The Company's Voluntary Green Pricing programs have clear statutory bases and are supported by clear Commission guidance on implementation.

Q: PLEASE DESCRIBE THE STATUTORY BASIS FOR THE COMPANIES VOLUNTARY GREEN PRICING PROGRAMS.

A: Section 61 of 2016 PA 342 provides:

> Sec. 61. An electric provider shall offer to its customers the opportunity to participate in a voluntary green pricing program under which the customer may specify, from the options made available by the electric provider, the amount of electricity attributable to the customer that will be renewable energy. If the electric provider's rates are regulated by the commission, the program, including the rates paid for renewable energy, must be approved by the commission. The customer is responsible for any additional costs incurred and shall accrue any additional savings realized by the electric provider as a result of the customer's participation in the program. If an electric provider has not yet fully recovered the incremental costs of compliance, both of the following apply:
>
> (a) A customer that receives at least 50% of the customer's average monthly electricity consumption through the program is exempt from paying surcharges for incremental costs of compliance.

> (b) Before entering into an agreement to participate in a commission-approved voluntary green pricing program with a customer that will not receive at least 50% of the customer's average monthly electricity consumption through the program, the electric provider shall notify the customer that the customer will be responsible for the full applicable charges for the incremental costs of compliance and for participation in the voluntary renewable energy program as provided under this section. (M.C.L.A. 460.1061).

Q: WHAT GUIDANCE HAS THE COMMISSION PROVIDED ON IMPLEMENTATION OF VOLUNTARY GREEN PRICING PROGRAMS GENERALLY AND ON THE COMPANY'S PROGRAMS SPECIFICALLY?

A: In the Commission's Order of July 12, 2017 in Case U-18349 the Commission set forth principles for VGP programs generally:

- Programs should be cost-of-service based to avoid subsidization by non-participants;
- Program terms, RE technologies utilized, location of RE sources and costs and savings incurred by a customer should be transparent and clearly explained;
- Program should contain accurate price signals with costs clearly broken down by category, especially with respect to marketing and administrative costs; and
- RE must be additional to the 15% requirement under Section 28 and separate from the provider's renewable energy plans (REPs).

In addition, the Commission provided guidance and direction on the Company's VGP programs through its orders on U-18352 and U-20343, discussed further below.

Q: WHAT ADDITIONAL GENERAL GUIDANCE HAS THE COMMISSION PROVIDED TO DTE ON IMPLEMENTATION OF ITS VGP PROGRAMS?

A: In the December 20, 2017 order in Case No. U-18352, the Commission provided guidance to the Company on its implementation of VGP for residential & small commercial customers and provided separate guidance directing the implementation of a program to be dedicated for large customers. In general, the Commission echoed the direction provided in U-18349 in finding that VGP programs should meet the following requirements:

- The programs should be cost-of-service based to avoid subsidization by nonparticipants;
- The program terms, RE [renewable energy] technologies utilized, location of RE sources, and costs and savings incurred by a customer should be transparent and clearly explained;
- The program should contain accurate price signals with clearly broken-down costs, especially with respect to marketing and administrative costs; and
- RE generation under the program must be additional to the 15% requirement under [MCL 460.1028] and separate from the provider's renewable energy plans (REPs), which will require accurate accounting and verification of RECs [renewable energy credits] to avoid overlap.

2. <u>Previous concerns with the Company's VGP programs have been raised by numerous parties and continue to pertain.</u>

Q: WHAT GENERAL CONCERNS DO YOU HAVE ABOUT THE LARGE CUSTOMER VOLUNTARY GREEN PRICING PROGRAM AND THE MIGREENPOWER PROGRAM?

A: In her Direct Testimony in Case No. U-18352, my colleague ELPC Witness Rebecca Stanfield identified a number of issues with the Company's initial VGP proposal that continue to be salient:

> First, there is no clear relationship between participation in the program and any real-world benefit, including either a reduction in greenhouse gas and other air pollution that impacts air, land or water in Michigan, or local economic development. Second, the net premium customers would pay for the power is based on a credit rate that does not represent the full savings realized by the company as a result of the underlying generation. Third, DTE has no plan to offer tailored program offerings to specific customer types to ensure, to the extent practicable, that all customers have options to choose from to meet their objectives. Fourth, the size of offering bears no relationship to any serious effort to understand the level of demand, and there is no plan to scale the program up to meet demand. Fifth, the program does not harness the power of competitive markets to ensure that the most cost-effective resources available are made accessible to customers.[6]

In addition, Witness Stanfield also pointed out that the Company's proposal did not address the issue of providing access to the benefits of clean energy to communities that have been left behind in the clean energy economy:

> I am also concerned because it does not offer tailored options to ensure, for example, that low income customers are able to participate in the benefits of clean

[6] Direct Testimony of Rebecca Stanfield, *In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determination and/or approvals necessary for DTE ELECTRIC COMPANY to comply with Section 61 of 2016 PA 342.* Case No. U-18352, April 23, 2018, pp. 2-3.

energy, and that it does not give customers access to the renewable energy markets to source clean energy at lower costs. It does not offer any programs targeted to schools, churches, non-profits or other customer types who have specific needs and objectives.[7]

3. The MIGreenPower should be further developed and reviewed to ensure that it provides full and fair value to customers before being relied up to expand renewable capacity in the IRP.

Q: PLEASE DESCRIBE THE COMPANY'S MIGREENPOWER PROGRAM.

A: MIGreenPower began as a pilot program (with a different name) as part of their Renewable Energy Plan. The original pilot was proposed in the Company's April 15, 2016 application in Case No. U-18076. The pilot was approved by the Commission October 11, 2016. A revised MIGreenPower program was approved by the Commission in its February 21, 2019 Order in Case U-18352.

MIGreenPower allows customers to attribute a certain amount of their energy use to pay for the costs of the dedicated renewable energy resources through a subscription fee. Customers are then issued a credit for the value of the energy and capacity of the generation from the dedicated renewable energy resources. At current levels of cost and credit, customers pay a $0.033/kWh premium to participate in the program. The program is implemented as Rider 17 – Voluntary Renewable Energy.[8]

[7] *Ibid.*Stanfield, pp. 16-17.
[8] Standard Contract Rider 17 – Voluntary Renewable Energy, MPSC No. 1, DTE Electric Company, Second Revised Sheet No. D-109.00, Issued March 1, 2019.

As of February 28, 2019, MIGreenPower had 5,327 residential and 24 non-residential (small commercial) customers enrolled, representing 22, 980 MWh/year subscribed.[9]

Q: PLEASE DESCRIBE THE COSTS AND CREDITS USED IN THE MIGREENPOWER PROGRAM.

A: Participating customers pay a subscription fee of $0.072/kWh. The customer is then credited with the energy and capacity value of the energy produced. The credit rate in 2019 is $0.039/kWh.

The subscription fee is described in the tariff as follows:

> The subscription charge will be a flat fee, based on the levelized cost of service of the designated renewable energy facilities approved within the Program, plus a nominal marketing and administrative fee of $0.002/kWh. The initial subscription charge for the blended wind and solar program is $0.072 per kWh based on the orginally (*sic*) approved assets in the program. The initial subscription charge for the blended wind-only program is $0.052 per kWh based on the orginally (*sic*) approved wind asset in the program.[10]

Q: DOES THE MIGREENPOWER PROGRAM APPROPRIATELY VALUE THE SOLAR ENERGY?

A: No, as was discussed in testimony provided in Case No. U-18352 by my colleague ELPC Witness Rebecca Stanfield[11] and Michigan Environmental Council Witness Douglas Jester[12], the subscription costs reflect inflated project costs and the credit does not fully

---

[9] DTE Voluntary Green Pricing Programs Report, filed in Case No. U-18352, April 1, 2019.
[10] *Ibid*, Second Revised Sheet No. D-110.00.
[11] *Ibid*, Stanfield.
[12] Direct Testimony of Douglas Jester on Behalf of the Michigan Environmental Council and on Behalf of Energy Innovation Business Council, Institute for Energy Innovation, and Advanced Energy Economy, *In the matter on the Commission's own motion, regarding the regulatory reviews, revisions, determinations and/or approvals necessary for DTE ELECTRIC COMPANY to comply with Section 61 of 2016 PA 342*, Case No. U-18352, April 23, 2018.

reflect the value of the energy and capacity provided to the system. Specifically, Witness Jester demonstrated in his testimony that when appropriately valued, the MIGreenPower subscription for unbundled Renewable Energy Credits ("RECs") should provide a small net benefit to the subscriber rather than a premium, even using current program cost figures.

As the costs of building systems at scale, especially for systems 1 MW and larger continue to follow cost reduction trajectories as projected in the estimates recommended by Witness Kevin Lucas[13] and the credits reflect the actual avoided costs that the VGP resources provide, participants in the program should realize a financial benefit to participating in the program as opposed to having to pay a premium. The appropriate forum to revisit the subscription cost and credit will be in the biennial review in April 2020 in Case No. U-18352 or its successor. However, the existence of a premium or not has a material impact on the expected consumer interest in the programs (as will be discussed below in addressing the consumer propensity studies). As such, the fairness of the subscription costs and credits is relevant to this case.

Q: WHAT DO YOU RECOMMEND WITH RESPECT TO THE CALCULATION OF SUBSCRIPTION COSTS AND CREDITS FOR THE MIGREENPOWER PROGRAM?

A: I recommend that the commission revisit calculations of the subscription costs and benefits in the biennial review of the Company's VGP programs in April 2020.

[13] Direct Testimony of Kevin Lucas on Behalf of the Environmental Law and Policy Center,the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of the Application of DTE Electric Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.*, Case No. U-20471, August 21, 2019.

4. <u>The Large Customer Voluntary Green Pricing Program should be further developed and reviewed to ensure that it provides full and fair value to customers before being relied upon to expand renewable capacity in the IRP.</u>

Q: PLEASE DESCRIBE THE COMPANY'S LARGE CUSTOMER VOLUNTARY GREEN PRICING PROGRAM.

