BEFORE THE COUNCIL OF THE CITY OF NEW ORLEANS

SUPPLEMENTAL AND AMENDING APPLICATION OF ENTERGY NEW ORLEANS, INC. FOR APPROVAL TO CONSTRUCT NEW ORLEANS POWER STATION AND REQUEST FOR COST RECOVERY AND TIMELY RELIEF	**)))))**	**DOCKET NO. UD-16-02**

Direct Testimony

of

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of

Synapse Energy Economics, Inc.

On Behalf of
Sierra Club, Deep South Center for Environmental Justice, the Alliance for Affordable Energy, and 350 Louisiana – New Orleans

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Introduction/Purpose of Testimony

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 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. 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 RMF-1 hereto.

Q. Have you testified before the New Orleans City Council before?

A. No. But I did support Mr. Patrick Luckow, my former colleague at Synapse, in preparing his direct testimony that was filed with the Council in January 2016 in this case. Mr. Luckow has since left Synapse for another job opportunity. As described below, I have fully reviewed

Mr. Luckow's testimony, agree with its methodology and conclusions, and I am formally adopting his testimony here as if it were my own.

Q: Have you provided witness testimony in any other jurisdictions?

A: I have testified in numerous state and provincial jurisdictions over the years, and at the FERC. As is particularly relevant to the issues in this case, I recently studied Midwest Independent System Operator (MISO) capacity and resource adequacy issues in great depth and provided testimony on those matters in proceedings at FERC and before the State of Michigan Public Service Commission. For a complete description of my prior testimony in electrical regulatory cases, please see my resume, attached as Exhibit RMF-1 hereto.

Q. Please summarize your specific experience and familiarity with MISO resource adequacy issues.

A. In December 2016, I submitted an affidavit in FERC Docket No. ER17-284 on MISO resource adequacy issues as they affected the then-proposed Competitive Retail Solution (CRS) to implement a forward reserve auction in MISO. In February 2016, I submitted an affidavit in FERC Docket ER16-833-000 concerning technical issues (including computation of Capacity Import Limits) associated with the MISO Planning Resource Auction (referred to as the "PRA"). I have testified on various resource need issues in Minnesota, Iowa, Wisconsin, and Illinois—all states within MISO's territory—over the past twelve years. I have also analyzed Integrated Resource Planning issues in Missouri, co-authored a report on wind and transmission in PJM, and estimated rate impact effects from increased levels of wind on the MISO grid.

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

A. I am testifying on behalf of Sierra Club, Alliance for Affordable Energy, the Deep South Center for Environmental Justice, and 350 Louisiana – New Orleans.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is threefold: 1) to summarize earlier testimony by Synapse addressing Entergy New Orleans (ENO)'s initial application in this case and to explain how that testimony's conclusions still remain valid; 2) to examine ENO's economic case for building a new gas-fired power plant instead of meeting its capacity needs with alternatives; and 3) to examine the transmission options available to ENO to ensure reliability, in the context of transmission reinforcement planning already underway by Entergy and MISO for the Downstream of Gypsy (DSG) load pocket and New Orleans regions.

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

A. I rely primarily upon:

- ENO's application, as supplemented and amended in July 2017;
- Documents and discovery responses exchanged in this docket;
- MISO documents on resource adequacy;
- MISO documents on MISO's Planning Resource Auction (PRA); and
- Appendices to MISO's transmission expansion plans (MTEP) for 2016 and 2017 that address the MISO South region.

Summary of Findings and Testimony Structure

Q. Please summarize your findings/observations.

A. This testimony expresses the following five conclusions, listed below.

1) **ENO's Economic Analysis of the two Proposed Gas Plants, and Alternatives, is**

Flawed. ENO's economic case[1] for both of its suggested, gas-fired peaking resources relies on misleading assumptions and is not paired with a full assessment of reasonable alternatives to building new gas-fired plants.

2) **ENO Understates MISO's Resource Surplus and Overstates MISO's Future Capacity Prices, Obscuring the Substantial Economic Risk to New Orleans Ratepayers of Building a new Gas Plant that is Not Needed**. According to MISO's most recent resource adequacy survey, MISO will have a 2.6-GW surplus of committed installed capacity in 2021.[2] The MISO region could be long tens of gigawatts of potential capacity during the early part of the next decade, when accounting for additional resources queued in MISO but not yet tallied by MISO as a "committed" resource[3] and for MISO's expansion of its transmission system to allow sizable increases in wind resource interconnection.[4] MISO's most recent Planning Reserve Auction (PRA) produced extremely low prices that were less than 2% of CONE (Cost of New Entry),[5] reflective of capacity surplus.

These critical forward indicators of resource surplus throughout a Midwest region with a flat peak load projection profile and unconstrained capacity zone boundaries indicates that the region is not likely to reach equilibrium at costs approaching CONE by

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[1] As summarized in Table 1 of the Supplemental Direct Testimony of Seth Cureington.

[2] The turnaround from the prior year survey's findings is due in large part to reduced load forecasts in the MISO region. See slides 2, 10, and 12 from the July 2017 OMS MISO Survey results. Attached as Exhibit RMF-2.

[3] Committed resources included resources within the rate base of MISO utilities, new generation with signed interconnection agreements, external resources with firm contracts to serve load, and certain non-rate based units. See slide 8 of Exhibit RMF-2.

[4] 2017 OMS MISO Survey results at slide 13, estimated from vertical bar graph. 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.

[5] Cost of New Entry, or CONE, is now a fairly industry standard term generally representing the cost of a "backstop" technology, often reflected in structured RTOs as the cost of a new combustion turbine. In MISO, it is roughly $95/kW-year for 2017.

2022, as ENO claims. Despite all of this recent MISO data, ENO's economic case for building either gas peaker continues to rest heavily on the scenario of MISO's capacity market clearing price increasing quickly. ENO ratepayers should receive the full benefit of the bargain of belonging to a regional transmission organization that allows for the sharing of capacity resources across an increasingly robust and reliable transmission grid. Rather than risk being "long" on capacity that is not needed, ENO should obtain the best bargain for its ratepayers by relying on the MISO market when it is economically reasonable to do so – which is now the case - for any remaining, relatively small residual need.

3) **Transmission Reinforcement to meet NERC (North American Electric Reliability Corporation) Reliability Requirements is Feasible and More Cost-Effective than Building a New Gas-Fired Power Plant**. Reinforcing transmission elements due to NERC requirements is a fundamental enterprise for an electric utility company with transmission planning and operation responsibilities such as Entergy or ENO. ENO can take steps to reduce peak load on its system over time, and/or utilize the existing generation in the DSG load pocket to reduce local loading on certain transmission circuits. All of the required reinforcements to mitigate NERC reliability concerns are associated with the reinforcement of existing transmission assets, and no rights-of-way are needed if outage scheduling for the existing lines is feasible.[6]

Transmission improvements, many of which are already approved, can address

[6] Response to SIE 4-11. The response notes ENO's "preference would be to rebuild the transmission lines listed in Table 1 [Direct Testimony of Charles Long] on the same ROW where the lines currently exist", but also notes ENO's concern that if outage scheduling is not possible "for the duration of the rebuild" they foresee possibly having to construct a new line on a new ROW.

the New Orleans' reliability issues far more cheaply than a new gas plant. Regardless of whether either of ENO's proposed gas plants is approved, planning for needed transmission reinforcements within and into the DSG load pocket is currently underway by Entergy[7] to meet new generation interconnection and reliability requirements. ENO's best estimate is that it would cost a nominal $57 million to build all transmission reinforcements necessary to mitigate any potential NERC reliability concerns, in the absence of building a new gas-fired power plant.[8] That figure is significantly lower than the $232 million cost of the 226 MW CT, or the $210 million cost of the reciprocating engine alternative offered by ENO largely on the basis of improving reliability.

Even ENO acknowledges that its Case 2 – no NOPS, with transmission reinforcement – "appears economically competitive under the reduced capacity price sensitivity".[9] But ENO has not conducted additional sensitivities that include lower peak load through energy efficiency implementation. Lower peak load may further limit the cost and number of transmission reinforcements that would be required under such alternative scenarios.

4) **ENO's Analysis of Energy Efficiency Potential is Woefully Deficient**. ENO is particularly deficient in examining the critical, almost decisive, issue of energy efficiency. For one, ENO fails to commit to implement the Council's goal of a 2 percent annual reduction in customer sales. But even further, ENO's consultant, Navigant,

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[7] See e.g. Entergy Monthly Long-Term Transmission Plan Project Status Report, Entergy Long Term Transmission Plan. Posted on OASIS August 15, 2017. See also Exhibits 4 and 5 to this testimony, appendices to the MISO 2016 and 2017 Transmission Expansion Plan that address MISO South transmission expansions. https://www.oasis.oati.com/EES/EESdocs/Entergy_Long_Term_Transmission_Plan_Status_Report_July_2017.pdf.
[8] CWL Table 1 page 11.
[9] Supplemental and Amending Direct Testimony of Seth E. Cureington at 30: 20-21.

reached the conclusion that ENO could "cost-effectively reduce forecast load by roughly 17% over the next 20 years, an average of 0.85%/year",[10] and notes that such a level would be double what ENO currently implements. Nonetheless, ENO did not conduct any economic analyses that included the 0.85%/year level of energy efficiency. As it turns out, even at only a peak load reduction level that achieved Navigant's "cost-effective" average annual incremental savings of 0.85%/year, ENO could almost fully cure its resource adequacy deficiency by 2026 without building a new gas-fired power plant.

5) **Incremental Solar PV in New Orleans, the DSG Load Pocket, or the Rest of Louisiana Generally Improves the Overall Reliability of the System.** Solar PV in the ENO service territory, in the DSG load pocket, and throughout other areas of Louisiana or MISO South contributes to resource adequacy because the aggregate of the solar PV resource base is accredited capacity by MISO.[11] Solar PV lowers summer peak load, and thus improves the overall reliability of the system, which is based primarily on the ability to serve load during summer peak times. The non-dispatchability of solar PV does not lessen these attributes.[12]

Overall, I find that neither of ENO's proposed gas-fired peaking resources are needed for resource adequacy. Neither gas-fired peaking plant would be a wise investment for New Orleans' ratepayers. Instead, New Orleans could reliably meet its electrical demand well into the future, with less risk to ratepayers, by: first, continuing the Council's energy efficiency

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[10] Exhibit SEC-14, page 7.
[11] MISO and ENO assign a 50% capacity credit to solar resources.
[12] The existing dispatchable asset base in DSG, Louisiana as a whole, and MISO South is more than sufficient to follow revised net load patterns that arise after increases in solar PV penetration in the region.

initiatives; and, second, by implementing transmission reinforcements already planned by MISO and ENO, along with additional reinforcements (as and when needed) of any remaining weak links in the local transmission system. ENO should also more carefully examine distributed resource options going forward (such as solar PV and potentially battery storage) to meet capacity deficits that arise in the future and make the grid more reliable.

Q. How is your testimony structured?

A. I first summarize Synapse's earlier testimony's conclusions in this case. I next review key aspects of ENO's economic analyses as presented in the testimony and exhibits of Mr. Seth Cureington and Mr. Charles W. Long. I then review MISO resource adequacy and related MISO capacity prices, and present evidence of surplus capacity in MISO, relying upon the most recent OMS MISO Survey and MISO PRA results. I address energy efficiency in the context of its importance for ensuring reliability at lowest cost, and helping to mitigate scheduling concerns for transmission reinforcement by reducing peak load. Lastly, I address transmission economic and reliability issues associated with ensuring compliance with NERC reliability standards for the New Orleans area.

Prior Testimony Findings

Q. What were Synapse's findings in prior testimony submitted in this docket?

A. Patrick Luckow submitted Direct Testimony in this case in January 6, 2016. His main findings included:

- The overall economics of proceeding with the 226 MW CT peaker that ENO is still proposing were tenuous at best. ENO overestimated the capacity need for the plant, since ENO had acquired other resources to meet the need and ENO's load forecast was lower compared to the 2015 IRP that originally called for building a CT. The Council also ordered ENO to investigate compliance with, ultimately, a 2 percent annual energy demand reduction target, which can lead to further load reductions. And, ENO had projected a relatively high price for capacity through MISO, thus overestimating the revenues it would receive from selling the surplus capacity that would have existed in ENO's system with the presence of the 226 MW peaker. In combination, all of these factors meant that ENO was making a very large bet with more than $200 million in ratepayers' money that the MISO capacity market clearing price would increase significantly and that the City's capacity shortfall would be high.

- There was no reliability need for the plant if ENO completed transmission reinforcements associated with existing circuits on their system. The estimated cost for the transmission reinforcement was considerably less than the capital cost for the proposed peaker. Such reinforcement would resolve all transmission-based reliability violations.
- ENO did not perform a sufficiently rigorous analysis, and didn't look at alternative resource options such as portfolios with a mix of energy efficiency, transmission improvements, incremental solar PV, peak shaving demand response, and possibly battery storage alternatives.

Q. Are these findings still valid?

A. Yes. In fact, ENO's latest load forecast and recent MISO studies have only further buttressed Mr. Luckow's conclusions. Since Mr. Luckow's testimony from last year, ENO's load forecast has dropped even further and MISO completed another annual Planning Reserve Auction (PRA) which cleared at extremely low prices in the ENO Zone 9 and all other zones in MISO, indicating surplus capacity. ENO has provided additional analysis of an alternative fossil-fired peaking resource in their amended testimony in July 2017, and included one case without any proposed peakers and a few cases with "requested portfolios", but they have still not completed rigorous analysis of alternative proposals with a portfolio of lower-cost resources. The original findings remain valid.

ENO Economic Analysis of Proposed Peaker and Alternative Cases is Flawed

Summary

Q. Please summarize ENO's core economic analysis findings.

A. ENO presents a comparison of levelized real supply costs for different alternatives.[13] The Case 2 "no NOPS" alternative is [redacted] less costly than ENO's Case 1 option which uses seven reciprocating engines totaling 128 MW.[14] Case 2 is [redacted] higher cost than the 226 MW combustion turbine (CT) peaking plant option – Case 1G – when using ENO's reference capacity pricing estimate; but Case 2 is [redacted] lower cost than Case 1G using ENO's "reduced capacity price"[15] sensitivity. In other words, when ENO models a more reasonable estimate of MISO's capacity clearing price, transmission solutions, without a new gas plant, are the most cost-effective option for the City's ratepayers.

Q. What additional portfolio options did ENO model?

A. ENO presents modeling results for four "requested portfolio" alternatives to their reference cases, all four of which contain the costs associated with Navigant's "Scenario 3: High

[13] Supplemental and Amending Direct Testimony of Seth. E. Cureington, page 5, Table 1.
[14] Synapse computation based on the information in Table 1.
[15] Supplemental and Amending Direct Testimony of Seth. E. Cureington, 30: 21, and Figure 3 (page 29).

Case Theoretical – Known and Unknown Measures" energy efficiency alternative.[16] Two of the four requested portfolio results include ENO's gas peaking plant alternatives (Case 3 and 3G), and the remaining two cases contain a solar and an on-shore wind option (Case 4A and 4B, respectively). All of those "requested portfolio" options are much higher cost than ENO's reference portfolio alternatives, primarily reflecting the extremely high incremental energy efficiency cost component associated with Navigant's purported highest-cost EE scenario.

Q. Why is the set of portfolios modeled by ENO, including the reference and requested portfolios, not sufficiently robust to reasonably determine the likely lowest cost approach to ensuring reliability for ENO customers? Why is the analysis flawed?

A. ENO's overall economic analysis of its proposed gas-fired resource and one possible set of alternatives is flawed primarily because it fails to incorporate least-cost energy efficiency resources and uses capacity prices that are too high. Other deficiencies – such as a lack of a more reasonable set of incremental solar PV installations - indicate that results are not robust. ENO has self-selected a set of scenarios that do not include reasonable mixes of low cost resources to address peak capacity needs, and resources that help improve reliability within New Orleans. Cost-effective energy efficiency measures, in particular, would be crucial to lessening any capacity shortfall, but ENO gives them short shrift. To ensure greater reliability, ENO should have more strongly considered, again, energy efficiency, as well as demand response, solar PV, and possibly bulk battery storage. In reasonable combination, and at relatively low cost, these resources can lower peak load levels seen on the transmission grid, thus relaxing

[16] Supplemental and Amending Direct Testimony of Seth. E. Cureington Table 1, DSM Fixed Costs.

scheduling constraints that may exist[17] and allowing for transmission outages required to undertake reinforcement of the weakest transmission system links in the New Orleans area, to the extent they still exist after the above-noted distributed resource implementation.

Q. Which alternative portfolio scenarios should have been analyzed by ENO?

A. ENO has not assessed a scenario that contains the most cost-effective levels of energy efficiency. None of the modeled scenarios contain the level of energy efficiency associated with Navigant's first "Key Finding" in its report, which included an energy efficiency portfolio with a total resource cost-effectiveness of 1.7 to 2.0 over the modeled period.[18] Thus, energy efficiency that pays back between $1.70 and $2.00 for every dollar spent, according to ENO's own consultant, is not part of ENO's preferred portfolio.

Compounding this oversight, ENO has also not assessed such a higher-efficiency scenario combined with its lower sensitivity estimate of the MISO capacity market's future clearing prices. This scenario would assess the effect of both a revised level of surplus capacity – because peak reductions from energy efficiency would increase ENO's capacity surplus for portfolio Cases 1 and 1G – and alternative MISO capacity market price projections.

Q. What other reasonable scenarios have not been tested?

A. ENO has not assessed a scenario with any additional level of solar PV resource beyond its baseline 2020 projection of 100 MW (installed), in combination with the most cost-effective energy efficiency portfolio (ENO only looked at incremental solar in combination with Navigant's highest-cost portfolio, in Case 4A). Almost inexplicably, ENO's projects that new

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[17] For example, see Direct Testimony of Charles W. Long, 6:4-7, "if the company needs to take an outage of a transmission element, scheduling such an outage would be extremely difficult in an environment where nearly all transmission elements are loaded near capacity".
[18] Exhibit SEC-14, page 7.

customer-owned solar installations will cease after 2020,[19] even though solar PV costs continue to decline precipitously with each passing year.[20] Incremental solar PV in the New Orleans area, either owned by ENO or customers, would reduce peak loading during the mid-daytime peak hours[21] (and to a lesser but still material extent late in the afternoon).

The effect of lower peak load during summer peak hours from solar PV combined with lower peak load from incremental energy efficiency should change the peak load inputs used in power flow modeling, and then could reduce or defer transmission reinforcements required to meet NERC reliability standards, because the modeled loading would be lower. At a minimum, lower peak loads would ease scheduling constraints by giving ENO more "headroom" to take outages on its system for reinforcement purposes. Thus, ENO has also not assessed a scenario that would defer or possibly eliminate some of the required transmission reinforcement needs indicated under its reference portfolios. The transmission reinforcement cost components (included in Mr. Cureington's Table 1) would be lower under such a scenario. Such a scenario would also ease ENO's asserted transmission maintenance outage burdens.[22]

And lastly, ENO has not analyzed scenarios that in the near future could include bulk system battery storage resources (either distributed across its system, or even potentially at a central location such as at Michoud, if conditions allow). In combination with lower peak loads from energy efficiency and solar PV, the effect of battery storage – or even less-costly, short

[19] ENO's response to ADV 7-3 attaches a spreadsheet that shows no new solar PV post-2020.
[20] This is the case even excluding the effect of the gradual ramping down of the Federal tax credits for solar. See, e.g., "Tracking the Sun 10: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States", https://emp.lbl.gov/publications/tracking-sun-10-installed-price. Included as Exhibit RMF-6.
[21] [redacted]
[22] Direct Testimony of Charles W. Long, 6:4-7.

duration storage[23] – would be to further reduce transmission system peak loads and reduce or defer transmission reinforcement needs to meet NERC reliability standards.

Q. How would these alternative scenarios effect the key economic parameters seen in Mr. Cureington's Table 1?

A. In general, these refinements to the model's inputs would either further shrink the already close gap between Case 1G (226-MW CT) and Case 2 (transmission-only), or lead to Case 2 outcomes that are more cost-effective than Case 1G. This is in part because New Orleans is already in the process of implementing many of the alternatives, with or without the gas plant. I understand the City Council already secured ENO's commitment to seek 100-MWs of new solar PV. New Orleans already ranks ninth in the nation for solar installations per capita.[24] Finally, I understand that New Orleans' City Council, starting in Res R-15-599, has already set a goal of steadily reducing ENO's customer energy sales until they begin to continuously decline by a 2 percent annual rate. As described below, Entergy, ENO and MISO are already planning transmission upgrades. Rather than embrace these trends, ENO largely ignores or caps them at current levels, such as is seen with ENO's lack of incremental solar after 2020. Case 2 would demonstrate increasingly greater cost-effectiveness than Case 1 under these refinements.

Q. Have you been able to directly gauge the quantitative effect of any of this?

A. No, because I have not re-run the Aurora production cost modeling. Given the tight timelines associated with responding to ENO's amended application, and the considerable

[23] See, for example, Lazard's Levelized Cost of Storage Version 2.0. https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf. In general, battery storage prices depend on the overall duration of required capacity, such as noted in slides 32 through 37 of the Lazard study, which shows duration assumptions for different functionality of a battery storage system. A 10 MW battery storage system available to provide 10 MW for 2 hours will be less costly than a 10 MW battery designed to provide capacity for four hours.
[24] Environment America, *Shining Cities 2017: How Smart Local Policies are Expanding Solar Power in America*, p. 14, Table 1, https://environmentamerica.org/sites/environment/files/reports/EA_shiningcities2017_print%20(1).pdf.

licensing cost for the Aurora software, I was not able to structure and re-run the model. Using the Aurora or equivalent production cost modeling would be the best way to fully incorporate the interactive effects of the various net loading scenarios that arise from different combinations of energy efficiency, solar PV, and potentially other load shifting effects with demand response or battery storage.

Q. Can you nonetheless estimate, at least directionally, the expected effects of a more reasonable scenario that includes additional energy efficiency, and potentially more solar PV, for example?

A. Yes. A revised production cost run would lead to a more accurate assessment of the dominant component of Table 1 costs labeled as "variable supply costs". Energy efficiency reduces the load and reduces the variable supply costs; solar PV reduces the variable supply costs, and if modeled as small-scale, or behind-the-meter solar PV, it also reduces the load. Both of those resources would also come with a fixed cost, although in general as long as the overall levelized costs of the resources are less than the levelized cost to produce energy using the gas-fired options, the economics would be improved for Case 2 – which is generally the case with cost-effectiveness energy efficiency, and with solar PV under current and projected costs and properly valuing the locational benefits of solar. The remaining key assumptions associated with the alternative scenarios would affect the other components seen in Table 1 – the capacity price affecting the "Capacity Purchase/(Sales)" component, and the specifics of the "DSM Fixed Costs", "Solar (ITC)", and "Transmission" costs dependent on both the scenario and the outcomes of revised power flow modeling. Revised power flow modeling would be needed to determine the equivalent set of transmission reinforcement which would be required under revised peak loading inputs.

Energy Efficiency

Q. What is critical concerning the role of energy efficiency in ENO's analysis?

A. As noted in my summary above, the Navigant energy efficiency potential study demonstrates that using its Scenario 1 would lead to reduced overall costs, as the cost-effective EE scenario results in load reductions of 0.85%/year relative to ENO's current load forecast. For example, applying an incremental 0.85%/year energy efficiency improvement (for each year beginning in 2019) for peak load levels to ENO's forecast load and reserve requirement leads to a change in ENO's projected 2026 capacity shortfall from [redacted] to just [redacted], indicating a total peak load plus reserve requirement reduction over the ten year timeframe of roughly [redacted].[25] With lower load, the capacity surplus associated with the CT and reciprocating-engine generator cases (Case 1 and 1G) will be even greater, and the residual need in Case 2 will be lower. This will improve the relative economics of Case 2.

MISO Resource Adequacy and Capacity Prices

Q. Why is MISO resource adequacy important to this case?

A. ENO's need for its suggested peaking resources is not evident from its load and capacity analyses. Absent the proposed resources, ENO's capacity shortfall is less than [redacted] of its peak load over the next decade, and less than [redacted] when considering what ENO's consultant, Navigant, believes to be the cost-effective energy efficiency available (Navigant's Scenario 1). Reliance on the broader MISO market in which ENO operates would be reasonable to make up any residual shortfalls and thus understanding the level of surplus in that market and expected prices is a critical part of the overall economic analysis of ENO resource options. I next examine these

[25]Synapse computation based on the load plus reserve margin forecast included in Exhibit SEC-11_L_C.

issues by reviewing the current status of resource adequacy in MISO.

<u>MISO Resource Adequacy</u>

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 current information on the projection of resource adequacy in MISO; the survey has been in place since 2014.[26]

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.[27] Indeed, the overall results compared to the 2016 OMS MISO survey indicates more than sufficient resources through 2022, even when counting only "committed"[28] resources. 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 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?

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[26] See for example the August 2017 Draft of 2017 MTPE Book 2 Resource Adequacy, page 12. Available at https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP17/MTEP17%20Book%202%20Resource%20Adequacy.pdf.

[27] See "2017 OMS MISO Survey Results", RASC, July 12, 2017, page 12. Available at https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/RASC/2017/20170712/20170712%20RASC%20Item%2002%20OMS%20Survey%20Results.pdf. Provided as Exhibit RMF-2.

[28] 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. Page 8.

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.[29] It also notes that "[f]uture resource ranges will shift as planned generation interconnections are firmed up,"[30] 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 MWs in 2022.[31]

This level of potential new resources through 2022 includes roughly 5.4 GW of wind and solar capacity additions alone.[32] The reserve requirement for 2017 is 15.8% (ICAP basis); MISO projects an ICAP planning reserve requirement ranging between 15.3% to 15.8% over the 2017 to 2026 period.[33]

Q. Please summarize MISO's overall resource adequacy projections.

A. Table 1 below summarizes MISO's resource adequacy projections over the near-term (through 2022) and over the longer term (through 2028), based in part on the 2017 OMS MISO resource adequacy survey (which extended out to 2022). The data from the survey results are used in the 2017 MTEP Resource Adequacy section, known as Book 2, currently available in

[29] 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.
[30] 2017 OMS MISO Survey Results at page 13.
[31] 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.
[32] 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.
[33] MISO Planning Year 2017-2018 Loss of Load Expectation Study Report, page 31.

"first draft" form.[34] The table also shows data from last year's OMS MISO resource adequacy survey, which were contained in the 2016 MTEP Resource Adequacy section (Book 2).[35]

Table 1. MISO Resource Adequacy as Projected in 2017 and as Projected in 2016

	MISO Projections 2016 MTEP Book 2 Resource Adequacy				MISO DRAFT Projections 2017 MTEP Book 2 Resource Adequacy			
Planning Year	Peak Demand GW	PRMR ICAP GW	Available ICAP Resources GW	PRMR Surplus (+) Shortfall (-) GW	Peak Demand GW	PRMR ICAP GW	Available ICAP Resources GW	PRMR Surplus (+) Shortfall (-) GW
2017/18	127.6	147.0	147.9	0.9	NA	NA	NA	NA
2018/19	128.4	147.9	147.6	-0.4	125.9	145.8	148.5	2.7
2019/20	129.5	149.2	148.7	-0.5	126.5	146.5	150.4	3.9
2020/21	130.2	150.0	148.2	-1.9	127	147.1	150.3	3.2
2021/22	130.9	150.8	148.1	-2.6	127.6	147.8	150.4	2.6
2022/23	131.7	151.7	146.3	-5.4	128.3	148.5	149.2	0.6
2023/24	132.3	152.4	145.0	-7.4	128.9	149.2	147.8	-1.4
2024/25	133.0	153.2	144.9	-8.2	129.4	149.9	147.5	-2.4
2025/26	133.6	153.9	144.3	-9.6	129.1	149.5	147.0	-2.5
2026/27	134.5	154.9	144.2	-10.7	128.9	149.3	146.8	-2.5
2027/28	NA	NA	NA	NA	128.9	149.3	146.8	-2.5
10-Yr. CAGR	0.6%	0.6%			0.3%	0.3%		

Notes/Sources: 2017 MTEP Book 2 Resource Adequacy Draft August 10, 2017, and 2016 MTEP Book 2 available at https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP17/MTEP17%20Book%202%20Resource%20Adequacy.pdf https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20Book%202%20Resource%20Adequacy.pdf.

The OMS MISO survey results and the current representation in the resource adequacy section of the 2017 MTEP clearly indicate no resource adequacy concerns over the next five years, with surplus capacity through 2022. This represents a dramatic departure from the projected near-term shortage contained in the 2016 OMS MISO survey results. Current

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[34] MISO 2017 MTEP Report Book 2. https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP17/MTEP17%20Book%202%20Resource%20Adequacy.pdf.

[35] MISO 2016 MTEP Report Book 2. https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20Book%202%20Resource%20Adequacy.pdf.

projections of surplus installed capacity ranges from 2.7 GW in 2018, to 0.7 GW[36] in 2022, when counting only the committed capacity projections.[37] The cushion is highest in 2019, with a forecast 3.9 GW surplus capacity or an 18.9% reserve margin.

The likely surplus is even greater once approximately 4,000 MWs of "potential capacity" is accounted for, which leads to forecasted surpluses in MISO of 4.8 GWs in 2018 to 5.4 GWs in 2022, and a high of 7.3 GWs in 2020.[38]

These computations exclude the incremental cushion that will likely become available from additional resources as their interconnection studies are finalized and as they sign final interconnection agreements. In particular, the 2017 OMS MISO survey results show by 2022 more than 5,000 MW of capacity in "final studies not included in potential capacity," and more than 15,000 MW of "not yet submitted" or "non-ready projects" in its categorization of "Potential Generation Additions," or (as noted earlier) a total through 2022 of over 20,000 MW of capacity in addition to what is currently considered committed and potential capacity.

Q. Please compare the 2016 and 2017 resource adequacy projections seen in Table 1.

A. Table 1 shows a dramatic change in resource adequacy in MISO between last year's OMS MISO survey release (and the associated data in the Resource Adequacy section of the 2016 MTEP Report) and this year's release. It shows both increased levels of future installed capacity resources, and it shows lower peak demand forecasts from MISO. It shows that over the course of one year the five-year out projected resource situation reversed from a 2,600 MW deficit to a 600 MW surplus, demonstrating why load forecast projections are crucial to assessing

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[36] The 2017 OMS MISO survey reports 0.7 GW of surplus in 2022. The August 10, 2017 draft of the Resource Adequacy section of the 2017 MTEP report lists 0.6 GW of surplus in 2022.
[37] 2017 OMS MISO survey results, page 9.
[38] 2017 OMS MISO Survey Results, page 12.

future resource adequacy. The 10-year-out shortfall was reduced by more than 75% as a greater-than 10 GW projected shortfall was revised downward to a 2.5 GW projected shortfall.

Q. What caused the dramatic change in resource adequacy in MISO between the 2016 and 2017 OMS MISO surveys?

A. As the 2017 OMS MISO survey reports, "decreases in demand forecast leads to a lower resource adequacy risk than previously projected."[39] As shown in Table 1 above, the 10-year combined annual growth rate for peak demand has been cut in half, from 0.6% in the 2016 OMS MISO survey to 0.3% in the 2017 survey. This decline in load growth is not entirely unexpected, as MISO itself acknowledged in the 2016 survey that its then "current forecasts of modest load growth are not in line with recent history of flat year- to- year loads."[40] MISO uses load forecasts provided by load serving entities to then determine its own business-as-usual load forecast.[41]

Q. Is there a reasonable concern that the dramatic swing in projected resource sufficiency seen with the 2017 OMS MISO Survey will occur in the opposite direction with subsequent surveys?

A. No. Rather, it is reasonable to expect the relative dampening of net load growth to continue. This has been the pattern seen in most regions of the nation. The 2016 NERC Long Term Reliability Assessment (LTRA), the most recent nationwide annual assessment conducted by NERC, noted the trending declines (relative to earlier year forecasts) in both peak load and

[39] 2017 OMS MISO Survey Results at page 2.
[40] 2016 OMS MISO Survey Results at page 10.
[41] 2017 MTEP Resource Adequacy, Book 2, first Draft August 10, Section 6.2, Long-Term Resource Adequacy, page 12.

energy consumption.[42]

Q. Does the current OMS MISO survey result provide evidence of a *likely* 2.5 GW shortfall ten years out?

A. No. As the survey noted, and as is noted in the MTEP Resource Adequacy section,[43] as resource plans are solidified, the overall values will change. As just one example, the 2.5 GW shortfall identified for the 2025/2026 planning year would be eliminated if just 15% of the more than 20,000 MWs of potential generation additions through 2022 that were not included in the resource adequacy projections set forth in the 2017 OMS MISO survey end up coming online by 2025.

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 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.[44]

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[42] NERC LTRA December 2016 "Most assessment areas continue to experience a flattening growth rate in both their ten-year peak demand and energy forecasts. This is largely due to widespread implementation of energy efficiency and conservation programs, DSM, and increasing installations of distributed energy resources (DERs) that are nonobservable by utilities and treated as passive load modifiers." Page 48. Available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf.

[43] 2017 MTEP Resource Adequacy, Book 2, first Draft August 10, Section 6.2, Long-Term Resource Adequacy, "The LTRA results represent a point in time forecast, and MISO anticipates the projected margins will change significantly as Load Serving Entities and state commissions solidify future capacity plans." Page 11. 2017 OMS MISO Survey results, in respect of near-term (through 2022) requirements, "These figures will change as future capacity plans are solidified by load serving entities and State commissions." Page 9.

[44] The cost of bulk storage resources, including battery storage resources, are projected to continue declining, and to be competitive with conventional resources. This is especially true for provision of peaking and ancillary services.

Overall, there is no indication of potential near or longer-term resource insufficiency in the broader MISO region, contrary to ENO's suggestion that the market will reach equilibrium at CONE by 2022.[45] 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 as to the future of the MISO-region capacity market and resource adequacy 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,[46] the underlying declining costs for new renewable resources,[47] the trends 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.[48] In

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See, e.g., Lazard's Levelized Cost of Storage Version 2.0, December 2016. Available at https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf.

[45] Supplemental and Amending Direct Testimony of Seth E. Cureington at 16, 40–41.

[46] There is currently almost 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. MISO Generation Interconnection Public Queue data as of August 7, 2017. Synapse tabulation.

[47] See, e.g., US DOE/EERE 2016 Wind Technologies Market Report for wind resource costs. Available at https://energy.gov/sites/prod/files/2017/08/f35/2016_Wind_Technologies_Market_Report_0.pdf. See also Lawrence Berkeley National Laboratory, Utility Scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States, available at https://emp.lbl.gov/publications/utility-scale-solar-2016-empirical.

[48] For example, Table 1 illustrates a change in the 2023 peak demand forecast in MISO of 3.4 GW downward over the course of just one years' update to load-serving entity forecasts.

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 this year's OMS MISO resource survey results, reserve margins are more than adequate over the near-term (through 2022) when such improved load forecasts are 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[49] 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 2016, from 2014 through 2016, and it also shows the actual peak load as reported by MISO for 2016.

Table 2. MISO Peak Load Forecasts for the Summer of 2016

	2016 Projected or Actual Peak Load, MISO		
	50/50 Demand	**Demand Response**	**Net Internal Demand**
2014 NERC LTRA (Nov 2014)	130,101	4,755	125,345
2015 NERC Summer Assessment	127,319	5,031	122,288
2015 NERC LTRA (Dec 2015)	128,087	5,631	122,457
2016 NERC Summer Assessment	126,081	4,923	121,158
2016 Actual Peak (July 2016)			120,700

Sources: NERC Long-Term Resource Assessments (LTRA), and MISO 2016 Summer Assessment Report, page 3.
http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx
https://www.misoenergy.org/Library/Repository/Report/Seasonal%20Market%20Assessments/2016%20Summer%20Assessment%20Report.pdf.

The projected 50/50 net peak load for MISO for year 2017 in NERC's most recent Long-Term Reliability Assessment (published in December 2016) was 121,814 MW; this was updated in the 2017 NERC Summer Assessment (posted May 24, 2107)[50] to be 119,858 MW. To date this year, the MISO peak load (uncorrected for any weather normalization) occurred on July 20,

[49] MISO 2016 OMS MISO Survey, "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". Page 10.
[50] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2017%20Summer%20Assessment.pdf.

120,214.5 MW.[51]

MISO Capacity Prices – Planning Resource Auction (PRA) Results

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 auctions, 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. ENO's service territory is located in MISO Zone 9.

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

[51] MISO Historical Regional Forecast and Actual Load market report, 8/28/2017, available at https://www.misoenergy.org/Library/MarketReports/Pages/MarketReports.aspx.

New Entry (CONE) in MISO, equal to $93.75/kW-year (zonal average), 2017/2018).[52] In ENO's Zone 9, prices have been at or near the lowest in the entire MISO system in each year.

Q. Are there other key parameters of interest for Zone 9 that inform the resource adequacy situation for ENO?

A. Yes. Table 4 below lists key parameters concerning the level of import capacity into Zone 9 and the resources available to the zone.

Table 4. MISO Zone 9 Key PRA Parameters at Time of Auction, and Preliminary for 2018/2019

Year	Zone 9 Capacity Import Limit	Zone 9 Actual Imports	LCR Z9	Z9 Offered Capacity (2016 & 2017) or "UCAP in Zone" (2018)
	UCAP MW	UCAP MW	UCAP MW	UCAP MW
2016	4,490	2,202	17,477	20,257
2017	3,371	2,198	17,295	20,392
2018 Prelim	3,679		19,265	21,674

Source: MISO PRA results data and 2018 Preliminary information (MISO 10/10/2017 LOLEWG). Note: Prior to 2016, Zone 9 included Mississippi.

Q. What do you observe in the MISO PRA auction result prices seen in Table 3 and parameter data seen 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; and prices in Zone 9 in that auction year remained very low, as

[52] See, e.g., 2017/2018 PRA summary results, slide 8, available here: https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/AuctionResults/2017-2018%20PRA%20Summary.pdf.

they did in 2017 also. The amount of import capacity "headroom" for Zone 9 remained high, as the actual import into the zone was lower than the capacity import limit. For the forthcoming auction, the LCR is higher than it has been for the prior two auctions, but the available capacity within Zone 9 remains more than 2,000 MW higher than the minimum requirement, the LCR.

Medium and Longer Term (Post-2022) MISO Resource Adequacy

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.

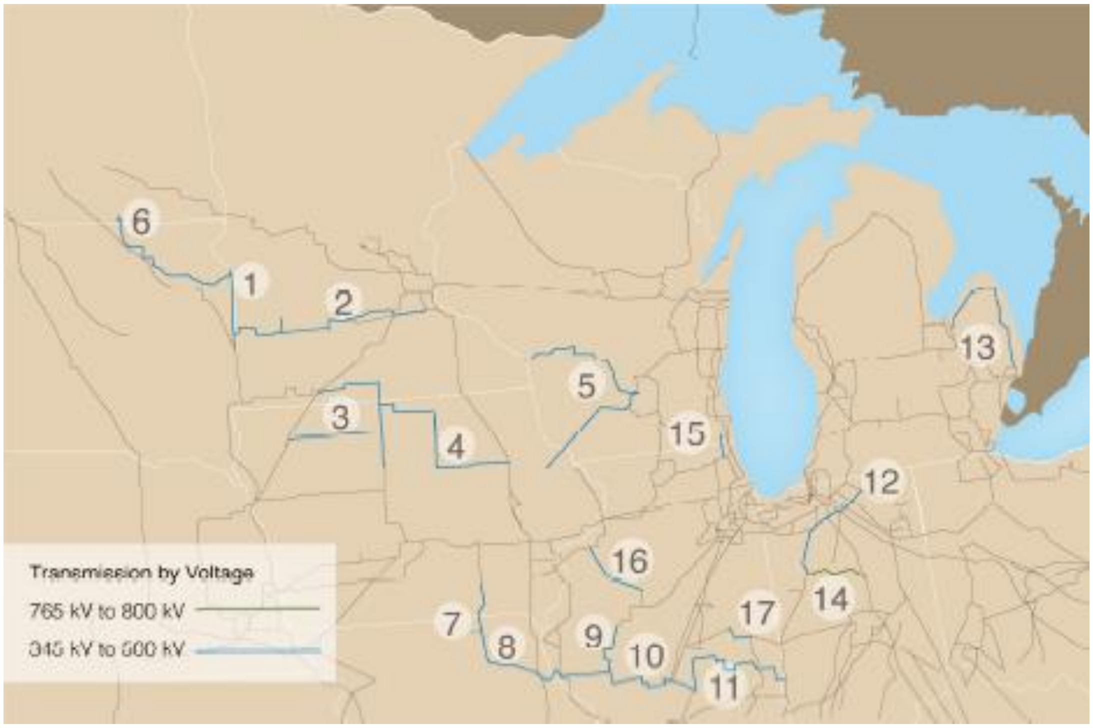
Q. How will improvements to MISO transmission elements help promote resource adequacy, and allow for LRZ 9 to access resources from the rest of MISO?

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 entire MISO market. The 2017 Loss of Load Expectation report indicated that this Zone 1 capacity export limitation will be effectively removed by 2021,[53] thus increasing the ability of wind resources with higher capacity credit values to be available as capacity (and energy) resources in MISO. Figure 1 below

[53] LOLE Report, page 21, indicating projected CELs for the MISO load zones.

shows the location of the Multi-Value Projects.

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



Source: MISO, Figure 2-1, MTEP14 MVP Triennial Review, September 2014. Page 11. Available 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.[54]

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: MISO.

Q. Please summarize the benefits available to ENO 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,[55] will continue to knit together the MISO region and allow broader access to resources in the rest of MISO to entities such as ENO and other MISO South load serving entities. 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,

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

[55] 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.

including reducing the level of required planning reserves. A significant surplus of capacity in one part of the MISO region can be utilized in another part of the MISO region, especially when transmission limitations are minimized.[56]

ENO Is Able to Rely on MISO Region Capacity Resources

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

A. Yes. ENO can and should rely upon surplus MISO South resources, especially since the amount of reliance required is minimal, less than [redacted][57] of total requirements over the next decade absent any incremental energy efficiency, and less than [redacted] when considering the effect of additional energy efficiency if done even at just the Navigant Scenario 1 levels (0.85%/year increment), let alone at the level of the Council's 2 percent target.[58] There is a sizable level of surplus capacity for LRZ 9, as seen in the 2017 OMS MISO survey results.[59] If ENO 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. ENO 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, ENO should aim for least-cost capacity procurement for its residual needs. As long as MISO capacity surplus is available, ENO should exploit the underlying economics and procure low-cost market capacity

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[56] See, for example, MISO's *MTEP14 MVP Triennial Review*, September 2014, Section 6.3, Planning Reserve Margin Requirements.

[57] Exhibit SEC-11, Synapse computation based on ENO data.

[58] Exhibit SEC-11, Synapse computation based on ENO data and estimating incremental peak load reduction at 0.85% per year starting in 2018.

[59] Slide 66 and 67 of the July 12, 2017 MISO OMS survey results indicates a range of installed capacity surplus in Zone 9 ranging from 800 MW (2018/19) to 2200 MW (2021/22).

to meet those residual needs.

Q. How does the current MISO resource surplus and the potential for continuing resource surplus affect ENO's capacity outlook?

A. ENO can meet its residual capacity obligations by either owning or contracting capacity resources. If resources are less expensive inside or outside of Zone 9 than ENO's proposed new resource, it is more economical to contract for these resources than to build new resources. Currently, there appears to be no limitations on delivery of resources from outside of load Zone 9 to the zone, in addition to surplus resource availability within the zone. There is no reason for ENO to forego economic purchase opportunities for capacity inside or outside of load Zone 9 to meet its residual needs.

Q. Why is it unlikely that capacity prices in MISO Zone 9, or the MISO South Zones 8 and 10, would approach or equal CONE levels between 2018-2022, or beyond?

A. The only way Zone 9 prices would reach CONE is if a capacity shortage existed in Zone 9. Based on the results of the most recent OMS MISO survey, no Zone 9, 8, or 10 or MISO-wide shortages are foreseen through 2022. In the 2017/2018 PRA, only 2,198 MW of the 3,371 MW import capacity was used (roughly 65%), indicating significant remaining capacity headroom into the zone. Beyond 2022, the increasing trend of surplus capacity (both within Zone 9, and within all of MISO) would have to reverse in order for capacity prices to rise to CONE. There is no evidence in ENO's application supporting such a reversal.

Transmission

Overview

Q. What do you address in this section of your testimony?

A. I examine ENO transmission and reliability issues.

Q. What is ENO's position on transmission and reliability as it pertains to this case and their preference for a NOPS resource?

A. It is my understanding that ENO prefers the installation of a gas-fired, local resource because of concerns with scheduling outages to complete transmission reinforcement in the event of no gas plant, and an unwillingness to rely on resources outside of the DSG load pocket to meet resource adequacy needs.[60] They also note their concern that "No NOPS" leaves New Orleans "without local generating resources to support reliability", and that "transmission upgrades provide no storm restoration benefit and leaves the city without a local source of dynamic reactive power for voltage control".[61]

Q. Is local – i.e., NOPS – generation required to support reliability, as a NERC standard?

A. No, as ENO has acknowledged.[62] Reliability associated with resource adequacy can be maintained through meeting MISO Zone 9 capacity obligations, which do not include a requirement for New Orleans generation. Reliability associated with transmission system security can be ensured by reinforcement of existing transmission system elements.

Q. Is there a "local" source of dynamic reactive power for voltage control?

A. Yes. The Nine Mile Station, while across the Mississippi River, is well within the DSG load pocket and serves as a source of local dynamic reactive supply. If required, additional dynamic reactive supply could be installed without having to install NOPS, for example using

[60] Supplemental and Amending Direct Testimony of Charles W. Long, 6: 4-7, and 16: 8-10, 14-19.
[61] Response to Advisors 8-6 d) iii).
[62] Response to Advisors 8-6 d).

Static Var Compensation (SVC) or synchronous condensing devices. Static reactive support is available with capacitor installation.[63] The testimony of Mr. Peter Lanzalotta addresses these types of reactive support resources.

Summary from Prior Testimony

Q. Please summarize the transmission and reliability issues as addressed by Mr. Luckow in his January 2016 Direct Testimony.

A. The January 2016 testimony referenced two overarching aspects of reliability: resource adequacy, and transmission system security. The testimony identified the following:

- Under ENO's then-current assumptions, a set of eight transmission line reinforcements would be required by 2019 to eliminate NERC violations to ensure transmission reliability. NOPS would not be required to eliminate NERC violations if these transmission improvements were made.
- Resources both within and outside of the DSG load pocket (and outside of New Orleans) can be used to meet MISO resource adequacy requirements. NOPS options are not necessary to meet resource adequacy requirements.
- The 226 MW CT would not provide black start capability. Black start capability is provided by other units in the region.
- Even with multiple line outages into the DSG load pocket, there would still be significant interconnection capability into the DSG load pocket.
- The Southeast Louisiana Economic Project, part of the 2016 MISO MTEP, would

[63] For example, the 2017 MISO MTEP Appendix D1 indicates a 30.5 MVAR capacity bank installation for the Gulf Outlet substation, in service in December 2019. Page 54.

provide for an additional 650 MW of import capability into the DSG load pocket.

Q. Do these findings still hold true?

A. Yes. In fact, ENO's updated load forecast, and updated power flow analyses have led to a reduction in the number of transmission reinforcements required, six (from eight), according to Mr. Charles Long's Supplemental and Amending Direct Testimony.[64] Also, the level of surplus capacity ENO would hold if it built the 226 MW CT has also increased, as ENO's reduced load forecast leads to even less of a need for resources to meet capacity requirements.[65] This need would be even lower if additional energy efficiency resources were deployed.

Q. Are there additional steps ENO can take to mitigate its concerns over outage scheduling, and secure adequate resources to meet requirements?

A. Yes. ENO can take steps to reduce peak load on its system over time, and/or continue to utilize the existing generation in the Downstream of Gypsy (DSG) load pocket to reduce local loading on certain transmission circuits to help schedule required outages. These steps include but are not limited to a more aggressive schedule for energy efficiency resource implementation, increased installation of local (e.g., DSG, or New Orleans proper) solar PV, use of existing within-DSG generation (such as the three major units at the Nine Mile station), and appropriate sequencing of any required outages - thus helping to mitigate outage scheduling difficulties that may exist by reducing local peak loading on transmission. Reducing system peak loads can have a material effect on the timing requirements for any required transmission reinforcements, because the magnitude of violations is lower with lower peak loading. ENO can effectively buy itself more time to ease any outage scheduling difficulties by taking steps to further reduce

[64] Page 11, Table 1, "No NOPS" Transmission Upgrades.
[65] Exhibit SEC-11_L_C_.

projected system peak loads.

NERC Reliability Requirements

Q. What is required to meet NERC transmission security standards?

A. As ENO has described in its testimony, reinforcement of five transmission circuits is needed in order to meet NERC standards. As ENO has responded, the system will be NERC compliant with these upgrades.[66]

Q. Do NERC or MISO reliability standards require ENO to have installed capacity within the New Orleans region, separate from capacity that exists within the DSG load pocket or just outside the DSG load pocket at and around the Gypsy and Waterford locations?

A. No. As long as the transmission requirements are met, meeting resource adequacy utilizing resources outside of New Orleans is acceptable.

Q. Does NERC require local, New Orleans capacity resources in order to provide black start services, or in preparation for restoration during extreme storm events?

A. No. The testimony of Mr. Peter Lanzalotta addresses storm-related reliability issues as they pertain to transmission, generation resources, and local load during restoration processes.

Cost Effectiveness of Transmission Reinforcement Option

Q. Is it cost effective to reinforce the transmission to meet NERC requirements?

A. Yes. It is marginally cost effective now – there is a very small difference between the modeling outcome for Case 2 compared to the CT (case 1G), and under ENO's capacity price

[66] Response to Advisors 8-6 d.

sensitivity, Case 2 is more cost effective than either Case 1G or Case 1. Even when using ENO's reference for projected MISO capacity prices, Case 2 is more cost effective than Case 1 (the reciprocating engines alternative). And MISO capacity prices could reasonably be projected to be lower than ENO's 60% of base scenario.

Current Transmission Reinforcement Activities In the New Orleans and DSG Load Pocket Areas

Q. ENO asserts a difficulty with accomplishing the Table 1[67] transmission reinforcement requirements, though it notes that it can construct the upgrades.[68] Is there additional transmission reinforcement planning underway in the region now?

A. Yes. Entergy Louisiana and ENO have numerous 115 kV and 230 kV reinforcement projects in the pipeline, for reliability and for generation interconnection reasons, according to the MISO 2016 and 2017 MTEP Appendices that detail transmission expansion in the MISO South region. The following are relevant to the DSG load pocket region and New Orleans, and come directly from the public MISO MTEP plans:[69]

1. Avenue C to Paris Tap 115 kV; Reconductor Line[70]
2. Gypsy to Claytonia 115 kV: Reconductor Line
3. Almonaster to Midtown 230 kV: Reconductor Line
4. Snakefarm 230-115 kV: Add second autotransformer
5. Jefferson Parish Area Reliability Plan Phase I (new 230 kV substation and increase of 650 MW capability into the DSG load pocket from the Waterford area)

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[67] Supplemental and Amending Direct Testimony of Charles W. Long, Table 1.
[68] Response to Advisors 8-12 d.
[69] See MISO 2017 MTEP Appendix D1 South, page 28 and MISO 2016 MTEP Appendix D1 South, page 23.
[70] [redacted].

6. Gulf Outlet 115 kV: Add capacitor bank
7. Cullichia 230 kV: New Substation
8. J396-Snakefarm to Labarre 230 kV Upgrade station
9. Ninemile to Westwego and Harvey, 115 kV Reconductor Line

In total, these projects illustrate that underlying transmission reinforcement is an ongoing enterprise in the region. Looking more carefully at the transmission map for the region, it can also be discerned [redacted].[71] It is reasonable to think that ongoing reinforcement of any remaining weak links will in general allow for resource planning that ensures reliability while aiming for the lowest cost sources of energy and capacity.

Conclusion and Recommendation

Q. What do you conclude from your analysis?

A. I conclude the following:

- ENO's economic case for its suggested peakers is flawed.
- ENO underestimates MISO capacity surplus, and overestimates MISO capacity prices;
- Transmission reinforcement to meet NERC reliability requirements is feasible and more cost-effective than building a new gas-fired power plant;
- ENO's incorporation of energy efficiency into its analysis is deficient; and
- Incremental solar PV resources generally improve the reliability of the system by

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[71] [redacted]

lowering summer period peak loads.

I conclude that the resources represented by either of the gas plant options proposed by ENO are not required for either resource adequacy purposes, or to support reliability in the ENO system. Lower cost means of securing resources to meet resource adequacy and maintain reliability are available. ENO's application does not sufficiently address, through careful economic modeling, the combinations of lowest cost resources that would obviate the need for more expensive gas resources that result in surplus capacity for ENO. Optimal levels of energy efficiency, increases in utility-scale or smaller-scale solar PV, and potentially increases in demand response and/or battery storage resources all contribute towards lowering peak load, easing transmission outage scheduling concerns, and even reducing or eliminating some of the NERC requirements for transmission reinforcement. If capacity obligations remain after exploring and/or deploying these distributed resources, ENO should rely on the MISO capacity market to meet any such residual needs.

Q. What do you recommend to the Council?

A. I recommend the Council deny approval for either of ENO's gas plant alternatives, direct ENO to deploy increasing amounts of energy efficiency resources, obtain current specific estimates for costs for increased levels of solar PV and other distributed resources such as demand response and battery storage, and re-run their economic analyses to address both more reasonable combinations of low-cost resources, and the most recent information available on the current and projected costs of those alternative resources.

Q. Does that complete your testimony?

A. Yes.

Exhibits to Testimony

RMF-1 Robert M. Fagan Resume

RMF-2 MISO OMS 2017 Survey Results

RMF-3 MISO Planning Resource Auction Results 2017/2018

RMF-4 MISO 2017 MTEP Appendix D1 South

RMF-5 MISO 2016 MTEP Appendix D1 South

RMF-6 Galen L. Barbose and Naïm R. Darghouth, Lawrence Berkeley National Laboratories, “Tracking the Sun 10: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States”, Report No. LBNL-2001062.

AFFIDAVIT

STATE OF Massachusetts)
)
COUNTY OF Middlesex)

I, Robert M. Fagan, do hereby swear under the penalty of perjury the following:

That I am the person identified in the attached prepared testimony and that such testimony was prepared by me under my direct supervision; that the answers and information set forth therein are true and accurate to the best of my personal knowledge and belief; and that if asked the questions set forth herein, my answers thereto would, under oath, remain the same.

Robt M. Fagan
____
Robert M. Fagan

SWORN TO AND SUBSCRIBED BEFORE ME THIS 12 **DAY OF** 10 , 2017

____
NOTARY PUBLIC

My commission expires: _______________

JENNIFER MARUSIAK
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
April 29, 2022

Robert M. Fagan, Principal Associate

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rfagan@synapse-energy.com

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

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

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-l): 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-l): 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 September 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

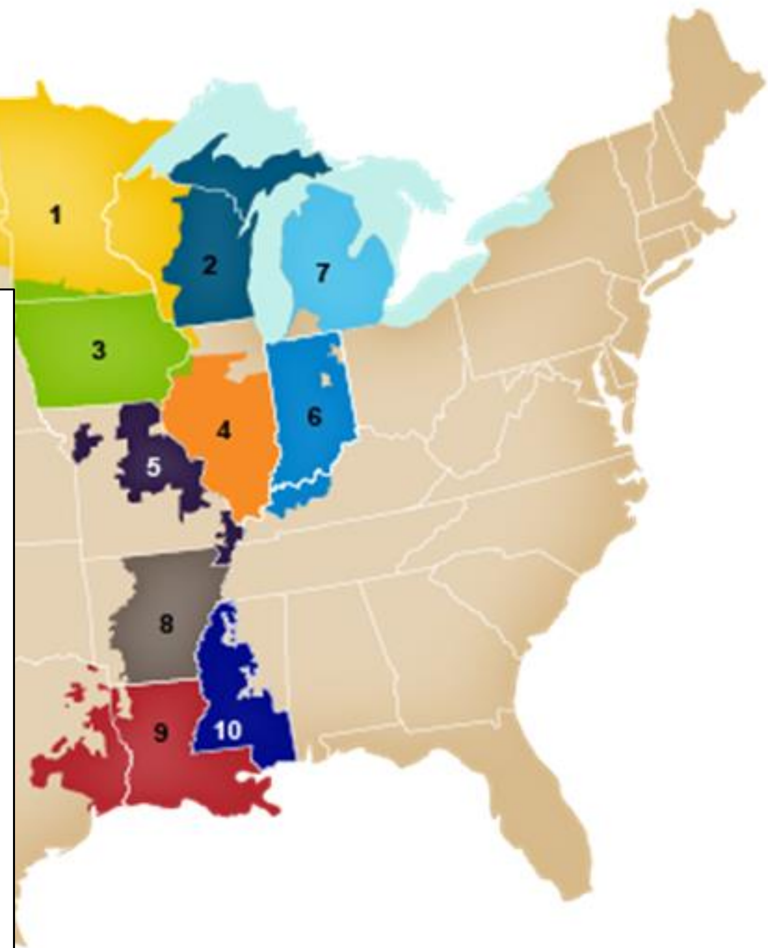
The 2017 OMS MISO survey projects sufficient resources to manage resource adequacy risk

- 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

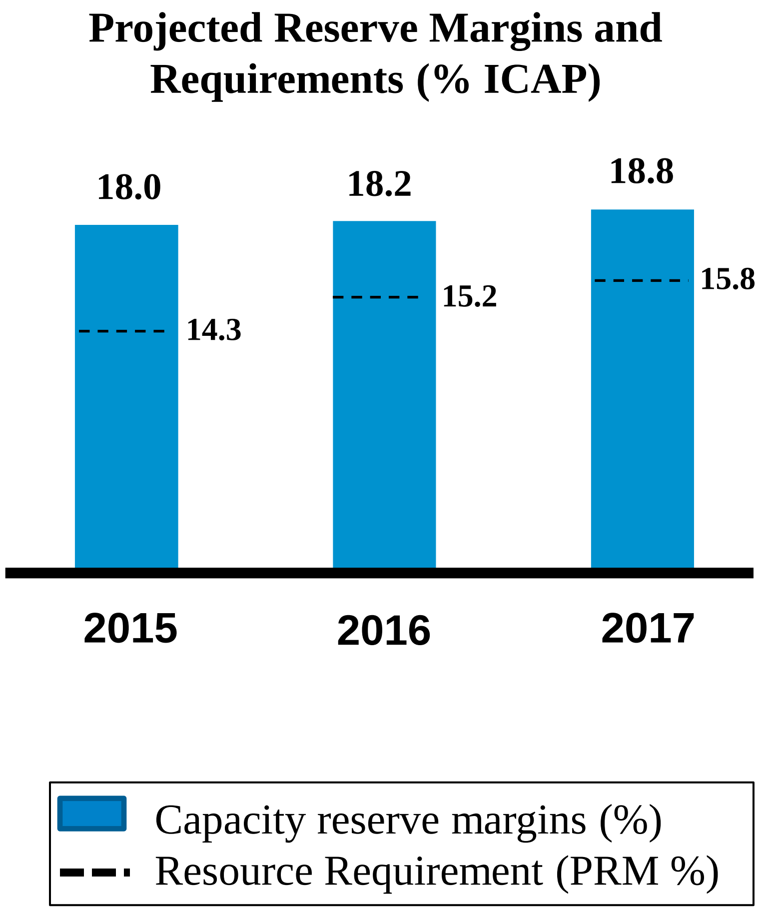
Understanding Resource Adequacy Requirements



- 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

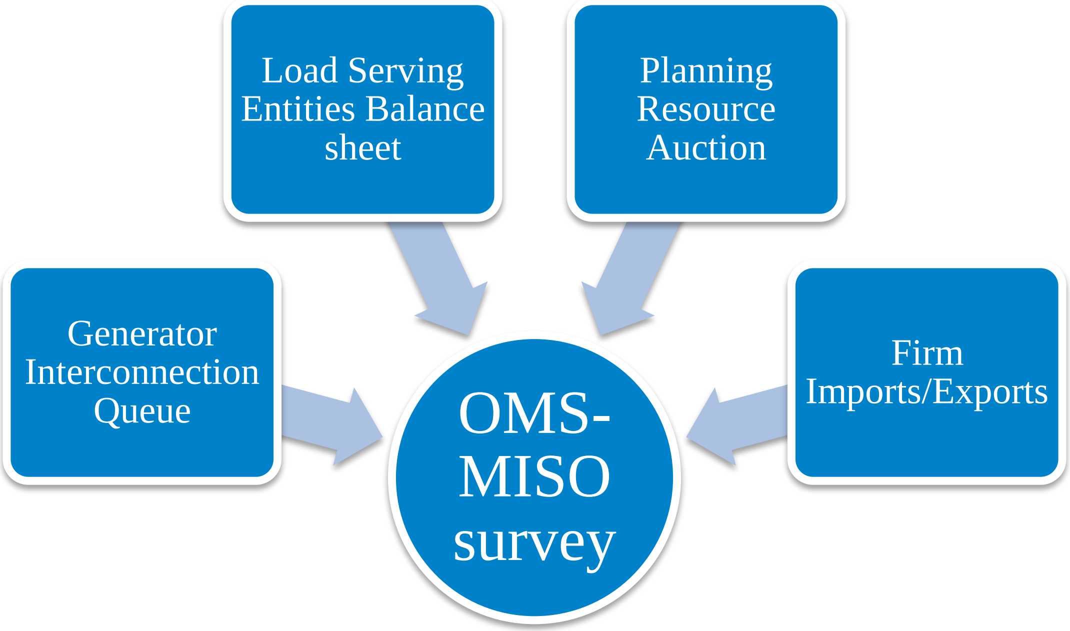
Planning Reserve Margins capture the risks in the load and generation on the system



- 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

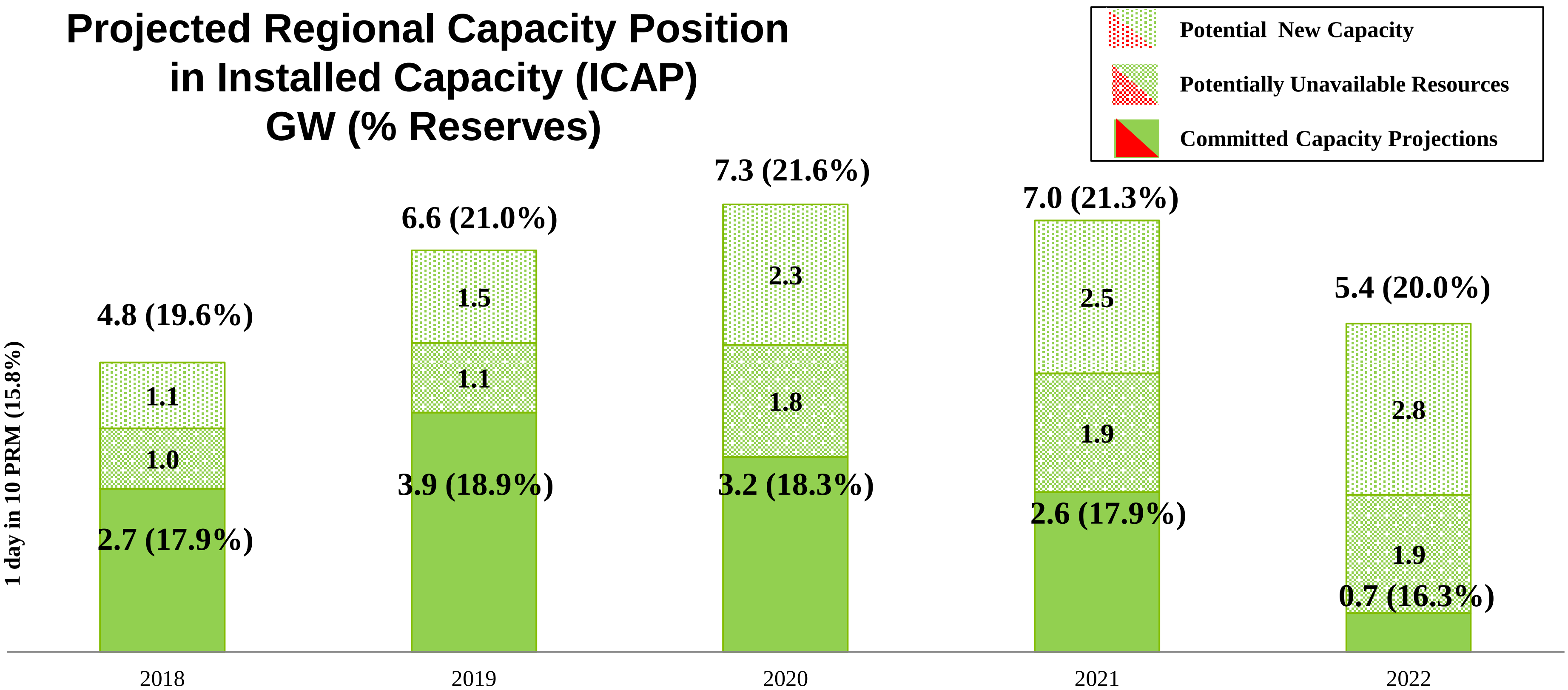
Understanding Resource Projections

- **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

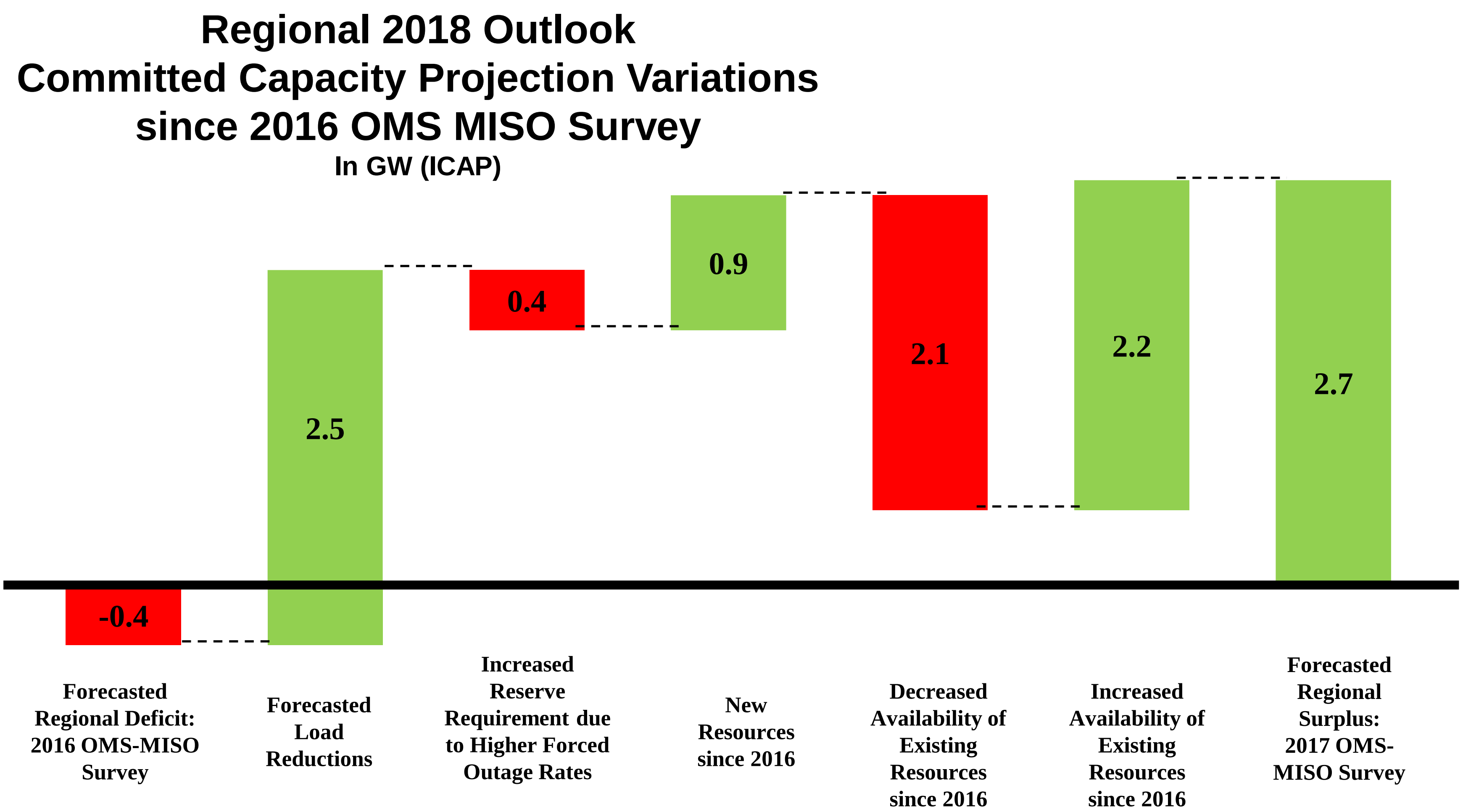
- **Unavailable resources** are not included in the survey totals
  - Resources with firm commitments to non-MISO load
  - Resources with finalized retirements or suspensions
  - Potential new generators without a signed Generator Interconnection Agreement or generators which have not entered the DPP phase of the queue

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



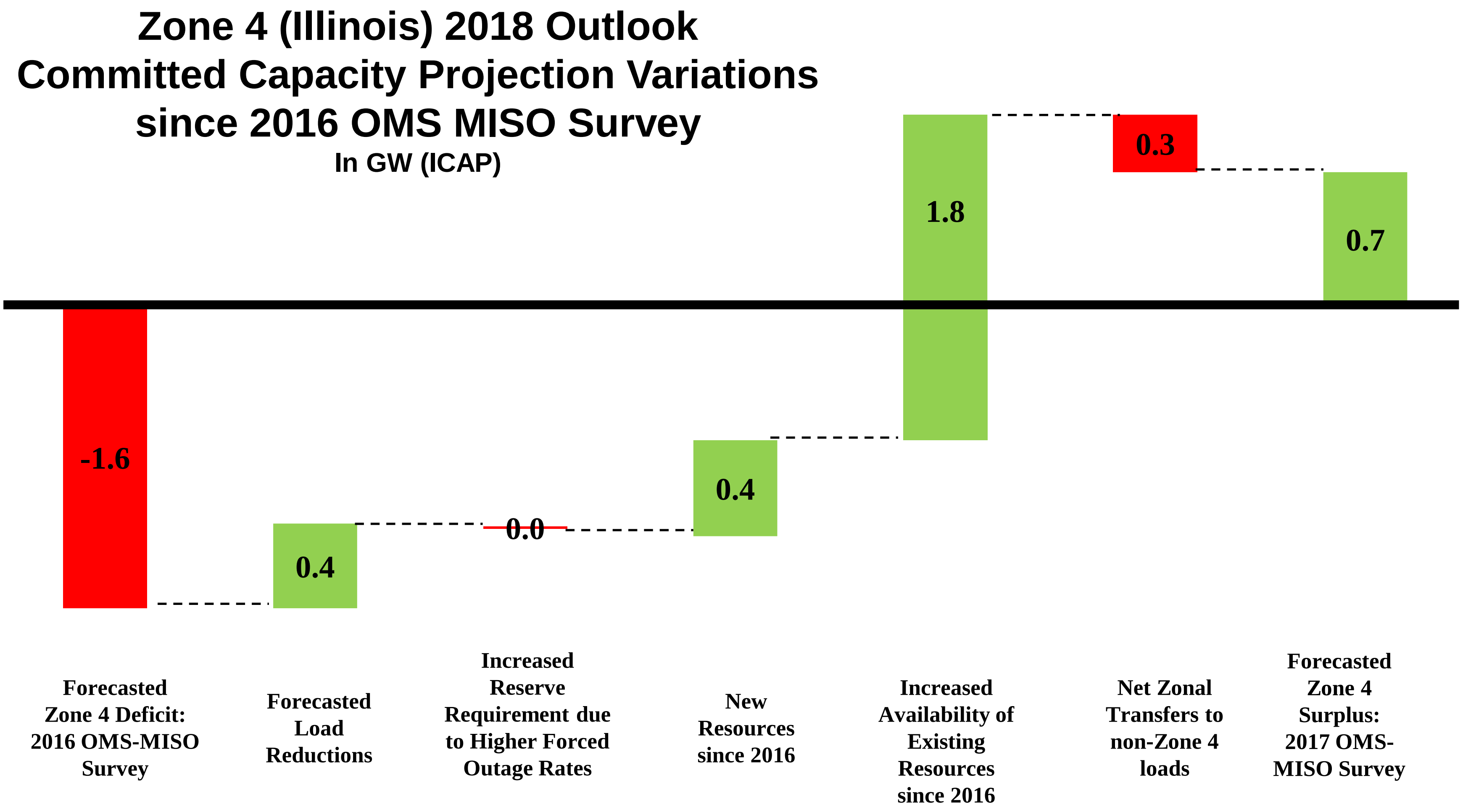
- Regional outlook includes projected constraints on capacity, including Capacity Export Limits and the Sub-regional Power Balance Constraint
- These figures will change as future capacity plans are solidified by load serving entities and state commissions.
- **Potential New Capacity** represents 35% 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



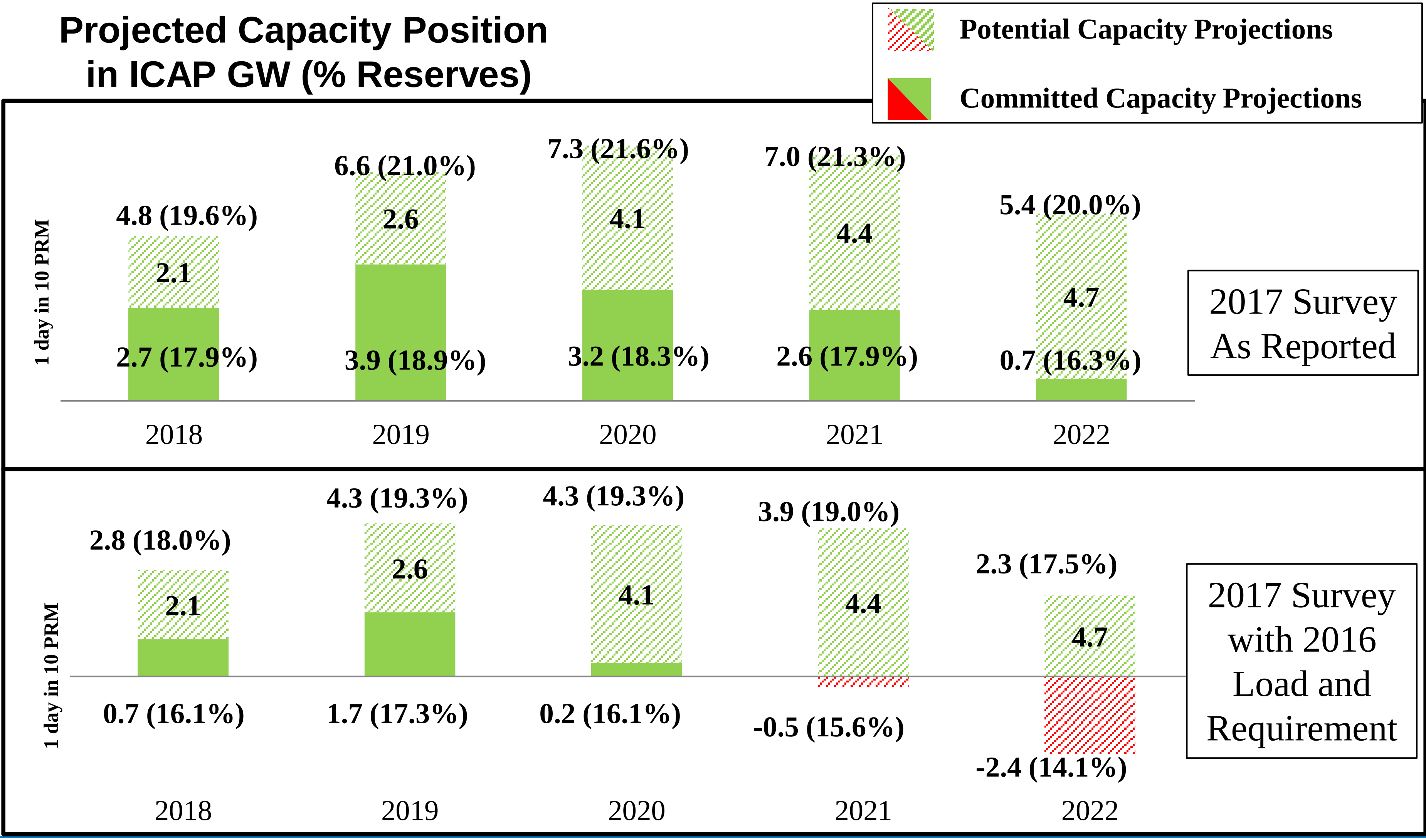
New resources include resources with newly signed Interconnection Agreements and new Load Modifying Resources
Decreased availability results from new retirements and more binding transfer limitations
Increased availability results from deferred retirements and internal resources with reduced commitments 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



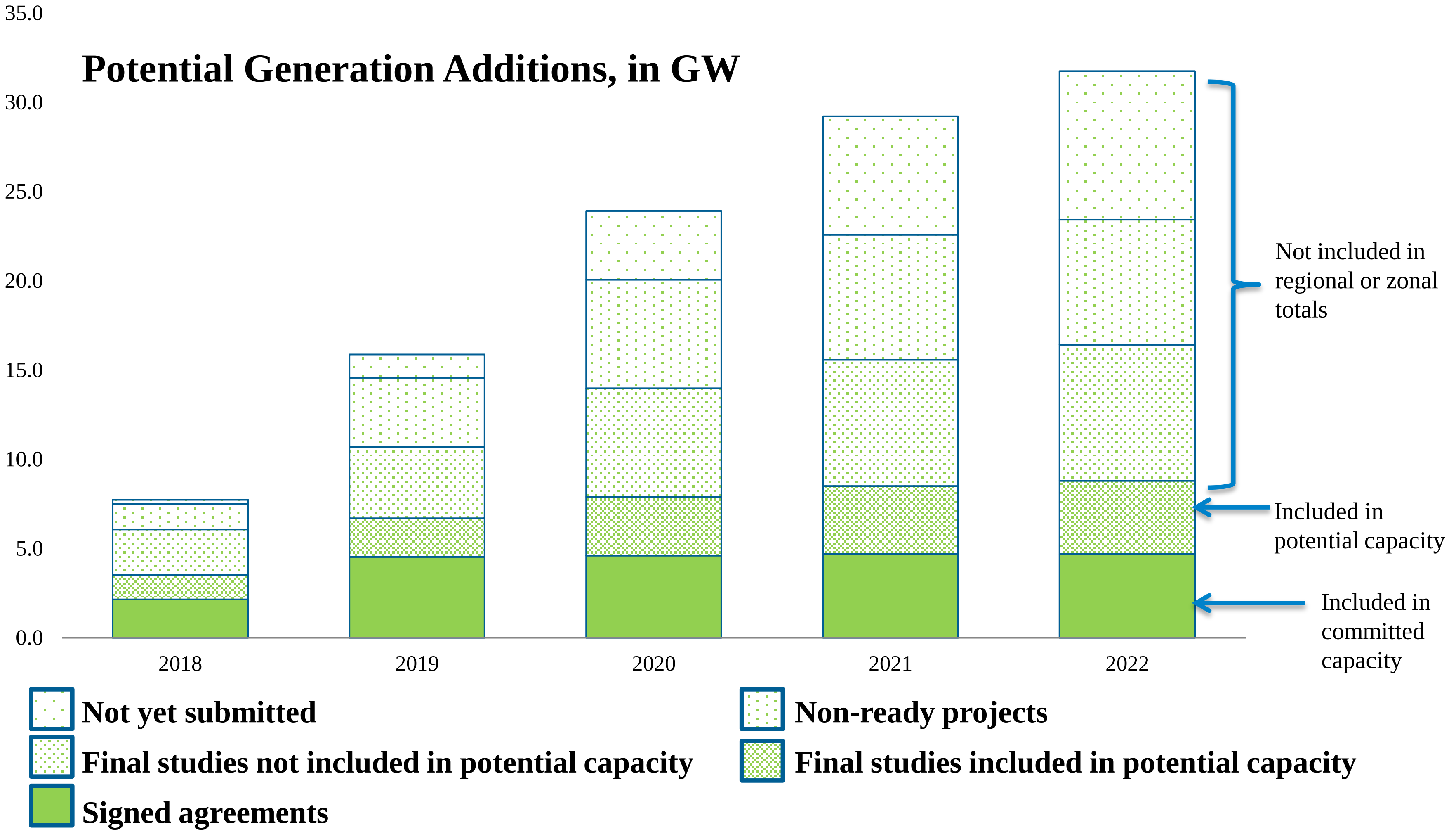
New resources include resources with newly signed Interconnection Agreements and new Load Modifying Resources
Increased availability results from deferred retirements and internal resources with reduced commitments to non-MISO load
Positions include reported inter-zonal transfers, but do not reflect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

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



 <u>Potential Capacity</u> includes potential new capacity and potentially unavailable resources

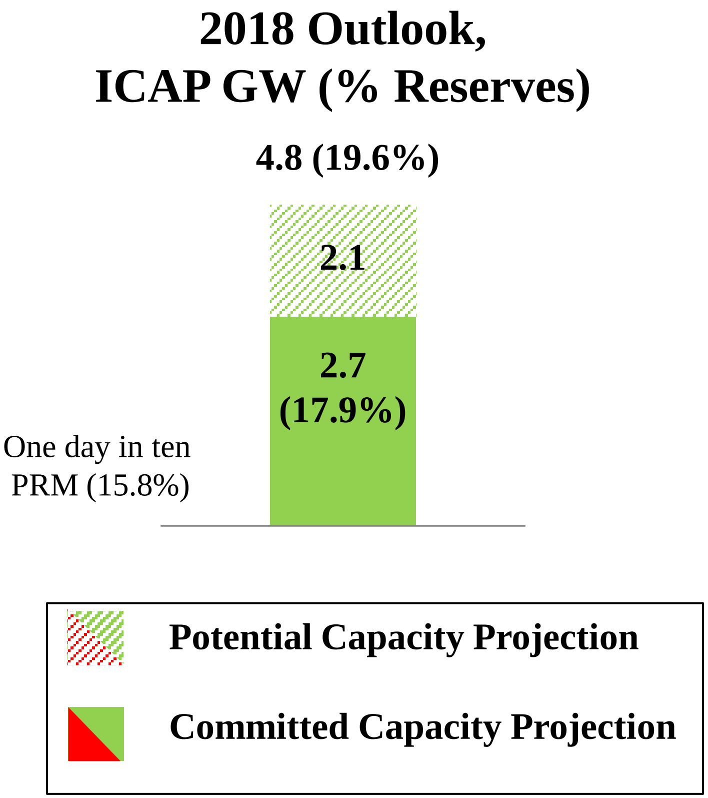
Future resource ranges will shift as planned generation interconnections are firmed up

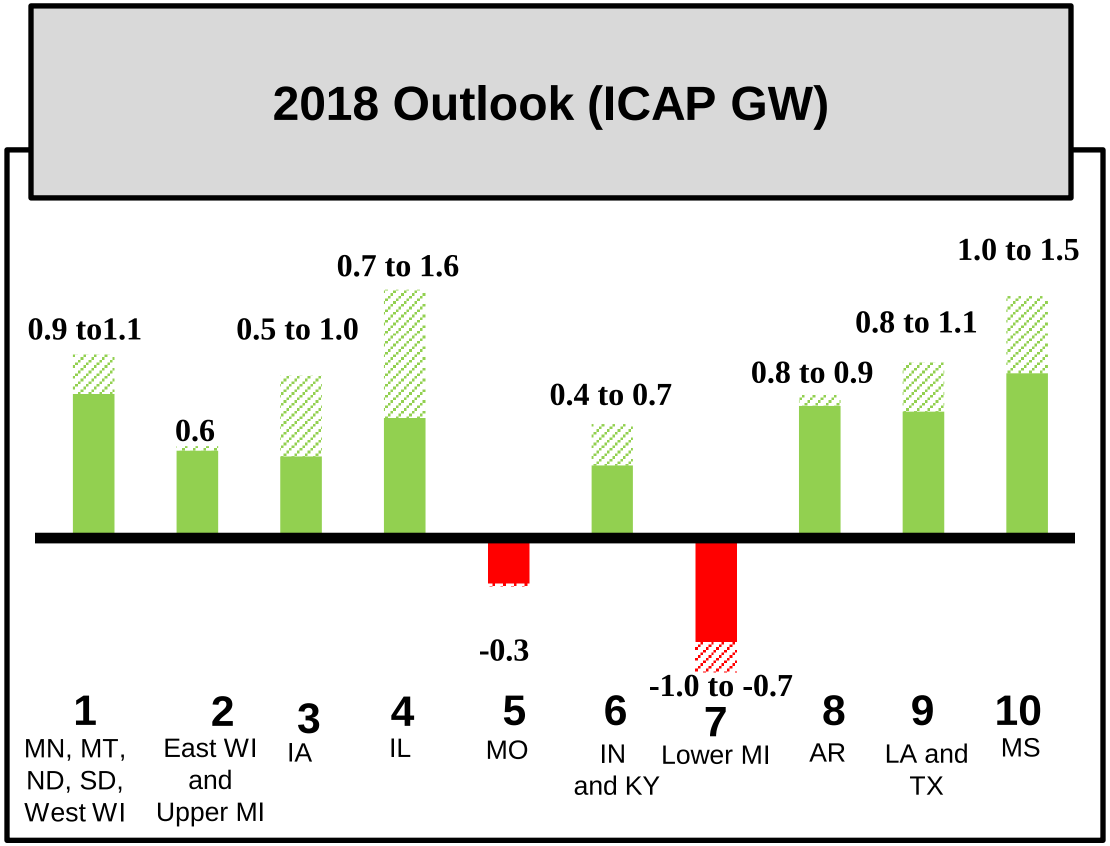


Wind and solar resources are represented at their expected capacity credit

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

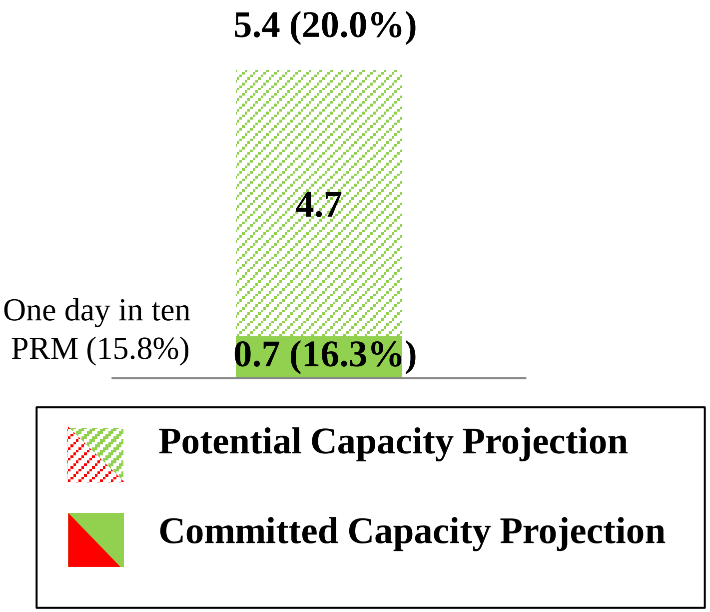


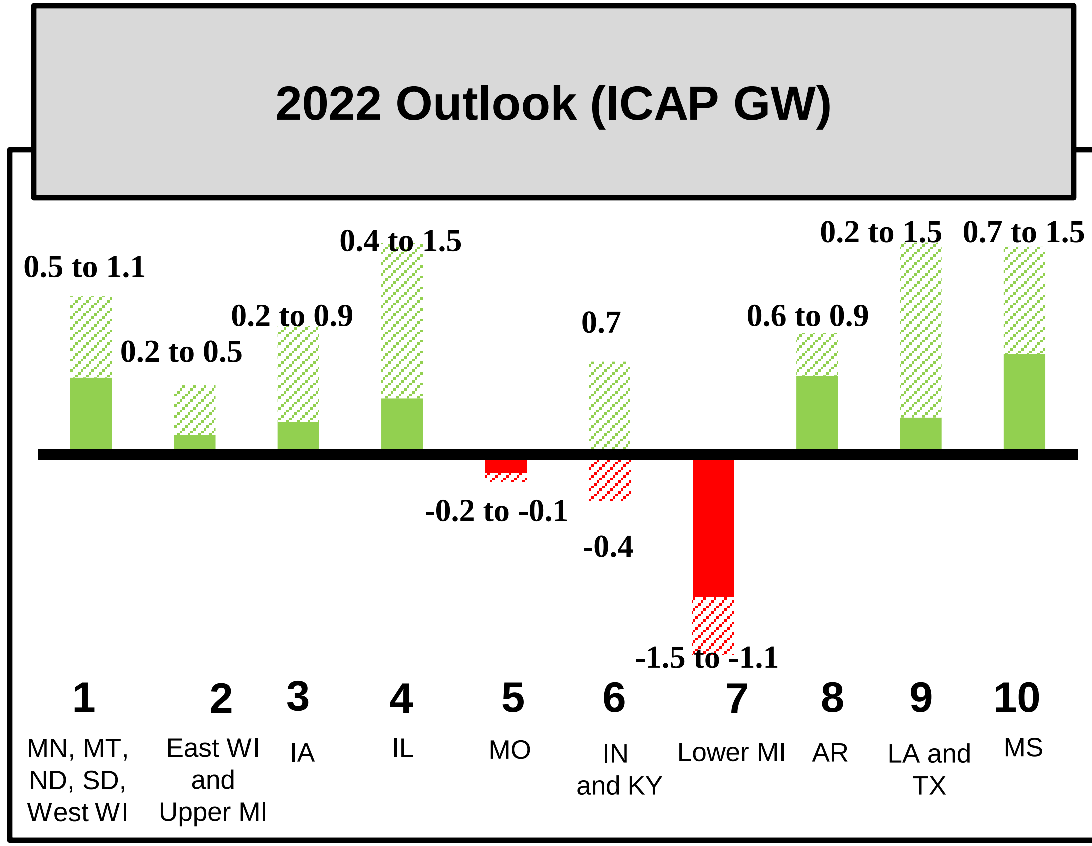


- Regional surpluses and potential resources are sufficient for all zones to serve their deficits while meeting local requirements.
- Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones
- Exports from Zone 1 were limited by the zone’s Capacity Export 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

2022 Outlook, ICAP GW (% Reserves)





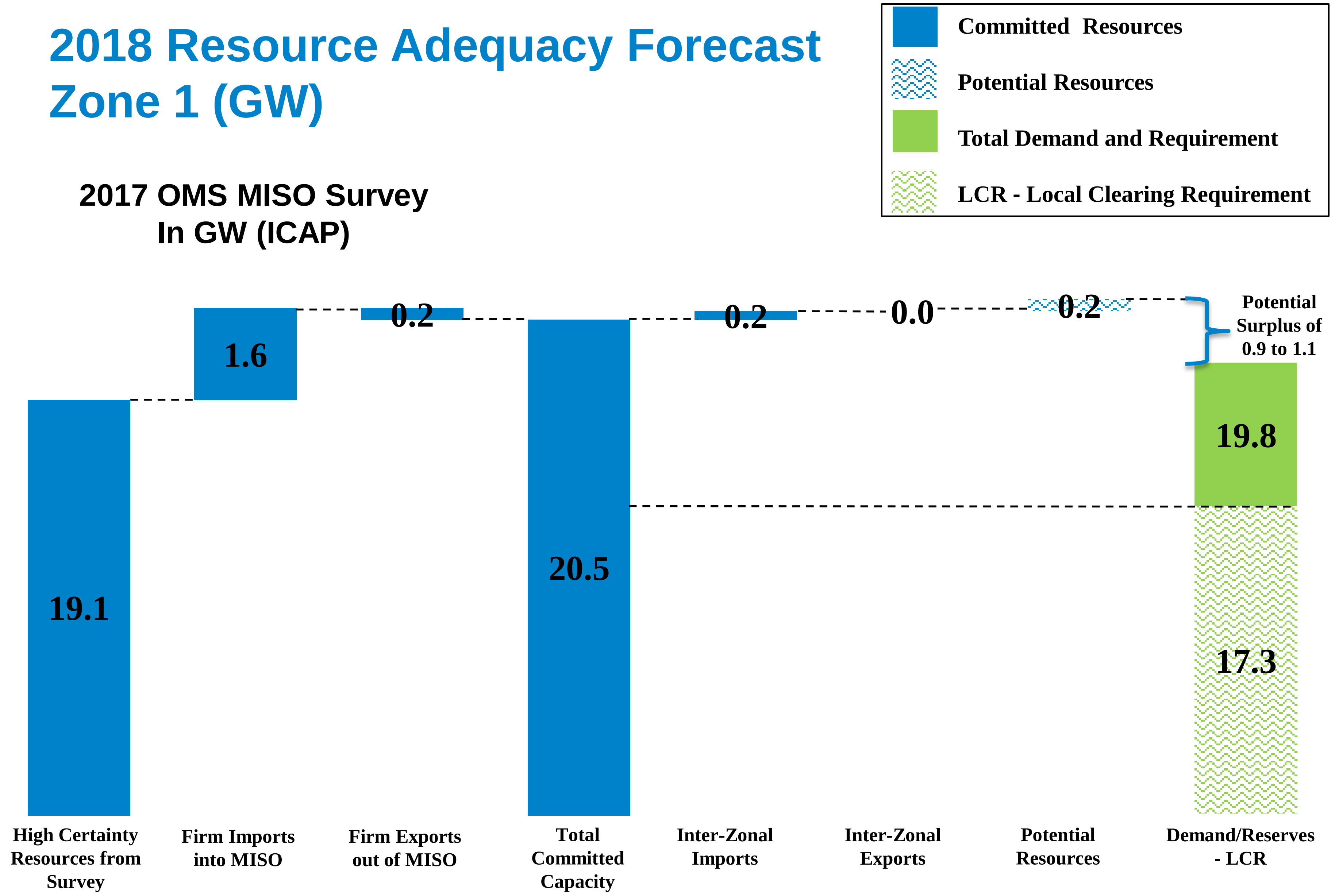
- Regional surpluses and potential resources are sufficient for all zones to serve their deficits while meeting local requirements
- Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones
- Results include load, but not identified resources, from some 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)



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

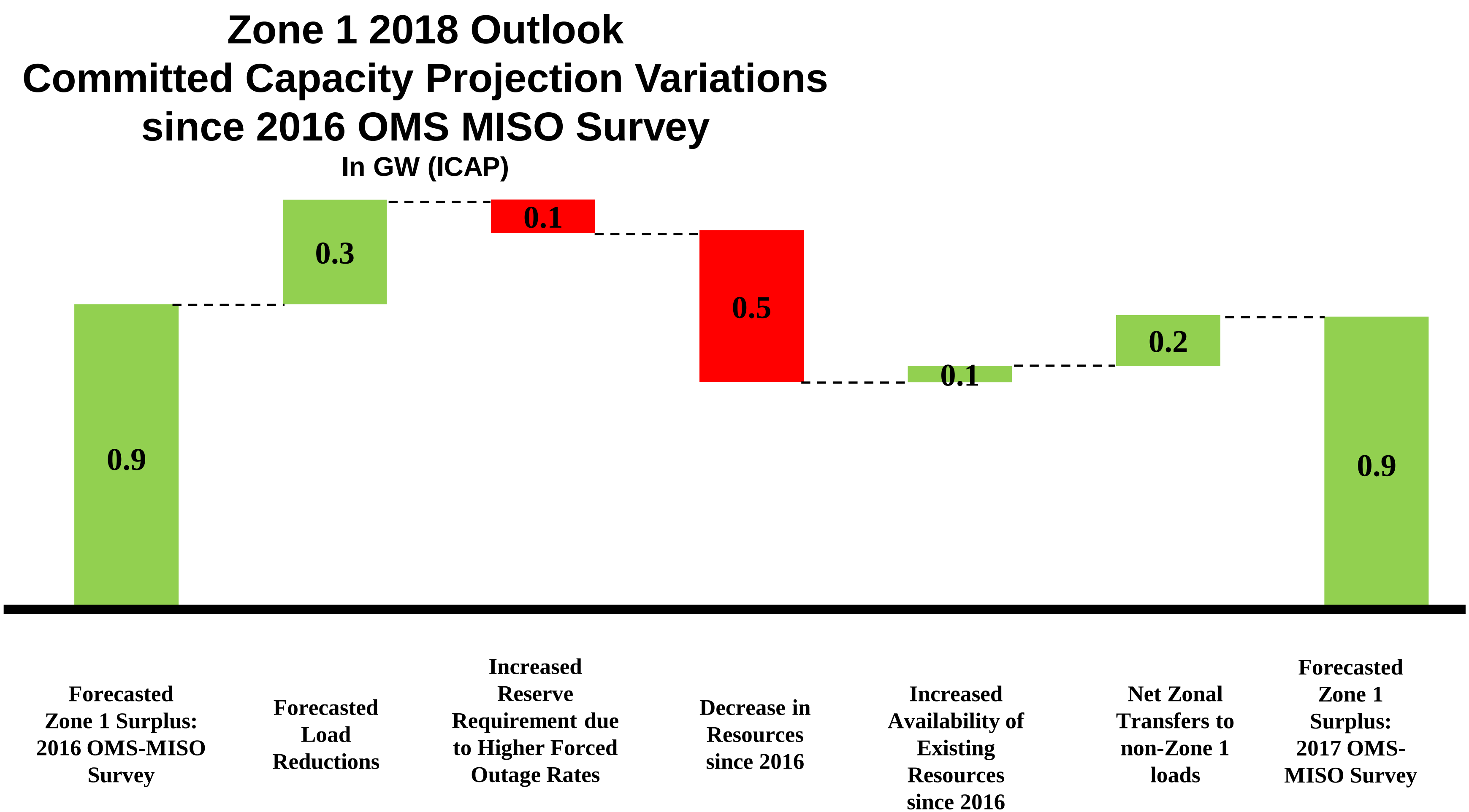
2019 - 2021 Resource Adequacy Forecast Zone 1 (GW)

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

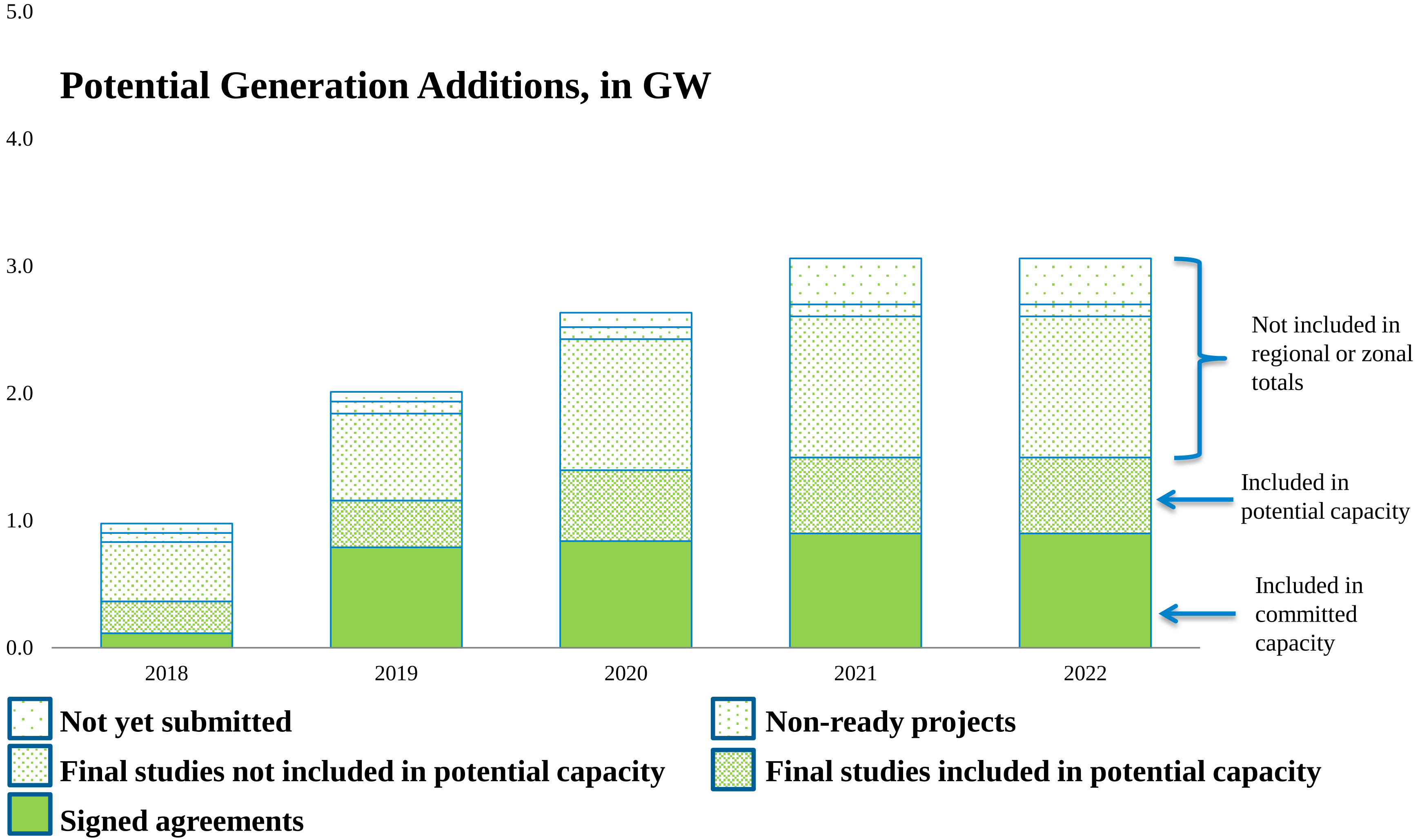


New resources include resources with newly signed Interconnection Agreements and new Load Modifying Resources

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

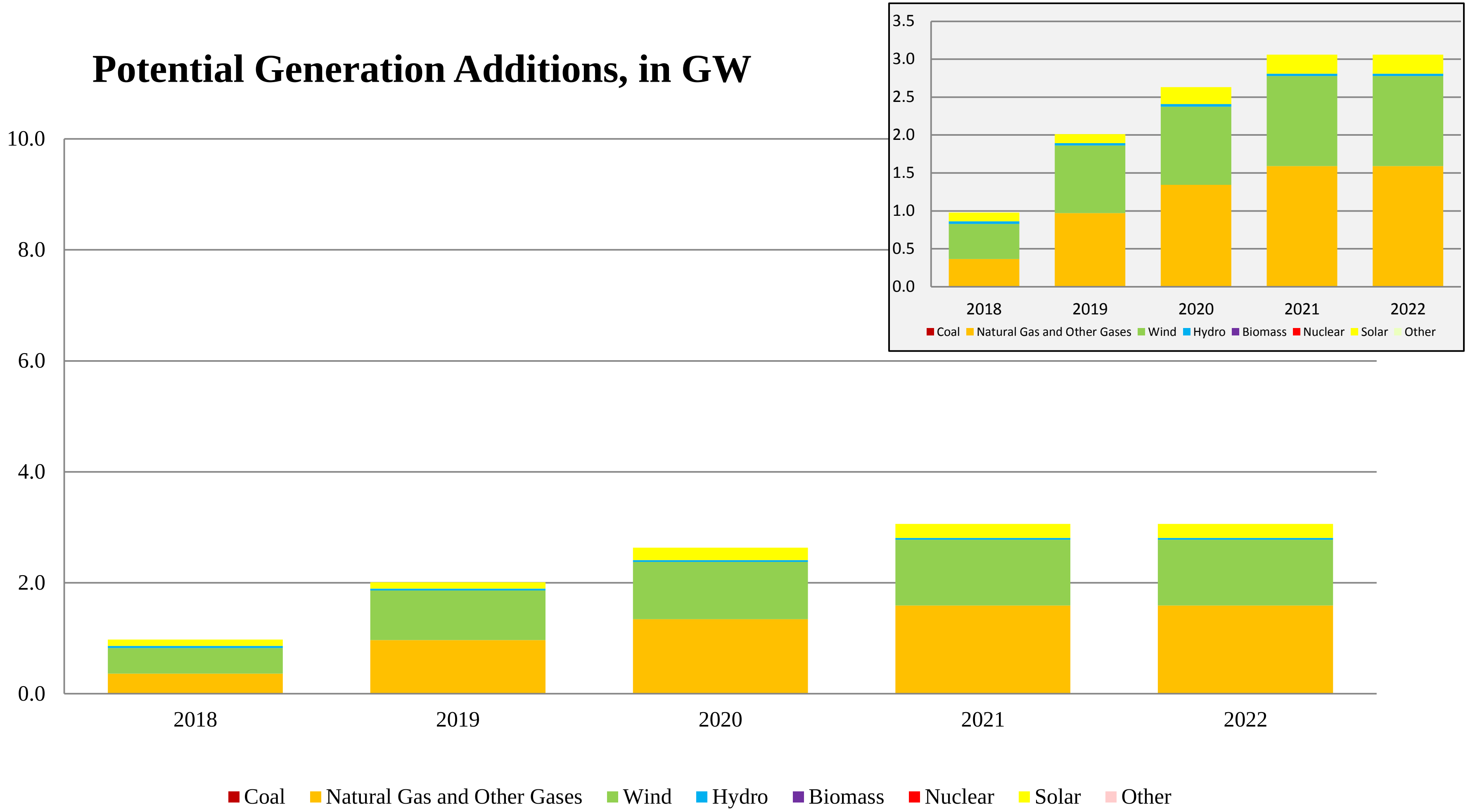
Zone 1 New Resource Additions by Queue Phase



Wind and solar resources are represented at their expected capacity credit

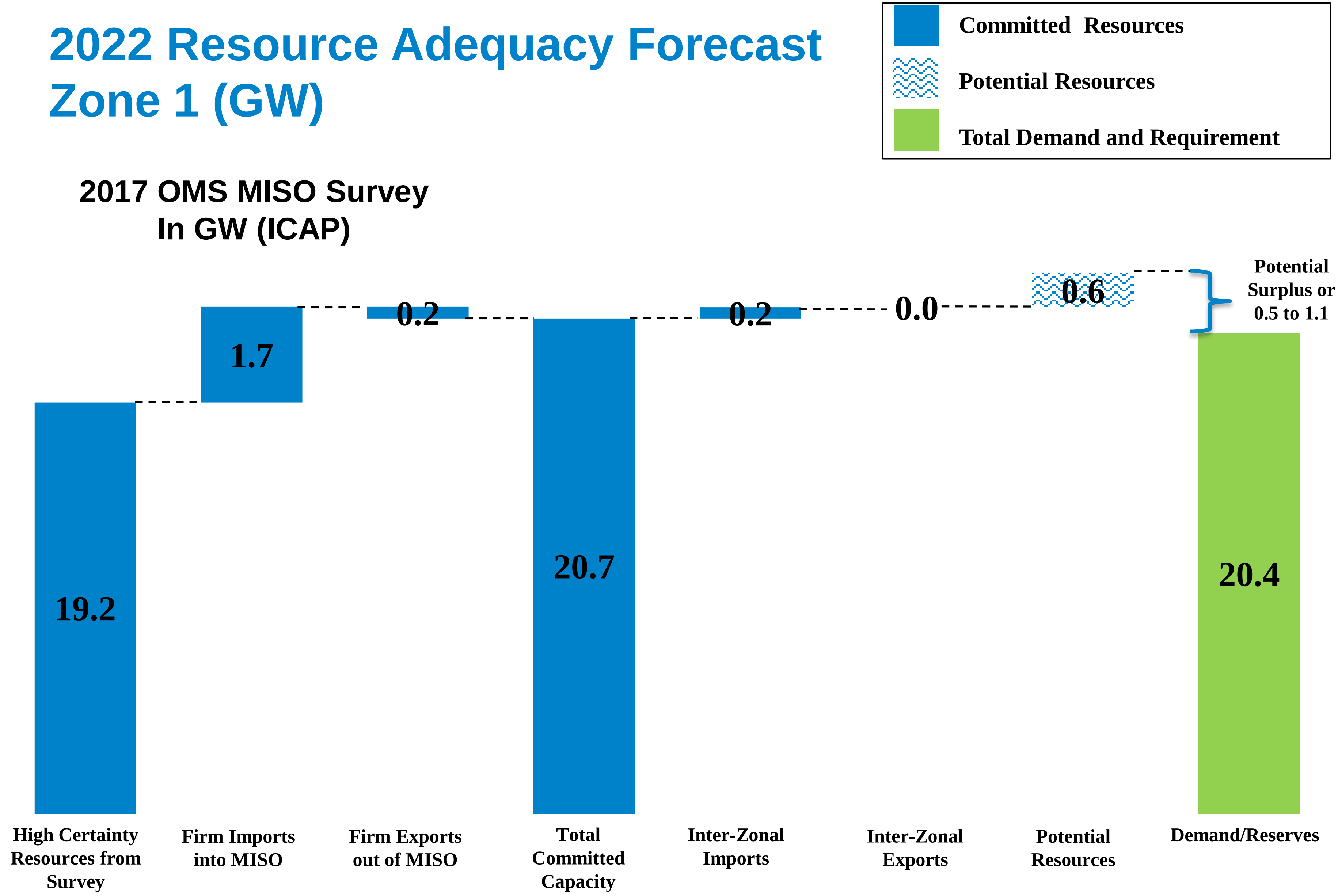
Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

