OLSON, BZDOK & HOWARD

January 12, 2018

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

Via E-filing

RE: MPSC Case No. U-18419

Dear Ms. Kale:

The following is attached for paperless electronic filing:

Direct Testimony of Robert Fagan on behalf of the Michigan Environmental Council, the Natural Resources Defense Council and Sierra Club

Exhibits MEC-90 and MEC-108

Proof of Service

Sincerely,

Digitally signed by Christopher M. Bzdok
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James Clift, MEC
Ariana Gonzalez and Rachel Fakhry, NRDC
Elena Saxonhouse, Sierra Club
Shannon Fisk, Jill Tauber and Cassandra McCrae, Earthjustice
Robert Fagan

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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 it generation fleet and for related accounting and ratemaking authorizations	U-18419 ALJ Suzanne D. Sonneborn

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DIRECT TESTIMONY OF ROBERT FAGAN

ON BEHALF OF MICHIGAN ENVIRONMENTAL COUNCIL, NATURAL RESOURCES DEFENSE COUNCIL, AND SIERRA CLUB

JANUARY 12, 2018

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I. Introduction

Q. Please state your name and occupation.

A. My name is Robert M. Fagan and I am a Principal Associate at Synapse Energy Economics.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in electricity industry regulation, planning, and analysis. Synapse works for a variety of clients, with an emphasis on consumer advocates, regulatory commissions, and environmental advocates.

Q. Have you testified in Michigan before?

A. Yes. I provided Direct Testimony in MPSC Case No. U-18255, addressing issues concerning the retirement of DTE's Tier 2 coal plants and the related MISO resource adequacy construct. I have also testified in numerous state and provincial jurisdictions over the years, and at FERC.

Q. Please summarize your qualifications.

A. I am a mechanical engineer and energy economics analyst, and I've analyzed energy industry issues for more than 25 years. My activities focus on many aspects of the electric power industry, in particular: production cost modeling of electric power systems, general economic and technical analysis of electric supply and delivery systems, wholesale and retail electricity provision, energy and capacity market structures, renewable resource alternatives, including wind and solar photovoltaic, and assessment and implementation of energy efficiency and demand response alternatives. I hold an MA from Boston University in energy and environmental studies and a BS from Clarkson University in mechanical engineering. My resume is included as Exhibit MEC-90 hereto.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club.

Q. What is the purpose of your testimony.

A. The primary purpose of my testimony is to evaluate DTE's claimed need for the proposed 1,100 MW natural gas combined cycle (NGCC) plant in 2022, or at any time prior to 2030, based on the results of Strategist modeling undertaken by MEC witness Mr. George Evans. I also utilize the findings of MEC witnesses Chris Neme, Douglas Jester, and Avi Allison, and my own findings, in addressing DTE's Strategist modeling results. I focus on the input assumptions used by DTE, in particular those for energy efficiency, demand response, renewable, and capacity import resources available to serve DTE's ratepayers.

Q. What documents do you rely upon in your analysis, and for your findings and observations?

A. I rely primarily upon DTE's application and responses to discovery; testimony from other MEC-NRDC-SC experts; the 2017 MISO OMS Survey results on resource adequacy, which is attached as **Exhibit MEC-91**; and the results of the 2017 MISO Planning Resource Auction (PRA), which is attached as **Exhibit MEC-92**. I also include references to additional material I used to develop this testimony.

Q. Are you sponsoring any exhibits?

A. Yes.

Exhibit MEC-90. Resume of Robert Fagan.

Exhibit MEC-91. 2017 MISO OMS Survey Results on Resource Adequacy.

Exhibit MEC-92.	2017/2018 MISO PRA Results.
Exhibit MEC-93.	Consumers Energy Dec 1, 2017 filing in Case No. U-18441.
Exhibit MEC-94.	2018/2019 LOLE Report.
Exhibit MEC-95.	Near Term MISO LOLEWG Presentation.
Exhibit MEC-96.	Out Year 2021 MISO LOLEWG Presentation.
Exhibit MEC-97.	MISO EUPG Presentation.
Exhibit MEC-98.	Lazard's Levelized Cost of Storage Analysis – Version 3.0.
Exhibit MEC-99.	MISO Generation Interconnection Public Queue Data (Sheet 1).
Exhibit MEC-100.	US DOE/EERE 2016 Wind Technologies Market Report.
Exhibit MEC-101.	Lawrence Berkely Nat'l Laboratory, Utility Scale Solar 2016.
Exhibit MEC-102.	2016 MISO OMS Survey.
Exhibit MEC-103.	NERC Long-Term Resource Assessments for 2014, 2015, 2016, and 2017.
Exhibit MEC-104.	NERC 2017 Summer Assessment.
Exhibit MEC-105.	MISO 2017/2018 Wind Capacity Credit Report.
Exhibit MEC-106.	MISO MTEP14 MVP Triennial Review.
Exhibit MEC-107.	Regionally Cost Allocated Project Reporting Analysis.
Exhibit MEC-108.	MISO Summer Peak Analysis 2017.

II. Summary of Findings and Testimony Structure

Q. Please summarize your findings.

A. My main findings are as follows:

- Based on the evidence of Mr. George Evans, which includes corrections made to Strategist modeling inputs (which use underlying DTE resource portfolio options), the proposed NGCC plant is not needed in 2022, and is seen to be not needed until 2029. The corrected Strategist run indicates a potential net present value ("NPV") savings of $1.882 billion for DTE customers when deferring the NGCC plant to 2029, and implementing a resource portfolio consisting of energy efficiency, demand response, renewable resources, and capacity purchases.

- Reasoned adjustments to DTE's modeling input parameters for energy efficiency, demand response, capacity import options, and renewables results in alternative resource portfolios that exhibit NPV savings compared to DTE's reference case plan. Using a 2% energy efficiency portfolio as described in Mr. Chris Neme's testimony, "low" demand response additions as described in Mr. Douglas Jester's testimony, and increasing the availability of capacity purchase options to 600 MW leads to deferring the need for the proposed NGCC plant to 2030, while saving DTE ratepayers $2.489 billion compared to their 2016 reference case, or $823 million compared to DTE's 2017 reference case. When the 2017 reference case is further adjusted to correct DTE's apparent heat rate errors described in Mr. Evans' testimony, the savings to customers of the combined alternative scenario increases to $1.272 billion.
- DTE's 2017 reference case analysis indicates that the Tier 2 coal plant (St. Clair units 1-4,[1] 6 and 7; River Rouge 3; and Trenton Channel 9) operations are uneconomic over the near term. DTE's Strategist modeling, however, "forced in" these units, requiring them to continue operating until their announced retirement dates.[2] Given the apparent

[1] It is my understanding that St. Clair 4 is either retired now or will be retired in 2018. Case No. U-18255, Response and Supplemental Response to STDE-5.50.

[2] Exhibit A-4 Revised. Page 189. "Coal and nuclear units were modeled as must-run units, as they are designed to cycle online and offline for short periods of time."

uneconomic nature of the Tier 2 coal units, and the adequate levels of resources that DTE can obtain (as discussed in my testimony below), the Company should thoroughly evaluate the orderly retirement of the Tier 2 coal units before their announced retirement dates so that the lowest cost approach for customers can be pursued

Q. How is your testimony structured?

A. After my introduction and summary findings, I address Mr. George Evans's corrections to Strategist input parameters associated with DTE's resource portfolio options. I then describe how we developed alternative resource portfolios by modifying Strategist inputs. I present Tier 2 coal plant operational data from DTE's 2017 reference case run, showing how DTE's own modeling results illustrate the extent to which those units are not cost effective in the near term (through 2023). Lastly, I provide overall recommendations stemming from our analyses.

III. Corrections to DTE's Strategist Reference Case Results

Q. What corrections did Mr. Evan's make to DTE's Strategist parameters?

A. Mr. Evans made corrections to the way in which DTE allowed Strategist to choose demand response resources, to the size of renewable resource options made available to the model, to the costs of renewable resource options and to the solar capacity credit, and to the way in which energy efficiency was accounted for in their 1.5% energy efficiency (EE) reference case. He then re-ran the model; he describes his results in his testimony.

Q. Please summarize Mr. Evans' results from those corrected Strategist runs.

A. Taken in combination, the corrections lead to a deferral of the proposed plant to 2029, and a ratepayer savings of $1.882 million (NPV).

Q. What does this mean?

A. When the Strategist construct is allowed to implement demand response resources before 2023, and when the energy efficiency associated with the 1.5% EE resource is properly modeled, and when solar and wind resources – with correct cost (wind, solar) and capacity performance (solar) - are offered as options at 50 MW (solar) and 100 MW (wind) instead of 502 MW and 1000 MW increments, the result is a different selection for the "optimal" portfolio. It excludes the proposed NGCC plant until the planned retirement of the Belle River 1 coal unit in 2029,[3] and it saves DTE ratepayers $1.882 billion (NPV).

IV. Alternative Resource Plans

Q. What do you address in this section?

A. I describe sets of specific changes made to DTE's Strategist input assumptions (beyond the corrections to DTE's reference case portfolio addressed by Mr. Evans in the corrected reference case run) and the rationale behind those changes. I reference the results of the Strategist model runs (from Mr. Evans' testimony) using those more reasonable input assumptions. The alternative resource plan results supplement the "corrected" reference case run, and clearly demonstrate that DTE's proposed NGCC plant is not needed, as alternative resource portfolios are available at a lower cost to ratepayers.

Q. Which assumptions are changed in the alternative portfolio runs?

A. Energy efficiency representation, demand response, available capacity import quantities, and renewable resources.

Q. Please summarize the steps taken to develop more reasonable input assumptions and determine a set of alternative portfolios to rerun in the Strategist model.

[3] Existing coal plant retirement schedule in Exhibit A-4 Revised, page 69, as input to Strategist by DTE.

A. DTE uses a specific set of input assumptions to support their assertion of need for the proposed NGCC plant. Mr. Evans identified deficiencies in the input parameters used by DTE when running Strategist, and corrected those deficiencies, resulting in a deferral of need for the plant, as noted above and seen as "case 0" in Table 1 below. But we also identified more reasonable input assumptions for energy efficiency, demand response, renewable resources, and capacity import options than those used by DTE in its 1.5% EE reference case. We adjusted these input assumptions, in different combinations, and re-ran the Strategist model. The results are reflected in cases 1 through 8a in Table 1 below.

Q. Why did you use this array of input assumption changes and Strategist re-executions?

A. The aim of the exercise was to demonstrate the sensitivity of the modeling outcomes to different, more reasonable input assumptions. I note that this array of changes is not exhaustive. There are numerous resources available, in some combination, to serve both capacity and energy requirements for DTE's customers. For example, two assumptions in particular that were not considered by DTE – the level of allowed capacity purchases, and the amount of energy efficiency reflected in the load forecast (or made available to the model to reduce otherwise forecasted load) – both singularly and in combination dramatically alter the Strategist outcome and defer the proposed NGCC plant to a much later year.

Q. What do you rely upon in support of the more reasonable input assumptions that you used?

A. The analysis conducted by Mr. Chris Neme supports the use of revised energy efficiency assumptions used in the alternative Strategist runs, and is explained in his testimony. The analysis of the capacity import limit issue was carried out by me, and is more fully detailed below. I rely on the testimony of Mr. Allison and Mr. Jester when addressing the input assumptions and results associated with demand response and renewable resources in some Strategist model runs. I also rely on the testimony of Mr. Dale Osborn in considering the overall magnitude of capacity imports that are available to DTE, and I conservatively suggest use of an amount even less than DTE's estimation of "ECIL" or "effective capacity import limit". I rely on my own analysis of MISO resource adequacy when assessing the availability of resources from the broader MISO region to then serve as capacity imports into Michigan, to meet resource adequacy obligations.

A. Strategist Results Demonstrate No Need for the Proposed NGCC Plant at This Time

Q. What do the results illustrate?

A. The results, shown in Mr. Evan's testimony, are reproduced below in Table 1. In short, the results illustrate that reasonably formulated alternative resource portfolios defer any need for the proposed NGCC plant to as late as 2030, and demonstrate lower cost to DTE ratepayers compared to DTE's 1.5% EE reference plan results, as indicated by the net present value revenue requirements metric output from the Strategist model.

Table 1. Alternative Portfolio Strategist Results

Case	Description	Supporting Witness	Proposed New CC Plant Deferred until:	NPV Savings Relative to Baseline (2016 $Billion)
0	Corrections to DTE Modeling	Evans, Neme, and Allison	2029	$1.882
1	2% Energy Efficiency Modeling	Neme	2030	$2.354
2	Low Demand Response Additions	Jester	2023	$0.322
3	High Demand Response Additions	Jester	2029	$0.645
4	Increased available MISO market capacity purchases to 600 MW	Fagan	2023	$0.107
5	Increased available MISO market capacity purchases to 1000 MW	Fagan	2026	$0.171
6	Increase MISO capacity purchases to 1000 MW at 2017 Reference capacity price	Fagan	2026	$0.258
7	Combined Analysis 2016 - Cases 1, 2 and 4	Neme, Jester & Fagan	2030	$2.489
8	Combined Analysis 2017 - Cases 1, 2 and 4	Neme, Jester & Fagan	2030	$0.823
8a	Combined Analysis 2017 - Cases 1, 2 and 4 – with correction to heat rate error	Neme, Jester, Fagan & Evans	2030	$1.272
9	Beach Scenario	Tom Beach	2028	$1.272

Source: Strategist Modeling Runs, Mr. George Evans.

Q. Describe each input assumption modified to produce the Alternative Portfolios shown in Table 1, and summarize the effect on NGCC plant deferral and the relative portfolio cost.

A. The input assumptions and their effects include the following:

1. **Corrections to DTE Assumptions**. As noted in the previous section, Mr. Evans corrected input parameters reflecting DTE's use of 1.5% EE, demand response, and

renewable resource attributes. Case 0 in Table 1 shows the results of the corrected run, indicating NGCC plant deferral need to 2029 and ratepayer savings of $1.882 billion (NPV).

2. **Energy Efficiency**. DTE incorrectly represented the effect of energy efficiency programs on their forecast peak load and resulting planning reserve margin requirements (PRMR). DTE assumed a much greater level of "embedded DSM" than already exists in their load when estimating the effects of a 1.5% or 2.0% energy efficiency scenario.[4] Thus, DTE's projection of the change in future peak demand and energy needs resulting from implementation of either a 1.5% or a 2.0% EE scenario was underestimated, as the Company overestimated the amount of energy efficiency already embedded in historical loads. We re-ran Strategist with a revised peak load forecast projection accounting for this deficiency. Table 1 shows that the effect, in case 1, is a deferral of need for the proposed plant until 2030, at a savings to DTE ratepayers of $2.354 billion, relative to DTE's 2016 1.5% EE reference case.

3. **Demand Response**. Mr. Douglas Jester identifies a modified set of demand response resources for inclusion as a portfolio option for Strategist to consider. He presents two alternative portfolio options, one with "low" demand response resources, and one with a "high" level of resource. As seen in cases 2 and 3 in Table 1, each of the options, on their own, are chosen by Strategist and each lead to a deferral of the proposed NGCC plant and net savings for ratepayers; until 2023 for the low demand response alternative, with a ratepayer NPV savings of $322 million, and until 2029 for the high demand response alternative, with a savings of $645 million.

[4] *See* Neme Direct.

4. **Import Capacity**. DTE consistently - in both its 2016 and 2017 reference cases, and in almost all of its sensitivity runs[5] - failed to properly consider the economic value of capacity imports (beyond 300 MW) to meet its PRMR. DTE unnecessarily limited the amount of capacity that can be imported to serve DTE resource obligations to 300 MW, even though their own testimony identifies 1200 MW of "effective capacity import limit" or ECIL into MISO LZ7,[6] and even though DTE's own consultant PACE identifies 700 MW as available for a "cushion" into the zone.[7] As noted in Mr. Osborn's testimony, use of "ECIL" is not reflective of the potential for imports into Michigan. DTE can also use as much of the import capacity as it may need if it procures capacity during the Planning Resource Auction, as long as the overall LCR for the Michigan zone is met. I note that in its December 1, 2017 filing in case U-18441, Consumers Energy does not indicate any need for purchases of capacity for import into Michigan using the LZ7 interface through 2022.[8] This demonstrates that DTE is constricting the options available to Strategist for securing low cost capacity. Cases 4, 5, and 6 in Table 1 indicate NGCC plant deferral and ratepayer benefit under increased utilization of import capacity.

Scenario 4's only change is to increase the available capacity for purchase from 300 MW to 600 MW. It results in a deferral of an NGCC plant build until 2023, and

[5] Excepting the "C&I Choice Returns" as part of the 2016 Reference Scenario cases, and the "No Build" option as part of the 2017 Reference Scenario Sensitivity Resource Plans (Exhibit A-8, page 6).

[6] Chreston Direct, page 19.

[7]Exhibit A-5, Appendix G PACE Capacity Price Methodology 2016, page 25, "Assumed available out-of-zone Resources to meet short-term imbalance ("cushion"), ICAP Basis, MW".

[8] Exhibit MEC-93, Consumers Energy filing, U-18441, Exhibit 2, "Planning Reserve Margin Requirements and Planning Resources to be Acquired (UCAP MW)", *see, e.g.*, line 33.

exhibits a NPV revenue requirement savings of $107 million. Scenario 5 increases the available import capacity to 1,000 MW. It results in a deferral of need for the NGCC plant until 2026, with an attendant NPVRR savings of $171 million. Scenario 6, which also assumes a 1,000 MW capacity purchase availability, updates the capacity price (or purchase cost) forecast to reflect DTE's 2017 update to capacity prices,[9] and it too leads to a deferral of the NGCC plant until 2026, but with larger savings since the capacity price projection is lower than that used in DTE's 2016 reference case. The NPVRR savings from the 2016 baseline in Scenario 6 is $258 million.

5. **Combined Analyses**. Cases 7 and 8 show the results of combining input assumption parameter changes. When energy efficiency, demand response and an increase in market capacity purchase options to 600 MW (as reflected in cases 1, 2 and 4) is used in combination, the proposed NGCC plant is deferred until 2030, with net ratepayer savings of $2.489 billion (based on the 2016 reference case) or $823 million (based on the 2017 reference case). With the added correction to the heat rate error discussed in Mr. Evans' testimony, the savings in the 2017 combined analysis scenario increase to $1.272 billion, as shown in scenario 8a.

6. **Case 9 –** Beach Scenario Analysis. Mr. Evans also ran the Strategist model using the input assumptions of Mr. Tom Beach. His testimony in this case explains those assumptions.

<u>B. Unreasonably Low MISO LZ7 Capacity Import Limitations Modeled in Strategist</u>

Q. What do you address in this section?

[9] Exhibit A-4 Revised, page 223, figure 12.2-7. The graph shows the two different capacity price forecasts used by DTE, one for the 2016 reference scenario and one for the 2017 reference scenario.

A. I explain why DTE's use of 300 MW as a capacity import limitation is a fatal flaw of the modeling process they undertook, and why it is critically important to represent in Strategist the full amount of available, purchasable capacity imports to the Michigan load zone 7 ("buy") before assessing the value of the proposed NGCC plant ("build").

Q. How does DTE model the capacity construct associated with the MISO market and MISO load zone 7?

A. DTE relied upon a market construct that limited the ability of DTE to use market purchase of capacity beyond 300 MW. This 300 MW limitation removes from consideration any resource from outside of Michigan that might be less expensive than DTE's proposed NGCC plant, or less expensive than, say, the renewable resource alternatives available to the Strategist model for selection in its optimization. Thus, DTE allows Strategist to select, or purchase, only up to 300 MW of capacity from the MISO market in its reference cases, and in most of its sensitivity cases.[10]

Q. In which sensitivity cases is a greater amount of capacity purchase represented in Strategist?

A. DTE indicated that the only Strategist run in which the 300 MW assumption was relaxed, "in the early years", was the "C&I Choice Return".[11] The results of DTE's Reference Scenario Sensitivity Resource Plans model runs (DTE Exhibit A-8, page 1) indicate that a purchase of 545 MW was seen in 2021 in the "C&I Choice Returns" run.

Q. Are there other scenarios with seemingly increased amounts of capacity purchases?

A. Yes. Exhibit A-8 at page 6 lists a "No Build" run with increased amounts of capacity

[10] Chreston Direct, page 20:2.

[11] Response to MECNRDCSC-6.14c.

purchase, but it is not clear that any Strategist runs were developed for that scenario.[12]

Q. Mr. Chreston references a "No Build" modeling result that is $663 million more expensive than DTE's 2017 Reference Plan.[13] Please comment.

A. The calculation of the $663 million noted by Mr. Chreston is premised on market purchases of capacity that reach roughly 1,300 MW by 2023, but they are also tied to "capacity prices [that] reach CONE early in the study period". DTE sets capacity prices to the full cost of new entry in 2022 in this estimation of the cost of the no build scenario, and keeps the prices at full CONE for all the rest of the study period through 2040.[14] I note that using DTE's 2017 reference case projection of capacity prices in the "No Build" scenario, instead of these higher prices would lead to a NPVRR result that shows an $89 million net effect favoring "No Build, rather than Mr. Chreston's estimation that the "No Build" option is $633 million more expensive than DTE's 2017 reference plan.[15]

Q. What level of capacity imports does DTE allow when modeling need for their proposed NGCC plant?

A. DTE specifies up to 300 MW of capacity purchase is allowed in the Strategist runs. All

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[12] Chreston Direct, page 58, figure 14, lists resource plans for two of the three "2017 Reference Scenario Sensitivity Reference Plans" listed on page 6 of Exhibit A-8.

[13] Chreston Direct, page 59.

[14] Workpaper KJC-346, Tab "Base Scenario Assumptions", with CONE 2022 equal to $111.50/kW-year. DTE's 2017 reference case capacity price forecast is $24.28/kW-year in 2022.

[15] Synapse modification to K.J. Chreston workpaper KJC-346, changing the CONE 2022 values on line 39 of tab "Base Scenario Assumptions" from DTE's "full CONE" values to those associated with DTE's 2017 capacity price forecast. The revised revenue requirement difference, of positive $89 million (vs. negative 633 million in KJC-346 original) is seen on the tab "Revenue Requirement Summary" in cell Z53, representing the cumulative revenue requirement difference by 2040.

other capacity must come from the specific set of resource options offered in Strategist.

Q. At what cost does DTE allow Strategist to choose up to 300 MW of capacity as an import?

A. DTE assigns a cost equal to its included forecast of capacity prices that would pertain to purchases. Its capacity price projection is provided in Exhibit A-4, at Figure 12.2-7, which contains DTE's 2016 and 2017 reference case capacity price forecast.

Q. What is DTE's rationale to allow for just 300 MW of capacity imports as available to Strategist?

A. DTE witness Kevin Chreston testifies to an "effective CIL" or effective capacity import limit (ECIL) of approximately 1,200 MW, based on the values for the Michigan load zone 7 planning reserve margin requirements (PRMR) and the local clearing requirements (LCR) in the zone for the 2017/2018 planning period. He cites "uncertainty with the annual ECIL" and concern about "excess MISO capacity availability"; along with stating that a portion of MISO LZ7 import capacity is utilized by others, and an estimate that DTE would have "just under 600 MW" based on "the LSE's [load-serving entity's] share of the PRMR", in support of his allowance of 300 MW for purchases in Strategist.[16]

Q. Is DTE limited to its "LSE share" of the import capacity into MISO LZ7?

A. No. DTE can utilize what is available at the time of the planning reserve auction.

Q. What is MISO's most recent available information on the capacity limits into Michigan's load zone 7, and your estimate of ECIL for 2018 and 2021?

A. The 2018 LOLE Report indicates a capacity import limit (CIL) of 3,785 MW for the

[16] Chreston Direct, page 19:1 – 20:4.

2018/2019 planning year, and 3,143 MW for 2021.[17] The CIL for 2017, upon which Mr. Chreston computes an "effective CIL", was 3,320 MW. Using the same formulation as used by Mr. Creston, I estimate the ECIL for MISO load zone 7 in 2018 as equal to 1,974 MW, and for 2021 I estimate the ECIL for MISO LZ7 to be 1,291 MW. These estimates are based on the information available from MISO and publicly posted for the 10/12/2017 loss-of-load working group meeting.

Q. Please explain how you obtained these specific estimates of "ECIL" for 2018.

A. I based these estimates on information available from MISO's 'near term" (2018) projections and "out year" (2021) projections of capacity import limit for MISO load zone 7, and MISO's estimates of the planning reserve margin requirement (PRMR) and the local reliability requirement (LRR) for load zone 7.[18] I use the same formulation as Mr. Chreston. Based on DTE's definition, the ECIL essentially reflects the portion of the planning reserve margin requirement that can be imported while still adhering to the local requirement, thus ECIL = PRMR minus LCR. The LCR is computed as equal to the LRR minus the CIL. Using these fundamental equations, the near term (2018) ECIL is equal to 1,974 MW (=PRMR-(LRR-CIL), = 22,734-(24,545-3,785)), and the 2021 out year ECIL is 1,291 MW (=PRMR-(LRR-CIL), = 22,620-(24,472-3,143)).

Q. Do any of these estimates account for any future increases in import capacity into

[17] Exhibit MEC-94, 2018-2019 LOLE Report, page 12 (2018) and page 16 (2021).
[18] Exhibit MEC-95**,** Near Term LOLE Results, also found at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/LOLEWG/2017/20171010/20171010%20LOLEWG%20Item%2004a%20Near%20Term%20LOLE%20Results.pdf. Page 4.
Exhibit MEC-96, Out Year 2021 LOLE Results, also found at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/LOLEWG/2017/20171010/20171010%20LOLEWG%20Item%2004b%202021%20LOLE%20Results.pdf. Page 6.

Michigan as a result of infrastructure investment?

A. No. I note the testimony of Mr. Dale Osborn, who addresses the options that could exist to increase imports into Michigan's load zone 7. This could include imports from MISO, PJM, or Ontario.

Q. Did DTE examine the potential for increases in import capacity, over the near- or longer-term, into Michigan's load zone 7?

A. No. Mr. Weber testified that there was no evidence of possible increases, but he did not conduct any analyses to assess if such options were potentially cost effective over either the near- or long-term. Mr. Osborn also addresses this deficiency in Mr. Weber's analysis. I also note that Mr. Weber did not mention the existence of MISO's Regional Transmission Overlay Study, which was undertaken by MISO's Economic Users Planning Group and has been underway since June of 2016.[19] The group's May 2017 Overlay Update includes indication of potential 345 kV transmission reinforcements in the Central/East regions that would allow increased import capacity into MISO load zone 7.[20]

Q. Do you agree with Mr. Chreston's use of 300 MW of capacity import for the maximum utilization in Strategist of outside capacity resources?

A. No. Mr. Chreston's use of 300 MW is far too low. DTE is excluding significant amounts of available capacity, at competitive prices, when setting up Strategist to select "optimal"

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[19] MISO Economic Users Planning Group materials available here: https://www.misoenergy.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/EPUG/Pages/home.aspx.

[20] Exhibit MEC-97, MISO EUPG Presentation (*see* slides 5, 8 and 10 for MI import increase indications), also found at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2017/20170525/20170525%20EPUG%20Item%2006b%20Indicative%20Overlay%20Design%20%20Work%20Session%20Central.pdf

resource choices while preventing it from seeing capacity resources outside of Michigan that are available, well within even DTE's estimation of the effective capacity import limits, when accounting for local clearing requirements. The existence of significant levels of import capacity into Michigan load zone 7 is a key source for increasing capacity purchase alternatives from MISO. This is coupled with a projected relative surplus of "committed" capacity outlook for the broader MISO region for the near term 2018-2022 period, and the existence of considerable generation supply interest in MISO for potential interconnection in the longer-term, after 2022.[21]

Q. Please summarize your opinion on DTE's use of 300 MW as a limit for capacity import purchases.

A. The Company's selection of a 300 MW capacity import limit is a fatal flaw in DTE's overall analysis, and the MPSC should not accept that value when considering whether the proposed NGCC plant is needed.

Q. What level of capacity purchase alternative should be enabled in Strategist?

A. DTE should not overly constrain its ability to utilize lower-cost market capacity, at least up to levels equal to its computation of ECIL. We use 600 MW as a conservative alternative in many runs, and test the results at 1,000 MW. A range of "ECIL" between 600 MW and 1,200 MW (DTE's computed ECIL value) is both much more reasonable than DTE's 300 MW, and likely overly conservative. I also note that the testimony of Mr. Dale Osborn offers extensive support for considering higher capacity import values, especially for later years of the analysis.

Q. You state that there is a projected relative surplus of committed capacity in the broader MISO region through 2022, and considerable generation supply interest in MISO

[21] The results of the 2017 MISO OMS Resource Adequacy Survey (Exhibit MEC-91) indicated no immediate resource shortage concern in MISO in the 2018-2022 period, and sizable levels of potential supply queued for longer-term interconnection to the MISO grid. See the following subsection of this testimony.

interconnection that would be applicable for the longer-term (post-2022). What is your evidence of such resource assurance?

A. I rely upon the 2017 MISO OMS resource adequacy survey results, which contain such indications, along with the results of the 2017 MISO Planning Resource Auction, which serves as an indicator of relative resource surplus in the region. I address those results in a subsequent section of this testimony.

C. Capacity Price Forecast

Q. Please comment on DTE's capacity price forecast.

A. In addition to underestimating the quantity of capacity it could import to meet its resource adequacy obligations, DTE overestimates the market price effect for imports into MISO LZ7, as described in the testimony of Mr. Allison. DTE has historically overestimated the cost of forward capacity, and all DTE runs in this application using its 2016 forecast continue to overestimate the capacity price, as DTE indicates a significant difference between its 2016 and 2017 capacity price projection for the years 2018 through 2022, and for many of the years beyond 2022.[22] These two aspects of the modeled representation of capacity imports are critical in order to properly include, in the assessment, the availability of less-expensive purchase capacity prior to turning to the capacity value provided by the proposed NGCC plant. Case 6 in Table 1 reflects the lower capacity price effect of DTE's 2017 forecast: when allowing for capacity imports of up to 1,000 MW, DTE's lower capacity price forecast from 2017 results in a greater NPV savings ($258 million, in comparison to DTE's 1.5% EE reference case) than is seen when using DTE's 2016 capacity price forecast ($171 million). Notably, either price projection results in a savings for ratepayers compared to DTE's reference case, and results in a

[22] See Figure 12.2-7, Capacity Price forecast ($/kW), Exhibit A-4 Revised, page 223.

deferral of need for the NGCC plant until 2026 (for case 6 alone; as noted for the other combined cases 7 and 8, the highest level of ratepayer savings is seen when the proposed plant is deferred to 2030).

V. MISO Resource Adequacy

A. 2017 MISO OMS Resource Adequacy Survey

Q. What do you address in this section, and why?

A. I address MISO region resource adequacy, in the context of out-of-state resources that are available for DTE to procure in support of its resource adequacy obligations, and as part of a portfolio of resources available at lower cost to DTE ratepayers than DTE's proposed NGCC plant.

Q. What is the OMS MISO resource adequacy survey?

A. It is an annual survey undertaken to estimate near-term planning reserve margins across MISO and within each local resource zone. The 2017 OMS MISO resource survey provides 2017 information on the projection of resource adequacy in MISO; the survey has been in place since 2014.

Q. Please summarize the results of the 2017 OMS MISO resource survey for the MISO region as a whole.

A. The 2017 MISO-wide survey results were notable for the dramatic increase in the projected capacity reserve provision for the region for the years 2018 through 2022 compared to forecasts using the load projection from 2016.[23] Indeed, the overall results compared to the 2016 OMS MISO survey indicate more than sufficient resources through 2021, when counting only

[23] *See* Exhibit MEC-91**,** 2017 OMS MISO Survey Results, page 12.

"committed"[24] resources, and through 2022 when counting potentially available resources and existing resources without commitments.[25] When considering what MISO has identified as potentially available new resources in addition to resources currently categorized as "committed," the outlook for capacity reserve is an even greater surplus than currently predicted using only committed resources, for both the out years of the OMS MISO survey (2021, 2022), and likely for the longer term.

Q. What are some of the key specific results of the 2017 OMS MISO resource survey?

A. The survey explicitly states that "[r]egional capacity balances increased largely due to lower demand forecasts," and shows more-than-sufficient planning reserve margin that varies from 17.9% on an ICAP (installed capacity) basis in 2018, to 16.3% (ICAP basis) in 2022.[26] It also notes that "[f]uture resource ranges will shift as planned generation interconnections are firmed up,"[27] and, compellingly, indicates the presence of significant amounts of potential capacity additions that were not counted as being available to meet longer-term needs, with a cumulative total increasing from approximately 5,000 MWs in 2018 to more than 20,000 MW in

[24] The 2017 OMS MISO survey results define "committed" to include i) resources within the rate base of MISO utilities, ii) new generators with signed interconnection agreements, iii) external resources with firm contracts to MISO load, and iv) non-rate base units without announced retirements or commitments to non-MISO load. **Exhibit** MEC-91, Page 8.

[25] Exhibit MEC-91, 2017 OMS MISO Survey Results at page 9, for 2022, "20.0%" when including these additional resources.

[26] Exhibit MEC-91**,** 2017 OMS MISO Survey Results at pages 9-10. ICAP reflects the nameplate capacity of a resource. Unforced capacity, or UCAP, is a derated capacity value reflecting either the forced outage rates of fossil resources, or the peak-period availability of intermittent resources such as wind or solar.

[27] Exhibit MEC-91, 2017 OMS MISO Survey Results at page 13.

2022.[28]

This level of potential new resources through 2022 includes roughly 5.4 GW of wind and solar capacity additions alone.[29] The reserve requirement for 2017 was 15.8% (ICAP basis); at the time of the 2017 MISO OMS survey, MISO had projected an ICAP planning reserve requirement ranging between 15.3% to 15.8% over the 2017 to 2026 period.[30] Since the publication of the survey results in July 2017, MISO's projection of reserve requirement percentage needs has increased, to a range of 17.1% to 17.2% (installed capacity, or ICAP, basis), for the 2018-2027 period.[31] Notably, even with this increase in MISO's projection of reserve requirement, the 2017 survey results show committed capacity exceeding reserve planning needs through 2021; only in 2022 does the "committed" capacity projection dip below currently-anticipated reserve margins. However, when including potential new capacity available in 2022, and accounting for existing capacity that MISO does not consider "committed", the 2022 reserve margin is seen to be 20%, in exceedance of requirements.

Q. What is the extent to which there will continue to be excess supply in MISO?

A. The extent to which there will continue to be excess supply in MISO relies upon the fundamentals: projected load and resource balances across the region, accounting for the presence of new small-scale and utility-scale renewable and gas-fired resources, the effects of

[28] Exhibit MEC-91, 2017 OMS MISO Survey Results, estimated from vertical bar graph, slide 13. These reflect solar and wind resources at their capacity credit values of 50% (solar) and 15.6% (wind); installed capacity levels of these potential resources are significantly higher.

[29] Exhibit MEC-91, 2017 OMS MISO Survey Results, estimated from vertical bar graphs showing distribution of wind and solar resources as potential capacity additions across each zone; see slides 22, 28, 34, 40, 46, 52, and 58.

[30] 2017/2018 LOLE Report, page 31 (attached as Exhibit MEC-73 to Osborn Direct).

[31] *See* Exhibit MEC-94, 2018/2019 LOLE Report, page 28.

ongoing energy efficiency improvements across the region, the effects of transmission expansion to allow new resource interconnection, retirements of existing resources in MISO, and potential storage additions.[32]

Overall, there is no indication of potential near or longer-term resource insufficiency in the broader MISO region, contrary to DTE's suggestion.[33] As aging and uneconomic coal plants retire, the need to meet capacity obligations will be met with demand-side resource reductions (the effect of increasing energy efficiency and available demand response resources), behind-the-meter resources (especially solar photovoltaic), and available new wind, storage and to some extent gas-fired resources.

Q. Are there additional guide points beyond the OMS MISO survey results and projections in the MTEP?

A. Yes. The results of the MISO PRAs are very useful snapshots of the existence of a relative resource surplus in the region. Additional guide points include the status of queued resources in MISO,[34] the underlying declining costs for new renewable resources,[35] the trends

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[32] The cost of bulk storage resources, including battery storage resources, are projected to continue declining, and to be competitive with conventional resources. *See, e.g.*, Exhibit MEC-98, Lazard's Levelized Cost of Storage Version 3.0, November 2017. Also found at https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf. *E.g.*, slide 16 and slide 18.

[33] *See, e.g.*, Chreston Direct, page 18:22-23 .

[34] There is roughly 28 GW of queued wind resources in MISO at the "DPP System Impact Stage" of interconnection request, and more than 9 GW of similarly queued solar PV resources. Exhibit MEC-99, MISO Generation Interconnection Public Queue data as of August 7, 2017. Synapse tabulation.

[35] *See, e.g.*, Exhibit MEC-100, US DOE/EERE 2016 Wind Technologies Market Report for wind resource costs. Also found at: https://energy.gov/sites/prod/files/2017/08/f35/2016_Wind_Technologies_Market_Report_0.pdf. *See also* Exhibit MEC-101, Lawrence Berkeley National Laboratory, Utility Scale Solar 2016:

for improving energy efficiency and installation of behind-the-meter solar PV across the region (thus affecting "net" peak load seen on the transmission grid), the relative strength of the transmission grid and its ability to continue to allow sharing of capacity resources across the entire regional transmission organization, and an appreciation for how load forecasts change over time.[36] In particular, peak load forecasts from just a few years ago exaggerate future load; more recent vintage forecasts reflect lower peak load. As is seen in the 2017 OMS MISO resource survey results, reserve margins are more than adequate over the near-term (through 2022) when such improved load forecasts and consideration of potential new capacity resources is accounted for.

Q. What has been the pattern of MISO forecasts of near "out year" loads, and have such forecasts proved correct?

A. Generally, the peak load forecasts have been high, as MISO has noted[37] and as is seen in the data. Table 2 below shows a sequence of different vintages of MISO peak load forecasts for the peak load in the summer of 2017, 2018, and 2023, and it also shows the actual weather-normalized peak load as reported by MISO for 2017.

Table 2. MISO Peak Load Forecasts for 2017, 2018, and 2023 – by Different Forecast Vintage

	2017 Projected or Actual Peak Load, MISO		
Forecast Vintage:	**50/50 Total Internal Demand**	**Demand Response**	**Net Internal Demand**
2014 NERC LTRA (Nov 2014)	131,242	4,766	126,475
2015 NERC LTRA (Dec 2015)	129,780	5,631	124,150

An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States, also found at: https://emp.lbl.gov/publications/utility-scale-solar-2016-empirical.

[36] For example, MISO's peak demand forecast for 2023 was 3.4 GW lower in 2017 compared to the 2016 forecast.

[37] Exhibit MEC-102, MISO 2016 OMS MISO Survey, page 10, "This outlook depends heavily on load projections; current forecasts of modest load growth are not in line with recent history of flat year-to-year loads".

2016 NERC LTRA (Dec 2016)	127,641	5,827	121,814
2017 NERC Summer Assessment	125,002	5,144	119,858
2017 Actual Weather Normalized Peak (July 2017)			119,600
	2018 Projected Peak Load, MISO		
Forecast Vintage:	**50/50 Total Internal Demand**	**Demand Response**	**Net Internal Demand**
2014 NERC LTRA (Nov 2014)	132,376	4,779	127,598
2015 NERC LTRA (Dec 2015)	130,670	5,631	125,039
2016 NERC LTRA (Dec 2016)	128,270	5,827	122,443
2017 NERC LTRA (Dec 2017)	125,568	5,621	119,947
	2023 Projected Peak Load, MISO		
Forecast Vintage:	**50/50 Total Internal Demand**	**Demand Response**	**Net Internal Demand**
2014 NERC LTRA (Nov 2014)	137,377	4,839	132,538
2015 NERC LTRA (Dec 2015)	135,255	5,631	129,624
2016 NERC LTRA (Dec 2016)	132,261	5,827	126,434
2017 NERC LTRA (Dec 2017)	128,897	5,621	123,276

Sources: Exhibit MEC-103, NERC Long-Term Resource Assessments (LTRA) 2014-2017, and Exhibit MEC-104, NERC 2017 Summer Assessment.
Also found at: http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx. Exhibit MEC-108, MISO Summer Peak Analysis 2017, MISO RA Subcommittee, November 8, 2017. Slide 6, "MISO estimate indicates weather-normalized system peak was about 1 GW lower than actual peak of 120.6 GW". Also found at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/RASC/2017/20171108/20171108%20RASC%20Item%2005d%20Summer%20Peak%20Analysis%202017.pdf.

The projected 50/50 net peak load for MISO for year 2018 in NERC's most recent Long-Term Reliability Assessment (published in December 2017) was 119,947 MW; this was updated from earlier year forecast vintages that projected dramatically higher loads. For example, the forecast just three years earlier (in 2014) for 2018 was roughly 7,500 MW higher than the current forecast for that year.

B. MISO Planning Resource Auction (PRA) Results and Key Parameters

Q. What is the MISO PRA?

A. MISO's PRA is an annual capacity auction held in the spring prior to MISO's planning year, which runs from June 1 to the following May 31. It is a "prompt" auction that allows load serving entities to procure or sell unforced capacity (UCAP) to meet their local capacity requirements (LCR), and allows MISO to ensure sufficient planning reserve margin (PRM) for the entire RTO. As with capacity acquired through other RTO auction constructs, capacity sold or procured in the PRA is used to meet reserve requirement obligations for one year.

Q. What are the results of the PRAs held to date?

A. Table 3 contains a summary of the auction price results.

Table 3. MISO Planning Auction Price Results, 2013/14 through 2017/18, $/kW-year (nominal)

	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
2013	0.38	0.38	0.38	0.38	0.38	0.38	0.38	#N/A	#N/A	#N/A
2014	1.20	6.13	6.13	6.13	6.13	6.13	6.13	6.01	6.01	#N/A
2015	1.27	1.27	1.27	54.88	1.27	1.27	1.27	1.20	1.20	#N/A
2016	7.21	26.34	26.34	26.34	26.34	26.34	26.34	1.09	1.09	1.09
2017	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55

Source: MISO. Note: Zone 10 became a separately-priced zone only in 2016.

Q. What do the PRA auction price results indicate?

A. The auction results generally indicate surplus capacity availability in MISO at the beginning of each capacity year, since the prices are relatively low (much lower than the Cost of New Entry (CONE) in MISO, equal to $93.75/kW-year (zonal average), 2017/2018).[38] They also show, for both 2016 and 2014, a binding constraint for exporting capacity from Zone 1 (because the prices in those years are lower for Zone 1 than for its adjacent zones), which covers the northwestern portion of MISO. Imports into Michigan's lower peninsula (Zone 7) have never been binding in any of the auctions to date (prices are equal between Zone 7 and its directly connected neighboring zones). The data also shows a somewhat anomalous price value

[38] *See, e.g.*, Exhibit MEC-92, 2017/2018 MISO PRA summary results, slide 8, also found at: https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/AuctionResults/2017-2018%20PRA%20Summary.pdf.

for Zone 4 in 2015, when the clearing price for that zone spiked relative to all other zones.[39]

Q. Are there other auction parameter data useful for assessing the extent of resource surplus in the region and available to DTE in the near-term, and potentially the long term?

A. Yes. Looking at the results of the auctions to date is useful, but assessing the year-over-year patterns underlying key auction input parameters can help in understanding likely future resource adequacy and the cost of capacity that will be available in MISO. The year-over-year patterns of planning reserve margin requirement and related load Zone 7 metrics from the inception of the PRA in 2013 through this year's auction are relevant and informative.

Table 4 below summarizes the Planning Reserve Margin Requirement (PRMR) for the Midwest zones of MISO (load zones 1 through 7) for each of the five auctions held to date, the PRMR for all of MISO including MISO South since its inclusion in 2014, the local reliability requirement (LRR) for Zone 7, the capacity import limit (CIL) for Zone 7, and the local clearing requirement (LCR) and Zone 7-specific PRMR. It includes the Zone 7 imports (or exports) that are seen in each auction, and lists the exports from Zone 1, the westernmost zone in MISO inclusive of Minnesota, western Wisconsin, and North Dakota.

Table 4. MISO PRA Parameters at Time of Auction – PRMR/Zone 7 LRR, LCR & CIL/Z7 Imports/Z1 Exports

Year	PRMR Z1-Z10	PRMR Z1-Z7	Zone 7 LRR	Z7 CIL	LCR Z7	Z7 PRMR	Z1 exports	Z7 imports (- = export)
	UCAP MW	UCAP MW	UCAP MW	MW	UCAP MW	UCAP MW	MW	MW
2013	No MISO South	102,156	25,631	4,576	21,055	22,702	Unk	Unk
2014	136,911	103,270	25,177	3,884	21,293	22,998	286	372
2015	136,360	103,072	25,255	3,813	21,442	22,678	175	(837)

[39] Subsequent tariff revisions resulting from a FERC inquiry adjusted MISO's mechanism for computing Capacity Import Limits (CIL).

2016	135,484	101,702	24,372	3,521	20,851	22,406	590	872
2017	134,753	100,672	24,429	3,320	21,109	22,295	613	338

Source: Exhibit MEC-92, MISO PRA results data.

Q. What do you observe in the MISO PRA auction result prices seen in Table 3, and the year-over patterns seen in the parameter data in Table 4?

A. As noted, the prices in Table 3 indicate a relative surplus of capacity in MISO at the time of the auction, for the prompt year ahead, in all years of the PRA since inception. In 2016, the year for which auction prices were highest across the entire region, the clearing price was still well below cost of new entry levels (CONE, equal to roughly $94/kW-year in 2017), indicating near-term surplus conditions.

Table 4 illustrates a number of patterns related to expectations of future resource need in MISO:

- The overall planning reserve margin requirements for the 10-zone region has declined in each year since MISO South's incorporation into MISO prior to the 2014 auction.[40]
- The planning reserve margin requirements for the Midwest part of MISO, Zones 1 through 7, have successively declined in each of the past four years. Only between 2013 (the first year of the MISO PRA) and 2014 was there an increase in PRMR.
- The Zone 7 local reliability requirement has both increased and decreased year-over-year, but overall there has been a local reliability requirement decline of roughly 1,200 MW between 2013 and 2017.
- Capacity imports into Zone 7 using the transmission system remain relatively low compared to the capacity import limit, indicating considerable headroom for further

[40] Preliminary PRMR for the 2018/19 planning year are higher than the 2017 values because of a significant shift in the outage rates used to compute the UCAP values. Final PRMR values will be available prior to the 2018 PRA to be held in the Spring of 2018.

imports of capacity.

- Capacity exports from Zone 1 to the rest of the MISO region have bumped up against binding transmission constraints in two of five auction years (2014 and 2016), as seen in Table 3 with price separation (lower prices in Zone 1 relative to its adjacent zones).

<u>C. Medium and Longer Term (Post-2022) MISO Resource Adequacy</u>

Q. What additional key factors will affect future resource adequacy in MISO, especially post-2022?

A. As noted, continuing improvements to the transmission system, installation of new wind and solar resources, continuing improvements in energy efficiency across the region, availability and costs for new storage systems, the pace of retirement of coal and other older fossil resources, and additions of new conventional resources (gas-fired technologies) will all affect the overall level of resource adequacy in the region.

Q. How will improvements to MISO transmission elements help promote resource adequacy, and allow for LRZ 7 to access resources from the rest of MISO?

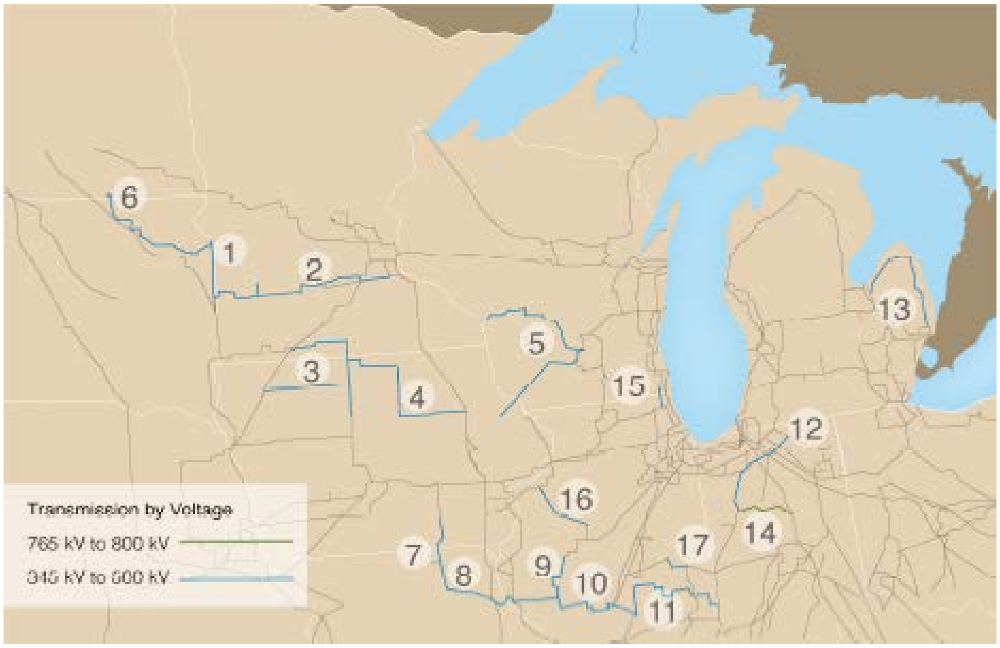
A. Improvements such as the completion of the portfolio of Multi-Value Projects (MVP) in MISO will relieve critical transmission constraints, such as the capacity export limit (CEL) of 686 MW that currently limits MISO Zone 1 resource exports, and in general allow for increased penetration of wind resources to be reliably incorporated into the MISO market. The 2017 Loss of Load Expectation report indicated that this Zone 1 capacity export limitation will be effectively removed by 2021,[41] thus increasing the ability of wind resources with higher capacity

[41] Exhibit MEC-73 (Osborn), 2017/2018 LOLE Report, page 21, indicating projected CELs for the MISO load zones.

credit values to be available as capacity (and energy) resources in MISO. Capacity credit values for Zone 1 wind resources are roughly 18%, whereas Zone 7 wind resources are only 12%.[42] Figure 1 below shows the location of the Multi-Value Projects.

[42] Exhibit MEC-105, 2017/18 Wind Capacity Credit Report, MISO, Figure 1-1: MISO Local Resource Zones (LRZ) And Distribution of Wind Capacity Table, page 4. Also found at: https://www.misoenergy.org/Library/Repository/Study/LOLE/2017%20Wind%20Capacity%20Report.pdf.

Figure 1. MISO's MVP Portfolio Map from 2014 Triennial Review Report



Source: Exhibit MEC-106, MISO, MTEP14 MVP Triennial Review, page 11, figure 2-1. (September 2014). Also found at: https://www.misoenergy.org/Library/Repository/Study/Candidate%20MVP%20Analysis/MTEP14%20MVP%20Triennial%20Review%20Report.pdf

Q. What is the effect on capacity resource sharing across MISO as transmission constraints are relieved?

If transmission constraints are not binding in the capacity auction, it indicates that the promise of shared capacity within RTOs is being met – there is no reliability reason to not utilize the transmission import and export capacity between the historically designated zones in MISO, to achieve resource adequacy at the lowest overall cost. The Multi-Value Project portfolio in total promises to allow continued interconnection of the rich wind resources in the region. MISO has indicated that progress in completing the portfolio of 17 transmission projects continues. As seen in Figure 2 below, by 2023, the completion of the entire Multi-Value Project portfolio is expected by 2023.[43]

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[43] Based on the currently estimated in-service dates for the Wisconsin and Iowa projects identified as MVP #5 in the MVP portfolio dashboard.

Figure 2. MVP Portfolio Dashboard – Transmission Expansion Progress

Multi-Value Project Status as of Q2 2017

MVP No.	Project Name	State	Estimated In Service Date[1]		Status		Cost[1]	
			MTEP Approved	Q2 2017	State Regulatory Status	Construction	MTEP Approved	Q2 2017
1	Big Stone-Brookings	SD	2017	2017	●	Underway	226.7	141.3
2	Brookings, SD-SE Twin Cities	MN/SD	2011-2015	2013-2015	●	Complete	738.4	672.6
3	Lakefield Jct. - Winnebago-Winco-Burt area & Sheldon-Burt Area-Webster	MN/IA	2015-2016	2016-2018	●	Underway	550.4	545.7
4	Winco-Lime Creek-Emery-Black Hawk-Hazelton	IA	2015	2015-2018	●	Underway	468.6	470.3
5	N. LaCrosse-N. Madison-Cardinal (a/k/a Badger-Coulee Project)	WI/IA	2018-2020	2018-2023	●	Pending	797.5	1016.1
	Cardinal-Hickory Creek	WI/IA	2018-2020	2018-2023	◑	Pending		
6	Big Stone South - Ellendale	ND/SD	2019	2019	●	Pending	330.7	395.7
7	Ottumwa-Zachary	IA/MO	2017-2020	2018-2019	◑	Pending	152.3	217.0
8	Zachary-Maywood	MO	2016-2018	2016-2019	◑	Pending	112.8	173.9
9	Maywood-Herleman-Meredosia-Ipava & Meredosia-Austin	MO/IL	2016-2017	2016-2017	●	Underway	432.2	723.2
10	Austin-Pana	IL	2018	2016-2018	●	Underway	99.4	134.6
11	Pana-Faraday-Kansas-Sugar Creek	IL/IN	2018-2019	2016-2018	●	Underway	318.4	422.9
12	Reynolds-Burr Oak-Hiple	IN	2019	2019	●	Underway	271.0	388.0
13	Michigan Thumb Loop Expansion	MI	2013-2015	2012-2015	●	Complete	510.0	510.0
14	Reynolds-Greentown	IN	2018	2018	●	Pending	245.0	388.4
15	Pleasant Prairie-Zion Energy Center	WI	2014	2013	●	Complete	28.8	33.0
16	Fargo-Sandburg-Oak Grove	IL	2014-2019	2016-2018	●	Underway	199.0	204.5
17	Sidney-Rising	IL	2016	2016	●	Complete	83.2	88.1
						Totals:	*5,564*	*6,525*

State Regualtory Status Indicator Scale

○ Pending

◑ In regulatory process or partially complete

● Regulatory process complete or no regulatory process requirements

1. Estimates provided by constructing Transmission Owners. Costs stated in millions of nominal dollars.

Source: Exhibit MEC-107, MISO, Regionally Cost Allocated Project Reporting Analysis. Also found at: https://www.misoenergy.org/Library/Repository/Study/MTEP/MVP%20Portfolio%20Triennial%20Review/MVP%20Dashboard.pdf

Q. Please summarize the benefits available to DTE as the Multi-Value Project portfolio is completed.

A. New transmission investment in MISO, especially the completion of the regionally benefitting Multi-Value Project Portfolio,[44] will continue to knit together the MISO region and allow broader access to resources in the rest of MISO to entities such as DTE. One of the benefits of a better-integrated Balancing Authority region such as MISO is the efficient use of capacity resources to serve load throughout the region, including reducing the level of required planning reserves. A significant surplus of capacity in one part of the MISO region can be

[44] This long-term planning initiative will allow for on the order of 41-48 million MWh (annually) of renewable energy to be connected to the grid and used to serve RPS requirements and allow for additional wind resource connection.

utilized in another part of the MISO region, especially when transmission limitations are minimized.[45]

D. DTE Is Able to Rely on MISO Region Capacity Resources

Q. Can DTE rely upon MISO resource availability to meet a portion of its capacity needs in the near and longer-term?

A. Yes. DTE can and should rely upon these resources to a greater extent than it indicates in its Strategist results. There is a sizable level of delivery headroom (capacity imported, versus capacity import limits) available across the MISO interfaces into LRZ 7, as seen in the 2017 PRA results and earlier year results (Table 4); and even using DTE's conservative "ECIL", delivery room exists for additional broader-MISO-region-sourced imports. If DTE can obtain capacity resources – in the bilateral market and/or to some extent at the PRA – ratepayers will be able to benefit from the lowest-cost marginal capacity resource. DTE should fully utilize the transmission system capability when seeking to meet capacity requirements.

In the same way that least-cost energy dispatch is conducted MISO-wide, DTE should aim for least-cost capacity procurement. As long as MISO capacity surplus is available, DTE should exploit the underlying economics and procure as much low-cost market capacity as is available, in line with its needs and with careful attention to the effective avoided costs associated with earlier retirement of at least a portion of DTE's Tier 2 coal plants, addressed below.

[45] See, for example, Exhibit MEC-106**,** MISO's *MTEP14 MVP Triennial Review*, September 2014, Section 6.3, Planning Reserve Margin Requirements.

VI. DTE Tier 2 Coal Plants in Strategist

A. DTE 2017 Reference Case Results Using 2017 Capacity Price Projection Show Tier 2 Coal Plants are Very Likely Uneconomic

Q. Does DTE's modeling include operation of the Tier 2 coal plants?

A. Yes. St. Clair units 1, 2, 3, 4, 6, and 7; River Rouge unit 3; and Trenton Channel unit 9 are all operated as "must run" coal units in DTE's Strategist modeling.[46] DTE does not allow the model to "choose" whether or not to retire the units economically, but instead assumes them in operation until DTE's modeled retirement dates.

Q. What are DTE's modeled retirement dates for those units?

A. The modeled dates are May 31, 2020 (River Rouge 3), May 31, 2022 (St. Clair 1-4, 6), and May 31, 2023 (St. Clair 7, Trenton Channel 9).[47]

Q. Has DTE made any showing that it is economic to continue operating the Tier 2 coal units until their announced retirement dates?

A. No. Both DTE's Strategist modeling and its separate retirement analysis simply assume that the Tier 2 coal units will continue operating until their announced retirement dates, rather than evaluating the economics of doing so.

Q. Is there evidence that the Tier 2 coal units are not economic to continue operating until their announced retirement dates?

A. Yes. Using data from DTE's own modeling and discovery responses, it appears that each of the Tier 2 coal units are not economic for continued operation through their announced retirement dates, as the NPV of net revenues (i.e., the NPV of energy and capacity revenues net

[46]While St. Clair unit 4 is included in the Strategist modeling, its retirement has been announced by DTE.

[47] Exhibit A-4 Revised, page 69.

of operating costs including incremental capital and O&M) is negative. Essentially, the value of their energy and capacity is less than their cost of operation. This is true for all years of operation for all units except St. Clair 7, which has net positive or breakeven revenues for four of the near-term operating years. Table 5 below summarizes the results of our analysis of the economics of these units. As seen, all of the units are uneconomic, when considering all years or when considering the net revenues during just the planned operating years.

Table 5. Tier 2 Unit Coal Plant Economics – DTE Strategist 2017 Reference Case Run

Units	NPV Net Revenue, All Years (2016 $Million)	NPV Net Revenue, Operating Years (2016 $Million)	DTE Planned Retirement Year in Model	# Years with Positive or Breakeven Net Revenues
River Rouge 2-3	($47)	($38)	2020	0
St. Clair 1-4	($52)	($44)	2022	0
St. Clair 6	($44)	($39)	2022	0
St. Clair 7	($14)	($10)	2023	4
Trenton 9	($33)	($26)	2023	0

Source: Strategist DTE 2017 reference case outputs for individual units; workpaper KJC-397; DTE 2017 projection of capacity prices. Synapse tabulation.

Q. Please describe how you arrived at the values in Table 5.

A. Total revenues from each unit were computed based on the sum of energy revenues received for energy output, and capacity revenues received based on unit-specific UCAP and DTE's 2017 projection of capacity market prices. Energy revenues were taken directly from the Strategist output (2017 reference case) for each unit. Net revenues were computed by subtracting total costs for each unit from the total revenues. Costs consist of fuel costs (taken directly from Strategist, by unit), total non-fuel operation and maintenance costs, incremental capital costs, and property taxes and insurance costs.

Total non-fuel operations and maintenance costs, which are composed of both fixed and variable costs, were taken from directly from the workpaper of K.J. Chreston (KJC-397) indicating total O&M costs from DTE's "retirement" run. The 2017 Strategist reference case did not include fixed O&M costs, but did include variable O&M costs; in order to capture the full non-fuel O&M costs, we used the information from Mr. Chreston's workpaper. We did not directly use the variable O&M costs available from the 2017 reference case Strategist run.

Incremental capital costs and property tax and insurance costs were also taken from workpaper KJC-397.

Q. Can the Tier 2 coal units be retired earlier than DTE's projected retirement dates?

A. Likely yes. It is clear that River Rouge Unit 3 should be retired by May 31, 2018, given its poor economics, and can be retired by May 31, 2018 given the capacity available in MISO to replace that unit. Based on the apparent economic unattractiveness of the rest of the Tier 2 coal units seen in Table 5, and the availability of more than sufficient capacity from any number of different combinations of MISO imports, new renewable resources and demand response implementation, and ongoing effects from increased levels of energy efficiency, the orderly retirement of the remaining Tier 2 coal units before their announced retirement dates should be thoroughly evaluated so that the lowest cost approach for customers can be pursued.

VII. Recommendations

Q. What are your overall recommendations to the MPSC?

A. I have three recommendations.

1. Do not approve DTE's request for Certificates of Necessity. Using DTE's own resource alternatives with corrections to its Strategist modeling, the proposed plant can be deferred until 2029 at a net savings to DTE ratepayers of roughly $1.882 billion. Using a

combination of resources making up the most cost-effective alternative resource proposal we modeled, the proposed NGCC plant can be deferred until 2030 at a savings to DTE ratepayers of between $823 million to $2.489 billion, depending on the reference case considered.

2. MPSC should direct DTE to first:
    a. Obtain all cost-effective energy efficiency at levels at least equal to its 2% energy efficiency option. On its own, based on the results of the Strategist runs, this approach defers the need for the NGCC plant until 2030.
    b. Seek out renewable resource procurements in advance of the planned "sunsetting" of the federal ITC and PTC, to the extent that it affords DTE the opportunity to obtain less expensive renewable resources than if purchases were made later in time.
    c. Simultaneous with the above, DTE should accelerate its implementation of the most cost-effective demand response programs and obtain more DR resources than the incremental 125 MW it includes as part of its proposed plan.
    d. Procure incremental capacity from the least expensive resources available in order to meet its PRMR residual need after accounting for its own Michigan resources. This can be across the load zone 7 interface in MISO, or via PJM as an "external" MISO resource, or via an external resource from Ontario. These procurements can be spot purchases or longer-term bilateral procurements.
    e. MPSC should Order DTE to look into examining specific transmission reinforcement alternatives that would allow for MISO to increase the CIL and lower the LCR for MISO Z7. See Mr. Osborn's testimony.

3. Lastly, the MPSC should direct DTE to undertake an analysis of the benefits to ratepayers of accelerating the retirement of any Tier 2 coal plant that is uneconomic, while simultaneously ensuring DTE meets its resource adequacy obligations through resources addressed in recommendation 2 above.

Q. Does that complete your testimony?

A. Yes.

Robert M. Fagan, Principal Associate

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SUMMARY

Mechanical engineer and energy economics analyst with over 30 years of experience in the energy industry. Activities focused primarily on electric power industry issues, especially economic and technical analysis of transmission, wholesale electricity markets, renewable resource alternatives and assessment and implementation of demand-side alternatives.

In-depth understanding of the complexities of, and the interrelationships between, the technical and economic dimensions of the electric power industry in the US and Canada, including the following areas of expertise:

- Wholesale energy and capacity provision under market-based and regulated structures; the extent of competitiveness of such structures.
- Potential for and operational effects of wind and solar power integration into utility systems; modeling of such effects.
- Transmission use pricing, encompassing congestion management, losses, LMP and alternatives; transmission rights; and transmission asset pricing (embedded cost recovery tariffs).
- Physical transmission network characteristics; related generation dispatch/system operation functions; and technical and economic attributes of generation resources.
- RTO and ISO tariff and market rules structures and operation, and related FERC regulatory policies and initiatives, including those pertaining to RTO and ISO development and evolution.
- Demand-side management, including program implementation and evaluation; and load response presence in wholesale markets.
- Building energy end-use characteristics, and energy-efficient technology options.
- Fundamentals of electric distribution systems and substation layout and operation.
- Energy modeling (spreadsheet-based tools, industry standard tools for production cost and resource expansion, building energy analysis, understanding of power flow simulation fundamentals).
- State and provincial level regulatory policies and practices, including retail service and standard offer pricing structures.
- Gas industry fundamentals including regulatory and market structures, and physical infrastructure.

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Principal Associate*, 2004 – Present.

Responsibilities include consulting on issues of energy economics, analysis of electricity utility planning, operation, and regulation, including issues of transmission, generation, and demand-side management. Provide expert witness testimony on various wholesale and retail electricity industry issues. Specific project experience includes the following:

- Analysis of New England region electric capacity need issues, including assessment of the effects of energy efficiency and small scale solar resources on net load projections, and implications for carbon emissions based on regional supply alternatives.
- Analysis of California renewable energy integration issues, local and system capacity requirements and purchases, and related long-term procurement policies.
- Analysis of air emissions and reliability impacts of Indian Point Energy Center retirement.
- Analysis of PJM and MISO wind integration and related transmission planning and resource adequacy issues.
- Analysis of Nova Scotia integrated resource planning policies including effects of potential new hydroelectric supplies from Newfoundland and demand side management impact; analysis of new transmission supplies of Maritimes area energy into the New England region.
- Analysis of Eastern Interconnection Planning Collaborative processes, including modeling structure and inputs assumptions for demand, supply and transmission resources. Expanded analyses of the results of the EIPC Phase II Report on transmission and resource expansion.
- Analysis of need for transmission facilities in Maine, Ontario, Pennsylvania, Virginia, Minnesota.
- Ongoing analysis of wholesale and retail energy and capacity market issues in New Jersey, including assessment of BGS supply alternatives and demand response options.
- Analysis of PJM transmission-related issues, including cost allocation, need for new facilities and PJM's economic modeling of new transmission effects on PJM energy market.
- Ongoing analysis of utility-sponsored energy efficiency programs in Rhode Island as part of the Rhode Island DSM Collaborative; and ongoing analysis of the energy efficiency programs of New Jersey Clean Energy Program (CEP) and various utility-sponsored efficiency programs (RGGI programs).
- Analysis of California renewable integration issues for achieving 33% renewable energy penetration by 2020, especially modeling constructs and input assumptions.
- Analysis of proposals in Maine for utility companies to withdraw from the ISO-NE RTO.
- Analysis of utility planning and demand-side management issues in Delaware.

- Analysis of effect of increasing the system benefits charge (SBC) in Maine to increase procurement of energy efficiency and DSM resources; analysis of impact of DSM on transmission and distribution reinforcement need.
- Evaluation of wind energy potential and economics, related transmission issues, and resource planning in Minnesota, Iowa, Indiana, and Missouri; in particular in relation to alternatives to newly proposed coal-fired power plants in MN, IA and IN.
- Analysis of need for newly proposed transmission in Pennsylvania and Ontario.
- Evaluation of wind energy “firming” premium in BC Hydro Energy Call in British Columbia.
- Evaluation of pollutant emission reduction plans and the introduction of an open access transmission tariff in Nova Scotia.
- Evaluation of the merger of Duke and Cinergy with respect to Indiana ratepayer impacts.
- Review of the termination of a Joint Generation Dispatch Agreement between sister companies of Cinergy.
- Assessment of the potential for an interstate transfer of a DSM resource between the desert southwest and California, and the transmission system impacts associated with the resource.
- Analysis of various transmission system and market power issues associated with the proposed Exelon-PSEG merger.
- Assessment of market power and transmission issues associated with the proposed use of an auction mechanism to supply standard offer power to ComEd native load customers.
- Review and analysis of the impacts of a proposed second 345 kV tie to New Brunswick from Maine on northern Maine customers.

Tabors Caramanis & Associates, Cambridge, MA. *Senior Associate*, 1996 – 2004.

- Provided expert witness testimony on transmission issues in Ontario and Alberta.
- Supported FERC-filed testimony of Dr. Tabors in numerous dockets, addressing various electric transmission and wholesale market issues.
- Analyzed transmission pricing and access policies, and electric industry restructuring proposals in US and Canadian jurisdictions including Ontario, Alberta, PJM, New York, New England, California, ERCOT, and the Midwest. Evaluated and offered alternatives for congestion management methods and wholesale electric market design.
- Attended RTO/ISO meetings, and monitored and reported on continuing developments in the New England and PJM electricity markets. Consulted on New England FTR auction and ARR allocation schemes.

- Evaluated all facets of Ontario and Alberta wholesale market development and evolution since 1997. Offered congestion management, transmission, cross-border interchange, and energy and capacity market design options. Directly participated in the Ontario Market Design Committee process. Served on the Ontario Wholesale Market Design technical panel.
- Member of TCA GE MAPS modeling team in LMP price forecasting projects.
- Assessed different aspects of the broad competitive market development themes presented in the US FERC's SMD NOPR and the application of FERC's Order 2000 on RTO development.
- Reviewed utility merger savings benchmarks, evaluated status of utility generation market power, and provided technical support underlying the analysis of competitive wholesale electricity markets in major US regions.
- Conducted life-cycle utility cost analyses for proposed new and renovated residential housing at US military bases. Compared life-cycle utility cost options for large educational and medical campuses.
- Evaluated innovative DSM competitive procurement program utilizing performance-based contracting.

Charles River Associates, Boston, MA. *Associate*, 1992 – 1996.

Developed DSM competitive procurement RFPs and evaluation plans, and performed DSM process and impact evaluations. Conducted quantitative studies examining electric utility mergers; and examined generation capacity concentration and transmission interconnections throughout the US. Analyzed natural gas and petroleum industry economic issues; and provided regulatory testimony support to CRA staff in proceedings before the US FERC and various state utility regulatory commissions.

Rhode Islanders Saving Energy, Providence, RI. *Senior Commercial/Industrial Energy Specialist*, 1987 – 1992.

Performed site visits, analyzed end-use energy consumption and calculated energy-efficiency improvement potential in approximately 1,000 commercial, industrial, and institutional buildings throughout Rhode Island, including assessment of lighting, HVAC, hot water, building shell, refrigeration and industrial process systems. Recommended and assisted in implementation of energy efficiency measures, and coordinated customer participation in utility DSM program efforts.

Fairchild Weston Systems, Inc., Syosset, NY. *Facilities Engineer*, 1985 – 1986.

Designed space renovations; managed capital improvement projects; and supervised contractors in implementation of facility upgrades.

Narragansett Electric Company, Providence RI. *Supervisor of Operations and Maintenance*, 1981 – 1984.

Directed electricians in operation, maintenance, and repair of high-voltage transmission and distribution substation equipment.

EDUCATION

Boston University, Boston, MA
Master of Arts in Energy and Environmental Studies – Resource Economics, Ecological Economics, Econometric Modeling, 1992

Clarkson University, Potsdam, NY
Bachelor of Science in Mechanical Engineering – Thermal Sciences, 1981

ADDITIONAL EDUCATION

- **Utility Wind Integration Group**: Short Course on Integration and Interconnection of Wind Power Plants into Electric Power Systems, 2006
- **University of Texas at Austin**: Short course in Regulatory and Legal Aspects of Electric Power Systems, 1998
- **Illuminating Engineering Society**: courses in lighting design, 1989
- **Worcester Polytechnic Institute and Northeastern University**: Coursework in Solar Engineering; Building System Controls; and Cogeneration, 1984, 1988 – 1989
- **Polytechnic Institute of New York**: Graduate coursework in Mechanical and Aerospace Engineering, 1985 – 1986

REPORTS AND PAPERS

Horowitz, A., A. Allison, N. Peluso, B. Fagan, M. Chang, D. Hurley, P. Peterson. 2017. *Comments on the United States Department of Energy's Proposed Grid Resiliency Pricing Rules (FERC Docket RM18-1-000)*. Prepared for Earthjustice.

Fagan, B., A. Napoleon, S. Fields, P. Luckow. 2017. *Clean Energy for New York: Replacement Energy and Capacity Resources for the Indian Point Energy Center Under New York Clean Energy Standard (CES).* Synapse Energy Economics for Riverkeeper and Natural Resources Defense Council.

Jackson, S., J. Fisher, B. Fagan, W. Ong. 2016. *Beyond the Clean Power Plan: How the Eastern Interconnection Can Significantly Reduce CO_2 Emissions and Maintain Reliability.* Prepared by Synapse Energy Economics for the Union of Concerned Scientists.

Luckow, P., B. Fagan, S. Fields, M. Whited. 2015. *Technical and Institutional Barriers to the Expansion of Wind and Solar Energy.* Synapse Energy Economics for Citizens' Climate Lobby.

Stanton, E. A., P. Knight, J. Daniel, R. 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.

Fagan, R., R. Wilson, D. White, T. Woolf. 2014. *Filing to the Nova Scotia Utility and Review Board on Nova Scotia Power's October 15, 2014 Integrated Resource Plan: Key Planning Observations and Action Plan Elements.* Synapse Energy Economics for the Nova Scotia Utility and Review Board.

Fagan, R., T. Vitolo, P. Luckow. 2014. *Indian Point Energy Center: Effects of the Implementation of Closed-Cycle Cooling on New York Emissions and Reliability.* Synapse Energy Economics for Riverkeeper.

Fagan, R., J. Fisher, B. Biewald. 2013. *An Expanded Analysis of the Costs and Benefits of Base Case and Carbon Reduction Scenarios in the EIPC Process.* Synapse Energy Economics for the Sustainable FERC Project.

Fagan, R., P. Luckow, D. White, R. Wilson. 2013. *The Net Benefits of Increased Wind Power in PJM.* Synapse Energy Economics for the Energy Future Coalition.

Hornby, R., R. Fagan, D. White, J. Rosenkranz, P. Knight, R. Wilson. 2012. *Potential Impacts of Replacing Retiring Coal Capacity in the Midwest Independent System Operator (MISO) Region with Natural Gas or Wind Capacity.* Synapse Energy Economics for the National Association of Regulatory Utility Commissioners.

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

Woolf, T., M. Wittenstein, R. Fagan. 2011. *Indian Point Energy Center Nuclear Plant Retirement Analysis.* Synapse Energy Economics for the Natural Resources Defense Council (NRDC) and Riverkeeper.

Napoleon, A., W. Steinhurst, M. Chang, K. Takahashi, R. Fagan. 2010. *Assessing the Multiple Benefits of Clean Energy: A Resource for States*. US Environmental Protection Agency with research and editorial support from Stratus Consulting, Synapse Energy Economics, Summit Blue, Energy and Environmental Economics, Inc., Demand Research LLC, Abt Associates, Inc., and ICF International.

Peterson, P., E. Hausman, R. Fagan, V. Sabodash. 2009. *Synapse Report and Ohio Comments in Case No. 09-09-EL-COI, "The Value of Continued Participation in RTOs."* Synapse Energy Economics for Ohio Consumers' Counsel.

Hornby, R., J. Loiter, P. Mosenthal, T. Franks, R. Fagan and D. White. 2008. *Review of AmerenUE February 2008 Integrated Resource Plan.* Synapse Energy Economics for the Missouri Department of Natural Resources.

Hausman, E., R. Fagan, D. White, K. Takahashi, A. Napoleon. 2007. *LMP Electricity Markets: Market Operations, Market Power, and Value for Consumer.* Synapse Energy Economics for the American Public Power Association.

Fagan, R., T.Woolf, W. Steinhurst, B. Biewald. 2006. "Interstate Transfer of a DSM Resource: New Mexico DSM as an Alternative to Power from Mohave Generating Station." Proceedings and presentation at 2006 American Council for Energy Efficient Economy (ACEEE) Summer Study on Energy Efficiency in Buildings Conference, August 2006.

Fagan, R., R. Tabors, A. Zobian, N. Rao, R. Hornby. 1999. *Tariff Structure for an Independent Transmission Company*. Tabors Caramanis & Associates Working Paper 101-1099-0241.

Fagan, R. 1996. *The Market for Power in New England: The Competitive Implications of Restructuring*. Tabors Caramanis & Associates and Charles River Associates for the Office of the Attorney General, Commonwealth of Massachusetts.

Fagan, R., D. Gokhale, D. Levy, P. Spinney, G. Watkins. 1995. "Estimating DSM Impacts for Large Commercial and Industrial Electricity Users." Proceedings and presentation at The Seventh International Energy Program Evaluation Conference in Chicago, IL, August 1995.

Fagan, R., P. Spinney. 1995. *Demand-side Management Information Systems (DSMIS) Overview*. Charles River Associates for Electric Power Research Institute. Technical Report TR-104707.

Fagan, R., P. Spinney. 1994. *Northeast Utilities Energy Conscious Construction Program (Comprehensive Area): Level I and Level II Impact Evaluation Reports*. Charles River Associates, Energy Investments (Abbe Bjorklund) for Northeast Utilities.

PRESENTATIONS

Fagan, R., R. Tabors. 2003. "SMD and RTO West: Where are the Benefits for Alberta?" Keynote paper prepared for the 9th Annual Conference of the Independent Power Producers Society of Alberta, March 2003.

Fagan, R. 1999. "A Progressive Transmission Tariff Regime: The Impact of Net Billing". Presentation at the Independent Power Producer Society of Ontario Annual Conference, November 1999.

Fagan, R. 1999. "Transmission Congestion Pricing Within and Around Ontario." Presentation at the Canadian Transmission Restructuring Infocast Conference in Toronto, June 1999.

Fagan, R. 1998. "The Restructured Ontario Electricity Generation Market and Stranded Costs." Presentation to the Ontario Ministry of Energy and Environment on behalf of Enron Capital and Trade Resources Canada Corp., February 1998.

Fagan, R. 1998. "Alberta Legislated Hedges Briefing Note." Presentation to the Alberta Department of Energy on behalf of Enron Capital and Trade Resources Canada, January 1998.

Fagan, R. 1997. "Generation Market Power in New England: Overall and on the Margin." Presentation at Infocast Conference: New Developments in Northeast and Mid-Atlantic Wholesale Power Markets in Boston, MA, June 1997.

Spinney, P., J. Peloza, R. Fagan presented. 1993. “The Role of Trade Allies in C&I DSM Programs: A New Focus for Program Evaluation.” Charles River Associates and Wisconsin Electric Power Corp presentation at the Sixth International Energy Evaluation Conference in Chicago, IL, August 1993.

TESTIMONY

Council of the City of New Orleans (Case UD-16-02): Pre-Filed Direct Testimony examining and critiquing Entergy New Orleans proposal to install gas-fired generation in New Orleans at the existing site of the retired Michoud generating station. Testimony filed on behalf of Sierra Club, Deep South Center for Environmental Justice, the Alliance for Affordable Energy, and 350 Louisiana – New Orleans. October 16, 2017.

Michigan Public Service Commission (Case U-18255): Pre-Filed Direct Testimony examining Midwest ISO resource adequacy issues and DTE Energy Tier 2 coal plant retirement issues in Michigan and the broader MISO region. Testimony filed on behalf of Michigan Environmental Council, NRDC and Sierra Club. August 29, 2017.

Rhode Island Energy Facilities Siting Board (Docket No. SB 2015-06): Pre-Filed Direct Testimony examining reliability need for the proposed Clear River Energy Center in Burrillville, RI. Testimony filed on behalf of Conservation Law Foundation, August 7, 2017.

Nova Scotia Utility and Review Board (Matter No. 07718): Joint direct testimony of Robert Fagan and Tyler Comings regarding economic analysis of the Maritime Link Project. On behalf of Nova Scotia Utility and Review Board Counsel. April 19, 2017.

Illinois Commerce Commission (Docket No. 16-0259): Direct and rebuttal testimony on Commonwealth Edison Company’s annual formula rate update and revenue requirement reconciliation on distribution and business intelligence investments. On behalf of the Office of Illinois Attorney General. June 29, 2016 and August 11, 2016.

Connecticut Siting Council (Docket No. 470): Direct and Surrebuttal Testimony regarding the need for and emissions impact of NTE's proposed 550 MW combined cycle power plant ("Killingly Energy Center"). On behalf of Sierra Club and Not Another Power Plant. November 15, 2016 and December 22, 2016.

Federal Energy Regulatory Commission (Docket No. ER17-284): Affidavit examining and critiquing the Midwest Independent System Operator's (MISO) proposal for a "Competitive Retail Solution (CRS)", a proposed change to the capacity procurement construct for a portion of MISO load. December 15, 2016.

Massachusetts Electric Facilities Siting Board (Docket 15-06): Direct and Supplemental Direct Testimony regarding the impact of Exelon’s proposed Canal 3 power plant on compliance with the Global Warming Solutions Act and estimation of emissions avoided with its operation. On behalf of Conservation Law Foundation. July 15, 2016 and September, 2016.

Rhode Island Public Utilities Commission (Docket No. 4609): Pre-Filed Direct Testimony examining reliability need for the proposed Clear River Energy Center in Burrillville, RI. Testimony filed on behalf of Conservation Law Foundation, June 14, 2016.

California Public Utilities Commission (Docket No. A.15-04-012): Testimony examining San Diego Gas & Electric's Marginal Energy Costs and LOLE Allocation among TOU Periods. Jointly, with Patrick Luckow. On behalf of the California Office of Ratepayer Advocate. June, 2016.

Federal Energy Regulatory Commission (Docket No. ER16-833-000): Affidavit addressing certain technical issues (accounting for "counterflow" effects on capacity import limits (CIL) for Local Reliability Zones) surrounding MISO's then-forthcoming Planning Resource Auction (PRA), which took place in April 2016. February 2016.

Massachusetts Electric Facilities Siting Board (Docket 15-1): Testimony regarding the impact of Exelon's proposed Medway power plant on compliance with the Global Warming Solutions Act. On behalf of Conservation Law Foundation. November 13, 2015.

California Public Utilities Commission (Docket No. A.14-06-014): Testimony examining Southern California Edison (SCE) proposals for Marginal Energy and Capacity Costs in Phase 2 of its 2015 General Rate Case (GRC). On behalf of the California Office of Ratepayer Advocate. Jointly, with Patrick Luckow. February 13, 2015.

California Public Utilities Commission (Docket No. A.14-11-014): Testimony examining Pacific Gas and Electric's Marginal Energy Costs and LOLE Allocation among TOU Periods. Jointly, with Patrick Luckow. On behalf of the California Office of Ratepayer Advocate. May 1, 2015.

California Public Utilities Commission (Docket No. A.14-11-012): Testimony reviewing Southern California Edison 2013 local capacity requirements request for offers for the western Los Angeles Basin, specifically related to storage. On behalf of Sierra Club. March 25, 2015.

California Public Utilities Commission (Docket No. A.14-01-027): Testimony examining San Diego Gas & Electric's proposal to change time-of-use periods in its application for authority to update its electric rate design. Jointly, with Patrick Luckow. On behalf of the California Office of Ratepayer Advocate. November 14, 2014.

California Public Utilities Commission (Docket No. R.12-06-013): Rebuttal testimony regarding the relationship between California investor-owned utilities hourly load profiles under a time-of-use pricing and GHG emissions in the WECC regions in the Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations. On behalf of the California Office of Ratepayer Advocate. October 17, 2014.

California Public Utilities Commission (Docket No. R.13-12-010): Direct and reply testimony on Phase 1a modeling scenarios in the Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans. On behalf of the California Office of Ratepayer Advocate. August 13, 2014, October 22, 2014, and December 18, 2014.

New York State Department of Environmental Conservation (DEC #3-5522-00011/000004; SPDES #NY-0004472; DEC #3-5522-00011/00030; DEC #3-5522-00011/00031): Direct, rebuttal, and surrebuttal testimonies regarding air emissions, electric system reliability, and cost impacts of closed-cycle cooling as the "best technology available" (BTA), and alternative "Fish Protective Outages" (FPO), for the Indian Point nuclear power plant. On behalf of Riverkeeper. February 28, 2014, March 28, 2014, July 11, 2014, June 26, 2015, and August 10, 2015.

California Public Utilities Commission (Docket No. RM.12-03-014): Reply and rebuttal testimony on the topic of local reliability impacts of a potential long-term outage at the San Onofre Nuclear Power Station (SONGS) in Track 4 of the Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans. On behalf of the California Office of Ratepayer Advocate. September 30, 2013 and October 14, 2013.

Nova Scotia Utility and Review Board (Matter No. 05522): *Filing to the Nova Scotia Utility and Review Board on Nova Scotia Power's October 15, 2014 Integrated Resource Plan, Key Planning Observations and Action Plan Elements*. On behalf of Board Counsel to the Nova Scotia Utility and Review Board, October 20, 2014. With Rachel Wilson, David White and Tim Woolf.

Nova Scotia Utility and Review Board (Matter No. 05419): Direct examination regarding the report *Economic Analysis of Maritime Link and Alternatives: Complying with Nova Scotia's Greenhouse Gas Regulations, Renewable Energy Standard, and Other Regulations in a Least-Cost Manner for Nova Scotia Power Ratepayers* jointly authored with Rachel Wilson, Nehal Divekar, David White, Kenji Takahashi, and Tommy Vitolo. In the Matter of The Maritime Link Act and In the Matter of An Application by NSP MARITIME LINK INCORPORATED for the approval of the Maritime Link Project. On behalf of Board Counsel to the Nova Scotia Utility and Review Board. June 5, 2013.

Prince Edward Island Regulatory and Appeals Commission (Docket UE30402): Jointly filed expert report with Nehal Divekar analyzing the Proposed Ottawa Street – Bedeque 138 kV Transmission Line Project in the matter of Summerside Electric's Application for the Approval of Transmission Services connecting Summerside Electric's Ottawa Street substation to Maritime Electric Company Limited's Bedeque substation. Oh behalf of the City of Summerside. November 5, 2012.

New Jersey Board of Public Utilities (Docket No. GO12070640): Direct testimony regarding New Jersey Natural Gas Company's petition for approval of the extension of the SAVEGREEN energy efficiency programs. On behalf of the New Jersey Division of the Ratepayer Advocate. October 26, 2012.

California Public Utilities Commission (Docket No. RM.12-03-014): Direct and reply testimony regarding the long-term local capacity procurement requirements for the three California investor-owned utilities in Track 1 of the Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans. On behalf of the California Office of Ratepayer Advocate. June 25, 2012 and July 23, 2012.

California Public Utilities Commission (Docket No. A.11-05-023): Supplemental testimony regarding the long-term resource adequacy and resource procurement requirements for the San Diego region in the Application of San Diego Gas & Electric Company (U 902 3) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center, and Quail Brush Power. On behalf of the California Office of Ratepayer Advocate. May 18, 2012.