A: The Company was directed by the Commission in its October 5, 2018 Order in Case Number U-18352 to create a voluntary green pricing program for large customers. The Company's proposed a Large Customer Voluntary Green Pricing Program in its November 8, 2018 application to create the large customer program in Case Number U-20343. The Large Customer Voluntary Green Pricing Program was approved by the Commission in its January 18, 2019 Order. The program is implemented through Rider 19, the Large Customer Voluntary Pricing Program (LCVGP) Pilot.[14]

Q: PLEASE DESCRIBE THE COSTS AND CREDITS USED IN THE LARGE CUSTOMER VOLUNTARY GREEN PRICING PROGRAM PILOT.

A: Subscription costs for program participants are set as a flat fee, based on the "levelized cost of service of the designated renewable energy facilities approved within the Program."[15]

Program participants receive a "Renewable Energy Resource Credit" for their subscribed kilowatt-hours. The energy credit is based on the Locational Marginal Price for the

[14] Standard Contract Rider No. 19, Large Customer Voluntary Green Pricing Program Pilot. MPSC No. 1. – Electric, DTE Electric Company, Original Sheet No. D-117.00, Issued January 28, 2019.
[15] *Ibid*, Original Sheet No. D-118.00.

generation node of the designated renewable energy facility. The capacity credit is described in Tariff 19:

> The customer will be provided a monthly capacity credit based on the customer's renewable energy subscription under this Program and the value of the Zone 7 Auction Clearing Price in the annual MISO Planning Resource Auction for the planning period, as determined by the Company. The auction clearing price will be calculated on a per MWh basis using the formula below. The annual MISO capacity auction takes place in March with the revenue from system capacity being updated for the next twelve months beginning June 1st of each year.[16]

$$\frac{(Auction\ Clearing\ Price) * (365\ Days) * \left(MISO\ Zone\ 7\ Capacity\ Credit\ (MW)\right)}{(Project\ Size) * (Resource\ NCF) * (8760\ Hours)}$$

Q: DOES THE LARGE CUSTOMER VOLUNTARY GREEN PRICING PROGRAM APPROPRIATELY VALUE THE SOLAR ENERGY RESOURCES?

A: No, similar to the MIGreenPower program, the LCVGP pilot significantly undervalues the credit to the customer. Calculating the capacity credit based on the zonal Planning Resource Auction (PRA) price while at the same time including these resources in the Company's Starting Point for the PCA in this IRP significantly undervalues the capacity and improperly benefits the Company by undercompensating participating customers through the credit.

In addition, it is notable that the Company's calculation of the capacity credit in Case No. U-20343 (the LCVGP pilot) is significantly different than the calculation of the capacity credit that was litigated in Case No. U-18352 (the MIGreenPower program discussed

[16] *Ibid.*, Original Sheet No. D-118.00

above). As discussed in the review of the MIGreenPower program, using CONE as the starting point for the calculation of the capacity value is an appropriate measure, but as Witness Jester pointed out in in his testimony in that case, there was no evidentiary basis for the 75% reduction.[17]

Q: WAS THIS CAPACITY CREDIT CALCULATION LITIGATED IN THE COMMISSION'S CONSIDERATION AND APPROVAL OF THE LCVGP PILOT?

A: No, the Company applied for *ex parte* consideration of the LCVGP pilot in Case No. U-20343 in its application on November 1, 2018. The Commission approved the pilot in its January 18, 2019 Order in Case No. U-20343 on an *ex parte* basis without a contested case.

V. Overview of Renewables in the 2019 IRP

1. The Company's PCA includes existing company-owned and contracted renewable energy in its Starting Point.

Q: HOW DOES RENEWABLE ENERGY GENERALLY FIT INTO THE COMPANY'S 2019 INTEGRATED RESOURCE PLAN?

A: The Company proposes three categories of renewables in the 2019 IRP corresponding to the requirements or commitments that drive them:

- 15% Renewable Portfolio Requirements from PA 342 of 2016
- Clean Energy and Carbon Reduction Goals established by the Company
- Voluntary Green Pricing Program Requirements

[17] *Ibid.* Jester, pg. 11.

The renewable resources required to meet these requirements or commitments are shown in Exhibit A-18 to the testimony of Witness Terri Schroeder. These resources include both Company owned and contracted (third party-owned) wind, solar, biomass, and landfill gas resources which renewable energy attributes are accounted for in achieving each of these three categories of goals.

Q: WHAT RENEWABLE RESOURCES ARE INCLUDED IN THE STARTING POINT?

A: The Starting Point used by the Company in its modeling consists of existing resources that are anticipated to be built to meet requirements and resources that are planned to meet the Company's carbon reduction requirements. The Starting Point resources include 1,157 MW of existing capacity and 5,136 MW of total renewable capacity. That means that an additional 3,979 MW of renewable capacity is included in the Company's modeling Starting Point.

2. The Defined Period in the PCA includes the completion of previously committed renewables projects, some new RPS and carbon reduction projects, and a modest opportunity for additional renewables in the VGP programs.

Q: WHAT RENEWABLE RESOURCES ARE PROPOSED TO BE DEVELOPED IN THE DEFINED PERIOD OF THE PCA?

A: In the Defined Period of the PCA, the Company plans to develop 1,419 MW of renewables to meet requirements and commitments. The Defined Period additions consist of 1,158 MW of new wind, 11.4 MW of new solar and 250 MW of new wind or solar. The 250 MW of "wind or solar" consist of estimated additions in 2021, 2022 and 2023 to meet Voluntary Green Pricing program goals.

Witness Schroeder described the renewable resourced included in the IRP defined PCA

> "The defined PCA contains defined levels of renewables for the first five years to meet RPS requirements and the company's Clean Energy and Carbon Reduction requirements. See Exhibit A-18, lines 47 through and 55. In addition, the Company plans to install 465 MW up to 715 MW in the first five years to support the VGP programs. The first 465 MW will be sourced by wind; the potential incremental 250 MW is assumed to be solar and thereafter the determination is to be decided."[18]

3. <u>The Flexible Period of the PCA includes building new renewable resources to meet carbon reduction commitments and the opportunity for additional VGP resources.</u>

Q: WHAT RENEWABLE RESOURCES ARE PROPOSED TO BE DEVELOPED IN THE FLEXIBLE PERIOD?

A: Witness Schroeder indicated that the flexible period of the PCA contains a range of options because the Company is allowing customer demand to drive the amount that is built. "The Company plans to actively market voluntary renewables through multiple programs under MIGreenPower and will monitor actual customer subscription rates."[19] The Company does not require any additional resources to meet PA 342 RPS requirements in the Flexible Period. All proposed additions in the Flexible Period are to meet VGP requirements or Clean Energy and Carbon Reduction Goals. In the Flexible

[18] TLS-14
[19] TLS-14 to TLS 15

Period, the Company proposes a total of 3,500 MW of new renewables consisting of 300 MW or new wind, 2,525 MW of new solar and 675 MW of new wind or solar.

Q: HOW DID THE COMPANY SELECT THE ADDITIONS TO EXISTING RENEWABLE RESOURCES IN THE DEFINED AND FLEXIBLE PERIODS OF THE PCA?

A: In response to discovery included as Exhibit ELP-71 (WK-1), the Company indicated that they selected resources already approved in its Renewable Energy Plan:

> The selection of the wind in the defined period of the PCA to achieve the renewable portfolio standard and clean energy goals outlined in the case was based (*sic*) 2017 NREL ATB forecasts of wind versus solar costs and their calculated LCOEs, which were calculated for the Renewable Energy Plan case (Case Number U-18232). Please see attachment for the LCOE comparison. The selection of primarily wind in the defined period of our PCA was not influenced by Strategist or Promod runs.[20]

Thus, the Company's 2018 Renewable Energy Plan using 2017 Annual Technology Baseline data becomes the basis for its renewable buildout. The Starting Point included no analysis of the financial or economic value of accelerating or expanding the scope of the renewable energy buildout.

Q: DID THE COMPANY'S MODELING INFORM ITS PLANS FOR DEVELOPING RENEWABLE RESOURCES IN THE DEFINED AND FLEXIBLE PERIODS OF THE PCA?

[20] ELP-72 (WK-2): ELPCDE-13.88a.

A: No, the Company acknowledged in response to discovery requests that its plans did not rely on modeling conducted in the IRP to select the renewables resources proposed in the PCA:

> The selection was not based on Strategist or PROMOD runs. The renewable energy assets identified for the PA 342 15% RPS, the Clean Energy and Carbon Reduction Goals were selected based on forecasted levelized cost of energy. Based on Attachment U-20471 ELPCDE-13.88a Renewable forecasted LCOEs, the costs of wind and solar became more comparable in 2024, which is when DTE Electric proposed to switch to primarily building solar.[21]

Q: WHAT DO YOU RECOMMEND ABOUT THE COMPANY'S USE OF MODELING TO DEVELOP ITS PCA?

A: The Commission should require the Company to develop a PCA that is based on optimization of resources in the model rather than building outdated plans from its last Renewable Energy Plan into the non-variable Starting Point. ELPC Witness Kevin Lucas addresses this issue in his testimony and I endorse his conclusions and recommendations.

4. The Company did not fully evaluate the potential for increased adoption of distributed generation to reduce load and thus reduce resources required in the IRP.

Q: IS THE COMPANY DIRECTED TO EVALUATE THE POTENTIAL FOR INCREASED BEHIND-THE-METER ADOPTION TO DECREASE LOAD?

[21] ELP-73 (WK-3): ELPCDE-13.88c.

A: Yes, the "Michigan IRP Modeling Input Assumptions and Sources" in Michigan Integrated Resource Planning Parameters includes in item 15 the direction to evaluate behind-the-meter resources.[22]

Q: DID THE COMPANY EVALUATE HOW HIGHER PENETRATION OF DISTRIBUTED RENEWABLE RESOURCES COULD REDUCE LOAD AND THUS REDUCE RESOURCES REQUIRED IN THE IRP?

A: No, although the Company acknowledges the requirement in *Exhibit A-1 IRP Filing Requirements*, none of the testimony references or exhibits identified in Row 284 of the "Checklist" sheet of that exhibit demonstrate that the Company performed sensitivity analysis to evaluate the impact of increased customer behind-the-meter distributed generation on load.