Zone 1 New Resources Additions by Fuel Type



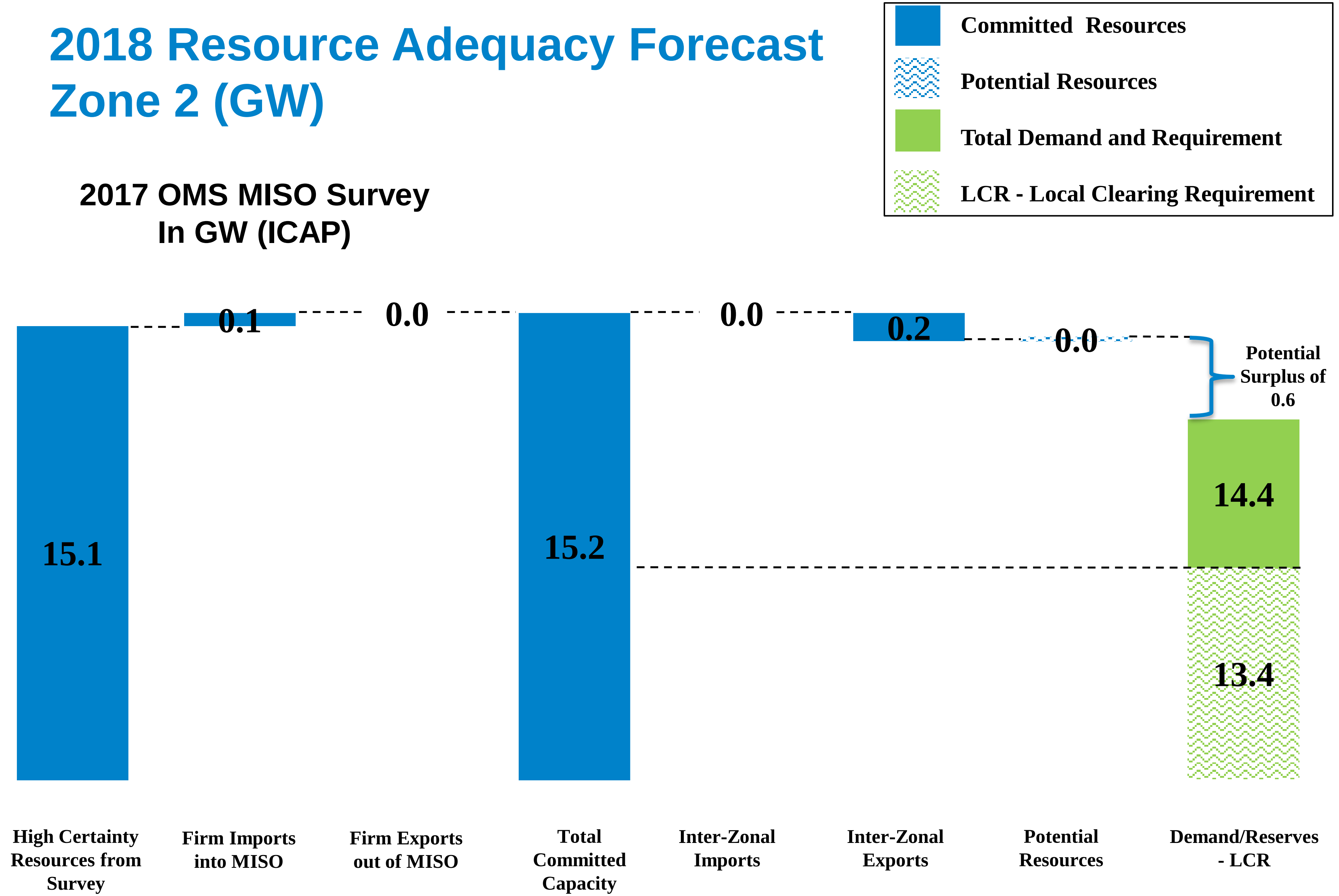
Includes all queued generation along with resources which have not yet been submitted to the MISO queue process
Wind and solar resources are represented at their expected capacity credit
Non-ready projects will be deemed withdrawn, as of June 15th, with an option to move to final studies

2022 Resource Adequacy Forecast Zone 1 (GW)



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

2018 Resource Adequacy Forecast Zone 2 (GW)



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

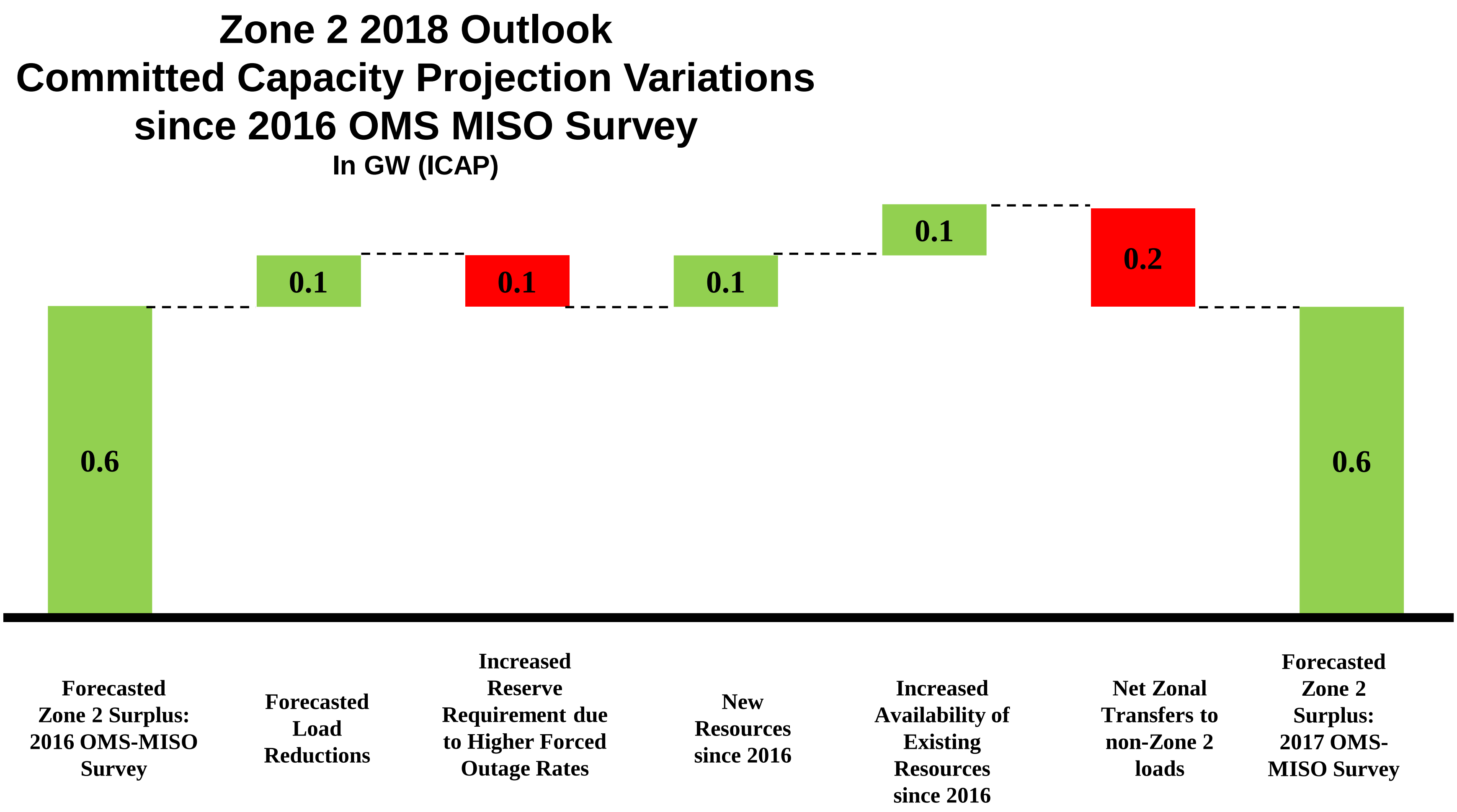
2019 - 2021 Resource Adequacy Forecast Zone 2 (GW)

2017 OMS MISO Survey

Values In GW (ICAP)

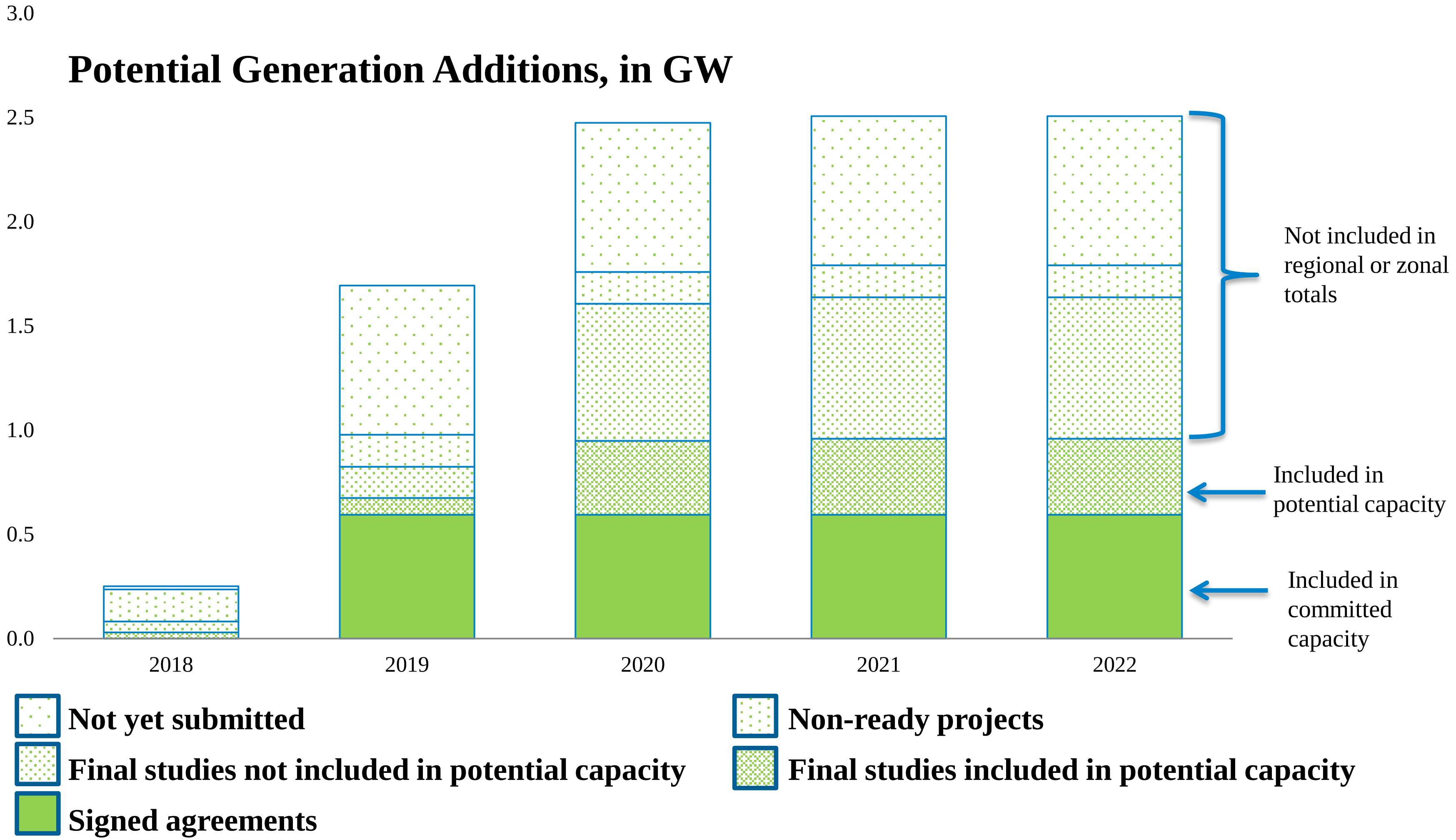
Zone 2	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	15.1	15.0	15.0	A
Firm Imports into MISO	0.1	0.1	0.1	B
Firm Exports out of MISO	0.0	0.0	0.0	C
Total High Certainty Capacity	**15.2**	**15.1**	**15.1**	D = (A+B)-C
Inter-Zonal Imports	0.0	0.0	0.0	E
Inter-Zonal Exports	0.3	0.3	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

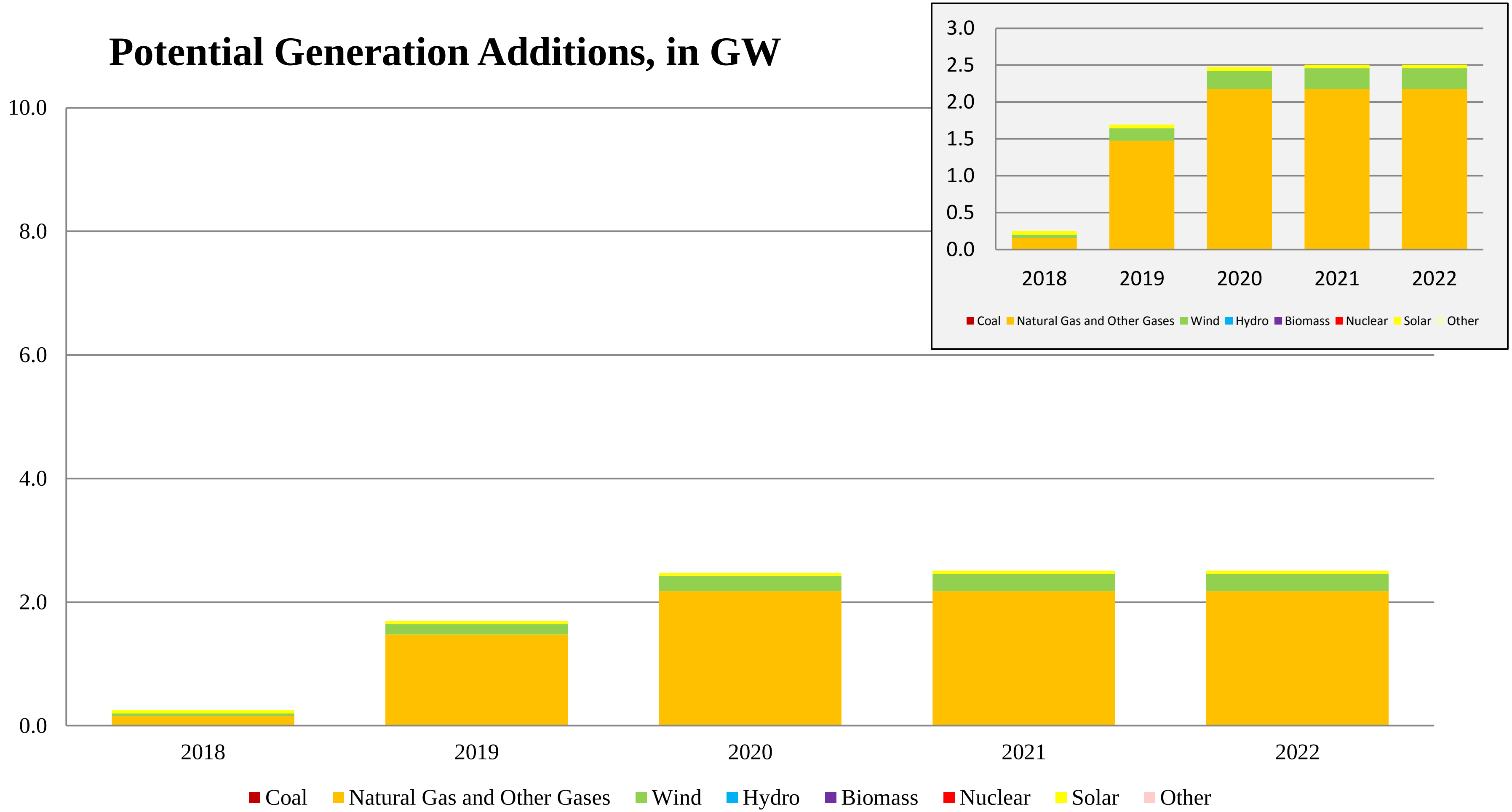
Zone 2 New Resource Additions by Queue Phase



Wind and solar resources are represented at their expected capacity credit

Non-ready projects 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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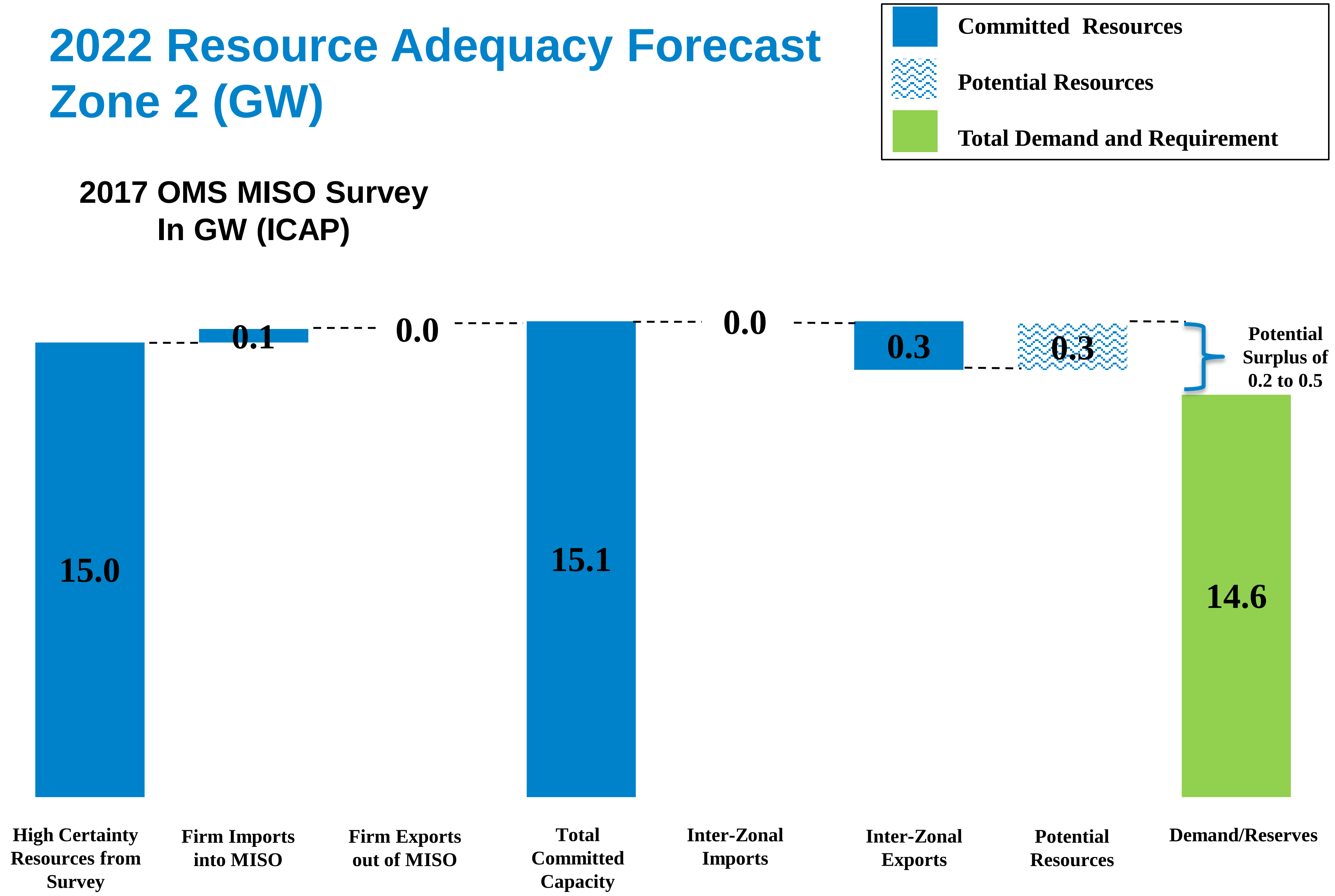
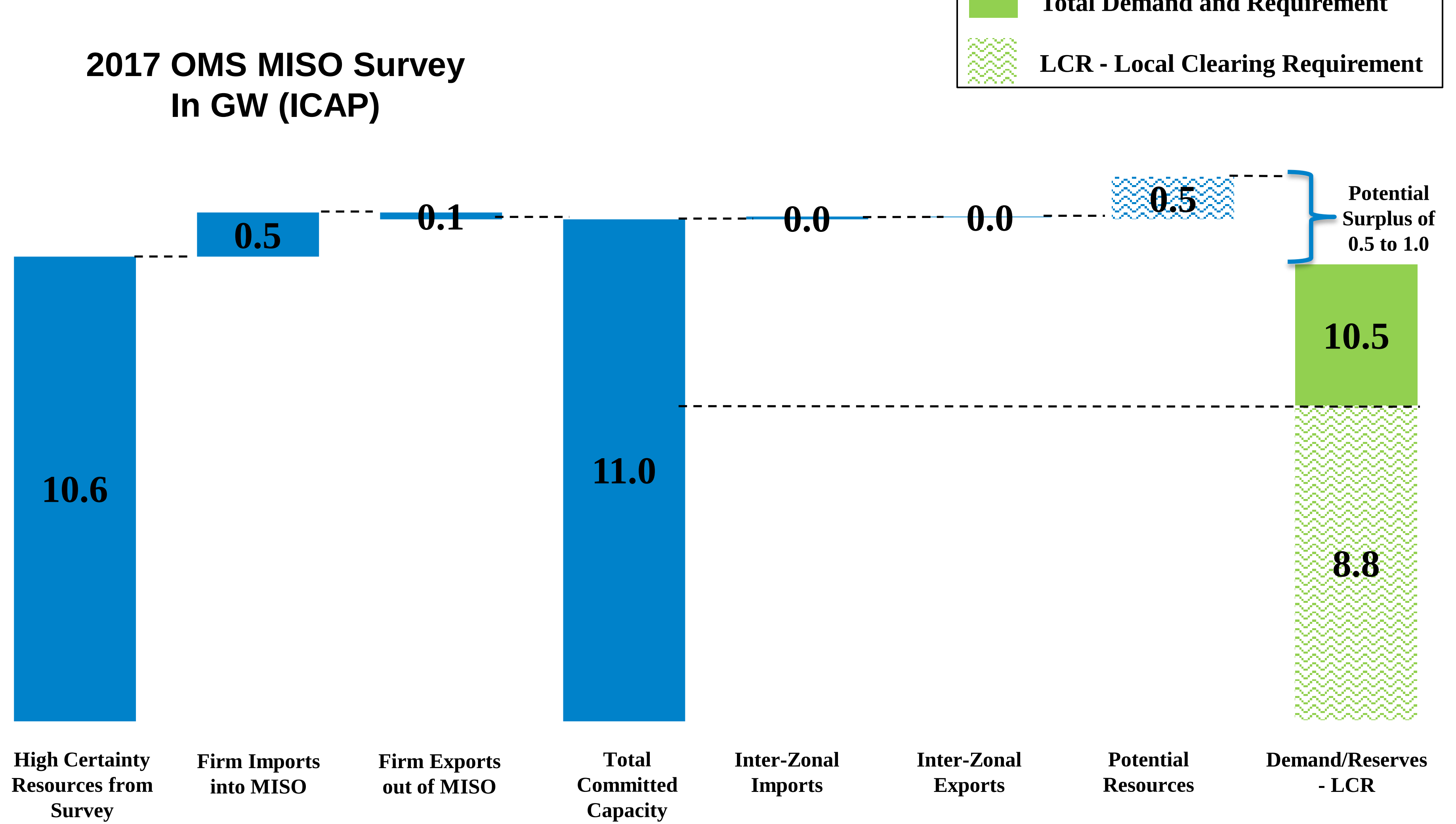
2022 Resource Adequacy Forecast Zone 2 (GW)



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

2018 Resource Adequacy Forecast Zone 3 (GW)



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

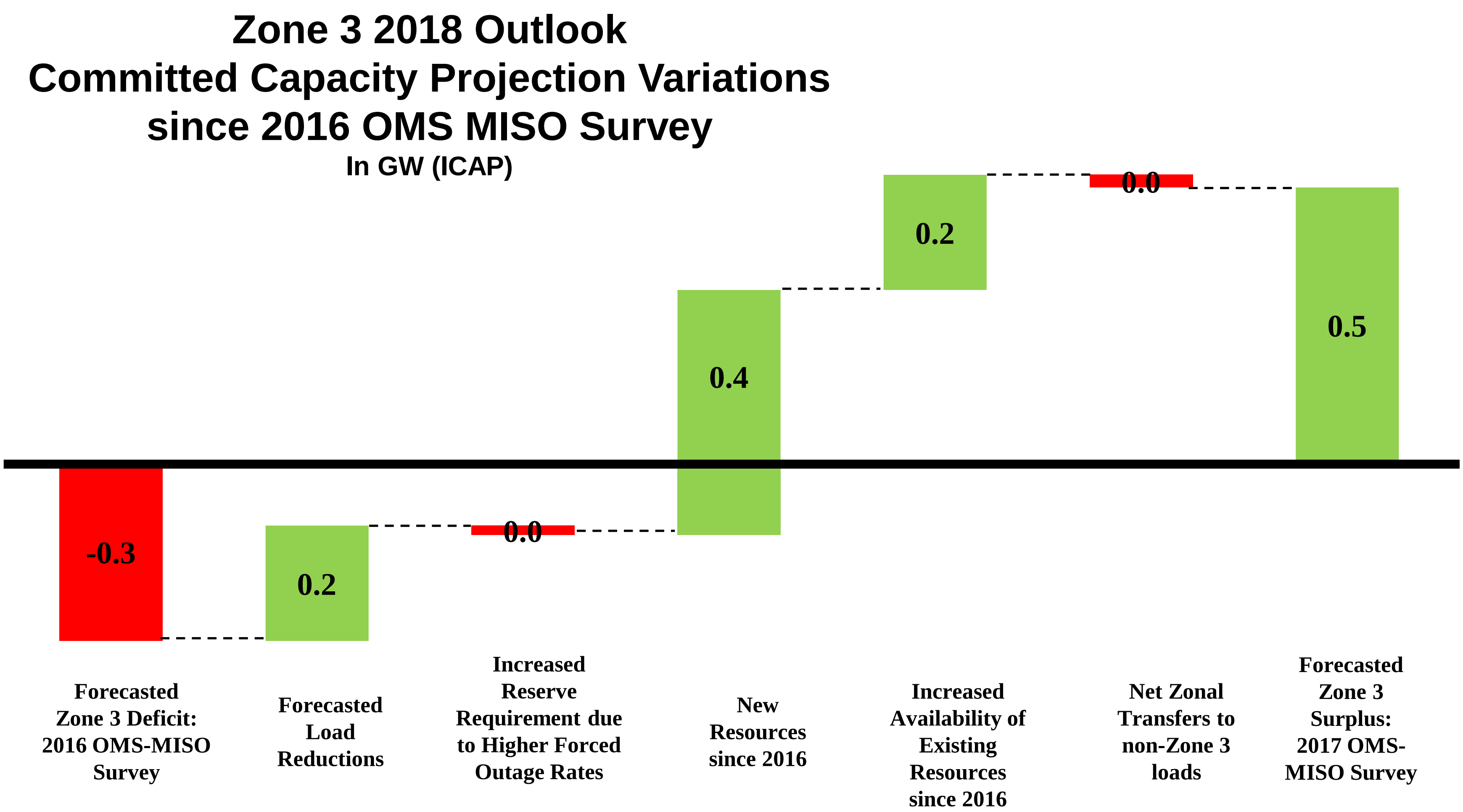
2019 - 2021 Resource Adequacy Forecast Zone 3 (GW)

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

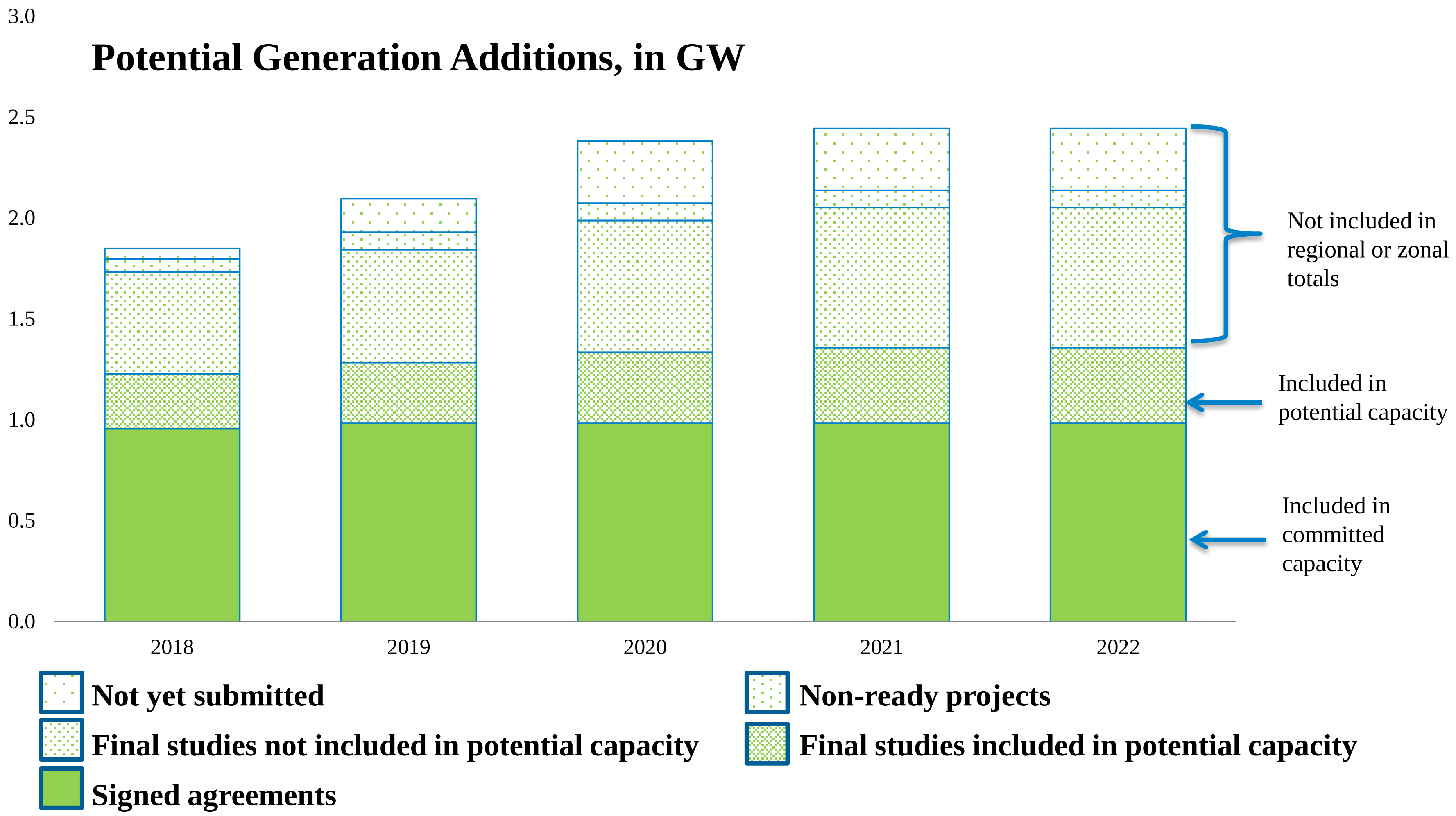


<u>**New resources**</u> include resources with newly signed Interconnection Agreements and new Load Modifying Resources

<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 3 New Resource Additions by Queue Phase



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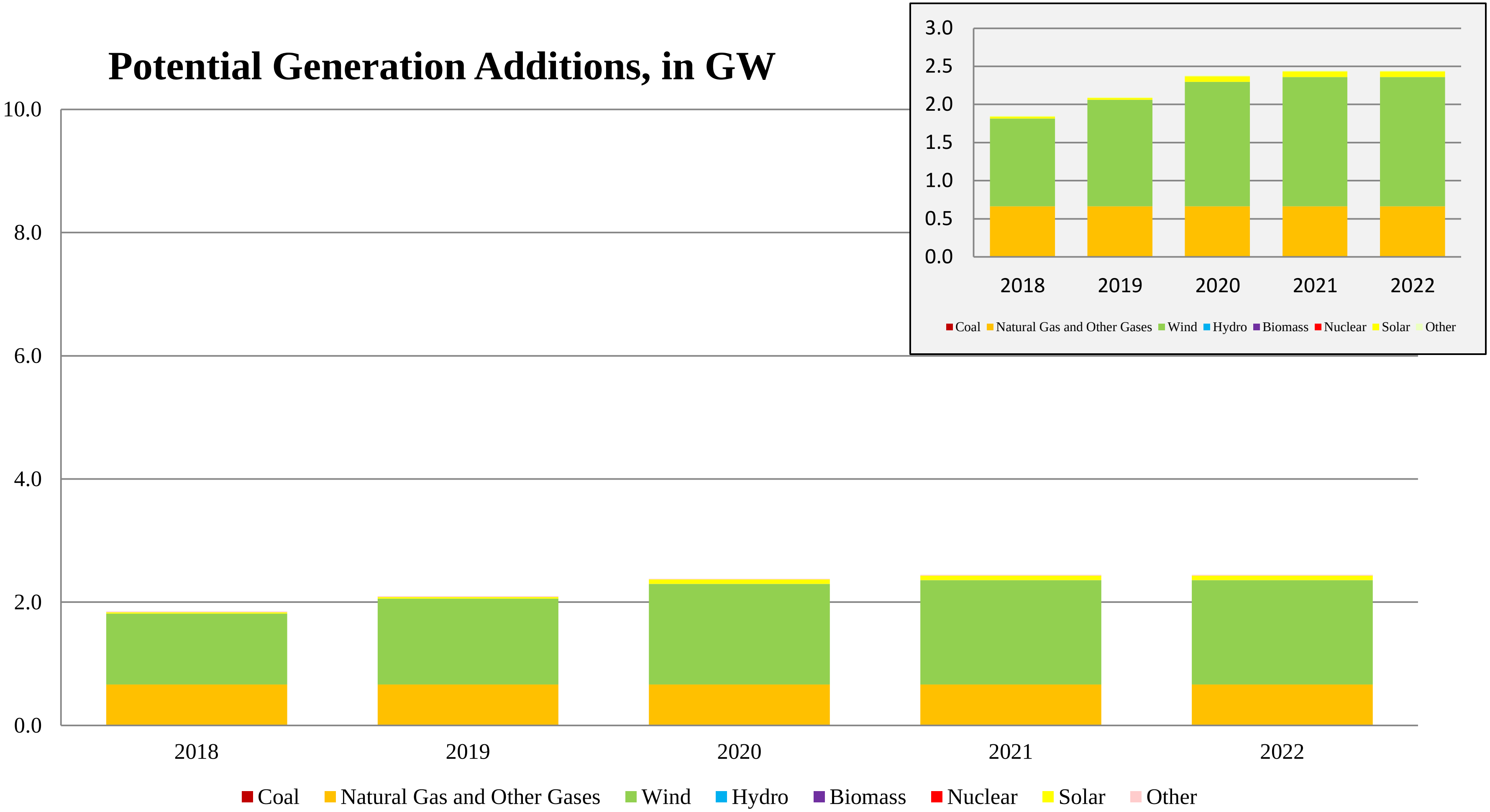
Zone 3 New Resources Additions by Fuel Type



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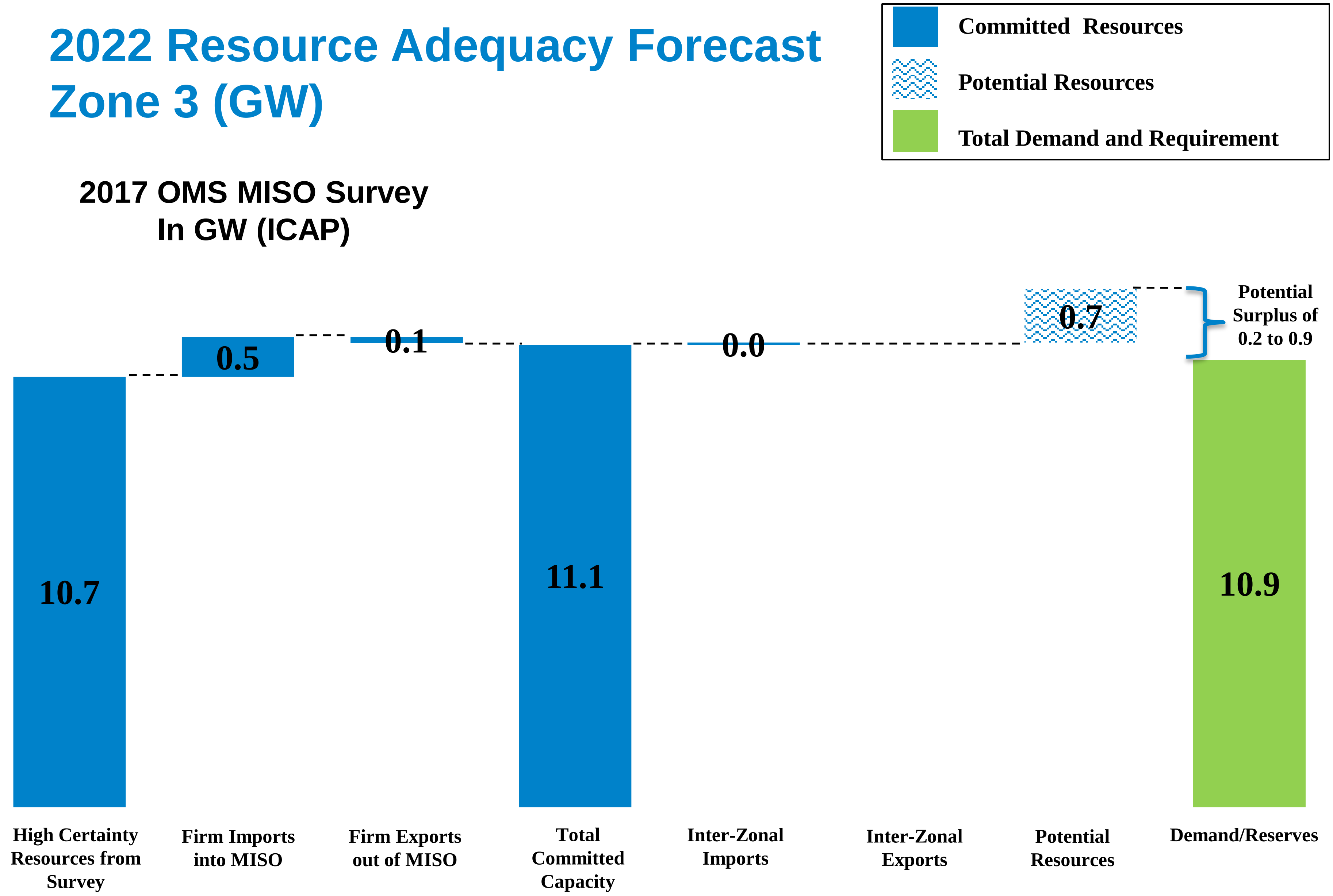
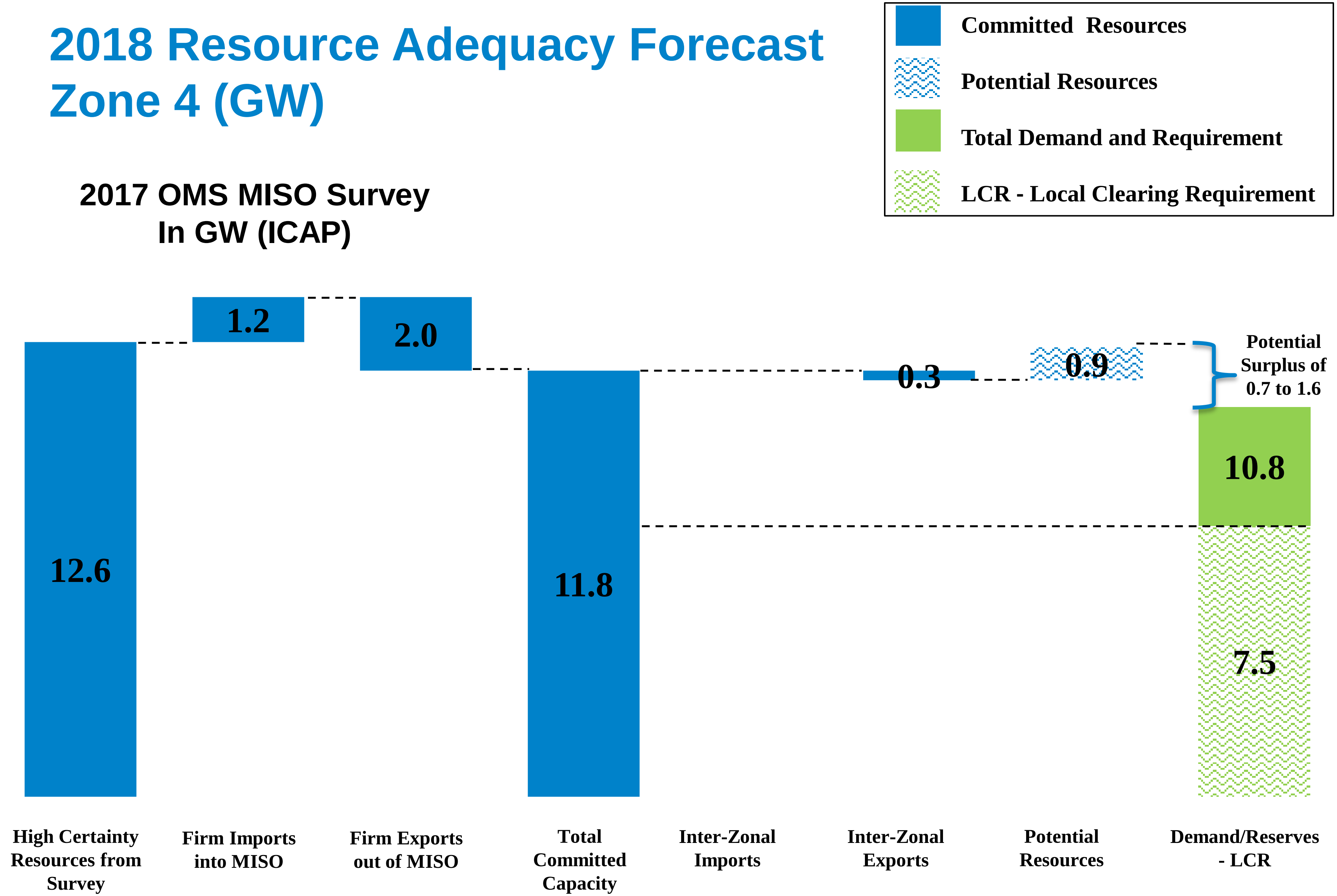
2022 Resource Adequacy Forecast Zone 3 (GW)



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

2018 Resource Adequacy Forecast Zone 4 (GW)



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

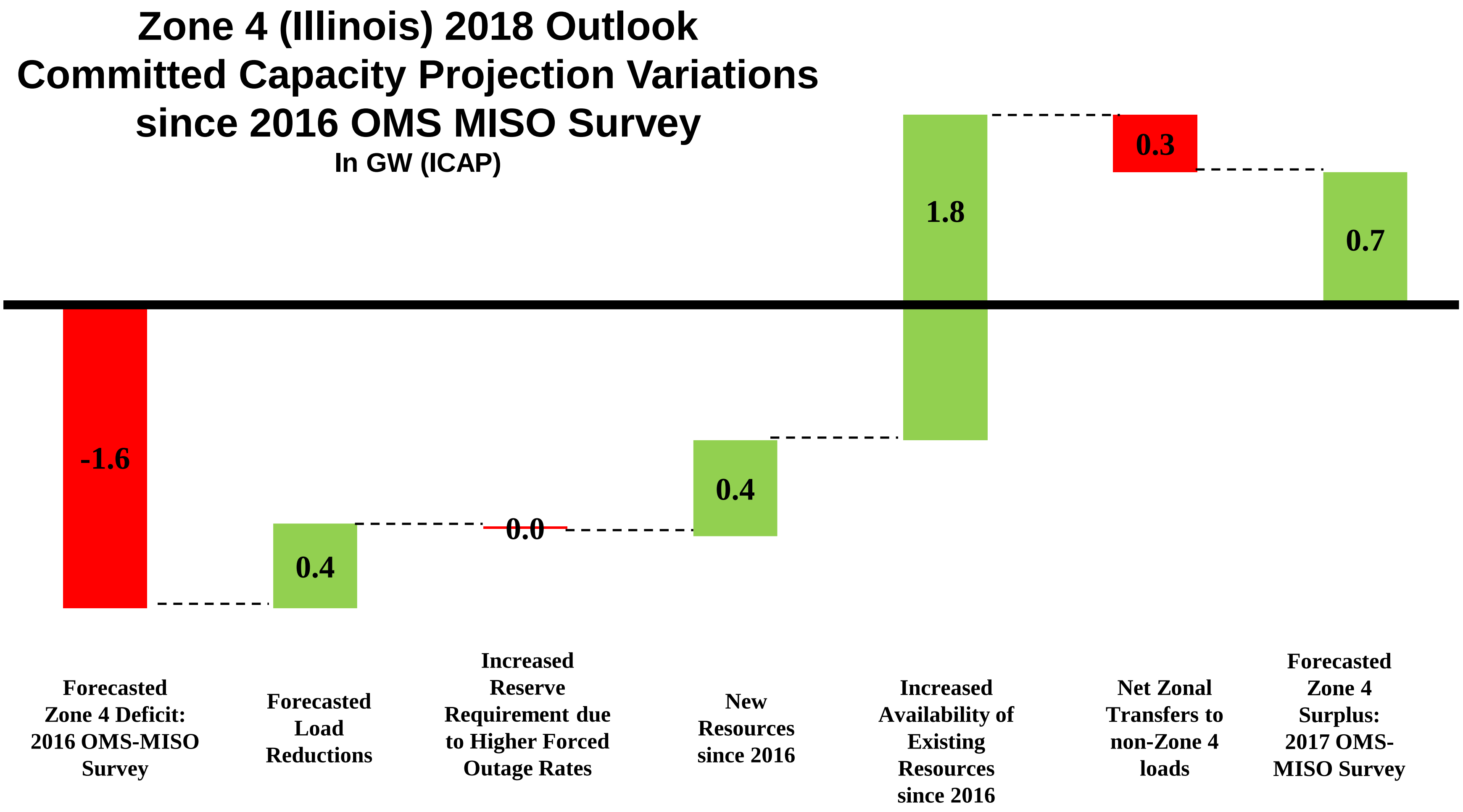
2019 - 2021 Resource Adequacy Forecast Zone 4 (GW)

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



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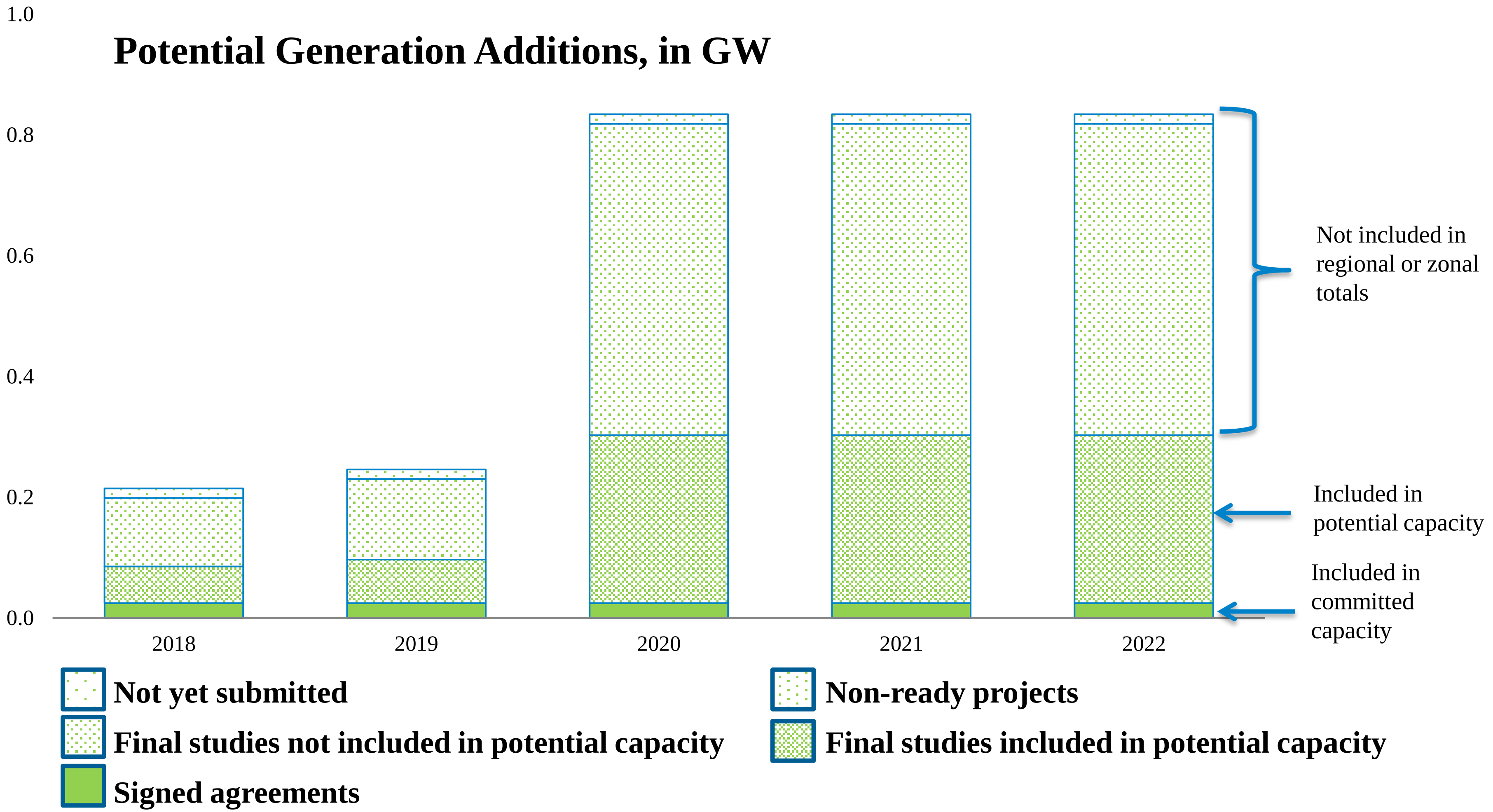
Zone 4 New Resource Additions by Queue Phase



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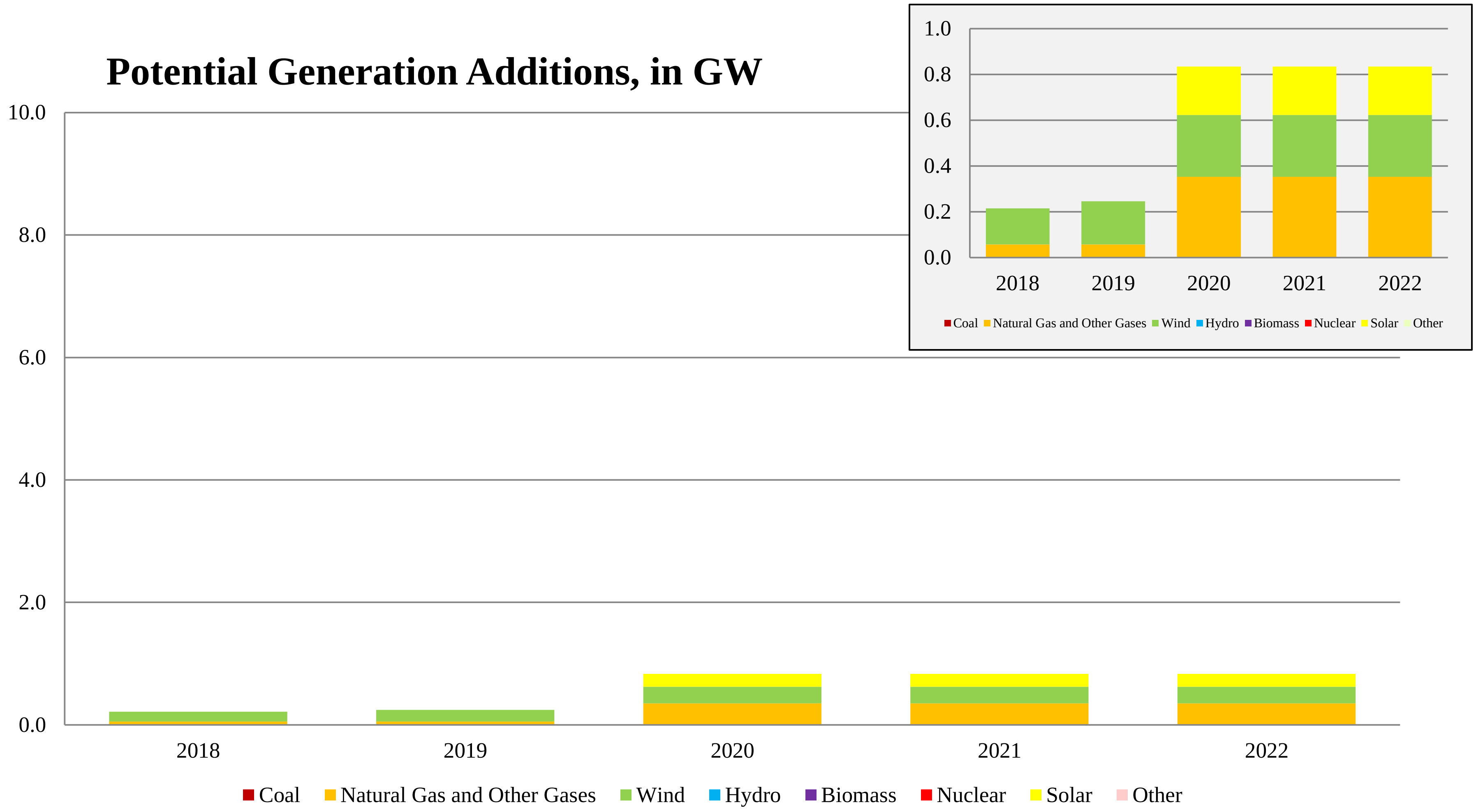
Zone 4 New Resources Additions by Fuel Type



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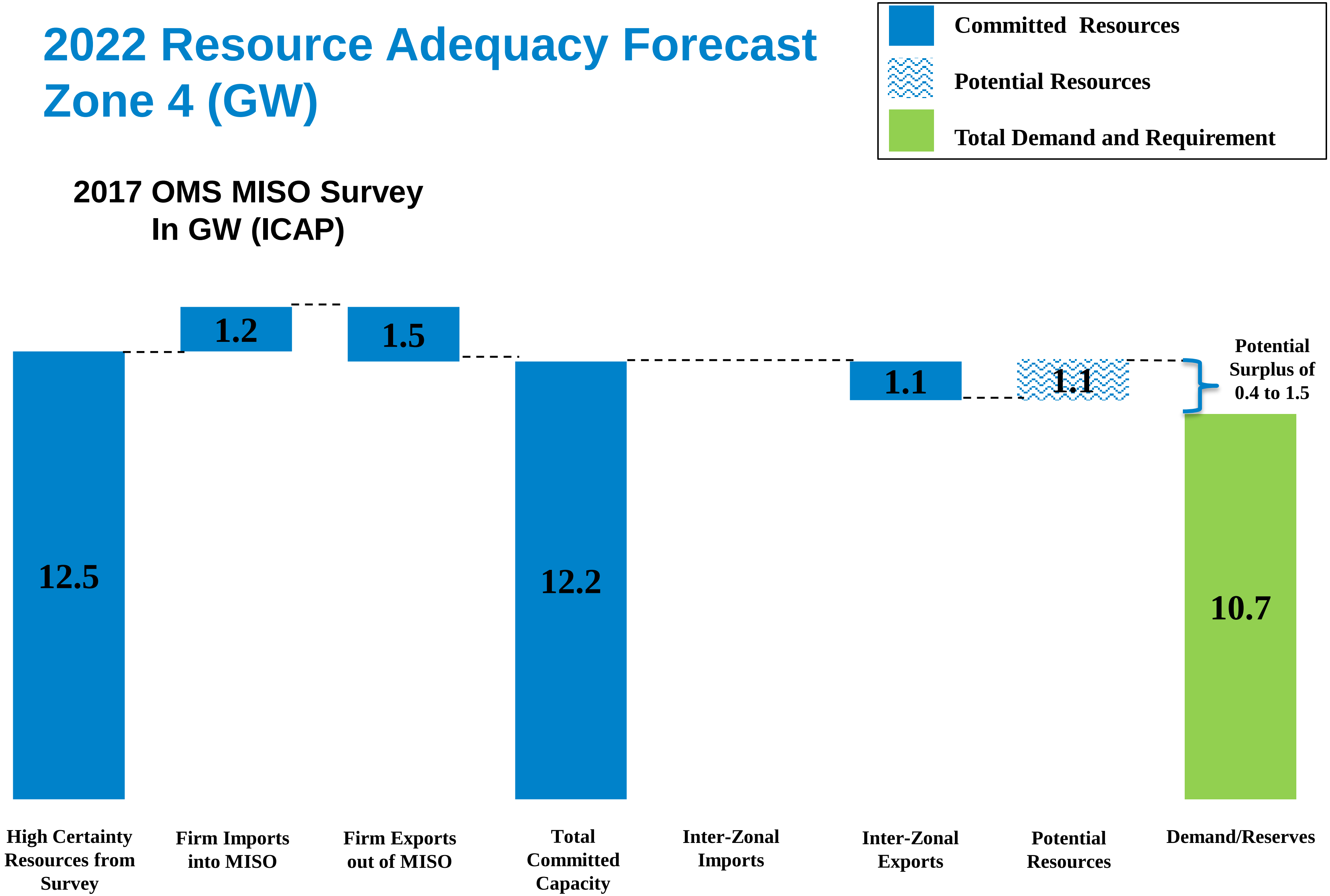
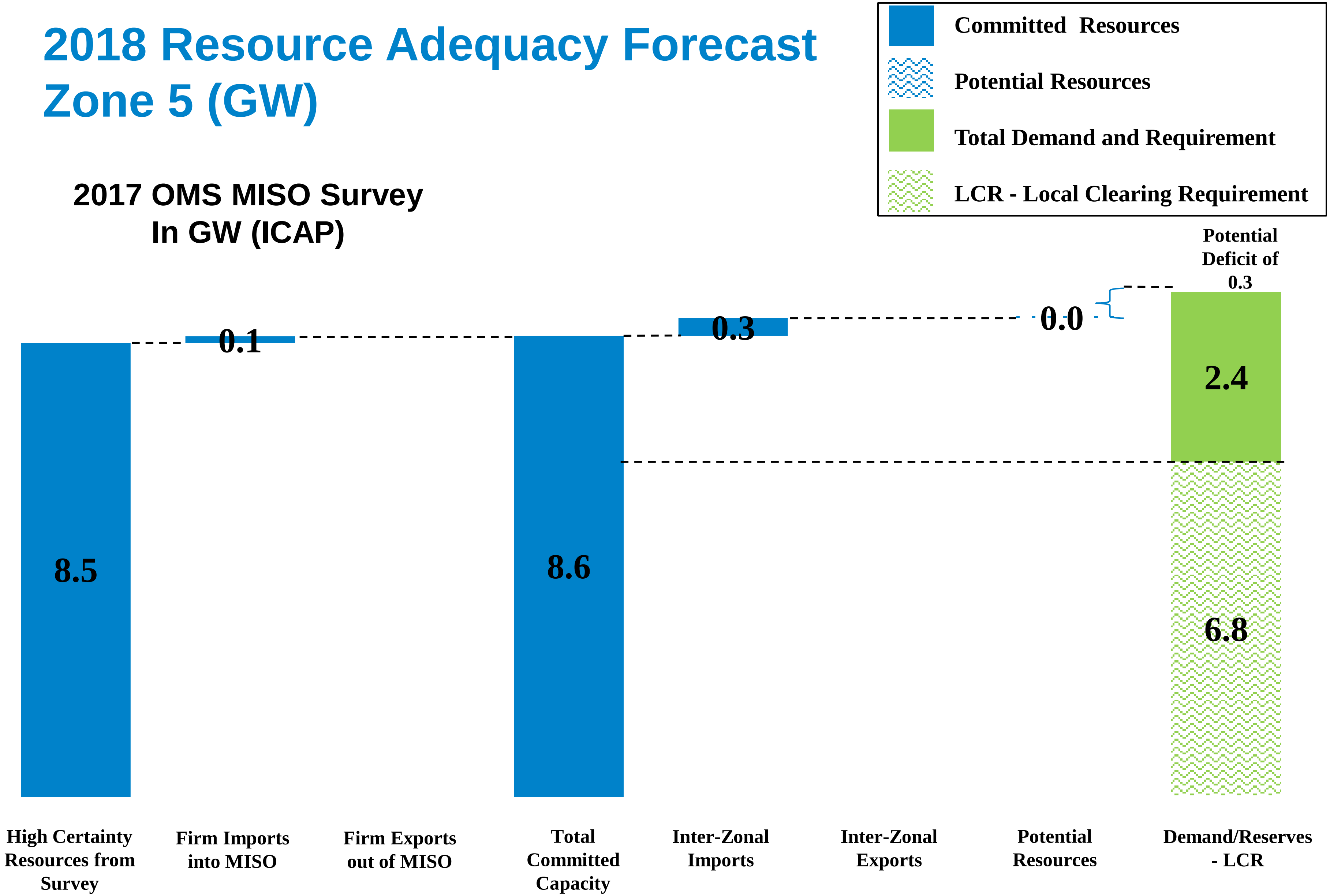
2022 Resource Adequacy Forecast Zone 4 (GW)



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

2018 Resource Adequacy Forecast Zone 5 (GW)



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

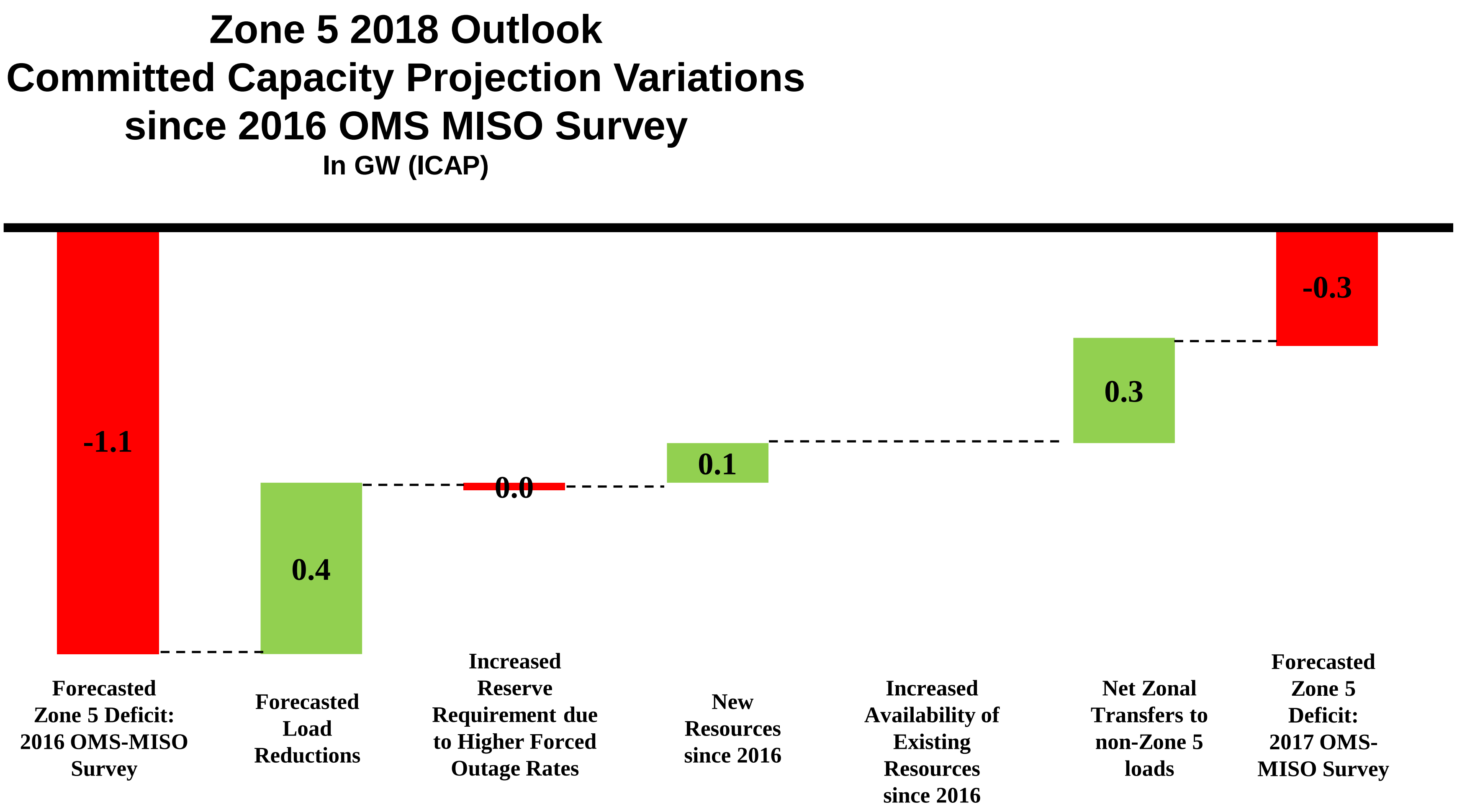
2019 - 2021 Resource Adequacy Forecast Zone 5 (GW)

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



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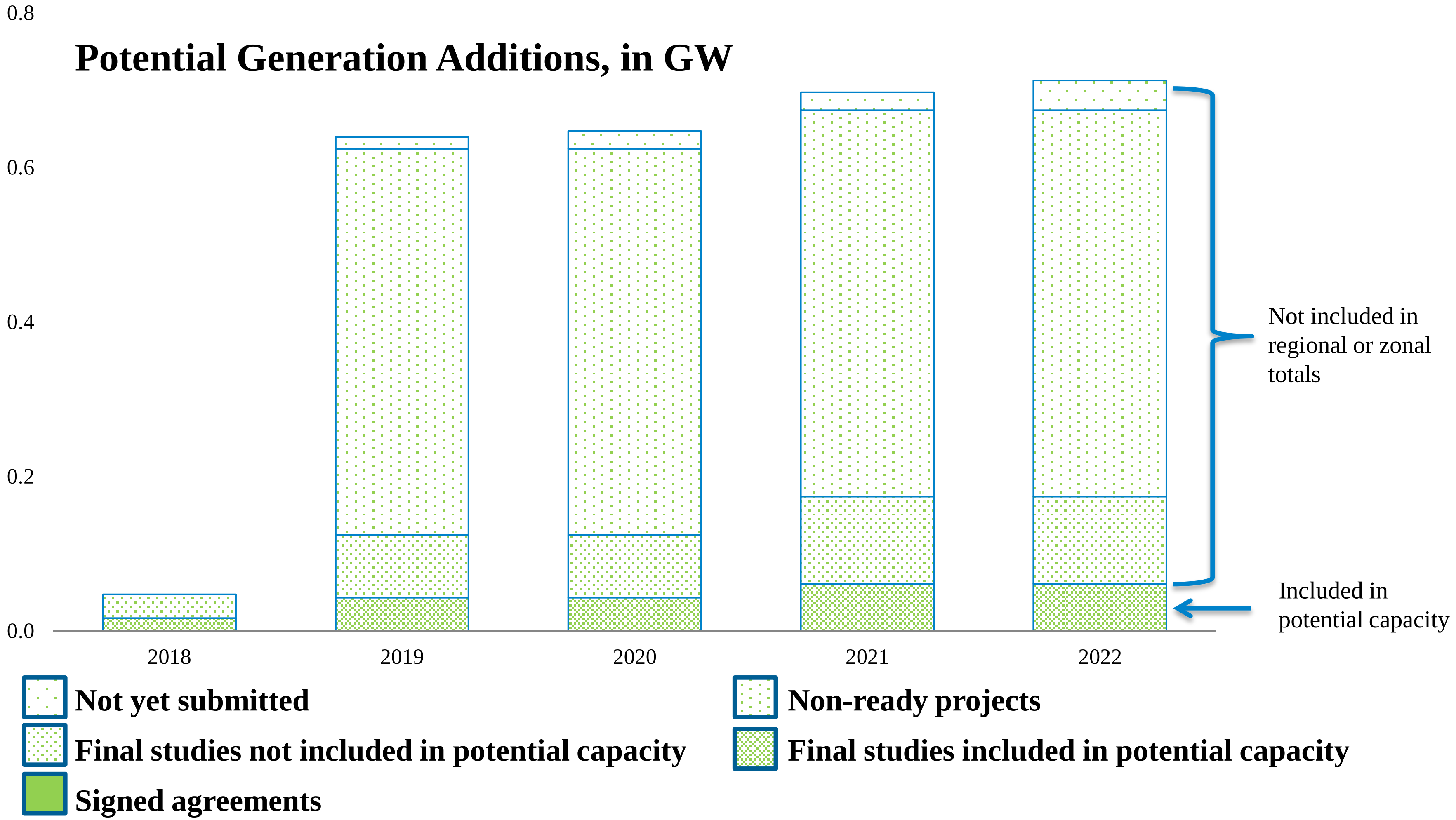
Zone 5 New Resource Additions by Queue Phase



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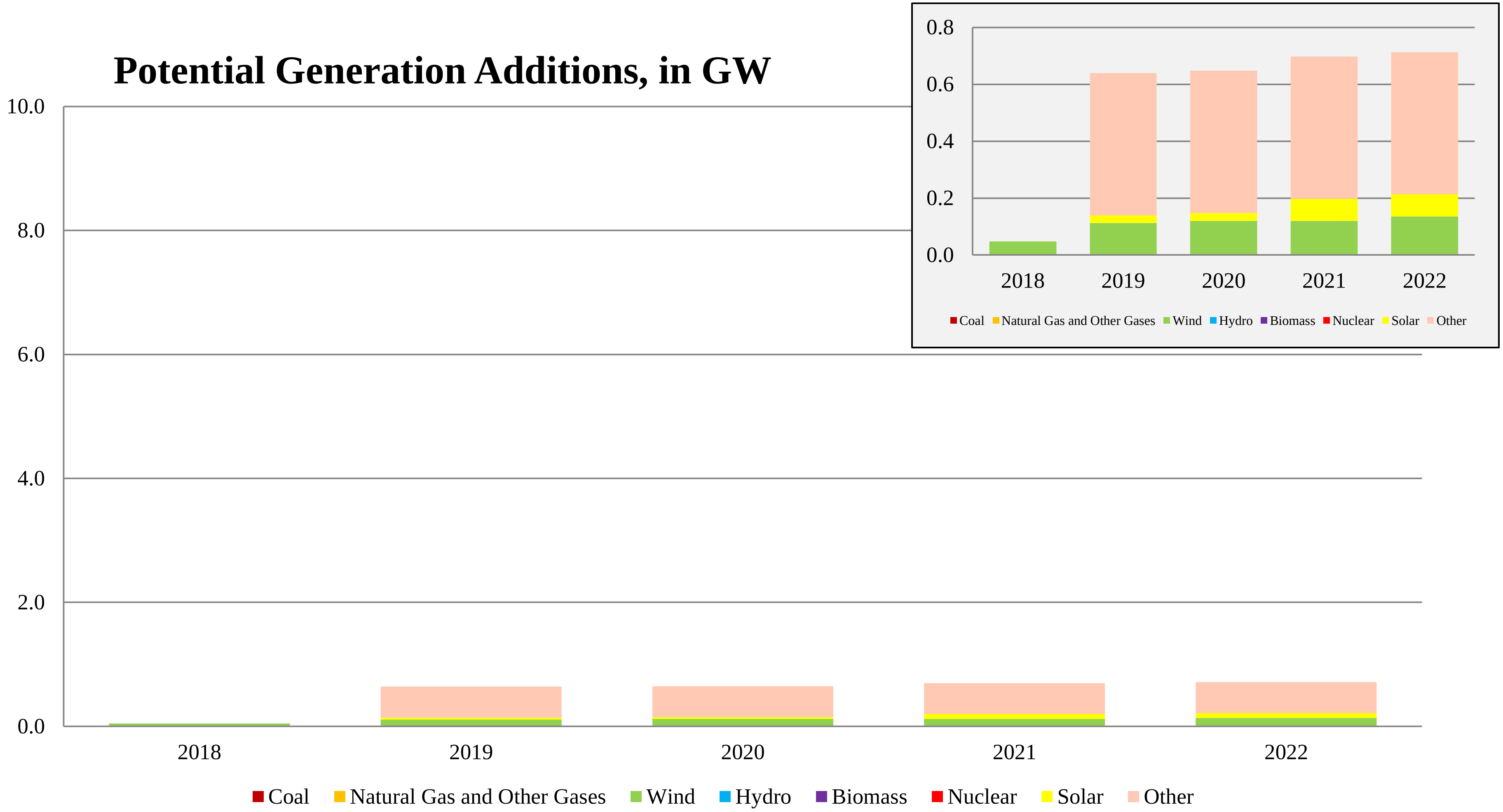
Zone 5 New Resources Additions by Fuel Type



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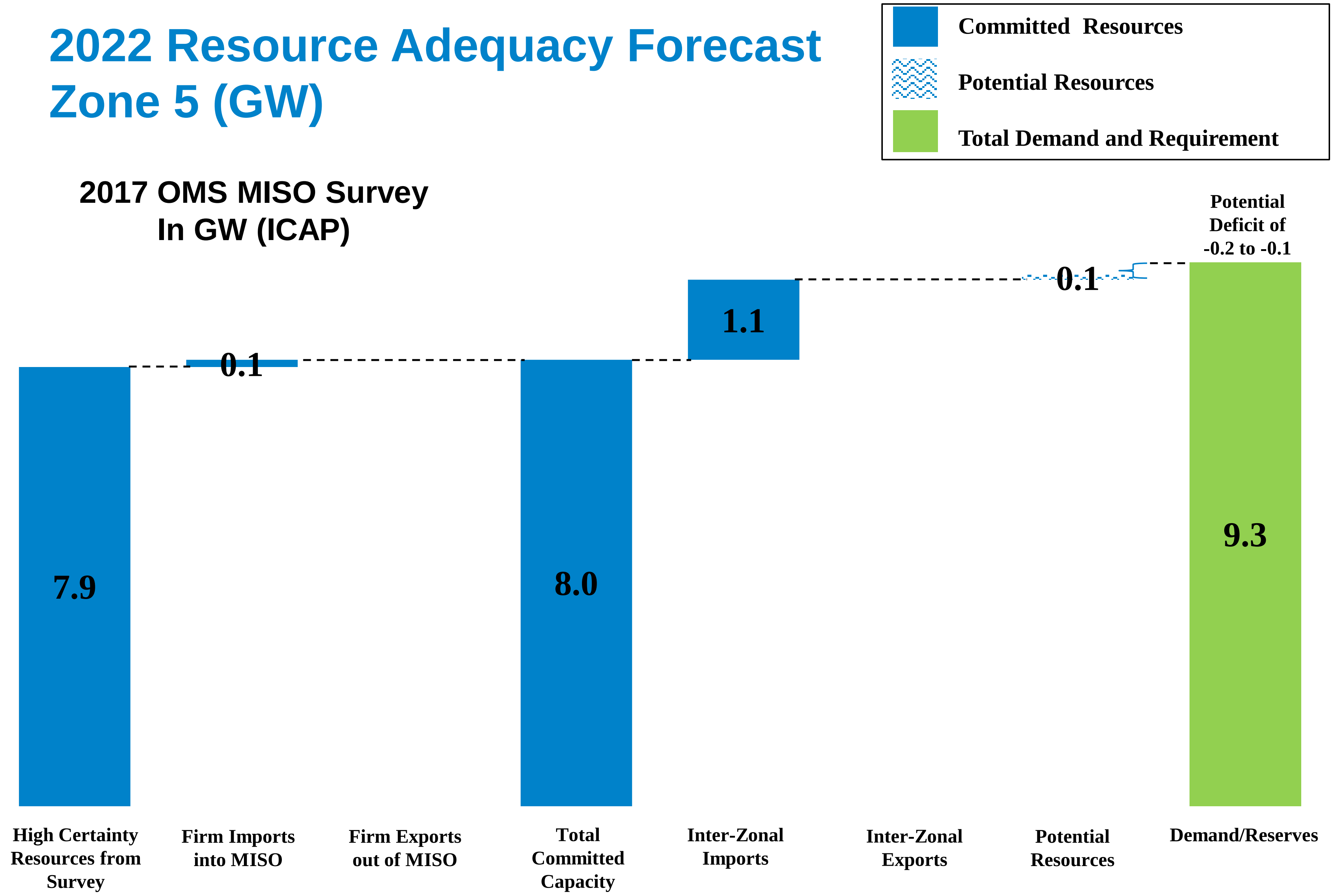
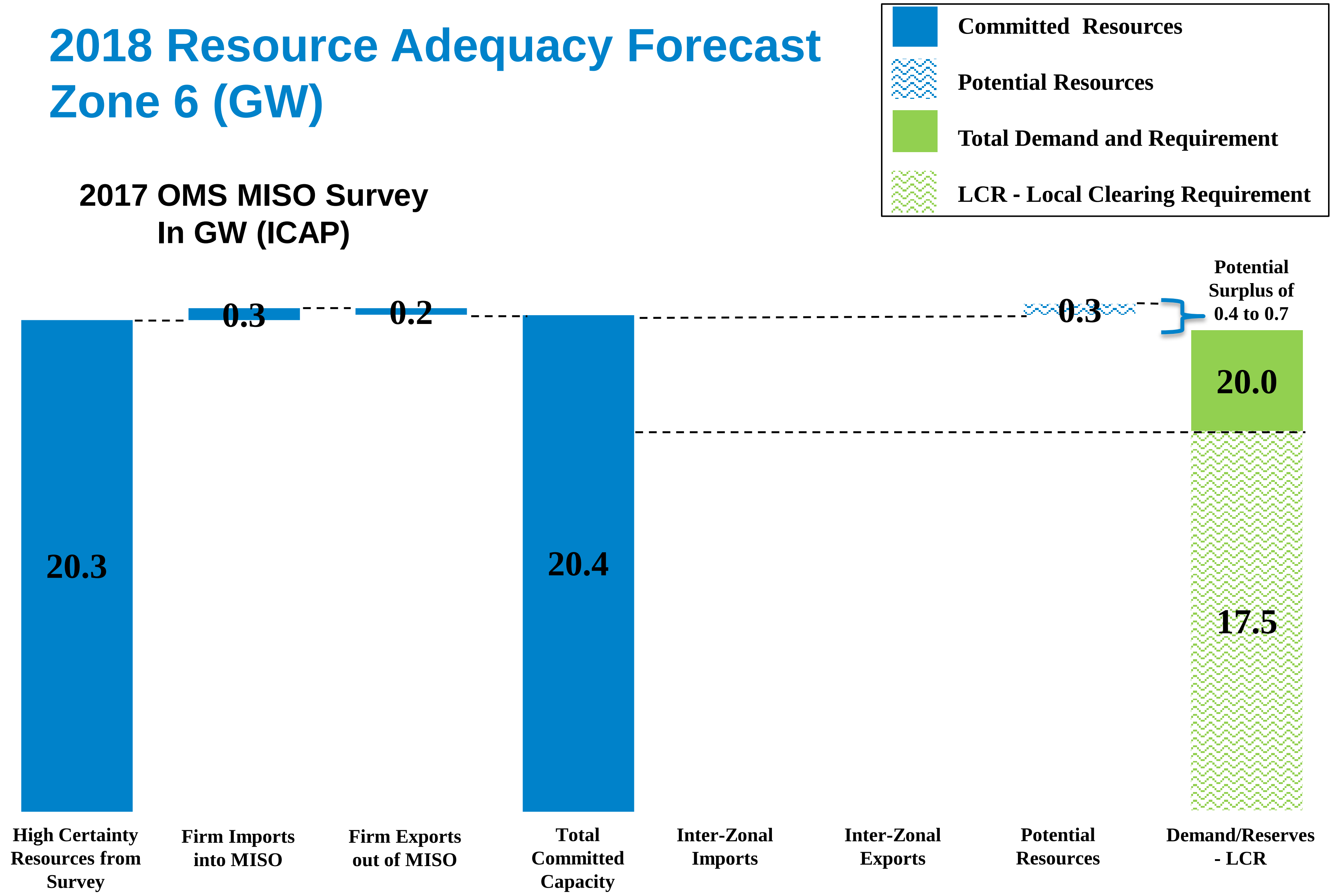
2022 Resource Adequacy Forecast Zone 5 (GW)



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

2018 Resource Adequacy Forecast Zone 6 (GW)



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

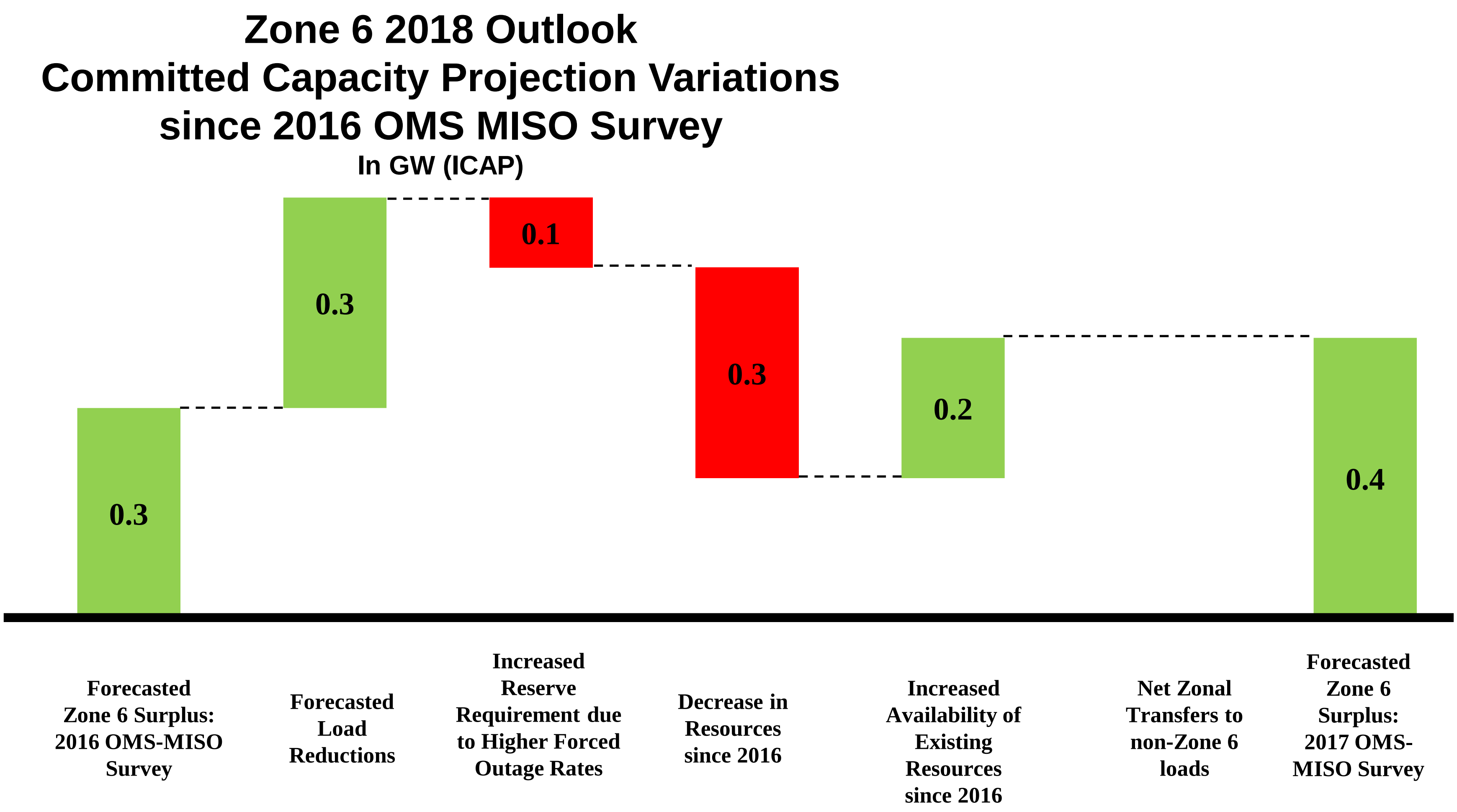
2019 - 2021 Resource Adequacy Forecast Zone 6 (GW)

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



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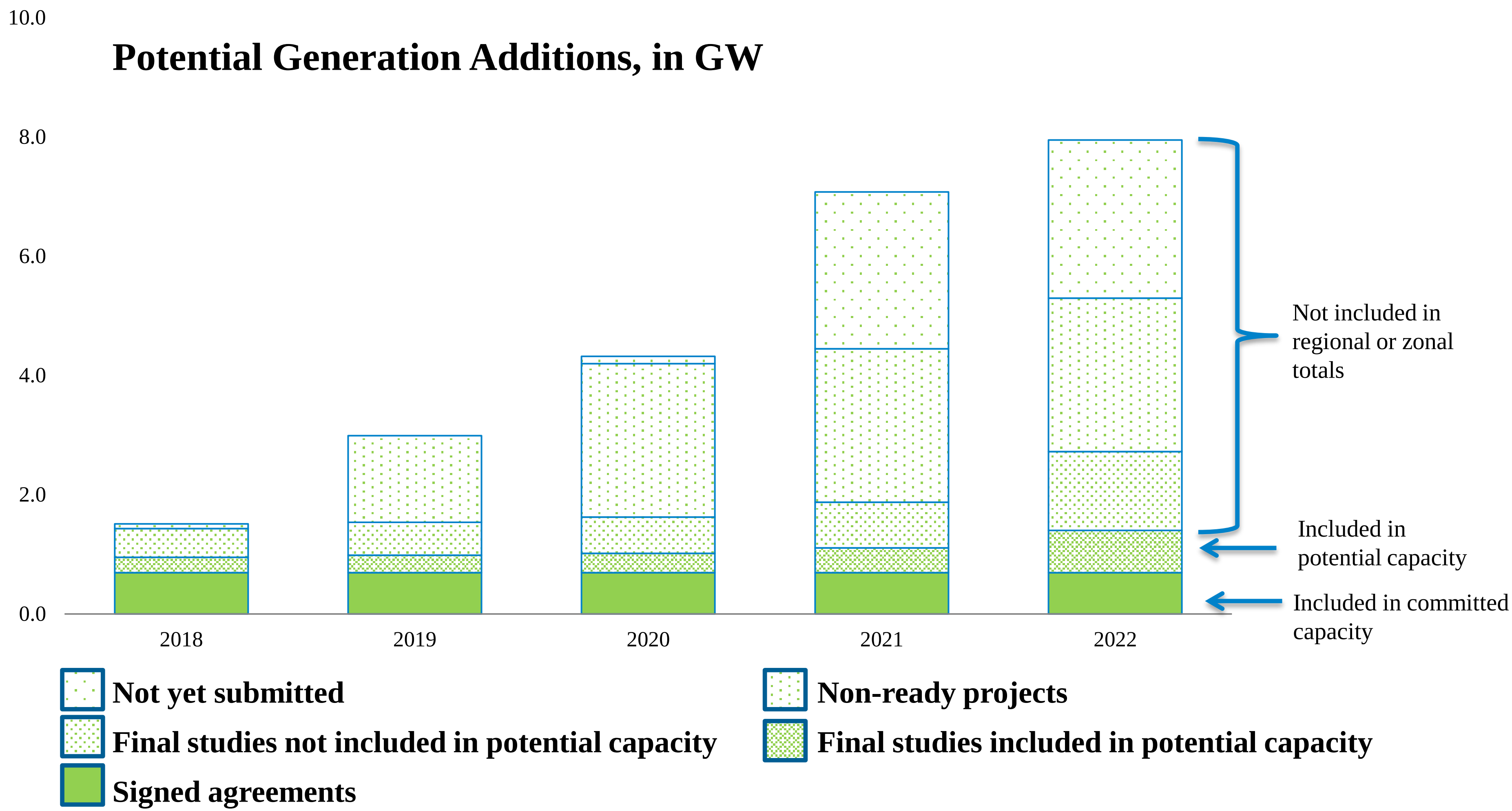
Zone 6 New Resource Additions by Queue Phase



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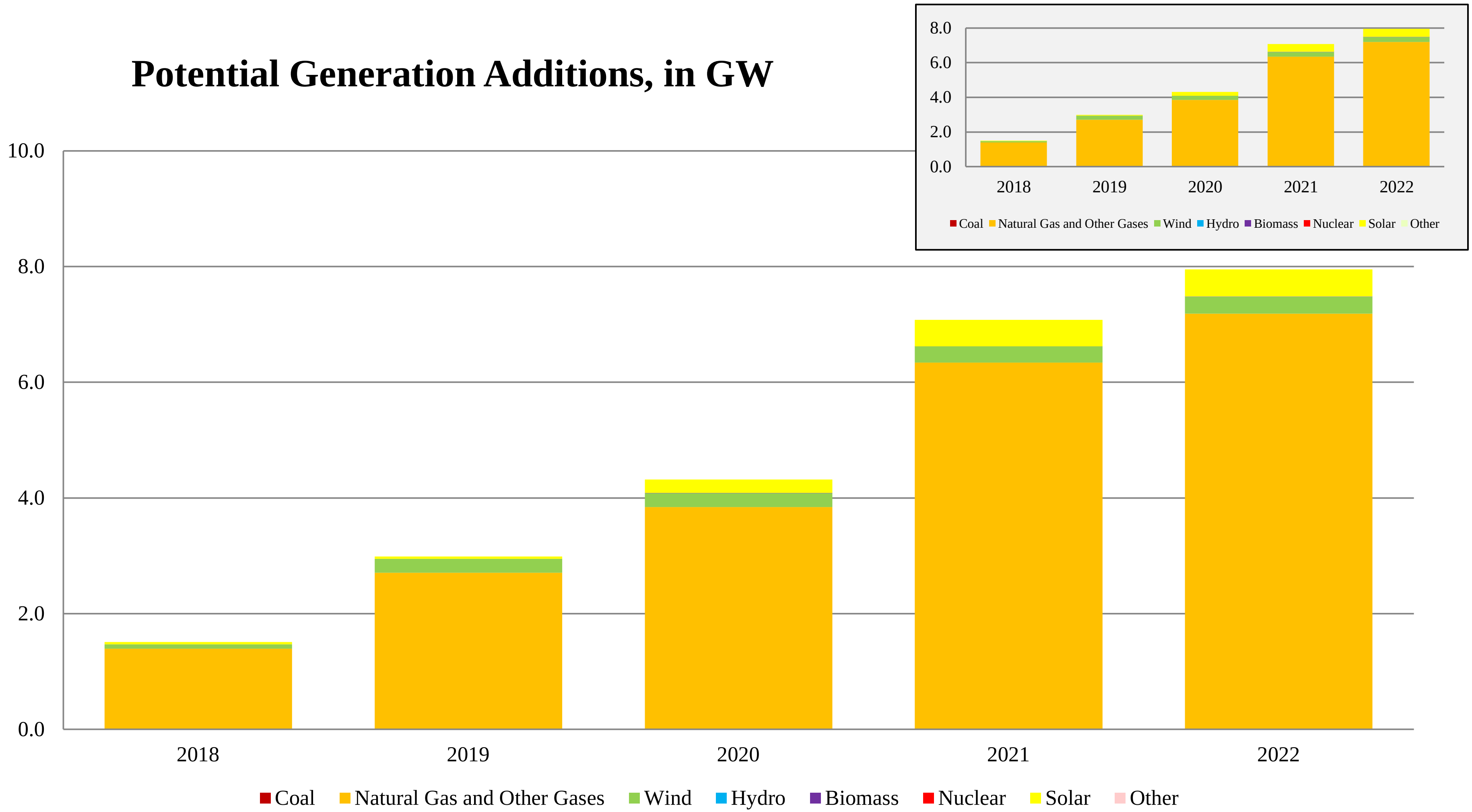
Zone 6 New Resources Additions by Fuel Type



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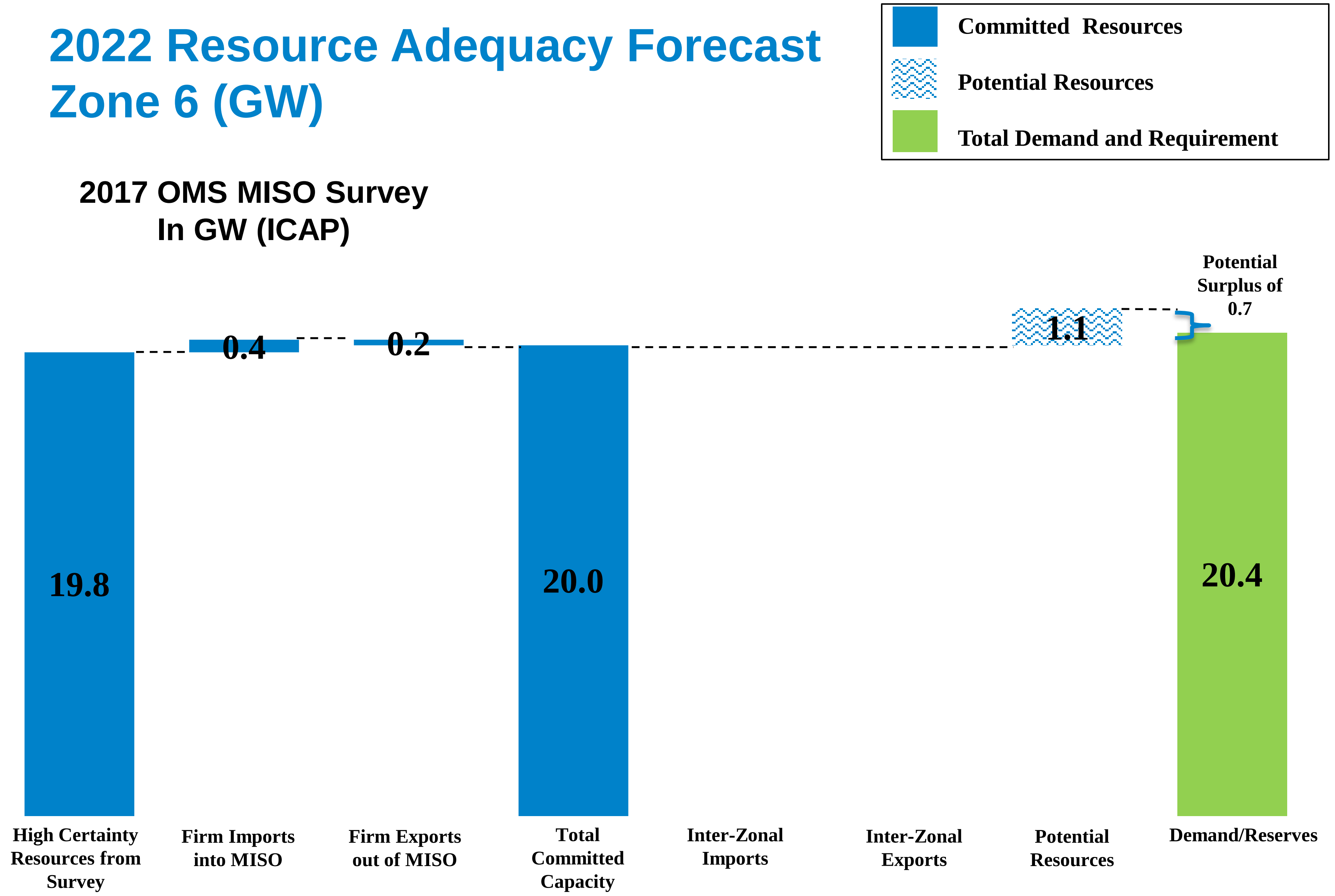
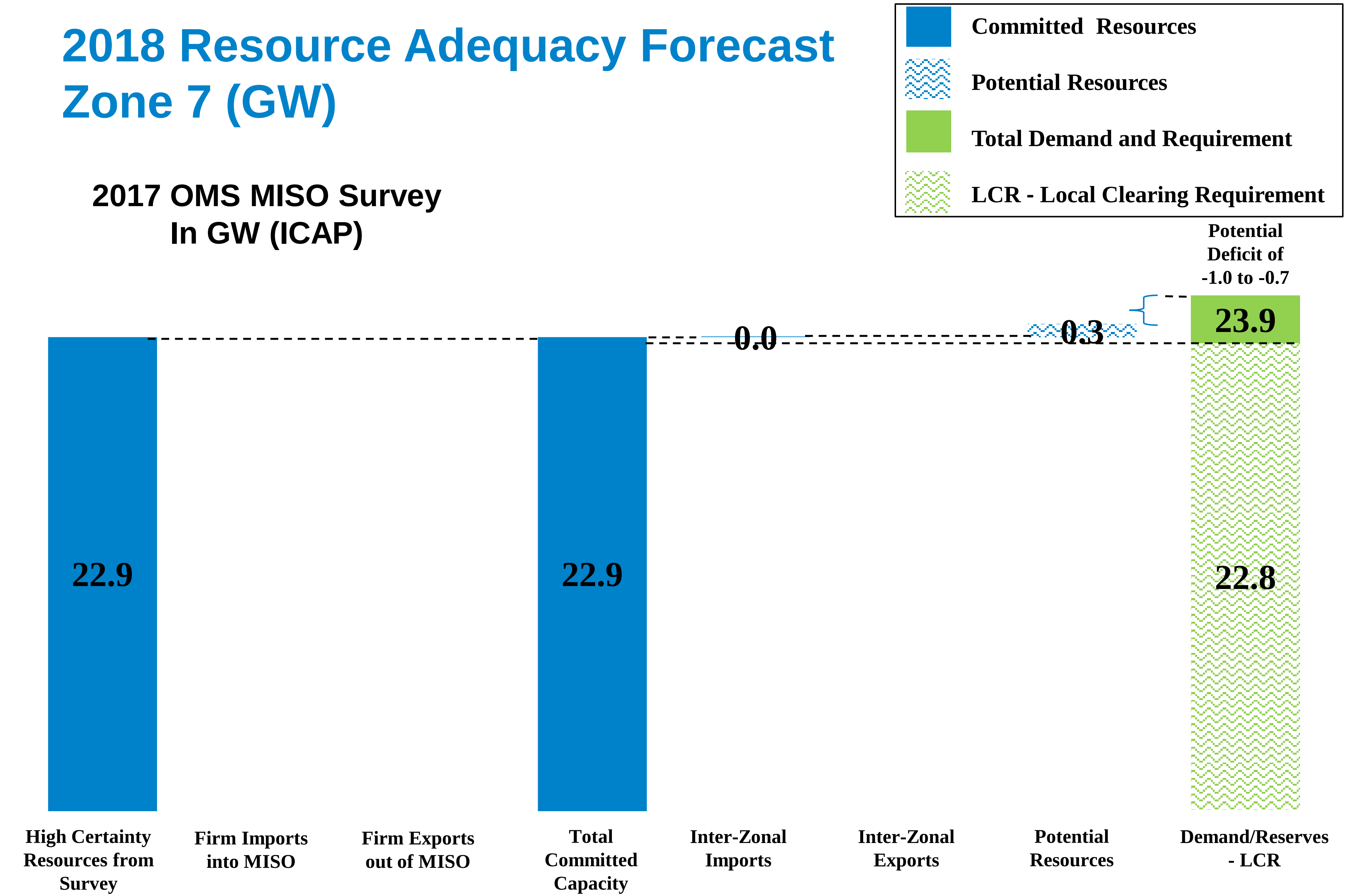
2022 Resource Adequacy Forecast Zone 6 (GW)



__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

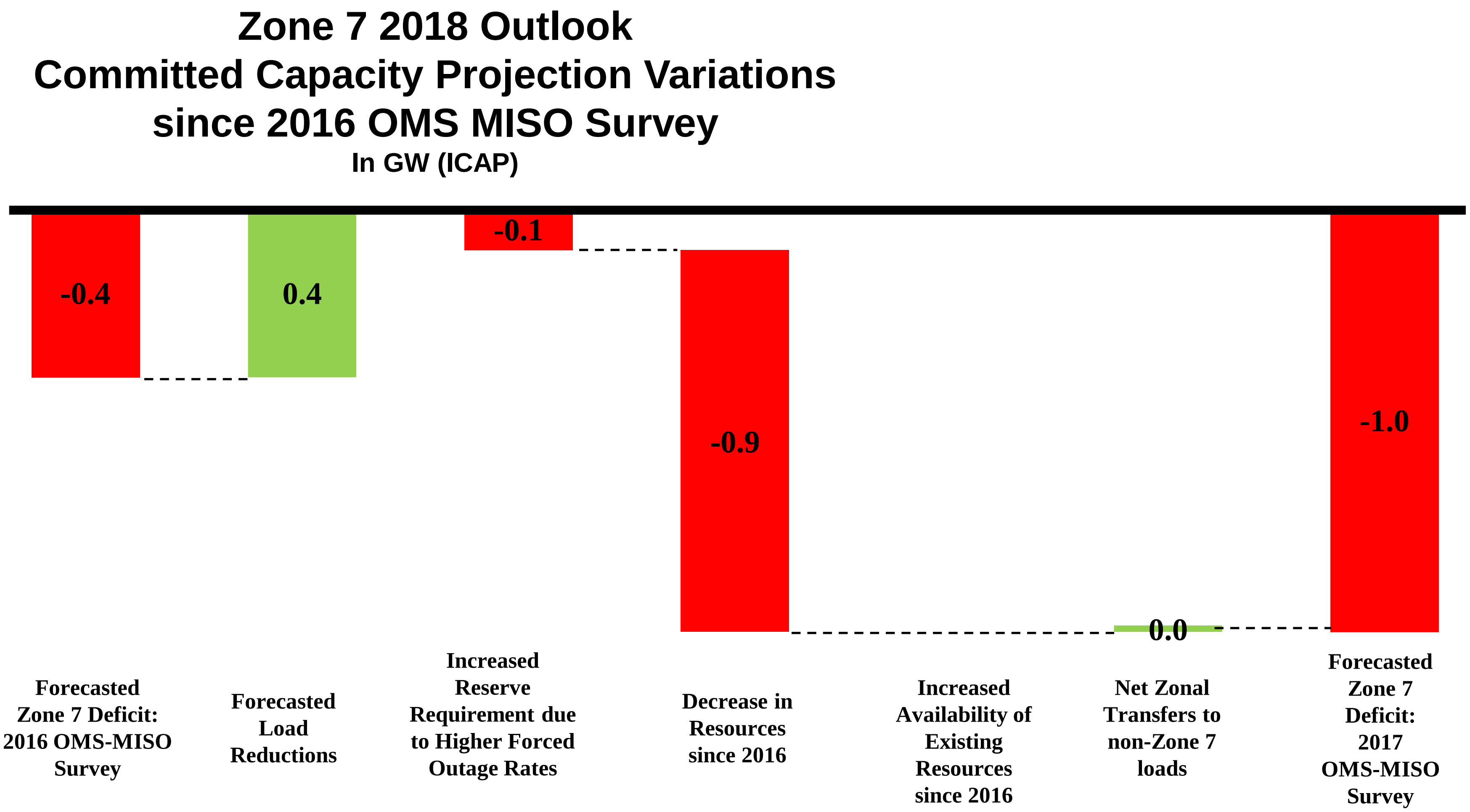
2019 - 2021 Resource Adequacy Forecast Zone 7 (GW)

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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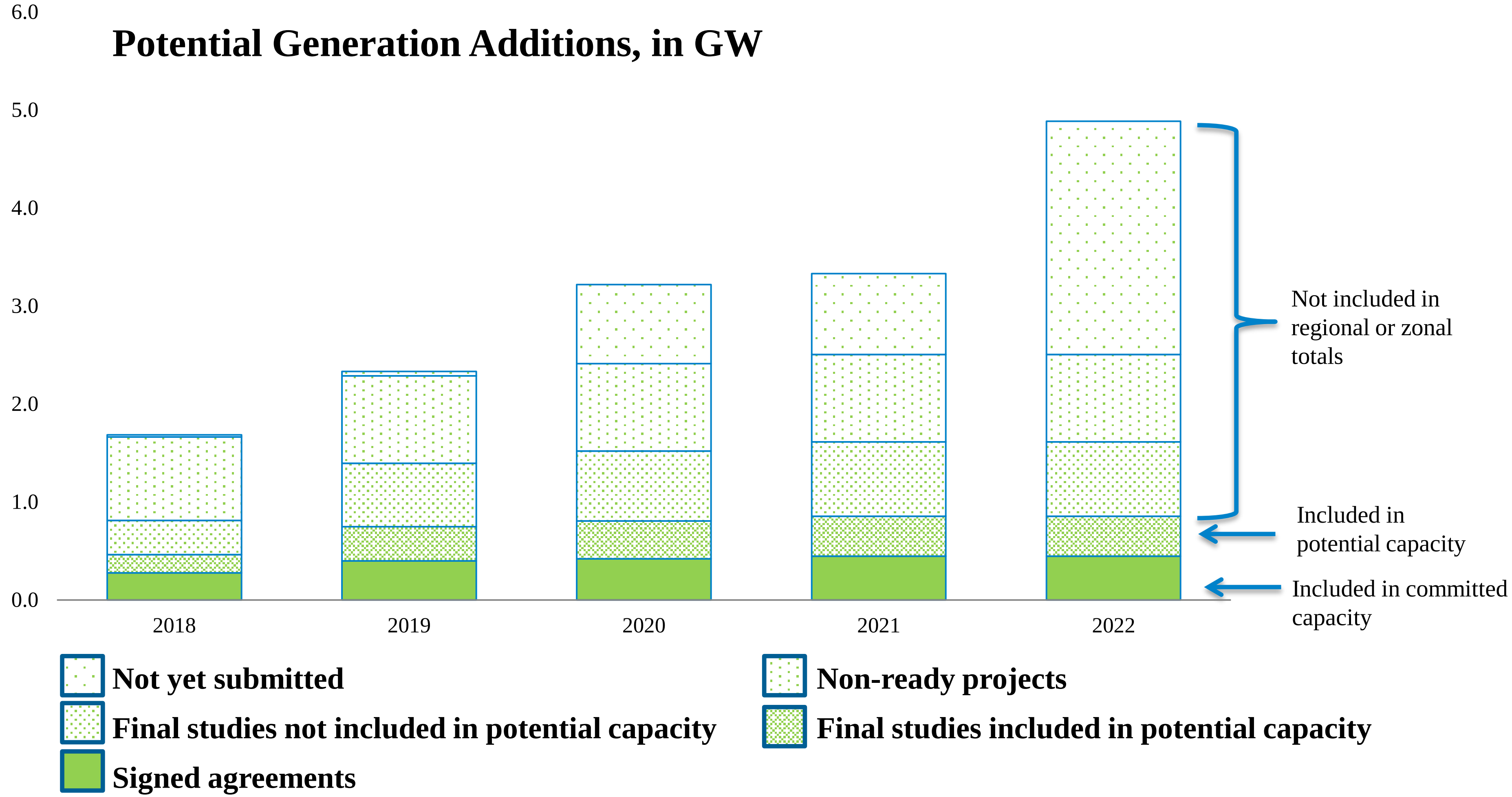
Zone 7 New Resource Additions by Queue Phase



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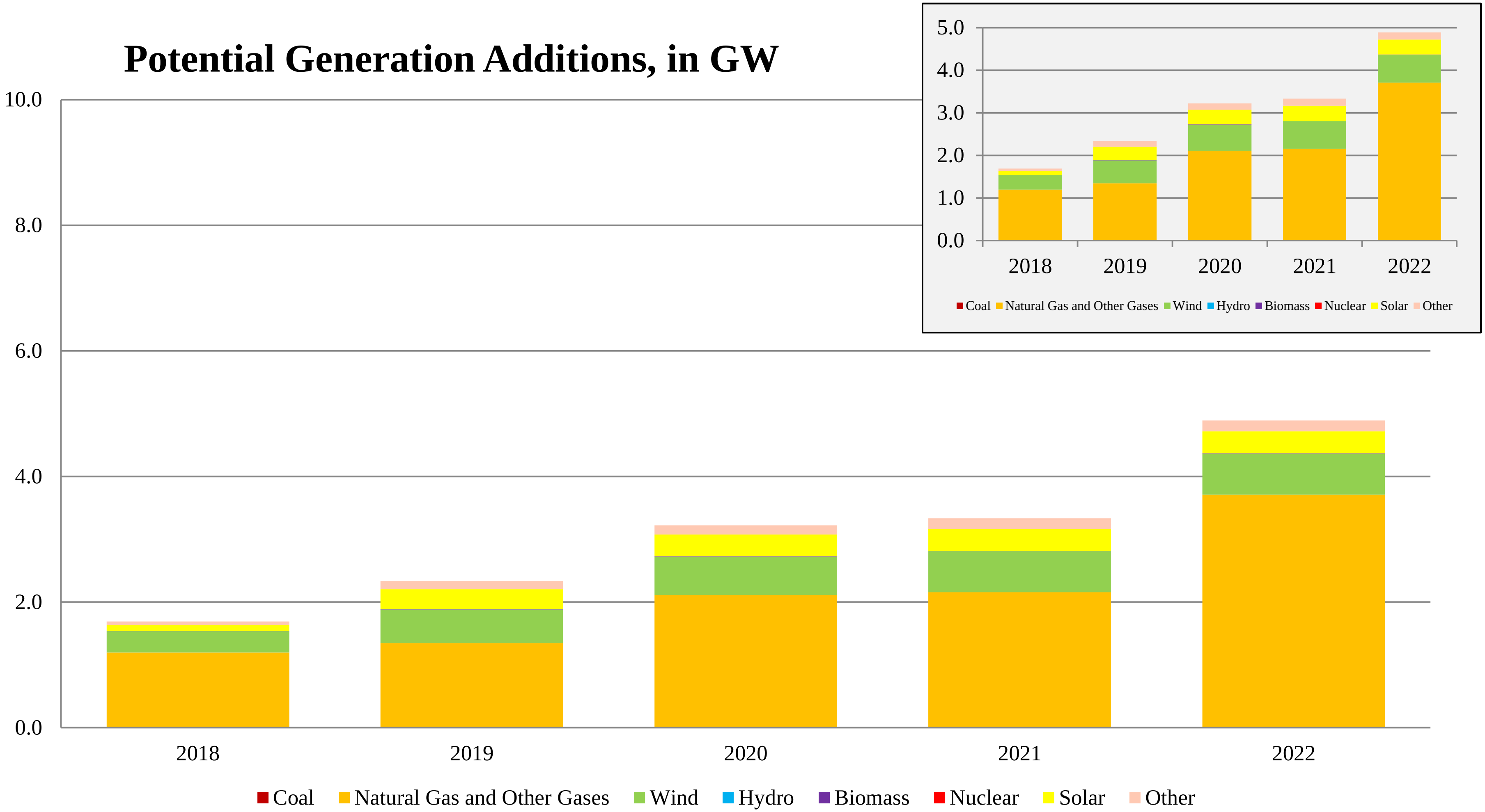
Zone 7 New Resources Additions by Fuel Type