New Jersey Board of Public Utilities (Docket No. GO11070399): Direct testimony in the matter of the petition of Pivotal Utility Holdings, Inc. D/B/A Elizabethtown Gas for authority to extend the term of energy efficiency programs with certain modifications and approval of associated cost recovery. On behalf of New Jersey Division of Rate Counsel. December 16, 2011.

New Jersey Board of Public Utilities (Docket No. EO11050309): Direct testimony regarding aspects of the Board's inquiry into capacity and transmission interconnection issues. October 14, 2011.

Federal Energy Regulatory Commission (Docket Nos. EL11-20-000 and ER11-2875-000): Affidavit regarding reliability, status of electric power generation capacity, and current electric power procurement policies in New Jersey. On behalf of New Jersey Division of Rate Counsel. March 4, 2011.

New Jersey Board of Public Utilities (Docket Nos. GR10100761 and ER10100762): Certification before the Board regarding system benefits charge (SBC) rates associated with gas generation in the matter of a generic stakeholder proceeding to consider prospective standards for gas distribution utility rate discounts and associated contract terms. On behalf of New Jersey Division of Rate Counsel. January 28, 2011.

New Jersey Board of Public Utilities (Docket No. ER10040287): Direct testimony regarding Basic Generation Service (BGS) procurement plan for service beginning June 1, 2011. On behalf of New Jersey Division of Rate Advocate. September 2010.

State of Maine Public Utilities Commission (Docket 2008-255): Direct and surrebuttal testimony regarding the non-transmission alternatives analysis conducted on behalf of Central Maine Power in the Application of Central Maine Power Company and Public Service of New Hampshire for a Certificate of Public Convenience and Necessity for the Maine Power Reliability Program Consisting of the Construction of Approximately 350 Miles of 345 and 115 kV Transmission Lines, a $1.55 billion transmission enhancement project. On behalf of the Maine Office of the Public Advocate. January 12, 2009 and February 2, 2010.

Virginia State Corporation Commission (CASE NO. PUE-2009-00043): Direct testimony regarding the need for modeling DSM resources as part of the PJM RTEP planning processes in the Application of Potomac-Appalachian Transmission Highline (PATH) Allegheny Transmission Corporation for CPCN to construct facilities: 765 kV proposed transmission line through Loudoun, Frederick, and Clarke Counties. On behalf of Sierra Club. October 23, 2009.

Pennsylvania Public Utility Commission (Docket number A-2009-2082652): Direct and surrebuttal testimony regarding the need for additional modeling for the proposed Susquehanna-Roseland 500 kv transmission line in portions of Luckawanna, Luzerne, Monroe, Pike, and Wayne counties to include load forecasts, energy efficiency resources, and demand response resources. On behalf of the Pennsylvania Office of Consumer Advocate. June 30, 2009 and August 24, 2009.

Delaware Public Service Commission (Docket No. 07-20): Filed the expert report *Review of Delmarva Power & Light Company's Integrated Resource Plan* jointly authored with Alice Napoleon, William Steinhurst, David White, and Kenji Takahashi In the Matter of Integrated Resource Planning for the Provision of Standard Offer Service by Delmarva Power & Light Company Under 26 DEL. C. §1007 (c) & (d). On behalf of the Staff of Delaware Public Service Commission. April 2, 2009.

New Jersey Board of Public Utilities (Docket No. ER08050310): Direct testimony filed jointly with Bruce Biewald on aspects of the Basic Generation Service (BGS) procurement plan for service beginning June 1, 2009. On behalf of the New Jersey Division of the Ratepayer Advocate. September 29, 2008.

Wisconsin Public Service Commission (Docket 6680-CE-170): Direct and surrebuttal testimony in the matter of the alternative energy options available with wind power, and the effect of the MISO RTO in helping provide capacity and energy to the Wisconsin area reliably without needed the proposed coal plant in the CPCN application by Wisconsin Power and Light for construction of a 300 MW coal plant. On behalf of Clean Wisconsin. August 11, 2008 and September 15, 2008.

Ontario Energy Board (Docket EB-2007-0707): Direct testimony regarding issues associated with the planned levels of procurement of demand response, combined heat and power, and NUG resources as part of Ontario Power Authority’s long-term integrated planning process in the Examination and Critique of Demand Response and Combined Heat and Power Aspects of the Ontario Power Authority’s Integrated Power System Plan and Procurement Process. On behalf of Pollution Probe. August 1, 2008.

Ontario Energy Board (Docket EB-2007-0050): Direct and supplemental testimony filed jointly with Peter Lanzalotta regarding issues of congestion (locked-in energy) modeling, need, and series compensation and generation rejection alternatives to the proposed line of in the matter of Hydro One Networks Inc.’s application to construct a new 500 kV transmission line between the Bruce Power complex and the town of Milton, Ontario. On behalf of Pollution Probe. April 18, 2008 and May 15, 2008.

Federal Energy Regulatory Commission (Dockets ER06-456, ER06-954, ER06-1271, ER07-424, EL07-57, ER06-880, et al.): Direct and rebuttal testimony addressing merchant transmission cost allocation issues on PJM Regional Transmission Expansion Plan (RTEP) Cost Allocation issues. On behalf of the New Jersey Division of the Ratepayer Advocate. January 23, 2008 and April 16, 2008.

State of Maine Public Utilities Commission (Docket No. 2006-487): Pre-file and surrebuttal testimony on the ability of DSM and distributed generation potential to reduce local supply area reinforcement needs in the matter of the Analysis of Central Maine Power Company Petition for a Certificate of Public Convenience and Necessity to Build a 115 kV Transmission Line between Saco and Old Orchard Beach. On behalf of Maine Office of the Public Advocate. February 27, 2007 and January 10, 2008.

Minnesota Public Utilities Commission (OAH No. 12-2500-17037-2 and OAH No. 12-2500-17038-2; and MPUC Dkt. Nos. CN-05-619 and TR-05-1275): Supplemental testimony and supplemental rebuttal testimony on applicants' estimates of DSM savings in the Certificate of Need proceeding for the Big Stone II coal-fired power plant proposal In the Matter of the Application by Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota and In the Matter of the Application to the Minnesota Public Utilities Commission for a Route Permit for the Big Stone Transmission Project in Western Minnesota. On behalf of Fresh Energy, Izaak Walton League of America – Midwest Office, Wind on the Wires, Union of Concerned Scientists, Minnesota Center for Environmental Advocacy. December 8, 2006 and December 21, 2007.

Pennsylvania Public Utility Commission (Docket Nos. A-110172 *et al.*): Direct testimony on the effect of demand-side management on the need for a transmission line and the level of consideration of potential carbon regulation on PJM's analysis of need for the TrAIL transmission line. On behalf of the Pennsylvania Office of Consumer Advocate. October 31, 2007.

Iowa Public Utilities Board (Docket No. GCU-07-01): Direct testimony regarding wind energy assessment in Interstate Power and Light's resource plans and its relationship to a proposed coal plant in Iowa. On behalf of Iowa Office of the Consumer Advocate. October 21, 2007.

New Jersey Board of Public Utilities (Docket No. EO07040278): Direct testimony on certain aspects of PSE&G's proposal to use ratepayer funding to finance a solar photovoltaic panel initiative in support of the State's solar RPS. September 21, 2007.

Indiana Utility Regulatory Commission (Cause No. 43114): Direct testimony on the topic of a proposed Duke – Vectren IGCC coal plant and wind power potential in Indiana. On behalf of Citizens Action Coalition of Indiana. May 14, 2007.

British Columbia Utilities Commission: Pre-filed evidence regarding the "firming premium" associated with 2006 Call energy, liquidated damages provisions, and wind integration studies In the Matter of BC Hydro 2006 Integrated Electricity Plan and Long Term Acquisition Plan. On behalf of the Sierra Club (BC Chapter), Sustainable Energy Association of BC, and Peace Valley Environment Association. October 10, 2006.

Maine Joint Legislative Committee on Utilities, Energy and Transportation (LD 1931): Testimony regarding the costs and benefits of increasing the system benefits charge to increase the level of energy efficiency installations by Efficiency Maine before in support of an Act to Encourage Energy Efficiency. On behalf of the Maine Natural Resources Council and Environmental Defense. February 9, 2006.

Nova Scotia Utility and Review Board: Direct testimony and supplemental evidence regarding the approval of the installation of a flue gas desulphurization system at Nova Scotia Power Inc.'s Lingan station and a review of alternatives to comply with provincial emission regulations In The Matter of an Application by Nova Scotia Power Inc. for Approval of Air Emissions Strategy Capital Projects and The Public Utilities Act, R.S.N.S., 1989, c. 380, as amended. On behalf of Nova Scotia Utility and Review Board Staff. January 30, 2006.

New Jersey Board of Public Utilities (BPU Docket EM05020106): Joint direct and surrebuttal testimony with Bruce Biewald and David Schlissel regarding the Joint Petition Of Public Service Electric and Gas Company And Exelon Corporation For Approval of a Change in Control Of Public Service Electric and Gas Company And Related Authorizations. On behalf of New Jersey Division of the Ratepayer Advocate. November 14, 2005 and December 27, 2005.

Indiana Utility Regulatory Commission (Cause No. 42873): Direct testimony addressing the proposed Duke – Cinergy merger. On behalf of Citizens Action Coalition of Indiana. November 8, 2005.

Indiana Utility Regulatory Commission (Causes No. 38707 FAC 61S1, 41954, and 42359-S1): Responsive testimony addressing a proposed Settlement Agreement between PSI and other parties in respect of issues surrounding the Joint Generation Dispatch Agreement in place between PSI and CG&E. On behalf of Citizens Action Coalition of Indiana. August 31, 2005.

Illinois Commerce Commission (Dockets 05-0160, 05-0161, 05-0162): Direct and rebuttal testimony addressing wholesale market aspects of Ameren's proposed competitive procurement auction (CPA). On behalf of Illinois Citizens Utility Board. June 15, 2005 and August 10, 2005.

Illinois Commerce Commission (Docket 05-0159): Direct and rebuttal testimony addressing wholesale market aspects of Commonwealth Edison's proposed BUS (Basic Utility Service) competitive auction procurement. On behalf of Illinois Citizens Utility Board and Cook County State's Attorney's Office. June 8, 2005 and August 3, 2005.

State of Maine Public Utilities Commission (Docket No. 2005-17): Joint testimony with David Schlissel and Peter Lanzalotta regarding an Analysis of Eastern Maine Electric Cooperative, Inc.'s Petition for a Finding of Public Convenience and Necessity to Purchase 15 MW of Transmission Capacity from New Brunswick Power and for Related Approvals. On behalf of Maine Office of the Public Advocate. July 19, 2005.

Indiana Utility Regulatory Commission (Cause No. 38707 FAC 61S1): Direct testimony in a Fuel Adjustment Clause (FAC) proceeding concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E, and related issues of PSI lost revenues from inter-company energy pricing policies. On behalf of Citizens Action Coalition of Indiana. May 23, 2005.

Indiana Utility Regulatory Commission (Cause No. 41954): Direct testimony concerning the pricing aspects and merits of continuation of the Joint Generation Dispatch Agreement in place between PSI and CG&E. On behalf of Citizens Action Coalition of Indiana. April 21, 2005.

State of Maine Public Utilities Commission (Docket No. 2004-538): Joint testimony with David Schlissel and Peter Lanzalotta regarding an Analysis of Maine Public Service Company Request for a Certificate of Public Convenience and Necessity to Purchase 35 MW of Transmission Capacity from New Brunswick Power. On behalf of Maine Office of the Public Advocate. April 14, 2005.

Nova Scotia Utility and Review Board (Order 888 OATT): Testimony regarding various aspects of OATTs and FERC's *pro forma* In The Matter of an Application by Nova Scotia Power Inc. for Approval of an Open Access Transmission Tariff (OATT). On behalf of the Nova Scotia Utility Review Board Staff. April 5, 2005.

Texas Public Utilities Commission (Docket No. 30485): Testimony regarding excess mitigation credits associated with CenterPoint's stranded cost recovery in the Application of CenterPoint Energy Houston Electric, LLC. for a Financing Order. On behalf of the Gulf Coast Coalition of Cities. January 7, 2005.

Ontario Energy Board (RP-2002-0120): Filed testimony and reply comments reviewing the Transmission System Code (TSC) and Related Matters, Detailed Submission to the Ontario Energy Board in Response To Phase I Questions Concerning the Transmission System Code and Related Matters. On behalf of TransAlta Corporation. October 31, 2002 and November 21, 2002.

Alberta Energy and Utilities Board (Application No. 2000135): Filed joint testimony with Dr. Richard D. Tabors in the matter of the Transmission Administrator's 2001 Phase I and Phase II General Rate Application pertaining to Supply Transmission Service charge proposals. On behalf of Alberta Buyers Coalition. March 28, 2001.

Ontario Energy Board (RP-1999-0044): Testimony critiquing Ontario Hydro Networks Company's Transmission Tariff Proposal and Proposal for Alternative Rate Design. On behalf of the Independent Power Producer's Society of Ontario. January 17, 2000.

Massachusetts Department of Public Utilities (Docket # DPU 95-2/3-CC-I): Filed a report (Fagan R., G. Watkins. 1995. *Sampling Issues in Estimating DSM Savings: An Issue Paper for Commonwealth Electric*. Charles River Associates). On behalf of COM/Electric System. April 1995.

Massachusetts Department of Public Utilities (Docket # DPU 95-2/3-CC-I): Filed initial and updated reports (Fagan R., P. Spinney, G. Watkins. 1994. *Impact Evaluation of Commonwealth Electric's Customized Rebate Program*. Charles River Associates. Updated April 1996). April 1994 and April 1995.

Resume dated November 2017

2017 OMS MISO Survey Results

Furthering our joint commitment to regional resource assessment and transparency in the MISO region, OMS and MISO are pleased to announce the results of the 2017 OMS MISO Survey

July 2017

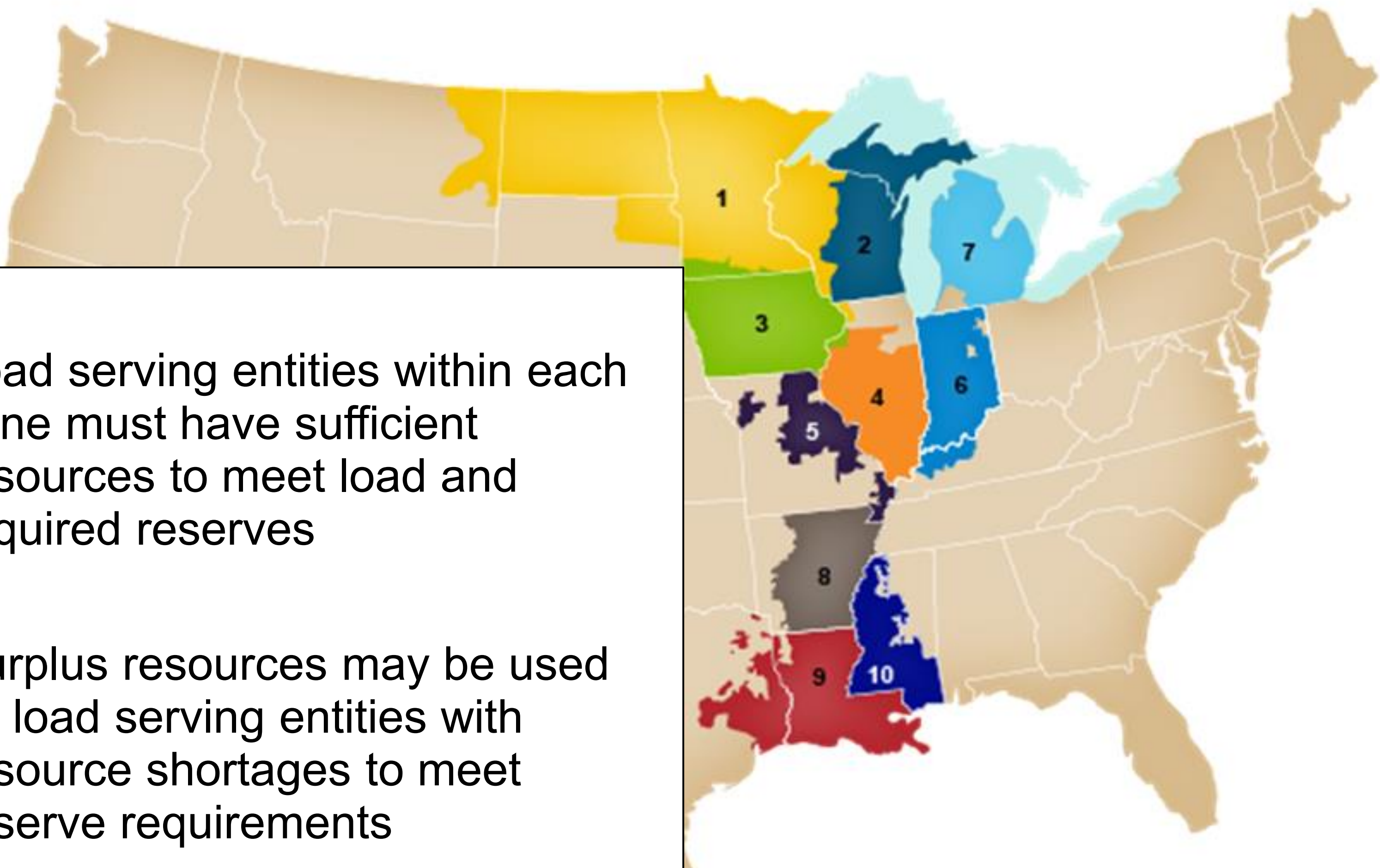
The 2017 OMS MISO survey projects sufficient resources to manage resource adequacy risk

- In 2018, changes in resource commitment and decreased demand lead to a regional surplus
  - The region is projected to have 2.7 GW to 4.8 GW resources in excess of the regional requirement, based on responses from over 96% of MISO load

- Decreases in demand forecast leads to a lower resource adequacy risk than previously projected
  - 2018 summer peak forecasts decreased 2.5 GWs from 2017 projections
  - Regional 5 year growth rate is 0.5%, down from 0.8% last year

- Beyond 2018, continued focus on load growth variations and generation retirements will reduce uncertainty in future resource adequacy assessments

Understanding Resource Adequacy Requirements

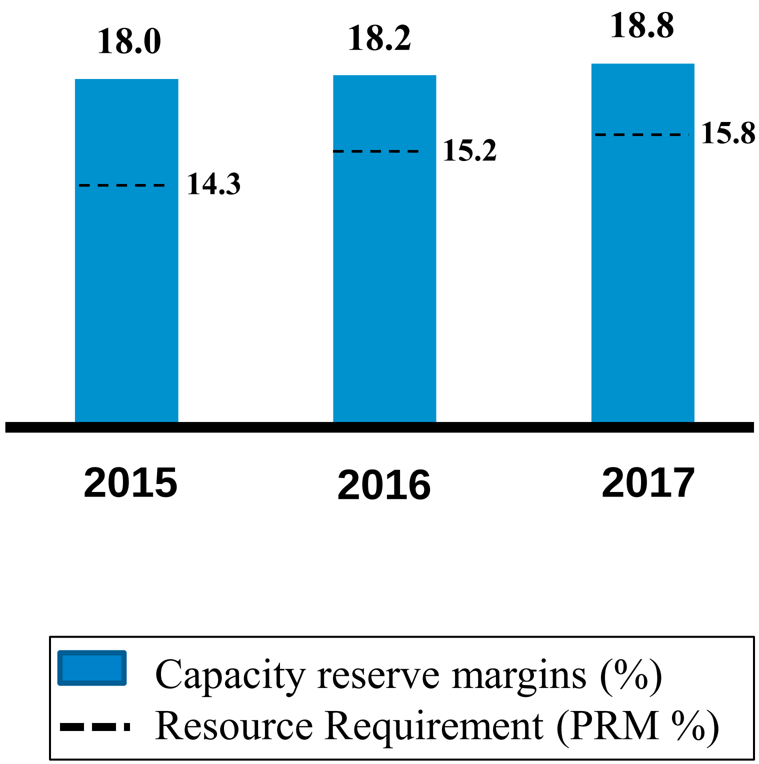


- Load serving entities within each zone must have sufficient resources to meet load and required reserves

- Surplus resources may be used by load serving entities with resource shortages to meet reserve requirements

Planning Reserve Margins capture the risks in the load and generation on the system

Projected Reserve Margins and Requirements (% ICAP)

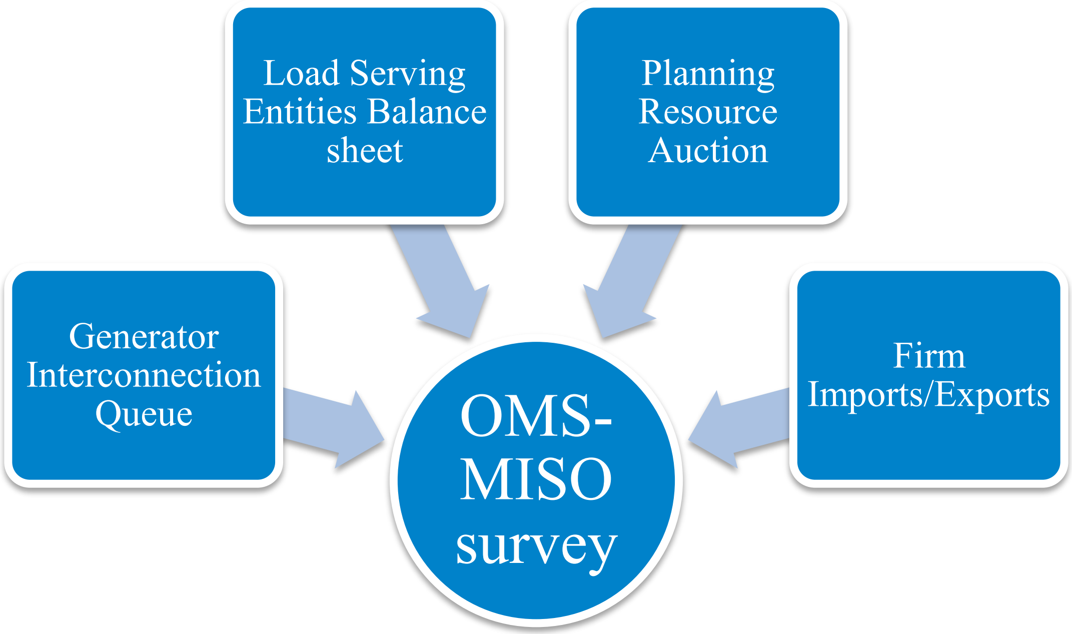


- Planning Reserve Margins show how much capacity is needed as a percentage above load, to maintain resource adequacy

- The percent resource requirements may be **higher** when
  - Fleet forced outage rate is **higher**
  - Load volatility is **higher**
  - Load forecasts are **lower**

What's in the survey?

- OMS-MISO survey responses
  - Insight into confidence around availability of resources
- Load data
- All generation within MISO, including merchant resources, considered
- External imports, exports, and inter-zonal transfers accounted for



Illustrative OMS MISO Data Request

Existing Resources

									2018*	2018**	…	2026	2026
LSE	LBA	Actual LRZ Resource Location	Physical Location (City, State)	MECT Planning Resource Name	Fuel Type of Planning Resource	Planning Resource Type	Corrected ICAP (UCAP Renewables)	UCAP MW	YES/NO	Factor	…	YES/NO	Factor
TEST_LSE		Zone X	TBD	Example unit 1	Coal	Gen	165.0	159.2	Yes	H	…	No	H
TEST_LSE		Zone X	TBD	Example unit 2	Gas	Gen	153.0	145.9	Yes	H	…	Yes	H
TEST_LSE		Zone X	TBD	Example unit 3	Diesel	BTMG	26.5	21.3	Yes	H	…	Yes	H
TEST_LSE		Zone X	TBD	Example unit 4		DRR	36.8	36.8	Yes	H	…	Yes	L
TEST_LSE		Zone X	TBD	Example unit 5	Gas	ER	88.6	84.7	Yes	H	…	No	L

New Resources

LSE	Actual LRZ Resource Location	Project Name	Tier 1, Tier 2, Tier 3	Resource Type	Location	ICAP (Intermittent Non- Wind & Solar UCAP)	MISO Class EFORd	UCAP MW	Year Expected for Capacity Credit	GIQ - Project Number
TEST_LSE	Zone X	New Project	Tier 1	CC		500	0.00378	498.1	2020	JXXX
TEST_LSE	Zone X	New Project II	Tier 3	CC		250	0.00378	249.1	2021	

* Resource Availability
** Certainty Factor

Illustrative OMS MISO Data Request

Internal MISO Transfers

									2018	2018	…	2026	2026
LSE	LBA	Actual LRZ Resource is Physically Located	MECT Contract Name	MECT Planning Resource Name	Planning Resource Fuel Type	LRZ Internal Transfer Type (In/out)	Corrected ICAP (UCAP Renewables)	UCAP MW	YES/ NO	Factor	…	YES/ NO	Factor
TEST_LSE A		Zone X	Contract with LSE B and LSE A	Unit 1	Coal	LRZ Internal Transfer- Out	287.7	285.3	Yes	H	…	Yes	H
TEST_LSE A		Zone X	Capacity Deal with LSE C and LSE A	Unit 2	Coal	LRZ Internal Transfer- In	276.7	274.4	Yes	H	…	Yes	H
TEST_LSE B		Zone Y	Contract with LSE B and LSE A	Unit 1	Coal	LRZ Internal Transfer- In	287.7	285.3	Yes	H	…	Yes	H
TEST_LSE C		Zone Z	Capacity Deal with LSE C and LSE A	Unit 2	Coal	LRZ Internal Transfer- Out	276.7	274.4	Yes	H	…	Yes	H

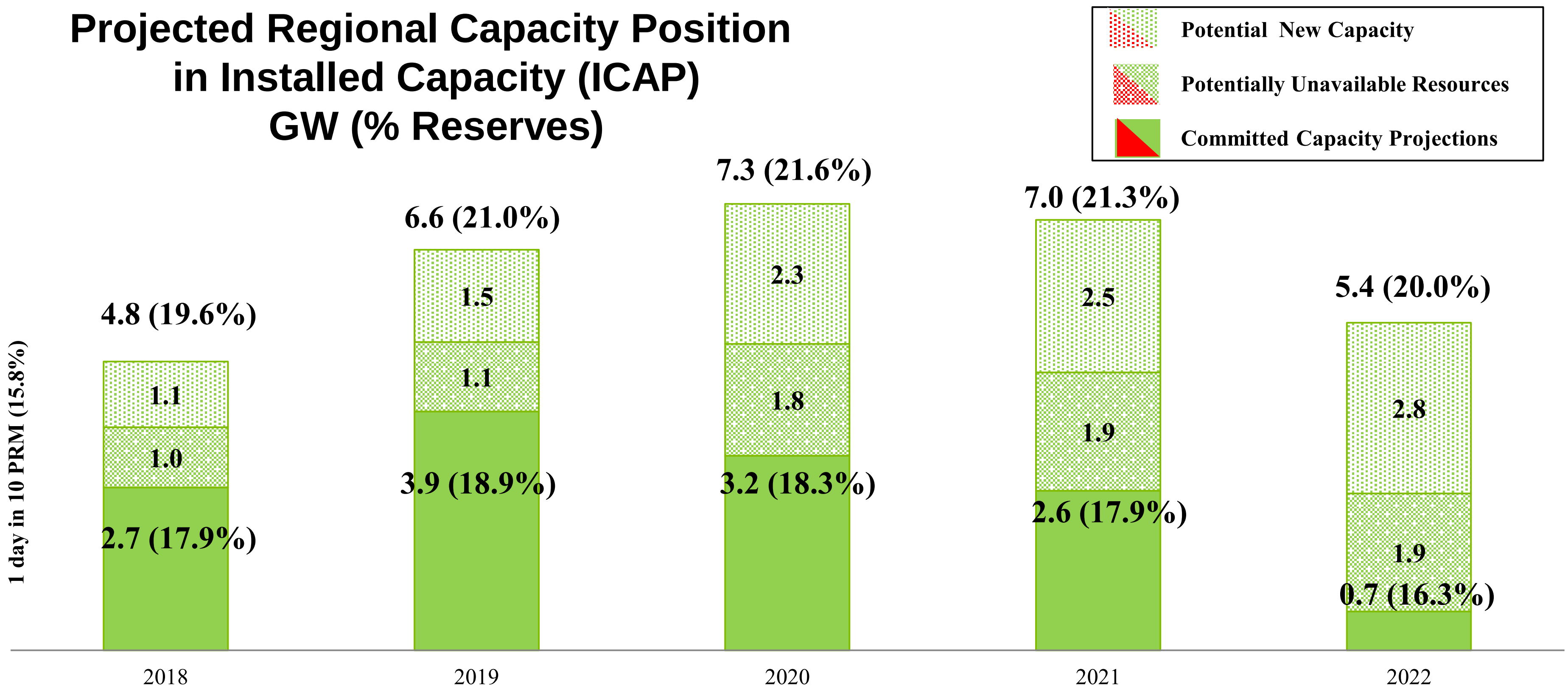
Full Responsibility Transactions

						2018	2018	...	2026	2026
LSE	LRZ	MECT Contract Name	Sale or Purchase	Counterparty	FRT MW Sales (-) Purchase (+)	YES/NO	Factor	...	YES/NO	Factor
TEST_LSE A	Zone X	LSE A to LSE C PY16-17	Sale	TEST_LSE C	-50	Yes	H	...	Yes	H
TEST_LSE C	Zone X	LSE A to LSE C PY 16-17	Purchase	TEST_LSE A	50	Yes	H	...	Yes	H

Understanding Resource Projections

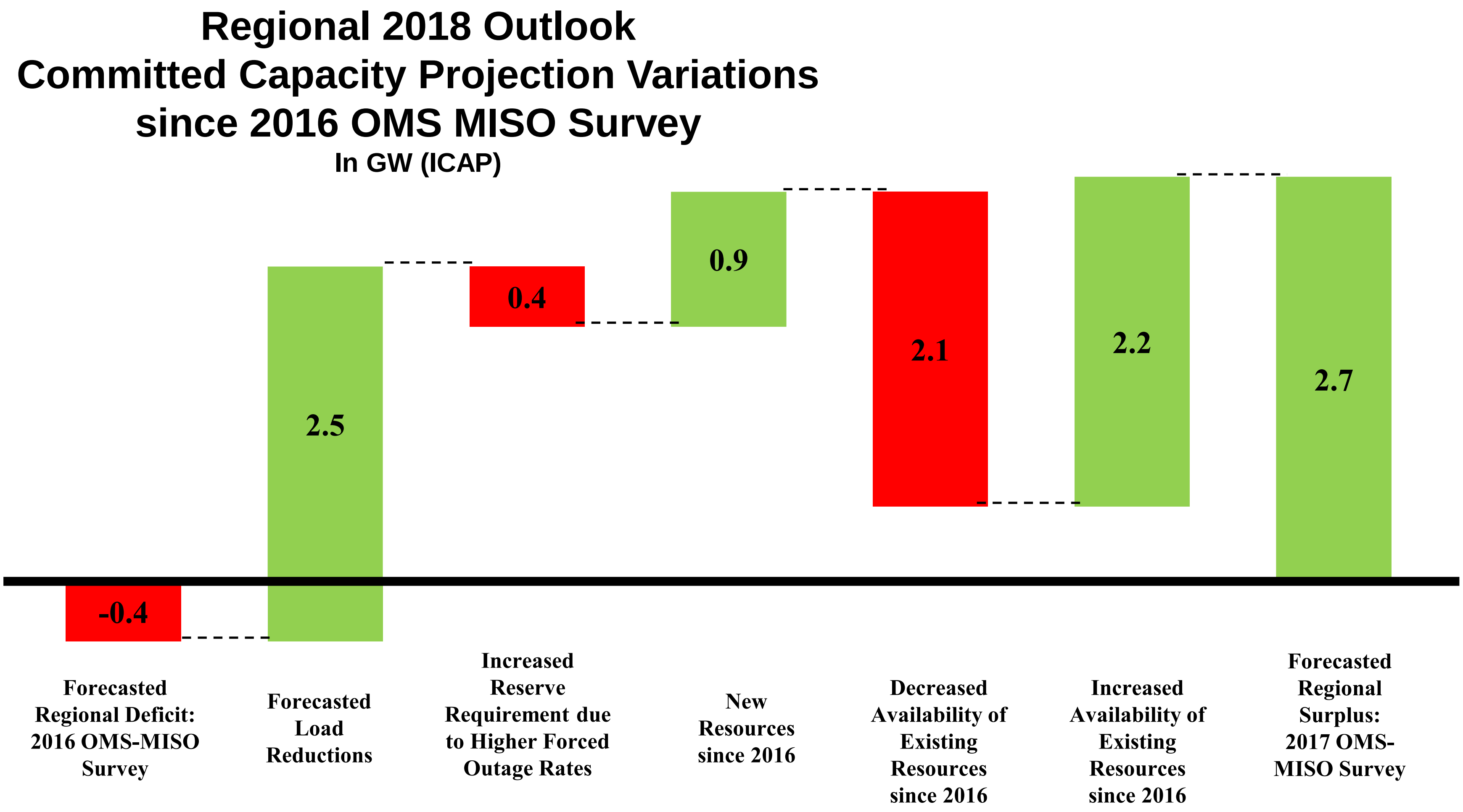
- **Committed Capacity Projections** include resources committed to serving MISO load
  - Resources within the rate base of MISO utilities
  - New generators with signed interconnection agreements
  - External resources with firm contracts to MISO load
  - Non-rate base units without announced retirements or commitments to non-MISO load
- **Potential Capacity Projections** include resources that may be available to serve MISO load but do not have firm commitments to do so
  - Potential retirements or suspensions
  - 35% of new resources in the Definitive Planning Phase (DPP) of the MISO queue
- **Unavailable resources** are not included in the survey totals
  - Resources with firm commitments to non-MISO load
  - Resources with finalized retirements or suspensions
  - Potential new generators without a signed Generator Interconnection Agreement or generators which have not entered the DPP phase of the queue

Existing resources, potential retirements, and new resources create a range of resource balances



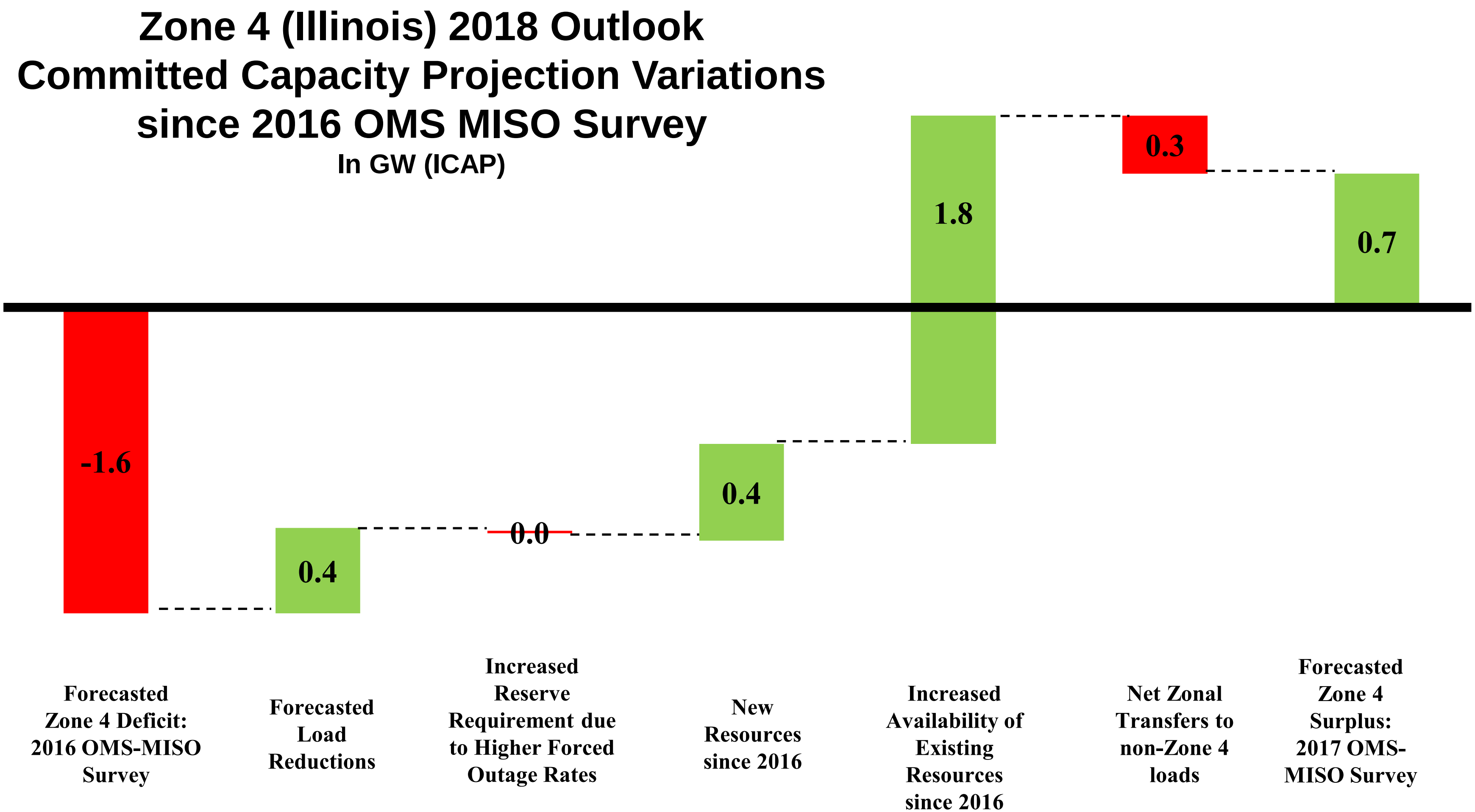
- Regional outlook includes projected constraints on capacity, including Capacity Export Limits and the Sub-regional Power Balance Constraint
- These figures will change as future capacity plans are solidified by load serving entities and state commissions.
- **Potential New Capacity** represents 35% of the capacity in the final stage of the MISO Generator Interconnection queue, as of May 11, 2017.
- **Potentially Unavailable Resources** includes potential retirements and capacity which may be constrained by future firm sales across the Sub-regional Power Balance Constraint

Regional capacity balances increased largely due to lower demand forecasts



<u>New resources</u> include resources with newly signed Interconnection Agreements and new Load Modifying Resources
<u>Decreased availability</u> results from new retirements and more binding transfer limitations
<u>Increased availability</u> results from deferred retirements and internal resources with reduced commitments to non-MISO load

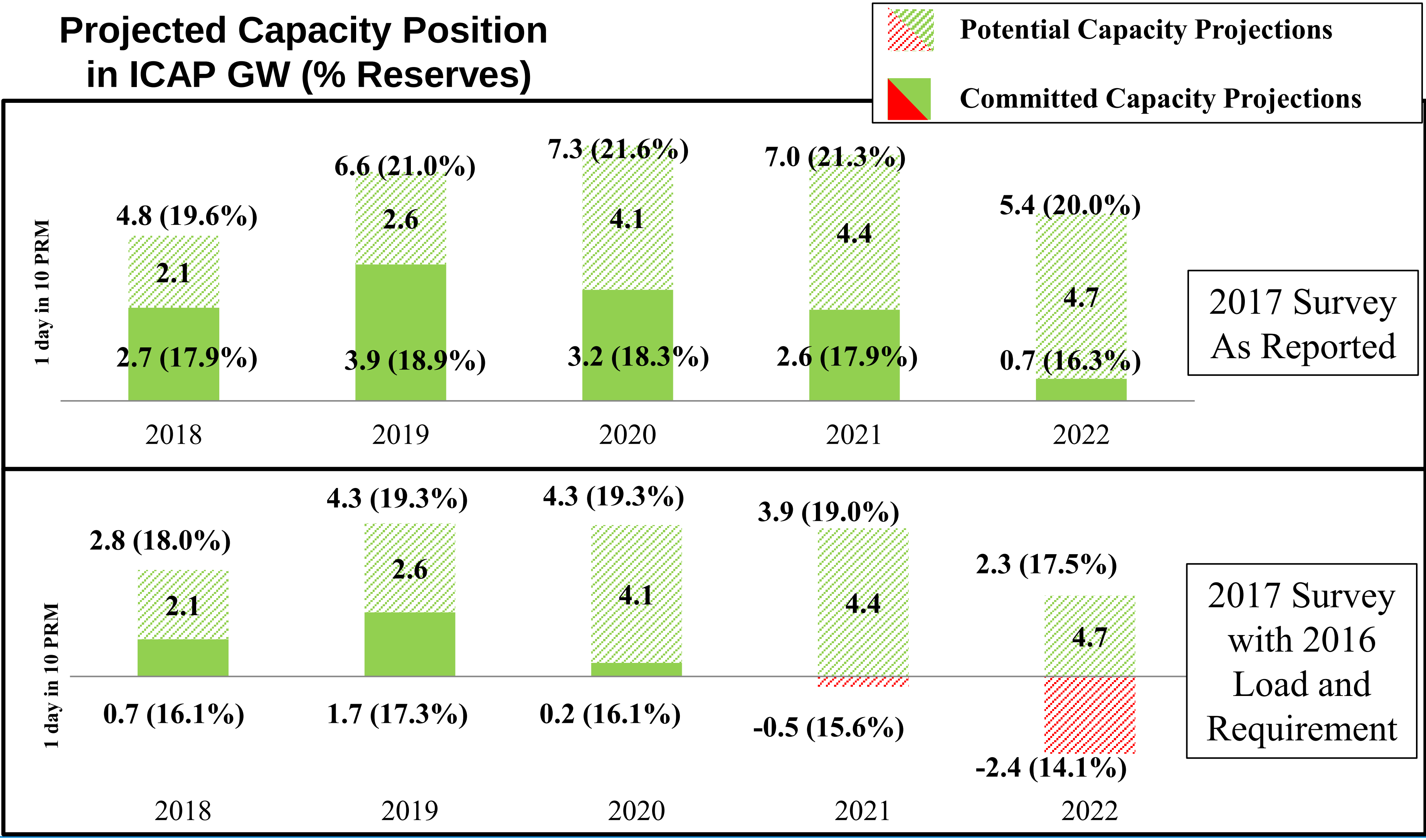
Activity in Illinois resulted in much of the year-over-year regional change; continued action is required to achieve forecasted balances



New resources include resources with newly signed Interconnection Agreements and new Load Modifying Resources
Increased availability results from deferred retirements and internal resources with reduced commitments to non-MISO load
Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones

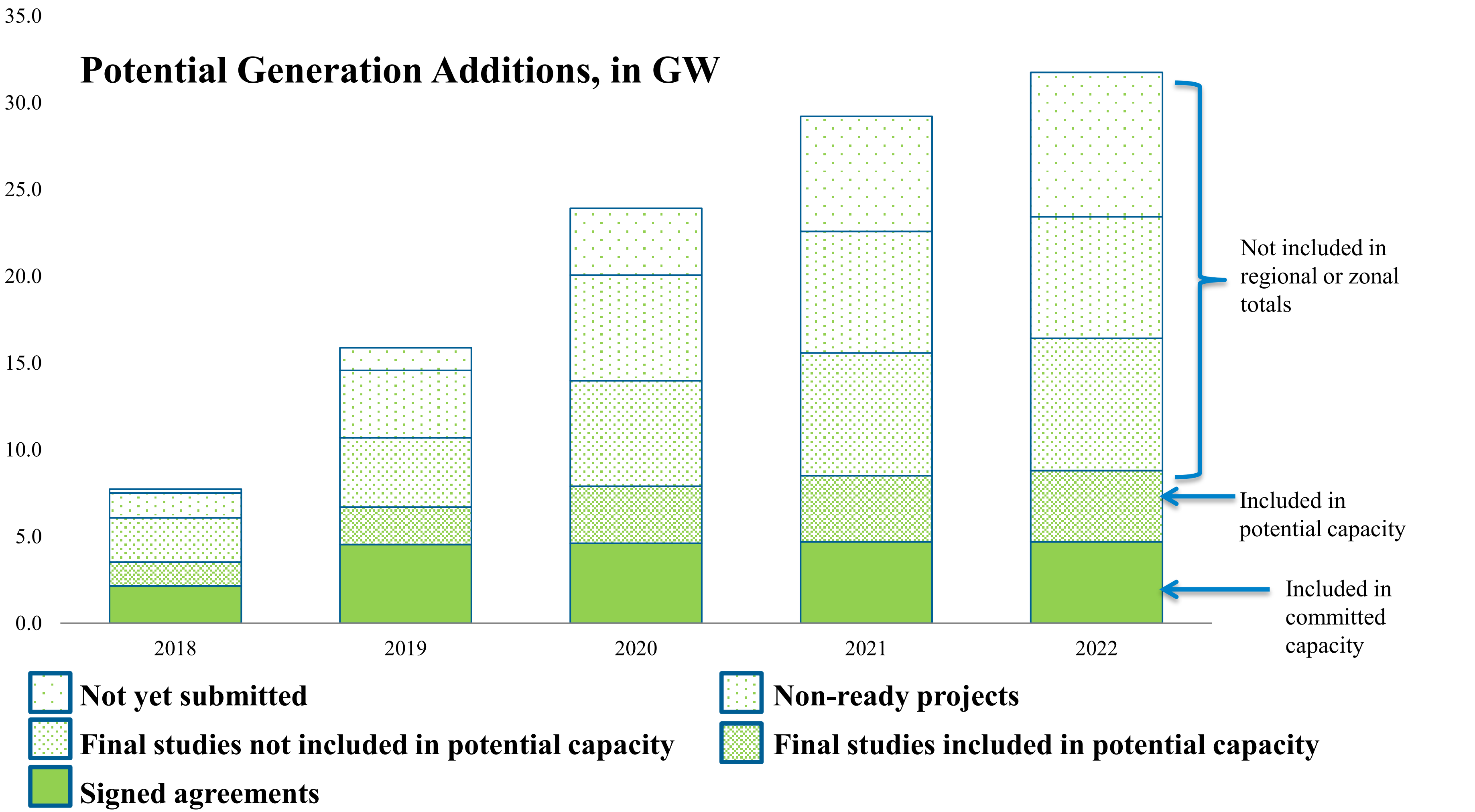
Demand forecast variation creates risk for forward-looking resource adequacy projections

Projected Capacity Position in ICAP GW (% Reserves)



Potential Capacity includes potential new capacity and potentially unavailable resources

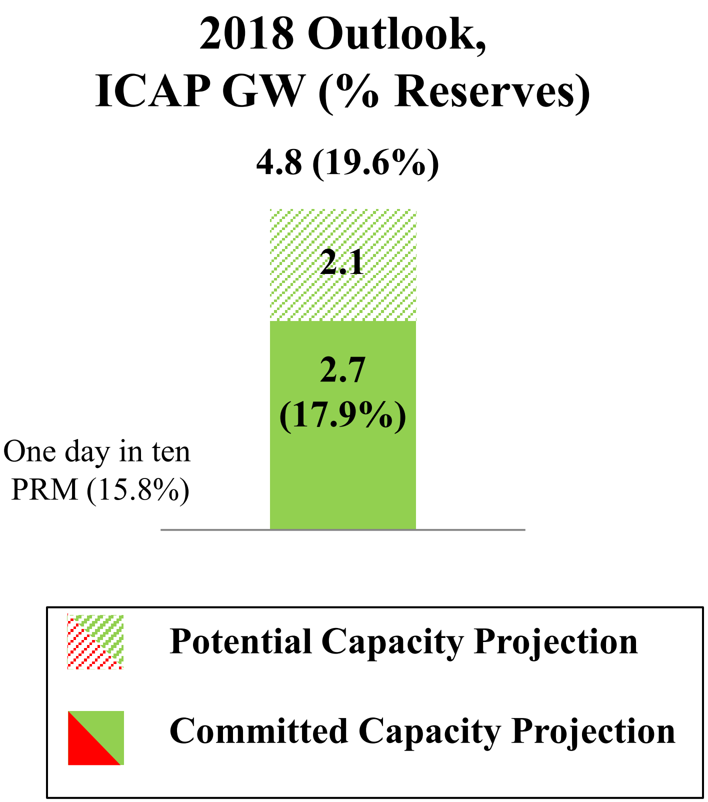
Future resource ranges will shift as planned generation interconnections are firmed up

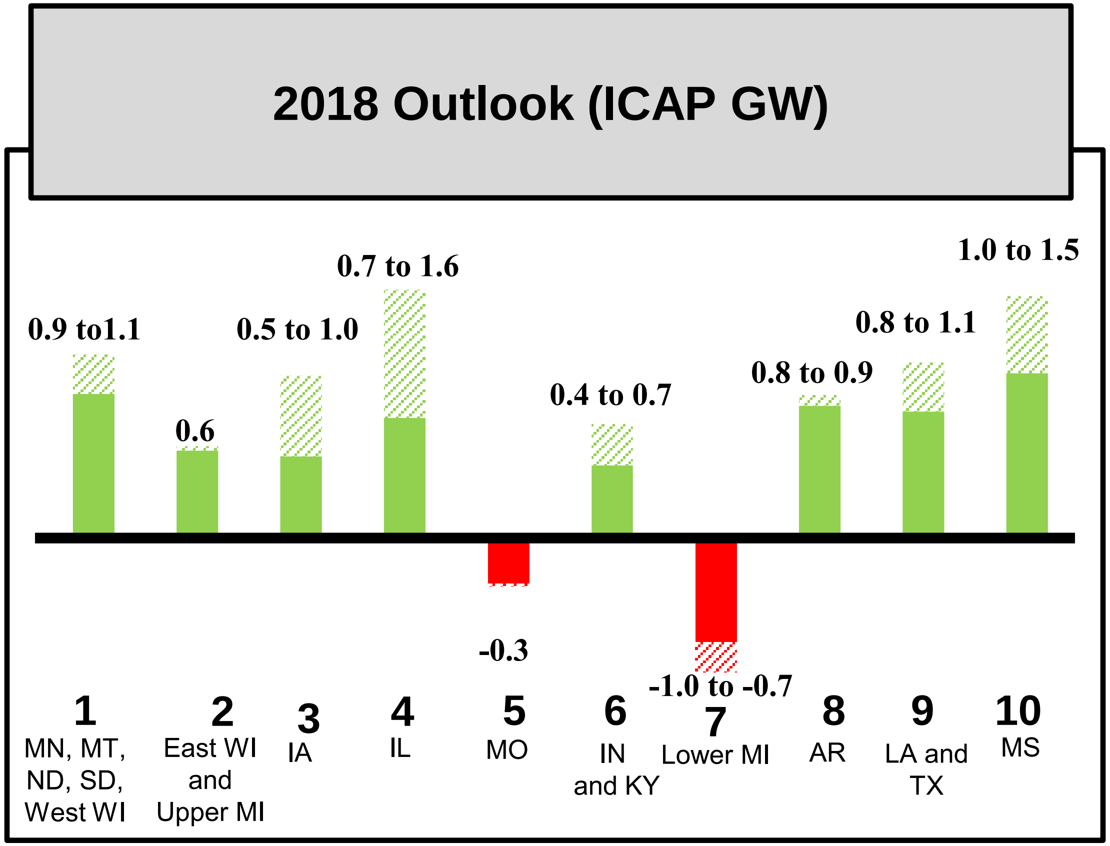


Wind and solar resources are represented at their expected capacity credit

Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

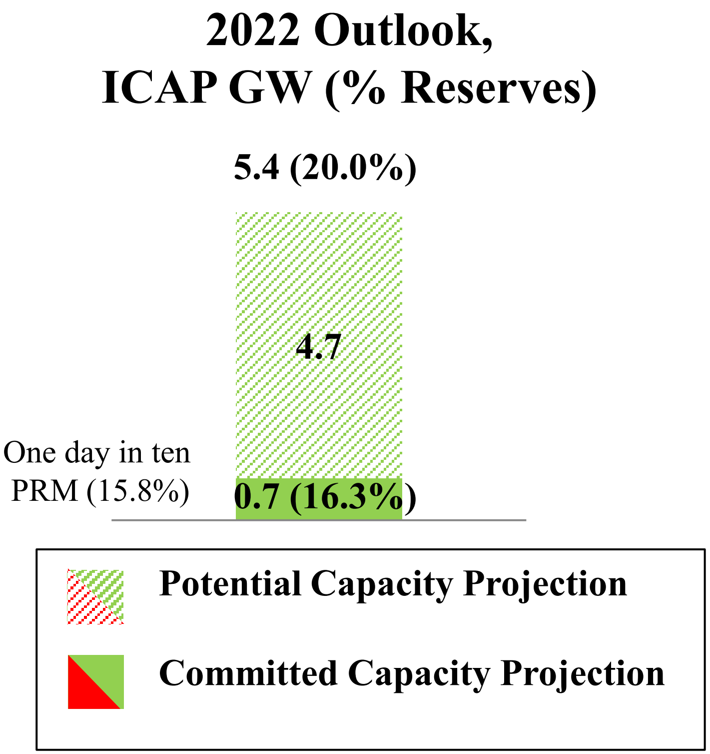
In 2018, regional surpluses are sufficient to cover areas with resource deficits

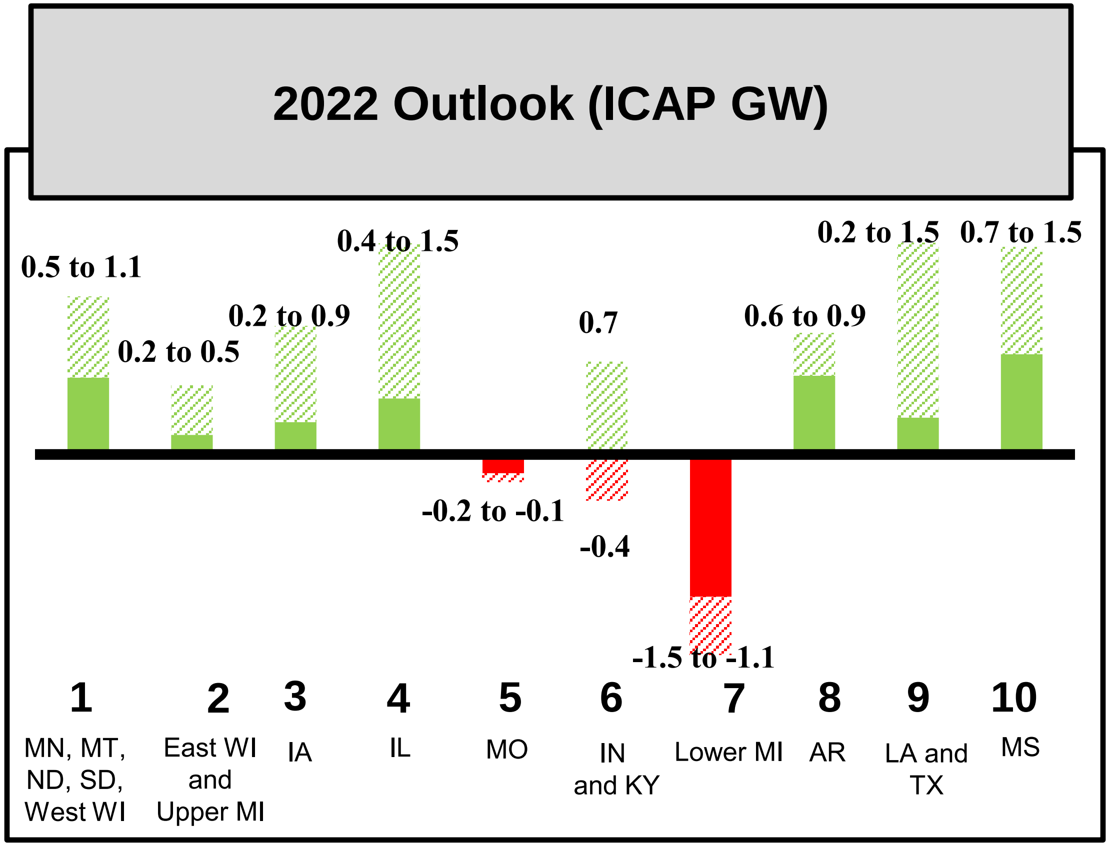




- Regional surpluses and potential resources are sufficient for all zones to serve their deficits while meeting local requirements.
- Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones
- Exports from Zone 1 were limited by the zone's Capacity Export Limit to 0.6 GW
- Results include load, but not identified resources, from some non-jurisdictional load in Zone 5
- Exports from Zones 8, 9, and 10 were limited by the Sub-regional Power Balance Constraint to 1.2 GW

Continued focus on load growth variations and generation retirements will reduce uncertainty around future resource adequacy assessments





- Regional surpluses and potential resources are sufficient for all zones to serve their deficits while meeting local requirements
- Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones
- Results include load, but not identified resources, from some non-jurisdictional load in Zone 5
- Exports from Zones 8, 9, and 10 were limited by the Sub-regional Power Balance Constraint to 1.5 GW in committed capacity projections and 1.9 GW in potential capacity projections

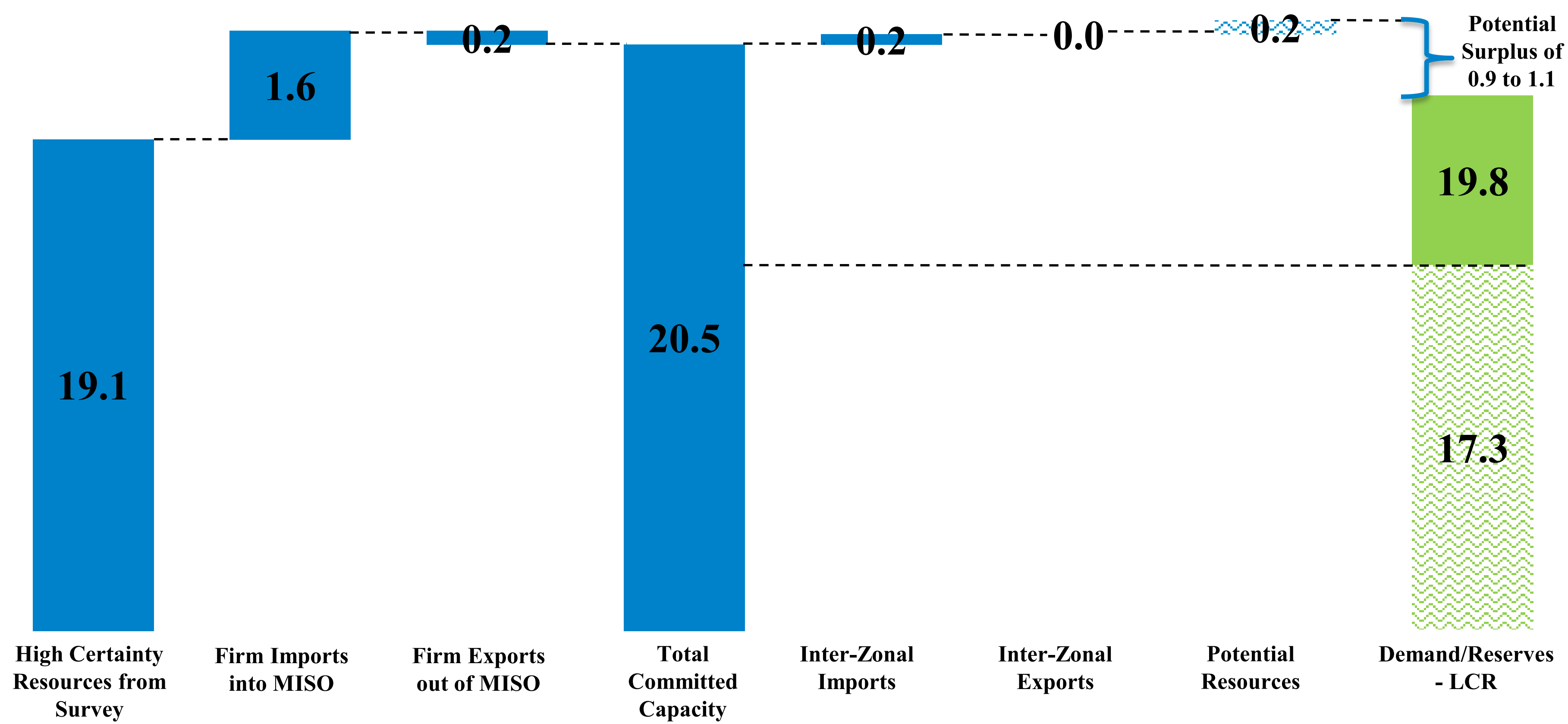
Appendix

Definitions

- Committed Capacity Resources
  - High Certainty From Survey
    - Resources within the MISO footprint committed to serving demand, based on survey responses
    - Includes resources with signed Interconnection Agreements
  - Firm Imports into MISO
    - Resources located outside of MISO committed to serving demand in MISO and included in zonal capacity totals
  - Firm Exports out of MISO
    - Resources located inside of MISO committed to serving demand outside MISO and excluded from zonal capacity totals
- Total Committed Capacity
  - Total capacity available to serve demand in the given Planning Year. This will not include Potential resources
- Potential Capacity Resources
  - Resources have some indication of not being available to serve demand and classified as ‘low certainty’ by survey responses
  - An example of a “low” certainty resource could be a resource that has submitted an attachment Y2
  - 35% of all resources in the final stages of the Definitive Planning Phase of the MISO Interconnection Queue
- Inter-zonal Imports / Exports
  - Resources from one zone within MISO which were designated as serving load in a different MISO zone by survey responses
- Demand/Reserves
  - Projected demand plus the MISO Planning Reserve Margin Requirement of 15.8%
  - A portion of this requirement may be served by capacity located outside of the zone

2018 Resource Adequacy Forecast Zone 1 (GW)

2017 OMS MISO Survey
In GW (ICAP)



<u>Potential Resources</u> includes 35% of resources in the final study phase of the MISO Interconnection Queue

2019 - 2021 Resource Adequacy Forecast Zone 1 (GW)

2017 OMS MISO Survey

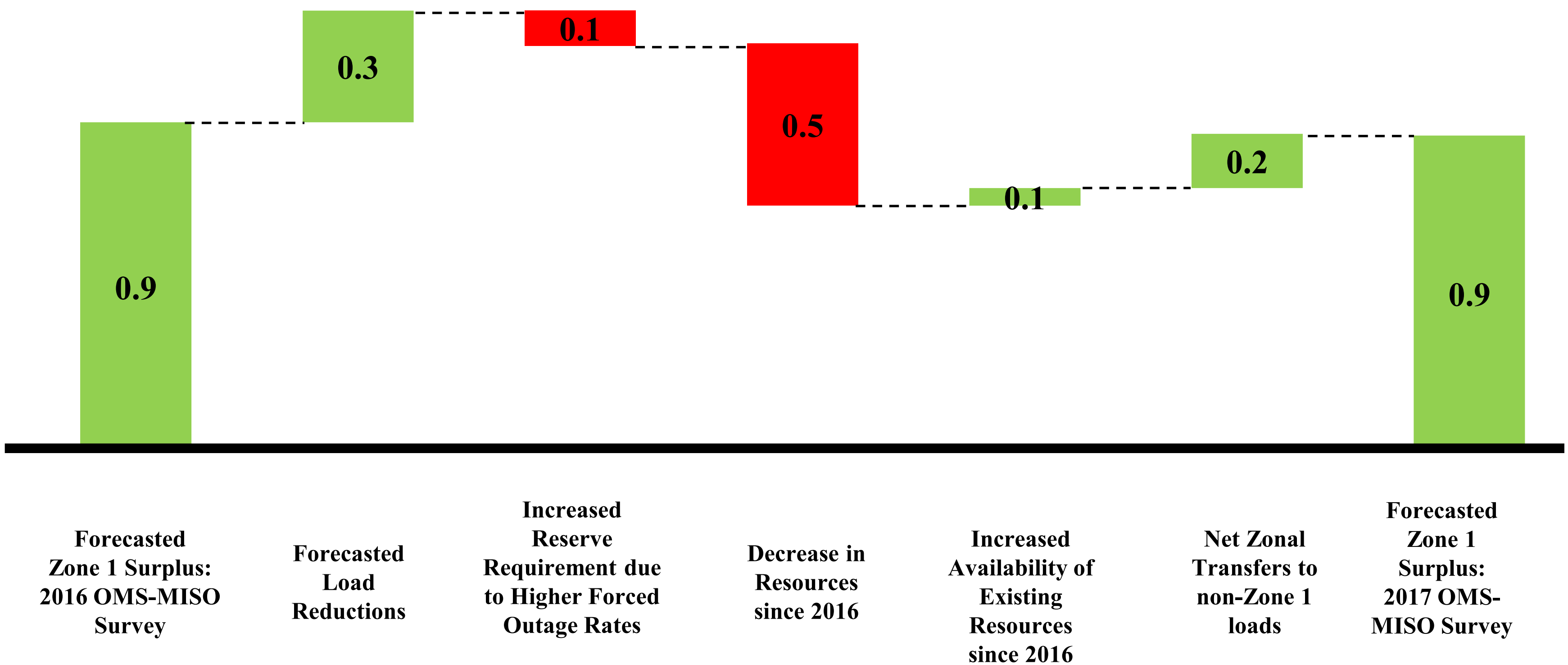
Values In GW (ICAP)

Zone 1	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	19.3	19.3	19.2	A
Firm Imports into MISO	1.6	1.6	1.7	B
Firm Exports out of MISO	0.2	0.2	0.2	C
Total High Certainty Capacity	**20.7**	**20.6**	**20.7**	D = (A+B)-C
Inter-Zonal Imports	0.3	0.3	0.4	E
Inter-Zonal Exports	0.0	0.0	0.0	F
Demand/Reserves	**20.0**	**20.2**	**20.3**	G
Firm Capacity Position	**1.0**	**0.7**	**0.8**	H =(D+E-F)-G
Low Certainty Resources	0.4	0.6	0.6	I
Potential Capacity Surplus/Deficit	**1.4**	**1.3**	**1.4**	J =(H+I)

2016 vs 2017 OMS MISO Survey Results Zone 1

Zone 1 2018 Outlook
Committed Capacity Projection Variations since 2016 OMS MISO Survey

In GW (ICAP)

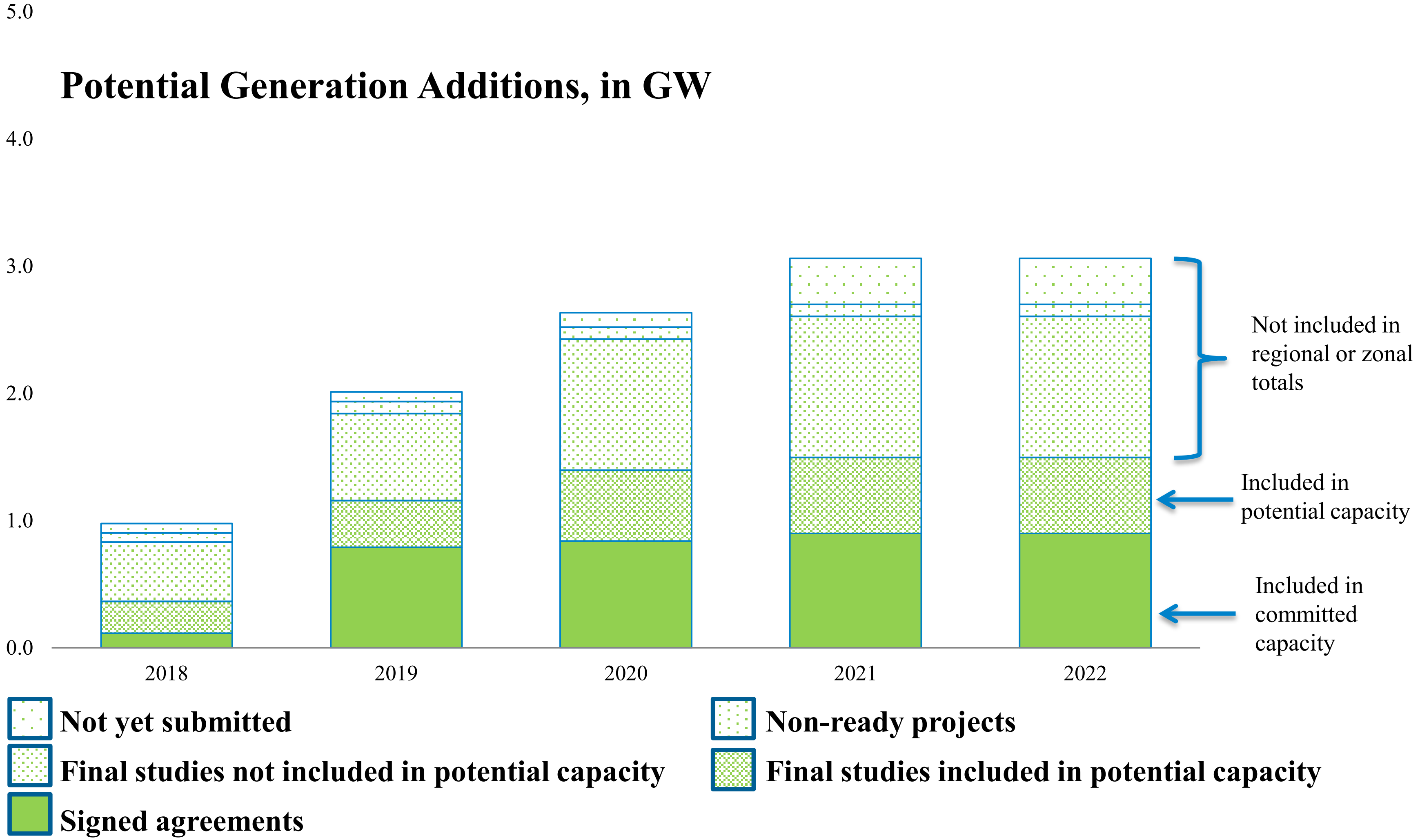


<u>**New resources**</u> include resources with newly signed Interconnection Agreements and new Load Modifying Resources

<u>**Increased availability**</u> results from deferred retirements and internal resources with reduced commitments to non-MISO load

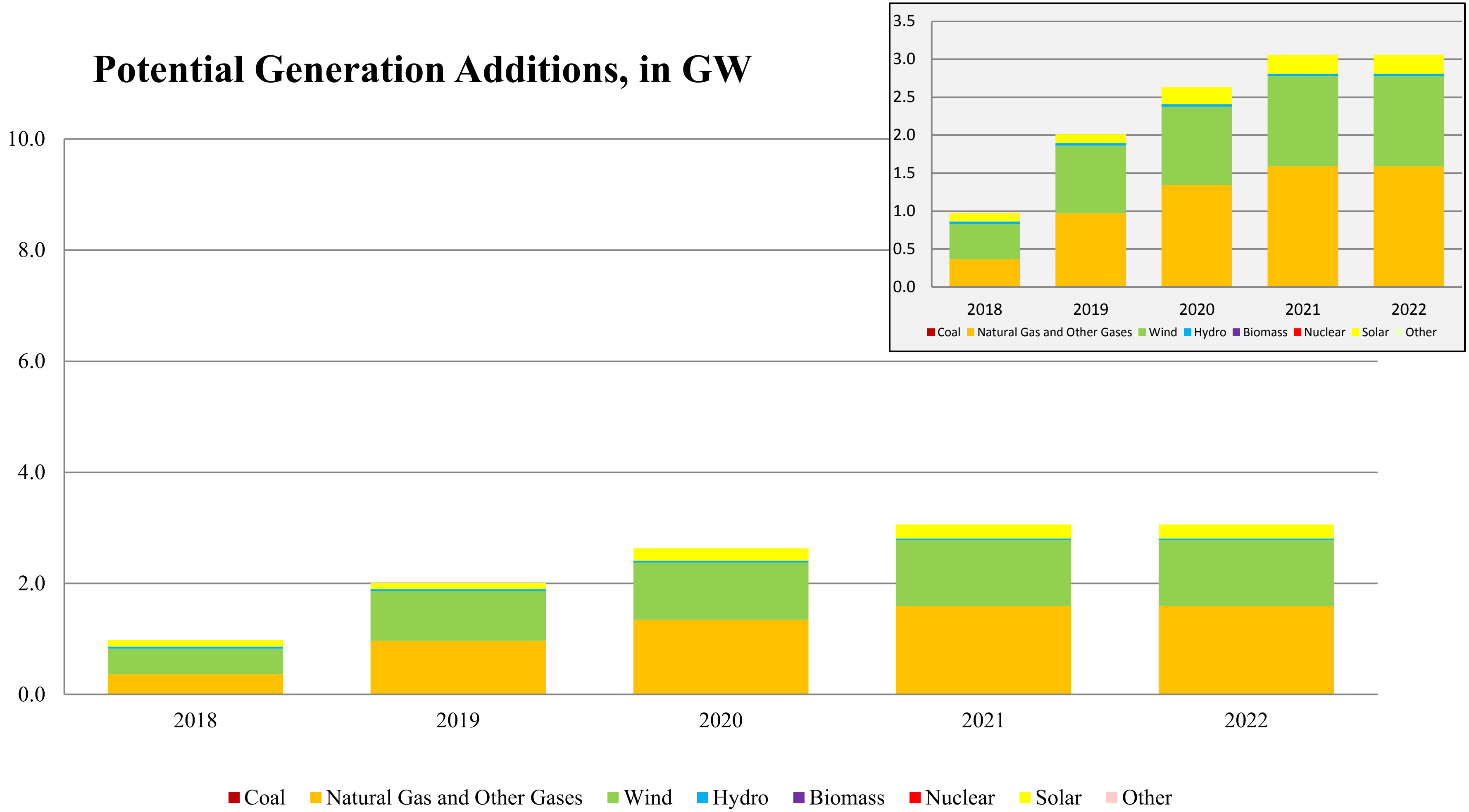
Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones

Zone 1 New Resource Additions by Queue Phase



Wind and solar resources are represented at their expected capacity credit
Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

Zone 1 New Resources Additions by Fuel Type

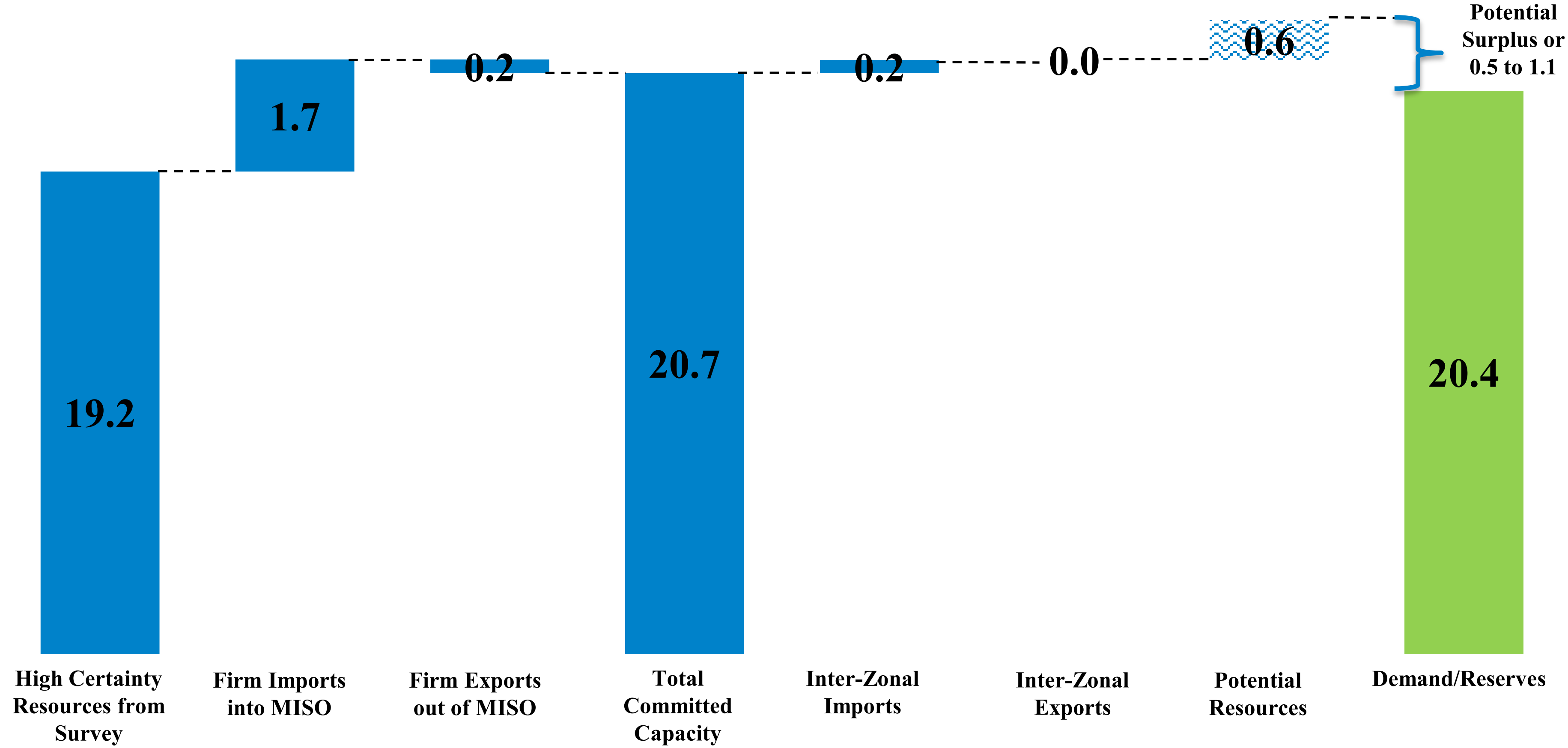


Includes all queued generation along with resources which have not yet been submitted to the MISO queue process
Wind and solar resources are represented at their expected capacity credit
Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

2022 Resource Adequacy Forecast Zone 1 (GW)

Committed Resources
Potential Resources
Total Demand and Requirement

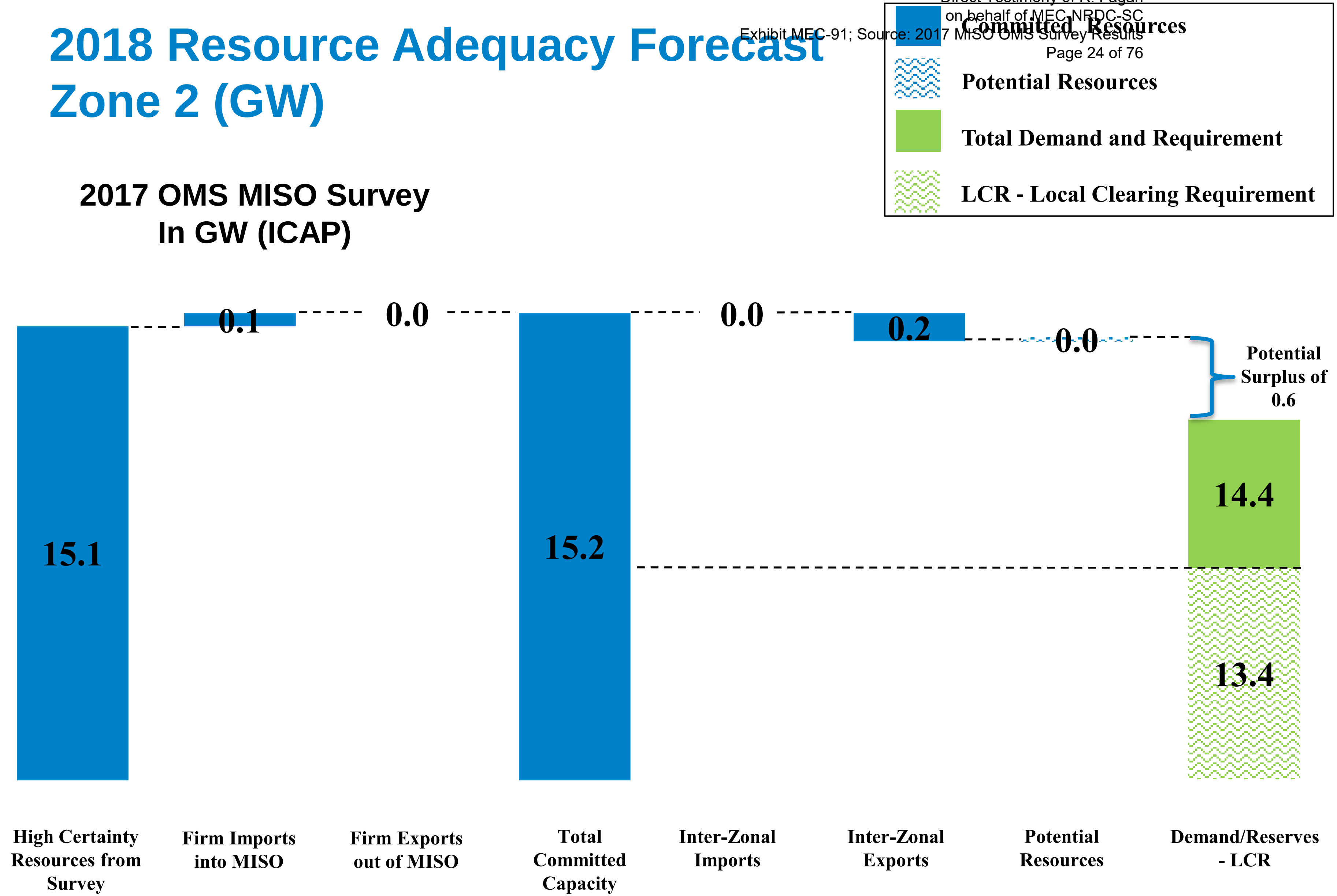
2017 OMS MISO Survey In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2018 Resource Adequacy Forecast Zone 2 (GW)

2017 OMS MISO Survey
In GW (ICAP)



<u>Potential Resources</u> includes 35% of resources in the final study phase of the MISO Interconnection Queue

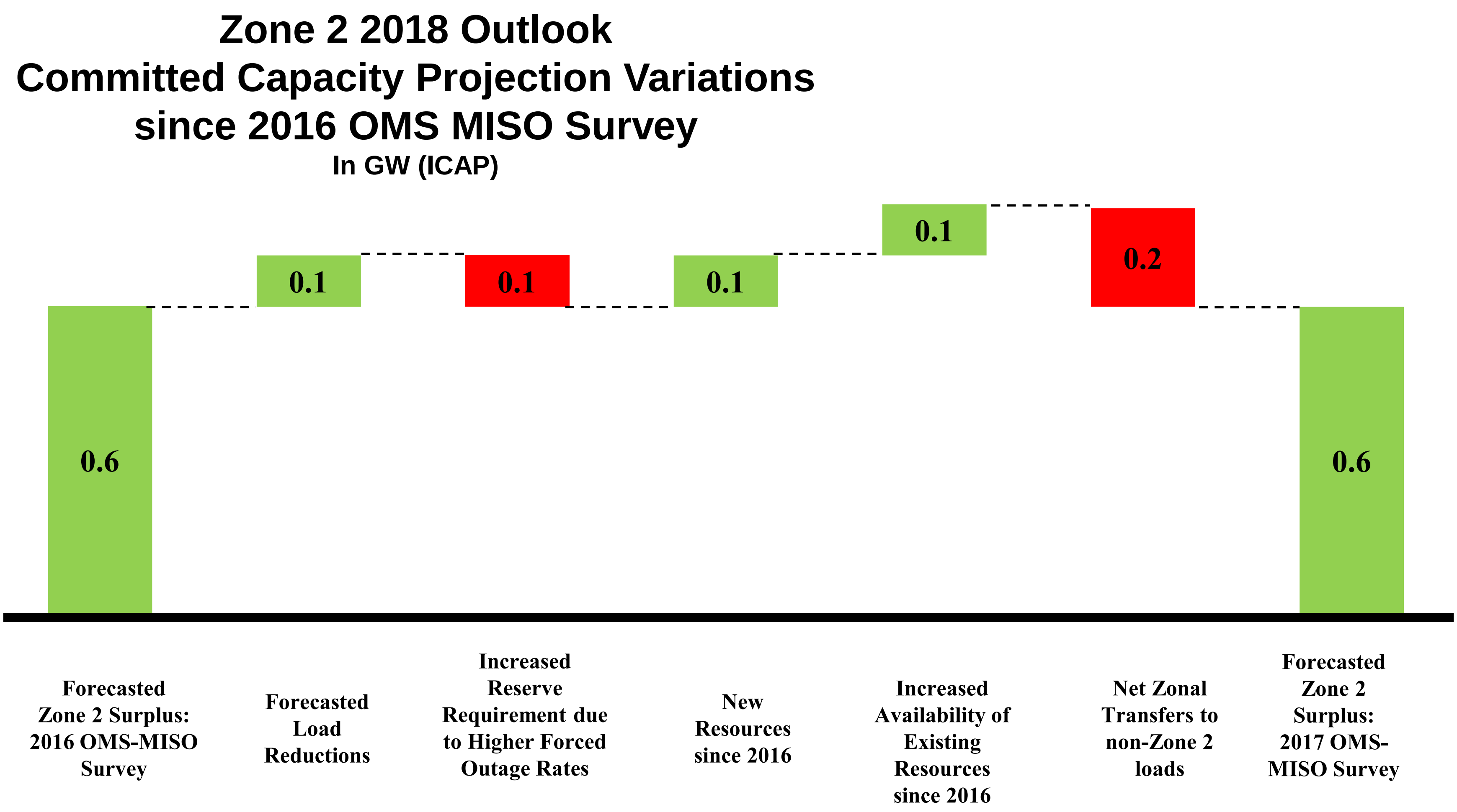
2019 - 2021 Resource Adequacy Forecast Zone 2 (GW)

2017 OMS MISO Survey

Values In GW (ICAP)