The Company should be required to evaluate the opportunity to increase adoption of behind-the-meter distributed energy resources to cost-effectively reduce load. An incentive in the form of a rebate to increase adoption of behind-the-meter generation to reduce load should be evaluated to cost effectively reduce resource requirements.

[22] Michigan Integrated Resource Planning Parameters, Pursuant to Public Act 341 of 2016, Section 6t November 21, Docket No. U-18418, November 21, 2017.

VI. Voluntary Green Pricing in the 2019 IRP

1. Beyond the Starting Point and renewable resources needed to meet the company's carbon commitments, the PCA relies upon customers selecting premium priced VGP programs for additional renewable resources rather than evaluating replacement of existing resources with renewables for economic reasons.

Q: PLEASE DESCRIBE THE PLANS UNDERLYING THE VOLUNTARY GREEN PRICING PROGRAMS IN THE STARTING POINT AND THE DEFINED PERIOD OF THE PCA.

A: The Starting Point includes 372.5 MW of renewable resources dedicated to serving existing VGP commitments.[23] Beyond the Starting Point, Witness Schroeder identified an incremental 1,090 MW of incremental voluntary green pricing projects that could be "driven by customer demand."[24] Of that incremental demand 465 MW of wind are included in the defined PCA to reflect existing contracts.[25] In addition, the Defined period also includes and 250 MW of planned VGP capacity. Witness Schroeder indicated in her testimony that the additional 250 MW is "assumed to be solar."[26] However, in response to discovery requested, Witnesses Schroeder and Mikulan indicated that 100 MW of that was modeled to be solar.[27]

Q: WHAT DOES THE COMPANY PROPOSE FOR THE VGP DURING THE FLEXIBLE PORTION OF THE PCA?

[23] Schroeder Exhibit A-18, lines 77-80.
[24] TLS-13
[25] Schroeder Exhibit A-18, Lines 81 and 82
[26] TLS-14, lines 10-12
[27] ELP-74 (WK-4): ELPCDE-1.12

A: The Flexible Period assumes an additional 675 MW of wind or solar. The exact amount of additional renewables during the Flexible period is left entirely to be determined by customer demand. The Company does attempt to quantify the impact of different levels of VGP adoption in its Pathways analysis, where they examine two Pathways with high levels of VGP adoption (Pathways A & B) and two with low VGP adoption (Pathways C &D). The Company evaluated the net present value of revenue requirements for alternative means of meeting resource requirements depending on the level of VGP adoption.

Q: DOES THE PCA RECOMMEND A PARTICULAR LEVEL OF DEPLOYMENT OF VGP?

A: No, while there are modest VGP investments planned in the Defined period, only the first 465 MW are planned. The remainder of the proposed potential expansion comes entirely in the form of optional resources that will only be developed if customers demand it. The Company identified a number of steps it has taken to evaluate the potential for expanding the VGP programs. Witness Schroeder identifies three different customer segments for VGP programs and describes steps that the Company will take to evaluate and expand those programs. The Company determined that these three segments could add up to an incremental 925 MW of renewables.[28]

2. *The potential demand for residential and small commercial VGP depends upon a study of propensity to purchase at a premium price.*

Q: WHAT DID THE COMPANY DETERMINE ABOUT THE POTENTIAL FOR EXPANSION OF THE RESIDENTIAL SEGMENT OF THE VGP MARKET?

[28] *Ibid.*, Schroeder Direct, TLS-15.

A: Witness Schroeder estimated that the residential segment of the VGP market could grow by an additional 20 MW to 50 MW in the next decade if residential demand continues to grow.[29] Witness Schroeder described a propensity study of its residential customer base and estimates approximately 60,000 to 75,000 customers could reasonably be forecasted to join MIGreenPower.

Q: DOES THE COMPANY APPROPRIATELY ESTIMATE THE OPPORTUNITY FOR EXPANSION OF THE RESIDENTIAL SEGMENT?

A: The propensity study conducted by the Company assumes continuation of the pricing model currently in place for MIGreenPower, which charges a premium for participation. However, if the program were priced appropriately as discussed in Section IV of my testimony, the demand could reasonably be expected to increase significantly.

3. The Community solar potential is based only on anecdotal conversations with existing customers willing to pay a premium price.

Q: WHAT DID THE COMPANY ASSUME ABOUT THE COMMUNITY SEGMENT FOR VGP RENEWABLES?

A: Witness Schroeder explained that the Company is considering a program similar to what is currently understood to be community solar and estimated that this segment could add 20 MW – 50 MW of capacity. As described by Witness Schroeder, "The Community segment will likely include solar energy installed locally, potentially with an anchor municipal customer, that may also include subscriptions from members of the community."[30] The Company indicated that they have identified at least 10 customers

[29] *Ibid.*, Schroeder Direct, TLS-15.
[30] *Ibid.*, Schroeder Direct, TLS-16.

interested in pursuing community solar projects and are currently in discussion with several of them.

Q: DOES THE COMPANY APPROPRIATELY ESTIMATE THE OPPORTUNITY FOR EXPANSION OF THE COMMUNITY SOLAR SEGMENT?

A: It appears from the testimony provided that the Company has provided only cursory evaluation of the opportunity for expanding community solar. Similar to the residential segment, it appears that the Company assumes extension of the pricing model for the LCVGP program for the community solar segment which would result in a premium for participation. However, if the program were priced appropriately as discussed in Section IV of my testimony, the demand could reasonably be expected to increase significantly.

4. The Company estimates significant demand for VGP from Commercial and Industrial customers but has not systematically evaluated the potential for adoption of a program based on the full and fair valuation of VGP resources.

Q: WHAT DID THE COMPANY ASSUME ABOUT THE COMMERCIAL AND INDUSTRIAL (C&I) SEGMENT FOR VGP RENEWABLES?

A: Witness Schroeder identified the C&I segment as the largest potential increase in capacity need for the VGP program, indicating that it could represent between 900 MW and 1,000 MW due to the segment's large energy usage requirement and corporate sustainability commitments.[31] Witness Schroeder indicated that of the 300 or so of the Company's largest customers, approximately 70 of them have corporate sustainability

[31] *Ibid.*, Schroeder Direct, TLS-16 – TLS-17)

goals, including renewable energy, carbon reduction goals, etc. This represents over 6,000,000 MWh of annual consumption.

Q: DOES THE COMPANY APPROPRIATELY ESTIMATE THE OPPORTUNITY FOR EXPANSION OF THE C&I SEGMENT FOR VGP RENEWABLES?

A: While the Company's estimates of the potential for expansion of the C&I segment are significant, the Company also extends the inappropriate undervaluation of renewable resources in the LCVGP program. As such, the Company does not estimate the potential for a fairly priced program, thus leading to an underestimate of likely demand.

VII. Appropriateness of Voluntary Green Pricing as Significant Plan Component

1. The Company relies too heavily on the VGP to meet customer demand for clean energy and fails to set forth a decisive plan for taking advantage of renewable resources.

Q: DOES THE COMPANY'S RENEWABLE EXPANSION PLAN RELY TOO HEAVILY ON VGP?

A: Yes, a prudent IRP would set forth a plan for meeting customer demands and resource requirements through definitive means. The Company's PCA relies too heavily upon customers selecting premium priced products to meet demands for clean energy, especially in light of the fact that a full and fair valuation of the VGP programs should result in net benefits to participating customers.

2. ***<u>The Company only modeled utility-owned VGP programs and ignores the opportunity for customers to benefit from customer-sited distributed generation and the benefits of competitive markets for meeting customer demand for clean energy.</u>***

Q: DID THE COMPANY CONSIDER OTHER MODELS FOR EXPANSION OF VGP PROGRAMS, SUCH AS THIRD-PARTY OWNERSHIP?

A: No, the Company only considered utility-owned renewable resources for expansion of VGP programs. In response to a discovery, Witness Schroeder explained:

> The Company modeled all renewable energy as owned. There are significant benefits to customers from owned assets, including decreased performance risk (DTE Electric is a top quartile operator), long-term benefits to customers after the asset's depreciated life, decreased contract risk including risk of termination and change of ownership, and reduced balance sheet impacts from long term liabilities.[32]

Q: ARE UTILITY-OWNED RENEWABLE ASSETS THE MOST COST EFFECTIVE?

A: It is in the interests of customers and ratepayer that they receive the lowest cost services. When those services can be provided cost-effectively by the utility then they should, but there are a number of reasons that utility ownership of renewable resources may not be the lowest-cost alternative:

- Utility cost of capital may be higher;
- Utility depreciation requirements (fully depreciated over 30 years as opposed to a salvage value for third party financed systems); and

[32] ELP-75 (WK-5): ELPCDE-1.20e

- Investment tax credit accounting – Utilities are required to monetize the value of tax credits over the life of a project, however the time value of money for recognizing tax credits when earned is substantial.

As such, when considering VGP proposals, the Commission should consider alternatives to utility ownership of distributed generation assets that may provide equal or greater benefits to customers. When regulators consider VGP programs they should investigate the ability of customers to implement alternatives of their own initiative on a non-discriminatory basis.

ELPC Witness Kevin Lucas treats this subject more thoroughly in examining the costs of solar resources and the merits of different ownership structures.[33] I endorse the findings of Witness Lucas.

Finally, when utility ownership of renewable resources in VGP programs is found to be desirable, the Commission should ensure that participants should benefit from efficient and cost-effective distributed generation resources through competitive markets. The Company should take advantage of the competitive market and the existence of the mature solar industry in developing distributed generation and put the development of the renewable energy facilities out to bid. The Company is obligated to build these facilities in the most cost-effective manner possible, and this will help ensure that customers are not overcharged for the services that they are receiving.

[33] Direct Testimony of Kevin Lucas on Behalf of the Environmental Law and Policy Center,the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of the Application of DTE Electric Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.*, Case No. U-20471, August 21, 2019. Section V.