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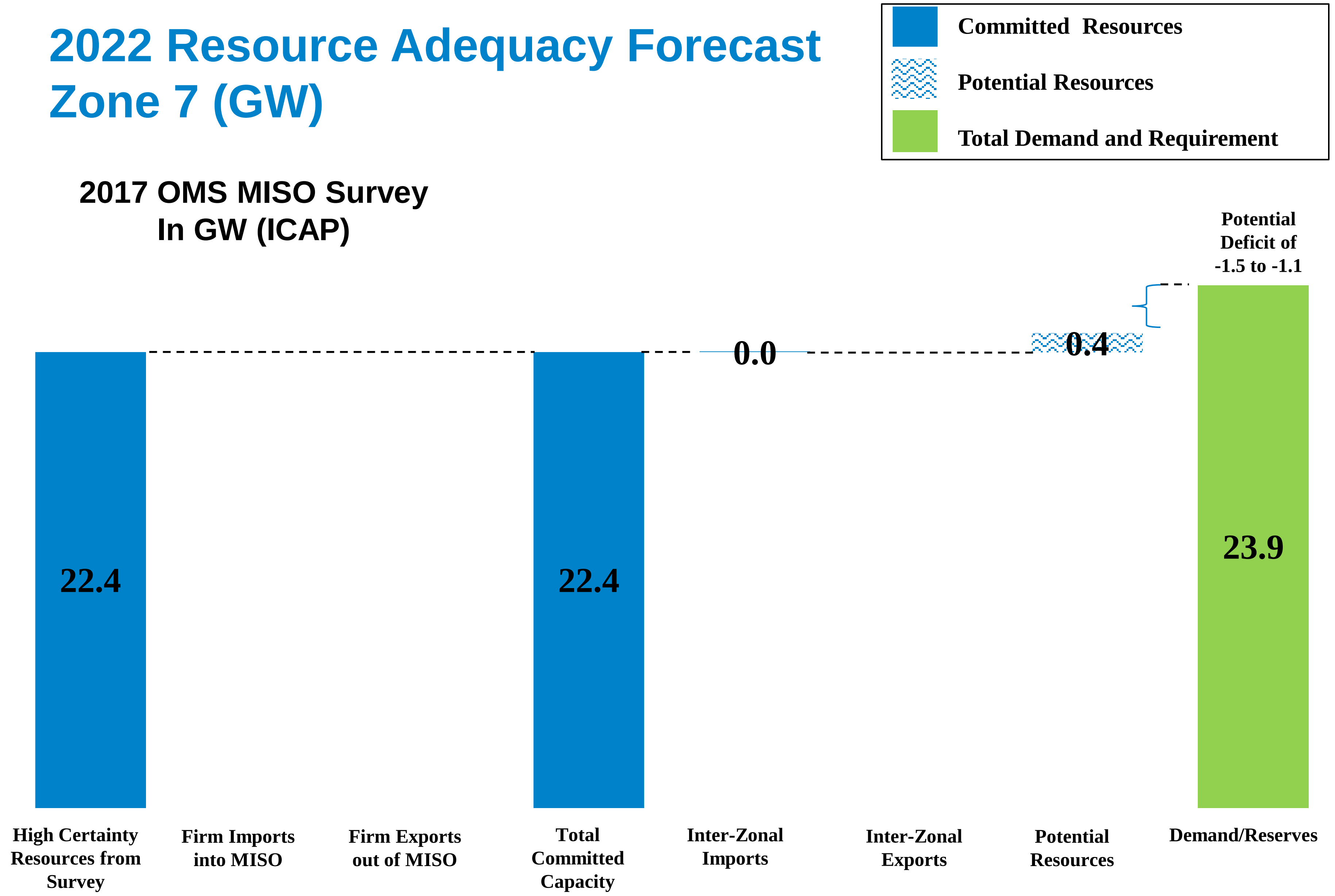
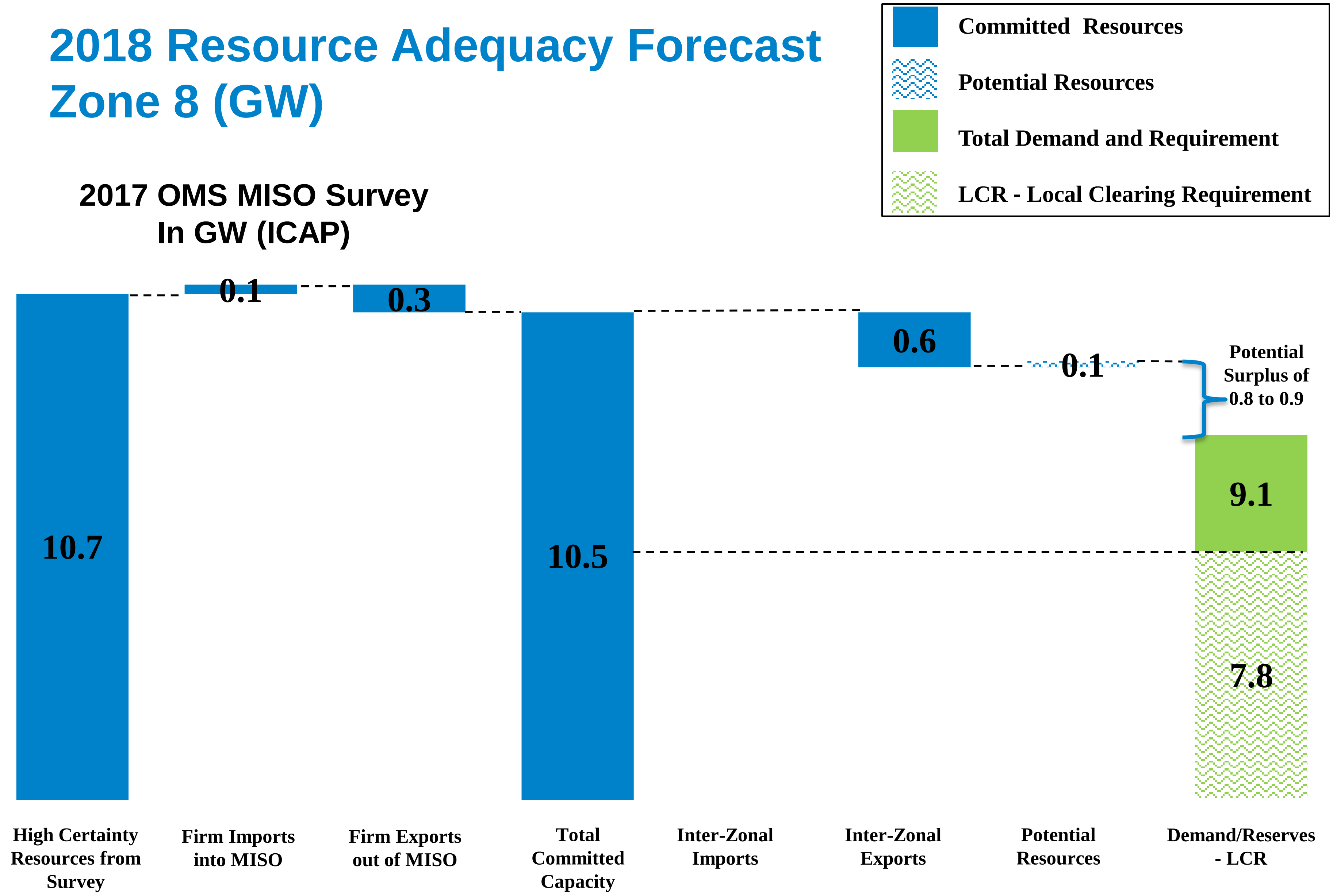
2022 Resource Adequacy Forecast Zone 7 (GW)



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

2018 Resource Adequacy Forecast Zone 8 (GW)



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

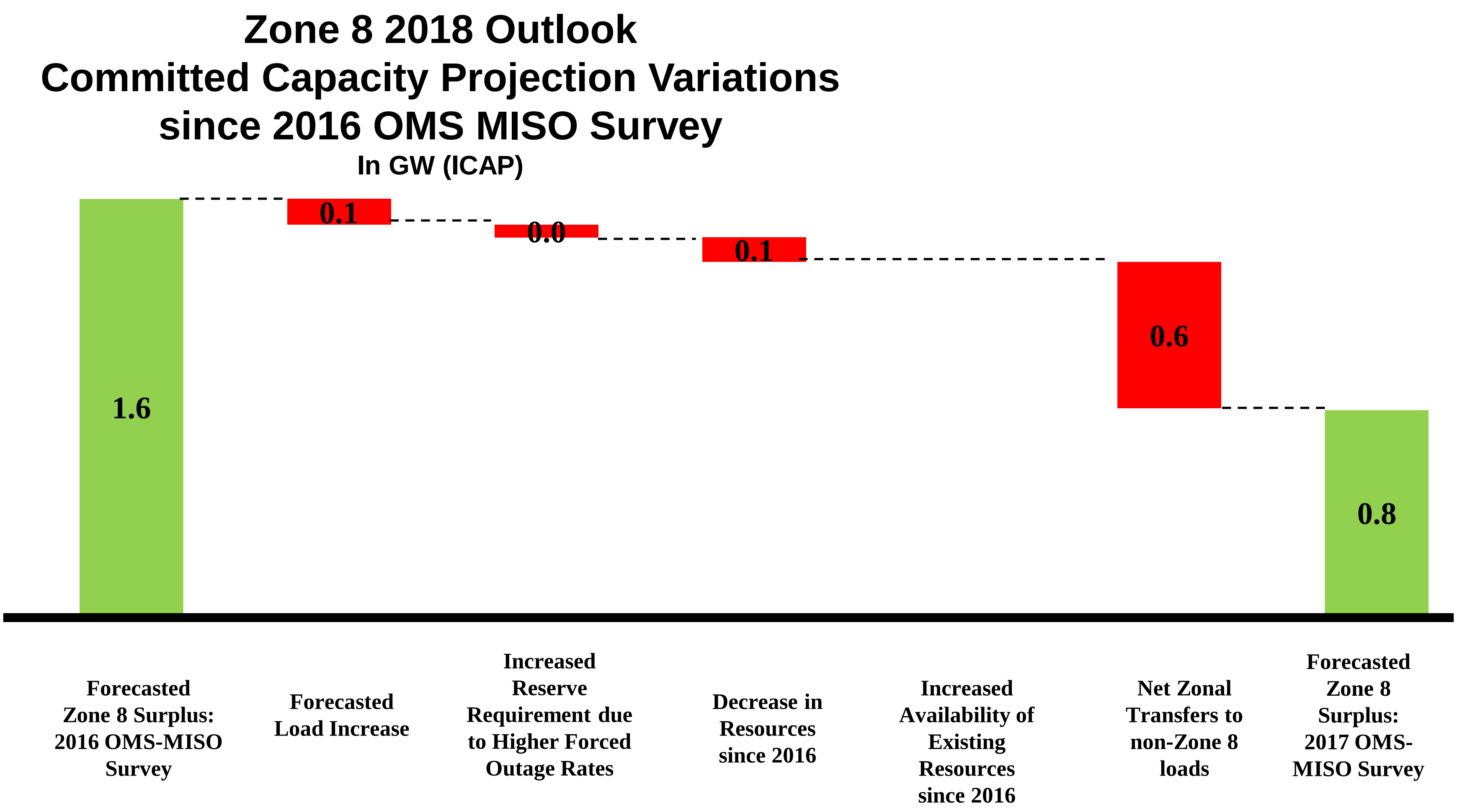
2019 - 2021 Resource Adequacy Forecast Zone 8 (GW)

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



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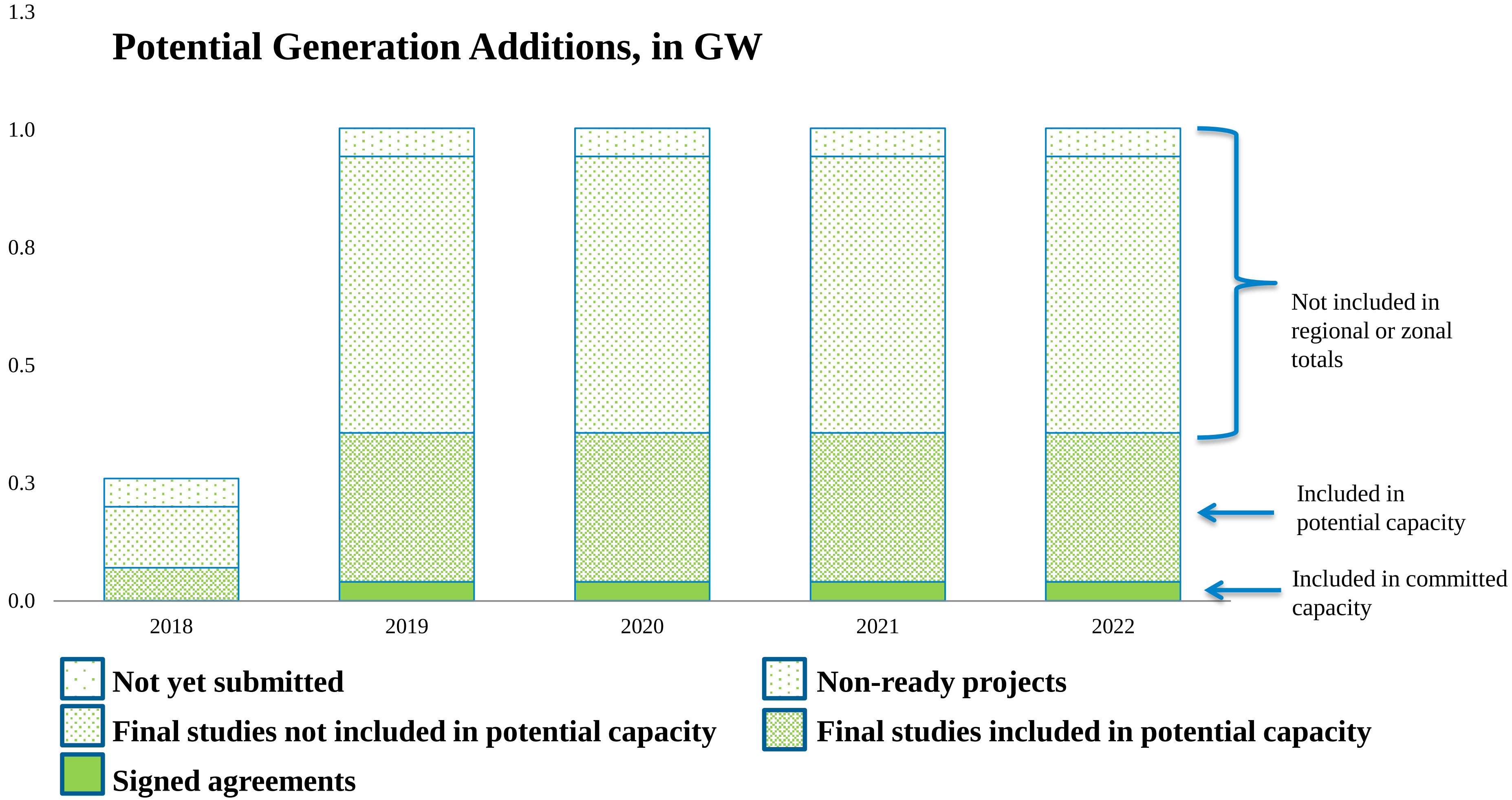
Zone 8 New Resource Additions by Queue Phase



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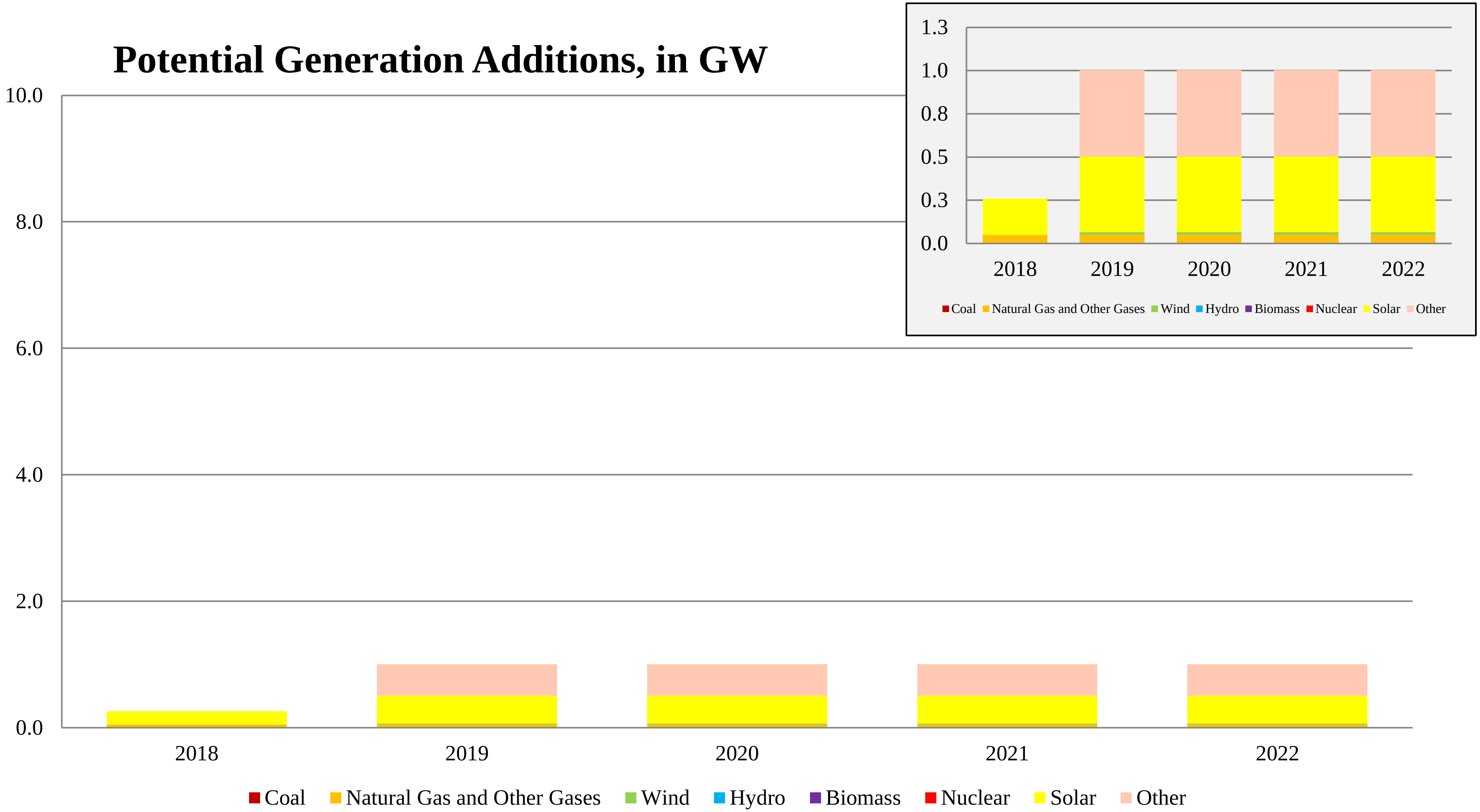
Zone 8 New Resources Additions by Fuel Type



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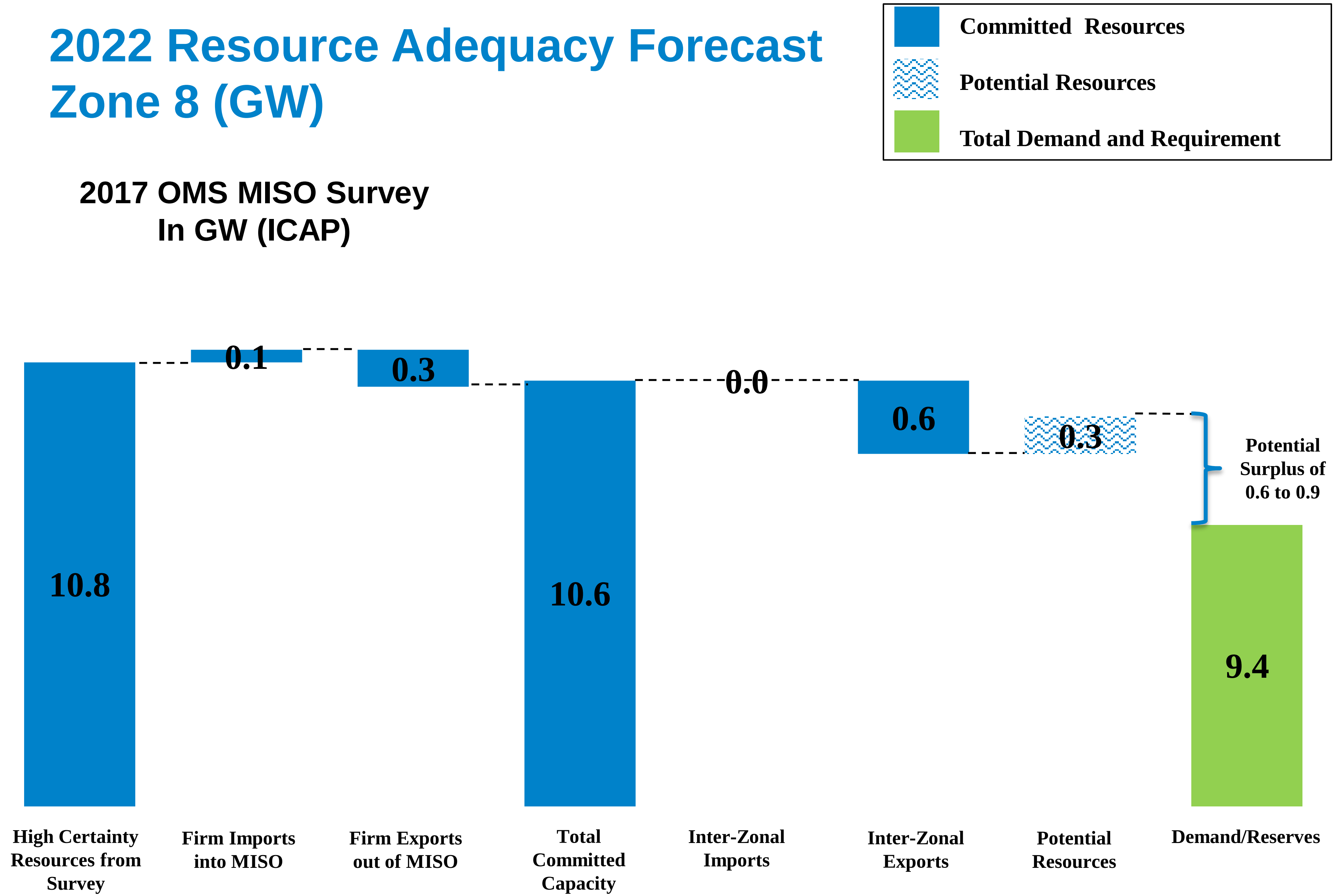
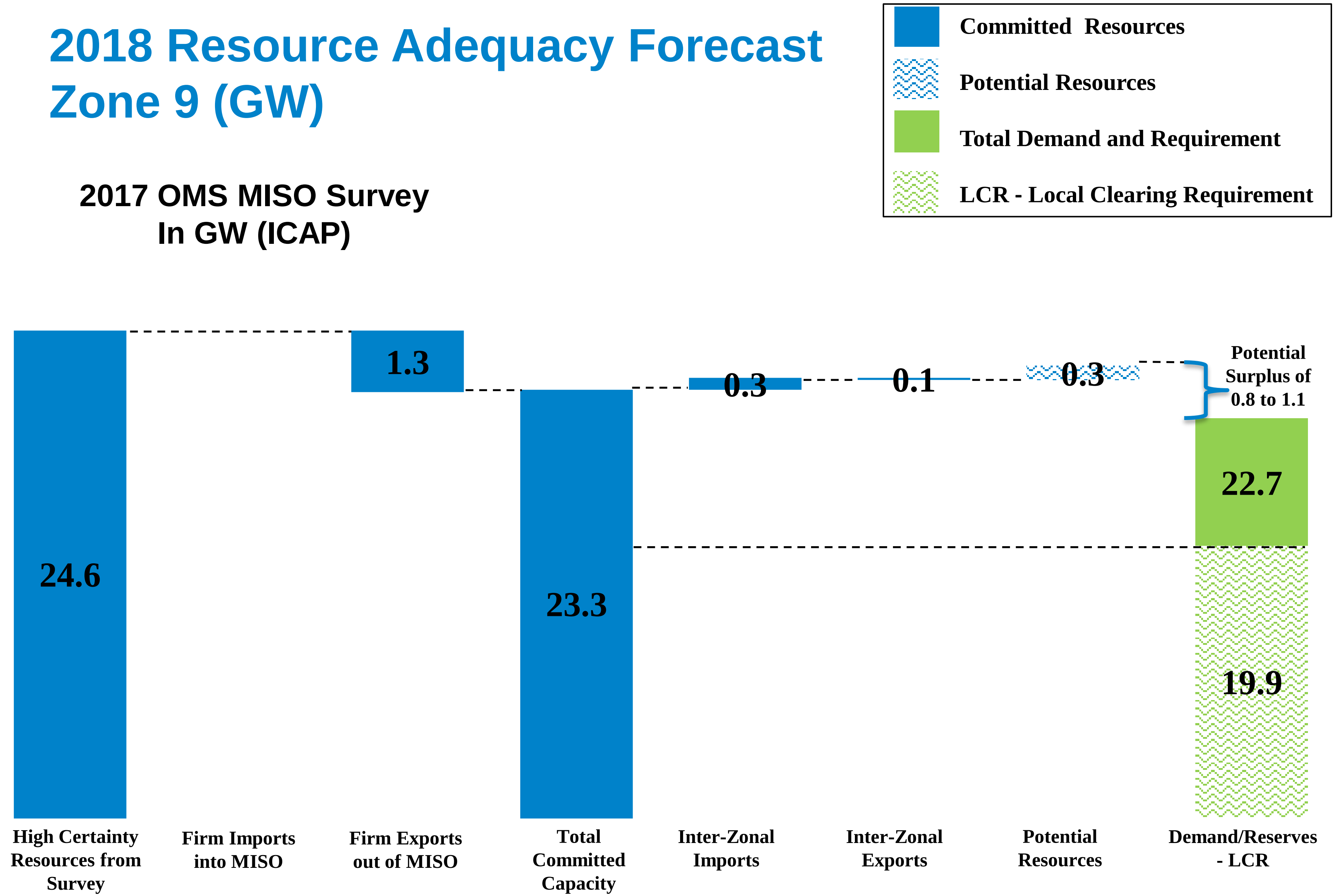
2022 Resource Adequacy Forecast Zone 8 (GW)



Potential Resources 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

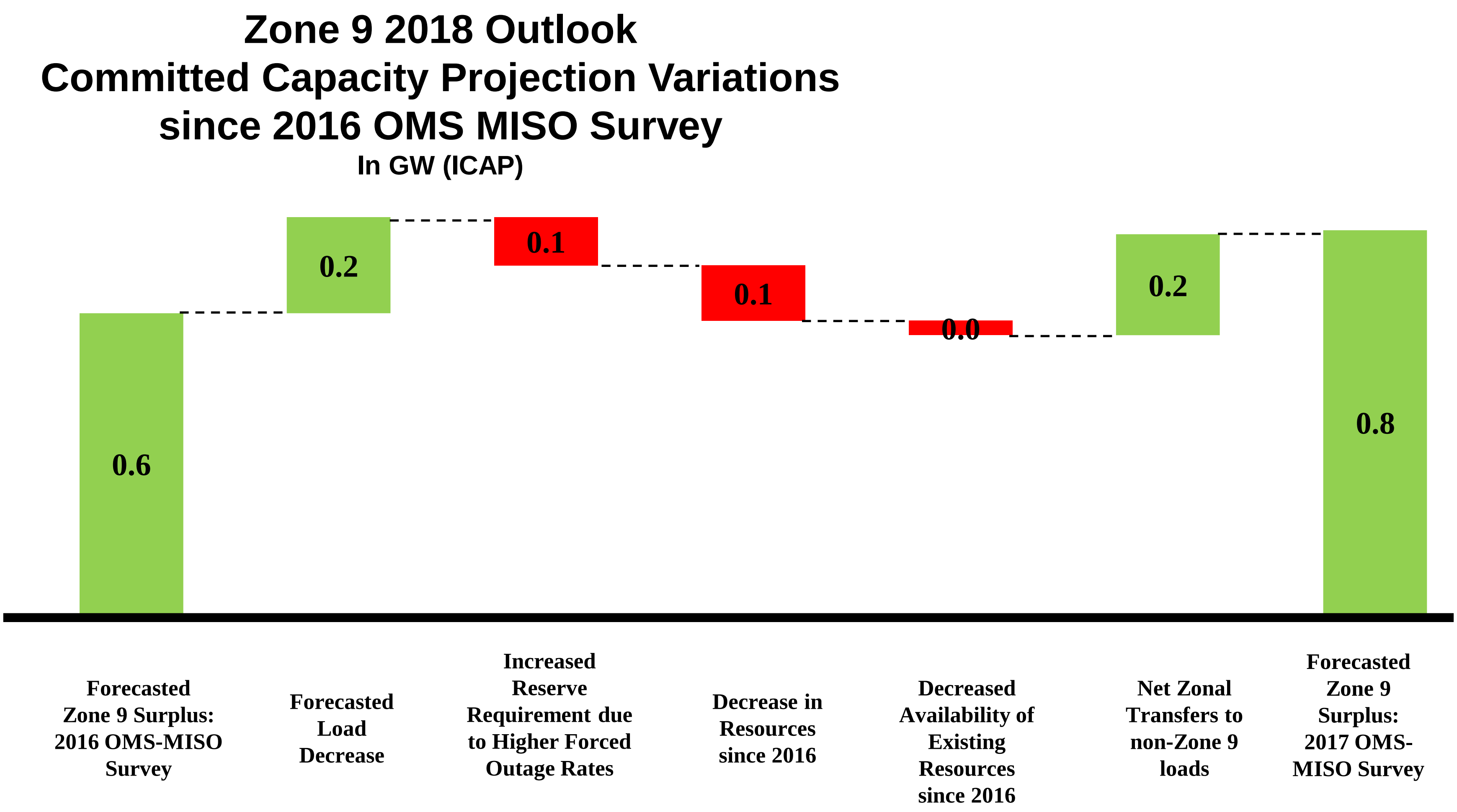
2019 - 2021 Resource Adequacy Forecast Zone 9 (GW)

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



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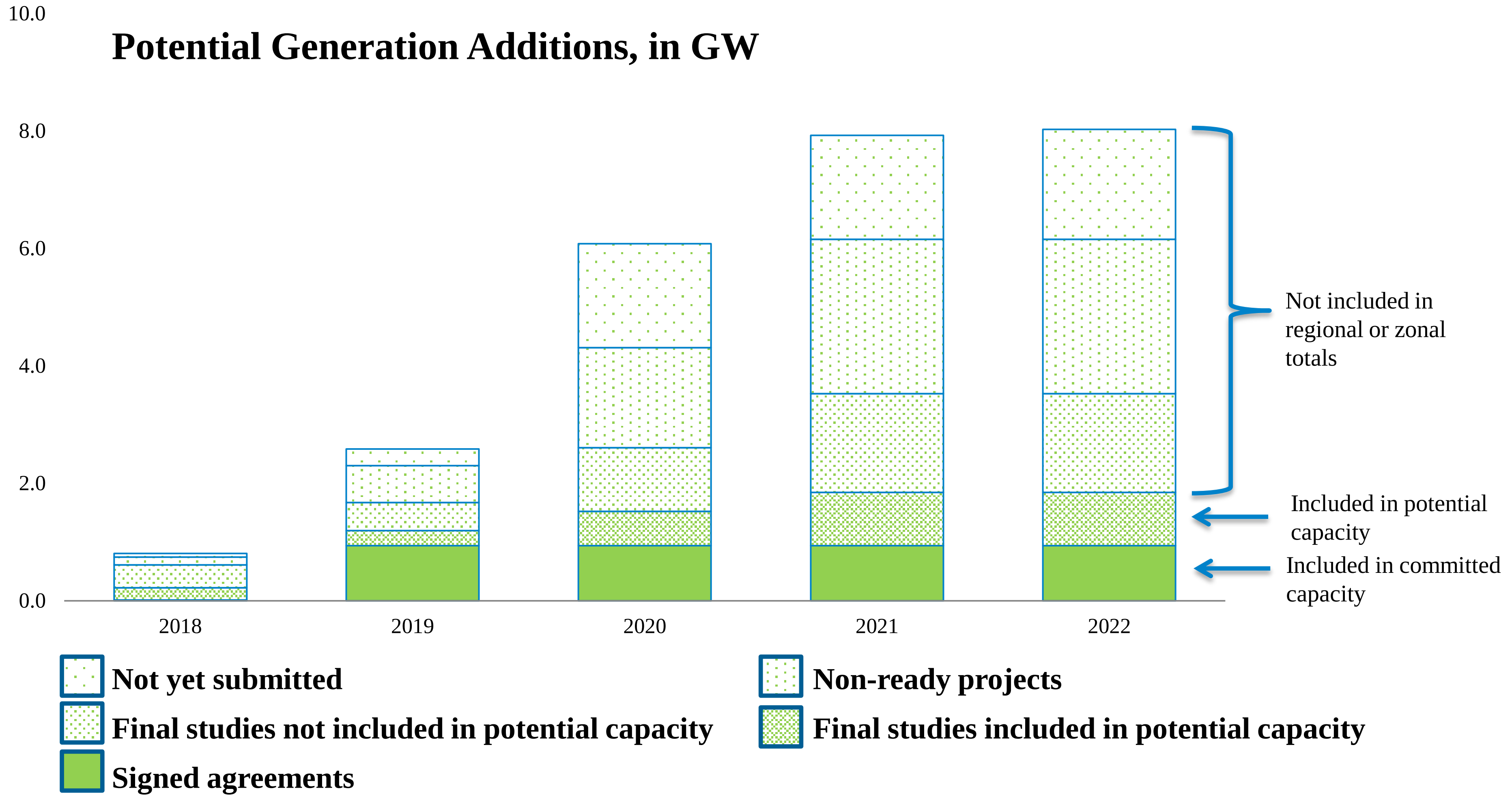
Positions include reported inter-zonal transfers, but do not reflect other possible transfers between zones

Zone 9 New Resource Additions by Queue Phase

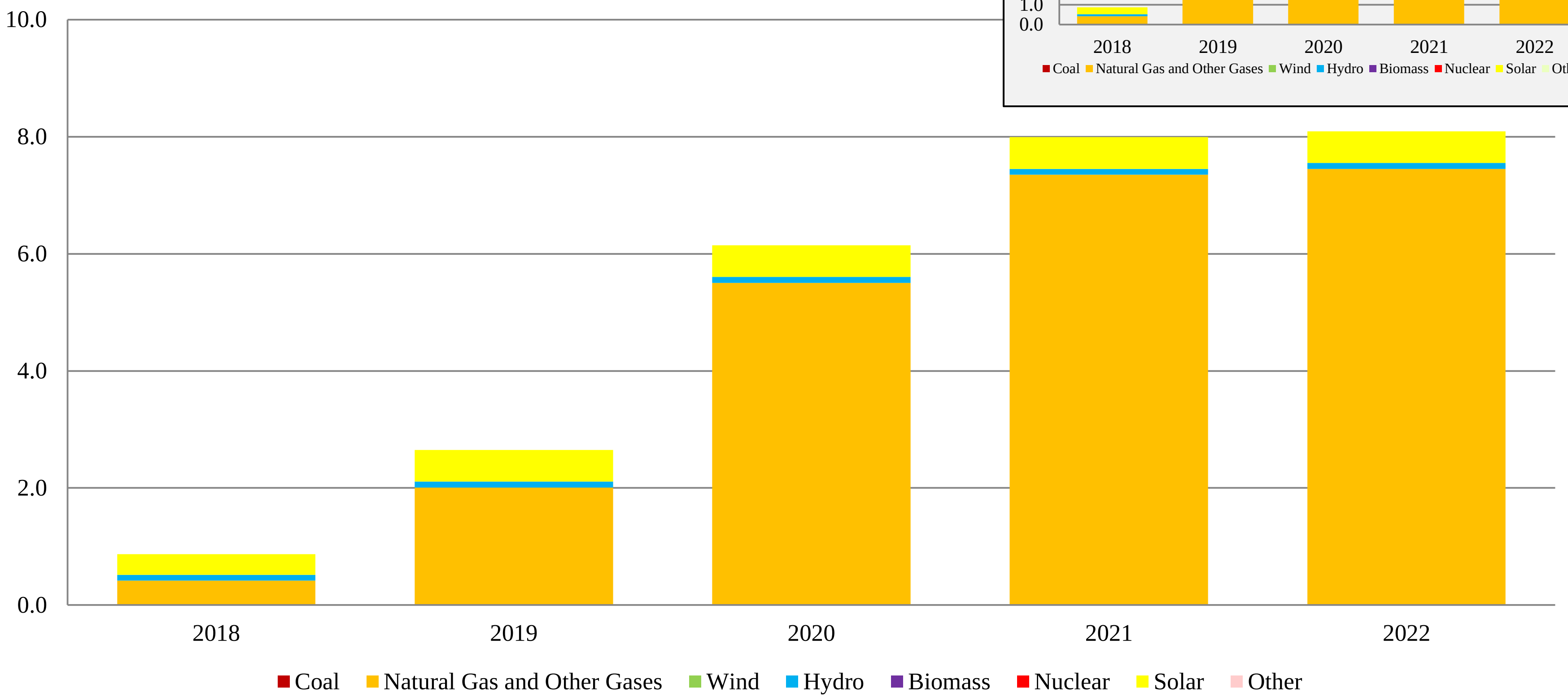


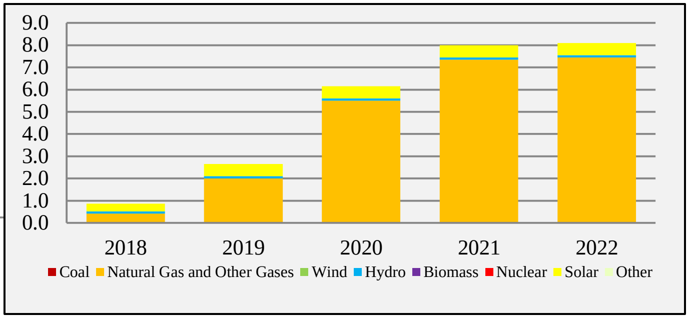
Wind and solar resources are represented at their expected capacity credit

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

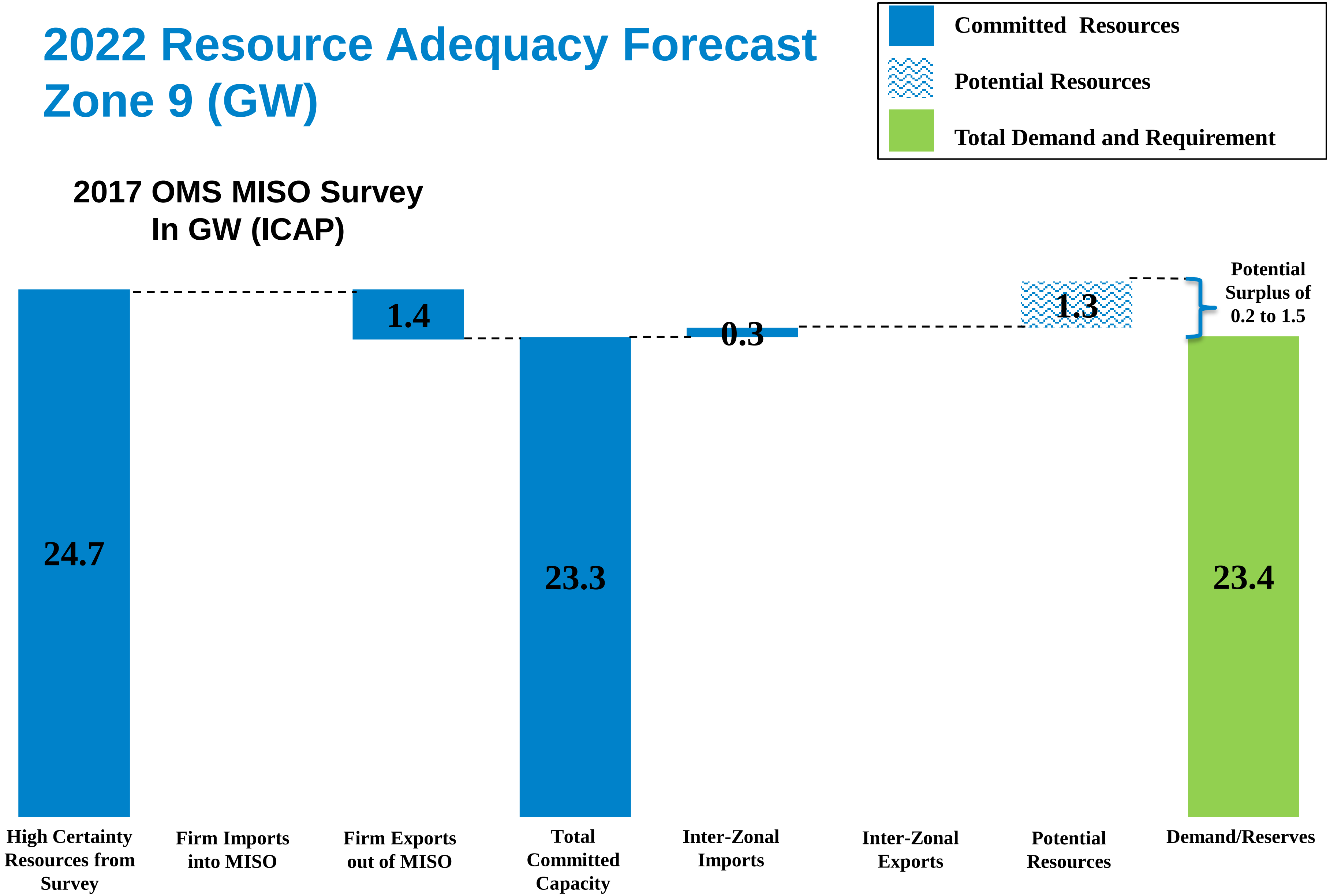
Potential Generation Additions, in GW





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

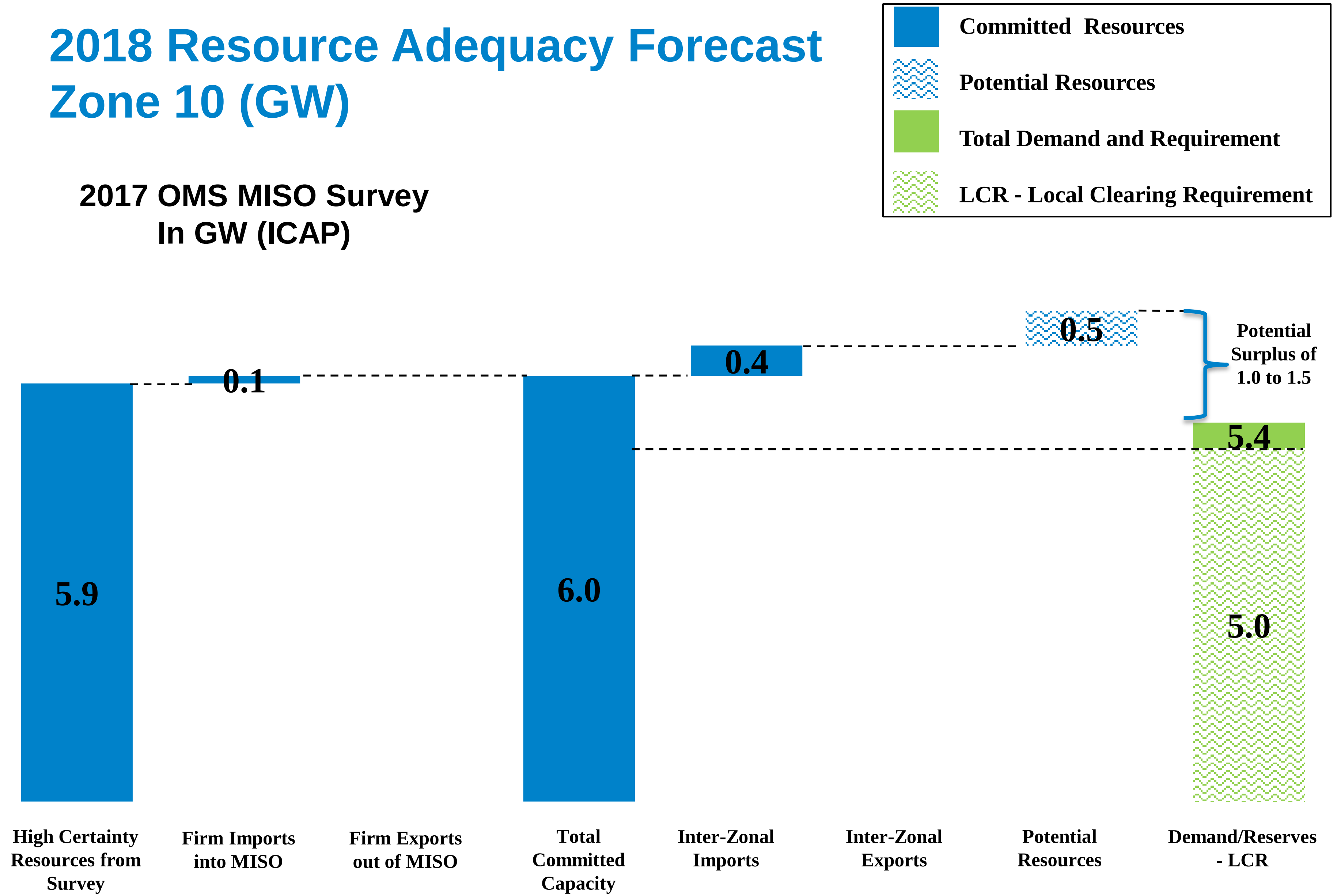
2022 Resource Adequacy Forecast Zone 9 (GW)



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

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

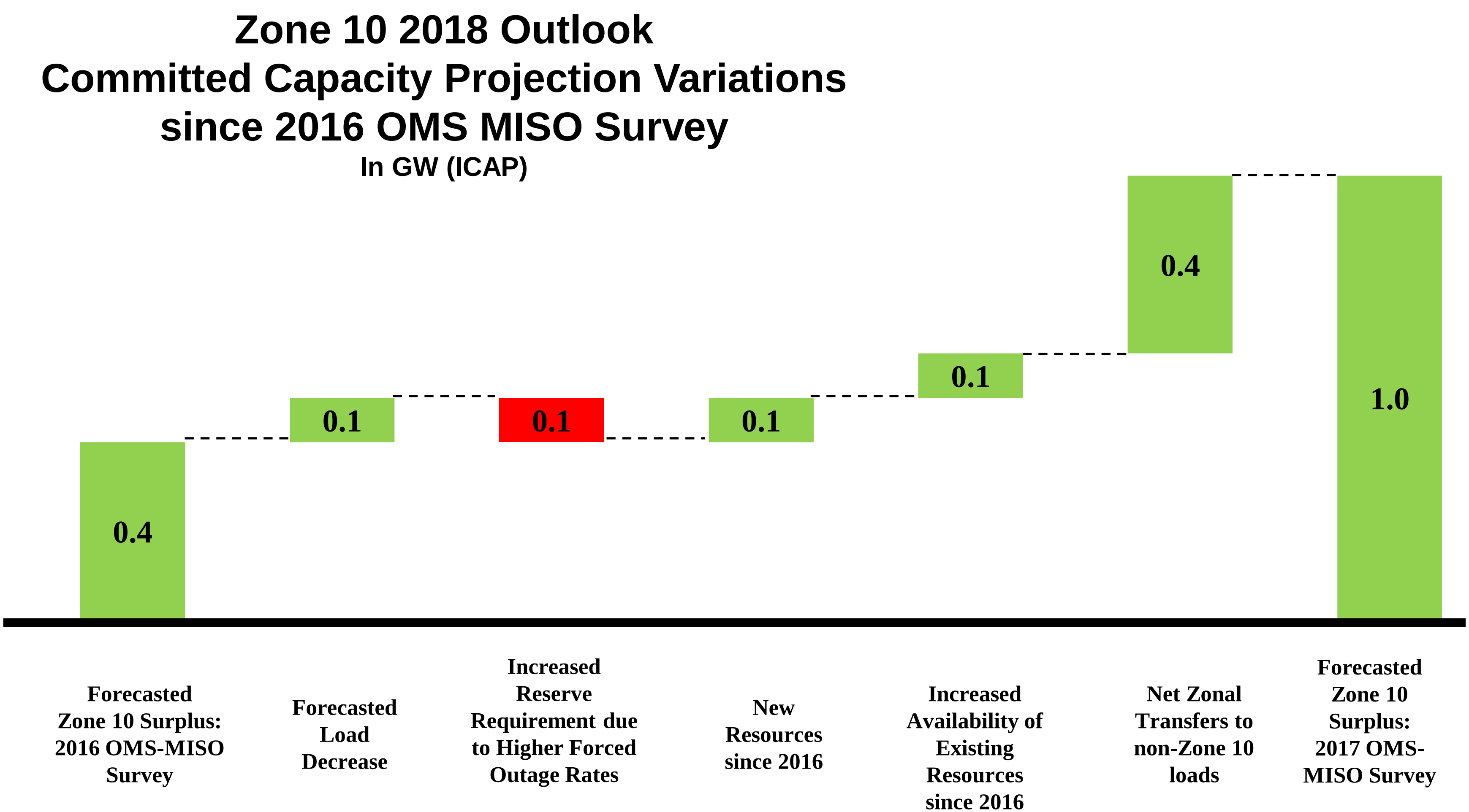
2019 - 2021 Resource Adequacy Forecast Zone 10 (GW)

2017 OMS MISO Survey

Values In GW (ICAP)

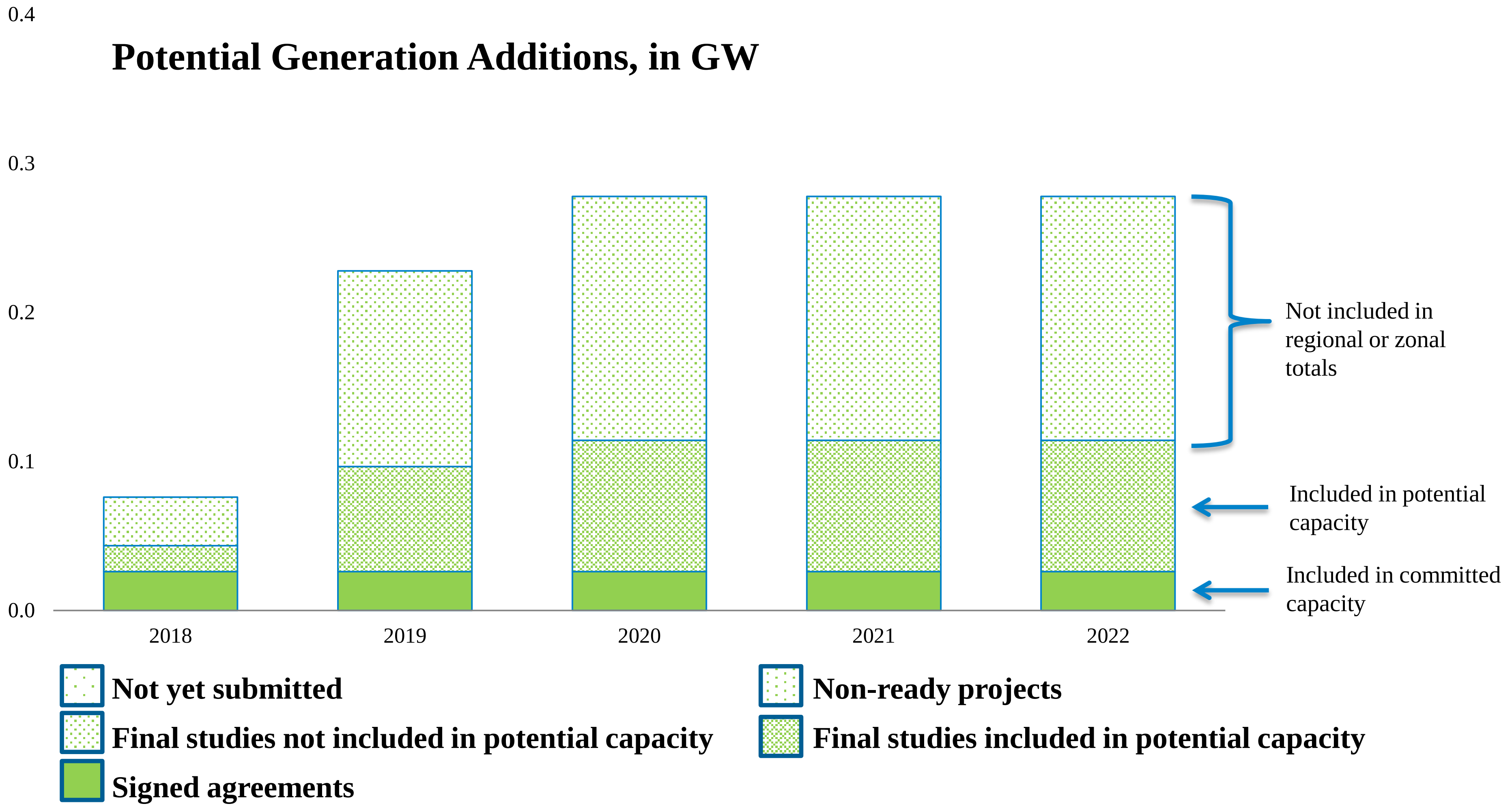
Zone 10	2019/20	2020/21	2021/22	Calculation
High Certainty Resources From Survey	5.7	5.7	5.7	A
Firm Imports into MISO	0.1	0.1	0.1	B
Firm Exports out of MISO	0.0	0.0	0.0	C
Total High Certainty Capacity	**5.8**	**5.8**	**5.8**	D = (A+B)-C
Inter-Zonal Imports	0.4	0.4	0.4	E
Inter-Zonal Exports	0.1	0.1	0.1	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

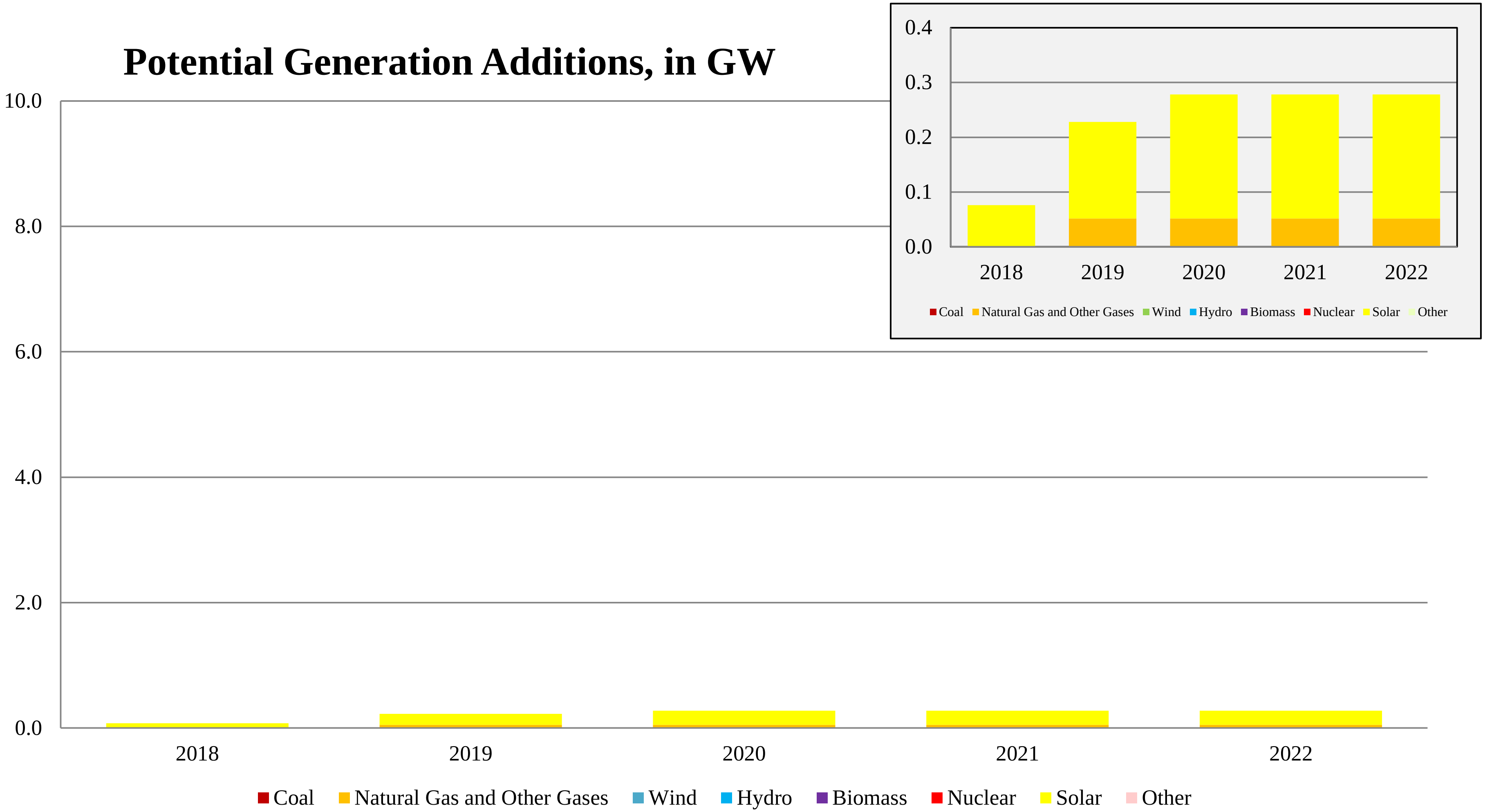
Zone 10 New Resource Additions by Queue Phase



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

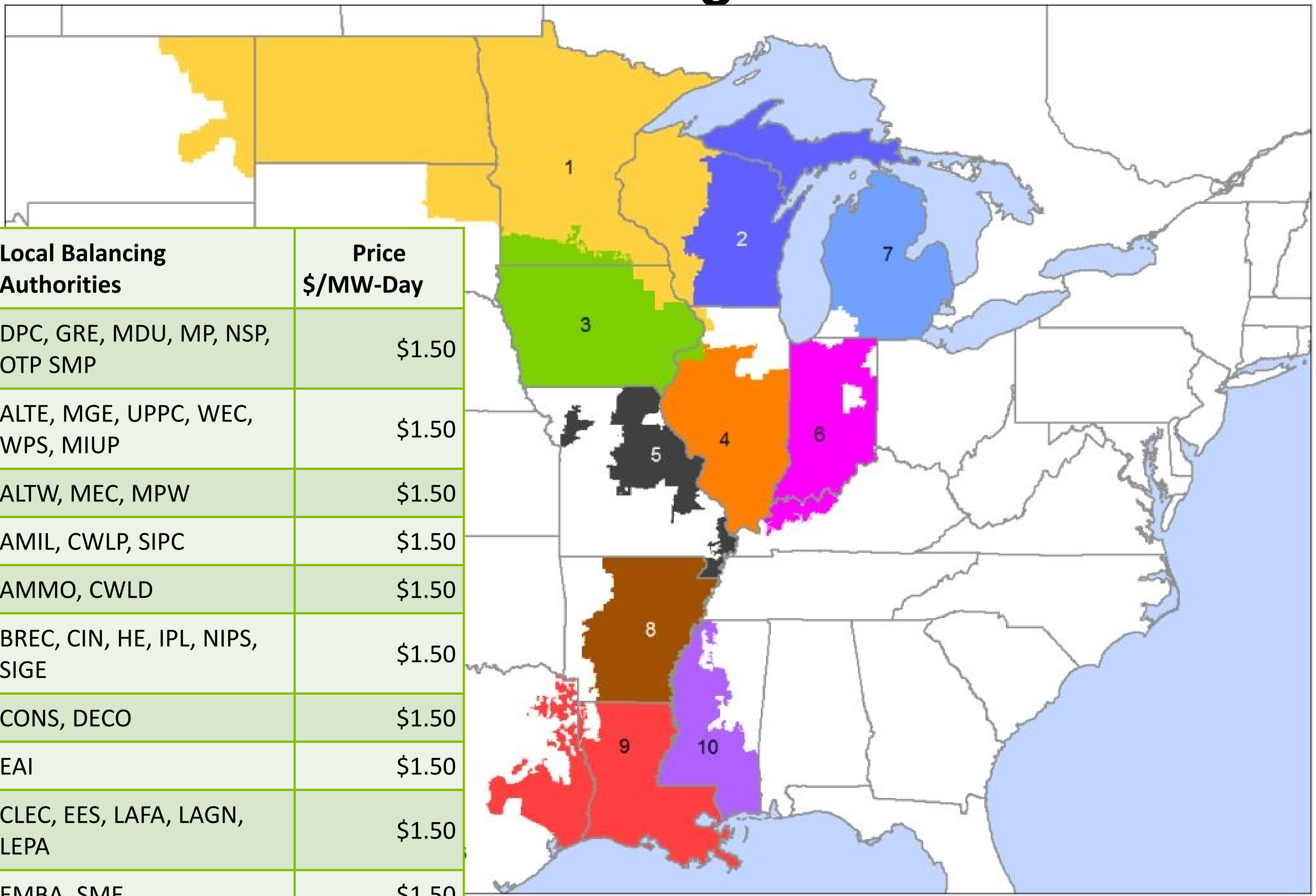
Resource Adequacy Subcommittee
May 10, 2017

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

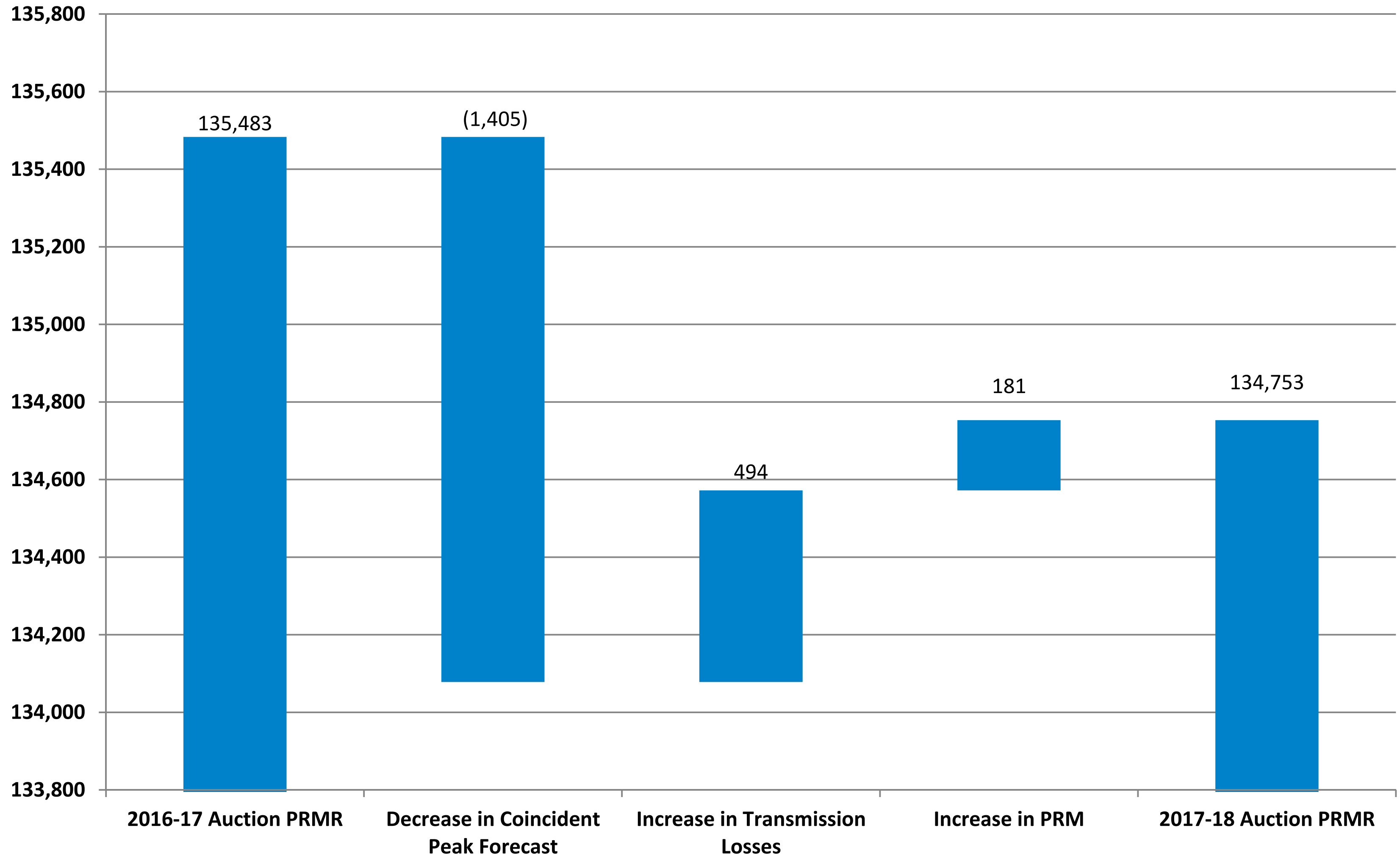
Planning Year	2016-17		2017-18		Change	
GADS Fuel Type	System (MW)	% Fuel	System (MW)	% Fuel	Delta (MW)	Delta (%)
Coal	53,332	39.36%	52,240	38.80%	(1,092)	-0.6%
Gas	48,784	36.01%	48,458	36.00%	(326)	0.0%
Nuclear	12,885	9.51%	12,563	9.30%	(322)	-0.2%
Load Modifier (DR/EE)	5,819	4.29%	6,112	4.50%	293	0.2%
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

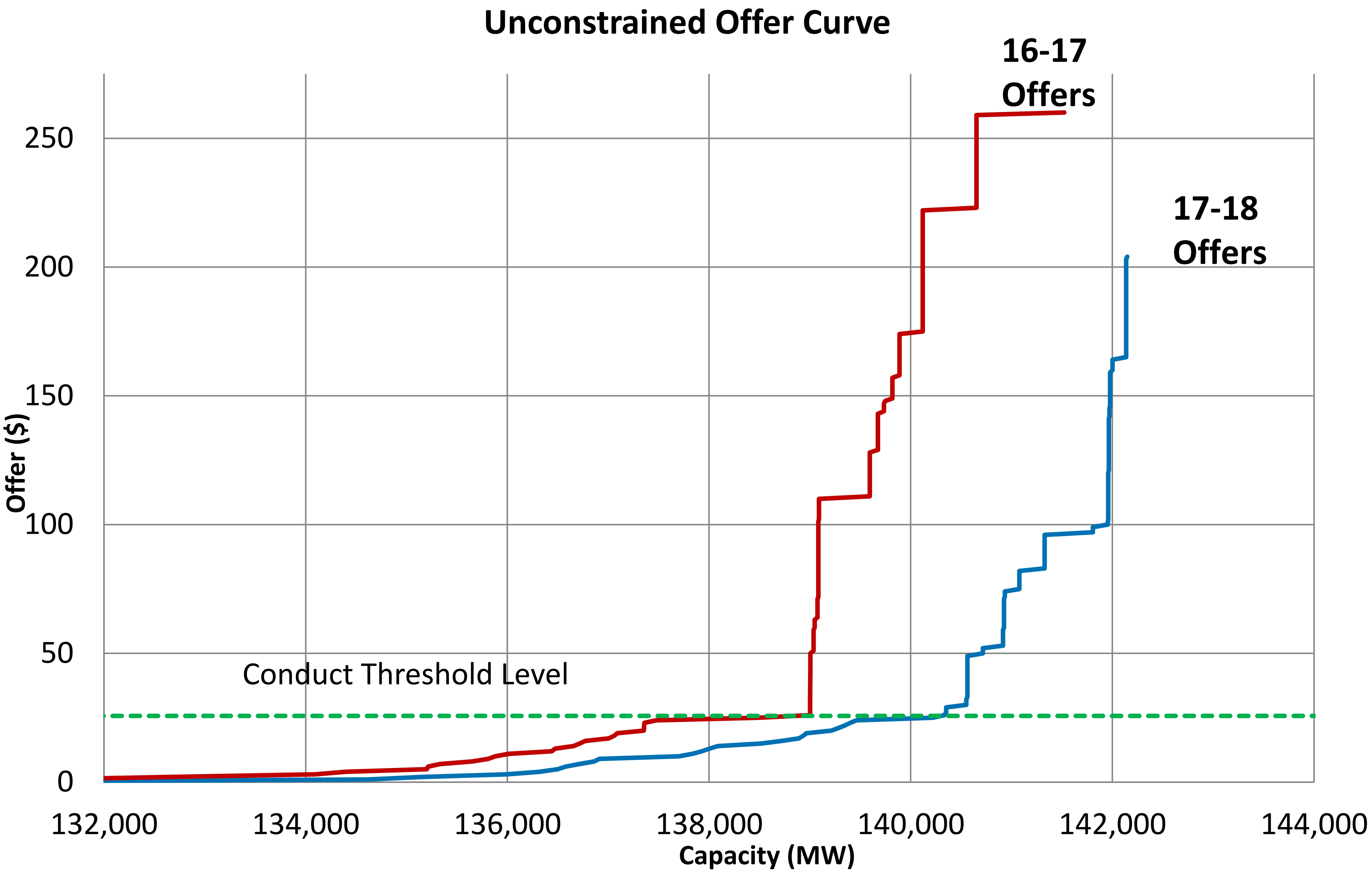
Planning Reserve Margin Requirement (PRMR)



All values in MW

MISO

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 1st
  - 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)

Appendix D1

South

2017

Entergy Arkansas Inc. (EAI)
Arkansas Electric Cooperative Corp. (AECC)
Entergy Gulf States Louisiana LLC (EGSL)
Entergy Louisiana LLC (ELL)
Entergy New Orleans Inc. (ENOI)
Cleco Power LLC (CLEC)
Lafayette Utilities System (LAFA)
Entergy Mississippi Inc. (EMI)
South Mississippi Electric Power Association (SMEPA)
Entergy Texas Inc. (ETI)
East Texas Electric Cooperative (ETEC)

Appendix D1: South Planning Region

Arkansas

Regional Information

MISO-Arkansas is a network of generation resources and major load centers interconnected through an array of 500-115 kV transmission networks. There is also a significant 69 kV network interspersed across the footprint.

MISO-Arkansas consists of a diverse generation profile, including nuclear, gas, coal and hydro units that fuel major load centers such as the Little Rock, Jonesboro, and Pine Bluff regions. Together, these load centers constitute approximately 40 percent of the total power consumption in this region. The remaining load is distributed across the footprint, and is served through several electric cooperatives.

Figure AR-1 illustrates the major generation sources and load centers in MISO-Arkansas.

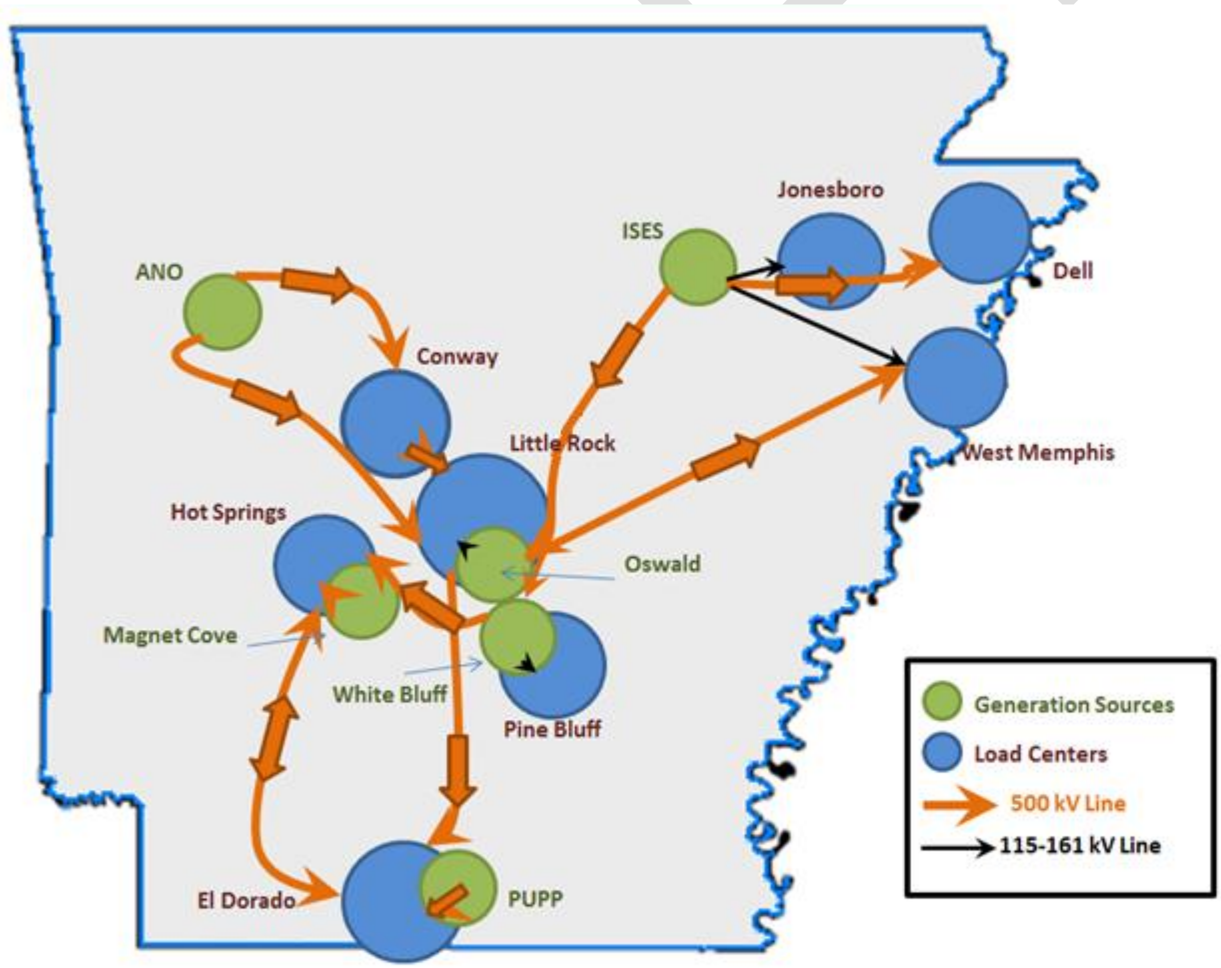


Figure AR-1: MISO-Arkansas – Major Generation Sources, Load Centers and Major Gen-Load Transmission

The projects proposed in the current MTEP17 cycle are part of a continuing effort to strengthen the existing transmission network. For instance, several projects were proposed to reconfigure substations to avoid breaker or bus events occurring on the 115 or 161 kV system that had the potential to cause load loss. Several projects were also proposed to facilitate new load additions, by either proposing new points of delivery or upgrading existing ones.

Transmission Profile

The transmission network within the footprint of MISO-Arkansas covers approximately 5,000 miles of the 115 kV to 500 kV bulk electric system (BES) network. An additional 1,000 miles is dedicated as the 69 kV network.

Major transmission hubs such as El Dorado, McNeil, Arklahoma, Hot Springs, Woodward, West Memphis, Arkansas Nuclear, Independence, Little Rock, and Dell are interconnected via a network of 500 kV circuits and form the backbone of the MISO-Arkansas transmission network.

Load Profile

According to the 2019 Summer Peak model estimates, the total load within the MISO-Arkansas footprint is approximately 8.6 GW. Around 40 percent of the total load is centered on several major load centers within this footprint. The largest of these load centers are City of Little Rock, Dell, Jonesboro, Pine Bluff, Conway, El Dorado, Hot Springs and West Memphis. The remainder of the load is spread across the footprint.

Generation Profile

The generation portfolio of MISO- Arkansas is composed of nuclear, hydro, coal, Combined Cycle Gas Turbines (CCGT), and legacy gas units. According to the 2019 Summer Peak model estimates, the system has about 12.4 GW of generation capacity. The major sources constituting this profile are ANO, Oswald, Magnet Cove, ISES, White Bluff and the PUPP generation units. Combined, as estimated in the 2019 Summer Peak model, these sources have a combined generation capacity of 72 percent of the MISO Arkansas' total generation portfolio.

Overview of Projects

For the current MTEP17 cycle, 16 projects were targeted for Appendix A with an estimated combined cost of $245.1 million. Of these 16 projects, 9 projects have an estimated cost greater than $5 million; 4 projects have an estimated cost between $1 million and $5 million; and 3 projects have an estimated cost lower than $1 million. Six of these 16 projects are labeled as baseline reliability projects, and the remaining 10 projects are designated as other projects. The Hickman Central project was presented at the Planning Advisory Committee meeting in December, 2016, as an expedited project request. Figure AR-2 shows the approximate geographic locations of the projects submitted as Target Appendix A in the current MTEP cycle. Figures AR-3 and AR-4 show the baseline reliability and other projects by their estimated costs and their expected in-service dates. Project details, such as estimated cost and in-service dates, may change between the creation of Appendix D1 and the board approval date. Refer to Appendix A of this report for final approval information.

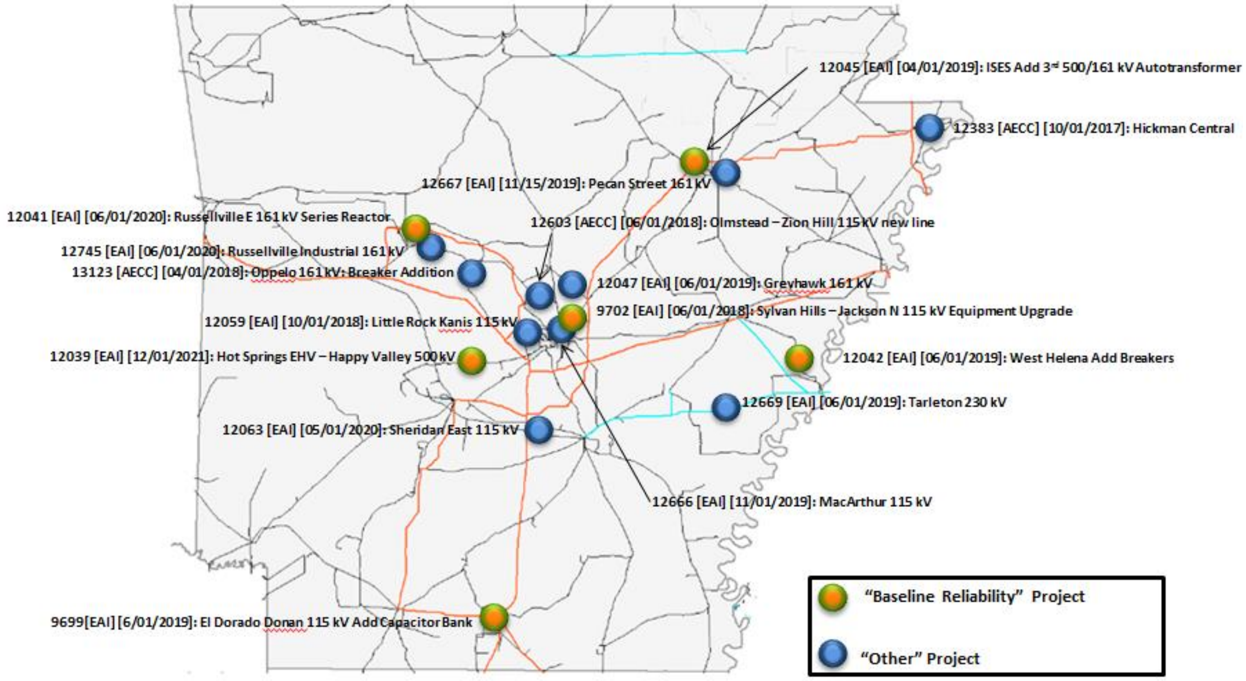


Figure AR-2: Geographical transmission map of MISO-Arkansas with project locations

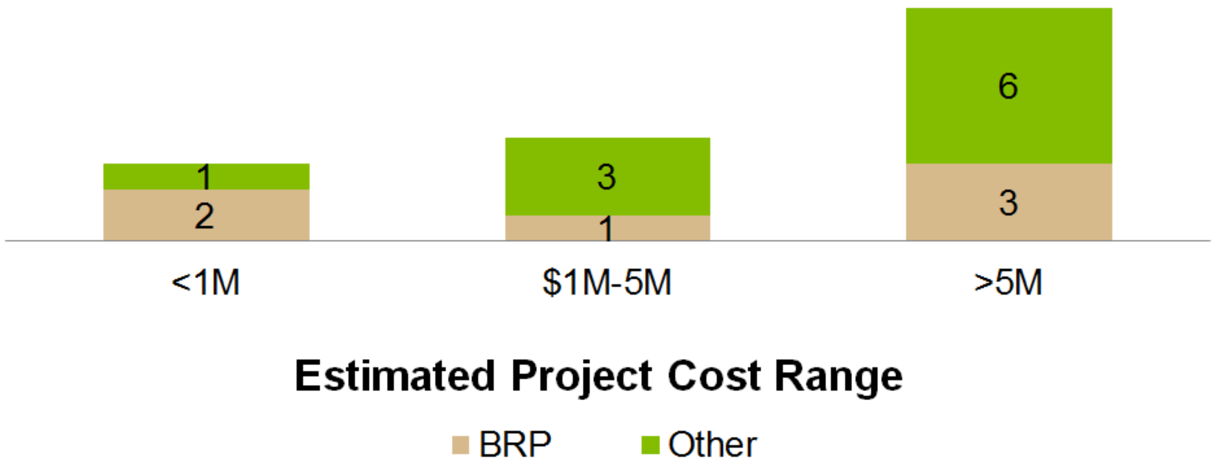


Figure AR-3: Graph of cost range by project type

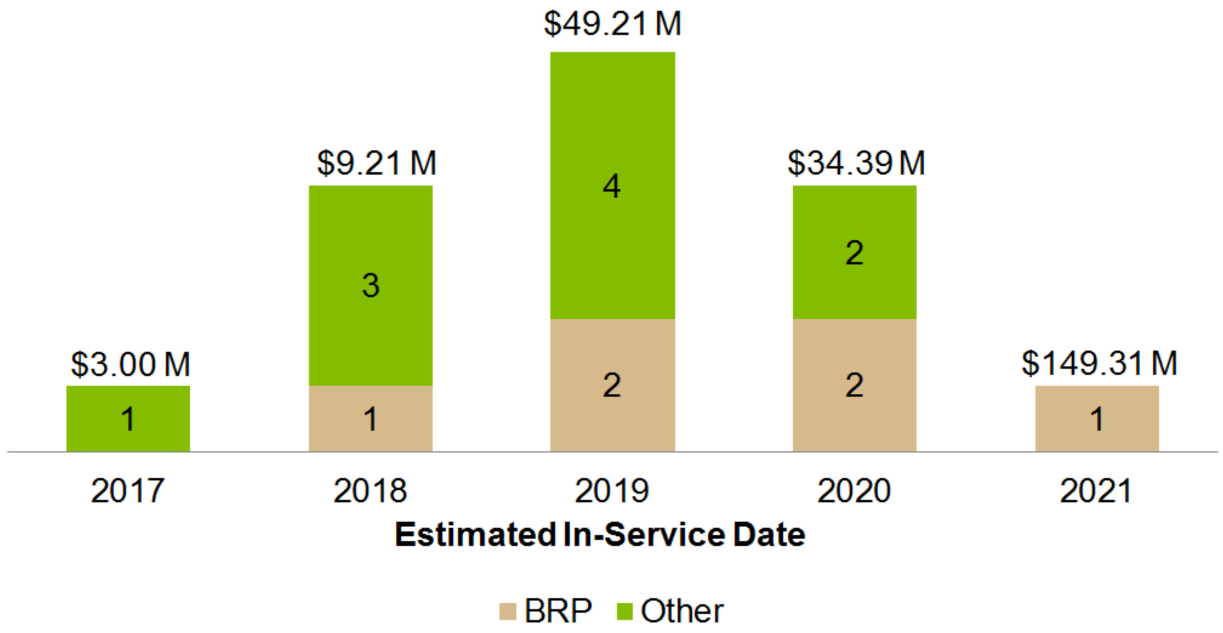


Figure AR-4: Graph of estimated in-service date

Entergy Arkansas Inc. (EAI)

This section contains a summary of each project submitted by Entergy Arkansas in the current MTEP17 cycle. Thirteen projects were submitted as Target Appendix A. Of these projects, 6 were submitted as Baseline Reliability projects. The remaining 7 projects are designated as Other projects which involve new delivery points. The total estimated cost for these projects is $236.8 million. The estimated in-service dates for these projects are between 2018 and 2021.

Project 9699: El Dorado Donan 115 kV add 30 MVAR Capacitor

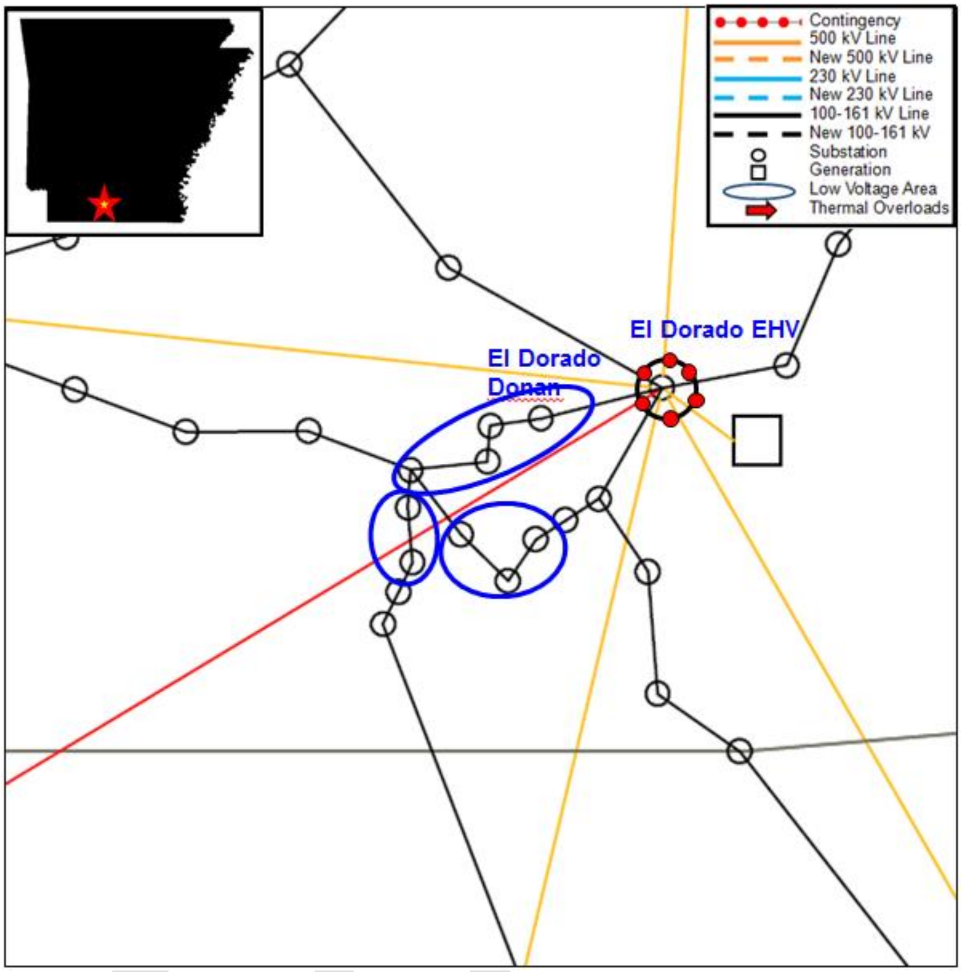
Transmission Owner: Entergy Arkansas Inc. (EAI)

Project Description

This project involves adding a 30 MVAR capacitor bank at the El Dorado Donan 115 kV substation. The expected in-service date for this project is June 1, 2018, and it has an estimated cost of $870 thousand. Figure P9699 shows the contingencies and violations that drive this project.

Project Need

A breaker failure or bus fault at El Dorado EHV substation results in low voltages in the range of 0.90 and 0.91 p.u. at 10 substations between the El Dorado Donan and Newell 115 kV substations. These violations were observed in the 2022 and 2027 Summer Peak models. The addition of a 30 MVAR capacitor bank at El Dorado Donan 115 kV substation boosts the voltages in this area and mitigates these issues.



MISO, using Ventyx Velocity Suite © 2014

Figure P9699: Breaker Failure or Bus Fault at El Dorado EHV causes low voltages in the area.

Alternatives Considered

One alternative that was considered for this project involved reconfiguring the El Dorado EHV substation by adding breakers. This alternative was not selected because it would be significantly more expensive because of the breaker additions.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 9702: Sylvan Hills – Jacksonville North 115 kV Equipment Upgrade

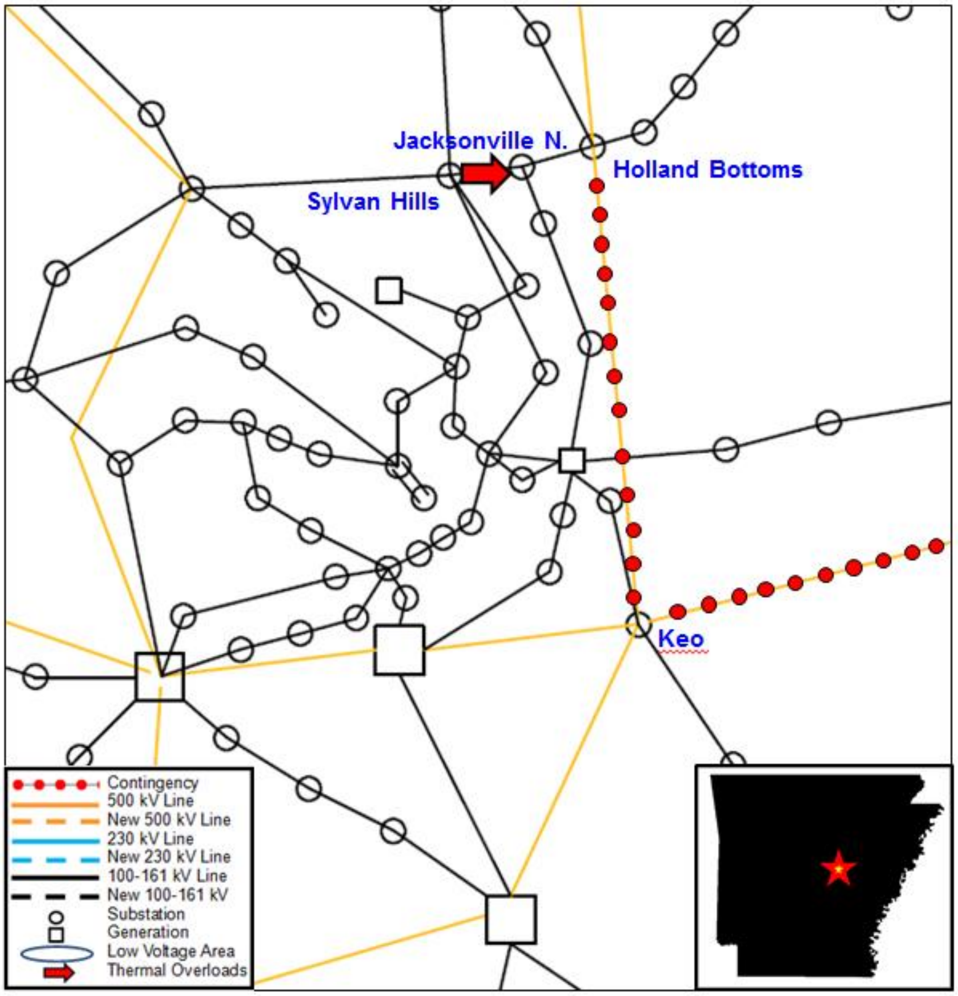
Transmission Owner: Entergy Arkansas Inc. (EAI)

Project Description

This project involves upgrading terminal equipment at Sylvan Hills and Jacksonville North in order to increase the line rating from 194 MVA to 239 MVA and 1200 Amps. The expected in-service date for this project is June 1, 2018, and it has an estimated cost of $26 thousand. Figure P9702 shows the contingency and resulting thermal violations that drive this project.

Project Need

A breaker failure at Keo 500 kV substation results in overloads on the Sylvan Hills to Jacksonville North 115 kV line between 106% and 119%. These violations were observed in the 2019 Summer Peak and Light Load models. Upgrading the terminal equipment for this line increases its rating so that it no longer overloads for the breaker failure event.



MISO, using Ventyx Velocity Suite © 2014

Figure P9702: Breaker Failure at Keo Causes Overloads on Sylvan Hills-Jacksonvill N. Line

Alternatives Considered

No alternatives were considered for this project because of the minor cost of the terminal equipment upgrades.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 12039: Hot Springs – Happy Valley 500 kV: New Line

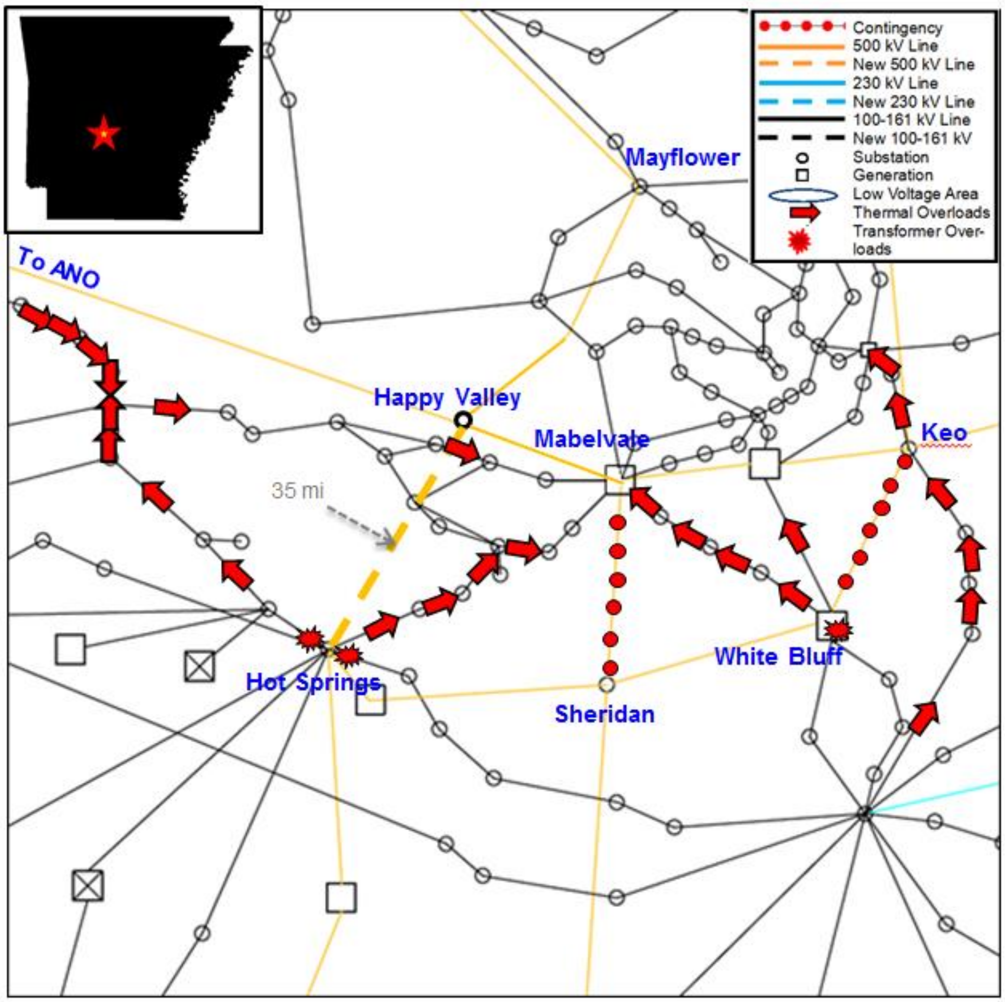
Transmission Owner: Entergy Arkansas Inc. (EAI)

Project Description

This project involves tapping the ANO to Mabelvale and Mayflower to Mabelvale 500 kV lines and constructing a new switching station at this point called Happy Valley. Additionally, a new 35 mile 500 kV line would be constructed between Happy Valley and Hot Springs 500 kV substations. The expected in-service date for this project is June 1, 2021, and it has an estimated cost of $149.31 million. Figure P12039 shows the contingency and resulting thermal violations that drive this project, as well as the proposed project to address the identified reliability concerns.

Project Need

An outage on the White Bluff to Keo 500 kV line and the Mabelvale to Sheridan 500 kV line results in 25 different lines and 3 transformers in the area to overload between 101% and 168%. The loss of these two 500 kV lines results in there being no 500 kV path from the southern 500 kV network to the northern 500 kV network, which significantly increases flows on the 115 kV lines in the area. These violations were observed in the 2019, 2022, and 2027 Summer Peak models. Building the new 500 kV line from Hot Springs to Happy Valley creates a new path from the southern 500 kV network to the northern 500 kV network, which mitigates these issues.

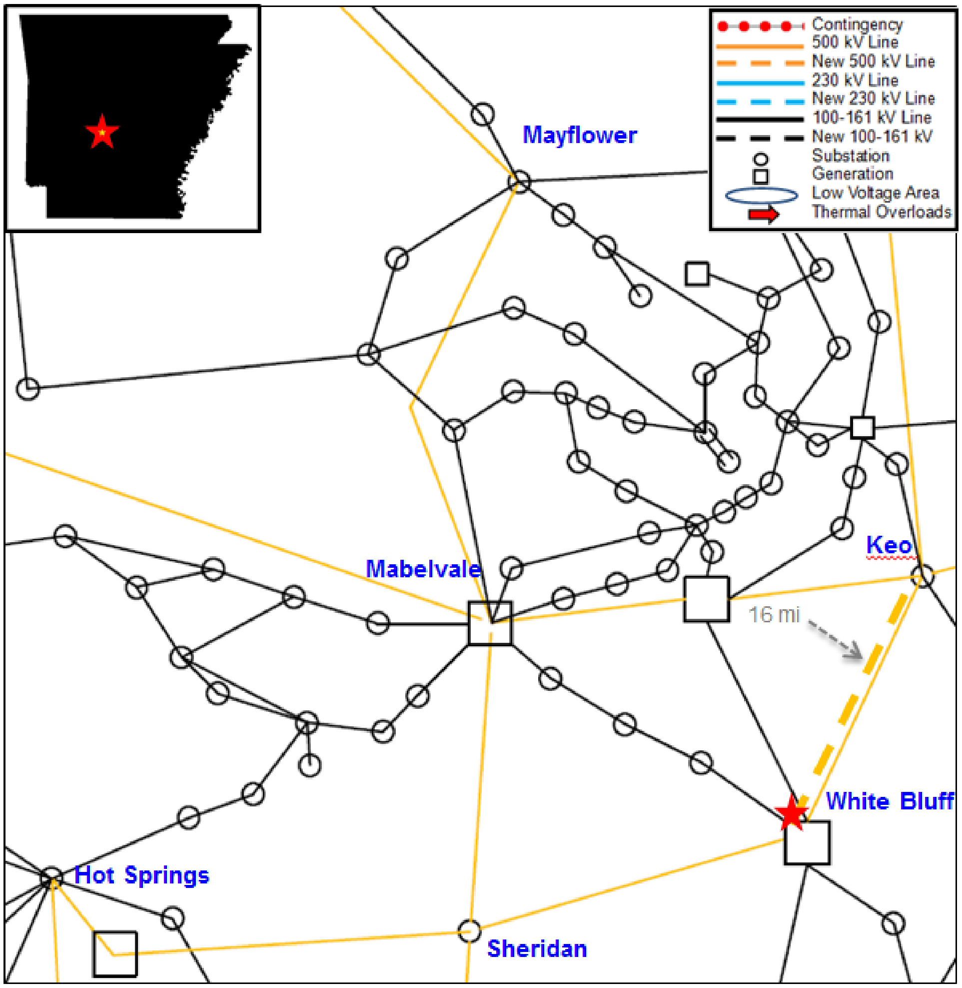


MISO, using Ventyx Velocity Suite © 2014

Figure P12039: Loss of Two 500 kV Lines Causes 28 Elements to Overload

Alternatives Considered

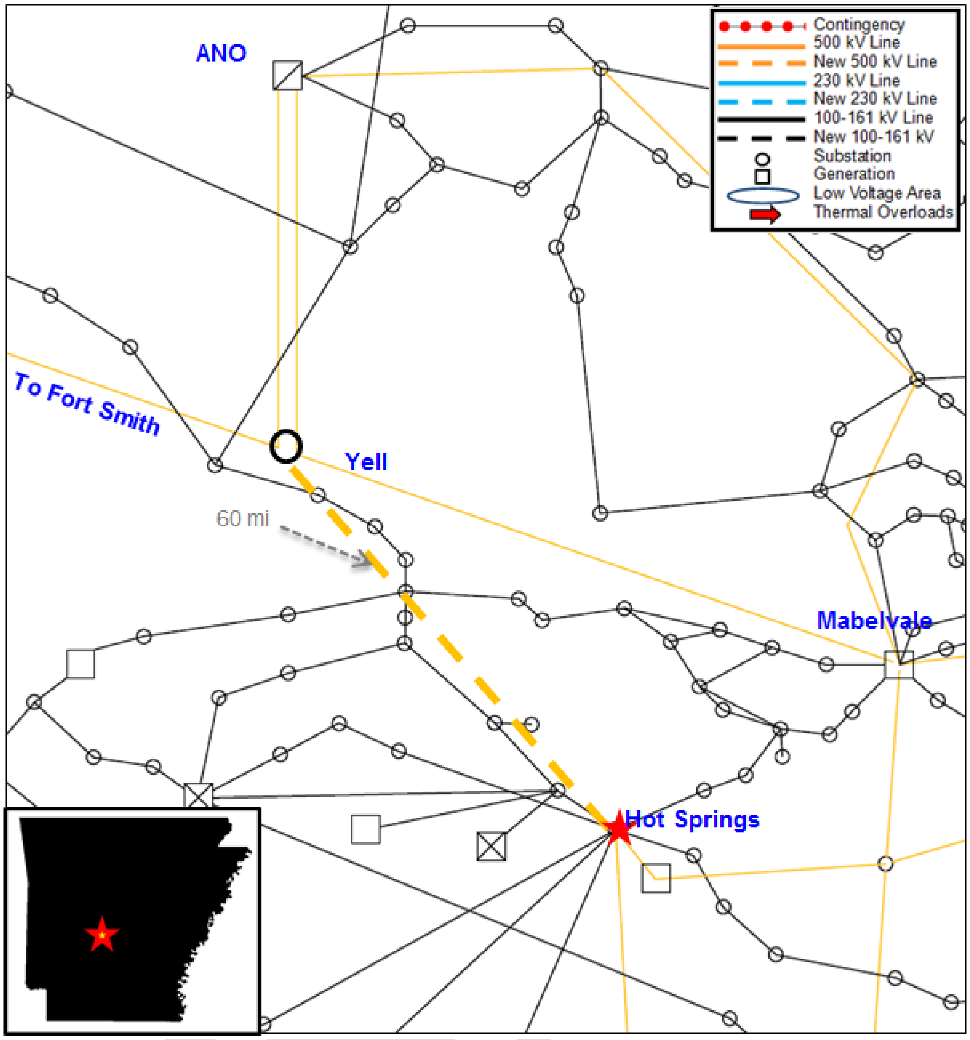
Two alternatives to this project were considered. The first alternative is to build a parallel 16 mile 500 kV line from White Bluff to Keo and is shown in Figure A1. Build this line would essentially eliminate the contingency that drives the Happy Valley project. While this alternative would be slightly cheaper than the recommended project, it is not as robust because it would not sufficiently address voltage recovery issues in the Hot Springs area. Additionally, the new line would be parallel to the existing Keo – White Bluff line, so the right of way would be in close proximity.



MISO, using Ventyx Velocity Suite © 2014

Figure A1: First Considered Alternative to Project 12039

The second alternative that was considered involved tapping the ANO to Mabelvale and ANO to Fort Smith 500 kV lines, and construct a new double-bus double-breaker station called Yell at this location. This alternative is shown in Figure A2. Additionally, this alternative would involve building a new 60 mile 500 kV line from Yell to Hot Springs. This alternative was rejected because the line would need to go through the Ouchita National Forest. Furthermore, an additional 25 miles of 500 kV line would be needed for this project, which would significantly increase the cost when compared with the Happy Valley project.



MISO, using Ventyx Velocity Suite © 2014

Figure A2: Second Considered Alternative to Project 12039

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing. All 345 kV and above Baseline Reliability Projects are further evaluated for economic benefit. Projects with a benefit to cost ratio of 1.25 or greater are eligible for cost sharing as a Market Efficiency project. The weighted benefit to cost ratio of the Happy Valley project is 0.15, so this project is not eligible for cost sharing as a Market Efficiency Project.

Project 12041: Russellville East 161 kV: Add Series Reactor

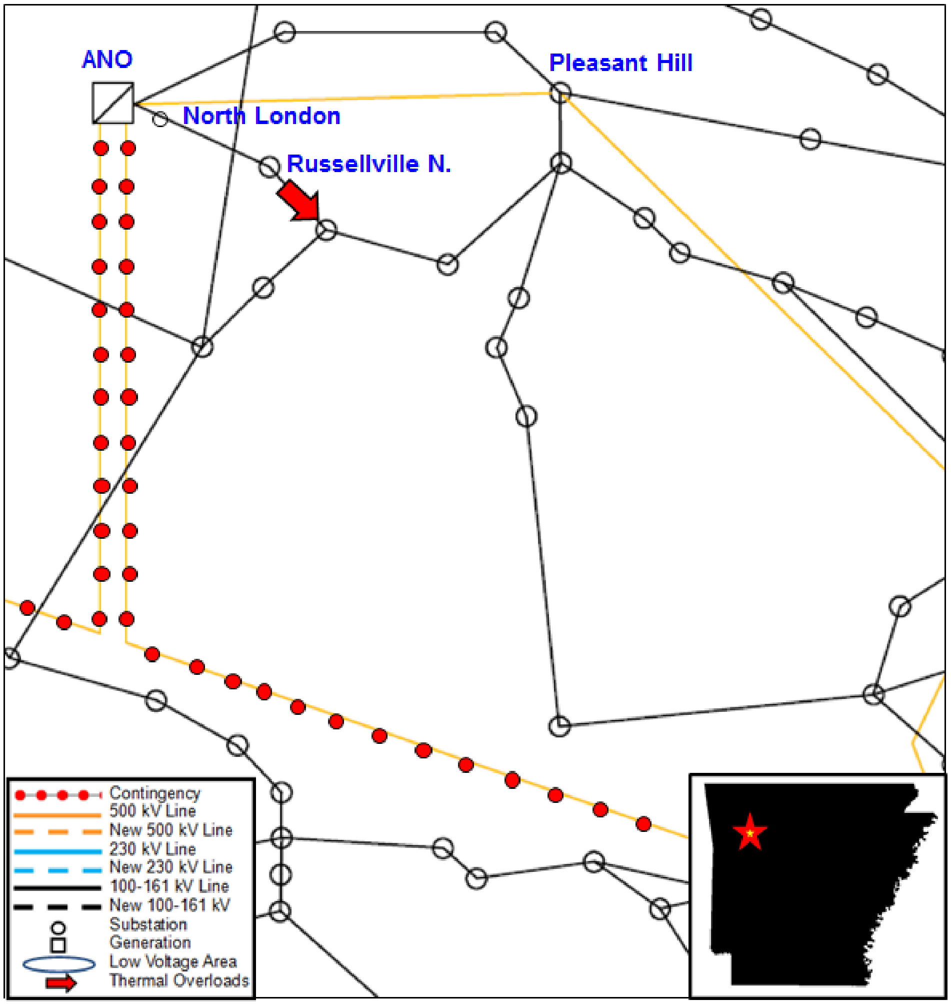
Transmission Owner: Entergy Arkansas Inc. (EAI)

Project Description

This project involves installing a 5 Ohm series reactor at Russellville East 161 kV substation. The expected in-service date for this project is June 1, 2020, and it has an estimated cost of $2.30 million. Figure P12041 shows the contingency and resulting thermal violations that drive this project.

Project Need

A breaker failure at ANO, or the loss of the ANO to Fort Smith line results in overloads on the Russellville North to Russellville East 161 kV line in the range of 101.3% to 109%. The loss of the path from ANO to Fort Smith cause the generation at ANO to be diverted through other surrounding lines. These overloads were observed in the 2019 and 2027 Summer Peak models. Adding a series reactor to Russellville East would reduce the flow on this line and mitigate the issue.