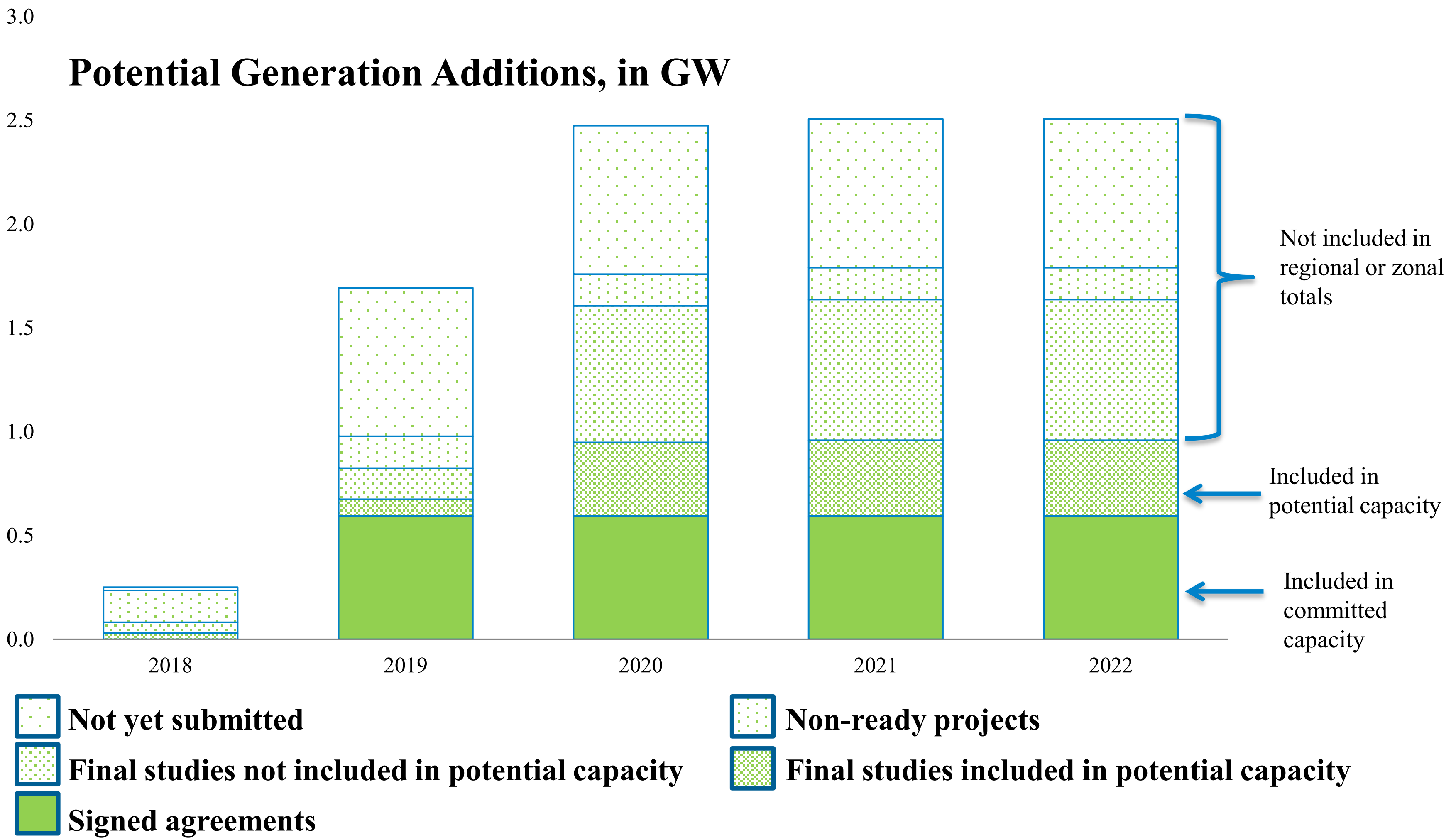
Zone 2	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	15.1	15.0	15.0	A
Firm Imports into MISO	0.1	0.1	0.1	B
Firm Exports out of MISO	0.0	0.0	0.0	C
Total High Certainty Capacity	**15.2**	**15.1**	**15.1**	D = (A+B)-C
Inter-Zonal Imports	0.0	0.0	0.0	E
Inter-Zonal Exports	0.3	0.3	0.4	F
Demand/Reserves	**14.5**	**14.5**	**14.6**	G
Firm Capacity Position	**0.4**	**0.3**	**0.1**	H =(D+E-F)-G
Low Certainty Resources	0.1	0.3	0.4	I
Potential Capacity Surplus/Deficit	**0.5**	**0.6**	**0.5**	J =(H+I)

2016 vs 2017 OMS MISO Survey Results Zone 2



New resources include resources with newly signed Interconnection Agreements and new Load Modifying Resources
Increased availability results from deferred retirements and internal resources with reduced commitments to non-MISO load
Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones

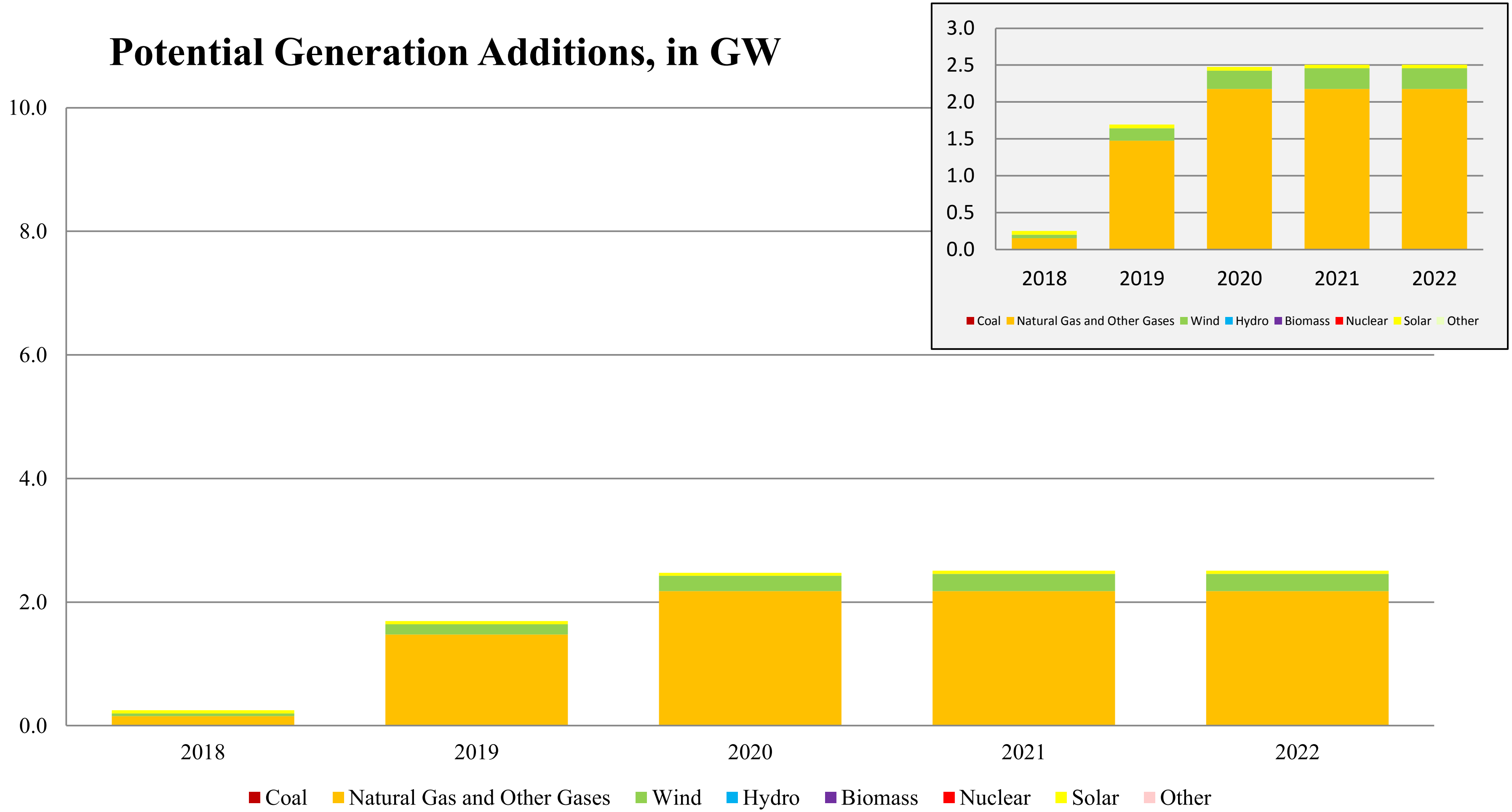
Zone 2 New Resource Additions by Queue Phase



Wind and solar resources are represented at their expected capacity credit

<u>**Non-ready projects**</u> will be deemed withdrawn, as of June 15th, with an option to move to final studies

Zone 2 New Resources Additions by Fuel Type



Includes all queued generation along with resources which have not yet been submitted to the MISO queue process
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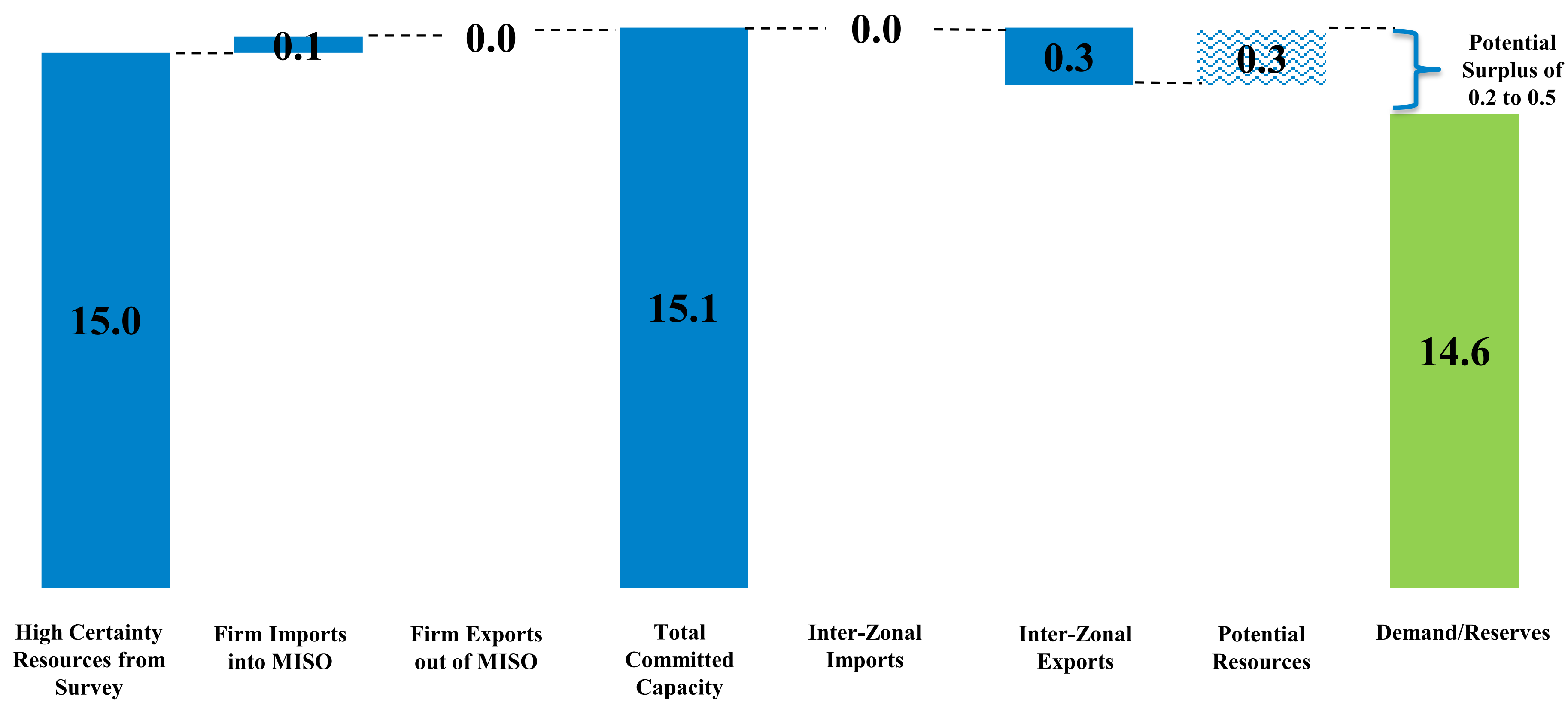
2022 Resource Adequacy Forecast Zone 2 (GW)

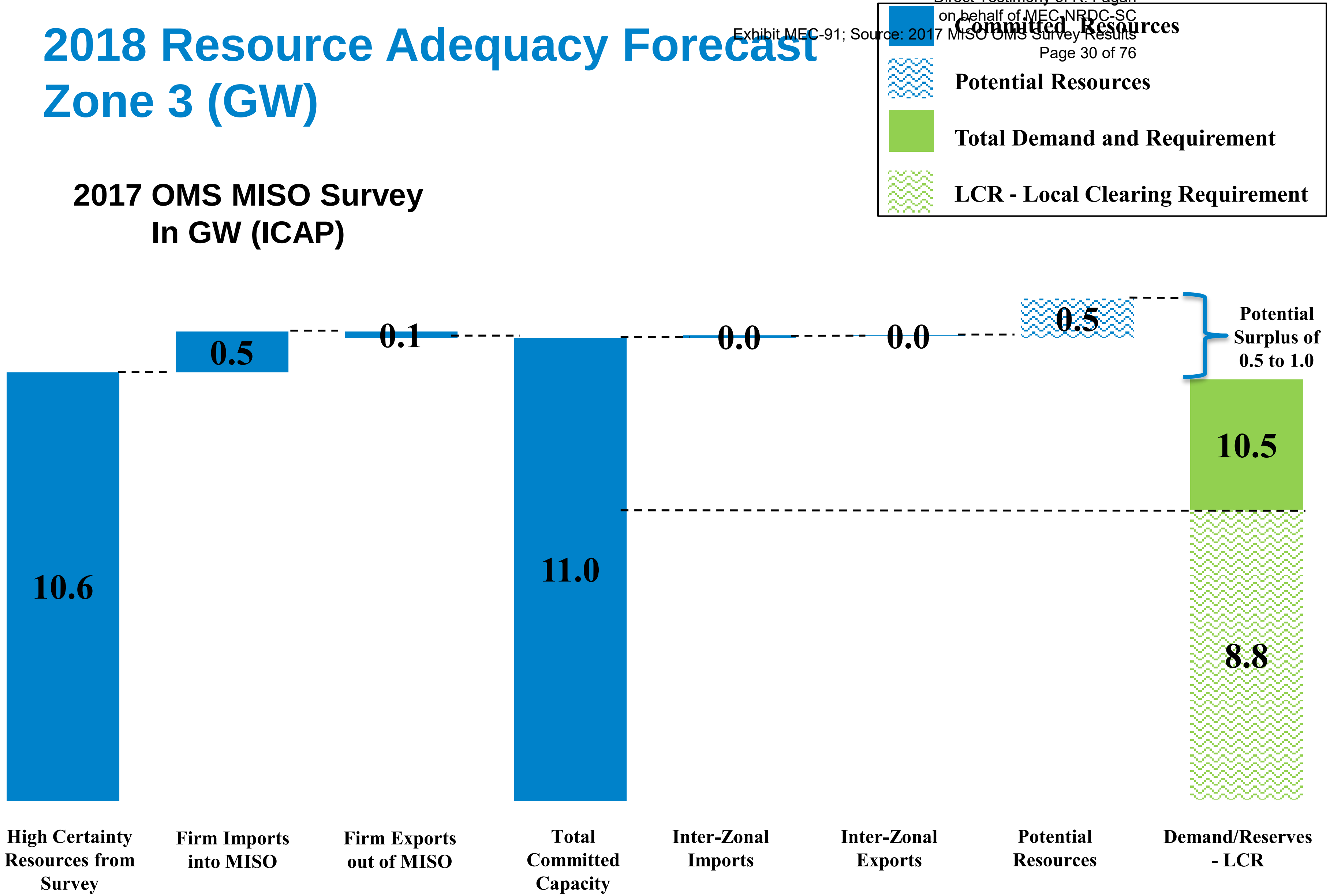
2017 OMS MISO Survey In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2018 Resource Adequacy Forecast Zone 3 (GW)

2017 OMS MISO Survey In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

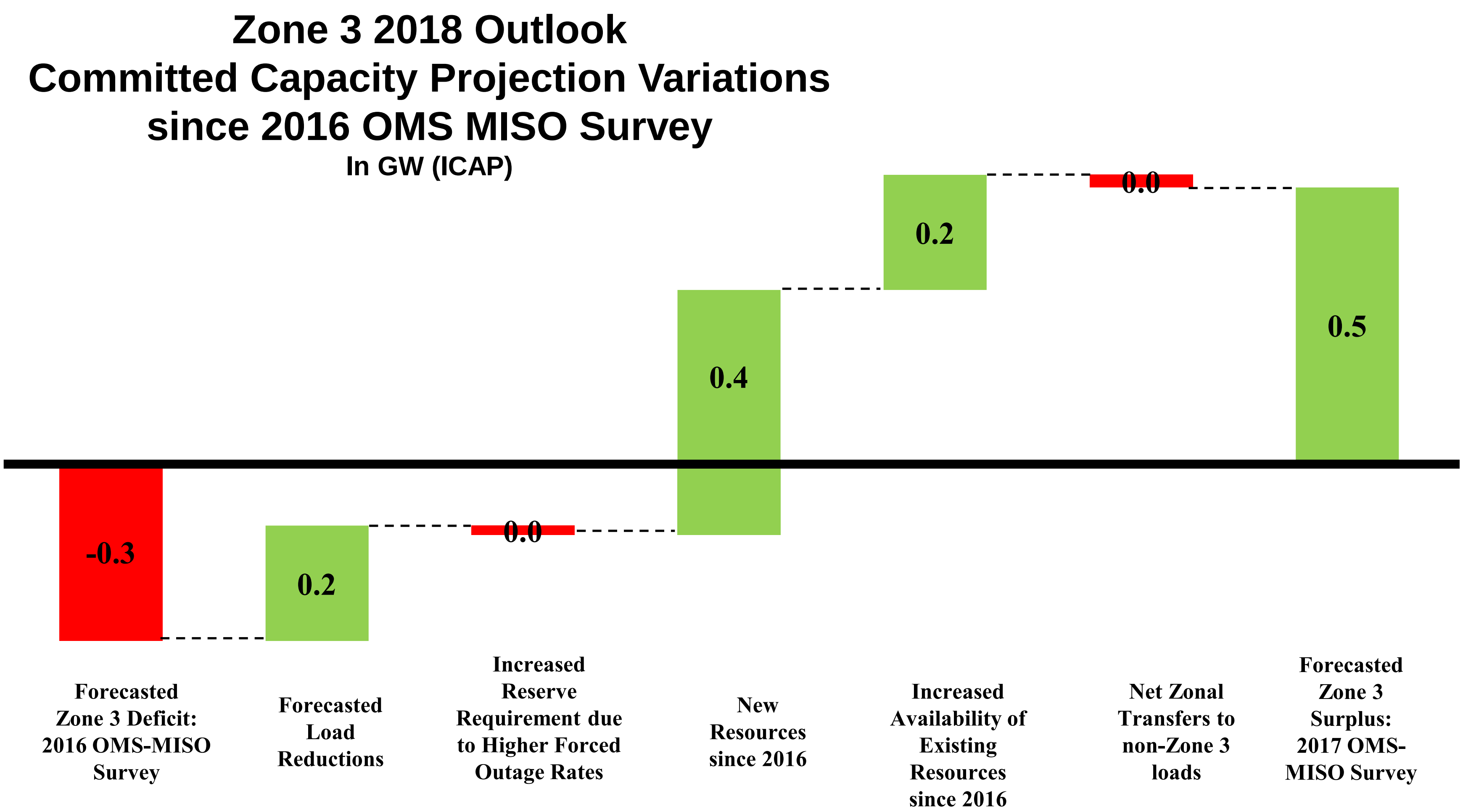
2019 - 2021 Resource Adequacy Forecast Zone 3 (GW)

2017 OMS MISO Survey

Values In GW (ICAP)

Zone 3	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	10.6	10.6	10.7	A
Firm Imports into MISO	0.5	0.5	0.5	B
Firm Exports out of MISO	0.1	0.1	0.1	C
Total High Certainty Capacity	**11.0**	**11.0**	**11.1**	D = (A+B)-C
Inter-Zonal Imports	0.0	0.0	0.0	E
Inter-Zonal Exports	0.0	0.0	0.0	F
Demand/Reserves	**10.6**	**10.7**	**10.8**	G
Firm Capacity Position	**0.4**	**0.3**	**0.3**	H =(D+E-F)-G
Low Certainty Resources	0.6	0.7	0.7	I
Potential Capacity Surplus/Deficit	**1.0**	**1.0**	**1.0**	J =(H+I)

2016 vs 2017 OMS MISO Survey Results Zone 3



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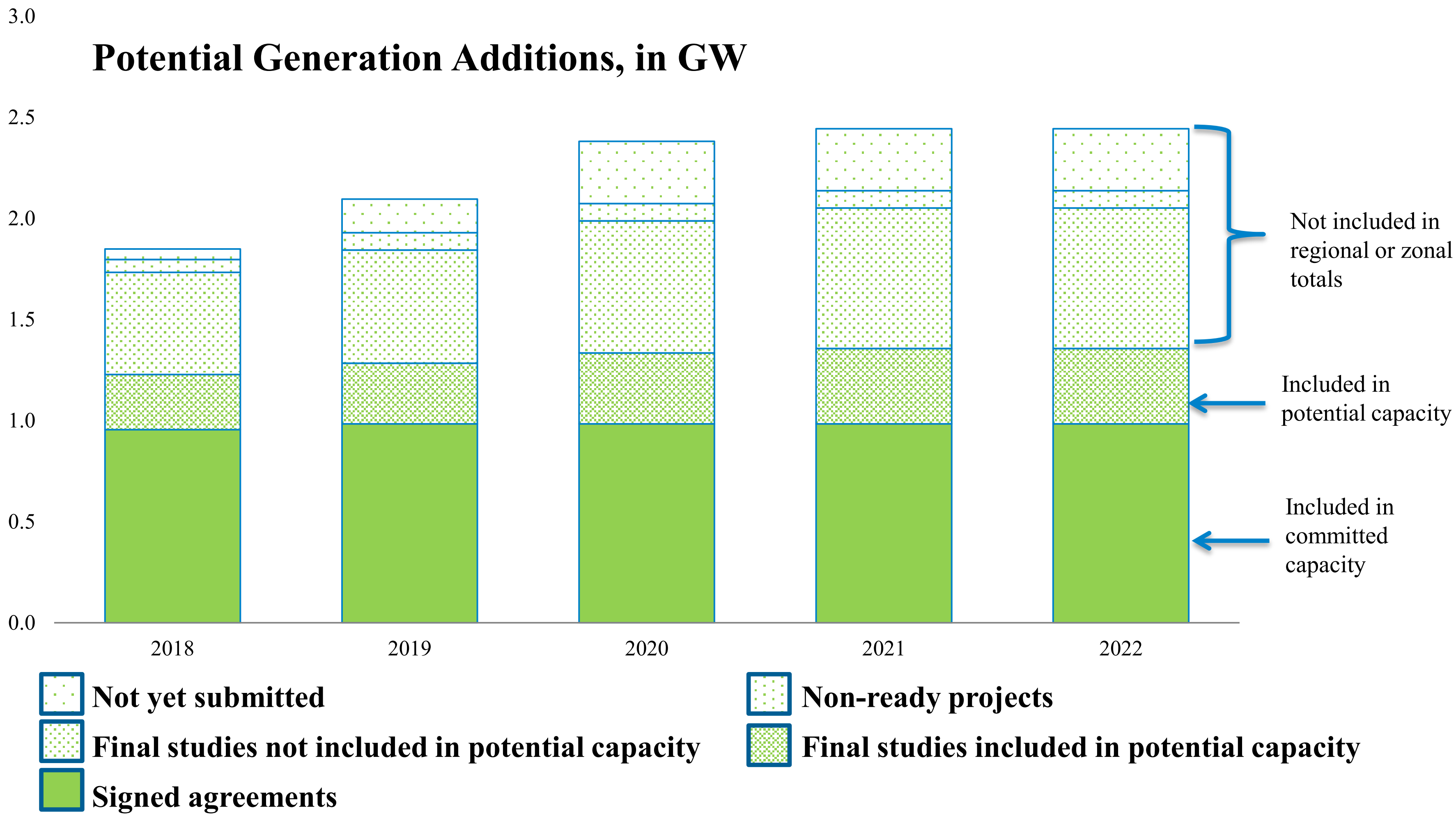
Zone 3 New Resource Additions by Queue Phase



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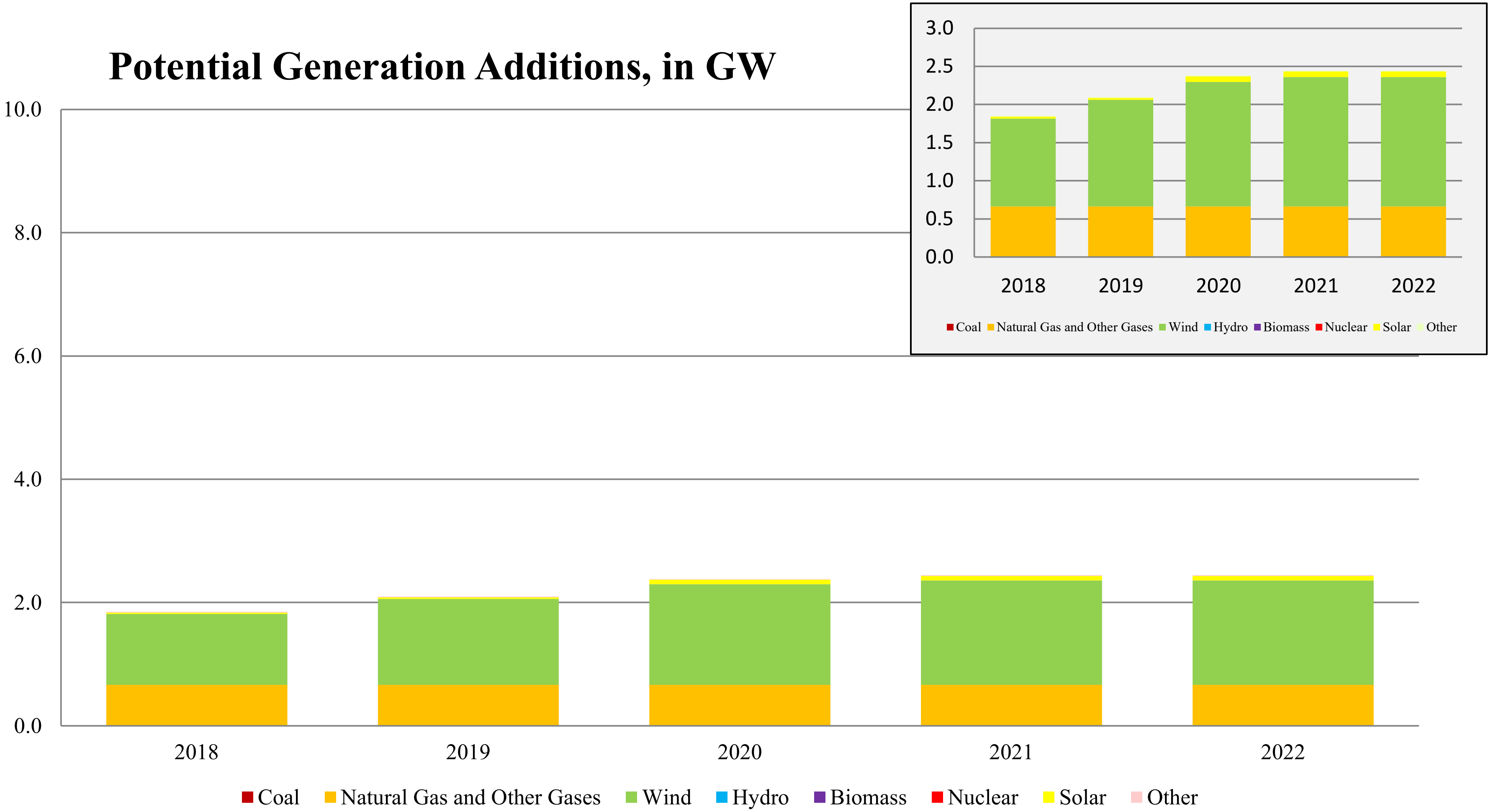
Zone 3 New Resources Additions by Fuel Type



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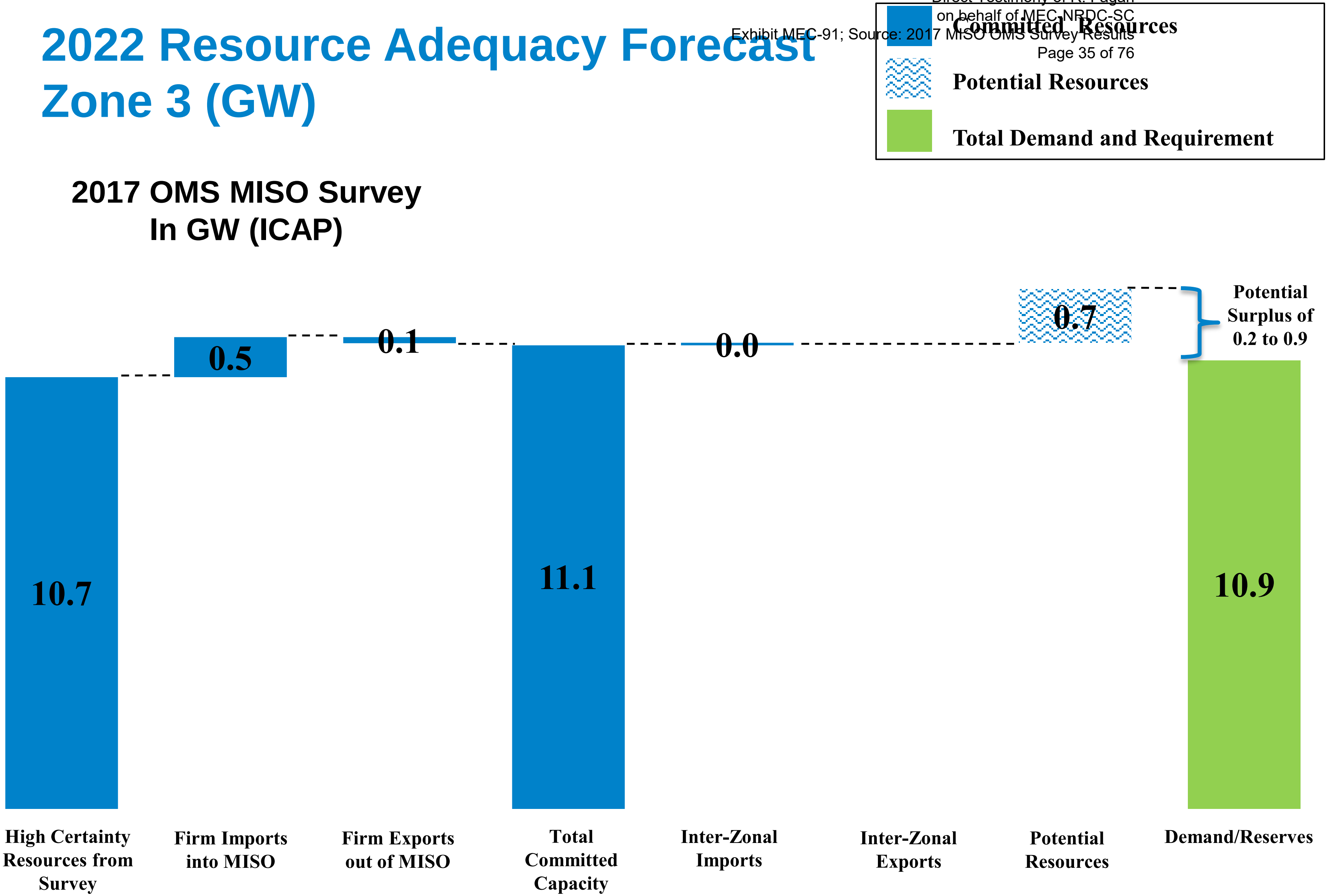
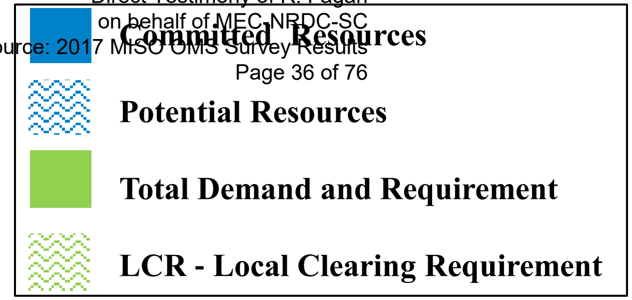
2022 Resource Adequacy Forecast Zone 3 (GW)

2017 OMS MISO Survey
In GW (ICAP)

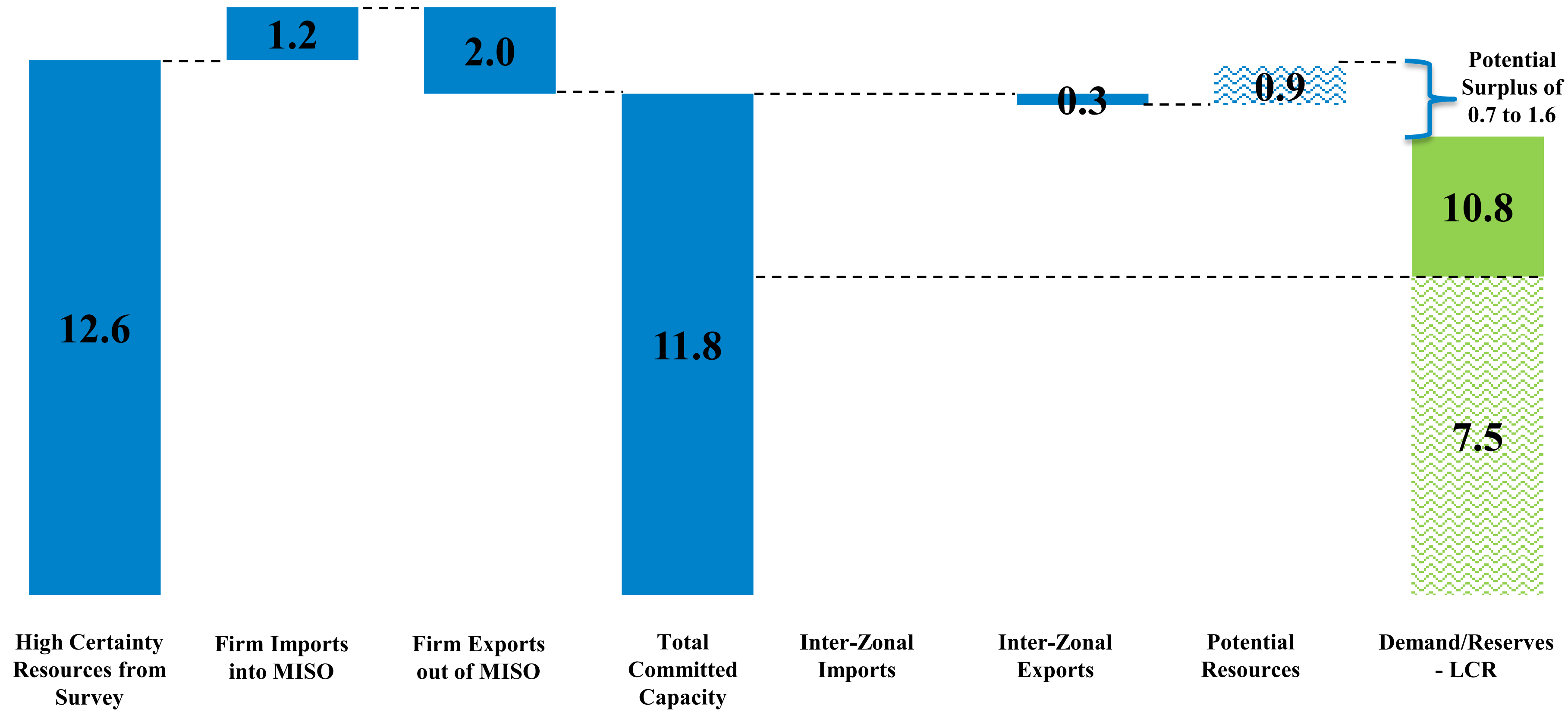


Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2018 Resource Adequacy Forecast Zone 4 (GW)



2017 OMS MISO Survey
In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2019 - 2021 Resource Adequacy Forecast Zone 4 (GW)

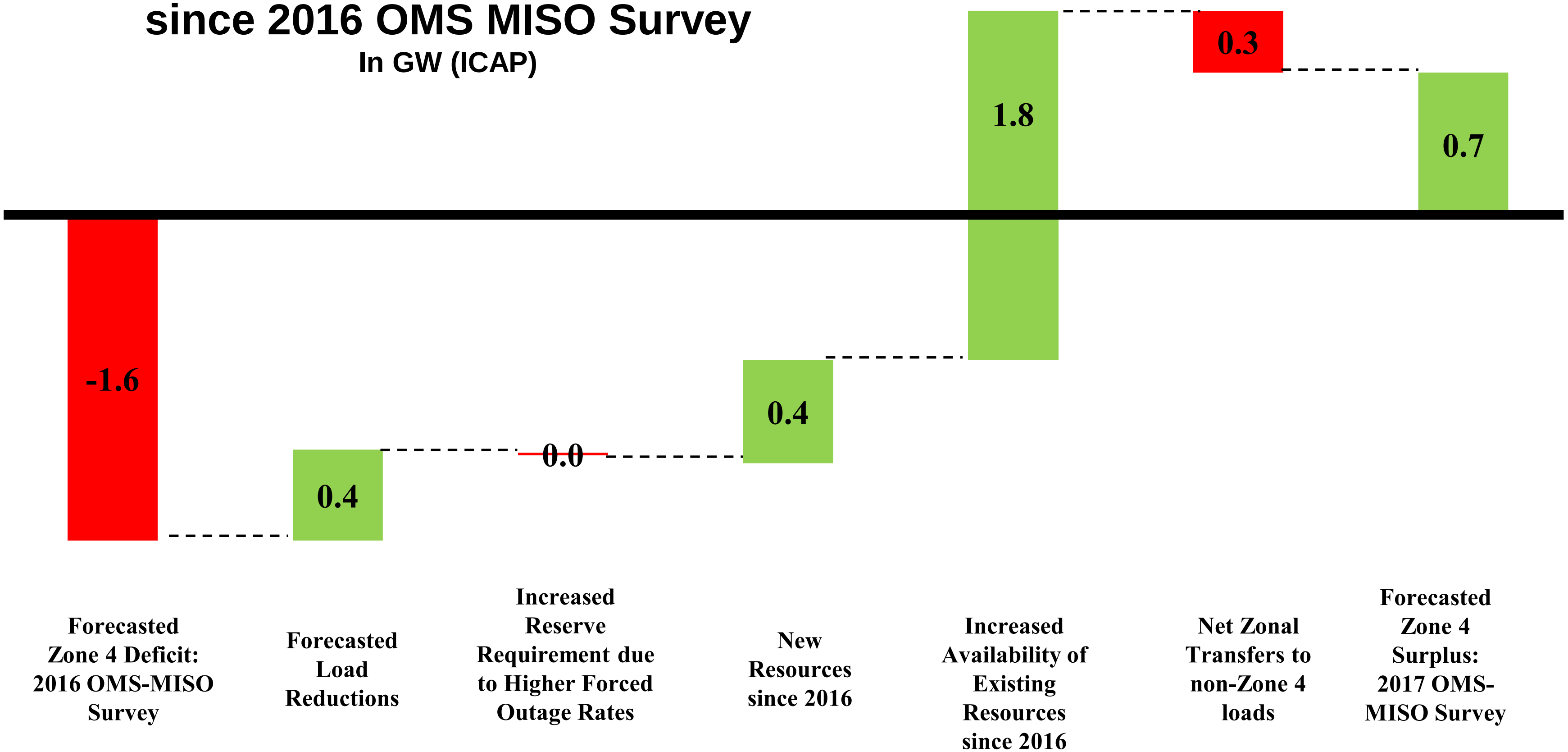
2017 OMS MISO Survey

Values In GW (ICAP)

Zone 4	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	12.6	12.6	12.5	A
Firm Imports into MISO	1.2	1.2	1.2	B
Firm Exports out of MISO	1.8	1.5	1.5	C
Total High Certainty Capacity	**12.0**	**12.3**	**12.2**	D = (A+B)-C
Inter-Zonal Imports	0.0	0.0	0.0	E
Inter-Zonal Exports	0.2	0.2	0.4	F
Demand/Reserves	**10.9**	**10.8**	**10.8**	G
Firm Capacity Position	**0.9**	**1.3**	**1.0**	H =(D+E-F)-G
Low Certainty Resources	0.9	1.0	1.1	I
Potential Capacity Surplus/Deficit	**1.8**	**2.3**	**2.1**	J =(H+I)

Activity in Illinois resulted in much of the year-over-year regional change; continued action is required to achieve forecasted balances

Zone 4 (Illinois) 2018 Outlook
Committed Capacity Projection Variations since 2016 OMS MISO Survey
In GW (ICAP)



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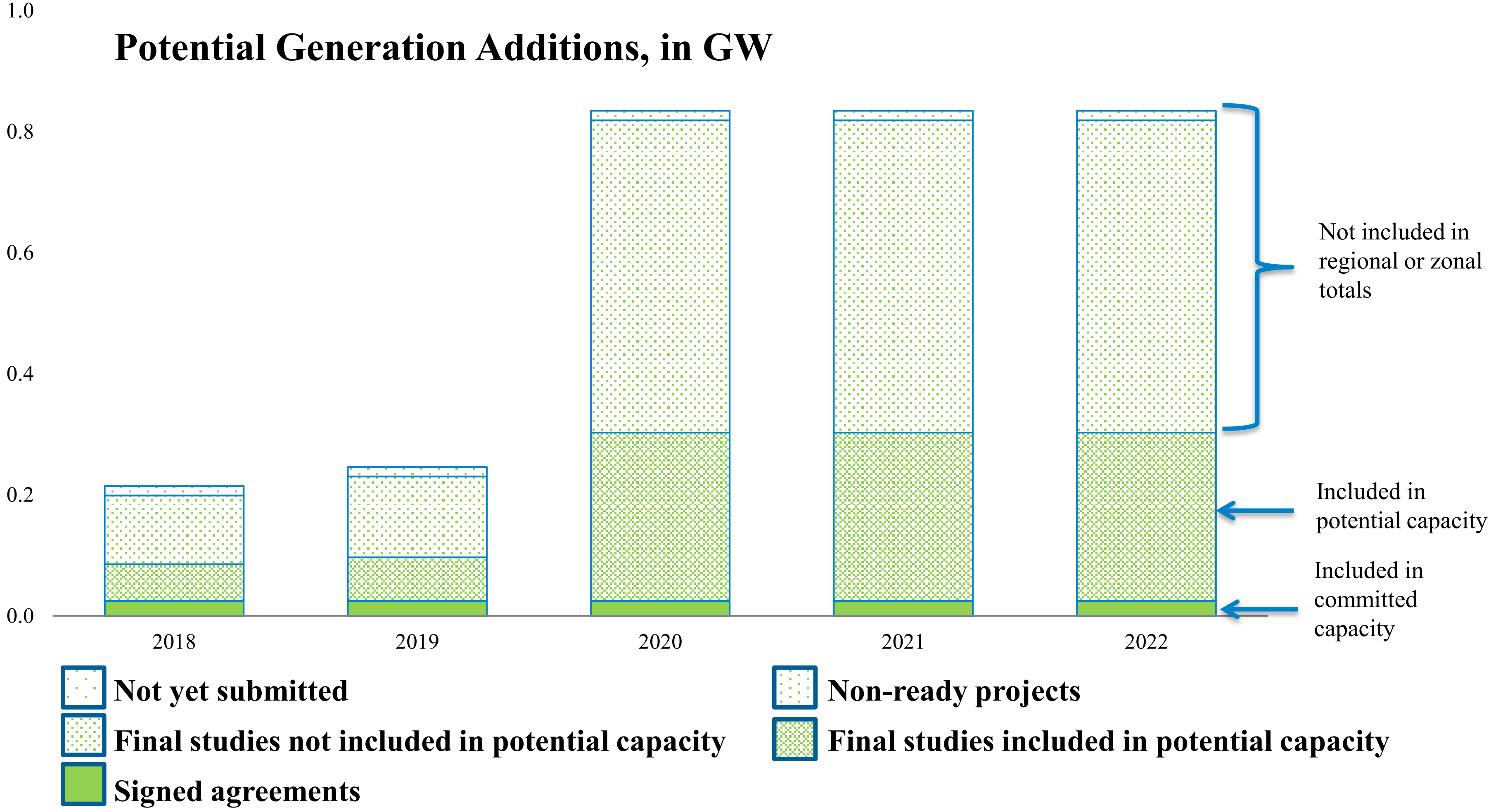
Zone 4 New Resource Additions by Queue Phase



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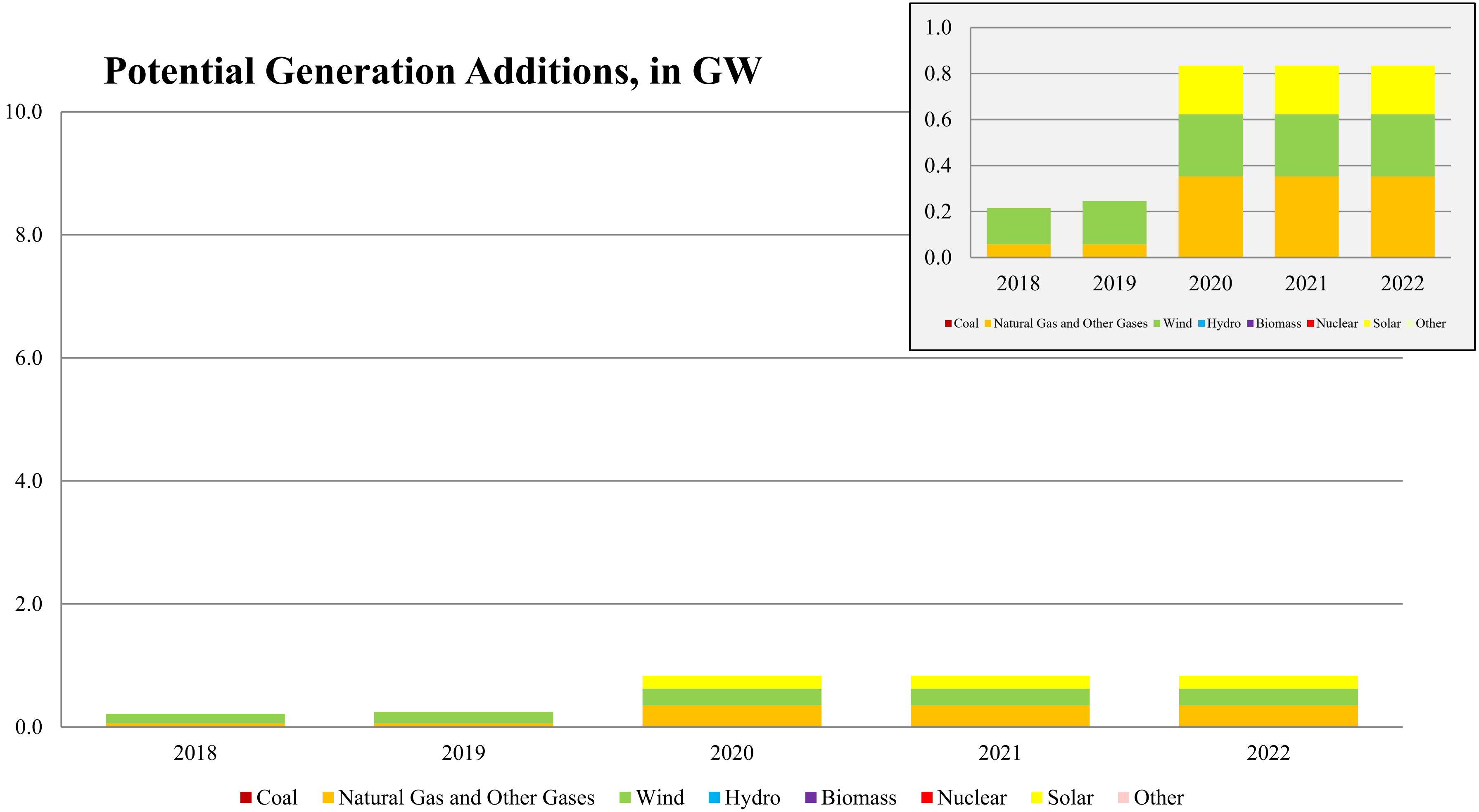
Zone 4 New Resources Additions by Fuel Type



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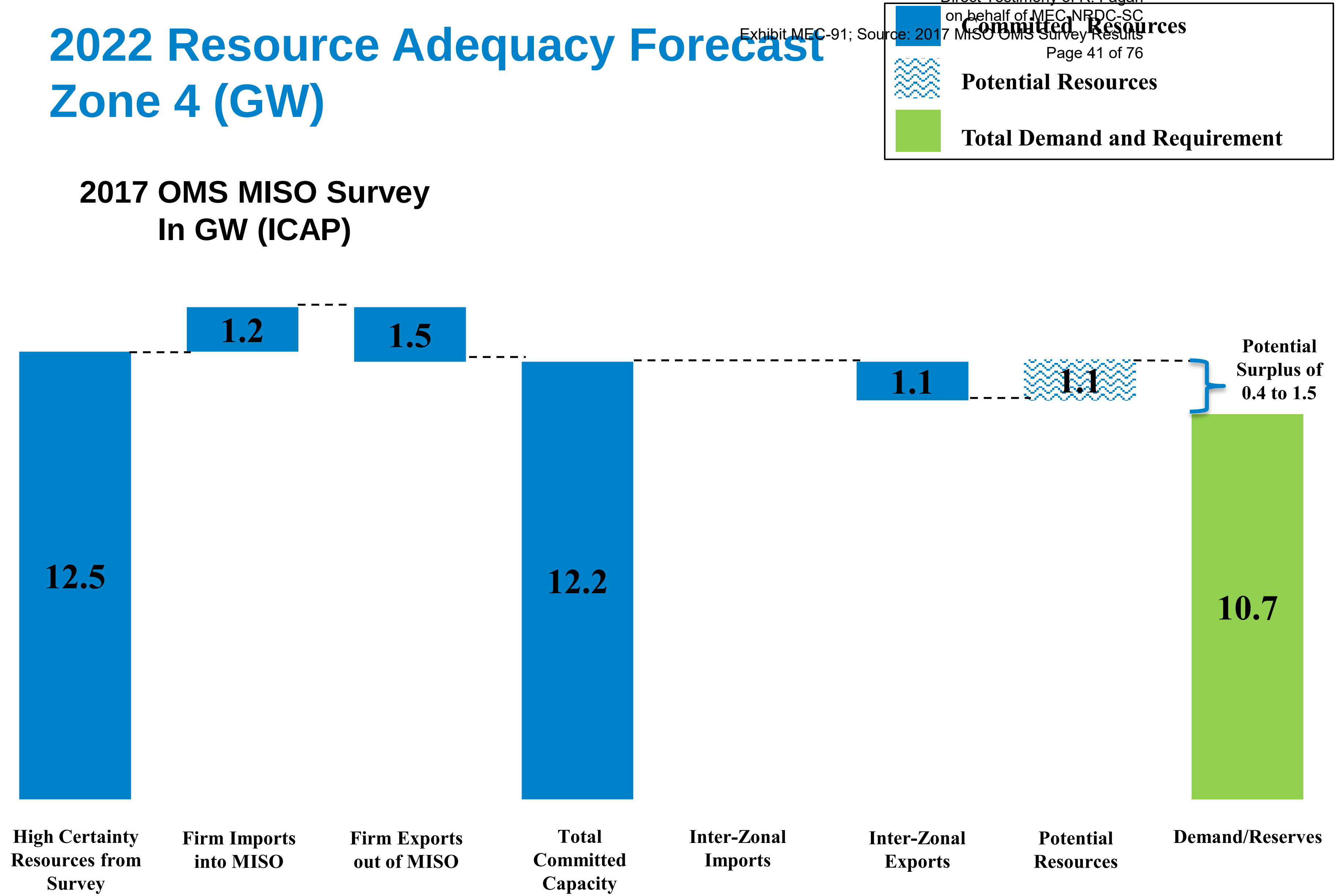
2022 Resource Adequacy Forecast Zone 4 (GW)

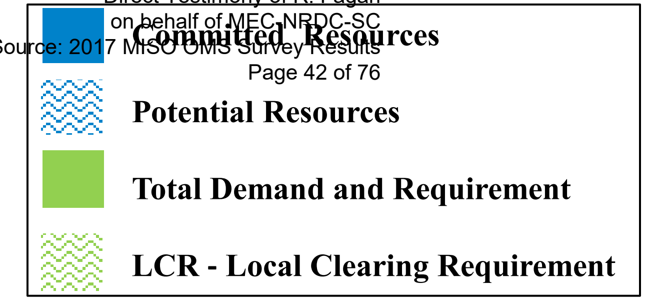
2017 OMS MISO Survey
In GW (ICAP)



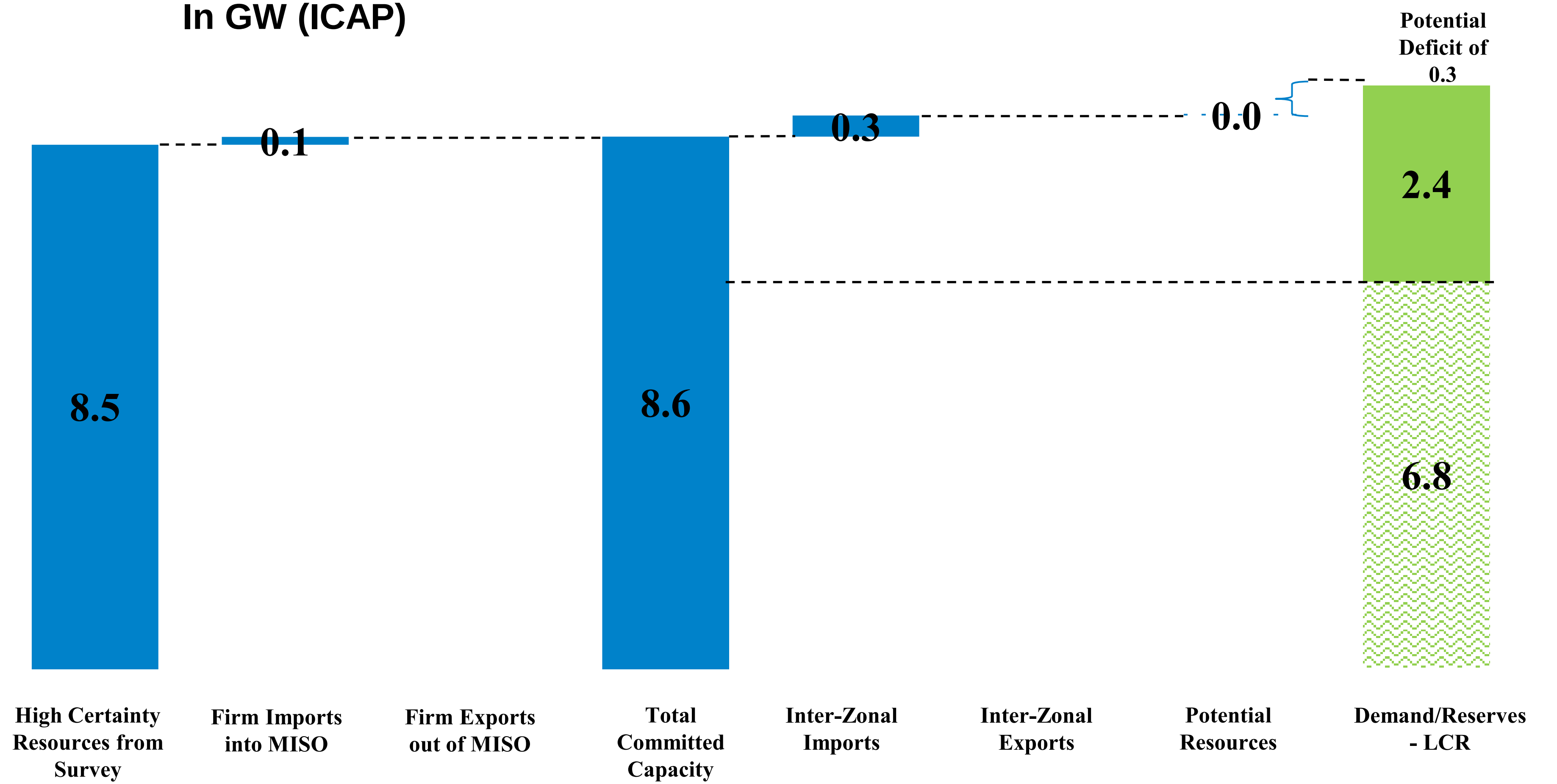
Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

OMS MISO

2018 Resource Adequacy Forecast Zone 5 (GW)



2017 OMS MISO Survey In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2019 - 2021 Resource Adequacy Forecast Zone 5 (GW)

2017 OMS MISO Survey

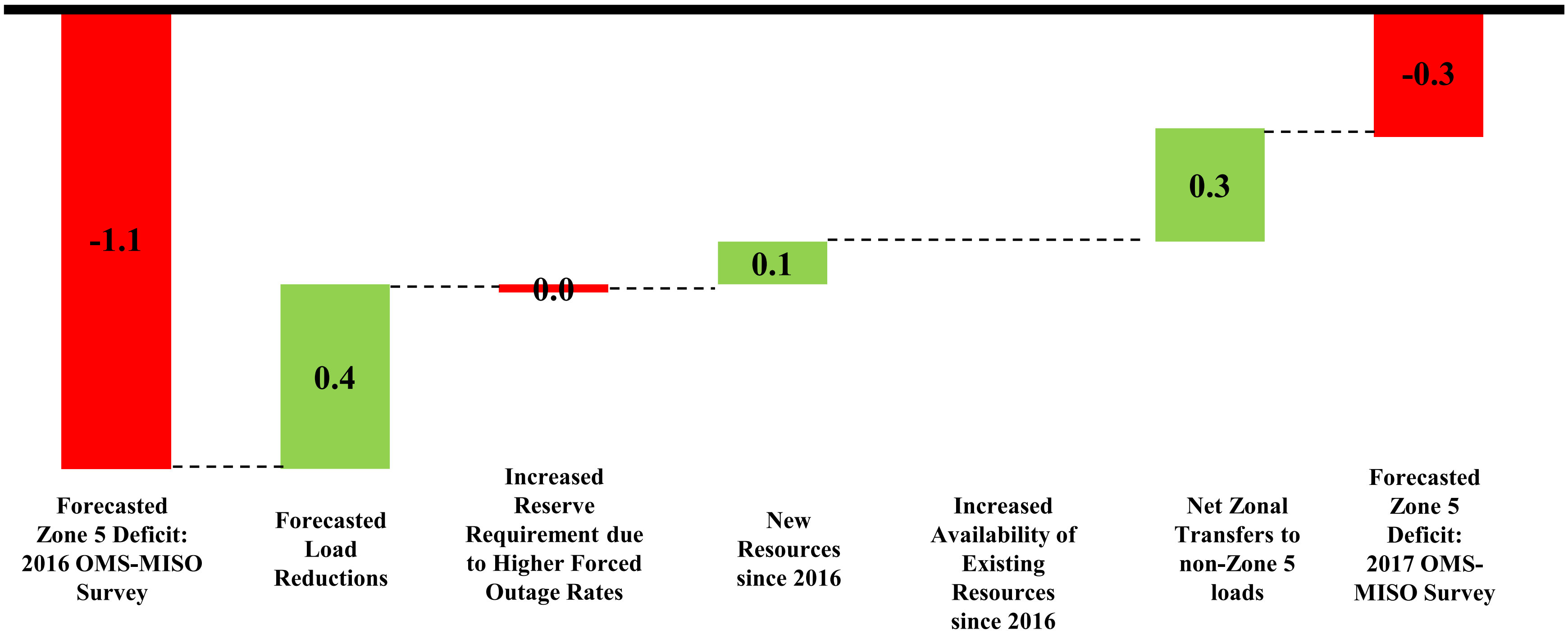
Values In GW (ICAP)

Zone 5	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	8.6	8.6	8.4	A
Firm Imports into MISO	0.1	0.1	0.1	B
Firm Exports out of MISO	0.0	0.0	0.0	C
Total High Certainty Capacity	**8.7**	**8.7**	**8.5**	D = (A+B)-C
Inter-Zonal Imports	0.2	0.2	0.4	E
Inter-Zonal Exports	0.0	0.0	0.0	F
Demand/Reserves	**9.2**	**9.2**	**9.2**	G
Firm Capacity Position	**-0.3**	**-0.3**	**-0.3**	H =(D+E-F)-G
Low Certainty Resources	0.0	0.0	0.1	I
Potential Capacity Surplus/Deficit	**-0.3**	**-0.3**	**-0.2**	J =(H+I)

2016 vs 2017 OMS MISO Survey Results Zone 5

Zone 5 2018 Outlook Committed Capacity Projection Variations since 2016 OMS MISO Survey

In GW (ICAP)



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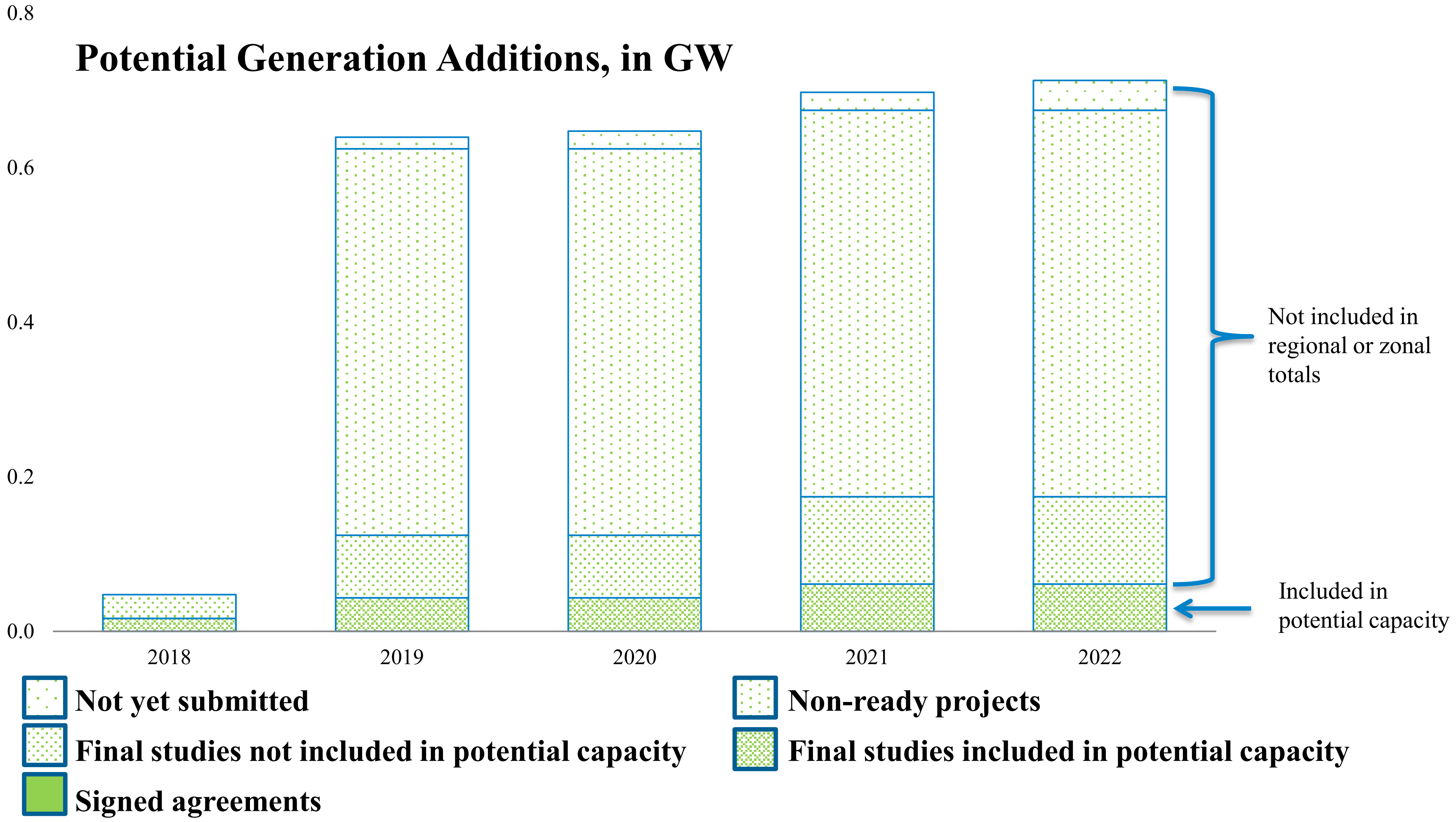
Zone 5 New Resource Additions by Queue Phase



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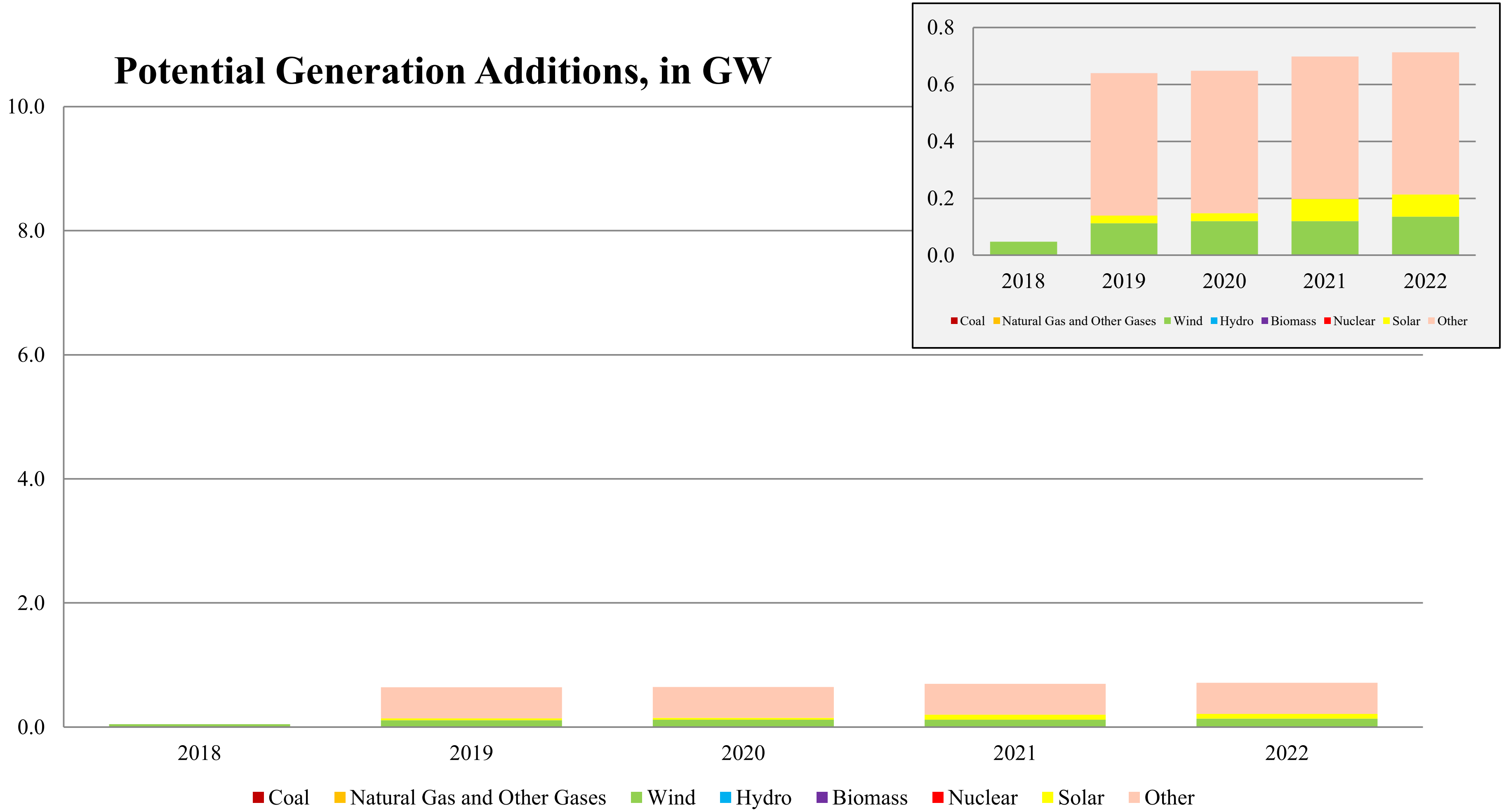
Zone 5 New Resources Additions by Fuel Type



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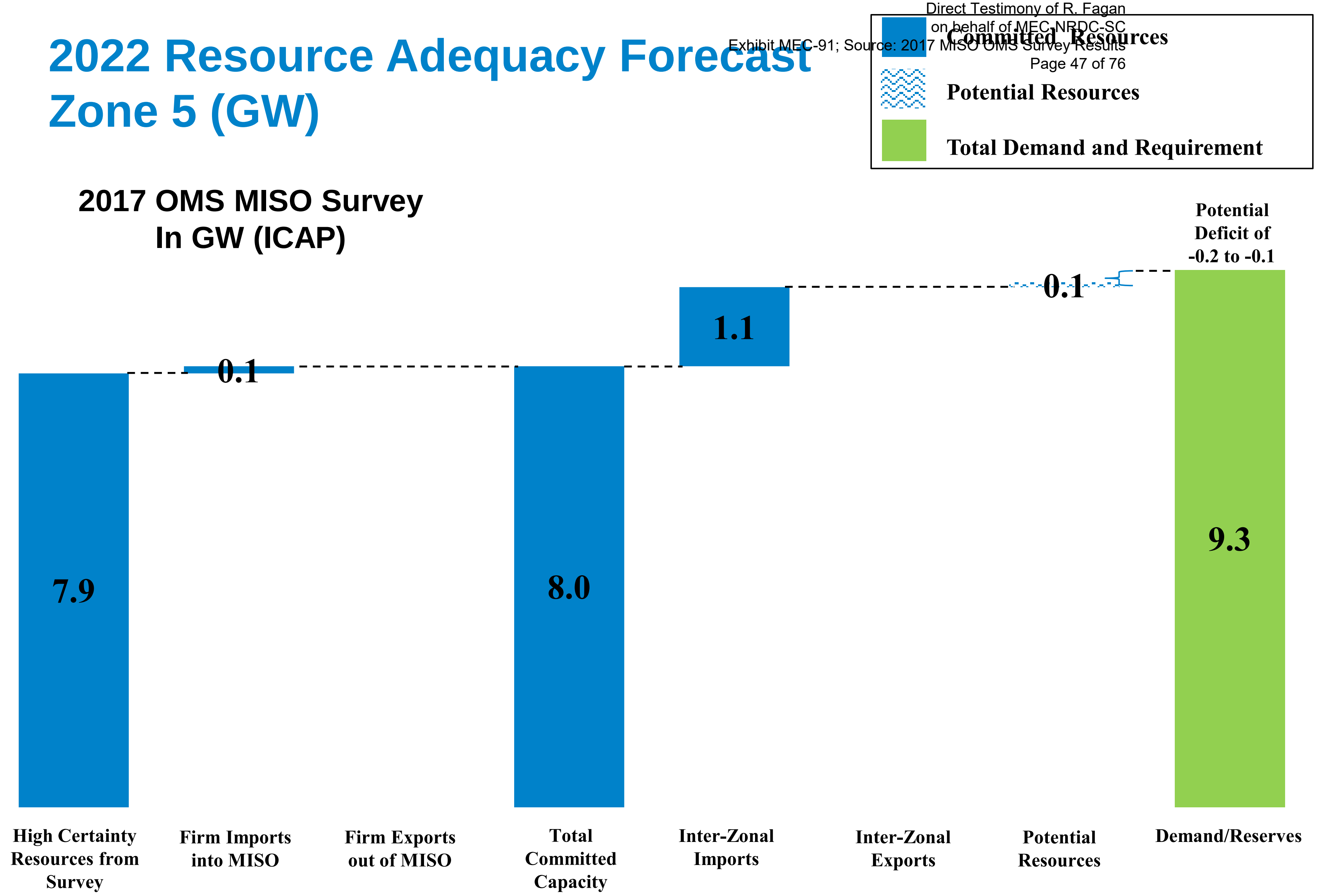
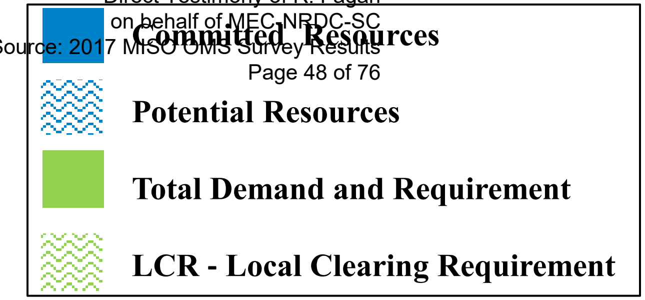
2022 Resource Adequacy Forecast Zone 5 (GW)

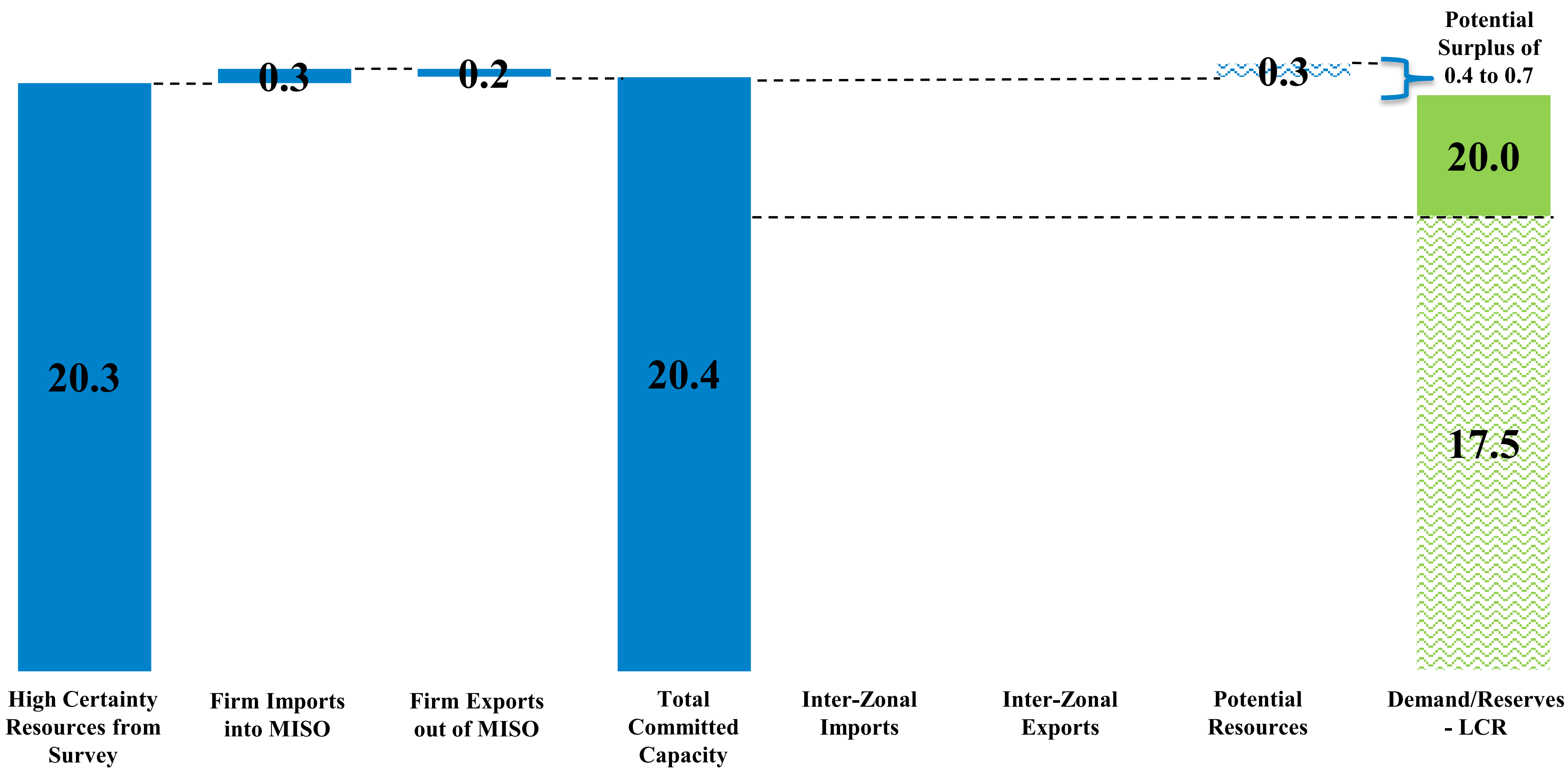


Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2018 Resource Adequacy Forecast Zone 6 (GW)



2017 OMS MISO Survey In GW (ICAP)



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2019 - 2021 Resource Adequacy Forecast Zone 6 (GW)

2017 OMS MISO Survey

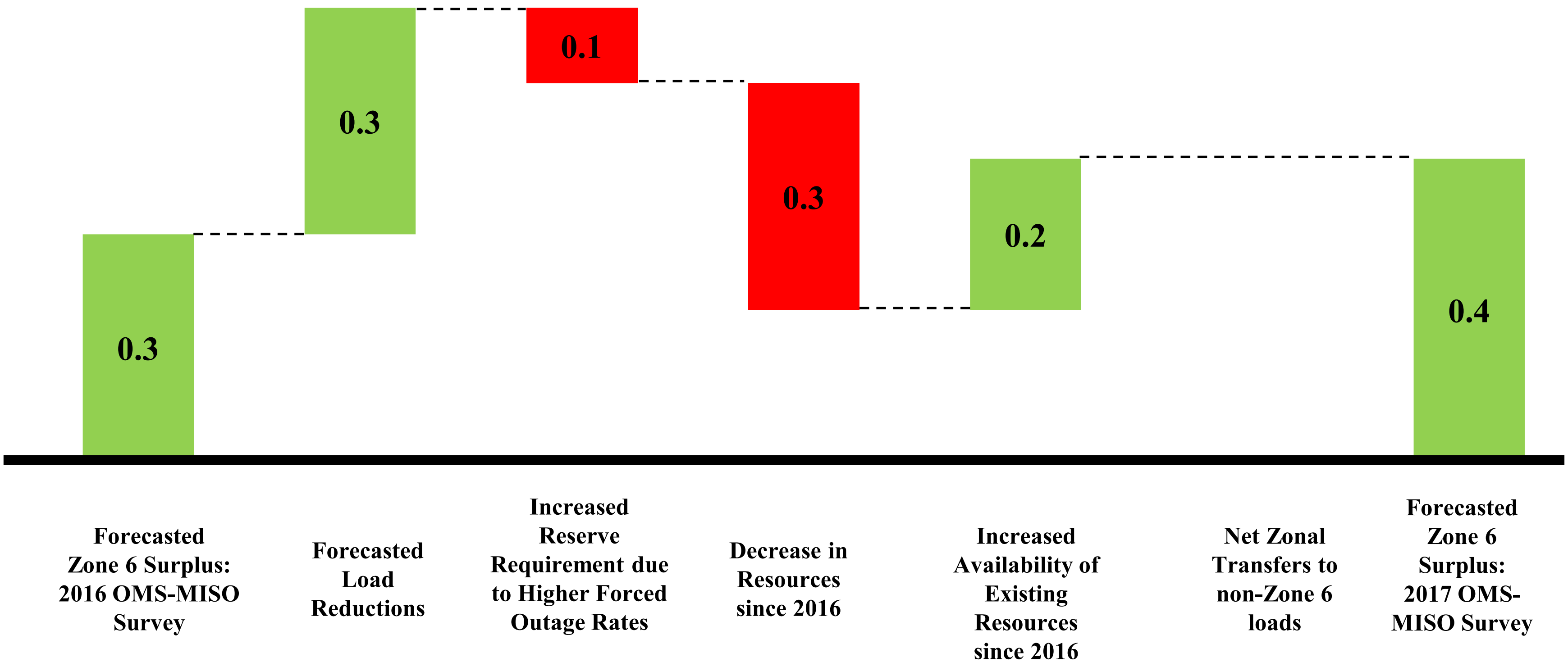
Values In GW (ICAP)

Zone 6	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	20.3	20.0	20.0	A
Firm Imports into MISO	0.4	0.4	0.4	B
Firm Exports out of MISO	0.2	0.2	0.2	C
Total High Certainty Capacity	**20.5**	**20.2**	**20.2**	D = (A+B)-C
Inter-Zonal Imports	0.0	0.0	0.0	E
Inter-Zonal Exports	0.0	0.0	0.0	F
Demand/Reserves	**20.0**	**20.2**	**20.3**	G
Firm Capacity Position	**0.5**	**0.0**	**-0.1**	H =(D+E-F)-G
Low Certainty Resources	0.3	0.6	0.7	I
Potential Capacity Surplus/Deficit	**0.8**	**0.6**	**0.6**	J =(H+I)

2016 vs 2017 OMS MISO Survey Results Zone 6

Zone 6 2018 Outlook Committed Capacity Projection Variations since 2016 OMS MISO Survey

In GW (ICAP)



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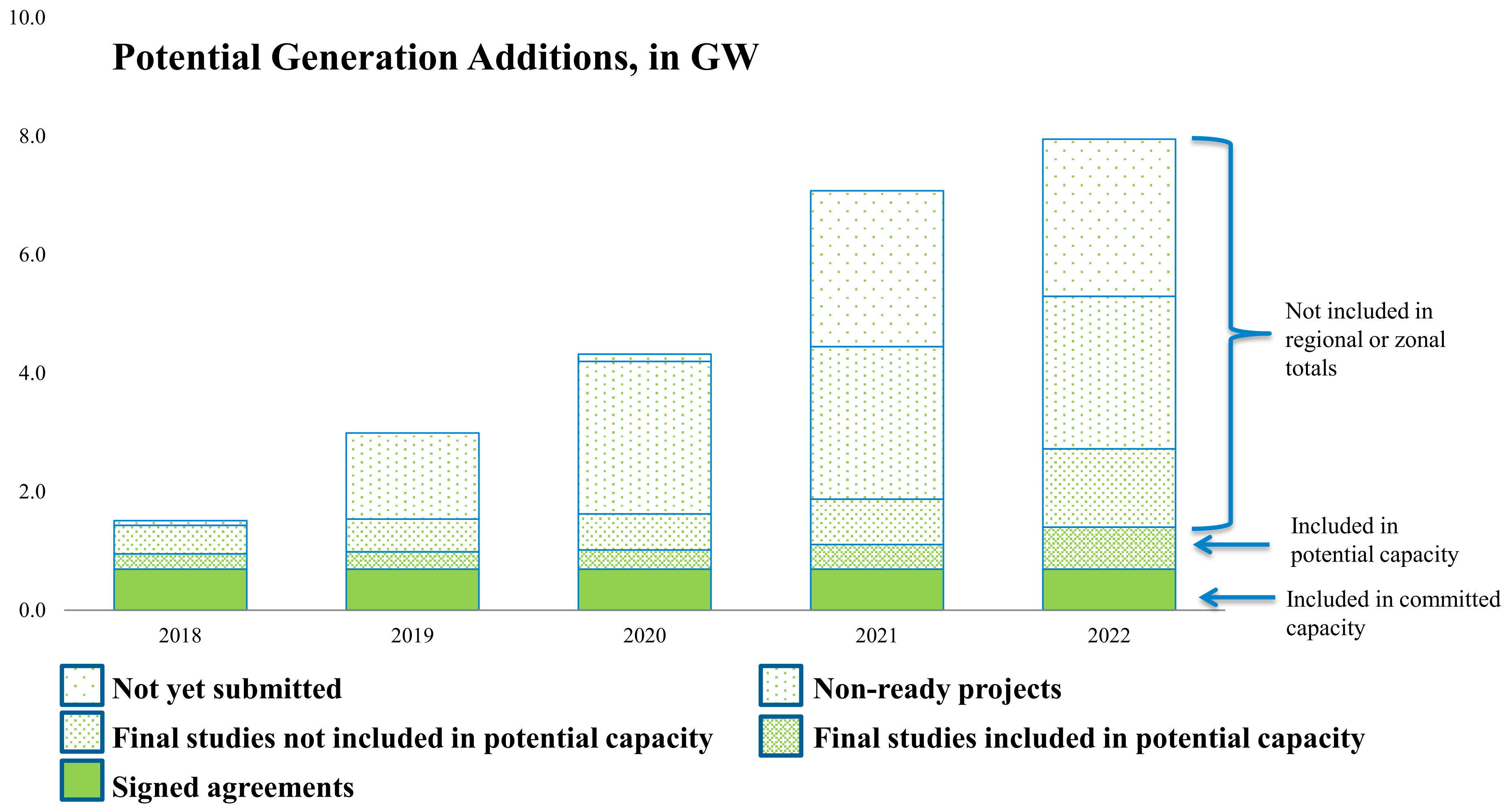
Zone 6 New Resource Additions by Queue Phase