Q: WHAT IMPACT DOES THE COMPANY'S EMPHASIS ON UTILITY-OWNED VGP HAVE ON ALTERNATIVE METHODS OF ACHIEVING CUSTOMERS' CLEAN ENERGY DEMAND?

A: To the extent that any VGP program displaces behind-the-meter distributed generation, the overreliance on VGP results in sub-optimal outcomes for customers. That is to say, in my experience, for customers for whom on-site DG is an option, it will virtually always provide a superior value proposition compared to utility-owned, remote renewables programs.

As discussed in section III of my testimony, by limiting the ability of the competitive market to provide distributed generation services to customers, the Commission forgoes opportunities for significant customer savings and economic growth.

3. The Company should consider the use of VGP programs to ensure access to clean energy for low-income households and communities left behind in the clean energy economy.

Q: PLEASE EXPAND ON THE PRINCIPLES OF PROVIDING ACCESS TO THE CLEAN ENERGY ECONOMY FOR ALL CUSTOMERS.

A: The benefits of the clean energy economy and, in particular, the benefits VGP programs should be available to all members of the public. Engaging and empowering low-income families and communities of color who are disproportionately impacted by the negative effects of the fossil fuel economy and have the most to gain from a transition to affordable clean energy can be a benefit in and of itself, even if it is less easily quantified than energy savings.

Providing access to the clean energy economy is of particular importance when dealing with solar technology due to historical barriers to solar adoption for lower income customers and customers who cannot install solar on their own roofs. The advent of shared renewables programs, including community solar, and third-party financing has gone a long way to begin rectifying this inequity, but only when structured correctly. When it comes to VGP programs, there are specific design elements that can make it much easier or much harder for all households, and in particular low-income households, to participate and benefit. Not every VGP program will target every customer class, but when designing any VGP program, it is important to critically examine whether additional steps can be taken to expand access to clean energy.

In order for VGP proposals to effectively expand customer access to the clean energy economy and, specifically, to low-income customers, the proposals should follow these guidelines for a successful low-income solar program:

1. Provide immediate tangible economic benefits for low-income participants, with no up-front costs.
2. Fully compensate low-income customers for the services and benefits solar projects provide.
3. Design replicable, scalable programs for long-term program sustainability and opportunities for adjustment.
4. Complement existing programs to reduce overall household energy burden.
5. Drive local economic opportunity in underserved communities through workforce development and participation for minority- and women-owned business enterprises.

6. Prioritize community engagement throughout the program design, planning, implementation and ongoing operations, ideally through partnerships with local community organizations.
7. In the case of utility-owned projects, ensure non-discriminatory treatment between utility- and non-utility-owned projects.
8. In the case of community solar projects, ensure subscriptions are easily portable and transferable at minimal or no cost to participants.[34]

While these guidelines are intended for low-income solar programs, many can improve access and outcomes for all customers.

Q: HOW DO YOU RECOMMEND THAT THE COMPANY INCORPORATE THE PRINCIPLES OF EQUITY AND ACCESS INTO THE VGP PROGRAMS IN THIS IRP?

A: I recommend that the Company should adopt principles of equity and access into its MIGreenPower program that explicitly address inequities in the needs of low-income households and communities of color.

VIII. The Company should have done an All-Source RFP to accurately determine the most cost-effective resources for the modeling.

Q: WHAT IS THE STATUTORY REQUIREMENT FOR ISSUING AN RFP IN THE IRP PROCESS?

A: Each electric utility whose rates are regulated by the Commission shall issue a request for proposals (RFP) to provide any new supply-side capacity resources needed to serve the utility's reasonably projected electric load, applicable planning reserve margin, and local

[34] These guidelines are drawn from a forthcoming publication by ELPC, GRID Alternatives, and Vote Solar on Principles and Recommendations for Utility Participation in Solar Programs for Low-Income Customers.

clearing requirement for its customers in this state, as well as customers located in other states but served by the utility, during the initial three-year planning period to be considered in each IRP to be filed, as outlined in MCL 460.6t:

> (6) Before filing an integrated resource plan under this section, each electric utility whose rates are regulated by the commission shall issue a request for proposals to provide any new supply-side generation capacity resources needed to serve the utility's reasonably projected electric load, applicable planning reserve margin, and local clearing requirement for its customers in this state and customers the utility serves in other states during the initial 3-year planning period to be considered in each integrated resource plan to be filed under this section.
>
> …
>
> A utility that issues a request for proposals under this subsection shall use the resulting proposals to inform its integrated resource plan filed under this section and include all of the submitted proposals as attachments to its integrated resource plan filing regardless of whether the proposals met the qualifying performance standards, contract terms, technical competence, capability, reliability, creditworthiness, past performance, or other criteria specified for the utility's request for proposals under this section. (MCL 460.6g(6))

Q: DID THE COMPANY CONDUCT PRE-FILING RFP?

A: No, DTE Witness Sharon G. Pfeuffer indicated that the Company did not conduct an RFP pursuant to the statute because it found that it did not have a capacity need:

> In the first five years of the PCA, based on the planned coal retirements by 2022, and with the already planned additions of the BWEC and renewable generation,

as well as planned additions in demand side resources, the Company will have sufficient capacity to meet its PRMR. In the longer-term, the Company does not project to have a capacity need until 2030, associated with the Belle River Power Plant retirement. Given the Company does not anticipate a need for additional capacity in the short-term planning horizon, there is no need or requirement to issue an RFP to third parties to supply capacity resources.[35]

Q: SHOULD THE COMPANY HAVE CONDUCTED A PRE-FILING RFP?

A: The Company could have benefitted from conducting an all-source RFP for energy and capacity. Throughout the Midwest in the past year, Companies that have conducted RFPs prior to filing integrated resource plans have found renewable resources to be economically more attractive than operating existing fossil fueled resources.

The most notable example of the benefits to customers of conducting a thorough analysis including an all source RFP was the Integrated Resource Plan filed by the Northern Indiana Public Service Commission ("NIPSCO") last year in Indiana. NIPSCO issued an All Source RFP and used the results to inform the inputs to its IRP. This resulted in up-to-date inputs with lower price risk.

Most importantly, the All-Source RFP responses provided transactable cost and price information to be incorporated in the IRP analysis. Overall, much of the cost information was relatively consistent with the third-party data review, but renewable offers were at the low end of the estimates observed in the public literature. This indicated that technology change and developer activity in a

[35] Direct Testimony of Sharon G. Pfeuffer, Case No. U- 20147, pp. SGP-29 – SGP-30.

> competitive process are dynamic forces that influence the costs of resource options for NIPSCO in the future.[36]

As described in the company's IRP Executive Summary:

> New to NIPSCO's IRP, we issued a formal Request for Proposals (RFP) solicitation to uncover the breadth of actionable projects that were available to NIPSCO within the marketplace across all technology types. The RFP also served to collapse uncertainty about the costs of various technologies, particularly renewables.[37]

The RFP provided extremely valuable information that improved the quality of the RFP, increased value for shareholders, and provided the best plan for their customers' needs.

Q: DID THE COMPANY ANALYZE THE IMPACTS OF INCREASING THE BUILDOUT OF RENEWABLE ENERGY IN DETERMINING THE PCA?

A: No, as discussed in Section V., the Company relied upon its 2018 Renewable Energy Plan using 2017 Annual Technology Baseline data to set the Starting Point. The Starting Point, including planned 2021-2024 included no analysis of the financial or economic value of accelerating or expanding the scope of the renewable energy buildout.

In the Commission's July 18, 2019 Order in the Company's Renewable Energy Plan (Case No. U-18232), the Commission explicitly directed the Company to conduct a thorough analysis of all options available:

> As such, the Commission will examine DTE Electric's proposed renewable generation not approved in this order in the IRP, enabling the Commission to look

[36] Northern Indiana Public Service Company, *2018 Integrated Resources Plan*, pg. 56. Available online: https://www.nipsco.com/our-company/about-us/regulatory-information/irp

[37] *Ibid*, NIPSCO. Executive Summary pg. 2.

at the proposed projects along with other renewable technologies with the aid of a fully developed and more robust evidentiary record. The Commission notes the importance of comparing technologies as the renewable energy technology landscape is quickly evolving and the company should consider expanding the inputs to its bidding parameters to be inclusive of these changes.[38]

IX. Recommendations

Q: PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS

A: I find that the Company's PCA suffers from numerous deficiencies with regards to its consideration of the renewable resources in the Voluntary Green Pricing programs and recommend that the Commission require the Company to address the following issues:

- During the biennial review of the Company's VGP programs required in April 2020, the programs should be updated to properly reflect fair compensation to participating customers.
- The renewable resources included in the Company's Starting Point should be informed by the results of the Company's IRP modeling to determine the most effective mix of renewables to meet the Company's future RPS, Carbon Reduction and Voluntary Green Pricing requirements and commitments.
- The Company should be required to conduct rigorous potential adoption evaluations of all segments of the VGP programs prior to including voluntary programs in the PCA.

[38] Commission Order, In the matter, on the Commission's own motion regarding the regulatory reviews, revisions, determinations, and approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, Case No U-18232, pg. 25

- The Company should be required to evaluate the opportunity to increase adoption of behind-the-meter distributed energy resources to cost-effectively reduce load.
- The Company should be required to consider opportunities for third-party owned resources to fulfill all renewable energy requirements, including VGP programs.
- The Company should consider the use of VGP programs to ensure access to clean energy for low-income households and communities left behind in the clean energy economy.
- The Company should be required to conduct an all-source RFP prior to developing a revised PCA that reflects the opportunity for renewable resources to replace existing resources in its generation portfolio.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
DTE ELECTRIC COMPANY	)	Case No. U-20471
for approval of its integrated resource plan	)	
pursuant to MCL 460.6t, and for other relief	)	

EXHIBITS OF

WILL KENWORTHY

ON BEHALF OF

THE ENVIRONMENTAL LAW & POLICY CENTER,
THE ECOLOGY CENTER,
THE SOLAR ENERGY INDUSTRIES ASSOCIATION,
THE UNION OF CONCERNED SCIENTISTS,
AND
VOTE SOLAR

AUGUST 21, 2019

Testimony and Comments
of
William D. Kenworthy
Regulatory Director, Midwest
Vote Solar
August 20, 2019

Testimony

Direct Testimony of Will Kenworthy on behalf of the Environmental Law and Policy Center, the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of the Application of DTE Electric Company for authority to increase its rate schedules and rules governing the distribution and supply of electric energy, and for other relief*, Case No. U-20162, November 7, 2018.