MISO, using Ventyx Velocity Suite © 2014

Figure P12041: Contingencies at ANO Cause Overloads on Russellville N – Russellville E

Alternatives Considered

The alternative that was considered for this project involved rebuilding the Russellville East to Russellville North 161 kV line. This alternative was rejected because it would significantly increase the cost of the project.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 12042: West Helena: Close NO Point & Install Breakers

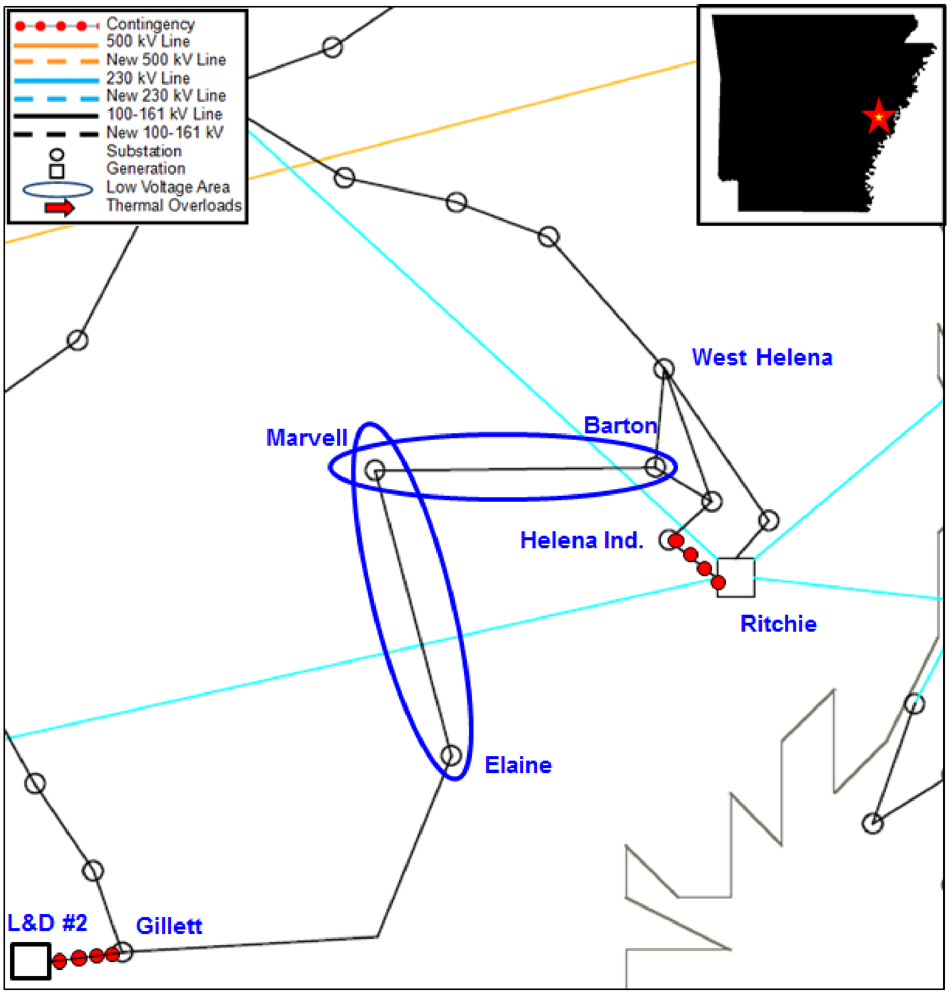
Transmission Owner: Entergy Arkansas Inc. (EAI)

Project Description

This project involves closing a normally open point at West Helena substation and adding breakers to the substation. The expected in-service date for this project is June 1, 2019, and it has an estimated cost of $9.13 million. Figure P12042 shows the contingency and resulting voltage violations that drive this project.

Project Need

The loss of the Ritchie to Helena Industrial 115 kV line and the 115 kV line between Gillett and Lock and Dam #2 results in low voltages in the range of 0.89 to 0.91 p.u. at Marvell, Barton, and Elaine substations. For this event, the generators at Ritchie and Lock and Dam #2 are isolated from this area because of the normally open point at West Helena, which causes the low voltages. These low voltages were observed in the 2019 and 2027 Summer Peak models. Closing the normally open point at West Helena and installing breakers would allow the generation at Ritchie to reach this area, and mitigate the low voltages.



MISO, using Ventyx Velocity Suite © 2014

Figure P12042: Loss of Multiple Lines Causes Low Voltages in Area

Alternatives Considered

The alternative that was considered for this project involved installing breakers and a capacitor at Marvell substation. This alternative would be comparable in cost to the recommended project; however, it is not as robust because it does not address the underlying issue of nearby generation being isolated from the area.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 12045: Independence Upgraded 500/161 kV autotransformers

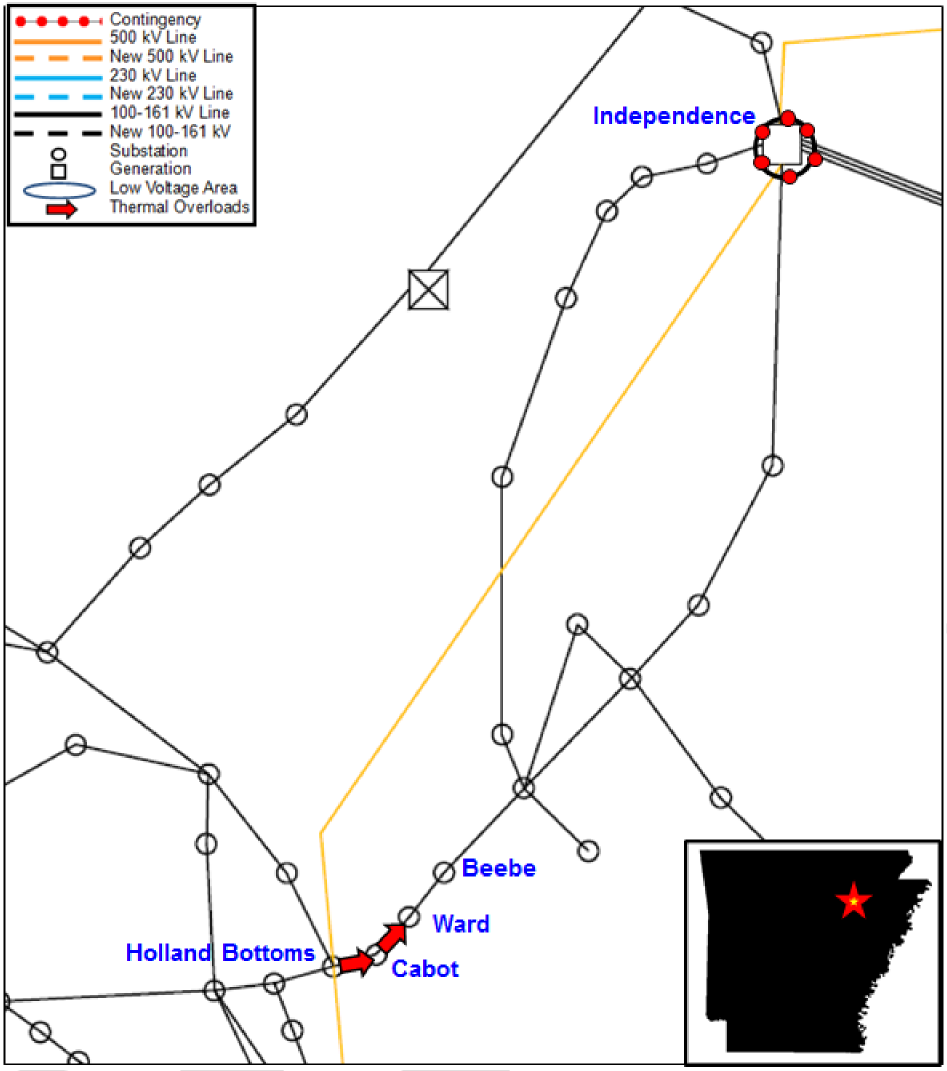
Transmission Owner: Entergy Arkansas Inc. (EAI)

Project Description

This project involves upgrading the 500/161 kV auto transformers at Independence to be rated a minimum of 800 MVA. Additionally, the new autotransformers will be connected to separate nodes with breakers to operate separately upon a fault. The expected in-service date for this project is April 1, 2020, and it has an estimated cost of $15.77 million. Figure P12045 shows the contingency and resulting overloads that drive this project.

Project Need

An outage of a 500/161 kV autotransformer combined with the loss of generator unit 1 at Independence results in overloads in the range of 109% to 113% on the Holland Bottoms to Cabot and Cabot to Ward 161 kV lines. Since the 500/161 kV autotransformers are currently connected to the same nodes, they trip in parallel. Increasing the rating of these autotransformers from 425 MVA to 800 MVA will allow them to operate separately because the loss of one autotransformer will no longer overload the other autotransformer. These thermal violations were observed in the 2019, 2022, and 2027 Summer Peak models. Upgrading the autotransformers and connecting them to separate nodes will mitigate the overload issues in this area.



MISO, using Ventyx Velocity Suite © 2014

Figure P12045: Loss of a Autotransformer and Generator at Independence Causes Overloads.

Alternatives Considered

The alternative that was considered for this project involved build a 15 mile 161 kV line from Holland Bottoms to Beebe and installing breakers at Beebe. This estimated cost for this alternative was $55.4 million, so it was rejected over the preferred project because of its higher cost.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

New Delivery Points

Several projects were proposed to facilitate new points of delivery. These projects serve new or increasing loads, give new points of connection, or upgrade existing points of delivery. The most effective ways to serve these loads is to construct new substations, or add new load transformers and feeder breakers for new points of delivery. A table summarizing these projects is shown on the following page. No-harm tests were conducted to ensure that baseline reliability issues are not caused by any of these projects.

Cost Allocation

These projects are classified as Other (Distribution Reliability) – New Delivery Point projects, which are not eligible for regional cost sharing.

ID	Name	Description	ISD	Cost ($M)
12059	Little Rock Kanis 115 kV: Install 3rd transformer and reconfigure bus	Add a 3rd 50 MVA load transformer and two new feeders. Convert the 115kV bus to a six element breaker-and-a-half configuration.	06/01/2018	$3.89 M
12063	Sheridan East 115 kV: Construct new substation	Construct a new 115kV substation called Sheridan East with two 115kV breakers, a 40 MVA load transformer, and four feeder breakers.	05/01/2020	$9.30 M
12666	MacArthur 115kV: Construct new substation	Construct a new substation on Highway 365 that will include one 40 MVA 115/13.8kV LTC transformer and four feeder breaker bays.	11/1/2019	$8.20 M
12667	Pecan Street 161kV: Construct new substation	Construct a new substation on the Newport to Parkin 161kV line. Install one 40 MVA LTC transformer and one 2000 Amp main breaker with four 1200 Amp feeder breakers.	11/15/2019	$10.85 M
12669	Tarleton 230kV: Construct new substation	Construct a new 230/13.8kV substation with two 20 MVA load transformers.	6/1/2019	$12.10 M
12745	Russellville Industrial 161kV: Construct new substation	Construct a new substation on E. 6th street and Tyler Road in Russellville, AR. Install one 40 MVA 161/13.8kV LTC and four feeder breaker bays. Split the Russellville East D220 and D260 circuits into three feeders.	6/1/2020	$7.02 M
12047	Greyhawk 161kV: Construct new substation	Construct a new 161kV substation with a 40 MVA 161/13.8kV LTC transformer and four feeder breaker bays.	6/1/2019	$8.06 M

Arkansas Electric Cooperative Corp. (AECC)

This section contains a summary for each project submitted by Arkansas Electric Cooperative Corporation (AECC) in the current MTEP17 cycle. Three projects were submitted to Target Appendix A in MTEP17, and are classified as Other projects. The cost estimate of these projects is $8.3 million, and their expected in-service dates are between 2017 and 2018. The project that is going in-service in 2017 was presented at the Planning Advisory Committee meeting early in the MTEP17 cycle as an expedited project request.

Project 12603: Olmstead to Zion Hill 115 kV New Line

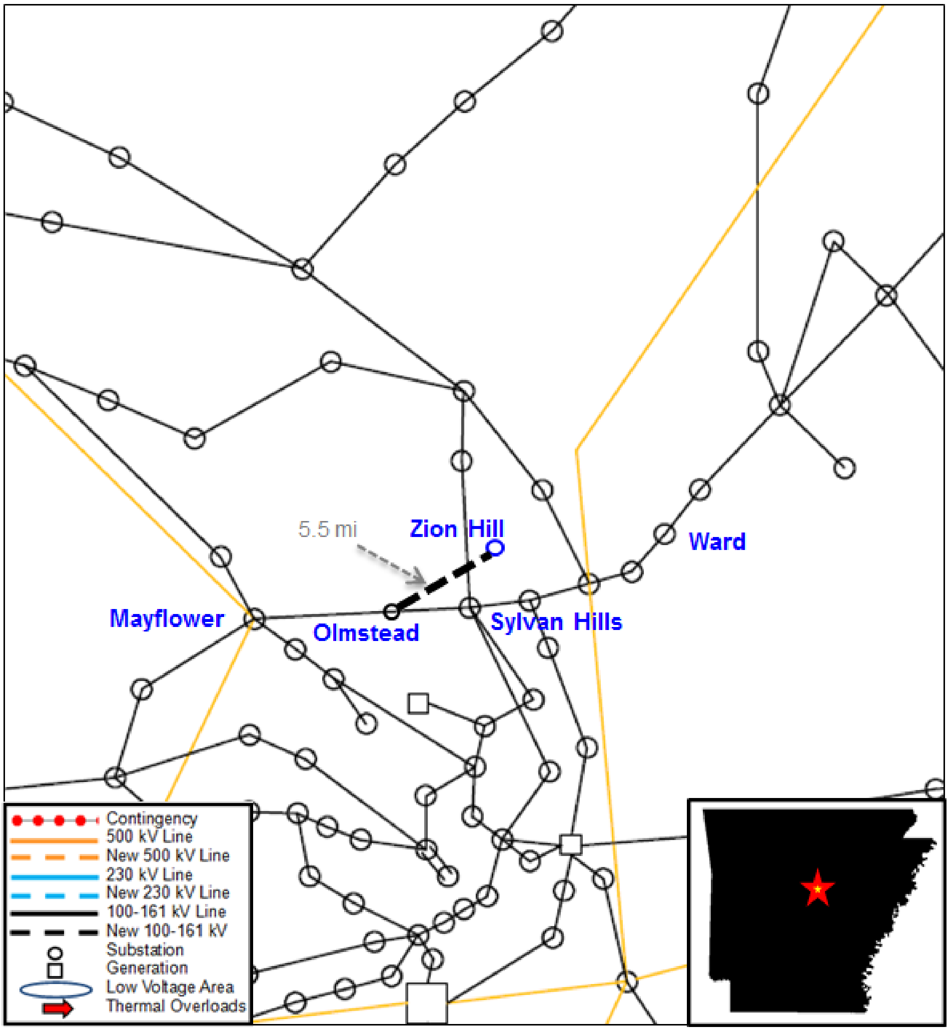
Transmission Owner: Arkansas Electric Cooperative Corporation (AECC)

Project Description

This project involves converting the 69 kV Zion Hill substation into a 115 kV substation. Additionally, a new 5.5 mile 115 kV line will be constructed between Olmstead and Zion Hill. The expected in-service date for this project is June 1, 2018, and it has an estimated cost of $4.5 million. Figure P12603 shows the approximate location of the Zion Hill substation as well as the new 115 kV line.

Project Need

This project will shift load that is currently being served from the Ward substation to Zion Hill, and it is needed in order to provide increased reliability to the distribution system.



MISO, using Ventyx Velocity Suite © 2014

Figure P12603: Conversion of Zion Hill Substation from 69 kV to 115 kV

Alternatives Considered

No alternatives were considered for this project.

Cost Allocation

This project is classified as an Other – Distribution Reliability project, which is not eligible for regional cost sharing.

Project 13123: Oppelo 161 kV line breakers

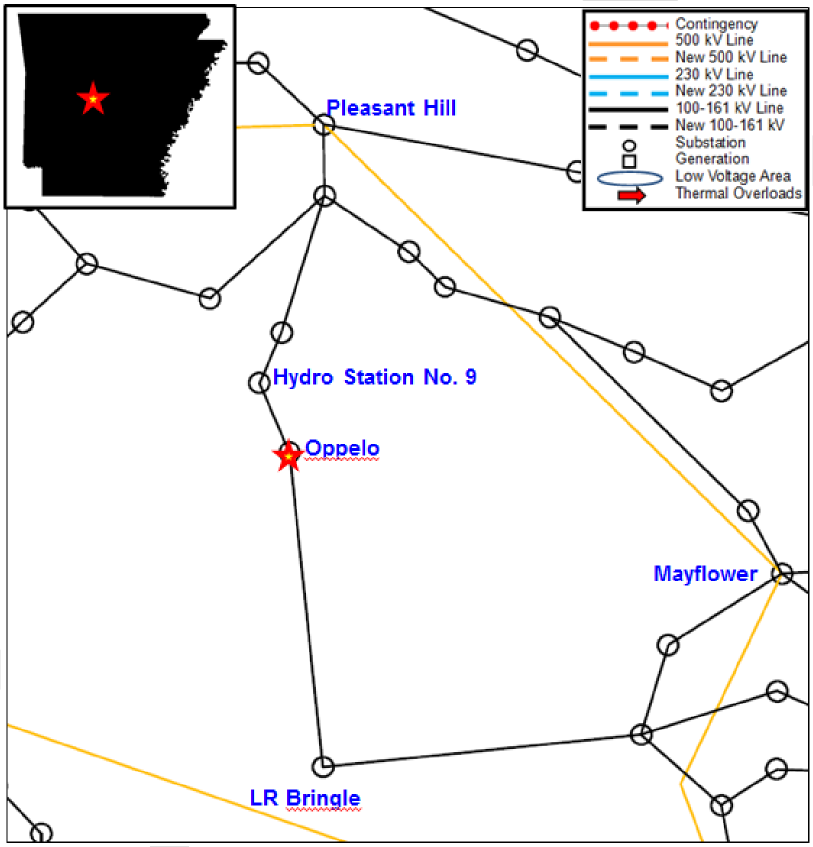
Transmission Owner: Arkansas Electric Cooperative Corporation (AECC)

Project Description

This project involves installing breakers and protective relays at Oppelo 161 kV substation. The expected in-service date for this project is April 1, 2018, and it has an estimated cost of $800 thousand. Figure P13123 shows the approximate location in Arkansas where these installations will occur.

Project Need

This project is needed in order to address power quality issues in the Oppelo area.



MISO, using Ventyx Velocity Suite © 2014

Figure P13123: Breaker and Relay Additions at Oppelo 161 kV Substation

Alternatives Considered

No alternatives were considered for this project.

Cost Allocation

This project is classified as an Other – Distribution Reliability project, which is not eligible for regional cost sharing.

Project 12383: Hickman Central

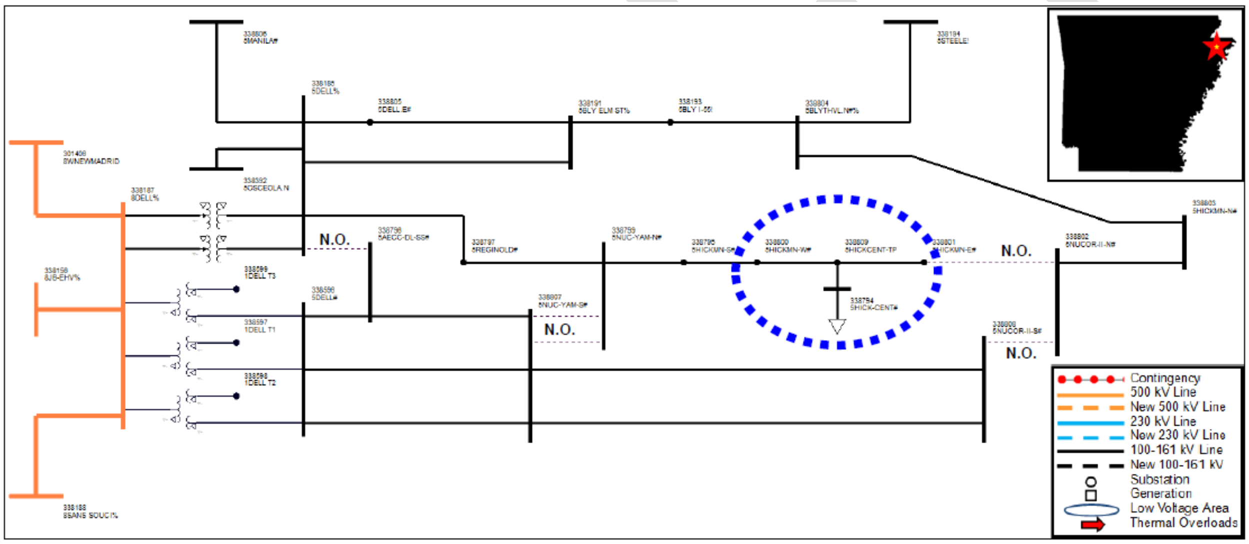
Transmission Owner: Arkansas Electric Cooperative Corporation (AECC)

Project Description

This project involves tapping the existing Dell to Blytheville North 161 kV line and constructing the new Hickman Central substation. Additionally, a new 0.25 mile line will be constructed from Hickman Central Tap to the new Hickman Central substation. The expected in-service date for this project is October 1, 2017, and it has an estimated cost of $3 million. This projects was presented at the Planning Advisory Committee meeting in December 2016 as an expedited project request, and was presented at the first Sub-regional Planning meeting. Figure P12383 shows the approximate location in Arkansas where this new substation will be constructed.

Project Need

This project is needed in order to accommodate a new industrial load customer of around 35 MW.



MISO, using Ventyx Velocity Suite © 2014

Figure P12383: Hickman Central New Load and Substation

Alternatives Considered

No alternatives were considered for this project.

Cost Allocation

This project is classified as an Other – Distribution Reliability (New Delivery Point) project, which is not eligible for regional cost sharing.

Region Louisiana

Regional Information

MISO-Louisiana is a network of generation resources and major load centers interconnected through an array of 500-115 kV transmission networks. There is also a significant 69 kV network interspersed across its footprint.

MISO-Louisiana consists of a diverse generation profile, such as nuclear, gas and hydro units that fuel major load centers such as the Monroe, Alexandria, Lake Charles, Lafayette and Baton Rouge areas, as well as two load pockets - the West of the Atchafalaya Basin (WOTAB), Amite South and Down Stream Gypsy (DSG) load pockets.

Figure LA-1 illustrates the major generation sources, load centers and generation-to-load power flow of the EHV transmission system in Louisiana.

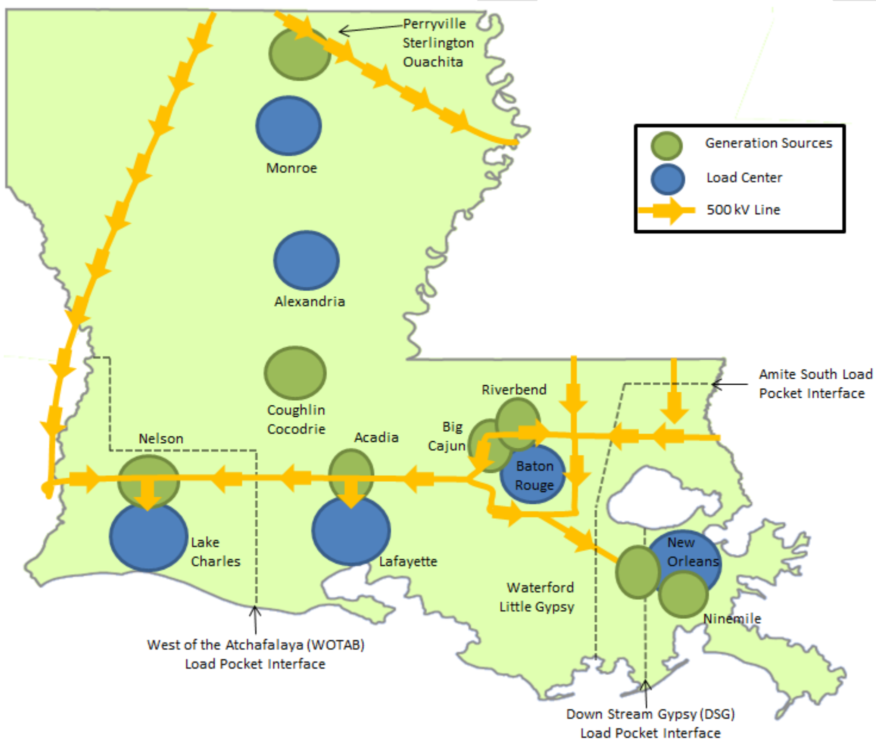


Figure LA-1: MISO-Louisiana – Major generation sources, load centers and EHV transmission

The projects proposed in the MTEP17 cycle are part of a continuing effort to strengthen the existing transmission network. The projects that are detailed in this report include, substation reconfiguration, rebuilding under rated transmission lines, new 230kV and 115kV transmission lines, transformer replacements, transformer additions and generation interconnection projects. Additionally, several projects are proposed to create new delivery points to either facilitate new load or load growth.

Transmission Profile

The transmission network within the footprint of MISO-Louisiana covers approximately 5,400 miles of the 115 kV to 500 kV bulk electric system (BES) network. An additional 1000 miles is dedicated as the 69 kV network.

Major transmission hubs - such as Big Cajun, Rhodes, Patton, Nelson, Richard, Wells, Webre, Willow Glen, Fancy Point, McKnight, Coly, Bayou Labutte, Bogalusa, Waterford, Mount Olive, Sterlington and Perryville - interconnected via a network of 500 kV circuits form the backbone of the MISO-Louisiana transmission network.

Louisiana contains three load pockets, one of which is nested within another load pocket. The West of the Atchafalaya Basin (WOTAB), Amite South, and Down Stream Gypsy (DSG) load pockets cover the coastal region of Louisiana, and contain many industrial customers in the Lake Charles and New Orleans areas (Figure LA-1).

The WOTAB load pocket is geographically bound by the Gulf of Mexico (South), the Atchafalaya Basin (East), and extends into the eastern portion of Texas. Local generation within WOTAB meets much of the pocket’s demand. Generation sources at Nelson, PPG, and Calcasieu support the Lake Charles area. WOTAB is also supported by 500 kV taps at Nelson (Lake Charles) and Richard (Lafayette). There are also many smaller units on the 138 and 69 kV transmission networks used to serve local demand.

The Amite South load pocket lies to the east of Baton Rouge. This load pocket is bound by the Louisiana eastern border, the Gulf of Mexico, and a narrow corridor of transmission lines between Baton Rouge and New Orleans. This load pocket is split by the Mississippi River, and the densely populated city of New Orleans lies beneath Lake Pontchartrain. These geographic obstacles provide narrow corridors for transmission lines, and the pocket lacks multiple EHV lines to import power deep into load centers.
The Amite South load pocket also utilizes local generation sources to meet local demand. Generation at Waterford, Oxy, Union Carbide, Little Gypsy, St. Gabriel and Ninemile provide strong sources for local demand.

Amite South contains three 500 kV taps to import power to the area: Waterford, Bayou Labutte and Bogalusa. However, of these three taps, only the Willow Glen to Waterford transmission line penetrates deep into the pocket and this tap still remains outside of the DSG load pocket. The Bayou Labutte 500 kV tap is located on the load pocket interface near Baton Rouge, and the Bogalusa tap is located on the northern pocket interface.

The DSG load pocket is a subset of the Amite South load pocket. This load pocket contains the city of New Orleans. DSG is densely populated, and the pocket is surrounded by Lake Pontchartrain to the north, and the Gulf of Mexico to the east and south. The Mississippi River also runs through the middle of this pocket. The dense population and surrounding bodies of water provide a limited number of transmission line corridors. There are no EHV lines within the pocket for import, and the local demand is primarily supplied by the Ninemile power plant, as well as 230 kV lines extending out of the Little Gypsy and Waterford power plants.

Load Profile

According to the 2019 Summer Peak model estimates, load within MISO-Louisisana footprint is held at approximately 20 GW. Around 50 percent of the total load is centered on the Amite South and WOTAB load pockets within this footprint.

Generation Profile

The generation portfolio MISO- Louisiana mainly constitutes a mix of nuclear, hydro, Combined Cycle Gas Turbines (CCGT), and legacy gas units. Currently, the system holds about 21 GW of generation capacity. The major sources constituting this profile are Nelson, Acadia, Big Cajun, Riverbend, Waterford, Little Gypsy, Ninemile, Sterlington, Perryville, Coughlin and Rodemacher generation units. Together, as per the 2019 Summer Peak model estimates, they share a combined generation capacity of 63 percent of the total generation portfolio.

Overview of Projects

For the current MTEP17 cycle, 35 projects were targeted as Appendix A at a combined cost of $590 million. Of these, 20 projects have an estimated cost greater than $5 million; 6 projects have a projected cost between $1 million and $5 million; and 9 projects have an estimated price tag lower than $1 million. 18 of these 34 projects are labeled as baseline reliability projects, while the 14 are designated as Other projects and 3 are designated as Generation Interconnection projects. Figure LA-2 illustrates the approximate geographic locations of the projects submitted as Target Appendix A in the current MTEP cycle. Figures LA-3 and LA-4 illustrates the Base Line Reliability, Generation Interconnection and Other projects as either distributed by their estimated costs or the year they're expected to be in service. Some project details, such as estimated cost and in- service dates, may change between the creation of Appendix D1 and the board approval date. Refer to Appendix A of this report for the final approval information.

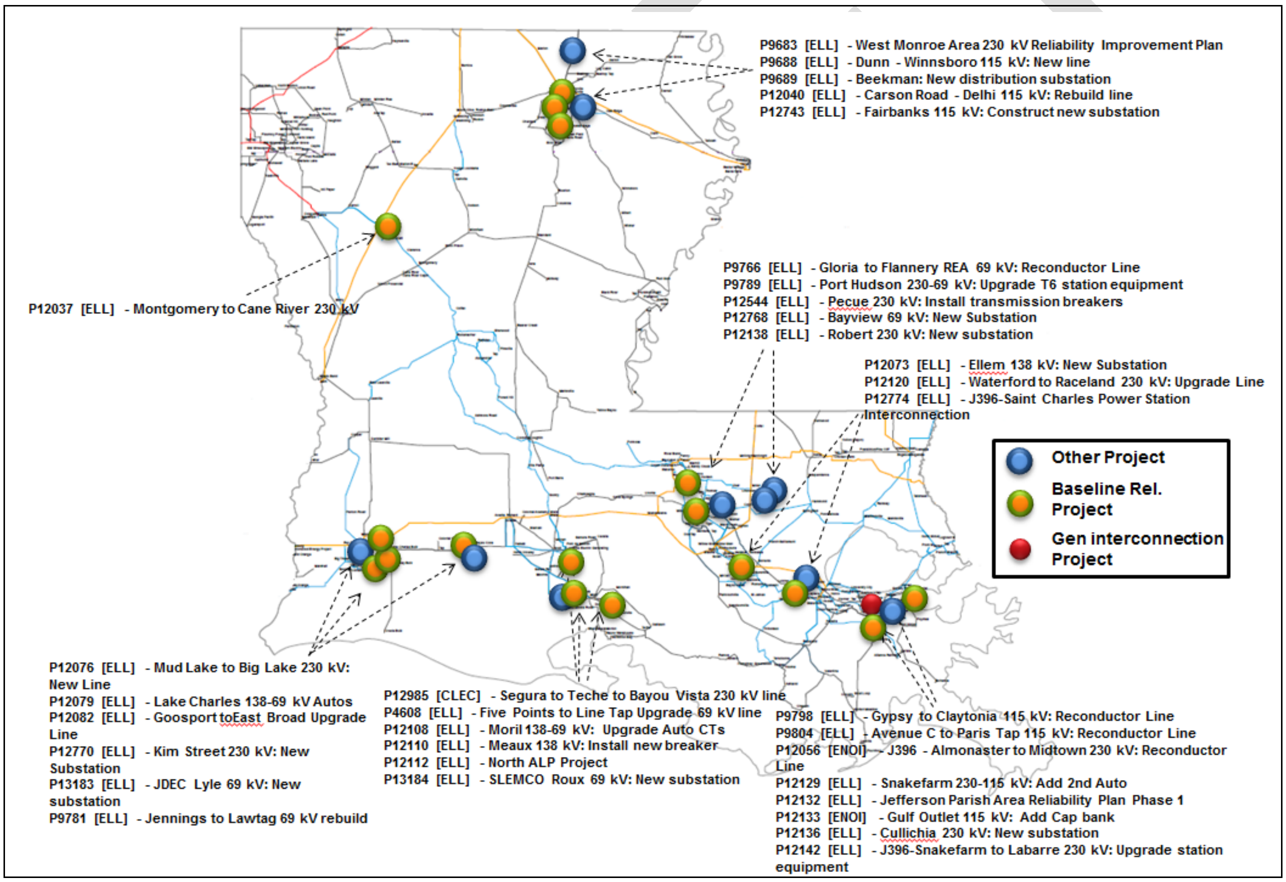


Figure LA-2: Geographical transmission map of MISO-Louisiana with project locations

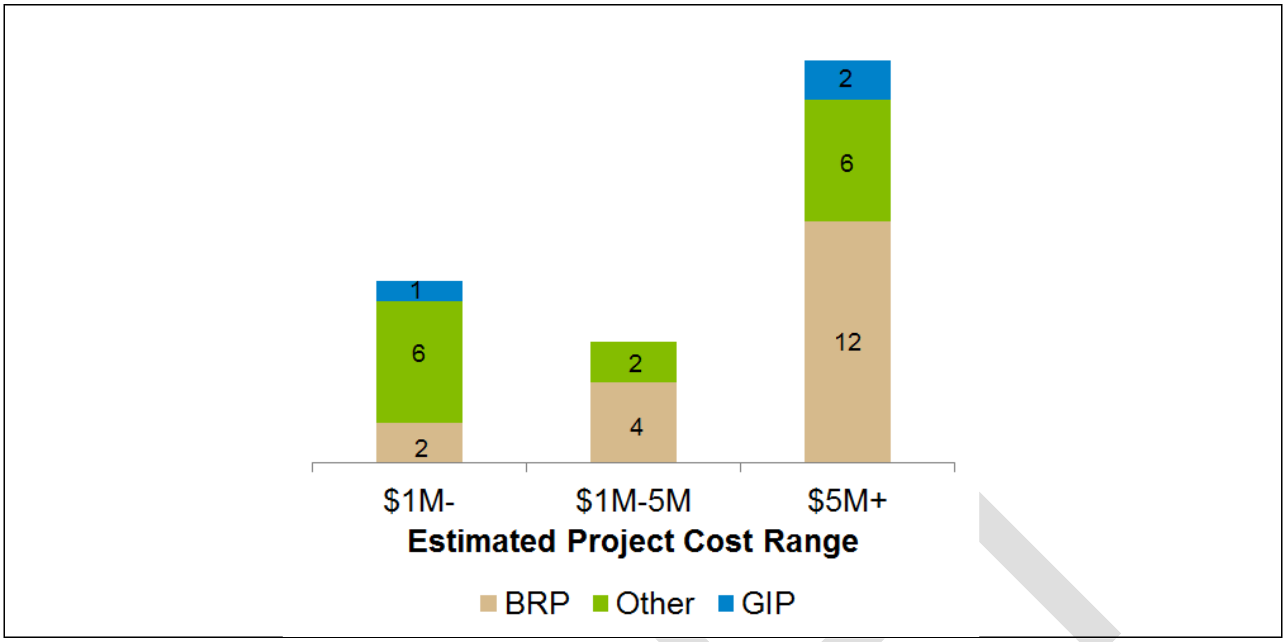


Figure LA-3: Graph of cost range by project type

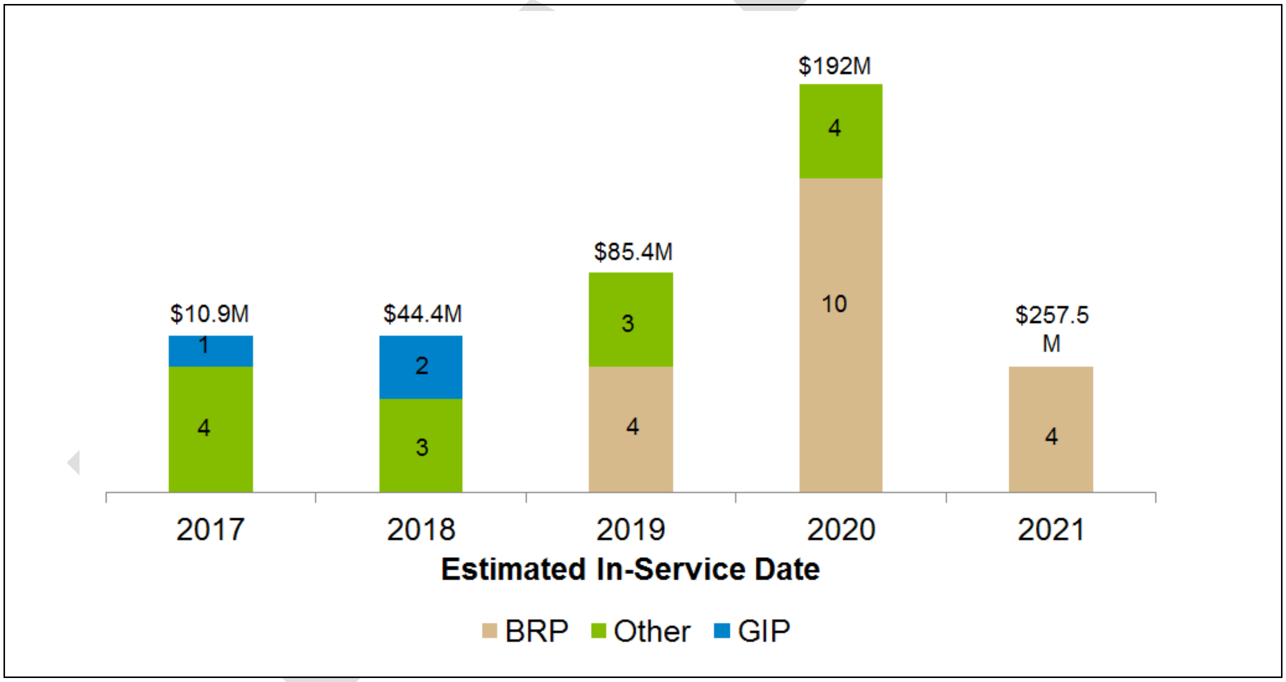


Figure LA-4: Graph of estimated in-service date

Entergy Louisiana, LLC. (ELL)

This section presents a summary of each project submitted by Entergy Louisiana in the MTEP17 cycle. 31 projects were submitted as Target Appendix A; of these, 16 are Baseline Reliability projects. The remaining projects are designated as either Generator Interconnection or Other Projects. The combined cost estimate for these projects is approximately $493 million. They are scheduled to come into service between 2017 and 2021.

Project 9798: Reconductor Little Gypsy to Claytonia 115kV Line

Transmission Owner: Entergy Louisiana, LLC.

Project Description

Project 9798 is located in the Down Stream Gypsy (DSG) load pocket, which includes the metropolitan area of New Orleans. The load pocket is historically import limited. Import into to the load pocket primarily occurs across several 230 and 115kV transmission lines supplied by generation at the Waterford and Little Gypsy power plants.

This project proposes to replace the conductor of the 4.8 mile Little Gypsy to Claytonia transmission line at an estimated cost of $7.4 million. The projected in-service date for this project is June 1, 2020. Figure P9798 illustrates the contingency, resultant violation and proposed project to mitigate the reliability concerns.

Project Need

A bus fault at the Snakefarm substation will result in the loss the transformer at Snakefarm and multiple transmission lines at the substation, which results in loss of a 230kV source downstream of the Waterford and Little Gypsy generation facilities. Increased flow from the Little Gypsy area on the 115kV network causes the Little Gypsy to Claytonia circuit to overload to 105%. The overload was first observed in the 2019 summer model.

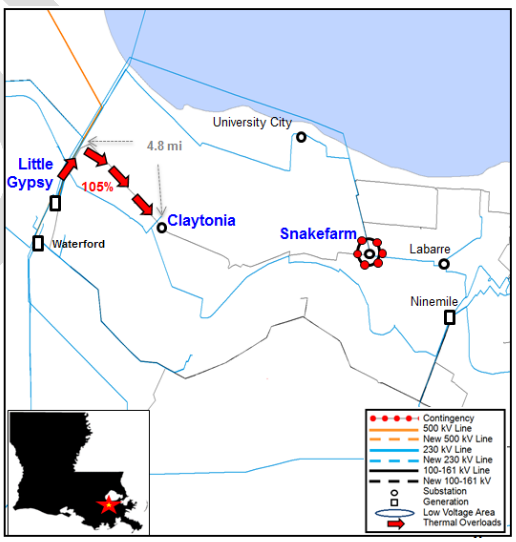


Figure P9798: Bus fault at Snakefarm 230kV substation results in an overload of the Little Gypsy to Claytonia 115kV circuit

Alternatives Considered

Rather than replacing the Little Gypsy to Claytonia conductor, rebuilding the Snakefarm substation was considered. Space limitations of the substation's surrounding area and a higher cost compared to the reconductor eliminated this option.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 9804: Reconductor Avenue C to Paris Tap 115kV Line

Transmission Owner: Entergy Louisiana, LLC.

Project Description

The Avenue C to Paris Tap transmission line is one of three transmission line segments connecting Avenue C, Paris and Lakeshore 115kV substations. This 115kV circuit is located in the Down Stream Gypsy load pocket and it is primarily supplied by generation at the Little Gypsy generation plant and a 230kV tap at the Paris substation.

Project 9804 replaces 0.5 miles of conductor on Avenue C to the Paris Tap point at an estimated cost of $220,000. The expected in-service date of this project is June 1, 2020. Figure P9804 illustrates the contingency, resultant violation and proposed project to mitigate the reliability concerns.

Project Need

The loss of the Market Street 230/115kV transformer removes a 230kV tap downstream of the Paris Tap to Avenue C line. The power flow out of Paris tap to compensate for the loss of the transformer causes the Paris Tap to Avenue C line to exceed its thermal rating, first observed in the 2019 summer scenario.

Additionally, several NERC TPL category P6 contingencies (loss of two transmission elements) results in up to 1000 MW of generation curtailment and 50 MW of non-consequential load shed due to the Paris Tap to Avenue C overload.

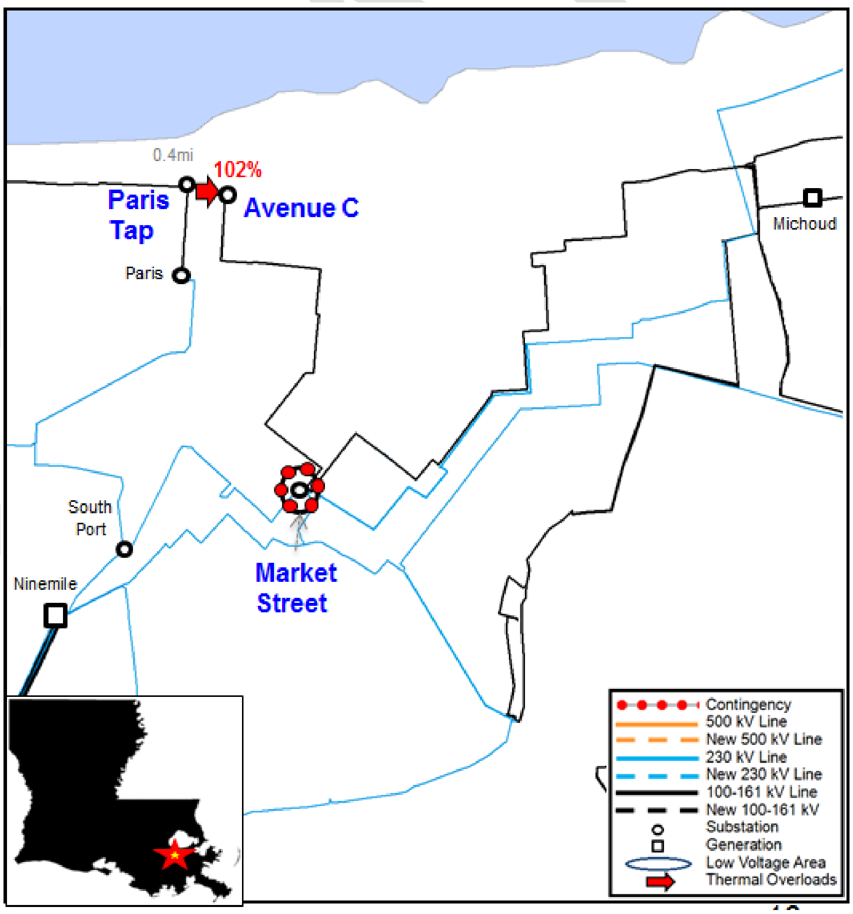


Figure P9804: Loss of the Market Street autotransformer results in an overload of

the Paris Tap to Avenue C transmission line

Alternatives Considered

None

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 12129: Second 230/115kV Transformer at Snakefarm 230kV substation

Transmission Owner: Entergy Louisiana, LLC.

Project Description

The Snakefarm substation is located in the DSG load pocket. The 230/115kV tap at Snakefarm, as well as the Little Gypsy to Claytonia and Paris Tap to Lakeshore 115kV lines, supply a section of the 115kV network in DSG which includes over 200MW of demand in the summer scenarios.

Project 12129 will add a second 230/115kV transformer at the Snakefarm substation. The estimated cost to add a transformer at the Snakefarm substation is $7.5 million, with an expected in-service date of December 1, 2019. Figure P12129 illustrates the contingency, resultant violation and proposed project to mitigate the reliability concerns.

Project Need

Following the loss of the Little Gypsy to Claytonia 115kV circuit and the 230/115kV transformer at the Snakefarm substation the Paris Tap to Lakeshore 115kV circuit is the only source to a section of the 115kV network in DSG. The resultant loading of the Paris 230/115 kV transformer and the Paris to Lakeshore 115kV circuit causes up to 230 MW of nonconsequential load loss, first observed in the 2019 summer scenario.

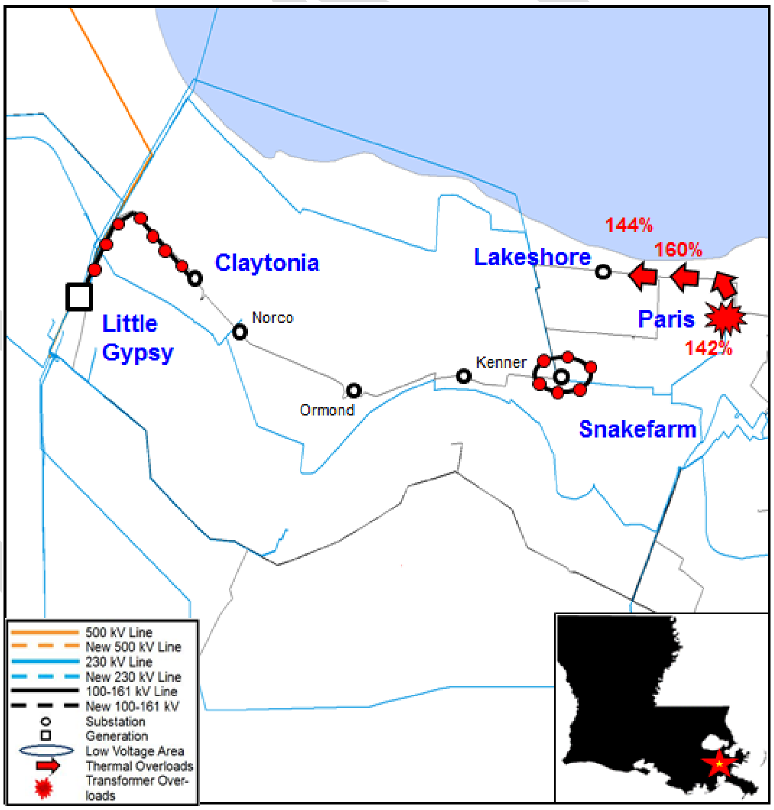


Figure P12129: The Paris transformer and Paris to Lakeshore circuit exceed thermal limits for the loss of the Snakefarm transformer and Little Gypsy to Claytonia circuit

Alternatives Considered

Rather than the addition of a second transformer at the Snakefarm substation, a second 115kV line from Little Gypsy to Claytonia was considered. A second circuit from Little Gypsy to Claytonia was rejected to the additional cost to implement.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 12132: Jefferson Parish Area Reliability Plan Phase One

Transmission Owner: Entergy Louisiana, LLC.

Project Description

Project 12132 is located in Jefferson Parish Louisiana, within the Down Stream Gypsy (DSG) load pocket. The DSG load pocket is historically import limited. This area consists of 230kV and 115kV transmission networks, as well as more than 2 Gigawatts of generation capacity at the Ninemile generation plant.

This project will construct a new 230kV substation, south of the Ninemile generation facility, named Churchill. The existing Waterford to Ninemile 230kV line and the Ninemile to Estelle 230kV line will be cut into the Churchill substation. The existing Ninemile to Barataria 115kV line will also be cut into the Churchill substation and energized at 230kV. A 230kV station will be built at Barataria, including one 230/115kV autotransformer installation. This will create a new 5 terminal, 230kV Churchill substation.

The abandoned portion of the Ninemile to Barataria 115kV line that stretches from Ninemile to Churchill will be extended to the Westwego substation. This will create a second Ninemile to Westwego 115kV circuit.

The estimated cost to implement project 12132 is $55.4 million, with an expected in-service date of June 1, 2020.

Project Need

The substations between Ninemile and Michoud illustrated in figure P12132 serve over 300MW of demand in the 2019 summer scenario and contains a 115kV tap point at the Behrman substation. This stretch of 230kV circuits is supplied by the Michoud and Ninemile 230kV substations. Loss of the Michoud to Meaux and Ninemile to Estelle 230kV circuits results in the local 230kV network supply coming from the 115kV tap at Behrman. This results in voltage levels below local planning criteria threshold at multiple 230kV substations and thermal overloads on the 115kV network. 1000 MW of generation curtailment and up to 300 MW of nonconsequential load loss is required to mitigate the reliability issues. Energizing the Ninemile to Barataria 115kV circuit to 230kV creates a new 230kV source into this area, effectively paralleling one of the two contingencies.

Additionally, a Transmission Structure Failure – NERC TPL Category P7 Contingency – between Ninemile and Churchill results in an overload of the Behrman to Gretna 115kV circuit. Utilizing the abandoned portion of the Ninemile to Barataria 115kV circuit to build a second Ninemile to Westwego circuit parallels one of the lines lost due to the transmission structure failure.

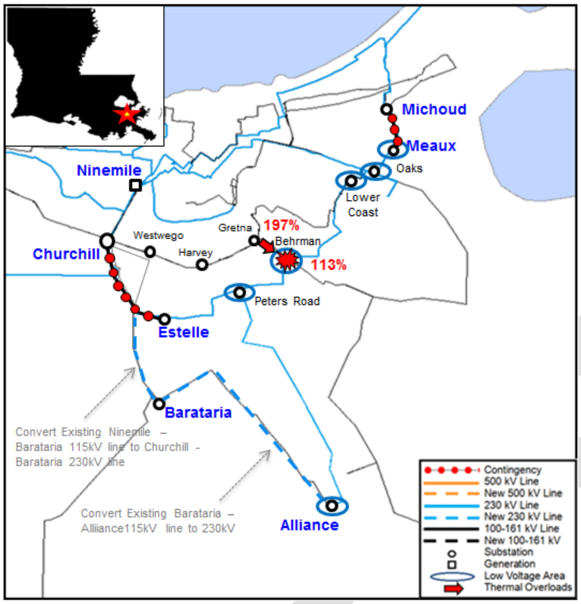


Figure P12132: Loss of the Michoud to Meaux and Ninemile to Estelle 230kV circuits results in voltage levels below local planning criteria threshold and thermal overloads on the 115kV network

Alternatives Considered

Alternatively, constructing two new 230kV lines to parallel the contingencies described above was considered. This alternative would require new 230 kV lines from Ninemile to Behrman and Behrman to Michoud, totaling 40 miles of new 230 kV conductor with one Mississippi River crossing. This option was rejected based on the lack of availability of right of way for the transmission path.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 12073: New Ellem 138 kV Substation

Transmission Owner: Entergy Louisiana, LLC.

Project Description

Project 12073 is located on the Amite South load pocket interface. The area between Willow Glen 500/230/138/115kV substation and Conway 230/138kV substation consists of a single 230kV loop and two 138kV loops. The 138kV loops are supplied by 230/138kV and 500/138kV transformers at Willow Glen, as well as a 230/138kV transformer the Conway substation.

This project will reconfigure the local 138 kV network, tying the Monochem to Alchem and Monochem to Southwood 138 kV lines into a new substation, Ellem, adjacent to Geismar 138 kV substation. The estimated cost to implement project 12073 is $11.7 million, with an expected in-service date of June 1, 2020.

Project Need

The loss of the Southwood to Conway 138kV line results in the Southwood substation on a radial feed from Geismar 138kV substation. Following the loss of local generation at Southwood and the Southwood to Conway 138kV line voltage levels below 0.92 are seen at the Southwood substation.

Additionally, the loss of Willow Glen to Alchem and Willow Glen to Geigy 138kV circuits leaves the Conway 230/138kV transformer as the only source to a portion of the 138kV network in the area, which results in up 418 MW of nonconsequential load loss.

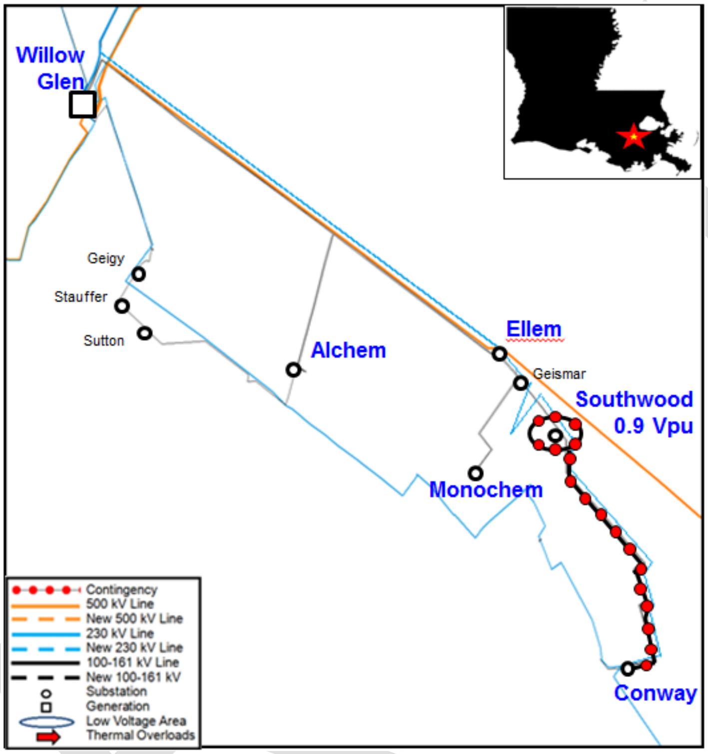


Figure P12073: Loss of the Conway to Southwood 138 kV line along with Southwood generation causes low voltage at Southwood 138 kV

Alternatives Considered

Rather than reconfigure the 138kV network with the new Ellem substation, constructing a second Willow Glen to Geigy 138 kV line and a second Conway to Southwood 138 kV line was considered. This option was rejected due to the additional cost associated with implementing this solution in lieu of the Ellem substation.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 9683: West Monroe Area 230 kV Reliability

Transmission Owner: Entergy Louisiana, LLC.

Project Description

Project 9683 is located in Ouachita Parish Louisiana, near the Monroe load center. This area contains 500kV and 115kV networks, as well as the Sterlington and Perryville generation facilities. The 115kV network in the Monroe load center is primarily supplied by three 500/115kV transformers at Sterlington, which provide the area access to the Sterlington and Perryville generation resources.

This project will create new 230kV sources to help support the 115kV network. The existing Perryville 500kV station will be converted to a 500/230kV substation, with a single 1200 MVA transformer installation. The existing Dunn to Swartz 115kV circuit will be disconnected from the Dunn substation, converted to 230kV and extended to the new 230kV station at Perryville. Additional 115kV circuits at Selman Field and Rilla will be converted to 230kV and extended to the new Perryville 230kV station. 230/115kV transformers will be installed at Dunn and Rilla, while a 230/69kV transformer will be installed at Selman Field. This will create three new 230kV access points in the Monroe load center.

The estimated cost to implement project 9683 is $78.9 million, with an expected in-service date of June 1, 2021.

Project Need

The generation resources at Sterlington and Perryville supply the 115kV network in Monroe by way of three 500/115kV transformers. Loss of one of the three transformers causes the remaining transformers to exceed their thermal capacity, first observed in 2022 summer scenario and illustrated in figure P9683.

Additionally, the loss of two 500/115kV transformers at Sterlington results in overloads up to 122% of the remaining transformer, which requires 900 MW of generation curtailment and up to 135 MW of nonconsequential load loss.

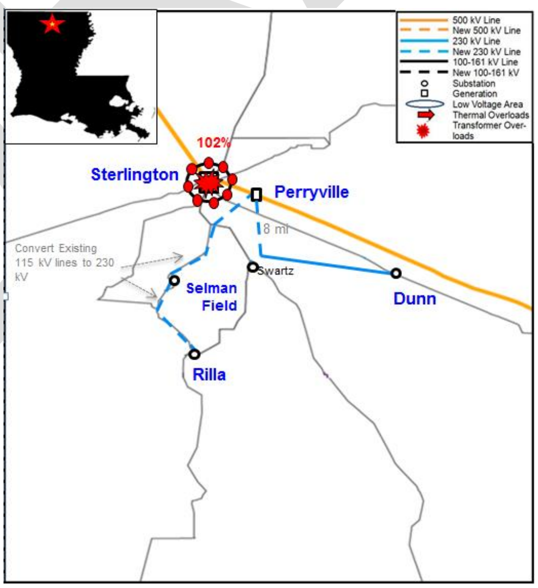


Figure P9683: Loss of one of three 500/115kV transformers at Sterlington overloads the remaining transformers

Alternatives Considered

In lieu of the West Monroe Reliability Plan described above, creating a new 500/230/115kV substation at the existing Dunn substation was considered. This alternative required the construction of a new 500kV and 230kV substations at the Dunn 115kV substation, a 500/230kV transformer at Dunn, a 500/115kV transformer at Winnfield, a new Swartz to Rilla 230kV line and a 230/115kV transformer at Rilla.

This solution was considered as an alternative to projects 9683, 9688 and 12040. This alternative was rejected due to higher cost to implement when compared to projects 9683, 9688 and 12040. It is also viewed as a less robust solution, as the 230kV support provided would have been farther away from the Monroe load center.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 9688: Dunn - Winnsboro 115 kV New line

Transmission Owner: Entergy Louisiana, LLC.

Project Description

Project 9688 is also located in Ouachita Parish Louisiana. This project extends the previous project, 9683, building a new 230kV circuit, energized at 115kV, from Dunn to Winnsboro. The new transmission line is approximately 23 miles long, with an estimated cost of $35 million and an expected in-service date of June 1, 2020. Figure P12129 illustrates the contingency, resultant violation and proposed project to mitigate the reliability concerns.

Project Need

The loss of the Grand Gulf Nuclear plant creates a power sink in the area which increases flows out of the Sterlington and Perryville area to compensate. With the additional loss of the Perryville to Baxter Wilson 500kV line the increased flow out of the Sterlington area in forced on the 115kV network between Sterlington and Grand Gulf. This results in thermal overloads of the Swartz to Alto and Alto to Baskin 115kV circuits as illustrated in figure 9688. Up to 800 MW of generation curtailment is required to mitigate the constraints on the Swartz to Alto and Alto to Baskin 115kV circuits.

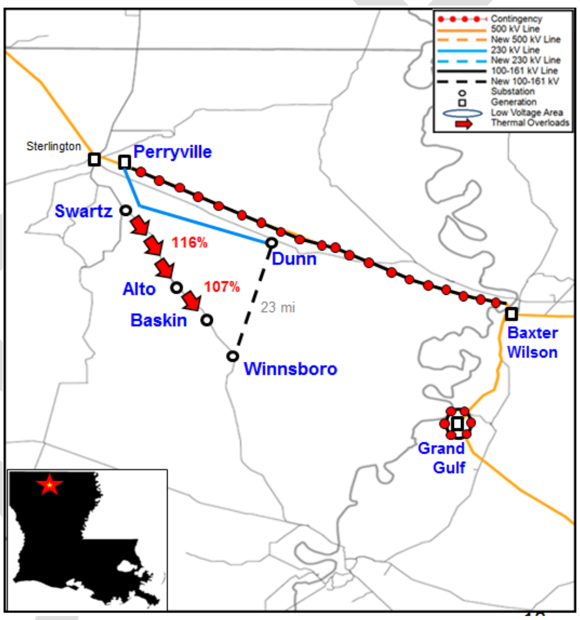


Figure P9688: The loss of Grand Gulf Nuclear generation and the Perryville to Baxter Wilson 500kV circuit results in thermal overloads of the Swartz to Alto and Alto to Basin 115kV circuit

Alternatives Considered

See "Alternatives Considered" for project 9683.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 12040: Rebuild Carson Road - Delhi 115 kV Line

Transmission Owner: Entergy Louisisana, LLC.

Project Description

Project 12040 is also located in Ouachita Parish Louisiana. This project will replace the conductor of the Carson Road to Delhi 115kV circuit. The estimated cost to implement project 12040 is $3.7 million, with an expected in-service date of June 1, 2020. Figure P12129 illustrates the contingency, resultant violation and proposed project to mitigate the reliability concerns.

Project Need

The loss of the Grand Gulf Nuclear plant creates a power sink in the area which increases flows out of the Sterlington and Perryville area to compensate. With additional loss of the Perryville to Baxter Wilson 500kV line the increased flow out of the Sterlington area is forced on the 115kV network between Sterlington and Grans Gulf. This results in thermal overloads of the Carson Road to Delhi 115kV circuit as illustrated in figure P12040. Up to 400 MW of generation curtailment is required to mitigate the constraints on the Carson Road to Delhi 115kV circuit.

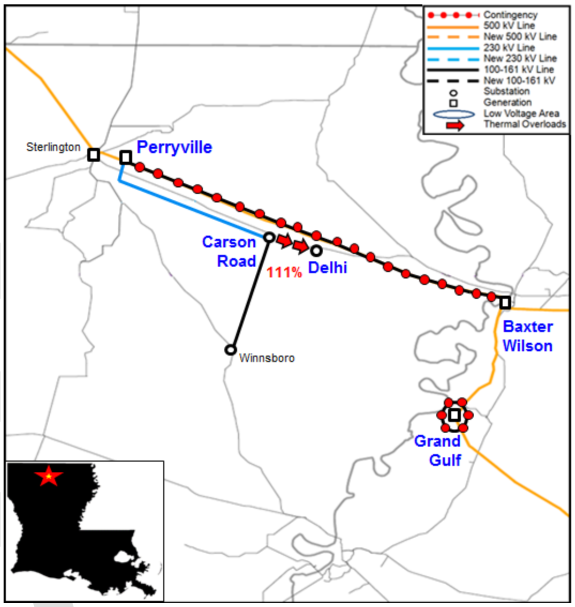


Figure P12040: The loss of Grand Gulf Nuclear generation and the Perryville to Baxter Wilson 500kV circuit results in thermal overload of the Carson Road to Delhi circuit

Alternatives Considered

See "Alternatives Considered" for project 9683.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 12037: Montgomery - Cane River 230 kV New line

Transmission Owner: ENTERGY LOUISIANA, LLC.

Project Description

The 115kV network in North-Central Louisiana shown in figure P12037 consists of the Many, Provencal, Texas East, Cane River and Winnfield substations. This area is supplied by 230kV taps at Winnfield and Fisher substations.

Project 12037 will construct a new 10 mile, 230kV line from Montgomery to Cane River, creating a new 230/115kV tap at Cane River and adding a new source to the 115kV network in the area. The estimated cost to implement project 12037 is $40.7 million, with an expected in-service date of April 1, 2020. Figure P12037 illustrates the contingency, resultant violations and project to mitigate the reliability concerns.

Project Need

Following the loss of the Fisher 230/115kV transformer, the local 115kV network is supplied by a radial feed from Winnfield. The resulting voltage at the Provencal, Many, Texas East and Cane River substations are below the 0.92 pu voltage threshold, and power flow on the Winnfield to Cane River 115kV circuit exceeds the thermal rating of the line.

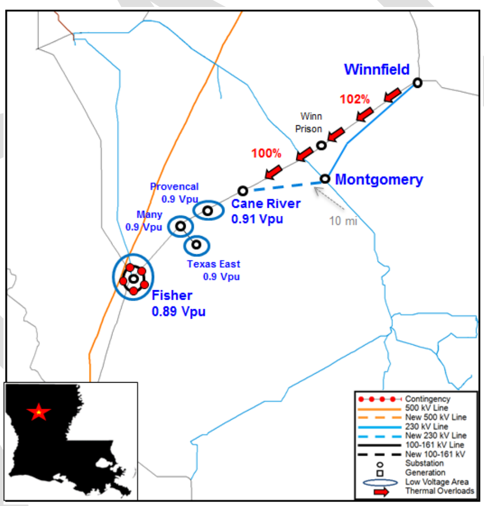


Figure P12037: Loss of Fisher 230/115kV transformer causes high loading on the Winfield to Cane River circuit and voltage beneath criteria limit at Provencal, Texas East, Many and Fisher substations

Alternatives Considered

Rather than adding a new 230kV source at Cane River, rebuilding the Winnfield to Cane River line and installing a capacitor bank at Cane River was considered. Rebuilding the Winnfield to Cane River 115kV line would require 26 miles of rebuild compared to 10 miles of new conductor specified in project 12037. Additionally, adding a second source to this area is preferred for the long-term loading relief on the Winnfield and Fisher sources.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 12076: New Mud Lake to Big Lake 230 kV Line

Transmission Owner: ENTERGY LOUISIANA, LLC.

Project Description

Project 12076 is located in Calcasieu Parish, which includes the cities of Lake Charles and Sulphur. The transmission network in this area contains 500, 230, 138 and 69kV networks. The 500kV access points are at Nelson and near Carlyss, and generation plants at the Nelson, Calcasieu and PPG substations, are the primary power suppliers in this area. The 230kV network forms three loops between Carlyss and Nelson substations.

This project will construct a 10 mile 230kV line from Mud Lake substation to Big Lake substation. The estimated cost to construct the new line is $23.6 million, with an expected in-service date of June 1, 2021. Figure P12076 illustrates the contingency, resultant violations and project to mitigate the reliability concerns.

Project Need

Following the loss of two 230kV transmission lines in the area, the Moss Bluff through Boudoin substations are supplied radially out of Nelson. The resulting flows cause the Moss Bluff to Solac 230kV lines to exceed their thermal capacity by up to 132%, first observed in 2022 summer scenario. Up to 750 MW of nonconsequential load loss are needed to mitigate this issue.

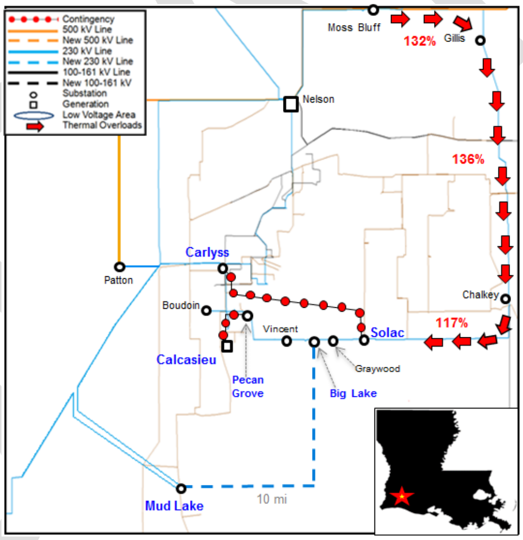


Figure P12076: Loss of Carlyss to Solac and Calcasieu to Pecan Grove circuits results in 117-132% loading on the Moss Bluff-Gillis-Chalkey-Solac circuits

Alternatives Considered

Alternatively, a 15 mile transmission line from Patton to Big Lake was considered. The line length and routing resulted in a higher cost when compared to project 12076. This alternative was rejected due to the higher cost to implement.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 12079: Lake Charles 138/69kV Transformer Upgrade

Transmission Owner: ENTERGY LOUISIANA, LLC.

Project Description

Project 12079 is located in Calcasieu Parish, which includes the cities of Lake Charles and Sulphur. The transmission network in this area contains 500, 230, 138 and 69kV networks. The 69kV network is primarily supplied by 230kV and 138kV taps at Mossville, Carlyss, Lake Charles Bulk and Solac substations.

This project will replace the two parallel 138/69kV transformers at the Lake Charles Bulk substation. The cost to replace the two transformers is $6.3 million, with an expected in-service date of June 1, 2020. Figure P12079 illustrates the contingency, resultant violations and project to mitigate the reliability concerns.

Project Need

Following the loss of one 138/69kV transformer at the Lake Charles Bulk substation, the remaining unit exceeds its thermal capacity by 103%. This need was first observed in the 2027SUM scenario.

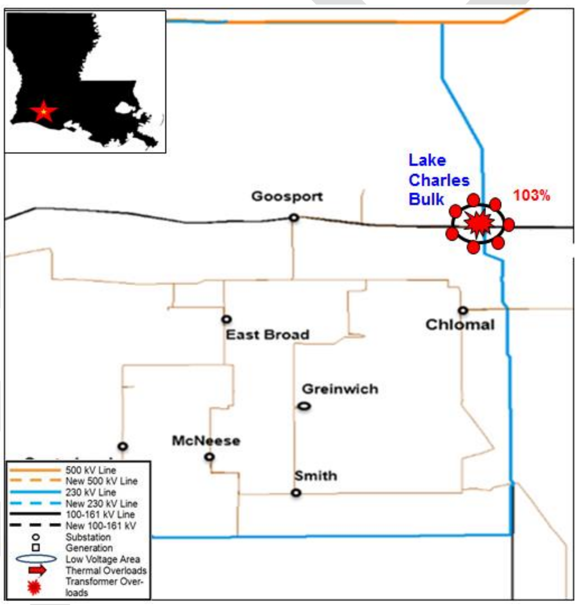


Figure P12079: Loss of Lake Charles Bulk transformer #1 or #2 results in the other exceeding its thermal limit

Alternatives Considered

Adding a third transformer was considered in lieu of replacing the two transformers at Lake Charles Bulk substation. However, the substation expansion and the addition of a third transformer resulted in a higher cost.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 12112: North ALP Project

Transmission Owner: ENTERGY LOUISIANA, LLC.

Project Description

Project 12112 is located in Lafayette Parish Louisiana. The area contains 230, 138 and 69kV networks, as well as 100 MW of generation resources at the Labbe generation plant.

This project will create two new 230/138kV taps in the area. The first new tap point is a new substation called Cankton, which will be constructed at the intersection of the Wells to Labbe 230kV line and the Colton to Bloomfield 138kV line. Both lines will be cut into the new substation. The second tap requires a new 230kV line to be built from Cankton to the existing 138kV Cecelia substation. 230/138kV transformers will be installed at both the Cankton and Cecelia substations. Figure P12112 illustrates the contingency, resultant violations and project to mitigate the reliability concerns. The estimated cost to implement project 12112 is $65 million, with an expected in-service date of December 1, 2021.

Project Need

Following a bus tie breaker fault at the Scott substation, multiple 138kV lines extending from Scott are removed from service. This contingency results in a thermal overload of the Scott to Cecelia circuit and voltage below the local planning criteria threshold at the Cecelia substation. These violations were observed in the 2027 summer scenario and illustrated in figure P12112.

Additionally, the loss of Delcambe to Moril and Meaux to Sellers Road – NERC TPL Category P6 Contingency – results in thermal overloads of Judice to Scott and Judice to Meaux 138kV circuit up 132%, observed in the 2019 summer scenario. This contingency results in over 300 MW of nonconsequential load loss. Project 12112 is part one of a two phase project to mitigate the load at risk following this contingency.

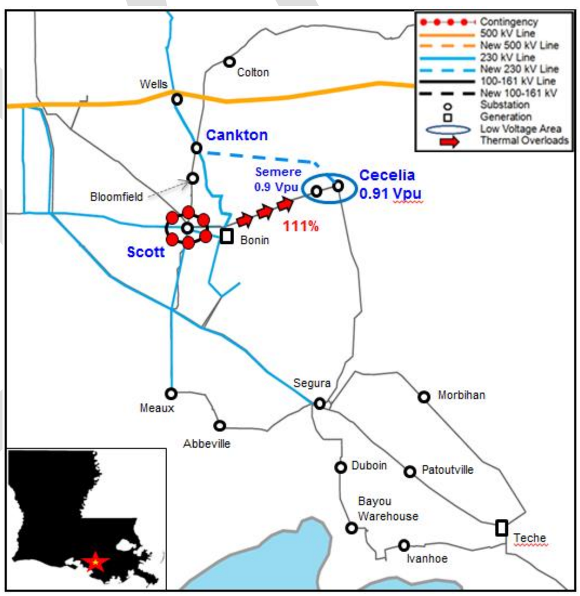


Figure P12112: A bus tie breaker fault at the Scott substation results in thermal overload of the Bonin to Cecelia 138kV line and voltage below criteria threshold at the Cecelia substation

Alternatives Considered

Alternatively, a rebuild option was considered. This alternative would have rebuilt the Scott substation, the Cecelia to Bonin 138kV line, the Scott to Semere 138kV line, the Champagne to Sunset 69kV line and the Richard to Colonial Academy 138kV line.

The rebuild option was rejected based on a higher cost to implement, numerous outages required to implement and project 12112 provides additional operational flexibility compared to this alternative.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project P4608: Reconductor Five Points to Tap 69kV line

Transmission Owner: ENTERGY LOUISIANA, LLC.

Project Description

Project 4608 is located in Lafayette Parish. The transmission network in the area consists of 230, 138 and 69kV circuits. A section of the 69kV network in the area, consisting of Leblanc, Texas Erath and Five Points substations is illustrated in figure P4608. These 69kV substations are supplied by 138kV taps at Meaux and Moril substations.

This project will replace the line conductor of the five mile Five Points to Tap Point 281 transmission line. The estimated cost of the Reconductor is $4.7 million, with an expected in-service date of December 1, 2020. Figure P4608 illustrates the contingency, resultant violations and project to mitigate the reliability concerns.

Project Need

Loss of either the Moril to Leblanc or Meaux to Five points circuit sections results in the Five Points, Leblanc and Texas Erath 69 substations to be supplied radially from the opposite end. The Five Points to Line Tap 281 reaches 99% capacity in the 2022 summer scenario, and 111% of capacity in the 2027 summer scenario, following the loss of the Moril to Leblanc circuit section.

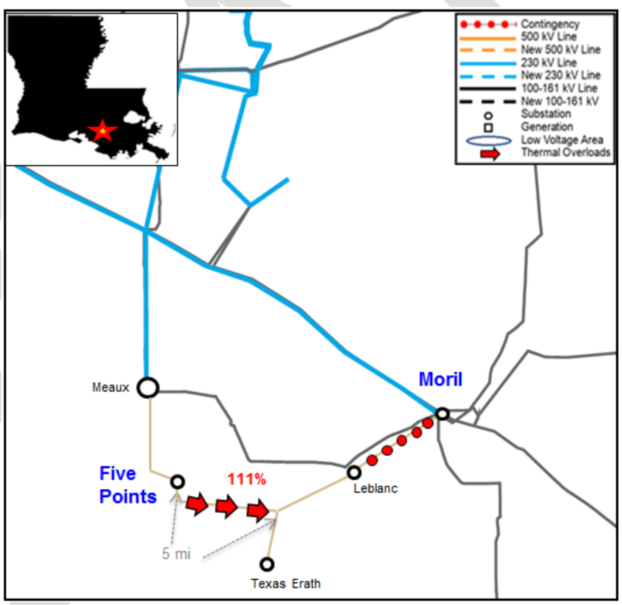


Figure P4608: An open breaker at the Moril substation on the Moril Leblanc 69kV line causes the Five Points to Leblanc circuit to exceed its limit

Alternatives Considered

Constructing a second Moril to Leblanc 69kV circuit was considered in lieu of project 4608. However, this alternative resulted in a higher cost when compared to project 4608.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 9766: Reconductor Gloria to Flannery REA 69 kV Line
Transmission Owner: ENTERGY LOUISIANA, LLC.

Project Description

Project 9766 is located in the East Baton Rouge Parish of Louisiana. This area contains 230 and 69kV transmission networks. The local 69kV network is primarily supplied by 230kV taps at Harrelson, Coly and Jaguar substations.

This project will replace the conductor of the Gloria to Flannery 69kV transmission line. The estimated cost to replace the 3.5 miles of conductor is $2 million, with an expected in-service date of June 1, 2019. Figure P9766 illustrates the contingency, resultant violations and project to mitigate the reliability concerns.

Project Need

The Gloria, Harrelson, Flannery and Sharp 69kV substations form a 69kV loop in East Baton Rouge Parish. Loss of the Harrelson to Tap 369 69kV breaks the loop and causes increased flow on the remaining portion. This contingency results in the Gloria to Flannery circuit section to exceed its capacity to 103%, first identified in the 2022 summer scenario.

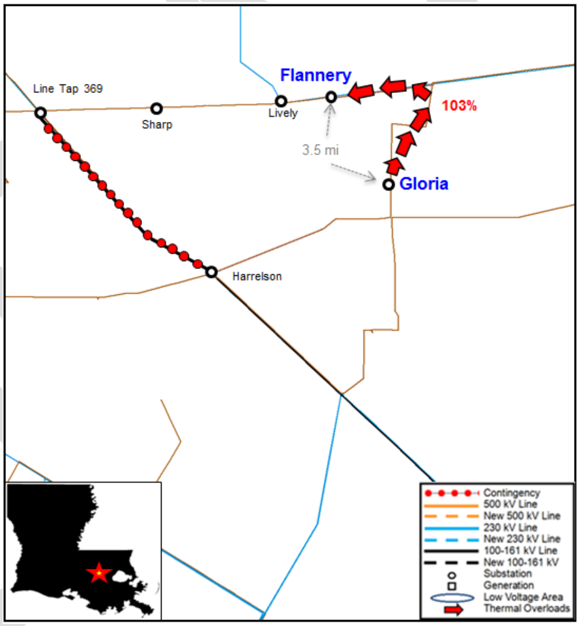


Figure P9766: Gloria to Flannery 69kV circuit overload to 103% for an open breaker at the Harrelson substation on the Harrelson – Tap369 69kV line

Alternatives Considered

Alternatively, constructing a new transmission line from Harelson to Sharp, which would parallel the contingency described above, was considered to mitigate this reliability concern. However, the new circuit resulted in a higher cost the implement when compared to project 9766.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 9781: Reconductor Jennings to Lawtag 69kV Line

Transmission Owner: ENTERGY LOUISIANA, LLC.

Project Description

Project 9781 is located in the Jefferson Davis Parish of Louisiana. The local area consists of 138 and 69kV transmission networks. The local 69kV network is supplied by 138kV taps at the Jennings and Meaux substations.

This project was reviewed through the MISO Expedited Review process. The Expedited Review process was necessary to facilitate a new delivery point request by the Jefferson Davis Electric Cooperative (JDEC).

Project 9781 will replace the conductor of two parallel 69kV transmission lines, each approximately 5 miles long. The estimated cost to replace the conductor of the two lines is $7.9 million, with an expected in-service date of 6/1/2020.

Project Need

The Jennings to Lawtag 69 kV transmission line will exceed its thermal rating during the single contingency, breaker to breaker loss of the Jennings to Lawtag 69 circuit. Prior to the JDEC Lyle substation, thermal loading of 98% was observed on the Jennings to Lawtag line - for the loss of the parallel 69kV circuit - in the 2022 summer scenario. The loading of the Jennings to Lawtag line increases to 131% following the new delivery point and same contingency.

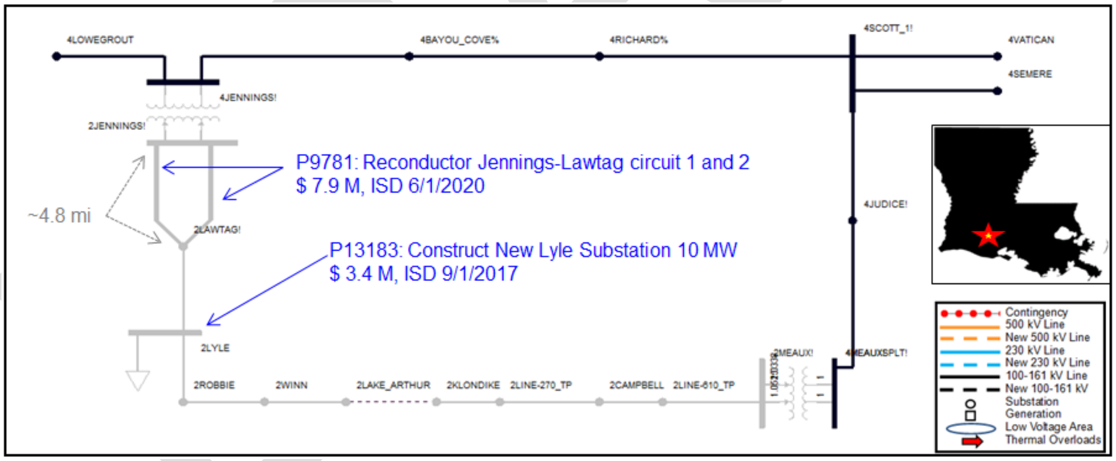


Figure P9781: The loading of the Jennings to Lawtag line increases to 131% following the new delivery point and the loss of the parallel circuit

Alternatives Considered

None

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Generator Interconnection Projects

These are projects that are required by generator interconnection agreements.

GI ID	ID	Name	Description	ISD	Cost ($M)
J396	12774	Saint Charles Power Station Interconnection	Generation interconnection projects needed for Saint Charles Power Station.	6/1/2018	$25.5 M
J396	12142	Snakefarm to Labarre 230 kV: Upgrade station equipment	Generation Interconnection Project. Upgrade the line bay bus to a minimum of 1608 Amps matching conductor rating.	6/1/2018	$20,000

Cost Allocation

These projects are classified as Generation Interconnection projects and are all below 345 kV, which are not eligible for regional cost sharing.

New Delivery Points

Several projects were proposed to facilitate new points of delivery; these either serve new loads, give new point of connection, or upgrade existing points of delivery.

ID	Name	Description	ISD	Cost ($M)
9689	Beekman: New distribution substation	Construct a new 115 kV substation on the North Bastrop - Crossett North 115 kV line.	6/1/2020	$7.9 M
12136	Cullichia 230 kV: New substation	Construct a new 230 kV substation to replace the existing Arabi substation.	12/31/2018	$18.1 M
12138	Robert 230 kV: New substation	Construct a new 230 kV substation to serve load growth in the area.	4/1/2019	$58.8 M
12743	Fairbanks 115 kV: Construct new substation	Construct new 115 kV distribution substation on the Sterlington - Swartz 115 kV line circuit.	5/1/2020	$10.9 M

12768	Bayview 69 kV: New Substation	Build new distribution substation	12/1/2019	$5.9 M
12770	Kim Street 230 kV: New Substation	Build new distribution substation	6/1/2019	$10 M
13183	JDEC Lyle 69 kV: New substation	Construct new 69 kV substation on the Lawtag - Robbie 69 kV line.	12/1/2017	$3.4 M
13184	SLEMCO Roux: New substation	Construct new 69 kV substation along the New Iberia-Line Tap 625 circuit	10/1/2017	$ 1.25 M

Cost Allocation

These projects are classified as Other projects, which are not eligible for regional cost sharing.

Substation Equipment Replacement

These projects are needed to increase operational flexibility and to replace substation equipment limiting the capacity of transmission line conductor.

ID	Project Name	Description	Expected ISD	Cost
9789	Port Hudson 230-69 kV: Upgrade T6 station equipment	Upgrade substation equipment on the T6 autotransformer to utilize the full	11/1/2017	$21,435
12082	Goosport to L271 TP to East Broad 69 kV: Upgrade Line	Upgrade line switches at Goosport and Gillis Gas Tap to 1200 A. The new limit will be the conductor at 93 MVA.	6/1/2020	$163,832
12110	Meaux 138 kV: Install new breaker	Install new breaker at the Meaux 138 kV substation.	12/1/2018	$582,418
12120	Waterford to Raceland 230 kV Upgrade Line	Upgrade the line bay riser at Waterford 230 kV to a minimum of 1600 Amps.	6/1/2019	$76,808
12544	Pecue 230 kV: Install transmission breakers	Install line breakers at the Pecue substation.	12/31/12017	$325,000
12108	Moril Transformer Upgrade	Upgrade the CTs on the Moril 138-69 kV Auto	6/1/2018	$134,250.00

Project Needs

P9789: The Port Hudson 230/69 kV T6 autotransformer overloads for a (P2.4) breaker failure at Port Hudson 138 kV. This project will upgrade all station equipment on the 69 kV side of the transformer to utilize the full capacity of the transformer.

P12082: The loss of the Solac to Contraband 69 kV line results in a thermal overload of the Goosport to East Broad 69 kV line section. Upgrading terminal equipment will increase the thermal rating of the Goosport to East Broad 69kV circuit.

P12110: A Bus-tie breaker failure at the Meaux 138 kV substation causes a thermal violation on the Moril 138-69 kV auto and results in low voltage at multiple 69 kV substations in the area.

P12120: A Breaker Failure contingency at Waterford 230 kV causes a thermal violation on the Waterford to Raceland 230 kV line. Upgrading the line bay riser will increase the thermal rating in order to alleviate the thermal violation.

P12544: Installing line breakers at the Pecue substation to enhance system performance and operational flexibility.

P12108: The loss of the Meaux to Five Points 69 kV line overloads the Moril 138-69 kV Auto-transformer. This project will alleviate the overload by upgrading the CT on the Auto to achieve the full 100 MVA rating of the transformer.

Cost Allocation

These projects are classified as Other projects, which are not eligible for regional cost sharing.

Entergy New Orleans, Inc. (ENO)

This section contains two projects submitted by Entergy New Orleans as Target Appendix A in the MTEP17 cycle.

Project 12133: Gulf Outlet 115kV Capacitor Bank

Transmission Owner: Entergy New Orleans, Inc.

Project Description

Project 12133 is located in the Orleans Parish of Louisiana, within the Down Stream Gypsy load pocket. The Down Stream Gypsy load pocket consists of 230 and 115kV transmission networks. Local generation is supplied by the Ninemile generation plant, which consists of three active generation units. The eastern side of the DSG load pocket contains a 115kV loop which includes NASA, Gentilly, Bayou Sauvage and Gulf Outlet substations. This local 115kV network is primarily supplied by a 230kV tap at the Michoud substation.

This project will install a 30.5 MVAR capacitor bank at the Gulf Outlet 115kV substation. The capacitor bank will add VAR support to the 115kV loop that includes Gulf Outlet. The estimated cost to install the capacitor bank is $1.1 million, with an expected in-service date of December 1, 2019. Figure P12133 illustrates the contingency, resultant violation and proposed project to mitigate the reliability concerns.

Project Need

Following a Bus Fault contingency at the Michoud substation, the NASA, Gentilly, Bayou Sauvage and Gulf Outlet substation are supplied radially from Paterson substation. Voltage levels at NASA, Gentilly, Bayou Sauvage and Gulf Outlet range from 0.88 – 0.89 V p.u. following this contingency, first observed in the 2022 summer scenario.

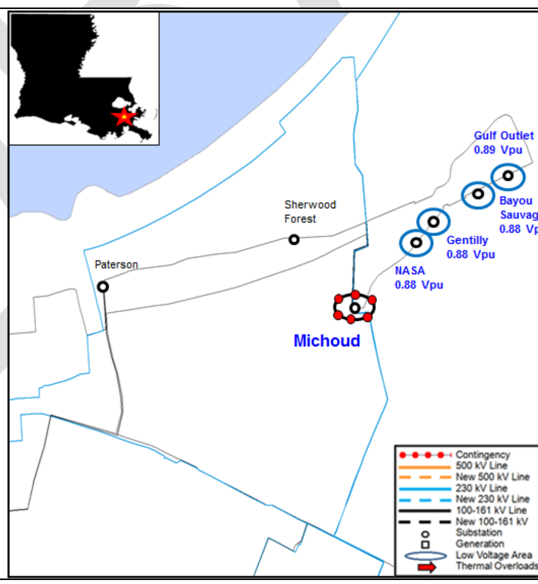


Figure 12133: Voltage levels at NASA, Gentilly, Bayou Sauvage and Gulf Outlet range from 0.88 – 0.89 V p.u. for a breaker failure at the Michoud substation

Alternatives Considered

Reconfiguration of the Michoud substation in order to eliminate the loss of transmission elements following a bus fault was considered. However, this alternative was found to be cost prohibitive when compared with the installation of a capacitor bank.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Generator Interconnection Projects

These are projects that are required by generator interconnection agreements.

GI ID	ID	Name	Description	ISD	Cost ($M)
J396	12056	Midtown to Almonaster 230kV Line Upgrade	Upgrade the Almonaster to Midtown 230 kV line to a minimum of 1600 A.	12/30/2017	$5.9 M

Cost Allocation

These projects are classified as Generation Interconnection projects and are all below 345 kV, which are not eligible for regional cost sharing.

Cleco Power, LLC. (CLEC)

This section contains the single project for Cleco Power in the MTEP17 cycle.

Project 12985: Bayou Vista – Teche – Segura 230kV Circuit

Transmission Owner: Cleco Power, LLC.

Project Description

Project 12985 is located in the St. Mary and Iberia Parishes of Louisiana. The 138 kV network in these Parishes connects the Lafayette load center and Amite South load pocket along the Gulf of Mexico. A portion of this network, illustrated in figure P12985, between Segura and Bayou Vista contains 115 miles of 138kV conductor and over 350 MW of peak demand.

This project will construct two 230kV transmission lines, a 230kV substation and install one 230/138kV transformer. The 230kV substation and 230/138kV transformer will be placed at the existing Teche 138kV substation, which is the location of the recently retired Teche Generation Unit 3. A 25 mile, 230kV transmission line from Segura to Teche and a 22 mile, 230kV transmission line from Bayou Vista to Teche will be used to connect the new substation at Teche to the Lafayette load center and the Amite South load pocket.

The estimated cost of the two 230kV transmission lines, the 230kV substation and 500MVA 230/138kV transformer is $90 million. The expected in-service date of this project is June 1, 2021.

Project Need

The local 138kVnetwork between Segura and Bayou Vista substations, illustrated in figure P12985, becomes constrained when two of the four transmission lines supplying the area are removed from service.

Following the failure of a breaker at the Segura substation - NERC TPL Category P2 Contingency - the Segura to Hopkins and Segura to Moril 138kV transmission circuits are removed from service. The resultant loading on the remaining two feeds into the area causes an overload on Moril to Duboin 138kV line of 103%, first observed in the 2019 Light Load scenario.

Following the failure of a transmission structure in the area – NERC TPL Category P7 Contingency - the Hopkins to Segura and Hopkins to Moril 138kV lines are removed from service. Loss of these two transmission circuits results in 130% loading of the Moril to Duboin 138kV circuit and 111% loading of the Duboin to Bayou Warehouse 138kV circuit. Both overloads were first observed in the 2019 summer scenario, but appear in all 8 MTEP scenarios studied.

Following the independent loss of the Hopkins to Segura and Hopkins to Moril 138kV transmission circuits – NERC TPL Category P6 Contingency - the Moril to Duboin 138kV circuit reaches 130% of capacity, the Duboin to Bayou Warehouse 138kV circuit reaches 111% of capacity and the Bayou Warehouse to Ivanhoe circuit reaches 97% of capacity. All three overloads were first observed in the 2019 summer scenario, but appear in all 8 MTEP scenarios studied. The application of this contingency to 2019 summer scenario results in 1000MW of generation curtailment and 52 MW of nonconsequential load loss.

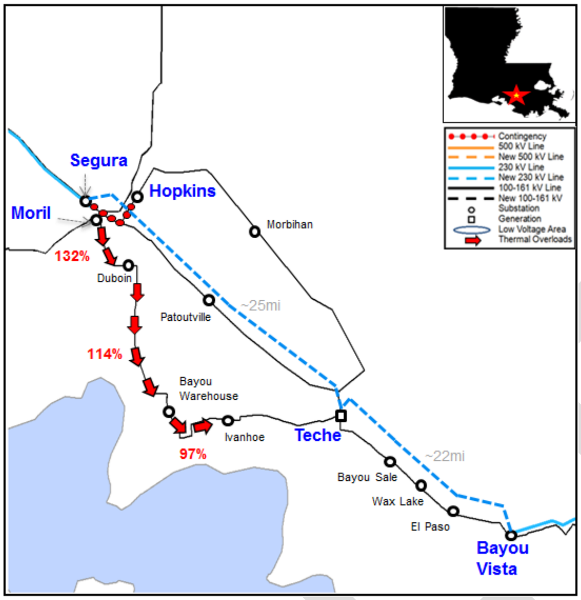


Figure P12985: Moril to Ivanhoe 138kV lines overload for the loss of Moril to Hopkins and Hopkins to Segura 138kV lines

Alternatives Considered

In lieu of project 12985, a rebuild and reconfigure alternative was considered. In order to mitigate the thermal issues observed by the breaker failure at Segura and the Transmission Structure Failure loss of the Moril to Hopkins and Hopkins to Segura circuits, the Segura substation would require a reconfiguration and the Hopkins to Segura and Hopkins to Moril transmission lines would be rebuilt with independent structures.

Additionally, 22 miles of transmission line conductor, from Moril to Ivanhoe, would require upgrade due to the thermal issues resulting for the independent loss of the Moril to Hopkins and Hopkins to Segura transmission lines.

This alternative was rejected due to the number of transmission outages required to implement, cost considerations and remaining potential reliability concerns on the remaining 138kV circuits supplying the area. A new 230kV source at Teche provides additional operational flexibility and longevity by reducing the demand placed on all facilities supplying the area.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

MISO South Market Congestion Planning "Other" Projects

In the MISO Louisiana region, one project is recommended as economic "Other" projects. This project provides quantifiable economic benefits addressing market competition and efficiency needs with production cost savings in excess of their costs and a benefit-to-cost ratio above 1.25. The project is sub-345 kV and does not qualify for regional cost allocation as MEPs based on the voltage rating. Cost of this project is directly assigned to the local Transmission Owner Pricing Zone.

Project 13999: Substation equipment upgrades at the existing Carlyss substation

Transmission Owner: Entergy Louisiana, LLC.

Project Description

The estimated cost of project 13999 is $500,000, with an expected in-service date in the year of 2020.

For full details of the network upgrades associated with project 13999 please see section 5.3 of the MTEP report.

Project Need

For full details of the economic justification of project 13999 please see section 5.3 of the MTEP report.

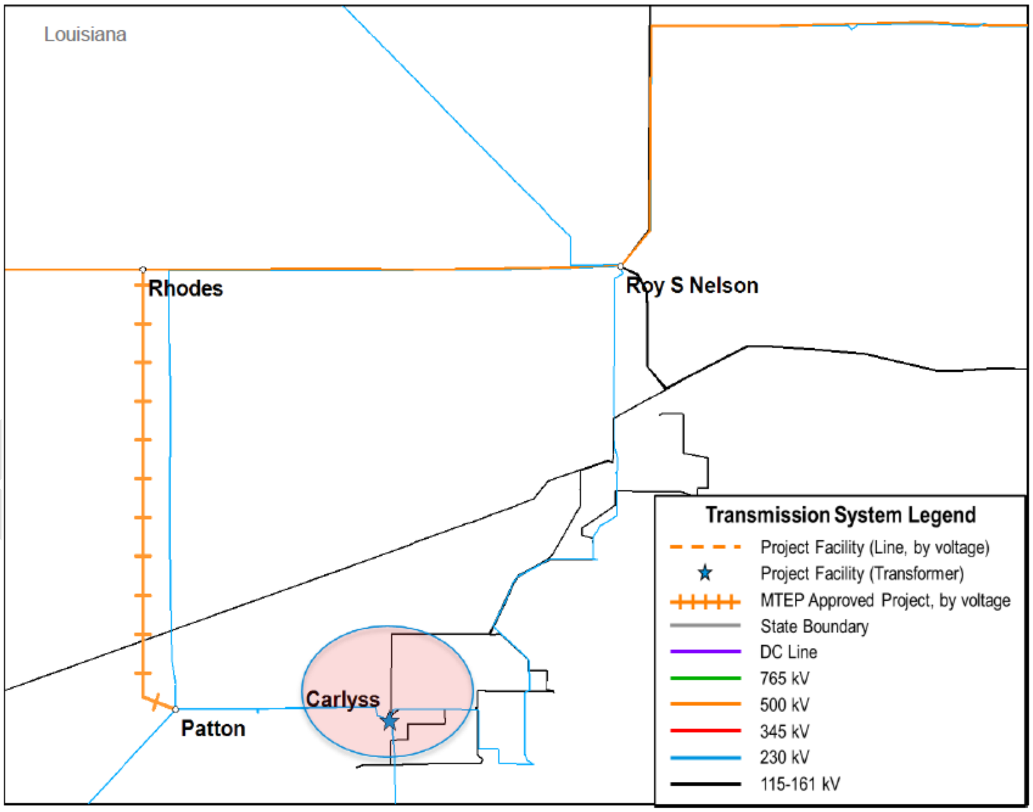


Figure P13999

Cost Allocation

This is an Other - Economic Project, which is not eligible for cost sharing.

Region Mississippi

Regional Information

MISO-Mississippi is a network of generation resources, largely consisting of rural loads, and load centers interconnected through an array of 500-115 kV transmission networks. There is also a significant 69 kV network interspersed across part of the footprint.

MISO-Mississippi consists of a diverse generation profile, such as nuclear, gas, solar and coal units that fuel the larger load centers include Jackson, Hattiesburg, Natchez, Vicksburg and Greenville regions. The latter three are located near the Mississippi River and have transmission lines that cross over the river and into Louisiana or Arkansas (Figure MS-1).

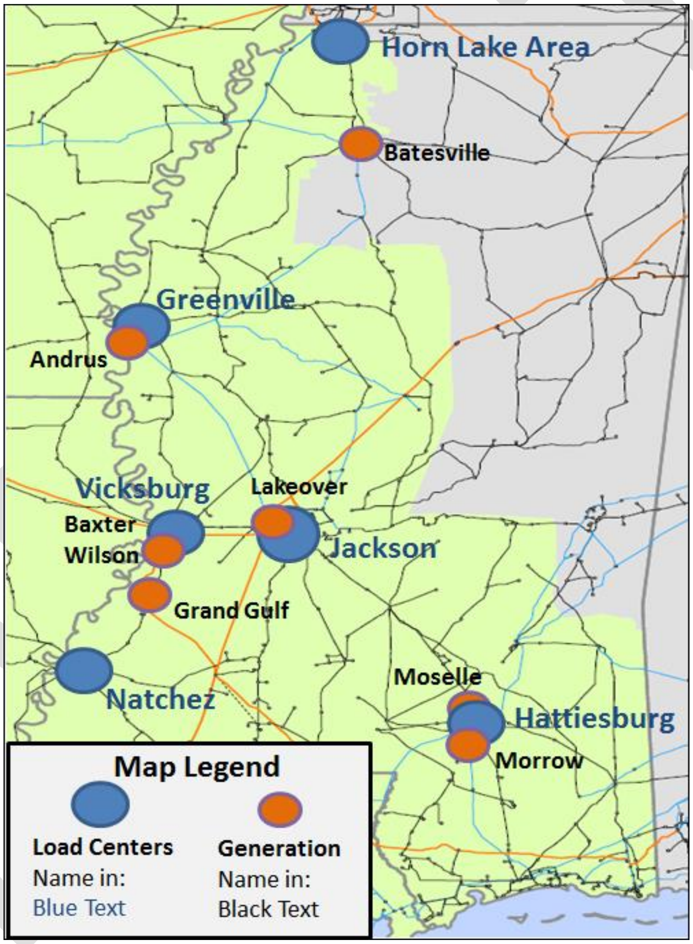


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Figure MS-1: Geographic Transmission Map of Mississippi Area

The projects proposed in the current MTEP17 cycle are part of a continuing effort to strengthen the existing transmission network. For instance, projects were proposed to reconfigure substations or add breaker stations to avoid breaker or bus events occurring on the system that had the potential to cause load loss. Several projects were proposed to facilitate new points of delivery; these either serve new loads, give new point of connection, or upgrade existing points of delivery.

Transmission Profile

The transmission network within the footprint of MISO-Mississippi covers approximately 3,800 miles of the 115 kV to 500 kV bulk electric system (BES). An additional 1,000 miles is dedicated as the 69 kV network.

Major transmission hubs - such as McAdams, Lakeover, Ray Braswell, Franklin, Grand Gulf, and Baxter Wilson, interconnected via a network of 500 kV circuits form the backbone of the MISO-Mississippi transmission network.

Load Profile

According to the 2019 Summer Peak model estimates, load within MISO-Mississippi footprint is held at approximately 5 GW.

Generation Profile

The generation portfolio MISO-Mississippi mainly constitutes a mix of nuclear, coal, Combined Cycle Gas Turbines (CCGT), and gas units. Currently, the system holds about 8.2 GW of generation capacity. The major sources constituting this profile are Grand Gulf, Gerald Andrus, and Baxter Wilson.

Overview of Projects

There are a total of 18 projects in Mississippi that are seeking approval for the MTEP17 cycle. The projects designations are as follows: six baseline reliability and 12 other (Distribution Reliability) projects. Figure MS-2 illustrates the approximate geographic locations of the projects submitted as Target Appendix A in the current MTEP cycle.

Total cost for all projects in Mississippi is $153.61 million. The breakdown by costs ranging from less than $1 million, between $1 and $5 million, and projects greater than $5 million are as follows: three projects have an estimated cost of less than $1 million; six projects are in the cost range of $1 to $5 million, and nine have cost estimates greater than $5 million. Project breakdown by estimated in-service date and cost range can be seen in Figures MS-3 and MS-4.

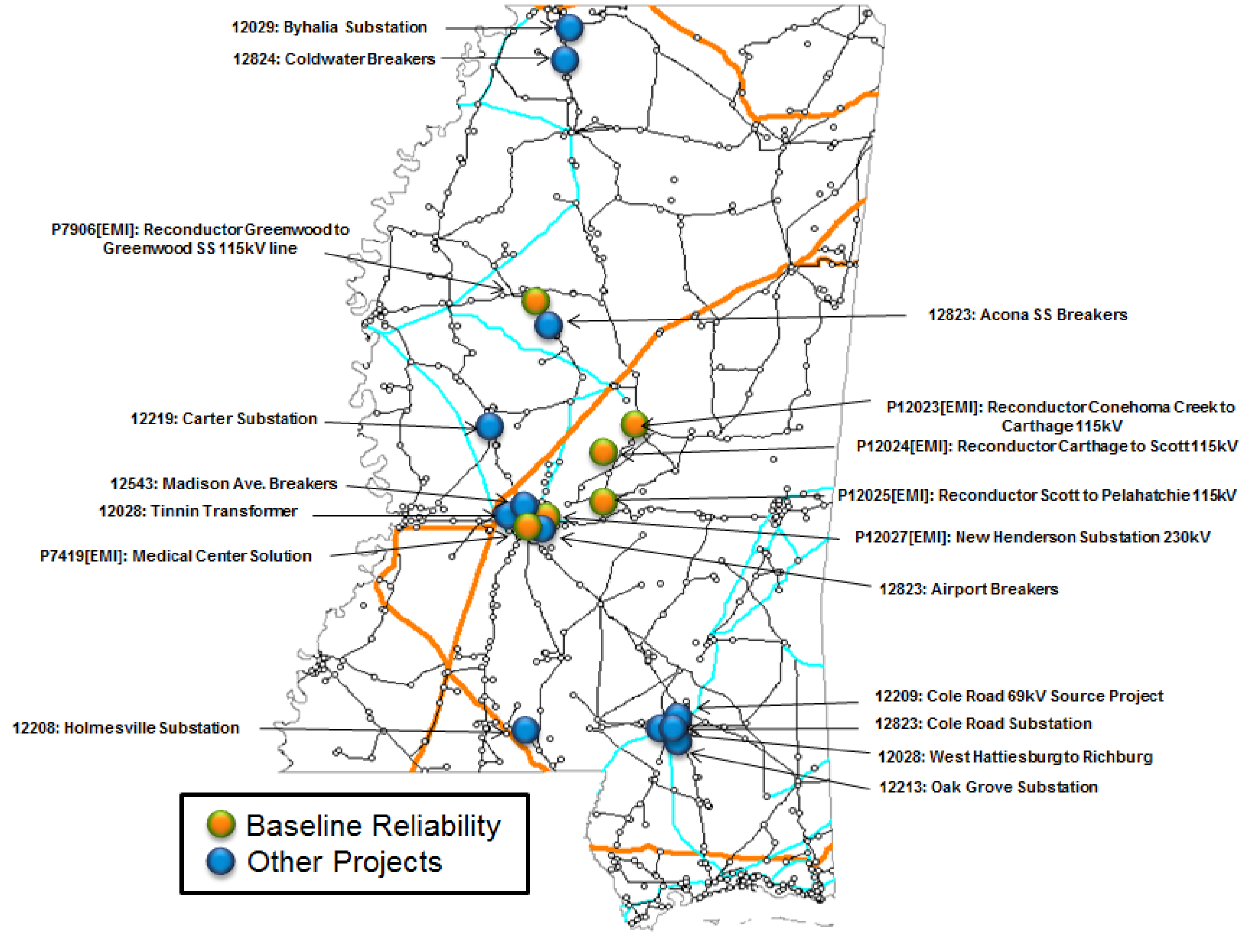

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Figure MS-2: Geographic Transmission Map of Mississippi with Project Locations

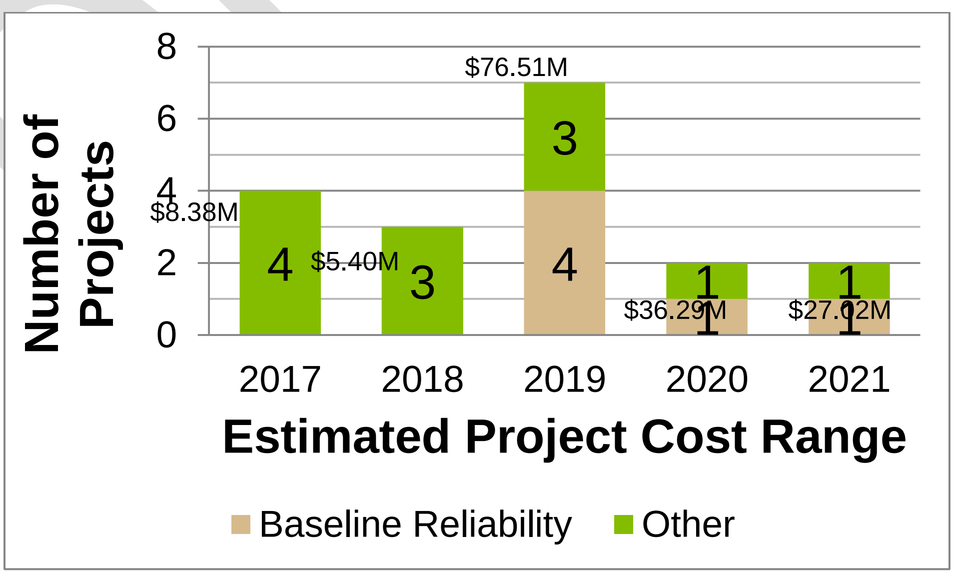

Figure MS-3: Project Type and Estimated In-Service Date

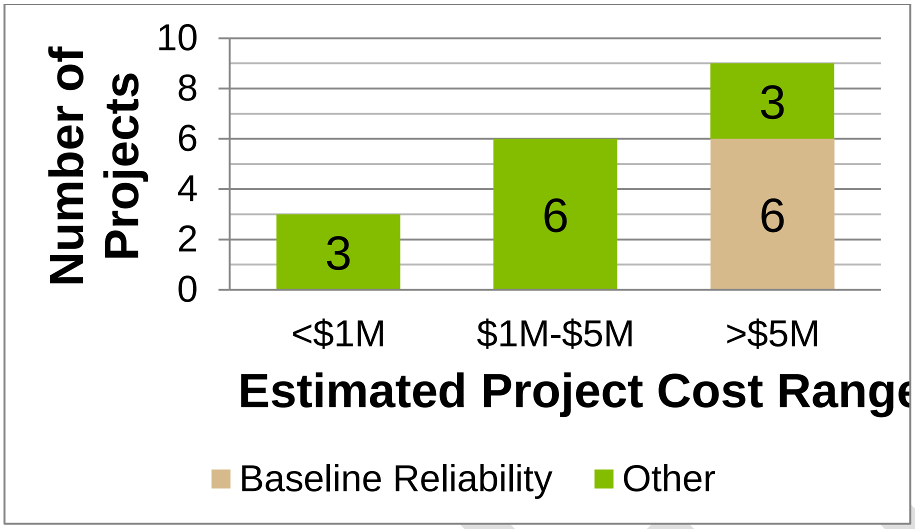

Figure MS-4: Cost Range by Project

Entergy Mississippi Inc. (EMI)

Baseline Reliability Projects

Project 7906: Greenwood to Greenwood SS 115 kV Line Upgrade

Transmission Owners: Entergy Mississippi Inc.

Project Description

Project 7906 is located near the eastern edge of Entergy Mississippi's system. One source to the 115 to 230kV Bulk Electric System (BES) is the McAdams Substation. Flow into the area is supplied via the 500kV from the Attala (MISO), Choctaw (TVA), and Reliant (TVA) units to McAdams 500kV substation.

The 115 kV Greenwood bus has four transmission circuits; three of which flow into Greenwood to support the northward flow. Generation from Attala, Choctaw (TVA), and Reliant (TVA) units contributes to the flow on the Pickens to Greenwood 115kV circuit. The line segment from Greenwood to Greenwood SS currently has a rating well below the rest of the circuit at 70MVA.

The project consists of upgrading the Greenwood to Greenwood SS 115kV line from 70MVA to at least 239MVA. The total estimated cost of this project is $13.1 million. The expected in service date for this project is June 2019.

Project Need

The single element loss of Choctaw to Clay 500kV Line increases flow on the 500kV circuit from TVA into MISO which results in the overload of the Greenwood to Greenwood SS 115kV line, as seen in Figure P7906. The earliest overload of 139% was observed in the 2019LL model. There are multiple double element contingency events that cause overloads.

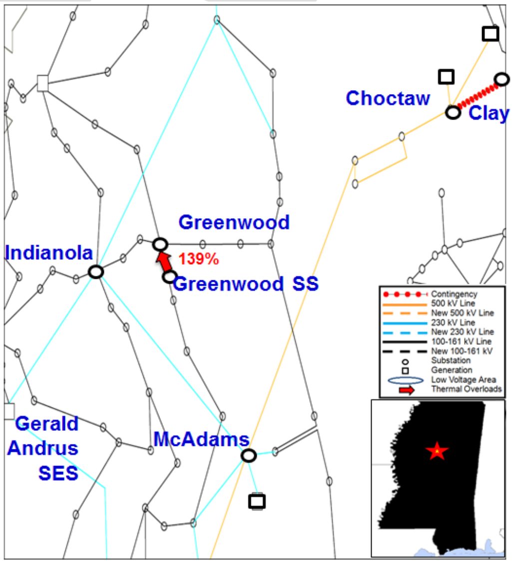

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Figure P7906: Contingency and Overload for Greenwood 115kV Line

Alternatives Considered

Build parallel line from Greenwood to Greenwood SS. The cost of building a parallel line would be considerably more than to upgrade the line.