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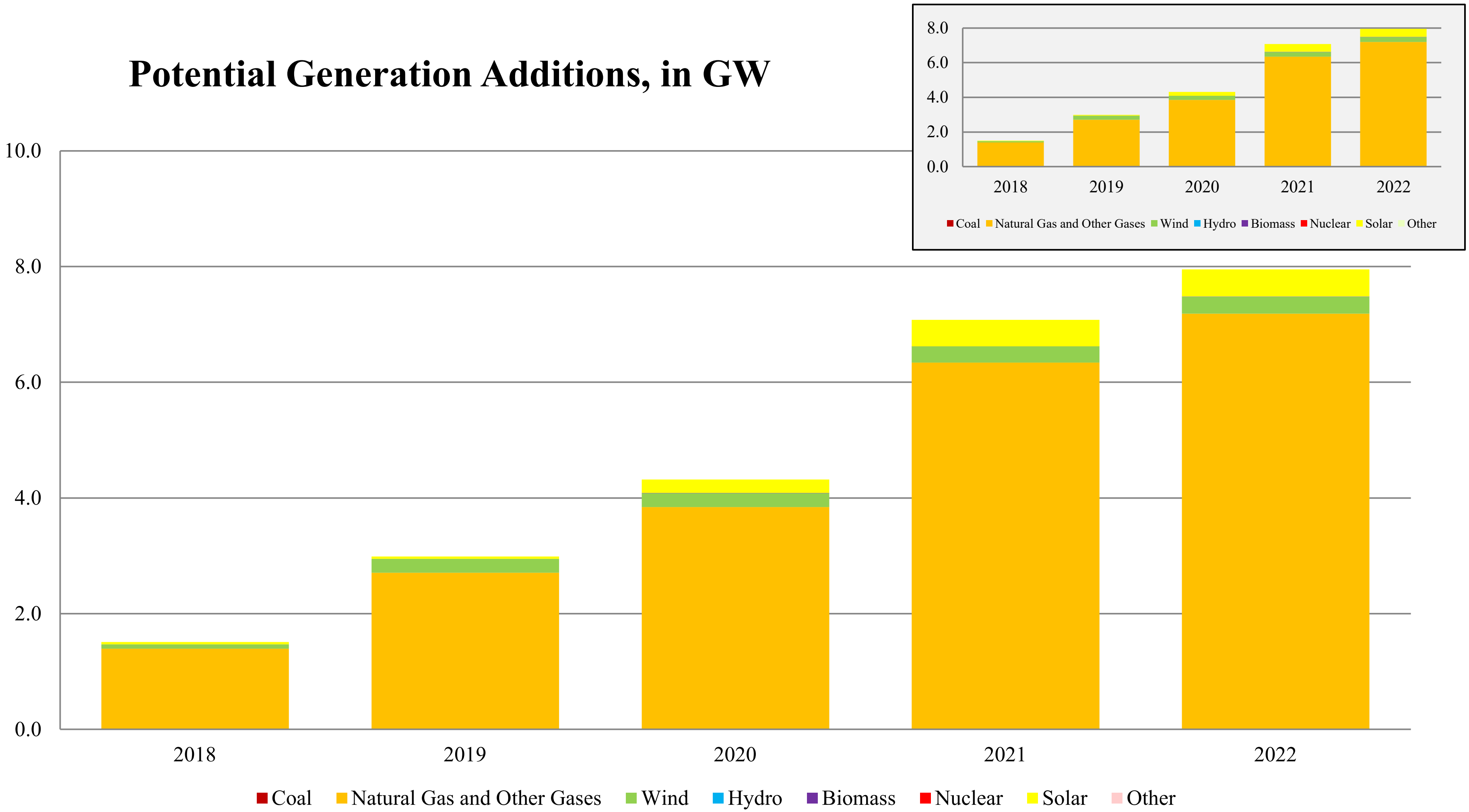
Zone 6 New Resources Additions by Fuel Type



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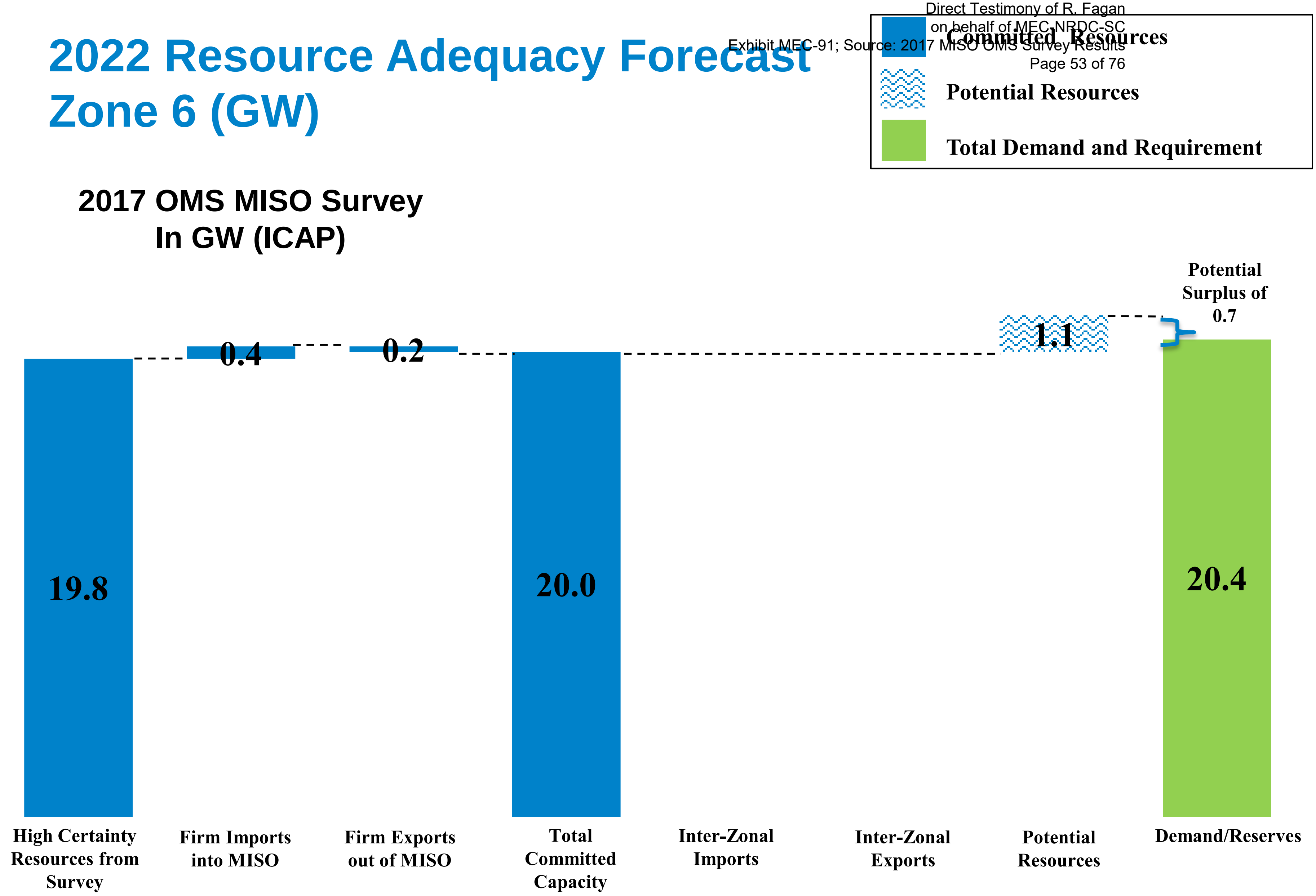
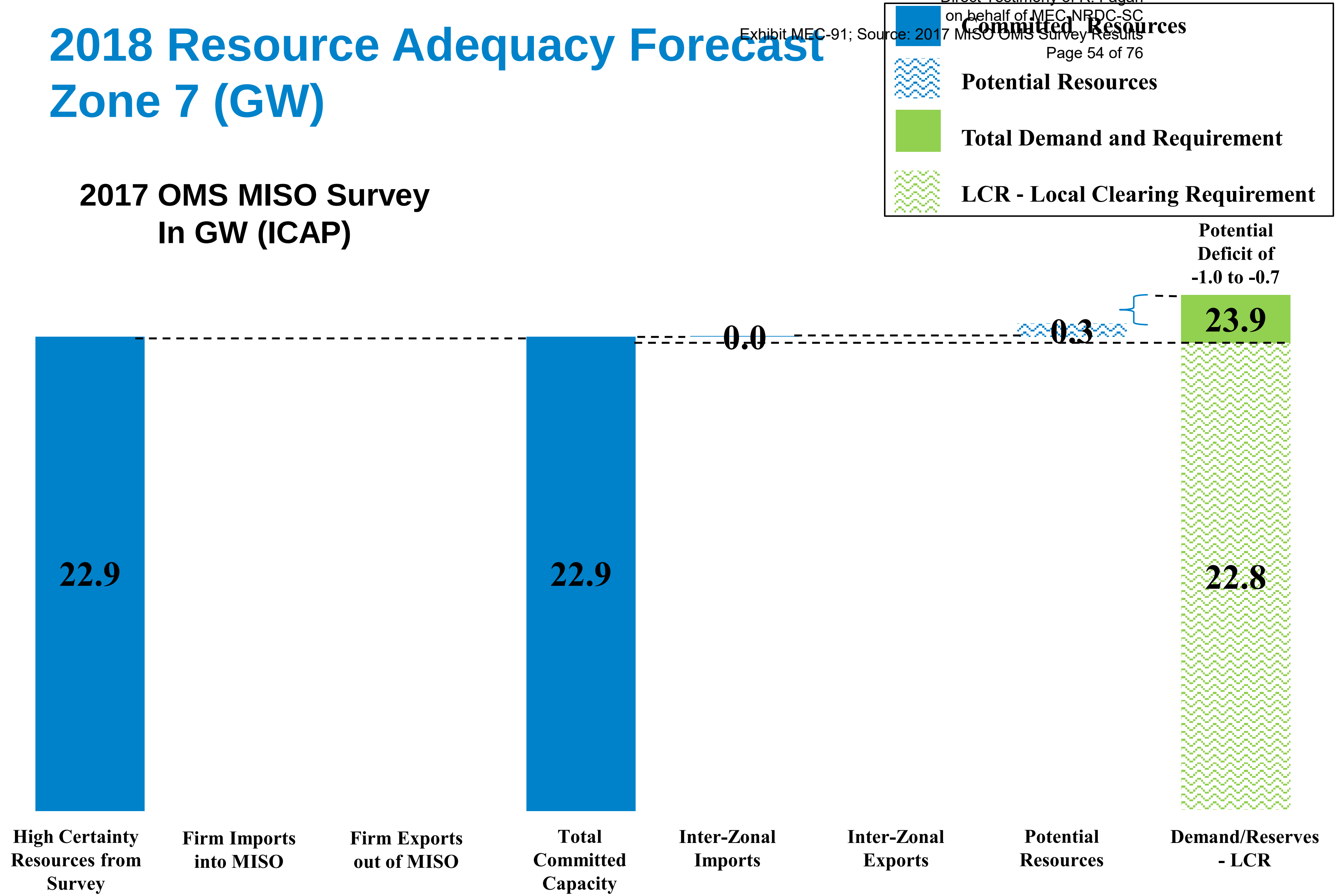
2022 Resource Adequacy Forecast Zone 6 (GW)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2018 Resource Adequacy Forecast Zone 7 (GW)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

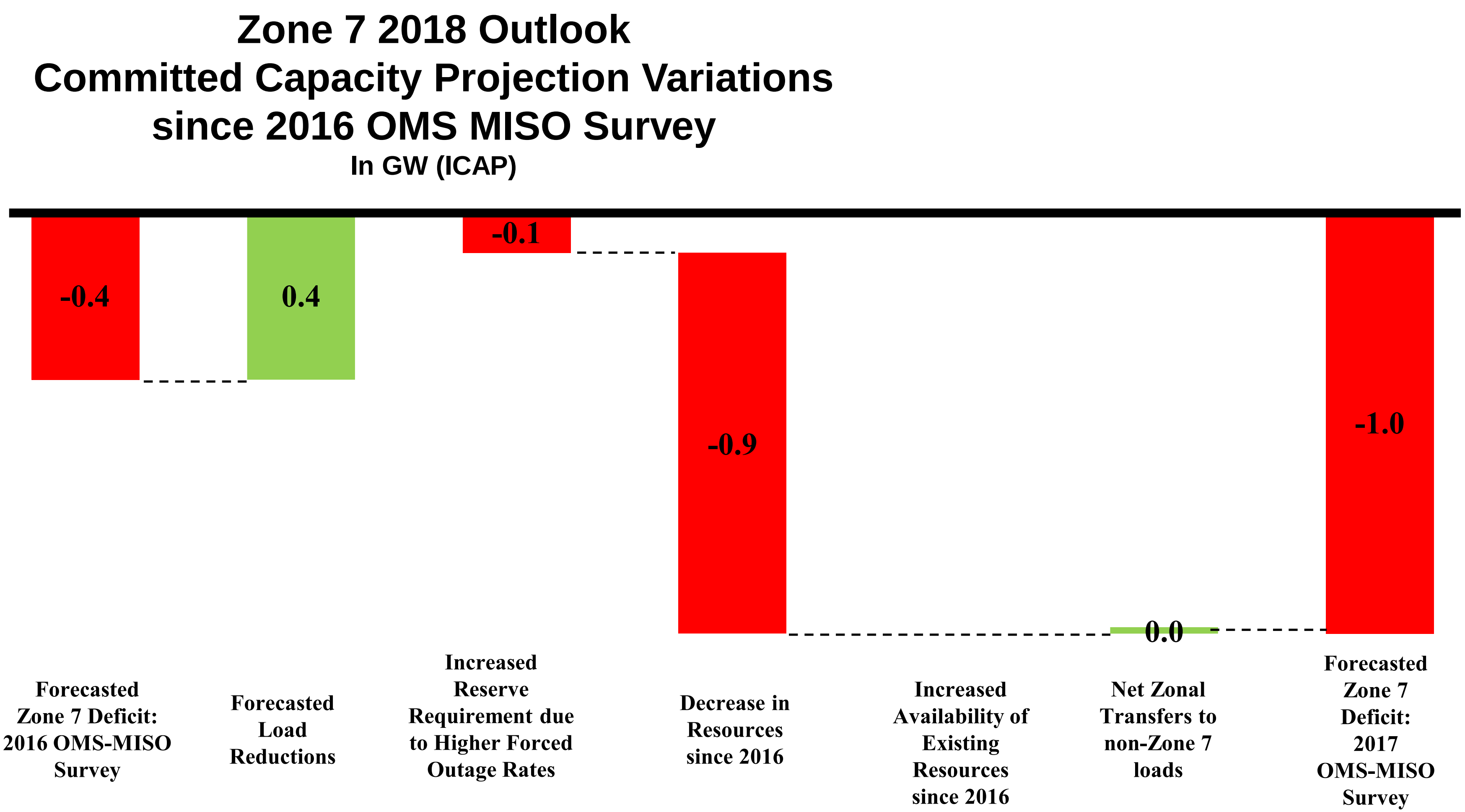
2019 - 2021 Resource Adequacy Forecast Zone 7 (GW)

2017 OMS MISO Survey

Values In GW (ICAP)

Zone 7	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	23.4	23.2	23.3	A
Firm Imports into MISO	0.0	0.0	0.0	B
Firm Exports out of MISO	0.0	0.0	0.0	C
Total High Certainty Capacity	**23.4**	**23.2**	**23.3**	D = (A+B)-C
Inter-Zonal Imports	0.0	0.0	0.0	E
Inter-Zonal Exports	0.0	0.0	0.0	F
Demand/Reserves	**23.8**	**23.7**	**23.7**	G
Firm Capacity Position	**-0.4**	**-0.5**	**-0.4**	H =(D+E-F)-G
Low Certainty Resources	0.3	0.4	0.4	I
Potential Capacity Surplus/Deficit	**-0.1**	**-0.1**	**0.0**	J =(H+I)

2016 vs 2017 OMS MISO Survey Results Zone 7



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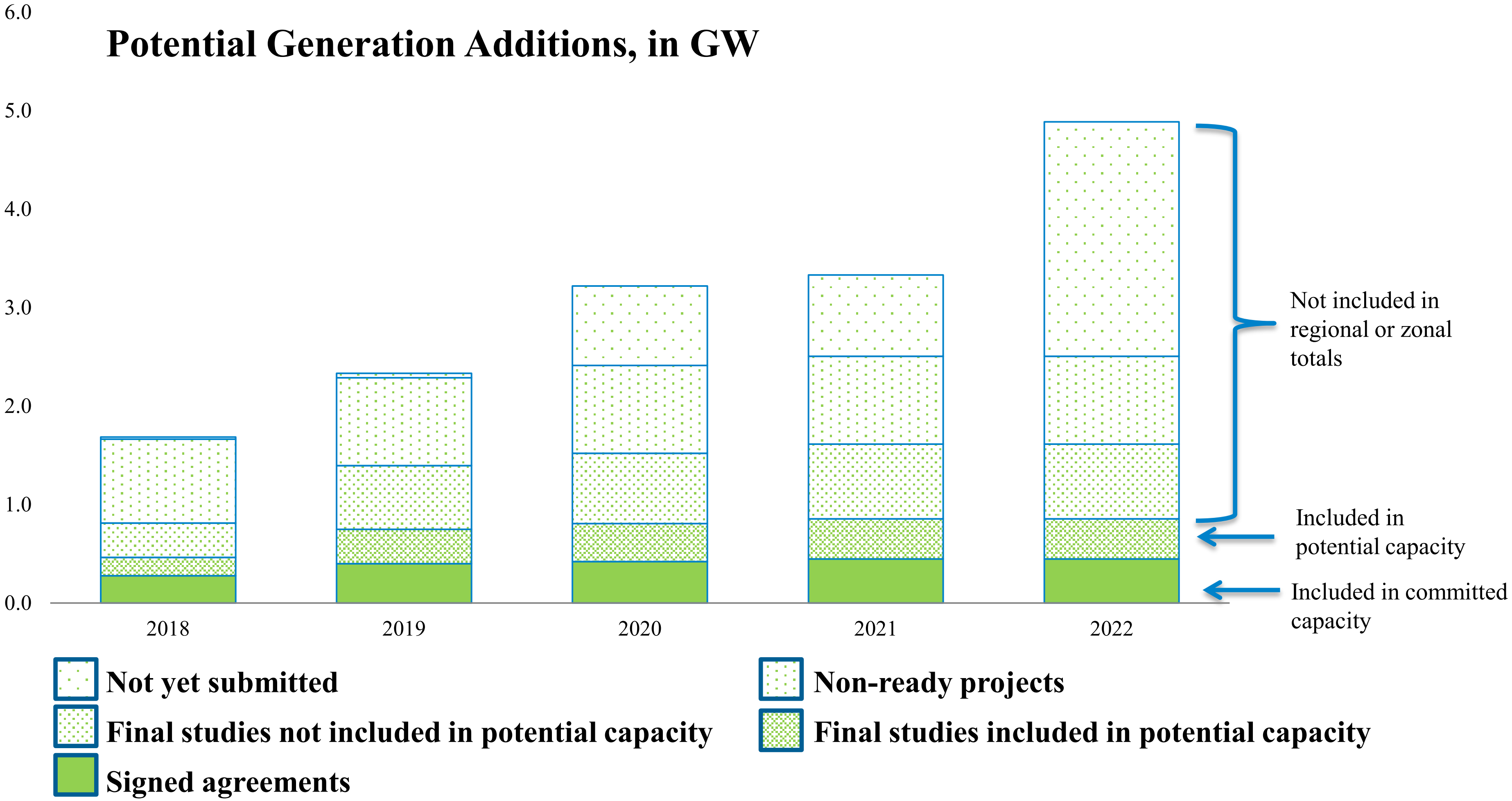
Zone 7 New Resource Additions by Queue Phase



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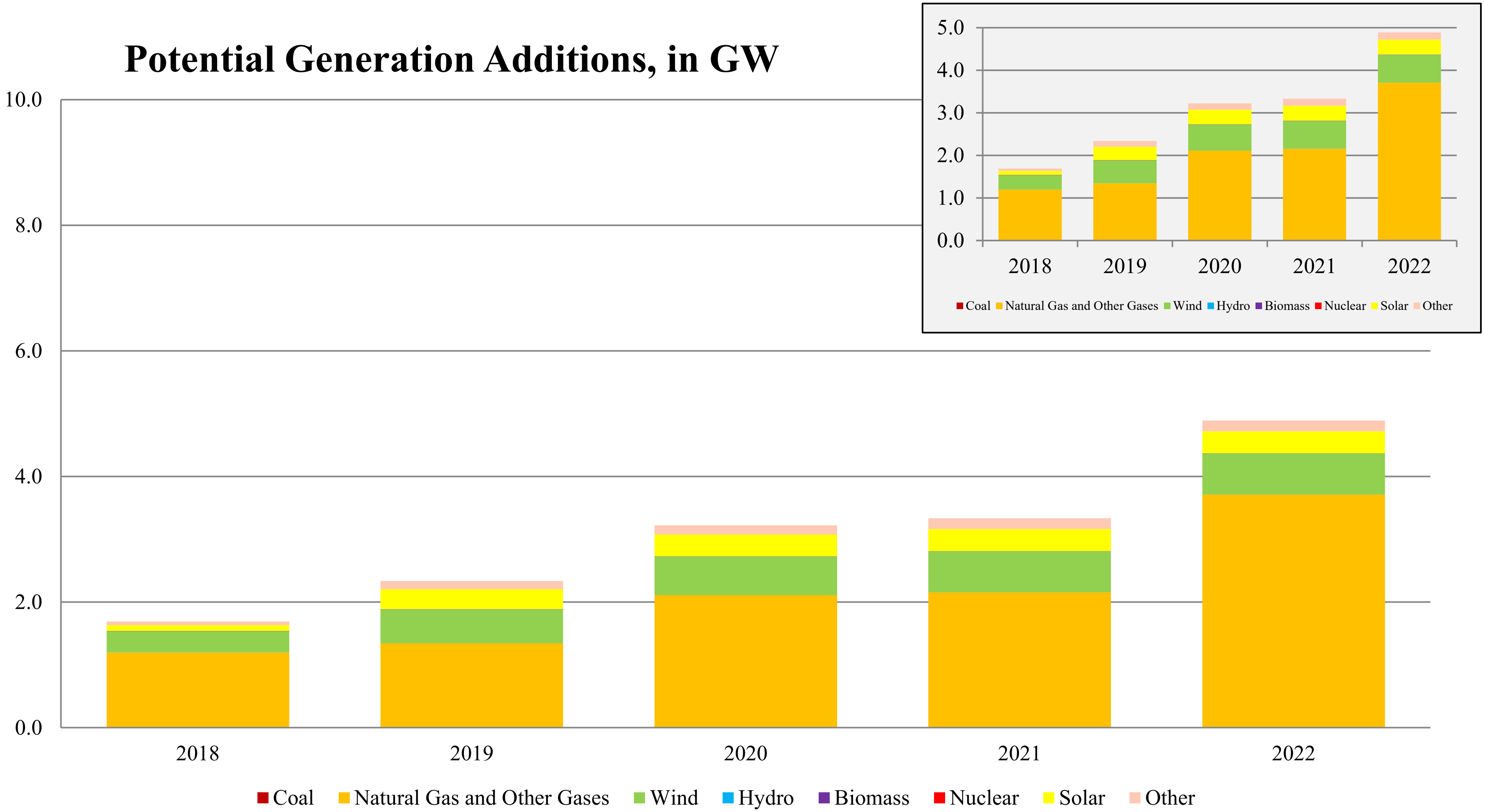
Zone 7 New Resources Additions by Fuel Type



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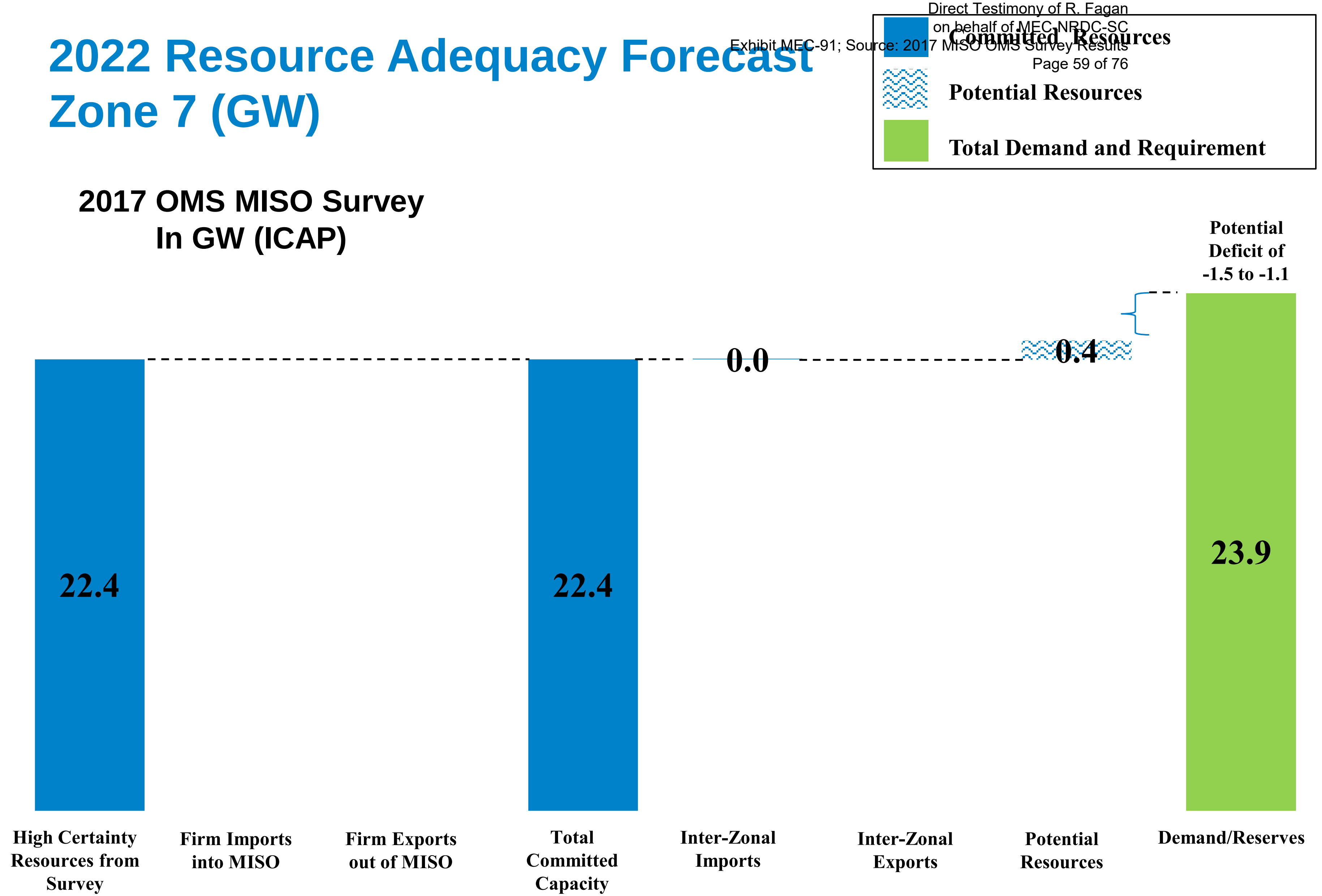
2022 Resource Adequacy Forecast Zone 7 (GW)



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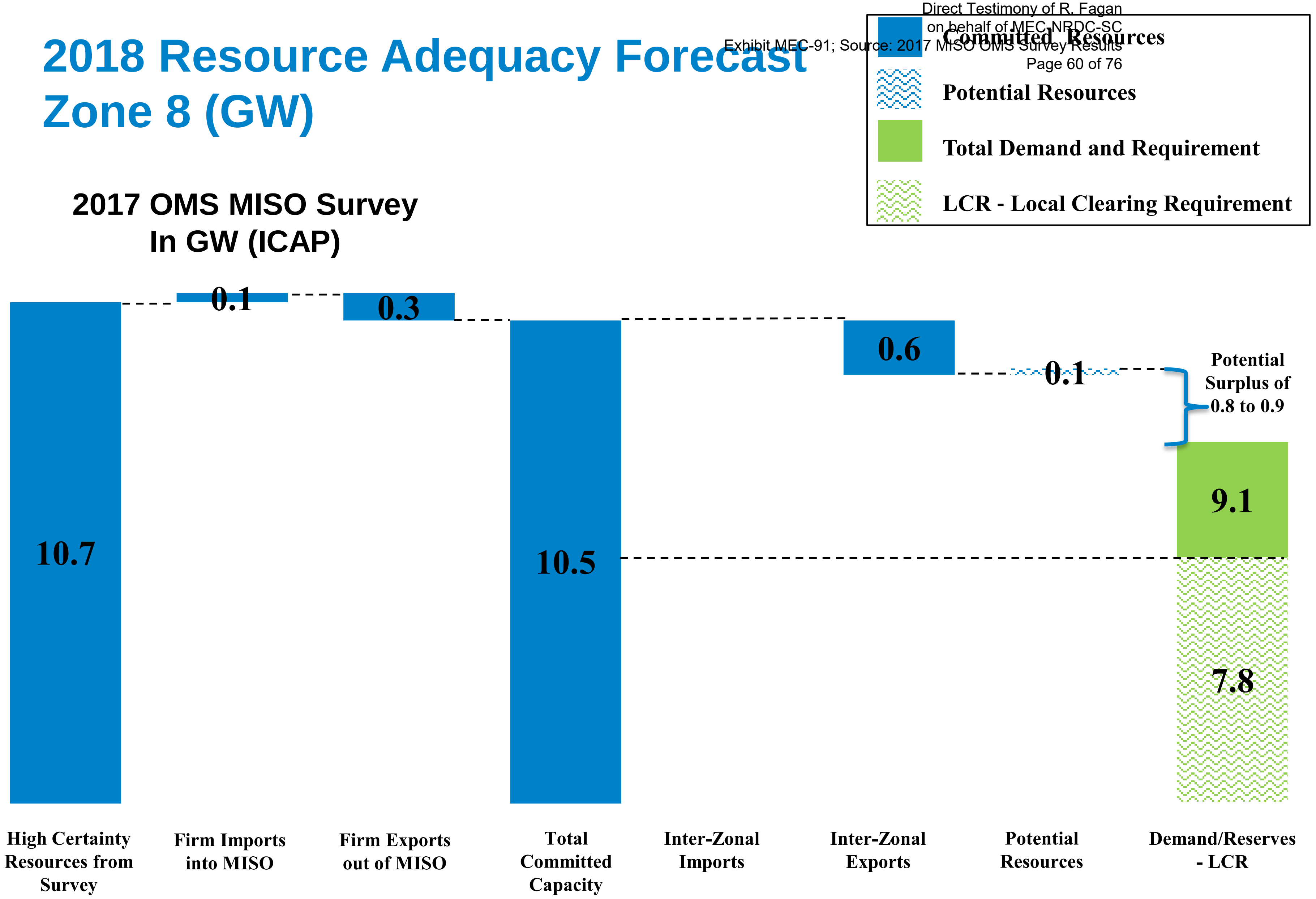
2018 Resource Adequacy Forecast Zone 8 (GW)

2017 OMS MISO Survey In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2019 - 2021 Resource Adequacy Forecast Zone 8 (GW)

2017 OMS MISO Survey

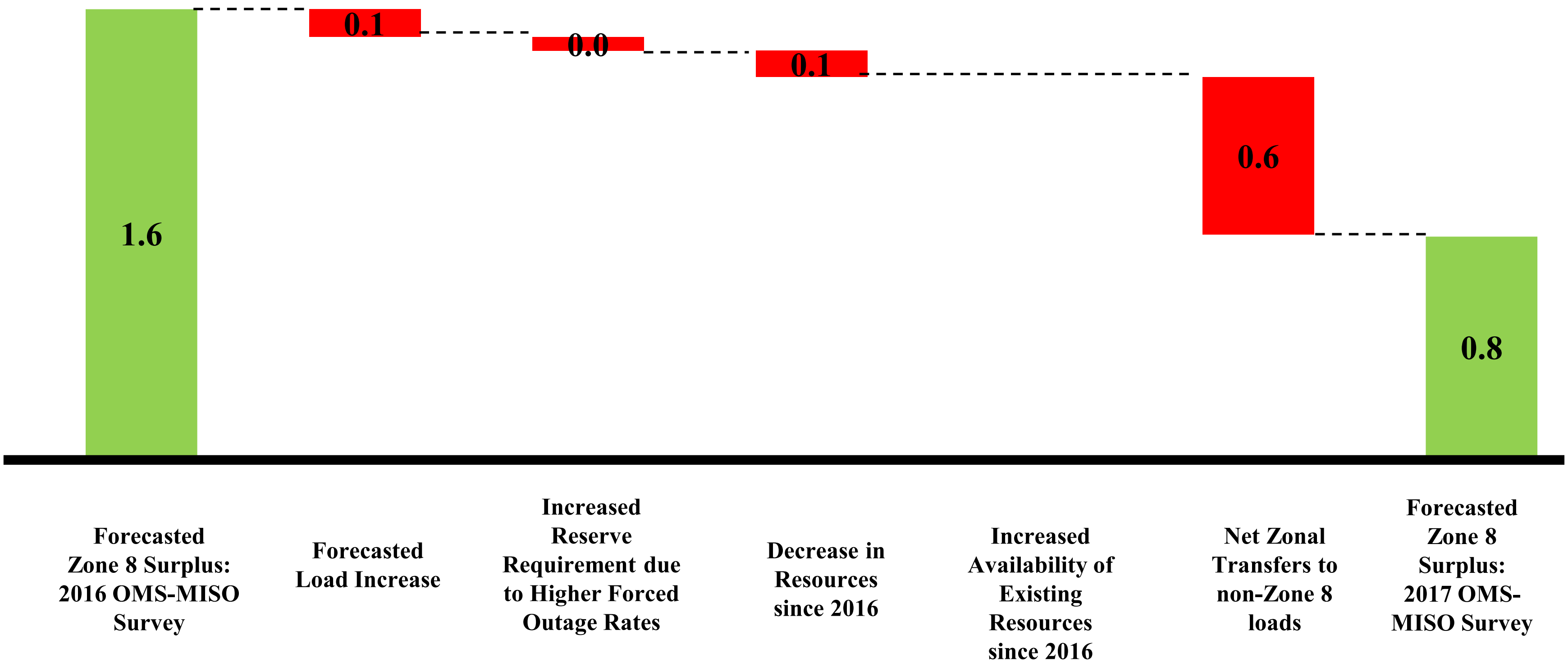
Values In GW (ICAP)

Zone 8	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	10.8	10.8	10.8	A
Firm Imports into MISO	0.1	0.1	0.1	B
Firm Exports out of MISO	0.3	0.3	0.3	C
Total High Certainty Capacity	**10.6**	**10.6**	**10.6**	D = (A+B)-C
Inter-Zonal Imports	0.0	0.0	0.0	E
Inter-Zonal Exports	0.6	0.6	0.6	F
Demand/Reserves	**9.2**	**9.3**	**9.3**	G
Firm Capacity Position	**0.8**	**0.7**	**0.7**	H =(D+E-F)-G
Low Certainty Resources	0.3	0.3	0.3	I
Potential Capacity Surplus/Deficit	**1.1**	**1.0**	**1.0**	J =(H+I)

2016 vs 2017 OMS MISO Survey Results Zone 8

Zone 8 2018 Outlook Committed Capacity Projection Variations since 2016 OMS MISO Survey

In GW (ICAP)



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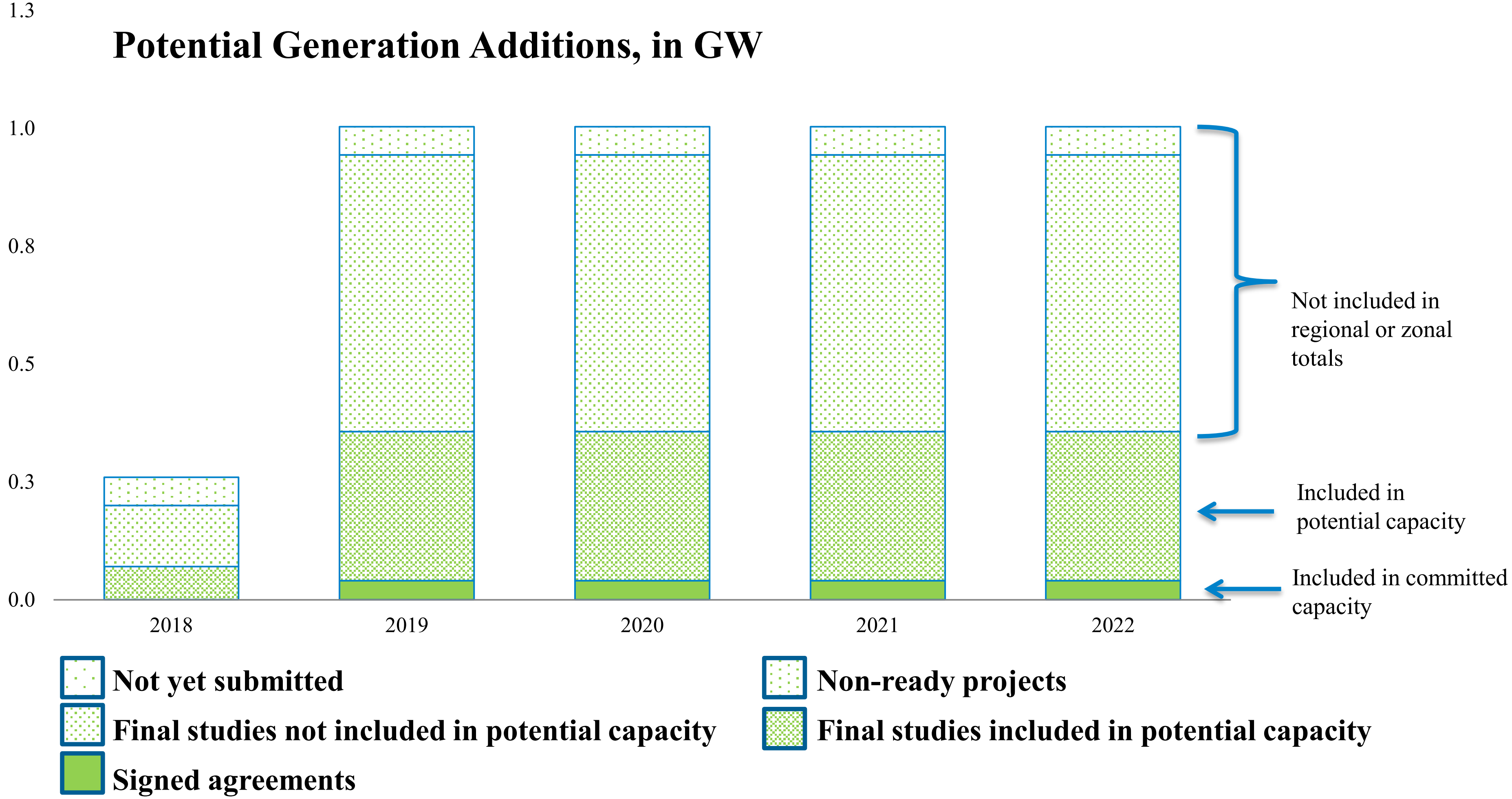
Zone 8 New Resource Additions by Queue Phase



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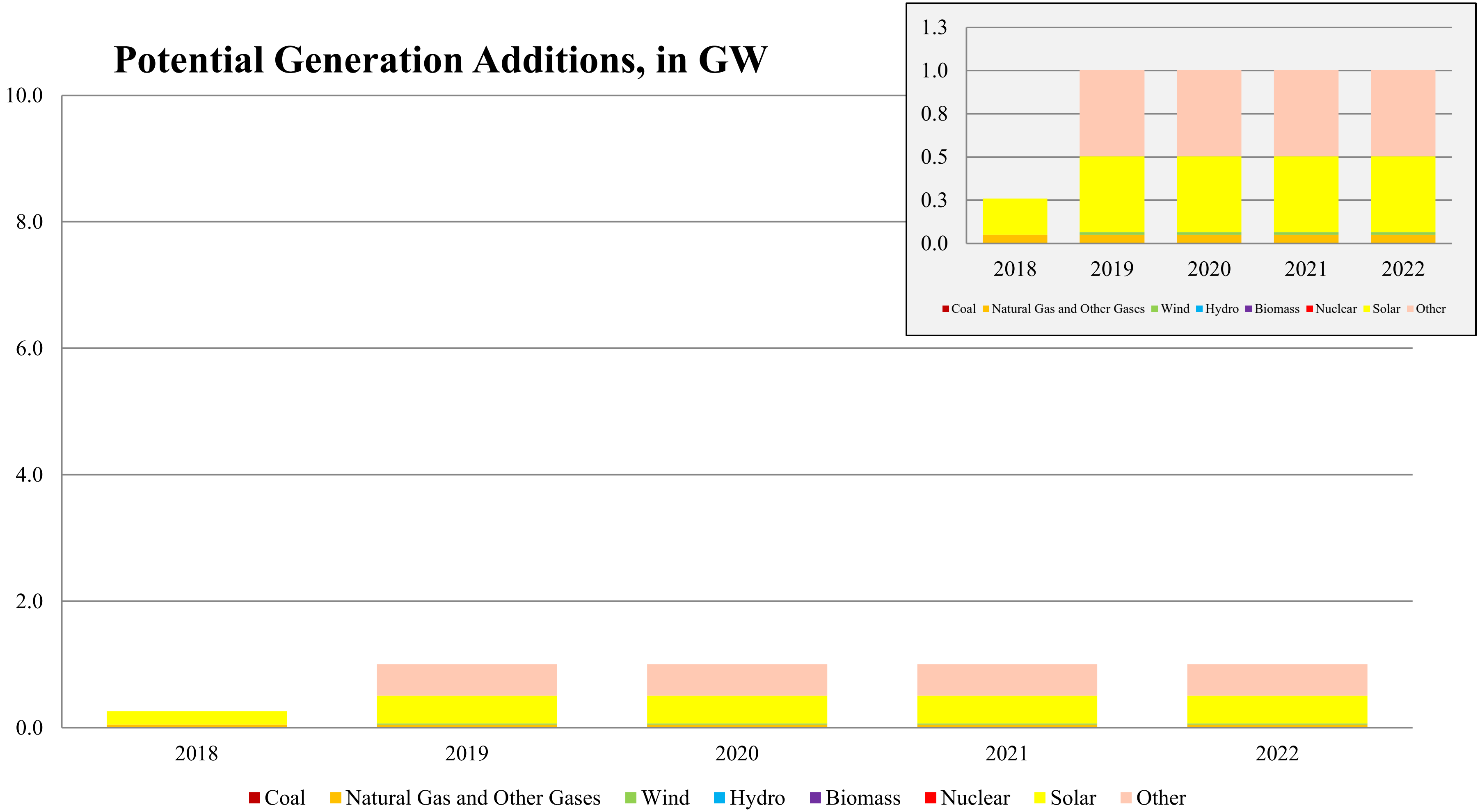
Zone 8 New Resources Additions by Fuel Type



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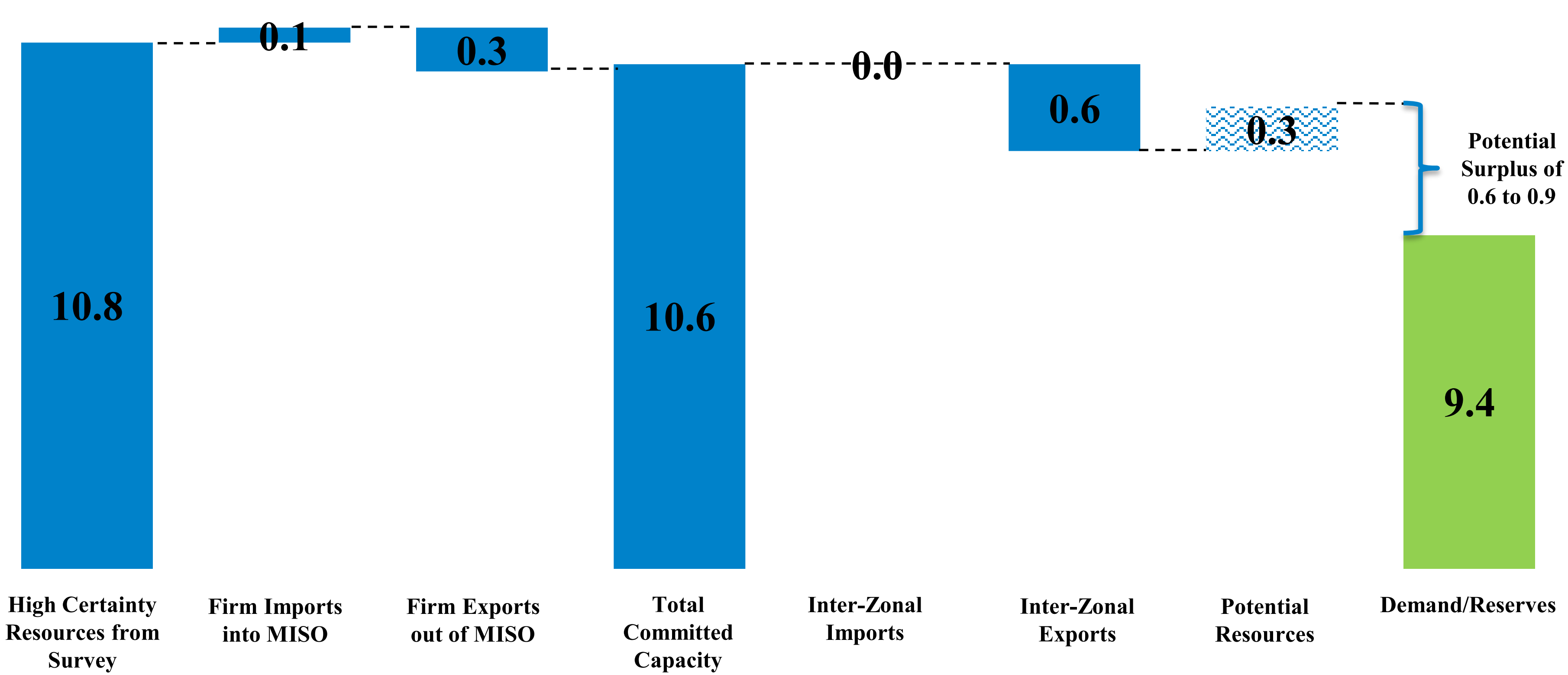
2022 Resource Adequacy Forecast Zone 8 (GW)

Committed Resources

Potential Resources

Total Demand and Requirement

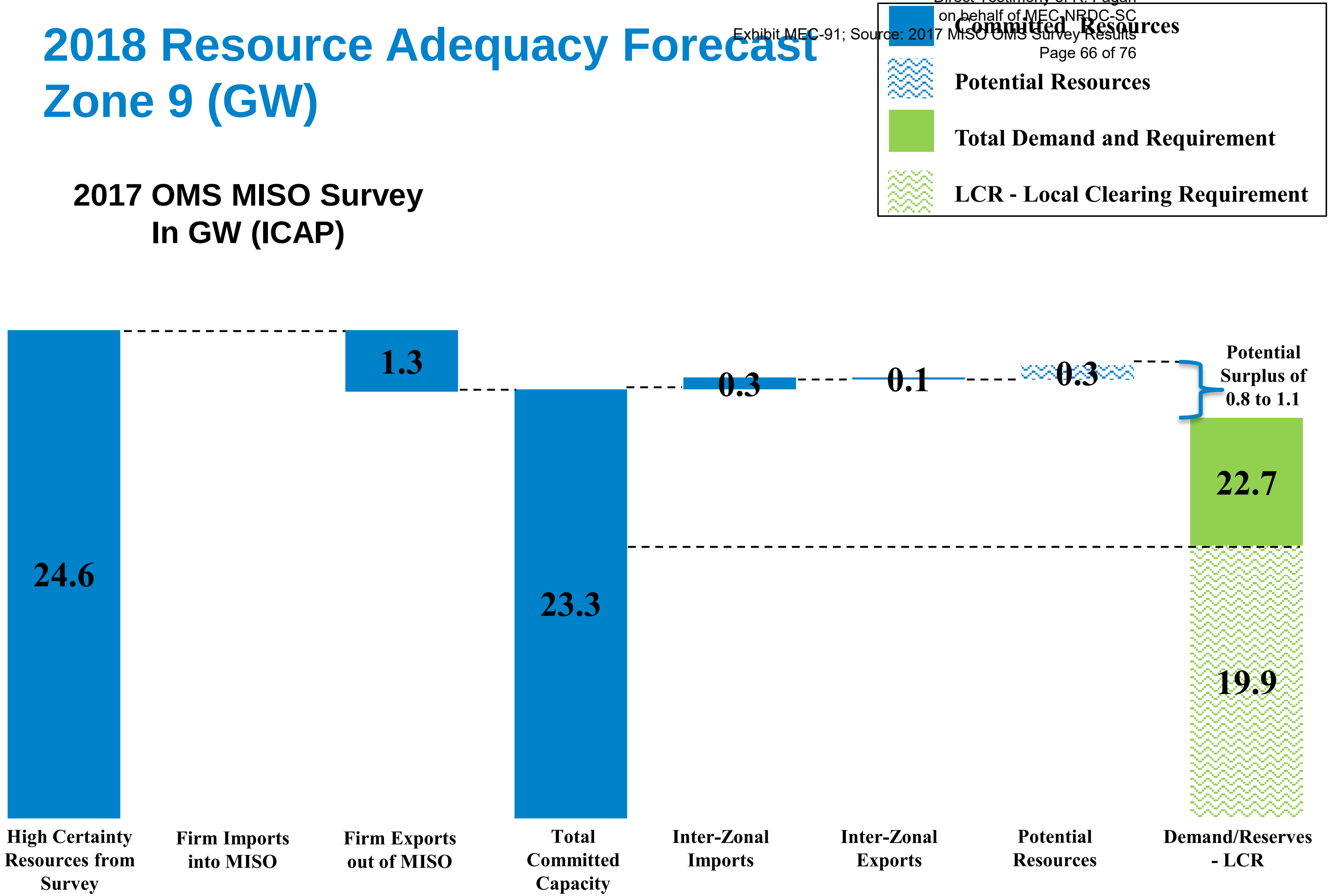
**2017 OMS MISO Survey
In GW (ICAP)**



<u>Potential Resources</u> includes 35% of resources in the final study phase of the MISO Interconnection Queue

2018 Resource Adequacy Forecast Zone 9 (GW)

2017 OMS MISO Survey In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

2019 - 2021 Resource Adequacy Forecast Zone 9 (GW)

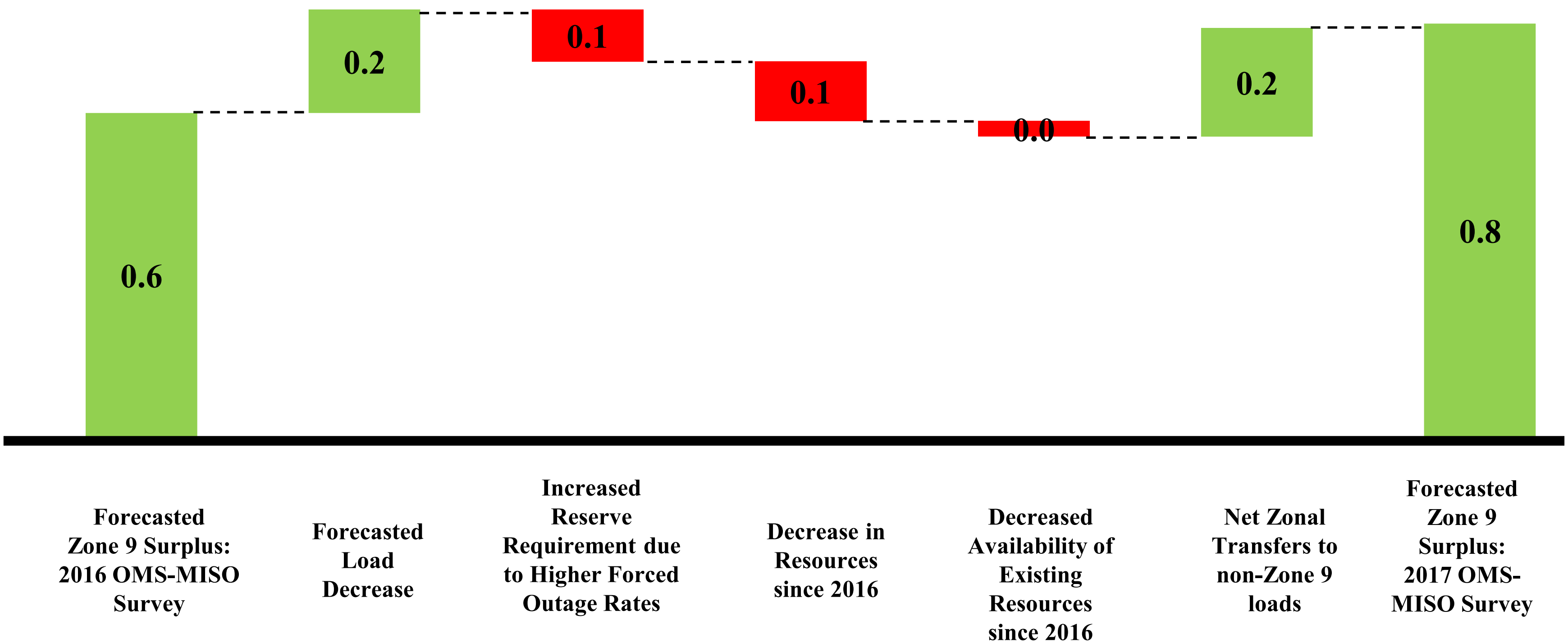
2017 OMS MISO Survey

Values In GW (ICAP)

Zone 9	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	25.4	25.4	25.4	A
Firm Imports into MISO	0.0	0.0	0.0	B
Firm Exports out of MISO	1.3	1.3	1.3	C
Total High Certainty Capacity	**24.1**	**24.1**	**24.1**	D = (A+B)-C
Inter-Zonal Imports	0.3	0.3	0.3	E
Inter-Zonal Exports	0.1	0.0	0.0	F
Demand/Reserves	**22.8**	**23.0**	**23.2**	G
Firm Capacity Position	**1.5**	**1.4**	**1.2**	H =(D+E-F)-G
Low Certainty Resources	0.3	0.7	1.0	I
Potential Capacity Surplus/Deficit	**1.8**	**2.1**	**2.2**	J =(H+I)

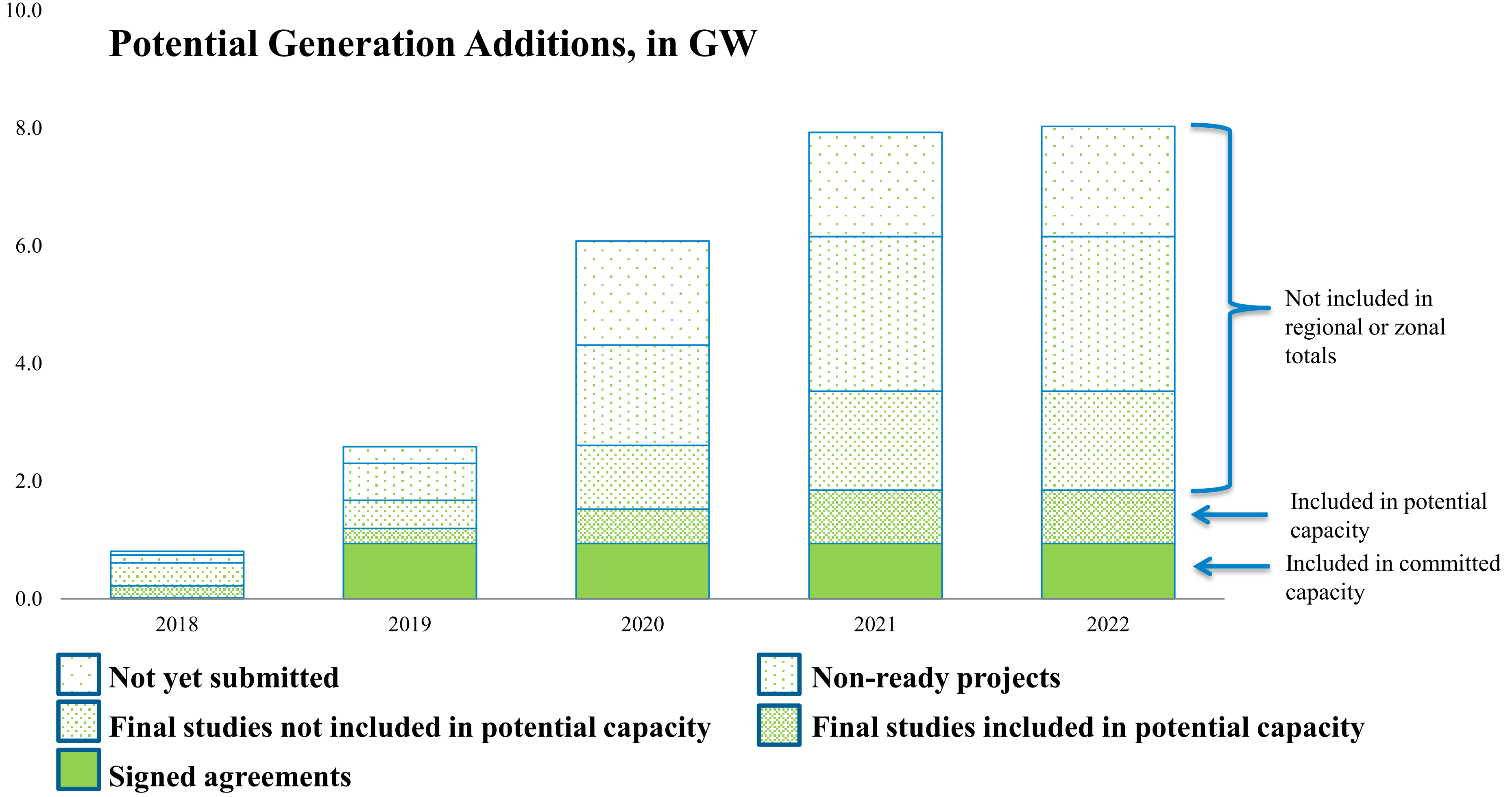
2016 vs 2017 OMS MISO Survey Results Zone 9

Zone 9 2018 Outlook
Committed Capacity Projection Variations since 2016 OMS MISO Survey
In GW (ICAP)



<u>**New resources**</u> include resources with newly signed Interconnection Agreements and new Load Modifying Resources
<u>**Increased availability**</u> results from deferred retirements and internal resources with reduced commitments to non-MISO load
Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones

Zone 9 New Resource Additions by Queue Phase

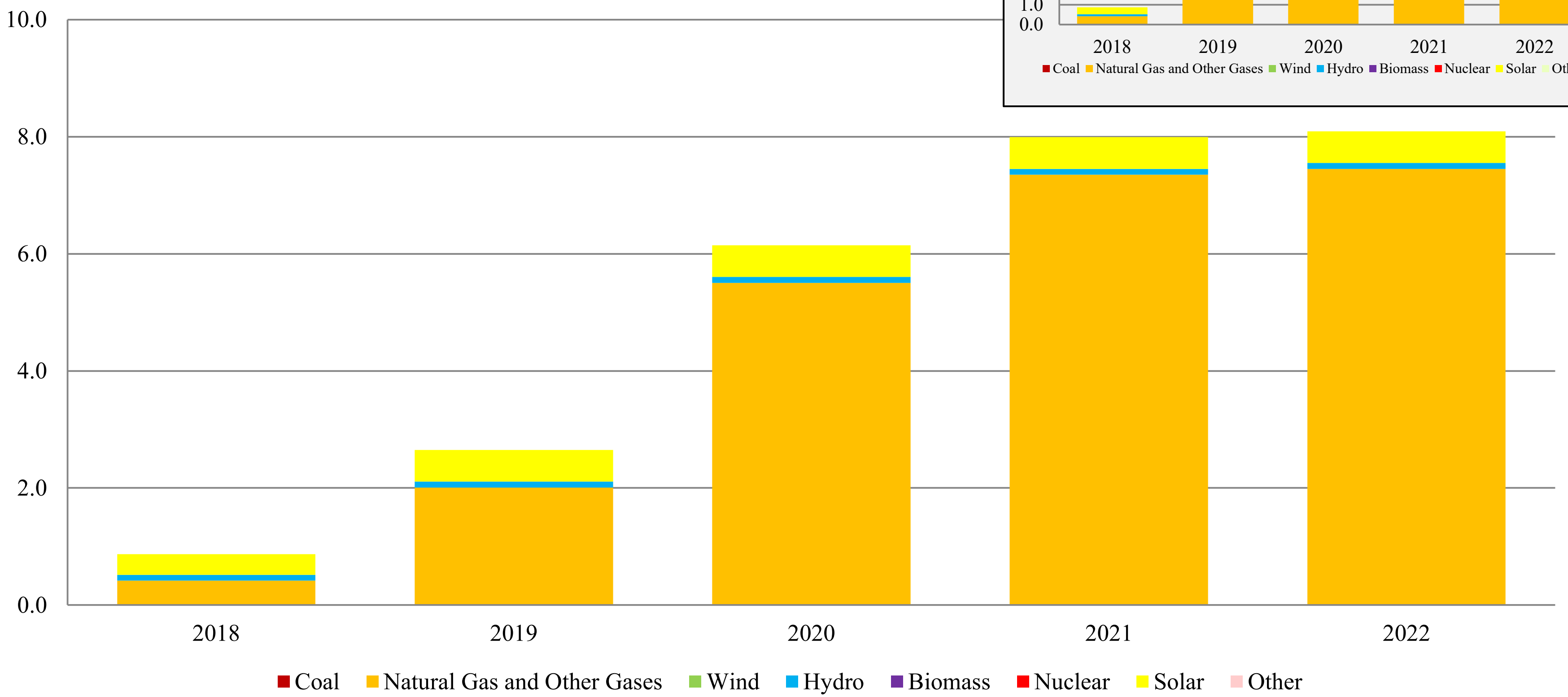


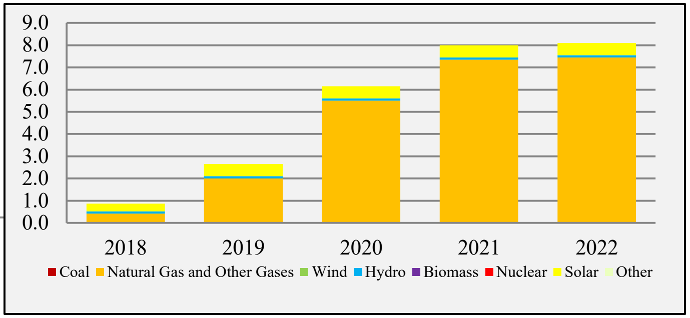
Wind and solar resources are represented at their expected capacity credit

Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

Zone 9 New Resources Additions by Fuel Type

Potential Generation Additions, in GW



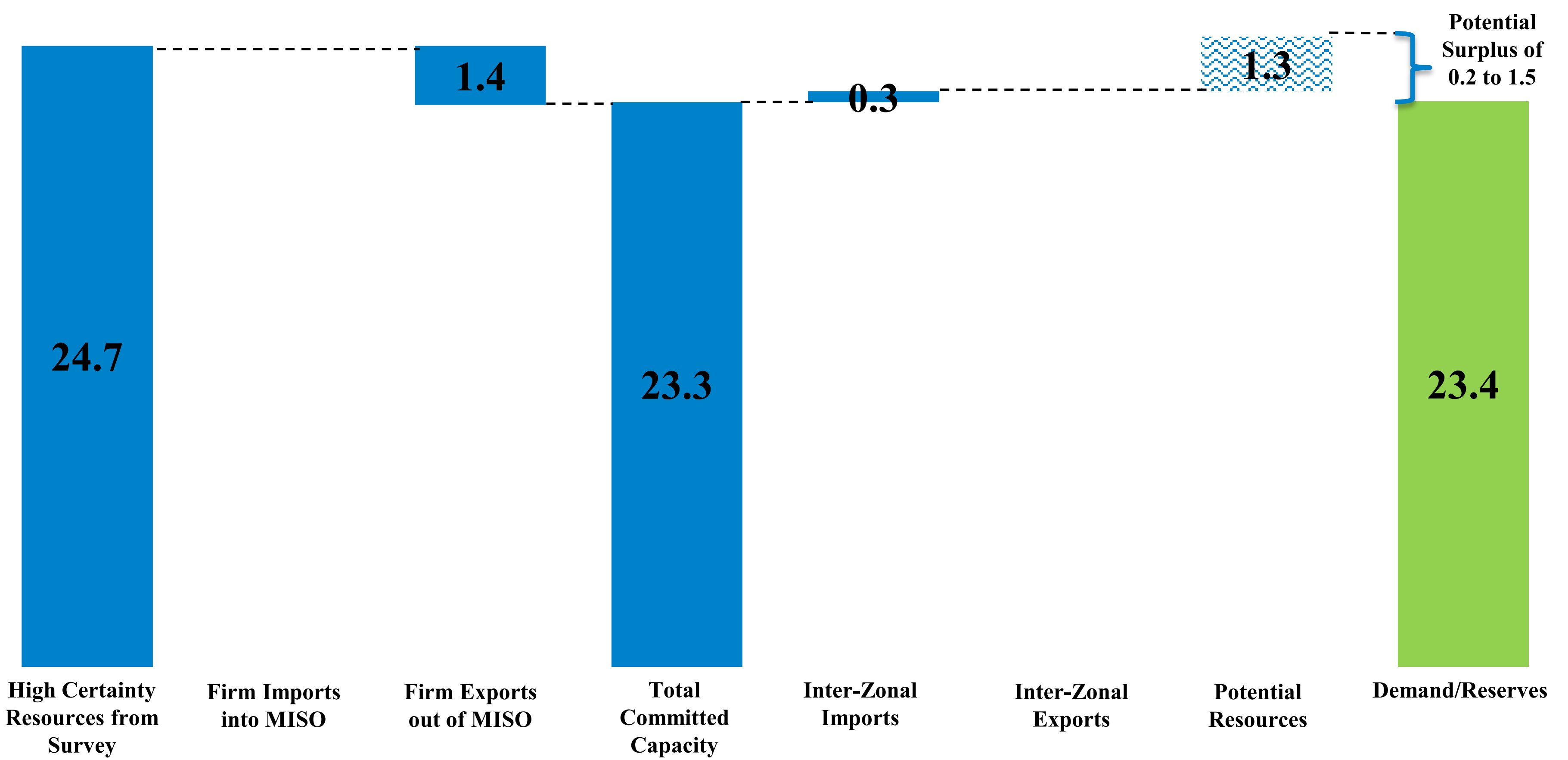


Includes all queued generation along with resources which have not yet been submitted to the MISO queue process
Wind and solar resources are represented at their expected capacity credit
Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

2022 Resource Adequacy Forecast Zone 9 (GW)

Committed Resources
Potential Resources
Total Demand and Requirement

2017 OMS MISO Survey In GW (ICAP)

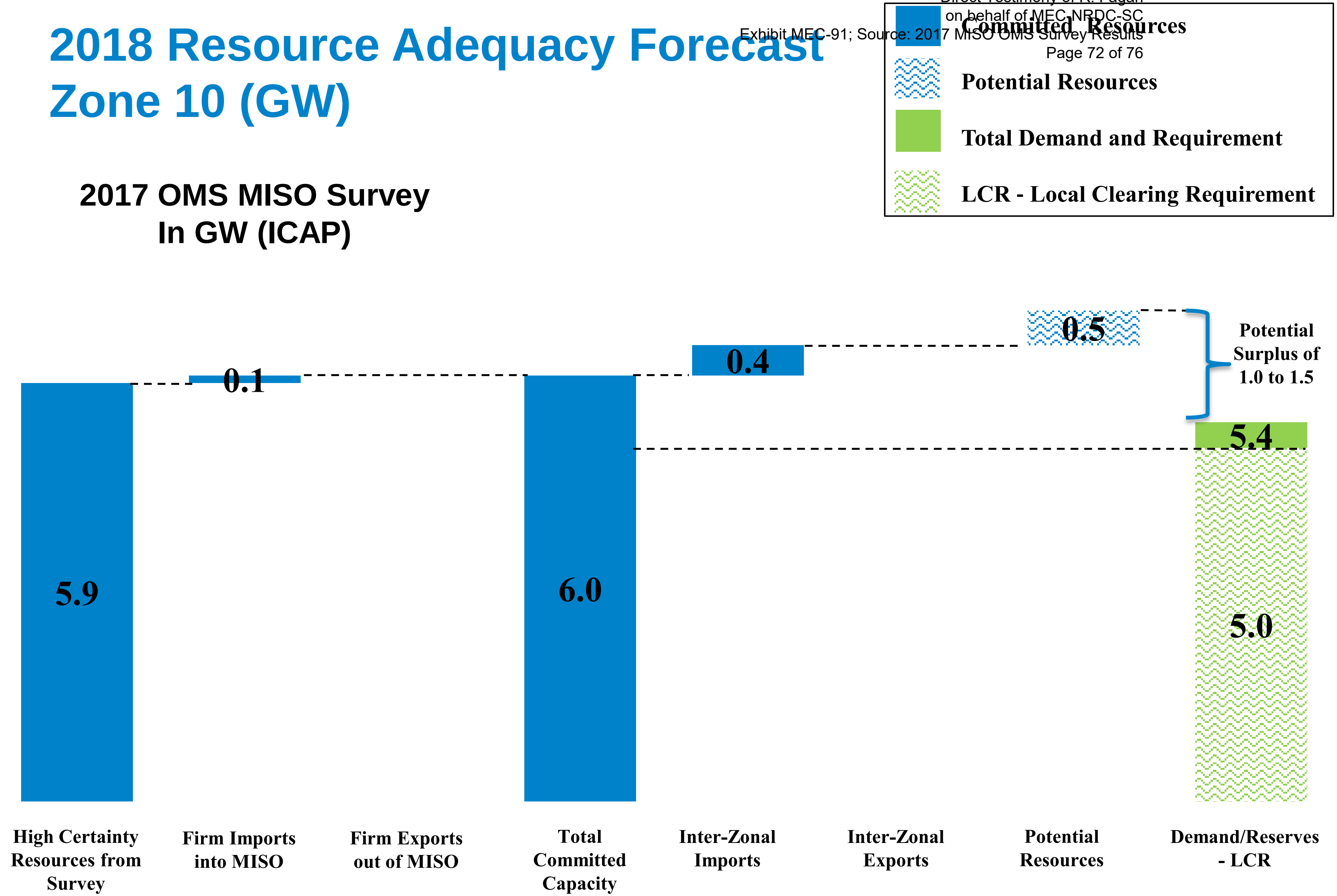


Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

OMS MISO

2018 Resource Adequacy Forecast Zone 10 (GW)

2017 OMS MISO Survey In GW (ICAP)



Potential Resources includes 35% of resources in the final study phase of the MISO Interconnection Queue

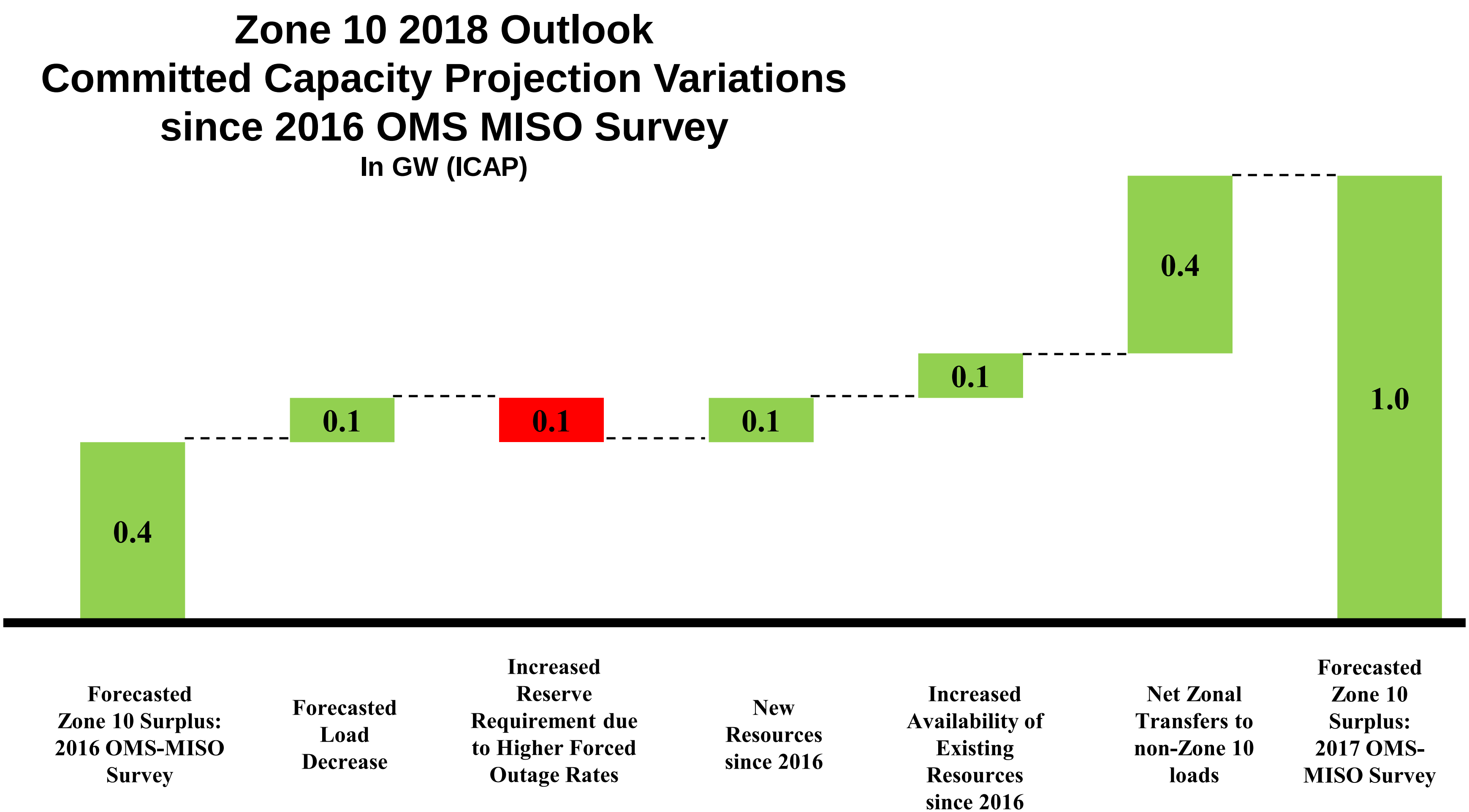
2019 - 2021 Resource Adequacy Forecast Zone 10 (GW)

2017 OMS MISO Survey

Values In GW (ICAP)

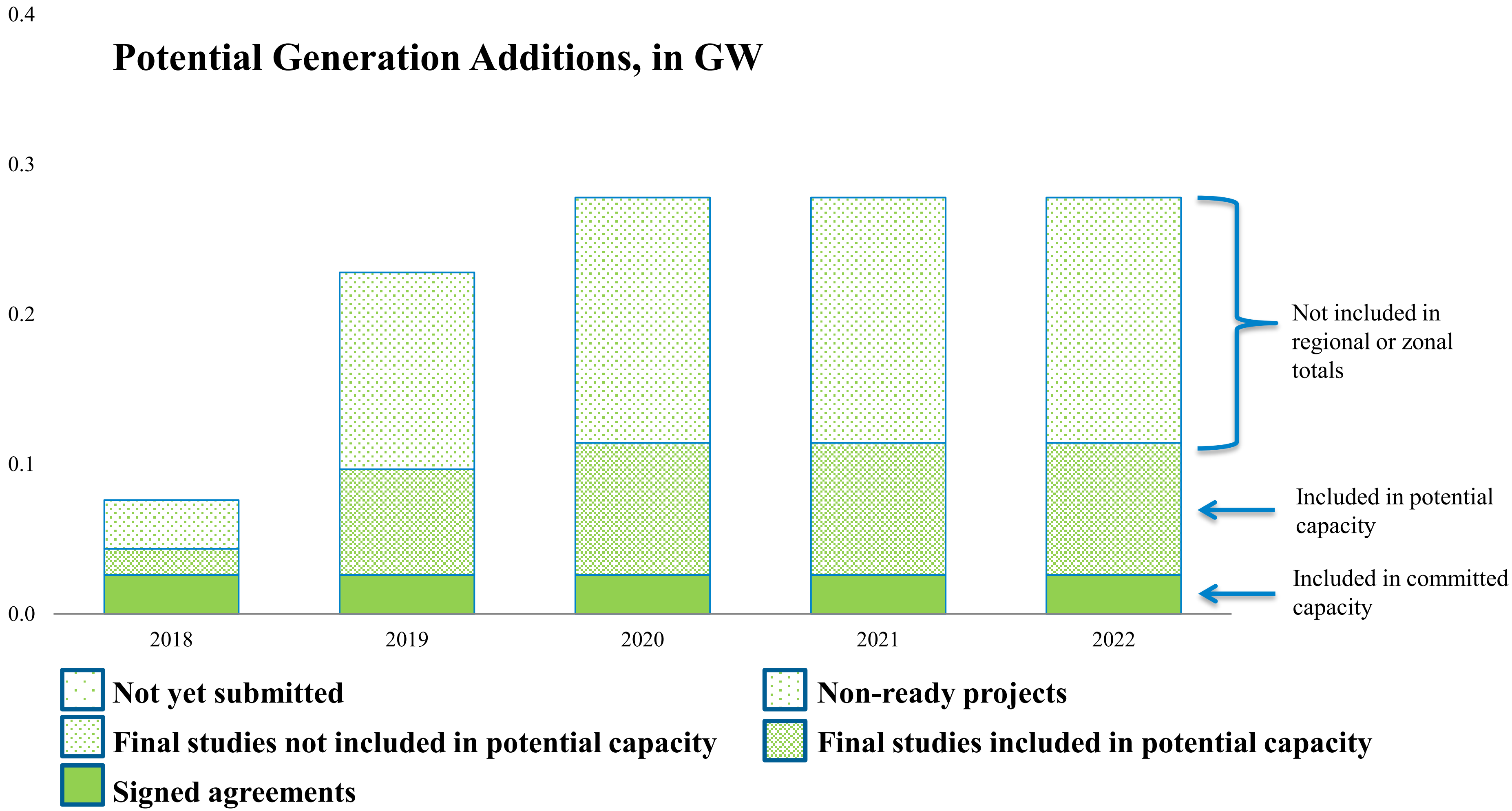
Zone 10	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	5.7	5.7	5.7	A
Firm Imports into MISO	0.1	0.1	0.1	B
Firm Exports out of MISO	0.0	0.0	0.0	C
Total High Certainty Capacity	**5.8**	**5.8**	**5.8**	D = (A+B)-C
Inter-Zonal Imports	0.4	0.4	0.4	E
Inter-Zonal Exports	0.1	0.1	0.1	F
Demand/Reserves	**5.4**	**5.4**	**5.4**	G
Firm Capacity Position	**0.8**	**0.7**	**0.7**	H =(D+E-F)-G
Low Certainty Resources	0.8	0.8	0.8	I
Potential Capacity Surplus/Deficit	**1.5**	**1.5**	**1.5**	J =(H+I)

2016 vs 2017 OMS MISO Survey Results Zone 10



New resources include resources with newly signed Interconnection Agreements and new Load Modifying Resources
Increased availability results from deferred retirements and internal resources with reduced commitments to non-MISO load
Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones

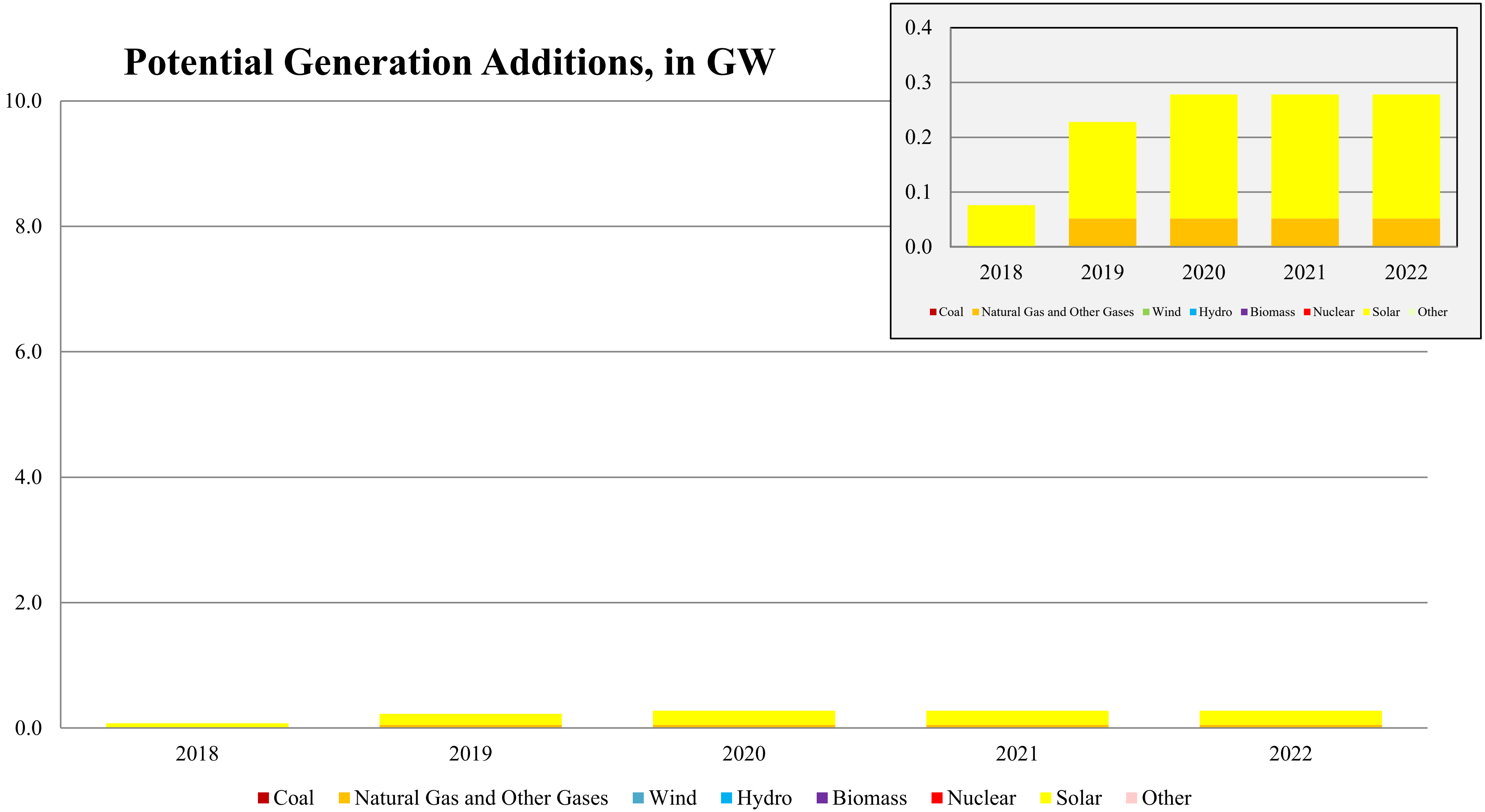
Zone 10 New Resource Additions by Queue Phase



Wind and solar resources are represented at their expected capacity credit

Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

Zone 10 New Resources Additions by Fuel Type



Includes all queued generation along with resources which have not yet been submitted to the MISO queue process
Wind and solar resources are represented at their expected capacity credit
Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

2017/2018 Planning Resource Auction Results

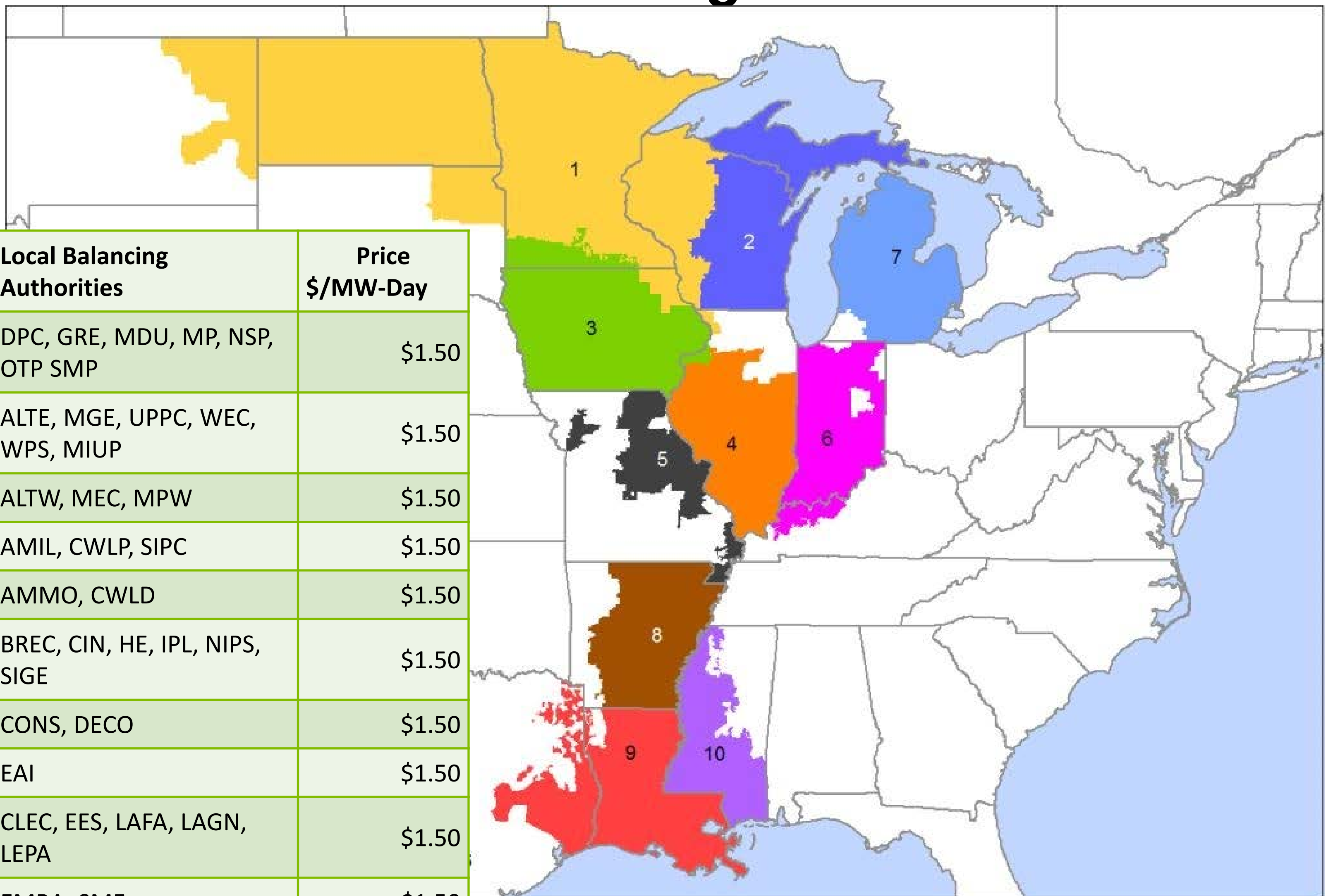
Resource Adequacy Subcommittee
May 10, 2017