Rebuttal Testimony of Will Kenworthy on behalf of the Environmental Law and Policy Center, the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of the Application of DTE Electric Company for authority to increase its rate schedules and rules governing the distribution and supply of electric energy, and for other relief*, Case No. U-20162, November 28, 2018.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law and Policy Center and the Iowa Environmental Council, In re: Interstate Power & Light Company, Docket No. RPU-2019-001, August 1, 2019.

Comments

Comments of Vote Solar, the Environmental Law and Policy Center, Natural Resources Defense Council, and Plugged In Strategies on the Michigan Distributed Planning Framework: MPSC Report. *In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their five-year distribution investment and maintenance plans and for other related, uncontested matters.* Case No. U-20147, October 5, 2018.

Comments of Vote Solar, the Environmental Law and Policy Center, Natural Resources Defense Council, and Plugged In Strategies on the Indiana Michigan Power Company’s draft *Michigan*

Five Year Distribution Plan for 2019-2023 per the Commission's November 21, 2018 Order in Case No. U-20147, December 21, 2018.

Comments of Vote Solar in the Matter of Updating Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611, Minnesota Public Service Commission Docket No: E-999/CI-16-521, September 19, 2018.

Comments of Vote Solar in the Matter of a Commission Investigation to Identify and Develop Performance Metrics, and Potentially, Incentives for Xcel Energy's Electric Utility Operations, , Minnesota Public Service Commission Docket No: E002/CI-17-401, May 6, 2019.

Reply Comments of Vote Solar in the Matter of a Commission Investigation to Identify and Develop Performance Metrics, and Potentially, Incentives for Xcel Energy's Electric Utility Operations, , Minnesota Public Service Commission Docket No: E002/CI-17-401, June 6, 2019.

Comments of Vote Solar in the Matter of the Commission's Inquiry into Standby Service Tariffs, Minnesota Public Service Commission Docket No: E999/CI-15-115, February 19, 2019.

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-13.88a
Respondent:	L. K. Mikulan/ T. L. Schroeder
Page:	1 of 1

Question: Refer to Exhibit A-5.

a. In the "Defined" period of the IRP, nearly all new capacity is wind, with very little solar. What was the basis for this decision? How, if at all, was this decision influenced from the various Strategist or PROMOD runs?

Answer: The selection of the wind in the defined period of the PCA to achieve the renewable portfolio standard and clean energy goals outlined in the case was based 2017 NREL ATB forecasts of wind versus solar costs and their calculated LCOEs, which were calculated for the Renewable Energy Plan case (Case Number U-18232). Please see attachment for the LCOE comparison. The selection of primarily wind in the defined period of our PCA was not influenced by Strategist or Promod runs.

Refer to the attachment below:

Attachments: The document listed below is available for download at the following hyperlink:

https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U-204712019IRPPublic/default.aspx

U-20471 ELPCDE-13.88a Renewable forecasted LCOEs

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-13.88c
Respondent:	L. K. Mikulan/T. L. Schroeder
Page:	1 of 1

Question: Refer to Exhibit A-5.

c. In the “Flexible” portion of the IRP, the PCAs largely switch from building wind to building solar. What was the basis for this decision? How, if at all, was this decision influenced from the various Strategist or PROMOD runs?

Answer: The selection was not based on Strategist or PROMOD runs. The renewable energy assets identified for the PA 342 15% RPS, the Clean Energy and Carbon Reduction Goals were selected based on forecasted levelized cost of energy. Based on Attachment U-20471 ELPCDE-13.88a Renewable forecasted LCOEs, the costs of wind and solar became more comparable in 2024, which is when DTE Electric proposed to switch to primarily building solar.

Refer to the attachment provided in the Company’s response to ELPCDE-88a.

Attachments: N/A

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-1.12
Respondent:	T. L. Schroeder/ L. K. Mikulan
Page:	1 of 1

Question: Please refer to Schroeder Direct Testimony at 14. What was the basis of the decision to have the first 465 MW be wind with a potential incremental 250 MW to be solar?

Answer: The 465 MW is wind based on contracts under negotiation. For modeling purposes the incremental 250 MW is not all solar. See Exhibit A-5, page 3 where of the total 715 MW, 615 MW is wind and 100 MW is solar. If the Company expands the Voluntary Green Pricing Program above the 465 MW based on customer interest, the Company will select the generation technology based on costs.

Attachments: *N/A*

MPSC Case No.:	U-20471
Requestor:	ELPC
Question No.:	ELPCDE-1.20e
Respondent:	T. L. Schroeder
Page:	1 of 1

Question: Please refer to Mikulan Direct Tesitmony regarding the Voluntary Green Pricing program.

e) Did DTE consider signing PPAs with third-party developers to provide the renewable energy for the VGP programs? If not, please explain why.

Answer: The Company modeled all renewable energy as owned. There are significant benefits to customers from owned assets, including decreased performance risk (DTE Electric is a top quartile operator), long-term benefits to customers after the asset's depreciated life, decreased contract risk including risk of termination and change of ownership, and reduced balance sheet impacts from long term liabilities.

Attachments: *None.*

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t, and for other relief	))))	Case No. U-20471

DIRECT TESTIMONY OF ANNA SOMMER

ON BEHALF OF

THE ENVIRONMENTAL LAW & POLICY CENTER,
THE ECOLOGY CENTER,
THE SOLAR ENERGY INDUSTRIES ASSOCIATION,
THE UNION OF CONCERNED SCIENTISTS,
VOTE SOLAR,

AND ON BEHALF OF
THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL

AUGUST 21, 2019

I. INTRODUCTION & QUALIFICATIONS

Q: Please state for the record your name, position, and business address.

A: My name is Anna Sommer. I am a Principal of Energy Futures Group ("EFG"), a Hinesburg, Vermont, based consulting company. My business address is 9 Main Street, Canton, NY 13617.

Q: On whose behalf is this testimony being offered?

A: I am testifying on behalf of Environmental Law and Policy Center ("ELPC"), the Union of Concerned Scientists ("UCS"), the Solar Energy Industries Association, Vote Solar ("VS"), the Ecology Center ("EC"), and on behalf of the Michigan Energy Innovation Business Council ("MiEIBC").

Q: Please summarize your educational experience.

A: I hold a B.S. in Economics and Environmental Studies from Tufts University and an M.S. in Energy and Resources from University of California Berkeley. I have also taken coursework in data analytics at Clarkson University and in Civil Engineering and Applied Mechanics at McGill University and participated in the U.S. Department of Energy sponsored Research Experience in Carbon Sequestration ("RECS").

Q: Please summarize your work experience.

A: I have worked for over 15 years in electric utility regulation and related fields. During that time I have reviewed dozens of integrated resource plans ("IRPs") and related planning exercises. I have reviewed planning modeling based on multiple models including AURORA, Capacity Expansion Model, Plexos, PowerSimm, PROSYM, PROMOD, SERVM, and System Optimizer and have had formal training on the Strategist and EnCompass planning models.

Prior to joining to EFG, I founded my own consulting firm, Sommer Energy, LLC in 2010 to provide integrated resource planning, energy efficiency, renewable energy, and carbon capture and sequestration expertise to clients around the country.

I was previously employed at Energy Solutions where I helped implement energy efficiency programs on behalf of utilities like Pacific Gas & Electric. Prior to that, I was a Research Associate at Synapse Energy Economics where I provided regulatory and expert witness support to clients on topics including integrated resource planning.

Finally, I am a member of GridLab's[1] Expert team and sit on the Board of the Public Utility Law Project of New York ("PULP"), New York State's advocate for residential low-income consumers of utility services.

My work experience is summarized in my resume, provided as Exhibit ELP-76 (AS-1).

Q: Have you testified before this Commission or as an expert in any other proceeding?

A: I have not testified before this Commission previously. However, I have testified or provided docketed comments on IRPs, the relationship of IRPs to demand-side management plans and certificate of need proceedings, and other planning related matters in numerous dockets. And I have testified before commissions in Indiana, Minnesota, New Mexico, North Carolina, Puerto Rico, and South Dakota.

[1] GridLab's mission is to provide "technical grid expertise to enhance policy decision-making and to ensure a rapid transition to a reliable, cost effective, and low carbon future."

II. PURPOSE OF TESTIMONY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to discuss one of the flaws in DTE's Strategist modeling that would prevent proper optimization of new resources, outline the Strategist modeling I performed for this case, explain key aspects of Strategist's capabilities, and provide my opinion on where DTE ought to move for modeling purposes in its next IRP/CON case.

Q: Please summarize your testimony.

A: My testimony describes the changes I made to DTE's Strategist modeling at the direction of ELPC, et al. witnesses Kevin Lucas and Joe Daniel and MiEIBC witness Douglas Jester. Then I will discuss how Strategist's functionalities impact its results as well as the ability to extract certain information from those results. Finally, with ABB no longer supporting Strategist, I will offer my opinion about the type of IRP model DTE should license for future planning related cases.

III. FLAWS PREVENTING PROPER OPTIMIZATION OF NEW UNITS

Q: What problems with DTE's optimization within Strategist did you encounter?

A: I won't belabor the problems discussed by my co-witnesses Lucas, Jester, Woychik, and Daniel such as the fixing of DTE's "Starting Point". Instead, I want to call to the Commission's attention an additional way in which DTE used Strategist that is, in my view, improper modeling that biases the modeling results.