Cost Allocation

This is a Baseline Reliability Project which is not eligible for regional cost sharing.

Projects 12023, 12024, and 12025: Conehoma Creek to Carthage, Carthage to Scott, and Scott to Pelahatchie 115 kV Line Upgrades

Transmission Owners: Entergy Mississippi Inc.

Project Description

Projects 12023, 12024, and 12025 are located near the eastern edge of Entergy Mississippi's system. One source to the 115 to 230kV Bulk Electric System (BES) is the McAdams Substation. Flow into the area is supplied via the 500kV from the Attala (MISO), Choctaw (TVA), and Reliant (TVA) units to McAdams 500kV substation.

McAdams to Attala is a source to the 115kV system that runs north and south from Attala. Projects 12023, 12024, and 12025 are three line segments on the 115kV circuit that runs from Attala to Pelahatchie substations. The other source into Pelahatchie is the Rankin to Pelahatchie 115kV line. Flow out of Pelahatchie goes from Pelahatchie to Morton 115kV toward the seam with Southern Company.

This project consists of rebuilding the facilities to upgrade the line ratings to a minimum 260MVA. Facilities will be reconstructed to 230kV specifications. The total estimated cost and expected in service dates (ISD) are as follows:

Prj ID	Project Name	Estimated Cost ($M)	Expected ISD
12023	Conehoma Creek to Carthage 115kV	$ 23.3	June 1, 2019
12024	Carthage to Scott 115kV	$ 18.1	December 1, 2019
12025	Scott to Pelahatchie 115kV	$ 20.0	December 1, 2021

Project Need

The double element loss of Choctaw to Clay 500kV line and the Rankin to Pelahatchie 115kV line increases the flow on the Attala to Pelahatchie 115kV circuit. This results in overloads on the Conehoma Creek to Scott 115kV lines, as seen in Figure P712023. The earliest overload of 119% for Conehoma Creek to Carthage and 103% for Carthage to Scott was observed in the 2019 summer model. After P12023 is applied to the model the rating for Carthage to Scott 115kV increased to 107% and the Scott to Pelahatchie 115kV line increased from 98% to 102%, as seen in Figure P12025. There are other double element contingency events that cause overloads on these lines.

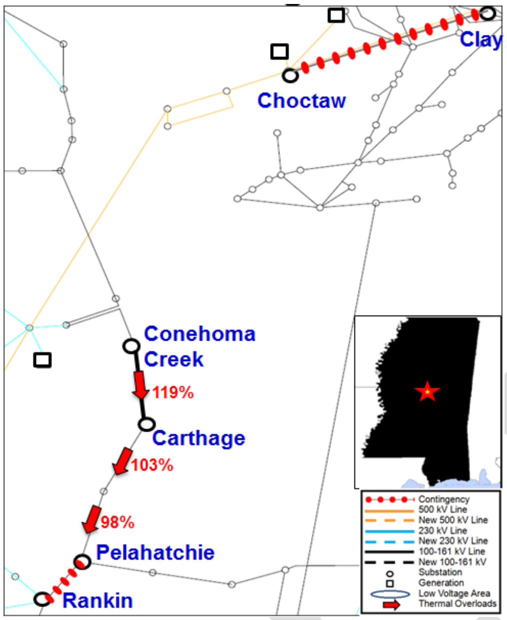

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Figure P12023: Contingency and Overload for Attala to Pelahatchie 115kV Circuit

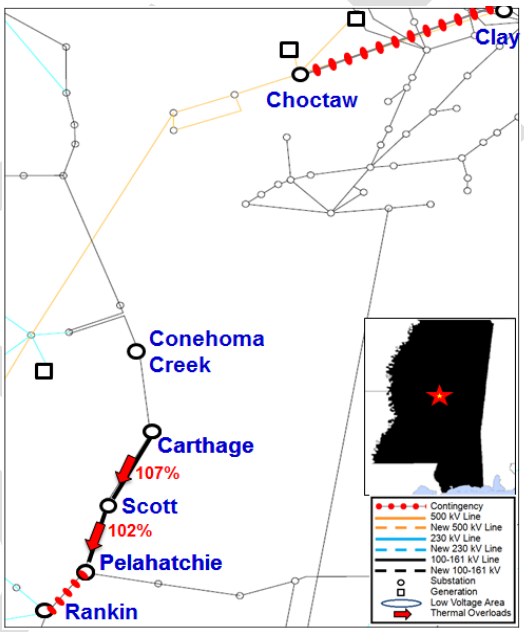

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Figure P12025: Contingency and Overload for Attala to Pelahatchie 115kV Circuit

Alternatives Considered

Construct a new 230kV line from Rankin to Pelahatchie and install a new 230/115kV autotransformer at Pelahatchie.

Cost Allocation

This is a Baseline Reliability Project which is not eligible for regional cost sharing.

Project 7914: Medical Center Solution

Transmission Owners: Entergy Mississippi Inc.

Project Description

Project 7914 is in the central Mississippi network, which includes the city of Jackson. The transmission network in this area includes 500, 230, and 115kV networks. This project consists of constructing the new Memorial 115kV breaker station on the Monument Street to Fondren 115kV line, and to construct a new 115kV line from Rex Brown to Memorial. The Rex Brown to Memorail line will utilize the existing HICO to Fondren 115kV line path, closing in a normally open path. The Memorial substation will provide a second source into the area to help support the Medical Center Complex. The total estimated cost of this project is $19.3 million. The expected in service date for this project is June 1, 2020.

Project Need

The double element loss of Rex Brown to Monument Street 115kV and the loss of the 230/15kV transformer at South Jackson will cause multiple overloads in the Jackson area, as seen in Figure P7914. The earliest these overloads are observed is in the 2019 summer model.

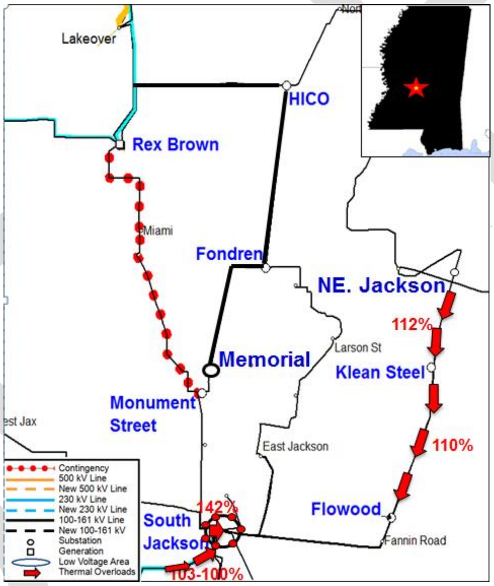

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Figure P7914: Image of Contingency and Overloads for the Jackson Area

Alternatives Considered

Rebuild the South Jackson to West Jackson 115kV line. This rebuild is not robust enough. It does address the overloads in South Jackson, but does not alleviate the Northeast Jackson to Flowood overloads. The South Jackson rebuild would also not give distribution support that would be needed to alleviate the reliability issues for the Jackson area hospitals. The proposed Medical Center Project does both.

Cost Allocation

This is a Baseline Reliability Project which is not eligible for regional cost sharing.

Project 12027: Henderson 230kV Substation

Transmission Owners: Entergy Mississippi Inc.

Project Description

Project 12027 is in the central Mississippi network, which includes the city of Jackson. The transmission network in this area includes 230, and 115kV networks. This project is on the 230kV loop that goes around city Jackson. A new Henderson 230kV substation will be constructed on the Lakeover to Rankin 230kV circuit. Breakers will also be installed along the circuit at the Luckney substation to reduce customer exposure. Load will be shifted off of the 115kV system and onto the Henderson 230kV substation. The total estimated cost of this project is $14.5 million. The expected in service date for this project is June 1, 2019.

Project Need

With the loss of Southern Company's Ratcliff Units and the loss the Rankin 115/230 transformer flows on the South Jackson to Rankin Industrial 115kV overloads to 101% as seen in Figure P12027. This line will overload for a multiple of single element contingencies that are paired with the loss of the Rankin 115/230 transformer. These overloads are seen as early as the 2019 summer model and range from 101% to 114%.

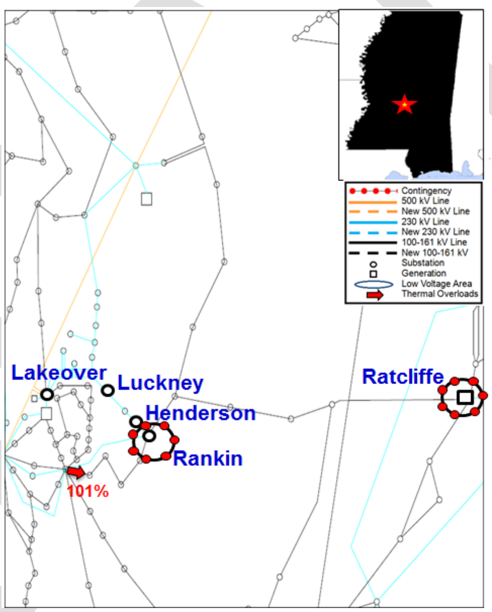

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Figure P12027: Image of Contingency and Overload for loss of Ratcliff Units and Rankin 115/230 Transformer

Alternatives Considered

Rebuild the South Jackson to Rankin Industrial 115kV line. This does not address distribution needs in the area and would likely result in additional 115 kV upgrades.

Cost Allocation

This is a Baseline Reliability Project which is not eligible for regional cost sharing.

Other Type Projects

Other Reliability

These are areas with long 115kV line circuits. Installation of breakers along these lines is necessary to improve customer reliability by reducing transmission line exposure.

Prj ID	Project Name	Description	Project Need	Estimated Cost ($M)	Expected ISD
12543	Madison Ave: Install Transmission Breakers	Installation of transmission breakers at Madison Avenue 115 kV substation on the Lakeover - Northpark 115 kV transmission line	Breakers requested along line to provide system redundancy for area distribution network in the event of a transmission line outage.	$ 0.7	10/31/2017
12823	Airport JAN 115 kV: Install transmission breakers	Installation of substation transmission breakers at the Airport JAN 115 kV substation in Brandon, MS, which is located on the South Jackson - Rankin 115 kV transmission circuit.	The South Jackson - Rankin 115 kV transmission circuit is a ~22.5 mi transmission circuit which serves approximately 18,500 customers and 153 MW of load at system peak. Installation of breakers at Airport will help to improve substation reliability for all the customers served along the line and will firm transmission service at the Airport substation, which provides electrical service to the largest commercial airport in the state of Mississippi..	$ 3.9	6/1/2018
12824	Coldwater 115kV: Install transmission breakers	Installation of substation transmission breakers at the Coldwater 115 kV substation in Coldwater, MS, which is located on the Batesville - Getwell 115 kV transmission circuit.	Installation of transmission breakers on the Batesville - Getwell 115 kV transmission line circuit will improve transmission system performance along the ~40 mi transmission circuit, serving approximately 16,900 customers and 114 MWs of load split between 4 substations.	$ 3.9	4/1/2019

Cost Allocation

These are designated as Other Projects which are not eligible for regional cost sharing

New Delivery Point

Several projects were proposed to facilitate new points of delivery; these either serve new loads, give new point of connection, or upgrade existing points of delivery.

Prj ID	Project Name	Description	Estimated Cost ($M)	Expected ISD
12028	Tinnin 230 kV: Install Transformer	Install 230/13.8 kV distribution facilities at the future Tinnin 230 kV switching station.	$ 6.62	12/31/2017
12029	Byhalia 230 kV: New distribution substation	Construct new substation in eastern Desoto County, MS along currently under-construction I-69 corridor.	$17.03	12/1/2022

Cost Allocation

These are designated as Other Projects which are not eligible for regional cost sharing

Cooperative Energy

Other Reliability Projects

Project 12018: West Hattiesburg SS to Richburg 69kV

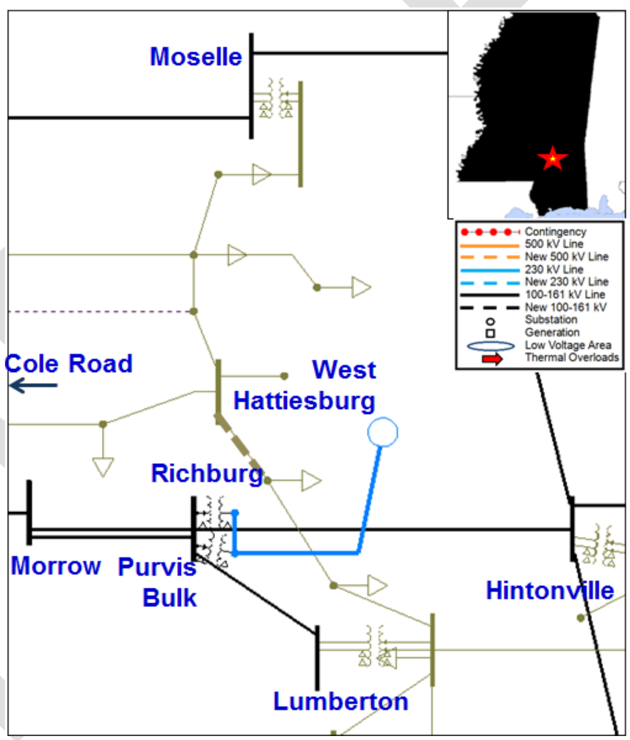
Transmission Owners: Cooperative Energy

Project Description

This project will include structural upgrades that raise the conductor height increasing operational temperature. Raising the conductor allows the West Hattiesburg S.S. to Richburg GOAB 69kV line to be operated at 71 MVA. The total estimated cost of this project is $0.1 million. The expected in service date for this project is September 1, 2017.

Project Need

Currently the West Hattiesburg S.S. to Richburg GOAB 69kV line is limited to 45MVA due to distribution line underbuilds.



PSS®E Oneline

Figure P12018: Image of Oneline for Project Area Information

Cost Allocation

This is designated as Other Projects which are not eligible for regional cost sharing

Project 12209: Cole Road 69kV Source Project

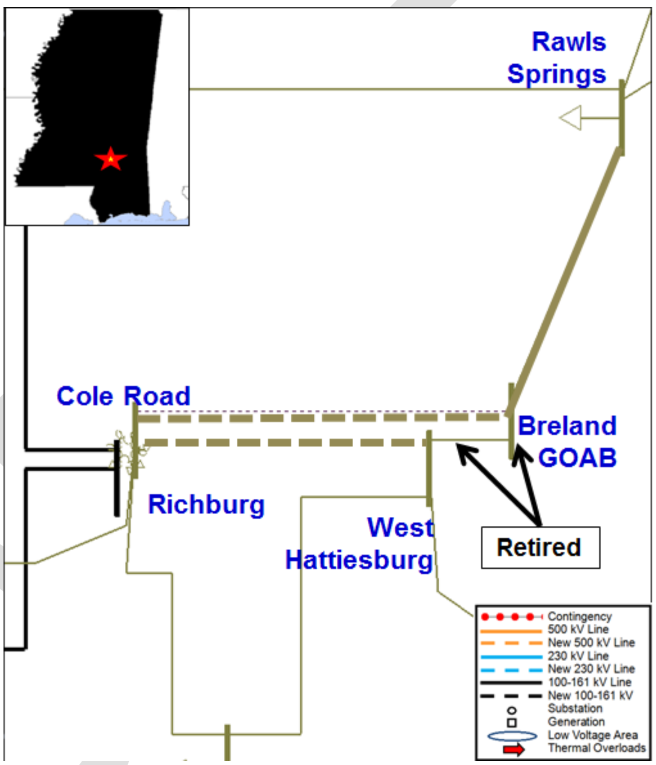
Transmission Owners: Cooperative Energy

Project Description

This project rebuilds the Cole Road to Breland 69kV line as a double circuit. The Breland to West Hattiesburg Switching station will be rebuilt, and it will loop in Rawls Springs to Breland 69kV into Cole Road substation. The Breland GOAB will be retired with the new 69kV line configuration. The total estimated cost of this project is $1.4 million. The expected in service date for this project is June 1, 2019.

Project Need

The Cole Road substation currently has two 69kV sources, one of which is normally open and cannot be energized without being rebuilt. A second 69kV source at Cole Road increases system reliability and support to the surrounding area.



PSS®E Oneline

Figure P12209: Image of Oneline for Project Area Information

Cost Allocation

This is designated as Other Projects which are not eligible for regional cost sharing.

Project 120213: Oak Grove Substation

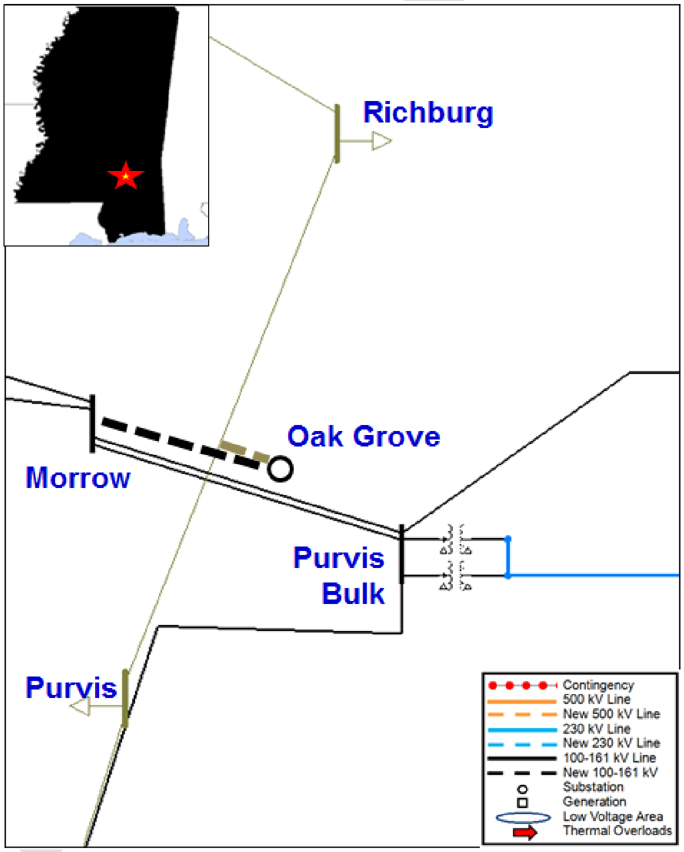
Transmission Owners: Cooperative Energy

Project Description

A 161/69kV breaker substation will be constructed with a single 112MVA, 161/69kV transformer. Cooperative Energy's existing 69kV Lines 39, 39B and 91 will be routed into the 161/69kV substation utilizing the same transmission right-of-way corridor. This project will include rebuild of approximately two and a half miles of Cooperative Energy's existing de-energized Morrow to Purvis Bulk 161kV line. It will also build approximately half a mile of new transmission line to the site. The total estimated cost of this project is $7 million. The expected in service date for this project is January 1, 2021.

Project Need

A 69kV source at Oak Grove increases system reliability and support to the surrounding area.



PSS®E Oneline

Figure P12018: Image of Oneline for Project Area Information

Cost Allocation

This is designated as Other Projects which are not eligible for regional cost sharing.

Other Reliability

These are areas with long 115kV line circuits. Installation of breakers along these lines is necessary to improve customer reliability by reducing transmission line exposure.

Prj ID	Project Name	Description	Project Need	Estimated Cost ($M)	Expected ISD
12219	Install New Switching Station at Acona	Install a new switching station with 3 breakers at Acona.	Currently, there is approximately 33MWs (5 delivery points) of load between 115kV breakers. Installation of a new switching station with breakers at Acona will improve system reliability and have a positive impact of outage times.	$ 2.2	12/1/2019

Cost Allocation

This is designated as Other Projects which are not eligible for regional cost sharing.

New Delivery Point

Several projects were proposed to facilitate new points of delivery; these either serve new loads, give new point of connection, or upgrade existing points of delivery.

Prj ID	Project Name	Description	Estimated Cost ($M)	Expected ISD
12207	Carter 115kV Delivery Point	The Carter delivery point requires installing one (1) 115kV switching station with 3 motor operated switches within the distribution substation fence.	$ 1.0	6/1/2018
12208	Holmesville 115kV Delivery Point	The Holmesville delivery point requires installing one (1) 115kV switching station with 3 motor operated switches within the distribution substation fence.	$ 1.0	6/1/2018
12214	Cole Road Delivery Point	The new delivery point is adjacent to SMEPA's Cole Road substation and will require adding a 69kV bay and breaker to SMEPA's existing Cole Road substation. A short 69kV service feed will be constructed to the new delivery point.	$ 0.5	6/1/2018

Cost Allocation

This is designated as Other Projects which are not eligible for regional cost sharing.

Region Texas

Regional Information

MISO Texas is primarily the Texas portion of the West of the Achafalaya Basin (WOTAB) load pocket with the entire Western load pocket embedded inside WOTAB. There is a major 500 kV feed in the eastern portion that feeds into the Hartburg 500 kV substation and there is a major 345 kV line feeding into the Grimes 345 kV substation in the west. Major generation sources are the Sabine units in WOTAB and the Frontier and Lewis Creek units in Western. These generators are typically dispatched for voltage and local reliability issues.

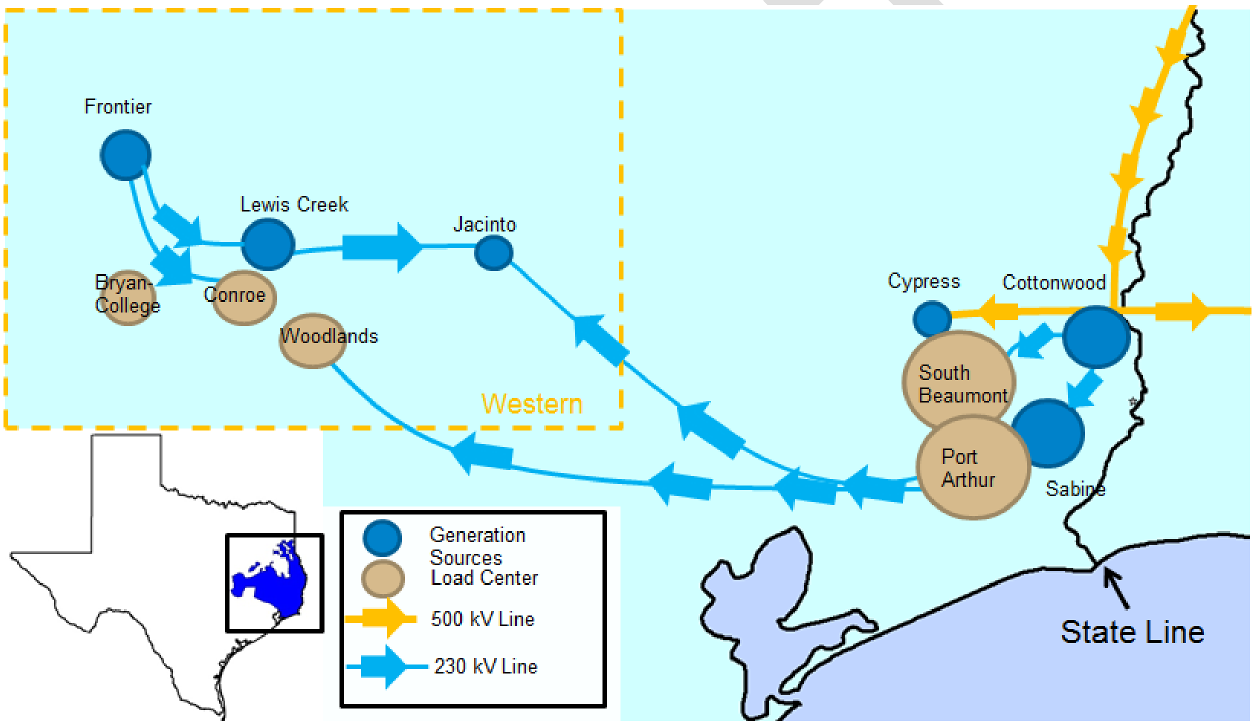


Figure TX-1: MISO-Texas – Major Generation Sources, Load Centers and Major Gen-Load Transmission

The projects proposed in the current MTEP17 cycle are part of a continuing effort to strengthen the existing transmission network. For instance, some projects were proposed to reconfigure substations to avoid breaker or bus events occurring on the 138 kV system that had the potential to cause load loss. Several projects were also proposed to facilitate new load additions, by either proposing new points of delivery or upgrading existing ones.

Transmission Profile

The transmission network within the footprint of MISO-Texas covers approximately 2,500 miles of the 138 kV to 500 kV bulk electric system (BES) network. An additional 500 miles is dedicated as the 69 kV network. Major transmission hubs in the WOTAB region, such as Hartburg, Sabine, Port Arthur, Cypress, interconnected via a network of 230 kV circuits.

Major transmission hubs in the Western region, such as Bryan-College Station, Grimes, Lewis Creek, Alden, Conroe, Porter, Rivtrin, and Jacinto are primarily connected via 138 kV transmission lines, though there is some 230 kV lines with plans to build more in the future.

Load Profile

According to the 2019 Summer Peak model estimates, load within MISO-Texas footprint is held at approximately 5.0 GW. Around 35 percent of the total load is located in with Western load pocket. Major load centers in the Western load pocket include Bryan College and the Woodlands area. The major load center in the WOTAB load pocket portion of Texas is in South Beaumont and the Port Arthur Area. The remainder of the load is spread across the footprint.

Generation Profile

The generation portfolio MISO- Texas mainly constitutes a mix of Hydro, CCGT, and Legacy Gas units. Currently, the system holds about 5.9 GW of generation capacity. The major sources constituting this profile are Sabine, Cottonwood, Lewis Creek, Frontier, Jacinto, and Cypress generation units. Together, as per the 2019 Summer Peak model estimates, they share a combined generation capacity of 75 percent of the total generation portfolio.

Overview of Projects:

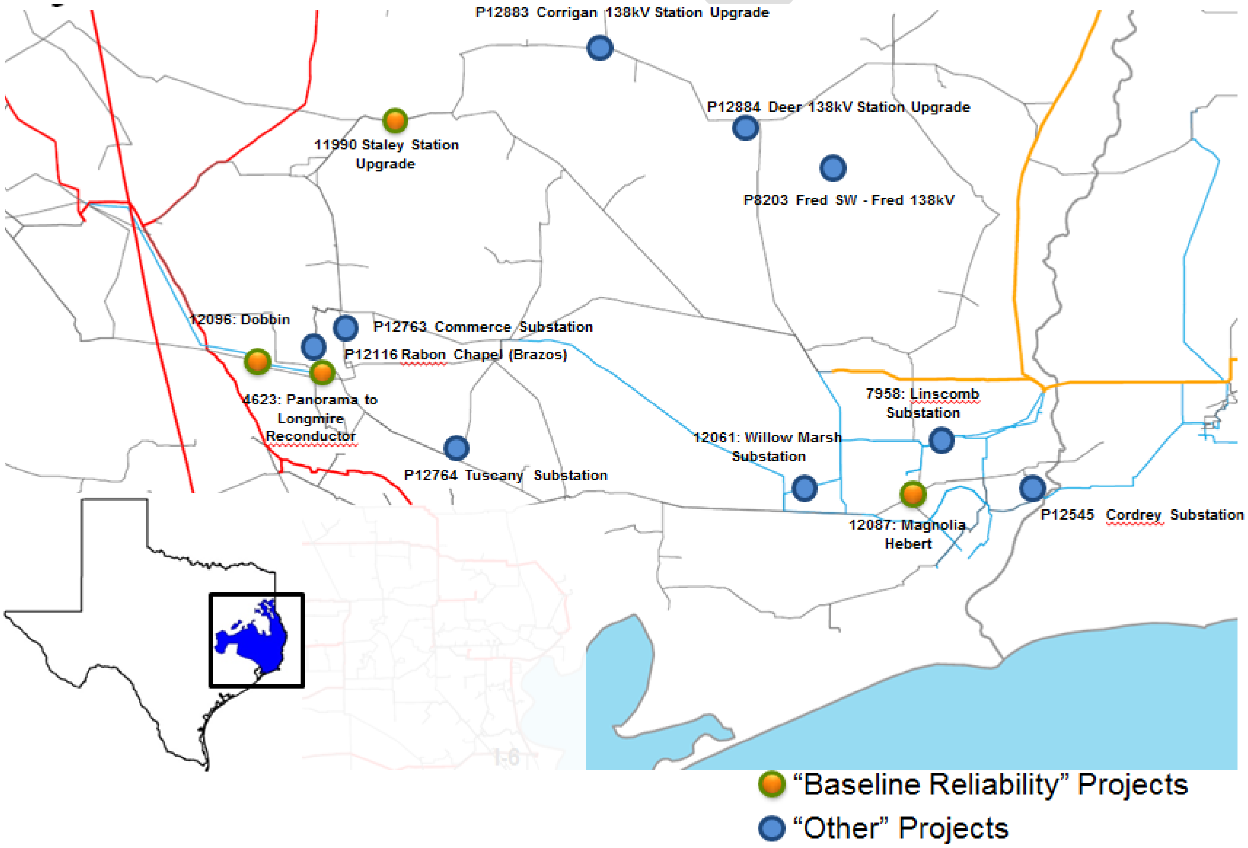


Figure TX-2: This map shows the geographical location of the projects and identified drivers.

For the MTEP17 cycle there were 12 projects targeted for Appendix A with a total cost of $134 million. Of these 12 projects: 6 have an estimated cost greater than $5 M, 3 have an estimated cost between $1M-$5 M, and 3 have an estimated cost lower than $1 M. The designations of project type are as follows: 3 Baseline Reliability and 9 other.

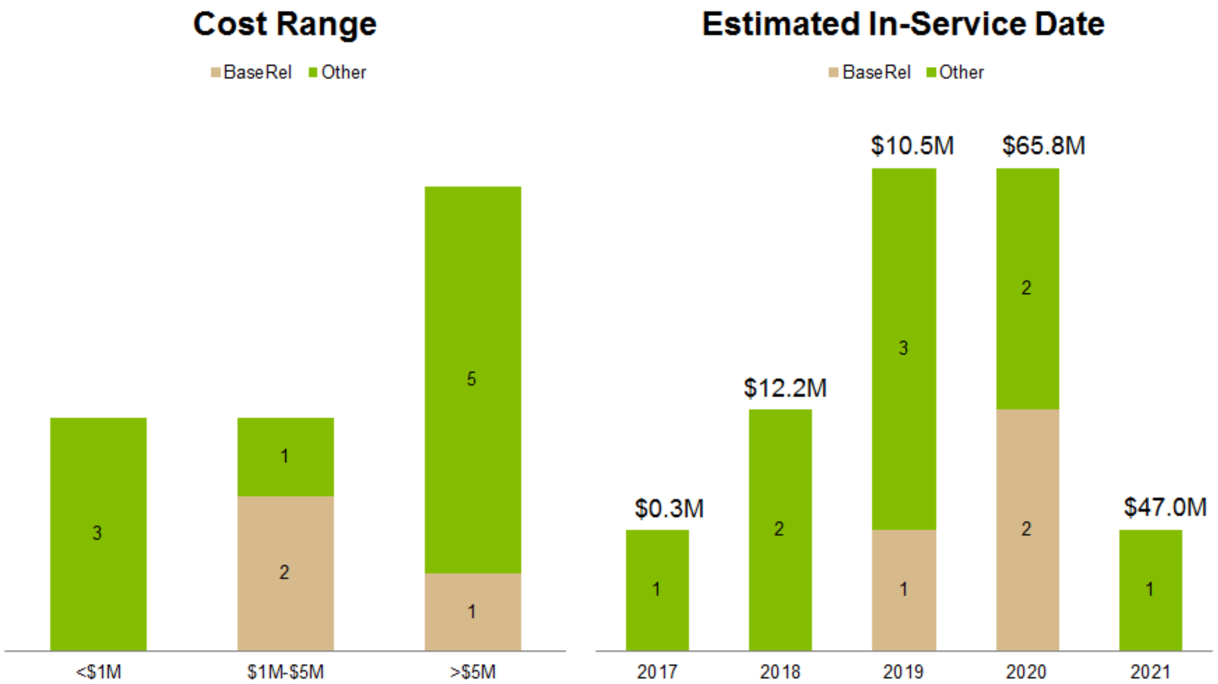


Figure TX-3: Graphs of Cost Range by Project Type and Estimated In-Service Date by Project Type

Transmission Owner: Entergy Texas, Inc. (ETI)

This section presents a summary of each project submitted by Entergy Texas in the MTEP17 cycle. 8 projects were submitted as Target Appendix A; of these, 2 are Baseline Reliability projects. The remaining projects are designated as Other Projects. The combined cost estimate for these projects is approximately $104 million. They are scheduled to come into service between 2017 and 2021.

Project 4623 Panorama to Longmire 138 kV Line: Reconductor

Transmission Owners: Entergy Texas, Inc. (ETI)

Project Area Information:

The Panorama to Longmire 138 kV line segment is south of the Lewis Creek generators. It is on the 138 kV path that leads from those generators to the Woodlands Area of Texas, which is one of the major load centers in the Western load pocket.

Project Need:

During multiple breaker failure scenarios at the Lewis Creek 138 kV substation, there are thermal overloads on the Panorama to Longmire 138 kV line. Under these conditions, the line will reach up to 137% of its emergency rating. To solve the thermal issues and to not require load shed, Entergy will implement this project to reconductor the line.

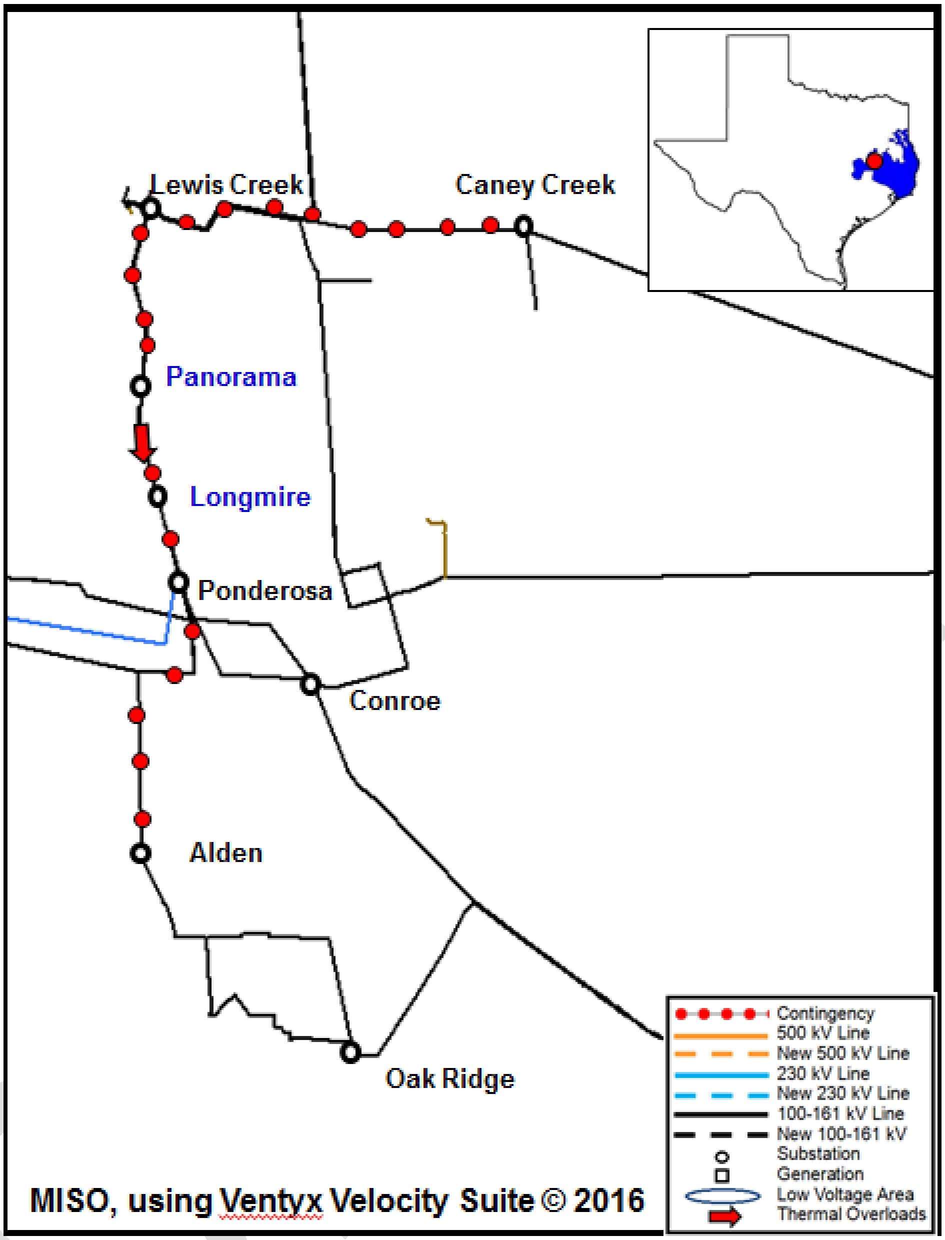


Figure TX-4: Breaker failure at the Lewis Creek substation causes an overload on Panorama to Longmire 138 kV. This is seen in various MTEP17 models.

Project Description:

Entergy will reconductor approximately 2.73 miles of 138 kV line to a minimum of 468 MVA Line Bay Bus and risers at Panorama will also need to be replaced. The line rating will continue to be limited by the 1200 amp breaker at Longmire (287 MVA).The estimated cost is $3.2M. The estimated in service date is June 1st, 2019.

Cost Allocation:

This is a Baseline Reliability Project which is not eligible for regional cost sharing.

Project 12096 Dobbin 138 kV: Install 230-138 kV Auto & Reconfigure 138 kV to Ring Bus

Transmission Owners: Entergy Texas, Inc. (ETI)

Project Area Information:

The Dobbin Substation is on the 138 kV system in between the Grimes substation, where there is frontier generation and a major 345 kV import line, and the Woodlands load center. The 138 kV path that the substation is one helps transfer power from Grimes to the Woodlands. It is also near the parallel 230 kV line from Grimes to Ponderosa.

Project Need:

During multiple simultaneous single element contingencies around the Grimes substation we see the 138 kV line from Fish Creek to Ponderosa exceed its emergency rating by up to 140%. These overloads are seen in the MTEP17 2022 Summer Model. Installing a 230-138 kV transformer and reconfiguring the Dobbin Substation by June 1st 2020 will correct the issue before the need arises.

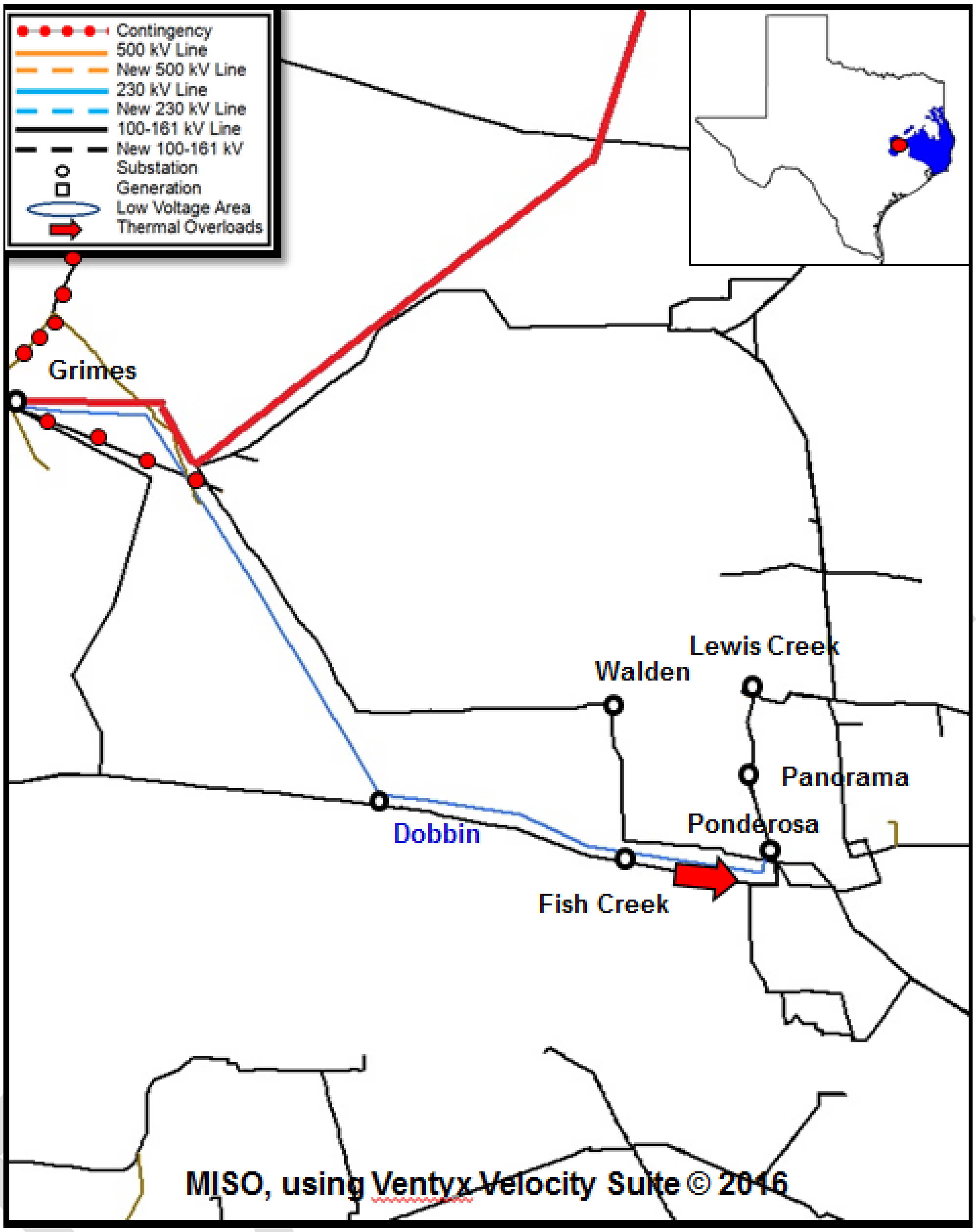


Figure TX-5: Multiple contingencies at Grimes will cause an overload on the Fish Creek to Ponderosa 138 kV line. This is seen in the MTEP17 2022 Summer Model.

Project Description:

This project is to convert the Dobbin 138 kV substation to a (5) breaker ring bus. It will also cut the Grimes – Ponderosa 230 kV in and out of Dobbin, construct a (3) breaker 230 kV ring bus at Dobbin, and install a 230-138 kV, 400 MVA autotransformer at Dobbin.

Cost Allocation:

This is a Baseline Reliability Project which is not eligible for regional cost sharing.

New Load Additions

These projects are needed in order to serve new loads. The existing distribution system is not sufficient to supply these additions. The most effective way to serve these new loads is to provide a new substation. No harm test was conducted to make sure no addition baseline reliability issues were caused by the new load additions.

ID	Name	Description	ISD	Cost
7958	Linscomb - Construct new 230 kV substation	Construct new Linscomb 230 kV substation on line 195 between the new Chisholm Road substation and Helbig.	6/1/2019	$5,500,000.00
12061	Willow Marsh 230 kV: Construct New Substation	Construct a 230 kV substation that cuts into the China to Amelia 230 kV line 599 in order to serve a new block load addition.	12/29/2017	$11,185,291.00
12116	Rabon Chapel (Brazos) 138 kV: Construct New Substation	Cut into the Lake Forest - Woodhaven 138 kV line 700 feet from Lake Forest and construct a 138 kV substation with a 138 kV straight bus owned and operated by Entergy Texas.	6/1/2018	$1,100,000
12763	Commerce 138 kV: New Substation	Build new distribution substation to serve load.	5/15/2020	$11,900,000.00
12764	Tuscany 138 kV: New Substation	Build new Tuscany 138 kV distribution substation	5/1/2021	$47,000,000.00

Alternatives Considered

MISO and ETI considered serving the load from alternative locations but as these solutions provides the least amount of new facilities and costs; they are the most cost-effective way to serve this new load obligation.

Cost Allocation:

These are Other: Distribution Projects which are not eligible for regional cost sharing.

Projects Driven by Other Reliability Issues

This project is needed in order to enhance the system reliability and to increase operational flexibility.

ID	Name	Description	ISD	Cost
12545	Cordrey 69 kV: Install transmission breakers	Install line breakers at the Cordrey 69 kV.	12/31/2017	$300,000.00

Cost Allocation:

This is an Other: Reliability Project which is not eligible for regional cost sharing.

Transmission Owner: East Texas Electric Cooperative (ETEC)

This section presents a summary of each project submitted by Entergy Texas in the MTEP17 cycle. 4 projects were submitted as Target Appendix A; of these, 1 is a Baseline Reliability project. The remaining projects are designated as Other Projects. The combined cost estimate for these projects is approximately $30 million. They are scheduled to come into service between 2019 and 2020.

Project 11990 Staley 138kV Station Upgrade

Transmission Owners: East Texas Electric Cooperative (ETEC)

Project Area Information:

The Staley substation is on the northern 138 kV path of MISO Texas. Somewhat far from generation sources and load centers, this 138 kV path is used to serve the load local to the area.

Project Need:

During multiple simultaneous single contingency event, low voltage is seen at the Staley Substation. Under these conditions, the voltage at the substation could reach 0.82 per unit value. To solve the voltage issues and to not require load shed, ETEC will implement this project to upgrade the substation.

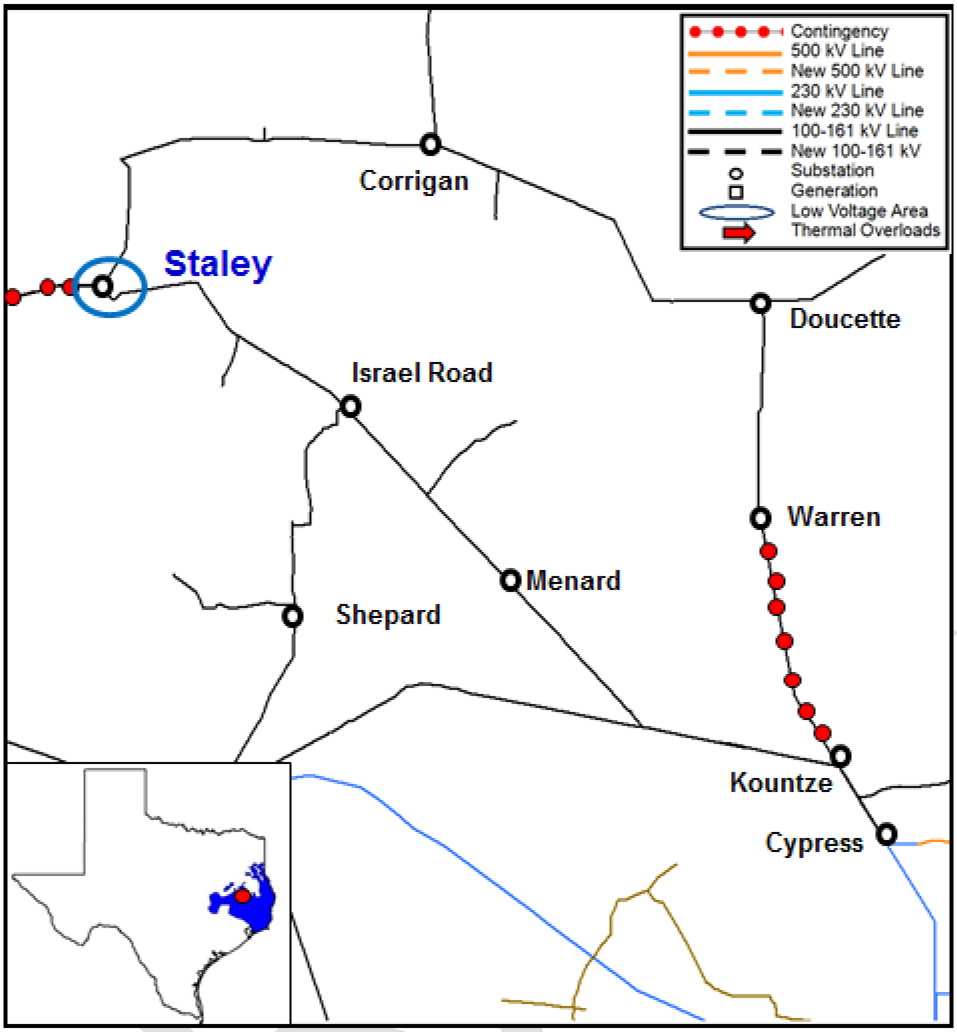


Figure TX-6: Multiple contingency events cause a low voltage on the Staley 138 kV Substation. This is seen in the MTEP17 2019 summer model.

Project Description:

This project will upgrade the SHECO Staley 138kV substation to 6 breaker ring bus configuration. Cut-in existing ETI 138kV line from Rivtrin to Gulf Trinity and connect into Staley 138kV substation. The estimated cost is $4.65M. The estimated in service date is June 1st, 2019.

Cost Allocation:

This is a Baseline Reliability Project which is not eligible for regional cost sharing.

Other Reliability Projects

Projects that are not defined as Baseline Reliability, Generation Interconnection or Transmission Delivery Service Planning per Attachment FF transmission project definitions but are still needed for system reliability for various reasons are categorized as Other projects.

New Load Additions

These projects are needed in order to serve new loads. The existing distribution system is not sufficient to supply these additions. The most effective way to serve these new loads is to provide a new substation. No harm test was conducted to make sure no addition baseline reliability issues were caused by the new load additions.

ID	Name	Description	ISD	Cost
8203	Fred SW - Fred 138kV	Construct new Fred switching station on Dogwood-Warren 138 kV line, construct new 138kV Fred substation, construct new 138 kV line from Fred switching station to new Fred substation.	08/01/2020	$24,200,000.00

Alternatives Considered

MISO and ETEC considered serving the load from alternative locations but as these solutions provides the least amount of new facilities and costs; they are the most cost-effective way to serve this new load obligation.

Cost Allocation:

This is an Other: Distribution Project which is not eligible for regional cost sharing.

Projects Driven by Other Reliability Issues

These projects are needed in order to enhance the system reliability and to increase operational flexibility.

ID	Name	Description	ISD	Cost
12883	Corrigan 138kV Station Upgrade	Upgrade of existing switch substation with addition of 138kV line breakers for through-bus operation	8/1/2019	$900,000.00
12884	Deer 138kV Station Upgrade	Upgrade of existing switch substation with addition of 138kV line breakers for through-bus operation	8/1/2019	$900,000.00

Cost Allocation:

These are Other: Reliability Projects which are not eligible for regional cost sharing.

MISO South Market Congestion Planning “Other” Projects

In the MISO Texas region, one project is recommended as economic “Other” projects. This project provides quantifiable economic benefits addressing market competition and efficiency needs with production cost savings in excess of their costs and a benefit-to-cost ratio above 1.25. The project is sub-345 kV and does not qualify for regional cost allocation as MEPs based on the voltage rating. Cost of this project is directly assigned to the local Transmission Owner Pricing Zone.

Project 14002: Substation equipment upgrades at the existing Carlyss substation

Transmission Owner: Entergy Texas, Inc.

Project Description

The estimated cost of project 14002 is $1,534,000, with an expected in-service date in the year of 2020.

For full details of the network upgrades associated with project 14002 please see section 5.3 of the MTEP report.

Project Need

For full details of the economic justification of project 14002 please see section 5.3 of the MTEP report.

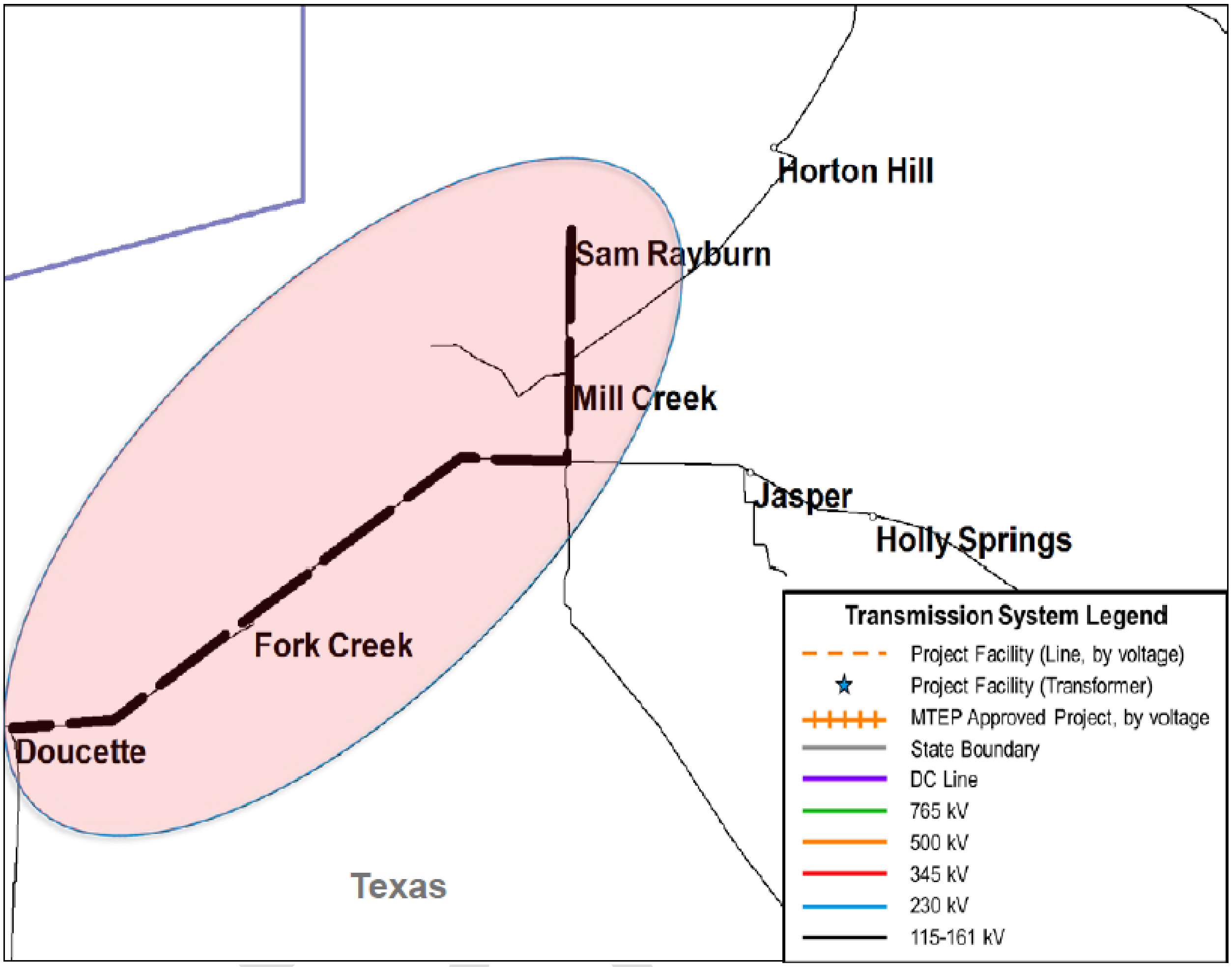


Figure P14002

Cost Allocation

This is an Other - Economic Project, which is not eligible for cost sharing.

Appendix D1
South
2016

Entergy Arkansas Inc. (EAI)

Arkansas Electric Cooperative Corp. (AECC)

Entergy Gulf States Louisiana LLC (EGSL)

Entergy Louisiana LLC (ELL)

Entergy New Orleans Inc. (ENOI)

Cleco Power LLC (CLEC)

Lafayette Utilities System (LAFA)

Entergy Mississippi Inc. (EMI)

South Mississippi Electric Power Association (SMEPA)

Entergy Texas Inc. (ETI)

East Texas Electric Cooperative (ETEC)

Appendix D1: South Planning Region

Arkansas

Regional Information

MISO-Arkansas is a network of generation resources and major load centers interconnected through an array of 500-115 kV transmission networks. There is also a significant 69 kV network interspersed across its footprint.

MISO-Arkansas consists of a diverse generation profile, such as nuclear, gas, coal and hydro units that fuel major load centers such as the Little Rock, Jonesboro and Pine Bluff regions. Together, these load centers constitute approximately 40 percent of the total power consumption in this region. The remaining load is distributed across the footprint, and is served through several electric cooperatives.

Figure AR-1 illustrates the major generation sources, load centers and generation-to-load powerflow in MISO-Arkansas.

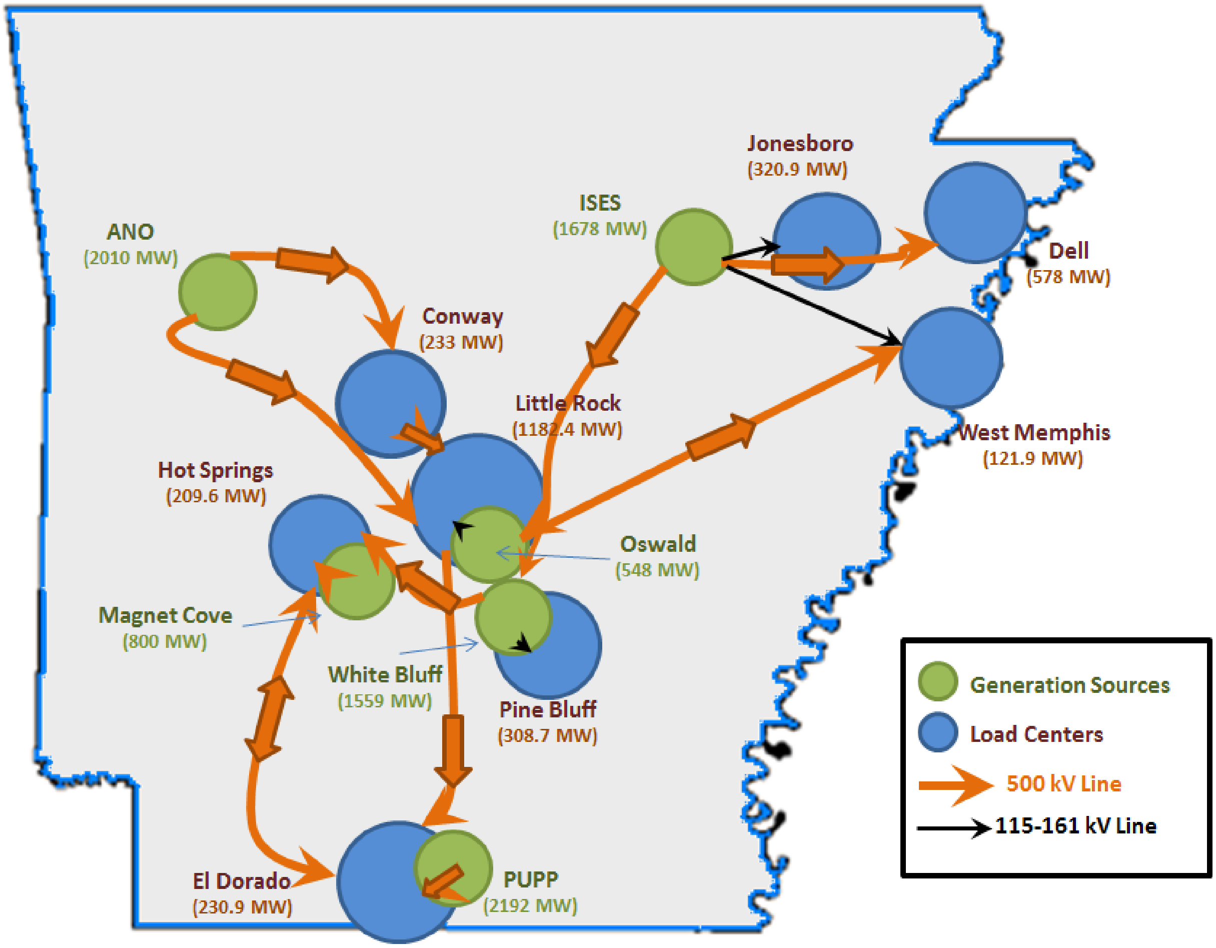


Figure AR-1: MISO-Arkansas – Major generation sources, load centers and major gen-load transmission

The projects proposed in the current MTEP16 cycle are part of a continuing effort to strengthen the existing transmission network. For instance, several projects were proposed to reconfigure substations to avoid breaker or bus events occurring on the 115 or 161 kV system that had the potential to cause load loss. Several projects were also proposed to facilitate new load additions, by either proposing new points of delivery or upgrading existing ones.

Transmission Profile

The transmission network within the footprint of MISO-Arkansas covers approximately 5,000 miles of the 115 kV to 500 kV bulk electric system (BES) network. An additional 1,000 miles is dedicated as the 69 kV network.

Major transmission hubs - such as El Dorado, McNeil, Arklahoma–Hot Springs, Woodward, West Memphis, Arkansas Nuclear, Independence, Little Rock and Dell - interconnected via a network of 500 kV circuits form the backbone of the MISO-Arkansas transmission network.

Load Profile

According to the 2018 Summer Peak model estimates, load within MISO-Arkansas footprint is held at approximately 8 GW. Around 40 percent of the total load is centered on several major load centers within this footprint. Chief amongst them are: City of Little Rock, Dell, Jonesboro, Pine Bluff, Conway, El Dorado, Hot Springs and West Memphis. The remainder of the load is spread across the footprint.

Generation Profile

The generation portfolio MISO- Arkansas mainly constitutes a mix of nuclear, hydro, coal, Combined Cycle Gas Turbines (CCGT), and legacy gas units. Currently, the system holds about 11.7 GW of generation capacity. The major sources constituting this profile are ANO, Oswald, Magnet Cove, ISES, White Bluff and PUPP generation units. Together, as per the 2018 Summer Peak model estimates, they share a combined generation capacity of 75 percent of the total generation portfolio.

Overview of Projects

For the current MTEP16 cycle, 21 projects were targeted as Appendix A at a combined cost of $176.3 million. Of these, 12 projects have an estimated cost greater than $5 million; six projects have a projected cost between $1 million and $5 million; and three projects have an estimated price tag lower than $1 million. Eleven of these 21 projects are labeled as baseline reliability projects, while the eight are designated as Other (Distribution Reliability) projects and two are designated as Generation Interconnection projects. Figure AR-2 illustrates the approximate geographic locations of the projects submitted as Target Appendix A in the current MTEP cycle. Figures AR-3 and AR-4 illustrates the Base Line Reliability, Generation Interconnection and Other projects as either distributed by their estimated costs or the year they’re expected to be in service. Some project details, such as estimated cost and in-service dates, may change between the creation of Appendix D1 and the board approval date. Refer to Appendix A of this report for the final approval information.

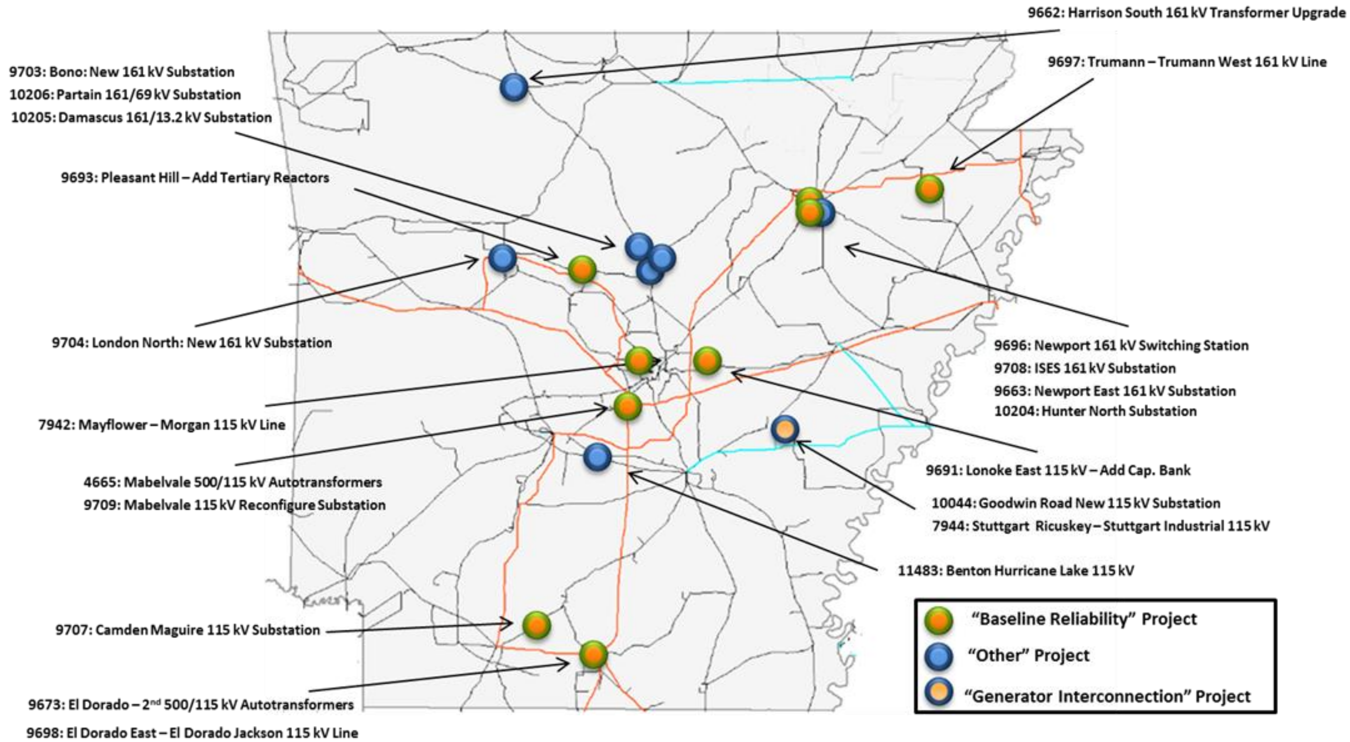


Figure AR-2: Geographical transmission map of MISO-Arkansas with project locations-2

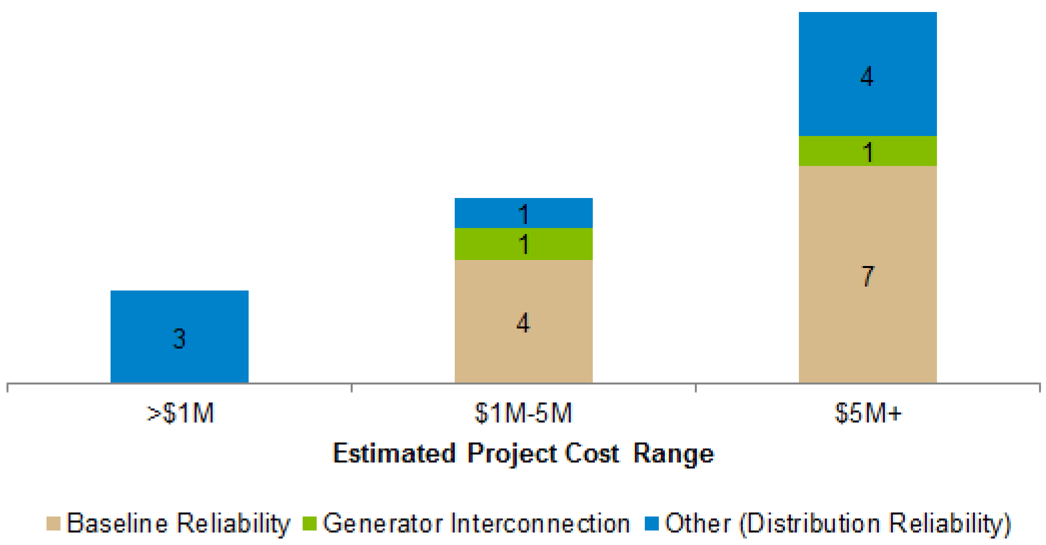


Figure AR-3: Graph of cost range by project type

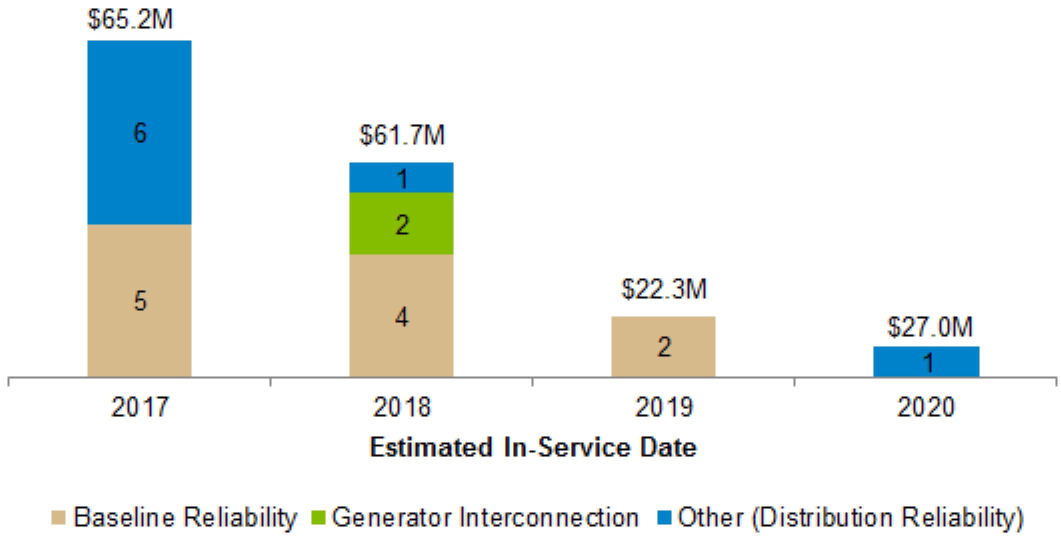


Figure AR-4: Graph of estimated in-service date

Entergy Arkansas Inc. (EAI)

This section presents a summary of each project submitted by Entergy Arkansas in the current MTEP16 cycle. Sixteen projects were submitted as Target Appendix A; of these, eleven are Baseline Reliability projects. The remainders are labeled as either Other (Distribution Reliability) – New Delivery Point or Generator Interconnection Project. The combined cost estimate for these projects is about $139.7 million. They are scheduled to come into service between 2017 and 2019.

Project 4665: Replace Mabelvale 500-115 kV Autotransformers

Transmission Owner: Entergy Arkansas Inc. (EAI)

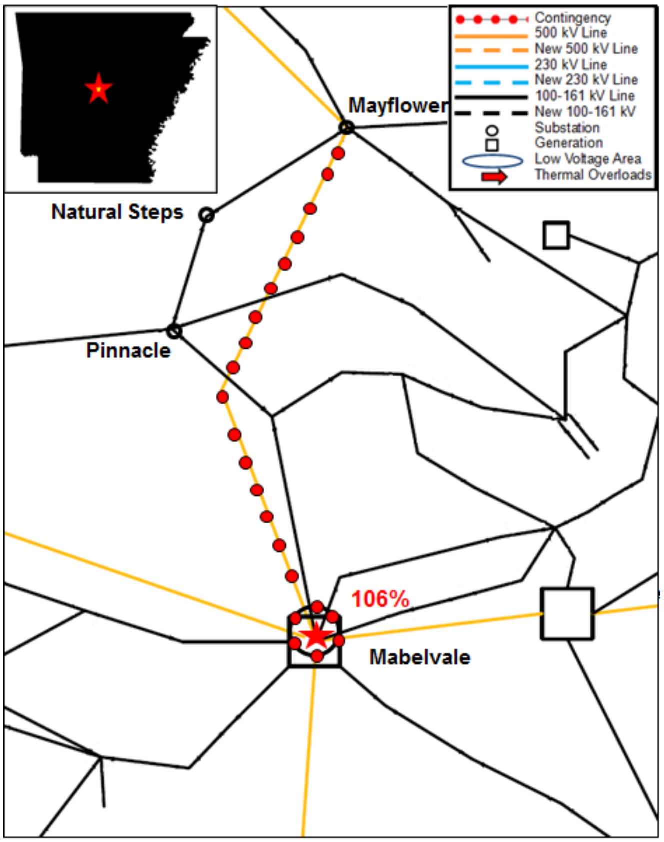
Project Description

The Mabelvale substation serves as a major source to the load in Little Rock and surrounding area. The 500 kV at Mabelvale provides a strong connection to several large generators in Arkansas; while the 115 kV at Mabelvale provides service the load located in the southwest Little Rock area. The two existing 500-115 kV autotransformers are currently rated at 443 and 447 MVA.

This project proposes to upgrade both Mabelvale 500-115 kV autotransformers to 598 MVA. The projected in-service date for this project is December 1, 2017 and has an estimated cost of $17.42 million. Figure P4665 illustrates the contingency, the resultant violations and the proposed project to address the identified reliability concerns.

Project Need

A breaker fault at Mabelvale 500 kV will result in the loss of one of the 500-115 kV autotransformers and the Mabelvale to Mayflower 500 kV line, which causes the remaining 500-115 kV autotransformer to overload to 103 percent or 106 percent (depending on which breaker is faulted). These violations were observed in the 2026 Summer Peak model.



MISO, using Ventyx Velocity Suite © 2014

Figure P4665: Breaker fault at Mabelvale causes thermal violation on either transformer to 103 percent or 106 percent

Alternatives Considered

No alternatives were considered.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 7942: Rebuild Mayflower – Morgan 115 kV Line

Transmission Owner: Entergy Arkansas Inc. (EAI)

Project Description

The Mayflower to Morgan 115 kV line is one of the main sources to the load in the Northern Little Rock area. The current Mayflower to Morgan 115 kV line is approximately 4.89 miles long and is rated at 283 MVA.

This project proposes rebuilding Mayflower–Morgan 115 kV line to 390 MVA. The projected in-service date is June 1, 2019, with an estimated cost of $4.88 million. Figure P7942 illustrates the contingency, the resultant violations and the proposed project to address the identified reliability concerns.

Project Need

A breaker fault at Keo 500 kV will result in the loss of the Keo to Wrightsville and Keo to White Bluff 500 kV lines which causes the Mayflower to Morgan 115 kV like to load to 97 percent. This violation was observed in the 2026 Summer Peak model.

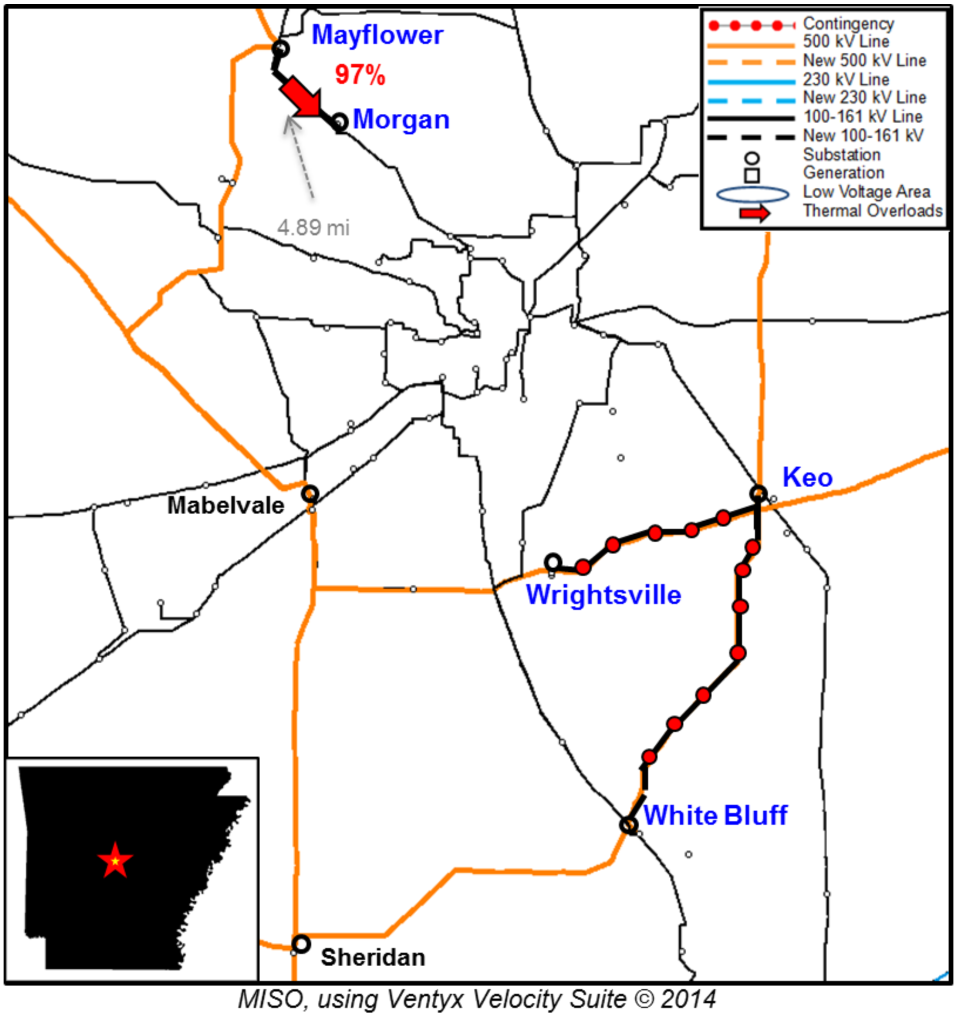


Figure P7942: Breaker fault at Keo causes thermal violation on Mayflower to Morgan and overloads to 97 percent

Alternatives Considered

Build a new 23-mile 500 kV line from Mayflower to Holland Bottom.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 9673: Add 2nd 500-115 kV Autotransformer at El Dorado

Transmission Owner: Entergy Arkansas Inc. (EAI)

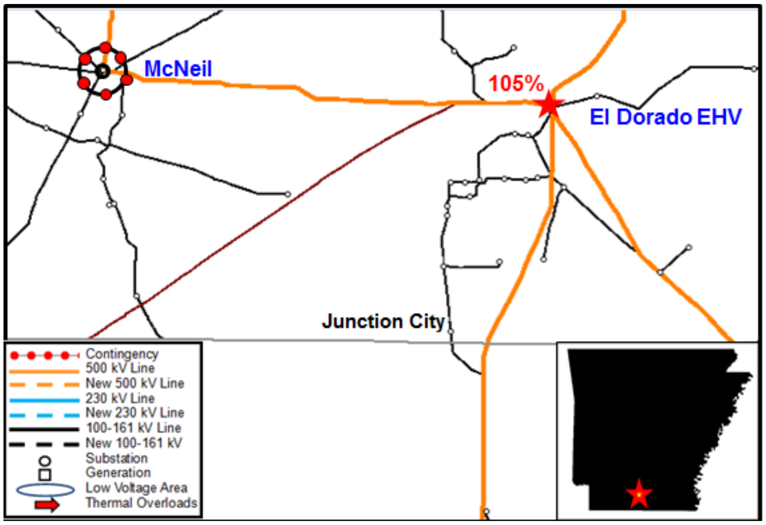
Project Description

The El Dorado substation serves as a major source to the load in El Dorado and the surrounding area. The 500 kV at El Dorado provides a strong connection to several large generators in Arkansas; while the 115 kV at El Dorado provides service the load located in the El Dorado area. The existing 500-115 kV autotransformer is currently rated at 443 MVA.

This project proposes installing a second 500-115 kV autotransformer at El Dorado EHV rated at 448 MVA. The projected in-service date is June 1, 2018, with an estimated cost of $16.45 million. Figure P9673 illustrates the contingency, the resultant violation, and the proposed project to address the identified generation deliverability concerns.

Project Need

The loss of the McNeil 500-115 kV autotransformer causes the El Dorado 500-115 kV autotransformer to overload to 105 percent. Additionally, for bus and breaker faults at McNeil 115 kV that cause the loss of the McNeil 500-115 kV autotransformers and 115 kV lines from McNeil result in the El Dorado 500-115 kV autotransformer to overload to 107 percent. These violations were observed in the 2026 Summer Peak model.



MISO, using Ventyx Velocity Suite © 2014

Figure P9673: Loss of McNeil 500-115 kV transformer causes thermal violation and overloads El Dorado 500-115 kV transformer to 105 percent

Alternatives Considered

No alternatives were considered.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 9691: Add 20.5 MVAR Capacitor Bank at Lonoke East 115 kV

Transmission Owner: Entergy Arkansas Inc. (EAI)

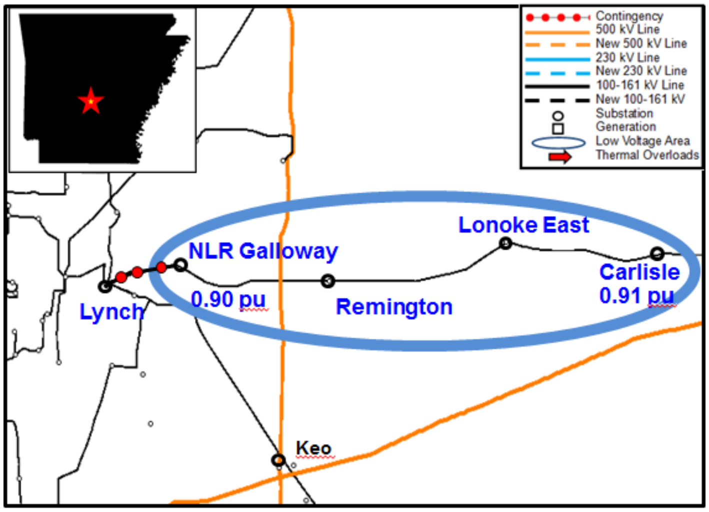
Project Description

The Lonoke East 115 kV substation is one of the several load taps along a 115 kV line between Northern Little Rock and Brinkley that provides service to rural customers.

This project proposes installing a new 20.5 MVAR capacitor bank at Lonoke East 115 kV. The projected in-service date is June 1, 2017, with an estimated cost of $1.46 million. Figure P9691 illustrates the contingency, the resultant violations and the proposed project to address the identified reliability concerns.

Project Need

The opening of the line section between Lynch and Northern Little Rock–Galloway 115 kV causes low voltages to be observed from Northern Little Rock–Galloway to Carlisle 115 kV, the lowest voltage observed was 0.90 pu at Northern Little Rock–Galloway. Additionally, for several bus and breaker faults at Lynch 115 kV that cause the loss of the Lynch to Northern Little Rock–Galloway 115 kV, low voltages were also observed from Northern Little Rock–Galloway to Carlisle 115 kV. These violations were observed in the 2018 Summer Peak model.



MISO, using Ventyx Velocity Suite © 2014

Figure P9691: Open Line section Lynch to NLR Galloway causes voltage violation of 0.90 – 0.91 pu voltage at NLR Galloway through Carlisle

Alternatives Considered

No alternatives were considered.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 9693: Add 3x30 MVAR Tertiary Reactors at Pleasant Hill

Transmission Owner: Entergy Arkansas Inc. (EAI)

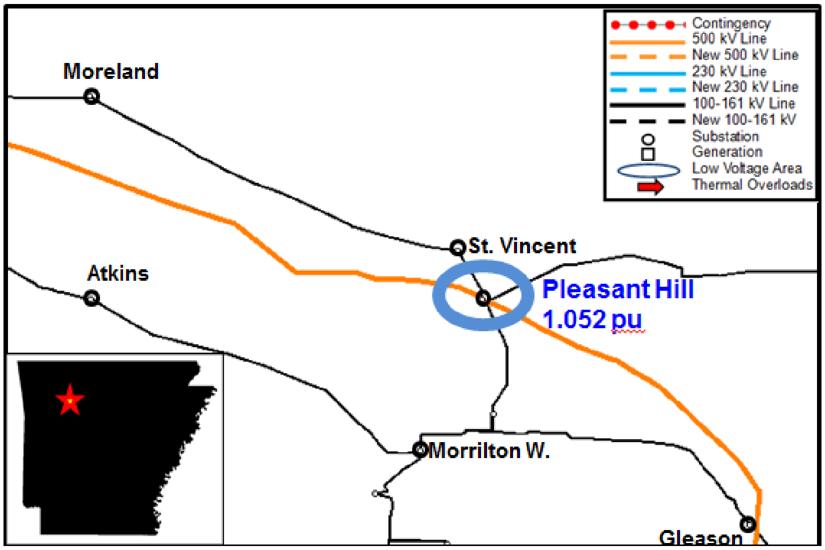
Project Description

The Pleasant Hill substation is located in Northwestern Arkansas and is along one of the major outlets for the Arkansas nuclear generation.

This project proposes adding three 30 MVAR reactors on the tertiary windings of the 500-161-13.8 kV transformer at the Pleasant Hill EHV substation to maintain voltages during light loading conditions. The projected in-service date is October 1, 2017, with an estimated cost of $2.19 million. Figure P9693 illustrates the contingency, the resultant violations and the proposed project to address the identified reliability concerns.

Project Need

System intact voltage at Pleasant Hill 161 kV was observed to be 1.052 pu in the 2018 Spring Light Load model. Additionally, for events (bus, breaker and line faults) that result in the loss of Pleasant Hill to Morrilton East 115 kV high voltage were observed at Pleasant Hill 161 kV.



MISO, using Ventyx Velocity Suite © 2014

Figure P9693: With system Intact, voltage violation of 1.052 pu voltage at Pleasant Hill 161 kV

Alternatives Considered

No alternatives were considered.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 9696: Newport New 161 kV Switching Station

Transmission Owner: Entergy Arkansas Inc. (EAI)

Project Description

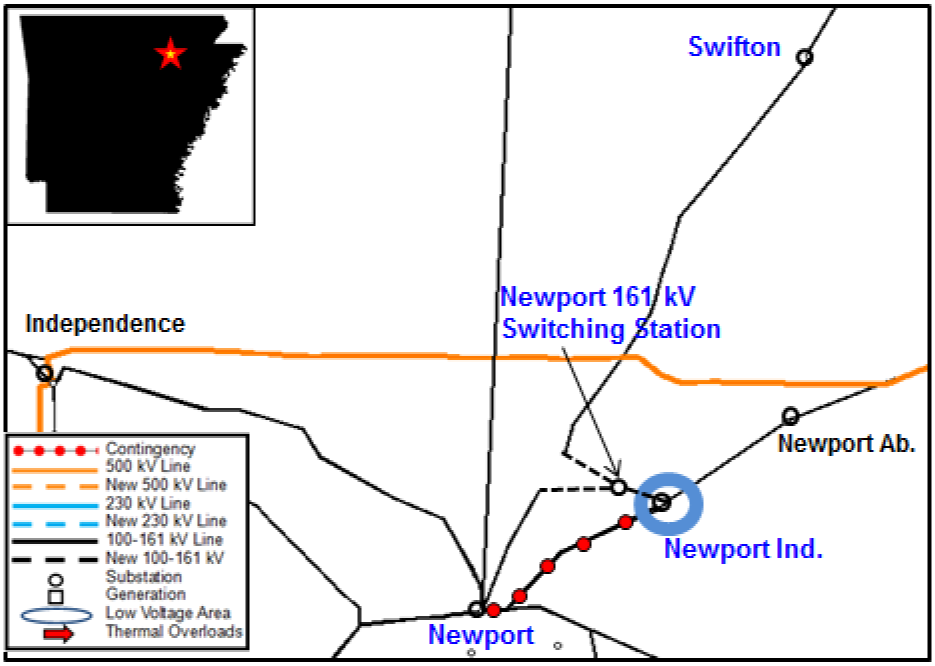
This project proposes:

- Building a four-breaker switching station near Newport Industrial
- Terminating the exiting Newport-Swifton 161 kV line into the new switching station
- Building a new 161 kV line between the Newport switching station and Newport Industrial to eliminate the voltage issue

The projected in-service date is June 1, 2018, with an estimated cost of $15.15 million. Figure P9696 illustrates the contingency, the resultant violations and the proposed project to address the identified reliability concerns.

Project Need

A single element contingency loss of Newport–Newport Industrial 161 kV line could cause flicker issues in the Newport area. This issue is heightened during times of reduced generation near the area.



MISO, using Ventyx Velocity Suite © 2014

Figure P9696: loss of Newport –Newport Industrial 161 kV line could potentially cause flicker issues in the Newport area.

Alternatives Considered

No alternatives were considered.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 9697: Rebuild Trumann – Trumann West 161 kV Line

Transmission Owner: Entergy Arkansas Inc. (EAI)

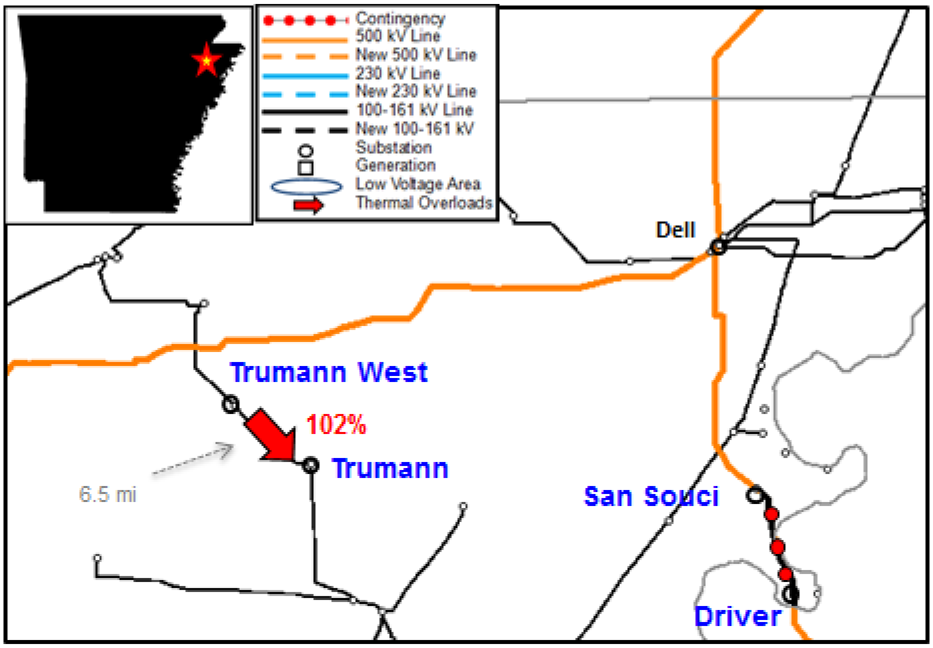
Project Description

The Trumann to Trumann West 161 kV line is one of the primary 161 kV lines connecting to Jonesboro from the south. The current Trumann to Trumann West 161 kV line is approximately 6.5 miles long and is rated at 148 MVA.

This project proposes rebuilding Trumann–Trumann West 161 kV, 6.5-mile-long line to a minimum rating of 1300A. The projected in-service date is June 1, 2018, with an estimated cost of $12.12 million. Figure P9697 illustrates the contingency, the resultant violations and the proposed project to address the identified reliability concerns.

Project Need

The Trumann-Trumann West 161 kV line overloads to 102 percent due to the loss of the Sans Souci–Driver 500 kV line. This violation was observed in the 2026 Summer Peak model.



MISO, using Ventyx Velocity Suite © 2014

Figure P9697: Loss of San Souci – Driver 500 kV line causes thermal violation on Trumann – Trumann West 161 kV and overloads to 102 percent

Alternatives Considered

No alternatives were considered.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 9698: Rebuild El Dorado East – El Dorado Jackson 115 kV Line

Transmission Owner: Entergy Arkansas Inc. (EAI)

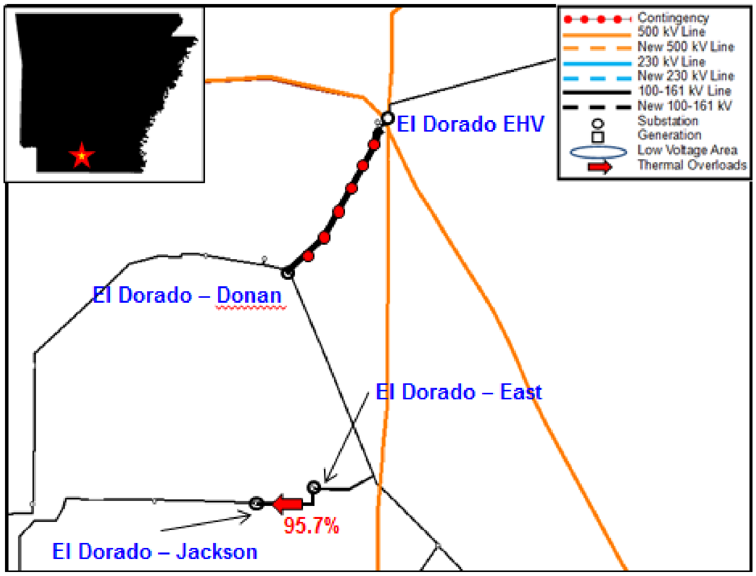
Project Description

The El Dorado East to El Dorado Jackson 115 kV line is part of the 115 kV loop providing service to the El Dorado area. The current El Dorado East to El Dorado Jackson 115 kV line is approximately 2.92 miles long and is rated at 159 MVA.

This project proposes upgrading El Dorado East–El Dorado Jackson 115 kV line to a rating of minimum 1300A. The projected in-service date is June 1, 2018, with an estimated cost of $4.93 million. Figure P9698 illustrates the contingency, the resultant violations and the proposed project to address the identified reliability concerns.

Project Need

The loss of El Dorado EHV to El Dorado Donna causes the El Dorado East to El Dorado Jackson 115 kV line to load to 95.7 percent. This loading was observed in the 2026 Summer Peak model.



MISO, using Ventyx Velocity Suite © 2014

Figure P9698: Line section opening of El Dorado EHV – El Dorado Donan 115 kV causes thermal violation on El Dorado East – El Dorado Jackson 115 kV and loads to 95.7 percent

Alternatives Considered

No alternatives were considered.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 9707: Reconfigure Camden Maguire 115 kV Substation

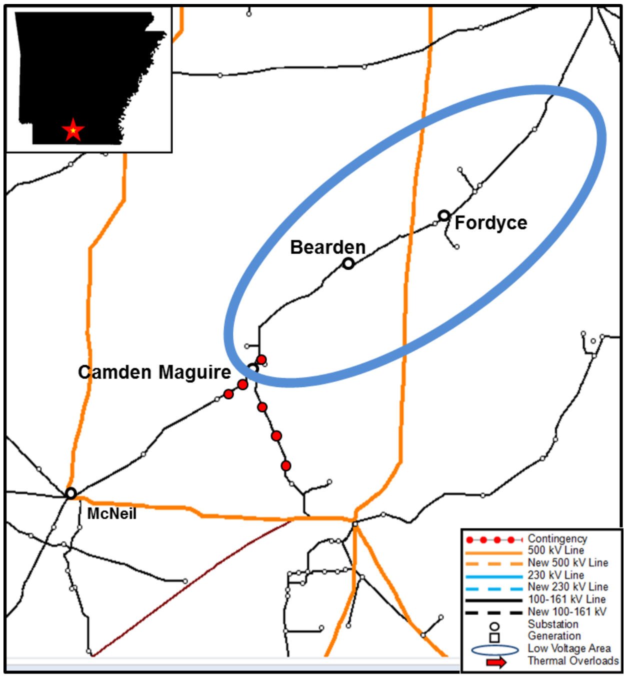
Transmission Owner: Entergy Arkansas Inc. (EAI)

Project Description

This project proposes reconfiguring Camden Maguire 115 kV substation to a double bus/double breaker configuration so that a single bus failure will not open all the elements in the Camden Maguire substation. The projected in-service date is June 1, 2017, with an estimated cost of $5.77 million. Figure P9707 illustrates the contingency, the resultant violations and the proposed project to address the identified reliability concerns.

Project Need

The Camden Maguire 115 kV substation is configured as a single bus, single breaker substation. A bus or breaker fault at Camden Maguire 115 kV will result in the loss of the entire 115 kV substation and cause low voltages northeast of Camden Maguire at Bearden and Fordyce ranging from 0.85 to 0.91 pu. These violations were observed in the 2018 Summer Peak model.



MISO, using Ventyx Velocity Suite © 2014

Figure P9707: Breaker/Bus fault at Camden Maguire 115 kV causes voltage violation and results 0.85 to 0.91 pu voltages Northeast of Camden Maguire 115 kV

Alternatives Considered

No alternatives were considered.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 9708: Reconfigure Independence (ISES) 161 kV Substation

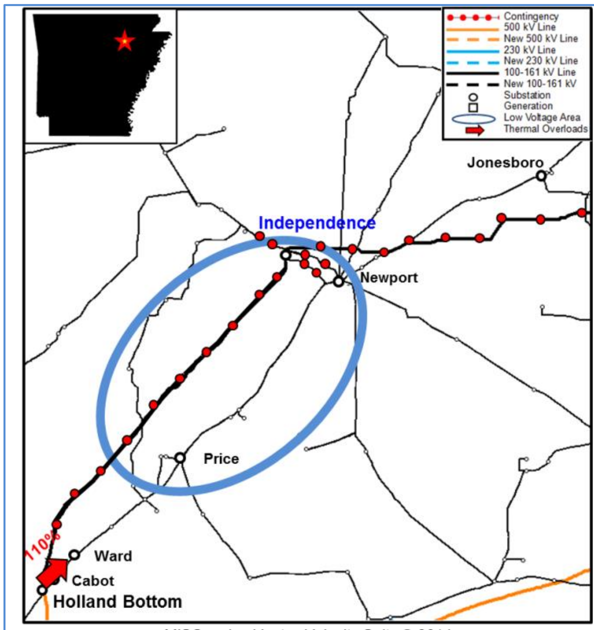
Transmission Owner: Entergy Arkansas Inc. (EAI)

Project Description

This project proposes reconfiguring Independence 161 kV to a double bus/double breaker configuration. The projected in-service date is October 1, 2017, with an estimated cost of $9.10 million. Figure P9708 illustrates the contingency, the resultant violations and the proposed project to address the identified reliability concerns.

Project Need

The Independence 161 kV substation is configured as two separate single bus, single breaker substations with a bus tie breaker connecting the two operating buses. A fault on the bus tie breaker at Independence 161 kV results in loss of both the 161 kV operating buses at Independence. This causes low voltages along the 115 kV and 161 kV networks around Independence ranging from 0.88 to 0.91 pu. The bus tie breaker fault also results in overloading the Holland Bottoms to Cabot to Ward 115 kV line to 110 percent. These violations were observed in the 2018 Summer Peak model.



MISO, using Ventyx Velocity Suite © 2014

Figure P9708: Breaker/Bus fault at Independence 161 kV causes thermal violation on Holland Bottom–Cabot–Ward 161 kV overloads to 110 percent; and voltage violation of 0.88–0.91 pu voltages Southwest of Independence 161 kV

Alternatives Considered

No alternatives were considered.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 9709: Mabelvale 115 kV Substation Reconfigure

Transmission Owner: Entergy Arkansas Inc. (EAI)

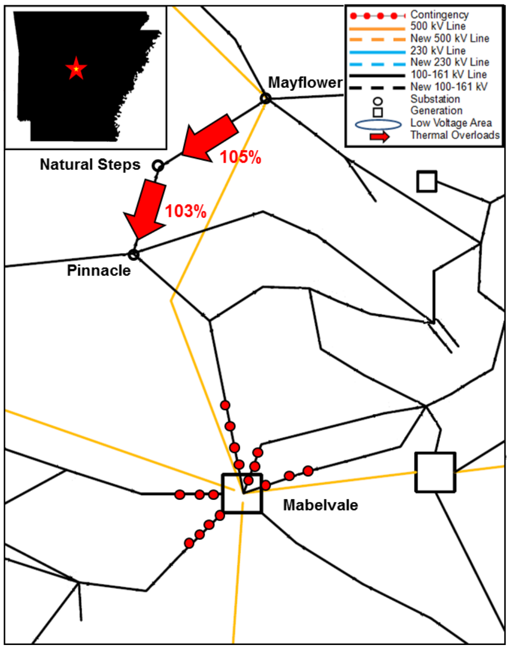
Project Description

This project proposed to re-configure the Mabelvale 115 kV substation so that a single bus tie breaker failure will not open all the elements in the Mabelvale 115 kV substation. Some potential configurations are double bus double breaker, breaker-and-a-half, and a ring bus. The final configuration will be decided during project scoping.

The projected in-service date is June 1, 2019, with an estimated cost of $17.45 million. Figure P9709 illustrates the contingency, the resultant violations and the proposed project to address the identified reliability concerns.

Project Need

The Mabelvale 115 kV substation is configured as two separate single bus, single breaker substations with a bus tie breaker connecting the two operating buses. A single internal breaker fault on the bus tie breaker will result in overloading the Mayflower-Natural Steps-Pinnacle 115 kV line to 102 percent to 105 percent (depending on which section). These violations were observed in the 2018 Summer Peak model.



MISO, using Ventyx Velocity Suite © 2014

Figure P9709: Breaker/Bus fault at Mabelvale 115 kV causes thermal violation on Pinnacle–Natural Steps–Mayflower 115 kV and overloads to 102 percent-105 percent

Alternatives Considered

No alternatives were considered

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

New Load Additions

These projects are needed in order to serve new loads. The existing distribution system is not sufficient to supply these additions. The most effective way to serve these new loads is to provide a new substation for a new point of delivery. No-harm tests were conducted to make sure no addition baseline reliability issues were caused by the new load additions.

ID	Name	Description	ISD	Cost ($M)
9703	Bono: New 161 kV Substation	Build new 161 kV substation to support existing load and future growth	10/01/2017	$9.38
9704	London North: New 161 kV Substation	Build new 161 kV substation to support load growth in area	10/01/2017	$9.24
11483	Benton Hurricane Lake 115 kV: New point of delivery	Cut-in new delivery point on River Ridge – Mabelvale 115 kV line	05/01/2017	$1.59

Cost Allocation

These projects are classified as Other (Distribution Reliability) – New Delivery Point projects, which are not eligible for regional cost sharing.

Generator Interconnection Projects

These are projects that are required by generator interconnection agreements.

GI ID	ID	Name	Description	ISD	Cost ($M)
J348	7944	Stuttgart Ricuskey – Stuttgart Industrial 115 kV line	Upgrade Stuttgart Ricuskey – Stuttgart Industrial 115 kV line to 176 MVA	01/30/2018	$2.53
J348	10044	Goodwin Road 115 kV: New Substation	Construct a new 115 kV 3 breaker ring bus switching station named Goodwin Road on the Stuttgart Ricuskey – Almyra 115 kV line	01/30/2018	$10.06

Cost Allocation

These projects are classified as Generation Interconnection projects and are both below 345 kV, which are not eligible for regional cost sharing.

Arkansas Electric Cooperative Corp. (AECC)

This section presents a summary for each project submitted by Arkansas Electric Cooperative Corporation (AECC) in the current MTEP16 cycle. Five projects, classified as Other Distribution Reliability, were submitted as Target Appendix A. The combined cost estimate of these projects is $36.6 million, and they are scheduled to come into service from 2017 through 2020.

Project 10205: New Damascus 161-13.2 kV Substation

Transmission Owner: Arkansas Electric Cooperative Corporation (AECC)

Project Description

This project proposes:

- Build 161/13.2 kV Damascus substation, and add 161 kV line breaker
- Build 6.8-mile, 161 kV line from existing AECC Bee Branch substation to the proposed Damascus substation.

The estimated in-service date for this project is February 28, 2017, with an approximate cost of $8 million. Figure P10205 illustrates the approximate location of Damascus 161/13.2 kV Substation.

Project Need

This project is needed to increase reliability by building a station closer to the load center.

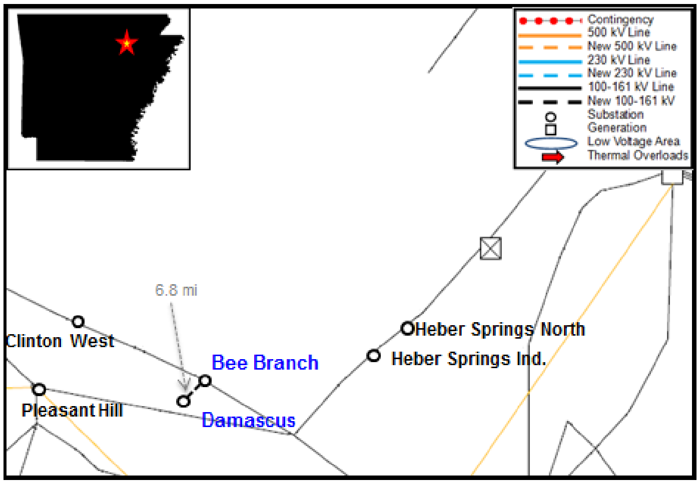


Figure P10205: Geographical representation of Damascus new 161/13.2 kV substation

Alternatives Considered

No alternatives were considered.

Cost Allocation

This project is classified as an Other – Distribution Reliability (New Delivery Point) project, which is not eligible for regional cost sharing.

Project 10206: New Partain 161-69 kV Substation

Transmission Owner: Arkansas Electric Cooperative Corporation (AECC)

Project Description

This project proposes:

- Construction of a new 161/69 kV Partain Substation
- Build 14 mile 161 kV line from the existing Clinton West substation to the proposed Partain 161/69 kV substation.

The estimated in-service date for this project is December 1, 2016, with an approximate cost of $27 million. Figure P10206 illustrates the approximate location of the Partain Substation.

Project Need

This project is needed to provide voltage support and increased reliability to the existing Clinton West to Heber Springs North 69 kV system.

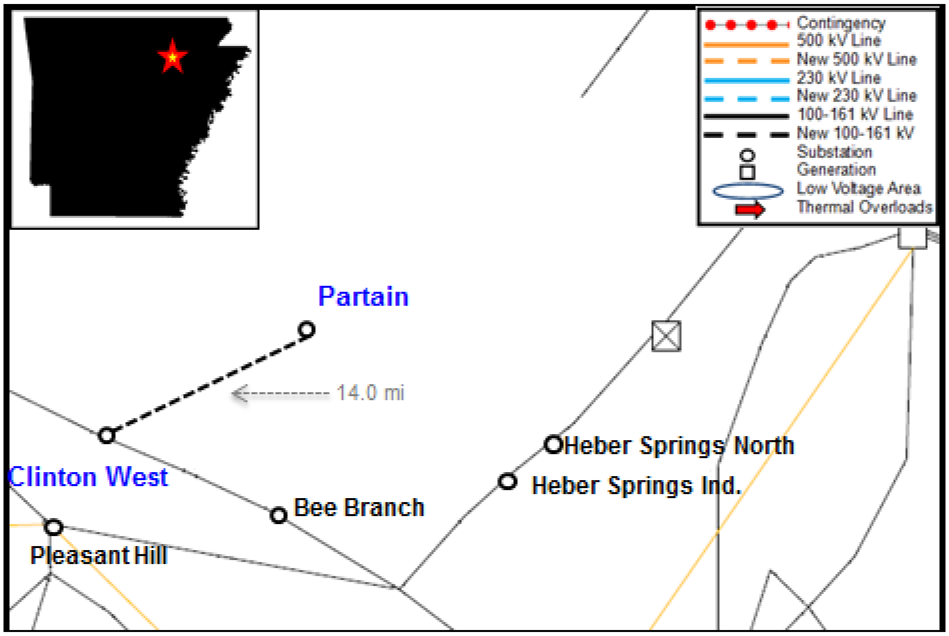


Figure P10206: Geographical representation of Partain 161/69 kV Substation

Alternatives Considered

No alternatives were considered.

Cost Allocation

This project is classified as an Other – Distribution Reliability project, which is not eligible for regional cost sharing.

New Load Additions

These projects are needed in order to serve new or growing loads. The existing distribution system is not sufficient to supply these additions. The most effective way to serve these new loads is to provide a new substation or additional connections to the Bulk Electric system. No-harm tests were conducted to make sure no additional baseline reliability issues were caused by the new load additions.

ID	Name	Description	ISD	Cost
9662	Harrison South Transformer Upgrade	Upgrade the autotransformer at the Harrison South 161-69 kV substation to support normal load growth	01/01/2017	$600,000
9663	Newport East New 161 kV Substation	Construct 20 MVA, 161-13.2 kV substation under EAI Newport – Parkin 161 kV line. The load for this substation will be transferred from the Newport and Cherokee Acres distribution delivery points. Once the load is transferred the two distribution delivery points will no longer be needed.	07/01/2017	$500,000
10204	Hunter North New 161 kV Substation	Construct 161-13.2 kV Hunter North substation. Tap the existing EAI Moses to Bailey 161 kV line	06/01/2018	$500,000

Cost Allocation

These projects are classified as Other Distribution Reliability (New Delivery Point) projects, which are not eligible for regional cost sharing.

Appendix D1: South Planning Region

Louisiana

Regional Information

Louisiana contains three load pockets, one of which is nested within another load pocket. The West of the Atchafalaya Basin (WOTAB), Amite South, and Down Stream Gypsy (DSG) load pockets cover the coastal region of Louisiana, and contain many industrial customers in the Lake Charles and New Orleans areas (Figure LA-1).

The WOTAB load pocket is geographically bound by the Gulf of Mexico (South), the Atchafalaya Basin (East), and extends into the eastern portion of Texas. The portion of WOTAB within the Louisiana state boundary contains the industrial customer-laden Lake Charles area and the city of Lafayette. Entergy Gulf States Louisiana, Lafayette Utilities Systems, and Cleco power transmission companies service this area. This load pocket is expected to see considerable industrial load growth over the next three years.