Revised May 9, 2017 to correct a typo on Slide 8 for the Zone 6 Coincident Peak Demand Forecast MW

Overview

- Auction Results Summary
- Year Over Year Comparison
- Additional Details on PRMR and Supply

2017/2018 Auction Clearing Price Overview



Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP SMP	$1.50
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$1.50
3	ALTW, MEC, MPW	$1.50
4	AMIL, CWLP, SIPC	$1.50
5	AMMO, CWLD	$1.50
6	BREC, CIN, HE, IPL, NIPS, SIGE	$1.50
7	CONS, DECO	$1.50
8	EAI	$1.50
9	CLEC, EES, LAFA, LAGN, LEPA	$1.50
10	EMBA, SME	$1.50

Summary of Auction Results

- MISO Region has adequate resources to meet its Planning Reserve Margin Requirement of 134,753 MW
  - Resource in LRZ 1 set price for all LRZs
  - No ZDB allocation for the planning year
  - SFT passed on the 1st iteration
  - Increased supply and lower demand in the Midwest largely responsible for lower clearing prices compared to last year

- The Independent Market Monitor reviewed the results for physical and economic withholding to ensure a competitive market outcome
  - There were no instances of mitigation for physical or economic withholding

2017-2018 Planning Resource Auction Results

Local Resource Zone	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	System
PRMR	18,316	13,366	9,781	9,894	8,598	18,422	22,295	8,329	20,850	4,902	134,753
Total Offer Submitted (Including FRAP)	19,635	15,149	11,009	10,618	7,950	18,718	22,031	10,914	20,392	5,732	142,146
FRAP	14,361	11,559	4,197	712	0	4,155	12,374	470	182	1,454	49,463
Self Scheduled	4,004	2,113	5,575	7,723	7,948	13,009	9,462	9,660	16,505	3,556	79,554
ZRC Offer Cleared	4,568	2,207	6,088	8,412	7,950	14,510	9,583	9,669	18,470	3,833	85,290
Total Committed (Offer Cleared + FRAP)	18,929	13,766	10,285	9,124	7,950	18,665	21,956	10,139	18,652	5,287	134,753
LCR	15,975	11,980	7,968	5,839	5,885	13,005	21,109	6,766	17,295	4,831	N/A
CIL	3,531	2,227	2,408	5,815	4,096	6,248	3,320	3,275	3,371	1,910	N/A
Import	0	0	0	771	648	0	338	0	2,198	0	3,955
CEL	686	2,290	1,772	11,756	2,379	3,191	2,519	2,493	2,373	1,747	N/A
Export	613	400	503	0	0	243	0	1,810	0	385	3,955
ACP ($/MW-Day)	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	$1.50	N/A

*Price-sensitive offers cleared in the PRA represent the difference between ZRC Offer Cleared and Self Scheduled

Year over Year Comparisons

Policy Changes since PRA 2016/2017

- Tariff revisions approved in FERC Docket No. ER17-806-000 exempting Demand Resources (DR), Energy Efficiency Resources (EER) and External Resources (ER) from Market Monitoring and Mitigation in the 2017-18 PRA

- Tariff revisions approved in FERC Docket No. ER17-806-000 modified the application of the Physical Withholding Threshold to include Market Participants and their Affiliates

- Tariff revisions approved in FERC Docket No. ER16-833-004 established default technology specific avoidable costs, in lieu of providing facility specific operating cost information, to request facility specific Reference Levels from the IMM

- Sub-Regional Export Constraint in the South to Midwest direction increased to a 1500 MW limit from 876 MW and increased to a 3000 MW limit from 2794 MW in the Midwest to South direction

Capacity Requirements

Local Resource Zone	Local Clearing requirement (LCR) in MW		Planning Reserve Margin Requirement (PRMR) in MW		Coincident Peak Demand Forecast (CPDF) in MW	
	2016-17	2017-18	2016-17	2017-18	2016-17	2017-18
1	15,918	15,975	18,185	18,316	16,386	16,367
2	12,986	11,980	13,589	13,366	12,386	12,144
3	8,715	7,968	9,879	9,781	8,985	8,828
4	5,476	5,839	10,375	9,894	9,433	8,952
5	5,026	5,885	8,518	8,598	7,773	7,838
6	13,698	13,005	18,750	18,422	17,011	16,496
7	20,851	21,109	22,406	22,295	20,274	20,012
8	6,270	6,766	8,178	8,329	7,436	7,560
9	17,477	17,295	20,713	20,850	18,890	18,943
10	3,978	4,831	4,891	4,902	4,461	4,493

Zonal Import and Export Limits

Local Resource Zone	Capacity Import Limit (MW)		Capacity Export Limit (MW)		Import/(Export) in Auction (MW)	
	2016-17	2017-18	2016-17	2017-18	2016-17	2017-18
1	3,436	3,531	590	686	(590)	(613)
2	1,609	2,227	2,996	2,290	(1,315)	(400)
3	1,886	2,408	1,598	1,772	(258)	(503)
4	6,323	5,815	7,379	11,756	1,224	771
5	4,837	4,096	896	2,379	592	648
6	5,610	6,248	2,544	3,191	352	(243)
7	3,521	3,320	4,541	2,519	872	338
8	3,527	3,275	2,074	2,493	(1,817)	(1,810)
9	4,490	3,371	1,261	2,373	2,202	2,198
10	2,653	1,910	1,857	1,747	(1,260)	(385)

ZRC FRAP & Offer Information

LRZ	FRAP + Self Schedule (SS)		Price Sensitive Offer		Total (FRAP + ZRC Offer)		FRAP + SS as % of Total	
	2016-17	2017-18	2016-17	2017-18	2016-17	2017-18	2016-17	2017-18
1	18,139	18,365	1,291	1,270	19,430	19,635	93%	94%
2	13,702	13,672	1,202	1,477	14,903	15,149	92%	90%
3	9,866	9,771	271	1,238	10,138	11,009	97%	89%
4	7,523	8,435	3,848	2,183	11,371	10,618	66%	79%
5	7,914	7,948	13	2	7,927	7,950	100%	100%
6	17,277	17,165	1,121	1,553	18,398	18,718	94%	92%
7	21,418	21,836	197	195	21,615	22,031	99%	99%
8	7,404	10,129	3,183	785	10,587	10,914	70%	93%
9	16,807	16,687	3,450	3,704	20,257	20,392	83%	82%
10	5,613	5,009	1,285	723	6,899	5,732	81%	87%
System	125,662	129,017	15,862	13,130	141,524	142,146	89%	91%

Additional Details Regarding Supply

Planning Resource Type	2017-2018 Offered	2016-2017 Offered	2017-2018 Cleared	2016-2017 Cleared
Generation	127,637	127,329	121,807	122,379
Behind the Meter Generation	3,678	3,487	3,456	3,462
Demand Resources	6,704	6,322	6,014	5,819
External Resources	4,029	4,385	3,378	3,823
Energy Efficiency	98	0	98	0
Total	142,146	141,523	134,753	135,483

- Demand Resource quantities include Aggregator of Retail Customers (ARCs) that registered for the 2017-18 PRA

- Registered Energy Efficiency Resources for the 2017-18 PRA for the first time since the 2013-14 PRA

Cleared Capacity by Fuel Type

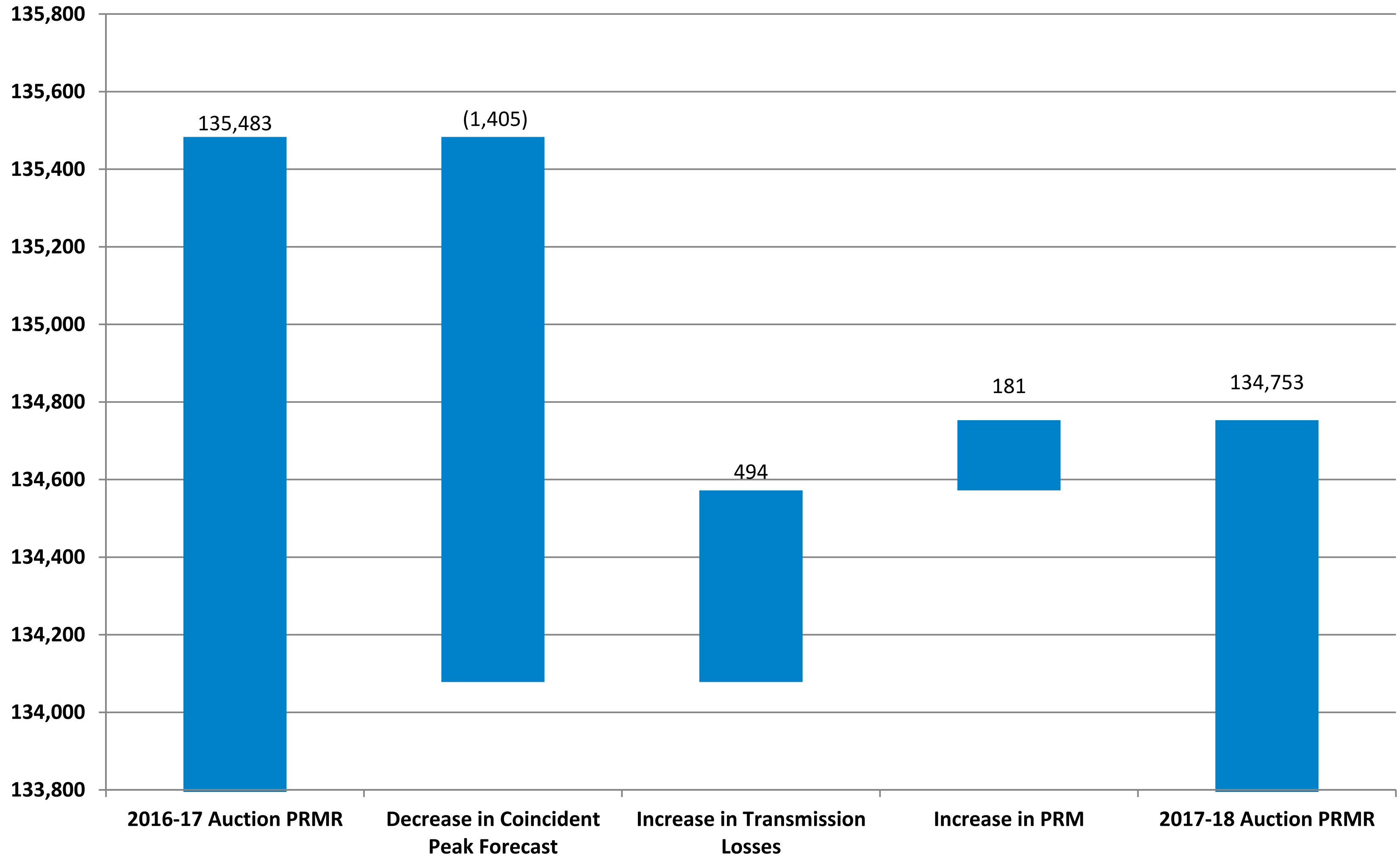
Planning Year	2016-17		2017-18		Change	
GADS Fuel Type	System (MW)	% Fuel	System (MW)	% Fuel	Delta (MW)	Delta (%)
Coal	53,332	39.36%	52,240	38.80%	(1,092)	-0.6%
Gas	48,784	36.01%	48,458	36.00%	(326)	0.0%
Nuclear	12,885	9.51%	12,563	9.30%	(322)	-0.2%
Load Modifier (DR/EE)	5,819	4.29%	6,112	4.50%	293	0.2%
Water	5,676	4.19%	5,851	4.30%	175	0.1%
Oil	3,659	2.70%	3,551	2.60%	(108)	-0.1%
Wind	1,862	1.37%	2,190	1.60%	328	0.2%
Waste Heat	1,329	0.98%	1,452	1.10%	123	0.1%
Other-Solid (Tons)	789	0.58%	782	0.60%	(7)	0.0%
Distillate Oil	658	0.49%	658	0.50%	0	0.0%
Other-Liquid(BBL)	0	0.00%	47	0.00%	47	0.0%
Other-Gas(Cu Ft)	573	0.42%	582	0.40%	9	0.0%
Wood	106	0.08%	89	0.10%	(18)	0.0%
Solar	11	0.01%	180	0.10%	169	0.1%
SYSTEM	135,483	100.00%	134,753	100.00%	(730)	-

Additional Details on PRMR and Supply

Supplemental Data for PRMR and LCR Calculations

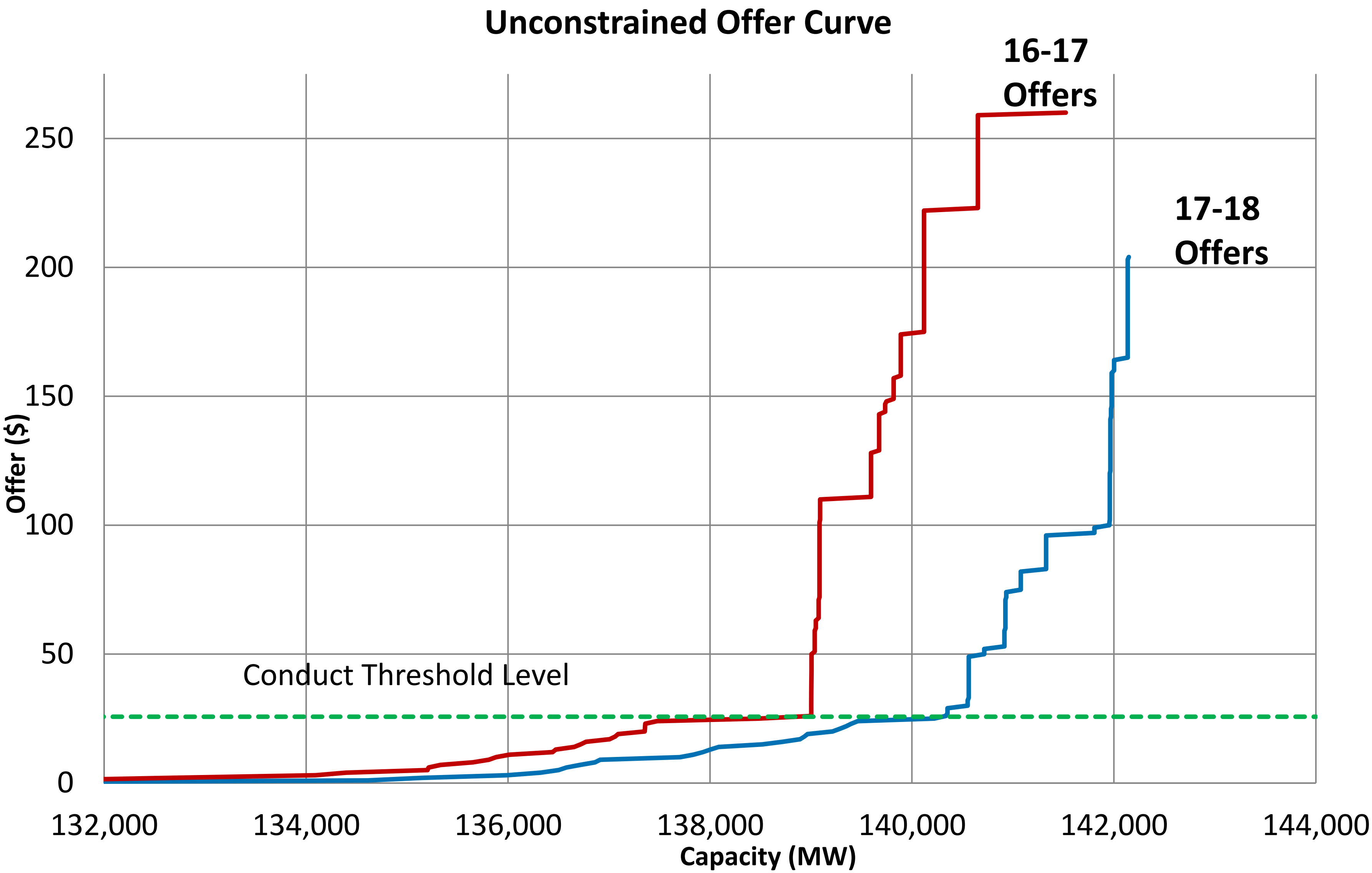
Local Resource Zone	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	SYSTEM
CPDF (Coincident Peak Demand Forecast)	16,367	12,144	8,828	8,952	7,838	16,496	20,012	7,560	18,943	4,493	121,631
CPDF + Transmission Losses	16,990	12,399	9,073	9,179	7,975	17,089	20,681	7,726	19,342	4,547	125,002
Planning Reserve Margin (PRM)	7.80%										
PRMR (Planning Reserve Margin Requirement)	18,316	13,366	9,781	9,894	8,598	18,422	22,295	8,329	20,850	4,902	134,753
ZCPDF (Zonal Coincident Peak Demand Forecast)	17,047	12,457	9,088	9,332	8,054	16,637	20,717	7,854	19,953	4,718	125,856
ZCPDF + Trans. Losses	17,695	13,033	9,600	9,948	8,411	17,377	22,115	8,322	21,383	4,999	132,883
LRR (Local Reliability Requirement) Factor	1.113	1.117	1.125	1.228	1.218	1.117	1.141	1.258	1.118	1.412	N/A
LRR	19,695	14,207	10,508	11,750	9,982	19,253	24,429	10,098	22,777	6,741	N/A
CIL (Capacity Import Limit)	3,531	2,227	2,408	5,815	4,096	6,248	3,320	3,275	3,371	1,910	N/A
Non-Pseudo Tied Exports	188	0	132	96	0	0	0	57	2,111	0	2,584
LCR (Local Clearing Requirement)	15,975	11,980	7,968	5,839	5,885	13,005	21,109	6,766	17,295	4,831	N/A
LCR as a % of PRMR	87%	90%	81%	59%	68%	71%	95%	81%	83%	99%	N/A

Planning Reserve Margin Requirement (PRMR)



All values in MW

MISO Offer Curve



Supplemental Data Regarding UCAP and ZRCs

- IMM reviews all offers for market monitoring to ensure:
  - Valid explanation for resources that don't offer into the PRA
  - Offers are not an exercise of market power
  - Provided 32 facility specific Reference Levels
    - Majority used default technology specific avoidable costs

- Below are reasons approved by the IMM why "qualified" resources did not offer into the PRA for 2017-2018:
  - Capacity sales to other markets
  - Generator pending retirement
  - Generator Suspended and isn't able to return by July 1^{st}
  - Lack of available firm transmission service

UCAP Confirmation and Conversion

LRZ	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	Total	Formulas
UCAP Total	20,413	15,201	11,354	12,485	7,985	19,236	22,159	11,341	22,235	5,775	148,184	A
UCAP (Confirmed)	20,353	15,194	11,306	12,484	7,971	19,236	22,135	11,341	22,235	5,775	148,031	B
UCAP (Unconfirmed)	60	7	48	0	14	0	24	0	0	0	154	C=A-B
Converted UCAP (ZRC)	19,677	15,176	11,018	10,982	7,960	18,880	22,036	11,102	20,392	5,775	142,997	D
Unconverted UCAP	676	18	289	1,503	12	356	99	239	1,844	0	5,034	E=B-D
FRAP + ZRC Offer	19,635	15,149	11,009	10,618	7,950	18,718	22,031	10,914	20,392	5,732	142,146	F
ZRC Not Offered/FRAP	42	27	9	364	10	163	5	188	0	43	851	G=D-F
MW/ZRC not participating in MISO PRA	**778**	**52**	**345**	**1,867**	**36**	**518**	**128**	**427**	**1,844**	**43**	**6,038**	**H=C+E+G**

- Non-participating MW/ZRC represents total of Unconfirmed UCAP, Confirmed but Unconverted UCAP and Converted UCAP (ZRCs) that were not offered or used in a FRAP
- Common reasons why ZRCs may not participate in a PRA:
  - Capacity sales to other markets
  - Suspensions not participating in PRA
  - Exclusion granted by the IMM
  - General physical withholding from the PRA within the Physical Withholding Threshold

Cleared MW by Resource Type by LRZ

- **MISO grouped multiple LRZs together as needed to ensure data confidentiality**

<table>
<tr><th>RESOURCE TYPE</th><th>Z1</th><th>Z2</th><th>Z3</th><th>Z4</th><th>Z5</th><th>Z6</th><th>Z7</th><th>Z8</th><th>Z9</th><th>Z10</th></tr>
<tr><td>Demand Resources</td><td colspan="2">1,673</td><td colspan="3">908</td><td colspan="2">2,215</td><td colspan="3">1,218</td></tr>
<tr><td>Behind the Meter Generation</td><td>874</td><td>247</td><td colspan="3">847</td><td>265</td><td>1,153</td><td colspan="3">70</td></tr>
<tr><td>Energy Efficiency</td><td colspan="7">98</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td>External Resources</td><td>1,551</td><td>0</td><td colspan="3">1,368</td><td>326</td><td>0</td><td colspan="3">133</td></tr>
<tr><td>Generation</td><td>15,287</td><td>13,029</td><td>9,071</td><td>7,396</td><td>7,748</td><td>16,672</td><td>19,947</td><td>9,312</td><td>18,192</td><td>5,151</td></tr>
</table>

Next Steps

- Masked offer data will be available May 12, 2017
  www.misoenergy.org → Planning → Resource Adequacy (Module E) → Resource Adequacy Construct → Auction Results and Summaries → 2017-2018 Detailed Report

- For reference, MISO posted slides with the PRA Results meeting on April 14, 2017

Common Acronyms

- **ACP** Auction Clearing Price ($/MW-Day)
- **BTMG** Behind The Meter Generator
- **DR** Demand Resource
- **DBZ** Deliverability Benefit Zone
- **CEL** Capacity Export Limit (MW)
- **CIL** Capacity Import Limit (MW)
- **CPDF** Coincident Peak Demand Forecast (MW)
- **FRAP** Fixed Resource Adequacy Plan (MW)
- **FSRL** Facility Specific Reference Level ($/MW-day)
- **LCR** Local Clearing Requirement (MW)
- **LOLE** Loss Of Load Expectation
- **LRZ** Local Resource Zone
- **PRA** Planning Resource Auction
- **PRM** Planning Reserve Margin (%)
- **PRMR** Planning Reserve Margin Requirement (MW)
- **SFT** Simultaneous Feasibility Test
- **SREC** Sub-Regional Export Constraint
- **UCAP** Unforced Capacity (MW)
- **ZCPDF** Zonal Coincident Peak Demand Forecast (MW)
- **ZDB** Zonal Deliverability Benefits
- **ZRC** Zonal Resource Credit (MW)

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Compliance Officer

SHAUN M JOHNSON
Vice President and Deputy
General Counsel

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Ashley L Bancroft
Robert W Beach
Don A D'Amato
Robert A. Farr
Gary A Gensch, Jr.
Gary L Kelterborn
Chantez P Knowles
Mary Jo Lawrie
Jason M Milstone
Rhonda M Morris
Deborah A Moss*
Mirče Michael Nestor
James D W Roush
Scott J Sinkwitts
Adam C Smith
Theresa A G Staley
Janae M Thayer
Bret A Totoraitis
Anne M Uitvlugt
Aaron L Vorce
Attorney

December 1, 2017

Ms. Kavita Kale
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

Re: MPSC Case No. U-18441 – In the matter, on the Commission's own motion, to open a docket for load serving entities in Michigan to file their capacity demonstrations as required by MCL 460.6w.

Dear Ms. Kale:

Enclosed for electronic filing in the above-captioned case, please find the **Redacted Version of Consumers Energy Company's Capacity Demonstration for Planning Years 2018 Through 2021** pursuant to the Michigan Public Service Commission Order issued September 15, 2017. A confidential version of this filing is being filed under seal with the Michigan Public Service Commission. This is a paperless filing and is therefore being filed only in PDF.

Sincerely,

Digitally signed by
Gary A. Gensch, Jr.
Date: 2017.12.01
14:52:38 -05'00'

Gary A. Gensch, Jr.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to open a docket for load serving entities in Michigan to file their capacity demonstrations as required by MCL 460.6w.)))))	Case No. U-18441

AFFIDAVIT OF TIMOTHY J. SPARKS

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Timothy J. Sparks, being duly sworn, states:

1. I am the Vice President of Electric Grid Integration for Consumers Energy Company ("Consumers Energy" or the "Company"). My responsibilities include, in part, overall responsibility for the Company's long-term and short-term energy supply planning, investments, and strategy. I am a registered professional engineer with the State of Michigan and a senior member of the Institute of Electrical and Electronics Engineers.

2. Consumers Energy is a public utility engaged in the generation, purchase, distribution, and sale of electric energy to approximately 1.8 million retail electric customers in the lower peninsula of the State of Michigan. For 130 years, Consumers Energy has provided reliable, affordable electricity to advance its customers' quality of life. We remain committed to planning for and ensuring an adequate electric supply to meet the needs of Michigan homes and businesses, now and in the future. The Company's impact extends beyond supplying a commodity. Consumers Energy is a vital part of the state's economic, social, and environmental fabric, and we care for the customers and communities we serve.

3. The information provided in this Affidavit is based on my first-hand knowledge of the Company's long-term and short-term energy supply planning, investments, and strategy. Pursuant to Section 6w of 2016 PA 341, and as required pursuant to the Michigan Public Service Commission's ("MPSC" or the "Commission") September 15, 2017 Orders in Case Nos. U-18197 and U-18441, this Affidavit is a demonstration to the Commission that the Company has or will have sufficient electric capacity arrangements for Planning Years[1] 2018 through 2021. The remainder of this Affidavit discusses the Planning Reserve Margin Requirement ("PRMR"), peak demand outlook, and the capacity resources planned to fulfill customer need.

4. PRMR

On October 20, 2017, Midcontinent Independent System Operator ("MISO") determined an unforced[2] capacity planning reserve margin target of 8.4% in Planning Years 2018 and 2019 and 8.3% in Planning Years 2020 and 2021 (as opposed to an installed capacity ("ICAP") planning reserve margin target of 17.1% to 17.2%).[3]

Consumers Energy continues to maintain a diverse and flexible resource portfolio. The Company's resources include a balanced mix of baseload, intermediate, peaking, intermittent, demand-side, and storage resources to reduce energy usage and deliver energy to customers in an affordable, environmentally responsible, and reliable manner.

[1] Planning Year, as defined by Midcontinent Independent System Operator, Inc. ("MISO"), is the 12-month period commencing on June 1 of each year and concluding on May 31 of the following year.
[2] MISO's evaluation of Loss of Load Expectation utilizes net demonstrated capacity less the three-year Equivalent Forced Outage Rate on demand, or "EFORd." The resulting capacity value is commonly referred to as "unforced" capacity.
[3] Exhibit 2, line 11 indicates the Total PRMR. These numbers are consistent with the 2018 MISO Loss of Load Expectation Study results published on page 28 of MISO's report titled "Planing Year 2018-2019 Loss of Load Expectation Study Report."

By meeting the Company's expected peak load and required reserve margin target, the Company will adequately maintain resources to meet full-service customer electricity needs throughout the Planning Year, including during peak load periods.

5. Peak Demand

The Company's historical peak demand for 2015 through 2017 is shown in Exhibit 1.[4] The actual loads provided in Exhibit 1 are not weather normalized.

The forecasted peak system demand shown in Exhibit 1[5] includes servicing demand associated with the following:

- Bundled service;
- Retail Open Access ("ROA") customers;
- Demand otherwise avoided through interruptible service and other future Demand Response Programs expected to be registered as capacity resources with MISO;
- Demand otherwise avoided through Energy Efficiency Programs;
- Demand otherwise avoided through Smart Energy Programs; and
- Transmission losses.

The Company's peak demand forecast shown in Exhibit 1 is based on the level of residential air conditioning saturation, average monthly temperatures, and expected energy usage.[6]

[4] See Exhibit 1, columns (b) through (d). The historical values for the Electric Distribution Company, ROA Load, and Bundled Load for the load serving entities are provided, both coincident to bundled peak demand (lines 1 through 3) and coincident to MISO peak demand (lines 4 through 6). The historical values are net of the Company's Energy Efficiency Programs.
[5] See Exhibit 1, line 1, columns (e) through (i).
[6] The forecasted bundled peak demand prior to any demand-side reductions is shown in Exhibit 1, line 3. Exhibit 1, line 3, is line 1 less line 2, the ROA demand forecast coincident to bundled peak demand. Exhibit 1, lines 4 through 6, correspond to Exhibit 1, lines 1 through 3, but are the forecasted peak demands at the time of MISO's system peak.

The demand adjustments associated with ROA and capacity avoided through energy efficiency and demand response are shown in Exhibit 2.

The Company must plan for capacity during periods when MISO experiences its peak demand. The Company's forecast of peak bundled service demand (including transmission losses) during the period that MISO experiences its peak for the 2018 through 2021 capacity planning period is shown in Exhibit 2.[7] The average transmission loss factor for the local balancing authority area in which the Company operates is 3.5%.[8]

6. In response to the energy industry's rapid evolution, due in part to both a changing resource portfolio and an increased focus on reliability, Consumers Energy remains dedicated to meeting the needs of its full-service electric customers over the four-year planning period while maintaining adequate reserve margins. Consumers Energy plans to draw on a diverse portfolio of energy resources to meet expected peak demand plus reserves. Those resources include: utility-owned generation; long-term supply contracts; energy efficiency and demand response resources; and bilateral Zonal Resource Credit ("ZRC") purchases.

The Company expects its supply portfolio to change to meet customers' future needs, as shown in Figure 1 of this Affidavit.

Some key aspects reflected in the following Figure 1 include:

- Continued use and expansion of the Company's Energy Efficiency Programs and demand response resources to help reduce the overall demand, as shown in the green and blue areas;

[7] See Exhibit 2, line 5. Line 5 is derived using a Consumers Energy diversity factor to MISO of -4.46%, based on historical analysis of peak occurrences, as shown in Exhibit 2, line 4. Line 5 has also been reduced by line 2, which includes projected Demand-Side Management Programs that are netted from the peak load forecast rather than treated as supply resources. Line 2 includes projections for Energy Efficiency and Smart Energy (Time-of-Use Program).
[8] The Company modified Exhibit 2, line 9, to be equal to Exhibit 2, line 7; Exhibit 2, line 7, to be equal to line 5/(1+line 6), consistent with MISO's calculation; and Exhibit 2, line 8, to be equal to line 6 times line 7.

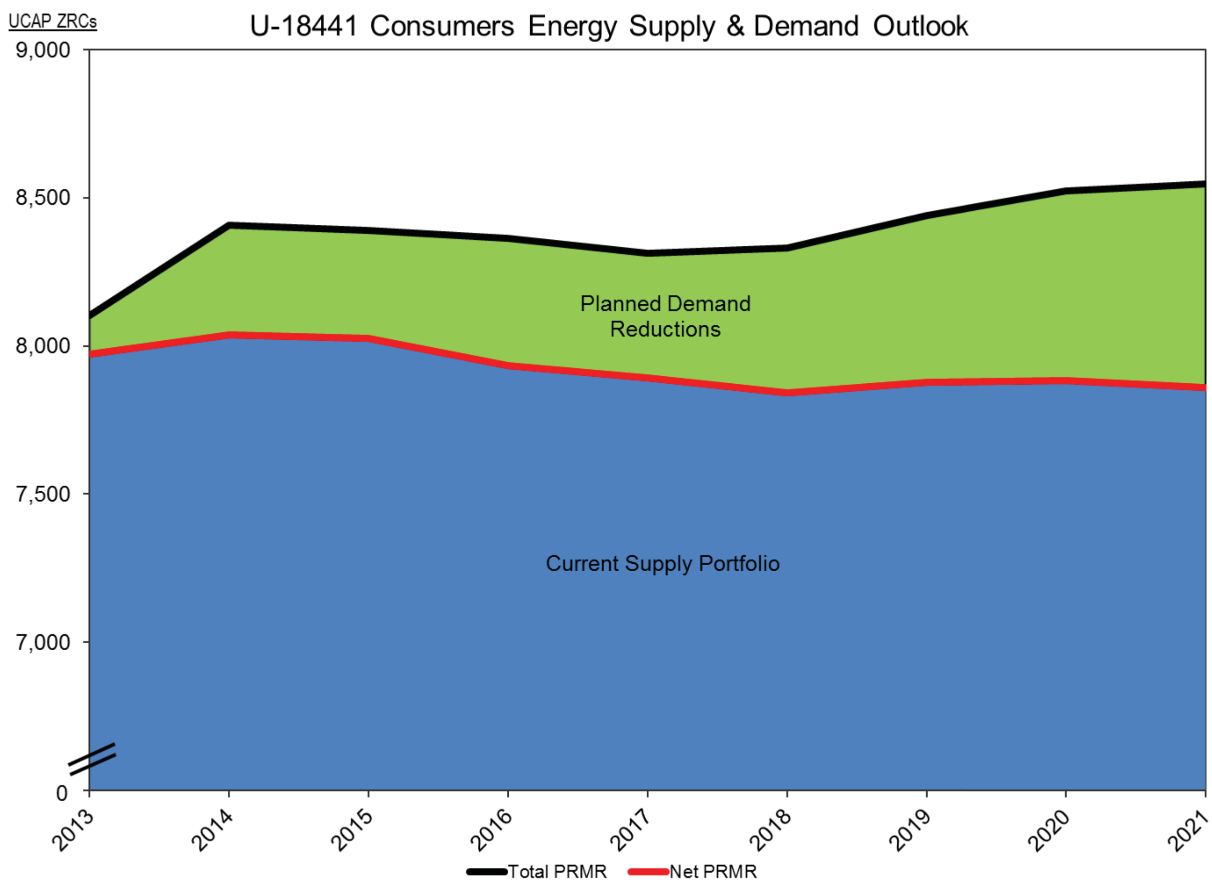
- Continuation of existing resources including the J.H. Campbell and D.E. Karn facilities, the Ludington Pumped Storage Plant, the Zeeland Generating Plant, the Jackson Generating Plant, the Cross Winds Energy Park, and the Lake Winds Energy Park;

- Power supply contracts with Midland Cogeneration Venture Limited Partnership and other non-utility generators, a key part of the overall plan to provide reliable service to customers (these resources are also part of the blue-shaded area);

- Wind and solar additions to meet the 2016 Public Act 342 ("Act 342") Renewable Portfolio Standard of 15% and in support of the state's 35% goal for renewable energy and enegy waste reduction; and

- Modifications of the existing Power Purchase Agreement ("PPA") with TES Filer City Station, LLC ("Filer City"), facilitating the conversion of a coal-fueled power plant to a natural gas-fueled power plant.

Figure 1: Consumers Energy Supply Portfolio



7. Consumers Energy plans to sufficiently serve its full-service customers with safe, affordable, reliable, and sustainable energy for the next four years and beyond. The Company's plans are outlined in the following paragraphs, covering Planning Years 2018 through 2021, and address each of the seven required capacity areas as outlined in the Commission's September 15, 2017 Order in Case No. U-18197:

- Exhibit 1 – Utility Bundled Service Peak Demand for the Lower Peninsula of Michigan;
- Exhibit 2 – PRMRs and Planning Resources to be Acquired (Unforced Capacity ("UCAP") MW);
- Exhibit 3 – Demand Response Capacity Resources – An overview of demand response resources by MW, PRMR UCAP, and the resulting ZRCs;
- Confidential Exhibit 4 – Company-Owned Electric Generation – Details the Company's owned generation resources by type, location, ICAP, and UCAP;
- Exhibit 5 – New or Updated Generation Owned – An overview of upcoming resources available by MW and ZRC;
- Confidential Exhibit 6 – PPA Resource List – List of current PPAs and capacity contracts by type and both ICAP and UCAP details;
- Exhibit 7 – New or Upgraded Purchased Power – Identifies future obligations in PPAs; and
- Exhibits 8 through 11 – MISO Module E Exports (Exhibits 8, 10, and 11 are confidential) – Planning Year 2017/2018 MISO Module E Report for Existing Owned Generation; Demand Response Programs – Not Netted Against Load; Existing PPAs; and Existing Transactions.

8. <u>Existing Generation – Owned</u>

Consumers Energy currently owns, operates, and manages 5,766 MW of installed capacity equivalent to 5,212 ZRCs (assuming Planning Year 2017 Equivalent Forced Outage Rate on demand ("EFORd") values), all located within Michigan and within MISO Zone 7. The total capacity associated with these resources is expected to increase over the next four years as a result of unit uprates and improved EFORd values.

A summary of the Company's forecast for its owned resources – including resource type, installed capacity, and unforced capacity – is provided in Exhibit 2 (by category) and Exhibit 4 (by unit). Exhibit 8 contains Existing Owned Generation data from the MISO Module E Report for Planning Year 2017.[9]

Consumers Energy remains committed to offering the load serving entity load capacity generated from existing resources in the applicable Michigan Zone throughout the 2018 through 2021 capacity Planning Years.

9. Existing And New Demand Response Or Energy Efficiency Resources (Not Netted Against Load)

Consumers Energy offers a suite of Demand-Side Management Programs targeting residential, commercial, and industrial customer classes to deliver significant peak load reductions. Existing programs offered by the Company that are not netted against load and can be bid into MISO as a capacity resource include:

- Peak Power Savers – Air Conditioning Cycling Program;
- Intensive Primary Tariff;
- Commercial and Industrial Demand Response ("C&I DR"); and
- Interruptible Service ("Rate GI") Provision.

Over Planning Years 2018 through 2021, the Company is forecasting to reach a demand response level of nearly 570 ZRCs. The Company continues to evaluate and learn how best to meet customer interest and has not yet forecasted new Demand Response Programs to add to upcoming Planning Years. Existing demand response resources will continue to be renewed with MISO.

[9] Module E data supplied was prepared in 2016 and represents Planning Year 2017.

For energy efficiency, the Company currently does not offer an energy efficiency resource that is not netted against load and does not have existing plans to develop new Energy Efficiency Programs that would apply to this capacity demonstration filing. However, the Company does offer natural gas and electric Energy Efficiency Programs focused on reducing customers' overall energy usage.

There are no new demand response resources to add to upcoming Planning Years. The Company will renew our existing demand response resources with MISO through the Resource Adequacy process.

The capacity gained through qualified Demand Response Programs is shown in Exhibit 2, lines 21 through 23 and Exhibit 3, which provides additional details regarding specific amounts of MW and ZRCs expected to be credited to the Company's capacity portfolio. Exhibit 9 contains requested Demand Response Programs that are not netted against load data from the MISO Module E Report for Planning Year 2017. Relevant tariffs are included in this filing as Exhibit 12. In lieu of filing a copy of the customer supply contracts with this capacity demonstration, the Company agrees to produce the customer supply contracts relevant to the C&I DR Program and Rate GI Provision for the Commission Staff's review (along with the MPSC Commissioners, if needed) at the Commission's office, upon a one-day notice and upon request, without the Commission Staff or Commissioners retaining a copy. Exhibit 13 contains the contact information of the persons designated to produce the customer supply contracts.

Consumers Energy remains committed to maintaining at least the same level of demand response and energy efficiency resources that are not netted against load throughout the four-year planning period 2018 through 2021.

10. New Or Upgraded Utility-Owned Generation

New or upgraded utility-owned generation planned for 2018 through 2021 includes expansion of the Cross Winds Energy Park, further investment in renewable resources, and upgrades to the existing Ludington Pumped Storage Plant.

The Company plans to expand upon the Solar Garden initiative that accounts for solar projects equating to a total of 6 MW by Planning Year 2019, and 0.5 MW of research and development that is consistent with the Renewable Energy Plan filed in Case No. U-18231. Additionally, Cross Winds Energy Park Phase III is a part of the Company's plan to meet the new 15% Renewable Portfolio Standard, and to support the state's 35% goal for renewable energy and energy waste reduction, as stated in Act 342.

Exhibit 2, lines 12 through 20, includes new and upgraded generation sources. Detailed plans for new or upgraded generation owned by the Company, including planned in-service date(s), expected regulatory approval date(s), planned date to enter the MISO generator interconnection queue, and expected date(s) for a MISO Generator Interconnection Agreement may be found in Exhibit 5. Exhibit 5 details new or upgraded generation by type, added ZRCs, capacity credit, and expected Commercial Operation Date.

11. Existing Generation Capacity Contracts

Consumers Energy's power supply contracts, including PPAs, are entirely within Michigan and within MISO Zone 7, with the exception of the Heritage Garden Wind Farm[10] which is located in MISO Zone 2.

The Company has several contracts in place with Qualifying Facilities, in accordance with the Public Utility Regulatory Policy Act of 1978 ("PURPA"), that will terminate during the

[10] The Heritage Garden Wind farm contributes approximately 3 ZRCs to the Company's capacity portfolio.

time period from 2018 to 2022. The Company has forecasted that these existing contracts will be replaced with new PURPA-based agreements at the rates established in Case No. U-18090. Obligations to contract are projected to remain throughout the four-year planning period. The ZRCs associated with the contracts are identified in Exhibit 7.

To reduce potential risks associated with mid-Planning Year retirements of generation assets, the Company has assumed the ZRCs associated with existing generation capacity contracts terminating before the end of each Planning Year are not included in that Planning Year's contracted capacity.

- Exhibit 2, lines 24 through 34, factor the PPA and other capacity contracts into the Planning Years' 2018 through 2021 forecast;
- Exhibit 6 details the Company's capacity contracts and specifies the unit(s), or pool of generation, and the location of the generators (note that on May 8, 2017, the Company filed an Application in Case No. U-18392 for approval of an amendment to the existing PPA with Filer City to allow the plant to be converted from a coal-fueled facility to a natural gas-fueled facility);
- Exhibit 7 details new or upgraded existing PURPA obligations for the four-year planning period;
- Exhibit 10 contains data regarding Existing PPAs from the MISO Module E Report for Planning Year 2017; and
- Exhibit 11 contains Existing Transactions from the MISO Module E Report for Planning Year 2017.

Consumers Energy remains committed to maintaining the contracted amounts of these PPAs as shown in the attached exhibits and in accordance with the terms of the applicable agreements throughout the four-year planning period, regardless of any early-out clauses in the contract. The Company has entered into numerous PPAs that have been filed with and approved by the Commission. Exhibit 13 designates an individual that, upon request, will provide copies of any of the Company's PPAs for review by MPSC Commissioners or Commission Staff within one day of receiving the request.

12. Forward ZRC Contracts

The Company has several "Forward ZRC Contracts" that are sourced by suppliers with generation facilities located within MISO Zone 7. The contracts shown in Exhibit 6, line 45, are for entire Planning Years.

Consumers Energy remains committed to maintaining the contracted amounts as shown in Exhibit 6, line 45 (bi-lateral ZRC purchases), throughout the four-year planning period. In lieu of filing a copy of the forward ZRC contracts with this capacity demonstration, the Company agrees to produce the contracts for review by the MPSC Commissioners or Commission Staff at the Commission's office, upon a one-day notice and upon request, without the Commission Staff or Commissioners retaining a copy. Exhibit 13 designates individuals that will provide copies of any of the Company's forward ZRC contracts to the MPSC Staff upon request, and within one day after reciept of such request.

13. Planning Reserve Auction Purchases

All entities with available generation in the MISO footprint are required to participate in the annual Planning Reserve Auction ("PRA"), and make such generation that clears in the PRA available[11] for all hours of the Planning Year. The forward capacity market is designed to ensure sufficient resources are in place to reliably serve load on a forward-looking basis. The Company can meet its planning resource requirements by offering capacity resources and demand into the PRA through one or both of the following methods:

- Offering or self-scheduling capacity resources and bidding demand into the PRA; or
- Opting out of the PRA by submitting a Fixed Resource Adequacy Plan, offsetting capacity resources and demand against each other.

[11] Except for approved planned derates and outages and forced outages.

PRA purchases are not assumed in Planning Years 2018 through 2021. If PRA purchases are needed prior to each Planning Year, the Company may choose to purchase up to 5% from the PRA.

If sworn as a witness, I would testify as set forth above.

Digitally signed by Timothy J. Sparks
Date: 2017.12.01 14:53:59 -05'00'

Timothy J. Sparks

Subscribed and sworn to before me this 1st day of December, 2017.

Digitally signed by Tara L. Hilliard
Date: 2017.12.01 14:54:37 -05'00'

Tara L. Hilliard, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 09/12/20
Acting in the County of Jackson

MICHIGAN PUBLIC SERVICE COMMISSION

Pursuant to the Order in Commission Case No.

U-18441

Entities are directed to use this form to submit a capacity demonstration of their ability to meet their customers' expected electric requirements during the four-year period of 2018 - 2021.

December 1, 2017

As directed by the Commission in the September 15, 2017 Order in Case No. U-18441, the attached exhibits will be filed by regulated electric utilities by December 1, 2017 in accordance to Commission order in Case No. U-18197. Subsequently, alternative electric suppliers, utility affiliates, municipal utilities, and power supply cooperatives and associations shall file by February 9, 2018 in accordance to Commission order in Case No. U-18197. Companies are encouraged to submit a written narrative, which will support the data provided in these tables. Submittal of this form does not necessarily ensure complete compliance with the requirements outlined in the Order; each company should be certain that their filing meet the full extent of the Order.

Notes

1. In addition to those requirements outlined by the Order, all filings should include:
   a. Discussion of any observed risks associated with mid-planning year retirement of generation assets.
   b. Discussion of the plan to meet any identified capacity shortfall.
   c. Discussion supporting the data provided in the attached tables.

2. Definitions of key line items are included as comments on the individual cell.

3. Please report all data in the units specified by the corresponding row/column.

4. Exhibit 1 provides sample calculations, including formulae, used to derive the final result.
   a. Any deviation from the intended formulae should be noted and justified in the narrative of the filing.

Case No.: U-18441
Utility: Consumers Energy Company
Date: December 1, 2017
Exhibit 1: Peak Demand Bundled Service

Utility Bundled Service Peak Demand for the Lower Peninsula of Michigan

Actual and Forecast including Transmission Losses (MW)

Line	(a)	(b) PY 2014-15 Actual [1]	(c) PY 2015-16 Actual [1]	(d) PY 2016-17 Actual [1]	(e) PY 2017-2018 Actual [1]	(f) PY 2018-2019 Forecast	(g) PY 2019-2020 Forecast	(h) PY 2020-2021 Forecast	(i) PY 2021-2022 Forecast
	Peak Demand (MW)								
1	Service Territory, Coincident to Bundled	7,490	7,812	8,227	7,634	8,630	8,713	8,800	8,861
2	Choice, Coincident to Bundled	575	581	592	577	588	565	563	600
3	Bundled (line 1 - line 2)	6,915	7,231	7,635	7,057	8,043	8,148	8,237	8,260
	Coincident to MISO Sys.Peak Demand (MW)								
4	Service Territory	7,490	7,812	6,728	7,336	8,246	8,325	8,408	8,466
5	Choice	575	581	559	558	561	540	538	574
6	Bundled (line 4 - line 5)	6,915	7,231	6,170	6,777	7,684	7,785	7,870	7,892

[1] The Company did not make any adjustment for Demand-Side Programs in forecasted years; however, the actual loads are net of any demand-side reductions.

Case No.: U-18441
Utility: Consumers Energy Company
Date: December 1, 2017
Exhibit 2: Planning Resources

Planning Reserve Margin Requirements and Planning Resources to be Acquired (UCAP MW)

Line	(a)	(b) PY 2018-2019	(c) PY 2019-2020	(d) PY 2020-2021	(e) PY 2021-2022	
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW	8,043	8,148	8,237	8,260	
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	472	541	618	666	
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	7,571	7,607	7,619	7,595	
4	Load Diversity Factor coincident to MISO Factor, %.	95.54%	95.54%	95.54%	95.54%	
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	7,233	7,268	7,280	7,256	
6	Transmission Losses, %	3.50%	3.50%	3.50%	3.50%	
7	Adjusted Total Peak Demand, MW (line 5/ (1+ line 6))	6,988	7,022	7,034	7,011	[1]
8	Applied Transmission Losses, MW (line 6 x line 7)	245	246	246	245	[1]
9	Adjusted Total Peak Demand, MW (same as line 7)	6,988	7,022	7,034	7,011	[1]
10	Planning Reserve Margin % UCAP Basis	8.40%	8.40%	8.30%	8.30%	
11	Total Planning Reserve Margin (expected reserves), ZRC ((line 8 + line 9) x (1 + line 10))	7,841	7,878	7,884	7,858	
12	Company Owned, In-State, Non-Intermittent, ZRC	5,124	5,190	5,263	5,283	
13	Company Owned, Out-of-State, Non-Intermittent, ZRC	0	0	0	0	
14	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	17	17	17	17	[2]
15	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	0	0	0	0	[2]
16	Company Owned, In-State, Intermittent, ZRC	60	60	99	154	
17	Company Owned, Out-of-State, Intermittent, ZRC	0	0	0	0	
18	Company Owned, In-State, Intermittent (BTMG), ZRC	11	11	12	12	[2]
19	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	0	0	0	0	[2]
20	Total Company Owned Generation, ZRC (sum of lines 12-19)	5,212	5,278	5,391	5,466	[2]
21	Load Modifying Resources, Treated as Capacity, MW	270	339	428	504	
22	Applied Transmission Losses, MW (line 21 x line 6)	9	12	15	18	
23	Total Qualified Demand Response Resources including PRMUCAP, ZRC ((line 21 + line 22) x (1 + line 10))	302	380	479	565	
24	PPA, In-State, Intermittent Resource, ZRC	67	67	66	66	[4]
25	PPA, Out-of-State, Intermittent Resource, ZRC	0	0	0	0	[4]
26	PPA, In-State, Intermittent (BTMG), ZRC	2	1	1	1	[3] [4]
27	PPA, Out-of-State, Intermittent (BTMG), ZRC	0	0	0	0	[3] [4]
28	PPA, In-State, Non-Intermittent Resource, ZRC	2,359	2,517	2,517	1,753	[3] [4]
29	PPA, Out-of-State, Non-Intermittent Resource, ZRC	0	0	0	0	[3] [4]
30	PPA, In-State, Non-Intermittent (BTMG), ZRC	39	39	39	39	[3] [4]
31	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	0	0	0	0	[3] [4]
32	Other Forward Capacity Contract, ZRC - In-State	20	20	20	0	
33	Other Forward Capacity Contract, ZRC - Out-of-State	0	0	0	0	
34	Total PPA, ZRC (sum of lines 24-33)	2,487	2,644	2,644	1,859	[3]
35	Total Planning Resources, ZRC (line 20 + line 23 + line 34)	8,001	8,303	8,514	7,890	
36	UCAP Surplus/(Shortfall), ZRC (line 35- line 11)	161	424	630	32	

[1] The Company modified line 9 to be equal to line 7 (rather than line 5 as originally proposed by Staff). Furthermore, the Company modified Staff's formulas in line 7 to be line 5/(1+line 6), and line 8 to be line 6 times line 7.

[2] The Company modified these lines to include breakdowns of owned resources which are classified as Behind-The-Meter-Generation ("BTMG"), for both intermittent and non-intermittent resources, for consistency with Power Purchase Agreement ("PPA") breakouts.

[3] The Company modified these lines to break down PPAs into categories based on intermittency and BTMG.

[4] Details that are not expressly broken out in this exhibit, such as which resources are PURPA and PA 295, are shown in Exhibit 6.

Case No.: U-18441
Utility: Consumers Energy Company
Date: December 1, 2017
Exhibit 3: Demand Response Program Resources

Demand Response - Capacity Resources

Line	(a)	(b) Demand Response Program Name	(c) Demand Response Program (MW)	(d) Credit Transmission Losses and PRM $_{UCAP}$(MW)	(e) Total ZRC per Program Name
	PY 2018-UCAP	Peak Power Savers (AC Cycling)	24.1	2.9	27.0
1		Rate EIP	48.3	5.9	54.2
2		C&I DR	60.0	7.3	67.3
3		Rate GI	137.2	16.7	153.9
4					
5					
6					
7					
8					
	Total Demand Response - Capacity Resources PY 2018-2019 (ZRC)				302.4
	PY 2019-UCAP	Peak Power Savers (AC Cycling)	43.5	5.3	48.8
9		Rate EIP	48.3	5.9	54.2
10		C&I DR	110.0	13.4	123.4
11		Rate GI	137.2	16.7	153.9
12					
13					
14					
15					
16					
	Total Demand Response - Capacity Resources PY 2019-2020 (ZRC)				380.3
	PY 2020-UCAP	Peak Power Savers (AC Cycling)	62.0	7.5	69.5
17		Rate EIP	48.3	5.8	54.1
18		C&I DR	180.0	21.8	201.8
19		Rate GI	137.2	16.6	153.8
20					
21					
22					
23					
24					
	Total Demand Response - Capacity Resources PY 2020-2021 (ZRC)				479.2
	PY 2021-UCAP	Peak Power Savers (AC Cycling)	78.8	9.5	88.3
25		Rate EIP	48.3	5.8	54.1
26		C&I DR	240.0	29.0	269.0
27		Rate GI	137.2	16.6	153.8
28					
29					
30					
31					
32					
	Total Demand Response - Capacity Resources PY 2021-2022 (ZRC)				565.2

EXHIBIT 4
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

Case No.: U-18441
Utility: Consumers Energy Company
Date: December 1, 2017
Exhibit 5: New or Upgraded Generation Owned

New or Upgraded Generation Owned

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
Line	Electric Generator Name	Fuel or Renewable Type	Added Unit Nameplate MWs	Class Average / MISO Capacity Credit	Added ZRCs	Expected COD	Planned MPSC Regulatory Approval Date	Planned MISO Interconnection Queue Date	Planned MISO Interconnection Agreement Approval	Construction Start Date	Construction End Date	
1	Cross Winds II	Wind	44.0	15.60%	6.9	January 2018	December 2016	August 2010	June 2013	December 2016	December 2017	
2	Cross Winds III	Wind	75.9	15.60%	11.8	January 2020	December 2016	November 2016	September 2018	September 2018	December 2019	
3	Renewable Energy Plan - "Circuit West"	Solar	0.5	50.00%	0.3	October 2018	September 2018	N/A	N/A	October 2017	September 2018	[1]
4	Solar Gardens - Project 3	Solar	2.0	50.00%	1.0	January 2020	September 2018	N/A	N/A	January 2019	December 2019	[2]
5	PA 342 15% RPS Assumption - Wind 1	Wind	175.0	15.60%	27.3	January 2020	September 2018	Varies	Varies	Varies	December 2019	
6	PA 342 15% RPS Assumption - Wind 2	Wind	175.0	15.60%	27.3	December 2020	September 2018	Varies	Varies	Varies	November 2020	
7	PA 342 15% RPS Assumption - Wind 3	Wind	175.0	15.60%	27.3	December 2020	September 2018	Varies	Varies	Varies	November 2020	
8	Ludington Unit 6	Pumped Storage	35.7	90.84%	32.4	April 2018	March 2018, U-18322	September 2011	June 2013	April 2017	April 2018	
9	Ludington Unit 1	Pumped Storage	35.7	90.84%	32.4	April 2019	TBD-Rate Case	September 2011	June 2013	April 2018	April 2019	
10	Ludington Unit 3	Pumped Storage	35.7	90.84%	32.4	April 2020	TBD-Rate Case	September 2011	June 2013	April 2019	April 2020	

Source:
Class Average Capacity for Wind: MISO Business Practice Manual 11 (r17).
Class Average Capacity for Solar: MISO Business Practice Manual 11 (r17).
Class Average EFORd for Pumped Storage: MISO October 2017 Pooled EFORd Class Averages.

Notes:
[1] Renewable Energy Plan - "Circuit West" is part of the Company's Renewable Energy Plan filed in Case No. U-18231.
[2] Solar Gardens Project 3 capacity is a part of the Company's Solar Gardens Program.

EXHIBIT 6
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

Case No.: U-18441
Utility: Consumers Energy Company
Date: December 1, 2017
Exhibit 7: New or Upgraded Purchased Power

New or Upgraded Purchased Power

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line	**Electric Generator Name**	**Fuel or Renewable Type**	**Added Unit Nameplate MWs**	**Class Average / MISO Capacity Credit**	**Added ZRCs**	**Expected COD**	**Planned MPSC Regulatory Approval Date**	**Planned MISO Interconnection Queue Date**	**Planned MISO Interconnection Agreement Approval**	**Construction Start Date**	**Construction End Date**
1	Geronimo Huron Wind, LLC (Apple Blossom)	Wind	100.0	15.60%	15.6	November 2017	November 2015	May 2014	August 2015	September 2016	November 2017
2	PURPA Obligations - Planning Year 2018-2021	Various Renewable	69.1	N/A	68.3	Existing	Varies	Varies	Varies	N/A	N/A
3	Modification of Existing PPA - TES Filer City	Natural Gas	164.7	N/A	157.4	June 2019	February 2018	December 2016	N/A	June 2018	May 2019

Source:
Class Average Capacity for Wind: MISO Business Practice Manual 11 (r17).
Class Average Capacity for Solar: MISO Business Practice Manual 11 (r17).

EXHIBIT 8
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

Case No.: U-18441
Utility: Consumers Energy Company
Date: December 1, 2017
Exhibit 9: Module E Report - Demand Response Programs

Demand Response Programs - Not Netted Against Load
MISO Module E Report for Planning Year 2017/2018 [1]

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
Line	Demand Response Program Name	MISO Resource Name	LRZ	Asset Owner	Type	Effective ICAP	GVTC	Total IS	NRIS	ERIS	XEFORd	Wind %	TL% Inc	UCAP (Total)	UCAP (ERIS)	Status
1	C&I DR	C AND I EMERGENCY	Zone 7	CETR	LMR (DR)	56.6	0.0	56.6	56.6	0	0.00%			56.6	0.0	Confirmed
2	Rate GI	INNTERRUPTIBLE	Zone 7	CETR	LMR (DR)	126.8	0.0	126.8	126.8	0.0	0.00%			126.8	0.0	Confirmed
3	Rate EIP	RATE EIP	Zone 7	CETR	LMR (DR)	54.3	0.0	54.3	54.3	0.0	0.00%			54.3	0.0	Confirmed
4	Peak Power Savers (AC Cycling)	RESID AC LOADCONTROL	Zone 7	CETR	LMR (DR)	9.0	0.0	9.0	9.0	0.0	0.00%			9.0	0.0	Confirmed
5	**Total**													**246.7**		

[1] Abbreviations for this exhibit can be found on pages 68-69 at https://www.misoenergy.org/Library/Repository/Study/Stakeholders/MECT User Guide.pdf

EXHIBITS 10 AND 11 ARE *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

M.P.S.C. No. 13 - Electric
Consumers Energy Company
(To update Energy Purchase, rename program)

Seventh Revised Sheet No. D-11.00
Cancels Sixth Revised Sheet No. D-11.00

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-10.00)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access customers.**

Senior Citizen Credit: $(3.50) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Peak Power Savers Program:

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary *Peak Power Savers Program for load management of eligible* electric central air conditioning, central heat pump, or other qualifying electric equipment. Customer eligibility to participate in this *program* is determined solely by the Company. The customer must be located within an area in which Advanced Metering Infrastructure (AMI) is deployed and *have a* fully operational *AMI meter* for purposes of this *program*. The Company will accept a customer's central air conditioning, central heat pump, and other qualifying electric equipment under this *program* only if it has the capability to be controlled by the Company. Load Management of a customer's swimming pool pump is permitted under this *program* only if the customer is allowing Load Management of their air conditioner or heat pump unit. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

(Continued on Sheet No. D-11.10)

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-11.00)

Monthly Rate: (Contd)

***Peak Power Savers Program*: (Contd)**

The Company reserves the right to specify the term or duration of the *program*. The participating customer may elect to terminate service for any reason by providing the Company with thirty days' notice prior to the customer's next billing cycle. The customer's enrollment shall be terminated if the voluntary *program* ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load Management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the *Peak Power Savers* Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this *Peak Power Savers Program*.

The monthly credit for the *Peak Power Savers Program* shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Power Savers Credit: $*(7.84)* per *customer per month* during the billing months of June-September

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C 11., Net Metering Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Non-Transmitting Meter Provision:

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

(Continued on Sheet No. D-11.20)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-33.00)

Monthly Rate (Contd)

Self-Generation Provision (SG)

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge

$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

Energy Purchase

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Interruptible Service Provision (GI)

This provision is available to any customer account willing to contract for at least 500 kW of On-Peak Billing Demand as interruptible. The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 50,000 kW. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 250,000 kW.

The customer may choose to have the interruptible load separately metered. The customer shall bear any expense incurred by the Company in providing a separate service for the interruptible portion of an existing customer load. The customer must provide space suitable for the separate metering.

(Continued on Sheet No. D-34.10)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.00)

Monthly Rate (Contd)

Interruptible Service Provision (GI) (Contd)

For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate. All contracts under this provision shall be negotiated on an annual basis. Within *30* minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity or have the total facility subject to interruption.

The minimum On-Peak Billing Demand that shall be billed for the interruptible portion of a customer's bill is the contracted interruptible amount. At the Company's discretion, the customer may reduce the contracted amount one time within the annual contract period.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements as determined by the Company and may require the installation and maintenance of equipment that allow the Company to remotely interrupt the customer's load. If the company determines it is required to install and maintain equipment at the customer's site to comply with any requirements associated with the GI service provision then it shall do so at the customer's expense. In addition, the customer shall also adhere to any advance notification requirements the Company deems are necessary to comply with its obligations to MISO under this provision.

Conditions of Interruption

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall endeavor to provide notice in advance of probable interruption, and if possible, a second notice of positive interruption. However, this service shall be interrupted immediately upon notice should the Company deem such action necessary. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $50.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges - These charges are applicable to Full Service Customers.

Interruptible Credit:	$(7.00)	per kW of On-Peak Billing Demand during the billing months of June-September
	$(*6.00*)	per kW of On-Peak Billing Demand during the billing months of October-May

(Continued on Sheet No. D-35.00)

ENERGY INTENSIVE PRIMARY RATE EIP

Availability:

Subject to any restrictions, the Energy Intensive Primary Rate EIP is available to any Full Service electric metal melting customer taking service at the Company's Primary Voltage levels, where the electric load on this rate is utilized for industrial metal melting processes such as electric arc or induction furnaces or to any Full Service electric industrial customer who qualified as energy intensive as defined herein. *E*xisting metal melting customers taking service under the Company's *former Metal Melting Primary Pilot as of November 30, 2015 are eligible for service on Rate EIP*. An additional 200 MW of Maximum Demand capacity will be available on a first-come, first-served basis to Full Service customers with new electric metal melting or energy intensive industrial load not previously served by the Company. To qualify as energy intensive load, the customer must demonstrate viable options to site the production outside of the state and the customer's incremental load must exceed 2 MW at a single site *with* an annual load factor that exceeds 70% *or the customer's incremental load must exceed 15 MW with a minimum of 75% of their total consumption occurring during Off-Peak Hours*. New electric metal melting load must be separately metered. The customer must provide a special circuit or circuits in order for the Company to install separate metering

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

For purposes of this rate, the appropriate measure of market price is the Real-Time LMP for the Company's retail aggregating node CONS.CETR established by the Midcontinent Independent System Operator Inc. (MISO).

Critical Peak Event Determination:

The Company shall call a Critical Peak Event to signal either the market price has exceeded an Economic Trigger Price or a system integrity event is enacted.

A System Integrity Event is enacted when MISO declares that a Maximum Generation Emergency Event has occurred and MISO has instructed the Company to implement Load Management Measures using Load Modifying Resources and Load Management Measures - Stage 1. A System Integrity Event shall occur at any time for any duration. A Critical Peak Event caused by a System Integrity Event shall be billed at the greater of 150% of the High Peak Energy Charge or the average market price during the duration of the event.

The Summer Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 3:00 PM to 5:00 PM for the period of June 1 through September 30 of the previous year. The Summer Economic Trigger Price will be set on January 30 of each year by the Company.

The Winter Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 5:00 PM to 7:00 PM for the period of October 1 through May 31 of the previous year. The Winter Economic Trigger Price will be set on July 31 of each year by the Company.

Energy Intensive Primary Rate customers will be notified after the Summer and Winter Economic Trigger Prices are set. The Company shall endeavor to provide notice in advance of a probable System Integrity Event.

(Continued on Sheet No. D-37.10)

M.P.S.C. No. 13 - Electric
Consumers Energy Company
(To update prices)

Fourth Revised Sheet No. D-37.10
Cancels Third Revised Sheet No. D-37.10

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.00)

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:

Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
Mid-Peak Hours:	2:00 PM to 3:00 PM and 5:00 PM to 6:00 PM
High-Peak Hours:	3:00 PM to 5:00 PM
Critical Peak Hours:	3:00 PM to 5:00 PM during a Critical Peak Event

Winter:

Off-Peak Hours:	12:00 AM to 4:00 PM and 8:00 PM to 12:00 AM
Mid-Peak Hours:	4:00 PM to 5:00 PM and 7:00 PM to 8:00 PM
High-Peak Hours:	5:00 PM to 7:00 PM
Critical Peak Hours:	5:00 PM to 7:00 PM during a Critical Peak Event

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4, or December 25 fall on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Monthly Rate:

Power Supply Charges:

<u>Charges for Customer Voltage Level 3 (CVL 3)</u>

Energy Charge:

Off-Peak - Summer	$*0.040349*	per kWh during the calendar months of June - September
Low-Peak - Summer	$*0.056447*	per kWh during the calendar months of June - September
Mid-Peak - Summer	$*0.075074*	per kWh during the calendar months of June - September
High-Peak - Summer	$*0.086898*	per kWh during the calendar months of June - September
Critical Peak - Summer	the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June - September	
Off-Peak - Winter	$*0.043142*	per kWh during the calendar months of October - May
Mid-Peak - Winter	$*0.052278*	per kWh during the calendar months of October - May
High-Peak- Winter	$*0.054634*	per kWh during the calendar months of October - May
Critical Peak - Winter	the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May	

(Continued on Sheet No. D-37.20)

Issued March 10, 2017 by
Patti Poppe,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after March 7, 2017

Issued under authority of the
Michigan Public Service Commission
dated February 28, 2017
in Case No. U-17990

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.10)

Power Supply Charges: (Contd)

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

Off-Peak - Summer	$0.051349	per kWh during the calendar months of June - September
Low-Peak - Summer	$0.067447	per kWh during the calendar months of June - September
Mid-Peak - Summer	$0.086074	per kWh during the calendar months of June - September
High-Peak - Summer	$0.097898	per kWh during the calendar months of June - September
Critical Peak - Summer	the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June – September	
Off-Peak - Winter	$0.054142	per kWh during the calendar months of October - May
Mid-Peak - Winter	$0.063278	per kWh during the calendar months of October - May
High-Peak- Winter	$0.065634	per kWh during the calendar months of October - May
Critical Peak - Winter	the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October – May	

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

Off-Peak - Summer	$0.048349	per kWh during the calendar months of June - September
Low-Peak - Summer	$0.064447	per kWh during the calendar months of June - September
Mid-Peak - Summer	$0.083074	per kWh during the calendar months of June - September
High-Peak - Summer	$0.094898	per kWh during the calendar months of June - September
Critical Peak - Summer	the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June – September	
Off-Peak - Winter	$0.051142	per kWh during the calendar months of October - May
Mid-Peak - Winter	$0.060278	per kWh during the calendar months of October - May
High-Peak- Winter	$0.062634	per kWh during the calendar months of October - May
Critical Peak - Winter	the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October – May	

Delivery Charges:

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL 3):

Capacity Charge: $4.92 per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL 2):

Capacity Charge: $2.07 per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1):

Capacity Charge: $1.14 per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the *Power Plant* Securitization Charges shown on Sheet No. D-5.10.

(Continued on Sheet No. D-37.30)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.20)

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $(*0.64*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $(0.44) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Self-Generation Provision (SG):

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

(Continued on Sheet No. D-37.40)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.30)

Self-Generation Provision (SG) (Contd)

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data /billing determinants necessary for billing purposes.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Green Generation Programs:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

General Terms:

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate *and any applicable non-consumption based surcharges*.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall require a written contract with a minimum term of one year.

The Company designates a primary and secondary contact to assist with producing customer contracts for review at the Michigan Public Service Commission's office, upon request, in the presence of the designated party are:

Primary Designee:

Name: Karen Wienke
Address: 910 Center Street
Lansing, MI 48909
Email: karen.wienke@cmsenergy.com
Office Phone: (517) 643-1793

Secondary Designee:

Name: Antonette Noakes
Address: 910 Center Street
Lansing, MI 48909
Email: toni.noakes@cmsenergy.com
Office Phone: (517) 745-7712

Planning Year 2018-2019 Loss of Load Expectation Study Report

Loss of Load Expectation Working Group

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Revision History

Reason for Revision	Revised by:	Date:
Draft Posted	MISO	9/29/2017
Final Posted	MISO	10/19/2017

1 Executive Summary

Midcontinent Independent System Operator (MISO) conducts an annual Loss of Load Expectation (LOLE) study to determine a Planning Reserve Margin Unforced Capacity (PRM UCAP), zonal per-unit Local Reliability Requirements (LRR), Capacity Import Limits (CIL) and Capacity Export Limits (CEL). The results of the study and its deliverables supply inputs to the MISO Planning Resource Auction (PRA).

The 2018-2019 Planning Year LOLE Study:

- Establishes a PRM UCAP of 8.4 percent to be applied to the Load Serving Entity (LSE) coincident peaks for the planning year starting June 2018 and ending May 2019
- Uses the Strategic Energy Risk Valuation Model (SERVM) software for Loss of Load analysis to provide results applicable across the MISO market footprint
- Provides initial zonal CIL and CEL for each Local Resource Zone (LRZ) (Figure 1-1). The CILs and CELs may be adjusted in March 2018 based on changes to MISO units with firm capacity commitments to non-MISO load, equipment rating changes since the LOLE analysis, and during the Simultaneous Feasibility Test (SFT) process to assure the resources cleared in the auction are simultaneously reliable.
- Determines a minimum planning reserve margin that would result in the MISO system experiencing a less than one-day loss of load event every 10 years, as per the MISO Tariff.[1] The MISO analysis shows that the system would achieve this reliability level when the amount of installed capacity available is 1.171 times that of the MISO system coincident peak.
- Sets forth initial zonal-based (Table 1-1) PRA deliverables in the LOLE charter

The stakeholder review process played an integral role in this study and the collaboration of the Loss of Load Expectation Working Group (LOLEWG) was much appreciated by the MISO staff involved in this study. Stakeholder feedback resulted in multiple updates to LOLE results, including updated CIL and CEL values due to improved redispatch, use of existing Op Guides, and constraint invalidation.

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
PRM UCAP	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%
LRR UCAP per-unit of LRZ Peak Demand	1.148	1.186	1.152	1.216	1.239	1.144	1.153	1.267	1.127	1.489
Capacity Import Limit (CIL) (MW)	4,546	2,317	2,812	6,278	3,580	7,375	3,785	4,778	3,679	2,618
Capacity Export Limit (CEL) (MW)	516	2,017	5,430	4,280	2,122	3,249	2,578	2,424	2,149	1,824

Table 1-1: Initial Planning Resource Auction Deliverables

[1] A one-day loss of load in 10 years (0.1 day/year) is not necessarily equal to 24 hours loss of load in 10 years (2.4 hours/year).

Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

Figure 1-1: Local Resource Zones (LRZ)

2 LOLE Study Process Overview

In compliance with Module E-1 of the MISO Tariff, MISO performed its annual LOLE study to determine the Planning Reserve Margin (PRM) on an unforced capacity (UCAP) basis for the MISO system and the per-unit Local Reliability Requirements (LRR) of Local Resource Zone (LRZ) Peak Demand for the planning year 2018-2019.

In addition to the LOLE analysis, MISO performed transfer analysis to determine initial Capacity Import Limits (CIL) and Capacity Export Limits (CEL). CIL and CEL are used, in conjunction with the LOLE analysis results, in the Planning Resource Auction (PRA).

The 2018-2019 per-unit LRR UCAP values determined by the LOLE analysis will be multiplied by the updated LRZ Peak Demand forecasts submitted for the 2018-2019 PRA to determine each LRZ's LRR. Once the LRR is determined, the CIL values and non-pseudo tied exports are subtracted from the LRR to determine each LRZ's Local Clearing Requirement (LCR) consistent with Section 68A.6[2] of Module E-1. An example calculation pursuant to Section 68A.6 of the current effective Module E-1[3] shows how these values are reached (Table 2-1).

The actual effective PRM Requirement (PRMR) will be determined after the updated LRZ Peak Demand forecasts are submitted by November 1, 2017, for the 2018-2019 PRA. The CIL and CEL values are

[2] https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx#
[3] Effective Date: September 21, 2015

subject to updates in March 2018 based on changes to exports of MISO resources to non-MISO load, changes to pseudo tied commitments, and updates to facility ratings since completion of the LOLE.

Finally, the simultaneous feasibility test (SFT) is performed as part of the PRA to ensure reliability and is maintained by adjusting CIL and CEL values as needed.

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP (1d in 10yr)	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Capacity Import Limit (CIL)	3,469	[G]
Capacity Export Limit (CEL)	2,317	[H]
Proposed PRA (UCAP) EXAMPLE	**Example LRZ**	**Formula Key**
Forecasted LRZ Peak Demand	14,270	[I]
Forecasted LRZ Coincident Peak Demand	13,939	[J]
Non-Pseudo Tied Exports UCAP	150	[K]
Local Reliability Requirement (LRR) UCAP	16,376	[L]=[F]x[I]
Local Clearing Requirement (LCR)	12,757	[M]=[L]-[G]-[K]
Zone's System Wide PRMR	15,110	[N]=[1.084]X[J]
PRMR	15,110	[O] = Higher of [M] or [N]
Planning Reserve Margin (PRM)	8.4%	[P]=[O]/[J]-1

Table 2-1: Example LRZ Calculation

2.1 Study Enhancements

For the 2018-2019 planning year, several changes were made to the LOLE modeling assumptions. Modeling enhancements are necessary in order to mature the planning reserve margin and reliability requirements.

The 2018-2019 LOLE analysis includes these enhancements:

- 30 historical weather and load shape correlation modeling
- More accurate dispatch limited Demand Response Modeling
- Modified schedule to allow more time for review of Planning Year CIL and CEL results
- Allow the MISO-committed portion of partial pseudo-ties to participate in transfer and redispatch

2.2 Future Study Improvement Considerations

MISO's LOLE analysis underwent enhancements in the past few years to ensure that MISO continues to send the appropriate capacity planning signals in the forward time horizon. The 2018-2019 planning year was the first LOLE study MISO completed with the SERVM software managed by Astrapé Consulting. SERVM provides additional capabilities such as unit commitment and more accurate unit outage probabilities that could potentially be implemented for future studies. All future enhancements and modeling changes will be vetted through the Loss of Load Expectation Working Group and any other impacted stakeholder forums. Possible future enhancements may include:

- Maintenance outage and planned outage enhancements
- Seasonal outage rates
- Unit commitment
- Demand response availability
- Additional high temperature resource derates
- Increased visibility on out-year LOLE metrics and risk

The electric industry is going through resource portfolio changes and a reduction in overall reserve margins. This is due, in large measure, to retirements of coal-based generation resources that are being replaced, in part, by generation fueled by natural gas and renewables. This has increased focus on Resource Adequacy within the MISO region. The LOLE study will continue to develop model enhancements and deliverables to align with the evolving Resource Adequacy construct.

3 Transfer Analysis

3.1 Calculation Methodology and Process Description

Transfer analyses determined initial CILs and CELs for LRZs for the 2018-2019 Planning Year. The objective of transfer analysis is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Multiple factors impacted the analysis when compared to previous studies, including:

- Completion of MTEP transmission projects
- Generation retirements and commissioning of new units
- External system dispatch changes

3.1.1 Generation pools

To determine an LRZ's import or export limit, a transfer is modeled by ramping generation up in a source subsystem and ramping generation down in a sink subsystem. The source and sink definitions are dependent on the limit being tested. The LRZ studied for CIL is the sink subsystem and the adjacent MISO areas are the source subsystem. The LRZ studied for CEL is the source subsystem and the rest of MISO is the sink subsystem.

Transfers can cause potential issues, which are addressed through the study assumptions. First, an abundantly large source pool spreads the impact of the transfer widely, which potentially masks constraints. Second, ramping up generation from remote areas could cause electrically distant constraints for any given LRZ, which should not determine a zone's limit. For example, export constraints due to dispatch of LRZ 1 generation in the northwest portion of the footprint should not limit the import capability of LRZ 10, which covers the MISO portion of Mississippi.

To address these potential issues, the transfer studies limit the source pool for the import studies to the areas adjacent to the study zone. Since export study subsystems are defined by the LRZ, these issues only apply to import studies. Generation within the zone studied for an export limit is ramped up and constraints are expected to be near the zone because the ramped-up generation concentrates in a particular area.

3.1.2 Redispatch

Limited redispatch is applied after performing transfer analyses to mitigate constraints. Redispatch ensures constraints are not caused by the base dispatch and align with potential actions that can be implemented for the constraint in MISO operations. Redispatch scenarios can be designed to address multiple constraints as required and may be used for constraints that are electrically close to each other or to further optimize transfer limits for several constraints requiring only minor redispatch. The redispatch assumptions include:

- The use of no more than 10 conventional fuel units or wind plants
- Redispatch limit at 2,000 MW total (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units
- No adjustments to the portions of pseudo-tied units committed to non-MISO load

3.1.3 Generation Limited Transfer for CIL/CEL

When conducting transfer analysis to determine a CIL or CEL, the source subsystem might run out of generation to dispatch before identifying a constraint caused by a transmission limit. MISO developed a Generation Limited Transfer (GLT) process to identify transmission constraints in these situations, when possible, for both CIL and CEL.

After running the First Contingency Incremental Transfer Capability (FCITC) analysis to determine limits for each LRZ CIL or CEL, MISO will determine whether a zone is experiencing a GLT (e.g. whether the first constraint would only occur after all the generation is dispatched at its maximum amount). If the LRZ experiences a GLT, MISO will adjust the base model based on whether it is a CIL or CEL analysis and re-run the transfer analysis.

For a CEL study, when a transmission constraint has not been identified after dispatching all generation within the exporting system (LRZ under study) MISO will decrease load and generation dispatch in the study zone. The adjustment creates additional capacity to export from the zone. After the adjustments are complete, MISO will run the transfer analysis again. If a GLT reappears, MISO will make further adjustments to the load and generation of the study zone.

For a CIL study, when a transmission constraint has not been identified after dispatching all generation within the source subsystem, MISO will adjust load and generation in the source subsystem. This increases the import capacity for the study zone. After the adjustments are complete, MISO will run the transfer analysis again. If a GLT reappears, MISO will make further adjustments to the model's load and generation in the source subsystem.

FCITC could indicate the transmission system can support larger thermal transfers than would be available based on installed generation for some zones, but large variations in load and generation for any zone may lead to unreliable limits and constraints. Therefore, MISO limits load scaling for both CIL and CEL to 50 percent of the zone's load.

3.1.4 Voltage Limited Transfer for CIL/CEL

Zonal imports may be limited by voltage constraints due to a decrease in the generation in the zone prior to the thermal limits determined by linear FCITC. As such, LOLE studies may evaluate Power-Voltage curves for LRZs with known voltage-based transfer limitations identified through prior MISO or Transmission Owner studies. Evaluation may also happen if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from non-zonal resources. MISO will coordinate with stakeholders as it encounters these scenarios.

3.2 Powerflow Models and Assumptions

3.2.1 Tools used

MISO used the Siemens PTI Power System Simulator for Engineering (PSS E) and Transmission Adequacy and Reliability Assessment (TARA) as transfer analysis tools.

3.2.2 Inputs required

Thermal transfer analysis requires powerflow models and input files. MISO used contingency files from MTEP[4] reliability assessment studies. Single-element contingencies in MISO/seam areas were also evaluated.

MISO developed a subsystem file to monitor its footprint and seam areas. LRZ definitions were developed as sources and sinks in the study. See Appendix B for maps containing adjacent area definitions (Tiers 1 and 2) used for this study. The monitored file includes all facilities under MISO functional control and single elements in the seam areas of 100 kV and above.

3.2.3 Powerflow Modeling

Two summer peak models were required for the analysis: 2018 and 2021. All models were built using MISO's Model on Demand (MOD) model data repository, each with an effective date and base assumptions (Table 3-1).

Scenario	Effective Date	Projects Applied	External Modeling	Load and Generation Profile
2018	6/1/2018	MTEP17 Appendix A and Target A	2016 Series 2018 Summer ERAG MMWG	Summer Peak
2021	6/1/2021	MTEP17 Appendix A and Target A	2016 Series 2021 Summer ERAG MMWG	Summer Peak

Table 3-1: Model assumptions

MISO excluded several types of units from the transfer analysis dispatch; these units' base dispatch remained fixed.

- Nuclear dispatch does not change for any transfer
- Intermittent resources can be ramped down, but not up
- Pseudo-tied resources were modeled at their expected commitments to non-MISO load, although portions of these units committed to MISO could participate in transfer analyses

System conditions such as load, dispatch, topology and interchange have an impact on transfer capability. Models were reviewed as part of the base model build for MTEP17 analyses, with study files made available on the MTEP ftp site. The LOLEWG requested stakeholder feedback. MISO worked closely with transmission owners and stakeholders in order to model the transmission system accurately, as well as validate constraints and redispatch.

3.2.4 General Assumptions

MISO uses TARA to process the powerflow model and associated input files to determine the import and export limits of each LRZ by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions. The incremental amount of power that can be transferred will be determined through FCITC analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of transferrable power

[4] Refer to the Transmission Planning BPM for more information regarding MTEP input files. https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=19215

before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (Equation 3-1). All published limits are based on the zone's FCTTC, and may be adjusted for capacity exports.

$$First\ Contingency\ Total\ Transfer\ Capability\ (FCTTC) = FCITC + Base\ Power\ Transfer$$

Equation 3-1: Total Transfer Capability

Facilities were flagged as potential constraints for loadings of 100 percent or more in two scenarios: the normal rating for system intact conditions and the emergency rating for single event contingencies. Linear FCITC analysis identifies the limiting constraints using a minimum transfer Distribution Factor (DF) cutoff of 3 percent, meaning the transfer and contingency must increase the loading on the overloaded element by 3 percent or more.

A pro-rata dispatch is used, which ensures all available generators will reach their maximum dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit.

Table 3-2 and Equation 3-2 show an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Unit Dispatch Max – Unit Dispatch Min)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	**310**

Table 3-2: Example subsystem

$$\boldsymbol{Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = \frac{Machine\ 1\ Reserve\ MW}{Source\ Subsystem\ Reserve\ MW} \times Transfer\ Level\ MW}$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = 25.8$$

Equation 3-2: Machine 1 dispatch calculation for 100 MW transfer

FERC issued an order on December 31, 2015, that required CIL studies be neutral to exports from MISO capacity to non-MISO load. CIL will be equal to the base interchange plus the incremental transfer capacity in a model where the exporting units are not dispatched to non-MISO load. This analysis uses the same steps as previously described, and the results are then adjusted to remove the impacts of exporting units from both the base power transfer and the FCITC values.

3.3 Results

Constraints limiting transfers and the associated CIL and CEL for each LRZ were presented and reviewed through the LOLEWG. Preliminary results for Planning Year 2018/19 were presented in the August 2017 meeting and updates were presented in the September 2017 meeting. Preliminary results for the out-year study covering 2021 were also presented in the September meeting and updates were presented in the October meeting.

Detailed constraint and redispatch information for all limits is found in the Transfer Analysis section of this report. Table 3-3 presents a summary of the Planning Year 2018-19 Capacity Import Limits.

LRZ	Tier	18-19 Limit (MW)[5]	Monitored Element	Contingent Element	Figure 3.3-1 Map ID	GLT applied	Generation Redispatch MW	17-18 Limit (MW)
1	1&2	4,546	Sherman Street to Sunnyvale 115 kV	Arpin to Rocky Run 115 kV	1	No	0	3,531
2	1&2	2,317	Plano B to Electric Junction B 345 kV	Plano R to Electric Junction R 345 kV	2	No	2,000	2,227
3	1&2	2,812	Sub 3458 to Sub 3456 345 kV	Sub 3455 to Sub 3740 345 kV	3	No	2,000	2,408
4	N/A	6,278	North Decatur West Bus 138 kV voltage	Clinton Generation	4	No	N/A	5,815
5	1&2	3,580	Joppa 345/161 kV	Shawnee 500/345 kV	5	No	2,000	4,096
6	1&2	7,375	Paradise to BRTAP 161 kV	Phillips Bend to Volunteer 500 kV	6	Yes	2,000	6,248
7	N/A	3,785	Hager 120 kV bus voltage	Wayne – Monroe 345 kV	7	No	N/A	3,320
8	1&2	4,778	Sterlington 500/115 kV #2	Sterlington to El Dorado 500 kV	8	No	2,000	3,275
9	1&2	3,679	Sterlington to Downsville 115 kV	Mt. Olive to El Dorado 500 kV	9	Yes	2,000	3,371
10	1	2,618	Hernando to Coldwater 115 kV	Moon Lake to Batesville 230 kV	10	No	1,670	1,910

Table 3-3: Planning Year 2018–2019 Capacity Import Limits

[5] Results after applying redispatch and shift factor adjustments for the Dec. 31, 2015, FERC order.