DTE modeled several units including new combined cycles, new peakers, and some existing peakers as being able to dispatch only at their minimum and maximum capacities. I believe this to be the reason that some of these units operate at extremely high capacity factors, e.g., Renaissance Peaker Unit 1 has a capacity factor in the double digits in every year of the planning period and oftentimes well over [redacted]. The plant as a whole achieved its highest capacity factor over the past seven years, 15.28%, in 2016 according to EIA data. Even more concerning is the simulated operation of the new 1x1 combined cycles. Because they can only operate at their max and min levels, a new 1x1 has a capacity factor in excess of [redacted] in every year (see WP AS-2) except the first year it is online.[2]. This is an extremely surprising and poor modeling choice that would almost certainly bias the modeling in favor of the construction of a 1x1 because its cost is offset by significant off-system sales revenue. I am further mystified that DTE would choose to represent these units in this manner because it is clearly not how combined cycles are actually operated, and DTE specified more disaggregated capacity segments[3] for many of its other units including the Blue Water Energy Center.

IV. STRATEGIST'S CAPABILITIES AND LIMITATIONS

Q: Please describe the capabilities and limitations of Strategist.

A: Strategist is a well-known, well established planning tool that has been around for decades. It has served its clients well in IRP and other similar regulatory cases, but as with any model, it has its limitations. Strategist is what is known as a dynamic programming model, which means, at a high level, that it determines every feasible

[2] This is simply an artifact of the online month being [redacted] , while the unit's capacity factor is calculated over the whole year

[3] Capacity segments, as defined in Strategist, are the loading levels at which a power plant can be dispatched. For example, a hypothetical 200 MW thermal generator with capacity segments defined at the 50, 150 and 200 MW levels would have three capacity segments.

combination of resources in each year of the optimization.[4] However, because the number of feasible "states" as Strategist calls it, can become incredibly large, it is difficult to perform a true optimization of all resources. Strategist has limits on the number of states it will save. The "truncation" of those states can sometimes result in the elimination of what would otherwise be the least-cost plan. Even if truncation can be avoided, evaluation of too many resources can lead to model run times that are impractically long, i.e., days long. The modeler has essentially two options to deal with this issue: 1) iteratively test different combinations of resources until the least cost plan is determined or 2) create different and distinct portfolios of resources that are tested under the same scenarios and sensitivities.

Q: Which option did DTE choose to address these limitations in Strategist?

A: DTE did not appear to fully develop either solution. That is, it did not iteratively test different combinations of resources to reach its preferred plan, nor did it create different and distinct portfolios of resources to test under the same scenarios and sensitivities. DTE did a little of both, i.e., testing different levels of energy efficiency and creating four Reference Case planned course of action ("PCA") plans, but I would not characterize these runs as adequately capturing the possible economic permutations of its available resources. Nor did DTE's supplemental modeling relieve this concern.

V. STRATEGIST MODELING

Q: What changes were you directed to make to DTE's Strategist modeling?

A: The changes I made to DTE's Strategist modeling focused on three issues:

[4] A more thorough description of Strategist's dynamic programming logic is contained in its user manual, which has been made available only to direct users of Strategist in this case.

1. I modified certain solar related inputs per SEIA Witness Kevin Lucas' direction including solar price, effective load carrying capability ("ELCC"), and escalation rate. The specific changes are discussed in the testimony of Witness Lucas.
2. At the direction of UCS witness Joseph Daniel, I removed DTE's "must run" constraints on its coal and peaker units.
3. At the direction of MiEIBC witness Douglas Jester and SEIA witness Kevin Lucas, I performed several runs to test DTE's "superfluous" settings for renewable units available to the model.

Each of these changes is described in more detail below.

Q: What solar related inputs do you modify?

A: I modified the "SITC" solar unit cost, i.e., "Base Year Revenue Requirements", its ELCC value, i.e. "Percent Firm", and Escalation Rate per the inputs developed by Witness Lucas. Two main factors prevented Strategist from selecting solar prior to 2029, the first was DTE's settings preventing the selection of superfluous units and the second was that the Belle River units were not modeled with all of their costs, specifically fixed costs, which makes testing early retirement of those units largely meaningless.

Q: Please explain the term "superfluous units".

A: Superfluous units, in Strategist nomenclature, are the number of any given resource alternative that can be chosen in any year that resource is available even if minimum reliability constraints, e.g. reserve margin, have already been met. If the number of superfluous units is set to zero, then no additional units can be selected even if the selection of those units reduces the overall cost of the plan. If the number of superfluous units is set at a value of 1 or greater, than Strategist may add that unit if its reduces plan cost so long as maximum reliability constraints are not violated, e.g. the maximum reserve margin.

Q: Why is this important?

A: Though DTE Witness Mikulan has characterized DTE's modeling as considering "all supply and demand-side resource options…on equal merit "[5] DTE's Reference PCA cases and it supplemental Reference Case all assume that no superfluous units can be chosen. DTE prevents the selection of superfluous units despite the fact that the Strategist manual specifically states:

[redacted]

[5] Mikulan Direct at 63, 12 – 13.

[redacted]

[redacted]

Q: Should DTE have allowed each new resource alternative at least one superfluous unit?

A: Doing so would have very likely made the model run time untenably long and/or created a truncation issue. The solution is to make incremental changes to test whether relaxing settings such as the number of superfluous units results in a lower cost plan.

Q: Did DTE perform one or more runs relaxing the superfluous unit settings?

A: If it did, DTE did not share those runs with intervenors. Further, if it did perform those runs it absolutely should have made them part of its filing because of the Strategist manual's specific warning and because adding superfluous units does indeed result in a lower cost plan.

Q: Did you perform one or more runs relaxing the superfluous unit settings?

A: I did. On behalf of MiBEIC Witness Jester I added one superfluous wind unit available in 2021 to DTE's Reference Case runs provided in response to STDE 2.3-b. While the run "truncated" meaning there may be an even lower cost plan, the PVRR of this run was $14,315,136,000 (*see* WP AS-3) whereas the PVRR of DTE's Reference Case run, i.e. without superfluous units was $14,346,133,000.

It wasn't possible to let Strategist optimize superfluous units without encountering run time and/or truncation issues, so I also performed several runs that hardcoded additional wind and solar into DTE's reference case run in combination with the solar specific inputs provided to me by Witness Lucas.

Q: Which units did you hardcode and why?

A: Because of the inability to optimize all superfluous units simultaneously, the lack of time, and the inability to correct many of the other flaws in DTE's modeling, hardcoding these units was the most efficient way to develop a substantially different expansion plan. I determined the least-cost new wind and solar units in Strategist, after Witness Lucas' solar cost modifications, and constructed two portfolios that forced in different combinations of those units and of energy efficiency at the latest possible date so as to minimize the number of years with excess capacity. These portfolios are not optimized for timing or even necessarily for the quantity of wind, solar, and demand side management. They were merely done to demonstrate how important DTE's assumptions about solar and its limitations on superfluous units would be to the modeling results. The results of these runs are discussed in the testimony of Witness Lucas.

Q: What change did you make to DTE's "must run" constraints?

A: As I described previously, thermal units in Strategist are dispatched by modeler defined capacity "segments." The first segment normally approximates the minimum loading level of a power plant. It is possible to set this first segment to, in effect, always run. This setting is know as a "must run" indicator. DTE applied this indicator to the majority of its coal and peaking power plants. To test the impact of this must run indicator on the dispatch of those plants, I turned off the indicator applied to all thermal units except Fermi in the Reference Case 2040 plan provided in response to STDE 2.3-b and reran the optimization. The results of that modeling run are discussed in the testimony of Witness Joseph Daniel.

Q: Would you characterize your modeling as identifying the least-cost, least-risk plan?

A: No, it was not possible for me to do so. As described in my and in the testimonies of Witnesses Lucas, Jester, Woychik, and Daniel, there were so many significant issues with both DTE's original and supplemental modeling that it was not possible to correct for all the identified problems.

III. RECOMMENDATIONS FOR FUTURE PLANNING DOCKETS

Q: What modeling software would you recommend that DTE use for future planning related dockets?

A: ABB, Strategist's vendor, will, in the future, no longer support the software. This is an opportunity to move to a model with more detailed resource optimization and dispatch capabilities. However, I am very concerned that utilities are adopting models that decrease transparency around their modeling, when transparency should be increasing. IRP models are inherently complex; there is no getting around that. However, it is my firm belief that modeling results will be more robust and lead to better long term planning if vendors and utilities make their models as accessible and transparent as possible. Some key ingredients in making those models transparent are:

1) the ability to provide the entirety of the modeling database in a format that is readable without a model license;[6]

[6] An alternative may be to offer a read-only copy of the model, but at least one firm, Energy Exemplar, the vendor for Aurora and Plexos, has told me that it would expect intervenors to pay several thousand dollars for access to a read-only license.

2) a well-documented manual, available to non-licensees, that details the logic of the model, the definitions of the inputs and outputs, and provides guidance on its use; and

3) the ability to license the model at a reasonable cost if a license is not otherwise provided by the utility.

Each is critical, but they are listed in order of priority. The first is essential because every model has settings that can dramatically influence the results, e.g. superfluous unit settings in Strategist. Even if I did not have access to a Strategist license for this case, I would be able to see DTE's superfluous unit settings because that information is exported in Strategist's standard input reports. Other models have related, model-specific settings such as restrictions on the total amount of a resource than can be selected, restrictions on the total amount of a resource that can be selected in any one year, restrictions on selecting resources at the same time, etc. that are enormously consequential for modeling results. It has been my direct experience in my many years of reviewing IRP modeling that there is no substitute for being able to personally view and verify those all inputs.[7] Second, a well-documented manual is essential in understanding how each model works. The logic of capacity selection and dispatch can be different, even between models of a similar type, e.g. all dynamic programming models. Also, there are often terms used that have no commonly-held meaning outside of that particular model. For example, a key input for renewables in DTE's modeling is "seasonal transaction capacity." Although it may sound that way, this input is not necessarily the nameplate value of a transaction by

[7] By "inputs" I do not mean merely the prototypical information like the load forecast, fuel prices, market prices, and so on which are normally easily shareable, I also mean the model-specific settings, which many new models have difficulty exporting.

season. Having the Strategist manual is very useful in understanding what that input means and how it is used. While I had access to the Strategist Manual in this case, I was directed by counsel that ABB and DTE would not permit me to share the manual with any of the expert witnesses for whom I was performing modeling runs.