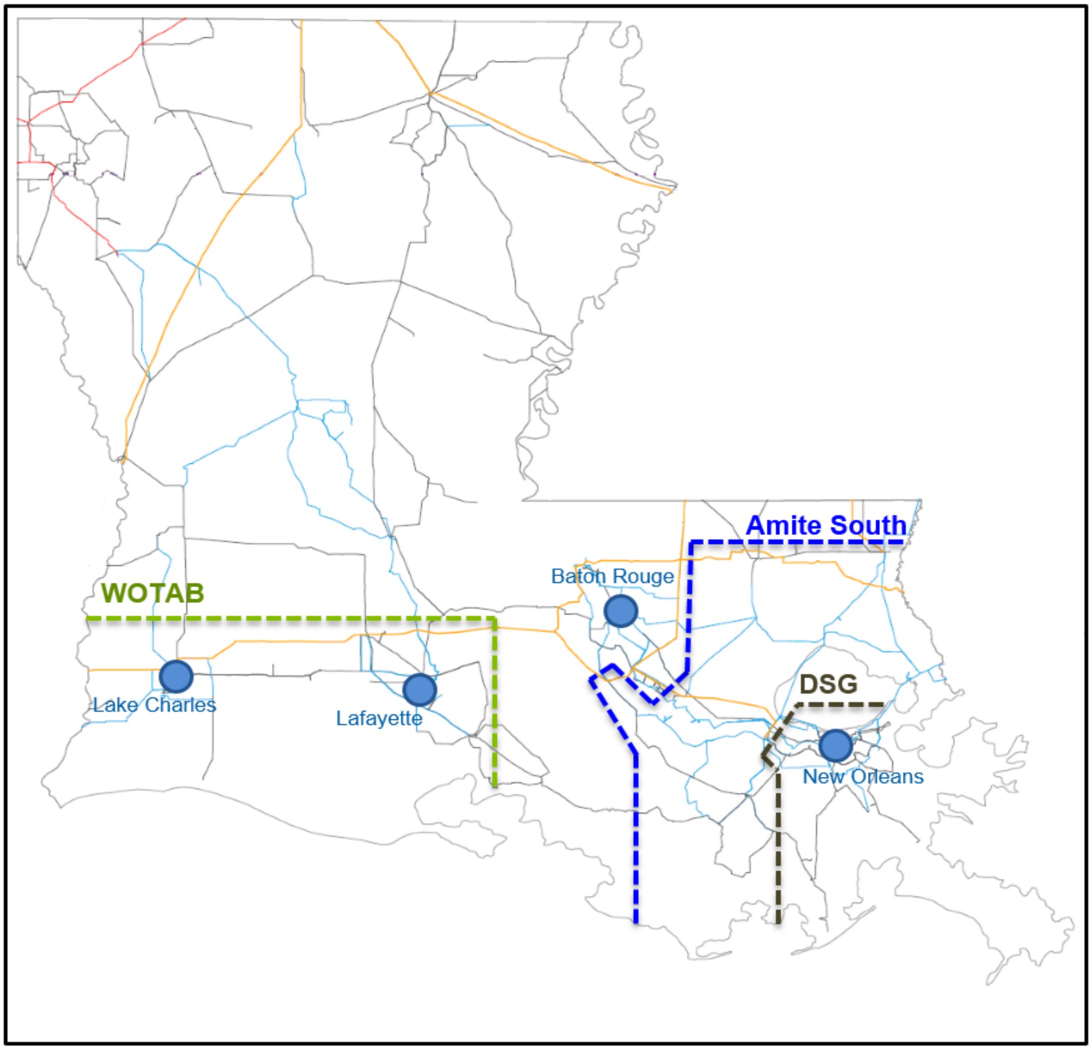
Local generation within WOTAB meets much of the pocket's demand. Generation sources at Nelson, PPG, and Calcasieu support the Lake Charles area, while Acadia and Bonin provide local resources in the Lafayette area. WOTAB is also supported by 500 kV taps at Nelson (Lake Charles) and Richard (Lafayette). There are also many smaller units on the 138 and 69 kV transmission networks used to serve local demand.

The Amite South load pocket lies to the east of Baton Rouge. This load pocket is bound by the Louisiana eastern border, the Gulf of Mexico, and a narrow corridor of transmission lines between Baton Rouge and New Orleans. This load pocket is split by the Mississippi River, and the densely populated city of New Orleans lies beneath Lake Pontchartrain. These geographic obstacles provide narrow corridors for transmission lines, and the pocket lacks multiple EHV lines to import power deep into load centers.

The Amite South load pocket also utilizes local generation sources to meet local demand. Generation at Waterford, Oxy, Union Carbide, Little Gypsy, St. Gabriel, Michoud and Ninemile provide strong sources for local demand.

Amite South contains three 500 kV taps to import power to the area: Waterford, Bayou Labutte and Bogalusa. However, of these three taps, only the Willow Glen to Waterford transmission line penetrates deep into the pocket and this tap still remains outside of the DSG load pocket. The Bayou Labutte 500 kV tap is located on the load pocket interface near Baton Rouge, and the Bogalusa tap is located on the northern pocket interface.

The DSG load pocket is a subset of the Amite South load pocket. This load pocket contains the city of New Orleans. DSG is densely populated, and the pocket is surrounded by Lake Pontchartrain to the north, and the Gulf of Mexico to the east and south. The Mississippi River also runs through the middle of this pocket. The dense population and surrounding bodies of water provide a limited number of transmission line corridors. There are no EHV lines within the pocket for import, and the local demand is primarily supplied by the Ninemile power plant, as well as 230 kV lines extending out of the Little Gypsy and Waterford power plants.

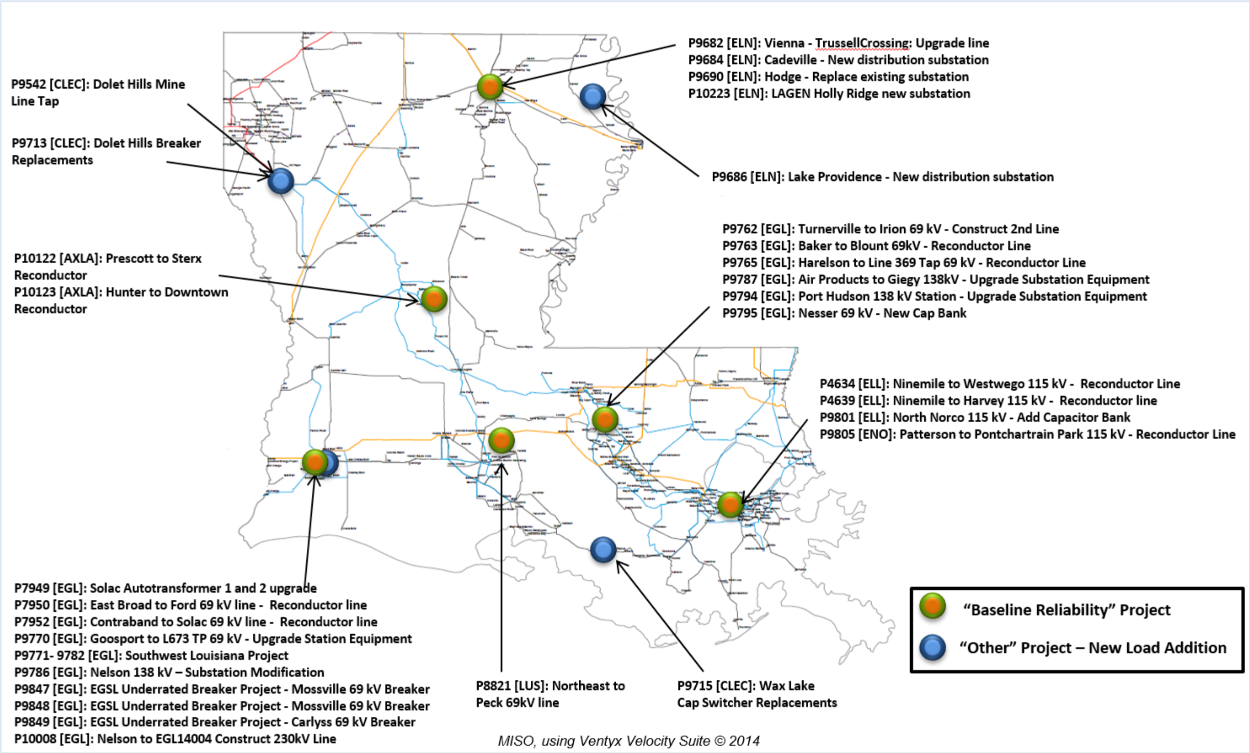


MISO, using Ventyx Velocity Suite © 2014

Figure LA-1: Geographic transmission map of Louisiana with load pocket and load center locations

Overview of Projects:

There are 52 MTEP16 projects targeted for Appendix A, with a total cost of $428 million (Figure LA-2). Of these 52 projects, 27 have an estimated cost greater than $5 million; 11 have an estimated cost between $1 million and $5 million; and 14 have an estimated cost lower than $1 million. The designations of project type are as follows: 27 Baseline Reliability Projects and 25 Other Projects (Figure LA-3).



MISO, using Ventyx Velocity Suite © 2014

Figure LA-2: Geographic transmission map of Louisiana with project locations

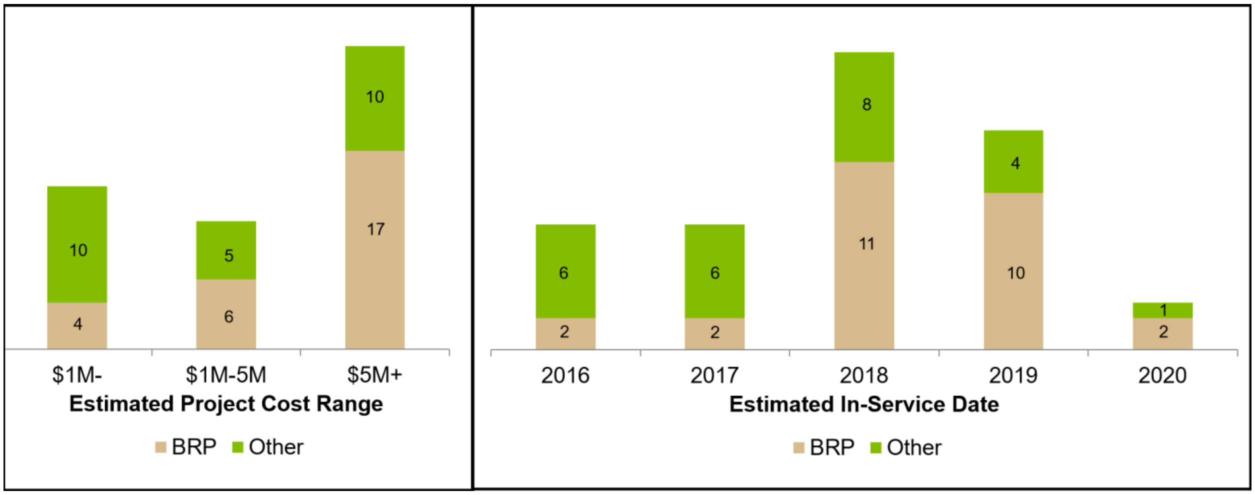


Figure LA-3: Graphs of cost range by project type and estimated in-service date

Entergy Louisiana LLC

Project 4634: Ninemile to Westwego 115 kV Line Upgrade

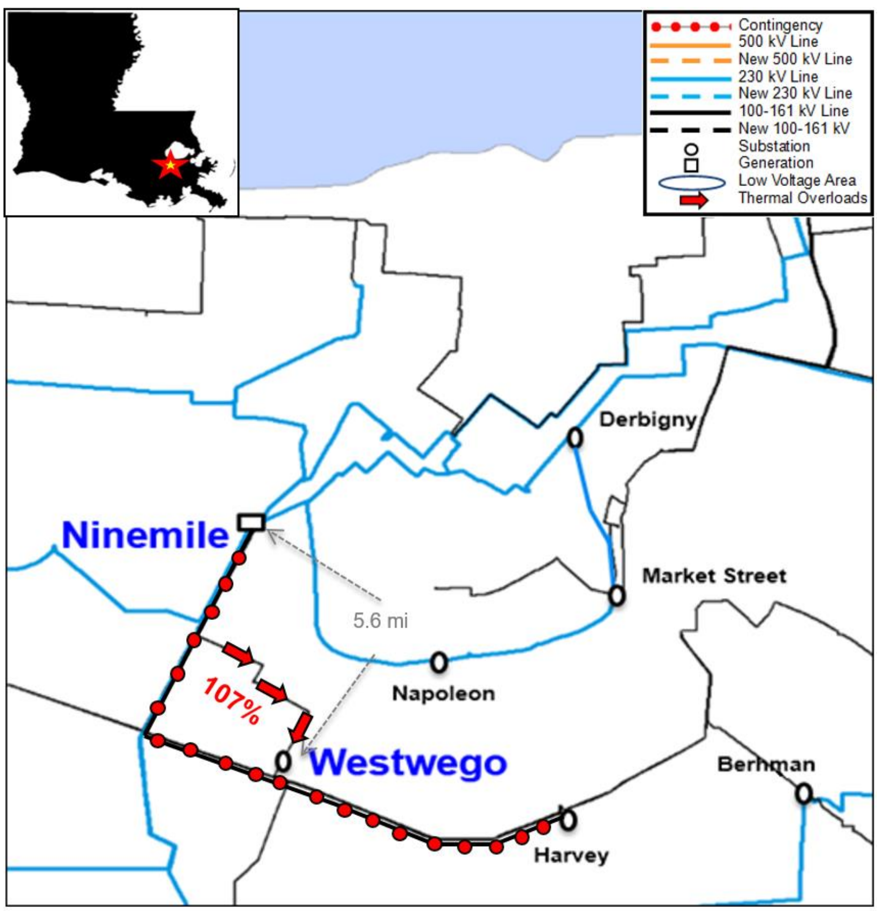
Transmission Owner: Entergy Louisiana LLC

Project Area Information

Project 4634 resides in the Down Stream Gypsy (DSG) load pocket (Figure P4634-1). The DSG load pocket contains the greater New Orleans area in Southeast Louisiana. Ninemile power plant contains over 2,000 MW of generation capacity. Ninemile, Westwego and Harvey form a 115 kV loop downstream of the generation at Ninemile.

Project Area Need

Loss of the Ninemile to Harvey circuit (NERC TPL Category P2.1) causes an increase in powerflow to the remaining portion of the 115 kV loop. The resulting powerflow exceeds the thermal limit of the Ninemile to Westwego circuit.



MISO, using Ventyx Velocity Suite © 2014

Figure P4634-1**: The Ninemile to Westwego 115 kV line will exceed maximum capacity for the loss of Ninemile to Harvey 115 kV line**

Project Description

Project 4634 details the replacement of the Ninemile to Westwego conductor. The new conductor will have a minimum rating of at least 320 MVA. The cost to replace the existing 5.6 miles of conductor is estimated at $9,030,000. The expected in-service date for this project is June 1, 2018.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for cost sharing.

Project 4639: Ninemile to Harvey 115 kV Line Upgrade

Transmission Owner: Entergy Louisiana LLC

Project Area Information

Project 4639 resides in the Down Stream Gypsy (DSG) load pocket (Figure P4939-1). The DSG load pocket contains the greater New Orleans area in Southeast Louisiana. Ninemile power plant contains over 2,000 MW of generation capacity. Ninemile, Westwego and Harvey form a 115 kV loop downstream of the generation at Ninemile.

Project Area Need

Loss of the Ninemile to Westwego circuit (NERC TPL Category P1.2) causes an increase in powerflow to the remaining portion of the 115 kV loop. The resulting powerflow exceeds the thermal limit of the Ninemile to Harvey circuit.

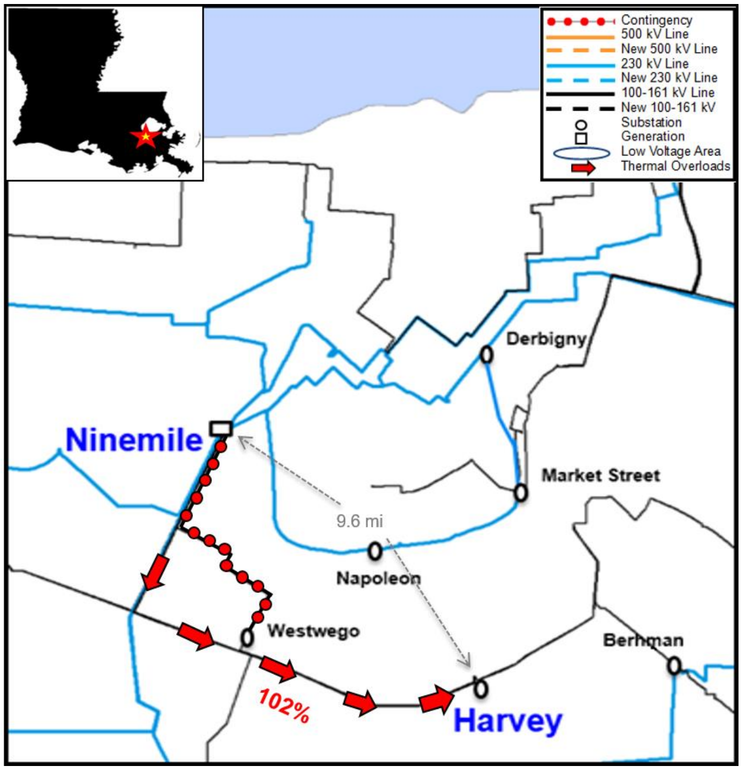


Figure P4939-1**: The Ninemile to Harvey 115 kV line will exceed maximum capacity for the loss of Ninemile to Westwego 115 kV line**

Project Description

Project 4639 details the replacement of the Ninemile to Harvey conductor. The new conductor will have a minimum rating of at least 320 MVA. The cost to replace the existing 9.6 miles of conductor is estimated at $15,120,000. The expected in-service date for this project is June 1, 2018.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for cost sharing.

Project 9805: Paterson to Pontchartrain Park 115 kV Line Upgrade

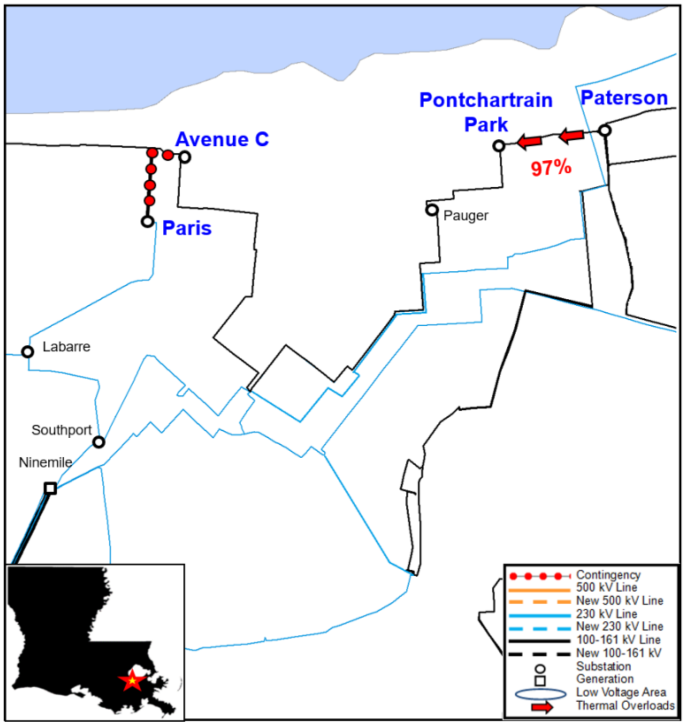
Transmission Owner: Entergy Louisiana LLC

Project Area Information

Project 9805 resides in the Down Stream Gypsy (DSG) load pocket (Figure P9805-1). The DSG load pocket contains the greater New Orleans area in Southeast Louisiana. Ninemile power plant in DSG contains more than 2,000 MW of generation capacity, mostly connected to the 230 kV network in the area. Powerflows from the 230 kV to the 115 kV network to serve local needs.

Project Area Need

Loss of the Avenue C to Paris circuit (NERC TPL Category P2.1) removes a 115 kV access point to the 230 kV network. Powerflow increases from the east, out of Paterson, to compensate. The resulting powerflow exceeds the thermal limit of the Paterson to Pontchartrain Park circuit.



MISO, using Ventyx Velocity Suite © 2014

Figure P9805-1: The Paterson to Pontchartrain Park 115 kV line will exceed maximum capacity for the loss of Paris to Avenue C 115 kV line

Project Description

Project 9805 details the replacement of the Paterson to Pontchartrain Park conductor. The existing conductor runs under a local canal in a heavily populated area of DSG. The cost to replace the existing conductor is estimated at $11.9 million. The expected in-service date for this project is December 1, 2018.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for cost sharing.

Project 9801: North Norco 115 kV Capacitor Bank Addition

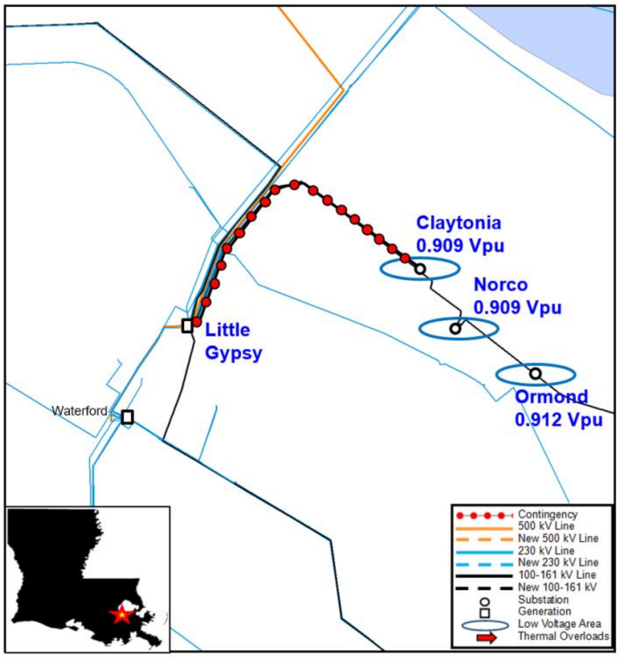
Transmission Owner: Entergy Louisiana LLC

Project Area Information

Project 9805 resides along the interface of the Down Stream Gypsy (DSG) load pocket (Figure P9801-1). Approximately 1,000 MW of generation capacity resides at the Little Gypsy generation plant near the DSG interface. In addition to the 1,000 MW of capacity, the Little Gypsy plant is a strong reactive power support for the 230 and 115 kV networks in the area.

Project Area Need

Loss of the Little Gypsy to Claytonia circuit (NERC TPL Category P1.2) removes the 115 kV networks access to the Little Gypsy plant. Loss of access to reactive source at Little Gypsy causes depressed voltage in the area. The capacitor bank addition at Norco mitigates the voltage issue.



MISO, using Ventyx Velocity Suite © 2014

Figure 9801-1: The 115 kV network near Norco substation experiences low voltage for the loss of Little Gypsy to Claytonia 115 kV line

Project Description

Install a 31 MVAR capacitor bank at Norco substation. The capacitor bank addition has an estimated cost of $1,800,000. The expected in-service date for this project is December 1, 2017.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for cost sharing.

Project 10008: Nelson to Menena New 230 kV Line

Transmission Owner: Entergy Louisiana LLC

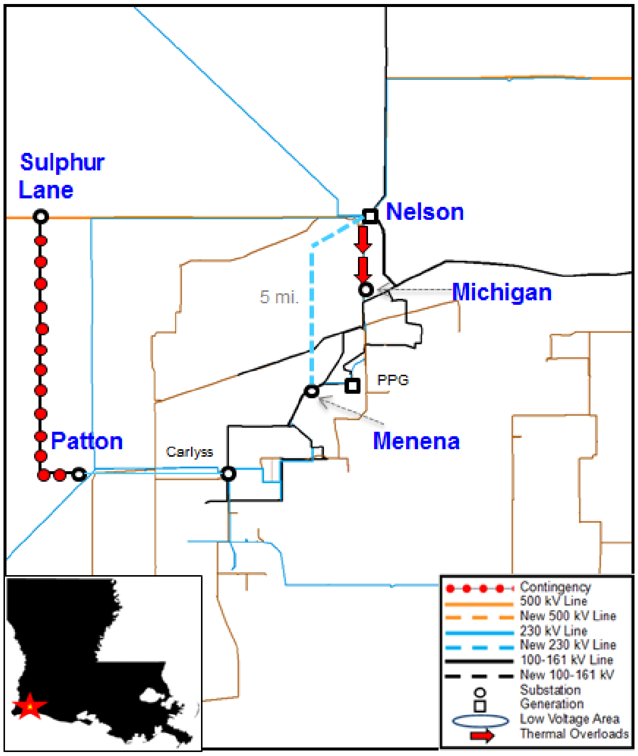
Project Area Information

Project 10008 is in the West of the Atchafalaya Basin (WOTAB) load pocket (Figure P10008-1). The WOTAB load pocket includes the Gulf Coast area from east Texas to the Atchafalaya Basin. This load pocket is import limited, containing two EHV lines and serving more than 6,000 MW of load. The load pocket relies primarily on local 138 and 23 0kV networks to serve load.

The Lake Charles area serves approximately 2,000 MW of the WOTAB load pocket demand. This area has a high concentration of industrial customers.

Project Area Need

The Nelson generation plant provides more than 1,200 MW of generation capacity to the area. Nelson output typically flows South to supply the industry-laden Lake Charles area. Loss of the 500 kV circuit from Patton to Sulphur Lane (NERC TPL Category P1.2) removes a strong power source from Carlyss in the South. Loss of the southern source increases North to South flow from Nelson to compensate. The increase in North to South flow causes the Nelson to Michigan 230 kV line to exceed the thermal limit of the circuit.



MISO, using Ventyx Velocity Suite © 2014

Figure P10008-1: The Nelson to Michigan 230 kV line will exceed maximum capacity for the loss of the Patton to Sulphur Lane 500 kV line

Project Description

Project 10008 details the construction of a new 5-mile, 230 kV circuit from Nelson to Menena substations. The new circuit runs parallel to the Nelson to Michigan line, relieving the loading issue caused by the loss of the Patton to Sulphur Lane 500 kV circuit. The estimated cost of the new line is $15,500,000. The expected in-service date for this project is June 1, 2020.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for cost sharing.

Project 7949: Solac 230/69 kV Autotransformer Upgrades

Transmission Owner: Entergy Louisiana LLC

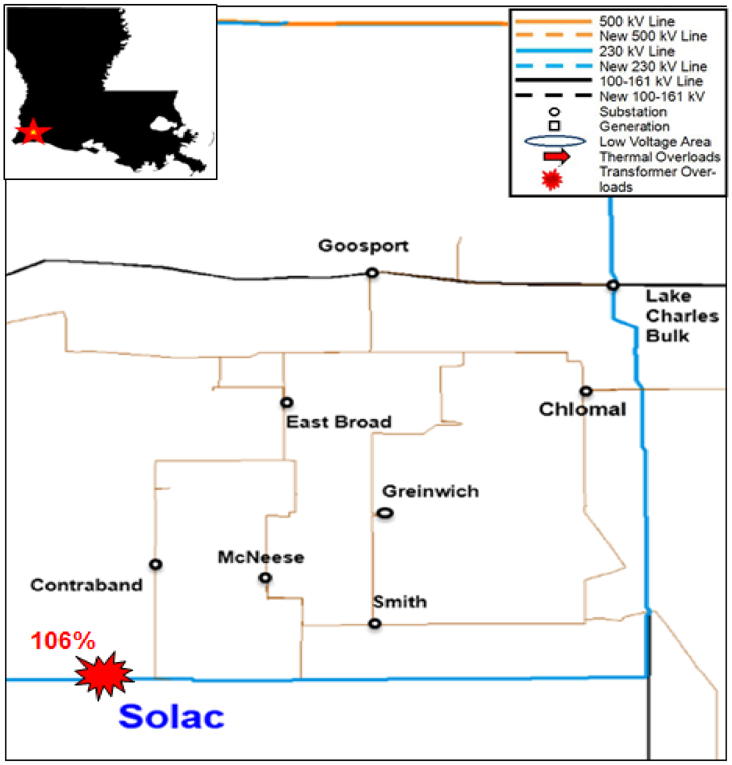
Project Area Information

Project 7949 is in the West of the Atchafalaya Basin (WOTAB) load pocket (Figure P7949-1). The WOTAB load pocket includes the Gulf Coast area from east Texas to the Atchafalaya Basin. This load pocket is import limited, containing 2 EHV lines and serving more than 6,000 MW of load. The load pocket relies primarily on local 138 and 230 kV networks to serve load.

The Lake Charles area serves approximately 2,000 MW of the WOTAB load pocket demand. This area has a high concentration of industrial customers.

Project Area Need

High voltage access points at Solac, Lake Charles Bulk, and Carlyss substations supply the 69 kV network in Lake Charles. The Solac substation contains two 230/69 kV autotransformers to supply the low-voltage network. Loss of either transformer (NERC TPL Category P1.3) will cause the remaining Solac unit to exceed its 200 MVA thermal limit.



MISO, using Ventyx Velocity Suite © 2014

Figure 7949-1: The Solac 230/69 kV autotransformer will exceed the thermal limit for the loss of the parallel unit.

Project Description

Project 7949 details the replacement of two 230/69 kV, 200 MVA autotransformers. Both units at the Solac substation are to be replaced with 300 MVA units. The estimated cost to replace both autotransformers is $8,460,000. The expected in-service date for this project is June 1, 2018.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for cost sharing.

Project 7950: East Broad to Ford 69 kV Line Upgrade

Transmission Owner: Entergy Louisiana LLC

Project Area Information

Project 7950 is in the West of the Atchafalaya Basin (WOTAB) load pocket (Figure P7950-1). The WOTAB load pocket includes the Gulf Coast area from east Texas to the Atchafalaya Basin. This load pocket is import limited, containing two EHV lines and serving more than 6,000 MW of load. The load pocket relies primarily on local 138 and 230 kV networks to serve load.

The Lake Charles area serves approximately 2,000 MW of the WOTAB load pocket demand. This area has a high concentration of industrial customers.

Project Area Need

High voltage access points at Solac, Lake Charles Bulk, and Carlyss substations supply the 69 kV network in Lake Charles. Loss of the Solac to Contraband 69 kV circuit in the southern area of Lake Charles (NERC TPL Category P1.2) will cause increased flow from Lake Charles Bulk to compensate. The increased North to South flow causes the East Broad to Ford 69 kV circuit to exceed the thermal limit of the conductor.

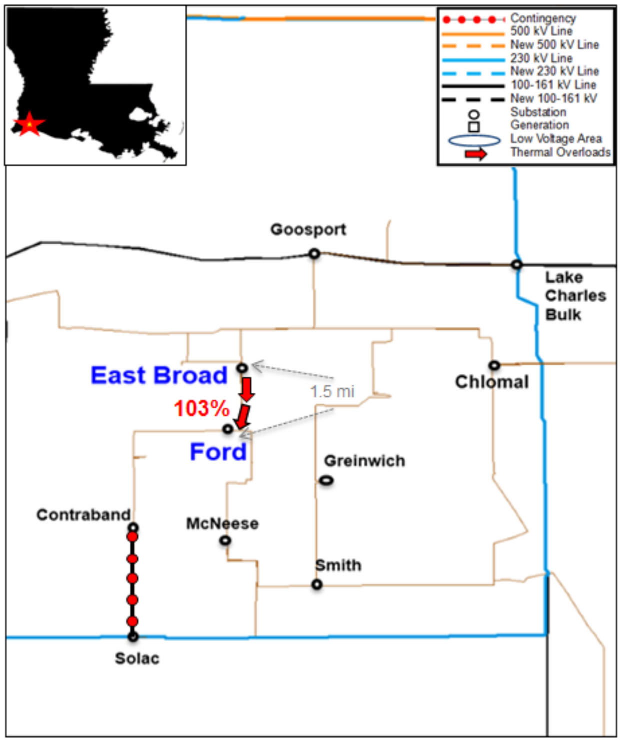


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Figure P7950-1: The East Broad to Ford 69 kV line conductor will exceed thermal limits for the loss of the Solac to Contraband 69 kV circuit.

Project Description

Project 7950 details the replacement of the East Broad to Ford 69 kV line conductor. The estimated cost to replace the 1.5 miles of conductor is $1.5 million. The expected in-service date for this project is June 1, 2018.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for cost sharing.

Project 7952: Solac to Contraband 69 kV Line Upgrade

Transmission Owner: Entergy Louisiana LLC

Project Area Information

Project 7952 is in the West of the Atchafalaya Basin (WOTAB) load pocket (Figure 7952-1). The WOTAB load pocket includes the Gulf Coast area from east Texas to the Atchafalaya Basin. This load pocket is import limited, containing two EHV lines and serving more than 6,000 MW of load. The load pocket relies primarily on local 138 and 230 kV networks to serve load.

The Lake Charles area serves approximately 2,000 MW of the WOTAB load pocket demand. This area has a high concentration of industrial customers.

Project Area Need

High voltage access points at Solac, Lake Charles Bulk, and Carlyss substations supply the 69 kV network in Lake Charles. Loss of the East Broad to Ford 69 kV circuit in the central area of Lake Charles (NERC TPL Category P1.2) will cause increased flow from Solac to compensate. The increased South to North flow causes the Solac to Contraband 69 kV circuit to exceed the thermal limit of the conductor.

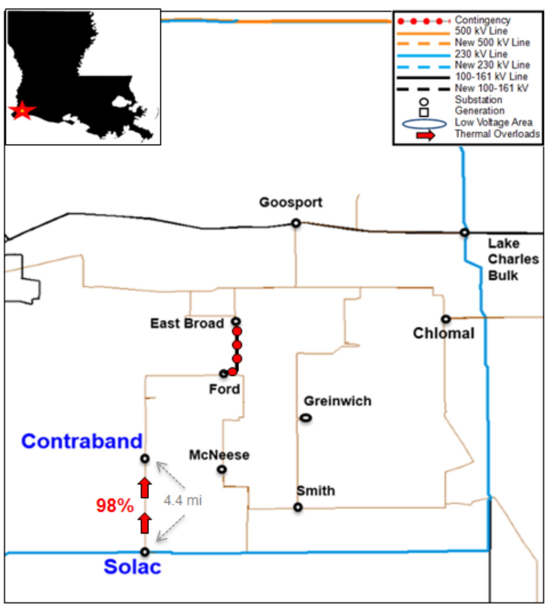

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Figure P7952-1: The Solac to Contraband 69 kV line conductor will exceed thermal limits for the loss of the East Broad to Ford 69 kV circuit.

Project Description

Project 7952 details the replacement of the Solac to Contraband 69 kV line conductor. The estimated cost to replace the 4.4 miles of conductor is $4.1 million. The expected in-service date for this project is June 1, 2018.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for cost sharing.

Projects 9771, 9772, 9773, 9774, 9775, 9776, 9777, 9778, 9779, 9780: Southwest Louisiana Project

Transmission Owner: Entergy Louisiana LLC

Project Area Information

The Southwest Louisiana Project describes a group of network upgrades designed to reconfigure the 69 kV network that runs from Lake Charles Bulk to Jennings substations (Figure P9771-9780-1). High voltage taps at Lake Charles Bulk and Jennings supply the heavily loaded 69 kV network from opposite ends.

The 69 kV lines in this area form a double circuit network from Lake Charles to Lafayette, La. The area between Lake Charles Bulk and Jennings spans 30 miles and contains approximately 100 miles of 69 kV conductor.

Project Area Need

Four 138/69 kV autotransformers are the primary feeds for the 69 kV network in this area. Lake Charles Bulk and Jennings substations each contain parallel transformers 100 MVA. The loss of either transformer at Lake Charles Bulk (NERC TPL Category P1.3) will cause the other to exceed maximum capacity. Similarly, loss of either autotransformer at Jennings (NERC TPL Category P1.3) will cause the other to exceed maximum capacity.

Long lines and heavy loading render the line conductor capacity of the low-voltage network insufficient to meet demand. The loss of Chlomal to Iowa (NERC TPL Category P2.1) or Chlomal to Lacassine (NERC TPL Category P1.2) reduce the effective source at Lake Charles Bulk. This severs the supply on the west side of the system and greatly increases flow out of the east. The resulting powerflow through Jennings substation exceeds the capacity of Jennings to Lawtag and Jennings to Compton transmission line conductors.

Contingent conditions on the east side of the network have a similar effect on the Lake Charles Bulk area. The loss of the Jennings to Lawtag (NERC TPL Category P1.2) or the Jennings to Compton (NERC TPL Category P2.1) circuit reduces the effective source at Jennings. The loss of supply on the eastern side of the network greatly increases the flow from the Lake Charles Bulk area. The power flow from Lake Charles Bulk causes multiple conductors, from Lake Charles Bulk to Serpent substations, to exceed their thermal limit.

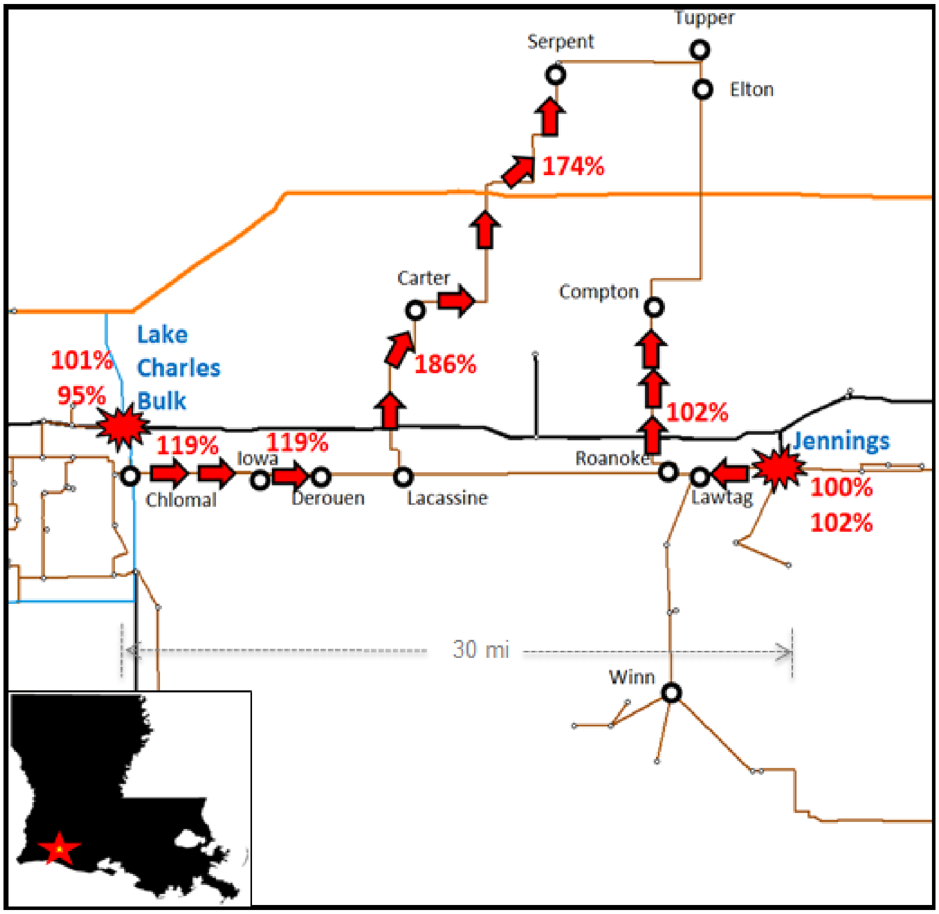

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Figure P9771-9780-1: Lake Charles to Lafayette low-voltage network thermal constraints

Project Description

Phase 1: Project ID P9771, 9772, 9773, 9774, 9775, 9776, 9777, 9778 and 9782 detail the construction of a new 138/69 kV substation, Jefferson Davis (Figure P9771-9780-2). This substation will be cut into the 138 kV network near the Colonial Welsh substation. Jefferson Davis will contain two new 138/69 kV autotransformers. These autotransformers will create a new high-voltage tap for the low-voltage network between Lake Charles Bulk and Jennings.

A new 5-mile 69 kV line will be constructed from Jefferson Davis to Carter. The existing Compton to Roanoke line will be extended and looped into the Jefferson Davis substation. The loop-in and new line will create three 69 kV network connections to the Jefferson Davis substation.

Existing 69 kV lines from Derouen to Lacassine and Lawtag to Roanoke will be reconfigured as Normally Open points. The new Normally Open points, coupled with the new access point at Jefferson Davis, will isolate the low-voltage network between Jennings and Lawtag. This will relieve the burden on the Jennings and Lake Charles Bulk substations to supply the region between Lake Charles and Lafayette. Phase one of the Southwest Louisiana project has an estimated cost of $76.6 million. The expected in-service date of this project is June 1, 2019.

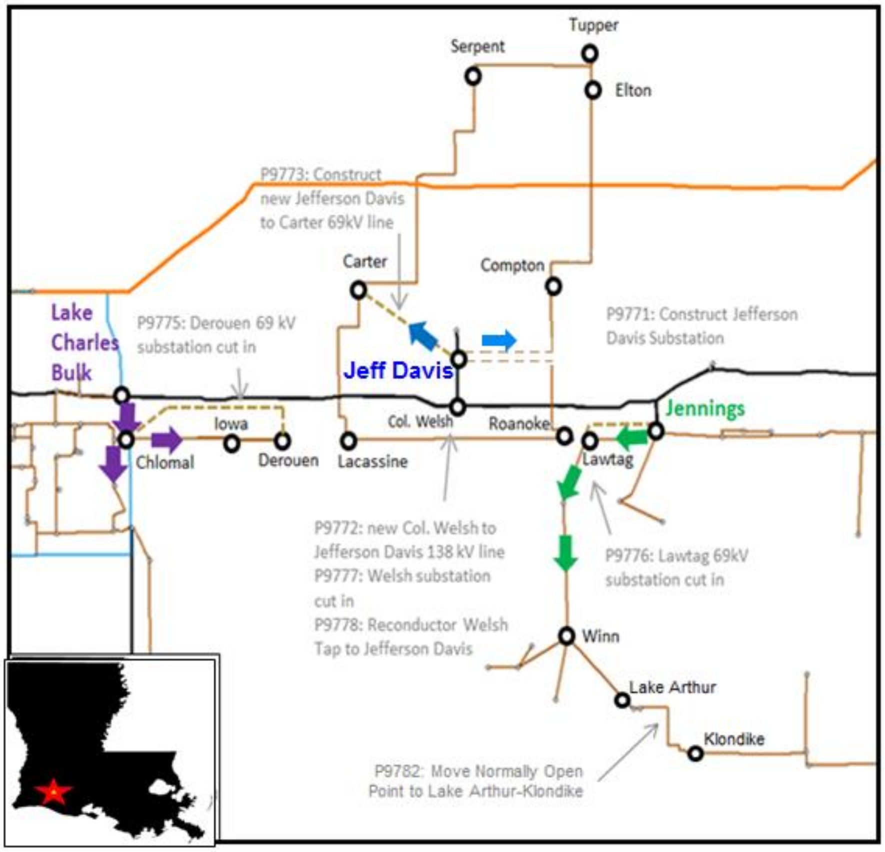

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Figure P9771-9780-2: Southwest Louisiana Project Phase 1

Phase 2: Post phase 1 of the Southwest Louisiana project, a 69 kV loop will be supplied by the Jefferson Davis substation (Figure P9771-9780-3). Loss of one section of the loop causes increased flow from the remaining half to compensate. Loss of the Compton to Elton 69 kV line (NERC TPL Category P1.2) causes the Carter to Serpent 69 kV line conductor to exceed maximum capacity.

Project ID 9779 details the replacement of 15.5 miles of 69 kV conductor from Carter to Serpent substations. Phase 2 of the Southwest Louisiana project has an estimated cost of $19.2 million. The expected in-service date of this project is December 1, 2018.

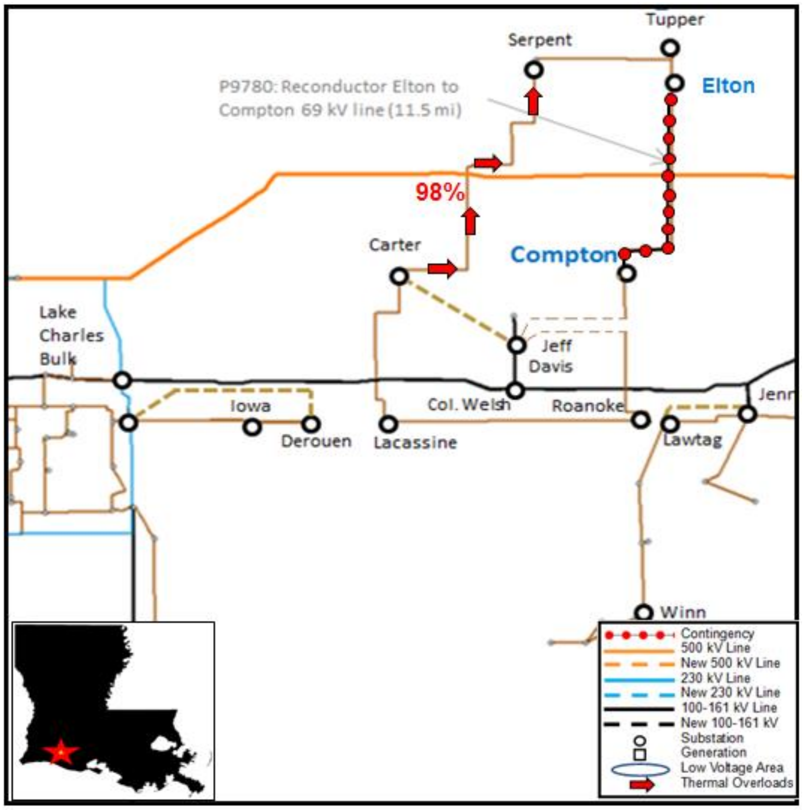

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Figure P9771-9780-3: Southwest Louisiana Project Phase 2

Phase 3 -

Post phase 1 of the Southwest Louisiana project, a 69 kV loop will be supplied by the Jefferson Davis substation (Figure P9771-9780-4). Loss of one section of the loop causes increased flow from the remaining half to compensate. Loss of the Carter to Serpent 69 kV circuit (NERC TPL Category P1.2) causes the Compton to Elton 69 kV line conductor to exceed maximum capacity.

Project ID 9780 details the replacement of 11.5 miles of 69 kV conductor from Compton to Elton substations. Phase 3 of the Southwest Louisiana project has an estimated cost of $12,800,000. The expected in-service date of this project is December 1, 2019.

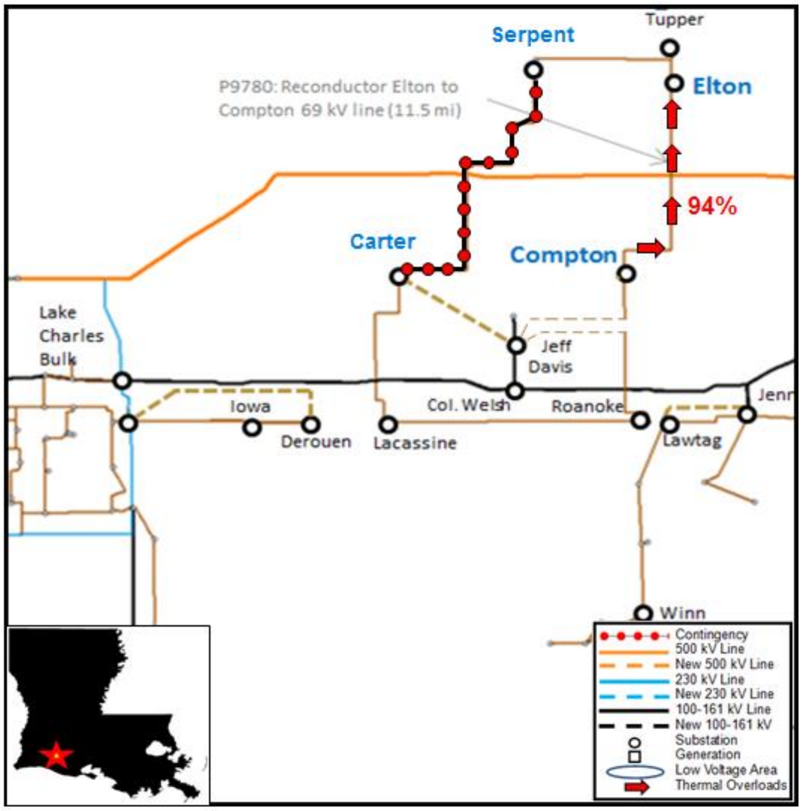

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Figure P9771-9780-4: Southwest Louisiana Project Phase 3

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for cost sharing.

Project 9682: Vienna to Trussell Crossing 115 kV Line Upgrade

Transmission Owner: Entergy Louisiana LLC

Project Area Information

Project 9682 resides on the western edge of the Entergy transmission network in the Minden area (Figure P9682-1). This area is primarily supplied by EHV taps at Sarepta and Mount Olive.

Project Area Need

The loss of the Sarepta to Minden 115 kV circuit (NERC TPL Category P1.2) forces removes the Sarepta source from the Minden area. The loss of the western source causes increased flow from the east to compensate. Increased powerflow from the east causes the Vienna to Trussell Crossing 115 kV circuit to exceed the thermal limit of the line conductor.

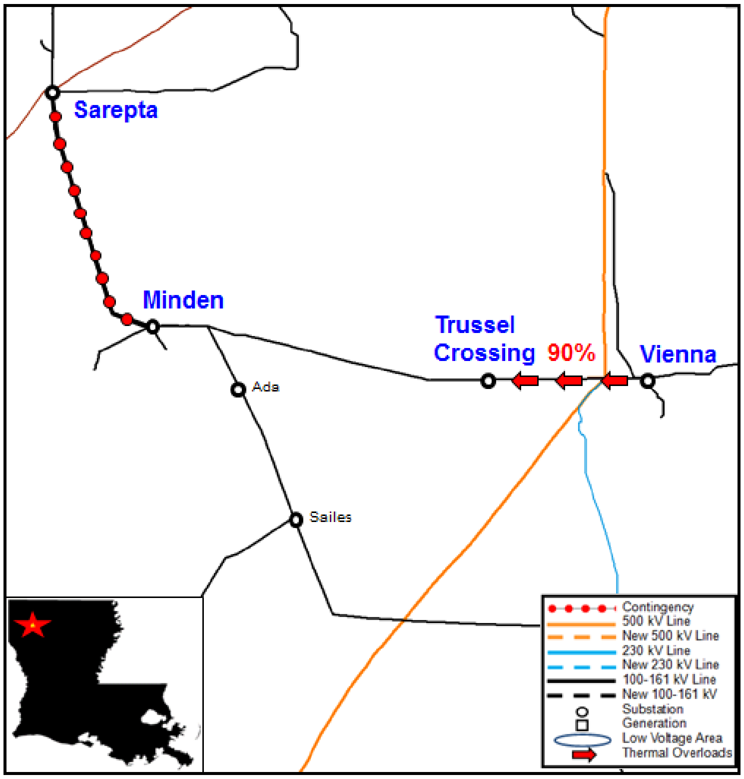

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Figure P9682-1: The Trussell Crossing to Vienna 115 kV line conductor will exceed maximum capacity for the loss of Sarepta to Minden 115 kV circuit.

Project Description

Project 9682 details the replacement of the Vienna to Trussell Crossing 115 kV line conductor to meet a minimum rating of 260 MVA. The replacement of 4.5 miles of 115 kV conductor has an estimated cost of $8.8 million. The expected in-service date of the project is June 1, 2020.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for cost sharing.

Project 9763: Baker to Blount 69 kV Line Upgrade

Transmission Owner: Entergy Louisiana LLC

Project Area Information

Project 9763 resides in northern region of the Baton Rouge area (Figure P9763-1). The local 69 kV network of Zachary, Zachary REA, Baker, Blount and Dixie Baker substations are supplied through high-voltage taps at the Port Hudson and Jaguar substations.

Project Area Need

The loss of the Port Hudson to Zachary 69 kV circuit (NERC TPL Category P1.2) removes the source at Port Hudson from the local 69 kV network. All demand at the Zachary, Zachary REA, Baker, and Dixie Baker substations are supplied through the Blount substation with the loss of the Port Hudson to Zachary circuit. Increased powerflow from the south causes the Blount to Baker 69 kV circuit to exceed the thermal limit of the line conductor.

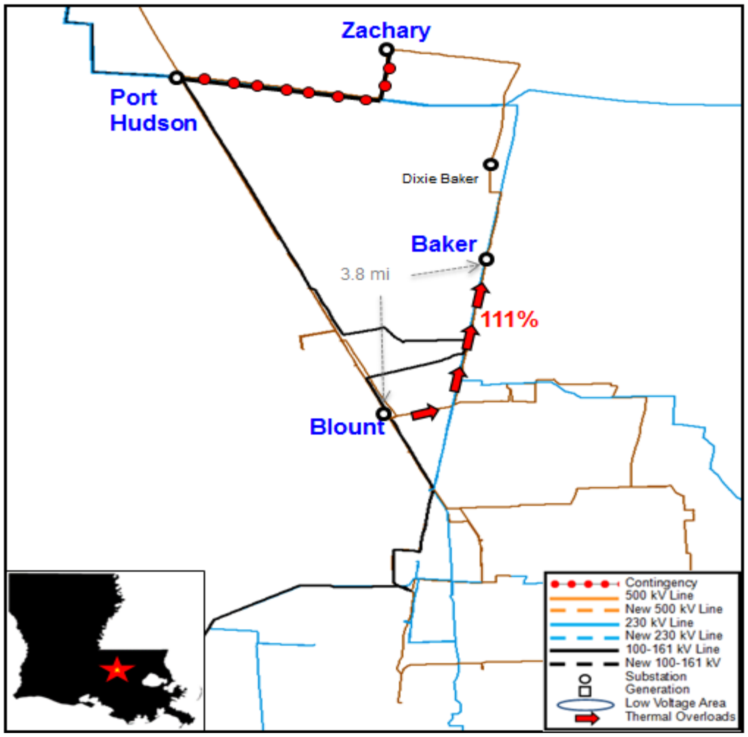

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Figure P9763-1: The Baker to Blount 69 kV line conductor will exceed maximum capacity for the loss of the Port Hudson to Zachary 69 kV circuit.

Project Description

Project 9682 details the replacement of the Blount to Baker 69 kV line conductor. The replacement of 3.8 miles of 69 kV conductor has an estimated cost of $5.2 million. The expected in-service date of the project is June 1, 2018.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for cost sharing.

Project 9765: Harrelson to Line-369 Tap 69 kV Line Upgrade

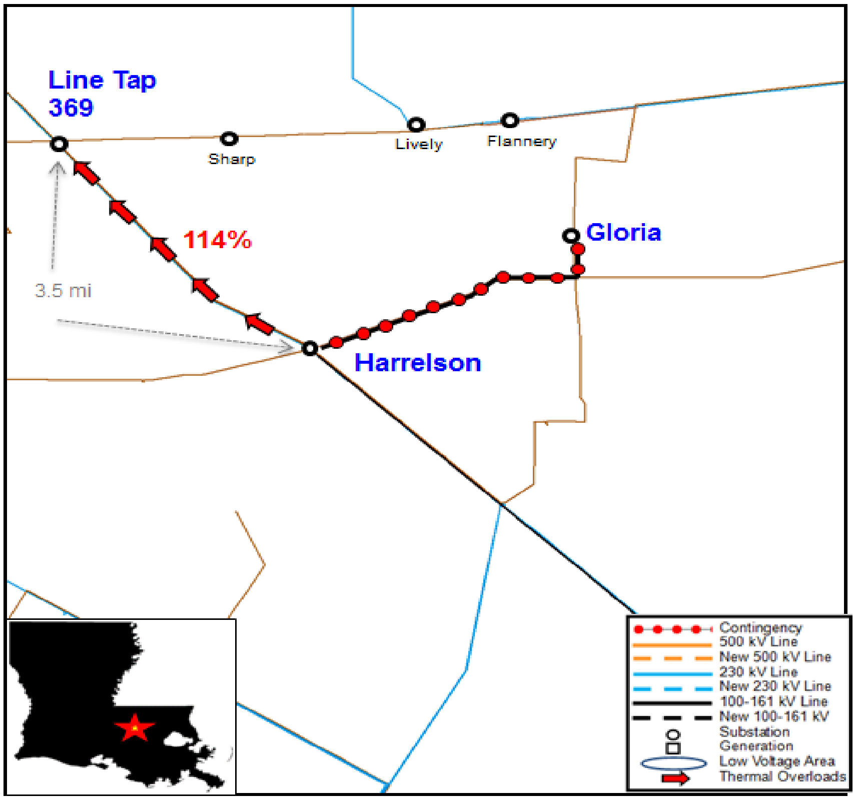
Transmission Owner: Entergy Louisiana LLC

Project Area Information

Project 9765 resides in the Baton Rouge area of Louisiana (Figure P9765-1). The local 69 kV network of Harrelson, Gloria, Flannery, Lively, and Sharp substations form a 69 kV loop supplied by a high-voltage tap at the Harrelson substation.

Project Area Need

The loss of the Harrelson to Gloria 69 kV circuit (NERC TPL Category P1.2) removes half the electrical path from the 69 kV loop. The powerflow through the remaining portion of the 69 kV loop causes excessive flow on the conductor of the Harrelson to Line 369 tap line segment.



MISO, using Ventyx Velocity Suite © 2014

Figure P9765-1: The Harrelson to Line 369 tap 69 kV line conductor will exceed maximum capacity for the loss of the Harrelson to Gloria 69 kV circuit.

Project Description

Project 9765 details the replacement of the Harrelson to Gloria 69 kV line segment conductor. The replacement of 3.5 miles of 69 kV conductor has an estimated cost of $3.2 million. The expected in-service date of the project is December 1, 2018.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for cost sharing.

Project 9788: Port Barre 69 kV Capacitor Bank Addition

Transmission Owner: Entergy Louisiana LLC

Project Area Information

Project 9788 resides along in south-central Louisiana (Figure P9788-1). The local 69 kV network that includes Port Barre and Champagne 69 kV substations is primarily supplied by a 138 kV tap at the Champagne substation.

Project Area Need

Loss of the Champagne 138/69 kV autotransformer (NERC TPL Category P1.3) isolates this area of the low-voltage network from the high-voltage network. Loss of access to the 138 kV source at Champagne causes depressed voltage on the low-voltage network in the area. The capacitor bank addition at Port Barre mitigates the low voltage issue.

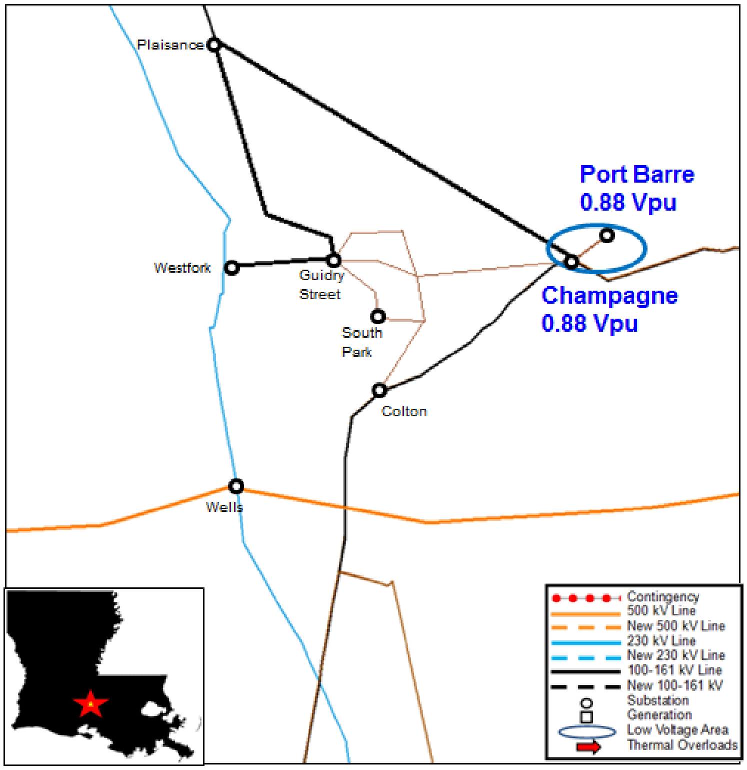


Figure P9778-1: The 69 kV network near Champagne substation experiences low voltage for the loss of the Champagne 138/69 kV autotransformer

Project Description

Install a capacitor bank at the Port Barre substation to mitigate the low voltage issue. The capacitor bank addition has an estimated cost of $800,000. The expected in-service date for this project is June 1, 2018.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for cost sharing.

Project 9795: Nesser 69 kV Capacitor Bank Addition

Transmission Owner: Entergy Louisiana LLC

Project Area Information

Project 9795 resides in the Baton Rouge area of Louisiana (Figure P9795-1). The local 69 kV network that includes Nesser and Jones Creek 69 kV substations is primarily supplied by a 230 kV tap at the Harrelson substation.

Project Area Need

Loss of the Champagne to Jones Creek line segment (NERC TPL Category P2.1) isolates this area of the low-voltage network from the high-voltage network. Loss of access to the 230 kV source at Harrelson causes depressed voltage on the low-voltage network in the area. The capacitor bank addition at Nesser mitigates the low voltage issue.

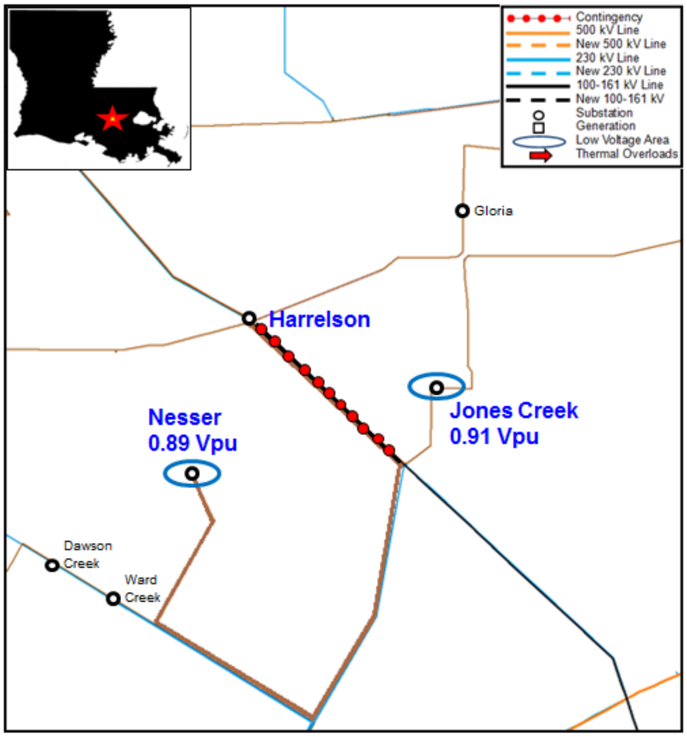


Figure P9795-1: The 69 kV network near Harrelson substation experiences low voltage for the loss of the Harrelson to Jones Creek line segment

Project Description

Install a capacitor bank at the Nesser substation to mitigate a low voltage issue. The capacitor bank addition has an estimated cost of $1,100,000. The expected in-service date for this project is December 1, 2017.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for cost sharing.

Generation Interconnection Projects

The following projects were identified through the Generation Interconnection process. These projects are needed to maintain reliability with the addition of new firm resource (J396) added to the system. J396 is a 904 MW combined cycle gas plant connecting to Little Gypsy Power Station, with an in-service date of May 2018.

ID	Transmission Facility	Facility Owner	Description	Cost
J396	Circuit Breakers at Little Gypsy substation	Entergy	CB replacement	$12,300,000
J396	Snake Farm – Labarre 230 kV line	Entergy	Replace existing line bay bus	$33,000
J396	Midtown – Almonaster 230 kV line	Entergy	Re-conductoring	$1,206,000
J396	Midtown Substation – Tap Ninemile to Derbigny Line	Entergy	Midtown Substation – Tap Ninemile to Derbigny Line	$737,000
J396	J396 Interconnection Facility	Entergy	Three new 2-breaker bays for interconnection transmission lines. Iron Man and Belle Point 230 kV lines separated into their own bays to mitigate a breaker failure issue. Relay Settings at Belle Point and Iron Man Switchyards.	$13,296,000

MISO South Market Congestion Planning "Other" Projects

In the MISO South region, four projects are being recommended as economic "Other projects." Two of the four projects are located in Louisiana area. These projects provide quantifiable economic benefits addressing market competition and efficiency needs with production cost savings in excess of their costs with benefit-to-cost ratios above 1.25. These projects address market efficiency needs because the projects are sub-345 kV projects, but do not qualify for regional cost allocation as MEPs. Costs of these projects are directly assigned to the local Transmission Owner Pricing Zone.

Project 12017: Southeast Louisiana Economic Project

Transmission Owner: Entergy Louisiana LLC

Project Area Information

The Southeast Louisiana Economic project connects the Amite South load pocket to the Down Stream Gypsy (DSG) load pocket (Figure P12017-1). The DSG load pocket includes the greater New Orleans area in Southeast Louisiana. Ninemile power plant contains over 2,000 MW of generation capacity to locally supply the area. Ninemile, Westwego, and Harvey form a 115 kV loop downstream of the generation at Ninemile.

Project Need

The Southeast Louisiana economic project, with an estimated cost of $87.7 million, provides production cost savings in excess of its cost with benefit-to-cost ratios above 1.25. This project provides an outlet and improves the import capability by 650 MW into the DSG load pocket. Also, it provides operational flexibility in the region during planned transmission and generation outages as well as accommodating the system for any future retirements. The project will also provide enhanced resilience to the area during extreme events such as hurricanes.

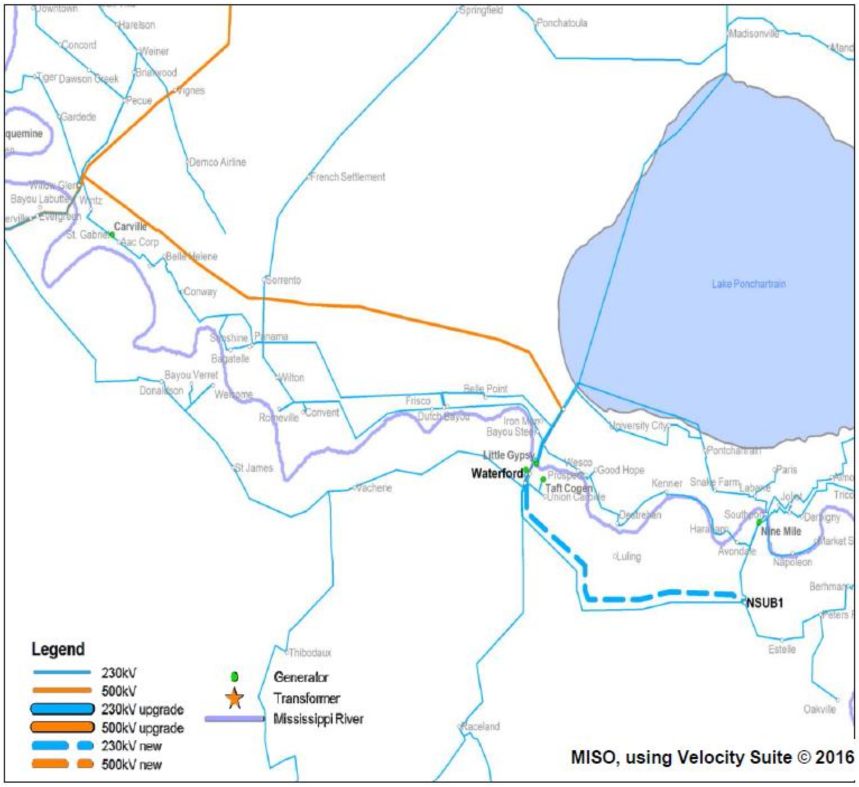


Figure P-12017-1: Southeast Louisiana Project

Project Description

The Southeast Louisiana economic project, with an estimated cost of $87.7 million and estimated in-service date of 2022, is compromised of the following facilities:

- Construction of a new 230 kV substation called Churchill
- Construction of approximately 26 miles of new 230 kV transmission line connecting the existing 230 kV Waterford substation to the Churchill 230 kV substation crossing the Down Stream Gypsy load pocket interface
- Re-configuration of the existing Waterford to Ninemile and Ninemile to Estelle 230 kV lines into the Churchill 230 kV substation and out to the existing Ninemile 230 kV substation to provide access to the strong sources at the Ninemile substation
- Add a breaker at the Michoud 115 kV substation to address the findings during the reliability no-harm robustness analysis

Cost Allocation

This is an economic “Other Project” which is not eligible for cost sharing.

Project 12016: Upgrade Minden to Sarepta Terminal Equipment Economic Project

Transmission Owner: Entergy Louisiana LLC

Project Area Information

Project 9682 resides on the western edge of the Entergy transmission network in the Minden area (Figure P9682-1). This area is primarily supplied by EHV taps at Sarepta and Mount Olive.

Project Need

The Minden to Sarepta Terminal Equipment Upgrade project was shown to provide economic benefit to the region. The weighted benefit-to-cost ratio for future scenarios is 1.83, which is above the 1.25 MISO economic threshold.

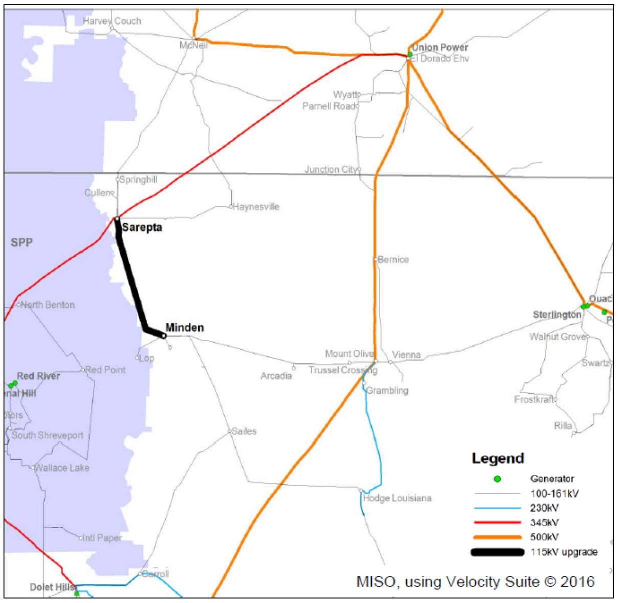


Figure P12016-1: Minden to Sarepta 115 kV circuit terminal equipment upgrade

Project Description

This project details the upgrade of terminal equipment on the Minden to Sarepta 115 kV circuit. Upgrading the terminal equipment will improve the capacity of the circuit to 176 MW. The estimated cost of the Minden to Sarepta terminal upgrade is $1,900,000. The expected in-service date of the project is December 31, 2020.

Cost Allocation

This is an Other - Economic Project, which is not eligible for cost sharing.

New Load Additions

These projects are needed to serve new load. The existing distribution system is not sufficient to supply the additional load. The most effective way to serve the new load is to construct a new substation.

ID	Name	Description	ISD	Cost
9686	Lake Providence (16-ELN-005): New Distribution Substation	Construct a new radial 115 kV transmission line (approx. 10 mi.) to the Lake Providence area to serve area load	6/1/2020	$31,800,000
9684	Cadeville (16-ELN-004): New Distribution Substation	Construct a new radial 115 kV transmission line (approx. 15 mi.) to a new 115 kV substation in the Cadeville area to serve area load	6/1/2018	$41,600,000
9690	Hodge (16-ELN-010): Replace Existing Substation	Construct a new 230 kV substation to serve area load in the Hodge area.	12/1/2018	$14,100,000
9790	Swisco (16-EGL-026): Construct New Substation	Construct a new 138 kV substation to serve area load on the Mossville to Carlyss 138 kV line	6/1/2017	$8,200,000
9791	Thompson Road (16-EGL-027): Construct New Substation	Construct a new 230 kV substation to serve area load on the Patton to Carlyss 230 kV line	6/1/2018	$9,200,000
9792	Lowe Grout Road (16-EGL-028): Construct New Substation	Construct a new 138 kV substation to serve area load on the Lake Charles to Jennings 138 kV line	6/1/2019	$7,000,000
10223	LAGEN Holly Ridge (16-ELN-011) Construct New Substation	Construct a new 115/13.8 kV distribution serving substation on the Oak Ridge - Dunn 115 kV transmission line in North Central Louisiana	12/31/2016	$254,000
10588	Fleur 230 kV Substation: New Substation	Construct a new 230 kV substation on the Oakville to Alliance 230 kV transmission line. This substation will be the primary feed to a customer in the area. Load will move from other substations in the area. Rebuild the Ninemile to Barataria 115 kV line.	12/31/2018	$42,700,000
10623	Sadie 230 kV: Construct New Substation	Construct a new 230 kV substation on the PPG to Rosebluff 230 kV line.	6/1/2018	$24,814,742
10624	Big Lake 230 kV: Construct New Substation	Construct a new 230 kV substation on the Vincent to Graywood 230 kV line.	6/1/2019	$28,000,000

11423	Menena 230 kV: Construct New Substation	Industrial Customer Connection: This is a customer-driven project to install a new 230 kV substation on the PPG to Rose Bluff 230 kV line.	12/1/2017	$7,290,000

Alternatives Considered:

MISO and Entergy Louisiana considered serving the load from alternative locations, but these solutions are the most cost-effective way to serve the new load.

Cost Allocation

These are Other designated projects: Distribution Projects, which are not eligible for regional cost sharing.

Underrated Breaker Projects

These projects are needed in order to increase the short circuit interrupting capability of specific circuit breakers. In Entergy's annual short circuit assessment, Entergy identified and targeted specific circuit breakers throughout the Entergy transmission system to be replaced in order to increase the short circuit capability of the breaker above the projected fault currents. Increased fault currents are due to system configuration changes caused by new projects additions.

ID	Name	Description	ISD	Cost
9847	ELL Underrated Breaker Project (16-EGL-030-1): Mossville 69 kV Breaker 17985	Breaker number 17985 at the Mossville 69 kV substation will be replaced due to the short circuit analysis.	12/1/2017	$700,000
9848	ELL Underrated Breaker Project (16-EGL-030-2): Mossville 69 kV Breaker 17995	Breaker 17995 at the Mossville 69 kV substation will be replaced due to the short circuit analysis.	12/1/2017	
9849	ELL Underrated Breaker Project (16-EGL-030-3): Carlyss 69 kV Breaker 7840	Breaker number 7840 at the Carlyss 69 kV substation will be replaced due to the short circuit analysis.	12/1/2017	

Cost Allocation

These are Other designated projects, which are not eligible for regional cost sharing.

Substation Equipment Replacement

These projects are needed to increase operational flexibility and to replace substation equipment limiting the capacity of transmission line conductor.

ID	Project Name	Description	Expected ISD	Cost
9770	Goosport to L673 TP 69 kV; (16-EGL-011): Upgrade Station Equipment	Upgrade the substation equipment at Goosport to increase the rating of the line	11/18/2016	$145,205
9787	Air Products to Giegy 138 kV; (16-EGL-021): Upgrade Substation Equipment	Upgrade substation equipment on the Air Products and Giegy terminals to increase the rating of the line	6/1/2016	$300,000
10591	Willow Glen 500/138 kV Auto: Adjust Taps	Changing the position of the de-energized tap changer to 500kV (3/C) from 487.5kV (2/B).	12/1/2016	$15,027
9794	Port Hudson Station 138 kV Substation Equipment Upgrade (16-EGL-032)	Upgrade substation equipment at Port Hudson 138 kV.	6/1/2018	$101,000

Cost Allocation

These are Other designated projects: Reliability Projects which are not eligible for regional cost sharing.

Alternatives Considered:

There were no other viable alternatives to replacing the substation equipment.

Substation Reconfiguration Projects:

This project is needed to increase operational flexibility and increase reliability of the system in the area by eliminating some contingency events.

ID	Name	Description	ISD	Cost
9786	Nelson 138 kV Breaker Failure Project (16-EGL-020)	Add L-274, L-654, L-656 and L-698 to the double bus double breaker scheme at Nelson.	6/1/2017	$1.1 M
10583	Coly 230 kV: Breaker Addition (16-EGL-037)	Add a breaker at the Coly 230 kV substation.	6/1/2018	$1.7 M
10584	Tiger 230 kV: Breaker Addition (16-EGL-038)	Add a 230 kV breaker at the Tiger substation.	6/1/2018	$1.7 M
10585	Harelson 230 kV: Breaker Addition (16-EGL-039)	Add a breaker at the Harrelson 230 kV substation.	6/1/2018	$1.7 M

Alternatives Considered:

MISO and Entergy Louisiana considered serving the load from alternative locations, but these solutions are the most cost-effective way to serve the new load.

Cost Allocation

These are Other designated projects, which are not eligible for regional cost sharing.

Cleco Power LLC

Other Projects

Underrated Breaker Projects

This project is needed in order to increase the short circuit interrupting capability of specific circuit breakers. In Cleco's annual short circuit assessment, Cleco identified and targeted specific circuit breakers throughout the Cleco transmission system to be replaced in order to increase the short circuit capability of the breaker above the projected fault currents. Increased fault currents are due to system configuration changes caused by new projects additions.

ID	Name	Description	ISD	Cost
9713	Dolet Hills Breaker Replacements	Replace one of the 345 kV Breakers at Dolet Hills	11/1/2016	$295,000

Cost Allocation

These are Other designated projects which are not eligible for regional cost sharing.

Substation Equipment Replacement

This project is needed to increase operational flexibility, and to provide automated control of the capacitor bank at the Wax Lake substation.

ID	Project Name	Description	Expected ISD	Cost
9715	Wax Lake Cap Switcher Replacements	Replace Manually Operated Switches at Wax Lake with Cap Switchers	10/1/2016	$406,000

Cost Allocation

These are Other designated projects: Reliability Projects, which are not eligible for regional cost sharing.

Substation Reconfiguration Projects

This project is needed to increase operational flexibility and increase reliability of the system in the area by eliminating some contingency events.

ID	Name	Description	ISD	Cost
10983	Hopkins Breaker Addition	Add a second Breaker in Series with Hopkins Breaker 8061.	6/1/2016	$300,000

Cost Allocation

These are Other designated projects which are not eligible for regional cost sharing.

New Load Additions

These projects are needed to serve new load. The existing distribution system is not sufficient to supply the additional load. The most effective way to serve the new load is to construct a new substation.

ID	Name	Description	ISD	Cost
9542	Dolet Hills Mine Line Tap	Tap the existing 230 kV line from Dolet Hills to Mansfield Compressor to serve existing load, which is moving its operations.	12/1/2016	$5,000,000

Alternatives Considered

MISO and Cleco Power LLC considered serving the load from alternative locations, but these solutions are the most cost-effective way to serve the new load.

Cost Allocation

These are Other designated projects, which are not eligible for regional cost sharing.

Lafayette Utilities System

Baseline Reliability Projects

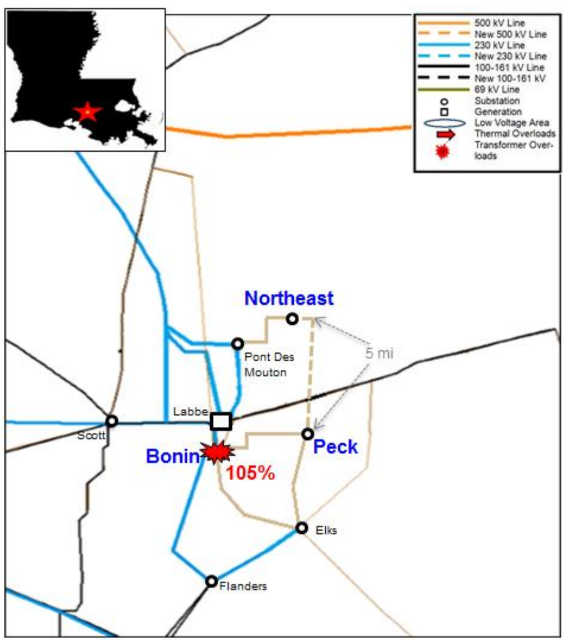
Project 8821: Northeast to Peck 69 kV line
Transmission Owner: Lafayette Utilities System

Project Area Information

The Lafayette Utilities System network, which includes 230 and 69 kV substations, is located in Lafayette, La. (Figure P8821-1) The area contains more than 200 MW of local generation capacity and low voltage taps to the 230 kV network at Pontes Des Mouton and Bonin substations.

Project Area Need

Loss of Bonin generation, connected to the 69 kV network, coupled with the loss of one of the 230/69 kV autotransformers at Bonin (NERC TPL Category P3.3) causes the remaining autotransformer to exceed the thermal limit of the unit.



MISO, using Ventyx Velocity Suite ©2014

Figure P8821-1: Either Bonin 230/69 kV autotransformer will exceed the thermal limit of the unit for the loss of the parallel transformer coupled with a generation unit at Bonin.

Project Description

Project 8821 details the construction of a new 5 mile line from Northeast to Peck 69 kV substations. The 5 mile long line will create a new circuit path supplying the Lafayette area. The support provided by the new line mitigates the thermal issues on the Bonin autotransformers.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for cost sharing.

City of Alexandria

Other Projects

Age Related Replacement Projects

These projects are needed to replace existing conductor that has exceeded its expected life span or condition of the line requires replacement to maintain reliability of the system.

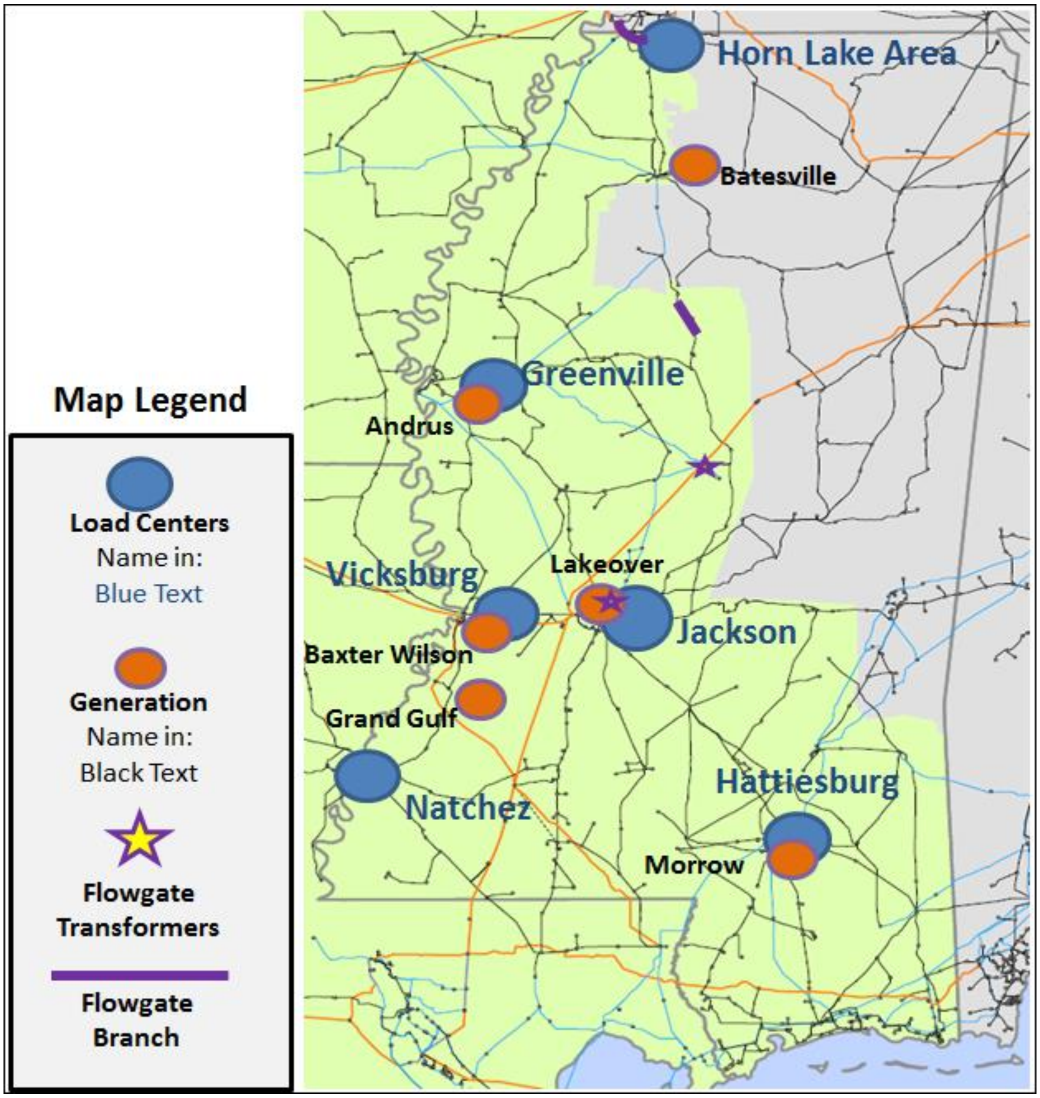
ID	Name	Description	ISD	Cost
10122	Hunter to Downtown 138 kV Line Upgrade	Re-conductor the existing Hunter - Downtown 138 kV transmission line.	7/1/2019	$340,000
10123	Prescott to Sterx 138 kV Line Upgrade	Re-conductor the existing Hunter - Downtown 138 kV transmission line.	7/1/2019	$490,000

Appendix D1: South Planning Region

Mississippi

Mississippi Regional Information

Mississippi largely consists of rural loads throughout the area. Some of the larger load centers include the cities of Jackson, Hattiesburg, Natchez, Vicksburg, and Greenville. The last three mentioned are located near the Mississippi River and have lines that cross over the river and into Louisiana or Arkansas. There are four congested flowgates within MISO Mississippi. They include Elliot to South Grenada 115 kV and Horn Lake to Allen 161kV lines, also the Lakeover 500/115 kV and McAdams 500/230 kV transformers (Figure MS-1).

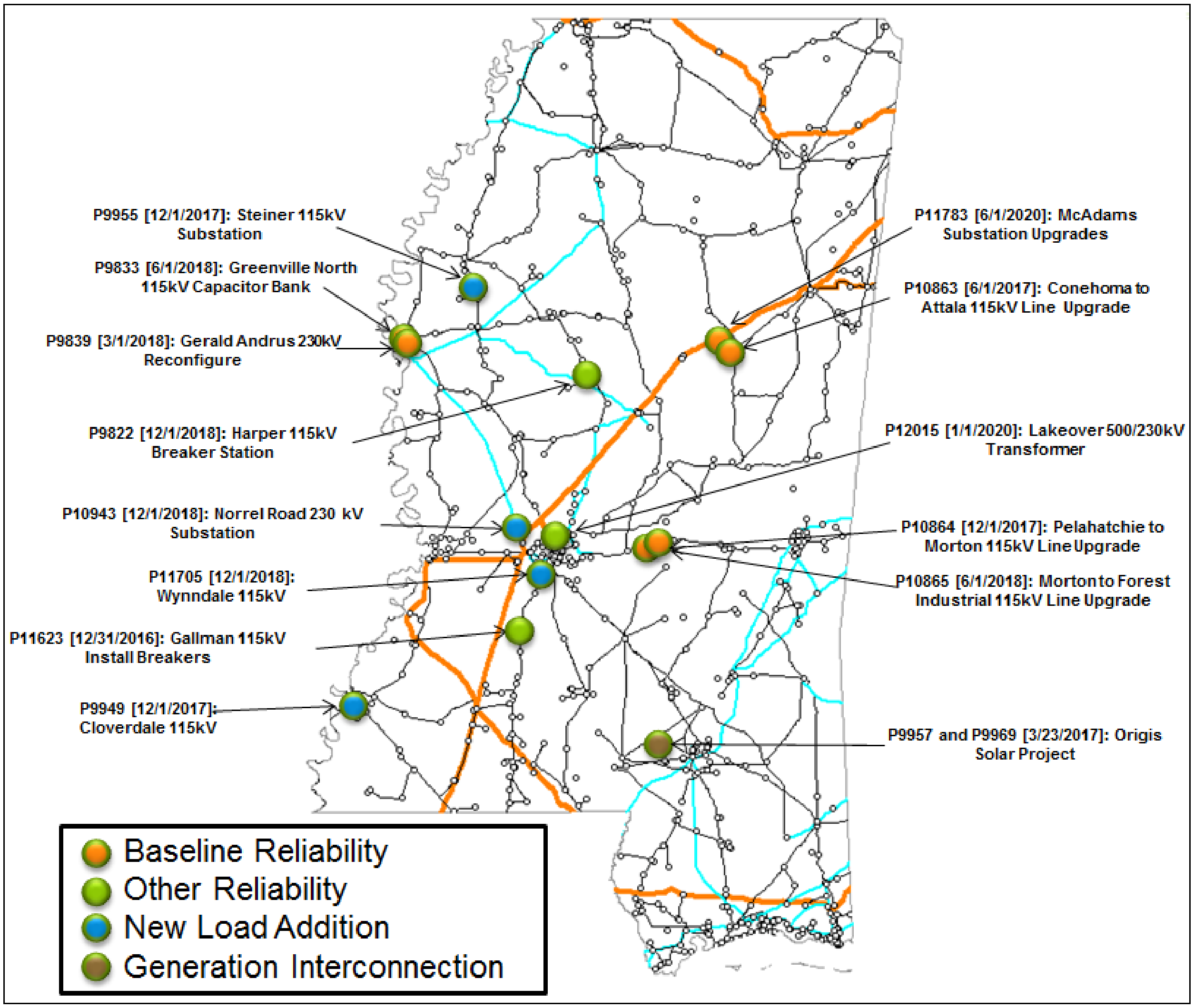


Ventyx Velocity Suite © 2014

Figure MS-1: Geographic transmission map of Mississippi area

Overview of Projects

There are a total of 15 projects in Mississippi that are seeking approval for the MTEP16 cycle. The projects designations are as follows: six Baseline Reliability, three Other, four New Load Additions, and two Generation Interconnection Projects. Project designation and approximate locations are in figure MS-2.



Ventyx Velocity Suite © 2014

Figure MS-2: Geographic transmission map of Mississippi with project locations

Total cost for all projects in Mississippi is $70.48 million. The breakdown by costs ranging from less than $1 million, between $1 and $5 million, and projects greater than $5 million are as follows: three projects have an estimated cost of less than $1 million; five projects are in the cost range of $1 to $5 million, and seven have cost estimates greater than $5 million. Project breakdown by estimated in-service date and cost range can be seen in figures MS-3.

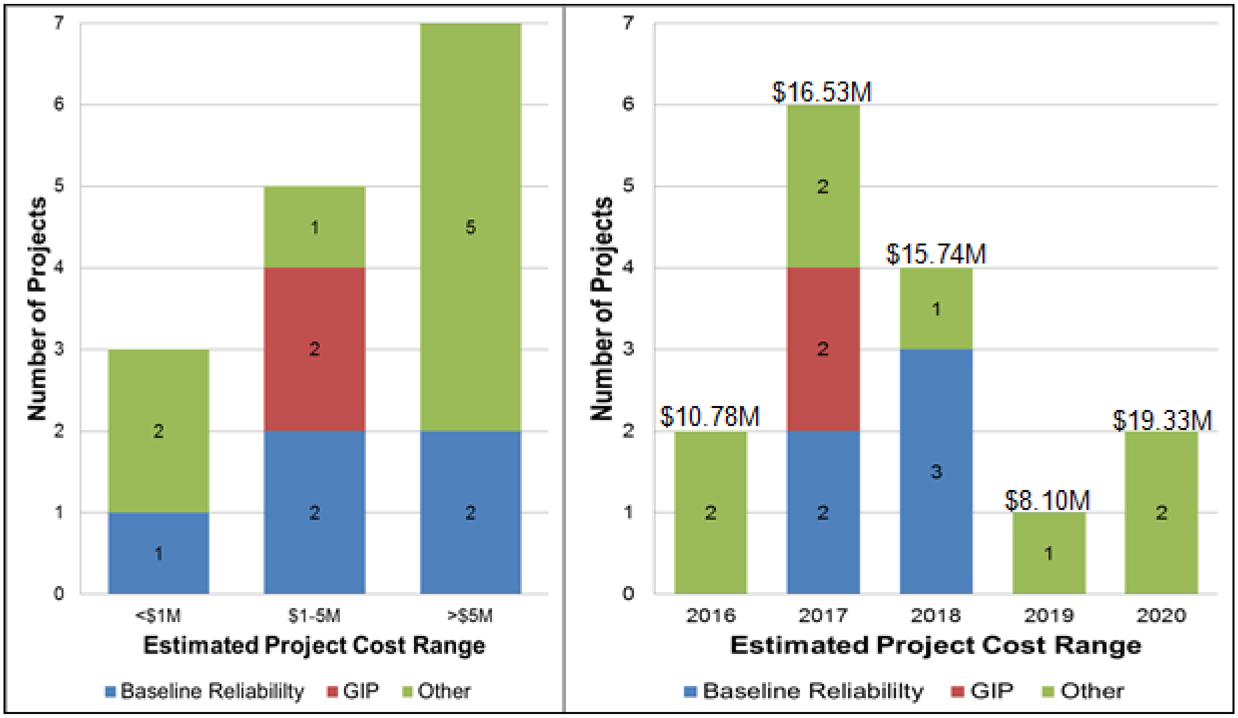


Figure MS-3: Graphs of cost range by project type and estimated in-service date

Entergy Mississippi Inc. (EMI)

Baseline Reliability Projects

Project 9833: Greenville North 115 kV Capacitor Bank

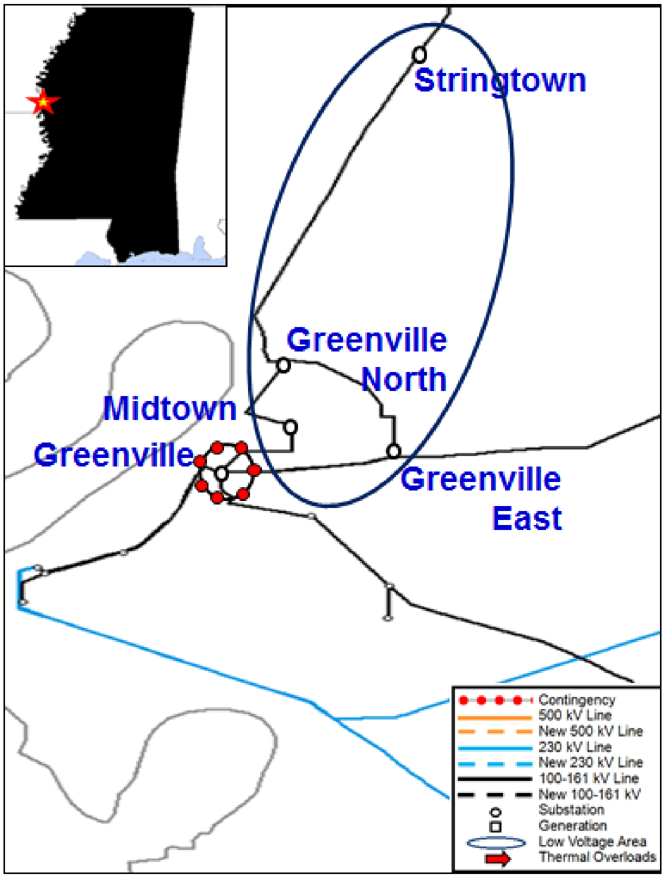
Transmission Owners: Entergy Mississippi Inc.

Project Area Information

The 115 kV loop around Greenville consists of four substations that serve their own load (Figure P9833-1). These substations are Greenville, Greenville East, Greenville Midtown and North Greenville. The area is mainly supplied from Gerald Andrus to Greenville lines 115 kV.

Project Need

A breaker fault event at the Greenville substation can cause loss of access to the Gerald Andrus source and voltage support. This loss causes depressed voltage in the Greenville area. The addition of a second 20.5 MVAR capacitor bank does mitigate the issue.



MISO, using Ventyx Velocity Suite © 2014

Figure P9833-1: Image of contingency and overload for Reenville area

Project Description

The project consists of installing a second 20.5 MVAR capacitor bank at the Greenville North substation. The total estimated cost of this project is $1.2 million. The expected in service date for this project is June 2018.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Project 10863: Conehoma to Attala 115 kV

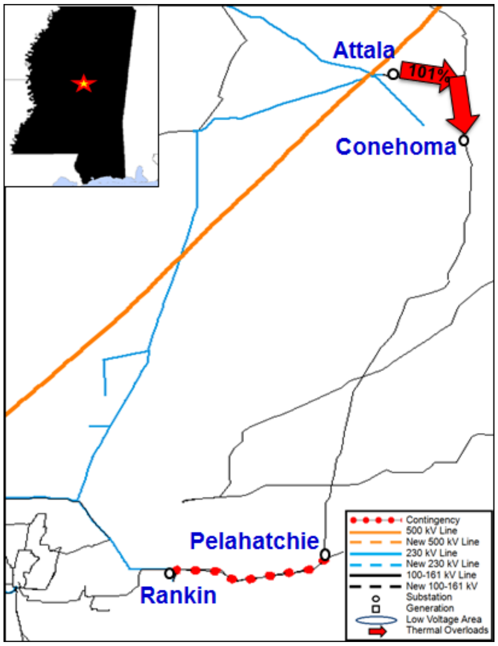
Transmission Owners: Entergy Mississippi Inc.

Project Area Information

This area is the eastern edge of Entergy Mississippi's system. Attala is a source to the 115 kV system that runs north and south from Attala (Figure P10863-1). Conehoma to Attala is the first line segment of a long stretch of 115 kV line circuit that provides flow south from Attala to Pelahatchie substations. The other source into Pelahatchie is the Rankin to Pelahatchie 115 kV line. Flow out of Pelahatchie goes from Pelahatchie to Morton 115 kV toward the seam with Southern Company.

Project Need

When the Rankin to Pelahatchie line is lost, Attala is the single source into the area. The increase of flow on the lines causes overloads on the Attala to Conehoma 115 kV line. Overloads are also seen for breaker faults or complete loss of the Rankin 115 kV substation. With the loss of Rankin to Pelahatchie and the Ratcliff Units the overload increases to 120 percent.



MISO, using Ventyx Velocity Suite © 2014

Figure P10863-1: Image of contingency and overload for Conehoma to Attala 115 kV.

Project Description

This project consists of upgrading the line rating of Attala to Conehoma Creek to a minimum of 1303A. The total estimated cost of this project is $2.45 million. The expected in-service date for this project is June 2017.

Alternatives Considered

Submitted alternative of installing 2nd Rankin 230/115 kV autotransformer and rebuilding South Grenada to Elliott 115 kV led to a decrease in reliability to customer along the Attala to Winona and Attala to Pelahatchie 115 kV lines.

Cost Allocation

This is a Baseline Reliability Project which is not eligible for regional cost sharing.

Project 10864 and 10865: Pelahatchie to Morton and Morton to Forest Ind 115 kV

Transmission Owners: Entergy Mississippi Inc**.**

Project Area Information

This area is the eastern edge of Entergy Mississippi's system (Figure P10864-1). Flow provided to the Pelahatchie substation from the north and west, and flow out the Pelahatchie to Morton 115 kV toward the Morton to Forest Ind 115 kV tie line with Southern Company.

Project Need

With the loss of Southern Company's Ratcliff Units and the loss of the Tennessee Valley Authority's Choctaw to Clay 500 kV line flows across the Pelahatchie to Morton to Forest Ind 115 kV lines increases to 108 percent and 103 percent, respectively.

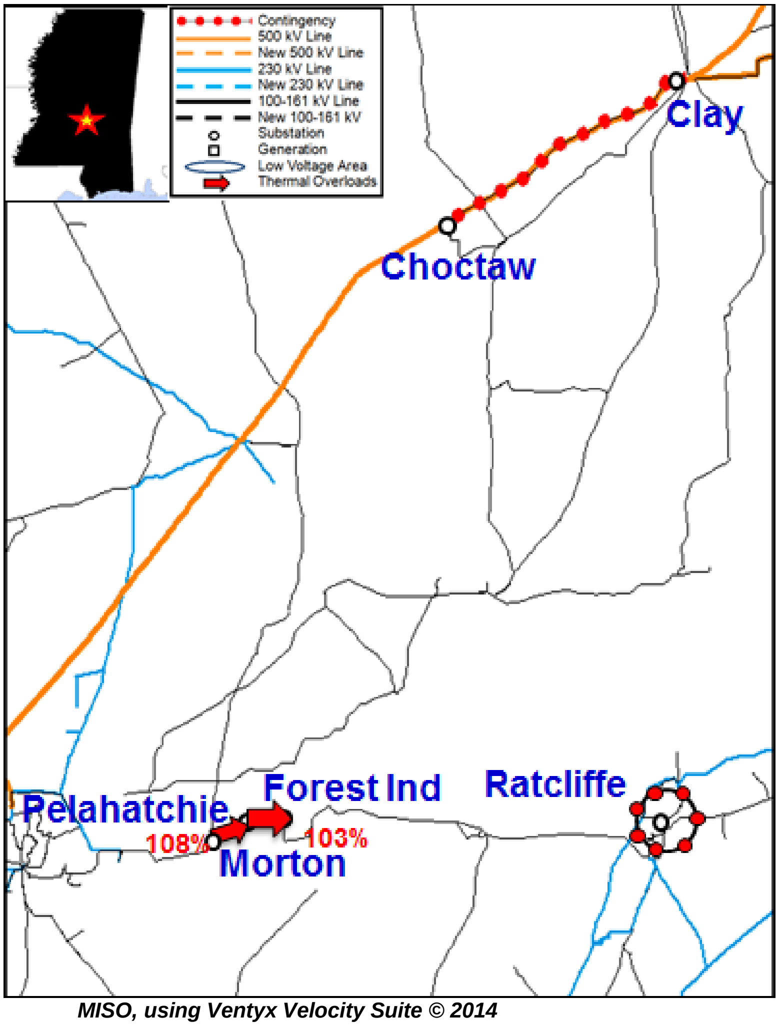


Figure 10863: Image of contingency and overload for Pelahatchie to Morton 115 kV.

Project Description

This project consists of upgrading the line rating of Attala to Conehoma Creek to a minimum of 1303A. The total estimated cost of this project is $2.45 million. The expected in-service date for this project is June 2017.

Alternatives Considered

Pelahatchie Reactor project no longer sufficiently addresses thermal overloading. Sizing a large reactor will put added transmission flows on other highly loaded lines as well as reduce voltage profile into Southern Company system.

Cost Allocation

This is a Baseline Reliability Project, which is not eligible for regional cost sharing.

Substation Upgrade Projects

These projects are for substation reconfigure and upgrades that address baseline reliability drivers.

Prj ID	Project Name	Description	Project Need	Estimated Cost ($M)	Expected ISD
9839	Reconfigure Gerald Andrus 230 kV line terminals	Re-terminate Ray Braswell 230 kV line circuit into Bagby line bay.	Single element contingency causes outages. Reconfigure will eliminate the possible event.	$ 0.35	3/1/2018
11783	McAdams Upgrades	Upgrade equipment and transformer at McAdams substation	TSR-negotiated upgrade	$ 12.6	6/1/2020

Cost Allocation

This is a Baseline Reliability Project which is not eligible for regional cost sharing.

Other Reliability Projects

These are areas with long 115 kV line circuits. Installation of breakers along these lines is necessary to improve customer reliability by reducing transmission line exposure.

Prj ID	Project Name	Description	Estimated Cost ($M)	Expected ISD
9822	Harper 115 kV Breaker Station	Construct a new 115 kV breaker switching station.	$ 5.30	12/1/2018
11623	Gallman 115 kV	Install transmission breakers at Gallman 115 kV substation	$ 2.99	12/31/2016

Cost Allocation

These are designated as Other Projects which are not eligible for regional cost sharing.

MISO South Market Congestion Planning "Other" Projects

In MISO South region, four economic projects are being recommended as "Other" projects. One of the four projects is located in the Mississippi area. The project provides quantifiable economic benefits addressing market competition and efficiency needs with production cost savings in excess of their costs with benefit-to-cost ratios above 1.25.

Project 12015: Lakeover 500/230 kV Transformer

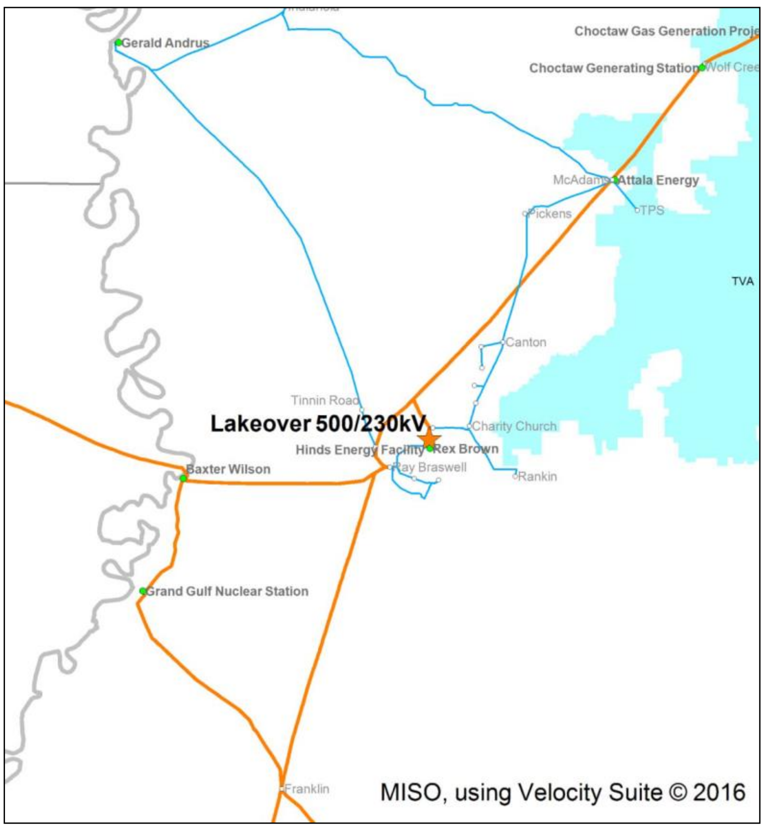
Transmission Owners: Entergy Mississippi Inc.

Project Area Information

Lakeover EHV is located north-northwest of Jackson, and is a source for the 230 kV and 115 kV transmission circuits. Hinds units supply generation to the 230 kV transmission circuit, while the 500kV source at Lakeover is electrically connected to the 115 kV transmission circuit.

Project Need

The Lakeover 500/115 kV transformer is one of the four congested flowgates in Mississippi. This project will alleviate congestion. Lakeover 500/230 kV transformer economic project provides cost savings in excess of its cost with benefit-to-cost ratios above 1.25.



MISO, using Ventyx Velocity Suite © 2014

Figure 10863: Image of contingency and overload for Pelahatchie to Morton 115 kV.

Project Description

This project consists of relocating and installing a 500/230 kV transformer from the McAdams substation to Lake over EHV substation. The total estimated cost of this project is $6.7 million. The expected in-service date for this project is June 2020.

Cost Allocation
While this project addresses market efficiency needs, because the projects are sub-345 kV projects, these do not qualify for regional cost allocation as MEPs. Costs of these projects are directly assigned to the local Transmission Owner Pricing Zone.

New Load Additions

These projects are needed to serve new load. The existing distribution system is not sufficient to supply the additional load. The most effective way to serve the new load is to construct a new substation.

Prj ID	Project Name	Description	Estimated Cost ($M)	Expected ISD
10943	Norrel Road	Construct new 230 kV substation	$ 8.10	12/1/2018
11705	Wynndale 115 kV	Install 2x115/13.8 kV distribution transformers in the Wynndale substation	$ 7.79	12/31/2016

South Mississippi Electric Power Association (SMEPA)

Generation Interconnection Projects 9957 and 9969

The following projects were identified through the Generation Interconnection process. The Generation Interconnection study id for these projects is J473. The projects are needed to maintain reliability with the addition of new firm resource added to the system. J473 is a 52MW solar power plant that will tap SMEPA's Sumrall to Rawls 69 kV line.

Project Number	Transmission Facility / Constraint	Transmission Facility Owner	Mitigation / Type of Upgrade	Cost ($ M)
J473	69 kV line from J473 substation to Rawl SP.	SMEPA	All pole structures on Line 42 (Rawls Springs to J473_Sub) will be replaced resulting in a final conductor rating of 71MVA (100°C). Optical ground wire will be installed on Line 42 for communication purposes. The existing 336 ACSR conductor will not be replaced.	1.147
	69 kV line from J473 Substation to Sumrall	SMEPA	All pole structures on Line 42A (Sumrall to J473_Sub) will be replaced resulting in a final conductor rating of 71MVA (100°C). The existing 336 ACSR conductor will not be replaced.	1.027
	69 kV line from Sumrall and Columbia	SMEPA	All pole structures on Line 43 (Columbia to Sumrall) will be replaced resulting in a final conductor rating of 71MVA (100°C). The existing 336 ACSR conductor will not be replaced.	2.532
	Replacement of 1312 Mosell Breaker - as per SC study	SMEPA	Breaker replacement	0.075
	J473 Interconnecting Facility	SMEPA	Transmission Owner's 69kV switching Station with 2-69kV breakers & Transmission Owner's Interconnection Facilities at the 69/26.4kV Interconnection Substation	1.59

New Load Additions

These projects are needed to serve new load. The existing distribution system is not sufficient to supply the additional load. The most effective way to serve the new load is to construct a new substation.

Prj ID	Project Name	Description	Estimated Cost ($M)	Expected ISD
9955	Steiner	The Steiner DP will be located approximately 1.6 miles northeast of the existing Shaw Switching Station and will be served from Entergy's existing 115 kV Cleveland to Shaw transmission line via a looped transmission feed. This DP will require installation of a new switching station with motor operated	$ 0.81	12/1/2017

		switches and other miscellaneous upgrades to accommodate the new 115 kV looped service.		
9949	Cloverdale	The Cloverdale DP will be served from the existing Entergy IP to Johns Manville 115 kV transmission line via a looped transmission feed into a new switching station to be constructed at the DP site.	$ 0.90	12/1/2017

Cost Allocation
These are designated as Other Projects which are not eligible for regional cost sharing.

South Planning Region

Texas

Regional Information

MISO Texas is primarily the Texas portion of the West of the Achafalaya Basin (WOTAB) load pocket with the entire Western load pocket embedded inside WOTAB. There is a major 500 kV feed in the eastern portion that feeds into the Hartburg 500 kV substation and there is a major 345 kV line feeding into the Grimes 345 kV substation in the west. Major generation sources are the Sabine units in WOTAB and the Frontier and Lewis Creek units in Western. These generators are typically dispatched for voltage and local reliability issues.