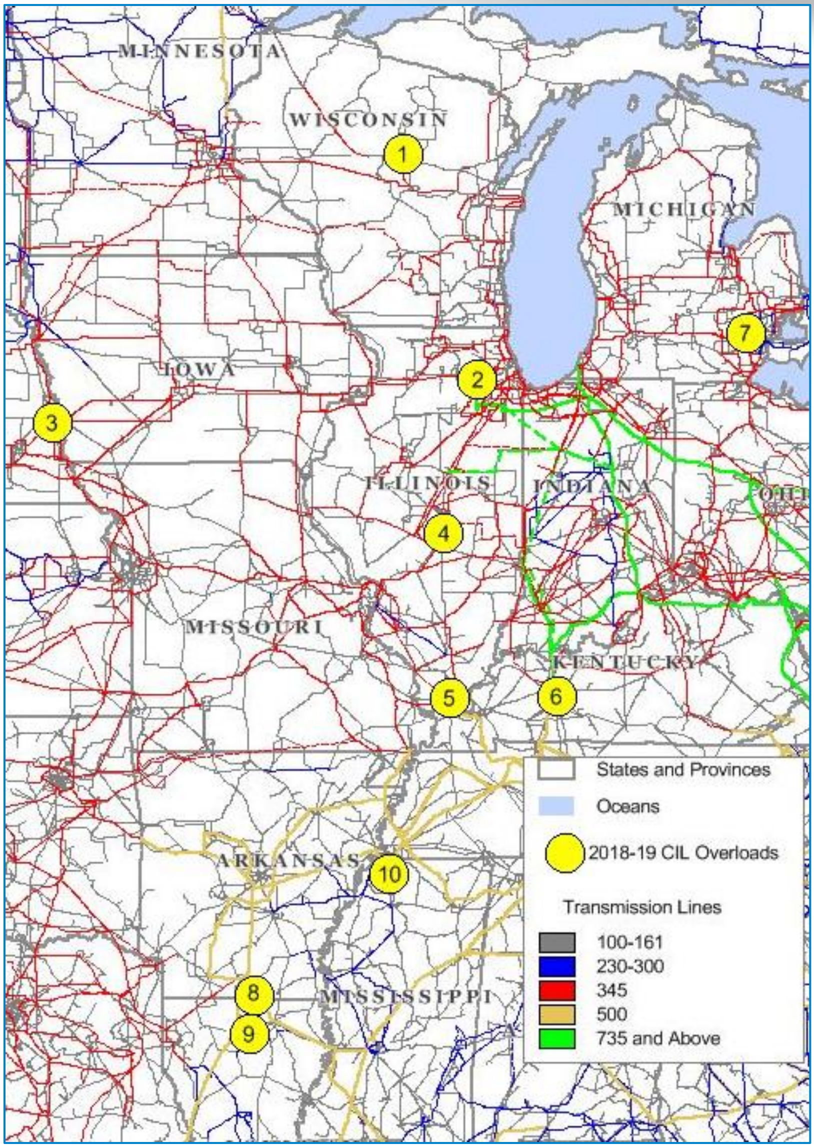


Figure 3-1: Planning Year 2018-19 CIL Constraint Map

Capacity Exports Limits were found by increasing generation in the zone being studied and decreasing generation in the rest of the MISO footprint. Table 3-4 summarizes Planning Year 2018-19 Capacity Export Limits.

LRZ	18-19 Limit (MW)	Monitored Element	Contingent Element	Figure 3.3-2 Map ID	Generation Redispatch (MW)	GLT applied	17-18 Limit (MW)
1	516	Lakefield to Dickinson 161 kV	Webster to Kossuth 345 kV	1	1,685	Yes	686
2	2,017	Zion EC to Zion Station 345 kV	Zion to Pleasant Prairie 345 kV	2	950	Yes	2,290
3	5,430	Council Bluffs to Sub 3456 345 kV	Nebraska City Unit 2	3	1,111	Yes	1,772
4	4,280	Marion CT to Renshaw 161 kV	Marion Ct to Marion S 161 kV	4	0	Yes	11,756
5	2,122	Maywood to Spencer Creek 161 kV	System Intact	5	353	Yes	2,379
6	3,249	Wilson to Matanzas 161 kV	Green River to Wilson 161 kV	6	1,058	Yes	3,191
7	2,578	Monroe to Allendorf 345 kV	Lulu to Morocco to Milan 345 kV	7	0	Yes	2,519
8	2,424	Russelville South to Dardanelle 161 kV	Arkansas Nuclear to Fort Smith 500 kV	8	0	No	2,493
9	2,149	Clay to Aberdeen 161 kV	West Point to Clay 500 kV	9	2,000	No	2,373
10	1,824	Batesville to Tallahachie 161 kV	Choctaw to Clay 500 kV	10	1,534	No	1,747

Table 3-4: Planning Year 2018–2019 Capacity Export Limits

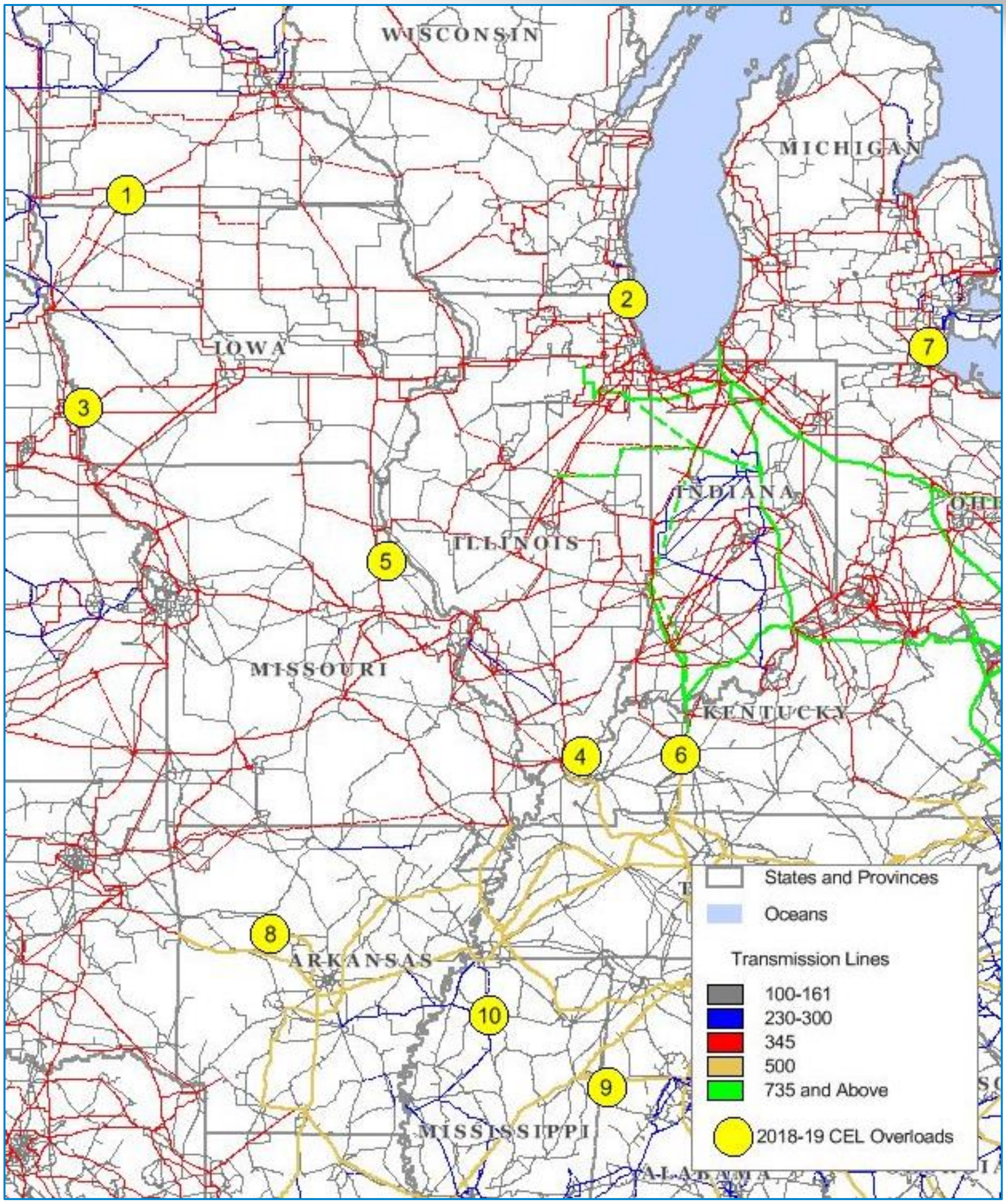


Figure 3-2: Planning Year 2018-19 CEL Constraint Map

3.3.1 2021 Results

Table 3-5 summarizes 2021 Capacity Import Limits.

LRZ	Tier	2021 Limit (MW)	Monitored Element	Contingent Element	GLT applied	Generation Redispatch (MW)
1	1&2	5,166	Colby to Northern Iowa Wind 161kV	Adams to Mitchell County 345kV	No	1,129
2	1&2	2,495	Stoneman to Nelson Dewey 161kV	Seneca to Genoa Op-Guide Contingency161 kV	No	1,926
3	1&2	3,319	Ottumwa 345/161kV	Ottumwa Generation Unit 1	No	1,625
4	1&2	6,391	North Decatur West Bus 138kV voltage	Clinton Generation	No	NA
5	1&2	3,279	Heritage to Fredtown 161 kV	Lutesville to St. Francois 345kV	No	2,000
6	1&2	7,962	Reo to Enterprise 138kV	Eckert to Central 138kV	Yes	0
7	1&2	3,143	Lafayette 138kV bus voltage	Argenta to Battle Creek 345kV	No	NA
8	1&2	5,772	Sterlington 500/230 kV Ckt. 2	Sterlington to El Dorado 500 kV	No	1,601
9	1	3,227	Mt. Olive 500/230kV	Mt. Olive to Layfield 500kV	Yes	500
10	1&2	3,484	No Constraint Identified			

Table 3-5: 2021 Capacity Import Limits

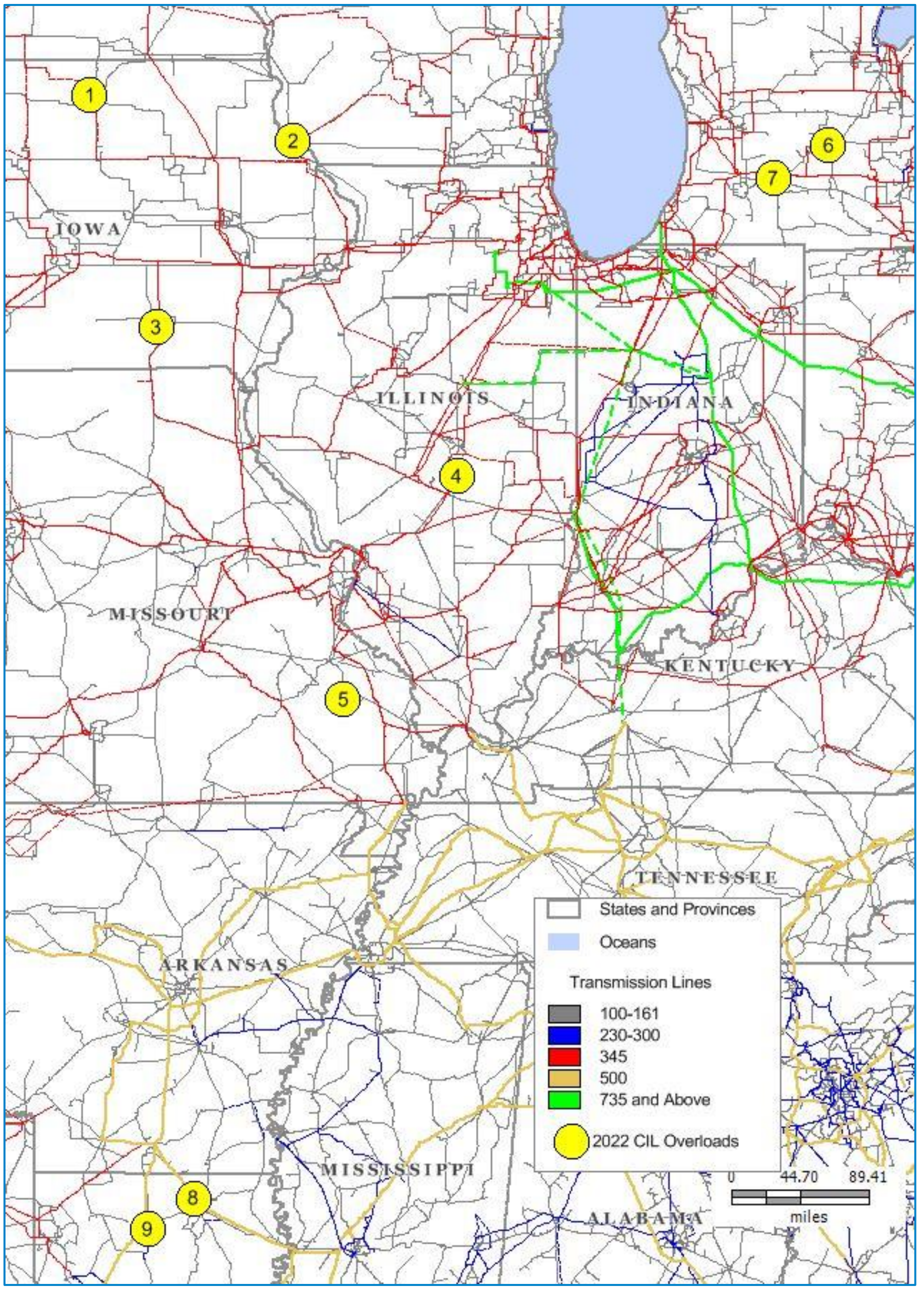


Figure 3-3: Planning Year 2021 CIL Constraint Map

Table 3-6 summarizes 2021 Capacity Export Limits.

LRZ	2021 Limit (MW)	Monitored Element	Contingent Element	GLT applied	Generation Redispatch (MW)
1	2,247	Blueeta to Huntley 161 kV	Lakefield Junction to Lakefield 345 kV	Yes	0
2	4,316	Zion Station to Waukegan 345kV	Waukegan to Zion Station 345kV	Yes	0
3	4,137	Council Bluffs to Sub 3456 345kV	Arbor Hills to Grimes 345kV	Yes	0
4	No transmission constraint identified after applying GLT process				
5	1,818	Marion Tap to Spalding 161kV	Maywood to Spencer Creek 345kV	Yes	0
6	2,764	Wilson to Matanzas 161kV	Green River to Wilson 161kV	Yes	1,743
7	1,659	Reo to Enterprise 138kV	Eckert to Central 138kV	Yes	0
8	5,070	Russellville South to Dardanelle 161 kV	Arkansas Nuclear to Ft. Smith 500 kV	Yes	671
9	2,021	White Bluff to Keo 500 kV	Sheridan to Mabelvale 500 kV	No	1,988
10	2,369	Batesville to Tallahachie 161 kV	Choctaw to Clay 500 kV	Yes	493

Table 3-6: 2021 Capacity Export Limits

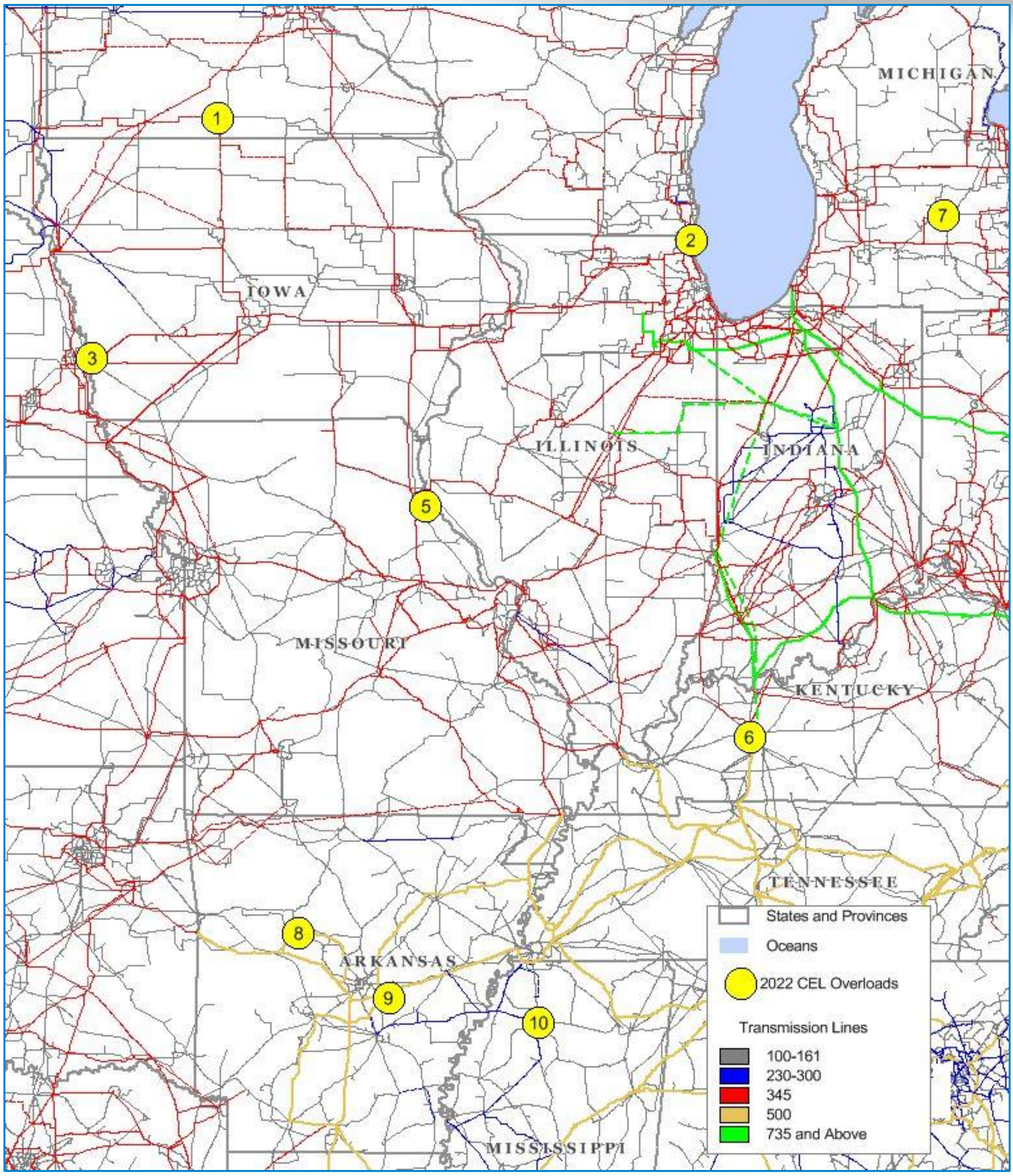


Figure 3-4: Planning Year 2021 CEL Constraint Map

4 Loss of Load Expectation Analysis

4.1 LOLE Modeling Input Data and Assumptions

MISO utilizes a program managed by Astrapé Consulting called SERVM to calculate the LOLE for the applicable planning year. SERVM uses a sequential Monte Carlo simulation to model a generation system and assess the system's reliability based on any number of interconnected areas. SERVM calculates the annual LOLE for the MISO system and each LRZ by stepping through the year chronologically and taking into account generation, load, load modifying and energy efficiency resources, equipment forced outages, planned and maintenance outages, weather and economic uncertainty, and external support.

The SERVM model build is the most time-consuming task of the PRM study. Many scenarios are built in order to determine how certain variables impact the results. The base case models determine the MISO PRM Installed Capacity (ICAP), PRM UCAP and the LRRs for each LRZ for years one, four and six.

4.2 MISO Generation

4.2.1 Thermal Units

The 2018-2019 planning year LOLE study utilized the 2017 PRA converted capacity as a starting point for which resources to include in the study. This ensured that only the resources eligible as a Planning Resource were included in the LOLE study. An exception was made for those resources in MISO's March 2017 Commercial Model that weren't part of the 2017 PRA but stated in the Organization of MISO States - MISO Survey that they would be available in 2018. These resources were also included. All internal Planning Resources were modeled in the LRZ in which they are physically located.

Forced outage rates and planned maintenance factors were calculated over a five-year period (January 2012 to December 2016) and modeled as one value for each unit. Some units did not have five years of historical data in PowerGADS, but if they had at least 12 consecutive months of data then unit-specific information was used. If a unit had less than 12 consecutive months of unit-specific data in PowerGADS, then that unit was assigned the corresponding MISO class average forced outage rate and planned maintenance factor based on its fuel type. If a particular MISO class had less than 30 units, then the overall MISO weighted class average forced outage rate of 9.16 percent was used.

Nuclear units have a fixed maintenance schedule, which was pulled from ABB PowerBase and was modeled for each of the study years.

The historical class average outage rates as well as the MISO fleet wide weighted average forced outage rate are in Table 4-1.

Pooled EFORd GADS Years	2012-2016 (%)	2011-2015 (%)	2010-2014 (%)	2009-2013 (%)	2008-2012 (%)	2007-2011 (%)
LOLE Study Planning Year	2018-2019 PY LOLE Study	2017-2018 PY LOLE Study	2016-2017 PY LOLE Study	2015-2016 PY LOLE Study	2014-2015 PY LOLE Study	2013-2014 PY LOLE Study
Combined Cycle	4.62	3.56	3.78	3.92	4.74	5.23
Combustion Turbine (0-20 MW)	29.02	24.2	23.58	18.39	27.22	22.50
Combustion Turbine (20-50 MW)	13.48	13.94	16.03	53.12	25.27	25.37
Combustion Turbine (50+ MW)	6.19	5.94	5.69	5.61	5.76	6.10
Diesel Engines	10.42	13.12	12.51	14.00	9.83	9.98
Fluidized Bed Combustion	*	*	*	**	**	**
HYDRO (0-30MW)	*	*	*	**	**	**
HYDRO (30+ MW)	*	*	*	**	**	**
Nuclear	*	*	*	**	**	**
Pumped Storage	*	*	*	**	**	**
Steam - Coal (0-100 MW)	5.14	5.99	7.12	8.45	8.82	8.58
Steam - Coal (100-200 MW)	*	*	*	6.39	6.85	6.93
Steam - Coal (200-400 MW)	9.77	8.64	8.46	8.44	8.33	8.15
Steam - Coal (400-600 MW)	*	*	7.04	6.99	6.98	7.38
Steam - Coal (600-800 MW)	7.90	7.42	7.58	7.36	**	**
Steam - Coal (800-1000 MW)	*	*	*	**	**	**
Steam - Gas	11.94	11.68	10.18	8.79	**	**
Steam - Oil	*	*	*	**	**	**
Steam - Waste Heat	*	*	*	**	**	**
Steam - Wood	*	*	*	**	**	**
MISO System Wide Weighted	9.16	8.21	7.98	7.67	7.55	7.58

*MISO system-wide weighted forced outage rate used in place of class data for those with less than 30 units reporting 12 or more months of data

**Prior to 2015-2016PY the NERC class average outage rate was used for units with less than 30 units reporting 12 or more months of data

Table 4-1: Historical Class Average Forced Outage Rates

4.2.2 Behind-the-Meter Generation

Behind-the-Meter generation data came from the Module E Capacity Tracking (MECT) tool. These resources were explicitly modeled just as any other thermal generator with a monthly capacity and forced outage rate. Performance data was pulled from the MISO Generator Availability Data System (GADS).

4.2.3 Sales

This year's LOLE analysis incorporated firm sales to neighboring capacity markets as well as firm transactions off system where information was available. For units with capacity sold off-system, the monthly capacities were reduced by the megawatt amount sold. This totaled 3,147 MW UCAP for Planning Year 2018-2019. See Section 4.4 for a more detailed breakdown. These values came from PJM's Reliability Pricing Model (RPM) as well as exports to other external areas taken from the Independent Market Monitor (IMM) exclusion list.

4.2.4 Attachment Y

For the 2018-2019 planning year, generating units that have approved suspensions or retirements (as of June 1, 2017) through MISO's Attachment Y process were removed from the LOLE analysis. Any unit retiring, suspending, or coming back online at any point during the planning year was excluded from the year-one analysis. This same methodology is used for the four- and six-year analyses.

4.2.5 Future Generation

Future thermal generation and upgrades were added based on unit information in the MISO Generator Interconnection Queue. The LOLE model included only units with a signed interconnection agreement (as of June 1, 2017). These new units were assigned class-average forced outage rates and planned maintenance factors based on their particular unit class. Units upgraded during the study period reflect the megawatt increase for each month, beginning the month the upgrade was finished. The LOLE analysis also included future wind and solar generation at the MISO capacity accreditation amount (wind at 15.6 percent and solar at 50 percent).

4.2.6 Intermittent Resources

Intermittent resources such as run-of-river hydro, biomass and wind were explicitly modeled as demand-side resources. Non-wind intermittent resources such as run-of-river hydro and biomass provide MISO with up to 15 years of historical summer output data during hours ending 15:00 EST through 17:00 EST. This data is averaged and modeled in the LOLE analysis as UCAP for all months. Each individual unit is modeled and put in the corresponding LRZ.

Each wind-generator Commercial Pricing Node (CPNode) received a capacity credit based on its historical output from MISO's top eight peak days in each past year for which data was available. The megawatt value corresponding to each CPNode's wind capacity credit was used for each month of the year. New units to the commercial model without a wind capacity credit as part of the 2017 Wind Capacity Credit analysis received the MISO-wide wind capacity credit of 15.6 percent as established by the 2017 Wind Capacity Credit Effective Load Carrying Capability (ELCC) analysis. The capacity credit established by the ELCC analysis determines the maximum percent of the wind unit that can receive credit in the PRA while the actual amount could be less due to other factors such as transmission limitations. Each wind CPNode receives its actual wind capacity credit based on the capacity eligible to participate in the PRA. Only Network Resource Interconnection Service or Energy Resource Interconnection Service with firm point-to-point is considered an eligible capacity resource. The final value from the 2017 PRA for each wind unit was modeled at a flat capacity profile for the planning year. The detailed methodology for establishing the MISO-wide and individual CPNode Wind Capacity Credits can be found in the 2017 Wind Capacity Credit Report.

4.2.7 Demand Response

Demand response data came from the MECT tool. These resources were explicitly modeled as dispatch-limited resources. Each demand response program was modeled individually with a monthly capacity and was limited to the number of times each program can be called upon as well as limited by duration.

4.3 MISO Load Data

The 2018-2019 LOLE analysis used a load training process with neural net software to create a neural-net relationship between historical weather and load data. This relationship was then applied to 30 years of hourly historical weather data in order to create 30 different load shapes for each LRZ in order to capture both load diversity and seasonal variations. The average monthly loads of the predicted load shapes were adjusted to match each LRZ's Module E 50/50 monthly zonal peak load forecasts for each study year. The results of this process are shown as the MISO System Peak Demand (Table 5-1) and LRZ Peak Demands (Table 6-1).

Prior to the 2018-2019 LOLE analysis MISO adapted the 2011 NERC bandwidth methodology to perform load forecast uncertainty (LFU) analysis and developed regression models similar to NERC. This analysis was then applied to base 50/50 load forecast to represent the various probabilistic load levels for the LOLE analysis using the GE MARS (Multi-Area Reliability Simulation) software.

With MISO switching to the SERVM software for the 2018-2019 planning year LOLE study a new methodology was adopted to capture the weather and economic uncertainties associated with LFU, as described further below. In prior analyses the 2011 NERC bandwidth methodology captured both weather and economic uncertainties, however, the new methodology allows for the decoupling of the weather and economic uncertainties.

Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load.

4.3.1 Weather Uncertainty

MISO has adopted a six step load training process in order to capture the weather uncertainty associated with the 50/50 load forecasts. The first step of this process requires the collection of five years of historical real-time load modifying resource (LMR) performance and load data, as well as the collection of 30 years of historical weather data. Both the LMR and load data are taken from the MISO market for each LBA, while the historical weather data is collected from the National Oceanic and Atmospheric Administration (NOAA) for each LRZ. After collecting the data the hourly gross load for each LRZ is calculated using the five years of historical data.

With the data collected the second step of the process is normalize the five years of load data to consistent economics. With the load growth due to economics removed from 5 years of historical LRZ load the third step of the process utilizes neural network software to establish functional relationships between the five years of historical weather and load data. In the fourth step of the process the neural network relationships are applied to the 30 years of historical weather data in order to predict/create 30 years' worth of load shapes for each LRZ.

In the fifth step of the load training process extreme temperature verification is undertaken on the 30 years of load shapes to ensure that the hourly load data is accurate at extremely hot or cold temperatures. This is required due to the fact that there are fewer data points available at the temperature extremes when determining the neural network functional relationships. This lack of data at the extremes can result in inaccurate predictions when creating load shapes, which will need to be corrected before moving forward.

The final step of the load training process is to average the monthly peak loads of the predicted load shapes and adjusted them to match each LRZ's Module E 50/50 monthly zonal peak load forecasts for each study year. In order to calculate this adjustment the ratio of the first year's non-coincident peak forecast to the zonal coincident peak forecast was applied to future year's non-coincident peak forecast.

By adopting this new methodology for capturing weather uncertainty MISO is able to model multiple load shapes based off a functional relationship with weather. This modeling approach provides a variance in load shapes, as well as the peak loads observed in each load shape. This approach also provides the ability to capture the frequency and duration of severe weather patterns.

4.3.2 Economic Load Uncertainty

In order to account for economic load uncertainty in the 2018-2019 planning year LOLE model MISO utilized a normal distribution of electric utility forecast error accounting for projected and actual Gross Domestic Product (GDP), as well as electricity usage. The historic projections for GDP growth were taken from the Congressional Budget Office (CBO), the actual GDP growth was taken from the Bureau of Economic Analysis (BEA), and the electric use was taken from the U.S. Energy Information Administration (eia). Due to lack of statewide projected GDP data MISO relied on United States aggregate level data when calculating the economic uncertainty.

In order to calculate the electric utility forecast error MISO first calculated the forecast error of GDP between the projected and actual values. The resulting GDP forecast error was then translated into electric utility forecast error by multiply by the rate at which electric load grows in comparison to the GDP. Finally a standard deviation is calculated from the electric utility forecast error and used to create a normal distribution representing the probabilities of the load forecast errors (LFE) as shown in Table 4-2.

	LFE Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability assigned to each LFE				
1.1%	8.6%	23.8%	35.1%	23.8%	8.6%

Table 4-2: Economic Uncertainty

Based off stakeholder feedback MISO completed an internal analysis comparing the "weather normalized" MISO peak demand to the LSE forecasted demand and compared it to the results of the economic uncertainty modeling used in the 2018-2019 planning year LOLE model. This internal analysis resulted in a standard deviation of 1.1 percent, which was equal to the value calculated for the 2018-2019 planning year LOLE model. MISO will continue to investigate different methods for economic load uncertainty modeling for future studies.

4.4 External System

Within the LOLE study, a 1 MW increase of non-firm support from external areas leads to a 1 MW decrease in the reserve margin calculation. It is important to account for the benefit of being part of the eastern interconnection while also providing a stable result. In order to provide a more stable result and remove the false sense of precision, the external non-firm support was set at an ICAP of 2,987 MW and a UCAP of 2,331 MW.

Firm Imports from external areas to MISO are modeled at the individual unit level. The specific external units were modeled with their specific installed capacity amount and their corresponding Equivalent Forced Outage Rate demand (EFORd). This better captures the probabilistic reliability impact of firm external imports. These units are only modeled within the MISO PRM analysis and are not modeled when calculating the LRZ LRRs. The external resources to include for firm imports were based off of the amount offered into the 2017-18 planning year PRA. This is, historically, an accurate indicator of future imports. For 2017-18 planning year this amount was 4,938 MW ICAP.

Firm exports from MISO to external areas were modeled the same as previous years. As stated in Section 4.2.3, capacity ineligible as MISO capacity due to transactions with external areas is removed from the model. Table 4-3 shows the amount of firm imports and exports in this year's study.

Contracts	ICAP (MW)	UCAP (MW)
Imports (MW)	4,938	4,764
Exports (MW)	3,457	3,147
Net	**1,481**	**1,617**

Table 4-3: 2017 Planning Year Firm Imports and Exports

4.5 Loss of Load Expectation Analysis and Metric Calculations

Upon completion of the SERVM database, MISO determined the appropriate PRM ICAP and PRM UCAP for the 2018-2019 planning year as well as the appropriate Local Reliability Requirement for each of the 10 LRZ's. These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year.

4.5.1 MISO-Wide LOLE Analysis and PRM Calculation

For the MISO-wide analysis, generating units were modeled as part of their appropriate LRZ as a subset of a larger MISO pool. The MISO system was modeled with no internal transmission limitations. In order to meet the reliability criteria of 0.1 day per year LOLE, capacity is either added or removed from the MISO pool. The minimum amount of capacity above the 50/50 net internal MISO Coincident Peak Demand required to meet the reliability criteria was used to establish the PRM values.

The minimum PRM requirement is determined using the LOLE analysis by either adding or removing capacity until the LOLE reaches 0.1 day per year. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate is added until the LOLE reaches 0.1 day per year. The perfect negative unit adjustment is akin to adding load to the model. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

For the 2018-2019 planning year, the MISO PRM analysis removed capacity (4,550 MW) using the perfect unit adjustment.

The formulas for the PRM values for the MISO system are:

PRM ICAP = ((Installed Capacity + Firm External Support ICAP + ICAP Adjustment to meet a LOLE of 0.1 days per year) – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

PRM UCAP = (Unforced Capacity + Firm External Support UCAP + UCAP Adjustment to meet a LOLE of 0.1 days per year) – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

Where Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – XEFORd)

4.5.2 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the LRZ analysis, each LRZ included only the generating units within the LRZ and was modeled without consideration of the benefit of the LRZ's CIL. Much like the MISO analysis, unforced capacity is either added or removed in each LRZ such that a LOLE of 0.1 day per year is achieved. The minimum amount of unforced capacity above each LRZ's Peak Demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

The 2018-2019 LRR is determined using the LOLE analysis by either adding or removing capacity until the LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

For the 2018-2019 planning year, only LRZ-8 had sufficient capacity, internal to the LRZ to achieve the LOLE of 0.1 day per year as an island. In the nine zones without sufficient capacity as an island, proxy units of typical size (160 MW) and class-average EFORd (6.19 percent) were added to the LRZ. When needed, a fraction of the final proxy unit was added to achieve the exact LOLE of 0.1 day per year for the LRZ.

5 MISO System Planning Reserve Margin Results

5.1 Planning Year 2018-2019 MISO Planning Reserve Margin Results

For the 2018-2019 planning year, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 17.1 percent and a planning UCAP reserve margin of 8.4 percent. These PRM values assume 4,764 MW UCAP of firm and 2,331 MW UCAP of non-firm external support. Numerous values and calculations went into determining the MISO system PRM ICAP and PRM UCAP (Table 5-1).

MISO Planning Reserve Margin (PRM)	**2018/2019 PY** (June 2018 - May 2019)	**Formula Key**
MISO System Peak Demand (MW)	125,805	[A]
Installed Capacity (ICAP) (MW)	149,901	[B]
Unforced Capacity (UCAP) (MW)	138,505	[C]
Firm External Support (ICAP) (MW)	4,938	[D]
Firm External Support (UCAP) (MW)	4,764	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-4,550	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-4,550	[G]
Non-Firm External Support (ICAP) (MW)	2,987	[H]
Non-Firm External Support (UCAP) (MW)	2,331	[I]
ICAP PRM Requirement (PRMR) (MW)	147,302	[J]=[B]+[D]+[F]-[H]
UCAP PRM Requirement (PRMR) (MW)	136,388	[K]=[C]+[E]+[G]-[I]
MISO PRM ICAP	**17.1%**	[L]=([J]-[A])/[A]
MISO PRM UCAP	**8.4%**	[M]=([K]-[A])/[A]

Table 5-1: Planning Year 2018-2019 MISO System Planning Reserve Margins

5.1.1 LOLE Results Statistics

In addition to the LOLE results SERVM has the ability to calculate several other probabilistic metrics (Table 5-2). These values are given when MISO is at its PRM UCAP of 8.4 percent. The LOLE of 0.1 day/year is what the model is driven to and how the PRM is calculated. The loss of load hours is defined as the number of hours during a given time period where system demand will exceed the generating capacity during a given period. Expected Unserved Energy (EUE) is energy-centric and analyzes all hours of a particular planning year. Results are calculated in megawatt-hours (MWh). EUE is the summation of the expected number of MWh of load that will not be served in a given planning year as a result of demand exceeding the available capacity across all hours.

MISO LOLE Statistics	
Loss of Load Expectation - LOLE [Days/Yr]	0.100
Loss of Load Hours - LOLH [hrs/yr]	0.341
Expected Unserved Energy - EUE [MWh/yr]	726.4

Table 5-2: MISO Probabilistic Model Statistics

5.2 Comparison of PRM Targets Across Eight Years

Figure 5-1 compares the PRM UCAP values over the last eight planning years. The last endpoint of the green line shows the Planning Year 2018-2019 PRM value.

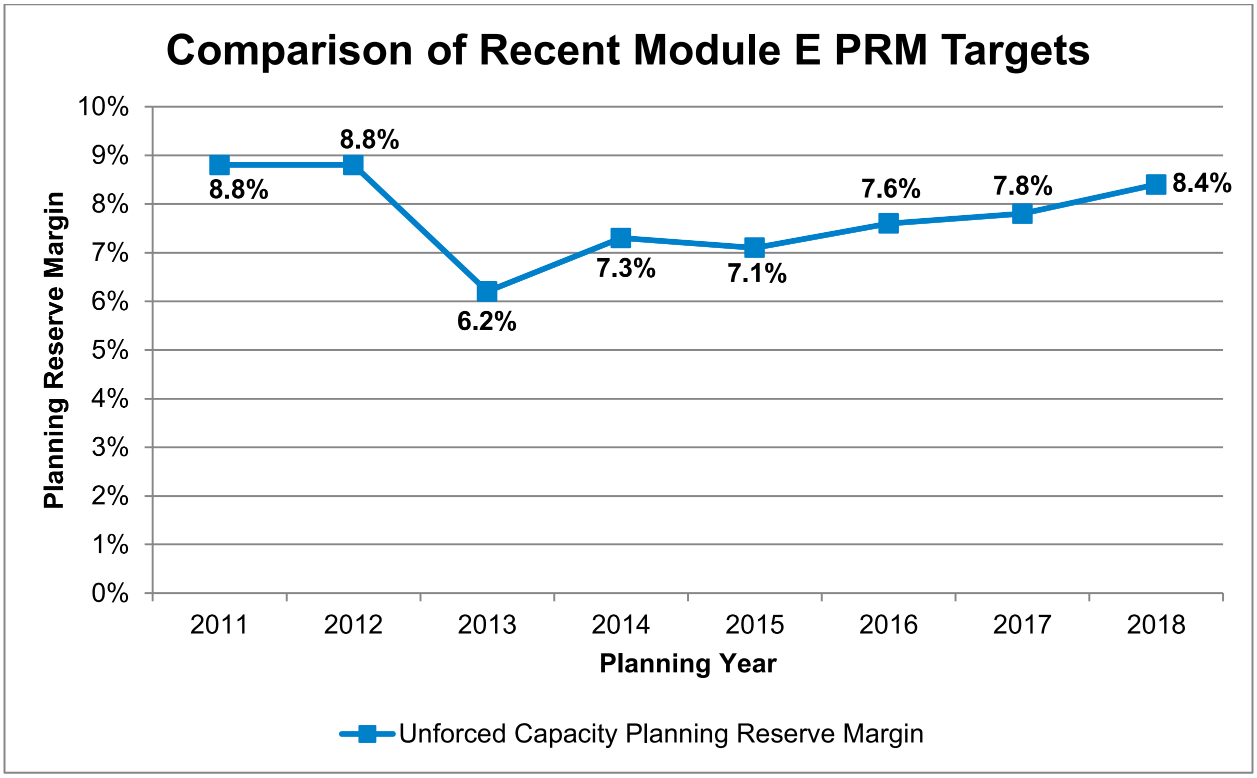


Figure 5-1: Comparison of PRM targets across eight years

5.3 Future Years 2018 through 2027 Planning Reserve Margins

Beyond the planning year 2018-2019 LOLE study analysis, an LOLE analysis was performed for the four-year-out planning year of 2021-2022, and the six-year-out planning year of 2023-2024. Table 5-3 shows all the values and calculations that went into determining the MISO system PRM ICAP and PRM UCAP values for those years. Those results are shown as the underlined values of Table 5-4. The data from the in between years is determined through interpolation of the 2018, 2021, and 2023 results. Note that the MISO system PRM results assume no limitations on transfers within MISO.

The 2021-2022 planning year PRM decreased slightly from the 2018-2019 planning year driven mainly due to changes in LSE peak loads. The forecasts for the 2023-2024 Planning Year more aligned with the 2018-2019 planning year forecasts, which drove the return to the 8.4 percent PRM UCAP.

MISO Planning Reserve Margin (PRM)	**2021/2022 PY** (June 2021 - May 2022)	**2023/2024 PY** (June 2023 - May 2024)	Formula Key
MISO System Peak Demand (MW)	127,820	129,059	[A]
Installed Capacity (ICAP) (MW)	155,611	155,661	[B]
Unforced Capacity (UCAP) (MW)	143,843	143,843	[C]
Firm External Support (ICAP) (MW)	4,960	4,960	[D]
Firm External Support (UCAP) (MW)	4,783	4,783	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-7,850	-6,450	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-7,850	-6,450	[G]
Non-Firm External Support (ICAP) (MW)	2,987	2,987	[H]
Non-Firm External Support (UCAP) (MW)	2,331	2,331	[I]
ICAP PRM Requirement (PRMR) (MW)	149,784	151,184	[J]=[B]+[D]+[F]-[H]
UCAP PRM Requirement (PRMR) (MW)	138,445	139,845	[K]=[C]+[E]+[G]-[I]
MISO PRM ICAP	**17.2%**	**17.1%**	[L]=([J]-[A])/[A]
MISO PRM UCAP	**8.3%**	**8.4%**	[M]=([K]-[A])/[A]

Table 5-3: Future Planning Year MISO System Planning Reserve Margins

Metric	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
PRM ICAP	<u>17.1%</u>	17.1%	17.2%	<u>17.2%</u>	17.2%	<u>17.1%</u>	17.2%	17.2%	17.2%	17.2%
PRM UCAP	<u>8.4%</u>	8.4%	8.3%	<u>8.3%</u>	8.4%	<u>8.4%</u>	8.3%	8.3%	8.3%	8.3%

Table 5-4: MISO System Planning Reserve Margins 2018 through 2027
(Years without underlined results indicate values that were calculated through interpolation)

6 Local Resource Zone Analysis – LRR Results

6.1 Planning Year 2018-2019 Local Resource Zone Analysis

MISO calculated the per-unit LRR of LRZ Peak Demand for years one, four and six (Table 6-1, Table 6-2, and Table 6-3). The UCAP values in Table 6-1 reflect the UCAP within each LRZ and the adjustment to UCAP values are the megawatt adjustments needed in each LRZ so that the reliability criterion of 0.1 days per year LOLE is met. The LRR is the summation of the UCAP and adjustment to UCAP megawatts. The LRR is then divided by each LRZ's Peak Demand to determine the per-unit LRR UCAP. The 2018-2019 per unit LRR UCAP values will be multiplied by the updated demand forecasts submitted for the 2018-2019 PRA to determine each LRZ's LRR.

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
2018-2019 Planning Reserve Margin (PRM) Study											
Installed Capacity (ICAP) (MW)	19,055	15,863	11,145	10,638	8,665	19,458	23,225	11,594	23,514	6,756	[A]
Unforced Capacity (UCAP) (MW)	18,095	14,892	10,613	9,481	7,751	18,165	21,196	10,991	21,674	5,657	[B]
Adjustment to UCAP {1d in 10yr} (MW)	2,326	352	202	2,326	2,411	1,782	3,349	-760	1,595	1,581	[C]
LRR (UCAP) (MW)	20,422	15,244	10,815	11,807	10,162	19,948	24,545	10,231	23,269	7,237	[D]=[B]+[C]
Peak Demand (MW)	17,789	12,858	9,391	9,709	8,199	17,443	21,296	8,072	20,649	4,859	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.8%**	**118.6%**	**115.2%**	**121.6%**	**123.9%**	**114.4%**	**115.3%**	**126.7%**	**112.7%**	**148.9%**	[F]=[D]/[E]

Table 6-1: Planning Year 2018-2019 LRZ Local Reliability Requirements

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
2021-2022 Planning Reserve Margin (PRM) Study											
Installed Capacity (ICAP) (MW)	19,926	17,045	11,498	11,892	8,665	19,618	23,381	11,594	25,298	6,756	[A]
Unforced Capacity (UCAP) (MW)	18,928	16,020	10,955	10,630	7,751	18,316	21,338	10,991	23,267	5,657	[B]
Adjustment to UCAP {1d in 10yr} (MW)	2,083	-615	131	1,365	2,420	1,984	3,133	-465	600	1,668	[C]
LRR (UCAP) (MW)	21,011	15,405	11,086	11,995	10,172	20,300	24,472	10,526	23,867	7,324	[D]=[B]+[C]
Peak Demand (MW)	18,312	12,966	9,660	9,773	8,211	17,790	21,209	8,383	21,119	4,944	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.7%**	**118.8%**	**114.8%**	**122.7%**	**123.9%**	**114.1%**	**115.4%**	**125.6%**	**113.0%**	**148.2%**	[F]=[D]/[E]

Table 6-2: Planning Year 2021-2022 LRZ Local Reliability Requirements

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
2023-2024 Planning Reserve Margin (PRM) Study											
Installed Capacity (ICAP) (MW)	19,926	17,045	11,498	11,892	8,665	19,618	23,381	11,594	25,298	6,756	[A]
Unforced Capacity (UCAP) (MW)	18,928	16,020	10,955	10,630	7,751	18,316	21,338	10,991	23,267	5,657	[B]
Adjustment to UCAP {1d in 10yr} (MW)	2,369	-523	300	1,276	2,505	2,115	3,321	-380	929	1,717	[C]
LRR (UCAP) (MW)	21,297	15,497	11,255	11,905	10,256	20,432	24,659	10,611	24,195	7,373	[D]=[B]+[C]
Peak Demand (MW)	18,584	13,054	9,813	9,694	8,286	17,921	21,384	8,483	21,440	4,998	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.6%**	**118.7%**	**114.7%**	**122.8%**	**123.8%**	**114.0%**	**115.3%**	**125.1%**	**112.9%**	**147.5%**	[F]=[D]/[E]

Table 6-3: Planning Year 2023-2024 LRZ Local Reliability Requirements

Weather Year Time of Peak Demand (ESTHE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
1987	6/13/87 16:00	6/14/87 18:00	7/30/87 17:00	7/26/87 17:00	8/2/87 18:00	8/2/87 16:00	7/20/87 16:00	8/3/87 16:00	8/20/87 17:00	7/30/87 15:00	8/2/87 16:00
1988	7/31/88 17:00	8/1/88 13:00	8/16/88 16:00	7/31/88 17:00	8/17/88 15:00	7/9/88 17:00	7/6/88 16:00	6/29/88 16:00	8/15/88 17:00	6/28/88 17:00	8/1/88 16:00
1989	7/5/89 18:00	7/9/89 18:00	7/10/89 19:00	7/10/89 17:00	7/10/89 18:00	7/11/89 16:00	7/26/89 16:00	8/27/89 15:00	12/25/89 7:00	8/27/89 16:00	7/10/89 17:00
1990	7/3/90 18:00	7/4/90 17:00	7/3/90 16:00	7/4/90 16:00	7/4/90 16:00	7/9/90 18:00	7/4/90 19:00	7/3/90 17:00	8/6/90 17:00	8/27/90 18:00	7/4/90 16:00
1991	7/16/91 18:00	7/18/91 15:00	7/20/91 17:00	7/6/91 18:00	8/3/91 16:00	7/2/91 15:00	7/20/91 14:00	7/24/91 16:00	7/13/91 17:00	8/2/91 17:00	7/19/91 16:00
1992	8/9/92 17:00	8/10/92 18:00	7/2/92 16:00	7/2/92 16:00	7/2/92 17:00	7/10/92 15:00	7/2/92 15:00	7/16/92 17:00	7/11/92 18:00	7/12/92 17:00	7/9/92 16:00
1993	7/31/93 16:00	8/27/93 14:00	8/22/93 18:00	7/27/93 18:00	7/27/93 16:00	7/25/93 17:00	7/4/93 18:00	7/31/93 16:00	7/31/93 17:00	8/20/93 17:00	8/27/93 15:00
1994	6/14/94 18:00	6/15/94 16:00	7/19/94 17:00	6/19/94 18:00	8/13/94 18:00	7/20/94 17:00	6/18/94 18:00	6/29/94 18:00	1/19/94 9:00	1/19/94 9:00	7/5/94 17:00
1995	7/13/95 18:00	7/13/95 16:00	7/13/95 17:00	7/13/95 17:00	7/13/95 17:00	7/13/95 15:00	7/13/95 17:00	8/17/95 14:00	8/16/95 16:00	8/29/95 17:00	7/13/95 17:00
1996	8/6/96 17:00	6/29/96 18:00	7/19/96 15:00	7/18/96 17:00	7/18/96 19:00	7/19/96 17:00	8/7/96 15:00	7/20/96 15:00	2/5/96 9:00	7/3/96 18:00	8/7/96 16:00
1997	7/16/97 17:00	7/16/97 17:00	7/25/97 17:00	7/18/97 15:00	7/26/97 17:00	7/26/97 16:00	7/16/97 16:00	7/27/97 15:00	7/26/97 16:00	7/23/97 16:00	7/26/97 16:00

1998	7/13/98 16:00	6/25/98 16:00	7/20/98 19:00	7/20/98 16:00	7/20/98 17:00	7/19/98 17:00	7/20/98 16:00	8/28/98 16:00	8/28/98 17:00	8/29/98 16:00	7/20/98 16:00
1999	7/25/99 15:00	7/30/99 15:00	7/30/99 17:00	7/18/99 22:00	7/30/99 17:00	7/30/99 15:00	7/30/99 14:00	7/25/99 17:00	8/14/99 18:00	8/2/99 17:00	7/30/99 16:00
2000	8/14/00 19:00	7/9/00 17:00	9/3/00 16:00	9/3/00 16:00	8/17/00 16:00	8/9/00 16:00	6/11/00 16:00	8/30/00 15:00	8/30/00 16:00	8/30/00 17:00	7/9/00 16:00
2001	8/6/01 17:00	8/9/01 18:00	7/23/01 16:00	7/23/01 16:00	8/22/01 16:00	8/8/01 16:00	8/8/01 17:00	7/11/01 16:00	1/4/01 2:00	7/30/01 15:00	7/31/01 16:00
2002	7/6/02 17:00	8/1/02 15:00	7/20/02 16:00	7/9/02 17:00	8/1/02 16:00	7/4/02 15:00	7/3/02 16:00	7/30/02 16:00	1/4/02 7:00	7/6/02 17:00	7/3/02 16:00
2003	8/24/03 17:00	8/21/03 16:00	8/24/03 17:00	7/4/03 17:00	8/21/03 18:00	7/4/03 17:00	8/21/03 16:00	7/18/03 15:00	1/24/03 8:00	7/23/03 16:00	8/21/03 16:00
2004	6/7/04 17:00	6/8/04 17:00	7/20/04 18:00	7/13/04 16:00	7/13/04 16:00	1/31/04 4:00	8/27/04 16:00	7/16/04 15:00	12/26/04 6:00	7/25/04 15:00	7/16/04 16:00
2005	7/17/05 17:00	7/24/05 16:00	7/23/05 17:00	7/24/05 17:00	7/24/05 18:00	7/25/05 17:00	7/24/05 17:00	8/21/05 18:00	7/25/05 16:00	8/21/05 15:00	7/24/05 17:00
2006	7/31/06 18:00	8/1/06 17:00	7/19/06 18:00	7/31/06 18:00	8/2/06 18:00	7/31/06 18:00	7/31/06 16:00	7/20/06 17:00	8/15/06 18:00	8/15/06 17:00	7/31/06 16:00
2007	7/26/07 15:00	8/2/07 16:00	7/18/07 15:00	8/28/07 16:00	8/15/07 18:00	8/29/07 15:00	9/25/07 14:00	8/14/07 16:00	8/16/07 15:00	8/14/07 18:00	7/9/07 17:00
2008	7/11/08 18:00	7/16/08 16:00	8/3/08 16:00	7/3/08 18:00	7/20/08 16:00	8/23/08 16:00	8/24/08 13:00	8/2/08 17:00	7/20/08 17:00	7/27/08 16:00	7/17/08 16:00
2009	6/22/09 19:00	8/9/09 15:00	8/8/09 18:00	6/25/09 18:00	8/9/09 16:00	6/26/09 15:00	8/9/09 16:00	7/11/09 18:00	7/2/09 16:00	6/28/09 16:00	8/9/09 16:00
2010	8/8/10 18:00	8/20/10 14:00	7/23/10 16:00	8/10/10 17:00	8/3/10 17:00	7/23/10 17:00	7/5/10 15:00	8/3/10 18:00	8/1/10 17:00	8/2/10 17:00	7/23/10 17:00
2011	6/7/11 18:00	7/20/11 18:00	7/20/11 16:00	7/23/11 15:00	8/31/11 17:00	7/20/11 16:00	7/20/11 18:00	8/3/11 16:00	7/2/11 17:00	7/10/11 18:00	7/20/11 16:00
2012	7/6/12 18:00	7/4/12 20:00	7/25/12 18:00	7/6/12 17:00	7/24/12 18:00	7/6/12 18:00	7/6/12 17:00	7/30/12 17:00	7/3/12 16:00	7/4/12 16:00	7/6/12 17:00
2013	7/18/13 18:00	7/17/13 16:00	9/10/13 16:00	7/19/13 17:00	8/31/13 17:00	7/17/13 17:00	9/11/13 14:00	7/10/13 17:00	8/7/13 17:00	8/8/13 16:00	7/17/13 17:00
2014	7/23/14 17:00	9/4/14 16:00	8/24/14 17:00	8/24/14 15:00	7/26/14 15:00	1/7/14 8:00	9/5/14 15:00	7/13/14 17:00	1/8/14 3:00	8/24/14 17:00	8/23/14 16:00
2015	8/14/15 16:00	8/2/15 16:00	7/13/15 15:00	9/4/15 16:00	7/13/15 17:00	9/4/15 14:00	8/2/15 17:00	8/7/15 18:00	1/8/15 9:00	8/9/15 18:00	8/2/15 16:00
2016	7/20/16 15:00	7/24/16 17:00	7/24/16 15:00	7/24/16 16:00	7/24/16 16:00	7/24/16 14:00	7/23/16 15:00	7/23/16 16:00	7/20/16 16:00	6/27/16 14:00	7/23/16 15:00

Table 6-4: Time of Peak Demand for all 30 weather years

Appendix A: Comparison of Planning Year 2017 to 2018

Multiple study sensitivity analyses were performed to compute changes in the PRM target on an UCAP basis, from the 2017-2018 planning year to the 2018-2019 planning year. These sensitivities included one-off incremental changes of input parameters to quantify how each change affected the PRM result independently. Note the impact of the incremental PRM changes from 2017 to 2018 in the waterfall chart of Figure A-1; see Section A.1 Waterfall Chart Details for an explanation.

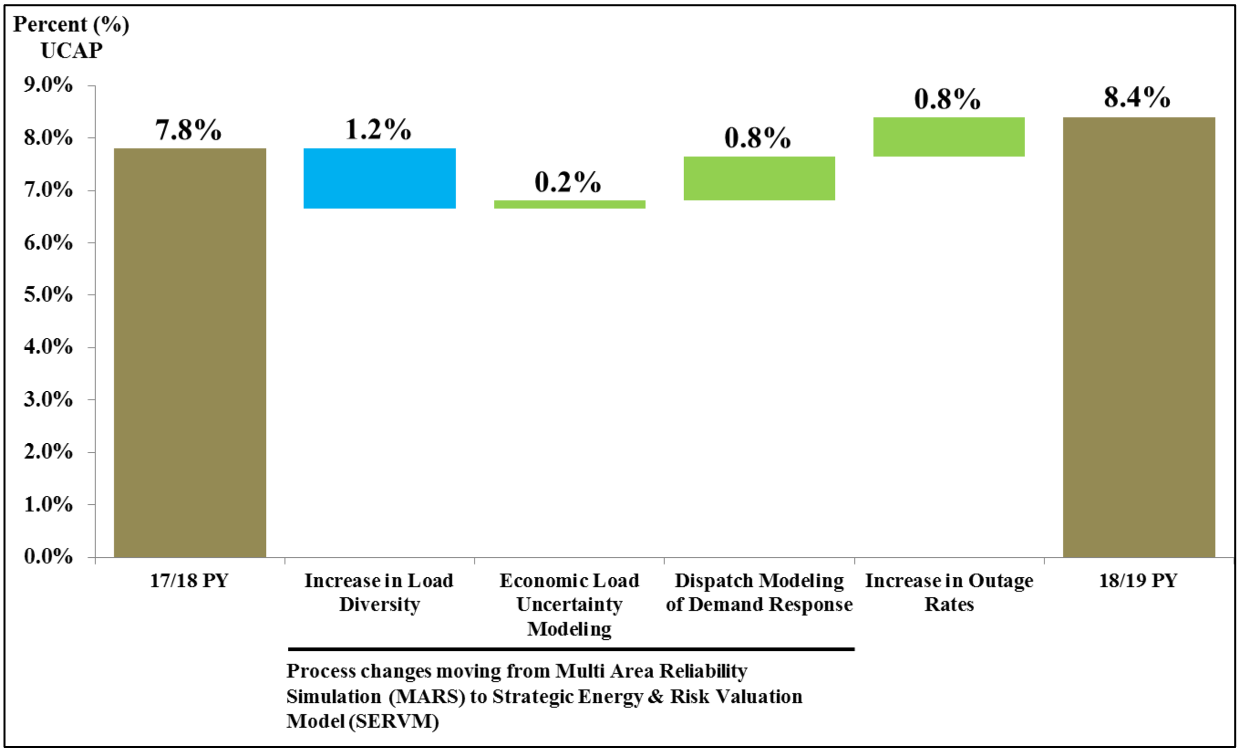


Figure A-1: Waterfall Chart of 2017 PRM UCAP to 2018 PRM UCAP

A.1 Waterfall Chart Details

A.1.1 Process changes moving from MARS to SERVM

For the 2018-2019 planning year MISO implemented several process changes when switching from MARS to the SERVM software, the impacts of which were quantified in Figure A-1.

The MISO Coincident Peak Demand decreased from the 2017-2018 planning year, which was driven by the updated actual load forecasts submitted by the LSEs. The reduction was mainly driven by reduction in anticipated load growth and changes in diversity. This reduction in demand forecasts coupled with the change in weather uncertainty detailed in Section 4.3.1 resulted in a 1.2 percentage point decrease in the PRM UCAP.

The inclusion of economic load uncertainty modeling, detailed in Section 4.3.2, in the 2018-2019 planning year resulted in a 0.2 percentage point increase in the PRM UCAP. The modeling of economic load uncertainty effectively increases the risk associated with high peak loads, thus resulting in larger adjustment to UCAP for the same MISO peak load. Upon incorporating the increased adjustment into the equations of Section 4.5.1 of the report, the mathematical calculations result in a higher PRM in percentage.

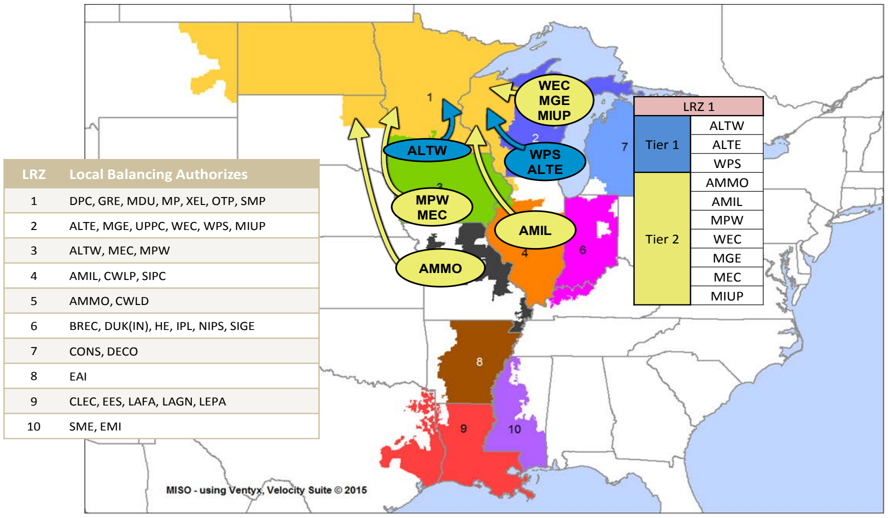
The demand response modeling, detailed in Section 4.2.7, in the 2018-2019 planning year resulted in a 0.8 percentage point increase in the PRM UCAP. Modeling demand response as dispatch limited resources, versus energy limited, decreases the available thus limiting the available capacity within the system during peak hours. This reduction of available capacity during peak loads results increases the adjustment necessary in the equations of Section 4.5.1 leading to a higher PRM in percentage.

A.1.2 Units

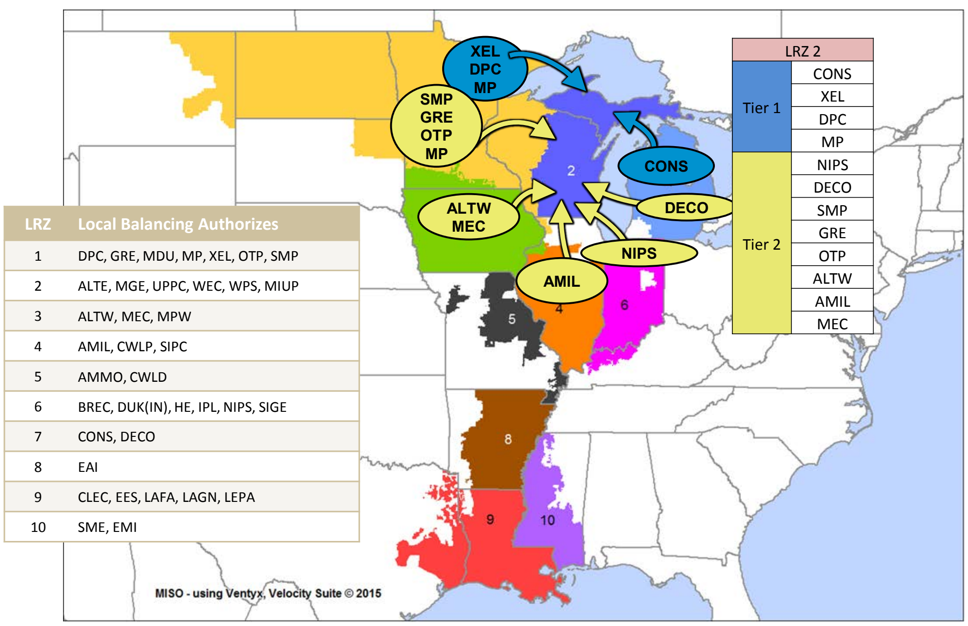
Changes from 2017-2018 planning year values are due to changes in Generation Verification Test Capacity (GVTC); EFORd or equivalent forced outage rate demand with adjustment to exclude events outside management control (XEFORd); new units; retirements; suspensions; and changes in the resource mix. The MISO fleet weighted average forced outage rate increased from 8.21 percent to 9.16 percent from the previous study to this study. An increase in unit outage rates will lead to an increase in reserve margin in order to cover the increased risk of loss of load. This change in unit risk due to outage rates and changes in resource mix resulted in a 0.8 percentage point increase in PRM UCAP.

Appendix B: Capacity Import Limit source subsystem definitions (Tiers 1 & 2)

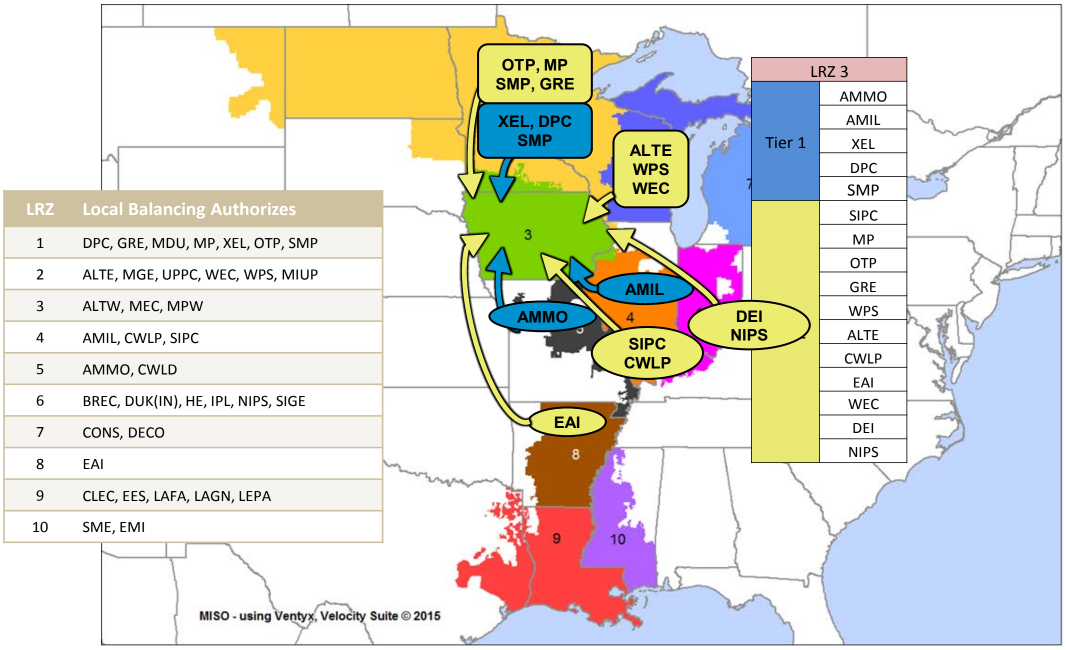
MISO Local Resource Zone 1



MISO Local Resource Zone 2



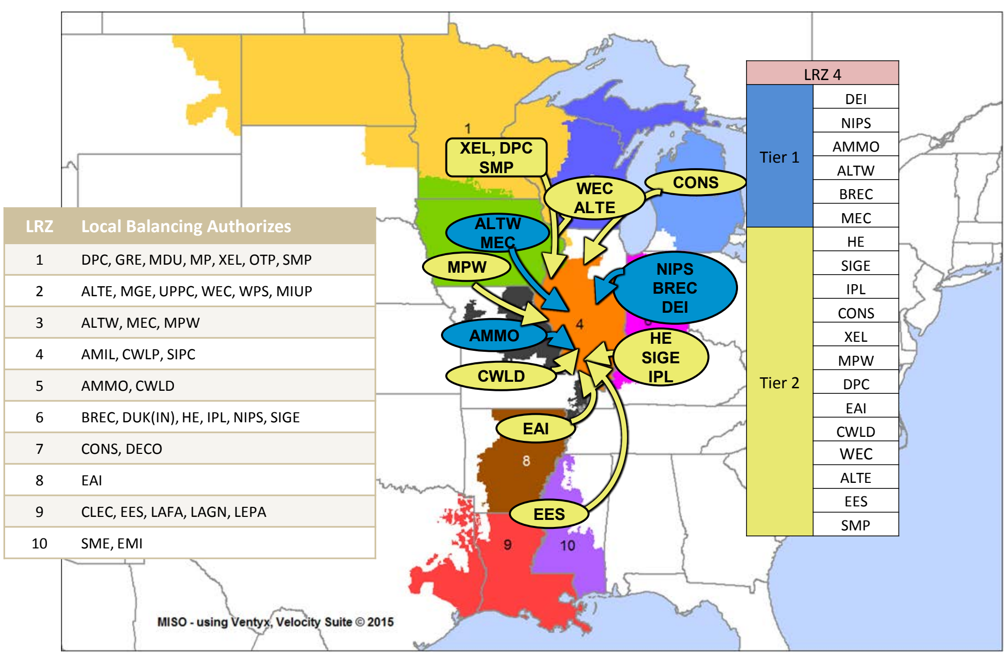
MISO Local Resource Zone 3



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

LRZ 3	
Tier 1	AMMO
	AMIL
	XEL
	DPC
	SMP
	SIPC
	MP
	OTP
	GRE
	WPS
	ALTE
	CWLP
	EAI
	WEC
	DEI
	NIPS

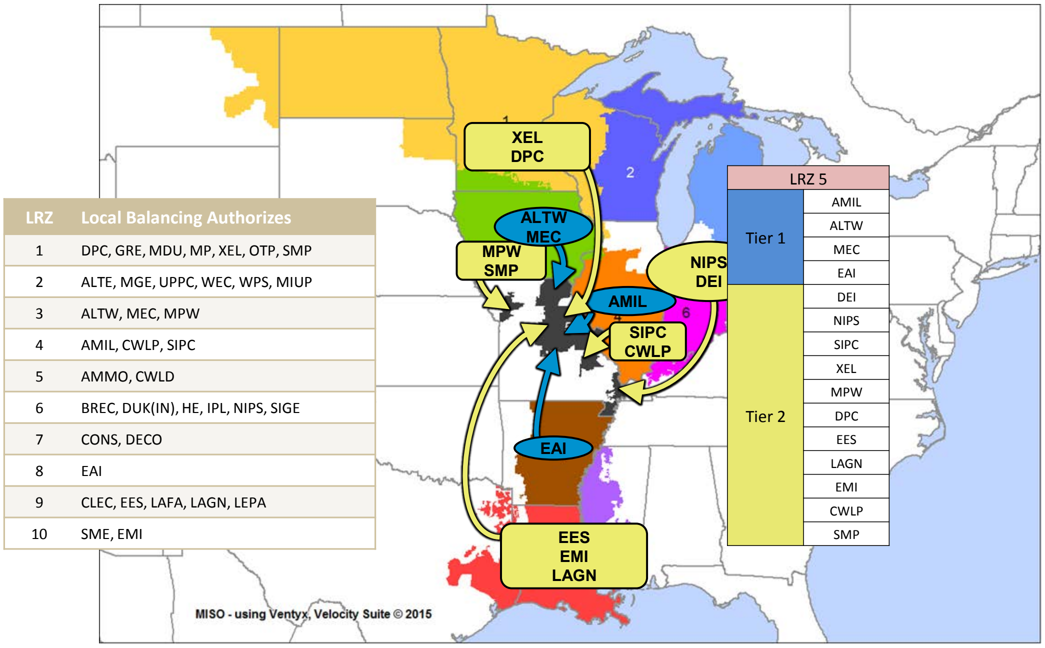
MISO Local Resource Zone 4



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

LRZ 4	
Tier 1	DEI
	NIPS
	AMMO
	ALTW
	BREC
	MEC
Tier 2	HE
	SIGE
	IPL
	CONS
	XEL
	MPW
	DPC
	EAI
	CWLD
	WEC
	ALTE
	EES
	SMP

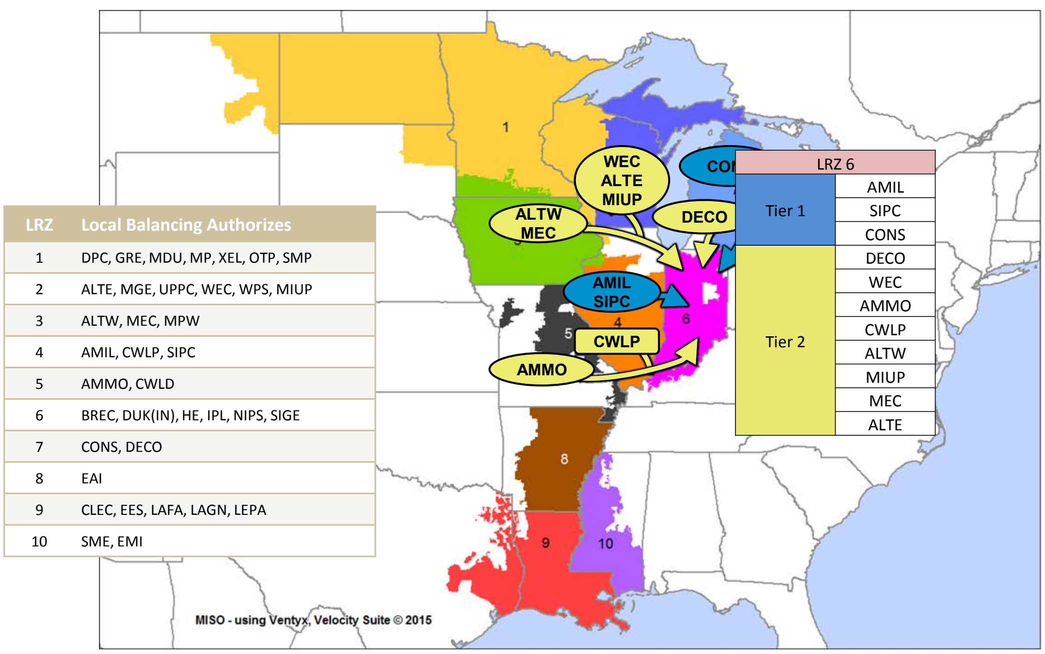
MISO Local Resource Zone 5



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

LRZ 5	
Tier 1	AMIL
	ALTW
	MEC
	EAI
Tier 2	DEI
	NIPS
	SIPC
	XEL
	MPW
	DPC
	EES
	LAGN
	EMI
	CWLP
	SMP

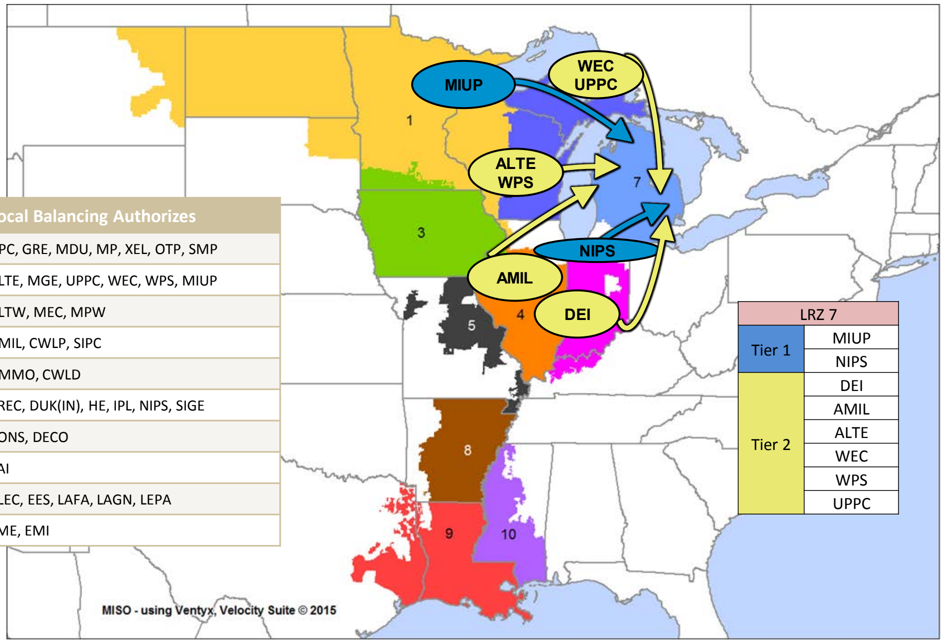
MISO Local Resource Zone 6



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

LRZ 6	
Tier 1	AMIL
	SIPC
	CONS
Tier 2	DECO
	WEC
	AMMO
	CWLP
	ALTW
	MIUP
	MEC
	ALTE

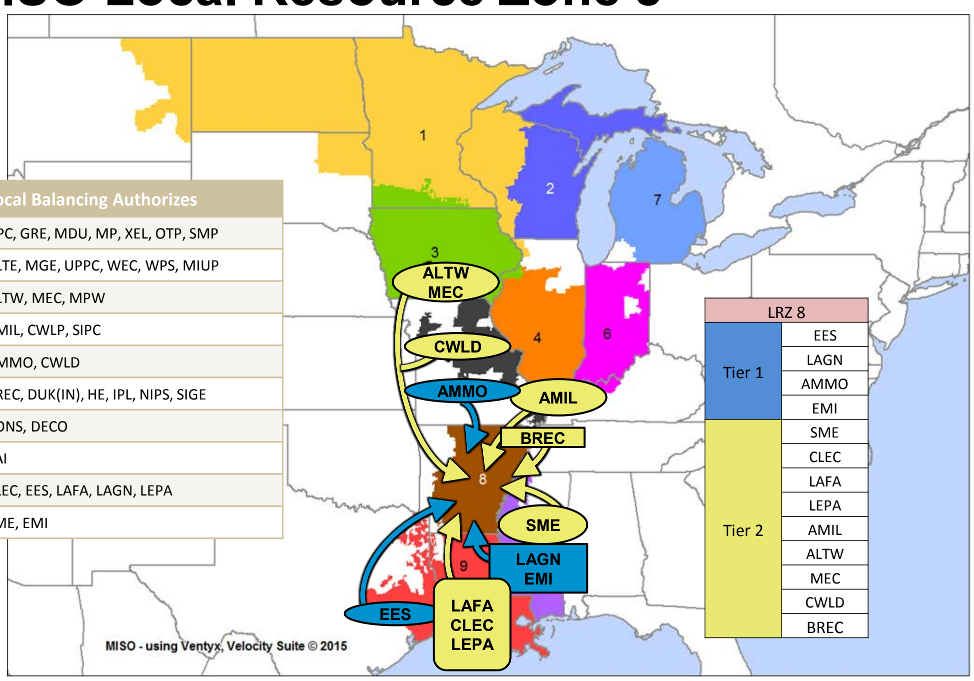
MISO Local Resource Zone 7



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

LRZ 7	
Tier 1	MIUP
	NIPS
Tier 2	DEI
	AMIL
	ALTE
	WEC
	WPS
	UPPC

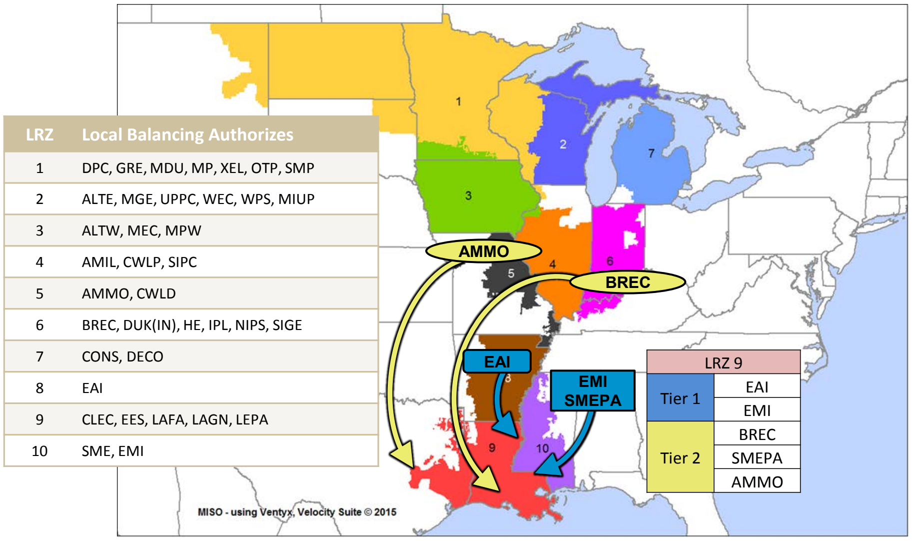
MISO Local Resource Zone 8



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

LRZ 8	
Tier 1	EES
	LAGN
	AMMO
	EMI
Tier 2	SME
	CLEC
	LAFA
	LEPA
	AMIL
	ALTW
	MEC
	CWLD
	BREC

MISO Local Resource Zone 9

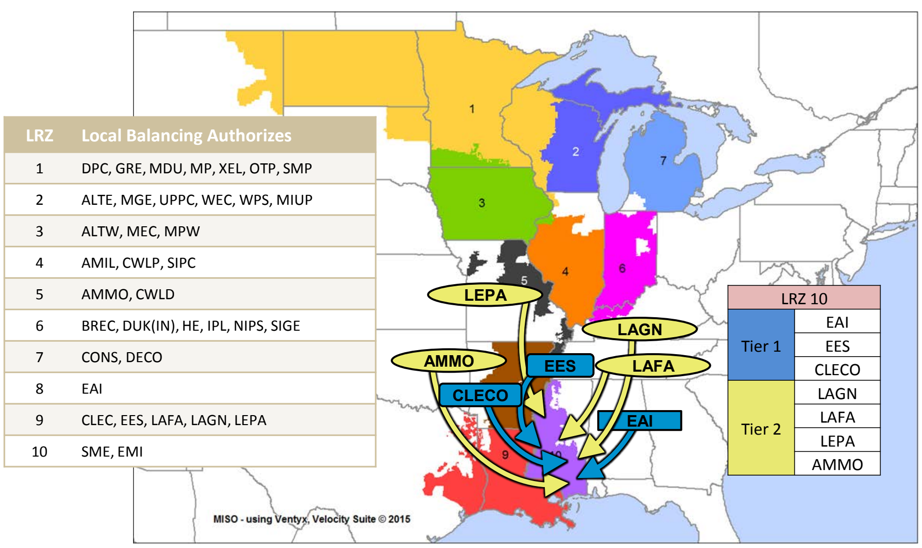


LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

LRZ 9	
Tier 1	EAI
	EMI
Tier 2	BREC
	SMEPA
	AMMO

* BRAZ, DERS, EES-EMI, and BCA now modeled in EES power flow area

MISO Local Resource Zone 10



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	SME, EMI

LRZ 10	
Tier 1	EAI
	EES
	CLECO
Tier 2	LAGN
	LAFA
	LEPA
	AMMO

Appendix C: Compliance Conformance Table

Requirements under: Standard BAL-502-RF-03	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2018 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2018 through May 2019 and beyond. Analysis of Planning Year 2018 is in Sections 5.1 and 6.1 Analysis of Future Years 2019-2027 is in Sections 5.3 and 6.1
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).	Section 4.5 of this report outlines the utilization of LOLE in the reserve margin determination. "These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year."
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 4.3 of this report. "Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 4.5.1 of this report. "The minimum amount of capacity above the 50/50 net internal MISO Coincident Peak Demand required to meet the reliability criteria was used to establish the PRM values."
R1.2 Be performed or verified separately for each of the following planning years.	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In Sections 5.1 and 6.1, a full analysis was performed for planning year 2017.
R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.	Sections 5.3 and 6.1 show a full analysis was performed for future planning years 2021 and 2023.
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.	Analysis was performed.
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.

R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts). • Load diversity. • Seasonal Load variations. • Daily demand modeling assumptions (firm, interruptible). • Contractual arrangements concerning curtailable/Interruptible Demand.	Median forecasted load – In Section 4.3 of this report: "The average monthly loads of the predicted load shapes were adjusted to match each LRZ's Module E 50/50 monthly zonal peak load forecasts for each study year." Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties are given in Sections 4.3.1 and 4.3.2. Load Diversity/Seasonal Load Variations — In Section 4.3 of this report: "For the 2018-2019 LOLE analysis, a load training process utilizing neural net software was used to create a neural-net relationship between historical weather and load data. This relationship was then applied to 30 years of hourly historical weather data in order to create 30 different load shapes for each LRZ in order to capture both load diversity and seasonal variations." Demand Modeling Assumptions/Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E. As stated in Section 4.2.7: "Each demand response program was modeled individually with a monthly capacity and was limited to the number of times each program can be called upon as well as limited by duration."
R1.3.2 Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area. • Resource planned outage schedules, deratings, and retirements. • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration. • Criteria for including planned resource additions in the analysis.	Section 4.2 details how historic performance data and seasonal ratings are gathered, and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in Section 4.4.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves	Section 3 of this report details the transfer analysis to capture transmission limitations that prevent the delivery of generation reserves. The results from this analysis are shown in Section 3.3 and represent known prompt (1 year) and out year (4 year) constraints. Previous LOLE study results captured other interim deliverability constraints.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Inclusion of the planned transmission addition assumptions is detailed in Section 3.2.3.
R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 4.4 provides the analysis on the treatment of external support assistance and limitations.

R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel. • Common mode outages that affect resource availability. • Environmental or regulatory restrictions of resource availability. • Any other demand (Load) response programs not included in R1.3.1. • Sensitivity to resource outage rates. • Impacts of extreme weather/drought conditions that affect unit availability. • Modeling assumptions for emergency operation procedures used to make reserves available. • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.	Fuel availability, environmental restrictions, common mode outage and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 4.2. The use of demand response programs are mentioned in Section 4.2. The effects of resource outage characteristics on the reserve margin are outlined in Section 4.5.2 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 3 treats worst-case theoretical outages by Perform First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category P0 (system intact) and Category P1 (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis	MISO internal resources are among the quantities documented in the tables provided in Sections 5 and 6.
R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis	MISO load is among the quantities documented in the tables provided in Sections 5 and 6.
R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.	In Sections 5 and 6, the peak load and estimated amount of resources for planning years 2018, 2021, and 2023 are shown. This includes the detail for each transmission constrained sub-area.
R2.1 This documentation shall cover each of the years in Year One through ten.	Section 5.3 and Table 5-4 shows the three calculated years, and in-between years estimated by interpolation. Estimated transmission limitations may be determined through a review of the 2018 LOLE study CIL and CEL values shown in Section 3 of this report, along with the results from previous LOLE studies.
R2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	Section 5.3 and Table 5-4 shows the three calculated years underlined.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.	The 2018 LOLE Study Report documentation is posted on November 1 prior to the planning year.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2.	In Sections 5 and 6, the difference between the needed amount and the projected planning reserves for planning years 2018, 2021, and 2023 are shown the adjustments to ICAP and UCAP in Table 5-1, Table 5-3, Table 6-1, Table 6-2, and Table 6-3.