Finally, the ability to license the model at reasonable cost ensures that the utility is not the only entity capable of using its modeling software. This could be done by allowing project-based licenses for specific cases, as ABB does for Strategist, by directing the utility to make modeling licenses available to intervenors, or by choosing a model with a reasonable licensing fee to begin with.

Q: Does this conclude your testimony?

A: Yes.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
DTE ELECTRIC COMPANY	)	Case No. U-20471
for approval of its integrated resource plan	)	
pursuant to MCL 460.6t, and for other relief	)	

EXHIBITS OF

ANNA SOMMER

ON BEHALF OF

THE ENVIRONMENTAL LAW & POLICY CENTER,
THE ECOLOGY CENTER,
THE SOLAR ENERGY INDUSTRIES ASSOCIATION,
THE UNION OF CONCERNED SCIENTISTS,
AND
VOTE SOLAR

AND ON BEHALF OF
THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL

AUGUST 21, 2019

ANNA SOMMER, PRINCIPAL

EDUCATION

M.S. Energy and Resources, University of California Berkeley, 2010

Master's Project: *The Water and Energy Nexus: Estimating Consumptive Water Use from Carbon Capture at Pulverized Coal Plants with a Case Study of the Upper Colorado River Basin*

B.S., Economics and Environmental Studies, Tufts University, 2003

ADDITIONAL TRAINING

Graduate coursework in Data Analytics – Clarkson University, 2015 – 2016.
Graduate coursework in Civil Engineering and Applied Mechanics – McGill University, 2010.
Research Experience in Carbon Sequestration (RECS), 2009.

EXPERIENCE

2019-present: Principal, Energy Futures Group, Hinesburg, VT
2010-2019: President, Sommer Energy, LLC, Canton, NY
2007-2008: Project Manager, Energy Solutions, Oakland, CA
2003-2007: Research Associate, Synapse Energy Economics, Cambridge, MA

PROFESSIONAL SUMMARY

Anna Sommer is a principal of Energy Futures Group in Hinesburg, Vermont. She has more than 15 years' experience working on a wide variety of energy planning related issues. Her primary focus is on all aspects of integrated resource planning (IRP) including capacity expansion and production costing simulation, scenario and sensitivity construction, modeling of supply and demand side resources, forecast inputs such as fuel prices, wholesale market prices, etc., and reviewing and critiquing load forecasts. Additionally, she has experience with various aspects of DSM planning including construction of avoided costs and connecting IRPs to subsequent DSM plans. Anna is trained to run the Strategist and EnCompass models and has reviewed modeling performed using numerous models including AURORA, Capacity Expansion Model, Plexos, PowerSimm, PROSYM, PROMOD, SERVM and System Optimizer. She has provided expert testimony in front of utility commissions in Indiana, Minnesota, New Mexico, North Carolina, Puerto Rico, and South Dakota.

SELECTED PROJECTS

- ***Coalition for Clean Affordable Energy*** – Evaluation of Public Service Company of New Mexico's abandonment and replacement of the San Juan Generation Station. (2019 to present)
- ***Minnesota Center for Environmental Advocacy*** – Evaluation of Xcel Energy's 2020 Integrated Resource Plan and Strategist modeling in support of that evaluation. (2019 – present)
- ***Environmental Law and Policy Center*** – Evaluation of DTE Energy's 2019 Integrated Resource Plan modeling and Strategist modeling in support of that evaluation. (2019 – present)

- *Institute for Energy Economics and Financial Analysis and Earthjustice* – Evaluation of the Puerto Rico Electric Power Authority's 2019 Integrated Resource Plan. (2019 to present)
- *Citizens Action Coalition of Indiana* - Advising stakeholders on stakeholder workshops in preparation for Southern Indiana Gas and Electric's integrated resource plans to meet future energy and capacity needs. (2019 to present)
- *Citizens Action Coalition of Indiana* – Advising stakeholders on stakeholder workshops in preparation for Indianapolis Power & Light's integrated resource plans to meet future energy and capacity needs. (2019 to present)
- *Citizens Action Coalition of Indiana* – Advising stakeholders on stakeholder workshops in preparation for Duke Energy Indiana's integrated resource plans to meet future energy and capacity needs and reviewing and critiquing DEI's IRP filing. (2018 to present)
- *Citizens Action Coalition of Indiana* – Advising stakeholders on stakeholder workshops in preparation for Indiana Michigan Power Company's integrated resource plans to meet future energy and capacity needs and reviewing and critiquing I&M's IRP filing. (2018 to present)
- *Citizens Action Coalition of Indiana* – Comments on Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (2019)
- *Citizens Action Coalition of Indiana* – Evaluation of Southern Indiana Gas and Electric's proposal to build a new natural gas combined cycle power plant. (2018)
- *Minnesota Center for Environmental Advocacy* – Evaluation of Minnesota Power Company's proposal to build a new natural gas combined cycle power plant and Strategist modeling of alternatives to the plant. (2018)
- *Minnesota Center for Environmental Advocacy* – Comments regarding Great River Energy's integrated resource plan to meet future energy and capacity needs. (2018)
- *New Energy Economy* – Evaluation of Public Service Company of New Mexico's Strategist modeling of coal plant retirement scenarios. (2017)
- *Citizens Action Coalition of Indiana* – Evaluation of Duke Energy Indiana's proposal to offer DSM programs to its customers. (2017)
- *Citizens Action Coalition of Indiana* – Evaluation of Southern Indiana Gas and Electric's proposal to offer DSM programs to its customers. (2017)
- *Institute for Energy Economics and Financial Analysis* - Evaluation of Puerto Rico Electric Power Authority's plan to build an offshore LNG port. (2017)
- *Citizens Action Coalition of Indiana* – Comments regarding Southern Indiana Gas and Electric Company's integrated resource plans to meet future energy and capacity needs. (2017)

ANNA SOMMER, PRINCIPAL

- *Citizens Action Coalition of Indiana* – Comments regarding Indianapolis Power & Light's integrated resource plan to meet future energy and capacity needs. (2017)
- *Citizens Action Coalition of Indiana* – Comments regarding Northern Indiana Public Service Company's integrated resource plan to meet future energy and capacity needs. (2017)
- *Minnesota Center for Environmental Advocacy* – Comments regarding Otter Tail Power's integrated resource plan to meet future energy and capacity needs. (2016)
- *Minnesota Center for Environmental Advocacy* – Comments regarding Xcel Energy's integrated resource plan to meet future energy and capacity needs and conducting Strategist modeling of additional planning scenarios. (2016)
- *Institute for Energy Economics and Financial Analysis* – Evaluation of Puerto Rico Electric Power Authority's proposal to meet future energy and capacity needs. (2016)
- *Minnesota Center for Environmental Advocacy* – Comments regarding Minnesota Power's integrated resource plan to meet future energy and capacity needs. (2016)
- *Institute for Energy Economics and Financial Analysis* – Comments regarding Duke Energy Indiana and Indiana Michigan Power's integrated resource plans to meet future energy and capacity needs. (2016)
- *Minnesota Center for Environmental Advocacy* – Comments regarding Great River Energy's integrated resource plan to meet future energy and capacity needs. (2015)
- *Minnesota Center for Environmental Advocacy* – Comments regarding Otter Tail Power's integrated resource plan to meet future energy and capacity needs. (2014)
- *Minnesota Center for Environmental Advocacy* – Comments regarding Xcel Energy's Sherco 1 and 2 Life-Cycle Management Study. (2013)
- *Minnesota Center for Environmental Advocacy* – Comments regarding Minnesota Power's proposal to retrofit Boswell Unit 4. (2013)
- *Minnesota Center for Environmental Advocacy* – Comments regarding Minnesota Power's integrated resource plan to meet future energy and capacity needs. (2013)
- *Minnesota Center for Environmental Advocacy* – Comments regarding Xcel Energy's integrated resource plan to meet future energy and capacity needs. (2013)
- *Minnesota Center for Environmental Advocacy* – Evaluation of Otter Tail Power's plan to diversify its baseload resources. (2012)
- *Minnesota Center for Environmental Advocacy* – Comments regarding Minnesota Power's "Baseload Diversification Study" – a resource planning exercise examining the use of fuels other than coal to serve baseload needs. (2012)
- *Minnesota Center for Environmental Advocacy* – Comments regarding IPL's integrated resource plan to comply with pending EPA regulations and meet future capacity and energy needs. (2011)

- *Minnesota Center for Environmental Advocacy* – Evaluation of a proposal by seven utilities to build a new supercritical pulverized coal plant including alternatives to the plant and potential for greenhouse gas regulation. (2006)
- *Nova Scotia Utility and Review Board* – Evaluation of Nova Scotia Power's air emissions reduction strategy including its proposal to put a scrubber on Lingan Station. (2006)

PUBLICATIONS

- The Husker Energy Plan: A New Energy Plan for Nebraska, prepared by Anna Sommer, Tyler Comings, and Elizabeth Stanton for the Nebraska Wildlife Federation. January 16, 2018.
- Pennsylvania Long-Term Renewables Contracts Benefits and Costs, prepared by Elizabeth Stanton, Anna Sommer, Tyler Comings, and Rachel Wilson for the Mid-Atlantic Renewable Energy Coalition. October 27, 2017.
- Implementing EPA's Clean Power Plan: A Menu of Options [Pursue Capture Capture and Utilization or Storage, Establish Energy Savings Targets for Utilities, & Tax Carbon Dioxide Emissions chapters], prepared by Anna Sommer for the National Association of Clean Air Agencies and the Regulatory Assistance Project. June 7, 2015.
- Overpaying and Underperforming: The Edwardsport IGCC Project, prepared by Anna Sommer for Citizens' Action Coalition, Save the Valley, Valley Watch, and Sierra Club. February 3, 2015.
- Public Utility Regulation Without the Public: The Alabama Public Service Commission and Alabama Power, prepared by David Schlissel and Anna Sommer for Arise Citizens' Policy Project. March 1, 2013.
- A Texas Electric Capacity Market: The Wrong Tool for a Real Problem, prepared by Anna Sommer and David Schlissel for Public Citizen of Texas. February 12, 2013.
- Best Practices in Designing and Implementing Energy Efficiency Obligation Schemes, prepared by John Gerhard, Camille Kadoch, Edith Pike-Biegunska, Anna Sommer, Wang Xuan, Nancy Wasserman and Elizabeth Watson for the International Energy Agency. June 2012.
- A Study of the Economics and Risks of Operation of Boiler 4 by the New Ulm Public Utilities Commission, prepared by Anna Sommer for Sierra Club – Northstar Chapter and Minnesota Center for Environmental Advocacy. July 15, 2011.
- Comments on the Technical Memorandum for the Georgia Statewide Energy Sector Water Demand Forecast, prepared by Anna Sommer and David Schlissel for the Southern Alliance for Clean Energy. June 22, 2011.
- Don't Get Burned: The Risks of Investing in New Coal-Fired Generating Facilities, prepared by David Schlissel, Lucy Johnston, Jennifer Kallay, Christopher James, Anna Sommer, Bruce Biewald, Ezra Hausman and Allison Smith for Interfaith Center of Corporate Responsibility. February 26, 2008.