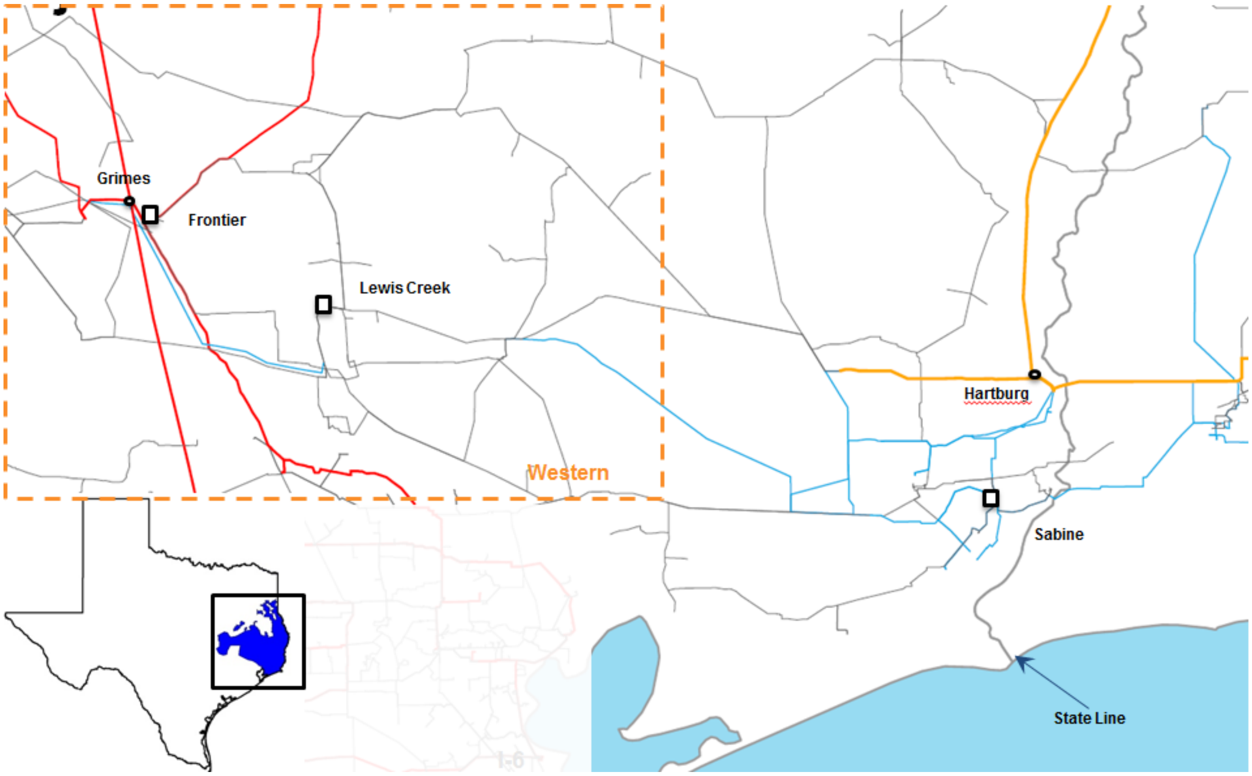


Figure TX-1: Geographic transmission map of MISO Texas

Overview of Projects:

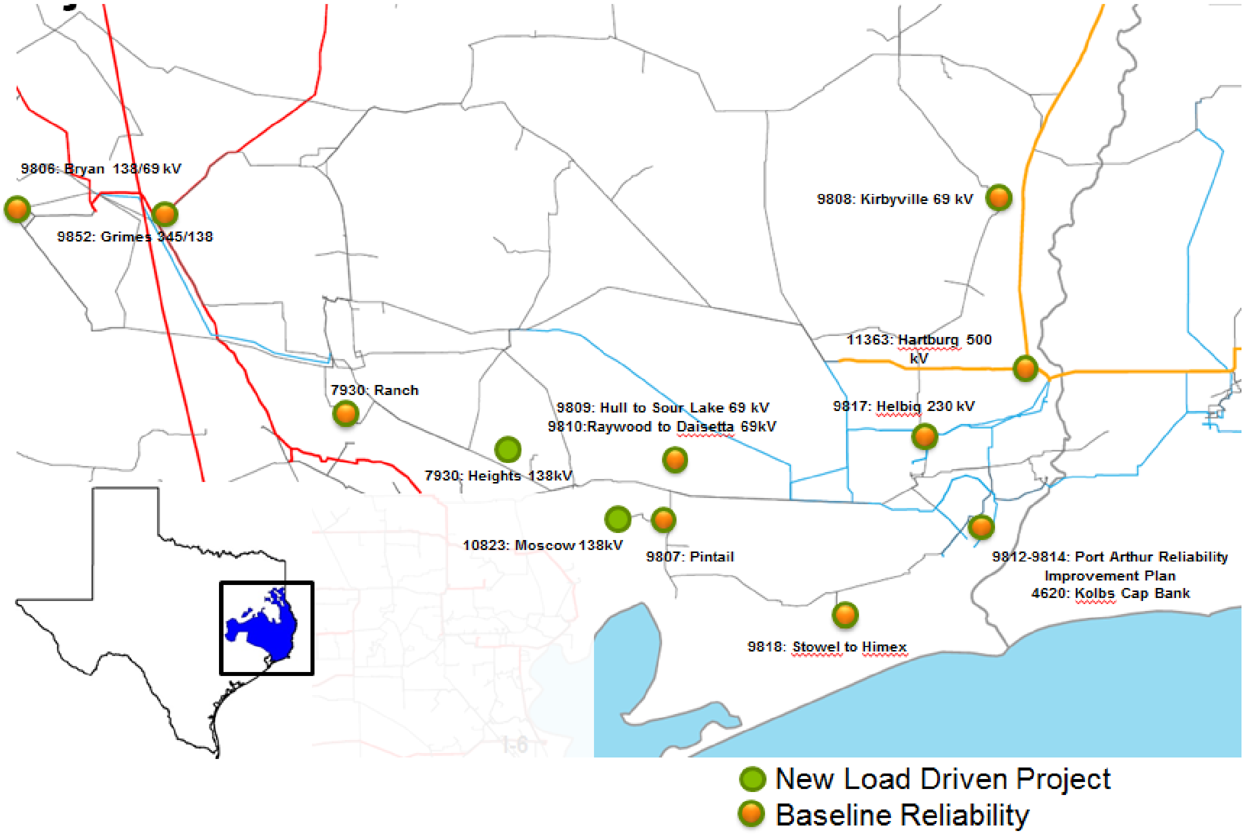


Figure TX-2: This map shows the geographical location of the projects and identified drivers.

For the MTEP16 cycle there were 15 projects targeted for Appendix A with a total cost of $172 million. Of these 15 projects: 11 have an estimated cost greater than $5 M, 4 have an estimated cost between $1M-$5 M, and 0 have an estimated cost lower than $1 M. The designations of project type are as follows: 13 Baseline Reliability and 2 Other.

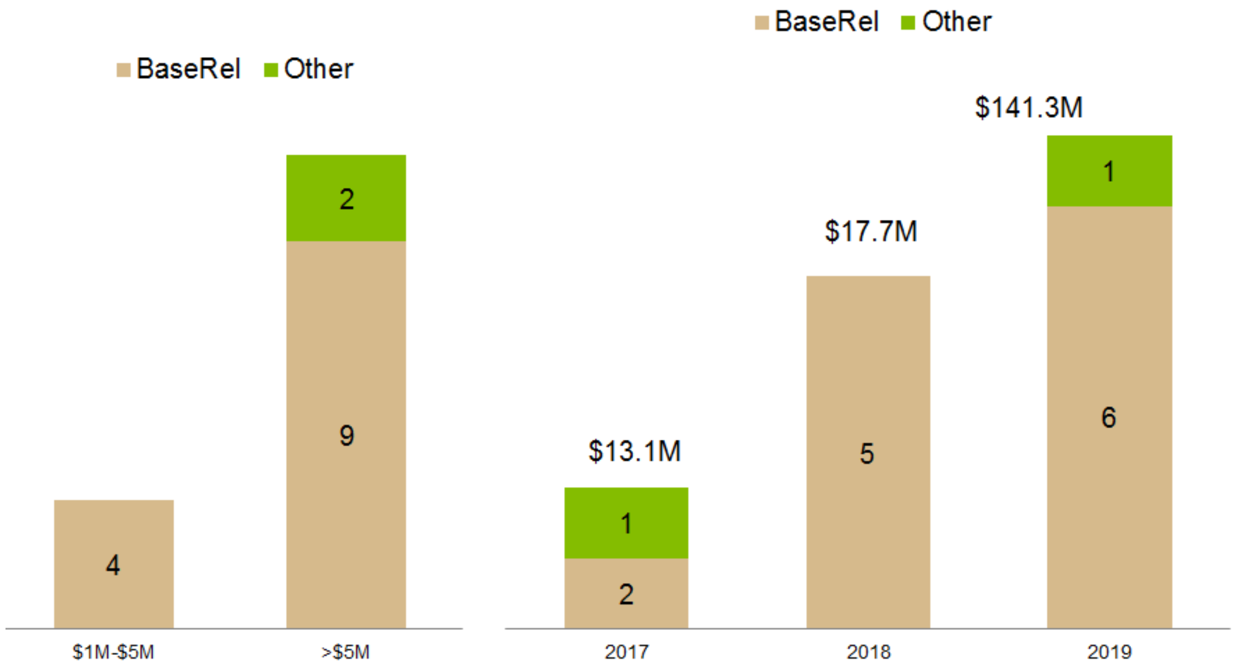


Figure TX-3: Graphs of cost range by project type and estimated in-service date by project type

Entergy Texas Inc. (ETI)

Project 9812, 9813, 9814 Port Arthur Reliability Improvement Plan

Transmission Owners: Entergy Texas Inc. (ETI)

Project Area Information

The Port Arthur Texas area has many industrial loads. The bulk electric system in the area includes a 230 kV and 138 kV network. These networks are fed from the Sabine generating units.

Project Need

During multiple N-2 scenarios in the area, there are thermal overloads on the 138 kV system. These scenarios allow for load shed as a mitigation, but to relieve the overloads requires large amounts of industrial load. To solve the thermal issues and to not require load shed, Entergy is building 2 new substations on the 230 kV system, called Garden and Legend, and building a new 230 kV line between them.

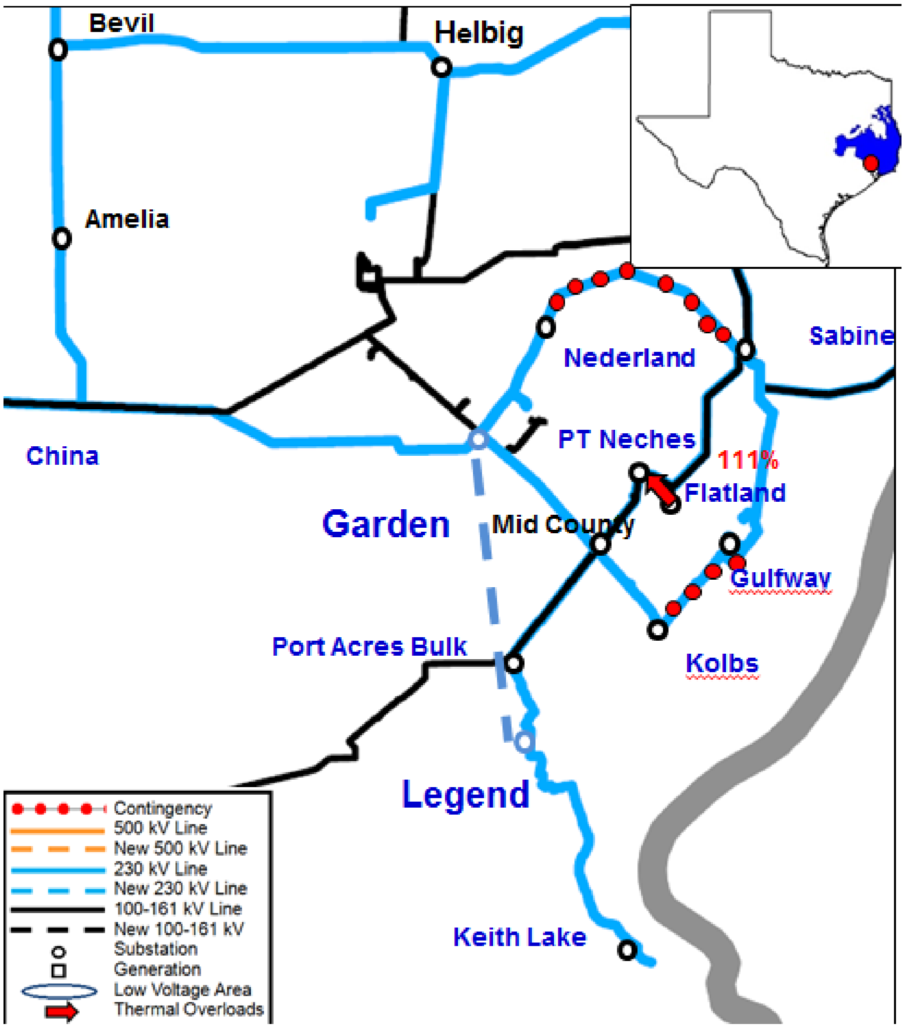


Figure TX-4: Multiple line contingency of Sabine to Nederland 230 kV and Kolbs to Gulfway 230 kV causes an overload on Port Neches to Flatland 138 kV. This is seen in the MTEP16 2021 Summer Model.

Project Description
This project comes in 3 parts. Part 1, project 9812, is to Cut the Sabine to China 230 kV line and the Nederland to Mid County 230 kV line into a new 230 kV substation named Garden. Part 2, project 9813, is to Construct a new substation and cut one of the Port Acres to Keith Lake 230 kV lines (L-829). The new substation will be named Legend The final part, project 9814, is to construct a new line from the new Garden substation to the new Legend substation. The estimated cost is $65.8M. The estimated in-service date is June 1st, 2019.

Cost Allocation
This is a Baseline Reliability Project which is not eligible for regional cost sharing.

Project 9809: Hull to Sour Lake 69 kV Reconductor Line

Transmission Owners: Entergy Texas Inc. (ETI)

Project Area Information
This project is close to the center of the Miso portion of Texas. The 69 kV system in this area is fed from the Raywood Substation and the Amelia Substation. The 69 kV line from Raywood to Amelia passes through the Hull, Quality Mills, Transco, and Sour Lake substations, all serving their own load.

Project Need
During the single contingency at Raywood, either line or transformer, one of the feeds to the 69 kV system is lost. To serve the load, the 69 kV line from Raywood to Amelia now pulls all the power needed from the Amelia 138 kV Substation. This overloads the line in the MTEP16 2021 Summer Model. Re-conductoring the line in by June 1st 2019 will increase the rating to 105 MVA and correct the issue before the need arises.

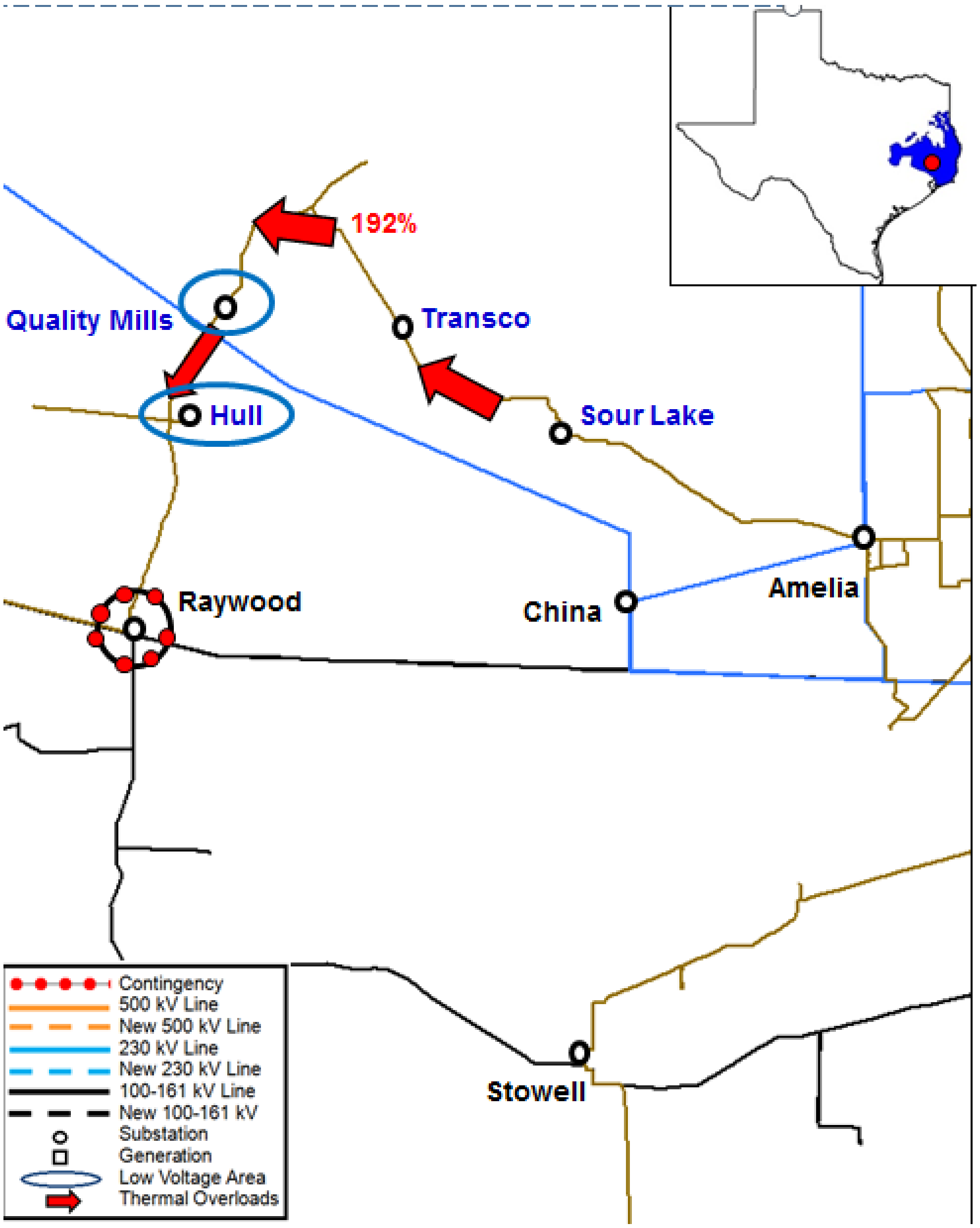


Figure TX-5: Single contingency at Raywood will cause an overload and low voltage issues from Hull to Sour Lake. This is seen in the MTEP16 2021 Summer Model.

Project Description
This project is to re-conductor the 69 kV line and upgrade terminal equipment from Hull to Sour Lake to reach an emergency rating of 105 MVA. The estimated cost is $30M. The estimated in-service date is June 1st, 2019.

Cost Allocation
This is a Baseline Reliability Project which is not eligible for regional cost sharing.

Project 9818: Stowell to Himex 69 kV Convert to 138 kV

Transmission Owners: Entergy Texas Inc. (ETI)

Project Area Information
Stowell is near the South Beaumont Load center. The 69 kV system in this area is fed from the South Beaumont Substation and the Stowell Substation. The 69 kV line from South Beaumont to Winshire passes through the Texas Hill, Lovels Lake, Byfanta, Pansy, and Craigen substations, all serving their own load.

Project Need
During a bus section fault at Stowell, the connection to the 69 kV system is lost which forces it to be fed from the other end which draws a lot of power. This causes an overload on the line in the MTEP16 2021 summer models. To correct the issue, Entergy will convert the Stowell to Himex 69 kV Line to 138 kV. In fact, the line is already built to that standard. This will reconfigure the bus so that the bus section fault will not occur. Also, the project requires a 138/34 kV transformer installed at the Himex Substation.

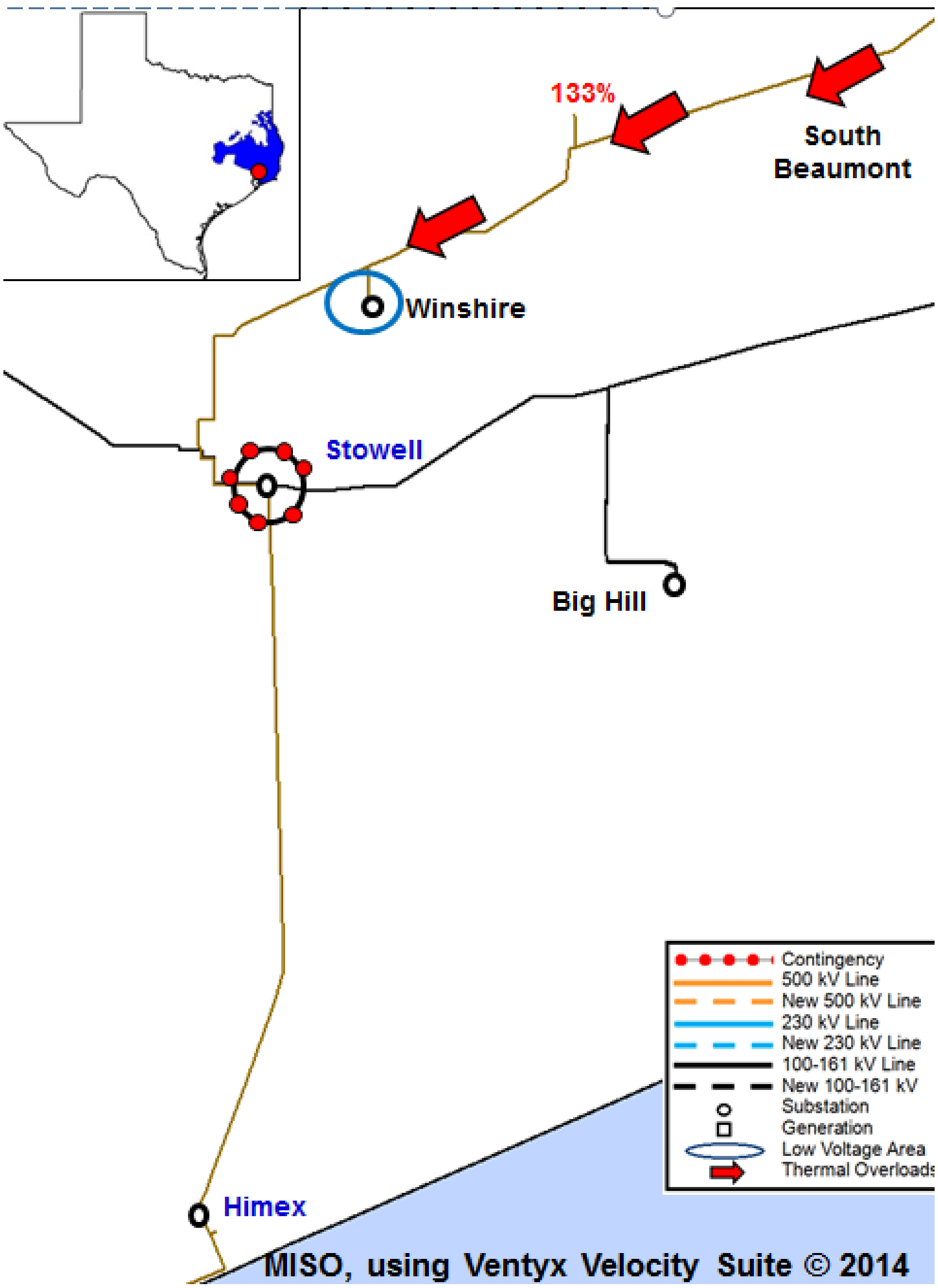


Figure TX-6: The Substation fault at Stowell causes thermal issues on the South Beaumont to Windshire 69 kV line. This issue is seen in the MTEP16 2021 Summer.

Project Description

The project will convert the Stowell to Himex 69 kV line to 138 kV and install a 138/34 kV transformer at Himex The estimated cost is $13.6M. The estimated in-service date for all projects is June 1st, 2018.

Cost Allocation

These are Baseline Reliability Projects which are not eligible for regional cost sharing.

Project 9807: Pintail 138 kV Construct new Switching Substation

Transmission Owners: Entergy Texas Inc. (ETI)

Project Area Information

This is another project near the Raywood Substation. There is a long 138 kV line heading south from there which typically has a normally open point. This line runs along the bottom of the Western and WOTAB load pockets and is normally open in the middle for stability issues.

Project Need

An open breaker issue at Raywood would cause low voltage issues near the normally open point, which is now cut off from Raywood due to the open breaker. This is seen in the MTEP16 2021 models. As a correction, Entergy will install a new switching station, called Pintail, on the line. This will allow the normally open point to close and correct the low voltage issue.

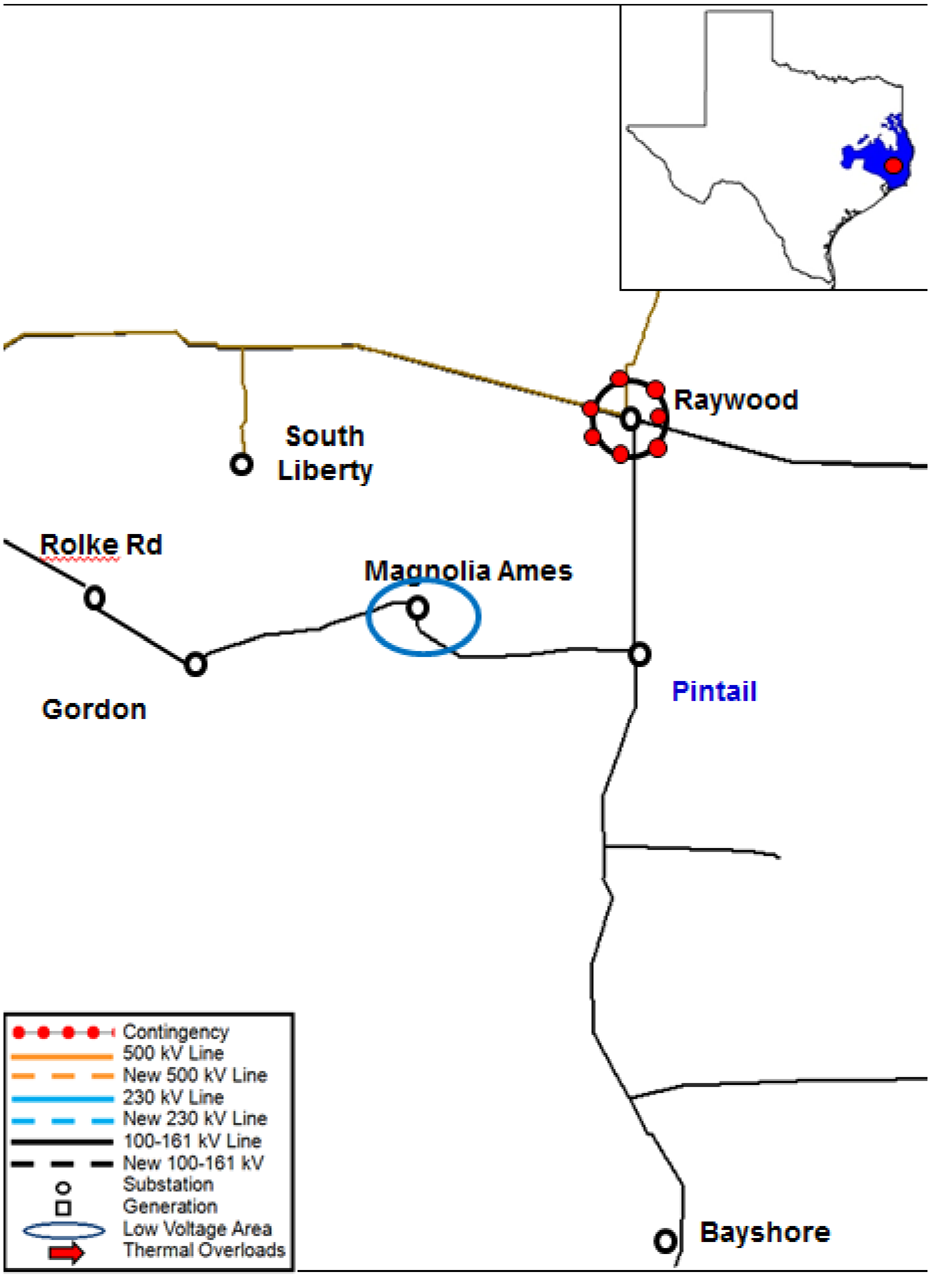


Figure TX-7: Open breaker at Raywood causes low voltage issues at Magnolia Ames. This is seen in the MTEP16 2021 Summer Model.

Project Description

This project will construct a new switching station south of Raywood called Pintail and close the normally open point between Gordon and Magnolia Ames. The estimated cost to upgrade one line is $9.5M. The estimated in-service date for both projects is June 1st, 2018, with the upgrade to Line 1 complete by June 1st 2018.

Cost Allocation

These are Baseline Reliability Projects which are not eligible for regional cost sharing.

Project 9810: Raywood to Daisetta 69 kV Re-conductor Line

Transmission Owners: Entergy Texas Inc. (ETI)

Project Area Information

This project is close to the center of the Miso portion of Texas. The 69 kV system in this area is fed from the Raywood Substation and the Amelia Substation. The 69 kV line from Raywood to Amelia passes through the Daisetta, Hull, Quality Mills, Transco, and Sour Lake substations, all serving their own load.

Project Need

The single line outage of Sour Lake to Amelia 69 kV will cause an overload from Raywood to Daisetta, since the power for the entire line must now be fed from that end. This overloads the line in the MTEP16 2021 Summer Model. Re-conductoring the line in by June 1st 2018 will increase the rating to 105 MVA and correct the issue before the need arises.

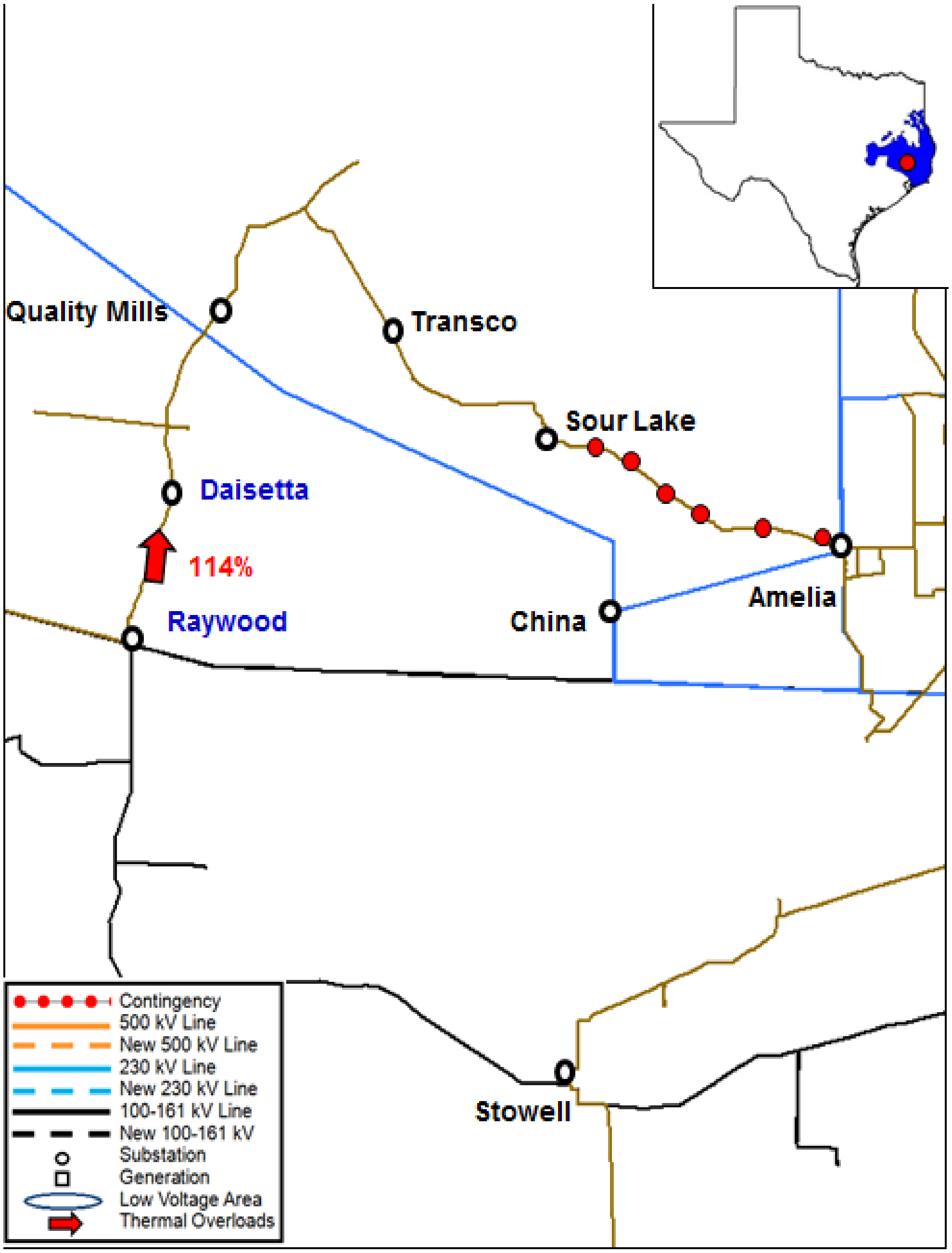


Figure TX-8: The loss of one of the Sour Lake to Amelia 69 kV line will overload the Raywood to Daisetta 69 kV line. This is seen in the MTEP16 2021 Summer Model.

Project Description

Project upgrade: approximately 6 mile line and corresponding equipment to increase the rating to 105 MVA. The estimated cost to upgrade the transformers is $8,655,000. The estimated in-service date for this project is June 1st, 2018.

Cost Allocation

These are Baseline Reliability Projects which are not eligible for regional cost sharing.

Project 9806: Bryan 138/69 kV Replace Autos and Reconfigure 69 kV

Transmission Owners: Entergy Texas Inc. (ETI)

Project Area Information
The Bryan-College station is located in the eastern edge of the Western Load Pocket. It is fed from the 138 kV system which is connected to the Frontier generation at Grimes.

Project Need
Open breaker contingencies at the Bryan substation cause thermal and voltage violations on the 69 kV system. This is seen in the MTEP16 and 2021 Summer Model. Reconfiguring the Bryan 138 kV and 69 kV substation by June 1st, 2019 will correct the issue.

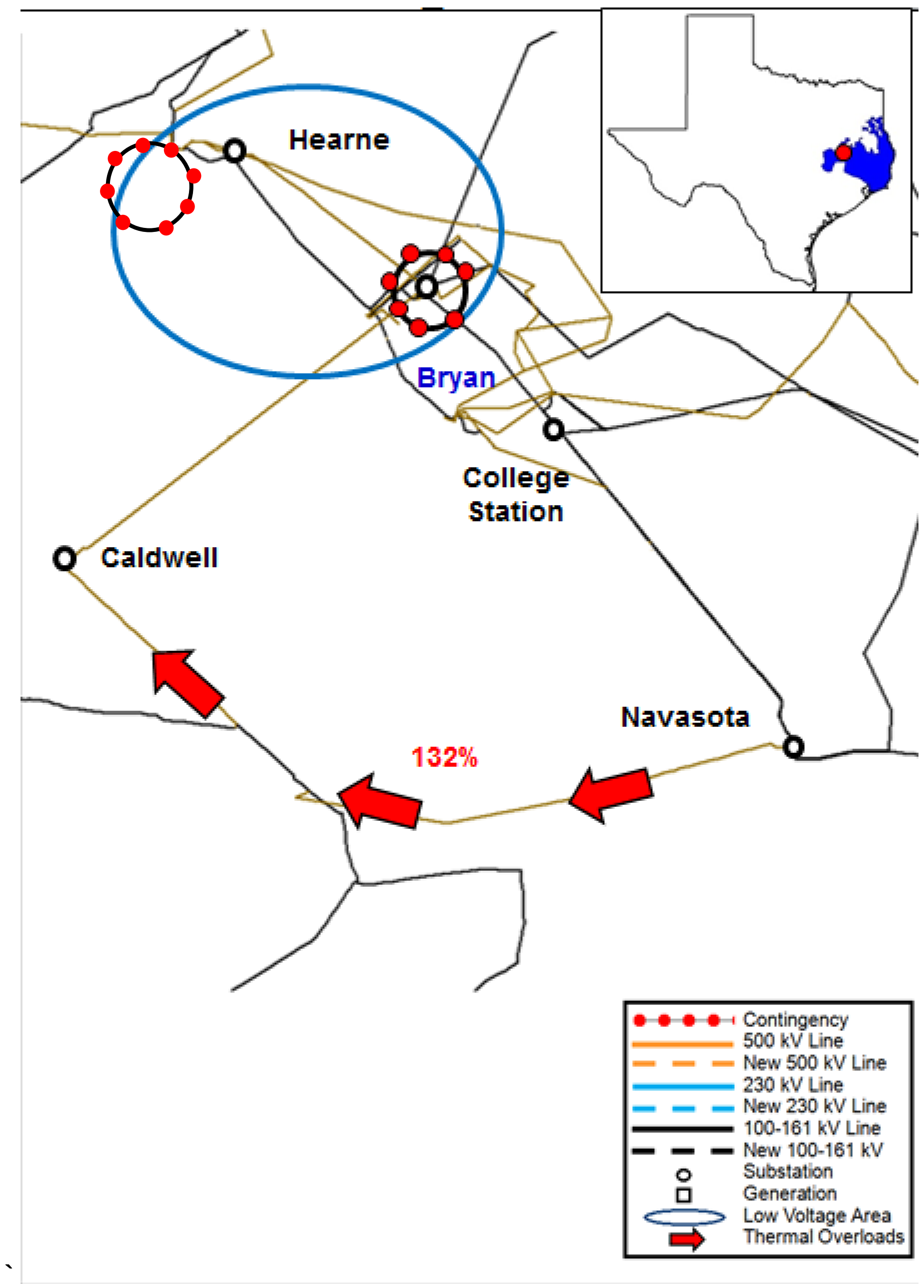


Figure TX-9: **During a breaker failure at the Bryan Substation, thermal overloads and low voltage violations are seen on the 69 kV system. This is seen in the MTEP16 2021 Summer Model.**

Project Description

This project will reconfigure the 138 kV bus to a ring bus and reconfigure the 69 kV bus. Also, it will replace the 2 138/69 kV transformers at that substation. The estimated cost to upgrade the transformers is $8,268,000. The estimated in-service date for this project is June 1st, 2019.

Cost Allocation

These are Baseline Reliability Projects which are not eligible for regional cost sharing.

Project 9817: Helbig 230 kV Reconfigure Bus

Transmission Owners: Entergy Texas Inc. (ETI)

Project Area Information
Beaumont Texas is a large load center. The Helbig substation is a major connection between the 230 kV and the 69 kV substation with two transformers located at that station.

Project Need
In the current configuration, the loss of one of the 230/69 kV transformers will also cause the loss of the 230 kV line from Helbig to Amelia. These outages will cause an overload on the other transformer. To correct the issue, Entergy will reconfigure the bus to a ring bus so they will not lose more than one element for a single outage.

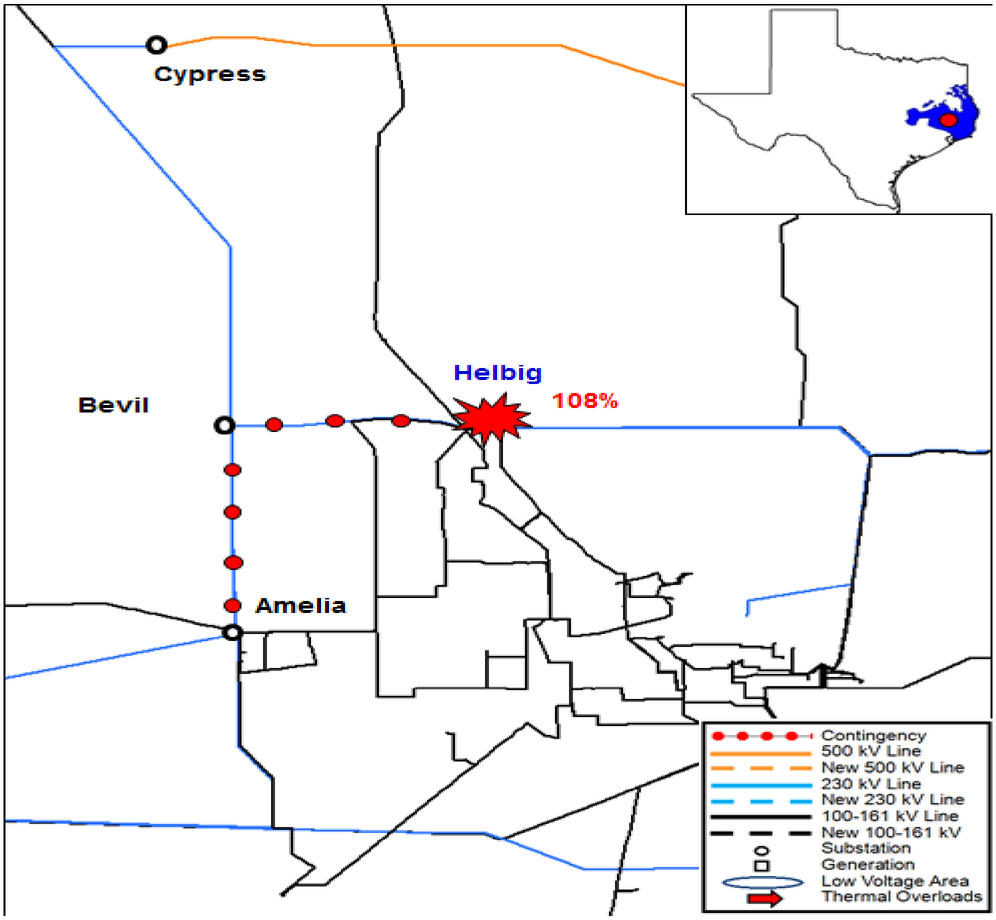


Figure TX-10: Losing one of the transformers at the Helbig substation also causes the loss of the Helbig to Amelia 230 kV line. This causes an overload on the 2nd transformer. This is seen in the MTEP16 2021 Models.

Project Description
Entergy will reconfigure the Helbig 230 kV substation to a ring bus. This will also upgrade the terminal equipment on the Helbig to Georgetown 230 kV Line The estimated cost is $7,196,000. The estimated in-service date is June 1st, 2018.

Cost Allocation
These are Baseline Reliability Projects which are not eligible for regional cost sharing.

Project 4620: Kolbs 230 kV - Add capacitor bank

Transmission Owners: Entergy Texas Inc. (ETI)

Project Area Information

In the east portion of MISO Texas, the generation source is primarily Sabine. The area around Sabine is supported by a network of 230 kV lines. This is an area known for serving large industrial loads.

Project Need

During the outage of one of the Sabine units coinciding with the outage of Kolbs to Gulfway 230 kV line, we see low voltage issues on the 230 kV system around Kolbs. This is seen in the MTEP16 2021 cases.

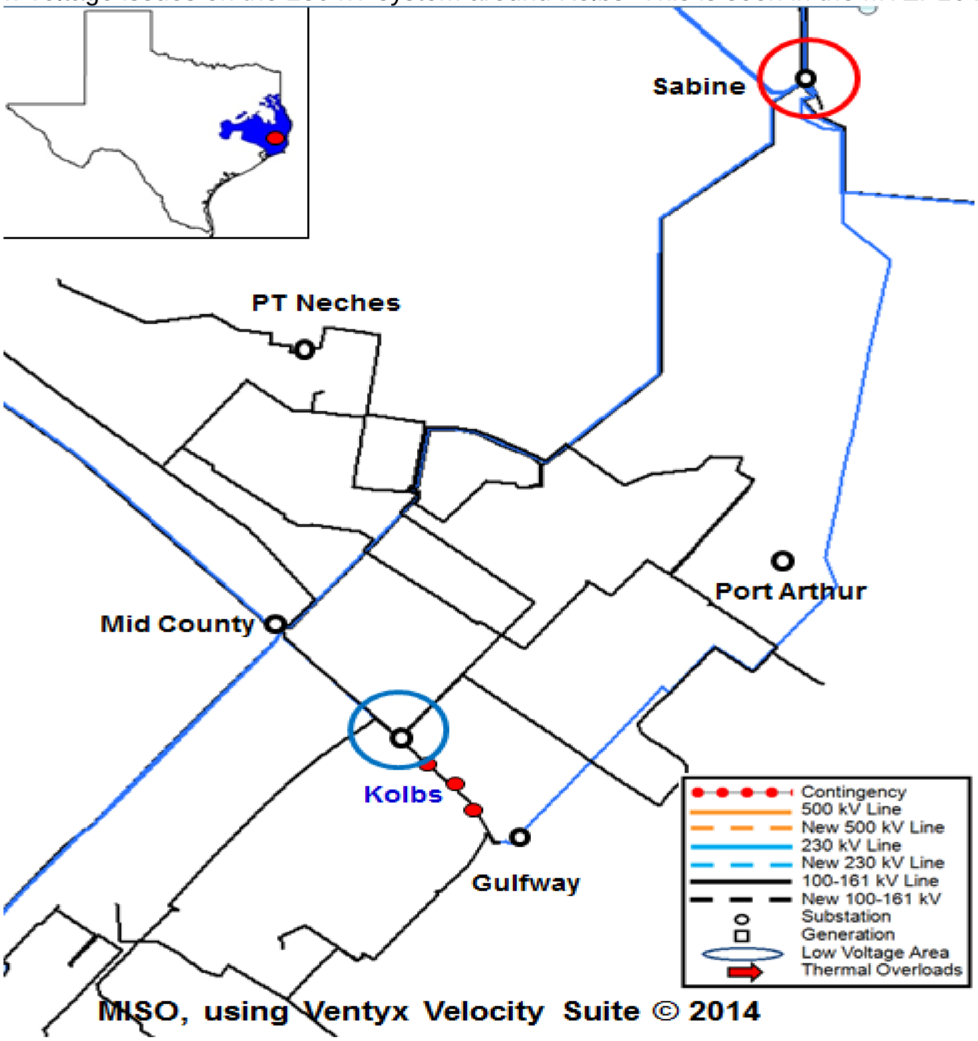


Figure TX-10: A line plus generator outage causes low voltage issues on the 230 kV system near Kolbs. This is seen in the MTEP16 2021 Summer Model.

Project Description

Entergy will add a 86.4 Mvar capacitor at the Kolbs substation. The estimated cost is \$3.0M. The estimated in-service date is June 1st, 2018.

Cost Allocation

This is a Baseline Reliability Project which is not eligible for regional cost sharing.

Project 9852: Grimes 345/138 kV Install Breakers on Low Side of AT2

Transmission Owners: Entergy Texas Inc. (ETI)

Project Area Information
Grimes is a major 345 kV connection in the Western load pocket. In its current configuration, there is no breaker protection on the low side of one of the 345/138 kV transformers.

Project Need
A single breaker fault can currently results in the outage of both Grimes 345/138 kV transformers. The loss of both transformers causes a thermal issue down the 138 kV system. The proposed solution is to install a breaker on the low side of the transformer so single event taking out both transformers is not possible.

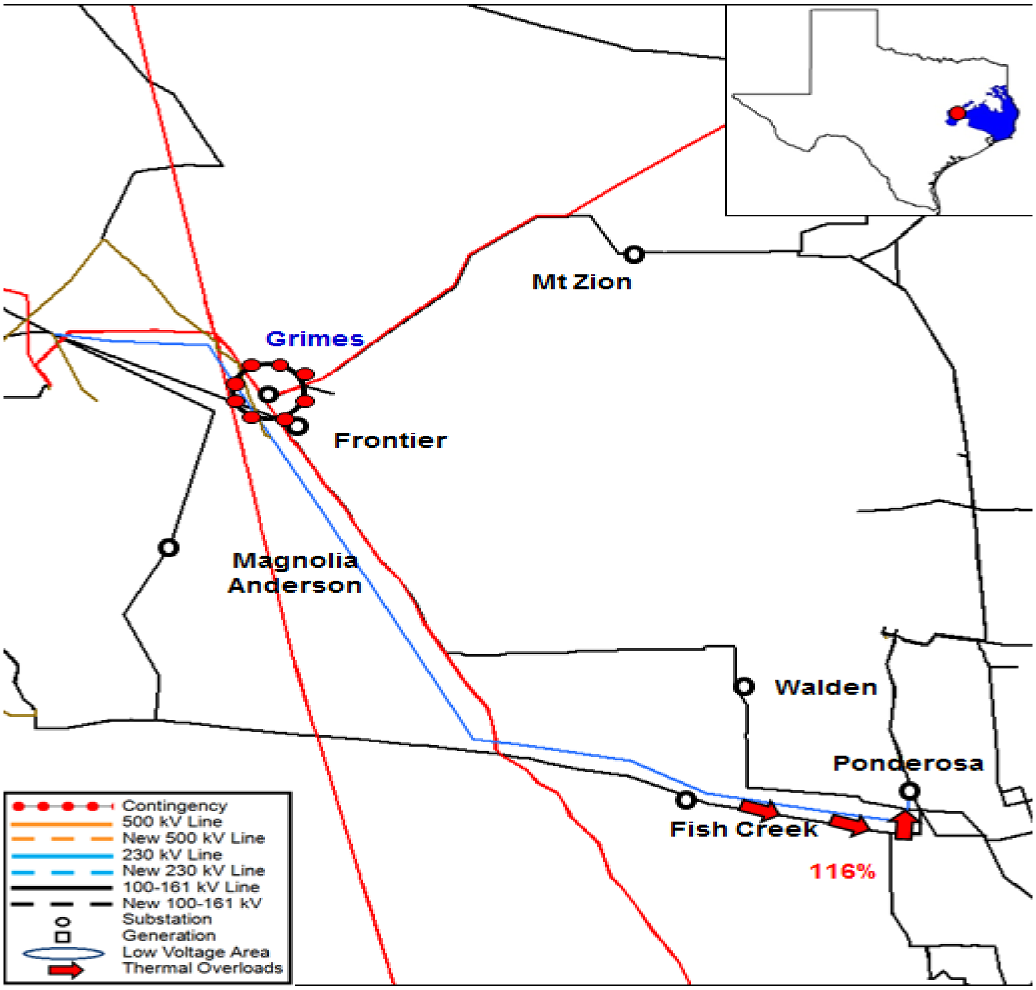


Figure TX-11: The loss both transformers at Grimes will results in thermal issues on the Fish Creek to Ponderosa 138 kV line. This is seen in the MTEP16 2021 Model.

Project Description
Entergy will install breakers on the low side of autotransformer number 2 at the Grimes 345/138 kV substation. The estimated cost is $1,142,000. The estimated in-service date is June 1st, 2017.

Cost Allocation
This is a Baseline Reliability Project which is not eligible for regional cost sharing.

Project 9808: Kirbyville 69 kV Add Cap Bank

Transmission Owners: Entergy Texas Inc. (ETI)

Project Area Information

North of Baumont, the bulk electric system is a 138 kV Loop, connecting the Woodville and Sam Rayburn generators down to the 500kV line between Cypress and Hartburg. One side of the loop has a 69 kV system connecting one of the load pocket import lines. This 69 kV line is connected between the Fawil and Kirbyville substations

Project Need

A single transformer contingency at Fawil can cause low voltage issues at the Kirbyville 69 kV Substation. The proposed solution is to install a Capacitor at the 69 kV substation to correct the violation.

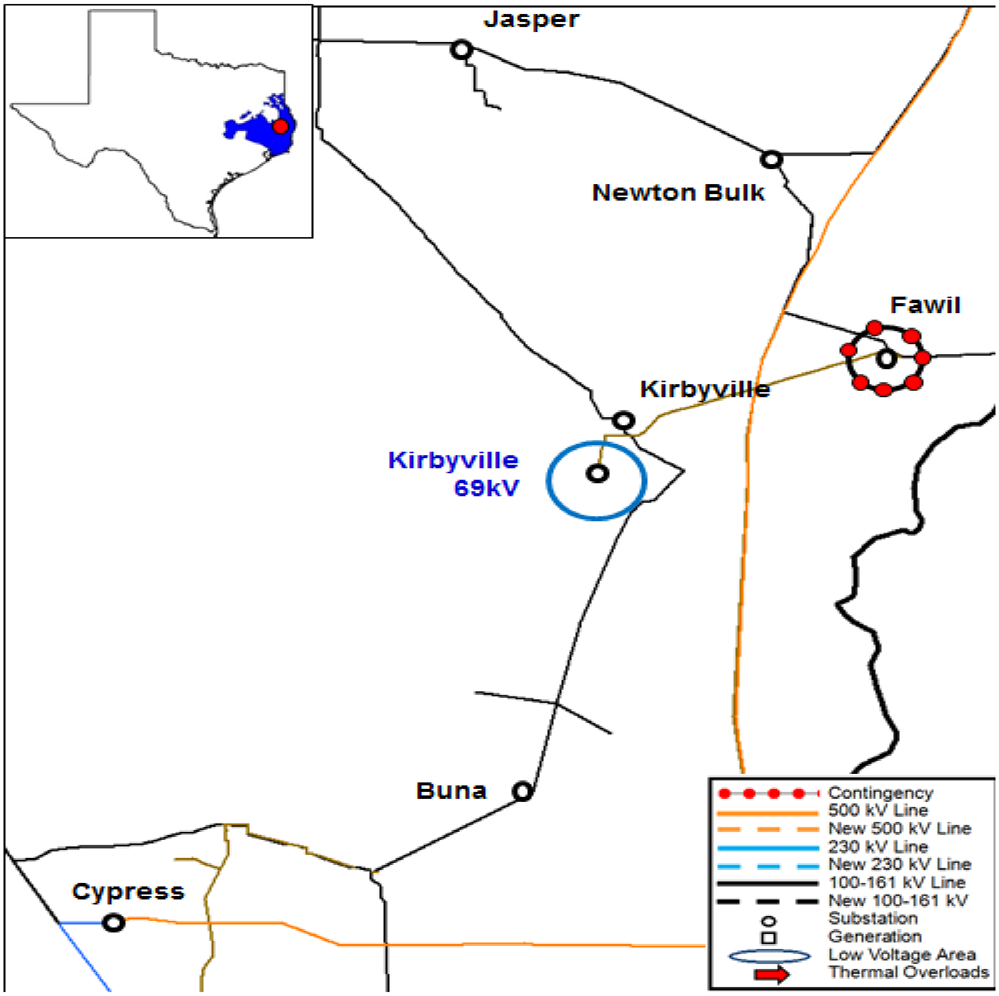


Figure TX-12: The outage of the transformer at Fawil will cause a low voltage violation at the Kirbyville 69 kV Substation. This is seen in the MTEP16 2021 Model.

Project Description
Entergy will install a 7.2 Mvar capacitor bank at the Kirbyville 69 kV substation. The estimated cost is $1,000,000. The estimated in-service date is June 1st, 2018.

Cost Allocation
This is a Baseline Reliability Project which is not eligible for regional cost sharing.

New Load Additions

These projects are needed in order to serve new loads. The existing distribution system is not sufficient to supply these additions. The most effective way to serve these new loads is to provide a new substation. No harm test was conducted to make sure no addition baseline reliability issues were caused by the new load additions.

ID	Name	Description	ISD	Cost
7930	Heights: Construct new 138 kV substation	Construct new 230 kV substation for load growth in the Woodlands area to offload the New Caney 138 kV substation. New substation will be tapped into 230 kV line between China and Porter.	6/01/2019	$14,208,000
10823	Moscow: Construct new 138 kV substation	Construct a new 138 kV substation on L-411 Corrigan Bulk to Kickapoo 138 kV line to serve an industrial customer.	6/01/2017	$7,004,002

Alternatives Considered
MISO and ETI considered serving the load from alternative locations but as these solutions provide the least amount of new facilities and costs; they are the most cost-effective way to serve this new load obligation.

Cost Allocation
These are Other: Distribution Projects which are not eligible for regional cost sharing.

Projects Driven by Attachment Y studies
This project's need was determined in a confidential Attachment Y study.

ID	Name	Description	ISD	Cost
11363	Hartburg 500 kV: Reconfigure Line Bays	Re-position the line bays of line L-800 (Hartburg-Cottonwood 500 kV Circuit 1) and line L-547 (Hartburg-Cypress 500 kV line) at Hartburg 500 kV substation.	6/01/2017	$2,000,000

Cost Allocation
These are Other: Reliability Projects which are not eligible for regional cost sharing.

Transmission Owner: East Texas Electric Cooperative (ETEC)

Baseline Reliability Projects

There are no Baseline Reliability Projects moving to Appendix A in this MTEP cycle for ETEC.

Other Reliability Projects

Projects that are not defined as Baseline Reliability, Generation Interconnection or Transmission Delivery Service Planning per Attachment FF transmission project definitions but are still needed for system reliability for various reasons are categorized as Other projects. There are no Other-type projects moving to Appendix A for ETEC in this MTEP cycle.

RMF - 6

Tracking the Sun 10

The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States

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September 2017

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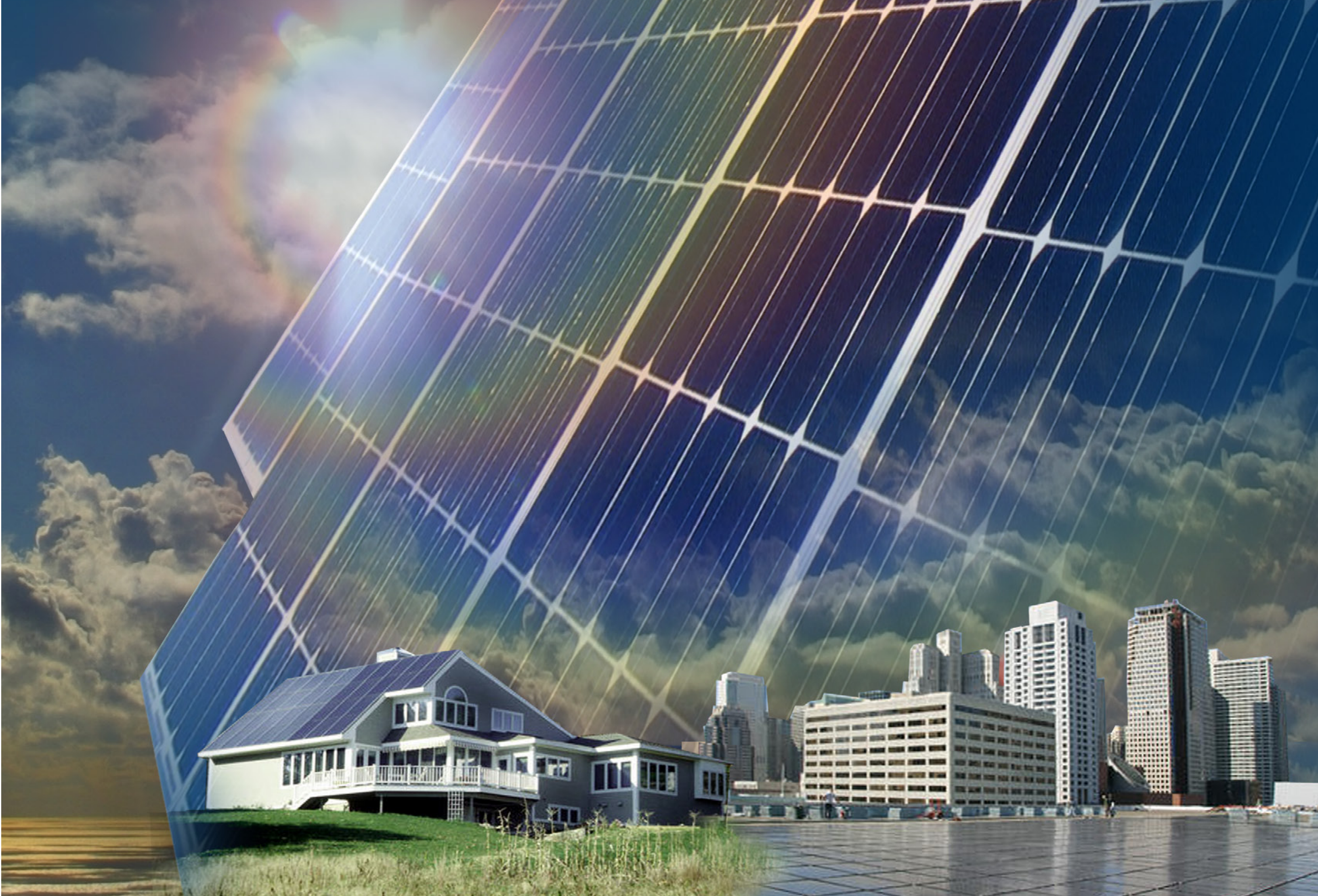

Tracking the Sun 10

The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States

Primary Authors: Galen Barbose and Naïm Darghouth
Energy Technologies Area, Lawrence Berkeley National Laboratory

Executive Summary

Now in its tenth edition, Lawrence Berkeley National Laboratory (LBNL)'s *Tracking the Sun* report series summarizes trends in the installed price of grid-connected, residential and non-residential solar photovoltaic (PV) systems in the United States. The present report focuses on systems installed through year-end 2016, with preliminary trends for the first half of 2017. An accompanying LBNL report, *Utility-Scale Solar*, addresses trends in the utility-scale sector.

Installed pricing trends presented within this report derive primarily from project-level data reported to state agencies and utilities that administer PV incentive programs, solar renewable energy credit (SREC) registration systems, or interconnection processes. Refer to the text box to the right for several key notes about the data. In total, data were collected and cleaned for more than 1.1 million individual PV systems, representing 83% of U.S. residential and non-residential PV systems installed through 2016. The analysis in this report is based primarily on a subset of this sample, consisting of roughly 630,000 systems with available installed price data, representing 47% of all installed systems. LBNL has made the full dataset publicly available through the National Renewable Energy Laboratory (NREL)'s Open PV data portal.

Key Points on the Data in This Report

Installed price data presented in this report:

- Represent the up-front price paid by the PV system owner, prior to receipt of incentives
- Are self-reported by installers and customers
- Differ from the underlying cost borne by the developer and installer
- Are historical and therefore may not be indicative of prices for systems installed more recently or prices currently being quoted for prospective projects
- Exclude those third-party owned (TPO) systems for which reported installed prices represent appraised values, but include other TPO systems (see Text Box 2 in the main body of the report for further details)

Key findings from this year's report are as follows, with all numerical results denoted in real 2016 dollars and direct current (DC) Watts (W):

Installed Prices Continued to Decline through 2016 and into 2017. National median installed prices in 2016 declined year-over-year by \$0.1/W (2%) for residential systems, by \$0.1/W (3%) for non-residential systems ≤500 kW, and by \$0.2/W (8%) for non-residential systems >500 kW. These were the smallest year-over-year reductions since 2009, partly reflecting changes in the underlying population of the data sample (namely, a sharp increase in the proportion of the sample from California, a relatively high-priced state). Preliminary data for the first six months of 2017 show the pace of price reductions picking back up. Extrapolated over a full year, those partial-year price declines correspond to year-over-year installed price reductions of at least 10% for each customer segment, consistent with the long-term historical rate of decline.

Recent Installed Price Reductions Have Been Driven by Declining Hardware Costs. Over the long-term, both hardware and non-hardware (i.e., soft) costs have fallen substantially, contributing in almost equal measure to overall reductions in installed prices. Since 2000, for example, roughly 53% of the total decline in residential system installed prices can be attributed to falling module and inverter prices, while the remaining 47% is associated primarily with reductions in the aggregate set of soft costs. More recently, however, hardware costs have been the dominant driver for installed price declines. In fact, the aggregate drop in module, inverter, and racking prices over the 2015 to 2016 period exceeded the observed decline in total system-level installed prices over the same span. That apparent disconnect reflects a natural lag between changes in component prices and system prices, and is consistent with the larger installed-price decline observed in the first half of 2017.

Increasing Module Efficiencies and System Sizes Contribute to Installed Price Declines. Many soft costs, as well as some secondary hardware costs, are either fixed in nature or scale with the physical dimensions of the system. Accordingly, these costs can be directly reduced (on a per-watt) basis through increases in module efficiency and system size, which spread such costs out over a larger number of installed watts. Among projects in the data sample, median module efficiencies grew from 12.7% to 17.3% from 2002 to 2016, while the median size of residential systems grew from 2.9 kW to 6.2 kW. Together, these two dynamics are ostensibly responsible for roughly a $1.0/W reduction in residential system costs over the long-term (about 12% of the total decline in residential installed prices). Within the last year of the analysis period, median module efficiencies increased from 17.0% to 17.3%, and median system sizes remained constant (with negligible year-over-year effects on installed prices).

Installed Price Declines Have Been Partially Offset by Falling Incentives. Cash incentives (i.e., rebates and performance-based incentives) provided through state and utility PV incentive programs have fallen substantially since their peak a decade ago, and have been largely phased-out in many key markets. Depending on the particular program, reductions in cash incentives over the long-term equate to roughly 70% to 120% of the corresponding drop in installed prices. This trend is partly a response to installed price declines and the emergence of other forms of incentives, however it has also been a deliberate strategy by program administrators to drive cost reductions in the industry.

National Median Installed Prices Are Relatively High Compared to Other Recent Benchmarks. Median installed prices of systems in the LBNL dataset installed in 2016 were $4.0/W for residential systems, $3.4/W for small (≤500 kW) non-residential systems, and $2.3/W for large (>500 kW) non-residential systems. These values are high compared to many other recently published PV pricing and cost benchmarks. These apparent discrepancies can be traced to a variety of differences in underlying data, methods, and conventions. Many of the other published benchmarks, instead, align more closely with 20th percentile pricing levels observed within the LBNL data, highlighting the wide variability in installed prices described further below.

Installed Prices in the United States Are Higher than in Many Other Major National PV Markets. Compared to median U.S. prices, installed prices reported for a number of other key national solar markets are substantially lower. In Australia, for example, typical pricing for residential systems was reported to be around $1.8/W in 2016 (i.e., less than half the median price observed within the LBNL dataset). Though data comparability across countries may be imperfect, these pricing disparities can be attributed primarily to differences in soft costs, as hardware costs are relatively uniform between countries.

Installed Prices Vary Widely Across Individual Projects. Among residential systems installed in 2016, roughly 20% of systems were priced below $3.2/W (the 20th percentile value), while 20% were priced above $5.0/W (80th percentile). Non-residential systems also exhibit wide pricing variability, with the 20th-to-80th percentile ranging from $2.7/W to $4.4/W for smaller (≤500 kW) projects and from $1.9/W to $3.2/W for larger (>500 kW) projects. The potential underlying causes of this variability are numerous, including differences in project characteristics, installers, and local market or regulatory conditions. The wide pricing distributions also serve to demonstrate the potential for low-cost installations. For example, more than 15,000 residential systems installed in 2016 (9%) were priced below $2.5/W, and 8,000 (5%) were below $2.0/W.

Strong Economies of Scale Exist Among Both Residential and Non-Residential Systems. Among residential systems installed in 2016, median prices were roughly $0.8/W (19%) lower for systems in the 10-12 kW size range compared to 2-4 kW systems. For non-residential systems, median prices were $1.9/W (46%) lower for systems >1,000 kW in size compared to the smallest non-residential systems ≤10 kW. Even greater economies of scale may arise when progressing to utility-scale systems, which are outside the scope of this report.

Installed Prices Vary Widely Among States, with Relatively High Prices in Some Large State Markets. For residential systems installed in 2016, median installed prices range from a low of \$2.9/W in Nevada to a high of \$5.0/W in Delaware. Pricing in most states is below the aggregate national median price. This is because some of the largest state markets – California, Massachusetts, and New York – are relatively high-priced, which tends to pull overall U.S. median prices upward. Cross-state installed pricing differences can reflect a wide assortment of factors, including installer competition and experience, retail rates and incentive levels, project characteristics particular to each region, labor costs, sales tax, and permitting and administrative processes.

Third-Party Owned Systems in the Residential Sector Were Significantly Lower-Priced than Host-Owned Systems in 2016. This report does not evaluate lease terms or power purchase agreement (PPA) rates for TPO systems; however, it does include data on the dollar-per-watt installed price of TPO systems sold by installation contractors to non-integrated customer finance providers. Nationally, the median installed price among of residential TPO systems in 2016 was \$0.7/W lower than for host-owned residential systems. The lower installed prices for TPO systems may reflect a combination of factors: loan origination fees rolled into the price of some host-owned systems, customer acquisition and other project development costs that may be borne by the TPO financier (and thus not captured in the installed price), negotiating power of TPO financiers, and potentially greater standardization among TPO systems.

Prices Vary Considerably Across Residential Installers Operating within the Same State. In examining five large residential markets (Arizona, California, Massachusetts, New Jersey, and New York), installer-level median prices within each state differ by anywhere from \$0.7/W to \$1.4/W between the upper and lower 20^{th} percentiles, suggesting a substantial level of heterogeneity in pricing behavior or underlying costs from one installer to another. Low-priced installers in each state—e.g., 20% of installers in New York had median residential prices below \$3.3/W in 2016, compared to the overall state median price of \$3.8/W—can serve as a benchmark for near-term price reduction potential in each state. The data show no clear evidence that installer-level pricing differences are the result of differences in installer size, though other more-depth analyses have found relationships in both directions.

Installed Prices Are Substantially Higher for Systems with Premium-Efficiency Modules. As noted earlier, higher module efficiencies allow for lower balance-of-system (BOS) costs, and increasing module efficiencies over time has contributed to declining system costs and prices. At any given point in time, however, various module efficiencies are commercially available, and higher efficiency products tend to sell for a premium. Among the 2016 systems in the data sample, roughly one-third have module efficiencies greater than 18%, and installed prices for these systems have consistently been higher-priced than for those with lower- or mid-range module efficiencies (<18%). In 2016, the differential in median prices was roughly \$0.5/W among both residential systems and small non-residential systems. These trends suggest that the price premium for high-efficiency modules available on the market tends to outweigh any offsetting reduction in BOS costs.

Residential New Construction Offers Significant Installed Price Advantages Compared to Retrofit Applications. Within California, residential systems installed in new construction have been consistently lower-priced than those installed on existing homes, with a median differential of \$0.1/W in 2016, *despite* the significantly smaller size and higher incidence of premium efficiency modules among new construction systems. If comparing among systems of similar size and module technology, the installed price of new construction systems was $0.8/W lower than for retrofits.

Installed Prices Continue to Be Higher for Systems at Tax-Exempt Customer Sites than at For-Profit Commercial Sites. Roughly 18% of all 2016 non-residential systems in the data sample were installed at tax-exempt site hosts, including schools, government facilities, religious organizations, and non-profits. These systems are consistently higher priced than similarly sized systems at for-profit commercial customer sites. In 2016, the differential in median prices was roughly $0.2/W for systems ≤500 kW and $0.8/W for >500 kW systems. Higher prices at tax-exempt customer sites reflect potentially lower negotiating power and higher incidence of prevailing wage/union labor requirements, domestically manufactured components, and shade or parking structures.

Module-Level Power Electronics Have a Seemingly Small Effect on Installed Prices. Module-level power electronics (MLPEs), including both microinverters and DC optimizers, have made substantial gains in market share in recent years. Despite higher hardware costs associated with these devices, installed prices for systems with MLPEs have generally been nearly identical to, or even less than, installed prices for systems without MLPEs. For example, among residential systems installed in 2016, median installed prices were identical for systems with microinverters and those with no MLPE, while the median price of systems with DC optimizers was $0.3/W lower. The negligible (or negative) installed price premium exhibited by the data suggest that MLPEs may offer some savings on non-inverter BOS costs or soft costs.

Non-Residential Systems with Tracking and Ground-Mounting Are Generally Higher Priced than Rooftop Systems. Among both small and large non-residential systems installed in 2016, the median installed price was roughly $0.3/W higher for fixed, ground-mounted systems than for rooftop systems. Tracking equipment adds additional costs, though this is not always readily or precisely discernible with the installed price data. Within the small non-residential segment, the median installed price of systems with tracking was about $0.4/W higher in 2016 than for fixed, ground-mounted systems. However, within the large non-residential segment, systems with tracking actually had a lower median price in both 2015 and 2016 than fixed-tilt, ground-mounted projects.

1. Introduction

The market for solar photovoltaics (PV) in the United States has been driven, in large measure, by various forms of policy support for solar and renewable energy. A central goal of many of these policies has been to facilitate and encourage cost reductions over time. Most prominently, the U.S. Department of Energy's SunShot Initiative has sought to make solar energy cost-competitive with other forms of electricity by the end of the decade, with an initial goal of $1/W by 2020, and an additional 50% reduction by 2030.[1] Others have argued that even deeper cost reductions may be needed over the longer-term, given the declining value of solar with increasing grid penetration, suggesting a goal of $0.25/W by 2050 (Sivaram and Kann 2016). As public and private investments in these efforts have grown, so too has the need for comprehensive and reliable data on the cost and price of PV systems, in order to track progress towards cost reduction targets, gauge the efficacy of existing programs, and identify opportunities for further cost reduction. Such data are also instrumental to cultivating informed consumers and efficient and competitive markets, which are themselves essential to achieving long-term cost reductions.

To address these varied needs, Lawrence Berkeley National Laboratory (LBNL) initiated the annual *Tracking the Sun* report series to summarize historical trends in the installed price of grid-connected, residential and non-residential PV systems in the United States. It is produced in conjunction with several other ongoing National Lab research products that also address PV system costs and pricing, including a companion LBNL report focused on trends in the utility-scale solar market (see text box to the right).

The present edition of *Tracking the Sun*, the tenth in the series, describes installed price trends for projects installed from 1998 through 2016, with preliminary data for the first half of 2017. The report is intended to provide an overview of both long-term and more-recent trends, highlighting key drivers for installed price declines over different time horizons. The report also seeks to highlight *variability* in system pricing, comparing installed prices across states, market segments, installers, and various system and technology characteristics. Other LBNL research products have also explored pricing variability using more complex statistical methods.

Related National Lab Research Products

Tracking the Sun is produced in conjunction with several related and ongoing research activities:

- *Utility-Scale Solar* is a separate annual report series produced by LBNL that focuses on utility-scale solar (ground-mounted projects larger than 5 MW_{AC}) and includes trends and analysis related to project cost, performance, and pricing.
- *In-Depth Statistical Analyses* of PV pricing data by researchers at LBNL and several academic institutions seek to further explore PV pricing dynamics, applying more-advanced statistical techniques to the data collected for *Tracking the Sun*. These and other solar energy publications are available here.
- *The Open PV Project* is an online data-visualization tool developed by the National Renewable Energy Laboratory (NREL) and hosts the public version of the *Tracking the Sun dataset*.
- *PV System Cost Benchmarks* developed by NREL researchers are based on bottom-up engineering models of the overnight capital cost of residential, commercial, and utility-scale systems (for example, see Fu et al. 2017).

[1] The $1/W target for 2020 refers specifically to utility-scale PV, with correspondingly higher targets for commercial ($1.25/W) and residential ($1.5/W), all denominated in real 2010 dollars. The 2030 goals are specified in terms of the levelized cost of energy (LCOE), with targets of 5 ¢/kWh (residential), 4 ¢/kWh (commercial), and 3 ¢/kWh (utility-scale), all denominated in real 2016 dollars.

The trends presented in this report are based primarily on project-level data provided by state agencies, utilities, and other entities that administer PV incentive programs, solar renewable energy credit (SREC) registration systems, or interconnection processes. The underlying dataset used for this year's report consists of more than 1.1 million residential and non-residential PV systems,[2] representing roughly 83% of all residential and non-residential PV systems installed in the United States through 2016. LBNL applies a substantial degree of quality control and undertakes numerous steps to clean these data, as described further within the report. In order to enable further analysis of these data by other researchers and facilitate greater price transparency in the solar marketplace, LBNL has also made the full cleaned dataset (excluding any confidential or otherwise sensitive data) publicly available as a downloadable file, accessible through NREL's Open PV data portal.[3]

Essential to note at the outset are several important characteristics of the installed price data described within this report. These reported prices represent the up-front price paid by the system owner, prior to receipt of incentives; for a variety of reasons, such prices may differ from the underlying costs borne by the developer or installer. The data are also self-reported, and therefore may be subject to inconsistent reporting practices (e.g., in terms of the scope of the underlying items embedded within the reported price or whether the administrator validates reported prices against invoices). Furthermore, these data are historical, and therefore may not be indicative of prices for systems installed more recently or prices currently being quoted for prospective projects. Finally, the trends presented in this report exclude data for the subset of third-party owned (TPO) systems installed by integrated companies that perform both installation and customer financing; the prices reported for these systems represent appraised values rather than transaction prices. Partly in recognition of these limitations, the report compares reported installed price data to several other recent benchmarks for PV system prices and costs, in order to provide a broader snapshot of current system costs and prices.

The remainder of the report is organized as follows. Section 2 summarizes the data sources, key methodological details, and characteristics of the data sample. Section 3 presents an overview of long-term, installed-price trends, focusing on median values drawn from the large underlying data sample. The section illustrates and discusses a number of the broad drivers for those historical installed-price trends, including reductions in underlying hardware component prices and soft costs, increasing module efficiency and system size, and declining state and utility incentives. The section also compares median installed prices for systems installed in 2016 to a variety of other recent U.S. benchmarks, and to prices in other international markets. Section 4 describes the variability in installed prices within the dataset, and explores a series of specific sources of installed pricing differences across projects, including: system size, state, installer, host-owned vs. TPO, residential new construction vs. retrofit, for-profit commercial vs. tax-exempt site host, module efficiency level, the use of module-level power electronics, and rooftop vs. ground-mounted with or without tracking. Finally, Section 5 offers brief conclusions.

Additional technical and methodological details are included in the appendix, which provides additional details on the data cleaning process and data sample. In addition, the values plotted in each figure are available in tabular form in an accompanying data file, which can be downloaded at trackingthesun.lbl.gov. Finally, as mentioned above, the underlying project-level data summarized in this report are publicly available through NREL's Open PV Project.

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[2] As explained further within the report, the analysis in this report is based primarily on a subset (approximately 630,000 systems) of the larger data sample.

[3] The public data file can be downloaded from Open PV as a stand-alone file, and has also been incorporated into the larger Open PV database and visualization tools.

2. Data Sources, Methods, and Sample Description

The trends presented in this report derive from data on individual residential and non-residential PV systems. This section describes the underlying data sources and the procedures used to standardize and clean the data, with further information provided in the Appendix. The section then describes the sample size over time and by market segment, comparing the data sample to the overall U.S. PV market and highlighting any significant gaps. Finally, the section summarizes several key characteristics of the data sample, including: trends in system size over time and by market segment, the geographical distribution of the sample across states, and the distribution between host host-owned and TPO systems.

Data Sources

The data are sourced primarily from state agencies, utilities, and other organizations that administer PV incentive programs, solar renewable energy credit (SREC) registration systems, or interconnection processes (see Table B-1 in the Appendix for a list of data providers and associated sample sizes).

The data sources for this report series have evolved over time, particularly as incentive programs in a number of states have expired. In these instances, data collection has generally transitioned to other administrative processes, such as system interconnection or SREC registration. One significant data gap that did emerge, albeit temporarily, was in California, where the state's primary incentive began to wind down in 2013. Data collection responsibilities were eventually transitioned to the investor-owned utilities' (IOUs') interconnection processes; however, in the intervening period, installed pricing data was unavailable for a sizeable fraction of the California market. Further discussion of this issue, and its impact on the trends presented in this report, are provided below.

Text Box 1. Customer Segment Definitions

This report segments the trends according to whether the site host is residential or non-residential, and among non-residential systems into those that are ≤500 kW_{DC} and >500 kW_{DC}.

Residential: Includes single-family residences and, depending on the conventions of the data provider, may also include multi-family housing.

Non-Residential: Includes non-residential rooftop systems regardless of size, and ground-mounted systems up to 5 MW_{AC}.

Both categories consist mostly, but not exclusively, of systems installed behind the customer meter.

Ground-mounted systems larger than 5 MW_{AC} are considered **utility-scale**, regardless of whether they are installed on the utility- or customer-side of the meter. The size threshold for utility-scale is denominated in AC capacity terms, as is more common for utility-scale systems. Those systems are not covered within this report, but are instead addressed in LBNL's companion *Utility-Scale Solar* annual report.

These customer segment definitions may differ from those used by other organizations, and therefore some care must be taken in comparisons.

Data Standardization and Cleaning

Various steps were taken to clean and standardize the raw data. First, all systems missing data for system size or installation date, as well as any utility-scale PV systems or duplicate systems contained in multiple datasets, were removed from the raw sample. The remaining data were then cleaned by correcting text fields with obvious errors and by standardizing the spelling of installer names and module and inverter manufacturers and models. Using module and inverter names, each PV system was then classified as building-integrated PV or rack-mounted; module technology type and efficiency were determined; and systems with microinverters or DC optimizers were identified. Finally, all price and incentive data were converted to real 2016 dollars (2016$), and if necessary system size data were converted to direct current nameplate capacity under standard test conditions (DC-STC). Further details on these steps, as well as other elements of the data cleaning process, are described in Appendix A. The resulting dataset, following these initial steps, is referred to hereafter as the **full data sample** and is the basis for the public data file (which differs only in the exclusion of confidential or sensitive data).

For the purpose of the analysis presented in this report, several other categories of systems were then removed from the data. The most significant group of excluded systems are those where reported prices are assumed to represent an appraised value, rather than a transaction price (see Text Box 2 below). Also excluded from the analysis are systems with missing installed price data, systems with battery-back up, self-installed systems, and systems with installed prices less than $1/W or greater than $20/W (assumed to be data entry errors). The resulting dataset, after these various additional exclusions, is denoted hereafter as the **final analysis sample** and is the basis for all trends presented in the report, unless otherwise indicated.

Text Box 2. Treatment of Third-Party Owned Systems in the Data Sample and Analysis

Third-party ownership of customer-sited PV systems through power purchase agreements and leases is the dominant ownership model in many markets, and this trend has created certain complications for the tracking of installed prices. The nature of these complications, however, depends on whether the company providing the customer financing also performs the installation (i.e., an "integrated" TPO provider) or instead procures the system through an independent installation contractor.

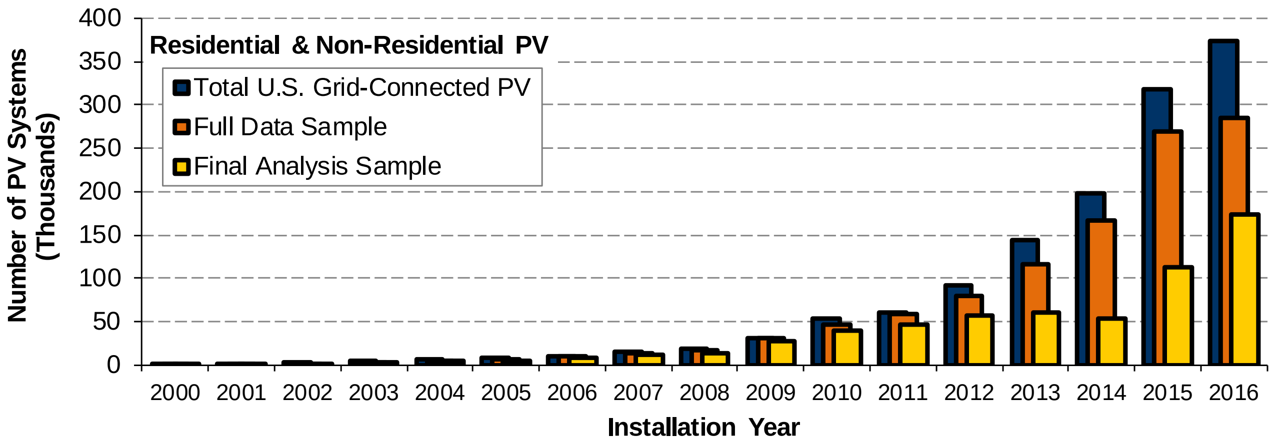
For systems financed by integrated TPO providers, reported installed price data generally represent appraised values, as no sale of the individual PV system occurs from which a price is established. To the extent that systems installed by integrated TPO providers could be identified, they were removed from the final data sample. Further details on the number of excluded appraised-value systems are provided below, and details on the procedure used to identify those systems are described in Appendix A, along with data on installed prices reported for those systems. Although excluded from the installed price trends presented in this report, we do summarize installed cost data from the financial reports of several integrated TPO providers in Figure 11, as a point of comparison.

In contrast, systems financed by non-integrated TPO providers were retained in the data sample. The installed price data reported for these systems represent an actual transaction price: namely, the price paid to the installation contractor by the customer finance provider. That said, differences may nevertheless exist between these prices and those reported for host-owned systems. Later sections compare installed prices reported for non-integrated TPO systems and host-owned systems, in order to discern whether those differences are potentially significant.

Sample Size

The full data sample includes the majority of all U.S. grid-connected residential and non-residential PV systems. In total, it consists of roughly 1.1 million individual PV systems installed through year-end 2016, including more than 280,000 systems installed in 2016 (Figure 1 and Table 1). This represents roughly 83% of all U.S. residential and non-residential systems installed cumulatively through 2016 and 76% of installations in 2016. The largest gaps in the 2016 sample are for Hawaii, which is wholly absent from the sample, and Maryland and Utah, which have quite low coverage (roughly 3% of systems installed in 2016 in those states).[4] Coverage among other large state markets is relatively complete, with at least 50% of all systems in each of the other top-10 state markets contained within the sample.

The final analysis sample, following removal of appraised-value and all other excluded systems, consists of roughly 630,000 systems installed through year-end 2016 (56% of the full sample and 47% of all U.S. systems) and more than 170,000 systems installed in 2016 (61% of the full sample and 47% of all U.S. systems installed in that year). The gap between the full and final data samples consists primarily of appraised-value systems (approximately 250,000 systems) and systems missing installed price data (approximately 210,000 systems). The latter includes all systems from several states for which installed price data are wholly unavailable, as well as a sizeable number of California systems installed from 2013 through 2015, during which time the state's incentive program was winding down and the new data collection process had not yet been fully implemented. As shown in Figure 1, the gap between the full and final data samples narrowed in 2016, primarily due to the increased availability of installed price data for California.



Notes: Total U.S. grid-connected PV system installations are based on data from IREC (Sherwood 2016) for all years through 2010 and data from GTM Research and SEIA (2017) for each year thereafter.

Figure 1. Comparison of Data Sample to All U.S. Residential and Non-Residential PV Systems

[4] In the case of Hawaii, none of the available data sources track the minimal set of data fields needed for inclusion in the full data sample. For Maryland and Utah, we rely on data from incentive programs that have limited budgets and therefore cover only a small portion of each state's market.

Table 1. Full Data Sample and Final Analysis Sample by Installation Year and Market Segment

Installation Year	Full Data Sample				Final Analysis Sample			
	Residential	Non-Res. ≤500 kW_{DC}	Non-Res. >500 kW_{DC}	*Total*	Residential	Non-Res. ≤500 kW_{DC}	Non-Res. >500 kW_{DC}	*Total*
1998	18	3	0	***21***	12	1	0	***13***
1999	162	10	0	***172***	131	7	0	***138***
2000	145	9	0	***154***	97	7	0	***104***
2001	1,142	40	0	***1,182***	977	32	0	***1,009***
2002	2,153	171	2	***2,326***	1,916	142	1	***2,059***
2003	3,188	278	3	***3,469***	2,903	236	3	***3,142***
2004	5,159	416	6	***5,581***	4,799	362	6	***5,167***
2005	5,480	446	7	***5,933***	5,125	370	7	***5,502***
2006	8,910	512	22	***9,444***	8,367	433	20	***8,820***
2007	12,945	845	35	***13,825***	11,910	679	30	***12,619***
2008	15,356	1,572	88	***17,016***	12,629	1,389	74	***14,092***
2009	29,239	2,027	87	***31,353***	25,319	1,768	56	***27,143***
2010	42,360	3,761	199	***46,320***	37,034	3,344	135	***40,513***
2011	53,076	6,230	403	***59,709***	41,754	5,095	314	***47,163***
2012	72,907	6,068	408	***79,383***	51,884	4,762	293	***56,939***
2013	111,680	4,707	422	***116,809***	56,871	3,137	316	***60,324***
2014	160,898	5,445	442	***166,785***	50,819	2,532	270	***53,621***
2015	264,517	5,185	510	***270,212***	109,240	3,005	309	***112,554***
2016	277,118	6,832	722	***284,672***	168,976	4,986	506	***174,468***
Total	***1,066,453***	***44,557***	***3,356***	***1,114,366***	***590,763***	***32,287***	***2,340***	***625,390***

Notes: See Text Box 1 for an explanation of the three customer segments delineated in this table and used throughout the report.

Sample Characteristics

Characteristics of the data sample provide important context for understanding installed price trends presented in this report. Generally, these characteristics correspond reasonably well to the broader market from which the sample is drawn. Below, we highlight trends associated with three key characteristics of the data sample: the evolution of system sizes over time, the geographical distribution among states, and the distribution between host-owned and TPO systems. Unless otherwise indicated, the trends refer to the final analysis sample.

System Size Trends

System sizes have grown over time within each of the three customer segments used in this report, as shown in Figure 2. In particular, residential systems have more-than-doubled in size, rising from a median of 2.9 kW per system in 2000 to 6.2 kW in 2016. The class of non-residential systems ≤500 kW have grown from a median size of 5 kW in 2000 to 32 kW in 2016. Irrespective of this growth, it is worth noting that the vast majority of systems in this class are well below the 500 kW mark; as such, this customer segment is sometimes described in the report as “small” or “smaller” non-residential systems. Finally, system sizes for the large (>500 kW) non-residential class have also generally risen over time, with a median size of roughly 970 kW in 2016, reflecting the growing prevalence of multi-MW rooftop systems and “baby ground-mount” systems in the 1-5 MW range. Year-over-year trends for this size class can be volatile, however, as a result of small sample sizes.

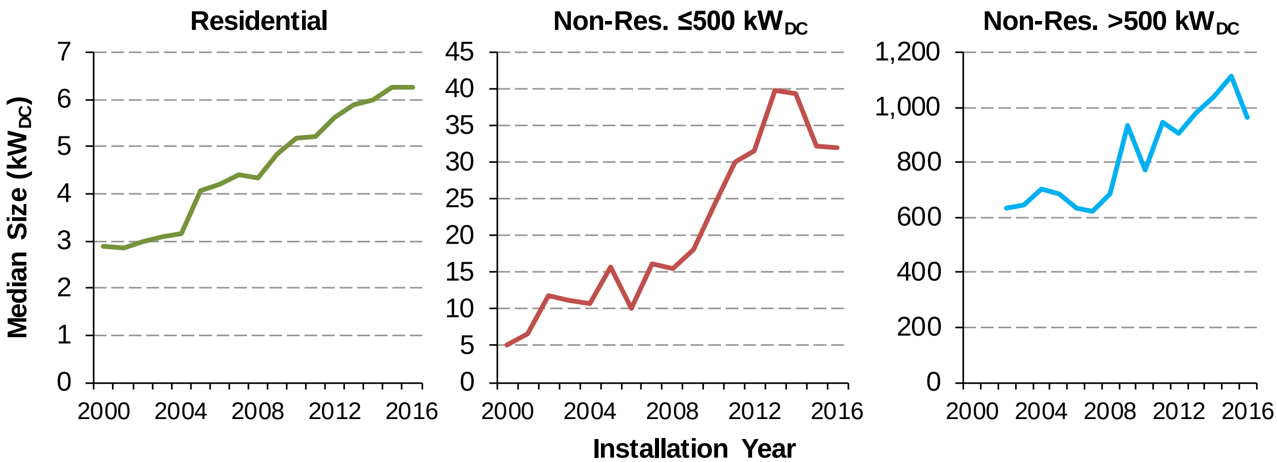


Figure 2. Median System Size over Time

Geographic Distribution

The final analysis sample includes systems installed across 25 states. As with the broader U.S. PV market, however, the sample is concentrated in a relatively small number of state markets, though it has diversified to some extent over time. This is illustrated in Figure 3, which shows the sample distribution over time, identifying the five-largest states (in terms of the number of systems) for each customer segment in 2016.

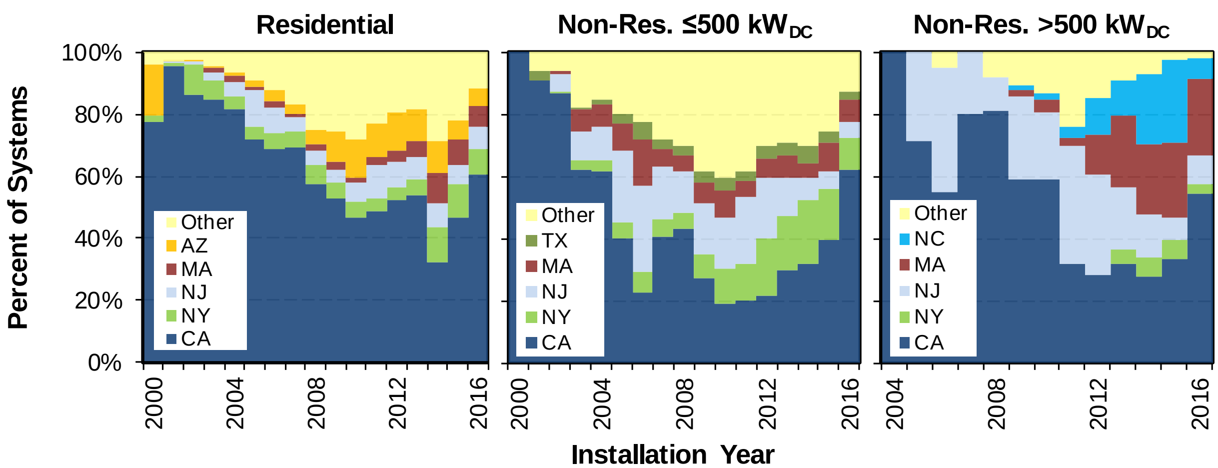


Figure 3. Sample Distribution among States

Across all three customer segments, California has remained the largest state in the data sample representing 61% of residential systems, 62% of non-residential systems ≤500 kW, and 54% of non-residential systems >500 kW installed in 2016. Although the state's share of the sample has generally declined over the long-term, it increased sharply in 2016, as a result of the renewed collection of installed price data for systems installed in the IOUs' service territories. As discussed later in the report, this has implications for recent trends in aggregate national installed pricing.

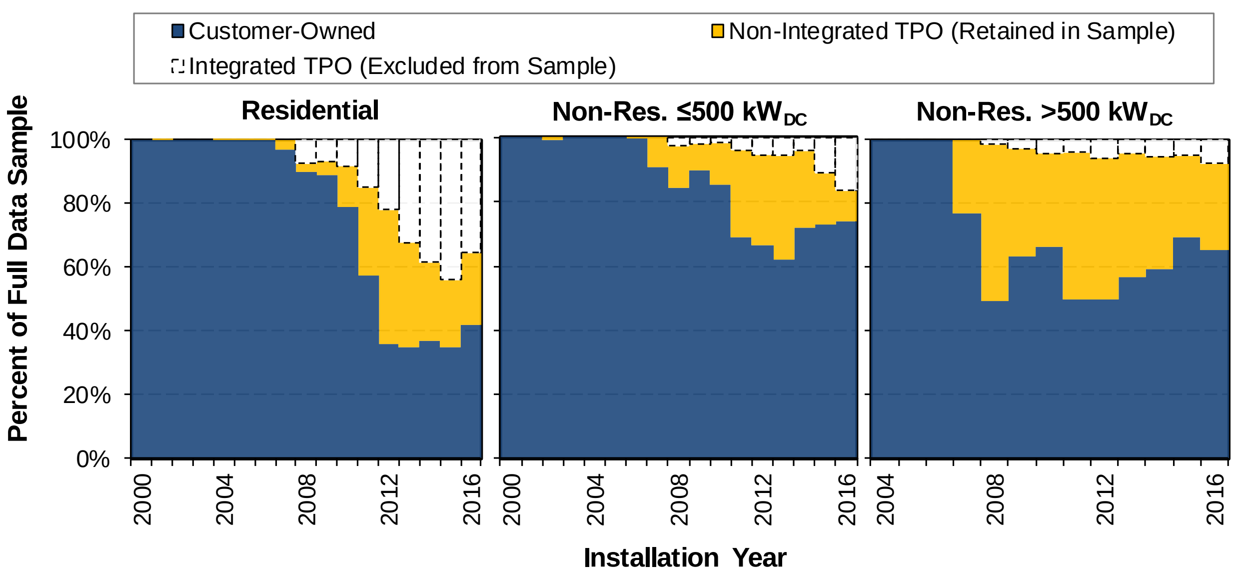
New York, New Jersey, Massachusetts, Arizona, Texas, and North Carolina make up the bulk of the remaining sample, though each of the latter three states are prominent mostly within particular customer segments. For example, North Carolina constitutes a large share of non-residential systems >500 kW, but has a negligible presence within the other segments. Also worth noting is that the sample of non-residential systems >500 kW has the least geographic diversity among the three segments, with virtually all 2016 installations in the sample located in the five states shown in Figure 3.

Distribution between Host-owned and TPO Systems

The composition of the data sample reflects the growth of third-party ownership (TPO) and increasing concentration of market share within the TPO segment. This is shown in Figure 4, which is based on the full data sample in order to illustrate growth of both integrated and non-integrated TPO systems (unlike most other figures in the report, which exclude integrated TPO systems).

Within the residential data sample, the TPO share grew dramatically from 2007 up until 2012, reaching 65% and remaining at roughly that level through 2015. Consistent with movement in the broader market back towards customer ownership, the TPO share of the data sample shrank slightly in 2016, constituting 58% of all residential systems in the full data sample. Of the TPO systems in the sample, the integrated TPO share continued to grow through 2015, as the U.S. market consolidated among several large residential installers. That fraction receded as well in 2016, with 35% of residential systems in the full data sample installed by an integrated TPO provider.

The trends differ markedly within the non-residential sample, in two respects. First, the overall TPO percentages are considerably lower: 26% of the sub-500 kW class and 34% of the >500 kW class of non-residential systems installed in 2016. Second, and more importantly, is that integrated TPO systems represent a small share of non-residential TPO systems, and thus relatively few non-residential systems were excluded from the final analysis sample.



Notes: Excluded from the figure is the relatively small percentage of systems for which the ownership model is unknown or could not be readily inferred.

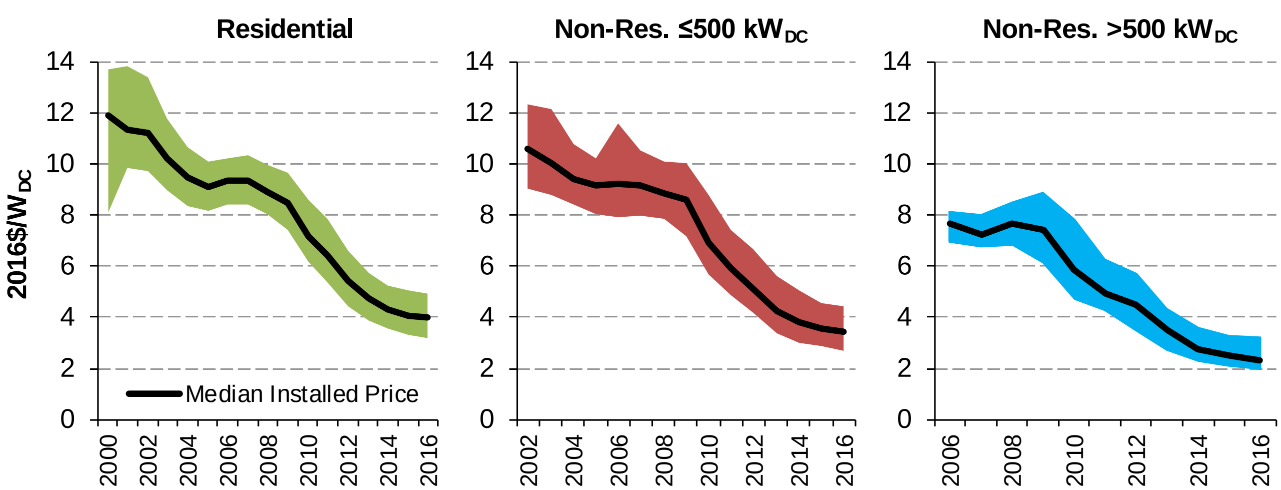
Figure 4. Sample Distribution between Host-owned and TPO Systems

3. Historical Trends in Median Installed Prices

This section presents an overview of both long-term and more-recent historical trends in the installed price of residential and non-residential PV, based on *median values* derived from the large underlying data sample. It begins by describing the installed price trajectory over the full historical period of the data sample through 2016, along with preliminary data for the first half of 2017. The section then discusses a number of broad drivers for those historical trends, including reductions in underlying hardware component prices and soft costs, increasing module efficiency and system size, and declining state and utility incentives. It then compares median installed prices for systems installed in 2016 to other recent benchmarks for the installed price or cost of PV, and finally compares installed prices between the United States and other international markets.

Long-Term and Recent Installed Price Trends

Installed prices for both residential and non-residential PV have fallen dramatically over time, as shown in Figure 5. Over the full duration of the available time series, median installed prices fell by roughly \$0.5/W per year on average, for each of the three customer segments shown, equating to an average annual percentage drop of 7% per year for residential and small (≤500 kW) non-residential systems, and 11% per year for large (>500 kW) non-residential systems. The trajectory, however, has not been smooth. Prices fell rapidly in the early years through 2004, followed by little price movement over the 2005-2009 period, and then a resumption of price declines in 2010. Though prices have fallen each year since 2010, the pace has slowed in recent years. Over the last year of the analysis period, from 2015 to 2016, median prices fell by just \$0.1/W (2%) for residential, \$0.1/W (3%) for small non-residential, and \$0.2/W (8%) for large non-residential systems. These were the smallest year-over-year reductions in all three segments since 2009. As discussed further below, installed prices tend to lag behind movements in underlying component prices; the data in Figure 5 therefore likely do not fully capture reductions in the price of PV modules and other hardware components that occurred over the course of 2015 and 2016.

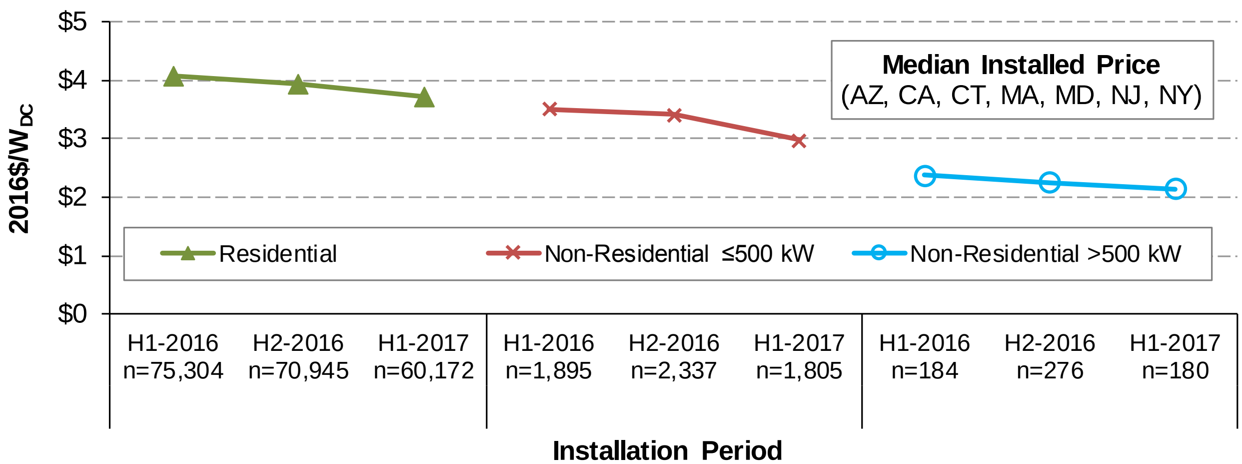


Notes: Solid lines represent median prices, while shaded areas show 20th-to-80th percentile range. See Table 1 for annual sample sizes. Summary statistics shown only if at least 20 observations are available for a given year and customer segment.

Figure 5. Installed Price Trends over Time

More generally, the slowing rate of price declines over the past several years likely reflects several factors. In part, it may be the natural result of diminishing opportunities for cost reductions and growing customer acquisition costs as early adopters are converted. However, two other factors—both artifacts of the data—are likely also at play. The first is an increasing proportion of the sample from California, as shown earlier in Figure 3. This is particularly true in the residential sector, where 61% of all systems in the sample were from California in 2016, compared to 47% in 2015 and 32% in 2014. As shown in later sections, California is a relatively high-priced state, and thus its growing proportion of the sample tends to dampen the decline in national median prices. In addition, price declines in California have also been relatively slow, with median residential system prices falling by just 2% from 2015 to 2016, compared to at least 5% in most other states. A second factor behind the apparent slowing in the decline of national median prices is the growing share of loan-financed systems. Residential loan products have become more prevalent, comprising 18% of all residential systems installed in 2016, or roughly 40% of all host-owned systems (Shao and Mond 2017). Dealer origination fees associated with such loans—which can range from 15-20% of the loan amount, adding \$0.6 to \$0.8/W to a median-priced system—are often embedded in the installed prices paid by customers and reported to PV incentive program administrators.

Preliminary data for the first six months of 2017 suggest that the pace of price reductions is picking back up. As shown in Figure 6, median installed prices for the first half (H1) of 2017 fell by an additional \$0.2/W for residential systems, by \$0.4/W for small non-residential systems, and by \$0.1/W for large non-residential systems, relative to the second half (H2) of 2016. Extrapolated over a full year, these installed price declines would yield an 11% year-over-year decline for residential, 25% for small non-residential, and 10% for large non-residential systems. These percentage reductions are greater than or equal to the long-term average rate of decline, though should be considered somewhat provisional, given the more-limited sample used for this partial-year analysis, and potential seasonality in installed price trends.

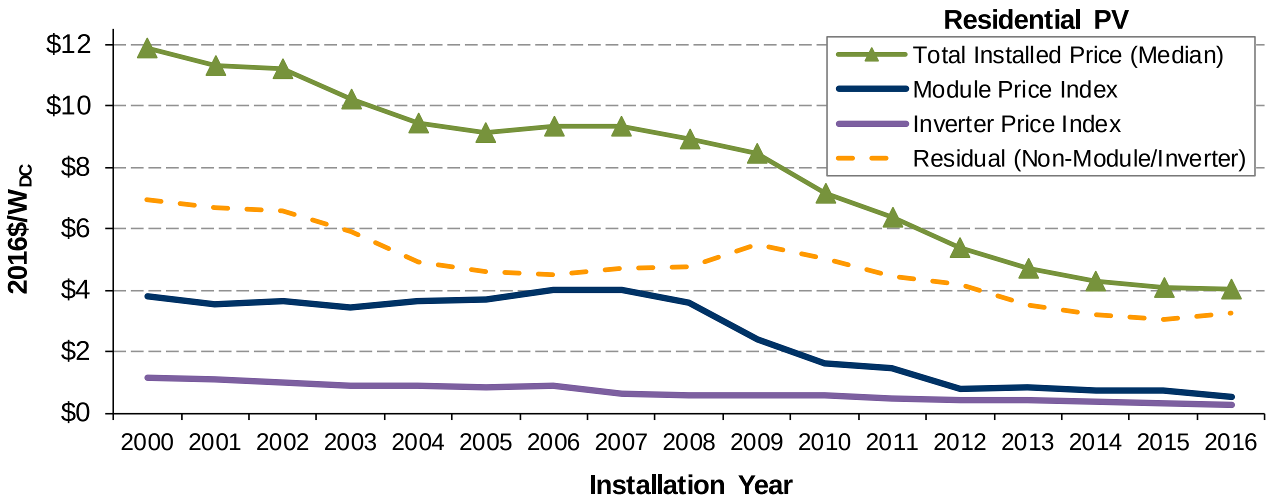


Notes: The figure is based on a subset of states and data sources used for the larger dataset, and therefore cannot be directly compared to Figure 5.

Figure 6. Median Installed Prices for Systems Installed in 2016 and the First Half of 2017

Underlying Hardware and Soft Cost Reductions

The decline in system-level installed prices over the last year of the analysis period, from 2015 to 2016, would appear to be primarily attributable to reductions in hardware costs. Benchmark prices for the three primary hardware components—modules, inverters, and racking—fell in aggregate by roughly $0.3/W for residential systems over that time span (GTM Research and SEIA 2017). That aggregate drop in hardware costs is actually greater than the decline in total residential system prices observed within the LBNL dataset. This apparent disconnect may be partially the result of a lag between changes in component prices and installed system prices, arising due to the gap in time between when installers purchase equipment and when that equipment is installed at customer sites.[5] Accordingly, the more substantial reduction in installed prices during the first half of 2017 is suggestive of a latent effect of hardware cost reductions during the prior year.



Notes: The Module Price Index is the global module price index for large quantity buyers, published by SPV Market Research (2017). The Inverter Price Index is a weighted average of residential string inverter and microinverter prices published by GTM Research and SEIA (2017); that price series begins in 2010, and we extend it backwards in time using inverter costs reported for individual systems within the LBNL data sample. The Residual term is calculated as the Total Installed Price minus the Module Price Index and Inverter Price Index.

Figure 7. Installed Price, Module Price Index, Inverter Price Index, and Residual Costs over Time for Residential PV Systems

Over the long-term, however, both hardware and non-hardware (i.e., soft) costs have fallen substantially, contributing in almost equal measure to overall reductions in system-level installed prices. Among hardware costs, PV modules have been, far and away, the largest single driver for system-level installed price declines over the long-term. Since 2000, module prices have fallen by roughly $3.3/W (based on a global module pricing index), equating to 41% of the decline in total residential installed system prices over that time. As shown in Figure 7, most of that drop occurred between 2008 and 2012, when total installed prices fell more or less in tandem. Second in significance among hardware cost reductions are inverters, which have fallen by roughly $0.9/W since 2000, representing 12% of the long-term decline in residential system prices.[6]

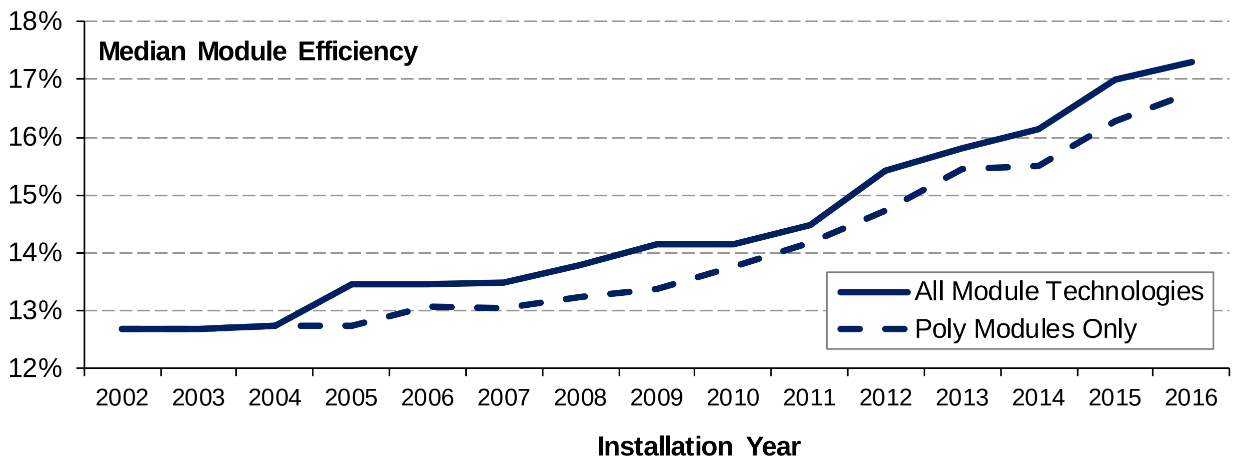
The remaining 47% of long-term installed price declines is therefore associated primarily with the wide assortment of soft costs, including such things as marketing and customer acquisition, system design, installation labor, permitting and inspection costs, and installer margins. These soft costs are captured by the "residual" term plotted in Figure 7 (which also includes other ancillary

[5] The disconnect between changes in component prices and observed system prices may reflect a number of other factors as well, for example: changes in the composition of module technologies and installer base within the sample over time, and the ability of some installers to potentially retain a portion of component cost reductions in their margin.
[6] Long-term, time-series data for other hardware elements are not available. For residential racking equipment, index data published by GTM Research and SEIA (2017) suggest roughly a $0.3/W reduction from 2012 to 2016.

hardware costs, such as racking and wiring).[7] Long-term reductions in soft costs reflect a combination of factors. Recent years have seen significant emphasis in the industry and among policymakers on reducing soft costs, and those efforts have likely borne some fruit. Financial incentives for PV in most states have also fallen substantially over time, placing further pressure on installers and others in the supply chain to streamline business processes. Finally, two technical factors—increasing module efficiency and increasing system size—have also helped to reduce soft costs (on a per-watt basis). These underlying drivers are explored further in the following sections.