Appendix D: Acronyms List Table

CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
DF	Distribution Factor
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GADS	Generator Availability Data System
GLT	Generation Limited Transfer
GVTC	Generation Verification Test Capacity
ICAP	Installed Capacity
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFE	Load Forecast Error
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt hours
NERC	North American Electric Reliability Corp.
PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRM ICAP	PRM Installed Capacity
PRM UCAP	PRM Unforced Capacity

PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
RCF	Reciprocal Coordinating Flowgate
RPM	Reliability Pricing Model
SERVM	Strategic Energy & Risk Valuation Model
SPS	Special Protection Scheme
TARA	Transmission Adequacy and Reliability Assessment
UCAP	Unforced Capacity
XEFORd	Equivalent forced outage rate demand with adjustment to exclude events outside management control

MISO

Near Term LOLE Results

LOLEWG

10/10/2017

2018 LOLE Study Results

- Current Planning Reserve Margin analysis results for 2018-2019 Planning Year:
  - 8.4% PRM UCAP
  - 17.1% PRM ICAP
- Increase in forced outage rates and reduction in load forecasts driving increase in PRM

MISO

MISO Planning Reserve Margin

MISO Planning Reserve Margin (PRM)	2018/2019 PY	Formula Key
MISO System Peak Demand (MW)	125,805	[A]
Installed Capacity (ICAP) (MW)	149,901	[B]
Unforced Capacity (UCAP) (MW)	138,505	[C]
Firm External Support ICAP (MW)	4,938	[D]
Firm External Support UCAP (MW)	4,764	[E]
Adjustment to ICAP {1d in 10yr} (MW)	(4,550)	[F]
Adjustment to UCAP {1d in 10yr} (MW)	(4,550)	[G]
ICAP PRM Requirement (PRMR) (MW)	150,289	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	138,719	[I] = [C]+[E]+[G]
MISO PRM ICAP	19.5%	[J]=[H]-[A]/[A]
MISO PRM UCAP	10.3%	[K]=[I]-[A]/[A]
Post-Processing accounting for non-firm external support		
External Non-Firm Support ICAP (MW)	2,987	[L]
External Non-Firm Support UCAP (MW)	2,331	[M]
With External Support ICAP PRM Requirement (MW)	147,302	[N]=[B]+[D]+[F]-[L]
With External Support UCAP PRM Requirement (MW)	136,388	[O]=[C]+[E]+[G]-[M]
With External Support MISO PRM ICAP	17.1%	[P]=([N]-[A])/[A]
With External Support MISO PRM UCAP	8.4%	[Q]=([O]-[A])/[A]

Local Resource Zone Results

Local Resource Zone (LRZ)	**LRZ-1 MN/ND**	**LRZ-2 WI**	**LRZ-3 IA**	**LRZ-4 IL**	**LRZ-5 MO**	**LRZ-6 IN**	**LRZ-7 MI**	**LRZ-8 AR**	**LRZ-9 LA/TX**	**LRZ-10 MS**	**Formula Key**
2018-2019 Planning Reserve Margin (PRM) Study											
Installed Capacity (ICAP) (MW)	19,055	15,863	11,145	10,638	8,665	19,458	23,225	11,594	23,514	6,756	[A]
Unforced Capacity (UCAP) (MW)	18,095	14,892	10,613	9,481	7,751	18,165	21,196	10,991	21,674	5,657	[B]
Adjustment to UCAP {1d in 10yr} (MW)	2,326	352	202	2,326	2,411	1,782	3,349	-760	1,595	1,581	[C]
Local Reliability Requirement (LRR) UCAP (MW)	20,422	15,244	10,815	11,807	10,162	19,948	24,545	10,231	23,269	7,237	[D]=[B]+[C]
Peak Demand (MW)	17,789	12,858	9,391	9,709	8,199	17,443	21,296	8,072	20,649	4,859	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.8%**	**118.6%**	**115.2%**	**121.6%**	**123.9%**	**114.4%**	**115.3%**	**126.7%**	**112.7%**	**148.9%**	[F]=[D]/[E]
Capacity Import Limit (CIL) (MW)	4,546	2,317	2,812	6,278	3,580	7,375	3,785	4,778	3,679	2,618	[G]
Capacity Export Limit (CEL) (MW)	516	2,017	5,430	4,280	2,122	3,249	2,578	2,424	2,149	1,824	[H]

Potential 2018-2019 Planning Resource Auction - Pending Updated Demand Forecasts and Exports											
LRZ Peak Demand (MW)	17,789	12,858	9,391	9,709	8,199	17,443	21,296	8,072	20,649	4,859	[I]
Forecasted LRZ Load at MISO Peak (MW)	16,931	12,731	9,034	9,364	7,989	17,039	20,973	7,592	19,624	4,530	[J]
Local Reliability Requirement (LRR) UCAP (MW)	20,422	15,244	10,815	11,807	10,162	19,948	24,545	10,231	23,269	7,237	[K]=[F]x[I]
Forecasted Non-Pseudo Tied Exports (UCAP) (MW)	522	0	516	146	0	238	0	388	325	418	[L]
Local Clearing Requirement (LCR) (MW)	15,354	12,927	7,487	5,383	6,582	12,334	20,760	5,065	19,265	4,201	[M]=[K]-[L]-[G]
Zone's System Wide PRMR (MW)	18,353	13,801	9,793	10,151	8,660	18,470	22,734	8,229	21,272	4,910	[N]=[1.084]X[J]
PRMR (MW)	18,353	13,801	9,793	10,151	8,660	18,470	22,734	8,229	21,272	4,910	[O]= Higher of [M] or [N]
PRM (%)	8.4%	8.4%	8.4%	8.4%	8.4%	8.4%	8.4%	8.4%	8.4%	8.4%	[P]=[O]/[J]-1

MISO

Questions?

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Appendix

LOLE Terms and Definitions

- **Firm External Support:** Represents the external resources offered into 2017-18 planning year PRA and are modeled at the individual unit level.
- **External Non-Firm Support:** Represents the benefit of being part of the Eastern Interconnection, where 1 MW increase of no-firm support reduces requirement by 1MW.
- **Peak Demand:** The zone's annual peak demand including transmission losses.
- The full list of LOLE terms and definitions can be found in the 2017 LOLE Fundamentals slide deck

MISO

Out Year 2021 LOLE Results

LOLEWG

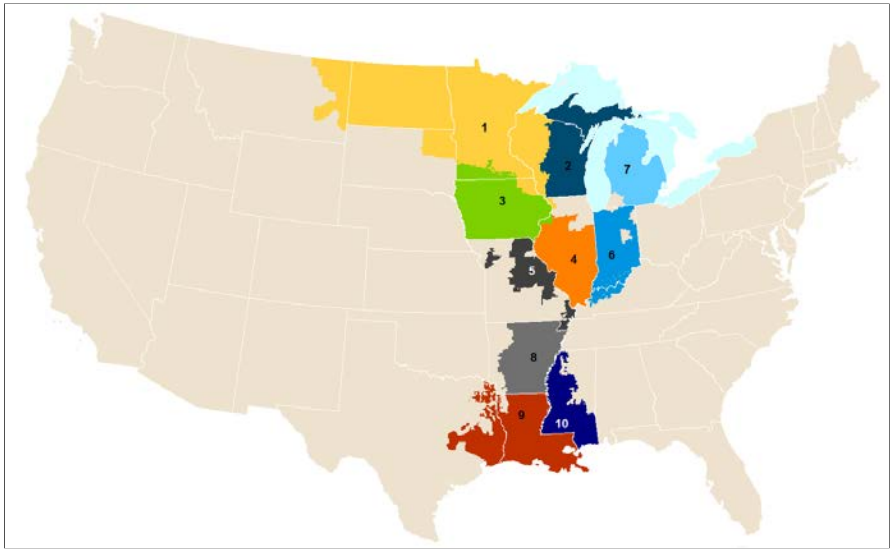
October 10, 2017

Purpose and Key Takeaways

- Purpose
  - Inform stakeholders of 2021 LOLE results, with a focus on CIL and CEL revisions
- Key Takeaways
  - The PRM for the 2018-2019 Planning Year is 8.4% UCAP
  - CIL and CEL values were updated based on stakeholder feedback
    - Values updated for zones 1, 2, 8, 9, & 10
  - Final values will be included in the LOLE report

2021 Capacity Import Limits

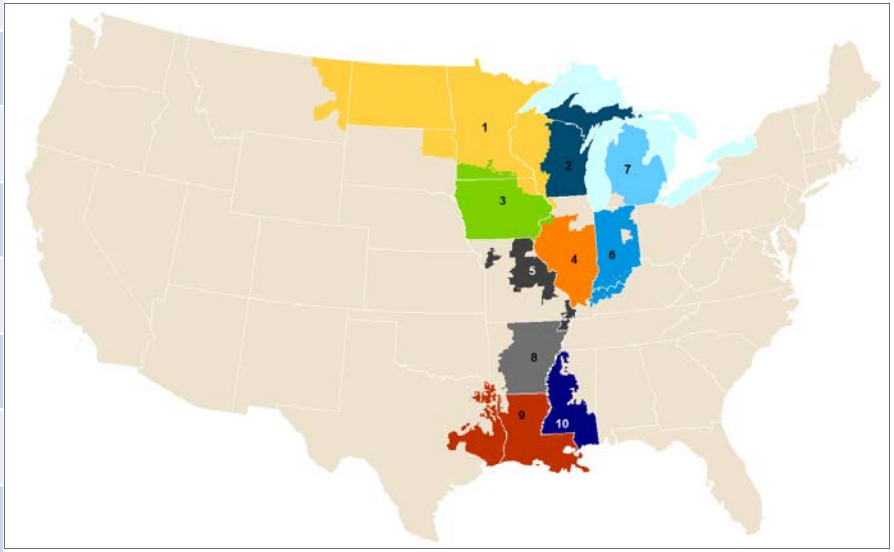
Zone	2021 Limit[1] (MW)	18-19 Limit[1] (MW)
1	5,166	4,546
2	2,495	2,317
3	3,319	2,812
4[2]	6,391	6,278
5	3,279	3,580
6	7,962	7,375
7[2]	3,143	3,785
8	5,772	4,778
9	3,227	3,679
10[3]	3,484	2618



[1] Limits after applying changes due to December 31, 2015 FERC Order on exports
[2] Denotes voltage limited transfers
[3] A Voltage Limited Transfer will be investigated for LRZ 10 in the next LOLE Cycle

2021 Capacity Export Limits

Zone	2021 Limit (MW)	18-19 Limit (MW)
1	2,247	516
2	4,316	2,017
3	4,137	5,430
4	Not Found[1]	4,280
5	1,818	2,122
6	2,764	3,249
7	1,659	2,578
8	5070	2,424
9	2,021	2,149
10	2,369	1,824



[1]No transmission limits identified for LRZs 4 after applying GLT process

MISO Planning Reserve Margin

MISO Planning Reserve Margin (PRM)	2021/2022 PY	Formula Key
MISO System Peak Demand (MW)	127,820	[A]
Installed Capacity (ICAP) (MW)	155,661	[B]
Unforced Capacity (UCAP) (MW)	143,843	[C]
Firm External Support ICAP (MW)	4,960	[D]
Firm External Support UCAP (MW)	4,783	[E]
Adjustment to ICAP (MW)	(7,850)	[F]
Adjustment to UCAP (MW)	(7,850)	[G]
ICAP PRM Requirement (PRMR) (MW)	152,771	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	140,776	[I] = [C]+[E]+[G]
MISO PRM ICAP	19.5%	[J]=[H]-[A]/[A]
MISO PRM UCAP	10.1%	[K]=[I]-[A]/[A]
External Non-Firm Support ICAP (MW)	2,987	[L]
External Non-Firm Support UCAP (MW)	2,331	[M]
With External Support ICAP PRM Requirement (MW)	149,784	[N]=[B]+[D]+[F]-[L]
With External Support UCAP PRM Requirement (MW)	138,445	[O]=[C]+[E]+[G]-[M]
With External Support MISO PRM ICAP	17.2%	[P]=([N]-[A])/[A]
With External Support MISO PRM UCAP	8.3%	[Q]=([O]-[A])/[A]

Local Resource Zone Results

Local Resource Zone (LRZ)	**LRZ-1 MN/ND**	**LRZ-2 WI**	**LRZ-3 IA**	**LRZ-4 IL**	**LRZ-5 MO**	**LRZ-6 IN**	**LRZ-7 MI**	**LRZ-8 AR**	**LRZ-9 LA/TX**	**LRZ-10 MS**	**Formula Key**
2021-2022 Planning Year											
Installed Capacity (ICAP) (MW)	19,926	17,045	11,498	11,892	8,665	19,618	23,381	11,594	25,298	6,756	[A]
Unforced Capacity (UCAP) (MW)	18,928	16,020	10,955	10,630	7,751	18,316	21,338	10,991	23,267	5,657	[B]
Adjustment to UCAP {1d in 10yr} (MW)	2,083	-615	131	1,365	2,420	1,984	3,133	-465	600	1,668	[C]
Local Reliability Requirement (LRR) UCAP (MW)	21,011	15,405	11,086	11,995	10,172	20,300	24,472	10,526	23,867	7,324	[D]=[B]+[C]
Peak Demand (MW)	18,312	12,966	9,660	9,773	8,211	17,790	21,209	8,383	21,119	4,944	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.7%**	**118.8%**	**114.8%**	**122.7%**	**123.9%**	**114.1%**	**115.4%**	**125.6%**	**113.0%**	**148.2%**	[F]=[D]/[E]
Capacity Import Limit (CIL) (MW)	5,166	2,495	3,319	6,391	3,279	7,962	3,143	5,772	3,227	3,484	[G]
Capacity Export Limit (CEL) (MW)	2,247	4,316	4,137	-1	1,818	2,764	1,659	5,070	2,021	2,369	[H]

Potential 2021-2022 Planning Resource Auction - Pending Updated Demand Forecasts and Exports											
LRZ Peak Demand (MW)	18,312	12,966	9,660	9,773	8,211	17,790	21,209	8,383	21,119	4,944	[I]
Forecasted LRZ Load at MISO Peak (MW)	17,414	12,837	9,286	9,425	8,000	17,371	20,886	7,873	20,060	4,607	[J]
Local Reliability Requirement (LRR) UCAP (MW)	21,011	15,405	11,086	11,995	10,172	20,300	24,472	10,526	23,867	7,324	[K]=[F]x[I]
***Forecasted Non-Pseudo Tied Exports** (UCAP) (MW)	522	0	516	146	0	238	0	388	325	418	[L]
Local Clearing Requirement (LCR) (MW)	15,323	12,910	7,251	5,458	6,893	12,100	21,329	4,366	20,315	3,422	[M]=[K]-[L]-[G]
Zone's System Wide PRMR (MW)	18,860	13,903	10,057	10,207	8,664	18,813	22,620	8,526	21,726	4,989	[N]=[1.083]X[J]
PRMR (MW)	18,860	13,903	10,057	10,207	8,664	18,813	22,620	8,526	21,726	4,989	[O]= Higher of [M] or [N]
PRM (%)	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	[P]=[O]/[J]-1

[1]No transmission limits identified for LRZs 4 after applying GLT process

*Non-pseudo tied exports assumed constant with near term

Appendix

2021 CIL Constraints

Zone	18-19 Limit (MW)	Monitored Element	Contingent Element	Redispatch MW	GLT applied
1	5,166	Colby to Northern Iowa Wind 161kV	Adams to Mitchell County 345kV	1,129	No
2	2,495	Stoneman to Nelson Dewey 161kV	Seneca to Genoa Op-Guide Contingency161 kV	1,926	No
3	3,319	Ottumwa 345/161kV	Ottumwa Generation Unit 1	1,625	No
4	6,391	North Decatur West Bus 138kV voltage	Clinton Generation	NA	No
5	3,279	Heritage to Fredtown 161 kV	Lutesville to St. Francois 345kV	2,000	No
6	7,962	Reo to Enterprise 138kV	Eckert to Central 138kV	0	Yes
7	3,143	Lafayette 138kV bus voltage	Argenta to Battle Creek 345kV	NA	No
8	5,772	Sterlington 500/230 kV Ckt. 2	Sterlington to El Dorado 500 kV	1,601	No
9	3,227	Mt. Olive 500/230kV	Mt. Olive to Layfield 500kV	500	Yes
10*	3,484	No Constraint Found			

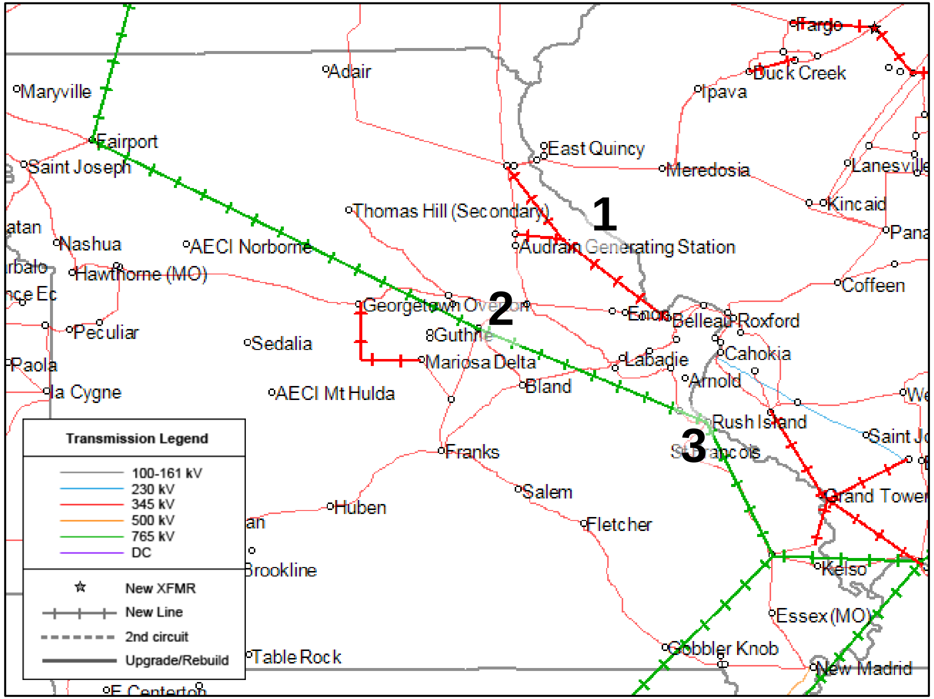
* A Voltage Limited Transfer will be investigated for LRZ 10 in the next LOLE Cycle

2021 CEL Constraints

Zone	2021 Limit (MW)	Monitored Element	Contingent Element	Redispatch MW	GLT applied
1	2,247	Blueeta to Huntley 161 kV	Lakefield Junction to Lakefield 345 kV	0	Yes
2	4,316	Zion Station to Waukegan 345kV	Waukegan to Zion Station 345kV	0	Yes
3	4,137	Council Bluffs to Sub 3456 345kV	Arbor Hills to Grimes 345kV	0	Yes
4	No transmission constraint identified after applying GLT process				
5	1,818	Marion Tap to Spalding 161kV	Maywood to Spencer Creek 345kV	0	Yes
6	2,764	Wilson to Matanzas 161kV	Green River to Wilson 161kV	1,743	Yes
7	1,659	Reo to Enterprise 138kV	Eckert to Central 138kV	0	Yes
8	5,070	Russellville South to Dardanelle 161 kV	Arkansas Nuclear to Ft. Smith 500 kV	671	Yes
9	2,021	White Bluff to Keo 500 kV	Sheridan to Mabelvale 500 kV	1,988	No
10	2,369	Batesville to Tallahachie 161 kV	Choctaw to Clay 500 kV	493	Yes

Central and East Region

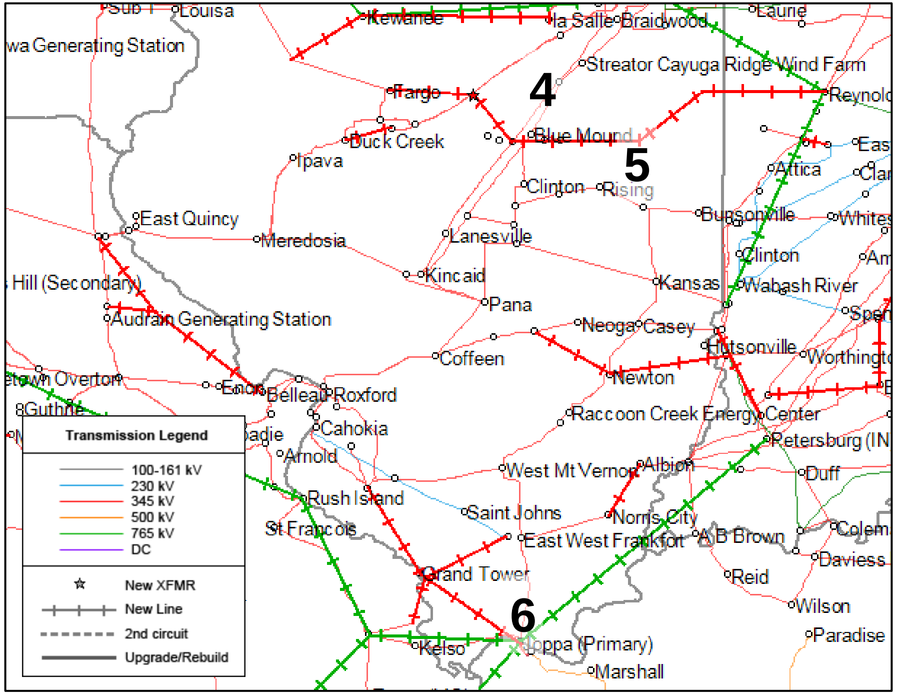
AAT Overlay Updates Central/East Region (1/4)



1 Modified to be Maywood – Pike – Belleau 345 kV and Spencer Creek – Pike 345 kV address R51: Maywood – Spencer Creek 345 kV, E15: Palmyra 345/161 kV XFMR, and Hannibal – Palmyra 161 kV without causing additional issues, and helps strengthen system for the loss of new nearby 765kV lines

2/3 Moved 765 kV terminal points from Montgomery and St Francois to Callaway and Rush Island, as these substations tend to have more outlet capability and/or cause less harm to the underlying 345 kV system if the new nearby 765 kV lines are outaged

AAT Overlay Updates Central/East Region(2/4)

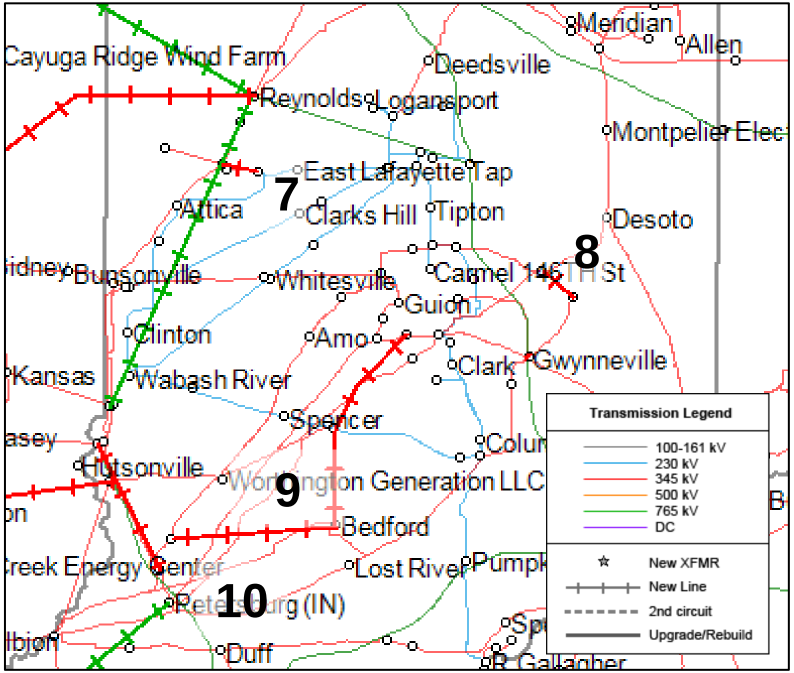


4 Removed Fargo – Eureka – Brokaw 345 kV to lessen pressure at Brokaw, leading to less congestion on Brokaw – North Leroy 138 kV

5 Tapped Paxton in between Brokaw – Sheldon South 345 kV, continues to fully relieve E24: Goodland – Reynolds 138 kV and provide a high-voltage path from IL to IN

6 Added 345/161 kV XFMR at Joppa as C18, C75, and R35 all add additional high-voltage connections at Joppa. Also, tapped E W Frankfort – Shawnee 345 kV at Joppa to help address R52 and R332: Joppa – related reliability issues

AAT Overlay Updates Central/East Region(3/4)



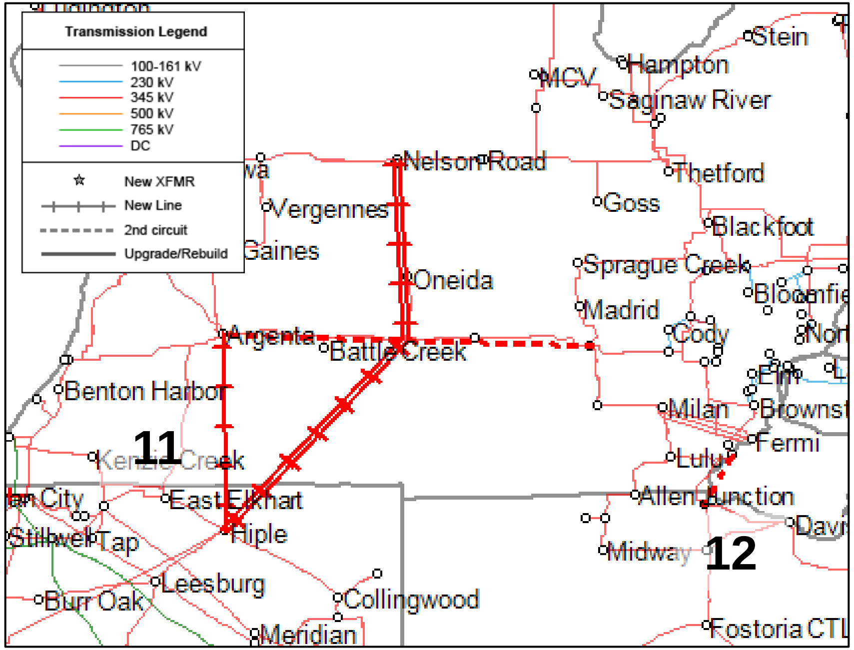
7 Added Dequine – Lafayette 345 kV to mitigate E26: Northwest Tap – Purdue 138 kV, a top economic issue in the Central/East region

8 Added Fall Creek – Greensboro 345 kV to mitigate various economic issues near Fall Creek (E27, E28, E29)

9 Added Bedford – Bloomington – Pritchard – Stout 345 kV to better leverage new 765 kV into Petersburg and relieve some reliability issues near Edwardsport, while also strengthening the transmission corridor into the Indianapolis area

10 Moved 765 kV terminal point from Rockport to Petersburg and tapped Rockport – Sullivan 765 kV at Petersburg, allowing for greater outlet at the Petersburg hub while still supporting the 765 kV loop

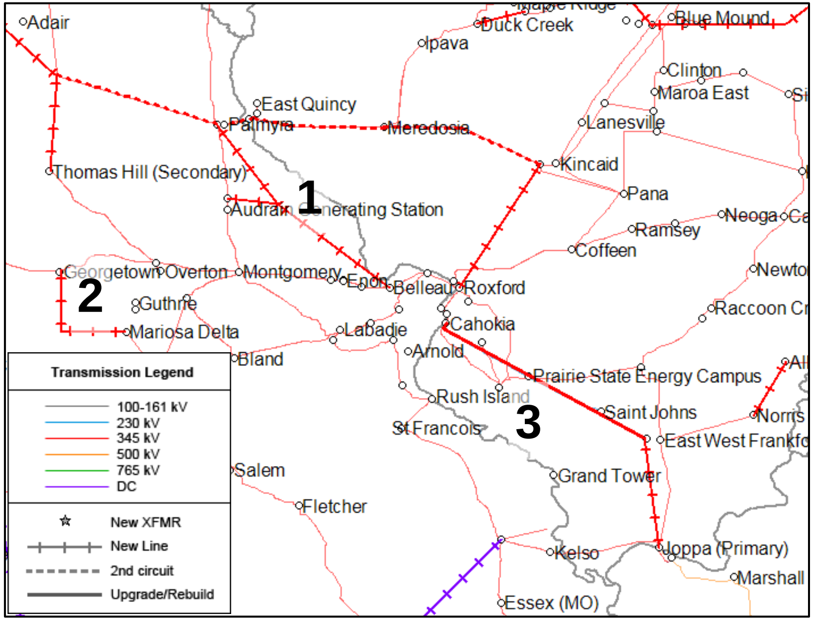
AAT Overlay Updates Central/East Region (4/4)



11 Added Hiple – Argenta 345 kV to better leverage 2nd Argenta – Tompkins – Majestic 345 kV, as well as provide additional import capability into MI

12 Refined idea in this area to be a 2nd Monroe – Lallendorf 345 kV in order to more directly address congestion on the existing Monroe – Lallendorf 345 kV

PR Overlay Updates Central/East Region (1/3)

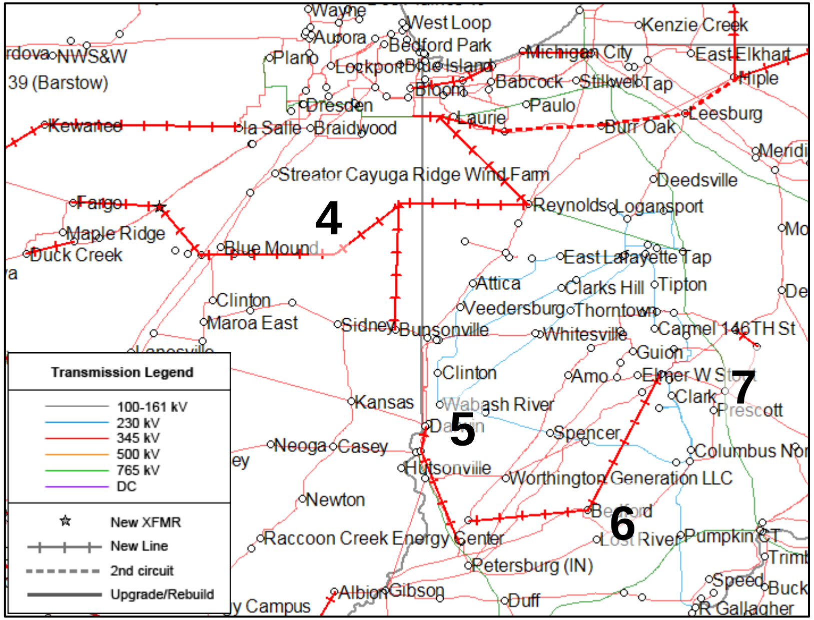


1 Modified to be Maywood – Pike – Belleau 345 kV and Spencer Creek – Pike 345 kV address R51: Maywood – Spencer Creek 345 kV, E15: Palmyra 345/161 kV XFMR, and Hannibal – Palmyra 161 kV without causing additional issues, and helps strengthen system for the loss of new nearby 765kV lines

2 Added Overton – Eldon Mariosa 345 kV to provide full relief to significant issue at E16: Overton 345/161 kV XFMR

3 Added the rebuild of Cahokia – West Frankfort to 345 kV as well as an extension to Joppa to better leverage new 345 kV corridor going into St. Louis and provide increased flow on the Lutesville – Independence DC line, while also relieving reliability issues at Joppa

PR Overlay Updates Central/East Region (2/3)



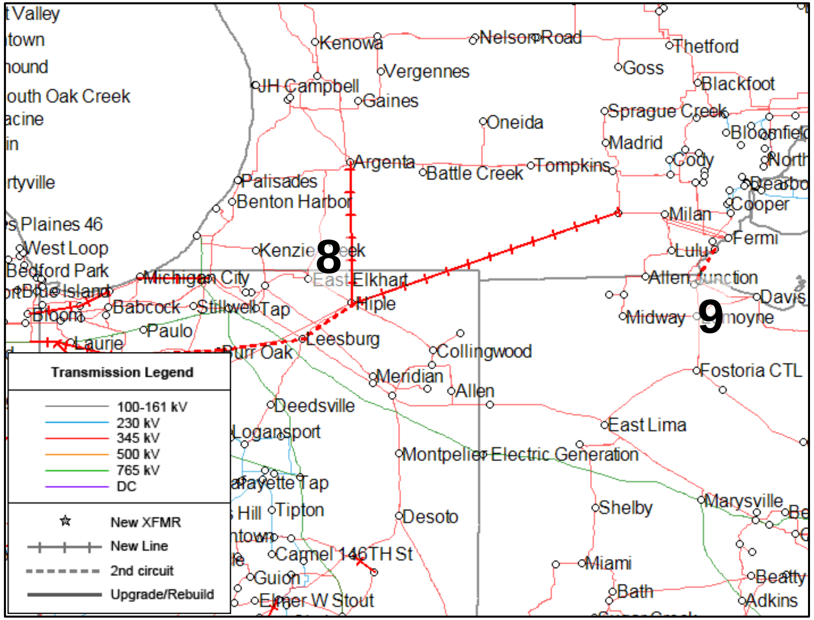
4 Tapped Paxton in between Brokaw – Sheldon South 345 kV, continues to fully relieve E24: Goodland – Reynolds 138 kV and provide a high-voltage path from IL to IN

5 Added Breed – Wheatland 345 kV as it resolves Wabash River-reliability issues

6 Added Edwardsport – Bedford – Bloomington to resolve R200: Edwardsport – Amo 345 kV, while also strengthening the transmission corridor into the Indianapolis area

7 Added Fall Creek – Greensboro 345 kV to mitigate various economic issues near Fall Creek (E28, E29)

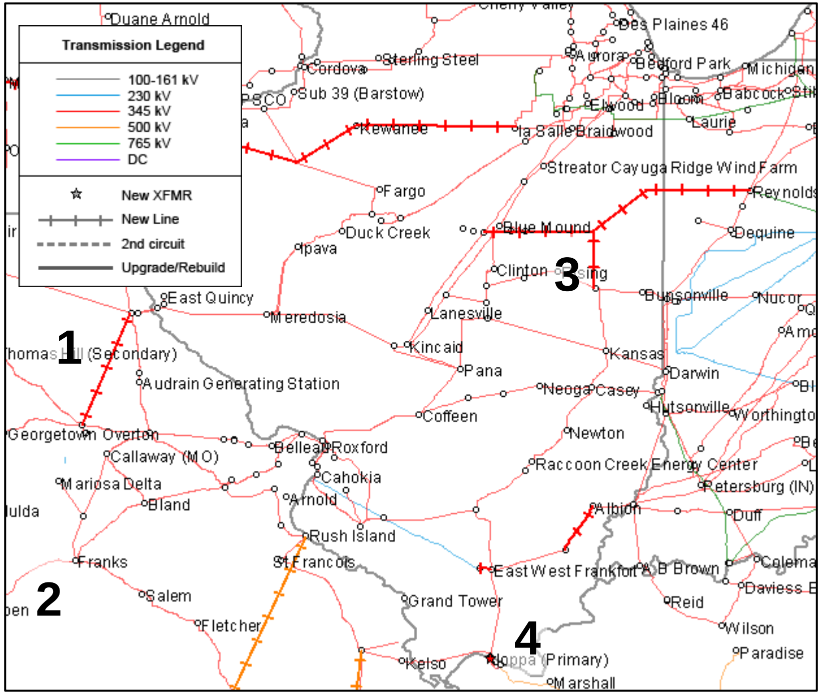
PR Overlay Updates Central/East Region (3/3)



8 Added Hiple – Argenta 345 kV to better to provide additional import capability into MI

9 Refined idea in this area to be a 2nd Monroe – Lallendorf 345 kV in order to more directly address congestion on the existing Monroe – Lallendorf 345 kV

EF Overlay Updates Central/East Region (1/2)



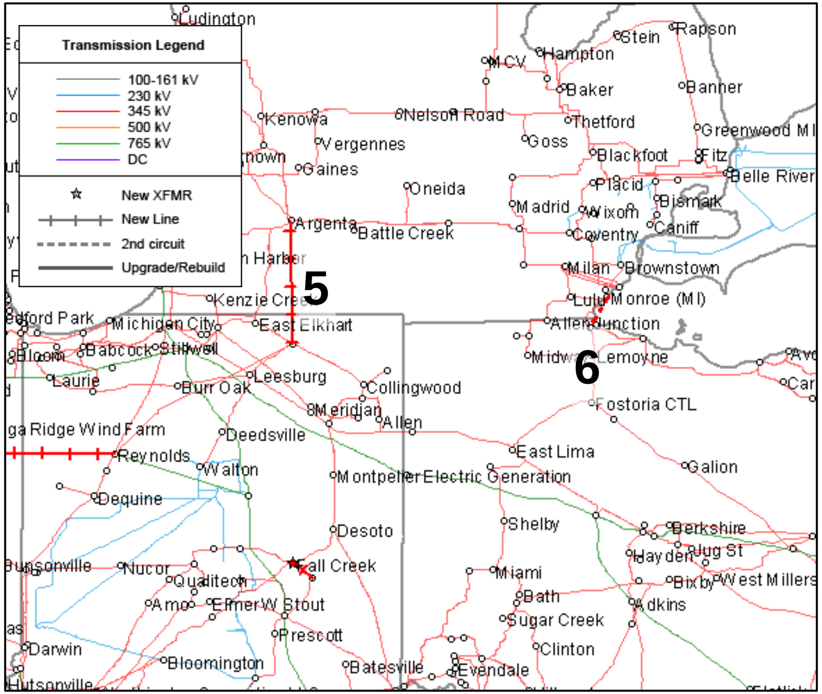
1 Removed Zachary – Thomas Hill kV as it was redundant to Maywood - McCredie

2 Removed Overton – Eldon – Mariosa 345 kV as it did not resolve any issues in EF and only had 5% line utilization

3 Added Sidney – Paxton 345 kV as a shorter alternative to Sidney – Reynolds 345 kV

4 Tapped E W Frankfort – Shawnee 345 kV at Joppa to help address R52: Joppa – Marion 161 kV

EF Overlay Updates Central/East Region (2/2)



5 Added Hiple – Argenta 345 kV to better provide additional import capability into MI

6 Modified to be a 2nd Monroe – Lallendorf 345 kV, however, may not be needed anymore as there is fairly low congestion on Monroe – Lallendorf 345 kV in EF

MISO

Central/East refined overlays more fully mitigate issues, provide comparable or greater congestion relief even with additional contingency analysis

Economic Congestion Statistics for MISO Central/East					
Overlay	**Congestion Relieved (%)**	**# of Mitigated Issues**	**# of Helped Issues**	**# of Worsened Issues**	**# of New Issues**
AAT Overlay May 25th EPUG	61%	30	5	4	5
AAT Overlay March 17th EPUG	49%	22	13	8	2
EF Overlay May 25th EPUG	55%	9	-	-	1
EF Overlay March 17th EPUG	46%	7	1	2	1
PR Overlay May 25th EPUG	53%	20	-	2	2
PR Overlay March 17th EPUG	62%	16	3	-	1

CONFIDENTIAL

NOVEMBER 2017

LAZARD'S LEVELIZED COST OF STORAGE ANALYSIS—VERSION 3.0

LAZARD

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I Introduction and Executive Summary

Introduction

This report represents the next iteration of Lazard's Levelized Cost of Storage ("LCOS") analysis

- **The intent of the LCOS analysis is to provide an objective, transparent methodology for comparing the cost and performance of various energy storage technologies across a range of illustrative applications**

Objectives

- Provide a clear methodology for comparing the cost and performance of commercially available energy storage technologies for a selected subset of illustrative use cases
- Analyze current cost and performance data for selected energy storage technologies and use cases, sourced from an extensive survey of leading equipment vendors, integrators and developers
- Analyze identifiable sources of revenue available to energy storage projects
- Provide an overview of illustrative project returns ("Value Snapshots") for selected use cases, based on identifiable revenues (or savings) and costs potentially available in selected markets/geographies

Scope and Limitations

- Emphasis on commercially applied, electrochemical energy storage technology
  - Mechanical, gravity and thermal technologies are not analyzed
  - Technologies without existing or very near-term commercial projects are not analyzed
- While energy storage costs and performance data are global in nature, Lazard's LCOS survey and resulting analysis is most representative of the current U.S. energy storage market
- Analysis of revenue streams is limited to actually monetized sources of project earnings, including reductions in host customer's energy bills
- Lazard's LCOS does not include additional potential system value provided by energy storage (e.g., reliability)

Evolution of Lazard's LCOS

LCOS 1.0 *2015*	Launched ongoing cost survey analogous to Lazard's LCOE to chart evolution of energy storage cost and performance • Set out rigorous definition of use cases and cost methodology • Conducted ~70 interviews with industry participants to validate methodology
LCOS 2.0 *2016*	Provided a more robust and comprehensive gauge of storage technology performance • Revised use cases to reflect market activity • Reported results for expanded and more detailed set of storage technologies • Narrowed LCOS ranges • Introduced "Value Snapshots" to profile project economics • Presented LCOS in $/kW-yr. and $/MWh
LCOS 3.0 *2017*	Narrowed scope of energy storage technologies and use cases surveyed to more accurately reflect current commercial opportunities • Selected near-term/commercial use cases and technologies • Introduced and included survey of identifiable revenue streams available for energy storage projects in the U.S. • Revised Value Snapshots to illustrate typical project returns for each use case • Updated methodology for reflecting storage system replacement costs/degradation through augmentation costs

Note: This study has been prepared by Lazard for general informational purposes only, and it is not intended to be, and should not be construed as, financial or other advice.

Summary of LCOS 3.0 Findings

Continued Decreasing Cost Trends	• Among commercially deployed technologies, lithium-ion continues to provide most economic solution across all use cases; however, flow battery technologies claim to offer lower costs for longer duration, in-front-of-the-meter applications • Compared to LCOS 2.0, cost improvements for lithium-ion modules (particularly lithium-ion deliveries scheduled for post-2019) are offset by increases in engineering, procurement and construction ("EPC") costs (in addition to revised roundtrip efficiency figures) – Limited direct evidence of impact of rising commodity costs (e.g., Cobalt) on prices • Reduced variance in cost and performance estimates for lithium-ion compared to LCOS 2.0, with narrowed ranges for in-front-of-the-meter use cases – Larger dispersion of estimates for Commercial and very large dispersion for Residential use cases – Evidence of significant variance and potential cost increases in EPC/installation costs for projects reported by industry participants • Slight flattening of projected capital cost decreases for lithium-ion (i.e., median of ~10% CAGR vs. ~12%) compared to LCOS 2.0 – Similar trend for other storage technologies except for zinc flow batteries
Evolving Revenue Streams	• The mix of monetizable revenue streams vary significantly across geographic regions in the U.S., mirroring state/ISO subsidies and storage-related product design • Among wholesale revenue sources: – Demand response ("DR") represents potentially lucrative revenue opportunities in selected markets (e.g., ERCOT and ISO-NE) – Energy arbitrage and spinning reserves generally offer lower revenue opportunities in contrast to other wholesale products • Utility revenue streams for T&D deferral are highly situation-specific and opaque and DR revenues are also diverse and complex; however, in high-cost regions (e.g., ConEd's territory) they can be attractive • Customer revenue sources are dominated by bill savings, which are highly lucrative in high-cost investor-owned utility ("IOU") service territories for selected tariffs – Data on actual revenue associated with specific payments for enhanced reliability is limited (exceptions include ERCOT, where gas-fired Distributed Generation ("DG") is reported to have received $8 – $10/kW-mo.)
Project Economics Remain Highly Variable	• The Value Snapshots illustrate the wide range of project economics for energy storage: – Commercial use case in CAISO provides an attractive illustrative ~11% IRR, reflecting a combination of Local Capacity Requirements ("LCR") and bill management savings – Distribution Deferral use case in NYISO provides an illustrative ~21% IRR, reflecting T&D deferral plus resource adequacy (estimate based on ConEd's Brooklyn-Queens Demand Management ("BQDM") program) – Peaker Replacement use case in CAISO provides a potentially viable illustrative IRR of ~9% reflecting LCR payments as a dominant revenue source – Microgrid project revenue sources in ISO-NE were limited and provides negative illustrative returns and Residential use case in California also reflected negative illustrative project economics due to the relatively high installed cost of the storage unit, which offset revenues from bill savings and participation in DR

II LCOS Methodology, Use Cases and Technology Overview

What Is Lazard's Levelized Cost of Storage Analysis?

Lazard's LCOS study analyzes the observed costs and revenue streams associated with the leading energy storage technologies and provides an overview of illustrative project returns; the LCOS is focused on providing a robust, empirically based indication of actual cash costs and revenues associated with leading energy storage technologies

- **It does not purport to measure the full set of potential benefits associated with energy storage to Industry participants or society, but merely those demonstrable in the form of strictly financial measures of observable costs and revenues**

LCOS Methodology

It clearly defines a set of use cases in terms of output and operating characteristics (e.g., number of charging cycles, depth of discharge, etc.) → **It applies a transparent set of financial and operating assumptions provided by industry participants across a range of commonly employed energy storage technologies to calculate the levelized cost of each** → **In addition, the study surveys the range of identifiable revenue streams available to energy storage projects** → **Finally, it applies currently observed costs and revenues associated with existing storage projects, as well as available local and national subsidies, to measure the financial returns realized by a representative set of storage projects**

What the LCOS Does

- Defines operational parameters associated with energy storage systems designed for a selected subset of the most prevalent use cases of storage
- Aggregates cost and operational survey data from original equipment manufacturers and energy storage developers, after validation from additional Industry participants/energy storage users
- Analyzes, based on the installed cost, what revenue is required over the indicated project life to achieve certain levelized returns for various technologies, designed for a selected subset of identified use cases
- Provides an "apples-to-apples" basis of comparison among various technologies within a selected subset of identified use cases
- Aggregates robust survey data to define a range of future/expected capital cost decreases by technology
- Surveys currently available, pecuniary revenue streams associated with each use case across selected geographies
- Profiles the economics of typical examples of each use case, located in geographic regions where they are most common, providing a Value Snapshot of the associated financial returns

What the LCOS Does Not Do

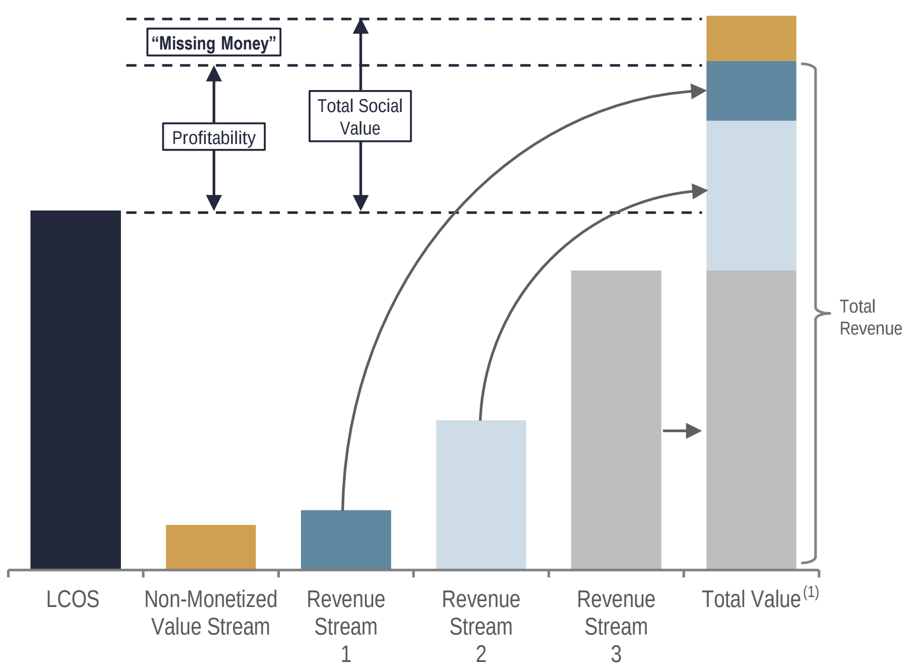
- Identify the full range of use cases for energy storage, including "stacked" use cases (i.e., those in which multiple value streams are obtainable from a single storage installation)
- Profile all potentially viable energy storage technologies and use cases
- Authoritatively establish or predict prices for energy storage projects/products
- Provide parameter values which, by themselves, are applicable to detailed project evaluation or resource planning
- Identify and quantify all potential types of benefits provided by energy storage for power grids or consumers
- Provide a definitive view of project profitability, overall or to specific individuals/entities, for the various use cases across all potential locations and specific circumstances
- Purport to provide an "apples-to-apples" comparison to conventional or renewable electric generation

The Energy Storage Value Proposition—Balancing Costs and Revenues

Understanding the economics of energy storage is challenging due to the highly tailored nature of potential value streams associated with an energy storage installation

- **This study takes a decidedly practical view by analyzing the levelized cost and the currently monetized sources of revenue (or savings) available to energy storage projects**
- **Conversely, it ignores what may be even larger sources of value—for the power grid, or for individual users, or for society at large—for which current regulatory and market rules do not assign a pecuniary value**

Energy Storage Value Proposition—Monetized and Total Social Value



Selected Observations

- Energy storage systems are configured to support one or more specific revenue streams. The operating requirements of one use case may preclude efficient/economic operations in another use case for the same system
  - The availability and magnitude of different revenue sources reflect local regulatory and energy market conditions
  - The ability to participate in multiple revenue streams depends on the commercial terms of different potential streams, physical constraints and the cost implications of operating an energy storage system
  - Optimizing the design and operation of a storage system to maximize combined revenue streams can be a source of competitive differentiation
- The total of all potential value streams available for a given system thus defines the maximum, economically viable cost for that system
- Importantly, incremental sources of revenue may only become available as costs (or elements of levelized cost) decrease below a certain value
- In many cases, local market/regulatory rules are not available to reward the owner of an energy storage project to provide all (or the optimal combination) of potential revenue streams

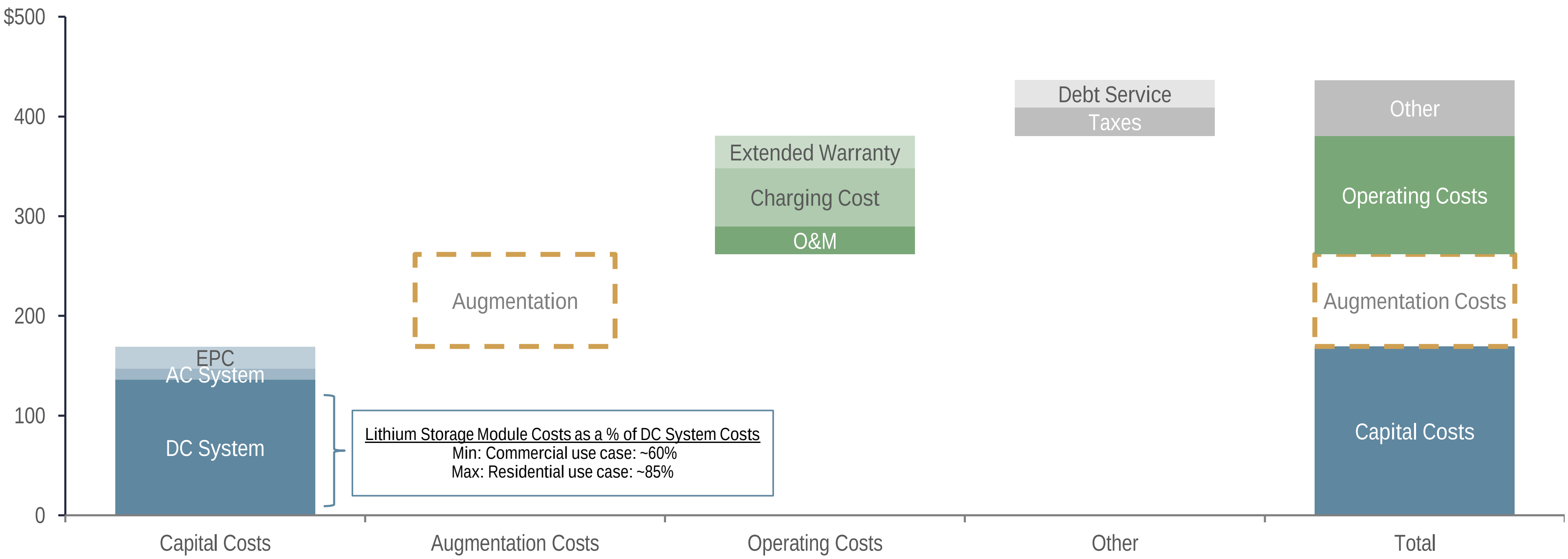
(1) Presented here as the simple sum of all available value streams. Due to operational and other factors, such "stacked" value would likely differ from the simple sum of all value streams in practice.

Illustrative Energy Storage System Costs

LCOS values are examined in the context of a **particular project's** specific application

- **A cost category's contribution to total levelized cost varies dramatically across use cases and technologies**
- **Where applicable, amortized technology augmentation costs are included to ensure the system maintains its required output for the duration of the project's contracted life**

Illustrative System Costs: LCOS by Category ($/kW-yr.)

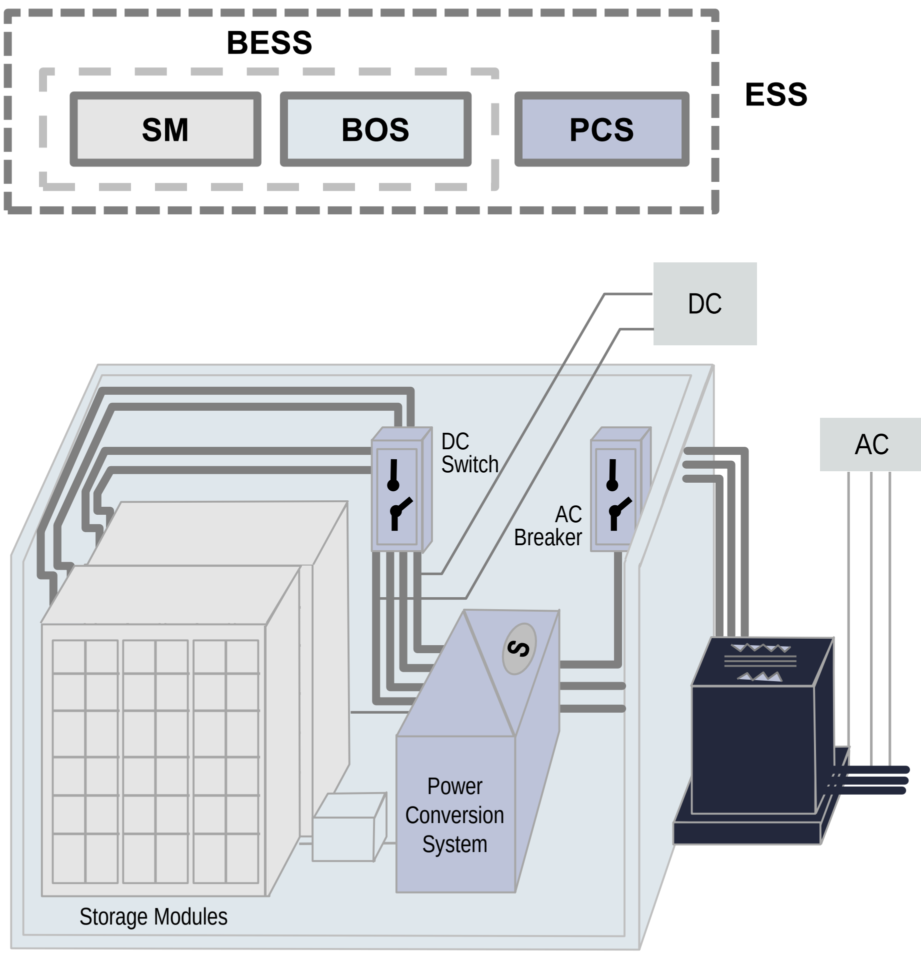


Note: Augmentation costs represent the additional energy storage system ("ESS") equipment needed to maintain the "Usable Energy" capability to cycle the unit according to the usage profile in the particular use case for the life of the system. Additional equipment is required in the following circumstances: (1) if the particular unit does not charge and discharge 100% of the rated energy capacity (kWh) per cycle; (2) if the battery chemistry does not have the cycle-life needed to support the entire operating life of the use case; or (3) if the energy rating (kWh) of the battery chemistry degrades due to usage. The cost of these additional ESS equipment takes into account the falling price of ESS system costs, specified for each chemistry. This time-series of varying costs is then converted into a level charge over the life of the system to provide greater clarity for project developers.

Components of Energy Storage System Equipment Costs

Lazard's LCOS study incorporates capital costs for the entirety of the energy storage system ("ESS"), which is composed of the storage module ("SM"), balance of system ("BOS" and, together with the SM, the Battery Energy Storage System "BESS"), power conversion system ("PCS") and related EPC costs

Physical Energy Storage System



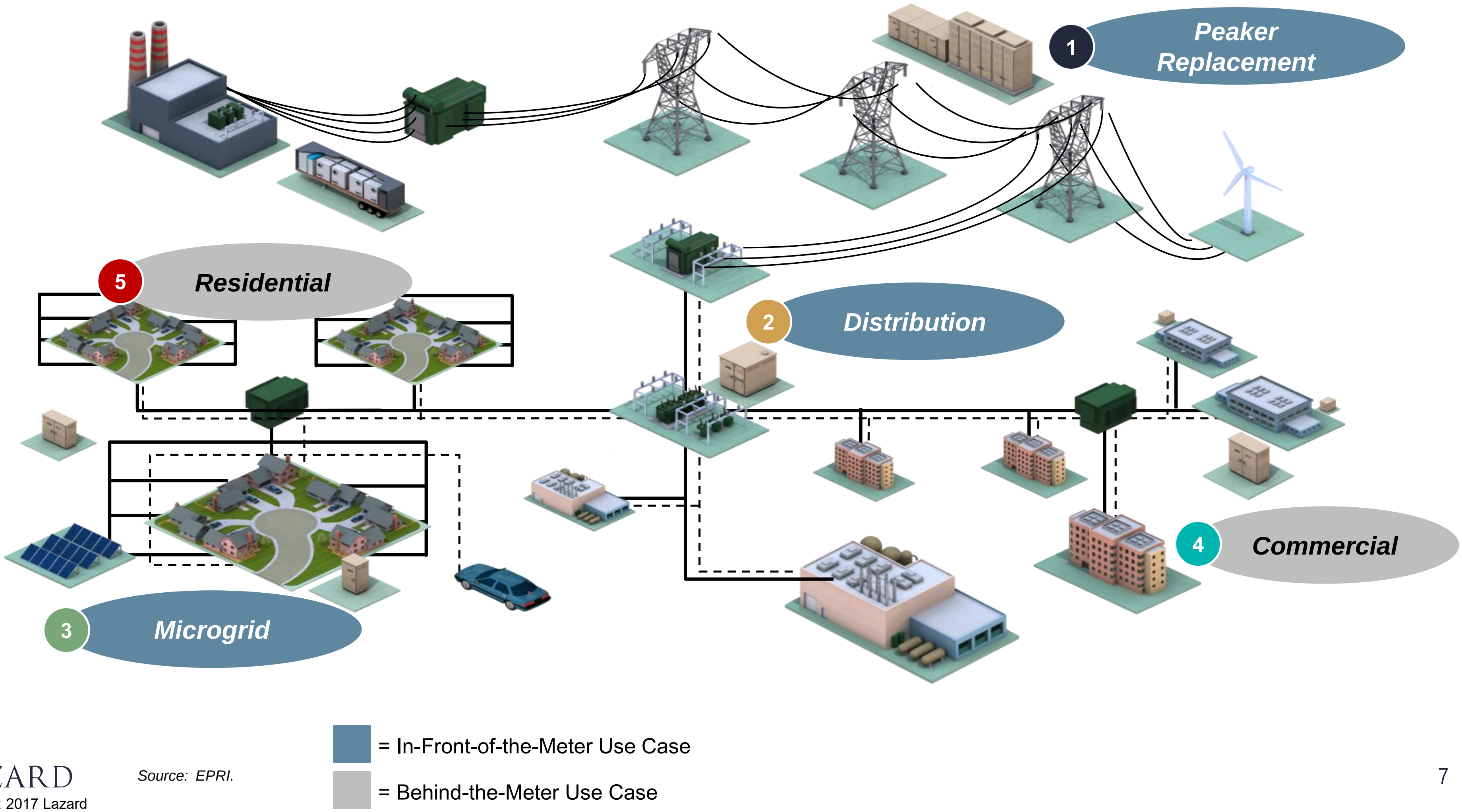
Selected Equipment & Cost Components

System Layer		Component
SM	Storage Module	• Racking Frame/Cabinet • Battery Management System ("BMS") • Battery Modules
BOS	Balance of System	• Container • Monitors and Controls • Thermal Management • Fire Suppression
PCS	Power Conversion System	• Inverter • Protection (Switches, Breakers, etc.) • Energy Management System ("EMS")
EPC	Engineering, Procurement & Construction	• Project Management • Engineering Studies/Permitting • Site Preparation/Construction • Foundation/Mounting • Commissioning
Other (not included in analysis)		• SCADA • Shipping • Grid Integration Equipment • Metering • Land

Source: Sandia National Laboratories.

Use Case Overview

Dozens of potential applications for energy storage technology have been identified and piloted; for the purposes of this assessment, we have chosen to focus on a subset of use cases which are the most identifiable and distinctive



Source: EPRI.

Use Case Overview (cont'd)

Lazard's LCOS examines the cost of energy storage in the context of its specific applications on the grid and behind-the-meter; each use case specified herein represents an application of energy storage that market participants are utilizing now or will be utilizing in the near future

- **Commonly employed energy storage technologies for each use case are included below**

		Use Case Description	Technologies Assessed[(2)]
In-Front-of-the-Meter	1 Peaker Replacement	• Large-scale energy storage system designed to replace peaking gas turbine facilities; brought online quickly to meet rapidly increasing demand for power at peak; can be quickly taken offline as power demand diminishes[(1)]	• Lithium-Ion • Vanadium Flow Battery • Zinc Bromide Flow Batteries
In-Front-of-the-Meter	2 Distribution	• Energy storage system designed to defer distribution upgrades, typically placed at substations or distribution feeder controlled by utilities to provide flexible peaking capacity while also mitigating stability problems (typically integrated into utility distribution management systems)	• Lithium-Ion • Vanadium Flow Battery
In-Front-of-the-Meter	3 Microgrid	• Energy storage system designed to support small power systems that can “island” or otherwise disconnect from the broader power grid (e.g., military bases, universities, etc.) – Provides ramping support to enhance system stability and increase reliability of service (emphasis is on short-term power output vs. load shifting, etc.)	• Lithium-Ion • Vanadium Flow Battery
Behind-the-Meter	4 Commercial	• Energy storage system designed for behind-the-meter peak shaving and demand charge reduction services for commercial energy users – Units typically sized to have sufficient power/energy to support multiple Commercial energy management strategies and provide option of the system providing grid services to utility or wholesale market	• Lithium-Ion • Lead-Acid • Advanced Lead (Lead Carbon)
Behind-the-Meter	5 Residential	• Energy storage system designed for behind-the-meter residential home use—provides backup power, power quality improvements and extends usefulness of self-generation (e.g., “solar plus storage”) – Regulates the power supply and smooths the quantity of electricity sold back to the grid from distributed PV applications	• Lithium-Ion • Lead-Acid • Advanced Lead (Lead Carbon)

(1) Specific operational revenue streams include: capacity, energy sales (e.g., time-shift/arbitrage, etc.), spinning reserve and non-spinning reserve.
(2) Microgrid and Distribution use cases are beginning to use ZnBr flow batteries; however, they are not included in the LCOS output due to the limited sample size.

Energy Storage Use Cases—Operational Parameters

For comparison purposes, this study assumes and quantitatively operationalizes five use cases for energy storage; while there may be **alternative or combined/"stacked" use cases available to energy storage systems, the** five use cases below represent illustrative current and contemplated energy storage applications and are derived from Industry survey data

		Project Life (Years)	MW(1)	MWh of Capacity(2)	100% DOD Cycles/Day(3)	Days/ Year(4)	Annual MWh	Project MWh
In-Front-of-the-Meter	1 Peaker Replacement	20	100	400	1	350	140,000	2,800,000
	2 Distribution	20	10	60	1	350	21,000	420,000
	3 Microgrid	10	1	4	2	350	2,800	28,000
Behind-the-Meter	4 Commercial	10	0.125	0.25	1	250	62.5	625
	5 Residential	10	0.005	0.01	1	250	2.5	25

[dashed box] = "Usable Energy"(5)

Note: Distribution use case represents emerging longer duration application.
(1) Indicates power rating of system (i.e., system size).
(2) Indicates total battery energy content on a single, 100% charge, or "usable energy." Usable energy divided by power rating (in MW) reflects hourly duration of system.
(3) "DOD" denotes depth of battery discharge (i.e., the percent of the battery's energy content that is discharged). Depth of discharge of 100% indicates that a fully charged battery discharges all of its energy. For example, a battery that cycles 48 times per day with a 10% depth of discharge would be rated at 4.8 100% DOD Cycles per Day.
(4) Indicates number of days of system operation per calendar year.
(5) Usable energy indicates energy stored and able to be dispatched from system.

Overview of Selected Energy Storage Technologies

A wide variety of energy storage technologies are currently available or in development; however, given limited current or future commercial deployment expectations, only a subset are assessed in this study

		Description	Size (MW)	Selected Providers	Life (Yrs)(1)
Mechanical/Gravity/Thermal	Compressed Air	• Compressed Air Energy Storage ("CAES") uses electricity to compress air into confined spaces (e.g., underground mines, salt caverns, etc.) where the pressurized air is stored. When required, this pressurized air is released to drive the compressor of a natural gas turbine	150 MW+	Dresser Rand, Alstom Power	20 years
	Flywheel	• Flywheels are mechanical devices that spin at high speeds, storing electricity as rotational energy, which is released by decelerating the flywheel's rotor, releasing quick bursts of energy (i.e., high power and short duration) or releasing energy slowly (i.e., low power and long duration), depending on short-duration or long-duration flywheel technology, respectively	30 kW – 1 MW	Amber Kinetics, Vycon	20+ years
	Pumped Hydro	• Pumped hydro storage uses two vertically separated water reservoirs, using low cost electricity to pump water from the lower to the higher reservoir and running as a conventional hydro power plant during high electricity cost periods	100 MW+	MWH Global	20+ years
	Thermal	• Thermal energy storage uses conventional cryogenic technology, compressing and storing air into a liquid form (charging) then releasing it at a later time (discharge). Best suited for large-scale applications; the technology is still emerging, but has a number of units in early development and operation	5 MW – 100 MW+	Highview Power	20+ years
Chemical	Flow Battery‡	• Flow batteries store energy through chemically changing the electrolyte (vanadium) or plating zinc (zinc bromide). Physically, systems typically contain two electrolyte solutions in two separate tanks, circulated through two independent loops, separated by a membrane. Emerging alternatives allow for simpler and less costly designs utilizing a single tank, single loop, and no membrane. • The subcategories of flow batteries are defined by the chemical composition of the electrolyte solution; the most prevalent of such solutions are vanadium and zinc-bromide. Other solutions include zinc-chloride, ferrochrome and zinc chromate	25 kW – 100 MW+	Sumitomo, UET, Primus Power	20 years
	Lead-Acid‡	• Lead-acid batteries date from the 19th century and are the most common batteries; they are low-cost and adaptable to numerous uses (e.g., electric vehicles, off-grid power systems, uninterruptible power supplies, etc.) • "Advanced" lead-acid battery technology adds ultra-capacitors, increasing efficiency, lifetimes and improve partial state-of-charge operability(2)	5 kW – 2 MW	Enersys, GS Yuasa, East Penn Mfg.	5 – 10 years
	Lithium-Ion‡	• Lithium-ion batteries have historically been used in electronics and advanced transportation industries; they are increasingly replacing lead-acid batteries in many applications, and have relatively high energy density, low self-discharge and high charging efficiency • Lithium-ion systems designed for energy applications are designed to have a higher efficiency and longer life at slower discharges, while systems designed for power applications are designed to support faster charging and discharging rates, requiring extra capital equipment	5 kW – 100 MW+	LG Chem, Samsung, Panasonic, BYD	10 years(3)
	Sodium‡	• "High temperature"/"liquid-electrolyte-flow" sodium batteries have high power and energy density and are designed for large commercial and utility scale projects; "low temperature" batteries are designed for residential and small commercial applications	1 MW – 100 MW+	NGK	10 years
	Zinc‡	• Zinc batteries cover a wide range of possible technology variations, including metal-air derivatives; they are non-toxic, non-combustible and potentially low-cost due to the abundance of the primary metal; however, this technology remains unproven in widespread commercial deployment	5 kW – 100 MW+	Fluidic Energy, EOS Energy Storage	10 years

[dashed box] Technologies analyzed in LCOS 3.0.
‡ Denotes battery technology.
(1) Indicates general ranges of useful economic life for a given family of technology. Useful life will vary in practice depending on sub-technology, intensity of use/cycling, engineering factors, etc.
(2) Advanced lead-acid is an emerging technology with wider potential applications and greater cost than traditional lead-acid batteries.
(3) In this report, augmentation costs account for the assumed a 20-year project life for Peaker Replacement and Distribution Substation.

Overview of Selected Energy Storage Technologies (cont'd)

A wide variety of energy storage technologies are currently available or in development; however, given limited current or future commercial deployment expectations, only a subset are assessed in this study

		Selected Advantages	Selected Disadvantages
Mechanical/Gravity/Thermal	Compressed Air	• Low cost, flexible sizing, relatively large-scale • Mature technology and well-developed design • Proven track record of safe operation • Leverages existing gas turbine technologies	• Requires suitable geology • Relatively difficult to modularize for smaller installations • Exposure to natural gas price changes • Relies on natural gas
	Flywheel	• High power density and scalability for short-duration technology; low power, higher energy for long-duration technology • High depth of discharge capability • Compact design with integrated AC motor	• Relatively low energy capacity • High heat generation • Sensitive to vibrations
	Pumped Hydro	• Mature technology (commercially available; leverages existing hydropower technology) • High-power capacity solution • Large scale, easily scalable in power rating	• Relatively low energy density • Limited available sites (i.e., water availability required) • Cycling generally limited to once per day
	Thermal	• Low cost, flexible sizing, relatively large-scale • Power and energy ratings independently scalable • Leverages mature industrial cryogenic technology base; can utilize waste industrial heat to improve efficiency	• Technology is pre-commercial • Difficult to modularize for smaller installations • On-site safely concerns from cryogenic storage
Chemical	Flow Battery‡	• Power and energy profiles independently scalable for Vanadium system • Zinc-Bromide designed in fixed modular blocks for system design • No degradation in "energy storage capacity" • No potential for fire • High cycle/lifespan	• Power and energy rating scaled in a fixed manner for zinc-bromide technology • Electrolyte based on acid • Relatively high balance of system costs • Reduced efficiency due to rapid charge/discharge
	Lead-Acid‡	• Mature technology with established recycling infrastructure • Advanced lead-acid technologies leverage existing technologies • Low cost	• Poor ability to operate in a partially charged state • Relatively poor depth of discharge and short lifespan • Acid based electrolyte
	Lithium-Ion‡(1)	• Multiple chemistries available • Rapidly expanding manufacturing base leading to cost reductions • Efficient power and energy density • Cost reduction continues	• Cycle life limited, especially in harsh conditions • Safety issues from overheating • Requires advanced manufacturing capabilities to achieve high performance
	Sodium‡	• High temperature technology: Relatively mature technology (commercially available); high energy capacity and long duration • Low temperature technology: Smaller scale design; emerging technology and low-cost potential; safer	• Although mature, inherently higher costs—low temperature batteries currently have a higher cost with lower efficiency • Potential flammability issues for high-temperature batteries • Poor cycling capability
	Zinc‡	• Deep discharge capability • Designed for long life • Designed for safe operation	• Currently unproven commercially • Lower efficiency • Poor cycling/rate of charge/discharge

[dashed box] Technologies analyzed in LCOS 3.0.
Source: DOE Energy Storage Database.
‡ Denotes battery technology.
(1) Lithium-Ion assessed on this report is NMC (Lithium, Nickel, Manganese, Cobalt).

III Lazard's Levelized Cost of Storage Analysis

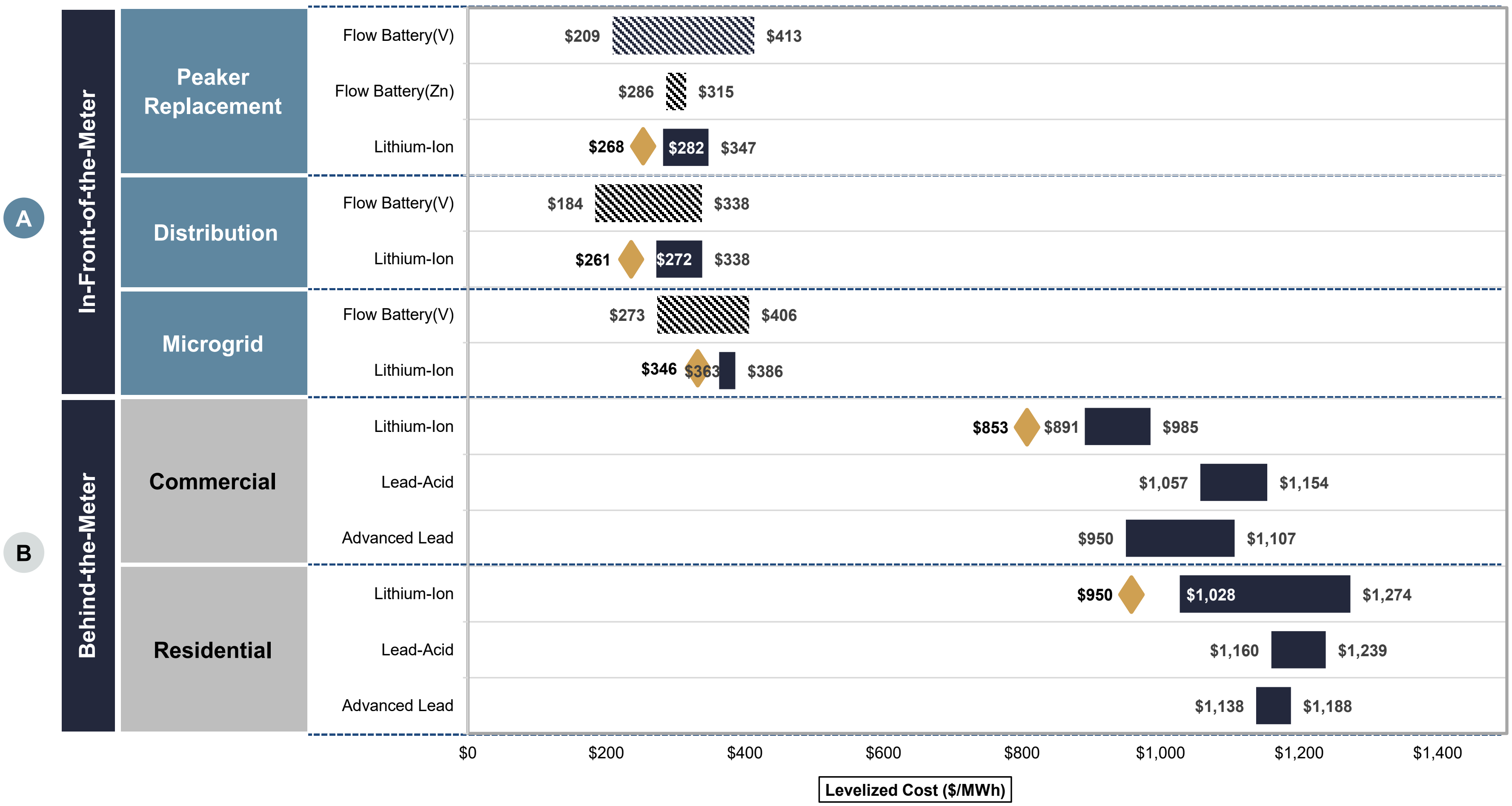
Unsubsidized Levelized Cost of Storage Comparison—$/MWh

A **Selected Observations**

- Flow battery manufacturers have claimed that they do not require augmentation costs and can compete with lithium-ion; however, operational experience is lacking to practically verify these claims
- Flow Batteries lack the widespread commercialization of lithium-ion
- Longer duration flow batteries could potentially be used in T&D 8-hour use case

B **Selected Observations**

- As compared to in-front-of-the-meter, behind-the-meter system costs are substantially higher due to higher unit costs
- Low initial cost of Lead and Lead Carbon are outweighed by higher augmentation and operating costs



...s indicative Flow Battery LCOS value. Flow battery LCOS ranges are shaded given the lack of operational experience required to verify survey results.

Source: Lazard and Enovation Partners estimates.

Note: Here and throughout this presentation, unless otherwise indicated, analysis assumes 20% debt at an 8% interest rate and 80% equity at a 12% cost of equity. All costs estimates are for 2017 unless otherwise noted. Flow Battery Vanadium and Flow Battery Zinc denoted in this report as Flow Battery(V) and Flow Battery(Zn), respectively.

Unsubsidized Levelized Cost of Storage Comparison—$/kW-year

A Selected Observations

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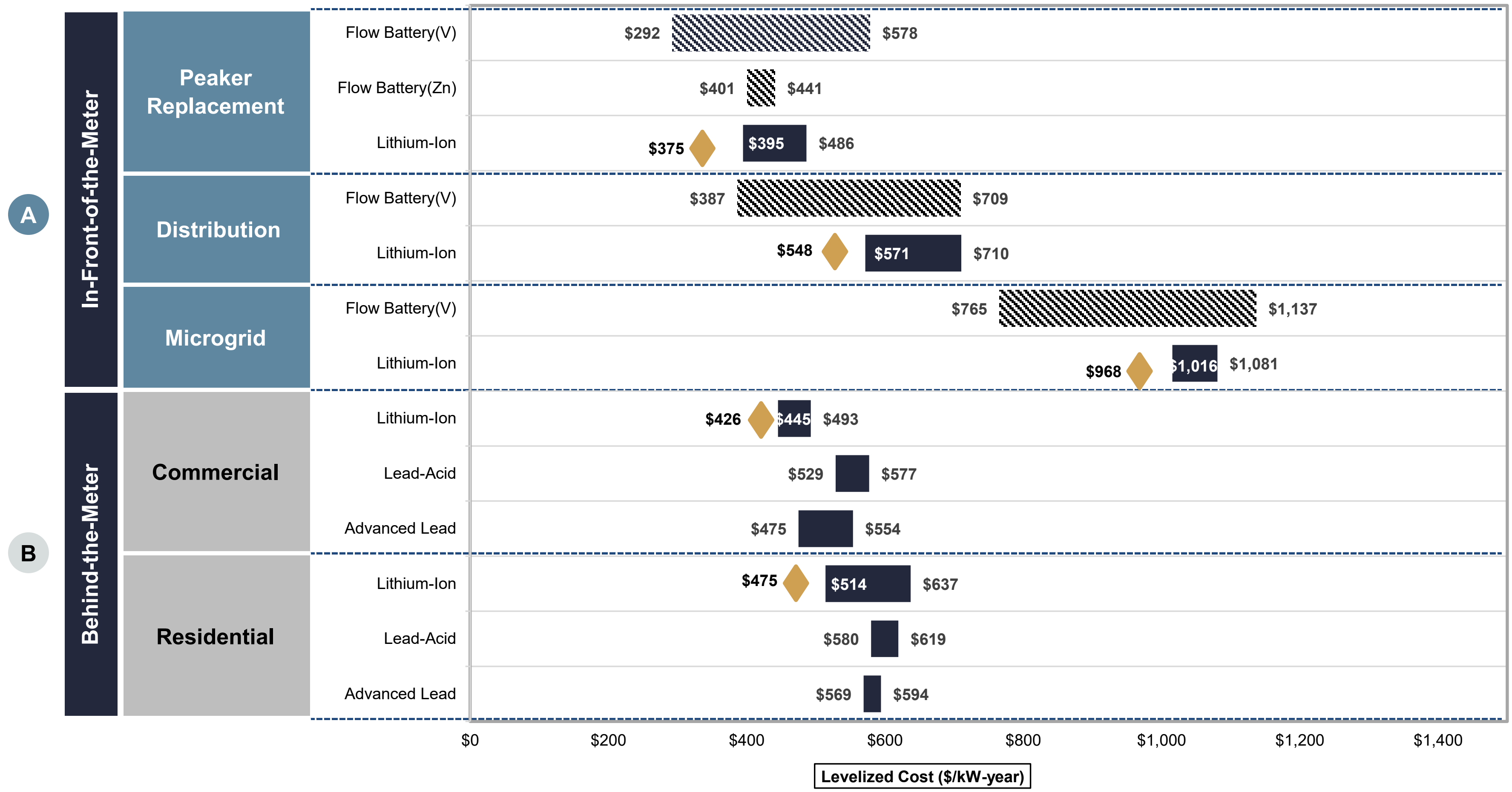

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Source: *Lazard and Enovation Partners estimates.*

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◆ = Denotes 2018 Estimate

Capital Cost Comparison—$/kWh

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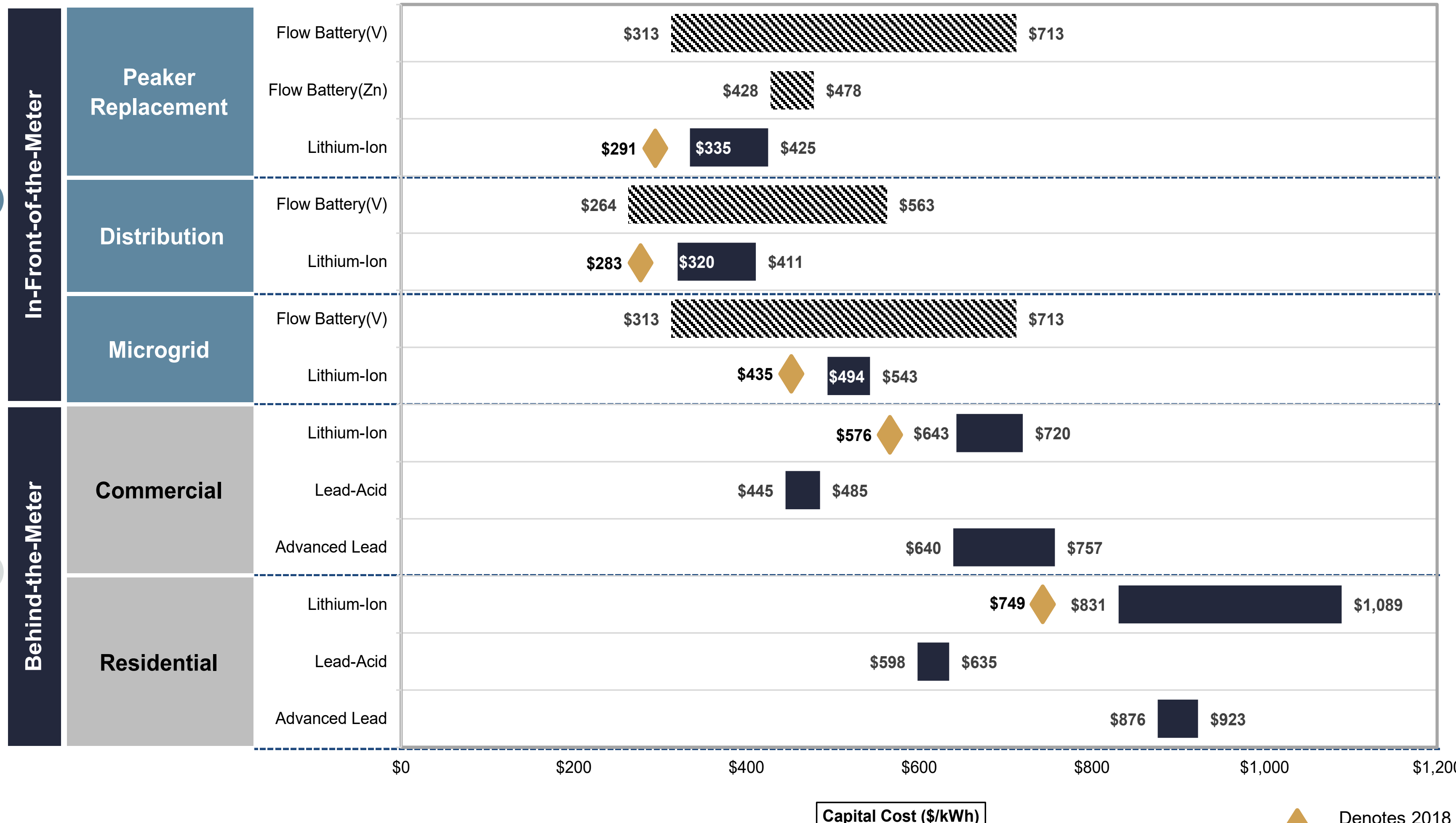
- Longer duration flow batteries could potentially be used in T&D 8-hour use case

B **Selected Observations**

- Lead-acid capital costs are the lowest costs for behind-the-meter rated equipment; however, augmentation costs increase their final LCOS value
- Advanced Lead batteries benefit from lower balance of system costs



= Denotes 2018 Estimate

Note: s indicative Flow Battery LCOS value. Flow battery LCOS ranges are shaded given the lack of operational experience required to verify survey results.

Source: Lazard and Enovation Partners estimates.

Note: All costs estimates are for 2017 unless otherwise noted. Capital costs represent overnight costs of equipment only. This excludes augmentation costs that represent the energy storage capacity required to maintain the full usable energy storage capacity (kWh) over the life of the unit. These augmentation costs vary due to usage profiles and lifespans. Capital cost units are the total investment divided by the storage equipment's energy capacity (kWh rating) and inverter rating (kW rating).