ANNA SOMMER, PRINCIPAL

- Quantifying and Controlling Fine Particulate Matter in New York City, prepared by Alice Napoleon, Geoff Keith, Charles Komanoff, Daniel Gutman, Patricio Silva, David Schlissel, Anna Sommer, Cliff Chen and Amy Roschelle for Coalition Helping Organize a Kleaner Environment, Natural Resources Defense Council and Reliant Energy. August 28, 2007.
- Independent Administration of Energy Efficiency Programs: A Model for North Carolina, prepared by David Nichols, Anna Sommer and William Steinhurst for Clean Water for North Carolina. April 13, 2007.
- Integrated Portfolio Management in a Restructured Supply Market, prepared by Paul Chernick, Jonathan Wallach, William Steinhurst, Tim Woolf, Anna Sommer and Kenji Takahashi. June 30, 2006.
- Ensuring Delaware's Energy Future: A Response to Executive Order No. 82, prepared by the Delaware Cabinet Committee on Energy with technical assistance at Synapse Energy Economics from William Steinhurst, Bruce Biewald, David White, Kenji Takahashi, Alice Napoleon, Amy Roschelle, Anna Sommer and Ezra Hausman. March 8, 2006.
- Mohave Alternatives and Complements Study: Assessment of Carbon Sequestration Feasibility and Markets, a Sargent & Lundy and Synapse Energy Economics, Inc. report prepared for Southern California Edison by Anna Sommer and William Steinhurst. February 2006.
- Potential Cost Impacts of a Renewable Portfolio Standard in New Brunswick, prepared by Tim Woolf, David White, Cliff Chen and Anna Sommer for the New Brunswick Department of Energy. October 2005.
- Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value, a Synapse Energy Economics, Inc. report prepared by Lucy Johnston, Amy Roschelle, Ezra Hausman, Anna Sommer and Bruce Biewald. September 20, 2005.
- Potential Cost Impacts of a Vermont Renewable Portfolio Standard, a Synapse Energy Economics, Inc. report prepared for the Vermont Public Service Board, by Tim Woolf, David E. White, Cliff Chen, and Anna Sommer. October 16, 2003.
- Estimating the Environmental Benefits of Renewable Energy and Energy Efficiency in North America: Experience and Methods, a report for the Commission for Environmental Cooperation, by Geoffrey Keith, Bruce Biewald, Anna Sommer, Patrick Henn, and Miguel Breceda, September 22, 2003.
- Comments on the RPS Cost Analyses of the Joint Utilities and the DPS Staff, a Synapse Energy Economics, Inc. report prepared for the Renewable Energy Technology and Environment Coalition, by Bruce Biewald, Cliff Chen, Anna Sommer, William Steinhurst, and David E. White. September 19, 2003.
- Cleaner Air, Fuel Diversity and High-Quality Jobs: Reviewing Selected Potential Benefits of an RPS in New York State, a Synapse Energy Economics, Inc. report prepared for the Renewable Energy Technology and Environment Coalition, by Geoff Keith, Bruce Biewald, David White, Anna Sommer and Cliff Chen. July 28, 2003.

ANNA SOMMER, PRINCIPAL

PRESENTATIONS AND ARTICLES

- "Practical Strategies for the Electricity Transition." A presentation at Energy Finance 2019. June 18, 2019.
- "Carbon Capture and Storage." A presentation at Energy Finance 2018. March 13, 2018.
- "Puerto Rico's Electric System, Before and After Hurricane Maria." A webinar with Cathy Kunkel on behalf of the Institute for Energy Economics and Financial Analysis. October 24, 2017.
- "Rebutting Myths About Energy Efficiency." A presentation at the Beyond Coal to Clean Energy Conference sponsored by Sierra Club and Energy Foundation. October 8, 2015.
- "The Energy and Water Nexus: Carbon Capture and Water." A presentation at the Water and Energy Sustainability Symposium. September 28, 2010.
- "Carbon Sequestration." A presentation to Vermont Energy Investment Corporation. August 17, 2009.
- "Carbon Dioxide Emissions Costs and Electricity Resource Planning." A presentation before the New Mexico Public Regulation Commission with David Schlissel. March 28, 2007.
- "Electricity Supply Prices in Deregulated Markets – The Problem and Potential Responses." A presentation at the NASUCA Mid-Year Meeting with Rick Hornby and Ezra Hausman. June 13, 2006.
- "IGCC: A Public Interest Perspective." A presentation at the Electric Utilities Environmental Conference 2006. January 24, 2006.
- Woolf, Tim, Anna Sommer, John Nielsen, David Barry and Ronald Lehr. "Managing Electric Industry Risk with Clean and Efficient Resources," The Electricity Journal, Volume 18, Issue 2, March 2005.
- Woolf, Tim and Anna Sommer. "Local Policy Measures to Improve Air Quality: A Case Study of Queens County, New York," Local Environment, Volume 9, Number 1, February 2004.

PROFESSIONAL AFFILIATIONS

- Board Member, **Public Utility Law Project of New York,** 2018 – present
- Board Member, **Community Development Program of St. Lawrence County,** 2017 – present

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE Electric Company** for approval of its integrated resource plan pursuant to MCL 460.6t, and for other relief.	)))))	Case No. U-20471

PROOF OF SERVICE

I hereby certify that a true copy of the foregoing *Direct Testimony and Exhibits ELP-1 through ELP-76 on behalf of the Environmental Law & Policy Center, the Ecology Center, the Solar Energy Industries Association, the Union of Concerned Scientists, and Vote Solar (and Michigan Energy Innovation Business Council)* was served by electronic mail upon the following Parties of Record, this 21st of August, 2019.

Administrative Law Judge Sally Wallace	wallaces2@michigan.gov
MPSC Staff Heather M.S. Durian Daniel Sonneveldt Amit T. Singh Benjamin J. Holwerda Sarah Mulkoff	durianh@michigan.gov sonneveldtd@michigan.gov singha9@michigan.gov holwerdab@michigan.gov mullkoffs1@michigan.gov
Attorney General Joel B. King Michael Deupree David Dismukes	kingj38@michigan.gov MichaelDeupree@acadianconsulting.com DavidDismukes@acadianconsulting.com ag-enra-spec-lit@michigan.gov
DTE Energy Lauren D. Donofrio Martin L. Heiser Kevin O'Neill Sarah Mullkoff	lauren.donofrio@dteenergy.com martin.heiser@dteenergy.com kevin.oneill@dteenergy.com mullkoffs1@michigan.gov mpscfilings@dteenergy.com
ITC Transmission Richard J. Aaron Courtney F. Kissel	raaron@dykema.com ckissel@dkyema.com

Michigan Environmental Council; Natural Resources Defense Council; Sierra Club Christopher M. Bzdok Tracy Jane Andrews Lydia Barbash-Riley	chris@envlaw.com tjandrews@envlaw.com Lydia@envlaw.com
Great Lakes Renewable Energy Association Don L. Keskey Brian W. Coyer	donkeskey@publiclawresourcecenter.com bwcoyer@publiclawresourcecenter.com
ABATE Bryan A. Brandenburg Michael J. Pattwell Brian C. Andrews James R. Dauphinais Colin Fitzhenry	bbrandenburg@clarkhill.com mpattwell@clarkhill.com bandrews@consultbai.com jdauphinais@consultbai.com cfitzhenry@consultbai.com mdecker@consultbai.com
Heelstone Development, LLC; Midland Cogeneration Venture, LP Jason T. Hanselman John A. Janiszewski	jhanselman@dykema.com jjaniszewski@dykema.com
Cypress Creek Renewables Jennifer Utter Heston	jheston@fraserlawfirm.com
City of Ann Arbor; Geronimo Energy Timothy Lundgren Justin Ooms Matt Rechtien	tjlundgren@varnumlaw.com jkooms@varnumlaw.com mrechtien@a2gov.org
Convergen Energy, LLC Tim Lundgren Laura Chappelle	tjlundgren@varnumlaw.com lachappelle@varnumlaw.com
Energy Michigan Tim Lundgren Laura Chappelle Justin K. Ooms Alex Zakem Energy Michigan	tjlundgren@varnumlaw.com lachappelle@varnumlaw.com jkooms@varnumlaw.com ajz-consulting@comcast.net
Michigan Energy Innovation Business Council and the Institute for Energy Innovation Laura A. Chappelle Toni L. Newell	lachappelle@varnumlaw.com tlnewell@varnumlaw.com

Michigan Public Power Agency Peter H. Ellsworth Nolan J. Moody	pellsworth@dickinsonwright.com nmoody@dickinsonwright.com
Soulardarity Robert A. Weinstock Mark N. Templeton Rebecca Boyd	rweinstock@uchicago.edu templeton@uchicago.edu rebecca.j.boyd@gmail.com

Margrethe Kearney
Environmental Law & Policy Center
MKearney@elpc.org