Impacts of Increasing Module Efficiency on Installed Prices

Installed price declines over time are partly tied to increasing PV module efficiency: higher module efficiencies reduce installed prices on a per-watt basis by spreading fixed project costs (e.g., permitting and customer-acquisition) and area-related costs (e.g., racking and installation labor) across a larger base of installed watts. As shown in Figure 8, median module efficiencies among systems in the LBNL dataset rose from 12.7% in 2002 to 17.3% in 2016. Based on modeled residential PV cost relationships developed by Fu et al. (2017), this increase in module efficiency corresponds to roughly a $0.3/W reduction in fixed and area-related costs—equivalent to 8% of all non-module/non-inverter cost declines over the same time period.[8] Within the last year of the analysis period, from 2015 to 2016, median module efficiencies rose from 17.0% to 17.3%, which would be expected to yield about a $0.01/W reduction in fixed and area-related costs.



Notes: "All Module Technologies" is based on all systems in the data sample, regardless of module type, while "Poly Modules Only" is based on only those systems with poly-crystalline modules.

Figure 8. Module Efficiency Trends over Time within the Project Data Sample

[7] This residual term has risen at various points in time, including in 2009 and again in 2016. Although some soft costs, such as customer acquisition, indeed may have risen, these apparent "spikes" should be viewed primarily as an artifact of the lag between component prices and total installed prices.

[8] The estimated non-module cost reduction associated with module efficiency gains represent only the *marginal* effect, given all other sources of cost reduction that occurred over the corresponding time span. Had other cost reductions not occurred (e.g., no change in installation labor efficiency or reduction in permitting costs), the effects of module efficiency improvements would be greater.

Impacts of Increasing System Size on Installed Prices

A second technical factor behind the long-term decline in residential system prices, and soft costs in particular, has been the steady growth in system sizes. Larger systems enable lower installed prices (on a per-watt basis) for reasons similar to those noted above for module efficiency: namely, the ability to spread fixed project costs over a larger base of installed watts. As shown previously in Figure 2, the median size of residential systems in the data sample grew from 2.9 kW in 2000 to 6.2 kW in 2016. Roughly one-third of that growth is nominally the result of increasing module efficiencies (i.e., higher wattages per panel). The remainder is instead associated with growth in the number of panels per system.

Relying again on the modeled cost relationships developed by Fu et al. (2017), the increase in residential system sizes since 2000 would be expected to yield roughly a $1.0/W reduction in non-module/inverter costs (inclusive of the effects of increasing module efficiency).[9] This equates to 12% of the total decline in residential installed prices over that period, and 26% of the decline in non-module/non-inverter costs (i.e., the residual term in Figure 7). Within the final year of the analysis period, median residential system sizes remained effectively unchanged, thus no further cost reductions can be attributed to system size increases in the most recent year.

State and Utility Cash Incentives

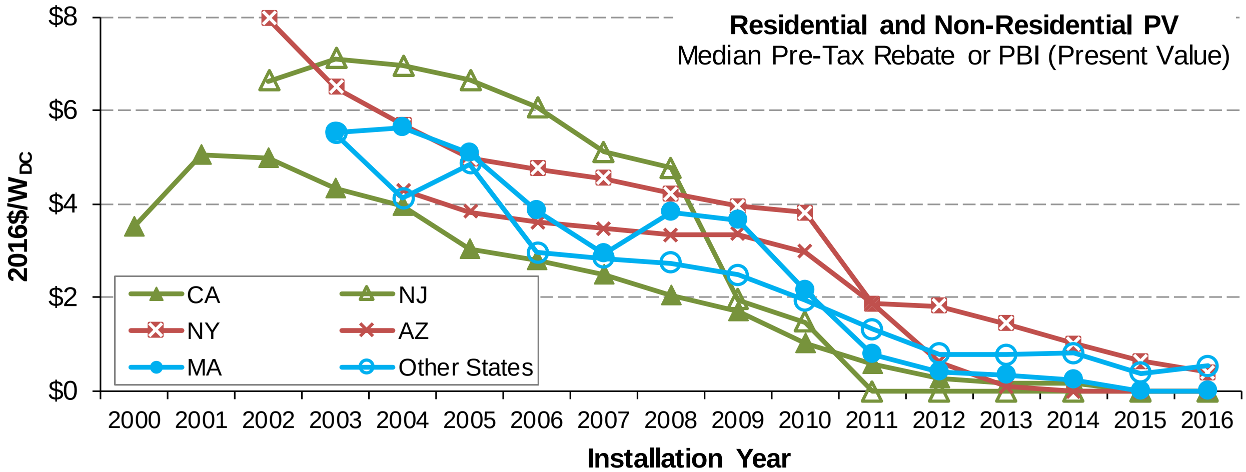
Financial incentives provided through utility, state, and federal programs have been a driving force for the PV market in the United States. For residential and non-residential PV, those incentives have – depending on the particular place and time – included some combination of cash incentives provided through state and/or utility PV programs (rebates and performance-based incentives), the federal investment tax credit (ITC), state ITCs, revenues from the sale of solar renewable energy certificates (SRECs), accelerated depreciation, and retail rate net metering.

Focusing *solely* on direct cash incentives provided in the form of rebates or performance-based incentives (PBIs), Figure 9 shows how these incentives have declined steadily and significantly over the past decade across all of the major incentive programs. At their peak, these programs were providing incentives of $4-8/W (in real 2016 dollars). By 2016, direct rebates and performance-based incentives were largely phased-out in many key markets – including Arizona, California, Massachusetts, and New Jersey – and had diminished to well below $1/W elsewhere. This continued ratcheting-down of incentives is partly a response to the steady decline in the installed price of PV and the emergence of other forms of financial support (for example, SRECs, as discussed in Text Box 3). In many states, it has also been a deliberate strategy to provide a long-term signal to the industry to reduce costs and improve installation efficiencies. The steady decline in incentives is thus both a cause and an effect of installed price reductions over time.

From the perspective of the customer-economics of PV, however, one thing is clear: the steady reduction in cash incentives has offset reductions in installed prices to a significant degree. Among the five state markets profiled in Figure 9, the decline in incentives from each market's respective peak is equivalent to anywhere from 70% to 120% of the drop in installed PV prices over the corresponding time period. Of course, other forms of financial support have simultaneously become more lucrative over this period of time – for example, the increase in the federal ITC for residential

[9] This estimated impact of system size increases represents only the *marginal* effect, given all other sources of cost reduction that occurred over the corresponding time span. Had other cost reductions not occurred (e.g., no change in installation labor efficiency or reduction in permitting costs), the effects of system size increases would be greater.

solar starting in 2009 and the emergence of SREC markets – and new financing structures have allowed greater monetization of existing tax benefits. Thus, the customer economics of solar in many states and markets has undoubtedly improved, on balance, over the long-term, but the decline in state and utility cash incentives has nevertheless been a significant counterbalance to falling installed prices.



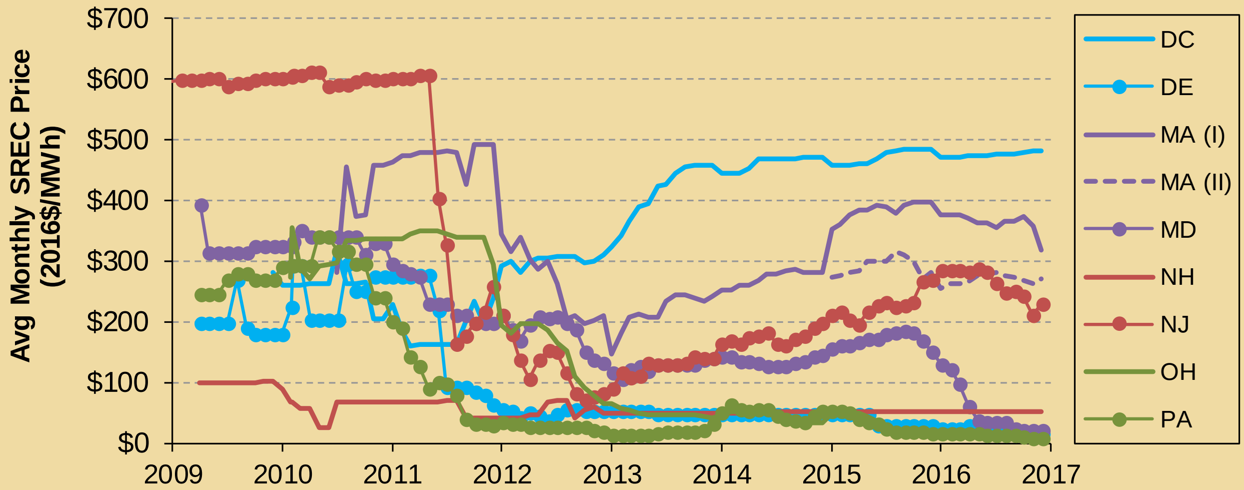
Notes: The figure depicts the pre-tax value of rebates and PBI payments (calculated on a present-value basis) provided through state/utility PV incentive programs.

Figure 9. State/Utility Rebates and PBIs over Time

Text Box 3. SREC Price Trends

Eighteen states plus the District of Columbia have enacted renewables portfolio standards with a solar or distributed generation set-aside (also known as a "carve-out"), and many of those states have established solar renewable energy certificate (SREC) markets to facilitate compliance. PV system owners in these states, and in some cases neighboring states, may sell SRECs generated by their systems, either in addition to or in lieu of direct cash incentives received from state/utility PV incentive programs. Many solar set-aside states have transitioned away from standard-offer based incentives, particularly for larger and non-residential systems, and towards SREC-based incentive mechanisms with SREC prices that vary over time.

Prior to 2011, SREC prices in most major RPS solar set-aside markets ranged from $200 to $400/MWh, topping $600/MWh in New Jersey (Figure 10). Starting around 2011 or 2012, SREC supply began to outpace demand in these markets, leading to a steep drop in SREC pricing. As with the broader decline in solar incentives, this contraction in SREC pricing served as a source of further downward pressure on installed prices. Since then, SREC prices have generally stabilized or even risen, relieving some of that downward pressure on installed prices.



Notes: Data sourced from Marex-Spectron, SRECTrade, and Flett Exchange (data averaged across available sources). Plotted values represent SREC prices for the current or nearest future compliance year traded in each month. MA (I) and MA (II) refer to prices in the SREC I and SREC II programs, respectively.

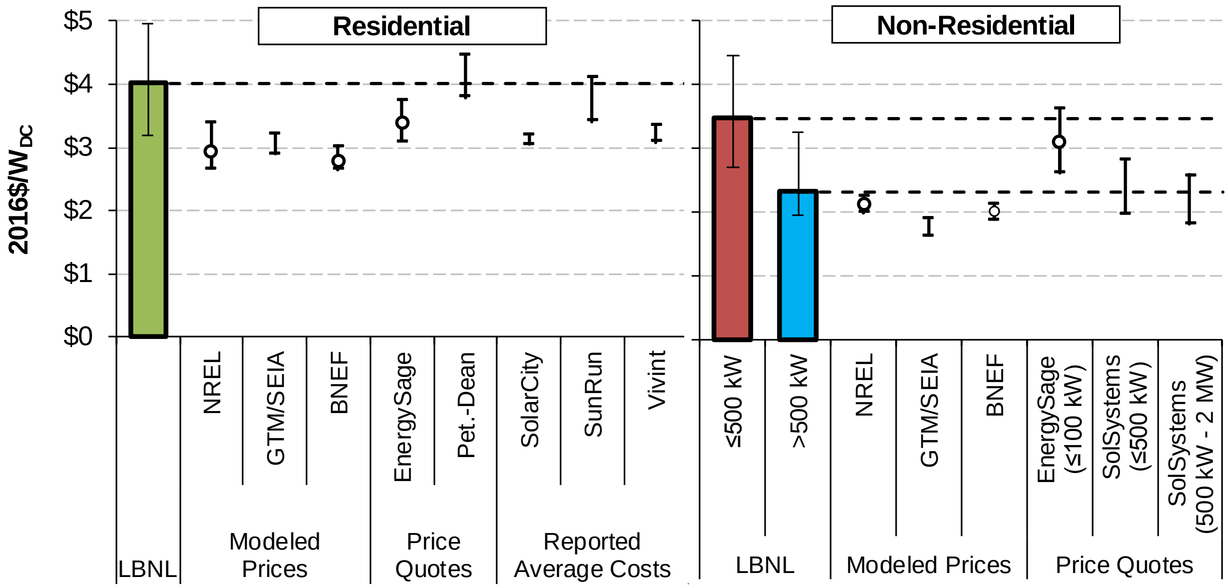
Figure 10. Monthly Average SREC Prices for Current or Nearest Future Compliance Year

Comparison of Median Installed Prices to Other Recent U.S. Benchmarks

National median prices can provide a useful metric for tracking temporal trends, but may or may not provide a relevant benchmark for system prices in all contexts. To provide a broader view of current PV system pricing, Figure 11 compares median installed prices of 2016 systems in the LBNL data sample to a diverse set of other recent PV price and cost benchmarks. These other benchmarks include modeled PV system prices, price quotes for prospective PV systems, and average costs reported directly by several major residential installers (see the notes below the figure for further details).

As evident in Figure 11, these various benchmarks vary substantially from one another, reflecting their underlying diversity of data, methods, and definitions. Of particular note is that median prices drawn from the LBNL dataset are generally higher than the other benchmarks shown. Among residential systems, for example, the median installed price within the LBNL sample was $4.0/W in 2016. The other residential benchmarks vary from $2.7/W to $4.5/W, though most are clustered at the lower end of that range. Similarly, national median prices for non-residential systems in the LBNL dataset ($3.4/W for systems ≤500 kW and $2.3/W for systems >500 kW) are also higher than most of the other benchmarks shown, which range from $1.6/W to $3.6/W. These differences between the LBNL median values and other benchmarks occur for a number of reasons, as described more fully in Text Box 4.

Notwithstanding the divergence noted above, many systems in the LBNL dataset exhibit prices well aligned with the other PV pricing and cost benchmarks. Indeed, the 20th percentile pricing levels for both residential systems ($3.2/W) and large non-residential systems ($1.9/W) fall squarely in the range of the other benchmarks. Later sections of this report will further explore the wide spread in the data, and will show that prices observed in many contexts—i.e., for certain states, installers, module technologies, and TPO systems—are substantially below the national median, and correspond closely to the other benchmarks shown in Figure 11.



*Notes: **LBNL** data are the median and 20th and 80th percentile values among projects installed in 2016. **NREL** data represent modeled turnkey costs in Q1 2016 for a 5.6 kW residential system (range across system configuration and installer type, with weighted average) and a 200 kW commercial system (range across states and national average) (Fu et al. 2016). **GTM/SEIA** data are modeled turnkey prices for Q1 and Q4 2016; their residential price is for a 5-10 kW system with standard crystalline modules, while the commercial price is for a 300 kW flat-roof system (GTM Research and SEIA 2017). **BNEF** data are estimated PV capex with developer margin in 2016 (US averages and range across states/regions) (Serota and Bromley 2016). **EnergySage** data are the median and 20th and 80th percentile range among price quotes issued in 2016, calculated by Berkeley Lab from data provided by EnergySage; quote data for non-residential systems are predominantly from small (<100 kW) projects. **Petersen-Dean** data are the minimum and maximum values from a series of online price quotes for turnkey systems across a range of sizes (3.4 to 8.4 kW) and states (CA and TX), queried from the company website by Berkeley Lab in June 2016. **SolarCity**, **SunRun**, and **Vivint** data are the companies' reported average costs, inclusive of general administrative and sales costs, for Q1 and Q4 2016 (or Q3 2016 for SolarCity). **SolSystems** data are averages of the 25th and 75th percentile values of "developer all-in asking prices" published in the company's monthly Sol Project Finance Journal reports throughout 2016.*

Figure 11. Comparison to Other Installed Price or Cost Benchmarks

Text Box 4. Reasons for Differences between LBNL Median Values and Other Benchmarks

Variation across the benchmarks shown in Figure 11 arise for a number of reasons, and in general explain why median values drawn from the LBNL data sample are higher than the other benchmark values:

- *Timing*: The LBNL data in Figure 11 are based on systems installed over the course of 2016. A number of the other benchmarks cited in the figure are instead based on price quotes issued in 2016, which may precede installation by several months to even a year or more (especially for non-residential projects). These differences in timing can be significant given the rapid pace of cost and price declines within the industry.
- *Price versus cost:* The LBNL data, like the modeled prices and price-quote data, represent prices paid by PV system owners to installers or project developers. In contrast, the data points drawn from SolarCity's, SunRun's, and Vivint's publicly-available financial reports represent costs borne by these companies, which exclude profit margins and, for a variety of other reasons, may differ from the prices ultimately paid by PV system owners.
- *Value-based pricing*: Benchmarks may reflect developer/installer margins based on some minimally sustainable level, as may occur in highly competitive markets. In contrast, the market price data assembled for this report are based on whatever profit margin developers are able to capture or willing to

accept, which may exceed a theoretically competitive level in markets with high search costs and/or barriers to entry.

- *Location:* As noted earlier, statistics derived from the LBNL dataset are dominated by several high-cost states that constitute a large fraction of the sample (and of the broader U.S. market). Other benchmarks may instead be representative of lower-cost or lower-priced locations.
- *System size and components*: A number of the benchmarks in Figure 11 are based on turnkey project designs and prototypical system sizes. The LBNL data instead reflect the specific sizes and components of projects in the sample. For example, roughly 35% of 2016 residential systems in the sample have high efficiency modules, and most of the non-residential systems in the ≤500 kW class are, in fact, smaller than 30 kW.
- *Scope of costs included*: The set of cost components embedded in the installed price data collected for this report undoubtedly varies across projects, and in some cases may include items such as re-roofing costs or loan origination fees that typically would not be included in other PV pricing benchmarks (though, from the customer's perspective, are nevertheless part of the price of "going solar").
- *Installer characteristics*: Finally, the LBNL data reflect the characteristics and reporting conventions of the particular installers in the sample, many of which are relatively small or regional. Moreover, by virtue of excluding appraised value systems, the LBNL dataset excludes several of the largest U.S. residential installers. The other benchmarks in Figure 11 may, in many cases, be reflective of relatively large and experienced installers.

Comparison of U.S. Median Installed Prices to Other International Markets

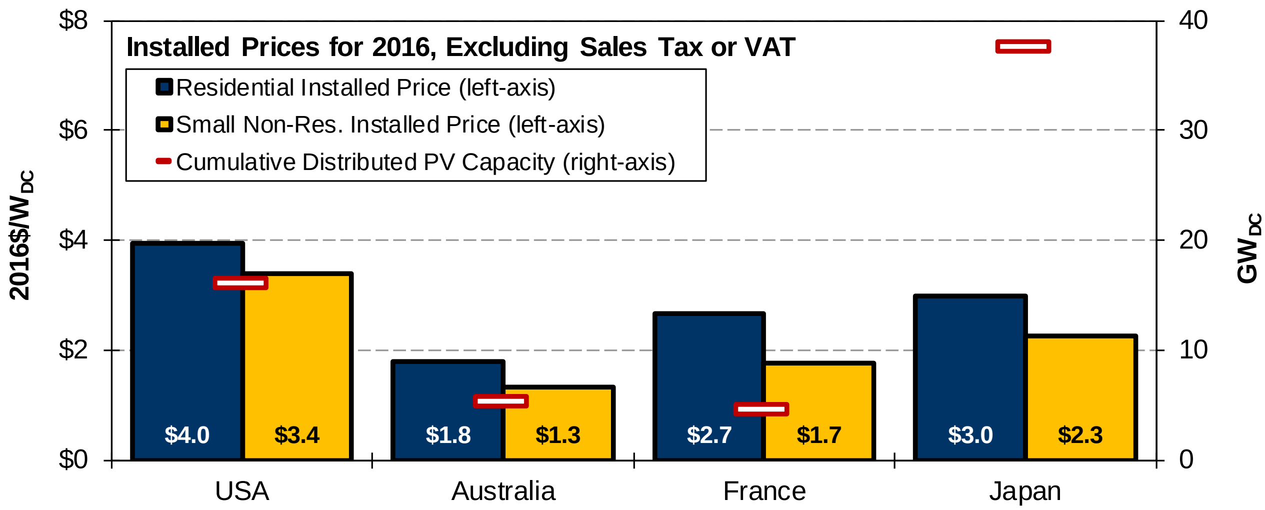
Notwithstanding the significant installed price reductions that have already occurred in the United States, international experience suggests that greater near-term reductions are possible. Figure 12 compares median installed prices for residential and sub-500 kW non-residential systems installed in the United States in 2016 to system prices for a number of other major national markets, in all cases excluding sales tax or value added tax (VAT). In Australia, for example, typical pricing for residential systems was reported to be around \$1.8/W in 2016: less than half the median price observed within the LBNL dataset.

To be sure, these data are not perfectly comparable to one another.[10] Perhaps most importantly, U.S. prices are based on median values, while prices for most of the other countries refer to "turnkey" systems, as reported for each country in its annual National Survey Report to the International Energy Agency's Photovoltaic Power Systems Programme (IEA-PVPS). However, even considering the broader set of U.S. benchmarks presented in the previous section, the data suggest that U.S. installed prices are still higher than in other major markets.

Other than the impacts of import duties, modules and other hardware items are similarly priced across countries. Differences in total system prices among countries can thus be attributed primarily to soft costs. Indeed, installer surveys in Australia and Japan (as well as Germany, which is not included in the above figure) have confirmed that soft costs in those countries are substantially lower than in the United States (Seel et al. 2014, Ardani et al. 2012, Friedman et al. 2014, RMI and GTRI 2014). Several time-and-motion studies have further homed-in on installation costs, identifying specific aspects of installation practices in Australia and Germany that enable lower labor costs in those countries than in the United States (RMI and GTRI 2013, 2014).

[10] The figure compares across those countries for which IEA PVPS 2016 national country reports were published as of August 2017.

At a high-level, differences in soft costs between countries may be attributable partly to differences in market size, on the theory that larger markets facilitate cost reductions through learning-by-doing and economies of scale that enable reductions across the broad swath of soft cost elements. Indeed, as shown in Figure 12, cumulative distributed PV capacity in Japan is significantly greater than in the United States. On the other hand, Australia and France—both of which are also relatively low-priced compared to the United States—have much smaller distributed PV markets in absolute terms (though Australia's market is significantly larger if compared on a per-capita basis). Thus, other factors, beyond absolute market size, clearly also contribute to installed price differences across countries. These may include differences in: incentive levels and incentive design, solar industry business models, demographics and customer awareness, building architecture, systems sizing and design, interconnection standards, labor wages, and permitting and interconnection processes.



Notes: Data for Australia, France, and Japan are based on each country's respective IEA Photovoltaic Power Systems Programme's (PVPS) 2016 National Survey Report (Johnston and Egan 2017, L'Epine 2017, and Yamada and Ikki 2017).

Figure 12. Comparison of Installed Prices in 2016 across National Markets (Pre-Sales Tax/VAT)

4. Variation in Installed Prices

While the preceding section focused on trends in median installed prices drawn from the dataset as a whole, this section instead highlights the substantial *variability* in installed prices and explores potential drivers for installed price differences across projects. The section begins by describing the overall distribution in installed prices across the dataset as a whole, and how that distribution has evolved over time. It then examines a series of specific sources of installed pricing variation, including differences in: system size, state, installer, host-owned vs. TPO, residential new construction vs. retrofit, tax-exempt vs. for-profit commercial site hosts, module efficiency, use of module-level power electronics, and rooftop vs. ground-mounted systems with and without tracking.

Overall Installed Price Variability

Considerable spread exists within the pricing data, which has persisted over time, despite continuing maturation of U.S. PV markets. This is evident in Figure 5, presented earlier, which shows the 20th-to-80th percentile installed-price range for each customer segment over time. Those percentile bands have shifted downward over time as prices have fallen, but the overall spread in pricing for each customer segment has remained relatively unchanged.

Figure 13 provides further detail on the pricing distribution for systems installed in 2016. Among residential systems, roughly 20% were installed at prices below \$3.2/W (the 20th percentile value) and 20% were above \$5.0/W (the 80th percentile), with the remaining systems distributed across the wide range in between. Non-residential systems in the sub-500 kW class exhibit a similar spread, with 20th and 80th percentile values of \$2.7/W and \$4.4/W, respectively. The distribution for larger non-residential systems >500 kW is somewhat narrower, with a 20th-to-80th percentile band of \$1.9/W to \$3.2/W.

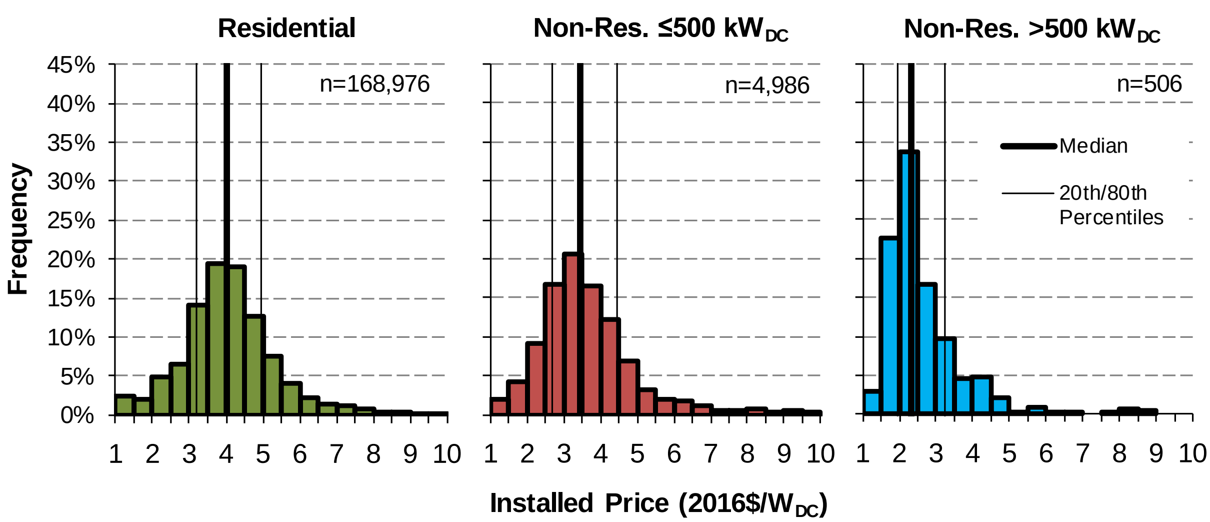


Figure 13. Installed Price Distributions for Systems Installed in 2016

The potential underlying causes for this persistent pricing variability are numerous, including differences in project characteristics (e.g., related to system size, technology type, or configuration) as well as attributes of individual installers. Installed price variation likely also reflects differences in regional or local market and regulatory conditions. For example, markets with less competition among installers, higher incentives, and/or higher electricity rates for net metering may have higher prices if installers are able to value-price their systems or if overheated demand strains the capacity of the local supply chain. Variability in prices also likely derives from differences in administrative and regulatory compliance costs (e.g., permitting and interconnection) as well as differences in labor wages and taxes. Many of these potential pricing drivers are explored throughout the remainder of this report using simple descriptive methods, and are also the subject of a series of econometric studies that LBNL and its collaborators have undertaken to better isolate the impacts of individual pricing drivers (see Text Box 5).

The wide pricing distributions observed within the data sample also serve to demonstrate the potential for low-cost installations. For example, though small in percentage terms, it is notable that more than 15,000 residential systems installed in 2016 (9%) were priced below $2.5/W, and 8,000 (5%) were priced below $2.0/W. The lower tail of the pricing distribution may offer insights into opportunities for broader price reductions, as LBNL and others have explored elsewhere.

Text Box 5. Findings from Recent In-Depth Analyses of PV Pricing Dynamics

In collaboration with researchers from Yale University, University of Wisconsin, and University of Texas at Austin, LBNL and NREL have engaged in a series of in-depth analyses to better understand PV pricing dynamics. These studies leverage the dataset assembled for Tracking the Sun in conjunction with other data sources, and apply a variety of statistical and econometric methods to explore PV pricing issues. To date, a number of studies in this series have been completed, and others are planned or underway.

Nemet et al. (2017) analyzed price dispersion in U.S. residential PV installations. The study found that price dispersion—defined as the variability in prices among systems installed within a given county and quarter—has increased over time. It further found that factors that increase consumer access to information—such as neighbors who have recently installed PV and the availability of third-party quotes—are associated with less price dispersion. These results provide support for the importance of efforts to enhance access to price information, especially in nascent PV markets where access to experiences of neighbors is unavailable.

O'Shaughnessy et al. (2016) developed a new approach to delineating solar PV market boundaries based on the spatial distribution of installer firms (instead of the more-typical approach using political boundaries, such as county or zip code).

Nemet et al. (2016a) sought to identify characteristics of the lowest priced systems (e.g., the lowest 10th percentile). That study found that low-priced systems are associated with experienced installers; customer ownership; larger system size; retrofits rather than new home construction; and thin-film, low-efficiency, and Chinese modules. The analysis also found that low-priced systems are much more likely to occur in some states than in others, and are more likely to occur in the presence of higher incentives, at least in California. Follow-up work by Nemet et al. (2016b) found that many of the same factors appear to drive low-priced systems to be even lower priced.

Gillingham et al. (2014) examined a broad range of potential drivers for PV pricing variability among residential systems installed during 2010 to 2012. Of the various factors considered, the single-largest contributor was system size ($1.5/W effect). The study also found that installed prices were lower in markets with the greatest density of installers ($0.5/W effect), potentially due to greater competition, and that prices were lower for systems installed by the most-experienced companies ($0.2/W effect). The study also found evidence that rich incentives can lead to higher prices ($0.4/W effect). That latter finding may reflect value-based pricing, though it may also simply be the natural result of high demand for solar enabling higher-cost installers and higher-cost systems.

Other studies in the series have focused on narrower issues related to the installed price of residential PV. Two of these studies have examined the impact of local permitting processes on residential PV pricing. Dong and Wiser (2013) found that cities in California with the most-favorable permitting practices had installed prices \$0.3/W to \$0.8/W lower than in cities with the most-onerous practices. Examining a broader geographical footprint, Burkhardt et al. (2014) found that variations in local permitting procedures lead to differences in average residential PV prices of approximately \$0.2/W across jurisdictions; when considering variations not only in permitting practices, but also in other local regulatory procedures, price differences grew to \$0.6/W to \$0.9/W between the most-onerous and most-favorable jurisdictions.

Another study, Dong et al. (2014), examined incentive pass-through – i.e., the degree to which installers pass through the value of incentives to consumers – in California's statewide rebate programs. This analysis included two wholly distinct modeling approaches, and in both cases found average pass-through rates ranging from 95% to 99%. These finding thus indicate that installers in California have not artificially inflated their prices as a result of available rebates, though the findings do not rule out the possibility of value-based pricing more generally, for example associated with utility bill savings or tax incentives.

Installed Price Differences by System Size

Larger PV installations benefit from economies of scale by spreading fixed project and overhead costs over a larger number of installed watts and by enabling volume purchases of materials. These scale economies are evident in the preceding figures that show lower installed prices for non-residential systems than for residential systems. They also arise within each customer segment, contributing to the observed pricing variability.

Among residential systems installed in 2016 (Figure 14), system sizes range from less than 2 kW to 20 kW and above, though the vast majority of systems fall within the range of 2-12 kW. Across that range, median prices are roughly \$0.8/W (19%) lower for systems at the upper end of that range than for those at the lower end.[11] Beyond 16 kW, further price declines appear to taper off for residential systems, indicative of strongly diminishing returns to scale (though sample sizes also become progressively thinner as well). These trends are generally consistent over time, as shown in Table B-2 in the appendix, which presents time series data across residential system sizes.

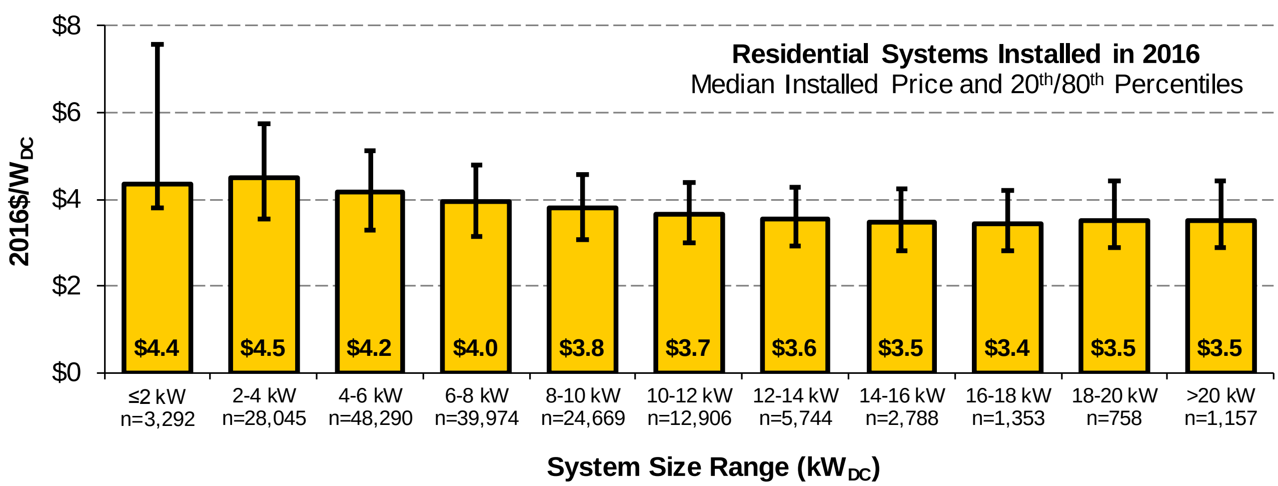


Figure 14. Installed Price of 2016 Residential Systems by Size

For non-residential systems (Figure 15), which span a wide range of system sizes, even more-pronounced economies of scale occur. Among systems installed in 2016, median installed prices

[11] Median prices for systems ≤2 kW are relatively low as a result of the high proportion of systems in that size range installed in new construction (which tend to be low-priced).

were $1.9/W (46%) lower for the largest class of non-residential systems >1,000 kW in size than for the smallest non-residential systems ≤10 kW.[12] Even greater scale effects may arise when moving from large non-residential systems to utility-scale, though the latter are outside the scope of this report. See Table B-3 in the appendix for time series data on non-residential pricing by system size.

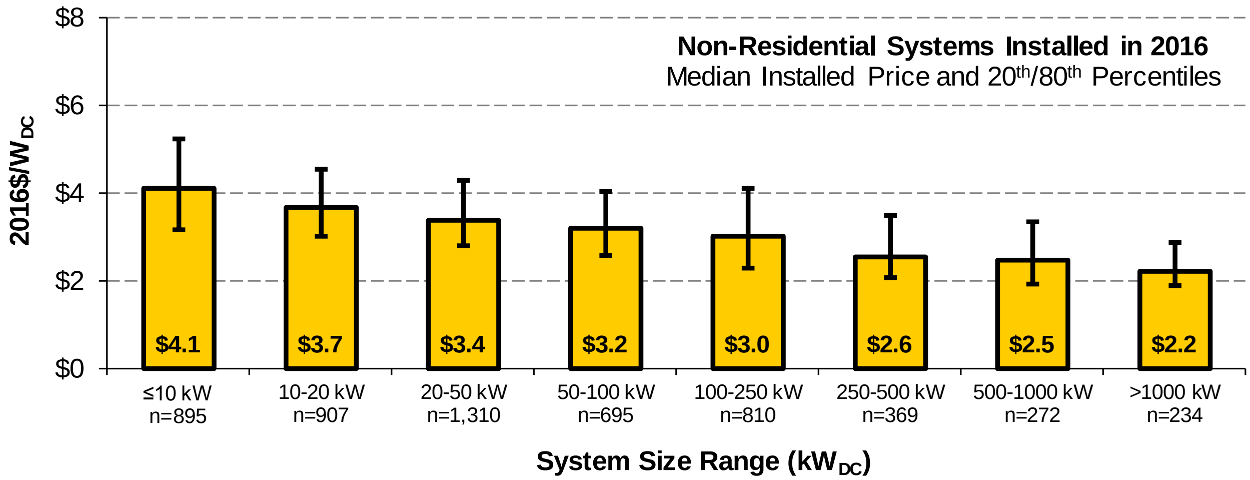


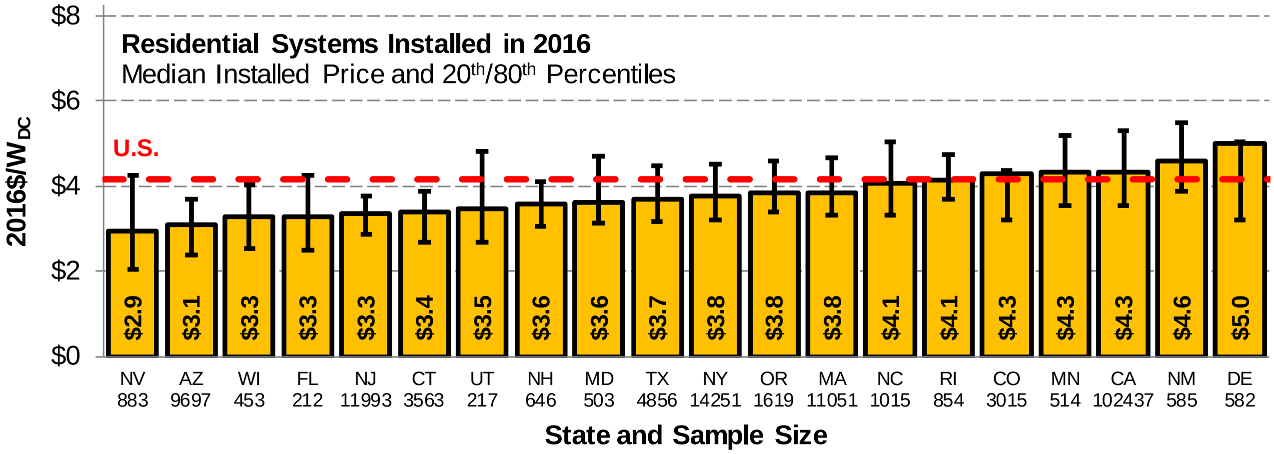
Figure 15. Installed Price of 2016 Non-Residential Systems by Size

Installed Price Differences across States

The U.S. PV market is fragmented into regional, state, and local markets, each with potentially unique pricing dynamics. Figure 16 and Figure 17 focus, in particular, on state-level differences for systems installed in 2016.

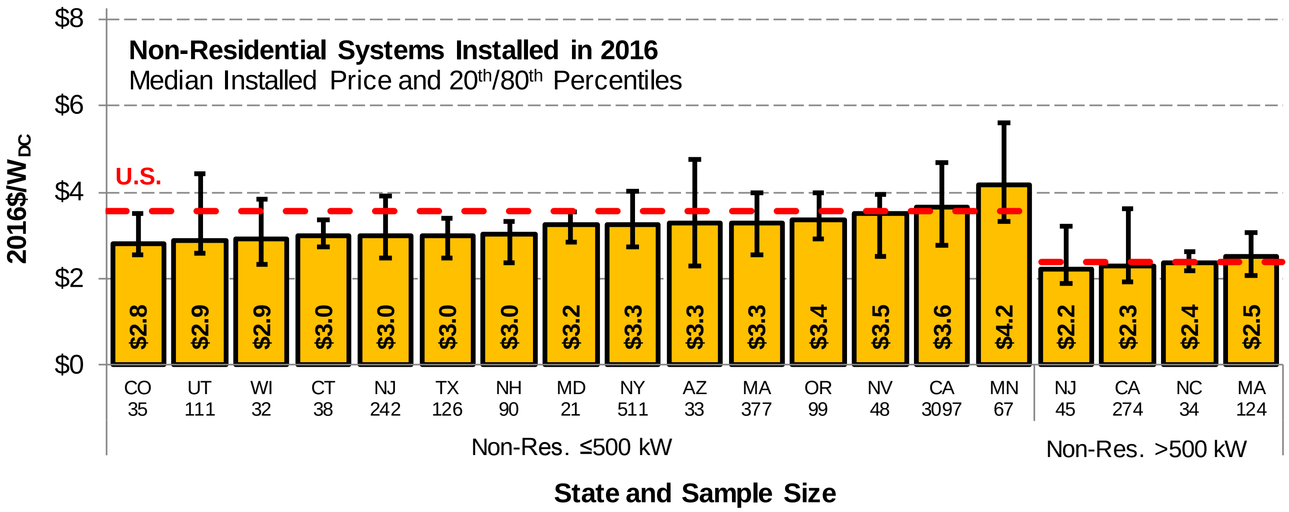
As shown, installed priced can differ quite substantially across states (though significant variability clearly also exists *within* most states). Among residential systems installed in 2016, median installed prices range from a low of $2.9/W in Nevada to a high of $5.0/W in Delaware.[13] Pricing for non-residential systems ≤500 kW similarly varies across a wide range, from $2.8/W in Colorado to $4.2/W in Minnesota. For both of these customer segments, three of the largest state markets (California, Massachusetts, and New York) are relatively high-priced, which naturally tends to pull overall U.S. median prices upward (also shown in the figures). Pricing in most states, however, is below—in some states, far below—the aggregate national median. For larger non-residential systems >500 kW in size, the cross-state comparisons are somewhat less telling, given the limited set of states for which sufficient data are available. Among this small set of states, median installed prices vary across a considerably narrower range, from $2.2/W in New Jersey to $2.5/W in Massachusetts.

[12] Note that non-residential systems also exhibit diminishing returns to scale, though this is not readily observable in the figure, because the bin intervals become progressively wider at larger system sizes.
[13] The median price for residential systems in Delaware is driven by a large contingent of systems with an installed price of $5.0/W. These could not be confirmed as appraised value and were therefore retained in the sample, but are nevertheless somewhat suspect.



Notes: Median installed prices are shown only if more than 20 observations are available for a given state.

Figure 16. Installed Price of 2016 Residential PV Systems by State



Notes: Median installed prices are shown only if more than 20 observations are available for a given state.

Figure 17. Installed Price of 2016 Non-Residential PV Systems by State

Some of the observed pricing differences across states may be idiosyncratic (e.g., due to small sample sizes or anomalous reporting by a single large installer); however, other factors may also be at play. All else being equal, one would expect larger or more mature state markets to have lower prices, as a result of greater competition and experience among installers. Clearly, though, other countervailing factors can predominate, given the trends noted above. For example, higher incentives and/or higher electricity rates—often a key driver behind large state markets—may lead to higher pricing. This may be the result of value-based pricing, or simply the fact that rich incentives increase demand, supporting higher-cost systems. Installed prices may also vary across states as a result of differences in labor costs, permitting and administrative processes, or sales tax. For example, differing sales tax rates and the fact that roughly half of the states shown in the figures exempt PV systems from state sales tax can lead to installed price differences of as much as $0.3/W between states with relatively high sales tax and those that exempt PV systems from sales tax or have no state sales taxes.

State-level price variation can also arise from differences in the characteristics of systems installed in each state, such as typical system size and configuration, the prevalence of TPO, as well as differences in the composition of the PV customer base and installer base. For example, a high percentage of residential systems in California have premium-efficiency modules (40% in 2016, compared to 25% in other states).

Notwithstanding the significant cross-state differences, substantial pricing variation also clearly exists *within* each state, and for many states is at least as wide as the cross-state differences. Such intra-state pricing variability likely reflects many of the same factors that contribute to pricing variability across states. Some pricing drivers, such as differences in permitting processes or installer experience, may manifest at more localized geographical scales than the individual state, contributing to intra-state pricing variability. Lastly, some pricing variability within individual states may also reflect anomalous price reporting by individual installers in a state, especially in relatively small markets where the width of the pricing distribution can be heavily impacted by a single installer.

Installed Price Differences between Host-Owned and TPO Systems

As described previously in Text Box 2, systems financed and installed by integrated TPO providers are excluded from the analysis, while those financed by non-integrated TPO providers are retained.[14] Installed prices reported for retained TPO systems represent the price paid to the installation contractor by the customer finance provider. In principle, these prices might be either lower or higher than for host-owned systems. On the one hand, installers selling systems to TPO providers may face incremental transaction costs or a more-complicated customer sales process, which could elevate system prices. On the other hand, customer acquisition and project development functions for some TPO projects may be performed by entities other than the installer, in which case the reported price might reflect just hardware and direct installation labor costs. TPO finance providers likely also have greater negotiating power with installation contractors, and may have a preference towards relatively standardized system designs, also tending to push pricing lower compared to host-owned systems. In addition, a growing share of host-owned systems may include loan origination fees in the installed price paid by the site host.

For residential systems, the data suggest that installed prices have become substantially lower for TPO systems than for host-owned systems (Figure 18). In particular, the median price of TPO systems was roughly $0.7/W below that of host-owned systems, in both 2016 and 2015. This marks a reversal from prior years, when median prices were slightly higher for TPO than for host-owned systems. A similar, though less dramatic, trend can be seen among small non-residential systems, with TPO systems dropping below the price of host-owned systems over the last two years of the analysis period. In part, these trends may reflect the growing prevalence of unsecured solar loans with origination fees, which may be dampening price declines for host-owned residential systems, resulting in virtually no price decline for those systems over the 2014-2016 timeframe. For large non-residential systems, Figure 18 instead shows higher median prices for TPO over host-owned systems in 2016, though in prior years median prices were virtually identical between TPO and host-owned systems in this size class.

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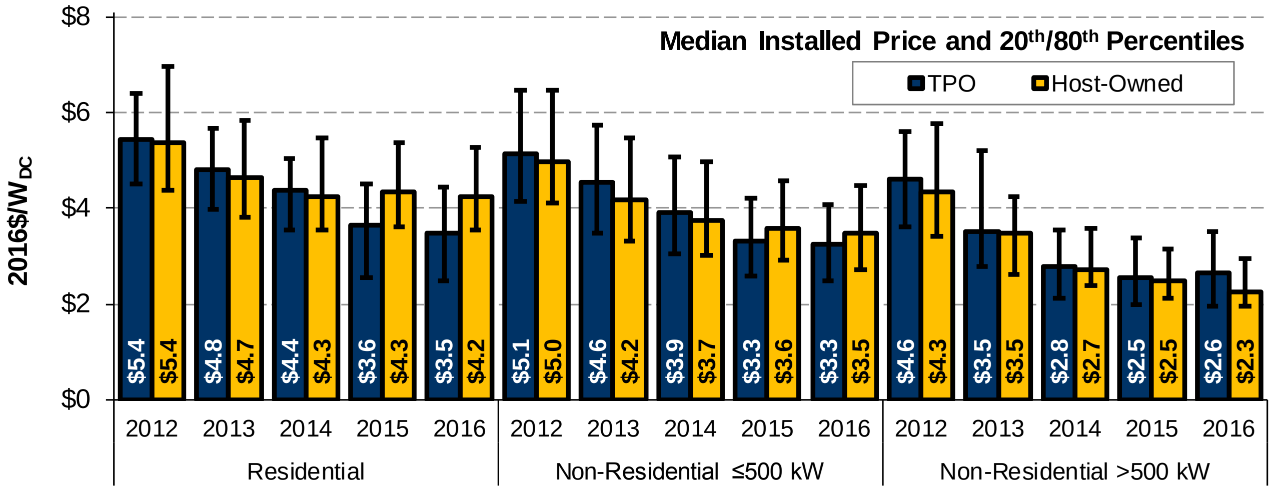
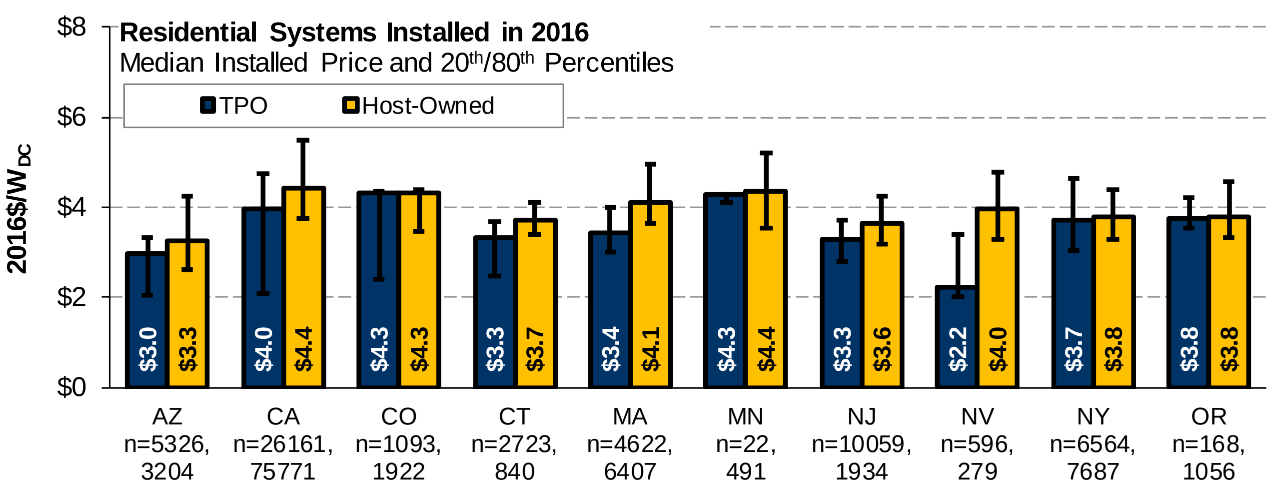
[14] For reference, installed prices reported by integrated TPO providers, otherwise excluded from the analysis presented in this report, are summarized in Appendix A and compared to prices reported for non-integrated TPO systems.



Notes: Data presented for TPO systems represent transaction prices between installation contractors and third-party finance providers; data from integrated companies that perform both installation and financing are excluded.

Figure 18. Installed Prices Reported for Host-Owned vs. TPO Systems over Time

The trend in the residential sector toward lower prices for TPO than for host-owned systems is relatively consistent across states, as shown in Figure 19. In all of the states shown, TPO systems were lower-priced than host-owned systems (even if only marginally so in several cases). It is also evident that installed prices for TPO systems vary to a much greater degree across states than do prices for host-owned systems. This may reflect differences in TPO business models across states—e.g., a greater prevalence of installation-only transactions in certain markets—though may also be symptomatic of small sample sizes and potentially idiosyncratic pricing behavior of individual installers in particular states. Whatever the cause, though, these results do suggest that differences in TPO penetration rates and pricing may contribute significantly to the broader cross-state pricing differences discussed previously.



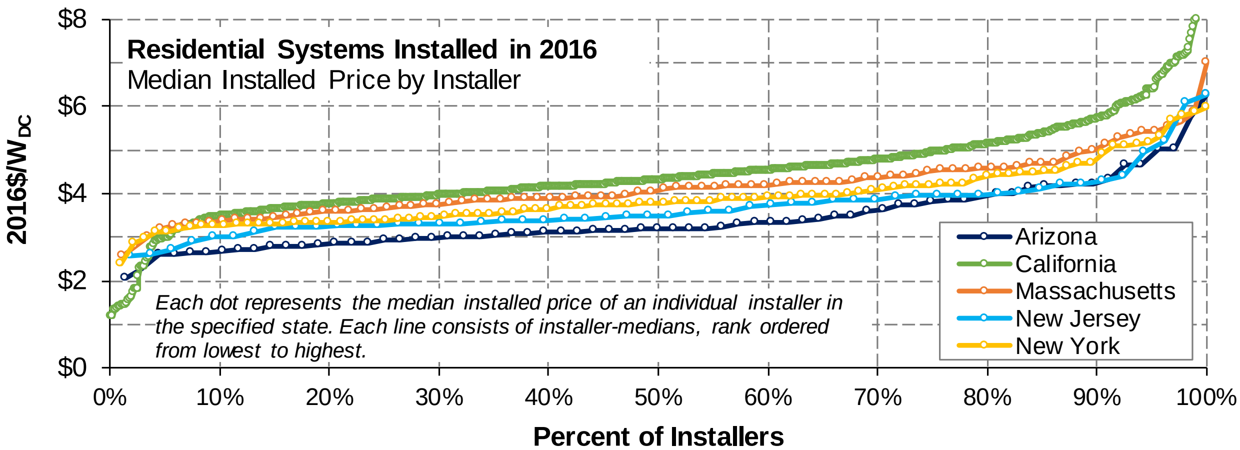
Notes: Data presented for TPO systems represent transaction prices between installation contractors and third-party finance providers; data from integrated companies that perform both installation and financing are excluded.

Figure 19. Installed Prices Reported for Host-Owned vs. TPO Residential Systems by State

Installed Price Differences across Installers

The U.S. PV market is serviced by a large number of installers of varying size, experience, and business models. Although the residential market, in particular, has become increasingly dominated by several large national companies, a great many smaller regional players and "mom-and-pop" shops continue to operate throughout the country. The data sample assembled for this report includes more than 3,000 companies that installed PV systems in 2016, active primarily in the residential sector.[15]

In order to illustrate how installed pricing may vary across installers, Figure 20 shows median prices for individual installers in the five largest state markets, focusing on residential systems installed in 2016. In each of these five states, installer-level median prices differ by anywhere from \$0.7/W to \$1.4/W between the upper and lower 20th percentiles of installer-medians, demonstrating substantial heterogeneity in pricing across installers. Related, the figure serves to highlight "low-price leaders" that could serve as benchmarks for what may be achievable more broadly in each state. In New York, for example, 20% of installers had median prices below \$3.3/W in 2016; this compares to a median price of \$3.8/W across all residential systems installed in the state in 2016. Even in California—a generally high-priced state—more than 40 installers, many with hundreds of systems installed in 2016, had median residential prices below \$3.0/W in 2016. At the other end of the spectrum, of course, are high-priced installers; these may be companies that specialize in "premium" systems of some form, or that include in their reported prices additional items beyond what might be typically counted as part of the PV system.



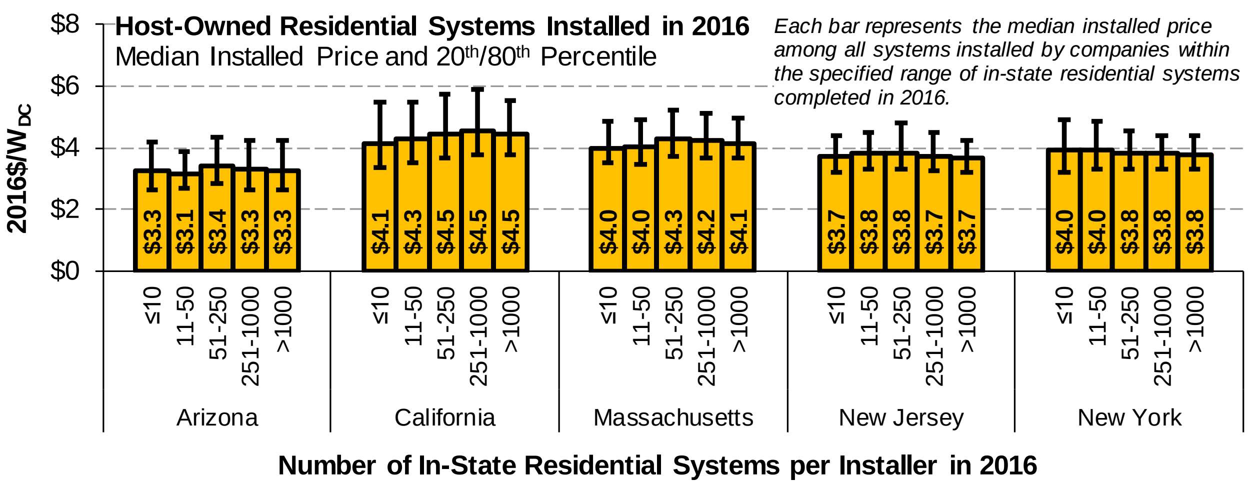
Notes: Includes only installers with at least 10 residential systems installed in the given state in 2016.

Figure 20. Median Installed Prices by Installer for Residential Systems in 2016

One other potential reason for pricing differences among installers is the size of the company, though the data present no clear pattern in this regard. Figure 21 shows installed prices for host-owned residential systems installed in 2016, segmented according to installer volume in each of the top-five states. As shown, pricing is generally quite similar across installer sizes in each state (with the possible exception of California, where larger-volume installers appear to be somewhat higher-priced). In part, this may be due to several competing dynamics. On the one hand, high-volume

[15] The spelling of installer names often varies within the raw data received from program administrators. As part of the data cleaning, we standardize these spellings, though this process is undoubtedly imperfect and thus the actual number of unique installers within the data sample may be somewhat lower than the number cited here.

installers may enjoy economies of scale and potentially greater efficiency in certain business operations as a result of accumulated experience. On the other hand, they may also face relatively high customer acquisition costs and other business operation costs associated with aggressive growth. High-volume installers (as well as smaller installers with a dominant presence in particular locations) may also possess a degree of market power and/or reputational advantages, enabling higher pricing. These competing dynamics have, to varying degrees, been substantiated in Gillingham et al. (2014) and O'Shaughnessy and Margolis (2017).



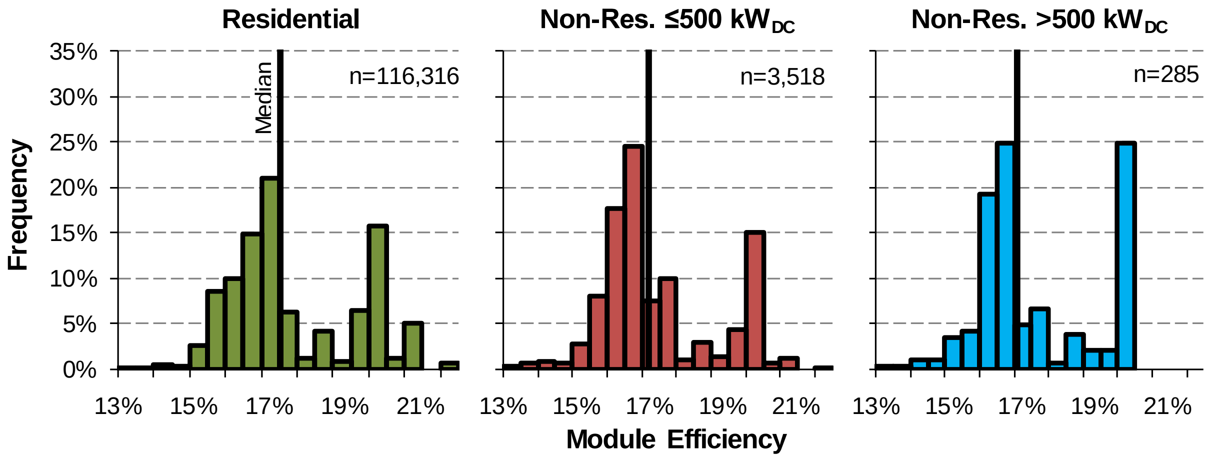
Notes: Installer volumes are calculated from the full data sample, and therefore include integrated TPO systems and other excluded systems that are not used for the purpose of calculating installed price statistics.

Figure 21. Installed Prices of Host-Owned Systems According to State-Level Installer Volume

Installed Price Differences by Module Efficiency

The conversion efficiency of commercially available PV modules varies considerably, from less than 13% for amorphous silicon and certain other types of thin-film modules to 20% or more for high-performance mono-crystalline silicon modules. Within the data sample for this report, the distributions of module efficiencies have several distinct "modes" or peaks (see Figure 22, which focuses on systems installed in 2016). The majority of systems within each customer segment have module efficiencies between 15.5% and 17.5%, typical of current poly-crystalline silicon technology. Localized peaks at higher efficiency levels represent premium efficiency, mono-crystalline modules offered by several manufacturers. Systems with premium efficiency modules (>18%) constitute a relatively sizeable share (roughly 35%) of the residential sample in 2016, and somewhat smaller percentages of non-residential systems.

Module efficiency impacts the installed price of PV systems in countervailing ways. On the one hand, increased module efficiency reduces area-related balance-of-systems (BOS) costs by shrinking the footprint of the system. Cost modeling by Fu et al. (2017) estimates that, for example, an increase in module efficiency from 16% to 20% would reduce residential system costs by roughly $0.2/W. On the other hand, premium-efficiency modules tend to be more expensive than standard efficiency modules. Recent spot market prices for high-efficiency n-type monocrystalline PV modules are roughly $0.3/W higher than for standard polycrystalline modules, and the differential may be considerably greater for some manufacturers of premium efficiency modules (PVInsights 2017).



Notes: Module efficiencies were pulled from manufacturer spec sheets for those systems with data on module manufacturer and model.

Figure 22. Module Efficiency Distributions for Systems Installed in 2016

To examine the net effect of these various and opposing cost drivers, Figure 23 compares installed prices according to module efficiency. The figure focuses on just residential and smaller (sub-500 kW) non-residential systems, and distinguishes between module efficiencies less than or greater than 18%. As shown, systems with high-efficiency modules have been consistently higher-priced than those with lower- or mid-range module efficiencies. In 2016, the median differential was roughly \$0.5/W among both residential small non-residential systems, and was of generally similar magnitude in prior years. The implication of these findings is that—at least among the specific mix of modules and systems within this data sample—the price premium for high-efficiency modules has generally outweighed any corresponding reduction in BOS costs.[16] This is distinct from the trend noted earlier, that increasing efficiencies over time across all module technologies have contributed to declining installed prices.

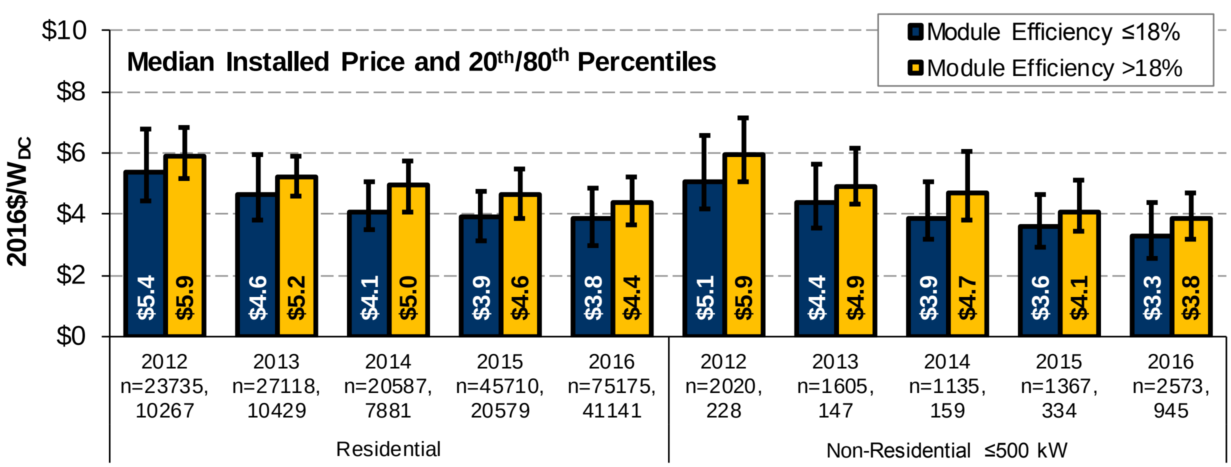


Figure 23. Installed Price Differences Based on Module Efficiency

[16] Indeed, the installed price premium for systems with high-efficiency modules is substantially greater than the global ASP premium for mono-crystalline over poly-crystalline modules, implying that high-efficiency systems in the data sample may have even-higher priced modules, or may differ in others ways (e.g., greater prevalence of tracking systems or more complex, space-constrained installations) compared to the lower-efficiency PV systems in the data sample.

Installed Price Differences between Residential New Construction and Retrofits

Residential solar markets in some states include a sizeable contingent of systems installed in new construction. Within the data sample assembled for this report, new construction systems are most readily identifiable for California, where roughly 3% of 2016 residential systems in the final analysis sample were new construction. As such, the following analysis focuses specifically on California, though the results may apply elsewhere as well.

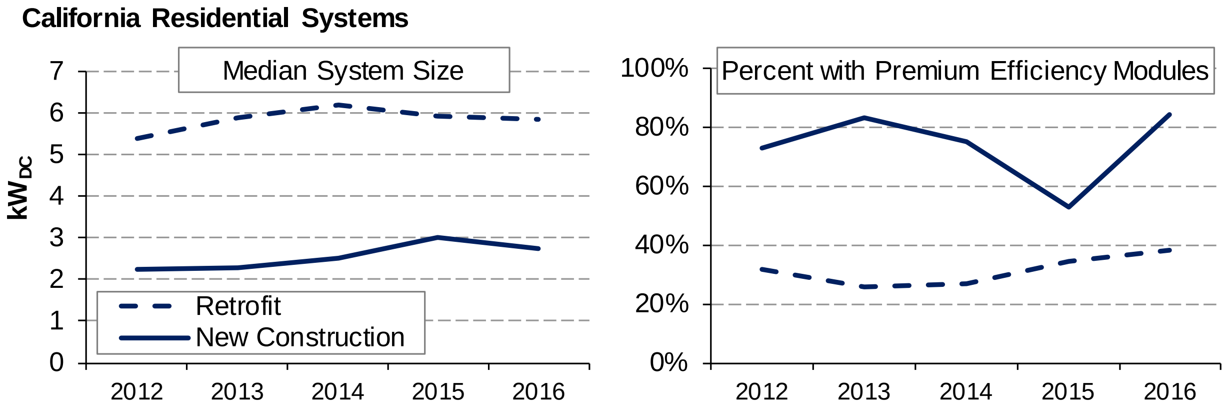


Figure 24. Key Characteristics of Residential Retrofit vs. New Construction in California

Residential systems installed in new construction differ from retrofit systems in several ways relevant when comparing installed prices. First, new construction systems tend to be quite small. This is shown in the left-hand panel of Figure 24, which compares median system sizes for residential retrofit and new construction systems in California. Among systems installed in 2016, residential new construction systems in California had a median size of just 2.8 kW, compared to 5.9 kW for residential retrofit systems in the state. Second, new construction systems have a much higher incidence of premium efficiency (>18%) modules and, in earlier years, building integrated PV (BIPV). This is shown in the right-hand panel of the figure, where more than 80% of new construction systems in 2016 had premium-efficiency modules, compared to roughly 40% of retrofit systems. All else being equal, these two differences—smaller systems and higher incidence of premium efficiency modules—would tend to boost the price-per-watt of new construction systems relative to retrofits.

Aside from those technical differences are several other inherent features of new construction systems that may have implications for their installed price. First and foremost, perhaps, is that most new construction systems (in California, at least) are installed in new housing developments with multiple solar homes, and may therefore benefit from scale economies in installation and bulk purchasing that reduce unit costs. New construction systems may also benefit from economies of scope, where certain labor or materials costs can be shared between PV installations and other elements of home construction. Conversely, some installers have reported more complex scheduling and logistics for new construction that might conceivably boost costs. Clearly, there are a variety of countervailing factors that could steer installed prices for new construction either higher or lower relative to systems on existing homes.

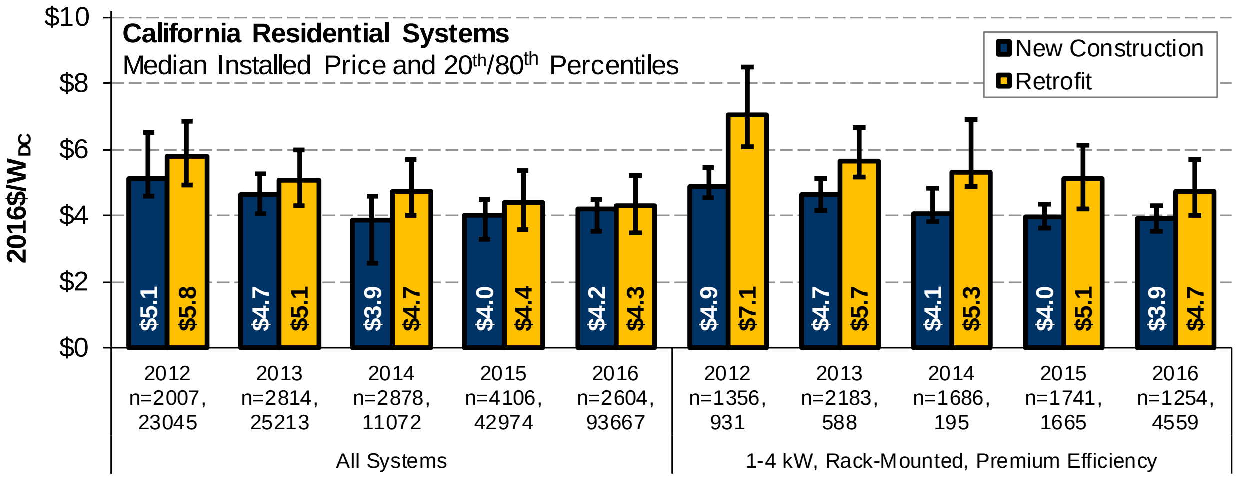


Figure 25. Installed Price of Residential Retrofit vs. New Construction in California

To reveal how these competing dynamics play out, Figure 25 compares the installed price of PV systems in residential retrofit and new construction in California. The left-hand half of the figure compares the two classes of systems, irrespective of key differences in their technical characteristics. As shown, new construction systems have consistently been lower-priced than retrofit systems, *despite* the smaller size and higher incidence of premium efficiency modules among new construction systems.

In order to better control for the differing technical characteristics between new construction and retrofit systems, the right-hand side of Figure 25 focuses solely on 1-4 kW, rack-mounted (i.e., non-BIPV) systems with premium efficiency modules. Not surprisingly, the cost advantages of new construction appear even greater in this comparison. Among systems installed in 2016, for example, the median price of systems installed in new construction was $0.8/W below similarly sized and configured residential retrofit systems. These trends therefore suggest that the economies of scope and scale with large developments of new solar homes may indeed offer quite substantial savings on PV system pricing.[17]

Installed Price Differences between Tax-Exempt and For-Profit Commercial Sites

The non-residential solar sector is highly diverse in terms of the composition of the underlying customer base, including not only for-profit commercial entities, but also a sizeable contingent of systems installed at schools, government buildings, religious organizations, and non-profit organizations. That latter set we collectively refer to as “tax-exempt” site hosts. In 2016, systems at tax-exempt customer sites comprised 18% of sub-500 kW non-residential systems and 17% of non-residential systems >500 kW, based on the sub-set of the sample for which data on type of site host could be obtained.

[17] Notwithstanding the general consistency of trends exhibited in Figure 25, some degree of caution is warranted, given potential complications or ambiguities in how installed price data may be reported for new construction systems. For example, to the extent that certain costs are shared between the PV installation and other aspects of home construction (e.g., roofing and electrical work), those reporting data may have some discretion in terms of how those shared costs are allocated to the PV system. It is also common practice for identical installed prices to be reported for all PV systems within an individual development, consistent with the manner in which those systems are procured by the housing developer, which partly explains the greater uniformity of pricing observed among new construction systems.

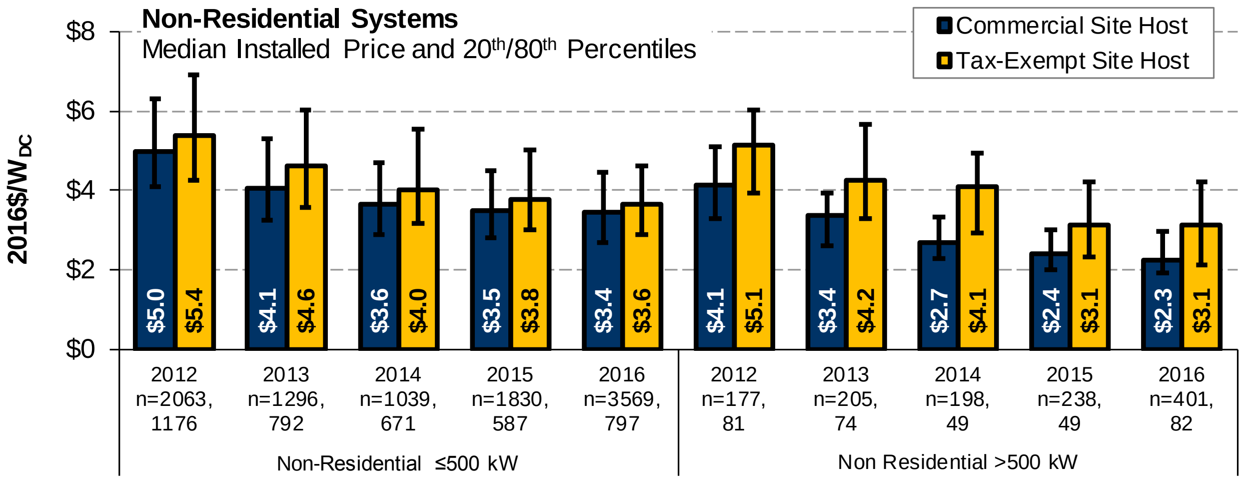


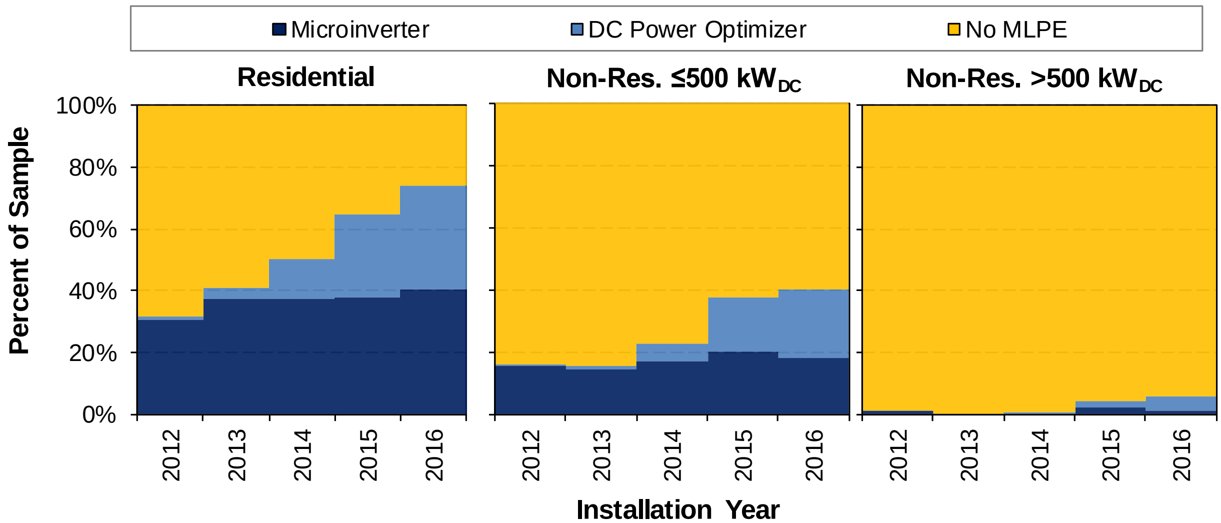
Figure 26. Installed Price Variation across Host Customer Sectors

Installed prices are consistently higher for systems at tax-exempt customer sites than at for-profit commercial facilities. This is evident in Figure 26, which compares installed prices for these two sub-sectors over time. In 2016, systems at tax-exempt customer sites were roughly $0.2/W higher-priced within the sub-500 kW non-residential segment, and $0.8/W higher among >500 kW non-residential systems. Similar price differentials also exist in most prior years. Higher prices at tax-exempt customer sites may reflect a number of underlying factors: prevailing wage/union labor requirements, preferences for domestically manufactured components, a high incidence of shade and parking structure PV arrays, additional permitting requirements, and potentially more complex government procurement processes. Tax-exempt customers may also have less stringent financial criteria than their for-profit commercial counterparts.

Installed Price Differences for Systems with Module-Level Power Electronics

Module-level power electronics (MLPEs), which include both microinverters and DC power optimizers, and offer performance advantages over standard string inverters, have been steadily gaining market share in recent years.[18] This is reflected in the final analysis sample used in this report, which shows rapidly increasing penetration, particularly in the residential sector, where 74% of all 2016 systems had some form of MLPE (see Figure 27). Less pronounced, though still significant, growth has also occurred among smaller non-residential systems, where microinverters and DC power optimizers together represent almost 40% of sub-500 kW non-residential systems in the final analysis sample installed in 2016. By comparison, penetration among larger non-residential systems >500 kW in size has remained negligible.

[18] Deline et al. (2012) estimate 4-12% greater annual energy production from systems with microinverters. Such performance gains are associated primarily with the ability to control the operation of each panel independently, eliminating losses that would otherwise occur on a string of panels when the output of a subset of the panels is compromised (e.g., due to shading or orientation) or when mismatch exists among modules in the string.



Notes: The DC power optimizer share includes only systems with SolarEdge inverters, and thus likely understates the actual share of DC power optimizers in the data sample.

Figure 27. Penetration of Module-Level Power Electronics within the Final Analysis Sample

In terms of their impacts on up-front installed prices, MLPEs can have both direct and indirect impacts. The direct impact comes in the form of a price premium over standard string inverters: roughly a $0.2/W premium for microinverters and a $0.1/W premium for DC optimizers (GTM Research and SEIA 2017). MLPEs can also have indirect cost impacts—both positive and negative—related to installation labor, system design, and electrical balance-of-system costs. These indirect cost impacts can be positive or negative.

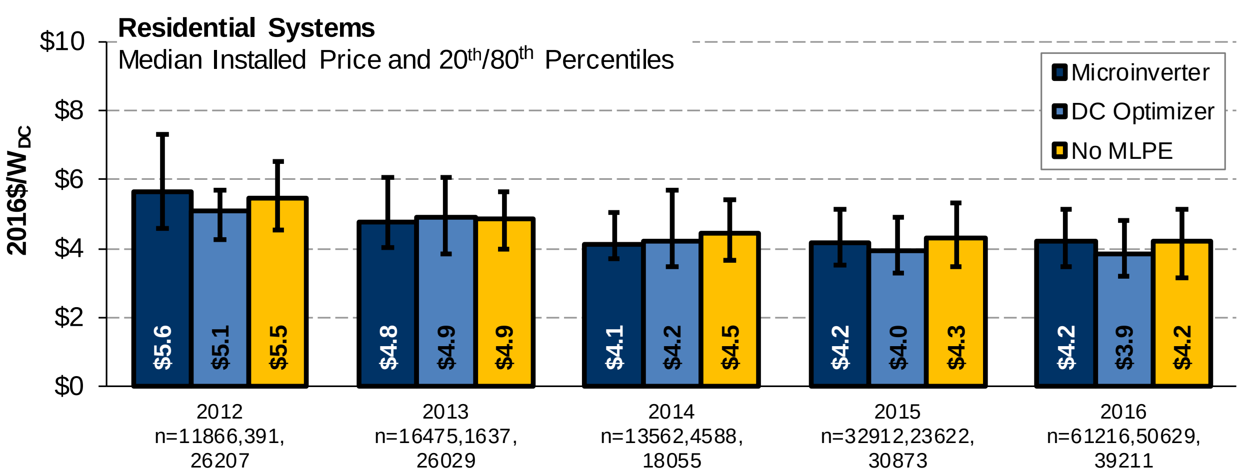
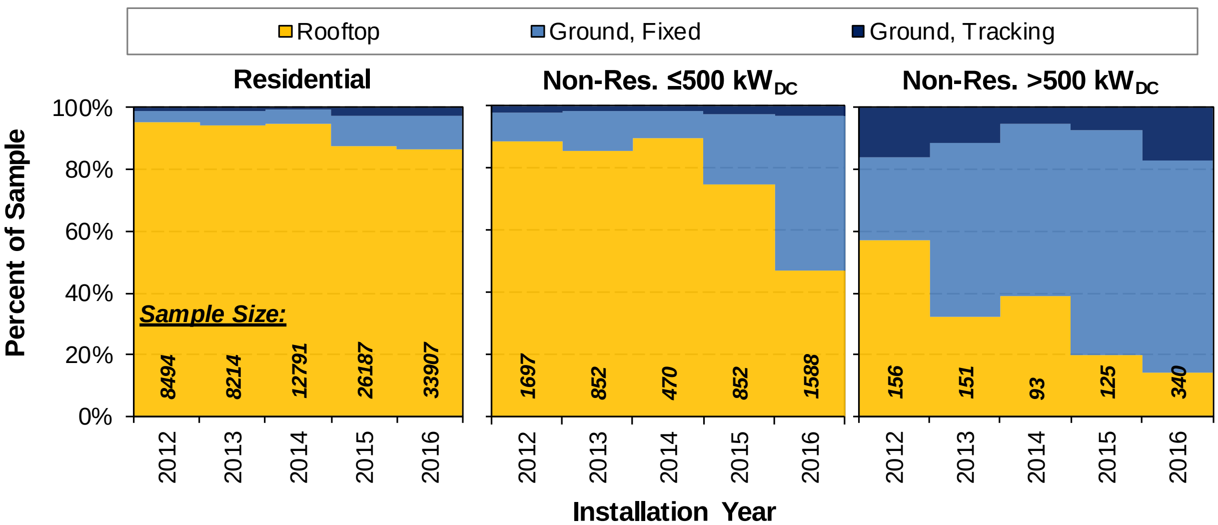


Figure 28. Installed Price Differences between Residential Systems with and without MLPEs

As shown in Figure 28, installed price differences between residential systems with and without MLPEs is quite small. Among residential systems installed in 2016, median installed prices were essentially identical for systems with microinverters and those with no MLPE, while those with DC power optimizers were roughly $0.3/W lower-priced than the other two groups. Similarly small differences occurred in prior years as well. Ultimately, the net effect of MLPEs on total installed prices is too small to reliably discern within these data without the use of more sophisticated statistical analysis. However, the fact that the total installed price premium for systems with MLPEs is consistently less than the incremental cost of MLPEs themselves suggests that these devices likely offer some offsetting savings on other balance-of-system or labor costs. This inference may be further justified when considering that installers tend to use MLPEs for more-complex installations (e.g., systems on multiple roof planes) or when space constraints are binding.

Installed Price Differences by Mounting Configuration

Unlike residential systems, which are predominantly roof-mounted, many non-residential systems are ground-mounted and may also include tracking equipment. Among the relatively limited set of systems in the sample with data on mounting configuration, 53% of small non-residential systems and 86% of large non-residential systems installed in 2016 were ground-mounted, while 3% and 17%, respectively, had tracking (see Figure 29). Many of what are referred to within this report as large non-residential systems might thus be classified elsewhere as small utility-scale systems.

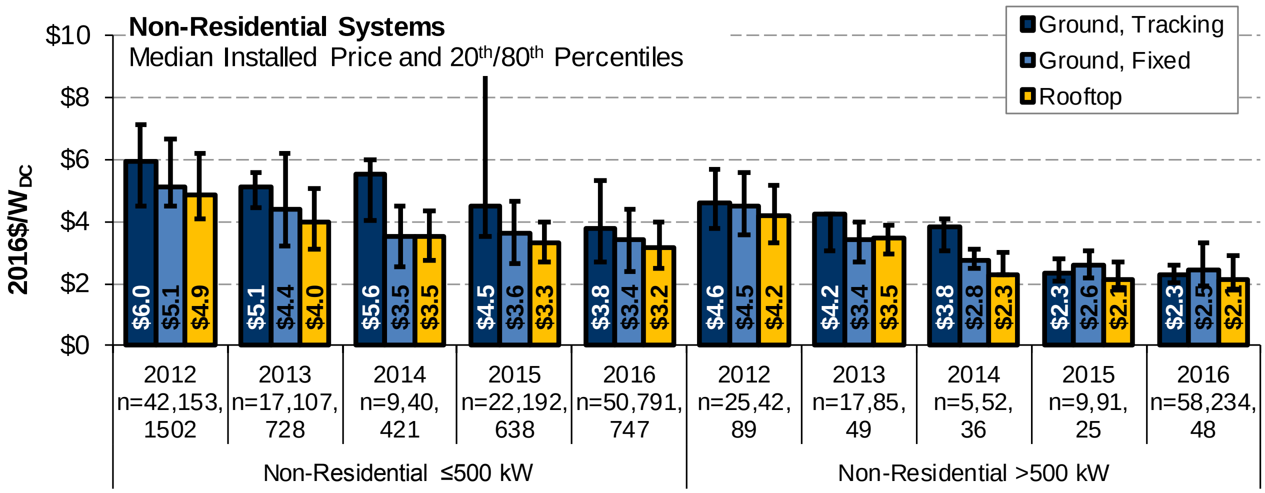


Notes: The figure is derived from the relatively small subsample of systems for which data were available specifying whether the system is roof- or ground-mounted and whether or not it has tracking.

Figure 29. Mounting Configuration among Systems in the Data Sample

As shown in Figure 30, installed prices for fixed ground-mounted systems tend to be somewhat higher than for rooftop systems, potentially reflecting additional costs associated with trenching and foundation work. In 2016, the median installed price of fixed, ground-mounted systems was roughly $0.3/W higher than for rooftop systems, in both the small and large non-residential categories. This is generally consistent with earlier years, though the trends exhibit a certain level of volatility from year to year as a result of small sample sizes.

Tracking equipment adds further to the cost of ground-mounted systems, though this is not always readily or precisely discernible with the installed price data. Within the small non-residential segment, the median installed price of systems with tracking was about $0.4/W higher in 2016 than for fixed, ground-mounted systems. This differential is smaller than in previous years, potentially reflecting the declining cost of tracking equipment. Within the large non-residential segment, however, systems with tracking actually had a lower median price in both 2015 and 2016 than fixed-tilt, ground-mounted projects. Clearly, this particular trend is the result of other unrelated factors that outweigh any cost impacts associated with tracking equipment. As a point of reference, cost modeling by Fu et al. (2016) and by GTM Research and SEIA (2017), as well as empirical data from Bolinger and Seel (2016), suggests an incremental cost of roughly $0.1/W to $0.2/W for tracking equipment (albeit in utility-scale systems applications).



Notes: The figure is derived from the relatively small subsample of systems for which data were available specifying whether the system is roof- or ground-mounted and whether or not it has tracking.

Figure 30. Installed Price of Non-Residential Systems by Mounting Configuration over Time

5. Conclusions

The number of PV systems installed in the United States has grown at a rapid pace in recent years, driven both by declining costs and supportive policies. Given the relatively high historical cost of PV, a key goal of these policies has been to encourage further cost reductions over time through increased deployment. Research and development (R&D) efforts within the industry have also focused on cost reductions, led by the U.S. DOE's SunShot Initiative, which aims to reduce the cost of PV-generated electricity by about 75% between 2010 and 2020, and by an additional 50% by 2030.

Available evidence confirms that the installed price of PV systems (i.e., the up-front cost borne by the PV system owner, prior to any incentives) has declined substantially since 1998, though both the pace and source of those cost reductions have varied over time. Following a period of relatively steady and sizeable declines, installed price reductions began to stall around 2005, as the supply-chain and delivery infrastructure struggled to keep pace with rapidly expanding global demand. Beginning in 2008, however, global module prices began a steep downward trajectory, and those module price reductions were the driving force behind the decline in total system prices for PV from 2008 through 2012. Since 2012, installed prices have continued to fall, partly due to continued progress in targeting soft costs.

Given the limits to further reductions in module and other hardware component prices, continued reductions in soft costs will be essential to driving further deep reductions in installed prices. Unlike module prices and other hardware component costs, which are primarily established through global markets, soft costs may be more readily affected by local policies—including deployment programs aimed at increasing demand (and thereby increasing competition and efficiency among installers) as well as more-targeted efforts, such as training and education programs. The heightened focus on soft cost reductions within the solar industry and among policymakers has spurred a flurry of initiatives and activity in recent years. The continued decline in installed prices suggests that these efforts have begun to bear fruit.

Nevertheless, lower installed prices in other major international markets, as well as the wide diversity of observed prices within the United States, suggest that broader soft cost reductions are possible. Although such cost reductions may accompany increased market scale, it is also evident that market size alone is insufficient to fully capture potential near-term cost reductions—as suggested by the fact that many of the U.S. states with the lowest installed prices are relatively small PV markets. Achieving deep reductions in soft costs thus likely requires a broad mix of strategies, including: policy designs that provide a stable and straightforward value proposition to foster efficiency and competition within the delivery infrastructure, targeted policies aimed at specific soft costs (for example, permitting and interconnection), and basic and applied research and development.

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Appendix A: Data Cleaning, Coding, and Standardization

To the extent possible, this report presents data as provided directly by PV incentive program administrators and other data sources; however, several steps were taken to clean and standardize the data.

Conversion to 2016 Real Dollars: Installed price and incentive data are expressed throughout this report in real 2016 dollars (2016$). Data provided by PV program administrators in nominal dollars were converted to 2016$ using the "Monthly Consumer Price Index for All Urban Consumers," published by the U.S. Bureau of Labor Statistics.

Conversion of Capacity Data to Direct Current (DC) Watts at Standard Test Conditions (DC-STC): Throughout this report, all capacity and dollars-per-watt ($/W) data are expressed using DC-STC capacity ratings. Most data providers directly provide system capacity in units of DC-STC; however, several did not. In those cases, PV system DC-STC capacity was calculated from the nameplate rating of the modules (by cross-referencing the module model name against manufacturer spec sheets) and module quantity.

Identification and Treatment of Duplicate Systems: For a number of states (California, Florida, Massachusetts, and Oregon), data provided by multiple different entities contain overlapping sets of systems. In order to avoid double-counting, duplicate observations were merged or eliminated. These duplicate observations were identified using, wherever possible, a common ID number across datasets or customer street address. In cases where neither of those pieces of information are available, more-aggressive measures were taken to avoid double counting. For systems within the California investor-owned utilities' service territories, the California Public Utilities Commission's Currently Interconnected Dataset was used as the base data sample, and additional data for those systems was incorporated from the various incentive program datasets (CSI, NSHIP, SGIP, and ERP) based on CSI ID numbers and street addresses. Within the Oregon Department of Energy dataset, systems were excluded if located within an investor-owned utility service territory, on the grounds that the vast majority of such systems likely would have participated in the Energy Trust of Oregon's incentive program and would be included in that program's data file.

Incorporating Data on Module and Inverter Characteristics. The raw data provided by PV incentive program administrators generally included module and inverter manufacturer and model names. We cross-referenced that information against public databases of PV component specification data (namely, the CSI eligible equipment lists[19] and SolarHub[20]) to characterize the module technology efficiency, module technology (e.g., mono-crystalline vs. poly-crystalline, building-integrated PV vs. rack-mounted systems), and inverter technology (microinverter or standard string/central inverter). All systems with SolarEdge inverters were assumed to also be equipped with DC power optimizers.

Identification of Customer Segment: Almost all programs provided some explicit segmentation of host customers, at least into residential and non-residential customers. In the rare cases where even this minimal level of segmentation was not provided, systems less than or equal to 20 kW in size were assumed to be residential, and those larger than 20 kW were assumed to be non-residential. The choice of this threshold was based on an inspection of data where customer segmentation was available, and is roughly the value that minimizes the error in these assignments to customer segments.

Identification of Host-Owned vs. TPO Systems: Most programs explicitly identify the ownership type of each system as either host-owned or TPO. Where such data were not provided, however, inferences were made wherever possible. First, systems were assumed to be host-owned if: (a) installed in a state where TPO was not allowed at the time of installation, (b) installed in a state where TPO is technically allowed but actual market activity is known to be quite low, or (c) the PV incentive program providing data is not available to

[19] http://www.gosolarcalifornia.ca.gov/equipment/
[20] http://www.solarhub.com/

TPO systems. Next, any remaining systems with unknown ownership type were assumed to be TPO if installed by companies known to be providers mostly of TPO systems, including: SolarCity/Tesla, Sungevity, Vivint, SunRun, and Roof Diagnostics & Solar.

Identification and Removal of Appraised Value Systems: A total of 249,910 systems were removed from the final data sample, on the grounds that installed prices reported for these systems were appraised values, rather than transaction prices. The vast majority of these systems were identified simply based on reported installer name and system ownership type. Specifically, prices reported for TPO systems installed by the three integrated TPO providers—SolarCity/Tesla, Sungevity, and Vivint—were assumed to be appraised values and removed from the final data sample. Upon inspection of the data, prices reported for host-owned systems installed by SolarCity/Tesla were also deemed likely to be appraised values and were thus also removed from the data sample.

If data on installer name were not available, appraised-value systems were identified using a "price clustering" approach. The logic for the price clustering approach is founded on the observation that identical prices are reported for large clusters of systems installed by individual integrated TPO providers. These prices may reflect, for example, the average per-kW assessed fair market value of a bundle of systems sold to tax equity investors. The first step in the price clustering analysis was to identify the price clusters among the systems explicitly identified in the dataset as TPO and installed by an integrated TPO provider. Then, for systems where installer name data were unavailable, reported prices were assumed to be appraised value if they fell within the aforementioned set of price clusters and the system was not explicitly identified as host host-owned. In addition, systems within those price clusters installed by integrated TPO providers but labeled as host-owned were assumed to, in fact, be TPO systems and were accordingly re-classified as TPO and flagged as appraised value.

For reference, Figure 31 compares the reported installed prices for these integrated TPO systems to prices for other, non-integrated TPO systems that are retained in the data sample. As shown, installed prices reported for integrated TPO systems in 2010 and 2011 were dramatically higher than for non-integrated TPO systems. For many integrated TPO systems, the appraised values used as the basis for reported installed prices are an assessed "fair market value", often based on the discounted cash flow from the project (or a bundle of projects). Starting in 2012, at least one major integrated TPO provider changed its installed price reporting methodology for PV incentive programs. Following that, the disparity between installed prices reported for integrated and non-integrated TPO systems initially diminished (during 2012-2013), but has grown over the last several years of the analysis period as integrated TPO prices remained flat.

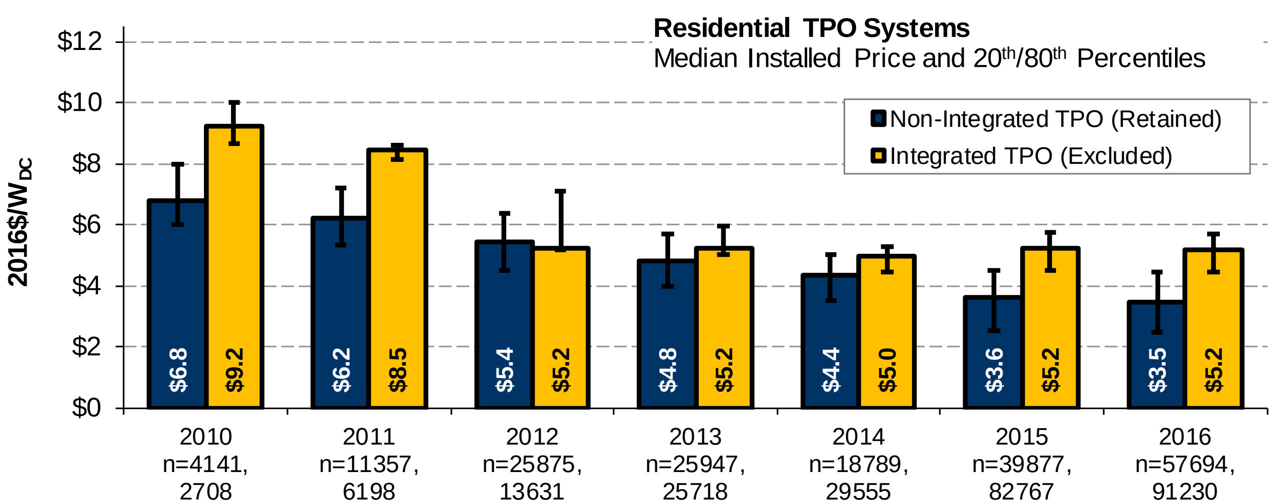

Figure 31. Installed Prices Reported for Non-Integrated and Integrated Residential TPO Systems

Identification of Self-Installed Systems: Self-installed systems were identified in several ways. In some cases, these systems could be identified based on the reported installer name (e.g., if listed as "owner" or "self"). In addition, all systems installed by Grid Alternatives or Habitat for Humanity were treated as self-installed, as these entities rely on volunteer labor for low-income solar installations.

Calculation of Net Present Value of Reported PBI Payments: A number of PV incentive programs in the data sample provided performance-based incentives (PBIs), paid out over time based on actual energy generation and a pre-specified payment rate, to some or all systems. In order to facilitate comparison with up-front rebates provided to the other systems in data sample, the net present value (NPV) of the expected PBI payments were calculated based on an assumed 7% nominal discount rate.

Appendix B: Additional Details on Final Analysis Sample

Table B-1. Sample Summary by Program Administrator

State	Data Provider	Size Range (kW_{DC})	Year Range	2016 Sample		Total Sample	
				No. of Systems	Total MW_{DC}	No. of Systems	Total MW_{DC}
AR	Arkansas Energy Office	0.5 - 25	2010 - 2011	0	0.0	97	0.7
AZ	Ajo Improvement Company	2.1 - 2.1	2012 - 2012	0	0.0	3	0.0
	Arizona Public Service	0.4 - 3,903	2002 - 2016	8,003	66.0	30,432	415.3
	Duncan Valley Electric Coop.	0.5 - 11	2006 - 2009	0	0.0	4	0.0
	Graham County Electric Coop.	0.06 - 25	2005 - 2010	0	0.0	119	0.6
	Mohave Electric Coop.	1.0 - 47	2008 - 2016	53	0.5	222	1.6
	Morenci Water & Electric	5.8 - 20	2014 - 2015	0	0.0	3	0.0
	Navopache Electric Coop.	1.0 - 55	2007 - 2016	38	0.3	130	0.9
	Salt River Project	0.2 - 1,703	2005 - 2016	552	7.0	8,074	81.9
	Sulpher Springs Valley Electric Coop.	1.0 - 984	2009 - 2016	16	0.2	1,078	7.9
	Tucson Electric Power	0.4 - 1,000	2006 - 2016	124	1.2	882	7.3
	Trico Electric Coop.	0.3 - 353	1999 - 2016	943	6.6	6,464	46.6
	UniSource Electric Services	0.5 - 98	1999 - 2016	4	0.0	1,541	14.1
CA	California Center for Sustainable Energy (Bear Valley Electric)	1.5 - 20	2015 - 2016	27	0.2	37	0.2
	California Center for Sustainable Energy (Pacific Power)	1.3 - 257	2011 - 2016	10	0.4	165	2.7
	CPUC and CEC (Currently Interconnected Dataset, CSI, NSHP, ERP, SGIP) [(a)]	0.1 - 4,597	1998 - 2016	99,886	1072.2	300,660	3313.7
	Imperial Irrigation District	1.0 - 1,152	2005 - 2016	491	7.7	1,405	36.9
	Los Angeles Dept. of Water & Power	0.3 - 3,377	1999 - 2016	4,328	29.2	17,128	155.8
	Palo Alto Utilities	0.7 - 881	1999 - 2016	6	0.2	579	5.9
	Sacramento Municipal Utility District	0.7 - 2,840	2005 - 2016	1,060	7.6	5,010	57.3
CO	Xcel Energy	0.5 - 1,998	2006 - 2016	3,050	19.8	27,126	222.8
CT	Clean Energy Finance and Investment Authority	0.5 - 1,000	2004 - 2016	3,602	36.8	12,687	132.4
DE	Department of Natural Resources and Environmental Control	0.2 - 1,434	2002 - 2016	600	5.2	2,657	28.4
FL	Florida Energy & Climate Commission[(b)]	2.0 - 283	2006 - 2012	0	0.0	1,203	9.1
	Gainesville Regional Utilities[(b)]	1.8 - 1,277	2006 - 2016	37	2.2	501	23.1
	Orlando Utilities Commission[(b)]	0.5 - 1,040	2008 - 2016	181	1.2	363	5.0
IL	Dept. Commerce and Economic Opportunity	0.8 - 700	1999 - 2016	15	0.1	1,175	13.0

State	Data Provider	Size Range (kW_{DC})	Year Range	2016 Sample		Total Sample	
				No. of Systems	Total MW_{DC}	No. of Systems	Total MW_{DC}
MA	Massachusetts Clean Energy Center[c]	0.3 - 5,756	2001 - 2016	22	0.2	3,072	73.7
	Dept. of Energy Resources[c]	0.3 - 6,000	2008 - 2016	11,530	306.5	32,605	1007.6
MD	Maryland Energy Administration	0.1 - 200	2005 - 2016	524	5.1	7,146	63.2
ME	Efficiency Maine	0.9 - 171	2011 - 2013	0	0.0	550	3.5
MN	Dept. of Commerce	0.5 - 40	2001 - 2016	354	4.5	1,138	10.9
	Xcel Energy	0.5 - 40	2012 - 2016	227	2.2	957	12.9
NC	NC Sustainable Energy Association	0.7 - 5,932	2005 - 2016	1,069	172.6	5,320	1154.3
NH	New Hampshire Public Utilities Commission	0.3 - 653	2001 - 2016	737	9.0	3,491	30.2
NJ	New Jersey Board of Public Utilities (CORE & REIP Programs)	0.7 - 2,372	2001 - 2012	0	0.0	7,718	122.4
	New Jersey Board of Public Utilities (SREC Program)	0.4 - 8,135	2007 - 2016	12,280	215.0	38,990	1259.1
NM	Energy, Minerals & Natural Resources Dept.	0.4 - 349	2007 - 2016	590	3.6	7,283	40.8
NV	NVEnergy	0.4 - 1,145	2004 - 2016	934	11.5	8,882	122.9
NY	New York State Energy Research and Development Authority	0.3 - 2,827	2000 - 2016	14,780	180.0	47,877	609.3
OR	Energy Trust of Oregon[d]	0.8 - 5,702	2002 - 2016	1,268	15.1	7,553	81.6
	Oregon Dept. of Energy[d]	0.1 - 5,702	1999 - 2016	429	2.1	1,885	17.8
	Pacific Power	1.6 - 500	2010 - 2016	23	0.2	531	8.3
PA	Dept. Community and Economic Development	8.0 - 3,252	2010 - 2012	0	0.0	49	34.9
	Dept. of Environmental Protection	1.0 - 922	2009 - 2014	0	0.0	7,041	98.1
	Sustainable Development Fund	1.1 - 12	2002 - 2008	0	0.0	200	0.7
RI	National Grid	0.8 - 384	2010 - 2016	865	7.2	1,166	9.7
TX	Austin Energy	0.2 - 364	1999 - 2016	997	12.0	6,152	52.2
	CPS Energy	0.6 - 400	2007 - 2016	3,954	31.9	7,019	61.7
	Clean Energy Associates (El Paso Electric)	0.9 - 168	2001 - 2015	0	0.0	347	2.8
	Clean Energy Associates (Entergy)	1.1 - 29	2009 - 2012	0	0.0	57	0.4
	Clean Energy Associates (Oncor Electric Delivery Company)	0.4 - 300	2001 - 2012	0	0.0	868	10.2
	Clean Energy Associates (Sharyland Utilities)	7.4 - 10	2014 - 2016	1	0.0	3	0.0
	Clean Energy Associates (Southwestern Electric Power Company)	2.7 - 77	2010 - 2013	0	0.0	39	0.5
	Clean Energy Associates (Texas Central Company)	1.2 - 259	2010 - 2016	30	0.7	175	2.9
	Clean Energy Associates (Texas New Mexico Power Company)	1.2 - 12	2010 - 2012	0	0.0	23	0.2
	Clean Energy Associates (Texas North Company)	0.9 - 95	2010 - 2015	0	0.0	74	0.8
UT	Rocky Mountain Power	0.7 - 364	2011 - 2016	328	5.6	945	14.3

State	Data Provider	Size Range (kW_{DC})	Year Range	2016 Sample		Total Sample	
				No. of Systems	Total MW_{DC}	No. of Systems	Total MW_{DC}
VT	Vermont Energy Investment Corporation	0.2 - 389	2003 - 2016	15	0.1	3,916	27.1
WI	Focus on Energy	0.2 - 273	2002 - 2016	485	3.5	2,573	18.5
Total		***0.1 - 8,135***	***1998 - 2016***	***174,468***	***2,253***	***625,390***	***9,537***

[(a)] Data for California's three large investor owned utilities (PG&E, SCE, and SDG&E) are developed by merging the CPUC's Currently Interconnected Data Set with data from the various incentive programs that have been or are currently offered in the utilities' service territories. See Appendix A for more details on this merging process.

[(b)] A small number of PV systems that received an incentive through the Florida Energy & Climate Commission (FECC)'s statewide solar rebate program also participated in one of the Florida utility programs. Those systems were retained in the data sample for the utility program and removed from the sample for FECC's program. The values shown here for FECC reflect the residual sample, after overlapping systems were removed.

[(c)] The vast majority of the systems in the data file provided by the Massachusetts Clean Energy Center (MassCEC) were also included the data provided by the Dept. of Energy Resources (DOER). Overlapping systems were removed from the MassCEC dataset (but retained in the DOER dataset). The values shown here for MassCEC reflect the residual sample, after overlapping systems were removed.

[(d)] Oregon systems that received incentives through both the Oregon Dept. of Energy's tax credit program and the Energy Trust of Oregon were retained in the data sample for the Energy Trust and removed from sample for the Dept. of Energy. The values shown here for the Oregon DOE reflect the residual sample, after overlapping systems were removed.

Table B-2. Median Installed Price of Residential Systems by Size over Time (2016\$/W_{dc})

Installation Year	≤2 kW	2-4 kW	4-6 kW	6-8 kW	8-10 kW	10-12 kW	12-14 kW	14-16 kW	16-18 kW	18-20 kW	>20 kW
2000	12.0	11.9	-	-	-	-	-	-	-	-	-
2001	11.9	11.4	11.0	11.3	10.3	-	-	-	-	-	-
2002	11.9	11.5	10.9	10.8	10.5	10.6	-	-	-	-	-
2003	11.6	10.3	10.0	9.8	9.7	9.6	-	-	-	-	-
2004	10.2	9.4	9.4	9.2	9.0	9.0	8.8	8.7	-	-	9.3
2005	10.3	9.1	9.1	8.8	9.1	9.1	8.6	8.6	8.7	8.6	8.6
2006	10.5	9.5	9.4	9.0	9.2	8.9	8.6	8.6	8.7	8.4	8.7
2007	10.4	9.5	9.2	9.0	9.2	9.1	9.0	9.0	9.0	9.0	9.2
2008	10.0	9.1	8.8	8.7	8.8	8.7	8.6	8.5	8.7	8.5	8.5
2009	10.1	8.8	8.3	8.2	8.2	8.3	7.9	7.9	8.0	8.0	8.2
2010	9.8	7.7	7.1	6.9	6.9	6.9	6.7	6.7	6.7	6.9	7.0
2011	7.8	6.9	6.4	6.1	6.0	6.0	5.8	6.0	5.8	6.0	6.0
2012	6.2	5.7	5.5	5.3	5.1	5.1	5.1	5.0	5.2	5.2	5.2
2013	5.0	5.0	4.9	4.6	4.4	4.4	4.2	4.2	4.3	4.2	4.6
2014	4.6	4.7	4.5	4.2	4.0	4.0	4.0	4.0	4.0	4.0	4.0
2015	4.3	4.5	4.3	4.0	3.9	3.8	3.7	3.6	3.7	3.8	3.7
2016	4.4	4.5	4.2	4.0	3.8	3.7	3.6	3.5	3.4	3.5	3.5

Notes: Median installed price data omitted if fewer than 20 observations available. Although not presented here, large variation exists around these median values.

Table B-3. Median Installed Price of Non-Residential Systems by Size over Time (2016\$/W_{dc})

Installation Year	≤10 kW	10-20 kW	20-50 kW	50-100 kW	100-250 kW	250-500 kW	500-1000 kW	>1000 kW
2000	-	-	-	-	-	-	-	-
2001	-	-	-	-	-	-	-	-
2002	11.2	10.9	10.4	-	-	-	-	-
2003	10.6	9.6	10.0	9.6	-	-	-	-
2004	9.8	9.3	9.3	9.2	-	-	-	-
2005	9.6	9.6	8.7	8.8	8.6	-	-	-
2006	10.0	9.3	9.1	8.8	8.6	-	-	-
2007	9.7	9.1	9.0	8.6	8.5	7.5	7.4	-
2008	9.2	9.1	8.6	8.5	8.3	7.9	7.9	7.6
2009	9.1	8.7	8.4	8.4	8.1	7.5	7.6	7.1
2010	7.7	7.4	6.9	6.5	5.9	5.9	5.9	5.7
2011	6.5	6.3	5.9	5.6	5.3	5.1	5.1	4.8
2012	5.7	5.2	5.1	4.9	4.7	4.7	4.6	4.3
2013	4.6	4.3	4.4	4.2	4.1	3.9	3.7	3.4
2014	4.1	3.9	3.9	3.6	3.5	3.2	2.8	2.7
2015	4.3	3.7	3.5	3.2	3.2	2.8	2.8	2.4
2016	4.1	3.7	3.4	3.2	3.0	2.6	2.5	2.2

Notes: Median installed price data omitted if fewer than 20 observations available. Although not presented here, large variation exists around these median values.

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