Capital Cost Comparison—$/kW

A **Selected Observations**

- Flow battery manufacturers have claimed that they do not require augmentation costs and can compete with lithium-ion; however, operational experience is lacking to practically verify these claims
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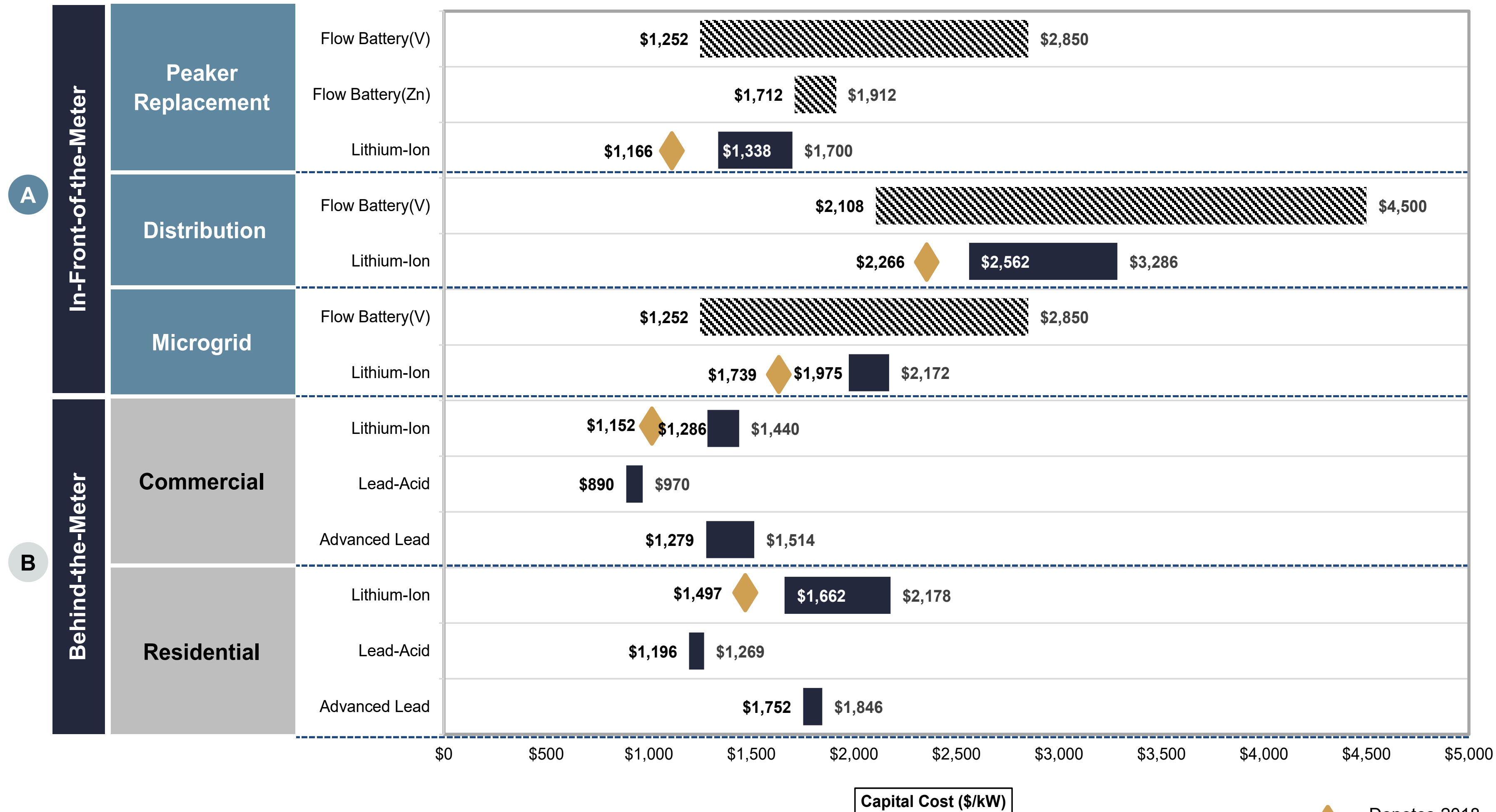

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Source: Lazard and Enovation Partners estimates.

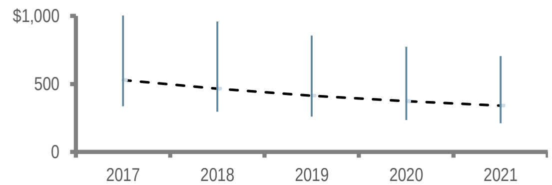
Note: All costs estimates are for 2017 unless otherwise noted. Capital costs represent overnight costs of equipment only. This excludes augmentation costs that represent the energy storage capacity required to maintain the full usable energy storage capacity (kWh) over the life of the unit. These augmentation costs vary due to different usage profiles and lifespans. Capital cost units are the total investment divided by the storage equipment's energy capacity (kWh rating) and inverter rating (kW rating).

Capital Cost Outlook by Technology

The average capital cost outlook accounts for the relative commercial maturity of different offerings (i.e., more mature offerings influence the cost declines per technology)

Capital Cost ($/kWh) | **Avg** | **Technology Trends & Opportunities**

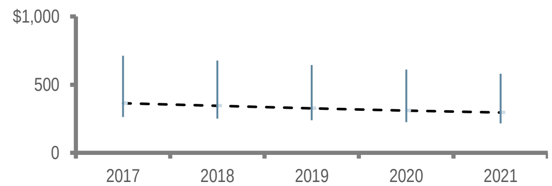
Lithium-Ion



	Avg
CAGR	(10%)
5-Year	(36%)

- OEM competition continues to drive cost reductions
- Lower cost allows for competing with long-duration applications
- System integrators driving cost reductions in BOS and installation
- Benefits from growing electric vehicle production

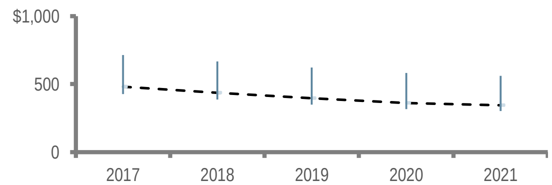
Flow Battery–Vanadium



	Avg
CAGR	(5%)
5-Year	(19%)

- Shift to long-duration application drives lower costs ($/kWh)
- Focus on high energy throughput drives lower levelized costs ($/MWh)
- OEMs provide complete turnkey system

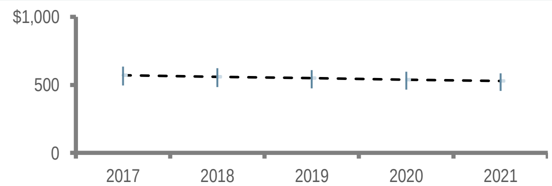
Flow Battery–Zinc Bromide



	Avg
CAGR	(8%)
5-Year	(28%)

- Longer durations can be achieved by adding multiple flow battery modules at the same cost ($/kWh), but possibly requiring additional integration costs
- OEM focus on high energy throughput with little operating costs
- OEMs focusing on customers wanting modular AC unit

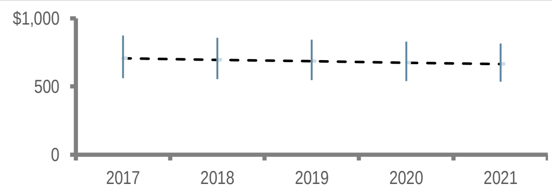
Lead



	Avg
CAGR	(2%)
5-Year	(8%)

- Low cost energy storage option
- Limited usability and performance translates into high levelized cost
- Limited cost improvement expected

Advanced Lead



	Avg
CAGR	(2%)
5-Year	(6%)

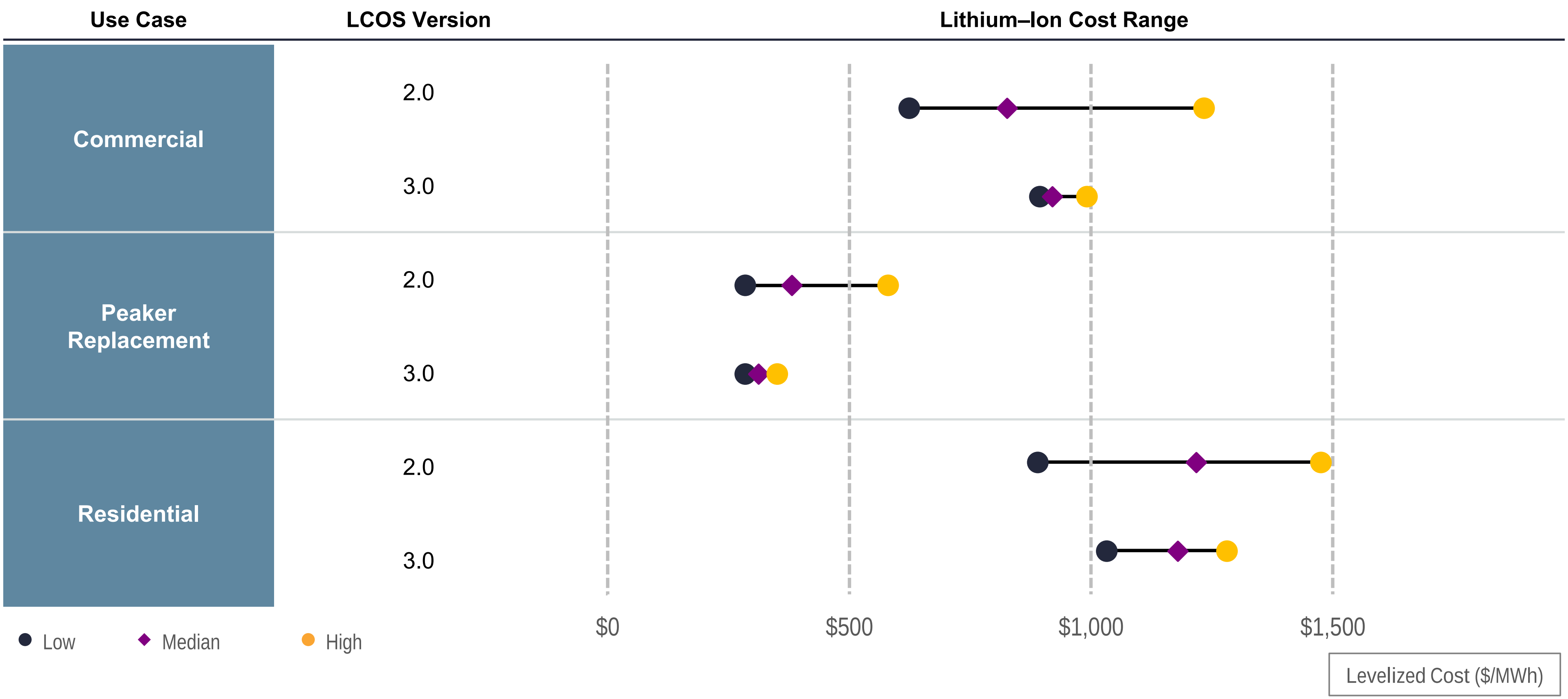
- Greater performance than typical lead-acid options
- Cost reduction and performance improvements expected to continue
- OEMs looking to use this class to address larger commercial systems not typically served by lead-acid

Note: Capital Costs reported are based on year 1 costs for systems designed for all LCOS use cases. Capital cost units are the total investment divided by the storage equipment's energy capacity (kWh rating) and inverter rating (kW rating). Capital cost outlook represents weighted average expected cost reductions across use cases

Evidence of Cost Decreases—Lithium Examples

Lithium-ion equipment cost declines contend with system scale, installation and operating realities

- **Lithium-ion equipment costs continue to decline based on more cost-effective batteries, better integration and longer life products**
- **However, as more battery systems are deployed, estimates of actual round trip efficiencies are lower and installation costs are higher than expected and than reported in last year's LCOS 2.0**
- **Consequently, estimates for total "Commercial" use case LCOS rose slightly, despite lower equipment cost estimate**



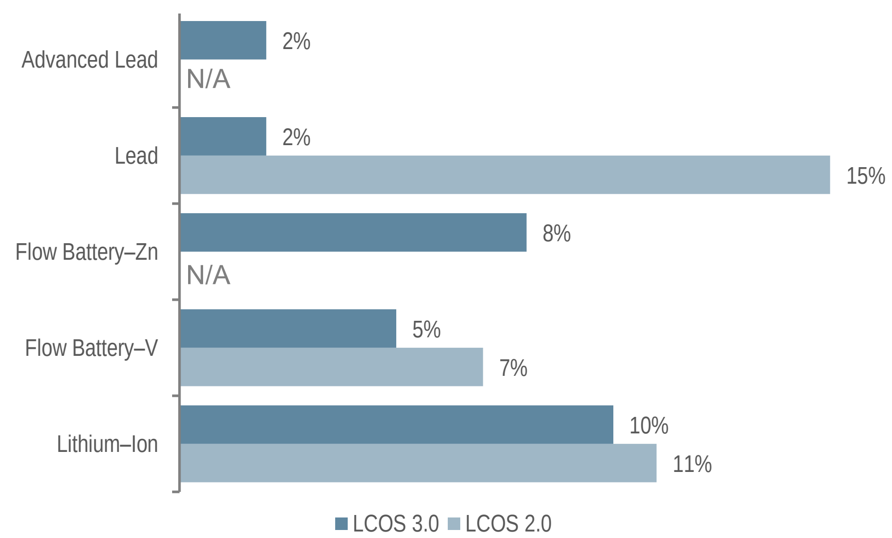
Expectation of Sustained Cost Improvements—Capital Costs

Lithium-ion equipment costs continue to decline based on more cost-effective batteries, better integration, and lower cost inverters

- **Battery module prices are expected to continue declining, driven by sustained manufacturing competition**
- **System integration costs will decline as more and larger electrical equipment manufacturers enter the energy storage market**
- **Energy storage inverters continue to follow solar inverter price declines, with sustained price reductions expected in the coming years**

Expected Energy Storage Capital Cost Declines(1)

Five-Year Cost Decrease Outlook (CAGR %)



Observations

- **Advance Lead:** Enhanced performance allows some competition with lithium-ion in small-to-medium-sized commercial systems
- **Lead:** Continues to be a low-cost option; OEMs looking to expand deployment to applications with low cycling requirement
- **Flow Battery–Vanadium:** Cost reductions continue to present the greatest competitive position for any flow batteries, especially at the 8-Hr applications
- **Flow Battery–Zinc Bromide:** Continued cost reduction seen, but ZnBr technology limited by plating requirements. Modular system designs allow for wider range of longer-duration application possibilities, but requires additional design and integration requirements
- **Lithium–Ion:** Continued strong price declines expected, especially at the very large system scale where purchasing power allows significant competition from developers

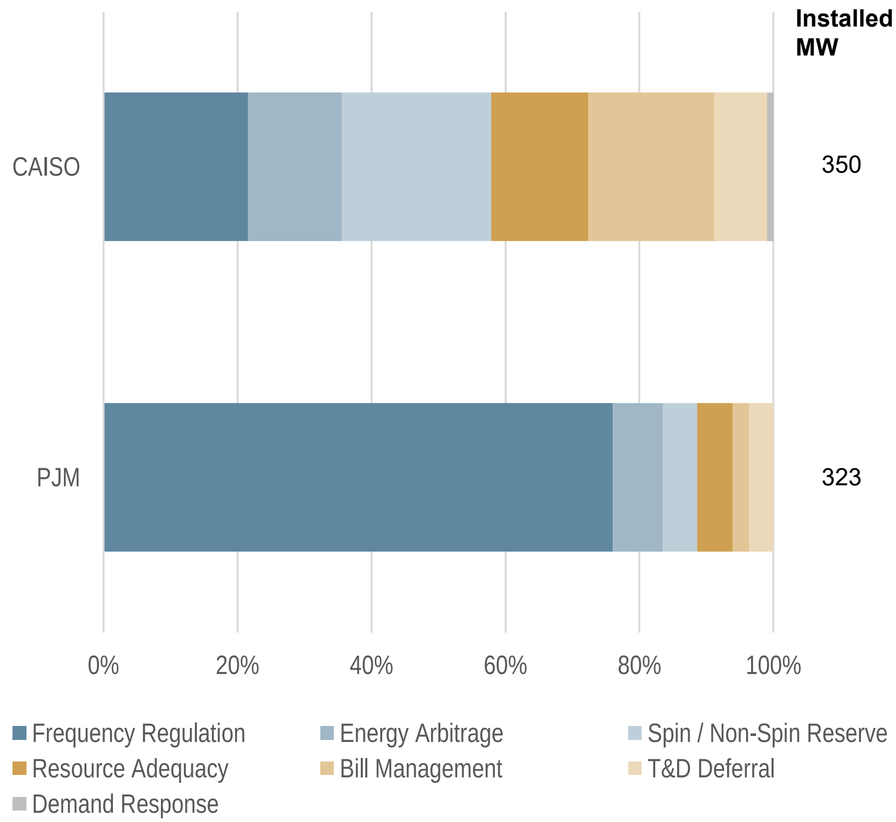
Source: Lazard and Enovation Partners analysis.
(1) Technology cost decreases reflect weighted-average estimates across all use cases.

IV Energy Storage Revenue Streams

Currently Identifiable Sources of Revenue for Energy Storage Projects

As the energy storage market continues to evolve, several forms of potential revenue streams have emerged in selected U.S. markets; **Lazard's LCOS analyzes only those revenue streams that are quantifiable and identifiable from currently deployed energy stora**ge systems

Selected U.S. Energy Storage Projects vs. Stated Revenue Stream (2017)(1)



Although energy storage developers/project owners often include Energy Arbitrage and Spinning/Non-Spinning Reserves as sources of revenue for commissioned energy storage projects, Frequency Regulation, Bill Management and Resource Adequacy are currently the predominant forms of realized sources of revenue

Key Drivers of Energy Storage Market Growth

- **Enabling policies:** Include explicit targets and/or state goals incentivizing procurement of energy storage
  - Example—CA energy storage procurement targets (e.g., AB2514) require 1,325 MW by 2020
- **Incentives:** Upfront or performance-based incentive payments to subsidize initial capital requirements
  - Example—CA Self-Generation Incentive Programs ("SGIP"): $450 million budget available to behind-the-meter storage
- **Market fundamentals:** Endogenous market conditions resulting in higher revenue potential and/or increased opportunity to participate in wholesale markets
  - Example—CA Real-Time Energy: 100+ hours with >$200/MWh locational marginal price in 2016
- **Favorable wholesale/utility program rules:** Accessible revenue sources with operational requirements favoring fast-responding assets
  - Example—PJM Reg. D: avg. prices of $15.5/eff. MW in 2016, with significant revenue upside for performance for storage
- **High Peak and/or Demand Charges:** Opportunities to avoid utility charges through peak load management during specified periods or system peak hours
  - Example—ERCOT 4CP Transmission Charges: ~$2 – $5/kW-mo. Charges applied to customers during system coincident peak hours in summer months

Source: DOE Global Energy Storage Database, Lazard and Enovation Partners estimates.

(1) Includes electro-chemical, electro mechanical, and thermal energy storage technologies. Only operating projects as of Q3 2017 included. Percentage allocations do not account for multiple stated use cases, and thus are not directly proportional to total installed MW. Allocations do not consider frequency of participation in stated revenue streams, and thus do not reflect revenue mix associated with projects across markets. Non-quantifiable use cases (e.g., Black Start, Ramping, Voltage Control, Resiliency, Microgrid) are not shown.

LAZARD

Overview of Selected Energy Storage Revenue Sources

Numerous potential sources of revenue available to energy storage reflect system and customer benefits provided by projects

- **Given the methodological approach employed in the LCOS, the scope of revenue sources is limited to those actually applied in existing or soon-to-be commissioned projects**
- **Revenue sources that are not identifiable or without publicly available price data (e.g., Black Start, Ramping, Voltage Control, Resiliency, Microgrid) are not analyzed**

		Description
A Wholesale	Demand Response–Wholesale	• Manages high wholesale price or emergency conditions on the grid by calling on users to reduce or shift electricity demand
	Energy Arbitrage	• Allows storage of inexpensive electricity to sell at a higher price later (includes only wholesale electricity purchase)
	Frequency Regulation	• Provides immediate (4-second) power to maintain generation-load balance and prevent frequency fluctuations
	Resource Adequacy	• Provides capacity to meet generation requirements at peak loading in a region with limited generation and/or transmission capacity
	Spin/Non-Spin Reserve	• Maintains electricity output during unexpected contingency event (e.g., an outage) immediately (spinning reserve) or within a short period (non-spinning reserve)
B Utility	Distribution Deferral	• Provide extra capacity to meet projected load growth for the purpose of delaying, reducing or avoiding distribution system investment in a region
	Transmission Deferral	• Provide extra capacity to meet projected load growth for the purpose of delaying, reducing or avoiding transmission system investment
	Demand Response–Utility	• Manages high wholesale price or emergency conditions on the grid by calling on users to reduce or shift electricity demand
C Customer	Bill Management	• Allows reduction of demand charge using battery discharge and the daily storage of electricity for use when time of use rates are highest
	Backup Power	• Supplies power reserve for use by Residential and Commercial when the grid is down

Revenue Sources Available to Different Use Cases

Revenue sources available for energy storage can be categorized according to the type of entity paying the project owner; a wholesale market (e.g., PJM, CAISO), a wires or integrated utility or a customer (potentially via a competitive retailer or aggregator)

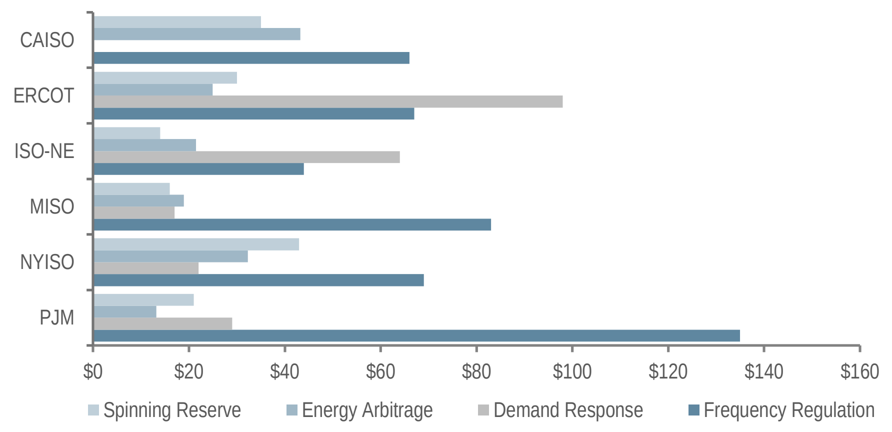
- **Available revenue sources for a given use case depend partially on the technical configuration of the energy storage system, including maximum power and usable energy, as well as permissible number of cycles per day and/or over the life of the project**
- **In addition, ISO and utility-specific regulations determine the combination of different potential revenue streams which can be pursued together (simultaneously or in sequence)**
- **A project's optimal combination of revenue sources may thus reflect trade-offs between different sources or modifying the equipment configuration (e.g., over-sizing or derating units)**

	Typical Revenue Sources									
	A Wholesale					B Utility			C Customer	
Use Case	Energy Arbitrage	Frequency Regulation	Demand Response (Wholesale)	Spin/Non-Spin Reserve	Resource Adequacy	Distribution Deferral	Transmission Deferral	Demand Response-Utility	Bill Management	Backup Power
Peaker Replacement	✓	✓		✓	✓					
Distribution					✓	✓	✓			
Microgrid	✓	✓	✓	✓	✓	✓		✓	✓	✓
Commercial		✓	✓	✓	✓	✓		✓	✓	✓
Residential			✓					✓	✓	

A Wholesale Market Revenue Streams

Availability and value of wholesale market products to energy storage varies based on ISO rules and project specifications

2016 Wholesale Revenue Streams ($/kW-yr.)



Assumptions Employed

- Energy markets
  - Assumed perfect foresight
  - Daily charging at the minimum price, discharge at maximum
  - Efficiency loss estimate 90%
- Frequency regulation
  - Assumed participation in day ahead market(s) and fast response, energy neutral and continuous market where available
  - Assumed either 90% performance factor or ISO-wide average performance if reported
  - Assumed system average mileage ratio (fast resources where available)
- Spinning Reserve
  - Assumed capable to participate in spinning reserve market
  - Self scheduled/price taker in the day ahead market
- Demand Response
  - Revenue estimates are based on DR program-enabled participation in the capacity markets (NYISO, PJM and ISO-NE), responsive reserve service (ERCOT) and resource adequacy & spinning reserve (MISO)
  - Energy payments outside of these markets are not included in revenue estimates

Resource Adequacy ("RA") Revenue Streams

CAISO: Distributed resources in CAISO can access resource adequacy payments through one of two auction programs run by the IOUs

- Local Capacity Resource ("LCR") Auction
  - IOUs acquire RA and DR-like capabilities from bidders in a pay-as-bid 10-year contract auction
  - Focused on providing capacity to constrained zones
- Demand Response Auction Mechanism ("DRAM") Pilot
  - IOUs acquire RA for 1 – 2 years and Distributed Energy Resources ("DERs") assets are given a type of must-bid responsibility in the wholesale markets
  - Focused on creating new opportunities for DERs to participate in wholesale markets
- Estimate of $35/kW-yr. – $60/kW-yr.

MISO: Energy storage can qualify in MISO as behind-the-meter generation and participate alongside all conventional resources in public Planning Resource Auction ("PRA")

- Estimate of $0.55/kW-yr. based on the notably poor 2016 auction which was criticized for its unsustainably low outcomes by the independent market monitor

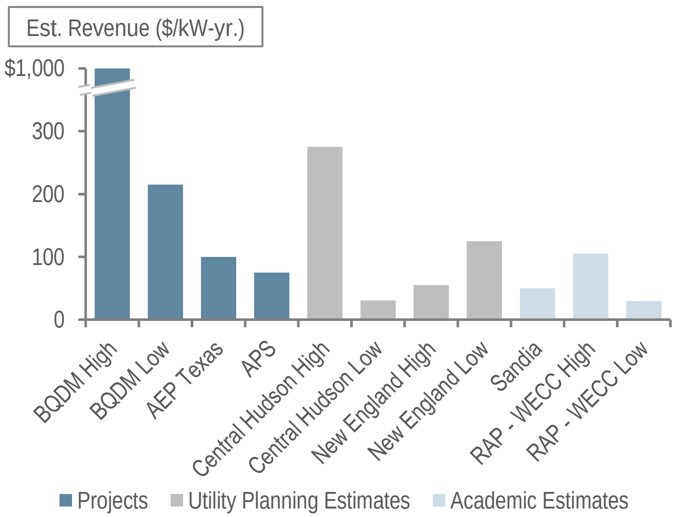
Technical Factors Impacting Value/Availability of Wholesale Revenue Stream Issue

Technical Factor	Description	Streams Impacted
Minimum Size	There is a minimum size to qualify as a generator, under which the asset must qualify through an ISO DR program or by aggregation	All
Energy Neutrality	Some ISOs provide FR signals that are energy neutral over a set time period and thus allow energy storage assets to perform better	Frequency Regulation
Performance	The ability to accurately follow the AGC signal and the energy to meet performance standards throughout the course of an hour will have a strong impact on payment from the FR market	Frequency Regulation
Qualification Method	If an energy storage asset qualifies for the wholesale markets through a DR program, there may be limitations placed on the asset or additional revenues sources available (beyond capacity)	DR Programs
Congestion Constraints	The Locational Based Marginal Pricing ("LBMP") for an energy storage asset will be different from the system-wide energy price (used here), as will the spread between daily high and daily low price	Energy Arbitrage

B Utility Revenue Streams

Utilities provide valuable revenue sources in exchange for location-based grid services, with most common applications being in utility DR programs and T&D deferral applications

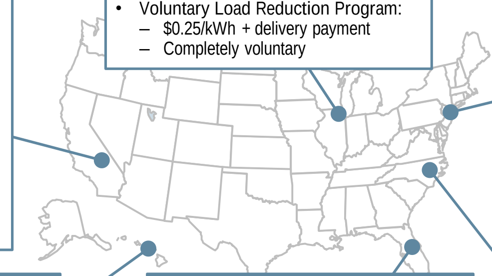
Value of Deferral



Observations

- Jurisdictional and regulatory concerns have limited deployment thus far
- Transacted values do not typically equal price; in most installations value substantially exceeds price
- Assets are typically transacted as a capital purchase by utilities
- Asset value is highly location dependent
- Deferral length varies based on factors independent of the battery
- Projects are rarely transacted in absence of other revenue streams

Utility Funded Demand Response Programs—Examples



CA IOUs
- Capacity Bidding Program (**"CBP"**):
  – PG&E: ~$9.9/kW-mo., 6 mo.
  – SCE: ~$4.5/kW-mo., 12 mo.
  – SDG&E: Varies on notice, from $10.6 – $15.2/kW-mo., 6 mo.
- Base Interruptible Program (**"BIP"**):
  – PG&E: $8 – $9/kW-mo., 12 mo.
  – SCE: $24 – $30/kW-mo., 6 mo.
  – SDG&E: $12/kW-mo. summer, $2/kW-mo. winter
- Demand Bidding Program
  – $0.50/kWh during events

Com Edison
- Voluntary Load Reduction Program:
  – $0.25/kWh + delivery payment
  – Completely voluntary

ConEd
- Commercial System Relief Program (**"CSRP"**):
  – $6 – $18/kW-mo., depending on location
  – 5 mo. period, $1/kWh
- Distribution Load Reduction Program (DLRP):
  – $18 – $25/kW-mo., depending on location
  – 5 mo. period, $1/kWh

Hawaiian Electric
- Fast DR Pilot Program:
  – $5/kW-mo., 12 mo.
  – $0.50/kWh during events

FPL
- Commercial Demand Reduction Program:
  – $8.20/kW-mo.
  – FPL controls the asset during events

Duke Energy Progress
- Demand Response Automation (**"DRA"**) Program:
  – $3.25/kW-mo. + $500/kW for 1st & 2nd event + $6/kW at each event

Observations

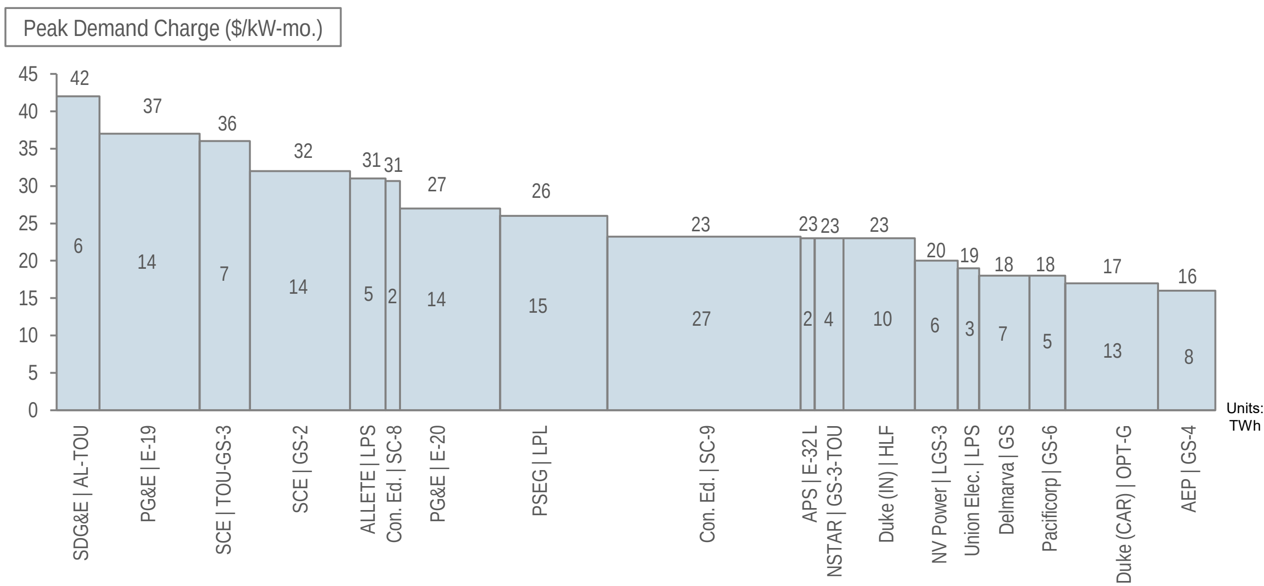
- Capacity type programs
  – Paid a substantial standby payment to be available on a monthly or seasonal basis
  – Paid a comparatively lesser rate per energy reduced when called
  – Calls are typically mandatory
  – Tend to have harsher penalties for underperformance
- Energy type programs
  – Paid only based on energy reduced
  – No capacity payment, often DR calls are not mandatory
  – Penalties are rare and when they do exist, tend to be less severe than in capacity type programs
- Common issues to DR programs
  – Length of notice
  – Payment size and ratio of capacity to energy payments
  – Frequency of calls
  – Call trigger (supply economics or emergency situation)
  – Severity of penalty
  – Baseline methodology (how the demand reduction is calculated based on prior energy usage)

Source: Utility Dive, GTM, AEP Central Hudson and ISO NE regulatory filings, Sandia and WWECC.

C Customer Revenue Streams

Utility bill management is a key driver of returns for behind-the-meter energy storage projects; project-specific needs for reliability and microgrid integration can be significant, but currently are rarely monetized

Representative Utility Demand Charges & Reported Volumes (2016)[(1)(2)]



Additional Avoidable Retail Electricity Charges

Type	Example	Description	Charge (2017 $/kW-yr.)[(3)]
Capacity	PJM GENCAP	• Applied to avg. load usage during PJM's 5 noncoincident peak; referred to as 5CP hours	• RTO: 44 • PSEG: 78
Transmission	ERCOT 4CP	• Applied to avg. load during system coincidental peaks occurring in June, July, August and September	• CNP: 9 • Oncor: 17 • TNMP: 22

Reliability Benefits

- Microgrid integration
  - Energy storage as part of an islanding microgrid system can substantially improve reliability
  - Storage units within microgrids are usually purchased outright or financed rather than contracted as a service
  - The benefit of increased reliability to a microgrid varies substantially based on the types of generating assets on the island
- Behind-the-meter reliability
  - Behind-the-meter energy storage installations designed to provide outage protection are challenged by the high overall reliability of the grid
  - Storage units sized to provide other benefits (e.g. demand charge reduction) often are too small to provide long-term reliability
  - Best example of payment for long-term reliability is from Texas, priced at $8 – $10/kW-mo.

Source: FERC Form 1 Filings, PUC of TX; PJM RPM; OpenEI; Lazard and Enovation Partners estimates.
(1) Demand charges are fixed, monthly costs typically limited to commercial customers. The rate is typically a function of a customer's peak demand as measured over a pre-defined period. Energy storage can enable customers to save money through reducing peak consumption, lowering their demand charge.
(2) Non-exhaustive list based on FERC Form 1 total reported TWh by tariff, sorted by highest total demand charges during peak periods.
(3) Values based on PJM 17/18 DY Reliability Pricing Model results & Transmission Cost Recovery Factors for customers with >5kVA demand in ERCOT.

V Illustrative Energy Storage Value Snapshots

Illustrative Value Snapshots—Introduction

While the LCOS methodology allows for "apples-to-apples" comparisons within use cases, it is narrowly focused on costs, based on an extensive survey of suppliers and market participants. To supplement, Lazard has included several **illustrative "Value Snapshots" that reflect** typical economics associated with merchant behind-the-meter and in-front-of-the-meter storage projects across geographies

- **Based on illustrative storage systems configured to capture value streams available in a number of ISOs/RTOs**
  - Streams serving RTO markets (energy arbitrage, frequency regulation, spin/non-spin and demand response)
  - Streams serving utilities (demand response, transmission deferral and distribution deferral)
  - Streams serving customers (bill management and backup power)
  - Behind-the-Meter load profiles based on California-specific US-DOE standard medium/large-sized commercial building profile load and example residential profiles
  - Specific tariff rates reflect medium or large commercial power with peak load floors and caps of 10 kW and 100 kW, respectively; assumes demand charges ranging from $4 to $53 per peak kW, depending on jurisdiction and customer type
  - Assumes state-level, non-tax-oriented incentive payments (e.g., LCR/SGIP in California and NY-BEST in New York) are treated as taxable income for federal income tax purposes(1)
- **Cost estimates(2) based on LCOS framework (i.e., assumptions regarding O&M, warranties, etc.), but sized to reflect the system configuration described above**
  - System size and performance adjusted to capture multiple value streams and to reflect estimated regional differences in system installation costs(3)
  - System costs based on individual component (lithium-ion battery, inverter, etc.) sizing based on the needs determined in the analysis
  - Operational performance specifications required to serve various modeled revenue streams, based on lithium-ion system in LCOS v3.0 (cycling life, Depth of Discharge, etc.)
- **System economic viability described by Illustrative Value Snapshot-levered IRR(4)**

Note: All "value snapshots" assume Lithium-Ion batteries.
(1) Based on discussions with developers of merchant storage projects in New York and California.
(2) "Costs" for Illustrative Value Snapshots denote actual cost-oriented line items, not "LCOS" costs (i.e., $/MWh required to satisfy assumed equity cost of capital).
(3) Based on survey data and proprietary Enovation Partners case experience.
(4) This report does not attempt to determine "base" or "typical" IRRs associated with a given market or region. Results and viability are purely illustrative and may differ from actual project results.

Illustrative Value Snapshots

Lazard's LCOS analyzes the financial viability of illustrative energy storage projects for selected use cases; geographic regions, assumed installed and operating costs and associated revenue streams reflect current market activity

- **Actual project returns may vary due to differences in location-specific costs, revenue streams and owner/developer risk preferences**
- **Detailed cash flow statements for each project, along with underlying assumptions, follow below**

Use Case	Location	Owner	Revenue Streams
Peaker Replacement	CAISO (SP-15)	• IPP in a competitive wholesale market	• Wholesale market settlement • Local capacity resource programs
Distribution	NYISO (New York City)	• Wires utility in a competitive wholesale market	• Capital recovery in regulated rates, avoided cost to wires utility, NY-BEST and other avoided cost incentives
Microgrid – RE Integration	ISO-NE (Boston)	• IPP in a competitive wholesale market	• Wholesale market settlement, avoided costs to loads within the microgrids, and direct payments from loads within the microgrid, investment tax credit
Commercial	CAISO (San Francisco)	• Customer or financier in a competitive wholesale area	• Wholesale market settlement, tariff settlement, DR participation, avoided costs to commercial customer (PG&E E-19 TOU rate), local capacity resource programs
Residential	CAISO (San Francisco)	• Customer or financier	• DR participation, tariff settlement, avoided costs to residential customer (PG&E TOU E-6) and SGIP

Note: California residential modeled residential profiles use a rate that was closed to new customers after 2016; modeling assumes grandfathered customers seeking the best opportunity for storage benefits.

Illustrative Value Snapshots—Summary Results and Assumptions

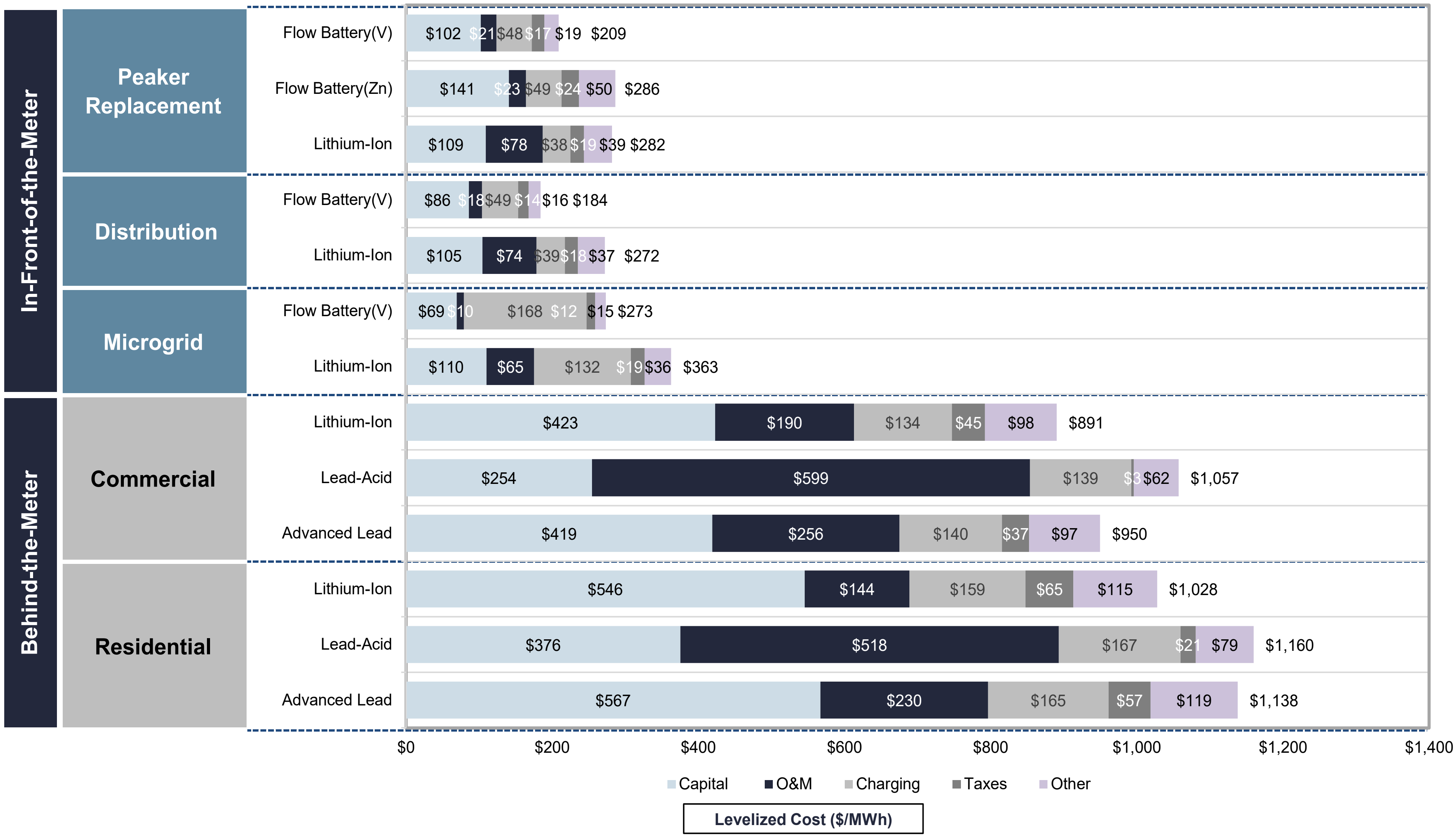
	Peaker Replacement	Distribution	Microgrid	Commercial	Residential
Region	CAISO	NYISO	ISO-NE	CAISO	CAISO
Revenue Sources(1)					
Energy Arbitrage	24.1%	- -	37.0%	- -	- -
Frequency Regulation	4.1%	2.2%	2.3%	- -	- -
Spin/Non-Spin Reserve	- -	- -	- -	- -	- -
Resource Adequacy	71.8%	17.4%	- -	55.4%(2)	- -
Dist. Deferral	- -	42.5%	- -	- -	- -
Trans. Deferral	- -	37.9%	- -	- -	- -
DR–Wholesale	- -	- -	60.7%	- -	- -
DR–Utility	- -	- -	- -	11.6%	77.8%
Bill Management	- -	- -	- -	33.0%	22.2%
Energy Storage Configuration					
Battery Size (MWh)	400	80	4	0.250	0.010
Inverter Size (MW)	100	10	1	0.125	0.005
C-Rating	C/4	C/6	C/4	C/2	C/2
Cycles Per Year (Full DoD)	91	15	127	169	200
IRR	8.8%	20.8%(3)	N/A	10.9%	N/A(4)
Economic Viability(5)	Potentially Viable	Viable	Not Viable	Viable	Not Viable

Source: *DOE, Lazard and Enovation Partners estimates.*
Note: Augmentation costs are adjusted to reflect the number of actual cycles versus projected cycles outlined in the operational parameters.
(1) Percentages reflect share of total project revenue and cost savings associated with each source of such revenue/cost savings. Revenue includes savings, market revenue and incentives/subsidies.
(2) Includes benefits from Local Capacity Resource programs.
(3) Includes 50% NYSERDA ("NY-BEST") incentive.
(4) Includes 40% Self-Generation Incentive Program ("SGIP") incentive.
(5) Systems are considered economically viable if they generate levered returns over 10%. Required returns/hurdle rates may vary in practice by market participant.

Appendix

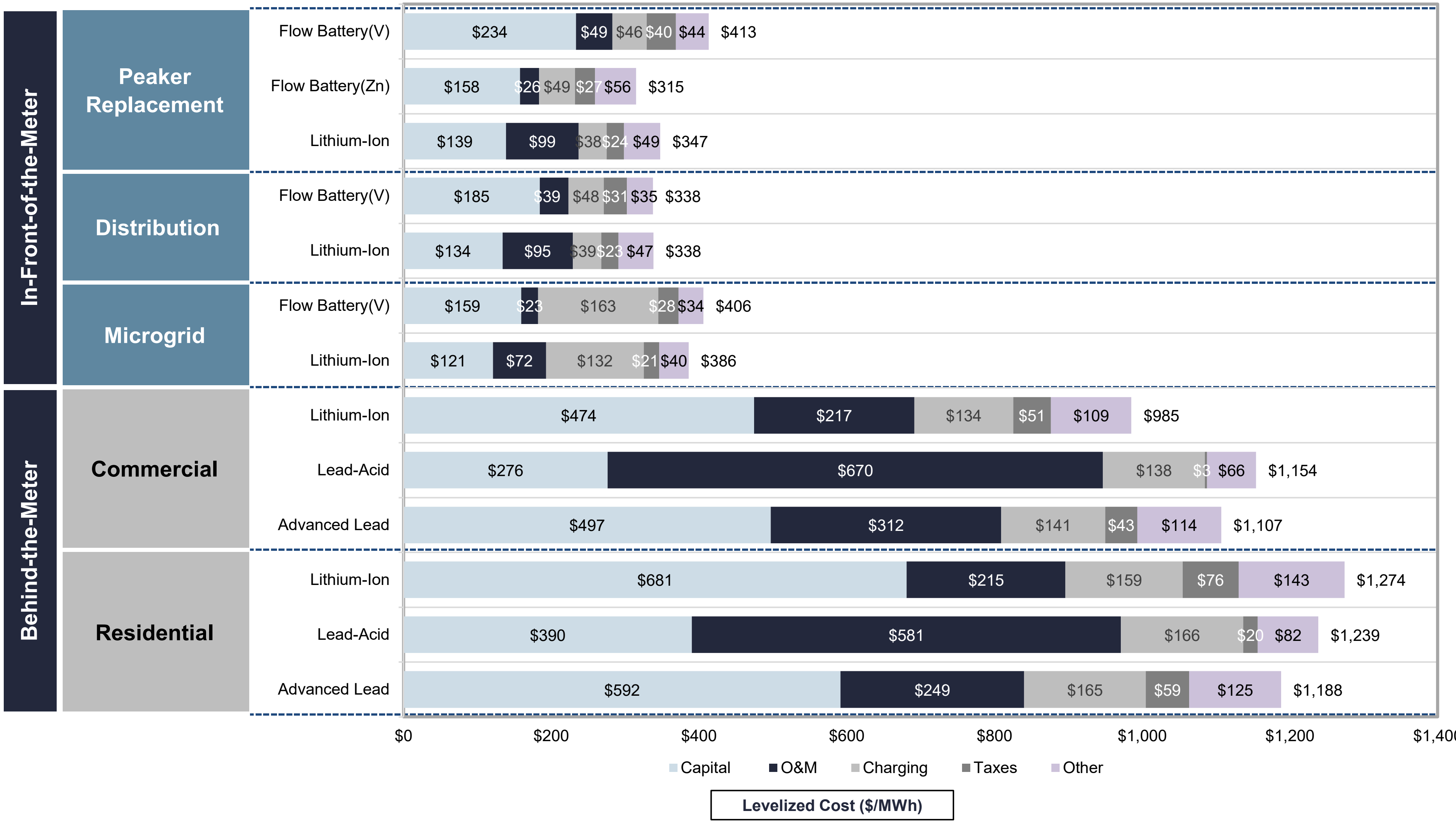
A Supplementary LCOS Analysis Materials

Levelized Cost of Storage Components—Low



Source: *Lazard and Enovation Partners estimates.*
Note: O&M costs include augmentation costs.

Levelized Cost of Storage Components—High



Source: *Lazard and Enovation Partners estimates.*
Note: O&M costs include augmentation costs.

Levelized Cost of Storage—Key Assumptions

		Peaker Replacement			Distribution Substation		Microgrid	
	Units	Flow Battery (Vanadium)	Flow Battery (Zinc-Bromine)	Lithium	Flow Battery (Vanadium)	Lithium	Flow Battery (Vanadium)	Lithium
Power Rating	MW	100 – 100	100 – 100	100 – 100	10 – 10	10 – 10	1 – 1	1 – 1
Duration	Hours	4 – 4	4 – 4	4 – 4	6 – 6	6 – 6	4 – 4	4 – 4
Usable Energy	MWh	400 – 400	400 – 400	400 – 400	60 – 60	60 – 60	4 – 4	4 – 4
100% Depth of Discharge Cycles/Day		1 – 1	1 – 1	1 – 1	1 – 1	1 – 1	2 – 2	2 – 2
Operating Days/Year		350 – 350	350 – 350	350 – 350	350 – 350	350 – 350	350 – 350	350 – 350
Project Life	Years	20 – 20	20 – 20	20 – 20	20 – 20	20 – 20	10 – 10	10 – 10
Memo: Annual Used Energy	MWh	140,000 – 140,000	140,000 – 140,000	140,000 – 140,000	21,000 – 21,000	21,000 – 21,000	2,800 – 2,800	2,800 – 2,800
Memo: Project Used Energy	MWh	2,800,000 – 2,800,000	2,800,000 – 2,800,000	2,800,000 – 2,800,000	420,000 – 420,000	420,000 – 420,000	28,000 – 28,000	28,000 – 28,000
Initial Capital Cost—DC	$/kWh	$313 – $713	$400 – $450	$307 – $397	$264 – $563	$302 – $392	$313 – $713	$455 – $504
Initial Capital Cost—AC	$/kWh	$0 – $0	$28 – $28	$28 – $28	$0 – $0	$19 – $19	$0 – $0	$39 – $39
Initial Other Owners Costs	$/kWh	$47 – $107	$64 – $72	$50 – $64	$40 – $84	$48 – $62	$63 – $143	$99 – $109
Total Initial Installed Cost	$/kWh	$360 – $819	$492 – $550	$385 – $489	$303 – $647	$368 – $472	$376 – $855	$593 – $652
O&M Cost	$/kWh	$2.88 – $6.56	$3.08 – $3.43	$2.44 – $3.06	$0.36 – $0.78	$0.34 – $0.44	$0.03 – $0.07	$0.04 – $0.04
O&M % of Capex	%	0.80% – 0.80%	0.63% – 0.62%	0.63% – 0.63%	0.12% – 0.12%	0.09% – 0.09%	0.01% – 0.01%	0.01% – 0.01%
Warranty Expense	$	$0.000 – $0.000	$3.423 – $3.823	$2.676 – $3.400	$0.000 – $0.000	$0.384 – $0.493	$0.000 – $0.000	$0.040 – $0.043
Augmentation Charge	$	$0.000 – $0.000	$0.000 – $0.000	$8.029 – $10.200	$0.000 – $0.000	$1.153 – $1.478	$0.000 – $0.000	$0.143 – $0.157
Augmentation Charge (Oversize)	$	$0.000 – $0.000	$0.000 – $0.000	$0.000 – $0.000	$0.000 – $0.000	$0.000 – $0.000	$0.000 – $0.000	$0.000 – $0.000
Augmentation Charge (Year 6)	$	$0.000 – $0.000	$0.000 – $0.000	$0.000 – $0.000	$0.000 – $0.000	$0.000 – $0.000	$0.000 – $0.000	$0.000 – $0.000
Investment Tax Credit	%	0.0% – 0.0%	0.0% – 0.0%	0.0% – 0.0%	0.0% – 0.0%	0.0% – 0.0%	0.0% – 0.0%	0.0% – 0.0%
Production Tax Credit	$/MWh	$0 – $0	$0 – $0	$0 – $0	$0 – $0	$0 – $0	$0 – $0	$0 – $0
Charging Cost	$/MWh	$30 – $30	$30 – $30	$30 – $30	$30 – $30	$30 – $30	$106 – $106	$106 – $106
Charging Cost Escalator	%	0.9% – 0.9%	0.9% – 0.9%	0.9% – 0.9%	0.9% – 0.9%	0.9% – 0.9%	1.0% – 1.0%	1.0% – 1.0%
Efficiency	%	67% – 70%	67% – 67%	86% – 86%	67% – 70%	86% – 86%	67% – 70%	86% – 86%
Levelized Cost of Storage	$/MWh	$209 – $413	$286 – $315	$282 – $347	$184 – $338	$272 – $338	$273 – $406	$363 – $386

Source: *Lazard and Enovation Partners estimates.*
Note: Assumed conservative capital structure of 80% equity (with a 12% cost of equity) and 20% debt (with an 8% cost of debt). Capital cost units are the total investment divided by the storage equipment's energy capacity (kWh rating) and inverter rating (kW rating).

Levelized Cost of Storage—Key Assumptions (cont'd)

		Commercial			Residential		
	Units	Lithium	Lead	Advanced Lead	Lithium	Lead	Advanced Lead
Power Rating	MW	0.125 – 0.125	0.125 – 0.125	0.125 – 0.125	0.005 – 0.005	0.005 – 0.005	0.005 – 0.005
Duration	Hours	2 – 2	2 – 2	2 – 2	2 – 2	2 – 2	2 – 2
Usable Energy	MWh	0.25 – 0.25	0.25 – 0.25	0.25 – 0.25	0.01 – 0.01	0.01 – 0.01	0.01 – 0.01
100% Depth of Discharge Cycles/Day		1 – 1	1 – 1	1 – 1	1 – 1	1 – 1	1 – 1
Operating Days/Year		250 – 250	250 – 250	250 – 250	250 – 250	250 – 250	250 – 250
Project Life	Years	10 – 10	10 – 10	10 – 10	10 – 10	10 – 10	10 – 10
Memo: Annual Used Energy	MWh	63 – 63	63 – 63	63 – 63	3 – 3	3 – 3	3 – 3
Memo: Project Used Energy	MWh	625 – 625	625 – 625	625 – 625	25 – 25	25 – 25	25 – 25
Initial Capital Cost—DC	$/kWh	$520 – $597	$322 – $362	$516 – $634	$517 – $775	$284 – $321	$562 – $609
Initial Capital Cost—AC	$/kWh	$123 – $123	$123 – $123	$123 – $123	$314 – $314	$314 – $314	$314 – $314
Initial Other Owners Costs	$/kWh	$161 – $180	$111 – $121	$160 – $189	$200 – $200	$200 – $200	$200 – $200
Total Initial Installed Cost	$/kWh	$804 – $900	$556 – $606	$800 – $946	$1,031 – $1,289	$798 – $835	$1,076 – $1,123
O&M Cost	$/kWh	$0.00 – $0.00	$0.00 – $0.00	$0.00 – $0.00	$0.00 – $0.00	$0.00 – $0.00	$0.00 – $0.00
O&M % of Capex	%	0.00% – 0.00%	0.00% – 0.00%	0.00% – 0.00%	0.00% – 0.00%	0.00% – 0.00%	0.00% – 0.00%
Warranty Expense	$	$0.001 – $0.001	$0.001 – $0.001	$0.001 – $0.001	$0.000 – $0.000	$0.000 – $0.000	$0.000 – $0.000
Augmentation Charge	$	$0.000 – $0.000	$0.000 – $0.000	$0.000 – $0.000	$0.000 – $0.000	$0.000 – $0.000	$0.000 – $0.000
Augmentation Charge (Oversize)	$	$0.055 – $0.063	$0.125 – $0.140	$0.080 – $0.098	$0.002 – $0.003	$0.004 – $0.005	$0.003 – $0.004
Augmentation Charge (Year 6)	$	$0.000 – $0.000	$0.125 – $0.140	$0.000 – $0.000	$0.000 – $0.000	$0.004 – $0.005	$0.000 – $0.000
Investment Tax Credit	%	0.0% – 0.0%	0.0% – 0.0%	0.0% – 0.0%	0.0% – 0.0%	0.0% – 0.0%	0.0% – 0.0%
Production Tax Credit	$/MWh	$0 – $0	$0 – $0	$0 – $0	$0 – $0	$0 – $0	$0 – $0
Charging Cost	$/MWh	$106 – $106	$106 – $106	$106 – $106	$124 – $124	$124 – $124	$124 – $124
Charging Cost Escalator	%	1.0% – 1.0%	1.0% – 1.0%	1.0% – 1.0%	1.0% – 1.0%	1.0% – 1.0%	1.0% – 1.0%
Efficiency	%	86% – 86%	72% – 72%	82% – 82%	85% – 85%	72% – 72%	82% – 82%
Levelized Cost of Storage	$/MWh	$891 – $985	$1,057 – $1,154	$950 – $1,107	$1,028 – $1,274	$1,160 – $1,239	$1,138 – $1,188

Source: *Lazard and Enovation Partners estimates.*
Note: Assumed conservative capital structure of 80% equity (with a 12% cost of equity) and 20% debt (with an 8% cost of debt). Capital cost units are the total investment divided by the storage equipment's energy capacity (kWh rating) and inverter rating (kW rating).

Charging Cost and Escalation Assumptions

	Charging Cost ($/MWh)	Charging Cost Source	Charging Cost Escalation (%)	Charging Cost Escalation Source
Peaker Replacement	$29.50	EIA 2016 Wholesale Price $/MWh—Weighted Average (Low)	0.9%	EIA AEO 2017 Energy Source–Electric Price Forecast (10-year CAGR)
Transmission/ Distribution	$30.30	EIA 2016 Wholesale Price $/MWh—Weighted Average	0.9%	EIA AEO 2017 Energy Source–Electric Price Forecast (10-year CAGR)
Microgrid	$106.40	EIA Average Commercial Retail Price 2016	1.0%	EIA AEO 2017 Commercial Electric Price Forecast (10-year CAGR)
Commercial	$106.40	EIA Average Commercial Retail Price 2016	1.0%	EIA AEO 2017 Commercial Electric Price Forecast (10-year CAGR)
Residential	$124.40	EIA Average Residential Retail Price 2016	1.0%	EIA AEO 2017 Residential Electric Price Forecast (10-year CAGR)

Source: EIA, Lazard and Enovation estimates.

B Supplementary Value Snapshot Materials

Illustrative Value Snapshots—Assumptions

	Revenue Source	Description	Modeled Price	Annual Rev. ($/kW-year)	Cost Assumptions
Peaker Replacement	Energy Arbitrage	• Energy prices based on 2015 CAISO-SP-15 real-time • Annual escalation of 0.9%	Hourly LMP	$80.09	• AC system: $28/kWh • DC system: $346/kWh • EPC: 15% • Efficiency: 85% • Augmentation Costs: 3.3% of BESS
	Frequency Regulation	• Includes Reg-Up and Reg-Down products; participation based on hourly price and battery state of charge	$7.6/MWh	$13.64	
	Resource Adequacy	• Assumes participation in SCE Local Capacity Resource programs • Reliability ($/kW-mo.) payment amounts vary by contract and are not publicly available • Estimates assume a modified Net CONE methodology based on assumed technology costs and other available revenue sources	$19.83/kW-mo	$283	
Distribution	Frequency Regulation	• Includes Reg-Up and Reg-Down products; participation based on hourly price and battery state of charge	$7.9/MWh	$11.89	• AC system: $14/kWh • DC system: $341/kWh • EPC: 15% • Efficiency: 85% • Augmentation Costs: 3.0% of BESS
	Resource Adequacy	• NYC Zone J ICAP annual estimates	Summer: $12/kW-mo Winter: $3.5/kW-mo	$93.00	
	Brooklyn-Queens Demand Management (BQDM)	• Program based on deferred $1.2 billion substation upgrade, driven by contracts for demand reductions and distributed resource investments • Estimates based on program expense and capacity	$4,545.45/kW	$227.27	
	NYSERDA Energy Storage Programs	• Upfront incentives for storage projects supporting technology development, demonstrating value stacking, and reducing soft costs	50% of eligible installed capital	$81.31	

Source: *ISO/RTO markets, DOE, Lazard and Enovation Partners estimates.*
Note: Capital cost units are the total investment divided by the storage equipment's energy capacity (kWh rating) and inverter rating (kW rating).

Illustrative Value Snapshots—Assumptions (cont'd)

	Revenue Source	Description	Modeled Price	Modeled Rev. ($/kW-yr.)	Cost Assumptions
Microgrid	Energy Arbitrage	• Energy prices based on 2015 ISO-NE NEMASSBOS real-time • Annual escalation of 2.5%	Hourly LMP	39.07	• AC system: $39/kWh • DC system: $478/kWh • EPC: 20% • Efficiency: 85% • Augmentation Costs: 3.2% of BESS
	Frequency Regulation	• Participation based on hourly price and battery state of charge	$5/MWh	2.42	
	Capacity	• Behind-the-meter resources providing capacity to meet ISO–NE generation requirements	$5.3/kW-mo.	64.00	
Commercial	Local Capacity Resources	• IOUs acquire RA from bidders in a pay-as-bid 10-year contract auction • Focused on providing capacity to constrained zones	$238kW-yr.	238.31	• AC system: $123/kWh • DC system: $542/kWh • EPC: 25% • Efficiency: 85% • Augmentation Costs: 22.0% of BESS
	Demand Bidding Program ("DBP")	• Year-round, event-based program; credited for 50% – 200% of event performance; no underperformance penalties	$0.5/kWh	50.00	
	Bill Management	• Reduction of demand and energy charges through time shifting • Prices netted on PG&E E-19 TOU rate • Annual escalation of 2.5%	PG&E E-19 TOU Tariff	141.81	
Residential	Self-Generation Incentive Program	• Provides incentives to support DER projects via performance-based rebates for qualifying distributed energy systems	$0.35/Wh	46.65	• AC system: $314/kWh • DC system: $652/kWh • EPC: 0% • Efficiency: 85% • Augmentation Costs: 30.0% of BESS
	Third-Party Demand Response	• Electric Rule 24 allows participation in 3rd party offered demand response programs • Rates are negotiated between 3rd party and customer, not PG&E	$0.5/kWh	100.00	
	Bill Management	• Reduction of demand and energy charges through time shifting • Prices netted on PG&E E-6 TOU rate • Annual escalation of 2.5%	PG&E E-6 TOU Tariff	28.57	

Source: ISO/RTO markets, DOE, Lazard and Enovation Partners estimates.
Note: Capital cost units are the total investment divided by the storage equipment's energy capacity (kWh rating) and inverter rating (kW rating).

Illustrative Value Snapshot—CAISO Peaker Replacement

($ in thousands, unless otherwise noted)

CA	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Revenue	**$0**	**$33,205**	**$33,290**	**$33,375**	**$33,461**	**$33,547**	**$33,635**	**$33,723**	**$33,812**	**$33,902**	**$33,992**
Energy Arbitrage (1)	0	8,009	8,081	8,154	8,227	8,301	8,376	8,451	8,528	8,604	8,682
Frequency Regulation (2)	0	1,365	1,377	1,390	1,402	1,415	1,427	1,440	1,453	1,466	1,480
Spin / Non-Spin Reserve	0	0	0	0	0	0	0	0	0	0	0
Resource Adequacy	0	23,831	23,831	23,831	23,831	23,831	23,831	23,831	23,831	23,831	23,831
Dist. Deferral	0	0	0	0	0	0	0	0	0	0	0
Trans. Deferral	0	0	0	0	0	0	0	0	0	0	0
DR - Wholesale	0	0	0	0	0	0	0	0	0	0	0
DR – Utility	0	0	0	0	0	0	0	0	0	0	0
Bill Management	0	0	0	0	0	0	0	0	0	0	0
Backup Power	0	0	0	0	0	0	0	0	0	0	0
Local Incentive Payments	0	0	0	0	0	0	0	0	0	0	0
Total Operating Costs	**$0**	**($6,465)**	**($6,532)**	**($8,902)**	**($8,972)**	**($9,044)**	**($9,118)**	**($9,193)**	**($9,269)**	**($9,348)**	**($9,428)**
O&M	0	(2,359)	(2,418)	(2,479)	(2,541)	(2,604)	(2,669)	(2,736)	(2,804)	(2,875)	(2,946)
Warranty (3)	0	0	0	(2,302)	(2,302)	(2,302)	(2,302)	(2,302)	(2,302)	(2,302)	(2,302)
Augmentation Costs	0	(3,221)	(3,221)	(3,221)	(3,221)	(3,221)	(3,221)	(3,221)	(3,221)	(3,221)	(3,221)
Augmentation Costs (Y0)	0	0	0	0	0	0	0	0	0	0	0
Charging (4)	0	(885)	(893)	(901)	(909)	(917)	(926)	(934)	(942)	(951)	(959)
EBITDA	**$0**	**$26,740**	**$26,757**	**$24,472**	**$24,488**	**$24,503**	**$24,517**	**$24,530**	**$24,543**	**$24,554**	**$24,564**
Less: MACRS D&A (5)	0	(24,366)	(41,758)	(29,822)	(21,297)	(15,227)	(15,210)	(15,227)	(7,605)	0	0
EBIT	**$0**	**$2,374**	**($15,001)**	**($5,350)**	**$3,191**	**$9,277**	**$9,308**	**$9,304**	**$16,938**	**$24,554**	**$24,564**
Less: Interest Expense	0	(2,728)	(2,669)	(2,604)	(2,535)	(2,460)	(2,378)	(2,291)	(2,196)	(2,094)	(1,984)
Less: Cash Taxes	0	0	0	0	0	0	0	0	(3,970)	(8,759)	(8,806)
Tax Net Income	**$0**	**($354)**	**($17,669)**	**($7,954)**	**$657**	**$6,817**	**$6,929**	**$7,013**	**$10,771**	**$13,700**	**$13,774**
MACRS D&A	0	24,366	41,758	29,822	21,297	15,227	15,210	15,227	7,605	0	0
EPC	(20,784)	0	0	0	0	0	0	0	0	0	0
Storage Module Capital	(97,600)	0	0	0	0	0	0	0	0	0	0
Inverter / AC System Capital	(11,167)	0	0	0	0	0	0	0	0	0	0
Balance of System Capital	(40,960)	0	0	0	0	0	0	0	0	0	0
Maintenance Capital	0	0	0	0	0	0	0	0	0	0	0
ITC	0	0	0	0	0	0	0	0	0	0	0
Principal	0	(745)	(805)	(869)	(939)	(1,014)	(1,095)	(1,183)	(1,277)	(1,379)	(1,490)
After Tax Levered Cash Flow	**($170,511)**	**$23,267**	**$23,284**	**$20,999**	**$21,015**	**$21,030**	**$21,044**	**$21,057**	**$17,099**	**$12,321**	**$12,284**
Levered Project IRR	8.8%										
Levered Project NPV	($15,038.3)										
End of project NOL credits	$0										

Model Assumptions

Size (MW)	100.000	Extended Warranty (%)	1.5%	Debt	20.0%	Combined Tax Rate	39%
Capacity (MWh)	400.000	EPC Cost (%)(7)	15.0%	Cost of Debt	8.0%	Charging Cost Escalation	1%
Cycles Per Year (6)	91	O&M Cost (%)(8)	1.5%	Equity	80.0%		
Depth of Discharge (%)	100%	Useful Life (years)(9)	20	Cost of Equity	12.0%		
Efficiency (%)	85.0%	Regional EPC Scalar(10)	1.05	WACC	10.6%		

Source: *DOE, Lazard and Enovation Partners estimates.*
(1) Energy curve modeled as real-time prices at SP–15.
(2) Assumes 0.9% revenue escalation.
(3) Represents extended warranty costs that provide coverage beyond the initial two-year product warranty (included in equipment capital costs).
(4) Assumes 0.9% charging cost escalation.
(5) Assumes 7-year MACRS depreciation.
(6) Reflects full depth of discharge cycles per year.
(7) Sized as a percentage of total installed capex, annually, after expiration of initial two-year product warranty.
(8) Assumes EPC costs as a percentage of AC and DC raw capital costs.
(9) Sized as a portion of total installed capital cost. Assumes O&M escalation of 2.25%.
(10) Scalars are adjustment factors for the national averages, determined by Bloomberg estimates and Labor Department statistics.

LAZARD

Illustrative Value Snapshot—NYISO Distribution

($ in thousands, unless otherwise noted)

NY	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Revenue (1)	**$12,337**	**$5,352**	**$5,353**	**$5,354**	**$5,356**	**$5,357**	**$5,358**	**$5,359**	**$5,360**	**$5,361**	**$5,362**
Energy Arbitrage (2)	0	0	0	0	0	0	0	0	0	0	0
Frequency Regulation	0	119	120	121	122	123	124	125	127	128	129
Spin / Non-Spin Reserve	0	0	0	0	0	0	0	0	0	0	0
Resource Adequacy (3)	0	930	930	930	930	930	930	930	930	930	930
Dist. Deferral (4)	0	2,273	2,273	2,273	2,273	2,273	2,273	2,273	2,273	2,273	2,273
Trans. Deferral (5)	0	2,031	2,031	2,031	2,031	2,031	2,031	2,031	2,031	2,031	2,031
DR - Wholesale	0	0	0	0	0	0	0	0	0	0	0
DR – Utility	0	0	0	0	0	0	0	0	0	0	0
Bill Management	0	0	0	0	0	0	0	0	0	0	0
Backup Power	0	0	0	0	0	0	0	0	0	0	0
Local Incentive Payments	12,337	0	0	0	0	0	0	0	0	0	0
Total Operating Costs	**$0**	**($791)**	**($799)**	**($1,138)**	**($1,147)**	**($1,156)**	**($1,165)**	**($1,175)**	**($1,185)**	**($1,195)**	**($1,205)**
O&M (6)	0	(338)	(346)	(355)	(364)	(373)	(382)	(392)	(402)	(412)	(422)
Warranty	0	0	0	(330)	(330)	(330)	(330)	(330)	(330)	(330)	(330)
Augmentation Costs	0	(439)	(439)	(439)	(439)	(439)	(439)	(439)	(439)	(439)	(439)
Augmentation Costs (Y0)	0	0	0	0	0	0	0	0	0	0	0
Charging (7)	0	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(14)	(15)	(15)
EBITDA	**$12,337**	**$4,562**	**$4,554**	**$4,217**	**$4,209**	**$4,201**	**$4,193**	**$4,184**	**$4,175**	**$4,166**	**$4,157**
Less: MACRS D&A (8)	0	(3,526)	(6,042)	(4,315)	(3,082)	(2,203)	(2,201)	(2,203)	(1,100)	0	0
EBIT	**$12,337**	**$1,036**	**($1,488)**	**($98)**	**$1,127**	**$1,998**	**$1,992**	**$1,981**	**$3,075**	**$4,166**	**$4,157**
Less: Interest Expense	0	(395)	(386)	(377)	(367)	(356)	(344)	(331)	(318)	(303)	(287)
Less: Cash Taxes	(4,811)	(250)	0	0	0	(20)	(643)	(643)	(1,075)	(1,507)	(1,509)
Tax Net Income	**$7,525**	**$391**	**($1,874)**	**($475)**	**$761**	**$1,621**	**$1,005**	**$1,006**	**$1,682**	**$2,357**	**$2,361**
MACRS D&A	0	3,526	6,042	4,315	3,082	2,203	2,201	2,203	1,100	0	0
EPC	(3,073)	0	0	0	0	0	0	0	0	0	0
Storage Module Capital	(14,640)	0	0	0	0	0	0	0	0	0	0
Inverter / AC System Capital	(1,117)	0	0	0	0	0	0	0	0	0	0
Balance of System Capital	(5,844)	0	0	0	0	0	0	0	0	0	0
Maintenance Capital	0	0	0	0	0	0	0	0	0	0	0
ITC	0	0	0	0	0	0	0	0	0	0	0
Principal	0	(108)	(116)	(126)	(136)	(147)	(158)	(171)	(185)	(200)	(216)
After Tax Levered Cash Flow	**($17,148)**	**$3,809**	**$4,052**	**$3,714**	**$3,706**	**$3,678**	**$3,047**	**$3,038**	**$2,597**	**$2,157**	**$2,145**
Levered Project IRR	20.8%										
Levered Project NPV	$8,883.9										
End of project NOL credits	$0										

Model Assumptions

Size (MW)	10.000	Extended Warranty (%)	1.5%	Debt	20.0%	Combined Tax Rate	39%
Capacity (MWh)	60.000	EPC Cost (%) (10)	15.0%	Cost of Debt	8.0%	Charging Cost Escalation	1%
Cycles Per Year (9)	15	O&M Cost (%) (11)	1.5%	Equity	80.0%		
Depth of Discharge (%)	100%	Useful Life (years) (12)	20	Cost of Equity	12.0%		
Efficiency (%)	85.0%	Regional EPC Scalar (13)	1.21	WACC	10.6%		

Source: *DOE, Lazard and Enovation Partners estimates.*
(1) Energy curve modeled as real-time prices at NY ZONE_J.
(2) Assumes 0.9% revenue escalation.
(3) Resource adequacy was determined to be estimate of $1,800/kW from the NYSERDA/ConEdison programs from the BQDM project.
(4) Distribution deferral estimates of $227/kW-yr. from DOE estimates in ConEdison territory.
(5) Transmission savings assume the incremental benefit of avoiding transmission upgrades at $221/kW as estimated by the University of Texas.
(6) Represents extended warranty costs that provide coverage beyond the initial two-year product warranty (included in equipment capital costs).
(7) Assumes 0.9% charging cost escalation.
(8) Assumes 7-year MACRS depreciation.
(9) Reflects full depth of discharge cycles per year.
(10) Sized as a percentage of total installed capex, annually, after expiration of initial two-year product warranty.
(11) Assumes EPC costs as a percentage of AC and DC raw capital costs.
(12) Sized as a portion of total installed capital cost. Assumes O&M escalation of 2.25%.
(13) Scalars are adjustment factors for the national averages, determined by Bloomberg estimates and Labor Department statistics.

Illustrative Value Snapshot—ISO-NE Microgrid

($ in thousands, unless otherwise noted)

MA	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Revenue	**$0**	**$105**	**$107**	**$108**	**$109**	**$110**	**$111**	**$112**	**$113**	**$114**	**$115**
Energy Arbitrage[(1)]	0	39	39	40	40	41	41	41	42	42	43
Frequency Regulation	0	2	2	2	2	3	3	3	3	3	3
Spin / Non-Spin Reserve	0	0	0	0	0	0	0	0	0	0	0
Resource Adequacy	0	0	0	0	0	0	0	0	0	0	0
Dist. Deferral	0	0	0	0	0	0	0	0	0	0	0
Trans. Deferral	0	0	0	0	0	0	0	0	0	0	0
DR - Wholesale[(2)]	0	64	65	65	66	67	67	68	69	69	70
DR – Utility	0	0	0	0	0	0	0	0	0	0	0
Bill Management	0	0	0	0	0	0	0	0	0	0	0
Backup Power	0	0	0	0	0	0	0	0	0	0	0
Local Incentive Payments	0	0	0	0	0	0	0	0	0	0	0
Total Operating Costs	**$0**	**($95)**	**($96)**	**($125)**	**($126)**	**($127)**	**($128)**	**($129)**	**($130)**	**($131)**	**($132)**
O&M	0	(29)	(29)	(30)	(31)	(32)	(33)	(33)	(34)	(35)	(36)
Warranty[(3)]	0	0	0	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
Augmentation Costs	0	(41)	(41)	(41)	(41)	(41)	(41)	(41)	(41)	(41)	(41)
Augmentation Costs (Y0)	0	0	0	0	0	0	0	0	0	0	0
Charging[(4)]	0	(25)	(25)	(25)	(25)	(26)	(26)	(26)	(27)	(27)	(27)
EBITDA	**$0**	**$11**	**$11**	**($17)**	**($17)**	**($17)**	**($17)**	**($17)**	**($17)**	**($17)**	**($17)**
Less: MACRS D&A[(5)]	0	(283)	(452)	(271)	(163)	(163)	(81)	0	0	0	0
EBIT	**$0**	**($272)**	**($441)**	**($289)**	**($180)**	**($180)**	**($98)**	**($17)**	**($17)**	**($17)**	**($17)**
Less: Interest Expense	0	(32)	(30)	(28)	(25)	(22)	(19)	(16)	(12)	(9)	(4)
Less: Cash Taxes	0	0	0	0	0	0	0	0	0	0	0
Tax Net Income	**$0**	**($304)**	**($472)**	**($316)**	**($205)**	**($202)**	**($118)**	**($33)**	**($29)**	**($26)**	**($21)**
MACRS D&A	0	283	452	271	163	163	81	0	0	0	0
EPC[(6)]	(200)	0	0	0	0	0	0	0	0	0	0
Storage Module Capital	(1,292)	0	0	0	0	0	0	0	0	0	0
Inverter / AC System Capital	(154)	0	0	0	0	0	0	0	0	0	0
Balance of System Capital[(6)]	(373)	0	0	0	0	0	0	0	0	0	0
Maintenance Capital	0	0	0	0	0	0	0	0	0	0	0
ITC[(7)]	606	0	0	0	0	0	0	0	0	0	0
Principal	0	(28)	(30)	(33)	(35)	(38)	(41)	(44)	(48)	(52)	(56)
After Tax Levered Cash Flow	**($1,413)**	**($50)**	**($49)**	**($77)**	**($77)**	**($77)**	**($77)**	**($77)**	**($77)**	**($77)**	**($77)**
Levered Project IRR	N/A										
Levered Project NPV	($1,850)										
End of project NOL credits	$1,726										

Model Assumptions

Size (MW)	1.000	Extended Warranty (%)[(9)]	1.5%	Debt	20.0%	Combined Tax Rate	39%
Capacity (MWh)	4.000	EPC Cost (%)[(10)]	12.0%	Cost of Debt	8.0%	Charging Cost Escalation	1%
Cycles Per Year[(8)]	127	O&M Cost (%)[(11)]	1.5%	Equity	80.0%		
Depth of Discharge (%)	100%	Useful Life (years)	10	Cost of Equity	12.0%		
Efficiency (%)	85.0%	Regional EPC Scalar[(12)]	1.09	WACC	10.6%		

Source: *DOE, Lazard and Enovation Partners estimates.*

(1) Energy arbitrage was calculated as the benefit from the spread between the PPA price during solar producing hours and the real-time market price (NEMASSBOST).
(2) Assumes 1.0% revenue escalation.
(3) Represents extended warranty costs that provide coverage beyond the initial two-year product warranty (included in equipment capital costs).
(4) Assumes 1.0% charging cost escalation.
(5) Assumes 5-year MACRS depreciation.
(6) EPC and BOS equipment was assumed to be 60% of the total for non-solar integrated energy storage projects.
(7) ITC benefits of 30% were captured for the eligible equipment.
(8) Reflects full depth of discharge cycles per year.
(9) Sized as a percentage of total installed capex, annually, after expiration of initial two-year product warranty.
(10) Assumes EPC costs as a percentage of AC and DC raw capital costs.
(11) Sized as a portion of total installed capital cost. Assumes O&M escalation of 2.25%.
(12) Scalars are adjustment factors for the national averages, determined by Bloomberg estimates and Labor Department statistics.

Illustrative Value Snapshot—CAISO Commercial

($ in thousands, unless otherwise noted)

CA	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Revenue	**$0.0**	**$53.8**	**$53.9**	**$54.1**	**$54.3**	**$54.5**	**$54.7**	**$54.9**	**$55.0**	**$55.2**	**$55.4**
Energy Arbitrage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Frequency Regulation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Spin / Non-Spin Reserve	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Resource Adequacy (1)	0.0	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8	29.8
Dist. Deferral	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trans. Deferral	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR - Wholesale	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR – Utility	0.0	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
Bill Management (2)	0.0	17.7	17.9	18.1	18.3	18.4	18.6	18.8	19.0	19.2	19.4
Backup Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Local Incentive Payments	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Operating Costs	**($29.8)**	**($2.7)**	**($2.8)**	**($3.5)**	**($3.5)**	**($3.6)**	**($3.7)**	**($3.8)**	**($3.8)**	**($3.9)**	**($4.0)**
O&M	0.0	(2.7)	(2.8)	(2.9)	(2.9)	(3.0)	(3.1)	(3.1)	(3.2)	(3.3)	(3.4)
Warranty (3)	0.0	0.0	0.0	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)
Augmentation Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Augmentation Costs (Y0)	(29.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Charging (4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EBITDA	**($29.8)**	**$51.0**	**$51.2**	**$50.7**	**$50.8**	**$50.9**	**$51.0**	**$51.1**	**$51.2**	**$51.3**	**$51.4**
Less: MACRS D&A (5)	0.0	(28.6)	(49.0)	(35.0)	(25.0)	(17.9)	(17.9)	(17.9)	(8.9)	0.0	0.0
EBIT	**($29.8)**	**$22.4**	**$2.1**	**$15.6**	**$25.8**	**$33.0**	**$33.1**	**$33.2**	**$42.3**	**$51.3**	**$51.4**
Less: Interest Expense	0.0	(3.2)	(3.0)	(2.7)	(2.5)	(2.2)	(1.9)	(1.6)	(1.2)	(0.9)	(0.4)
Less: Cash Taxes	0.0	0.0	0.0	(0.6)	(9.1)	(12.0)	(12.2)	(12.3)	(16.0)	(19.7)	(19.9)
Tax Net Income	**($29.8)**	**$19.2**	**($0.9)**	**$12.3**	**$14.2**	**$18.8**	**$19.0**	**$19.3**	**$25.0**	**$30.8**	**$31.1**
MACRS D&A	0.0	28.6	49.0	35.0	25.0	17.9	17.9	17.9	8.9	0.0	0.0
EPC	(33.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Storage Module Capital	(85.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Inverter / AC System Capital	(30.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Balance of System Capital	(49.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maintenance Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Principal	0.0	(2.8)	(3.0)	(3.2)	(3.5)	(3.8)	(4.1)	(4.4)	(4.7)	(5.1)	(5.5)
After Tax Levered Cash Flow	**($230.1)**	**$45.1**	**$45.2**	**$44.1**	**$35.7**	**$32.9**	**$32.8**	**$32.8**	**$29.2**	**$25.7**	**$25.6**
Levered Project IRR	10.9%										
Levered Project NPV	$2.5										
End of project NOL credits	$0										

Model Assumptions

Size (MW)	0.125	Extended Warranty (%)	0.4%	Debt	20.0%	Combined Tax Rate	39%
Capacity (MWh)	0.250	EPC Cost (%) (7)	25.0%	Cost of Debt	8.0%	Charging Cost Escalation	1%
Cycles Per Year (6)	169	O&M Cost (%) (8)	1.6%	Equity	80.0%		
Depth of Discharge (%)	100%	Useful Life (years) (9)	10	Cost of Equity	12.0%		
Efficiency (%)	85.0%	Regional EPC Scalar (10)	1.05	WACC	10.6%		

Source: *DOE, Lazard and Enovation Partners estimates.*
(1) CAISO Commercial storage benefits come from participation in the Local Capacity Resource (LCR) resource adequacy program, with payments modeled at $175/kW-yr.
(2) Assumes 1.0% revenue escalation.
(3) Represents extended warranty costs that provide coverage beyond the initial two-year product warranty (included in equipment capital costs).
(4) Charging cost is a function of BTM utility rates (PG&E E-19).
(5) Assumes 7-year MACRS depreciation.
(6) Reflects full depth of discharge cycles per year.
(7) Sized as a percentage of total installed capex, annually, after expiration of initial two-year product warranty.
(8) Assumes EPC costs as a percentage of AC and DC raw capital costs.
(9) Sized as a portion of total installed capital cost. Assumes O&M escalation of 2.25%.
(10) Scalars are adjustment factors for the national averages, determined by Bloomberg estimates and Labor Department statistics.

Illustrative Value Snapshot—CAISO Residential

($ in thousands, unless otherwise noted)

CA	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Revenue	**$2.3**	**$1.1**	**$1.1**	**$1.1**	**$1.1**	**$1.1**	**$0.7**	**$0.7**	**$0.7**	**$0.7**	**$0.7**
Energy Arbitrage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Frequency Regulation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Spin / Non-Spin Reserve	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Resource Adequacy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dist. Deferral	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trans. Deferral	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR - Wholesale	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DR – Utility[(1)]	0.0	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Bill Management[(2)]	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Backup Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Local Incentive Payments	2.3	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0	0.0	0.0
Total Operating Costs	**($2.0)**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
O&M	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Warranty[(3)]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Augmentation Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Augmentation Costs (Y0)	(2.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Charging[(4)]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EBITDA	**$0.4**	**$1.1**	**$1.1**	**$1.1**	**$1.1**	**$1.1**	**$0.7**	**$0.7**	**$0.7**	**$0.7**	**$0.7**
Less: MACRS D&A[(5)]	0.0	(1.7)	(2.9)	(2.0)	(1.5)	(1.0)	(1.0)	(1.0)	(0.5)	0.0	0.0
EBIT	**$0.4**	**($0.6)**	**($1.7)**	**($0.9)**	**($0.3)**	**$0.1**	**($0.4)**	**($0.4)**	**$0.1**	**$0.7**	**$0.7**
Less: Interest Expense	0.0	(0.2)	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)
Less: Cash Taxes	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tax Net Income	**$0.2**	**($0.7)**	**($1.9)**	**($1.1)**	**($0.5)**	**($0.1)**	**($0.5)**	**($0.5)**	**$0.1**	**$0.6**	**$0.6**
MACRS D&A	0.0	1.7	2.9	2.0	1.5	1.0	1.0	1.0	0.5	0.0	0.0
EPC	(2.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Storage Module Capital	(5.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Inverter / AC System Capital	(3.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Balance of System Capital	(1.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maintenance Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ITC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Principal	0.0	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)
After Tax Levered Cash Flow	**($11.4)**	**$0.8**	**$0.8**	**$0.8**	**$0.8**	**$0.8**	**$0.3**	**$0.3**	**$0.3**	**$0.3**	**$0.3**
Levered Project IRR	N/A										
Levered Project NPV	($7.7)										
End of project NOL credits	$4.0										

Model Assumptions

Size (MW)	0.005	Extended Warranty (%)[(7)]	0.0%	Debt	20.0%	Combined Tax Rate	39%
Capacity (MWh)	0.010	EPC Cost (%)[(8)]	30.7%	Cost of Debt	8.0%	Charging Cost Escalation	1%
Cycles Per Year[(6)]	200	O&M Cost (%)	0.0%	Equity	80.0%		
Depth of Discharge (%)	100%	Useful Life (years)[(9)]	10	Cost of Equity	12.0%		
Efficiency (%)	85.0%	Regional EPC Scalar[(10)]	1.05	WACC	10.6%		

Source: *DOE, Lazard and Enovation Partners estimates.*
(1) Assumes 1.0% revenue escalation.
(2) Assumes the 40% of eligible installed capital cost is covered under step 2 of the revised Self-Generation Incentive Program ("SGIP").
(3) Represents extended warranty costs that provide coverage beyond the initial two-year product warranty (included in equipment capital costs).
(4) Charging cost is a function of BTM utility rates (PG&E E-6).
(5) Assumes 7-year MACRS depreciation.
(6) Reflects full depth of discharge cycles per year.
(7) Sized as a percentage of total installed capex, annually, after expiration of initial two-year product warranty.
(8) Assumes EPC costs as a percentage of AC and DC raw capital costs.
(9) Sized as a portion of total installed capital cost. Assumes O&M escalation of 2.25%.
(10) Scalars are adjustment factors for the national averages, determined by Bloomberg estimates and Labor Department statistics.